COVER SHEET

FEDERAL ENERGY REGULATORY COMMISSION

DRAFT ENVIRONMENTAL IMPACT STATEMENT
FOR THE KLAMATH HYDROELECTRIC PROJECT
Docket No. P-2082-027

Section 4
Developmental Analysis
Pages 4-1 to 4-21
DEIS

4.0 DEVELOPMENTAL ANALYSIS

In this section, we analyze the project's use of the water resources of the Klamath River to generate power, estimate the economic benefits of the Klamath Hydroelectric Project, and estimate the cost of various environmental protection and enhancement measures and the effects of these measures on project operations.

Under its approach to evaluating the economics of hydropower projects, as articulated in Mead Corporation, Publishing Paper Division (72 FERC ¶61,027, July 13, 1995), the Commission employs an analysis that uses current costs to compare the costs of the project and likely alternative power with no consideration for potential future inflation, escalation, or deflation beyond the license issuance date. The Commission's economic analysis provides a general estimate of the potential power benefits and costs of a project and reasonable alternatives to project-generated power. The estimate helps to support an informed decision concerning what is in the public interest with respect to a proposed license.

For our economic analysis of alternatives, we used the assumptions, values, and sources shown in tables 4-1 and 4-2.

Table 4-1. Staff assumptions for economic analysis of the Klamath Hydroelectric Project. (Source: Staff)

Assumption	Value	Source
Energy rate (2006$)	43.62 mills/kWh (on-peak) 34.20 mills/kWh (off-peak)	PacifiCorp[a]
Capacity rate (2006$)	Included in energy value	
Return on project equity	10.8 percent	PacifiCorp[b]
Bond/debt ratio	0.5	PacifiCorp[c]
Overall cost of money	8.057 percent	PacifiCorp[d]
Discount rate	7.5 percent	PacifiCorp[e]
State and federal income tax rate	35 percent	PacifiCorp[f]
Local tax rate	3 percent	Staff
Insurance rate	0.25 percent of initial net investment	Staff
Term of financing	20 years	Staff
Period of analysis	30 years	Staff
Escalation rate prior to 2006	2.4 percent	Staff
Escalation rate after 2006	0 percent	Staff
Relicensing costs	$12,600,000 (as of 3/31/03)	PacifiCorp
No-action average annual generation (MWh)[g]	716,820	PacifiCorp
No-action dependable capacity (MW)	42.7	PacifiCorp

[a] Value provided by PacifiCorp for April 1, 2006, through March 31, 2007, in its AIR response dated April 1, 2005. The value was based on the average of Mid-Columbia and California-Oregon border estimates. Given the current estimate of on-peak and off-peak generation, the resulting composite energy rate was assumed to be about $41.50/MWh.

[b] Value provided by PacifiCorp in its 2004 U.S. Securities and Exchange Commission Form 10-K report, p. 13 (Oregon); p. 15 (California), not provided in 2005 10-K.

[c] Value based on the ratio of long-term debt to total capitalization from PacifiCorp's 2005 Form 10-K, p. 24.

[d] Value from Order #05-1050 Oregon Public Utility Commission, September 28, 2005, p. 10.

[e] Value provided by PacifiCorp in its July 21, 2004, deficiency response.

[f] Value provided by PacifiCorp in its 2005 Form 10-K report, p. 105.

[g] The no-action alternative does not include any incremental energy at the Fall Creek powerhouse associated with flows provided by the Spring Creek diversion. PacifiCorp provided the average annual generation based on a 30-year long-term average.

Table 4-2. Net investment value and operation and maintenance cost assumptions for the economic analysis of the Klamath Hydroelectric Project. (Source: PacifiCorp deficiency response dated July 21, 2004)

Development	Net Investment[a] (as of 3/31/03)	Operation and Maintenance[a] (as of 3/31/03)
Upper Klamath Lake	$4,237,220	$25,000
East Side	$691,500	$256,000
West Side	$28,410	$73,000
Keno	$4,810,350	$54,000
J.C. Boyle	12,571,160	$1,165,000
Copco No. 1	$5,298,730	$772,000
Copco No. 2	$4,897,600	$999,000
Fall Creek	$107,160	$134,000
Fall Creek (Spring Creek)	$64,308	$67,000
Iron Gate	$9,121,440	$666,000

[a] For the No-action Alternative, all of the net investment values and operation and maintenance values shown above would be included, except for the values associated with the Spring Creek facilities, which were not part of the current license. For PacifiCorp's Proposal, all of the values shown above would be used, except for the values for Upper Klamath Lake, East Side, West Side, and Keno developments, which would not be included in a new license. The net investment values do not include relicensing costs.

Table 4-3 compares the power value, annual costs, and net benefits for the No-action Alternative, Pacificorp's Proposal, the Staff Alternative, the Staff Alternative with Mandatory Conditions, and the Retirement of Copco No. 1 and Iron Gate Developments, which are discussed in details in sections 4.1, 4.2, 4.3, 4.4, and 4.5, respectively. Appendix A, table A-1, shows the effect on costs and power values of individual measures proposed by PacifiCorp, recommended by others, and considered by staff for inclusion in the Staff Alternative. In section 5.2, *Discussion of Key Issues*, we discuss our reasons for including key measures in the Staff Alternative and why we consider the environmental benefits to be worth these costs.

Table 4-3. Summary of the annual net benefits in 2006 dollars for PacifiCorp's Proposal, the Staff Alternative, Staff Alternative with Mandatory Conditions, Retirement of Copco No. 1 and Iron Gate Developments, and the No-action Alternative for the Klamath Hydroelectric Project. (Source: Staff)

	No Action	PacifiCorp's Proposal	Staff Alternative	Staff Alternative with Mandatory Conditions	Retirement of Copco No. 1 and Iron Gate Developments
Installed capacity (kW)	161,338	157,550	157,550	157,550	119,550
Annual generation (MWh)	716,820	676,455	669,215	497,931	448,605
Annual power value	$29,748,030	$28,072,880	$27,772,420	$20,664,130	$18,617,110
(mills/kWh)	41.50	41.50	41.50	41.50	41.50
Annual cost	$10,337,630	$15,319,450	$20,245,720	$49,413,530	$24,297,140
(mills/kWh)	14.42	22.65	30.25	99.24	54.16
Annual net benefit	$19,410,400	$12,753,430	$7,325,700	-$28,749,400	-$5,680,030
(mills/kWh)	27.08	18.85	11.25	-59.70	-12.66

4.1 POWER AND ECONOMIC BENEFITS OF THE NO-ACTION ALTERNATIVE

Under the No-action Alternative, the Klamath Hydroelectric Project would include all of the facilities that are included under the current license, which includes East Side, West Side, and Keno developments. The Spring Creek diversion was not included in the current license and is not included in the No-action Alternative. The project would continue to operate as currently operated.

The project would continue to generate an average of 716,820 MWh of electricity annually, have an annual power value of $29,748,030 (41.50 mills/kWh), and total annual costs of $10,337,630 (14.42 mills/kWh), resulting in a net annual benefit of $19,410,400 (27.08 mills/kWh).

4.2 POWER AND ECONOMIC BENEFITS OF PACIFICORP'S PROPOSAL

As proposed by PacifiCorp, the Klamath Hydroelectric Project would include only J.C. Boyle, Copco No. 1, Copco No. 2, Fall Creek (including the Spring Creek diversion), and Iron Gate developments. East Side and West Side developments would be retired and decommissioned, and Keno development would not be included in the new license.

The retirement and decommissioning of East Side and West Side developments would remove 3.8 MW from the available generating capacity of the region and would reduce the amount of generation produced annually in the region by 18,800 MWh, based on the long-term average annual generation for years 1973-2002 (30 years). The decommissioning of these facilities would slightly increase the need for power in the region, as discussed in section 1.2, *Need for Power*.

Essentially all of the project facilities associated with these two developments would be removed, and the sites would be re-graded to the natural contours and re-vegetated (section 2.2.1 provides a detailed description of the decommissioning of these developments). PacifiCorp estimates that the decommissioning of East Side and West Side developments would cost about $844,000 in 2006 dollars (letter from T. Olsen, PacifiCorp, to the Commission, dated July 21, 2004).

The removal of Keno development from the licensed project would not affect the annual generation of the proposed project as there are no generating facilities at the site, and PacifiCorp states that the operation of Keno development does not affect the generation of downstream hydroelectric facilities. Costs associated with the continued operation of Keno would not be included as part of the proposed project, but would continue to be borne by PacifiCorp, the owner of Keno dam.

The facilities and operation and maintenance costs associated with the Spring Creek diversion would be included in the proposed project.

The proposed project would generate an average of 676,455 MWh of electricity annually, have an annual power value of $28,072,880 (41.50 mills/kWh) and total annual costs of $15,319,450 (22.65 mills/kWh), resulting in a net annual benefit of $12,753,430 (18. 85 mills/kWh).

4.3 POWER AND ECONOMIC BENEFITS OF THE STAFF ALTERNATIVE

Resource agencies and non governmental organizations recommend implementing a variety of measures at the project. We reviewed each recommendation and determined the measures that were most appropriate for implementation. We also considered other recommendations that are warranted for inclusion in a new license to protect and enhance project resources.

The Staff Alternative for the Klamath Hydroelectric Project would include J.C. Boyle, Copco No. 1, Copco No. 2, Fall Creek (including the Spring Creek diversion), and Iron Gate developments.

Under the Staff Alternative, the project would generate an average of 669,215 MWh of electricity annually, have an annual power value of $27,772,420 (41.50 mills/kWh) and total annual costs of $20,245,720 (30.25 mills/kWh), resulting in a net annual benefit of $7,526,700 (11.25 mills/kWh).

4.4 POWER AND ECONOMIC BENEFITS OF THE STAFF ALTERNATIVE WITH MANDATORY CONDITIONS

NMFS and Interior have made preliminary fishway prescriptions for this project pursuant to section 18 of the FPA which, when finalized, the Commission would need to include in a new license for this project (see section 2.3.1.2). Similarly, the Bureau of Land Management and Bureau of Reclamation have specified in accordance with section 4(e) of the FPA, preliminary conditions which, when finalized, would also need to be included in a new license for this project (see section 2.3.1.3). The Staff Alternative with Mandatory Conditions includes those measures, and in some cases, the mandatory conditions replace staff-recommended measures. We describe this alternative in section 2.3.3. Under this alternative, the project would generate an average of 497,931 MWh of electricity annually, have an annual power value of $20,664,130 (41.50 mills/kWh) and total annual costs of $49,413,530 (99.25 mills/kWh), resulting in a net annual benefit of -$28,749,400 (-59.70 mills/kWh).

4.5 POWER AND ECONOMIC BENEFITS OF RETIREMENT OF COPCO NO. 1 AND IRON GATE DEVELOPMENTS

Staff also analyzed an alternative that would reduce the financial implications, while meeting most of the environmental objectives, of the Staff Alternative with Mandatory Conditions. Under Retirement of Copco No. 1 and Iron Gate Developments, the Copco No. 1 and Iron Gate dams would be removed to facilitate anadromous fish passage to historical habitat and eliminate water quality problems associated with Copco and Iron Gate reservoirs. We describe this alternative in section 2.3.4. Under this alternative, the project would generate an average of 448,605 MWh of electricity annually, have an annual power value of $18,617,110 (41.50 mills/kWh) and total annual costs of $24,297,140 (54.16 mills/kWh), resulting in a net annual benefit of -$5,680,030 (-12.66 mills/kWh).

4.6 CONCEPTUAL COSTS OF PROJECT DAM REMOVAL

Various entities have advocated the removal of some or all project dams to facilitate restoration of anadromous fish to historic habitat upstream of Iron Gate dam and as a potential means to enhance water quality in the Klamath River downstream of Iron Gate dam. We prepared an independent conceptual evaluation of the potential costs associated with removal of Keno, J.C. Boyle, Copco No. 1, Copco No. 2, and Iron Gate dams with decommissioning of the hydroelectric facilities. In addition, we evaluated the decommissioning of the Fall Creek hydroelectric facilities and removal of the diversion structures to facilitate movement of resident fish. If any project dams are removed, more detailed on-site evaluations would be necessary to develop detailed decommissioning and dam removal engineering and environmental plans.

We have not estimated the potential salvage value of any materials removed from the developments that would offset the decommissioning and removal costs. We assume for our base costs that any sediment in the reservoirs would be re-distributed downstream naturally (similar to conditions assessed by Stillwater Sciences, 2004) in a controlled manner at no additional cost (other than costs associated with a staged, sequential dam removal process to avoid sediment release during a single event). This assumption is predicated on the fact that sediment in each of the project reservoirs is uncontaminated (similar to the assumption made by G&G Associates (2003) in its independent dam removal assessment).

If contaminated sediment is found, and is not suitable for downstream transport, the costs of dam removal would be substantially higher. Actual costs for contaminated sediment removal and disposal would depend on the nature of the contaminants. We use a range of $162,500 to $487,500 per acre-foot, based on estimates developed for removal of contaminated sediment at other dam removal projects to provide a general framework of what such costs could be at each mainstem development. The amount of sediment to be removed would depend on site-specific conditions and the nature of contaminants. It could be feasible to allow sediment not subject to scour following dam removal to remain in place with or without capping. However, to provide a conservative estimate of costs, we assume all sediment associated with reservoir lost storage (as shown in table 3-3) would need to be removed. Our base costs also assume that the exposed bottoms of the reservoirs would naturally re-vegetate, except for the areas disturbed by dam removal. We assume that no additional restoration costs for reservoir or downstream riparian habitat that may be influenced by sediment releases during dam removal would be required beyond the immediate dam site. In addition, we assume that all project-related roadways would remain in place with no modifications.

4.6.1 Keno Development

The Taintor gates would be opened to drain the reservoir and then removed. The dam and fishway concrete, earthen abutment, and control building with contents would be removed. The site would be re-graded and re-vegetated along the shore of the river channel in proximity to the dam. We estimate the decommissioning and removal of the Keno facilities would cost about $2,680,000 (2006 dollars). If contaminated sediment requires removal prior to dam removal, it could cost an additional $14 to $43 million. Substantial additional costs would be incurred by others if the water supply intakes at Keno reservoir need to be redesigned to retain their current function.

4.6.2 J.C. Boyle Development

The reservoir would be drained in stages to allow much of the dam and associated structures to be removed in the “dry.” This also would enable shoreline habitat to gradually acclimate as the reservoir drains. This approach would be used, to the extent possible, for the removal of other project dams on the mainstem. The Taintor gates could be opened to drain the reservoir to elevation 3,781.5 feet. The reservoir could be further lowered to elevation 3,768 feet through the powerhouse conveyance pipeline, canal, and tunnel. If operable, the dam bypass drains could be used to draw the reservoir down to approximately elevation 3,750 feet. The base of the embankment dam is at about elevation 3,726 feet. The remaining water in the reservoir would need to be removed prior to completion of dam removal. This could be accomplished by creating a diversion channel through the dam using sheetpile driven to bedrock. The entire embankment dam would be removed. Once this occurs, all concrete structures associated with the power conveyance intake, Taintor gate structure, fishway, and other structural components would be removed. The embankments at each end of the former dam would be re-graded and re-vegetated.

The steel pipeline and supporting steel and concrete would be removed. The concrete structures associated with the canal intake, canal flume, canal spillway, and tunnel entrance structure would be removed. The lands under and adjacent to the canal flume would be backfilled and re-graded to stabilize the slopes and the area would be re-vegetated. The downslope channel associated with the former canal emergency spillway would be backfilled and stabilized to the edge of the Klamath River. The penstocks, supports, and anchors would be removed, and the tunnel portals would be sealed.

The powerhouse crane would be dismantled and removed. The powerhouse substructure and surface slab would remain intact. The powerhouse equipment would be removed. Any wooden materials in the powerhouse would be removed. Any components from the powerhouse containing chemical or other hazardous materials would be removed from the site, including transformers, bushings, batteries, tanks, lead bearings, and asbestos-based insulating products. Windows and doors in the powerhouse and the penstock entrance would be sealed to prevent public access. The turbine/generator openings in the concrete powerhouse slab would be sealed with concrete, as would the draft tube openings. The walls of the tailrace flume would remain. The tailrace area would be backfilled and re-graded to match the river embankment upstream and downstream of the powerhouse area and stabilized as necessary.

The 0.24-mile-long, 69-kV, de-energized transmission line from the switchyard to Transmission Line 18 would be removed, and the transmission right-of-way would be restored to natural conditions. The switchyard serves non-project purposes and would be retained.

We assume that the support buildings located near the dam would be sold for other purposes. The warehouse near the powerhouse would be removed.

We estimate the decommissioning and removal of the J.C. Boyle facilities would be $13,951,000 (2006 dollars). If contaminated sediment requires removal prior to dam removal, it could cost an additional $2 to $7 million.

4.6.3 Copco No. 1 Development

We assume that it would be feasible to restore the existing dam drain gates and use them to drain the reservoir. This would allow for removal of the dam by sawcutting or other methods without the need to notch the dam to lower the reservoir. The dam would be removed to the natural river channel upstream and downstream of the dam. No excess foundation material that was required to provide a solid foundation for the dam would be removed. The penstocks would be removed entirely. The powerhouse intake structure foundation and gatehouse would be sealed and the gatehouse secured. Once the dam is removed, the dam drain structures would be removed and the tunnel sealed.

The powerhouse would remain. The penstock and tailrace openings would be sealed. The powerhouse equipment and any wooden materials in the powerhouse would be removed. Any components from the powerhouse containing chemicals or other hazardous materials would be removed from the site. Windows and doors in the powerhouse would be sealed to prevent public access.

The two 0.7-mile-long, 69-kV lines from the Copco No. 1 powerhouse to the Copco No. 1 switchyard would be removed (the Copco No. 1 switchyard serves as a point of interconnection for the Iron Gate and Copco No. 2 powerhouses). We assume for cost estimation purposes that Copco No. 1 dam would only be removed if the Iron Gate and Copco No. 2 developments were decommissioned, and therefore, the Copco No. 1 switchyard would no longer be needed as a point of interconnection. The switchyard site and transmission line rights-of-way would be restored to natural conditions.

We estimate the decommissioning and removal of the Copco No. 1 facilities would cost $10,986,000 (2006 dollars). If contaminated sediment requires removal prior to dam removal, the costs could increase an additional $955 million to $2.9 billion.

4.6.4 Copco No. 2 Development

The reservoir would be drained through the Taintor gates. Once drained, the gates and gate structure would be removed. The power tunnel entrance would be sealed and the majority of the tunnel intake structure removed. The river banks would be re-graded and re-vegetated, and the area where the intake structure had been would be backfilled, re-graded, and re-vegetated.

The woodstave penstock, supports, and anchors would be removed, and the tunnel entrances sealed. The tunnel exit portal and the tunnel spillway portal would be sealed. The powerhouse would remain, and the penstock and tailrace openings would be sealed. The powerhouse equipment and any wooden materials in the powerhouse would be removed. Any components from the powerhouse containing chemicals or other hazardous materials would be removed from the site. Windows and doors in the powerhouse would be sealed to prevent public access.

The Copco No. 2 powerhouse serves as the point of interconnection for the Iron Gate development via the Copco No. 2 transmission connection to the Copco No. 1 switchyard. We assume for cost estimation purposes that Copco No. 2 development would only be decommissioned if Iron Gate development was decommissioned. Thus, the 1.23-mile-long, 69-kV transmission line from the Copco

No. 2 powerhouse to the Copco No. 1 switchyard would be removed. The transmission line right-of-way would be restored to natural conditions. Since the Copco No. 2 switchyard serves non-project purposes, it would be retained.

We estimate the decommissioning and removal of the Copco No. 2 facilities would cost $2,381,000 (2006 dollars). It is unlikely that there would be enough sediment in Copco No. 2 reservoir to substantially influence this cost estimate.

4.6.5 Fall Creek Development

The Spring Creek diversion dam and diversion structures would be removed. The excavated diversion ditch from the diversion dam to its end in the Fall Creek drainage basin would be backfilled and graded. The diversion site would be restored to natural grades, if possible, and re-vegetated along the creek banks.

The Fall Creek diversion dam and diversion structures also would be removed. The earth and rock diversion ditch from the Fall Creek diversion dam to the penstock intake would be backfilled and graded. The diversion site would be restored to natural grades, if possible, and re-vegetated along the creek banks.

The penstock, supports, and anchors would be removed. The powerhouse would remain. The penstock and tailrace openings would be sealed. The powerhouse equipment and any wooden materials in the powerhouse would be removed. Any components from the powerhouse containing chemicals or other hazardous materials would be removed from the site. Windows and doors in the powerhouse would be sealed to prevent public access.

The short 69-kV tap line connection to Transmission Line 18 and the 1.65-mile-long, 69-kV transmission line extending from the Fall Creek powerhouse to the Copco No. 1 switchyard would be removed. The transmission line rights-of-way would be restored to natural conditions. There is no switchyard at Fall Creek.

We estimate the decommissioning and removal of the Fall Creek facilities would cost $1,183,000 (2006 dollars). It is unlikely that there would be enough sediment behind the Spring or Fall Creek diversion dams to substantially influence this cost estimate.

4.6.6 Iron Gate

We assume that the dam diversion tunnel used during project construction could be used to gradually drain the reservoir and control the release of sediment to the Klamath River downstream of the dam. Once the reservoir has been drained, the dam would be removed. The drainage tunnel would be used to maintain flow past the site during dam removal. The concrete penstock intake structure and penstock would be removed as dam removal progresses, as would the water supply lines for the fish facilities. The reservoir spillway would be abandoned in place.

The powerhouse crane would be dismantled and removed. The powerhouse equipment and any wooden materials in the powerhouse would be removed. Any components from the powerhouse containing chemicals or other hazardous materials would be removed from the site. The powerhouse substructure and surface slab would be removed to the lowest slab, which would remain. The powerhouse and tailrace area would be backfilled and re-graded to match the new river embankment upstream and downstream of the powerhouse area. The fish facilities at the base of the dam would be removed entirely. We assume that the Iron Gate Fish Hatchery located south of the dam would remain, although its ability to function as a fish hatchery without its historic water supply would be questionable.

The switchyard and 6.55-mile-long, 69-kV transmission line from the Iron Gate switchyard to the Copco No. 2 powerhouse would be removed. The switchyard site and transmission line rights-of-way would be restored to natural conditions.

We estimate the decommissioning and removal of the Iron Gate facilities would cost $49,863,000 (2006 dollars). If contaminated sediment requires removal prior to dam removal, it could cost an additional $485 million to $1.5 billion.

Table 4-4 contains a summary of our recommendations and costs for dam removal at the Klamath Hydroelectric Project.

Table 4-4. Dam removal recommendations and costs. (Source: Staff)

Dam/Environmental Measure	Capital Costs (2006$)	Annual Costs (2006$)	Annual Energy Costs (2006$)	Total Annualized Cost (2006$)
Keno				
Remove Keno from the licensed project	-$3,935,470 (remove net investment in project facilities from project – this represents the 2003 net investment value of the Keno facilities ($4,810,350) depreciated to 2006)	-$57,980 (remove 2003 O&M cost ($54,000) from project expenses)	$0 (no energy implications)	-$589,210 (reduction in annual expenses)
Remove Keno dam (in some cases, if meeting water quality standards and/or if fish passage is not feasible)	$2,679,680	$0	$0	$361,710
Decommissioning plan for Keno development	$75,000 (staff)	$0	$0	$10,120
J.C. Boyle				
Remove J.C. Boyle development from the licensed project	-$10,284,780 (remove net investment in project facilities from project – this represents the 2003 net investment value of the JCB facilities ($12,571,160) depreciated to 2006)	-$1,250,910 (remove 2003 O&M cost ($1,165,000) from project expenses)	$13,653,500 (Loss of 329,000 MWh)	$11,014,310
Remove J.C. Boyle dam (in some cases, if meeting water quality standards and/or if fish passage is not feasible)	$13,950,560	$0	$0	$1,883,100

Dam/Environmental Measure	Capital Costs (2006$)	Annual Costs (2006$)	Annual Energy Costs (2006$)	Total Annualized Cost (2006$)
Decommissioning plan for J.C. Boyle development	$150,000 (staff)	$0	$0	$20,250
Copco No. 1				
Remove Copco No. 1 development from the licensed project	-$4,335,030 (remove net investment in project facilities from project – this represents the 2003 net investment value of the Copco No. 1 facilities ($5,298,730) depreciated to 2006)	-$828,930 (remove 2003 O&M cost ($772,000) from project expenses)	$4,399,000 (Loss of 106,000 MWh)	$2,984,910
Remove Copco No. 1 dam (in some cases, if meeting water quality standards and/or if fish passage is not feasible)	$10,986,430	$0	$0	$1,482,990
Decommissioning plan for Copco No. 1 development	$250,000 (staff)	$0	$0	$33,750
Copco No. 2				
Remove Copco No. 2 development from the licensed project	-$4,006,850 (remove net investment in project facilities from project – this represents the 2003 net investment value of the Copco No. 2 facilities ($4,897,600) depreciated to 2006)	-$1,072,670 (remove 2003 O&M cost ($999,000) from project expenses)	$5,602,500 (Loss of 135,000 MWh)	$3,988,970
Remove Copco No. 2 dam (in some cases, if meeting water quality standards and/or if fish passage is not feasible)	$2,381,280	$0	$0	$321,440
Decommissioning plan for Copco No. 2 development	$75,000 (staff)	$0	$0	$10,120
Fall Creek/Spring Creek				
Remove Fall Creek development from the licensed project	-$87,670 (remove net investment in project	-$215,820 (remove 2003 O&M cost	$654,540 (Loss of 15,772 MWh)	$426,880

Dam/Environmental Measure	Capital Costs (2006$)	Annual Costs (2006$)	Annual Energy Costs (2006$)	Total Annualized Cost (2006$)
	facilities from project – this represents the 2003 net investment value of the Fall Creek facilities (including Spring Creek diversion) ($171,470) depreciated to 2006)	($201,000) from project expenses)		
Remove Fall Creek and Spring Creek diversion dams (in some cases, if fish passage is not feasible)	$1,183,400	$0	$0	$159,740
Decommissioning plan for Fall Creek development, including Spring Creek diversion	$50,000 (staff)	$0	$0	$6,750
Iron Gate				
Remove Iron Gate development from the licensed project	-$7,462,480 (remove net investment in project facilities from project – this represents the 2003 net investment value of the Iron Gate facilities ($9,121,440) depreciated to 2006)	-$715,110 (remove 2003 O&M cost ($666,000) from project expenses)	$4,814,000 (Loss of 116,000 MWh)	$3,091,570
Remove Iron Gate dam (in some cases, if meeting water quality standards and/or if fish passage is not feasible)	$49,863,720	$0	$0	$6,730,810
Decommissioning plan for Iron Gate development	$250,000 (staff)	$0	$0	$33,750

4.7 KENO DEVELOPMENT ANALYSIS

Keno development is a regulating facility that controls the water level of Keno reservoir by releasing water downstream at a rate roughly equivalent to net inflow. This development, located about 21 miles downstream of Reclamation's Link River dam, has no generation capability, and it regulates the water level of, and controls releases from, Upper Klamath Lake. The Commission requires PacifiCorp, in accordance with a 1965 license amendment, to operate Keno reservoir consistent with an agreement with Reclamation that specifies a maximum water surface elevation of 4,086.5 feet and a minimum water surface elevation of 4,085 feet. However, at the request of irrigators, PacifiCorp generally operates Keno dam to maintain the reservoir at elevation 4,085.4 +/-0.1 foot from October 1 to May 15 and elevation 4,085.5 +/-0.1 foot from May 16 to September 30 (see figure 3-7). This allows reliable operation of irrigation canals and pumps and results in an active storage volume of 495 acre-feet. Occasional 2-foot drawdowns are implemented before the irrigation season to allow irrigators to clean out their water withdrawal systems. J.C. Boyle reservoir, located about 4.7 miles downstream of Keno dam, has an active storage volume of 1,724 acre-feet.

Keno reservoir receives most of its water from Upper Klamath Lake via Link River. Keno reservoir also loses and receives a substantial amount of water from the Lost River diversion channel, North canal, Klamath Straits drain, and the Ady canal associated with the Reclamation's Klamath Irrigation Project (see figure 2-4). According to the Oregon Water Resources Department, in addition to the larger Reclamation diversions, there are numerous much smaller water permits and claims along Keno reservoir, mostly for irrigation on adjacent privately owned agricultural lands. Flows released from Keno dam to the Keno reach are measured about 1 mile downstream at USGS gage no. 11509500.

PacifiCorp does not include Keno development as part of its proposed Klamath Hydroelectric Project, stating that, because current operation of the development does not influence hydropower production, it no longer serves any project purpose and is not under the Commission's jurisdiction. Although it would continue to own the dam and appurtenant facilities, PacifiCorp proposes to relinquish all hydropower responsibilities associated with the current license and operate the development according to state of Oregon and Reclamation direction.

Keno dam would serve project purposes if it enhanced generation at PacifiCorp's downstream developments. Downstream generation could be enhanced if the dam was able to store water for later release that would otherwise spill (bypassing the turbines) at downstream developments, or by controlling the magnitude and timing of releases to correspond to generation needs at the downstream developments. No parties claim Keno dam is operated to prevent spillage at downstream developments, and we agree that its limited active storage prevents it from serving that function. PacifiCorp's ability to alter the timing and magnitude of flows is limited by its need to maintain the reservoir elevation within a narrow range. Keno dam also would serve project purposes if it was operated to reregulate generation flows from the upstream East Side and West Side powerhouses. Because PacifiCorp proposes to decommission those two developments, we do not consider any reregulation function in our analysis.

In response to stakeholder comments, PacifiCorp conducted an analysis of Keno reservoir operation to determine Keno's contribution, if any, to downstream power generation. PacifiCorp modeled 92 years (1905-1997) of inflow to Upper Klamath Lake, to which outflows through Link River dam directly correlate. PacifiCorp based its modeling exercise on the following (letter to the Commission dated May 12, 2006):

- The assumption that the majority of water reaching Keno reservoir is from Upper Klamath Lake.
- Separation of water years into five categories (wet to dry) based on their likelihood of occurrence.
- Use of the 1.5-foot operation range at Keno reservoir based on the current contract between Reclamation and PacifiCorp.
- Use of a theoretical 9-foot operation range at Keno reservoir to examine model sensitivity.
- Simulation of Keno development operating in a run-of-river mode by assuming Keno dam and reservoir are removed from the physical system and ignoring any irrigation withdrawals or return flows from the Klamath Irrigation Project (outflow from Keno dam is equal to inflow from Link River).
- Comparison of simulated run-of-river operation to Keno development's current operation, which includes irrigation withdrawals and return flows to Keno reservoir from the Klamath Irrigation Project.

Table 4-5 shows the results of PacifiCorp's modeling.

Table 4-5. Estimated annual generation (GWh) with and without operation of Keno facilities. (Source: PacifiCorp, 2006c)

Inflow Exceedance Level with Current Upper Klamath Lake BiOp Restrictions	Without Keno (GWh/Year)	With Keno			
		1.5 foot Operational Range		9.0 foot Operational Range	
		(GWh/Year)	(% Benefit)	(GWh/Year)	(% Benefit)
P5	964	1,000	3.80%	1,001	3.80%
P25	948	948	0.00%	951	0.40%
P50	804	803	-0.10%	802	-0.20%
P75	685	645	-6.00%	643	-6.20%
P95	428	322	-24.70%	321	-24.80%

Notes: P5: Annual inflow is equal to or greater than, in 5% of the record (Wet year).
P25: Annual inflow is equal to or greater than, in 25% of the record (Upper Quartile year).
P50: Annual inflow is equal to or greater than, in 50% of the record (Median year).
P75: Annual inflow is equal to or greater than, in 75% of the record (Lower Quartile year).
P95: Annual inflow is equal to or greater than, in 95% of the record (Dry year).
Annual period is from May 1 through April 30.

According to PacifiCorp, these results show that the contribution of Keno dam to downstream generation varies depending on water year type. Keno dam benefited downstream generation only during the wettest 5 percent of years, and that benefit was at most a 3.80 percent increase in generation. PacifiCorp also states that its modeling demonstrates that, during the driest 5 percent of years, Keno dam resulted in a 24.7 percent loss of generation. During the middle 90 percent of the years, Keno resulted in no benefit to a 6.0 percent decrease in downstream generation.

To assess the extent that recent operation of Keno development may have benefited PacifiCorp's downstream peaking operations, we analyzed flow and water level records for the locations shown in table 4-6 for water years 1991 to 2004. We based our analysis on hourly changes in inflow from all major sources to Keno reservoir, including back-calculated hourly flows from Klamath Irrigation Project channels that enter Keno reservoir (besides Link River), hourly reservoir elevation changes at Keno and J.C. Boyle reservoirs, and hourly (or smaller interval) gage data. Releases from Keno dam take about 2 to 3 hours to reach J.C. Boyle reservoir.

Table 4-6. Data description and sources. (Source: Reclamation, 2006a; PacifiCorp, 2005j; USGS, 2005)

Gage No.	Description	Source	Time Interval
11507001	Upper Klamath Lake near Klamath Falls, OR	USGS	Daily
	West Side powerhouse	PacifiCorp	Hourly
11507500	Link River at Klamath Falls, OR	USGS	Quarter Hourly
	From Lost River canal	Reclamation	Daily
	To Lost River canal	Reclamation	Daily
	To North canal	Reclamation	Daily
	From Klamath Straits drain	Reclamation	Daily
	To Ady canal	Reclamation	Daily
	Keno reservoir at Keno dam, OR	PacifiCorp	Hourly
11509500	Klamath River at Keno, OR (below Keno dam)	USGS	Half Hourly
	J.C. Boyle reservoir	PacifiCorp	Hourly
	J.C. Boyle powerhouse	PacifiCorp	Hourly
11510700	Gage below J.C .Boyle powerhouse	USGS	Half Hourly
11511400	Copco reservoir	PacifiCorp	Hourly
	Copco No. 1 powerhouse	PacifiCorp	Hourly

Flow records show that water year 1996 best represents the variety of hydrologic conditions during the period from 1991 to 2004 (figure 4-1). Because releases in accordance with Reclamation's BiOps and water bank provisions did not begin until 2003, there is a limited amount of information available that reflects operations under current flow conditions. However, the monthly flow targets specified in the BiOps would have little bearing on whether or not PacifiCorp operates Keno development to enhance downstream hydroelectric operations. Trends shown in flows measured at the Keno gage during 1996 are also representative of the trends that were evident during 2003 and 2004. The data that we used to develop figure 4-1 indicate several general relationships:

- Inflow to Keno reservoir, as measured at the USGS Link River gage and the West Side powerhouse, is normally lower than the flow measured at the USGS gage below Keno in the non-irrigation months of December through May, indicating that there is accretion from sources such as the Lost River diversion channel, Klamath Straits drain, and smaller natural sources not associated with the Klamath Irrigation Project.
- Inflow to Keno reservoir is higher than outflow during the irrigation months, indicating diversion of water to the Lost River diversion channel, North canal, Ady canal, and other withdrawals.
- The J.C. Boyle powerhouse generally operates in a peaking mode when the USGS gage below Keno is below 2,000 cfs, because there is not enough flow to sustain continuous operation and to take advantage of the cost difference between peak and off-peak generation.
- West Side powerhouse (with a maximum hydraulic capacity of 250 cfs) operates in a cyclical mode (i.e., it is either operating at full capacity or not operating at all).

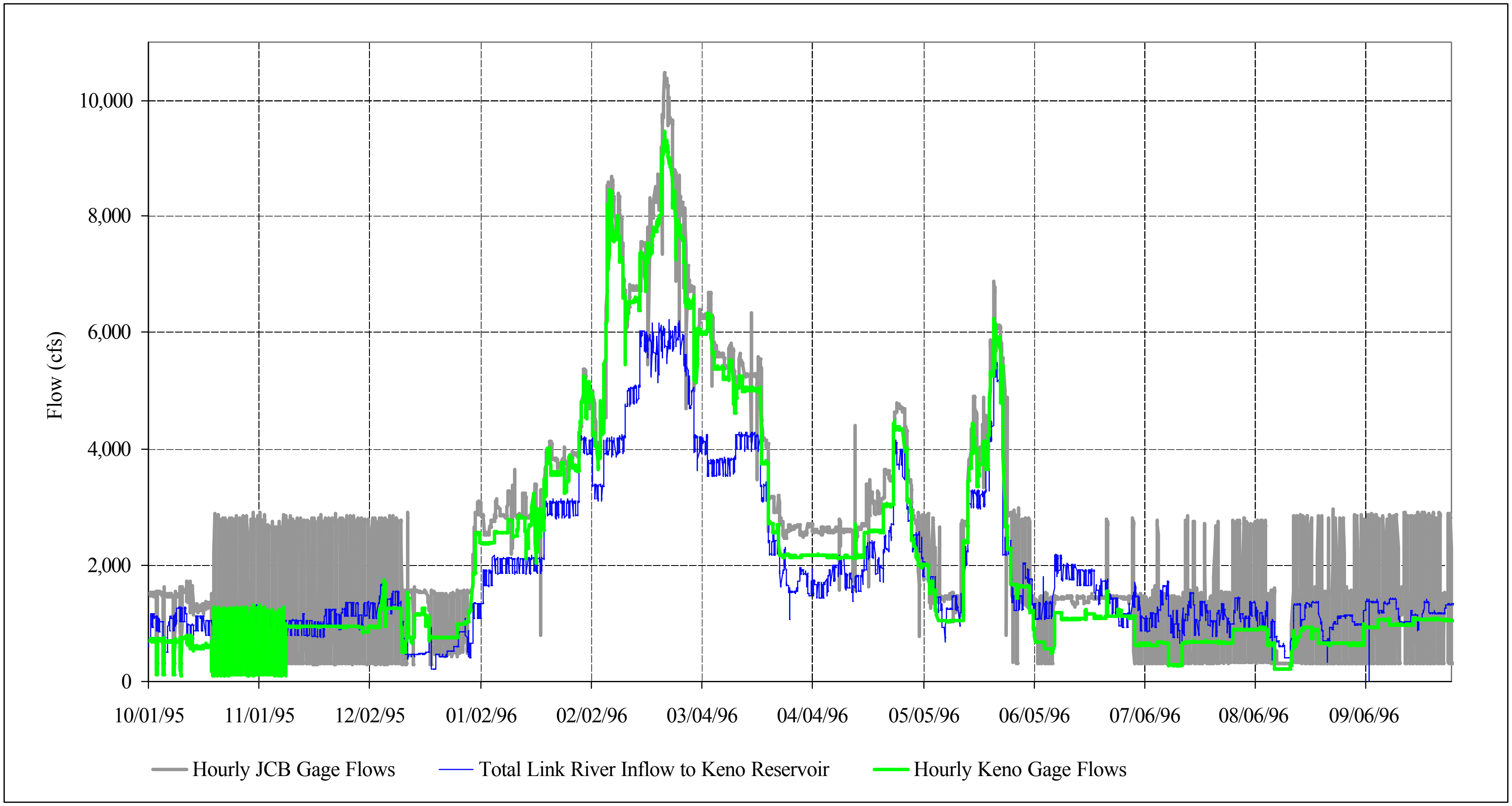


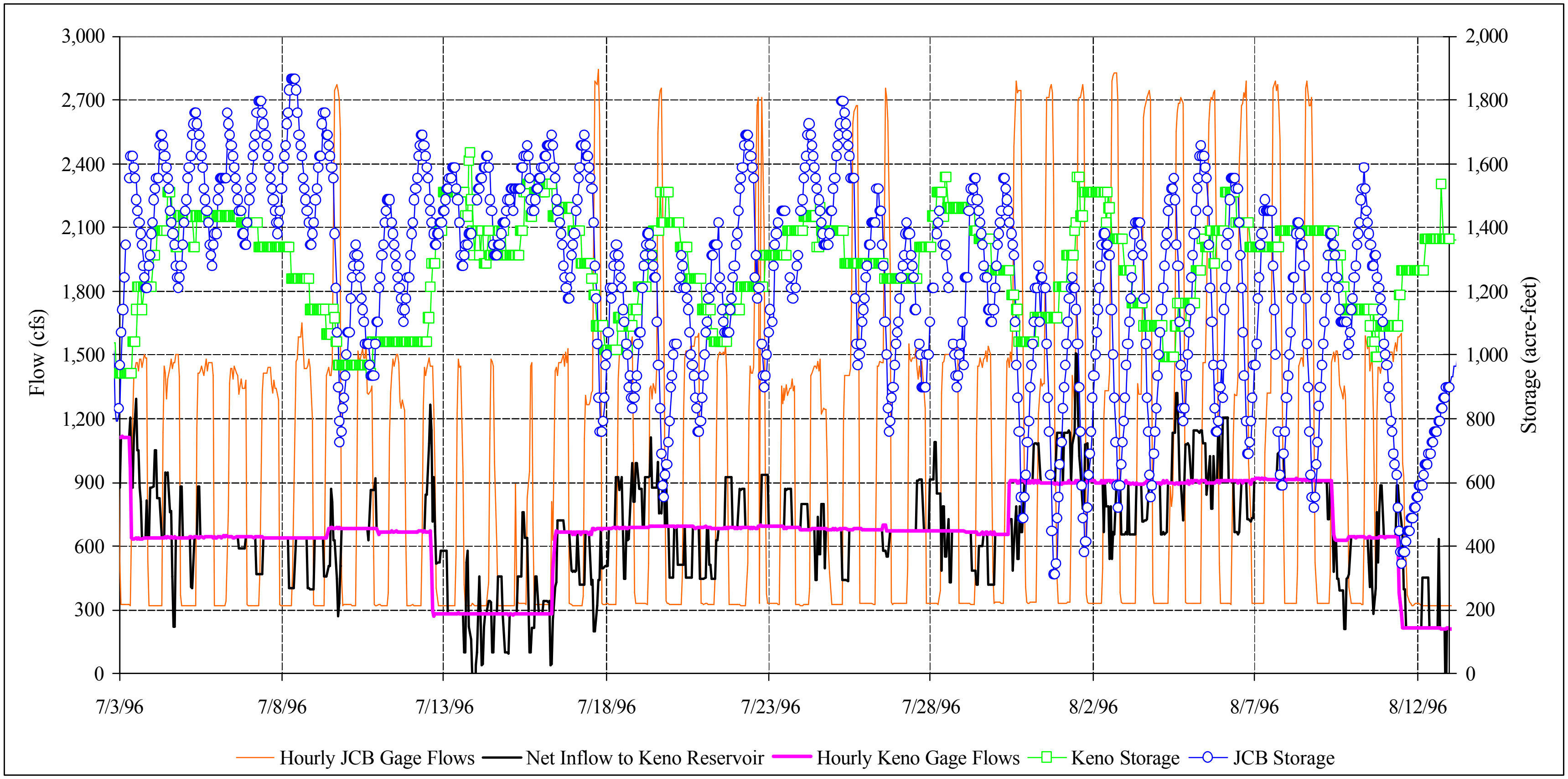
Figure 4-1. Flows entering Keno reservoir via Link River and in the Klamath River downstream of Keno development at USGS gage no. 11509500 and J.C. Boyle development at USGS gage no. 11510700 for water year 1996. (Source: USGS, 2005, as modified by staff)

During the irrigation months, most of the difference between the combined flow at the Link River gage and West Side powerhouse and flows released at Keno dam is caused by withdrawals from Keno reservoir by the Lost River diversion channel, North canal, Ady canal, and other withdrawals used largely for irrigation. During the non-irrigation months, other than flows withdrawn from Keno to flood seasonal wetland habitat in the Lower Klamath National Wildlife Refuge, flows enter Keno reservoir from the Lost River diversion channel and the Klamath Straits drain, in addition to Link River. Based on flow data from the gage below the J.C. Boyle powerhouse and accounting for the minimum flow releases from J.C. Boyle dam (100 cfs) and spring accretion in the J.C. Boyle bypassed reach, the J.C. Boyle powerhouse operates or had the ability to operate at full capacity all day about 12 percent of the days in water years 1991 to 2003. The generation from these days, when peaking operations would not have occurred, produced about 33 percent of the total generation during that 13-year period.

The flow relationships shown in figure 4-2 are representative of the vast majority of the 1991 to 2004 water year period that we assessed. If PacifiCorp was manipulating flows from Keno dam to enhance its peaking ability at the J.C. Boyle development and the other downstream powerhouses, we would expect to see a spike in flows measured at the Keno gage about 2 hours before the beginning of peaking operations at the J.C. Boyle powerhouse, which the spikes in flow at the USGS gage downstream of the J.C. Boyle powerhouse, shown in figure 4-2, represent. No such spikes in flow are evident during nearly all periods when J.C. Boyle is operating in a peaking mode, and figure 4-2 shows that water stored in J.C. Boyle reservoir provides the necessary flows to support the peaking operations, not the limited storage available in Keno reservoir.

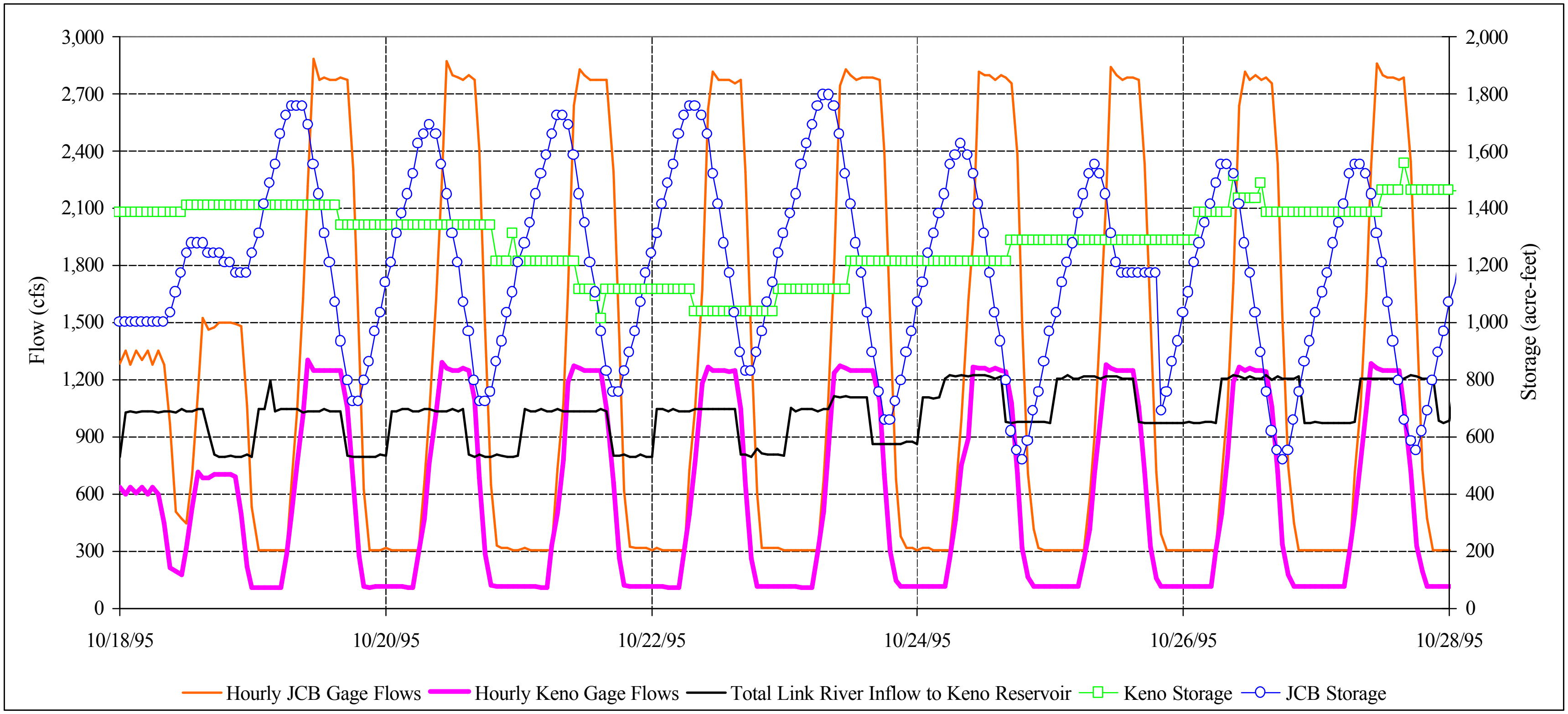
Interior, in its March 27, 2006, letter to the Commission, disagreed with PacifiCorp's assertion that Keno does not serve project purposes and provided three examples consisting of 2 days of flow data each from the USGS gages at Link River, below Keno dam, and below J.C. Boyle powerhouse to show that PacifiCorp has been operating Keno development to enhance hydroelectric power generation downstream of Keno.

During late October and early November, outflow from Keno dam, as measured at the Keno gage, spiked when the J.C. Boyle powerhouse was operating in a peaking mode (see figure 4-1). Figure 4-3 shows detailed flow characteristics during this period. Based on the spikes of flow measured at the Keno gage that correspond to peaking releases from the powerhouse, one could conclude, as did Interior, that operation of Keno development was enhancing peaking operations at J.C. Boyle development. This relationship appears similar to the relationship portrayed in the three examples from Interior (March 27, 2006, letter).



Notes: Storage based on water volume between elevations 4,085.00 and 4,086.00 feet for Keno and 3,788.00 and 3,793.20 feet for J.C. Boyle.
During the time period shown on this graph, the elevation at Keno reservoir varied between elevation 4,085.31 and 4,085.66 feet and 3,788.4 and 3,793.4 feet for J.C. Boyle reservoir.

Figure 4-2. Relationship between inflow to Keno reservoir, USGS gages at Keno and below J.C. Boyle powerhouse, and storage at J.C. Boyle and Keno reservoirs—June 1, 1996, until September 12, 1996. (Source: Reclamation, 2006a; PacifiCorp, 2005j; USGS, 2005; as modified by staff)



Notes: Storage based on water volume between elevations 4,085.00 and 4,086.00 feet for Keno and 3,788.00 and 3,793.20 feet for J.C. Boyle. During the time period shown on this graph, the elevation at Keno reservoir varied between elevation 4,085.41 and 4,085.57 feet and 3,789.50 and 3,793.20 feet for J.C. Boyle reservoir.

Figure 4-3. Relationship between inflow to Keno reservoir, USGS gages at Keno and below J.C. Boyle powerhouse, and storage at J.C. Boyle and Keno reservoirs—October 18, 1995, until October 28, 1995. (Source: Reclamation, 2006a; PacifiCorp, 2005j; USGS, 2005; as modified by staff)

While we understand why, based on our figure 4-3, Interior would conclude that Keno dam influences generation at J.C. Boyle, neither figure 4-3 or Interior's analysis considers water surface elevation in Keno reservoir and likely changes in the Klamath Irrigation Project withdrawals and return flows to Keno reservoir, other than flows that entered the reservoir via Link River. Figure 4-3 does not show the relationship of flows measured at the Keno gage and the total inflow to Keno reservoir, which includes flows from Link River in addition to flows from other Klamath Irrigation Project channels. PacifiCorp states that water from Reclamation's Klamath Irrigation Project entering Keno reservoir via the Klamath Straits drain and the Lost River diversion channel can be highly variable and problematic for maintenance of a stable reservoir elevation. We reviewed inflow and outflow data records for the Klamath Irrigation Project canals and channels at Keno reservoir (available on Reclamation's website), including Klamath Straits drain, Ady and North canals, and the Lost River diversion channel, and these records show a high degree of daily variance. PacifiCorp's maximum and average 24 hour change analysis (PacifiCorp, 2004a) of the Klamath Straits drain for 1995 to 2001 showed an average 24 hour change of 86 cfs. However, about 10 percent of the months during this time period had a maximum daily change in excess of 1,000 cfs. To help maintain a relatively constant level in Keno reservoir, PacifiCorp manages the releases from Keno reservoir as well as spill at Link River dam (on behalf of Reclamation) and generation adjustments at the East Side and West Side powerhouses. If East Side and West Side developments are decommissioned, as PacifiCorp proposes, all aspects of Link River flow that are within the Commission's jurisdiction would be eliminated.

Based on the known hourly or shorter interval flow and water level (see table 4-6), mass balance techniques, and assuming that the majority of the unknown inflow or outflow in the Keno reservoir area is from the Klamath Irrigation Project, we estimated hourly inflows and outflows to Keno reservoir. Figure 4-4 shows our calculated hourly net inflows to Keno reservoir that can be attributed to operation of the Klamath Irrigation Project, including Link River flows and flows through other irrigation project channels and outflow from Keno dam and J.C. Boyle powerhouse. Releases from Keno dam during this period are virtually identical to the net inflow to Keno reservoir. Without such closely coordinated releases at Keno dam, the water level of Keno reservoir would quickly vary beyond the 0.2 foot operating band that PacifiCorp seeks to maintain. PacifiCorp is successful in maintaining this narrow operating band under most circumstances (see figure 3-7). Consequently, despite Interior's assertions otherwise, the fluctuations in releases from Keno dam are a direct response to equivalent fluctuations in the net inflow to Keno reservoir, rather than an attempt to enhance downstream peaking operations. We cannot determine with certainty the reason for the fluctuations in the inflow to the reservoir shown in figure 4-4, but diversions during the October and November time frame are likely associated with planned seasonal flooding of wetland habitat at the Lower Klamath National Wildlife Refuge (Risley and Gannett, 2006).

Our analysis, conducted with a different method than PacifiCorp's analysis, shows that Keno dam is clearly managed to maintain the water level within the restrictive 0.2-foot operational band. Inflow to Keno reservoir tends to often vary on an hourly or daily basis, partly due to Klamath Irrigation Project operations. Our results agree with the results of PacifiCorp's analyses. While in infrequent instances the operation of Keno dam to maintain a steady reservoir elevation results in a very minor enhancement in downstream generation; overall, Keno dam results in no benefit to, or a small net loss of, generation at the downstream developments.

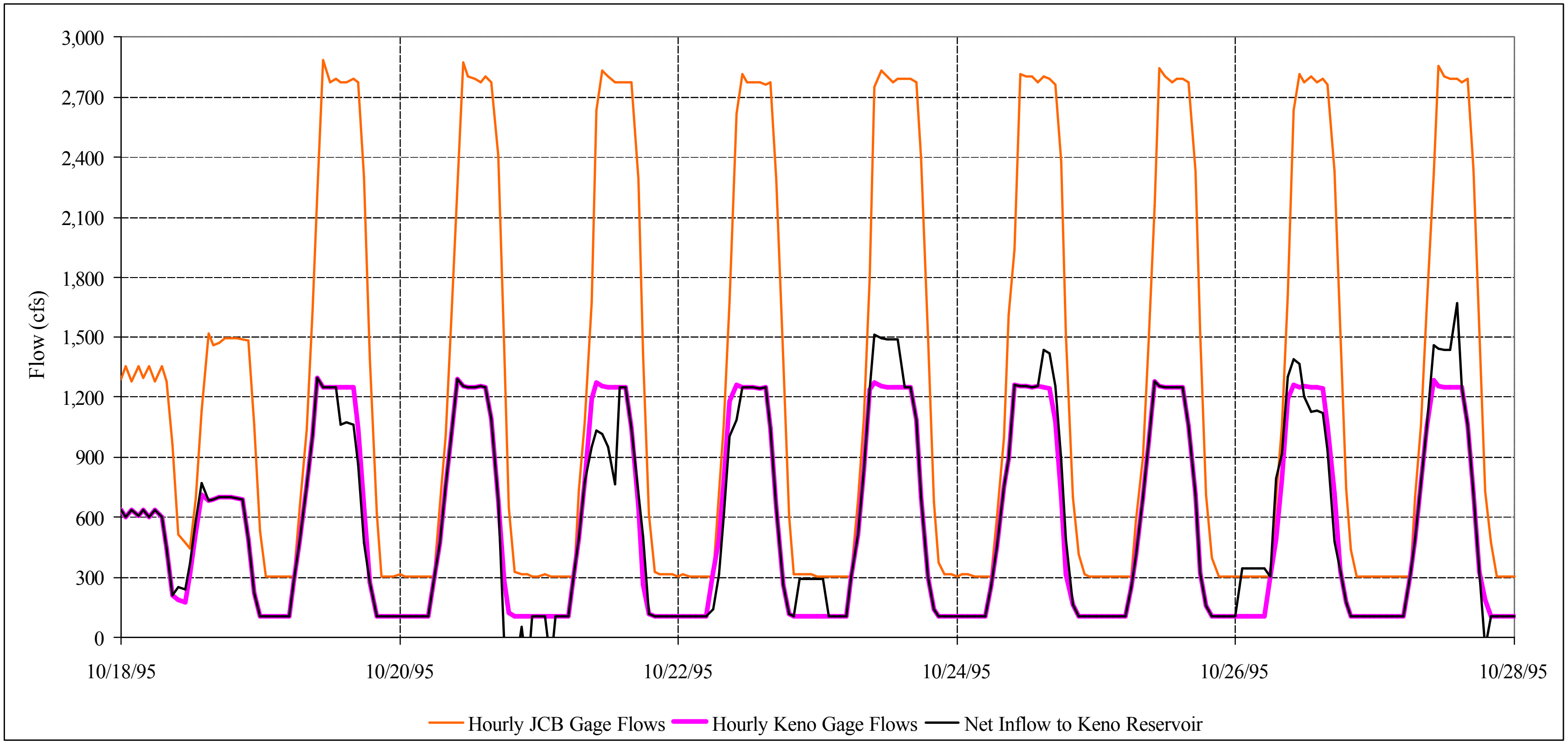


Figure 4-4. Relationship between net inflow to Keno reservoir, USGS gages at Keno and below J.C. Boyle powerhouse—October 18, 1995, until October 28, 1995. (Source: Reclamation, 2006a; PacifiCorp, 2005j; USGS, 2005; as modified by staff)

4.8 GREENHOUSE GAS EMISSIONS

The project provides low-cost energy that displaces non-renewable, fossil-fueled generation and contributes to a diversified generation mix. Displacing the operation of fossil-fueled facilities avoids some power plant emissions and creates an environmental benefit. Table 4-7 shows the amount of carbon emissions displaced by each development. If the electric output of the current project (716,820 MWh) was replaced with fossil-fueled generation, greenhouse gas emissions could potentially increase by 110,787 metric tons of carbon per year (using a carbon intensity factor of 155 kg*C*/MWh). We consider the most likely fuel for generation in the project area to be natural gas.

Table 4-7. Klamath Project carbon emissions displacement. (Source: Staff)

Development	Average Annual Generation (MWh)	Carbon Emissions (metric tons of carbon per year)
East Side	15,400	2,372
West Side	3,400	527
J.C. Boyle	329,000	50,666
Copco No. 1	106,000	16,430
Copco No. 2	135,000	20,952
Fall Creek	12,000	1,860
Iron Gate	116,000	17,980
Total	716,800	**110,787**

Both Oregon and California are working with the state of Washington to develop greenhouse gas reduction programs as part of the West Coast Governor's Global Warming Initiative (Governor's Advisory Group on Global Warming, 2004). The governors have approved recommendations for actions to reduce greenhouse gas emissions that are contributing to global warming. Among these initiatives are goals for greenhouse gas emission on both a short- and long-term basis. Table 4-8 shows those goals.

Table 4-8. Oregon and California greenhouse gas reduction goals. (Source: ODE, 2005; California Energy Commission, 2005; CPUC, 2006)

Target deadline	Target goal	Target maximum emissions (million metric tons of CO_2)
	Oregon	
2010	Reduce to 1990 levels	59
2020	Reduce to 10% below 1990 levels	53
2050	Reduce to 75% below 1990 levels	15
	California	
2010	Reduce to 2000 levels	473
2020	Reduce to 1990 levels	426
2050	Reduce to 80% below 1990 levels	85

Both Oregon and California are in the process of developing Renewable Energy Action plans that call for increases in the amount of renewable energy used in each state. Although these resources do not necessarily need to be located in the states, both states are implementing incentives to encourage developers to construct the facilities in their respective states. Oregon has set a goal of supplying 10 percent of the power used in the state with renewable energy by 2015 and increased the goal to 25 percent by 2025 (ODE, 2005). California has accelerated its Renewable Portfolio Standard to require 20 percent of all power used in the state to be generated by renewable resources by 2010 and 33 percent by 2020 (CEPA, 2006).

Most of the planned or approved facilities in the northwest involve construction a considerable distance from the Klamath Hydroelectric Project (NPCC, 2006). The majority of facilities proposed in the state of Oregon would be located along the Oregon-Washington border. Those facilities would primarily be fueled by natural gas, although a number of wind projects also are proposed. However, there are some proposed and newly constructed generation facilities located within the local area (WECC, 2005a; 2005b; OEFSC, 2006). Among the larger local projects are the recently completed Klamath Cogeneration Project (542.5 MW), which is fueled by natural gas and the proposed Klamath Generating (500 MW) and COB Energy facilities (1,150 MW). The two proposed facilities also would be fueled by natural gas. Although PacifiCorp owns both the Klamath Cogeneration Project and the Klamath Hydroelectric Project, market rules prevent the power from the cogeneration facility from being sold to Pacific Power (a PacifiCorp subsidiary) for local use. The Klamath Generating Facility is being proposed by Pacific Power /PPM Energy (PacifiCorp subsidiaries). The COB Energy facility is being proposed by People's Energy. It is not known if the power from the facility could be sold to Pacific Power for local use (PPM Energy, 2006). Smaller facilities planned in the area include the Dorena (8.3 MW) and Applegate (12 MW) hydroelectric projects, several potential wind projects, and a geothermal project.

Although one new generation facility exists and two additional facilities are proposed in the Klamath Falls area; the electricity generated at these three facilities may not be available to replace generation from the Klamath Hydroelectric Project facilities if any of the dams are removed and the hydroelectric facilities shut down, depending on applicable market rules for the two proposed new facilities. Any facilities that may be available most likely would be fueled by natural gas. The loss of hydroelectric facilities and replacement by energy facilities fueled by non-renewable natural gas would hinder the efforts of the West Coast Governor's Global Warming Initiative to reduce greenhouse gas emissions and increase the percentage of energy consumed in the states produced by renewable resources.