

# **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 <sup>a</sup>
Capacity rate (2006\$)	Included in energy value	
Return on project equity	10.8 percent	PacifiCorp <sup>b</sup>
Bond/debt ratio	0.5	PacifiCorp <sup>c</sup>
Overall cost of money	8.057 percent	PacifiCorp <sup>d</sup>
Discount rate	7.5 percent	PacifiCorp <sup>e</sup>
State and federal income tax rate	35 percent	PacifiCorp <sup>f</sup>
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) <sup>g</sup>	716,820	PacifiCorp
No-action dependable capacity (MW)	42.7	PacifiCorp

<sup>a</sup> 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.

<sup>b</sup> 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.

<sup>c</sup> Value based on the ratio of long-term debt to total capitalization from PacifiCorp’s 2005 Form 10-K, p. 24.

<sup>d</sup> Value from Order #05-1050 Oregon Public Utility Commission, September 28, 2005, p. 10.

<sup>e</sup> Value provided by PacifiCorp in its July 21, 2004, deficiency response.

<sup>f</sup> Value provided by PacifiCorp in its 2005 Form 10-K report, p. 105.

<sup>g</sup> 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.

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

<b>Development</b>	<b>Net Investment<sup>a</sup> (as of 3/31/03)</b>	<b>Operation and Maintenance<sup>a</sup> (as of 3/31/03)</b>
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

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

9 Table 4-3 compares the power value, annual costs, and net benefits for the No-action Alternative,  
 10 Pacificorp's Proposal, the Staff Alternative, the Staff Alternative with Mandatory Conditions, and the  
 11 Retirement of Copco No. 1 and Iron Gate Developments, which are discussed in details in sections 4.1,  
 12 4.2, 4.3, 4.4, and 4.5, respectively. Appendix A, table A-1, shows the effect on costs and power values of  
 13 individual measures proposed by PacifiCorp, recommended by others, and considered by staff for  
 14 inclusion in the Staff Alternative. In section 5.2, *Discussion of Key Issues*, we discuss our reasons for  
 15 including key measures in the Staff Alternative and why we consider the environmental benefits to be  
 16 worth these costs.

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

	<b>No Action</b>	<b>PacifiCorp's Proposal</b>	<b>Staff Alternative</b>	<b>Staff Alternative with Mandatory Conditions</b>	<b>Retirement of Copco No. 1 and Iron Gate Developments</b>
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 (mills/kWh)	\$29,748,030 41.50	\$28,072,880 41.50	\$27,772,420 41.50	\$20,664,130 41.50	\$18,617,110 41.50
Annual cost (mills/kWh)	\$10,337,630 14.42	\$15,319,450 22.65	\$20,245,720 30.25	\$49,413,530 99.24	\$24,297,140 54.16
Annual net benefit (mills/kWh)	\$19,410,400 27.08	\$12,753,430 18.85	\$7,325,700 11.25	-\$28,749,400 -59.70	-\$5,680,030 -12.66

1 **4.1 POWER AND ECONOMIC BENEFITS OF THE NO-ACTION ALTERNATIVE**

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

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

9 **4.2 POWER AND ECONOMIC BENEFITS OF PACIFICORP’S PROPOSAL**

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

14 The retirement and decommissioning of East Side and West Side developments would remove  
15 3.8 MW from the available generating capacity of the region and would reduce the amount of generation  
16 produced annually in the region by 18,800 MWh, based on the long-term average annual generation for  
17 years 1973-2002 (30 years). The decommissioning of these facilities would slightly increase the need for  
18 power in the region, as discussed in section 1.2, *Need for Power*.

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

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

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

31 The proposed project would generate an average of 676,455 MWh of electricity annually, have an  
32 annual power value of \$28,072,880 (41.50 mills/kWh) and total annual costs of \$15,319,450 (22.65  
33 mills/kWh), resulting in a net annual benefit of \$12,753,430 (18.85 mills/kWh).

34 **4.3 POWER AND ECONOMIC BENEFITS OF THE STAFF ALTERNATIVE**

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

39 The Staff Alternative for the Klamath Hydroelectric Project would include J.C. Boyle, Copco No.  
40 1, Copco No. 2, Fall Creek (including the Spring Creek diversion), and Iron Gate developments.

41 Under the Staff Alternative, the project would generate an average of 669,215 MWh of electricity  
42 annually, have an annual power value of \$27,772,420 (41.50 mills/kWh) and total annual costs of  
43 \$20,245,720 (30.25 mills/kWh), resulting in a net annual benefit of \$7,526,700 (11.25 mills/kWh).

1 **4.4 POWER AND ECONOMIC BENEFITS OF THE STAFF ALTERNATIVE WITH**  
2 **MANDATORY CONDITIONS**

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

13 **4.5 POWER AND ECONOMIC BENEFITS OF RETIREMENT OF COPCO NO. 1**  
14 **AND IRON GATE DEVELOPMENTS**

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

23 **4.6 CONCEPTUAL COSTS OF PROJECT DAM REMOVAL**

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

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

40 If contaminated sediment is found, and is not suitable for downstream transport, the costs of dam  
41 removal would be substantially higher. Actual costs for contaminated sediment removal and disposal  
42 would depend on the nature of the contaminants. We use a range of \$162,500 to \$487,500 per acre-foot,  
43 based on estimates developed for removal of contaminated sediment at other dam removal projects to  
44 provide a general framework of what such costs could be at each mainstem development. The amount of  
45 sediment to be removed would depend on site-specific conditions and the nature of contaminants. It  
46 could be feasible to allow sediment not subject to scour following dam removal to remain in place with or

1 without capping. However, to provide a conservative estimate of costs, we assume all sediment  
2 associated with reservoir lost storage (as shown in table 3-3) would need to be removed. Our base costs  
3 also assume that the exposed bottoms of the reservoirs would naturally re-vegetate, except for the areas  
4 disturbed by dam removal. We assume that no additional restoration costs for reservoir or downstream  
5 riparian habitat that may be influenced by sediment releases during dam removal would be required  
6 beyond the immediate dam site. In addition, we assume that all project-related roadways would remain in  
7 place with no modifications.

#### 8 **4.6.1 Keno Development**

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

#### 16 **4.6.2 J.C. Boyle Development**

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

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

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

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

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

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

### 9 **4.6.3 Copco No. 1 Development**

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

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

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

27 We estimate the decommissioning and removal of the Copco No. 1 facilities would cost  
28 \$10,986,000 (2006 dollars). If contaminated sediment requires removal prior to dam removal, the costs  
29 could increase an additional \$955 million to \$2.9 billion.

### 30 **4.6.4 Copco No. 2 Development**

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

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

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

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

4 We estimate the decommissioning and removal of the Copco No. 2 facilities would cost  
5 \$2,381,000 (2006 dollars). It is unlikely that there would be enough sediment in Copco No. 2 reservoir to  
6 substantially influence this cost estimate.

#### 7 **4.6.5 Fall Creek Development**

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

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

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

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

25 We estimate the decommissioning and removal of the Fall Creek facilities would cost \$1,183,000  
26 (2006 dollars). It is unlikely that there would be enough sediment behind the Spring or Fall Creek  
27 diversion dams to substantially influence this cost estimate.

#### 28 **4.6.6 Iron Gate**

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

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

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

4 We estimate the decommissioning and removal of the Iron Gate facilities would cost \$49,863,000  
 5 (2006 dollars). If contaminated sediment requires removal prior to dam removal, it could cost an  
 6 additional \$485 million to \$1.5 billion.

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

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

<b>Dam/Environmental Measure</b>	<b>Capital Costs (2006\$)</b>	<b>Annual Costs (2006\$)</b>	<b>Annual Energy Costs (2006\$)</b>	<b>Total Annualized Cost (2006\$)</b>
<b>Keno</b>				
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
<b>J.C. Boyle</b>				
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

<b>Dam/Environmental Measure</b>	<b>Capital Costs (2006\$)</b>	<b>Annual Costs (2006\$)</b>	<b>Annual Energy Costs (2006\$)</b>	<b>Total Annualized Cost (2006\$)</b>
Decommissioning plan for J.C. Boyle development	\$150,000 (staff)	\$0	\$0	\$20,250
<b>Copco No. 1</b>				
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
<b>Copco No. 2</b>				
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
<b>Fall Creek/Spring Creek</b>				
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

<b>Dam/Environmental Measure</b>	<b>Capital Costs (2006\$)</b>	<b>Annual Costs (2006\$)</b>	<b>Annual Energy Costs (2006\$)</b>	<b>Total Annualized Cost (2006\$)</b>
	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
<b>Iron Gate</b>				
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

#### 1 **4.7 KENO DEVELOPMENT ANALYSIS**

2 Keno development is a regulating facility that controls the water level of Keno reservoir by  
3 releasing water downstream at a rate roughly equivalent to net inflow. This development, located about  
4 21 miles downstream of Reclamation’s Link River dam, has no generation capability, and it regulates the  
5 water level of, and controls releases from, Upper Klamath Lake. The Commission requires PacifiCorp, in  
6 accordance with a 1965 license amendment, to operate Keno reservoir consistent with an agreement with  
7 Reclamation that specifies a maximum water surface elevation of 4,086.5 feet and a minimum water

1 surface elevation of 4,085 feet. However, at the request of irrigators, PacifiCorp generally operates Keno  
2 dam to maintain the reservoir at elevation 4,085.4 +/-0.1 foot from October 1 to May 15 and elevation  
3 4,085.5 +/-0.1 foot from May 16 to September 30 (see figure 3-7). This allows reliable operation of  
4 irrigation canals and pumps and results in an active storage volume of 495 acre-feet. Occasional 2-foot  
5 drawdowns are implemented before the irrigation season to allow irrigators to clean out their water  
6 withdrawal systems. J.C. Boyle reservoir, located about 4.7 miles downstream of Keno dam, has an  
7 active storage volume of 1,724 acre-feet.

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

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

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

31 In response to stakeholder comments, PacifiCorp conducted an analysis of Keno reservoir  
32 operation to determine Keno's contribution, if any, to downstream power generation. PacifiCorp modeled  
33 92 years (1905-1997) of inflow to Upper Klamath Lake, to which outflows through Link River dam  
34 directly correlate. PacifiCorp based its modeling exercise on the following (letter to the Commission  
35 dated May 12, 2006):

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

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

1 Table 4-5. Estimated annual generation (GWh) with and without operation of Keno facilities.  
 2 (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%

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

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

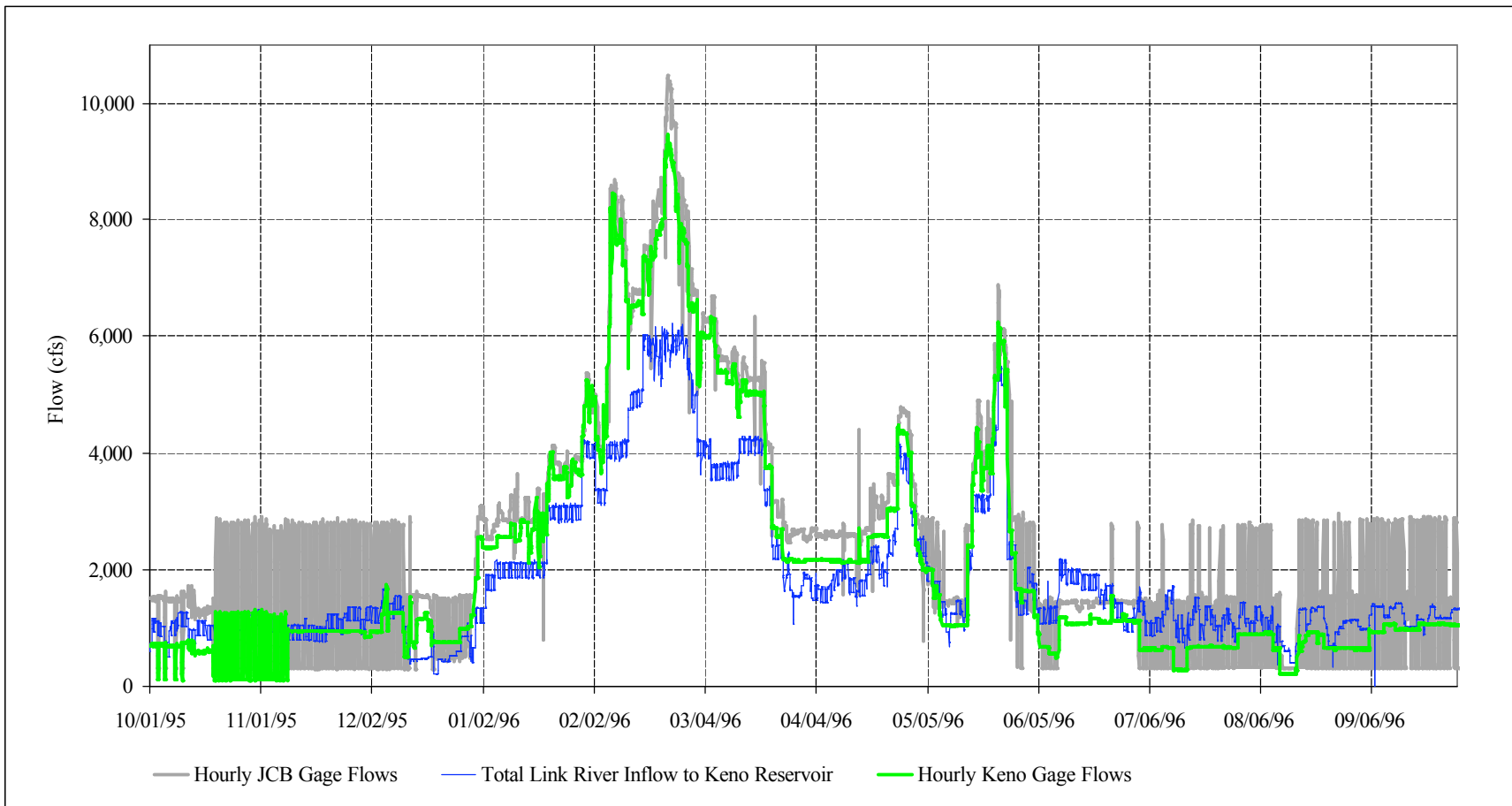
15 To assess the extent that recent operation of Keno development may have benefited PacifiCorp's  
 16 downstream peaking operations, we analyzed flow and water level records for the locations shown in  
 17 table 4-6 for water years 1991 to 2004. We based our analysis on hourly changes in inflow from all major  
 18 sources to Keno reservoir, including back-calculated hourly flows from Klamath Irrigation Project  
 19 channels that enter Keno reservoir (besides Link River), hourly reservoir elevation changes at Keno and  
 20 J.C. Boyle reservoirs, and hourly (or smaller interval) gage data. Releases from Keno dam take about 2 to  
 21 3 hours to reach J.C. Boyle reservoir.

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

<b>Gage No.</b>	<b>Description</b>	<b>Source</b>	<b>Time Interval</b>
11507001	Upper Klamath Lake near Klamath Falls, OR	USGS	Daily
11507500	West Side powerhouse	PacifiCorp	Hourly
	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
11509500	Keno reservoir at Keno dam, OR	PacifiCorp	Hourly
	Klamath River at Keno, OR (below Keno dam)	USGS	Half Hourly
	J.C. Boyle reservoir	PacifiCorp	Hourly
11510700	J.C. Boyle powerhouse	PacifiCorp	Hourly
	Gage below J.C. Boyle powerhouse	USGS	Half Hourly
11511400	Copco reservoir	PacifiCorp	Hourly
	Copco No. 1 powerhouse	PacifiCorp	Hourly

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

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



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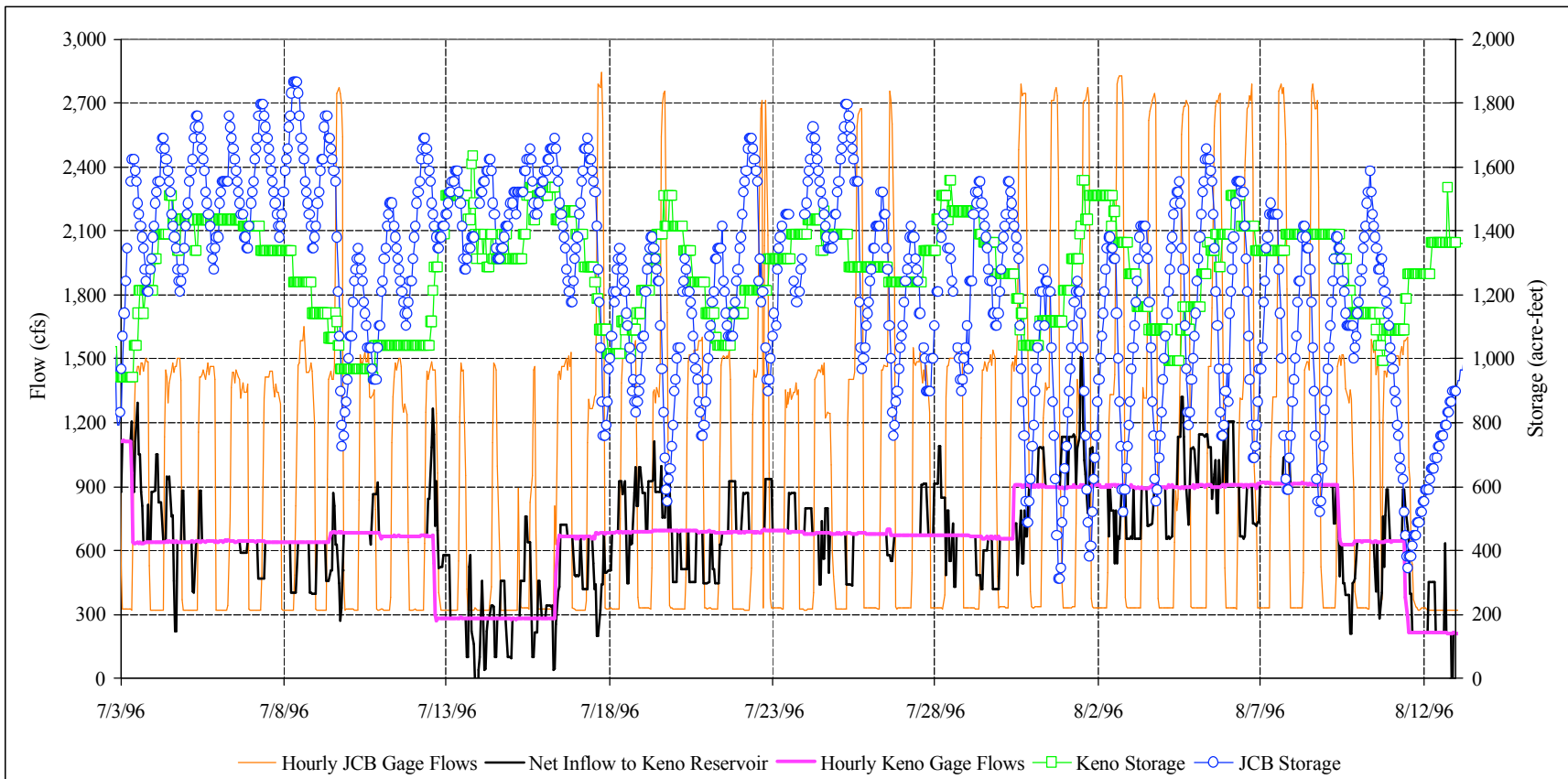
Figure 4-1. Flows entering Keno reservoir via Link River and in the Klamath River downstream of Keno development at USGS gage no. 11509500 and J.C. Boyle development at USGS gage no. 11510700 for water year 1996. (Source: USGS, 2005, as modified by staff)

1           During the irrigation months, most of the difference between the combined flow at the Link River  
2 gage and West Side powerhouse and flows released at Keno dam is caused by withdrawals from Keno  
3 reservoir by the Lost River diversion channel, North canal, Ady canal, and other withdrawals used largely  
4 for irrigation. During the non-irrigation months, other than flows withdrawn from Keno to flood seasonal  
5 wetland habitat in the Lower Klamath National Wildlife Refuge, flows enter Keno reservoir from the Lost  
6 River diversion channel and the Klamath Straits drain, in addition to Link River. Based on flow data  
7 from the gage below the J.C. Boyle powerhouse and accounting for the minimum flow releases from J.C.  
8 Boyle dam (100 cfs) and spring accretion in the J.C. Boyle bypassed reach, the J.C. Boyle powerhouse  
9 operates or had the ability to operate at full capacity all day about 12 percent of the days in water years  
10 1991 to 2003. The generation from these days, when peaking operations would not have occurred,  
11 produced about 33 percent of the total generation during that 13-year period.

12           The flow relationships shown in figure 4-2 are representative of the vast majority of the 1991 to  
13 2004 water year period that we assessed. If PacifiCorp was manipulating flows from Keno dam to  
14 enhance its peaking ability at the J.C. Boyle development and the other downstream powerhouses, we  
15 would expect to see a spike in flows measured at the Keno gage about 2 hours before the beginning of  
16 peaking operations at the J.C. Boyle powerhouse, which the spikes in flow at the USGS gage downstream  
17 of the J.C. Boyle powerhouse, shown in figure 4-2, represent. No such spikes in flow are evident during  
18 nearly all periods when J.C. Boyle is operating in a peaking mode, and figure 4-2 shows that water stored  
19 in J.C. Boyle reservoir provides the necessary flows to support the peaking operations, not the limited  
20 storage available in Keno reservoir.

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

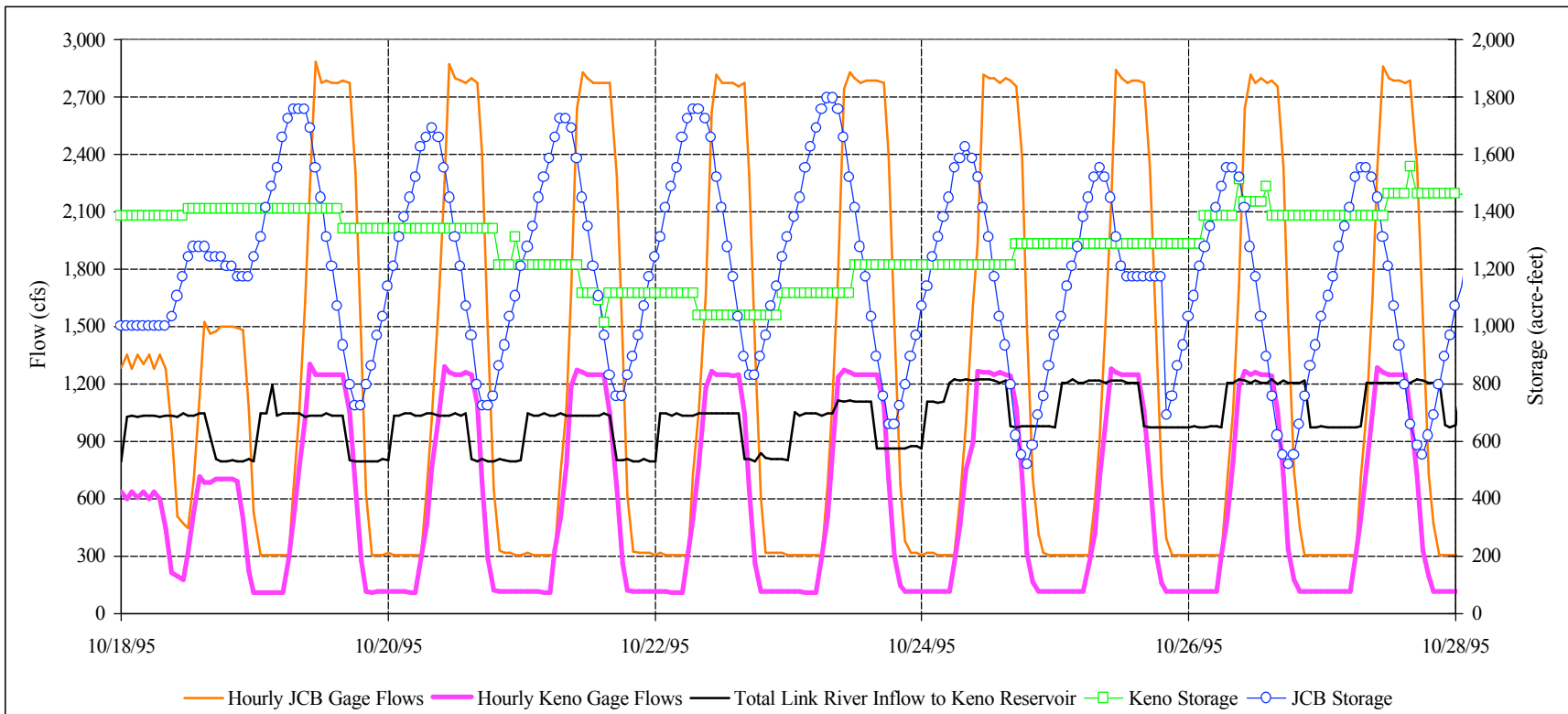
26           During late October and early November, outflow from Keno dam, as measured at the Keno gage,  
27 spiked when the J.C. Boyle powerhouse was operating in a peaking mode (see figure 4-1). Figure 4-3  
28 shows detailed flow characteristics during this period. Based on the spikes of flow measured at the Keno  
29 gage that correspond to peaking releases from the powerhouse, one could conclude, as did Interior, that  
30 operation of Keno development was enhancing peaking operations at J.C. Boyle development. This  
31 relationship appears similar to the relationship portrayed in the three examples from Interior (March 27,  
32 2006, letter).



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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)



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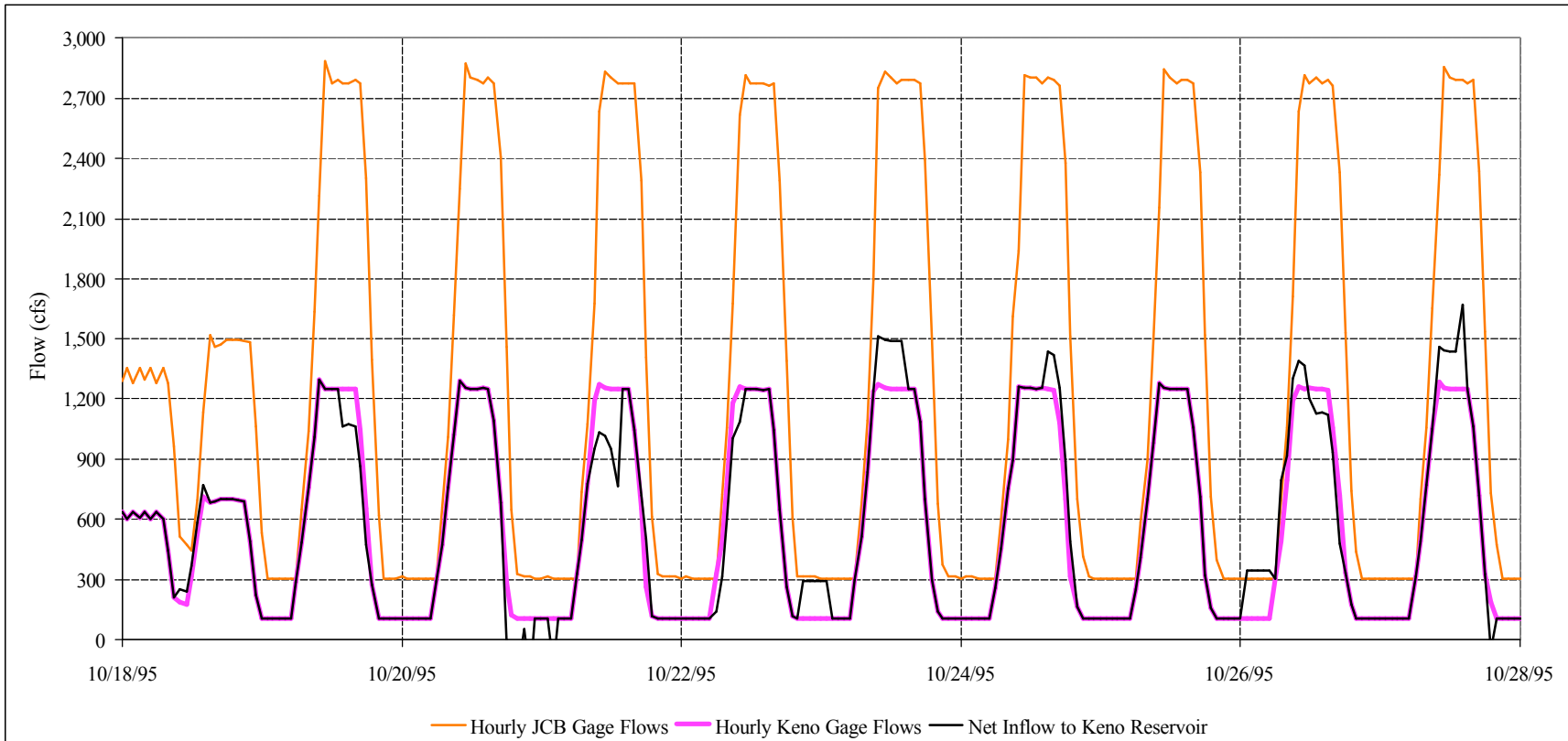
Notes: Storage based on water volume between elevations 4,085.00 and 4,086.00 feet for Keno and 3,788.00 and 3,793.20 feet for J.C. Boyle.  
 During the time period shown on this graph, the elevation at Keno reservoir varied between elevation 4,085.41 and 4,085.57 feet and 3,789.50 and 3,793.20 feet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

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

20 Based on the known hourly or shorter interval flow and water level (see table 4-6), mass balance  
21 techniques, and assuming that the majority of the unknown inflow or outflow in the Keno reservoir area is  
22 from the Klamath Irrigation Project, we estimated hourly inflows and outflows to Keno reservoir. Figure  
23 4-4 shows our calculated hourly net inflows to Keno reservoir that can be attributed to operation of the  
24 Klamath Irrigation Project, including Link River flows and flows through other irrigation project channels  
25 and outflow from Keno dam and J.C. Boyle powerhouse. Releases from Keno dam during this period are  
26 virtually identical to the net inflow to Keno reservoir. Without such closely coordinated releases at Keno  
27 dam, the water level of Keno reservoir would quickly vary beyond the 0.2 foot operating band that  
28 PacifiCorp seeks to maintain. PacifiCorp is successful in maintaining this narrow operating band under  
29 most circumstances (see figure 3-7). Consequently, despite Interior's assertions otherwise, the  
30 fluctuations in releases from Keno dam are a direct response to equivalent fluctuations in the net inflow to  
31 Keno reservoir, rather than an attempt to enhance downstream peaking operations. We cannot determine  
32 with certainty the reason for the fluctuations in the inflow to the reservoir shown in figure 4-4, but  
33 diversions during the October and November time frame are likely associated with planned seasonal  
34 flooding of wetland habitat at the Lower Klamath National Wildlife Refuge (Risley and Gannett, 2006).

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



1  
 2 Figure 4-4. Relationship between net inflow to Keno reservoir, USGS gages at Keno and below J.C. Boyle powerhouse—  
 3 October 18, 1995, until October 28, 1995. (Source: Reclamation, 2006a; PacifiCorp, 2005j; USGS, 2005; as  
 4 modified by staff)

1 **4.8 GREENHOUSE GAS EMISSIONS**

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

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

<b>Development</b>	<b>Average Annual Generation (MWh)</b>	<b>Carbon Emissions (metric tons of carbon per year)</b>
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
<b>Total</b>	<b>716,800</b>	<b>110,787</b>

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

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

<b>Target deadline</b>	<b>Target goal</b>	<b>Target maximum emissions (million metric tons of CO<sub>2</sub>)</b>
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

17 Both Oregon and California are in the process of developing Renewable Energy Action plans that  
 18 call for increases in the amount of renewable energy used in each state. Although these resources do not  
 19 necessarily need to be located in the states, both states are implementing incentives to encourage

1 developers to construct the facilities in their respective states. Oregon has set a goal of supplying 10  
2 percent of the power used in the state with renewable energy by 2015 and increased the goal to 25 percent  
3 by 2025 (ODE, 2005). California has accelerated its Renewable Portfolio Standard to require 20 percent  
4 of all power used in the state to be generated by renewable resources by 2010 and 33 percent by 2020  
5 (CEPA, 2006).

6 Most of the planned or approved facilities in the northwest involve construction a considerable  
7 distance from the Klamath Hydroelectric Project (NPCC, 2006). The majority of facilities proposed in  
8 the state of Oregon would be located along the Oregon-Washington border. Those facilities would  
9 primarily be fueled by natural gas, although a number of wind projects also are proposed. However, there  
10 are some proposed and newly constructed generation facilities located within the local area (WECC,  
11 2005a; 2005b; OEFSC, 2006). Among the larger local projects are the recently completed Klamath  
12 Cogeneration Project (542.5 MW), which is fueled by natural gas and the proposed Klamath Generating  
13 (500 MW) and COB Energy facilities (1,150 MW). The two proposed facilities also would be fueled by  
14 natural gas. Although PacifiCorp owns both the Klamath Cogeneration Project and the Klamath  
15 Hydroelectric Project, market rules prevent the power from the cogeneration facility from being sold to  
16 Pacific Power (a PacifiCorp subsidiary) for local use. The Klamath Generating Facility is being proposed  
17 by Pacific Power /PPM Energy (PacifiCorp subsidiaries). The COB Energy facility is being proposed by  
18 People’s Energy. It is not known if the power from the facility could be sold to Pacific Power for local  
19 use (PPM Energy, 2006). Smaller facilities planned in the area include the Dorena (8.3 MW) and  
20 Applegate (12 MW) hydroelectric projects, several potential wind projects, and a geothermal project.

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

29