20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

117 FERC ¶ 61, 077

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

OPINION NO. 486

Kern River Gas Transmission Company **Docket No. RP04-274-000**

OPINION AND ORDER ON INITIAL DECISION

(Issued October 19, 2006)

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

UNITED STATES OF AMERICA FERC
FEDERAL ENERGY REGULATORY COMMISSION

Kern River Gas Transmission Company Docket No. RP04-274-000

OPINION NO. 486

APPEARANCES

Jeffrey G. Disciullo, David Shaffer, Richard Stapler, and *Michael J. Thompson* for Kern River Gas Transmission Company ("Kern River" or "company").

Jennifer Spina and *Mark Sundback* for BP Energy Company ("BP").

Matthew Binette and *Paul F. Forshay* for Calpine Energy Services, LP ("Calpine").

Kevin J. Lipson and *Christopher Schindler* for Edison Mission Energy, LLC ("Edison Mission").

Bruce Bedwell and *Kenneth W. Irvin* for El Paso Merchant Energy, L.P ("El Paso").

Robert Fallon for High Desert Power Trust ("High Desert").

Timothy Bolden, Kelly A. Daly, and *Lucy Holmes Plovnick for* Pinnacle West Capital Corporation ("Pinnacle West").

David S. Anderson for Questar Gas Company ("Questar").

Katherine B. Edwards and *John Paul Floom* for the Rolled-In-Customer Group ("RCG").

Alana Steele for Southern California Generation Coalition ("SCGC").

Thomas J. Burgess and *Arnold H. Meltz* for the Federal Energy Regulatory Commission ("Staff").

OPINION NO. 486

Table of Contents

I. Background 2
II. Levelized Rates/Levelized Cost of Service Proposal 8
A. General 8
B. Shipper Rate Differential 26
C. 95 Percent Load Factor Billing Determinants for the Original System 29
D. Inflation Factor for A&G and O&M Expenses 37
E. Capital Structure 44
i. Ozark Methodology 44
a. The Use of Equity Rate Base and the Ozark Methodology 46
b. Inputs to Ozark Calculation 48
c. The Use of Contract by Contract Capital Structure vs. The Use of One Average Capital Structure for All Customers 49
III. Cost of Capital 50
A. Proxy Group 51
B. Placement in Zone 68
C. Debt Costs 75
i. Blended v Separate Debt Costs 76
ii. Series A Debt Costs 81
IV. Tax Issues 84
A. Income Tax Allowance 84
B. Tax Net Operating Loss 89
C. Allocation of ADIT 93
i. The Acquisition-Related ADIT 93
ii. Allocation of Bonus Depreciation-Related ADIT 96
D. Utah Compressor Taxes 97
V. Other Cost of Service 102
A. O&M Expenses 102
B. A&G Expenses 107
C. Allocation of A&G Costs 110
D. Miscellaneous 116
VI. Rate Design 116
A. Enhanced Fixed Variable Design 116
B. 100 Percent Load Factor Rate for IT and AOS Service 122
i. General 122
ii. Rates for IT versus AOS transportation 131
iii. Miscellaneous 132
C. Allocation of Cost of Facilities 133
D. 2002 Expansion Roll-In 137
E. Blended Fuel Reimbursement Rate 139
F. Mirant Capacity and MOR Credit and Fuel Adjustment 142
i. Mirant Capacity 142
ii. Allocation of market-oriented revenue credits 148

iii. Market-Oriented Revenue credit and fuel adjustment 150
VII. Depreciation 153
A. Book Depreciation 153
i. Rolled-in Transmission Plant 153
a. Kern River Gas Supply Testimony 156
b. Staff Gas Supply Testimony 162
ii. Negative Net Salvage Rate 170
iii. Solar Mars Compressor Engines 178
iv. High Desert and Big Horn Laterals 182
v. General Plant 186
vi. Intangible Plant 187
VIII. Regulatory Assets 189
i. Inclusion of Deferred Depreciation in Rate Base 190
ii. Amortization Period of Regulatory Asset 192
iii. Unamortized Portion of Regulatory Asset 195

117 FERC ¶ 61, 077
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

Kern River Gas Transmission Company Docket No. RP04-274-000

OPINION NO. 486

ORDER ON INITIAL DECISION

(Issued October 19, 2006)

1. This order addresses briefs on and opposing exceptions to an Initial Decision (ID) issued on March 2, 2006 by the Presiding Administrative Law Judge (ALJ) in the captioned proceeding.[1] The Initial Decision set forth the ALJ's findings concerning a general rate case filed by Kern River Gas Transmission Company (Kern River) pursuant to section 4 of the Natural Gas Act (NGA) on April 30, 2004.

2. In this order, the Commission affirms the ALJ on most issues. However, the Commission does reverse the ALJ on several issues. The Commission finds that Kern River's return on equity (ROE) should be set at 11.2 percent, rather than the 9.34 percent adopted by the ALJ. The Commission finds that the ALJ should have excluded from her six-company proxy group two companies, whose adverse financial circumstances are not representative of the natural gas pipeline industry. However, the Commission does affirm the ALJ's refusal to include master limited partnerships (MLPs) in the proxy group, since our concerns about the inclusion of MLPs have not been adequately addressed on this record. The median return of our revised proxy group is 10.7 percent. In addition, because this proxy group is small and includes companies with a relatively low proportion of pipeline business and substantial distribution operations, we approve a 50 basis point adjustment above the median to 11.2 percent. This accounts for differences in risk between Kern River and the proxy group companies.

---

[1] 114 FERC ¶ 63,031 (2006) (ID).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

3. The Commission also reverses the ALJ's rejection of Kern River's proposal to use a weighted average cost of debt in designing rates for all groups of shippers on its system and the ALJ's denial of a corporate tax allowance. In addition, the Commission orders Kern River to include in its tariff the stepdown rates that will take effect after the shippers' current contracts expire. Finally, the Commission addresses an issue concerning the allocation of Utah compressor taxes not addressed by the ALJ. In all other respects, we affirm the results reached by the ALJ.

I. Background

4. Kern River began providing open-access firm and interruptible transportation services under Part 284 of the Commission's regulations on February 15, 1992.[2] Kern River's transmission system stretches from southwestern Wyoming through Utah and the southern portion of Nevada to southern California. Kern River's facilities include approximately 1,964 miles of transmission lines: 1,671 miles which it owns and operates and 293 miles, located in California, which it owns with Mojave Pipeline Company, the operator of that section.[3]

5. Kern River's transmission facilities are divided into five segments: the original system and the 2002 expansion which constitute its rolled-in system and three incremental facilities--the Big Horn lateral in Nevada, the High Desert lateral in California, and the 2003 expansion.[4] The original pipeline could provide up to 700,000 Mcf/day of firm transportation service. As discussed below, a 2002 expansion project and a related project called the California Action Project increased Kern River's capacity to 869,500 Dth per day. An additional 2003 expansion increased the capacity of the pipeline to 1,755,626 Dth per day.[5]

---

[2] 62 FERC ¶ 61,191, at 62,251, *order on compliance and reh'g*, 64 FERC ¶ 61,049 (1993). Initially, Kern River was a partnership owned equally by Kern River Corp., an affiliate of Tennessee Gas Pipeline Company, and Williams Western Pipeline Company, an affiliate of The Williams Companies. Other companies covered by this same partnership included Kern River Gas Supply Corp. and Kern River Service Corp.

[3] Ex. S-7 at 14, *citing* Kern River's 2003 FERC Form No. 2: Annual Report of Major Natural Gas Companies (Form No. 2).

[4] *Id.* at 14-15; Ex. S-8 (map).

[5] 114 FERC ¶ 63,031, at P 12-17 (2006).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

6. Kern River transports natural gas supplies from the Rocky Mountain area. In the Rocky Mountain supply area, Kern River has interconnections with processing plants and interstate pipelines. Currently, it has interconnections with Northwest Pipeline Corporation, Colorado Interstate Company, and Questar Pipeline Company.[6]

7. Initially, Kern River's primary market consisted of gas and electric utilities, plus industrial customers in California, particularly the enhanced oil recovery (EOR) and cogeneration markets in Kern County, California.[7] Kern River competed with two other pipelines to serve the gas requirements of the EOR operations in the heavy oil fields of Kern County.[8] Today, California continues to be Kern River's primary market, but it also has delivery points in Utah and Nevada.[9] In the market area, Kern River connects with Pacific Gas & Electric Company, and Southern California Gas Company, two major gas distributors.[10]

8. The Commission authorized Kern River to construct its facilities in 1990 under the Commission's Optional Certificate procedures adopted in Order No. 436.[11] A pipeline is eligible for an optional certificate if it provides open access transportation and is willing to assume the risks of the project. At that time, the Commission used the Modified Fixed Variable (MFV) rate design. Under MFV, return on equity and usage costs for firm transportation service were collected in the volumetric or usage rate. Fixed costs other than return on equity were collected in the reservation rate. Assuming the risks meant that, except for a reservation charge for firm service, the rate charged by the pipeline for transportation service must be a one-part volumetric rate that "'recovers the cost of the new service to the extent that the projected units of service are actually purchased,'"[12] the Commission concluded that Kern River's maximum reservation fee was not greater than the MFV demand charge and thus imposed sufficient risk on Kern River. Thus Kern River, as initially certificated, had to recover its return on equity through rates for units of service actually purchased.

---

[6] Ex. S-7 at 14-15.

[7] 62 FERC ¶ 61,191, at 62,252.

[8] *Id.*

[9] Ex. S-7 at 15.

[10] *Id.*

[11] 50 FERC ¶ 61,069 (1990).

[12] 62 FERC ¶ 61,191, at 62,252 *citing* 50 FERC ¶ 61,069, at 61,149.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

9. The Commission included several other conditions in Kern River's Optional Certificate. It prohibited Kern River from shifting any costs originally allocated to the new service to any other service, absent a filing under 18 C.F.R § 154.63 and a Commission determination that the costs to be reallocated are, in fact, being incurred for the benefit of the other services.[13] The Commission required Kern River to make the lowest negotiated reservation fee it offered to any customer available to all customers on a non-discriminatory basis.[14] It also required Kern River to base its rates on a 95 percent load factor and to use a 25-year depreciation life for its facilities.[15]

10. However, the Commission permitted Kern River to use a levelized cost of service.[16] The levelized costs included both capital costs and operating costs such as O&M costs and A&G costs. The original shippers had contracts with a term of 15 years, expiring in 2007.[17] The Commission authorized one volumetric rate for the first 15 years of service (based on the 15-year levelized cost of service, 25-year depreciation life, a 700 MMcf/day maximum capacity, and 95 percent load factor), another volumetric rate for years 16 through 25, and a third volumetric rate for service rendered after 25 years. The Commission stated that this structure would allow Kern River to recover all of its debt service, which is approximately 70 percent of the original investment in the pipeline, during the first 15 years, and its return on equity primarily during the second period (years 16 through 25). However, Kern River would assume the risks of recovery of depreciation not recovered in the first 15 years. The charges for service beyond 25 years were intended to provide for the recovery of Kern River's operating expenses, taxes, and a reasonable management fee equivalent to no more than 10 percent of Kern River's average pre-tax return.[18] The Commission required that the difference between depreciation amounts charged to expense and plant costs recoverable through rate base should be accounted for as regulatory assets.[19]

---

[13] *Id.*

[14] *Id.*

[15] *Id.* at 62,252-53.

[16] 50 FERC ¶ 61,069, at 61,150. 58 FERC ¶ 61,073, at 61,242-44 (1992), *order on reh'g*, 60 FERC ¶ 61,123, at 61,437 (1992).

[17] 92 FERC ¶ 61,061, at 61,155 (2000).

[18] 62 FERC ¶ 61,191, at 62,253.

[19] 58 FERC ¶ 61,074, at 61,244.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

11. In 1992, the Commission restructured the gas industry in Order No. 636.[20] As part of its restructuring, it adopted the Straight Fixed Variable (SFV) method of rate design. Under SFV, a pipeline collects all of its fixed costs for firm transportation service, including return on equity, through the reservation charge. It collects only variable or usage costs through its usage rate. The Commission made usage charges on gas pipelines similar, so that only the seller's cost of producing the gas, and not pipeline usage charges, would cause variation in gas prices.[21] The Commission found that this pricing structure for firm transportation service would increase competition between gas suppliers since pipeline usage charges would not distort gas prices.

12. In Kern River's restructuring proceeding,[22] the Commission changed the pipeline's rate design from MFV to SFV to coincide with its objective to foster competition for gas supplies. The Commission noted that this change would decrease the risk of the project to Kern River, but found it was justified because Kern River would be unable to compete for the throughput necessary to recover the fixed costs included in the MFV usage charge since other pipelines would now have much reduced usage charges.[23]

13. On March 31, 1999, Kern River filed a settlement (1999 Settlement) proposing a reduction in its maximum rates for firm, interruptible, and authorized overrun rates on its system, as well as a three-year rate increase moratorium, levelized rates, and a departure from the SFV rate design.[24] Kern River made this filing in lieu of its obligation under the

---

[20] *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 636, 57 FR 13267 (April 16, 1992), FERC Statutes and Regulations ¶ 30,939 (April 8, 1992); *order on reh'g*, Order No. 636-A, 57 FR 36128 (August 12, 1992), FERC Statutes and Regulations ¶ 30,950 (August 3, 1992); *order on reh'g*, Order No. 636-B, 57 FR 57911 (December 8, 1992), 61 FERC ¶ 61,272 (1992), *reh'g denied*, 62 FERC ¶ 61,007 (1993); *aff'd in part and remanded in part*, *United Distribution Companies v. FERC*, 88 F.3d 1105 (D.C. Cir. 1996).

[21] 62 FERC ¶ 61,191, at 61,407.

[22] Docket No. RS92-65-000.

[23] 62 FERC ¶ 61,191, at 61,408.

[24] Under Article VIII of the Settlement, Kern River also proposed to share with its maximum rate firm transportation customers revenues received by Kern River above an Annual Revenue Threshold level initially set at $177.3 million. All revenues above this threshold level will be shared on a fifty-fifty basis with all primary firm and replacement firm customers paying maximum rates on an annual or seasonal basis. 87 FERC ¶ 61,128 (1999).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

settlement of its last general section 4 rate case to submit either a general rate change or a restatement of rates prior to April 1999.[25] The Commission accepted the lower rates included in the 1999 Settlement, subject to refund, but withheld its approval of the Settlement so that Kern River could engage in further negotiation with its customers.[26] Subsequently, the Commission approved the 1999 Settlement.[27]

14. In May 2000, Kern River proposed to lower its rates by refinancing its debt and providing for longer debt recovery periods by extending the terms of firm contracts. The Commission accepted a settlement containing this proposal (2000 ET Settlement).[28] Pursuant to the 2000 ET Settlement, a Shipper could keep its original 15-year contract term expiring in 2007, or extend its contract term and pay its existing debt service obligations over a longer period of time, thereby reducing its current rates. If a shipper extended its contract term to 2011, it would receive a ten-year Extended Term (ET) rate (October 1, 2001 – 2011). If a shipper extended its contract term through 2016, it would receive a 15-year ET rate (October 1, 2001 – 2016).[29] Kern River explained that under the 2000 ET Settlement, its rates would be designed consistent with the principles espoused in its Original Certificate order described above, which would permit it to recover 70 percent of the costs of the plant being depreciated by the end of the new repayment period.[30] Subsequently, all of the shippers elected to lengthen their contracts by either 5 or 10 years since this produced significantly lower rates.[31] Therefore, after

---

[25] 70 FERC ¶ 62,072 (1995).

[26] 87 FERC ¶ 61,128 (1999).

[27] 90 FERC ¶ 61,124 (2000); 98 FERC ¶ 61,245 (2002).

[28] 92 FERC ¶ 61,061 (2000) (*2000 ET Settlement*), *order on reh'g*, 94 FERC ¶ 61,115 (2001). Under the 2000 ET Settlement, Kern River did not require a general reallocation of revenue responsibility among its shippers and maintained that its cost of service (other than financing and depreciation components) would remain unchanged. 92 FERC at 61,156.

[29] 92 FERC ¶ 61,061, at 61,156.

[30] *Id*. at 61,157. Kern River stated that in designing its rates, cost of service and rate base components would first be allocated to each rate option based upon the percentage of contract demand of those shippers electing to pay the new 10-year rates, the new 15 year rates, and the existing rates. Then, the levelized rates for the 10-year and 15-year rate options will be calculated by levelizing the cost of service over the extended contracts terms, and the existing rates will be reduced as appropriate. *Id*.

[31] Ex. KR-45 at 5; Kern River Initial Brief at 3.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

this election, only two customer groups existed: 10-year ET shippers and 15-year ET shippers.

15. The 2000 ET Settlement also provided that Kern River's original 25-year depreciation life for book purposes would be extended by 15 years from 2017 to September 30, 2032 and that the depreciation rate for the remaining book life of the pipeline of 31 years beginning October 1, 2002 would be two percent per year. As before, Kern River proposed to record the difference between the book depreciation and the levelized depreciation as a regulatory asset. Kern River stated that approximately 70 percent of the costs of the plant will be recovered during the life of the contracts and that no regulatory assets will remain unrecovered after the contracts have expired. Kern River stated that this ensures that its customers will not have to pay for regulatory assets after the rate "step down" periods which it described as the period after which Kern River's debt has been satisfied. [32]

16. In May 2002, Kern River completed an expansion project by adding additional compression to its system. This 2002 Expansion increased Kern River's capacity to 869,500 Dth/day.[33] The costs associated with the 2002 Expansion project were rolled into the original system costs. As before, shippers were permitted to choose 10 or 15-year terms for this additional capacity. However, since the contract expiration dates were different from the dates in the original system shipper contracts, Kern River did not combine the cost-of-service and revenues together to derive the rates. Rather, Kern River elected to calculate the rolled-in rate reduction benefit of the system expansion on an equal per unit basis for all original system shippers in order to derive an additional rate reduction benefit.[34] Kern River stated that the rolled-in rate treatment of the costs for this project would result in recovery of the total debt-related depreciation expenses over the primary terms of the expansion shippers' contracts and, therefore, Kern River requested

---

[32] 92 FERC ¶ 61,061, at 61,159. Kern River states that after the debt attributable to the original system construction is repaid, its transportation rates will step down to a lower level. Kern River explains that while the rates are originally designed based on levelizing the cost of service over the debt payment period, after 70 percent of the investment recovery, the rates will step down to recover the remaining 30 percent of the remaining investment. Thus, the step down rates will be lower and will be calculated over the extended depreciable life of the Kern River System. *Id*.

[33] 96 FERC ¶ 61,137 (2001).

[34] Ex. KR-45 at 5.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

and the Commission accepted, the same regulatory asset treatment as it accepted in the settlement described above.[35]

17. In May 2003, Kern River completed another expansion project. This 2003 Expansion included approximately 700 miles of pipeline and expanded the capacity of the pipeline to 1,755,626 Dth/day.[36] Kern River priced these services on an incremental basis and again permitted shippers to chose either 10-year or 15-year firm contracts.

18. On April 30, 2004, Kern River filed a general rate case under section 4 of the Natural Gas Act, 15 U.S.C. § 717c (2000), in accordance with its obligation under the 1999 settlement in Docket No. RP99-274-000.[37] Kern River used a test period consisting of a base period of the twelve months ending January 31, 2004, as adjusted for known and measurable changes occurring through October 31, 2004. The Commission accepted and suspended the rates subject to refund, conditions, and hearing.[38] The rates went into effect November 1, 2004.[39] The hearing was held from August 17, 2005 through August 26, 2005. The ALJ issued her Initial Decision on March 2, 2006.[40]

II. Levelized Rates/Levelized Cost of Service Proposal

A. General

19. Kern River proposes to continue using the levelization methodology and cost of service rate principles approved in the original Kern River certificate,[41] the extended term (ET) rate settlement,[42] the 2003 Expansion certificate,[43] and the prior Kern River rate

---

[35] 96 FERC 61,137, at 61,591 (2001).

[36] 100 FERC ¶ 61,056 (2002), *order on reh'g*, 101 FERC ¶ 61,042 (2002).

[37] 87 FERC ¶ 61,128, *order on reh'g*, 89 FERC ¶ 61,144 (1999).

[38] 107 FERC ¶ 61,215, *order on reh'g*, 109 FERC ¶ 61,060 (2004).

[39] Unpublished Letter Order (October 27, 2004).

[40] 114 FERC ¶ 63,031 (2006) (ID).

[41] *Kern River Gas Transmission Co.*, 50 FERC ¶ 61,069 (1990).

[42] *Kern River Gas Transmission Co.*, 92 FERC ¶ 61,061 (2000), *reh'g denied*, 94 FERC ¶ 61,115 (2001).

[43] *Kern River Gas Transmission Co.*, 100 FERC ¶ 61,056 (2002).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

case settlements, [44] with modifications. As described above, the levelized rates approved in Kern River's certificate included separate, levelized rates for three different periods, (1) the term of the firm shippers' initial contracts, (2) the period from the expiration of those contracts to the end of Kern River's depreciable life, and (3) the period thereafter. The levelized rates for the first period (hereafter Period One Rates) were designed to recover 70 percent of Kern River's invested capital, an amount approximately equal to the portion of its invested capital funded through debt. Since this would allow Kern River to recover more invested capital during Period One than it would under ordinary straight-line depreciation for the depreciable life of its system, the rates for the second two periods (hereafter Period Two and Period Three Rates) were lower than for the first period. Subsequent Kern River rate proceedings have continued this same methodology, as updated to reflect (1) the extended terms of the original shippers' contracts and longer overall depreciable life of the original system provided for in the 2000 ET Settlement, and (2) the new contracts of the 2002 and 2003 expansion shippers and the Big Horn Lateral contracts.

20. In this case, Kern River proposes to continue to design its rates using this levelized cost of service methodology, with a few modifications.[45] All of Kern River's firm shippers subject to levelized rates are still paying Period One Rates.[46] Accordingly, as in

---

[44] *Kern River Gas Transmission Co.*, 70 FERC ¶ 61,072; *Kern River Gas Transmission Co.*, 90 FERC ¶ 61,124 *order on reh'g*, 91 FERC ¶ 61,103 (2000).

[45] While Kern River previously used this method to levelize its entire cost-of-service, in this rate case it proposes to exclude compressor and general plant included. Other modifications to Kern River levelized cost of service methodology are discussed in subsequent sections of this order.

[46] As a result of the contractual options presented to the shippers through the various expansions of Kern River's system, the contract expiration profiles as of November 1, 2004, the end of the adjustment period in the instant proceeding, were as follows:

> Original system – 10-year contracts (remaining term of 6 years, 11 months); Original system – 15-year contracts (remaining term of 11 years, 11 months); 2002 Expansion – 10-year contracts (remaining term 7 years, 6 months); 2002 Expansion – 15-year contracts (remaining term 12 years, 6 months); 2003 Expansion – 10-year contracts (remaining term 8 years, 6 months); 2003 Expansion – 15-year contracts (remaining term 13 years, 6 months); and Big Horn Lateral contracts (remaining term 13 years, 2 months). Negotiated rate contracts pertaining to the High Desert Lateral

(footnote continued)

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

the tariff sheets implementing the 2000 ET Settlement, Kern River only proposed to set forth Period One Rates in its tariff. Consistent with the existing levelized cost of service methodology, Kern River designed the Period One rates to recover 70 percent of its invested capital on a levelized basis over the life of its various firm transportation contracts.[47]

21. Because Kern River's firm contracts expire on seven different dates, Kern River proposed different levelized rates for each of the seven groups of contracts. Thus, there are different proposed rates for (1) original firm shippers with 10-year contracts, (2) original firm shippers with 15-year contracts, (3) 2002 expansion shippers with 10-year contracts, (4) 2002 expansion shippers with 15-year contracts, (5) 2003 expansion shippers with 10-year contracts, (6) 2003 expansion shippers with 15-year contracts, and (7) Big Horn Lateral shippers.[48] The rates of the first four groups of shippers are based on the rolled-in cost of service of the original system and the 2002 expansion. The rates of the 2003 expansion and Big Horn shippers are based on the incremental costs of their expansion projects.

22. Kern River's proposed book depreciation rates, based on the economic lives of its various groups of facilities, are sufficiently low that none of its facilities will be 70 percent depreciated on its books as of the end of the relevant shipper contract terms. Thus, at the end of their contract terms, all the shippers will have paid more of Kern River's plant costs than it will have depreciated on its books. Thus, consistent with the requirement in Kern River's certificate orders that it account for differences between (1) depreciation amounts charged to expense on its books and (2) amounts recovered through rates as regulatory assets and liabilities, the proposed Period One rates for each group of shipper would generate a regulatory liability by the end of their contract terms. That regulatory liability would be subtracted from rate base for purposes of designing

---

under a traditional depreciation methodology also have a remaining term of 13 years, 2 months. Ex. KR-45 at 4, 7.

[47] Ex. KR-45 at 3.

[48] While rates are proposed for each of the seven groups of contracts, several groups of contracts have identical rates. For example, original firm shippers with 10-year contracts and 2002 expansion shippers with 10-year contracts each pay the same rate. Additionally, original firm shippers with 15-year contracts and 2002 expansion shippers with 15-year contracts each pay the same rate (*See* Eighteenth Revised Sheet No. 5 and Fourteenth Revised Sheet No. 5-A to Kern River's FERC Gas Tariff, Second Revised Volume No. 1).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

Period Two rates, thereby reducing the Period Two rates below the level of the Period One rates.

Initial Decision

23. The ALJ described Kern River's levelized cost-of-service/ratemaking methodology as "depreciation-based." The ALJ explained that Kern River's proposed methodology relied on varying the annual depreciation expense to arrive at equal cost-of-service for each year of the levelized period and maintained that initial depreciation-based levelized rates are lower than traditional cost-of-service/ratemaking beginning rates. The ALJ reasoned that this levelization keeps initial rates from being prohibitive to pipeline customers and promotes the construction of new pipelines.[49]

24. The ALJ stated that Kern River's position was that its proposed levelized methodology allows it to meet the demands of California's enhanced oil recovery (EOR) producers for the lowest transportation rate achievable while still maintaining the ability to cover its debt costs, recoup its operating expenses, and earn a fair return on its equity investment. The ALJ noted that Kern River claimed that its levelized methodology has produced many customer benefits[50] and that Kern River pointed out that the Commission has reviewed and accepted its levelization methodology numerous times.[51]

25. As to other parties, the ALJ noted that Commission Trial Staff (Staff) and BP Energy Company (BP) opposed Kern River's levelized rates arguing that traditional rates will be more transparent, more likely to remain in effect over the long term, and less susceptible to control and manipulation by Kern River. Staff contended that under the levelization methodology, Kern River over-collects an average of $42 million each year in depreciation expense from its 10-year and 15-year shippers. Staff concludes this over-collection is a result of a regulatory depreciation rate of 4.28 percent, which is more than

---

[49] ID at P 256.

[50] ID at P 244. Among the benefits claimed by Kern River and noted by the ALJ were: lower return requirements due to rate base averaging in the levelization calculations; declines in rate base each year of the levelization periods; high debt capitalization and lower early years of the contracts; and, no recovery of equity investment until after the contracts expire. *Id*.

[51] *See Kern River Gas Transmission Co.*, 50 FERC ¶ 61,069 at 61,149-51 (OC Order); *Kern River Gas Transmission Co.* 58 FERC ¶ 61,073, at 61,242 (1992) (OC Rate Order); *Kern River Gas Transmission Co.* 92 FERC ¶ 61,061, at 61,155-59, 61,161 (2000); *Kern River Gas Transmission Co.* 96 FERC ¶ 61,137, at 61,591 (2001); *Kern River Gas Transmission Co.* 98 FERC ¶ 61,205, at 61,721-22 (2002) (2003 Expansion).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

double the booked depreciation rate of 2 percent. Staff also argued that Kern River's levelized methodology is overly complex. BP argued that Kern River's levelization methodology is inconsistent with Kern River's useful life, and that Kern River's debt service obligations are not synchronized with the timing of the cash it receives.

26. The position of various other parties including the Rolled-in Customer Group (RCG) was that Kern River should use a modified version of levelized cost-of-service/ratemaking methodology which corrects the alleged over-recovery of depreciation problem with Kern River's methodology.

27. The ALJ found that Kern River has carried its burden of proving that its levelized cost-of-service/ratemaking methodology would produce just and reasonable rates (subject to certain limited changes discussed later in this order).[52] The ALJ stated that Kern River's levelized cost-of-service/ratemaking methodology has achieved the goal of lower initial rates, an obvious benefit to shippers, and that Staff's proposed traditional cost-of-service/ratemaking methodology would cost $38.6 million more than does application of Kern River's levelized methodology.[53] The ALJ also found that there was no proof that application of the levelized methodologies proposed by RCG and Southern California Generation Coalition (SCGC) yielded more favorable rates than did Kern River's methodology.[54]

28. In analyzing claims that Kern River's levelization methodology resulted in "over-recovery" or "over-collection" of depreciation expense, the ALJ found that such allegations are not legitimate because Kern River keeps track of depreciation recovered from ratepayers in a reserve account. As depreciation expenses are projected to be recovered each levelized year, Kern River recognizes such collections in accumulated depreciation and an appropriate adjustment is made to rate base.[55]

III. <u>Briefs on Exceptions and Opposing Exceptions</u>

29. Various parties, including Staff and BP, argue that the ALJ erred in rejecting the use of traditional depreciation methodology for Kern River's system. They argue that the ALJ erred in finding that Kern River's levelized methodology can produce just and reasonable rates. Kern River filed a brief opposing exceptions challenging these claims.

---

[52] ID at P 253.

[53] ID at P 257.

[54] *Id*.

[55] ID at P 258.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

30. The Staff contends that Kern River's levelized rate methodology over-recovers costs and creates intergenerational inequities and inequities between the existing 10 and 15-year shippers on Kern River's system.[56] The Staff argues that traditional rates would be more transparent, more likely to remain in effect over the long term, and less susceptible to manipulation by Kern River.[57] The Staff and BP argue that Kern River's certificated levelized rate design is extremely complex, no longer functions as originally intended, and therefore, should be supplanted by the traditional cost of service methodology.

31. The Staff argues that to design transportation rates to recover 70 percent of plant investment over the initial (10-year or 15-year) contracts may have been appropriate to establish Kern River's initial certificate rates, but that these short contract lives do not provide a just and reasonable basis for establishing depreciation rates that underlie the transportation rates for Kern River's existing and future shippers.

32. Staff argues that the Commission certificated this rate design methodology with the intent that Kern River, after 15 years, would be able to retire its debt and, thereafter, the project would be capitalized with 100 percent equity.[58] However, Staff points out that Kern River's Original System will not recover 100 percent of its debt by the end of its 15-year levelization period.[59] Staff argues that Kern River apparently is not using all of its current cash flow to retire debt.[60] Staff argues that instead of paying down the debt principal from the funds already collected from the original firm shippers, Kern River has used the money to pay dividends to its then parent, the Williams Company.[61] Staff argues that to saddle its customers with the resulting unretired debt would be an unwarranted double recovery by Kern River.[62] Thus, Staff argues that the two major

---

[56] Staff Brief on Exceptions at 6-7.

[57] *Id*. at 9.

[58] Staff Brief on Exceptions at 10, *citing* Ex. S-12 at 14.

[59] *Id., citing* Ex. KR-23 at 19.

[60] *Id., citing* Ex. S-27 at 5; Ex. KR-50 at 21.

[61] *Id., citing* Ex. S-27 at 9.

[62] *Id., citing*, Ex. S-27 at 9; Ex. KR-37 at 2; Ex. KR-35 at 1. Specifically, Staff argues that Kern River has two large balloon payments ($105,000,000 and $108,262,000) due its lenders at the end of the respective 10-year and 15-year contract terms. Staff argues that Kern River's levelized rate design, as certificated, assumed this debt would be retired on time. However, it points out that Kern River has given no guarantee that these

(footnote continued)

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

claimed benefits of the levelization methodology, *i.e.*, having the debt paid off at the end of the contract periods and thereafter removing its costs from rates, will not be realized.

33. Further, the Staff argues that under its levelized approach, Kern River over-collects an average of $42,590,732 each year in depreciation expense from its 10-year and 15-year contract shippers. The Staff argues that this is because the regulatory depreciation rate (4.28 percent) is more than double the booked depreciation rate (2.00 percent).[63] The Staff argues that if Kern River does not return the over-payment to the shippers at the end of the ten-year contracts, Kern River would be required to design future rates for the next generation of customers taking into account the over-collection of depreciation dollars from the earlier generation (since there is no dispute that the economic life of Kern River will exceed the current ten- and fifteen-year contract lives).[64] The Staff argues that Kern River wants to have all the front-load collection benefits of the levelization rate design but then not have to live up to its bargain of assuring shippers they will not be required to pay for a portion of Kern River's debt cost twice.[65]

34. BP argues that Kern River's levelization methodology harms the shippers on the system because it results in an overcollection of depreciation reflected in Kern River's rates by $500 million by the end of shippers' contract terms relative to rates that accurately reflect Kern River's 35-year depreciable life. Second, BP argues that Kern River's version of levelization overcollects more than $140 million that Kern River has treated and can treat as equity withdrawals over and above Kern River's debt service requirements, even though Kern River's certificate order was premised on the deferral of equity recovery until the step-down rates went into effect.[66] In contrast, BP argues that the benefits of levelization, the step down of rates after Period One, is tenuous and is unlikely to be received by the shippers. Therefore, BP argues that this complex and non-transparent methodology should be reversed.

---

balloon payments will be made on time from funds already collected from its ratepayers for this purpose. Ex. S-28. It also asserts that Kern River has not proposed lower rates to take effect at the end of the levelization period. Ex. S-27 at 10. Staff argues that Kern River benefits from the balloon payment because it generates an over-recovery of $109,884,969 for 2004 alone. Staff Brief on Exceptions at 42, *citing* Ex. S-12 at 16, as corrected, Tr. 1484. Ex. S-27 at 10.

[63] *Id*. at 11, *citing* Ex. S-36 at 58.

[64] Staff Brief on Exceptions at 11-12, *citing* Ex. S-7 at 51-54.

[65] *Id.* at 12, *citing* Ex. S-7 at 56-57.

[66] BP Brief on Exceptions at 12, *citing Kern River Gas Transmission Co.*, 50 FERC ¶ 61,069, at 61,150 (1990).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

35. BP argues that Kern River's rates reflect a regulatory depreciation rate that will recover 70 percent of its initial transmission plant costs from shippers by the end of their present respective contract maturities, *i.e.*, within the next 5 to 12 years.[67] BP argues that the regulatory liability accrued by Kern River in the later years of its levelized methodology will not evenly match the regulatory asset built up in the early years of the facilities' operation.[68] Rather, it argues that Kern River's regulatory liability not only will extinguish the regulatory asset, but ultimately will dwarf it under the levelized depreciation methodology. Accordingly, BP argues that at that time Kern River will have accrued approximately $500 million in net aggregate regulatory liabilities at the end of the respective levelization periods. BP asserts that Kern River claims, and the ALJ apparently agrees, that these regulatory liabilities will be returned to shippers through future reduced step-down rates on the Kern River's system.

36. BP argues that the Commission's policies have reduced, or eliminated, the value of any step-down in rates by Kern River.[69] BP argues that in the 1999 Policy Statement, the Commission specifically recognized that where a pipeline has incremental rates, its existing customers exercising the right of first refusal (ROFR) rights at the conclusion of their contracts may be required to match competing bids up to the pipeline's maximum rate in order to retain their capacity on the pipeline's system.[70] BP argues that this re-subscription process arguably could require commitment by shippers seeking the "step-down" benefit of their bargain to offer to re-subscribe for an indefinite period in order to preclude other shippers from capturing the capacity. BP argues that the Commission must either recognize that its current policies can strip purported beneficiaries of the step-down rate benefit of their levelization bargain (requiring implementation of a traditional rate design), or the Commission must establish that current Commission policies do not

---

[67] BP Brief on Exceptions at 13, *citing* Ex. BP-1 at 29:1-14.

[68] BP Brief on Exceptions at 13, *citing* Tr. at 1434:6-1437:24.

[69] BP Brief on Exceptions at 14, *citing Policy Statement Concerning Certification of New Interstate Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999) (1999 Policy Statement), Order No. 637, Reg. Preamble, FERC Stats & Regs. ¶ 31,091 (2000), and Order No. 637-A, Reg. Preamble, FERC Stats & Regs. ¶ 31,099 (2000).

[70] *Id.*, *citing* 1999 Policy Statement, 88 FERC ¶ 61,227, at 61,746-47. Additionally, BP argues that Order No. 637 stated that "a shipper [on an incremental rate pipeline which is fully subscribed] . . . could be required to match a bid [for capacity] up to a maximum rate higher than the historic maximum rate applicable to its capacity," Order No. 637 at 31,337-38, rather than a lower stepdown rate originally offered as justification for levelization's accelerated overcollection of depreciation from existing shippers. *See also* Order No. 637-A at 31,629-30.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

apply to Kern River and its shippers so that shippers over the next 5 to 12 years have a claim to step-down rates.

Commission Determination

37. The Commission affirms the ALJ's finding and, for the reasons discussed below, finds that Kern River's rates should continue to be designed based on the levelized methodology approved in its certificate proceeding and updated in the 2000 ET Settlement and subsequent proceedings. However, the Commission will require that Kern River include in its tariff the Period Two rates that will take effect when the firm shippers' existing contracts expire. This will assure that these shippers will obtain the benefit of the lower Period Two rates if they continue service beyond the terms of their existing contracts.

38. The Commission has previously considered, in *Mojave Pipeline Co*., 81 FERC ¶ 61,150 (1997) (*Mojave*), a similar issue concerning the continuation, in a subsequent NGA section 4 rate case, of a levelized rate methodology agreed to in an optional expedited certificate. In that case, the Commission stated:

> In order to satisfy the Commission's regulations, an applicant for an optional certificate, such as Mojave, must be willing to assume the economic risks of the project. Therefore, a central issue when an application for an optional certificate is considered, is whether the proposed rates reflect an appropriate allocation of proceeding with a project as between the pipeline and its customers. Mojave's levelized rate structure was agreed to during its certificate proceeding; that levelized rate structure, including its schedule of plant recoveries, was obviously a key aspect of the allocation of the risks of Mojave's project as between it and its customers . . . Although there is a divergence between debt retirement (70 percent in the first 15 years) and plant cost recovery (79 percent in the first 15 years), this divergence was present in the optional certificate as approved, and *the Commission will not lightly change the allocation of risk inherent in the optional certificate as granted*. Since we find no overarching policy reason that would impel the Commission to alter the debt or plant recovery percentages so as to make them identical, we reject the Firm Customers' request for such an alteration. *Id.* at 61,682-683. (emphasis added) (footnote omitted).

39. The same reasoning applies equally to Kern River. The Commission granted an optional expedited certificate to Kern River and Mojave at the same time.[71] Both

[71] 50 FERC ¶ 61,069 (1990); 58 FERC ¶ 61,073 (1992), *order on reh'g*, 60 FERC ¶ 61,123 (1992).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

pipelines proposed the same levelized rate methodology in their certificate applications with 70 percent of the invested capital to be recovered during the initial contract terms to coordinate with the pipeline's payment of their debt. The Commission considered the two pipelines' rate proposals in tandem using virtually identical language to approve each.[72] Consistent with our holdings in Mojave's Docket No. RP95-175-000 NGA section 4 rate case, we hold that in Kern River's instant rate case, it may and should continue the levelized rate model agreed to in its certificate proceeding and subsequent proceedings.[73]

40. Generally, under Kern River's levelization methodology, annual depreciation recovery in rates starts very low and increases during the levelization period as the return component of the cost-of-service decreases (in tandem with the declining total rate base) to obtain a constant or "level" annual cost of service.[74] In the early years of the levelization period, regulatory depreciation (*i.e.*, the amount of depreciation expense approved for recovery in rates) is less than book depreciation (the product of the approved book depreciation rates times gross plant in service), and the cumulative differences in those amounts are recorded as a regulatory asset.[75] The benefits of using a

---

[72] *Compare*, 50 FERC ¶ 61,069, at 61,151-153, 58 FERC ¶ 61,074, at 61,248-51 (1992), and 60 FERC ¶ 61,123, at 61,436-38 (1992), approving Mojave's initial rate with 50 FERC ¶ 61,069, at 61,149-51, 58 FERC ¶ 61,073, at 61, 242-44 (1992), and 60 FERC ¶ 61,123, at 61,436-38 (1992), approving Kern River's initial rates.

[73] 81 FERC ¶ 61,150 (1997), *order on reh'g*, 83 FERC ¶ 61, 267 (1998).

[74] In discussing Kern River's levelized methodology as set forth in its certificate application, the Commission observed:

> [t]he above plant costs recoveries vary from year to year because they are calculated using a present value methodology. The varying plant cost recoveries are analogous to the principle repayment on a fixed rate mortgage on a house. In the early years of the mortgage, most of the payment is applied to the interest and very little goes toward principle, whereas, in the latter years, most of the payment goes toward the principle, and the interest portion is relatively small. 58 FERC ¶ 61,074, at 61,244, fn.38.

[75] The regulatory asset is a rate base account that represents invested capital that has not yet been recovered in rates. In the latter years of levelization, when annual regulatory (rate) depreciation begins to exceed book depreciation, the regulatory asset is gradually reduced and, eventually, exhausted. Thereafter, annual regulatory depreciation that exceeds book depreciation will be recorded as a regulatory liability, which will be a reduction to rate base.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

levelized methodology are that shippers benefit from rates being lower during the early years after the project goes into service, than they would be under a traditional rate design. The pipeline benefits by securing construction loans as well as competing with other well established pipelines in the area charging low rates.

41. Other parties, such as BP and Staff, champion a traditional rate design for recovering depreciation on Kern River's system. Under a traditional rate design, the cost-of-service reflects the rate base level existing at the end of the test period.[76] As a result, traditional ratemaking generates rates applicable to future periods based on past period data and does not take into account future declines in the rate base as depreciation is recovered. Therefore, traditional rate design rates start high. Subsequently, the rates would decline as the rate base declines but this would occur only if the pipeline files a new NGA section 4 rate case.

42. As set forth above, the Commission approved levelized rates for Kern River in the past. In the Commission's view, the depreciation recovery under levelized rates is, by necessity, a long term proposition. In essence, the pipeline defers recovery of depreciation, which would otherwise be recoverable in the early years, relying on the assurance that it will be able to recover these costs in later years. Since this trade off is at the heart of any levelization plan, it is inherent in any such plan that the levelized rate will remain in effect for the entire agreed upon period.

43. In this case, Kern River refinanced its project in the year 2000, after the levelized rates initially went into effect and agreed with its customers in the 2000 ET Settlement to, in effect, "reset the clock" for the recovery of 70 percent of invested capital. The Commission accepted the refinancing settlement which extended recovery of the debt cost beyond the original periods contemplated when the pipeline was certificated. As a result, shippers are still in the initial stages of their contract lives and are receiving the benefits of reduced depreciation collection in the early years of contract lives which results in lower rates to the shippers. As of November 1, 2004 (*i.e.* the end of the test period), shippers with 10-year and 15-year contracts still had remaining contract lives ranging from 6 years to 13 years.[77]

44. Therefore, the Commission finds that the levelization methodology must remain in place for shippers to realize the benefits bargained for as a part of the refinancing settlement.

---

[76] *See* Ex. KR-45 at 18.

[77] Ex. KR-45 at 4.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

45. Indeed, Kern River has correctly shown upon comparison of comparable cost data that Staff's traditional cost-of-service is approximately $40 million greater than Kern River's levelized cost-of-service.[78] This study reflects that under Staff's traditional cost-of-service methodology, depreciation expense is approximately $16 million greater,[79] return is approximately $15 million greater,[80] and federal income tax is approximately $10 million greater[81] than under Kern River's levelized methodology. Further, an additional study submitted by Kern River reflects that when depreciable life is adjusted to 26 years and return on equity (ROE) remains at 15.1 percent, Staff's cost-of-service under the traditional ratemaking methodology is $65 million greater than Kern River's levelized approach.[82] The Commission finds that these studies prove that when factors such as ROE level and depreciable life are held comparable, Kern River's levelization methodology provides lower rates to shippers than the traditional methodology.

46. As previously described, in both Kern River's certificate proceeding and the 2000 ET Settlement, the parties agreed that the Period One levelized rates would recover approximately 70 percent of Kern River's invested capital during the term of the shippers' current contracts.[83] However, Kern River's book depreciation rates, based upon the economic lives of its various groups of facilities, are sufficiently low that its facilities will not be 70 percent depreciated on its books at the end of the relevant shipper contract terms. Thus, at the end of their contract terms, the shippers will have paid more of Kern River's plant costs than it will have depreciated on its books.

47. The Staff and BP argue that, as a result, Kern River's Period One rates over-collect an average of $42 million each year in depreciation expense. The Commission agrees with the ALJ's findings that Kern River keeps track of its recovered depreciation

---

[78] Ex. KR-47, Study B revised at 3. Under this study, Kern River has adjusted Staff's proposed ROE from 9 percent to 15.1 percent to align the ROE proposed by Kern River.

[79] *Id*. at line 6.

[80] *Id*. at line 8.

[81] *Id*. at line 9.

[82] Ex. KR-47 at 5, Study C revised.

[83] Kern River testifies that a recovery of 70 percent of capital investment over the primary term of the firm service agreements has been Kern River's practice since the establishment of initial, levelized rates in Kern River's original certificate proceeding. *See* Ex.KR-36.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

from ratepayers in a separate account, thereby preventing Kern River from over-collection.[84] As depreciation expenses are projected to be recovered by Kern River in each year within the levelization rate model, Kern River recognizes such collection in accumulated depreciation and that a corresponding adjustment is made to rate base.[85] Further, Kern River records annual book depreciation as an addition to Account No. 108 (Accumulated Depreciation Expense), and a regulatory asset or liability is booked for the difference between the annual regulatory depreciation expense it recovers in rates and the book depreciation expense it records in Account No. 108. [86]

48. In the early years of Period One, when Kern River's rates recover less than its book depreciation, Kern River records a regulatory asset. But in the later years, when its accumulated regulatory depreciation exceeds its accumulated book depreciation, the regulatory asset will become a regulatory liability and serve to lower its Period Two rates. The Commission finds that this process is in concert with the Commission's Uniform System of Accounts and therefore, does not permit Kern River to over-collect its depreciation expense. The provision for Kern River to recover 70 percent of its invested capital in the Period One rates effective during the shippers' contract terms has been a part of its levelized model from the beginning. This was intended to permit Kern River to pay off its debt during that period. As we held in *Mojave*, the pipeline and its capital providers rely on this provision in deciding to proceed with the project.[87]

49. Further, the Commission finds that Staff's argument that Kern River is not using all of its cash flow to retire its debt and BP's argument that Kern River is receiving an accelerated repayment of its equity investment contrary to the Commission's intent are without merit. Regardless of whether debt or equity is to be paid down through the collection of depreciation, the pipeline may only collect the regulatory costs included in its rates. Kern River's Period One firm rates in the instant case are designed to collect an amount equal to 70 percent of the investment in the subject facilities, which coincides with the amount of debt used to finance such facilities.[88] Moreover, the Commission has

---

[84] ID at P 258;Ex. KR-50 at 21.

[85] Ex. KR-50 at 21.

[86] *Id*.

[87] *Mojave Pipeline Co*., 81 FERC ¶ 61,150, at 61,638 (1997).

[88] Kern River testifies that the levelized calculations do not project actual costs in a manner that exactly reflects the pipeline's debt payment obligations and that its "levelized calculations are not intended to reflect the actual timing of the payments of debt principle (a timing of payments to lenders concept). Therefore, the levelized

(footnote continued)

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

recognized that there may not be an exact correlation between the debt amortization schedule and the schedule of plant cost recoveries through the allowed regulatory depreciation.[89] Subsequently, the step-down rates will be designed by Kern River to recover only the remaining 30 percent of the costs of the facilities, which will coincide with the amount of equity Kern River originally placed into the project.[90]

---

calculations do not and should not reflect the indenture's schedule for debt principle payments." Ex. KR-23 at 40-41.

[89] *Mojave*, 81 FERC at 61,681-83. In *Mojave*, similar to this case, the pipeline's rates were intended to enable it to recover substantially all of its debt capital (70 percent of its invested capital) during the first 15 years and its equity capital during the next 10 years. However, Mojave's effective rates reflected a schedule of plant cost recoveries that would recover approximately 79 percent of its rate base during the first 15 years of operations. The Commission found that Mojave's levelized rate structure was agreed to during its certificate proceeding and that the levelized rate structure, including its schedule of plant recoveries, was a key aspect of the allocation of the risks of the project and the appropriate schedule of plant cost recoveries was considered with some care during the certificate proceeding, where all parties had an opportunity to express their views. The Commission found that although there was a divergence between debt retirement (70 percent in the first 15 years) and plant cost recovery (79 percent in the first 15 years), such divergence was present in the optional certificate it approved, and the Commission stated that it would not lightly change the allocation of risk inherent in the optional certificate.

[90] Even in approving this levelized method in Kern River's initial certification proceeding the Commission did not mandate the recovery of debt in any particular time frame; it only observed that "[t]his rate structure will enable Kern River to recover all of its debt service during the first 15 years and to recover its return of equity *primarily* during the second period. Debt service is levelized throughout the first period, while the depreciation schedule is maintained at 25 years. Kern River will assume the risk of any depreciation not recovered in the first 15 years." 50 FERC at 61,069. (emphasis added). The Commission also discussed the recovery of plant balances in a subsequent order amending Kern River's certificate for its original facilities. 58 FERC ¶ 61,073 (1992). In that order, the Commission observed that "the levelized rate structure will enable Kern River to recover substantially all of its debt capital during the first 15 years and its equity during the next 10 years." *Id*. at 61,242. The Commission also stated that:

> Kern River's rates are designed to recover enough plant costs to allow Kern River to repay most of its original debt capital which is 70 percent of its capital structure, in the first 15 years. Therefore, when added together, the plant recoveries for the first 15 years approach 70 percent. The rates are

(footnote continued)

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

50. Further, in the design of the step-down rates, the issue of whether Kern River has previously collected enough revenue to retire its debt related to this service will not be relevant, as this rate will only be calculated based upon the 30 percent of the costs corresponding to the equity Kern River used to finance its system. For like reasons, the Commission also rejects arguments that a possible refinancing of the balloon debt payments will negate the benefits of levelization. Although Kern River maintains that its existing contracts are the only security for its debt and, as such, Kern River is obligated to pay all of its debt at or before the termination date of its current firm shippers' contracts,[91] as stated, the step-down rates available to the shippers upon the termination of their contracts will only be calculated based upon the 30 percent of costs related to the original equity position taken by Kern River.

51. BP argues that the benefit provided by the step down of Kern River's rates is tenuous and that the Commission's policies place the shippers' ability to receive this benefit in jeopardy. However, BP has not fully considered the Commission's statements regarding its policies in light of the facts of the instant case. In the 1999 Policy Statement and in Order Nos. 637 and 637-A, the Commission discussed ROFR procedures under which a shipper with an expiring contract may be required to pay a price higher than its previous maximum contract rate in order to keep its capacity. In the 1999 Policy Statement, although primarily focused on pricing issues related to new construction, the Commission discussed certain policies related to the roll-in of costs related to the expansion of a pipeline and stated:

> also designed to recover enough plant costs to allow Kern River to recover its original equity capital, which is 30 percent of the capital structure during the next 10 years. . . . Thus, Kern River's rates are designed to recover approximately 70 percent of its capital in the first 15 years and its remaining capital in the last 10 years. *Id*. at 61,244 (footnote omitted).

[91] Kern River Brief on Exceptions at 32, *citing* Ex. KR-23 at 42:9-16, 43:7-11. Kern River explains that it expects its capital structure "to include a significant debt component after the end of the shipper's contracts. This reflects Kern River's plan to roll over some debt, similar to the current balloon payments as a part of a refinancing at the time the last of the current shippers' contracts terminate." However, Kern River goes on to explain that because it is contractually obligated to pay off its debt within the levelization periods and because it is uncertain whether any debt will be refinanced it "is appropriate and necessary to ensure that the levelized rates produce sufficient revenue to pay off the debt in full in accordance with the terms of the indentures." Ex. KR -23 at 42-43.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

> [A]nother instance where a form of rolling in would be appropriate is where a pipeline has vintages of capacity and thus charges shippers different prices for the same service under incremental pricing, and some customers have the right of first refusal (ROFR) to renew their expiring contracts. Those customers could be allowed to exercise a ROFR at their original contract rate except when the incremental capacity is fully subscribed and there are competing bids for the existing customer capacity. In that case, the existing customer could be required to match the highest competing bid up to a maximum rate which could be either an incremental rate or a "rolled-up rate" in which costs for expansions are accumulated to yield an average expansion rate. 88 FERC at 61,746-47.

52. Subsequently, in Order No. 637-A, the Commission stated that:

> [I]n Order No. 637, the Commission explained that, consistent with the holding in the Policy Statement concerning Certification of New Interstate Natural Gas Pipeline Facilities (Certificate Policy Statement), the maximum rate that the existing shipper must meet in order to exercise its right of first refusal may be higher than its current rate *in certain very limited circumstances*, *i.e.*, where a shipper has a right of first refusal on a pipeline that has vintages of capacity and thus charges different prices for the same service under incremental pricing, the pipeline is full, and a competing shipper bids a rate for the capacity that is above the existing shipper's current maximum rate. *In addition, in order to charge a higher rate than the previous maximum rate, the pipeline must have in place an approved mechanism for reallocating costs between the historic and incremental rates so all rates remain within the pipeline's cost of service*. Order No. 637-A at 31,635- 36. (emphasis added)

53. Therefore, this policy only contemplates certain limited circumstances. In the instant case, it appears that the pipeline has different vintages of capacity, and it is difficult to determine whether the pipeline will be full at the time that the subject contracts expire. Even more speculation would be necessary to determine whether a bidder would be likely to outbid an existing 10 or 15-year shipper for its expiring capacity. However, as stated above, in order to charge a higher rate than the previous maximum rate, the pipeline must have in place an approved mechanism for reallocating costs between the historic and incremental rates so all rates remain within the pipeline's cost of service. No party argues that such a mechanism is in place on Kern River's system or that Kern River is considering such a mechanism. Kern River states that it has

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

no such mechanism.[92] Therefore, BP's concerns that the Commission's policies would inhibit the shippers' step-down benefits are without merit.[93]

54. However, the Commission's original and subsequent approvals of the levelized methodology for Kern River were premised on the eventual availability of the step-down of rates bargained for by the shippers. In the instant proceeding, this step-down benefit of the lower Period Two rate remains an essential component of Kern River's proposal. Here, parties argue that Kern River's proposed rates are complex and are not transparent. While the Commission finds that these claims are overstated, in the Commission's view, all of Kern River's proposed rates should be easily ascertained. For example, in the Commission's order accepting Kern River's initial use of the levelized methodology, the Commission required Kern River to file tariff sheets setting forth the Period One rates it proposed to charge for the first 15 years of its project, the Period Two rates it proposed to charge for years 16-25 and the Period Three rates to be charged thereafter.[94] This action permitted all parties to know what rates were to be in effect at any given time on Kern River's system and assured that the reduced rate would take effect upon the agreed to dates. Therefore, the Commission directs Kern River to file revised tariff sheets setting forth its currently proposed rates based upon the instant cost of service as well as the rates and effective date of the step-down rates to be available to its 10 and 15 year shippers. Absent further action pursuant to sections 4 or 5 of the NGA, the rates as set forth will become effective, as noted, as a component of the filed rate accepted by the Commission.

55. Parties argue that, even if stepdown rates were implemented, shippers would still not receive the benefit of their bargain because Kern River's unilateral changes to its levelization methodology, including the acceleration of compressor engine depreciation

---

[92] Kern River Brief on Exceptions at 40-41.

[93] Moreover, as the Commission stated in Order No. 637-A:

> [P]rocedures for approving such a mechanism will allow interested petitioners to participate, and settlements can be taken into account in determining whether a particular methodology is just and reasonable on a particular pipeline. Order No. 637-A at 31,141.

Therefore, even if Kern River proposed such a mechanism in the future, Kern River would be required to show that the possible denial of stepdown rates to its 10 and 15-year customers would be just and reasonable.

[94] *Kern River Gas Transmission Co.*, 50 FERC ¶ 61,069 at 61,150-51 (1990).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

which Kern River proposed to carve out from levelization for the first time in this proceeding, change the terms of the levelization "bargain." [95]

56. Kern River argues that certain compressor engines and general plant should be removed from the levelized methodology because they constitute short-lived assets and are retired at a faster rate than Kern River's longer-lived transmission facilities. Therefore, Kern River argues that applying the levelized depreciation rates to these short-lived assets results in their retirement and replacement long before Kern River can recoup its capital investment in such facilities. BP and Pinnacle West Capital Corporation (Pinnacle West) argue that Kern River's proposal to remove compressors and general plant from its levelized methodology and to collect depreciation for these expenses using a straight line depreciation methodology is unwarranted and inconsistent with the levelized depreciation methodology.

57. As the Commission stated earlier, the plan for recovery of depreciation is by nature a long-term proposition. As the Commission has found, Kern River will be permitted to maintain its levelized depreciation methodology as originally accepted by the Commission and revised by the agreement of the parties to the ET Settlement. The Commission understands Kern River's argument that this levelized methodology may not be uniquely suited for the precise recovery of all depreciation for all facilities, but this is the method that Kern River originally proposed, and the Commission accepted, and that all parties have relied upon. The Commission will not now permit Kern River to continue its preferred method of depreciation for most of its assets while at the same time consider its argument that it might benefit to a greater extent if certain facilities were excluded from the levelized methodology and treated to a more advantageous depreciation recovery methodology. For its part, Kern River states that, if the Commission determines that keeping compressor engines and general plant in the calculation of the levelized cost of service is essential for its acceptance of Kern River's levelized methodology, Kern River would be willing to forego its proposal to remove these categories of plant from the levelzation calculations.[96] The Commission so finds, and Kern River is directed to include these amounts in its levelized methodology calculations.

58. RCG and SCGC argue that that Kern River should use a modified version of levelized cost-of-service/ratemaking methodology. However, based upon the discussion above, the Commission finds that Kern River's proposal, as modified, is just and

---

[95] BP Brief on Exceptions at 15-16, *citing*, Ex. CES-86; Tr. 288:13-17.

[96] Kern River Brief on Exceptions at 37.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

reasonable. Therefore, the Commission need not consider whether RCG and SCGC's proposed levelized rate methodology would also be just and reasonable.[97]

A. Shipper Rate Differential

Initial Decision

59. The ALJ found that Kern River carried its burden of proving that the distinction in rates between the ten-year and fifteen-year shippers produces just and reasonable rates.[98] The ALJ also found that different rates are merited for shippers with contracts that expire in 2011 and shippers with contracts that expire in 2016 because the former "bargained for the option of paying rates that included more depreciation expense."[99] The ALJ reasoned that "[t]he bargained-for benefit for the ten-year shippers [*e.g.*, with contracts expiring in 2011] is that they qualify for the lower, stepdown rates . . . sooner than do the fifteen-year shippers." [100] The ALJ concluded that the different rates for 10 and 15-year shippers must be maintained in order to avoid any disruption of the expectation of the signatories to these contracts.[101]

Briefs on Exceptions and Opposing Exceptions

60. The Staff argues that Kern River's proposal to require its customers with 10-year contracts to pay higher rates than shippers with 15-year contracts is inequitable and discriminatory.[102] The Staff argues that it is unfair to require unique and excessive debt payments from the 10-year shippers that are burdened with the same amount of debt as the 15-year shippersStaff argues that the Natural Gas Act requires that shippers receiving similar service should pay similar rates.[103] Further, it argues that this differential is discriminatory because rates should be designed based on the use of the system and not

---

[97] *Consolidated Edison Co. v. FERC*, 165 F.3d 992, 998, 1002-4 (D.C. Cir. 1999) and cases cited therein.

[98] ID at P 479.

[99] ID at P 480.

[100] *Id.*

[101] *Id.*

[102] Staff Brief on Exceptions at 14-15.

[103] Staff Brief on Exceptions at 79, citing *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332 (1956).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

on the length of the contracts.[104] Staff concludes that since contracts can be extended, renewed or replaced by another contract, they cannot be relied upon to accurately reflect the remaining life of the facility. Pinnacle West also supports the position taken by Staff.

61. BP also argues that there is no valid justification for customers who subscribe to the same facilities for the same service at the same priority under the same rate schedule to pay different rates. BP argues that the shippers whose contracts expire in 2011 receive precisely the same quality of service that shippers whose contracts expire in 2016 receive, yet they pay significantly higher rates and that this unlawfully discriminates between various shippers on Kern River's system based solely upon differences in contract expiration dates.[105] BP also argues that the ALJ's rationale for maintaining the rate differential ignores the fact that shippers have no assurance that the bargain for lower stepdown rates will be honored.

Commission Determination

62. On exceptions, the parties have argued that shippers receiving similar service utilizing the same facilities should pay the same rates for service. The Commission's role under the NGA is to ensure that the rates offered and accepted as a result of individual negotiations are just and reasonable and not unduly discriminatory.[106] The Supreme Court has held that the purpose of the NGA was not to "abrogate private contracts to be filed with the Commission" and that the NGA "expressly recognized that rates to particular customers may be set by individual contracts."[107] Therefore, not all differentiations in rate treatment are unreasonable or illegal. Rather, "[it] is only when a preference or advantage accorded to one customer over another is undue or a difference in service as

---

[104] *Id.*at 15, *citing* Ex. S-35 at 20.

[105] BP Brief on Exceptions at 48-52.

[106] *United Gas Pipeline Co. v. Mobile Gas Service Corp. (Mobile),* 359 U.S. 332 at pp. 338-39 (1956); *FPC v. Sierra Pacific Power Co. (Sierra),* 350 U.S. 348 (1956). NGA section 4 prohibits natural gas companies subject to the Commission's jurisdiction from:

> (1) making or granting any undue preference or advantage to any person or subjecting any person to any undue prejudice or disadvantage, or (2) maintaining any unreasonable difference in rates, charges, service, facilities or in any other respect, either as between localities or as between classes of service.

[107] *Mobile,* 350 U.S. 332 at 338-39.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

between them is unreasonable that . . . [the undue discrimination provisions] of the Act come [ ] into play." [108]

63. Moreover, in *Cities of Bethany, et al v. FERC*, [109] the Court of Appeals found that the "mere fact of a rate disparity [between customers receiving the same service] does not establish unlawful rate discrimination" under the NGA, and that "rate differences may be justified and rendered lawful by facts - cost of service or otherwise."[110] Relying on the Supreme Court's decisions in *Mobile* and *Sierra*, the court held that the anti-discrimination mandate of NGA section 4(b) should not be interpreted as "obliterating the public policy supporting private rate contracts" between natural gas pipelines and their customers. [111] Therefore, it is clear that pipelines may provide different rates to different customers based upon different circumstances.[112]

64. Here, the Commission cannot find that the rate disparity is unduly discriminatory or preferential. No party on exceptions argues that the shippers on Kern River's system

---

[108] *Michigan Consolidated Gas Co. v. FPC*, 203 F.2d 895, 901 (3rd Cir. 1953).

[109] 727 F2d. 1131 (D.C. Cir. 1984).

[110] *Id.* at 1139. Thus, the court observed that fixed rate contracts between the parties may justify a rate disparity, *citing, Town of Norwood v. FERC*, 587 F.2d 1306, 1310 (D.C. Cir. 1978); *Boroughs of Chambersburg, et al. v. FERC*, 580 F.2d 573, 577 (D.C. Cir. 1978) (per curium). *See also, United Municipal Distributors Group v. FERC*, 732 F.2d 202 (D.C. Cir. 1984).

[111] *Id.*

[112] Consistent with this statutory scheme, the Commission has authorized natural gas companies to negotiate individualized rates with particular customers under its discounted rate, *See Policy For Selective Discounting By Natural Gas Pipelines*, 113 FERC ¶ 61,173 (2005), and negotiated rate programs. *See Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines, Regulation of Negotiated Transportation Services, Statements of Policy and Comments*, 74 FERC ¶ 61,076 (1996), *order on clarification*, 74 FERC ¶ 61,194 (1996), *order on reh'g*, 75 FERC ¶ 61,024 (1996). In addition, in the Commission's 1999 *Policy Statement Concerning Certification of New Interstate Natural Gas Pipeline Facilities* (1999 *Pricing Policy Statement*) 88 FERC ¶ 61,227 (1999), *order on clarification*, 90 FERC ¶ 61,128 (2000), *order granting further clarification*, 92 FERC ¶ 61,094 (2000), the Commission encouraged pipelines to negotiate risk sharing agreements with shippers participating in a new project regarding the effect of cost overruns and underutilized capacity on rates for the proposed construction of facilities. 88 FERC ¶ 61,128 at 61,747.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

were not permitted a choice concerning the length of their contract term and the rate treatment associated with that choice. In essence, 10-year Shippers were given the option of obtaining 15-year contracts but voluntarily chose 10-year contracts retiring 70 percent of the project's costs for a 10-year term in order that they might receive step down rate benefits after their contract terminated. Conversely, 15-year Shippers chose rates that retired the same amount of costs over 15 years and deferred the benefit of step down rates until the termination of their contracts. Based on their choices, these two classes of shippers are not similarly situated and the rates for the services they choose need not be similar.[113] The Commission cannot find that the pipeline, in giving all shippers an opportunity to elect various rate options, is now unduly discriminating against shippers based on the fact that some of its shippers chose different rate options than other shippers.

B. 95 Percent Load Factor Billing Determinants for the Original System

65. When the Commission certificated Kern River's original system under the optional expedited certificate procedures adopted in Order No. 436, the Commission required Kern River's rates to be designed based on volumes equal to 95 percent of its design capacity.[114] This has been referred to as the 95 percent load factor condition. Its purpose was to place the risks of underutilization of capacity on Kern River.[115] The Commission rejected Kern River's request for permission to design its rates based upon an 85 percent load factor. The Commission pointed out that it had already imposed a 95 percent load factor condition in the optional expedited certificates of two competing pipelines, Mojave and WyCal,[116] and the three pipelines should "be accorded

---

[113] Whether a shipper now believes that it might have fared better in choosing another option is not at issue. As the court found in *Exxon Mobil Corp. v. FERC*, 430 F.3d 1166, 1177 n.7 (D.C. Cir. 2005), a company "is not typically 'entitled to be relieved of its improvident bargain.'" *Transmission Access Policy Study Group v. FERC*, 343 U.S. App. D.C. 151, 225 F.3d 667, 710 (D.C. Cir. 2000) (quoting *Sierra*, 350 U.S. at 355). "Despite recent cynicism, sanctity of contract remains an important civilizing concept"; moreover, "'the general rule of freedom of contract includes the freedom to make a bad bargain.' *Morta v. Korea Ins. Corp*., 840 F.2d 1452, 1460 (9th Cir. 1988) (citations omitted). While BP may now regret choosing 10-year service, "'wise or not, a deal is a deal,'" and therefore "people must abide by the consequences of their choices." *Id*. (alteration in the original) (citations omitted).

[114] *Kern River Gas Transmission Co.,* 50 FERC ¶ 61,069, at 61,150 (1990).

[115] *Id.*.

[116] *Wyoming-California Pipeline Co*., 45 FERC ¶ 61,234, at 61,687 (1989) (*WyCal I*) and *Mojave Pipeline Co*., 47 FERC ¶ 61,200, at 61,697 (1989).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

comparable regulatory treatment"[117] in order to "compete on a level playing field."[118] Finally, the Commission required that Kern River make a tariff filing three years after its in-service date either justifying its existing rates or proposing alternative rates, and that the filing "must use the same or greater throughput levels on which Kern River's initial rates have been predicated."[119]

66. In Kern River's Order No. 636 restructuring proceeding, the Commission permitted Kern River to continue to design its rates based on the 95 percent load factor condition.[120] However, the Commission stated that, in light of the required shift to an SFV rate design, the 95 percent load factor condition may serve little purpose, and therefore in Kern River's next section 4 rate case, "the parties may consider removal of the 95 percent throughput condition so that costs may be allocated based upon actual projected volumes instead of 95 percent of design capacity."[121]

67. Kern River states that, in the 1995 settlement of its Docket No. RP92-226-000 section 4 rate case[122] and the 1999 settlement of its Docket No. RP99-274-000 rate proceeding,[123] the parties agreed to design its rates using reservation billing determinants equal to 96 percent of its Original System's design capacity.[124] The 2000 ET Settlement provided for continued use of those same billing determinants.[125]

68. In this case, since at least 2002, Kern River has had firm contracts for 100 percent of the capacity of its Original System.[126] Nevertheless, Kern River proposed to continue to design its rates for Original System firm shippers using demand and commodity billing

---

[117] 50 FERC at 61,150.

[118] *Id.*

[119] *Id.* at 61,151.

[120] 64 FERC ¶ 61,049, at 61,418 (1993).

[121] *Id.*

[122] *Kern River Gas Transmission Co.*, 70 FERC ¶ 61,072 (1995).

[123] *Kern River Gas Transmission Co.*, 87 FERC ¶ 61,128 (1999).

[124] Ex. KR-17 at 15.

[125] 92 FERC ¶ 61,061, at 61,157 (2000).

[126] Exs. S-27 at 18; S-22.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

determinants equal to 95 percent of the design capacity of its Original System, arguing the 95 percent load factor condition capped its billing determinants at that level.[127]

Initial Decision

69. The ALJ concluded that Kern River had not carried its burden of proving that continued use of the 95 percent load factor rate design for the Original System produces just and reasonable rates. According to the ALJ, the original purpose of the 95 percent load factor rate design, which was to place the risk of lack of full subscription on the new pipeline rather than on shippers, does not now apply. More specifically, the throughput requirement is intended as a floor to the throughput/design determinants to keep the pipeline at risk of at least that level of contract entitlements in its rates. The ALJ stated that Kern River has been fully contracted on the Original System since its inception and has operated above a 100 percent load factor design level for more than a decade. The ALJ found that Kern River's 95 percent load factor does not produce just and reasonable rates, since the amounts of guaranteed revenue attained by Kern River above the designed-for-revenue requirement of the pipeline were between $5.4 and $7.8 million annually- essentially a built-in rate design over-collection. Since the 95 percent load factor was not to be a windfall for the pipeline, the ALJ determined that the 95 percent requirement should be dropped, leaving the normal test period ratemaking concepts to govern the rate determinants for Kern River.

Briefs on Exceptions and Opposing Exceptions

70. Kern River urges the Commission to reverse the Initial Decision and approve Kern River's proposal, asserting that its longstanding 95 percent load factor rate design for the Original System is a critical component of Kern River's levelized cost-of-service methodology. Kern River argues that its levelization methodology is a package which Kern River, its shippers, and lenders agreed to in arms-length negotiations in order to allocate the risks and rewards of the construction of its original system, and which the Commission approved in the certificate order. Since Kern River relied on the overall package in deciding to proceed with the project, it contends that the entire package should remain in place, including the 95 percent load factor condition.

71. Kern River argues that the 95 percent load factor condition gives it an opportunity to offset other aspects of the levelization package that depress its revenues. Kern River asserts that the use of a levelized rate base and the *Ozark* capital structure method both produce a lower equity rate base, and thus a lower return allowance, than would occur under a traditional rate calculation. However, designing its rates based on 95 percent of

[127] Ex. KR-17 at 11, 15-16.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

design capacity allows it to obtain some additional return if it is able to exceed the 95 percent load factor level. Kern River therefore, argues that under the ALJ's ruling it could no longer have a reasonable opportunity to earn its allowed return. Kern River takes exception to the ALJ's findings[128] that Kern River's proposal provides a "built-in rate design over-collection[129] and is not just and reasonable. Kern River claims that it continues to face the potential of unsubscribed capacity and the risks of remarketing that capacity in the future. Kern River also claims that the Commission's orders requiring a continuation of Mojave's similar 95 percent load factor condition[130] supports its position to maintain the 95 percent load factor condition.

72. Several parties and Staff all oppose Kern River's exception and support the ALJ's decision. The RCG states that Kern River's proposal conflicts with Commission regulations,[131] precedent, and violates sections 4 and 5 of the NGA. Basing the billing determinants for the design of just the original system component of rolled-in rates on the 95 percent load factor condition, constitutes undue discrimination against one class of customers and results in unjust and unreasonable rates. Several parties argue that the 95 percent load factor condition permits Kern River to over-recover costs from its shippers on the original system component of the rolled-in system. BP argues that Kern River has, in conflict with the Commission's order,[132] been computing the load factor as 95 percent of firm shipper *contracted* capacity (*i.e.,* MDQs) rather than as a percentage of actual system *physical* capacity, which has increased Kern River's overrecovery.[133]

73. Several parties and Staff argue that Kern River erroneously relies on outdated Commission precedent[134] and that *Mojave* is not controlling. BP and the RCG assert that *Mojave* is distinguishable on several grounds.

---

[128] *See* ID at P 444, 509.

[129] ID at P 510.

[130] *Mojave,* 81 FERC at 61,683-84.

[131] 18 C.F.R. § 284.10(c)(2) (2005) (that pipelines' transportation rates must be based on "projected units of service.")

[132] *Kern River Gas Transmission Co.,* 50 FERC ¶ 61,059, at 61,146 (1990).

[133] Ex. BP-42 at 15:22-16:7.

[134] 66 FERC 63,014 (1994).

74. BP, the RCG, and Staff, argue that the Initial Decision's rejection of Kern River's 95 percent load factor rate design is supported by the record and should be upheld by the Commission. BP and the RCG argue that much has changed since the issuance of Kern River's optional expedited certificate, including the balance of risk and reward, and that the 95 percent load factor is not necessary to ensure that Kern River has the opportunity to earn its allowed return. Further, Staff and BP argue that Kern River cannot claim that its levelization "package" is inviolable when the change is not to its liking yet at the same time seek changes to its levelization "package" when doing so benefits Kern River.

75. Several intervenors state that the ALJ appropriately recognized that the 95 percent load factor condition was meant to be a floor and not a permanent condition of Kern River's rates.

Commission Determination

76. We affirm the result reached by the ALJ, although for somewhat different reasons. We agree with Kern River that the 95 percent load factor condition imposed by Kern River's optional expedited certificate was a part of the allocation of risks as between the pipeline, its customers and lenders approved by the certificate order. Consistent with our holding earlier in this order requiring a continuation of the levelized rate methodology approved in the certificate proceeding, we also hold that the 95 percent load factor condition should continue in effect. Therefore, the rates for Original System shippers should be designed consistent with the 95 percent load factor condition imposed by our orders in Kern River's optional expedited certificate proceeding.

77. However, where we part company with Kern River is in the interpretation of what the 95 percent load factor condition requires. We interpret the 95 percent load factor condition as requiring that Kern River design its original system rates based upon *at least* 95 percent of its design capacity. We see nothing in the certificate orders to support Kern River's assertion that the 95 percent load factor condition also capped its rate design volumes, so that in future section 4 rate cases it could continue to design its Original System rates based upon 95 percent of design capacity, even when it obtained contracts for more than 95 percent of design capacity. In the same certificate order imposing the 95 percent load factor condition, the Commission also required Kern River to make a tariff filing three years after its in-service date either justifying its existing rates or proposing alternative rates under NGA section 4. The Commission stated, "That filing must use the same *or greater* throughput levels on which Kern River's initial rates have been predicated."[135] This language is consistent with our interpretation of the 95 percent load factor condition as only establishing a floor on Kern River's rate design volumes. If

[135] 50 FERC at 61,151 (emphasis supplied).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

the Commission had intended that the 95 percent load factor condition also act as a cap on Kern River's rate design volumes, there would have been no reason to include the phrase "or greater" in the requirement concerning the throughput to be used to design Kern River's rates in the future tariff filing required by the certificate order.

78. This interpretation of the 95 percent load factor condition is buttressed by the fact it carries out the intent of the Commission's then effective optional expedited certificate regulations. In the certificate order,[136] the Commission began its discussion by pointing out that Kern River had applied for an optional certificate and therefore the Commission would examine its application in view of the optional certificate regulations, citing sections 157.100 through 157.106 of the Commission's regulations.[137] Section 157.103(d)(3) of those regulations provided, "Any rate filed for new service must be designed to recover costs on the basis of projected units of service. The units projected for the new service in the initial rates filed under this subpart may be increased in a subsequent rate filing but may not be decreased." Order No. 436 explained that the purpose of this requirement was to help ensure that the applicants for such certificates were "willing to assume the full responsibility of their ventures."[138] Thus, the optional expedited certificate regulations required that such certificates include a floor on the rate design volumes to be used to design the pipeline's rates in future rate cases as a means of ensuring that the pipeline assumed the risk of the project. The regulations did not provide for any cap on the rate design volumes in order to give the pipeline a reciprocal opportunity to increase its profits above the return allowed in its rates. To the contrary, the regulations required that rates be designed based on projected units of service, subject only to the proviso that rate design volumes not be "decreased" below the level set in the certificate.

79. The language of the Commission order granting Kern River's certificate and imposing the 95 percent load factor conditions is fully consistent with section 157.103(d)(3) of the optional certificate regulations, particularly the requirement that in its next tariff fling Kern River use "the same or greater throughput levels." If the Commission had intended to depart from the optional certificate regulations and permit Kern River to design its rates based upon 95 percent of its design capacity even when its projected units of service exceeded that level, the Commission would have more expressly stated that intent.

---

[136] *Id.*, at 61,149.

[137] 18 C.F.R. §§ 157.100-157.106 (1989). Ex. BP-77.

[138] Ex. BP-78. *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 436, 50 Fed. Reg. 42,408 (1985).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

80. Kern River points to no specific language in the orders granting its optional expedited certificate to support its claim that the 95 percent load factor condition acts as a cap as well as a floor on its rate design volumes. Rather, it relies on (1) provisions in its precedent agreements with two of its original shippers[139] and (2) language in subsequent orders issued by an ALJ and the Commission. Kern River's reliance on the two precedent agreements is misplaced. Those two contracts, which were entered into in 1989 before the Commission issued Kern River's certificate, simply provided that neither Kern River nor the shipper would seek to change the use of a 95 percent load factor for rate design purposes as set forth in the particular contracts and in Kern River's certificate application, without the consent of the other. However, those contractual provisions only govern the positions the parties to the contract would take concerning rate design in subsequent proceedings. The contracts did not purport to bind the Commission to any particular action, and in fact, as discussed above, the Commission's subsequent certificate order actually adopted only a 95 percent load factor floor on rate design volumes.

81. Second, Kern River relies on an initial decision issued in its Docket No. RP92-226-000 section 4 rate case, in which the ALJ held that the 95 percent load factor condition required that Kern River's rates be designed based upon 95 percent of capacity, even when its projected units of service exceeded that level.[140] However, the Commission later approved a settlement of that rate case and vacated the initial decision, as provided in the settlement.[141] In any event, the ALJ's analysis of this issue was contrary to our discussion above.

82. Finally, Kern River relies on the Commission's orders in a section 4 rate proceeding filed by Mojave Pipeline Co.[142] Mojave's optional expedited certificate also contained a 95 percent load factor condition. In a subsequent Mojave section 4 rate case, shippers sought to increase Mojave's rate design volumes above 95 percent of its certificated design capacity, or 380 MMBtu. The shippers argued that this was appropriate because Mojave had firm contracts for 392.5 MMBtu. The Commission rejected the shippers' contentions, and approved Mojave's proposal to continue to design its rates based upon 95 percent of design capacity. Among other things, the Commission stated it was not clear that rates based on continued use of the 380 MMBtu figure would overrecover Mojave's cost-of-service, since Mojave's firm contracts had rate caps and

---

[139] Exs. KR-23 at 55-56; KR-41.

[140] 66 FERC ¶ 63,014, at 65,090 (1994).

[141] 70 FERC ¶ 61,072, at 61,180 (1995).

[142] *Mojave*, 81 FERC 61,150, at 61,683-4 (1997), *reh'g*, 83 FERC ¶ 61,267, at 62,110-3 (1998).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

other provisions that caused it to collect about $1,000,000 less per year than if it were able to charge its maximum rates.[143] By contrast, Kern River does not assert it has any similar contractual provisions that would prevent collection of the maximum rates established in this proceeding.

83. The Commission recognizes that *Mojave* did state that, while the 95 percent load factor condition in Mojave's certificate imposed on it a risk of underrecovery, "the reciprocal of that risk is that if Mojave is able to sell more than 95 percent of its capacity, then it is normally entitled to keep the balance for the term of the contracts."[144] To the extent this language may be read as interpreting 95 percent load factor condition in Mojave and Kern River's optional certificates as capping the rate design volumes at the 95 percent level, the Commission now believes that such an interpretation is incorrect. For the reasons discussed above, we find that the 95 percent load factor conditions in the certificate orders only set a floor on the rate design volumes.

84. We thus conclude that the ALJ correctly held that Kern River's rates should be designed based on projected units of service, consistent with the Commission's ordinary test period methodology, to the extent those projected units of service exceed the 95 percent load factor condition. As we stated in *Williston*, "rates for pipelines are based on actual data for a one-year base period, as adjusted to reflect known and measurable changes that will occur within the following nine months (adjustment period)."[145] In the present case, Kern River concedes that during the test period for this rate case it had firm contracts for 100 percent of its Original System capacity.[146] It points to no known and measurable change that occurred during the test period that would justify reducing its projected units of service below that level.

85. Kern River does argue that it "continues to face significant business risks associated with the near-term prospect of remarketing unsubscribed original system capacity."[147] Kern River Witness Smith[148] describes several risks Kern River faces due to past and possible future occurrences: the credit quality of Kern River's shippers, which

---

[143] *Mojave*, 83 FERC at 62,113.

[144] *Id*.

[145] *Id.*

[146] Ex. KR-86 at 12.

[147] Kern River Brief on Exceptions at 62.

[148] Ex. KR-12 at 16-24.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

was affected by the 2000-2001 California energy crisis and the Enron scandal; the possibility of supply constraints in the Rocky Mountain region; in the event of supply shortages and reduced demand, an exposure to throughput risk due to its rate design; and the possibility of being required to discount its rates, should competing pipelines expand or new projects be built. However, Kern River points to no loss of contract or throughput that actually occurred during the test period. It is well settled that the speculative risks described by Kern River's witness are not "known and measurable" as required by Commission policy and precedent.[149]

86. Therefore, as explained above, we reject Kern River's proposal to design its Original System rate using billing determinants equal to 95 percent of its design capacity. Instead, we adopt Staff's proposed demand billing determinants equal to 100 percent of Kern River's design capacity and commodity billing determinants equal to Kern River's actual throughput over the last 12 months of the test period.[150]

C. Inflation Factor for A&G and O&M Expenses

87. In order to levelize its Period One rates, Kern River first projects its annual costs of service for each of the years included in the levelization period, assuming it used a traditional ratemaking methodology. It then uses an iterative process to determine the variations in annual depreciation expense necessary to produce equal costs of service for each year.

88. In projecting annual costs of service for each year of the levelization period, Kern River has consistently included an inflation adjustment of 3 percent per year for its A&G and O&M costs. In its January 30, 1992 certificate amendment order, the Commission included a 3 percent per year increase in O&M and A&G expenses for years 1-15.[151] The Commission initially employed a slightly lower adjustment for years 16-25, but reverted to Kern River's position on rehearing.[152] In subsequent rate settlements[153] and the

---

[149] *Williston Basin Interstate Pipeline Co.* 87 FERC ¶ 61,265, at 62,021 (1999) (*Williston*) (citing 18 C.F.R. § 154.303 (2000)).

[150] Ex. S-12.

[151] Ex. 31 at 23; Ex. 36 in Docket No. RP92-226-000.

[152] *Id.*

[153] 70 FERC ¶ 61,072 (1994) (approving settlement filed October 19, 1994); 90 FERC ¶ 61,124 (2000) (approving settlement filed March 31, 1999); 92 FERC ¶ 61,061 (2000) (approving settlement filed June 13, 2000).

compliance filings to implement the initial rates for the 2002 and 2003 Expansions,[154] the Commission approved rates which reflected this same inflation factor in conjunction with Kern River's overall levelization methodology. In the instant filing, Kern River proposes to continue including an inflation factor that increases its O&M and A&G expenses at a rate of 3 percent per year.

Initial Decision

89. The ALJ concluded that Kern River had not carried its burden of proving that its proposed 3 percent inflation factor for O&M and A&G expenses produces just and reasonable rates. The ALJ determined that Kern River had not shown that it had experienced such inflation. The ALJ found that Calpine had effectively demonstrated that Kern River had incorrectly calculated its inflation rate and that the properly adjusted amounts showed no material inflation had occurred with respect to O&M and A&G expenses. The ALJ noted that while Kern River had opportunity to address Calpine's claim, it failed to do so.

Briefs on Exceptions and Opposing Exceptions

90. On exceptions, Kern River argues that the 3 percent inflation factor is a longstanding key component of Kern River's levelization package that should be retained. Moreover, Kern River claims that the Commission approved an identical 3 percent inflation factor in *Mojave* and that the record in this case fully supports retaining the 3 percent inflation factor. Kern River challenges Calpine's analysis of an inflation study submitted by Kern River witness Warner in order to show that Kern River's A&G and O&M costs have experienced inflation of about 3 percent. Kern River also challenges the accuracy of Calpine's own inflation study. Kern River further challenges arguments of the parties contending that Kern River's ability to make periodic section 4 rate increase filings permit it to recover increases in O&M and A&G expenses without the need for an inflation adjustment. Kern River claims that such filings would not offset or recoup Kern River's earnings lost to inflation between rate cases and defeats the objective and benefit of levelized rates. Kern River contends that the Initial Decision presents no valid factual or legal basis for changing Kern River's levelization methodology.

91. Staff and intervenors[155] argue that the ALJ's decision should be affirmed. They contend that Kern River's proposal is contrary to Commission policy, speculative, unsubstantiated, and leads to unjust and unreasonable results.

---

[154] 103 FERC ¶ 61,102 (2003) (order accepting compliance filing by Kern River for 2003 Expansion Project).

[155] BP, Calpine, High Desert, SCGC, and the RCG.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

92. Several intervenors argue that Commission policy precludes the use of an automatic inflation adjustment factor.[156] They point out that automatically changing rates by use of an index or periodic adjustment is prohibited by the Commission's regulations: "The tariff may not provide for any rate or charge to be automatically changed by an index or other periodic adjustment, without filing for a rate change pursuant to these regulations."[157] Moreover, use of an inflation factor to project costs has been consistently rejected by the Commission, as contrary to the known and measurable changes contemplated by its regulations.

93. Several intervenors contend that Kern River's reliance on *Mojave* is misplaced.[158] In *Mojave*, the intervenors explain, the Commission approved the reduction of an annual inflation adjustment from 5 percent to 3 percent, noting that the 3 percent inflation factor did "not appear unreasonable given the current economy and the levelized rate methodology authorized in the certificate."[159] Intervenors assert that in the instant case, Kern River is not proposing to reduce its inflation adjustment and the ALJ has already determined that the 3 percent inflation factor "would not produce just and reasonable rates because Kern River has not shown that it has had such inflation."[160] According to the RCG, the rate impacts are not comparable because the shippers in *Mojave* had negotiated rate caps, which protected them from the effects of an automatic escalator.[161]

94. RCG also argues that, while *Mojave* and earlier Kern River decisions before the Commission "may stand for the proposition that an inflation factor is generally permissible when establishing levelized rates over the entire useful life of the pipeline, such a rule should not be applied to Kern River, which files to adjust its rates on a regular basis."[162] The RCG states that Kern River's practice of filing a rate case every five years

---

[156] Calpine Brief on Exceptions at 66-67; High Desert Brief on Exceptions at 18; the RCG Brief on Exceptions at 34; SCGC Brief on Exceptions at 12-13; Staff Brief on Exceptions at 49.

[157] 18 C.F.R. § 154.3 (2005).

[158] BP Brief on Exceptions at 22-23; Calpine Brief on Exceptions at 69; the RCG Brief on Exceptions at 32; SCGC Brief on Exceptions at 13-14.

[159] 81 FERC ¶ 61,150, at 61,680.

[160] Initial Decision at P 445.

[161] The RCG Brief on Exceptions at 32.

[162] SCGC Brief on Exceptions at 14.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

has permitted it to update its O&M and A&G costs at regular intervals to account for inflation. Given these rate adjustment filings, RCG asserts, the 3 percent inflation factor results in a double counting of inflation-related costs: inflation is recovered by the 3 percent increase built into the rates, and is also recovered by the multiple rate filings which have increased the same cost category.[163] The RCG claims it demonstrated that this double counting has permitted Kern River to significantly overrecover costs, and such overrecovery will continue if the 3 percent inflation factor is retained. The RCG contends it demonstrated that this is true even if Kern River experiences a 3 percent annual increase in costs due to inflation, which the RCG argues has not happened.

95. Calpine and BP argue that Kern River fails to substantiate that it has experienced increases in its A&G and O&M costs of 3 percent and thus has not shown a need for an automatic annual inflation adjustment.[164] Calpine argues that O&M expenses have been shown to either be on the decline, stable, or, in recent years, to be experiencing an average annual inflation rate of approximately 1 percent.

96. Calpine recommends that, should the Commission permit Kern River to retain an inflation adjustment as part of its levelization model, the inflation adjustment should be reduced to 1 percent consistent with Kern River's own reported experience with inflation.

Commission Determination

97. The Commission affirms the ALJ's decision on this issue, but based on somewhat different reasoning. We find that the levelized rate methodology approved in Kern River's original certificate proceeding does permit the use of an inflation factor in calculating its levelized A&G and O&M costs. However, in each subsequent section 4 rate filing, Kern River has the burden to justify its proposed adjustments to A&G and O&M to account for inflation. For the reasons discussed below, we find that in this case, Kern River has failed to meet its section 4 burden to support its proposed 3 percent inflation adjustment. Nor does the record contain sufficient support for the Commission to determine any specific inflation adjustment. Thus, the Commission denies any inflation adjustment in this case, without prejudice to Kern River seeking a properly supported inflation adjustment in its next section 4 rate case.

98. We recognize that Kern River's initial levelized rates, as approved in its certificate proceeding, included a 3 percent inflation adjustment in the calculation of the A&G and O&M component of its levelized cost of service.[165] Thus, an inflation factor may be

---

[163] The RCG Brief on Exceptions at 33.

[164] BP Brief on Exceptions at 23-24; Calpine Brief on Exceptions at 67-68.

[165] Ex. KR-49 at 3-4.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

considered a part of Kern River's approved levelized rate methodology, just as the Commission held in *Mojave*[166] that an inflation factor was part of that pipeline's approved levelized rate methodology. Moreover, the Commission does not consider the inclusion of such an inflation factor in the calculation of levelized rates to be contrary to Commission policy. As intervenors point out, no such inflation adjustment is permitted under a traditional rate design.[167] That is because, under traditional ratemaking, rates are determined based on best projection of the pipeline's annual cost-of-service on the day rates go into effect, without consideration as to how that cost-of-service may change in the future. However, levelized rates are based on projections of annual costs of service for each year of the levelization period. In projecting such future annual costs of service, it is reasonable to include an inflation factor for components of the cost-of-service for which the pipeline can make a reasonable projection of inflation.[168]

99. While the Commission's orders issuing Kern River's certificate approved the inclusion of an inflation factor for A&G and O&M costs in the formula used to determine Kern River's levelized rates, the Commission sees nothing in those certificate orders providing that the specific inflation factor to be used in subsequent section 4 rate cases would always be 3 percent. Indeed, the fact the Commission approved a reduction in Mojave's inflation factor from 5 percent to 3 percent in one of that pipeline's section 4 rate cases demonstrates that the inflation factor can change in subsequent section 4 rate cases. Thus, in this rate case, Kern River has the burden of demonstrating that its A&G and O&M costs will increase over the remainder of the levelization and justifying its projection of the annual inflation rate.

100. Moreover, in Kern River's certificate proceeding, the issue of how an inflation adjustment should be determined in a section 4 rate case, after levelized rates have been

---

[166] 81 FERC ¶ 61,150 at 61,680.

[167] *ANR Pipeline Co.*, 78 FERC ¶ 63,003 (1997) (*citing ANR Pipeline Co.*, 69 FERC ¶ 61,432, at 62,542 (1994)); *Panhandle Eastern Pipe Line Co.*, 68 FERC ¶ 63,008, at 65,094 (1994) (rejecting inflation adjustment to O&M expenses); *Columbia Gulf Transmission Co.*, 67 FERC ¶ 61,242, at 61,802 (1994) (rejecting Columbia's proposed inflation allowance as against Commission policy and comparing it to a prohibited tracker that allows a pipeline to change its rates without filing a section 4 rate case); *Williston Basin Interstate Pipeline Co.*, 56 FERC ¶ 61,104 at 61,371 (1991) (rejecting inflation factor applied to increase insurance expenses).

[168] *See Mojave*, 81 FERC at 61,180.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

in effect for a period of time, did not arise.[169] Thus, the certificate order left open the question of how to carry out an inflation factor in a section 4 rate case. As RCG points out,[170] the levelization of A&G and O&M costs has the effect of setting rates which reflect more A&G and O&M costs in the early years of the levelization period than the pipeline projects it will incur in those years. This excess recovery in the early years will then be offset by an underrecovery in later years when the levelized rate reflects less than the pipeline's projected A&G and O&M costs for those years. Thus, if a pipeline files a section 4 rate case during the first half of the levelization period, it will likely have recovered more A&G and O&M costs than it has thus far incurred. Since the purpose of allowing this excess recovery of A&G and O&M costs in the early years is to help fund the underrecovery of those costs in the later years of the levelization period, that existing excess recovery must be taken into account in determining the A&G and O&M costs to be included in the new levelized rate being established in the section 4 rate case. Otherwise, the pipeline would be permitted an overrecovery of its overall A&G and O&M costs for the levelization period, contrary to the purpose of the levelization methodology.

101. Thus, in this section 4 rate case, Kern River has a twofold burden in order to support its proposed inflation adjustment for its A&G and O&M costs. It must (1) show how its proposal takes into account any existing excess recovery of A&G and O&M costs, and (2) support its projection of the amount of inflation that will occur over the remainder of the levelization period. In this case, Kern River has failed to do either. Kern River has not proposed any method of taking into account any existing excess recovery of A&G and O&M costs in the determination of the A&G and O&M allowance to be included in the levelized rates proposed in this rate case. Indeed, Kern River has provided no information that would enable us to compare the allowance for such costs included in its past rates with the projected amount of such costs for each of the past years used to determine the allowance.

102. Kern River has also failed to provide evidence from which a reliable projection of future inflation of A&G and O&M costs could be made. In order to support its projection of 3 percent inflation, Kern River's Witness Warner compared system O&M and A&G expenses included in its Docket No. RP92-228 section 4 rate case, which took effect in 1993, with its updated test period O&M and A&G costs in this rate case for the entire Kern River system, including the 2002 and 2003 expansions.[171] In recognition of the fact

---

[169] Nor has that issue been addressed on the merits in Kern River's section 4 rate cases until this one, since those cases settled.

[170] Exs. RCG-18 at 29-30; RCG-23.

[171] Exs. KR-23 at 50-51; KR-26.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

that Kern River's post-1993 expansions had contributed to the growth of its O&M and A&G costs, the witness removed "Total Direct O&M Costs Related to Incremental Transmission." Based on this calculation, the witness asserted that Kern River's A&G and O&M costs related to its Original system had increased from $19,000,007 in 1993 to $26,407,000 today, or by an average of 2.86 percent per year since 1993.

103. While Witness Warner adjusted his figures to remove O&M costs related to its 2003 expansion, it is not clear that he made a sufficient adjustment to account for increased costs related to post-1993 expansions. First, the post-1993 expansions also include the rolled-in 2002 expansion and the California Action Project. Yet Kern River's witness proposed no adjustment to account for increased costs related to those expansions.[172] Second, while Kern River's witness removed O&M costs related to the 2003 expansion, he did not make any comparable adjustment to A&G costs. Calpine's witness pointed out that Kern River has allocated $9,981,187 of A&G expenses to its proposed 2003 Expansion incremental rates, and accordingly argued that those costs should be removed from the comparison of 1993 Original System A&G and O&M costs to current such costs. When those costs were removed, Calpine's analysis showed that O&M/A&G costs did not increase, as claimed by Kern River, but actually decreased from $19,000,007 to $16,426,240. Kern River responds that the $9.9 million amount referred to by Calpine's witness is half of its A&G costs, and asserts, "While the 2003 Expansion essentially doubled the size of Kern River's system, due to economies of scale and other efficiencies, it is inconceivable that the expansion doubled Kern River's A&G costs. On its face, therefore, Mr. Hughes' argument is counterintuitive."[173] While it may be counterintuitive that the 2003 Expansion doubled Kern River's A&G costs, we think it is equally counterintuitive to assume that a project which doubled Kern River's size had no effect on its A&G costs. Yet Kern River's estimate of 2.86 percent inflation is based on that assumption.

104. Kern River witness Warner's inflation analysis, attempting to demonstrate that Kern River has historically experienced inflation of O&M/A&G expenses at about a 3 percent annual rate since 1993, fails to justify the proposed 3 percent inflation adjustment. Calpine presented evidence that Kern River had improperly included $9,981,187 in A&G costs related to incremental facilities in its comparison. Kern River's arguments on exception are not persuasive. Kern River did not present evidence to dispute that the $9,981,187 should not be removed from the analysis. The

---

[172] Ex. CES-69 at 12.

[173] Kern River Brief on Exceptions at 65, citing Ex. KR-94, Stmt. A, at 2, lines 3 and 4.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

Commission agrees with Calpine that Kern River has failed to justify a 3 percent inflation adjustment.

105. In these circumstances, we are left with a record that does not support any inflation adjustment. Even assuming there was some basis to project a lesser amount of inflation than Kern River's unsupported claim of a 3 percent inflation, we would have no basis to determine to what extent the projected increase in future A&G and O&M costs should be offset by an existing excess recovery of such costs. We therefore affirm the ALJ's rejection of any inflation adjustment in this case. However, this is without prejudice to Kern River seeking to support such an inflation adjustment in a future section 4 rate case.

D. Capital Structure

i. Ozark Methodology

106. Kern River proposes to use an equity rate base approach to impute an average capital structure. The capital structure is derived, and subsequently projected, from Kern River's current actual debt and regulatory asset amounts throughout the levelization period for each customer class. Kern River's model projects the current per book end-of-test period invested capital including all regulatory assets (deferred depreciation). This methodology of determining the actual equity investment of a pipeline was first adopted in *Ozark*.[174] Kern River applies the Ozark methodology or equity rate base in order to reflect to each customer class the cost of debt and equity expense resulting from the levelized cost-of-service established in the original certificate proceeding.[175] As previously described, in the certificate proceeding, the Commission approved levelized rates that would permit Kern River to recover 70 percent of its invested capital during the terms of its shippers' initial contracts since Kern River financed 70 percent of its rate base through debt since this would enable Kern River to pay off its entire debt by the end of the shippers' initial contracts, leaving a rate base entirely financed by equity. Kern River states that in this rate case, it has continued to derive its capital structure for each year of the levelization period based upon the assumption that the depreciation expense

---

[174] *Ozark Gas Transmission Co.*, 32 FERC ¶ 63,019, *aff'd*, 39 FERC ¶ 61,142 (1985), *reh'g denied*, 41 FERC ¶ 61,207 (1987), *rev'd on other grounds sub nom.*, *Public Service Commission v. FERC*, 866 F.2d 487 (D.C. Cir 1989) (*Ozark*). The equity investment or equity rate base calculation is generally referred to as the "Ozark" methodology.

[175] OC Rate Order, 58 FERC at 61,243; *Kern River Gas Transmission Co.*, 98 FERC ¶ 61,205, at 61,722 (2002), *reh'g denied*, 100 FERC ¶ 61,056 (2002) (2003 Expansion PD)..

included in the levelized cost-of-service recovers debt costs first and recovers equity investment only after the levelization period.[176] Therefore, the rates produced by Kern River's levelization models are based on the average equity ratio over the levelization period.

107. The levelization calculations reflect the fact that, as Kern River re-pays debt principal, the debt portion of its capitalization declines and, accordingly, the equity portion of total capital (the equity ratio) increases over time. According to Kern River, while the increasing equity ratio over the levelization period has the effect of increasing the total levelized cost-of-service (equity is more expensive than debt cost), that effect is largely offset by the corresponding decline in the total rate base.[177] The end result is that the average equity ratio employed in Kern River's levelization models (38.01 percent, weighted by the annual rate base amounts during the levelization period) is lower than the actual, end-of-test period book equity ratio (38.73 percent).[178]

Initial Decision

108. The ALJ found that Kern River carried its burden of proving that its proposed capital structure, in conjunction with its levelized cost-of-service/ratemaking methodology, produces just and reasonable rates. The ALJ also found that Kern River carried its burden of proving that it is appropriately using the Ozark method. Central to the ALJ's determination was the fact that the Commission approved the use of the Ozark method in the optional certificate rehearing order, concluding that the Ozark method more accurately reflected the proposed rate structures of the projects over time. The ALJ explained that although the Commission reserved its right to reexamine in a later rate case the issue of whether use of Ozark remained appropriate, she found that in this case, the lawful debt costs and ROE have also been determined and will ensure that use of the Ozark method in calculating a levelized cost-of-service accurately reflects the proposed rate structures of the projects over time. The ALJ found that Kern River's models calculate the levelized cost-of-service based on a more leveraged, and therefore less costly, capital structure than Kern River's actual, end-of-test period capitalization and that the models are functioning appropriately based on evidence of the declining debt ratios throughout the project's levelization period.[179]

---

[176] Kern River Brief on Exceptions at 49.

[177] *See* Exs. KR-23 at 11-12, KR-38, KR-39, KR-50 at 11-13, KR-51 at 3-6, 11.

[178] Kern River Brief on Exceptions at 50*;* Ex. KR-27.

[179] ID at P 325-328.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

a. The Use of Equity Rate Base and the Ozark Methodology

Briefs on Exceptions and Opposing Exceptions

109. Staff opposes the levelized rate model including the use of the Ozark methodology. Staff suggests the Commission adopt a traditional cost-of-service approach utilizing a traditional end-of-test period rate base and capitalization amount in establishing its rates on a going forward basis.[180]

Commission Determination

110. We find that Kern River's application of the equity rate base, or Ozark methodology, is consistent with our prior rulings in Ozark and Mojave[181] because, as in those cases, one hundred percent of Kern River's debt is used to finance rate base. The Ozark method was originally developed for project-financed pipelines whose debt indentures required tariff provisions that track the debt principal repayment and interest payments. The Ozark levelization model is determined by calculating an equity return and associated income taxes based only on the remaining equity rate base of the utility over the life of the pipeline. The equity rate base is calculated by using the investment in plant as the first year and subtracting the amount of accumulated depreciation expenses, accumulated deferred income taxes, and outstanding debt balances in each year. A uniform return on equity is applied to the resulting rate base calculation. The associated income taxes are determined for each year over the remaining depreciable life of the pipeline.[182]

111. The Ozark method differs from the traditional cost-of-service model in that it assumes that all debt was raised to finance rate base. Thus in establishing the capitalization for the model, all outstanding debt is subtracted from the total rate base and the remainder is assumed to be financed by equity. In contrast, the traditional cost-of-service model applies an overall, weighted cost of book debt and equity (rate of return) to the entire rate base to determine an appropriate return allowance, thus assuming that both debt and equity are used to finance rate base proportionally through out the term of the project.

112. Staff contends that a traditional cost-of-service is more appropriate over-all than a levelized cost-of-service. Kern River responds to Staff by generally pointing out that it is

---

[180] Staff Brief on Exceptions at 7.

[181] 81 FERC ¶ 61,150, at 61,681-83.

[182] *Ozark Gas Transmission System,* 53 FERC ¶ 61,451, at 62,586 (1990).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

not required to use the Ozark method since its debt does not require a debt tracker, but that its application is valid since all of its debt has always been secured by its shippers' firm service agreements and thus is structured to be repaid in full within the primary terms of those contracts. Further, Kern River argues its levelization model provides for the recovery of its investment in utility plant through the recognition of annual depreciation expense (current and deferred) since these projects were financed on a project-specific basis. Kern River's models anticipate that the collection of depreciation for the early years included in the levelization will be used to pay debt principal first, such that the debt is paid in full by the end of the contract terms, which vary in this case. Equity repayment is deferred until after the obligations of the debt indenture are satisfied, i.e., paid in full within the required loan period.[183]

113. We find Kern River's application of the Ozark methodology appropriate and consistent with our rulings in the certificate proceeding.[184] We find that its application here is consistent with our application of the equity rate base methodology in the Ozark[185] and Mojave[186] proceedings where the pipeline is one hundred percent financed with debt exclusive to its operations and expansion projects. Additionally, we find the application of a traditional cost-of-service as proposed by Staff in fact increases shippers' rates without justification for the change from the pricing model originally adopted by the Commission in the certificate proceeding. Indeed, Kern River has correctly shown upon comparison of comparable cost data that Staff's traditional cost-of-service is approximately $40 million greater than Kern River's levelized cost-of-service.[187] This study reflects that under Staff's traditional cost-of-service methodology, depreciation expense is approximately $16 million greater,[188] return is approximately $15 million greater,[189] and federal income tax is approximately $10 million greater[190] than under Kern

---

[183] *See* Ex. KR-50 at 23-24; OC Rate Order, 50 FERC at 61,150.

[184] 60 FERC ¶ 61,123 at 61,437.

[185] 53 FERC ¶ 61, 451 (1990).

[186] 81 FERC at 61,681-83.

[187] Ex. KR-47, Study B corrected at 3. Under this study, Kern River has adjusted Staff's proposed ROE from 9 percent to 15.1 percent to align the ROE proposed by Kern River.

[188] *Id*. at line 6.

[189] *Id*. at line 8.

[190] *Id*. at line 9.

River's levelized methodology including its application of the Ozark methodology. Further, an additional study offered by Kern River reflects that when depreciable life is adjusted to 26 years and ROE remains at 15.1 percent, Staff's cost-of-service under the traditional ratemaking methodology is $65 million greater than Kern River's levelized approach.[191] These studies demonstrate that when factors such as ROE are level and depreciable life are comparable Kern River's levelization methodology provides lower rates to shippers than the traditional methodology.

b. Inputs to Ozark Calculation

Briefs on Exceptions and Opposing Exceptions

114. Parties except to the ALJ's finding that Kern River is appropriately using the *Ozark* method. RCG, BP, and SCGC argue that the ALJ erred in approving Kern River's use of an average annual capital structure. These parties advocate using only the actual end-of-test period capital structure throughout the levelization period with no projections for deferred amounts. These parties claim that the use of a hypothetical approach is inconsistent with Commission policy.

Commission Determination

115. Two arguments are presented. First, RCG's primary criticism of Kern River's levelization model is that it overstates equity by treating the amount of depreciation in each year as if that were the debt principal repayment, and reducing the annual debt balance accordingly.[192] RCG argues that Kern River will recover more in depreciation than it must pay out on debt on an annual basis and that even if these over-collections balance out; Kern has over collected by the time value of money of which it estimates to be $113.1.[193] Kern River counters that RCG's Exhibit RCG-21 is flawed because it uses average annual regulatory depreciation amounts, rather than the actual levelized regulatory depreciation amounts used in Kern River's models. Kern River argues that this distortion overstates the equity by not showing the proper deferrals from the earlier years.

116. We find that the record evidence does not support RCG's position. We find that RCG's study is flawed because it does not make an apples to apples comparison. RCG uses a significantly higher depreciation rate in the initial years of its study thus distorting

---

[191] Ex. KR-47, Study C corrected at 5.

[192] RCG Brief on Exceptions at 23.

[193] Ex. RCG-21.

timing differences, and increasing the results of any net present value calculation. Under the levelized cost-of-service model, all deferrals and the time value of money for such deferrals are treated as a regulatory asset. These deferrals are properly reflected in Kern River's model. This concept is fundamental to Kern River's over-all levelized rate methodology and recovery in rates over the entire levelization period.[194] Kern River provides several studies that demonstrate that its levelization models reasonably reflect the collection of the deferred costs and, therefore produce just and reasonable results.[195]

117. We also find the question of using the actual end-of-test period capitalization amount has previously been addressed by the Commission. There the Commission found that the use of an average capital structure properly reflects changes in the capitalization that will occur over the time the debt used to finance Kern River system is repaid.[196] We find that neither BP nor SCGC has shown any changed circumstances that require us to depart from our prior ruling. The average equity ratio in the levelization models is 38.01 percent, versus the actual-end-of-test period capital structure equity ratio of 38.73 percent.[197] We find that Kern River's continued application of the model we approved in the certificate proceeding properly reflects to each customer class the appropriate costs and impacts while the debt is being repaid. As such, based upon the evidence in the record we find that Kern River's projected capital ratios are an accurate reflection of the costs and therefore are reasonable for use in its levelization model.

c. The Use of Contract by Contract Capital Structure vs. The Use of One Average Capital Structure for All Customers

Briefs on Exceptions and Opposing Exceptions

118. RCG argues that the same capital structure should be applied in each of the levelization models to develop the rates for all shippers. RCG argues that Kern River will over-recover because Kern has received the time value of money of which it estimates to be $113.1 million over the remaining term of the shippers' contracts.

---

[194] *See* section Levelized Rates/Levelized Cost of Service, *supra*. *See* Ex.. KR-17 at 19; Ex. KR-23 at 22-23; Ex. KR-36; OC Rate Order, 50 FERC at 61,150; 2000 ET Settlement Order, 92 FERC at 61,156-57; 2003 Expansion PD, 98 FERC at 61,722.

[195] *See* Ex. KR-23; Ex. KR-24; Ex. KR-27; Ex KR-34; Ex KR-50.

[196] 60 FERC at 61,437.

[197] *See* Ex. KR-23 at 41; Ex. KR-27.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

Commission Determination

119. Kern River has developed individual rates based upon separately calculated equity rate base amounts for each customer class. The calculations are based upon the same levelization model but differ in that they reflect the customer's actual investment, debt, and deferral. Parties argue that the same constant or uniform capital structure should be applied to all customers regardless of customer contracts or class. Kern River points out that the impact of these recommendations generally results in increased rates or a cost shift from the Expansion shippers to the Rolled-in customers. Kern River quantifies these shifts stating Expansion shippers would experience a $5.7 million dollar increase in rates while the Rolled-in customers would receive a $1.3 million dollar rate decrease.[198]

120. We find that the record evidence demonstrates that Kern River's use of average capital structure in each levelization model or for each customer class is appropriate. Use of the same capital structure for all customers would alter each customer's cost responsibility under the existing contract and levelization model previously agreed to and adopted by the Commission. Kern River has developed rates for each customer class under levelization models that reflect the deferrals associated with the particular levelization model. We find no merit to arguments that an improper shift of the benefits occurs as a result of subsequent financing arrangements. A levelized cost-of-service requires that the deferrals that enable a pipeline to charge lower rates in the initial years of the levelization period are assessed to customers in the later years of the levelization period. As such, under the levelized model, a customer rates are higher in the later years than under a traditional cost-of-service. To relieve a customer of those deferrals by using an artificial reduced rate base would in fact shift costs (the early year's deferrals) to the Expansion shippers. Accordingly, the Commission finds Kern River has properly developed its capital structure for each customer group.

IV. Cost of Capital

121. We now turn to the issue of return on equity for Kern River. The Commission determines return on equity based on the Discounted Cash Flow (DCF) analysis. The DCF methodology is based on the premise that a stock is worth the present value of its future cash flows, discounted at a market rate commensurate with the stock's risk. Under the constant growth DCF formula used by the Commission, the cost of capital is equated with the dividend yield (dividends divided by market price) plus the estimated constant growth in dividends to be reflected in capital appreciation.[199] The Commission uses a

---

[198] *See* Ex. KR-51 at 10; Ex. KR-23 at 46-47.

[199] *Northwest Pipeline Corp.*, 79 FERC ¶ 61,309, at 62,378 (1997) (Opinion No. 396-B).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

two-step procedure to determine the projected growth in dividends of the proxy group companies, averaging short-term and long-term growth estimates. The Commission uses five-year Institutional Broker's Estimate System (IBES) growth projections for each proxy group company for the short-term growth projection. The Commission uses the growth rate of the Gross Domestic Product (GDP) as its long-term growth rate, since the Commission has found that pipeline-specific projections of long-term growth cannot reasonably be developed based on available data sources. The Commission averages these growth projections, giving two-thirds weight to the short-term growth projection and one-third weight to the long-term growth projection.[200] The DCF methodology produces a zone of reasonableness in which the pipeline's rate may be set based on specific risks.[201]

122. In this case, the parties have not disputed this basic methodology. The issues litigated by the parties center upon (1) the composition of the proxy group; and (2) where to place Kern River in the range of reasonable returns developed using the Commission's constant growth DCF model. The ALJ adopted the proxy group proposed by BP. The returns for that proxy group range from 7.31 percent to 13.62 percent, with a median of 9.34 percent. The ALJ determined that Kern River's return on equity should be set at the 9.34 percent median. Kern River excepts to the ALJ's holdings both with respect to the proxy group and its placement within the range, arguing that its return on equity should be substantially higher than 9.34 percent. Staff excepts to the ALJ's rejection of its proxy group proposal. For the reasons discussed below, the Commission grants in part Kern River's exceptions and adopts an 11.2 percent return on equity for Kern River. The Commission denies Staff's exception.

A. <u>Proxy Group</u>

123. The Commission has historically required that each company included in the proxy group satisfy the following conditions. First, the company's stock must be publicly traded. Second, the Commission has required that the company be recognized as a natural gas pipeline company and that its stock be recognized and tracked by an investment information service. Third, the Commission has required that pipeline operations constitute a high proportion of the company's business.[202] However, in recent years fewer and fewer companies have met these standards, because of mergers,

---

[200] *Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260, at P 215 (2002) (footnotes omitted).

[201] *Williston Basin Interstate Pipeline Co. v. FERC*, 165 F.3d 54, 57 (D.C. Cir. 1999).

[202] *Transcontinental Gas Pipe Line Corp.*, 90 FERC ¶ 61,279, at 61,933 (2000).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

acquisitions, and other changes in the natural gas industry. In a July 2003 order in *Williston Basin Interstate Pipeline Co.*,[203] the Commission found that only three companies remained that met the Commission's traditional standards for inclusion in the proxy group. In those circumstances, the Commission approved the pipeline's proposal to use a proxy group based on nine companies listed among the Value Line Investment Survey's group of diversified natural gas companies that own Commission-regulated natural gas pipelines. The Commission found that, based on the record in that case, those companies represented a functional proxy group to establish the pipeline's return on equity.

124. The Commission was again faced with the issue of an appropriate proxy group in *HIOS*,[204] and again used a proxy group based on the corporations listed among the Value Line Investment Survey's group of diversified natural gas companies that own Commission-regulated natural gas companies. The proxy group approved in *HIOS* consisted of four out of the nine companies used in *Williston*: Kinder Morgan, Inc. (KinderMorgan), Equitable Resources, Inc. (Equitable Resources), National Fuel Gas Company, and Questar. This group included only one company that met the Commission's historical standards, KinderMorgan. The remaining three companies derived more revenue from the gas distribution business than the pipeline business. The Commission excluded the other five companies used in *Williston*: Columbia and Coastal Corp. because these entities had been acquired by other companies and are no longer publicly traded; Enron because it was in bankruptcy; El Paso Corporation (El Paso) and Williams Companies (Williams) because financial difficulties had resulted in lowered, and thus unrepresentative, dividends for these companies.

125. In *HIOS*, the Commission rejected the pipeline's proposal to include four master limited partnerships (MLPs) in the proxy group. The Commission recognized that, in theory, it might be appropriate to compare *HIOS*, a limited liability company owned by an MLP, with other MLPs whose business is made up primarily of pipeline operations. However, the Commission found that before it could consider including an MLP in the proxy group, the record would have to contain reliable financial data concerning the MLP, comparable to that for corporations, so as to permit the Commission to determine a return on equity for the MLP under the DCF analysis. The Commission pointed out that under the DCF analysis, return on equity is considered to equal dividend yield (dividends divided by stock price), plus the estimated constant growth in dividends. Thus, data concerning dividends paid by the proxy group companies is a key component of any DCF

---

[203] 104 FERC ¶ 61,036, at P 35 (2003) *(Williston)*.

[204] *High Island Offshore System, L.L.C.*, 110 FERC ¶ 61,043, *reh'g*, 112 FERC ¶ 61,050 (2005) (*HIOS*).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

analysis. However, it was not clear from the evidence presented by *HIOS* that the "dividend" figures supplied by *HIOS* for the MLPs it proposed to include in the proxy group are comparable to the corporate dividends the Commission uses in its DCF analysis.[205] The Commission explained that:

> Partnerships make distributions to their partners, rather than pay dividends to stockholders. Those distributions may include payment to the partners of a share of the partnership's earnings; to that extent the distribution is comparable to corporate dividend payments. However, the distributions may also include a return of a portion of the partners' original investment, unlike a corporate dividend. Use of a distribution payment that includes both earnings and a return of investment as an MLP's "dividend" for purposes of a DCF analysis would skew the DCF results, since the dividend yield would appear higher than it actually was. Thus, the Commission will not consider including an MLP in the proxy group, unless the record demonstrates that the distribution used as the "dividend" includes only a payment of earnings and not a return of investment . . . However, there is nothing in the record to indicate whether the dividend amounts included in HIOS's exhibits represent only that portion of the MLPs' distributions that pays earnings to the partners or also includes a return of investment.[206]

Initial Decision

126. In this case, the ALJ adopted the proxy group proposed by BP, consisting of El Paso, Equitable Resources, KinderMorgan, National Fuel Gas, Questar and Williams. BP's proxy group includes all four companies included in the *HIOS* proxy group. In addition, the BP proxy group includes El Paso and Williams, which had been excluded in *HIOS* due to their financial difficulties. BP argued that the financial situations of those two companies had improved sufficiently to once again include them in the proxy group. Moreover, BP argued, those two companies were the only two companies that still satisfied the Commission's traditional standards for inclusion in the proxy group. In finding that BP's proposed proxy group was appropriate for Kern River, the ALJ reasoned that "BP adjusted for mergers, sales, and consolidations in the nine-company *Williston* proxy group, to arrive at the six natural gas companies it used. The six companies are publicly-traded. Two of them, KinderMorgan and Williams, are included

---

[205] *HIOS*, 110 FERC at P 125-126 (citations omitted).

[206] *HIOS*, 110 FERC at P 126 (citations omitted).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

in the Kern River's and Staff's proxy groups. Two other companies, El Paso and National Fuel, are also Staff proxy group companies."[207]

127. The ALJ rejected the alternative proxy group proposals by Kern River, Staff and RCG. Kern River's proxy group included KinderMorgan, Williams and three MLPs: Enterprise Products Partners (Enterprise); Kinder Morgan Energy Partners; and Northern Border Partners.[208] Two of the MLPs own oil pipeline assets: Enterprise and Kinder Morgan Energy Partners. The companies chosen are primarily involved in the pipeline processing and storage business.

128. In rejecting Kern River's argument that MLPs should be included in the proxy group, the ALJ noted that all parties responding to the issue of appropriate proxy group for Kern River object to Kern River's inclusion of MLPs in its proxy group.[209] She found their objections to be well-taken in that "MLPs in gas pipeline proxy groups cause dividend yields to be inordinately high." The ALJ further noted that in this case, the dividend yields resulting from Kern River's inclusion of MLPs in its proxy group, are more than double the yields of Staff or other *Williston*-based proxy group yields.[210] She further observed that the Commission, thus far, has only permitted the use of MLPs in oil pipeline rate cases on the ground that MLPs were the only companies available to be included in oil pipeline proxy groups,[211] and that the Commission has not, that she is able to determine, yet expressed that regarding gas pipelines. The ALJ further found that Kern River did not show that its proxy group would produce just and reasonable rates because it presented no evidence that the distributions of the MLPs excluded a return of capital. She noted that the Commission held in *HIOS* that it would not consider including an MLP in a proxy group, unless the record clearly showed that the distribution used as

---

[207] ID at P 275.

[208] Kern River originally included another MLP, Gulfterra Partners, in the proxy group, but by the time its witness prepared his rebuttal testimony Gulfterra had merged with Enterprise.

[209] While Edison Mission Energy, LLC (Edison Mission) did not propose a specific return on equity, it argued that Kern River's proposed return on equity was unreasonably inflated due to the presence of MLPs in its proxy group. Edison Mission also argued that Kern River's proxy group does not comport with *HIOS*, because *HIOS* allows inclusion of LDCs in gas pipeline proxy groups.

[210] ID at P 272.

[211] *HIOS*, 110 FERC ¶ 61,043 at P 129 (2005).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

the "dividend" in the DCF formula was only a payment of earnings and not a return of investment.

129. The ALJ also rejected Staff's proxy group. Staff proposed to include in the proxy group companies with publicly-traded stocks which (1) own 100 percent of a major Commission-regulated natural gas pipeline and (2) derive at least 50 percent of their operating earnings from an energy-related line of business, including local distribution of natural gas and/or transmission and distribution of electricity.[212] Staff asserted that nine companies satisfied these criteria.[213] However, Staff proposed to exclude two of the nine, El Paso and Williams, because of their poor financial condition. Of the remaining seven companies, CenterPoint Energy, Dominion Resources, Duke Energy, Entergy, Inc., and NiSource, Inc. have dominant electric operations; Equitable Resources, and National Fuel Gas own significant gas distribution assets.

130. The ALJ observed that Kern River's markets include merchant electric generators and enhanced oil recovery operations, not monopoly franchises, and further that no party challenged Kern River's assertion that LDCs and retail electric utilities are able to attract capital at lower cost than the more risky gas transmission utilities like Kern River.[214] The ALJ noted that the Commission in *HIOS* held open the possibility that, as changes continue to occur in the natural gas industry, it may be that companies with significant distribution functions would not automatically be disqualified from inclusion in pipeline-oriented proxy groups.[215] However, the ALJ was not persuaded to conclude, based on the evidence on the record, that the LDCs and electric companies in Staff's proxy group have evolved to the point that they may be considered to have risk comparable to that of Kern River.[216] The ALJ also rejected RCG's proposed proxy group, which also included companies with electric utility operations.[217]

---

[212] Ex. S-10 at 12-13.

[213] CenterPoint Energy; Dominion Resources; Duke Energy; El Paso Corporation; Entergy, Inc.; KinderMorgan; National Fuel Gas; NiSource, Inc.; and Williams Company.

[214] ID at P 89, 92.

[215] ID at P 274 (*citing HIOS*, 110 FERC ¶ 61,043 at P 131).

[216] ID at P 275 (citing *Williston*, 104 FERC ¶ 61,036 at 61,104).

[217] RCG's proxy group included CenterPoint Energy; Dominion Resources; Duke Energy; Equitable Resources; National Fuel Gas; NiSource; and Questar.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

Briefs on Exceptions and Opposing Exceptions

131. Kern River argues on exceptions that the ALJ erred in rejecting its proposed proxy group. Kern River contends that the ALJ's proxy group is comprised of non-representative LDC enterprises whose business risks are not comparable to Kern River and excludes more comparable proxies that compete with Kern River for investor capital. Kern River further argues that the ALJ first rejected Staff's proxy group because it included LDCs, then inexplicably adopted the BP group, which itself includes three companies with dominant LDC operations. Kern River also argues that the ALJ erred in excluding its proposed four MLPs from the proxy group.

132. Kern River asserts that the ALJ failed to even consider evidence that its proxy companies were more comparable to Kern River than those proposed by other parties and that properly applying the investor-oriented DCF method justifies utilizing MLPs' unadjusted, cash distribution yields. Kern River asserts that viewed from the investor's perspective, the DCF results hold true regardless of the business construct of the proxy entity because the composition of the cash flow received from an enterprise, *i.e.*, whether it is a "distribution" by an MLP or a "dividend" paid by a corporation, is immaterial.[218] Kern River claims that the ALJ simply disregards the evidence that prospective investors in natural gas pipeline businesses view pipeline MLPs and corporations as alternative investments and the information on yields that investor publications present to them reflect MLPs' full cash distributions. Kern River further argues that even if the ALJ believed there should be an adjustment to MLPs' yields to incorporate only their reported earnings, she erred by not only ignoring, but declaring non-existent, Kern River's evidence setting forth DCF results for its proxy group based on the MLPs' earnings-only yields.

133. As an alternative to its preferred option of including MLPs in the proxy group discussed above, Kern River suggests using a proxy group of only three pipeline companies: El Paso, Williams, and KinderMorgan, and reopening the record to use updated, current information for those companies. According to Kern River, this option would result in a return on equity for Kern River of approximately 12.56 percent due to the significantly improved financial performance of El Paso and Williams as compared to the period considered at the hearing.[219]

---

[218] Kern River Brief on Exceptions at 24-25 (*citing* Ex. KR-107 at 18-20).

[219] For illustrative purposes, Kern River attaches to its brief on exceptions return calculations for the three companies using updated data. *See* Kern River Brief on Exceptions, Appendix 3.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

134. Kern River points out that two of the companies in its alternative proxy group proposal (Williams and KinderMorgan) were included in the proxy group of all but one of the participants that sponsored return on equity evidence in the proceeding – Staff, BP, and Kern River – and all three were included in the proxy group accepted by the Commission in *Williston*. Kern River asserts that while it is true that, all things being equal, a proxy group with more than three companies would be preferable, a broader array of reliable gas pipeline corporation proxies is simply not available. Kern River urges that "any conclusion that this three-company group is appropriate should be conditioned on utilizing it with updated information. Kern River points out that at the time the written evidence in this case was prepared, El Paso and Williams were still suffering through serious financial distress born in the aftermath of the Enron meltdown and bankruptcy. Kern River further notes that there was considerable controversy on the record about whether either or both companies were unsuitable for use as proxies in this case because of their inordinately low dividend yields and/or abnormally low estimated earnings growth rates."[220]

135. Staff excepts to the ALJ's rejection of its proposed proxy group. Staff contends that the record does contain sufficient evidence as to the comparability in risk between Kern River and the LDCs and electric utilities in Staff's proxy group. Citing *Williston*, Staff argues that two of the four companies in the proxy group used by the Commission in *HIOS*, Equitable Resources and Questar, now derive less than 50 percent of their operating income from regulated gas pipeline operations, one of the selection criteria formerly used by the Commission. Staff further notes that nonetheless, both Equitable Resources and Questar are included in the proxy group adopted by the ALJ.[221] Staff, noting that El Paso and Williams, which it excluded from the proxy group in *HIOS* because financial difficulties made their DCF calculations unreliable, are also included in the proxy group adopted by the ALJ in this proceeding. Staff explains that while it "considered these companies in its analysis, Staff ultimately excluded their DCF results from the return on equity calculation because they were too low to be credible."[222] Therefore, Staff asserts that only two of the six companies in the proxy group adopted by the ALJ can be considered as reliable for purposes of a DCF analysis, KinderMorgan and National Fuel Gas.

136. Staff also excepts to the ALJ's finding that there is insufficient evidence on the record to conclude that the LDCs and electric companies in Staff's proxy groups have evolved to the point that they may be considered to have risk comparable to that of Kern

---

[220] Kern River Brief on Exceptions at 30-31.

[221] Staff Brief on Exceptions at 20.

[222] *See* Ex. S-10 at 34.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

River. Staff maintains that in *HIOS* the Commission recognized that it would be appropriate to include LDCs in the proxy group. While Staff acknowledged that the Commission had not yet concluded that it would be appropriate to include companies with significant electric operations, Staff argues that given further changes in the industry and the weight of the evidence on the record there is now a compelling need, as well as a legitimate basis, for the Commission to revise its policy on proxy groups to allow the consideration of electric utilities – if such companies can be shown to be comparable in risk to the subject natural gas pipeline company.

137. Staff, RCG, BP and Edison Mission each oppose the exceptions of the Kern River. Kern River opposes the exceptions of Staff, RCG and BP.

Commission Determination

138. We affirm, in part, and reverse, in part, the ALJ's decision on the appropriate proxy group for Kern River. We find that, based on the record in this case, the ALJ properly rejected both Kern River's proposal to include MLPs in the proxy group and Staff's proposal to include companies with significant electric operations. However, we find that the ALJ should have excluded El Paso and Williams from the proxy group on the same grounds the Commission excluded those two companies from the proxy group that we approved in *HIOS*. We thus adopt the same proxy group in this case as was used in *HIOS*. The returns of this proxy group range from a low of 8.94 percent to a high of 13.62 percent.[223] The median is 10.7 percent.[224]

139. In recent years, fewer and fewer companies have met the Commission's historical standard for inclusion in the proxy group, including that pipeline operations constitute a high proportion of the companies' business.[225] This has required that the Commission depart from its historical proxy group standards for pipelines in one way or another in order to have a reasonable number of companies to include in the proxy group. In both

---

[223] The returns for each member of the proxy group are: National Fuel 8.94%; Questar 9.74%; Equitable Resources 11.66%; and KinderMorgan 13.62%.

[224] Since there are four companies in the proxy group, the median is the average of the two companies in the middle of the range, Questar and Equitable Resources.

[225] *Transcontinental Gas Pipe Line Corp.*, 90 FERC ¶ 61,279 at 61,933 (2000). In *Williston*, 104 FERC at P 35 fn. 46, the Commission stated that it determined whether pipeline operations constituted a high proportion of the company's business based on whether its pipeline business accounted for, on average, over the most recent three-year period for which data was available, approximately 50 percent or more of the total dollars in at least one of the two areas, operating income and total assets.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

Williston and *HIOS*, the Commission addressed this problem by using proxy groups based on the companies included in the Value Line Investment Survey group of diversified natural gas companies whose business includes Commission-regulated natural gas pipelines. The Commission continues to find that the Value Line Investment Survey natural gas companies provide the best starting point for determining the proxy group.

140. However, similarly to *HIOS*, we believe that it is appropriate to exclude El Paso and Williams from the proxy group on the ground that, at the time the record in this case was developed, their financial circumstances continued to make those companies inappropriate for inclusion in the proxy group. Based on BP's evidence, the ALJ found that the estimated costs of equity for El Paso and Williams were 7.31 percent and 7.32 percent respectively. Staff's witness in this case testified that the estimated returns on equity for those two companies "were too low to be credible."[226] Staff's witness explained that the estimated returns on equity for those companies were barely above the June-November 2004 average yield for the public utility debt of 6.21 percent, as shown by Moody's Investors Service.[227] In *SoCal Edison* the Commission held that "investors generally cannot be expected to purchase stock, if debt, which has less risk than stock, yields essentially the same return."[228] Kern River voiced similar concerns with regard to including El Paso and Williams in the proxy group in this case.[229] We find these contentions by Staff and Kern River to be persuasive on this issue.

141. Moreover, we reject the contentions of BP that exclusion of El Paso from the proxy group amounts to cherry-picking companies that have ROEs of a certain level.[230] The losses experienced by El Paso, and similarly by Williams, were largely related to their respective energy trading and related risk management operations, rather than to

---

[226] Ex. S-10 at 34.

[227] Staff's witness estimated El Paso's and Williams' costs of equity to be 7.18 and 7.47 percent, respectively, and pointed out that these estimates were only 97 and 126 basis points, respectively, above the 6.21 percent June-November 2004 average yield for public utility debt. Exh. S-10 at 34. Similarly, the 7.31 and 7.32 percent costs of equity for El Paso and Williams found by the ALJ are only 110 and 122 basis points above that average yield for public utility debt.

[228] *Southern California Edison Co.*, 92 FERC ¶ 61,070, at 61,266 (2002).

[229] Testimony of Charles E. Olson, Ex. KR-10 at 23 (stating that he considers Williams to be a marginal proxy since, like El Paso, it has experienced financial turmoil owing to losses in merchant generation and trading investments).

[230] Testimony of Elizabeth Crowe, Ex. BP-1 at 17:5-9.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

their gas pipeline businesses. These businesses proved to be much more volatile and risky than those of the gas pipeline industry. Thus, their financial difficulties are not representative of the gas pipeline industry, which is a further reason for excluding them from the proxy group.

142. We recognize that the four-company HIOS proxy group we approve here includes three companies (Equitable, National Fuel and Questar) whose pipeline operations are not as significant as we have historically required. However, these three companies all meet the criteria used in *Williston* and *HIOS*. The data supplied by Staff's witness Knight confirms this finding.[231] In each instance, the natural gas company has significant interstate pipeline operations, is subject to Commission jurisdiction, and is included in the Value Line group of diversified natural gas companies. Because the data demonstrate that two of the companies' distribution activities account for a greater share of the companies' income than their pipeline activities, Kern River argues that this renders the risk profiles of these companies unrepresentative of the risk profiles of pipelines, since the distribution business is less risky than the pipeline business due to the distributors' franchised territories. We have determined, however, that any risk differential can be addressed adequately by taking it into account in determining Kern River's placement in the range of reasonable returns, as discussed in the next section. Adopting either Kern River's or Staff's alternative proxy group proposals, therefore, is neither necessary nor appropriate.

---

[231] Ex. S-10, Sched. 2 at 1:

	Pipeline%	Distribution%
Questar, operating income	20.9	15

	Pipeline%	Distribution%
National Fuel, net income	24.1	30.24

	Pipeline%	Distribution%
Equitable Resources, EBIT	7.4	20.88

	Pipeline%	Distribution%
KinderMorgan, EBIT	137.3	10.4

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

143. Kern River has not met its burden to include in its proxy group three MLPs in addition to KinderMorgan and Williams.[232] Kern River is not an MLP, but a general partnership that is ultimately owned by a corporation. For ratemaking purposes, we are treating Kern River as a corporation. For example, Kern River incurs a corporate income tax liability under its corporate parent's consolidated income tax return, and thus should receive a tax allowance. Moreover, as discussed below, the record demonstrates significant differences between partnerships that are not organized as MLPs, such as Kern River, and MLPs as investment vehicles. As discussed in the *Policy Statement*, some partnerships are owned by corporations since this is the most efficient way of organizing joint control. For example, this eliminates any concerns about the ability to file a consolidated return and thereby avoids a problem of intra-corporate double taxation. Since Kern River in fact functions more closely to the corporate model given that it is completely controlled by Subchapter C corporations, we find that it is more appropriate to follow the corporate model rather than one that is premised on a different investment structure, as is the case with most MLPs. Therefore, given the continued availability of the proxy companies used in *HIOS*, we find that in this case the *HIOS* proxy group is preferable to the use of MLPs.

144. At hearing, Staff and others presented evidence that the tax-advantaged nature of MLPs, combined with the inclusion in distributions of a return of investment as well as return on investment, enable MLPs to offer investors a "dividend" yield (MLP distributions divided by share price) that is substantially higher than pipelines organized as corporations. In filed testimony, RCG and Staff[233] objected to the inclusion of MLPs in the proxy group, asserting that (1) the distributions from MLPs, because they contain both a return on and a return of investment, do not conform to the income stream depicted in the Commission's traditional constant dividend model DCF analysis, which is premised upon the dividend yield from earnings only;[234] (2) MLPs do not have the same

---

[232] Initially, Kern River's proxy group consisted of six companies -- four MLPs and two corporations. Subsequently, Enterprise Products Partners acquired Gulfterra Partners, and Kern River updated its analysis to reflect a revised five-company proxy group. Ex. KR-107 at 35; Ex. KR-108, Schedule 4.

[233] *See* Ex. S-10 at 22-27; Ex. RCG-1 at 15-17.

[234] *See* Tr. 455, *citing* Ex. RCG-29, a portion from a book by Dr. Roger Morin, titled Regulatory Finance: Utilities' Cost of Capital. Dr. Morin explains that one of the critical assumptions for DCF analysis is that dividends, rather than earnings, constitute the source of value. Dr. Olson admitted this distinction during cross-examination when he acknowledged that MLPs do not pay dividends, but rather distribute earnings. Tr. 459: 8-11.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

financial structure as a traditional corporation, in that the MLP does not pay income taxes on its earnings;[235] (3) MLPs are perceived by investors as being different from corporations, with higher yields than corporations[236] and tax deferral advantages;[237] and (4) MLPs are perceived by security analysts as being different from corporations.[238]

145. In rebuttal testimony, Kern River's witness, Dr. Olson, asserted that, from an investor perspective, the DCF analysis is applied to MLPs in the same manner as it is applied to corporations:

> Both MLPs and corporations pay cash returns in the form of dividends or distributions and consensus earnings growth rates are published for both by independent analysts. The cost of common equity capital is simply the sum of these two return components. These returns from cash and growth are the two sources of income available to investors.[239]

The witness concluded that from an investor's orientation, the DCF results hold true regardless of the business construct of the proxy entity.

146. Dr. Olson further testified that, while an MLP's "dividend" yield may be higher than a typical corporation's, because the MLP's distribution includes a return of invested capital in addition to earnings, that fact should be offset by a correspondingly lower growth projection. Dr. Olson explained, "The analysts know that the MLPs pay out more than they earn. This is reflected in the growth rates they estimate, which are presumably

---

[235] *See* Tr. 512: 2-13. *See also* Ex. S-10 at 22-24 (Staff explains that Congress created a difference between MLPs and corporations, and recognized a competitive advantage for MLPs over corporations).

[236] *See* Ex. S-10 at 26 (yields of Olson proxy companies (7.36%) are much higher than Staff proxy group (3.53%)).

[237] *See* Ex. RCG-1 at 25 and Schedule 7.

[238] *See* Ex. S-10 at 24-25 (Value Line stated "warning" in report on Northern Border Partners (an MLP) that its "dividends include a return of capital and are not to be confused with regular quarterly dividends"); and Ex. RCG-1 at 29-30 (Smith Barney report stating that "given the unique nature of MLPs, traditional equity valuation techniques, such as price-to-earnings ratios, do not accurately depict fair value for an MLP").

[239] Ex. KR-107 at 17.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

lower than they would be at lower payout ratios."[240] Moreover, Kern River argues that the tax advantages enjoyed by MLPs should not cause their cost of capital, as estimated under the DCF methodology, to be improperly skewed upward. According to Kern River, logic supports just the opposite conclusion – *i.e.*, MLPs may be able to obtain capital at a lower cost than corporations because of their tax status.[241]

147. The Commission finds that the evidence presented by Kern River does not satisfy its section 4 burden to justify inclusion of its three proposed MLPs in the proxy group to be used in determining Kern River's return on equity under the Commission's traditional constant dividend growth DCF model. We are not making a generic finding that MLPs cannot, in future cases, be considered for inclusion in the proxy group if a proper evidentiary showing is made. Rather, for the reasons discussed below, we find that the record in this case does not support including the subject three MLPs in the proxy group for Kern River.

148. The DCF model is one method for investors to estimate the value of securities, including common stocks.[242] As the United States Court of Appeals for the District of Columbia Circuit has held, "The premise of the DCF model is that the price of a stock is equal to the stream of expected dividends, discounted to their present value."[243] The Commission uses the DCF model not to determine stock value, but to determine the rate of return on equity to be included in a pipeline's rates. To derive the return on equity, the Commission solves the DCF formula for the discount rate, so that the discount rate, or rate of return on equity, equals the dividend yield plus the growth rate of dividends per share.

149. As part of its proposal to include the subject three MLPs in the proxy group, Kern River would treat those MLPs' distributions to their unit holders as equivalent to a corporation's payment of dividends. However, as Kern River's witness concedes, there can be significant differences between a corporation's dividends and an MLP's distributions. Corporations pay dividends in order to distribute a share of their earnings to their stockholders. As such, dividends do not include any return <u>of</u> invested equity to the stockholders. Rather, dividends represent solely a return <u>on</u> the stockholders' invested equity. Put another way, dividends represent profit that the stockholder is

---

[240] *Id*. at 18.

[241] *Id*. at 19-20.

[242] *See* Ex. RCG-29, a portion from a book by Dr. Roger Morin, titled <u>Regulatory Finance: Utilities' Cost of Capital</u>.

[243] *Williston Basin Interstate Pipeline Co.*, 165 F.3d 54, 57 (D.C. Cir. 1999).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

making on its investment. Moreover, corporations typically reinvest some earnings to provide for future growth of earnings and thus dividends. Since the return on equity which the Commission awards in a rate case is intended to permit the pipeline's investors to earn a profit on their investment and provides the funds to finance future growth, the use of dividends in the DCF analysis is entirely consistent with the purpose for which the Commission uses that analysis.

150. By contrast, as Kern River concedes, the cash distributions of the MLPs it seeks to add to the proxy group in this case include a return of invested capital, in addition to a return on invested capital through an allocation of the partnership's net income.[244] While the level of an MLP's cash distributions may be a significant factor in the unit holder's decision to invest in the MLP, the Commission uses the DCF analysis solely to determine the pipeline's return on equity. The Commission provides for the return of invested capital through a separate depreciation allowance. For this reason, to the extent an MLP's distributions include a significant return of investment, a DCF analysis based on those distributions, without any adjustment, will tend to overstate the estimated return on equity because the "dividend" would be inflated by cash flow representing return of equity, thereby overstating the earnings the dividend stream purports to reflect.

151. Kern River argues that the increased "dividend" yield resulting from the fact that an MLP's cash distributions include a return of equity would ordinarily be expected to reduce an MLP's growth projections below those of a corporation, thus balancing out the increased "dividend" yield. If this expectation were borne out in the growth projections of an MLP proposed for inclusion in a proxy group, our concerns about the use of that MLP could be alleviated. However, while Kern River's assertion of reduced growth may be generally true over the long term, during the shorter term reflected in IBES growth projections MLPs may have other means of financing growth apart from retained earnings, including the issuance of additional debt or equity.[245] That appears to be the case here, since the average IBES five-year growth projections for Kern River's proposed MLPs was comparable to that of the four corporations we have included in the proxy group (6.45 percent for the MLPs as compared to 7.61 percent for the corporations).[246]

---

[244] Ex. KR-107 at 35:21-36:13. *See* Tr. 459:8-15, 460:14-22; *see also* Ex. BP-1 at 14:4-14; Ex. RCG-I at 24:1-15.

[245] Wachovia Securities, Master Limited Partnerships: A Primer, Ex. BP-19 at 11. ("Because MLPs pay out virtually all of their cash to unitholders, they must continuously access the debt and equity markets to finance growth. If MLPs were unable to access these markets or could not access these markets on favorable terms, this could inhibit long term distribution growth.")

[246] Ex. S-10, Sched. 12.

152. The short-term growth factor of the traditional DCF model is based on the additional dividends that will come from the growth that is caused by reinvesting a share of earnings in the company. Since the model is driven by growth in dividends derived from the reinvestment of current earnings, the traditional DCF model does not incorporate growth arising from external sources of capital such as issuing additional debt or equity.[247] Therefore, a cost of equity capital analysis using MLPs in the proxy group should explain whether and how external sources of capital have affected the short term growth patterns of the subject MLPs. If the growth forecasted for an MLP comes from external capital, it is necessary either (1) to explain why the external sources of capital do not distort the DCF results for that MLP, or (2) propose an adjustment to the DCF analysis to eliminate any distortion. On this record, we find that Kern River has not provided an adequate explanation concerning the short term growth patterns of its proposed MLPs, and thus has failed to carry its burden to demonstrate that the use of its proposed MLPs in the proxy group, without any such adjustments, resolve the differences between MLP distributions and corporate dividends and would produce just and reasonable rates.[248]

153. As a fall back position, Kern River proposed to include the above three MLPs in the proxy group, but reduce their cash distributions by removing the return of investment. This has the effect of determining the three MLPs' "dividend" yield based on the assumption that they paid "dividends" equal to 100 percent of their earnings. By limiting the distributions he used in calculating "dividend" yields to the earnings of the MLPs, Kern River's witness obtained an alternative zone of reasonableness of 8.6 percent to 13.6 percent, with a median of 12.4 percent.[249] On this record, we are not satisfied that this adjustment adequately addresses our concerns regarding the fact the distributions of the MLPs at issue here include a return of capital. The proposed adjustment would have

---

[247] Wachovia Securities, Master Limited Partnerships: A Primer, Ex. BP-19 at 11.

[248] In addition, some of the proposed MLPs-- Enterprise, Gulfterra and Kinder Morgan Energy Partners-- own significant oil pipeline assets. However, Kern River's Dr. Olson has stated (in other proceedings) that oil pipelines should not be compared to gas pipelines for ROE purposes. Dr. Olson explained that oil pipelines typically command higher ROEs due to the fact that as common carriers, they operate under a different regulatory regime from natural gas pipelines, and face greater risks than natural gas pipelines. Dr. Olson also noted that in contrast to natural gas pipelines, oil pipelines do not enjoy the certainty of contractual relationships with shippers. See Ex. BP-66 at 24:3-5; Tr. 495:22-496:5, 496:19-22, Tr. 497:2-16**.** We find these arguments to be persuasive and conclude that oil pipelines are not appropriate proxies for Kern River.

[249] Ex. KR-108 at 6, Schedule 6.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

the effect of basing the DCF analysis solely on the MLPs' earnings, rather than dividends. However, a "crucial assumption[] of the DCF model" is "that dividends, rather than earnings, constitute the source of value."[250] In fact, as discussed above, retained earnings are a key source of dividend growth in the traditional DCF model, which reflects the fact that corporations normally do not pay out all of their earnings as dividends,[251] and the dividends that are paid are assumed to be a distribution of stable long term surplus earnings not required for future growth. Kern River has not established here that its proposed MLPs have stable long term earnings that would justify treating a distribution of 100 percent of their earnings as equivalent to a corporate dividend for use in the DCF analysis.

154. We do not intend in this order to foreclose non-MLP pipelines from proposing to include MLPs in the proxy group, with an appropriate adjustment to reflect the differences between MLPs and corporations. In this regard, we recognize that further changes in the industry may necessitate expansion of the entities we consider for inclusion in the proxy group in one way or another. However, we find that, based on the record in this case, Kern River has not supported the particular adjustment to the MLP distributions proposed here.

155. As an alternative to its preferred option of including MLPs in the proxy group discussed above, Kern River has, for the first time in its brief on exceptions, suggested using a proxy group of only three pipeline companies: El Paso, Williams, and KinderMorgan, and reopening the record to use updated, current information for those companies. According to Kern River, this option would result in an ROE for Kern River

---

[250] Roger Morin, *Regulatory Finance: Utilities' Cost of Capital*, Ex. RCG-29 at 1-2. Dr. Morin explained, "Focusing on the present value of expected earnings can be misleading. It is earnings net of any investment required to produce earnings that are of interest, and not earnings alone. For example, a company expects earnings per share of $1.00 per year, but to sustain the stream of future earnings, the company needs to invest in real assets at the rate of $1.00 per year. Since an amount equal to each year's earnings must be channeled into new asset investment, no sustainable dividend payout, hence value, is possible."

[251] *SoCal Edison*, 92 FERC, at 61,262 n. 33 and 34, finding that, during the period 1994-97, industrial companies had, on average, a payout ratio of 29 percent, and gas pipelines had a payout ratio of 45 percent.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

of approximately 12.56 percent due to the significantly improved financial performance of El Paso and Williams as compared to the period considered at the hearing.[252]

156. Kern River points out that two of these companies (Williams and KinderMorgan) were included in the proxy group of all but one of the participants that sponsored ROE evidence in the proceeding – Staff, BP, and Kern River – and all three were included in the proxy group accepted by the Commission in *Williston*. Kern River asserts that while it is true that, all things being equal, a proxy group with more than three companies would be preferable, in Kern River's view a broader array of reliable gas pipeline corporation proxies is simply not available. Kern River urges that any conclusion that this three-company group is appropriate should be conditioned on utilizing it with updated information. Kern River points out that at the time the written evidence in this case was prepared, El Paso and Williams were still suffering through serious financial distress born in the aftermath of the Enron meltdown and bankruptcy. Kern River further notes that there was considerable controversy on the record about whether either or both companies were unsuitable for use as proxies in this case because of their inordinately low dividend yields and/or abnormally low estimated earnings growth rates."[253]

157. Kern River's proposal to use an alternative proxy group with current information is contrary to the Commission's policy in gas pipeline rate cases of only using the most recent data in the hearing record to update certain inputs in the DCF formula. Procedurally, the Commission cannot reopen the record established at hearing to permit Kern River to submit new evidence without giving the other parties a full opportunity to present opposing evidence, either through a remand to the ALJ or paper hearing procedures. Given our findings that the *HIOS* proxy group is appropriate for Kern River, we find it unnecessary to change our policy with respect to the composition of the proxy group and the use of extra-record evidence to determine ROE. Further, given our conclusions herein, we find that reopening the record to admit new data would result in an unnecessary use of the time and resources of the Commission and the parties to this proceeding. If Kern River desires to modify its rates based on more current data, it can file a new section 4 rate case.

158. We also affirm the ALJ's finding that the proponents of expanding the proxy group to include companies holding significant electric utility assets were not persuasive. No party challenged Kern River's assertion that retail electric utilities are able to attract capital at lower cost than the more risky gas transmission utilities such as Kern River.

---

[252] For illustrative purposes, Kern River attaches to its brief on exceptions return calculations for the three companies using updated data. *See* Kern River Brief on Exceptions, Appendix 3.

[253] Kern River Brief on Exceptions at 30-31.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

We have previously distinguished between electric utilities and natural gas pipelines in developing our approach to establish return on equity for companies in each industry, based on the different levels of maturity in each industry, and are reluctant, on this record, to abandon that practice at this time by including electric utilities in the proxy group used to establish return on equity for a natural gas pipeline.

159. We recognize that the structure of the natural gas industry is undergoing changes, and this makes it difficult to pick a representative proxy group. However, in this case, as we have concluded, the proxy group used in *HIOS* is a reasonable representative group of natural gas companies and nothing in this record has convinced us at this time of the need to include electric entities. However, as the natural gas industry continues to evolve, and if electric and gas companies continue to combine, we may have to revisit this issue in future cases.

B. Placement in Zone

160. After defining the zone of reasonableness through development of the appropriate proxy group for a gas pipeline, it is then necessary to assign the pipeline a rate within that range or zone, to reflect specific risks of that specific pipeline as compared to the proxy group companies.[254] Under existing policy, the Commission presumes that existing pipelines fall within a broad range of average risk as compared to other pipelines, and to overcome that presumption, a pipeline would have to show the existence of highly unusual circumstances.[255]

161. We find this test satisfied here because of the small number of companies eligible for inclusion in the proxy group under our traditional criteria and that fact that several of these companies have substantial distribution operations that are not reflective of the risks of natural gas pipelines. Specifically, and as discussed further below, because of the generally lower risk profile of distribution operations as compared to natural gas pipeline operations, we find that it is appropriate to account for this difference when determining the appropriate placement of a gas pipeline's return within the zone of reasonableness.

Initial Decision

162. In this case, based on the median return on equity for the BP proxy group, the ALJ approved a return on equity for Kern River of 9.34 percent. Finding that Kern River did

---

[254] *Williston Basin Interstate Pipeline Co. v. FERC*, 165 F.3d 54, 57 (citation omitted).

[255] *Transcontinental Gas Pipe Line Corp.*, 90 FERC ¶ 61,279 at 61,936 (2000). *HIOS*, 110 FERC, at P 154.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

not show highly unusual circumstances, the ALJ determined that Kern River did not carry its burden of proving that it should be placed at the high end of the zone of reasonableness.

163. Kern River argued that, as compared against other gas pipelines, it should be placed at the high end of the zone of reasonableness because it has extraordinary financial and business risks. However, the ALJ concluded that arguments of parties opposing Kern River's assessment of its risks were better supported and more persuasive.

Briefs on Exceptions and Opposing Exceptions

164. On exceptions, Kern River urges that the Commission undertake a fresh evaluation of the record as a whole regarding Kern River's relative risks. As a starting point, Kern River argues that the ALJ placed inordinate reliance on Kern River's credit rating for her determination of average risk. Kern River further argues that the ALJ disregarded specific data showing vastly increased pipeline development in the Rocky Mountain supply area and its depressive effect on the value of Kern River's capacity. Kern River objects to the ALJ's findings regarding its market growth in population-sensitive LDC markets. Kern River asserts that very little of Kern River's capacity is subscribed by LDCs, but much is held by electric generation customers whose profits and credit standing have been squeezed significantly by rapidly rising gas commodity prices and two of whom (Mirant and Calpine) have filed for bankruptcy protection.[256]

165. Kern River points out that within this shipper mix is an inordinately high percentage of merchant generators which are especially vulnerable to gas price increases, as the Mirant and Calpine bankruptcies prove. In this regard, Kern River contends that the ALJ's failure to recognize any upward adjustment to the median return, especially in light of the overwhelming evidence demonstrating the non-comparability of the chosen proxy companies and other Kern River specific risk factors, is particularly egregious. Kern Rivers identifies its very low percentage of LDC load and very high proportion of merchant electric generator load as perhaps the single most "anomalous" fact of Kern River's risk-related characteristics.

166. Kern Rivers states that this unusual shipper mix is significant because LDC markets provide pipelines with a stable and predictable revenue stream, whereas merchant generation load is far more vulnerable to commodity price swings. Kern River argues that the devaluation of Kern River's capacity due to the dramatic increases in natural gas prices since the 2003 Expansion commenced service further supports

[256] *See* Ex. KR-10 at 7-10; Ex. KR-107 at 25.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

placement of Kern River at the high end of the proxy zone.[257] In support of this contention, Kern River explains that "because the merchant generation sector operates on thin margins, the viability of gas-fired generation plants, like those owned by many Kern River shippers, is a direct function of gas prices. As the pressure on 'spark-spread' differentials continues due to sustained high gas prices, credit and profitability problems within the merchant generation sector will continue to grow."[258]

167. Kern River also argues that the ALJ's reliance on Kern River's "impressive number of firm contracts" overlooks undisputed evidence of severe shipper credit risk and further that "perhaps the gravest misstep in the ALJ's risk analysis is her utter failure to accord any weight to the overall credit quality of Kern River's firm shippers."[259] Specifically, Kern River argues that the ALJ's analysis does not take into account the fact that over one-third of Kern River's capacity is under contract to non-investment grade shippers.[260] In addition, Kern River notes that with respect to its non-investment grade shippers, the term of their contracts is largely irrelevant for purposes of evaluating Kern River's risks because these shippers secure their firm capacity by tendering an amount equal to only twelve months' reservation charges.[261] According to Kern River, in contracting its firm capacity under this type of alternative credit arrangement, it has absolutely no assurance of payment beyond a one-year contract term.[262]

168. Other factors cited by Kern River that warrant an upward adjustment in the zone of reasonable returns include Kern River's substantially more leveraged capital structure than that of the "average" interstate pipeline, its comparatively high capital recovery risk—a factor that Kern River attributes to the newness of its investments and highlighted by declining gas production in Kern River's Rocky Mountain supply area; the declining

---

[257] *See* Ex. KR-10 at 8-10; Ex. KR-1 at 11-13.

[258] Kern River Brief on Exceptions at 40 (*citing* Ex. KR-10 at 7:13-20).

[259] *Id.* at 35.

[260] *Id.* at 36 (*citing* Ex. KR-1 at 22; Ex. KR-3; Ex. KR-91).

[261] *Id.*

[262] *Id.* (*citing* Tr. 419, 553-54, 685:10-18).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

value of Kern River's IT service,[263] and the failure of its January 2005 open season for a proposed new expansion.[264]

169. Staff, BP, RCG and Edison Mission oppose Kern River's exceptions. Kern River opposes the exceptions of Staff, BP and RCG.

Commission Determination

170. Since Opinion No. 414-A, we have started our risk analysis with the assumption that gas pipelines generally fall into a broad range of average risk absent highly unusual circumstances that indicate an anomalously high or low risk as compared to other pipelines.[265] In *Transcontinental Gas Pipe Line Corp*.,[266] the Commission explained this policy as follows:

> While the Commission stated in Opinion No. 414-A that parties may present evidence to support any return on equity that is within the zone of reasonableness, the tools available to the Commission for determining the return on equity to be awarded a particular pipeline are blunt. Therefore, the Commission is skeptical of its ability to make carefully calibrated adjustments within the zone of reasonableness to reflect generally subtle differences in the risk among pipelines. Unless a party makes a very persuasive case in support of the need for an adjustment and the level of the adjustment proposed, the Commission will set the pipeline's return at the median of the range of reasonable returns.

171. The Commission adopted this policy at a time when the proxy group was made up entirely of companies that met our historical standards for inclusion in the proxy group, including that pipeline operations constitute a high proportion of the companies' business. However, changes in the industry have constricted the number of companies

---

[263] *Id.* at 40 (*citing* Ex. KR-1 at 11-13; Ex. KR-54 at 12-13; Ex. KR-55 (documenting declining market basis between Opal and California border)).

[264] *Id.*

[265] *Transcontinental Gas Pipe Line Corp.*, Opinion No. 414-A, 84 FERC ¶ 61,084 at 61,427-5 (1998), *reh'g denied*, Opinion No. 414-B, 85 FERC ¶ 61,323 (1998), *petition for review denied*, *North Carolina Utilities Commission v. FERC*, D.C. Cir. Case No. 99-1037 (February 7, 2000) (per curiam); *Iroquois Gas Transmission System*, 84 FERC ¶ 61,086, at 61,456 (1998). *Williams Natural Gas Co*., 86 FERC ¶ 61,232, at 61,859-61,860 (1998).

[266] 90 FERC ¶ 61,279, at 61,936 (2000).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

eligible for inclusion in the proxy group under our traditional criteria, such that companies with substantial distribution operations are now included in the proxy group. Because it is still true that, when compared to one another, pipelines generally fall into a broad range of average risk, we will continue to decide issues concerning whether a particular pipeline is more or less risky than other pipelines under our existing policy. However, where, as here, there is a small proxy group that contains companies with a relatively low proportion of pipeline business and substantial distribution operations, we must recognize that our traditional approach of selecting the median will tend to understate the required return on equity for the pipeline business. We will therefore permit an adjustment above the median of the range to account for differences in risk between the pipeline and proxy group companies whose LDC operations account for a greater proportion of their business than previously occurred under our traditional policy.

172. The evidence in this case is undisputed that the risk profile of LDCs is different from the risk profile of typical interstate pipelines. No party disagrees that LDCs face lower risks due to the nature of their operations. As Kern River's witness testified,[267] LDCs enjoy a natural service monopoly, with relatively low demand elasticity, price sensitivity and throughput risks. The franchise structure of an LDC results in lower overall business risk and lower investor expectations. In contrast, gas pipelines are one level removed from the end-use markets served by LDCs and retail utilities and enjoy no such service monopoly or territorial franchise.

173. The four-company proxy group we have adopted in this case contains only one company with a sufficiently high proportion of pipeline business to satisfy our traditional proxy group standards. That company is Kinder Morgan, whose pipeline business accounts for essentially all of its net income, and whose return on equity is 13.62 percent. The remaining three companies (National Fuel, Equitable Resources, and Questar) have proportionately far less pipeline business than Kinder Morgan, with their net income from pipeline business accounting for only 7.4 percent to 24.1 percent of their overall net income.[268] Moreover, National Fuel and Equitable obtain a greater proportion of their net income from their regulated distribution business, than from their regulated pipeline business, and Questar obtains nearly as much net income from its distribution business as from its pipeline business. Consistent with the lower risk profiles of LDCs, the returns for all three of these companies are significantly lower than Kinder Morgan's 13.62 percent return; the DCF analysis produces returns of 8.94 percent for National Fuel, 9.74 percent for Questar, and 11.66 percent for Equitable Resources.

---

[267] Ex. KR-10 at 20-21.

[268] *See supra*, note 232.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

174. The median return for the full four-company proxy group is 10.7 percent, determined by averaging the 9.74 percent and 11.6 returns of the two companies in the middle, Questar and Equitable, both of which have significant distribution business. However, the midpoint of the range of reasonable returns, determined by averaging Kinder Morgan's 13.62 return and National Fuel's 8.94 percent return, is 11.28 percent, 58 basis points higher than the median.

175. As we explained in *Northwest Pipeline Corporation*,[269] under the laws of statistics, it is more accurate to determine the central tendency of a skewed distribution of returns based on the median, than the midpoint. That is because the median is less affected by an outlier, than the midpoint. It is for that reason that we determine the middle of the range based on the median. Here, however, we are confronted with a situation where the furthest outlier from the median, Kinder Morgan,[270] is also the company whose business is most similar to Kern River's pipeline business. Thus, the median return in this case is less reflective of the cost of equity of the company whose risk profile is most representative of Kern River's risk profile. In these circumstances, we find that an adjustment of 50 basis points above the median is necessary to appropriately reflect the cost of equity for KinderMorgan, in the determination of Kern River's ROE. We therefore set the Kern River's ROE at 11.20 percent. In making the fifty basis point adjustment, we exercise our judgment in light of the evidence on the record and conclude that such an adjustment is reasonable in the circumstances presented.[271]

176. We recognize that in *HIOS* we rejected the argument that the return on equity for HIOS should be upwardly adjusted to reflect the greater risks faced by an interstate pipeline vis-a-vis an LDC. However, in that case, we found that, due in part to the large number of captive customers on the HIOS system,[272] an adjustment above the median of

---

[269] 99 FERC ¶ 61,305 at 62,276 (2002), *citing Robert D. Mason, Statistical Techniques in Business and Economics*, 86-7 (3d ed. 1974).

[270] Kinder Morgan's 13.62 percent return is 292 basis points above the median, while National Fuel's 8.94 percent return is only 126 basis points below the median.

[271] *Colorado Interstate Co. v. Comm'n*, 324 U.S. 581, 589 (1945) (The Commission's judgment about what is just and reasonable and otherwise lawful is to be made based upon an informed judgment in light of the evidence of record and any necessary pragmatic considerations, rather than slide-rule perfection or mathematical certainty.).

[272] In *HIOS*, the Commission found that the lower risks of the proxy group companies involving franchised service territories are not significantly less competitive than HIOS. . . . [because] virtually all of the gas moving through HIOS is captive to the

(footnote continued)

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

the range was not warranted. Kern River, in contrast, has fewer captive customers and faces a greater degree of competition from competing pipelines in the Rocky Mountain region. Much of Kern River's capacity is subscribed by merchant electric generators, other industrial users, and gas marketers, all of whose use of gas is sensitive to volatility in commodity prices.[273] Only seven percent of Kern River's firm capacity is held by LDCs.[274] We agree with Kern River that these factors are significant because LDC markets provide pipelines with a relatively more stable and predictable revenue stream as compared to merchant generation load. In addition, unlike HIOS, Kern River competes for its primary markets with a number of other interstate pipeline systems and with alternate energy supplies such as LNG. Kern River's gas supplies compete with gas sourced in other regions of the continent.[275]

177. However, we reject Kern River's contention that its risks are so far above average as compared to other natural gas pipelines as to justify a return at the top of the range. While Kern River does point to significant business risks, we are not persuaded that they are sufficiently high to justify a further increase in Kern River's return over the fifty basis point adjustment we have made already. A pipeline's credit ratings are an appropriate part of the risk analysis,[276] and Kern River's credit rating is somewhat above the average for natural gas pipelines. The parties make a number of arguments regarding Kern River's relative risks. While BP argues that Kern River has a level of long-term commitments under existing firm contracts that is unusual in today's gas transportation markets and that its service agreements have a weighted average remaining term of 12 years, Kern River points out that with respect to its non-investment grade shippers, the term of their contracts is largely irrelevant for purposes of evaluating Kern River's risks. According to Kern River, these shippers secure their firm capacity by tendering an amount equal to only twelve months' reservation charges, such that under this type of alternative credit arrangement, Kern River has no assurance of payment beyond a one-

---

system and has no direct alternative means of transportation." *HIOS* at P 131-32 (emphasis added); *HIOS*, 112 FERC ¶ 61,050 at P 59.

[273] Ex. KR-1 at 19-23; Ex. KR-10 at 5-6; Ex. KR-54 at 15-17, 20-21; Tr. 419, 553-54.

[274] Ex. KR-10 at 7:3- 9.

[275] Ex. KR-12 at 22:15-24; Ex. KR-54 at 6-9; Ex. KR-55.

[276] *See Transcontinental Pipeline Corp.*, 90 FERC ¶ 61,279 at 61,937 (2000), Opinion 414-A, 84 FERC at 61,427-4, and *Williston*, 84 FERC ¶ 61,081 at 61,388 (1998).

year contract term.[277] Further, BP cites the fact that Kern River has had an annual load factor of greater than 100 percent for the past ten years as further evidence of Kern River's advantageous situation.[278] However, Kern River offered evidence showing increased pipeline development in the Rocky Mountain supply area and its depressive effect on the value of Kern River's capacity. When all of these factors are weighed in the balance, we find that Kern River's risks fall within what the Commission has described as the broad range of average pipeline risk.

178. We therefore approve a return on equity for Kern River of 11.2 percent.

C. Debt Costs

179. Kern River's debt capitalization consists of two debt issues: Series A notes in the amount of $510 million, were issued in August 2001 in the form of 15-year amortizing senior notes bearing a fixed coupon rate of 6.676 percent. Proceeds from this issue were used to repay the remaining balance of existing long-term debt, fund capital expenditures associated with expansions, recover issuance costs, and breakage costs associated with the previously held interest rate swaps. Series B notes in the amount of $836 million, were issued in May 2003 in the form of 15-year amortizing senior notes bearing a fixed coupon rate of 4.893 percent. Proceeds from this issue were used to repay the outstanding balance and accrued interest under Kern River's construction financing facility for the 2003 Expansion and High Desert Lateral and to pay financing costs associated with the offering.[279] The certificate order for the 2003 Expansion required that Kern River's initial rates for the 2003 Expansion shippers reflect the incremental cost of debt financing for this project.[280]

180. Kern River's proposed rate calculations combine the two debt issues to compute a weighted average overall cost of debt, which Kern River uses in calculating rates for both the rolled-in system and the 2003 Expansion services. Kern River computes its weighted cost of debt to equal 6.62 percent. Kern River proposed that the actual debt cost relating to the Series A issuance (including the breakage fees and issuance costs) was 9.675 percent and that the debt cost of the Series B issuance was 5.145 percent (including issuance costs). As such, Kern River's 6.62 percent weighted average cost of debt includes the breakage fees and issuance costs in addition to the fixed interest rates for the

---

[277] Kern River Brief on Exceptions at 36.

[278] Ex. BP-1 at 19; Ex. BP-22.

[279] Ex. KR-14 at 3-4.

[280] *Kern River*, 98 FERC ¶ 61,205 at 61,721-23 (2002).

Series A and Series B notes. BP alleged errors in Kern's calculation of the 9.675 percent interest rate cost attributable to the Series A loan, and maintained that it should be 8.455 percent.

181. Thus, there are two debt cost issues in this case: (1) the use of a weighted average (blended) cost of debt of 6.62 percent proposed by Kern River, in designing both rolled-in system and expansion system rates, versus attributing a separate and disproportionate debt cost to each system (9.675 percent related to the Series A loan to the rolled-in system and 5.145 percent related to the Series B loan to the 2003 Expansion system) for designing the rates; and (2) the debt cost attributable to the Series A loan (including breakage fees and issuance costs) of 9.675 percent proposed by Kern River versus 8.455 percent proposed by BP.

i. <u>Blended v. Separate Debt Costs</u>

182. Staff, BP, and the rolled-in shippers (the RCG and SCGC) supported Kern River's proposed use of a weighted average or blended debt cost. The 2003 Expansion shippers Calpine, Edison Mission, Questar, and Pinnacle West opposed the use of blended debt.

183. The 2003 Expansion shippers argued that using a blended cost of debt, as proposed by Kern River, would constitute a subsidy of the rolled-in shippers by the 2003 Expansion shippers, contrary to the Commission's 1999 Pricing Policy Statement concerning pricing of services on new pipeline facilities. They further argued that the Commission's certificate proceeding for the 2003 Expansion approved and/or required the use of segregated debt cost for the 2003 Expansion shippers indefinitely. They also asserted that the lower debt cost of the Series B notes was partly attributable to the pooling effect created by the addition of the 2003 Expansion shippers and the general downward trends in interest rates at the time the debt was issued. The 2003 Expansion shippers maintained that the settlement in Docket No. RP99-274 does not specify that lower debt costs resulting from new debt issuances be shared.

184. Parties supporting a blended cost of debt argued that the 2003 Expansion shippers ignore the interrelated nature of the financing at the time of the contract extensions of existing shippers ($510 million) and the financing at the time of the expansion ($836 million). These parties point to the fact that all of Kern River's long-term contracts (both the extended contracts of the rolled-in shippers and the new contracts of the 2003 Expansion shippers) were used as collateral to obtain the low interest rate on the second debt issuance. They claim that such a favorable interest rate could not have been obtained absent the existence of the long-term contracts with creditworthy shippers on the rolled-in system. They further argue that the 2003 Expansion facilities were designed to be physically integrated with the rolled-in facilities, and could not have been constructed without relying on the rolled-in facilities. Thus, according to these parties, there is a clear

nexus among all of the firm contracts, and the two debt issuances, justifying the use of a weighted average cost of debt.

Initial Decision

185. The ALJ determined that a blended debt cost inappropriately raises the rates of the 2003 Expansion shippers who are already paying incremental rates. She further determined that the 1999 Pricing Policy Statement does not require that every benefit accruing to 2003 Expansion shippers be shared with existing shippers.[281] The ALJ also found that there was no precedent for a blended debt cost and that there were no changed circumstances to warrant changing the Commission's initial incremental rate determinations for the 2003 Expansion shippers.[282]

186. Finding that the 1999 Pricing Policy Statement neither requires, nor forbids blending the debt, the ALJ concluded the Commission's 1999 Pricing Policy Statement does not control in this case. She explained that the 1999 Pricing Policy Statement forbids any pipeline action that would constitute the subsidizing of 2003 Expansion shippers by existing shippers, but it does not require that every benefit accruing to 2003 Expansion shippers be shared with existing shippers. She further found misleading Staff's arguments that the 1999 Pricing Policy Statement provided for 2003 Expansion shippers "subsidizing" existing shippers in a situation such as that presented in the instant case.[283]

187. Citing the 1999 Pricing Policy Statement, the ALJ concluded that there is no allegation that the 2003 Expansion facilities should be regarded as the "cheap expansibility" that the 1999 Pricing Policy Statement cautioned may result in new customers receiving subsidies from existing customers. The ALJ determined that the primary claim here for blending the debt is that it was the good credit of the existing shippers which prompted banks to offer the lower debt cost for the 2003 Expansion. The ALJ was not aware of precedent that would require blending the debt even if that were so. In any case, the ALJ found it very likely that the 2003 Expansion lower debt cost significantly reflected the very low interest rates of that time, as well as the good credit ratings.

188. The ALJ found persuasive the arguments of Calpine and Edison Mission that the blended cost of debt proposal ignored the Commission's policy and its initial incremental

---

[281] ID at P 308.

[282] *Id.*

[283] *Id.*

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

rate determinations for the 2003 Expansion shippers.[284] As such, the ALJ concluded that the actual debt cost used to set initial incremental rates for the 2003 Expansion shippers should continue to be used to set rates for those shippers absent significantly changed circumstances. She further concluded that continuation of the incremental debt cost supported the Commission's rate-certainty goal.[285]

Briefs on Exceptions and Opposing Exceptions

189. BP, Staff, RCG and SCGC take exception to the ALJ's ruling that debt costs should be separately assigned to the rolled-in system and the 2003 Expansion. Kern River and the other parties to the proceeding do not except to the ALJ's ruling.

190. On exceptions, the parties opposing separate debt costs argue that neither the Commission's 1999 Pricing Policy Statement, nor its certificate order relating to the 2003 Expansion of Kern River precludes blending debt cost. They assert that the Commission's 1999 Pricing Policy Statement is not concerned with subsidies going from 2003 Expansion shippers to existing shippers, even if blending the debt cost could be considered a "subsidy." They do not find *Northwest Pipeline*[286] helpful to the 2003 Expansion shippers because the decision called for an incremental cost of equity, which no 2003 Expansion shipper has advocated.

191. Staff also points outs that Northwest Pipeline had a system-wide capital structure, which no 2003 Expansion shipper has advocated. Staff also noted that the Commission approved the use of Northwest Pipeline's rolled-in debt cost and then found in favor of the incremental cost of debt in the subsequent rate case in *Northwest Pipeline*. Staff argues that *Northwest Pipeline* represents the kind of change that the 2003 Expansion shippers claim cannot be made in this case. Further, the incremental debt interest rate in *Northwest Pipeline* was 19 percent making it clear, according to Staff, that the Commission made a policy judgment that rolling-in such a high cost of debt was unfair to the shippers.[287]

---

[284] *Id.*

[285] *Id*.

[286] *Northwest Pipeline Corp*., 27 FERC ¶ 61,012, *reh'g* 27 FERC ¶ 61,339, *clarified*, 29 FERC ¶ 61,286 (1984).

[287] Staff Initial Brief at 29-32 and Staff Reply Brief at 22-25.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

192. 2003 Expansion shippers argue that the ALJ appropriately decided the issue because use of a blended cost of debt is inconsistent with the Commission's 1999 Pricing Policy Statement and with the order authorizing construction of the 2003 Expansion System. They also argue a blended cost of debt would impermissibly raise the 2003 Expansion shippers' rates by shifting costs of more expensive pre-expansion debt from the rolled-in shippers to the 2003 Expansion shippers.

Commission Determination

193. We reverse the ALJ's finding and conclude that debt costs should be blended. We find that Kern River's debt costs should be blended because the use of an average debt cost is similar to the sharing of other common expenses and benefits between an original and an incremental pipeline system. It is also consistent with the use of the same ROE for an original and an expansion system.

194. We find the Series A and Series B debt financing to be sufficiently interrelated as to warrant a blended cost of debt. The revenue from all of Kern River's firm transportation agreements -- the revenues from the rolled-in shippers as well as the 2003 Expansion shippers -- is pledged as collateral for *all* of the long-term debt of Kern River, including the lower interest rate Series B debt.[288] Further, when a 2003 Expansion shipper defaults, revenue impairment would not fall exclusively on Series B debt.[289] Further, the lower debt service associated with Series A debt, accomplished through the refinancing of the original debt, reduced the burden upon the cash flow arising from rolled-in facilities, leaving a greater share of revenue available to service the requirements of Series B debt. The increased revenues lowered the financing cost for shippers paying the interest on Series B debt.[290]

195. We also find persuasive on this issue arguments made by Staff and RCG. As Staff noted, after a company engages in a financing, whether debt or equity, the proceeds from the financing are commingled with other liquid assets, derived from other financings and/or internally generated funds, which are then used to pay the company's operating and non-operating expenses.[291] Thus, there is no way to tell which dollars are used to pay which expenses. Therefore, contrary to the assertions made by the 2003 Expansion shippers, "dollar tracing" is not only inappropriate, but impossible. We also agree with

---

[288] *See* Ex. BP-31; Ex. RCG-7.

[289] Ex. BP-33 at 3.

[290] BP Brief on Exceptions at 33.

[291] Staff Initial Brief at 32, n 35.

RCG that there is no way to demonstrate that one group of shippers pays the interest and principal only for one specific debt issue."[292]

196. Although the 1999 Pricing Policy Statement does not require that every benefit accruing to expansion shippers be shared with existing shippers, it does not require that existing shippers forego a benefit that they were instrumental in creating. As discussed above, the evidence shows that both the Series A and Series B Notes are interrelated. The interrelationship of the Series A and Series B is the basis for our finding that the use of a blended cost of debt is consistent with the use of a single capital structure for the rolled-in facilities and the 2003 Expansion facilities.

197. We find the ALJ was incorrect in concluding the certificate proceeding requires the continued use of a separate cost of debt. In section 7 certificate proceedings, a pipeline generally cannot make proposals which would cause restatement of all of its system-wide base tariff rates. In such proceedings, the pipeline seeks to recover enough cost of service from expansion facilities to be able to pay for financing and operating those facilities until its next section 4 general rate case. With respect to the certificate order for the 2003 Expansion, the Commission required that Kern River's initial rates for the 2003 Expansion shippers reflect the incremental cost of debt financing for this project. However, there was no issue in the certificate proceeding, and certainly no determination made, as to whether to use the incremental cost of debt or a weighted average cost of debt or, for that matter, whether incremental pricing should be used. Not only did Kern River propose to use incremental pricing in the certificate proceeding, but it proposed as well to use the cost of the incremental debt related to the financing of the 2003 Expansion.

198. Thus, the debt issue in the certificate proceeding involved the question of whether to use Kern River's projected cost of incremental debt or its actual cost of incremental debt. In this regard, therefore, the Commission's ruling in the section 7 certificate case (under the public convenience and necessity standard) is not controlling in this section 4 rate case (under the just and reasonable standard) because such ruling did not reach the issue of whether to use the incremental cost of debt or the weighted average cost of debt in designing incremental rates.

199. We also disagree with the ALJ's conclusion that the blended cost of debt proposal ignores Commission determinations (*e.g.*, the 1999 Pricing Policy Statement and the order certificating the 2003 Expansion) that require use of "actual debt costs."[293] Kern River's blended debt cost does reflect the actual cost of Series B debt in the combined

---

[292] Ex. RCG-18 at 21.

[293] ID at P 308.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

calculation, and thus the ALJ's reasoning does not lend any support to switching from Kern River's debt cost allocation to a new one.

200. We further find that sourcing debt costs on a consistent incremental basis would mean that in 2005, 2003 Expansion shippers should be responsible for the Series B annual repayment obligation of $36,784,000 and rolled-in shippers responsible for an annual repayment obligation of $26 million. Indeed, the disparity in debt repayment schedules only grows larger by 2016, when the Series B annual amortization cost exceeds $54 million while the Series A debt repayment schedule requires only $31 million.[294] Thus, it is inappropriate on the one hand to attribute all of the lower Series B debt interest solely to the 2003 Expansion, yet to obligate the rolled-in shippers to help amortize the principal of the Series B debt.

ii. Series A Debt Costs

201. Kern River's debt cost for it Series A notes ($510 million) includes a component to recognize that certain of the payments to cancel interest rate swaps and to finance debt issuance fees were financed by stockholders' equity. Kern River witness Warner further explains that recovery of this component of debt is reasonable due to ET program's rate reduction benefit and further deferral (five to ten years) of the recovery of Kern River's equity investment in the Original System, as well as the very favorable interest rate achieved in the 2003 Expansion financing. This component of the debt cost includes carrying costs, including an income tax allowance, on the equity investment in the swap and debt insurance costs.[295]

202. However, BP argued that the monthly debt service obligations attributed to the Series A debt reflect an over-recovery of debt costs. According to BP, Kern River includes in Series A debt both its Premium to Redeem Swaps ($42,398,000) and its Issue Expense ($5,788,877) in its beginning debt balance of $510,000,000. BP asserted that Kern River further attributed 60.57 percent of Kern River's Premium to Redeem Swaps ($25,680,553) and its Issue Expense ($3,506,334) to Kern River's equity capitalization, but the total Premium to Redeem Swaps and Issue Expense (i.e., $48 million) is also included in the $510 million being amortized as debt (resulting in approximately $29,186,887 of costs being double-recovered as both debt and equity). According to BP, this double-recovery of costs, as well as the use of a 60.57 percent equity rate (contrary to *Northwest Pipeline Corp.*,[296] and the 70/30 percent debt to equity ratio reflecting Kern

[294] Ex. KR-122 at 1.

[295] Ex. KR-14 at 5.

[296] 71 FERC ¶ 61,253 at 61,996 (1995).

River's actual capital structure), results in a cost of money of 9.675 percent, which, when grossed-up for taxes, includes an equity cost of money near 25 percent (24.4 percent).[297] BP argues that the correct debt cost is 8.455 percent.[298] BP pointed out that Kern River originally calculated the correct 8.455 percent debt cost (labeled "was") before it inflated the effective rate to 9.675 percent.[299]

203. Kern River disputes the challenge made to its debt cost calculation by BP and RCG. Kern River maintained that the attribution of 60 percent of the refinancing cost to equity is consistent with Kern River's 70/30 debt/equity balance. According to Kern River, BP ignored undisputed evidence that stockholders' equity was used to cancel interest rate swaps and to finance the issuance fees associated with the Series A debt. Therefore, according to Kern River, the $29 million used in Kern River's debt cost calculations reflects the actual amount initially spent, making the percentage of the total swap costs and financing fees paid with equity irrelevant to Kern River's capital structure.[300]

204. Staff and the RCG agreed with BP that Kern River had inflated the calculation of the Series A debt cost. The other parties took no position.

Initial Decision

205. The ALJ also found that the evidence supported the contention of BP and Staff that Kern River's filed debt cost for Series A notes is excessive and should be reduced from 9.675 percent to 8.455 percent.

Briefs on Exceptions and Opposing Exceptions

206. Only Kern River excepts to the ALJ ruling on the issue. It argues that the ALJ's ruling should be reversed on procedural and substantive grounds. Kern River argues that the ALJ bases the adjustment to the cost of Series A debt entirely on evidence adduced by BP which was not offered until redirect examination of its witness. Thus, Kern River contends that it had no opportunity to respond to the evidence.

---

[297] *See* Ex. BP-71.

[298] Tr. 1431:3-14; BP-91.

[299] Ex. BP-71 at 5 (8th col. on line directly above line labeled "August 2001").

[300] Kern River Initial Brief at 18-19 and Kern River Reply Brief at 20-21.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

207. Kern River objects substantively, arguing that when debt issuance costs and swap costs are added to the Series A debt to be recovered in rates, it equates to 9.675 percent. Kern River maintains that a portion of its debt cost was paid with equity dollars, and that those dollars represent about 60 percent of the total refinancing costs. Therefore, claims Kern River, there is no inconsistency with its presumed 70/30 debt/equity balance.

Commission Determination

208. We affirm the ALJ's determination. In doing so, we reject Kern River's argument that BP's evidence was admitted improperly. Kern River itself calculated a debt cost of 8.455 percent. Kern River originally calculated the 8.455 percent figure in the Kern River spreadsheet introduced in cross-examination of Kern River witness Swensen as Ex. BP-71, labeled "was" (fifth page, 8th col. on the line directly above the line labeled "August 2001"). This exhibit was the focus of the cross-examination of Kern River's witness, not BP's witness. Thus Kern River itself calculated the 8.455 percent interest rate, and that result was introduced into the record while Kern River's witnesses were still on the stand.[301] The 8.455 percent figure was calculated by Kern River, its witness originally had sponsored the data containing the calculation,[302] and Kern River's witness gave the testimony that demonstrates the claimed 9.675 percent rate is significantly inflated.[303] Thus, we find that Kern River's procedural arguments against recognizing an 8.455 percent interest rate for Series A debt are without merit.

209. We also find Kern River's substantive arguments without merit. Therefore, we affirm the ALJ's decision to reduce the cost of the Series A note from 9.675 percent to 8.455 percent. We will deny Kern River's claim that it be allowed to recover an equity return on the $29 million component of its debt cost that it asserts was financed with stockholder equity. Under Commission policy, an equity return is not permitted for equity-financed debt costs.[304] Such costs receive a debt return, as reflected in the 8.455 percent Series A debt costs we approve here. While Kern River asserts that the 8.455 percent debt cost rate does not allow for even a debt return on the unamortized portion of the $29 million in debt swap costs and debt issuance fees for which it sought an equity return, its evidence fails to support its argument.[305] Kern River's claim that its proposed

---

[301] *See* Tr. 1431:1-14.

[302] Ex. BP-71 at I-2.

[303] Tr. 717:16-23.

[304] *Northwest Pipeline Corp.*, 71 FERC ¶ 61,253, at 61,996 (1995).

[305] Kern River Brief on Exceptions at 71 (citing Appendix 5 at 1-2).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

recovery of equity return should be allowed because of the rate reduction benefits, as well as the very favorable interest rate achieved in the 2003 Expansion financing is without merit and departs from Commission precedent.[306] Further, under the Commission's regulations, premiums, discounts and expenses associated with the issuance of long-term debt must be amortized over the life of the respective issue.[307]

V. Tax Issues

210. This portion of the order addresses federal and state income tax allowance issues and the related issues of net operating loss (NOL) and allowance for deferred income taxes (ADIT).

A. Income Tax Allowance

211. In this proceeding Kern River claimed that it is entitled to a Federal income tax allowance of 35 percent in its cost-of-service based on its equity return under the Commission's policy expressed in its *Policy Statement on Income Tax Allowances*,[308] since it generates taxable income that is reported by its corporate parent, Mid American Energy Holdings, a Subchapter C corporation, in consolidated Federal income tax returns.[309] Kern River requests a Federal income tax allowance of $49,566,467.[310]

Initial Decision

212. The ALJ concluded that Kern River had not carried its burden of proving it is entitled to an income tax allowance for the entity owner or individual partners as required by Commission policy expressed in its *Policy Statement* because it has not proven actual or potential income tax liability consistent with Commission policy as expressed in its *Policy Statement* and *Trans-Elect*.[311] The ALJ stated that what Kern River did not show is who has actual or potential liability on that income and under the Commission's policy,

---

[306] *Northwest Pipeline Corp.*, 71 FERC ¶ 61,253 (1995).

[307] 18 C.F.R., Part 201, General Instruction 17.

[308] *Policy Statement on Income Tax Allowances (Policy Statement)*, 111 FERC ¶ 61,139 at 61,741, *rehearing dismissed*, 112 FERC ¶ 61,203 (2005).

[309] Kern River Initial Brief at 46.

[310] Kern River Statement A, page 1, 45 day update filing, Item A by Reference.

[311] Initial Decision, 114 FERC ¶ 63,031 at P 445-46 (2006).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

a pass-through entity is permitted an income tax allowance if that entity, its members, or partners have an actual or potential liability on that income.[312]

Briefs on Exceptions and Opposing Exceptions

213. Kern River filed an exception arguing that the ALJ erred by rejecting Kern River's request for a Federal income tax allowance. Kern River asserts the record contains sufficient evidence, consistent with Commission policies, on which to grant the allowance. Kern River points to the fact that 100 percent of its utility income is reported in the consolidated tax returns of its corporate parent Mid American Energy Holdings (Mid American). Kern River claims the ALJ misread the Commission *Policy Statement* and its decisions in *Trans-Elect*. Kern River refers to the testimony of its witness Jeffery Valentine which shows that while Kern River itself is a partnership, it is also an operating division of KR Holding, a subsidiary of Mid American,[313] which is taxed as a Subchapter C corporation, and the record contains the consolidated income tax returns of Mid American Energy Holdings filed with the Internal Revenue Service which include the income of Kern River.[314] Accordingly, Kern River argues that the ALJ erred in stating that it had failed to show who has the actual or potential tax liability.

214. Kern River further asserts the ALJ erred in concluding that the decision in *Trans-Elect* supports the denial of a Federal income tax allowance to Kern River. There, the Commission subsequently found that the partners had satisfied the policy statement by submitting IRS returns for their shares of utility income, and when the additional information was supplied, the Commission approved Trans-Elect's entitlement to the claimed tax allowance.[315] Kern River also argues that its right to recover a Federal income tax allowance should not depend on the treatment of tax NOL issues and that 18 C.F.R. § 154.305(a) of the Commission's regulations, which requires tax normalization for computation of income tax allowances, produces tax losses which are deferred to a later period.

215. BP argued that Kern River is not entitled to a Federal income tax allowance because it is a general partnership that does not pay income taxes and has no income tax liability of its own. BP argued that Kern River's reliance on the Commission's *Policy*

---

[312] *Policy Statement on Income Tax Allowances*, 111 FERC ¶ 61,139 at 61,741.

[313] Ex. KR-66 at 3.

[314] Ex. KR-72-78.

[315] *See Trans-Elect*, Order Accepting Compliance Filing, 113 FERC ¶ 61,162 at P 15 (2005), *reh'g denied*, 115 FERC ¶ 61,047 (2006).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

Statement is misguided because Kern River has failed to meet the requirement that it demonstrate an "actual or potential income tax liability" associated with the income derived from public utility assets.[316] BP argues that neither Kern River nor its owners will be paying any taxes on income generated by Kern River during the test period or the foreseeable future and so Kern River should not be given an income tax allowance in its cost of service.[317] BP also contended that the Commission has recently interpreted its new income tax policy in *Trans-Elect* and that Kern River has not made the filings required by *Trans-Elect* to demonstrate that each Kern River equity owner has a projected taxable income level from all income sources under Commission policy.[318]

216. BP also asserts that pipelines are not entitled to an allowance for income taxes that are not paid.[319] BP argues that the record shows that Kern River booked a net operating loss as of the end of the test period carried forward into future years of $328 million and that loss will completely offset the pipeline's taxable income until 2009 and thus, Kern River will not have any tax liability. BP also argues that the Commission should reject Kern River's assertion that the tax NOL is separate and apart from and has no impact on Kern River's eligibility for an income tax allowance in this proceeding and thus cannot satisfy the requirement that it will be paying any taxes on income generated during the test period or for the foreseeable future.

217. Calpine asserts that the Commission should affirm the ALJ's decision because, as an entity within the Mid American corporation for Federal income tax payment obligations, the record does not show when Mid American will incur Federal income tax liability because of Kern River's claimed tax net operating loss as a result of 2002 and 2003 facility expansions and tax law changes. Calpine argues that to allow the tax allowance would result in an unmitigated windfall for Kern River. Calpine argued that because of Kern River's proposals regarding its claimed tax net operating loss (tax NOL), on a stand-alone basis, if the tax NOL were approved, Kern River's income from its 2003 Expansion services would not be fully taxable for six to eight years. It argues that therefore Kern River would gain an unmitigated windfall if afforded the tax allowance it

---

[316] BP Initial Brief at 36; *see Policy Statement on Income Tax Allowances*, 111 FERC ¶ 61,139 at P 23 (2005).

[317] *Id*.

[318] *Policy Statement on Income Tax Allowances*, 111 FERC ¶ 61,139 at 61,741 (2005).

[319] BP cites *BP West Coast Products LLC v. FERC*, 374 F.3d 1263, 1288 (D.C. Cir. 2004), *cert. denied*, 125 S. Ct. 2245 (2005).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

seeks. According to Calpine, if Kern River's proposed tax NOL is rejected, then it would be entitled to a full income tax allowance.[320] The RCG supports this position.

218. Kern River disputes the argument of Calpine that Kern River's right to recover a tax allowance should depend on the ultimate treatment of Kern River's tax NOL. Kern River argued that the tax NOL and tax allowance issues are separate and properly resolved independent from one another under the Commission's stand-alone policy.

Commission Determination

219. The Commission concludes that Kern River is entitled to a Federal income tax allowance consistent with the Commission's tax allowance policies governing Subchapter C corporations. The record shows that Kern River is a partnership of KR Acquisition 1, LLC and KR Acquisition 2, LLC, both of which are owned by KR Holding LLC (KR Holding), a Delaware limited liability corporation, which is taxed as a Subchapter C corporation.[321] KR Holding in turn is owned by Mid American, an Iowa Subchapter C corporation,[322] which filed consolidated Federal income tax returns (Forms 1120) on behalf of all entities it owns that are required to file those forms. The record establishes that under IRS regulations Kern River Funding Corporation, KR Holding and each of its limited liability corporations (LLC) or operating divisions and Mid American are all taxed as Subchapter C corporations.[323]

220. As such, the Commission's *Policy Statement* and the related issues raised by *BP West Coast* are irrelevant here because, while Kern River is structured as a pass-through entity consisting of partnerships and limited liability corporations, each of its elements is taxed as a corporation. The *Policy Statement* and *BP West Coast* both address entities that are pass-through entities such as partnerships, LLCs, or Subchapter S corporations that do not have an income tax liability for their income, but whose income tax liability is imputed to the owning interests. Each of the various Kern River entities at issue here has its own tax obligation regardless of its legal nomenclature and must file, at a minimum, a

---

[320] Calpine Initial Brief at 36-38.

[321] Ex. KR-69. The chart in this exhibit is confirmed by the actual Form 1120s filed by KR Holding and Mid American.

[322] Ex. KR-67. Kern River states on page 6 of Ex. KR-66 that the last year Kern River filed a partnership income tax return, Form 1065, was for the year 2000. If Kern River were taxed as a partnership in the test year it would be required to use the Form 1065, and not the Form 1120 at the partnership's operating levels.

[323] Ex. KR-66 at 22-23; Ex. KR-69.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

Form 1120 information return with a consolidated Form 1120 return being filed at the parent company level. Given this, there is no need to reach the *Trans-Elect* issues raised by the ALJ and the parties. For this reason, the ALJ is reversed and the Commission concludes that Kern River is entitled to an income tax allowance under the traditional standards applicable to Subchapter C corporations.

221. The Commission also concludes that Kern River should not be denied a Federal income tax allowance even though there is no actual tax payment in the test period or in the immediate future. As just discussed, since Kern River is taxed as a corporation, matters of tax deferral should be governed by the Commission's traditional stand-alone policy as that policy is applied to corporations, not as it might be applied to partnerships that are taxed as partnerships. The Commission's stand-alone policy was affirmed by the court in *City of Charlottesville*.[324] The Commission again affirms that policy and again finds that the "actual taxes paid" principle is a misnomer and should be expressed as "actual or estimated taxes paid *or incurred.*"[325] Accordingly, the fact that Mid American did not have a tax liability in the test year or in the years through 2008 does not affect the conclusion that a tax allowance on a stand-alone basis should be granted. As demonstrated by Ex. KR-16, the large net operating loss in the test year is caused by the exceptionally large depreciation allowance that was taken when the 2003 expansion was placed in service. On a book basis this net operating loss lasts for several years and understates Kern River's taxable income, and taxes, in the test year and in the several years thereafter. However, once the NOL is worked off, depreciation is lower in the subsequent years and taxable income, and taxes, will be higher in those years than otherwise would have been the case. Under standard Commission practice, as affirmed by *City of Charlottesville*, this presents a timing and normalization issue, but does not preclude an income tax allowance based on the normalized jurisdictional net income in the test year. Under this test, Ex. KR-16 demonstrates that taxable income before NOL for the partial year 2004 and 2005 is more than adequate to justify the maximum corporate income tax allowance of 35 percent. The ALJ is reversed on this matter as well.

222. Kern River also requested a state income tax allowance using a composite state statutory corporate income tax rate of 4.8 percent.[326] The composite takes into account the allocation and apportionment procedures used by the states to determine their respective shares of Kern River's taxable income. Kern River requested a state income

---

[324] C*ity of Charlottesville*, 774 F.2d 1205 (D.C. Cir. 1985).

[325] *Id.* at 1215.

[326] Ex. KR-15 at 5.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

tax allowance of $7,184,644.[327] The ALJ rejected Kern River's request for all income taxes without distinguishing between Federal income taxes and state income taxes.[328] Kern River argues that the ALJ erred by rejecting Kern River's request for state income tax allowances for the same reasons involved in federal income tax allowances.

223. The Commission concludes that Kern River is entitled to a state income tax allowance consistent with Commission policy. The Commission's policy is that it is appropriate to provide an income tax allowance for partnerships or similar pass-through entities that hold interests in a regulated public utility. Kern River presented evidence that it has paid state income taxes.[329] No specific evidence was offered by any party to show why Kern River should be denied a state income tax allowance. Accordingly, that portion of the ALJ's decision recommending denial of state income taxes in Kern River's cost of service is reversed.

B. Tax Net Operating Loss

224. Kern River claims it is entitled to reflect a $329 million tax net operating loss in its rate base, which produces an increased return and income tax allowances. Based on Kern River's claimed NOL, Kern River included a $112 million tax loss in Account No. 190, which it applied as an offset to accumulated deferred income taxes (ADIT) recorded in Account No. 282, [330] which results in a lower decrease in the rate base due to ADIT than would otherwise be the case. A tax NOL occurs when the allowable tax deductions exceed taxable income for a taxable year.[331] In 2003, Kern River's depreciation for tax

---

[327] Kern River Statement A, page 1, 45 day update filing, Item A by Reference.

[328] Initial Decision, at P 445-46.

[329] Ex. KR-71.

[330] ADIT accounts reflect the timing differences between a company's revenue and expense and booked for income tax purposes. Timing differences, multiplied by appropriate Federal and state tax rates, represent ADIT and a rate base reduction. Ex. S-1 at 6.

[331] Kern River's witness Jeffery Valentine testified that Commission regulation at 18 C.F.R. § 154.305 requires tax normalization, which is calculating the total income tax provision as though the taxable income in the tax return were the same as book income. He testified that tax laws passed in 2002 and 2003 significantly affected the calculation of tax depreciation. The Job Creation and Worker Assistance Act of 2002 and the Jobs and Growth Tax Relief Act of 2003 allow taxpayers to claim additional ("bonus") tax depreciation for the first year in service. *See* Job Creation and Worker Assistance Act of

(footnote continued)

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

purposes, based on $1.2 billion in new plant construction, produced a net operating loss of $329 million.[332] Kern River asserts that it calculated its taxable income and tax NOL consistent with the Commission's long-standing "stand-alone" income tax policy. Kern River notes that participants, who contest the tax NOL and want to disregard the effects of the tax NOL in Account No. 190, also want to continue to recognize the ADIT in rates in Account No. 282, associated with the bonus depreciation that precipitated the tax NOL. It follows, according to Kern River, that if the tax NOL is not reflected in rates, the related deferred income taxes from bonus depreciation likewise should be disregarded.[333] Kern River further argued that Staff's claim that the effect of tax NOL on ADIT is unrelated to the jurisdictional cost-of-service is contradicted by Staff's recognition of ADIT related to the bonus depreciation that led to the NOL. Staff's view, according to Kern River, is not consistent with required income tax normalization.[334] The ALJ concluded that Kern River carried its burden of proving that it is entitled to claim deferred income taxes related to tax NOL in its rate base. The ALJ held that the Commission's regulation at 18 C.F.R. §154.305 allows for Account No. 190 items to be included in the cost-of-service and Kern River presented credible evidence that it expected to use the tax NOL within the statutory carry forward period of twenty years.

225. The Staff argues that deferred income taxes related to tax NOL must be removed from rate base in order to conform to Commission policy.[335] The Staff argues that the claimed change in ADIT resulting from the tax NOL must be removed from rate base because such a proposal does not comply with the Commission's regulations at 18 C.F.R. §154.305 (c) (2), which requires that to be recognized in rates, deferred income taxes must be related to the jurisdictional cost of service.[336] Staff asserts that in the test year cost of service methodology, there can be no operating loss allowed or any related deferred income tax in Account No. 190 and that the ultimate gains or losses produced by the rates are not includible in the cost of service, even though booked in accordance with

---

2002 (JCWAA), Public Law 107–147 (116 Stat. 21) and Jobs and Growth Tax Relief Reconciliation Act of 2003, P.L. 108-27, (117 Stat. 752). Ex. KR-15 at 5-18.

[332] Ex. KR-15 at 10, 17; KR-66 at 13.

[333] Kern River Initial Brief at 26-27.

[334] *Id.* at 25-26 and Kern River Reply Brief at 25.

[335] Staff Initial Brief at 36.

[336] Ex. S-1 at 6-7.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

accepted accounting practices.[337] Staff therefore asserts that all deferred income taxes related to tax NOL should be removed from Account No. 190.[338]

226. Calpine argued that Kern River's treatment of the acquisition-related ADIT credit elimination and the treatment of the ADIT credit produced by bonus depreciation, does not support Kern River's claim to a tax NOL. Calpine argued that Kern River's claimed tax NOL and related ADIT adjustment should be rejected because, as a matter of tax law, Kern River cannot claim a tax-related NOL as Kern River has no Federal income tax liability.[339] As such, only Kern River's parent Mid American can accrue a tax NOL and can carry forward the balance to offset future tax liabilities because otherwise the stand alone method would be improperly applied here. Calpine thus concludes that the ALJ erroneously held that bonus depreciation should be recognized in rates, and for that reason the NOL must be included in the tax calculation.

227. On reply, Kern River argues that its treatment of bonus tax effects complies fully with generally accepted accounting principles, Commission guidelines and tax normalization regulations. Kern River also argues that it properly recorded its tax NOL in Account No. 190 as prescribed by the Commission's regulations. Kern River argues that Calpine's argument is inconsistent with stand-alone principles of calculating tax liabilities of a regulated entity within a consolidated corporate structure. Kern River states that Staff recognizes the tax NOL account and comports with the guidance provided by the chief accountant. Kern River responds to Staff arguments that tax NOL is not related to jurisdictional cost of service; however, all rate base and cost of service components that generate tax NOL are part of Kern River's cost of service and Staff's argument is contrary to longstanding tax normalization policy. If Staff's argument were accepted, it would preclude recognition of all tax timing differences. Kern River also argues that Staff's position is inconsistent in recognizing ADIT generated through bonus depreciation but opposing offsetting ADIT reduction attributible to tax NOL. Failure to credit the offset would result in a reduction in the rate base through ADIT in years in which Kern River in fact had no tax savings to offset through the ADIT account.

228. The Commission affirms the ALJ. As has been discussed, Kern River is taxed as a corporation, not a partnership, and the use of the stand-alone method is correct. Under this method differences in timing of depreciation, and the tax consequences that follow, are adjusted through normalization. The differences in tax timing can be caused by two different types of factors. If tax depreciation exceeds straight line regulatory

---

[337] *See* 18 C.F.R. § 154.305(c) (2) (2006).

[338] Ex. S-1 at 6.

[339] Calpine Initial Brief at 21-25.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

depreciation, the regulated entity has a tax savings because taxable income for IRS purposes is less than regulatory income. However, the tax allowance embedded in the rate generates cash flow at the same rate whether or not the taxes are actually paid. If the taxes are deferred, the cash that is not paid out in taxes provides the regulated entity with an opportunity for an additional return by investing the cash it was able to retain. This is sometimes called a "tax free" loan to the entity, although in fact it represents an investment opportunity. Normalization requires the regulated entity to reduce its rate base by the amount of the taxes so deferred. This reduces the return component of the rate and passes the savings back to the rate payers. The required reduction is recorded in Account No. 282, and as noted reduces the rate base. Over time the regulatory depreciation comes to exceed IRS tax depreciation and the reverse occurs. More income results under IRS tax accounting because IRS based depreciation is lower than regulatory depreciation and results in more income. The ADIT total in Account No. 282 begins to decline and fewer dollars are deducted from the rate base, and return, and the related taxes, increase.

229. There is a second type of timing that can have the opposite effect. It is possible that some accounting entries will decrease expenses or increase income for IRS purposes faster than would be the case for accounting purposes. In this case the cash flow from the tax allowance embedded in the regulated entity's rates is less than the income tax payments that are generated by the higher income. When the regulated entity pays for an expense earlier than would be done under the Commission's regulatory accounting system, it is in essence committing more funds to the business. The difference is therefore capitalized and added to the rate base. The difference in the timing that results is capitalized and added to the rate base to allow a somewhat higher return on the additional funds that have been committed to the enterprise. As the accounting entries for these expenses are entered (usually allowance for funds used during construction), the difference in timing is reversed, the short term addition to the rate base decreases, and return drops. This timing difference is reflected as an ADIT debit, or regulatory asset, in Account No. 190.

230. In the instant case the NOL was properly included in Account No. 190. The large depreciation deduction for the "bonus" depreciation was properly reflected as a credit in Account No. 282 and served to reduce the rate base to reflect the difference in timing previously described. However, the impact of this deduction was so great that it exceeded the taxable cash that would have been generated under the straight line regulatory method. Thus, Kern River was not able to use the full extent of the deduction in the first year it was available. However, as discussed, the full accelerated depreciation amount is included in the credit ADIT in Account No. 282. Without a corresponding debit in Account No. 190, Kern River's rate base would be reduced even though it did not achieve the tax savings, and additional cash flow, that a credit entry in Account No. 282 is intended to offset. Therefore the NOL is carried forward as a regulatory asset in future years and is reduced as the tax savings actually accrue to Kern River. Offsetting the

NOL against the total ADIT reduction in the first year assures that the rate base is reduced only as the company actually obtains the additional cash flows, and hence the return, that the ADIT tax methodology captures for the ratepayer.

231. The NOL generated by the 2003 expansion and the related depreciation bonus is so large that it dramatically reduces the amount of the ADIT credit reflected in Kern River's 2004 test year, and hence, the related reduction to its rate base. This means that rates would increase accordingly because the overall rate base is higher, and given a certain percentage allowed return, more cash flow is required to achieve the allowed return. Absent a levelized rate design, this situation would continue until the pipeline's next rate case. As such, the rate impact of the NOL in the test year would continue even though the NOL declined sharply over four or five years, thus increasing actual return to the pipeline as the corresponding increase in ADIT credit (Account No. 282) would not be reflected in the pipeline's rates. However, this difficulty is not an issue here. The levelized method starts with a test year, in this case 2004, and then adjusts the pipeline's cost-of-service for each year to reflect changes in depreciation and return in future years to achieve a levelized rate. ADIT is directly driven by the depreciation accounts, the amount of return, and the tax allowance provided for the equity return component of the rate. As such, both factors are an integral part of the iterative, forward looking approach used to design Kern River's levelized rates. As Kern River works off the NOL, this will be reflected in the future years and the rates adjusted accordingly.

C. Allocation of ADIT

232. The instant case presents two ADIT issues that do not normally arise in gas pipeline rate cases. The first is caused by the pre-payment of the credit ADIT account as a result of the Williams Companies' sale of Kern River to Mid American in 2002. The second relates to the large ADIT account changes just described that resulted from the construction of the 2003 expansion and the use of the "bonus" deprecation. In each case the issue arises because Kern River has completed a number of expansions, each with a different rate base, composite depreciation cost, and a resulting ADIT account that is tied to the depreciation account for each expansion. These are embedded in the rates contained in the contracts for the various facilities, with adjustments as appropriate to reflect past settlements and the rolling-in of some of the historical facilities.

i. The Acquisition-Related ADIT

233. As noted, Kern River was purchased by Mid American from the Williams Companies in 2002. As part of the purchase of assets of Kern River, the then-existing accumulated deferred Federal and state income taxes (ADIT) of $136.9 million were

removed from the books of Kern River.[340] Under the Commission's regulations, ADIT amounts are a deduction from rate base used to calculate return and income tax allowances, and thus an ADIT balance on a pipeline's books will result in lower rates at the time that the rates are designed. Upon the sale of Kern River to Mid American, the ADIT balance on the books became zero. This resulted in an increase in the rate base and higher cost-of-service and higher rates for rolled-in portions of the system.[341]

Initial Decision

234. The ALJ held that Kern River's proposed allocation of ADIT produces just and reasonable rates because the increase in rate base associated with reducing the pre-acquisition ADIT balance to zero is properly allocated to the rolled-in system and the step-up is plainly related to the rolled-in system only. The ALJ stated that the expansion facilities were not even built when the step-up occurred due to the sale of Kern River to Mid American. Further, the ALJ held, separate calculation of ADIT for the various shipper classes comports with Kern River's levelized methodology and the rolled-in shippers received benefits from the 2003 expansion of Kern River's facilities.[342]

Briefs on Exceptions and Opposing Exceptions

235. On exceptions, the RCG, BP, and SCGC[343] objected and proposed the lost $136.9 million be allocated to all shipper groups. These shippers argue that all shippers who benefited from Mid American's acquisition of Kern River should be responsible for paying the costs leading to those benefits. The Rolled-in shippers argue that all shippers benefited from the purchase of Kern River and the purchase would not have occurred absent the high credit ratings of the Rolled-in shippers and therefore the ADIT credit should be equitably shared over the entire system. They argue that Kern River was unable to proceed with the 2003 expansion, which it was contractually obligated to build, because of Williams' inability to provide equity and the necessary credit rating to borrow the money necessary to build the expansion. Thus, they argue, it is only fair that those who benefited from the sale of the company share a part of the burden associated with that sale. SCGC supports these positions.

---

[340] Ex. KR-15 at 13.

[341] Ex. RCG-2 at 38-39.

[342] Initial Decision at P 333-34.

[343] On this issue, the Rolled-in shippers are RCG, BP, and SCGC.

236. According to BP, the proposed 2003 expansion shippers' rates do not reflect any ADIT consequences arising from the Mid American purchase. Thus, the elimination of the ADIT balance is disproportionately attributed only to the rolled-in system.[344] BP argues the ALJ erred in rejecting the allocation of the pre-existing ADIT to all shippers because of the belief that the reduction of ADIT to zero is properly allocated exclusively to the rolled-in system. BP argues that the allocation of the entire ADIT credit reduction to the rolled-in shippers has, in part, resulted in the rolled-in shippers paying the largest rate increases, as compared to the rate increases to the expansion shippers. BP also further states that the expected cost of $1.25 billion to be financed in part by approximately $375 million could not be financed by Williams. In contrast, in March 2002, Kern River was sold to Mid American who arranged the $875 million construction credit for the 2003 expansion and provided the completion guarantee and the financing of debt at a very favorable interest rate of 4.893 percent. According to BP, the sale of Kern River to Mid American was instrumental in arranging the construction of the 2003 expansion and the acquisition was key to securing significant ongoing benefits to all shippers. Thus, BP argues, the ALJ erred in attributing the ADIT add back only to the rolled-in shippers.

237. In opposition to the exceptions of the Rolled-in shippers, Pinnacle West argues that the loss of ADIT resulted from the acquisition of Kern River by Mid American and was in no way related to the 2003 expansion; thus, the expansion shippers should have no responsibility for lost ADIT, and the ADIT loss should be directly assigned to the rolled-in system that generated the ADIT balance. Pinnacle West claims the sale of Kern River to Mid American had absolutely no impact on whether the 2003 expansion would be built. Calpine argues that the ALJ properly accepted Kern River's allocation of acquisition-related ADIT entirely to the rolled-in system because none of the expansion projects existed in 2002 when the sale of Kern River to Mid American occurred. Calpine also claims the record does not support any need for financial backing from Mid American to construct the 2003 expansion, assuming this is even relevant.

238. In arguments below, Kern River asserted that the ADIT effect relates to the rolled-in system only and no portion of the ADIT effect on the cost-of-service should be allocated to the 2003 expansion shippers because the step-up in basis relates to the rolled-in system only, and the rolled-in system rightfully experiences the entire effect of the increase in rate base associated with reducing the pre-acquisition ADIT balance to zero. Kern River argued that the cost-of-service levelization model minimized the effect of the step-up on current rates because the models took future ADIT into account in calculating the average cost-of-service of the levelized period.[345] Kern River indicated its opposition

[344] BP Initial Brief at 24-25; SCGC Initial Brief at 21.

[345] Kern River Initial Brief at 24-25.

to the exceptions but filed no brief arguments in support of its opposition, choosing to rely on the ALJ's analysis.

Commission Determination

239. The Commission affirms the ALJ. As stated earlier in this order, the controlling policy involved here is that the Commission will not change the balanced risks embedded in each of the levelized rates and shipper contracts at issue here. Each levelized rate has embedded in it the ADIT related depreciation and amortization related to the construction or expansion contract whose costs that rate is designed to recover. The positions advanced by the Rolled-in shippers would simply shift to the 2003 Expansion customers the cost of increased return and taxes that occur once an ADIT credit in Account No. 282 expires. That increase will eventually occur in any event under the specific terms the Rolled-in shippers levelized contracts. Prepayment of the ADIT credit balance moves the timing of the increase forward, but does not lessen those shippers' obligation to pay all the costs that arise under their contracts. Moreover, the Williams Companies' ability or inability to meet their obligations regarding the 2003 expansion is simply irrelevant. The possibility of non-performance may have placed the Williams Company at risk of a legal default and an adverse remedy regarding its obligations to build the expansion. These legal and financial matters, however, have no relationship to the strictly incremental cost allocation approach Kern River has used to the expansion of its system and in which all costs and risks are embodied within a series of discrete contracts.

ii. Allocation of Bonus Depreciation-Related ADIT

240. Kern River proposes to reduce the 2003 expansion shipper rates by attributing unusually high bonus depreciation deductions and ADIT to the expansion system because almost all of the bonus depreciation income tax deductions were directly attributable to the 2003 expansion facilities.[346] Several shippers on the rolled-in system proposed to determine ADIT on a company-wide basis and allocate the result to all services.

Initial Decision

241. The ALJ held that Kern River's proposed allocation of almost all of the bonus depreciation and ADIT to the 2003 expansion system produces just and reasonable rates.[347]

---

[346] Ex. KR-57 at 16, 20.

[347] ID at P 333.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

Briefs on Exceptions and Opposing Exceptions

242. SCGC filed an exception urging the Commission to allocate ADIT on a system-wide basis to benefit all shippers on both systems. Calpine argues that allocation of the bonus depreciation and ADIT associated with the 2003 expansion system rate base follows incremental rate policies, which require that expansion-related costs and ADIT resulting from bonus depreciation remain with the 2003 expansion shippers. Calpine states that attributing part of this ADIT to the rolled-in system in the form of a rate base credit would create a subsidy to the rolled-in shippers for depreciation they had no role in creating. High Desert also opposes the exception.

Commission Determination

243. The Commission concludes that the ADIT resulting from the bonus depreciation should be allocated only to the 2003 expansion system for the same reasons as the ADIT step-up at issue in the prior section would be allocated only to the Rolled In facilities. The ADIT associated with the expansion system is a cost that is unique to construction of those facilities and the related rates. As such, it should be considered within the incremental cost of that expansion. The ALJ is affirmed.

D. Utah Compressor Taxes

244. Kern River allocated the Utah compressor fuel use tax to all portions of its system, including the High Desert Lateral.[348] Kern River updated the record and reported its actual expenses for other taxes, including the Utah compressor fuel use tax, through the end of the test period. There appears to be no significant dispute as to the total cost level of these amounts.[349]

245. High Desert submitted testimony that this tax should not be allocated to the High Desert Lateral.[350] High Desert argued that its incremental rate for service, beginning and ending in California, should not include costs associated with a Utah compressor fuel tax. It stated that the Utah tax is a cost associated with the operation of the Kern River mainline, and the tax is based on the amount of compressor fuel used in the compressors located in Utah. High Desert stated the lateral's incremental rate should not include the cost of compressors in Utah, nor should it include the cost of fuel to run the Utah

---

[348] Kern River allocated $19,678 of Utah compressor fuel taxes to High Desert (Ex. KR-94, and Staff allocated $19,386 of this tax to High Desert (Ex. S-2 at 34).

[349] *See* Kern River Initial Brief at 46.

[350] Ex. HD-1 at 19-21.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

compressors. It asserted this tax should be recovered from the shippers on the mainline, not from an incremental shipper such as High Desert located on a lateral in California. High Desert argued that the Utah compressor fuel tax is specific in nature and should not be borne by all shippers.[351] High Desert stated that Kern River rationalized not allocating Joint Transmission capital costs to the High Desert Lateral. High Desert argues that the same reasoning that Kern River used to show that Joint Transmission costs should not be imposed on shippers of incremental laterals applies to the Utah compressor fuel use tax. [352]

246. In rebuttal testimony, Kern River stated that High Desert's allocation proposal was an attempt to shift costs away from High Desert Lateral shippers and onto other shippers that would bear High Desert Lateral shippers' portion.[353] Kern River stated it will generally recover the same cost-of-service regardless of how the Commission determines to apportion costs among services. While the pipeline is not directly financially affected, Kern River stated it intended to comply in such matters with applicable cost determination and allocation principles as set forth in Commission policies and precedents.[354] Finally, Kern River stated that High Desert benefits from Kern River's entire upstream operation and receives gas that passes through the compressor stations in Utah where the tax is incurred. [355]

247. Staff Witness Black accepted Kern River's as-filed amount of Utah compressor fuel taxes paid of $1,506,000.[356] She stated the updated amount was $1,506,896.[357] She stated that in calculating the update, she used the most recent twelve months of Utah compressor fuel taxes paid. She stated that the Salt Lake Compressor Station was out of service for November 2003 through February 2004[358] but that it would be speculative and not a known and measurable event as to whether additional Utah compressor fuel

---

[351] *See* High Desert IB at 21.

[352] *See Id.* at 22.

[353] *See* Ex. KR-57 at 21.

[354] *See Id.* at 19-20.

[355] *See Id.* at 21.

[356] Ex. S-6 at 3-4.

[357] Ex. S-3 at 11.

[358] *See* Ex. S-6, at 4.

taxes would have resulted had it been in service.[359] Ultimately, she used the as-filed amount.

Initial Decision

248. The ALJ did not comment on the Utah compressor fuel tax, but stated, however, that all issues raised but not discussed were considered and found to be without merit.[360]

Briefs on Exceptions and Opposing Exceptions

249. Kern River did not file any exceptions or oppositions to exceptions to this issue.

250. High Desert claims that the ALJ neglected to address High Desert's proposal that its cost of service should exclude costs associated with the Utah compressor fuel tax, a tax on the amount of compressor fuel used in Kern River's Utah compressors, and High Desert presumes its proposal is rejected.[361] High Desert contends that there is no basis for the ALJ not to address High Desert's proposal for excluding this tax from High Desert's portion of the cost of service and deem it "without merit."[362]

251. High Desert cites its testimony that its incremental service does not use compressors in Utah.[363] It also asserts that it does not ship gas on the Kern River mainline to the High Desert Lateral. Instead, it states, shippers using either the Kern River mainline or Pacific Gas & Electric, a local distribution company, deliver gas to the High Desert Lateral.[364] High Desert states that the Utah compressor fuel tax is a cost associated with the Kern River mainline. High Desert asserts that costs associated with the Kern River mainline should be recovered from the shippers that use the mainline and not from High Desert, an incremental shipper receiving service only on a lateral line in California.

---

[359] *Id.*

[360] *See* ID at P 567.

[361] *See* High Desert Brief on Exceptions at 8.

[362] *See* ID at P 567.

[363] High Desert Brief on Exceptions at 8-9 *citing* Ex. HD-1 at 19-20.

[364] High Desert asserts that the shippers using the Kern River mainline account for 31 percent of the gas delivered to the High Desert Lateral *citing* Ex. HD-5.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

252. High Desert also states that Kern River should not allocate Utah compressor fuel taxes to High Desert for the same reasons that it did not allocate Joint Transmission capital costs to High Desert. High Desert claims Kern River gave these reasons in a response to a data request as follows:

> The [Big Horn and High Desert] laterals are not part of the mainline transmission system. The shippers that use the laterals pay a mainline transmission rate (and will, therefore, pay for the Joint Transmission costs) to move their gas to the lateral receipt point. In addition, lateral customers pay for the incremental costs of their specific laterals. Allocating the Joint Transmission costs to the laterals (such as through a gross plant allocation process) would result in a double allocation of the Joint Transmission costs to gas volumes flowing to the lateral delivery points.[365]

253. High Desert argues that Kern River's position stating High Desert benefits from Kern River's entire upstream pipeline operation is flawed and that shippers using the mainline to move gas to the lateral should pay the tax in their rates for mainline service.[366]

Commission Determination

254. The Commission accepts Staff's proposal that the Utah compressor fuel tax total amount should be based on Kern River's as-filed amount because it reflects a representative quantity in light of the Salt River Compressor unit being offline for the four months November 2003 through February 2004. As stated by Staff, the Salt River Compressor unit outage causes the test period actual tax amounts to be unrepresentative of projected quantities, and it would be speculative to attribute additional taxes to the Utah Compressor Fuel.[367] Also, in a data response to the Staff Field Audit, Kern River noted that the compressor station's outage caused the fuel usage to be unrepresentative of normal operations.[368] Kern River's as-filed amount of Utah compressor fuel taxes paid is $1,506,000, and Staff's update, based on the most recent twelve months of taxes paid, is $1,506,896.[369] The Commission accepts Kern River's as-filed amount of $1,506,000.

---

[365] High Desert Brief on Exceptions at 10 *citing* Ex. HD-1 at 20, which, in turn, cites Kern River's response to Data Request Calpine 2-47.

[366] *See* High Desert Brief on Exceptions at 10.

[367] Ex. S-6 at 3-4.

[368] Ex. S-5 at 16.

[369] Ex. S-3 at 11.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

255. With regard to the allocation of the Utah compressor fuel tax for the High Desert Lateral shippers, the Commission finds that, because transportation on the High Desert Lateral is an incremental service, these shippers should not pay a portion of this tax.[370] The rate for an incremental service includes a reasonable allocation of general system costs, such as general plant and administrative and general expenses and other services; therefore lateral shippers already pay for the benefits of mainline services. As High Desert's testimony stated, the Utah compressor fuel tax is not a tax of a general nature. It is applicable to Utah compressors which are located in Utah on Kern River's mainline and is a tax on the fuel used at these facilities.[371] The Utah compressor fuel tax is incurred by mainline shippers in Utah. High Desert's incremental rate does not include the cost of compressors in Utah, nor the cost of fuel to run the Utah compressors.[372]

256. The Commission also agrees with High Desert that Kern River's treatment of its Joint Transmission costs provides support for omitting High Desert from the allocation of the Utah compressor fuel tax. Kern River's Joint Transmission costs consist of facilities that benefit the Rolled-In System and the 2003 Expansion (an incremental portion of the system),[373] but not the laterals, High Desert and Big Horn. Kern River allocated its Joint Transmission costs only to the Rolled-In System and the 2003 Expansion and not to the laterals.[374] Like the Joint Transmission costs, the Utah Compressor Fuel Tax should be allocated only to the portions of Kern River's system that it benefits. The Utah compressor fuel tax benefits only shippers on Kern River's mainline. Therefore the Utah compressor fuel tax should be allocated only to Kern River's mainline and not to the laterals like High Desert.

257. For the above reasons, the Commission concludes that the Utah compressor fuel tax should not be allocated to High Desert Lateral or Big Horn Lateral shippers and High Desert's or Big Horn's rates should not include a portion of this tax.

---

[370] Ex. KR-94; Ex. S-2 at 34.

[371] Ex. HD-1 at 19-20.

[372] *See id.*

[373] Ex. KR-9 at 7.

[374] *Id.*

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

VI. Other Cost of Service

A. O&M Expenses

Initial Decision

258. Kern River's position is that its rates should be based on actual test period O&M expenses.[375] The position of Staff and various other parties is that Kern River's proposed O&M updates are acceptable, except for Account Nos. 850 (Operation Supervision and Engineering) and 856 (Operating Transmission Mains). Staff's position is that the two O&M expenses listed above are unrepresentative as updated and should be based on the as-filed amounts. In addition, Staff recommends that labor expenses should be based on a three-year average.[376]

259. The ALJ found that Kern River carried its burden of proving that its proposal to base its O&M expenses on actual test period expenses produces just and reasonable rates.[377] The ALJ found that the most recent and updated, actual data should be used in the calculation of Kern River's cost-of-service.

Briefs on Exceptions and Opposing Exceptions

260. In general, Staff agrees with Kern River's proposed O&M updates. However, Staff takes exception arguing that updated amounts pertaining to Account Nos. 850 and 856 are unrepresentative and should be based on the as-filed amounts.[378] Staff also recommends a three-year average for labor expenses.[379] Staff contends that its proposal is consistent with the Commission's policy in *Williston Basin Interstate Pipeline*.[380] RCG makes the same recommendations.[381]

---

[375] *See* ID at P 422.

[376] *Id*. at P 424.

[377] *Id*. at P 430.

[378] *See* Staff Brief on Exceptions at 43-44.

[379] Staff advocates an 84.57 percent O&M labor expensing ratio based on a 3-year average (Exs. S-1 at 16 and S-3 at 17)

[380] *See* Staff Brief on Exceptions at 44. *See also, Williston Basin Interstate Pipeline*, 72 FERC ¶ 61,074, at 61,359 (1995) (*Williston*).

[381] Ex. RCG-2 at 27-28.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

261. Kern River argues on exception that O&M expenses should be based on end of test period actuals. Kern River argues that Staff presented no evidence to support its position that the above O&M expenses were unrepresentative of future expenses incurred by Kern River.[382] Kern River contends that its proposal to update O&M expenses using test period actuals is consistent with *Northwest Pipeline Corporation*.[383]

262. Kern River argues that Staff's use of a three-year average for labor expenses is distorted since it disregards the fact that during 2002 and 2003 Kern River built two major mainline expansions which include non-recurring expenses.[384] Kern River also argues that Staff's reliance on using a three-year average for labor expenses as accepted in *Williston* is misplaced.[385] Kern River argues the difference between the base and test period amounts in this proceeding was due to the fact that there was significant construction during the base period, but not during the test period. Kern River concludes that unlike the Commission's decision in *Williston*, the use of a three-year average would not be representative of Kern River's future costs.[386]

Commission Determination

263. The Commission affirms the ALJ's decision that basing O&M expenses on Kern River's end of test period costs rather than filed period costs is just and reasonable as it is the latest available data. In addition, the Commission finds that in *Northwest* the Commission determined that the use of actual data updated for the last twelve months of the test period should be used in the calculation of a pipeline's cost-of-service.[387] The Commission also affirms the ALJ's decision to base labor expense on annualized test period amounts rather than a ratio based upon a three-year average for the reasons discussed below.

264. Section 154.303(a)(4) of the Commission's regulations states that the rate factors (volumes, costs, and billing determinants) established during the base period may be adjusted for changes in revenues and costs which are known and measurable with

---

[382] *See* Kern River Brief Opposing Exceptions at 82.

[383] *See Northwest Pipeline Corp.,* 87 FERC ¶ 61,266, at 62,028-30 (1999).

[384] *See* Kern River Brief Opposing Exceptions at 83.

[385] *Id.* at 84.

[386] *Id.*

[387] *See Northwest Pipeline Corporation*, 87 FERC ¶ 61,266, at 62,027 (1999).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

reasonable accuracy at the time of the filing and which will become effective within the adjustment period (*i.e.* the test period). The base period factors must be adjusted to eliminate nonrecurring items.[388]

265. The Commission finds that Staff did not provide evidence that actual test period expenses for Account Nos. 850 and 856 were unusual and non-recurring items and therefore should be removed. Kern River claims that Staff did not analyze the reasons for differences between actual expenses and the test period projections and rejected higher test period balances, such as Account No. 850, while accepting lower test period balances, such as Account No. 855. Because of the lack of experience with the 2003 Expansion at the time of Kern River's test period projections, it is reasonable that some of the projections would be lower or higher than the actual test period expenses.[389] We acknowledge that there are times when non-recurring costs should be excluded as unrepresentative of future expense. However, to validate any such exclusion a review and a venting of the expense items is necessary as evidence to support the claim or at least a demonstration that an attempt was made to obtain the data.

266. Kern River argues that the test period actual costs are more reflective of the pipeline's going-forward capital costs because this period includes a full year of experience since the 2003 Expansion, which doubled the system's capacity.[390] Staff asserts that Kern River's adjustment for Account 850 is unrepresentative and should use the as-filed amount of $1,274,859 as opposed to Kern River's proposed test period actual cost amount of $1,863,643.[391] Staff claims that Kern River seemed to have excessive maintenance expenses during the final months of the test period.[392] The last four months for Account No. 850 totaled $972,955 or 76 percent of the as-filed amount. Because Staff believes that this expense rate likely would not continue in the future, they accept the company's as-filed position over the test period adjustments. Kern River claims that several reasons account for an increase to Account No. 850 including: safety costs, additional air quality, power cost increases, and additional costs related to compressors and a turbine exchange program.[393] High Desert and Kern River attest that the air quality

---

[388] 18 C.F.R. § 154.303(a)(4).

[389] *Id.*

[390] Ex. KR-93 at 22.

[391] *See* Ex. S-1 at 13.

[392] *Id*.

[393] Ex. KR-93 at 23.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

or success monitoring costs for the High Desert Lateral in particular are recurring semi-annual costs.[394] The Commission finds that these factors causing increases of Account No. 850 may in fact be recurring expenses that represent typical annual maintenance-related costs on the system and are reflective of future costs. Accordingly, we find that Kern River has met its burden and we will accept the amounts proposed by Kern River.

267. Concerning Account No. 856, Staff objected to Kern River's increase of the as-filed amount because the last two months of the updated period included $368,079 compared to $302,543, the amount in the remaining months of the test period actual costs.[395] Kern River states that it is not unusual for costs in this account to occur during the fall and early winter or the end of the test period; therefore, the test period actual cost should be accepted plus the adjustment related to an inventory correction.[396] Therefore, Kern River proposes that the test period actual cost of $712,158 should be accepted.[397] The Commission finds that Kern River provided sufficient explanation for the increase in cost of Account No. 856, and accepts the actual 12-month test period amount.

268. Regarding the treatment of labor expenses, the Commission finds that Kern River's use of annualized actual test period expense is appropriate. In addition, Staff's reliance on the use of a three-year average as decided in *Williston* is not applicable to this proceeding. In *Williston*, the test period actual amounts reflected non-recurring construction expenses. As a result, the Commission found that the use of a three-year average, which excluded the test period actual construction expenses, was appropriate.[398] Typically, the Commission uses a three-year or five-year average of labor expense ratio because the ratio properly reflects future expense costs. However, in the instant proceeding, the circumstances are dissimilar to *Williston* in that Kern River experienced significant construction expenses that overly inflate the ratio for the years prior to the test period.[399]

---

[394] Ex. KR-93 at 24; Ex. KR-102 at 1.

[395] Ex. S-1 at 13.

[396] Ex. KR-93 at 24.

[397] Ex. KR-93 at 25. This amount includes a $41,535 upward adjustment for an inventory correction (Ex. KR-99 at 1-2).

[398] *See Williston Basin Interstate Pipeline Co.*, 72 FERC ¶ 61,074, at 61,358-61,360 (1995).

[399] *See* Kern River Brief Opposing Exceptions at 84.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

269. Staff advocates an 84.57 percent O&M labor expensing ratio based on an average of the past three years including the 12-month test period (2002, 2003, and 2004 annualized), whereas Kern River requests that the Commission use only the 12-month test period labor expense with no adjustments to determine O&M versus capitalized labor expenses.[400] Based on Kern River's labor cost data for 2001-2004, the labor allocation for O&M accounts in 2004[401] is 91 percent compared to 72 percent, 82 percent, and 80 percent for 2001-2003, respectively; therefore, the data reflects a higher labor O&M to labor capitalization ratio.[402] Also, the data shows a significant decline of 60 percent in labor expenses attributed to construction accounts (Account Nos. 107 and 108) compared to the previous year-on-year increase of 24 percent between 2001 and 2002 and 26 percent between 2002 and 2003.[403] This phenomenon is a result of Kern River experiencing significant expansion expenses prior to the test period in years 2001 through 2003.[404] Kern River states that this construction included four major projects totaling a cost of approximately $1.3 billion dollars and expanding the system by more than double the previous capacity.[405] Therefore, using a three-year average as suggested by Staff that includes years 2002 and 2003 would not be representative of Kern River's future costs.

270. Further, using a three-year average that includes non-recurring construction costs would be inappropriate and inconsistent with section 154.303(a)(4) of the Commission's regulations. Kern River now has no planned or approved expansion projects to be built in the foreseeable future and believes that the activity during the twelve months of the test period better represents ongoing construction activity because that timeframe includes no major expansions.[406] In November 2004, Kern River held an open season to determine interest in firm transportation; however, no shippers requested new expansion capacity, and presently, the pipeline does not have an open season at large. Staff states that Kern River is not in an active construction period, but the company has plans for future construction. Kern's future capital expenditures were reviewed and considered in

---

[400] Ex. KR-93 at 12.

[401] Annualized based on 10 months of data through October 2004.

[402] Ex. S-3 at 17.

[403] *Id.*

[404] *See* Kern River Brief Opposing Exceptions at 83.

[405] Ex. KR-93 at 13.

[406] *Id.*

developing Staff's O&M expensing percentage recommendation.[407] The Commission finds this data to be minor plant additions compared to the recent expansion projects on Kern River's system. Kern River's annual average non-expansion capital additions and 12-month test period additions equate to approximately $8.3 million and $13.6 million, respectively; therefore, the Commission does not consider these construction projects significant enough to warrant an averaging of prior year labor capitalization ratios.[408] The Commission considers Kern River's test period labor expense ratio more representative of its future construction and expense activities.

B. A&G Expenses

Initial Decision

271. Kern River's position is that its rates should be based on actual test period A&G expenses.[409] The position of Staff and various other parties is that Kern River should use its as-filed A&G expense amounts instead of the updated, actual test period amounts since there is no material difference between the two.[410] Staff recommends a five-year amortization period for Account No. 928 (Regulatory Commission Expenses) in order to reflect the time periods between the last two rate cases.[411] Staff also proposes reducing the amounts in Account No. 923 (Outside Services Employed) because Staff claims that data for the most recent period is the most representative of future transactions due to two significant reductions in the account.[412] Staff states the most recent period should be representative of updated cost of debt.[413]

272. The ALJ found that Kern River carried its burden of proving that its proposal to base its A&G expenses on actual test period expenses produces just and reasonable

---

[407] Ex. S-1 at 16; Ex. S-5 at 1-2.

[408] Ex. KR-93 at 15.

[409] *See* ID at P 432.

[410] *Id*. P 433.

[411] *See* Staff Initial Brief at 43.

[412] *See* Ex. S-1 at 15.

[413] *Id.*

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

rates.[414] The ALJ found that the most recent and updated, actual data should be used in the calculation of Kern River's cost-of-service.

Briefs on Exceptions and Opposing Exceptions

273. Staff argues on exception that the ALJ erred in accepting Kern River's level of A&G costs.[415]

274. Kern River notes on exception that Staff took exception to the ALJ's approval of Kern River's actual test period A&G costs, but presented no argument.[416] Kern River argues that its proposed A&G expenses are fully supported and consistent with Commission precedent in *Northwest Pipeline Corporation*.[417] Kern River concludes that its proposed A&G expenses produce just and reasonable rates and should be affirmed.

Commission Determination

275. The Commission affirms the ALJ's decision that basing A&G expenses on Kern River's end of test period actual costs rather than filed costs is just and reasonable. The Commission finds that Kern River's use of the latest test period amounts for A&G expenses is consistent with both section 154.303(a)(4) of the Commission's regulations and with Commission precedent in *Northwest*.[418] In addition, the Commission accepts the latest 12 month test period cost amounts because they more accurately represent the ongoing expenses related to Kern River's mainline system as they reflect the latest available data. This decision is also consistent with the Commission's finding in this order to base other O&M expenses on the last 12 months of test period costs.

276. With regard to Account No. 923, the Commission affirms the ALJ's finding to base these expenses on the latest 12 months of test period amounts. Staff and Kern River's adjustments are similar, reflecting test period data.

---

[414] *Id*. P 440.

[415] *See* Staff Brief Opposing Exceptions at 5.

[416] *See* Kern River Brief Opposing Exceptions at 82 n. 76.

[417] *See Northwest Pipeline Corp.*, 87 FERC ¶ 61,266 at 62,028-30 (1999) (*Northwest*). *See also,* Kern River Brief Opposing Exceptions at 82 n. 76.

[418] *See id.,* at 62,028-30 (1999).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

277. With regard to Account No. 928, the Commission will modify the ALJ's findings in order to permit Kern River to recover its Regulatory Commission expenses related to the rate case from the base and test period over a five-year amortization period for the reasons discussed below. Regarding recurring expenses such as Annual Charge Adjustment (ACA) charges in Account No. 928, the Commission will affirm the ALJ's findings to base these amounts on test period actuals. As permitted in Order No. 472,[419] we will allow Kern River to include its latest 12 month expense for ACA charges as they are recurring expenses.

278. The Commission's general approach to Regulatory Commission expenses is to look at a historical three or five-year period in order to establish a representative level of a pipeline's future expense level during the period the rates are effective. However, here, Kern River did not provide historical data and both staff and Kern River concur that historical amounts are not reflective of potential future expense levels.[420] In our review of the record, we found the latest test period amounts which include the cost of litigating the most recent docket to be most representative of future expense levels.

279. Also, record evidence demonstrates Kern River's past rate case filings are generally filed in five-year increments.[421] Kern River concurs that it has a history of changing rates approximately every five years and no plans otherwise for the next five years.[422] The Commission finds this evidence informative for determining the amortization period.

280. Accordingly, the Commission finds that using a five-year amortization period as suggested by Staff is just and reasonable in projecting Kern River's regulatory expenses related to rate cases. Staff based this amortization period on Kern River's rate case history and states that the company has filed two rate cases at five to seven year intervals. In *Tarpon Transmission Company*,[423] the Commission found that the regulatory cost component of a pipeline's operating and maintenance expenses ordinarily does not include any amortization of past regulatory costs. Rather, normal Commission practice is

---

[419] *See* Reg-Preamble, FERC SR 1986-1990 ¶30,746, Annual Charges Under the Omnibus Budget Reconciliation Act of 1986, Order No. 472, May 29, 1987, Docket No. RM87-3-000.

[420] *See* Ex. No. S-1 at 14-15.

[421] *See* Ex. S-1 at 14 *citing* Docket Nos. RP92-226-000 and RP99-274-000.

[422] *See* Kern River Brief on Exceptions at 78.

[423] *See Tarpon Transmission Co.*, 59 FERC ¶ 61,241 (1992) (*Tarpon*).

to permit the pipeline to recover only those prudent costs which the pipeline projects it will incur in the future. Under the test period concept, the pipeline is at risk for any difference between its test period forecast and its actual operating costs. Its rates are designed based on those actual costs and that risk continues until the completion of its next rate case and the determination of a new just and reasonable rate. This risk attaches whether the costs actually occurring between the completion of one proceeding and the completion of the next proceeding are recurring or nonrecurring costs. However, as an equitable matter, the Commission found in *Tarpon* that the pipeline should be permitted to amortize extraordinary costs over a three-year period.[424] Those extraordinary regulatory costs in *Tarpon* were caused by the unusual litigation proceedings. Similarly, the Commission recognized in *Williston* that it has previously authorized the amortization of certain abnormal operating and maintenance expenses through rate base on a case by case basis.[425] The use of a three year as opposed to five-year amortization period was reflective of the circumstances in the particular proceeding or cost item. Here, as discussed above the record supports a five-year amortization as Kern River indicates it generally files on a five-year cycle. Therefore, consistent with Commission policy, Kern River should be permitted to recover its Regulatory Commission expenses related to the rate case and amortize these costs over a five-year amortization period.

C. Allocation of A&G Costs

Initial Decision

281. Kern River proposed to directly assign $9,362,790 of A&G costs to the different portions of its system.[426] It used the *Kansas-Nebraska (KN)* method[427] to allocate an additional $9,858,490 of A&G costs.[428] The position of Kern River is that a direct assignment of costs is always preferable to allocations when such assignments are based on a reliable accounting record.[429] Kern River states that to the maximum extent feasible,

---

[424] *Id.*

[425] *See Williston Basin Pipeline Co.*, 56 FERC ¶ 61,262, at 61,966 (1991).

[426] Ex. KR-94 (45-Day Update), Statement A at 2, line 3, col. (c).

[427] *Kansas-Nebraska Natural Gas Co., Inc.*, Opinion No. 731, 53 FPC 1691, 1721(*Kansas-Nebraska), reh'g denied*, 54 FPC 923 (1975), *aff'd Kansas-Nebraska Natural Gas Co., Inc. v. FPC*, 534 F. 2d 227 (10th Cir. 1976).

[428] Ex. KR-94 (45-Day Update), Statement A at 2, line 4, col. (c).

[429] *See* ID at P 458.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

administrative personnel directly charge their time and costs to the 2003 Expansion, the High Desert lateral, the Big Horn lateral, and the Rolled-In System. Kern River states that if direct assignment is not feasible, then a predetermined default code is established for each employee to distribute the charges to, or among the appropriate accounts.[430] Kern River argues that this is consistent with Commission precedent and believes that only A&G costs that cannot be directly assigned should be allocated based on the *KN* methodology, following Commission precedent in *Northwest Pipeline Corp.*[431]

282. The position of Staff and Pinnacle West is that all of Kern River's A&G costs should be allocated under the Commission-approved *KN* methodology because these are indirect costs relating to all the services Kern River provides.[432] Staff argues that it has demonstrated that Kern River has deviated from the Commission approved *KN* methodology by allocating only certain A&G costs to facilities and directly charging other expenses. Staff contends that any attempt to allocate A&G costs directly is strictly subjective since they are by their nature indirect, and because specific costs will change annually.[433]

283. The position of High Desert is that Kern River's direct allocation of A&G costs is appropriate.[434] High Desert argues that the approach based on *Northwest* and *Transcontinental Gas Pipeline Corp.*[435] should be adopted because direct assignment is consistent with the Commission's pro-competition policies for the natural gas industry. High Desert points out that no party, including Staff, questioned the accuracy of Kern River's direct assignments. High Desert also explains that adopting any other method has a significant impact on High Desert. For example, under proposals by Staff, High Desert's annual A&G allocation is increased by 450 percent.[436]

---

[430] *Id.*

[431] *See Northwest Pipeline Corp.*, 87 FERC ¶ 61,266, at 62,045 (1999) (*Northwest*).

[432] *See* ID at P 459 and 461.

[433] *Id.* P 459.

[434] *Id.* P 460.

[435] *See Transcontinental Gas Pipeline Corp.*, 106 FERC ¶ 61,299 (2004), *reh'g*, 112 FERC ¶ 61,170 (2005) (Transco).

[436] *See* ID at P 460.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

284. The ALJ found that Kern River had carried its burden of showing that its proposed methodology for allocating A&G costs among services produces just and reasonable results.[437] In addition, the ALJ found that Kern River is correct in its assertion that a direct assignment of A&G costs is preferable when such assignments are based on a reliable accounting record.[438] The ALJ found that Kern River's administrative personnel directly charge time and costs to the individual shippers: 2003 Expansion, the High Desert, the Big Horn, and the Rolled-In. If direct assignment is not feasible, then a predetermined default code is established for each employee to distribute the charges to, or among the appropriate accounts. The ALJ found that no party has challenged the reliability of Kern River's assignment. The ALJ concluded that use of the *KN* method is preferred when it is not possible to directly assign costs.[439]

Briefs on Exceptions and Opposing Exceptions

285. Staff and the RCG contend that the Initial Decision erred in adopting Kern River's proposed methodology for allocating A&G costs among services. Staff asserts the Initial Decision was incorrect that the *KN* method is preferred only when it is not possible to directly assign costs.[440] Staff claims that Commission precedent makes no distinction in types of cost and reiterates that Kern River should allocate all A&G costs solely on the Commission-approved *KN* method based on direct labor ratios and plant ratios.[441] Staff and the RCG assert A&G expenses are by nature indirect costs which cannot be identified with specific customers. Staff asserts the ALJ's rejection of Staff's position is contrary to Commission policy and not supported by the facts in this instant case. The RCG asserts the Initial Decision simply assumed that Kern River's direct assignment and predetermined default code were just and reasonable, without any demonstration that they accurately reflected a reasonable allocation of costs.

286. High Desert agrees with the ALJ's decision to allow Kern River to use direct assignment of A&G costs to specific sub-functions and that this is the best method to assign costs to High Desert.[442] High Desert also argues that during their visit to Kern

---

[437] *Id.* P 463.

[438] *Id.* P 464.

[439] *Id*.

[440] *See* Staff Brief on Exceptions at 44-45.

[441] *See Panhandle Eastern Pipeline Company*, 69 FERC ¶ 65,093 (1996), Opinion No. 404, 74 FERC ¶ 61,109, at 61,377 (1996).

[442] *See* High Desert Brief Opposing Exceptions at 5-6.

River's headquarters, Staff said it had no reason to question the accuracy of the methods Kern River employs.[443] High Desert states that the ALJ's decision is consistent with Commission precedent in *Transcontinental Gas Pipe Line Corp.*[444] High Desert states that in *Transco*, the Commission reiterated the general principle that direct assignment of costs is preferable because it more closely matches cost incurrence with cost responsibility. High Desert states that while it would bear a larger allocation of the costs than it should, other shippers such as RCG would enjoy the benefits of a considerably lower allocation if all A&G costs are subjected to the *KN* method outlined in Staff's proposal.[445]

287. Kern River did not file any arguments in its briefs on and opposing exception with regard to this issue.

Commission Determination

288. The Commission upholds the ALJ's decision that Kern River's allocation of A&G costs was appropriate and that the use of the KN formula allows for the direct assignment of A&G costs where possible to functions and sub-functions. Any remaining costs should then be allocated using the KN method, which establishes the functionalization of A&G direct labor and direct plant ratios for labor and plant related costs.

289. The Commission held in *Kansas-Nebraska*[446] that A&G expenses generally are to be categorized as belonging to labor or to plant. It follows that expenses related to labor should be allocated to various functions in the same ratio that the amount of direct labor in each function bears to the total direct labor. In addition, A&G expenses related to plant should be allocated to each function in the same ratio that the gross plant in each function bears to the total gross plant. Remaining A&G expenses are allocated to the "other" category, and portions are allocated on these same direct labor and plant expenses ratios. In *Kansas-Nebraska*, the Commission stated that administrative and general salaries relate primarily to the expenditure of direct labor.[447] Thus, costs such as A&G salaries, office supplies, expenses, workman's compensation and employee pensions and benefits are related to labor and should follow the concentration of labor effort.

---

[443] *Id.*

[444] *See Transcontinental Gas Pipe Line Corp.*, 106 FERC ¶ 61,299 (2004) (*Transco*); *reh'g*, 112 FERC ¶ 61,170 (2005).

[445] *See* High Desert Brief Opposing Exceptions at 7-8.

[446] *See Kansas-Nebraska*, 53 FPC at 1721.

[447] *Id.*

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

290. However, the Commission's general policy is that direct costs should always be directly assigned and that indirect costs should be allocated by formula. This policy is consistent with the concept that costs should follow cost causation. The first argument here is whether all A&G costs are by nature indirect. Kern River argues it has directly assigned some A&G labor costs where feasible thereby making these direct costs not indirect. Parties have not presented evidence nor challenged the accounting but rather argued summarily that all A&G costs by default are indirect costs and therefore must be allocated by formula. We disagree with this premise. Any cost can be accounted for on a direct basis regardless of the specific expense account in which the cost resides. The test is specifically whether the method of directly assigning the cost is consistent and the relationship obvious and reviewable. Here, Kern River directly assigned certain labor costs by use of employee time sheets filled out by the employees.[448] This is consistent with the same method that direct line employees use for their time reporting in the other operations and expense accounts. Accordingly, the accounting method is an established and accepted accounting practice and is auditable. Because we have no challenge or evidence demonstrating any counter position to the accounting data,[449] we find the costs at issue are in fact directly accounted for properly and meet the definition of directly assigned costs.

291. Subsequent to the *Kansas-Nebraska* decision, the Commission found in *Northwest Pipeline Corp.,*[450] *Transcontinental Gas Pipe Line Corporation,*[451] *and Michigan Gas*

---

[448] Kern River testified that its administrative personnel are directly required to charge time and expenses to the rolled-in system and incremental projects where feasible. Where direct charging of A&G time and expenses is not feasible, Kern River testified that a pre-determined default code established for each employee is used to distribute the charges to or among the appropriate A&G accounts. All other A&G costs are recorded to accounts that are allocated among the original system and the incremental projects using the *KN* methodology. See Ex. KR-94, Statement H-1; Ex. KR-14 at 9; and Ex. KR-93 at 37.

[449] The RCG has not presented any testimony to rebut Kern River's evidence that Kern River engages in these practices and that Kern River's direct charges for A&G costs correctly identify the facilities for which the charges are made.

[450] *See Northwest Pipeline Corporation,* 87 FERC ¶ 61,266 at 62,045 (1999); *order on reh'g,* 92 FERC ¶ 61,287 (2000).

[451] *See Transcontinental Gas Pipe Line Corporation,* 106 FERC ¶ 61,299 at 62,135 (2004).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

Storage Company,[452] that direct assignment of O&M expenses where possible is an acceptable methodology. The Commission finds these cases to be relevant to Kern River, since A&G expenses are part of Kern River's total overall O&M expenses. The Commission finds that when costs cannot be directly assigned, the Commission's policy is to apply the *KN* methodology as discussed above. This approach is supported by Kern River as reflected in its proposal.

292. The Commission finds further that Kern River's method of allocating A&G costs eliminates subsidization of administrative costs that can be directly assigned, more closely matches cost incurrence with cost responsibility, and promotes its goal of competition in the industry. In this vein, the Commission also finds that Kern River shippers on the High Desert lateral would subsidize other customer groups if all A&G costs, including expenses incurred by specific sub-functions, are allocated using plant and labor ratios under the *KN* method.

293. Parties cite *Transco*[453] for the supposition that the Commission always uses *KN* for all A&G costs. The Commission finds here that unlike *Transco*, where the Commission ruled that all A&G costs are to be included in the *KN* allocation formula since costs could not be quantified, Kern River as discussed above provides sufficient support that some A&G costs were directly accounted for by user. Also, in the case of *Transco*, [454] the Commission, consistent with the discussion above, required the pipeline to modify its accounting system so that it can directly assign O&M costs between incremental and non-incremental facilities. However, since *Transco's* accounting practices did not identify direct labor costs associated with incremental services, it was not possible to use the direct assignment method. Here Kern River has and it is possible.

294. For the reasons discussed above, the Commission affirms the ALJ's decision that Kern River has carried its burden of proof that its direct assignment and allocation of A&G costs is just and reasonable. In conclusion, we still find the *KN* formula is appropriate for allocation of indirect costs and affirm our principal decision on the use of the *KN* formula for indirect A&G costs. However, the Commission finds that as adopted for O&M costs, where feasible, if A&G costs can be directly assigned on a reasonable and auditable basis, the pipeline can directly assign those costs where possible and use

---

[452] *See Michigan Gas Storage Company*, 89 FERC ¶ 61,131 at 61,375 and n. 9 pertaining to the Distrigas methodology (1999).

[453] *Transcontinental Gas Pipe Line Corp.*, 106 FERC ¶ 61,299, at P 203 (2004) (*Transco*); *reh'g*, 112 FERC ¶ 61,170 (2005).

[454] *Id.*, 106 FERC ¶ 61,299 at P 190-191 and 203. *See also Michigan Gas Storage Company*, 89 FERC ¶ 61,131 at 61,376 (1999).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

the *KN* method for allocation of all remaining indirect A&G costs as Kern River has demonstrated.

D. Miscellaneous

295. The ALJ did not address the issues of ad valorem taxes and rate base issues including plant, accumulated deferred depreciation and accumulated deferred income taxes (ADIT)(other than NOL-related), working capital, and AFUDC on merits in its initial decision. The Commission interprets the ALJ's general statement in P 567 to be a rejection of the objections to Kern River's proposals on these issues. None of the parties objecting to Kern River's proposals to use end-of-test-period amounts for ad valorem taxes and rate base inclusions of plant, accumulated deferred depreciation, AFUDC, and ADIT excepted to the ALJ's rejection of their contentions (unlike High Desert with respect to the Utah compressor fuel taxes.) The Commission accepts the use of end-of-test-period amounts for these items consistent with our earlier discussion. Staff calculated the working capital amount to reflect an average of the most recent 13 monthly balances as of the end of the test period, a methodology consistent with filing requirements in 18 C.F.R. § 154.312(e).[455] The Commission accepts Staff's calculation consistent with the Commission's regulations.

VII. Rate Design

A. Enhanced Fixed Variable Design

296. Kern River proposed to continue using its current Enhanced Fixed Variable (EFV) rate design. Kern River argued that its proposal is consistent with Order No. 636[456] because the differing levels of fixed costs in the pipeline's transportation usage charge could operate to distort gas purchase decisions and hinder competition between gas

---

[455] *See* testimony of Staff witness Black, Ex. S-6 at 3.

[456] *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, FERC Stats. & Regs. ¶ 30,939 (1992) at 30,434, *order on reh'g*, Order No. 636-A, FERC Stats. & Regs. ¶ 30,950 (1992), *order on reh'g*, Order No. 636-B, 61 FERC ¶ 61,272 (1992), *aff'd in part, rev'd in part, United Distribution Cos. v. FERC*, 88 F.3d 1105 (D.C. Cir. 1996), *cert. denied*, 137 L. Ed. 2d 845, 117 S. Ct. 1723, 117 S. Ct. 1724 (1997), *on remand*, Order No. 636-C, 78 FERC ¶ 61,186 (1997), *order on reh'g*, Order No. 636-D, 83 FERC ¶ 61,210 (1998).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

sellers at the wellhead, and that accurate price signals must be based on the seller's costs in order to ensure fair and direct competition in the gas commodity markets.[457]

297. Kern River contended that proponents of a change to Straight Fixed Variable (SFV) rate design had not demonstrated the impacts of the rate design shift on the entire system. Additionally, Kern River argued that the proponents of a change to SFV have not demonstrated that EFV is unjust and unreasonable or that changing to SFV would be just and reasonable. Kern River also argued that since Kern River's system has historically moved firm and total transportation volumes at a very high load factor of capacity, slack usage of capacity by some shippers has been generally sold as IT, short-term firm or AOS services. Kern River contended that assuming these conditions continue, any upside to Kern River related to the EFV rate design is not a significant contributor to the desirability of continuing the rate design. Kern River argued that use of EFV rate design is clearly in the interests of the vast majority of shippers and should be retained.[458]

298. Calpine supported Kern River's proposal because it is appropriate under the circumstances that currently prevail on Kern River's system. Calpine argued that since Kern River's EFV rate design benefits the 2003 Expansion Shippers by lowering the financial burdens placed on those shippers during their initial years of service, a change to SFV rates would impose significant additional costs on all shippers who take service at less than 100 percent load factor. Calpine further argued that there has been no showing that Kern River's EFV rate design has yielded unjust and unreasonable results that warrant its replacement or that there are changed circumstances that require reconsideration of the EFV rate design in this case.

299. The SCGC argued that Kern River should continue to use the EFV rate design. SCGC argued that the burden of proof lies with those who are proposing a change from Kern River's current rate design and they have not shown that Kern River's EFV rate design has inhibited competition or distorted the creation of a national market for gas, or has had a negative impact on the Kern River system's throughput.

300. Questar argued that Kern River should use the SFV rate design, consistent with Order No. 636 and that in *Northwest Pipeline* the Commission rejected the argument that EFV should be required where the pipeline has a monopoly in the region in order to give the pipeline an incentive to maintain high throughput levels.[459] Questar contended that in

---

[457] Ex. KR-49 at 7.

[458] Ex. KR-23 at 56-59.

[459] *Citing Northwest Pipeline Corp.*, 63 FERC ¶ 61,124, at 61,794 (1993).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

another *Northwest Pipeline* proceeding the Commission found rate reductions for certain customers to be an inadequate justification for EFV and that the Commission in *Arkla Energy Resources* rejected the pipeline's argument that its circumstances warranted an exception from SFV.[460] Questar argued that while exceptions to SFV have been permitted by the Commission, an exception is not justified in Kern River's case. Questar argued that the Commission has permitted exceptions where interstate pipelines were involved, and that the Commission has granted exceptions pursuant to settlement agreements where there was shipper agreement. Questar argued however, that contrary to Kern River's justifications for deviation from SFV, this is a contested proceeding where the parties have not agreed to continue the use of EFV, and the fixed costs included in the transportation charge are not minimal. Questar pointed out that it is one of the highest load factor shippers on Kern River and that Kern River's proposed EFV rate design would require Questar to pay more than under a SFV rate design.

301. The Staff and BP argued that Kern River should not be allowed to use the EFV rate design because use of the SFV rate design is consistent with the Commission's current policy, and while the Commission has permitted some exceptions to its SFV policy, this case does not warrant an exception. Staff pointed out that the Commission has already said that Kern River should use the SFV rate design.[461]

Initial Decision

302. The ALJ held that Kern River has not proven that its continued use of the EFV design results in just and reasonable rates because EFV places a significant amount of fixed costs into the usage component of Kern's rates and is counter to the expressed Commission policy to lower usage charges to the minimum which would best allow the national pipeline grid to reveal the true cost of wellhead natural gas prices, thereby permitting the most effective competition between natural gas sources.[462] The ALJ stated that the Commission has repeatedly upheld the use of SFV for interstate natural gas pipeline companies and only permits exception when all parties agree[463] and the

---

[460] *Citing Northwest Pipeline Corp.*, 76 FERC ¶ 61,068, at 61,429-30 (1996); *Arkla Energy Resources Co.*, 62 FERC ¶ 61,076 (1993), *reh'g denied and granted*, 64 FERC ¶ 61,166 at 62,447-48 (1993).

[461] *See Kern River Gas Transmission Co.*, 62 FERC ¶ 61,191 at 62,256-58 (1993), *reh'g denied*, 64 FERC ¶ 61,049 (1993), *aff'd*, *Union Fuels v. FERC*, 129 F.3d 157 (D.C. Cir. 1997); *see also* Ex. S-12 at 21-22; Ex. S-27 at 12-13.

[462] ID at P 520.

[463] *Citing Northwest Pipeline Corp.*, 76 FERC ¶ 61,068 at 61,429-430 (1996), 63 FERC ¶ 61,124 at 61,794 (1993)and 65 FERC ¶ 61,007 (1993).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

Commission has previously ordered Kern River to adopt the SFV method.[464] Further, the ALJ held that no participant has presented evidence and carried the heavy burden the Commission requires with regard to its preference for SFV rate design method. Moreover, the ALJ held that the rate impacts presented by Kern River demonstrate that the bulk of the shippers will benefit from the switch to SFV due to the very high load factor most shippers maintain under their contracts, while only one shipper appears adversely impacted.[465] The ALJ held that such adverse impacts do not justify departing from the Commission's policy expressed in Order No. 636.[466] Consequently, the ALJ held that the EFV rate design method proposed by Kern River is unjust and unreasonable and the SFV method is found just and reasonable.

Briefs on Exceptions and Opposing Exceptions

303. Only SCGC excepts from the ALJ's decision on this issue. It argues that the ALJ erred in disregarding the fact that Kern River has been using EFV since its last two rate settlements and the Commission approved both settlements with rates based on EFV and noted Kern River's departure from SFV. It also claims the burden is on the proponents of SFV rate design to show that EFV is unjust and unreasonable. It asserts that low load factor customers would pay a higher share of the pipeline's fixed costs under SFV. The Southern California Generating Coalition also argues that where there are cost shifts, such rates should be phased in if the SFV results in an increase of 10 percent or more in the revenue responsibility of any specific class of customers,[467] and the proponents of the SFV did not present any evidence showing the impact of cost shifting among customers, and one-third of Kern River's customers would be adversely affected by a switch to SFV rate design.

304. BP argues that the ALJ's decision comports with Commission policy on SFV rate design policy and should be affirmed. BP argues that all customers agreed to the EFV in prior rate case settlements, but not in this case. Therefore, because all customers have not agreed to the EFV methodology, the Commission's policy in Order No. 636 requires that Kern River must use SFV rate design, and an exemption in this case is not justified. BP urges rejection of the argument that the Commission acceptance of EFV rate design in prior cases places the burden of proof on the proponents of SFV to show that EFV is

---

[464] *See Kern River Gas Transmission Co.*, 64 FERC ¶ 61,049 at 61,418 (1993), and 62 FERC ¶ 61,191 (1993).

[465] Ex. KR-42; Ex. KR-23 at 58.

[466] *Citing Northwest Pipeline Corp.*, 76 FERC ¶ 61,068 at 61,429-430 (1996).

[467] *Citing* Order No. 636 at 30,435-36.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

unjust and unreasonable. BP argues that the burden is on parties advocating something other than SFV,[468] rather than its proponents, and the parties advocating EFV have not carried that burden. BP also argues that while some shippers would be adversely affected by a switch to SFV, the Commission has held that such adverse impacts do not justify departing from the policy expressed in Order No. 636.

305. Questar argues that the Commission should adopt SFV rate design for Kern River's rates because its proposal is inconsistent with SFV rate design policy and the proponents of EFV rate design have not met their burden that Kern River's system warrants an exception to the SFV policy. Questar asserts that the ALJ properly found that EFV places some $17,798,706 of fixed costs into the usage component of rates, counter to the Commission's policy to lower usage charges to a minimum, which permits the most effective competition between natural gas sources. Questar also argues that the proponents of EFV rate design have not meet the burden of demonstrating that SFV is not needed to effectuate the goals of Order No. 636.[469] Further, Questar argues that this proceeding is contested and parties have not agreed to continue the use of EFV. Questar also asserts that the EFV rate design adversely affects Questar and its local distribution customers and that the bulk of shippers will benefit from a switch to the SFV rate design that the Commission previously ordered Kern River to implement. Questar argues that the pipeline, not the customers, is required to show whether mitigation measures are needed in Order No. 636 compliance filings.[470]

306. Staff filed a brief arguing that while the Commission had permitted some exceptions to its SFV policy, this case does not warrant an exception, primarily because the Commission had earlier determined that Kern River should use SFV rate design. Staff also argues that the parties proposing the EFV rate design have the burden with regard to the Commission's preference for SFV rate design method. Staff urges that because significant amounts of fixed costs are in the usage component of Kern River's rates, EFV rate design is counter to the Commission's policy to lower usage charges to the minimum, permitting the most effective competition between natural gas sources.

307. The briefs on exceptions raise these issues: (1) do the past settlements in Kern River's prior rate cases, which approved the use of EFV, control the decision in this proceeding; (2) does Commission policy allow an exemption to the SFV rule where all parties do not agree to use a different rate design method; (3) does the impact of the

---

[468] *Citing* Order No. 636 at 30,434.

[469] *Citing* Order No. 636-A, FERC Stats. & Regs. ¶ 30,950 at 30,605.

[470] Order No. 636, at 30,435-36.

proposed shift to SFV determine the use of EFV; (4) and does the evidence support use of the SFV in this case.

Commission Determination

308. We affirm the ALJ on this issue. While Kern River originally proposed to continue its existing EFV rate design, and both Calpine and SCGC supported that proposal, neither Kern River nor Calpine except from the ALJ's decision. Thus, only SCGC continues to seek an EFV rate design. In a contested proceeding, the proponents of an exception from SFV have a heavy burden to support that exception.[471] Here, the EFV design places a significant amount of fixed costs into the usage component of Kern River's rates and is counter to the expressed Commission policy to lower usage charges to the minimum. The Commission recognizes that there will be cost shifts among customer groups depending on which rate design policy is adopted, but that consequence of the adoption of the SFV methodology has been recognized and approved in prior proceedings.[472] No party presented evidence of unreasonable cost shifts.[473] More importantly, Kern River presented evidence the ALJ adopted reflecting that EFV rate design method places some $17,798,706 of fixed costs into the usage component of rates, which is counter to the Commission's policy to lower usage charges to a minimum. This evidence supports the adoption of SFV so as to meet the policy goals set out in Order No. 636. Further, we agree that the pipeline, not the customers, is required to show whether mitigation measures are needed in Order No. 636 compliance filings and that no mitigation proposals were submitted by Kern River.

309. In addition, past settlements in two Kern River prior rate cases, which approved the use of rates designed using the EFV methodology, do not control the decision in this contested proceeding, for among other reasons, prior settlements do not constitute a precedent for future proceedings.[474] Furthermore, Commission policy allows an exemption to the SFV rate design rule where the vast majority of the parties agree to a settlement providing for a different rate design method and there are no assertions of

---

[471] Order No. 636-A, at 30,604-5.

[472] *See Northwest Pipeline Corp.*, 76 FERC ¶ 61,068, at 61,429-430 (1996).

[473] SCGC stated that the largest impact would be on the Los Angeles Department of Water and Power; however, the city has not participated in this proceeding and is apparently not concerned with the outcome of this issue. SCGC Brief on Exceptions at 34-35.

[474] *See, e.g., Clifton Power Corp.*, 94 FERC ¶ 61,071, at 61,336 n. 25 (2001), *citing Kelly v. FERC*, 96 F.3d 1482 (D.C. Cir. 1996).

specific adverse competitive effects. This exemption policy is true not only with regard to other pipelines,[475] but is true with regard to Kern River where we directed Kern River to adopt SFV,[476] yet accepted the settlements in which all of the parties in those proceedings agreed to the use of EFV. In *Tennessee Gas Pipeline Co.*,[477] we found:

> "If the parties affected by a pipeline's rate design agree to a different method, the Commission will consider giving effect to the parties' agreement." In this case almost all of Tennessee's firm customers, and the participating state commissions, agree to the rate design. The opposition to this aspect of the settlement is generic in nature, and not specific to this settlement or the Tennessee system.

310. Since all of the parties to this contested proceeding have not agreed to the continued use of EFV, the exemption policy does not apply and Kern River's proposal must meet the requirements of Order No. 636. Accordingly, we find that the EFV rate design method sought by SCGC is unjust and unreasonable and the SFV method is found just and reasonable for use in designing Kern River's rates.

B. 100 Percent Load Factor Rate for IT and AOS Service

i. General

311. The 2000 ET Settlement provided for Kern River's maximum rate for both interruptible transportation (IT) service and authorized overrun service (AOS) to be designed based on a 100 percent load factor derivative of the maximum rate for status quo firm shippers on the Rolled-in System.[478] At the time, the maximum rate for status quo firm shippers on the Rolled-in System was Kern River's highest firm transportation rate, since firm shippers who chose the 10-year and 15-year extended contract options received substantially reduced maximum rates. Following the 2003 Expansion, the rate design for IT and AOS transportation service remained unchanged from the 2000 ET Settlement. In the instant section 4 rate case, Kern River proposes to design the maximum IT and AOS rates based on a 100 percent load factor equivalent of the

---

[475] *See, e.g., Northwest Pipeline Corp.*, 76 FERC ¶ 61,068, at 61,429-430 (1996), 63 FERC ¶ 61,124 at 61,794 (1993) and 65 FERC ¶ 61,007 (1993).

[476] *Kern River Gas Transmission Co.*, 62 FERC ¶ 61,191, at 62,256-58 (1993), *reh'g denied*, 64 FERC ¶ 61,049 (1993).

[477] *Tennessee Gas Pipeline Co.*, 77 FERC ¶ 61,083, at 61,356 (1996) (footnote omitted).

[478] *2000 ET Settlement Order*, 92 FERC at 61,157.

maximum incremental rate for 10-year, 2003 Expansion service, including the $0.06 per Dth commodity charge. Kern River justified this proposal on the ground that the 10-year 2003 Expansion rate is the highest maximum firm transportation rate on its system. As part of its section 4 rate proposal in this case, Kern River also proposed to eliminate from its tariff the maximum rate for status quo shippers, since no shipper on the Rolled-in System chose that option.[479]

Initial Decision

312. The ALJ concluded that Kern River had not carried its burden of proving that its proposal produces just and reasonable rates. Instead, the ALJ adopted Staff's proposal to design both the IT and AOS rates on a "blended" basis reflecting the costs of both the Rolled-in System and the 2003 Expansion. Staff calculated blended 100 percent load factor IT and AOS rates by dividing the total fixed costs of both the Rolled-in System and the 2003 Expansion System by total demand determinants and adding a commodity component equal to total variable costs divided by total throughput.[480]

313. The ALJ explained that, among the Commission's goals for rate design, is the objective that rates should promote allocative efficiency (the principle that during times of scarce capacity service should go to those who value it most, *i.e.*, those willing to pay the most). The ALJ determined that, because no showing had been made of the need for Kern River to ration its IT/AOS capacity, there was no justification for using the highest firm rate (ten-year Expansion 2003 firm transportation service rates) to calculate the maximum rate for IT/AOS services.

314. The ALJ also found that Staff's proposal did not cause any cross subsidy. She stated that Staff's proposal does not require the Original System shippers to pay for any costs associated with the 2003 Expansion capacity, nor does it allocate costs from the 2003 Expansion shippers to the Original System shippers. The ALJ explained that, since 2003 Expansion capacity was built onto the original system trunkline with operation on an integrated basis, usage of a particular shippers' capacity between the Original System design and the 2003 Expansion capacity is not distinguishably assignable to either on an operational basis. The ALJ also stated that Staff's approach is appropriate because it recognizes that Kern River's operations allow Original Shippers to benefit from the 2003 Expansion capacity through the ability to obtain AOS and IT service at fair rates. Finally, the ALJ stated that the blended approach further assured a level playing field and that all shippers benefited from the revenues received via a revenue credit to their respective facilities' cost-of-service.

---

[479] Thirteenth Revised Sheet No. 5.

[480] Ex. S-12 at 24.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

Briefs on Exceptions and Opposing Exceptions

315. Kern River and Calpine urge the Commission to reverse the ALJ's ruling on this issue and accept Kern River's proposal to continue designing its maximum rate for IT and AOS as the 100 percent load factor equivalent of the highest firm transportation rate on the system.

316. Kern River argues that the ALJ's rejection of Kern River's IT/AOS rate design contravenes section 5 of the NGA and is inconsistent with Commission precedent, citing, *e.g.*, *Viking Gas Transmission Co.*, 101 FERC ¶ 61,107 (2002) (*Viking Gas*).

317. Kern River argues that, since its proposed IT/AOS rate design has been in place since the Commission approved the 2000 ET Settlement,[481] the ALJ could adopt Staff's proposal only upon Staff satisfying its dual burden of proof under section 5 of the NGA.[482] Kern River claims that Staff failed to satisfy its burden of proof by: offering no rationale as to why Kern River's proposed rate is unjust and unreasonable, and failing to reconcile its position with the Commission's previous acceptance of Kern River's prevailing rate design.[483] Calpine argues that the ID never explains why continuation of the current approach to setting IT/AOS rates on the Kern River system is unjust and unreasonable. Kern River also contends that its rate design is consistent with the Commission's rate design policy statement.

318. Kern River highlights how Staff's blended IT rate would negatively impact the capacity release market, stating that it would force 2003 Expansion shippers to discount their capacity releases to compete when the IT rate constrains prices for IT transactions. Kern River argues that, likewise, the blended rate would effectively preclude Kern River from re-marketing its unsubscribed 2003 Expansion capacity at any rate higher than the IT rate.

319. Calpine argues that the ALJ's statement that an IT or AOS shipper's capacity usage cannot be assigned to either the rolled-in or 2003 Expansion system on an operational basis[484] is flatly contradicted by the ALJ's earlier factual finding that "AOS and IT . . . are primarily using (based on test period evidence) 2003 Expansion capacity

---

[481] Kern River cites *2000 ET Settlement Order*, 92 FERC at 61,157.

[482] Kern River cites *e.g.*, *W. Res. Inc. v. FERC*, 9 F.3d 1568 (D.C. Cir. 1993) (*Western Resources*).

[483] Kern River cites *2000 ET Settlement Order*, 92 FERC at .

[484] ID at P 533.

to receive service."[485] According to Calpine, all shippers would benefit from the pipeline's market-oriented revenue (MOR) credit[486] regardless of the IT/AOS rate design used and the IT/AOS rate design supported by Kern River and Calpine would generate greater IT/AOS revenues than the blended rate design, thereby enhancing the MOR credit received by all Kern River firm shippers.

320. The RCG and SCGC do not object to a blended rate for IT, but do object to a blended rate for AOS. The RCG and SCGC propose that the AOS transportation rate for the rolled-in shippers be calculated at the 100 percent load factor of the applicable firm rolled-in rate (e.g., the 100 percent load factor of the 15-year rolled-in rate for 15-year rolled-in shippers, and the 100 percent load factor of the 10-year rolled-in rate for 10-year rolled-in shippers). SCGC states that Staff's proposed blended rate may be just and reasonable for Kern River's IT service, given that IT shippers are competing with all the shipper groups on Kern River's system. However, SCGC and the RCG contend that issue of the AOS rate is wholly distinct from the IT rates or IT rate schedule and argue that the AOS rate associated with rolled-in service should be based on the rate of the underlying firm service contract.

321. The RCG claims the ALJ did not address its arguments or evidence that under Kern River's rolled-in rate schedules and contracts, the rolled-in shippers' transportation rates are not to be increased as a result of an expansion. According to the RCG, certain of Kern River's FT rate schedules (CH-1, MO-1, and UP-1) provide that if there is an expansion, the shipper will not bear "any" costs associated with the expansion, "whatsoever, including fuel." The RCG argues that the ID, in charging the rolled-in shippers an AOS transportation rate that would cause those shippers to bear increased costs associated with the expansion, violates the express terms of the CH-1, MO-1, and UP-1 rate schedules. The RCG argues that the AOS transportation rate for the rolled-in system should be derived from, and based upon, only the costs allocated to the rolled-in system, consistent with Commission regulations and Kern River's tariff.

322. The RCG asserts that, prior to the 2003 expansion, the rolled-in shippers paid an AOS rate calculated as the 100 percent load factor of their rolled-in firm transportation rates. But under this ID, the AOS rate associated with a firm rolled-in contract would be

---

[485] ID at P 499.

[486] Market-oriented revenue applies to revenues from services such as interruptible, short-term firm, backhaul and negotiated rate transportation for which costs are not allocated in the rate design process but for which a representative amount of revenues is credited to the cost of service. Ex. BP-1 at 23.

in excess of the underlying rolled-in rates. According to the RCG, if there had been no expansion, there would have been no basis for increasing the AOS rate. The RCG argues that it is unjust and unreasonable to increase the AOS rate for rolled-in shippers merely because Kern River chose to undertake the expansion.

323. SCGC claims that the only evidence supporting the ALJ's finding that Original System shippers benefit from the 2003 Expansion capacity through the ability to obtain AOS service, is not credible. SCGC states that Calpine's witness Mr. Hughes relies on general and inconclusive data regarding the relative annual utilization of capacity by 2003 Expansion and Rolled-In Shippers. SCGC contends that the ALJ correctly concluded that there is no way to determine whether 2003 Expansion capacity is being used by a particular AOS shipper on any given day. According to SCGC, different classes of shippers pay different rates for use of the same facilities, a fundamental characteristic of Kern River's rates that has always existed and which every shipper has known.

324. Kern River states that the ALJ was correct in rejecting the RCG's and SCGC's proposed AOS rate design, since AOS service provided to the rolled-in shippers cannot be attributed to any particular capacity. Kern River asserts that the ALJ correctly found no merit to the "subsidy" argument advanced by the RCG and SCGC in support of their AOS rate proposal. Kern River points out that, as the ALJ observed, the fact that Rolled-In customers might realize an increase in their AOS rate does not mean that any costs of the 2003 Expansion are being allocated to their firm service.[487]

325. In its brief opposing exceptions, Staff states that the ALJ properly rejected Kern River's proposed 100 percent load factor rate for IT/AOS services. Staff asserts that Kern River's reliance on *Viking Gas* is misplaced, since that order approved an uncontested settlement, which by its own terms is non-precedential. Staff urges the Commission to adopt the ALJ's determination.

Commission Determination

326. The Commission affirms the ALJ's determination adopting the blended approach proposed by Staff for designing both the IT and AOS rates. The Commission finds that Kern River failed to satisfy its burden under NGA section 4 to show that its proposed IT and AOS rate design is just and reasonable. Staff's proposal, on the other hand, meets the Commission's goal of promoting allocative efficiency, and accounts for IT/AOS shippers making use of the entire Kern River system. Additionally, we find that, because IT and AOS transportation are identical on the Kern River system, the same maximum rate should apply to both.

---

[487] *Id.*

327. The Commission rejects Kern River's argument that it is simply proposing to continue its existing IT/AOS rate design, and therefore, has no burden under NGA section 4 to support its proposed rate design. Although Kern River contends that its IT/AOS maximum rate proposal is "to continue designing its rates . . . at the 100 percent load factor equivalent of the highest firm transportation rate on Kern River's system (*i.e.*, the recourse rate for 10-year service on the 2003 Expansion)," as will be shown below, Kern River is proposing to change the design of its IT/AOS rates. Therefore, Kern River's proposal falls under the ambit of section 4 and must satisfy its burden of proof requirements.

328. Kern River is simply in error in its claims that its proposed rate design for IT/AOS service is a continuation of the IT/AOS rate design approved in the 2000 ET Settlement. The 2000 ET Settlement provided for the IT and AOS rates to be designed as a 100 percent load factor derivative of the rates provided in that settlement for Status Quo shippers. Status Quo shippers were firm shippers on Kern River's Original System who chose to continue their original contracts, and did not extend their contracts under either the 10-year or 15-year contract extension options. Thus, the 2000 ET Settlement provided for the IT and AOS rates to be designed based solely on the costs of the Original System and for those rates to be unaffected by the contract extensions offered to the firm shippers on the Original System. The design of the IT and AOS rates, based on a 100 percent load factor of the status quo shipper rate, remained in effect until Kern River's instant section 4 rate filing, except for a small reduction to the IT and AOS rates to reflect the roll-in of the costs of the 2002 expansion.

329. In this section 4 rate case, Kern River has proposed to eliminate the maximum rate for firm status quo shippers on the rolled-in system, since no firm shipper chose that option in the 2000 ET Settlement. As a result, there is no longer a status quo firm rate upon which to base the IT and AOS rates. Instead, Kern River is proposing for the first time to design the IT and AOS rates as the 100 percent load factor derivative of the firm 10-year 2003 Expansion rate. This is a clear change from the previous design of the IT and AOS rates, since under Kern River's proposal those rates will, for the first time, reflect the incremental costs of the 2003 Expansion, rather than being designed based on the costs of the rolled-in system. Also, for the first time, Kern River will be using a firm 10-year contract rate as the basis for the IT and AOS rates.

330. Therefore, in order for Kern River's proposal to be accepted by the Commission, Kern River must demonstrate that its proposal is just and reasonable as required under section 4 of the NGA.

331. We affirm the ALJ's decision that Kern River has not carried its burden of proof under section 4 of the NGA. The instant case presents for the first time, on a full record

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

developed at hearing, the issue of how interruptible rates should be designed in the section 4 rate case of a pipeline with incremental rates.[488] All parties are in agreement that Kern River's IT and AOS rates should be designed based upon a 100 percent load factor equivalent of firm service rates.[489] The dispute between the parties centers on whether the 100 percent load factor rates should be designed based upon (1) the highest incremental rate on the system, as proposed by Kern River, or (2) a blend of all Kern River's firm rates, which would in essence design the IT rate on a rolled-in basis. We find that, at least in the circumstances of Kern River's system as shown by the instant record, the IT and AOS rates should be designed on a rolled-in basis, rather than an incremental basis.

332. No party contests the ALJ's finding that Kern River operates its rolled-in facilities and 2003 expansion facilities on an integrated basis. In short, Kern River uses both the Rolled-in System and the 2003 Expansion System to provide service to all its shippers, including its IT shippers.[490] It follows that, as a Staff witness testified, both the Rolled-in System and the 2003 Expansion System provide the capacity available for interruptible service.[491] This fact supports designing the IT rate on a fully rolled-in basis. As the D.C. Circuit has held, "Properly designed rates should produce revenues from each class of

---

[488] Kern River is misplaced in its reliance on the Viking Gas rate settlement. In Viking Gas, the Commission issued an uncontested negotiated settlement, which by its own terms is non-precedential. Not only does Viking Gas lack precedential value, its settlement terms, as determined by the Commission, could be changed in a future merits rate proceeding. In addition, at the time of Kern River's 2000 ET Settlement, Kern River did not have incremental rates, and therefore that settlement presented no issue concerning the design of IT rates on a system with incremental rates.

[489] Since the 1989 Rate Design Policy Statement, the Commission has generally approved 100 percent load factor IT rates. As the Commission stated in *Southern Natural Gas Co.*, 75 FERC ¶ 61,146, at 61,138 (1996), "experience has shown that 100 percent load factor rates generally strike a reasonable balance among the various ratemaking goals set forth in the Policy Statement." Those include that IT rates "ration scarce capacity during peak periods, maximize throughput when capacity is available, and recognize quality of service considerations." *Id*., at 61,137.

[490] See Staff Reply Brief at 41; SCGC Brief on Exceptions at 36. *See also, Southeastern Michigan Gas Co. v. FERC*, 133 F.3d 34, 41 (1998), stating: "Because every shipper is economically marginal, the costs of increased demand may equitably be attributed to every user, regardless when it first contracted with the pipeline." The D.C. Circuit cited 1 Alfred E. Kahn, *The Economics of Regulation* 140 (1970).

[491] Ex. S-27 at 16:14-18.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

customer which match, as closely as practicable, the costs to serve each class or individual customer."[492] The costs incurred to serve IT customers are not just the higher per-unit incremental costs of the 2003 Expansion, but the average lower per-unit costs of the entire system. Thus, Kern River's proposal to design the IT rate based upon a 100 percent load factor derivative of the highest incremental rate on its system is inconsistent with the general rate making principle of matching cost incurrence and cost causation.

333. There is nothing in the Commission's policies concerning incremental versus rolled-in rates to support designing Kern River's IT rates on an incremental basis, as it has proposed. The focus of those policies is on the rates paid by firm shippers for the capacity they have reserved under their firm contracts, not on the design of rates for interruptible service. Under the1999 *Policy Statement Concerning Certification of New Interstate Natural Gas Pipeline Facilities* (1999 Pricing Policy Statement), [493] the Commission seeks to encourage efficient investment and contracting decisions by pipelines and shippers concerning the construction of new capacity. It does this by generally requiring that expansions be priced incrementally, so that expansion shippers will have to pay the full costs of the new capacity without subsidy from the existing customers through rolled-in pricing. This helps ensure that the market finds the project viable, because either the expansion shippers or the pipeline must be willing to fully fund the project. In addition, the Commission has held that existing shippers should not be required to pay the costs of an expansion during the term of their contract "because these shippers sign long-term contracts with the expectation that increases in their rate will be related to the costs and usage of the system for which they subscribe. Raising the rates of these existing shippers during the term of their long-term contracts to include expansion costs reduces rate certainty and increases contractual risk, and the Commission has determined their contracts should protect them from this risk."[494]

334. These various considerations underlying the Commission's rolled-in versus incremental rate policies all relate to firm service, not interruptible service. Pipelines build expansions to provide sufficient capacity to provide guaranteed firm service to those shippers who desire it. Thus, the investment and contracting decisions the Commission seeks to affect through its rolled-in vs. incremental rate policies are made by pipelines and their firm shippers, not interruptible shippers. Moreover, the existing shippers which the Commission seeks to protect from rate increases are shippers who

---

[492] *Alabama Electric Cooperative, Inc. v. FERC*, 684 F.2d 20, 27 (D.C. Cir. 1982); *K N Energy Inc. v. FERC*, 968 F. 2d 1295, 1300-1 (D.C. Cir. 1992).

[493] 88 FERC ¶ 61,227 (1999), 90 FERC ¶ 61,128 (2000), *reh'g*, 92 FERC ¶ 61,094 (2000).

[494] Order No. 637-A, at 31,637.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

"sign long-term contracts" for service on the existing system. Only firm shippers sign such long-term contracts. Since interruptible shippers do not contract with the pipeline to obtain any guaranteed entitlement to service on any part of the pipeline's system, the Commission's policy preference for incremental rates does not apply to those shippers.

335. Kern River claims that its proposal to design its interruptible rate based on the highest firm incremental rate is necessary to establish a level playing field among all shippers in the capacity release market. We recognize that we have held that the pipeline's sale of interruptible service and its firm shippers' capacity releases compete with one another. However, given that there are six different maximum firm rates for service on Kern River's Rolled-in system and its 2003 Expansion, and all parties agree that there should be a single uniform maximum rate for IT service, the maximum rate for IT service cannot match the 100 percent load factor rates of all firm services. Thus, no matter what IT maximum rate is adopted, there will be some competitive distortions. Under Kern River's proposal, interruptible shippers would be subject to a maximum rate that, on a 100 percent load factor basis, is substantially higher than the maximum rates applicable to all capacity releases, other than those by firm shippers with 10-year contracts for service on the 2003 Expansion. Yet the interruptible shippers would be obtaining a lower quality service than the firm service obtained by the replacement shippers.

336. Kern River also asserts that its proposal accomplishes the Commission's goal of allocative efficiency, as described in the Commission's rate design policy statement, by allowing Kern River to charge high prices to ration scarce capacity.[495] We agree with the ALJ that Kern River has not demonstrated that its proposed IT rate of over 60 cents per Dth is needed for purposes of rationing its IT/AOS capacity. Staff presented evidence that the highest monthly average rate Kern River was able to charge during the last 12 months of the test period was 22.56 cents per Dth during August 2004, while Staff's proposed rate would equal approximately 40 cents per Dth.[496] It thus appears that Staff's proposed rate is sufficiently high to permit Kern River to ration any scarce capacity. Finally, the Commission's policy is generally to not allow a separate IT rate for new projects.[497] Separate incremental rates for IT service, as is being proposed by Kern River, is allowed in situations where shippers using the new facilities would be separately identified and accounted for[498]- which is not the case here. Therefore, we affirm the

---

[495] *Policy Statement Providing Guidance with Respect to the Designing of Rates*, 47 FERC ¶ 61,295 (1989) (Rate Design Policy Statement).

[496] Ex. S-27, at 17.

[497] *Transcontinental Gas Pipeline Corp.*, 79 FERC ¶ 61,286 (1997).

[498] *Id.*

ALJ's rejection of Kern River's proposal and determine that Kern River not only failed to carry its burden of proof under section 4 of the NGA, but that Kern River's proposal is unjust and unreasonable.

337. We recognize that under *Western Resources*, the Commission, upon rejecting a section 4 proposal and proposing its own change to the pre-existing rate design, has the dual burden of proof under section 5 of the NGA to show that the pre-existing rate design is unjust and unreasonable and that the Commission's proposed change is just and reasonable. Here, as discussed above, Kern River previously designed its IT and AOS rates based on a 100 percent load factor derivative of the "status quo" rates for firm service on the Rolled-in System. However, that rate design is no longer an option, since Kern River has eliminated the status quo rates from its tariff on the ground that no firm shippers pays those rates any more. In any event, the first status quo rates reflected only the costs of the Rolled-in system, and therefore continued use of those rates to design the IT rates would be inconsistent with our holding above that, on an integrated system such as Kern River, the IT rates should be based upon the rolled-in costs of the entire system including the 2003 Expansion.

338. Therefore, we find that the pre-existing rate design is unjust and unreasonable. The blended rate proposal of Staff, which we adopt, is just and reasonable. Above, we have held that on an integrated system, the IT rates established in a section 4 rate case should be based on the rolled-in costs of the entire system, regardless of whether there are firm services priced on an incremental basis. Staff's blended rate proposal is consistent with that policy. Moreover, as discussed above, there are no other factors supporting a higher rate.

ii. <u>Rates for IT versus AOS transportation</u>

339. We now address a claim by the RCG and SCGC that IT and AOS are distinct and, therefore, should be charged differently. Neither the RCG not SCGC objects to a blended rate for IT. However, both parties object to the blended rate for AOS, arguing that the AOS rate associated with rolled-in service should be based on the rate of the underlying firm service contract.

340. Contrary to the RCG and SCGC, we find, based on the record and Commission precedent, that AOS and IT are identical services that should be charged the same rate. Both are interruptible services which are provided only to the extent that Kern River has capacity available after scheduling firm service. Under Section 13.2 of the General Terms and Conditions of Kern River's currently effective tariff, both the IT rate and the AOS rate hold the same priority. As we reasoned in a prior order addressing a Kern River compliance filing:

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

> In *Tennessee Gas*, we held that overrun service is not entitled to a higher priority than interruptible service. Firm customers have a firm right to service only up to the level of their contract demands. Authorized overrun service above that level is an interruptible service for which the firm shippers pay the same 100 percent load factor rate as other interruptible shippers receiving service at the maximum IT rate. In light of these facts, there is no reason why authorized overrun service should have a priority over other interruptible service at the maximum rate.[499]

AOS and IT, in being precluded from having different priorities, are therefore acknowledged as essentially being the same service for which rates should be identical. The RCG and SCGC offer no evidence demonstrating that this is not the case. The fact that firm customers on the Rolled-in System pay lower rates for their firm service does not entitle them to pay lower rates for the AOS service. The rolled-in shippers' firm contracts only entitle them to service up to their firm contract demand.

iii. <u>Miscellaneous</u>

341. Finally, we address an argument by the RCG that, under Kern River's rolled-in rate schedules and contracts, the rolled-in shippers' transportation rates are not to be increased as a result of an expansion. The FT rate schedules[500] to which the RCG cites as evidence that rolled-in shippers will not bear any costs associated with an expansion, are not applicable here because those rate schedules are only applicable to the firm service received by Rolled-In System shippers, and not interruptible AOS service. Of necessity, the AOS transportation rate should be based on the average of the entire system since it is not possible to determine if IT/AOS customers are using the incremental facilities or the existing facilities. Staff's blended rate proposal recognizes this fact, and for this and other reasons described above, is just and reasonable and therefore accepted.

---

[499] *Kern River Gas Transmission*, 64 FERC ¶ 61,049, at 61,434 (1993) (quoting Tennessee Gas Pipeline Co., 62 FERC ¶ 61,250, slip op. at pp. 82-83). *See also, Dominion Cove Point LNG LP*, 115 FERC ¶ 61,337 at P 122 (2006), in which the Commission stated that "Commission policy dictates that authorized overrun and interruptible service are identical, requiring pipelines to revise their tariffs so that interruptible and overrun service have the same scheduling priority."

[500] Rate Schedules UP-1, MO-1, and CH-1.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

C. Allocation of Cost of Facilities

Initial Decision

342. The position of Kern River is that allocation of costs to Rolled-in shippers existing before the construction of the 2003 Expansion produces just and reasonable rates. Those items include the cost of land, rights of way, compressor station structures, and certain communications equipment. Kern River believes that allocation of those costs to the Rolled-In shippers comports with the principles of fairness and cost responsibility.[501] The position of Calpine is that RCG's proposed allocation of common costs, as discussed below, should be rejected because it would create a subsidy flowing from Kern River's 2003 Expansion shippers to its Rolled-In shippers. Calpine argues that RCG has not met the "changed circumstances" criterion as required by the *1999 Pricing Policy Statement*. The position of Pinnacle West is that RCG's proposal is inconsistent with the Commission's *1999 Pricing Policy Statement*. Pinnacle West claims that there is no precedent requiring the creation of subsidies flowing from expansion shippers back to pre-existing shippers.[502]

343. The position of RCG is that certain common costs should be allocated to both sets of shippers. RCG argues that the land, rights of way, compressor station structures, and communications equipment benefit all of Kern River's customers.[503] The position of SCGC is that Kern River should be required to allocate the common costs to both the 2003 Expansion Shippers and the Rolled-In Shippers, as proposed by RCG. SCGC points out that no Participant disputes the fact that both Rolled-In and 2003 Expansion shippers use the common cost facilities. SCGC further claims that the *1999 Pricing Policy Statement* does not support the notion that facilities used by both existing shippers and expansion shippers should be borne by existing shippers only. According to SCGC, the *1999 Pricing Policy Statement* clearly indicates the Commission's concern about the possibility that costs of existing facilities that were used by the expansion shippers and that served to make the expansion less costly, would be borne solely by the existing shippers. SCGC argues that the Rolled-In Shippers are subsidizing the 2003 Expansion Shippers by bearing all of the common costs and that there is no evidence indicating that the Commission specifically addressed the costs associated with those facilities in its certificate order for the 2003 Expansion.[504]

---

[501] Kern River Initial Brief Findings of Fact III 1.

[502] Pinnacle West Initial Brief at 37-38.

[503] RCG Initial Brief at 41.

[504] SCGC Reply Brief at 3-6; *see 1999 Pricing Policy Statement*, 88 FERC ¶ 61,227 at 61,746.

(footnote continued)

344. Staff, BP, Edison Mission, and Questar take no position on this issue.

345. The ALJ concluded that Kern River carried its burden of proving that cost for items in existence before construction of the 2003 Expansion should be borne by the Rolled-In shippers. The ALJ cited to *Trailblazer Pipeline Company*, where the ALJ in that case stated "nowhere in Commission pronouncements has the Commission required the assignment of existing facility costs to expansion customers."[505] The ALJ found that in the instant proceeding, as in *Trailblazer Pipeline*, parties advocating sharing costs have not shown any changed circumstance since the authorizing certificate that would indicate the expansion shippers should pay such costs.

Briefs on Exceptions and Opposing Exceptions

346. RCG states on exception that the ALJ erred when relying on *Trailblazer Pipeline*, since this decision was dismissed as moot and cannot be relied upon as precedent.[506] RCG states that Kern River did not allocate to all shippers any common costs associated with the land, rights of way, compressor station structures, and communications equipment even though use of these facilities is shared by both rolled-in and expansion shippers. RCG argues that these costs are paid solely by the rolled-in shippers which is unjust and unreasonable, since all of Kern River's shippers benefit from these items.[507]

347. SCGC states on exception that unlike the decision in *Trailblazer Pipeline*, Kern River is already allocating certain shared facility costs, such as general plant and payroll taxes, among the Rolled-in and the 2003 expansion shippers.[508] SCGC argues that to be consistent and to ensure that those that use the facilities pay for them, Kern River should allocate the remaining costs of facilities that are used by both the Rolled-in and 2003 expansion shippers. SCGC also contends that unlike the decision in *Trailblazer Pipeline*

---

[505] *See Trailblazer Pipeline Company*, 106 FERC ¶ 63,005 at P 112 (2004).

[506] *See* RCG Brief on Exceptions at 36. *See also Trailblazer Pipeline Company*, 107 FERC ¶ 61,008 (2004).

[507] *See* RCG Brief on Exceptions at 37.

[508] *See* SCGC Brief on Exceptions at 30.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

where the ALJ found that historic customers are shielded from the financial impacts of the expansion project, Kern River shippers will not be shielded from the financial impact if the ALJ's determination to require a blended authorized overrun rate is approved.[509] Furthermore, SCGC argues that the Commission's *1999 Pricing Policy Statement* should not be relied upon since it does not address the allocation of costs that would apply in a section 4 rate proceeding. SCGC relies upon the Commission's decision in *Northwest Pipeline Corporation*,[510] to support its position that incremental rates that include costs associated with existing facilities have been approved as part of an initial rate. SCGC concludes that a requirement to show changed circumstance does not apply to the appropriate allocation of individual cost components among a pipeline's customers in a section 4 rate proceeding.[511]

348. Calpine states on exception that the Commission's *1999 Pricing Policy Statement* requires the separation of pre-expansion and expansion project costs.[512] Calpine states that Kern River has separated pre-expansion and 2003 expansion costs as part of the 2003 expansion certificate proceeding.[513] Calpine states that the Commission's certificate order expressly found that, with one negligible exception, there would be no cost overlaps between that project and Kern River's other facilities.[514] Calpine also states that in the 2003 expansion certificate proceeding, the Commission found that Kern River's expansion project will not be subsidized by its existing customers because Kern River proposes to charge the 2003 expansion project shippers incremental rates.[515]

349. Both Calpine and Pinnacle West argue that the Commission's decision in *Northwest Pipeline Corporation* does not support SCGC's claim for rolled-in pre-expansion costs in the Kern River instant rate case. Calpine states that in *Northwest Pipeline Corporation*, where formerly rolled-in capacity became part of a pipeline's expansion project, the cost of that capacity became an expansion cost. However, Calpine

---

[509] *Id.* at 31.

[510] *See Northwest Pipeline Corp.*, 98 FERC ¶ 61,352 at 62,493 (2002).

[511] *See* SCGC's Brief on exception at p. 32.

[512] *See* Calpine's Brief on exception at p. 76. *See also 1999 Pricing Policy Statement*, 88 FERC at 61,746-47 (1999).

[513] *See Kern River Gas Transmission Company*, 98 FERC ¶ 61,205 (2002).

[514] *Id.* at 61,723 (2002).

[515] *Id.* at 61,715 (2002).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

states that the Commission in both *Northwest Pipeline Corporation* and Kern River's 2003 expansion certificate proceeding did not allocate any other rolled-in system costs to the proposed expansion project.[516] Finally, Calpine argues that SCGC confuses a rate design issue pertaining to authorized overrun service with a cost allocation issue pertaining to expansion costs.

Commission Determination

350. The Commission will affirm the ALJ's decision that Kern River carried its burden of proving that the cost for items in existence before construction of the 2003 expansion should be borne solely by the Rolled-in shippers. The Commission finds that a change in Kern River's current methodology would create an unwarranted subsidy flowing from the 2003 Expansion shippers to Rolled-in shippers. In addition, no party in this proceeding has shown a changed circumstance exists since the 2003 expansion certificate order[517] that would now require 2003 expansion shippers to pay for such pre-2003 expansion costs. Further, Kern River's current methodology is consistent with Commission precedent to directly assign costs when possible.[518]

351. The Commission finds that SCGC's reliance on *Northwest Pipeline Corporation*,[519] is misplaced. The Commission finds that in both *Northwest Pipeline Corporation* and Kern River's 2003 expansion certificate proceedings, the Commission did not allocate any rolled-in system costs, with the exception of costs associated with rolled-in capacity as part of a pipeline's expansion project, to the proposed expansion project.[520] Further, the Commission's *1999 Pricing Policy Statement* requires the separation of pre-expansion and expansion project costs.[521] Finally, RCG and SCGC have not presented a valid reason for a change in Kern River's current methodology of allocating certain common costs to Rolled-in shippers other than for their own self-interest.

---

[516] *Id.* at 61,723 (2002).

[517] *See Kern River Gas Transmission Company*, 98 FERC ¶ 61,205 (2002).

[518] *See Northwest Pipeline Corp.*, 87 FERC ¶ 61,266 (1999).

[519] *See Northwest Pipeline Corp.*, 98 FERC ¶ 61,352, at 62,493 (2002). *See also Kern River Gas Transmission Company*, 98 FERC ¶ 61,205, at 61,723 (2002).

[520] *See Northwest Pipeline Corp.*, 98 FERC at 62,493 (2002).

[521] *See 1999 Pricing Policy Statement*, 88 FERC at 61,746-47 (1999).

D. 2002 Expansion Roll-In

Initial Decision

352. Kern River argued that it should not change the roll-in methodology for the 2002 Expansion because that would shift costs between shipper classes to the benefit of the ten-year shippers at the expense of the fifteen-year shippers.[522] Kern River argued that if the roll-in plan continues as originally implemented by Kern River and approved by the Commission, and if the ten-year shippers remain on the system after their current contracts expire, then over time all shippers would receive identical benefits of the roll-in of the 2002 Expansion.[523]

353. RCG and SCGC argued that Kern River should allocate the 2002 Expansion roll-in benefit on an equal-unit basis to the rolled-in rates. BP argued that if levelized rates are retained, the Commission should separately calculate for ten-year and fifteen-year shippers whether to roll-in the 2002 Expansion to Original System costs.[524] BP asserted that Kern River's approach causes the ten-year Rolled-In System shippers to bear the largest proposed rate increase of all Kern River's shippers. BP claimed that by adding the ten-year and fifteen-year Expansion 2002 costs and revenues to calculate a combine unit rate reduction for the ten-year and fifteen-year Original System shippers, Kern River causes a cross-subsidization of the fifteen-year shippers by the ten-year shippers.

354. The ALJ found that Kern River had carried its burden of proving that it should not change the calculation methodology for roll-in of the 2002 Expansion facilities.[525] The ALJ found that the only reason the ten-year and fifteen-year shipper class pay different rates is that those shippers voluntarily chose to pay for their shares of seventy percent of facility investments over either ten years or fifteen years.[526] The ALJ reasoned that the ten-year shippers chose to pay higher depreciation amounts during shorter contract terms and determined that no party to the 2002 Expansion certificate opposed Kern River's approach and the Commission accepted it. The ALJ therefore concluded that Kern River's approach was just and reasonable.

---

[522] ID at P 482.

[523] Ex. KR-57 at 39-42.

[524] BP Initial Brief at 48; Ex. BP-1 at 36.

[525] ID at P 488.

[526] *Id.* at P 489.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

Briefs on Exceptions and Opposing Exceptions

355. BP argues that Kern River's method results in 10-year original shippers paying higher rates by virtue of a hidden subsidy.[527] BP contends that the effects of rolling-in the 10-year, 2002 expansion shippers are spread to the 15-year shippers using Kern River's approach, even though the 10-year original facilities shippers have significantly higher rates. BP argues that if calculated on an incremental basis, using BP's proposed cost-of-service, the rate impact of rolling-in the 2002 expansion would be a reduction of $0.0381 per Dth for 10-year original shippers and $0.0203 per Dth for 15-year original shippers.[528] BP further argues that using an averaging approach along with BP's proposed cost-of-service, would produce a reduction of both 10-year and 15-year shipper rates by the same $0.0231 per Dth. BP concludes that the initial decision has adopted an internally contradictory methodology, that sometimes calculates rates separately and sometimes calculates rates on a rolled-in basis.[529]

356. Kern River argues that while BP has strongly advocated the use of traditional rates throughout this case, BP selectively supports a part of Kern River's levelization methodology (*i.e.* the separate treatment of 10-year and 15-year shippers) when it is to its own benefit.

Commission Determination

357. The Commission affirms the ALJ's finding on this issue. The Commission finds that the reason 10-year and 15-year shippers pay different rates is due to shippers voluntarily choosing to pay for their share of 70 percent of facility investments over either 10-years or 15-years.[530] The 10-year shippers chose to pay higher depreciation amounts during shorter contract terms in order to receive the benefits of the step-down rates sooner. The Commission also finds that under Kern River's proposed cost-of-service, the 2002 roll-in benefit to both 10-year and 15-year original system shippers is $0.0511 per Dth.[531] However, under BP's proposed cost-of-service, the 2002 incremental benefit is only $0.0381 per Dth for 10-year original shippers and $0.0203 per Dth for 15-

---

[527] BP Brief on Exceptions at 58.

[528] *Id.*

[529] *Id.* at 59.

[530] *Kern River Gas Transmission Co.*, 92 FERC ¶ 61,061 (2000).

[531] Schedule J-2, p.4; Ex.No. BP-1 at 35.

year original shippers.[532] The Commission concludes that under BP's proposal, both 10-year shippers and 15-year shippers would receive less of a benefit than under Kern River's proposal. As a result, the Commission finds that BP's argument lacks merit. Finally, the Commission finds that BP has not raised any new arguments justifying a change in Kern River's currently approved methodology.

E. Blended Fuel Reimbursement Rate

358. Kern River proposed to use blended compressor fuel reimbursement rates for market-oriented IT and AOS services. It derived the rates by weighting fuel consumption by a factor that compares each system's billing determinants to the total system billing determinants. Kern River considers this to be appropriate because the operationally available capacity that is used to provide such services is attributable to the system as a whole and not to either system individually, resulting in making the blended fuel rate equitable for all shippers.[533] Staff did not contest Kern River's proposal.

359. RCG argued that the AOS fuel rate for rolled-in shippers should also be the same fuel rate paid by rolled-in shippers for their firm transportation service.

360. Calpine argued that Kern River's proposed blended fuel rate would increase the fuel rate for IT and AOS customers, but would still leave those shippers with a fuel rate below that assessed against 2003 expansion shippers. Calpine argues that as Kern River's IT and AOS shippers primarily utilize 2003 expansion capacity, those shippers should pay the expansion service fuel cost, rather than a blended cost that incorporates the rolled-in system's lower fuel cost. Calpine argues that this approach would eliminate discrimination inherent in Kern River's proposal, and would be consistent with Kern River's IT rate design, which is based on a 100 percent load factor use of the 2003 expansion ten-year contract service rate, the highest firm rate on Kern River's system. Calpine argues that, alternatively, if the Commission does adopt a blended fuel rate for Kern River's short-term services, that fuel rate should be based on the actual capacity utilized, rather than on contract demand.

361. The SCGC argued that Kern River's proposed blended fuel reimbursement rate applicable to AOS for rolled-in shippers should not be applied to it because this is unfair to it for the same reasons Kern River's proposal to use the highest firm rate on Kern River's system as the basis of the AOS rate is unfair. BP took issue with Calpine's proposal for using the highest fuel rate for all IT and AOS service because, according to

---

[532] BP Brief on Exceptions at 58.

[533] Ex. KR-1 at 14-15.

BP, it unjustly benefits the 2003 expansion shippers. BP proposed that the AOS fuel rate should be based on the rate schedule under which the shipper's firm service is provided.

Initial Decision

362. The ALJ concluded that Kern River carried its burden of proving that its proposed blended fuel rate proposal for forward-haul, market-oriented and short-term capacity produces just and reasonable rates based on the finding that AOS and IT are identical services and are primarily using 2003 expansion capacity to receive service.[534] The ALJ concluded that Kern River's blended fuel rate proposal is consistent with the IT rate determination and is just and reasonable. The ALJ also concluded that although released capacity shippers on the 2003 expansion system do experience a disadvantage in fuel expenses when compared to firm rolled-in shippers, the 2003 expansion shippers were aware of this at the time of the original certification of the 2003 project as the understanding was that rates would be fully incrementally priced.

Briefs on Exceptions and Opposing Exceptions

363. SCGC argues that the ID is in error because the IT and AOS are not identical services and thus a blended fuel rate should be rejected in favor of an AOS fuel rate based on the underlying firm contracts. The RCG argues that the AOS service is a service in excess of its firm entitlement, and thus different from the IT rate, and accordingly, a blended fuel rate should be rejected. Further, it argues that Kern River's proposal violates existing rate schedules, and the fuel rate for AOS should be the same fuel rate as the firm service for each rolled-in shipper.

364. Calpine argues that the blended rate is discriminatory, especially to capacity release shippers on the 2003 expansion system. Further, Calpine argues that because the IT and AOS shippers would pay a lower fuel rate than the 2003 expansion shippers for the same capacity, this proposal is inequitable. Calpine also argues that the ALJ rejected the notion that capacity attributed to the AOS and IT services cannot be attributed to either system by finding that the services are primarily using 2003 expansion capacity. Unless all 2003 expansion capacity shippers pay the same fuel rate, the blended fuel rate is discriminatory.

365. Kern River argues that, on any given day, it is not possible to determine the source of operationally available capacity as between the rolled-in system and the 2003 expansion facilities, since variables such as the ambient air and flowing gas temperatures, favorable gas flow patterns and firm capacity utilization factors all contribute to capacity availability. Kern River asserts that IT and AOS service are available on a best efforts

[534] Initial Decision at P 498.

basis with no ability to identify sources of capacity or compression utilized. Further, Kern River argues that since there is no reliable way to tie fuel usage and capacity usage, the underlying firm service agreements do not mean that operationally the same capacity is used to provide AOS service.

Commission Determination

366. The Commission finds that Kern River's evidence supports its proposal for a blended compressor fuel rate for both systems, and specifically, that the operationally available capacity that is used to provide such services can only be attributable to the system as a whole and not to either system individually. The use of the firm billing determinants of both systems is a reasonable means of calculating the fuel rate since it incorporates the capacity of both systems in its computation. We also agree that the evidence supports the finding that variables such as the ambient air and flowing gas temperatures, favorable gas flow patterns and firm capacity utilization factors all contribute to capacity availability.

367. Calpine's argument that the blended rate is discriminatory especially to capacity release shippers on the 2003 expansion system is rejected because the capacity release shippers are enjoying the benefits of being firm shippers, whereas the IT and AOS shippers are subject to availability of capacity and other operational constraints. Thus the services are not the same and a different rate for the AOS and IT shippers is not discriminatory. Further, we reject Calpine's argument that the IT and AOS shippers would pay a lower fuel rate than the 2003 expansion shippers for the same capacity, and that this proposal is therefore inequitable. Once again, the services are different in that the 2003 expansion shippers enjoy a firm service whereas the IT and AOS shippers are subject to availability of capacity and other operational constraints.

368. We are not persuaded to accept Calpine's argument that the proposed blended fuel rate would inequitably provide the AOS and IT shippers with a fuel rate below that assessed against 2003 expansion shippers because we reject Calpine's argument that IT and AOS shippers primarily utilize 2003 expansion capacity. The record shows that it is not possible to identify the operationally available capacity that is used to provide such services and that it can only be attributable to the system as a whole and not to either system individually. Further, the quality of service to AOS and IT shippers is inferior to that provided the 2003 expansion shippers and justifies that the expansion shippers should pay the expansion service fuel cost, rather than a blended cost that incorporates the rolled-in system's lower fuel cost.

369. The RCG, SCGC, and BP argue that the AOS rate shippers should be required to pay fuel rates based only on such costs properly allocated to the rolled-in system. We reject that argument because the costs allocated to the rolled-in system are computed based on the incremental nature of the cost of service structure of Kern River, which

allocates the costs between the systems separately and computes the firm rates based on a number of specific circumstances on each system. However, the AOS service provided to the rolled-in shippers is provided through the facilities of both the rolled-in and 2003 expansion systems. Accordingly, it is just and reasonable that a fuel rate design method be adopted which reflects the operational reality of the different services. They also argue that the AOS rate is based on a service in excess of the firm entitlement and thus is different from the IT rate even though they have the same priority of service. The rolled-in shippers paid an AOS rate calculated at the 100 percent load factor of their firm transportation rates before the 2003 expansion was built, and they argue that their rate should not be increased because of the expansion. The reality of the current operations on Kern River is that compressors on both systems are used to provide AOS and IT services and thus the fuel rate should be based on both systems' fuel usage.

F. Mirant Capacity and MOR Credit and Fuel Adjustment

i. Mirant Capacity

370. Kern River's 2003 expansion included 90,000 Dth/day capacity contracted to Mirant. In December 2003, Mirant declared bankruptcy and turned the capacity back to Kern River. Kern River has been unable to contract that capacity to a new shipper but the capacity is used for interruptible transportation and produces market-oriented revenues. Kern River asserts a loss of approximately $17 million of annual firm transportation revenue resulting from Mirant's bankruptcy and subsequent contract default. Kern River proposed that revenues of approximately $6.7 million be applied against the rate design from the market-oriented revenue.[535] Kern River argued that if the Mirant capacity is included in its billing determinants, then the market-oriented revenue credit should be reduced by $5.185 million to recognize the risk of remarketing unsold firm contract space on the pipeline.[536] Staff agreed that if Kern River's billing determinants reflect the Mirant capacity, then Kern River's associated MOR crediting approach is appropriate.

371. SCGC argued that Kern River's downward adjustments to the market-oriented revenue credit is not appropriate and Kern River must remain at risk for any underutilized capacity on the 2003 Expansion system unless it negotiates a risk-sharing agreement with the remaining 2003 Expansion shippers. The RCG argued that Kern River's proposed downward adjustment to its market-oriented revenue is not appropriate because its adjustment to this credit is totally speculative. BP proposed that the Mirant capacity be

---

[535] Ex. KR-17 at 15. The proposed Mirant credit was subsequently revised to $5.185 million. Ex. KR-57 at 45.

[536] This rate design proposal is referred to as the Mirant adjustment.

removed from the expansion shippers' billing determinants, which would spread the loss of the contract among the expansion shippers and keep Kern River whole.

372. Calpine argued that Kern River's proposed Mirant adjustment should be rejected because Kern River must remain at risk for all costs associated with underutilized capacity that exists due to the Mirant bankruptcy, and Kern River's shippers should not be punished with a reduction to market-oriented revenue based on capacity sales it could have made without regard to the Mirant capacity. Also, according to Calpine, Kern River should not receive an adjustment to market-oriented revenue to compensate for Mirant capacity-related risk largely of the pipeline's own making. Rather than preventing a double benefit, Calpine argues that Kern River's proposed adjustment would eliminate approximately $5 million of the market-oriented revenue credit to which Kern River's firm shippers are entitled. Calpine also argued that Kern River's proposed Mirant adjustment is improperly inflated by its "first through the meter" quantification method. Calpine argued that Kern River's proposed Mirant adjustment is unjustified, overstated, and should be rejected, or at a minimum substantially reduced through application of a last-through-the-meter methodology.

373. Calpine stated that BP's proposed elimination of the Mirant billing determinants should be rejected because eliminating Kern River's risk by removing the Mirant billing determinants is against Commission policy. Calpine contended that the potential subsidy identified by BP could be avoided by retaining the Mirant billing determinants while rejecting Kern River's overstated Mirant-related adjustment to the market-oriented revenue credit. Calpine also contended that, contrary to BP's allegations, the Commission has found that Kern River did not sell more capacity to the 2003 Expansion shippers than it added, and that Kern River had the ability to deliver all of its contracted volumes. Calpine also contended that the Commission's decision on the California Action Project did not promise Rolled-In shippers a greater share of market-oriented revenue to offset reduced service quality as suggested by BP.

Initial Decision

374. The ALJ concluded that Kern River had not carried its burden of proving that Mirant's 90,000 Dth/d of capacity should be removed from its billing determinants and that it had proven that the market-oriented revenue credit should be reduced.[537]

375. The ALJ found that the Commission intended for Kern River to be at risk to manage any turned back capacity of the 2003 Expansion project through either an agreement with its shippers whereby the shippers would share the costs in some manner, or by assuming the risk itself. The ALJ also found that Kern River did not claim such

[537] Initial Decision at P 543.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

agreement with the 2003 Expansion shippers. In addition, the ALJ found that the 2003 Expansion facility throughput before and after the Mirant contract rejection has remained at a stable level, thus indicating that Kern River continues to serve the same markets, perhaps at a lower overall transportation revenue collection due in part to its obligation to adhere to the most favored nation (MFN) clauses of its other firm shipper contracts.

376. The ALJ also found that Kern River has shown that it has not priced its reduction to the market-oriented revenue credit the same amount as the firm revenues previously received from the Mirant contract, and the record, in fact, reflects that Kern River continues to be at risk for approximately $12.1 million annually after netting out the revenues for services which supplanted the previous Mirant throughput. The ALJ concluded that this evidence demonstrates that Kern River has successfully remarketed (at least in part) the former Mirant capacity and continues to be at risk to capture the remaining difference (i.e. that amount not included in the market-oriented revenue credit reduction proposal) to make up for the greater level of the Mirant loss.[538] The ALJ held that Kern River's proposal in this regard is deemed reasonable; the pipeline's proposal adheres to the Commission's policy, and fairly reflects its overall market oriented revenue in its rates.

Briefs on Exceptions and Opposing Exceptions

377. SCGC asserts that the ALJ's acceptance of the Kern River proposed market-oriented revenue adjustment shifts the risk associated with the Mirant capacity to the shippers, contrary to the Commission's policy, and that Kern River must remain fully at risk for any underutilized capacity on the 2003 expansion. Calpine argues that the ALJ erred in accepting Kern River's proposed Mirant adjustment to market-oriented revenue because allowing such a credit is contrary to the *Pricing Policy*,[539] which requires an agreement with shippers to share the costs or assume the risk itself (which the shippers have not agreed to). Calpine also asserts that the ALJ erroneously accepted the Mirant credit as a first through the meter methodology, which allows Kern River to avoid its full at-risk responsibility under the *Pricing Policy*, and the Commission should reject or reduce the Mirant market-oriented revenue credit.

378. BP argues that including the 90,000 Dth/day capacity in Kern River's billing determinants is not reasonable and any attempt to quantify the revenues attributable to the Mirant capacity would be arbitrary. Second, BP asserts that the Mirant market oriented

---

[538] Compare $5.1 million reduction to market-oriented revenue credit (Ex. KR-86 at 13) to $17 million Mirant lost revenues. Ex. KR-17 at 15.

[539] *Certification of New Interstate Natural Gas Pipeline Facilities, Statement of Policy*, 88 FERC ¶ 61,227 (1999).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

revenue credit to the benefit of Kern River creates a subsidy of the expansion shippers by the rolled-in shippers, contrary to the 2003 expansion project which was approved so that "existing shippers pay no costs associated with the new service," citing the certificate order.[540] BP argues that incremental pricing requires that incremental shippers use incremental billing determinants so that if a shipper is lost, the pipeline remains whole by removing the billing determinants associated with the lost contract, spreading the costs among the remaining incremental shippers. BP argues that the ID would allow the lost contract to be used to derive rates for the system-wide revenue credits, and thus the ID failed to address the subsidization issue. Further, BP argues that it is error to track the $5.1 million market-oriented revenue credit specifically to the former Mirant capacity.

379. Kern River opposes the exceptions and supports the ID, which requires Kern River to be at risk for the 90,000 Dth/day Mirant contract capacity by including it in the billing determinants used to design firm transportation rates, which accepts the market-oriented revenue, thus allowing Kern River to retain the revenues with the first 90,000 Dth/day of market-oriented revenue services. Kern River states it bears the risk of approximately $17 million lost firm transportation revenues resulting from the Mirant contract turn back and allowing the market-oriented revenue credit imposes no risk on the shippers.[541] Kern River also asserts the record shows that it could not accept bids for the firm capacity made available by the Mirant turn back because they would have triggered the MFN provisions in its contracts, thus imposing severe economic consequences on Kern River.

380. Calpine opposes BP's exception that Kern River's billing determinants include the Mirant contract for setting the 2003 expansion shipper rates. Calpine argues that only by including the Mirant contract capacity in the expansion shipper billing determinants is the pipeline responsible for costs associated with unutilized firm expansion capacity.

381. The exceptions raise these issues: (1) should the Mirant turned back capacity on the expansion system be included in the billing determinants used to set transportation rates; (2) may Kern River be allowed to retain approximately $5.185 million of the market-oriented revenue based on its absorption of the Mirant contract volumes in the billing determinants; (3) can the Mirant credit to the market-oriented revenue be properly quantified and tracked to the Mirant capacity; and (4) is the Mirant credit to Kern River appropriately based on the first through the meter volumes of market oriented services.

---

[540] *Kern River Gas Transmission Company*, 98 FERC ¶ 61,205 at 61,715 (2002).

[541] Ex. KR-86 at 14; KR-57 at 46.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

Commission Determination

382. The ID approved Kern River's proposal to include the Mirant turned back capacity on the expansion system in the billing determinants used to set transportation rates. The Commission's relevant *Pricing Policy* states:[542]

> This policy leaves the pipeline responsible for the costs of new capacity that is not fully utilized and obviates the need for an "at risk" condition because it accomplishes the same purpose. Under this policy the pipeline bears the risk for any new capacity that is under-utilized, unless . . . it contracts with the new customers to share that risk by specifying what will happen to rates and volumes under specific circumstances.…Thus, in pipeline contracts for service on newly constructed facilities, pipelines should not rely on standard "Memphis clauses," but should reach agreement with new shippers concerning who will bear the risks of underutilization of capacity . . . .

383. Thus, Kern River remains at risk for the turned back capacity consistent with its commitments and the *Pricing Policy*. Accordingly, we affirm the ALJ's recommendation.

384. BP argues that including the 90,000 Dth/day Mirant contract capacity in Kern River's billing determinants is not reasonable. The ALJ found, and we concur, that inclusion of the 90,000 Dth/d Mirant former capacity in the expansion shippers' billing determinants to compute incremental rates fulfils the requirement that, absent an agreement with the remaining expansion shippers, Kern River remain at risk for costs of the under-utilized capacity and that this rate design is a reasonable means of apportioning the risk of underutilization of the Mirant contract capacity.

385. The second issue relates to Kern River's request that it be allowed to retain approximately $5.185 million of the market-oriented revenue based on its absorption of the Mirant contract volumes in the expansion capacity billing determinants. The *Pricing Policy* and Kern River's concession to accept the risk places the risk of underutilization of firm capacity on Kern River's expansion system, and the pipeline recognizes its obligation and is willing to absorb approximately $12 million in net losses because of its inability to find a new shipper willing to contract for the 90,000 Dth/d available firm capacity. It therefore requests that it be allowed to retain approximately $5.185 million of the market-oriented revenue.

---

[542] *Certification of New Interstate Natural Gas Pipeline Facilities, Statement of Policy*, 88 FERC ¶ 61,227 at 61,747 (1999).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

386. SCGC asserts that Kern River's proposed market-oriented revenue Mirant adjustment shifts the risk associated with the former Mirant capacity to the shippers, contrary to the Commission's policy, and that Kern River must remain fully at risk for any underutilized capacity on the 2003 expansion system. Calpine argues that the Commission should reject Kern River's proposed Mirant adjustment to market-oriented revenue as contrary to the *Pricing Policy*, which requires an agreement with shippers to share the costs or assume the risk itself (which the shippers have not agreed to). The record reflects that all of Kern River's pipeline capacity is being utilized to generate market-oriented revenue.[543] Thus, to the extent that the former Mirant capacity is being utilized by Kern River, it is entitled to a credit for that effort and maximizes the utilization of available firm and interruptible capacity.[544] Further, this is consistent with the *Pricing Policy* that "the pipeline bears the risk for any new capacity that is under-utilized." Accordingly, we affirm the ALJ's finding that the evidence demonstrates that Kern River has successfully remarketed (at least in part) the former Mirant capacity and continues to be at risk to capture the remaining difference. We further agree with the ALJ that Kern River's proposal in this regard is reasonable, the pipeline's proposal adheres to the Commission's policy, and fairly reflects its market-oriented revenue in its rates.

387. BP asserts that the Mirant market-oriented revenue credit creates a subsidy of the expansion shippers by the rolled-in shippers, contrary to the 2003 expansion project which was approved so that "existing shippers pay no costs associated with the new service," citing the certificate order.[545] We reject BP's argument as the issue is not the costs associated with any new service, but the allocation of revenue credits, a projection based on test year results.[546]

388. SCGC asserts that Kern River's proposed market-oriented revenue adjustment shifts the risk associated with the Mirant capacity to the shippers, contrary to the Commission's policy, and that Kern River must remain fully at risk for any underutilized capacity on the 2003 expansion. We also reject SCGC's argument because Kern River must remain at risk for any underutilized capacity; however, the record shows that that capacity is being used to generate market-oriented revenue. The ALJ found that the 2003 expansion facility throughput before and after the Mirant contract rejection has remained

---

[543] Ex. KR-1 at 11.

[544] *See, e.g., Williston Basin Interstate Pipeline Co*., 85 FERC ¶ 61,247 at 62,029 (1998).

[545] *Kern River Gas Transmission Company,* 98 FERC ¶ 61,205 at 61,715 (1999).

[546] Ex. KR-86 at 14.

at a stable level, which indicates that Kern River continues to serve the same markets and utilizes the Mirant capacity but at a lower overall transportation revenue collection.

389. BP also argues that the Initial Decision would allow the lost Mirant contract capacity to be used to derive rates for the system-wide revenue credits, and thus the Initial Decision failed to address the subsidization issue. Because the Mirant capacity is now essentially used to transport interruptible and short term firm gas, the Mirant credit is a simple substitution of services from firm to interruptible, and thus there is no subsidization involved. Further, BP argues that it is error to track the $5.1 million market-oriented revenue credit specifically to the former Mirant capacity. With regard to this issue, Kern River's witness Dahlberg testified that after Mirant rejected its contract, it continued to serve the same markets and the volume of throughput remained virtually unchanged.[547] Thus we find that it is appropriate to track the Mirant capacity to the related market-oriented revenue and to assign it to Kern River in mitigation of its absorbing the risk of loss of the Mirant contract.

ii. <u>Allocation of market-oriented revenue credits</u>

390. Kern River proposed that the market-oriented revenue credits be allocated among the rolled-in system shippers and the 2003 expansion shippers based on their respective aggregate reservation billing determinants. Staff did not object to Kern River's proposal.

391. BP asserted that Kern River's market-oriented revenue should be allocated on reservation quantities. Calpine argues that Kern River's proposed allocation of the market-oriented revenue is unreasonable and recommends allocating market-oriented revenue to rolled-in and 2003 expansion shippers based on the level of available capacity from each class of service that makes such market-oriented sales possible. Calpine argues that a fair allocation of market-oriented revenue credit must reflect each shipper group's responsibility for that credit, and since the market-oriented revenue is derived from unused firm capacity, the shippers most responsible for Kern River's market-oriented revenue are shippers with unutilized firm capacity.

392. SCGC argued that Calpine's proposal to base the allocation on the level of available capacity from each class of service that makes such market-oriented sales possible should be rejected because unless the specific facilities which are used to provide such services can be clearly identified, basing the allocation of market-oriented revenue credits on reservation quantities is the most equitable allocation method. Southern California Generation Coalition argued that Kern River has shown that determining which facilities are used to provide the IT services on any given day is impossible.

---

[547] Ex. KR-86 at 12.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

Initial Decision

393. The ALJ found that Kern River carried its burden of proving that market-oriented revenue credit allocated among the rolled-in system shippers and the 2003 expansion shippers based on their respective aggregate reservation billing determinants produces just and reasonable rates because it is not possible on any given day to identify the specific facilities or capacity used to provide the market-oriented services.[548]

Briefs on Exceptions and Opposing Exceptions

394. Calpine argues that the ALJ erred in finding that it was not possible to identify the capacity employed in making market-oriented revenue services. Calpine also argued that the capacity load factors of 97.3 percent for the rolled-in system and 85.5 percent for the expansion system show that the expansion capacity is the primary resource for market-oriented revenue services. Thus, Calpine argues that the Commission should allocate the market-oriented revenue credit to the two systems based on the level of available capacity enumerated above. BP argues that there is no direct or measurable relationship between contract capacity load factors and operating capacity to earn market-oriented revenue or to attribute interruptible and short-term firm to any particular segment of unsubscribed capacity.[549] BP claims that many factors, such as capacity release, segmentation, availability of receipt and delivery points, AOS and backhaul, affect market-oriented revenue. SCGC argues that the ALJ's allocation is just and reasonable because it is not possible to identify facilities or capacity that is used on any given day to provide market-oriented services. The RCG argues that the evidence supports the ALJ's finding in this matter.[550] High Desert Power Trust requests that its cost of service be credited with approximately $165,000 of interruptible revenues from transportation on the High Desert lateral based on actual end of the test period data.[551]

Commission Determination

395. The principal argument on exceptions is that the ALJ erred in finding that it was not possible to identify the capacity employed in making market-oriented revenue services. The Commission affirms the Initial Decision in this matter. Because of the interrelated nature of the facilities of Kern River over the test year, it is not reasonable to

---

[548] Initial Decision at P 561-2.

[549] Ex. BP-27 at 12; Ex. KR-57 at 47.

[550] Ex. KR-1 at 15; Ex. KR-57 at 47.

[551] Ex. S-12 at 30.

trace facilities to their use. Specific capacity release, segmentation, availability of receipt and delivery points, AOS and backhaul factors affect market-oriented revenue but cannot be reduced to an allocation factor. Further, the capacity utilization factors cited by Calpine by themselves do not provide sufficient proof of how the Kern River facilities are utilized for the market-oriented services over the course of the test year. Accordingly, we conclude that the ALJ was reasonable in approving the allocation of market- oriented revenue to the shippers based on their respective aggregate reservation billing determinants. In addition, as there are no objections, High Desert Power Trust's cost of service may be credited with interruptible revenues from transportation on the High Desert lateral based on actual end of the test period data.[552]

iii. Market-Oriented Revenue credit and fuel adjustment

396. Kern River proposed a $2.9 million downward adjustment to its market-oriented revenue crediting to the cost of service, based on actual data through the end of the test period. It claims that with adoption of its new blended fuel rate, there is a reduction in the transportation rate that shippers are willing to pay for IT and AOS services, and in order to compensate for this reduction, it should be allowed a credit of $2.9 million to its market oriented revenue.[553]

397. Calpine argued that Kern River's proposed inclusion of a fuel adjustment in its market-oriented revenue credit proposal is not appropriate because the proposal erroneously assumes the price basis differentials are fixed and do not vary through time. Also, according to Calpine, a decrease in any credit belies the fact that Kern River's market-oriented revenue credits have more than doubled from $7.8 million to over $21 million over the test period.

398. The RCG argued that there is no test period experience with the proposed adjustment. It argues that the proposal assumes as fact events that are speculative, such as changes in market prices for natural gas and the change in Kern River's fuel methodology, and therefore, test period actual levels should be used. SCGC, Pinnacle West and BP also opposed Kern River's proposal.

399. Staff argued that Kern River's proposed inclusion of a fuel adjustment in its market-oriented revenue credit proposal is not appropriate. Staff points out that the fuel adjustment in the credit is not warranted because Kern River is fully reimbursed for fuel from its shippers.

---

[552] Ex. S-12 at 30.

[553] Ex. KR-1 at 14-15; Ex. KR-86 at 6-8; Ex. KR-57 at 49-50.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

400. Kern River argued that Staff's opposition to the adjustment, based on the claim that those fuel costs are paid by shippers, reflects a fundamental misunderstanding of this adjustment. Kern River argued that the adjustment recognizes that increased fuel costs reduce the transportation rate that IT and AOS shippers are willing to pay, meaning lower IT and AOS revenue available for crediting to firm shippers. Kern River argued that the adjustment would not result in Kern River retaining fuel expenses paid by shippers, while denying the adjustment would amount to an unfair double-revenue credit to shippers.

Initial Decision

401. The ALJ concluded that Kern River had not carried its burden of proving that its proposal to reduce its end-of-test-period revenue credits due to its proposed increase in fuel retainage from IT and AOS shippers produces just and reasonable rates.[554] The ALJ also found that the end-of-test-period actual market-oriented revenue is the best evidence on which to base an appropriate market-oriented revenue credit and not unsubstantiated conjecture. The ALJ concluded that the upward trend for the revenues collected by Kern River are appropriately credited to the company's cost-of-service. In addition, the ALJ held that Kern River did not prove its claim that not allowing a reduction to credit results in an unfair double collection by its shippers.

Briefs on Exceptions and Opposing Exceptions

402. Kern River argues that the ALJ's decision is arbitrary and lacks support in the record, and that the testimony of its witness Dahlberg is not unsubstantiated conjecture.[555] Kern River claims it can only charge market-oriented service rates based on the difference in gas commodity prices between Opal, Wyoming and the California border. Since the market value of market-oriented services is based directly on the difference in gas prices and the blended fuel charges which have been increased, there needs to be a commensurate reduction in the market-oriented revenues so Kern River can charge less to maintain its volumes. Kern River computed the effect of the change in fuel charges and claims these calculations support its proposed credit.[556] Kern River also asserts the ALJ's decision would allow the firm shippers to reap a double recovery of the reduction in their fuel charges by also permitting the increase in market-oriented revenues, which reduces the firm rates.

---

[554] Initial Decision at P 552.

[555] Ex. KR-86 at 7.

[556] Ex. KR-57 at 49.

403. The RCG argues that an adjustment to the test period data is permitted only by future changes which can be validated with a reasonable degree of certainty. Here the RCG claims that Kern River manufactured an exhibit which picks and chooses data in adjusting the test period in contradiction to the Commission's regulations. SCGC argues that test period market-oriented revenue is the best evidence and Kern River's proposed adjustment is based on changes in natural gas commodity prices which may occur in the future. Further, the increases in IT revenues have tripled and the claim in the proposal is not based on known and measurable changes.

404. Calpine argues that the ALJ correctly found that Kern River's proposed downward adjustment in market-oriented revenue is unsubstantiated conjecture and properly rejected the assertions of a double credit rationale as unproven.

405. Staff urges rejection of Kern River's proposal because it is not based on test period actual evidence and is unsubstantiated conjecture. The Staff argues that the evidence presented by the parties in opposition should be the basis of a decision.[557]

Commission Determination

406. The Commission rejects Kern River proposed $2.9 million downward adjustment to its market-oriented revenue crediting to the cost of service. This decision is based on the rule that an adjustment to the test period data is permitted only by known and measurable changes which can be validated with a reasonable degree of certainty.[558] Further, the proposed adjustment is unwarranted because the fuel charges are fully paid for by shippers through the fuel retainage percentages. The decision to permit the proposed crediting must be based on proof that the test period market-oriented revenue does not provide an appropriate representative value on which to determine future rates. Moreover, any adjustment to market-oriented revenue must necessarily be based on proof that Kern River's AOS and IT rates themselves will be so high as to make the transportation services unmarketable. This, Kern River has failed to demonstrate because its hypothetical example is entirely speculative and not based on actual commodity prices of natural gas in Wyoming or California and the IT and AOS rates which will be in effect after October 2004. Thus, Kern River's example fails to be persuasive.

407. Kern River also asserts the ALJ's decision would allow the firm shippers to reap a double recovery of the reduction in their fuel charges and increasing market-oriented revenues credits, which reduce the firm rates. We disagree with Kern River's analysis because it has proposed blended fuel rates, which it believes are just and reasonable on

---

[557] Ex. S-12 at 26, 29; Ex. CES-69 at 6-8; Ex. CES-71; Ex. RCG-2 at 32-34.

[558] *See e.g.,* 18 C.F.R. § 154.303(a)(4) (2006).

their own merits and of themselves do not constitute an unwarranted allowance to the firm shippers.

VIII. Depreciation

A. Book Depreciation

408. In this section, the Commission addresses the book depreciation rates for various types of plant on Kern River's system. The Commission makes the following determinations. The Commission affirms the Initial Decision's holding that the remaining economic life of Kern River's system is 35 years and that the corresponding book depreciation rate for its transmission plant is 1.95 percent. The Commission affirms the Initial Decision's holding that the negative net salvage rate for transmission plant other than compression engines must be based on a remaining economic life of 35 years, but revises the Initial Decision's negative net salvage rate by removing the amount for interim retirements so that Kern River's negative net salvage rate is 0.12 percent instead of the 0.18 percent adopted by the Initial Decision.

409. The Commission reverses the Initial Decision's determination that the book depreciation rate for Solar Mars compression engines should be 8.85 percent and finds that it should be 9.92 percent. The Commission affirms the Initial Decision's determination that the book depreciation rates for the High Desert and Big Horn Laterals should be based on the terms of their primary contracts and thus should be 4.76 percent and 6.67 percent respectively. The Commission determines that the book depreciation rates for General Plant should be those proposed by Kern River. Finally, the Commission affirms the Initial Decision's determination that an additional $6.25 million of Contributions in Aid of Construction (CIAC) should be included in intangible plant. It finds that the book depreciation rate should be 4.76 percent for the CIAC associated with the High Desert Lateral and 1.95 percent for the CIAC associated with the Blue Diamond delivery point.

i. Rolled-in Transmission Plant

410. Depreciation is the loss in service value of an asset that cannot be replaced by current maintenance.[559] The depreciation rate recovers this loss which is equal, initially,

---

[559] 18 C.F.R. Part 201, Definition 12.B (2005). The Commission has discussed depreciation of gas pipelines and related issues such as negative salvage extensively in *High Island Offshore System, L.L.C.*, 110 FERC ¶ 61,043 at P 58-79 (*HIOS I*), *order on reh'g*, 112 FERC ¶ 61,050 at P 19-36 (2005) (*HIOS II*); *Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260 at P 252-295 (2002) (*KPC I*), *order on reh'g*, 102 FERC ¶ 61,310 at P 106-117) (2003) (*KPC II*); *Williston Basin Interstate Pipeline Co.*, *Initial Decision*, 95

(footnote continued)

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

to the original cost of the asset. Generally, depreciation occurs over the physical life of an asset and is recovered over that life. However, the Commission has recognized that the economic life of gas pipeline assets may be shorter than the physical life of the assets because gas supplies may not last as long as the physical life of the assets. Consequently, the Commission uses the economic life of the pipeline in determining depreciation. The economic life depends on the remaining gas supplies that will be available to the pipeline. The economic life must be adjusted, however, because not all assets are retired at the same time. Calculations that take into account retirements during the pipeline's economic life provide the average remaining economic life (ARL) of the assets. The depreciation rate is then derived by dividing the percentage of assets that have not yet been depreciated (the net plant) by the ARL.[560]

411. Kern River proposed to increase its depreciation rate for its rolled-in transmission plant.[561] Its rolled-in transmission plant consists of the original system put in service in 1992 and the 2002 expansion. Kern River's initial proposal was to increase the combined, average depreciation rate for these facilities from 2.0 percent to 3.39 percent.[562] This proposal was based on an economic life of 26 years,[563] from the end of 2004 through the end of 2030, with an ARL of 23.4 years.[564] Kern River intended this proposal to determine only the book value of depreciation. The actual depreciation it

---

FERC ¶ 63,008, at 65,095 – 65,112 (2001) (*Williston I*), *order on Initial Decision,* 104 FERC ¶ 61,036, at P 53 – 57 (2003) (*Williston II*), *order on reh'g,* 107 FERC ¶ 61,164 at P 21 – 52 (2004) (*Williston III*); and *Trunkline Gas Company,* Opinion No. 441, 90 FERC ¶ 61,017, at 61,049-061 (2000).

[560] *See, for example,* Exs. S-7 at 13 and S-8, Schedule No. 4.

[561] Kern River's testimony concerning depreciation was presented by Mr. Edward H. Feinstein, primarily in Exs. KR-5 – 8 (direct testimony and exhibits); KR-52 – 53 (answering testimony and exhibits); and KR-111 – 116 (rebuttal testimony and exhibits).

[562] Kern River states that it proposes the 3.39 percent book depreciation rate only in the context of continuing levelization of cost-of-service (citing Ex. KR-111 at 2-4). It states that if the Commission requires Kern River to use a traditional cost-of-service, then it proposes the following, separate book depreciation rates for each of its mainline facilities groups: 2.39 percent for the Original System, 4.64 percent for the 2002 Expansion, and 4.09 percent for the 2003 Expansion (citing Exs. KR-52 and 53). Kern River Brief on Exceptions at 90 n. 103.

[563] Exs. KR-5 at 17, KR-111 at 9.

[564] Exs. KR-5 at 25, KR-111 at 71.

would charge its customers would be determined under its levelized rates. Kern River subsequently adjusted its proposed economic life to 28 years, from the end of 2004 through the end of 2032, with an ARL of 26 years.[565] This adjustment was made to coincide with the Commission's order of July 26, 2000 accepting a settlement for Kern River's rates in Docket No. RP00-298-000. The settlement included a remaining depreciation life for book purposes of 31 years ending September 30, 2032.[566]

412. Staff offered testimony [567] supporting a remaining economic life of 35 years, from October 1, 2004 through September 30, 2039, with an ARL of 30.6 years for the original system and 27.0 years for the 2002 expansion. Staff calculated an average 1.95 percent depreciation rate for the rolled-in transmission system as a whole.[568] BP offered testimony supporting a 35-year economic life for these assets with proposed depreciation rates for different classes of customers. [569]

413. The Initial Decision rejected Kern River's proposed remaining economic life for the rolled-in transmission plant and adopted that of Staff and BP. In support of her decision, the ALJ cited Staff's and BP's testimony concerning the remaining supply of

---

[565] Ex. KR-111 at 9.

[566] 92 FERC ¶ 61,061, at 61,157 and 61,160-161 (2000). The book depreciation life in the settlement was based on a gas supply study done by Kern River in 1998. The settlement provided for lower rates by permitting customers to extend their contract terms and thus the length of time over which they would have to pay for the amount of depreciation under their levelized rates.

[567] Staff's testimony was presented by Mr. Kevin J. Pewterbaugh, primarily in Exs. S-7 through S-9 (direct and answering testimony and exhibits) and S-36 and S-37 which are Corrected versions of S-7 and S-8.

[568] Ex. S-7 at 7, 28, 46; Ex. S-8, Schedule No. 24 (the Rolled-in System). The percent of net plant was 57.06 percent for the original system and 93.10 percent for the 2002 expansion. Ex. S-8, Schedule No. 24.

[569] BP's testimony was presented by Ms. Elizabeth H. Crowe, primarily in Ex. BP-1 at 5-12 (direct and answering testimony), and accompanying exhibits — Ex. BP 4-6; Ex. BP-17. BP proposed book depreciation rates of 1.7 percent for the Original System 10-year shippers; 1.8 percent for the Original System 15-year shippers; 2.4 percent for the 2002 Expansion 10-year shippers; 2.7 percent for the 2002 Expansion 15-year shippers; 2.6 percent for the 2003 Expansion 10-year shippers; and 2.8 percent for the 2003 Expansion 15-year shippers. Ex. BP-1 at 6:23-26; Ex. BP-6 at 1:19; Ex.BP-52 at 2:16.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

gas and Staff's use of the ultimate recovery method for determining that supply.[570] As discussed below, the Commission affirms the holdings of the ALJ concerning the 35-year remaining economic life of the rolled-in transmission system and the justness and reasonableness of the resulting depreciation rate of 1.95 percent. The Commission will first describe the gas supply studies and estimates done by Kern River and Staff. As explained above, the economic life of the pipeline depends on the gas supplies available for Kern River to transport. The Commission will then address the objections of the participants to these studies as contained in their briefs on and opposing exceptions.

a. Kern River Gas Supply Testimony

414. Kern River considered both gas supply and competition in estimating the remaining economic life.[571] With respect to gas supply, it considered the entire states of Wyoming, Utah and Colorado. The sources within these states consisted of basins[572] from which Kern River is currently transporting gas, the Overthrust Belt and the Green River Basin. Kern River also included some basins that are located one interconnection charge away from its current sources: the Uinta Basin and the Piceance Basin.[573] Kern River initially stated that one such basin, the San Juan Basin, was included, but later stated that it was not included.[574] In rebuttal testimony, Kern River stated it had also included the Wind River Basin and the Big Horn Basin as within the pipeline's current area of interest.[575] Finally, in its rebuttal testimony Kern River stated it included the Powder River Basin, the Denver Basin, and other smaller gas prone areas that are farther

[570] ID at P 372-373.

[571] Markets or demand are also a factor in determining remaining economic life. In this case, however, the parties agree that demand will remain strong or even increase and that it will not reduce Kern River's remaining economic life.

[572] For a map of gas supply basins as defined by the Potential Gas Committee (PGC), *see* Ex. BP 18 at 2.

[573] Ex. KR-5 at 12, 14; Ex. KR-111 at 59; Ex. KR-112, Schedule Nos. 25 and 27.

[574] *Compare* Ex. KR- 5 at 14 with Ex. KR-111 at 58-60.

[575] Ex. KR-111 at 59.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

away and involve more competition.[576] Kern River uses all of the above named basins when it compares its estimate of future gas supplies to the estimate of the PGC.[577]

415. Kern River then estimated future gas supplies for these basins.[578] It states it included gas available from existing sources and future discoveries in its estimate. Kern River states that "the quantity of gas available from existing sources is generally the product of studies published by the Energy Information Administration ("EIA")."[579] However, it does not provide the names of the studies, the years of their publication, or the page numbers on which the data can be found. In any event, Kern River stated that at the end of 2002, there were 38,550 Bcf of remaining, or proven, reserves.[580]

416. Kern River states it used an "Effectiveness of Exploration Model" to estimate gas supplies from future discoveries and that this model is based on the premise that the effectiveness of exploratory wells will decrease over time.[581] Kern River used the most recent five years of data, from 1999 through 2003, to establish the average number of exploratory wells drilled in the Rocky Mountain area--255 exploratory wells.[582] It used the most recent three years of data, from 2000 through 2002, to establish the effectiveness or the amount of reserve additions of the exploratory wells--18.73 Bcf, per exploratory

---

[576] Ex. KR-111 at 59.

[577] *See* Ex. KR-112, Schedule No. 25. This schedule and the map in Ex. BP-18 at 2 indicate that Kern River included the following seven basins as defined by the PGC in its gas supply study: P-510, Powder River Basin; P-515, Big Horn Basin; P-520, Wind River Basin; P-530, Greater Green River Basin; P-535, Denver Basin; P-540, Uinta-Piceance Basin; and P-590, the Wyoming-Utah-Idaho Thrust Belt (also called the Overthrust Belt).

[578] Ex. KR-5 at 15.

[579] Ex. KR-5 at 15.

[580] Ex. KR-7, Table 5.

[581] Ex. KR-5 at 15; Ex. KR-6, Schedule No. 3; Ex. KR-7 at 5-9.

[582] Ex. KR-7, Table 3 and Figure 4.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

well.[583] It then multiplied the number of exploratory wells actually drilled in 2003 times the estimated amount of reserve additions, 321 x 18.73 Bcf, to find reserve additions of 6,013 Bcf for the first year in which reserve additions were estimated, 2003. For the following twelve years, 2004 through 2015, Kern River assumed a constant level of effectiveness. It used 255 wells and 18.73 Bcf per well to estimate reserve additions of 4,779 Bcf per year. Thereafter, it kept the number of wells drilled at 255, but reduced the amount of new reserves discovered per well, until this amount dropped in 2033 to 2.81 Bcf per well for reserve additions in that year of 717 Bcf.[584] Kern River made similar calculations for development wells.[585] Adding all of the reserve additions from exploratory and development wells together for the years 2003 through 2033, Kern River estimated that there would be 122,785 Bcf of reserve additions.[586]

417. Kern River compared its estimate of 122,785 Bcf to a PGC estimate of reserve additions of 104,130 Bcf for the identified basins which it states was made in 2002.[587] Kern River stated that it used the PGC estimate for probable and possible reserves, but it did not state which category it used of the probable and possible reserves: minimum, most likely, or maximum.[588] Kern River stated its estimate for reserve additions exceeded by eighteen percent the PGC estimate of 104,130 Bcf.[589] When Kern River's estimated reserve additions were added together with remaining proven reserves, 122,785 Bcf + 38,550 Bcf, Kern River's total estimate for potential gas supplies was 161,335 Bcf in the basins it had identified as relevant.

418. Kern River then proceeded to estimate how long the potential supplies would last. It did this through a measure called variously "production capacity" and "Available

---

[583] Ex. KR-7, Table 3 and Figure 6. Although the effectiveness figure is given in Table 3 in terms of Bcf/1,000 feet, it appears that reserve additions were calculated using the number of exploratory wells drilled each year and not the footage of the exploratory wells.

[584] Ex. KR-7 at 7 and Table 3.

[585] Ex. KR-7, Table 4 and Figure Nos. 5 and 7.

[586] Ex. KR-7, Table 5.

[587] Exs. KR-111 at 64; KR-112, Schedule Nos. 25 and 27 at 2 (2002 estimate).

[588] Ex. KR-111 at 63.

[589] Ex. KR-5 at 23-24.

Capacity."[590] Kern River stated that it applied to each determined annual future reserve addition, "a production rate based on studies performed by the EIA from data derived from Petroleum Information/Dwights LLG"[591] and it referred to a graph in Figure 15. Kern River states this procedure results in the production capacity from new reserves beginning in 2002. The graph in Figure 15 is entitled "Hyperbolic Productive Capacity Rocky Mountain Region Gas Wells." It shows a hyperbolic curve with the first value at 25 percent of initial reserves in year one with the percent of initial reserves rapidly declining in succeeding years. There is no identifying information on Figure 15. In rebuttal testimony, Kern River stated that its forecasted discoveries were converted into producing capacity by applying a hyperbolic decline equation.[592] Table 6 of Ex. KR-7 shows figures for productive capability or capacity from 1999 reserves and 2000 and later reserves for the years 2000 through 2033. The productive capability for 2000 is shown as 9,674 MMcf/day (3,531 Bcf per year). It peaks in 2015 at 15,019 MMcf/day (5,482 Bcf per year) and declines to 5,833 MMcf/day (2,129 Bcf per year) in 2033. Ex. KR-7, Figure 10 shows the same information in the form of a graph.

419. Kern River concluded from its production profiles that the Rocky Mountain area had deficiencies in its ability to maintain high levels of throughput in all available pipeline capacity. It stated the availability profiles show that supply/demand deficiencies are projected to begin in the second decade of the 21st century. It further concluded that this may create situations where major retirements of pipeline facilities take place. By the year 2030, Kern River stated "the Rocky Mountain area could provide less than 60 percent of its current productive capacity."[593] Kern River predicted both that there would be excess pipeline capacity in the region due to new capacity being proposed and added, perhaps as early as 2015, and that Kern River's share of the region's productive capacity would fall from 13.03 percent in 2003 to 11.52 percent in 2015 and then to less than 4.34 percent in 2030.[594] Kern River cites Schedule No. 20 of Exhibit KR-6 for its profile of its throughput related to its capacity, but this schedule is not in the record.

420. Kern River stated that based on its gas supply model the economic life for its pipeline system was approximately 25 to 30 years, that is, from 2003 through either 2028

---

[590] Exs. KR-7 at 9, Table 6, and Figure Nos. 10 and 15; KR-111 at 42-43.

[591] Ex. KR-7 at 9.

[592] Ex. KR-111 at 42.

[593] Ex. KR-5 at 16.

[594] Ex. KR-5 at 16, 23-24.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

or from 2003 through 2033.[595] It states it determined the economic life of Kern River to be 26 years based upon the likelihood of "major retirements" due to depletion of its traditional gas supply sources and the effects of competition.[596] It further explained that major retirements are retirements of facilities due to economic, rather than physical, forces that cause underutilization and changes in system operations.[597] Kern River explains that major retirements do not necessarily indicate that portions of its pipeline will be physically retired prior to the end of the system's economic life. Instead, major retirements also reflect underutilization of capacity.[598] The recommended economic life of 26 years was thus an average life that took into account the forecasted major retirements.[599]

Exceptions and Commission Determination on Kern River's Gas Supply Testimony

421. Kern River excepts that the Initial Decision did not analyze or weigh the evidence of its witness Mr. Feinstein. It asserts the Commission should consider this testimony *de novo* and that this testimony fully supports its proposed 3.39 percent depreciation rate for transmission plant other than compressor engines and general plant. Staff, BP Energy, SCGC, the Rolled-in Customer Group (RCG), and Calpine respond that Kern River's 26 year average remaining life is too short and that Kern River's proposed 3.39 percent depreciation rate should be rejected. The Commission finds that Kern River's gas supply study is not probative and that its 26-year average remaining economic life is unsupported and rejects its proposed 3.39 percent depreciation rate as discussed below.

422. The opposing parties argue that Kern River's gas supply study should be rejected because, among other things, the Commission has previously rejected the Effectiveness of Exploration Model or efforts to results model that Kern River used to estimate future discoveries of gas supplies.[600] However, in this case, unlike in *Williston* and *KPC*, the Effectiveness of Exploration Model includes quantities discovered by development wells

---

[595] Ex. KR-5 at 16.

[596] Ex. KR-5 at 17.

[597] Ex. KR-5 at 18.

[598] Kern River Brief on Exceptions at 88 n. 101 *citing* Ex. KR-5 at 15-24; Ex. KR-6, Schedule No. 5; and Tr. 866:15-868:1.

[599] Ex. KR-5 at 17-21; Ex. KR-6, Schedule No. 5.

[600] *Citing Williston II*, 107 FERC ¶ 61,164 at P 35-37 (2004); *KPC I*, 100 FERC ¶ 61,260 at P 268-272 (2002).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

and takes into consideration reserves below the level of 15,000 feet for comparison purposes. In this case the Effectiveness of Exploration Model predicted that there are even more undiscovered resources than the probable and possible estimates of the PGC - 122,785 Bcf compared to a 2002 PGC estimate of reserve additions of 104,130 Bcf. Thus, according to Kern River's Effectiveness of Exploration Model, the potential gas supply in the Rocky Mountain area consisted of 122,785 Bcf plus the existing remaining proven reserves of 38,550 Bcf, for an estimated total potential gas supplies of 161,335 Bcf, an even greater amount than the existing remaining proven reserves of 38,550 Bcf plus the undiscovered resources predicted by the PGC--142,680 Bcf.

423. Kern River's estimate of a greater amount of undiscovered resources than that of the PGC should indicate a longer supply life for gas supplies in the Rocky Mountain area and thus a longer remaining economic life for Kern River.[601] However, Kern River's average remaining economic life of 26 years is relatively short. This is due to the way in which Kern River calculates how much of the undiscovered resources are produced and how soon. Kern River states that, to calculate available or productive capacity, it used a hyperbolic decline equation and its production rate was based on studies performed by the EIA. Kern River provides no information from the EIA (or any other source) describing this production methodology or the context in which it was used. Thus, it is unclear how Kern River calculated its production levels and whether or not its production methodology was appropriate.

424. In addition, Kern River claims that the methodology it used was that used by the EIA. However, evidence of record cited by opposing parties shows that EIA estimates of production in the Rocky Mountain region portray a much slower rate of production and, thus, a much longer supply life than those predicted by Kern River. The EIA *Annual Energy Outlook 2004 with Projections to 2025* states that Rocky Mountain natural gas production is projected to increase from 3,300 Bcf in 2002 to 4,600 Bcf in 2010 and 6,300 Bcf in 2025.[602] The EIA *Annual Energy Outlook 2005 with Projections to 2025* states that Rocky Mountain natural gas production is projected to increase from 3,700 Bcf in 2003 to 5,600 Bcf in 2025.[603] Both of these publications contain graphs showing production in the Rocky Mountain region increasing until 2025. In contrast, Kern River predicted that production in the region would reach 5,235 Bcf in 2010, would peak in

---

[601] *See* Ex. KR-111 at 25 indicating that logically, a remaining supply life should be greater if it is calculated using more gas resources.

[602] Ex. CES-23.

[603] Ex. EME-9 (at numbered page 96).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

2015 when it would reach 5,482 Bcf, and would decline thereafter.[604] The Commission notes that opposing parties cite numerous other documents in the record that support a longer remaining economic life for gas supplies in the Rocky Mountain region. These documents consist of internal Kern River documents, studies done for Kern River, and geological studies.[605]

425. The Commission finds that Kern River's production estimates were calculated according to a method that is unclear and are contradicted by rebuttal evidence. Consequently, the Commission finds Kern River's production estimates are not credible.

426. The Commission agrees with the opposing parties that the remaining economic life of Kern River will not decline because of competition. As just discussed, Kern River has not shown that Rocky Mountain gas supplies will begin to decline in the second decade of this century so that Kern River's forecasted reduction in throughput and major retirements prior to 2033 will not occur. In addition, the Commission agrees with the opposing parties that Kern River is in a good competitive position with respect to new pipeline projects because it is less expensive.[606] In any event, Kern River did not reduce its estimated average remaining economic life of 26 years because of the alleged effects of competition.[607]

427. Since Kern River's production estimates are not credible, the Commission rejects its proposed average remaining economic life of 26 years. As a result, the Commission rejects Kern River's proposed depreciation rate of 3.39 percent because it is not supported by substantial evidence.

b. <u>Staff Gas Supply Testimony</u>

428. Staff also considered both gas supply and competition in estimating the remaining economic life of the pipeline. With respect to gas supply, it considered the same gas

---

[604] Ex. KR-7, Table 6 (productive capability figures are given in MMcf/day and must be converted to the quantity per year).

[605] *See, for e.g.*, the following exhibits that state the supply life in the Rocky mounts is 60 years or more: Ex. CES-28; Ex. CES-29; Ex. BP-1 at 9, 13:8-16 and exhibits cited therein; Ex. BP-8 at Bates page KR009512; Ex. BP-10 at Bates page KR012860; Ex. BP-12 at KR015233; Ex. BP-18; and KR Item by Ref. A, Appendix A at 3.

[606] Ex. S-7 at 37.

[607] Ex. KR-111 at 9.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

producing basins in Colorado, Utah, and Wyoming as Kern River,[608] with one addition. Staff also seems to have considered P-550, Paradox Basin.[609] However, this is a small basin, forecasted by the PGC in 2002 to produce only 1.4 percent of new discoveries.

429. Staff estimated the life of the gas supplies in the Rocky Mountain area as follows. First, it estimated the amount of gas available to be recovered in this area.[610] To estimate future discoveries of gas, Staff extrapolated historical data for the ultimate recovery. The ultimate recovery is the yearly sum of cumulative production and the estimated remaining proven reserves. These figures change annually as gas is produced and new reserves are proven. Staff stated it used historical data for production and estimated remaining proven reserves from the EIA found in its annual publication, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves* for December 21, 2003 and cumulative production information from its publication *U.S. Oil and Gas Reserves, by Year of Field Discovery*.[611]

430. Staff extrapolated the historical ultimate recovery data by fitting an S-curve to the historical data using the least squares curve technique. Staff stated an S-curve matches the manner in which gas production fields are developed with cumulative production slowly increasing when a producing area is initially discovered and developed, then increasing at a greater rate as development of the area increases, and then slowing down and increasing at a slower rate as an area reaches its mature phase with most of the area explored and developed.[612] Staff did two extrapolations. During the last five years for which date were available, 1999-2003, the rate of annual production had been very high. Staff believed that the longer series of data for 27 years from 1977 through 2003 represented long-term trends in the area, but that the recent five-year history of high production should also be taken into account.[613] Consequently, Staff did one

---

[608] Ex. S-7 at 15.

[609] *See* Ex. S-8, Schedule No. 16, in which the Paradox basin is included as part of the PGC estimate of potential gas supplies for purposes of comparison with Staff's estimate.

[610] Ex. S-7 at 19-21 and 24.

[611] Ex. S-7 at 18.

[612] Ex. S-7 at 19-20 and 24.

[613] Ex. S-7 at 28.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

extrapolation using the 27 years from 1977 through 2003[614] and a second extrapolation using the five years from 1999 through 2003.[615]

431. The final ultimate recovery from the projection based on 27 data points was 137,500 Bcf which included an existing cumulative production of 47,356 Bcf, remaining discovered or proven reserves of 40,696 Bcf,[616] and undiscovered reserves of 49,448 Bcf. The result from the projection based on five data points was 150,000 Bcf, consisting of the same cumulative production and remaining discovered or proven reserves and 61,948 Bcf of undiscovered reserves.[617] Staff stated that these results were supported by, among other things, the estimate of the PGC for the most likely probable and possible resources in the supply basins Staff had considered.[618] For comparison purposes, Staff used the PGC estimate of December 31, 2002 for undiscovered reserves, adjusted for production and remaining proven reserves added in 2003.[619] Staff stated the adjusted PGC estimate for undiscovered resources as of December 31, 2003 was 100,608 Bcf.[620] Staff stated that both of its estimates of undiscovered reserves were within the PGC estimate of 100,608 Bcf of undiscovered reserves.

432. Staff then estimated how quickly the proven reserves and estimated undiscovered gas supplies would be produced. It did this by extrapolating historical data for the annual production in the area.[621] It again made two extrapolations, one using the 27 years of data for the years 1977 through 2003 and the other using five years of data for the years 1999 through 2003. Staff extrapolated the historical annual production data by fitting a bell-shaped curve to the historical data using the least squares curve technique. Staff stated annual production from a given producing area is expected to follow the shape of a

---

[614] Ex. S-8, Schedule No. 6.

[615] Ex. S-8 Schedule No. 7 as corrected in S-37.

[616] Ex. S-8, Schedule No. 5.

[617] Ex. S-7 at 22 as corrected in S-36.

[618] Staff explained the function and procedures of the PGC in Ex. S-7 at 30-33 and identified the PGC estimates that it used in Ex. S-7 at 30 and 33 and Ex. S-8, Schedule No.16.

[619] Ex. S-8, Schedule Nos. 5, 8, and 16.

[620] Ex. S-8, Schedule No. 8.

[621] Exs. S-7 at 23-27; S-8, Schedule Nos. 5, 9, 10, 11, and 12.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

bell-shaped curve, starting slowly as the area is first discovered and developed, increasing to a peak year of production as the area becomes fully developed, and then decreasing as reserves are exhausted.[622] Staff stated that this approach was based on the probability-type model developed originally by M. King Hubbert in his chapter in *Oil and Gas Supply Modeling,* U.S. Dept of Commerce (May 1982). Staff noted that cumulating annual production estimates given by a bell-shaped curve results in a cumulative production curve with an S-shape, so that the use of its bell-shaped curve to estimate annual production supports its use of the S-curve for estimating cumulative production.

433. Since production in the Rocky Mountain area is still increasing, Staff had to choose the peak years of production. It chose 2016 for the peak year for the bell curve based on 27 data points[623] and 2014 for the peak year for the bell curve based on five data points.[624] These were the earliest peak years that produced bell curves showing recovery of its estimated final ultimate recovery levels.[625] Staff then cumulated the estimated annual production and identified the year in which the cumulated amount reached the level of estimated new discoveries (final ultimate recovery). At that point, the economic life of the gas supply is at an end.[626] Using a cumulated estimated annual production curve based on the last 27 years of production, the final ultimate recovery occur 47 years from the year 2004 or in 2051.[627] Using the same curve based on the last 5 years of production, final ultimate recoverywould occur 38 years from 2004 or in 2042.[628]

434. Staff adjusted its estimate of the remaining economic life of the pipeline first by averaging the results of the two data sets to obtain 42.5 years.[629] It indicated that this combined approach was desirable because the long-term trend did not follow recent

---

[622] Ex. S-7 at 24.

[623] Ex. S-8, Schedule No. 9 at 2.

[624] Ex. S-8, Schedule No. 10 at 1 as corrected in S-37.

[625] Ex. S-7 at 26.

[626] Ex. S-7 at 27.

[627] Ex. S-8, Schedule No. 11.

[628] Ex. S-7 at 27 as corrected in Ex. S-36; Ex. S-8, Schedule No. 12 at 2 as corrected in Ex. S-37 (with peak year of 2014).

[629] Ex. S-7 at 28 as corrected in Ex. S-36.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

history closely and the short-term trend may not be sustained in the long term.[630] Staff further adjusted its estimate downward because it considered estimates much beyond 35 years to be too speculative. Staff recommended 35 years as the appropriate remaining life for Kern River's facilities.[631]

435. Staff also stated that it believed it was premature to shorten Kern River's remaining economic life because of the effects of competition.[632] Staff stated it believed these effects are speculative, that Kern River has an advantage over new pipeline projects because it has only 57 percent of its debt left to recover, and that Kern River will have opportunities for new contracts as a result of recontracting authorized by the California Public Utilities Commission. Staff concluded that Kern River's remaining economic life will not be shortened by competition or demand and therefore the remaining economic life should be 35 years.[633]

Exceptions and Commission Determination on Staff's Gas Supply Testimony

436. Kern River asserts there are numerous defects in Staff's statistical gas supply projections, and accordingly excepts to the ALJ's approval of Staff's recommended 35-year economic life. Staff, BP Energy, SCGC, the RCG, and Calpine support Staff's recommendation. As discussed below, the Commission rejects Kern River's exceptions and finds that Staff's estimated remaining economic life of 35 years is reasonable.

437. First, Kern River asserts that the Hubbert bell curve theory cannot be applied to the gas production area to determine future annual production because the three-state area is too small.[634] The Commission rejects this argument. The Commission considered whether the Hubbert bell curve could be applied to the Rocky Mountain region in *Wyoming Interstate Company Ltd.*[635] and determined that it could. The Commission and the ALJ noted that Mr. Hubbert recognized that for smaller areas there may not be a single maximum peak and that curves for a particular region or area may exhibit

---

[630] Ex. S-7 at 28.

[631] Ex. S-7 at 28.

[632] Ex. S-7 at 37.

[633] Ex. S-7 at 38.

[634] Kern River cites Ex. KR-111 at 18:4-23, 36-41.

[635] 67 FERC ¶ 63,01,5 at 65,081 and 65,087-088 (Initial Decision), *aff'd in relevant part*, 69 FERC ¶ 61,259, at 61,978-980 (1994).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

irregularities that are more apparent than they are for large regions.[636] The Commission noted Mr. Hubbert stated that the larger the area, the "'irregularities of small areas tend to conceal one another and the composite curve becomes a smooth curve with only a single principle maximum.'"[637] The Commission found that the Rocky Mountain area is not a single producing area, but consists of a number of producing areas and concluded that it fell within the broader concept, so that the bell curve was appropriate.[638] The Commission also found that, in the *Wyoming* case, the bell curve model was an accurate predictor of gas production in the Rocky Mountain region.[639]

438. Kern River insists Staff's projected peak annual production quantity in 2016 (using 27 years of data, Ex. S-8, Schedule No. 9 at 1-2) is in error because it is less than the area's actual gas production in 2002 and counts as future gas supplies amounts which have already been produced.[640] But this objection misconstrues the nature of the extrapolation that Staff has done. Staff has fit a bell curve to historical data points using the least squares method. The curve, as shown in Ex. S-8, Schedule No. 9 at 3, does not match the historical data points exactly. Some of the historical data points are above the curve and some of the historical data points are below the curve. Thus, the curve underrepresents production in some years and overrepresents production in other years. The least squares technique is intended to minimize the differences between the historical data points and the data points on the curve. The Commission finds that this technique is intended to and does provide a reasonable estimate of total production.

439. Kern River asserts that the 27-data point S curve Staff used to extrapolate ultimate recovery is defective because it departs significantly from the historical data and has a poor R^2 measure of statistical validity or fit to the actual data.[641] Staff testified that the R^2 value for both least square curves was approximately 0.87.[642] It stated that the highest R^2 value is 1.00 which would be the best fit and the lowest R^2 value is 0.00 which is the worst fit. Staff testified that 0.87 indicates acceptable fits for the two curves. Kern River

---

[636] 67 FERC ¶ 63,015, at 65,082.

[637] 69 FERC ¶ 61,259, at 61,980.

[638] 69 FERC ¶ 61,259, at 61,980.

[639] 67 FERC ¶ 63,015, at 65,089; 69 FERC ¶ 61,259, at 61,980.

[640] Kern River cites Ex. KR-111 at 30-31.

[641] Kern River cites Ex. KR 111 at 19-25; Ex. KR-112, Schedule Nos. 6 and 7.

[642] Ex. S-7 at 25.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

asserts, however, that Staff's R^2 shows only a "very weak statistical correlation" and is unacceptable as a least squares data fit. The Commission disagrees. An R^2 value of 1.00 would mean that every historical value fell on Staff's S curves. An R^2 value of 0.00 would indicate that there was no more relation between Staff's S curves and the historical data than there is between a straight line drawn through the average value of the historical data points and the historical data points. The higher the value of R^2, the closer the curve comes to the data points. The Commission finds that the R^2 value of 0.87 indicates a sufficiently good fit to the historical data to render the 27-data point S curve a reasonable estimate of ultimate recovery in the Rocky Mountain area and thus of future discoveries of resources in that region.[643]

440. Kern River asserts that Staff's extrapolation based on five data points is without probative value. It asserts the five-data point S curve (Ex. S-8, Schedule No. 7, corrected version in S-37) has too little data to support it; [644] yields a larger amount of cumulative production than the 27-data point S curve but a shorter supply life—the opposite of what should result;[645] and used the wrong inflection point, 2001 instead of 2002[646] which resulted in a supply life of 32 years rather than as little as 25 years.[647] Kern River also asserts that in the projection using five data points, Staff estimated that cumulative gas production would be greater than the projected ultimate recovery[648] which is physically impossible.

441. The Commission finds these exceptions do not invalidate Staff's recommended remaining economic life of 35 years. First, Staff redid its calculations for the five-data point S curve using 2001 as the inflection point.[649] The result was a supply life of 38

---

[643] Kern River appears to argue that Staff developed its 27-data point S curve in Ex. S-8, Schedule No. 6 at 4 predicting ultimate recovery from the allegedly erroneous calculations for peak annual production in Ex. S-8, Schedule No. 9. But Kern River is mistaken. The 27-data point S curve in Ex. S-8, Schedule No. 6 at 4 is based on data in Ex. S-8, Schedule No. 6 at 1-3.

[644] Kern River cites Ex. KR-111 at 25.

[645] *Id.*

[646] Kern River cites Ex. KR-111 at 34 and Ex. KR-112, Schedule No. 18.

[647] Kern River cites Ex. KR-111 at 34-36.

[648] Kern River cites Ex. KR-11 at 28-29.

[649] Tr. at 1448-1451 and Ex. S-36; Ex. S-37.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

years, not 25 years. Second, the five-data point extrapolation was not intended as a stand alone analysis, but was a means of taking into account the high rate of production of the most recent five years for which data were available. The results of the five-point data analysis shortened the estimated remaining economic life in Staff's analysis. In any event, even if Staff's extrapolation based on five data points were defective, it would have no effect on Staff's recommended remaining economic life of 35 years since Staff believed that longer estimates were too speculative.[650]

442. Finally, Kern River asserts that Staff failed to reconcile its supply life with the Commission's finding in the 2000 ET settlement order that Kern River's remaining life at that time was 31 years.[651] But the Commission finds that no such reconciliation is necessary. The Commission agrees with SCGC that Kern River took a conservative approach in the 2000 ET settlement in its assumptions concerning the reserve data used and that it could have used a less conservative approach which would have indicated greater supply reserves and lengthened Kern River's remaining economic life beyond 2032.[652] Moreover, in the 2000 ET settlement, Kern River used gas supply studies done in 1998.[653] Kern River's gas supply testimony in this proceeding was filed in April 2004. There have been changes in the intervening period in the Rocky Mountain area gas supply including changes in the amount of reserves produced, the amount of remaining proven reserves, and the estimates of undiscovered resources. The decision in this proceeding must take into account the current facts concerning gas supply. For this reason, the Commission normally uses the most recent data available in deciding rate cases. In addition, the Commission must decide a case based on the record in that case. For all of these reasons, the Commission is not bound to adopt in this case the remaining economic life that it approved in the 2000 ET settlement order.

443. The Commission finds Kern River has failed to show that Staff's gas supply study and its recommended remaining economic life of 35 years are unreasonable or lacking in probative value. The Commission finds that Staff's gas supply study results in a reasonable estimate of Kern River's remaining economic life of 35 years and affirms the

---

[650] Ex. S-7 at 28.

[651] Kern River cites to the ET Settlement Order at 61,161 (Brief on Exceptions at 85). In its Brief on Exceptions (at 11 n.18), the ET Settlement Order is identified as 92 FERC ¶ 61,061 (2000). The rehearing of this order is 94 FERC ¶ 61,115 (2001). ET stands for Extended Term. This settlement permitted customers to extend the terms of their transportation contracts.

[652] 92 FERC ¶ 61,061 at 61,160.

[653] *Id.*

Initial Decision's adoption of Staff's recommendation. Consequently, the Commission also adopts Staff's recommendations that flow from its remaining economic life of 35 years including its ARL of 30.6 years for the original system and 27.0 years for the 2002 expansion and its book depreciation rate for the rolled-in system of 1.95 percent.

ii. <u>Negative Net Salvage Rate</u>

444. Net salvage value is the salvage value of retired property less the cost of removal.[654] When the revenue realized from the sale of the property is less than the cost of removal, the net salvage value is negative. In *Iroquois Gas Transmission System, L.P.* (*Iroquois*),[655] the Commission established three criteria for approving a negative net salvage allowance: (1) the pipeline has a clearly discernable end-of-life; (2) the evidence is persuasive that interim retirements have been taken into account in computing negative salvage costs; and (3) sales and salvage values of abandoned or retired equipment are fully proven. In *KPC II*, the Commission stated that, with respect to the second requirement, it "uses the historical costs of interim retirements that have already occurred to project the costs of interim retirements, not estimates of future costs unsupported by any evidence as to actual past costs. Historical costs may show that the salvage cost was positive."[656]

445. Kern River proposed to implement a negative net salvage rate for the first time in this proceeding. It proposed a negative net salvage value of 0.21 percent for transmission plant other than compressor engines. This rate was based on its proposed average remaining economic life of 26 years. Staff proposed a negative net salvage rate of 0.18 percent for transmission plant exclusive of compressor engines based on a remaining economic life of 35 years.[657]

446. The Initial Decision adopted Staff's negative net salvage rate. The Commission affirms the Initial Decision's holding that the negative net salvage rate for transmission plant other than compression engines must be based on a remaining economic life of 35 years, but revises the Initial Decision's negative net salvage rate by removing the amount for interim retirements so that Kern River's negative net salvage rate is 0.12 percent.

---

[654] 18 C.F.R. Part 201, Definition 23 (2005).

[655] 84 FERC ¶ 61,086, at 61,440-41 (1998), *reh'g denied*, 86 FERC ¶ 61,261, at 61,941-44 (1999), *accord, Williston I*, 95 FERC ¶ 63,008 at 65,104 – 05.

[656] *KPC II*, 102 FERC ¶ 61,310 at P 114.

[657] Ex. S-7 at 61-63.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

Initial Decision

447. The Initial Decision held that Kern River had not carried its burden of proving that its proposed salvage rate for transmission plant excluding compressor engines produces just and reasonable rates if based on a 26-year average remaining economic life.[658] However, the Initial Decision found that Kern River had met the requirements in *Iroquois*. [659]

448. With respect to the first *Iroquois* requirement, the Initial Decision found that the 35-year remaining economic life adopted in the Initial Decision satisfied the end of life requirement.[660] With respect to the second *Iroquois* requirement, the Initial Decision found that Kern River had presented credible evidence of the costs of abandonment and removal of its facilities and credible historical data on actual interim retirements. It found further that Kern River had adjusted the total salvage estimate downward to take into account the cost of removing the existing plant and the cost of removal associated with interim removal requirements. With respect to the third *Iroquois* requirement, the Initial Decision found that Kern River should not be precluded from charging a negative net salvage rate because it is in its early years and lacks a history of sales and salvage value of abandoned or retired facilities. It reasoned that shippers currently using the pipeline should pay their fair share of the costs of receiving the benefits of the pipeline, including the costs of future retirement.

449. The Initial Decision also noted that Kern River's levelization cost-of-service/ratemaking methodology is depreciation-oriented ratemaking and not taking account of negative net salvage is inconsistent with the methodology. Finally, the Initial Decision noted that FAS 143 is not controlling because accounting does not control ratemaking.[661]

Exceptions and Commission Determination

450. Kern River asserts on exceptions that its proposed negative net salvage rate of 0.21 percent based on its average remaining economic life of 26 years should be adopted and that it has met the *Iroquois* requirements. The RCG and SCGC[662] assert Kern River

---

[658] ID at P 407.

[659] ID at P 408-409.

[660] ID at P 408-409.

[661] *Citing Mojave Pipeline Co.,* 81 FERC ¶ 61,150 (1997).

[662] SCGC, Brief Opposing Exceptions at 29 n.8.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

should not be permitted to collect a negative net salvage rate because it has not met the *Iroquois* requirements. Staff asserts Kern River should be permitted to collect a negative net salvage rate but that it should be based on the remaining economic life of 35 years. BP asserts that Kern River's objection to the 0.18 percent negative net salvage rate adopted by the Initial Decision is without merit since it is based on a 26-year average remaining economic life. SCGC states that, to the extent the Commission finds it appropriate for Kern River to implement a net negative salvage rate, it should affirm the Initial Decision's rejection of Kern River's proposed negative net salvage rate based on a 26-year average remaining life.[663] SCGC also asserts Kern River should be required to calculate its negative net salvage rate using the same interim retirements that it used in calculating its depreciation rate. If the Commission permits Kern River to have a negative net salvage rate, High Desert asks for specific provisions for negative net salvage related to the High Desert Lateral and SCGC asks that Kern River be required to establish a separate sub-account in Account No. 108 for negative salvage.[664]

451. As discussed below, the Commission finds that Kern River's negative net salvage rate estimate does not meet the requirements of *Iroquois* and cannot be used as the basis for a negative net salvage rate. The Commission finds that Staff's negative net salvage rate estimate, adjusted to remove the costs of interim retirements, provides a just and reasonable basis for a negative net salvage rate for Kern River and adopts the adjusted negative net salvage rate of 0.12 percent. The Commission finds in addition that Kern River must establish and use a separate subaccount in Account No. 108 for negative salvage. The Commission finds further that the negative net salvage rate proposed by Staff and adopted as modified by the Commission is not applicable to the High Desert and Big Horn Laterals and that, consequently, there is no need to establish procedures for negative net salvage costs collected from High Desert.

452. The RCG and SCGC assert that Kern River should not be permitted to have a negative net salvage rate because it has not met the *Iroquois* requirements. The RCG asserts that the facts for Kern River are similar to the facts in the record in *Iroquois*, with both being relatively new pipelines with no retirement experience, and that allowing Kern River to collect a negative net salvage allowance at this time would rest on pure speculation regarding the timing, degree, and cost of a retirement.[665] The RCG asserts

---

[663] *Id.* at 29.

[664] Kern River states it has no objection to such a sub-account and that the sub-account and cost tracking are already in place. Kern River, Brief Opposing Exceptions at 80.

[665] *Citing Iroquois*, 84 FERC at 61,441.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

the Commission should reverse the Initial Decision and reject a negative net salvage rate for Kern River.

453. The RCG first asserts that Kern River does not have a clearly discernible end-of-life as required by *Iroquois* because Kern River's accountants have concluded that the final retirement date of it assets is not determinable.[666] Kern River answers that it has a clearly discernable end-of-life consisting of its estimate of a 26-year average remaining economic life supported by its testimony and that accounting standards are not applicable to and do not invalidate its average remaining life analysis. The Commission agrees with Kern River that, for purposes of meeting the first *Iroquois* requirement, a remaining economic life constitutes a clearly discernable end-of-life [667] and that accounting concepts of retirement are not controlling. However, in this order the Commission affirms the Initial Decision's rejection of Kern River's proposed 26-year average remaining life and its adoption of a remaining economic life of 35 years. Thus, Kern River's negative net salvage rate must be based on a remaining economic life of 35 years.

454. The RCG asserts that Kern River's evidence of interim retirements in Ex. KR-6, Schedule 8, is arbitrary and theoretical and is not based on fact or evidence. Kern River counters that it conducted a thorough analysis of actual interim retirements based on historical data for facilities associated with its original system.[668] It states that it was appropriate to project the interim retirements of similar, 2003 Expansion facilities.[669] It states that the absence of interim retirements of 2003 Expansion facilities does not detract from its study, citing *HIOS I*.[670]

---

[666] *Citing* "Recent Accounting Standards" at p. 15, Statement M, April 30, 2004 Filing; Ex. RCG-2 at 69.

[667] *KPC I*, 100 FERC ¶ 61,260 at P 286-288, 295; *Williston I*, 95 FERC ¶ 63,008 at 65,105-65,110-111.

[668] *Citing* Ex. KR-5 at 29-31; Ex. KR-6, Schedule No. 8; Ex. KR-111 at 68:21-70:3.

[669] *Citing* Ex. KR-111 at 76-77. However, this testimony addresses the retirement of compressor engines. Kern River proposed its negative net salvage rate for transmission plant other than compressor engines so that its experience with the retirement of compressor engines is not relevant to its proposed negative net salvage rate.

[670] *Citing HIOS I*, 110 FERC ¶ 61,043 at P 59.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

455. But, contrary to Kern River's assertions, the Commission is unable to discover any historical data concerning interim retirements in Kern River's cited testimony.[671] Kern River's witness Mr. Feinstein states that he analyzed Kern River's historical retirements,[672] but does not include any testimony or exhibits showing what those retirements were, when they took place, or the costs associated with them. Schedule No. 8 of Exhibit KR-6 contains only a projection of retirements from 2003 through 2032, not historical data of past retirements. Mr. Feinstein states that the negative salvage estimate was developed by Mr. Barrie McCullough.[673] Mr. McCullough's study consists entirely of costs that are estimates.[674] It contains no historic costs of interim retirements. Mr. Feinstein states Kern River has had "little retirement experience" and that significant retirements "do not generally occur in the early years of a pipeline's life . . . ."[675] Thus, the Commission concludes that there is no historical data in the record concerning interim retirements on Kern River's system. In addition, Kern River used a retirement period based on its estimated average economic life of 26 years. This retirement period is too short. The Commission has affirmed a remaining economic life for Kern River of 35 years. Since Kern River used a retirement period that was too short, its interim retirements are too small, its plant remaining at the end of the retirement period is too great, and its net negative salvage costs for plant remaining at the end of the pipeline's economic life are too large. (This would be true even if Kern River had used historical cost data for interim retirements.) Consequently, for this reason as well, the Commission cannot adopt Kern River's proposed negative salvage costs or its proposed negative net salvage rate.[676]

456. Contrary to Kern River's assertion, *HIOS I* does not support the use of estimated retirement costs for Kern River's interim retirements. The Commission approved a negative net salvage rate in *HIOS I* based on the reasoning of the ALJ in that case.[677] The

---

[671] Ex. KR-5 at 29-31; Ex. KR-6, Schedule No. 8; Ex. KR-111 at 68:21-70:3.

[672] Ex. KR-5 at 29.

[673] Ex. KR-111 at 69. Mr. McCullough's study is in the record as Ex. KR-8, "Kern River Negative Salvage Value Study," (August 2003).

[674] Ex. KR-8 at 8-9.

[675] Ex. KR-111 at 69.

[676] *See KPC II*, 102 FERC ¶ 61,310 at P 117.

[677] *HIOS I*, 110 FERC ¶ 61,043 at P 61.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

ALJ noted that HIOS is an offshore pipeline and is unlike the land-based pipelines in *Iroquois, KPC, and Williston*.[678] She found that because HIOS is an offshore pipeline, it was likely that it would retire all of its pipeline at or near the end of its economic life.[679] Thus, it was unlikely that there would be any interim retirements or any historical data concerning such retirements. In these circumstances, the ALJ held that it would be unfair to deny HIOS a negative net salvage rate.[680] But Kern River is not an offshore pipeline. The considerations favoring the allowance of a negative net salvage rate in *HIOS* are not present here. The Commission agrees with the RCG that Kern River is like the pipeline in *Iroquois* and must meet the requirement to base its cost projections for interim retirements on the historical costs of retirements that have actually taken place. Since Kern River has not met this requirement, the Commission finds that a negative net salvage allowance for interim retirements is unjustified. Accordingly, the Commission reduces the negative net salvage amount for interim retirements to zero.[681]

457. Third, the RCG asserts Kern River's witness Mr. Feinstein conceded that Kern River had failed to prove sales and salvage values of abandoned or retired equipment because Kern River has little retirement experience due to its relatively young age.[682] Kern River replies that its testimony addressed the third *Iroquois* requirement that sales and salvage values of abandoned or retired equipment be fully proven by explaining that, as a relatively new pipeline, Kern River has little retirement experience.[683] Kern River also argues that waiting until it begins to experience significant retirements before recovering negative salvage costs "is inconsistent with depreciation ratemaking."[684] Kern River asserts that even though major retirements do not generally occur in the early years of a pipeline's operations, current rate payers who use and benefit from the Kern River system should bear their share of the costs associated with the future retirement of system assets.[685] As held above, Kern River did not provide probative evidence of the sales and

---

[678] *High Island Offshore System, L.L.C.*, 107 FERC ¶ 63,019 at P 87 (2004).

[679] *Id.*

[680] *Id.* at P 86-87.

[681] *KPC I*, 100 FERC ¶ 61,260 at P 294; *KPC II*, 102 FERC ¶ 61,310 at P 113.

[682] *Citing* Ex. KR-111 at 69:1-3.

[683] *Citing* Ex. KR-111 at 69:1-10.

[684] *Id.*

[685] *Id.*

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

salvage values of interim retirements because it did not provide evidence of the historic costs of these retirements.

458. Based on the above findings, the Commission holds that Kern River's negative net salvage study failed to meet the *Iroquois* requirements in that it used an incorrect end of discernable life and failed to provide evidence of historic costs of interim retirements. Therefore, the Commission rejects Kern River's proposed negative net salvage rate.[686]

459. However, the detailed study by Kern river's witness, Mr. McCullough, of estimates of sales and salvage values provides estimated costs for retirements at the end of Kern River's economic life. This study was not rebutted at hearing and provides substantial, probative evidence of these costs. Therefore, while the Commission will not permit Kern River to include interim retirements in its negative net salvage rate, the Commission will approve a negative net salvage rate for retirements at the end of Kern River's economic life, based upon Staff's negative net salvage rate study. The Commission has approved the use of negative net salvage rates to compensate pipelines for future costs associated with the retirement of facilities.[687] Staff's study meets the *Iroquois* requirements if the costs of interim retirements are removed. It has a discernable end of life consisting of a remaining economic life of 35 years which has been affirmed in this order. It used the sales and salvage values for retirements at the end of the pipeline's remaining economic life in the study provided by Mr. McCullough in Ex. KR-8.[688] With the costs of interim retirements removed, Staff's proposed negative

---

[686] SCGC asserts Kern River should be required to calculate its negative net salvage rate consistent with its book depreciation of its transmission plant, including Kern River's calculations with regard to the nature, dollar amounts, and timing of interim retirements as it argued in its testimony. *Citing* Ex. RCG 2 at 65-66. In particular, SCGC asserts Kern River should calculate negative net salvage rate consistent with the 35-year remaining life established for depreciation. Kern River responds that its negative net salvage rate is consistent with its book deprecation rate because both rates are based on a 26-year average remaining economic life. Since the Commission is rejecting Kern River's negative net salvage rate, it is not necessary to address these arguments.

[687] *KPC I*, 100 FERC ¶ 61,260 at P 295.

[688] Ex. S-7 at 63; Ex. S-8, Schedule No. 28, using total abandonment cost or negative net salvage amount of $114,369,697 which is the amount shown in Ex. KR-8 at 7.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

net salvage rate is 0.12 percent.[689] The Commission finds that this is the just and reasonable negative net salvage rate for Kern River.

460. SCGC asserts that Kern River should be required to establish a separate subaccount in Account No. 108, Accumulated Provision for Depreciation of Gas Utility Plant, to track transmission plant negative salvage accruals and actual net salvage experienced. This will allow Kern River's customers, it states, to "more easily determine the value of the reserve in the future and propose appropriate adjustments, if necessary."[690] Kern River states it has no objection to such a subaccount and that the subaccount and cost tracking are already in place.[691] The Commission adopts SCGC's proposed separate subaccount in Account No. 108 and requires Kern River to establish this subaccount to the extent it has not already done so and to use it in future.

461. High Desert proposes that if Kern River is permitted to recover negative net salvage costs from High Desert, Kern River should (1) separately account for any negative salvage dollars recovered from High Desert to retire High Desert's incremental facilities; (2) credit such dollars to the High Desert rate base in future proceedings until such dollars are actually used for negative salvage work on the High Desert Lateral; and (3) refund such dollars if not needed. High Desert states the Initial Decision did not rule on its proposal. High Desert states that the High Desert Lateral was placed in service only two years ago and that Kern River has presented no plans to retire the High Desert facility or remove assets. High Desert asserts that negative salvage costs for High Desert are not known and measurable at this time, so that its proposal will ensure that the amounts recovered from High Desert under the generic negative net salvage rate will be refunded if not needed in the future for retirement of the High Desert Lateral.

462. Kern River agrees that negative salvage costs recovered from High Desert should be accounted for separately and that High Desert's rate base should be credited in future rate cases by the negative salvage amounts collected until the High Desert facilities are retired and the salvage funds are needed. Kern River also agrees to refund unused salvage amounts to High Desert provided that, if applicable, such refund would occur

---

[689] Ex. S-8, Schedule No. 28. Annual costs of interim retirements are $810,121 + 506,729 = $1,316,850. Removing these costs from annual negative net salvage expense, the annual negative net salvage rate as a percent of gross plant is $2,665,055/$2,218,030,516 = 0.0012 or 0.12 percent.

[690] *Citing KPC I*, 100 FERC ¶ 61,260 at P 289, 295; *Williston I*, 95 FERC ¶ 63,008 at 65,109-110.

[691] Kern River, Brief Opposing Exceptions at 80.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

only after the physical retirement or abandonment of the facilities is complete and High Desert is required to pay for any shortfall in collections relative to actual negative salvage costs of the High Desert Lateral.

463. The Commission finds that Staff removed gross plant associated with the High Desert and Big Horn Laterals from its negative net salvage rate calculation.[692] Staff's proposed negative net salvage rate was not applicable to the High Desert and Big Horn Laterals. The negative net salvage rate adopted in this order consists of Staff's proposed negative net salvage rate adjusted to remove the annual costs of interim retirements. Consequently, the negative net salvage rate adopted in this order similarly is not based on gross plant for the High Desert and Big Horn Laterals and is not applicable to these laterals. Since there is no negative net salvage rate applicable to High Desert, there is no need to establish provisions for negative net salvage costs collected from High Desert and the Commission rejects High Desert's proposal.

iii. <u>Solar Mars Compressor Engines</u>

464. This section addresses a straight-line book depreciation rate for the Solar Mars compressor engines on Kern River's system. Elsewhere in this order, the Commission rejects Kern River's proposal to remove these compressor engines from its levelized rates. Thus, the costs of these engines will continue to be collected through levelized rates and not through traditional cost-of service rates with straight-line depreciation. Accordingly, this section establishes the depreciation rate for the Solar Mars compressor engines for book purposes only and not for purposes of Kern River's levelized rates.

465. The unrebutted testimony of record is that Kern River has eighteen Solar Mars compressor engines in operation.[693] These engines cost about $3.4 million each and have a short service life. They have a positive net salvage value, described as 70 percent or more.[694] Kern River initially proposed a 9.92 percent depreciation rate for the compressors based on an average service life method. It used an average service life of 2.91 years and a net salvage percentage of 71.11 percent.[695]

---

[692] Ex. S-8, Schedule No. 28.

[693] Exs. KR-4 at 2-3; KR-5 at 32-36; S-7 at 48-49.

[694] Ex. KR-5 at 32.

[695] Ex. KR-5 at 35-36; Ex. KR-6, Schedule Nos. 7, 15, and 17.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

466. Staff proposed an 8.85 percent depreciation rate based, in part, on a net salvage percentage of 75.00 percent.[696] BP proposed a depreciation rate of 9.4 percent and the RCG and SCGC proposed a depreciation rate of 5.86 percent.[697] Kern River subseqently revised its proposal and proposed a 12.53 percent depreciation rate for the compressors based on its corrections to alleged mistaken assumptions in Staff's calculations.[698]

467. The Initial Decision adopted Staff's proposal of 8.85 percent. The Commission reverses this decision and adopts Kern River's initial proposed rate of 9.92 percent.

Initial Decision

468. The Initial Decision found Staff had shown that Kern River's proposed depreciation rate for compressor engine plant of 9.92 percent does not result in just and reasonable rates and that Staff's proposed depreciation rate of 8.85 percent does result in just and reasonable rates. The Initial Decision adopted Staff's proposed rate of 8.85 percent.

Exceptions and Commission Determination

469. As discussed below, the Commission reverses the Initial Decision's adoption of Staff's book depreciation rate of 8.85 percent for the Solar Mars compressor engines. The Commission also rejects Kern River's revised depreciation rate of 12.53 percent.

---

[696] Ex. S-7 at 48-49; S-8, Schedule No.26. Staff explains in Ex. S-7 at 48 that it calculated the depreciation rate for the compressor engines by subtracting the net salvage percentage from the total plant percentage (100 percent) and dividing that result by the average life of the compressor engines. Most of the text of the copy of Ex. S-8, Schedule No. 26 that is in the record is illegible. It appears, however, that Staff used an average service life of 2.83 years. It also appears that Kern River reproduced Staff's figures in its 45-day Update filing. *See* "Docket No. RP04-274 (45-Day Update), Work Papers" (December 15, 2004), FERC eLibrary Accession No. 20041216-0184, at unnumbered page 18.

[697] ID at P 389-390.

[698] Ex. KR-111 at 76, 79 (referencing the "Other" tab in the workpapers in the 45-day update filing. The referenced workpapers can be found in "Docket No. RP04-274 (45-Day Update), Work Papers" (December 15, 2004), FERC eLibrary Accession No. 20041216-0184 at pp. 329-331 (pages are unnumbered; there is no "Other" tab in this electronic version of the document)).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

The Commission finds Kern River's initially proposed depreciation rate of 9.92 percent is just and reasonable.

470. Kern River asserts it showed that Staff's proposed 8.85 percent rate contained errors.[699] Specifically, Kern River states Staff overlooked $792,300 of capital cost components associated with the Filmore No. 1 replacement unit. Second, it states Staff erroneously attributed price discounts to the retirements of four units but that the price discounts were given on the initial installation of the units and were already reflected in the purchase price of the engines at the time of installment.[700] Last, Kern River asserts Staff omitted portions of the full costs of the replacement compressor engines consisting of sales tax, installation and freight, overheads, and AFUDC.[701] Kern River asserts that omitting these costs is contrary to Commission regulations which provide that such items are proper capital costs.[702] Kern River asserts that, as a result of these errors, Staff's depreciation rate study did not relate net retirement costs to the full costs of the retired compressor units. Kern River asks the Commission to reverse the Initial Decision and accept its corrections to Staff's depreciation rate calculation which result in a 12.53 percent depreciation rate for its compressor engines.

471. Staff asserts that it rejected the $792,300 of capital costs associated with the Filmore No. 1 replacement unit because it determined that Kern River had already recovered those costs. BP asserts that Kern River's second proposed rate of 12.53 percent is inappropriate. BP argues[703] that Kern River's 45-day update filing cannot serve as a means of increasing, without explanation, rates requested by the pipeline in its initial rate request.[704]

---

[699] Ex. KR-111 at 75-76; Ex. KR-112, Schedule No. 33.

[700] Kern River Brief on Exceptions at 80.

[701] *Id.*

[702] Kern River cites 18 C.F.R. Part 201, Gas Plant Instructions, §§ 2; 3, paragraphs 4, 11, 16, and 17; and 4.

[703] BP cites 18 C.F.R. § 154.301(c) (2005).

[704] Calpine argues that a levelized depreciation rate should be used for the compressor engines rather than Kern River's separate traditional straight line depreciation rate of 12.35 percent. Arguments concerning levelized rates are considered elsewhere in this order.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

472. The Commission finds Kern River has shown that Staff's compressor depreciation rate was calculated incorrectly. The only error alleged by Kern River that Staff disputes is the omission of $792,300 of capital costs associated with the Filmore No. 1 replacement unit. Consequently, the Commission finds that, as Kern River asserts, Staff incorrectly attributed purchase discounts to the retirements of four units and incorrectly omitted some costs of replacement units. In addition, the Commission cannot accept Staff's proposal because the copy of the calculations on which it is based that is in the record for Commission review is largely illegible.[705] Thus, it is not possible for the Commission to review Staff's calculations. Accordingly, the Commission reverses the Initial Decision on this issue.

473. At the same time, the Commission rejects Kern River's second proposal of 12.53 percent as the depreciation rate for the compressor engines. This rate is based, in part, on Kern River's adjustments to Staff's calculation of its proposed depreciation rate of 8.85 percent. Kern River used Staff's figures to calculate a revised net salvage rate of 0.6264 percent. But Kern River does not explain why its own net salvage rate of 0.71 is incorrect. In particular, Kern River does not explain why its figures[706] for Cost of Plant Retired and Salvage, which determine the net salvage rate, differ from Staff's figures[707] for these items. In addition, both salvage rates of 0.6264 and 0.71 were calculated using data from Kern River's original filing, not data from its updated filing. However, Kern River applied the 0.6264 salvage rate to updated data for compressor engine Gross Plant.[708] That is, Kern River updated part of its recalculation of the compressor engine depreciation rate, but not all of it. Consequently, the Commission finds that Kern River's recalculated depreciation rate of 12.53 percent is unconvincing.

---

[705] *See* Ex. S-8, Schedule No. 26. This exhibit consists of small print which appears to have been Xeroxed several times. Whatever the reason, many of the letters and numbers in this exhibit are unreadable.

[706] Ex. KR-6, Schedule No. 7. Kern River's figures are Cost of Plant Retired, $37,997,301, and Salvage, $26,950,587.

[707] Ex. S-8, Schedule No. 26. Staff's figures, as subsequently adjusted by Kern River, are Cost of Plant Retired, $38,831,941, and Salvage, $24,323,093. *See* FERC eLibrary Accession No. 20041216-0184 at p. 329.

[708] *See* FERC eLibrary Accession No. 20041216-0184 at p. 329 where the updated figure of $55,584,782 is used for this item. This figure can be found in Statement A of the 45-Day Update Work Papers at unnumbered page 19 (FERC eLibrary Accession No. 20041216-0184). Kern River originally used the amount of $57,111,874 for compressor engine Gross Plant. Ex. KR-6, Schedule No. 7.

474. The RCG and SCGC contend that the useful life of the compressor engines should be four years with a resulting depreciation rate of 5.86 percent. They assert their proposed useful life is based on a 35,000-hour exchange agreement which they claim took effect on July 1, 2002 prior to Kern River's test period in this case and equates to four years if the engines run at 100 percent usage.[709] The RCG asserts that the useful life of the compressor engines should be longer than four years because the average utilization rate of the compressor engines is 73 percent after the start of the 2003 Expansion.[710]

475. The Commission will not adopt the longer useful life advocated by the RCG and SCGC. The Commission bases its rate case determinations on historical data. Kern River put in place its new service agreement with a 35,000 hour life on July 1, 2002. In this rate case, Kern River used a test period consisting of a base period of the twelve months ending January 31, 2004, as adjusted for known and measurable changes occurring through October 31, 2004. The new agreement had been in operation only a little over two years by the end of the test period. Thus, there is insufficient data in the record to show that the useful life of the compressor units increased from the 2.91 years proposed by Kern River.

476. The Commission finds that Kern River's average service life depreciation rate study for the Solar Mars compressor engines in its direct testimony[711] provides a just and reasonable depreciation rate for these engines and adopts the 9.92 percent depreciation rate that Kern River proposed in its direct testimony.

iv. <u>High Desert and Big Horn Laterals</u>

477. The High Desert and Big Horn Laterals are lateral lines. Each Lateral has one firm customer. Kern River charges incremental rates for both Laterals. For both Laterals, Kern River proposed to continue book depreciation rates based on the contract term of the firm customer's gas service agreement.

---

[709] *Citing* Ex. RCG-2 at 61; Tr. 698:16-20, 700:9-12, 702:15-703:8; Ex. KR-4 at 4.

[710] *Citing* Ex. KR-4 at 4.

[711] Exs. KR-5 at 32-36; KR-6, Schedule Nos. 7, 15, and 17.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

478. Big Horn refers to a lateral line in Nevada constructed in 2002[712] and put into service in 2002.[713] In its update filing of December 15, 2004, Kern River showed the adjusted depreciable plant for the Big Horn Lateral as $3,679,873.[714] Kern River stated that the Big Horn Lateral is a facility reimbursement arrangement priced on an incremental, levelized cost-of-service basis. Kern River also stated that the Kern River service agreement with Big Horn provides for a levelized cost-of-service and a 60 percent equity/40 percent debt capital structure. [715]

479. The Commission issued a certificate to Kern River to construct the High Desert Lateral on April 24, 2002. [716] The High Desert Lateral consists of 31.6 miles of 24-inch diameter delivery lateral pipeline and related facilities in San Bernardino County, California. In its update filing of December 15, 2004, Kern River showed the adjusted depreciable plant for the High Desert Lateral as $29,893,032.[717] The High Desert Lateral provides natural gas to a 720 megawatt (MW) electricity generating plant constructed by the High Desert Power Project, LLC (High Desert Power) near Victorville, California. Victorville-Gas, LLC (Victorville-Gas) is the shipper of gas for the project.[718]

480. Victorville-Gas' service agreement provides for firm transportation at negotiated rates for 282,000 Dth/day with a primary term of 21 years.[719] Kern River used a levelized rate methodology for Victorville-Gas' negotiated rate. The incremental facility charge was designed to reimburse Kern River on a levelized basis through August 31, 2023 for the cost-of-service associated with this Lateral.[720] High Desert states that the

---

[712] Ex. KR-12 at 6.

[713] Ex. KR-12 at 10.

[714] Ex. KR-94, Statement H-2 at 1.

[715] Ex. KR-17 at 9; Ex. KR-57 at 3.

[716] *Kern River Gas Transmission Co*, 99 FERC ¶ 61,085, at 61,363 (2002).

[717] Ex. KR-94, Statement H-2 at 1.

[718] At the time the certificate was issued, High Desert Power and Victorville-Gas were subsidiaries of Constellation Energy Group.

[719] *Kern River Gas Transmission Co*, 99 FERC ¶ 61,085, at 61,365 (2002).

[720] *Id.*

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

rate is levelized by adjusting depreciation expense each year during the term of the 21-year agreement.[721]

481. For High Desert's recourse rates, Kern River used straight-line depreciation over a 21-year period that coincides with the primary term for Victorville-Gas' service agreement.[722] The straight-line depreciation rate was 4.76 percent, based on a 21-year amortization period for the High Desert Lateral. The Commission stated that the 21-year depreciable life coincided with the primary term for the Victorville-Gas service agreement and appeared reasonable. The Commission stated that, in addition, a straight-line depreciation method is a systematic and rational method consistent with the Commission's Uniform System of Accounts. For these reasons, the Commission approved Kern River's proposed use of a 4.76 percent depreciation rate for initial recourse rates for High Desert.[723]

482. In this proceeding, Kern River proposed that the book depreciation rates for the Laterals should remain the same as they had been previously.[724] That is, it proposed that the depreciation periods for the Laterals should remain the primary terms of the gas service agreements under which the laterals were constructed.[725] Kern River proposed that the depreciation rate for recourse rates for the High Desert Lateral should remain 4.76 percent based on the primary term for the Victorville-Gas service agreement of 21 years. It proposed that the book depreciation rate for the Big Horn Lateral remain 6.67 percent based on the term of the facility cost reimbursement agreement which is 15 years. Staff opposed Kern River's proposal. Staff proposed that depreciation for the Laterals should be determined using the same approach as that used for the rest of Kern River's transmission plant using a 35-year remaining economic life[726] with depreciation rates of 2.7 percent for Big Horn and 2.8 percent for High Desert.[727]

483. The Initial Decision adopted Kern River's proposal to base book depreciation for

---

[721] High Desert Brief on Exceptions at 4 n.7.

[722] *Kern River Gas Transmission Co*, 99 FERC ¶ 61,085, at p. 61,365 (2002).

[723] *Id.* at 61,372.

[724] Ex. KR-94, Statement H-2 at 1, lines 6 and 7.

[725] Ex. KR-5 at 45.

[726] Ex. S-7 at 39-42 and 47.

[727] Ex. S-8, Schedule No. 24.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

the Laterals on the terms of their primary contracts. The Commission affirms the Initial Decision on this issue.

Initial Decision

484. The Initial Decision held that Kern River had carried its burden of proving that using the contract life approach for the High Desert and Big Horn Laterals produces just and reasonable rates.[728] It found there appeared to be no good reason to upset the expectations of Kern River, Big Horn, and High Desert.[729]

Briefs on Exceptions and Opposing Exceptions

485. On exceptions, Staff asserts that its economic life study and its remaining economic life of 35 years should be used to determine depreciation for the Laterals rather than the lives of their primary contracts. Staff argues that while a contract can give an indication of the minimum life of a company, it cannot take the place of a depreciation study to determine the remaining life of that company's facilities. It states that contracts are merely agreements for services for a fixed term, not analyses of the useful lives of facilities. Given that contracts can be extended, renewed, or replaced by other contracts, Staff asserts they cannot be relied upon to accurately reflect the remaining life of a facility.[730] Staff asks that the Commission reject Kern River's use of contract life.

486. Kern River asserts the Initial Decision should be affirmed so that the annual book depreciation rates for the High Desert and Big Horn Laterals are based on the terms of the shippers' gas service contracts for which each of the laterals was constructed. Kern River asserts that while the Commission's general policy is not to limit a pipeline's depreciation to the life of customers' contracts, the Commission has approved the use of contract life to establish depreciation rates for facilities similar to those involved here, citing *Northwest Pipeline Corp.* (*Northwest*).[731] Kern River asserts the Commission has already approved basing the depreciation rate for the High Desert Lateral on the underlying contract.[732] Kern River states the Initial Decision properly chose to honor the expectations of Kern River and its lateral customers which were created by the

---

[728] Initial Decision at P 379.

[729] *Id.* at P 380.

[730] *Citing* Ex. S-7 at 39.

[731] 87 FERC ¶ 61,266, at 62,042-43 (1999).

[732] *Citing Kern River Gas Transmission Co.*, 99 FERC ¶ 61,085, at 61,372 (2002).

Commission's prior ruling. Kern River also states that Staff's economic life study focuses on Kern River's mainline facilities and fails to account for the differences in the physical and economic lives between mainline facilities and the single-purpose, single-customer Laterals.

Commission Determination

487. The Commission affirms the Initial Decision's decision to continue the existing book depreciation rates for Big Horn and High Desert. The Commission agrees with Kern River that the Laterals are similar to the facilities in *Northwest*. As we noted in *Northwest*, the Commission's general policy is not to limit the depreciable life of a pipeline to the life of the pipelines' current contracts with its customers.[733] We stated that if depreciation rates were based on the life of the pipeline's current contracts, but the facilities remain in service after the end of those contracts, the later ratepayers would not pay any depreciation component for that use. Such a result, we found, generally imposes an unfair burden on the first generation of ratepayers.

488. But here, as in *Northwest*, Kern River built facilities for specific customers. Those customers entered agreements that obligated them to pay for the full costs of the facilities. With respect to High Desert, the Commission specifically accepted the agreement and its associated recourse rate and book depreciation rate. The customers pay incremental rates for the Laterals so that the depreciation costs are not spread over other ratepayers. The original primary contracts are still in place. In these circumstances, the Commission sees no reason to disturb the arrangements of Kern River and the Lateral customers.

v. General Plant

489. General Plant includes items such as office furniture, computer equipment, communications equipment, transportation equipment, tools, and power-operated equipment. Kern River proposed that General Plant should be removed from Kern River's levelized rate determination and treated as a separate account subject to straight-line depreciation.[734] It proposed various straight-line depreciation rates for the different kinds of General Plant. [735] Staff accepted Kern River's General Plant

---

[733] *Northwest*, 87 FERC ¶ 61,266 at 62,042-43.

[734] This issue is addressed elsewhere in this order.

[735] Exs. KR-5 at 4-5 and KR-6, Schedule No. 12 show the following proposed depreciation rates for General Plant: Acct. No. 391—office furniture, 6.67 percent; computer hardware, 20.00 percent; PCs and laptops, 33.33 percent; computer software, 20.00 percent; office equipment, 6.67 percent; Acct. No. 397—communications

(footnote continued)

recommendation.[736]

Initial Decision

490. The Initial Decision does not appear to have made a specific determination concerning General Plant.

Exceptions and Commission Determination

491. Kern River asserts the Initial Decision did not explicitly rule on book depreciation for General Plant and asks the Commission to accept its proposed straight-line depreciation rates for General Plant. The Commission finds that Kern River's proposed straight-line General Plant depreciation rates appear reasonable and accepts them.

492. Calpine and Pinnacle West except to separate, straight-line depreciation for general plant if Kern River's levelized cost-of-service methodology is maintained on the grounds that a separate account for general plant using straight-line depreciation is inconsistent with a levelized rate design.

493. This issue is addressed elsewhere in this order.

vi. Intangible Plant

494. In its update filing of December 15, 2004, Kern River included an additional $6.25 million for intangible plant associated with CIAC for the High Desert Lateral and the Blue Diamond delivery point.[737] Previously, in an order concerning the certificate for the 2003 Expansion facilities, the Commission held that these CIAC contributions should be amortized to Account No. 404.3, Amortization of Other Limited-Term Gas Plant, over the 50-year service life consistent with the depreciation period set forth for the 2003 Expansion facilities.[738]

---

equipment, 10.00 percent; Acct. No. 392—transportation equipment, 18.00 percent; Acct. No. 394—tools, shop and garage equipment, 4.00 percent; and Acct. No. 396, power operated equipment, 4.00 percent.

[736] Exs. S-7 at 5 and S-8, Schedule No. 2.

[737] Ex. KR-5 at 44.

[738] *Kern River Gas Transmission Co.*, 98 FERC ¶ 61,205, at 61,724-25 (2002).

495. In this proceeding, Kern River proposed that the High Desert CIAC be recovered over the 21-year term of the transmission contract at a 4.76 percent amortization rate. It proposed that the Blue Diamond CIAC be recovered over the life of the transmission system and that the amortization rate should be 3.92 percent. Staff stated that Kern River had not shown its intangible plant in separate accounts, but had included its intangible plant in different transmission accounts.[739] It accepted Kern River's handling of its intangible plant for depreciation purposes.[740]

Initial Decision

496. The Initial Decision held Kern River had shown the CIAC allowance is appropriately included in intangible plant. It found the Commission had permitted this accounting for $6.25 million of CIAC due to the project for the 2003 Expansion facilities.[741]

Briefs on Exceptions and Opposing Exceptions

497. There are no exceptions concerning intangible plant.

Commission Determination

498. The Commission affirms the Initial Decision's determination that the $6.25 million of CIAC may be included in intangible plant. The Commission also finds that a book depreciation rate of 4.76 percent for the High Desert CIAC is in keeping with its determination that the book depreciation rate for this Lateral should be 4.76 percent based on its primary contract term of 21 years. However, the Blue Diamond CIAC must be recovered over the remaining economic life of the transmission system. The Commission has determined that the remaining economic life of Kern River's transmission system is 35 years and that the corresponding book depreciation rate for Kern River's transmission system is 1.95 percent. Thus the amortization rate for the Blue Diamond intangible plant is 1.95 percent as well.

---

[739] Ex. S-7 at 5.

[740] *Id.*

[741] *Citing* 98 FERC ¶ 61,205, at 61,724-25 (2002).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

IX. Regulatory Assets

499. A regulatory asset is a cost that a pipeline is entitled to collect but has not collected in its current rates. The Commission permits a pipeline to collect a return on and a return of a regulatory asset; *i.e.*, the Commission permits a pipeline to include the regulatory asset in rate base and collect a return on the amount of the regulatory asset that is actually invested. The Commission also permits the pipeline to recover the amount of the regulatory asset through an annual amortization charge. The Commission bases both the period during which the pipeline can collect a return on the regulatory asset and the period during which the pipeline can recover the amount of the regulatory asset on the amortization period of the regulatory asset.

500. As indicated earlier, Kern River proposed to maintain its levelized rates, but to remove compressor engine and general plant from its levelized rates and collect them through traditional cost-of-service rates with straight-line depreciation. As a result of and in keeping with these proposals, Kern River also proposed to create regulatory assets for compressor engine and general plant consisting of deferred depreciation for these items that it had not collected in prior years under its levelized rates. The amount of this deferred depreciation was $45.1 million. Together with about $13 million of "other regulatory assets"[742] it comprises the regulatory assets that are disputed in this proceeding. These amounts will be referred to as "regulatory assets" and addressed in this section of the order.

501. With respect to a return on the regulatory assets, Kern River proposed that they be included in its rate base, that the amount to be included in rate base be the full unamortized amount of the regulatory assets, and that the period over which it would collect the return be the remaining lives of its current customers' contracts. With respect to the amortization of the regulatory assets, Kern River proposed an amortization period for the regulatory assets equal to the remaining terms of its current customers' contracts.

502. The Initial Decision made three findings concerning these proposals. First, it found the regulatory assets should be included in rate base. Second, it held that the amounts of the regulatory assets for compressor engines and general plant should be amortized over the remaining terms of the firm shippers' contracts. Third, it held that the

---

[742] Ex. KR-100 at 2 shows the other regulatory assets as Equity AFUDC-Original System; Equity AFUDC-2003 Expansion; Equity AFUDC-High Desert; Equity AFUDC-Big Horn; Regulatory Asset Rate Change; Regulatory Asset- Muddy Crk; Regulatory Asset – Filmore; Regulatory Asset – Rent; and Regulatory Asset FAS 106.

amount of the unamortized regulatory assets that should be included in rate base is the average balance, *i.e.*, on half the full unamortized balance.

503. Staff excepts to the first finding; Staff and the RCG except to the second; and Kern River excepts to the third.

i. Inclusion of Deferred Depreciation in Rate Base

Initial Decision

504. Kern River's position is that the rate base appropriately includes the $58 million of regulatory assets related to general plant and compressor engine plant and other regulatory assets.[743]

505. Staff argued that compressor engine plant and general plant should be removed from the regulatory asset because any discrepancies between the amount collected in rates and the book depreciation amounts are provided for in the unrecovered depreciated regulatory asset with its corresponding amortization expense. BP's position is that any Kern River regulatory asset for deferred depreciation should be allocated to all shippers. Pinnacle West's position is that Kern River's calculation and proposed direct assignment of the regulatory asset is appropriate, because the customers receiving the benefit of reduced levelized rates should be allocated the regulatory asset generated by such rate levelization. Pinnacle West argues that BP's proposal is nothing more than an attempt to shift costs to the 2003 Expansion shippers that are properly the responsibility of the Rolled-In shippers.

506. The ALJ found that Kern River had carried its burden of proving that inclusion of compressor engine plant, general plant, and other regulatory assets in the rate base produces just and reasonable rates. The ALJ found that deferred costs have been held to be regulatory assets that are properly added to rate base, citing *Florida Gas Transmission Co.*[744] The ALJ further found that the Commission's regulations allow inclusion of regulatory assets, net of deferred amounts, in rate base.[745] Consequently, the ALJ permitted Kern River to include the regulatory assets in rate base.

---

[743] Initial Decision at P 344.

[744] Initial Decision at 350, n.429, *citing Florida Gas Transmission Co.*, 88 FERC ¶ 61,142, at 61,472-74 (1999) (*Florida Gas*).

[745] Initial Decision at 350, n.428, *citing* 18 C.F.R. § 154.312(b)(2), Schedule B-2 and *El Paso Natural Gas Co.*, 84 FERC ¶ 63,004, at 65,013 (1992).

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

Briefs on Exceptions and Opposing Exceptions

507. Staff takes exception to the inclusion of the regulatory assets in rate base.[746] Staff claims that Kern River should use a traditional cost-of-service methodology, not levelized rates, and that under a traditional cost-of-service methodology, the discrepancies between the amounts collected and the book depreciation amounts are provided for in the Unrecovered Depreciation Regulatory Asset with its corresponding amortization expense so that there is no need for the regulatory assets. Staff argues that, even if levelization is continued, there is no reason to treat these categories of plant differently by removing them from transmission plant and accounting for them separately using straight-line depreciation. Staff states that, under levelized rates, an appropriate book depreciation rate would be applied to these items for the book depreciation reserve while the levelized rate model will continue to spread the depreciation over the model's time frames. Staff also contends that *Florida Gas* is inapposite, for it involved a certificate proceeding under section 7 of the NGA and that this case is a section 4 proceeding under the NGA with a stricter "just and reasonable" standard.

508. Kern River asserts on exception that the Commission should reject Staff's belated opposition to including the other regulatory assets in rate base. Kern River contends that Staff has never before questioned the propriety of including these other regulatory assets in rate base and, in fact, included these assets in its proposed cost-of-service calculations. Kern River further states that, if Staff is opposing including the deferred depreciation regulatory assets for compressor engines and general plant in rate base even if the Commission upholds Kern River's proposed levelization with separate, straight-line depreciation of the compressor engines and general plant, Staff is taking a new position that is inapplicable in the context of separately calculating cost-of-service for compressor engines and general plant on a traditional basis.

Commission Determination

509. The Commission rejects Staff's argument that there is no need for all of the regulatory assets. Contrary to Staff's assertion, the Commission finds that *Florida Gas* is relevant here. The fact that *Florida Gas* was a certificate proceeding does not affect the circumstances in which it is appropriate to establish a regulatory asset. As we stated in that case, ". . . a regulatory asset is recorded for costs that would otherwise be chargeable to expense, when it is probable that the costs will be recovered in future rates."[747] That principle applies here and justifies treating the deferred depreciation for compressor

---

[746] Staff Brief on Exceptions at 36-37.

[747] *Florida Gas*, 88 FERC ¶ 61,142 at 61,473.

engines and general plant and for other small items as regulatory assets. The Commission therefore finds that Kern River has properly recorded these items as regulatory assets. As a result, the items are correctly included in Kern River's rate base.

ii. Amortization Period of Regulatory Asset

Initial Decision

510. Kern River proposes to amortize the regulatory asset for deferred depreciation over the remaining lives of the current shippers' firm service agreements, under either the levelized or traditional methodologies.[748] Kern River's position is that amortization over the lives of its firm shipper contracts has always been a feature of its levelized methodology and that the Commission had recently approved using contract life in its review of Kern River settlement agreements.[749] Kern River argues that Staff's proposal that the regulatory asset be amortized over thirty-five years violates the "probability standard" for maintaining and recovering a regulatory asset, because recovery of deferred depreciation would extend past the end of a pipeline's firm service agreements existing at the time of the deferral.[750]

511. Staff's position is that the amortization period should be thirty-five years because amortization should coincide with the period used to develop depreciation rates and not with contract life.[751]

512. With respect to the period over which the proposed regulatory assets should be amortized, the ALJ found that Kern River had carried its burden of proving that depreciating its regulatory asset over the remaining terms of the firm shippers' contracts produces just and reasonable rates. The ALJ stated that the Commission, as a general policy, does not favor limiting depreciation to the life of the customers' current contracts because such a limit can create an intergenerational inequity. The inequity would occur if the facilities remain in use after the end of the contracts; later customers using the facilities would not bear the cost of depreciation for those facilities. The ALJ noted,

---

[748] KR IB at 28-29.

[749] Initial Decision at P 352, KR IB at 29, *citing* 92 FERC at 61,157 and 98 FERC at 61,722.

[750] Initial Decision at P 352.

[751] Initial Decision at P 353-354.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

however, that the Commission has departed from this policy on occasion, such as when shippers agree to pay the full incremental cost of the facilities.[752]

513. The ALJ noted that Order No. 552 established accounting requirements for regulatory assets and liabilities that require the recognition of an asset or liability for any item that would normally be included in net income determinations under the requirements of the USofA, but for it being probable that the item will be recovered from or returned to customers in future rates. As used in Order No. 552, "probable" means that which can, based on credible evidence, reasonably be expected to occur. The ALJ noted that, in *San Patricio Pipeline, LLC*, the Commission would not approve the levelization proposal based on a finding that it did not meet the probability requirement to record a regulatory asset because the company's regulatory asset would not be recovered during the term of the pipeline's contracts with its shippers.[753] The ALJ concluded that, while it does not appear that Kern River is at peril of not recovering its regulatory asset, traditional rules do not always fit. The ALJ found that, based on the record and Kern River's levelized cost-of-service ratemaking methodology, limiting depreciation to the terms of the firm shippers' contracts produces just and reasonable rates.[754]

Briefs on Exceptions and Opposing Exceptions

514. RCG contends that this issue has no impact on calculated rates under the levelized methodology. However, if the Commission requires traditional rates, which RCG argues that it should not, both RCG and Staff contend that the ALJ erred in permitting Kern River to depreciate its regulatory asset over the remaining terms of its firm shippers' contracts instead of the economic life of the pipeline. RCG and Staff note that the ALJ acknowledged that the Commission's general policy does not favor limiting pipeline depreciation to the life of a pipeline's current contracts with customers. Nevertheless, RCG and Staff argue that the ALJ relied upon several cases where the Commission has deviated from this policy and concluded that the same should apply to Kern River even though the ALJ recognized that the facts on Kern River were quite different.

---

[752] Initial Decision at P 356.

[753] Initial Decision at P 356, n.435, *citing San Patricio Pipeline, LLC*, 112 FERC ¶ 61,101, at 61,657-58 (2005); *see also Questar Southern Trails Pipeline Co.*, 89 FERC ¶ 61,050, at 61,147 (1999); *Portland Natural Gas Transmission System*, 76 FERC ¶ 61,123, at 61,658 (1996).

[754] Initial Decision at P 357.

515. Staff argues that an amortization period of 35 years is appropriate because the amortization should coincide with the period over which the facilities are expected to be used, not the negotiated contract life. RCG contends that there is no evidence on the record that Kern River will be unable to recover its depreciation expense after the termination of its existing contracts. RCG further asserts that the ALJ's finding with regard to the depreciation rate corroborates the fact that Kern River's economic life is in excess of 35 years. RCG concludes that there would be no basis for requiring existing shippers, if traditional rates are required, to carry the entire burden in their rates of Kern River's regulatory assets during the terms of their contracts. RCG contends that to limit recovery to current contracts would result in unacceptable intergenerational inequities.

516. Kern River replies that Staff is mistaken in arguing that the remaining life of the facilities is the proper amortization period for the deferred depreciation regulatory assets. Kern River contends that the deferred depreciation in the regulatory assets at issue here relates to compressor engines and general plant items that have already been retired. Thus, Kern River argues that the "period over which the facilities are expected to be used" has already passed. Kern River states that the question is what is the appropriate period over which to recover the deferred portion of previous years' book depreciation expense that has not yet been included in rates. Kern River further argues that since current shippers have been the beneficiaries of the deferrals, and future shippers will not benefit from already-retired plant, it is appropriate to amortize the deferred depreciation regulatory assets over the remaining terms of the current firm shippers' contracts.

517. Kern River further argues that Staff did not address the principal basis for the ALJ's ruling, *i.e.*, the Commission's "probability of recovery" requirement for regulatory assets. Kern River contends that Staff's position cannot be reconciled with the Commission's precedents establishing that the "probability" standard is not met when collection of the deferred costs would extend past the end of the firm service agreements in existence at the time of the deferral.[755]

Commission Determination

518. Given our finding that the compressor engines and general plant and other regulatory assets should be included in levelization, the issue of the appropriate amortization period for these items under a traditional cost-of-service method is now moot. The total amount of the regulatory assets will be included in the overall levelized rate which effectively averages the collection period over the term of the levelized calculation, which is here based on contract life.

---

[755] Kern River Reply Brief at 70, *citing Portland and Ingleside Energy Center, LLC, et al.*, 112 FERC ¶ 61,101 at P 76-78 (2005).

iii. Unamortized Portion of Regulatory Asset

Initial Decision

519. Kern River's position is that leaving the full balance of the unamortized portion of the regulatory asset in rate base will produce just and reasonable rates. Kern River argues that Staff's proposal to include only the "average balance" of the unamortized balance of the regulatory asset over thirty-five years is Staff's effort to reduce cost of service in order to hide the rate increase which would occur if Kern River converted to the traditional methodology.

520. Staff argues that leaving the full balance of the unamortized portion of the regulatory asset in rate base while also amortizing that amount through rates will, over time, result in a rate base that will become more and more overstated. Staff argues that use of average unamortized balances in rate base is required by the Commission.[756]

521. The ALJ found that Kern River had not carried its burden of proving that leaving the full balance of the unamortized portion of the regulatory asset in rate base produces just and reasonable rates. The ALJ cited *Williston Basin Interstate Pipeline Co*.[757] for the proposition that Kern River is obliged to only include the average unamortized balance in rate base.[758]

Briefs on Exceptions and Opposing Exceptions

522. Kern River argues that the Commission should reverse the Initial Decision on this issue because the ALJ erred in finding that *Williston I*[759] is controlling. Kern River argues that, in *Williston I*, the Commission approved the "one-half balance" approach for recovery of approximately $1.6 million of one-time, deferred expenses over a three-year amortization period which is in contrast to the recovery of Kern River's regulatory assets of $46.5 million over an amortization period of as long as 14 years.[760] In addition, Kern

---

[756] Initial Decision at P 360, citing Staff IB at 34-35.

[757] *Williston Basin Interstate Transmission Co.*, 84 FERC ¶ 61,081, at 61,373-74 (1998) (*Williston I*).

[758] Initial Decision at P 363.

[759] Kern River Brief on Exceptions at 76.

[760] *Id.* at 76, noting that Kern River's existing, 15-year firm transportation agreements have primary terms ending in either 2016 (for Rolled-In System shippers) or 2018 (for 2003 Expansion shippers).

River contends that the ALJ failed to take account of the fundamentally different character of the costs in this case. *Williston I* involved recovery of deferred expenses for certain retirement benefits that the pipeline incurred due to a change in applicable financial accounting standards. Kern River argues that the unamortized balance of its regulatory assets, on the other hand, predominantly represents book depreciation expense that the Commission authorized, but collection of which was deferred to provide customers lower rates through levelization of the cost-of-service. Thus, Kern River argues that these amounts are primarily investment in plant that has not yet been recouped through depreciation expense included in rates and are the equivalent of undepreciated plant investment. Kern River asserts that all other portions of its undepreciated plant investment are included in rate base at 100 percent of original cost as of the end of the test period. Kern River concludes that there is no more justification for averaging the unamortized portion of the regulatory assets than there would be for averaging other rate base items under a traditional cost-of-service.

523. Kern River further argues that the "average balance" approach would cause it to underrecover its allowed return on the unamortized balance of the regulatory assets. Kern River asserts that this shortfall would increase considerably if a new "average balance" is calculated in each of Kern River's future rate cases, as claimed by Staff. Kern River contends that the unamortized balances on which it would earn a return would steadily decline and would always be inadequate over the course of the amortization period.

524. Kern River further states that, even if averaging were appropriate, the ALJ did not provide calculation of a proper average balance.[761] Kern River argues that the average balance should reflect the expected average of the relevant assets over the period the rates are likely to be in effect. Since Kern River has a history of changing rates every five years, Kern River contends that a properly computed average balance would reflect at most a two and one-half year amortization of the deferred depreciation regulatory assets from the end of the test period through the end of the average life of the shipper contracts. Similarly, Kern River states that, if averaging is used for the other regulatory assets, the average balances should properly reflect amortization for two and one-half years, using amortization amounts reflecting the life of each individual regulatory asset or liability included in the $1.5 million end of test period balance for those items. Kern River concludes that the ALJ's arbitrary, one-half reduction of the unamortized balances of its regulatory assets is not only unreasonable, but unlawfully confiscatory as well, for it precludes Kern River from an opportunity to earn its allowed return on a portion of its investment.

---

[761] Kern River Brief on Exceptions at 78-79.

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

Commission Determination

525. Given the Commission's finding herein that the full cost-of-service should be included in levelization, this issue is now moot. The total amount of the regulatory assets will be included in the overall levelized rate which effectively averages the collection period over the term of the levelized calculation, which is here based on contract life.

The Commission orders:

(A) The Initial Decision is affirmed and modified as discussed in the body of this order.

(B) Within 30 days of the issuance of this order, Kern River must file revised tariff sheets and rates, including workpapers, reflecting the Commission's rulings in this order.

(C) Within 30 days of a final order in this case, Kern River must refund amounts recovered in excess of the just and reasonable rates approved by the Commission.

By the Commission. Commissioner Spitzer concurring with a separate statement attached.

(S E A L)

Magalie R. Salas,
Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Kern River Gas Transmission Company Docket No. RP04-274-000

(Issued October 19, 2006)

SPITZER, Commissioner, *concurring*:

I support this Order. I believe the Return on Equity balances ratepayer and investor interests and results in just and reasonable rates. The Kern River line provides benefits not only to California shippers, but eases supply constraints throughout the west.

I must address application of the discounted cash flow ("DCF") model in *futuro* in light of the increasing importance of the master limited partnership entity ("MLP") in the energy sector. A key issue in this case is the paucity of reliable proxies for natural gas pipelines. The Order recognizes that in recent years fewer and fewer companies have met the Commission's historical standard for inclusion in natural gas pipeline proxy groups, particularly in which pipeline operations constitute a high proportion of their business. The determination of the types of entities to be included in natural gas pipeline proxy groups now squarely confronts the DCF model and the Commission.

The pleadings reflect a general observation that natural gas pipelines are not organized as C corporations. I pose the question "why?"

I recognize that pipelines are now rarely stand alone enterprises under any form of business organization. However, the risk profile of the pipeline business increasingly favors organization in partnership form, be it a general partnership, limited partnership or MLP. Several aspects of tax and corporate law suggest this trend will continue.

Partnerships are "tax efficient" because passthrough entities under subchapter K are subject to one level of income taxation. Partnership income is generally taxable to the partners based on their distributive share of income regardless of whether cash distributions are made. Thus, the tax paid by the partner is a first-tier tax on the income of the partnership rather than a second-tier tax on cash distributed to the partner. C corporations, on the other hand, pay in the first instance the income tax on the income from corporate operations (a first-tier tax), then if the corporation distributes cash by paying a dividend, a shareholder in the corporation generally is taxed on the amount of the dividend received (a

20061019-3082 Issued by FERC OSEC 10/19/2006 in Docket#: RP04-274-000

second-tier tax). Further, upon liquidation a C corporation is subject to entity level income tax and its shareholders recognize a gain on the ensuing corporate distribution, unlike a partnership. There is one incidence of tax upon realization of gains by passthrough entities.

Corporate governance matters also favor the MLP form for equity capital formation. Sarbanes-Oxley established important disclosures for investors in publicly traded corporations. Corporate audit and compliance fees have increased dramatically. Private investment has become, therefore, comparatively less costly. Further, the increasing frequency of shareholder derivative lawsuits and recent events regarding corporate boards may accelerate the trend towards private equity. Partnerships avoid some of these issues, and the MLP entity facilitates public equity capital formation in a partnership form.

In summary, the MLP form of business is likely to increase, particularly in the entrepreneurial energy sector. This argues for inclusion of MLPs in the DCF proxy group. I understand that a potentially duplicative return of capital from MLPs is a major concern of Staff. I also recognize the record in this proceeding did not adequately address the extent to which MLP distributions of capital can be "backed out" from aggregate partnership distributions. I would point out, however, that there has been frequent litigation in the context of corporate taxation as to whether distributions to corporate shareholders are capital redemptions or dividends. Thus, absolute clarity in the demarcation between a capital and dividend distribution is elusive.

In cost-of-service ratemaking the objective is to allow a fair profit, after taxes, ascertained after taking into account a variety of factors, such as the risks of the business and the necessity of attracting capital. The return necessary to attract investors is measured by the return an investor could obtain from investments bearing having commensurate risks. Further, the basic regulatory premise that a utility must earn a comparable return refers to the after tax return to the investor, regardless of the form of ownership. Therefore, I look forward to a more fulsome factual record on MLP proxies in forthcoming cases.

_____

Commissioner Marc Spitzer