123 FERC ¶ 61,056
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Kern River Gas Transmission Company **Docket No. RP04-274-006**
RP04-274-007

OPINION NO. 486-A

ORDER ON REHEARING ESTABLISHING PAPER HEARING PROCEDURES

(Issued April 18, 2008)

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

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ORDER ON REHEARING ESTABLISHING PAPER HEARING PROCEDURES

(Issued April 18, 2008)

1. This order addresses requests for rehearing of Opinion No. 486 which the Commission issued on October 19, 2006, in the captioned docket.[1] Opinion No. 486 addressed briefs on and opposing exceptions to an Initial Decision issued on March 2, 2006 concerning a general Natural Gas Act (NGA) rate case filed by Kern River Gas Transmission Company (Kern River).[2] As discussed below, the Commission generally denies the requests for rehearing of Opinion No. 486 with the exception of the issue whether MLPs may be included in the composition of a proxy group.

I. **Background**

2. The Commission authorized Kern River to construct its Original System in 1990 under the Optional Certificate procedures adopted in Order No. 436.[3] In order to be eligible for an optional certificate, a pipeline must be willing to assume the risks of the project. In its certificate proceeding, the Commission approved initial rates for the Original System based on (1) a levelized cost of service, (2) rate design volumes equal to

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[1] *Kern River Gas Transmission Co.*, 117 FERC ¶ 61, 077 (2006) (Opinion No. 486). The parties requesting rehearing of Opinion No. 486 are: Kern River Gas Transmission Co. (Kern River), Edison Mission Energy, Inc. (Edison Mission), Calpine Energy Service, L.P. (Calpine), Pinnacle West Capital Corp. (Pinnacle West), the Rolled-In Customer Group (RCG), and BP Energy Company (BP).

[2] *Kern River Gas Transmission Co.*, 114 FERC ¶ 63,031 (2006) (Initial Decision).

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

95 percent of the project's design capacity, and (3) a 25-year depreciation life.[4] In addition, the Commission accepted Kern River's proposal for separate levelized rates for three different periods: (1) the 15-year 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 permit Kern River to recover approximately 70 percent of its original investment, 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 the project, the rates for the second two periods (hereafter Period Two and Period Three Rates) were lower than the Period One rates.

3. 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 its firm contracts. The Commission accepted a settlement containing this proposal (2000 ET Settlement).[5] Pursuant to the 2000 ET Settlement, a firm 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).[6] 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.[7] Subsequently, all of the shippers elected to lengthen their contracts

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

[5] *Kern River Gas Transmission Co.,* 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. *Kern River Gas Transmission Co.,* 92 FERC ¶ 61,061, at 61,156 (2000).

[6] *Kern River Gas Transmission Co.,* 92 FERC ¶ 61,061, at 61,156 (2000).

[7] *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*.

by either 5 or 10 years since this produced significantly lower rates.[8] Therefore, after this election, only two customer groups existed: 10-year ET shippers and 15-year ET shippers.

4. In May 2002, Kern River completed an expansion project by adding additional compression to its system.[9] The costs associated with the 2002 Expansion project were rolled into the original system costs. As before, the 2002 Expansion 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.[10] 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.[11]

5. In May 2003, Kern River completed another expansion project.[12] Kern River priced these services on an incremental basis and again permitted shippers to choose either 10-year or 15-year firm contracts.

6. On April 30, 2004, Kern River filed the instant general rate case under section 4 of the NGA, in accordance with its obligation under the 1999 settlement of its previous section 4 rate case.[13] Kern River proposed to continue using the rate levelization methodology and cost of service rate principles as approved in the original Kern River certificate,[14] the extended term (ET) rate settlement,[15] the 2003 Expansion certificate,[16]

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

[9] *Kern River Gas Transmission Co.*, 96 FERC ¶ 61,137 (2001).

[10] Ex. KR-45 at 5.

[11] *Kern River Gas Transmission Co.*, 96 FERC ¶ 61,137, at 61,591 (2001).

[12] *Kern River Gas Transmission Co.*, 100 FERC ¶ 61,056, *order on reh'g*, 101 FERC ¶ 61,042 (2002).

[13] *Kern River Gas Transmission Co.*, 87 FERC ¶ 61,128, *order on reh'g,* 89 FERC ¶ 61,144 (1999).

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

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

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

and the prior Kern River rate case settlements, [17] with certain modifications such as the exclusion of certain compressors and general plant in its levelized methodology.[18] The Commission accepted and suspended the rates subject to refund, conditions, and hearing.[19] The Presiding Administrative Law Judge (ALJ) issued her Initial Decision on March 2, 2006.[20]

7. In Opinion No. 486, the Commission generally affirmed the ALJ's determinations; however, the Commission determined that several issues required revisions. Therefore, Opinion No. 486 found that, due to several required modifications of the proxy group, 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 also reversed 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 ordered Kern River to include in its tariff the Period Two step-down rates that will take effect after the shippers' current contracts expire. The Commission affirmed most other rulings by the ALJ, including her holding that Kern River should continue its existing rate levelization methodology.

8. Kern River, Edison Mission, Calpine, Pinnacle West, RCG, and BP requested rehearing of Opinion No. 486.[21] For the reasons discussed below, the Commission generally denies rehearing. However, the Commission grants rehearing on the issue of Kern River's return on equity in order to permit appropriate master limited partnerships (MLPs) to be included in the proxy group, consistent with our contemporaneous *Policy Statement on the Composition of Proxy Groups for Determining Gas and Oil Pipeline*

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[17] *Kern River Gas Transmission Co.*, 70 FERC ¶ 61,072 (1995); *Kern River Gas Transmission Co.*, 90 FERC ¶ 61,124, *order on reh'g*, 91 FERC ¶ 61,103 (2000).

[18] A more detailed history of recent regulatory proceedings on Kern River's system is available in Opinion No. 486 at P 4-17.

[19] *Kern River Gas Transmission Co.*, 107 FERC ¶ 61,215, *order on reh'g,* 109 FERC ¶ 61,060 (2004).

[20] *Kern River Gas Transmission Co.,* 114 FERC ¶ 63,031 (2006).

[21] On December 1, 2006, BP and Pinnacle West also filed a request for rehearing and/or clarification of a November 15, 2006 notice granting Kern River a 30-day extension of time to file tariff sheets in compliance with Opinion No. 486. The Commission dismisses that request for rehearing as moot since Kern River submitted its compliance filing on December 18, 2006, and on May 21, 2007, pursuant to a May 2, 2007 order, *Kern River Gas Transmission Co.*, 119 FERC ¶ 61,106 (2007), Kern River provided to its shippers additional information, including computer models, to support its compliance filing.

Return on Equity.[22] In addition, the Commission establishes further procedures in order to allow participants to submit additional evidence on this issue.

II. Levelized Rates/Levelized Cost of Service Proposal

A. General

9. At the hearing, several parties, including BP, opposed Kern River's proposal to continue its levelized rate methodology and sought to have the Commission require Kern River to use a traditional rate design. Under a traditional rate design, Kern River's cost of service would reflect its rate base as of the end of the test period. Thus, 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. The parties' primary objection to Kern River's levelized rate methodology was the provision for the Period One rates to recover 70 percent of Kern River's invested capital during the terms of the firm shippers' current contracts. These parties contended that, as a result, Kern River would overrecover its costs during Period One, with no assurance that Kern River would ever put into effect the lower Period Two rates.

10. The ALJ found that Kern River carried its burden of proving that its levelized cost-of-service/ratemaking methodology would produce just and reasonable rates subject to certain modifications.[23]

Opinion No. 486

11. In Opinion No. 486, the Commission affirmed the ALJ's finding and found that Kern River's rates should continue to be designed based upon the levelized methodology.[24] The Commission pointed out that it had previously faced a situation concerning the continuation, in a subsequent NGA section 4 rate case, of a levelized rate methodology agreed to in an optional expedited certificate, in *Mojave Pipeline Co.*, 81 FERC ¶ 61,150 (1997) (*Mojave*). *Mojave* held that a central issue when an application for an optional certificate is considered is whether the proposed rates reflect an appropriate allocation of the risks of proceeding with the project. Mojave's levelized rate structure, including the schedule of plant recoveries, was a key aspect of the risk sharing agreement underlying its optional certificate, and accordingly the Commission would not lightly change that agreement. Opinion No. 486 found that the same reasoning applied in this case. The Commission stated that it granted an optional expedited certificate to Kern

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[22] 123 FERC ¶ 61, (2008) (*Policy Statement*).

[23] *Id.* at P 253.

[24] Opinion No. 486 at P 37.

River and Mojave at the same time,[25] that both 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 and that it considered the two pipelines' rate proposals in tandem using virtually identical language to approve each.[26] The Commission, therefore, found that Kern River should continue its levelized rate model in the instant case.[27]

12. In Opinion No. 486, the Commission further stated that issues such as the recovery of depreciation under levelized rates is a long term proposition. The Commission reasoned that:

> 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. [28]

13. The Commission recognized that Kern River's Period One rates will recover more depreciation expense than it will have depreciated on its books. However, Kern River books a regulatory asset or liability for the difference between the annual regulatory depreciation expense it recover in rates and its book depreciation expense. At the end of Period One, Kern River's books would reflect a regulatory liability, and this would serve to lower its Period Two rates. The Commission rejected a variety of arguments as to why shippers might not receive the benefit of the lower Period Two rates. However, in order to increase the assurance that Kern River's shippers will obtain the benefit of the lower Period Two rates if they continue service beyond the terms of their existing contracts, the Commission directed that Kern River include in its tariff the Period Two rates that will take effect when the firm shippers' existing contracts expire.

<u>Rehearing Requests</u>

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[25] Opinion No. 486 at P 39, *citing*, 50 FERC ¶ 61,069 (1990); *Kern River Gas Transmission Co.*, 58 FERC ¶ 61,073, *order on reh'g*, 60 FERC ¶ 61,123 (1992).

[26] Opinion No. 486 at P 39, *citing*, 50 FERC ¶ 61,069, at 61,151-153, *Mojave Pipeline Company*, 58 FERC ¶ 61,074, at 61,248-51, and *Kern River Gas Transmission Co.*, 60 FERC ¶ 61,123, at 61,436-38 (1992), approving Mojave's initial rate with 50 FERC ¶ 61,069, at 61,149-51, *Kern River Gas Transmission Co.*, 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.

[27] Opinion No. 496 at P 38-39.

[28] Opinion No. 486 at P 42.

14. Both BP and Kern River seek rehearing of Opinion No. 486's rulings concerning Kern River's levelized rates. BP argues that the acceptance of levelized rates was not justified, and that traditional rates should be implemented on Kern River's system. Kern River contends that the Commission should not have required it to include its Period Two rates in its tariff. Kern River also objects to certain other rulings by Opinion No. 486 related to its levelized rates which are discussed in later sections of this order.

15. BP's primary objection to Kern River's levelized rates continues to be that they are designed to enable Kern River to recover 70 percent of its invested capital during Period One. BP argues that this requires shippers to pay the pipeline $500 million more in depreciation during Period One than they would if depreciation were recovered evenly throughout Kern River's service life, consistent with the manner in which it records depreciation on its books. BP asserts, on a number of grounds, that there is no assurance that Kern River will return the $500 million to its shippers in the Period Two step-down rates or that the step-down or post step-down rates will remain in effect for agreed upon periods. BP argues that Opinion No. 486's requirement that Kern River file revised tariff sheets setting forth its step-down (Period Two) rates and the effective date of these rates fails to protect the shippers because Kern River may file to change those rates. In addition, BP argues that the Kern River has stated its intent to negotiate step-down rates for Period Two and that the Commission cannot ignore the signs that Kern River will seek to avoid or minimize its obligation to accept the reduced step-down rates.

16. In addition to its contentions concerning Kern River's specific levelized rate methodology, BP also raises more general objections to the use of levelized rates. For example, it argues that determining levelized rates requires the use of long-term projections, which are less reliable than the short-term projection underlying traditional rate. BP also argues that levelized rates violate the filed rate doctrine and the rule against retroactive ratemaking, since they permit pipelines to carry forward underrecoveries from the early years of the levelized period for recovery during the later years.

17. Kern River objects to the requirement that it include its Period Two rates in its tariff now, arguing that the Commission lacks authority under NGA sections 4 and 5 or 7 to require it to set forth rates which will not take effect until many years in the future. It also argues that any calculation of its Period Two rates now would be speculative.

Commission Determination

18. The Commission denies both BP and Kern River's requests for rehearing on this issue. We address BP's contentions first.

19. BP's various contentions as to why the Commission should reject Kern River's proposal to continue its levelized rate methodology largely ignore the fundamental reason relied upon in Opinion No. 486 for approving continuation of Kern River's levelized

methodology, including the recovery of 70 percent of invested capital during the terms of the shippers' current contracts. That reason is that Kern River's levelized rate methodology is part of the risk sharing agreement among Kern River, its shippers and lenders underlying Kern River's optional expedited certificate. As the Commission explained in Opinion No. 486, the Commission's optional expedited certificate regulations required that an applicant for such a certificate must be willing to assume the economic risks of the project.[29] Therefore, a central issue in approving an application for an optional certificate was whether the pipeline's proposed rates reflected an appropriate allocation of the risks of the project as between the pipeline, its customers, and other interested parties. As the Commission held in *Mojave*, once the Commission has issued the certificate, "the Commission will not lightly change the allocation of risk inherent in the optional certificate as granted," absent some "overarching policy reason."[30]

20. During Kern River's certificate proceeding, the Commission and the parties carefully considered Kern River's levelized rate methodology, including the schedule of plant recoveries to which BP now so strenuously objects. For example, in its January 1992 order amending Kern River's certificate, the Commission set forth the schedule of plant recoveries over the originally agreed upon 25-year depreciation life of the project. The Commission then stated, "to further explain the above table, we note that Kern River's capital structure is based on a 70/30 debt/equity ratio. 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 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."[31] Kern River sought rehearing of the January 1992 Order, asserting that, in calculating the schedule of plant recoveries, the Commission had erroneously maintained Kern River's 70/30 debt equity ratio throughout the life of the project. It argued, that since its levelized rates were intended to permit it to pay off its debt during the first 15 years, the Commission should have reflected the gradual shift to a project capitalized with 100 percent equity at the end of 15 years. The Commission agreed and approved Kern River's proposed schedule of plant recoveries, which allowed it to recover somewhat in excess of 70 percent of its plant costs during the 15-year term of the shippers' original contracts.[32]

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[29] Opinion No. 486 at P 38, *citing*, *Mojave Pipeline Co.*, 81 FERC, at 61,682-683 (1997). *See also*, *Mojave Pipeline Co.*, 47 FERC ¶ 61,200 at 61,696-7 (1989).

[30] *Mojave Pipeline Co.*, 81 FERC ¶ 61,150 at 61,682-83 (footnote omitted).

[31] *Kern River Gas Transmission Co.,* 58 FERC ¶ 61,073, at 61,243 (1992). (emphasis added.)

[32] *Kern River Gas Transmission Co.,* 60 FERC ¶ 61,123, at 61,363-61,437 (1992).

21. It is thus clear that Kern River's levelized rate methodology, including its provision for recovery of approximately 70 percent of its invested capital during the terms of the initial shipper contracts, was part of the allocation of risks and costs of the project agreed upon in the certificate proceeding between Kern River, its lenders, and its shippers. All parties had an opportunity in that proceeding to express their views on the levelized rate methodology, and whether recovery of 70 percent of invested capital during the terms of the shippers' contracts was appropriate. Once the Commission approved Kern River's levelized rates and its schedule of plant recoveries, Kern River and its lenders could reasonably rely on that approval in deciding whether to proceed with the project. In Opinion No. 486, the Commission determined that the same reasoning applied to the Kern River proceeding before it, and held that Kern River would be permitted to continue the levelized rate model agreed to in its certificate proceeding and subsequent proceedings in a manner consistent with the Commission's holdings in *Mojave*.[33]

22. In the 2000 ET Settlement, the parties agreed to certain modifications in the risk sharing agreement underlying the certificate, consistent with Kern River's refinancing of its debt and extension of the period over which it was required to repay its loans. Kern River's levelized rates continued to be designed to recover 70 percent of its invested capital during the terms of the shippers' contracts. However, the shippers were given an opportunity to extend the terms of their contracts either by 10 years to 2011 or by 15 years to 2016. This had the effect of giving the shippers a longer period of time over which to pay these costs, corresponding to the extension of Kern River's debt repayment obligation.

23. BP, as the corporate successor to Amoco Corporation, was an original shipper on the Kern River system, who participated in the optional expedited certificate proceeding. BP also supported the 2000 ET settlement,[34] and chose the option provided by that settlement of extending its contract by ten years. Therefore, BP has agreed to the use of Kern River's levelized methodology, including its provision for shippers to pay approximately 70 percent of Kern River's invested capital requirement during their current contract terms, on several occasions.

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

[34] In the ET 2000 settlement proceeding, the ET Firm Shippers, which included Amoco Energy Production Co. and Amoco Energy Trading Corp., stated that shippers receiving lower rates in return for contract extensions is in the public interest and that it accomplished the goals of Order No. 637 to strengthen the long-term market. 92 FERC ¶ 61,061, at 61,159 (2000).

24. Thus, by asking the Commission to require Kern River to eliminate its levelized rates and use traditional rates instead, BP is seeking a fundamental change in the allocation of the risks of the project which it agreed to in both the original certificate proceeding and the 2000 ET Settlement. While BP may now regret having agreed to this allocation of the risks, it has provided no basis for modifying that agreement, which the other parties have relied upon in making investment decisions.[35] BP points to no significant change in circumstances which renders the agreement previously approved by the Commission no longer just and reasonable. Nor does it point to any overarching public policy reasons for changing the agreement.

25. Levelized rates, by their very nature, are intended to be in effect for the life of a project. Their purpose is to address the fact that, under a traditional rate design, the Commission awards a return based on the rate base existing at the end of the test period, without taking into account subsequent declines in the rate base as depreciation is recovered until the pipeline files a new NGA section 4 rate case. Therefore, under traditional ratemaking, a pipeline's rates are higher during the early years of its life, than in its later years, unless the pipeline makes new rate base investments.[36] Levelizing the pipeline's rates over its life provides lower rates at the initiation of service than a traditional rate making methodology but, over time as the traditional rate base declines, the levelized rate will become higher than traditionally designed rates. In essence, levelization is accomplished by the pipeline deferring to later years recovery of costs that would otherwise be recoverable early in its life. Therefore, as the Commission stated in Opinion No. 486:

> 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. Opinion No. 486 at P 42.

Given this fundamental fact concerning levelized rates, BP, and all the other parties who agreed Kern River's levelized rate methodology, should have reasonably anticipated from the beginning that methodology would continue in effect throughout Kern River's life, absent agreement by all parties to modify or eliminate that rate design. Nor should it come as any surprise to the parties that the Commission would hold the parties to their agreement.

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[35] As we pointed out in Opinion No. 486, the D.C. Circuit held in *Exxon Mobil Corp. v. FERC,* 430 F.3d 1166, 1177 n.7 (D.C. Cir. 2005), that a company "is not typically entitled to be relieved of its improvident bargain. . . . Wise or not, a deal is a deal," and therefore "people must abide by the consequences of their choices." Opinion No. 486 n.113.

[36] *See Public Service Commission of New York vs. FERC*, 866 F.2d 487, 492-3 (D.C. Cir. 1989).

Excess Recovery During Period One

26. Kern River's levelization methodology does have the unusual feature of levelizing Kern River's rates over several different periods, so that Kern River can recover 70 percent of its invested capital through the Period One levelized rates in effect during the terms of the shippers' current contracts. As a result, unlike the usual situation with levelized rates, Kern River's levelized rates will recover less of its costs during the early years of Period One than under traditional rates. However, by the end of Period One those rates will have recovered more costs than traditional rates would have recovered at that stage of Kern River's life. Kern River will then return this excess recovery to its shippers during Period Two, through the step-down rates to be implemented at the start of Period Two. BP asserts that the excess recovery as of the end of Period One is $500 million, and this excess recovery is the primary focus of BP's various contentions as to why Kern River must be required to shift to a traditional rate design.

27. As already discussed, the fact Kern River will be in an excess recovery position at the end of Period One has been an essential feature of the agreed-upon levelized rate methodology from the beginning. This was agreed to in order to provide Kern River the funds to repay its loans during the terms of the shipper's existing contracts, and both Kern River and its lenders have relied on this aspect of the levelized rate methodology in proceeding with the project. Thus, this is not a changed circumstance that might justify a change the levelized rate methodology.

28. In any event, the fact Kern River will be in an excess recovery position at the end of Period One does not lead to an unjust and unreasonable overrecovery of its costs. As the Commission explained in Opinion No. 486,[37] Kern River must keep track of its recovered depreciation from ratepayers in a separate account. 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. At the end of Period One, the regulatory liability, which BP asserts will amount to $500 million, will be reflected in the Period Two rates and thereby returned to Kern River's shippers.

29. BP argues that the accrual of a regulatory liability and separate tracking of depreciation expense do not provide assurance that the excess recoveries will be returned to the over-contributing shippers. BP argues that this confuses keeping account of amounts returning the money to the overcharged party.[38] Further, BP argues that Kern

[37] Opinion No. 486 at P 47-48.

[38] BP argues that compliance with the Uniform System of Accounts does not obviate compliance with separate rate review provisions of NGA Sections 4 and 5.

(continued…)

River's levelization model does not track the regulatory liability beyond the end of the test period. Therefore, the model allegedly does not provide any assurance of what amount the regulatory liability should be at any future date. BP also argues that under Kern River's view of the applicable standards, Kern River's over-recovery of depreciation does not qualify for regulatory liability status. Consequently, it argues that the Commission's view that the $500 million in over-recoveries will be returned to the shippers does not appear to be shared by the pipeline.

30. The Commission recognizes that these accounts do not drive ratemaking, and therefore, the fact that Kern River has recorded a regulatory liability by the end of Period One will not, by itself, guarantee return of the excess recovery amounts through rates. However, in Opinion No. 486, the Commission stated that the step-down benefit of the lower Period Two rate was an essential component of Kern River's proposal. Therefore, in order that all of Kern River's proposed rates might be easily ascertained and so that the reduced rate would take effect upon the agreed to dates, the Commission directed 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. The Commission also stated that 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.[39] Below the Commission denies Kern River's request for rehearing of this requirement.

31. Moreover, in regard to BP's contention that Kern River's levelization model does not track the regulatory liability beyond the end of the test period in this proceeding, Kern River has submitted testimony that it recognizes depreciation amounts each year within the levelization model and that it records that annual depreciation as an addition to its Account No. 108 and that a regulatory asset is booked for the difference between the annual depreciation expense it recovers in its rates and the book depreciation expense it

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Citing, *United Gas Pipe Line Co*., 32 FERC ¶ 63,080, at 65,242 (1985) (holding that the USOA "do[es] not control ratemaking situations"); *accord Public Service Comm'n of New Mexico*, 13 FERC ¶ 63,041 (1980) (*citing Tennessee Gas Pipeline Co. v. FPC,* 561 F.2d 955 (D.C. Cir.1977) and *Alabama-Tennessee Natural Gas Co. v. FPC*, 359 F.2d 318 (5th Cir. 1966) for the proposition that "[a]lthough relevant, . . . accounting principles are not to be blindly followed . . .for ratemaking purposes")), *aff'd*, 17 FERC ¶ 61,123, at 61,245 (1981); *Transcontinental Gas Pipeline Corp*., 55 FPC 635 (1976) (the "fact that an agency treats an item a certain way for purposes of its uniform system of accounting does not mark the end of judicial scrutiny; on the contrary, a reviewing court must assure itself that the accounting practice is consistent with underlying substantive principles of public utility law").

[39] Opinion No. 486 at P 54.

records in Account No. 108.[40] In any event, because the Commission has required that Kern River file its Period Two rates the parties will have an opportunity in Kern River's compliance filing proceeding to determine whether the Period Two Rates are appropriately calculated with regard to the regulatory assets and liabilities that Kern River has incurred and recovered.

Return Of Excess Recoveries During Period Two

32. BP asserts, on numerous grounds, that despite our requirement that Kern River file its Period Two rates now, there is no assurance that the $500 million will be returned to the shippers in the Period Two step-down rates.[41] First, BP argues that Kern River may file a new rate case under NGA section 4 at any time, proposing to shift to a traditional rate design or proposing some other change that would eliminate the requirement to implement the reduced Period Two rates. It points out that a Kern River witness testified that the outcome of the case could cause Kern River to file to eliminate its levelized rates.[42] Everything the Commission has said above about its strong preference for maintaining the risk sharing agreement underlying Kern River's optional certificate and subsequent settlements applies equally to all interested parties, including Kern River. Thus, the Commission would be as skeptical of any contested proposal by Kern River to change that agreement, including its obligation to implement the Period Two rates, as the Commission has been of BP's efforts in this proceeding to change that risk sharing agreement. Indeed, as we reaffirm below, in this proceeding we are rejecting Kern River's proposal to remove the costs of its compressors from the rate levelization for that very reason.

33. Second, BP suggests that Kern River's levelization model is so complex, cumbersome and unwieldy, that Kern River may make changes without the knowledge of the parties or a Commission determination of whether those changes are just and reasonable. BP argues that Opinion No. 486 fails to address how the Commission will ensure that the levelization model is not changed by Kern River. BP argues that unless the model in the form used to produce the rates at issue in this case (modified to reflect the holdings of Opinion No. 486) has been filed with the Commission, participants will not be able to ascertain whether the benefit of their bargain is being preserved.

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[40] Ex. KR-50 at 21.

[41] Additionally, BP states that the Commission would need to grant waiver of 18 C.F.R. § 154.207 (2006), to accept in 2006, tariff sheets setting forth Period Two rates that may not take effect for another dozen years. As shown here, the Commission finds good cause to waive its regulations to provide the rate certainty provided by the Period Two rates discussed herein.

[42] *Citing* Ex. KR-54 at 4.

34. On May 2, 2007, the Commission addressed a motion filed by several Kern River Shippers requesting that the Commission direct Kern River to provide certain additional information with respect to its December 18, 2006 compliance filing in this proceeding and schedule a technical conference to discuss the additional information.[43] The Kern River Shippers requested that the Commission direct Kern River to furnish all participants in the captioned docket, electronic copies of each model with cells, links, formulae and data intact, used to calculate the data contained in Kern River's December 18, 2006 compliance filing in the instant proceeding. Kern River responded that the Commission should deny the request in part because all participants in this proceeding already have electronic copies of the models and they and their consultants have had well over two years to use and understand them.[44] The Commission granted the Kern River Shippers' request that Kern River provide them with the model that it used to derive rates consistent with the Commission's directive in Opinion No. 486. The Commission found it was appropriate for the parties to have the computer model on which Kern River based its December 18, 2006 compliance filing so that they may properly evaluate it.[45] The Commission also responded to Kern River's point that the parties have already seen two prior computer models, stating that this fact was irrelevant to the parties' ability to examine the most recent computer model underlying its compliance filing. Therefore, since the Commission has ordered Kern River to provide all interested parties with electronic copies of each model, with cells, links, formulae and data intact, used to calculate the data contained in Kern River's December 18, 2006 compliance filing, the Commission finds that all parties during the compliance phase of this proceeding will be able to determine whether Kern Rivers rates are appropriately derived consistent with the approved levelization model and the Commission's directives in Opinion No. 486.

35. Third, BP points out that Kern River has stated that it intends to negotiate with its customers the step-down rates which it implements for Period Two. As set forth above, the Commission has required Kern River to set forth its Period Two rates in this proceeding. Any negotiation between Kern River and its shippers, by necessity, implies that the shippers must agree to such a change. If BP desires to obtain the benefits of its Period Two rates instead of entering into a negotiation with Kern River, it has every right

[43] *Kern River Gas Transmission Co.*, 119 FERC ¶ 61,106 (2007). The Kern River shippers making the motion were: BP; Calpine; Pinnacle West; and, Questar Gas Co. (Questar).

[44] *Id*. at P 8, c*iting*, Ex. KR-118 [Protected Material] (original filing), Ex. KR-119 [Protected Material] (45-day update filing); Ex. BP-54 (instructions).

[45] The Commission also noted that Kern River may request that parties who receive the information be subject to a protective order as it did with the previous computer models in this proceeding. Initial Decision at P 9.

to forego any such negotiation attempt by Kern River and take the Period Two rates on file by virtue of this proceeding.

36. Fourth, BP argues that, under the Commission's current rolled-in vs. incremental rate policies, the Original System shippers could be deprived of the benefit of the Period Two rates by being required to pay higher rolled-in rates in order to renew their contracts. BP points out that in the 1999 Certificate Policy Statement[46] the Commission held that, on a system with incremental rates, shippers paying the lower pre-expansion rates who exercise their right of first refusal rights (ROFR) at the end of their contracts could be required to match third party bids up to the higher expansion rate. BP suggests that under this policy, when its contract for service on the Original System expires, it could be required to pay up to the incremental 2003 Expansion System Rate, instead of the Period Two step-down rate for the Original system.

37. In Opinion No. 486, the Commission addressed this issue, and stated that in its 1999 Policy Statement[47] and in Order Nos. 637 and 637-A, it 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. The Commission determined that its policies only contemplated a roll-in of costs in certain limited circumstances, and noted particularly that 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. The Commission noted that Kern River did not have such a mechanism in its tariff.[48]

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[46] *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999), *clarified*, 90 FERC ¶ 61,128, *order on reh'g*, 92 FERC ¶ 61,094 (2000).

[47] *Id.* at 61,746-47.

[48] BP takes issue with the Commission's statement that "Kern River states that it has no such mechanism" Opinion No. 486 at P 53 and n.92, *citing* Kern River Brief on Exceptions at 40-41. BP argues that Kern River does not make such a statement at the cited passage, or at 40-41 of its Brief Opposing Exceptions. However, Kern River in its Brief Opposing Exceptions at 41 states that:

> Moreover, as Order No. 637-A makes clear, BP's purported worry cannot occur in any event *unless Kern River elects to propose* a mechanism for re-allocating costs and *until the Commission, after an opportunity for all affected parties to be heard, has approved a specific allocation mechanism* to ensure that all rates stay within the total cost-of-service. (emphasis added).

(continued…)

38. BP argues, however, that Kern River has not offered any legally-binding commitment to abstain from filing to include such a mechanism in its tariff, which would allow Kern River to vitiate step-down rates, and the Commission has not suggested that it would reject such a filing. As discussed above, the Commission would be very skeptical of any NGA section 4 proposal by Kern River that would have the effect of modifying the risk sharing agreement underlying its optional expedited certificate and subsequent settlements. Therefore, if Kern River proposed such a mechanism in the future, Kern River would be required to show that the possible denial of step-down rates to its 10 and 15-year customers would be just and reasonable. Consistent with the discussion above, the Commission, in making such a determination, would consider its position that the levelization methodology including the step down rates must remain in place for shippers to realize the benefits of their bargain.

39. Finally, BP argues that the Commission should require that Kern River set up a fiduciary account or require direct bilateral agreement between Kern River and its shippers. BP, as well as other shippers, already have contracts with Kern River under the 2000 ET settlement that provides them with service and step-down rates. Furthermore, the Commission in accepting the continuation of Kern River's rate design, need not modify these agreements to require Kern River to set up fiduciary accounts as suggested by BP, especially given the fact that the Commission has required Kern River to set forth its Period Two step-down rates so that all parties may see the rates and their effective dates.

<u>Alleged Changes To Original Bargain</u>

40. BP also argues that contrary to the original bargain, Kern River's proposal recovers more than $140 million in depreciation revenue over its debt service requirements.[49] BP asserts that this amount is used to recover Kern River's equity

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More importantly, no party argues that Kern River has such a tariff mechanism at this point, nor does the Commission's review of Kern River's tariff reveal such a mechanism.

[49] To support its assertions, BP refers to the testimony of Elizabeth H. Crowe who stated that testimony provided by Kern River omitted depreciation from general plant and from the Big Horn Lateral and had attributed depreciation to both compressor engines and the High Desert Lateral equal to the debt cost assigned to the facilities. In addition, Ms. Crowe asserted that Kern River omitted depreciation related to compressors engines and general plant depreciation related regulatory assets. Ms. Crowe stated that to correct all these deficiencies, she prepared a comparison of all the depreciation included in Kern River's test period levelization models and the actual unrecovered debt principal of Kern River's outstanding loans. Ms. Crowe stated that this comparison, shown in Exhibit No. BP- 44, reflects that "Kern River's levelized depreciation recovered over the

(continued…)

investment even though the original bargain was to recover 70 percent of original plant which corresponded to Kern River's original debt component. BP argues that this benefits Kern River's equity holders, who will own a system with far lower net invested capital, at the expense of Kern River's shippers, contrary Commission's intent under *Kern River Gas Transmission Company*, 50 FERC ¶ 61,069 at 61,150.[50] BP argues that Opinion No. 486 erred in stating that "in approving this levelized method in Kern River's initial certification proceeding, the Commission did not mandate the recovery of debt in any particular timeframe."[51] BP argues that the premise of Kern River's original certificate order was that all debt would be retired during Period One. BP argues that in the order implementing the ET program, the Commission stated that "after the debt attributable to the original system construction is repaid, [Kern River's] transportation rates will step-down to a lower level,"[52] and that "[R]ates have been designed based on levelizing the cost of service over the debt repayment period . . . ."[53] Therefore, BP argues that the Period One rates were clearly linked to full debt recovery by Kern River.

41. BP argues that if the justification for levelization is that the parties' bargain should be preserved, then all of Kern River's debt must be extinguished during Period One. BP also asserts that the Commission's statements regarding the collection of debt

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remaining 13.5 years of its current levelized rates schedules is 143.9 million greater than its outstanding debt principal at the end of the test period." Exh. BP- 42 at 11:10 - 13.

[50] *Citing Kern River Gas Transmission Co.*, 98 FERC ¶ 61,205, at 61,721-22 (2002) ("Kern River's levelized model . . . assumes that 70% of the 2003 Expansion investment will be depreciated over the 10-year and 15-year terms of the 2003 Expansion [transportation service agreements] . . . to reflect recovery of the related debt-financed investments over those periods"); *Kern River Gas Transmission Co.*, 50 FERC ¶ 61,069 (1990) ("This rate structure will enable Kern River to recover all of its debt service during the first 15 years . . . .").

[51] *Citing* Opinion No. 486 at n.90. BP argues that the Commission did not explain how its conclusion is to be reconciled with its finding on this issue that the recovery of 70 percent of Kern River's original investment is "intended to permit Kern River to pay off its debt during that period" Opinion 486 at P 48 and that "Kern River . . . has continued to derive its capital structure . . . upon the assumption that the depreciation expense included in the levelized cost-of-service recovers debt costs first and recovers equity investment only after the levelization period." Opinion 486 at P106. Moreover, BP states that the Commission also stated that "[T]he Commission approved levelized rates . . . since this would enable Kern River to pay off its entire debt by the end of the shippers' contracts leaving a rate base entirely financed by equity." Opinion 486 at P 112.

[52] BP request for rehearing at 30, *citing, Kern River Gas Transmission System*, 92 FERC ¶ 61,061, at 61,159 (2000).

[53] Exh. BP- 42 at 11.

leave the door open for Kern River to assert that the repayment of all debt is a condition precedent for the implementation of the Period Two step down rates.[54]

42. The fact that Kern River's Period One rates are designed to recover approximately $140 million more in depreciation costs than is required to meet Kern River's outstanding debt principal as of the end of the test period is not a violation of the original bargain underlying Kern River's levelized rates. That bargain relates to Kern River's recovery of the *original* capital invested in its Original System, the mainline expansions, and the High Desert Lateral.[55] As Kern River points out, its rate base is not solely limited to the original capital invested in those facilities. Kern River's witness testified that some of the facilities in its rate base, including general plant, retirement costs, and the Big Horn Lateral, "were financed by internally generated equity or temporarily through cash flows available due to accelerated income tax deductions."[56] Further, Kern River pointed out that portions of the depreciation expense relate to the recovery of past investments in the replacement of general plant and compressor engines that were not fully depreciated in the levelized rates before they were retired and replaced.[57] BP makes no contention that any of these investments were imprudent, nor does it provide any other basis for the Commission to exclude their recovery from Kern River's rates. Kern River has shown that, once these amounts are subtracted from the total depreciation included in its Period One rates, the remaining depreciation in its Period One rates very closely approximates its net unrecovered debt principal, consistent with the original bargain underlying Kern River's levelized rates.[58]

43. BP also contends that the levelized rate bargain between the parties underlying Kern River's optional expedited certificate mandates that Kern River must use the revenue it recovers during Period One to pay off all its debt, and therefore argues that any use of that revenue to pay down its equity would violate that bargain. However, BP

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[54] As noted in Opinion No. 486, 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. Opinion No. 486 at P50, *citing* Ex. KR-23 at 42:9-16, 43:7-11.

[55] *See Kern River Gas Transmission Co.*, 58 FERC at 61,243 (emphasis supplied), stating that Kern River's rates were designed to allow Kern River "to repay most of its *original* debt capital" during Period One and "its *original* equity capital" during Period Two.

[56] Ex. KR-23 at 48.

[57] Kern River Brief Opposing Exceptions at 23, *citing*, Tr. 1184-1186:6; Exh. No. KR-23 at 48-49.

[58] Kern River Brief Opposing Exceptions at 23.

points to no Commission order containing such a requirement. The statements in past Commission orders, such as that the Period One rates "will enable Kern River to recover all of its debt service" (50 FERC at 61,069) or that "rates have been designed based on levelizing the cost of service over the debt repayment period" (92 FERC ¶ 61,061 at 61,159), do not constitute requirements that Kern River actually pay off its debt during that period. Consistent with our general ratemaking practices, such statements merely explain that the Period One rates are designed to give Kern River an opportunity to pay off all its debt during Period One. The Commission includes a depreciation allowance in a pipeline's cost of service in order to enable the pipeline to recover its invested capital. However, the Commission does not require pipelines to put the money they recover through rates to any particular use, such as paying off debt. How a pipeline uses particular revenues collected from customers, as a general matter, is within its business discretion.[59] Given these facts, we find that, if the optional expedited certificate orders had intended, contrary to the Commission's usual practice, to actually require Kern River to pay off its debt during Period One, the orders would have set forth that requirement more clearly.

44. In addition, the Commission examined testimony by Kern River 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 calculations do not and should not reflect the indenture's schedule for debt principle payments.'"[60] The Commission also examined its action in the *Mojave* proceeding and determined that it did not require that all debt be extinguished before the implementation of the Period Two rates.[61] Moreover, as to concerns that Kern River has accelerated recovery of its equity investment, the Commission stated:

> 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. Moreover, the Commission has 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. Subsequently, the step-down rates will be designed by Kern River to recover only the remaining 30 percent of the

[59] *See, City of Charlottesville, Virginia, v. FERC*, 774 F.2d 1205, 1218 (1985).
[60] Opinion No. 486 at n.88, *citing* Ex. KR-23 at 40-41.
[61] Opinion No. 486 at n.89, *citing Mojave*, 81 FERC at 61,681-83.

> costs of the facilities, which will coincide with the amount of equity Kern River originally placed into the project.[62]

45. Therefore, the Commission has effectively mitigated BP's concerns on this issue by, requiring that the Period Two rates be filed with the effective dates linked to the expiration of the 10 or 15 year contracts currently held by Kern River's shippers, and by holding that these Period Two rates must be based upon no more than 30 percent of Kern River's current rate base which is an amount corresponding to the amount of equity under Kern River's capital structure.

46. However, the Commission will clarify one aspect of this finding. If Kern River refinances its debt, and the debt, therefore, is not extinguished before the implementation of the Period Two rates, the level of the Period Two rates may be adjusted to reflect any benefits to shippers from such action but not any detriment to shippers. As Kern River states in its Brief Opposing Exceptions:

> refinancing would not change the remaining rate base at the end of levelization, because '[i]rrespective of whether debt or equity is to be paid down, through the collection of depreciation, the utility is only permitted to collect depreciation in an amount equal to its investment, and no more.' Ex. No. KR-50 at 20:20-22, KR50 at 20 6-22:16, KR-29. The only effect of a refinancing would be that the remaining rate base after levelization would be capitalized partly with debt and partly with equity, rather than entirely with equity. Moreover, because debt capital costs less than equity capital, Kern River's post levelization shippers *would be better off* under refinancing than if Kern River maintained the nearly 100 percent equity capital structure that would otherwise exist. Ex. Nos. KR-23 at 20, KR-29 (emphasis in original).[63]

Therefore, if Kern River refinances its debt and/or debt is not fully extinguished at the end of the respective shipper contracts, Kern River's Period Two rates cannot be higher than if it had used all the depreciation collected during Period One to pay off its debt. The entire depreciation allowance reflected in Kern River's Period One rates must be subtracted from rate base in calculating the Period Two rates regardless of Kern River's actual use of these funds. Thus, the rate base used to design Kern River's Period Two rates may not reflect more than 30 percent of its original invested capital no matter what the level of its outstanding debts. However, as Kern River states, if some of that rate base is, contrary to current expectations, financed by debt rather than equity, that fact will be reflected in the

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[62] Opinion No. 486 at P 49 (footnotes omitted).
[63] Kern River Brief Opposing Exceptions at 33.

> calculation of the Period Two rates. Since debt is cheaper than equity, this would reduce the Period Two rates below what they would be otherwise. Thus, there is no way that the shippers could be harmed by Kern River's failure to pay off all of its debt during Period One.

BP's Other Objections to Levelized Rates

47. BP argues that Opinion No. 486 erroneously claims that traditional rates would increase costs to shippers by $40 million annually above rates developed using a levelized methodology. BP claims that if traditional and levelized rates are analyzed over the same period of time and recover all of the same underlying cost of service amounts based on the same depreciable life for book and rate purposes, each alternative has the same total dollar cost.[64] BP further claims that because Kern River's levelized rates do not utilize the same depreciable life for book and rate purposes, during Period One, they produce total revenue during Period One above traditional rates of $500 million. BP argues that the Commission's reliance on Kern River's comparison between levelized and traditional methodologies is flawed since the comparison does not look beyond the twelve month test period ending October 31, 2004. BP asserts that the comparison does not reflect the fact that over time, with rate base decreases, cost-based traditional rates go down. BP argues that this one-year snapshot does not provide support for the Commission's assertion in Opinion No. 486 that over the life of the contracts, "Kern River's levelization methodology provides lower rates to shippers than the traditional methodology."[65]

48. The Commission agrees with BP's assertion that the studies referenced in Opinion No. 486, which reflect the use of a twelve-month test period ending October 31, 2004, do not consider future periods.[66] The Commission also agrees that the total amount of depreciation recovered under both a levelized rate design and a traditional rate design is the same. However, as discussed above, the Commission has accepted the proffered levelized rate methodology based on the prior agreements of the parties. Moreover, a precise comparison of cost recoveries under these two different methodologies over the future periods is difficult to achieve. This is because such a comparison would necessarily depend on how often Kern River would file a rate case during those future periods. Under traditional ratemaking, shippers only receive the benefits of a declining rate base to the extent that the pipeline files a rate case or the Commission institutes a NGA section 5 proceeding. Until then the pipeline continues to collect a return based on

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[64] *Citing* Tr. 1425:25-1426:4; Ex. BP-42 at 10:12-14.

[65] BP request for rehearing at 33, *citing* Opinion No. 486 at P 45.

[66] *See* Ex. No. KR-47, pages 1-8. *See also* Opinion No. 486 a P 18 ("Kern River used a test period consisting of the twelve months ending January 31, 2004, as adjusted for known and measurable changes occurring through October 31, 2004.")

its rate base as of the test period in its previous rate case. If Kern River were to file few rate cases, then levelization would likely lead to lower rates, since this methodology guarantees passthrough of the full benefit of a declining rate base, unlike traditional rates.[67] In any event, the Commission approves the levelization methodology in the instant proceeding because it is a just and reasonable methodology that the parties agreed to utilize, not because of whether it will in fact lead to lower rates.

49. BP complains that Kern River's levelized rate design requires conjectures about, *inter alia*, the rate of inflation, capital structure and other items more than a decade into the future and that Opinion No. 486 does not explain how just and reasonable results are achieved by giving equal weight to model inputs (i) for values estimated 12 years in the future and (ii) for presently known values. BP asserts that the Commission precedent reveals that it considers estimates more than five years into the future are not as reliable as more current data.[68] BP argues that Opinion No. 486 does not explain why such less reliable long term projections on which levelized rates are founded should be given the same weight as the more accurate actual test period data that form the primary basis for the traditional rates and submit that this future data also have disproportionate weight under Kern River's levelization methodology.

50. The Commission finds that BP's argument regarding the use of estimates for the implementation of a levelized rate methodology is without merit. As set forth in this order the Commission is permitting Kern River to continue its use of the levelized methodology agreed to in Kern River's certificate proceeding and carried forward with changes in the 2000 ET settlement. Estimates are, by necessity, an integral part of the levelized methodology. However, any concern regarding the reliability of such estimates is outweighed by the interest in maintaining the risk sharing agreement agreed to by all parties in the earlier proceedings.

51. Further, BP argues that the Commission has not addressed how its acceptance of Kern River's rate regime is consistent with the rule against retroactive ratemaking. BP argues that Opinion No. 486 states that "[i]n the early years of Period One, when Kern River's rates recover less than its book depreciation, Kern River records a regulatory

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[67] *See Trailblazer Pipeline Co*. 50 FERC ¶ 61,188, at 61,586-87 (1990) (requiring a pipeline to implement levelized rates to ensure that its shippers received to benefits of its declining rate base).

[68] BP argues that typically, "elements of the pipeline's cost-of-service represent a short-term projection of a pipeline's costs, because they do not reflect changes that may occur after the test period. . . . [L]ong-term projections are inherently more difficult to make, and thus less reliable, then short-term projections. Over a longer period, there is a greater likelihood for unanticipated developments to occur . . . ." *Transcontinental Gas Pipeline Corp*., 84 FERC ¶ 61,084, at 61,423 (1998).

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." Opinion No. 486 at P 48. BP argues that the rule against retroactive ratemaking:

> prevents utilities from collecting revenues to compensate for [prior over-or] underrecoveries . . . That is, even charges that are imposed prospectively, and therefore satisfy the filed rate doctrine, are improper if they are based on the pipeline's losses in a prior period.[69]

52. The *California PUC* case cited by BP states that to determine whether either the filed rate doctrine or the rule against retroactive ratemaking have been violated the courts inquire whether, as a practical matter, the parties had sufficient notice that the approved rate in question was subject to change.[70] Here, because Kern River has always utilized a levelized methodology since its inception and because Kern River has filed in the instant proceeding to continue this methodology in the instant proceeding, all parties to the instant proceeding are on notice concerning Kern River's use of a levelized methodology and the manner in which such a methodology will recover costs.

53. BP also argues that Kern River's levelization methodology results in inequitable treatment of replacement shippers taking capacity releases, and points out that capacity release transactions have increased significantly since Kern River's original levelization proposal was reviewed by the Commission. BP argues that replacement shippers currently paying high Period One rates to depreciate 70 percent of plant by 2011 for some contracts, will not be able to obtain step-down Period Two rates, because their release period expires before the initiation of the Period Two rates. Thus, it asserts that the entity

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[69] BP Request for Rehearing at p.28, *citing Public Utilities Commission of the State of California v. FERC, et al.*, 988 F2.d 154, 161 (D.C. Cir. 1993) (*California PUC*).

[70] *Public Utilities Commission of the State of California v. FERC, et al.*, 988 F2.d 154, 164 (D.C. Cir. 1993). The court observed that:

> [i]t is not that notice relieves the Commission of the bar on retroactive ratemaking, but that it "changes what would be purely retroactive ratemaking into a functionally prospective process by placing the relevant audience on notice at the outset that the rates being promulgates are provisional only subject to later revision." *Id*. at 164, *citing Natural Gas Clearinghouse v. FERC*, 965 F.2d 1066, 1072 (D.C. Cir.1992) (quoting, *Columbia Gas Transmission Co. v. FERC*, 895 F.2d 791, 797 (D.C. Cir.), *cert. denied sub nom., Panhandle Eastern Pipe Line v. Columbia Gas Transmission Co.*, 498 U.S. 907 (1990). *See also*, *NStar Electric and Gas Corp., v. FERC,* 2007 U.S. App. LEXIS 5521 (2007).

ultimately benefiting from over-payment would only by chance match the identity of the shipper that originally paid the higher rate.

54. The Commission agrees that capacity releases have significantly increased since Kern River initially proposed its levelized rate methodology. In fact, the capacity release program was initiated by Order No. 636 in 1992, after Kern River initially implemented its levelized rate methodology. However, the allegation that a replacement shipper taking a release during Period One may not recover the benefit of the lower Period Two rates does not compel the Commission to revisit its approval of Kern River's levelization methodology. Under Commission policy, the replacement shipper pays the rate up to the maximum rate applicable to its releasing shipper during the term of the release and has no other expectation under either the levelized methodology or traditional ratemaking. The intergenerational inequity posited by BP concerning replacement shippers under Kern River's levelized methodology could also occur under traditional ratemaking, for example, if the replacement shipper held contracts that terminated before a pipeline filed to implement lower rates to reflect a declining rate base via a new NGA section 4 rate case.

55. BP also argues that Kern River's accelerated recovery of depreciation during Period One will give Kern River a competitive advantage, when it implements its lower Period Two rates, because other systems serving California do not have such an accelerated depreciation schedule. BP argues that the distorting effects of special rate designs that give one pipeline an advantage in marketing its capacity against other pipelines traditionally have been the subject of Commission concern.[71] However, none of the affected pipelines have raised this concern, either in this rate case or in Kern River's various earlier proceedings. Mojave had a similar rate design to Kern River, but has voluntarily chosen to shift to a traditional rate design with the consent of all its shippers. Kern River's obligation to file substantially reduced Period Two rates has been well known to any competing pipelines since the inception of the project. If they were concerned about the competitive effects of such rates, they could have participated in the various proceedings in which we have approved this rate design. They did not.

56. BP's arguments concerning the effects on competition or on replacement shippers do not justify disturbing Kern River's longstanding rate design. The Commission's interest in maintaining the risk sharing agreement reached by the parties outweighs any of the potential effects on competing shippers or on replacement shipper described by BP.[72]

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[71] *Citing Pacific Gas Transmission Co.*, 50 FERC ¶ 61,067 (1990). The "rate structures of competing pipelines should be substantially similar so that customers will not purchase gas on the basis of rate design," *id.* at 61,128.

[72] *See Midcoast Interstate Transmission v. FERC*, 198 F.3d 960 (D.C. Cir. 2000). *See also, Transcontinental Gas Pipeline Corp.*, 112 FERC ¶ 61,170, at P 66-68 (2005).

<u>Kern River's Opposition to Period Two Rate Filing Requirement</u>

57. In order to increase the assurance that Kern River's shippers will obtain the benefit of the lower Period Two rates if they continue service beyond the terms of their existing contracts, the Commission directed that Kern River include in its tariff the Period Two rates that will take effect when the firm shippers' existing contracts expire.

58. On rehearing, Kern River argues that the Commission's directive that Kern River must file tariff sheets setting forth the Period Two step-down rates to take effect after the shippers' current contracts expire is unreasonable and unlawful. Kern River asserts that the Commission lacks authority to order Kern River to file different rates to be effective at multiple future dates. Kern River argues that for the last sixteen years, the Commission consistently has reviewed and approved Kern River's tariff sheets stating the Period One rates only, without ever suggesting that Kern River's tariff must also include future, Period Two or Period Three rates.

59. Kern River argues that stating rates for the future periods in Kern River's tariff is not a condition of Kern River's NGA section 7(e) certificate because the Commission accepted Kern River's compliance filings that stated rates only for Period One. Kern River also argues that the Commission lacks the authority to force a utility to file a particular rate unless it finds the existing rate unlawful, and it cannot deprive the jurisdictional company of the right to initiate rate changes.[73] Thus, Kern River argues that the Commission cannot, under section 4 of the NGA, direct Kern River to file new rates to take effect in Period Two.[74] Kern River also contends that the Commission cannot justify its directive under the authority of section 5 of the NGA because such action requires the Commission first to find that the existing rate is unjust and unreasonable, and only then may the Commission prescribe a new rate. Kern River asserts that the Commission has made no such finding in the case and that the Commission could not have, because Kern River has never filed a Period Two rate.

60. Kern River asserts that to establish rates for Period Two at this time would serve little purpose of informing Kern River's current customers of their future options which is the stated purpose for the Commission's order.[75] Kern River asserts that its prerogative is to decide whether and when to seek a rate change under NGA section 4, and to decide whether to implement step-down rates through a section 4 filing or,

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[73] *Citing Atl. City Elec. Co. v. FERC*, 295 F.3d 1, 10 (D.C. Cir. 2002).

[74] *Citing Consumers Energy Co. v. FERC*, 226 F.3d 777, 781 (6th Cir. 2000) (Commission cannot direct pipeline company to file a petition for rate approval to justify its current rate or establish a new maximum rate).

[75] *Citing* Opinion No. 486 at P 54.

alternatively, either to offer customers whose contracts expire a discount from the maximum rate then on file or to negotiate new rates with them.

61. The Commission does not agree with Kern River. In Opinion No. 486, the Commission found that Kern River's proposal to continue its levelized methodology did not result in just and reasonable rates unless the pipeline included tariff sheets reflecting the Period Two step down rates referred to in its proposal, in addition to its proposed Period One rates. As previously discussed, as of the end of Period One, Kern River will have an excess recovery of its depreciation expense. Accordingly, we can only find the Period One rates to be just and reasonable, if Kern River's tariff also provides for the return of that excess recovery in its Period Two rates. The Commission is well within its authority to take such action pursuant to section 5 of the NGA, even though Kern River filed its proposal pursuant to section 4 of the NGA.[76]

62. Accordingly, the Commission found that, Kern River's proposal to file Period One rates that would collect approximately 70 percent of its original costs from its shippers over either a ten or fifteen year period (depending on their contracts) which would then be followed by Period Two rates that would be based upon the remaining 30 percent at the expiration of the original ten or fifteen year term was unjust and unreasonable. The Commission determined that Kern River's proposal did not provide adequate assurances that its shippers would obtain the benefit of the lower Period Two rates if they continued service beyond the terms of their existing contracts. Because the Commission viewed the opportunity for shippers to obtain the lower Period Two rates upon the expiration of their existing contracts as a vital component of the levelization methodology proposed by Kern River,[77] and because the Commission concluded that the makeup of the Period Two rates would be more transparent, the Commission concluded that the implementation of the Period One rates without the benefit of the stepdown Period Two rates included in Kern River's tariff was unjust and unreasonable.[78] Therefore, the Commission directed that

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[76] *Western Resources, Inc. v. FERC*, 9 F.3d 1568, 1577-79 (D.C. Cir. 1993) (finding that under the NGA, an action may originate as a § 4 proceeding only to be transformed later into an NGA § 5 proceeding).

[77] The Commission stated that its:

> 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. Opinion 486 at P 54.

[78] Opinion No. 486 at P 54, *citing* Kern *River Gas Transmission Co.*, 50 FERC ¶ 61,069, at 61,150-51 (1990), where the Commission required Kern River in its initial use of the levelized methodology, to file tariff sheets setting forth the Period One rates it

(continued…)

Kern River 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 Period Two rates to be available to its 10 and 15 year shippers. Nothing raised by Kern River on rehearing compels the Commission to find that such action was beyond its authority.

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

63. When the Commission certificated Kern River's original system under the optional expedited procedures adopted in Order No. 436, the Commission required Kern River to design its rates based on volumes equal to 95 percent of its design capacity.[79] This has been referred to as the 95 percent load factor condition. The 95 percent load factor condition was intended to ensure compatibility in rate terms and conditions between Kern River and its then-principal rivals, Mojave Pipeline Company and Wyoming-California Pipeline Company[80] and to put Kern River at risk for any unsubscribed capacity below the 95 percent load factor level for the entire life of the system.[81] In the optional certificate proceeding, 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."[82]

64. In subsequent rate proceedings, the Commission approved settlements under which Kern River designed its rates based on slightly more than 95 percent of its Original System's design capacity.[83] Since at least 2002, Kern River has had firm contracts for

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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 so that all parties could ascertain what rates were to be in effect at any given time and be assured that the reduced rate would take effect upon the agreed to dates. Therefore, the requirement to file such rates was part of the original agreement.

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

[80] *Id.* at 61,141 and 61,150.

[81] *See* Ex. KR-23 at 52. The Commission rejected Kern River's request for permission to design its rates based upon an 85 percent load factor. *Kern River Gas Transmission Co.*, 50 FERC at 61,150.

[82] *Kern River Gas Transmission Co.*, 50 FERC at 61,151.

[83] Kern River states that, in the 1995 settlement of its Docket No. RP92-226-000 section 4 rate case and the 1999 settlement of its Docket No. RP99-274-000 rate proceeding, the parties agreed to design its rates using reservation billing determinants equal to 96 percent of its Original System's design capacity. *See Kern River Gas Transmission Co.*, 70 FERC ¶ 61,072 (1995); *Kern River Gas Transmission Co.*, 87 FERC ¶ 61,128 (1999); Ex. KR-17 at 15. The 2000 ET Settlement provided for

(continued…)

100 percent of the capacity of its Original System.[84] Nevertheless, in this case, Kern River proposed to design its rates for Original System firm shippers using demand and commodity billing determinants equal to 95 percent of the design capacity of its Original System, arguing that the 95 percent load factor condition capped its billing determinants at that level and that Kern River continues to face the future prospect of remarketing unsubscribed capacity that arises due to business risk.[85]

65. The Initial Decision found that Kern River had not carried its burden of proving that continued use of the 95 percent load factor rate design produces just and reasonable rates. The ALJ determined that the original purpose of the 95 percent load factor rate design does not now apply since 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, finding that such circumstances lead to a built-in rate design over-collection, recommended that the normal test period ratemaking concepts govern the rate determinants for Kern River.

Opinion No. 486

66. The Commission affirmed the result reached by the ALJ, although for somewhat different reasons. The Commission agreed 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. Therefore, the Commission found that 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.

67. However, the Commission disagreed with Kern River's interpretation of the 95 percent load factor condition. The Commission held that the condition simply required that Kern River design its original system rates based upon *at least* 95 percent of its design capacity. The Commission thus rejected 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.

68. In reaching this conclusion, Opinion No. 486 pointed out that the same certificate order imposing the 95 percent load factor condition also required Kern River to make a

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continued use of those same billing determinants. *Kern River Gas Transmission Co.,* 92 FERC ¶ 61,061, at 61,157 (2000).

[84] Ex. S-27 at 18; S-22.

[85] Kern River Reply Brief at 39-41.

tariff filing three years after its in-service date using "the same *or greater* throughput levels on which Kern River's initial rates have been predicated."[86] The Commission stated that, if it had intended the 95 percent load factor condition to cap 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.

69. The Commission also explained that its interpretation of the 95 percent load factor condition was buttressed by the fact it carries out the intent of the Commission's then effective optional expedited certificate regulations. Among other things, the Commission pointed out that 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." Thus, the optional expedited certificate regulations expressly 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.

70. Opinion No. 486 also rejected Kern River's reliance on Commission's orders in a section 4 rate proceeding filed by Mojave Pipeline Co.[87] The Commission stated that, unlike the situation here, in *Mojave* it was not clear that Mojave's proposed rate design volumes would overrecover its cost of service. The Commission recognized 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."[88] However, the Commission stated that, 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.

<u>Rehearing Request</u>

71. Kern River argues that the Commission erred in rejecting its proposal to design the rates for Original System shippers based upon 95 percent of its design capacity. Kern River argues that the Commission's reliance on its order issuing Kern River's original certificate and the optional certificate regulations to support its ruling in this case cannot be squared with the Commission's later decision in *Mojave*, which is in stark contrast to

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[86] *Kern River Gas Transmission Co.*, 50 FERC at 61,151 (emphasis supplied).

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

[88] *Id*.

the Commission's position in this case, and therefore, does not comport with reasoned decision-making.

72. Kern River argues that the Commission's departure from *Mojave*, which recognized that the 95 percent load factor rate design was part of the risk-reward allocation of the optional certificate, arbitrarily alters the risk-reward allocation underlying Kern River's original certificate authorization. Kern River asserts that the Commission fails in its attempt to explain its disparate treatment between similarly-situated pipelines. Kern River further asserts that the Commission acknowledged that its determination that the 95 percent load factor condition is only a "floor" under Kern River's Original System billing determinants is a wholly new "interpretation" of the 95 percent load factor condition and is in stark contrast to *Mojave*.

73. Kern River argues that the Commission should grant rehearing and should approve Kern River's continued use of 95 percent load factor billing determinants for the design of Original System rates.

<u>Commission Determination</u>

74. The Commission denies rehearing on this issue. For the reasons discussed below, we affirm our determination in Opinion No. 486 that Kern River use demand billing determinants equal to 100 percent of Kern River's design capacity and commodity billing determinants equal to its actual throughput over the last 12 months of the test period. We further affirm our determination that the 95 percent load factor condition is only a floor under Kern River's original system billing determinants.

75. As we stated in Opinion No. 486, we are in agreement with Kern River that the 95 percent load factor condition established in Kern River's optional expedited certificate proceeding was a part of the allocation of risk as between the pipeline, its customers and lenders approved by the certificate order, and therefore Kern River's rates for Original System shippers should be designed consistent with that condition. Therefore, resolution of the issue of the billing determinants to be used in designing the Original System rates turns on the appropriate interpretation of the 95 percent load factor condition established in the orders certificating Kern River's Original System. Our interpretation of that condition in Opinion No. 486 was based on our review of the certificate orders establishing the condition and the then effective regulations pursuant to which Kern River's optional expedited certificate was issued. Nothing in the certificate orders supports Kern River's assertion that the 95 percent load factor condition capped its rate design volumes. Rather, the optional certificate order states that Kern River's next

"[tariff] filing must use the same *or greater* throughput levels on which Kern River's initial rates have been predicated."[89]

76. Additionally, in the order granting Kern River's certificate the Commission stated that it was examining Kern River's application based on the optional expedited certificate regulations.[90] Those 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. In fact, the regulations expressly permitted an increase in rate design volumes in subsequent section 4 rate cases. Section 157.103(d)(3) of the Commission's then effective optional expedited certificate 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* [emphasis supplied].

77. Opinion No. 486 concluded that, if the Commission had intended in the orders certificating Kern River's original system to depart from this aspect of 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.

78. On rehearing, Kern River does not point to any language in the certificate orders as supporting a different interpretation than the one we adopted in Opinion No. 486. Nor does Kern River contest our interpretation of the then-effective optional certificate regulations.[91] Instead, Kern River relies solely on the Commission's orders in a subsequent section 4 rate case filed by Mojave Pipeline Co., which was issued its optional expedited certificate in the same orders as Kern River was issued its certificate. Kern River points out that in *Mojave* the Commission stated,

> The requirement in Mojave's certificate that it design its rates based on rate design volumes equal to 95 percent of its capacity, imposed on Mojave the risk that it could market at least 95 percent of its capacity. However, 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. Greater risk for

[89] *Kern River Gas Transmission Co.,* 50 FERC at 61,151 (emphasis supplied).

[90] 18 C.F.R. §§ 157.100-157.106 (1989).

[91] 18 C.F.R. §§ 157.100 – 157.106 (1989) (OC regulations).

> any unused capacity is balanced by greater reward if the pipeline sells capacity that is not subject to the at risk condition. In contrast, if a traditionally certificated pipeline overrecovers its cost of service, the pipeline's rates may be lowered in its next rate case.[92]

79. Kern River concludes that *Mojave* clearly interpreted the 95 percent load factor condition not only as requiring that the pipeline's rate be designed based on at least 95 percent of its design capacity, but also capping the rate design volumes at the same level. Kern River argues that, having interpreted the 95 percent load factor condition in that manner in *Mojave*, the Commission must continue to follow the same interpretation in all subsequent Kern River rate cases.

80. Kern River acknowledges that "the Commission may depart from its precedents," but argues that "it must explain why it is changing course." As we explained in Opinion No. 486, to the extent that the above quoted passage from *Mojave* may interpret the 95 percent load factor condition in Mojave and Kern River's optional certificates as capping their rate design volumes at the 95 percent level, we are not following that precedent, because it is incorrect. The *Mojave* order failed to recognize that the optional certificate order stated that Mojave and Kern River's next "[tariff] filing must use the same *or greater* throughput levels on which Kern River's initial rates have been predicated, thus clearly indicating that the 95 percent load factor condition did not cap the pipelines' rate design volumes. Moreover, the *Mojave* order did not recognize that the optional expedited certificate regulations expressly provided that the volumes used to design the pipeline' initial rates in the certificate proceeding "may be increased in a subsequent rate filing but may not be decreased." Thus, the *Mojave* order's suggestion that pipelines certificated under the optional expedited certificate regulations, unlike traditionally certificated pipelines, need not lower their rates to reflect increased billing determinants was contrary to the optional expedited certificate regulations.[93]

81. Kern River does not contest these facts. Rather, its argument boils down to an assertion that the Commission, having erroneously interpreted the 95 percent load factor condition in *Mojave*, is now bound to abide by that incorrect interpretation in all subsequent rate cases involving the two pipelines. We disagree. We have held that the risk sharing agreement between the pipeline and its customers approved as part of an optional certificate order should be maintained in subsequent rate cases, absent agreement by all parties to a change. To follow *Mojave's* incorrect interpretation of the 95 percent load factor condition in this case would be inconsistent with that principle, since it would change a key part of the original risk sharing agreement over the objection of Kern River's shippers. There is no reason why Kern River's shippers should be deprived of

[92] *Mojave Pipeline Company*, 83 FERC at 62,113 (1998).

[93] *Id.*

the benefit of one aspect of their original risk sharing agreement simply because an order in another pipeline's rate case contained an erroneous description of that aspect of the risk sharing agreement.

82. Kern River makes various contentions as to why it would be unfair not to follow the *Mojave* precedent in this case. First, Kern River asserts that it has relied on applying the 95 percent load factor condition in rate and certificate proceedings over the last 15 years in the same manner as upheld in *Mojave*. However, both of Kern River's rate cases during that period settled, with the parties agreeing to design its rates using reservation billing determinants equal to 96 percent of its Original System's design capacity.[94] In addition, the 2000 ET Settlement provided for continued use of those same billing determinants.[95] Thus, this issue was not addressed on the merits in those proceedings, and the fact those proceedings ended with settlements under which Kern River's rates were designed based upon volumes somewhat in excess of 95 percent of its capacity indicates that Kern River's interpretation of the load factor condition was not followed.

83. Second, Kern River contends that the failure to follow *Mojave* will lead to disparate treatment of the two pipelines, because Mojave will continue to be allowed to design its rates based upon only 95 percent of its capacity, even if it subscribes capacity in excess of that level, while Kern River will be required to design rates based upon the full level of its contracted capacity. However, Mojave has recently filed a new section 4 rate case, in which it has proposed, without objection from its customers, to shift to a traditional rate design and eliminate its levelized rate structure.[96] As part of this proposal, it has proposed to design its rate based upon the full level of its contracted capacity. In any event, even if Mojave were to continue its existing rate design, our holding here would apply equally to it, and we would not follow the *Mojave* orders relied on by Kern River in future Mojave rate cases.

84. We also note that in the rate case in which the *Mojave* orders were issued, the shippers were proposing to design Mojave's rates based on rate design volumes of 408 MMBtu, even though Mojave only had contracts for 392.5 MMBtu of capacity. Therefore, the Commission found that Mojave would underrecover its costs unless it obtain firm capacity for an additional 15.5 MMBtu of capacity, and for various reasons it was unlikely Mohave could do so.[97] The Commission also found that, even if Mojave's rates were designed based upon its actual billing determinants of 392.5 MMBtu, as

[94] Ex. KR-17 at 15.

[95] *Kern River Gas Transmission Co.*, 92 FERC ¶ 61,061, at 61,157 (2000).

[96] *Mojave Pipeline Co.*, 118 FERC ¶ 61,252 (2007).

[97] *Mojave Pipeline Co.*, 81 FERC ¶ 61,150, at 61,684 (1997), *order on reh'g*, 83 FERC ¶ 61,267, at 62,111 (1998).

opposed to 95 percent of its design capacity, which was assumed to be 380 MMBtu, it was not clear that Mojave would overrecover its costs. That was because some of Mojave's existing firm contracts had rate caps in the form of rate discounts totaling about $250,000 per year, and, Mojave's contract with Texaco had a *force majeure* provision in its contract with Texaco, providing Texaco with reservation charge credits of $750,000 per year on average.[98]

85. In the present case, however, Kern River does not face a similar risk of underrecovery. Kern River has been 100 percent subscribed since 2000.[99] Additionally, Kern River does not refute our finding that it "does not assert it has any [] contractual provisions [similar to Mojave's] that would prevent collection of the maximum rates established in this proceeding."[100]

86. In fact, it appears that Kern River's proposed rate design volumes for the Original System would overrecover its costs. While Kern River's Original System is fully contracted and is thus operating at a 100 percent load factor, it proposes to design its rates for that system on a 95 percent load factor. Thus, Kern River recovers 100 percent of its cost of service through revenues associated with 95 percent of its capacity; all revenues for the remaining 5 percent represent revenues in excess of its revenue requirement. As the ALJ noted, Kern River has received annual revenues between $5.4 and $7.8 million in excess of its revenue requirement. The Commission's regulations, including as discussed above the optional expedited certificate regulations in effect when the certificate for the Original System was issued, require pipelines to design rates based on projected units of service.[101] Rates are designed to give the pipeline an opportunity to recover its cost of service, but should not be designed to guarantee overrecovery of that cost of service. Under Kern River's analysis, the Commission would be made to follow an incorrect interpretation that leads to unjust and unreasonable results and is contrary to the Commission's policy against overrecovery.

87. Moreover, although Kern River states that a relevant factor we have overlooked is our "decision adopting a blended rate for designing Kern River's IT rates,"[102] we find that the blended IT rate is irrelevant here. Should Kern River be required to remarket its Rolled-In System capacity on an IT basis, it would still have the opportunity to recover its costs. In the event there is capacity turnback when current Original System contracts expire in 2011 so that Kern River's system is not fully subscribed, several possible scenarios emerge: 1) Kern River may be able to resell such capacity on an IT basis, 2)

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[98] *Mojave Pipeline Company*, 83 FERC at 62,113 (emphasis added).

[99] Kern River rehearing request at 21.

[100] Opinion No. 486 at P 82.

[101] 18 C.F.R. § 284.10(c)(2) (2006), 18 C.F.R. §§ 157.100-157.106 (1989).

[102] Kern River rehearing request at 31, n.27.

under the blended rate for IT, the capacity may be sold for greater than actual cost, and 3) Kern River may be able to sell capacity on a firm basis. Our decision allows Kern River a "reasonable opportunity to recover its costs and earn an adequate return,"[103] rather than a guarantee of cost recovery.

88. Finally, Kern River does not refute our finding under *Williston Basin Interstate Pipeline Company,* that "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)."[104] Kern River is silent on this point in its rehearing request, yet reiterates the argument, addressed in Opinion No. 486, that it faces future risks to "maintaining at least the 95 percent load factor design level."[105] Kern River claims that it "faces the real risk of re-marketing the Original System capacity when the current shippers' contracts begin to expire in 2011."[106] However, Kern River again "points to no known and measurable change that occurred during the test period that would justify reducing its projected units of service below"[107] 100 percent of its Original System capacity. The termination of certain contracts in 2011 is long after the end of the test period in this rate case. Further, if Kern River experiences significant turnback in 2011, or any other time, if can file a new rate case to reflect changed circumstances.

89. As explained above, we find that Kern River's arguments on this issue are not persuasive and, therefore, deny its request for rehearing.

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

90. 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. In projecting the annual costs of service, Kern River has consistently included a 3 percent inflation adjustment for O&M and A&G expenses.[108] In the instant filing, Kern River proposed that it be allowed to continue to include a 3 percent annual inflation factor for O&M and A&G expenses.

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[103] *El Paso Natural Gas Co.*, 88 FERC ¶ 61,139, at 61,407 (1999).

[104] *Williston Basin Interstate Pipeline Company*, 87 FERC ¶ 61,265, at 62,021 (1999).

[105] Kern River rehearing request at 32.

[106] *Id.*

[107] *Kern River Gas Transmission Co.,* 117 FERC ¶ 61,077 at P 84.

[108] Ex. KR-23 at 49.

91. The ALJ denied Kern River's continued use of the 3 percent O&M and A&G inflation factor, concluding that Kern River's proposal would not produce just and reasonable rates because Kern River had "not shown that it has had such inflation."[109] The ALJ agreed with Calpine's argument that Kern River incorrectly failed to remove certain incremental A&G costs and noted that Kern River failed to address Calpine's argument.

Opinion No. 486

92. The Commission found that the levelized rate methodology approved in Kern River's original certificate proceeding permits the use of an inflation factor in calculating its levelized A&G and O&M costs. In addition, while an inflation adjustment is not permitted under a traditional rate design, the Commission found, that because levelized rates require a projection of 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.

93. Opinion No. 486 nevertheless rejected Kern River's proposal to use an inflation adjustment for A&G and O&M costs in this rate case. The Commission stated that nothing in Kern River's certificate orders guarantees that the specific inflation factor to be used in subsequent section 4 rate cases would always be 3 percent. Thus, in each section 4 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.

94. In addition, the Commission found that in each section 4 rate case Kern River must take into account any existing excess recovery of A&G and O&M costs in determining the A&G and O&M costs to be included in the new levelized rate. Opinion No. 486 explained that 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

[109] Initial Decision at P 445.

O&M costs for the levelization period, contrary to the purpose of the levelization methodology.

95. The Commission accordingly concluded that Kern River had a two-fold section 4 burden in order to support its proposed inflation adjustment for its A&G and O&M costs in this case, requiring that Kern River: (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. The Commission found that Kern River had failed to do either. It did not propose 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. Kern River also failed to provide evidence from which a reliable projection of future inflation could be made.

96. In order to support its projection of future 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.[110] In recognition of the fact 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 $19,007,000 in 1993 to $26,407,000 today, or by an average of 2.86 percent per year since 1993.

97. However, the Commission found this evidence to be flawed, because it was not clear that Witness Warner made a sufficient adjustment to account for increased costs related to post-1993 expansions. The post-1993 expansions included the rolled-in 2002 expansion and the California Action Project, as well as the 2003 Expansion. Yet Kern River's witness proposed no adjustment to account for increased costs related to the first two expansions.[111] 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. The Commission noted that Kern River had responded that the $9.9 million amount referred to by Calpine's witness is half of its A&G costs, and asserted, "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

[110] Ex. KR-23 at 50-51; Ex. KR-26.

[111] Ex. CES-69 at 12.

doubled Kern River's A&G costs. On its face, therefore, Mr. Hughes' argument is counterintuitive."[112] The Commission was unpersuaded by this assertion, stating that while it may be counterintuitive that the 2003 Expansion doubled Kern River's A&G costs, it is equally counterintuitive to assume that a project which doubled Kern River's size had no effect on its A&G costs.

98. The Commission concluded that the record did not contain adequate support for the Commission to determine any specific inflation adjustment. Therefore, the Commission affirmed the ALJ's rejection of any inflation adjustment in this case, but without prejudice to Kern River seeking to support such an inflation adjustment in a future section 4 rate case.

Rehearing Request

99. Kern River argues that the Commission's denial of Kern River's 3 percent inflation factor was unlawful under three theories: (1) the Commission's application of a new, two-part burden of proof to Kern River's proposed inflation factor in this case violates Kern River's due process rights, (2) the Commission's finding that Kern River has not satisfied its section 4 burden is contrary to the record evidence, and (3) the Commission unfairly denies Kern River the opportunity to present evidence under the Commission's newly articulated standard of proof.

100. Kern River argues that the Commission's decision to retroactively apply its new evidentiary standard to Kern River's proposed inflation factor without adequate prior notice of the standard's applicability violates due process and Administrative Procedure Act requirements and is arbitrary and capricious. Kern River states that, because the Commission announced this two-part burden for the first time, Kern River was unaware of this new evidentiary standard and the Commission, not surprisingly, found that Kern River had failed to carry its burden. Additionally, because the Commission's stated rationale for this new evidentiary burden fails to recognize that Kern River's Commission-approved levelization methodology is based on an average, total cost-of-service over the levelization period, it is arbitrary and capricious. Moreover, while the Commission agrees that an inflation factor is a valid part of Kern River's approved levelization methodology, it has provided no justification as to why its A&G and O&M costs should be treated differently from other aspects of its overall cost-of-service in the light of the averaging that occurs within the levelization calculation.

101. Kern River also argues that, contrary to the Commission's criticisms of Kern River witness Mr. Warner's inflation study, Kern River provided a reasonable projection

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

of future inflation that is fully supported on the record. Kern River states that the Commission's criticisms of Mr. Warner's inflation study included: (1) that it did not include a necessary adjustment to account for all post-1993 expansions, and (2) that it did not remove the A&G costs related to those expansions. Kern River claims that Mr. Warner's adjustment did not reflect the very minor O&M and A&G costs associated with either the California Action Project (CAP) or the 2002 Expansion. This oversight, however, has no significant effect on the validity of Mr. Warner's inflation study since: (1) the costs associated with CAP, a short-term project (i.e., one year) that was rolled into the 2002 Expansion, were no longer relevant when Mr. Warner did his analysis, and (2) the 2002 Expansion facilities are now, for rate-making purposes, part of both the 2003 Expansion and the Rolled-in System.

102. Kern River argues that correcting Mr. Warner's analysis to account for all post-1993 expansions, including the 2002 Expansion and CAP, has no significant impact on the results of Kern River's inflation study and, contrary to the conclusion of Opinion No. 486, shows that Kern River's proposed 3 percent inflation factor for O&M and A&G costs is reasonable.

103. Kern River also argues that the Commission's conclusion that Kern River improperly failed to remove the A&G costs associated with the 2003 Expansion Project is contrary to the record. Kern River claims that it was not necessary for Mr. Warner's study to make an additional adjustment for A&G costs associated with the incremental facilities because the A&G costs attributed to the incremental facilities are not, in fact, incremental costs. Instead, those A&G costs were incurred by Kern River even before the incrementally priced expansion – they are merely allocated to the incremental facilities based on the KN methodology. Kern River asserts that it confirmed in its brief on exceptions, with an analysis of data from Kern River's FERC Forms 2, that there is no incremental A&G associated with the 2003 Expansion. Thus, Kern River contends that Mr. Warner's study demonstrating that Kern River has historically experienced inflation of A&G and O&M costs at about a 3 percent annual rate since 1993 is fully supported on the record.

104. Kern River states that, in addition to Mr. Warner's historical analysis of inflation of Kern River's O&M and A&G costs, its 10-year Business Plan projecting O&M expenses from 2004 through 2013 was included in the record. By performing a weighted calculation of the labor and non-labor expenses approved by the Commission in this case, an average inflation rate of 2.44 percent can be computed. Kern River states that there is also unrefuted testimony that the rate of inflation generally ranges between 2 to 3.4 percent annually. Therefore, the Commission's stated rationale for adopting no O&M and A&G inflation adjustment for Kern River cannot be squared with the record. The Commission's decision, therefore, is not a product of reasoned decision-making and is not supported by substantial evidence. Kern River concludes that the Commission,

accordingly, should reverse Opinion No. 486 and accept Kern River's proposed 3 percent annual inflation adjustment for O&M and A&G costs.

105. Finally, Kern River argues that, since the Commission has established a new evidentiary burden for the first time in this case, the Commission must, at a minimum, give Kern River a reasonable opportunity to satisfy that new standard. In the event the Commission declines to reverse its decision and approve an inflation factor in accordance with the record, Kern River claims the Commission must reopen the record to allow Kern River to submit evidence to demonstrate that it can support its proposed inflation adjustment under the Commission's new two-part evidentiary standard.

Commission Determination

106. The Commission denies rehearing on this issue.

107. We first address Kern River's contentions concerning Opinion No. 486's requirement that its proposed inflation adjustment for A&G and O&M costs take into account any existing excess recovery of A&G and O&M costs. Kern River attacks this requirement on both procedural and substantive grounds. We reject both lines of attack.

108. Kern River's procedural argument is, in essence, that because this is a new evidentiary standard of which it had no notice, any application of this standard without reopening the record to give it an additional opportunity to present evidence satisfying the standard violates due process. We find that Kern River had ample notice that it could be required to make such a showing, and therefore there has been no violation of its due process rights. The issue of the need to account for any existing excess recovery was first raised on March 15, 2005 by RCG Witness Doering in prepared rebuttal testimony,[113] five months before the commencement of the hearing on August 17, 2005. Doering explained:

> For 15-year 2003 Expansion Shippers that have 13.5 years remaining on their contracts at November 1, 2004, the 3% inflation factor means that every $10,000 of O&M expenses in the test period year will have become almost $14,500 of O&M expenses by the end of their contracts. When the inflated O&M is levelized into rates, those 15-year shippers will immediately begin paying Kern River $12,189 for O&M costs, even though Kern River (at a 3% rate of inflation) will not experience that level of cost for another seven years. Thus, if Kern River keeps filing rate cases every five years, as it has in the past, its shippers will be

[113] Ex. RCG-18 at 28–30.

> forced to pay a higher level of O&M costs in their rates than Kern River will ever actually experience.[114]

109. Kern River had several opportunities either to contest RCG's right to raise this issue in rebuttal testimony or to present evidence explaining the level of inflation adjustment it required in light of the alleged overrecovery of these costs in the early years of its levelized rates. Although Kern River had the opportunity to file a motion to strike portions of the rebuttal testimony of RCG Witness Doering, as Kern River did on March 29, 2005 by moving to strike portions of the prepared rebuttal testimony and exhibits of BP Witness Crowe, it declined to do so. In addition, under the ALJ's January 11, 2005 order establishing the procedural schedule, Kern River was provided the opportunity to perform discovery on rebuttal evidence, including that of RCG Witness Doering, by April 8, 2005. Thus, Kern River had an opportunity to explore the bases of Doering's testimony in order to help prepare a response. In its prehearing brief of August 12, 2005, RCG gave further notice of its intent to pursue this issue, reiterating Doering's testimony that "Kern River has, and will continue to significantly overrecover its costs if the 3% inflation factor is permitted," and "that even if Kern River did experience 3% inflation, which it has not, it would still overrecover its costs, because Kern River has continued to file rate cases over the years and upwardly adjusted its O&M and A&G costs in such rate filings (which has taken account of inflation)," calling the 3 percent inflation factor unjust and unreasonable.[115] Kern River had the opportunity to question RCG's witness Doering or to present additional evidence on this issue through its own witness Warner at the hearing in August 2005. However, Kern River failed to do so. As is clear from the record, while Kern River was provided with plenty of opportunities to present both written and oral testimony regarding its need to account for any existing over-recovery, it chose for the most part to remain silent on the matter.

110. When Kern River finally presented evidence on this issue, in a post-hearing reply brief filed October 27, 2005, Kern River never claimed that such an evidentiary burden was new or raised any due process issues. In its reply brief, Kern River stated that over-recovery was not occurring because it had historically been experiencing an increase of operating costs by an average of 3 percent annually.[116] Kern River also suggested that, even if over-recovery was occurring, several features of its levelization methodology actually caused Kern River to under-recover its costs, implying, as it did in its rehearing request, that an averaging occurs.[117] Clearly, the record refutes Kern River's claims that a new evidentiary standard is being applied and that its due process rights have been violated by not having notice and opportunity to present evidence on this standard.

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[114] *Id.* at 29. *See also* Ex. RCG-23.
[115] RCG Prehearing Brief at 20.
[116] Kern River Reply Brief at 37.
[117] *Id.* at 37-38.

111. Under these circumstances, *Hatch v. FERC*, which is relied on by Kern River, does not require the Commission to provide Kern River an additional opportunity to present evidence on the three percent inflation factor issue. That case involved a petitioner's application under section 305(b) of the Federal Power Act for authorization to hold interlocking directorates. The court held that for forty years the Commission had granted such applications absent a showing that the interlocking directorate would have specific adverse effects. The petitioner presented his case at hearing under that standard. However, the Commission denied the application, applying a new standard that the applicant must show that the interlocking directorate will provide a clear overriding public benefit The court remanded the case, finding that, while the Commission had the discretion to apply a new standard of proof in denying petitioner Hatch's application to hold interlocking directorates, the Commission failed to offer an adequate explanation for adopting the changed standard and to give adequate notice to the petitioner and to provide the petitioner an opportunity to supplement the record with evidence relevant to the standard.

112. Unlike the situation in *Hatch v. FERC,* the present situation does not deal with a change to a standard that has been in place for decades. "[I]n 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 in effect for a period of time, did not arise."[118] Additionally, until the present section 4 rate case, this issue had not been addressed on the merits in Kern River's previous section 4 rate cases, as those cases had settled.[119] As a result, the issue of how to determine the inflation adjustment in a section 4 rate case is largely one of first impression. In this situation, the Commission may adopt a party's position as to what showing is needed. When the Commission makes such an adoption, it is not required to provide further opportunity to present evidence as the parties will have already had opportunity to present evidence during the course of discovery, the hearing, and filing briefs.

113. Therefore, the Commission rejects Kern River's request to reopen the record in this proceeding. There has already been a full hearing before an ALJ in this proceeding, with all parties having an opportunity for discovery and presentation of evidence. Additionally, as discussed previously, Kern River has had sufficient notice and opportunity to meet its burden to show that its proposal must take into account any existing excess recovery of A&G and O&M costs and that it must support its projection of the amount of inflation that will occur over the remainder of the levelization period. The Commission will not delay resolution of this proceeding by reopening the record for further presentation of evidence.

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[118] Opinion No. 486 at P 100.

[119] *Id.* at n.169.

114. Aside from its due process arguments, Kern River also contests on the merits the requirement that it take into account any existing excess recovery of A&G and O&M costs. Kern River does not take issue with Opinion No. 486's finding that 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. 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. However, Kern River contends any over-recovery that does occur will be offset by the averaging that occurs within the levelization calculations. Kern River points out that rate base and return allowance are significantly lower in the early years of the levelization period, than under a traditional cost of service due to the averaging calculations. It asserts that the Commission has never required ratepayers to account in rates paid to Kern River for the "early year 'underages' in these cost of service components."[120] Kern River claims that the Commission had provided no justification why Kern River's A&G and O&M costs should be treated differently from other aspects of Kern River's overall cost-of-service.

115. Contrary to Kern River's assertions, Kern River's levelization methodology does require ratepayers to account in rates for early year underages in Kern River's recovery of its return on equity and rate base. As described in Opinion No. 486, Kern River keeps track of those underages through the creation of regulatory assets. When it files a rate case during the early years of the levelization period, those regulatory assets permit Kern River to carry forward the past underages and include them in its new rates. By contrast, Kern River uses no similar method to account for overrecoveries of A&G and O&M during the early years of the levelization period. This guarantees that the A&G and O&M amounts it has overrecovered in the early years of the current levelization period will be retained. Such an overrecovery is guaranteed because, in order to start the new levelization period, the old levelization period is cut short before later year underrecoveries are realized and can balance out early year overrecoveries. The new levelization period averages the costs projected to occur during the levelization period and does not cover prior overrecovered costs. In short, Kern River is seeking to treat the various components of its cost of service differently, with early year underrecoveries of certain cost-of-service components carried forward and reflected in rates, while early year overrecoveries of other cost-of-service components are not carried forward but instead are retained by Kern River. We have simply held that Kern River must account for both the under and over recoveries.

116. Kern River does not contest that it filed this rate case during the early part of the relevant levelization period. For example, it does not contest the testimony of RCG's

[120] Kern River rehearing request at 35.

witness that the 15-year 2003 Expansion Shippers have 13.5 years remaining in their contracts. Additionally, 15-year 2002 Expansion Shippers and Original System shippers have approximately 12 years remaining on their contracts while 10-year Shippers for all systems have over 5 years remaining on their contracts.[121] Thus, there was clearly a need for Kern River to show that its proposal take into account existing over-recoveries. Yet despite having sufficient notice of this issue, Kern River failed to do so. Without this demonstration by Kern River, we cannot determine how much is currently being over-recovered and how much future inflation is being offset by such over-recovery. Further, the current level of over-recovery may be enough to compensate Kern River for most, if not all, future inflation. For this reason alone, there is no basis in the record to allow any inflation adjustment. Even if Kern River were to adequately support a future projection for inflation to its costs, which it has not done here, without a demonstration to account for overrecoveries we would be unable to allow an inflation adjustment. In its next section 4 rate case if Kern River were to request an inflation adjustment this demonstration to account for overrecoveries will be necessary and required of Kern River.

117. In Opinion No. 486, the Commission found two flaws in Kern River's projection of future inflation in its A&G and O&M costs. Kern River compared system O&M and A&G expenses included in its 1993 rate case 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. It then adjusted the current A&G and O&M costs to account for increased costs related to post-1993 expansions. The Commission found that the adjustment appeared insufficient, because (1) Kern River's witness proposed no adjustment to account for increased costs related to the CAP and 2002 rolled-in expansion projects, and (2) 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.

118. In its rehearing request, Kern River demonstrates that its failure to remove the minor O&M and A&G costs for the CAP or 2002 Expansion Project from the total only reduces its annual inflation rate projection from 2.86 percent to 2.62 percent.[122] In addition, reiterating arguments from its Brief on Exceptions, Kern River attempts to justify its failure to remove the A&G costs related to the 2003 Expansion Project by claiming that an analysis of its FERC Form 2 data shows that "there is no incremental A&G associated with the 2003 Expansion."[123] This analysis, which compares the total O&M and A&G expenses incurred just before the 2003 Expansion went into operation with those incurred after the 2003 Expansion had been operating for a full year, shows an

[121] Ex. KR-45 at 4, 7.

[122] *See* Kern River rehearing request at 37, showing its derivation of this revised estimate based on information in Ex. KR-26.

[123] Kern River rehearing request at 38.

increase of $7.1 million in Kern River's total system O&M and A&G costs.[124] Because this amount is less than the $7.5 million which Warner removed from the current, total system O&M and A&G in his inflation study, Kern River states that Warner's adjustment was appropriate. However, Kern River did not present the relevant Form 2 data at the hearing, but only included the data in its Brief on Exceptions filed after the record closed. Thus, the other parties had no opportunity to contest these assertions at hearing. As the ALJ noted, Kern River had an opportunity to address the issue of the appropriate adjustment to A&G costs to reflect the 2003 Expansion Project prior to the issuance of the Initial Decision, but did not do so.[125] Instead, Kern River chose to revise its evidence for the first time in its Brief on Exceptions. Therefore, even accepting Kern River's argument that the record contains sufficient evidence to remove the minor A&G and O&M costs related to the CAP and 2002 Rolled-in Expansion, it lacks sufficient evidence to show an appropriate adjustment to A&G expenses to ensure that increased A&G costs related to the 2003 Expansion are removed. The Commission thus reaffirms that Kern River has failed to support its projection that future inflation of A&G and O&M costs will be 3 percent.

119. Therefore, the exhibits in the record fail to provide the necessary justification for a 3 percent inflation factor for the proposed levelization period. Kern River discusses its 10-year Business Plan, included in the record as Exhibit No. BP-11 (Protected), to attempt to demonstrate that "an average inflation rate of 2.44 can be computed."[126] Kern River further cites to Exhibit No. RCG-1 as evidence that, "since 1992 the rate of inflation, as reflected by the Consumer Price Index (CPI), has been between 3.4 and 1.6 percent)." However, neither of these exhibits provides support for the amount of inflation that will occur for Kern River's O&M and A&G costs over the levelization period. Exhibit No. BP-11, as a ten-year business plan for Kern River, is merely a forecast of the A&G and O&M expenses that Kern River expects to incur and does not provide any actual data to justify that inflation rate. Kern River has not shown that the CPI is a good indicator of how Kern River's A&G and O&M costs may increase. The CPI reflects the average change in the prices paid by urban consumers for a market basket of consumer goods and services. Those goods and services, such as food, housing, transportation, medical, and entertainment expenses, are quite different from Kern River's A&G and O&M costs. Kern River has provided no evidence to support a conclusion that the CPI's basket of goods and services experience the same inflation factor as Kern River's A&G and O&M costs.

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[124] Kern River cites to its Brief on Exceptions, Appendix 4 at 1.

[125] Initial Decision at P 445.

[126] Kern River rehearing request at 39.

120. Kern River erroneously argues that the Commission's denial of any inflation adjustment is contrary to controlling precedent.[127] As we stated in Opinion No. 486, an inflation factor may be considered a part of Kern River's approved levelized rate methodology, just as the Commission held in *Mojave*. However, while we recognize that an inflation factor may be included as part of Kern River's proposal, that does not require us to automatically grant a particular inflation factor. Additionally, *Mojave* only demonstrates that an inflation factor may be appropriate where a reasonable projection for inflation is provided. As Kern River has acknowledged and we have repeatedly stated, Kern River must demonstrate that its proposed 3 percent inflation factor is justified. The Commission has never found the 3 percent inflation factor to be a permanent feature of Kern River's rates without the necessity for Kern River to support its projection of inflation. Instead, the Commission has merely approved various settlements for which the Commission has never reached the merits of the 3 percent inflation factor issue.[128] Therefore, there is no controlling precedent on this issue which requires that we grant Kern River's proposed 3 percent inflation factor.

121. Finally, Kern River asserts that our rulings with respect to both the 95 percent load factor condition and the inflation adjustment factor have effectively reduced its allowed return on equity from the 11.2 percent granted in Opinion No. 486 to 9.88 percent. Kern River arrives at the 9.88 percent figure by using a rate base determined under the traditional method of calculating rate base, rather than the *Ozark* method it agreed to use in its original certificate proceeding. As described in the section of this order discussing capital structure, the *Ozark* method of determining rate base generally results in a somewhat lower rate base, than the traditional method. In Appendix 1 of its rehearing request, Kern River shows that the dollar amount of its return on equity calculated based upon 11.2 percent of the equity portion of its *Ozark* rate base would only be the equivalent of a 9.88 percent return on equity on the equity portion of a higher, traditional rate base. Kern River argues that its proposed inflation adjustment factor, together with its proposal to design its rates based upon 95 percent of its design capacity, gave it an opportunity to offset the lower actual return resulting from its use of the *Ozark* method, and that by rejecting these proposals the Commission has modified the original levelized rate package agreed to in the certificate proceeding.

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[127] *Mojave Pipeline Company*, 81 FERC ¶ 61,150 at 61,680 (which affirmed the ALJ's ruling that a reduction of Mojave's annual O&M escalation factor from 5 percent to 3 percent was justified).

[128] The uncontested individual components of a contested settlement are not precedential since the Commission only reaches the merits of contested issues and not uncontested issues. Orders approving uncontested settlements are not precedential. *See Florida Power Corp.*, 70 FERC ¶ 61,321, at 61,980 (1995).

122. Kern River points to no language in its certificate orders or subsequent Commission orders on its levelized rates to suggest that its use of the *Ozark* method was tied to either (1) its interpretation of the 95 percent load factor condition or (2) its ability to base the inflation adjustment factor in each section 4 rate case solely on future inflation, without regard to existing excess recoveries of A&G and O&M costs. We have already explained why our actions with regard to the 95 percent load factor condition and the inflation adjustment factor are consistent with the original levelized rate package. That package also included the use of the *Ozark* method to determine rate base. To the extent use of that method reduces the dollar amount of Kern River's return on equity below what it would be if its rate base were determined under a traditional method, that fact is consistent with the agreed-upon levelized rate structure.

D. Capital Structure

123. We now turn to the issue of how to determine Kern River's capital structure in light of its levelized method of determining rates, which the Commission accepted in Opinion No. 486 and reaffirms here. However, before addressing the contentions raised on rehearing, we first clarify the nature of the issue and the terminology that has been used to described the issue both in Kern River's certificate proceeding and in Opinion No. 486.

124. Kern River's original capitalization consisted of 70 percent debt and 30 percent equity. Kern River's original and current agreements with its debt providers require it to pay off all of its debt on or before the termination dates of its current firm shippers' contracts.[129] Accordingly, both in the certificate proceeding and in the ET Settlement, the parties agreed that Kern River's levelized rates would recover approximately 70 percent of its invested capital (the amount financed by debt) during the term of the shippers' current contracts, which we have labeled Period One. This would provide Kern River the funds necessary to satisfy its contractual obligation to its debt providers to repay that debt over the terms of the firm shippers' current contracts.

125. Because Kern River would devote essentially 100 percent of its depreciation recovery during Period One to retiring its debt, its original 70/30 debt/equity capitalization would not be maintained throughout the life of the pipeline. Rather, each year during Period One, the debt percentage of Kern River's capital would decline as Kern River paid off its debt, and the equity percentage would increase. As a result, at the end of Period One when the current contracts expire, Kern River would no longer have any debt and would be capitalized with 100 percent equity.

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[129] Ex. KR-23 at 42-43.

126. Consistent with these facts, the Commission held, in the certificate proceeding, that Kern River's Period One rates should not be designed based upon the assumption that the original 70/30 debt equity ratio would remain constant throughout the life of the project, but should be designed based upon this projected change in its debt/equity ratio during Period One.[130] In the certificate proceeding and Opinion No. 486, the Commission loosely described the requirement that Kern River design its Period One rates in this manner as a requirement that Kern River use the *Ozark* method to determine its capital structure. That was not correct. Kern River's use of the *Ozark* method to determine the equity portion of its rate base is a separate capital structure issue unrelated to its levelized rate methodology.

127. The *Ozark* method of determining capital structure originated in *Ozark Gas Transmission System*,[131] a case involving a project-financed pipeline whose rates were designed to pass through its actual cost of debt on a monthly basis. In *Ozark* and subsequent cases,[132] the Commission has held that pipelines with special rate mechanisms to guarantee recovery of debt must calculate the equity portion of their rate base in a different manner than is traditionally used to divide rate base between debt and equity. As explained in *WIC*,[133] a pipeline's rate base is generally less than the pipeline's actual capitalization. That is because the rate base comprises only a portion of the pipeline's net assets. Traditionally, a pipeline's rate base is divided between debt and equity based on the same percentages of debt and equity as the pipeline's overall capitalization. However, under the *Ozark* method, the equity rate base is calculated by subtracting from rate base the entire dollar amount of the debt included in the pipeline's actual capitalization, which the company is assured of recovering.[134] As illustrated by the numerical examples in *WIC*, the *Ozark* method generally results in a lower equity rate base than the traditional method, and thus benefits the rate payers by accurately reflecting equity return included in the pipeline's rates.

128. As the Commission explained in *WIC*,[135] "the use of the *Ozark* method is not dependent on the use of levelized rates. As we have stated previously, the use of the *Ozark* method is appropriate for project-financed pipelines that are assured rate recovery of their debt costs. It ensures that the allowed return on rate base will not exceed a reasonable level. In contrast, rate levelization is a method of determining an appropriate

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[130] *Kern River Gas Transmission Co.*, 60 FERC ¶ 61,123, at 61,436-7 (1992).

[131] *Ozark Gas Transmission System*, 53 FERC ¶ 61, 451 (1990) (*Ozark)*.

[132] *See Trailblazer Pipeline Co.*, 50 FERC ¶ 61,188, *Overthrust Pipeline Co.*, 53 FERC ¶ 61,118 (1990), and *Wyoming Interstate Pipeline Co.*, 69 FERC ¶ 61,259 (1994).

[133] *Wyoming Interstate Company Ltd.*, 69 FERC at 61,984-5 (1994).

[134] Deferred taxes are also subtracted in the same manner.

[135] *Wyoming Interstate Company Ltd.*, 69 FERC at 61,987-8.

pattern of *recovery* of a company's cost-of-service, including its return on rate base (however that return is determined)." Thus, the *Ozark* method has been used to determine an equity-only rate base both for pipelines without levelized rates, as in *Ozark* and *WIC*, and for pipelines with levelized rates, as in *Trailblazer* and *Overthrust*. Because Kern River's rates are designed to recover the entire debt portion of its capitalization during the terms of its firm shippers' current contracts, Kern River has consistently used the *Ozark* method to calculate the equity portion of its rate base to be used in determining its levelized rates.

129. In this rate case, Kern River proposed to continue to reflect in its Period One levelized rates the forecasted changes in its capital structure during the period those rates would be in effect, rather than simply using its end of test period capital structure. It also proposed to continue to use the *Ozark* method of determining each year's equity-only rate base. Several parties, including BP, contended that the Commission should require Kern River to use its end of test period capital structure, which consisted of 38.73 equity for the entire levelization period. Parties also asserted that Kern River had applied the *Ozark* method incorrectly. As discussed below, the Commission affirms its acceptance of Kern River's reflection of the forecasted change in its capital structure as part of Kern River's levelized rates and finds that Kern River's application of the *Ozark* method was reasonable.

<u>Opinion No. 486</u>

130. In Opinion No. 486,[136] the Commission found that Kern River's application of the equity rate base, or Ozark methodology for determining rate base, known as the equity only rate base, was consistent with its prior rules in *Ozark* and *Mojave* [137] because, as in those cases, one hundred percent of Kern River's debt is used to finance rate base. It noted that the *Ozark* method is valid for Kern River since all of Kern River's 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.[138] It also noted that Kern River's models anticipated 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 and that equity repayment is deferred until after the obligations of the debt indenture are satisfied, that is, paid in full within the required loan period.[139]

[136] Opinion No. 486 at P 110.

[137] *Citing Mojave Pipeline Co*., 81 FERC ¶ 61,150, at 61,681-83 (1997).

[138] Opinion No. 486 at P 112.

[139] *Id., citing* Ex. KR-50 at 23-24; *Kern River Gas Transmission Co.,* OC Rate Order, 50 FERC at 61,150.

131. Specifically, the Commission found Kern River's application of the *Ozark* methodology in this rate case appropriate and consistent with its rulings in Kern River's certificate proceeding.[140] It also found that Kern River's application of the *Ozark* methodology is consistent with the equity rate base methodology in the *Ozark*[141] and *Mojave*[142] proceedings where the pipeline is one hundred percent financed with debt exclusive to its operations and expansion projects.

132. Additionally, the Commission found that application of a traditional cost-of-service methodology in this case would improperly increase shippers' rates from the pricing model originally adopted by the Commission in the certificate proceeding. It found Kern River had shown, upon comparison of comparable cost data, that a traditional cost-of-service as proposed by Staff was approximately $40 million greater than Kern River's levelized cost-of-service.[143]

133. The Commission rejected arguments that Kern River was overcollecting its debt because it was recovering more in depreciation than it must pay out on debt on an annual basis.[144] It found that Kern River properly reflected deferrals as regulatory assets. It stated that this concept is fundamental to Kern River's over-all levelized rate methodology and recovery in rates over the entire levelization period and cited the section of Opinion No. 486 concerning Levelized Rates/Levelized Cost of Service.[145] The Commission found Kern River had presented several studies that demonstrated that its levelization models reasonably reflected the collection of the deferred costs and therefore produced just and reasonable results.[146]

134. The Commission also stated it had previously addressed the question of using the actual end-of-test period capitalization amount as opposed to an average capital structure and had 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 is repaid.[147] The Commission found the opposing parties had not shown any changed

[140] *Id.* at P 113, *citing Kern River Gas Transmission Co.*, 60 FERC ¶ 61,123 at 61,437.

[141] *Ozark*, 53 FERC ¶ 61,451 (1990).

[142] *Mojave Pipeline Company*, 81 FERC at 61,681-83.

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

[144] Opinion No. 486 at P 116.

[145] *Id.* P 19-120.

[146] *Citing* Exs. KR-23 (public); KR-24; KR-27; KR-34; KR-50.

[147] Opinion No. 486 at P 117 *citing Kern River Gas Transmission Co.*, 60 FERC ¶ 61,123, at 61,437 (1992).

circumstances that would require it to depart from its prior ruling. The Commission noted 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.[148] It found that Kern River's continued application of the model approved in the certificate proceeding properly reflects to each customer class the appropriate costs and impacts while the debt is being repaid. As such, the Commission found that Kern River's projected capital ratios are an accurate reflection of the costs and therefore are reasonable for use in its levelization model.

i. Capitalization to be Used – Forecasted Increase in Equity Ratio versus Actual End of Test Period Amount

Rehearing Requests

135. On rehearing, BP asserts that the Commission erred in approving Kern River's proposed capital structure reflecting the forecasted increase in its equity ratio during Period One. It asserts that this hypothetical capital structure consists of a 100 percent equity ratio by the end of the levelization period.[149] BP asserts that Kern River's levelized rates are premised on this hypothetical capital structure.[150]

136. BP contends that both the alleged imputed hypothetical capital structure and the use of an average capital structure are inappropriate because Kern River will not have a 100 percent equity ratio by the end of the levelization period. BP asserts this is so because Kern River's collection of debt will not be used to pay debt principal first and pay down Kern River's debt by the end of the shippers' contract terms. BP asserts that, instead, Kern River will roll over its balloon debt repayments, use shipper revenues to repay a portion of its existing equity investment, and maintain an overall equity ratio of 55-60 percent after the expiration of current shipper contracts (i.e., after Period One).[151] In addition, BP states that Kern River's owners have already cashed out over $40 million

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[148] *See* Exs. KR-23 at 41; KR-27.

[149] *Citing* BP-27 at 16:27-17:9.

[150] BP asserts, in addition, that a hypothetical capital structure is inconsistent with Commission policy unless debt is issued for a pipeline with the guarantee of its parent corporation. BP states none of Kern River's debt is obligations of or guaranteed by partners in Kern River or by MEHC. BP cites *Transcontinental Gas Pipe Line Corp.*, 60 FERC ¶ 61,246, at 61,823 (1992), *aff'd*, 64 FERC ¶ 61,039 (1993), *rev'd and remanded on other grounds, North Carolina Utilities Comm'n v. FERC*, 42 F.3d 659 (D.C. Cir. 1994) and also *Transcontinental Gas Pipe Line Corp.*, 90 FERC ¶ 61,279, at 61,296-27 (2000); *Michigan Gas Storage co.,* 87 FERC ¶ 61,038, at 61,153-57 (1999).

[151] *Citing* Ex. BP 24 at 3; Ex. BP-43 at 2.

of the prior equity investment and ultimately will take out $143 million in equity recoupment before the shippers' present contract terms have expired.[152]

137. BP also asserts that the alleged hypothetical capital structure incorporated in Kern River's levelized rates presumes a far greater degree of equity financing than is likely for any year during the levelized period. It asserts that, as a result, use of the *Ozark* method of adjusting the capital structure will provide a windfall for Kern River if levelized rates continue to be used. It states that Kern River would be compensated at the cost of equity, at least 11.2 percent, for $300 million in capital when that amount of capitalization was actually funded by debt with a much lower cost of capital, 6.2 percent. BP estimates the result is an excess recovery of $35 million annually to Kern River.

138. BP states that the fact that the average equity ratio of 38.01 percent used in Kern River's levelization models is lower than the actual, end-of-test period book equity ratio of 38.73 percent[153] does not justify the use of a rate derivation method that is reliant on a hypothetical capital structure. BP states that Kern River has not, in fact, calculated an average equity ratio. It states that, instead, Kern River's calculation represents a comparison of the total dollar level of equity capitalization during the levelization period, which, BP asserts, is far different than the equity portion of capital structure. BP claims the average of the equity percentages across the levelization period is 69 percent. It implies that Kern River should be averaging equity percentages over a range that begins at 38.73 percent and rises to 100 percent, and that, therefore, a resulting average of 38.01 percent is incorrect.

139. BP states that Kern River's departure from its original projections presuming 100 percent equity financing at the respective contracts' ends constitutes changed circumstances from the Commission's rulings in Kern River's certificate proceeding. It states that these changed circumstances require the Commission to depart from its holdings in Opinion No. 486[154] and prior orders that use of the actual end-of-test period capitalization is inappropriate. BP also asserts that failure to achieve a 100 percent equity rate base warrants reversing the Commission's alleged holding in Opinion No. 486 that use of an average capital structure with 38.01 percent equity for Period One properly reflects changes in the capitalization that will occur over the time the debt used to finance Kern River's system is repaid. BP asserts that the actual end of test period capital structure should be applied (e.g., throughout the levelization period) for purposes of calculating rates.

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[152] *Citing* Ex. BP-42 at 11:10-13 and also Ex. S-12 at 18:19-20:2; Ex. BP-27 at 20:18-21:6.

[153] Opinion No. 486 at P 107.

[154] *Id. at* P 117.

Commission Determination

140. The Commission rejects BP's request to use the end-of-test-period capital structure for the same reason that it has rejected BP's request to require Kern River to use traditional ratemaking in place of its existing levelized rate structure. Use of a projected changing capital structure has been part of Kern River's levelized rates since the certificate proceeding and thus part of the risk sharing agreement that we have held should remain in place.[155] In the August 1992 rehearing order in Kern River's certificate proceeding, the Commission expressly held that the forecasted change in capital structure should be included in levelized rates and rejected use of a day-one capital structure.[156] Similarly, the Commission held in a section 4 rate case of Mojave Pipeline Co., which received an optional expedited certificate at the same time as Kern River, that the changing capital structure was part of the original risk sharing agreement and should be continued in the subsequent rate case.[157] In *Mojave,*[158] the Commission pointed out that in the certificate proceeding the Commission held that it had erred in originally approving rates which maintained Mojave's 70/30 debt equity ratio throughout the life of the project and concluded that the levelized rates should reflect the changing capital structure.[159] Accordingly, accepting BP's request to use the end-of-test-period capital structure for the entire levelized period would be contrary to the risk sharing agreement underlying Kern River's rates and contrary to the certificate order and to the precedent established in *Mojave*.

141. BP also contends that Kern River's use of forecasted increases in equity rate base and its resulting average capital structure are inappropriate because Kern River will not have a 100 percent equity ratio by the end of the levelization period. BP claims that Kern River does not actually plan to pay off all its debt in Period One but will, instead, roll over its balloon debt repayments and maintain an overall equity ratio of 55-60 percent after the expiration of current shipper contracts. The Commission rejects this argument. While Kern River uses levelized rates requiring projections of future changes in rate base, those projections still have to be made based upon actual experience during the test period, including relevant contracts that were in effect during the test period. That is, Kern River must base its rates on twelve months of the most recent historical data (the base period), adjusted for known and measurable changes "which will become

[155] *Id.* at P 37-39.

[156] *Kern River Gas Transmission Co.,* 60 FERC ¶ 61,123 at 61,437.

[157] *Id.*

[158] *Id.* at 61,682.

[159] *Id., citing Kern River Transmission Company and Mojave Pipeline Company,* 60 FERC ¶ 61,123, at 61,437 (1992).

effective within" the following nine months (the adjustment period).[160] Kern River cannot base its rates on speculative changes in its contracts with its lenders that will not occur until after the test period and may never occur.

142. The record shows that, continuing to the present, Kern River has a contractual obligation to pay off all debt by the end of the shippers' current contracts.[161] Therefore, in this rate case it is appropriate to project that Kern River will pay off all its debt as required by its current agreements with its lenders and therefore project that Kern River's capital structure will change accordingly. Kern River has said it might seek to alter those agreements or issue more debt, but that is speculative. Kern River testified that "[w]hether it will be prudent to roll-over the entire balloon amounts, to pay them off permanently, or to do something in between, will depend on the magnitude and quality of the recontracting of system transportation capacity that is accomplished at that time."[162] Kern River further testified that it was presently unknown whether any of the debt would be refinanced and that it would depend on a number of factors.[163] In Ex. BP-43, which BP cites, Kern River states that it had in the past projected equity and debt ratios of 55 to 60 percent equity and 45 to 40 percent debt, but that the projection assumed that Kern River would fully re-contract its system which may or may not occur. Thus this exhibit outlines a plan to roll over balloon debt payments into a new debt issuance once levelization periods are completed, but such a refinancing has not taken place and there is uncertainty as to whether or when it will take place. Even if Kern River undertakes the refinancing, it does not intend to do so until the end of Period One.

143. In addition, the Commission rejects BP's arguments that future refinancing and the resulting capital structure require the use of the end-of-test-period capital structure rather than levelized rates for the reasons stated in Opinion No. 486.[164] As we stated in Opinion No. 486, "regardless of whether debt or equity is to be paid down through the collection

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[160] 18 C.F.R. § 154.303(a)(4) (2006). *See Mojave*, 81 FERC at 61,679-80, applying the test period regulations in the context of determining Mojave's levelized rates.

[161] Ex. KR-23 at 42 ("Kern River will repay all of its existing long-term debt prior to or at the end of the levelization periods for the Rolled-In system and the 2003 Expansion. In fact, full repayment of each debt issue is required by the debt covenants by no later than the end of the existing shippers' contracts. This was also the case under Kern River's original debt financing and thus was an assumption underlying the original levelized rate design. . . .") and at 43 ("Kern River is contractually bound to repay all of its debt within the levelization periods."); KR-28 (showing balloon payment due dates and termination dates for 15 year ET and 2003 Expansion shippers).

[162] Ex. KR-23 at 43.

[163] *Id.*

[164] Opinion No. 486 at P 49-50.

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." [165] The Commission also rejected BP's arguments concerning refinancing because the step-down, Period Two rates available to shippers upon termination of their contracts that are calculated in this case will "only be calculated based upon the 30 percent of the costs corresponding to the equity Kern River used to finance its system."[166] The Commission noted that 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."[167]

144. BP states Kern River used an average equity ratio of 38.01 percent in its levelization models for all customer groups and that instead of 38.01 percent, this average should be 69 percent, the average of a range that begins at 38.73 percent and rises to 100 percent. BP is mistaken. The 38.01 percent average equity ratio to which BP refers was the result of a study in which Kern River combined all of the debt and equity only rate base ratios for the different customer groups.[168] Kern River did not use this figure to calculate rates. Instead it calculated separate average equity only rate bases and ratios to calculate levelized rates for each customer group.[169]

145. In addition, 38.01 percent is the correct average of the equity percentages for all customers across the levelization periods.[170] BP's figure of 69.0 percent is incorrect. The average equity ratio for all customer classes is 38.01 for a number of reasons. First, Kern River's models begin with an overall equity ratio of 33.0 percent rather than the actual end of test period equity ratio of 38.73 percent.[171] The appropriateness of Kern River's models is discussed below. Second, the equity ratios for the customer groups do not increase evenly over all of the years in a levelization period. Some increase only slowly in the early years.[172] This is due, in part, to the fact that Accumulated Deferred

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[165] *Id.* at P 49 (footnote omitted).

[166] Opinion No. 486 at P 50, P 54.

[167] Opinion No. 486 at P 49, n.90, *citing Kern River Gas Transmission Company*, 50 FERC ¶ 61,069, at [61,150] (1990).

[168] Ex. KR-27.

[169] *See* "Average Equity Rate Base," Schedule J-2 at 5-6, 10, 16-17, 25, 31-32, and 41, Ex. KR-94.

[170] Ex. KR-27.

[171] *Id.*, 11/1/2004, cols. 48 and 56.

[172] *See* "AVERAGE EQUITY RATE BASE," Schedule J-2 at 5-6, 10, 16-17, 25, 31-32, and 41, Ex. KR-94.

Income Taxes (ADIT) are also removed from rate base to derive the equity only rate base. The amount of ADIT increases for some customer groups each year during the early years, thus lowering the amount of equity only rate base during those years.[173] The debt and equity ratios thus remain practically the same in the early years for those customer groups. Only in the later years do these equity ratios, and hence the average of these ratios, increase significantly.

146. Finally, the Commission rejects BP's contention that the Commission has approved a hypothetical capital structure for Kern River. In traditional cost-of-service ratemaking, the Commission sometimes imputes a hypothetical capital structure to a pipeline. This occurs when the Commission finds that a pipeline's actual capital structure is anomalous, for example because the pipeline has an atypically high equity ratio.[174] In this case, however, the pipeline is not using traditional cost-of-service ratemaking and the principles concerning the use of a hypothetical capital structure in traditional cost-of-service ratemaking do not apply. In this case, the Commission has approved the recovery of the debt-financed portion of rate base over the terms of the shippers' contracts through the use of levelized rates and the deferral of the recovery of the equity-financed portion of rate base. All of Kern River's depreciation recovery during Period One is devoted to retiring its debt. This means that its original 70/30 debt/equity capitalization is not maintained through the life of the pipeline and, instead, that the debt percentage declines as Kern River collects the depreciation for its debt-financed plant and the equity percentage increases. The debt and equity ratios at the end of Period One are the result of the recovery of only debt-related depreciation during Period One. They are not an imputed hypothetical capital structure. To the contrary, the Commission is simply projecting what Kern River's actual capital structure will be during the course of Period One.

ii. <u>Application of the Ozark Method</u>

147. BP also states that Kern River does not accurately apply the *Ozark* method. BP asserts that under the *Ozark* method of adjusting capital structure, an entity's equity capitalization is calculated by deducting the outstanding debt principal from total rate base. BP states that, instead, Kern River has deducted the accumulated depreciation, rather than debt repayment, from total rate base to determine equity capitalization. BP states that, consequently, contrary to Opinion No. 486,[175] Kern River's method of

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[173] *See* "AVG ACCM DEF INCOME TAXES," Schedule J-2 at 5-6, 10, 16-17, 25, 31-32, and 41, Ex. KR-94.

[174] *See Transcontinental Gas Pipe Line Corp.*, 84 FERC ¶ 61,084, at 61,413-5 (1998), and cases cited in n.27 of that order.

[175] Opinion No. 486 at P 110.

adjusting capital structure is not consistent with *Mojave*[176] and *Ozark*. BP asserts that this *Mojave* order and *Ozark* deducted debt as opposed to Kern River's deduction of accumulated depreciation. For this reason as well, BP states the approval of Kern River's application of the Ozark method is in error and should be reversed.

148. The Commission continues to find that Kern River's methodology is consistent with the equity rate base methodology in the *Ozark* and *Mojave* proceedings. In calculating the equity-only rate base, Kern River first deducted accumulated depreciation to obtain net plant.[177] This is consistent with the Commission's method for determining net plant. Kern River then made further adjustments, such as subtracting ADIT, to obtain the total average rate base. Kern River then subtracted what is identified as "the average outstanding debt"[178] from the total average rate base to obtain the average equity rate base.[179]

149. With respect to the subtraction of debt from rate base, Kern River testified that the rate models have never reflected the actual debt amortization schedules entered into as Kern River has financed its debt from time to time.[180] It explained the reflection of debt repayments in the levelized rate models as follows:

> The debt repayments reflected in the levelized rate models, using the Ozark rate design methodology, are a function of the levelization methodology itself, the beginning actual debt balances (excluding amounts related to debt-financed swaps and fees) and the 70 percent of investment depreciation assumption. The amortization schedules for the debt within the models reflect the iterative mathematics in the models, such as an average year rate base and debt and equity ratio calculations in which regulatory depreciation reduces the calculated debt balances. The model depreciation amounts (which are reflected as debt principal repayments in the models) are a function of the goal of calculating a level cost of service within the constraints of the other non-depreciation –related costs (such as the balances for accumulated deferred income taxes, O&M and A&G expense, property taxes, etc.) within the models. [181]

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[176] *Mojave Pipeline Company*, 81 FERC at 61,681-83 (1997).

[177] *See, e.g.* Schedule J-2 at 5, lines 1, 2, and 3, cols. (c) – (n), Ex. KR-94 and Item by Reference A.

[178] *See e.g. id.*, line 13.

[179] *Id.*, lines 12, 13, and 14.

[180] Ex. KR-32.

[181] *Id. See also* Ex. KR-23 at 43-46.

Kern River also testified that the levelization calculations are intended to keep track of the recovery of Kern River's investment in rate base, a cost recovery from shippers' concept, to permit the pipeline to recover the proper returns and income taxes on unrecovered rate base.[182] It testified that the levelization calculations are not intended to reflect the actual timing of the payments of debt principal, a timing of payments to lenders concept. Kern River testified that the timing of the debt payments in the models, compared to the debt payments in the debt amortization schedules, is a temporary timing difference.[183] It stated that the models reflect repayment of all of the actual debt, with one minor exception, by the end of the shippers' contracts, just as is required by the debt amortization schedules.[184] Kern River testified further that the major variances between the models' timing and the amortization schedule occur near the end of the shippers' contracts, when rate base is smallest, so differences at that point have less potential to affect rates than they would if they occurred in earlier years.[185] Kern River also testified that "the levelization models cannot include a changing capital structure that is based on the projected actual debt balances that will be outstanding, because the debt principal is paid monthly, whereas rate calculations are performed on an annual basis."[186]

150. The Commission finds that Kern River's method for calculating its equity capitalization is reasonable and in keeping both with the *Ozark* method and with the calculations upon which Kern River's rates have been based since it was certificated. From Kern River's testimony, it appears that it subtracted depreciation amounts rather than actual debt repayments from its debt balance each year. That is, Kern River assumed that the amount of depreciation it calculates for each year in the levelized cost of service is equal to the annual debt principal repayment and it then subtracted the depreciation amount from the outstanding debt balance. The Commission finds Kern River has provided a reasonable basis for using depreciation instead of actual debt repayments to reduce its debt balance and ultimately derive the equity rate base. Kern River has shown that the annual depreciation amount reasonably represents the amount of debt that must be subtracted each year from the debt balance. It has also shown that the amount of actual debt and the timing of actual debt repayments cannot be used because they are different from the amount of debt and the timing of debt reductions that are needed for the levelized methodology and the recovery of the 70 percent of plant associated with debt during Period One. The Commission concludes that Kern River's annual reduction of the average rate base by the amount of depreciation is in keeping with the requirement of *Ozark* that debt must be subtracted from rate base to obtain the

[182] Ex. KR-23 at 40-41.
[183] *Id.* at 43.
[184] *Id.*
[185] *Id.* at 43-44.
[186] *Id.* at 41.

equity financed investment on which a project-financed pipeline may earn a rate of return on equity.[187]

151. The 1997 *Mojave* order that BP cites does not demand otherwise. In the portion of the order that BP cites, the order accepts the divergence during the first fifteen years of the pipeline's operation between its plant cost recovery of 79 percent through depreciation and its amortization of 70 percent of its outstanding debt. The Commission affirmed the plant cost recoveries based on the original agreement of the parties during Mojave's certificate proceeding. The 1997 *Mojave* order does not address how the equity-only rate base should be calculated either in this or any other section of the order.

III. Return on Equity

152. 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 share price) plus the estimated constant growth in dividends.[188] The Commission uses a 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 the short-term growth projection. The Commission uses the growth rate of the Gross Domestic Product as its long-term growth rate. The Commission gives two-thirds weight to the short-term growth projection and one-third weight to the long-term growth projection.[189]

153. Most gas pipelines are wholly-owned subsidiaries and their common stock is not publicly traded. Therefore, the Commission uses a proxy group of firms with corresponding risks to set a range of reasonable returns for both natural gas and oil pipelines. The Commission then assigns the pipeline a rate within that range or zone, to reflect specific risks of that pipeline as compared to the proxy group companies.[190]

154. 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

[187] *Ozark*, 32 FERC at 65,049-50.

[188] *Northwest Pipeline Corp.*, 79 FERC ¶ 61,309, at 62,378 (1997).

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

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

constant growth DCF model. In addition, Kern River contends that, under no circumstances, should the Commission reduce the ROE for its 2003 Expansion below the level approved for that expansion when it was certificated.

A. Composition of the Proxy Group

155. 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.[191]

156. Until the Commission's 2003 decision in *Williston Basin Interstate Pipeline Co.*,[192] the third standard could only be satisfied, if a company's pipeline business accounted for, on average, at least 50 percent of a company's assets or operating income over the most recent three-year period. However, in recent years, fewer and fewer companies have met these standards, because of mergers, acquisitions, and other changes in the natural gas industry. Therefore, in *Williston*, the Commission relaxed this requirement. Instead, the Commission approved a pipeline's proposal to use a proxy group based on the corporations listed in the Value Line Investment Survey's list of diversified natural gas firms that own Commission-regulated natural gas pipelines, without regard to what portion of the company's business comprises pipeline operations.

157. Subsequently, in *HIOS*,[193] the Commission again used a proxy group based on the Value Line Investment Survey's group of diversified natural gas companies. The proxy group approved in *HIOS* consisted of four companies: Kinder Morgan, Inc. (Kinder Morgan), Equitable Resources, Inc. (Equitable Resources), National Fuel Gas Company, and Questar. The Commission excluded El Paso Corporation (El Paso) and Williams Companies (Williams), because financial difficulties had resulted in lowered, and thus unrepresentative, dividends for these companies. The Commission also rejected a proposal by the pipeline to include four master limited partnerships (MLPs) in the proxy group, essentially on the ground that the pipeline had provided insufficient support for a finding the MLPs' cash distributions were comparable to the corporate dividends used in the DCF analysis.

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

[192] *Williston Basin Interstate Pipeline Company*, 104 FERC ¶ 61,036, at P 35, n.46 (2003).

[193] *HIOS*, 110 FERC ¶ 61,043, *order on reh'g*, 112 FERC ¶ 61,050 (2005).

Opinion No. 486

158. In Opinion No. 486, the Commission continued to find that the Value Line Investment Survey list of diversified natural gas companies provides the best starting point for determining the proxy group, and therefore approved the same four-company proxy group as in *HIOS*. The Commission rejected BP's proposal to also include El Paso and Williams from the proxy group. The Commission found 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. The Commission found that their estimated ROEs were only slightly above the June-November 2004 average yield for the public utility debt,[194] and investors generally cannot be expected to purchase stock, if debt, which has less risk than stock, yields essentially the same return.[195] The Commission also pointed out that the two companies' financial difficulties were largely related to their respective energy trading and related risk management operations, and thus their low returns were not representative of the gas pipeline industry.

159. The Commission recognized that only one of the companies in the *HIOS* four-company proxy group, Kinder Morgan with an ROE of 13.62 percent, had as high a proportion of pipeline business as the Commission historically required. The remaining three companies (Equitable, Questar, and National Fuel, with ROEs ranging from 8.94 percent to 11.66 percent) derived more, or almost as much, revenue from their regulated distribution business, as from their regulated pipeline business. Kern River argued 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. The Commission determined, however, that any risk differential could be addressed adequately by taking it into account in determining Kern River's placement in the range of reasonable returns.

160. Opinion No. 486 also rejected Kern River's proposal to include three MLPs in the proxy group in addition to Kinder Morgan and Williams, including its fall-back proposal to include the MLPs with their distributions capped at earnings.[196] The Commission

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[194] The 7.31 and 7.32 percent costs of equity for El Paso and Williams were only 110 and 122 basis points above the 6.21 percent average yield for public utility debt.

[195] *Citing Southern California Edison Co.*, 92 FERC ¶ 61,070, at 61,266 (2000).

[196] The three MLPs Kern River proposed to include were: Enterprise Products Partners (Enterprise), Kinder Morgan Energy Partners (KMEP), and Northern Border Partners (Northern Border). Their DCF results based upon their full cash distributions were: Enterprise - 15 percent, KMEP – 13.6 percent, and Northern Border 12.4 percent. Their adjusted DCF results with cash distributions capped at earnings are: Enterprise – 12.6 percent; KMEP - 12.4 percent; and Northern Border - 11.3 percent. *See* Ex. KR-108, pages 4 of 6 and 6 of 6 respectively.

made clear that it was not making a generic finding that MLPs cannot be considered for inclusion in the proxy group if a proper evidentiary showing is made, but concluded that Kern River had not done so. The Commission pointed out that data concerning dividends paid by the proxy group members is a key component in any DCF analysis, and expressed concern that an MLP's cash distributions to its unit holders may not be comparable to the corporate dividends the Commission uses in its DCF analysis. Consistent with its reasoning in *HIOS*, the Commission stated:

> Corporations pay dividends in order to distribute a share of their earnings to stockholders. As such, dividends do not include any return *of* invested capital to the stockholders. Rather, dividends represent solely a return *on* invested capital. Put another way, dividends represent profit that the stockholder is 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 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. 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 through an allocation of the partnership's net income. 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 invested capital, 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.[197]

161. Opinion No. 486 also rejected Kern River's proposal to include the above three MLPs in the proxy group, but cap their cash distributions at the level of their earnings. The Commission stated that the DCF model assumes that dividends, rather than earnings constitute the source of value. The Commission then explained, "retained earnings are a key source of dividend growth in the traditional DCF model, which reflect the fact that corporations normally do not pay out all of their earnings as dividends, and dividends that are paid are assumed to be a distribution of stable long term surplus earnings not required

[197] Opinion No. 486 at P 149-50.

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 earnings as equivalent to a corporate dividend for use in the DCF analysis."[198]

162. The median ROE for the four company proxy group approved by Opinion No. 486 was 10.7 percent. As discussed further below, in order to account for the lower risk of the three LDC companies in the proxy group, the Commission adjusted Kern River's ROE 50 basis points above the 10.7 percent median to 11.2 percent.[199]

Rehearing Requests

163. Both shippers and Kern River challenge Opinion No. 486 determinations on the proxy group, but from different directions. The shippers (BP and the Rolled-in Customer Group) assert that the Commission's exclusion of El Paso and Williams from the proxy group was arbitrary and artificially increased the proxy group return by excluding these traditional gas pipelines. They argue that the Commission included El Paso and Williams in the proxy group in past rate cases when they were enjoying premium earnings from their trading activities, and therefore those pipelines should also be included when their trading activities are under performing.

164. In contrast, Kern River contends that the Commission erred in rejecting its proposal to include MLPs in the proxy group. First, it asserts that the Commission did not provide an adequate explanation of its refusal to allow use of the unadjusted MLP DCF results. It argues, the investors are concerned with cash flows, and as such do not distinguish between corporate dividends and MLP distributions because cash is cash. It asserts that there is no basis in the financial literature to conclude that the results of a DCF model are different depending on the source of the cash flows.[200] Kern River argues that therefore the Commission incorrectly concluded that there is a double recovery of depreciation if MLPs are included in the proxy group without adjusting the DCF model to reflect this purported double recovery.

165. It further argues that even if the Commission was correct that any use of MLP distributions in the DCF model must somehow account for the source of the cash, the lower growth rate of MLPs offsets any arguably increase in the return from the different sources. It notes that the Commission's own numbers indicate that the IBES five year projected growth rate for MLPs was some 120 basis points below that of lower risk LDCs included in the Commission's proxy group.[201] Moreover, the Commission's own

[198] *Id.* at P 153.

[199] *Id.* at P 175.

[200] Kern River rehearing request at 55-56.

[201] *Id.* 57-58.

numbers show that the reliance on the lower risk LDCs results in a greater distortion of risk than the inclusion of MLPs in the proxy group. It asserts that the proxy group adopted by the Commission is simply not LDC weighted, it is LDC determinative. Thus, Dr. Olson's proposed proxy group is much more representative of pipeline risk than that adopted by the Commission.[202]

166. Kern River further argues that the Commission denied it due process in rejecting Dr. Olson's alternative to base the proxy group on earnings-capped MLPs. It argues that it provided the reliable information required by *HIOS* despite its fundamental position that the distinction drawn in Opinion No. 486 between dividends and distributions is meaningless. It argues that Dr. Olson presented alternative calculations that removed from the DCF calculation the portion of the distribution in excess of earnings. It thus concludes that that the record adequately supports its position that using MLP adjusted ROEs, while not a particularly desirable solution, would result in just and reasonable rates. Kern River further contends that Opinion No. 486 erred in assuming that the MLPs use of external capital distorts the DCF results. Kern River states that corporations also raise capital through debt and equity offerings and presumably such capital is used to facilitate earnings growth.[203] Finally, Kern River argues it had no opportunity to comment on much of the Commission's analysis and therefore due process requires that the Commission reopen the record to permit Kern River to submit evidence on this point.[204]

Commission Determination

167. For the reasons discussed below, the Commission generally grants Kern River's request for rehearing concerning the inclusion of MLPs in the proxy group and denies the shippers' request for rehearing concerning the exclusion of El Paso and Williams from the proxy group. The Commission also establishes further procedures for the limited purpose of allowing all parties to submit additional evidence as to which specific MLPs should be included in the proxy group and where Kern River's ROE should be set in the resulting range of reasonable returns.

168. As described above, Opinion No. 486 adopted the same proxy group as the Commission adopted in *HIOS*. That proxy group was based on the policy adopted in *Williston* of using a proxy group based on the corporations listed in the Value Line Investment Survey's list of diversified natural gas firm that own Commission-regulated natural gas pipelines without regard to what portion of the company's business comprises pipeline operations. As in *HIOS,* at the time of Opinion No. 486, there were six

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[202] *Id.* 59-60.
[203] *Id*. at 60-63.
[204] *Id.* at 64.

corporations that satisfied the *Williston* standard, but the Commission excluded two due to their financial difficulties. This left only four corporations eligible for inclusion in the proxy group under the *Williston* standard, three of whom derived more revenues from the distribution business than the pipeline business.

169. While rehearing of Opinion No. 486 was pending, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion in *Petal Gas Storage, L.L.C. v. FERC*,[205] holding that the Commission had failed to support its choice of proxy group in *HIOS* and another case.[206] The court emphasized that the Commission's "proxy group arrangements must be risk-appropriate."[207] The court explained that this means that firms included in the proxy group should face similar risks to the pipeline whose ROE is being determined, and any differences in risk should be recognized in determining where to place the pipeline in the proxy group range of reasonable returns.

170. Recognizing that changes in the gas pipeline industry compel a change in the Commission's historical approach to determining the proxy group, the court stated that "controversy about how it should change has been bubbling up in a number of recent cases," citing both *Williston* and *Opinion No. 486*. But the court found that the cases on appeal "seem[] to represent an arrival point of sorts for the Commission," pointing out that *Opinion No. 486* had reversed an administrative law judge for deviating from the *HIOS* proxy group.[208]

171. The court held that the Commission had not shown that the proxy group arrangements it approved in *HIOS* and *Petal* were risk-appropriate. The court pointed out that the Commission had rejected the inclusion of MLPs in the proxy group on the ground that MLP distributions, unlike dividends, might provide returns *of* equity as well as returns *on* equity. While stating that this proposition is not "self-evident," the court accepted it for the sake of argument. Nonetheless, the court stated that nothing in the Commission's decision explained why the companies selected by the Commission for inclusion in the proxy group are risk-comparable to HIOS. The court stated that when the

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[205] 496 F.3d 695 (D.C. Cir. 2007)(*Petal v. FERC*).

[206] In the second case, the Commission had calculated the initial rate for an expansion by Petal Gas Storage, L.L.C., using the same median ROE it had approved in *Williston*. *Petal Gas Storage, L.L.C.*, 97 FERC ¶ 61,097 (2001), *reh'g granted in part and denied in part*, 106 FERC ¶ 61,325 (2004)(*Petal*).

[207] *Petal v. FERC*, 496 F.3d at 697, quoting *Canadian Association of Petroleum Producers v. FERC*, 254 F.3d 289 (D.C. Cir. 2001).

[208] *Opinion No. 486* reversed the ALJ's inclusion of the two financially troubled pipelines in the proxy group

goal is a proxy group of comparable companies, it is not clear that natural gas companies with substantial distribution activities should be regarded as comparable. The court further stated that the Commission's usual assumption that pipelines generally fall into a broad range of average risk as compared to other pipelines is decisive only given a proxy group composed of other pipelines. If gas distribution companies generally face lower risk than gas pipelines, [209] a risk-appropriate placement would be at the high end of the group. The court concluded that the Commission erred by failing to explain how its proxy group arrangements were based on the principle of relative risk.

172. In a contemporaneous *Policy Statement on the Composition of Proxy Groups for Determining Pipeline Return on Equity*,[210] the Commission has reexamined its proxy group policy in light of the court's decision in *Petal v. FERC* and current trends in the gas and oil pipeline industries. As a result, the Commission is modifying its policy to permit MLPs to be included in the proxy group. These MLPs are often more representative of predominantly pipeline firms than the diversified gas corporations still available for inclusion in a proxy group. As such, including MLPs in the gas pipeline proxy group should render the proxy group more "risk-appropriate," consistent with *Petal*. This, in turn, should help minimize the need to make adjustments to account for differences in risk, because the proxy group should be more representative of the regulated firms whose rates are at issue.

173. In addition, the policy statement finds that the ROEs of any MLPs included in the proxy group should be determined using the same DCF analysis as the Commission uses for corporations, with only one exception. That exception is that the projected long-term growth rate for MLPs should be 50 percent of projected long-term growth in GDP, instead of the full long term GDP currently used for corporations. That is because evidence in the record of the policy statement proceeding showed that investment houses project that the long-term growth of MLPs will be less than the long-term growth of GDP.

174. The policy statement also finds that there should be no cap on the level of the MLP's distributions used to calculate dividend yield. The DCF analysis presumes that the market value of an MLP's units is a function of the entire present and future cash flow provided by an investment in those units. Therefore the policy statement finds that, if the Commission were to cap the distribution used to determine an MLP's dividend yield at below the market-determined level, but use the actual market price of the MLP's publicly traded units and a growth projection reflecting the actual level of distributions, the DCF analysis would fail to achieve its intended purpose of determining the return the

[209] The court noted that this seems likely.

[210] Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity, 123 FERC ¶ 61,048 (2008) (*Policy Statement*).

equity market requires in order to justify an investment in the pipeline. Given the interlocking nature of the variables in the DCF formula, limiting the distribution input to earnings, while using market values for the other inputs to the DCF formula, would result in the calculation of a return below that implied in the share price. Moreover, the Policy Statement explains why use of the MLPs full distribution would not result in the pipeline double recovering depreciation. Finally, the Policy Statement held that, because the Commission's current proxy group policies as applied in prior cases have not withstood court review, the Commission would apply the Policy Statement in all current proceedings where the ROE issue has not been finally resolved.

175. In this case, as described above, Opinion No. 486 adopted the same proxy group as in *HIOS*. The court reversed *HIOS*, in an opinion which expressly took note of the fact that Opinion No. 486 had used the *HIOS* proxy group. Therefore, the Commission having modified its policy in response to the court's reversal of *HIOS*, the Commission must apply its new proxy group policy in this case. Accordingly, consistent with the Policy Statement, the Commission grants Kern River's request for rehearing in part in order to permit the inclusion of MLPs in the proxy group pursuant to the standards established in the Policy Statement.

176. In this regard, the Supreme Court has stated, "the return to the equity owner should be commensurate with the return on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital,"[211] and the D.C. Circuit emphasized this principle in *Petal v. FERC*. As is argued by both sides on rehearing, the inclusion in the gas proxy group of companies whose pipeline operations account for only a small proportion of their overall business raises serious questions concerning whether those companies have sufficiently comparable risk to the pipeline business to permit the determination of a just and reasonable return on equity. Opinion No. 486 sought to address that problem by adjusting Kern River's ROE within the range established by the proxy group to account for the differences in risk between Kern River and the proxy companies. However, neither Kern River nor its shippers are satisfied with that approach.

177. Including MLPs in the proxy group in this case, pursuant to the Policy Statement, will help ameliorate these problems, because MLPs devote a much higher percentage of their business to pipeline operations than most of the corporations currently included in the proxy group. Thus, including MLPs in the proxy group should reduce the need to make necessarily arbitrary adjustments from the median of the range, since the proxy

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[211] *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *Bluefield Water Works & Improvement Co. v. Public Service Comm'n*, 262 U.S. 679 (1923).

group should contain firms that are more representative of the regulated firm whose rates are at issue.

178. Consistent with the Policy Statement, we also agree with Kern River's contention on rehearing that, in performing a DCF analysis of an MLP, the MLP's dividend yield should be calculated based upon the full amount of its distributions, without any cap at the level of earnings. The premise of the DCF model is that a firm's stock price should equal the present value of its future cash flows, discounted at a market rate commensurate with the stock's risk. Consistent with that theory, an investor performing a DCF analysis to determine the value of an investment in an MLP, may include the entire amount of the MLP's cash distributions in the analysis, without distinguishing between return *on* invested capital and return *of* invested capital. As Kern River's witness, Dr. Olson testified, "Investors evaluating an MLP clearly look at and value cash flows they expect to receive, not accounting based definitions."[212]

179. The fact an MLP makes distributions in excess of earnings is more appropriately accounted for in the growth component of the DCF analysis by using a growth projection which accurately reflects investor's expectations of reduced growth prospects due to the high level of distributions. As Dr. Olson also testified, "In doing the discounted cash flow analysis for an MLP, investors realize that large cash flow based distributions reduce the ability to increase earnings later. Thus the higher distributions that are calculated in the yield result in lower IBES growth rates than would be the case with greater cash flow retention."[213]

180. Therefore, assuming a proper growth projection is used in the DCF analysis as more fully discussed below, any adjustment to the MLP's actual cash distributions would lead to distorted results. Under the DCF model, all cash flows, whatever their source, are reflected in the value of stock. On the one hand, large cash flows in excess of earnings add value to the stock by increasing the current dividend yield. On the other hand, such cash flows take value away from the stock by reducing future growth potential. This being the case, it is theoretically inconsistent to use less than the actual cash flows when using the DCF model to determine the return required by investors purchasing the stock. Any cap on the distribution would artificially reduce MLP's dividend yield below that assumed by the investor in valuing the stock. Adding the artificially reduced dividend yield to a growth projection that properly reflects investors' expectations of the MLP's reduced growth prospects due to its high actual distributions would inevitably result in an ROE lower than that actually required by the market.

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[212] Ex. KR-107 at 29.

[213] *Id.*.

181. Thus, the key issue in performing a DCF analysis of an MLP is determining the appropriate growth projection to be used. As described previously, the Commission requires that the DCF analysis of gas pipelines include both a short-term and a long-term growth projection. We agree that for purposes of the short-term growth projection, an MLP's reduced growth potential due to high cash distributions should be reflected in the IBES short-term growth projections for the MLPs. As Kern River's witness Dr. Olson testified at the hearing, "market analysts, such as IBES and Yahoo Finance, all use the same framework for estimating the five-year growth rate for MLPs and corporations. The analysts know that the MLPs pay out more than they earn. This is reflected in the growth rates they estimate, which are presumably lower than they would be at lower payout rates."[214]

182. Dr. Olson stated that this presumption is confirmed by a comparison of the IBES growth projections for the Kinder Morgan Corporation and for the KMEP MLP. The Kinder Morgan growth projection was 9.9 percent, while the KMEP growth projection was 260 basis points lower at 7.3 percent. Similarly, as Kern River points out on rehearing, the average IBES growth projections for all three of the MLPs Kern River proposed to include in the proxy group in this proceeding were some 120 basis points below the average IBES growth projections for the four corporations the proxy group adopted by Opinion No. 486 (6.45 percent for the MLPs as compared to 7.61 percent for the corporations.[215] Similarly, as pointed out in the Policy Statement, this conclusion is also supported the fact the most recent IBES growth forecasts for the six MLPs included in the gas pipeline proxy group in Appendix B of the Policy Statement average 6.67 percent, while the IBES growth projections for the four corporations average 10.5 percent. Thus, those MLP growth projections are almost 400 basis points below those for the corporations. We conclude that the IBES growth projections are properly used as the short-term growth projection in our DCF analysis of MLPs.

183. In the Policy Statement, the Commission also finds that investors expect the long-term growth of MLPs to be less than the projected growth in GDP, which the Commission now uses to project the long-term growth of GDP. Accordingly, based on the record developed in the Policy Statement proceeding, the Commission has adopted a policy that the long-term growth projection to be used in the DCF analysis of an MLP should be equal to 50 percent of projected long-term growth in GDP. Thus, in the paper hearing on the proxy group issue established by this order, parties must address the issue of the appropriate long-term growth projection.

184. In Opinion No. 486, the Commission expressed concern that use of a proxy MLP's full distribution in determining ROE would cause a double recovery of the depreciation

[214] Ex. KR-107 at 18.

[215] *Id.* 57-58.

component included in the pipeline's cost-of-service rates. Consistent with the Policy Statement, we find that that concern was misplaced. In a rate case, the Commission determines the dollar amount of the ROE component of the cost-of-service of the pipeline filing the rate case by multiplying (1) the percentage return on equity required by the market by (2) the actual rate base of the pipeline in question. Having found that use of a proxy MLP's full distribution is necessary for the DCF analysis to accurately determine the percentage return on equity required by the equity markets, it necessarily follows that the same percentage should be used in determining the dollar amount of the ROE component of the pipeline's cost of service. Awarding the pipeline an ROE allowance based on that percentage of its own rate base will give the pipeline an opportunity to provide its investors with the return on their investment required by the market. Such an ROE allowance does not implicate the separate depreciation allowance the Commission also includes in a pipeline's cost of service to provide for return of investment.[216]

185. Moreover, while the Commission stated in Opinion No. 486 that the traditional DCF model does not incorporate growth arising from external sources of capital, the Commission concludes that this was not correct. As Kern River argues on rehearing, most pipelines organized as corporations also use external borrowings and to some extent equity issuances. For example, Kern River borrowed the funds required for its large 2003 expansion.[217] To the extent that gas pipelines are controlled by diversified energy companies with unregulated assets (either federal or state), the financial practices may be the same, although perhaps not as highly leveraged, and the results are likewise reflected in the IBES projections.[218] A prudent investor deciding whether to invest in a security will reasonably consider all factors relevant to assessing the value of that security. The potential effect of future borrowings or equity issuances on share values is one such factor. Since a DCF analysis is a method for investors to estimate the value of securities, it follows that such an analysis may reasonably take into account potential growth from external capital. Therefore on rehearing the Commission concludes that market forces will adjust for the external financing included in the IBES growth projections and grants rehearing in that regard.

186. At the previous hearing, Shippers asserted that the income tax advantages of MLPs may also inflate an MLP's equity cost-of-capital.[219] This is because a regulated

[216] Ex. KR-107 at 29. *See also* Appendix B of the Policy Statement, giving a detailed explanation of why including an MLP's full distribution in the DCF analysis does not lead to a double recovery of depreciation.

[217] Opinion No. 486 at P 179.

[218] *Id.* at P 151.

[219] Opinion No. 486 at P 144.

MLP may have an income tax allowance built into its rates, which generates additional cash flow that may be distributed to the partners. The argument is that this additional cash does not reflect earnings, and that therefore like the distribution of cash flow from depreciation, overstates capitalized dividend return portion of the model. First, as discussed in the tax portion of this order, the Commission's policy decision to grant partnerships an income tax allowance was upheld in *Exxon Mobil v. FERC*.[220] Thus, the income tax allowance is permitted provided that the partnership establishes that its partners have an actual or potential income tax liability on their partnership income. The converse of this statement is that if this test is not met, then the income tax allowance will not be included in the rates of regulated entity. Second, if there is an actual or potential income tax liability on the part of the partners, the cash flow from the tax allowance will not be available for reinvestment, the price of the security, and hence the yield, should reflect this. Conversely, if the income tax allowance is available, the cash flow that is available for distribution and any cash generated by any tax deferrals will also be reflected in the price of the security. The effect of the increased distributions either from the income tax allowance or any income tax deferrals is to reduce the entity's equity cost of capital because the price of the equity securities is lower.[221]

187. Finally, the Commission has recognized that MLPs often present some present value to unit holder during the period before the potential income tax liability is actually recognized, information on the value of that deferral is not available to adjust the return of the MLP proxy group members to compensate for that modest advantage.[222] Given this practical concern, the Commission will not require an adjustment of distributions of the proxy group MLPs in a specific rate proceeding as a condition of their inclusion in the proxy group because any tax benefits are already reflected in the price of the limited partnership interests to be included in the proxy group. In any event, because of the difficulty of determining the shareholder's marginal tax rate, and whether taxes on a corporate dividend are actually paid, the Commission has never considered the marginal tax rate of the shareholder in determining the DCF calculation, or for that matter, whether the corporation receiving a tax allowance has actually paid taxes in particular year. [223] At bottom, the conclusions here regarding income tax allowance issues are consistent with the December 2005 and December 2007 SFPP Orders.

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[220] *Exxon Mobil Oil Corporation v. FERC*, 487 F.3d 945 (D.C. Cir 2007) at 948-955 (*Exxon Mobil*).

[221] See Ex. KR-107 at 20.

[222] *See SFPP, L.P.*, 121 FERC ¶ 61,240 (2007) (December 2007 SFPP Order) at P 28-30.

[223] *See SFPP, L.P.*, 113 FERC ¶ 61,277 (2005) (December 2005 SFPP Order) at P 34. The instant order follows that practice.

188. Accordingly, for the reasons discussed above, the Commission grants Kern River's request for rehearing in part and will permit the use of appropriate MLPs in the proxy group to be used to determine Kern River's ROE. The Commission also reopens the record for a paper hearing in order to give all participants, including litigation staff, an opportunity to submit additional evidence as to, (1) which specific MLPs should be included in the proxy group consistent with the Policy Statement, (2) the appropriate DCF analysis of each entity proposed for inclusion in the proxy group, and (3) where Kern River's ROE should be set in the resulting range of reasonable returns. The MLPs proposed to be included in the proxy group need not be limited to those Kern River proposed in the initial hearing. A primary goal of the new policy is to develop proxy groups made up of firms whose risk profiles correspond as closely as possible to that of the pipeline whose ROE is being determined. Thus, all participants are free, in the paper hearing, to propose whichever MLPs will best accomplish that goal. In addition, parties may modify their prior positions concerning which corporations to include in the proxy group in light of the addition of MLPs to the proxy group, subject to our reaffirmation of our ruling that El Paso and Williams must not be included in the proxy group. Parties should include as much information as possible regarding the business profile of the firms they propose to include in the proxy group, for example, based gross income, income, or assets, using SEC reports, investment service analyses, or other materials.

189. As has been discussed, Opinion No. 486 excluded El Paso and Williams from the proxy group on the grounds that their financial difficulties had resulted in lowered and unrepresentative dividends. The Shippers' rehearing requests do not present any grounds to conclude that during the test period here, that ending October 31, 2004, this conclusion was inappropriate. As the Shippers state in their rehearing requests, those pipelines' financial difficulties were caused by losses in non-pipeline activities. Thus, including those pipelines in the proxy group would be contrary to the goal of the Policy Statement of including firms in the proxy group whose risk profile is most similar to the pipeline whose return is being determined. Therefore the Commission denies rehearing on that issue and will continue to exclude El Paso and Williams from the proxy group in this proceeding.

190. Initial briefs on the issues set for paper hearing by this order will be due within 60 days after this order issues. Reply briefs are due 90 days after this order issues, and rebuttal briefs are due 105 days after this order issues. Each participant's presentations in its initial reply and rebuttal briefs must separately state the facts and arguments advanced by the participant and include any and all exhibits, affidavits and/or prepared testimony upon which the participant relies.

B. Placement within the Zone

Opinion No. 486

191. In Opinion No. 486, the Commission set Kern River's ROE at a level 50 basis points above the 10.7 median of the proxy group. The Commission pointed out that it ordinarily determines the middle of the range based on the median, rather than the midpoint. That is because under the laws of statistics the median is the more accurate method to determine the central tendency of a skewed distribution of returns. However, in this case the 10.7 median was determined by averaging the ROEs of two companies in the middle of the range, Equitable Resources and Questar, both of which have significant lower risk distribution business. By contrast, the midpoint is determined by averaging the ROEs of Kinder Morgan and National Fuel, thus giving weight to the ROE of the one company whose business is most similar to Kern river's, Kinder Morgan. The midpoint in this case is 11.28 percent, 58 basis points above the median. Accordingly, the Commission concluded that its 50 basis point adjustment above the median was necessary to appropriately reflect the cost of equity of Kinder Morgan in the determination of Kern River's ROE.[224]

Rehearing Requests

192. The Shippers assert that the Commission erred in adjusting Kern River's ROE 50 basis points above the median. They argue that there are grounds to conclude that the three LDC oriented companies included in the proxy group may not be materially less risky than Kern River. The shippers also present independent financial analyses concluding that Kern River's market position is strong, it has a favorable cost structure, it possesses more firm transportation gas contracts than most pipelines, and has a high credit rating. They also note that MWEH paid a $258 million premium over book value to purchase Kern River.[225]

193. Kern River asserts that 50 basis point adder is inadequate, and that in any event, there is no reasoned basis for this conclusion.[226] Kern River further questions the adder arguing that, given the Commission's conclusion that it has higher risk than the three LDC oriented companies in the proxy group, the only truly comparable firm is the pipeline dominated firm Kinder Morgan with an ROE of 13.62 percent. Therefore, it contends that 50 basis point adjustment, derived by averaging Kinder Morgan's ROE with the lowest ROE of the three LDC oriented companies, was insufficient. Kern River

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[224] Opinion No. 486 at P 173-75.
[225] Rehearing request of BP at 41-45.
[226] *Id.* at 42, 44.

also presents a number of reasons why its business risk is greater than that of other pipelines.

Commission Determination

194. The Commission need not reach merits of the 50 point adder and its relevance to placement within the zone here given its conclusion to grant rehearing on the issue of whether MLPs may be included in the proxy group. The Commission does not determine placement within the equity zone until the proxy group is defined and the risk of the proxy group members is determined. Since the matter will be addressed by the paper hearing previously established, the Commission defers further action on the placement of the return within the return zone until completion of the paper hearing. Therefore Commission grants rehearing for the purpose of permitting the issue of placement within the zone to be further addressed at the paper hearing established by this order.

C. Whether there Should be Different Returns on Equity for Different Portions of Kern River's System

Rehearing Requests

195. On rehearing, Kern River asserts the Commission should have adopted its proposal of approving different returns on equity for the different vintages of its pipeline facilities. Kern River asserts that most of the risk presented by its shippers' poor and declining credit quality is associated with the 2003 Expansion rather than the Rolled-In System, and that, therefore, the 2003 Expansion has a greater business risk than the Rolled-In System. Kern River asserts that in Opinion No. 486, the Commission did not consider its alternatives based on relative vintage of its different facilities.

196. Kern River proposes, first, that the Commission retain the existing 13.25 percent return on equity for the 2003 Expansion and perform a separate DCF calculation for the Rolled-In facilities. It also proposes that the Commission employ separate analyses for zone-placement purposes and place the Rolled-In System at the median of the DCF range and the 2003 Expansion at the top of the range. Kern River states that the blended overall return on equity resulting from this calculation would be 13.12 percent. It states that an illustrative calculation of this approach can be developed based on data included in Ex. KR-100, assuming the 2003 Expansion and laterals are about 60 percent of Kern River's total rate base and that the equity return for these assets is set at the high-end of Dr. Olson's modified MLP proxy group, and that the Rolled-In facilities are about 40 percent of Kern River's total rate base and the equity return for these assets would be set at the median of the modified MLP proxy group.[227]

[227] Kern River request for rehearing at 67, n.41.

197. Kern River also inveighs that failure to maintain or adopt a higher return on equity for the 2003 Expansion facilities is a punitive, *post-hoc* rate adjustment that undermines the project's economic assumptions and expectations. It asserts that Opinion No. 486 reduces the return on equity of the 2003 Expansion without any evidence that the risk factors and economic circumstances that supported the initial 13.25 percent return have changed. It also asserts that reducing the return on equity of the 2003 Expansion within eighteen months of its completion will discourage investment in new pipeline facilities.

Commission Determination

198. The Commission denies Kern River's rehearing requests for separate returns on equity for its Rolled-in System and 2003 Expansion facilities and for a return of 13.25 percent on the 2003 Expansion facilities or a blended return of 13.12 percent on all its facilities. These requests are denied for the following reasons, discussed in detail below. The Commission generally views a pipeline as a single business entity and assesses business risk for the pipeline as a whole, not for separate portions of the pipeline. Therefore, the Commission generally does not adopt separate returns on equity for separate portions of pipeline facilities. In this case, the return on equity of 13.25 percent was not unique to the 2003 Expansion facilities. When the Commission adopted 13.25 percent as the return on equity for the initial incremental rates of the 2003 Expansion facilities, there was no consideration of the risk factors and economic circumstances supporting the 13.25 percent return on equity for the 2003 Expansion.[228] As Kern River notes, the 13.25 percent return on equity was originally adopted in its 1994 rate settlement and was continued in its 1999 rate settlement.[229] Subsequently, the 13.25 percent return on equity was incorporated in the rates authorized in the certificates issued by the Commission for the 2002 Expansion and the 2003 Expansion.[230] The

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[228] "In setting initial rates in section 7(c) certificate proceedings, the Commission is unable to perform the type of detailed analysis of a pipeline's risk profile conducted in general section 4 rate proceedings. Thus, to permit timely processing of certificate applications, the Commission generally adopts the rate of return approved in the pipeline's most recent rate case." *Texas Eastern Transmission Corp.*, 61 FERC ¶ 61,208, at 61,778 (1992).

[229] Kern River Request for Rehearing at 7-8 *citing Kern River Gas Transmission Co.*, 70 FERC ¶ 61,072, at 61,178 (1995) (1994 Settlement); *Kern River Gas Transmission Co.*, 87 FERC ¶ 61,128, at 61,503, *order on reh'g*, 88 FERC ¶ 61,261 (1999), *order approving settlement*, 90 FERC ¶ 61,124 (1999 Settlement); *Kern River Gas Transmission Co.*, 92 FERC ¶ 61,061 (2000) (ET Settlement Order).

[230] *Kern River Gas Transmission Co.*, 96 FERC ¶ 61,137, *reh'g denied*, 97 FERC ¶ 61,080 (2001) (2002 Expansion); *Kern River Gas Transmission Co.*, 98 FERC ¶ 61,205, at 61,722 (2002) (2003 Expansion Preliminary Determination on Non-Environmental Issues).

13.25 percent return on equity was thus the existing return on Kern River's system at the time the 2003 Expansion was certificated. When 13.25 percent was adopted as the return on equity for the 2003 Expansion, it became the return on all of Kern River's facilities, not just the 2003 Expansion facilities. Moreover, the 2003 Expansion certificate orders contained no provisions for the continuation of the 13.25 percent return on equity when Kern River's initial incremental rates for the 2003 Expansion were superceded by new rates approved under section 4 or section 5 of the NGA. In the Preliminary Determination on the 2003 Expansion, the Commission simply accepted the return on equity of 13.25 percent because that return was previously approved in Kern River's last rate proceeding and for two recent expansions, the California Action Project and the 2002 Expansion Project.[231]

199. Finally, the Commission rejects Kern River's contentions that changing the return on equity for the 2003 Expansion was a punitive, *post-hoc* rate adjustment and will discourage investment in new pipeline facilities. Kern River's return on equity was changed in accordance with the Commission's statutory and regulatory rate procedures, as described above, including Kern River's agreement in the 1999 Settlement to file a section 4 rate case. Moreover, Kern River knew that the initial rates for the 2003 Expansion, including the return on equity, could change when it filed the section 4 rate case required by the 1999 Settlement. In its August 1, 2001 application for a certificate for the 2003 Expansion, Kern River noted that its latest rate settlement required it to file a new rate case no later than May 1, 2004 and that, therefore, its proposed initial incremental rates for the 2003 Expansion would be effective only for up to eighteen months before being subjected to a new general section 4 rate proceeding.[232] In its rehearing request, Kern River states that its parent, MidAmerican Energy Holdings Company (MEHC), knew when it acquired Kern River that the company was required to file the present rate case in 2004 and that the return on equity would be an issue in that proceeding.[233] Thus Kern River knew that its initial incremental rates for the 2003 Expansion would be superceded within eighteen months by a new rate case that it was obligated to file under the 1999 Settlement and that the return on equity could be different from the 13.25 percent that it received for its initial incremental rates for the 2003 Expansion.

200. For all of the above reasons, the Commission declines to adopt or maintain separate returns on equity for the 2003 Expansion Facilities and the Rolled-in System or to adopt Kern River's proposed return on equity of 13.25 percent for the 2003 Expansion Facilities or its proposed blended rate of 13.12 percent.

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[231] *Kern River Gas Transmission Co.,* 98 FERC ¶ 61,205 at 61,722.
[232] *Id.*
[233] Kern River Request for Rehearing at 8.

IV. Debt Costs

201. Calpine, Edison, and Pinnacle West (collectively, Expansion shippers), assert the Commission erred in approving a blended cost of debt for two debt financings, Series A and Series B. They state that using a blended cost of debt shifts over $11 million in debt costs from the rolled-in shippers to the 2003 Expansion shippers.[234] They assert generally that the Series A and Series B Debt are not interrelated, that the certificate orders require the use of actual debt for the 2003 Expansion, that there are no changed circumstances as required by the *1995 Pricing Policy Statement* and the *1999 Pricing Policy Statement*,[235] and that a blended cost of debt is inconsistent with other aspects of Opinion No. 486. They ask the Commission to reinstate the use of separate debt costs for Kern River's rolled-in and 2003 Expansion rates. The Commission denies the rehearing requests and affirms its prior findings in Opinion No. 486 that the Series A and Series B Debts are interrelated and that the just and reasonable cost of debt for all shippers is the blended cost of debt of 6.62 percent.

Background

202. Kern River's debt capitalization consisted of two debt issues. The first was Series A notes in the amount of $510 million issued in August 2001 in the form of 15-year amortizing senior notes bearing a fixed coupon rate of 6.676 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. 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 recover breakage costs associated with the previously held interest rate swaps.

203. The second debt issue was Series B notes in the amount of $836 million issued in May 2003 in the form of 15-year amortizing senior notes bearing a fixed coupon rate of 4.893 percent. Kern River proposed that the debt cost of the Series B issuance was 5.145 percent (including issuance costs). 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

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[234] *See, e.g.*, Edison Mission Request for Rehearing at p.11.

[235] *Pricing Policy for New and Existing Facilities Constructed By Interstate Natural Gas Pipelines*, 71 FERC ¶ 61,241, at 61,918 (1995) (*1995 Pricing Policy Statement*); *Policy Statement Concerning Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999) (*1999 Pricing Policy Statement*), *order on clarification*, 90 FERC ¶ 61,128, *order granting further clarification*, 92 FERC ¶ 61,094 (2000).

associated with the offering.[236] 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.[237]

204. Kern River's proposed rate calculations combined the two debt issues to compute a weighted average overall cost of debt, which Kern River used in calculating rates for both the rolled-in system and the 2003 Expansion services. Kern River computed its weighted cost of debt to equal 6.62 percent. 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 Series A and Series B notes.

Opinion No. 486

205. In Opinion No. 486, the Commission upheld Kern River's proposed blended cost of debt.[238] In general, the Commission found 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.[239] Specifically, the Commission found the Series A and Series B debt financing to be sufficiently interrelated as to warrant a blended cost of debt for the following reasons.[240]

206. The Commission found the Series A and Series B Notes to be interrelated for the following reasons. It found 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.[241] It found further that when a 2003 Expansion shipper defaults, revenue impairment would not fall exclusively on Series B debt.[242] In addition, 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

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

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

[238] Opinion No. 486 at P 193-96.

[239] The Commission also noted that the interrelationship of the Series A and Series B debt issues was the basis for its finding that the use of a blended cost of debt was consistent with the use of a single capital structure and the same ROE for the rolled-in facilities and the 2003 Expansion Facilities. Opinion No. 486 at P 193, 196.

[240] *Id.* at P 194.

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

[242] Ex. BP-33 at 3.

shippers paying the interest on Series B debt.[243] The Commission also found persuasive on this issue arguments that 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 so that there is no way to demonstrate that one group of shippers pays the interest and principal only for one specific debt issue.[244] The Commission noted further that, 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 forgo a benefit that they were instrumental in creating.

207. The Commission also found that the certificate proceeding did not require the continued use of a separate cost of debt. The Commission noted that section 7 certificate proceedings do not usually provide for a restatement of all of a pipeline's base tariff rates and are only concerned with recovering enough costs to pay for expansion facilities until the pipeline's next section 4 general rate case. It stated that in the certificate order for the 2003 Expansion, it required that Kern River's initial rates for the 2003 Expansion shippers reflect the actual incremental cost of debt financing for this project. It found that its ruling in the section 7 certificate case is not controlling in this section 4 rate case because that ruling did not reach the issue of whether to use the incremental cost of debt or a weighted average cost of debt. The Commission found Kern River's blended debt cost reflects the actual cost of Series B debt in the combined calculation, and thus that the blended cost of debt proposal was consistent with Commission determinations (e.g., the 1999 Pricing Policy Statement and the order certificating the 2003 Expansion) that require use of "actual debt costs" and that a new allocation of debt cost was not needed.[245]

208. The Commission found further 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 would be 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.[246] The Commission found it would be 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.

[243] BP Brief on Exceptions at 33.
[244] Opinion No. 486 at P 195.
[245] *Id.* at P 199.
[246] Ex. KR-122 at 1.

Rehearing Requests

Procedural Issue

209. Pinnacle West asserts that Kern River's failure to file exceptions to the ALJ's decision on the cost of debt issue effectively terminated Kern River's proposal to include a blended cost of debt in the Expansion Shippers' incremental rates. It argues that, accordingly, the change to a blended cost of debt had to meet NGA section 5 requirements and that they were not met here. Pinnacle West relies on *Consol. Edison of New York v. FERC* (*ConEd*).[247]

210. However, this case holds the opposite of what Pinnacle West contends. In *ConEd* the pipeline had proposed to roll in the costs of some facilities. Evidence to support the proposal was presented by Commission Trial Staff and some of the parties, but not by the pipeline. The court found the pipeline did not, in fact, withdraw its proposal and did not abandon its stated desire for rolled-in pricing.[248] It also found that when choosing between section 4 and section 5, the Act makes the source of the proposed rate change decisive.[249] It held that because the pipeline proposed the rate change concerning the facilities, "the Commission properly followed the framework set up by the Act and applied section 4."[250] The same is true here. The pipeline proposed the blended cost of debt and has not withdrawn its proposal. Therefore, section 4 applies here.

A. Interrelation of Series A and Series B Debt

Rehearing Requests

211. The Expansion shippers assert the record evidence shows that the Series A and Series B Debt are not interrelated but are independent of each other. They state the two debts were incurred for different purposes, Series A to finance debt incurred in 1996, and Series B to finance the 2003 Expansion and High Desert Lateral Projects. They state Kern River allocated the Series A debt to the rolled-in services and the Series B debt to the 2003 Expansion Services.[251] They also state that, contrary to Opinion No. 486, [252] rolled-in shippers are not obligated to help amortize Series B debt principle. The

[247] 165 F. 3d 992, 1007-08 (D.C. Cir. 1999) (*ConEd*).

[248] *Id.* at 1008.

[249] *Citing East Tenn. Natural Gas Co. v. FERC,* 863 F.2d 932, 937 (D.C. Cir. 1988).

[250] *Complex* at 1008, *citing See Sea Robin Pipeline Co. v. FERC,* 795 F.2d 182, 183-84 (D.C. Cir. 1986).

[251] *Citing* Ex. KR-123.

[252] Opinion No. 486 at P 200.

Expansion Shippers state Kern River recoups its Series B debt principle through the depreciation component of the 2003 Expansion service rates.[253] They conclude the Series A debt and the Series B debt are not common expenses and are not interrelated, and, therefore, do not justify a blended debt cost.

212. The Expansion shippers also challenge the Commission's rationales for supporting a blended cost of debt. They state that cost allocation should be based on cost causation.[254] They state that Kern River's decision to pledge revenues from its rolled-in customer service agreements as collateral for Series B debt does not change the purpose of the Series B debt, the construction of the 2003 Expansion facilities. They reason that, consequently, the Series B debt cost should be allocated only to Expansion shippers since their service is the cause of this debt. Pinnacle West states that testimony showed that even when two debt series rely upon the same consolidated cash flows to make interest and principal payments, each debt series has a separate amortization schedule designed to match the contract terms of the separate customer groups.[255] The Expansion shippers reason that, thus, Kern River should not be permitted to charge Expansion shippers a blended cost of debt and that only the Series B debt cost should be allocated to them.

213. The Expansion shippers also object to the Commission's other rationales for the blended debt cost. They state there is no evidence in the record that the rolled-in shippers obtained an interest rate for the Series B debt that was lower than the interest rate that Kern River would have obtained without them. They state the lower Series B debt costs were due to changes in market conditions consisting of declines in the risk-free Treasury rate and in the risk-related portion of debt cost, or credit spread. They also state that the fact that revenue dollars cannot be traced to specific payments has no bearing on cost allocation.

214. The Expansion shippers assert there is no support in the record for the finding that when an Expansion shipper defaults, revenue impairment would not fall exclusively on Series B debt. They assert the Commission relies for this conclusion on one exhibit.[256]

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[253] *Citing* Ex. KR-123.

[254] *Citing* S*ystem Energy Resources, Inc.*, 41 FERC ¶ 61,238, at 61,616 (1987) (*System Energy*) and also *KN Energy Inc. v. FERC*, 986 F.2d 1295, 1300-01 (D.C. Cir. 1992); *Alabama Elec. Cooperative, Inc. v. FERC,* 684 F.2d 20, 27 (D.C. Cir. 1982).

[255] *Citing* Ex. EME-1 at 10.

[256] In Opinion No. 486 at P 194, the Commission cited Ex. BP-33 at 3 which states in relevant part:

> **BP-EDISON MISSION-16**: Is it Edison's position that if a 2003 Expansion shipper defaults, any impairment in revenue would affect (if at all) only the revenue stream used to pay the May 1, 2003 Series B issuance?

(continued…)

They state this exhibit means that an Expansion shipper default would impact revenue streams used to pay other incremental costs for which the Expansion shippers are responsible besides the Series B debt revenue stream. They assert this exhibit does not show that an Expansion shipper default would affect repayment of Series A debt or that the Series A and B debt costs are interrelated.

215. The Expansion shippers also state that the reduction in debt service for the Series A debt associated with the refinancing did not create a greater share of revenue available to service the requirements of the Series B debt. They assert that, instead, the reduction in debt service for the Series A debt resulted in a rate decrease for rolled-in shippers and thus reduced the revenues collected from the rolled-in shippers and, by extension, revenues available to service the Series B debt.

216. The Expansion shippers state that use of a single debt cost cannot be supported as consistent with the use of the same rate of return on equity for the original and the expansion system. They state debt cost and rate of return on equity are quite different. For example, Calpine states that debt costs are known and measurable costs previously incurred by the pipeline, while rate of return on equity is set using the system-wide approach of the discounted cash flow method and requires an assessment of the pipeline's overall business risk.

217. Calpine states that using a single cost of debt contradicts the Commission's acceptance of the Ozark method to determine individual capital structures by subtracting project-specific debt balances based on separate debt costs from the relevant customer rate base to determine the equity portion of the rate base. They state that, contrary to Opinion No. 486, Kern River did not use a single capital structure,[257] but separate capital structures which were used to calculate levelized rates for each class of customer.[258]

218. Pinnacle West states that the disparity in debt repayment schedules for the Series A and Series B debt[259] cannot be used to support a blended cost of debt. It states the amortization schedules address return of debt. It states the cost of debt deals with return on debt, not return of debt. It states that, therefore, return of debt as shown in the amortization schedules is not relevant to whether it is equitable to blend the costs of debt.

RESPONSE: No.

[257] Opinion No. 486 at P 196.

[258] *Id.* at P 120.

[259] Opinion No. 486 at P 200 *citing* Ex. KR-122 at 1.

Commission Determination

219. The Commission denies the rehearing requests and affirms its findings in Opinion No. 486 that the Series A and Series B debt issues are interrelated and that a blended cost of debt is just and reasonable.

220. Kern River testified that use of the composite cost of debt was appropriate because of the interrelated nature of the financings of the ET [Extended Term] program and the 2003 Expansion.[260] It testified that "the debt was issued in both cases under the same debt covenants."[261] It testified further that "the consolidated cash flows of Kern River were relied upon by both series of debt holders, since the 2003 Expansion was a known, projected event at the time of the ET financing."[262] Kern River stated that "[t]he credit quality of the Rolled-In System shippers and related cash flows of Kern River were major factors resulting in the favorable credit rating and interest rate obtained for the 2003 Expansion shippers."[263] Kern River believed that the settlement in Docket No. RP99-274 stands for the sound principle that existing shippers should benefit from any lower interest rate in a subsequent financing that they helped make possible.[264] Kern River believed that this approach was equitable and that it was reasonable to continue it.[265]

221. Also in the record is Kern River's response to a data request it received from RCG. The data request asked whether all of Kern River's transmission system is collateralized to all of Kern River's long-term debt, or whether specific portions of the system are collateralized to specific long-term debt. In response, Kern River stated that its physical pipeline assets are not pledged as collateral for Kern River's long-term debt.[266] Kern River stated that "[a]ll of Kern River's firm transmission service agreements, amounts payable thereunder and underlying shipper credit support instruments (letters of credit, cash deposits) are pledged as collateral for all of its long-term debt."[267] Kern River stated that documentation for these pledges existed in the indentures for the Series A debt of $510 million and the Series B debt of $836 million.[268]

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[260] Ex. KR-17 at 17.

[261] *Id.*

[262] *Id.* at 17-18.

[263] *Id.* at 18.

[264] *Id.*

[265] *Id.*

[266] Ex. RCG-7.

[267] *Id.*

[268] *Id.* Kern River described the documentation of these pledges as follows: For documentation, see the Kern River-Kern River Funding Corp. indenture dated August 13, 2001, related to the $510 million notes due 2016, previously produced as Protected Material in response to data request

(continued…)

222. The Commission finds that the above testimony establishes that the refinancing of the rolled-in system was not based on either the assets of the rolled-in system or on the financial viability of the rolled-in shippers only, but, instead, on the financial viability of all of Kern River's shippers, including the Expansion shippers. In addition, the Commission finds that the above testimony establishes that the financing for the 2003 Expansion Project was not based on either the assets of the Project or on the financial viability of the Expansion shippers only, but, instead, on the financial viability of all of Kern River's shippers, including the rolled-in shippers. The testimony shows that both the Series A debt and the Series B debt were issued under the same debt covenants [269] and both series of debt holders relied upon the consolidated cash flows of Kern River, not just on revenues from one group of customers like the Expansion shippers.

223. Similarly, the testimony above establishes that the firm transmission service agreements, amounts payable thereunder, and underlying shipper credit support instruments (letters of credit, cash deposits) of the rolled-in customers are pledged as collateral for the 2003 Expansion Project. In case of a default on the Expansion Project, creditors could look to the collateral supplied by the rolled-in shippers to pay for the Expansion Project. The testimony also establishes that the firm transmission service agreements, amounts payable thereunder, and underlying shipper credit support instruments (letters of credit, cash deposits) of the Expansion shippers are pledged as collateral for the rolled-in system. In case of a default on the rolled-in system, creditors could look to the collateral supplied by the Expansion shippers to pay for the rolled-in system.

224. Finally, the testimony establishes that Kern River received a favorable credit rating and interest rate for the 2003 Expansion Project based in substantial part on the cash flows and credit quality of the rolled-in shippers.

225. Given the manner in which the financings were made, the Commission concludes that neither the debt cost for the Series A financing nor the debt cost for the Series B financing can be attributed to a single group of Kern River's customers. Both debt costs were based on the characteristics of all of Kern River's shippers and are supported by collateral supplied by all of Kern River's shippers. The Commission concludes these findings are sufficient to support its finding in Opinion No. 486 that the Series A debt

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Calpine-1 No. 61, particularly the Assignment of Contracts, Pledge and Security Agreement between Kern River and Chase Manhattan Bank contained therein, and the Third Supplemental Indenture among Kern River Funding Corp., Kern River and JP Morgan Chase Bank, dated May 1, 2003, for the $836 million notes due 2018, previously produced as Protected Material in response to data request Calpine-2 No. 84.

[269] *Id.*

cost and the Series B debt cost are interrelated. It finds further that both these debt costs are attributable to all of Kern River's customers. The Commission finds there is no testimony in the record that rebuts these findings. Consequently, the Commission affirms that the two debt costs are interrelated.

226. The Expansion shippers assert, however, that cost allocation must follow cost causation, that is, that "those who are responsible for the incurrence of costs be the ones who bear those cost burdens."[270] As the above analysis explains, the debt costs are essentially commingled and cannot be attributed to a single group of customers. Moreover, matching cost allocation to cost incurrence is not a mechanical formula. The *System Energy* case explains that the principle of matching cost incurrence and cost responsibility is based on principles of fairness in ratemaking.[271] In this case, the rolled-in shippers have produced a benefit for the Expansion shippers in the form of a lower interest rate for the 2003 Expansion Project. The rolled-in shippers are also supporting the Series B debt with their cash flows and may be asked to bear the burden of paying for the Series B debt if there is a default. Applying the principles of fairness of *System Energy* to this case, the Commission finds that, given the circumstances in this case, it is fair to use a blended cost of debt and to provide some of the benefit of the lower Series B debt cost to the rolled-in shippers.

227. For the reasons discussed above, the Commission affirms its finding that the two debt series are interrelated and its holding, based on that finding, that it is appropriate to use a blended cost of debt and denies the rehearing requests to use separate costs of debt.

B. Consistency with Settlement, Certificate Orders, and Pricing Policy Statements

Rehearing Requests

228. Expansion shippers assert that a blended cost of debt is inconsistent with the settlement in Docket No. RP94-274-000, Kern River's certificate orders, and both the 1995 and 1999 *Pricing Policy Statements*.

229. Pinnacle West states that the settlement in Docket No. RP99-274-000 provides that the interest component of rates arising from any financing issued in connection with system expansions must be determined in the certificate application.[272] Pinnacle West

[270] *System Energy*, 41 FERC at 61,616.

[271] *Id.* "Principles of fairness in ratemaking support the concept that those who are responsible for the incurrence of costs be the ones who bear those cost burdens."

[272] *Citing* PW-4, Stipulation and Agreement at 8, Article VII, third paragraph, Docket No. RP94-274-000 (March 31, 1999).

states that Kern River's proposed incremental rates in the certificate proceeding included only the Series B debt cost and they were determined in accordance with the settlement. Pinnacle West also states that the settlement does not require that existing customers should benefit from any subsequent debt issuances with lower debt costs unless they are part of an overall cost of a system expansion which would decrease existing rates.[273]

230. The Expansion shippers state the certificate orders found that the 2003 Expansion Project "is separately financed with no overlapping of facilities and costs"[274] and that Kern River should use incremental rates[275] that included only the Series B debt costs. The Expansion shippers also state that the certificate orders reached and decided the issue of whether Kern River should use actual, long-term incremental debt costs or weighted average debt costs in setting rates for the 2003 Expansion.[276] They state these orders directed that Kern River's rates "should reflect actual costs associated with both its short-term and long-term financing arrangements."[277] They state that, contrary to Opinion No. 486,[278] the blended debt cost does not reflect the actual cost of Series B debt because the combined calculation includes the Series A debt cost.

231. The Expansion shippers state that the initial incremental rates for the 2003 Expansion Project cannot be changed in this first section 4 rate filing for the Project unless there has been a significant change of circumstances since the certificate was

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[273] Article IX, Stipulation and Agreement, Docket No. RP94-274-000 (March 31, 1999) (contained in Ex. PW-4) provides in relevant part:

> With respect to system expansions, if any such expansion would increase existing Rate Schedule KRF-1 rates during the term of this Settlement on a rolled-in basis, Kern River will seek incremental rate treatment for the cost of such system expansion in order to avoid increasing such existing Rate Schedule KRF-1 rates. If any system expansion would decrease existing Rate Schedule KRF-1 [or rates derived from Schedule KRF-1 rates] during the term of this Settlement on a rolled-in basis, Kern River will seek rolled-in rate treatment for the cost of such system expansion and agrees as part of this Settlement to make a Settlement Compliance Tariff Filing to reduce the Reservation/Demand Rate for firm transportation services. . . .

[274] *Kern River Gas Transmission Co.*, 98 FERC at 61,723.

[275] *Kern River Gas Transmission Co.*, 98 FERC at 61,715 and 61,722.

[276] *Citing Kern River Gas Transmission Co.*, 98 FERC ¶ 61,205, at 61,723, *reh'g denied*, 100 FERC ¶ 61,056 (2002); *Kern River Gas Transmission Co.*, 103 FERC ¶ 61,102, at P 9 (2003).

[277] *Kern River Gas Transmission Co.*, 98 FERC at 61,723.

[278] Opinion No. 486 at P 199.

issued.[279] They state the intent of this policy is to provide efficient pricing signals to expansion shippers and existing pipeline customers. They assert there have been no changed circumstances so that the incremental rate determinations, including the use of actual debt cost, made in the February 27 certificate order[280] should apply in setting incremental rates for the 2003 Expansion services in this section 4 rate case.

232. Pinnacle West states that the Series B debt cost cannot be rolled into the Series A debt cost because the *1999 Pricing Policy Statement* requires incremental pricing for expansions with only two exceptions and the 2003 Expansion Project does not come within the exceptions. It states the exceptions to incremental pricing are (1) where the cost of the expansion capacity is less than the embedded cost of existing capacity and (2) where a Right-of-First Refusal situation is present.[281] Pinnacle West also states that there is an equitable concern underlying the *1999 Pricing Policy Statement* of avoiding a subsidy (there, of expansion shippers by existing shippers). It asserts that equitable concern should also apply here so that the Expansion shippers should not be required to subsidize the rolled-in shippers.

Commission Determination

233. The Commission denies the rehearing requests. It finds that the settlement, certificate proceeding, and *Pricing Policy Statements* do not provide impediments to the adoption of a blended cost of debt.

234. A blended cost of debt is not inconsistent with the certificate proceeding. First, the statement cited by Expansion shippers that the 2003 Expansion Project was separately financed with no overlapping of facilities and costs[282] was made in the context of examining whether any physical facilities were used by both the rolled-in shippers and the Expansion shippers; it did not apply to debt costs.

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[279] *Citing1995 Pricing Policy Statement*, 71 FERC ¶ 61,241, at 61,918 (1995); *1999 Pricing Policy Statement*, 88 FERC ¶ 61,227 (1999), *order on clarification*, 90 FERC ¶ 61,128, *order granting further clarification*, 92 FERC ¶ 61,094 (2000); and *Texas Gas Transmission, LLC*, 110 FERC ¶ 61,132, at P 16 (2005).

[280] *Kern River Gas Transmission Co.*, 98 FERC ¶ 61,205 (2002).

[281] *Citing 1999 Pricing Policy Statement* at 61,746.

[282] *Kern River Gas Transmission Co.*, 98 FERC at 61,723.

235. Contrary to the assertion of Calpine,[283] there was no determination in the certificate proceeding as to whether a blended debt cost should be used.[284] As we stated in Opinion No. 486, 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.[285] As we pointed out in Opinion No. 486, a pipeline generally cannot make proposals that would cause restatement of all of its system-wide base tariff rates in section 7 certificate proceedings.[286] In the certificate proceeding, Kern River could reflect only the incremental cost of debt for the 2003 Expansion Project.[287] The certificate proceeding determined only that Kern River must use actual debt costs.[288] The certificate proceeding 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 in Kern River's next section 4 rate case.

236. In this section 4 rate case Kern River was able, for the first time, to propose a blended cost of debt. Contrary to the contentions of the Expansion shippers, that blended debt cost is the actual debt cost for both the rolled-in customers and the Expansion

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[283] Calpine Request for Rehearing at 19.

[284] Pinnacle West, however, states that no consideration was given in the approval of the initial rates for the 2003 Expansion Project as to whether the debt instruments were interrelated. Pinnacle West Request for Rehearing at 11.

[285] Opinion No. 486 at P 197-98.

[286] *Id.* at P 197.

[287] Thus, Kern River complied with the terms of the Docket No. RP94-274-000 settlement requiring it to include the expected interest cost component of the cost of service in the certificate proceeding for an expansion to the extent that it was able to do so. (*See* below.) In addition, the settlement does not prohibit Kern River from proposing a blended cost of debt in this proceeding. The settlement only binds Kern River to the rate design issues decided in the certificate proceeding "for the duration of the Settlement Rates . . . ." Kern River's filing in this section 4 proceeding supercedes the settlement rates in Docket No. RP94-274-000. *See* PW-4, Stipulation and Agreement, Article VII, third paragraph, at p. 8 Docket No. RP94-274-000 (March 31, 1999):

> Regarding any refinancing in connection with a system expansion, Kern River will present in the certificate application its proposal for the rate design applicable to the system expansion, including the expected interest cost component of the cost of service. Any customer may contest such rate design and cost of service treatment in the certificate docket, and Kern River agrees to abide by the Commission's final determination of any rate design issues raised upon acceptance of the certificate for the duration of the Settlement Rates contemplated herein.

[288] *Kern River Gas Transmission Co.*, 98 FERC at 61,723.

shippers. As discussed above, both Series A and Series B debt costs are attributable to both customer groups—the rolled-in customers and the Expansion shippers. Thus, the actual cost of debt for both groups of customers is the blended debt cost resulting from combining the cost of debt of Series A and the cost of debt of Series B.

237. Expansion shippers argue that the *1999 Pricing Policy Statement* prohibits rolling in the costs of an expansion, including the cost of debt, unless the expansion is cheaper than the rolled in system or there is a ROFR situation. They also assert that the incremental rate determinations for the 2003 Expansion Project, including the use of the actual cost of debt, cannot be changed unless there has been a significant change in circumstances.[289]

238. The Commission believes these arguments mischaracterize Kern River's proposal to use a blended cost of debt. The *1999 Pricing Policy Statement* and the *Texas Gas* case they cite are concerned with whether the costs of an expansion will be recovered through incremental rates or through rolled-in rates. Kern River has not proposed to abandon incremental rates for the 2003 Expansion Project by rolling the costs of that expansion, over $1.2 billion, into its existing rates. Kern River has proposed an adjustment to the cost of debt to reflect the fact that the costs of debt of both Series A and Series B are attributable to all of its customers. The Expansion shippers state the effect of the adjustment would be a cost shift to them of $11 million,[290] an amount of costs that would have a negligible impact on the incremental rates for the Expansion Project.[291] The cost of debt adjustment proposed by Kern River does not transform the Expansion shippers' incremental rates to rolled-in rates, but, instead, a minor adjustment to the incremental rates. Moreover, Kern River's adjustment to the cost of debt is consistent with the purpose of the *1999 Pricing Policy Statement.* The fundamental goal of the *1999 Pricing Policy Statement* is that existing shippers should not subsidize expansion shippers. In this case, we have found that the low level of debt cost of the Series B debt was the result of creditors' relying on the cash flows and credit quality of the existing, rolled-in shippers and that creditors look to the service agreements and related obligations of the rolled-in shippers in case of a default in the payment for the 2003 Expansion. The Expansion shippers enjoyed this lower rate of Series B interest for the initial eighteen months of

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[289] *Citing1995 Pricing Policy Statement*, 71 FERC ¶ 61,241, at 61,918 (1995); *1999 Pricing Policy Statement,* 88 FERC ¶ 61,227 (1999), *order on clarification*, 90 FERC ¶ 61,128, *order granting further clarification*, 92 FERC ¶ 61,094 (2000); and *Texas Gas Transmission, LLC,* 110 FERC ¶ 61,132, at P 16 (2005).

[290] Edison Mission Request for Rehearing at 11.

[291] *See Kern River Gas Transmission Co.,* 98 FERC at 61,723 (stating that including $12 million of existing capacity in the total projected costs of the 2003 Expansion Project of approximately $ 1.27 billion had a negligible impact on Kern River's incremental rates for the Expansion Project).

their service on the 2003 Expansion facilities. In effect, the existing rolled-in shippers provided the Expansion shippers with a subsidy in the form of a lower interest rate during this period. Kern River's blended debt cost proposal puts an end to that subsidy and thus fulfills the intent of the *1999 Pricing Policy Statement*.

C. Consistency with Treatment of Bonus Depreciation ADIT and Pre-Existing Common Costs in Opinion No. 486

239. The Expansion shippers assert the use of a blended cost of debt is inconsistent with the treatment of a number of other costs in Opinion No. 486 such as ADIT related to bonus depreciation.[292] They state the Commission found that this ADIT was a cost unique to construction of the 2003 Expansion facilities and, as such, should be included within the incremental cost of the Expansion facilities. They state the Commission should find the Series B debt cost is a cost unique to the Expansion facilities and allocate this debt cost solely to the Expansion shippers, just like the ADIT related to bonus depreciation.

240. They also assert that the debt cost associated with Series A debt is a cost that was in existence before the construction of the 2003 Expansion Project and, therefore, should be allocated solely to the rolled-in shippers, just like pre-existing common costs were allocated to the rolled-in shippers.[293] They assert that allocating this cost to Expansion shippers creates a subsidy for rolled-in shippers.

241. The Commission denies these rehearing requests. In the case of the bonus depreciation ADIT and of the pre-existing common costs, the relation of the costs to one group of customers or the other was sharply delineated. The bonus depreciation ADIT arose without reference to the rolled-in shippers and was related solely to the engineering and construction costs of the 2003 Expansion. The pre-existing common costs were incurred without reference to the Expansion shippers and were related solely to the engineering and construction costs of the earlier rolled-in projects. ADIT is a cost-of-service factor derived from a specific set of capital expenditures. That is not the case with the Series A debt cost and the Series B debt cost. As explained above, these debt costs were related to both groups of shippers. Therefore, the Series A and B debt costs are not like the bonus depreciation ADIT or the pre-existing common costs and neither should be allocated solely to either the rolled-in customers or the Expansion shippers.

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[292] Opinion No. 486 at P 240-244.

[293] *Id.* at P 350-351. The common costs at issue there were costs associated with land, rights of way, compressor station structures, and communications equipment.

D. Series A Debt Costs

Background

242. In its testimony and at hearing Kern River stated that $29 million from equity, was used to pay for approximately 60 percent of the issuance and swap redemption costs associated with Series A issuance, from a total of $48.2 million. Kern River calculated that the effective cost of money for the Series A note was 9.675 percent, which included a return on equity for the equity funds used to pay for 60 percent of the issuance and swap redemption costs. Kern River argued that the cost of debt calculation should include carrying charges related both to the funds supplied by equity investors and to the borrowed funds used to pay the issuance and swap redemption costs.

243. BP argued that the monthly debt service obligations attributed to the Series A debt reflected an over-recovery of debt-costs. According to BP, Kern River included 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 so that all of the swap redemption and issuance costs were amortized as debt. BP asserted further that Kern River 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 with the result that approximately $29,186,887 of costs were 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, was contrary to *Northwest Pipeline Corporation*.[294] BP argued that when the carrying cost for the equity financed debt cost is eliminated from the calculation, the correct debt cost for the Series A note is 8.455 percent rather than 9.675 percent. BP pointed out that Kern River originally calculated the correct 8.455 percent debt cost before it inflated the effective rate to 9.675 percent.[295] BP entered two exhibits into evidence which reflect a downward adjustment to the effective cost of debt for the Series A debt issue. Ex. BP-91 reflected the effective cost of debt for the Series A notes at 8.455 percent and Ex. BP-71 provided a portion of the workpapers used to establish the effective cost of debt for the Series A notes, as well as the blended cost of debt.[296] BP concluded that the appropriate overall embedded/blended cost of debt is 6.34 percent.

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[294] 71 FERC ¶ 61,253 at 61,996 (1995) (*Northwest*).

[295] Exhibit No. BP-71 at 5 (labeled "was").

[296] Within Exhibit No. BP-71, Kern River listed twelve data files which contained additional detail for computing the effective cost of debt for the Series A issue. These files were not offered as evidence by any party.

244. In the Initial Decision the ALJ found that the evidence supported the contention of BP (and also 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.

Opinion No. 486

245. Opinion 486 affirmed the ALJ's determination and found that the appropriate effective cost of debt for the Series A note should be adjusted downward from 9.675 percent to 8.455 percent. The Commission found that BP's evidence was admitted properly and that Kern River itself calculated a debt cost of 8.455 percent which did not include carrying charges for the equity portion of the debt issuance expense and premium to redeem swaps. Kern River's witness provided extensive testimony with regard to Exhibit No. BP-71, which Kern River had previously provided to BP in response to its first set of data requests.

246. The Commission affirmed the ALJ's decision to reduce the cost of the Series A notes from 9.675 percent to 8.455 percent.[297] It denied Kern River's claim that it be allowed to recover an equity return on the $29 million component of its debt cost that it asserted was financed with stockholder equity. It stated that under Commission policy, an equity return is not permitted for equity-financed debt costs,[298] but that such costs received a debt return, as reflected in the 8.455 percent Series A debt cost it was approving. The Commission found that Kern River's claim that its proposed 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, was without merit and departed from Commission precedent.[299] The Commission noted further that 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.[300] The Commission also found that Kern River's assertions that the 8.455 percent debt cost rate does not allow for a debt return on the unamortized portion of the $29 million were unsupported.

Rehearing Request

247. Kern River argues that if it is not permitted to earn an equity return on the $29 million then, at a minimum and consistent with Opinion No. 486 and the Commission's own findings, it is entitled to adjust the effective rate of its Series A debt

[297] Opinion No. 486 at P 209.
[298] *Citing Northwest Pipeline Corp.*, 71 FERC ¶ 61,253, at 61,996 (1995).
[299] *Id*.
[300] *Citing* 18 C.F.R., Part 201, General Instruction 17.

to ensure that the $29 million in equity funds earn a debt return, thus allowing it to fully recovery its cost of borrowing.

248. On rehearing, Kern River first asserts it is entitled to earn an equity return on the equity-financed portion of its refinancing costs, the $29 million. Kern River argues that *Northwest* is distinguishable. Kern also asserts that if it had chosen to include all the refinancing costs with the debt principle, the carrying costs on all of the investment would have been recoverable, since, in its view, the yield to maturity calculation required in the Commission's regulation includes both monthly principal and interest payments on debt.[301] Kern River concludes that it makes no sense for the Commission to permit recovery of interest carrying costs on the debt restructuring fees funded with debt, since they are included in the yield to maturity calculation, but deny comparable treatment of amounts funded with equity.

249. Next, Kern River states that the Commission incorrectly found that the composition and derivation of the 8.455 percent Series A debt cost rate includes a debt return on the $29 million. Kern River states that the $29 million was not included in the calculation of the 8.455 percent debt cost and that the 8.455 percent debt cost does not contain a debt return on the $29 million. Kern River claims that the Commission misconstrued the data depicted on the top portion of Ex. BP-71 and in Ex. BP-91. Kern River provides information in Appendix 3 of its Request for Rehearing, which, it asserts, establishes that the 8.455 percent debt cost does not include a debt return on the $29 million.

250. Kern River states that in directing an adjustment to Kern River's Series A debt cost, the Commission made clear that the $29 million of refinancing fees are entitled to earn a debt return.[302] If it is not permitted to earn an equity return on this amount, then, Kern River requests that it should be allowed to earn a debt return on its investment. In the alternative, if the Commission denies even a debt return on the $29 million, then Kern River asserts it would follow that an adjustment to its capitalization would be warranted to reflect the $29 million of equity financing in its equity ratio.

Commission Determination

Whether Kern River Should Receive Carrying Costs, Either as a Return on Equity or a Return on Debt, on its Series A Notes Refinancing Costs

251. Kern River claims on rehearing both that it should earn an equity return on equity capital used to fund refinancing costs for the Series A debt and that it should earn a debt

[301] Kern River cites 18 C.F.R. § 154.312 (h)(5) (2006).
[302] *Citing* Opinion No. 486 at P 209.

return on other monies used to fund the refinancing costs for Series A debt. The Commission denies these rehearing requests. The costs at issue are costs of reacquiring debt. The Commission has recognized the importance of refinancing debt in order to obtain lower interest rates and decrease rates for consumers. Because of this important function, the Commission has, for many years, permitted pipelines to amortize premiums and other expenses for refinancing debt.[303] However, the Commission has not permitted pipelines to earn carrying charges either as a return on equity or as interest on expenses incurred in refinancing debt. Consequently, the Commission affirms its finding in Opinion No. 486 that Kern River is not entitled to a return on equity on the $29 million of refinancing costs that it claims was financed by equity. In addition, the Commission finds that Kern River is not entitled to a return on these funds as if they were debt. The Commission's regulations and case law provide that the appropriate treatment of refinancing expenses is to amortize them. That is, the pipeline is entitled to a return of the refinancing costs, but not on the refinancing costs.

252. In *Northwest Pipeline*, the Commission reiterated its findings in *Manufacturers Light and Heat Company* that "utility management is under a duty to act prudently to take advantage of changing interest rates and provide the consumer with the lowest embedded debt costs."[304] The Commission therefore permits pipelines to reflect legitimately incurred discounts and premiums by amortizing such costs over the remaining original life of the retired debt.[305] This method provides pipelines with reasonable recovery of such costs.[306] In *Northwest Pipeline*, the Commission further stated that the above policy "… does not include the reflection of carrying charges regardless of whether the pipeline experiences a gain or incurs a cost. When pipelines realize gains from the refinancing of

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[303] 18 C.F.R. Part 201, General Instructions, 17 C (2006); *KPC*, 100 FERC ¶ 61,260, at P 102,204-05, 209-13 (2002); *Northwest*, 71 FERC ¶ 61,253, at 61,995-96 (carrying costs as equity not permitted); *Panhandle Eastern Pipe Line Co.,* 71 FERC ¶ 61,228, at 61,830-31 (1995) (carrying costs as debt not permitted); *Manufacturers' Light and Heat Co.,* Opinion No. 583, 44 FPC 314, at 318-26 (1970) (*Manufacturers' Heat and Light*). The Commission has also required the amortization of discounts that occur in refinancing.

[304] *Northwest*, 71 FERC at 61,996.

[305] *Id. See also Manufacturers' Light and Heat*, 44 FPC at 324; *Accounting for Premium, Discount, and Expense of Issue, Gains and Losses on Refunding and Reacquisition of Long-Term Debt, and Interperiod Allocation of Income Taxes*, Order No. 505, 51 FPC 714, *aff'd*, Order No. 505-A , 51 FPC 832 (1974), *remanded, Texas Eastern Transmission Corporation v. FPC*, 574 F.2d 637 (D.C. Cir. 1978), *aff'g orders on remand*, Order No. 505-B, 59 FPC 591 (1977); *Consolidated Gas Supply Corporation*, 10 FERC ¶61,029, at 61,051-52 (1980); 18 C.F.R. Part 201, General Instructions 17 (2006).

[306] *Northwest*, 71 FERC at 61,996.

debt, the Commission does not require the pipeline to reduce its rate base by the amount of gains. Similarly, pipelines are not permitted to recover carrying charges when they incur costs to refinance debt."[307]

253. We find that the effective cost of debt becomes inflated and takes on the cost characteristics of equity by including a return on equity component in the debt cost calculation. Kern River's witness testified to this very point by stating that the adjusted effective cost of debt for the Series A issue is higher when a 15.1 percent return on equity and a gross-up for income taxes are included in the yield to maturity computation. Kern River's witness agreed that the cost was 300 basis points higher than the 6.76 percent coupon rate when a return on equity is permitted in the debt cost calculation.[308] Since we find that an equity return should not be included in the cost of debt calculation we find it unnecessary to address Kern River's argument on the appropriate common equity ratio to include in the debt cost calculation.

254. Kern River argues that the facts here differ from *Northwest Pipeline* since in Northwest the company acted on its own, between rate cases, to initiate the debt refinancing as a means of reducing its own costs until it next rate case, where, Kern River did not pursue its Series A refinancing but instead was the product of settlement negotiations between Kern River and its shippers who chose to receive the benefits in lower rates. On this point we find that Kern River received other meaningful benefits from its settlement that would offset its claims here, otherwise it would not have been prudent to agree to the settlement.

255. Next, Kern River claims, that unlike *Northwest Pipeline*, it did not seek rate base treatment for the refinancing costs, but did seek to recover the carrying costs on the unamortized equity-financed portion of the swap buyout and redemption fees by including those costs in computation of the effective cost of debt (i.e. internal rate of return calculation). The resultant net proceeds, after expenses is $462 million. By decreasing the gross proceeds to account for issuance and debt swap redemption costs, the effective cost of debt for the Series A issue increases to recover these incurred expenses, for example the effective cost of debt is 8.455 percent, 178 basis points higher then the 6.676 percent coupon rate.[309] It is the higher rate (effective cost of debt) that gets imputed into establishing the rates for Kern River. Whether or not recovery was sought through rate base, it is the internal rate of return calculation for the yield to maturity that captures the recovery of issuance and swap redemption costs. Kern River's argument is off point since in both instances, whether an equity or debt return is requested, the pipeline attempted to recover carrying charges on the issuances and swap

[307] *Id.*

[308] Tr. at 717: 8-23

[309] See Ex. BP-71 and Kern River request for rehearing, Appendix 3, Tab 2.

redemption costs which the Commission had denied. Additionally, on this point in *Northwest Pipeline*, the Commission reiterated its policy and found that pipelines are not permitted to include losses on reacquired debt in rate base. We agree, that Kern River correctly excluded these costs from rate base, but incorrectly included carrying charges in its debt cost calculation, and it is this point which is before us and that our findings here address.

256. Based on our findings we affirm Opinion No. 486 and 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. Additionally, we will deny Kern Rivers alternate request that an adjustment to its capitalization ratio be made since the effective cost of debt granted the Series A issue will allow Kern River to fully recover its issuance and swap redemption costs.

257. In addition, we find that Kern River is mistaken in its claim that it could recover its carrying costs on the $29 million if it had included them in the debt principle because the yield to maturity calculation in the Commission's regulations includes both monthly principal and interest payments on debt. The $29 million and also the remainder of the refinancing costs are costs of reacquiring debt. They are not costs of current long-term debt. Since they are costs of reacquiring debt, they are recovered in accordance with section 154.312 (h)(7) (2006) of the Commission's regulations[310] which provides for the amortization of discounts and premiums and not in accordance with section 154.312 (h)(5) which contains the yield to maturity method for determining the cost of money.[311]

<u>Whether 8.455 Percent Includes Interest Expense on the $29 Million of Equity and Whether 8.455 Percent Is the Correct Cost of Debt for the Series A Notes</u>

258. In Opinion No. 486, the Commission accepted 8.455 percent as the cost of the Series A issue, including breakage fees and issuance costs relying on Ex. BP-71; Ex. BP-91; and Tr. 1431:3-14. [312] The Commission found that the 8.455 percent Series A debt cost included a debt return on the $29 million of equity capital Kern River stated it used for refinancing costs.

259. On rehearing, Kern River asserts that the debt cost of 8.455 percent does not include interest expense related to the $29 million of equity that it used to pay the Series A issuance fees and swap redemption costs. Kern River asserts that it is entitled to a debt return on the $29 million if it is not permitted an equity return on this amount, and that it

[310] 18 C.F.R. § 154.312(h)(7) (2006).

[311] *KPC* at 204-13.

[312] Opinion No. 486 at P 202, 209.

should receive the debt return of 8.455 percent on the $29 million. It asserts that the Commission was mistaken when it interpreted Exs. BP-71 and BP-91 as including a debt return on the $29 million. Kern River provides spreadsheets and other materials in Appendix 3 to its Rehearing Request to show that the $29 million was not part of the calculation of the 8.455 percent debt rate.

260. The Commission finds as follows. First, the materials in Kern River's Appendix 3 to its Rehearing Request have not been admitted as evidence and are not otherwise part of the record in this case and, therefore, cannot be considered. Second, the Commission has determined above that Kern River is not entitled to a debt return on the $29 million. Third, the Commission finds that it is difficult to tell whether the 8.455 debt cost included a return on debt for the $29 million. Even if it did not, however, it appears the 8.455 debt cost may include a return on debt for the $19 million of non-equity funds used to pay refinancing costs for the Series A notes.[313] To the extent that the 8.455 percent debt cost includes a return on debt for the $19 million, it is incorrect and overstated. It appears likely that the 8.455 percent is overstated because page 3 of Ex. BP-71 reflects a cost of debt for the Series A issuance of 8.22 percent, which differs from the 8.455 percent cost of debt that we approved for the Series A issuance. We will require Kern River to make a compliance filing removing any return on debt for refinancing costs, including the $19 million, from the calculation of its cost of debt for the Series A notes. The recalculation of the cost of debt for the Series A notes, may, in turn, affect the blended cost of debt that was accepted in Opinion No. 486.

V. <u>Tax Issues</u>

261. Opinion No. 486 addressed three tax issues that are the subject of rehearing requests here: (1) whether Kern River should receive a federal and state income tax allowance; (2) the allocation of ADIT; and (3) the treatment of the tax net operating loss (NOL) incurred since Kern River's acquisition by MEHC. Opinion No. 486 held that Kern River should receive a full 35 percent corporate income tax allowance[314] and that the impact of the tax net operating loss should be allocated to the expansion shippers.[315] The ADIT issue had two components. The first was the allocation of the increase in rate

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[313] *See* Kern River rehearing request at 73. Kern River states that carrying costs on all of the investment would have been recoverable since they would be included in the yield to maturity calculation includes both monthly principal and interest payments on debt, citing 18 C.F.R. § 154.312 (h)(5). This indicates that Kern River included the $19 million in its calculation of the 8.455 percent debt cost. However, the applicable section is 18 C.F.R. § 154.312 (h)(7) which does not provide for a debt return on refinancing costs. *KPC* at P 204-13.

[314] Opinion No. 486 at P 219-23.

[315] *Id.* at P 228-31.

base resulting from the payment by Williams of Kern River's historical ADIT balance when the pipeline was sold. Opinion No. 486 held that this increase in rate base should be allocated to the rolled-in shippers.[316] The second ADIT issue was the allocation of the ADIT resulting from the 2003 expansion, which Opinion No. 486 allocated to the expansion shippers.[317] Rehearing is denied in all regards.

A. Income Tax Allowance

262. Opinion No. 486 analyzed Kern River's business structure and concluded that (1) the various limited liability corporations and limited partnerships controlling its assets are disregarded for income tax purposes, and (2) that all income of those limited liability corporations and limited partnerships must be taxed as corporate income.[318] The Commission concluded that its *Policy Statement on Income Tax Allowances*[319] was not relevant in the instant case because the applicable IRS regulations require that if a number of partnerships, or other pass-through entities, are controlled by a Schedule C corporation, then all income must be taxed as if it were earned by that corporation. At bottom, the Commission held that if the partnerships or other pass through entities must be disregarded for tax purposes, there are no partnership income tax allowance issues to be addressed. The Commission further concluded that the record establishes that the corporations controlling Kern River have sufficient taxable income to justify a 35 percent federal income tax allowance and the related state income tax allowance.

263. On rehearing, the Rolled-In Customer Group, BP, and Calpine assert that the Commission erred in granting Kern River an income tax allowance. They assert that the Commission mischaracterized Kern River's financial structure and that several of the entities the Commission identified as corporations, KR Acquisition 1, LLC and KR Acquisition 2, LLC (the Acquisition LLCs), are pass-through entities and are not taxed as Schedule C corporations. They further assert that these two entities are controlled by a Schedule C corporation, KR Holding LLC, which is taxed as a corporation and elects to file a consolidated return with its parent company, MEHC, an Iowa Schedule C corporation. Thus, they claim, the two Acquisition LLCs, and all of Kern River's operating divisions are pass through entities that are within the ambit of the *Income Tax Policy Statement.* They argue that even though these entities do not file an IRS Form 1065, they are in the nature of partnerships that do not pay income taxes and the Commission was wrong to conclude that the issues raised by the *Income Tax Policy Statement* do not apply. They assert further, that while Kern River is a non-entity for tax purposes, nonetheless it should be viewed in the same light as its operating components,

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[316] *Id.* at P 239.

[317] *Id.* at P 243.

[318] Pursuant to Treasury Regs. § 301.7701-3. *See* discussion at Ex. KR-66 at 5-8.

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

i.e., as a pass through entity that does not pay taxes. More fundamentally, they argue that *BP West Coast*[320] held that partnerships, or other pass-through entities, may not obtain an income tax allowance because such entities do not pay any income taxes. Therefore the Commission erred in granting Kern River a federal and state income tax allowance. This, they argue, is true whether Kern River is viewed as a composite pass through entity with a tax allowance in its rates, or through the prism of the numerous operating components which make up its financial structure and are controlled by KR Holding LLC.[321]

264. The Commission first concludes that its initial analysis was fundamentally sound. While only KR Holding LLC is taxed as a corporation, this does not change the fact the income generated by Kern River's operations is taxed as corporate income on a consolidated basis regardless of the legal ownership form under the controlling Treasury regulations. Since the lower pass-through LLC forms are irrelevant for tax purposes, this would appear to resolve the partnership (pass-through) tax issue since those entities do not exist for tax purposes, as the Shipper Rehearing parties appear to conceded.

265. However, even if one assumes that the partnership issues are relevant here, the issue would be resolved by the court opinion issued on May 29, 2007, by the D.C. Circuit in *ExxonMobil Oil Corporation v. FERC,*[322] which upheld the Commission's *Income Tax Policy Statement*. The court expressly upheld the Commission's conclusion that a partnership (or other pass-through entity such as an LLC), is permitted to have income tax allowance if the partners establish that they have "an actual or potential" income tax liability on the partnership income attributed to them.[323] Thus, while the Shipper Rehearing requests are correct that the certain of the entities listed in Opinion No. 486 are not Schedule C corporations, this alone does not invalidate the Commission's conclusion that the income of those entities is ultimately taxed as corporate income. *ExxonMobil* affirmed that pass-through entities may be afforded an income tax allowance if the partners have an actual or potential income tax liability on the partnership income

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[320] *BP West Coast Products, LLC v. FERC*, 374 F.3d 1263 (D.C. Cir. 2004) (*BP West Coast*).

[321] Kern River's financial structure is particularly complex and includes a number of LLCs and other pass through entities that control the different assets for which there are different rate structures. Ex. KR-67 and 69 demonstrate the overall structure. Ex. KR-67 shows how income and expense accounts for Kern River as an operating jurisdictional entity flow up through the two Acquisition LLCs. Ex. KR-69 shows how the operating divisions are structured as part of KR Holding, LLC, some of which are clearly designed to hold the assets related to Kern River's different expansions.

[322] *ExxonMobil* at 4-18.

[323] *Id.* at 8, 11-13, 16, 18.

distributed to them.

266. The Shipper Rehearing Parties concede that KR Holding, LLC, is a Schedule C corporation that elects to file a consolidated return with its parent, MEHC.[324] The issue therefore would be whether KR Holding, LLC, as Kern River's sole partner, has an actual or potential income tax liability on the income derived from its subsidiary pass- through entities. BP asserts that Kern River cannot meet this test because Kern River's witnesses concede that KR Holding, LLC will have no actual tax liability until 2009 due to Kern River's large NOL. This fact is reflected in the 2002 and 2003 pro forma returns for KR Holdings in confidential Exs. KR-74 and KR-75.[325] The 2002 pro forma income shows positive income,[326] but the 2003 pro forma shows an unusually large loss, [327] which will be carried forward for several years. The tax impact of the NOL is reflected in confidential Ex. KR-80. In the instant case the test year is the twelve months ended January 1, 2004, adjusted for know and measurable changes through October 31, 2004.[328] Confidential Ex. KR-80 displays pro forma taxable income for the years 2002 though 2004 after elimination of the bonus depreciation from the actual taxable income figure for each year.[329] Moreover, as confidential Ex. KR-60 demonstrates, exceptionally large amounts of depreciation result in lower income, and hence taxes, in earlier years, but higher income, and therefore taxes, in later years as the accelerated or bonus depreciation is worked off the subsequent years. Thus, even though Kern River's controlling Schedule C partner will not have to pay any actual taxes in 2004 and may not have taxable income until 2009, that partner has a potential income tax liability that will occur as income begins to be recognized, which BP concedes will occur in 2009. Thereafter taxable income will continue to increase as both ADIT and the bonus depreciation accounts are reduced, as is discussed *infra*.

267. Thus, in this case what is involved here is a large tax deferral that is generated by the Kern River's depreciation schedules, but not an unquantified avoidance of the partner's long term income tax liability on the income that will be generated by Kern

[324] While KR Holding LLC elects to file a consolidated return with its parent Schedule C corporation, MECH, it meets the "stand alone" test under *City of Charlottesville* in its capacity as Kern River's sole corporate partner. *City of Charlottesville v. FERC*, 774 F.2d 1205 (D.C. Cir. 1985) (*City of Charlottesville*).

[325] The use of the pro forma returns is appropriate because it reflects the income that would be earned by Kern River's Schedule C partner, KR Holding, LLC, under the Commission's "stand alone" policy before that income is included in the consolidated return filed by MECH.

[326] Ex. KR-74 (Confidential Materials).

[327] Ex. KR-75 (Confidential Materials).

[328] *Opinion No. 486* at P 18.

[329] Ex. KR-80 (Confidential Materials).

River's rates. Moreover, the Commission assures that the present value of the tax deferrals does not come as an "interest free loan" at the expense of the rate payers by requiring a regulated entity (Kern River) to normalize its income by reducing its rate base by the amount of the deferrals, which in turn reduces its return and the level of its rates.[330] In this case the required reduction reflects the predicted turn around of Kern River's various tax deferrals and identifies the amount of the rate base adjustment that must be made. Thus, it is proper here to design an income tax allowance based on the normalized income that will be generated by Kern River and that will be attributed to its controlling Schedule C LLC, KR Holding, which is taxed as a corporation.

268. Finally, *City of Charlottesville* also explicitly approved the Commission's practice of applying the marginal tax rate to determine the income tax allowance.[331] The Commission also explained in detail in *Texaco Refining and Marketing, Inc.* why the use of the marginal rate, not the effective tax rate, is the proper interpretation of the *Income Tax Allowance Policy Statement.*[332] The Commission adopts those analyses and concludes that Kern River has established that it should be afforded a 35 percent federal income tax allowance and the related state income tax allowance. Rehearing is denied.

<u>Other Tax Issues</u>

269. The remaining tax issues in this case involve allowances for deferred income taxes and the capitalized of portions of a net operating loss carry forward incurred after 2003. Both are grounded in the Commission's income tax normalization procedures. As explained in detail in Opinion No. 486[333] and in Kern River's direct and rebuttal testimony,[334] in both instances Commission policy requires a regulated firm to adjust its rate base to reflect the timing difference between the receipt of cash flows generated by the income tax component of its rates and the timing of its actual tax payments.

270. Specifically, accelerated depreciation results in a delay between the time cash flow is received from the income tax allowance and the tax payment because book income is less than it would otherwise be absent the accelerated depreciation. The additional cash can be reinvested and thus increases the firm's return. Thus, the Commission requires a

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[330] Opinion No. 486 at P 228-31.

[331] *City of Charlottesville* at 1207.

[332] *Texaco Refining and Marketing, Inc. v. SFPP*, 117 FERC ¶ 61,285, at P 52-55 (2006), *citing City of Charlottesville* at P 53, n.80, as well as other administrative cases at n.83. *See also SFPP, L.P.*, 121 FERC ¶ 61,240, at P 31-35 (2007),.

[333] Opinion No. 486 at P 228-231, 239.

[334] See Ex. KR-15 at 7-18, discussing the point in overall terms; Ex. KR-17 at 21, noting that the levelized rates give shippers full credit for the tax benefits from accelerated depreciation; and Ex. KR-57 at 28-30.

regulated firm to reduce its rate base by creating an allowance for deferred income taxes. Similarly, if a regulated entity has net operating loss carry forwards that it may not use in a given year due to limits on the use of that NOL, the entity pays more cash in income tax payments than it otherwise would have absent the limitations because its book income is more than it would otherwise be. This reduces the entity's potential return below what it would otherwise have been if the regulated entity had paid fewer income taxes in a given year. Thus, the Commission permits the firm to increase its rate base by the foregone tax loss carry forward to compensate for the lost investment opportunity in a particular fiscal year.

271. The two adjustments described here are reciprocal, and both even out over time. Thus, the accelerated component of the depreciation declines and as it does taxable income increases. As the taxes are paid, the ADIT account is reduced because the firm no longer has the advantage of untaxed cash flows that it can reinvest. Similar, as the NOL carry forward is used up, the gap between the cash flow generated by the income tax allowance and the firm's actual tax payments narrows and the loss investment opportunity declines, the amount of the net operating loss the firm is unable to use to offset taxable income declines. The instant hearing requests do not challenge these basis concepts but request rehearing of their application on three grounds.

272. First, BP West Coast and Calpine point out that the ADIT and NOL determinations assume that a partnership may obtain an income tax allowance to recover income tax costs. They assert that since a partnership or other pass through entities pay no income taxes, there is no basis for either an ADIT or NOL adjustment. Thus, they would deny these adjustments arguing that there should be no deferred income tax account because partnerships or other pass-through entities may not be afforded an income tax allowance. This argument is no longer relevant given *ExxonMobil*, *supra*. Thus, the Commission denies their requests to direct Kern River to flow its ADIT back to its customers and to deny Kern River's proposed NOL carry forward adjustment.

273. The second ground involves the elimination of the ADIT balance that had accumulated prior to Williams' sale of Kern River to MEHC in 2002. Williams recognized income on the sale and was required to pay the requisite taxes and to eliminate the existing ADIT on Kern River's book. This resulted in a step up of Kern River's rate base in a single year rather than the more gradual increase that would have resulted if the ADIT existing at the time of sale had been reduced over time under the Commission's normalization rules. Finding that the relevant ADIT was generated by the depreciation expense contained in the Rolled-In Shippers' contracts, Opinion No. 486 held that the increase in Kern River's rate base should be allocated to those contracts. On rehearing, the Rolled-In Shippers argue that income generated from their contracts is used to pay all of Kern River's taxes and the Commission has never before allocated all of the step up from the early realization of ADIT to one group of shippers. They therefore conclude that Opinion No. 486 violates the fundamental benefits – burdens

concept embedded in Commission rate making policy, and that the prior decision should be reversed.

274. The Commission denies rehearing. As stated in Opinion No. 486, the Rolled-In Shippers' normalized rate includes the present value of the turn around of the historical ADIT from the depreciation embedded in their contracts.[335] In the absence of the sale, any up front rate benefit Rolled-In Shippers obtained from a rate base reduction due to ADIT would gradually decline over time and in time Rolled-In Shippers rates would increase as the ADIT account turned around. Williams' sale of Kern River accelerated this turn around and changed the present value calculation embedded in Rolled-In Shippers' contracts to their disadvantage. This does not change the cost causation involved, which is grounded in the depreciation function of their specific contracts. As discussed in the cost of debt section, *supra*, a company's revenues are normally used to pay all its expenses, including taxes, absent some a covenant restricting the use of specific revenues. However, the homogeneous nature of cash flow does not determine cost allocation based on benefits and the related liability for the costs. Kern River's levelized rate model has consistently derived ADIT from the depreciation costs resulting from a specific investment and the related depreciation cost are included in the rate structure of a specific contract. Opinion No. 486 continues this practice by allocating the step-up in rate base to the assets that generated the ADIT.

275. The remaining issue on rehearing is whether the ADIT and NOL occurring after the 2002 sale were appropriately allocated to contracts other than the rolled-in contracts. BP West Coast requests the Commission to clarify that the ADIT and NOL adjustments related to the 2003 expansion were incurred in tandem rather than being separated as advocated by some of the Rolled-in Shippers. BP West Coast is correct. The 2003 expansion generated a large ADIT which worked to sharply reduce Kern River's rate base in the initial years of operating the 2003 expansion. This is reflected in the levelized rate for that expansion and on balance works to the rate payers' advantage. However, the bonus depreciation, which is reflected in the ADIT, created such a large income tax deduction that Kern River was unable to use all of that deduction in a single year. As has been described, the Commission policy permits the normalization of the lost tax savings by increasing the rate base. However, Calpine asserts that the NOL was caused by many sources, and as such it was error to attribute the NOL at issue here only to projects outside the scope of the rolled-in contracts, and only to the 2003 expansion in particular.

276. As was discussed in Opinion No. 486, no portion of this NOL was properly attributable to the Rolled-In contracts. First, confidential Ex. KR-80 demonstrates that the NOL is overwhelmingly attributed to the Expansion projects. Moreover, Ex. KR-83 contains a series of tables that summarize the accumulated deferred income tax account for Kern River as a whole and for each of the different rate structures supported by its

[335] Opinion No. 486 at P 228-29.

contracts. Page one of the exhibit shows the total NOL as of October 31, 2004 was $106,293,000, reflected as an addition to rate base per Commission policy, compared to a total bonus depreciation ADIT account of -$133,756,300, a proper negative entry to the rate base. Page two addresses the Rolled-In Transmission and shows a small bonus depreciation ADIT account of -$5,914,600 reducing the rate base. There is no NOL on this sheet. Page three shows the same figures for the 2003 Expansion, with a bonus depreciation ADIT of -$123,140,900, reducing rate base, and a NOL of $108,994,000 increasing the rate base. Page 4 shows the same accounts for the Desert Lateral with a bonus depreciation ADIT account of - $3,163,600, reducing the rate base, and a NOL of $2,609,000 increasing the rate base. The numbers on page four for the Big Horn Lateral are a bonus depreciation ADIT of - $383,700, reducing the rate base and a NOL of $285,000, increasing it. The method is consistent, and the results are proportionate to and separated by the relevant contracts. The rehearing requests present no reason to conclude that the calculations underlying the summaries are incorrect, that the results are not proportionate to the net revenue generated by each specific set of contracts, or that the summaries are not properly reflected in the costs embedded in the relevant contracts. Rehearing is denied.

VI. Rate Design

A. MOR Credits to Cost-of-Service

Background

277. In designing its rates, Kern River reduces its overall cost-of-service by a credit equal to its revenues from interruptible, authorized overrun, and short-term firm services.[336] It refers to these revenues as its "Market-Oriented Revenues," and thus the credit is known as the "MOR Credit." Kern River then uses only its firm billing determinants to design its rates, and does not allocate any costs to the services producing the Market-Oriented Revenues.

278. Kern River's total Market-Oriented Revenues during the last twelve months of the test period in this rate case (November 2003 through October 2004) were approximately $20.2 million. However, in calculating the MOR credit, Kern River proposed two downward adjustments to its test period Market-Oriented Revenues. The first is the Mirant adjustment. In December 2003 during the test period, Mirant Americas Energy Marketing (Mirant) declared bankruptcy and turned back to Kern River 90,000 Dth/d of firm capacity it had contracted on the 2003 Expansion. This caused Kern River to lose approximately $17 million in annual firm transportation revenues.[337] Kern River

[336] *See* Kern River Schedule J-2, at 2. Ex. KR-86 at 10.
[337] Ex. KR-17 at 15.

nevertheless proposed to keep the Mirant turned back capacity in the 2003 Expansion firm billing determinants used to design its transportation rates, stating that this would shield its customers from the risks and costs associated with the loss of Mirant. Consequently, Kern River claims that at a minimum it should be entitled to reduce the MOR credit by interruptible revenues obtained by remarketing the Mirant capacity.[338] Kern River proposed to do this by treating the first 90,000 Dth/d of interruptible service through the meter as remarketed Mirant capacity, and subtract the $5.185 million in revenues associated with those volumes from the MOR credit.

279. The second adjustment related to Kern River's proposal in this rate case to use a single, blended fuel retention percentage for interruptible and unauthorized overrun services. That proposal went into effect on November 1, 2004 at the end of the suspension period in this rate case. Kern River stated that the blended fuel rates would increase the fuel retention percentages experienced by the users of those services which produce the Market-Oriented Revenues. Kern River claimed that the market value of those services is based directly on the difference in gas prices between its receipt point at Opal, Wyoming and its delivery point into Pacific Gas & Electric Co. at the California border.[339] Therefore, Kern River argued, the increased cost of fuel retention would require it to give greater discounts of its base interruptible rates in order to maintain the volumes. It estimated this would reduce its Market-Oriented Revenues by about $2.9 million below the level it received during the test period before the blended fuel retention percentages went into effect.[340] Kern River therefore proposed to reduce its MOR credit by that amount.[341]

280. After reducing the MOR credit by both these amounts, Kern River allocated the remaining credit between its rolled-in system and the 2003 Expansion based on the total firm billing determinants for each.

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[338] MOR is derived from sales of firm shippers' underutilized capacity.

[339] The ALJ approved Kern River's proposed blended fuel rate (114 FERC ¶ 63,031, at P 498 (2006)), and the Commission affirmed the ALJ on that issue. Opinion No. 486 at P 366-369.

[340] Kern River calculated the $2.9 million reduction by multiplying (1) its actual interruptible throughput during the last twelve months of the test period by (2) the cost of the increased amount of gas it would have retained if the blended fuel rates had been in effect. Kern River used the actual Opal gas price for each day of the test period to determine the cost of the retained gas. Ex. KR-1 at 15-16.

[341] Pursuant to Section 18.1 of the General Terms and Conditions of Kern River's tariff, Kern River is required to share 50 percent of its revenues generated with its firm shippers which pay maximum rates once the annual revenue threshold of approximately $177 million has been exceeded.

281. On rehearing, parties raise issues with respect to Opinion No. 486's rulings on (1) the calculation of the Mirant adjustment, (2) the effect of the Mirant Adjustment on the rates for the Rolled-in System, and (3) the justification for the fuel adjustment to the MOR Credit. We discuss each of these issues below.

i. Methodology for Calculating the Mirant Adjustment

Opinion No. 486

282. Opinion No. 486 affirmed the ALJ's approval of Kern River's proposal to include the Mirant turned-back capacity in the 2003 Expansion firm billing determinants used to design Kern River's transportation rates, but to reduce the MOR credit by $5.185 million in interruptible revenues obtained from remarketing the Mirant capacity. The Commission found that, because the Mirant capacity is now essentially used to transport interruptible and short-term firm gas, the Mirant credit is a simple substitution of service from firm to interruptible. The Commission pointed out that Kern River's witness had testified that, after Mirant terminated its contract, Kern River continued to serve the same markets and its volume of throughput remained virtually unchanged. Therefore, the Commission found it appropriate to track the Mirant capacity to the related MOR revenue and to assign it to Kern River in mitigation of its absorbing the risk of loss of the Mirant contract.

Rehearing Request

283. On rehearing, no party contests the Commission's approval of Kern River's proposal to include the Mirant turned-back capacity in the 2003 Expansion billing determinants used to design Kern River's firm rates. However, Calpine, a shipper on the 2003 Expansion, argues that the Commission did not provide a basis for approving Kern River's "first-through-the-meter" method of calculating level of the Mirant Adjustment to the MOR credit. Calpine claims that under the first-through-the-meter approach, the $5.185 million Mirant Adjustment is overstated. Calpine proposed a "last-through-the meter" approach, where the Mirant adjustment would be based only on MOR revenues collected during the 77 test period days on which Kern River had less than 90,000 Dth/day of unutilized operational capacity, thereby yielding a substantially reduced adjustment of $1.467 million.[342] Calpine argues that on those days when Kern River had unutilized capacity in excess of the 90,000 Dth/day contract demand of the former Mirant contract, Kern River did not need to use the Mirant capacity to provide interruptible service, and thus the service provided on those days should not be treated as utilizing remarketed Mirant capacity. Calpine requests that the Commission find in its favor and

[342] Calpine Request for Rehearing, n.123.

accept its last-through-the-meter methodology, or at a minimum provide the rationale for accepting Kern River's first-through-the-meter calculation.

Commission Determination

284. The Commission denies Calpine's rehearing request and affirms its findings in Opinion No. 486 that the first-through-the-meter methodology of calculating the Mirant Adjustment is just and reasonable. Kern River lost revenues of approximately $17 million when Mirant terminated its contract. By retaining Mirant's 90,000 MMBtu of billing determinants in the volumes used to design the 2003 Expansion rates, Kern River is bearing the risk of remarketing Mirant's 2003 Expansion capacity in order to make up that revenue. In recognition of this risk, Kern River proposes to reduce the MOR credit by $5.185 million, calculated by assuming the first 90,000 MMBtu of interruptible volumes through the meter are attributable to remarketing the Mirant capacity. We find this is reasonable, in light of the facts (1) that Commission policy would permit Kern River to exclude the contract demand associated with the Mirant contract from its 2003 Expansion firm billing determinants, and (2) Kern River appears to have continued to serve the same markets that Mirant served.

285. The Commission generally designs a pipeline's rates based upon a projection of the units of service that the pipeline will provide during the time the proposed rates are in effect.[343] In projecting long-term firm contract demand, the Commission's general policy has been to treat the contract demand in effect on the last day of the test period as the latest, best projection of the long-term firm contract demand that will be in effect once the rates go into effect.[344] Here, it is undisputed that Mirant terminated its contract before the end of the test period and Kern River was not able to sell the Mirant capacity to another firm shipper.[345] Thus, Kern River could have sought to exclude the Mirant long-term contract demand from the rate design volumes used to design the incremental 2003 Expansion rates. Nevertheless, Kern River is treating the Mirant capacity (90,000 Dth/d) for rate design purposes as though it were still firm capacity under contract. Kern River's proposed $5.185 million reduction in the MOR credit, based on its first-through-the-meter methodology, is less than one-third of the $17 million in firm revenues, which Kern River could have sought to collect from its remaining 2003 Expansion firm customers if it had removed the Mirant contract demand from the volumes used to design the 2003 Expansion rates.[346]

[343] 18 C.F.R. § 284.10(c)(2) (2007).

[344] *Trunkline Gas Co*., 90 FERC ¶ 61,017, at 61,084 (2000).

[345] Ex. KR-86 at 14.

[346] However, under our policy concerning incremental rates, Kern River may not shift any of the costs of unsubscribed 2003 Expansion capacity to the rates for firm service on the Rolled-in system. As the Commission stated in the *Certificate Pricing*

(continued…)

286. Moreover, treating the first 90,000 Dth of interruptible service through the meter as remarketed Mirant capacity is consistent with the fact Kern River continues to ship gas to the same markets as were formerly served through Mirant. Kern River presented evidence that Mirant used its firm capacity on Kern River to serve its Apex electric generation plant and various other markets. Kern River states that it continues to use its 2003 Expansion capacity to ship gas to those same markets, but on an interruptible rather than a firm basis. It points out that the throughput on the 2003 Expansion has remained virtually the same since the termination of the Mirant contract, representing 89.11 percent of total 2003 Expansion capacity before the termination and 88.92 percent thereafter. Calpine's approach of using last through the meter would unreasonably reduce Kern River's opportunity to recover its costs, by reducing the Mirant Adjustment to less than $2 million, or less than one eighth of Kern River's lost revenues. We affirm the findings in Opinion No. 486 and find that the first-through-the-meter methodology recognizes the inclusion of the Mirant capacity in the design of firm transportation rates.

ii. Allocation of Mirant Adjustment

Opinion No. 486

287. Opinion No. 486 approved Kern River's proposal to subtract the $5.185 million amount of the Mirant Adjustment from the $20.2 million in overall MOR revenues, before the net MOR credit was allocated between the Rolled-in System and the 2003 Expansion. This had the effect of eliminating revenues from the resale of the Mirant capacity from the MOR credit allocated to both the Rolled-in System and the 2003 Expansion. The Commission found that the record reflects that all of Kern River's pipeline capacity is being utilized to provide the interruptible services that generate the market-oriented revenues, and therefore the MOR credit should be allocated to the Rolled-in System and the 2003 Expansion based on the total firm billing determinants for each. The Commission rejected contentions that a reduction in the MOR credit given to the Rolled-in System based on the Mirant Adjustment would require the Rolled-in System shippers to subsidize the 2003 Expansion contrary to the Commission's *Certificate Pricing Policy Statement*.[347] The Commission stated that the issue here is not the costs associated with any new service, but the allocation of revenue credits, a projection based on test period results.

Policy Statement, "the pipeline must be prepared to financially support the project without relying on subsidization from its existing shippers." 88 FERC ¶ 61,227 at 61,746. *See also Policy for Selective Discounting by Natural Gas Pipelines*, 113 FERC ¶ 61,173, at P 98 (2005).

[347] *Certificate Pricing Policy Statement*, 88 FERC ¶ 61,227, at 61,747 (1999).

Rehearing Requests

288. On rehearing, both BP and RCG contend that Opinion No. 486 erred in permitting the MOR credits allocated to the Rolled-in System to be reduced as a result of the Mirant Adjustment. BP argues that any reduction in MOR credits due to that adjustment should be redirected so that it only affects the 2003 Expansion. BP claims that increasing the Rolled-In Shippers' rates as a result of reducing the revenue credits otherwise allocated to them improperly causes them to subsidize the 2003 Expansion Shippers' rates, contrary to the *Certificate Pricing Policy Statement*. BP argues that Opinion No. 486 ignores numerous cases where the Commission looks to the net result – costs less revenues – to determine whether a subsidy is present.[348] In short, BP argues that the Rolled-In shippers should not be forced to subsidize the 2003 Expansion by having their MOR revenues diminished.

289. RCG echoes these concerns and claims that the Commission's allowance of a reduction to the MOR credit to compensate Kern River for the assumption of risk in the transportation rate design has the effect of shifting a portion of this risk to Kern River's shippers on the Rolled-in System by reducing the credit to the cost of service of the Rolled-in System. RCG claims that the effect of this is to shift part of the risk to Kern River's shippers by reducing the credit to the cost of service. RCG argues that the *Certificate Pricing Policy Statement* does not permit any mitigation of risk associated with an expansion and that Kern River's Mirant Adjustment is inconsistent with that principle and should be rejected.

Commission Determination

290. The Commission denies the rehearing requests of BP and RCG on this issue. Kern River's proposal to subtract the $5.185 million amount of the Mirant Adjustment from the $20.2 million in overall MOR revenues, before the net MOR credit is allocated between the Rolled-in System and the 2003 Expansion, means that the MOR credit allocated to the Rolled-in System does not include Kern River's revenues from the resale of the Mirant capacity. The Commission continues to find Kern River's proposal to be reasonable. The Commission determined that by making the Mirant adjustment the remaining, or net MOR revenues available for allocation amongst the Rolled-In shippers and the 2003 expansion shippers would be the same as if the 90,000 Dth/d of Mirant capacity continued to be subscribed on a long-term firm basis and was not available to

[348] *Citing Southern Natural Gas Co.*, 115 FERC ¶ 61,328 (2006), *East Tennessee Natural Gas LLC*, 114 FERC ¶ 61,122, at P 31 (2006); *Northern Natural Gas Co.*, 114 FERC ¶ 61,308, at P 18-21 (2006).

generate MOR revenue credits. Because Mirant was a shipper on the 2003 Expansion, it is reasonable that the Rolled-in System shippers should be unaffected by Mirant's departure. This means that Mirant's departure should neither harm, nor benefit, the Rolled-in System shippers.

291. Kern River's voluntary agreement to retain Mirant's contract demand of 90,000 MMBtu in the billing determinants used to design its firm rates and thereby absorb the risk of cost collection associated with that rate design ensures that the Expansion shippers are not harmed by Mirant's departure. Likewise the Rolled-in shippers should also be unaffected by the Mirant departure. In the preceding section, we found that the $5.185 million amount of the Mirant Adjustment appropriate represents revenues Kern River obtained by remarketing of the Mirant's capacity on the 2003 Expansion on an interruptible and short-term firm basis to shippers serving the same markets Mirant previously served.[349] We agree this provides Kern River the opportunity to collect its costs associated with the 90,000 MMbtu Mirant capacity. If Mirant had not terminated its contract, this market-oriented revenue would not have existed and Kern would have collected its costs from Mirant's demand charges. In short, including the revenue from remarketing the Mirant capacity in the MOR credit allocated to the Rolled-in System would result in the rolled-in shippers benefiting from the Mirant's rejection of its contract. Subtracting the Mirant Adjustment from the MOR credit before that credit is allocated between the Rolled-in System and the 2003 Expansion reasonably assures that the Rolled-in System shippers do not receive such a benefit, nor are they any worse off as a result of the Mirant departure.

iii. Market-Oriented Revenue Credit and Fuel Adjustment

Opinion No. 486

292. In Opinion No. 486 the Commission affirmed the ALJ's rejection of Kern River's proposed $2.9 million fuel adjustment to its MOR crediting. The Commission's decision was 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.[350] Further, the Commission determined that the proposed adjustment is unwarranted because the fuel charges are fully paid for by shippers through the fuel retainage percentages. The Commission stated that in order to permit the proposed reduction it must be based on evidence that the test period market-oriented revenue does not provide an appropriate representative value on which to determine future rates.

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[349] Kern River witness Dahlberg testified that after Mirant rejected its contract, Kern River continued to serve the same markets and the volume of throughput on the 2003 Expansion remained virtually unchanged. Ex. KR-86 at 12.

[350] *See* 18 C.F.R. § 154.303(a)(4) (2006).

Moreover, any adjustment to market-oriented revenue must necessarily be based on evidence that Kern River's AOS and IT rates themselves will be so high as to make the transportation services unmarketable. The Commission determined that Kern River had failed to demonstrate this because its hypothetical example was 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. The Commission determined that Kern River's example fails to be persuasive.

Rehearing Request

293. On rehearing, Kern River argues that it did meet the Commission's standard that a test period MOR credit can be adjusted to reflect known and measurable changes when demonstrated with reasonable accuracy. Kern River states that it presented undisputed evidence that the rate Kern River can charge for IT and AOS services is a function of the basis differential between Opal, Wyoming, and the California border, less the cost of fuel to the shipper.[351] Kern River states it showed that there is a direct and inverse relationship between fuel costs and the market value of pipeline transportation when shippers are deciding on transportation options.[352] Kern River explains that its proposed blended fuel rate, which the Commission accepted, resulted in higher fuel costs for IT and AOS services. Kern River explains that this in turn lowered the IT/AOS rate that a shipper is willing to pay for those market-oriented services by the value of the additional fuel that the shipper is now required to supply.[353] Kern River argues that this change in fuel rates results in Kern River receiving lower revenues from these market-oriented services. Kern River claims that this economic principle justifying the MOR adjustment was not challenged at the hearing in this proceeding.[354]

294. Kern River states that it was able to quantify with reasonable accuracy the known and measurable magnitude of the downward MOR adjustment. Kern River refers to the direct testimony of Ms. Dahlberg where Kern River derived a rate adjustment based on the increased cost of fuel retention under the new blended fuel rate, using the actual daily Opal gas prices as reported in *Gas Daily*, through the end of the test period. Kern River explains that this rate adjustment was then applied to the actual IT and AOS throughput levels during this same period to calculate the reduced level of revenues for Kern River's market-oriented services.[355]

[351] Kern River cites to Ex. KR-86 at 7:16-8:4.

[352] *Id.* at 8:5-7.

[353] *Id.* at 7-8.

[354] Kern River cites to Ex. KR-92 where Calpine agrees that a higher fuel rate will result in a reduction to MOR.

[355] Kern River cites Ex. KR-1 at 15-16; Item by reference Kern River B, 45-day update filing, workpaper J-3.

295. Kern River argues it made clear that its fuel adjustment to the MOR credit does not result in Kern River collecting fuel expenses that are already paid by shippers in the fuel reimbursement charge.[356] Kern River states it has shown that the proposed fuel adjustments accounts for the reduction in the value of IT and AOS services in terms of the rate a shipper is willing to pay. Kern River argues that this reduces revenues that Kern River can generate as a result of the new blended fuel rate.[357]

Commission Determination

296. The Commission reaffirms its decision in Opinion No. 486 that Kern River's proposed $2.9 million reduction in its MOR crediting to account for the increased fuel rates is unwarranted for the reasons discussed below. As a result, Kern River's request for rehearing of this issue is denied.

297. Kern River's new blended fuel rate took effect on November 1, 2004, the day after the test period ended. Thus, it is seeking to reduce its projection of its market-oriented revenues based upon a change in circumstance that did not occur until after the test period. As a result, there is no actual test period experience with the increase in the fuel rate upon which to base a projection as to how that increase will affect Kern River's market oriented revenues. Kern River simply hypothesizes that the increase in its fuel rate will cause its market oriented revenues to decrease by the cost of the additional gas that it retains each month. By contrast, when a change in circumstance occurs before the end of the test period, there is at least some actual test period experience with the change upon which to base a projection as to how the change will affect the pipeline's revenues. For example, if a significant change occurred six months before the end of the test period, the Commission might consider annualizing the actual experience during the last six months of the test period in order to develop a projection of how the change would affect the pipeline's revenues.

298. Here, while Kern River presented a theoretical justification as to how the post-test period increase in its fuel rate would reduce its market-oriented revenues, Calpine presented evidence suggesting that, at least during the first two months after the test period, no such reduction actually occurred. Calpine asserted that for calendar year 2004, which extended two months after the October 2004 end of the test period, Kern River's total market-oriented revenues were about $26 million.[358] This is $5.8 million in excess of the $20.2 million in total market oriented revenues Kern River reported for the last

[356] *Citing* Ex. KR-86 at 7:10-11.
[357] *Citing* Ex. KR-1 at 15-16; Ex. KR-86 at 7:11-15.
[358] Ex. CES-69 at 8.

year of the test period (November 2003 through October 2004).[359] This increase could only have occurred if Kern River's market-oriented revenues during the last two months of calendar year 2004, which were the first two months after the blended fuel rate took effect, substantially exceeded the approximately $530,000 in market oriented revenues which it reported for the last two months of 2003. Thus, the only actual experience with the increase in Kern River's fuel rate reflected in the record of this case is exactly the opposite of Kern River's claim as to what the effect of that increase would be. In these circumstances, we conclude that the ALJ reasonably found that Kern River had not satisfied its burden under NGA section 4 to support its proposed fuel adjustment to the MOR credits. As a result, Kern River's request for rehearing of this issue is denied.

B. 100 Percent Load Factor Rate for IT and AOS Service

i. General

299. 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.[360] 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 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. 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.[361]

The ALJ's Initial Decision

300. The ALJ concluded that Kern River had not carried its burden of proving that its proposal produces just and reasonable rates. 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

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[359] Item by reference Kern River B, 45-day update filing, workpaper J-3.

[360] *2000 ET Settlement Order*, 92 FERC at 61,157.

[361] Thirteenth Revised Sheet No. 5.

Expansion System by total demand determinants and adding a commodity component equal to total variable costs divided by total throughput.[362]

301. 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 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.

302. The ALJ found that Staff's proposal did not cause any cross subsidy. The ALJ 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 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.

Opinion No. 486

303. The Commission affirmed the ALJ's determination adopting the blended approach proposed by Staff for designing both the IT and AOS rates. The Commission found that Kern River failed to satisfy its burden under NGA section 4 to show that its proposed IT and AOS rate design was just and reasonable. The Commission found that Staff's proposal met the Commission's goal of promoting allocative efficiency, and accounts for IT/AOS shippers making use of the entire Kern River system. The Commission found that because IT and AOS transportation are identical on the Kern River system, the same maximum rate should apply to both.

304. The Commission rejected Kern River's argument that it was simply proposing to continue its existing IT/AOS rate design, and therefore, had no burden under NGA section 4 to support its proposed rate design. The Commission found that Kern River was simply in error in its claims that its proposed rate design for IT/AOS service was a

[362] Ex. S-12 at 24.

continuation of the IT/AOS rate design approved in the 2000 ET Settlement. The Commission found that 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. This meant that the IT and AOS rates were designed based solely on the costs of the Original System and those rates were unaffected by the contract extensions offered to the firm shippers on the Original System. The Commission stated that 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.

305. In the section 4 rate case, Kern River 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. The Commission stated that, as a result, there was no longer a status quo firm rate upon which to base the IT and AOS rates. Instead, Kern River proposed 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. The Commission found that this was 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 used a firm 10-year contract rate as the basis for the IT and AOS rates.

306. The Commission affirmed the ALJ's decision that Kern River had not carried its burden of proof under section 4 of the NGA. The Commission found that the case presented for the first time, on a full record developed at hearing, the issue of how interruptible rates should be designed in the section 4 rate case of a pipeline with incremental rates.[363] The dispute between the parties centered 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. The Commission found that the IT and AOS rates should be designed on a rolled-in basis, rather than an incremental basis.

[363] 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.

307. The Commission found that Kern River uses both the Rolled-in System and the 2003 Expansion System to provide service to all its shippers, including its IT shippers.[364] The Commission found that 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 was inconsistent with the general rate making principle of matching cost incurrence and cost causation.

308. The Commission rejected Kern River's claims that its proposal to design its interruptible rate based on the highest firm incremental rate was necessary to establish a level playing field among all shippers in the capacity release market. The Commission recognized that it has 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, the Commission found no matter what IT maximum rate is adopted, there will be some competitive distortions.

309. The Commission also rejected Kern River's assertion 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.[365] The Commission found that Staff's proposed rate was sufficiently high to permit Kern River to ration any scarce capacity.

310. The Commission recognized that upon rejecting a section 4 proposal and proposing its own change to the pre-existing rate design, it 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. The Commission found that 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 was 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. The Commission found that the first status quo rates reflected only the costs of the Rolled-in system, and therefore continued use of those rates to design the

[364] 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).

[365] *Policy Statement Providing Guidance with Respect to the Designing of Rates,* 47 FERC ¶ 61,295 (1989) (Rate Design Policy Statement).

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.

311. Therefore, the Commission found that the pre-existing rate design was unjust and unreasonable. The Commission found the blended rate proposal of Staff just and reasonable. Staff's rate was consistent with the policy 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.

Rehearing Request

312. Kern River asserts that in designing the IT/AOS rates it simply employed the then-existing, Commission-approved rate design to calculate updated rates. Kern River asserts that it should not have any burden of proof for this rate, as it is based on a rate design reviewed and approved by the Commission as producing just and reasonable rates, subject only to Commission review under section 5 of the NGA. Kern River contends that the Commission erroneously has determined that this existing, approved rate design is no longer applicable for the Kern River system.

313. Kern River argues that the Commission never fully explains how this change from the existing rate design for Kern River, a change proposed by the Staff, results in a new rate that Kern River must justify under section 4. Kern River asserts that the rate design proposed, using a 100 percent load factor rate based on the system's highest firm service rate, has been used for IT and AOS services since 2000. Kern River submits that the IT and AOS rate design proposed by Kern River is, by definition, just and reasonable, inasmuch as it is derived (on a 100 percent load factor basis) from a just and reasonable firm transportation rate.

314. Kern River asserts that it has no obligation to support the justness and reasonableness of an existing, Commission-approved rate design under section 4 of the NGA. Kern River contends that because the Commission's proposed change in rate design is a departure from the settled practice of rates on the Kern River system, the Commission and the intervenors necessarily have the burden of proof under section 5(a) of the NGA.

315. Contrary to the Commission's findings, Kern River asserts that the rate proposed by Kern River cannot be unjust and unreasonable, as it is derived from another Commission-approved, just and reasonable rate. Further, Kern River contends that the Commission never explains why Kern River's IT and AOS rate design is unjust and unreasonable in light of its effects on Kern River's ability to recover its costs and the Commission's goals of allocative efficiency.

316. Kern River submits that the blended rate ordered by the Commission denies Kern River the ability to fully recover its costs related to unsubscribed capacity. Kern River submits that unless it has the ability to charge (though with no assurance the market will bear) its proposed IT rate, it will be precluded from even an opportunity to cover the cost associated with the 94,000 Dth/d of capacity that has been turned back due to shipper bankruptcies and/or contract defaults. Kern River argues that the prospect for cost under-recovery is not merely theoretical, but reflects the most likely scenario on the Kern River system, inasmuch as rates for three out of four firm mainline rate classes are higher than the blended IT rate approved in Opinion No. 486.

317. Kern River argues that the Commission should further reject the blended rate design as inconsistent with the Commission's stated goals in its 1989 Rate Design Policy Statement. Kern River states that in the Policy Statement, the Commission specifically outlined its desire to achieve allocative and productive efficiency. Kern River states that in its 1989 Policy Statement, the Commission noted that it had required the allocation of capacity using the "first-come first-served" principle, but would consider a shift in emphasis to mechanisms and rates which more directly allocate capacity to those who value it more highly. Kern River argues that by approving a blended rate that uses the average of costs from the existing and expanded system, the Commission has prevented these goals from being achieved. Kern River contends that the blended rate design approved by the Commission will force the 2003 Expansion and 10-year Rolled-In shippers to discount capacity releases to compete for service to IT shippers who are willing to pay the maximum blended rate.

318. Kern River contends that the lower the maximum IT/AOS rate is set, the less efficiently it will allocate capacity when demand is strong. Kern River asserts that though Staff's analysis shows that actual prices for these services over a single test year did not reach the maximum rate Kern River proposed (i.e., that demand was relatively weak during that particular year), the Staff and the Commission have not analyzed what maximum rate will be necessary to ensure that capacity is allocated to those who value it the most during periods of strong demand. Further, Kern River argues that a rate that maximizes revenues from IT and AOS services will benefit firm shippers, as such revenues will serve to reduce Kern River's cost-of-service.

Commission Determination

319. Kern River raises three issues on rehearing of the Commission's decision approving a blended rate for IT/AOS service: (1) the Commission incorrectly placed the burden of proof on Kern River; (2) the blended rate will prevent Kern River from recovering its cost of service on unsubscribed capacity; and (3) the blended rate is contrary to the principle of allocative efficiency.

320. The Commission rejects Kern River's argument that the Commission incorrectly shifted the burden of proof to Kern River to justify its IT/AOS rate proposal. The Commission correctly found that Kern River had the section 4 burden of proof to justify its proposed IT/AOS rate, because the proposal was not, in fact, a continuation of an existing rate. The IT/AOS rate was previously designed based on a 100 percent load factor of the status quo shipper rate and was based on the rolled-in costs of the original system and the 2002 Expansion. In the section 4 rate filing, Kern River eliminated the maximum rate for status quo shippers since no shippers were using that option. Thus, there was no longer a status quo rate upon which to base the IT and AOS rates. Kern River instead proposed for the first time to design the IT and AOS rates based on the 100 percent load factor derivative of the firm 10-year incremental 2003 expansion rate. Even though Kern River used an existing rate, i.e., the 10-year 2003 expansion rate, its proposal was a clear change from the previous rate design of the IT and AOS rate because it would reflect the incremental costs of the 2003 expansion rather than the costs of the rolled-in system. In essence, Kern River proposed to shift from a rolled-in to an incremental rate design for its IT and AOS rates. Therefore, Kern River appropriately had the burden under NGA section 4 to show why its proposed change in rate design, which reflected the incremental 2003 Expansion costs for the first time, was just and reasonable.[366]

321. The Commission found that Kern River had not satisfied its section 4 burden to show that its incremental IT/AOS rate proposal was just and reasonable for several reasons. First, the Commission found that Kern River uses both its Rolled-in System and the 2003 Expansion to provide service to all its shippers, including its IT shippers. Therefore, the costs incurred to serve IT customers are not just the higher per unit incremental costs of the 2003 Expansion, but the lower per-unit average costs of the entire system. Therefore, the Commission concluded that Kern River's incremental rate proposal would be inconsistent with the ratemaking principle of matching cost causation and cost incurrence. Second, the Commission found that its policies concerning rolled-in vs. incremental rates do not support designing Kern River's IT rates on an incremental basis. For the reasons described in detail in Opinion No. 486,[367] the Commission found that its policy preference for incremental rates only applies to firm shippers, and not to interruptible shippers. On rehearing, Kern River does not contest either of these findings.

322. Having rejected Kern River's section 4 proposal, the Commission recognized that, under *Western Resources*,[368] it had a dual burden under NGA section 5 in order to impose its own design of the IT and AOS rates. The Commission must show that (1) the

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[366] *See Consolidated Edison Co. v. FERC*, 165 F.3d 992, (D.C. Cir. 1999).
[367] Opinion No. 486 at P 333-34.
[368] *Western Resources, Inc. v. FERC,* 9 F.3d 1568, 1578 (D.C. Cir. 1993).

preexisting rate design is unjust and unreasonable[369] and (2) the Commission's proposed rate design is just and reasonable. The Commission found that the existing rates, which were based on the 100 percent load factor derivative of the status quo rates for firm services on the rolled-in system, were unjust and unreasonable because the Commission determined that on an integrated system the IT rates should be based on the rolled-in costs of the entire system including the 2003 expansion. The Commission then found the Staff's blended IT rate proposal to be just and reasonable because it properly reflected the rolled-in costs of the entire system regardless of the fact that certain firm services were priced on an incremental basis.

323. On rehearing, Kern River contends that the Commission failed to meet its section 5 burden to show that the blended rate design is just and reasonable for two reasons. First, Kern River contends that the blended rate design could prevent Kern River from fully recovering its cost of service related to unsubscribed capacity, because the blended rate design will prevent Kern River from selling unsubscribed capacity at an interruptible rate that is as high as the firm rate for three out of the four firm mainline rate classes.

324. As a general matter, the Commission designs a pipeline's rates so that the pipeline can recover 100 percent of its projected cost of service, if it sells the same amount of service as during the test period and market conditions require the same level of discounts.[370] As discussed in the preceding section, Kern River does not allocate any costs to its IT and AOS services. Rather, it includes both those services among its so-called Market-Oriented Services, and credits the projected revenues from those services against its cost-of-service. Thus, Kern River designs its rates based upon the assumption that it will collect revenues from its IT/AOS services equal to the MOR credit against the cost-of-service. Therefore, our requirement that Kern River adopt a blended rate design for its IT/AOS services should not affect its opportunity to recover its cost-of-service, so long as Kern River is still able to recover the projected market-oriented revenues upon which the MOR credit against the cost-of-service is based.

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[369] In its rehearing request, Kern River attempts to cast the Commission's references in Opinion No. 486 to Kern River's "preexisting rate design" (Opinion No. 486 at P 338) as somehow constituting an admission by the Commission that Kern River was proposing to continue the preexisting rate design. However, the Commission's references to Kern River's preexisting rate design were to the design of the IT/AOS rates based on a 100 percent load factor of the "status quo" rates for firm service on the Rolled-in System, not to Kern River's proposal to design those rates based on a 100 percent load factor of the 10-year contract rate for firm service on the 2003 Expansion.

[370] *Policy for Selective Discounting by Natural Gas Pipelines*, 111 FERC ¶ 61,309 at P 4 (2005).

325. From the present record, it does not appear that the blended rate design should affect Kern River's ability to collect IT/AOS revenues equal to the MOR credit. The MOR credit is based on Kern River's actual IT/AOS revenues during the last twelve months of the test period. During that period, Kern River substantially discounted its then effective maximum IT/AOS rates, with the result that the highest average monthly IT rate that Kern River was able to charge was 22.56 cents per Dth during August 2004.[371] That was significantly less than Staff's proposed blended maximum IT/AOS rate of approximately 40 cents per Dth. Thus, the blended maximum IT/AOS rate should not affect Kern River's ability to collect the same revenues from its IT/AOS services as it collected during the last twelve months of the base period. However, in the compliance phase of this proceeding, the Commission will give Kern River an opportunity to show that some of the IT/AOS transactions upon which the MOR credit is based were at rates in excess of the maximum IT/AOS maximum rate approved in this proceeding, thereby justifying a reduction in the MOR credit in order to give Kern River an opportunity to recover its costs under the blended rate design. Thus, the fact blended IT/AOS rates will be lower than a 100 percent derivative of several of Kern River's firm rates should not cause Kern River to underrecover its cost of service.

326. Second, Kern River argues that the blended rate design is inconsistent with the Commission's policy of promoting allocative efficiency. Kern River narrowly focuses on the Rate Design Policy Statement's principle of rationing scarce capacity to those who value it most. However, the goal of the Policy Statement was to design interruptible rates "in a manner which balances the Rate Design Policy Statement's rate objectives of rationing scarce capacity and maximizing throughput."[372] The Commission also seeks interruptible rates which recognize quality of service considerations.[373]

327. In Opinion No. 486, the Commission found that Kern River had not shown that its proposed IT/AOS rate of over 60 cents per Dth was necessary to allocate scarce capacity. The Commission pointed out that Staff had presented evidence that during the last 12 months of the test period, the highest average monthly IT rate that Kern River was able to charge was 22.56 cents per Dth during August 2004, as compared to Staff's proposed blended rate of approximately 40 cents per Dth and Kern River's proposed IT/AOS rate of over 60 cents per Dth.[374] The Commission found that this indicated that Staff's proposed rate was sufficiently high to ration any scarce capacity. On rehearing, Kern River does not challenge the accuracy of Staff's evidence. Rather, it asserts that Staff's evidence simply indicates that demand was relatively weak during that particular

[371] Ex. S-27, at 17.

[372] *See, e.g., Tennessee Gas Pipeline Company,* 80 FERC ¶ 61,070, at 61,204 (1997).

[373] *Southern Natural Gas Co.,* 75 FERC ¶ 61,046, at 61,137 (1996).

[374] Ex. S-27, at 17.

year and a higher rate will be necessary to allocate capacity to those who value it most during periods of strong demand. Kern River cites nothing in the record to support its assertion that demand was relatively weak during the last 12 months of the test period. Nor does it point to any other evidence in the record to indicate that its proposed rate, which is three times higher than the highest average monthly rate it charged during the test period, will be necessary to allocate scarce capacity.

328. The Commission finds that the blended IT rate strikes a reasonable balance among the Commission's various objectives for interruptible rates. Because the rate is approximately twice the highest average monthly rate Kern River was able to charge for IT service during the last 12 months of the test period, it appears adequate to ration scarce capacity, yet it would also better maximize throughput because it is not as high as the proposed rate of Kern River.[375] In addition, the blended rate is more consistent with quality of service considerations than Kern River's proposed rate. Interruptible service is, by definition, of lower quality than firm service. Yet Kern River's proposal to design the IT/AOS rate as a 100 percent load factor derivative of its highest firm rate would require interruptible shippers to pay a higher per unit rate than that paid by its firm shippers.

329. The Commission also rejects Kern River's related arguments that the blended rate will have adverse impacts on the capacity release market. The Commission already determined that there will be some competitive distortions in the capacity release market given that there are six different firm rates for service and that any single uniform maximum rate for IT service could not match the 100 percent load factor rates of all firm service. Moreover, no firm shippers have sought rehearing of the blended IT rate arguing that they will have to discount capacity releases to compete for service to IT shippers who are willing to pay the maximum blended rate. Accordingly, Kern River's request for rehearing is denied.

C. 2002 Expansion Roll-In

330. In May 2002, Kern River completed its 2002 Expansion Project by adding additional compression to its system.[376] Because that expansion provided a greater proportional increase in Kern River's billing determinants than in its overall costs, rolling in the costs of the 2002 expansion reduced the rates for shippers on the Original System. Therefore, in the certificate proceeding for the 2002 Expansion, the Commission approved Kern River's proposal to roll the costs associated with the 2002 Expansion project into the original system costs. As with the Original System, shippers on the 2002

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[375] *See Kern River Gas Transmission Company,* 117 FERC ¶ 61,077, at P 336 (2006).

[376] *Kern River Gas Transmission Co*., 96 FERC ¶ 61,137 (2001).

Expansion 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 for the Original System and the 2002 Expansion together to derive the rates. Rather, Kern River elected to calculate a rate reduction on an equal per unit basis for all original system shippers in order to reflect the benefit of rolling in the cost and volumes of the 2002 Expansion.[377]

331. In the instant rate case proceeding, Kern River did not propose to change the roll-in methodology for the 2002 Expansion.[378] BP argued that if the levelized rates are to be retained, then the Commission should separately calculate the effect of the roll-in of the 2002 Expansion costs for ten year and fifteen year Original System shippers. BP asserted that Kern River's approach, which calculates a uniform per unit reduction for both 10 and 15 year shippers, causes the ten year shippers on the Original System to receive a lesser benefit from the roll-in than the 15 year shippers. BP also argued that by adding the 2002 Expansion costs to calculate a single combined unit rate reduction that is the same for both the ten year and fifteen year Original System shippers, Kern River causes the ten year shippers to subsidize the fifteen year shippers.

332. The ALJ determined that Kern River carried its burden of proving that it should maintain the existing combined, uniform unit rate roll-in methodology. The ALJ found that the only reason that the ten and fifteen year Original System shippers paid different rates is that they voluntarily chose to pay their share of the Original System facility recovery over different time periods. The ALJ determined that the ten year shippers chose to pay a higher depreciation amount over a shorter period and that no party to the 2002 Expansion certificate proceeding opposed this approach and that the Commission accepted it.[379] Therefore, the ALJ concluded that the approach proposed by Kern River was just and reasonable.

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[377] Ex. KR-45 at 5.

[378] Ex. KR-57 at 40. Kern River explains that under normal roll-in methodology, rates are computed through a division of the combined billing determinants into the combined cost of service producing a uniform rate decrease for all shippers. Kern River further explains that due to its levelized methodology and its 10-year and 15-year shipper classes this standard approach did not work. Kern River explains that instead it proposed a uniform per unit rate reduction methodology for its 2002 expansion to simulate the results of the normal roll-in methodology. Kern River states that this approach was not opposed by any party to the 2002 expansion certificate proceeding and the Commission accepted it.

[379] Initial Decision at P 488-89.

333. In Opinion No. 486, the Commission affirmed the ALJ's finding and determined that Kern River should not change its currently approved methodology for roll-in of the 2002 expansion facilities.[380] The Commission also found that the reason 10-year and 15-year Original System shippers pay different rates was due to shippers choosing to pay for their share of 70 percent of the Original System facility investments over either 10-years or 15-years. In addition, the Commission also determined that under Kern River's proposal, the roll-in of the 2002 Expansion costs to the ten and fifteen year Original System shippers was $0.0511 per Dth, but that under BP's proposal the benefit would only accrue to a reduction of $0.0381 per Dth to ten year Original System shippers and $0.0203 per Dth to fifteen year Original system shippers.

334. On rehearing, BP argues that in Opinion No. 486, the Commission determined that the calculation of rates resulting from the roll-in of the 2002 Expansion facilities should ignore the distinction between the ten year and the fifteen year Original System contracts for service. BP argues that so long as the Commission allowed separate rates for 10-year and 15-year Original System contracts on Kern River's system, it is an error to ignore their incremental status when calculating the rate impacts of rolling-in the 2002 expansion facilities.[381]

335. BP asserts that the classification of 10-year and 15-year Original System shipper contracts under the extended term program was approved by the Commission in 2000.[382] BP then argues that under the extended term program, the 10-year and 15-year Original System rates were derived independently of one another so that costs were not shifted between those two different contract durations. BP asserts that when the Commission certificated the 2002 expansion, it calculated the 10-year and 15-year Original System rates without blending their billing determinants. BP argues that averaging in the roll-in calculation results in 10-year shippers paying a portion of the 15-year shipper's costs which is improper.[383]

336. BP also argues that the Commission erred in Opinion No. 486 when it compared Kern River's calculated roll-in benefit of $0.0511 per Dth for both 10-year and 15-year extended term shippers versus BP's calculated benefit of $0.0381 per Dth for 10-year shippers and $0.0203 per Dth for 15-year shippers. BP argues that the Commission did not take into account the differences between return on equity and debt cost. BP argues that the Commission erred in concluding that under BP's proposal, both 10-year and 15-year shippers would receive less of a benefit than under Kern River's proposal.[384]

[380] Opinion No. 486 at P 357.
[381] BP request for rehearing at 51.
[382] *Kern River Gas Transmission Co.,* 92 FERC ¶ 61,061 (2000).
[383] BP request for rehearing at 55.
[384] Opinion No. 486 at P 357.

Finally, BP argues that the Commission ignored the requirement set forth in the 1999 Policy Statement and made by the Commission in the 2002 expansion certificate of no subsidization between classes of shippers.

Commission Determination

337. The Commission finds that Kern River's currently-approved 2002 Expansion roll-in methodology has not been shown to be unjust and unreasonable under NGA section 5. The Commission, therefore, accepts the combined uniform methodology for both 10 and 15 year shippers, even though other methodologies may exist that are also reasonable.

338. In its rehearing request, BP contends that the Commission's acceptance of Kern River's proposal to provide equal per unit rolled-in rate reductions to 10 and 15 year Original System shippers was erroneous on two grounds. First, it argues that Kern River is not proposing a continuation of its existing rolled-in rate methodology, but is, in fact, proposing a change in rate methodology. Therefore, BP argues that the Commission erred in stating that Kern River's proposal could only be modified under NGA section 5. Second, BP argues that, regardless of whether Kern River is proposing a change in its existing rolled-in rate proposal, the proposal is not just and reasonable and should be modified. The Commission rejects both contentions.

339. Kern River's proposal in this rate case to provide an equal per unit rate reduction to all Original System shippers as a result of the roll-in of the 2002 Expansion costs is simply a continuation of its preexisting rolled-in methodology. In the 2002 expansion proceeding, Kern River proposed to calculate the rolled-in rate reduction benefit on an equal per unit basis for all Original System shippers in order to derive an additional rate reduction benefit.[385] BP claims that in the 2002 expansion certificate proceeding, Kern River actually calculated separate rolled-in rates for the 10 and 15 year shippers and did not calculate an equal per unit rate reduction. BP cites, for the first time in this proceeding, Exhibits N and P to Kern River's certificate application to support this contention. However, the Commission's review of Exhibit P of Kern River's certificate proceeding indicates that the rate reduction was in fact calculated on an equal per unit basis, resulting in a per unit rate reduction of $0.0273 per Dth for both 10 and 15 year

[385] 96 FERC ¶ 61,137 (2001). Ex. KR-45 at 5-6. Ex. KR-57 at 40. Kern River explains that in the 2002 expansion certificate proceeding, that it elected to calculate the rolled-in rate reduction benefit of the system expansion on an equal per unit basis for all original system shippers. Kern River further explains that in the instant rate case proceeding, Kern River has continued to calculate a similar equal per unit rate reduction for both the ten and fifteen year original system shippers.

Original System shippers.[386] In addition, the information contained in Exhibit P is consistent with the per unit rate reduction reflected in Attachment No. 2 of Kern River's April 24, 2002, Docket No. RP02-231-000 filing to implement its 2002 expansion service. That filing reflects an equal rate reduction benefit of $0.0296 per Dth for the two classes of shippers.[387] This per unit rate reduction approach was taken in order to account for Kern River's unique levelized methodology and different shipper contract lengths, while still preserving a uniform rate reduction for all original system shippers. No party to the 2002 roll-in expansion proceeding opposed Kern River's approach and the Commission accepted it.

340. BP also points out that the 2002 certificate order stated that roll-in would reduce a 10 year shipper's rates by 5.6 percent and a 15 year shipper's rates by 7.0 percent.[388] The Commission finds that these percentages are consistent with equal per unit reductions. This is because, as explained in greater detail above, an equal per unit reduction results in a greater percentage of reduction for the lower overall 15-year rate, than for the higher overall 10-year rate.

341. Thus, the Commission reaffirms its holding that in this case Kern River is proposing to continue its existing approved rolled-in rate methodology which gives equal per unit rate reductions to both 10 and 15 year shippers.[389] Therefore, the Commission could only change this methodology under NGA section 5. In seeking such a change, BP argues, in essence, that the ten-year and fifteen-year Original System shippers should receive the same overall benefit from the roll-in of the 2002 Expansion costs *during the*

[386] Exhibit P to Kern River's amended 2002 Expansion certificate application in Docket No.CP01-31-001, filed May 11, 2001. The Commission calculated this reduction by multiplying the total daily billing determinants of 871,325 Dth reflected on page 5 of Exhibit P, which includes billing determinants for status quo shippers as well as 10 and 15 year shippers, by 365 to determine an annual amount. This annual billing determinant amount of 318,033,625 Dth was then divided into the annual excess revenue amount of $8,689,422 reflected on page 3 of Exhibit P. The result of this calculation is a rate reduction benefit of $0.0273 per Dth. Page 3 of Exhibit P also shows the allocated benefit to each customer class based on total billing determinants. It stands to reason that the 15-year shipper benefit of $5,625,624 reflected on page 3 of Exhibit P is twice as much as the 10-year shipper benefit of $2,437,316 since 15-year shippers have twice as many billing determinants as the 10-year shippers as shown on page 5 of Exhibit P.

[387] Further, footnote No. 4 of Attachment No. 2 states that the rate reduction methodology is consistent with the Settlement in Docket No. RP99-274 because it ensures that all existing customers participate equally on a per unit basis in the benefits of rolling-in the 2002 expansion project into Kern River's rate design.

[388] BP Rehearing Request at 53, *citing*, 96 FERC at 61,577.

[389] Kern River's Schedule J-2 at p.3.

terms of their current contracts. Because the current contracts of the ten-year Original System shippers terminate before those of the fifteen-year shippers, BP's proposal would necessitate giving the shippers with ten-year contracts a greater rate reduction per unit of contract demand than the fifteen-year shippers.

342. The Commission sees no reason why the rate reduction benefits to shippers on the Original System from rolling in the costs and volumes of the 2002 Expansion should be tied to the terms of their current contracts. The Original System shippers with ten-year contracts pay higher per-unit rates than the shippers with fifteen-year contracts, because each class of Original System shipper agreed to pay 70 percent of the facility costs of the Original System over the terms of their initial contracts. As Kern River's witness testified, that choice only related to the recovery of the costs of the Original System. It had nothing to do with the 2002 Expansion or the allocation of the overall unit cost reduction the 2002 Expansion provided to shippers on the Original System.[390] The per-unit cost reduction resulting from rolling in the costs and volumes of the 2002 Expansion extends beyond the terms of the Original System shippers' current contracts. Thus, rolling in the 2002 Expansion billing determinants and costs not only reduces the current Period One rates of the ten-year and fifteen-year Original system shippers, it will also reduce their subsequent Period Two rates. The Commission finds that if the ten-year extended term shippers remain on the system after their current contracts expire, over time such shippers will receive an identical benefit resulting from the roll-in of the 2002 Expansion, on an equal per unit basis.[391]

343. BP asserts that existing shippers will subsidize expansion shippers as a result of the roll-in of the 2002 expansion costs and states that the Commission in its Opinion No. 486 did not properly address the issue of subsidization as set forth in the 1999 Policy Statement. The Commission finds that the 1999 Policy Statement and subsequent orders[392] make clear that expansion costs should be rolled-in if doing so results in lower rates for existing shippers. In the 2002 expansion proceeding, the Commission found that upon review of the application and supporting workpapers that rolling-in the costs of the 2002 expansion into rate base would reduce the existing shippers' system-wide transportation rates and therefore, a roll-in would not cause the existing shippers to subsidize the expansion.[393] However, the Commission conditioned its acceptance of Kern River's rolled-in methodology upon the requirement that Kern River submit, in future compliance tariff filings, revised exhibits showing the net benefits after fuel costs

[390] Ex. KR-57 at 41.

[391] Ex. KR-57 at 39-42.

[392] *Certification of New Interstate Natural Gas Pipeline Facilities,* 88 FERC ¶ 61,227 (1999), *clarified*, 90 FERC ¶ 61,128, *order on reh'g,* 92 FERC ¶ 61,094 (2000). *See also Transwestern Pipeline Co.*, 90 FERC ¶ 61,032, at 61,162 (2000).

[393] *Kern River Gas Transmission Co.,* 96 FERC ¶ 61,137, at 61,581-82 (2001).

were considered.[394] The Commission explained that the level of excess revenues would serve as a benchmark that Kern River must not exceed when recovering the incremental fuel costs associated with the 2002 expansion from existing shippers. In order to prevent any subsidization from existing shippers, the Commission found that if during any year the level of fuel expenses exceeded the benchmark level of excess revenues, then Kern River must allocate the excess portion of fuel costs to its expansion shippers. Therefore, because Kern River continues to use its currently approved methodology for rolling in the 2002 expansion costs, any concerns expressed by BP with regard to subsidization are without basis.

344. In Opinion No. 486, the Commission concluded that under BP's proposal both ten year and fifteen year shippers would receive less of a benefit than under Kern River's proposal.[395] BP argues that the Commission erred in this statement because the Commission did not take into account the fact that BP's proposal reflected a lower return on equity and debt cost than Kern River's proposal. The Commission recognizes that the differences between return on equity and debt cost used in BP and Kern River's estimates of the rate effect of their different proposals make valid comparisons of the purported benefits difficult to achieve. However, BP has not raised any arguments to compel the Commission to require that Kern River modify its approved 2002 roll-in methodology, which is reasonable given the circumstances. Therefore, BP's request for rehearing of this issue is rejected.

VII. Depreciation

A. Treatment of Depreciation and Deferred Depreciation of Compressor Engines and General Plant in Kern River's Rates

345. In this section we discuss the treatment of book depreciation and deferred depreciation for Kern River's compressor engines and general plant. This section also includes a discussion of the necessity of determining book depreciation rates for all of Kern River's plant categories and the relation of book depreciation rates to Kern River's levelized rates.

346. First the Commission notes that it is necessary to establish book (straight-line) depreciation rates for all of Kern River's plant categories, not only compressor engines and general plant. The book depreciation rates are the depreciation rates that Kern River is entitled to collect. Kern River is required to keep track of the actual amount of depreciation costs it recovers for its plant items and to compare that amount to the

[394] *Id.* at 61,582 (2001).

[395] Opinion No. 486 at P 357.

amount that it would have collected under its book depreciation rates.[396] It may over or under collect the amount of book depreciation to which it is entitled. If it overcollects its book depreciation, then it must credit that amount against its Period Two rates.[397] If it undercollects its book depreciation, however, it may not recover for undercollections as it has assumed the risk of undercollecting its depreciation amounts.[398]

347. In this case Kern River proposed generally to maintain its levelized rates and to charge annual depreciation rates based on the calculations of its levelized model. As the Commission explained in Opinion No. 486, under Kern River's levelized methodology, annual depreciation recovery in rates starts very low and increases during the levelization period.[399] In the early years of the levelization period, regulatory depreciation, that is, 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.[400] In later years, 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.[401]

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[396] When rates are levelized, the pipeline does not charge the book depreciation amount in its rates. Instead, it charges an amount that varies each year. For example, in *Mojave Pipeline Company,* 58 FERC ¶ 61,074, at 61,250-51 (1992), in which the pipeline was authorized to use levelized rates, the pipeline's book depreciation rate for plant cost recovery for accounting purposes was 4.0 percent, but the pipeline was authorized to charge depreciation rates for plant cost recovery under levelized rates ranging from 1.0545 percent in the first year and increasing to 9.2166 percent in the fifteenth year. The difference between the book depreciation rate, 4.0 percent, and the plant cost actually recovered through levelized rates was accounted for as a regulatory asset (if positive) or a regulatory liability (if negative).

[397] Opinion No. 486 at P 48 (stating that "in the later years of Period One when its accumulated regulatory depreciation exceeds its accumulated book depreciation, Kern River will have a regulatory liability which will serve to lower its Period Two rates").

[398] *Id.* at P 49 and 50 (stating that Kern River's Period Two rates will be designed to recover only the remaining 30 percent of the costs of the facilities which coincide with the amount of equity Kern River originally placed in the project) and n. 90 (citing 50 FERC ¶ 61,069 at p. 61,150 (1990) (stating that Kern River will assume the risk of recovery of depreciation not recovered in the first 15 years, the original duration of the Period One rates).

[399] Opinion No. 486 at P 40.

[400] *Id.*

[401] *Id.* at P 40, n.74.

348. However, in addition, to maintaining its levelized rates for most of its assets, Kern River also proposed to remove compressor engines and general plant from its levelized rates and collect depreciation costs for these plant items through traditional cost-of-service rates with straight-line depreciation. In addition, in keeping with its proposal to collect rates for compressor engines and general plant through straight line depreciation, Kern River proposed to create regulatory assets for compressor engine and general plant for the deferred depreciation for these items that it had not collected in prior years under its levelized rates. Kern River proposed that these regulatory assets be included in its rate base and that the proposed regulatory assets be amortized over the remaining terms of its current customers' contracts.

349. In Opinion No. 486, the Commission rejected Kern River's proposal to remove the compressor engines and general plant from its levelized rates so that the depreciation costs of these assets will continue to be collected through levelized rates and not through traditional cost-of service rates with straight-line depreciation.[402] Accordingly, Opinion No. 486 established the book depreciation rate for the Solar Mars compressor engines and items of general plant for book purposes only and not for purposes of collecting depreciation through traditional cost-of-service rates with straight-line depreciation.

350. In this order, as discussed below, the Commission affirms its prior determinations in Opinion No. 486 that compressor engines and general plant may not be removed from Kern River's levelized rates; that deferred depreciation for compressor engines and general plant is correctly included in regulatory asset or regulatory liability accounts; and that the just and reasonable book depreciation rate for compressor engines is 9.92 percent.

B. Whether Depreciation for Compressor Engines and General Plant Should Be Included in Levelized Rates

351. Kern River takes issue with the findings in Opinion No. 486 concerning its proposed treatment of certain compressor and general plant costs. In its proposal, Kern River argued 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. In Opinion No. 486, the Commission disagreed with Kern River on this issue and determined that these items should not be removed from the levelized methodology.[403]

352. In Opinion No. 486, the Commission reasoned that the plan for recovery of depreciation is by nature a long-term proposition, and stated that it had permitted Kern

[402] *Id.* at P 56-57.
[403] *Id.* at P 57.

River 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 acknowledged that this levelized methodology may not be uniquely suited for the recovery of all depreciation for all facilities, but found that because this was the method that Kern River originally proposed, and the Commission accepted, and that all parties have relied upon, the Commission would not permit Kern River to continue its preferred method of depreciation for most of its assets while permitting a more advantageous depreciation recovery methodology for certain plant and or facilities. The Commission also noted that Kern River had stated 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 levelization calculations.[404] Accordingly, for these reasons, the Commission directed Kern River to include the subject amounts in its levelized methodology calculations.

Rehearing Requests

353. On rehearing, Kern River raises several arguments. First, Kern River argues that it was only willing to forego its proposed change concerning depreciation of compressor engines and general plant if the Commission retained the levelization package in all material respects.[405] Kern River states that unless the Commission reverses its rulings

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[404] Opinion No. 486 at P 57.

[405] Kern River relies on the following language from its Brief Opposing Exceptions:

> For clarity, Kern River emphasizes that this alternative position regarding depreciation of compressor engines and general plant would apply only in the event that the Commission held that the depreciation treatment of such plant was the deciding factor in whether it would reaffirm its acceptance of Kern River's levelization "package" in all material respects, including 70 percent depreciation of investment over shippers' (10-year or 15-year) contract lives, the 95 percent load factor rate design for Original System service, the 3 percent O&M inflation factor, amortization of the entire regulatory asset for deferred depreciation over the levelization period, and including the entire unamortized balance of that regulatory asset in rate base. In all other circumstances, Kern River seeks the Commission's acceptance of continued use of Kern River's levelization methodology, as the company proposed, with straight-line depreciation of compressor engines and

(continued…)

regarding the 95 percent load factor rate design and 3 percent O&M and A&G inflation factor, the Commission should reverse its decision regarding Kern River's proposal to recover depreciation of compressor engines and general plant on straight-line basis, rather than as part of the levelized cost-of-service.

354. Second, Kern River argues that to defer much of the cost of these short-lived assets over the course of the levelization periods requires it to experience large under-recoveries of investment in compressor engines and general plant prior to retirement of such plant items as they are retired before they are fully depreciated for rate purposes within the levelized cost-of-service. Furthermore, Kern River argues that with its completed expansions, the number of turbine compressor engines in use on Kern River's mainline has increased from four to eighteen, and the amount of general plant has increased as well. Therefore, Kern River argues that leaving the compressor engines and general plant in the levelization calculations will cause the amount of deferred depreciation related to such assets to continue to grow at an accelerated rate and that as such it raises serious questions of intergenerational equity among ratepayers and increasingly distorts Kern River's cost-of service.

355. Kern River argues that straight-line depreciation better synchronizes cost recovery with cost incurrence related to these assets and that it is fully consistent with the rate stability objective of the levelization methodology. Kern River asserts that because these assets are continuously retired and replaced, Kern River will require roughly the same amount of investment in such plant over time to support its operations. Kern River argues that the only difference between the levelized and straight-line depreciation mechanisms is the timing of the annual recoveries of the depreciation expense required for Kern River to recover its investment in compressor engines and general plant. However, Kern River asserts that its need to finance the ongoing and growing deferrals of recovery of investment in compressor engines and general plant, which must be replaced in relatively constant amounts at relatively constant intervals, will become an increasing burden for Kern River over the course of the levelization period. Therefore, Kern River argues that the Commission should accept Kern River's proposal to depreciate compressor engines and general plant on a straight-line basis and to calculate a separate, traditional cost-of-service related to those categories of plant.

Commission Determination

356. First, the Commission finds that whether Kern River was willing to forego its proposed change concerning depreciation of compressor engines and general plant only if

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general plant included in the cost-of-service, also as proposed. Kern River Brief Opposing Exceptions at 37-38.

the Commission retained the levelization package in a manner acceptable to Kern River is not dispositive of this issue.

357. As explained earlier in this order, Kern River's existing levelized rate methodology is part of the risk sharing agreement among Kern River, its shippers and lenders underlying Kern River's optional expedited certificate. All parties had an opportunity in Kern River's certificate proceeding to express their views on the proposed levelized rate methodology. Once the Commission approved that methodology all parties, including Kern River, its lenders, and its shippers could reasonably rely on that approval in deciding whether to proceed with the project. As a result, the Commission will not lightly change the allocation risk inherent in the optional certificate as granted, absent some overarching policy reason or agreement of all the parties to a change.

358. The Commission has relied on this reasoning to reject BP's request that we eliminate Kern River's levelized rate methodology altogether and require Kern River to adopt a traditional rate design. The same reasoning applies to Kern River's instant proposal to modify the agreed-upon levelized rate methodology to exclude Kern River's compressor engine costs and certain other general plant. Kern River has failed to show any overarching policy reason or significant inequity that would justify modifying its levelized rate methodology in the manner it has proposed.

359. Kern River argues that straight-line depreciation better synchronizes cost recovery with cost incurrence related to these assets and that the cost of these short-lived assets over the course of the levelization periods requires it to experience large under-recoveries of investment in compressor engines and general plant prior to retirement of such plant items and that this may also cause questions of intergenerational equity among ratepayers. However, the parties were presumably aware of the fact compressor engines have a relatively short life both when the levelized rate methodology was originally adopted in the certificate proceeding and when all the parties agreed to continue that methodology in the 2000 ET Settlement. While inclusion of the compressor engine and related plant costs in the levelized rate methodology may require Kern River to defer recovery of some of those costs, the levelized rate methodology allows it to treat such deferred recoveries as a regulatory asset. Therefore, such deferred recoveries are included in its rate base which allows it to earn a return on any deferred cost recovery. Finally, no ratepayer has raised a concern about intergenerational inequities on rehearing. For these reasons, the Commission reaffirms its holding that Kern River must continue to include its compressor engine and related plant costs in its levelized rate methodology.

C. Book Depreciation for Compressor Engines and General Plant and Regulatory Asset Treatment of Deferred Depreciation for Compressor Engines and General Plant

360. In this section, the Commission clarifies that it determined book depreciation rates for compressor engines and general plant because the book depreciation rates determine the total amount of depreciation to which Kern River is entitled for its Period One levelized rates, even though depreciation is actually collected each year at the levels determined by Kern River's levelized rates. It also clarifies that deferred depreciation for these plant assets should be treated as regulatory assets and as part of Kern River's rate base in accordance with and as determined by Kern River's levelized rate model.

Opinion No. 486

361. As indicated above, Kern River had proposed generally to maintain its levelized rates, but it had also proposed to remove compressor engine and general plant from its levelized rates and collect these costs through traditional cost-of-service rates with straight-line depreciation.[406] In addition, in keeping with its proposal to collect rates for compressor engines and general plant through straight line depreciation, Kern River proposed to create regulatory assets for compressor engine and general plant consisting of the 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.[407] With respect to a return on these proposed 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 these proposed regulatory assets, Kern River proposed an amortization period for the regulatory assets equal to the remaining terms of its current customers' contracts.

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[406] Kern River proposed straight-line or book depreciation rates for all of its assets, including compressor engines and general plant. The necessity of determining book depreciation rates is discussed below.

[407] Together with about $13 million of "other regulatory assets," it comprised the regulatory assets that were disputed in this proceeding. All of these amounts were referred to as "regulatory assets" in Opinion No. 486. Ex. KR-100 at 2 showed 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.

362. The Commission found that Kern River should maintain its levelized depreciation methodology as originally accepted by the Commission and revised by agreement of the parties to the ET Settlement.[408] The Commission would not permit Kern River to continue to use the levelized method of depreciation for most of its assets but exclude compressor engines and general plant. It directed Kern River to include these categories of plant in its levelized methodology calculations.[409]

363. In paragraphs 408 through 498 of Opinion No. 486, the Commission addressed Kern River's proposed book (or straight-line) depreciation rates for various types of plant on Kern River's system, including compressor engines and general plant. Among other things, the Commission reversed the Initial Decision's determination that the book depreciation rate for Solar Mars compression engines should be 8.85 percent and found that it should be 9.92 percent.[410] The Commission determined that the book depreciation rates for General Plant should be those proposed by Kern River.[411]

364. In paragraphs 499 through 525 of Opinion No. 486, the Commission discussed and ruled on Kern River's proposed regulatory asset treatment for the depreciation of compressor engines and general plant that Kern River had not previously collected under its levelized rates. The Commission found first that the proposed regulatory assets should be included in rate base since the uncollected depreciation amounts would probably be recovered in future rates.[412]

365. The Commission then reiterated that compressor engines and general plant and other regulatory assets should be included in Kern River's levelized rates.[413] It found that, consequently, the appropriate amortization period for the regulatory assets associated with unrecovered depreciation for compressor engines and general plant was moot. The Commission stated that 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 based on contract life.[414] The

[408] Opinion No. 486 at P 57.

[409] *Id.*

[410] *Id.* at P 476.

[411] *Id.* at P 491.

[412] *Id.* at P 509. The Commission explained that 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 and that this principle justified treating the deferred depreciation for compressor engines and general plant and for other small items as regulatory assets. The Commission found Kern River had properly recorded these items as regulatory assets and that the items were correctly included in Kern River's rate base.

[413] *Id.* at P 518.

[414] *Id.*

Commission also found moot the amount of the proposed regulatory assets that should be included in rate base. The Commission stated again that 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, here based on contract life. [415]

i. Book Depreciation Rates for Compressor Engines and General Plant

366. First, RCG is concerned about the statement "[t]he Commission finds that Kern River's proposed straight-line General Plant depreciation rates appear reasonable and accepts them."[416] RCG asks the Commission to clarify that this statement refers only to Kern River's book depreciation rates and was not intended to apply straight-line depreciation to compressor engines or general plant for rate purposes. RCG also asks the Commission to clarify that its approval of a 9.92 percent straight-line depreciation rate for compressor engines[417] is also only for book purposes and not rate purposes. RCG states that, given the finding that levelized depreciation is to continue for all plant categories,[418] there was no need to establish straight-line depreciation rates for compressor engines or general plant for rate purposes.

367. The Commission grants clarification as follows. The Commission's statement in paragraph 491 of Opinion No. 486 that Kern River's proposed straight-line General Plant depreciation rates appear reasonable and the Commission accepts them referred only to depreciation for book purposes. It does not determine the plant recovery rates to be used under Kern River's levelized rates, which are the rates that the Commission approved for Kern River. The determination in paragraphs 467, 469, and 476 of Opinion No. 486 concerning a depreciation rate of 9.92 percent for compressor engines is similarly for book purposes only and does not determine the plant recovery rates to be used under Kern River's levelized rates.

368. As noted in the introduction to this section, it is necessary to establish book (straight-line) depreciation rates for Kern River's assets, including compressor engines and general plant. These are the depreciation rates to which Kern River is entitled for its assets. Kern River is required to keep track of the actual amount of costs it recovers for these plant items and to compare that amount to the amount that it would have collected

[415] *Id.* at P 525.
[416] *Id.* at P 491.
[417] *Id.* at P 476.
[418] *Id.* at P 57.

under its book depreciation rates.[419] It may over or under collect the amount of book depreciation to which it is entitled. If it overcollects its book depreciation, then it must credit that amount against its Period Two rates.[420] If it undercollects its book depreciation, however, it may not recover for undercollections as it has assumed the risk of undercollecting its depreciation amounts.[421]

ii. <u>Regulatory Asset Treatment for Deferred Depreciation for Compressor Engines and General Plant</u>

369. RCG also asks the Commission to eliminate its language in Opinion No. 486 suggesting that it is accepting for ratemaking purposes Kern River's regulatory assets that include deferred depreciation for compressor engines and general plant. RCG refers to paragraph 509 of Opinion No. 486 which states that it is justified to treat the deferred depreciation for compressor engines and general plant and for other small items as regulatory assets, that Kern River has properly recorded these items as regulatory assets, and that, as a result, these items are correctly included in Kern River's rate base.

370. RCG contends this language is inconsistent with the Commission's rejection of the change from levelized to straight-line depreciation for these items.[422] It also contends it is inconsistent with the finding that the amount and period of amortization of deferred depreciation associated with compressor engines and general plant are moot since they

[419] When rates are levelized, the pipeline does not charge the book depreciation amount in its rates. Instead, it charges an amount that varies each year. For example, in *Mojave Pipeline Company,* 58 FERC ¶ 61,074, at 61,250-51 (1992), in which the pipeline was authorized to use levelized rates, the pipeline's book depreciation rate for plant cost recovery for accounting purposes was 4.0 percent, but the pipeline was authorized to charge depreciation rates for plant cost recovery under levelized rates ranging from 1.0545 percent in the first year and increasing to 9.2166 percent in the fifteenth year. The difference between the book depreciation rate, 4.0 percent, and the plant cost actually recovered through levelized rates was accounted for as a regulatory asset (if positive) or a regulatory liability (if negative).

[420] Opinion No. 486 at P 48 (stating that "in the later years of Period One when its accumulated regulatory depreciation exceeds its accumulated book depreciation, Kern River will have a regulatory liability which will serve to lower its Period Two rates").

[421] *Id.* at P 49 and 50 (stating that Kern River's Period Two rates will be designed to recover only the remaining 30 percent of the costs of the facilities which coincide with the amount of equity Kern River originally placed in the project) and n. 90 (*citing* 50 FERC ¶ 61,069, at p. 61,150 (1990) (stating that Kern River will assume the risk of recovery of depreciation not recovered in the first 15 years, the original duration of the Period One rates).

[422] Opinion No. 486 at P 57.

will be included in levelized rates. RCG states that once the Commission determined that levelized depreciation was appropriate for all plant categories, then all other depreciation-related issues related to compressor engines and general plant, including the creation of a regulatory asset for deferred depreciation, became moot for ratemaking purposes. It states there is no deferred uncollected depreciation for these items under levelized rates both because there is no change in depreciation method and because of the averaging of the costs to be collected over the term of the levelized rates. RCG asks the Commission to confirm that, for rate purposes, compressor engines and general plant will be treated the same as all other plant under the levelized methodology and there will be no creation of regulatory assets associated with deferred depreciation for these plant categories.

371. The Commission denies RCG's rehearing requests. The Commission affirms that compressor engines and general plant will be treated the same as all other plant under Kern River's levelized methodology. That means that deferred depreciation for these plant assets will be treated as a regulatory asset or a regulatory liability and that the regulatory asset or regulatory liability will be included in Kern River's rate base (as an increase if it is a regulatory asset and as a decrease if it is a regulatory liability), as determined by Kern River's levelized model.

372. As the Commission explained in Opinion No. 486 and above, under Kern River's levelized methodology, annual depreciation recovery in rates starts very low and increases during the levelization period.[423] In the early years of the levelization period, regulatory depreciation, that is, the amount of depreciation expense approved for recovery in the levelized 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.[424] In later years, 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.[425]

373. Opinion No. 486 makes clear that under Kern River's levelized model amounts of deferred depreciation, that is, invested capital that has not yet been recovered in rates, is a regulatory asset. "Under Kern River's levelized cost-of-service model, all deferrals [such as depreciation] and the time value of money for such deferrals are treated as a regulatory asset."[426] Thus, the amounts of depreciation for compressor engines and general plant that were previously deferred are correctly included in Kern River's regulatory asset and

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[423] *Id.* at P 40.
[424] *Id.*
[425] *Id.* at P 40 n.74.
[426] *Id.* at P 116.

regulatory liability accounts for its current levelized rates. The Commission affirms these findings here.

374. Opinion No. 486 also makes clear that Kern River's regulatory assets are included in its rate base. It states that Kern River's 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."[427] It also states that deferrals and the time value of money for such deferrals are properly reflected in Kern River's model and that this concept is fundamental to Kern River's over-all levelized rate methodology and recovery in rates over the entire levelization period.[428] When Kern River collects the deferred depreciation, it ceases to be a regulatory asset or a part of Kern River's rate base under Kern River's levelized methodology.[429] Again, the Commission affirms these findings in Opinion No. 486.

375. Accordingly, the Commission affirms that deferred depreciation of compressor engines, general plant, and other small items is correctly treated as a regulatory asset under Kern River's levelization method and is properly included in rate base in accordance with and as determined by Kern River's levelized model.

D. <u>Book Depreciation for Compressor Engines</u>

376. In this section we consider the book depreciation rate for Kern River's compressor engines. This rate, as indicated above, is for book purposes only, and is not for the purposes of collecting compressor engine depreciation through traditional cost-of-service rates with straight-line depreciation.

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[427] *Id.* at P 106. "Kern River's model projects the current per book end-of-test period invested capital including all regulatory assets (deferred depreciation)." *Id.*

[428] *See* section Levelized Rates/Levelized Cost of Service, *supra*. *See also* 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.

[429] As part of its levelized rate methodology, Kern River uses an equity rate base or Ozark methodology for its capital structure and to determine its rate of return on common equity. Kern River's 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. Opinion No. 486 at P 110. Under this method, as Kern River re-pays debt principle, the debt portion of its capitalization declines and, accordingly, the equity portion of total capital (the equity ratio) increases over time. *Id.* at P 106.

377. Kern River has eighteen Solar Mars compressor engines in operation.[430] These engines cost about $3.4 million each and have a short service life. Under Kern River's maintenance agreement with the manufacturer, the manufacturer replaces the engines approximately every three years. While the average service life is relatively short, the retirement of each compressor engine returns a positive net salvage value, described as 70 percent or more of the original cost, with relatively little cost of removal.[431]

378. On rehearing, Kern River asserts the Commission erred in accepting its original proposal of 9.92 percent and that the just and reasonable book depreciation rate for compressor engine depreciation is 12.53 percent. Kern River's contentions focus on the determination of the net salvage percentage. The Commission rejects Kern River's arguments and affirms its prior holding, as discussed below.

Opinion No. 486

379. Kern River initially proposed a 9.92 percent book depreciation rate for the compressor engines based on an average service life method.[432] Under that method, Kern River determined the annual depreciation expense by calculating the original cost of the compressor engines minus the net negative salvage value and then dividing the result by the average life of the compressor engines.[433] Kern River stated that the original cost was $57,111,874. It determined that the net salvage value of compressors which had thus far been retired was 71.11 percent of their original cost.[434] Applying this percentage to the $57,111,874 original cost of all the compressors, it determined a net negative salvage value of $40,613,315. This left plant to be recouped through depreciation of $16,498,559. Dividing that amount by an average service life for each compressor of 2.91 years resulted in an annual depreciation expense of $5,667,086.[435] Kern River then used this amount to calculate an annual depreciation rate of 9.92 percent, based on actual retirements.

[430] Exs. KR-4 at 2-3; KR-5 at 32-36; S-7 at 48-49.

[431] Ex. KR-5 at 32.

[432] The average service life is the whole life of the equipment, rather than the remaining life. Ex. KR-5 at 34. The average service life method is appropriate for short-lived, high turnover properties such as the compressors at issue here.

[433] Ex. KR-5 at 34.

[434] The original cost of the retired compressors was $37,997,301, and their net salvage value was $26,880,587. Ex. KR-6, Schedule 7.

[435] Ex. KR-5 at 35-36; Ex. KR-6, Schedule Nos. 7, 15, and 17.

380. Staff proposed an 8.85 percent book depreciation rate based, in part, on a net salvage percentage of 75.00 percent.[436] Staff apparently calculated the 75 percent net salvage percentage based on certain updated data provided by Kern River. Kern River subsequently revised its proposal allegedly relying on the same updated data as Staff had used, with modifications to correct alleged mistaken assumptions in Staff's calculations, and proposed a 12.53 percent depreciation rate for the compressors.[437] Kern River argued that Staff's mistaken assumptions had primarily affected Staff's calculation of the net salvage percentage, and that, with those assumptions corrected, the actual net salvage percentage should be 62.64 percent.[438] This lower net salvage percentage meant that a greater proportion of the costs of the compressors had to be recovered through the depreciation allowance, and thus provided the basis for Kern River's revision in its depreciation proposal to increase the depreciation rate from the originally proposed 9.92 percent to 12.53 percent.

381. The Initial Decision adopted Staff's proposal of 8.85 percent. The Commission, however, reversed this decision and adopted Kern River's initial proposed rate of 9.92 percent.[439] In Opinion No. 486, the Commission found that Staff's book depreciation rate for compressor engines was calculated incorrectly because Staff incorrectly attributed purchase discounts to the retirements of four units and incorrectly omitted some costs of replacement units. In addition, the Commission stated it could not accept Staff's proposal because the copy of the calculations on which it is based that is in

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[436] 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.

[437] 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 329-331 (pages are unnumbered; there is no "Other" tab in this electronic version of the document)).

[438] Ex. KR-112, Schedule 33.

[439] Opinion No. 486 at P 472-76.

the record for Commission review is largely illegible.[440] Thus, the Commission stated, it was not possible for the Commission to review Staff's calculations.

382. In Opinion No. 486, the Commission also rejected Kern River's second proposal of 12.53 percent as the book depreciation rate for the compressor engines which was 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 62.64 percent. The Commission found Kern River did not explain why its own net salvage rate of 71.11 percent was incorrect. In particular, it stated, Kern River did not explain why its figures[441] for Cost of Plant Retired and Salvage, which determine the net salvage rate, differed from Staff's figures[442] for these items.

383. In addition, the Commission stated, both Kern River's net salvage rates of 62.64 percent and 71.11 percent were calculated using data from Kern River's original filing, not data from its updated filing. The Commission noted that, nevertheless, Kern River applied the 62.64 net salvage percentage to updated data for compressor engine Gross Plant.[443] Accordingly, the Commission found Kern River had updated part of its recalculation of the compressor engine depreciation rate, but not all of it. Consequently, the Commission found that Kern River's recalculated depreciation rate of 12.53 percent was unconvincing.[444]

384. In Opinion No. 486, the Commission found that Kern River's average service life depreciation rate study for the Solar Mars compressor engines in its direct testimony[445]

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[440] *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.

[441] Ex. KR-6, Schedule No. 7. Kern River's figures are Cost of Plant Retired, $37,997,301, and Salvage, $26,950,587.

[442] 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 329.

[443] *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.

[444] The Commission also rejected a depreciation rate of 5.86 percent proposed by RCG and SCGC because there was 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. Opinion No. 486 at P 474-75.

[445] Exs. KR-5 at 32-36; KR-6, Schedule Nos. 7, 15, and 17.

provides a just and reasonable depreciation rate for these engines and adopted the 9.92 percent depreciation rate that Kern River proposed in its direct testimony.[446]

Rehearing Requests

385. First, Kern River asserts that 62.64 percent, its revised net salvage rate, is the correct net salvage rate and that it explained why 62.64 percent is correct and its original net salvage rate of 71.00 percent is incorrect. It states that, as the Commission recognized, Kern River's revised net salvage rate was calculated using Staff's depreciation rate methodology.[447] It states this methodology was presented by Staff witness Mr. Pewterbaugh, whose compressor depreciation rate study was based on compressor engine retirement and salvage data provided by Kern River.[448] Kern River states, in addition, that the data in Mr. Pewterbaugh's study reflected corrected plant accounting data from Kern River's 45-day update filing.[449] It states that, therefore, Kern River's revised net salvage rate was not based on data from Kern River's original filing, but presented a rate that was more accurate because it properly accounted for updated data which was not available when Kern River's original net salvage rate was calculated. Kern River asserts that the net salvage rate of 62.64 percent is correct because it is based on the same plant accounting data that the Commission has otherwise accepted.

386. Kern River asserts that it demonstrated, and the Commission agreed, that Staff's study incorrectly attributed purchase discounts to the retirements of four units and omitted some costs of replacement units.[450] Kern River states the Commission recognized that, after making Kern River's recommended adjustments to Staff's depreciation study, the correct Cost of Plant Retired is $38,831,941 and Salvage is $24,323,093.[451] Kern River states it then showed that with these corrected figures the proper net salvage rate is 62.64 percent.[452] Kern River states that, therefore, while Kern River's revised net salvage rate and the figures used to derive that rate clearly differ from Kern River's calculation in its original filing, this change appropriately reflects the fact that the calculations in Kern River's original filing were superseded by the updated

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[446] Opinion No. 486 at P 476.

[447] *Citing* Opinion No. 486 at P 473.

[448] *Citing* Ex. S-7 at 49:3-4.

[449] Stating that Ex. KR-6, Sched. 7 should be compared with Item by Reference Kern River B, Work Papers, Sched. 7 Updated.

[450] *Citing* Ex. KR-111 at 75-76; Opinion No. 486 at P 472.

[451] *Citing* Opinion No. 486 at n.707.

[452] *Citing* Ex. KR-112, Sched. 33.

figures and calculations reflected in Staff's study and Kern River's 45-day update filing.[453]

387. Kern River states that the Commission criticizes Kern River's recalculated depreciation rate because, in the Commission's view, Kern River did not use updated numbers for all factors.[454] It states the Commission is incorrect. It states that as shown above, Kern River's revised net salvage rate was calculated using all of the same updated numbers that Staff used in its depreciation study and did not include data from Kern River's original filing.[455] In addition, Kern River states, contrary to the Commission's finding, Kern River correctly applied this updated net salvage rate to the updated data for compressor engine Gross Plant.[456]

388. Kern River states it went even further to make sure its recalculated depreciation rate reflected all updated data. It states that, in this regard, Kern River revised Staff's depreciation study to account for an updated average service life of 2.98 years for Kern River's compressor engines in the calculation of the 12.53 percent depreciation rate.[457] Kern River states, if the Commission elected not to accept this updated average service life, then Staff's average service life of 2.83 years would result in a 13.20 percent depreciation rate.[458]

389. Kern River states that, in the alternative, if the Commission adopted Kern River's as-filed average service life of 2.91 years, it would result in a 12.84 percent depreciation rate.[459] Therefore, Kern River states that its recalculation with an updated service life produces the lowest depreciation rate supported by the record, i.e., 12.53 percent. It states that all of the factors used in Kern River's recalculated depreciation rate of 12.53 percent are properly updated and fully supported by the record. Therefore, Kern River states, the Commission should adopt Kern River's 12.53 percent rate as proper and adequate for the book depreciation of Kern River's Solar Mars compressor engines.

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[453] *Citing* Item by Reference Kern River B, 45-day Update Filing, Work Papers, Sched. 7 Updated.

[454] *Citing* Opinion No. 486 at P 473.

[455] *Citing* Ex. KR-112, Sched. 33.

[456] *Citing* Item by Reference Kern River B, 45-day Update Filing, Work Papers, Sched. 7 Updated.

[457] *Citing* Ex. KR-111 at 76; Item by Reference Kern River B, 45-day Update Filing, Work Papers, Sched. 7 Updated.

[458] *Citing* Tr. 1458.

[459] Stating that the calculation is (1-0.6264)/2.91 = 12.84 percent. See Ex. S-8, Sched. 26.

Commission Determination

390. Kern River claims that it correctly adjusted Staff's figures to arrive at a just and reasonable book depreciation rate for the Solar Mars compressor engines of 12.53 percent. The Commission finds, however, that Kern River has not supported its contention that it correctly adjusted Staff's figures. The Commission denies Kern River's rehearing requests related to the book depreciation rate for compressor engines and affirms its holding in Opinion No. 486 that 9.92 percent is the just and reasonable book depreciation rate for the Solar Mars compressor engines.

391. Specifically, Kern River claims to have adjusted Staff's figures to recalculate the net salvage percentage for its compressor engines. The net salvage percentage is equal to the total amount of net salvage from engines that have thus far been retired divided by the total original cost of those retired engines. A reduction in the net salvage rate for the engines to 62.64 percent, as Kern River proposes, would yield a higher depreciation allowance since a greater proportion of the costs of the engines would have to be recovered through the depreciation allowance.

392. Kern River's recalculation of Staff's figure for the net salvage rate is contained in Ex. KR-112, Schedule No. 33, and Updated Schedule No. 7 in the Work Papers accompanying Kern River's December 15, 2004 update filing.[460] Ex. KR-112 shows that Kern River added $4,370,500 to Staff's figure of $34,461,441 for the original cost of retired engines. In Ex. KR-112, Kern River states that the addition is for sales tax, installation and freight, overheads and Allowance for Funds Used During Construction (AFUDC), but does not show the costs on which it relies. That is, Kern River does not provide these costs per engine, nor does it provide the total of each type of cost for all the retired engines. Nor does Updated Schedule No. 7 provide such figures. These figures are needed to explain the $4,370,500 addition. Kern River appears to rely on Staff's Exhibit S-8, Schedule No. 26, for the needed figures. To the extent it does so, that reliance is misplaced. The Commission stated in Opinion No. 486 that Ex. S-8, Schedule No. 26, in the record is illegible and cannot be reviewed.[461] Thus, there is nothing in the record to support Kern River's $4,370,500 addition to the cost of retired engines.[462] Since Kern River's recalculated depreciation rate of 12.53 percent relies in part on its recalculated cost of retired engines, its recalculated depreciation rate also lacks support.

[460] "Docket No. RP04-274 (45-Day Update), Work Papers" (December 15, 2004). FERC eLibrary Accession No. 20041216-0184 at 329.

[461] Opinion No. 486 at P 472 and n.705 stating that Ex. S-8, Schedule No. 26 consists of small print which is unreadable.

[462] In addition, it is unclear whether Kern River subtracted discounts in calculating the capital costs of retired engines.

393. Contrary to Kern River's contentions, the Commission did not recognize in Opinion No. 486 that the correct figure for Cost of Plant Retired is $38,831,941 after making Kern River's recommended adjustments to Staff's depreciation study. Instead, the Commission stated that Kern River did not explain why its figure for cost of retired plant differed from Staff's figure and provided Kern River's figure for the purpose of indicating how it differed from Staff's figure.[463]

394. The Commission finds Kern River's testimony regarding its proposed 12.53 percent rate is unpersuasive for an additional reason as well. Kern River's original testimony was that net salvage plays a significant role in the depreciation determination of the compressor engines because net salvage can be more than 70 percent of the original cost of plant retired.[464] This testimony casts doubt on the 62.64 percent salvage rate that it calculates using its adjustments to Staff's figures.

395. For all of the above reasons, the Commission finds that Kern River's proposed revision of Staff's figures is unreliable and rejects it. The Commission finds that the credible evidence of record supports Kern River's original proposed book depreciation rate for the Solar Mars compressor engines of 9.92 percent and affirms that rate.

<u>The Commission orders:</u>

(A) The requests for rehearing of Opinion No. 486 are granted and denied as set forth herein.

(B) BP and Pinnacle West's request for rehearing and/or clarification of the November 15, 2006 notice granting Kern River a 30-day extension of time to file tariff sheets in compliance with Opinion No. 486 is dismissed as moot.

(C) The Commission establishes a paper hearing on the issue of the composition of the return on equity proxy group, the DCF analysis of the firms included in the proxy group, and related issues of risk, as more fully described herein. The Commission directs all interested participants to file initial briefs within 60 days after this order issues. Reply briefs are due 90 days after this order issues, and rebuttal briefs are due 105 days after this order issues. Each participant's presentation in its initial, reply and rebuttal briefs should separately state the facts and arguments advanced by the participant and include any and all exhibits, affidavits and/or prepared testimony upon which the participant relies. The statement of facts must also include citations to supporting exhibits,

[463] Opinion No. 486 at P 473 and n.706 and 707.

[464] Ex. KR-5 at 35.

affidavits, and/or prepared testimony. All material must be verified and subscribed as set forth at 18 CFR § 385.2005 (2007).

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.