114 FERC ¶63,031

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

INITIAL DECISION

(Issued March 2, 2006)

APPEARANCES

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

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

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

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

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

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

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

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

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

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

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

Charlotte J. Hardnett, Presiding Administrative Law Judge

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INTRODUCTION

PROCEDURAL HISTORY

1. On April 30, 2004, Kern River Gas Transmission Company submitted a general rate change filing in Docket No. RP04-274-000, pursuant to Section 4 of the Natural Gas Act, 15 U.S.C. §717c ("Section 4") and in accordance with its obligation under Article VI of the Stipulation and Agreement dated March 31, 1999, and approved by the Federal Energy Regulatory Commission ("Commission" or "FERC") in Docket No. RP99-274-000.[1] Kern River's filing utilized a test period consisting of a base period of the twelve months ending January 31, 2004, as adjusted for known and measurable changes occurring through October 31, 2004. Kern River submitted two sets of tariff sheets, presenting new rates proposed to become effective June 1, 2004, and January 1, 2005, to reflect the 366-day leap year in 2004 and the 365-day years thereafter, respectively.

2. By order dated May 28, 2004, the Commission accepted and suspended Kern River's filing, subject to refund and other conditions, and established the instant evidentiary hearing proceeding, designating the case as a Track III proceeding.[2] Chief Administrative Law Judge Curtis L. Wagner, Jr. ("Chief Judge"), subsequently designated Administrative Law Judge Isaac D. Benkin as the presiding judge for this proceeding. An initial prehearing conference was held on June 8, 2004, at which time a procedural schedule was adopted.

3. On September 28 and 29, 2004, an informal conference of the Participants was convened to explore the possibility of settlement. The settlement discussions were not successful.

4. On October 1, 2004, Kern River moved to place its proposed new rates into effect, subject to refund, at the end of the suspension period on November 1, 2004. The Commission accepted Kern River's filing, to be effective as proposed, by unpublished letter order dated October 27, 2004.

5. Staff, Intervenors and Kern River then filed prepared direct, answering, cross-answering and rebuttal testimony on prescribed dates from early December 2004 to mid-March 2005 and conducted discovery on each round of such filed testimony. Discovery concluded on April 8, 2005.

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[1] *Kern River Gas Transmission Co.*, 88 FERC ¶ 61,128, *order on reh'g*, 88 FERC ¶ 61,201, *reh'g denied*, 89 FERC ¶ 61,144 (1988).

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

6. During the course of these activities, by order dated December 20, 2004, the Chief Judge substituted Administrative Law Judge Bobbie J. McCartney for Administrative Law Judge Benkin as the presiding judge and extended the hearing and other Track III procedural dates. At a prehearing conference before Judge McCartney on January 11, 2005, a new procedural schedule was adopted. Another informal settlement conference thereafter was convened, but again the negotiations did not result in a settlement.

7. By order dated April 21, 2005, the Chief Judge, at the request of the Participants, convened a settlement conference with Administrative Law Judge William J. Cowan acting as a settlement judge. The same order substituted Administrative Law Judge Charlotte J. Hardnett for Judge McCartney as the presiding judge for this proceeding. A subsequent order of the Chief Judge, dated May 24, 2005, further modified the hearing date and other elements of the Track III procedural schedule.

8. The Participants' negotiations facilitated by the Settlement Judge ultimately proved unsuccessful and the settlement judge procedure was formally ended by the Chief Judge's order dated June 22, 2005. On the same date, a prehearing conference was convened before The Undersigned to establish arrangements for the hearing, including dates for certain procedural filings to be made prior to the start of the evidentiary proceeding.

9. The hearing commenced on August 17, 2005, and concluded on August 26, 2005. The evidentiary record includes testimony from twenty-four witnesses, eight volumes of transcripts of the evidentiary hearing, approximately 435 exhibits (including the Participants' pre-filed written testimony and exhibits) and eight items by reference.

10. By order dated November 8, 2005, the Chief Judge extended the initial decision date from January 5, 2006 to February 3, 2006, due to the complexity of the issues presented and amount of evidence to be considered. By order dated January 25, 2006, the Acting Chief Judge, William Cowan, extended the initial decision date again from February 3, 2005, to March 3, 2005, for the same reasons.

11. All previous Kern River rate filings were settled before Commission decision on them.[3]

BACKGROUND

12. The Kern River natural gas pipeline system extends about 900 miles from Wyoming receipt delivery points, through Utah and Nevada, to the San Joaquin Valley near Bakersfield, Kern County, California. The pipeline was originally constructed

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[3] *See Kern River Gas Transmission Co.*, 70 FERC ¶ 61,072 (1995) and *Kern River Gas Transmission Co.*, 87 FERC ¶ 61,124 (2000).

pursuant to an optional certificate of public convenience and necessity issued on January 24, 1990, to provide up to 700,000 Mcf/d of year-round firm transportation services. [4] The pipeline was built to transport 700 MMcf of gas per day on a firm basis. Kern River is a "transportation only" pipeline; it provides no gathering or storage services. Kern River began service in 1992.[5]

13. On November 15, 2000, Kern River filed an application for authority to construct and operate a compression-only expansion. This expansion of the pipeline is known as the "2002 Expansion Project."[6] On March 15, 2001, due to the need for natural gas in California in 2000-2001, Kern River filed an application for an expedited construction schedule that would put in place most of the facilities proposed in the 2002 Expansion Project. This project was known as the California Action Project ("CAP"). Before the CAP was completed, Kern River filed an amendment to the 2002 Expansion Project application to reduce the size of that expansion due to the CAP.[7]

14. The 2002 Expansion Project and the CAP expanded the Kern River pipeline system to 869,500 Dth per day. The Commission approved incremental rates for the CAP and rolled-in rates for the 2002 Expansion Project.

15. On August 1, 2001, Kern River filed another certificate application to expand the pipeline. This expansion included about 634 miles of 36-inch pipeline and 82 miles of 42-inch pipeline. This expansion of the pipeline was known as the "2003 Expansion Project." This brought the capacity of the pipeline to 1,755,626 Dth per day.[8]

16. Kern River also constructed two incremental projects, the High Desert [9] and the Big Horn laterals.

17. The following may facilitate following the discussion of the case:

- "Original System" refers to the Kern River facilities constructed in 1991-92 under the optional certificate issued in Docket No.CP89-2048-000 [10] and firm transportation service using the capacity of those facilities;

[4] *Kern River Gas Transmission Company*, 50 FERC ¶ 61,069 (1990).
[5] Ex. S-12 at 4-5.
[6] *Kern River Gas Transmission Co.*, 96 FERC ¶ 61,137 (2001).
[7] Ex. S-12 at 5.
[8] *Id*. at 6. *See Kern River Gas Transmission Co.*, 100 FERC ¶ 61,056 (2002), *reh'g denied*, 101 FERC ¶ 61,042 (2002).
[9] *Kern River Gas Transmission Co*, 99 FERC ¶ 61,085 (2002)
[10] *Kern River Gas Transmission Co.*, 50 FERC ¶ 61,069 (1990).

- "CAP," as indicated above, refers to the California Action Project, an expansion constructed to provide additional short-term service to California markets in 2001 under the certificate issued in Docket No. CP01-31-000 [11];

- "2002 Expansion" refers to the permanent CAP facilities used for the 2002 Expansion project and other new mainline expansion facilities that Kern River put in service in 2002 under the certificate issued in Docket No. CP01-31-001 [12] and firm transportation service using the additional capacity provided by that expansion;

- "Rolled-In System" refers collectively to Kern River's transportation services related to the Original System and the 2002 Expansion, which are provided at rolled-in rates based on the combined costs of those facilities;

- "2003 Expansion" refers to the mainline expansion facilities Kern River placed in service in 2003 under the certificate issued in Docket No. CP01-422-000 [13] and the incrementally-priced firm transportation service using the additional capacity provided by that expansion;

- "High Desert" refers to a lateral line in California of the same name constructed in 2001 and 2002, and the transportation service provided on that facility;

- "Big Horn" refers to a lateral line in Nevada of the same name, constructed in 2002, and transportation service provided on that facility.[14]

WITNESSES AND THEIR TESTIMONY

Kern River Witnesses

18. Kern River presented the testimony of the following witnesses: John R. Smith, Bruce E. Warner, Darrell Swensen, Martin Hansen, Jeffrey Valentine, Michael D. Falk, Edward H. Feinstein, Lynn Dahlberg, Charles E. Olson, Alan R. Lovinger, and R. Bruce MacLennan.[15]

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[11] *Kern River Gas Transmission Co.*, 97 FERC ¶ 61,080 (2001).
[12] *Id.*
[13] *Kern River Gas Transmission Co.*, 100 FERC ¶ 61,056 (2002).
[14] Ex. KR-12 at 6.
[15] Ex. KR-1-17, 23-52, 55-111.

JOHN R. SMITH

19. John R. Smith is Director of Regulatory and Governmental Affairs for Kern River. His duties for Kern River include responsibility for tariffs, rates, certificates, regulatory filings, contracting, scheduling pipeline services, relationships with customers and regulatory agencies, governmental affairs and business expansion projects. Mr. Smith previously worked for Northwest Pipeline Corporation and has a total of twenty-seven years of pipeline work experience.[16]

20. Mr. Smith testified that Kern River wants to continue using the levelization methodology and cost of service rate principles approved in the original Kern River certificate,[17] the extended term ("ET") rate settlement,[18] the 2003 Expansion certificate,[19] and the prior Kern River rate case settlements, [20] with some modifications. The modifications that Kern River wants are:

- to use straight-line depreciation for compressors and general plant to closely match their respective depreciation periods to their actual asset lives;
- to use a net negative salvage allowance as part of the required depreciation of transmission and compression plant; increase the rate of return on common equity ("ROE") to 15.1% from 13.25%;
- to adjust the Rolled-In System rate base for the restatement of accumulated deferred income taxes ("ADIT") related to the acquisition of Kern River by MidAmerican Energy Holdings Company ("MEHC") in March 2002[21] ;
- to eliminate the annual revenue sharing with firm transportation customers that was part of the Docket No. RP99-274-000 [22] general rate settlement;
- to eliminate credit market-oriented revenues to its overall cost of service after certain proposed rate design adjustments are made;
- and, to implement direct charges and other cost allocation methodologies to better apportion costs between the Rolled-In System and the incrementally priced expansions (i.e., 2003 Expansion, High Desert, and Big Horn). [23]

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[16] Ex. KR-12 at 1.
[17] *Kern River Gas Transmission Co.*, 50 FERC ¶ 61,069 (1990)..
[18] *Kern River Gas Transmission Co.*, 92 FERC ¶ 61,061 (2000), *reh'g denied*, 94 FERC ¶ 61,115 (2001).
[19] *Kern River Gas Transmission Co.*, 100 FERC ¶61,056 (2002).
[20] *Kern River Gas Transmission Co.*, 70 FERC ¶ 61,072; *Kern River Gas Transmission Co.*, 90 FERC ¶ 61,124 *reh'g*, 91 FERC ¶ 61,103 (2000).
[21] Ex. KR-12 at 2.
[22] *Kern River Gas Transmission Co.*, 87 FERC ¶ 61,128 (1999).
[23] *Id.* at 7-14.

21. Mr. Smith identified other parts of the levelized methodology "package" that Kern River presents in the subject Section 4 rate filing as an integral part of the levelized cost-of-service/ratemaking methodology for setting rates that Kern River wants. They include: inclusion of a 3% inflation factor; use of the *Ozark*[24] methodology for determining pipeline risk; amortization of the regulatory asset over the term of the firm shipper contracts (if amortized over thirty-five years instead of the life of the shipper contracts as Kern River wants, another generation of customers has to pay for that regulatory asset and all shippers knew that the regulatory asset would built and be fully amortized by the end of the term of their contracts); use of 95% load factor method of deriving rates on the original facilities which was put in as a penalty for the pipeline.[25]

22. Mr. Smith testified that completion of the 2003 Expansion allowed about 50% of Kern River's administration and general expenses ("A&G") and operation and maintenance expenses ("O&M") to be properly charged to the 2003 Expansion shippers; the 2003 Expansion doubled the size of the Kern River system. This sharing of cost of about $17.5 million provided significant shared efficiency benefits of a larger system to the Rolled-In System shippers, including additional service reliability. If weighted average cost of debt (8.22% for Rolled-In System versus 5.14% for 2003 Expansion shippers) is allowed as requested in the subject rate filing, the Rolled-In System shippers would receive another financial benefit of the 2003 Expansion due to lower debt financing costs.[26]

23. Mr. Smith identified developments affecting Kern River's operations since the settlement of the Docket No. RP99-274 rate case and contributing to the content of this rate filing. The most important of those developments, as identified by Mr. Smith, are:

- implementing the extended term ("ET") rate settlement in Docket No. RP00-298 and refinancing $510 million of existing debt to implement the new lower ET rates on October 1, 2001, allowing a 28% rate reduction for the ten-year ET shippers and 35% rate reduction for the fifteen-year ET shippers;
- completing the 2001 CAP expansion (incremental rates), 2002 Expansion (rolled-in to the Original System cost of service as provided in the RP99-274 Settlement Agreement), 2003 Expansion (incremental rates), High Desert (incremental, levelized rates under negotiated agreement with the anchor shipper), and Big Horn

[24] *Ozark Gas Transmission Co.*, 32 FERC ¶ 63,019, *aff'd*, 39 FERC ¶ 61,142 (1985), *reh'g denied*, 41 FERC ¶ 61,207 (1987), *rev'd on other grounds sub nom.*, *Public Service Commission v. FERC*, 866 F.2d 487 (D.C. Cir 1989).
[25] Tr. 269.
[26] Ex. KR-12 at 14.

(incremental, levelized cost-of-service rates);[27]

- amending its previous $510 million credit facility on May 1, 2003 to provide for an additional $836 million of long-term debt to finance construction projects, including the 2003 Expansion and High Desert at a 4.893% interest coupon rate;
- using new income tax laws to significantly increase the income tax deductions for the investment in the 2003 Expansion System and later capital additions thereby reducing the rate base primarily for the 2003 Expansion shippers as the associated cash flow benefits were realized; and
- being able to make a significant adjustment to its rate base due to the reduction of its accumulated deferred income taxes ("ADIT") on begin acquired by MEHC from Williams Company to zero -- Williams paid all ADIT owed by Kern River to the Internal Revenue Service.[28]

24. Mr. Smith testified that the increase in rates for the Rolled-in System reflected in the subject Section 4 filing is due primarily to the adjustment to ADIT that occurred when MEHC bought Kern River, a higher rate of ROE, generally increased costs of service, and a lower market-oriented revenue ("MOR") credit. He testified that increase in rates for the incrementally priced 2003 Expansion shippers is due primarily to Kern River's overall higher costs (ROE, depreciation, and operating costs) and to cost allocations between the Rolled-In System and the 2003 Expansion. The increase to the 2003 Expansion was offset in part due to the effect of adjusting the investment in the expansion to the current estimate of plant balances and applying the market-oriented revenue credit. The 2003 Expansion shippers also had their increase reduced due to the effect of the bonus income tax depreciation which increased ADIT and reduced the rate base.[29]

25. Mr. Smith testified that use of the levelized cost-of-service/ratemaking methodology benefited shippers by providing initial low rates. Use of the levelized methodology to set initial rates also permitted Kern River to be constructed and thereby assisted in meeting the country's need for energy. Mr. Smith expressed Kern River's position that its levelized methodology should be continued in its present form. Non-Kern River proposed changes should be subject to the "public interest" *Mobile-Sierra* doctrine, [30]according to Mr. Smith. Any changes other than those proposed by Kern

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[27] The 2002 Expansion resulted in a $0.029 per Dth reduction in reservation rates for the Original System shippers. The initial reservation rates for the 2003 Expansion shippers were $.0479 per Dth lower for the 10-year shippers and $.0564 per Dth for the 15-year shippers than the rates approved in the certificate order. KR-12 at 9.

[28] Ex. KR-12 at 8-12.

[29] *Id*. at 15.

[30] *United Gas Pipel Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956) and *FPC*
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River would make the levelized methodology totally unworkable from Kern River's point of view. Kern River would rather, in that circumstance, use the traditional methodology for setting rates retroactive to the end of the test period. Mr. Smith also posited that a change to the traditional methodology would likely compel Kern River to file another rate case using the traditional methodology for setting rates to establish just and reasonable rates.[31]

26. Mr. Smith testified that a pipeline's business risk is a component of the ROE. Mr. Smith testified that Kern River's superior Moody's and Standard and Poor's (S&P) ratings do not establish that Kern River's financial status is good. Competition for market share and for gas to supply that share, competition from other energy sources, and creditworthiness of the shippers it serves are also important. According to Mr. Smith all of the above were problematic for Kern River.[32]

BRUCE E. WARNER

27. Bruce E. Warner is Director, Rates and Government Affairs. He is responsible for Kern River's rate, certificate, and tariff-related filings before the Commission. He also directs governmental relations activities in proceedings before other federal agencies and before state agencies. In addition, he develops regulatory strategies and rate studies.[33]

28. Mr. Warner testified that Kern River's position was that if the Commission did not approve continuation of the company's levelization methodology as a "package" and through the end of the shipper contracts, Kern River wanted the Commission to order it to convert to the traditional methodology effective the end of the test period (i.e., October 31, 2004).[34] Mr. Warner admitted however, that Kern River made this Section 4 rate filing based on the levelized methodology for setting rates. [35] He also said that although

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v. Sierra Pacific Power Co., 350 U.S. 348 (1956) (Commission may only use § 5 [15 U.S.C. § 717(d)] power to abrogate existing contracts where a public interest "impertively demands action.") *Mobiel-Sierra* does not apply to Kern River because the contracts between Kern River and its shippers anticipated FERC rate changes. *Union Pacific Fuels, Inc. v. FERC*, 129 F.3d 157 at 161 (1997).

[31] *Id*. 5 and 15-16.

[32] *Id*. at 5-17.

[33] Ex. KR-17 at 1-2.

[34] *Id*. at 3.

[35] Under Section 4, the Commission reviews rate increases that have been proposed by a utility company, and the utility bears the burden of proving just and reasonable rates. The Commission has authority under Section 5 ("Section 5") (15 U.S.C. § 717(d)), to impose its own rate determinations, but must first establish that the proposed or existing (con't next page)

Kern River wanted levelization continued as a "package," the company was not promising it would not exercise its Section 4 right to propose changes to the approved levelization methodology during the terms of the shipper contracts.[36]

29. Mr. Warner testified that Kern River had used a levelized methodology for setting rates since the pipeline began operation.[37] He testified that, including the initial approval, the Commission had approved Kern River's levelization models five times.[38] He testified that the basic theory, formulas, and methodology of the levelization computations had remained the same although there had been some refinements to adapt to changes over the years.[39] He testified that the levelized depreciation schedule was designed to maintain a constant total cost of service over an initial period (in this case, it was originally the first fifteen years of operation of the pipeline). Under Kern River's levelization model, annual depreciation recovery in rates increases during the levelization period as the return component of the cost of service decreases (in tandem with the declining total rate base) to obtain a constant or "level" annual cost of service.[40]

30. Mr. Warner testified that levelized depreciation of pipeline investment occurs during the levelization period. Depreciation amounts accumulate in an accumulated depreciation account and are reflected as reductions to rate base. As accumulated depreciation is recorded, the cost-reducing benefit of the difference between Kern River's annual income tax obligations and normalized amount of income taxes payable to the pipeline by shippers, is reflected as a rate base reduction. This, according to Mr. Warner, was appropriate because tax-related revenue related to tax payment timing difference is a cost-free source of capital to the pipeline. Accumulated depreciation and accumulated deferred income taxes ("ADIT") accruals reduce the pipeline's investment in its facilities over time.[41]

31. Mr. Warner testified that Kern River's use of the *Ozark* methodology allowed the pipeline's equity investment to be smaller under the levelized methodology than it would have been under the traditional methodology. A lower equity ratio generally means a

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rates are unjust and unreasonable. Once the Commission establishes that, it must show that its imposed rates are both just and reasonable. *See Algonquin Gas Transmission Co. v. FERC*, 292 U.S. App. D.C. 197, 948 F.2d 1305, 1311 (D.C. Cir. 1991)) (citations omitted). Under Section 4, rates must be made effective prospectively, under Section 5, rates can be made effective retroactively.

[36] Tr. 1019.

[37] Ex. KR-23 at 5.

[38] Tr. 1019.

[39] Ex. KR-17 at 23.

[40] Ex. KR-23 at 4.

[41] *Id*. at 7.

lower total cost of service, since the equity-financed portion of the rate base is more costly than the debt-financed portion. Under *Ozark*, both accumulated depreciation and debt are subtracted from the net rate base to derive the equity rate base. All accumulated depreciation is assumed to have financed the pipeline's equity investment. Shippers benefit because the cost of service reduction associated with the accumulated depreciation is based on the ROE, rather than on the overall rate of return. The overall rate of return is lower.[42]

32. Mr. Warner testified that a pipeline with levelized rates will have a significantly lower cash flow in its early years; therefore, it was essential to design a levelization model to match cash flows in order to meet the repayment obligations of the pipeline.[43] Mr. Warner admitted that Kern River had not, prior to the subject Section 4 filing, advised the Commission that its capital structure was expected to include a significant debt component after the end of the shippers' contracts.[44]

33. Mr. Warner testified that for the Rolled-In System, the proposed revised rates were derived from the updated cost of service and reflected the rate principles approved in Kern River's initial system certificate, as modified by the ET rate settlement, the rolled-in rate design for the 2002 Expansion, and Kern River's prior rate settlements.[45]

34. Mr. Warner testified that for the 2003 Expansion, the proposed revised rates are derived on an incremental cost basis in accord with the Commission's September 15, 1999, *Policy Statement for Certification of New Interstate Natural Gas Pipeline Facilities* ("*1999 Pricing Policy Statement*")[46] and its orders authorizing the 2003 Expansion.[47]

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[42] *Id*. at 10.
[43] *Id*. at 9.
[44] Tr. 1092.
[45] Ex. KR-17 at 7.
[46] *Policy Statement Concerning Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶61,227 (1999), *reh'g*, 90 FERC ¶61,128 (2000), *reh'g*, 92 FERC P61,094 (2000) ("1999 Pricing Policy Statement") ("Under the 1999 Certificate Policy Statement, the Commission changed the focus of its rolled-in versus incremental rate policy so that the primary goal is to achieve efficient pricing signals to expansion shippers and existing pipeline customers, while remaining within the pipeline's revenue requirement. Under this new policy, when a project is first certificated, the Commission requires that existing shippers not be required to subsidize the expansion. This generally means that expansion will be priced incrementally so that expansion shippers will have to pay the full costs of the project, without subsidy from the existing customers through rolled-in pricing." *Transcontinental Gas Pipe Line Corporation*, 94 FERC ¶61,360 at 62,301 (2001) ("*Transco*").
[47] *Kern River Gas Transmission Co.*, 100 FERC ¶61,056.

Otherwise, the rates for the 2003 Expansion were generally developed under the same principles used to determine the Rolled-In system rates.

35. Mr. Warner testified to the following additional "principal rate design features" contained in the subject Section 4 filing:

- the firm transportation rates reflect the firm rate design in Docket No. RP99-274 and include a commodity (usage rate) designed to collect a negotiated level of fixed costs.
- those firm shipper rates are referred to as enhanced fixed variable ("EFV") rates. To make the commodity rates for the Rolled-In System and 2003 Expansion uniform, all proposed firm transportation rates reflect a $.06 Dth commodity charge;
- a 95% load factor for the Original System shippers' billing determinants, as approved in the original optional certificate, for designing firm reservation and commodity billing determinants;
- a 100% load factor for 2003 and 2002 Expansion shippers' reservation billing determinants and historical experience for deriving commodity billing determinants for those shippers;
- a 100% load factor interruptible transportation rate;
- a "levelized rate design" that recovers 70% of Kern River capital investments over the terms of the contracts of the shippers;
- an approximate 70% debt/30% equity starting capital structure (although the Kern River certificate and later rate computations provided for a changing capital structure yearly through the levelization processes or the *Ozark* methodology).[48]

36. Mr. Warner testified that costs were allocated among the ten-year and fifteen-year shippers before designing rates due to the ET program principles. Mr. Warner noted that the contract lengths and the ET program were factors in the allocation of costs among the shipper groups because Kern River's May 2000 ET program filing provided for allocating costs based on contract demand which produced the same rate as if the entire system were to convert to either a ten-year or fifteen-year rate option.[49]

37. Mr. Warner further testified regarding allocation of costs that:

- it was appropriate to subject the shippers to a composite or blended cost of debt because: 1) although admittedly interest rates were lower at the time of financing the 2003 Expansion, the credit quality of the combined groups of shippers was

[48] Ex. KR-17at 7-8.
[49] *Id*. at 9.

also considered by the creditors; 2)Staff had accepted composite cost of debt calculations in other cases, 3) otherwise Kern River would have to allocate ongoing fees to each of the two debt issuances, 4) it is a practice employed by other pipelines; and

- it is appropriate to separate O&M and A&G costs between rolled-in and incremental services and that promotion of other allocations by the various shippers was no more than attempts to shift costs away from themselves and onto other shippers, i.e., the proposals: 1) that ADIT should be determined on a company-wide basis and the allocated over all services, 2) that equity and debt capital structure balances be constant over the life of the pipeline and be the same for all services, 3) that certain of all shippers' general cost items existing before the 2003 Expansion be borne all shippers, 4) that the regulatory asset for deferred depreciation under the traditional rate design be borne by all shippers, 5) that compressor fuel tax attributed to the laterals be eliminated.

38. Mr. Warner testified that the proceeds of the $510 million debt issue were used to refinance then-existing debt, to fund the 2002 Expansion, and to pay for the interest rate swap agreement buyout and debt issuance costs. The proceeds of the $836 million were used to fund the 2003 Expansion and the High Desert projects and debt issuance costs. Thus, debt principal amounts associated with the $510 million debt issue were associated with the Rolled-In System. Debt principal amounts associated with the $836 million issue were associated with the 2003 Expansion and High Desert. He testified that Kern River directly assigned the portions of the debt principal to the facilities that the debt actually financed. In addition, according to Mr. Warner, Kern River allocated an appropriate amount of debt principal to the compressor engine rate base based on gross plant ratio.[50]

39. Mr. Warner testified that it was appropriate to calculate the cost-of-service for general plant and compressor engine plant on a straight-line depreciation basis, instead of levelized, because those items were short-lived, were recycled repeatedly through periods, assets are added, and were then retired. If subject to a levelized calculation, they would distort current cost-of-service. [51]

40. Mr. Warner testified that the laterals, High Desert and Big Horn, had been separately priced. The traditional cost of service method was not appropriate for them because of the negotiated rate agreement between each of the laterals and Kern River. High Desert had incremental rates derived using a traditional, declining rate base methodology, calculated over the term of the anchor shipper's contract. According to Mr. Warner, that ensured that costs were properly allocated to the High Desert service

[50] Ex. KR-57 at 24.
[51] *Id.* at 27.

and ensured the calculation of appropriate rates for other shippers on that lateral. The rate design was a recourse rate calculation, but the actual project rates charged to the anchor shipper were levelized, negotiated rates. The Kern River agreement with Big Horn provides for a levelized cost-of-service and a 60% equity/40% debt capital structure. [52]

41. Mr. Warner testified that the Commission determined in the 2002 certificate order [53] that Kern River would be allowed to roll-in the costs of the 2002 Expansion because that would reduce the rates of Original System shippers after accounting for incremental fuel costs associated with the new facilities. All Original System and 2002 Expansion shippers were given the same, per unit rate reduction reflective of the roll-in calculations. This methodology was used because the Original System and 2002 Expansion shipper contracts end on different dates. The levelized calculations are done separately for each group of shippers.[54]

42. Mr. Warner testified that the firm reservation and commodity billing determinants for Original System services had been reduced to a quantity equivalent to the 95% load factor amount. The reservation billing determinants for the 2002 Expansion and 2003 Expansion determinants include the 90,000 Dth per day of firm capacity turned back to Kern River by Mirant Americas Energy Marketing, L.P. ("Mirant") after it declared bankruptcy. He testified that attempts to fully re-subscribe Mirant capacity on a firm basis had not been successful although the capacity had been used and useful. He testified that if the Commission did not approve Kern River's requested ROE, the Commission should exclude Mirant billing determinants from the firm service rate design. If that did not happen, Mr. Warner testified, Kern River would be denied adequate compensation to offset a shortfall in the cost-of-service recovery related to used and useful Mirant capacity.

43. Mr. Warner testified that Kern River was proposing to use the ten-year 2003 Expansion system recourse rate as the rate for interruptible ("IT") and authorized overrun ("AOS") transportation services. That rate is the system's maximum rate. Mr. Warner testified that the Commission had sanctioned that approach when it approved the ET rate settlement which established the three firm transportation rates. [55] According to Mr. Warner, this rate design would benefit firm shippers by creating a level playing field for the maximum rate and by providing Kern River an appropriate opportunity to maximize MOR while complying with the requirement that the rate must be cost-based.[56]

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[52] Ex. KR-17 at 9 and KR-57 at 3.
[53] *Kern River*, 96 FERC ¶ 61,137 (2001).
[54] Ex. KR-17 at 11.
[55] *Kern River*, 92 FERC ¶ 61,061 (2000).
[56] Ex. KR-17 at 16.

44. Mr. Warner testified that Kern River was proposing changing the fuel reimbursement procedures for IT and other market-oriented services. Kern River was proposing using a blended fuel factor, with 52% of the fuel requirement being derived from the fuel reimbursement requirement for the 2003 Expansion services and 48% of the fuel requirement based on the fuel factor of the Rolled-In System. According to Mr. Warner, this blended or weighted fuel factor results in a higher fuel cost for market-oriented transactions compared to previous rates and provides a fuel reduction benefit to both groups of firm shippers. Mr. Warner admitted, however, that Kern River missed the deadline for effectuating the downward adjustment by a day. The downward adjustment did not become effective during the adjustment period which ended on October 31, 2004; it became effective on November 1, 2004. Consequently, Kern River's proposal does not strictly comport with the requirements of 18 C.F.R. § 154.303(a)(4). Section 154.303(a)(4) is a test period rate design regulation which allows adjustment to rate factors established during the base period for changes in revenues and costs known and measurable at the time of the filing if the change becomes effective during the adjustment period. The fuel adjustment was both known and measurable with reasonable accuracy at the time of Kern River's Section 4 rate filing, but the adjustment period here ended October 31, 2004, and Kern River asks for a waiver of the time-frame requirement.[57]

<u>DARRELL R. SWENSON</u>

45. Darrell R. Swenson is a Kern River controller. He has over thirty years of experience in the natural gas pipeline business, twenty of which was spent serving in financial and accounting management positions. Mr. Swenson directs Kern River's finance and accounting functions, including financial reporting, general and property accounting, accounts payable and disbursements, financial planning and budgeting, and income and other taxes.[58]

46. Mr. Swenson testified that Kern River issued $510 million in debt securities through a subsidiary on August 13, 2001. The offering was in the form of $510 million of 15-year amortizing senior notes bearing a fixed rate of interest of 6.676% ("6.676 % Senior Notes"). Proceeds from the issuance of the 6.676% Senior Notes were used to repay the remaining outstanding balance of long-term debt, fund the debt part of capital expenditure including the 2002 Expansion, and to pay a part of financing costs associated with the offering. The financing costs included breakage costs associated with the previously held interest rate swaps.[59]

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[57] Ex. KR-57 at 49.
[58] Ex. KR-14 at 3.
[59] *Id*.

47. Mr. Swenson testified that Kern River also issued $836 million in debt securities on May 1, 2003. The offering was in the form of $836 million of 15-year amortizing senior notes bearing a fixed rate of interest of 4.893% ("4.893% Senior Notes). Proceeds of the 4.893% Senior Notes were used to repay the outstanding balance and the accrued interest under its $875 million construction facility, and to pay the financing costs associated with the offering. [60]

48. Mr. Swenson testified that both series are scheduled to achieve final maturity after fifteen years from the issue date. He testified that both series contain a final balloon payment designed to benefit shippers because the balloon payments would result in a capital structure that would include a significant debt component after the expiration of current shipper contracts, thereby lowering rates. The balloon arrangement helped Kern River maintain it's A- credit rating as well as provided a higher debt service coverage ratio than would have been possible at the time the debt was issued. It did so by reducing the amount of debt principal to be amortized. The A- credit rating made possible the reasonable interest rates Kern River obtained at the time of the financings.[61]

49. Mr. Swenson testified that Kern River combined the two debt issuances to compute a weighted average overall cost of debt. Kern River used this blended cost of debt to calculate rates for both the Rolled-In and the 2003 Expansion systems. He further testified that the calculations had been updated to cover actual payments of financing costs and revised estimates of future fees, where necessary, and to make a correction related to the $510 million debt issue. The correction accounts for the erroneous exclusion from the initial ET transportation rate calculations some of the unamortized fees that were paid in connection with the refinancing. The cost of debt was also updated to include a component to recognize stockholders' equity was used to provide some payments to cancel interest rate swaps and to finance debt issuance fees. That component of the debt cost included carrying costs, including an income tax allowance, on the equity investment in the swap and debt issuance costs. According to Mr. Swenson, it was reasonable to recover that component of the debt cost because of the ET program's rate reduction benefit and further deferral (five to ten years) of the recovery of Kern River's equity investment in the Original System, as well as the favorable interest rate obtained in the 2003 expansion financing.[62]

<u>MARTIN J. HANSEN</u>

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[60] *Id*.
[61] *Id*. at 3-4.
[62] *Id*. at 5.

50. Martin J. Hansen is a staff analyst in the Rates Department of Kern River. Mr. Hansen is an accountant and has been employed in the natural gas pipeline business for more than twenty-seven years. Mr. Hansen assisted in the preparation and settlement of Docket No. RP99-274 rate filing and various Kern River rate matters since, including the ET rate settlement, the CAP, and the 2002 and 2003 Expansion project. He is currently responsible for Kern River's rate filings and expansion studies before the Commission.[63]

51. Mr. Hansen testified that he was familiar with Kern River levelized rate models as he worked with them regularly. Mr. Hansen said that "Kern River model," as used in his testimony refers to the entire cost of service/rate design model used to prepare the subject rate filing. He said that "Kern River models," refers collectively to the levelized cost of service/rate calculation components of the overall package. Mr. Hansen testified that each levelized model was easy to use, but admitted that the overall package could be considered complex; however, the models ensured accurate and fully documented results. He testified that the models included several Excel levelization models and produced all the statements needed for a section 4 rate filing as well as details on depreciation expense, deferred income taxes, and other accounting matters. [64]

52. Mr. Hansen testified that the levelization model developed, and recommended by RCG witness Charles Doering, did not have all the necessary allocation calculations needed to support a Section 4 rate case. Mr. Hansen testified that the 116 steps identified by Mr. Doering as needed to derive rates in Kern River's rate model, were necessary. Kern River's levelization calculations require an iterative process to develop the annual depreciation expense to levelize the cost of service and depreciate 70% of Kern River's investment in its facilities over the life of its various firm transportation contracts. Kern River's methodology allows for levelizing costs for partial years since shipper contracts expire on different dates and that is required for accuracy. Mr. Hansen testified that he could make changes and run all the steps necessary to produce a set of rates in about fifteen to twenty minutes. He testified that a newly hired rate analyst was able to learn the model well enough to begin running studies on it after just a few hours of training. Mr. Hansen testified that copies of the model and instructions were provided to all parties who asked for them in discovery. He also testified that Kern River had offered to provide personal assistance to shippers or participants who requested it. [65]

53. Mr. Hansen testified that the eight Excel models employed by Kern River use seven levelized rate designs (High Desert is not levelized). The number of models reflects the service provided and the lengths of the shipper contracts. Mr. Hansen testified that the lengths of shipper contracts are varied because of choices the shippers

[63] Ex. KR-9 at 2.
[64] Ex. KR-45 at 3-4.
[65] *Id.* at 3-4, 8 and 10.

made. Mr. Hansen testified that Kern River and the Original System shippers negotiated a settlement agreement [66] under which Kern River agreed to re-finance its debt and the shippers agreed to an extension of the depreciable life of the system and of their firm service agreements. Kern River offered a ten-year contract extension to shippers who did not want fifteen-year extensions. Kern River also offered shippers the option of not extending their contracts and of maintaining the then-existing rate and rate design. Mr. Hansen testified that all of the shippers elected to lengthen their contracts by either five or ten years because that produced significantly lower rates. The re-negotiated contracts and refinancing reduced the total annual cost of service by $56.4 million. Mr. Hansen testified that the accommodation of both the ten- and fifteen-year contract terms must be reflected in Kern River's models in order that accurate levelized rates for both groups of shippers can be designed. Mr. Hansen further testified that one procedure operates models one through six. Another procedure operates models seven and eight because those models represent High Desert Lateral and Big Horn Lateral which have different incremental rate calculations. [67]

54. Mr. Hansen testified to problems with the levelization models of SCGC witness Jack Jones. He testified that the models of Mr. Jones did not have sufficient data and schedules for a Section 4 rate case. He testified that the capital structure was inappropriately constant, rather than calculated on the *Ozark* method as they should have been resulting in inconsistent depreciation percentages. Mr. Jones proposed holding the capital structure constant at the end-of-test period capitalization ratios in each year of the levelization calculations. Mr. Hansen testified that he conducted a study that showed the 2003 Expansion shippers would pay a higher cost of service if the capital structure were to remain constant at the actual end of test period capitalization ratios during the levelization models. Mr. Hansen also took issue with Mr. Jones' depreciation numbers, the failure to include the 3% inflation factor, and the exclusion of Big Horn and High Desert. [68]

55. Mr. Hansen testified that all other things being equal, Staff's proposed traditional cost-of-service/ ratemaking design methodology produces a higher cost of service than Kern River's levelized cost-of-service/ratemaking methodology. That was so, according to Mr. Hansen, because Kern River was still in the relatively early years of its service life resulting in its rate base still being high; therefore, a traditional cost of service calculation would create relatively high rates. Under Kern River's levelized methodology, the rate base is averaged over the remaining years of the firm shippers' contracts. Depreciation expense is adjusted to keep the cost of service level for each year of the levelization period. That results in depreciation expense being low in the early years and higher in

[66] *Kern River Gas Transmission Co.*, 92 FERC ¶61,061 (2000).
[67] Ex. KR-45 at 4-5.
[68] *Id.* at 16-17.

the later years, benefiting shippers with a lower average rate base, in turn lowering return and income tax requirements. Mr. Hansen's calculations showed Staff's proposed traditional methodology total would be $38.6 million more than the levelized methodology presented in the 45-day update filing.[69]

56. Mr. Hansen testified that his initial testimony was a snapshot in time, i.e., October 31, 2004, the end of the subject Section 4 rate filing test period. The data in the statements and schedules Mr. Hansen sponsored in his testimony were the starting point for Kern River's levelized computations. The levelized computations required forecasting future costs of service for the remainder of the firm shippers' contract terms. Mr. Hansen testified that the statements and schedules separately detail cost of service and rate base information for the Rolled-In System (Original System and 2002 Expansion), and each of the three incrementally priced projects (2003 Expansion, High Desert, and Big Horn). The separation reflects the requirements of the Commission's preliminary determination order in Docket No. CP01-422-000 [70] that rates for the 2003 Expansion be developed under the guidelines of the 1999 Pricing Policy Statement. The 1999 Pricing Policy Statement provided that existing pipelines proposing new projects must be prepared to financially support the project without relying on subsidization from existing customers. [71] The *1999 Pricing Policy Statement* applied to the other two incremental projects (i.e., the laterals, High Desert and Big Horn) also. [72]

57. Mr. Hansen testified that Kern River had set up a new account on its books for Joint Transmission Plant. He testified that those facilities benefit, and were allocated to both the Rolled-In System and 2003 Expansion. Because of levelization, Kern River's accumulated book deprecation and amortization balances were directly relevant to the derivation of rates. The adjusted accumulated depreciation for amortization as of the end of the test period for rate purposes were the starting points for determining the total amount of additional investment that has to be recovered over the remainder of each levelization period. High Desert book and regulatory depreciation expense are the same because the adjusted balances of accumulated depreciation and amortization for rate purposes is reflective of straight-line depreciation from the in-service date, as is consistent with the traditional declining rate base methodology employed to design the recourse rates for that project. Mr. Hansen testified that the total regulatory depreciation reserve was not changed, but the reserve was divided into three categories: transmission, general plant, and compressor engines. The adjustments to establish the accumulated

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[69] *Id.* at 18-22 and KR-93 at 3-8. Commission regulation at 18 C.F.R. § 154.311 requires rate filers to file updates 45 days after the end of the test period. In the subject Section 4 rate filing, the 45-day-update was filed on December 15, 2004.
[70] *Kern River*, 98 FERC ¶ 61,205 (2002), *reh'g denied*, 100 FERC ¶ 61,056 (2002).
[71] *Transwestern Pipeline Co.*, 88 FERC ¶ 61,277 (1988).
[72] Ex. KR-9 at 7.

depreciation balances for general plant and compressor engines were debits reflecting their under-depreciated status. [73]

58. Mr. Hansen testified that Kern River had no plans for further expansion. The system had been in an intensive construction mode (2003 Expansion costing $1.2 billion, 2002 Expansion costing $52.5 million, High Desert Lateral costing $30 million, and Big Horn Lateral costing $4 million) planned. He testified that in November 2004 Kern River had held an open season to determine interest in additional firm year-round transportation which might have suggested a possible future expansion, but no shippers requested additional expansion capacity and, in addition, some existing capacity was offered for turn back.[74]

JEFFREY VALENTINE

59. Jeffrey Valentine is Manager of Taxes, Property Accounting, and Accounts Payable for Kern River. Mr. Valentine has a degree in accounting and has worked in tax since 1974, and for natural gas pipelines since 1977. Mr. Valentine is responsible for the administration of the tax, property accounting, and accounts payable functions for Kern River.[75]

60. Mr. Valentine testified that Generally Accepted Accounting Principles ("GAAP") require recording an income tax provision (expense) that represents the expected income tax liability that will arise as a result of the pre-tax book income recognized by a company. That tax provision, for accounting purposes, is divided into a current tax component, representing the amount of tax that should be reflected on the income tax return for the current year, and a deferred tax component, which represents a tax obligation that will be paid sometime in the future. He testified that the specific accounting principle dealing with income taxes is Statement of Financial Accounting Standards No. 109 ("FAS 109"). Mr. Valentine testified that the Commission's Uniform System of Accounts ("USOA") require regulated companies to follow FAS 109 in Accounting Instruction A193-5-000. [76]

61. Mr. Valentine testified that per FAS 109, a "temporary difference" is a difference between the tax basis of a liability or asset and its reported amount in the financial statements that will result in deductible or taxable amounts in future years when the reported amount of the liability or asset is recovered or settled. He testified that deferred taxes, technically, are calculated based on the difference between the book basis of

[73] *Id*. at 7-9.
[74] Ex. KR-93 at 13-14.
[75] Ex. KR-15 at 1-2.
[76] *Id.* at 5-6.

asset/liabilities and the tax basis of those assets/liabilities. However, usually, the difference in book and tax basis is tied back to a temporary timing difference between book income and taxable income. Both current and deferred taxes were considered in arriving at the overall income tax rate for the subject rate filing. [77]

62. Mr. Valentine testified that Commission regulation at 18 C.F.R. § 154.305 requires "tax normalization," which is calculating the total income tax provision as though the taxable income in the tax return were the same as book income. He testified that tax laws passed in 2002 and 2003 significantly affected the calculation of tax depreciation. The Job Creation and Worker Assistance act of 2002 and the Jobs and Growth Tax Relief Act of 2003 allow taxpayers to claim additional ("bonus") tax depreciation for the first year in service. [78] The balance of the tax basis, after deducting the first year bonus depreciation, is also eligible for accelerated tax depreciation. [79]

63. Mr. Valentine testified that when MEHC bought Kern River from Williams, the transaction was a purchase of assets for income tax purposes. A new tax basis was established. Also, as a result of the sale, Williams was required to include all of the previously accumulated, temporary differences related to Kern River's assets in its 2002 federal and state income tax returns and to pay the related income taxes to the IRS and state authorities. On the sale of Kern River to MEHC in March 2002, the net ADIT balance of $136,914,000 was reduced to zero. A net debit entry was made to the ADIT accounts and a credit entry was made to the shareholder equity account. According to Mr. Valentine, MEHC made no election, the adjustment to the prior ADIT balance was consistent with Commission regulations[80], and Internal Revenue Code § 168(f)(2). As Kern River continues to use accelerated tax depreciation, the deferred tax balance is expected to build up to levels even higher than that on the books at the time of the sale to MEHC. [81]

MICHAEL D. FALK/DANIEL C. ZEBELEAN

64. Michael D. Falk was Vice President, Operations, Information Technology and Engineering at Kern River at the time he prepared written testimony for filing in this case. Mr. Falk began his career in energy as an engineer working on coal gasification

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[77] *Id.* at 7-8.
[78] Job Creation and Worker Assistance Act of 2002 (JCWAA), Public Law 107–147 (116 Stat. 21). Jobs and Growth Tax Relief Reconciliation Act of 2003, P.L. 108-27, (117 Stat. 752).
[79] KR-15 at 8-28.
[80] 18 CFR § 201.
[81] Ex. KR-15 at 10-15.

and tar sands projects before moving into pipeline design and construction engineering. [82] Mr. Falk had left Kern River's employ by the time of the hearing. Daniel C. Zebelean, Director of Engineering, Land and Environment for Kern River, sponsored Mr. Falk's written testimony. Tr. 95. Mr. Zebeleans's testimony was that after the 2003 Expansion, Kern River began operating twenty-three compressor engines at eleven compressor stations. Kern River keeps an additional twenty-fourth unit as a spare. All but three of the units are gas turbine engines. Two units at Anschutz, Wyoming, are small reciprocating compressors. The Daggett, California, compressor is electric motor-driven. [83]

65. Mr. Zebelean further testified that Kern River had eighteen Solar Mars 100 compressors rated at 15,000 horsepower each, and two Solar Centaur turbines rated at 5,500 horsepower each. The Mars compressors are located at the mainline compressor stations and generally run at high annual utilization factors. For most of Kern River's history (commencement of service in 1992 until May 2003), the system operated at annual load factors approaching or exceeding 100% annual utilization of the system's firm summer design capacity. After the 2003 expansion began operation, utilization factors for the Mars units had been somewhat lower, but were still much higher than the other compressor engines. Kern River has an agreement with the manufacturer of the Mars compressor engines, Solar, to exchange worn-out units for overhauled turbine units. Mr. Zebelean testified that in the initial years of Kern River's operation, most turbines were exchanged after 20,000 to 30,000 fired hours of operation. At the hearing Mr. Zebelean testified that as of July 1, 2002, a new contract with Solar provided for exchanging the compressors at about 35,000 fired hours of operation or about once every four years. [84]

<u>EDWARD H. FEINSTEIN</u>

66. Edward H. Feinstein is a consulting petroleum engineer with the firm of Brown, Williams, Moorhead & Quinn, Inc. Mr. Feinstein was employed at FERC for about thirty-five years before becoming a consultant. At FERC, Mr. Feinstein's duties involved determining appropriate depreciation rates for pipeline facilities. [85]

67. Mr. Feinstein testified that he had completed a detailed depreciation study and assessment of Rocky Mountain gas supplies as they related to the useful life of Kern

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[82] Mr. Falk had left Kern River's employ by the time of the hearing. Daniel C. Zebelean, Director of Engineering, Land and Environment for Kern River, sponsored Mr. Falk's written testimony. Tr. 95.
[83] Ex. KR-4 at 2.
[84] Tr. 698; *see also id*. at 3-6.
[85] Ex. KR-5 at 1-2.

River's pipeline system. He explained that depreciation was the allocation of the original cost of tangible facilities in service over their useful lives. Depreciation is intended to recover the invested capital systematically over the useful life of the relevant assets. For accounting purposes, depreciation is treated as an operating expense. Mr. Feinstein testified that in the gas pipeline industry, functional causes (inadequacy, obsolescence, inadequacy of supply or markets) are probably more prevalent causes of retirements from useful service of an asset, than are physical causes (wear-and-tear and deterioration). Adequacy of supply and markets is referred to as "economic life." [86]

68. Mr. Feinstein testified that a gas supply study showed a trend suggesting that the Rocky Mountain gas supply market was moving from a supply/demand balance controlled by demand to one controlled by supply. His production profiles indicated deficiencies in the ability of the Rocky Mountain area to maintain high levels of throughput in all available pipeline capacity to the point that, by the year 2030, its productive capacity may be less than 60% of its current productive capacity. Underutilization of the pipeline would occur when supply declined and resulted in excess pipeline capacity. Mr. Feinstein testified that because Kern River was largely dependent on Rocky Mountain gas, his studies indicated that Kern River had an economic life of about twenty-five to thirty years. However, taking into account competition for the gas supply that exists in the market in which Kern River operates, the economic life would be twenty-six years. Mr. Feinstein used the straight-line, average-remaining-life method formula to determine depreciation. Average remaining life ("ARL") is the denominator in the formula. ARL represents the average year of the final investment recoupment. It reflects a point in time around which major retirements will occur. Economic life is a factor in determining ARL. [87]

69. Mr. Feinstein testified that "negative salvage" was the net amount of funds necessary to retire a specific facility or group of them. Negative salvage is the difference between the cost of removal and gross salvage. He testified that the negative salvage rate was the annual rate as a percent of the gross plant subject to retirement that will accrue enough funds to cover the cost of removal. Mr. Feinstein used the same straight-line, remaining life method he used to determine deprecation rates to accrue negative salvage funds. The cost of removing decommissioned facilities and restoring the land to its usual condition is also included in the negative salvage rate. Including that cost in rates ensures current ratepayers pay the cost of using the facilities. Based on his studies of the matter, Mr. Feinstein concluded that Kern River would average approximately 5% net negative salvage for each dollar of plant retired. [88]

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[86] *Id.* at 3-8.
[87] *Id.* at 3-27.
[88] *Id*. at 27-32.

70. Mr. Feinstein testified that staff witness Kevin Pewterbaugh was misguided in his conclusion that the recommended negative salvage rate should be 0.18%. According to Mr. Feinstein, Mr. Pewterbaugh used a thirty-five year economic life as opposed to Mr. Feinstein's recommended twenty-six years. Mr. Feinstein testified that Mr. Pewterbaugh was incorrect in his conclusion that Mr. Feinstein's proposal did not conform to Commission criteria set forth in *Iroquois Gas Transmission Co.* [89] Mr. Feinstein's proposal had a clearly discernable pipeline end-of-life and took interim retirements into account. It was only with the third criteria that his proposal fell short, but not for any reason that Mr. Feinstein could control. The third criterion is that salvage values of abandoned or retired equipment be fully proven. Because of its relatively young age, Kern River had little retirement experience. Significant retirements do not usually occur until the middle-age of a pipeline. [90]

71. Mr. Feinstein also took issue with the testimony of RCG witness Bruce Doering regarding negative salvage. Mr. Doering opposed any accrual for negative salvage finding Mr. Feinstein's negative salvage rate determination to be inconsistent and unreliable. Mr. Doering also claimed that since Kern River did not seek FAS 143[91] treatment for some of its transmission plant, the Commission should not allow the company to accrue funds for negative salvage. Mr. Feinstein testified in rebuttal that he had used the negative salvage estimate developed by a Kern River engineer and adjusted it downward to remove existing plant and the cost of removal associated with interim retirements. Mr. Doering's problem, according to Mr. Feinstein, was that Mr. Doering did not understand all of the factors Mr. Feinstein had taken into account in making his negative salvage rate determination. Mr. Feinstein further testified that FAS 143 is only an approach to determine accounting accruals to reflect for financial statement purposes the eventual cost of system retirement and accounting does not control ratemaking. [92]

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[89] *Iroquois Gas Transmission Co., L.P.,* 86 FERC ¶ 61,261 (1999).

[90] Ex. KR-111 at 68-69.

[91] "Essentially under the requirements of FAS 143, an entity must estimate and record the present value of future legal obligations related to the final removal of its plants and facilities. Entities will be required to record the asset retirement obligation as a liability with a corresponding increase to the capitalized cost of the related plant or facility. The capitalized cost of the asset retirement obligation will subsequently be depreciated over the life of the asset. Additionally, the asset retirement liability will be increased over time to account for the time value of money through charges to operating expense until the liability is ultimately extinguished when the actual removal work is performed. Finally, the statement requires that the cumulative-effect related to the adoption of the pronouncement be flowed through the income statement." *Accounting for Asset Retirement Obligations,* 98 FERC ¶ 62,222 (2002).

[92] KR-111 at 68-72.

72. Mr. Feinstein testified that compressor engines should be depreciated separately on a traditional straight-line depreciation method. He testified regarding compressor engines that they should be treated differently for ratemaking purposes because of the high investment turnover and short service life. He testified that inclusion of the short-lived compressors in the levelized cost-of-service approach would not allow Kern River to recoup its capital investment over a reasonable period of time. Inclusion would also cause significant intergenerational inequities to shippers, according to Mr. Feinstein. The average service life ("ASL") of the compressor engines is only 2.91 years, but the retirement does return a positive net salvage value of over 70% of the original cost with little cost of removal. Mr. Feinstein testified that Kern River had historically capitalized replacement engines, rather than expensed them. Kern River's treatment of the compressor engines resulted in a regulatory asset because the depreciation rate that was applied to the short-lived engines was based on long-lived transmission properties (such as mains), and the differences between the cost of retired property, salvage and cost of reserve applied to the reserve, resulted in a negative reserve. This reserve for depreciation is accrued as a credit in plant service. [93]

73. Mr. Feinstein testified that general plant should be depreciated separately on a traditional straight-line depreciation method. General plant includes: office furniture and equipment; transportation equipment; tools, shop and garage equipment; power-operated equipment; and communication equipment. Mr. Feinstein testified that separate depreciation treatment for general plant was appropriate because of high-turnover rate of general plant items. [94]

74. Mr. Feinstein testified that Kern River should be allowed to increase its book depreciation transmission plant to 3.39 percent from the current 2.0%. He testified that from the beginning of operation until October 1, 2001, Kern River's facilities were depreciated at a 4% book deprecation rate based on stipulations in the Optional Certificate order that was based on a twenty-five year life for the system. As of October 2001, the Original System was about nine years old. The 2.0% depreciation rate reflected the previous depreciation of the system at the 4.0% depreciation rate, conformed to a Commission finding that the remaining system life was thirty-one years as of October 31, 2001.[95] The increase is appropriate, according to Mr. Feinstein, because Kern River had more than doubled its transmission plant investment since the 2.0% was authorized. The 2002 and 2003 Expansions had depreciated little by the end of the test period. Therefore, a composite book depreciation rate incorporating new and old plant had to reflect the fact that there were additional un-depreciated plant units in service. [96]

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[93] *Id*. at 3 and 32-41.
[94] *Id*. at 3 and 41-45.
[95] *Kern River Gas Transmission Co*., 92 FERC ¶ 61,061, at 61,161 (2002).
[96] KR-111 at 2-5.

75. Mr. Feinstein testified that there had been no major changes during the 2001 to 2004 period to warrant an increase in Kern River's depreciable life. The system expansions were not the result of expected increases in gas supply. The expansions hasten depletion of the gas supply. Mr. Feinstein also noted several other changes contra-indicative of an increase in depreciable life: increase in planning and positioning of liquefied natural gas (LNG) plants in the Kern River market area; natural gas retrieval from Alaska; new large pipelines. [97]

76. Mr. Feinstein criticized the testimony of Staff's witness Kevin Pewterbaugh. Mr. Pewterbaugh had also performed a gas supply study to determine the remaining economic life of Kern River's system, in order to compute an average remaining life for deprecation purposes. Mr. Pewterbaugh came up with a thirty-five year economic life. According to Mr. Feinstein, Mr. Pewterbaugh erred in failing to consider the effects of the following on the life of Kern River's facilities: the relationship between falling gas supply, increasing take-away capacity of other pipelines, market competition from LNG and potentially Canadian and Alaskan gas alternatives. Mr. Feinstein testified that Kern River had not been successful in competing with existing pipelines for California business (i.e., failed open season). Mr. Feinstein further found fault with Mr. Pewterbaugh's supply study, especially Mr. Pewterbaugh's use of a symmetrical curve instead of a symmetrical bell-shaped or symmetrical S-shaped curve. [98]

77. Mr. Feinstein also took issue with the criticisms of Thomas R. Hughes, Calpine's witness, and of James A. Doering, RCG's witness. According to Mr. Feinstein, Mr. Hughes and Mr. Doering failed to establish a logical and reasonable connection between the gas supply and the particular pipeline in question. The geographic area has to be considered, as do the pipelines already in the area, as well as the gas supply estimates. Mr. Feinstein testified that Mr. Hughes and Mr. Doering relied on the Potential Gas Committee ("PGC") resource life studies, as did he. The PGC, according to Mr. Feinstein, is a highly-regarded source of information on gas reserves. PGC uses the following categories: probable resources, possible resources, and speculative resources. Mr. Feinstein testified that he used the possible and probable categories, which according to Mr. Feinstein are the only categories used by the Commission. [99] According to Mr. Feinstein, Mr. Hughes and Mr. Doering were not as circumspect. [100]

78. Mr. Feinstein testified that BP witness Elizabeth Crowe erred in the choice of production component as the dividend in the resource life equation, producing a

[97] *Id*. at 5-9 and Tr. 837-895.
[98] *Id*. at 9-80.
[99] *See Trunkline Gas Co.*, 90 FERC ¶61,017 at 61,057 (2000).
[100] Ex. KR-111 at 55-80.

production component that is too low. Ms. Crowe should not have included proven reserves in her total gas supply because potential resources would replace proven reserves as they are depleted. She also failed to consider new pipelines proposing to transport gas out of the Rocky Mountain area. [101]

LYNN DAHLBERG

79. Lynn Dahlberg is Manager of Marketing and Customer Service for Kern River. Ms. Dahlberg manages Kern River's daily commercial activities. Those activities include, among other things, customer service, implementation of new services, contract generation and administration, nominations and scheduling, invoicing, capacity release, revenue and gas accounting and certain reports. Ms. Dahlberg testified that Kern River had the following types of service agreements: 1) fifteen-year and ten-year Original System; 2) fifteen-year and ten-year 2002 Expansion; 3) limited-term CAP; 4) fifteen-year and ten-year 2003 Expansion System; 5) High Desert; 6) forward-haul short-term firm; 7) forward-haul interruptible; 8) negotiated back-haul short term firm; 9) back-haul interruptible. She testified that all negotiated rate transactions during the base period, except High Desert Lateral, were short-term firm back-haul transactions that may have flowed on a forward-haul basis as secondary, out-of-path firm. All negotiated rate agreements, except High Desert, had either a primary term of one month with a month-to-month evergreen provision, or a primary term of one year with a year-to-year evergreen provision. The rate for these negotiated agreements was a discounted, fixed rate for all transportation quantities scheduled at the receipt and delivery points specified in the shipper's agreement, up to the specified Maximum Daily Quantity ("MDQ") at those points. Any scheduled transportation in excess of the shipper's MDQ and/or any scheduled transportation at receipt or delivery points not in the agreement, the rate was equal to Kern River's maximum interruptible rate plus one-half of the Daily Price Survey Flow Date spot price reported in *Gas Daily* for "Others SoCalGas" minus Kern River Opal Plant.[102]

80. Ms. Dahlberg testified, respecting reservation billing determinants, that for the Original System all firm service agreements set forth the MDQs applicable to demand/reservation charges and transportation rights on the mainline, as well as entitlements at receipt and delivery points on a Mcf basis. In May 2002, the MDQs of the Original System firm agreements were converted to dekatherms. Current reservation billing determinants for the firm, year-round Original System are 724,449 Dth/d. The 2002 Expansion added 124,500 Dth/d for a total of 848,949 Dth/d. The 2003 Expansion added 906,626 Dth/d so that Kern River's year-round, reservation billing determinants

[101] *Id*. at 66-67.
[102] Ex. KR-1 at 1-6.

became 1,755,575 Dth/d.[103]

81. Ms. Dahlberg testified that changes in system throughput that occurred during the first ten months of operations after the 2003 expansion went into service (May 2003 through February 2004) included: 1) decline in the value of Kern River's interruptible transportation service; 2) unutilized 2003 Expansion capacity; 3) increase in service to electric generation markets; and 4) formerly IT service markets changed to firm service. She testified that Kern River was proposing a blended fuel rate for all shippers because that would be equitable to all shippers because capacity that is used for interruptible ("IT") and/or authorized overrun service ("AOS") is operationally available capacity resulting from: 1) favorable ambient and flowing gas temperatures; 2) favorable gas flow patterns; and/or 3) unutilized form capacity. She testified that none of those factors were attributable or applicable solely to the Rolled-In or 2003 Expansion shippers. Consequently, it was reasonable to use the reservation billing determinants for each group of shippers as the weighting factor for calculating the blended fuel rate. [104]

82. Ms. Dahlberg testified that Kern River's credit policy provided that shippers with a rating of lower than BBB for *S&P* and Baa3 for Moody's must provide: 1) a guaranty from an investment grade third party; 2) cash collateral equal to the amount of reservation charges for one year; or 3) a letter of credit equal to the amount of reservation charges for one year. She testified that other factors contributing to Kern River's increased exposure to credit risks since the 2003 Expansion included changes to the electricity industry and business and financial difficulties of many energy companies. [105]

83. Ms. Dahlberg testified that her credit analysis of long-term firm shippers included those holding Rolled-In capacity and those holding 2003 Expansion capacity. Some below-grade shippers had parent companies that provided security and some provided cash assurance or letters of credit. Calpine was one of those companies. However, according to Ms. Dahlberg, a parent-company guarantee does not reduce the potential risk to Kern River by shippers of less-than-investment grade credit. Also a shipper could still default despite collateral. Considering investment grade and non-investment grade shippers differently for purposes of assigning credit ratings is appropriate, according to Ms. Dahlberg, because if a shipper is below investment grade and it provides a one-year letter of credit or a reservation equal to one year of collateral, that is only the equivalent of a one-year contract as that is all that is guaranteed. Ms. Dahlberg testified that after stabilizing in 2003, the credit quality began deteriorating in 2004. [106]

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[103] *Id*. at 8-9.
[104] *Id*. at 14-15.
[105] *Id*. at 17-23.
[106] Tr. 561-65, 640-45 and 685-687.

84. Ms. Dahlberg testified that Kern River remained at risk for re-marketing Mirant capacity. Kern River had not attributed Mirant capacity to specific IT shippers. She testified that the last-through-the-meter, common bankruptcy concept is a lost-volume-seller concept. It means that if a creditor is able to sell IT capacity before the rejection in bankruptcy, it should be able to sell it after the rejection without calling that "mitigation." That is why Mirant capacity is last-through-the-meter in the bankruptcy proceedings. Kern River called that Mirant capacity first-through-the-meter because Kern River was treating the Mirant capacity for rate design purposes as if it were still under firm contract although it is actually in the IT bucket. Kern River took it out of the IT bucket and put in the firm bucket to avoid double counting. Ms. Dahlberg testified that Kern River incurred 100% of the damages in the *Mirant* litigation and in this rate case Kern River is proposing to continue taking 100% of the risk. [107]

85. Ms. Dahlberg testified that billing determinants reflect throughput used to design rates. Kern River has a two-part firm transportation rate: a reservation fee and commodity fee. A "reservation fee" is paid for contracted quantity of capacity regardless of whether the shipper actually ships the gas. A "commodity fee" is what is paid for as actually shipped. A "unit rate" is calculated by dividing costs (numerator) by throughput or billing determinant (denominator) to calculate unit rate. Ms. Dahlberg testified that if Kern River used 100% of its billing determinants instead of 95% (95% is only applicable to the Original Shippers) when designing rates, affected rates would be lower. [108]

86. Ms. Dahlberg testified that AOS was service that is operationally available to firm shippers that want to transport more gas than is provided for in their contracts. The rates are the same. Underlying firm rates for expansion shippers are higher than underlying firm rates for Rolled-In shippers. If a Rolled-In shipper used AOS, that shipper would have to pay a rate equivalent to the higher 2003 Expansion shipper rate. Kern River is proposing to increase the AOS transportation rate for Rolled-In shippers and the AOS fuel rate associated with that transportation for Rolled-In shippers. Ms. Dahlberg testified that used capacity cannot be attributed to either Rolled-In or Expansion capacity. [109]

<u>DR. CHARLES E. OLSON</u>

87. Dr. Charles E. Olson is an economist and currently is a Teaching Professor at the University of Maryland. Dr. Olson has thirty-five years as a public utility and pipeline rate consultant. Dr. Olson testified that he is an expert in evaluating business and financial risks for natural gas pipelines. He testified that risk became a pipeline ROE

[107] Tr. 639, and 688-90.
[108] Tr. 630-11.
[109] Tr. 612-17.

issue after the 1995 *Northwest Pipeline* [110] decision, Opinion 396-B[111], and various decisions that came after, which established several factors to be considered in establishing ROE. Some of those factors are: load factor (usually ½ percent); shipper's contract profile (amount of capacity committed under long-term vs. short-term contracts, depending on the situation); availability and adequacy of the gas supply to the pipeline; level of competition; extent of depreciation of the pipeline's assets. Dr. Olson testified that the Commission assigns pipelines to three points along a risk continuum: low, middle, high; the higher the pipeline's risk, the greater the ROE an expert would recommend. [112]

88. Dr. Olson testified that his opinion was that Kern River was the most risky pipeline in the lower forty-eight states. He testified that one influencing factor was that the price of natural gas has changed dramatically since the time Kern River signed contracts with the shippers. He testified that three major risks for Kern River were: 1) huge competition for Rocky Mountain area gas; 2) high-end depreciation asset base; and, 3) poor credit profiles of the shippers. The latter factor, the lack of creditworthiness of Kern River shippers, according to Dr. Olson, is unique to Kern River and is the factor that makes Kern River the riskiest of profiles. [113] The quality and character of the markets Kern River serves is also a factor. [114]

89. Dr. Olson elaborated on Kern River's business risks testifying that unlike older pipelines, Kern River has not recovered much of its capital investment. He testified that Kern River's levelized cost-of-service/ratemaking process exacerbates Kern River's capital recovery issue. Dr. Olson testified that Kern River's market profile was a problem because unlike other pipelines that were built to primarily serve local distribution companies ("LDC") with large numbers of retail customers, Kern River was constructed to primarily serve the enhanced oil recovery ("EOR") markets of California. However, the newer markets that had developed on Kern River over time are largely in the electric generation sector. He testified that, although creditworthiness of shippers can be a problem for all pipelines, Kern River's current shipper profile includes an unusually high percentage of merchant generator shippers. Merchant generator shippers overall are of poorer credit quality than LDC shippers, according to Dr. Olson. LDCs account for over 50% of firm capacity subscriptions across the interstate gas pipeline network, while Kern River's is less than 7%. Dr. Olson testified that Kern River's merchant generator

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[110] *Northwest Pipeline Co.*, 71 FERC ¶ 61,253 (1995), *reh'g*, 76 FERC ¶ 61,068 (1998), *reh'g denied*, 768 FERC ¶ 61,289 (1987).
[111] *Northwest Pipeline Co.*, 79 FERC ¶ 61,309 (1997), *reh'g denied*, 81 FERC ¶ 61,036 (1997).
[112] KR-10 at 30.
[113] Tr. 530-31, 538, 425, 429 and 452.
[114] Ex. KR-10 at 5.

shippers are much more vulnerable to gas price volatility than are LDCs. [115]

90. Dr. Olson testified that energy literature was reporting that coal was making a comeback as a viable energy source. Dr. Olson testified that any energy source that could cause underutilization of the pipeline was a threat to Kern River, as it would likely deter investors. [116]

91. Dr. Olson testified that although his original estimate of appropriate ROE made in January 2004 was 15.1%., he testified that further studies led him to conclude that the rate should actually be 15.7%; however, Kern River, he noted, had chosen to propose using the 15.1% figure. [117] Dr. Olson testified that return on taxes made up more than 50% of the revenue requirements. He testified that every percentage point change in ROE had a significant impact on the cost of service. A percentage point is one hundred basis points. If Kern River's proposal were approved, the ROE would go from 13.25% to 15.1%. Dr. Olson admitted that was a significant change in the number of basis points. [118]

92. Dr. Olson testified that he used the Commission's preferred, two-step discounted cash flow ("DCF") methodology in determining ROE for Kern River. The first of the two steps involves selecting a proper proxy group. Dr. Olson testified that the DCF methodology has generally been implemented by using publicly-traded holding companies that own FERC-regulated pipeline companies and imputing the results to those companies. In the past that would yield a FERC pipeline proxy group of between four and six companies; this number included most of the major operating gas pipelines in the United States. Dr. Olson testified that recent bankruptcies and mergers in the industry had changed the proxy group selection process for DCF purposes, however. Dr. Olson testified that for this case he had chosen six companies that were primarily involved in the pipeline processing and storage business. According to Dr. Olson, those companies owned gas pipelines or other midstream assets and did not extensively serve residential and small commercial customers. He chose: Enterprise Products Partners; Gulfterra Energy Partner's, L.P.; KinderMorgan Energy Partners; Kinder Morgan, Inc.; Northern Border Partners; and, Williams Companies. Dr. Olson's opinion is that an analysis of Kern River's ROE requirements cannot reasonably or accurately be based on a proxy group of holding companies with high percentages of retail electric and gas customers. Those companies are not comparable to Kern River because of their lower risk and return requirements. Dr. Olson took particular exception to using LDCs which, according to Dr. Olson, have a natural monopoly with relatively low demand elasticity,

[115] *Id.* at 5-10.
[116] *Id.* at 10-13.
[117] Tr. at 1-4 and Tr. 391-405.
[118] Tr. 379-81.

price sensitivity and throughput risks. Companies Dr. Olson would find to be inappropriately included in a Kern River proxy group, for reasons outlined above, are: CenterPoint Energy, Dominion Resources, Duke Energy, El Paso Corporation, Entergy, National Fuel Gas, and Questar. [119]

93. Dr. Olson testified that the six companies in his proxy group paid dividends or distributions. He testified that his DCF study supported a ROE of no less than 13.4% and no more than 15.1%. Dr. Olson justified the higher ROE because of risks previously discussed which make the probability of full recovery of Kern River's equity investment lower than for the comparable companies. [120]

94. Dr. Olson testified that he was aware that the Commission had issued a decision, subsequent to Kern River's making the subject Section 4 rate filing, which addressed the issue of comparable proxy group companies in the post-Enron environment. That case was *High Island Offshore Syste*m ("*HIOS*"). [121] According to Dr. Olson, three findings in that case have some bearing on Kern River's current rate filing. First, the Commission found El Paso and Williams should not be included in the proxy group because financial difficulties had resulted in lowered dividends for those companies. However, Staff, BP, RCG**,** as well as Kern River had included Williams in their proxy groups. Second, the Commission found that the proxy group proposed by Staff which included Manganelo of Equitable Gas, Kinder Morgan, National Fuel, and Questar was the best available proxy group for *HIOS* based on the record in that case. However, Dr. Olson was of the opinion that the four companies that remained of the original nine-company *Williston* [122] were not appropriate proxy companies for Kern River because Kern River has no downstream operations; Equitable, National Fuel, and Questar do have downstream operations. [123]

95. Dr. Olson testified that a third applicable *HIOS* consideration was that the Commission concluded it was not appropriate to include master limited partnerships ("MLPs") in the a gas pipeline proxy group unless the record had demonstrated that the distribution used as the dividend did not include a return of investment, but was instead only a payment of earnings. Fourth, the Commission found that a proxy group consisting of only four companies could be used in making an equity determination. Finally, according to Dr. Olson, the Commission did not approve the inclusion of gas distribution

[119] Ex. KR-10 at 16-28.
[120] *Id*. at 28-32.
[121] *High Island Offshore System*, L.L.C., 110 FERC 61,043 (2005).
[122] *Williston Basin Interstate Pipeline Co.*, 71 FERC ¶ 63,010 (1997), *order on initial decision*, 84 FERC ¶ 61,081(1998), *reh'g*, 87 FERC ¶ 61,264 (1999), *reh'g*, 88 FERC ¶ 61,301 (1999).
[123] Ex. KR-107 at 4-6.

companies in the proxy group. The Commission also noted that it had previously rejected inclusion of electric companies. [124]

96. Dr. Olson testified that "debt-service" is to be distinguished from "equity-related risk." Kern River's debt-service is not subject to the hazards previously described by Dr. Olson. Rather, although the credit risks of its shippers was becoming problematic, Kern River's debt was secure because of its historic ability to keep throughput at levels that provided necessary debt-service coverage. The equity-related risk is that the authorized ROE will not be earned because of unsubscribed throughput or will have to be sold at less than prevailing contract prices. Dr. Olson testified that he realized that the Commission had not in recent times found any pipeline to be above average risk in any rate case. He termed the Commission's action in this regard to be an "unwavering refusal." [125]

97. Dr. Olson testified that he disagreed with witnesses who proposed a lower ROE for Kern River. Dr. Olson testified that Staff witness Vladimir Ekzarkhov arrived at a recommended 9.0% ROE because he included companies with significant retail electric and gas distribution operations. Mr. Ekzarkhov thought it appropriate to include such companies in his proxy group because they are regulated and energy-related companies. Dr. Olson's opinion is that companies with significant retail distribution operations do not have the same equity risk as an interstate natural gas pipeline like Kern River even if they are regulated and energy-related. Also, Mr. Ekzarkhov did not include MLPs that own gas pipelines as did Dr. Olson. Further, Mr. Ekzarkhov erroneously put Kern River in the middle of the zone of reasonableness when, according to Dr. Olson, it is illogical to find all pipelines have the same degree of risk. Moreover, Dr. Olson testified, he was aware of no regulated gas pipeline with an equity return as low as 9.0%. [126]

98. Dr. Olson testified that RCG witness David C. Parcell arrived at a recommended 9.4% ROE. Again the problem was, according to Dr. Olson, the proxy group companies. Mr. Parcell inappropriately included gas and electric companies with distribution operations and relatively low capital costs. Dr. Olson testified that because pipelines are riskier than electric and gas distribution companies, they historically have received higher returns. Also, Mr. Parcell found Kern River was not a high risk pipeline; it was in the middle range of return. However, he, like Mr. Ekzarkhov, had improperly considered Kern River's bond rating an important factor; according to Dr. Olson, bond rating reflects debt risk and is not a meaningful measure of equity risk. [127]

99. Dr. Olson testified that BP witness Elizabeth Crowe arrived at a recommended

[124] *Id*.
[125] *Id*. at 33.
[126] *Id*. at 4-26.
[127] *Id*. at 28-31.

ROE of 9.34%. Dr. Olson noted that Ms. Crowe also had not included MLPs, nor had she found Kern River's arguments about risk persuasive. Those failures, according to Dr. Olson, drove down the ROE developed by Ms. Crowe. [128]

ALAN R. LOVINGER

100. Alan R. Lovinger is Vice President of the firm of Brown, Williams, Moorhead & Quinn, Inc. Mr. Lovinger's firm provides consultant services on business and regulatory matters to the gas, electric and oil industries. Prior to his service with that firm, Mr. Lovinger had been Senior Accountant at FERC for twenty-five years, working primarily on cost-of-service matters with an emphasis on tax issues. [129]

101. Mr. Lovinger answered testimony of Participants that criticized Kern River's levelized methodology. Mr. Lovinger testified that given identical inputs a model simulating that of RCG witness Bruce Doering's annuity levelization model yielded results very close to those of Kern River's model. Mr. Doering testified that the annuity levelization methodology can be useful and that he had used it to develop rate for clients, but only when that client was interested in certificating a new project. In working with a new project, there are numerous changes in costs and in billing determinants and the annuity levelization methodology model can easily be adapted to handle the changes. However, it is Mr. Lovinger's opinion that before making the certificate filing to the Commission, the annuity model has to be converted to a deprecation levelization model like Kern River's, because of annuity model limitations in the calculating of the dollars to be levelized. [130]

102. Mr. Lovinger testified that an annuity levelized methodology model inadequacy is that there is no clear understanding or documentation of which cost element in the model is being levelized. That fault, according to Mr. Lovinger, adversely affects the depreciation consideration. Because a utility using a levelization model is recovering less depreciation to which it would otherwise be entitled, there needs to be a mechanism in place that assures it the ability to recover the deferred depreciation in succeeding years before the levelization period has expired. Mr. Lovinger testified that the mechanism for reporting deferred depreciation for accounting and rate purposes is the creation of a regulatory asset; that is set out at 18 C.F.R. part 210, Definition 31. The regulatory asset is increased each year for the difference between the depreciation collected in the levelized rate and the book depreciation. Mr. Lovinger testified that the weakness of the annuity levelized model is that the amount of annual deprecation collected in rates is not known and that Commission regulation at 18 C.F.R. Part 201, § 182.3 requires that

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[128] *Id*. at 31-34.
[129] Ex. KR-50 at 1-3.
[130] *Id*. at 4-16.

documentation. He testified that the cost element that drives the ability to levelize is the ability to defer the recognition of depreciation expense in rates. However, according to Mr. Lovinger, the annuity levelization methodology model does not reflect the depreciation expense that is recognized in determining rates; it only reflects the book depreciation. Since, the computation of ADIT and net plant are computed from levelized depreciation expense, the computation of rate base and the corresponding return and related income taxes as computed in the annuity approach are not accurate. Finally, Mr. Lovinger testified that he did not find Kern River's levelization methodology model as complex as Mr. Doering testified that it was. [131]

103. Mr. Lovinger testified that the conclusion of Staff witness Bonnie Pride that Kern River's collection of depreciation and interest payments will exceed Kern River's debt amortization payments by $385,119,494 is incorrect. Mr. Lovinger testified that Ms. Pride did not appear to understand levelization. A utility is allowed to recover its investment in utility plant through the recognition of annual depreciation expense. The annual depreciation expense includes both a recovery of debt and of equity-financed investments. In the traditional cost-of-service/ratemaking methodology, the utility generally will recover debt and equity depreciation in proportion to the debt and equity ratios in its capitalization. Mr. Lovinger testified that in the case of Kern River, however, collection of depreciation for the years included in the levelization period was used to pay debt principal first. Mr. Lovinger testified that regardless of whether debt or equity is to be paid down through the collection of depreciation, the utility is only allowed to collect depreciation in an amount equal to its investment. [132]

104. Mr. Lovinger testified that as depreciation is collected, a reserve for deprecation keeps track of the amount of depreciation recovered from ratepayers. As depreciation expenses are projected to be recovered by Kern River each levelized methodology rate year, Kern River recognizes such collection in accumulated depreciation and makes a corresponding adjustment to rate base. According to Mr. Lovinger, Kern River's collection of depreciation expense consistent with its levelized methodology model is also consistent with the USOA, which does not allow Kern River to over-collect its depreciation expense. [133]

105. Mr. Lovinger testified that the conclusion of SCGC witness Jack Jones that Kern River's use of the *Ozark* methodology allows it to overstate return and related income taxes is incorrect. Mr. Lovinger explained that while in the traditional methodology a capitalization assigns a weighted cost of debt and equity to determine an appropriate return allowance, the *Ozark* method assumes that all debt was raised to finance rate base.

[131] *Id.* at 16-19.
[132] *Id*. at 19-20.
[133] *Id*. at 21-22.

Therefore, in computing capital structure, all outstanding debt is subtracted from total rate base and the remainder is assumed to be financed by equity. The cost of service, accordingly, reflects a ROE and a separate computation of debt interest cost. Mr. Lovinger testified that Kern River is not fully compensated for its capital investment in the pipeline using the *Ozark* methodology. Using constant capitalization, as would occur not using the *Ozark* methodology, Kern River would be entitled to collect an additional $4.2 million, according to Mr. Lovinger. [134]

106. Mr. Lovinger testified that Staff witness Bonnie Segal's proposal to amortize Kern River's regulatory asset of $108,233,363 over thirty-five years is unreasonable. It would only apply if the Commission ordered Kern River to use the traditional methodology for setting rates, in any event. According to Mr. Lovinger, Ms. Segal's proposal has three problems: 1) it creates an intergenerational rate issue by establishing an amortization period that extends beyond the expiration of Kern River's current shippers' contractual obligations; 2) Kern River is unjustifiably placed at risk for the recovery of a substantial part of the regulatory asset if the recovery period is extended beyond the expiration of the current firm contracts; 3) and, it causes Kern River to be significantly under-compensated for the appropriate return on it actual rate base investment. According to Mr. Lovinger, Ms. Segal provided no support for her position beyond citing *Williston Basin Interstate Pipeline Co.* [135] Mr. Lovinger pointed out that in *Williston* the amortization period was five years, not thirty-five years. [136]

107. Mr. Lovinger testified that BP witness Elizabeth Crowe's proposed use of a three-year rate base (assuming a change to traditional is ordered) is not supported by Commission precedent. According to Mr. Lovinger, the Commission in *Iroquois Gas Transmission System, L.P*. ("*Iroquois"*) [137] rejected arguments that the use of end-of-test-period rate base was unjust and unreasonable and that the pipeline's rate base should be adjusted downward to reflect an average for a thirty-year period. [138]

108. Mr. Lovinger testified that Staff witness Kevin Pewterbaugh's argument that straight-line depreciation treats generations of ratepayers equitably by applying a constant deprecation amount to each year, indicates that Mr. Pewterbaugh is taking too narrow a perspective of levelization. According to Mr. Lovinger, Mr. Pewterbaugh appears only to

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[134] *Id*. at 22-25.
[135] *Williston Basin Interstate Pipeline Co*., 95 FERC ¶ 63,008 (2001), o*rder on Initial Decision*, 104 FERC ¶ 61,036 (2003).
[136] Ex. KR-50 at 26-34.
[137] *Iroquois Gas Transmission System, L.P.*, 81 FERC ¶ 63,094 at 63,094 (1997), *order on Initial Decision*, 84 FERC ¶ 61,086 (1998), *reh'g*, 86 FERC ¶ 61,261 (1999), *reh'g denied*, 87 FERC ¶ 61,268 (1999).
[138] Ex. KR-50 at 34-35.

be considering the implications of depreciation and disregarding the rate implications from a declining rate base. Mr. Lovinger testified that constant assignment of depreciation expense, without considering other relevant rate implications is unreasonable. [139]

109. Mr. Lovinger testified that Mr. Pewterbaugh's position that if Kern River is allowed to continue its levelized methodology, that it should not be allowed to remove certain compressors and general plant from levelization, shows an inequity. While Mr. Pewterbaugh recognizes the regulatory inequity that the short-lived facilities would have by deferring depreciation expense to periods beyond the end of the facilities' depreciable lives, he nevertheless seems to favors continuing this inequity by offsetting it against a perceived inequity (the alleged overpayment of depreciation during the levelization period) that is irrelevant if levelization is continued. [140]

110. Mr. Lovinger testified in opposition to the position of Staff (testimony of Mr. Pewterbaugh), RCG (Mr. Doering), and BP (Ms. Crowe) that Kern River should recover depreciation expense on the basis of book depreciable life. He testified that Kern River had a unique aspect to its levelization cost-of-service/ratemaking methodology not present in other levelized pipeline situations. He testified that depreciation rate usually establishes the amount of total invested capital to be recovered over the depreciable life of a pipeline system. Mr. Lovinger explained that if, for example, you assume a 50/50 debt/equity capitalization with fifteen-year shipper contracts, with deprecation based on thirty years, the utility would recover 50% of the depreciable basis and would be able to pay off its debt obligation during a fifteen-year period from return of capital through the depreciation allowance. If the utility had a levelized rate design, the utility would have no regulatory asset or liability remaining after the end of the fifteen-year levelization period. According to Mr. Lovinger, this happens because a levelized rate design defers depreciation in the early years and recaptures the deferred depreciation dollars (or regulatory asset) in the later years. With the lower debt ratio in the capital structure and collecting enough book depreciation dollars to pay off the pipeline's debt obligation at the end of the shippers' contract terms by the end of the levelization period, the collection of invested capital (debt) would be in sync with the remaining depreciable plant investment at the end of fifteen years. Capitalization would consist of 100% equity at the end of the period because all debt would have been paid off and 50% of the depreciable basis would remain. [141]

111. Mr. Lovinger testified that Kern River's situation is different because Kern River started with a 70/30 debt equity capitalization to allow for lower rates for the shippers.

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[139] *Id*. at 35.
[140] *Id*. at 35-38.
[141] Ex. KR-105 at 2-3.

Kern River was authorized a fifteen-year recovery of its entire debt principal, but was only allowed a book deprecation rate of 4%, a rate Mr. Lovinger testified was below the depreciation rate of 4.67% needed to achieve a regulatory asset elimination as occurred in the example given by Mr. Lovinger. The 4% annual depreciation, reduced to 2% in 2001, would have only provided a recovery of 65% of investment and not the 70% of invested capital the Commission had authorized Kern River to recover in its rates during the levelization periods. [142] Mr. Lovinger testified that the gap between the 60% recovery of invested capital through book depreciation and the authorized 70% recovery of invested capital for rate purposes (to repay debt) results in Kern River showing a regulatory liability at the end of the shippers' contracts. Mr. Lovinger testified that what shippers and Staff complain about as over-recovery of costs is a regulatory asset that, for rate purposes, is treated as a reduction to rate base due to the fact that it represents capital that shippers have already paid. Those amounts exceed the amount of depreciation that would have been generated if Kern River had been allowed to collect its invested capital based on the computation of book depreciation rates over the term of current shipper contracts. [143]

112. Mr. Lovinger testified that if required under the traditional methodology to recover its invested debt and equity capital over its book depreciable life rather than the remaining shipper contract life, Kern River would be unable to collect enough debt capital recovery through its depreciation expense to allow it to cover its debt principal payments. Mr. Lovinger testified that Staff's proposal which would allow Kern River to earn its allowed return in its invested capital over the book depreciable life period would be unfair and totally unacceptable if Kern River were also required to maintain its levelized cost-of-service. According to Mr. Lovinger, that would cause a serious disconnect between capital recovery and Kern River's debt repayment obligations, which would be an unacceptable financial risk. [144]

113. Mr. Lovinger testified that the regulatory liability accruing on Kern River's books at the end of current shipper contracts would not cause an intergenerational liability because the shippers knew, or should have known that they would be paying 70% of Kern River's invested total capital in the fifteen-year levelization period. The regulatory liability necessarily follows from the Commission order providing for 4% book depreciation rate and 70% recovery of investment over fifteen years. Mr. Lovinger testified that, in addition, the fifteen-year debt repayment obligation has been an element of all of Kern River submissions to the Commission. The fifteen-year debt repayment obligation has also been a factor of Kern River's financing decisions. [145]

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[142] *See Kern River Gas Transmission Co.*, 50 FERC ¶ 61,069 at 61,160 (1990).
[143] Ex. KR-105 at 4.
[144] *Id*. at 7-12.
[145] *Id*. at 12-13.

114. Mr. Lovinger testified in opposition to the position of Staff (Ms. Segal) and Calpine (Mr. Hughes and Mr. Rodriquez) on the appropriate rate treatment for the net operating loss ("NOL") that Kern River incurred, primarily as a result of claiming bonus tax depreciation in 2003. He testified that it was appropriate for a company to offset taxable income from earlier years (carry back) and in later years (carry forward), even if the company is a general partnership that is not, per se, taxable and to reflect the effects of NOL in its rates. Mr. Lovinger testified that Kern River is not just a "pass-through" entity; it, in fact, generates taxable income and is, therefore, distinguishable from the pipeline under review in *BP West Coast*.[146] *BP West Coast* involved a limited partnership that calculated its profit and losses at the partnership level and then flowed through any income or loss to its limited and general partners without recognizing any tax liability. According to Mr. Lovinger, Kern River's taxable income is accounted for in MEHC's consolidated corporate tax return and, for rate purposes, is calculated on the Commission-approved "stand alone" methodology. Mr. Lovinger testified that Kern River's stand-alone tax obligation reflected a NOL in 2003 that was primarily the result of recognition of bonus tax depreciation. The income tax effect of the differences in the annual recognition of book depreciation and tax depreciation are recorded as accumulated deferred income tax ("ADIT"), which balance is treated as a deduction within the computation of rate base. According to Mr. Lovinger, treatment of the depreciation in that manner was appropriate because recognition of book/tax timing differences in the computation of depreciation expense provides utilities a source of interest free loans that are available as a source of funds to finance rate base and is consistent with Commission Order No. 144.[147] Mr. Lovinger testified that consistent with Commission Order No. 144, investors do not finance a portion of rate base represented by the interest free loan and Kern River is properly recognizing the cash flow coming to the pipeline from the offset to future taxable income by the carry forward NOL as the cash flow is realized.[148]

115. Mr. Lovinger criticized the testimony of BP witness Ms. Crowe that the regulatory asset should be allocated equitably among all the shippers if Kern River converted to traditional rates and that the Original Shippers are improperly burdened with the ADIT adjustment. Mr. Lovinger testified that Ms. Crowe was ignoring how the regulatory asset was created on Kern River's books: the regulatory asset is the difference between the

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

[147] *Regulations Implementing Tax Normalization for Certain Items Reflecting Timing Differences in the Recognition of Expenses or Revenues for Ratemaking and Income Tax Purposes*, ("Order No. 144"), FERC Stats. & Regs. ¶ 30,254 at 31,539 (1981), *reh'g denied*, Order No. 144-A, FERC Stats. & Regs. ¶ 30,340 (1982), *aff'd*, *Public Systems v. FERC*, 709 F.2d 73 (D.C. Cir. 1983).

[148] Ex. KR-105 at 14-20.

authorized book depreciation record on Kern River's books and the amount of depreciation expense Kern River collected on its rates. If Kern River had used the traditional methodology, and not levelized, the shippers' rates would have included the depreciation expense calculated by the authorized book depreciation rates multiplied by the plant in service. Levelization caused the deferral of a portion of the otherwise allowed book depreciation recorded as a regulatory asset. Therefore, according to Mr. Lovinger, shippers are responsible for the eventual payment of the deferred depreciation expense for each year that an entry for the regulatory asset was recorded in Kern River books. To accomplish what Mr. Crowe proposes on behalf of BP, the Commission would have to find that the accumulated regulatory asset is the responsibility of all current shippers equally regardless of when the shippers received service. Mr. Lovinger testified that that approach would give equal responsibility for the reimbursement of the regulatory asset to the 2003 Expansion Shippers as compared to the Original Shippers who had the benefit of lower rates due to levelization. [149]

116. Mr. Lovinger responded to Ms. Crowe's testimony that Original Shippers are disadvantaged because when MEHC acquired Kern River the ADIT balance of $136.9 million went to zero just before the expansions were put into service. He testified that rates charged to the Original Shippers through the date of acquisition met the "actual taxes paid" rules set forth in Commission Order No. 144 regarding tax normalization and its impact in the computation of an income tax allowance. So, according to Mr. Lovinger, Original Shippers paid no more than their fair share of the income tax cost before the acquisition. Mr. Lovinger further testified that the Original Shippers benefited from the acquisition due to the step-up in tax basis. Kern River would generate more deferred taxes on the Original System after the sale than it would have if the sale had not occurred. He testified further that when the "cross-over point" was reached in the future, the Original Shippers would enjoy more ADIT as a rate base deduction due to the change of ownership. Mr. Lovinger testified that the ADIT result appropriately measured the results of the actual business transactions. [150]

ADRIAN L. MOORHEAD

117. Adrian L. Moorhead is an officer and employee of the consulting firm Brown, Williams, Moorhead & Quinn, Inc. The firm provides technical and policy consulting services to natural gas pipelines and other utilities on business and regulatory matters. Prior to joining the firm Mr. Moorhead was employed at FERC and its predecessor for thirty-two years in a number of positions involving the setting of rates. Mr. Moorhead offered testimony on the issues of Kern River's use of an inflation factor in its levelized methodology, an EFV rate design, and the highest transportation rates on the system for

[149] *Id*. at 26-28.
[150] Ex. KR-105 at 28-29.

designing IT rates. [151]

118. Mr. Moorhead testified that Kern River had applied the 3% inflation factor in its levelized rate design since inception of the pipeline. He testified that the Commission approved the inflation factor in each of Kern River's rate cases and compliance filings to implement the 2002 and 2003 Expansions. According to Mr. Moorhead, citing *Mojave Pipeline Company*,[152] the Commission approvals reflect the Commission's recognition that test period O&M and A&G costs will rise annually and that using a fixed escalation factor tied to the inflation rate is a reasonable way to adjust costs. Mr. Moorhead testified that under this method, the anticipated capital costs are totaled for the entire useful life of the pipeline. The total costs are then discounted back to an annualized cost that is used to establish applicable reservation and commodity charges. He testified that it was appropriate to recognize an escalation factor for total O&M and A&G costs since, under the levelized methodology, the pipeline has to recover the increase in O&M and A&G costs over the life of the project. [153]

119. Mr. Moorhead testified that Kern River's EFV rate design allocated costs and designed rates fostered competition consistent with Commission Order No. 636 [154] by ensuring that a minimal amount of fixed costs were collected through the usage charge. He testified that, in addition, changing from the historic EFV rate design to the straight fixed variable ("SFV") rate design would cause large cost shifts from one set of customers to another. [155]

120. Mr. Moorhead testified that Kern River's IT rate was designed on the basis of the 100% load factor derivative of the firm transportation rate, resulted in a fully allocated rate which recovered all costs properly assignable to IT service, and promoted the Commission's goal of allocative efficiency. This, according to Mr. Moorhead, was consistent with *Viking Gas*, and Kern River's ET rate settlement. [156] He testified that Staff's (Ms. Pride) and RCG's (Mr. Doering) proposed IT rate design would not promote

[151] Ex. KR-49 at 1-2

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

[153] Ex. KR-49 at 4-5.

[154] *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations and Regulations of Natural Gas Pipelines After Partial Wellhead Decontrol*, FERC Stats. & Regs. ¶ 30,939 (1992).

[155] Ex. KR-49 at 6-9.

[156] *Viking Gas Transmission Co.*,101 FERC ¶61,170 (2002); *Kern River Gas Transmission Co.*, 92 FERC ¶ 61,061 ( )..

the Commission's goal of allocative efficiency. [157] It would price IT service too low to allow for proper ration capacity during high demand periods and would, therefore, not be assigned to customers who value the service the most. [158]

R. BRUCE MACLENNAN

121. R. Bruce MacLennan is a Director in the Corporate and Investment Banking Division of Credit Suisse First Boston, LLC. ("CSFB"). CSFB provides financial services to customers and has provided such services to MEHC and its affiliates, including Kern River. Mr. MacLennan testified that Kern River had been financed on a project-financed basis and that the levelized cost-of-service/ratemaking methodology had a significant role in the structuring, pricing and execution of Kern River's debt financings. The fixed amortization schedules of each series of Notes were based largely on the profiles of cash flows projected to be generated by Kern River under the current rate structure over the terms of the ten- and fifteen-year firm transportation service agreements. Mr. MacLennan testified that Staff (Mr. Ekzarkhov) put too much emphasis on *S&P* financial criteria in its DCF analysis. He testified that while financial institutions did consider such criteria, they also considered a large number of other quantitative and qualitative factors about a company's operations, including competitive environment, management, technology, customers, etc.[159]

122. Mr. MacLennan testified that he did concur with Mr. Ekzarkhov's conclusion that a reduction in Kern River's ROE would likely result in a downgrade of KR's credit ratings. That would be because Kern River's bondholders would bear increased financial risk due to the reduction in the cash flow cushion in excess of debt service requirements. The reduction from the prefiling 13.25% to Mr. Ekzarkhov's proposed 9% would reduce Kern River's cushion by almost a third, which is a meaningful deterioration in debt service coverage. Mr. MacLennan testified that although he also agreed with Mr. Ekzarkhov's conclusion that a pipeline with a BBB credit rating should have access to debt capital in the future, he expected that the cost of that debt capital would increase resulting in greater costs to ratepayers. He testified that a change to the traditional methodology cost-of-service/ratemaking methodology and a reduction in the ROE to 9% would result in uncertainty in capital markets which could affect Kern River's ability to attract investors.[160]

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[157] *Policy Statement Providing Guidance with Respect to the Designing of Rates*, 47 FERC ¶ 61,295 (1989).
[158] Ex. KR-49 at 9-12.
[159] Ex. KR-110 at 1-8.
[160] *Id*. at 9-13.

Commission Trial Staff

123. Staff presented the testimony of the following: Frances T. Segal, Chrystina L. Black, Kevin J. Pewterbaugh, Vladimir Ekzarkhov, and Bonnie J. Pride.

FRANCES T. SEGAL

124. Frances T. Segal, a Certified Public Accountant, is a Staff Accountant in the Office of Administrative Litigation, FERC. She has been employed at FERC since 1986. Ms. Segal testified that she computed a recommended total cost of service for Kern River that was $57,597,692 lower than that calculated by the company. She testified that she decreased rate base after finding lower allowable amounts for: gas plant; accumulated depreciation, depletion, and amortization (ADD&A); and, working capital. She also found an increase in regulatory assets/liabilities and in ADIT. Ms. Segal testified that the adjustments she made to gas plant, ADD&A, working capital, and ADIT numbers reflected actual book balances as of the end of the test period. She testified that the remaining reduction was due to proposed changes in ROE and capital structure. Ms. Segal testified that the changes to accumulated depreciation were primarily due to use of the traditional methodology for setting rates instead of Kern River's levelized methodology.[161]

125. Ms. Segal testified that she removed deferred income taxes (DIT) related to revenue sharing reserve, compensation, benefits and bad debt from the accounts to which Kern River had assigned them. She did the same with NOL. Ms. Segal testified that she made those changes because Commission policy requires that rate base reductions or additions are to be limited to deferred taxes related to rate base, construction, or other costs and revenues affecting jurisdictional cost-of-service.[162] She testified that DIT related to Revenue Sharing Reserve are not costs normally included in rate base. Ms. Segal testified that Compensation and Benefits DIT relate to timing differences between when salaries were paid and vacations and other benefits were taken, and such timing differences are not entitled to extra labor dollars in the cost of service. Ms. Segal testified that she removed DIT because Bad Debts are not properly accounted for in the cost of service. NOL deferred income taxes were removed because it is not appropriate to include them for ratemaking purposes. The DIT related to Kern River's NOL resulting from application of the new tax laws was recorded as an add-back to rate base. She testified that Staff's cost-of-service provided for a return of, and on, capital and resulted in no operating loss and no NOL-related DIT to calculate.[163]

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[161] Ex. C-1 at16.
[162] *See* 18 C.F.R. § 154.305(c)(2).
[163] Ex. C-1 at 6-7.

126. Ms. Segal testified that Commission policy is that an average unamortized regulatory asset balance should be included in rate base rather than in the entire balance in order to avoid over-recovery because the unamortized balance decreases over time; consequently, she made necessary adjustments. Ms. Segal testified that she removed the regulatory assets for general plant and compressor plant. She reclassified the accumulated regulatory/ratemaking depreciation reserve for transmission plant to the reserves for general plant and compressor engine plant. This adjustment is due to Staff's use of the traditional methodology. She testified that even if the Commission finds that levelized rates are appropriate, there would be no reason to treat general and compressor engine plant any differently than the rest of plant. [164]

127. Ms. Segal testified that to make Kern River whole using the traditional methodology for setting rates, Staff proposes to amortize the uncollected amount of accumulated depreciation over the remaining life of the plant and provide an average unamortized regulatory asset in rate base. She testified that Staff's position is that the inflation adjustment does not need to be continued if the Commission finds that Kern River may continue to use the levelized methodology. If there were to be significant inflation which caused the company to under-collect its revenue requirement, Kern River would be free to come in for a rate increase to address the shortfall. Ms. Segal further testified that she removed intangible plant from the plant on which she applied negative salvage because Kern River would not have to remove intangible plant. Ms. Segal testified that she used the *Kansas Nebraska* [165] ("KN") method to functionalize A&G costs, but that her computations were different from Kern River's because she allocated certain labor costs differently. [166]

128. Ms. Segal testified that Staff's amortization period of thirty-five years was an appropriate period on which to base the depreciation rates. The regulatory asset is related to depreciation expense and its associated depreciation rate, so the same period is properly used for both. She testified that there was no nexus between the contracts and the appropriate period on which to calculate deprecation expense; depreciation is not determined on the basis of contracts or on which shipper pays for an asset. According to Ms. Segal, the thirty-five year period was not chosen for the purpose of lowering the rates for a traditional cost of service; the asset is an uncollected depreciation asset and is to be amortized over the remaining life of the related plant. Using the thirty-five year amortization expense puts the amortization of the asset on the same basis as normal deprecation expense. Because the asset pertains to deprecation, the proper time frame for recovery is the depreciation period. Ms. Segal testified that Kern River would not be at

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[164] *Id*. at 9-10.
[165] *Kansas-Nebraska Natural Gas Co., Inc*., 53 FPC 1691 (1975), *aff'd*, *Kansas Nebraska Natural Gas Co, Inc. v. FERC*, 5 34 F.2d 227 (1996).
[166] Ex. C-1 at 10-11, 21-22, and 25.

risk for recovery of the regulatory asset if recovery of the regulatory asset were beyond the current shippers' contract periods; Kern River's concern that it may have to write off the unamortized portion was pure speculation and unlikely in her opinion. According to her, Kern River is a pipeline going through a geographical area that is growing and, therefore, it should not have to worry about having enough shippers in the future to be able to recover the asset. [167]

129. Ms. Segal testified that the Commission approves the use of an average unamortized balance in rate base for regulatory assets because the unamortized balance will decrease during the time the rates are in effect. According to Ms. Segal, the Commission so stated in *Williston Basin*. [168] The short amortization time frames, according to Ms. Segal, were a happenstance in that case, but were not the basis of the Commission's finding. [169]

CHRYSTINE L. BLACK

130. Chrystina L. Black is an Energy Industry Analyst in the Office of Administrative Litigation at FERC. She testified that she made the adjustments to Kern River's Working Capital Statement and Taxes Other Than Income Statement. She testified that her adjustments were not at issue in this case. [170]

KEVIN J. PEWTERBAUGH

131. Kevin J. Pewterbaugh is a Petroleum Engineer in the Office of Administrative Litigation in the Office of Administrative Litigation FERC. He has been employed at FERC about twenty-six years. His current duties include determining the appropriate depreciation rates in formal gas rate case proceedings. [171]

132. Mr. Pewterbaugh testified that Kern River facilities are almost all transmission. The facilities are divided into Rolled-in (Original System and 2002 Expansion facilities) and Incremental (2003 Expansion, Big Horn Lateral and High Desert Lateral facilities). He testified that depreciation rates he developed would allow Kern River to recover its investment over the remaining economic life of Kern River's facilities. The Kern River facilities he considered included: about 1,964 miles of transmission lines. Kern River owns and operates 1,671 miles of the system alone; it owns 293 miles which Mojave Pipeline Company ("Mojave") operates. Kern River's system, built to transport natural

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[167] *Id*. at 2-3.
[168] *Williston Basin Interstate Pipeline Co.*, 84 FERC 61,081 at 61,374-375.
[169] Ex. S-25 at 4-6.
[170] Ex. S-6 at 1-4.
[171] Ex. S-7 at 1-2.

gas supply from the Rocky Mountain area to major markets in Utah, Nevada, and California, stretches from southwestern Wyoming through Utah, Southern Nevada, to Southern California. [172] Kern River receives gas from the Rocky Mountain area and connects with Pacific Gas & Electric Company and Southern California Gas Company, two major gas distributors. Kern River also has delivery points in Utah and Nevada although California is Kern River's primary market. Other pipelines in the area include Northwest Pipeline Corporation, Colorado Interstate Company, and Questar Pipeline Company. [173]

133. Mr. Pewterbaugh testified that in determining the remaining economic life of Kern River's facilities, he: identified the applicable supply area and obtained historical production, remaining reserves, and ultimate recovery data for the supply area; extrapolated ultimate recovery into the future; extrapolated production into the future; determined the supply life of Kern River's facilities; and considered demand and competition. After determining the remaining economic life, Mr. Pewterbaugh adjusted the remaining economic life for interim retirements and calculated depreciation rates. [174]

134. Mr. Pewterbaugh testified that he used Energy Information Administration ("EIA") publications to determine historical annual ultimate recovery levels for 1977 through 2003. He testified that he extrapolated ultimate recovery into the future because the current sum of the cumulative production and the estimated remaining proved reserves have to be considered in order to give a full picture of the total amount of gas that would eventually be produced in Kern River's supply area. He testified that he used the least-squares-curve-fitting technique to fit an S-curve to the historical data. The S-curve traces the shape that estimates of ultimate recovery are expected to have. "Ultimate recovery" for a particular year is the sum of the cumulative production up to that point and the remaining reserves as reported that year. He testified that ultimate recovery level is only one component necessary to determining the supply life; it is also necessary to extrapolate production into the future. Extrapolation is done by assuming that production will increase for a period of time and then begin to decline. Mr. Pewterbaugh testified that he used the probability-type model developed originally by M. King Hubbert. [175] Hubbert's theory predicts that natural resources will be discovered and produced in a way that looks like a bell-shaped curve. Mr. Pewterbaugh determined that 2016 was the earliest peak year that would result in a curve where cumulative production reaches the final ultimate recovery level. The final ultimate recovery would occur forty-seven years from 2004 using a curve based on the last twenty-seven years of production, and thirty-two years when using a curve based on the last five years of production. Mr.

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[172] Kern River 2003 FERC Form No. 2 Annual Report of Major Natural Gas Companies.
[173] Ex. S-7 at 14-15.
[174] *Id*. at 2and 14-17.
[175] U.S. Dept. of Commerce, *Oil and Gas Supply Modeling* (1982).

Pewterbaugh concluded that Kern River had a thirty-five year remaining life. He noted that the Commission adopted a thirty-five year remaining life in *Williston Basin* [176] and the Williston Basin pipeline has part of its supply area in common with Kern River's supply area. [177]

135. Mr. Pewterbaugh testified that a reduced demand for gas would have a negative impact on the life of a facility. He testified, however, that *U.S. Energy Outlook, Summer 2004* predicted that gas consumption was expected to grow nationally and especially in California; California is Kern River's main market area. Mr. Pewterbaugh further testified that Kern River was not disadvantaged by competition. It would be in a better position than any new start-up pipelines because those pipelines would have to recover 100% of their initial investments, while Kern River by December 2004 had already recovered about 43% of its Original System plant investment. He testified that Kern River was very competitive in the California markets. Mr. Pewterbaugh's conclusion was that neither demand, nor competition were factors negatively impacting Kern River's remaining economic life of thirty-five years. [178]

136. Mr. Pewterbaugh testified that there were two problems with using contract life versus using remaining economic life for depreciation periods. First, contracts can be extended, renewed, or replaced by another, resulting in significant understatement of remaining economic life. Second, depreciation rates based on contract life also violate the intent of a properly calculated depreciation rate, which is that no generation of ratepayer should be unfairly burdened with facilities' costs vis-à-vis other generations of ratepayers. If depreciation rates were based on contract life but the facilities remained in service after that contract was over, later ratepayers would not pay any depreciation component for the use of the facilities. Mr. Pewterbaugh testified that "contract life" is not mentioned in the USOA definition of depreciation, nor is "contract life" mentioned in the Commission's definition of depreciation. [179] He testified that the *Memphis* decision [180] refers to the useful life of the facility, and not to its contract life. Mr. Pewterbaugh testified that in *Trailblazer Pipeline Company*, [181] the Commission upheld the decision of the administrative law judge rejecting the determination of economic life solely on contracts. Mr. Pewterbaugh also cited *Wyoming Interstate Company, Ltd,* where the administrative law judge concluded that using the expiration of firm contracts as the end

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[176] *Williston* Basin, 95 FERC ¶ 63,008 at 65,104 (2001)**.**
[177] Ex. S-7 at 18-35.
[178] *Id*. 36-38.
[179] *Id*. at 40; *see 18 C.F.R. Part 201 (2005).*
[180] *Memphis Light, Gas and Water Division v. Federal Power Commission*, 504 F.2d 225 (1974).
[181] *Trailblazer Pipeline Company*, 15 FERC ¶ 63,046 at 65,174, *aff'd* 18 FERC ¶ 61,244 (1982), *reh'g denied*, 19 FERC ¶ 61,115 (1982).

of a pipeline's useful life would not fall within the *Memphis* "zone of reasonableness" standard. [182]

137. Mr. Pewterbaugh testified that he accounted for interim retirements of Kern River's facilities by the use of a statistical analysis of historical retirement patterns. He used Iowa-Type Survivor Curves ("Iowa curve"). He testified that using an Iowa curve and an estimated average age of the facilities, along with the remaining economic life, he determined an ARL of all plant, including that which would be retired in the interim as well as that which would not be retired until the end of the remaining economic life. Mr. Pewterbaugh testified that it was the ARL, not the thirty-five year remaining economic life that goes into the equation for calculating depreciation rates. That formula, according to Mr. Pewterbaugh, compensates for interim retirements that decrease the gross plant to which the depreciation rate is applied. That allows the full investment to be recovered at the end of the thirty-five year period. [183]

138. Mr. Pewterbaugh testified that he calculated the depreciation rates for Kern River's facilities by dividing the ARL by the percent of the gross plant left to be depreciated (i.e., the "net plant"). The net plant is the result of subtracting the accrued depreciation from the gross plant. Mr. Pewterbaugh testified that for general plant he used the whole life or average service life ("ASL") approach. That approach calculates a depreciation rate apart from the ARL and the accrued depreciation balance and is often used for general plant facilities, according to Mr. Pewterbaugh. He testified that he accepted Kern River's ASLs for general plant. However, Mr. Pewterbaugh testified that he did not use an ARL approach for determining Solar Mars compressor engine depreciation rate. He testified that compressor engine depreciation rate is calculated by subtracting the net salvage percentage from the total plant percentage (100%) and dividing that result by the average life of the compressor engines as determined from actual data provided by Kern River. Mr. Pewterbaugh testified that he calculated a depreciation rate for the compressor engines of 8.83%, rounded to 8.85%, as opposed to Kern River's 9.92% deprecation calculation. [184]

139. Mr. Pewterbaugh testified that straight-line depreciation rate allocates recovery of a company's investment equally over the life of the investment. Assuming a fifteen-year life for an investment, the ratepayer would pay a rate of 6.67% for each year of the fifteen years. With a levelized depreciation rate, using the same fifteen-year life a rate payer would initially pay a rate below 6.67%, but by the end of the life would be paying a rate higher than 6.67%. He testified that Kern River's levelized model is different in that it is

[182] *Wyoming Interstate Company, Ltd.*, 67 FERC ¶ 63,015 at 65,090 (1994), aff'd in parat and rev'd in part, 69 FERC ¶ 61,259 (1990), *dismissed*, 70 FERC ¶ 61,320 (1995).
[183] Ex. S-7 at 45-46.
[184] *Id*. at 46-49.

designed to recover an even greater share of depreciation costs in early years. According to Mr. Pewterbaugh, Kern River's model leads to an over-recovery of depreciation costs during the first portion of its remaining life, leading to inequity of cost burden between generations of ratepayers. In Kern River's levelized rate model, both the depreciation expense, and the depreciation rate increase each year as total debt is retired each year. [185]

140. Mr. Pewterbaugh testified that Kern River's levelized methodology causes an intergenerational inequity due to the manner in which it handles depreciation. He testified that the intergenerational inequity was a primary reason Staff opposes Kern River's continuation of its levelized methodology model. Mr. Pewterbaugh testified that the difference between the traditional methodology booked depreciation and Kern River's levelized rate models regulatory/ratemaking depreciation is that with the latter, depreciation is recorded each year by Kern River as either a deferred regulatory asset (when regulatory/ratemaking depreciation is lower than book depreciation) or a deferred regulatory liability (when regulatory/ratemaking depreciation is greater than book depreciation). With regulatory/ratemaking, rate depreciation is recorded as either a deferred regulatory asset or deferred regulatory liability. If, for example, the ten-year shippers are paying transportation rates with an embedded regulatory/ratemaking depreciation rate of 7% while the book depreciation rate is only 2% over time, according to Mr. Pewterbaugh, there would be a significant deferred regulatory liability on the books of Kern River. That deferred regulatory liability represents an over-payment of depreciation dollars to Kern River from the ten-year shippers. Mr. Pewterbaugh testified that if Kern River does not return the over-payment to the shippers at the end of the ten-year contracts, Kern River would be required to design future rates for the next generation of customers taking into account the over-collection of deprecation dollars from the earlier generation (since there is no dispute that the economic life of Kern River will exceed the current ten- and fifteen-year contract lives). [186] Mr. Pewterbaugh concluded that Kern River's levelized depreciation rates would cost its shippers an over-collection of $42,590,732 in depreciation expense over the ten- and fifteen-year contract periods. [187]

141. Mr. Pewterbaugh testified that Kern River witness, Mr. Feinstein, recognized that intergenerational inequities resulting from the levelization process need to be addressed and recommended that general plant and compressor engine plant be removed from the levelized process due to their much more abbreviated deprecation life than the life of the transmission facilities. According to Mr. Pewterbaugh, Kern River is interested in a different depreciation method for general plant and compressor engine plant because those plant costs are not being fully recovered due to the depreciation rate being higher

[185] *Id*. at 49-51.
[186] *Id*. at 51-54.
[187] *Id*. at 56-58.

than the regulatory/ratemaking rate. According to Mr. Pewterbaugh, Mr. Feinstein has no problem with intergenerational inequity when it benefits Kern River. That is, according to Mr. Pewterbaugh, a deferred regulatory asset occurs when a company recovers fewer depreciation dollars in its regulatory/ratemaking depreciation rate than in its book deprecation rate. A deferred regulatory liability occurs when a company recovers more depreciation dollars in its regulatory/ratemaking depreciation rate than in its book depreciation rate. Mr. Pewterbaugh noted that Mr. Feinstein testified against Kern River incurring a deferred regulatory asset (where customers pay too little, or less than their fair share, over a period of time), but says nothing about Kern River incurring a deferred regulatory liability (where current customers pay too much, or more than their fair share, over a period of time). [188]

142. Mr. Pewterbaugh testified that rates the Commission approves in Section 7 [189]certificate proceedings are subject to review. He testified that the Commission specifically made that observation in the *Iroquois* certificate proceeding and, in fact, made adjustments in a later Section 4 proceeding. [190] Section 7 rates are "interim" rates in Mr. Pewterbaugh's view. Mr. Pewterbaugh further testified that there is no requirement in the Commission's USOA that financial considerations, such as debt repayment schedules, are a factor to be considered in setting rates. Financial side effects of a deprecation proposal are to be accorded no weight, according to Mr. Pewterbaugh.[191]

143. Mr. Pewterbaugh testified that although the terms "negative salvage" and "negative net salvage" are used interchangeably, they are not technically the same. He testified that when an item is retired, it can experience negative salvage (cost of retiring the item) or positive salvage (value received from the item, i.e., scrap value), or both. Both are reflected in rates and, therefore, the net salvage is used. If the net salvage is negative, the appropriate term is "negative net salvage." Mr. Pewterbaugh proposed that a 0.18% negative net salvage be applied to Kern River's transmission facilities, exclusive of its compressor engines. Kern River proposes 0.21%. Mr. Pewterbaugh's proposal results in a decrease of about $765,000 annually from Kern River's proposal. He testified that the interim calculation resulted in 82.77% of the plant surviving until final retirement. He accepted that 82.77 % of the total negative net salvage estimate from Kern River would be needed to retire that plant. The plant, which would last to the end of the remaining life, would have an ARL of thirty-five years. [192]

[188] *Id*. at 54-56.
[189] 15 U.S.C. § 716f(c).
[190] *Iroquois*, 52 FERC ¶ 61,091 at 61,393, *reh'g* ¶ 53 FERC ¶ 61,194, *aff'd, Louisianna Ass'n of Indep. Producers and Royalty Owners v. FERC* , 294 (1990).
[191] Ex. S-7 at 58-60; see, *Texas Gas Transmission Corporation*, 50 FPC 1751 at 1769 (1973).
[192] *Id*. at 61-63.

144. Mr. Pewterbaugh testified that Kern River's false plant retirements inappropriately inflates the deprecation rates. Mr. Pewterbaugh testified that Kern River witness Edward Feinstein includes factors in his depreciation calculation that should not be included. He testified that Mr. Feinstein inaccurately assumes that major retirements will occur in lockstep. Mr. Pewterbaugh testified, however, that there were a number of reasons why a facility might remain in service even when there was a decrease in throughput. Those reasons include: 1) to avoid interruption of service while another facility is tested; 2) to provide insurance against problems with other facilities; 3) to meet peak day deliveries; and, 4) to ensure ability to respond should throughput increase. Mr. Pewterbaugh further posited that Mr. Feinstein's position just did not make sense. For example, according to Mr. Pewterbaugh, Mr. Feinstein would have a pipeline that had a 10% drop in throughput retire 10% of its plant, or ten miles of its pipeline. In that case, the pipeline would end ten miles before reaching its market. According to Mr. Pewterbaugh, *Offshore Gulf of Mexico* is not support for Mr. Feinstein's position because Kern River is not offshore.[193] Nor is *Trans-Northern Pipelines, Inc*., availing to Kern River though cited by Mr. Feinstein, because Trans-Northern Pipelines is a lateral while Kern River's facilities are primarily main transmission lines.[194] Nor is Trunkline Gas Company's retirement of a 700-mile loop line,[195] persuasive in this case because, according to Mr. Pewterbaugh, the Kern River line is much larger. [196]

145. Mr. Pewterbaugh testified that there were other factors incorrectly included in Mr. Feinstein's depreciation calculation. One such factor, according to Mr. Pewterbaugh, was inclusion of three years of future plant additions in determining depreciation rate when those costs are outside of the test period plant additions. Outside-of-test-period additions may not be used to influence results and transmission rates inside the test period. In addition, according to Mr. Pewterbaugh, the Commission rejected the use of future additions in determining depreciation rates.[197] Mr. Pewterbaugh also pointed out that the USOA does not mention future facilities. Depreciation is defined as loss of service and, Mr. Pewterbaugh pointed out, service value cannot be lost on future facilities. [198]

146. Mr. Pewterbaugh testified that it was Kern River's throughput as a percentage of its own capacity that was important, and not its percentage of total production that it

[193] *Id*. at 65.
[194] *Id*.
[195] *Id*.
[196] *Id*. at 64-66.
[197] *Indiana & Michigan Distributors Association and City of Auburn, Indiana v. Indiana Michigan Power Company*, 59 FERC ¶ 61,260 at 61,969 (1992).
[198] Ex. S-7 at 67-68.

transports from an area. According to Mr. Pewterbaugh, the decline of gas supply falling below the aggregate pipeline capacity is not synonymous with the end of the remaining economic life of a pipeline. Mr. Feinstein had testified that the future gas supply could fall below aggregate pipeline capacity as soon as 2015. Mr. Pewterbaugh testified that, even if it did fall, a purported supply deficiency could lead to an impetus to increase supply, not to shut-down. Finally, Mr. Pewterbaugh testified that Mr. Feinstein's statement that Kern River's estimate of future availability from future discoveries of gas showed more availability than estimates made by the PGC, was misleading because Kern River's estimate included discovered reserves as well as undiscovered resources while PGC's estimate was just of undiscovered resources. [199]

Vladimir Ekzarkhov

147. Franklin D. Knight was a Financial Analyst in the Office of Administrative Litigation, FERC, at the time he submitted Prepared Direct and Answering Testimony and Exhibits on behalf of Staff. Because Mr. Knight left FERC's employ before the hearing began, his written testimony and exhibits, S-10 and S-11, were adopted by Vladimir Ekzarkhov, on August 4, 1005. Mr. Ekzarkhov is a Financial Analyst in the Office of Administrative Litigation, FERC. Mr. Ekzarkhov testified that Kern River was a general partnership that owns and operates 1,678 miles of interstate natural gas pipeline form Opal, Wyoming, to Bakersfield, California. Gas transported on the pipeline is used in EOR in the heavy oil fields, food processing, electricity generation and other applications. He testified that Kern River is an indirect, wholly-owned subsidiary of MEHC. Mr. Ekzarkhov's testimony concerned the rate of return that should be allowed on Kern River's debt and equity investments. [200]

148. Mr. Ekzarkhov testified that although the Commission authorized a 70/30 debt equity ratio for Kern River and Mojave in *Kern River Gas Transmission Company, Docket No. CP89-2048-00*; *Mojave Pipeline Company*, Docket No. CP89-1-011 (not consolidated), the Commission also noted that the rate of return being allowed then may not be appropriate as the overall rate of return in later years and specifically reserved its right to reexamine the issue in the general rate proceedings it had ordered be filed later. [201] According to Mr. Ekzarkhov, the Commission had noted in *Kern River*/*Mojave Pipeline* that Kern River and Mojave Pipeline had used the *Ozark* methodology in calculating the return on capital investment and related taxes in their amendment applications. The Commission noted that the *Ozark* methodology recognizes that the original capitalization ratio of the projects (70% debt and 30% equity) would not be

[199] *Id*. at 68-71.
[200] Ex. S-10 at 1-2 and Appendix A 1-2.
[201] *Kern River Gas Transmission Co.*, 60 FERC ¶ 61,123 at 61,437 (1992), *aff'd*, *Pacific Gas Transmission Co. v. FERC*, 998 F.2d 1303 (1993).

maintained throughout the project lives. Instead, the depreciation accumulated during the first fifteen years of the project would be used to retire the debt principal resulting after fifteen years in projects being capitalized with 100% equity. [202]

149. Mr. Ekzarkhov testified that the current 13.25% ROE allowed Kern River to earn excessive returns. He noted that Kern River had actually earned 15.21% ROE in 2003. Mr. Ekzarkhov concluded that under the traditional cost-of-service/ratemaking methodology proposed by Staff, Kern River should have a "thicker" equity ratio than 70/30 in order to attract capital. Mr. Ekzarkhov testified that he had concluded that Kern River did not need to maintain an A debt quality rating in order to attract capital as other gas pipelines were able to attract capital with a BBB rating. Mr. Ekzarkhov testified that he calculated a ROE of 9.00% and a debt cost of 6.616% to be applied to Kern River's actual capital structure of 38.69% common equity and 61.31% long-term debt, as projected for the end of the test period. The weighted cost after tax would allow a return of 7.54%. He testified that he believed that a 38.69% equity ratio would better enable Kern River to attract capital in the future at rates that were competitive with other gas pipelines than would a 70/30% debt/equity ratio under Kern River's levelized rate design. [203]

150. Mr. Ekzarkhov testified that he used a four-part process to determine the proper ROE for Kern River that would be a reasonable reflection of the risks faced by its investors. He testified that he: 1) used the DCF methodology to determine the "zone of reasonableness;" 2) placed Kern River within the median of the zone of reasonableness; 3) tested the adequacy of the 9.0 % return to enable Kern River to attract future capital; and 4) compared the equity costs produced by the DCF model with the results produced by the DCF model of Merrill Lynch, one of the largest investment firms in the world. Mr. Ekzarkhov testified that he accepted the debt cost given by Kern River and used the actual capital structure at the end of the test period in conjunction with his estimated cost of equity for Kern River, which he said was sufficient to allow Kern River to maintain a BBB, investment grade, debt quality rating. [204]

151. Mr. Ekzarkhov testified that his DCF calculations reflected the Commission's guidelines outlined in Opinion Nos. 396-B and 414-A. [205] He observed that the Commission's expressed policy was that a pipeline's ROE should normally be set within the DCF-derived zone of reasonableness. The Commission stated that it started with the assumption that a pipeline faced average risk. Mr. Ekzarkhov testified that in estimating

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[202] Ex. S-10 at 2.
[203] *Id* at 2-4.
[204] *Id*. at 6-11.
[205] *Northwest Pipeline Co.*, 79 FERC ¶ 61,309 at 62,385 (1997) and *Transcontinental Gas Pipe Line, Corp.*, 84 FERC ¶ 61,084 at 61,423 (1997).

ROE in gas pipeline cases, it was necessary to pick a group of companies to serve as proxies for the risks a particular gas company may be expected to face. It was necessary to select proxies because the number of purely publicly-owned companies principally engaged in the transportation of natural gas for others, had essentially disappeared due to mergers and acquisitions and shifts in management focus to unregulated lines of business. He testified that to provide the inputs necessary to estimate ROE using the Commission's preferred DCF methodology, the proxy group companies needed to be publicly owned with publicly traded stock. In addition, the companies had to own 100% of a "major" [206] FERC-regulated natural gas pipeline. Finally, according to Mr. Ekzarkhov, the proxy group companies had to derive at least 50% of their operating earnings from a regulated, energy-related line of business. That would include, for example, the distribution of natural gas and/or the transmission and distribution of electricity in addition to the transmission of natural gas. Mr. Ekzarkhov noted that the Commission had not accepted Staff's proxy group in *Williston Basin*, [207] but had observed in that case that it may have to reconsider its position as the gas and electric industries continued to evolve. Mr. Ekzarkhov testified that only two of the four proxy group companies the Commission had used in the initial *Williston Basin rate* case and several others were currently suitable. Those companies were El Paso and Williams. Moreover, Mr. Ekzarkhov testified, that since the Commission's decision in *Williston Basin*, three of the nine companies in the Commission's proxy group were no longer in business. Hence, Mr. Ekzarkhov's conclusion that it was time for the Commission to revisit the issue. [208]

152. Mr. Ekzarkhov testified that he found expanding the proxy group to include publicly-owned companies engaged in other regulated lines of energy-related business would likely increase the level of confidence in the reasonableness of the DCF analysis results. He testified that he had focused the line-of-business analysis on the proportions of a proxy company's lines of business that were regulated. He testified that he previously would focus on the proportion of a proxy company's lines of business that were not only regulated but also were concentrated in the transmission of natural gas by pipeline. He testified that he had changed focus because he believed it was necessary in order to have a larger proxy group and one that would better reflect the risks of natural gas pipelines currently. He testified that he believed that investors found regulation to be the common denominator. To investors, regulation set apart risk profiles of lines of businesses involved in the transmission and distribution of natural gas, and the generation, transmission, and distribution of electricity, from the risk profiles of unregulated business activities. Mr. Ekzarkhov additionally testified that gas pipelines

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[206] Defined at 18 C.F.R. § 260.1 (2004) as "a natural gas company whose combined gas transported or stored for a fee exceeded 50 million Dekatherms (Dth) in each of the three previous calendar years."

[207] *Williston Basin Interstate Pipeline, Co.*, 84 FERC ¶ 61,081 at 61,105.

[208] Ex. S-10 at 11-14.

and transmission facilities for electricity have characteristics in common in that they both transmit a product with time and weather-sensitive demand profiles over the rights-of-way that are capital intensive and mostly inflexible. He testified that various S&P publications, which have a wide circulation among investors, supported his view. [209]

153. Mr. Ekzarkhov testified that he excluded companies (Berkshire Hathaway, Equitable Resources, MDU Resources, and Questar) that did not meet the criterion of at least 50% of operating earnings from regulated, energy-related lines of business. He testified that he excluded one company (Enron) that was in bankruptcy. He excluded one company (Southern Union) that did not pay a cash dividend and, hence, did not have the inputs necessary for a DCF analysis. One company (Northern Border Pipeline, L.P.) was excluded because it was organized as a limited partnership. According to Mr. Ekzarkhov, limited partnerships should not be used in pipeline proxy groups because the DCF-derived equity cost estimates for limited partnerships are not comparable to the DCF-derived estimates for corporations. Mr. Ekzarkhov noted that the Court of Appeals of the District of Columbia recognized that in *BP West Coast Products LLC*. [210] Mr. Ekzarkhov further noted that Congress had passed legislation in 1987 to allow some MLPs to be treated as sub-chapter S corporations for federal income tax purposes. However, Congress specifically exempted some categories of MLPs. Gas pipelines were specifically exempted. [211] According to Mr. Ekzarkhov, Congress recognized MLPs' competitive advantage over corporations and, therefore, denied them the tax benefit. Mr. Ekzarkhov testified that use of MLPs in proxy groups would cause the dividend yields to be inordinately high. Dr. Olson's use of MLPs resulted in the dividend yields he developed to be more than double Mr. Ekzarkhov's, or *Williston Basin's* yields. [212]

154. Mr. Ekzarkhov testified that he tested the reasonableness of the results produced by his first proxy group against the results produced by applying the Commission's DCF methodology to six gas pipelines that remain from a group of nine publicly-owned gas companies used by the Commission in the *Williston*. Mr. Ekzarkhov testified that he calculated the zone of reasonableness without El Paso and Williams. That zone of reasonableness ranged from 8.80% to 13.67%, with an average equity return of 11.01%, a median of 10.79% and a midpoint of 11.24%. Mr. Ekzarkhov found that the DCF analysis results of the six-company proxy group from *Williston* was very close to the equity returns produced by the DCF analysis on the nine-company Staff proxy group. Mr. Ekzarkhov concluded, therefore, that the latter proxy group produced reasonable

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[209] *Id*. at 14-17.
[210] *BP West Coast Products LLC v. FERC*, 374 F.3d 1263 (2004) (remanded to the Commission after finding that the Commission erred in including an allowance for income taxes in a partnership's cost of service.)
[211] 26 U.S.C. § 7704 (2005).
[212] Ex. S-10 at 21-26.

estimates of the cost of common equity to FERC-regulated natural gas pipelines. [213]

155. Mr. Ekzarkhov testified that he placed Kern River at the median equity return of 8.97%, rounded up to 9.0%, within the zone of reasonableness after observing, among other things: 1) the Commission's decision in *Transco* [214] placing that pipeline at the median of the zone of reasonableness rather than the midpoint; 2) S&P in its weekly *Utilities & Perspectives* dated November 1, 2004, rated the risk of Kern River's business profile as 3 on a scale of "1" (strong) to "10" (weak) with a debt credit rating of A-; 3) neither Mr. Smith, nor Mr. Olson persuasively identified such unusual circumstances as would warrant placing Kern River outside of the broad middle of the zone of reasonableness, as measured by the median equity return (he also noted that the Commission had previously found that most pipelines would fall within the broad middle of the range of reasonable returns absent a showing of unusual circumstances); [215] and, 4) with Staff's traditional rate design and 6.616% debt cost, his recommended 9.00 % equity return and 61.31/38.69 % debt/equity ratio should enable Kern River should be competitive with other gas pipelines in attracting capital. [216]

156. Mr. Ekzarkhov testified that equity investors were always concerned about whether a company's earnings would be sufficient to cover the company's interest expenses on long-term debt by a margin sufficient to provide protection against default in the case of a significant earnings downturn. He testified that he used S&P guidelines because those guidelines were straight-forward and were widely accepted by investors as measures of a company's financial stability. He testified that using the S&P matrix on Kern River with a business risk profile of 3, indicating below average business risk, yielded Kern River a BBB rating. Mr. Ekzarkhov testified that a BBB rating is an investment-grade rating.[217]

<u>BONNIE J. PRIDE</u>

157. Bonnie J. Pride is an Energy Industry Analyst I the Office of Administrative Litigation, FERC. She has been a FERC employee about twenty-eight years. Ms. Pride testified that in the subject Section 4 case, Kern River proposed its revised tariff sheets become effective June 1, 2004 (for rates based on a 366-day leap year) or January 1, 2005 (for the rates based on 365 days). The Commission conditionally accepted and suspended the proposed tariff sheets for five months to be effective November 1, 2004

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[213] Ex. S-10 at 35-44.
[214] *Transcontinental Gas Pipe Line Corp*, 84 FERC ¶ 61,084 at 61,427-25 (1998).
[215] *Transcontinental Gas Pipe Line Corp*., 80 FERC ¶ 61,157 at 61,674 (1997).
[216] Ex. S-10 at 35-38.
[217] *Id.* at 39-44.

and January 1, 2005, respectively.[218] She testified that the test period in this case consisted of twelve months of actual data ending January 31, 2004, adjusted for known and measurable changes occurring through October 31, 2004.[219]

158. Ms. Pride outlined the various rate models Kern River proposed to use to develop rates. Ms. Pride testified that Kern River used levelized models for the Original System, the 2002 Expansion, the 2003 Expansion, and the Big Horn project. She said that Kern River used a traditional declining-rate-base model to determine cost-of-service for the recourse rate for High Desert. Actual rates charged for the High Desert project are levelized negotiated rates. She testified that for the 2002 and 2003 Expansion shippers, Kern River developed rates using six levelized models: two for Original System (one for the ten year shippers and one for the fifteen year shippers); two for the 2002 Expansion shippers (one for the ten year shippers and one for the fifteen year shippers); two for the 2003 Expansion shippers (one for the ten year shippers and one for the fifteen year shippers). Each model for the respective systems calculates levelized rates over the remaining contract terms of each part of the system.[220]

159. Ms. Pride further explained that Kern River's levelized methodology provides future estimates for each of the cost of service elements (O&M, depreciation, taxes, interest, return, etc.) over the life of the contracts for each levelized model. She testified that the recovery of the total of those cost elements were averaged or levelized over the contract period in each of the levelized models. In other words, according to Ms. Pride, a cost of service is developed under each levelized rate model representing an estimate of the average cost of service elements over the contract period. Those average costs were then divided by the appropriate billing determinants to develop transportation rates. Ms. Pride testified that the levelization models also included a 3% annual inflation factor applied to O&M and A&G costs. She testified that Kern River's levelization models also used an average rate base for each year of the contract by using beginning and end-of-year rate base balances for that year. Kern River proposed an increase in the depreciation rate for book depreciation purposed from 2.00% to 3.39% for the Original System, 2002 Expansion, and 2003 Expansion transmission plants.[221] Ms. Pride noted, as did previous witnesses, that Kern River recorded the difference between the book and levelized depreciation expense as either a deferred regulatory asset or deferred regulatory liability.[222]

160. Ms. Pride testified that Kern River's levelized methodology for setting rates as

[218] *Kern River Gas Transmission Co.*, 107 FERC ¶ 61,215 at 61,948 (2004).
[219] Ex. S-12 at 1-10.
[220] *Id.*
[221] *See* S-8, Schedule No. 27.
[222] Ex. S-12 at 10-12.

presented in the subject Section 4 rate filing was not what the Commission envisioned when it gave Kern River authority to implement a levelized rate design in its certificate authorization. [223] The authority to initially use a levelized rate design was a way to meet the gas requirements of the EOR operations in the heavy oil fields of Kern County, California, and to encourage investment. She further testified that in a later rehearing order, the Commission anticipated testing of Kern River's levelization methodology in a later Section 4 rate proceeding; the Section 4 "just and reasonable" standard is more exacting than Section 7's "public convenience and necessity "standard. Ms. Pride testified that the Commission expected that after fifteen years Kern River would retire its debt and be capitalized with 100% equity. Shippers would then have lower rates. However, Ms. Pride noted that Kern River was making no assurances that it intended to lower rates after contract terms expire. [224]

161. Ms. Pride explained her view that there were inequities for ratepayers in Kern River's levelized rate design. She noted first that the models provided for accelerated collection of deprecation over the length of the contracts; however the length of the contracts did not correspond to the pipeline's remaining useful life. Second, Ms. Pride noted that debt costs collected in the model did not correspond with the amortization periods and debt payments on the financing agreements on the loans; that resulted in unreasonable over-recovery of Kern River's financing costs, according to Ms. Pride. Third, the Original System and Rolled-In System projects would not be at 100% equity as the Commission had anticipated when it initially allowed Kern River to use a levelized rate design the end of the terms of the contracts. Ms. Pride testified that was so even though the transportation rates paid by Kern River's shippers fully recover the debt costs that Kern River designed into the levelized models. [225]

162. Ms. Pride testified that Kern River generated revenues and the payback of principle on its loans in large measure from the regulatory/ratemaking depreciation expense that it generated from the levelized rate models. She testified that the depreciation rates that Kern River used for each of the six models resulted in a composite regulatory/ratemaking depreciation rate of 4.28%, while Kern River actually used a book depreciation rate of 2.00%. She testified that the over-collection of depreciation from the ten-year and fifteen-year shippers resulted in a significant over-recovery of costs from that generation of customers. According to Ms. Pride, under Kern River's levelized methodology, the regulatory/ratemaking depreciation expense is much higher than is needed for the servicing of Kern River's current debt payments, even though under Kern River's design there should have been a direct linkage of the recovery of the 70% of plant that was debt related. She testified that, in addition, shippers were being held responsible

[223] *Kern River Gas Transmission Co.,* 50 FERC ¶ 61,069 (1980).
[224] Ex. S-12 at 12-14.
[225] *Id*. at 14-15.

for, and being assessed through their rates much higher debt payments than is required under the debt instruments of Kern River's financing agreements. According to Ms. Pride, those debt payments resulted in an over-recovery of $54,625,440 in 2004. [226]

Rolled-In Customer Group

163. RCG presented the testimony of David C. Parcell and James A. Doering.

DAVID C. PARCELL

164. David C. Parcell is Executive Vice President and Senior Economist of Technical Associates, Inc. He has been employed by Technical Associates as a consultant since 1970. The majority of Mr. Parcell's consulting experience has been in the area of cost-of-capital in utility ratemaking. [227]

165. Mr. Parcell testified that he recommended a cost of common equity or ROE of 9.4%. He used the DCF model to derive his cost of ROE; he followed the DCF model "literally". His proxy group had no MLPs, but rather was made up of publicly-traded corporations that own interstate natural gas pipelines. Mr. Parcell computed a range of ROE figures of a low of 8.0% and a high of 11.7%. The median return on equity based on those figures is 9.4%. According to Mr. Parcell, the Commission's preference is that the median figure be used unless there is evidence that the pipeline whose rates are being established is entitled to an upward or downward adjustment within the range of return figures to account for an atypical business risk. Mr. Parcell testified that the 9.4% DCF result for his proxy group was corroborated by DCF results for several alternative groups of pipeline owners and/or gas distribution companies. [228]

166. Mr. Parcell testified that his understanding of the economic and legal principles which underlie the concept of a fair rate of return for a regulated utility was that regulated public utilities primarily have their rates established using the "rate base-rate of return" concept. Pursuant to that method, utilities are allowed an opportunity to recover their legitimate operating expenses, taxes and depreciation, in addition to being allowed an opportunity to earn a fair rate of return on the assets utilized (i.e., rate base) in providing service to their customers. The rate base is derived from the assets side of the utility's balance sheet as a dollar amount and the rate of return is developed from the liabilities/owners equity (i.e., debt/equity) side of the balance sheet as a percentage. Rate of return is developed from cost of capital, which is estimated by weighting the capital structure components (i.e., debt, preferred stock, and common equity) by their

[226] *Id*.
[227] Ex. RCG-1 at 1-2.
[228] *Id*. at 2-4.

percentages in the capital structure and multiplying these by their cost rates (i.e., "weighted cost of capital"). According to Mr. Parcell, the "fair rate of return" is a legal and accounting concept which refers to an after-the-fact earned return on an asset base. The cost of capital is an economic and financial concept which refers to a before-the-fact expected or required return on a liability base. Mr. Parcell testified that in regulatory proceedings, the terms are often used interchangeably and that he did so in his testimony.[229]

167. Mr. Parcell testified that from an economic standpoint, a fair rate of return is normally considered to incorporate the financial concepts of financial integrity, capital attraction, and comparable returns for similar risk investments. He testified that those concepts were derived from economic and financial theory and were generally implemented using financial models and economic concepts such as DCF, capital asset pricing model, and comparable earnings. Mr. Parcell testified that from a legal standpoint, *Bluefield Water Works*, [230] and *Hope Natural Gas*, [231] are cited as providing the legal standards for a fair rate of return for regulated utilities. Those cases provide that setting rates for a utility requires balancing the interests of the investor/company and of the consumer. The investor/company is concerned with enough revenue for operating expenses as well as for the capital costs of the business. The capital costs include service on the debt and dividends on the stock. Mr. Parcell testified that he read the *Bluefield* and *Hope* decisions and later cases citing those decisions as having identified three economic factors relevant to the determination of a fair rate of return. Those factors are: 1) comparable earnings; 2) financial integrity; and 3) capital attraction. According to Mr. Parcell, the legal standards reflect the economic criteria of the "opportunity cost' principle of economics. According to Mr. Parcell, that principle holds that a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could reasonably expect to achieve on investments of similar risk. The opportunity-cost principle reflects the regulation principle that regulation is intended as a surrogate for competition. [232]

168. Mr. Parcell testified that the Commission has made use of the DCF methodology as its principal methodology for estimating the cost of equity for interstate natural gas pipelines since 1983. [233] The preferred formula was set forth in *Transcontinental Gas Pipe Line Corp*. (Opinion No. 414-A).[234] He testified that the formula requires, among

[229] *Id*. at 4.
[230] *Bluefield Water Works and Improvement Company v. Public Service Commission of the State of West Virginia* 262 U.S. 679 (1923).
[231] *FPC v. Hope Natural v. Hope Natural Gas Company,* 320 U.S. 591 (1944).
[232] Ex. RCG-1 at 5-6.
[233] *Consolidated Gas Supply Corp.*, 24 FERC ¶ 61,046 (1983).
[234] 84 FERC ¶ 61,084 (1998).

other things, a short-term growth calculation which is measured by median five-year earnings-per-share projections. [235]

169. Mr. Parcell testified that the cost-of-capital for both fixed-cost (debt and preferred stock) components and common equity, are partly determined by economic and financial conditions. Level of economic activity, stage of business cycle, level of inflation, and expected economic conditions are factors that affect costs of capital. Mr. Parcell testified that he had examined economic statistics for the period from 1975 until the time he prepared his testimony. Mr. Parcell testified that capital costs were currently low in comparison to the levels that had existed over the past three decades and that it was reasonable that cost-of-equity models, such as the DCF, would produce current returns that were lower than was the case in previous years. [236]

170. Mr. Parcell testified that the results called for a much lower ROE than those figures produced. ROE had decreased over the over the past decade by application of the DCF formula because capital costs had declined significantly in recent years, as witnessed by almost historic lower interest rates. In addition, over the previous five years stock returns had been much lower than during the 1980s and 1990s. Mr. Parcell further testified that the median DCF result is appropriate for Kern River because Kern River had no more risk than the companies comprising the proxy group. He testified that that was shown by, among other things, the bond ratings of Kern River and the other proxy group companies; Kern River's bond rating was as high as, or higher than those of the proxy group companies. [237]

171. Mr. Parcell testified that, consistent with Commission precedent, a proxy group of natural gas pipeline proxy companies is selected to which the DCF methodology is to be applied. Companies previously included by cost-of-capital witnesses in FERC pipeline proceedings had included: Coastal, El Paso Energy, Enron, Panhandle Eastern, Sonat, Transco and the Williams Companies. However, Coastal, Panhandle Eastern, Sonat and Transco merged, or were acquired, and are no longer publicly-traded companies. Enron went into bankruptcy. Williams and El Paso had recently experienced financial difficulties. Mr. Parcell testified that the Commission in 2003, relying on data as of early 2000 in *Williston Basin* used a proxy group comprised of: Coastal Corporation, Columbia Gas, El Paso Corporation, Enron Corporation, Equitable Resources, Kinder Morgan, Inc., National Fuel Gas Company, Questar Corp., and the Williams Companies. According to Mr. Parcell, arguably only Equitable Resources, Kinder Morgan, National Fuel Gas, and Questar remained available to be included in a gas pipeline proxy group after mergers and financial difficulties; according to Mr. Parcell, he even had reservations about

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[235] Ex. RCG-1 at 7.
[236] *Id.* at 7 – 11.
[237] Ex. RCG-1 at 18-22.

including El Paso, Kinder Morgan, and Williams. Mr. Parcell testified that he was not aware that the Commission had used a proxy group that was as small as the four-company group. [238]

172. Mr. Parcell further testified that the Commission in *Petal Gas Storage* [239] used the following companies for its proxy group: CMS Energy, Duke Energy, El Paso Energy, Equitable, Kinder Morgan, MDU Resources, National Fuel Gas Company, NiSource, Questar Corp., Reliant Energy, and The Williams Companies. Mr. Parcell testified that, as the Commission did not state the reasons for including those companies, he assumed the Commission considered their businesses representative of a natural gas company. He noted that each of the companies is the parent of at least one major interstate natural gas pipeline company. He noted that the group included the four remaining companies from *Williston Basin*. Mr. Parcell testified that he started with the *Petal* companies and then excluded CMS Energy because it no longer paid dividends. He also excluded Kinder Morgan, Williams, and El Paso. He excluded Kinder Morgan because its business profile was peculiar in that it was the general partner of a separate, but affiliated energy MLP. He testified that both Williams and El Paso were too financially unstable to be included in a proxy group; in fact, El Paso had had its debt ratings reduced to junk status. Mr. Parcell testified that he added CenterPoint and Dominion because those companies had pipeline revenues in excess of $100 million. Mr. Parcell chose a $100 million threshold as the minimum annual revenues from gas pipeline operations as a standard for inclusion in the proxy group because he believed that figure indicates a significant level of pipeline operations. Mr. Parcell's chosen proxy group, thus, was: CenterPoint Energy, Dominion Resources, Duke Energy, Equitable Resources, National Fuel Gas, NiSource and Questar. Mr. Parcell included no MLPs in his proxy group. [240]

173. Mr. Parcell testified that he had applied the FERC DCF model to four groups: 1) his seven-company proxy group; 2) the *Williston Basin* group; 3) Staff proxy group in the *Northern Natural Gas* proceeding [241]; 4) a group of natural gas distribution companies that pay cash dividends. Mr. Parcell testified that the DCF results were as follows:

	Low	High	Median
Mr. Parcell's proxy group	8.0%	11.7%	9.4%

[238] *Id*. at 11-12.
[239] *Petal Gas Storage, L.L.C.*, 106 FERC ¶ 61,325 at 62,280 (2004).
[240] Ex. RCG-1 at 13 – 18.
[241] *Northern Natural Gas Co.*, 107 F.E.R.C. P61,247 (2004)

Williston-Basin group	7.2%	13.5%	9.4%
FERC Staff proxy group	7.2%	13.5%	8.9%
Gas Distribution group	7.6%	11.0%	9.3%

174. Mr. Parcell testified that there were two primary sets of differences between his ROE recommendation and that of Dr. Olson. First, their proxy groups were different. Second, their risk assessments of Kern River were different. Mr. Parcell's proxy group was comprised of publicly-traded corporations that owned interstate natural gas pipelines, while Dr. Olson's was comprised primarily of MLPs. Mr. Parcell testified that MLP data is not compatible with data from publicly-traded corporations. An MLP is a special type of investment that affords investors advantages over the conventional purchase of a share of corporate stock. The yield from an MLP does not conform to the income stream depicted in a DCF analysis which, for a corporation, is earnings per share. Mr. Parcell testified that to assemble yield data that would correspond to earnings per share, as contemplated by the DCF analysis, would require much more data than the price and growth estimates used in FERC practice. Mr. Parcell testified that Dr. Olson used data representing cash distributions, not dividends as are paid to holders of corporate common-stock shares. The cash distributions are not earnings or income and renders the use of MLPs erroneous and Dr. Olson's DCF analysis flawed. The cash distributions actually represent cash flow and are a return of investors' capital. Unless adjusted to account for this difference, the data cannot be used in the DCF formula. [242]

175. With respect to assessing risk, the second set of differences, Mr. Parcell assessed Kern River as of average risk, while Dr. Olson viewed it as a high-risk pipeline. Mr. Parcell testified that Kern River has had bond ratings generally similar to those of his proxy group companies. Therefore, Moody's, a major rating agency, assigned a similar assessment of risk to Kern River and to the proxy group companies. Mr. Parcell further noted that Dr. Olson's description of Kern River's risks was essentially subjective and did not consider bond ratings or other quantitative assessment of risk. [243]

176. Finally, Mr. Parcell testified that including companies with electric utility operations in his proxy group was appropriate. Mr. Parcell noted that the Commission did not accept Staff's inclusion of electric utilities in the *Williston Basin* proxy group. The Commission did note, however, that with the changes that the natural gas industry was undergoing it maybe would have to revisit its rule on electric companies. Mr. Parcell testified that his view was that a proxy group containing some companies with electric

[242] *Id*. at 22-23.
[243] *Id*. at 23-32.

utility operations is a more appropriate surrogate for a natural gas pipeline than is a proxy group comprised mainly of MLPs. [244]

JAMES A. DOERING

177. James A. Doering, is a management consultant specializing in financial, economic, and regulatory services to companies in the energy industry. Mr. Doering is a certified public accountant and before becoming a self-employed consultant, he was employed in accounting and financial positions in the financial services and distribution industries. He also was employed about eleven years with El Paso where he performed a variety of rate, regulatory, economic and strategic planning duties. Mr. Doering testified that he gained experience with levelized rate methodologies while at El Paso. Specifically, Mr. Doering developed the underlying levelized rate calculations for the estimated cost of service, rate base, and rates for Mojave Pipeline Company in its competition against Kern River's proposal. Mr. Doering testified that during the project development period, he had had the opportunity to consider various levelized rate methodologies, including the DCF method, a yearly depreciation rate method similar to Kern River's, and a deferred income/regulatory asset approach. [245]

178. Mr. Doering testified that both levelized and traditional ratemaking involves deriving rates from use of test period data (actual twelve-month period of a pipeline's past costs and volumes, adjusted for known and measurable changes that will occur in the next nine months). There is a difference, then, between the period from which the data are taken and the period during which the rates will be in effect. In traditional ratemaking, test period data are used to generate rates applicable to future periods. In levelized ratemaking, the test period data are used as a starting point for calculating estimated annual costs into the future. The data used to develop levelized rates are from the same annual periods that the rates will be in effect. [246]

179. Mr. Doering testified that the principal purpose of levelized ratemaking is to have lower rates in the early years than would be possible under traditional ratemaking. He testified that levelized ratemaking also provides more stability for shippers. Mr. Doering's opinion was that the benefits of having lower rates in the initial years outweigh having higher rates in later years. Mr. Doering testified that the 2003 Expansion Shippers, in particular, were benefiting from levelized rates because those facilities were relatively new. He testified that the Rolled-In shippers also benefit because their rates are lower than traditional rates in the near term and provide more stability in the longer term. He testified that levelized rates facilitate the development and construction of pipelines

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[244] *Id.* at 31.
[245] Ex. RCG-2 at 1-3.
[246] *Id*. at 7-8.

because pipelines can offer competitive rates initially and thereby be economically attractive to producers, shippers, and consumers. Traditional method initial rates may make the rate level prohibitive to producers, shippers, and consumers. According to Mr. Doering, with properly designed levelized rates there is a much closer match between rates paid by shippers and the pipeline's cost-of-service than there would be if the pipeline filed traditional rates every three to five years. Mr. Doering admitted, however, that levelization does have some drawbacks. One is that rates levelized for periods longer than the term of firm contracts can result in cost shifting between generations of shippers. Another is that levelized rates involve calculations over the entire period that rates are to be levelized, rather than a single test year as under traditional ratemaking, causing the levelized approach to appear more complex than does traditional ratemaking.[247]

180. Mr. Doering testified that although all of Kern River's shippers benefited from levelized rates, there were some problems with Kern River's model. He testified that Kern River's shippers were not subject to cost shifting between generations of shippers because Kern River proposed rate periods that were concurrent with contract terms. Mr. Doering testified that the concurrent levelization and contract periods also rendered Kern River not at risk for under-recovery. While the annual amounts of shipper payments to Kern River are different from those which would be paid under traditional rates, the current generation of shippers would still pay all the costs appropriate to include in rates during the term of their contracts. However, Mr. Doering testified that he could not support Kern River's rate model because it was too complex and used flawed assumptions. He testified that Kern River's model may have been appropriate in 1990 when there was only one transmission system and one class of firm shippers on its system, but complexity results from Kern River having to accommodate more classes of shippers. Moreover, according to Mr. Doering, Kern River further expanded the model in this proceeding to incorporate its proposed changed depreciation rate treatment for general plant and compressor engine plant, which treats them differently from transmission plant by depreciating them on a traditional, straight line, cost-of-service basis. Mr. Doering testified that Kern River's rate model describes the steps to be followed to calculate rates for shippers; he calculated that it requires hundreds of steps to derive rates. Mr. Doering maintained that the Kern River model had changed dramatically since adopted in the original certificate proceeding and, he pointed out, the Commission had not approved the model in its present form.[248]

181. Mr. Doering testified that another source of complexity of the Kern River rate model is its depreciation-oriented methodology. Mr. Doering testified that he referred to Kern River's model as the "depreciation levelized" rate method because of its reliance on

[247] *Id*. at 8-11.
[248] *Id*. at 5 and 11-14.

varying the annual depreciation expense as the means to equalize the annual cost-of-service. He testified that Kern River's model varies the year-to-year depreciation expense as the means to achieve an equal cost of service for each year of the levelized rate period. The calculations are iterative because a change in depreciation in one year changes the accumulated depreciation and ADIT balances in rate base, which in turn changes the cost of service for that year. Further, a change in the level of depreciation in one year affects all the other years because Kern River's model assumes that a fixed amount of depreciation must be achieved over the entire period. [249]

182. Mr. Doering testified that the 3% annual inflation factor for O&M and A&G built into Kern River's model was unreasonable. He testified that over a period of fifteen years, the 3% inflation factor causes Kern River's costs to increase to more than 150% of their test period level. He testified that it was the equivalent of the Commission issuing a prior approval for salary and wage increases of 3% for each year of the entire levelized rate period. Moreover, according to Mr. Doering, Kern River has historically filed a new rate case every few years and inflation has therein been taken into account. Mr. Doering noted that Kern River provided no objective evidence to support an inflation factor. Consequently, Mr. Doering's view was that Kern River should file to change its rates it if experiences a change in its operating costs to the point that its rates were no longer adequate to recover those costs. [250]

183. Mr. Doering testified that the Kern River model does not use test period amounts for all rate base items. According to Mr. Doering, some of the rate base amounts are different from the estimated end-of-test period amounts filed by Kern River. Mr. Doering testified that the variances led to an over-statement of its cost of service and unnecessarily increased rates. According to Mr. Doering, Kern River should be required to use rate base amounts to derive rates that do not exceed its estimated end-of-test period rate base. In addition, Mr. Doering testified that the Kern River rate model used capital structure assumptions that depart not only from test period data, but from Kern River's future debt repayment obligations as well. Kern River has, in effect, used a hypothetical capital structure, tilting its capitalization an unwarranted degree toward equity capital. This tilting of capital structure, according to Mr. Doering, artificially raised Kern River's overall rate of return with the result that Kern River's cost-of-service is overstated. Mr. Doering expressed the view that Kern River should be required to use test period data for cost of service, rate base, and capitalization. [251]

184. Mr. Doering testified that Kern River incorporates too little debt into the capital structure used to derive the cost-of-service in each year of the levelized rate period. He

[249] *Id*. at 14.
[250] *Id*. at 14-15.
[251] *Id*. at 16-18.

testified that Kern River's debt capital consists of two debt issues: 1) a $510 million note at 6.676% interest; and 2) a $836 million note at 4.893% interest. Both notes require monthly payments with final payments due in 2016 and 2018, respectively. He testified that Kern River's estimated test period capital structure was 64.98% debt and 35.02% equity or, rounded off 65/35 debt/equity ratio. Kern River used the weighted average cost of debt to derive rates for all shippers, but assigned an amount related to the $510 million loan to the Rolled-In System and an amount related to the $836 million loan to the incremental lateral facilities. Mr. Doering testified that Kern River's assumption that repayment of debt principal and depreciation are equal over time to an amount approximately 70% of the cost of gas plant results in a calculation of debt balance that bears little relationship to Kern River's actual outstanding debt balance. The debt amounts from the $510 million issue that are used in Kern River's model are hypothetical amounts derived from assumptions regarding the disposition of funds from the loan, accumulated depreciation, and annual depreciation expense, rather than the actual balance of $510 million loan. The hypothetical amount of debt is less than the actual outstanding balance of debt, resulting in too little debt being incorporated into the capital structure in each year of the levelized rate period. [252]

185. Mr. Doering testified that the *Ozark* methodology, which Kern River uses, assumes that the outstanding debt balance is applied to rate base first, and that the remaining balance of rate base (i.e., rate base less the amount of debt capital) is financed by equity capital. If debt is understated, then equity capital will be overstated. According to Mr. Doering, this results in an excessive amount of ROE and associated income taxes. Also, since equity capital bears a much higher cost than debt, overall return on rate base is exaggerated. Mr. Doering testified that rather than reduce the debt balance from year-to-year to reflect its actual debt payment obligations, Kern River assumes that the annual debt principal repayment is equal to the amount of depreciation it calculates for each year in the levelized cost-of-service. He testified that the amount of depreciation in the levelized cost of service is greater than Kern River's actual debt repayment obligations. Consequently, Kern River not only starts with a hypothetical debt balance that is too low, it also applies hypothetical annual principal payments that exceed its debt payment obligations, resulting in a constantly growing understatement of debt capital and overstatement of equity capital in the rate model. This calculation with its flawed assumptions, according to Mr. Doering, inappropriately drives up Kern River's cost of service. [253]

186. Mr. Doering testified that he compared the debt balances Kern River used in its rate model with its actual debt balances (as provided by Kern River in a data response) for the $510 million debt and found that Kern River significantly departed from actual

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[252] *Id*. at 18-20.

[253] *Id*. at 20-21.

debt financing. For example, one calculation found Kern River understated its test period debt capital and over-stated its equity capital by almost $37 million. Mr. Doering testified that the levelized rate calculation should start with end-of-test period debt capital and adjust the debt capital balance in each year based on Kern River's debt repayment amortization schedule. He also testified that Kern River should use its overall capital structure in the derivation of rates for all shippers, instead of assigning portions of the Kern River debt to the various rate classes. [254]

187. Mr. Doering testified that although he supported use of a blended rate for debt capital for all Kern River shippers, he did not think it appropriate to segregate Kern River's debt into separate portions for each of its segregated systems and for each shipper, as Kern River had done in its rate model. He testified that the "dollar tracing" that Kern River was attempting was no more than arbitrarily assigning or allocating dollars where there was no objective or quantifiable basis for the allocation. He testified that it was too subjective. [255]

188. Mr. Doering testified that an annuity levelized rate model would be a less complex way to derive levelized rates for the Kern River system. The annuity levelized rate method uses the traditional ratemaking approach to calculate a cost-of-service and rate base for each year of the period over which rates are being levelized. It starts with the traditional test period cost-of-service and rate base, and then uses that data to calculate the next year's cost-of-service and rate base, then that year becomes the basis for the next year, and so forth. The annuity levelized rate approach is a compromise between Kern River's depreciation-oriented levelized rate model and a traditional cost-of-service ratemaking model. [256]

189. Mr. Doering testified that Kern River's treatment of ADIT did not maximize income tax benefits on a system-wide basis for all shippers. He testified that Kern River used ADIT balances derived as if each of the portions of its system filed income taxes separately for the Rolled-In and Incremental Facilities. Consequently, the bonus depreciation and NOL associated with the bonus depreciation are derived based only on the taxable income for the incremental facilities and only the incremental facilities benefit from the bonus depreciation. Mr. Doering testified that his view was that such inequitable treatment was not appropriate. [257]

190. Mr. Doering testified that the current book depreciation rate of 2.0% depreciation for Kern River's transmission system (excluding compressor engines) should not be

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[254] *Id*. at 21-23.
[255] *Id*. at 23-24.
[256] *Id*. at 76-84.
[257] *Id*. at 34-42.

increased. Mr. Doering said that Kern River's depreciation rates were based on flawed and biased analysis of gas supplies available to its system; the analysis was not consistent with other Kern River supply forecasts in other regulatory proceedings or with other pipeline gas supply forecasts for a similar geographic area. Mr. Doering testified that Mr. Feinstein ignored basic economic theories in his forecast of domestic gas supplies, ignored differences between his studies and others, and used unorthodox models. The result, according to Mr. Doering, was an unreasonably low estimate of the remaining economic life of the Kern River system. [258]

191. Mr. Doering testified that the depreciation rate proposed by Kern River for its compressor engine plant was excessive. First, according to Mr. Doering, Kern River did not have much experience with the Rolled-In System useful life of compressor engines, and none with the 2003 Expansion on which to base a depreciation rate. According to Mr. Doering, a reasonable useful life for the compressor engines is four years, not Kern River's 2.91 years. Mr. Doering's depreciation formula was based on manufacturer contract terms requiring that the compressor engines be removed and traded-in for rebuilt compressor engines before they exceed 35,000 hours of run time. Kern River was subject to a penalty for exceeding the 35,000 hours of run time. A run-time of 35,000 hours equals four years, assuming an engine is run twenty-four hours a day, seven days a week, fifty-two weeks a year. He testified that with a useful life of four years, Kern River should only have to replace 25% of its compressor engines a year. Mr. Doering testified that Kern River's numbers indicate an average of 71.11% salvage when it replaces its compressor engines. His calculations indicated a depreciation rate of 5.86% would be appropriate for compressor engines and not the 9.92% proposed by Kern River. According to Mr. Doering, Kern River's compressor engine deprecation rate would result in $11.9 million over-recovery. [259]

192. Mr. Doering testified that Kern River should not be allowed to recover negative salvage because neither the timing, nor the cost of the retirement liability has been adequately determined. Kern River's estimated retirement cost, net of salvage, is $114.4 million (for some reason, Mr. Doering noted, Mr. Feinstein developed his own retirement cost estimate of $111.8 million and interim estimates of $6.1 million). Mr. Doering testified that Kern River should not be allowed to recover any negative salvage because it admitted it had not implemented FAS 143. FAS 143 requires that the fair market value of a liability for an asset retirement obligation be recognized in the period in which it is incurred, if a reasonable estimate of the fair value can be made. FAS 143 establishes accounting standards for recognition and measurement of a liability for an asset retirement obligation and the associated asset retirement cost. FAS 143 was developed to rein-in the diverse accounting practices with respect to the retirement of long-lived assets

[258] *Id*. at 43-57.
[259] *Id*. at 61-63.

among various entities. Mr. Doering testified that it was inconsistent for Kern River to request negative salvage for ratemaking while not implementing FAS 143.[260]

193. Mr. Doering testified that one of the fundamental precepts of rate design is the concept that cost responsibility should follow either cost causation or economic benefit. Common costs are those costs incurred by Kern River for facilities or expenses that benefit more than one segment of its system or more than one class of shippers. Kern River allocated one type of common cost, A&G, to the Rolled-In System, 2003 Expansion, and the High Desert and Big Horn Laterals. General plant facilities costs were allocated among its categories of transmission facilities on the basis of gas plant. Kern River recorded payroll and ad valorem taxes as common costs and allocated them among the categories of facilities. However, Mr. Doering testified that Kern River had not allocated all of the types of common costs included in its rate base and cost of service among its categories of facilities. He particularly noted that Kern River had not allocated any common costs associated with the land, rights of way, compressor station structures, and communications equipment among its categories of facilities. Mr. Doering testified that Kern River allocated all of the costs associated with land, rights of way, and communications equipment solely to Rolled-In System shippers even though 2003 Expansion shippers used those assets also. Rolled-In shippers were also charged with all costs associated with compressor station facilities in spite of the fact that additional compression was added for the 2003 Expansion. According to Mr. Doering, 2003 Expansion shippers get a 'free ride' from Wyoming to California using the land and rights of way on which the 2003 Expansion pipeline and compressor stations are situated. According to Mr. Doering, this results in the Rolled-In shippers subsidizing the 2003 Expansion shippers.[261]

194. Mr. Doering testified that Kern River's use of rates applicable to 2003 Expansion shippers (i.e., rate applicable to ten year 2003 Expansion shippers, or highest firm transportations rate on its system) to develop an AOS rate for Rolled-In shippers was not appropriate because it would require Rolled-In shippers to pay rates at a level much higher than the rates for AOS than they would have paid had the 2003 expansion not been constructed. Mr. Doering testified that it was his opinion that the Rolled-In shippers should pay AOS rates based on the costs associated with the Rolled-In System only. Mr. Doering testified that blended fuel rates were also unfair to Rolled-In shippers.[262]

195. Mr. Doering testified that the Rolled-In shippers did not concede that Kern River's designation of Section 4 versus Section 5 issues in Kern River's answering testimony was appropriate. Mr. Doering testified that Kern River's position that loan proceeds that were

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[260] *Id*. at 63-69.
[261] Ex. RCG-2 at 69-73.
[262] *Id*. at 73-75.

disbursed to pay debt issuance and swap costs should be deducted from Kern River's outstanding debt balance because those funds did not pay for facilities, was not reasonable. He testified that would penalize the shippers twice for one element of cost. He testified that the impact of Kern River's debt issuance and swap costs were already reflected in the cost of Kern River's long-term debt. Since shippers were repaying that portion of the loan proceeds by means of return on debt, they should be permitted to enjoy the full benefit of those loan proceeds according to Mr. Doering. According to Mr. Doering, by deducting a portion of the debt issuance and swap cost from Kern River's outstanding debt balance, Kern River was denying shippers the full benefit of a loan that they were repaying in full in their rates. [263]

196. Mr. Doering testified that Kern River was not applying the *Ozark* method as envisioned by the Commission in that, according to Kern River witness Mr. Warner, Kern River's levelization calculations did not reflect the actual timing of the payments of debt principal. Mr. Doering testified that, despite Kern River's statements to the contrary, Kern River was able to determine the test-period balances for gross plant investment, accumulated depreciation, working capital, and ADIT for rate base purposes even though the accounting for each of those rate base items was monthly. Mr. Doering noted his agreement with the testimony of Kern River witness Mr. Lovinger that the *Ozark* methodology assumes that all debt was raised to finance rate base. Therefore, according to Mr. Doering, in the computation of capital structure, all outstanding debt is subtracted from total rate base and the remainder is assumed to be financed by equity. And, according to Mr. Doering, Mr. Lovinger was in a position to know what *Ozark* stands for since he had been personally involved in the *Ozark* case. Mr. Doering concluded that Kern River not only applied the *Ozark* methodology inconsistently among its various categories of facilities, but also had stopped applying it to general plant and compressor engine plant. [264]

197. Mr. Doering testified that the timing differences between the years in which Kern River collects the debt principal from its shippers and the years in which it repays the debt principal to its lenders, have a significant adverse impact on the shippers. Mr. Doering testified that in the five-year period beginning November 1, 2004, Kern River would collect $198 million more in depreciation than it would need to pay on its long-term debt. After ten years the amount would be $299 million. The net present value of Kern River's timing differences is $138 million, calculated over the remaining life of firm shipper contracts and using Kern River's 15.1% ROE as the discount rate. [265]

198. Mr. Doering testified that Kern River shippers were being penalized a second time

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[263] Ex. RCG-18 at 5.
[264] *Id*. at 6-10.
[265] *Id*. at 10-11.

by Kern River's application of the *Ozark* methodology because the shippers have to pay increased equity return and income tax costs due to the unnecessarily high equity component of rate base that results from Kern River's understatement of its outstanding debt. Under the *Ozark* method, debt is subtracted from net rate base to determine the equity-financed portion of rate base. The amount by which debt-financed rate base in understated is the amount by which Kern River's equity-financed portion of rate base is overstated. Mr. Doering testified that since by year ten Kern River would be applying $299 million too little debt to its net rate base under the *Ozark* method, it must also be applying $299 million too much equity. According to Mr. Doering, if Kern River used the annual average of its actual outstanding debt balance instead of its understated, hypothetical debt balance, it would be adequately compensated for its cost of debt capital and its shippers would not be paying excessive equity-related capital costs. He testified that the Commission in *Trailblazer* [266] had already rejected the argument Kern River was trying to make: to wit, that since Kern River had a larger total balance of debt and equity capital than its net investment in rate base under *Ozark*, some part of Kern River's equity capital was unable to earn a return on rate base and was, therefore, under-compensated. [267]

199. Mr. Doering testified that Kern River had changed its position from being a 100% project-financed pipeline to being a project-financed pipeline for some facilities, but not for others. He testified that before the subject Section 4 rate case, all of Kern River's assets were incorporated in its levelized rate calculations for purposes of determining rate base, levelized depreciation expense, and hypothetical debt principal repayment. In this rate proceeding, Kern River changed the designation of its general plant and compressor engine plant from project-financed to traditionally-financed by applying its traditional test-period capital structure to calculate debt and equity return, rather than the *Ozark* method. Mr. Doering found Kern River's explanation that the proposed change for general plant and compressor engines was that those assets were not financed by debt, did not answer the question of why they had been project-financed for twelve years. Mr. Doering also noted that Kern River claims a 60/40 debt/equity capital ratio for rate purposes for Big Horn even though Kern River admitted that no debt was issued in connection with construction of the Big Horn facilities. He also noted that Kern River did not apply the *Ozark* methodology to rate calculations for the Big Horn. Mr. Doering further noted that Kern River claims a 70/30 debt/equity capital ratio for rate purposes for High Desert even though Kern River witness Mr. Smith testified that those facilities were financed by the same debt issue that paid for the 2003 Expansion facilities. He also noted that Kern River did not apply the *Ozark* method to High Desert, indicating that it does not consider those facilities to be project-financed. [268]

[266] *Trailblazer Pipeline Co.*, 50 FERC ¶ 61,188 (1990).
[267] Ex. RCG-18 at 11-12.
[268] *Id*. at 15-16.

200. Mr. Doering testified that the position of Calpine witness Mr. Hughes on debt capital was unrealistic. He testified that Mr. Hughes apparently believed that all subsequent events related to the $8.36 million debt issue were also related to the 2003 Expansion. However, Mr. Doering pointed out that Kern River pledged all of its firm contracts against all of its debt. Because Kern River did not segregate or escrow revenues from Rolled-In shippers separately from the revenues from 2003 Expansion shippers, there was no way to show that one group of shippers pays the interest and principal only for one specific debt issue. Mr. Doering testified that Kern River had funds available from other sources to make its debt interest and principal payments. [269]

201. Mr. Doering testified that the agreed-on 70/30 capital structure was not appropriate for High Desert. He testified that the negotiated rate calculated on a levelized basis did not excuse Kern River from its obligation to derive a test-period cost-of-service and cost-based rate for the High Desert. According to Mr. Doering, that calculation was necessary to determine whether the negotiated rate for High Desert Power was creating cost shifting and cross subsidies between the High Desert Lateral and other Kern River shippers. Mr. Doering's opinion is that Kern River should be required to derive a test-period cost-of-service and cost-based rates for all of its facilities based on its actual outstanding debt using the *Ozark* method. [270]

202. Mr. Doering testified that he disagreed with Calpine and High Desert that the 2003 Expansion shippers should only pay the lower debt cost associated with the $836 million debt issue because, among other things, they ignore the issue of identification of which debt and equity capital may have been used to pay for which assets. Mr. Doering noted that the position of Calpine on allocation of the higher cost $510 million debt to the Rolled-In shippers is not consistent with its position that the Rolled-In shippers should pay fuel costs at the level attributable to the 2003 Expansion when they use AOS service. [271]

203. Mr. Doering testified that the position of RCG is that it supports the 95% load factor condition, properly applied. Properly applied, Kern River would use as reservation and commodity billing determinants for the Original System the greater of 95% of the Original System capacity, or the actual test-period contract quantities and throughput for the Original System. The 95% load factor only applies to the capacity of the Original System, not to the firm contract quantities of the Original System shippers. The 95% load factor certificate condition requires that Kern River design rates for its Original System using billing determinants that are least equal to 95% of the Original System

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[269] *Id*. at 21.
[270] *Id*. at 22-23.
[271] *Id*. at 23-24.

capacity. Therefore, if either aggregate test-period contract or throughput quantities for the Original System are less than 95% of the capacity of the Original System, then Kern River must use 95% of the capacity as the billing determinants. He testified that, conversely, if the aggregate test-period contract quantities and throughput for the Original System are greater than 95% of the capacity of the Original System, the 95% load factor condition has no effect. Since, the test-period quantities in this proceeding exceed 95% of the Original System capacity, no further adjustment for reservation billing determinants was appropriate. However, according to Mr. Doering, Kern River applied the 95% load factor condition by reducing the firm contract quantities for Original System firm shippers to 95% of their test-period level for reservation billing determinant purposes.

204. Mr. Doering testified that the 95% load factor condition was not intended to provide an opportunity for Kern River for more earnings. Rather, the Commission put the 95% load factor condition on Kern River to place Kern River at risk for under-subscription that might occur as a result of having bypassed the gas supply and market showings. It was a trade-off for waiver of the gas supply and market showings under Kern River's optional expedited certificate ("OEC") application that would have been required under a Section 7 certificate application. Waiving the gas supply and market showings in the optional certificate process raised an obvious potential for the resulting pipeline system to be under-subscribed. [272]

205. Mr. Doering testified that he disagreed with Calpine that AOS service for Rolled-In shippers occurred in 2003 Expansion capacity. Rolled-In shippers had AOS before construction of the 2003 Expansion. Mr. Doering testified that 2003 Expansion shippers should not be heard to complain that having rates higher than those of the Rolled-In shippers was a competitive disadvantage since they agreed to those rates. Mr. Doering testified that Kern River's claim that higher rates for AOS service for Rolled-In shippers promoted allocative efficiency suffered from lack of discussion of productive efficiency. Mr. Doering explained that a need for "allocative efficiency" applies when demand for service exceeds the capacity of a pipeline system. "Productive efficiency" addresses a need to keep the pipeline throughput at a high load factor. According to Mr. Doering, since AOS service is a commodity-priced service that offers an opportunity for firm shippers to increase their throughput, it falls into the latter category of productive efficiency. Since firm shippers, which require their capacity for their own needs, will have their gas scheduled ahead of AOS service, there is no need to allocate that capacity by means of pricing. [273]

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[272] *Id*. at 32-34.

[273] *Id*. at 35-38.

206. Mr. Doering testified that Kern River overstated the case against an annuity levelized method and accounting requirements. According to Mr. Doering, Commission policy does not require that levelization be accomplished through depreciation as the Commission approved annuity levelization in *Trailblazer*.[274] He testified that the USOA provides enough latitude for an annuity levelized method to comply with accounting regulations. Mr. Doering testified that when he applied the same debt capital assumptions used in the Kern River model to the annuity model, the resulting levelized cost of service was $165,825 compared with $73,005 from the Kern River model, thus the annuity model produces lower rates. However, Mr. Doering testified, that Kern River's model could work if Kern River: 1) used test period data in the levelized rate calculations (would include eliminating all adjustments to accumulated depreciation, ADIT, and outstanding debt capital so that the beginning balances in the levelized calculations would flow directly from test period amounts without adjustment); 2) used total company outstanding debt capital under the *Ozark* method across all categories of rate base; 3) adjusted the depreciation target and depreciation rates, the ROE, and other cost of service and billing determinant data to reflect the commission's findings in this proceeding.[275]

207. At the hearing, Mr. Doering testified that Anadarko and Coral Energy Resources were not sponsoring his testimony regarding the 95% load factor because that condition was in their contracts.[276] He testified at the hearing that given the same inputs and assumptions, the annuity levelization approach and Kern River's depreciation levelization approach would yield very similar answers. The annuity approach was just a little easier to work with.[277]

BP

208. BP presented the testimony of Elizabeth H. Crowe.

<u>ELIZABETH H. CROWE</u>

209. Elizabeth H. Crowe is President of Foresite Energy Services, LLC, which provides consulting services to the regulated energy industry. Before forming Foresite Energy in 2001, Ms. Crowe had been employed in various positions at Swanson Energy Group, Inc., including the position of Vice President. Much of Ms. Crowe's consulting work has been in the area of rate and certificated proceedings in the regulated interstate natural gas

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[274] *Trailblazer Pipeline Co.*, 50 FERC at 61,188 *at* 61,587-98 (   ) .
[275] Ex. RCG-18 at 35-38 and 44-46.
[276] Tr. at 1347-52.
[277] Ex. RCG-18 at 1396-99.

pipeline industry. [278]

210. Ms. Crowe testified that she had been retained by BP to review cost-of-service, cost classification, cost allocation, billing units and rate design proposed by Kern River. Ms. Crowe testified that the subject Section 4 rate filing was made to comply with the terms of the March 31, 1999 Stipulation and Agreement that resolved the general rate proceeding in Docket No. RP99-274. [279] Ms. Crowe testified that the firm transportation reservation rates proposed by Kern River here reflect increases ranging from 10% for Expansion 2003 ten-year shippers, to 26% for Rolled-In ten-year shippers. She testified that the disparity was primarily due to the assignment of tax benefits received under recent tax legislation to the 2003 Expansion shippers, and the assignment to the Rolled-In shippers of rate base increases resulting from the sale of Kern River to MEHC in March 2002. She testified that the filed cost-of-service was $40 million, or 13% higher than the cost-of-service underlying existing rates. Ms. Crowe also noted that Kern River proposes increases to compressor engine depreciation rates, introduction of a negative salvage allowance, and use of a higher ROE. Ms. Crowe testified that Kern River had changed its transportation rates multiple times over the years despite the rate stability promised benefit of levelization. [280]

211. Ms. Crowe testified that her opinion was that depreciation rates for Kern River transmission facilities should be based on a thirty-five-year remaining life. By way of background, Ms. Crowe explained that Kern River calculated each set of levelized rates for each of the four classes of shippers on its system by setting the deprecation to recover 70% of the original gross plant costs attributable to that class of shippers, exclusive of certain compressor engine costs and adjusted for interim retirements, over the remaining term of the underlying contracts as of the end of the test period, October 31, 2004. She testified that the 70% capital recovery assumption dated back to Kern River's original certificate. The original certificate allowed the recovery of 70% of plant costs over the first fifteen years. The fifteen years matched Kern River's then debt service. Ms. Crowe testified that the number of years needed by Kern River to fully recovery gas plant costs from all four classes of firm shippers was 19.3 years after the end of the test period. She testified that because the full plant investment would be recovered from the Rolled-In shippers and from the ten-year 2003 Expansion shippers before that time, the weighted average remaining life of the system was actually 17.1 years. [281]

212. Ms. Crowe testified that she recommended a remaining economic life of thirty-five years, as opposed to the twenty-six years recommended by Kern River. She testified

[278] Ex. BP-1 at 1.
[279] *Kern River Gas Transmission Co.*, 87 FERC ¶ 61,128 (1999).
[280] Ex. BP-1 at 2-3.
[281] *Id*. at 4-6.

that she supported separate treatment of compressor engines, if depreciation was allocated using the associated compressor engine gas plant ratios. Ms. Crowe testified that the expected gas reserves supply life was the most important factor affecting a pipeline's remaining economic life. Ms. Crowe testified that she calculated the expected remaining supply life of gas available to Kern River to be thirty-eight years. Ms. Crowe observed that Kern River itself had made certain pertinent statements in material it developed in connection with its planned expansion. Some examples were that: the Rockies was the fastest growing producing United States region and had an estimated sixty-eight year supply of natural gas resources (assuming 2004 production levels); the Rocky Mountain supply basin had a sixty-six proven reserve life, which was the strongest production growth profile of any supply basin in the forty-eight lower states; the Rocky Mountain Basin provided attractively-priced gas to California. Ms. Crowe testified that she considered the 2002 report of the PGC on the estimated undiscovered resources of natural gas in the Rocky Mountain supply region (and Kern River is able to access virtually all of the gas supplies in that region). She testified that studies of market demand also showed Kern River was serving some of the fastest growing markets in the United States, and so would be expected to continue to have demand for that gas. [282]

213. Ms. Crowe testified that she recommended a ROE of 9.34%, as opposed to the 15.1% recommended by Kern River. Ms. Crowe noted that the 15.1% ROE recommended by Dr. Olson for Kern River was the highest return of the six-member proxy group used by Dr. Olson. She noted that since Kern River was not publicly traded on a stock exchange, a group of proxy companies was needed to perform the DCF analysis. She further noted that four of the six companies in Dr. Olson's proxy group were MLPs and that, in her opinion, it was not appropriate to use MLPs. She testified that when MLPs are used in the DCF calculation, cash distributions to partners are substituted for dividend yields in the formula. However, cash distributions are not identical to dividends. Cash distributions represent the return of partners' equity capital and not the return on equity capital. Using cash distributions as the equivalent of stock dividend yields distorts significantly the DCF analysis results and overstates the resulting expected ROE. MLPs pay cash distributions before income taxes, while corporations pay dividends after taxes and because of the tax advantages of the MLP structure, most MLPs maximize cash distributions to partners. That results in MLPs generating much higher "returns" than their corporate counterparts. For example, Kern River's data showed MLPs had a one-year return of 45.6% and a five-year return of 17.6% as of November 2003, while the Dow Jones fifteen Utilities Index returns were 13.7% and negative 4.0% respectively. S&P 500 returns were 18.8% and negative 0.2% respectively. [283]

214. Ms. Crowe testified that she recommended essentially the same proxy group

[282] *Id*. at 6-12.
[283] *Id*. at 12-15.

adopted by the Commission in the *Williston Basin* case, adjusted for the mergers, sales and consolidations that occurred since that the *Williston Basin* decision. Her adjusted *Williston Basin* proxy group consisted of six publicly-traded natural gas companies. She testified that the range of business risks represented the companies in her proxy group presented as reasonable spectrum of risk for most natural gas transmission system as could be found in a group of publicly-traded natural gas industry corporations, even if no one of them has business risks directly comparable to a pipeline like Kern River. Rather, some of the companies have much greater risk, and some have less. She testified that three major diversified energy companies in her proxy group had business risks significantly greater than an interstate pipeline like Kern River. Those companies were El Paso, Williams and Kinder Morgan, Inc., which are heavily invested in the merchant generation, oil and gas exploration and production, trading and/or other commodity-based (upstream) natural gas enterprises whose associated risks are much greater than those faced in the natural gas transmission industry. The other three companies in the proxy group have significant portions of their business in the gas distribution (downstream) side of the industry. [284]

215. Ms. Crowe testified that she was aware that the risks faced by large LDCs serving industrial markets with fuel-switching capabilities and/or high sensitivities to the price of gas are far more comparable to the risks faced by a pipeline like Kern River than are the risks of major diversified energy companies; however, the relatively higher proportion of their operations in gas distribution may provide some offset to the higher risk of El Paso, Williams, and Kinder Morgan, Inc. Therefore, according to Ms. Crowe, her proxy group provided the balance necessary to achieve overall comparability with the natural gas transmission industry. Ms. Crowe testified that it was inappropriate for Dr. Olson to use El Paso, a poorly performing company in proxy groups for other companies when El Paso was doing well, but then to exclude it when it was not. According to Ms. Crowe, that purposefully inflated the range of expected earnings produced by the DCF analysis. She testified that Dr. Olson, while now opposing use of Questar, Equitable Resources, and National Fuel as proxy companies, he had also recently used them. [285]

216. Ms. Crowe testified that it was reasonable to place Kern River at the median of the DCF range of equity returns, which was 9.34%. She testified that her reasoning was based on Kern River's own materials which showed that the company was well positioned in both the supply and demand markets, as well as in its competitive position with other pipelines serving the same markets. She noted that Kern River had maintained an annual load factor relative to capacity of greater than 100% for the ten years immediately preceding the subject rate filing. She noted that Warren Buffet, a well-known investor in the energy industry and a major MEHC stockholder, had agreed to pay

[284] *Id. at 15-18.*
[285] *Id*.

$960 million for Kern River, including the assumption of $510 million in debt. That $510 million in debt was about $200 million, or 26% above net book value at the time. Ms. Crowe testified that Kern River's relatively high debt ratio in its capital structure of 65% (it was initially at 70%, but was 65% at the time of this testimony) was not unusual for interstate pipelines. She testified that new pipelines were often financed at 70% or higher debt. She noted Kern River's strong credit ratings since it had been acquired by MEHC in 2002. She noted that Kern River had a high level of long-term firm contract commitments. In addition to concluding that Kern River's ROE should be 9.34%, Ms. Crowe expressed the view that if Kern River were allowed to keep levelized rates, the ROE should be adjusted downward by at least fifty basis points to compensate for the artificial thickening of the equity ratio that results under levelized rates. She also expressed the view that if the 5% reduction to rate design billing units for the Original System shippers were retained, the ROE should also be adjusted downward by twenty-five to fifty basis points to compensate for the built-in over-recovery of approved costs. [286]

217. Ms. Crowe testified that the decision of the Court of Appeals for the D.C. Circuit in *BP West Coast Products L.L.C.* ("SFPP") [287] would bar Kern River from collecting its proposed Federal and state income tax allowance. In *SFPP*, the Court had held that a limited partnership oil pipeline was not entitled to an allowance for income taxes it did not pay. Ms. Crowe noted that Kern River was a general partnership that does not pay income taxes and had no income tax liability. It was owned equally by two limited liability companies, which in turn were 100% owned by a limited liability company holding company, which in turn was 100% owned by MEHC, also a holding company. Therefore, according to Ms. Crowe, Kern River was in the same position as SFPP had been. [288]

218. Ms. Crowe testified that she recommended that Kern River use actual test period revenues for the twelve months ending October 31, 2004, or $19.9 million. She testified that that figure reflected a more representative level of market-oriented service revenues in the cost of service in this proceeding. Ms. Crowe testified that Kern River used the term "market-oriented" services to apply to such service as IT, short-term firm services, backhaul and certain negotiated transactions to which costs were not allocated in the rate design process, but for which a representative amount of revenue was credited to the cost of service. She testified that Kern River projected $6.1 million in revenue from market-oriented services for the test period, a reduction from the $7.8 million base period revenue received from market-oriented services. [289]

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[286] *Id*. at 18-20.
[287] *BP West Coast Products L.L.C. v. FERC*, 374 F.3d 1263.
[288] Ex. BP-1 at 22-23.
[289] *Id*. at 23-24.

219. Ms. Crowe testified that she did not agree with Kern River's reduction of Original System firm shippers daily contract demand ("DCD") quantities by 5% (also referred to as MDQ). She testified that the reduction was applied to the commodity billing determinants used to design rates for Original System shippers. She testified that Kern River justified the reduction based on a condition imposed in the order issued in 1990 at 50 FERC ¶ 61,069. Ms. Crowe's opinion was that the 95% load factor rate design condition was not longer reasonable and acted as a penalty. She testified that Original System shippers were penalized by that rate design in two ways. First, actual contracted capacity had been at or above the 100% of capacity level on the Original System since inception. Second, Original Shippers were the only shippers to which the reduction was applied, even though they got the same transportation from Kern River as did the other firm shippers. She testified that where Kern River did not loop its system by constructing parallel mainline facilities in order to accommodate expansion shippers' gas, the Original System shippers were paying the full costs of pipe now used to move those shippers' gas and the gas of the expansion shippers. The consequence was that the Original Shippers were being penalized for having underwritten the construction of the original facilities. Ms. Crowe claimed that violated 18 C.F.R. § 284.11(4), which requires that revenue responsibility be aligned with cost incurrence and cost benefit. Moreover, Ms. Crowe testified, the original rationale for the 95% load factor condition was not still applicable. Even though intended to put Kern River at risk for under-subscription, the condition actually had become a bonus for Kern River since the system had always been 100% subscribed. [290]

220. Ms. Crowe testified that her opinion was that Kern River had not justified departing from the SFV cost classification methodology. Also, according to Ms. Crowe, there was little likelihood that any shipper would be adversely affected by SFV. She testified that SFV closely aligns cost recovery with known and measurable reservation billing units, thus not providing windfall cost over-recovery to the pipeline due to firm commodity volumes increase. She testified that SFV significantly reduced the pipeline's risk of recovery of its approved costs. Finally, Ms. Crowe pointed out that it was the Commission's policy to use SFV cost classification. [291]

221. Ms. Crowe testified that she did not support Kern River's proposal to continue using its levelized cost-of-service/ratemaking method to design rates for its Rolled-In and 2003 Expansion systems, primarily because of the underlying depreciation period represented by the levelized rate process. She objected to Kern River levelizing its rates over the remaining primary terms of its shippers' contract such that 79% of its total transmission plant costs would be recovered from all classes of shippers at the end of the

[290] *Id*. at 25-26.
[291] *Id*. at 28.

respective levelization periods. That, according to Ms. Crowe, represented an unduly inequitable cost burden for current shippers relative to those who would be transporting gas on Kern River in the future. She testified that setting the depreciation component of the levelized rates to recover a lower percentage of Kern River's remaining plant costs over the remaining contract periods of the various shipper classes would be an acceptable alternative to converting to traditional rates, but would not overcome other drawbacks she saw with levelized method of setting rates. [292]

222. Ms. Crowe testified that it was BP's position that the regulatory asset created by virtue of use of the levelized cost-of-service/ratemaking methodology should be allocated among all shippers at the time the pipeline converts of traditional rates. She testified that she believed that allocation would be equitable because the Original Shippers had paid higher average annual depreciation rate than was proposed for any class of shippers under a thirty-five year remaining economic life. Ms. Crowe testified that Kern River should not be allowed to continue to reflect rate base increase caused by removal of the ADIT balance caused by sale of Kern River to MEHC, only to the Rolled-In system shippers. She testified that it produced an inequitable impact on rates paid by the Rolled-In shippers. It was unfair, according to Ms. Crowe, because the Rolled-In system shippers made the sale of Kern River economically attractive to MEHC. That sale, according to Ms. Crowe, among other things, made expansion possible. [293]

223. Ms. Crowe testified that the roll-in benefit should be applied separately to the ten-year and fifteen-year shippers. According to Ms. Crowe by adding the ten-year and fifteen-year Expansion 2002 costs and revenues to calculate a combined unit rate reduction for the ten- and fifteen-year Original System shippers, Kern River was producing a cross-subsidization of the fifteen-year shippers by the ten-year shippers. That was because the unit rate impact of the ten-year 2002 Expansion roll-in was significantly higher than the unit rate impact of the fifteen-year Expansion 2002 roll-in. [294]

224. In rebuttal testimony and at the hearing, Ms. Crowe restated BP's position that it supported levelization for Kern River, but with a much longer depreciation recovery period than Kern River uses. She testified that with Kern River's version of levelization there was a significant regulatory liability owed to shippers at the end of the contract periods and there was no assurance the shippers would ever recover that over-recovery. [295]

[292] *Id*. at 28-30.
[293] *Id*. at 31-36.
[294] *Id*. at 35-37.
[295] Ex. BP-42 at 4-6; Tr. 1406, 1429, and 1436-38.

Edison Mission

225. Edison Mission presented the testimony of Michael J. Vilbert.

MICHAEL J. VILBERT

226. Michael J. Vilbert is a principal of The Brattle Group, a consulting firm which specializes in the area of cost capital, investment risk, rate design and related matters for many regulated and unregulated industries. The firm's work is concentrated in financial and regulatory economics, with specialties in financial economics, regulatory economics, and the gas and electric industries. Mr. Vilbert offers testimony on the method Kern River used to allocate its embedded debt costs to its shipper groups under the levelization method it employed. [296]

227. Mr. Vilbert testified that Kern River had proposed incremental cost rates for the 2003 Expansion shippers to satisfy the Commission's requirement that expansion projects not be subsidized by existing shippers. Mr. Vilbert found objectionable Kern River's current proposal to change the interest cost allocation from actual costs of the debt used to finance the expansion, to a blended rate for all shippers including costs associated with the debt refinancing in 2001. Mr. Vilbert testified that the proposed allocation, without justification in his opinion, had the effect of increasing the rates for the 2003 Expansion shippers and lowering those for the Rolled-In system shippers. [297]

228. Mr. Vilbert testified that he found Kern River's rationale for allocating the blended cost of debt to all shippers/customers instead of maintaining separate interest costs not persuasive. First, although the two debt series relied on the same consolidated cash flows to make interest and principle payments, the amortization of the two debt series was structured to match the term on the contracts of the separate customer groups. The amortization and balloon payment of the Series B notes was based on the ten-year and fifteen-year contracts of the expansion shippers, not the blended contract term of all shippers. In addition, the two series of debt were clearly associated with the financing of separate facilities on the Kern River system and Kern River provided service to its 2003 Expansion shippers on an incremental cost basis. Second, according to Mr. Vilbert, the stronger average credit rating of the Rolled-In shippers did not play a significant role in the obtaining of a lower interest rate for the 2003 debt. In his opinion, the lower interest rate was primarily the result of a decrease in interest rates in the economy as a whole. He

[296] Ex. EME-1 at 1-2.
[297] *Kern River Gas Transmission Co.*, 90 FERC ¶ 61,124, order on reh'g, 91 FERC ¶ 61,103 (2000); Ex.EME-1 at 3-4.

testified further that the "pooling" or diversification effect of the cost of debt resulting from combining the revenues from additional investment grade shippers could not be attributed to any one set of shippers; rather, any pooling effect is the result of the presence of both sets of shippers. Third, Mr. Vilbert testified, nothing in the settlement of RP99-274 [298] stands for the principle that existing shippers should benefit from any lower interest rate in subsequent financing that they helped make possible, even if that had occurred. Finally, it would be unfair to charge the Expansion shippers incremental rates based on the stand-alone cost of debt only when debt costs were expected to be high, but to charge a blended debt cost only when the cost of incremental debt is less than the debt cost for existing shippers. [299]

High Desert

229. High Desert presented the testimony of Jeffrey L. Fink.

<u>JEFFRY L. FINK</u>

230. Jeffrey L. Fink is an independent consultant and provides consulting services on cost of service, cost allocation, rate design, regulatory policy, business strategy, tariffs, incentive rates, and litigation supports. Mr. Fink held various positions at Consolidated Gas Company over a twenty-eight period, including with the position of Vice President of Rates and Regulatory Affairs. Mr. Fink's testimony was on the issue of cost-of-service. [300]

231. Mr. Fink testified that Kern River provided firm transportation service to High Desert over a thirty-two mile, twenty-four inch lateral pipeline located in San Bernardino County, California. High Desert's agreement with Kern River was for a term of twenty-one years. High Desert pays an incremental cost-based recourse rate. The rate is a negotiated rate, which was essentially the recourse rate calculated on a levelized basis over the remaining term of the contract. Mr. Fink testified that High Desert should only have the 4.893% debt issue applied to it to calculate the overall ROE applied to the High Desert facilities. He testified that an incremental cost of service should only include the direct costs incurred to provide the incremental service, plus a reasonable allocation of general system costs. [301]

232. Mr. Fink testified that Kern River should not be allowed a 3% inflation factor. By

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[298] *Kern River Gas Transmission Co.,* 90 FERC ¶ 61,124, *order on reh'g, 91 FERC* ¶ 61,103 (2000); Ex EME-1 at 3-4.
[299] *Id*. at 6-18; Ex, EME-4 at 1-7.
[300] Ex. HD-1at 1-4.
[301] *Id*. at 10-14.

inflating O&M by 3% for a twenty-one year period, as would be the case for High Desert, the annual levelized cost of service is increased over what it would be without applying the inflation factor. Using the levelized cost of service from the original High Desert certificate application, Mr. Fink testified that the increase would be more than 25% of O&M expense. He testified that if Kern River finds in future years its rates are not sufficient to recover its O&M expense, it could file for a rate increase. Kern River should not be allowed to arbitrarily apply an inflation factor to test-period O&M. [302]

233. Mr. Fink testified that he eliminated expenses associated with negative salvage from his cost-of-service calculations. He testified that if the Commission did approve a negative salvage rate, then expenses applicable to High Desert should be recorded in a separate account and credited to High Desert rate base in future rate proceedings. If such amount exceeds what is necessary to abandon and remove the facilities, the excess amounts should be refunded to High Desert. [303]

Questar

234. Questar presented the testimony of Gary L. Robinson.

<u>GARY L. ROBINSON</u>

235. Gary L. Robinson is a Certified Public Accountant. He has over twenty-five years experience in rate case filings. Mr. Robinson testified that he did not agree with Kern River's proposal to use an EFV rate-design methodology, instead of the SFV method. Mr. Robinson also did not agree with Kern River's proposal to blend the two debt issuances. As to the SFV, Mr. Robinson testified that the Commission policy favored the SFV method, as recorded in Order 636. A party recommending deviation from the SFV method has a heavy burden of persuasion. [304] The Commission's rationale is that the SFV method encourages competition. As to the blending of the debt issuances, Mr. Robinson testified that his opinion was that a corollary to the rule that existing customers would not subsidize expansion shippers, is that expansion shippers will not have to subsidize existing customers. [305]

SCGC

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[302] *Id*. at 15-16.
[303] *Id*. at 17-18.
[304] *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation under Part 284 of the Commission's Regulations, Regulation of Natural Gas Pipelines after Partial Wellhead Decontrol*, FERC Stats. And Regs. 59 FERC ¶ 61,030 at 30,434 (1992).
[305] Ex. QGC-1at 1-7.

JACK N. JONES

236. SCGC presented the testimony of Jack N. Jones.

237. Jack N. Jones is a partner and founding member of Pendulum Energy, LLC. Pendulum Energy provides consulting service to the natural gas industry including rate and regulatory analysis. Mr. Jones has over thirty years experience in the natural gas industry, with a concentration in the regulatory and marketing areas. Mr. Jones stated that The Williams Companies and Reliant Energy, Inc., were not sponsoring his testimony. [306]

238. Mr. Jones testified that Kern River's levelized cost-of-service/ratemaking methodology had a number of flaws. First, Kern River reflected anticipated changes in its capitalization over the levelized period due to repayments of its existing debt. As a result, the ROE and associated income taxes were overstated when those changes that were anticipated do not occur. Second, Kern River arbitrarily equated the depreciation expense to be recovered under the levelization period to a level that approximates the principal payments associated with its long-term debt. As a result, the levelized rates recover an amount of depreciation expense over the levelized period that is not consistent with the depreciation expense that results from application of the approved depreciation rates over the same period. This accelerates recovery of depreciation expense that should be deferred for recovery until after the end of the levelization period. Third, according to Mr. Jones, Kern River's depreciation rate determination does not use the composite straight-line rate ("CSLR"). Mr. Jones testified that the CSLR is based on the overall remaining life estimated for the transmission facilities. He testified that Kern River was proposing an overall remaining life of 23.8 years, resulting in a CSLR of 3.39%. When that 3.39% is applied to each levelized period, the resulting remaining life varies from eighteen to twenty-nine years for each levelized vintage. Mr. Jones testified that an alternate methodology that he was proposing corrected that so that each levelized group or vintage CSLR is based on the same remaining life of 23.8 years. [307]

239. Mr. Jones gave a history of the levelized methodology in FERC ratemaking procedures, similar to that given by other witnesses. He observed that a primary problem with the Kern River levelization methodology was that the company's actual proportion of debt and equity capital had not changed as originally anticipated. When debt is paid off, capitalization will not be made up of 100% equity as was stated in Kern River's initial certificate application. Mr. Jones noted that many unanticipated changes had occurred since Kern River's initial rates were designed including, among other things:

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[306] Ex. SCGC-1 at 1-2 and attached resume of Jack N. Jones.
[307] *Id*. at 2-3.

the initial debt was retired and replaced with new issues; the pipeline changed ownership several times; and, there were expansions to serve new markets. According to Mr. Jones, that reflects the essential problem with levelized rates, which is that it is not feasible to forecast what a pipeline's actual capitalization will be ten to fifteen years in the future. [308]

240. Mr. Jones testified that a better alternative to Kern River's levelization methodology would be to use the test period capitalization for all future periods as it had done with Big Horn Lateral. If there should be future actual capitalization changes adversely affecting Kern River, the company could file a Section 4 rate case to protect its ROE. Mr. Jones noted that Kern River's capitalization had historically been fairly stable and there would possibly be little, if any, need for subsequent rate adjustments. Mr. Jones testified that another problem with Kern River's methodology is that Kern River allocates an overall depreciation expense to be recovered during the levelization period. He testified that the allocated overall depreciation expense was not based on the depreciation expense that would be incurred under its approved depreciation rates, but is based instead on the sinking fund requirements that Kern River associated with each of its six levelized vintages. This, according to Mr. Jones, is a carryover from the initially certificated rates that reflected a 70/30 debt/equity ratio. [309]

241. The term of the debt coincided with the life of Kern River's contracts. Mr. Jones testified that the Commission at that time required pipelines to design rates on the modified faxed variable ("MFV") method that recovered all fixed costs including debt costs in the demand rate. ROE and related income taxes were collected in the commodity rate. According to Mr. Jones, lenders considered a loan to be secured, to a large degree, by demand charges and underlying contracts, including the credit rating of a pipeline's customers. Pipelines were at a greater relative risk with the MFV given that a lot of revenue was placed at risk and was dependent on actual volume of flow than under the SFV method. The SFV method recovers all fixed costs including ROE and related taxes in the demand charge. He testified that accelerating depreciation expense to match the sinking fund requirements of the debt provided greater security in an MFV environment. This, according to Mr. Jones, presumably led to favorable terms in the debt covenants. Mr. Jones testified that Kern River accelerated depreciation expense by allocation about 70% of its debt cost to be recovered during the levelized periods. Mr. Jones testified that this misallocation resulted in the overstatement of depreciation expense during the initial levelized periods, which in turn leads to higher levelized rates. However, according to Mr. Jones, Commission policy is that depreciation is based on the useful remaining life of facilities and not on financial considerations. In other words, depreciation should not be based on debt recovery, according to Mr. Jones. [310]

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[308] Ex. SCGC-at 2-10.
[309] *Id.* 11.
[310] *Id*. at 11-13.

242. Mr. Jones testified that because Kern River had multiple levelized vintages with each having a different amount of net depreciable plant, applying a single composite rate (i.e.,. Kern River's proposed 3.39%) would distort the remaining life associated with each vintage. He testified that Kern River's approach shortens and, therefore, increased the Original Shippers' depreciation expense, while decreasing that for the 2002 and 2003 Expansion shippers. Therefore, according to Mr. Jones, Kern River should apply a depreciation expense for each levelized period based on each vintage's pro rata share of the depreciation expense based on net remaining life rather than a system-wide percentage. [311]

ISSUES/POSITIONS/CONCLUSIONS/DISCUSSION

I. Cost-of-Service/Ratemaking Methodology

A. Levelized Versus Traditional

243. ISSUE -- Levelized cost-of-service/ratemaking methodology

244. POSITIONS - - The position of Kern River is that its levelized cost-of-service/ratemaking methodology produces just and reasonable rates. Kern River argues that its levelized methodology allows it to meet the demands of California's EOR producers for the lowest transportation rate achievable while still maintaining the ability to cover its debt costs, recoup its operating expenses, and earn a fair return on its equity investment. Kern River states that its levelized methodology has produced many customer benefits, including: lower return requirements due to rate base averaging in the levelization calculations; declines in rate base each year of the levelization periods; high debt capitalization and lower early years of the contracts; no recovery of equity investment until after the contracts expire; and voluntary use of the *Ozark* methodology to depress the equity component of capitalization in the cost-of- service calculations. Kern River claims its financing arrangements are partly based on its levelized cost-of-service/ratemaking methodology for setting rates. Kern River acknowledges its levelization models are complex, but claims they are relatively user friendly. Kern River denies that its levelization methodology causes an over-recovery of debt costs. [312]

245. The position of Staff is that Kern River should use the traditional cost-of-service/ratemaking methodology in order to set rates that are just and reasonable. Staff argues that Kern River's levelization methodology is overly complex and no longer

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[311] *Id*. at 13-17.

[312] Kern River Initial Brief ("KR IB") at 3-13 and Kern River Reply Brief ("KR RB") at 2-4.

produces just and reasonable rates. Staff argues that while designing transportation rates to recover a large portion of plant investment over initial contract lives may have been appropriate when the initial certificate rates were established, those short-lived contracts are no longer a just and reasonable basis for establishing the depreciation rates that underlie the transportation rates for Kern River's existing and future shippers. Staff contends that Kern River's failure to retire its debt after fifteen years and thereby have the project capitalized with 100% equity means that another generation of Kern River shippers will be burdened with that debt. Staff also contends that Kern River over-collects an average of $42,590,732 in depreciation expense annually from its ten-year and fifteen-year shippers because the regulatory depreciation rate is more than double the book depreciation rate. Staff posits Kern River is entitled to no presumption of reasonableness of its levelized cost-of-service/ratemaking methodology because the Commission has not considered the methodology in a Section 4 rate case before now. Moreover, the levelization methodology model Kern River presented in the subject Section 4 case, according to Staff, is not the model Kern River presented in the certification proceedings; it has been changed several times since certification. [313]

246. The position of Staff is further that other versions of the levelized methodology offered by Participants in this proceeding do not meet the just and reasonable standard either. RCG's annuity proposed levelized rate design does not overcome the problems with Kern River's levelization methodology and is, according to Staff, inferior to Kern River's and less likely to produce just and reasonable rates for all shippers than would the traditional methodology. Staff contends that the SCGC and High Desert proposed versions have problems similar to RCG's. [314]

247. The position of BP is that Kern River should use the traditional cost-of-service/ratemaking methodology. BP argues that Kern River's levelized cost-of-service/ratemaking methodology does not produce just and reasonable rates. BP argues that Kern River's methodology harms shippers. The methodology does not promote rate stability and its use results in about a $100 million over-collection of depreciation expense. BP's arguments were otherwise similar to Staff's. [315]

248. The position of RCG is that Kern River should use an annuity levelized cost-of-service/ratemaking methodology which, according to RCG, corrects the alleged over-recovery of depreciation problem with Kern River's methodology. RCG maintains that Kern River's levelized methodology does not produce just and reasonable rates. RCG otherwise makes arguments similar to those of Staff and BP. [316]

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[313] Staff Initial Brief ("Staff IB") at 3-7.
[314] Staff IB at 5-7.
[315] BP Initial Brief ("BP IB") at 2-10.
[316] RCG Initial Brief ("RCG IB") at 5-10.

249. The position of SCGC is that Kern River should use a levelized cost-of-service/ratemaking methodology with modifications in the areas of capitalization and depreciation expense allocable to the different groups of facilities. SCGC maintains that Kern River's methodology does not produce just and reasonable rates. SCGC otherwise makes arguments similar to those of Staff, BP, and RCG. [317]

250. The position of High Desert is that Kern River's levelized cost-of-service/ratemaking methodology is appropriate as applied to it. High Desert points out that its rates are already based on the traditional methodology. [318]

251. Pinnacle West supports Staff's position. [319]

252. Edison Mission and Questar take no position on this issue.

253. CONCLUSIONS -- Kern River has carried its burden of proving that its levelized cost-of-service/ratemaking methodology can produce just and reasonable rates. However, Kern River has not proven that its levelized methodology will produce just and reasonable rates if all of its proposed cost-of-service and cost-allocation elements are approved.

254. DISCUSSION_ -- Kern River's levelized methodology has not been tested in a Section 4 rate proceeding before the instant case. [320] Section 4's "just and reasonable" standard is more exacting than Section 7's "public convenience and necessity" standard. [321] Determining what is "just and reasonable" standard is pragmatic and involves balancing consumer and investor interests. There is no one formula for making the just and reasonable determination.[322]

255. The Commission has found that levelized cost-of-service/ratemaking methodology

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[317] SCGC Initial Brief ("SCGC IB") at 6-10.
[318] High Desert Power Trust Initial Brief ("HD IB") 8-10; High Desert Power Trust Reply Brief ("HD RB") at 4.
[319] Pinnacle West Capital Corporation Initial Brief ("Pinnacle West IB") at 5; Pinnacle West Capital Corporation Reply Brief ("Pinnacle West RB") at 3.
[320] Initial Decision ¶¶ 12, 17, 20, 23 and 29 (***Note: references to "Initial Decision" refer to the Initial Decision in this proceeding and includes the content of applicable material cited in the referenced paragraphs and in the footnotes of the referenced paragraphs).**
[321] 15 U.S.C. §§ 717c(a) and 717f(e)(2005).
[322] *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 602-03.

designs can produce just and reasonable rates. [323] The Commission observed that the levelized methodology is an innovative ratemaking methodology, designed to shift costs away from a pipeline's early years of operation. [324] The Commission further observed that the levelization concept allowed for rate stability and predictability and, thereby, provided better opportunity for planning for both pipelines and their customers. [325]

256. Kern River's levelized cost-of-service/ratemaking methodology is "depreciation-based." That methodology relies on varying the annual depreciation expense to arrive at equal cost-of-service for each year of the levelized period. Initial depreciation-based levelized rates are lower than are traditional cost-of-service/ratemaking beginning rates. This keeps initial rates from being prohibitive to pipeline customers and promotes the construction of new pipelines. Kern River has used its levelized methodology and has done so since initiation of operation of the pipeline, with modifications to its levelized models to accommodate various events and Kern River seeks further modifications in the subject rate case. [326] Even if there is no presumption in favor of continuing its levelized methodology, the fact that the methodology was approved in OEC proceedings and four later settlements is of some weight as to the legitimacy of the methodology. Moreover, Participants identified no case where the Commission has required a pipeline to change from the use of a levelized methodology to a traditional methodology in order to produce just and reasonable rates.

257. Kern River's levelized cost-of-service/ratemaking levelized methodology has achieved the goal of lower initial rates, an obvious benefit to shippers. Using the 45-day update data in this case, Staff's proposed traditional cost-of-service/ratemaking methodology would cost $38.6 million more than does application of Kern River's levelized methodology. [327] Nor was there proof that application of the levelized methodologies proposed by RCG and SCGC yielded more favorable rates than did Kern River's methodology. [328]

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[323] *Sabine Pass LNG, L.P.* and *Cheniere Sabine Pass Pipeline Co.*, 109 FERC ¶ 61,324 (2004) at 62,548.

[324] *Mojave Pipeline Co.*, Order Granting Rehearing in Part, Denying Rehearing in Part and Modifying Prior Order, 70 FERC ¶ 61,296 (1995) at 61,863, citing, *Sunshine Interstate Transmission Co.*, 67 FERC ¶ 61,200 (1994) and *Pacific Gas Transmission Co.*, 70 FERC ¶ 61,016 (1995).

[325] *Wyoming-California Pipeline Co.*, 44 FERC ¶ 61,001 (1988).

[326] Initial Decision ¶¶ 21, 23, 25, 28, 29, 31, 36, 43, 44, and 180.

[327] Initial Decision ¶ 55.

[328] Initial Decision ¶¶ 101-02, 180, 206-07, and 246.

258. Participants' claims of "over-recovery" or "over-collection" of depreciation expense, are not legitimate. Kern River keeps track of deprecation recovered from ratepayers in a reserve account. As depreciation expenses are projected to be recovered each levelized year, Kern River recognized collection in accumulated depreciation and an appropriate adjustment is made to rate base. This comports with the ASOA, which does not allow for "over-recovery" or "over-collection." [329]

259. Kern River's statements that if its "package" is not approved, then the Undersigned should order it to convert to the traditional cost-of-service/ratemaking methodology will not be considered. Kern River did not file this rate case based on the traditional cost-of-service/ratemaking methodology. [330] The Undersigned considered the rate case Kern River filed.

260. Section 4 [331] places the burden on the filing pipeline of proving that proposed rates are just and reasonable. Section 5 [332] places the burden of proof on the Commission or others proposing different rates, to show that the proposed rates are not just and reasonable and that those they would substitute are. Section 4(e) may not be used by the Commission to institute any change in a ratemaking component. However, the Commission may make changes pursuant to Section 5 in a proceeding that began as a Section 4 rate case. [333] The Commission has authority to investigate all aspects of the rates and to order changes, even to rate provisions that a company does not ask to be changed, if the ordered changes are needed to produce just and reasonable rates. [334] The Undersigned is unable to find Kern River's "package" produces just and reasonable rates. The problems are apparent in the discussion below of other contested issues.

II. Cost-of-Service Elements

A. Cost of Capital

1. Rate of return on equity ("ROE")

261. ISSUE -- Appropriate proxy group

262. POSITIONS -- Kern River proposes a ROE of 15.1%. Kern River's proxy

[329] 18 C.F.R. Part 101 (2005).
[330] Initial Decision ¶¶ 21 and 28.
[331] 15 U.S.C. § 717c.
[332] 15 U.S.C. § 717d.
[333] *Tennessee Gas Pipeline Co. v. FERC*, 860 F.2d 446 at 453-54 (1988).
[334] *Ozark Gas Transmission System*, 41 FERC 61,207 at 61,567 (1987), *citations omitted.*

group, chosen by Kern River witness Dr. Olson, included: Enterprise Products Partners; Gulfterra Energy Partner's L.P.; KinderMorgan Energy Partners; Kinder Morgan, Inc.; Northern Border Partners; and, Williams Companies. Kern River's proxy group includes some companies that own oil pipeline assets and some that are MLPs. The companies chosen are primarily involved in the pipeline processing and storage business. Because Dr. Olson believes companies with extensive residential and small commercial customer bases, and those with high percentages of retail electric or companies have much lower risk than does Kern River, he did not include any in the proxy group he chose for Kern River. [335]

263. Dr. Olson was aware of the Commission's decision in *HIOS*, rendered after he selected his proxy group companies, but concluded that *HIOS*-approved companies were not appropriate proxy companies for Kern River because Kern River had no downstream operations as did three of the *HIOS* companies (i.e., Equitable, National Fuel, and Questar). Dr. Olson was aware that the Commission in *HIOS* stated that it would not consider including MLPs in a proxy group unless it was clear that the MLP distribution did not include a return of investments, but was only a payment of earnings. Dr. Olson made no representation that the distributions made by MLPs in the Kern River proxy group only included earnings and not a return of investments. Dr. Olson argued, however, that through the use of a distribution yield and IBES growth rates, capital projections for MLPs can be as representative of investor expectations as those derived using corporation dividend yields. Nor was Dr. Olson concerned that MLPs did not pay federal income taxes. His position, on behalf of Kern River, is that use of MLPs in the Kern River proxy group does not inflate the cost of equity. His position is that using LDC and low-risk electric utility companies as proxy companies produces a far greater downward distortion to the DCF analysis than any upward bias that would result from use of MLPs. [336]

264. Staff proposes a ROE of 9.0%. Staff's proxy group was chosen by Staff witness Mr. Ekzarkhov and included nine companies: CenterPoint Energy; Dominion Resources; Duke Energy; El Paso Corporation; Entergy, Inc.; KinderMorgan, Inc; National Fuel Gas; NiSource, Inc.; and Williams Company. Mr. Ekzarkhov testified that only two of the four proxy-group companies that the Commission had used in the initial *Williston Basin* case and several others were currently suitable. Those *Williston Basin* companies Mr. Ekzarkhov identified as suitable were El Paso and Williams. According to Mr. Ekzarkhov, three of the nine *Williston Basin* proxy-group companies were no longer in business. [337]

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[335] Initial Decision at ¶¶ 92-93; KR IB at 12-14.
[336] Initial Decision at ¶¶ 94-95.
[337] *Id*. at ¶¶ 152- 53.

265. In light of the changes in the gas industry, Staff developed proxy-group company criteria it believes appropriate for use in the DCF analysis in this rate case: 1) have publicly-traded common stock; 2) own 100% of a major FERC-regulated natural gas pipeline; and, 3) derive 50% or more of its operating earnings from a regulated energy-related line of business, including the distribution of natural gas and/or the transmission and distribution of electricity, in addition to the transmission of natural gas. Staff's position is that inclusion of MLPs is not appropriate because that produces estimates of costs of equity that are unreasonably high relative to the cost of equity estimates produced by a DCF analysis using corporations. Staff believes its three-prong set of criteria is a preferable method of addressing the limited number of gas pipeline companies still available for inclusion, Staff noted that the Commission in *Williston Basin* would not include electric utility companies in the proxy group, but also noted that the Commission observed in *HIOS* that the significant changes in the natural gas industry invited a reexamination of its policy. Staff pointed out that S&P's *Utilities and Perspectives* shows that companies in different industries can have similar credit ratings and business profile scores. [338]

266. BP proposes a ROE of 9.34%. BP's proxy group, chosen by BP witness Ms. Crowe, is the same proxy group used by the Commission in *Williston Basin*, [339] adjusted for mergers, sales, and consolidations that have occurred since the *Williston Basin* decision. The companies in BP's proxy group are: El Paso; Equitable; KMI; NFG; Questar; and Williams. BP's position is that Kern River's inclusion of MLP's and companies operating oil pipelines conflicts with *HIOS* and the position of Kern River's witness in other proceedings. BP states that the Commission held in *Equitrans, L.P.*, [340] that oil pipelines operate in a very different regulatory and contract environment than do gas pipelines. BP's position is that Dr. Olson's explanation that Kern River's proxy companies have oil pipeline assets, but are not oil pipeline companies and, therefore, are different, was not persuasive. [341]

267. RCG proposes a ROE of 9.4%. RCG's proxy group, chosen by RCG witness Mr. Parcell, includes: CenterPoint Energy; Dominion Resources; Duke Energy; Equitable Resources; National Fuel Gas; NiSource; and, Questar. Those proxy-group companies, according to RCG, are similar to those in Staff's proxy group in this proceeding and to one the Commission recently approved in *Petal Gas Storage, L.L.C.* [342] RGC argues that including MLPs in a proxy group has the effect of artificially increasing

[338] *Id*. at ¶ 156 and Staff IB at 14-17.
[339] *Williston Basin Interstate Pipeline Co.*, 104 FERC ¶ 61,063 (2003).
[340] *Equitrans, L.P.*, 80 FERC ¶ 61,144 at 61,562 (1997), *reh'g*, 81 FERC ¶ 61,030 (1997).
[341] Initial Decision at ¶¶ 213-15; BP IB at 1-4, 15; BP Reply Brief at 14 -18.
[342] 97 FERC ¶ 61,097 at 61,519(2001), *order amending certificate*, 100 FERC ¶61,100 (2002).

the range of returns. [343]

268. While Edison Mission does not propose a specific ROE, it argues that Kern River's ROE is unreasonably inflated due to the presence of MLPs in its proxy group. EME also argues that Kern River's proxy group does not comport with *HIOS*. Edison Mission argues that *HIOS* allows inclusion of LDCs in gas pipeline proxy groups. [344]

269. Calpine, High Desert SCGC, Pinnacle West and Questar take no position on this issue.

270. CONCLUSIONS -- Kern River did not carry its burden of proving that the proxy group it used, which included MLPs, would produce just and reasonable rates. Inclusion of MLPs unreasonably inflates ROE. Staff's inclusion of LDCs in its proxy group, on the other hand, understates ROE. The BP proxy group, based on *Williston Basin*, does produce just and reasonable rates.

271. DISCUSSION -- To determine a gas pipeline's rate of return on common equity or ROE, the Commission first determines a "zone of reasonableness." The zone of reasonableness gauges returns experienced in the industry. This is usually done by reference to a proxy group of publicly-traded companies for which market data is available. The Commission has found the two-step DCF analysis to be the preferable methodology for determining ROE for natural gas pipelines. The DCF methodology projects investor long-term growth expectations by adding average dividend yields to estimated constant growth in future dividends. [345] 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 rise. Under the DCF formula, the cost of capital is equated with the dividend yield plus the estimated constant growth in dividends to be reflected in capital appreciation. [346]

272. Since Kern River is not publicly traded, the DCF analysis requires use of a proxy group of companies whose risks are considered to be similar to those of Kern River. All Participants responding to the issue of appropriate proxy group for Kern River object to Kern River's inclusion of MLPs in its proxy group. [347] Their objection is well-taken. MLPs in gas pipeline proxy groups cause dividend yields to be inordinately high. In this

[343] Initial Decision ¶¶ 165 and 171-73.
[344] EME IB at 4-6 and EME RB at 4-7.
[345] *Williston Basin Interstate Pipeline Co. v. FERC*, 165 F.3d 54 at 57 (D.C. Cir. 1999) (*citation omitted)*.
[346] *HIOS*, 110 FERC ¶ 61,043 at 61,155 and *Williston Basin*, 104 FERC ¶ 61,036 at 61,099
[347] Initial Decision at ¶¶ 153, 174, 213, 265-68, and *HIOS*, 107 ¶ 63,019 at 65,108 (2004).

case, the dividend yields resulting from Kern River's inclusion of MLPs in its proxy group, are more than double the yields of Staff or other *Williston Basin*-based proxy group yields. [348] The Commission, thus far, has only permitted the use of MLPs in oil pipeline rate cases after conclusion that MLPs were the only companies available to be included in oil pipeline proxy groups. [349] The Commission has not, that the Undersigned is able to determine, yet expressed that regarding gas pipelines.

273. In addition, Kern River cannot be found to have carried its burden of proving that the proxy group it used would produce just and reasonable rates because it produced no evidence that the distributions of the MLPs excluded a return of capital. The Commission held in *HIOS* that it would not consider including an MLP in a proxy group, unless the record clearly showed that the distribution used as the "dividend" in the DCF formula was only a payment of earnings and not a return of investment. The inquiry regarding appropriateness of including MLPs in a gas pipeline proxy group ends when it is determined that the record lacked evidence as to whether dividend amounts included a return of capital. [350] In the instant case, although Kern River's witness said he was familiar with the *HIOS* decision's pronouncements on MLPs in gas pipeline proxy groups, he offered no evidence about whether the MLPs he included in the proposed Kern River proxy group included a return of capital in their distributions. He, rather, attempted an argument about how capital projections for MLPs can be as representative of investor expectations as those derived using corporation dividend yields. [351] Therefore, Kern River did not meet the *HIOS* requirement of proving that the "dividends" of MLPs in its proxy group did not include a return of capital.

274. Staff was not persuasive on the legitimacy of expanding the proxy group to include companies holding significant state-regulated LDCs and/or significant retail electric utility assets rendering them low-risk utilities. Kern River's markets include merchant electric generators and EOR operations, not monopoly franchises. No Participant challenged Kern River's assertion that LDCs and retail electric utilities are able to attract capital at lower cost than the more risky gas transmission utilities like Kern River. [352] The Commission observed in *HIOS* that, as changes continue to occur in the natural gas industry, it may be that companies with significant distribution functions would not automatically be disqualified from inclusion in pipeline-oriented proxy groups. [353] However, the Undersigned is not persuaded that there is enough evidence on this record from which to conclude that the LDCs and electric companies in Staff's proxy

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[348] Initial Decision at ¶ 153.
[349] *HIOS*, 110 FERC ¶ 61,043 at 61,157 (2005).
[350] *Id*.
[351] Initial Decision at ¶¶ 94-95.
[352] Initial Decision at ¶¶ 89 and 92.
[353] *HIOS*, 110 FERC ¶ 61,043 at P 131.

groups have evolved to the point that they may be considered to have risk comparable to that of Kern River. [354]

275. The Undersigned finds that BP has presented persuasive evidence that its proxy group is an appropriate Kern River proxy group. [355] BP adjusted for mergers, sales, and consolidations in the nine-company *Williston Basin* proxy group, to arrive at the six natural gas companies it used. The six companies are publicly-traded. Two of them, KinderMorgan and Williams Companies, are included in the Kern River's and Staff's proxy groups. Two other companies, El Paso and National fuel, are also Staff proxy group companies. Further evidence of the reasonableness of BP's proxy group, is the fact that Staff used the same six-company *Williston Basin* proxy group to double check the accuracy of its nine-company proxy group and came up with similar results. However, as noted, Staff used the lower-risk LDCs and electric utilities which the Commission excluded in *Williston Basin*. [356]

276. ISSUE -- Position in zone of reasonableness.

277. POSITIONS - - The position of Kern River is that it should be placed at the high end of the zone of reasonableness because it has extraordinary financial and business risks. Kern River pointed out that it has a highly-leveraged capital structure. Using levelized rates results in relatively thin equity capitalization. Kern River claims that its shippers are poor credit risks and that the low supply of gas is further aggravated by the intense competition for that limited supply. [357]

278. Kern River concedes that all pipelines have high fixed costs, but claims that Kern River's relatively short life span, as compared to that of other pipelines, means that very little of its capital investment has been recovered in rates (i.e., via depreciation rates). Older pipelines have already recovered a large percentage of their capital investment so that those companies have relatively few capital dollars still at risk. Kern River also points out that its levelized ratemaking formula exacerbates the problem because it delays recovery of its capital investment through the creation of a regulatory asset. [358]

279. Kern River argues that its shippers are worse credit risks than those of other companies and that opposing Participants had not rebutted that claim. Kern River claims that it is disadvantaged because it had been originally built to primarily serve the

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[354] *See Williston Basin* 104 FERC ¶ 61,036 at 61,104.
[355] Initial Decision ¶¶ 214, 215, and 266.
[356] Ex. BP-1 at 15; BP-21; KR-108 at 4; S-10, Schedules No. 3, p.2; S-10 at 35-37; *Williston Basin* 104 FERC ¶ 61,036 at 61,104.
[357] KR IB at 15-16.
[358] Ex. KR-10 at 5.

California EOR markets. According to Kern River, other pipelines were built to primarily serve regulated LDC's which largely serve retail customers. In addition, the newer markets that have developed on Kern River were largely in the electric generation sector and that sector has been undergoing wide-spread upheaval due to rising gas prices. This has led to financial problems for Kern River shippers. The marginal status of Kern River's merchant generation shipper customers had been reported in S&P's *Utilities Report* of February 26, 2004; merchant generators, a large number of Kern River's shippers, are especially susceptible to gas price increases. Kern River pointed to the bankruptcy of Mirant and its subsequent return of capacity to Kern River. Kern River claims that a forecasted upsurge in coal use and of liquefied natural gas ("LNG") also threatened Kern River shippers, leading to lower credit ratings for Kern River. Lower credit ratings for Kern River's shippers mean higher financing costs for Kern River. [359]

280. Kern River acknowledged that it had a policy in place to address the creditworthiness of its shippers. Its policy is that shippers with a credit rating lower than BBB- for S&P or Baa3 for Moody's must provide one of the following three credit supports: 1) a guaranty from an investment grade third party; 2) a letter of credit equal to the amount of reservation charges for one year; or 3) cash collateral equal to the amount of reservation charges for one year. The higher concentration of firm capacity subscribed by electric generation shippers and changes in the electric industry affected the credit quality of Kern River's shippers. Kern River's credit exposure was affected by the assignments or terminations of contracts and/or resale of capacity held by shippers that had become unable to provide the required credit support. Kern River identified ten shippers as presenting credit issues and particularly noted that it had been unable to resell Mirant's long-term service turn-back capacity even after holding several open seasons. Kern River indicated that between conclusion of the open season for the 2003 Expansion Project and the May 1, 2003 in-service date of that project, six shippers representing about 26% of the total system capacity needed to reestablish creditworthiness due to credit rating downgrades. By the time rebuttal testimony was filed in this case, Kern River claimed that over one-third of Kern River's firm-capacity shippers required credit support. [360]

281. Kern River pointed out that "debt service risk" had to be distinguished from "equity-related risk." Kern River acknowledged that its debt was secure because of its historic ability to keep throughput at levels that provided necessary debt-service coverage despite the credit problems of its shippers. Kern River argues that the equity-related risk, on the other hand, is that the authorized ROE will not be earned because of unsubscribed throughput or will have to be sold at less than prevailing contract prices. Kern River acknowledges that the cost of equity is estimated using a combination of a cash return

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[359] *Id*. at 8-12.
[360] Initial Decision ¶¶ 82-84.

(the dividend yield) to the equity investor and expected growth of a company's earnings. Kern River denies, however, that bond ratings are of much concern to investors in project-financed ventures like Kern River. Moreover, Kern River pointed out, S&P projections had not withstood the test of time as Kern River has not obtained new long-term contracts and has no plans to expand. [361]

282. The position of Staff is that Kern River's risks are in the average range and that placement at the high end of the zone of reasonableness is not warranted. Staff argues that Kern River did not fully consider investors' risk perceptions, but instead simply identified a subjective list of risk factors it claims affects the company and then concludes that Kern River was the riskiest pipeline in the lower forty-eight states. Staff argues that Kern River gave no good reason for its discounting of S&P research as a proxy for the risk perception of investors; S&P's opinion should certainly be considered more valid and objective than that of Kern River's witness. Staff pointed out that Kern River's witness had consistently used bond ratings in ROE testimony he gave in other ratemaking proceedings. Staff argues that Kern River's A- bond rating, a rating higher than all but one gas pipeline in the United States, is an important tool in assessing Kern River's risk. Staff also noted S&P gave Kern River a business profile score of three on a scale of one-to-ten, with ten being the greatest risk. Therefore, according to Staff, Kern River could hardly be thought to present a great risk when its credit and business ratings were so high. [362] He concluded that Kern River had no more risk than the companies in Staff's proxy group.

283. The position of BP is that Kern River does not have a significant risk. BP contends that Kern River's claims that the credit quality of its shippers places it at a significant risk vis-à-vis other pipelines is misleading because Kern River did not disclose important credit support and multi-layered protections it has. BP points out that no coal-fired generation facilities are currently under construction in California and that demand for new peaking units, which are fired by gas, is growing. BP also points out that Kern River's claims about its risk of cancellation or non-renewal of contracts is a risk faced by every pipeline and is not unique to Kern River. BP argued that Kern River's market area is booming, the pipeline itself had projected significant future load growth, its supply basin was prolific, and that it had historically operated at very high load factors. BP argues that Kern River's claim that Mirant's bankruptcy is evidence of its increased risk is not valid. BP states that the bankruptcy court had recognized a general, unsecured Kern River claim for $74 million in damages against the Mirant estate and that more gas-fired capacity is being built on Mirant's property. BP concluded that Kern River is well-positioned in both supply and demand markets, enjoys a favorable competitive position with respect to other pipelines serving some of the same markets,

[361] Ex. KR-107 at 17-26; Tr. 456-58 and 568-75.
[362] Ex. Staff IB at 24-28; Staff RB at 18-20.

has maintained a 100% load factor for the past ten years, has had good credit ratings since it had been acquired by MEHC, and has a level of long-term firm contracts that is unusual in today's gas transportation markets. BP maintains that Kern River could reduce its alleged risk considerably if it would: 1) adopt a traditional cost of service and rate structure with a three-year average rate base; 2) move to a straight-fixed variable rate design; and 3) exclude the 90,000Dth/d of Mirant capacity from its billing determinants. BP's position is that Kern River's risks were not abnormally high and that it should be placed in the median of the DCF range of equity returns. [363]

284. The position of RCG is that Kern River is not a high risk pipeline and that it should be placed no higher than the median of the RCG range of reasonableness, resulting in a ROE of 9.4%. RCG argues that even a conclusion that Kern River has median risk is generous to Kern River because the record shows that Kern River has the second highest credit rating out of the twenty-eight major interstate pipelines. RCG argues that Kern River's risk profile is low risk because: 1) it has an A- credit rating from S&P and an A3 rating from Moody's; 2) it has long-term contracts, of which only five of fifty-three expire in 2011 or before; 3) its capacity is almost 100% contracted and it operates at a very high load factor; 4) its market area is experiencing high growth and demand; 6) and, it faces little competition from other energy sources. RCG points out that the testimony of Kern River's ROE witness, Dr. Olson, is not credible because: 1) he had not performed any analysis of contract expiration dates, load factor, abundance of gas supply in the receipt basin, or abundance of demand in its delivery market; 2) he admitted he had not considered the credit risks of other pipeline companies in coming to a conclusion that Kern River's customers were less creditworthy than those of other pipeline companies; 3) and, Dr. Olson included inappropriate companies in his proxy group. [364]

285. RCG also argues that Kern River is incorrect in its claims that Participants offered no evidence which contradicted its claims about the severity of risk factors specific to Kern River. RCG argues that it is not necessary to address and evaluate each risk factor Kern River claims it has because the independent rating agencies have already done the evaluating. According to RCG, the Commission approved a capital structure similar to highly-leveraged capital structure provided for in this proceeding in Kern River's original certificate orders which placed Kern River at the median. RCG argues that Kern River provided no evidence that natural gas commodity prices are higher on its pipeline than on others, and the fact that the price of natural gas has increased does not impact Kern River any more detrimentally than it does other pipelines. RCG notes the lack of evidence of gas use displacement by coal. RCG argues that Kern River's inability to generate interest in a new expansion project could be explained by factors having nothing to do with risk.

[363] Ex. BP IB at 16-20 and BP RB at 18.
[364] RCG IB at 19-22.

RCG further noted that Kern River relied on a forecast of huge growth in the Rocky Mountain supply basin for purposes of justifying its 2003 expansion and should be stopped from claiming a lack of supply now. [365]

286. The position of Calpine is that Kern River has one of the least risky pipelines and that its ROE should reflect its low risk profile. Calpine argues that Kern River's claims of extraordinary risk are not supported by the evidence. Calpine points out that S&P has characterized merchant generators and natural gas producers as posing similar levels of risk, so that Kern River's claim that it has a high level of merchant generators as customers increases its risk, is contradicted by objective industry analysis. Calpine further contends that Kern River's own analysis shows that demand supports each Kern River shipper contract, that the vast majority of Kern River's fixed costs are through demand charges, and that Kern River has greatly exaggerated the credit quality issues of its shippers. [366]

287. The position of Edison is that Kern River is one of the most financially stable major pipelines in the United States. It is, according to Edison, a "textbook example" of a low risk pipeline and, at most, could only be considered an average-risk pipeline. Edison argues that Kern River shines in all of the factors the Commission considers in determining a pipeline's risk. Edison points out that Kern River has maintained an annual load factor of greater than 100% for the past ten years and that the weighted average term of Kern River's firm contracts is twelve years. Edison points out that Kern River serves a growing population area and is connected to the only production basin in the country in which growth is anticipated. Kern River also has a credit rating that is only surpassed by one other pipeline. Edison notes that there is not one coal-fired generation construction project underway in California. Edison claims that any risks Kern River has by virtue of having a high percentage of merchant generation load and a low percentage of LDC load, are offset by the fact the Kern River has its capacity locked up in long-term contracts. Edison also points out that Kern River did not consider the relative risk of other pipelines in each of the factors considered by the Commission in coming to the conclusion that Kern River is most risky. Finally, Edison points out that Kern River itself has indicated to independent auditors that it has protected its interests by requiring its non-investment grade customers to provide cash deposits or letters of credit. [367]

288. High Desert, SCGC, Pinnacle West, and Questar do not take a position on this issue.

[365] RCG RB at 15-17.
[366] CES RB at 10-11.
[367] Edison Mission IB at 7-15 and Edison Mission RB at 11-12.

289. CONCLUSIONS -- Kern River did not carry its burden of proving that it should be placed at the high end of the zone of reasonableness. The evidence shows that Kern River should be at the median, or broad range of average risk.

290. DISCUSSION -- Under Commission policy, after defining the zone of reasonableness through development of the appropriate proxy group for a gas pipeline, it is then necessary to assign the pipeline a rate within that range or zone, to reflect specific risks of that specific pipeline as compared to the proxy group companies.[368] The Commission presumes that existing pipelines fall within a broad range of average risk. A pipeline would have to show highly unusual circumstances existed in order to avoid the presumption.[369] Kern River does not show such "highly unusual circumstances;" the pipeline, hence, does not carry its burden of proving that it should be placed at the high end of the zone of reasonableness. Kern River argued that its thin capital structure was a problem. It argued that its risk was unique due to the poor creditworthiness of its shippers. It also argued it had risk due to dwindling gas supply and competition for customers, and competition from other energy sources. Kern River also, contrary to every Participant weighing in on the issue and to most investors, concluded that data contained in publications of such sources of financial information as Moody's and S&P on credit and business risk could not be relied on to provide meaningful information on the financial status of a pipeline[370] (except when it wants to rely on an S&P report on merchant generators that it believes supports one of its arguments[371]).

291. Participants' opposition to Kern River's assessment of its risk is better supported and more persuasive as the discussion in the immediately preceding paragraphs make abundantly clear.[372] Participants are quite convincing in making the points, among others, that Kern River has: great credit ratings, good supply and demand, impressive number of firm contracts, little risk from the Mirant bankruptcy, and otherwise shows no extraordinary risk. It is especially telling that although Kern River claims to be the most risky pipeline, its witness admitted he had not done a study of the credit risks of the pipelines in the Kern River proxy group.[373] Therefore, it seems he is not in a position to make the comparison which could lead to a conclusion of Kern River's risk vis-à-vis that of other gas pipelines.

292. The lawful return on equity in this proceeding is 9.34% as calculated by the BP witness Crowe. Her proxy group and DCF calculations that result in a median return on

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[368] *Williston Basin Interstate Pipeline Co. v. FERC*, 165 F.3d 54 at 57 (*citation omitted*).
[369] *Petal Gas Storage*, 106 FERC ¶ 61,325 at 62,282 (2004).
[370] Initial Decision at ¶¶ 26, 96, 156, 170, 175, 263, 281-84, and 286.
[371] Initial Decision ¶ 279.
[372] Initial Decision at ¶¶ 282-87.
[373] Tr. 418-21, 426, 437 and 440-41.

equity of 9.34% are reproduced as follows:

Kern River Pipeline Company
Docket No. RP04-274
BP Energy Proxy Companies and DCF Calculation

Company	Symbol	Dividend Yield	5 Year Analyst Growth Estimate	Estimated GDP Growth Rate	Weighted Avg. Growth	Adjusted Dividend Yield	Yield Plus Growth
El Paso Corp.	EP	1.95%	6.00%	5.83%	5.31%	2.00%	7.31%
Equitable Resources	EQT	2.90%	10.00%	5.83%	8.64%	3.02%	11.66%
Kinder Morgan, Inc.	KMI	3.68%	11.70%	5.83%	9.78%	3.84%	13.62%
National Fuel Gas	NFG	4.20%	4.00%	5.83%	4.54%	4.39%	8.94%
Questar	STR	2.00%	8.50%	5.83%	7.64%	2.10%	9.75%
Williams Cos.	WMB	0.33%	7.60%	5.83%	6.98%	0.34%	7.32%
						Mean	9.76%
						Median	9.34%
						High	13.62%
						Low	7.31%

Source: Yahoo Finance, http://finance.yahoo.com

[374] Note that Dr. Olson proposes a ROE of 15.1% for Kern River, a regulated enterprise, while his DCF analysis shows a ROE of 13.6% for its highest proxy company, Kinder Morgan, Inc. (KR-108, schedule No. 6 at p.6.), which is an unregulated (and thus riskier) entity.

2. Debt Cost

293. ISSUE -- Blended debt cost

294. POSITIONS - - The position of Kern River is that the debt costs for the two debt issuances involved in this case should be combined or blended. Kern River explained that its debt capitalization consists of two debt issues. The first, Series A, was offered in August 2001 in the form of $510 million of fifteen-year amortizing senior notes at a fixed coupon rate of 6.67%. The second, Series B, was offered in May 2003 in the form of fifteen-year amortizing senior notes bearing a fixed coupon interest rate of 4.893%. Kern River's view is that the blended debt cost approach properly spreads the benefits of lower-cost debt obligations across all tariff services. [375] Kern River's proposed blended interest rate is 6.62%. [376]

295. Kern River also disputes the challenge made to its debt cost calculation by BP and RCG. Kern River argues that BP's contention that Kern River's attribution of 60% of the refinancing cost to equity is not consistent with Kern River's 70/30 debt/equity balance, is without merit. Kern River states that BP ignores undisputed evidence that stockholders' equity was used to cancel interest rate swaps and to finance the issuance

[374] Ex. BP-21 at 1.
[375] KR IB at 18-19.
[376] Item by Ref. Kern River A, Statement F-2.

fees associated with the Series A debt. Therefore, according to Kern River, the $29 million used in Kern River's debt cost calculations reflects the actual amount initially spent, making the percentage of the total swap costs and financing fees paid with equity irrelevant to Kern River's capital structure. [377]

296. The position of Staff is that a blended debt cost is just and reasonable in this case. Staff argues that neither the Commission's 1999 Pricing Policy, nor its certificate order relating to the 2003 expansion of Kern River precludes blending debt cost. Staff's view is that the Commission's 1999 Pricing Policy is not concerned with subsidies going from expansion shippers to existing shippers, even if blending the debt cost could be considered a "subsidy." Staff argues that *Northwest Pipeline* [378] is not helpful to the 2003 Expansion shippers because the decision called for an incremental cost of equity, which no 2003 Expansion shipper has advocated. In addition, Northwest Pipeline had a system-wide capital structure, which no expansion shipper has advocated. Also, Staff points out, that the Commission approved the use of the company's rolled-in debt cost and then found in favor of the incremental cost of debt in the subsequent rate case in *Northwest Pipeline*. Staff argues that the *Northwest Pipeline* represents the kind of change that the 2003 Expansion shippers claim cannot be made in this case. Further, the incremental debt interest rate in *Northwest Pipeline* was 19% making it clear, according to Staff, that the Commission made a policy judgment that rolling-in such a high cost of debt was unfair to the shippers. [379]

297. Staff argues that the claim of Calpine that Commission policy requires that its incremental pricing determinations made in setting the incremental rates for the 2003 Expansion services be adhered to here, is not correct. Staff claims that the Commission is concerned only with ensuring that the pricing issues in the first case are consistent with the certificate decision; that is not a concern here because Kern River has proposed incremental pricing for the 2003 Expansion shippers that is consistent with the Commission's decision in the certificate case. Staff believes that all Kern River shippers should receive the benefit of the lower interest rate because all shippers were responsible for Kern River's good credit rating and because the low interest rate on the Series B notes was, in large part, happenstance because the notes were issued during a period of historically low interest rates for which 2003 Expansion shippers could take no credit. [380]

298. The position of BP is that the cost of debt should be blended. According to BP, which holds Rolled-In and Expansion capacity, separate debt costs would create a

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[377] KR IB at 18-19 and KR RB at 20-21.
[378] *Northwest Pipeline Corp.*, 27 FERC ¶ 61,012, reh'g 27 FERC ¶ 61,339, *clarified*, 29 FERC ¶ 61,286 (1984).
[379] Staff IB at 29-32 and Staff RB at 22-25.
[380] Staff RB at 26-27.

subsidy of expansion shippers by the Original shippers because the higher risk associated with the lower credit rating of the 2003 Expansion shippers has increased Kern River's overall financial risk thereby increasing the cost of equity capital. BP contends that if separate debt costs are used, then separate equity costs should be used and all other capital costs should be tracked on an incremental basis. BP argues that no policy prohibits existing shippers from enjoying a direct or indirect benefit from expansion. BP also maintains that blending debt costs is appropriate because the Rolled-In shippers' higher credit rating lowering the lenders' overall risk in issuing the 2003 Expansion debt and all of Kern River's firm-transportation service agreements are pledged as collateral for all of its long-term debt. BP further claims that Kern River's calculation of debt costs is erroneous and the Series A notes debt cost should be 8.455%. [381]

299. The position of RCG is that the cost of debt should be blended. RCG claims that the Commission regularly approves a fair allocation of certain shared costs even where a facility is incrementally priced. RCG pointed out that the 2003 Expansion shippers have not pointed to a pipeline where a separate debt cost had been used in designing incremental rates associated with an expansion. RCG maintains that any reliance on the Commission's 1995 Pricing Policy [382] statement is unavailing because that statement is no longer in effect. RCG argues that a "changed circumstances" standard for one cost component cannot be applicable in the context of a general rate case as it is not the applicable legal standard when comparing a Section 7 conclusion to a Section 4 conclusion. RCG otherwise shares BP's points of view. [383]

300. The position of Calpine is that Kern River's proposed blended or weighted average cost of debt is not just and reasonable. Calpine argues that the blended-cost-of-debt proposal ignores both the Commission's pricing policies and its initial incremental rate determinations for the 2003 Expansion shippers. Calpine contends that the actual debt cost used to set initial incremental rates for the 2003 Expansion shippers, should continue to be used to set rates for those shippers absent significantly "changed circumstances". Calpine claims that interclass subsidy is inconsistent with the Commission's policy goal of sending efficient pricing signals to existing and expansion shippers. [384]

301. Calpine argues that BP ignored the fact that non-creditworthy shippers are required to post significant collateral that essentially puts them on par with creditworthy shippers insofar as it affects Kern River's risks. Calpine claims that the 2003 Expansion

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[381] BP IB at 21-23 and BP RB at 19-28.
[382] *See Pricing Policy for New and Existing Facilities Constructed by Interstate Natural Gas Pipelines*, 71 FERC ¶ 61,241 (1995), *reh'g denied*, 75 FERC ¶ 61,105 (1996).
[383] RCG IB at 22 and RCG RB at 19-23.
[384] CES IB at 9-12.

shippers did not contribute to the cost-of-debt achieved with regard to the Series A senior notes, nor was the credit of Rolled-In shippers' responsible for the lower interest rate for the Series B notes. Calpine points out that the type of blended debt cost proposed by Kern River had not resulted from Commission decision but was rather, a result of settlements. Calpine also points out that no *Northwest Pipeline* participant contested that decision. [385]

302. The position of High Desert is that the debt cost should not be blended. High Desert argues that its debt cost should be the actual debt cost incurred to construct the High Desert facilities and not Kern River's source of cash to pay the debt, or speculation about whether the debt cost was lower because lenders relied on Rolled-In shippers' creditworthiness. High Desert argues that the *Northwest Pipeline* case [386] supports its position because the Commission found in that case that rolling-in debt was not appropriate for incremental facilities just because the financial agencies may have looked to the company as a whole in issuing debt for the incremental facilities. High Desert also claims that the Commission found no reason to roll-in debt when other costs were charged incrementally. [387]

303. The position of SCGC is that the debt costs should be blended as proposed by Kern River, and for reasons expressed by other approving Participants. [388]

304. The position of Pinnacle is that the debt cost should not be blended. In addition to arguments that are consistent with those of High Desert, Pinnacle further posits that the Commission's 1999 Pricing Policy indicates that pipeline expansion projects will be incrementally priced, unless the cost of expansion capacity is less than the embedded cost of existing capacity or where there is a Right-of-First-Refusal. Kern River has not stated that either exception exists and could not do so, according to Pinnacle. [389]

305. The position of Edison Mission is that the debt cost should not be blended. In addition to arguments made by some other Participants against blending, Edison Mission takes the position that Kern River would have to show there were changed circumstances in order to blend debt costs. Edison Mission counters BP's assertion that the Commission has allowed incremental facilities to use average debt costs, by pointing out that the Commission has never issued a reported decision authorizing the roll-in of discrete debt costs associated with incremental expansion facilities while continuing to maintain separate rolled-in and incremental rates. Edison Mission states that adoption of

[385] CES IB at 13-20.
[386] 27 FERC ¶ 61,012 at 61,657, *reh'g*, 27 FERC ¶ 61,339, *clarified*, 29 FERC ¶ 61,286.
[387] HD IB at 12-14 and HD RB at 7.
[388] SCGC IB at 13.
[389] Pinnacle West IB at 6, 9-12, and 15-17.

such a policy would upset settled expectations of expansion shippers, skew price signals in the market, lead to inefficient economic decisions for new construction and frustrate the goals of the Commission's 1999 Pricing Policy. [390]

306. The position of Questar is that the debt cost should not be blended for reasons expressed by the other Participants opposing blending debt costs. [391]

307. CONCLUSION -- Kern River has not carried its burden of proving that its proposed weighted-average or blended cost of debt would yield just and reasonable rates. Separate costs-of-debt should be calculated for the Rolled-In System and the 2003 Expansion System. Further, Kern River's debt costs of 9.675% for the Series A notes should be adjusted to 8.455%.

308. DISCUSSION -- Blending the cost-of-debt inappropriately raises the rates charged to the 2003 Expansion shippers when they are already paying incremental rates. The Commission's 1999 Pricing Policy Statement does not control here. The 1999 Pricing Policy neither requires, nor forbids blending the debt. What the 1999 Pricing Policy does do is to forbid any pipeline action that would constitute subsidizing of expansion shippers by existing shippers, but it does not require that every benefit accruing to expansion shippers be shared with existing shippers. Staff misleads when it claims that the Commission explicitly provided in its 1999 Pricing Policy for expansion shippers "subsidizing" existing shippers in a situation like that presented in the instant case. [392] What the Commission actually said was:

> A requirement that the new project must be financially viable without subsidies Does not eliminate the possibility that in some instances the project costs should Be rolled into the rates of existing customers. In most instances incremental pricing will avoid subsidies for the new project, but the situation may be different in cases of inexpensive expansibility that is made possible because of earlier, costly construction. In that instance, because the existing customers bear the cost of the earlier, more costly construction in their rates, incremental pricing could result new customers receiving a subsidy from existing customers because the new customers would not face the full cost of the construction that makes their new service possible. ***The issue of the rate treatment for such cheap expansibility is one that always should be resolved in advance, before the construction of the pipeline.*** [393]

[390] EME IB at 17, 19, 23-26-28 and EME RB at 13-15.
[391] Questar IB at 3, 6, and 9.
[392] Staff RB at 23.
[393] *See 1999 Pricing Policy Statement*, 88 FERC ¶ 61,227 at 61,746, *emphasis added*.

There is no allegation of "cheap expansibility" as described in the Policy Statement in this case. The primary claim here for blending the debt is that it was the good credit of the existing shippers which prompted banks to offer the lower debt cost for the 2003 Expansion. There is no precedent of which the Undersigned is aware which would require blending the debt even if that were so, however, in any event, it seems very likely that the 2003 Expansion lower debt cost significantly reflected the very low interest rates of that time, as well as the good credit ratings. As Calpine and Edison Mission argues, the blended cost-of-debt proposal ignores the Commission's policy and its initial incremental rate determinations for the 2003 Expansion shippers. [394] Those shippers persuasively argue that the actual debt cost used to set initial incremental rates for the 2003 Expansion shippers should continue to be used to set rates for those shippers absent significantly changed circumstances. Continuation of the incremental debt cost supports the Commission's rate-certainty goal. [395]

309. The evidence also supports the contention of BP and Staff that Kern River's filed debt cost for Series A notes is excessive and should be reduced from 9.675% to 8.455%. Kern River witness Mr. Swenson testified that Kern River's debt cost included a component to recognize that certain of the payments to cancel interest rate swaps and to finance debt issuance fees were financed by stockholders' equity. He testified that the component of the debt cost included carrying costs, including an income tax allowance, on the equity investment in the swap and debt insurance costs. However, BP pointed out that Kern River attributed an inflated equity cost to its debt cost calculation by presuming that over 60% of the Series A debt refinancing cost relied on equity. Kern River then used that inflated refinancing convention to calculate debt service needs. Staff agreed.[396] The Undersigned agrees as well.

3. Capital Structure

310. ISSUE -- Capital structure and *Ozark* method

311. POSITIONS -- The position of Kern River is that it should be allowed to continue use of its levelized cost-of-service/ratemaking methodology, and to continue using the *Ozark* method. Kern River explained that the *Ozark* method calculates the equity capitalization by deducting the outstanding debt principal from total rate base. The equity ratio is thereby reduced as ADIT balances increase. Kern River points out that its models calculate the levelized cost-of-service based on a more leveraged, and less costly, capital structure than its actual end-of-test period capitalization. The calculations reflect the fact that, as Kern River re-pays debt principal, the debt portion of its

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[394] *Kern River Gas Transmission Company*, 98 FERC ¶ 61,205 at

[395] CES IB at 9-20 and EME IB 17, 19, 23, 26-28 and RB 13-15.

[396] Ex. KR 15 at 5, BP Initial Brief at 23, and Staff RB at 22, n. 35.

capitalization declines over time and the equity capital increases. The end result is that the average equity ratio used in the levelization models (38.01% weighted by the annual rate base amounts during the levelization period) is lower than the actual, end-of-test-period book equity ratio (38.73%). Kern River maintains that this approach does not cause it to over-recover its debt. [397]

312. Kern River argues that the capital structure that RCG, BP, and SCGC would have Kern River use (i.e., actual, end-of-test-period capitalization) would result in Kern River using more costly capitalization. Kern River says it has shown that the total debt capital used in its models to calculate the levelized cost of service, is greater than the company's actual outstanding debt at the end of the test period by about $20 million. Kern River says it has shown that the future book equity ratios are projected to exceed the equity ratios used in the levelization models which, according to Kern River, indicates the benefits to ratepayers of using the *Ozark* method. Kern River further points out that that its past book equity ratios have also exceeded the *Ozark* ratemaking equity ratios. Finally, Kern River argues that it has fully shown that its levelization models do not over-recover its debt. [398]

313. Kern River argues that RCG, BP, and SCGC also err in making no attempt to distinguish the Commission's expressed adoption of Kern River's use of the average capital structure over the remainder of the levelization period. Kern River points out that the Commission approved this approach. The discussion was that use of a constant, end-of-test-period capital structure to calculate the levelized cost-of-service does not reflect Kern River's actual financing. [399]

314. Kern River argues that its use of the *Ozark* method is appropriate because its debt has always been secured by its shippers' firm service agreements and is scheduled to be repaid in full within the primary terms of those contracts. Because of that, according to Kern River, what it collects in transmission depreciation expense during the terms of its contracts to the extent that the depreciation is attributable to plant financed with debt is required to be used for the repayment of the debt. Kern River argues that all recovery of the equity invested in its pipeline is deferred until after the debt is fully repaid, making Kern River's equity ratio increase over time as it pays down its outstanding debt. Because the *Ozark* method reflects changes to Kern River's capital structure over time, Kern River contends, use of that method is essential to a fair ratemaking approach in Kern River's circumstances. Without use of the *Ozark* method, Kern River argues, it would be required to reflect reductions in rate-base related costs, but not increases in

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[397] KR IB at 19-20 and Ex. KR-27.

[398] KR IB at 20-21 and Exs. KR-21, 30, 31, 34, 35, and 51.

[399] *Kern River Gas Transmission Company*, 60 FERC ¶ 61,123 at 61,437 (1992); KR IB at 19-20.

other costs, including the greater proportion of rate base financed by equity, rather than by debt. Kern River further argues that not using the *Ozark* method would force Kern River to forego a fully compensatory ROE between rate cases and/or to file frequent rate changes and that, according to Kern River, would undermine the levelization objective of providing stable rates over the terms of the shippers' contracts. [400]

315. Kern River counters SCGC's argument that the *Ozark* method should be used in conjunction with SCGC's proposed fixed capital structure, arguing that the whole purpose of the *Ozark* method is for the ratemaking capitalization to correspond with changes in the actual capitalization. Kern River contends that using a fixed capital structure would break the required link between the cost-of-service and changes in the actual capital structure. Kern River also points out that BP's position fails for the same reason as does SCGC. Kern River additionally argues that BP is proposing that Kern River use the *Ozark* method in conjunction with the traditional methodology and argues that is not appropriate. [401]

316. The position of Staff is that Kern River should use the traditional cost-of-service/ratemaking methodology and use the actual end-of-test-period capital structure of 61.31% debt and 38.69% equity. Therefore, the *Ozark* method is not pertinent. [402]

317. The position of BP is that the actual end-of-test-period capital structure should be used to calculate rates, levelized or traditional. BP points out that the original Kern River projections assumed 100% equity financing at the end of the contracts and, therefore, the Kern River methodology presents practical difficulties. The position of BP is that use of the *Ozark* method is not appropriate if levelized rates are used as that would allow Kern River to reap a huge windfall. If traditional rates are used, then the use of the end-of-test-period outstanding debt is appropriate. [403]

318. The position of RCG is that Kern River should use the actual end-of-test-period debt balance and its debt repayment schedule to determine the debt-financed portion of rate base under the *Ozark* method. RCG also states that Kern River should assign debt system-wide rather than assigning portions of the debt to the various rate classes. Kern River should not be allowed to allocate the two debt issuances separately to each of its separate systems; rather, Kern River should be required to use its total outstanding debt under the *Ozark* method across all of its plant for ratemaking purposes. RCG argues that Kern River shifted its historical position regarding its project-financed status and link between rate depreciation and debt repayment. RCG claims that it is unjust and

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[400] KR IB at 22-24.
[401] KR RB at 24.
[402] Staff IB at 33 and Staff RB at 27-28.
[403] BP IB at 23.

unreasonable to allow Kern River to change certain assumptions underlying its model to defend attacks of over-recovery, while maintaining other assumptions in its model to maximize cash flow. RCG argues that it demonstrated that Kern River's hypothetical capital structure arbitrarily increases the equity component of rate base, off of which the return is calculated. [404]

319. The position of Calpine is that Kern River should use its actual incremental capital structure approach to setting incremental rates for the 2003 Expansion shippers. Calpine points out that the Commission had no difficulty separating Kern River's debt costs and capital structures when setting Kern River's initial rates for the 2003 Expansion shippers. Calpine claims that other proposals would have severe economic consequences for the 2003 Expansion shippers, while its proposal would preserve the status quo. A system-wide capital structure would cause the 2003 Expansion shippers to experience an increase in their cost of debt and to have to share more expensive equity capital. [405]

320. The position of High Desert is that Kern River's proposed 70/30 debt/equity is appropriate for it because High Desert pays incremental rates and because there is no reason to lower the debt percentage and increase the equity percentage in the ratio. High Desert's view is that a pipeline recovering the costs of a lateral should use the capital structure incurred in financing the facility. High Desert states that the only reason to make an adjustment would be to attract capital to High Desert, but the need for new capital for High Desert would be unlikely because High Desert's facilities had been recently constructed. [406]

321. The position of SCGC is that a constant end-of-test-period capital structure should be used throughout the levelization period. SCGC states that Kern River arbitrarily allocates debt to each levelized group in order to accomplish its "self-imposed" recovery goal of 70% of its capitalization over each levelized period. SCGC states that each year thereafter the model shows an annual decrease in debt and increase in equity to reflect Kern river's estimates of decreasing debt due to repayment of Kern River's long-term debt. SCGC contends it is not feasible to forecast a pipeline's actual capitalization over a ten-year or fifteen-year period. SCGC argues that Kern River should file a new rate case if changes in its capitalization warrant a change in the cost-of-services and rates which, SCGC argues, is how Kern River has been tracking the changes in its capital structure (although SCGC also claims that Kern River's debt/equity has remained fairly constant since it began operations in 1992). SCGC claims that its proposed levelized methodology

[404] RCG IB at 25-27 and RCG RB at 23-27; *Ozark Gas Transmission System*, 53 FERC ¶ 61,451 and 62,583 n. 3; *see Wyoming Interstate Co., Ltd.* 69 FERC ¶ 61,259 at 61,988 (1994).

[405] CES IB at 20 and CES RB at 22-25.

[406] High Desert IB at 14-15 and HD RB at 7-8.

model, including both its fixed capitalization proposal and its depreciation expense proposal, will result in an $8.9 million decrease when using Kern River's proposed capitalization as reflected in its 45-day update. [407]

322. The position of SCGC is that the problem is not with the *Ozark* method, but with Kern River's application of it. According to SCGC, Kern River's application allows it to over-collect because Kern River is not able to accurately project the decreases in debt. SCGC contends that Kern River should be required to use a constant capital structure. [408]

323. The position of Pinnacle West, like that of Calpine, is that Kern River should use the actual capital structure and actual debt repayment schedules to finance the Rolled-In and 2003 Expansion systems. Pinnacle West contends that use of separate actual capital structures matches cost incurrence with cost responsibility and is, therefore, consistent with the Commission's 1999 Pricing Policy and the initial 2003 Expansion rates. [409]

324. Edison Mission and Questar take no position on the capital structure issue. Calpine, High Desert, Edison Mission, Questar, and Pinnacle West take no position on the *Ozark* issue.

325. CONCLUSIONS -- Kern River has carried its burden of proving that its proposed capital structure, in conjunction with its levelized cost-of-service/ratemaking methodology, produces just and reasonable rates. Kern River has also carried its burden of proving that it is appropriately using the *Ozark* method.

326. DISCUSSION -- Since the Undersigned has found that Kern River may continue use of its depreciation-oriented, levelized cost-of-service/ratemaking methodology, it follows that Kern River should continue using the *Ozark* methodology. There seems to be no reason to break the link between the levelized rates and changes in the actual capital structure. The Commission approved use of the *Ozark* method in the optional certificate rehearing order, conslucion that the *Ozark* method more accurately reflected the proposed rate structures of projects over time. The Commission did reserve its right to reexamine in a later rate case the issue of whether use of *Ozark* remained appropriate. However, in this case, the determination of lawful debt costs and ROE has also been determined and will ensure that use of the *Ozark* method in calculating a levelized cost-of-service "accurately reflects the proposed rate structures of the projects over time," which is the goal expressed by the Commission in its order. [410]

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[407] SCGS IB at 18-19; *see* KR-100, Statement F-2 and Ex. SCGC-2 at 2.
[408] SCGC IB at 21.
[409] Pinnacle West IB at 19.
[410] *Kern River Gas Transmission Company*, 60 FERC ¶ 61,123 at 61,1437(1992).

327. Kern River's *Ozark* capital structure at the end of the test period is derived as follows:

	Amount	Record Source
Rate base, end of test period	$ 1,867,022,629 (A)	Ex. KR-100 Corrected
Debt financing rate base	1,225,035,667	Ex. KR-94, Statement F-3
Less: Unamortized swaps & fees	(19,617,339)	Ex. KR-37, p.1, lines 27-28
Total debt related to rate base	$ 1,205,418,328 (B)	
Equity rate base per Ozark	$ 661,604,301 (A) minus (B)	

The actual end of test period capital structure is 64.56% debt/35.44% equity:

Debt	$1,205,418,328	64.56%
Equity	661,604,301	35.44%
Total	$1,867,022,629	100.00%

[411]

328. The excluded amounts of $19.6 million reflect costs associated with financing the buyout of interest rate swaps and other fees related to the debt issuances. Since this amount does not finance rate base, it is properly excluded from rate base as shown above. Based on Kern River's levelization model that shows debt/equity ratio calculations from 67.0%/33.0% (November 2004) to 5.9%/94.1% (November 2017), the pipeline would approach 100% equity financing. In addition, although the equity ratio approaches 100%, debt capital would be reduced from $1,149,125 (November 2004) to $12,016 (November 2017). In turn, equity capital for November 2017 would be $193,106, which results in the debt/equity ratio of 5.9%/94.1%. [412] Consequently, the record fully supports Kern River's approach. Kern River's models [413] calculate the levelized cost of service based on a more leveraged, and therefore less costly, capital structure than Kern River's actual, end of test period capitalization -- which is the capital structure RCG and SCGC would hold constant in the levelization calculations. Accordingly, the *Ozark* method is operating the way it was intended to in the optional certificate rehearing order.

B. RATE BASE

329. ISSUE -- Allocation of ADIT

330. POSITIONS -- The position of Kern River is that the ADIT effect relates to the Rolled-In System only. No portion of the ADIT effect on the cost-of-service should be

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[411] KR RB at 23-24.
[412] Ex. KR-17 at 22, KR-14 at 5, KR IB at 23-24.
[413] Ex. KR-27.

allocated to the 2003 Expansion because, Kern River argues, the step-up plainly relates to the Rolled-In System only. The 2003 Expansion was not even built when the step-up occurred. Accordingly, the Rolled-In System rightfully experiences the entire effect of the increase in rate base associated with reducing the pre-acquisition ADIT balance to zero. However, Kern River points out that its cost-of-service levelization models minimized the effect of the step-up on current rates because the models took future ADIT into account in calculating the average cost-of-service over the levelization period. [414]

331. The position of BP and SCGC is that all shippers who benefited from MEHC's acquisition of Kern River should be responsible for paying the costs leading to those benefits. According to BP, the 2003 Expansion shippers' rates do not reflect any of the ADIT consequences arising from the MEHC purchase. Rather, elimination of the ADIT balance is disproportionately attributed only to the Original System. [415]

332. Staff and other Participants take no position on this issue.

333. CONCLUSION -- Kern River's proposed allocation of ADIT produces just and reasonable rates.

334. DISCUSSION -- The increase in rate base associated with reducing the pre-acquisition ADIT balance to zero is properly allocated to the Rolled-In System. As Kern River pointed out, the step-up is plainly related to the Rolled-In System only. The incremental facilities were not even built when the step-up occurred due to the sale of Kern River to MEHC. Further, separate calculation of ADIT for the various shipper classes comports with Kern River's levelized methodology. [416] The position of Rolled-In shippers, like their position on other cost items, serves only to reduce their rates at the expense of the expansion shippers who already pay higher rates due to incremental pricing. Rolled-In shippers do receive benefits from the expansion, including the benefit of a more efficient system. [417]

335. ISSUE -- Tax NOL

336. POSITIONS -- The position of Kern River is that it is entitled to a tax NOL and that including the NOL in the rate base produces just and reasonable rates. Kern River explains that it incurred the NOL in 2003 in connection with placing the 2003 Expansion System in service. The NOL occurred because the company was entitled to accelerated bonus depreciation for much of the 2003 Expansion project. Kern River points out that

[414] KR IB at 24-25.
[415] BP IB at 24-25 and SCGC IB at 21.
[416] Initial Decision ¶ 116.
[417] Initial Decision ¶¶ 22 and 116.

although it is not a taxable entity itself, its revenues and expenses create a federal income tax liability for its owner, MEHC. That Kern River reported its taxable income on MEHC's consolidated corporate income tax return is not controlling for ratemaking purposes, according to Kern River, and does not negate the fact that Kern River generated and separately reported tax NOLs in MEHC's consolidated return. Kern River argues that it calculated its taxable income and tax NOL consistent with the Commission's long-standing "stand-alone" income tax policy. Kern River notes that Participants who contest the NOL and want to disregard the effects of the NOL in Account 190, also want to continue to recognize the ADIT in rates in Account 292, associated with the bonus depreciation that precipitated the NOL. It follows, according to Kern River, that if the NOL is not reflected in rates, the related deferred income taxes from bonus depreciation likewise should be disregarded.[418] Kern River further argues that Staff's claim that the effect of NOL on ADIT is unrelated to the jurisdictional cost-of-service is contradicted by Staff's recognition of ADIT related to the bonus depreciation that led to the NOL. Staff's view, according to Kern River, is also contradicted by undisputed evidence and is not consistent with required income tax normalization.[419]

337. The position of Staff is that if Kern River uses the traditional cost-of-service/ratemaking methodology, NOL or deferred income taxes related to NOL have to be removed from rate base in order to conform to Commission policy.[420]

338. The position of Calpine is that Kern River's treatment of the acquisition-related ADIT credit elimination and the treatment of the ADIT credit produced by bonus depreciation, does not support Kern River's claim to a tax NOL. Calpine argues that Kern River's claimed NOL and related ADIT adjustment should be rejected because, as a matter of tax law, Kern River cannot claim a NOL.[421]

339. Edison Mission and Questar take no position on this issue. The other Participants only concerned themselves with how the NOL should be allocated if Kern River were allowed one.

340. CONCLUSION -- Kern River has carried its burden of proving that it is entitled to claim deferred income taxes related to NOL in its rate base

341. DISCUSSION -- Most of Account 190 balance recorded represents the deferred tax benefit related to this NOL. For rate base purposes, this deferred tax asset is an offset to the deferred tax liabilities in Accounts 282 and 283. Staff removed NOL-deferred

[418] KR IB at 26-27.
[419] KR IB at 25-26 and KR RB at 25.
[420] Staff IB at 36.
[421] CES IB at 21-25.

income taxes since it is inappropriate for ratemaking purposes. Staff's witness, Ms. Segal, noted that Commission Accounting Guidance A 193-5-000 provides that the income tax effect of a NOL carryforward and a tax credit carryforward should be accounted for in a separate sub-account of Account 190, but acknowledged, that "accounting does not dictate ratemaking." [422]

342. However, the Commission's regulation at 18 C.F.R. §154.305 allows for Account 190 items to be included in the cost-of-service. Kern River presented credible evidence that it expected to use the NOL within the statutory carryforward period of twenty years. Kern River witness, Mr. Valentine, explained:

> Just as Kern River's levelized rate models consider future decreases to rate Base caused by increases to the deferred tax liability account, the 2003 Expansion models also consider the reduction of this deferred tax asset Each year going forward. As taxable income is recognized in the levelized rate model, it will gradually use up the NOL. As the NOL is used each year, the Related deferred tax asset in Account 190 will be reduced until it reaches Zero, which is projected to occur in 2009. [423]

343. ISSUE -- Inclusion of deferred depreciation (i.e., regulatory asset) resulting from levelization of compressor engine plant, general plant, and other smaller regulatory assets ("other regulatory assets") in the rate base

344. POSITIONS -- The position of Kern River is that under the levelized cost-of-service/ratemaking methodology, the rate base appropriately includes regulatory assets of approximately $58 million. Kern River states that about $45.1 million of the regulatory asset represents deferred depreciation related to general plant and compressor engine plant. Other regulatory assets total about $13 million. Although the other regulatory assets for deferred depreciation is not a separately identifiable amount in rate base under the levelized methodology, Kern River wants to include it in regulatory asset. Kern River acknowledges that the regulatory liability is not specifically mentioned in the certificate order, but necessarily flows from the terms of the order (i.e., the $4 book depreciation rate) and 70% recovery of investment over fifteen years. [424]

345. The position of Staff is that compressor engine plant and general plant should be removed from the regulatory asset because any discrepancies between the amount collected in rates and the book deprecation amounts are provided for in the unrecovered

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[422] Ex. S-1 at 7 and Ex. KR-15 at 17.
[423] Ex. KR-15 at 18.
[424] KR IB at 27-28 and Ex. 12-13.

depreciation regulatory asset with its corresponding amortization expense. [425]
346. The position of BP is that any Kern River regulatory asset for deferred depreciation that may be allowed should be allocated to all shippers. [426]

347. The position of Pinnacle West is that Kern River's calculation and proposed direct assignment of the regulatory asset is appropriate. Pinnacle West argues that BP's proposal is nothing more than an attempt to shift costs that are properly the responsibility of the Rolled-In shippers, to the 2003 Expansion shippers. Pinnacle West asserts that the customers receiving the benefit of reduced levelized rates should be allocated the regulatory asset generated by such rate levelization. [427]

348. RCG, Questar, SCGC, Edison Mission, and High Desert take no position on this issue.

349. CONCLUSION -- Kern River has carried its burden of proving that including compressor engine plant, general plant, and other regulatory assets in the rate base produces just and reasonable rates.

350. DISCUSSION -- Regulation 154.312(b)(2) Schedule B-2 allows inclusion of regulatory assets, net of deferred tax amounts, in rate base. [428] Deferred costs have been held to be regulatory asset that is properly added to rate base. [429] The Undersigned finds no basis to exclude inclusion of Kern River's deferred regulatory asset.

351. ISSUE -- Amortization of Regulatory Asset over Remaining Lives of Firm Shipper contracts.

352. POSITIONS -- The position of Kern River is that it should be allowed to amortize its regulatory asset (except compressor engine plant) over the remaining lives of its firm shipper contracts. Kern River points out that amortization over the lives of its firm shipper contracts has always been a feature of its levelized methodology. Kern River states that the Commission had recently approved using contract life in review of Kern River settlement agreements. Kern River argues that Staff's proposal that its regulatory asset be amortized over thirty-five years violates the "probability standard" for maintaining and recovering a regulatory asset. [430] The probability standard is violated,

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[425] Staff IB at 35.
[426] BP IB at 24-27.
[427] Pinnacle West IB at 21-27 and Pinnacle West RB at 98-100.
[428] 18 C.F.R. ¶ 154.312(b)(2), Schedule B-2; *see also El Paso Natural Gas Company*, 84 FERC ¶ 63,004 at 65,013 (1992)
[429] *Florida Gas Transmission Company*, 88 FERC ¶ 61,142 at 61,472-74 (1999).
[430] KR IB, Proposed Findings of Fact and Conclusions of Law at 12.

according to Kern River, when recovery of deferred depreciation would extend past the end of a pipeline's firm service agreements existing at the time of the deferral. [431]

353. The position of Staff is that the amortization period should be thirty-five years because, it says, amortization should coincide with the period used to develop depreciation rates and not with contract life. [432]

354. The other Participants take no position on this issue.

355. CONCLUSION -- Kern River has carried its burden of proving that depreciating its regulatory asset over the remaining terms of the firm shippers' contracts produces just and reasonable rates.

356. DISCUSSION -- As a general policy, the Commission does not favor limiting pipeline depreciation to the life of a pipeline's current contracts with customers. One concern the Commission has with limiting depreciation in that fashion is that it tends to create an intergenerational inequity. If facilities remain in use after the end of the contracts, the later ratepayers would not be responsible for any depreciation component for use. The Commission observed that that would generally impose an unfair burden on the first generation of ratepayers. However, this "general" policy is not encased in stone. For example, the Commission allowed depreciation over the terms of shipper contracts in *Northwest Pipeline Corporation* because the facilities in question were built under a tariff wherein the shippers agreed to pay the full incremental cost of the facilities. [433] In *Questar Southern Rails Pipeline Company*, the Commission would not approve that company's levelization plan because the plan would leave the balance of the regulatory asset unrecovered at the end of the five-year and ten-year contract terms. The Commission pointed out that *Order No. 552* established accounting requirements for regulatory assets and liabilities that require recognition of the asset or liability for items that would be included in net income determinations, but for the probability that the asset will be recovered from, or returned to customers in future rates. "Probable" as used in *Order No. 552* means that which can, based on credible evidence, reasonably be expected to occur. [434] In *San Patricio Pipeline, LLC*, the Commission would not approve San Patricio's levelization proposal because it did not meet the probability requirement to record a regulatory asset because the company's regulatory asset would not be recovered

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[431] KR IB at 39-41.

[432] Staff IB at 41.

[433] *Northwest Pipeline Corp.*, 87 FERC ¶ 61,266 at 62,043-44 (1999).

[434] *Questar Southern Trails Pipeline Co.*, 89 FERC ¶ 61,141 at 61,147 (1999), *citing, Order No. 552, FERC Statutes and Regulations, Regulations Preambles January 1991-June 1996 ¶ 30,967 (1993).*

during the term of the pipeline's contracts with its shippers. [435]

357. While the facts of the instant case do not mirror those of the cases cited above, in that it does not appear that Kern River is at peril of not recovering its regulatory asset; however, the Undersigned concludes that given that we are considering application of a levelized cost-of-service/ratemaking methodology, traditional rules do not always fit and, on this record, the Undersigned concludes that limiting depreciation to the terms of the contracts of the firm shippers produces just and reasonable rates.

358. ISSUE -- Leaving the full balance of the unamortized portion of the regulatory asset in the rate base

359. POSITIONS -- The position of Kern River is that leaving the full balance of the unamortized portion of the regulatory asset in the rate base will produce just and reasonable rates. Kern River argues that Staff's proposal to include only the "average balance" (i.e., half) of the unamortized balance of the regulatory asset over thirty-five years is Staff's effort to reduce cost-of-service in order to hide the rate increase which would occur if Kern River converted to the traditional methodology. [436]

360. The position of Staff is that leaving the full balance of the unamortized portion of the regulatory asset in rate base, as proposed by Kern River, while also amortizing that amount through rates will, over time, result in a rate base that will become more-and-more overstated. Staff argues that Kern River's challenge to the use of average unamortized balances in the rate base is not well taken since the Commission requires it. [437]

361. Other Participants take no position on this issue.

362. CONCLUSION -- Kern River has not carried its burden of proving that leaving the full balance of the unamortized portion of the regulatory asset in the rate base produces just and reasonable rates.

363. DISCUSSION -- Staff cites *Williston Basin Interstate Pipeline Company* [438] for the proposition that Ken River is obliged to only include the average unamortized balance in rate base. The Commission noted in that case that the "average" approach was a

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[435] *San Patricio Pipeline, LLC.*, 112 FERC ¶ 61,101 at 61,657-658 (2005), *citing, Questar Southern Trails Pipeline Co*., 89 FERC ¶ 61,141; *see also, Portland Natural Gas Transmission System*, 76 FERC ¶ 61,123 at 61,658 (1996).
[436] *Id*. at 27-31.
[437] Staff IB at 34-35.
[438] 84 FERC ¶ 61,081 at 61,373-61,374 (1998).

"levelized" approach. It further noted, in that case that Williston would experience a slight under recovery the first year; however, the company would experience full recovery the second year, and slight over recovery the third. [439] The Undersigned concludes, despite Kern River's protestations, that *Williston Basin* applies here.

C. Depreciation

364. ISSUE -- 3.39% book depreciation rate for transmission plant (not including general plant, compressor engine plant, and the laterals)

365. POSITIONS - - The position of Kern River is that the remaining useful life of the Kern River system is approximately twenty-six years. Kern River claims that this book depreciation rate affords it a reasonable opportunity to recoup its investment in all of its pipeline facilities, matches revenues to the costs of providing gas transportation services, and achieves long term intergenerational equity among ratepayers. Kern River proposes a 3.39% book depreciation rate for transmission plant (other than general plant, compressor engine plant, and the laterals) if it is allowed to continue using levelized cost-of-service/ratemaking. Kern River proposes that depreciation rates for the described transmission plant should be: 2.39% for the Original System, 4.84% for the 2002 Expansion, and 4.09% for the 2003 Expansion. [440]

366. The position of Staff is that the depreciation rates proposed by Kern River would result in an over collection of depreciation. Staff believes that the recovery of the plant investment through depreciation should be spread evenly to all of the existing and future shippers on the Kern River System over a projected thirty-five year remaining life of these pipeline facilities. Staff argues that Kern River is using the "efforts to results" approach which was rejected in *Williston Basin* [441] and *Kansas Pipeline*, [442] but should use the "ultimate recovery approach" favored by Staff and upheld by the Commission in both cases. Additionally, Staff argues that Kern River's remaining life estimate includes out-of-test-period changes in costs which is contrary to Commission policy. Staff recommends respective annual reductions to Kern River's depreciation expense of approximately $21 million and to its annual negative salvage expense of $700,000. [443]

367. The position of BP is that the remaining economic life should be thirty-five years, which yields book depreciation rates of 1.7% for the Original System ten-year Shippers; 1.8% for the Original System fifteen-year shippers; 2.4% for the 2002 Expansion ten-year

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[439] *Id*. at 61,374.
[440] KR IB at 34-37.
[441] *Williston Basin Interstate Pipeline Co.*, 95 FERC ¶ 63,008 at 65,104 (2001).
[442] *Kansas Pipeline Co.*, 100 FERC ¶ 61,260 at 61,977 (2002).
[443] Staff IB at 39and Staff RB at 32.

shippers; 2.7% for the 2002 Expansion fifteen-year shippers; and 2.8% for both the 2003 Expansion ten-year and fifteen-year shippers. BP claims that Kern River's depreciation study estimating a supply life of twenty-six years was created solely for this proceeding and relies on a method of calculating depreciation rates that is not consistent with *Trunkline Gas*. [444] BP claims that Kern River did not consider its universe of available supply, basing remaining economic life studies on a limited production area. BP contends that Kern River's witness, despite assertions to the contrary, did not use the PGC estimates favored by the Commission. [445]

368. The position of RCG is that Staff's mainline depreciation rate of 1.95% based on a thirty-five year remaining life should be adopted. [446]

369. The position of Calpine is that Kern River's book depreciation rate for transmission plant should remain at 2.0%. According to Calpine, there is overwhelming evidence refuting the twenty-six year supply life estimate and, in fact, a likely gas supply life two to three times higher is indicated. Calpine argues that Kern River's depreciation rate proposals in this case represent an expedient repudiation of its own prior analyses and Kern River's proposed increase to its depreciation rate on transmission assets should be rejected.[447]

370. The position of SCGC is that a separate depreciation rate for each levelized vintage based on the net depreciable plant amortized over the remaining life of transmission plant should be calculated. Then those depreciation expenses should be aggregated and used in place of the 70% debt recovery target Kern River is using to determining levelized rates. SCGC feels that this approach avoids understating or overstating the depreciation remaining to be recovered at the end of the levelization period. SCGC also supports Staff and other parties who advocate a thirty-five year remaining life for calculating Kern River's mainline depreciation rate. SCGC emphasizes that Kern River's reliance on new and pending pipelines in the Rocky Mountain production basin, as support for the contention that such pipeline projects serve to decrease the useful life of Kern River's facilities, is misplaced because other pipelines in that same basin have proposed to base their depreciation of a thirty-five year useful life. [448]

371. High Desert, Pinnacle West, Edison Mission, and Questar take no position on this issue.

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[444] *Trunkline Gas Co.*, 90 FERC ¶ 61,017 at 61,054-55.
[445] BP IB at 27-33 and BP RB at 30-31.
[446] RCG IB at 27-33.
[447] CES IB at 25-27 and RB at 31-32.
[448] SCGC IB at 22-23.

372. CONCLUSION -- Kern River fails in its burden of proving a remaining economic life of only twenty-six years.

373. DISCUSSION -- The credible evidence of record supports a conclusion that the Kern River remaining economic life is thirty-five years, at least, and that a thirty-five year remaining life produces just and reasonable rates. [449]

374. ISSUE -- Depreciation rates for the laterals

375. POSITIONS -- The position of Kern River is that it has fully supported proposed annual book depreciation rates of 6.67% for Big Horn and 4.76% for High Desert. Kern River adds that the Commission has approved its contract-life approach for depreciation of the High Desert when it authorized construction of that facility and no evidence has been presented here to justify departing from the Commission's previous rulings with respect to either lateral. [450]

376. The position of Staff is that Kern River's depreciation rates for Big Horn and High Desert should be based on remaining economic life, not on contract life. Staff believes that while a contract can give an indication of the minimum life of a company, it cannot take the place of a depreciation study to determine the remaining life of that company's facilities. Staff argues that since contracts can be extended, renewed, or replaced by another contract, they cannot be relied on to accurately reflect the remaining life of a facility. [451]

377. The position of High Desert is that Kern River's depreciation rate based on the twenty-one year contract term with High-Desert is appropriate.[452]

378. BP, CES, RCG, SCGC, Pinnacle West, Edison Mission, and Questar take no position on this issue.

379. CONCLUSION -- Kern River has carried its burden of proving that using the contract life approach for High Desert and Big Horn produces just and reasonable rates.

380. DISCUSSION -- Only Staff disagrees with the approach Kern River wants to take with respect to Big Horn and High Desert. In this instance, there appears to be no good reason to upset the expectations of Kern River, Big Horn, and High Desert. In

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[449] Initial Decision ¶¶ 128, 133-35, 211-12, and 366-70.
[450] KR IB at 38.
[451] Staff IB at 39 and Staff RB at 34.
[452] High Desert IB at 17.

addition, see DISCUSSION ¶¶ 356-57.

381. ISSUE -- Book amortization rates for intangible plant

382. POSITIONS -- The position of Kern River is that its proposed book amortization rates for intangible plant produces just and reasonable rates. Kern River states that the inclusion of the $6.25 million is the result of an accounting reclassification of Contributions in Aid of Construction ("CIAC") allowance by the Commission in its 2003 Expansion project certification. Kern River points out that until Calpine raised an issue in its Reply Brief, no Participant had raised a challenge to Kern River's proposed book amortization rates for intangible plant. Kern River argues that Calpine's request that $6.25 million of intangible plant costs for the 2003 Expansion be excluded, should not be granted as Calpine's concern is late and without merit.[453]

383. The position of Calpine is that Kern River's proposed book amortization rates for intangible plant does not produce just and reasonable rates. Calpine claims Kern River inappropriately included an additional $6.25 million of intangible plant allocated solely to the 2003 Expansion shippers in its 45-day filing whereas the base case has only $8 million going only towards the Original System. The total in the 45-day update equals $14.25 million. Calpine claims that Kern River has neither supported the increase, nor the exclusive allocation of this rate base item to 2003 Expansion shippers.[454]

384. CONCLUSION -- Kern River has carried its burden of proving that its proposed book amortization rates for intangible plant produces just and reasonable rates.

385. DISCUSSION -- Although Kern River apparently neglected to include the $6.25 in its original filing, Kern River has shown that the allowance is appropriate. The certificate order[455] allows the accounting for CIAC in the amount of $6.25 million due to the project for the 2003 Expansion facilities (subject to testing in a Section 4 rate case). Calpine's complaint is procedural and not substantive.

386. ISSUE -- Depreciation rate for compressor engine plant

387. POSITIONS -- The position of Kern River is that the appropriate annual depreciation rate for compressor engine plant is 12.53%. Kern River claims that Staff's

[453] Ex. KR-5 at 4, KR IB at 2, KR RB at 33-34, and Staff IB at 39.
[454] CES IB at 28, and CES RB at 33.

[455] 98 FERC ¶ 61,205 (2002).

lower depreciation rate of 8.85% is not appropriate as that rate did not include sales tax, freight, overhead, or allowance funds used during construction ("AFUDC") in the net salvage calculations. Kern River claims those costs should be included in capital costs of compressor engines. Further, Kern River counters RCG's contention that Kern River's proposed depreciation rate for compressor engines is excessive based on a useful life of four years, arguing that RCG uses an overly simplistic approach which ignores the actual operation and retirement history of the engines. Kern River further argues that RCG is mistaken when it claims that the calculation used for depreciation rate did not remove the accumulated depreciation associated with previously retired compressor engines because Kern River's accumulated regulatory depreciation reserve is negative, due to repeated retirements of engines before they were fully depreciated.[456]

388. The position of Staff is that 8.85% is the appropriate annual depreciation rate for compressor engines. Staff came to that figure by using actual length of life and the net salvage date provided by Kern River. Staff further contends that Kern River argues in error that Staff's witness overlooked the $792,300 capital cost of components associated with the Filmore No. 1 replacement unit and misstated the retirement analysis by not relating net retirement costs to the full cost of the compressor units. Staff argues, instead, that the costs were considered but rejected as not appropriate to include in determining a representative rate based on using historical data. According to Staff, the replacement costs should not be included because they represent an anomaly ratepayers should not have to pay as Kern River has already recovered those costs. [457]

389. The position of BP is that 9.4% is the appropriate annual depreciation rate for compressor engine plant. BP accepts the concept of a separate depreciation schedule for the Solar Mars compressor engines, provided that the other units are not subject to such a schedule. Additionally, BP argues that compressor depreciation should be allocated to the different classes of shippers using associated compressor engine gas plant ratios, rather than based on gross plant ratios. [458]

390. The position of RCG is that 5.86% is the appropriate annual depreciation rate for turbine compressor engines. RCG claims that Kern River based its numbers on unreasonable assumptions regarding the useful life of its compressor engines. RCG argues that it has demonstrated that Kern River's assumptions regarding the useful life of its compressor engines are not based on a reasonable useful life, as the record indicates that RCG's proposed useful of four years very conservative and Kern River's proposed 2.91 years is unreasonably short. Additionally, RCG contends that it has demonstrated that Kern River failed to take into account the accumulated depreciation already on its

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[456] KR IB at 2 and 39 KR RB at 33-34.
[457] Staff IB at 40 and Staff RB at 34-35.
[458] BP IB at 33.

books related to compressor depreciation, which caused an $11.9 million error in Kern River's depreciation calculation. [459]

391. RCG further argues that Kern River's proposal to change its proposed 9.92% depreciation rate to 12.53% was not permitted in the direct case, but Kern River ignored that ruling by proposing a 12.53% rate in its brief. RCG argues that Kern River's argument in favor of the 12.53% rate must be disregarded. RCG argues that Kern River's reliance on historical retirements of compressor engines is not appropriate because it is not based on base or test period data and it ignores the evidence of longer running time related to the new compressors Kern River has brought on line.[460]

392. The position of Calpine is that Kern River's request to depreciate its compressor engines at a separate rate should be rejected because there is no reason to treat compressor engine equipment any differently than any other type of transmission facilities. Calpine argues that Kern River's proposed traditional depreciation methodology for compressors would defeat the purpose of a levelized cost of service and that if compressor engine equipment is retired earlier than other transmission equipment, Kern River's interim retirements information could address this and the average remaining life of the pipeline's assets would be reduced.[461]

393. The position of SCGC is that RCG's position is appropriate. [462]

394. High Desert, Pinnacle West, Edison Mission, and Questar take no position on this issue.

395. CONCLUSIONS -- Kern River's proposed depreciation rate for compressor engine plant does not result in just and reasonable rates. Staff's proposal does.

396. DISCUSSION -- Staff has shown that Kern River's proposed depreciation rate for compressor engine plant does not result in just and reasonable rates and that its proposed 8.85% is. [463]

397. ISSUE -- 0.21% negative salvage rate for transmission plant (excluding compressor engine plant)

398. POSITIONS - - The position of Kern River is that its rate base should include a

[459] RCG IB at 32-34.
[460] RCG RB at 30-31.
[461] CES IB 28-29.
[462] SCGC IB at 24.
[463] Initial Decision ¶ 386.

0.21% negative salvage rate to recover the future cost of removing transmission plant (excluding compressor engine plant) from service. Kern River argues that although Staff has generally adopted Kern River's estimate of the negative salvage costs associated with abandonment and removal of Kern River's facilities, Staff calculated a lower negative salvage rate due to its different estimate of the remaining economic life of Kern River's facilities. Kern River contends that its average remaining economic life of twenty-six is correct and therefore, the negative salvage rate of 0.21% should be adopted. [464]

399. Kern River argues that the contention of Calpine, BP, and RCG that Kern River's proposed negative salvage rate does not satisfy the *Iroquois* [465] criteria is not correct. Kern River maintains that it has fully satisfied *Iroquois* criteria. Kern River argues that it has provided a fully supported study on the clearly discernable end of life for Kern River's pipeline facilities, analyzed historical data on actual interim retirements for Kern River's facilities in computing Kern River's negative salvage costs, and provided a detailed study of the costs of abandonment and removal of its facilities in lieu of actual history because of its lack of such due to the pipeline's relatively young age.[466]

400. The position of Staff is that it supports Kern River's proposal to collect costs for negative salvage; however, Staff proposes a lower rate than that proposed by Kern River (0.18% as opposed to 0.21%). Staff also argues that since negative salvage should be recovered equitably over the remaining economic life of the system, its recommendation of utilizing a remaining economic life of thirty-five years should be used. Additionally, Staff contends that intangible plant should be removed from Kern River's negative salvage calculation. Staff argues that intangible plant arises from ADFUC made by Kern River and does not represent plant that will actually have to be removed from service.[467]

401. The position of BP is that negative salvage should not be included in Kern River's rates. BP argues that Kern River does not meet the *Iroquois* criteria for negative salvage allowances because the pipeline does not have a clearly discernable end of life, there is no persuasive evidence that interim retirements have been taken into the negative salvage costs calculation, and the sales and salvage values of retired or abandoned equipment are not fully proven. BP argues that Kern River's retirement study should be rejected because it is incomplete. Finally, BP contends that Kern River will be able to refile a proposal for negative net salvage allowance when the retirement of its pipeline facilities becomes a known and measurable event. [468]

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[464] KR IB at 39-40.
[465] *Iroquois Gas Transmission System, L.P.*, 84 FERC ¶61, 086 at 61, 440-41 (1998), *reh'g denied*, 86 FERC ¶ 61, 261, at 61,941-944 (1999).
[466] KR RB at 35-36.
[467] Staff IB at 40 and RB at 35.
[468] BP IB at 31 and 35.

402. The position of RCG is that Kern River should not be allowed to collect negative salvage because Kern River has conceded that its facility retirement date is not determinable and it has not implemented accounting rules which would record the asset retirement obligation. RCG also argues, as does BP, that Kern River does not satisfy the criteria established in *Iroquois* for allowing a pipeline to receive a negative salvage allowance.[469] RCG argues that Kern River does not have a clearly discernible end life, Kern River's alleged evidence of interim retirements are not persuasive, and Kern River has failed to prove sales and salvage values of abandoned or retired equipment. RCG argues that Kern River is not prejudiced, because it is free to propose a negative net salvage rate after it has established a record. RCG contends that Kern River's statement that its net salvage study was not challenged is untrue, arguing that RCG's witness did challenge it when he indicated that it was inconsistent with other depreciation assumptions made by Kern River's witness. Additionally, RCG argues that Kern River has offered no explanation as to how its negative salvage proposal complies with the *Iroquois* test and it is not supported by the record. [470]

403. The position of Calpine is that Kern River has not shown that its proposed negative salvage charge is just and reasonable. Calpine also argues that Kern River has not met the *Iroquois* criteria. Calpine indicates that the case for a negative salvage charge is especially weak with respect to the 2003 Expansion facilities, which commenced service about a year before this rate case. Finally, Calpine claims that if the Commission determines that a negative salvage allowance is appropriate, the rate should be reduced to reflect a longer remaining economic life. Calpine proposes a 0.08% negative salvage rate. [471]

404. The position of SCGC is that Kern River's proposal to implement a negative salvage rate is not appropriate. If, however, the Commission determines that Kern River should be allowed to collect negative salvage costs, Calpine argues that the negative salvage rate for Kern River should based on the appropriate remaining economic life of Kern River facilities and should be consistent with Kern River's proposed book depreciation of its transmission plant, including Kern River's calculations with regard to the nature, dollar amounts, and timing of interim retirements.[472]

405. The position of High Desert is that it does not oppose approval of a negative salvage adjustment for Kern River. However, if a negative salvage adjustment is approved for Kern River, High Desert argues that Kern River should separately account

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[469] RCG IB at 35-36.
[470] *Id.* at 36-37 and RCG RB at 31-32.
[471] CES IB at 29-31.
[472] SCGC at 24-25.

for negative salvage amounts and credit such amounts to the High Desert rate base in future rate proceedings until the funds are needed at the time of retirement. High Desert argues that this approach makes sense because unlike other facilities on the system, High Desert was just placed in service two years before the subject Section 4 rate filing and will have a service life well into the future. According to High Desert, since the timing, degree, and cost of any retirement of any of the High Desert's facilities is unknown, prudence dictates that any negative salvage amounts collected from High Desert be separately accounted for and refunded if not needed in the future.[473]

406. Pinnacle West, Edison Mission, and Questar take no position on this issue.

407. CONCLUSION -- Kern River has not carried its burden of proving that its proposed salvage rate for transmission plant (excluding compressor engines) produces just and reasonable rates if based on a twenty-six year remaining economic life.

408. DISCUSSION -- Net salvage value is the salvage value of retired property less the cost of removal. [474] A pipeline is allowed to include a charge for negative net salvage in its cost of service to compensate for costs to be incurred in future retirement of facilities. Costs to be incurred include the net amount of funds necessary to retire a specific facility or a group of them. It includes the cost of removal of the decommissioned facilities, as well as the cost of restoring the land to its usual condition, if the land has been affected. If the anticipated cost of removal is greater than the remaining value of the asset to be retired, that asset has a negative net salvage value. [475] The three criteria for establishing a negative salvage allowance articulated by the Commission in *Williston Basin Interstate Pipeline are*: 1) the pipeline has a clearly discernable end-of-life; 2) there is persuasive evidence that interim retirements have been taken into account in computing negative salvage costs; and, 3) sales and salvage values of abandoned or retired equipment are fully proven. [476] The thirty-five year remaining economic life determination satisfies the end-of-life requirement. Kern River presented credible historical data on actual interim retirements. Kern River presented credible evidence of the costs of abandonment and removal of its facilities. [477]

409. Answering the objections to Kern River's negative salvage proposal, the Undersigned first notes that the thirty-five year remaining economic life determination is based on Participants' credible studies and testimony. Secondly, Kern River's witness

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[473] High Desert IB at 18.
[474] 18 C.F.R. Part 201, Definition 23 (2005).
[475] *High Island Offshore System, L.L.C.*, 107 FERC ¶¶ 63,019 at 65,102-04 (2004) (citations omitted); Initial Decision ¶ 70.
[476] *Williston Basin Interstate Pipeline*, *95* FERC ¶ 63,008 at 65,104-05 (2001).
[477] Initial Decision ¶¶ 396-97.

used the salvage estimate of a Kern River engineer and adjusted that estimate downward to take into account the cost of removing the existing plant and the cost of removal associated with interim removal requirements. Kern River studies show that facilities will be retired over time and not all at once. Third, because Kern River is in its early years and lacks a history of sales and salvage value of abandoned or retired facilities, should not preclude it from having shippers currently using the pipeline pay their fair share of costs of receiving the benefits of the pipeline, including the costs of future retirement. It is also of note that Kern River's levelization cost-of-service/ratemaking methodology is depreciation-oriented ratemaking and not taking account of negative salvage is inconsistent with that methodology. Finally, FAS 143 is not controlling; accounting does not control ratemaking. [478]

410. ISSUE -- Regulatory depreciation expense

411. POSITIONS -- The position of Kern River is that regulatory depreciation expense has always included recovering, over the levelization period, a depreciation expense equal to 70% of the capital investment in the relevant facilities. Kern River argues that while it is true that this means it will collect more depreciation expense in rates initially than would be collected through straight-line book depreciation under the traditional methodology, that is not a basis for change. Kern River alleges that opponents must demonstrate "an overarching policy reason" for changing the allocation of risk among Kern River, its lenders, and its shippers. [479] Kern River further argues that there are benefits to the 70% depreciation recovery. Those benefits include: 1) calculation of return and income taxes in the cost-of-service on the average rate base over the levelization period; 2) a lower overall debt cost because of favorable coverage ratios and repayment of debt within the contract periods; and, 3) the significantly lower, "step-down" rates after the levelization periods that repayment of debt principal during the contract terms will make possible. Kern River also alleges that changing the combination of depreciation recoveries, and existing debt terms may violate the *Hope* requirement that equity investors are entitled to a reasonable opportunity to earn adequate returns.[480]

412. The position of Staff is that it need not address the issue directly. Staff did state that Kern River's model caused an over-recovery of depreciation costs during the first portion of its remaining economic life. That, according to Staff, exacerbated the inequity of the cost burden between generations of ratepayers. [481]

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[478] Initial Decision ¶¶ 69-71, 143-144, and 192; Exs. KR-5 at 3, KR-6 at Schedules 8-10, and KR-112 at Schedule 29.
[479] KR IB at 40-41, c*iting Mojave Pipeline Co.*, 81 FERC ¶61,150 at ¶61,683 (1997).
[480] *Id*. at 42, *citing FPC v Hope Natural Gas Co*., 320 US 591 (1944).
[481] Staff IB at 41.

413. The position of BP is that Kern River's regulatory depreciation expense should not continue to be based on recovering 70% of plant investment by the end of shipper contracts. Rather, Kern River should not have a regulatory depreciation expense because it should use the traditional cost-of-service/ratemaking methodology, or the depreciation should be based on a thirty-five year remaining economic life. [482]

414. The position of RCG is that depreciation should be based on a thirty-five year remaining life of the system. RCG argues that, according to *Trailblazer*, depreciation rates cannot be set based on a pipeline's cash flow needs, but should be set on the remaining economic life of the facilities.[483] RCG argues that Kern River's 70% depreciation target allows it to unjustly accelerate recovery of depreciation expense within the contract periods.[484]

415. The position of SCGC is that Kern River's use of a 70% target for its regulatory depreciation expense is inconsistent with Kern River's proposed capital structure and results in accelerated recovery of depreciation expense that otherwise would be recovered after the end of the levelization period and discriminates against current shippers in favor of future shippers. SCGC proposes that Kern River use a target depreciation expense equal to the aggregate depreciation expense over the entire levelized period resulting from the application of the straight-line depreciation rate. SCGC argues that it is not proposing that the depreciation expense for any given year be the same as that resulting from application of the straight-line depreciation rate for that year; rather, SCGC's methodology adjusts the depreciation expense in each year to arrive at a levelized cost of service.[485]

416. SCGC argues that the term of Kern River's current debt no longer precisely coincides with the terms of its shipper contracts. In addition, Kern River's proposed debt component of capitalization no longer coincides with its 70% debt capital recovery target. In any event, Commission policy is that depreciation should be based on the remaining economic life of the facilities. SCGC proposes that Kern River should, for each levelized vintage, base its depreciation on the system-wide remaining economic life ultimately adopted in this case and, therefore, recover depreciation equitably between current and future ratepayers. [486]

417. The position of Pinnacle West is that Kern River should not be allowed to continue depreciating at an accelerated rate designed to recover 70% of transmission

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[482] BP IB at 2, 27, and 35.
[483] RCG IB at 37-38.
[484] *Id.* at 33.
[485] SCGC at 25-27.
[486] *Id.* at 28-30, c*iting Trailblazer Pipeline Co.*, 50 FERC ¶ 61,188 at 61,601.

plant investment by the end of the term of shipper contracts. Pinnacle West argues that by using a 70% recovery for a ten-year contract period, Kern River is essentially using a fourteen-year life for the assets of shippers with ten-year contracts which creates an inequity between the existing firm shippers and succeeding generations of shippers on the Kern River System. [487]

418. CES, High Desert, Edison Mission, and Questar take no position on this issue.

419. CONCLUSION -- Kern River has carried its burden of proving that its regulatory depreciation expense, based on recovering 70% of transmission plant investments by the end of shipper contracts, produces just and reasonable rates.

420. DISCUSSION -- Participants have offered no policy reason which would compel changing the allocation of risk among Kern River's lenders and shippers. Kern River's arguments are persuasive. [488]

D. O&M and A&G Expenses

421. ISSUE -- Basing O&M rates on actual test period expenses for the twelve months ending October 31, 2004

422. POSITIONS -- The position of Kern River is that its rates should be based on actual test period O&M expenses. Kern River argues that the Commission held in *Northwest Pipeline*, [489] that the use of the most recent and updated, actual data should be used in the calculation of a pipeline's cost-of-service. Kern River argues that its actual test period O&M labor expenses more accurately reflect Kern River's anticipated, going-forward capital spending levels and should be accepted. [490]

423. Kern River dismisses Staff's views that certain of Kern River's updated expenses are not representative of Kern River's ongoing costs. Kern River argues that Staff disregards the fact that its three-year average includes years in which Kern River built two major mainline expansions and two laterals, far more than doubling the size of the system. Kern River contends that because of this, Staff's proposed three-year average labor capitalization ratio does not produce a representative amount of O&M labor expenses and therefore does not accurately reflect Kern River's anticipated going forward capital spending levels and should be rejected. [491]

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[487] Pinnacle West IB at 29-30.
[488] Initial Decision ¶ 409 and KR IB at 40-41.
[489] *Northwest Pipeline Corp.*, 87 FERC ¶ 61,266 at 62,028-30 (1999)
[490] KR IB at 44.
[491] *Id*. at 44-45.

424. The position of Staff is that Kern River's proposed O&M updates are acceptable, except for Account No. 850, Operation Supervision and Engineering, and Account No. 856, Mains. Staff maintains that those two accounts, even updated, still appear unrepresentative and Staff recommends that Kern River's "as-filed" numbers for these accounts be used. Staff also accepts Kern River's updated proposed pipeline safety costs. Staff claims, however, that Kern River's filed labor amount should be adjusted by $1,406,361. Staff recommends an O&M expense of $7,564,423 which is a reduction of $868,693 from the O&M expense claimed by Kern River in its filing. Staff also argues that its recommendation for averaging best reflects a balance between past activity and future uncertainty and is consistent with Commission policy and precedent.[492] Pinnacle West agrees.[493]

425. The position of RCG is that Staff is correct and that Kern River's end-of-test-period actual costs, based on the 45-day update should be used. However, RCG contends that an average capitalization percentage over the most recent three-year period would accurately reflect future costs, because this would incorporate both construction and non-construction periods applied to the end-of-test period O&M expenses.[494]

426. The position of High Desert is that it accepts Kern River's O&M expenses from Kern River's filed rate. It takes no position on the O&M expenses filed in the 45-day update, with the exception of Account No. 850.[495]

427. The position of SCGC is that Kern River should be required to use end-of-test-period actual costs, rather than base period costs, to the extent that those costs are shown to be representative of Kern River's ongoing expenses. SCGC also agrees with Staff that Kern River should be required to average its capitalized O&M expense over a three-year period.[496]

428. BP, CES, Edison Mission, and Questar take no position on this issue.

429. CONCLUSION -- Kern River carried its burden of proving that its proposal to base its O&M expenses on actual test period expenses for the twelve months ending October 31, 2004 produces just and reasonable rates.

430. DISCUSSION -- Kern River appropriately proposes to base its O&M expenses

[492] Staff IB at 41-42 and Staff RB at 36-37.
[493] Pinnacle West IB at 34.
[494] RCG IB at 38.
[495] High Desert IB at 19.
[496] SCGC IB at 30.

on actual test period expenses for the twelve months ending October 31, 2004. Kern River's argument that its use of the most recent and updated, actual data should be used in the calculation of its cost-of-service is persuasive. [497]

431. ISSUE -- A&G Expenses

432. POSITIONS -- The position of Kern River is that its proposed A&G expenses are based on actual test period A&G expenses and, hence, are the best evidence of ongoing costs and should be adopted. Staff's claim that Kern River should adjust certain accounts downward to reflect its as-filed A&G expense amounts instead of its updated, actual end-of-test-period amounts disregards the principle of *Northwest Pipeline*. [498]

433. The position of Staff is that the issue is whether Kern River's as-filed amounts must be updated and reflected in its rates if there is no material difference between the two. Staff contends that updates are not required to be used in rates, but can be used to test the reasonableness of filed-for amounts. Staff also recommends a five year amortization period for Account 928 and proposes reducing the amounts in Account 923 by $1,059,525. Staff further argues that Kern River's A&G costs should be functionalized using the Commission-approved *KN* methodology. Staff has reduced Kern River's filed-for A&G expense of $10,521,677 by $917,840. [499]

434. The position of BP is that use of the A&G expense levels reflected in the 45-Day update is appropriate.[500]

435. The position of RCG and Pinnacle West is that Staff is correct. [501]

436. The position of High Desert is that Staff's contention that A&G costs should be allocated among customer classes should be rejected.[502]

437. The position of SCGC is that it agrees with Kern River that it should use end-of-test- period actual costs, with the proviso of only to the extent that those costs are shown to be representative of Kern River's ongoing expenses.[503]

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[497] Initial Decision ¶¶ 42-21 and KR IB at 44-45.
[498] KR IB at 2 and 45; *Northwest Pipeline Co.*, 87 FERC ¶ 61,266 (1999), *order on reh'g*, 92 FERC ¶ 61,287 (2000).
[499] Staff IB at 43 and Staff RB at 37.
[500] BP IB at 36.
[501] RCG IB at 39 and Pinnacle West IB at 34.
[502] High Desert IB at 19.
[503] SCGC IB at 31.

438. CES, High Desert, Edison Mission, and Questar take no position on this issue.

439. CONCLUSION -- Kern River carried its burden of proving that its proposed A&G expenses are just and reasonable.

440. DISCUSSION -- Kern River's proposal regarding basing A&G expenses on actual test-period data produces just and reasonable rates. *Northwest Pipeline*, as Kern River points out, controls. [504] *KN* is not appropriate when actual costs can be ascertained.

441. ISSUE -- 3% automatic inflation factor for O&M and A&G expenses

442. POSITIONS - - The position of Kern River is that it should be allowed a 3% annual inflation factor for O&M and A&G expenses. Kern River argues that the 3% comports with its experience regarding inflation and is an integral part of its overall methodology which had been approved by the Commission since the pipeline's original certification. Kern River says the Commission has recognized the need for escalators in approving levelized rates for other pipelines. Kern River argues that none of the pipelines in the cases cited by Staff and Participants in support of their view that an automatic escalator is not appropriate have levelized rates. [505]

443. The position of every Participant, except Edison Mission and Questar who take no position on this issue, is that Kern River should not be allowed an automatic inflation adjustment. They argue, among other things, that such adjustment is speculative and contrary to Commission policy, as the Commission has consistently rejected such adjustments as not "known and measurable" in Section 4 rate cases. [506]

444. CONCLUSION -- Kern River has not carried its burden of proving that its proposed 3% inflation factor for O&M and A&G expenses produces just and reasonable rates.

445. DISCUSSION -- Kern River's proposed 3% inflation factor for O&M and A&G expenses would not produce just and reasonable rates because Kern River has not shown that it has had such inflation. Calpine presented effective argument on this issue Calpine

[504] Initial Decision ¶ 430.
[505] *KR IB* at 34-36 and 45; *see Mojave*, 81 FERC at 61,680.
[506] Staff IB at 44, BP IB at 36, RCG IB at 39-40, RCG RB at 34, CES IB 33, CES RB at 34-35, High Desert IB at 20, SCGC IB at 31, Pinnacle West IB at 31; *see Trunkline Gas Co.*, 90 FERC ¶ 61,299 at 62,136; *Columbia Gulf Transmission Co.*, 67 FERC ¶ 61,242, at 61,802 (1994), *reh'g*, 68 FERC ¶ 61,123 (1994); *Central Maine Power Co.*, ¶ 61,192 at 61,929 (1993)

demonstrates that Mr. Warner did not remove certain incremental A&G costs along with the associated O&M expenses he subtracted as shown on Ex. KR-26. Removing the additional $9,981,187 from the total $26,407,000 shows that the O&M/A&G level for the Rolled-In System actually decreased from the 1993 levels to the most recent amounts. Comparing the $19,007,000 (1993) from the adjusted current Statement A figure of $16,426,240 (2004) shows that no material inflation has occurred with respect to those expenses.[507] Including the A&G expenses was incorrect. Moreover, Calpine raised the issue in its prepared rebuttal testimony, so Kern River cannot rightfully claim surprise. Kern River had opportunity to address Calpine's claim and did not.[508]

E. Income Taxes

446. ISSUE -- Inclusion of federal income tax allowance in cost-of-service

447. POSITIONS - - The position of Kern River is that under Commission policy expressed in its *Inquiry Regarding Income Tax Allowances*,[509] Kern River is entitled to a federal income tax allowance since it generates taxable income that is reported by its parent, MEHC, in a consolidated federal income tax return.[510]

448. Kern River disputes the argument of Calpine that Kern River's right to recover a tax allowance should depend on the ultimate treatment of Kern River's NOLs. Kern River argues that the NOL and tax allowance issues are separate and properly resolved independent from one another under the Commission's stand-alone policy. Kern River further argues that the Commission has recently rejected arguments like Calpine's in a proceeding involving a tax allowance for an electric utility organized as a limited liability corporation.[511]

449. The position of Staff is that Kern River's filed for federal income tax allowance should be reduced by $14,953,276 and Kern River's state income tax should be reduced by $2,491,441. Staff claims that Kern River has not complied with the Commission's policy as outlined in *Inquiry Regarding Income Tax Allowances*.[512]

450. The position of BP is that Kern River is not entitled to a federal income tax

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[507] Ex. KR-26 at lines 26, 35, Ex. CES-69 at 12, II. 4-17, and Item by Reference A, Summation of Statement A at 1, lines 2 and 3 Column (e).
[508] CES RB at 33-36.
[509] 111 FERC ¶ 61,139 at 61,741 (2005).
[510] KR IB at 46.
[511] KR RB at 38; *see Trans-Elect NTD Path 15, LLG,* 112 FERC ¶ 61,202 at 62,045 (2005).
[512] Staff IB at 44 and Staff RB at 38.

allowance because it is a general partnership that does not pay income taxes and has no income tax liability of its own. BP argues that Kern River's reliance on the Commission's *Inquiry Regarding Income Tax Allowances* is misguided because Kern River has failed to meet the requirement that it demonstrate an "actual or potential income tax liability" associated with the income derived from public utility assets.[513] BP argues that neither Kern River nor its owners will be paying any taxes on income generated by Kern River during the test period or the foreseeable future and so Kern River should not be given an income tax allowance in its regulated cost of service.[514]

451. BP contends that the Commission has recently interpreted its new income tax policy in *Trans-Elect*. BP argues that Kern River has not made the filings required by *Trans-Elect* to demonstrate that each Kern River equity owner has a projected taxable income level from all income sources which would result in that equity being subject to the 35% marginal corporate income tax bracket. According to BP, Kern River has made no showing that its equity owners have any other source of income and, further, Kern River admits that its NOL will completely offset the pipeline's taxable

income until 2009. [515]

452. The position of Calpine is that the Commission's *Inquiry Regarding Income Tax Allowances* appears to afford Kern River the opportunity to request an allowance for federal income taxes as part of its cost of service. Calpine contends that in order to determine the proper tax allowance for Kern River, Commission policy requires application of the "stand-alone" principle which would, in determining Kern River's tax liability, account for all jurisdictional income and deductions. Because of Kern River's proposals regarding its claimed NOL, on a stand-alone basis, if the NOL were approved, Kern River's income from its 2003 Expansion services would not be fully taxable for six to eight years and therefore Kern River would gain an unmitigated windfall if afforded the full tax allowance it seeks. Calpine, therefore, contends that if Kern River's NOL proposal were to be accepted as proposed, Kern River's federal income tax allowance should be predicated on the level of projected end-of-test-period taxable income attributed to its rolled-in services. If Kern River's NOL were to be allowed but, as recommended by Calpine, were to be spread to all shippers, Kern River should be denied a federal income tax allowance. Calpine contends that under either approach, Kern River could submit a Section 4 filing to adjust its tax allowance once its NOL is exhausted. According to Calpine, if Kern River's proposed NOL is rejected, then it would be entitled

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[513] BP IB at 36, see *Inquiry Regarding Income Tax Allowance*, 111 FERC ¶61,139 at P23 (2005).
[514] *Id*.
[515] BP RB at 32-33.

to a full income tax allowance. [516]

453. The position of SCGC is that the Commission should require Kern River to show an actual or potential income tax liability in order to include a tax allowance in its cost of service.[517]

454. RCG, High Desert, Pinnacle West, Edison Mission, and Questar take no position on this issue.

455. CONCLUSION -- Kern River has not carried its burden of proving it is entitled to an income tax allowance for the entity or individual partners as required by Commission policy expressed in its *Inquiry Regarding Income Tax Allowance*.

456. DISCUSSION -- Kern River is not entitled to an income tax allowance because it has not proven actual or potential income tax liability consistent with Commission policy as expressed in its *Inquiry Regarding Income Tax Allowance* and *Trans-Elect, NTO Path 15*. Kern River simply maintains that it generates taxable income that is reflected in the consolidated corporate income tax return of Kern River's parent and establishes actual tax liability associated with public utility income generated by Kern River. What Kern River does not show is who has actual or potential liability on that income. Under the Commission's policy, a pass-through entity is permitted an income tax allowance if that entity, its members, or partners have an actual or potential liability on that income. [518] The Commission would not accept affidavits filed by the individual Trans-Elect partners which simply said that the partner was subject to actual or potential income tax liability. The Commission found that not sufficient proof of liability. [519] Kern River does not, therefore, meet Commission requirements.

II. Cost Allocation and Rate Design

A. Cost Allocation

457. ISSUE - - Allocating A&G costs among shippers

458. POSITIONS - - The position of Kern River is that a direct assignment of costs is always preferable to allocations when such assignments are based on a reliable accounting record.[520] Kern River indicates that to the maximum extent feasible, Kern

[516] CES IB at 36-38.
[517] SCGC IB at 34.
[518] *Inquiry Regarding Income Tax Allowance,* 111 FERC ¶ 61,139 at 61,741.
[519] *Trans-Elect NTD Path 15, LLC,* 112 FERC ¶ 61,202 at 62,044.
[520] Exhibit KR-93 at 37.

River's administrative personnel directly charge their time and costs to the 2003 Expansion, the High Desert, the Big Horn, and the Rolled-In System. If direct assignment is not feasible, then a predetermined default code is established for each employee to distribute the charges to, or among the appropriate accounts. Kern River argues that this is consistent with Commission precedent and believes that only A&G costs that cannot be directly assigned should be allocated based on the *KN* [521] methodology, following Commission precedent in *Northwest Pipeline Corp.*[522]

459. The position of Staff is that all of Kern River's A&G costs should be allocated under the Commission-approved *KN* methodology because these are indirect costs relating to all the services Kern River provides. Staff argues that it has demonstrated that Kern River has deviated from the Commission approved *KN* methodology by allocating only certain A&G costs to facilities and directly charging other expenses. Staff contends that any attempt to allocate A&G costs directly is strictly subjective since they are by their nature indirect, and because specific costs will change annually.[523]

460. The position of High Desert is that Kern River's direct allocation of A&G costs to it is appropriate. High Desert argues that the approach based on *Northwest* and *Transco* should be adopted because direct assignment is consistent with the Commission's pro-competition policies for the natural gas industry. High Desert points out that, no Participant, including Staff, questioned the accuracy of Kern River's direct assignments. High Desert also explains that adopting any other method has a significant impact on High Desert. For example, under proposals by Staff, High Desert's annual A&G allocation is increased by 450%. [524]

461. The position of Pinnacle West is that the *KN* methodology should be used for all A&G costs.[525]

462. BP, RCG, CES, SCGC, Edison Mission, and Questar take no position on this issue.

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[521] *Kansas-Nebraska Natural Gas Co*., 53 FPC 1691 at P22 (1975).

[522] Exhibit KR-14 at 9 and Exhibit KR-93 at 38; see *Northwest Pipeline Corp.*, 87 FERC ¶ 61,266 at 62,045 (1999).

[523] Staff IB at 45 and Staff RB at 39.

[524] High Desert IB at 23-26 and High Desert RB at 13; Ex. HD-6; see *Northwest Pipeline Corp.*, 87 FERC ¶ 61,266 (1999), *reh'g*, 92 FERC ¶ 61,287 (2000), *petition for review dismissed in part and denied in part sub nom. Canadian Association of Petroleum Producers v. FERC,* 308 FERC F.3d 11 (2002).; *Transcontinental Gas Pipeline Corp.,* 106 FERC ¶ 61,299 (2004), *reh'g*, 112 FERC ¶ 61,170 (2005).

[525] Pinnacle West IB at 36.

463. CONCLUSION -- Kern River has carried its burden of showing that its proposed methodology for allocating A&G costs among services produces just and reasonable results.

464. DISCUSSION -- Kern River is correct in its assertion that a direct assignment of A&G costs is preferable when such assignments are based on reliable accounting record.[526] Kern River's administrative personnel directly charges time and costs to the individual shippers: 2003 Expansion, the High Desert, the Big Horn, and the Rolled-In. If direct assignment is not feasible, then a predetermined default code is established for each employee to distribute the charges to, or among the appropriate accounts. No Participant has challenged the reliability of Kern River's assignment. Use of the *KN* method, on the other hand, is preferred when it is not possible to directly assign costs.

465. ISSUE -- Allocation of cost of facilities used by both Rolled-In shippers and 2003 Expansion shippers

466. POSITIONS -- The position of Kern River is that its allocating to the Rolled-In shippers of the cost of item that existed before the construction of the 2003 Expansion produces just and reasonable rates. Those items include the cost of land, rights of way, compressor station structures, and certain communications equipment. Kern River believes that allocation of those costs to the Rolled-In shippers comports with the principles of fairness and cost responsibility. [527]

467. Staff does not contest Kern River's position. [528]

468. The position of RCG is that certain common costs should be allocated to both sets of shippers. RCG argues that the land, rights of way, compressor station structures, and communications equipment benefit all of Kern River's customers. [529]

469. The position of Calpine is that RCG's proposed allocation of common costs should be rejected because it would create a subsidy flowing from Kern River's 2003 Expansion shippers to its Rolled-In shippers. Calpine argues that RCG has not met the "changed circumstances" criterion as required by the *1999Pricing Policy Statement*. Calpine argues that, contrary to the Commission's incremental pricing policies, RCG's proposal would leave virtually all Rolled-In system costs eligible for reallocation to incremental services on an integrated pipeline system like Kern River.[530]

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[526] Exhibit KR-93 at 37.
[527] KR IB Findings of Fact III 1.
[528] Staff IB at 45.
[529] RCG IB at 41.
[530] CES IB at 38-39 and CES RB at 37.

470. The position of SCGC is that Kern River should be required to allocate the common costs to both the 2003 Expansion Shippers and the Rolled-In Shippers, as proposed by RCG. SCGC points out that no Participant disputes the fact that both Rolled-In and 2003 Expansion shippers use the common cost facilities. SCGC further claims that the *1999 Pricing Policy Statement* does not support the notion that facilities used by both existing shippers and expansion shippers should be borne by existing shippers only. According to SCGC, the *1999 Pricing Policy Statement* clearly indicates the Commission's concern about the possibility that costs of existing facilities that were used by the expansion shippers and that served to make the expansion less costly, would be borne solely by the existing shippers. SCGC argues that the Rolled-In Shippers are subsidizing the 2003 Expansion Shippers by bearing all of the common costs and that there is no evidence indicating that the Commission specifically addressed the costs associated with those facilities in its certificate order for the 2003 Expansion. [531]

471. The position of Pinnacle West is that RCG's proposal is inconsistent with the Commission's *1999 Pricing Policy Statement*. Pinnacle West claims that there is no precedent requiring the creation of subsidies flowing from expansion shippers back to pre-existing shippers. [532]

472. BP, Edison Mission, and Questar take no position on this issue.

473. CONCLUSION -- Kern River carried its burden of proving that cost for items in existence before construction of the 2003 Expansion should be borne by the Rolled-In shippers.

474. DISCUSSION -- The Undersigned agrees with the observation of the Administrative Law Judge in *Trailblazer Pipeline Company*: "nowhere in Commission pronouncements has the Commission required the assignment of existing facility costs to expansion customers." [533] In this case, as in *Trailblazer Pipeline*, Participants advocating sharing costs have not shown any changed circumstance since the authorizing certificate that would indicate the expansion shippers should pay such costs.

475. ISSUE: Rate distinction between ten-year and fifteen-year shippers on the Rolled-In System and on the 2003 Expansion System

476. POSITIONS: The position of Kern River is that it is appropriate that the ten-year and fifteen-year shippers have different rates. Kern River explains that the ten-year

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[531] SCGC RB at 3-6; *see 1999 Pricing Policy Statement*, 88 FERC ¶ 61,746 at 61,746.
[532] Pinnacle West IB at 37-38.
[533] 106 FERC ¶ 63,005 at P 80 (2004).

shippers bargained for the right to pay additional depreciation expense during their contract terms in order to qualify for the lower, step-down rate five years earlier than if they had signed fifteen-year contracts. [534] RCG and SCGC agree that different rate is appropriate. [535]

477. The position of Staff is that there should be no distinction in rates between ten-year and fifteen-year shippers because the length of the contracts has no bearing on the value of the service they receive. Staff argues that where shippers are provided the same benefit they should be charged the same rate, and to do otherwise is discriminatory.[536]

BP and Pinnacle West agree. [537]

478. CES, High Desert, Edison Mission, and Questar take no position on this issue.

479. CONCLUSION -- Kern River carried its burden of proving that the distinction in rates between the ten-year and fifteen-year shippers produces just and reasonable rates.

480. DISCUSSION -- The ten-year Rolled-In shippers and the ten-year Expansion shippers bargained for the option of paying rates that included more depreciation expense than the rates for the fifteen-year shippers. The ten-year shippers pay more depreciation expense because all debt associated with their contracts is amortized, in depreciation expense, over the shorter contract terms. The bargained-for-benefit for the ten-year shippers is that they qualify for the lower, step-down rate five years sooner than do the fifteen-year shippers. [538] No Participant presented persuasive evidence justifying disruption of the expectations of signatories to the contracts.

481. ISSUE -- Calculation of the 2002 Expansion Roll-in

482. POSITIONS -- The position of Kern River is that it should not change the roll-in methodology now because that would shift costs between shipper classes to the benefit of the ten-year shippers at the expense of the fifteen-year shippers. Kern River argues that if the roll-in plan continues as implemented by Kern River and approved by the Commission, and if the ten-year shippers remain on the system after their current contracts expire, then over time all shippers would receive an identical benefit of the roll-in of the 2002 Expansion, both as to the cost reduction amounts received and as to

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[534] Ex. KR 23 at 30-31 and Ex. KR-17 at 9.
[535] RCG IB at 44, SCGC IB at 36, and SCGC RB at 12-13.
[536] Staff IB at 48 and Staff RB at 40.
[537] BP IB at 44 and BP RB at 41-42, Pinnacle West IB at 38-39, and Pinnacle West RB at 25; *see* FERC Statutes and Regs. ¶ 31,091 (2000).
[538] Ex- KR-23 at 20-31; Initial Decision ¶ 53.

the timing and receipt of those benefits. [539]

483. Staff does not contest Kern River's position on this issue. [540]

484. The position of BP is that if levelized rates are retained, the Commission should separately calculate for ten-year and fifteen-year shippers whether to roll-in the 2002 Expansion to Original System costs. BP says Kern River's current approach causes the ten-year Rolled-In System shippers to bear the largest proposed rate increase of all Kern River's shippers in the subject Section 4 rate case. BP claims that by adding the ten- and fifteen-year Expansion 2002 costs and revenues to calculate a combine unit rate reduction for the ten- and fifteen-year Original System shippers, Kern River causes a cross-subsidization of the fifteen-year shippers by the ten-year shippers. That occurs because the unit rate impact of the ten-year Expansion 2002 roll-in is much higher than the unit rate impact of the fifteen-year Expansion 2002 roll-in. According to BP, the difference is due to the greater relative proportion of Expansion 2002 services represented by ten-year contracts relative to the proportion represented by ten-year Original System services. [541]

485. The position of RCG is that Kern River should allocate the 2002 Expansion roll-in benefit on an equal-unit basis to the rolled-in rates. RCG opposes BP's position claiming it would create unfair cross-subsidies between the ten-year and fifteen-year Rolled-In shippers.[542]

486. The position of SCGC is that RCG's position on this issue is correct. SCGC opposes BP's position. SCGC argues that, despite BP's assertions to the contrary, BP's proposal implies a relationship between the ten-year 2002 Expansion shippers and the ten-year Original System shippers, but such relationship does not exist. SCGC argues that there is no reason for entitling the ten-year Original System shippers to the benefit generated by the ten-year 2002 Expansion shippers, and entitling fifteen-year Original System shippers only to the benefit generated by the fifteen-year 2002 Expansion shippers, solely based on their contract terms. SCGC argues that BP's proposal lacks logic and should be rejected. [543]

487. CES, High Desert, Pinnacle West, Edison Mission, and Questar take no position on this issue.

488. CONCLUSION -- Kern River has carried its burden of proving that it should not

[539] Exhibit KR-57 at 39-42.
[540] Staff IB at 50.
[541] BP IB at 48-49 and Ex. BP1 at 36-37.
[542] RCG IB at 48.
[543] SCGC IB at 37 AND SCGC at 19.

change the calculation methodology for roll-in of the 2002 Expansion facilities.

489. DISCUSSION -- BP recommended the change and is the only Participant arguing for it. Kern River argues persuasively against BP's recommended change. Kern River points out that the only reason the ten- and fifteen-year shipper class pay different rates is that those shippers voluntarily chose to pay for their shares of seventy percent of facility investments over either ten years or fifteen years. The ten-year shippers chose to pay higher depreciation amounts during shorter contract terms. No party to the 2002 Expansion certificate opposed Kern River's approach and the Commission accepted it. BP has not proven that Kern River's approach is not just and reasonable.

b. Rate Design

490. ISSUE -- Blended fuel reimbursement rate for forward-haul, market-oriented and short-term (IT and AOS) capacity

491. POSITIONS -- The position of Kern River is that its proposed blended compressor fuel reimbursement rate for IT and AOS, which is derived by weighting fuel consumption by a factor that compares each system's billing determinants to the total system billing determinants, is appropriate. According to Kern River, this approach is reasonable because the operationally available capacity that is used to provide such services is attributable to the system as a whole and not to either system individually, making the blended fuel rate equitable for all shippers. [544]

492. Staff does not contest Kern River's position on this issue. [545]

493. The position of BP is that blending fuel reimbursement rate is appropriate. BP takes issue with Calpine's proposal for the highest fuel rate for all IT and AOS service because, according to BP, it unjustly benefits the 2003 Expansion shippers. BP proposes that the AOS fuel rate should be based on the rate schedule under which the shipper's firm service is provided. [546]

494. The position of RCG is that the AOS fuel rate for Rolled-In shippers should also be the same fuel rate paid by Rolled-In shippers for their firm transportation service. Finally, RCG argues that there is no basis for applying the use of a blended fuel rate for IT to AOS associated with the Rolled-In System.[547]

[544] KR IB at 50; Ex. KR-1 at 14-15.
[545] Staff IB at 50. Staff RB at 42.
[546] BP IB at 49.
[547] RCG IB at 46-47 and RCG RB at 39.

495. The position of Calpine is that Kern River's proposed blended fuel rate finds no support in Commission precedent. Calpine argues that Kern River's proposal would increase the fuel rate for IT and AOS customers, but would still leave those shippers with a fuel rate below that assessed against 2003 Expansion shippers. Calpine argues that because Kern River's IT and AOS shippers primarily utilize 2003 Expansion capacity, those shippers should pay the expansion service fuel cost, rather than a blended cost that incorporates the Rolled-In System's lower fuel cost. Calpine argues that this approach would eliminate discrimination inherent in Kern River's proposal, and would be consistent with Kern River's IT rate design, which is based on 100% load factor use of the 2003 Expansion ten-year rate, the highest firm rate on Kern River's system. Calpine argues that alternatively, if the Commission does adopt a blended fuel rate for Kern River's short-term services, that fuel rate should be based on the actual capacity utilized, rather than on contract demand. [548]

496. The position of SCGC is that Kern River's proposed blended fuel reimbursement rate applicable to AOS for Rolled-In shippers should not be applied to SCGC. SCGC argues that this is unfair to it for the same reasons Kern River's proposal to use the highest firm rate on Kern River's system as the basis of the AOS rate is unfair. SCGC supports RCG's position on this issue.[549]

497. High Desert, Edison Mission, Pinnacle West, and Questar take no position on this issue.

498. CONCLUSION -- Kern River carried its burden of proving that its proposed blended fuel rate proposal for forward-haul, market-oriented and short-term capacity produces just and reasonable rates.

499. DISCUSSION -- AOS and IT are identical services and are primarily using (based on the test period evidence) 2003 Expansion capacity, to receive service. They are not committed to reservation charges so they do not incur any expenses unless they choose to receive the benefit of an actual movement of natural gas. Consequently, Kern River's blended fuel rate proposal is consistent with the IT rate determination made herein and is found just and reasonable. Although released capacity of 2003 Expansion shippers do, and will experience a disadvantage in fuel expenses when compared to firm Rolled-In shippers, the 2003 Expansion shippers were aware of this at the time of the original certification of the 2003 project. The understanding was that rates would be fully incrementally priced. The conclusion made herein is fully consistent with the Commission's *1999 Pricing Policy*.

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[548] CES IB at 48-49.
[549] SCGC RB at 20 and SCGC IB at 37.

500. ISSUE -- Use of a 95% load factor billing determinants (based on original system year-round firm capacity)

501. POSITIONS -- The position of Kern River is that the 95% load factor, which is applicable to the Original System, is just and reasonable. Kern River argues that there is no factual or legal support for modifying the 95% load factor condition and that there is no justification for disturbing the risk allocation that the Commission imposed, and Kern River accepted, for the life of its Original System. Kern River counters the argument that it typically operates at 100% of the Original System capacity, by contending that this argument overlooks the fact that Kern River has borne the risk of under recovery owing to the 95% load factor condition, and that it continues to face the future prospect of remarketing unsubscribed capacity that arises due to business risk. [550]

502. Kern River further argues that the 95% load factor condition was specifically designed to address the competition between Kern River and other proposed EOR pipelines and was a departure from the policy of basing rates on projected service levels. Kern River argues that the OEC requirement that rates be designed on projected units of service was inapplicable and that the Commission rejected identical requests to remove the same 95% load factor condition in *Mojave Pipeline*. [551]

503. The position of Staff is that rates for the Original System (the 95% load factor only applies to the Original System) be designed using a 100% load factor, since there is strong demand for the system and the Commission has recognized that the 95% load factor OEC condition could be addressed in a future rate proceeding. Staff further contends that Kern River has not met its burden of showing that continuance of a 95% load factor will result in just and reasonable rates.[552]

504. The position of BP is that Kern River's use of a 95% load factor is neither just nor reasonable; instead it is unduly discriminatory and constitutes a penalty for the Original System shippers. First, the original discussion for imposing the 95% load factor condition no longer exists, since Kern River has run at 100% of its Original System capacity or above for more than a decade. Additionally, the 95% load factor was clearly the floor, limiting how far billing determinants could be reduced; it was not a ceiling. BP argues that Kern River's application of the 95% load factor condition to firm shipper contracted capacity rather than as a percentage of actual system physical capacity has increased Kern River's over recovery. Further, BP argues that the use of a 95% load factor penalizes the Original System shippers because the Original System is used at, or above 95% of the contracted capacity. BP also contends that the use of a 95% load factor

[550] KR RB at 39.
[551] *Id.* at 40-41; s*ee Mojave Pipeline,* 81 FERC at 61,684.
[552] Staff IB at 45-46, Staff RB at 40, Ex. S-12 at 26, Ex. S-21, Ex. S-27 at 13-14,

is unduly discriminatory because even though the Original System shippers receive the same quality of transportation from Kern River as is received by any other firm shipper on the system, the Original System Shippers are the only shippers to which the 95% load factor applies. BP argues that the undue discrimination has no cost basis and is contrary to regulatory requirements that revenue responsibility be aligned with cost incurrence and benefits and that rates be designed to recover the costs properly allocated to the respective service. BP argues that *Mojave Pipeline* does not support Kern River's position because, contrary to the facts in *Mojave Pipeline*, Kern River has experienced a windfall of as much as $50 million annually under the 95% load factor for more than a decade. [553]

505. The position of RCG is that Kern River's use of a 95% load factor is not appropriate. RCG argues that Kern River's rates should be based on the actual billing determinants, which are 100% of the Original System capacity.[554] RCG counters Kern River's contention that its certificate provides a 95% load factor ceiling for design of the Original System component of the rolled-in rates. RCG argues that the position has never been approved as just and reasonable by the Commission and that the OEC order provided that Kern River's subsequent rate case filings "must use the same or greater throughput levels."[555] Further, RCG contends that the Commission's OEC regulations clarify that the 95% load factor throughput assumption can be exceeded.[556]

506. RCG argues there is no legal or policy justification for Kern River's claim that it should be permitted to reduce the billing determinants below the actual quantity for the calculation of the Original System rolled-in rates. RCG further argues that this is a Section 4 issue because it is integrally related to the throughput which Kern River must justify as part of its proposed rate calculation and its elimination should have a retroactive effect. RCG also argues that Kern River's reliance on the *Mojave Pipeline* order is misplaced because, unlike Mojave, Kern River's original system is 100% subscribed, and Kern River's contracts do not have rate caps. [557]

507. The position of SCGC is that Kern River's use of a 95% load factor billing determinants is inappropriate. SCGC supports RCG on this issue. SCGC argues that the Commission determinations that Kern River relies on do not support a continued use of

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[553] BP IB at 37-42, BP RB at 34-36, Ex. BP-77, Ex. BP-78, Ex. BP at 15 and Tr. 1094-97.
[554] RCG IB at 41-42, *citing Mojave*, 81 FERC at 61,684, RCG RB at 43, RCG-2 at 30.
[555] *Id.* at 41, *citing Kern River Gas Transmission Co., et al.*, 50 FERC ¶ 61,069 at 61,151 (1990).
[556] *Id. at* 43; see BP-77 (18 C.F.R. § 157.1039(d)(4)). RCG notes that although the Commission has withdrawn the OEC regulations, Kern River's OEC remains in effect for the original system, as has been confirmed on cross-examination by Kern River.
[557] Id. at 36-37 and RCG RB at 36.

the 95% load factor. SCGC counters Kern River's claim that creating a level playing field among competitors was the Commission's primary goal in requiring a 95% load factor. SCGC argues that the similarities between Kern River and WyCal provided the basis for the Commission's conclusion that the 95% load factor established for WyCal was also appropriate for Kern River. SCGC further counters Kern River's argument that the Commission has already considered and rejected changing the 95% load factor, contending that Kern River does not clarify when this occurred and that Kern River's reliance on *Mojave Pipeline* is misplaced because the Commission decided it was not appropriate to modify the 95% load factor for Mojave only because of Mojave's shift to an SFV rate design. Further, SCGC argues that as noted by RCG the Commission viewed the 95% load factor as a floor and that Kern River's use of the 95% load factor billing determinants raises Rolled-In shippers rates by $5.4 million annually. [558]

508. Calpine, Pinnacle, Edison Mission, and Questar take no position on this issue.

509. CONCLUSION -- Kern River has not carried its burden of proving that continued use of the 95% load factor produces just and reasonable rates.

510. DISCUSSION -- Kern River has operated at 100% load factor since inception of services. The original purpose of the 95% load factor does not now apply. The 95% load factor was intended to place the risk of lack of full subscription on the new pipeline versus on the shippers. It was intended to protect shippers and not be a windfall for the pipeline. The throughput requirement is intended as a floor to the throughput/design determinants to keep the pipeline at risk of at least that level of contract entitlements in its rates. Kern River has been fully contracted on the Original System since its inception and has operated above a 100% load factor design level for more than a decade. Therefore, the 95% requirement should be dropped,leaving the normal test period ratemaking concepts to govern the rate determinants for Kern River. The amounts of guaranteed revenue attained by Kern River above the designed-for-revenue requirement of the pipeline about $5.4. million - $7.8 million annually. [559] It amounts to a built-in rate design over-collection. It does not produce just and reasonable rates.

511. ISSUE -- Use of the EFV design

512. POSITIONS -- The position of Kern River is that its current EFV design allocates costs and designs rates without in any way inhibiting the creation of a national gas market, because it properly assigns cost responsibility so that each shipper pays its fair share of Kern River's cost of service. Kern River argues that this is consistent with

[558] SCGC IB at 35 and SCGC RB at 6-9.
[559] KR RB at 40-41 and Ex. KR 125.

Order No. 636 [560] because the Commission explained that differing levels of fixed costs in the pipeline's transportation usage charge could operate to distort gas purchase decisions and hinder competition between gas sellers at the wellhead; Kern River argues that in the Commission's view, accurate price signals must be based on the seller's costs in order to ensure fair and direct competition in the gas commodity markets. [561]

513. Kern River contends that proponents of a change to SFV have not demonstrated the impacts of the rate design shift on the entire system. Additionally, Kern River argues that the proponents of a change to SFV have not demonstrated that EFV is unjust and unreasonable or that changing to SFV would be just and reasonable. Kern River also argues that since Kern River's system has historically moved firm and total transportation volumes at a very high load factor of capacity, slack usage of capacity by some shippers has been generally sold as IT, short-term firm or AOS services. Kern River contends that assuming these conditions continue, any upside to Kern River related to the EFV rate design is not a significant contributor, from the pipeline's viewpoint, to the desirability of continuing the rate design. Kern River argues that use of EFV rate design is clearly in the interests of the vast majority of shippers and should be retained.[562]

514. The position of Staff and BP is that Kern River should not be allowed to use the EFV rate design. They argue that use of the SFV rate design is consistent with the Commission's current policy. The Commission has permitted some exceptions to its SFV policy, however, this case does not warrant an exception. [563] Staff points out that the Commission, in fact, has already said that Kern River should use the SFV rate design. [564]

515. The position of Calpine is that Kern River's proposal is permitted by Commission policy and is appropriate under the circumstances that currently prevail on Kern River's system. Calpine argues that since Kern River's EFV rate design benefits the 2003 Expansion Shippers by lowering the financial burdens placed on those shippers during their initial years of service, a change to SFV rates would impose significant additional costs on all shippers who take service at less than 100% load factor. Calpine further argues that there has been no showing that Kern River's EFV rate design has yielded unjust and unreasonable results that warrant its replacement or that there are changed

[560] 57 FR 13267, FERC Statutes and Regs. at P 30,939 at 30,434 (1992).
[561] Ex. KR-49 at 7.
[562] Ex. KR-23 at 56-59.
[563] Staff IB at 46-48, Staff RB at 40, BP IB at 42-43, and BP RB at 37.
[564] *Kern River Gas Transmission Co*., 62 FERC ¶ 61,191 at 62,256-58 (1993), *reh'g denied*, 64 FERC ¶ 61,049 (1992), *aff'd*, *Union Fuels v. FERC*, 129 F.3d 157 (D.C. Cir. 1997); *see also* Ex. S-12 at 21-22 and Ex. S-27 at 12-13.

circumstances that require reconsideration of the EFV rate design in this case.[565]

516. The position of SCGC is that Kern River should continue to use the EFV rate design. SCGC counters arguments that Kern River bears the burden of showing that a change from the Commission-preferred SFV rate design is appropriate, contending that the burden of proof lies with those who are proposing a change from Kern River's current rate design. SCGC argues that the proponents of changing to SFV have not shown that Kern River's EFV rate design has inhibited competition or distorted the creation of a national market for gas. SCGC argues that proponents of changing to SFV have also not shown that the slight rate difference between Kern River's EFV method and the SFV method has decreased or has had a negative impact on the Kern River system's throughput.[566]

517. The position of Questar is that Kern River should use the SFV rate design, arguing that it is consistent with the Commission's rate design policy in Order No. 636 and consistent with the Commission's DISCUSSION for encouraging the use of the SFV method pursuant to that order.[567] Questar contends that in *Northwest Pipeline* the Commission rejected the argument that EFV should be required where the pipeline has a monopoly in the region in order to give the pipeline an incentive to maintain high throughput levels.[568] Questar contends that in another *Northwest Pipeline* proceeding the Commission found rate reductions for certain customers to be an inadequate justification for EFV and that the Commission in *Arkla Energy Resources Company* rejected the pipeline's argument that its circumstances did not warrant an exception from SFV.[569]

518. Questar argues that while exceptions have been permitted by the Commission, an exception is not justified in Kern River's case. Questar argues that the Commission has permitted exceptions for intrastate pipelines where: 1) the proposed rate design has lower reservation charges than even the modified fixed variable method ("MFV"); 2) use of SFV would essentially assure that the pipeline would not be competitive and could not attract firm customers; 3) some of the pipeline's interstate competitors used non-SFV rate designs; 4) no party was harmed; and 5) the Commission goal of fostering a national pipeline grid was not impeded. Further, Questar argues that where interstate pipelines were involved, the Commission had granted exceptions pursuant to settlement

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[565] CES IB at 40-41.
[566] SCGC IB at 35 and SCGC RB at 10-11.
[567] Questar IB at 10 and 12.
[568] *Id.*
[569] Questar IB at 10 and 12-13; *see Northwest Pipeline Corporation,* 63 FERC ¶ 61,124 at 61,794 (1993) and *Northwest Pipeline Corp.,* 76 FERC ¶ 61,068 at 61,429-30 (1996); *Arkla Energy Resources Company,* 62 FERC ¶ 61,076 (1993), *reh'g denied and granted,* 64 FERC ¶ 61,166 at 62, 447-48 (1993).

agreements where there was shipper agreement and where there was a natural gas fired combined cycle cogeneration project. Questar argues however, that contrary to Kern River's justifications for deviation from SFV: 1) this is a contested proceeding where the parties have not agreed to continue the use of EFV; 2) the fixed costs included in the transportation charge are not minimal; and, 3) Kern River has shown that, excluding one low-load factor customer, in the aggregate, firm shippers may pay less under SFV than EFV. Questar points out that it is one of the highest load factor shippers on Kern River and that Kern River's proposed EFV rate design would require Questar to pay more than under a SFV rate design [570]

519. RCG, Pinnacle West, and Edison Mission take no position on this issue.

520. CONCLUSION -- Kern River has not proven that its continued use of the EFV design results in just and reasonable rates.

521. DISCUSSION -- EFV places a significant amount of fixed cost into the usage component of Kern's rates, some $17,798,706 – this proposal goes counter to the expressed Commission policy to lower usage charges to the minimum which would best allow the national pipeline grid to reveal the true cost of wellhead natural gas prices – thereby permitting the most effective competition between natural gas sources. The Commission has repeatedly upheld the use of SFV for interstate natural gas pipeline companies and only permits exception when all parties agree. [571] The Commission has previously ordered Kern River to adopt the SFV method. [572] No Participant has presented evidence that has carried the heavy burden the Commission requires with regard to its preference for SFV rate design method. Moreover, the rate impacts presented by Kern River, demonstrate that the bulk of the shippers are benefited from the switch to SFV (due to the very high load factor most shippers maintain under their contracts) – only one shipper appears adversely impacted (a load factor phenomenon). [573] However, the Commission has held that such adverse impacts do not justify departing from its policy expressed in Order No. 636. [574] Consequently, the EFV rate design method proposed by Kern River is unjust and unreasonable. The SFV method is found

[570] *Id*. at 13-16; *see EPGT Texas Pipeline*, 99 FERC ¶ 61,295 at 61,251-253 (2002), *reh'g denied., GulfTerra Texas Pipeline*, 106 FERC ¶ 61,184 (2004) (EPGT Texas Pipeline renamed GulftTerra Texas Pipeline prior to this order).

[571] *Northwest Pipeline*, 76 FERC¶61,068 at 61,429-430, 63 FERC¶61,124 at 61,794, and 65 FERC¶61,007.

[572] See 64 FERC¶61,049 at 61,418, and 62 FERC ¶ 61,191.

[573] BP RB at 37-38, Ex. KR-42, Ex. KR-23 at 58, and Initial Decision ¶¶ 517, 520 and 522. 63FERC¶61,124 at 61,794 (1993), 65 FERC¶61,007 (1993), Northwest Pipeline Corp., 76 FERC¶61,068 at 61,429-430 (1996).

[574] *Northwest Pipeline Corp.*, 76 FERC 61,068 at 61,429-430 (1996).

just and reasonable.

522. ISSUE -- Use of 100% load factor rate for IT and AOS service based on the highest firm service rate on the system

523. POSITIONS -- The position of Kern River is that maintaining its currently effective rate design for IT/AOS sevice produces just and reasonable rates. Those rates are based on the 100% load factor formula applied to the firm transportation recourse rate for ten-year 2003 Expansion shippers. This ten-year incremental firm service rate is the highest rate for transportation service on the pipeline. Kern River argues that its rate design for IT/AOS service benefits all firm shippers by creating a level playing field for the maximum rate and by providing Kern River an appropriate opportunity to maximize MOR, while remaining consistent with the requirement that the rate must be cost based. Kern River argues that this approach is consistent with its historic use of the highest, 100% load factor rate on the system for interruptible service. Kern River further notes its approach had been approved in the ET rate settlement, when three firm transportation rates were established.[575] Kern River argues that its IT/AOS design is consistent with Commission policy and that the Commission, in *Viking Gas Transmission*[576] approved a similar IT/AOS rate design.

524. Kern River argues that Staff's proposal would not promote the Commission's goal of allocative efficiency, because it would price IT/AOS service too low to properly ration capacity during periods of high demand. Kern River argues that this prevents capacity from being assigned to those customers who value the service the most. Kern River argues that RCG's proposal under prices the services and, therefore, would not allocate capacity in an efficient matter. Kern River also argues that RCG's proposal is discriminatory because it provides a lower preferential rate for Original System shippers than for 2003 Expansion shippers, which would essentially charge different IT/AOS rates for the same service.[577]

525. The position of Staff and Pinnacle West is that Kern River's proposal for IT/AOS rates should be rejected; they recommend that Kern River use a blended IT rate instead. The blended IT rate should be designed based on total costs of both the Rolled-In System and the 2003 Expansion System divided by total demand determinants. Staff and Pinnacle West argue that the blended IT/AOS rate equitably reflects the fact that IT/AOS shippers use all of Kern River's transportation facilities, not just those related to the ten-

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[575] Ex. KR-17 at 11 and 16, Ex. KR-49 at 11, Ex KR-57, RCG-2 at 74, and *Kern River Gas Transmission Co.* 92 FERC ¶ 61,061 (2002).
[576] *Viking Gas Transmission Company*, 101 FERC ¶ 61,170 (2002).
[577] Exhibit KR-49 at 9-10.

year 2003 Expansion service. [578]

526. The position of RCG is that both the AOS transportation rate and the AOS fuel rate for the Rolled-In System should be derived from, and based only on costs allocated to the Rolled-In System. RCG does not take issue with the IT rate. However, RCG points out that the AOS is a separately stated rate for the interruptible service and is a service authorized by Kern River in excess of the contracted firm service. RCG argues that Kern River's proposal to calculate the AOS rate for Rolled-In shippers at 100% load factor of the highest 2003 Expansion rate is unjust and unreasonable. RCG argues that the AOS transportation rate for the Rolled-In shippers should be calculated at the 100% load factor of the applicable firm rolled-in rate. [579]

527. RCG argues that Kern River's claim that its proposal promotes the goal of allocative efficiency and has been previously approved by the Commission is not pertinent. RCG argues that the issue of allocative efficiency is only relevant where there is the need to allocate capacity, or where demand for service exceeds capacity, which is not the case with AOS. AOS has a lower priority than does firm service. [580]

528. The position of Calpine is that Kern River's proposed 100% load factor rate for IT and AOS service is appropriate. Calpine argues that basing Kern River's AOS rate on the 100% load factor equivalent of the firm shipper's applicable ten- or fifteen-year service would undermine the capacity release market by forcing the 2003 Expansion shippers to discount their released expansion capacity to compete with AOS. Calpine contends that designing Kern River's AOS rate on the 100% load factor equivalent of the firm shippers applicable ten- or fifteen-year service would provide Rolled-In shippers with a permanently discounted rate for 2003 Expansion capacity. Calpine further explains that Kern River's AOS rate proposal does not allocate expansion costs to the Rolled-In shippers, but rather Kern River derives its AOS rate from a rate that includes expansion costs. Calpine argues that while the approach may increase the AOS rate, it does not represent a prohibited allocation of expansion costs to Rolled-In shippers.[581]

529. The position of SCGC is that an increase in the AOS rate in excess of the 100% load factor firm transportation rates on the Rolled-In system is not appropriate. SCGC supports RCG's position on this issue. SCGC argues that the arguments of Kern River and Calpine in support of Kern River's proposal do not withstand scrutiny. SCGC contends that rate case settlements have no precedential value and that the proposals of Kern River and Calpine are contrary to Commission policy since the Commission

[578] Staff IB at 49, Staff RB at 49 and Pinnacle West IB at 40.
[579] RCG IB at 45-47.
[580] RCG RB at 38-39.
[581] CES IB at 41-42 and CES RB at 38.

requires that IT/AOS services be based on the underlying firm rate with which they compete. SCGC argues that on Kern River's system different vintages of shippers have always paid different rates for use of the same facilities and every shipper has always been aware of this and, therefore, Kern River should not be allowed to calculate AOS rates on the basis of the highest firm service rate on the system.[582]

530. BP, High Desert, Edison Mission, and Questar take no position on this issue.

531. CONCLUSION -- Kern River has not carried its burden of proving that use of 100% load factor rate for IT and AOS service based on the highest firm service rate on the system produces just and reasonable rates. The blended approach Staff proposes would produce just reasonable rates.

532. DISCUSSION -- The Commission's goals for rate design include the objective that rates should promote allocative efficiency (principle that during times of scarce capacity service should go to those who value it most, i.e., those willing to pay the most). However, there has been no showing that Kern River has need to ration its IT/AOS capacity. Because there is no need to ration capacity, there is no reason justifying use of the highest firm rate (ten-year Expansion 2003 firm transportation service rates) to calculate the maximum rate for IT/AOS services. [583]

533. Also, there is no cross subsidy involved here. Original System shippers are not being asked to pay for any costs associated with the 2003 Expansion capacity. Nor are there are any costs allocated from the 2003 Expansion shippers to the Original System shippers. [584] The 2003 Expansion capacity was created through an increase in compression and pipeline looping built onto the original system trunkline and operation is on an integrated basis. Usage of a particular shippers' capacity between the Original System design and the later addition of the 2003 Expansion capacity is not distinguishably assignable to either on an operational basis. The blended approach proposed by Staff is appropriate here because it recognizes the operations of Kern River allow Original Shippers to benefit from the 2003 Expansion capacity through the ability to gain AOS and IT service at fair states. This blended approach further assures that there is a level playing field and that all shippers benefit from the revenues received via a revenue credit to their respective facilities' cost-of-service. [585]

534. ISSUE -- Mirant capacity and associated MOR credit deduction

535. POSITIONS -- The position of Kern River's that if set at the "broad middle of

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[582] SCGC IB at 36 and SCGC RB at 14-16.
[583] Ex. RCG-2 at 74-75, Ex. RCG-18 at 37-38, RCG IB at 46, and RCG RB at 38-40.
[584] *See* CES RB at 38 and Tr. 1032.
[585] Ex. S-12 at 33, Ex. S-22 at 1-2, Ex. S-27 at 15, and Staff IB at 48-49.

the range" (which it has been), then the 90,000 Dth/day Mirant capacity should be removed from its firm rate design billing determinants. Kern River claims a loss of approximately $17 million of annual firm transportation revenue resulting from Mirant's bankruptcy and subsequent contract default. Kern River argues that if the Mirant capacity is included in its billing determinants, then the MOR credit should be reduced by $5.2 million to recognize the risk of remarketing vacant firm contract space on the pipeline. Kern River maintains that MOR adjustment prevents shippers from benefiting twice from the removal of the Mirant billing determinants from the rate design. [586]

536. Staff and Pinnacle West agree that if Kern River is billing determinants reflect the Mirant capacity, then Kern River's associated MOR crediting approach is appropriate. [587]

537. BP agrees that Kern River should remain at risk for the Mirant capacity, but BP does not agree with Kern River's proposal to modify the allocation of MOR credit so that the 2003 Expansion shippers receive credit for all MOR Kern River attributes to the former Mirant capacity. BP claims that amounts to a subsidization of the 2003 Expansion shippers by the Rolled-In shippers. [588]

538. The position of SCGC is that Kern River's downward adjustments to the MOR credit is not appropriate. SCGC argues that Kern River must remain at risk for any underutilized capacity on the 2003 Expansion system unless it negotiates a risk-sharing agreement with the remaining 2003 Expansion shippers. SCGC claims that Kern River's proposal to decrease MOR for anticipated increases in fuel rates and changes in natural gas prices could result in Kern River over recovering its costs. [589]

539. The position of RCG is that Kern River's proposed downward adjustment to its MOR is not appropriate because its adjustment to this credit is totally speculative.[590]

540. Calpine also argues that Kern River's proposed Mirant adjustment should be rejected because Kern River must remain at risk for all costs associated with underutilized capacity that exists due to the Mirant bankruptcy. Kern River's shippers should not be punished with a reduction to MOR based on capacity sales it could have made without regard to the Mirant capacity. Also, according to Calpine, Kern River

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[586] KR IB at 49.

[587] KR IB at 48, Ex. KR-17 at 14-15, Ex. KR-86 at 13-15, Ex. Staff IB at 49, Pinnacle West IB at 40, and Tr. 601.

[588] BP IB at 44-45 and 47-48, CES IB at 43-44, CES RB at 39-41, BP RB at 43, 45 and 48, and SCGC RB at 16.

[589] SCGC IB at 36; SCGC RB at 16-18; *see 1999Pricing Policy Statement,* 88 FERC at 61,747.

[590] RCG IB at 47-48.

should not receive an adjustment to MOR to compensate for Mirant capacity-related risk largely of the pipeline's own making. Additionally, Calpine argues that, contrary to Kern River's contention, its shippers would not receive a double benefit absent the Mirant adjustment. Rather than preventing a double benefit, Kern River's proposed adjustment would eliminate approximately $5 million of the MOR credit to which Kern River's firm shippers are entitled. Calpine also argues that Kern River's proposed Mirant adjustment is improperly inflated by its "first through the meter" quantification method. Calpine argues that Kern River's proposed Mirant adjustment is unjustified, overstated, and should be rejected, or at a minimum substantially reduced through application of a last-through-the-meter methodology.[591]

541. According to Calpine, BP's proposed elimination of the Mirant billing determinants should be rejected because eliminating Kern River's risk by removing the Mirant billing determinants is against Commission policy. Calpine contends that the potential subsidy identified by BP could be avoided by retaining the Mirant billing determinants while rejecting Kern River's overstated Mirant-related adjustment to the MOR credit. Calpine also contends that contrary to BP's allegations, the Commission has found that Kern River did not sell more capacity to the 2003 Expansion shippers than it added, and that Kern River had the ability to deliver all of its contracted volumes. Calpine also contends that the Commission's decision on the CAP did not promise Rolled-In shippers a greater share of MOR to offset reduced service quality as suggested by BP. Calpine also argues that Kern River's attempt to link the Mirant billing determinants to the equity return ultimately authorized, is flawed because Kern River should not be allowed to mitigate the impact of an unwelcomed equity return outcome by manipulating its billing determinants.[592]

542. RCG, High Desert, Edison Mission, and Questar take no position on this issue.

543. CONCLUSIONS -- Kern River has not carried its burden of proving that Mirant's 90,000 Dth/d of capacity should be removed from its billing determinants produces just and reasonable rates if it is found in the "broad middle of the range" of the zone of reasonableness. It has proven that the MOR credit should be reduced.

543. DISCUSSION -- The record shows that the Commission intended for Kern River to be at risk to manage any turned back capacity of the 2003 Expansion project through either an agreement with its shippers whereby the shippers would share the costs in some manner, or by assuming the risk itself. Kern River did not claim such agreement with the 2003 Expansion shippers. In addition, the 2003 Expansion facility throughput before and after the Mirant contract rejection has remained at a stable level. This indicates that Kern

[591] CES IB at 43-44.
[592] CES IB at 43-44 and CES RB at 39-41.

River continues to serve the same markets, and perhaps at a lower overall transportation revenue collection due in part to its obligation to adhere to the most favored nation ("MFN") clauses of its other firm shipper contracts. Kern River is not required to breach its contracts with MFN clauses in order to market the former Mirant capacity. [593]

544. Kern River has shown that it has not priced its reduction to the MOR credit the same amount as the firm revenues previously received from the Mirant contract. The record, in fact, reflects that Kern River continues to be at risk for approximately $12.1 million annually after netting out the revenues for services which supplanted the previous Mirant throughput. This evidence demonstrates that Kern River has successfully remarketed (at least in part) the former Mirant capacity and continues to be at risk to capture the remaining difference, (i.e. that amount not included in the MOR credit reduction proposal), to make up for the greater level of the Mirant loss. [594] Consequently, Kern River's proposal in this regard is deemed reasonable; the pipeline's proposal adheres to the Commission's policy and fairly reflects its overall MOR in its rates. [595]

545. ISSUE -- MOR credit and fuel adjustment

546. POSITIONS -- The position of Kern River is that its MOR fuel adjustment is based on actual data through the end of the test period, and with the adoption of Kern River's new blended fuel rate there is a necessary and corresponding reduction in the transportation rate that shippers are willing to pay for IT and AOS service. Kern River argues that Staff's opposition to the MOR fuel adjustment based on the claim that those costs are paid by shippers, reflects a fundamental misunderstanding of this adjustment. Kern River argues that the adjustment recognizes that increased fuel costs reduce the transportation rate that IT and AOS shippers are willing to pay, meaning lower MOR available for crediting to firm shippers. Kern River argues that the MOR adjustment would not result in Kern River retaining fuel expenses paid by shippers, while denying the adjustment would amount to an unfair double-revenue credit to shippers. [596]

547. The position of Staff is that Kern River's proposed inclusion of a fuel adjustment in its MOR credit proposal is not appropriate. Staff points out that the fuel adjustment in the credit is not warranted because Kern River is fully reimbursed for fuel from its shippers. [597]

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[593] KR RB at 43-44.

[594] Compare $5.1 million reduction to MOR credit (Ex. KR-86 at 13) to $17 million Mirant lost revenues (Ex. KR-17 at 15).

[595] Ex. KR-86 at 12-13, Ex. KR-17 at 14-15, and *1999 Pricing Policy Statement at 61,747*.

[596] Ex. KR-1 at 14-15, Ex. KR-86 at 7-8, and Ex. KR-57 at 49-50.

[597] Staff IB at 49, Staff RB at 42, Ex. S-12 at 23, and 26-29.

548. The position of Calpine is also that Kern River's proposed inclusion of a fuel adjustment in its MOR credit proposal is not appropriate. First, according to Calpine, the proposal erroneously assumes the price basis differentials are fixed and do not vary through time. Also, according to Calpine, a decrease in any credits belies the fact that Kern River's MOR credits have more than doubled from $7.8 million to over $21 million just beyond the test period. [598]

549. The position of RCG is that of Staff and Calpine. RCG adds the argument that there is no test period experience with the proposed adjustment and that the proposal assumes as fact events that are speculative, such as changes in market prices for natural gas and change in Kern River's fuel methodology. Therefore, according to RCG, test period actual levels should be used. [599]

550. SCGC, Pinnacle West, and BP also oppose Kern River's proposal. [600]

551. High Desert, Edison Mission, and Questar take no position on this issue.

552. CONCLUSION -- Kern River has not carried its burden of proving that its proposal to reduce its end-of-test-period revenue credits due to its proposed increase in fuel retainage from IT and AOS shippers produces just and reasonable rates.

553. DISCUSSION -- The end-of-test-period actual MOR is the best evidence on which to base an appropriate MOR credit and not unsubstantiated conjecture. MOR and associated volumes surpassed historical levels for Kern River. Market conditions are not constant. The upward trend for the revenues collected by Kern River are appropriately credited to the company's cost-of-service. In addition, Kern River did not prove its claim that not allowing a reduction to credit results in an unfair double collection by its shippers. [601]

554. ISSUE -- Allocation of MOR Credit

555. POSITIONS: The position of Kern River is that the MOR credit should be allocated among the Rolled-In System shippers and the 2003 Expansion shippers based on their respective aggregate reservation billing determinants. [602]

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[598] Ex. CES-1 at 25, Ex. CES-69 at 6 and 8, and Ex. CES-71.
[599] Ex RCG-2 at 32-34.
[600] SCGC IB at 36-37, PW IB at 40, and Ex. BP-69.
[601] KR RB at 44, Ex. KR-1 at 11-12, Ex. KR-57 at 50, Ex. CES-69 at 6 and 8, and Ex. BP-69.
[602] *KR IB* at 49.

556. Staff does not object to Kern River's position.[603]

557. The position of BP is that Kern River's MOR should not be allocated to the Rolled-In and 2003 Expansion shippers based on the available capacity in each class of service. According to BP, doing so creates a subsidy of the 2003 Expansion by the existing shippers. Instead, BP proposes an allocation based on reservation quantities.[604]

558. The position of Calpine is that Kern River's proposed allocation of the MOR is unreasonable. Calpine recommends allocating MOR to Rolled-In and 2003 Expansion shippers based on the level of available capacity from each class of service that makes such market-oriented sales possible. Calpine argues that a fair allocation of MOR credit must reflect each shipper group's responsibility for that credit, and since the MOR is derived from unused firm capacity, the shippers most responsible for Kern River's MOR are shippers with unutilized firm capacity. Calpine argues that its proposed allocation reflects average utilization and is similar to other cost allocations based on the pipeline's actual operating experience during the base and test period.[605]

559. The position of SCGC is that Calpine's proposal to base the allocation on "the level of available capacity from each class of service that makes such market-oriented sales possible" should be rejected. SCGC argues that unless the specific facilities which are used to provide the IT services can be clearly identified, basing the allocation of MOR credits on reservation quantities is the most equitable allocation method. SCGC argues that Kern River has shown that determining which facilities are used to provide the IT services on any given day is impossible, and this is not disputed by Calpine.[606]

560. RCG, High Desert, SCGC, Pinnacle West, Edison Mission, and Questar take no position on this issue.

561. CONCLUSION -- Kern River carried its burden of proving that MOR credit allocated among the Rolled-In System shippers and the 2003 Expansion shippers based on their respective aggregate reservation billing determinants produces just and reasonable rates.

562. DISCUSSION -- Kern River has shown that it is not possible on any given day to identify the specific facilities or capacity used to provide the market-oriented services.[607]

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[603] Staff IB at 50.
[604] BP IB at 48.
[605] CES IB at 47-48 and CES RB at 44.
[606] SCGC RB at 18-19.
[607] KR IB at 49-50, Ex. KR-1 at 15, and Ex. KR-57 at 47.

FURTHER FINDINGS AND CONCLUSIONS

563. Kern River is a natural gas pipeline company engaged in transporting gas from Wyoming receipt delivery points to the San Joaquin Valley near Bakersfield, Kern County, California.

564. 563. On April 30, 2004, Kern River submitted a general rate change filing in Docket No. RP04-274-000, pursuant to Section 4 of the NGA, in accordance with its obligation under Article VI of the Stipulation and Agreement dated March 31, 1999, approved by the Commission in Docket No. RP99-274-000.

565. Kern River's proposals were contested, settlement discussions were unsuccessful, the matter proceeded to hearing, and the matter proceeded to hearing as outlined in the Procedural History in this Initial Decision.

566. This NGA proceeding is subject to the jurisdiction of the Commission.

567. All issues raised but not discussed, were considered and found to be without merit.

568. Rates that are consistent with the findings and conclusions of this Initial Decision will be just and reasonable.

ORDER

569. IT IS ORDERED, subject to review by the Commission on exceptions or on its own motion, as provided by the Commission's Rules of Practice and Procedure, that:

(a) within thirty (30) days from the issuance of the final order of the Commission in this proceeding, Kern River shall conform its rate filing to the findings and conclusions of this Initial Decision; and

(b) within sixty (60) days from the issuance of the final order of the Commission shall refund amounts that exceed rates found just and reasonable with interest at rates found appropriate by the Commission.

Charlotte J. Hardnett
Presiding Administrative Law Judge