UNITED STATES OF AMERICA 120 FERC ¶ 63,014
FEDERAL ENERGY REGULATORY COMMISSION

Idaho Power Company — Docket Nos. ER06-787-002, ER06-787-003

INITIAL DECISION

(Issued August 31, 2007)

APPEARANCES

David B. Raskin, Gary A. Morgans, Heather M. Horne and James R. Thompson on behalf of Idaho Power Company.

Todd E. Miller, Stephen R. Larsen, and Craig W. Silverstein on behalf of the Bonneville Power Administration.

Craig W. Silverstein on behalf of Pacific Northwest Generating Cooperative, Inc. and Raft River Rural Electric Cooperative, Inc.

Margaret A. McGoldrick and Dean J. Miller on behalf of A&B Irrigation District, Burley Irrigation District, Falls Irrigation District, Black Canyon Irrigation District, and Owyhee Irrigation District.

Mark R. Thompson on behalf of the Public Power Council.

Peter J. Richardson on behalf of the Idaho Energy Authority.

Amie V. Colby and Rebecca Roback on behalf of PacifiCorp.

Edith A. Gilmore and Marcia C. Hooks on behalf of the Commission Trial Staff.

STEVEN A. GLAZER, Presiding Administrative Law Judge

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I. INTRODUCTION

1. This case concerns whether Idaho Power Company's proposed formula rates for point-to-point transmission service and network integration transmission service, which have been included in its Open Access Transmission Tariff to replace its former stated rates, are just and reasonable. Most of the issues of the case have already been resolved by a partial settlement agreement that has been approved by the Commission, and this Initial Decision addresses the remaining issues involving whether the revenue that Idaho Power receives under certain pre-Order No. 888 transmission agreements between Idaho Power and PacifiCorp should be credited against the total transmission revenue requirement that is attributed to OATT customers, or whether the load generated by those agreements should be included as part of the total firm load over which the total transmission revenue requirement paid by OATT customers is allocated.

II. PROCEDURAL HISTORY

A. Docket No. ER06-787-002

2. On March 24, 2006, Idaho Power Company (Idaho Power) submitted, pursuant to Section 205 of the Federal Power Act (FPA),[1] revisions to its Open Access Transmission Tariff, FERC Electric Tariff, First Revised Volume No. 5 (OATT). The revisions proposed to implement formula rates in place of the stated rates that were then being used in the OATT. The Commission issued a public notice of the filing on March 31, 2006.

3. Bonneville Power Administration, Pacific Northwest Generating Cooperative, Raft River Rural Electric Cooperative, Public Power Council, A&B Irrigation District, Burley Irrigation District, Falls Irrigation District, Black Canyon Irrigation District, Owyhee Irrigation District, and Idaho Energy Authority (collectively, Intervenors), filed protests and motions to intervene challenging various aspects of Idaho Power's filing. Idaho Power filed an answer to the protests and motions to intervene on May 4, 2006. PacifiCorp later filed a motion to intervene, which was granted. Hereafter, the term "Intervenors" refers to the intervenors other than PacifiCorp unless otherwise stated.

4. On May 31, 2006, the Commission issued an Order (May 31 Order) accepting and suspending Idaho Power's filing, establishing hearing and settlement judge procedures, and directing Idaho Power to submit a compliance filing.[2] The hearing and settlement judge proceedings were designated as Docket No. ER06-787-002. The May 31 Order

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[1] 16 U.S.C. § 824d (2000).

[2] *Idaho Power Co.*, 115 FERC ¶ 61,281 (2006).

also granted the motions to intervene (PacifiCorp's motion to intervene was filed later and granted as well).

5. The May 31 Order directed Idaho Power to submit a compliance filing revising its Period I Statements and tariff sheets in order to properly reflect SFAS 109 amounts.[3] Idaho Power submitted that compliance filing on June 23, 2006, and the Commission accepted the compliance filing in a Letter Order dated August 28, 2006, effective as of June 1, 2006. The subject matter of that compliance filing was not set for this hearing and is not dealt with in this Initial Decision.

6. The May 31 Order further directed Idaho Power to submit another compliance filing providing tariff requirements for an informational filing with the Commission.[4] Idaho Power submitted this compliance filing on September 28, 2006.

7. Pursuant to the May 31 Order, the parties engaged in settlement discussions that were convened before the Honorable Bruce L. Birchman. On September 7, 2006, Judge Birchman reported to the Chief Judge that, after three settlement conferences, the parties were at an impasse. As a result, on September 8, 2006 the Chief Judge terminated settlement discussions and designated me as Presiding Judge.

8. I convened a pre-hearing conference on September 19, 2006, and by order that day I established a procedural schedule. In accordance with that order, as revised by an order issued December 4, 2006, Idaho Power filed supplemental direct testimony on October 6, 2006, Intervenors and PacifiCorp filed answering testimony on December 15, 2006, Commission Trial Staff filed answering testimony on January 19, 2007, Intervenors filed cross-answering testimony on February 26, 2007, and Idaho Power filed rebuttal testimony on April 2, 2007. After reaching the partial settlement discussed later herein, the parties withdrew those parts of their testimony that covered the settled issues. The testimony that remains covers only the issues that remain for hearing.

B. Notices to the Parties

9. On December 28, 2006, I issued a Notice to the Parties stating that an article published by Dr. Paul L. Joskow, entitled *Regulation of the Electricity Market: Incentive Regulation for Electricity Networks*, would be made a judicial exhibit, and allowing the parties to file additional supplemental testimony addressing the article. In accordance with that notice, Idaho Power filed supplemental direct testimony on January 16, 2007,

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[3] *Id.* at P 28.

[4] *Id.* at P 29.

Intervenors filed supplemental answering testimony on January 30, 2007, and Commission Trial Staff filed supplemental answering testimony on February 13, 2007.

10. On February 22, 2007, I issued a second Notice to the Parties which required the Parties to include as an issue in the Joint Stipulation of Issues whether good cause exists to waive the filing and notice requirements of section 205 of the FPA. The parties complied with this request in the Joint Stipulation of Issues that they submitted on June 15, 2007; it is Issue Three of this Initial Decision.

C. Summary Disposition Motion

11. On November 6, 2006, Intervenors filed a motion for partial summary disposition pursuant to Commission Rule 217,[5] calling for certain pre-Order No. 888 transmission contracts between Idaho Power and PacifiCorp, known in this litigation as the "Legacy Agreements," to be treated as a cost allocation in the proposed formula rate rather than as a revenue credit. Idaho Power filed a response in opposition to the motion on November 21, 2006, and Staff filed a response to the motion on November 28, 2006. Staff, in its response to the motion, took no position on its merits but instead raised a procedural issue as to whether Idaho Power should be required to submit the supporting affidavits and attached documents included in Idaho Power's response to the motion for summary disposition as part of its case-in-chief.

12. On December 15, 2006, I denied Intervenors' motion, finding that the record was not sufficiently developed to determine whether the Legacy Agreements should be cost-allocated or revenue-credited in Idaho Power's proposed OATT formula rate.[6] In addition, I rejected the issue raised by Staff on the ground that Idaho Power was not required to submit evidence countering the contentions of Intervenors and Staff in its case-in-chief, but instead could wait to do so until it submitted its rebuttal case.

D. Docket No. ER06-787-003

13. By Order on February 28, 2007 (February 28 Order), the Commission set for hearing the merits of Idaho Power's September 28, 2006 compliance filing regarding its proposal for an informational filing protocol.[7] The hearing proceedings were designated

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[5] 18 C.F.R. § 385.217 (2006).

[6] *Idaho Power Co.*, 117 FERC ¶ 63,050 (2006).

[7] *Idaho Power Co.*, 118 FERC ¶ 61,156 (2007).

as Docket No. ER06-787-003. In that Order, the Commission also consolidated ER06-787-003 with ER06-787-002 for hearing and additional settlement judge proceedings.

14. Shortly thereafter, the parties proposed a revised procedural schedule for the filing of testimony on the issues set for hearing in the February 28 Order as well as to accommodate their additional efforts to settle the case. On March 21, 2007, I convened another pre-hearing conference and revised the procedural schedule in view of the Commission's February 28 Order.

E. The Partial Settlement

15. Pursuant to the Commission's February 28 Order and an Order of the Chief Judge issued on March 26, 2007, new settlement discussions were initiated under the guidance of the Honorable Herbert Grossman. These settlement discussions resulted in an uncontested partial settlement that resolved all issues in the proceeding other than the proper ratemaking treatment of the Legacy Agreements.

16. By order issued May 8, 2007, I suspended the procedural schedule with respect to all issues other than the proper ratemaking treatment of the Legacy Agreements. This action suspended the procedural schedule with respect to the issues set for hearing in the Commission's February 28 Order, eliminating the need for the additional testimony called for by Docket No. ER06-787-003.

17. The Partial Settlement Agreement was filed with the Commission on June 15, 2007. On June 29, 2007, the Commission Trial Staff filed comments in support of the Partial Settlement Agreement. All participants to the proceeding waived reply comments. By order on July 11, 2007, I certified the Partial Settlement Agreement to the Commission.

18. On July 13, 2007, Idaho Power submitted to the Commission its first annual information filing showing the formula rate and rate revenue requirements in effect under Schedules 7, 8 and 9 of its OATT for the period beginning June 1, 2007 and ending May 31, 2008. This proceeding was designated as Docket No. ER07-1149-000. On July 20, 2007, Intervenors informed the Commission that if the Partial Settlement Agreement is ultimately approved by the Commission as filed, the July 13 filing will be rendered moot and a new informational filing conforming to the terms of the settlement will need to be submitted for Commission review. Therefore, Intervenors requested that the Commission stay any action, including the issuance of a notice of filing establishing a date for intervention, comments or protest, in connection with ER07-1149-000 until it has had an opportunity to act on the merits of the Partial Settlement Agreement.

19. The uncontested Partial Settlement Agreement was approved by the Commission in an Order issued on August 8, 2007.[8] As a result, the hearing and this Initial Decision addresses only the issues that were left unresolved by the Partial Settlement Agreement.

F. Hearing and Briefs

20. On June 15, 2007, the parties submitted to me, pursuant to the procedural schedule, a Joint Stipulation of Issues to be decided in this case. The issues presented in this Initial Decision are the ones that were set forth in the Joint Stipulation of Issues.

21. A hearing on the merits was held June 20, 21, 22 and 26. The record was closed on June 26, 2007.

22. Following the hearing, Initial Briefs were filed on July 27, 2007 and Reply Briefs were filed on August 10, 2007.

III. BACKGROUND

23. Idaho Power is a wholly-owned subsidiary of IDACORP, Inc. and is principally engaged in providing integrated retail electric utility service in a 24,000 square mile area in southern Idaho and eastern Oregon. Idaho Power provides point-to-point transmission service and network integration service to FERC jurisdictional customers pursuant to its Open Access Transmission Tariff (OATT).

24. Intervenor Bonneville Power Administration (BPA) is a federal power marketing agency authorized by statute to construct and operate a large transmission system in the Pacific Northwest and directed to market electricity from 31 Federal hydroelectric dams in the Pacific Northwest that are operated by the United Stated Corps of Engineers or the United States Bureau of Reclamation. The Pacific Northwest region includes Washington, Oregon, Idaho, the western part of Montana, a portion of northern Nevada, and a small portion of western Wyoming and northern California within 75 miles of the Columbia River drainage. Out of approximately 20,000 MW of capacity available to BPA, about 250 MW is located in southern Idaho. BPA serves about 150 wholesale customers in the region and markets surplus power in and outside of the region as available. BPA also owns and operates more than 15,000 miles of transmission lines.

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[8] *Idaho Power Co.*, 120 FERC ¶ 61,144 (2007).

25. BPA's wholesale power customers include, by statute, public power utilities in the Pacific Northwest such as cooperatives, public utility districts and municipalities. These entities have priority rights to buy BPA power to serve their loads and to purchase that power at BPA's lowest, cost-based rates. Of these, the following are also Intervenors: Raft River Electric Cooperative, Pacific Northwest Generating Cooperative (PNGC), Idaho Energy Authority (IDEA), Public Power Council (PPC), and five irrigation districts.

26. Each of the irrigation districts is a quasi-municipal organization that has entered into a contract with the U.S. Bureau of Reclamation to operate and maintain irrigation projects constructed by Reclamation. Each district is obligated to repay construction costs incurred by Reclamation in the construction of the project and to provide for the payment of all costs incurred in the operation and maintenance of the project. The districts are authorized under state law to levy assessments on the lands within their boundaries to raise funds to maintain and operate the works of the district and for the satisfaction of any bonded indebtedness or contractual obligations due the United States.

27. The five irrigation districts that are Intervenors here are the A&B, Black Canyon, Burley, Falls, and Owyhee Irrigation Districts. A&B Irrigation District is located in Rupert, Idaho and provides service to approximately 82,200 acres of land in Minidoka and Jerome Counties. Burley Irrigation District is located in Burley, Idaho and provides service to approximately 48,000 acres of land in Cassia County. Falls Irrigation District is located in Aberdeen, Idaho and provides service to approximately 13,500 acres of land in Power County. Black Canyon Irrigation District is located in Notus, Idaho and provides service to approximately 61,255 acres in Canyon, Payette and Gem Counties. Owyhee Irrigation District is located in Nyssa, Oregon and provides service to approximately 67,100 acres in Malheur County in Oregon.

28. Intervenor PacifiCorp is an investor-owned utility with its principal place of business in Portland, Oregon. PacifiCorp is primarily engaged in the business of providing electric service to retail customers in six western states: Oregon, Washington, California, Wyoming, Utah, and Idaho. As a load-serving entity, PacifiCorp is responsible for providing electric service to more than 1.5 million consumers.

29. Idaho Power's original stated OATT transmission rates that were in place prior to the present tariff filing were established in 1996 pursuant to a tariff filing that Idaho Power made to the Commission in Docket No. ER96-350-000. That tariff filing was resolved by an uncontested settlement and Commission Letter Order dated September 13, 1996 implementing the OATT rates.[9]

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[9] *See* Exhibit No. INT-7.

30. In its present filing, Idaho Power states that its original OATT rates have not been sufficient to recover Idaho Power's actual costs of providing transmission service. Idaho Power claims that changing from the stated rate structure in the original OATT to its proposed formula rate structure will more accurately reflect the costs that it incurs in providing point-to-point and network integration transmission services.

31. Idaho Power proposes changing its OATT from stated tariff rates to formula rates for point-to-point transmission services in Schedules 7 and 8, and for network integration transmission services in Schedule 9. Idaho Power's proposed formula calculates a rate for firm point-to-point transmission service in an upcoming service year on the basis of its prior calendar year's costs to own, operate and maintain its transmission facilities, and produces a transmission revenue requirement that includes return and income taxes based on a year-end rate base, operation and maintenance expense (including an allocation of administrative and general expense), depreciation and amortization expense, amortization of other expenses, and taxes other than income taxes expense. Revenue in the prior calendar year from sources other than certain firm transmission loads are credited against these costs, and the result is divided by the monthly average firm transmission load for the prior calendar year to come up with a tariff rate in dollars per kilowatt-hour for firm point-to-point transmission service in the upcoming service year. Idaho Power's formula changes the dollar amount of the rates annually based on the preceding calendar year's costs.

32. Idaho Power proposes to base the OATT's maximum rate for non-firm point-to-point transmission service in the upcoming service year on the same formula. Idaho Power further proposes to base the rate for network transmission service in the upcoming service year on the numerator of the formula without the divisor and to charge that amount on a *pro rata* basis to all network transmission customers.

33. As a result of the partial settlement agreement reached in this case, Idaho Power has implemented its formula rate structure effective as of June 1, 2006, subject to refund and condition. The only issues that have been left unresolved by the partial settlement for hearing and this Initial Decision concern: (i) the treatment in the formula rate of certain pre-Order No. 888 transmission agreements, known as the "Legacy Agreements," that Idaho Power maintains with PacifiCorp for the transmission of PacifiCorp's power across Idaho Power's system from supply sources in Wyoming to loads in Oregon and Washington; (ii) if the Legacy Agreements are to be cost-allocated rather than revenue-credited, the manner in which the Legacy Agreement loads are to be incorporated into the divisor of the formula rate; and (iii) the applicability of regulatory incentives in considering whether to waive the provisions of section 205 of the FPA to implement the formula rate structure.

IV. ISSUES AND DISCUSSION

A. Issue One: *Whether Idaho Power's proposal to credit the revenues received from the three Legacy Agreements to the transmission revenue requirement, rather than including the associated demands in the determination of the rate divisor, is just and reasonable and not unduly discriminatory or preferential?*

34. Idaho Power's proposed firm, non-firm and network OATT formula rates are based in part on a total transmission revenue requirement for the Idaho Power system less certain revenue credits.[10] For Idaho Power's proposed firm and non-firm rates, that net amount is divided by the average of Idaho Power's twelve monthly peak firm loads on the transmission system to arrive at a rate expressed in dollars per kilowatt.[11]

35. The revenue credits are defined in the proposed formula as "the revenues received (expressed in dollars) from the provision of transmission and other related services as recorded in FERC Accounts 454 and 456 to the extent that such transactions are not included in the determination of load (E)."[12] "Load (E)" comprises the divisor of the ratio for Idaho Power's firm and maximum non-firm formula rates, consisting of the average of Idaho Power's twelve monthly peak firm loads as described above.[13]

36. In Statement AU of its tariff filing, Idaho Power identified $16,048,535 in revenue credits for the Period I (2004) test year to be applied against a total transmission revenue requirement in Period I of $86,198,886, for a net transmission revenue requirement in Period I of $70,150,351.[14]

37. There are some mistakes in the revenue credit figure as stated in Statement AU. Specifically, of the two accounts that make up the revenue credit, Account 456 is short by $995,542 and Account 454 is overstated by $95,509, for a net shortage of $900,033 in

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[10] *See* Idaho Power Tariff Filing, Sheet Schedule 7, Appendix A; Schedule 8, Appendix A; Schedule 9, Appendix A.

[11] *See* Idaho Power Tariff Filing, Sheet Schedule 7, Appendix A; Schedule 8, Appendix A.

[12] *Id*.

[13] *Id*.

[14] *See* Exhibit Nos. IPC-5 at 2 (Idaho Power Tariff Filing, Statement AU); IPC-17 at 5 (Idaho Power Tariff Filing, Statement BG).

revenue credits.[15]

38. Of these revenue credits, $9,869,308 comprises 2004 revenues derived from four agreements that pre-date the establishment of Idaho Power's OATT pursuant to Commission Order No. 888. Three of these agreements (the only ones at issue here) are long-term transmission contracts between Idaho Power on the one hand and PacifiCorp and its predecessor companies on the other. These agreements, known in this proceeding as the "Legacy Agreements," have different rates, terms and conditions from those of the OATT.[16]

39. Most of the revenue credits for these three Legacy Agreements (*i.e.*, $8,756,646 in 2004) are recorded in Idaho Power's accounts as line and substation rental payments that are booked to FERC Account 454, "Rent From Electric Property."[17] The remaining revenue credits for these agreements (*i.e.*, $995,542 in 2004) are accounted for as revenue for transmission of electricity for others that is booked to FERC Account 456, "Other Electric Revenue."[18]

40. The Legacy Agreements and their 2004 revenues are identified as follows:[19]

Agreement	**Revenues**
Restated Transmission Services Agreement Between PacifiCorp and Idaho Power Company dated February 6, 1992 (RTSA)	$8,377,588
Transmission Facilities Agreement between Idaho Power Company, Pacific Power & Light Company, and Utah Power & Light Company dated June 1, 1974 (TFA)	$1,241,496
Agreement for Interconnection and Transmission Services between Idaho Power Company and Utah Power & Light Company dated March 19, 1982 (ITSA)	$133,104

[15] *See* Exhibit No. IPC-16 (Nichols Supp. Test. 4:12-14 and n.1).

[16] *See* Exhibit No. IPC-16 (Nichols Supp. Test. 3:5-4:2); *also see* Exhibit No. IPC-19 (Schellberg Supp. Test. 2:5-20).

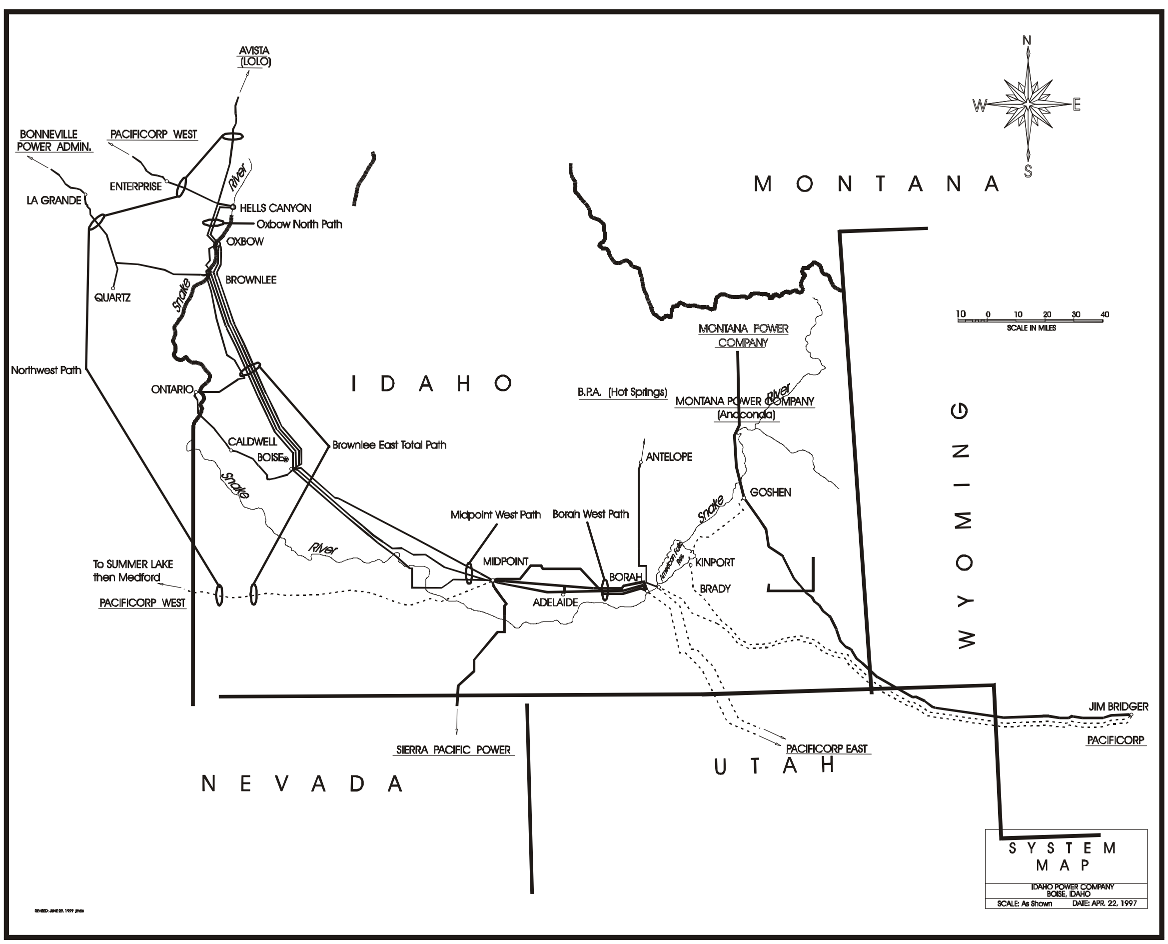
[17] *See* Exhibit No. IPC-16 (Nichols Supp. Test. 4:4-7).

[18] *See id*. at 4:8-10.

[19] *See id*. at 3:10.

41. The Legacy Agreements and certain predecessor contracts were entered into in the 1970s, 1980s and 1990s between Idaho Power on the one hand and several utilities on the other that eventually merged into PacifiCorp. The overall purposes of the Legacy Agreements were fourfold: (i) to form a partnership between Idaho Power and Pacific Power & Light Company, a predecessor of PacifiCorp, to build and operate the Jim Bridger power plant near convenient coal sources in western Wyoming that would serve both of their electric power loads; (ii) to provide transmission service between the Jim Bridger plant and PacifiCorp's western power loads in Oregon and Washington across Idaho Power's transmission lines that coursed from southeast to northwest through southern Idaho, and to provide bi-directional service across Idaho Power's lines between PacifiCorp's Wyoming system and its Utah system; (iii) to build upgrades and provide transmission service on a portion of Idaho Power's lines for the benefit of Utah Power & Light Company, another predecessor of PacifiCorp, and (iv) to make use of the counter-flows that the east-to-west movement of PacifiCorp's electricity across Idaho Power's transmission lines creates in order to reduce Idaho Power's losses resulting from its normal west-to-east movement of electricity along those lines to its own load in south-central Idaho and western Wyoming.

42. Exhibit No. IPC-29, shown below, is a map of the Idaho Power transmission system that details the principal pathways and interconnections covered by the Legacy Agreements:



43. As the map shows, Idaho Power's principal 230 kV power lines (represented by solid lines) run from Brownlee, Oxbow and Hells Canyon in northwest Idaho south along the Snake River through Midpoint and Adelaide, and end at substations in Borah and Kinport in southeast Idaho. Power flows generally eastward from Idaho Power's sources in the northwest to its principal loads in the south-central and southeastern part of the state. Idaho Power also owns a 345 kV power line running from the Jim Bridger power plant in Wyoming westward to Goshen in southeastern Idaho.

44. As a result of the Legacy Agreements, Pacific Power & Light Company built and PacifiCorp now owns two 345 kV power lines (represented by dotted lines) running from the Jim Bridger power plant westward through Utah and southeastern Idaho to meet Idaho Power's lines at Borah and Kinport, and a 500 kV power line (represented by a dotted line) running westward from Midpoint to Summer Lake, Oregon. PacifiCorp also acquired from predecessor Utah Power & Light Company, and now owns, a 345 kV power line (represented by a dotted line) that connects Goshen to Kinport. PacifiCorp's power flows westward from the Jim Bridger power plant along its lines and Idaho Power's lines to its principal loads in Oregon and Washington along the path from Midpoint to Summer Lake and along the "Northwest Path," consisting of Idaho Power's 230 kV power lines that interconnect with PacifiCorp's western system at La Grande, Enterprise and a location that is variously known as "Divide," "Avista" or "Lolo." Thus, PacifiCorp's westward energy transmission on Idaho Power's system acts as a counter-flow to Idaho Power's eastward energy transmission.

45. Another map showing in greater detail the specific power lines of the various systems in southern Idaho appears at Exhibit No. INT-15. A third map showing the map of IPC-29 with color indications of Idaho Power's Northwest Path, PacifiCorp's Northwest Interconnections, and the new transmission investments that were made pursuant to the Legacy Agreements, appears at Exhibit No. IPC-56.

46. The TFA was entered into on June 1, 1974 for a term of 50 years, automatically renewing with a 5 year notice of termination.[20] It was an agreement between three parties—Idaho Power, Utah Power & Light Company and Pacific Power & Light Company—the latter two of which subsequently merged to form PacifiCorp. The TFA provides for the joint operation and use of various transmission facilities in eastern Idaho and western Wyoming. It includes scheduling rights that Idaho Power provides to PacifiCorp on specific Idaho Power facilities, as well as usage rights that PacifiCorp provides to Idaho Power on specific PacifiCorp facilities. Under the agreement, Idaho

[20] *See* Exhibit Nos. S-1 (Tingle-Stewart Ans. Test. 17:17-19) and INT-12 (TFA § 9.1).

Power charges PacifiCorp "use of facilities" fees for various facilities constructed under the agreement. The TFA was accepted by the Commission by order issued April 21, 1987.[21]

47. The ITSA was entered into on March 19, 1982 and continues until June 1, 2025.[22] It provides for the construction, operation and maintenance of an additional interconnection between Utah Power and Idaho Power and for Idaho Power's provision of certain wheeling rights to Utah Power. As already noted, Utah Power has since merged into PacifiCorp. The ITSA requires PacifiCorp to pay Idaho Power for the cost of the additional facilities constructed to establish the interconnection, as well as "use of facilities" charges for specific Idaho Power facilities along the contract path. The ITSA was accepted by the Commission by order issued August 4, 1987.[23]

48. The RTSA is the successor agreement to a Transmission Service Agreement between Pacific Power & Light Company and Idaho Power dated September 10, 1980 (1980 TSA).[24] The RTSA was executed on February 6, 1992 and remains in effect for the life of the Jim Bridger plant.[25] PacifiCorp's rights under the RTSA are substantially the same as they were under the 1980 TSA. Like the 1980 TSA, the RTSA provides for PacifiCorp's transfer of up to 1,600 MW (currently limited to 1,410 MW) of electric power over certain of Idaho Power's transmission facilities in a westerly direction to PacifiCorp's northwest interconnections, as well as certain other services specified in the agreement. The agreement requires PacifiCorp to pay Idaho Power periodically for specific facilities that Idaho Power constructed under the agreement and to pay certain other charges. The 1980 TSA was accepted by the Commission by order issued April 21, 1987, and the RTSA was accepted by order issued July 29, 1992.[26]

49. The Idaho Power transmission system is operated as an integrated network, and all OATT customers, including Idaho Power itself, share the cost of operating the entire

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[21] *See* Exhibit Nos. IPC-19 (Schellberg Supp. Test. 3:13-4:3) and INT-12 (TFA).

[22] *See* Exhibit Nos. S-1 (Tingle-Stewart Ans. Test. 17:19-20) and INT-14 (ITSA § 2.1).

[23] *See* Exhibit Nos. IPC-19 (Schellberg Supp. Test. 4:5-13) and INT-14 (ITSA).

[24] *See* Exhibit No. INT-16 (1980 TSA).

[25] *See* Exhibit Nos. S-1 (Tingle-Stewart Ans. Test. 17:14-17) and INT-13 (RTSA § 2.5).

[26] *See* Exhibit Nos. IPC-19 (Schellberg Supp. Test. 3:1-11); INT-13 (RTSA); INT-16 (1980 TSA).

system with each other according to their respective demand loads.[27] PacifiCorp, by contrast, does not bear a *pro rata* share of system-wide costs according to its load. It bears only certain agreed-upon shares of the parts of the Idaho Power transmission system facilities that it actually uses pursuant to the Legacy Agreements, which consist primarily of Idaho Power transmission facilities that link the Jim Bridger plant in Wyoming to PacifiCorp's western connections in Oregon and Washington.

50. The payments per kilowatt-year that PacifiCorp makes to Idaho Power under the RTSA, TFA and ITSA for transmission service over particular facilities in Idaho Power's system have been lower than the payments per kilowatt-year that Idaho Power has charged its OATT customers for firm point-to-point transmission service under the OATT stated rates that were established in 1996, and are significantly lower than the payments per kilowatt-year that Idaho Power proposes to charge those customers for the same service under the OATT formula rate. The disparity is also growing. According to Intervenors' expert witness, the gap between the two rates was almost a three-to-one difference in terms of 1994 costs of service and has grown to an almost five-to-one difference in terms of 2004 costs of service.[28]

51. Idaho Power's net transmission revenue requirement of $70,150,351 for the Period 1 (2004) test year is divided in the rate formula by a transmission demand load of 2,942 MW for that year, resulting in an annual point-to-point transmission rate of $23.84 per kW-year.[29] The load in the divisor does not include the 2004 contracted transmission load of PacifiCorp on the Idaho Power system under the Legacy Agreements, which amounted to an additional 2,014 MW.[30]

52. Idaho Power contends that the transmission service that it provides to PacifiCorp under the Legacy Agreements should be treated as "non-firm" service, the revenue from which should be credited against the Total Transmission Revenue Requirement in the numerator of the OATT rate formula, as Idaho Power does in its present tariff filing and did in its previous stated rates. Intervenors and Staff, on the other hand, contend that the service from the Legacy Agreements should be treated as "firm" service, the revenue of which should not be credited against the Total Transmission Revenue Requirement in the numerator. Instead, Intervenors and Staff argue, the PacifiCorp load from the Legacy

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[27] *See* Exhibit No. INT-5 (Daniel Ans. Test. 54:17-57:12).

[28] *See id*. at 87:6-88:22.

[29] *See* Exhibit No. IPC-17 at 5 (Statement BG, page 4).

[30] *See* Idaho Power Tariff Filing, Statement BB; *also see* Exhibit Nos. S-1 (Tingle-Stewart Ans. Test. 12:17-19); INT-5 (Daniel Ans. Test. 82:21-83:5) and INT-19.

Agreements should be added to the network and firm loads of Idaho Power and OATT customers in the divisor of the formula. This change would result in a reduction in the rate derived from the OATT formula.

1. Positions of the Parties

a. *Idaho Power*

53. At the hearing, in order to demonstrate that PacifiCorp's Legacy Agreement load on Idaho Power system should not be included in the divisor of the rate formula, Idaho Power submitted the expert testimony of its energy consultant, Alan C. Heintz, to show that the Legacy Agreement service is not really "firm" service in the same manner as Firm Point-to-Point Transmission Service under the OATT. According to Mr. Heintz, services under the Legacy Agreements have curtailment priorities that fall below Idaho Power's native load. Since OATT firm service is required by Order No. 888 to be equal in firmness to Idaho Power's service to its native load customers, therefore Legacy Agreement service is "non-firm" and must be revenue-credited in the numerator of the OATT rate formula as required by Order No. 888 rather than cost-allocated in the divisor.[31]

54. Idaho Power also submitted the testimony of H. Charles Durick, its Manager of Regional Transmission Reform.[32] Mr. Durick described the primary differences between the RTSA and TFA on the one hand and Idaho Power's OATT on the other. According to Mr. Durick, they are as follows:

a. PacifiCorp faces restrictions (such as the lack of flexibility and resale rights) on the use of TFA and RTSA service that OATT point-to-point customers do not experience;

b. Firmness of service under the TFA and RTSA is more complex with components and circumstances less firm than FERC has defined for OATT Firm Point-to-Point Transmission Service; and

[31] *See* Exhibit No. IPC-23 (Heintz Reb. Test. 7:11-8:3, 9:17-21, 13:12-14:21, 24:17-26:3).

[32] *See* Exhibit No. IPC-28 (Durick Reb. Test. 1:6-8).

c. The TFA and RTSA provided significant transmission benefits through system expansion and counter-flow effects that were considered in the negotiation and pricing.[33]

55. Mr. Durick outlined the various categories of service that Idaho Power makes available to PacifiCorp under the RTSA. They are "East to West Transfer Service" (which includes subcategories known as "Bridger Integration Service," "Other Resource Transfer Service," and "Additional East to West Transfer Service") and "Other Services" (which includes subcategories known as "Dynamic Overlay Service" and "Wyoming-Utah Transmission Service").[34]

56. Regarding the firmness of these RTSA services, Mr. Durick admitted that RTSA section 3.5 states that "Idaho Power shall provide East to West Transfer Services on a continuous, firm basis."[35] He pointed out, however, the following exceptions to "continuous, firm" service that appear immediately after this clause: "(1) for limitations on transfer capability as described in Section 3.6; (2) for interruptions or reductions due to a force majeure as defined in Section 8; (3) for interruptions or reductions due to temporary impairments of transfer capability as described in Section 3.8; and (4) as provided in Section 3.5.1 with respect to Additional East to West Transfer Service."[36] These curtailment provisions, Mr. Durick stated, accord the overall RTSA service a lower priority than what Idaho Power's OATT Firm Point-to-Point Transmission Service customers receive.[37]

57. Regarding Idaho Power's curtailment rights under section 3.6 of the RTSA for East to West Transfer Service, Mr. Durick testified:

> For delivery across the interconnection from Idaho Power to the Pacific Northwest, [the RTSA] provides that Idaho Power will have first call on 570 MW of the westbound capacity. Thus, if the capacity of Idaho Power's interconnection with the Pacific Northwest was reduced below 1,980 MW (the level necessary to provide 1,410 MW of service to PacifiCorp and maintain Idaho Power's 570 MW share) during normal system conditions, and Idaho Power needed its full 570 MW share, the

[33] Exhibit No. IPC-28 (Durick Reb. Test. 11:8-19).

[34] *See* Exhibit No. IPC-28 (Durick Reb. Test. 15:2-8).

[35] *See id*. at 15:11-12.

[36] *See id*. at 15:12-17.

[37] *See id*. at 15:17-19.

> contract allows Idaho Power to curtail service to PacifiCorp while maintaining Idaho Power's 570 MW share. This places PacifiCorp in a lower priority than Idaho Power's other uses within this reserved block, including provision of OATT service to other customers.
>
> For transmission west of Borah and Kinport, the RTSA allocates two-thirds of the first 2,121 MW of capacity to PacifiCorp, and the remaining one-third to Idaho Power. The RTSA provides if the normal system transfer capability is reduced below 2,121 MW, PacifiCorp and Idaho Power will share the curtailment *pro rata* to their capacity entitlements.[38]

58. For service across other segments of Idaho Power's system, Mr. Durick testified, the RTSA establishes no specific access allocation or priority for service to PacifiCorp, but requires Idaho Power to "use its best efforts to maximize the transfer capability to PacifiCorp for East to West Transfer Services consistent with other obligations."[39] This type of curtailment has been rare, Mr. Durick stated, but when it has happened, "the operators from the two companies have talked to each other and worked out a response to the immediate circumstances with first priority given to maintaining either party's reliability."[40]

59. With regard to Additional East to West Service under section 3.5.1 of the RTSA, Mr. Durick testified that "this service has a lower priority than all firm services, and a lower priority than Idaho Power's other existing and future firm and non-firm uses of its transmission system."[41] Regarding Dynamic Overlay Service, section 4.2.1 of the RTSA "gives Idaho Power the right to curtail this service if it is causing Idaho Power to forego the opportunity to use its transmission system for transactions outside of the agreement."[42] Regarding Wyoming-Utah Transmission Service, Mr. Durick stated that this service is subject to Idaho Power having sufficient firm transmission capacity available on its system and on the Bridger transmission system, after taking into account Idaho Power's right to deliver its share of Bridger power to the Idaho Power system, and therefore this service is secondary to Idaho Power's use of its system for its own

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[38] *Id*. at 16:3-18.

[39] *See id*. at 17:18-18:1.

[40] *Id*. at 18:1-6.

[41] *Id*. at 18:10-13.

[42] *Id*. at 18:18-20.

deliveries from Bridger.[43]

60. Concerning the TFA, Mr. Durick testified that curtailment is left to the *ad hoc* judgment of Idaho Power's system operators involved during an event.[44] Mr. Durick believed, however, that Idaho Power would not interrupt its native load to maintain economic transfers under this service.[45]

61. Idaho Power also submitted the testimony of Tess Park, its Manager of Grid Operations, to show that the curtailment procedures followed by Idaho Power for the Legacy Agreements make the service under those agreements "non-firm" as that term is understood for OATT service. According to Ms. Park, "[c]urtailment procedures are those procedures used when an event – such as an outage – reduces the amount of available transfer capability. In situations such as these, certain procedures need to be followed to determine whose electricity services should be reduced in order to deal with the reliability situation."[46] Ms. Park testified that "if curtailments are necessary, but certain services under an agreement are not curtailed in a manner consistent with firm service under the OATT, this would indicate that those services are not OATT firm."[47]

62. Ms. Park explained how the curtailment provisions of the RTSA affect Idaho Power and PacifiCorp along the Idaho to Northwest path:

> When the Idaho to Northwest path, which comprises Idaho Power's western interconnections, needs to be curtailed, the operators will implement the following procedure. Idaho Power has priority over the first available 570 MW of the East to West capacity on the path. After Idaho Power has exercised this priority, the remainder of the path capacity is made available for PacifiCorp schedules under the RTSA, subject to the contract limits. An example of such a curtailment occurred in October 2006, when an outage of one of the tie lines on the Idaho to Northwest path resulted in a reduction of the transfer capability from 2,304 MW to 850 MW. Of the available 850 MW, Idaho Power retained priority rights to the first 570 MW. Thus, after Idaho Power exercised this priority, the remainder of the path capacity was made available to PacifiCorp. This

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[43] *Id.* at 19:4-10.

[44] *Id*. at 19:14-15.

[45] *Id*. at 19:15-18.

[46] Exhibit No. IPC-32 (Park Reb. Test. 5:7-11).

[47] *Id*. at 5:13-18.

> meant that PacifiCorp received only 280 out of the 1,410 MW of service under the RTSA. Had PacifiCorp been taking service under the OATT, PacifiCorp and Idaho Power would have shared the available 850 MW on a *pro rata* basis.[48]

63. Ms. Park gave other examples of curtailments occurring over the Idaho to Northwest path, which she said is curtailed more often than any other Idaho Power pathway.[49] For curtailments that occur in the path West of Midpoint, Ms. Park further testified, the RTSA does not establish a specific access or priority, and curtailments are determined "in response to current circumstances with primary consideration given to reliability."[50]

64. Ms. Park also described how Idaho Power's transmission service to PacifiCorp under the RTSA is subject to curtailment on the Borah West and Bridger West paths on the basis of a one-third split to Idaho Power and a two-thirds split to PacifiCorp.[51]

65. Ms. Park described curtailment procedures for the other components of RTSA service. When PacifiCorp's use of Dynamic Overlay Control Service under the RTSA is causing Idaho Power to forego the opportunity to use its transmission system for any transactions outside of the RTSA, Ms. Park testified, it has been Idaho Power's practice to curtail that service prior to any curtailment of firm or non-firm OATT transmission service.[52] Idaho Power's provision of Wyoming-Utah Transmission Service under the RTSA is also subject to Idaho Power having sufficient firm transmission capacity on its system to provide the service, Ms. Park stated.[53]

66. At the hearing, Ms. Park described the priority system that Idaho Power and other transmission providers use on a daily basis to set priorities among the various transmission products offered to customers in the event of curtailments and other interruptions. She explained that there are priorities established by the North American Electric Reliability Council (NERC) for transmission service, ranging from "8," the highest priority, down to "1," the lowest. The highest priority that Idaho Power deals with is "7" for

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[48] *Id*. at 6:17-7:10.

[49] *See id*. at 7:12-17; Exhibit Nos. IPC-35 and IPC-36.

[50] Exhibit No. IPC-32 (Park Reb. Test. 9:9-13).

[51] *See id*. at 10:2-11:20; Exhibit Nos. IPC-37, IPC-38 and IPC-39.

[52] *See* Exhibit No. IPC-32 (Park Reb. Test. 13:10-18).

[53] *See id*. at 13:18-20.

"firm" service, which includes OATT firm and network service. Priority "6" is the highest priority non-firm service. Priorities "5" down to "2" are monthly, weekly, daily and hourly non-firm service, respectively. Priority "1" is the lowest, a firm product that has been redirected to a new point of receipt or point of delivery on an hourly basis.[54]

67. This priority system, Ms. Park explained, is used for interruptibility purposes as well as for curtailments, but the Legacy Agreements do not fit neatly into the priorities as OATT and network services do.[55] Legacy Agreement services may be assigned one or more of these priorities, Ms. Park explained, but they are problematic for the priority system because they are not curtailed in the same manner as OATT and network services.[56]

68. The Legacy Agreements also receive unique treatment in Idaho Power's calculation of its available transfer capacity, or "ATC," on its transmission system. As Ms. Park explained, ATC is the amount of transfer capability that remains from the total transfer capability, or "TTC," on a specific transmission pathway that is posted on Idaho Power's OASIS, "after subtracting the contract rights, firm commitments, network usage, Capacity Benefit Margin and Transmission Reliability Margin."[57] "In other words," Ms. Park stated, ATC "is whatever is left over after everything else has been taken into account."[58] This ATC calculation reflects Idaho Power's contract obligations and firm OATT and network commitments and usage, and "the Company does not sell service that interferes with existing rights."[59]

69. ATC is not calculated by Idaho Power as a single number for the entire system. One ATC is computed for "firm" products and another ATC is computed for "non-firm" products.[60] When Idaho Power calculates its "firm" ATC, it deducts from its TTC the entire 1,410 MW contractual obligation that Idaho Power has to PacifiCorp under the Legacy Agreements.[61]

[54] *See* Park Hg. Tr. 290:21-291:9.

[55] *See id*. at 227:10-228:5.

[56] *See id*. at 291:10-19.

[57] *See* Exhibit No. IPC-32 (Park Reb. Test. 16:5-12).

[58] *Id*.

[59] *Id.* at 17:6-14.

[60] *See* Park Hg. Tr. 243:19-24.

[61] *See id*. at 152:2-13.

70. Ms. Park explained Idaho Power's treatment of the Legacy Agreements in calculating its firm ATC this way:

> After Order 888 was enacted, Idaho Power confronted the transitional issue of trying to determine where on the spectrum between firm and non-firm many contracts (like the Legacy Agreements) fell. This transitional issue existed because some contracts were less firm than native load, but could not be classified as non-firm. For contracts such as those, Idaho Power had to determine whether or not to honor the contracts by reducing TTC accordingly. In the case of the Legacy Agreements, Idaho Power chose to honor its contractual obligations by including them in the ATC calculation. As discussed above, this does not make these agreements firm under the definition in the OATT.[62]

71. Ms. Park further testified that counter-flows on Idaho Power's system do not increase TTC calculations.[63] This is so, Ms. Park stated, because Idaho Power cannot count on a counter-flow being received at any given time.[64]

b. *PacifiCorp*

72. PacifiCorp disagrees with Idaho Power's characterization of RTSA service as "inferior" in priority to firm OATT service. John A. Apperson, PacifiCorp's Trading Director in its commercial and trading department, testified consistently with Idaho Power that on the Idaho to Northwest path, Idaho Power has an unrestricted right under the RTSA to the first 570 MW of capacity.[65] Regarding the path west of Borah and Kinport substations, Mr. Apperson generally agreed with Idaho Power that there is a 2,307 MW system-normal transfer limit, and that Idaho Power has the right to 707 MW of transfer unless the rating on that path falls below 2,121 MW, in which case PacifiCorp's 1,414 MW of remaining transfer rights and Idaho Power's 707 MW of rights are reduced on a *pro rata* basis.[66]

73. Mr. Apperson took issue, however, with the notion that the RTSA is prioritized "under" Idaho Power's OATT. He noted that as a pre-Order No. 888 contract, the RTSA

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[62] Exhibit No. IPC-32 (Park Reb. Test. 19:2-17).

[63] Park Hg. Tr. 244:6-8.

[64] *Id*. at 244:9-11.

[65] *See* Exhibit No. PAC-1 (Apperson Ans. Test. 3:12-15).

[66] *Id*. at 3:15-23.

is not subject to the requirements of Order No. 888.[67] Mr. Apperson also noted that service under the RTSA includes several unique attributes that are different from Order No. 888 OATT service. Under the RTSA, he said, PacifiCorp cannot redirect to any alternate points of receipt or delivery nor reassign these rights to a third party. This is different from service under the OATT, Mr. Apperson stated, which would allow a customer to redirect and reassign transmission rights. Further, Mr. Apperson testified, the RTSA explicitly describes transmission capability and the parties' capabilities under abnormal conditions. Under the OATT, all firm users take a *pro rata* cut on their schedules after non-firm service has been curtailed. In addition, he stated, PacifiCorp cannot assign the service under the RTSA to any other party without sale of the Jim Bridger assets, including power plants and associated transmission system. Nor is third party wheeling allowed under the RTSA, which is allowed under the OATT. Finally, Mr. Apperson pointed out, the loss determination under the RTSA is different from the loss determination under OATT.[68]

c. *Intervenors*

74. Intervenors maintain that the service that Idaho Power provides to PacifiCorp under the Legacy Agreements is "firm" service, although admittedly not exactly the same as the type of firm service that is offered under the terms of the OATT.[69] Therefore, they argue, even though the firm service under the Legacy Agreements is not the same as "OATT firm service," the firm nature and characteristics of the arrangements set forth in the Legacy Agreements suffice to require their combination with OATT firm service in calculating the load divisor of the OATT rate formula and allocating system-wide costs to the combined firm load.

75. Intervenors offer the testimony of their expert witness, engineering consultant Stephen P. Daniel, to support their position. According to Mr. Daniel, Idaho Power's transmission system is planned and operated as an integrated transmission system.[70]

76. Mr. Daniel described the respective rights of Idaho Power and PacifiCorp under the TFA to share the transfer rights (one-third and two-thirds, respectively) over the three 345 kV power lines running westward from the Jim Bridger power plant in Wyoming to

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[67] *Id.* at 3:25-4:2.

[68] *Id*. at 4:21-5:4.

[69] *See* Exhibit Nos. INT-5 (Daniel Ans. Test. 59:14-22, 64:13-68:13); INT-35 (Daniel Cross-Ans. Test. 3:3-7).

[70] *See* Exhibit No. INT-5 (Daniel Ans. Test. 54:17-57:12).

Goshen, Borah and Kinport, Idaho.[71] The purpose of these rights is to deliver capacity from Bridger into Idaho Power's transmission system for the benefit of Idaho Power and to move power through the Idaho Power system for the benefit of PacifiCorp.[72] Also under the TFA, Idaho Power and PacifiCorp have the right to utilize capacity in PacifiCorp's Goshen-Kinport 345 kV line for transmission of power between Bridger and Kinport to the same degree as would have been the case if the 345 kV line had been routed directly from Bridger to Kinport.[73] This right was originally granted in the TFA by Utah Power to both Idaho Power and Pacific Power & Light Company before Utah Power and Pacific Power & Light Company merged into PacifiCorp.[74]

77. Mr. Daniel testified that under the TFA, Idaho Power also granted to Utah Power a right to schedule 250 MW of power from the Brady 230 kV switchyard eastward to the 345 kV terminus of the Goshen-Kinport 345 kV line at Kinport.[75] This right, Mr. Daniel testified, is in essence a firm transmission right granted to PacifiCorp (as successor to Utah Power) of 250 MW on this element of the Idaho Power integrated transmission system.[76]

78. Mr. Daniel also described the terms of the RTSA between Idaho Power and PacifiCorp. Under the RTSA, Mr. Daniel testified, there are three types of transmission services: (i) East to West Transfer Service; (ii) Dynamic Overlay Control Service; and (iii) Wyoming-Utah Transmission Service.[77] East to West Transfer Service, Mr. Daniel explained, has three component services, set forth in section 3 of the RTSA as follows:

> 3.1.1 <u>Bridger Integration Service</u>:
>
> Bridger Integration Service shall consist of the scheduled transfer (as provided in paragraph 5.5) of all or any portion of PacifiCorp's share of the Jim Bridger Project Net Generation from east to west across Idaho Power's system.

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[71] *See id*. at 58:15-20; Exhibit No. INT-12 (TFA § 6.2).

[72] *See* Exhibit No. INT-5 (Daniel Ans. Test. 58:20-23).

[73] *See id*. at 59:1-5; Exhibit No. INT-12 (TFA § 6.5).

[74] *See id*. at 59:1-5; Exhibit No. INT-12 (TFA § 6.5).

[75] *See* Exhibit Nos. INT-5 (Daniel Ans. Test. 59:14-17); INT-12 (TFA § 6.4).

[76] Exhibit No. INT-5 (Daniel Ans. Test. 59:17-19).

[77] Exhibit Nos. INT-5 (Daniel Ans. Test. 61:18-25); INT-13 (RTSA §§ 3 and 4).

3.1.2 Other Resource Transfer Service:

Other Resource Transfer Service shall consist of the scheduled transfer of Other Resources from east to west across Idaho Power's system in amounts up to the limits set forth in paragraph 3.4.2.2.

3.1.3 Additional East to West Transfer Service:

Additional East to West Transfer Service shall consist of the scheduled transfer of Other Resources from east to west across Idaho Power's system that are in excess of the maximum amounts of Other Resources that Idaho Power is required to transfer under paragraph 3.1.2 above.[78]

79. Dynamic Overlay Control Service, Mr. Daniel explained, allows PacifiCorp to dynamically schedule over Idaho Power's system up to plus or minus 100 MW of power and associated energy between PacifiCorp's western system and PacifiCorp's Wyoming system utilizing dynamic (*i.e.*, real-time) transfers.[79]

80. Wyoming-Utah Transmission Service, Mr. Daniel explained, allows PacifiCorp to make bidirectional transfers over Idaho Power's system of up to 104 MW of power between PacifiCorp's Wyoming system and PacifiCorp's Utah system in addition to transfer rights that PacifiCorp is entitled to under an earlier agreement.[80]

81. Overall, Mr. Daniel further explained, the RTSA provides PacifiCorp with transfer capability over Idaho Power's system of up to 1,600 MW (currently limited to 1,410 MW) of energy in a westerly direction to PacifiCorp's northwest interconnections.[81] This transfer limit, according to Mr. Daniel, is a maximum that includes the Bridger Integration Service, Other Resource Transfer Service, Additional East to West Transfer Service, and Dynamic Overlay Control Service in an amount up to plus or minus 100 MW.[82]

82. According to Mr. Daniel, East to West Transfer Services under the RTSA are firm

[78] Exhibit No. INT-5 (Daniel Ans. Test. 62:1-20); INT-13 (RTSA §§ 3.1.1-3.1.3).

[79] *See* Exhibit No. INT-5 (Daniel Ans. Test. 62:27-63:5); INT-13 (RTSA § 4.2).

[80] *See* Exhibit No. INT-5 (Daniel Ans. Test. 63:6-14); INT-13 (RTSA § 4.3).

[81] *See* Exhibit No. INT-5 (Daniel Ans. Test. 63:20-64:1).

[82] *See id.* at 64:1-6; INT-13 (RTSA §§ 3.1, 3.4 and 4.2.2).

services.[83] Mr. Daniel concluded that the service is firm based on section 3.5 of the RTSA, which provides that "Idaho Power shall provide East to West Transfer Services on a continuous, firm basis" except for certain enumerated exceptions.[84] Two of the exceptions, for interruptions in service due to *force majeure* and for interruptions or reductions due to temporary impairments of transfer capability, are the types of limitations on transfer capability that might occur and that would affect firm service in general and are similar to provisions found in Idaho Power's OATT, Mr. Daniel stated.[85]

83. Another exception, Mr. Daniel stated, is applicable only to Additional East to West Transfer Service and is a "secondary firm priority."[86] Section 3.5.1 of the RTSA states that Additional East to West Transfer Service has:

> … a higher priority than all other existing and future nonfirm transmission services provided by Idaho Power for third parties under other agreements, but shall have a lower priority than all of Idaho Power's other existing and future firm and nonfirm uses of its transmission system, including electric service to Idaho Power's customers, firm and nonfirm wholesale purchases and sales, and other firm transmission services. …[87]

84. Finally, Mr. Daniel stated, another exception to "continuous, firm" service under the RTSA recognizes that certain capacity limitations may exist on the Idaho Power system which may limit the capability of Idaho Power to deliver the full 1,600 MW for PacifiCorp.[88] This is the limitation that currently allows Idaho Power to reduce PacifiCorp's maximum use of the system from 1,600 MW to 1,410 MW, Mr. Daniel stated.[89] However, Mr. Daniel noted, the RTSA provides either party a process to alleviate these capacity limitations, and would most likely trigger upgrades to alleviate such limitations if they proved to be burdensome either economically or from a reliability perspective.[90]

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[83] *See* Exhibit No. INT-5 (Daniel Ans. Test. 64:13-68:13).

[84] *See id.* at 64:15-25; INT-13 (RTSA § 3.5).

[85] *See* Exhibit No. INT-5 (Daniel Ans. Test. 64:26-65:1).

[86] *See id*. at 65:3-5.

[87] *Id*. at 65:6-12; INT-13 (RTSA § 3.5.1).

[88] *See* Exhibit No. INT-5 (Daniel Ans. Test. 65:14-16; INT-13 (RTSA §§ 3.6 – 3.6.2).

[89] *See* Exhibit No. INT-5 (Daniel Ans. Test. 65:16-17).

[90] *See id*. at 65:17-22.

85. This last restriction, Mr. Daniel testified, is not unlike flow-gate limitations which may occur and restrict firm transmission services, for example, under an OATT.[91] In such situations, he said, operating procedures may be instituted to alleviate flow-gate constraints, but there may be times when service restrictions are actually imposed on firm transmission users. This limitation, therefore, does not constitute a restriction on the transfer services provided by Idaho Power to PacifiCorp such that those services should be deemed other than firm, and they do not render the RTSA services non-firm, Mr. Daniel said.[92]

86. Mr. Daniel also pointed to other evidence that Idaho Power considers its service under the RTSA to be firm service, particularly testimony of Mr. Schellberg on behalf of Idaho Power in Docket No. ER97-1481-003 and statements of Mr. Durick in a 2006 deposition.[93]

87. Mr. Daniel further pointed to evidence that PacifiCorp also considers its transmission rights from Bridger over the Idaho Power system to be firm service.[94] In particular, he pointed to PacifiCorp's Technical Appendix, Volume 2, Capacity Analysis of the 2004 Pacific Northwest Loads and Resources Study for Operating Years 2006 through 2015, specifically Table A-10, indicating that PacifiCorp's Bridger resource is considered a firm resource for load-serving purposes.[95] He further pointed out that Idaho Power does not sell OATT service that would interfere with service provided to PacifiCorp pursuant to the RTSA.[96] Mr. Daniel noted, in particular, that the impact on OATT service of this practice on Idaho Power's part is shown by the fact that, according to Idaho Power's OASIS, paths over which Idaho Power otherwise could sell transmission service indicate that no firm transmission service is available.[97]

88. In support of Mr. Daniel's point, Intervenors presented the testimony of Jason C. Bryan, a Public Utility Specialist in the Scheduling Department for the Bonneville Power Administration. Bryan described specific instances of the lack of firm transfer capability

[91] *See id.* at 65:23-25.

[92] *See id*. at 65:25-66:4.

[93] *See* Exhibit Nos. INT-5 (Daniel Ans. Test. 66:5-67:29); INT-17; INT-18.

[94] *See* Exhibit No. INT-5 (Daniel Ans. Test. 80:21-81:23).

[95] *See id*. at 81:1-4; INT-23 at 28-37.

[96] *See* Exhibit No. INT-5 (Daniel Ans. Test. 81:12-13).

[97] *See id.* at 81:13-16.

along several of Idaho Power's OASIS-posted paths that are affected by service under the Legacy Agreements.[98] According to Bryan, there is no short-term capacity available from Bridger to Midpoint and only a limited amount available on a short-term basis from Borah-Brady to Midpoint.[99] Also, Bryan said, there is no long-term (*i.e.*, yearly) firm capacity available from Bridger to Midpoint, and for Borah-Brady to Midpoint there is no long-term capacity available for 2007 and only 53 MW available on a long-term basis for 2008.[100]

89. Mr. Daniel testified that as firm service, the Legacy Agreements should be cost-allocated rather than revenue-credited in the proposed OATT formula rate.[101] He noted in this regard that in Docket No. ER96-350, in which Idaho Power's original OATT rate was determined, the rate for long-term firm point-to-point service was stated as $15.33 per kW-year, while PacifiCorp's 2,014 MW of power in that same year (1994) cost PacifiCorp approximately $5.51 per kW-year.[102] In this case, Mr. Daniel testified, Idaho Power's formula rate based upon 2004 data indicates a long-term point-to-point unit charge of $23.84 per kW-year, whereas PacifiCorp's 2,014 MW of power in 2004 cost PacifiCorp approximately $4.84 per kW-year.[103] Thus, Mr. Daniel testified, the pricing disparity has grown from almost three-to-one in 1994 to five-to-one in 2004, resulting in a sizable and growing cross-subsidy of PacifiCorp's service by OATT customers.[104]

d. *Staff*

90. Staff's expert witness, Energy Industry Analyst Natalie Y. Tingle-Stewart, disagreed in her testimony with Idaho Power's characterization of the Legacy Agreements as non-firm service.[105] Ms. Tingle-Stewart testified that Idaho Power's RTSA service to PacifiCorp is a long-term firm transmission service because Idaho Power and PacifiCorp included the Jim Bridger power plant in their 2004 Integrated Resource Plan (IRP) analysis as a "base resource" for planning purposes.[106] Therefore,

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[98] *See* Exhibit Nos. INT-2, INT-3 and INT-4.

[99] *See* Exhibit No. INT-2 (Bryan Ans. Test. 7:4-8).

[100] *See id.* at 7:9-12.

[101] *See* Exhibit No. INT-5 (Daniel Ans. Test. 83:6-85:14).

[102] *See id*. at 87:6-16.

[103] *See id*. at 87:17-22.

[104] *See id.* at 88:1-12.

[105] Exhibit No. S-1 (Tingle-Stewart Ans. Test. 1:19-24).

[106] *See id*. at 19:23-20:16; Exhibit No. S-2 at 5-18 and 19-27.

according to Ms. Tingle-Stewart, Idaho Power and PacifiCorp consider the Jim Bridger plant to be a firm source of power to serve their loads, and if the generation source is firm, then the transmission for the source should also be firm.[107]

91. Ms. Tingle-Stewart further testified that Idaho Power classifies the MW for the Legacy Agreements in its 2004 FERC Form 1 as long-term firm transmission service.[108] Ms. Tingle-Stewart mistakenly referred in her testimony to an exhibit showing Idaho Power's FERC Form 1 for 1994, which classifies Idaho Power's PacifiCorp-Wyoming service under the RTSA as "OS," the designation for "other transmission service," which is used for service that cannot be placed in other defined categories, such as all non-firm transmission service.[109] On cross-examination, Ms. Tingle-Stewart clarified that she meant to refer to Idaho Power's FERC Form 1 for 2004 (Test Period I in this proceeding). That form classifies Idaho Power's PacifiCorp-West service as "OLF," for "other long-term firm service."[110]

92. Ms. Tingle-Stewart also relied on section 3.5 of the RTSA, quoted previously herein, which states that Idaho Power's East to West Transfer Service will be provided on "a continuous, firm basis."[111]

93. Ms. Tingle-Stewart further relied on the testimony of Idaho Power's witness, Mr. Schellberg, in an earlier market power proceeding before this Commission in Docket No. ER97-1481-003, in which he characterized the RTSA as "allow[ing] for up to 1600 MW of service, however, due to transmission limitations west of the Jim Bridger power plant, only 1410 MW is available on a firm basis."[112]

94. Ms. Tingle-Stewart characterized Idaho Power's answers to Staff's data requests on the firmness of RTSA service as contradictory. Ms. Tingle-Stewart pointed in particular to Idaho Power's responses to Staff Data Requests STAFF-IDAHO-20 and

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[107] *See* Exhibit No. S-1 (Tingle-Stewart Ans. Test. 21:1-3).

[108] *See id*. at 21:4-6.

[109] *See* Exhibit No. INT-23 (Daniel workpapers at 43-51).

[110] *See* Tingle-Stewart Hg. Tr. 690:11-691:19; Exhibit No. INT-40 (FERC Form 1 at 2, lines 10-12).

[111] *See* Exhibit No. S-1 (Tingle-Stewart Ans. Test. 21:7-8); Exhibit No. INT-13 (RTSA, § 3.5).

[112] *See* Exhibit No. S-1 (Tingle-Stewart Ans. Test. 23:1-9); Exhibit No. INT-18 (September 27, 2004 Schellberg Aff. In ER97-1481-003 at 3, ¶ 6 n.1).

STAFF-IDAHO-27. The first answer related to the RTSA and the second related to the TFA, but both answers were otherwise identical. Regarding the RTSA, Idaho Power stated on the one hand:

> Since the issuance of Order 888, the Commission has defined long-term "firm" transmission service to have two primary characteristics. First, the service must have a priority equal to native load service. Second, the transmission provider must undertake an obligation to build in order to provide service. *Under that definition of firm service, the RTSA is not firm*.

Immediately following that statement, however, Idaho Power continued in its response:

> However, for the most part service under the *RTSA is also not "non-firm" service* as defined in Order 888 and the pro forma OATT. Under the OATT there are several categories of non-firm service, but one characteristic of all non-firm service under the OATT is that the service is subject to curtailment or interruption in order to provide firm OATT service under a separate service agreement. For the most part Idaho Power does not believe that it has the right to interrupt RTSA service in order to provide non-firm transmission service under the OATT to a third party. *Therefore, service under the RTSA has a priority that is above OATT non-firm service but below OATT firm service*.[113]

95. Ms. Tingle-Stewart testified that she does not characterize Idaho Power's service to PacifiCorp under the Legacy Agreements as "OATT firm service."[114] Rather, she points to the Commission's historical treatment of long-term firm transmission service in pre-Order No. 888 cases, notably *Boston Edison Co.*[115] and *American Electric Power* (*AEP*)[116], for the principle that pre-Order No. 888 contracts like the Legacy Agreements should be cost-allocated rather than revenue-credited.[117]

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[113] Exhibit Nos. S-1 (Tingle-Stewart Ans. Test. 23:15-24:8); S-2 at 29-30 (STAFF-IDAHO-20) and 31-32 (STAFF-IDAHO-27) (emphasis added).

[114] *See* Exhibit No. S-1 (Tingle-Stewart Ans. Test. 26:8-13).

[115] *Boston Edison Co.*, 8 FERC ¶ 61,077 (1979).

[116] *American Electric Power Service Corp.*, 80 FERC ¶ 63,006 (1997), *affirmed in relevant part*, Opinion No. 440, 88 FERC ¶ 61,141 (1999) (*AEP*).

[117] *See* Exhibit No. S-1 (Tingle-Stewart Ans. Test. 26:14-28:27).

2. Discussion

a. *Burden of Proof*

96. As an initial matter, Idaho Power asserts that it does not bear the burden of proof in this case. Rather, it asserts that Staff and Intervenors bear the burden of proving that Idaho Power's longstanding practice of revenue-crediting the Legacy Agreements against the total transmission revenue requirement in the numerator of its OATT rate formula is unjust and unreasonable.[118]

97. According to Phil A. Obenchain, Idaho Power's Senior Pricing Analyst in the Pricing and Regulatory Services Department, it has been the Company's longstanding practice for the Legacy Agreements to be revenue-credited.[119] The Commission has accepted Idaho Power rates that included a transmission cost of service in which the Legacy Agreements were revenue-credited in nine prior Commission dockets, Mr. Obenchain testified.[120] Idaho Power's retail rates have also been set using the same revenue-crediting methodology during that entire time period, he pointed out.[121] Also, according to Idaho Power's expert witness, Alan Heintz, Staff has also found this methodology to be "cost-justified" in its past evaluations of Idaho Power's transmission rates that were initiated through settlement agreements.[122]

98. Under section 205 of the FPA, "[a]t any hearing involving a rate or charge sought to be increased, the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the public utility."[123] Here, however, Idaho Power contends that a settled ratemaking practice may arise from a settlement agreement, and when one does a party who seeks to change that practice "bears a heavy burden." Idaho Power points to Commission pronouncements that where a utility files to increase its rates "[i]n the absence of changed circumstances requiring a different result, there appears no reason why substantive ratemaking principles, once established, should not continue to be

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[118] *See* Idaho Power Initial Brief 9-12; Idaho Power Reply Brief 16-18.

[119] *See* Exhibit No. IPC-40 (Obenchain Reb. Test. 4:1-6).

[120] *Id*. at 5:8-11 and 6:18-22.

[121] *Id.* at 7:11-13.

[122] Exhibit Nos. IPC-23 (Heintz Reb. Test. 37:18-38:14); IPC-27 at 10; *also see* Nichols Hg. Tr. 159:25-160:2.

[123] 16 U.S.C. § 824d (e) (2000).

applied."[124] Such is the case here, Idaho Power maintains.[125]

99. Staff and Intervenors point out that the revenue-crediting practice that Idaho Power has maintained over the years was established in Docket No. ER96-350-000, a case that was resolved by an uncontested offer of settlement that was approved by a Commission Letter Order.[126] They counter that both the offer of settlement and the Commission's Letter Order approving that settlement made clear that the settlement establishes no principle or precedent regarding any issue or ratemaking principle.[127] Therefore, they argue, the fact that Idaho Power's revenue-crediting practice is a longstanding one has no bearing on whether it is just and reasonable, and does not shift the burden of proof away from Idaho Power towards them.

100. The "burden of proof" issue that has arisen in this case should not engender as much controversy as it has among the parties, because there are ample facts on the record to support the outcome no matter who really bears the burden of proof. "If evidence is introduced in the proceeding supporting a rate increase, the increase can lawfully be imposed, regardless of the source from which that evidence comes."[128] Fortunately, this well-litigated case does not suffer from an absence of support that would make the outcome wholly dependent on who bears the burden of proof. Nevertheless, it is necessary to decide this sub-issue, and the applicable law places the burden on Idaho Power in this case.

101. In *Winnfield v. FERC*,[129] the U.S. Court of Appeals for the D.C. Circuit ruled:

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[124] Idaho Power Initial Brief at 11, *quoting Central Kansas Power Co., Inc.*, 5 FERC ¶ 61,291 at 61,621 (1978); *also citing Algonquin Gas Transmission Co. v. FERC*, 948 F.2d 1305, 1312 (D.C. Cir. 1991); *ANR Pipeline Co. v. FERC*, 771 F.2d 507, 513-14 (D.C. Cir. 1985); *Pub. Serv. Comm'n of N.Y. v. FERC*, 642 F.2d 1335, 1346 (D.C. Cir. 1980); *Columbia Gas Transmission Co. v. FERC*, 628 F.2d 578, 585-86 (1979); *Trunkline Gas Co.*, 64 FERC ¶ 61,030 at 61,323-24 (1993); *Panhandle Eastern Pipe Line Co.*, 60 FERC ¶ 61,288 at 61,977 (1992).

[125] Idaho Power Initial Brief at 11.

[126] *See* Intervenors Initial Brief 19-20; Staff Initial Brief 8-11; Exhibit No. INT-5 (Daniel Ans. Test. 49:15-51:2).

[127] *See* Intervenors Initial Brief 19-20; Staff Initial Brief 8-11; Intervenors Reply Brief 3-4; Exhibit No. INT-5 (Daniel Ans. Test. 50:7-10); Exhibit No. INT-7 at 1 (September 13, 1996 FERC Letter Order in ER96-350-000).

[128] *Winnfield v. FERC*, 744 F.2d 871, 877 (D.C. Cir. 1984).

[129] *Id*.

> The statutory obligation of the utility . . . is not to prove the continued reasonableness of *unchanged* rates or *unchanged* attributes of its rate structure. "We cannot accept the proposition that because a company files for higher rates, it bears the burden of proof on those portions of its filing that represent no departure from the status quo. . . . The emphasis is on making the petitioner justify the changes in rates, not the constant elements."[130]

The D.C. Circuit has also held that this principle does not change merely because the unchanged element of a rate structure was devised as part of a settlement agreement. In allocating the burden of proof, no significance is attached to the fact that a particular unchanged methodology is the result of a settlement.[131]

102. Intervenors and Staff do not challenge that Idaho Power is using the same revenue-crediting technique in its formula rate calculation that it utilized in its 1996 stated rate filing.[132] Idaho Power does not dispute that the uncontested, Commission-approved settlement that implemented those stated rates did not establish any principle or precedent regarding any issue or ratemaking principle. However, the fact that Idaho Power used this revenue-crediting technique only once, in its 1996 rate filing, to set its long-standing stated rates does not turn that technique into a "settled practice." Idaho Power did not thereafter engage in revenue-crediting unfailingly, year after year, right up to the present date. Revenue-crediting as a ratemaking "practice" is not the *status quo* here. It is only now that Idaho Power wants to institute revenue-crediting as a routine component of its proposed, annually-updated formula rate structure. As a "practice," this is entirely new.

103. *Winnfield* does not command a different conclusion. In that case, the utility proposed a new "incremental cost" rate structure; instead, the Commission rejected that new scheme and imposed a rate increase on the basis of the *existing* "average cost" rate structure.[133] The intervenor argued on appeal that this rate increase could not be imposed because the utility did not satisfy its burden under section 205 of the FPA of proving the justness and reasonableness of the rate increase; the utility, the intervenor argued, had

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[130] *Id*. (emphasis in original), *citing Pub. Serv. Comm'n of N.Y. v. FERC, supra*, 642 F.2d at 1345.

[131] *Pub. Serv. Comm'n of N.Y. v. FERC, supra*, 642 F.2d at 1346.

[132] *See* Exhibit No. IPC-40 (Obenchain Reb. Test. 4:1-6).

[133] *See Winnfield v. FERC, supra*, 744 F.2d at 874.

only proved the justness and reasonableness of a rate increase under its proposed, but rejected, incremental rate structure.[134] The Court of Appeals for the D.C. Circuit rejected the intervenor's argument on the ground that the utility did not bear that burden of proof, for the reason quoted above.[135]

104. Here, unlike *Winnfield*, Idaho Power is advocating the changed structure—an annually-changing formula rate—but the existing structure is completely dead—the fixed, stated rate. No one is advocating a return to a stated rate. All that went into Idaho Power's original 1996 computation of that fixed, stated rate dies with it. No component that went into that stated rate computation survives as an ongoing, "settled practice." Rather, it is only the imposition of a fixed rate year after year that constitutes Idaho Power's "settled practice." Thus, the burden of proving the justness and reasonableness of the new formula-rate structure, including the annual revenue-crediting of the Legacy Agreements, rests with Idaho Power.

b. *Order No. 888*

105. Idaho Power's OATT was established in accordance with the Commission's landmark Order No. 888, which became effective on July 9, 1996 and was the first in a series of Commission decisions dealing with open access transmission.[136] The purpose of Order No. 888 and its progeny, according to the Commission, was to promote the functional unbundling of transmission and generation services offered by public utilities in order "to remedy undue discrimination in access to the monopoly owned transmission wires that control whether and to whom electricity can be transported in interstate commerce" and "to address recovery of the transition costs of moving from a monopoly-regulated regime to one in which all sellers can compete on a fair basis and in which electricity is more competitively priced."[137]

106. Toward this end, the Commission required in Order No. 888 that all public utilities

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[134] *Id*. at 877.

[135] *Id*.

[136] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities*, Order No. 888, 61 Fed. Reg. 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996); *order on reh'g*, Order No. 888-A, 62 Fed. Reg. 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997); *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997); *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[137] Order No. 888, *supra*¸ FERC Stats. & Regs. ¶ 31,036 at 31,634-35.

that own, control or operate facilities used for transmitting electric energy in interstate commerce must file non-discriminatory open access transmission tariffs (OATTs) containing minimum terms and conditions of non-discriminatory service. The Commission also required those utilities to take transmission service (including ancillary services) for their own new wholesale sales and purchases of electric energy under the same OATT.[138]

107. The new pricing regime that the Commission introduced in Order No. 888 was applied only to transmission services under new contracts and to new transactions under existing contracts.[139] Specifically, the Commission ruled that:

> . . . because we are not abrogating existing requirements and transmission contracts generically and because the functional unbundling requirement of the Final Rule applies only to new wholesale services, the terms and conditions of the Final Rule pro forma tariff do not apply to service under existing requirements contracts.[140]

108. "Existing requirements and transmission contracts," as that term is used in Order No. 888, means contracts that were executed on or before July 11, 1994.[141] The Legacy Agreements that Idaho Power entered into with PacifiCorp and its predecessors meet this definition and, as stated above, remain in effect. Therefore, the unbundling and non-discrimination provisions of Order No. 888 do not apply to the transmission services that Idaho Power offers to PacifiCorp under these Legacy Agreements.

109. In Order No. 888-A, which the Commission issued to clarify Order No. 888, the Commission reiterated that "nothing in Order No. 888 affects prices or price-setting methodologies in existing contracts, unless specifically permitted in the contract on file."[142]

110. The Commission further considered in Order No. 888-A the specific question of how discounted firm transactions were to be handled in the calculation of open-access transmission rates. In considering whether discounted firm transactions should be counted as part of the load factor in the divisor of firm point-to-point rate ratios or instead

[138] *Id*. at 31,635-36.

[139] *Id*. at 31,662.

[140] *Id*. at 31,665.

[141] *See id*. at 31,664.

[142] Order No. 888-A, *supra*, FERC Stats. & Regs. ¶ 31,048 at 30,199.

credited against the transmission cost factor in the numerator, the Commission ruled that:

> We also are not convinced that we should require the calculation of load ratios using a particular method on a generic basis. Any such proposals, including those concerning the treatment of discounted firm transmission transactions in the load ratio calculation and revenue credits associated with such transactions, are best resolved on a fact-specific, case-by-case basis.[143]

111. As a result of these "grandfather" provisions of Order No. 888 and its progeny, the pricing structures of the Legacy Agreements between Idaho Power and PacifiCorp have been left intact and unaffected by the implementation of Idaho Power's OATT. They are not challenged by any party in this section 205 proceeding.[144] Nor could they be; that would require the non-contracting parties to file separate complaints under section 206 of the FPA.[145] Therefore, PacifiCorp cannot be forced in the instant proceeding to pay any more for the transmission services that it receives from Idaho Power under the Legacy Agreements than it does now.

112. Instead, the question here with regard to the structure of the proposed OATT formula rate is whether OATT customers should be paying Idaho Power what amounts to a "subsidy" to compensate it for the lower charge for transmission service that PacifiCorp pays under the Legacy Agreements. That subsidy arises because the discounted revenue from the Legacy Agreements is credited against Idaho Power's total transmission costs in the numerator of the formula in lieu of including the demand load from the Legacy Agreements in the divisor. If it were, then the subsidy would fall on Idaho Power alone, the entity that made the discounted arrangements with PacifiCorp and its predecessors in the first place.

113. It is Commission policy, as enunciated in a Transmission Pricing Policy Statement issued on October 26, 1994 and reaffirmed subsequently in Order No. 888 and its progeny, that third-party transmission customers should not be required to subsidize existing customers.[146] To that end, the Commission prescribed in Order No. 888 that

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[143] *Id.* at 30,256.

[144] *See* Exhibit Nos. INT-5 (Daniel Testimony at 89:1-9) and S-1 (Tingle-Stewart Testimony at 30:1-10).

[145] *See* 16 U.S.C. § 824e.

[146] *See Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act; Policy Statement*¸ 59 Fed. Reg. 55031, 55035 (November 3, 1994), FERC Stats. & Regs. ¶ 31,005 (1994)

(footnote continued on next page . . .)

OATT transmission rates are to be priced as follows:

> . . . we will allow all firm transmission rates, including those for flexible point-to-point service, to be based on adjusted system monthly peak loads. The adjusted system monthly peak loads consist of the transmission provider's total monthly firm peak load minus the monthly coincident peaks associated with *all* firm point-to-point service customers plus the monthly contract demand reservations for *all* firm point-to-point service.[147]

114. The Commission further stated in Order No. 888:

> In addition, revenue from non-firm services should continue to be reflected as a revenue credit in the derivation of firm transmission tariff rates. The combination of allocating costs to firm point-to-point service and the use of a revenue credit for non-firm service will satisfy the requirements of a conforming rate proposal enunciated in our Transmission Pricing Policy Statement.[148]

115. This case addresses whether the foregoing language of Order No. 888 requires service under a particular "grandfathered" contract to be included in the divisor of the OATT rate formula along with OATT firm service, rather than credited against the total cost of service in the numerator along with OATT non-firm service. Idaho Power approaches this question primarily by asserting that its transmission service to PacifiCorp under the Legacy Agreements is not really "firm," but is actually something in between "firm" and "non-firm" service, and therefore belongs in the numerator. This is so, Idaho Power maintains, because Legacy Agreement service is subject to curtailments that give it lower priority than firm service under the OATT, while at the same time having higher priority than OATT non-firm service. Intervenors and Staff assert that the PacifiCorp transmission service under the Legacy Agreements is and always has been "firm" service irrespective of the nature and characteristics of OATT firm service and therefore should be included in the divisor along with OATT firm service for the purpose of cost allocation over Idaho Power's total firm load.

(. . . footnote continued from previous page)
(*Pricing Policy Statement*) ("[W]e do not believe that third-party transmission customers should subsidize existing customers.").

[147] Order No. 888, *supra*, FERC Stats. & Regs. ¶ 31,036 at 31,738 (emphasis in original).

[148] *Id*.

c. *"Firm" vs. "Non-firm"*

116. The word "firm" is not expressly defined in the OATT. Only the services specifically designated as "Firm Point-to-Point Transmission Service" and "Non-firm Point-to-Point Transmission Service" are specifically defined in the OATT.[149] Each type of service has distinct characteristics that distinguish one from the other.

117. Outside of the OATT, "firm" service has a generic meaning in the electric industry. One common definition of "firm" service is that it is "electricity sold pursuant to a contract that entitles the customer to receive service from the seller on demand."[150] "Non-firm" service, by contrast, is used in the industry to describe "interruptible" service, meaning "electricity sold pursuant to a contract that entitles the seller to curtail service when it does not have enough capacity to produce electricity in excess of the quantity demanded by customers with contracts for firm service."[151]

118. For pre-Order No. 888 contracts, there is no bright-line test that delineates in all instances where electric transmission service crosses over from being "firm" to being "non-firm." The Commission has found in past cases that there are degrees of "firmness."[152] Service that is "subordinate to native load" has been deemed by the Commission to be non-firm.[153] The Commission has also required non-firm transmission service to be priced lower than firm transmission service "to reflect the lower quality of the service."[154]

119. Idaho Power's position that the transmission services that it provides to PacifiCorp under the Legacy Agreements is not firm service turns on its contention that curtailment

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[149] *See* Idaho Power OATT at §§ 13 and 14.

[150] *La. PUC v. FERC*, 482 F.3d 510, 513 (D.C. Cir. 2007).

[151] *Id*.

[152] *See, e.g., New England Power Co.*, Opinion No. 335, 49 FERC ¶ 61,129 at 61,554 (1989) ("Depending upon circumstances, a transmission constraint at a particular point of interconnection may render service less firm and even more susceptible to interruption than it would be if other transmission paths were available. . . . [We] find that under the curtailment provision, the service NEP provides is more akin to nonfirm service than firm service."), *reh'g denied*, Opinion No. 335-A, 50 FERC ¶ 61,151 (1990).

[153] *Id*.

[154] *Northeast Utilities Service Co.*, 84 FERC ¶ 61,159 at 61,867 (1998).

priority is "at the heart of the definition of firm service under the OATT."[155] Among the Legacy Agreements, the RTSA has curtailment provisions, but the TFA and the ITSA have none.[156]

120. There is a distinction in industry parlance between a "curtailment" of transmission service on the one hand and an "interruption" of transmission service on the other. As Tess Park, Idaho Power's Manager of Grid Operations, explained in her testimony, curtailment constitutes "those procedures used when an event – such as an outage – reduces the amount of available transfer capability. In situations such as these, certain procedures need to be followed to determine whose electricity services should be reduced in order to deal with the reliability situation."[157]

121. An interruption, by contrast, is a broader term that encompasses reductions of capability for economic reasons as well as for reliability reasons. Ms. Park, who oversees the operation of the Idaho Power control center that is responsible for deciding when transmission service is to be interrupted or curtailed,[158] was particularly well-suited at the hearing to testify from first-hand knowledge about this distinction. As Ms. Park explained at the hearing:

> Q In your daily work experience, is there a difference between curtailment of service and interruptible service?
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> A Yes, your Honor. In the interchange world, for us, curtailment is typically done for a reliability reason. An interruption is done because you have a higher-priority product that comes in and interrupts a lower-priority product. Hence, you have a firm OATT service, comes in and—say they didn't schedule on a prescheduled horizon or the day-ahead horizon. They came in on real-time and decided they were going to schedule on their rights and then they would interrupt a lower-priority product.[159]

122. In a sense, there is no such thing as absolutely "firm" service—that is, service that is *never* stopped. All service is really "non-firm" to some degree, because no transmission system is perfect and all service is subject to cutoffs of one kind or another. All systems experience outages that occasionally require some or all levels of

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[155] *See* Exhibit No. IPC-28 (Durick Reb. Test. 43:15-19).

[156] *See* Park Hg. Tr. 271:21-272:7.

[157] Exhibit No. IPC-32 (Park Reb. Test. 5:8-11).

[158] *Id*. at 2:11-3:5.

[159] Park Hg. Tr. 290:9-20.

transmission service to be halted or cut back. Thus, it makes sense to think of "firm" service as being different from "non-firm" service only in the manner and degree to which it can be cut back.

123. It is consistent with industry practice, as shown by the foregoing testimony, to call service "firm" where it is curtailed only in abnormal system conditions, such as to preserve reliability in outage or crisis situations. By contrast, it is equally consistent with that practice to call service "non-firm" where it is not only curtailable for reliability reasons, but also interruptible for economic reasons during normal conditions, such as when a low-priced "non-firm" product must make way for a higher-priced "firm" product on a given amount of transmission capacity during normal conditions.

124. The structure of the RTSA supports this distinction. It expressly states that "Idaho Power *shall* provide East to West Transfer Services *on a continuous, firm basis*" except in certain specific circumstances that only have to do with curtailments to preserve system reliability.[160] Idaho Power's view of how it treats service under the Legacy Agreements also supports this distinction. Idaho Power acknowledges that "one characteristic of all non-firm service under the OATT is that the service is subject to curtailment or interruption in order to provide firm OATT service under a separate service agreement. For the most part *Idaho Power does not believe that it has the right to interrupt [RTSA and TFA] service in order to provide non-firm transmission service under the OATT to a third party*."[161] Thus, Idaho Power treats Legacy Agreement service as a "firm" service, not as a "non-firm" service that must yield to OATT service.

125. The 1,410 MW of East to West Transfer Service that is set aside under the RTSA for PacifiCorp's use is not posted on Idaho Power's OASIS for non-firm use unless PacifiCorp does not schedule energy for transmission on that capacity.[162] This means that PacifiCorp's rights to East to West Transfer Service on Idaho Power's system are paramount over any non-firm user of that capacity. This treatment indicates that PacifiCorp's rights under the Legacy Agreements constitute firm service.

126. Another aspect of Idaho Power's treatment of its transmission services to PacifiCorp under the Legacy Agreements that points to characterizing them as firm service is how those services are accounted for in Idaho Power's calculations of its

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[160] *See* Exhibit No. INT-13 (RTSA § 3.5) (emphasis added).

[161] Exhibit No. S-2 at 29 and 31 (Responses to STAFF-IDAHO-20 and STAFF-IDAHO-27) (emphasis added).

[162] *See* Exhibit No. IPC-32 (Park Reb. Test. 17:16-18:11).

Available Transmission Capability, or "ATC," for certain constrained segments of its system. The ATC of Idaho Power's system is what remains of its Total Transfer Capability, or "TTC," and is posted on Idaho Power's OASIS "after subtracting the contract rights, firm commitments, network usage, Capacity Benefit Margin and Transmission Reliability Margin."[163] ATC is calculated separately for firm and non-firm services.[164]

127. The total capacity commitment to PacifiCorp under the Legacy Agreements is subtracted from firm TTC to reach firm ATC.[165] Thus, in making firm service available to other customers on its OASIS, Idaho Power does not interfere with PacifiCorp's Legacy Agreement rights. This is further indicative of the fact that the Legacy Agreements are treated by Idaho Power as firm services.

128. Idaho Power argues that its reduction of ATC to account for the Legacy Agreements does not show that such service is "firm" because Idaho Power does so only under a contractual commitment to provide the services and it cannot undermine that commitment by selling the same capacity to other parties.[166] Yet that fact is *precisely why* the service under the Legacy Agreements is "firm" rather than "non-firm." If it were not so, then Legacy Agreement service would be "non-firm," because Idaho Power would be able to sell the same capacity to other parties on a firm basis without breaching its contract to PacifiCorp.

129. The firmness of the service under the Legacy Agreements is further shown by the fact that both Idaho Power and PacifiCorp include the loads associated with the Legacy Agreements in their respective Integrated Resource Plans ("IRP").[167] As Ms. Tingle-Stewart explained in her testimony, an IRP is a plan that utilities submit to their regulatory bodies which contains their demand and energy forecasts for a certain time period, normally a 10- or 15-year period. This plan normally contains the utility's program for meeting the requirements shown in its forecast in an economic and reliable

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[163] *See id*. at 16:5-12.

[164] *See* Park Hg. Tr. 243:19-24.

[165] *See id*. at 152:2-13; *also see* Staff Initial Brief 22; Exhibit No. S-17 at 2 (IPCO Grid Operations & Planning Scheduling Business Practices).

[166] Idaho Power Reply Brief 10.

[167] *See* Staff Initial Brief 13-14; Exhibit No. S-1 (Tingle-Stewart Ans. Test. 19:23-21:8).

manner, including both demand-side and supply-side options. The utility also provides analyses which outline its assumptions and conclusions with respect to the effect of the plan on the cost and reliability of energy service.[168]

130. The 2004 PacifiCorp IRP Technical Appendix includes statistics on PacifiCorp's thermal units which are included as base resources for planning purposes. PacifiCorp included therein the Jim Bridger plant and associated transmission as an "existing or planned" resource.[169] Similarly, Idaho Power included the Jim Bridger units 1 through 4, of which Idaho Power owns a one-third share, in its 2006 IRP.[170] Thus, both Idaho Power and PacifiCorp include the Jim Bridger units in their IRPs and therefore consider the Jim Bridger units as a firm source of power to service load. As Ms. Tingle-Stewart correctly points out, if the generation source is firm, the transmission for the source should also be firm.[171]

131. Under Order No. 888-A, a transmission provider is obligated under the OATT to build or expand its transmission system to accommodate an application for firm point-to-point transmission service, provided that the transmission customer agrees to compensate the transmission provider for such an upgrade.[172] The utility is permitted to charge the higher of incremental expansion costs "or" a rolled-in embedded cost rate, typically known in the trade as "or" pricing.[173] Consistent with this obligation, Idaho Power usually adds whatever capacity it needs to continue to provide service to firm OATT customers and charges those customers a rolled-in rate rather than an incremental rate for the upgrade.[174]

132. By contrast, Idaho Power contends, it has no obligation under the RTSA to plan for PacifiCorp's use of Idaho Power's system on the same basis as for firm OATT and

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[168] Exhibit No. S-1 (Tingle-Stewart Ans. Test. 20:9-16).

[169] Exhibit Nos. S-1 (Tingle-Stewart Ans. Test. 19:26-20:2); S-2 at 17 (PacifiCorp IRP Table C.25).

[170] Exhibit Nos. S-1 (Tingle-Stewart Ans. Test. 20:3-8); S-2 at 19 (Response to STAFF-IDAHO-21), 20 (Table 2-3), 21, 24 and 26.

[171] Exhibit No. S-1 (Tingle-Stewart Ans. Test. 21:2-3).

[172] Order No. 888-A, *supra*, FERC Stats. & Regs. ¶ 31,048 at 30,268.

[173] *Id*.

[174] Durick Hg. Tr. 414:1-12.

native load customers.[175] Instead, according to Mr. Durick, PacifiCorp has always been "at the margin for transfer capability," meaning that new investment on Idaho Power's transmission system for the benefit of PacifiCorp has to be paid for by PacifiCorp on an incremental basis.[176] Also, under the ITSA and TFA, there is no planning and building obligation. Indeed, with regard to outages between Borah and Kinport, service to PacifiCorp under the ITSA simply stops until the lines are replaced.[177]

133. Idaho Power argues that the lack of a planning and building obligation for service under the Legacy Agreements is not equivalent to the planning and building obligation for firm transmission service under the OATT.[178] However, the mere difference in pricing structure between the way an OATT customer pays for an upgrade to the system and the way PacifiCorp pays for an upgrade to the system under the Legacy Agreements does not distinguish one service from the other as far as firmness is concerned. Under the "or" pricing policy of Order No. 888-A for obligatory system upgrades benefiting firm customers under the OATT, an OATT firm customer could be required to pay Idaho Power an incremental rate for the upgrade if it is higher than the rolled-in rate, just as PacifiCorp is obligated to do. Therefore, there really is no difference between the manner of paying for upgrades between OATT service and Legacy Agreement service, and thus no distinction on that basis as far as "firmness" is concerned.

134. In determining what additional facilities are needed for new OATT transmission service requests, Idaho Power has taken its commitments under the Legacy Agreements into account and has refused to offer new firm service to others without receiving incremental reimbursement for upgrades.[179] For example, when performing one study in 1999 of the Borah West path for a service request from Arizona Public Service Company (APS), Idaho Power maintained that it could not provide that service without new facility construction because it "had consistently considered 1600 MW to be committed to PacifiCorp, and had denied its own merchant group's request for firm service across Borah West due to this commitment."[180] This is further evidence of the firm nature of Idaho Power's commitment to PacifiCorp's Legacy Agreement service.

[175] *Id*. at 412:5-20.

[176] *Id*. at 412:17-20.

[177] *Id*. at 387:6-388:9; Exhibit No. INT-14 (ITSA § 6.1).

[178] Idaho Power Initial Brief 29-30; Idaho Power Reply Brief 2-3.

[179] *See* Intervenors Reply Brief 16; Exhibit No. INT-59 at 6.

[180] *See* Exhibit No. INT-59 at 6.

135. PacifiCorp's own position in this case is consistent with viewing its service under the Legacy Agreements as firm service. John A. Apperson, PacifiCorp's Trading Director in its commercial and trading department, testified as to PacifiCorp's belief "that Idaho Power does not have the right to curtail or interrupt PacifiCorp schedules over and above the conditions stated [in the RTSA] except during system emergencies, and such interruption will be on a *pro rata* basis."[181]

136. The fact that transmission services under the Legacy Agreements are available to PacifiCorp on demand and are scheduled by Idaho Power on its system separately from all other customers makes those services more akin to "firm" service under the common industry understanding of the word. Idaho Power bears the risk of loss under the Legacy Agreements if it does not deliver the transmission service demanded by PacifiCorp from the specified point of receipt to the specified point of delivery on the day, date and hour demanded and in the quantity demanded, within the quantity caps set forth in the agreements for the different segments of the system that the Legacy Agreements cover. Only the RTSA provisions that permit curtailment for specified reliability reasons are available to Idaho Power in order to mitigate that risk of loss.

137. Although curtailment procedures in the RTSA can be used to interrupt some aspects of Legacy Agreement service, that fact alone does not stand as proof that Legacy Agreement services are "non-firm." Curtailment procedures in the RTSA are available to Idaho Power for reliability purposes only. They deal with circumstances when capacity on Idaho Power's lines is reduced for some reason, such as an outage, thereby constraining the availability of PacifiCorp's contracted capacity and forcing a rationing of remaining capacity between Idaho Power and PacifiCorp. As a general rule in the electric transmission industry, curtailment procedures do not apply only to non-firm services. Both OATT Firm Service and OATT Non-firm Service have curtailment procedures that ration transmission capacity for both when a crisis hits.[182]

138. Concerning the first overall category of service under the RTSA, known as "East to West Transfer Service," the only exceptions recognized in the RTSA to the requirement that Idaho Power must provide this service "on a continuous, firm basis" are: "(1) for limitations on transfer capability as described in Section 3.6; (2) for interruptions or reductions due to a *force majeure* as defined in Section 8; (3) for interruptions or reductions due to temporary impairments of transfer capability as described in Section 3.8; and (4) as provided in Section 3.5.1 with respect to Additional East to West Transfer

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[181] Exhibit No. PAC-1 (Apperson Ans. Test. 3:20-23).

[182] *See, e.g.*, Idaho Power OATT §§ 13.6 and 14.7.

Service."[183]

139. In the first exception, Idaho Power and PacifiCorp acknowledge in section 3.6 of the RTSA that "capacity limitations exist on the Idaho Power system during normal system conditions with all facilities in service . . . which limit the capability of Idaho Power to deliver 1,600 MW for PacifiCorp from the Points of Receipt to the Points of Delivery simultaneous with Idaho Power's full use of its reserved transmission capacity on its transmission system."[184] This provision currently permits Idaho Power to limit PacifiCorp's capacity under the RTSA to 1,410 MW rather than 1,600 MW, as a result of the limited transfer capabilities of the Bridger system and the need to provide an allowance for Idaho Power to move its share of Bridger over to its own system.[185] Up to the current 1,410 MW limit, however, PacifiCorp enjoys service on a "continuous, firm basis."

140. As for the remaining restriction on the full 1,600 MW of service, Mr. Daniel pointed out that the RTSA contains procedures by which that restriction can be eliminated, similar to alleviating flow-gate restraints for OATT firm users.[186] Mr. Durick countered, however, that when flow-gate restraints happen to OATT firm customers, their services are uniformly curtailed on a *pro rata* basis along with native load service, unlike RTSA section 3.6.[187]

141. Section 3.6 of the RTSA restricts PacifiCorp's use of its full 1,600 MW allotment of East to West Transfer Service capacity only in specific circumstances, as described in subsections 3.6.1 and 3.6.2.[188] Subsection 3.6.1 of the RTSA describes those circumstances with regard to the total interconnection from Idaho Power to the Pacific Northwest, "comprised of Idaho Power's Western Interconnections plus PacifiCorp's Midpoint-Summer Lake 500 kV transmission line." It gives Idaho Power "the unrestricted right, at all times *and regardless of system conditions*, to the use of not less than 570 MW of the westbound transfer capability in Idaho Power's Western Interconnections. When Idaho Power is not fully utilizing its reserved capacity, such

[183] Exhibit No. INT-13 (RTSA § 3.5).

[184] Exhibit No. INT-13 (RTSA § 3.6).

[185] *See* Durick Hg. Tr. 369:1-8.

[186] *See* Exhibit Nos. INT-5 (Daniel Ans. Test. 65:14-66:4); INT-13 (RTSA §§ 3.7-3.7.3); *also see* Idaho Power OATT § 19.7.

[187] Exhibit No. IPC-28 (Durick Reb. Test. 45:10-13).

[188] *See* Exhibit No. INT-13 (RTSA § 3.6).

capacity shall be made available to PacifiCorp for East to West Transfer Services" up to the contracted limit.[189]

142. This means, according to Mr. Durick, that if the capacity of Idaho Power's Western Interconnections with the Pacific Northwest were reduced below 1,980 MW (the level necessary to provide 1,410 MW of service to PacifiCorp and maintain Idaho Power's 570 MW share) *during normal system conditions*, and Idaho Power needed its full 570 MW share, subsection 3.6.1 of the RTSA would allow Idaho Power to reduce service to PacifiCorp while maintaining Idaho Power's 570 MW share.[190] This type of curtailment priority, Idaho Power argues, is characteristic of non-firm service.[191]

143. The Western Interconnections are defined in the RTSA as Idaho Power's 230 kV Divide, LaGrande and Enterprise interconnections, and no other existing or future transmission interconnections at any location on the Idaho Power system.[192] They do not, however, include PacifiCorp's Midpoint-Summer Lake 500 kV transmission line.[193] As Intervenors point out and the witnesses for both Idaho Power and PacifiCorp agreed, the Midpoint-Summer Lake 500 kV line has the most capacity of any of these four interconnections and PacifiCorp tends to schedule most East to West Transfer Service to that line rather than to the other three points of delivery.[194] Thus, Idaho Power's 570 MW priority right on the Western Interconnections typically does not impact the bulk of PacifiCorp's East to West Transfer Service rights. What is more, according to Ms. Park, Idaho Power's current TTC for the entire westbound Idaho to Northwest path, if all facilities are in service and there are no curtailment conditions, is only 324 MW.[195] This TTC is well below the 570 MW share to which Idaho Power is entitled under subsection 3.6.1 of the RTSA, and that 570 MW share impacts only three of those four interconnections. Thus, Idaho Power is unlikely to need its entire 570 MW share in the event of an interruption or curtailment, and the remainder of the capacity above Idaho Power's use is reserved to PacifiCorp anyway, by subsection 3.6.1's own terms.

[189] *See id.* (RTSA § 3.6.1) (emphasis added).

[190] Exhibit No. IPC-28 (Durick Reb. Test. 16:5-12).

[191] *See* Idaho Power Initial Brief 25.

[192] Exhibit No. INT-13 (RTSA § 1.3)

[193] Durick Hg. Tr. 383:5-19.

[194] *See* Intervenors Initial Brief 29; Park Hg. Tr. 242:10-20; 245:5-246:1; Durick Hg. Tr. 380:23-381:8; Apperson Hg. Tr. 613:22-614:1.

[195] Park Hg. Tr. 245:5-14.

144. It is very difficult to see how Idaho Power could schedule up to 570 MW of firm service on its Western Interconnections under *normal* system conditions in a way that would bring subsection 3.6.1 of the RTSA into play to cause an economic interruption in PacifiCorp's usage of the westbound Idaho to Northwest path, even though that contract section permits Idaho Power to maintain its 570 MW share of capacity "regardless of system conditions." Under normal conditions, full capacity is available for the firm needs of both Idaho Power and PacifiCorp. Both Idaho Power and PacifiCorp have made clear that Idaho Power cannot interfere with PacifiCorp's rights in such circumstances.[196] Thus, Idaho Power is entitled to use and sell on that path up to its full 570 MW share and no more; it cannot sell an additional, say, 10 MW of firm service to a third party and cut back PacifiCorp's capacity in order to do so. What is more, Idaho Power's TTC on those interconnections is limited to well below 570 MW to begin with, and PacifiCorp's unassailable rights on the Midpoint to Summer Lake 500 kV westerly interconnection, combined with its right to all of the capacity on Idaho Power's Western Interconnections above Idaho Power's use, guarantee an uninterrupted pathway for PacifiCorp's power. It must also be borne in mind, as Idaho Power has acknowledged in briefing, that PacifiCorp uses, on average, less than fifty percent of the maximum available service during periods of Idaho Power system peak.[197] In short, PacifiCorp's use of the westbound Idaho to Northwest path, as governed by subsection 3.6.1 of the RTSA, does not have the hallmark of "non-firm" service, which is economic interruptibility.

145. As for curtailments for reliability reasons such as a system outage, subsection 3.6.1 could conceivably have an impact on PacifiCorp. Such situations have indeed happened, as Ms. Park described in her testimony.[198] But a curtailment of PacifiCorp's service for reliability reasons would be no different from its impact on any other type of "firm" service. Hence, subsection 3.6.1 of the RTSA does not serve to render PacifiCorp's service thereunder "non-firm" instead of "firm."

146. In RTSA subsection 3.6.2, Idaho Power and PacifiCorp agree to allocate the transfer capability through the existing 345 kV and 138 kV transmission lines west of the Borah and Kinport substations by deeming Idaho Power "to have 707 MW of reserved capacity in such path for its own use, and 1,414 MW shall be reserved by Idaho Power for the purpose of providing PacifiCorp East to West Transfer Services under the

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[196] *See* Exhibit Nos. IPC-32 (Park Reb. Test. 17:16-18:11); PAC-1 (Apperson Ans. Test. 3:30-23).

[197] Idaho Power Reply Brief 23, *citing* Exhibit Nos. INT-45 and INT-46.

[198] Exhibit Nos. IPC-32 (Park Reb. Test. 7:2-9:7); IPC-35; IPC-36.

Agreement."[199] The subsection further states that "[i]f the normal system transfer capability of the path is determined to be less than 2,121 MW, Idaho Power's reserved capacity for its own use and the capacity reserved for East to West Transfer Services shall be prorated accordingly."[200]

147. Idaho Power contends that subsection 3.6.2 of the RTSA is a different regime from the OATT because, for example, if PacifiCorp had 1,410 MW of OATT service, other customers (including Idaho Power) had 200 MW, and the Borah West path were reduced to 1,500 MW, the customers would share the available 1,500 MW on a *pro rata* basis and no ATC would be posted.[201] By contrast, under subsection 3.6.2 of the RTSA, PacifiCorp's service would decline to 1,000 MW, the 200 MW of service to other parties (including Idaho Power) would continue, and 300 MW of service would be posted as ATC.[202] Ms. Park described several curtailments over the Borah West path that resulted in curtailments of East to West Transfer Service.[203]

148. The terms of subsection 3.6.2, however, contradict Ms. Park's view that PacifiCorp is entitled under that provision to less capacity in the event of a curtailment than it would get under the OATT. As Intervenors point out,[204] Subsection 3.6.2 provides that "[w]hen Idaho Power is not fully utilizing its reserved capacity, such capacity will be made available to PacifiCorp for East to West Transfer Services" up to the maximum contract limits.[205] Hence, the additional 300 MW would not be posted as ATC, but instead would be made available to PacifiCorp for its use first. This provision works the same way as the restriction in subsection 3.6.1 and likewise keeps PacifiCorp's service "firm" in relation to all other Idaho Power customers.

149. In the second exception, section 8 of the RTSA relieves both parties from default under the Agreement for *force majeure* reasons such as failure of facilities, flood, earthquake, storm, fire, lightning, epidemic, war, riot and the like.[206] Obviously, this

[199] *See id*. (RTSA § 3.6.2).

[200] *Id*.

[201] *See* Idaho Power Initial Brief 27.

[202] Park Hg. Tr. 284:10-285:9.

[203] *See* Exhibit Nos. IPC-32 (Park Reb. Test. 10:10-11:20); IPC-37; IPC-38.

[204] *See* Intervenors Initial Brief 30.

[205] Exhibit No. INT-13 at 29-30 (RTSA § 3.6.2).

[206] *See* Exhibit No. INT-13 (RTSA § 8).

provision would allow for curtailment of PacifiCorp's service under the RTSA in extreme circumstances. The RTSA *force majeure* clause is not significantly different from the *force majeure* clause of Idaho Power's OATT, which covers both Firm Point-to-Point Service and Non-firm Point-to-Point Service.[207] As with the OATT, the presence of a *force majeure* clause in the RTSA does not make it "non-firm" instead of "firm."

150. Under the third exception, section 3.8 of the RTSA deals with temporary impairments on the Idaho Power system "due to conditions such as, but not limited to, forced outages of facilities, maintenance work, loop flow, etc."[208] This section provides for specific curtailments of PacifiCorp's service on Idaho Power's system for reasons related to system reliability. Section 3.8 is unique to the RTSA and is not identical to the OATT, as the experts for both Idaho Power and Intervenors agree.[209] However, the OATT provides for similar curtailments related to reliability. A "curtailment" is defined in the OATT as "[a] reduction in *firm or non-firm* transmission service in response to a transmission capacity shortage as a result of system reliability conditions."[210] The descriptions in the OATT of both Firm OATT Service and Non-firm OATT Service have explicit and relatively similar terms and conditions to deal with such curtailments.[211] Of the two, however, only Non-firm OATT Service also provides for interruptions for reasons other than reliability; namely, "*for economic reasons* in order to accommodate (1) a request for Firm Transmission Service, (2) a request for Non-firm Point-To-Point Transmission Service of greater duration, (3) a request for Non-firm Point-To-Point Transmission Service of equal duration with a higher price, or (4) transmission service for Network Customers from non-designated resources."[212]

151. As is evident from the foregoing provisions, the possibility that there can be curtailments of PacifiCorp's RTSA service for system reliability reasons is no different from the possibility that there can be curtailments for system reliability reasons under the Idaho Power OATT for Firm Point-to-Point Service.[213] Thus, the curtailment provisions

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[207] *See* Exhibit No. IPC-5 (Daniel Ans. Test. 64:26-65:3); *also see* Idaho Power OATT § 10.

[208] Exhibit No. INT-13 (RTSA § 3.8).

[209] *See* Exhibit Nos. IPC-28 (Durick Reb. Test. 44:13-45:2); IPC-31 at 2-4 (Response to IPC-INT-69 c.-e. and IPC-INT-70 c.-e.).

[210] *See* Idaho Power OATT § 1.7 (emphasis added).

[211] *See* Idaho Power OATT §§ 13.6 and 14.7.

[212] *See* Idaho Power OATT § 14.7 (emphasis added).

[213] *See* Exhibit No. INT-5 (Daniel Ans. Test. 64:26-65:3); *also see* Idaho Power OATT §§ 1.7 and 13.6.

of the RTSA do not render service under the RTSA less firm than OATT firm service. Moreover, OATT Non-firm Point-To-Point Transmission Service can be interrupted for economic reasons as well as reliability reasons, an aspect that is not present in the curtailment provisions of the RTSA. Therefore service under the RTSA resembles Firm Point-To-Point OATT Service more closely than Non-firm Point-To-Point OATT Service.

152. Finally, in the fourth exception, section 3.5.1 of the RTSA provides in connection with East to West Transfer Services that the "Additional East to West Transfer Service" component of that service "shall have a higher priority than all other existing and future non-firm transmission services provided by Idaho Power for third parties under other agreements, but shall have a lower priority than all of Idaho Power's other existing and future firm and non-firm uses of its transmission system, including electric service to Idaho Power's customers, firm and non-firm wholesale purchases and sales, and other firm transmission services."[214]

153. Additional East to West Transfer Service is a RTSA service that PacifiCorp schedules intermittently on Idaho Power's system.[215] Mr. Durick explained that Additional East to West Service "has a lower priority than all firm services, and a lower priority than Idaho Power's other existing and future firm and non-firm uses of its transmission system."[216] Ms. Park similarly testified that Additional East to West Transfer Service "is curtailed after non-firm transmission provided by Idaho Power for third parties under other agreements, but is curtailed before all of Idaho Power's firm and non-firm uses of its transmission system."[217] Mr. Daniel characterized the priority of Additional East to West Service as a "secondary firm priority."[218]

154. Mr. Durick testified that Additional East to West Transfer Service "is clearly of a lower priority than OATT firm service, yet it is embedded in and, in a practical sense, inseparable from, the overall bundle of east to west services."[219] PacifiCorp pays Idaho Power a supplemental fee for this service in addition to its usual facilities charges for

[214] Exhibit No. INT-13 (RTSA § 3.5.1).

[215] *See* Park Hg. Tr. 229:4-7, 15-18.

[216] Exhibit No. IPC-28 (Durick Reb. Test. 18:10-11).

[217] Exhibit No. IPC 32 (Park Reb. Test. 12:1-7).

[218] Exhibit No. INT-5 (Daniel Ans. Test. 65:3-13).

[219] Exhibit No. IPC-28 (Durick Reb. Test. 18:10-11).

RTSA service, equal to Idaho Power's non-firm rate plus one-half mill per kWH.[220]

155. There can be no doubt that Additional East to West Transfer Service is a non-firm component of RTSA service. However, there is no evidence in the record that breaks out from other Legacy Agreement services the load on Idaho Power's system or the revenues that PacifiCorp pays to Idaho Power for this component. What is more, Mr. Durick asserted on behalf of Idaho Power that this component is "embedded in" and "inseparable from" what is, in all other respects, firm RTSA East to West Transfer Service.[221] Hence, the evidence does not support treating Additional East to West Service as something separate and apart from the whole package of firm RTSA services. The Additional East to West Service component does not render the rest of RTSA service non-firm just because it is itself non-firm; to find otherwise would allow the tail to wag the dog. Accordingly, Additional East to West Transfer Service must be viewed as merely an intermittently-used, non-firm adjunct of firm East to West Transfer Service under the RTSA.

156. The second overall category of RTSA services that Idaho Power provides to PacifiCorp is known as "Other Services."[222] Of these, the first component of "Dynamic Overlay Service" can be interrupted by Idaho Power pursuant to section 4.2.1 of the RTSA if it "is causing Idaho Power to forego the opportunity to use its transmission system for transactions outside of this Agreement."[223] Concerning the second component of "Wyoming-Utah Transmission Service," RTSA section 4.3.1 states that Idaho Power's provision of this service is subject to "Idaho Power's having sufficient firm transmission capacity available on its system, and on the Bridger transmission system, to provide such service, after taking into account Idaho Power's rights to deliver its share of the Jim Bridger Project" power to its own system.[224]

157. Thus, Dynamic Overlay Service to PacifiCorp is fully interruptible by Idaho Power's other firm and non-firm uses. Wyoming-Utah Transmission Service to PacifiCorp is also subordinate to Idaho Power's native load, not equal to it. Both component services, therefore, must be viewed as "non-firm." Again, however, Idaho Power provides no breakout from other firm services of the load levels or revenue levels of these non-firm components. Therefore, it is impossible on these facts to consider these

[220] *See* Durick Hg. Tr. 365.6-9; Exhibit No. INT-13 (RTSA §7.2).

[221] *See* Exhibit No. IPC-28 (Durick Reb. Test. 18:10-11).

[222] *See* Exhibit No. INT-13 (RTSA § 4).

[223] *See* Exhibit Nos. IPC-28 (Durick Reb. Test. 18:18-21); INT-13 (RTSA § 4.2.1).

[224] *See* Exhibit Nos. IPC-28 (Durick Reb. Test. 19:4-8); INT-13 (RTSA § 4.3.1).

"Other Services" as something separate and apart from the rest of firm RTSA service.

158. Idaho Power also contends that a basic ratemaking principle requires sales to retail native load and wholesale requirements contracts that are equivalent to native load to be included in the rate divisor, and for other transactions that are provided at a rate below fully allocated costs to be revenue-credited.[225] Therefore, Idaho Power argues, services that are not equivalent in firmness to OATT and native load service must be revenue-credited rather than cost-allocated in the OATT rate formula, and therefore Legacy Agreement services should be revenue-credited rather than cost-allocated because they fall below native load services in firmness.[226] In support of this argument, Idaho Power points to the Staff expert witness' purported "acknowledgment" that the OATT rate divisor excludes transmission service with a priority below Idaho Power's native load.[227]

159. Ms. Tingle-Stewart did say in response to a discovery request that the term "firm usage" as used in section 1.47 of Idaho Power's OATT means "usage having a curtailment priority equivalent to Idaho Power's Native Load as the term is defined in Idaho Power's OATT."[228] But the conclusion that Idaho Power draws from that statement—namely, that it implies that usage having a curtailment priority "below Native Load" is "non-firm" service—does not necessarily follow from that statement. Usage having a curtailment priority below Native Load *may* be "firm" if it can only be "curtailed" (for reliability reasons), rather than both "interrupted" (for economic reasons) *and* "curtailed" (for reliability reasons). In other words, non-OATT "firm" service can have different curtailment priorities from Native Load service and still be considered "firm."

160. Idaho Power points to several Commission decisions to support its position that transmission service with a curtailment priority "below native load" is not firm service.[229] *Northeast Utilities Service Co.*,[230] Idaho Power argues, is one such case, in which the Commission characterized a service that had a curtailment priority below native load as

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[225] *See* Idaho Power Initial Br. 16.

[226] *See id*. at 16-17.

[227] *See id*. at 17, *citing* Exhibit No. IPC-23 at 24:12-25:24.

[228] Exhibit No. IPC-26 at 2 (Staff Response to IPC-STAFF-46).

[229] *See* Idaho Power Initial Brief 21-23.

[230] *Northeast Utilities Service Co.*, 84 FERC ¶ 61,159 (1998).

not constituting firm transmission service.[231] Indeed, the Commission stated in *Northeast Utilities* that NU's "preferred" service under a transmission service agreement (TSA) was "a form of non-firm service due to the possibility of curtailment of service."[232] However, the Commission's comparison of "preferred" service to native load service did not begin and end with those words. Rather, the Commission affirmed the Administrative Law Judge's finding that the "preferred" TSA service was "non-firm" rather than "firm" because "*under normal as well as emergency conditions* the service to [the preferred TSA customer] is of a lower priority than service to NU's native load and [third party wheeling] customers."[233] So, *Northeast Utilities* stands for the same proposition accepted here, not for Idaho Power's position; namely, that service is "non-firm" when it is "interruptible" for economic reasons as well as "curtailable" for reliability reasons, whereas "firm" service is only "curtailable" for reliability reasons.

161. Idaho Power also points to *QST Energy Trading Inc. v. Central Ill. Pub. Serv. Co.*(*QST*),[234] as an example of a Commission decision holding that transmission service that was curtailable ahead of native load in the event of a system outage is "not firm service."[235] QST had complained to the Commission that Central Illinois Public Service Company denied QST's request for firm monthly OATT service, even though Central Illinois' OASIS indicated that there was available transmission capacity (ATC). QST argued that Central Illinois should not have denied its request in order to preserve a margin of reliability on the system in case of an outage, but instead should have provided to QST "firm transmission service until Central Illinois has such an outage. At that point, . . . Central Illinois should totally curtail QST's 'firm' transmission service (rather than curtail on a *pro rata* basis), *while maintaining service to Central Illinois' native load*."[236] The Commission disagreed, holding that "[t]his scenario is not firm service—it is nonfirm service, the terms and conditions for which are already specified in the *pro forma* tariff. [footnote omitted]"[237] This ruling in *QST* does not prove Idaho Power's point, however. It merely holds that a form of service having priority below native load

[231] Idaho Power Initial Brief 22.

[232] *Northeast Utilities Service Co.*, *supra*, 84 FERC ¶ 61,159 at 61,867-68.

[233] *Northeast Utilities Service Co.*, 62 FERC ¶ 63,013 at 65,025 (1993) (ALJ Initial Decision) (emphasis added).

[234] *QST Energy Trading Inc. v. Central Ill. Pub. Serv. Co.*, 85 FERC ¶ 61,166 (1998) (*QST*).

[235] Idaho Power Initial Brief 22.

[236] *QST*, *supra*, 85 FERC ¶ 61,166 at 61,666 (emphasis added).

[237] *Id*.

is non-firm service *because it can be curtailed for reliability reasons*—which is true, but only half the story. Whether that service can or cannot be interrupted for economic reasons as well—the unique quality of non-firm service that really makes it different from "firm" service—is simply not discussed in *QST*. *QST*, therefore, is unhelpful.

162. Idaho Power also points to *Cleveland Elec. Illum. Co. v. City of Cleveland, Ohio*,[238] to show that the Commission has characterized a service that had a curtailment priority below native load as not constituting firm transmission service.[239] Again, in that case, a scheduling of service that was contractually identified as "non-firm" was found to be interruptible because "[n]on-firm or interruptible service may be curtailed before any interruption of service to firm customers.[footnote omitted] This less firm and thus less expensive service simply does not have the same availability feature of firm service."[240] Again, this case is not at odds with what is found here.

163. Both Idaho Power and Intervenors attempted at the hearing to characterize the testimony of opposing experts as being in conflict with their own prior testimony in other cases, or in conflict with the testimony of other allied experts.[241] There is, no doubt, a degree of ambiguity when it comes to characterizing transmission services as "firm" service, "non-firm" service, or something else. Experts and Staff have held varying positions on the characterization of different types of service and service terms and conditions from case to case, depending on the circumstances. However, taking expert testimony of other cases out of context in order to impeach the experts here, when the circumstances of each type of service are so unique, is inappropriate. None of the examples offered aids either point of view here.

164. The difficulty in characterizing transmission services is also evident in Idaho Power's own managerial indecision as to how to characterize the Legacy Agreements in

[238] *Cleveland Elec. Illum. Co. v. City of Cleveland, Ohio*, 75 FERC ¶ 61,258 (1996).

[239] Idaho Power Initial Brief at 22.

[240] *Cleveland Elec. Illum. Co. v. City of Cleveland, Ohio, supra*, 75 FERC ¶ 61,258 at 61,841.

[241] *See, e.g.*, Exhibit No. IPC-23 (Heintz Reb. Test. 9:1-15); Heintz Hg. Tr. 557:24-559:12; Exhibit No. IPC-25 at 4:11-14 (Excerpt from testimony of Stephen Page Daniel in Docket No. EL05-19-002); Tingle-Stewart Hg. Tr. 677:2-681:15; Exhibit No. IPC-59 at 6:7-10, 9:19-10:9 (Prepared Answering Testimony of Edward A. Gross dated April 30, 2002 in *Consolidated Edison Co. of New York*, Docket No. EL02-28-000).

its annual FERC Form 1 filings in years past. Idaho Power has referred to the Legacy Agreement services in its FERC Form 1 filings for 2004 through 2006 as "other long-term firm service," which is indicated on the FERC Form 1 with the designation "OLF."[242] Ms. Nichols testified, however, that this "OLF" designation was erroneous and should have been "NF," the designation for "non-firm service."[243] Then again, Mr. Schellberg testified that "NF" is not the correct designation either, and that it actually should have been "OS," for "other services," which he stated was the designation used by Idaho Power in FERC Form 1 filings during the 1990s.[244]

165. Idaho Power has never gone back to correct these entries on any of its FERC Form 1 filings.[245] Irrespective of management disagreements within Idaho Power as to how Legacy Agreement services should be characterized for regulatory reporting purposes, the Commission must look objectively at the nature and characteristics of these services to determine whether they are firm or non-firm for the purpose of deciding how they will be allocated for OATT pricing purposes. From that standpoint, the evidence in this record points to a proper designation of Legacy Agreement services as firm services, not non-firm services.

166. In brief, Idaho Power has attempted to steer its Legacy Agreement services to PacifiCorp between the Scylla of "firm" and the Charybdis of "non-firm" by arguing that the curtailment provisions of the Legacy Agreements put these services somewhere in between the two categories.[246] To the contrary, the facts demonstrate that curtailment is not the deciding factor, and that Idaho Power's services to PacifiCorp under the Legacy Agreements definitely fall within the zone of firm service rather than non-firm service and should be treated as such for the purpose of calculating the OATT formula rate.

d. *Revenue-crediting vs. Cost-allocating*

167. Having determined that the services that Idaho Power provides to PacifiCorp under the Legacy Agreements are "firm" services and should be allocated as such, the

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[242] *See* Nichols Hg. Tr. 50:4-14; Schellberg Hg. Tr. 521:6-522:1; Exhibit Nos. INT-40 at 2 (Idaho Power FERC Form 1 at p. 328 lines 10-12); INT 41 at 3.

[243] *See* Nichols Hg. Tr. 54:14-55:14, 66:22-67:7; Exhibit No. INT-41 at 3.

[244] *See* Schellberg Hg. Tr. 518:17-519:16; Tingle-Stewart Hg. Tr. 691:20-25; Exhibit No. INT-41.

[245] *See* Nichols Hg. Tr. 66:14-21; Schellberg Hg. Tr. 524:18-23.

[246] *See* Exhibit No. S-2 at 29-30 (STAFF-IDAHO-20) and 31-32 (STAFF-IDAHO-27).

next question to decide is whether these services should be revenue-credited in the numerator of the OATT formula rate or cost-allocated in the divisor. The answer to this question does not arise automatically from the previous inquiry, because the Commission has reserved for itself "a fact-specific, case-by-case" approach in dealing with this issue.[247] Thus, it is not enough to decide that PacifiCorp's service under the Legacy Agreements is "firm" rather than "non-firm" in order to know whether the service should be revenue-credited or cost-allocated; other factors may play a role as well.

168. The Commission has established no bright line test to help in coming up with this answer. Sometimes, the Commission has held that firm service may be revenue-credited in the numerator. For example, in *Public Service Co. of New Mexico*, the Commission observed that revenue-crediting is appropriate for so-called "opportunity sales," which it said can "take many forms, from interruptible split-the-savings economy sales (the seller's lowest dispatch priority) *to firm power transactions* in which the seller is able to commit capacity for a certain time period."[248] Thus, there is a spectrum of potential outcomes, depending on the facts, in deciding whether the firm services that Idaho Power offers to PacifiCorp under the Legacy Agreements should be cost-allocated or revenue-credited in Idaho Power's proposed OATT formula rate.

169. A good way to tackle this question is to begin with basic principles. One is the principle of "cost causation," which requires "that all approved rates reflect to some degree the costs actually caused by the customer who must pay them."[249] Compliance with this doctrine is generally evaluated "by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party," although "exacting precision" is not required.[250] Another basic principle, enunciated by the Commission in its Transmission Pricing Policy Statement and related cases, is that third-party transmission customers should not be required to subsidize existing customers.[251]

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[247] Order No. 888-A, *supra*, FERC Stats. & Regs. ¶ 31,048 at 30,256.

[248] *Public Service Co. of New Mexico*, 20 FERC ¶ 61,290 at 61,546 (emphasis added), *reh'g denied*, 21 FERC ¶ 61,334 (1982), *aff'd on other grounds sub nom. Public Service Co. of New Mexico v. FERC*, 832 F.2d 1201 (10th Cir. 1987).

[249] *Midwest ISO System Operators v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004) (*MISO Operators*).

[250] *Id*. at 1368-69.

[251] *See Pricing Policy Statement*, *supra*; *also see Minnesota Municipal Power Agency v. Southern Minnesota Municipal Power Agency*, 68 FERC ¶ 61,060, at 61,203 n.3 (1994) (*MMPA*).

170. Idaho Power argues that services that are provided "with a service priority below native load and OATT service" are typically discounted to reflect the inferior quality of service.[252] This is true of non-firm service, which is what Idaho Power is talking about, but it is not necessarily true of firm service, which is what PacifiCorp's service under the Legacy Agreements has been found here to be.

171. Idaho Power's charges to PacifiCorp for its firm service under the Legacy Agreements are significantly lower than charges for Firm Point-To-Point Transmission Service under the OATT formula rate. What was at one point a three-to-one disparity between the two in 1994 has grown to an almost five-to-one disparity in 2004.[253] Thus, PacifiCorp does not bear a share of transmission costs that is proportional to its firm load share.

172. The transmission costs of Idaho Power's system that are attributable to the loads of Idaho Power and PacifiCorp must be borne by others if they are not being borne wholly by Idaho Power and PacifiCorp. The only ones left to do so are third-party OATT customers. As things currently stand under Idaho Power's revenue-crediting approach to pricing OATT service, those customers bear a share of the cost that is disproportionately high for their level of system use. This puts them in a less favorable position than Idaho Power and PacifiCorp, with whom they compete in the transmission of wholesale electric power.

173. Idaho Power maintains an "integrated" system on its grid for planning and operating purposes.[254] To Idaho Power, this means that "the entire transmission system performs as more as a single entity, and that you don't take out pieces and parts and treat them as if they were somehow standalone systems."[255] In a system such as this one, the cost causation rule and the rule against cross-subsidization dictate that equally-weighted costs must be allocated among all users according to their respective load shares.

174. PacifiCorp's total Period I (2004) contract load on the Idaho Power system was 2,014 MW, whereas the total Period I (2004) contract load for all other firm and network

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[252] *See* Idaho Power Initial Brief 22.

[253] *See* Exhibit No. INT-5 (Daniel Ans. Test. 87:6-88:22).

[254] *See id*. at 54:17-56:19; INT-17 at 1-5 (Durick Dep.).

[255] Exhibit No. INT-17 at 1-5 (Durick Dep.).

customers on that system (including Idaho Power's own load) was 2,942 MW.[256] Thus, PacifiCorp's firm load accounts for roughly 40 percent of the total firm contract load on the Idaho Power system.

175. Idaho Power's own Period I (2004) network, firm and non-firm loads account for at least 2,210 MW, or 45 percent of the total Period I (2004) firm load on the system.[257] Thus, after the loads of Idaho Power and PacifiCorp are subtracted, the remaining third-party OATT firm customers on Idaho Power's system account only for 15 percent of the total firm load on the system.[258]

176. Based on the foregoing facts, it stands to reason under the Commission's "cost causation" principle that the firm loads of Idaho Power and PacifiCorp cause, and therefore should bear, the overwhelming majority of Idaho Power's integrated transmission costs. It also stands to reason under the Commission's rule against cross-subsidization that Idaho Power and PacifiCorp should pay those integrated costs according to their *pro rata* load shares. Idaho Power cannot push a disproportionately high share of those costs upon the other OATT transmission customers.

177. For these reasons, Idaho Power cannot require its OATT transmission customers to pay more than their *pro rata* load shares of Idaho Power's Total Transmission Revenue Requirement. Nor can Idaho Power in turn cover itself for PacifiCorp's under-compensation of its load share by collecting the difference from OATT transmission customers through revenue-crediting in the OATT formula rate.[259] Idaho Power must bear that under-recovery on its own.

178. Idaho Power argues that cost-allocating the Legacy Agreements instead of revenue-crediting them would result in discriminatory treatment between its own retail customers and OATT transmission customers because its own retail customer rates are

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[256] *See* Idaho Power Tariff Filing, Statement BB; *also see* Exhibit Nos. S-1 (Tingle-Stewart Ans. Test. 12:1-19); INT-5 (Daniel Ans. Test. 82:21-83:5) and INT-19.

[257] *See* Exhibit Nos. S-1 (Tingle-Stewart Ans. Test. 12:1-19); INT-5 (Daniel Ans. Test. 82:21-83:5) and INT-19.

[258] *See id*.

[259] *See MMPA*, *supra*, 68 FERC ¶ 61,060 at 61,203 n.3 ("If the utility excludes a firm customer from the cost allocation and simply credits the firm service revenues to the cost-of-service, other customers will subsidize the transaction if the revenues credited are less than the cost responsibility that should be allocated to that service.").

based on a revenue-crediting approach, as approved by the states having jurisdiction over Idaho Power's retail distribution.[260] Thus, Idaho Power contends, cost-allocating the Legacy Agreements in the OATT rate formula would result in a huge discount to wholesale OATT customers for the same service that Idaho Power's retail customers receive.[261]

179. Supporting this contention, Phil A. Obenchain, Idaho Power's Senior Pricing Analyst, testified that it is inappropriate to change the revenue-crediting methodology of the Legacy Agreements now because it has been Idaho Power's practice for over two decades in the determination of jurisdictional revenue requirements.[262] According to Mr. Obenchain, it has been accepted by FERC in numerous dockets in the determination of past rates and in the determination of Idaho Power's prior OATT tariff.[263] In addition to its acceptance by FERC, Mr. Obenchain said, Idaho Power's retail rates have been set using the same methodology of revenue-crediting these facility charge revenues, and any change in the formulas before FERC would necessitate a change in its revenue requirement methodology before its retail jurisdictions as well.[264]

180. In order to solve the problem of discriminatory pricing between transmission providers and their wholesale customers, Order No. 888 requires the transmission provider to take its own transmission service for all new wholesale sales and purchases of energy under the same OATT as all other transmission customers.[265] The Commission stated in Order No. 888 that this requirement is intended to "give public utilities an incentive to file fair and efficient rates, terms, and conditions, since they will be subject to those same rates, terms and conditions."[266] Therefore, transmission costs that are borne by third-party OATT customers, like Intervenors, are supposed to be borne equally by transmission providers like Idaho Power (and, in turn, by their native load customers), on a *pro rata* basis according to load.

181. However, it is not necessarily true that Idaho Power's retail customers bear a share

[260] *See* Idaho Power Initial Brief 13-15.

[261] *See id*.

[262] *See* Exhibit No. IPC-40 (Obenchain Reb. Test. 7:7-9).

[263] *Id*. at 7:9-11.

[264] *Id*. at 7:11-15.

[265] Order No. 888, *supra*, FERC Stats. & Regs. ¶ 31,036 at 31,654.

[266] *Id*. at 31,654-55.

of transmission costs that is strictly proportional to the cost share borne by third-party OATT customers. When it comes to transmission costs, Idaho Power's OATT customers pay charges in a different way than Idaho's retail distribution customers pay for transmission.[267] Since there are no facts in the record to show that Idaho Power's retail customers and OATT customers are charged comparably for transmission service (only that OATT transmission revenue requirements are developed differently from retail revenue requirements), it cannot be shown whether a change in the OATT methodology of accounting for the Legacy Agreements would result in a discriminatory and preferential difference in treatment between these two customer classes.

182. Since its issuance of Order No. 888, the Commission has endeavored to address and remedy ongoing discriminatory impacts of grandfathered transmission agreements. The Commission has done so, for example, in connection with the issue of whether grandfathered customers can be charged a "cost adder" to the same extent as OATT customers for the recovery of the administrative costs of the Midwest Independent System Operator (MISO).[268] The mere fact that pre-Order No. 888 contracts like the Legacy Agreements were grandfathered by Order No. 888 and have been around for a long time does not immunize transmission providers like Idaho Power from ongoing efforts on the Commission's part to remedy discriminatory or preferential treatment in wholesale transmission service.

183. On balance, applying the "fact specific, case-by-case" approach mandated by the Commission,[269] the basic principles of cost causation and against cross-subsidization as applied here militate against revenue-crediting the firm service that Idaho Power offers PacifiCorp under the Legacy Agreements in the numerator of the OATT rate formula and for cost-allocating that service in the divisor.

e. *Benefits and Burdens Attributable to Legacy Agreement Service*

184. Idaho Power argues that, aside from the question of the firmness of Legacy Agreement service, the benefits that PacifiCorp's service impart on Idaho Power's system and the burdens that PacifiCorp incurs from the limitations on that service justify

[267] *See* Nichols Hg. Tr. 164:19-166:5.

[268] *Midwest Indep. Transmission Sys. Operator, Inc.*, 97 FERC ¶ 61,033 (2001), *reh. denied*, 98 FERC ¶ 61,141(2002), *aff'd after remand*, 102 FERC ¶ 61,192 (2003), *reh. denied*, 104 FERC ¶ 61,012 (2003), *aff'd sub nom. Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361 (D.C. Cir. 2004).

[269] Order No. 888-A, *supra*, FERC Stats. & Regs. ¶ 31,048 at 30,256.

revenue-crediting that service instead of cost-allocating it.[270] In particular, Idaho Power maintains that PacifiCorp faces restrictions, such as the lack of flexibility and resale rights, on the use of TFA and RTSA service that OATT Point-To-Point customers do not experience.[271] On the other hand, Idaho Power notes that PacifiCorp's use of the system under the TFA and RTSA provide significant transmission benefits through system expansion and counter-flow effects that were considered in the negotiation and pricing of those agreements.[272]

185. Idaho Power points out that under the RTSA East to West Transfer Service, power must be delivered from the Jim Bridger transmission lines (RTSA section 3.2) east to west across the Idaho Power system to specific PacifiCorp western interconnections (RTSA section 3.3).[273] This is done to ensure that transfers scheduled by PacifiCorp are counter-flow to many other uses of the Idaho Power system.[274] Under the TFA, power must be delivered specifically from Brady to Kinport, again acting as a counter-flow on the Idaho Power system.[275]

186. By contrast, Idaho Power contends, OATT Firm Point-to-Point Transmission Service customers specify a receipt and delivery point for their service, but can redirect that service to alternative points of receipt and delivery on either a firm or non-firm basis.[276] Mr. Durick testified that this flexibility, which is not available to OATT Non-Firm Point-to-Point customers, is a key feature of OATT Firm Point-to-Point Transmission Service that enables the customer to make full use of its contract demand in hours when it chooses not to schedule all of its power over the contract path specified in the service agreement, whereas the RTSA and TFA lack any redirection rights.[277]

[270] Idaho Power Initial Brief 17-18, 36-43; Idaho Power Reply Brief 3-9.

[271] Idaho Power Initial Brief 34-36; Exhibit No. IPC-28 (Durick Reb. Test. 11:11-13).

[272] *See* Idaho Power Initial Brief 39; Exhibit No. IPC-28 (Durick Reb. Test. 11:17-19).

[273] Exhibit No. IPC-28 (Durick Reb. Test. 12:7-10).

[274] *Id*. at 12:10-11.

[275] *Id*. at 12:11-13.

[276] *Id.* at 12:13-16.

[277] *Id*. at 12:16-13:2.

187. Idaho Power also points out that PacifiCorp's transfers under the RTSA of power produced other than from the Bridger power plant are limited to power that is less than 124 average megawatts per year.[278] Under OATT Point-to-Point Transmission Service, there are no restrictions on the source of power that a customer transmits.[279] If power were delivered to the point of receipt from another source rather than generated at the point of receipt, Mr. Durick continued, the OATT transmission provider would still be required to deliver that power to the point of delivery.[280]

188. Idaho Power further contends that RTSA section 12.7 prohibits PacifiCorp from assigning the agreement to a third party.[281] OATT Point-to-Point Transmission Service, in contrast, expressly recognizes that the customer can reassign the service to a third party.[282] Mr. Durick further noted that RTSA sections 3.1 and 4.2 generally prohibit PacifiCorp from using the service for third party wheeling.[283] By contrast, an OATT customer can use its service for its own resources or to wheel power for a third party.[284] This lack of reassignment rights in the RTSA is important, in Mr. Durick's view, because the reassignment restriction was imposed in the RTSA mainly to limit the burden that RTSA service put on the Idaho Power system.[285] According to Mr. Durick, the original intent behind the RTSA was that PacifiCorp would pay for the facilities needed and use the service in a way that would not unduly diminish the Idaho Power's ability to serve load.[286]

189. Idaho Power also maintains that the loss provisions of the RTSA (RTSA section 6) are not comparable to the OATT.[287] Mr. Durick said that the loss provisions of the RTSA

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[278] *See* Idaho Power Initial Brief 35; Exhibit No. IPC-28 (Durick Reb. Test. 13:6-9).

[279] Exhibit No. IPC-28 (Durick Reb. Test. 13:9-10).

[280] *Id*. at 13:11-13.

[281] *See* Idaho Power Initial Brief 35; Exhibit No. IPC-28 (Durick Reb. Test. 13:17-18).

[282] Exhibit No. IPC-28 (Durick Reb. Test. 13:18-20).

[283] *Id*. at 13:20-14:1.

[284] *Id*. at 14:1-2.

[285] *Id*. at 14:5-6.

[286] *Id.* at 14:6-8.

[287] *See* Idaho Power Initial Brief 36; Exhibit No. IPC-28 (Durick Reb. Test. 20:1-7).

are designed to encourage PacifiCorp to avoid excessively reducing their westbound schedules.[288] This was implemented to maintain the displacement benefit provided by the East to West Transfer Service and to recognize its beneficial impact on losses.[289] Mr. Durick also pointed out that service under the RTSA differs from OATT Firm Point-to-Point Transmission Service in that RTSA section 3.7 requires that if, subsequent to execution, additional facilities are built by Idaho Power in order to improve transfer capability to fulfill PacifiCorp contract requirements, then PacifiCorp will share in the cost.[290] This is different from OATT service that would require Idaho Power to roll in the cost of such facilities rather than charging them incrementally to PacifiCorp.[291]

190. Turning to the benefits of PacifiCorp's use of the Idaho Power system, Idaho Power argues that one of the key benefits to Idaho Power and its transmission customers was PacifiCorp's payment for the cost of significant transmission upgrades.[292] Under the RTSA and the TFA, Idaho Power and PacifiCorp together created a new high capacity transmission path between Wyoming and Idaho, significantly improved the eastern portion of the Idaho Power transmission system, and built a new 500 kV transmission line from central Idaho to western Oregon (the Midpoint-Summer Lake line), all benefiting Idaho Power and its transmission customers.[293]

191. PacifiCorp's construction of these new facilities, Mr. Durick testified, not only enhanced the reliability of both PacifiCorp and Idaho Power systems and provided cost-effective transmission capacity to meet Idaho Power's growing transmission needs; they also expanded transmission usage from west-wide energy trade.[294] According to Mr. Durick, the ability to export power westward from Wyoming was increased by over 2,000 MW and the westbound transfer capability between Idaho Power and the Pacific Northwest was doubled.[295] As a consequence of this increase in system capacity, there has been an increase in energy traffic between the Pacific Northwest and inland states

[288] Exhibit No. IPC-28 (Durick Reb. Test. 20:4-5).

[289] *Id*. at 20:5-7.

[290] *Id*. at 20:11-13.

[291] *Id*. at 20:13-15.

[292] *Id*. at 22:9-10.

[293] *Id*. at 22:10-16.

[294] *Id*. at 23:1-4.

[295] *Id*. at 23:4-6.

such as Arizona, Nevada and Utah.[296] This increase in trade has benefited many users of the Idaho Power transmission system, Mr. Durick noted, including some intervening in this case.[297]

192. Mr. Durick further testified that the expanded capacity in the eastbound direction as a result of the construction of these new facilities has been used extensively by Idaho Power to wheel power from the northwest to the Sierra Pacific and to PacifiCorp in Utah under OATT services.[298] It has also been instrumental, he said, in improving the reliability and, thus, the rating of the 230 kV path east from Brownlee, which gives Idaho Power the ability to continue serving the growth in BPA's load in southern Idaho without building new transmission lines for that purpose.[299]

193. Mr. Durick also pointed out that at the time the Legacy Agreements were entered into, the prevailing flows on the Idaho Power system were strongly west to east.[300] Idaho Power's principal generating resources at the time were its hydroelectric power plants located on the Snake River, along the Oregon/Idaho border.[301] Power flowed from these plants to Idaho Power's primary load center in the Boise area.[302] The lines between the Snake River hydroelectric resources and Boise were Idaho Power's largest, and most constrained, transmission facilities.[303] Beyond Boise, power generally continued to flow eastward to eastern Idaho.[304] The services provided under the RTSA, in contrast, are east to west.[305] Electrically, the westward flowing power from the Jim Bridger power plant displaces power that would otherwise flow eastward.[306] This relieves transmission congestion on key parts of the Idaho Power system, increasing the amount of

[296] *Id*. at 23:6-9.

[297] *Id*. at 23:9-10.

[298] *Id.* at 24:9-13.

[299] *Id*. at 24:15-19.

[300] *Id*. at 25:13-14.

[301] *Id*. at 25:14-16.

[302] *Id*. at 25:16-17.

[303] *Id*. at 25:17-19.

[304] *Id*. at 25:19-20.

[305] *Id*. at 26:2.

[306] *Id*. at 26:3-4.

transmission capacity available to others.[307] It also decreases heat losses on the Idaho Power system that are experienced when power is transmitted though high voltage transmission wires, because PacifiCorp's east-to-west counter-flows offset Idaho Power's west-to-east flows.[308]

194. Staff takes issue with Idaho Power's reliance on certain restraints on PacifiCorp under the Legacy Agreements without considering other aspects that are beneficial to PacifiCorp.[309] For example, OATT firm service does not allow a transmission customer to schedule a thousand megawatts of firm transmission and not be obligated to contribute any associated losses.[310] By contrast, section 6.1 of the RTSA requires PacifiCorp to compensate Idaho Power for losses associated with East to West Transfer Services and the energy associated with Dynamic Overlay Control Service only to the extent of the energy equivalent to 2.8 percent of the hourly incremental amount of the total net scheduled transfers "that are less than or greater than 1,000 megawatt-hours per hour."[311] Also, OATT firm service does not provide for a Dynamic Overlay Service as exists in Section 4.2 of the RTSA.[312] In addition, OATT firm service does not allow a customer to counterschedule a point-to-point transmission contract in the opposite direction unless it also purchases firm point-to-point service in that direction.[313]

195. Intervenors question the relevance of the benefits that PacifiCorp brings to Idaho Power's system under the Legacy Agreements.[314] Mr. Daniel testified that the main purpose of the Legacy Agreements was to access major base-load generation, and the pricing of the transmission access that Idaho Power provided to PacifiCorp was a tradeoff for generation-related benefits derived from joint participation in Bridger rather than discounting transmission service to increase usage of the existing system at any given time as contemplated by Order No. 888.[315] According to Mr. Daniel, Idaho Power's argument that the RTSA and, presumably, the other Legacy Agreements, reflect

[307] *Id.* at 26:4-6.

[308] *Id*. at 26:9-20.

[309] *See* Staff Initial Brief 24-25.

[310] Schellberg Hg. Tr. 486:21-487:3.

[311] *See* Staff Initial Brief 24; Exhibit No. INT-13 at 53 (RTSA § 6.1).

[312] Schellberg Hg. Tr. 488:16-19; Exhibit No. INT-13 at 39 (RTSA § 4.2),

[313] Schellberg Hg. Tr. 489:10-490:24.

[314] Exhibit No. INT-5 (Daniel Ans. Test. 73:21-80:18).

[315] *Id*. at 74:1-6.

discounted pricing fails because when these contracts were entered into there was no standardized pricing of unbundled transmission service as there is today.[316] The fact that IPC was willing to agree to incremental pricing – which implies recovery of just the added cost of supplying a service – simply reflects the generation tradeoffs that Idaho Power received in this unique transaction, rather than any notion of discounting as the Commission uses that concept.[317]

196. Mr. Daniel further testified that the "use of facilities" charges in the Legacy Agreements are unjustified because it takes more than the incremental facilities installed under those agreements to provide the transmission services to PacifiCorp under those agreements.[318] PacifiCorp, he pointed out, receives that benefit without any contribution to the costs associated with such pre-existing transmission facilities or any subsequent transmission system additions on Idaho Power's system.[319] Further, he maintained, since Idaho Power acknowledges that the pricing under the RTSA is less than average-system (*i.e.*, rolled-in) costs, the agreement violates the Commission's Transmission Pricing Policy, which Mr. Daniel pointed out requires a transmission provider to charge the *higher of* incremental costs or average system costs for transmission service.[320]

197. At the time that the Legacy Agreements were conceived in the 1980s and 1990s as well as now, it has been Commission policy that a transmission provider is obligated to build or expand its transmission system to accommodate a customer's application for firm transmission service, provided that the transmission customer agrees to compensate the transmission provider for such an upgrade. The transmission provider is permitted to charge the higher of incremental expansion costs "or" a rolled-in embedded cost rate, typically known in the industry as "or" pricing. The policy was first enunciated by the Commission in its 1992 *Northeast Utilities* decision,[321] affirmed in the Commission's

[316] *Id*. at 74:10-13.

[317] *Id*. at 74:13-17.

[318] *Id*. at 76:8-9.

[319] *Id*. at 76:25-77:2.

[320] *Id.* at 77:8-17 (*citing Pricing Policy Statement*, *supra*, FERC Stats. & Regs. ¶ 31,005 at 31,138).

[321] *Northeast Utilities Service Company (Re: Public Service Company of New Hampshire), Opinion No. 364-A*, 58 FERC ¶ 61,070, *reh'g denied*, 59 FERC ¶ 61,042 *and* 59 FERC ¶ 61,089 (1992), *affirmed in part and remanded in part sub nom. Northeast Utilities Service Co. v. FERC*, 993 F.2d 937 (1st Cir. 1993).

1994 *Pricing Policy Statement*,[322] and reaffirmed in 1997 as applicable to OATT service in Order No. 888-A.[323]

198. According to Mr. Schellberg's testimony at the hearing, based on a reasonable estimate of what Idaho Power's rolled-in transmission rate would have been in 1980 (it had no such rate at the time), $6.1 million would have been raised from PacifiCorp for the transmission service that it was receiving under the Legacy Agreements.[324] This amount is *less than* the incremental "use of facilities" revenues under those agreements that PacifiCorp actually paid Idaho Power at the time, which amounted to $9.4 million in 1982 and $9 million in 1986.[325] If $4.2 million in carrying costs for the Midpoint 345/500 kV switchyard that was built by PacifiCorp pursuant to the Legacy Agreements and transferred to Idaho Power in 1988 is taken out of the figure in order to make it comparable to the status of service under the Legacy Agreements today, the net incremental revenue that Idaho Power received from PacifiCorp in the early 1980s would have been about equal to what it would have been under the estimated rolled-in rate charge.[326]

199. Thus, although the Legacy Agreement service fees that Idaho Power receives from PacifiCorp *currently* raise less revenue than a fully rolled-in rate charge would do, they did not do so originally when the Legacy Agreements were *conceived*. As Mr. Schellberg's testimony shows, the Legacy Agreement incremental fees agreed upon at the time were nearly the same as they would have been had they been rolled-in fees. No discount for "inferior service" was necessary, nor is there any evidence that any such discount was agreed to. Presumably, the Legacy Agreements made economic sense to the parties at the time at the agreed-upon rates.[327] No one can know for sure, because as Idaho Power observes, none of the individuals that that negotiated the Legacy Agreements were present in this case and most of them are not even alive.[328]

200. All we know is that the Legacy Agreements brought to these entities the benefits

[322] *Pricing Policy Statement*, *supra*, FERC Stats. & Regs. ¶ 31,005 at 31,137-38.

[323] Order No. 888-A, *supra*, FERC Stats. & Regs. ¶ 31,048 at 30,268.

[324] *See* Schellberg Hg. Tr. 532:2-534:8; Exhibit No. IPC-57.

[325] *See id*.

[326] *See* Exhibit No. IPC-57.

[327] *See* Idaho Power Initial Brief 42.

[328] *See* Idaho Power Reply Brief 25.

of accessing generation from the Jim Bridger plant and upgrading Idaho Power's then-existing transmission system, making it possible to transfer PacifiCorp's share of Bridger generation to its Washington and Oregon load centers and Idaho Power's share to its Idaho load center. The Legacy Agreements also introduced counter-flows into Idaho Power's system that increased its capacity to wheel power for third parties and reduce losses. At the same time, restrictions were placed on PacifiCorp's use of the system to assure that this use would not overtax it during periods of abnormal conditions. It is not necessary to quantify these benefits and burdens in order to determine whether the parties bargained for them or not. Moreover, as Mr. Schellberg's testimony shows, the Legacy Agreements did not violate Commission pricing policy at the time that they were entered into; they were approved "as is" by the Commission at that time.

201. The fact that the incremental pricing structure of the Legacy Agreements did not raise more or less revenue than what rolled-in rates would have raised at the time suggests that the large disparity that has developed since then between Legacy Agreement rates and OATT rates bears no relation to, and probably is an unintended consequence of, the original deal. Even if the Legacy Agreement's incremental rates made economic sense in the 1980s and 1990s when they were formed because they left the contracting parties no better or worse off than they would have been under a rolled-in rate structure, they do not make economic sense now that such a large gap has developed, causing inordinate problems with cost causation and cross-subsidization.

202. The existence of a growing gap between Legacy Agreement rates and OATT rates cannot justify the notion that the Legacy Agreements should be revenue-credited rather than cost-allocated in Idaho Power's OATT rate formula. There is no nexus between the benefits and burdens of the Legacy Agreements that were originally bargained for and the gap that has developed over time that suggests that the gap was really a bargained-for "discount." Hence, the gap does not justify any rationale for revenue-crediting instead of cost-allocating.

203. Idaho Power has attempted to justify the gap anyway, contending that its fees to PacifiCorp for Legacy Agreement services represent an appropriate "discount" that Commission policy recognizes when "inferior services" are provided or when "reciprocal services" are received in lieu of paying a charge for the service.[329] Idaho Power primarily cites the Commission's decision in *IES Utilities, Inc.* [330] in support of this position, noting

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[329] Idaho Power Initial Brief 17-18, 36-43.

[330] *IES Utilities, Inc*., 80 FERC ¶ 63,001 (1997), *aff'd in relevant part*, 81 FERC ¶ 61,187 (1997), *reh'g denied*, 82 FERC ¶ 61,089 (1998) (*IES*).

that in that case the Commission rejected a proposal to add 625 MW to a transmission provider's rate divisor because the services involved reciprocal benefits provided by the customers who received that power supply for free.[331]

204. *IES* involved the merger of three utilities into a holding company called Interstate Energy Corporation (IEC) and the formation of an ISO to manage their joint transmission system. Intervening customer Wisconsin Public Power, Inc. (WPPI) proposed that the merger applicants should increase their transmission rate divisor by 625 MW of output from generating plants jointly owned by merger co-applicant Wisconsin Power and Light Company (WPL) and other owners that was delivered by WPL without charge to the other owners.[332] WPL countered that the delivery obligation was not long-term firm delivery service, and therefore that only a revenue-credit was necessary, if anything at all.[333] In the Initial Decision, the Administrative Law Judge rejected WPPI's proposal, excluded the 625 MW adjustment from the divisor, and deemed consideration of the proposed revenue-credit to be unnecessary.[334]

205. In affirming this portion of the Initial Decision, the Commission in *IES* determined that "this single adjustment cannot be made in isolation, *i.e.*, without considering offsetting adjustments that quantify the benefits to IEC transmission customers of reciprocal facilities paid for by the other plant owners."[335] The Commission also found that "the proper treatment of this issue is problematic in individual, company-specific rate proceedings. We further note that intervenors' concern regarding evaluation of reciprocal benefits necessarily involves a regional solution. We believe that a regional institution such as an RTG or an ISO will provide the most appropriate means of resolving this concern."[336]

206. *IES* is unpersuasive because the Commission in *IES* did *not* resolve the issue in the way that Idaho Power says it did. Not only did the Commission in *IES* give no consideration to whether a revenue-credit was an appropriate substitute for a cost-allocation; the Commission also noted that "the proper treatment of this issue is

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[331] *See* Idaho Power Initial Brief 37.

[332] *IES*, *supra*, 80 FERC ¶ 63,001 at 65,007.

[333] *Id*.

[334] *Id*. at 65,008.

[335] *IES*, *supra*, 81 FERC ¶ 61,187 at 61,832.

[336] *Id*. at 61,833.

problematic in individual, company-specific rate proceedings" and left it up to a future ISO to come up with a regional solution that would take into account an evaluation of reciprocal benefits. No such "regional solution" is in the offing here.

207. Here, no nexus exists between the proposed revenue-credit and the asserted benefits and burdens of Legacy Agreement service. Neither Idaho Power nor PacifiCorp bargained for any "discount" when the Legacy Agreements were entered into. The compensation that was agreed upon was determined in an arms-length transaction that would have been the same if it been rolled-in or incremental in rate design, and that took the benefits and burdens of the agreements into account at that time. There is no reason to call the gap between the Legacy Agreement fees and OATT rates that has developed over decades to be a bargained-for "discount" when the discount did not even exist in the first place.

f. *Other Considerations*

208. Staff has raised two cases, *American Electric Power Service Corp.* (*AEP*)[337] and *Boston Edison Co.*,[338] to support its position that the services that Idaho Power offers to PacifiCorp under Legacy Agreements should be cost-allocated rather than revenue-credited.[339] Although I distinguished these cases away in the order denying summary disposition of this issue that I issued on December 15, 2006,[340] I now find on the basis of the fully-developed record in this proceeding that they are indeed applicable here.

209. In *AEP*, the Commission reviewed AEP's open-access transmission tariff, which was filed pursuant to Order No. 888. AEP proposed an OATT rate for non-firm service that was based on a ratio in which the divisor reflected the demand of multi-year point-to-point transmission service and the numerator credited certain other transmission revenues against the cost of service.[341] The credited transmission services were: (i) the transmission of electricity for other utilities booked to FERC Account 456, (ii) a portion of interruptible service revenues, and (iii) system sales revenues related to transmission.[342] Some of these transmission services were "firm" service. Staff in that

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[337] *American Electric Power Service Corp.*, 80 FERC ¶ 63,006 (1997), *affirmed in relevant part*, Opinion No. 440, 88 FERC ¶ 61,141 (1999) (*AEP*).

[338] *Boston Edison Co.*, 8 FERC ¶ 61,077 (1979).

[339] *See* Staff Initial Brief 15-16.

[340] *Idaho Power Co.*, 117 FERC ¶ 63,050 (2006).

[341] *AEP*, *supra*, 80 FERC ¶ 63,006 at 65,060.

[342] *Id*.

case opposed AEP's proposed methodology, recommending instead that all firm transmission service should be included in the divisor and only non-firm transmission service should be credited against the cost of service in the numerator.[343]

210. In the Initial Decision in *AEP*, the Administrative Law Judge agreed with Staff on the ground that the provisions of Order No. 888 recited above "are dispositive of this issue."[344] AEP countered that the revenue-credited transmission services were "not of the type contemplated by AEP's tariff but are part of comprehensive integration agreements between AEP and its customers," and that "these agreements involve terms, conditions and rates substantially different from those proposed here."[345] Nevertheless, the ALJ ruled that AEP's "argument that the concerned transmission services were not contemplated at the time the agreements were made cannot negate the clear instructions of Order No. 888. All customers of the same type of service should bear their proportionate share of the costs of providing the service."[346]

211. On review of the *AEP* Initial Decision, the Commission affirmed the ALJ on the ground that "we resolved this issue in Order No. 888, where we concluded that it is appropriate for non-firm service to be priced using up-to rates with the ceiling rate set at the firm service rate.[footnote omitted] In addition, we agree with trial staff that AEP should include the demand for all firm transmission service in the demand divisor, and only credit revenues from non-firm transmission against the cost of service."[347]

212. The salient facts of *AEP* are quite close to the facts of this case. Although I distinguished *AEP* from the instant facts for the purposes of deciding the summary disposition motion that Intervenors filed earlier in this case on the same issue now being decided after the full hearing, I find, upon further reflection and in view of the full factual record now available, that *AEP* stands as precedent to be followed here for the proposition that "firm" commitments under grandfathered contracts are to be included in the divisor of the OATT rate formula. Although the rate formula under examination in *AEP* was for a non-firm rate, it was structured as a maximum rate having its ceiling at the firm rate level, up to which prices for non-firm transactions could be negotiated.[348] The

[343] *Id*.

[344] *Id*.

[345] *Id*.

[346] *Id*. at 65,061.

[347] *Id*., 88 FERC ¶ 61,141 at 61,449.

[348] *Id*.

formula used in *AEP*, therefore, was no different in principle from the formula being proposed here, and the principles of cost causation and non-subsidization apply equally here as they did there.

213. In *Boston Edison*, the Commission was uncertain as to whether some of the utility's test period transactions with an "off-system" wholesale transmission customer, which were revenue-credited against the cost of service, fully compensated the utility for costs that were attributable to that customer. The ALJ found that some transactions were fully compensatory and some were not, and adjusted some, but not all, of the revenues from those transactions that were credited against the cost of service in order to lower the tariff rate. The Commission, however, reversed the ALJ and required the utility's entire revenue requirement to be allocated across the loads resulting from all of the transactions at issue as well as all other loads. The Commission held that "[t]he reasonableness of Edison's revenue credit method depends . . . on the reasonableness of the revenues in relation to fully allocated costs. Where information is readily available by which the proper allocation of costs can be made, it seems reasonable to do so and thereby to avoid the uncertainty as to whether the revenues may or may not be compensatory."[349]

214. *Boston Edison* holds that it is appropriate to cost-allocate instead of revenue-credit when it is unclear whether the transactions in question over- or under-compensate for system-wide costs. *Boston Edison* also held that while some transactions may over-compensate while others under-compensate, it is nevertheless better to cost-allocate all system-wide costs instead of cost-allocating some and revenue-crediting others, as the ALJ attempted to do in that case.

215. Having had an opportunity to review the fully-developed record in this case, I now consider it to parallel *Boston Edison*. Some aspects of Idaho Power's service to PacifiCorp under the Legacy Agreements qualify as "firm" service, such as the East to West Transfer Service under the RTSA. Other aspects qualify as "non-firm" service, such as the RTSA's Additional East to West Transfer Service. Nevertheless, all of the PacifiCorp revenues from all of the services under the Legacy Agreements clearly *under*-compensate Idaho Power for its fully-integrated, system-wide costs. It is consistent with *Boston Edison* to cost-allocate all of those services rather than to cost-allocate some and revenue-credit others on a piecemeal basis.

g. *Financial Impact*

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[349] *Boston Edison Co.*, *supra*, 8 FERC ¶ 61,077 at 61,283.

216. As the Commission stated in Order No. 888-A, "*nothing* in Order No. 888 affects prices or price-setting methodologies in existing contracts, unless specifically permitted in the contract on file."[350] Thus, since cost-allocating Idaho Power's Total Transmission Revenue Requirement over PacifiCorp's firm loads from the Legacy Agreements as well as all other firm loads does not change any specific price that PacifiCorp must pay to Idaho Power, it is clear that Idaho Power will bear the brunt of this revision in the structure of its OATT formula rate.[351]

217. According to the testimony of economic consultant W. Michael McHugh, Intervenors' expert witness, revising the proposed OATT formula rate to cost-allocate the Legacy Agreement services instead of revenue-crediting them will reduce Idaho Power's proposed firm point-to-point OATT rate by 33.2 percent.[352] This results in a reduction of Idaho Power's revenue by approximately $11.4 million per year.[353]

218. This reduction, however, is considerably mitigated when the findings on Issue Two of this Initial Decision are taken into account, as discussed later herein. Even if that were not the case, the Commission does not need to hunt for ways to ameliorate the negative impact on Idaho Power's revenue. The U.S. Court of Appeals for the D.C. Circuit has cautioned the Commission against implementing any kind of phase-out of Idaho Power's present accounting practice after having determined that the practice is unjust and unreasonable and therefore unlawful.[354] Idaho Power has other ways to lessen any financial blow that this decision may cause through appropriate rate changes at the retail level or through renegotiation of its agreements with PacifiCorp.

3. Conclusion

219. For the foregoing reasons, I find that Idaho Power has failed to meet its burden of proving that its proposal to credit toward the Total Transmission Revenue Requirement in its OATT rate formula the revenues received from PacifiCorp under the three Legacy Agreements, rather than to include the demands associated with the Legacy Agreements in the determination of the rate divisor, is just and reasonable, and not unduly discriminatory or preferential. I find that the transmission service that Idaho Power offers

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[350] Order No. 888-A, *supra*, FERC Stats. & Regs. ¶ 31,048 at 30,199 (emphasis added).

[351] *See* Tingle-Stewart Hg. Tr. 666:6-669:14.

[352] Exhibit No. INT-27 (McHugh Ans. Test. 29:7 (Table 4)).

[353] *See* Tingle-Stewart Hg. Tr. 666:18-667:5; Morgans Hg. Tr. 99:4-25.

[354] *See La. PUC v. FERC, supra*, 482 F.3d at 518.

to PacifiCorp under the Legacy Agreements must instead be accounted for in the rate formula by allocating the Total Transmission Revenue Requirement over the firm demands of the entire Idaho Power system, including PacifiCorp's firm demand under the Legacy Agreements, and not by crediting the revenues from those Agreements against the Total Transmission Revenue Requirement.

B. Issue Two: *If it is determined, as a result of the resolution of Issue One, that the demands associated with any of the three Legacy Agreements should be included in the rate divisor rather than revenue-credited, what is the appropriate method for incorporating such demands into the formula rate?*

220. Having determined that the proper treatment of the Legacy Agreements in Idaho Power's proposed OATT rate formula is to allocate the Total Transmission Revenue Requirement over the firm loads of the entire Idaho Power system, including PacifiCorp's load under the Legacy Agreements, rather than to credit the revenues from those Agreements against the Total Transmission Revenue Requirement, the next issue to address is whether those loads should be represented in the divisor of the rate formula by the coincident peak demands of the Legacy Agreements or by their contract demands.

221. The difference in result between the two methodologies is significant. If PacifiCorp's 2004 contract demands are used, then the divisor increases by PacifiCorp's full contract right to schedule up to 2,014 MW on Idaho Power's system. If PacifiCorp's 12 CP demand for the Legacy Agreements in 2004 is used instead, then the divisor increases by only 774 MW, resulting in a significantly smaller reduction in Idaho Power's revenue from the formula change.

1. Positions of the Parties

a. *Idaho Power*

222. Idaho Power contends that if the Legacy Agreements are cost-allocated in the rate divisor rather than revenue-credited, then the Legacy Agreement coincident peak demands, not their contract demands, should be included in the rate divisor.[355]

223. According to Idaho Power's expert, Alan C. Heintz, a transmission customer's coincident peak demand is the customer's usage of the transmission system at the time of

[355] Idaho Power Initial Brief 43-46.

the transmission provider's maximum (or "peak") demand. For a transmission customer, its usage is its scheduled demands. For example, Mr. Heintz explained, a transmission customer with a contract demand of 100 MW might only schedule 75 MW. These coincident peak demands are calculated monthly, and their average over the course of a 12-month period is known as the transmission customer's 12 coincident peak demands, or "12 CP" for short.[356]

224. Mr. Heintz testified that according to OATT section 34.3, the only contract demands that should be in the rate divisor are those for OATT Part II Firm Point-to-Point transactions. All other transactions that are included in the rate divisor are included based on their firm usage during the transmission provider's peak hour of the month, *i.e.*, their coincident peak demands. The proof of this, Mr. Heintz testified, is in the language of OATT section 34.3, which provides for the subtraction of the coincident peak demands of OATT Part II Firm Point-to-Point service from the maximum firm usage, and the addition of the OATT Part II Firm Point-to-Point service contract demands. In other words, Mr. Heintz explained, the maximum firm usage of a service other than an OATT Part II Firm Point-to-Point service that is to be included in the rate divisor and that has a contract demand is the coincident peak demand of the service, not the contract demand. Otherwise, Mr. Heintz pointed out, there would be no reason for the adjustment to the maximum firm usage only for OATT Part II Firm Point-to-Point services.[357]

225. Idaho Power maintains that the RTSA lacks a contract demand, providing only for transmission of "up to" 1,600 MW, which Ms. Tingle-Stewart admitted could be as low as zero.[358] The highest 12 CP demand under the RTSA for the period 2002-2006, as determined by Staff, was 656 MW.[359] This level, Idaho Power maintains, was well under PacifiCorp's total contract demand under the Legacy Agreements of 1,514 MW.[360]

226. According to Idaho Power, using the proposed OATT rate formula as filed (and revised on compliance) and the Period I (2004) cost of service, eliminating the revenue credit for the Legacy Agreements and increasing the rate divisor by 774 MW (the 12 CP demand for the Legacy Agreements in 2004) results in a reduction of $3,466,806 per year

[356] *See* Exhibit No. IPC-23 (Heintz Reb. Test. 39:19-40:4).

[357] *See id*. at 40:6-20.

[358] Idaho Power Initial Brief 45; Tingle-Stewart Hg. Tr. 680:6-9, 701:4-10.

[359] Idaho Power Initial Brief 45; Exhibit No. IPC-57 at 1.

[360] Idaho Power Initial Brief 45; *see* Exhibit Nos. INT-45 at 2; INT-46 at 2.

in revenues for Idaho Power.[361] By contrast, Idaho Power argues, under the method of Intervenors and Staff, eliminating the revenue credit and increasing the rate divisor by 2,014 MW (PacifiCorp's current contract demand as determined by the limits identified in the Legacy Agreements) results in a reduction of $11,374,236 per year.[362]

b. *PacifiCorp*

227. PacifiCorp does not take a position on this issue.

c. *Intervenors*

228. Intervenors argue that if the Legacy Agreements are cost-allocated in the rate divisor rather than revenue-credited, then the contract demands of each Agreement should be used for the associated loads in the divisor of the formula rate.[363]

229. According to Intervenors' expert, Stephen P. Daniel, the transmission service obligations under the Legacy Agreements should be based upon the capacity obligations. These contract capacity quantities reflect commitments that Idaho Power must plan for and be prepared to serve if requested by PacifiCorp, Mr. Daniel explained. Even if from time to time PacifiCorp were to schedule transfers under the Legacy Agreements at levels less than the contract capacities set forth therein, Mr. Daniel stated, Idaho Power still has an obligation to be prepared to supply the higher contract capacities when scheduled, including by changing pre-scheduled uses.[364]

230. According to Intervenors, eliminating the revenue credit and increasing the rate divisor by 2,014 MW (PacifiCorp's current contract demand as determined by the limits identified in the Legacy Agreements) results in a reduction of $5,651,040 per year in

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361 *See* Joint Stipulation of Issues at 6; Morgans Hg. Tr. 99:4-25.

362 *See* Exhibit Nos. INT-5 (Daniel Ans. Test. 86:8-18); INT-19; Joint Stipulation of Issues at 3; Morgans Hg. Tr. 99:4-25.

363 Intervenors Initial Brief 42-46.

364 *See* Exhibit No. INT-5 (Daniel Ans. Test. 86:8-18).

revenues for Idaho Power, only about half of what Idaho Power contends.[365]

d. *Staff*

231. Staff contends that the appropriate method for incorporating the demands associated with the Legacy Agreements in the rate divisor is based on contract demands.[366]

232. According to Staff's expert, Natalie Y. Tingle-Stewart, Idaho Power's divisor does not include the contract demands associated with the Legacy Agreements with PacifiCorp. Therefore, Ms. Tingle-Stewart testified, the divisor of the rate formula proposed by Idaho Power does not accurately represent its transmission system loads. Staff agrees with Intervenors that the MW amounts related to the Legacy Agreements total 2,014 MW, which is a significant amount in relation to the 2,942 MW divisor that Idaho Power has already proposed.[367]

2. Discussion

a. *Interpretation of Pro Forma OATT Language*

233. The Commission prescribed in Order No. 888 that OATT transmission rates were to be priced as follows:

> . . . [W]e will allow all firm transmission rates, including those for flexible point-to-point service, to be based on adjusted system monthly peak loads. The adjusted system monthly peak loads consist of the transmission provider's total monthly firm peak load minus the monthly coincident peaks associated with *all* firm point-to-point service customers plus the monthly contract demand reservations for *all* firm point-to-point service.[368]

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[365] *See* Intervenors Initial Brief 44-45; Exhibit Nos. INT-5 (Daniel Ans. Test. 85:20-21); INT-19; IPC 5 at Statement BB.

[366] Staff Initial Brief 27-28.

[367] Exhibit No. S-1 (Tingle-Stewart Ans. Test. 12:14-19).

[368] Order No. 888, *supra*, FERC Stats. & Regs. ¶ 31,036 at 31,738 (emphasis in original).

234. As will be seen below, the Commission in Order No. 888 categorized "firm transmission" more broadly than the "flexible point-to-point service" that it "included." "Firm transmission" service was to be represented in the divisor of the rate formula by its "total monthly firm peak load," but the "flexible point-to-point service" portion of that overall firm service—the firm service offered to OATT customers—was to be represented in the divisor by "monthly contract demand reservations." The fact that the word "all" is italicized twice in this portion of Order No. 888 in connection with "firm point-to-point service" does not bring all firm service into the contract demand factor—"all" still points only to OATT firm service, not any non-OATT firm service.

235. Consistent with this reading of Order No. 888 and the conforming wording of the *pro forma* OATT that was appended to the end of Order No. 888,[369] section 34.3 of Idaho Power's OATT states:

> **34.3 Determination of Transmission Provider's Monthly Transmission System Load:** The Transmission Provider's monthly Transmission System load is *the Transmission Provider's Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to Part II of this Tariff plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers*.[370]

236. As further stated in the *pro forma* OATT,[371] section 1.47 of Idaho Power's OATT defines Idaho Power's "Monthly Transmission System Peak" as follows:

> **1.47 Transmission Provider's Monthly Transmission System Peak**: The maximum *firm* usage of the Transmission Provider's Transmission System in a calendar month.[372]

237. "Reserved Capacity" is also defined in section 1.39 of Idaho Power's OATT, consistent with the *pro forma* OATT,[373] as follows:

> **1.39 Reserved Capacity:** The maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission

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[369] *Id*. at 31,958.

[370] Idaho Power OATT, § 34.3 (emphasis added).

[371] Order No. 888, *supra*, at 31,933.

[372] Idaho Power OATT, § 1.47 (emphasis added).

[373] Order No. 888, *supra*, at 31,932-33.

> Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery *under Part II of the Tariff*. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.[374]

238. It is clear from the foregoing emphasized terms in Idaho Power's OATT, and consistent with the original wording of the *pro forma* OATT of Order No. 888, that by not capitalizing the word "firm" in the phrase "monthly maximum firm usage" in the definition of "Monthly Transmission System Peak," the OATT uses that term in its generic sense rather than in terms of any defined service in the OATT, and therefore it intentionally includes in that maximum the monthly peak usages of *all* firm customers, including the usages of both firm OATT customers (like Intervenors) *and* firm non-OATT customers (like PacifiCorp). The definition of "Transmission Provider's Monthly Transmission System Load" subtracts from that "monthly maximum firm usage" only the coincident peak usage of OATT Firm Point-To-Point Transmission Service customers. This is so because the OATT expressly identifies these services as "pursuant to Part II of this Tariff." Likewise, only contract demands of the same OATT Firm Point-To-Point Transmission Service customers are added back in, because the OATT defines "Reserved Capacity" as being the contract demands "under Part II of the Tariff." What results in the divisor from the foregoing calculation is the sum of the monthly coincident peak usages of firm non-OATT customers (like PacifiCorp) and the monthly contract demands of OATT Firm Point-To-Point Transmission Service customers (like Intervenors).

239. "Where the terms of a statute are unambiguous, further judicial inquiry into the intent of the drafters is generally unnecessary."[375] Consequently, the proper way to read Order No. 888 and the *pro forma* OATT that was established by the Commission, and the Idaho Power OATT that is derived directly from it, is that monthly coincident peak usages of firm non-OATT customers, like PacifiCorp's monthly coincident peak firm usage under the Legacy Agreements, should be included in the divisor of the formula rate. Only the contract demands of Idaho Power's OATT Firm Point-To-Point Transmission Service customers should be substituted for their monthly coincident peak usages in the divisor of the OATT rate formula.

240. At the hearing, Intervenors and Staff raised in passing that Idaho Power's allocation demand in the divisor of its OATT rate formula includes 88 MW for short-term

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[374] Idaho Power OATT, § 1.47 (emphasis added).

[375] *Natural Resources Defense Council v. Browner*, 57 F.3d 1122, 1127 (D.C. Cir. 1995).

firm point-to-point transmission service.[376] They argue that these short-term firm transmission services, offered on a daily, weekly and monthly basis, should be revenue-credited in the numerator of the formula instead of cost-allocated in the divisor as Idaho Power has done.[377] However, the plain language of the *pro forma* OATT in Order No. 888, as adopted by Idaho Power in its OATT, precludes the treatment of short-term firm transactions as a revenue-credit. As noted above, the "Transmission Provider's Monthly Transmission System Load" is defined in section 34.3 of the OATT such that the contract demands of OATT Firm Point-To-Point Transmission Service customers are substituted for their monthly coincident peak usages. This definition does not distinguish between short-term firm OATT customers and long-term firm OATT customers. Rather, the substitution is expressly made for *all* OATT Firm Point-To-Point Transmission Service customers. This treatment leaves no room for revenue-crediting short-term firm amounts.

241. Staff argues that utilizing PacifiCorp's contract demand in the divisor of the OATT formula rate rather than its coincident peak demand is consistent with the Commission's established method of addressing the use of coincident peak versus contract demand in the rate divisor. Staff contends that the Commission has found that, if the contract between the company and the customer specifies a contract demand where the company is obligated to stand ready to provide that amount of contract demand, then the transmission unit rate should be developed using contract demands and not coincident peaks in the divisor.[378] Staff cites several cases that pre-date Order No. 888,[379] and for that reason alone they are not persuasive. Staff's only post-Order No. 888 citation[380] is equally unpersuasive because it, too, involves a pre-Order No. 888 transmission agreement.[381] This issue involves *only* an interpretation of the language of the OATT and does not bring into play the interpretation of language of other agreements in other contexts.

242. Intervenors and Staff point to several cases that, in their view, reflect that nothwithstanding the express language of the OATT, the contract demands of non-OATT customers receiving firm service should nonetheless be used instead of their coincident

[376] *See* Exhibit Nos. INT-5 (Daniel Ans. Test. 95:3-98:5); S-1 (Tingle-Stewart Ans. Test. 35:4-36:17).

[377] *Id*.; *also see* Idaho Power Tariff Filing, Statement BG and Workpaper WP-BB.

[378] Staff Initial Brief 28.

[379] *Illinois Power Co*., 62 FERC ¶ 61,147 at 62,062 (1993); *Northeast Utilities Services Co*., 62 FERC ¶ 61,294 at 62,906 (1993).

[380] *PacifiCorp*, 84 FERC ¶ 61,303 at 62,391 (1998).

[381] *See id*. at 62,390.

peak demands in the divisor of the formula that is used to calculate OATT rates.[382] Of the cited cases, however, only one—*CECo*—is on point here. That case involved the treatment in transmission provider CECo's OATT rate calculation of the demand associated with non-OATT customer Detroit Edison's use of CECo's network to wheel output from the Ludington power plant in western Michigan to loads in eastern Michigan.[383] OATT customer Michigan Systems (MS) proposed that 917 MW, representing Detroit Edison's full share of the plant's output, should be used in the divisor on the theory that CECo must be prepared to meet that level of demand if called upon to do so.[384] Staff favored using 443 MW, which was Detroit Edison's actual usage based upon the relevant test year data.[385] CECo favored using only 36 MW, which was based upon "an analysis of electron flows during the test year."[386]

243. The decision of the Administrative Law Judge in *CECo* on this issue, which was affirmed without comment by the Commission, was as follows:

> MS has the better argument. [MS] is correct that CECo's transmission network must be capable of transmitting Detroit Edison's full 49 percent ownership share of Ludington. To allocate a lesser amount would not give full recognition to the burden on CECo's network caused by this transmission commitment. Inclusion in the denominator of the lower actual usage of the system in the test year, as proposed by Staff, would not adequately reflect this firm service responsibility and would transfer to other ratepayers some of the cost burden associated with this arrangement. CECo's analysis is even less reliable and would result in practically no recognition of the burden of this large commitment. MS' proposal to include 917 MW in the denominator is thus adopted.[387]

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[382] *See* Intervenors Initial Brief 43-44 and Intervenors Reply Brief 22, *citing Consumers Energy Co.*, 86 FERC ¶ 63,004 (1999), *corrected*, 86 FERC ¶ 63,005 (1999), *aff'd in relevant part*, 98 FERC ¶ 61,333 (2002) (*CECo*) and *American Electric Power Service Corp*., 80 FERC ¶ 63,006 (1997), *aff'd in part and rev'd in part*, Opinion No. 440, 88 FERC ¶ 61,141 (1999) (*AEP*); *also see* Staff Initial Brief 28 and Staff Reply Brief 24, *citing Illinois Power Co.*, 62 FERC ¶ 61,147 at 62,062 (1993); *Northeast Utilities Services Co.*, 62 FERC ¶ 61,294 at 62,906 (1993); and *PacifiCorp*, 84 FERC ¶ 61,303 at 62,391 (1998).

[383] *CECo*, *supra*, 86 FERC ¶ 63,004 at 65,031.

[384] *Id*. at 65,032.

[385] *Id*.

[386] *Id*.

[387] *Id*.

244. In determining that Detroit Edison's full share of the Ludington plant had to be included in the divisor of the rate formula, the Administrative Law Judge in *CECo* observed that Order No. 888 made "clear that the Commission requires cost allocation of firm services" and that "[t]he commitment here is akin to firm, point-to-point service. Tr. at 999. The Commission's Order No. 888 similarly includes in the denominator for point-to-point service and network service the contract demands of all firm customers."[388]

245. *CECo* has superficial appeal here because it is a post-Order No. 888 decision involving a non-OATT transmission service for which the full load share is accounted for in the divisor of the OATT rate formula. But it is important to note that in *CECo*, the transmission provider itself characterized the service for Detroit Edison as "akin to firm, point-to-point service,"[389] a representation on which the Administrative Law Judge relied in his decision. In this case, by contrast, although the Legacy Agreement services are firm services, no one has contended that they are "akin" to point-to-point service; indeed, it is accepted by all parties here that Legacy Agreement service is *not* "OATT firm" or "point-to-point" in nature.[390] Hence, the consideration that persuaded the Administrative Law Judge and the Commission in *CECo* to allocate transmission costs to Detroit Edison's firm point-to-point service in virtually the same way as OATT firm point-to-point service, notwithstanding the different treatment that the contract language of the *pro forma* OATT expressly requires, is not present here and does not command the same result here.

246. Accordingly, the monthly coincident peak usages of firm non-OATT customers, like PacifiCorp's monthly coincident peak firm usage under the Legacy Agreements, should be included in the divisor of the formula rate, and only the contract demands of Idaho Power's OATT Firm Point-To-Point Transmission Service customers should be substituted for their monthly coincident peak usages in the divisor of the OATT rate formula.

3. Conclusion

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[388] *Id*.

[389] *CECo*, Waits Hg. Tr. 999:8-25 (Vol. 8, March 25, 1998).

[390] *See* Exhibit Nos. IPC-28 (Durick Reb. Test. 12:16); INT-35 (Daniel Cross-Ans. Test. 3:3-7); S-1 (Tingle-Stewart Ans. Test. 26:8-13).

247. Accordingly, I find that the appropriate method for incorporating PacifiCorp's demand associated with the Legacy Agreements into the OATT formula rate is to include PacifiCorp's monthly coincident peak usages under the Legacy Agreements (both long-term and short-term) in the divisor of the formula, not PacifiCorp's contract demands under those Agreements.

C. Issue Three: *Whether the theories on incentive regulation described in the article entitled* Regulation of the Electricity Market: Incentive Regulation for Electricity Networks, *by Paul L. Joskow, are applicable to the issues in this proceeding?*

248. The Commission has long accepted the use of formula rates as an alternative to stated rates. "The Commission has used formula rates for public utilities for many years as long as the formula is sufficiently clear that all parties can determine what costs go into the rate and how it will be calculated. [Footnote omitted] In such a case, the formula alone constitutes the filed rate. The Commission's acceptance of a formula rate authorizes the utility to use the formula rate on an ongoing basis."[391]

249. "[W]hen the Commission accepts a formula rate as a filed rate, it grants waiver of the filing and notice requirements of § 205, and the utility's rates, then, can change repeatedly, without notice to the Commission, provided those changes are consistent with the formula."[392] Thus, as long as the utility continues to apply the formula that has been accepted by the Commission, it is unnecessary for the utility to file for a rate change under section 205 of the Federal Power Act every time that new inputs to the formula vary the dollar amount of the rate.[393]

250. Doing away with statutory filing and notice requirements of section 205 in this

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[391] *PJM Interconnection, LLC*, 110 FERC ¶ 61,053 at P 120 (2005) (*PJM*); *also see Pub. Util. Comm'n of Cal. v. FERC*, 254 F.3d 250, 254 (D.C. Cir. 2001) ("the formula itself is the rate, not the particular components of the formula"); *Southern Company Services, Inc.*, 105 FERC ¶ 61,019 (2003) (formula rate OATT accepted in settlement); *ISO New England Inc.*, 96 FERC ¶ 61,261 (2001) (formula rate accepted in non-precedential letter order).

[392] *PUC of California v. FERC*, 254 F.3d 250, 254 (D.C. Cir. 2001) (emphasis and internal brackets omitted), *quoting Alabama Power Co. v. FERC*, 993 F.2d 1557, 1567-68 (D.C. Cir. 1993).

[393] *PJM, supra*.

manner is not simply a matter within a utility's sole discretion, however. Courts have ruled that "[a] market-based tariff cannot be structured so as to virtually deregulate an industry and remove it from statutorily required oversight."[394] In a similar vein, a formula rate cannot be implemented in a manner that "virtually deregulates" an OATT tariff rate from FERC oversight by substituting automatic annual rate changes and informal "informational filings" in lieu of statutorily-mandated rate filings, notices, hearings and Commission determinations of the rate's justness and reasonableness pursuant to section 205. That is why, in granting a waiver of the filing and notice requirements of section 205 for the purpose of accepting a formula rate as a transmission provider's filed rate, as with the granting of any statutory filing and notice requirement, the Commission must be shown "good cause" to do so.[395]

251. In Notices that I issued to the parties prior to the hearing, I asked them to address this issue. I included in the record as a judicial exhibit an article published by Dr. Paul L. Joskow, entitled *Regulation of the Electricity Market: Incentive Regulation for Electricity Networks* (*Joskow* article),[396] in order to put the matter to the parties in the context of the incentives that result from the implementation of a formula rate that changes annually on an automatic basis. The parties submitted testimony responsive to the issue.[397] The parties also briefed the issue.[398]

252. The *Joskow* article points out that with stated rates, which are set in advance and act like a price cap going forward until a subsequent rate change is filed with the Commission, a "potential moral hazard" that regulated utility managers may exert too little effort to avoid excessive costs is mitigated by the fact that the regulated firm and its managers keep 100 percent of any cost reductions that they realize by increasing effort, which acts as an incentive to maintain efficient levels of managerial effort and cost

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[394] *Public Utility District No. 1 of Snohomish County Washington v. FERC*, 471 F.3d 1053, 1080 (9th Cir. 2006).

[395] *See Kansas Gas and Electric Co*., 20 FERC ¶ 61,093 at 61,199 (1982).

[396] Exhibit No. J-1 (Paul L. Joskow, "Regulation of the Electricity Market; Incentive Regulation for Electricity Networks," *CESifo DICE Report* 3 (February 2006)) (*Joskow*).

[397] Exhibit Nos. J-1 (*Joskow* Article); IPC-20 (Heintz Dir. Test.); IPC-22 (Gale Dir. Test.); INT-34 (Daniel Supp. Ans. Test.); S-14 (Tingle-Stewart Supp. Ans. Test.); S-15 (Leger Supp. Ans. Test).

[398] Idaho Power Initial Brief 46-50; Idaho Power Reply Brief 30; Intervenors Initial Brief 46-49; Intervenors Reply Brief 24-25; Staff Initial Brief 28-42;

reduction.[399] As for the regulatory agency, having imperfect information and therefore being uncertain about the firm's true costs, it has a motivation to cap the stated rate at a level that is high enough to cover the possibility that the utility's costs will are efficient, but inherently high.[400] Thus, stated rates act as an incentive to regulated firms to reduce costs, but do not extract the "rent" that is charged to customers when the rates are too high relative to the firm's true cost opportunities.[401]

253. According to the *Joskow* article, with cost-based formula rates like Idaho Power's formula rates, which keep pace on an annual basis with changes in a regulated firm's costs, "the firm is assured that it will be compensated for all of the costs of production that it actually incurs and no more."[402] This mechanism solves the "rent extraction" problem because there is no "rent" left to the firm or its managers to capture in the form of excess profits.[403] At the same time, however, it does not avoid the "moral hazard" because it does not provide incentives for management to exert optimal efforts to contain costs, since they retain none of the cost savings.[404] Consumers, as a result, may end up paying higher than optimally efficient rates.[405]

254. In certifying the Partial Settlement Agreement to the Commission on July 11, 2007, and in light of the *Joskow* article, I proposed revising the Settlement Agreement to limit the circumstances under which the filing and notice requirements of section 205 of the Federal Power Act would be waived in this case. I proposed that the Commission impose a procedural limitation on annual automatic formula rate increases, such that in any service year in which the automatic rate increase resulting from the annual formula recalculation exceeds a certain level (*e.g.*, the increase in an appropriate price index), Idaho Power would be required to make a section 205 filing for that rate increase and bear the burden of proving its justness and reasonableness.

255. The Commission's August 8, 2007 Order approving the partial settlement in this case accepted section 6.3 of the Settlement Agreement, which states that "[i]n approving this Settlement Agreement, the Commission is granting the necessary waivers of the

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[399] *See* Exhibit No. J-1 (*Joskow* at 4).

[400] *See id*.

[401] *See id*.

[402] *Id*.

[403] *Id*.

[404] *See id*.

[405] *See id*.

notice and filing requirements of Section 205 associated with the operation of the OATT formula rate as filed and modified by this Settlement Agreement."[406] The Commission found in this regard that the issues concerning filing and notice requirements were raised earlier in this proceeding and have been negotiated and agreed upon in the Settlement Agreement, including annual informational filing procedures for formula rate updates. Additionally, the Commission noted, interested parties and the Commission retain the right to challenge any annual formula recalculation.[407]

256. Although a record has been made in this case to aid the Commission in exploring whether regulatory incentives for cost management, such as the proposal above, are appropriate for formula rates such as the one that Idaho Power has proposed, the parties have chosen through settlement to foreclose any such analysis and the Commission has accepted that choice. Accordingly, there is no need to discuss Issue Three further or to reach a conclusion on it here.

V. CONCLUSIONS

257. Based on the foregoing, it is concluded that Idaho Power's proposal to credit toward the Total Transmission Revenue Requirement in its OATT rate formula the revenues received from PacifiCorp under the three Legacy Agreements, rather than to include the demands associated with the Legacy Agreements in the determination of the rate divisor, is unjust and unreasonable, unduly discriminatory and preferential. It is concluded that the transmission service that Idaho Power offers to PacifiCorp under the Legacy Agreements must instead be accounted for in the rate formula by allocating the Total Transmission Revenue Requirement over the firm demands of the entire Idaho Power system, including PacifiCorp's demand under the Legacy Agreements, and not by crediting the revenues from those Agreements against the Total Transmission Revenue Requirement.

258. It is further concluded that the appropriate method for incorporating PacifiCorp's demand associated with the Legacy Agreements into the OATT formula rate is to include PacifiCorp's monthly coincident peak usages under the Legacy Agreements (both long-term and short-term) in the divisor of the formula, not PacifiCorp's contract demands under those Agreements.

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[406] *Idaho Power Co., supra*, 120 FERC ¶ 61,144 at P. 2-3 and P. 2 n.3.

[407] *Id*. at P. 3.

259. All findings and conclusions made in the ISSUES AND DISCUSSION section above are incorporated in these CONCLUSIONS even if not specifically made here.

260. All contentions made by the participants that are not specifically addressed or decided here are rejected or determined to be immaterial.

VI. ORDER

261. **IT IS ORDERED**, subject to review by the Commission on exceptions or on its own motion, as provided by the Rules of Practice and Procedure, that within thirty (30) days of issuance of the final order of the Commission in this proceeding, Idaho Power shall file revised compliance filings in accordance with the findings and conclusions of this Initial Decision, as adopted or modified by the Commission.

SO ORDERED.

Steven A. Glazer
Presiding Administrative Law Judge