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February 15, 2012

VIA HAND DELIVERY

Jean D. Jewell, Secretary
Idaho Public Utilities Commission
472 West Washington Street
Boise, Idaho 83702

Re: Case No. IPC-E-12-06
IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES DUE TO THE INCLUSION OF TRANSMISSION COSTS ASSOCIATED WITH FERC DOCKET NO. ER06-787

Dear Ms. Jewell:

Enclosed for filing please find an original and seven (7) copies of Idaho Power Company's Application in the above matter.

Very truly yours,

Jason B. Williams

JBW:csb
Enclosures

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES DUE TO THE INCLUSION OF TRANSMISSION COSTS ASSOCIATED WITH FERC DOCKET NO. ER06-787.	CASE NO. IPC-E-12-06 APPLICATION

Idaho Power Company ("Idaho Power" or "Company"), in accordance with Idaho Code § 61-524 and RP 052, 121, and 125, hereby respectfully makes Application to the Idaho Public Utilities Commission ("Commission") for authority to increase its rates related to the inclusion of certain transmission costs associated with the Federal Energy Regulatory Commission ("FERC") Order on Initial Decision, Docket No. ER06-787.[1] This Application is being filed with the Commission concurrently with three other applications that will impact customers' base rates: (1) removal of accelerated depreciation expense associated with non-Advanced Metering Infrastructure ("AMI") metering equipment; (2) revised depreciation rates as a result of a new depreciation

[1] All documents, filings and orders related to Docket No. ER06-787 can be found at http://elibrary.ferc.gov/idmws/docket_sheet.asp under the File List links for each filed document.

study; and (3) the inclusion of a balancing account for the early decommissioning of the Boardman power plant. Idaho Power is simultaneously filing these applications so as to necessitate a single rate change for customers as opposed to four individual rate adjustments had the applications not been filed all at once.

In support of this Application, Idaho Power asserts as follows:

I. BACKGROUND

1. On July 20, 2009, Idaho Power submitted an application in Case No. IPC-E-09-21 ("2009 Application") for an accounting order authorizing the deferral of costs associated with the FERC Order on Initial Decision in Docket No. ER06-787 ("Initial Decision"). The 2009 Application set forth a detailed description of the procedural history of FERC Docket No. ER06-787, which included a description of how the Initial Order adversely impacted Idaho Power. Specifically, the Initial Decision prescribed ratemaking treatment of certain Idaho Power Legacy Agreements[2] that resulted in an unanticipated revenue shortfall for Idaho Power. Idaho Power timely sought re-hearing of the Initial Decision at FERC on February 17, 2009 ("Rehearing Petition"), arguing that FERC erred in a number of significant ways with respect to the ratemaking treatment of the Legacy Agreements in Idaho Power's Open Access Transmission Tariff ("OATT") formula rate calculation.

[2] Legacy Agreements include (1) the Restated Transmission Services Agreement Between PacifiCorp and Idaho Power Company ("Restated Transmission Agreement"), (2) the Transmission Facilities Agreement Between Idaho Power Company, Pacific Power & Light Company, and Utah Power & Light Company ("Facilities Agreement"), and (3) the Agreement for Interconnection and Transmission Services Between Idaho Power Company and Utah Power & Light Company ("Interconnection Agreement"). Generally, these agreements were executed to support Idaho Power's and PacifiCorp's (formerly PP&L) efforts to build and operate the Jim Bridger power plant to serve their respective electric loads, to provide transmission service between the Jim Bridger power plant and PacifiCorp's western power loads in Oregon and Washington, and to provide bi-directional transmission service across Idaho Power's lines between PacifiCorp's Wyoming system and its Utah system.

2. As a result of the Initial Decision, however, the 2009 Application requested an accounting order from the Commission that allowed for the deferral of unrecovered transmission revenues resulting from the Initial Decision. Specifically, the 2009 Application requested that the Commission give Idaho Power the authority to defer the amount related to the difference between the forecasted third-party transmission revenues included in the Company's 2007 Idaho General Rate Case (Case No. IPC-E-07-08) and 2008 Idaho General Rate Case (Case No. IPC-E-08-10) and those third-party transmission revenues actually received by the Company until such time as the test year was updated and rates were changed, which occurred on June 1, 2010. At the time of the 2009 Application, the Company estimated total unrecovered transmission revenues for the Idaho jurisdiction through May 31, 2010, at $8,084,251.

3. On October 30, 2009, the Commission issued Order No. 30940 granting Idaho Power's request for deferral of the total estimated unrecovered transmission revenues in the amount of $8,048,251. Order No. 30940.

4. On October 13, 2010, Idaho Power filed for Commission approval of certain adjustments to the deferral approved by the Commission in Order No. 30940. Case No. IPC-E-10-28. Specifically, Idaho Power sought to adjust the deferral amount downward from the initial estimate of $8,084,251 to $2,064,469 and to authorize the Company to amortize the deferral effective as of January 1, 2012.

5. On February 9, 2011, the Commission issued Order No. 32177 granting Idaho Power's request to reduce the deferral balance to $2,064,469 but denied Idaho Power's request to amortize the deferral effective as of January 1, 2012. Instead, the Commission ordered that Idaho Power be required to advise the Commission when

FERC issued a final order on the Company's Rehearing Petition and to re-submit its request for amortization at that time.

6. On December 27, 2011, FERC issued an Order Denying Rehearing ("FERC Final Order") attached as Attachment No. 1 and incorporated herein by this reference, rejecting all the arguments made by Idaho Power in its Rehearing Petition.

II. <u>REQUEST FOR AMORTIZATION</u>

7. Based on the FERC Final Order, Idaho Power is now seeking approval, consistent with the terms of Commission Order No. 32177, to begin the three-year amortization of the deferral amount and to increase the annual revenue recovered from customers by $688,156 effective on June 1, 2012.

8. As a result of the amortization period, the Company proposes a uniform percentage increase of 0.08 percent to all customer classes effective June 1, 2012, for service provided on and after that date, as shown in Attachment No. 2, incorporated herein by this reference. Because the increase in the annual revenue requirement is relatively small, the Company is proposing to increase only the energy charges of customer rates.

III. <u>PROPOSED TARIFF</u>

9. As explained above, Idaho Power is proposing rate changes associated with the removal of accelerated depreciation expense associated with non-AMI metering equipment, revised depreciation rates, and the Boardman balancing account in addition to the OATT deferral amortization requested by this Application. In an attempt to satisfy RP 121.01, the Company is filing one set of proposed tariff sheets specifying the proposed rates for providing retail electric service to its customers in the state of Idaho

following the inclusion of all four of the proposed rate changes. The tariffs including all four of these rate adjustments will be filed as Attachment Nos. 2 and 3 to the Company's Application for Authority to Increase Its Rates for Electric Service to Recover the Boardman Balancing Account ("Boardman Application") in both clean and legislative format, respectively.

10. The Company believes that filing individual sets of tariff sheets with each case as required by RP 121.01 would be administratively complex and would not aid the Commission and interested parties with their review of these proposed rate adjustments. Idaho Power considers the filing of one set of tariff sheets with the cumulative impact of the proposed rates will comply with the spirit of the Commission's rule. The Company will make a compliance filing when final orders are received on all proposed requests to change rates effective June 1, 2012. The compliance filing will include tariff sheets that show the cumulative impact of rate changes associated with all four cases.

11. Attachment No. 3 to this Application shows a comparison of revenues from the various tariff customers under Idaho Power's existing rates and charges with the corresponding proposed new revenue levels resulting from the proposed rates from the four cases mentioned above.

12. This Application, together with Attachment Nos. 1, 2, 3, and 4, is filed with the Commission to be kept open for public inspection as required by law, and the same fully states the changes to be made in the rate schedules now in force. The new electric rate schedules contained in Attachment No. 2 to the Company's Boardman Application are requested to become effective June 1, 2012, for services provided on

and after that date, unless otherwise ordered by this Commission, and when effective, will supersede and cancel the present electric rate schedules now in existence.

13. It is in the public interest that the Commission allow Idaho Power to increase its revenues by approving the rates set out in Attachment No. 2 to the Boardman Application and that said rates are allowed to go into effect as filed for electric service rendered on and after June 1, 2012, and that the effective date of said rates not be suspended.

IV. MODIFIED PROCEDURE

14. Idaho Power believes that a hearing is not necessary to consider the issues presented herein and respectfully requests that this Application be processed under Modified Procedure; i.e., by written submissions rather than by hearing. RP 201 *et seq*. If, however, the Commission determines that a technical hearing is required, the Company stands ready to present its testimony and support the Application in such hearing.

V. COMMUNICATIONS AND SERVICE OF PLEADINGS

15. This Application will be brought to the attention of Idaho Power's customers by means of both a press release to media in the Company's service area and a customer notice distributed in customers' bills, both of which are included herein as Attachment No. 4. The customer notice will be distributed over the course of the Company's current billing cycle, with the last notice being sent on March 20, 2012. In addition to describing this filing, these customer communications also describe proposed rate changes associated with the removal of accelerated depreciation associated with non-AMI metering equipment, revised depreciation rates, and the

Boardman Application. Idaho Power will also keep its Application open for public inspection at its offices throughout the state of Idaho. Idaho Power asserts that this notice procedure satisfies the Rules of Practice and Procedure of this Commission; however, the Company will, in the alternative, bring the Application to the attention of its affected customers through any other means directed by this Commission.

16. Communications and service of pleadings with reference to this Application should be sent to the following:

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VI. REQUEST FOR RELIEF

17. Idaho Power respectfully requests that the Commission issue an Order: (1) authorizing that this matter may be processed by Modified Procedure; (2) approving an increase of $688,156 in the annual revenue recovered, which results in a uniform percentage increase of 0.08 percent to all customers; and (3) approving an effective date of June 1, 2012, for the amortization of the deferral and for the new rates.

DATED at Boise, Idaho, this 15th day of February 2012.

JASON B. WILLIAMS
Attorney for Idaho Power Company

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-06

IDAHO POWER COMPANY

ATTACHMENT NO. 1

137 FERC ¶ 61,235
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

Idaho Power Company Docket No. ER06-787-006

ORDER DENYING REHEARING

(Issued December 27, 2011)

1. This order denies Idaho Power's request for rehearing of the Commission's January 15, 2009 order,[1] which affirmed in part and reversed in part the August 31, 2007 Initial Decision in this proceeding.[2] The Initial Decision addressed how certain pre-Order No. 888[3] transmission agreements should be accounted for in Idaho Power's formula rates for point-to-point transmission service and network integration transmission service under Idaho Power's open access transmission tariff (OATT).

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[1] *Idaho Power Co.*, 126 FERC ¶ 61,044 (2009) (Order on Initial Decision).

[2] *Idaho Power Co.*, 120 FERC ¶ 63,014 (2007) (Initial Decision).

[3] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *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 relevant 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).

I. Background

2. The Order on Initial Decision includes a detailed description of Idaho Power's system and the procedural history of this proceeding.[4] Briefly, Idaho Power provides point-to-point transmission service and network integration service to jurisdictional customers pursuant to its OATT.

3. Starting in the 1960s, Idaho Power entered into long-term transmission service agreements with Pacific Power & Light Company (PP&L), Utah Power & Light Company (UP&L), and PacifiCorp.[5] These agreements, referred to as the "Legacy Agreements," include (1) the Restated Transmission Services Agreement Between PacifiCorp and Idaho Power Company (Restated Transmission Agreement), (2) the Transmission Facilities Agreement Between Idaho Power Company, Pacific Power & Light Company, and Utah Power & Light Company (Facilities Agreement), and (3) the Agreement for Interconnection and Transmission Services Between Idaho Power Company and Utah Power & Light Company (Interconnection Agreement). Generally, these agreements were executed to support Idaho Power's and PacifiCorp's (formerly PP&L) efforts to build and operate the Jim Bridger power plant[6] to serve their respective electric loads, to provide transmission service between the Jim Bridger power plant and PacifiCorp's western power loads in Oregon and Washington, and to provide bi-directional service across Idaho Power's lines between PacifiCorp's Wyoming system and its Utah system.[7]

4. The Restated Transmission Agreement provides for PacifiCorp to transfer up to 1,600 MW (currently limited to 1,410 MW)[8] of electric power, including its

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[4] *See* Order on Initial Decision, 126 FERC ¶ 61,044 at P 2-11.

[5] PP&L and UP&L have merged into PacifiCorp.

[6] The Jim Bridger power plant is a four-unit coal-fired electric power plant and related facilities located in Sweetwater County, Wyoming in which Idaho Power has a one-third ownership share and PacifiCorp has a two-thirds ownership share.

[7] The Order on Initial Decision includes a map of the Idaho Power transmission system detailing the principal pathways and interconnections covered by the Legacy Agreements.

[8] The transfer capability is limited to 1,410 MW due to the rating on the transmission limitations west of the Jim Bridger power plant.

share of output from the Jim Bridger station and certain other resources, from the Borah and Kinport points of receipt on Idaho Power's system to PacifiCorp's system at PacifiCorp's 500 kV Midpoint-Summer Lake transmission line and along Idaho Power's Northwest Path. In exchange, PacifiCorp is required to pay Idaho Power periodically for specific facilities that Idaho Power constructed under the agreement and to pay certain other charges. The services Idaho Power provides to PacifiCorp under the Restated Transmission Agreement consist of the "East to West Transfer Service," and "Other Services." The Restated Transmission Agreement remains in effect for the life of the Jim Bridger plant.

5. Under the Facilities Agreement, PacifiCorp can 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 and Idaho Power charges PacifiCorp "use of facilities" fees. The Facilities Agreement was executed in June 1974 with a 50-year term, subject to automatic renewals and a 5-year notice of termination.

6. Under the Interconnection Agreement, UP&L constructed a 345 kV transmission line running from Ogden, Utah to Idaho Power's system at Borah and Idaho Power built interconnection facilities at Borah. The Interconnection Agreement provides PacifiCorp with 250 MW of capacity and requires PacifiCorp to pay Idaho Power for the cost of the facilities constructed to establish the interconnection at Borah, as well as "use of facilities" charges for specific Idaho Power facilities along the contract path. The Interconnection Agreement was entered into on March 19, 1982 and continues until June 1, 2025.

7. Originally, Idaho Power's transmission rates were based on specific, "stated" rates for point-to-point service and network integration transmission service.[9] On March 24, 2006, under section 205 of the Federal Power Act (FPA),[10] Idaho Power submitted revisions to its OATT proposing to implement formula rates in place of its stated rates. On May 31, 2006, the Commission issued an order accepting and suspending Idaho Power's filing, subject to refund, establishing hearing and settlement judge procedures, and directing Idaho Power to submit compliance filings.[11] Subsequently, an uncontested partial settlement resolved all issues except how the Legacy Agreements should be accounted for in

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[9] *See Idaho Power Co.*, 76 FERC ¶ 61,276 (1996).

[10] 16 U.S.C. § 824d (2006).

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

Idaho Power's formula rates.[12] On August 31, 2007, after a hearing on the ratemaking treatment of the Legacy Agreements, the Presiding Judge issued the Initial Decision. Subsequently, upon consideration of briefs on exceptions and briefs opposing exceptions filed by Idaho Power, "Intervenors,"[13] and Commission trial staff (Staff), the Commission issued the Order on Initial Decision affirming the Presiding Judge's determination that the transmission service under the Legacy Agreements must be accounted for in the Idaho Power formula rate by including the associated demands in the divisor of the formula rate (i.e., cost allocated). However, the Commission reversed the Presiding Judge's determination that the appropriate method for incorporating PacifiCorp's demand associated with the Legacy Agreements into the OATT formula rates is to include PacifiCorp's 12 coincident peak usages[14] in the divisor of the formula. Instead, the Commission found that the long-term firm contract demands under the Legacy Agreements should be used.

8. On February 17, 2009, Idaho Power filed its request for rehearing (Request for Rehearing), arguing that the Commission erred in requiring Idaho Power to cost allocate demand associated with the Legacy Agreements rather than account for the Legacy Agreements by including the Legacy Agreements' revenues in the numerator of its formula rate (i.e., treating them as a revenue credit). Idaho Power also alleges error in the Commission's determination that the contract demands associated with the Legacy Agreements, rather than the "12 coincident peak demands, should be included in the OATT formula rate divisor. Idaho Power attached a Report and Affidavit of Dr. John R. Morris as Appendix D

[12] *See Idaho Power Co.*, 120 FERC ¶ 61,144 (2007) (approving uncontested partial settlement).

[13] The Intervenors are Bonneville Power Administration, 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, Idaho Energy Authority, and Pacific Northwest Generating Cooperative.

[14] "Coincident peak demand" is the customer's usage of the transmission system at the time of the transmission provider's maximum (i.e., "peak") demand, while a transmission customer's "usage" is its scheduled demands. 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." *See* Order on Initial Decision, 126 FERC ¶ 61,044 at P170 n.313.

(Morris Affidavit) to its request for rehearing. Indicated Intervenors[15] filed a motion to strike the Morris Affidavit, Idaho Power filed an answer to the motion to strike, and Indicated Intervenors filed an answer to Idaho Power's answer.

9. Additionally, on June 19, 2009 in Docket No. ER09-1335-000, Idaho Power submitted a section 205 filing revising the Interconnection Agreement to make the rates under that agreement consistent with the cost allocation required by the Order on Initial Decision and to align the charges in the Interconnection Agreement to the charges contained in Idaho Power's OATT.[16] The Commission approved a settlement resolving all of the issues in that proceeding.[17]

10. On August 10, 2011, Idaho Power filed a Motion for Prompt Resolution of Pending Rehearing Request.

II. Discussion

A. Morris Affidavit

1. Motion to Strike and Answers

11. In their motion to strike, Indicated Intervenors argue that the Morris Affidavit introduces new facts and arguments from a new source after the June 26, 2007 close of the record, and is, therefore, impermissible extra-record evidence. Indicated Intervenors argue that such late-filed extra record evidence denies hearing participants the right to submit rebuttal testimony, raise objections, and cross-examine the witness.

12. In its answer, Idaho Power states that it presented the Morris Affidavit to refute the Commission's assertion that the below-cost rates in the Legacy Agreements were not discounted rates. Idaho Power asserts that "[t]his was the first time that anyone in the proceeding had made this claim, so in order to refute it Idaho Power included Dr. Morris's Affidavit with its rehearing petition showing it not to be true."[18] Thus, according to Idaho Power, prior to the Order on Initial

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[15] "Indicated Intervenors" are all of the "Intervenors" listed above except Pacific Northwest Generating Cooperative, Inc.

[16] *See Idaho Power Co.*, 131 FERC ¶ 63,017, at P 2 (2010).

[17] *See Idaho Power Co.*, 132 FERC ¶ 61,060 (2010).

[18] Idaho Power Answer at 2.

Decision, there was no reason for Idaho Power to submit the evidence set forth in the Morris Affidavit. Idaho Power therefore asserts that the Commission should deny the Indicated Intervenors' motion to strike.

13. In response, Indicated Intervenors refute Idaho Power's assertion that neither Staff nor Intervenors alleged at trial that Idaho Power's below-average cost rates did not constitute a discount and that the assertion first surfaced when the Commission issued the Order on Initial Decision.[19] Indicated Intervenors argue that Idaho Power, Staff, and Intervenors addressed the discounting issue in motions, testimony, and briefs throughout the litigation and that the Presiding Judge based his determination upon Commission precedent and record evidence regarding this issue.[20] Referencing portions of the hearing transcript, exhibits, and briefs, Indicated Intervenors assert that the parties, including Idaho Power itself, addressed discounting of the Legacy Agreements.[21]

2. Commission Determination

14. We will strike the Morris Affidavit. Indicated Intervenors have shown that the discounting issue was thoroughly addressed on the record and that the Commission did not create this factor outside of the record, which is the alleged basis for Idaho Power's late-filed proffer of the Moore Affidavit. To accept such an affidavit at this stage would require, in fairness, that the record be reopened to allow other participants to provide rebuttal testimony and to cross-examine the affiant. As the Commission has stated elsewhere, it is reluctant to chase a "moving target" by considering new evidence presented for the first time at the rehearing stage of Commission proceedings.[22] This is particularly the case where a hearing has been conducted before an administrative law judge for the purpose of developing a factual record.[23]

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[19] Indicated Intervenors Answer at 2.

[20] *See id.* (citing Initial Decision, 120 FERC ¶ 63,014 at P 195-206).

[21] *See id.* at 3.

[22] *Boralex Livermore Falls LP*, 123 FERC ¶ 61,279, at P 62 (2008); *Southern Cal. Edison Co.*, 102 FERC ¶ 61,256, at P 17 (2003); *Philadelphia Elec. Co.*, 58 FERC ¶ 61,060, at 61,133 and n.4 (1992).

[23] *AES Ocean Express LLC v. Florida Gas Transmission Co., et al.*, Opinion No. 495-A, 121 FERC ¶ 61,267 (2007) and cases cited therein.

15. Idaho Power appears to have misapprehended the evidence in this .proceeding as well as the Commission's findings. Throughout this proceeding both at the hearing stage and in post-hearing briefs, the parties and Staff provided testimony and evidence regarding whether Idaho Power and PacifiCorp and its predecessors negotiated discounted firm transmission service.[24] The issue regarding whether the Legacy Agreement rates were discounted was thus addressed in motions, testimony, and briefs throughout the litigation. Furthermore, upon examining the entire record and considering witness testimony on the issue, the Presiding Judge found that at the time the Legacy Agreements were first conceived, the rates negotiated were the same as they would have been using rolled-in pricing.[25] The Order on Initial Decision agreed with the Presiding Judge that "the facts and circumstances surrounding the development of the Legacy Agreements do not support that the services under the agreements were inferior services for which a discount was negotiated."[26]

16. Therefore, Idaho Power's allegation that the Morris Affidavit was necessary because the Order on Initial Decision's determination—that the Legacy Agreement rates were not bargained-for discount rates—was the first time anyone had made this assertion is baseless. Accordingly, for the reasons discussed above, we shall strike the Morris Affidavit.

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[24] For example, to refute Intervenors' Witness Daniel's assertion that the pricing in the Restated Transmission Agreement was a trade-off for generation related benefits that Idaho Power received for the construction of the Jim Bridger Project, Idaho Power asserted that:

> Mr. Daniel's argument that Idaho Power reduced the rates to PacifiCorp under the [Restated Transmission Agreement] in return for collateral benefits is inconsistent with other parts of his own testimony. In his testimony, he asserted that the rates in the [Restated Transmission Agreement] cannot be found to represent a "discount" because there was no standardized pricing for unbundled transmission service at the time the [Restated Transmission Agreement] was first entered into. Idaho Power Brief on Exception at 35.

[25] *See* Initial Decision, 120 FERC ¶ 63,014 at P 197-198.

[26] Order on Initial Decision, 126 FERC ¶ 61,044 at P 153.

B. Burden of Proof

1. Rehearing Request

17. Idaho Power argues that "[t]he Commission erred in determining that Idaho Power bears the burden of proving the justness and reasonableness of annually crediting revenues it receives under the Legacy Agreements."[27] Idaho Power renews its argument that it has consistently used the revenue crediting rate practice for over twenty-five years with no objection from the Commission or others and disputes that in changing from stated rates to formula rates it changed the *status quo* and therefore has the burden to demonstrate that its new formula rate is just and reasonable.

18. Idaho Power argues that in *Winnfield v. FERC* "[t]he D.C. Circuit has held that the statutory obligation of a utility filing under Section 205 is 'not to prove the continued reasonableness of *unchanged* rates or *unchanged* attributes of its rate structure,' and that a settled practice can arise from a settlement agreement."[28]

19. Idaho Power also contends that the Commission did not challenge Idaho Power's position that the Commission must consider whether the rates it approves are unduly discriminatory or preferential in relation to the utility's retail rates. According to Idaho Power, the Commission asserted that Idaho Power has not established that its retail and OATT customers are charged comparably. Idaho Power insists that in fact it did establish that its wholesale and retail customers are comparably charged under its revenue crediting proposal.[29] Idaho Power contends that under the Order on Initial Decision, OATT customers are provided comparable service to that provided to retail customers but receive a preferential discount, which violates the FPA and is appropriately remedied by revenue crediting the Legacy Agreements.[30]

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[27] Request for Rehearing at 38.

[28] *See* Request for Rehearing at 39 (citing *Winnfield v. FERC,* 744 F.2d 871, 877 (D.C. Cir. 1984) (*Winnfield*)).

[29] *Id.* at 40.

[30] *Id.* (citing *FPC v. Conway Corp.*, 426 U.S. 271, 278 (1976)).

2. Commission Determination

20. The Commission denies rehearing on this issue. Idaho Power bears the burden of proof under section 205 as a first time formula rate applicant and misapplies the D.C. Circuit's holding in *Winnfield.*

21. When Idaho Power submitted its section 205 filing to change from stated rates to formula rates, Idaho Power changed the *status quo*; therefore, Idaho Power has the burden to demonstrate that its proposed formula rate is just and reasonable, and not unduly discriminatory or preferential.[31] As noted above, Idaho Power's transmission rates for network integration service and point-to-point services were developed as fixed, specific rates stated in its OATT determined in a black box settlement approved by the Commission in 1996. Despite the fact that Idaho Power submitted a section 205 application to change the methodology upon which it sets its OATT rates, Idaho Power's position is that revenue crediting is a settled practice, i.e., the *status quo*; therefore it believes it does not have the burden to prove the justness and reasonableness of that practice, in accordance with the court's holding in *Winnfield.*

22. Idaho Power is mistaken in its reliance on *Winnfield.* There the utility submitted an FPA section 205 application proposing a new "incremental cost" rate methodology. In that case, the Commission affirmed the judge's finding that the proposed new incremental cost rate methodology was unjust and unreasonable and that a rate increase under the existing "average cost" rate methodology was the just and reasonable rate. On appeal, an intervenor argued that this rate increase could not be imposed because the utility had not met its burden of proof under section 205 of the FPA to show the justness and reasonableness of the rate increase. In rejecting the intervenor's argument, the court found that "[t]he statutory obligation of the utility, however, is not to prove the continued reasonableness of *unchanged* rates or *unchanged* attributes of its rate structure."[32] The court further explained that

> [i]n this case, then, the utility had the burden of proving that its proposed new method of incremental cost rate computation was just and reasonable—a burden it was not able to sustain. It did not have the

[31] Order on Initial Decision, 126 FERC ¶ 61,044 at P 18.

[32] *Winnfield,* 744 F.2d 871 at 877.

> burden of proving the justness and reasonableness of the method of average cost rates already in place.[33]

23. Thus, the issue on appeal in *Winnfield* was whether an electric utility could meet its burden of proof under section 205 where Commission staff, not the utility, presented evidence in support of a rate change.[34] The court held that "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."[35] Thus, in *Winnfield* the court addressed the Commission's authority to increase a utility's rates in order to set a just and reasonable rate under an existing rate methodology after having found the utility's proposed change in rate methodology to be unjust and unreasonable.[36] Here, the issue is the justness and reasonableness of a change in rate methodology from one based on fixed, stated rates to formula rates. As the Presiding Judge stated

> 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

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[33] *Id.*

[34] *See Complex Consol. Edison Co. v. FERC*, 165 F.3d 992, 1008-1009 (D.C. Cir. 1999) (citing *Winnfield*, 744 F.2d 871 at 876).

[35] *Winnfield*, 744 F.2d 871 at 877.

[36] *See Winnfield*, 744 F.2d 871 at 875 ("The structure of the Act, however, is not 'undermined' or even threatened when, in a § 205 proceeding, the Commission declines to permit a new form of rate calculation but grants a rate increase under the form the utility had previously been using, which increase *the utility accepts*.").

> the annual revenue-crediting of the Legacy Agreements, rests with Idaho Power.[37]

24. Accordingly, *Winnfield* is inapposite because Idaho Power has the burden under section 205 of the FPA to support the justness and reasonableness of its new formula rate methodology.

25. Nor is Idaho Power's related argument in support of revenue crediting—namely that cost allocating the Legacy Agreements results in a preferential discount to its OATT customers—valid. When Idaho Power chose to submit its section 205 filing to change from fixed, stated rates to formula rates, the pre-existing rate methodology, including revenue-crediting the Legacy Agreements, ceased to exist, and even though revenue crediting was a proposed component of the new formula rate structure, it was open to fresh examination by the Presiding Judge and the Commission. This examination revealed that revenue crediting the Legacy Agreements under the new formula rate would require third-party OATT customers to bear a disproportionate share of the costs of Idaho Power's system, contrary to the cost-causation principle.[38] Substantial evidence was presented showing that the Legacy Agreements account for approximately 40 percent of the wholesale load on Idaho Power's network and Idaho Power uses approximately 45 percent of its network to serve its retail customers. On the other hand, Idaho Power's third-party OATT customers' firm usage accounts for only 15 percent.[39] As the Presiding Judge found and the Commission affirmed, applying the fact-specific, case-by-case approach mandated by Order No. 888, as

[37] Initial Decision, 120 FERC ¶ 63,014 at P 104.

[38] *See Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004) (*Midwest ISO TOs v. FERC*) (the court determines compliance with the principle of cost causation "by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party"); *California Power Exchange Corp.*, 106 FERC ¶ 61,196, at P 17 (2004) ("[t]he well-established principle of cost causation" requires allocation of costs, "where possible, to customers based on customer benefits and cost incurrence"); *California Indep. Sys. Operator Corp.*, 106 FERC ¶ 61,032, at P 10 (2004) ("while the fundamental idea of matching costs with customers is often referred to in terms of cost causation, it has also been described in terms of the costs which should be borne by those who benefit from them") (internal quotations omitted).

[39] Initial Decision, 120 FERC ¶ 63,014 at P 174-175.

clarified in Order No. 888-A,[40] the basic principles linking cost causation with cost responsibility and barring cross-subsidization between customer classes militate against revenue-crediting the Legacy Agreements; rather, they support cost-allocating the service under those agreements.[41] Based on the evidence presented in this record, we find that cost allocating the service under Legacy Agreements is just and reasonable because it treats all customer classes equally, and prevents any customer class from bearing a disproportionate share of Idaho Power's costs. Accordingly, we deny rehearing on the issue.

C. Non-monetary Benefits

1. Rehearing Request

26. Idaho Power asserts that the Commission erred by failing to consider evidence it proffered regarding the non-monetary benefits it receives from PacifiCorp under the Legacy Agreements. According to Idaho Power, "[t]he Order does not address the sufficiency of this evidence. It concludes that it need not reach it, because the rates in the agreements, which are determined by a fixed formula that provides for the rates to decline over time for very long terms, are not 'discounted' rates."[42] Idaho Power argues that the Commission's findings are contrary to Commission precedent. Idaho Power reiterates its argument that in *IES Utilities, Incorporated*[43] the Commission found that the rate applicant should not be required to add 625 MW of service to its rate divisor because the service involved reciprocal services provided by the customer.[44] Idaho Power contends that the Commission dismissed *IES Utilities* because Idaho Power had not shown that it negotiated for specific benefits other than monetary compensation.[45]

[40] *See* Order on Initial Decision, 126 FERC ¶ 61,044 at P 19 (citing Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,256).

[41] Initial Decision, 120 FERC ¶ 63,014 at P 176.

[42] Request for Rehearing at 6 (citing Order on Initial Decision, 126 FERC ¶ 61,044 at P 153-155).

[43] 80 FERC ¶ 63,001 (1997) (*IES Initial Decision*), *aff'd in relevant part*, 81 FERC ¶ 61,187 (1997), *reh'g denied*, 82 FERC ¶ 61,089 (1998) (*IES*).

[44] *See* Request for Rehearing at 7.

[45] *Id.* at 8 (citing Order on Initial Decision, 126 FERC ¶ 61,044 at P 155).

27. Idaho Power also argues that the Commission similarly dismissed *Arizona Public Service Company*[46] on factual grounds irrelevant to the ratemaking principle involved. Idaho Power argues that in *APS* the Commission rejected the allocation of average system costs to the service at issue and approved the company's revenue crediting proposal where the service provider received benefits from the transaction other than monetary compensation.[47]

28. In addition, Idaho Power contends that the Commission disregarded the language of the Restated Transmission Agreement and other evidence regarding the non-monetary benefits Idaho Power received from PacifiCorp. Idaho Power states that the Commission summarized the evidence in a footnote but the Commission then refused to consider the evidence.[48] Idaho Power reiterates its argument that the non-monetary compensation it received was central to the agreements and was taken into account in arriving at the rates under the Legacy Agreements.[49] According to Idaho Power, the Restated Transmission Agreement is explicit that Idaho Power would not have provided service at the charges set forth without this additional compensation.[50]

29. Next, as it did in its brief on exceptions, Idaho Power describes the features of the Legacy Agreements it asserts are non-monetary benefits. Specifically, Idaho Power states that under the Restated Transmission Agreement and Facilities Agreement, the entire eastern side of Idaho Power's system was expanded and rebuilt, and PacifiCorp constructed a major regional 500 kV line paralleling Idaho Power's system. Idaho Power maintains that the contractual restrictions on PacifiCorp's use of the Idaho Power system under the Restated Transmission Agreement means that capacity created by the construction of these facilities is available for OATT customers when PacifiCorp is not using the capacity. Idaho Power states that under the Interconnection Agreement, PacifiCorp (previously, UP&L) constructed an interconnection at Borah that improved the reliability of the Idaho Power transmission system and provided an additional interconnection

[46] 18 FERC ¶ 61,197, at 61,394-5 (1982) (*APS*).

[47] Request for Rehearing at 9.

[48] *Id.* at 8 (citing Order on Initial Decision, 126 FERC ¶ 61,044 at P 142 n.267).

[49] *Id.* at 9-10 (citing Ex. IPC-28 at 30:10-16).

[50] *Id.* (citing Restated Transmission Agreement section 2.5).

for transmission transactions. Idaho Power adds that the additional capacity created by the Legacy Agreements and transmission service provided to Idaho Power under the Facilities Agreement relieved Idaho Power from having to build new capacity, the cost of which would have been included in Idaho Power's OATT transmission rates. Idaho Power concludes that its OATT rates would be higher in the absence of the Legacy Agreements.

30. Idaho Power also renews its argument that at the time the Legacy Agreements were entered into, the prevailing flows on the Idaho Power system were strongly west to east while the services provided under the Restated Transmission Agreement are east to west. According to Idaho Power, under the Restated Transmission Agreement PacifiCorp is penalized if it does not schedule sufficient power to create this counter-flow effect. Idaho Power states that although counter-flows do not increase Total Transfer Capability, they relieve congestion on key parts of the Idaho Power system, creating more capacity that is available on a non-firm basis, and reducing average system losses on the Idaho Power system thereby reducing the cost of transmission service for OATT customers.[51]

31. Additionally, Idaho Power states that PacifiCorp's use of the Idaho Power transmission system is limited to the purposes defined in the Legacy Agreements (e.g., the transfer of power generated at Jim Bridger) and PacifiCorp cannot resell the services. Idaho Power contends that the Legacy Agreements services are more restrictive than OATT service in a variety of ways.[52]

32. Idaho Power also argues that while the Commission treated the Facilities Agreement as if Idaho Power were providing transmission service for free, Idaho Power receives reciprocal transmission service which makes the transaction similar to the one in *IES Utilities* except that Idaho Power also charges PacifiCorp for the cost of facilities constructed under that agreement.[53] Idaho Power states that it provides 250 MW of transmission service to PacifiCorp, and, in exchange, PacifiCorp provides over 700 MW of transmission service to Idaho Power, without charge under the Facilities Agreement. Idaho Power argues that the

[51] *Id.* at 14.

[52] *Id.* at 15. In Attachment B to its Request for Rehearing, Idaho Power provides a summary of the portion of its brief on exceptions describing what it considers are the differences between OATT and Legacy Agreement services.

[53] *See id.* at 16.

Commission treated this transaction as if no reciprocal services were provided and that such treatment is arbitrary and capricious.[54]

33. In addition, Idaho Power argues that the Commission's finding that revenue crediting the Legacy Agreements amounts to a subsidy to PacifiCorp is irreconcilable with its finding that the non-monetary compensation Idaho Power received under the agreements cannot be considered in determining the OATT rate because the rates for the Legacy Agreement services were not discounted.[55] According to Idaho Power, "the Commission's efforts to conclude that the rates to PacifiCorp are simultaneously undiscounted and subsidized are merely 'semantic somersaults' that do not look to the substance of the issues."[56] Idaho Power states that in common parlance, a rate that is below cost is discounted. Idaho Power contends that "[f]or the Commission to find that a rate is below cost, based on an analysis that ignores evidence of substantial non-monetary consideration on the ground that the rate is not 'discounted,' is arbitrary, capricious, and a departure from reasoned decisionmaking."[57]

2. <u>Commission Determination</u>

34. In promulgating Order No. 888 the Commission sought to ensure that transmission service was provided in an open, non-discriminatory basis, at just and reasonable rates.[58] The Commission also recognized that transmission providers had pre-existing contractual obligations for transmission service over

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[54] *See id.*

[55] *See id.* at 19.

[56] *Id.* 19-20 (citing *Chlorine Chemistry Council v. EPA*, 206 F.3d 1286, 1291 (D.C. Cir. 2000)).

[57] *Id.* at 21.

[58] *See Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, at P 14, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009) (Order No. 890) (describing open access and unbundling requirements of Order No. 888).

their systems.[59] The Commission prescribed in Order No. 888 the rules for transmission providers to file open access transmission tariffs that contained minimum terms and conditions for non-discriminatory service and to "functionally unbundle" their generation and transmission services, while providing sufficient flexibility to accommodate existing, transmission service arrangements. In addition, with respect to pre-existing transmission service agreements, the Commission did not establish a bright-line test for determining how a particular grandfathered service should be accounted for in a transmission provider's OATT rates. Instead the Commission held that such a determination was to be made on a fact-specific, case-by-case basis.[60] Accordingly, whether or not the parties to the Legacy Agreements bargained for a discounted rate in reliance on non-monetary benefits is part of the inquiry; however, a complete analysis requires a review of all of the circumstances on a fact-specific, case-by-case basis.

35. Idaho Power contends that the Commission failed to consider the evidence it proffered regarding the Legacy Agreements' non-monetary benefits, and therefore erred by determining that the Legacy Agreement charges should be cost-allocated rather than revenue-credited. As the Commission noted in the Order on Initial Decision, the Presiding Judge discussed in detail the benefits and burdens Idaho Power asserted were part of the bargained-for transactions underlying the Legacy Agreements.[61] Although the Commission summarized the evidence Idaho Power proffered[62] instead of restating the details provided in the Initial Decision, this does not mean that the Commission failed to consider whether the asserted benefits were relevant to the question of how the grandfathered agreements should be accounted for in this particular case. To the contrary, the Commission affirmed the Presiding Judge's determination, based on substantial record evidence, that the facts and circumstances surrounding the development of the Legacy Agreements did not support Idaho Power's argument that the services

[59] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,665; Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,189.

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

[61] Order on Initial Decision, 126 FERC ¶ 61,044 at P 153 (citing Initial Decision, 120 FERC ¶ 63,014 at P 184-193).

[62] *See id.* P 142 n.267 (describing the specific benefits and burdens Idaho Power asserts PacifiCorp and Idaho Power considered in executing the Legacy Agreements).

under the Legacy Agreements were inferior services for which a discount was negotiated.[63] Upon consideration of the record, the Presiding Judge determined that the compensation under the Legacy Agreements was determined through an arms-length transaction that took the benefits and burdens of the agreements into account at the time the agreements were negotiated and that Idaho Power and PacifiCorp did not bargain for any discount under the Legacy Agreements.[64]

36. The Presiding Judge found that under Commission pricing policy at the time that the Legacy Agreements were conceived (as well as now), 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 based on the higher of incremental expansion costs or a rolled-in embedded cost rate.[65] Based on the cost and revenue data provided by the parties, the Presiding Judge found that 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.[66] Accordingly,

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[63] Order on Initial Decision, 126 FERC ¶ 61,044 at P 153.

[64] *Id.* P 141.

[65] *See* Initial Decision, 120 FERC ¶ 63,014 at P 197 (*citing 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); *Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act; Pricing Policy Statement*, FERC Stats. & Regs. ¶ 31,005, at 31,137-38 (1994); Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,268).

[66] *Id.* P 198. The Presiding Judge reviewed testimony of Idaho Power's Witness Schellberg and found that based on a reasonable estimate of what Idaho Power's rolled-in transmission rate would have been in 1980, $6.1 million would have been raised under the Legacy Agreements. He also found that if $4.2 million in carrying costs for the Midpoint 345/500 kV switchyard (which PacifiCorp built and transferred to Idaho Power in 1988) were taken out of the figure in order to make it comparable to the service under the Legacy Agreements, 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. *Id.* (*citing* Ex. IPC-57).

although the Legacy Agreements charges currently raise less revenue than a fully rolled-in rate charge would, they did not do so when the Legacy Agreements originally were conceived.[67] Thus, no discount for "inferior service" was necessary, nor is there any evidence that any such discount was agreed to. The Presiding Judge also stated that presumably, the Legacy Agreements made economic sense to the parties at the time at the agreed-upon rates and he reasonably concluded that there was "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.'"[68] Further, he notes that

> as Idaho Power observes, none of the individuals that negotiated the Legacy Agreements were present in this case and most of them are not even alive. All we know is that the Legacy Agreements brought to these entities the benefits 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.[69]

We find that the totality of the evidence in the record supports the Presiding Judge's finding and re-affirm his determination.

37. Furthermore, Idaho Power misreads *IES* and *APS*. First, Idaho Power ignores the specific facts in *IES* that make it inapposite here. As the Presiding Judge observed, *IES* involved the merger of three utilities into a holding company and the formation of an Independent System Operator.[70] In *IES*, one of the merger applicants jointly owned generating plants with third-parties under a joint power supply agreement that governed the equitable sharing of generation and transmission costs associated with the plants and the applicant delivered output to

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[67] *Id.* P 199.

[68] Initial Decision, 120 FERC ¶ 63,014 at P 202.

[69] *Id.* P 199-200 (*citing* Idaho Power Reply Brief 25).

[70] Initial Decision, 120 FERC ¶ 63,014 at P 204 (*citing IES Initial Decision* 80 FERC ¶ 63,001 at 65,007).

the other owners without charge.[71] In that case, an intervening party proposed that the merger applicants increase their transmission rate divisor by 625 MW for output from the jointly-owned generating plants. The applicants argued that the delivery obligation was not long-term firm delivery service, and therefore, if anything, only revenue-crediting was necessary. Finding the applicants' evidence on how the jointly owned transmission facilities were owned and operated to be persuasive, the judge held that the intervenor's proposed adjustment was unwarranted and, therefore, found it unnecessary to address the applicant's revenue credit counter-proposal.[72] Accordingly, the judge there did not reach the question of whether revenue crediting or cost-allocating was appropriate where a transmission provider argues it receives non-monetary benefits under a grandfathered transmission service agreement.

38. In affirming this portion of *IES Initial Decision*, the Commission did not determine whether the asserted benefits should be considered because the Commission found that, under the circumstances of that case, such a determination could not be made without considering offsetting adjustments, which in that case were best made under a regional solution.[73]

39. Despite Idaho Power's allegations, the Commission did not treat the Facilities Agreement as if Idaho Power were providing transmission service for free. *IES* does not foreclose the Commission from considering whether non-monetary consideration should be factored into determining how a grandfathered transmission service agreement is accounted for in an OATT formula rate; however, a proper analysis requires a review all of the circumstances in a particular case pursuant to Order No. 888.

40. Second, we affirm our finding that *APS* is inapposite. In that case, the transmission provider and a customer entered into negotiations for the construction and operation of a generating plant. The customer agreed to this arrangement primarily in exchange for a wholesale power supply agreement guaranteeing "wholesale bus bar rates" based on the costs of plant for power supplied to the customer.[74] The Commission found that under the agreement, the

[71] *IES Initial Decision*, 80 FERC ¶ 63,001 at 65,007.

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

[73] Order on Initial Decision, 126 FERC ¶ 61,044 at P 155 (citing *IES*, 81 FERC ¶ 61,187 at 61,832-33).

[74] *APS*, 18 FERC ¶ 61,197 at 61,394.

customer had specific entitlements to a portion of the generating plant's capacity and that the rates to the customer would be based on capital costs and operating costs incurred at the plant. The customer took delivery of virtually all of its power at a 69 kV connection point adjacent to the plant. In reversing the *APS* judge's disallowance of the utility's revenue-crediting proposal, the Commission stated:

> The judge's decision reflects the apparent belief that NTUA [the customer] should be allocated system-wide production and transmission costs as is the case with requirements customers. We do not agree. The Wholesale Power Supply Agreement provides that NTUA is entitled to a wholesale bus bar rate based on the costs of the Four Corners Plant. Thus, the demand and energy cost for NTUA should be based on costs related to the Four Corners Plant and not costs based on average system costs as assumed by the Judge.[75]

41. In *APS*, the Commission found revenue crediting to be appropriate under the circumstances existing in that case; however, it did not come to that conclusion solely based on the non-monetary benefits the transmission provider received. Rather, the Commission's determination was based on all of the circumstances of that case, including the fact that the agreement called for wholesale bus bar rates based on the costs of the generating plant.

42. In sum, the Commission affirms the Presiding Judge's finding that the record does not support a finding that the Legacy Agreement services are inferior services for which a discount was negotiated, and his finding that a subsidy would arise under Idaho Power's revenue-crediting proposal. These findings are reasonable and correct, and not mutually exclusive. As discussed above, the rates under the Legacy Agreements would have been the same under a rolled-in or an incremental rate design, and thus did not clearly reflect any bargained-for discount. Although the Legacy Agreements service fees currently raise less revenue than a fully rolled-in rate charge would, they did not do so when the Legacy Agreements were originally conceived. Given this current gap between the fees Idaho Power receives from PacifiCorp and a fully rolled-in rate charge, revenue crediting would result in third-party OATT customers bearing a disproportionate share of Idaho Power's transmission system costs for the relative

[75] *Id.* at 61,395.

burden they place on Idaho Power's system. Therefore, we deny rehearing on this issue.

D. Curtailment Priority

1. Commission Precedent

a. Rehearing Request

43. Idaho Power argues that this is the first case since Order No. 888 in which the Commission has considered a factor other than priority relative to native load to establish whether a transmission service is firm for ratemaking purposes. Idaho Power also argues that the Commission found that the Legacy Agreements services "can be treated as firm transmission service because the services are only curtailable prior to native load during 'abnormal system conditions' on the Idaho Power system."[76] In Idaho Power's view, this is the first time that the Commission has found that services will be considered less than firm only if they are curtailable prior to native load during normal system conditions.[77] Idaho Power adds that the evidence showed and the Order on Initial Decision acknowledged that the Legacy Agreement services are curtailable before native load and firm OATT service.

44. In addition, Idaho Power states that the Commission conceded that in at least one case (i.e., *New England Power*[78]) the Commission found that transmission service with a priority below native load is not firm but in the Order on Initial Decision, without explanation, the Commission found that *New England Power* was not dispositive.[79]

45. Idaho Power also asserts that in *QST Energy Trading Inc. v. Central Illinois Public Service Company*,[80] the Commission found that a service that is

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[76] Request for Rehearing at 22-23 (citing Order on Initial Decision, 126 FERC ¶ 61,044 at P 37, 46).

[77] *Id.* at 23.

[78] *New England Power Co.*, 49 FERC ¶ 61,129, at 61,554 (1999) (*New England Power*).

[79] Request for Rehearing at 23 (citing Order on Initial Decision, 126 FERC ¶ 61,044 at P 99).

[80] 85 FERC ¶ 61,166 (1998) (*QST*).

provided subject to curtailment before native load in the event of a particular contingency is not firm transmission service. Similarly, Idaho Power disputes the Commission reading of *American Electric Power Company*,[81] arguing that at the time of that case the Commission defined firm service as service with a curtailment priority equal to firm native load.[82]

46. Additionally, Idaho Power argues that the Commission distinguished *Northeast Utilities Service Company*[83] because the service in *NU* was curtailable to serve native load in both normal as well as emergency conditions. Idaho Power insists that "the unambiguous holding of *NU* was that if the service was curtailable before native load *for any reason*, it was a form of non-firm service."[84] Idaho Power argues that the facts of that case clearly demonstrate that the service was not curtailable during normal conditions. Idaho Power also argues that in *Cleveland Electric Illuminating Company v. City of Cleveland, Ohio*[85] the Commission and the parties characterized the service as less than firm because the service could be curtailed prior to native load.

47. Idaho Power also argues that the Commission appears to establish for the first time a distinction between firm service for ratemaking purposes and firm service for other unidentified purposes.[86] According to Idaho Power, Commission precedent provides that ratemaking for a service should reflect the quality of the service. Idaho Power argues that in *Northern States Power Company v. FERC*,[87] the court directed the Commission to permit the

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[81] 88 FERC ¶ 61,141 at 61,449 (1999) (*AEP*).

[82] Request for Rehearing at 24 n.17.

[83] Opinion No. 422-A, 84 FERC ¶ 61,159 (1998) (*NU*).

[84] Request for Rehearing at 26 (citing *NU*, 84 FERC ¶ 61,159 at 61,867) (emphasis added by Idaho Power).

[85] 75 FERC ¶ 61,258 (1996) (*Cleveland*).

[86] Request for Rehearing at 27 (citing Order on Initial Decision, 126 FERC ¶ 61,044 at P 94).

[87] *Northern States Power Co.*, 83 FERC ¶ 61,098, *clarified*, 83 FERC ¶ 61,338, *reh'g, clarification and stay denied*, 84 FERC ¶ 61,128 (1998), *rev'd*, *Northern States Power Co. v. FERC*, 176 F.3d 1090 (8th Cir. 1999) (*NSP v.*

(continued...)

transmission service provider to provide firm OATT service on a priority that was curtailable in order to maintain physical service to retail load, in circumstances where the OATT service could be curtailed without causing any shedding of load.[88] According to Idaho Power, on remand, the Commission characterized this as a very narrow circumstance, such that the curtailment priority for OATT service was nearly the same as native load but the Commission made clear that this slightly lower priority service could not be treated the same as firm service for ratemaking purposes.[89] Idaho Power argues that "by requiring the Legacy Agreement services to be included in the divisor, the Commission assumes that the service is not inferior and should have been provided at the OATT rate, which the NSP Remand shows the Commission would not even have allowed."[90] Idaho Power concludes that the Commission found that transmission service that has a priority even slightly below that of native load priority is not comparable and has to be discounted.[91]

b. **Commission Determination**

48. In considering whether the Legacy Agreement services should be considered "firm" or "non-firm" in the context of this formula rate proceeding, the Commission affirmed the Presiding Judge's distinction between service interruption and curtailment. Specifically, he explained that it is consistent with industry practice to consider service "firm" where it is curtailed only in abnormal system conditions—such as to preserve reliability in outage or crisis situations—and to consider a service "non-firm" where it is not only curtailable for reliability

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FERC), *on remand, Northern States Power Co. Minn.*, 89 FERC ¶ 61,178 (1999) (*NSP Remand*), *accepting withdrawal*, 89 FERC ¶ 61,299 (*NSP Withdrawal*).

[88] *See* Request for Rehearing at 27 (citing *NSP Remand*, 89 FERC ¶ 61,178 at 61,553).

[89] *Id.*

[90] *Id.* at 28.

[91] *See id.* at 28-30.

reasons, but also interruptible for economic reasons during normal system conditions.[92]

49. Although curtailment of service is one relevant factor that the Commission has considered in examining how a particular pre-Order No. 888 transmission service should be treated in a transmission provider's OATT rates, the Order No. 888 mandated case-by-case inquiry does not end with consideration of that one factor. Here, we affirmed the Presiding Judge's well-reasoned, fact-specific

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[92] Order on Initial Decision, 126 FERC ¶ 61,044 at P 46. Notably, the Order No. 888 *pro forma* OATT also makes this distinction, describing curtailment and interruption of non-firm service as:

> The Transmission Provider reserves the right to *Curtail,* in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for reliability reasons when, an emergency or other unforeseen condition threatens to impair or degrade the reliability of its Transmission System. The Transmission Provider reserves the right to *Interrupt*, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff 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. Order No. 888 *pro forma* OATT, section 14.7 (Curtailment or Interruption of Service (emphasis added).

In contrast, the equivalent provision for firm OATT service indicates, in pertinent part:

> In the event that a Curtailment on the Transmission Provider's Transmission System, or a portion thereof, is required to maintain reliable operation of such system, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. Order No. 888 *pro forma* OATT at section 13.6 (Curtailment of Firm Transmission Service).

determination that based on the totality of record evidence, the Legacy Agreements services are firm services,[93] which means they should be cost-allocated, rather than revenue-credited. Nevertheless, we shall re-examine the cases upon which Idaho Power relies on exceptions.

50. With regard to *New England Power*, a transmission service agreement contained a provision under which the transmission service provider was required to transmit power subject to its use of its system for transmission of electricity for sale to its customers and any transmission agreements already in existence.[94] In an initial order in that proceeding, the Commission found that "the service NEP offered to the Towns had 'a firmness approaching that of NEP's native load,'"[95] which parties in a subsequent litigation interpreted to mean that the service was firm service. In vacating its previous findings regarding the nature of the service at issue, the Commission stated that it had previously compared the curtailment language in the agreement to the transmission provider's existing nonfirm transmission tariff, and acknowledged that both services were interruptible and subordinate to its native load.[96] The Commission went on to state:

> However, we note that the curtailment language in the Agreement further specifies that service is interruptible whenever the Niagara Mohawk *interconnection* is constrained. In contrast, under NEP's existing nonfirm transmission tariff, service is interruptible only if there is insufficient transmission capacity to accommodate the transmission requirements of NEP's system, i.e., whenever the *system* is constrained. Depending upon circumstances, a transmission constraint at a particular point of

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[93] As we found in the Order on Initial Decision, Additional East to West Transfer Service and Other Services is a non-firm component of East to West Transfer Service that does not so impair East to West Transfer Service as to render that entire service non-firm. Order on Initial Decision, 126 FERC ¶ 61,044 at P 75. Similarly, on the totality of the evidence, we found that characterizing the "Other Services" as non-firm does not render the rest of Restated Transmission Agreement service non-firm for ratemaking purposes. *Id.* P 84.

[94] *See New England Power*, 49 FERC ¶ 61,129 at 61,551.

[95] *New England Power*, 49 FERC ¶ 61,129 at 61,553.

[96] *See id.* at 61,554

> interconnection may render service less firm and even more susceptible to interruption than it would be if other transmission paths were available.[97]

51. There, the Commission found the relevant comparison to be between non-firm service under the transmission provider's tariff and the service under the agreement, which the Commission found had a lower curtailment priority than non-firm service.[98] This does not mean that a service that is marginally subordinate to native load must be deemed non-firm and subject to revenue crediting, where an Order No. 888 case-specific analysis shows it unreasonable to do so.

52. In *QST*, the customer wanted the utility to provide it with "firm" OATT transmission service even though the service would be subject to curtailment in the event of a particular system contingency. There, the Commission stated:

> In essence, QST argues that Central Illinois should provide QST "firm" transmission service until Central Illinois has such an outage. At that point, QST argues that 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. In this scenario, the transmission service that QST requests is not firm service -- it is nonfirm service, the terms and conditions for which are already specified in the pro forma tariff.[99]

53. Contrary to Idaho Power's arguments, in *QST* the Commission discussed curtailment as a result of an outage (i.e., reliability reasons) but did not discuss whether or not the service at issue could be interrupted for economic reasons as interruptible transmission service. Accordingly, *QST* does not support Idaho Power's theory that transmission service that is subject to curtailment before native load or OATT firm service should be revenue-credited.

54. Likewise, Idaho Power's reading of *AEP* is incorrect. Order No. 888-A clarified that the determination of how a particular grandfathered service should

[97] *Id.*

[98] *See id.*

[99] *QST*, 85 FERC ¶ 61,166 at 61,666.

be accounted for in a transmission service provider's tariff is to be made on a fact-specific, case-by-case basis.

55. Idaho Power is also mistaken that "the unambiguous holding of *NU* was that if the service was curtailable before native load *for any reason*, it was a form of non-firm service."[100] There, the judge found the transmission service agreement specified that under normal as well as emergency conditions the service to the customer was of a lower priority than service to NU's native load and its "transmission dependent utilities," which were utilities whose retail loads are served directly from NU's transmission or distribution system.[101] There was no question about whether or not the service could be curtailed for reliability purposes or interrupted for economic reasons. In affirming the judge's decision, the Commission found that the judge "correctly recognized that the 'preferred' service at issue in this proceeding is between firm and non-firm" and that "[w]hether or not the service has ever actually been interrupted is not controlling because NU has the contractual right to curtail service."[102] However, nowhere in that case did the judge or the Commission create a bright-line rule that a service that is curtailable before native load for any reason must be deemed non-firm service. Accordingly, *NU* does not stand for the proposition that to be deemed "firm," a service must have priority equal or greater than native load.

56. Likewise, *Cleveland* does not support Idaho Power's argument. As the Commission found in the Order on Initial Decision, in that case the customer itself acknowledged that it contracted for services that "are less than fully firm and can be interrupted under specified conditions."[103] While the Commission there confirmed that "[n]on-firm or interruptible service may be curtailed before any interruption of service to firm customers" it had no need to decide whether a service that in most circumstances was as firm as native load, but with a priority below native load is more firm than interruptible, and made no such determination.

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[100] Request for Rehearing at 26 (citing *NU*, 84 FERC ¶ 61,159 at 61,867) (emphasis supplied by Idaho Power).

[101] *Northeast Utilities*, 62 FERC ¶ 63,013, at 65,025 (1993).

[102] *See NU*, 84 FERC ¶ 61,159 at 61,867.

[103] Order on Initial Decision, 126 FERC ¶ 61,044 at P 98 (citing *Cleveland*, 75 FERC ¶ 61,258 at 61,841).

57. Furthermore, the Commission did not "establish for the first time a purported distinction between firm service 'for ratemaking purposes' and firm service for other (unidentified) purposes," as Idaho Power alleges. Nor did the Commission divorce consideration of the quality of service from its ratemaking inquiry here. Rather, "[p]riority vis-à-vis native load is but one factor that may be considered in a case-by-case analysis of whether a service is firm or non-firm for ratemaking purposes but is not alone the determinative factor."[104] This comports with Order No. 888's intention that a fact-specific, case-by-case inquiry be conducted to determine how a particular grandfathered service should be accounted for in a transmission provider's OATT rates. Having reviewed all the facts in this case, the Commission reasonably found here that the grandfathered service should be considered firm for purposes of Idaho Power's new formula rate.

58. Finally, Idaho Power's reference to the *NSP Remand* does support its position. That case involved remand of a Commission order rejecting the transmission provider's proposal to curtail firm point-to-point transmission service without directing *pro rata* curtailments of transmission service for its network/native load.[105] The Commission modified its prior order to permit the proposed curtailment procedures subject to the transmission provider's revising its tariff "to reflect the narrow circumstances addressed in the Court's order as well as revisions to NSP's rates for firm point-to-point transmission service to reflect the inferior quality of service provided to point-to-point customers compared to the service provided to native load customers."[106]

59. Accordingly, the Commission's direction that the firm point-to-point rates should be adjusted to reflect the inferior quality of service was tailored to the

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[104] Order on Initial Decision, 126 FERC ¶ 61,044 at P 94.

[105] *NSP Remand*, 89 FERC ¶ 61,178 at 61,551.

[106] *Id.* Specifically, the Commission directed the transmission provider to modify its tariff to (1) specify procedures to ensure that it had exhausted all of its redispatch options before implementing a curtailment; (2) a methodology that the transmission provider will use to confirm that any firm point-to-point transmission customer that is curtailed in excess of its *pro rata* curtailment has redispatch or other options available; and (3) specify a method to compensate a firm point-to-point transmission customer for any redispatch costs the customer may incur to protect the transmission provider's native load and network customers from *pro rata* curtailment. *See id.* at 61,553.

circumstances in that case—i.e., the implementation of curtailment over a transmission constraint after the transmission provider had exhausted all of its network/native load generation redispatch options but the firm point-to-point transmission customers still had options with which to avoid having to shed load.[107] It was not a blanket holding that transmission service with a curtailment priority "even slightly below native" was so inferior as to warrant treatment as interruptible in designing a new formula rate. We therefore deny rehearing on this issue.

2. Curtailment under the Legacy Agreements

a. Rehearing Request

60. Idaho Power asserts that even if the distinction between services that are curtailable during normal versus outage conditions is appropriate, the evidence shows that service under the Restated Transmission Agreement is curtailable during normal system conditions. Idaho Power argues that East to West Transfer Service is curtailable under "normal system conditions with all facilities in service" and that the Commission recognized that Other Services under the Restated Transmission Agreement are also curtailable in these situations.[108] In addition, Idaho Power contends that its position, which Idaho Power claims was the Commission's prior to this case, "was and is that transmission service with a curtailment priority below native load is not 'firm.'"[109]

61. Idaho Power also takes issue with the Commission's finding that nothing in sections 3.5 and 3.6 of the Restated Transmission Agreement allows Idaho Power to curtail PacifiCorp's service below 1,410 MW under normal system conditions.[110] Idaho Power argues that section 3.6 "addresses how PacifiCorp's

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[107] *See id.* at 61,552. In response *to NSP Remand,* the transmission provider filed to withdraw its proposed amendment to the curtailment procedures in its OATT, which the Commission accepted. *See NSP Withdrawal,* 89 FERC ¶ 61,299 at 61,933.

[108] Request for Rehearing at 29 (citing Restated Transmission Agreement section 3.6).

[109] *Id.* at 29-30.

[110] *See id.* at 29 n.21 (citing Order on Initial Decision, 126 FERC ¶ 61,044 at P 77.

service will be curtailed if the Northwest Path is reduced under normal system conditions due to deratings."[111] Idaho Power also argues that its Witness Durick provided unrefuted testimony addressing how section 3.6.1 of the Restated Transmission Agreement would permit Idaho Power to curtail service to PacifiCorp below 1,410 MW to preserve Idaho Power's 570 MW priority block during "normal system conditions."[112] Idaho Power argues that, for example, a 550 MW reduction of the path rating under normal system conditions where firm capacity was reduced without the loss of any facilities, as occurred in 1996, would require a curtailment of PacifiCorp's service, while Idaho Power's 570 MW block would be preserved.[113]

62. Idaho Power disagrees that its 570 MW right on the Western Interconnections (i.e., Divide, LaGrande, and Enterprise interconnections) typically does not affect the bulk of PacifiCorp's East to West Transfer Service rights such that the service should be considered non-firm.[114] Idaho Power argues that the Commission's reliance on the frequency of curtailment is contrary to its holding in *NU* that even if a service has never been interrupted the possibility of interruption is sufficient to render the service not firm.[115]

63. Further, in Idaho Power's view, the Commission found incorrectly that Restated Transmission Agreement section 3.6 does not apply to the Midpoint-Summer Lake interconnection. Idaho Power disputes that in the event of a curtailment situation with PacifiCorp using the Northwestern path, PacifiCorp has flexibility under the Restated Transmission Agreement to send its schedule to Midpoint, within the hour, in order to avoid disruption to service. Idaho Power argues that the Midpoint-Summer Lake, Divide, LaGrande, and Enterprise lines are part of a single rated path (i.e., the Northwest Path) and that PacifiCorp is allowed to deliver power to each of these four interconnections under the Restated Transmission Agreement. Idaho Power argues that when the Northwest Path is

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[111] *Id.* at 29 n.21

[112] *Id.*

[113] *Id.* (citing *Arizona Pub. Serv. Co. v. Idaho Power Co.*, 87 FERC ¶ 61,303, at 62,223 n.22 (1999) (*Arizona Pub. Serv. Co.*).

[114] *Id.* at 30 (quoting Order on Initial Decision, 126 FERC ¶ 61,044 at P 78) (emphasis by Idaho Power).

[115] *Id.* at 31 (citing *NU*, 84 FERC ¶ 61,159 at 61,867-68).

reduced below 1,980 MW with all facilities in place (under section 3.61 of the Restated Transmission Agreement) or due to an outage (under section 3.81 of the Restated Transmission Agreement), PacifiCorp must curtail its uses of East to West Transfer Service if Idaho Power is using its 570 MW.

64. Idaho Power also avers that the Commission found incorrectly that the Restated Transmission Agreement provides no specific access allocation or priority for service to PacifiCorp. Idaho Power argues that the language the Commission references requiring Idaho Power to use its best efforts to maximize the transfer capability to PacifiCorp is a "catchall" under section 3.8.3 of the Restated Transmission Agreement relating to priority over the "Remaining Idaho Power System," not to Idaho's priority rights over its Northwest Interconnections or between Borah/Kinport and Midpoint.

65. Idaho Power adds that like the Presiding Judge, the Commission only analyzed the Restated Transmission Agreement but concluded that the services under the Facilities Agreement and Interconnection Agreement are firm.

b. <u>Commission Determination</u>

66. Idaho Power asserts that the evidence shows that service under the Restated Transmission Agreement is curtailable during normal system conditions. We disagree.

67. Idaho Power's characterization of section 3.6 as allowing it to curtail PacifiCorp's service under the Restated Transmission Agreement under "normal system conditions" is misleading. We affirm our finding that section 3.6 limits PacifiCorp's capacity under the Restated Transmission Agreement to 1,410 MW (rather than 1,600 MW) because of the limited transfer capabilities of the Bridger system at the time the Restated Transmission Agreement was executed. Specifically, section 3.6 (Limitations During Normal System Conditions) provides as follows:

> The Parties understand and agree that, *as of the date of this Agreement is executed, capacity limitations exist on the Idaho Power system during normal system conditions with all facilities in service*, as specified in paragraphs 3.6.1 and 3.6.2, 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 capacity on its transmission system.[116]

68. We affirm our finding that Idaho Power limits PacifiCorp's capacity under the Restated Transmission Agreement to 1,410 MW rather than the full 1,600 MW contracted-for amount as a result of the limited transfer capabilities of the Bridger system as memorialized in section 3.6 of the Restated Transmission Agreement. Furthermore, as we stated in the Order on Initial Decision, this reduction of PacifiCorp's rights is a result of the capacity limitations on Idaho Power's system "during normal system conditions with all facilities in service."

69. Moreover, reading section 3.6 as Idaho Power advocates would be unreasonable in light of Idaho Power's and PacifiCorp's on the record interpretations of PacifiCorp's rights under the Restated Transmission Agreement. As the Presiding Judge found, Idaho Power does not believe that it has the right to interrupt Restated Transmission Agreement and Facilities Agreement services in order to provide non-firm transmission service under the

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[116] Ex. INT-13 (Restated Transmission Agreement section 3.6). Subsection 3.6.1 (Northwest Interconnections) provides as follows:

> Idaho Power shall have 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 capacity shall be made available to PacifiCorp for East to West Transfer Services up to the limits provided in paragraph 3.4.

Subsection 3.6.2 (Transmission West of Borah and Kinport Substations), provides that Idaho Power is allocated for its own use 707 MW of reserved capacity of transfer capability provided through the 345 kV and 138 kV transmission lines west of the Borah and Kinport substations and 1,414 MW is allocated to Idaho Power to provide East to West Transfer Services to PacifiCorp. Subsection 3.6.2 also provides 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." Like subsection 3.6.1, subsection 3.6.2 provides that when Idaho Power is not fully utilizing its reserved capacity, such capacity shall be made available to PacifiCorp for East to West Transfer Services.

OATT to a third party.[117] In addition, the record shows that PacifiCorp believes that, except for limited conditions specified in the Restated Transmission Agreement,[118] Idaho Power does not have the right to curtail or interrupt PacifiCorp's schedules except in emergencies and in such cases, on a *pro rata* basis.[119]

70. In addition, the "unrefuted testimony" Idaho Power references is unpersuasive. Witness Durick merely restates the language of section 3.6 of the Restated Transmission Agreement but offers no evidence to support a reading of section 3.6 to allow Idaho Power to interrupt PacifiCorp's service in a non-reliability situation.[120] Similarly, the example from 1996 that Idaho Power offers does not support it position. In that case, transfer capability was reduced because the transmission line was derated to maintain system reliability.[121]

71. Idaho Power also misconstrues the Commission's observation that Idaho Power's 570 MW right on the Western Interconnections typically does not affect the bulk of PacifiCorp's East to West Transfer service and is therefore contrary to *NU.*

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[117] Initial Decision, 120 FERC ¶ 63,014 at P 122 (*citing* Ex. S-2 at 29, 31).

[118] These limited circumstances are as follows: (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. Order on Initial Decision, 126 FERC ¶ 61,044 at P 47.

[119] Initial Decision, 120 FERC ¶ 63,014 at P 135 (*citing* Ex. PAC-1 (Apperson Ans. Test. 3:20-23)).

[120] *See* Ex. IPC-28 (Durick Reb. Test. 16:1-2) (describing section 3.6).

[121] *See Arizona Pub. Serv. Co.*, 87 FERC ¶ 61,303 at 62,223 n.22 ("The Brownlee East Path was originally rated at 2100 MW by the Western Systems Coordination Council (WSCC), but was derated to 1550 MW in the summer of 1996. [] Idaho Power indicates that this derating resulted from generation and transmission outages on its system which occurred on July 2 and 3, 1996, whereupon the U. S. Department of Energy recommended that Idaho Power, among other utilities, reduce transfers to safe and prudent levels.") (internal citations omitted).

72. The Commission was not relying on the frequency of curtailment in determining that even with the four exceptions to "continuous firm" service delineated in the Restated Transmission Agreement, PacifiCorp enjoys service under that agreement that is appropriately found to be firm rather than non-firm under the circumstances of this case. As discussed above, in *NU* there was no question about whether or not the service could be curtailed for reliability purposes or interrupted for economic reasons. In *NU*, the Commission concluded that "[w]hether or not the service has ever actually been interrupted is not controlling because NU has the contractual right to curtail service."[122] Here, while the Restated Transmission Agreement allows Idaho Power to curtail PacifiCorp's service for reliability reasons both Idaho Power and PacifiCorp have made clear that Idaho Power cannot interfere with PacifiCorp's rights for economic reasons.[123]

73. Further, assuming *arguendo* that the Northwest Path is one rated path and section 3.8.3 does not apply to that path, we affirm the Presiding Judge's reading of section 3.5 of the Restated Transmission Agreement as specifying that "Idaho Power shall provide East to West Transfer Services on a continuous, firm basis" except in certain specific circumstances pertaining to curtailments to preserve system reliability.

74. Finally, regarding Idaho Power's complaint that the Commission only analyzed the Restated Transmission Agreement, Idaho Power itself acknowledged that the Restated Transmission Agreement has curtailment provisions but the Facilities Agreement and the Interconnection Agreement do not.[124] Further,

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[122] *See NU*, 84 FERC ¶ 61,159 at 61,867.

[123] Initial Decision, 120 FERC ¶ 63,014 at P 143 (*citing* Ex. IPC-32 (Park Reb. Test. 17:16-18:11); PAC-1 (Apperson Ans. Test. 3:30-23)).

[124] *See* Exhibit No. IPC-28 (Durick Reb. Test. 19:14-15) ("The [Facilities Agreement] does not state a specific or uniform curtailment priority for the service granted to UP&L; it leaves curtailment to the *ad hoc* judgment of the operators involved during an event. However, given the era in which the agreement was entered into, I do not believe that the parties would have intended that Idaho Power would interrupt native load in order to maintain economic transfers under this service as would be required by the OATT. If faced with curtailments, I would expect the operators to work out a response to the immediate circumstance with first priority given to maintaining either party's reliability.").

Idaho Power acknowledged that the Restated Transmission Agreement covers most of the service provided by Idaho Power to PacifiCorp under the three grandfathered agreements.[125] Accordingly, we deny rehearing on this issue.

E. Other Factors: Transfer Capability; Borah West Denial; Form No. 1

1. Rehearing Request

75. Idaho Power also questions other factors the Presiding Judge and the Commission considered in evaluating how the Legacy Agreement services should be accounted for in Idaho Power's formula rates. Idaho Power argues again that "the fact that Idaho Power subtracts from [Available Transfer Capability] the amount of capacity that it uses to serve PacifiCorp does not demonstrate that the service to PacifiCorp is firm; it simply shows that Idaho Power does not sell the same capacity to another party."[126] Idaho Power also reiterates that in some circumstances it would not subtract the full 1,410 MW from firm Available Transfer Capability. Idaho Power provides a hypothetical describing the Northwest Path's capacity being reduced to 980 MW with Idaho Power using 200 MW of its 570 MW contract capacity. Idaho Power states that it would reduce PacifiCorp's maximum use from 1,410 MW to 410 MW (i.e., 980 MW minus Idaho Power's 570 MW contract right), subtract that lower amount (410 MW) from firm Available Transfer Capability (980 MW) and post the remaining 370 MW of Available Transfer Capability on its OASIS.[127] Idaho Power argues that, in contrast, for firm OATT service 1,410 MW would be subtracted from the 980 MW path capacity, and zero Available Transfer Capability would be posted.

76. In Idaho Power's view, the Commission's finding that Idaho Power could not post extra capacity it was not using unless PacifiCorp decided not to use it assumes that Idaho Power's "utilization" of its 707 MW of reserved capacity across Borah West is restricted to providing retail service, but not unbundled transmission service. Idaho Power argues that it is required under its OATT to

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[125] The Restated Transmission Agreement provides PacifiCorp with 1,600 MW (currently limited to 1,410 MW) and the Facilities Agreement and Interconnection Agreement provide for 250 MW each. *See supra* P 5-7.

[126] Request for Rehearing at 33.

[127] *Id.* at 34.

make such extra capacity available for sale on its OASIS. According to Idaho Power, if it does not use its reserved capacity, whether to transmit electricity to its own customers, or to provide firm or non-firm transmission service to others, only then is the capacity made available to PacifiCorp.[128]

77. Next, Idaho Power questions the Commission's findings regarding Idaho Power's denial of a request for firm transmission service over Borah West.[129] Idaho Power argues that its response to that service request simply showed that Idaho Power honored its contractual commitments to PacifiCorp by not offering the same capacity for sale to others.

78. With regard FERC Form 1 reporting, Idaho Power avers that none of the services under the Facilities Agreement or Interconnection Agreement were classified as firm nor was the Restated Transmission Agreement's Bridger Integration Service. Idaho Power adds that the only portion of the East to West Transfer Service classified as firm was Additional East to West Transfer Service, which the Commission found in the Order on Initial Decision to be non-firm. Idaho Power argues that the only other revenues listed as firm were for Other Resource Transfer Service, which was a billing error and that the revenues were correctly reported as non-firm in most years with the few erroneous entries promptly corrected.[130]

2. Commission Determination

79. Idaho Power insists that when it subtracts the Legacy Agreement's capacity from Available Transfer Capability due to its contractual obligation this "says nothing about the service's curtailment priority, which is what determines its firmness."[131] But to the contrary, we disagree. As the Presiding Judge reasonably concluded, the fact that Idaho Power makes that subtraction

> [i]s precisely why the service under the Legacy Agreements is "firm' rather than "non-firm." If it

[128] *Id.* at 36 (citing Idaho Power OATT former section 1.49 (renumbered as section 1.54 in Idaho Power's Order No. 890 compliance tariff) and section 15.1).

[129] *See* Request for Rehearing at 37 (citing Order on Initial Decision, 126 FERC ¶ 61,044 at P 125).

[130] *Id.* at 37-38.

[131] Request for Rehearing at 33.

> 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.[132]

Idaho Power cannot and does not make the 1,410 MW of transmission capacity available to other customers and excludes that amount from its Available Transfer Capability. Thus, how the Legacy Agreement services' demand is treated in Idaho Power's Available Transfer Capability calculation is another factor that supports a finding the services Idaho Power provides to PacifiCorp should be considered more firm than interruptible.

80. Further, Idaho Power's hypothetical with the Northwest Path reduced to 980 MW is misleading. Using this example, Idaho Power argues that the full 1,410 MW of the Legacy Agreement demand would not be subtracted from Available Transfer Capability in this curtailment situation while 1,410 MW of demand for firm OATT service would be subtracted from the 980 MW path capacity. No one in this proceeding disputed that firm OATT services have a higher priority than the Legacy Agreement services in the event of a curtailment for reliability reasons. All transmission service, even the highest priority service, may be curtailed in the event of an outage or to preserve system reliability. Idaho Power's example merely demonstrates the difference between the curtailment priority of the Legacy Agreements services and firm OATT transmission service, the latter of which in the event of a curtailment for reliability purposes, is curtailed on a *pro rata* basis. However, in the normal course of operations Idaho Power deducts the entire 1,410 Legacy Agreements' demand from its firm Available Transfer Capability, which effectively treats the Legacy demand for practical purposes as firm.

81. Regarding Idaho Power's denial of a firm service request over Borah West, the Commission observed:

> Idaho Power responded to Arizona Public Service's protest stating that prior to the facility study, it did not know how much of Arizona Public Service's request it could accommodate without facility upgrades. Idaho Power states that it *consistently considered the capacity committed to PacifiCorp* and as a result denied third parties' requests for firm service, including requests by its own merchant function. After performing the facility study, it

[132] Initial Decision, 120 FERC ¶ 63,014 at P 128.

> determined that it could accommodate Arizona Public Service's request, subject to *PacifiCorp exercising its preexisting rights to 150 MW of capacity.*[133]

82. Accordingly, the record there showed that Idaho Power considered the capacity on that path to be committed to PacifiCorp. Idaho Power contends that this only reflected its contractual commitments to PacifiCorp. It is, however, this obligation to PacifiCorp that makes its service effectively firm. The fact that Idaho Power cannot and does not make the 1,410 MW of transmission capacity available to other customers supports a finding that the Legacy Agreement services are much more akin to firm service than to non-firm service.

83. Finally, despite Idaho Power's effort to recharacterize its historical treatment of the Legacy Agreement services in its FERC Form 1 reports, the record supports considering this historic treatment as a relevant factor in determining how to account for the Legacy Agreements. An objective look at the nature and characteristics of these services is needed to determine whether they are firm or non-firm for the purpose of deciding how they will be allocated for OATT pricing purposes. Having considered all of the evidence regarding the benefits and burdens, curtailment, the nature of the services under the agreements, and the "other factors" above, the Commission finds that for the reasons stated above, the Legacy Agreement services should be considered "firm" for the purpose of accounting for them in Idaho Power's new formula rates. Accordingly, rehearing is denied.

F. Measure of Demand

1. Rehearing Request

84. Idaho Power argues that the Commission erred in overturning the Presiding Judge's finding that the appropriate demand measure for the Legacy Agreements is their 12 coincident peak demand.

85. First, Idaho Power contends that the Presiding Judge's ruling was based on the language of Idaho Power's OATT, which, according to Idaho Power, is identical to the language of the Order No. 888 *pro forma* OATT.[134] Idaho Power

[133] *Idaho Power Company*, 90 FERC ¶ 61,009, at 61,019 (2000) (emphasis added).

[134] *See* Request for Rehearing at 41.

argues that the Presiding Judge found that Order No. 888 provides for the rate divisor to include "the monthly peak load minus the coincident monthly peaks associated with *all* firm point-to-point service customers plus the monthly contract demand reservations for *all* firm point-to-point service," as implemented in section 34.3 of the OATT.[135] According to Idaho Power, "[t]he tariff clearly states that the Transmission System load is calculated by subtracting coincident peak usage – usage as opposed to an entire contract demand that may or may not be fully used."[136] Idaho also argues that the Presiding Judge found that "monthly maximum firm usage" under the tariff includes the monthly peak usages of OATT and non-OATT firm customers and therefore concluded that the Legacy Agreements' 12 coincident peak demands must be included in the formula rate divisor.[137]

86. Idaho Power argues that the tariff language must govern in the absence of ambiguity and ignoring "the plain language of the tariff" in order to reach a different conclusion violates the filed rate doctrine.[138] In Idaho Power's view, the Commission's determination deviated from the plain language of the OATT, requiring the Commission to make a finding under section 206 of the FPA that Idaho Power's existing rate is unjust and unreasonable. Idaho states that the Commission made no such finding; thus, the Commission erred by failing to apply the language in Idaho's OATT.[139]

87. Second, Idaho Power argues that the Order on Initial Decision reflects a re-write of Order No. 888. Idaho Power argues that the language the Commission relied upon to find that a case-by-case analysis should be used to determine the

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[135] *Id.* at 41 (citing Initial Decision, 120 FERC ¶ 63,014 at P 233, quoting Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,738) (emphasis in original).

[136] *Id.* at 42.

[137] *Id.* (citing Initial Decision, 120 FERC ¶ 63,014 at P 238).

[138] *Id.* at 42-43 (citing *National Fuel Gas Supply Corp. v. FERC*, 811 F.2d 1563, 1572 (D.C. Cir. 1987) ("if the intent . . . is clearly expressed in the document, that is the end of the matter.") (quotation omitted); *Idaho Power Co. v. FERC*, 312 F.3d 454, 461 (D.C. Cir. 2001), quoting *Koch Gateway Pipeline Co. v. FERC*, 136 F.3d 810, 814 (D.C. Cir. 1998) ("We first look to see if the language of the tariff is unambiguous. . .")).

[139] *See id.* at 43-44.

appropriate measure of demand is not part of the section of Order No. 888 that addresses the use of the 12 coincident peak demand allocation method. Idaho Power also argues that Order No. 888 affirmed the use of the 12 coincident peak method, only applying a case-by-case analysis to utilities that chose to propose a method other than the 12 coincident peak method.[140] In Idaho Power's view, Order No. 888-A also attributed the case-by-case analysis only to proposals that would use a demand measure other than 12 coincident peak. Idaho Power argues it did not submit such a proposal. In addition, Idaho Power quotes Order No. 888-A as follows:

> Accordingly, utilities are free to propose in a section 205 filing an alternative to the use of the 12-month rolling average (e.g., annual system peak) in the load ratio share calculation . . . . 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.[141]

88. Idaho Power argues that even if a case-by-case analysis could be applied, the Commission was wrong to find that the 12 coincident peak method was inappropriate because the Legacy Agreements require Idaho Power to "stand ready to make the contracted-for amount of capacity available for PacifiCorp's use, except under narrow circumstances related to reliability."[142] Idaho Power suggests that the Commission should have defined what "stand ready" means. Idaho Power argues that the Legacy Agreements do not require Idaho Power to stand ready to deliver power in the same manner as it must stand ready to deliver power to native load.

89. Idaho Power interprets what it calls the "stand ready" standard as "bring[ing] within its reach any service with a contract demand that can be called upon by the buyer regardless of the contractual restrictions on the use of the

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[140] *Id.* at 44 (citing Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,736).

[141] *Id.* (citing Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,736; Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,256).

[142] *See id.* at 45 (citing Order on Initial Decision, 126 FERC ¶ 61,044 at P 212).

service or the curtailment priority that applies to the service."[143] Idaho Power also argues that it is inappropriate to treat the entire contract demand as "equivalent to load" for cost allocation purposes. According to Idaho Power, contract demand for firm OATT point-to-point service may be treated as "equivalent to load" for cost allocation purposes because the customer has delivery point and service reassignability, enabling it to utilize the entire contract demand, which the Legacy Agreements do not have. Idaho Power adds that the Legacy Agreements include capacity reductions but no such capacity reductions apply to native load.

90. Idaho Power also argues that in Order No. 888, the Commission found that OATT point-to-point service's flexibility provisions make it appropriate to treat the entire contract demand as if it would be used at time of the provider's system peak.[144] Idaho Power states that the Legacy Agreements do not include such provisions, and the amount of service used during peak periods is substantially below the contractually permissible maximums. Idaho Power also argues that the Restated Transmission Agreement and Interconnection Agreement prohibit PacifiCorp from assigning the agreements to a third party while OATT point-to-point transmission service allows customers to reassign their service to third parties.

91. Idaho Power further asserts that the Restated Transmission Agreement lacks a contract demand comparable to the reservations made under the OATT but instead provides for transmission service of "up to" 1,600 MW, which could be as low as zero. Idaho Power states, for example, that the highest one year 12 coincident peak demand under the Restated Transmission Agreement for the period 2002-2006 was 656 MW, well below the 1,600 MW figure in the Restated Transmission Agreement.

92. Idaho Power also rejects the Commission's interpretation of *Consumers Energy Company.*[145] Idaho Power states that the Presiding Judge found *CECo* inapplicable because the service at issue in that case was akin to point-to-point firm service, and all parties in this case agree that the service under the Legacy

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[143] *Id.* at 46.

[144] *Id.* at 47.

[145] 86 FERC ¶ 63,004 (1999), *corrected*, 86 FERC ¶ 63,005 (1999), *aff'd in relevant part*, Opinion No. 456, 98 FERC ¶ 61,333 (2002) (*CECo*).

Agreements cannot be characterized as such.[146] According to Idaho Power, the Commission ruled that *CECo* was applicable, finding that in that case "the service was firm and required the delivery of the output of a generating facility across the state, and that the customer's contract placed a significant burden on the network."[147] Idaho Power acknowledges that the Commission held nothing in *CECo* limited the rule of that case to "point-to-point" service.

93. In response, Idaho Power argues that although nothing in *CECo* explicitly limited the case to "point-to-point" service, the decision to include the point-to-point contract demands in the rate divisor was based on the nature of the burdens that the service placed on the service provider.[148] Idaho Power contends that the judge in *CECo* analogized the service to firm point-to-point OATT service, which represents a higher burden on the transmission system than the burdens associated with the Legacy Agreements.

94. Finally, Idaho Power asserts that the Commission ignored precedent regarding the use of the 12 coincident peak demand, which in Idaho Power's view indicates that absent delivery point flexibility and reassignability, cost should be allocated based on customers' respective contributions to the service provider's coincident peak demands, not contract demands.[149]

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[146] Request for Rehearing at 48.

[147] *Id.* at 48 (citing Order on Initial Decision, 126 FERC ¶ 61,044 at P 215).

[148] *See id.* at 49.

[149] *Id.* at 50 (citing *Arizona Public Serv. Co.,* 23 FERC ¶ 61,419, at 61,931 (1983), *aff'd sub nom. Papago Tribal Util. Auth. v. FERC,* 773 F.2d 1056 (9th Cir. 1985); *Commonwealth Edison Co.,* 15 FERC ¶ 63,048 (1981), *aff'd in relevant part,* 23 FERC ¶ 61,219, at 61,473 n.18 (1983); *Kansas Gas & Electric Co.,* 28 FERC ¶ 63,004, at 65,015 (1984), *aff'd in relevant part,* 31 FERC ¶ 61,012, at 61,023 (1985); *Florida Power & Light Co.,* 66 FERC ¶ 61,227, at 61,529 (1994) (option 1); Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,737-38. *See also Indiana & Michigan Electric Co.,* 4 FERC ¶ 63,010, at 65,076-77, *settlement approved,* 4 FERC ¶ 62,007 (1978); *Public Service Company of New Mexico,* 10 FERC ¶ 63,020, at 65,130 (1980), *settlement approved,* 14 FERC ¶ 61,087 (1981)).

2. Commission Determination

95. The Commission acted consistent with the requirements of Order No. 888 and its precedent in determining the measure of demand for Idaho Power's new formula rate.

96. Idaho Power misapprehends the Commission's holdings in Order Nos. 888 and 888-A. As discussed above, in Order No. 888 the Commission recognized that transmission providers had pre-existing contractual obligations for transmission service over their systems.[150] Order No. 888-A clarified that the Commission would use a case-by-case analysis to determine how pre-existing services should be accounted for in a transmission provider's OATT rates.[151] The Order on Initial Decision made the case-specific inquiry prescribed under Order No. 888. This inquiry was not limited to deciding whether a pre-existing contract should be cost allocated or revenue credited. Once a determination is made to cost allocate, by necessity a determination of the appropriate measure of demand must be made. The measure of demand is the second part of the Order No. 888-mandated case-by-case determination.

97. Contrary to Idaho Power's assertions, Order Nos. 888 and 888-A, as well as the *pro forma* and Idaho Power OATTs, do not plainly and clearly require the use of 12 coincident peak demand here. The portion of Order No. 888 that Idaho Power points to in support of its contention that the "plain language" of section 34.3 of *pro forma* OATT must be given effect, does not provide as Idaho Power claims.

98. Order No. 888, as affirmed in Order No. 888-A, addressed concerns that if annual system peak capability was used to determine rates for point-to-point service and 12 coincident peak was used to allocate costs for network service, point-to-point service may be underpriced relative to network service. In considering commenters' proposals to price both services on the same basis, the Commission reversed its prior rejection of firm point-to-point transmission rates developed by using the average of the 12 monthly coincident system peaks. The Commission noted the industry had changed since it first adopted that policy, stating:

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[150] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,665; Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,189.

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

> [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.[152]

99. While this reversed prior Commission policy by permitting transmission providers to propose to use 12 coincident peak demand to develop their point-to-point OATT rates, it did not prescribe how a grandfathered agreements' demand should be measured for the purposes of inclusion in OATT rates once the Commission had determined that they should be cost allocated.

100. Idaho Power may attempt to parse the language of Order Nos. 888 and 888-A and section 34.2 of the *pro forma* OATT to support its position, but the Commission did not intend Order Nos. 888 and 888-A and the *pro forma* OATT to specify the measure of demand to be used generally so as to predetermine how the Legacy Agreement services would be treated in Idaho Power's new OATT formula rate. Instead, in Order No. 888, the Commission declined to mandate generic changes to pre-existing transmission service contracts.[153] The Commission also did not specify how those pre-existing contracts, which were not subject to the functional unbundling of the Final Rule and the terms and conditions of the *pro forma* OATT, should be accounted for in OATT rates. Later, in Order No. 888-A, the Commission expanded on how these contracts should be treated.[154]

101. Idaho Power essentially argues that the Commission cannot clarify its orders, or somehow "erred" in pointing out those parts of Order No. 888-A that reflect the Commission's intent that a case-by-case determination should be made.[155] Idaho Power eschews language in Order No. 888-A discussing

[152] Initial Decision P 233 (*citing* Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,738).

[153] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,665; Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,189.

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

[155] *See* Request for Rehearing at 44.

consideration of requests to reconsider the use of the 12 coincident peak allocation method for pricing network service, where the Commission clarified how pre-existing services would fit into a transmission providers load ratio share calculations. In these portions of Order No. 888-A, the Commission was not only addressing proposals to use a demand measure other than 12 coincident peak but it also expressly avoided requiring a particular load ratio method. Instead, the Commission required a case-by-case determination of the treatment of such pre-existing agreements in a transmission provider's OATT rates.

> 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.[156]

102. The Commission intended "treatment of discounted firm transmission transactions in the load ratio calculation" to mean all aspects of the treatment of such transactions. That is, whether they should be cost-allocated or revenue credited in the first instance, as well as what measure of demand to use.

103. Idaho Power is also incorrect in asserting that the Commission created what Idaho Power dubs a "stand ready" standard. Rather, in weighing the case-specific facts here, the Commission found the services being provided under the Legacy Agreements and the burdens such services placed on Idaho Power's transmission system vis-à-vis the burden of Idaho Power's wholesale OATT customers, provided additional support for cost allocating the contracted-for amount of demand. Specifically, the total contract demand under the Legacy Agreements accounts for 40 percent of the total demand on Idaho Power's system and Idaho Power's use to service its native load accounts for approximately 45 percent of the demand on its system. In contrast, the demand associated with Idaho Power's wholesale OATT firm customers accounts for only 15 percent of the firm demand on Idaho Power's system. In addition, the Legacy Agreements are extended, long-term arrangements, which mean that Idaho Power's obligation to provide PacifiCorp the contracted-for amount of capacity will extend for a significant period of time.[157] Thus, the Commission reasonably determined that

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

[157] As noted above, the Restated Transmission Agreement remains in effect for the life of the Jim Bridger plant, the Facilities Agreement was executed in

(continued...)

the Legacy Agreements placed a significant burden on Idaho Power's transmission system.

104. Furthermore, as discussed above, the nature of the services offered under the Legacy Requirements require that Idaho Power's transmission system is available to PacifiCorp at the contracted-for capacity, except in limited circumstances related to system reliability.[158] Idaho Power has acknowledged this obligation at times, when it has failed to make capacity available to OATT customers because of its obligation to PacifiCorp under the Legacy Agreements.[159]

105. Under these circumstances, it would be unreasonable to use the 12 coincident peak demand, because this would shift costs associated with the burden imposed by the Legacy Agreements to OATT customers, which account for only 15 percent of Idaho Power's load. Such cost-shifting would be inconsistent with Commission policy that transmission service rates must reflect costs caused by customers who must pay them.[160]

106. Also meritless is Idaho Power's claim that the Restated Transmission Agreement lacks a contract demand comparable to OATT firm service reservations. Section 3.4 of the Restated Transmission Agreement specifies that the total quantity of the East to West Transfer Services "shall neither be less than zero (0) MW nor exceed 1,600 MW."[161] However, we find that in practice the Legacy Agreements' 1,410 MW capacity is a firm commitment, as evidenced, for example, by how Idaho Power treats the Legacy Agreements' capacity in the calculation of its Available Transfer Capability and its prior refusal to make that capacity available to other customers.

June 1974 with a 50-year term, subject to automatic renewals and a 5-year notice of termination, and the Interconnection Agreement was entered into on March 19, 1982 and continues until June 1, 2025.

[158] *See supra* P 69.

[159] *See* Order on Initial Decision, 126 FERC ¶ 61,044 at P 125.

[160] *See Midwest ISO TOs v. FERC*, 373 F.3d at 1368.

[161] Restated Transmission Agreement section 3.4. As noted above, the 1,600 MW maximum is limited to 1,410 due to the rating on the transmission limitations west of the Jim Bridger power plant.

107. Finally, as discussed in the Order on Initial Decision, *CECo* is germane because in *CECo*, as here, the customer's service placed a significant burden on the transmission provider's system. That factor in conjunction with other record evidence in this proceeding, support finding that the appropriate measure of demand is the Legacy Agreements' contract demand amounts. Other cases Idaho Power cites pre-date Order No. 888 and therefore do not address how demand should be measured for pre-Order No. 888 transmission services that are incorporated into a post-Order No. 888 OATT rate formula, and Order No. 888 does not mandate the calculation of load ratios using a particular method on a generic basis. Accordingly, for the reasons stated above the Commission denies rehearing on this issue.

The Commission orders:

Idaho Power's request for rehearing of the Order on Initial Decision is denied.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-06

IDAHO POWER COMPANY

ATTACHMENT NO. 2

Idaho Power Company
Calculation of Revenue Impact
State of Idaho
OATT Deferral Funding
Effective June 1, 2012

Summary of Revenue Impact

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers (1)	Normalized Energy (kWh) (1)	Current Base Revenue	Mills Per kWh	Total Adjustments to Base Revenue	Proposed Base Revenue	Mills Per kWh	Percent Change Base to Base Revenue
	Uniform Tariff Rates:									
1	Residential Service	1	399,329	4,896,272,827	$387,467,359	79.14	$252,021	$387,719,380	79.19	0.07%
2	Master Metered Mobile Home Park	3	23	4,942,681	$370,890	75.04	$254	$371,144	75.09	0.07%
3	Residential Service Energy Watch	4	0	0	$0	0.00	$0	$0	0.00	N/A
4	Residential Service Time-of-Day	5	0	0	$0	0.00	$0	$0	0.00	N/A
5	Small General Service	7	28,165	144,888,296	$14,582,874	100.65	$7,458	$14,590,331	100.70	0.05%
	Large General Service	9	31,614	3,480,101,459	$196,662,000	56.51	$179,128	$196,841,127	56.56	0.09%
7	Dusk to Dawn Lighting	15	0	6,481,376	$1,164,504	179.67	$334	$1,164,838	179.72	0.03%
8	Large Power Service	19	116	1,978,623,647	$83,932,246	42.42	$101,844	$84,034,090	42.47	0.12%
9	Agricultural Irrigation Service	24	16,642	1,720,204,410	$109,589,453	63.71	$88,542	$109,677,996	63.76	0.08%
10	Unmetered General Service	40	2,030	15,807,753	$1,093,478	69.17	$814	$1,094,292	69.23	0.07%
11	Street Lighting	41	361	23,165,568	$2,940,508	126.93	$1,192	$2,941,700	126.99	0.04%
12	Traffic Control Lighting	42	397	2,981,282	$143,102	48.00	$153	$143,255	48.05	0.11%
13	Total Uniform Tariffs		478,677	12,273,469,299	$797,946,413	65.01	$631,740	$798,578,153	65.07	0.08%
15	Special Contracts:									
16	Micron	26	1	451,138,622	$17,270,255	38.28	$23,221	$17,293,476	38.33	0.13%
17	J R Simplot	29	1	203,558,197	$6,775,566	33.29	$10,478	$6,786,044	33.34	0.15%
18	DOE	30	1	244,266,665	$8,452,111	34.60	$12,573	$8,464,684	34.65	0.15%
19	Hoku - Block 1	32	1	387,957,600	$25,311,225	65.24	$0	$25,311,225	65.24	0.00%
20	Hoku - Block 2	32		197,100,000	$7,380,681	37.45	$10,145	$7,390,826	37.50	0.14%
21	Total Special Contracts		4	1,484,021,084	$65,189,839	43.93	$56,417	$65,246,255	43.97	0.09%
23	Total Idaho Retail Sales		478,681	13,757,490,383	$863,136,252	62.74	$688,156	$863,824,408	62.79	0.08%

(1) June 1, 2012 - May 31, 2013 Forecasted PCA Test Year

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-06

IDAHO POWER COMPANY

ATTACHMENT NO. 3

Idaho Power Company
Calculation of Revenue Impact
State of Idaho
Combined Effect of Filings Funding
Effective June 1, 2012

Summary of Revenue Impact

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers [1]	Normalized Energy (kWh) [1]	Current Base Revenue	Mills Per kWh	Total Adjustments to Base Revenue	Proposed Base Revenue	Mills Per kWh	Percent Change Base to Base Revenue
	Uniform Tariff Rates:									
1	Residential Service	1	399,329	4,896,272,827	$387,467,359	79.14	($3,085,438)	$384,381,921	78.51	(0.80)%
2	Master Metered Mobile Home Park	3	23	4,942,681	$370,890	75.04	($3,101)	$367,789	74.41	(0.84)%
3	Residential Service Energy Watch	4	0	0	$0	0.00	$0	$0	0.00	N/A
4	Residential Service Time-of-Day	5	0	0	$0	0.00	$0	$0	0.00	N/A
5	Small General Service	7	28,165	144,888,296	$14,582,874	100.65	($80,024)	$14,502,849	100.10	(0.55)%
	Large General Service	9	31,614	3,480,101,459	$196,662,000	56.51	($2,099,509)	$194,562,491	55.91	(1.07)%
7	Dusk to Dawn Lighting	15	0	6,481,376	$1,164,504	179.67	$6,479	$1,170,983	180.67	0.56%
8	Large Power Service	19	116	1,978,623,647	$83,932,246	42.42	$542,759	$84,475,005	42.69	0.65%
9	Agricultural Irrigation Service	24	16,642	1,720,204,410	$109,589,453	63.71	($1,189,762)	$108,399,691	63.02	(1.09)%
10	Unmetered General Service	40	2,030	15,807,753	$1,093,478	69.17	$6,578	$1,100,056	69.59	0.60%
11	Street Lighting	41	361	23,165,568	$2,940,508	126.93	$13,889	$2,954,396	127.53	0.47%
12	Traffic Control Lighting	42	397	2,981,282	$143,102	48.00	($2,291)	$140,810	47.23	(1.60)%
13	Total Uniform Tariffs		478,677	12,273,469,299	$797,946,413	65.01	($5,890,421)	$792,055,992	64.53	(0.74)%
15	Special Contracts:									
16	Micron	26	1	451,138,622	$17,270,255	38.28	$114,396	$17,384,651	38.54	0.66%
17	J R Simplot	29	1	203,558,197	$6,775,566	33.29	$46,248	$6,821,814	33.51	0.68%
18	DOE	30	1	244,266,665	$8,452,111	34.60	$57,194	$8,509,306	34.84	0.68%
19	Hoku - Block 1	32	1	387,957,600	$25,311,225	65.24	$0	$25,311,225	65.24	0.00%
20	Hoku - Block 2	32		197,100,000	$7,380,681	37.45	$49,110	$7,429,791	37.70	0.67%
21	Total Special Contracts		4	1,484,021,084	$65,189,839	43.93	$266,948	$65,456,786	44.11	0.41%
23	Total Idaho Retail Sales		478,681	13,757,490,383	$863,136,252	62.74	($5,623,474)	$857,512,778	62.33	(0.65)%

(1) June 1, 2012 - May 31, 2013 Forecasted PCA Test Year

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-06

IDAHO POWER COMPANY

ATTACHMENT NO. 4

IDAHO POWER®
An IDACORP Company

NEWS RELEASE

Idaho Power Requests to Lower Rates for Most Customers

As part of Idaho Power's hard work to provide reliable, fair-priced electric service to its customers, the company has filed a request to reduce most customers' rates effective June 1.

BOISE, Idaho, Feb. 16, 2012 -- On Feb. 15, Idaho Power made four filings with the Idaho Public Utilities Commission (IPUC), the net effect of which is a proposed **decrease** to most customers' rates effective June 1. Idaho Power customers benefit from some of the lowest electricity rates in the nation.

Overall Impact

Idaho Power understands that multiple filings can be confusing for customers, and we want to help you understand what the result means to your bottom line. A summary of proposed changes to Idaho rates is shown below.

Revenue Impact By Class: Percentage Change from Current Billed Rates						
	Residential	Small General Service	Large General Service	Large Power	Irrigation	Overall Change
Depreciation Rate Change	0.31%	0.29%	0.32%	0.27%	0.32%	0.31%
Boardman Shutdown	0.18%	0.17%	0.19%	0.16%	0.19%	0.18%
Transmission Revenue Deferral Recovery	0.07%	0.05%	0.09%	0.11%	0.08%	0.08%
Non-AMI Meter Depreciation	(1.36%)	(1.07%)	(1.63%)	0.00%	(1.69%)	(1.22%)
Net Change	(0.80%)	(0.56%)	(1.03%)	0.54%	(1.10%)	(0.65%)

The net effect to customers of these four filings varies depending on your rate schedule. However the result is a decrease for most customers. The bill impact for an average Idaho

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P.O. Box 70 (83707)
1221 W. Idaho St.
Boise, ID 83702

Power residential customer in Idaho using 1,050 kilowatt-hours of energy a month will be a bill decrease of $0.67 beginning June 1, if all proposals are approved as filed.

We anticipate making additional filings this spring that, in combination with the above proposed changes, will have a net effect on rates.

Why Idaho Power Needs to Change Rates

As a regulated utility, Idaho Power invests up front to serve customers and recovers the cost of the investment, along with a commission-authorized fair return, later. The company also needs to pay its expenses as they occur.

To provide power today and to plan for tomorrow, we must invest in our aging infrastructure and in new infrastructure. As we add new resources in the future, to meet growth in customer demand or reduced generation from coal facilities, power supply expenses and customer rates will be impacted.

Details on the four Feb. 15 filings are as follows:

Depreciation Rate Change

Idaho Power has requested authorization from the IPUC to institute revised depreciation rates in our Idaho jurisdiction for our existing electric facilities. Depreciation rates establish the amount of time over which Idaho Power recovers its investments in the electrical system through rates.

The last changes to Idaho Power's depreciation rates became effective August 1, 2008. The revised depreciation rates proposed to become effective on June 1, 2012, are based on the results of a detailed depreciation study examining Idaho Power's existing electric facilities-in-service as of June 30, 2011.

The company is proposing a uniform increase of $2,656,213, or 0.31 percent for all customer classes. The change in depreciation rates and the corresponding customer rates would become effective June 1, 2012.

Early Shutdown of Boardman Coal Plant

Idaho Power's operating partner has announced plans to shut down the coal-fired Boardman Power Plant in north-central Oregon in 2020. Idaho Power owns 10 percent of the facility.
In recognition of these plans, Idaho Power is requesting an increase in customer rates effective June 1, 2012, resulting from the accelerated depreciation of the plant, decommissioning costs

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related to the plant shutdown and capital investments forecasted through the remaining life of the plant. These are not additional costs to customers, but ones that are being incurred earlier than we originally planned.

The proposed change equates to an overall increase of $1,583,373, or 0.18 percent.

Transmission Revenue Deferral Recovery

Idaho Power's Open Access Transmission Tariff (OATT) defines the rates, terms and conditions of transmission services the company provides to wholesale customers per Federal Energy Regulatory Commission (FERC) regulations. An ongoing transmission case with the FERC had a significant impact on actual transmission revenues Idaho Power received from OATT customers, resulting in an overstatement of revenue credits given to Idaho customers from March 2008 through May 2010.

Idaho Power worked hard to successfully reduce the shortfall by more than $6 million. We're now requesting IPUC approval to begin the three-year amortization of the remaining $2,064,469 deferral.

We have requested an increase of $688,156 in the annual revenue recovered from Idaho customers beginning on June 1, 2012, for service provided on and after that date. This is a uniform percentage increase of 0.08 percent to all customer classes.

Non-AMI Meter Depreciation

Idaho Power has applied to the IPUC for authority to decrease its base rates due to the removal of the accelerated depreciation expense associated with non-Advanced Metering Infrastructure (AMI) metering equipment (mechanical meters).

This equipment will be fully depreciated on May 31, 2012. As a result, Idaho Power proposes to decrease annual revenue recovered from residential, small business, irrigation, and metered lighting customer classes by $10,551,216.

Idaho Power proposes a uniform percentage decrease of 1.22 percent to the above customers effective June 1, 2012, for service provided on and after that date.

Opportunities for Public Review

Idaho Power's filing is a proposal that is subject to public review and approval by the IPUC. Copies of the application are available to the public at the IPUC offices (472 W. Washington, Boise, ID), Idaho Power offices or on Idaho Power's website, www.idahopower.com or the IPUC

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website, www.puc.idaho.gov. You can view additional, related materials on the filing at www.idahopower.com/rates.

About Idaho Power Company:
Idaho Power began operations in 1916. Today, the electric utility employs approximately 2,000 people who serve nearly 500,000 customers throughout a 24,000-square-mile area in southern Idaho and eastern Oregon. With 17 low-cost hydroelectric projects as the core of its generation portfolio, Idaho Power's residential, business and agricultural customers pay among the nation's lowest rates for electricity. IDACORP, Inc. (NYSE: IDA) is the investor-owned utility's parent company based in Boise, Idaho. To learn more, visit www.idahopower.com or www.idacorpinc.com.

Contact: Stephanie McCurdy
Communication Specialist
Idaho Power
208-388-6973 and SMcCurdy@idahopower.com
1-800-458-1443 media line

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We value your business and appreciate you taking the time to read this notice. Thank you.

Important Information About Idaho Power Rates

Additional Spring Filings

We do anticipate making additional filings this spring that, in combination with the proposed changes outlined in this notice, will have a net effect on rates. These are typical annual evaluations and will include the annual Fixed Cost Adjustment (FCA), Power Cost Adjustment (PCA) and Revenue Sharing Adjustment.

Why We Need to Change Rates

As a regulated utility, Idaho Power invests up front to serve customers and recovers the cost of the investment, along with a commission-authorized fair return, later. We also need to pay our expenses as they occur.

To provide power today and to plan for tomorrow, we must invest in our aging infrastructure and in new infrastructure. As we add new resources in the future, to meet growth in customer demand or reduced generation from coal facilities, power supply expenses and customer rates will be impacted.

Opportunities for Public Review

Idaho Power's filing is a proposal that is subject to public review and approval by the IPUC. Copies of the application are available to the public at the IPUC offices (472 W. Washington, Boise ID), Idaho Power offices or on Idaho Power's website, www.idahopower.com or the IPUC website, www.puc.idaho.gov. You can view additional, related materials, including frequently asked questions and a news release on the filing at www.idahopower.com/rates.

We value your business and appreciate you taking the time to read this notice. Thank you.

Idaho Power's customers benefit from some of the lowest electricity rates in the nation. Recent filings will result in a net decrease to those rates for most customers.

On Feb. 15, Idaho Power made four filings with the Idaho Public Utilities Commission (IPUC). The net effect of these proposals will have differing impacts on the rates paid by our customers, effective June 1, 2012, with most seeing a net decrease. Details on those filings are as follows.

Depreciation Rate Changes (an increase)

Idaho Power has requested authorization from the IPUC to institute revised depreciation rates in our Idaho jurisdiction for our existing electric facilities. Depreciation rates establish the amount of time over which Idaho Power recovers its investments in the electrical system through rates.

The last changes to Idaho Power's depreciation rates became effective August 1, 2008. The revised depreciation rates proposed to become effective June 1, 2012, are based on the results of a detailed depreciation study examining Idaho Power's existing electric facilities-in-service as of June 30, 2011.

We're proposing a uniform increase of $2,656,213, or 0.31 percent for all customer classes. The change in depreciation rates and the corresponding customer rates would become effective June 1, 2012.

IDAHO POWER. An IDACORP Company

IDAHO POWER. An IDACORP Company

Early Shutdown of Boardman Coal Plant (an increase)

Idaho Power's operating partner has announced plans to shut down the coal-fired Boardman Power Plant in north-central Oregon in 2020. Idaho Power owns 10 percent of the facility.

In recognition of these plans, we are requesting an increase in customer rates effective June 1, 2012, resulting from the accelerated depreciation of the plant, decommissioning costs related to the plant shutdown and capital investments forecasted through the remaining life of the plant. These are not additional costs to customers, but ones that are being incurred earlier than we originally planned.

The proposed change equates to an overall increase of $1,583,373 or 0.18 percent.

Transmission Revenue Deferral Recovery (an increase)

Idaho Power's Open Access Transmission Tariff (OATT) defines the rates, terms and conditions of transmission services we provide to wholesale customers per Federal Energy Regulatory Commission (FERC) regulations. An ongoing transmission case with the FERC had a significant impact on actual transmission revenues Idaho Power received from OATT customers, resulting in an overstatement of revenue credits given to Idaho customers from March 2008 through May 2010.

Idaho Power worked hard to successfully reduce the shortfall by more than $6 million. We're now requesting IPUC approval to begin the three-year amortization of the remaining $2,064,469 deferral.

We have requested an increase of $688,156 in the annual revenue recovered from Idaho customers beginning on June 1, 2012, for service provided on and after that date. This is a uniform percentage increase of 0.08 percent to all customer classes.

Non-AMI Meter Depreciation (a decrease)

Idaho Power has applied to the IPUC for authority to decrease its base rates due to the removal of the accelerated depreciation expense associated with non-Advanced Metering Infrastructure (AMI) metering equipment (mechanical meters).

This equipment will be fully depreciated on May 31, 2012. As a result, Idaho Power proposes to decrease annual revenue recovered from residential, small business, irrigation, and metered lighting customer classes by $10,551,216.

Idaho Power proposes a uniform percentage decrease of 1.22 percent to the above customers effective June 1, 2012, for service provided on and after that date.

Overall Impact (a decrease for most customers)

We understand that multiple filings can be confusing for customers, and we want to help you understand what the result means to your bottom line. A summary of proposed changes to Idaho rates is shown below.

The net effect to customers of these four filings varies depending on your rate schedule. However, the result is a decrease for most customers. The bill impact for an average Idaho Power residential customer in Idaho using 1,050 kilowatt-hours of energy a month will be a bill decrease of $0.67 beginning June 1, 2012, if all proposals are approved as filed.

Revenue Impact By Class: Percentage Change from Current Billed Rates

	Residential	Small General Service	Large General Service	Large Power	Irrigation	Overall Change
Depreciation Rate Change	0.31%	0.29%	0.32%	0.27%	0.32%	0.31%
Boardman Shutdown	0.18%	0.17%	0.19%	0.16%	0.19%	0.18%
Transmission Revenue Deferral Recovery	0.07%	0.05%	0.09%	0.11%	0.08%	0.08%
Non-AMI Meter Depreciation	(1.36%)	(1.07%)	(1.63%)	0.00%	(1.69%)	(1.22%)
Net Change	**(0.80%)**	**(0.56%)**	**(1.03%)**	**0.54%**	**(1.10%)**	**(0.65%)**