

134 FERC ¶ 61,129
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

OPINION NO. 510

Portland Natural Gas Transmission System

Docket No. RP08-306-000

OPINION AND ORDER ON INITIAL DECISION

(Issued February 17, 2011)

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Portland Natural Gas Transmission System

Docket No. RP08-306-000

OPINION NO. 510

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KAREN V. JOHNSON, Presiding Administrative Law Judge.

OPINION NO. 510

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

Portland Natural Gas Transmission System

Docket No. RP08-306-000

OPINION NO. 510

ORDER ON INITIAL DECISION

(Issued February 17, 2011)

1. This order addresses briefs on and opposing exceptions to an Initial Decision (ID) issued on December 24, 2009 by the Presiding Administrative Law Judge (ALJ) in the captioned proceeding.¹ The ID set forth the ALJ's findings concerning a general rate case filed by Portland Natural Gas Transmission System (Portland) pursuant to section 4 of the Natural Gas Act (NGA) on April 1, 2008.

2. In this order, the Commission affirms the ALJ in part and reverses the ALJ in part. The Commission affirms the ALJ's findings in the ID with regard to levelized rates, two out of four cost-of-service issues raised, negative salvage, and in part on determinations relating to depreciation. The Commission reverses the ALJ in part with regard to the appropriate return on equity (ROE), resulting in a 12.99 percent ROE instead of the 11.65 percent adopted by the ALJ. The Commission also reverses the ALJ in part on two cost-of-service issues, ad valorem taxes and Pipeline Integrity Projects (PIP)/Maintenance of Mains. In addition, the Commission reverses the ALJ's proposal to allow Portland to file for an increased depreciation rate, finding that there is insufficient record evidence to support such a change. The Commission also reverses the ALJ's recommendation that Portland be required to credit its interruptible transportation (IT) and Park and Loan (PAL) revenues against its cost-of-service. Instead, the Commission requires Portland to allocate costs to its IT/PAL services based upon a projected volume

¹ *Portland Natural Gas Transmission System*, Initial Decision, 129 FERC ¶ 63,027 (2009) (ID).

of interruptible transportation, subject to the condition that Portland's overall rate design volumes must satisfy the at-risk condition of Portland's original certificate orders. Consistent with this determination to require Portland to allocate costs to its IT/PAL services, we reverse the ALJ with regard to the treatment of bankruptcy proceeds and require Portland to include billing determinants associated with the bankruptcy.

I. Background

3. Portland's interstate pipeline system was authorized by a series of Commission orders, which approved Portland's initial and amended applications and issued certificates of public convenience and necessity pursuant to NGA section 7(c), 15 U.S.C. § 717f (c).² Portland filed its initial application to construct and operate import facilities near the United States-Canada border and construct and operate an interstate pipeline to run from the border facilities into Massachusetts on March 14, 1996. On July 31, 1996, the Commission issued a Preliminary Determination on Portland's application, subject to the outcome of its review of environmental matters (the 1996 Certificate Order).³ Portland subsequently amended those applications and, in addition, filed another construction application jointly with Maritimes and Northeast Pipeline, LLC (Maritimes/Northeast). Under the amended application, Portland's import facilities connected with facilities to be constructed in Canada by Trans-Quebec & Maritimes Pipeline, Inc. (Trans-Quebec & Maritimes) and the interstate pipeline facilities consisted of 142 miles of mainline from the border crossing at Pittsburg, New Hampshire to Westbrook, Maine as well as two laterals (Northern Facilities).⁴ In addition, Portland and Maritimes/Northeast proposed to construct in two phases and thereafter operate joint facilities of about 101 miles from Westbrook, Maine to Dracut, Massachusetts, as well as three laterals (Joint Facilities).⁵ On July 31, 1997, the Commission issued a Preliminary

² See *Portland Natural Gas Transmission System*, 76 FERC ¶ 61,123, at 61,655 (1996) (issuing preliminary determination) (1996 Certificate Order), *order on reh'g*, 80 FERC ¶ 61,134 (issuing preliminary determination on amended application and denying rehearing) (July 1997 Certificate Order), *order on reh'g*, 80 FERC ¶ 61,345, at 62,145 (1997) (granting certificate authority and addressing rehearing requests) (September 1997 Certificate and Rehearing Order).

³ 1996 Certificate Order, 76 FERC ¶ 61,123 at 61,655 (application filed in Docket Nos. CP96-248-000 and CP96-249-000).

⁴ July 1997 Certificate Order, 80 FERC ¶ 61,134 at 61,445 (amended application filed in Docket Nos. CP96-248-000, *et al.* and CP96-249-000, *et al.* and joint application filed in CP97-238-000).

⁵ *Id.* at 61,445-46.

Determination on the amended application and the new application and granted and denied certain requests for rehearing of its July 1996 Certificate Order.⁶

4. Thereafter, on September 24, 1997, the Commission granted the requested certificate authorizations for the Northern and Joint Facilities.⁷ In the September 1997 Certificate and Rehearing Order, the Commission placed Portland at risk for unsubscribed capacity based on 178,000 Mcf per day for the first year of operation.⁸ The Commission left open whether to place Portland at risk for a higher capacity after the first year, stating it would review that matter when Portland made its first NGA section 4 rate filing.⁹ The Commission thus required Portland to make a section 4 rate filing within three years of the in-service date of its system “so that rates may be effective no later than the third anniversary of its in-service date.”¹⁰

5. Thereafter, on October 1, 2001, Portland made the section 4 rate filing required by the certificate orders in Docket No. RP02-13-000 (2001 Rate Filing). The Commission, in an order issued October 31, 2001, accepted and suspended the 2001 Rate Filing for five months — until April 1, 2002 — and made it subject to refund.¹¹ Subsequently, on October 25, 2002, Portland filed an uncontested Stipulation and Settlement Agreement to resolve all issues in Docket No. RP02-13-000 (2002 Settlement).

6. On January 14, 2003, the Commission approved the 2002 Settlement.¹² The 2002 Settlement established a firm transportation (FT) maximum recourse rate of \$0.85 per Dekatherm (Dth) effective April 1, 2002.¹³ It further stated that the Settlement Base Tariff Rates were designed “using rate levelization through March 31, 2020.”¹⁴ The

⁶ *Id.*

⁷ September 1997 Certificate and Rehearing Order, 80 FERC ¶ 61,345.

⁸ *Id.*, 80 FERC at 62,146.

⁹ 16 U.S.C. § 717c (2006).

¹⁰ September 1997 Certificate and Rehearing Order, 80 FERC ¶ 61,345 at 62,147.

¹¹ *Portland Natural Gas Transmission System*, 97 FERC ¶ 61,131 (2001), *settlement accepted in*, 102 FERC ¶ 61,026 (2003) (letter order) (2002 Settlement Order).

¹² *See* 2002 Settlement Order, 102 FERC ¶ 61,026.

¹³ *See id.* P 3.

¹⁴ *Id.* P 5.

settlement stated that its rate levelization methodology was the same as that approved in Portland's certificate proceeding, except that the levelization period had been extended by one year. The 2002 Settlement also modified the Most Favored Nations (MFN) clause contained in the contracts of long-term firm shippers to allow Portland to discount contracts of less than two years without being required to offer the same terms to its long-term firm shippers.¹⁵ The 2002 Settlement required Portland to file a general NGA section 4 rate case no sooner than, and no later than, April 1, 2008.¹⁶ The 2002 Settlement required Portland to continue to propose to design its rates using the same rate levelization methodology as in the settlement. Finally, the 2002 Settlement required Portland to use a 2.0 percent depreciation rate for transmission plant in its next general rate filing.

7. On April 1, 2008, Portland made the NGA section 4 rate filing as required by the 2002 Settlement (2008 Rate Filing), which is the subject of the instant proceeding.¹⁷ In the 2008 rate filing, Portland sought to increase the FT recourse rate by approximately 6 percent, asserted that increased risk on its system warranted an ROE well above the median and, while filing to continue use of a 2.0 percent depreciation rate for transmission, submitted testimony seeking a significantly higher depreciation rate on a prospective basis. According to Portland, its proposed cost-of-service and determination of rates reflect the costs and throughput for the Base Period (12 months ending December 31, 2007) as adjusted through the Test Period ending September 30, 2008.¹⁸ The Commission accepted and suspended Portland's tariff sheets until September 1, 2008, subject to refund, and established procedures for an evidentiary hearing.¹⁹

8. On May 11, 2009, Portland submitted a Motion for Certification and Approval of Partial Settlement (2009 Settlement) resolving all outstanding issues related to the design of Portland's rates for short-term services. The motion was subject to comment by the parties. The ALJ certified the 2009 Settlement to the Commission on June 18, 2009, and the Commission approved the 2009 Settlement on September 23, 2010, finding that the

¹⁵ *Id.* P 6.

¹⁶ *Id.* P 7.

¹⁷ Portland filed its direct case with its proposed rate application.

¹⁸ Portland 2008 Rate Filing at 3.

¹⁹ *Portland Natural Gas Transmission System*, 123 FERC ¶ 61,108 (2008) (Hearing Order on 2008 Rate Filing), *partial settlement accepted in* 132 FERC ¶ 61,256 (2010) (Order on 2009 Settlement).

settlement was uncontested and reflected a just and reasonable negotiated resolution of issues related to the design of Portland's rates for short-term services.²⁰

9. The hearing on the remaining issues commenced on July 13, 2009 and concluded on July 28, 2009. Testimony was taken from 18 witnesses and over 300 exhibits were received into evidence. Portland, Trial Staff, PNGTS Shippers Group (PSG), Canadian Association of Petroleum Producers (CAPP), and Calpine Energy Services, L.P. (CES) were active participants.

10. Finally, on May 12, 2010 Portland filed a separate, general section 4 rate case (2010 Rate Filing). Thus, the resulting rates determined in this proceeding are effective only for a locked-in period from September 1, 2008 through November 30, 2010. The rates in the 2010 Rate Filing went into effect, subject to refund, on December 1, 2010.²¹

II. Levelized Rate Structure

11. As required by the 2002 Settlement, Portland proposed to design its rates in this proceeding using a levelized cost-of-service. The participants raised two major issues regarding the consistency of Portland's proposed levelized cost-of-service rates with the requirements of the settlement: (1) the appropriate rate levelization methodology and model for this proceeding; and (2) the appropriate period over which levelization is to take place. The ALJ in the ID found that the 2002 Settlement requires that an iterative levelization methodology and model must be used to establish Portland's levelized cost-of-service in this proceeding²² and the "appropriate levelization period is 21 years, such that the levelization period ends on March 31, 2020."²³ As discussed below, the Commission affirms the ALJ on both issues.

A. Levelization Methodology

12. The active participants in this proceeding agree that Portland must design its rates on a levelized rather than a traditional cost-of-service basis. As the Commission recently explained:

²⁰ Order on 2009 Settlement, 132 FERC ¶ 61,256.

²¹ See *Portland Natural Gas Transmission System*, 131 FERC ¶ 61,230 (2010) (Hearing Order on 2010 Rate Filing); see also Portland's Motion to Place Suspended Rates and Tariff Sheets into Effect, Docket No. RP11-1541-000 (Nov. 22, 2010).

²² ID, 129 FERC ¶ 63,027 at P 39.

²³ *Id.* P 63.

Under a traditional rate design, the Commission awards a return based on the rate base existing at the end of the test period, and subsequent declines in the rate base as depreciation is recovered are not taken into account unless and until the pipeline files a new NGA section 4 rate case. Levelizing a pipeline's rates over its life provides lower rates at the initiation of service than a traditional rate making methodology but, over time as the traditional rate base declines, the levelized rate will become higher than traditionally designed rates. In essence, levelization is accomplished by the pipeline deferring to later years recovery of costs that would otherwise be recoverable early in its life.²⁴

13. As the ALJ pointed out, levelized rates are generally derived by projecting the traditional cost-of-service for some number of annual periods into the future. Based upon this projection, the pipeline determines a single "levelized" cost-of-service that will be fully compensatory to investors throughout all of the annual periods projected for the "levelization period."²⁵ This levelization is "generally employed to reduce traditional cost-of-service rates in the early years of a project by deferring a portion of the annual cost-of-service to later years of the project's life when annual costs would generally be lower (due to the reduction of plant and rate base by depreciation accumulated in prior years)."²⁶

14. While the parties agree that Portland must derive its cost-of-service rates on a levelized basis in this proceeding, they disagree as to the manner in which the levelized rates are to be derived. Specifically, Portland proposed to levelize its rates in this case using a net present value (NPV) methodology.²⁷ However, PSG and Trial Staff argue that the 2002 Settlement Order requires that the rates should be derived through an iterative process.²⁸ The ALJ noted that the NPV process and the iterative process employ

²⁴ *Kern River Gas Transmission Co.*, Opinion No. 486, 117 FERC ¶ 61,077 (2006), *order on reh'g*, Opinion 486-A, 123 FERC ¶ 61,056 (2008), *order on reh'g*, Opinion 486-B, 126 FERC ¶ 61,034, *order on reh'g*, Opinion No. 486-C, 129 FERC ¶ 61,240 (2009), *order on reh'g*, Opinion No. 486-D, 133 FERC ¶ 61,162, at P 156 (2010) (*Kern River*).

²⁵ *Id.*, 129 FERC ¶ 63,027 at P 20 (citing Ex. No. PSG-19 at 4-5).

²⁶ *Id.*

²⁷ *Id.* P 21 (citing Ex. No. PNG-31 at 1-2).

²⁸ *Id.* (citing Ex. No. PSG-19 at 19-20 and Ex. No. S-15 at 5-6).

fundamentally different approaches to deriving a levelized cost-of-service, in that the NPV methodology takes a “financial” approach to calculating the levelized cost-of-service,²⁹ while the iterative methodology makes use of an “accounting” approach to calculating a levelized cost-of-service.³⁰ According to the ID, one significant difference between the NPV and the iterative methodologies is that the iterative method generates a schedule of Deferred Regulatory Assets (DRA) over the rate levelization period and the NPV model does not.³¹

²⁹ *Id.* P 22. The ALJ relied on testimony describing the NPV methodology as follows:

[A]ssume that a levelization period is ten years. Under the NPV methodology, a forward projection of the traditional cost-of-service would be made for each of the next ten years, and the present value of those projected costs-of-service is then calculated. Taking that present value as the target, one can employ the mathematics of finance to calculate a level annual payment which is equal to the (i) present value of the projected future cost-of-service; divided by (ii) a present value interest factor for an appropriate annuity. This level annual payment becomes the levelized cost-of-service to be utilized in each year over the levelization period. [ID, 129 FERC ¶ 63,027 at P 22 (citing Ex. PSG-19 at 7).]

³⁰ The ALJ relied on testimony describing the “iterative” methodology as follows:

Under this approach, costs that are deferred in the early years of the levelization period are recorded as a regulatory asset (in FERC Account No. 182.3 (“Other Regulatory Assets”)) and included in rate base. In employing this methodology to seek a levelized cost-of-service, one is searching for a periodic payment which (i) recovers all the traditional cost-of-service over the levelization period; (ii) recovers a compensatory return on the regulatory asset in Account No. 182.3; and (iii) fully amortizes as of the end of the rate levelization period the balance in Account No. 182.3. Technically, one makes repeated estimates of the levelized cost-of-service until the projected balance in Account No. 182.3 as of the end of the levelization period is zero. Since the procedure requires a series of repeated calculations, it is an “Iterative” methodology. [ID, 129 FERC ¶ 63,027 at P 23 (citing Ex. PSG-19 at 8).]

³¹ *Id.*

15. As noted, the ALJ's decision on this issue relies on the 2002 Settlement resolving Portland's first NGA section 4 rate filing, the 2001 Rate Filing.³² The 2002 Settlement established an FT maximum recourse rate effective April 1, 2002,³³ and stated that the Settlement Base Tariff Rates were "designed using rate levelization through March 31, 2020."³⁴ The following key provisions are also contained in the 2002 Settlement, Article III, section 3.1:

(a) The Settlement Base Tariff Rates are designed using rate levelization through March 31, 2020, as reflected in Appendix D (Levelization Schedule). The levelization methodology used by [Portland] is the same as that approved in [Portland's] certificate orders, except that the remaining levelization period has been extended by approximately one year (to reflect the full period covered by all of [Portland's] existing Long-term FT Contracts) and the cost-of-service has been modified consistent with Section 3.4 below.

(b) [Portland] shall continue to propose to design its FT rates based on the levelization methodology reflected in Appendix D for the entire period through March 31, 2020, subject to adjustments to the cost-of-service in accordance with this Settlement *or in future proceedings following termination of this Settlement in accord with Article VI below.*

(c) The Commission's order approving this Settlement in accord with Article VII shall constitute all necessary rate and accounting authority for [Portland] to continue to record and recover the deferred regulatory asset in accordance with the levelization methodology approved as part of this Settlement, as reflected on Appendix D, for the entire period levelized rates are in effect. [Emphasis added, footnote omitted].

16. Appendix D to the 2002 Settlement is a "Rate Levelization Schedule," which lists each year of the levelization period, the annual change in value of the deferred regulatory asset for each of the years in the levelization period, and the deferred asset balance for each of those years. According to the schedule, years 1-3 of the levelization period are

³² 2002 Settlement Order, 102 FERC ¶ 61,026.

³³ *Id.* P 3.

³⁴ *Id.* P 5.

represented by an “End of Test Period” designation, noting that the date is March 31, 2002. It then lists Years 4-21 with the information noted above. Footnote 3 to the Appendix D states that the levelization period ends March 31, 2021.

Initial Decision

17. The ALJ found that the 2002 Settlement required the use of an iterative levelization methodology and model in this case. The ALJ stated that only the iterative model could produce a DRA schedule such as the one contained in Appendix D of the 2002 Settlement. According to the ALJ, the “DRA schedule in Appendix D makes clear that the 2002 Settlement has used an iterative process to derive the levelized cost-of-service.”³⁵ The ALJ found that while the 2002 Settlement does not expressly use the term “iterative,” the DRA schedule in Appendix D makes clear that the 2002 Settlement used an iterative process to derive the levelized cost-of-service. In so finding, the ALJ declared that “the distinction [Portland] attempted to draw between ‘methodology’ and ‘model’ has no real meaning in the context of this case.”³⁶

18. The ALJ also found that that the iterative model proposed by PSG’s Witness Briden is able to “honor” the 2002 Settlement because that model, which yielded a cost-of-service within \$2.00 of that produced by the 2002 Settlement iterative model, demonstrates that the PSG model successfully replicated the 2002 Settlement iterative model.³⁷ In contrast, the ALJ found that the testimony of PSG Witness Briden and Trial Staff Witness Sosnick demonstrated that Portland Witness Lovinger’s NPV model does not replicate the 2002 Settlement model.³⁸

19. The ALJ also agreed with PSG and Trial Staff that the fact that an iterative model may not replicate the DRA balances in Appendix D of the 2002 Settlement is not relevant. The ALJ found that because footnote 2 in Appendix D to the 2002 Settlement states that the annual balances “are based on the Cost-of-Service” which, in turn, “is subject to change in accordance with the Settlement or in future proceedings,”³⁹ it

³⁵ ID, 129 FERC ¶ 63,027 at P 39.

³⁶ *Id.*

³⁷ *Id.* P 40.

³⁸ *Id.* (citing Ex. No. PSG-19 at 19-20; Ex. No.S-15 at 8-9).

³⁹ *Id.* P 41 (citing Ex. No. PSG-5 at 30 n.2).

“logically follows that the annual DRA balances will change as [Portland’s] cost-of-service changes from its October 2002 Settlement level.”⁴⁰

Briefs on Exceptions

20. Portland takes exception to the ALJ’s determination that an iterative levelization model, rather than a NPV model, should be used to establish the levelized cost-of-service for Portland.⁴¹ Portland states that in comparison to the NPV model, the iterative model endorsed by the ALJ would re-balance the recovery of the regulatory asset, deferring the date when the balance of the regulatory asset peaks, increasing the amount at which it peaks (thereby further deferring the recovery of the regulatory asset), and consequently increasing the risk to which Portland is exposed.

21. Portland argues that the 2002 Settlement did not define a levelization “model,” but rather it reflected a schedule over which the regulatory asset created by deferring depreciation would grow, peak and ultimately be amortized, to achieve levelization.⁴² According to Portland, the schedule that set out the annual balances of the regulatory asset was embodied in Appendix D to the 2002 Settlement. Portland argues that an NPV model permits the regulatory asset balances in Appendix D to the 2002 Settlement to be exactly replicated in future computations of rates.⁴³

22. Portland asserts that an iterative model, by contrast, “can generate regulatory asset balances by year.”⁴⁴ Portland argues that the inherent function of the iterative model is that it spreads the recovery of a regulatory asset balance across the remaining levelization period. Portland contends that if the iterative model is re-run at subsequent dates, the years remaining in the levelization period decrease, and the iterative model changes the amount of regulatory asset remaining in any given year of the levelization schedule. Therefore, Portland argues that if the rates are re-computed for Portland in the future, the use of the iterative model to do so will compound the effects identified above (such as re-balancing the recovery of the regulatory asset, deferring the date when the balance of the regulatory asset peaks, increasing the amount at which the regulatory asset peaks, and thereby increasing Portland’s risk exposure) relative to any regulatory asset recovery

⁴⁰ *Id.*

⁴¹ Portland Brief on Exceptions at 9.

⁴² *Id.*

⁴³ *Id.* at 10.

⁴⁴ *Id.*

schedule. Portland concludes therefore that its risks will be increased as the regulatory asset's collection is deferred by implementation of the iterative model. Portland argues that it is illogical to both increase its risks and to ignore the consequences of this change upon its risk profile, and thus the ALJ erred by rejecting Portland's proposed NPV model.

Briefs Opposing Exceptions

23. Trial Staff and PSG oppose Portland's exception to the ALJ's determination that Portland must use the iterative methodology to derive its levelized rates. In its Brief Opposing Exceptions, Trial Staff claims that Portland's tendency in this case to rely on general references to the evidence in the proceeding rather than specific references to specific facts causes Portland to ignore the factually supported findings made by the ALJ on the levelization issue.⁴⁵ Trial Staff also claims that given the fact that Portland's own witness admitted that an iterative levelization process was used to design the 2002 Settlement rates, it was reasonable for the ALJ to rule that honoring the 2002 Settlement requires the use of an iterative levelization methodology.⁴⁶

24. PSG also opposes Portland's contention that its proposed NPV rate levelization methodology and model should have been adopted instead of an iterative levelization methodology. PSG asserts that this contention contravenes Portland's obligations under the 2002 Settlement. According to PSG, the record in the instant proceeding establishes that the 2002 Settlement adopted essentially the same iterative levelization methodology and model that was approved in Portland's original system certification proceedings. Further, PSG argues that the 2002 Settlement obligated Portland to continue using this same iterative levelization methodology and model. PSG asserts that the ALJ was correct in rejecting Portland's attempt to substitute an entirely different methodology and model that would produce a substantially higher levelized cost-of-service.

25. PSG argues that Portland does not directly challenge four of the findings that underpin the ALJ's decision regarding the use of the iterative method. In particular, PSG argues that Portland did not specifically contest the finding that a proper interpretation of the 2002 Settlement did not require one to distinguish between a levelization "methodology" and a levelization "model." Secondly, PSG points out that Portland does not dispute that an iterative levelization methodology and model "honor" the 2002 Settlement. Thirdly, PSG argues that Portland does not dispute that the 2002 Settlement contemplates that the deferred regulatory asset balances resulting from rate levelization, reflected in Appendix D to the 2002 Settlement, will change over time in conjunction with changes to Portland's cost-of-service that occur in future rate cases. Lastly, PSG

⁴⁵ Trial Staff Brief Opposing Exceptions at 6.

⁴⁶ *Id.* at 7.

argues that Portland did not directly dispute that the 2002 Settlement requires the use of an iterative levelization methodology and model in this case.

26. PSG argues that instead of disputing the above findings by the ALJ, Portland merely contends that its risks will be increased by use of an iterative model, and that it is illogical for the ALJ to fail to acknowledge this increased risk profile. PSG states that this provides no legal basis to modify the ALJ's decision. PSG argues that because the undisputed facts establish that the 2002 Settlement employed an iterative levelization methodology, and that such settlement obligated Portland to continue using that same methodology, Portland's contention regarding its purported increased risks has no merit, for all else being equal, maintaining the status quo will not affect Portland's risks in any respect. According to PSG, the only way Portland's arguments as to increased risk could be legitimate would be if the ID required Portland to use a levelization methodology different from that adopted in the 2002 Settlement. PSG contends that is not the case, however, because the methodology adopted in the ID is exactly the same as that to which the parties to the 2002 Settlement agreed.⁴⁷

Commission Determination

27. The Commission finds that the ALJ's determination that Portland must use an iterative method to derive its levelized rates in this proceeding is just and reasonable. The record evidence shows that Portland agreed in the 2002 Settlement to utilize a levelized rate design for future rate cases. The 2002 Settlement also states that Portland must use the same methodology used in the 2002 Settlement to design its rates for future proceedings. The record demonstrates that Portland used the iterative methodology to derive the levelized rates in the 2002 Settlement. Accordingly, Portland must use that same iterative methodology in the instant case.

28. Portland's assertions to the contrary are without merit. No participant in the instant proceeding, including Portland, disputes that the 2002 Settlement requires Portland to use a rate levelization methodology to derive its rates in this proceeding. Section 3.1(a) of the 2002 Settlement identifies the levelization methodology to be used to derive the Settlement rates, namely the methodology adopted in Portland's original certificate proceedings.⁴⁸ Section 3.1(b) of the 2002 Settlement requires the use of that

⁴⁷ PSG Brief Opposing Exceptions at 13-14.

⁴⁸ See Tr. 824/15-826/17. The 2002 Settlement identifies the original certificate proceedings at issue: 1996 Certificate Order, 76 FERC at 61,657-58 (order issuing preliminary determination); July 1997 Certificate Order, 80 FERC at 61,455 (order on rehearing and clarification); September 1997 Certificate and Rehearing Order, 80 FERC ¶ 61,345 (order issuing certificates).

same methodology to design Portland's rates in the future. Thus, the 2002 Settlement requires that Portland use a levelized rate methodology in all future proceedings, including this one. Portland's own witness testified that the 2002 Settlement utilized the same iterative methodology that was used in Portland's certificate proceedings.⁴⁹ Accordingly, Portland must use that same iterative methodology to design its rates in this proceeding.

29. Second, with regard to Portland's assertion that the 2002 Settlement did not define a levelization model, but rather it reflected a schedule that set out the annual balances of the regulatory asset embodied in Appendix D to that Settlement, the ALJ expressly found that the DRA schedule in Appendix D makes clear that the Settlement used an iterative process to derive the levelized cost-of-service. As Portland's witness admitted, the NPV model will not produce a DRA schedule such as the one contained in Appendix D to the 2002 Settlement.⁵⁰ Because the record evidence demonstrates that only the iterative model can produce a DRA schedule such as the one in Appendix D of the 2002 Settlement, it was reasonable for the ALJ to conclude that the iterative model is able to "honor" the 2002 Settlement while the NPV model is not. In addition, the record shows that the iterative model yielded a levelized cost-of-service within \$2 of that produced by the 2002 Settlement model, which supports the conclusion that the iterative model in the record in this proceeding successfully replicated the 2002 Settlement model. In contrast, the record testimony of PSG Witness Briden and Trial Staff Witness Sosnick demonstrate that Portland Witness Lovinger's NPV model does not replicate the 2002 Settlement model.⁵¹ Portland provides no evidence to the contrary.⁵²

⁴⁹ Tr. 595-96; 882/16-20.

⁵⁰ ID, 129 FERC ¶ 63,027 at P 39:

Q And a net present value levelization methodology will not produce a schedule of deferred regulatory assets like that appearing in appendix D, will it, Mr. Lovinger?

A No, it will not.

⁵¹ *Id.* P 40 (citing Ex. No. PSG-19 at 19-20; Ex. No. S-15 at 8-9).

⁵² We also reject Portland's argument that the 2002 Settlement only set forth a "methodology," not a "model," for deriving its rates. As noted, Portland contends that because neither the 2002 Settlement nor the Commission's order approving that Settlement identified any "model" to be used to derive levelized rates, Portland may use its NPV model to derive rates under the levelized methodology. Portland's argument is lacking as it never describes, defines or provides evidence as to what it or the parties to

(continued...)

30. We also reject Portland's argument that requiring use of an iterative methodology to derive levelized rates would elevate Portland's risks. As shown above, Portland agreed to this methodology and risk sharing stipulation in the 2002 Settlement. The precepts of the 2002 Settlement are reflected in the instant filing as required by that Settlement and the rates are calculated in a like manner. Thus, the ALJ's finding that Portland must use an iterative methodology does not elevate Portland's risk level; it merely holds Portland to the risks Portland assumed in agreeing to the 2002 Settlement. In fact, permitting Portland to derive its levelized rates in some other manner than that required by the 2002 Settlement would unfairly prejudice the other parties to the Settlement. Accordingly, the Commission finds that the ALJ's determination is just and reasonable.

B. Levelization Deferral Period

31. In its 2008 rate filing, Portland proposed a 21-year levelization period commencing on April 1, 1999 and ending on March 31, 2020, which Portland claimed was consistent with the plain language of section 3.1 of the 2002 Settlement.⁵³ Portland also argued that the March 31, 2020 termination date is consistent with the Commission's order approving the 2002 Settlement,⁵⁴ as that order "unequivocally" stated that the levelization period ended March 31, 2020. Portland also argued that the levelized cost-of-service was intended to be fully compensatory to investors throughout the levelization period and that the only way this may be accomplished is if Portland can fully recover the deferred depreciation during the 2002 Settlement levelization period.⁵⁵

32. PSG argued that the levelization period spans 22 years such that the period ends on March 31, 2021. According to PSG, the 2002 Settlement levelization model and

the 2002 Settlement meant by "methodology." Portland does not argue this point in its Brief on Exceptions, and, as pointed out by the participants in this proceeding, Portland's witness used these two terms interchangeably and could not cite any instance in his rebuttal testimony in which he made the distinction between "methodology" and "model." *Id.* P 36.

⁵³ According to Portland, the first sentence of section 3.1 of the 2002 Settlement states that the levelized rates are designed using "levelization through March 31, 2020" and section 3.1(b) of the 2002 Settlement and the Explanatory Statement accompanying the 2002 Settlement support the claim that the levelization period would end in 2020.

⁵⁴ ID, 129 FERC ¶ 63,027 at P 42. *See* 2002 Settlement Order, 102 FERC ¶ 61,026.

⁵⁵ ID, 129 FERC ¶ 63,027 at P 43 (citing Ex. No. PNG-37).

Witness Briden’s model in the instant case both use a 22-year levelization period. PSG argued during the hearing that the source of this levelization period is a “2008 Case” tab in the Microsoft Excel version of the 2002 Settlement levelization model, which reflects the intent of the parties to that 2002 Settlement, and includes a “Year 22.”⁵⁶ PSG also argued that Footnote 3 in Appendix D to the 2002 Settlement, which states that the “levelization period ends March 31, 2021,” is dispositive.⁵⁷

33. Trial Staff argued before the ALJ that the appropriate levelization period was difficult to determine. However, Trial Staff ultimately argued that the appropriate end date for the levelization period was October 31, 2020, based on the language in section 3.1(a) stating that the levelization period would be extended by one year “to reflect the full period covered by all of [Portland’s] existing Long-term FT contracts. . . .” and the fact that at the time the 2002 Settlement was executed, Portland had a long term contract with Rumford Power Associates, LP that ran until October 31, 2020 (Rumford Agreement). Trial Staff argued that because the outstanding Rumford Agreement was scheduled to end on October 31, 2020, a levelization period that ends on October 31, 2020 best reflected the intent of the settling parties in section 3.1(a) of the 2002 Settlement to reflect the full period covered by all of Portland’s existing long-term FT contracts.⁵⁸

34. Portland replied that proposals of PSG and Trial Staff to extend the levelization period beyond March 31, 2020 would not be fully compensatory to investors as set forth above. Portland argued that footnote 3 in Appendix D of the 2002 Settlement, relied upon by those advocating extension, contains a typographical error and is inconsistent with both section 3.1 of the 2002 Settlement and the DRA deferral and recovery schedule in Appendix D to the 2002 Settlement.⁵⁹

⁵⁶ *Id.* P 49-50. According to PSG, Portland provided the “2008 Case” tab to the participants in the proceeding during discovery.

⁵⁷ *Id.* P 51.

⁵⁸ *Id.* P 62 (citing Trial Staff Initial Brief at 24).

⁵⁹ *Id.* P 47. According to the ALJ, Portland stated that Appendix D continues for a total of 17 complete years. However, Portland points out that as the total time period in Appendix D runs from Year 4 through Year 21, the time period actually appears to consist of 18 years. Eighteen years from the March 31, 2002 — the date of the end of the test year — is March 31, 2020. ID, 129 FERC ¶ 63,027 at P 47 & n.2.

Initial Decision

35. The ALJ found that the appropriate levelization period was 21 years and that such a levelization period ends on March 31, 2020.⁶⁰ The ALJ found that the March 31, 2020 date represented the original intent of the parties to the 2002 Settlement. The ALJ noted that section 3.1(a) of the 2002 Settlement states that, “The Settlement Base Tariff Rates are *designed* using rate levelization through March 31, 2020, as reflected in Appendix D ([Rate] Levelization Schedule).”⁶¹ The ALJ interpreted this statement to mean that the levelization period was meant to end on March 31, 2020 or else the provision would be devoid of any meaning.

36. To further support the finding in the ID, the ALJ noted that both the 1996 Certificate Order and the July 1997 Certificate Order referenced by section 3.1(a) of the 2002 Settlement state that the levelization period is 20 years.⁶² The ALJ pointed out that section 3.1(a) to the 2002 Settlement also states:

The levelization methodology used by [Portland] is the same as that approved in [Portland’s] certificate orders, except that the remaining levelization period has been extended *by approximately one year* (to reflect the full period covered by all of [Portland’s] existing Long-term FT Contracts).

The ALJ reasoned that because the original levelization period is 20 years, and the October 2002 Settlement extends the levelization period “by approximately one year,” the relevant levelization period is 21 years.

37. The ALJ also addressed Footnote 3 to Appendix D of the 2002 Settlement,⁶³ relied on by PSG. The ALJ determined that the context of this footnote in Appendix D lends credence to Portland’s assertion that the date in Footnote 3 was an error.⁶⁴ The ALJ reasoned that the fact the last period listed in the DRA schedule in Appendix D is “Year 21” and there was no reference to a “Year 22,” and that the DRA balance

⁶⁰ *Id.* P 63.

⁶¹ *Id.* P 64 (citing Ex. No. PSG-5 at 6).

⁶² *Id.* P 65 (citing 1996 Certificate Order, 76 FERC at 61,657; July 1997 Certificate Order, 80 FERC at 61,446, 61,455).

⁶³ *Id.* P 67.

⁶⁴ *Id.*

corresponding to “Year 21” is “(0),” imply that “Year 21” was the last year of the levelization period.⁶⁵

38. The ALJ also found that “2008 Case” tab, which was a part of a levelization model in the 2002 Settlement, contravened that Settlement. The ALJ noted that, contrary to Appendix D, under this model exhibit, the DRA balance is still positive in “Year 21” and becomes “(0)” in “Year 22.”⁶⁶ The ALJ also found that case tab was inconsistent with Exhibit No. PSG-21, the actual unformatted 2002 Settlement model, which also lists the DRA balance for “Year 21” as (0), and Exhibit No. PSG-26, Witness Briden’s reformatted model used to replicate the 2002 Settlement model.⁶⁷

Briefs On and Opposing Exceptions

39. PSG excepts to the ALJ’s finding that the levelization period in the instant proceeding should end on March 31, 2020. PSG argues that this finding is inconsistent with three separate pieces of record evidence, which it asserts the ALJ failed to reconcile with the finding in the ID on this matter. First, PSG argues that Section 3.1(a) of the 2002 Settlement stated that the “levelization methodology used by [Portland] is the same as that approved in [Portland’s] certificate orders, except that the remaining levelization period has been extended by approximately one year (to reflect the full period covered by all of [Portland’s] existing Long-term FT contracts)”⁶⁸ PSG argues that the ALJ recognized that at the time the Settlement was executed, Portland had the long term Rumford Agreement that ran until October 31, 2020. PSG argues that because the 2002 Settlement used an April-to-March levelization period, the first annual levelization period that would have encompassed the full period covered by the term of the Rumford Agreement would be one ending March 31, 2021, consistent with the levelization period

⁶⁵ *Id.* Further, the ALJ reasoned that, Appendix D of the 2002 Settlement clarifies that “Year 21” ends on March 31, 2020 and not March 31, 2021. The ALJ found that Footnote 1 in Appendix D, references the “End of Test Period” in Appendix D, and lists a date of March 31, 2002. Therefore, the ALJ reasoned that “Year 4,” the first year listed in Appendix D, runs from April 1, 2002 through March 31, 2003 and, therefore, “Year 5” must span from April 1, 2003 to March 31, 2004 and so forth concluding in “Year 21,” to which Footnote 3 refers, which must span from April 1, 2019 to March 31, 2020. *ID*, 129 FERC ¶ 63,027 at P 68.

⁶⁶ *ID*, 129 FERC ¶ 63,027 at P 69 (citing Ex. PSG-115).

⁶⁷ *Id.*

⁶⁸ PSG Brief on Exceptions at 18 (citing Ex. No. PSG-5 at 6, section 3.1(a) (footnote omitted)).

end-date stated in Appendix D. PSG contends that there is no evidence to contradict the express Settlement provision that the levelization period encompasses “the full period covered” by all of Portland’s then existing long term firm transportation agreements, and that one such agreement ran until October 31, 2020.

40. PSG argues that the ALJ recognized this fact but determined that because the October 31, 2020 Rumford Agreement end-date was not explicitly set forth elsewhere in the Settlement, this language of the Settlement could be ignored. PSG counters that the subject Settlement does not set forth any of Portland’s long-term FT agreement end-dates and that this determination effectively writes this language of Section 3.1(a) of the 2002 Settlement out of the agreement.

41. Second, PSG argues that footnote 3 to Appendix D of the 2002 Settlement states that “[t]he levelization period ends March 31, 2021,” which PSG asserts is consistent with the language of section 3.1(a) (i.e., asserting that the period reflected “the full period covered by all of [Portland’s] Long-term FT contracts”). PSG argues that the ALJ found this language to be an error, but PSG asserts that the only evidence considered by the ALJ to reach this determination was a self serving assertion from Portland’s Witness that the reference to March 2021 was an error.

42. Third, PSG argues that the ALJ’s finding renders meaningless the “2008 Case” tab included by the settling parties in the electronic levelization model designed to implement the 2002 Settlement levelization methodology in the instant proceeding. PSG argues that the ALJ accorded this model “little weight” for two reasons. First, the ALJ found it inconsistent with the levelization period employed by PSG Witness Dr. Briden in the electronic application of the 2002 Settlement levelization model to the 2002 Settlement inputs. Second, the ALJ found that the settling parties in Docket No. RP02-13-000 did not need to adapt the Docket No. RP02-13-000 electronic levelization model to correlate with an anticipated month-to-month annual effective rate period in the instant case that would be different from the annual effective rate period utilized in the RP02-13-000 proceedings, because the 2002 Settlement provided the 2008 case would be filed with a proposed April 1 (2008) effective date to match the April 1 (2002) effective date of the rates in the Docket No. RP02-13-000 proceeding.

43. PSG argues that both of these findings are based on the misconception that the parties to the 2002 Settlement would not have anticipated a five (5) month suspension in the 2008 rate case. However, PSG argues that this is the normal course of such rate cases. Furthermore, PSG argues that the parties would have anticipated such a suspension and that such suspension would result in a “mismatch” between the annual effective rate period occurring in the 2002 Settlement proceedings, on the one hand, and the instant or “2008 case” proceedings, on the other. PSG argues that this is why the 2002 Settlement electronic levelization model applied the 2002 Settlement levelization methodology to the April-to-March annual effective rate period occurring in the 2002

Settlement proceedings, and then in the “2008 Case” tab adapted it to account for the slightly different annual effective rate period (September-to-August) arising in the anticipated 2008 Rate Case.

44. Lastly, PSG argues that the ALJ evidenced confusion over how the October 2002 Settlement rates could be designed using levelization for one period, ending March 2021, while the pipeline’s obligation to employ levelization under section 3.1(b) ends on March 31, 2020. PSG argues that this confusion led to the rejection of the March 31, 2021 end-date stated in Appendix D to the 2002 Settlement. PSG asserts that because the 2002 Settlement does not guarantee Portland recovery of the DRA generated by the 2002 Settlement rate levelization methodology, it did not need to correlate Portland’s section 3.1(b) obligation to design rates employing levelization (which extended to March 31, 2020) with the levelization period used (ending March 31, 2021). PSG argues that the levelization period employed and the obligation to continue utilizing rate levelization are two different and independent periods that may often, but need not, run in perfect parallel.

45. In sum, PSG argues that the ALJ’s adoption of the March 31, 2020 levelization period shortens by one year the levelization period expressly stipulated in Appendix D to the 2002 Settlement, and effectively rolls back the timing of Portland’s recovery of its DRA such that shippers in March 2020 will now be required to pay a DRA balance which otherwise would have been recovered in the ensuing twelve months from a different mix of shippers. PSG argues that this action is contrary to the evidence in this case, and that the ALJ’s determination should be modified so that the levelization period to be utilized in the instant case extends until March 31, 2021.

46. Portland opposes PSG’s exception on this point. Portland asserts that PSG’s claims that levelization period should “extend to March 31, 2021 and end[] in Year 22” are inconsistent with the 2002 Settlement, the Appendix D thereto, and with the Commission order approving such Settlement.⁶⁹ Portland also contends that following PSG’s approach would disrupt the synchronization of the recovery of the deferred depreciation regulatory asset with the period over which Portland’s rates are to be levelized. Accordingly Portland argues that PSG has engaged in collateral attack on a final non-appealable settlement and asserts that the levelization period ending no later than March 31, 2020 is just and reasonable because it is what was agreed to in the 2002 Settlement.

⁶⁹ Portland Brief Opposing Exceptions at 5.

Commission Determination

47. The Commission finds that the ALJ properly analyzed the 2002 Settlement and correctly determined that the appropriate levelization period in the instant proceeding is a 21-year period that should end on March 31, 2020.

48. As noted by the ALJ, section 3.1(a) of the 2002 Settlement states that the rates in that Settlement “are designed using rate levelization through March 31, 2020.” Section 3.1(a) then explains that the levelization methodology used by Portland “is the same as that approved in [Portland’s] certificate orders, except that the remaining levelization period has been extended by approximately one year (to reflect the full period covered by all of [Portland’s] existing Long-term FT Contracts).” A review of the 1996 Certificate Order and the July 1997 Certificate Order referenced by section 3.1(a) of the 2002 Settlement by the ALJ found that both such orders state that the levelization period is 20 years.⁷⁰ Therefore, in reasoning that because the 2002 Settlement extends the levelization period “by approximately one year,” the ALJ reached the entirely logical determination that the appropriate levelization period intended in the instant proceeding is a period of 21 years. In approving the 2002 Settlement, the Commission also noted that the levelization period contemplated by the 2002 Settlement specified that the levelization period ended March 31, 2020.⁷¹

49. The ALJ further noted that section 3.1(a) of the 2002 Settlement states that the rate levelization through March 31, 2020 is “reflected in Appendix D ([Rate] Levelization Schedule).”⁷² Appendix D to the 2002 Settlement delineates the period covered by the Settlement, the Annual Changes in the Deferred Asset and the “Deferred Asset Balance” for each year covered by the levelization period envisioned by the 2002 Settlement. According to Appendix D, in Year 21 (which occurs in 2020 according to the End of Test Period reference in Appendix D) the Deferred Asset Balance is zero.⁷³

50. The Commission rejects PSG’s arguments regarding footnote 3 in Appendix D to the 2002 Settlement. As noted by the ALJ, Appendix D demonstrates that the parties to the Settlement intended that the levelization be 21 years. That Appendix specifically sets forth the changes in Portland’s deferred asset balance for each year of the levelization

⁷⁰ ID, 129 FERC ¶ 63,027 at P 65.

⁷¹ 2002 Settlement Order, 102 FERC ¶ 61,026 at P 5.

⁷² ID, 129 FERC ¶ 63,027 at P 64.

⁷³ Appendix D sets forth a levelization period which begins at the end of the Docket No. RP02-13-000 test period, which it identifies as March 31, 2002.

period contemplated by the 2002 Settlement. At Year 21, in the year 2020, the deferred asset balance is zero. Thus, it appears that footnote 3 to Appendix D, which without explanation states that the end of the levelization period is March 31, 2021, is incorrect because it is unsupported by the Rate Levelization Schedule set forth in Appendix D.

51. PSG also notes that section 3.1(a) of the 2002 Settlement states that “the remaining levelization period has been extended by approximately one year (*to reflect the full period covered by all of [Portland’s] existing Long-term FT Contracts*).” PSG argues accordingly that because at the time the 2002 Settlement was entered into Portland had a contract with Rumford with a termination date of October 31, 2020; therefore, the levelization period intended by the 2002 Settlement must have been intended to extend to March 31, 2021 in order to include the Rumford Agreement. PSG argues that the ALJ’s finding that the Rumford Agreement termination date of October 31, 2020 is not explicitly referenced in any provision of the 2002 Settlement Agreement is insufficient to over-ride the language of section 3.1(a) because the 2002 Settlement did not set forth any of Portland’s long-term FT agreement end-dates.

52. The Commission finds that the fact that the Rumford Agreement extended beyond March 31, 2020 does not overcome the express language in the 2002 Settlement discussed above stating that the levelization period would end on March 31, 2020. The 2002 Settlement added one year to the period of time set out in Portland’s original certificate orders and then parenthetically explained that this action was to reflect the full period covered by all of Portland’s existing long-term FT Contracts. The 2002 Settlement then set forth a levelization schedule through March 31, 2020 in Appendix D to the 2002 Settlement. The Rumford Agreement was in existence at the time the parties to the 2002 Settlement took these actions and set its levelization period. Therefore, the Commission can only infer that the parties were aware of the contract and set the March 31, 2020 period as reflected in Appendix D in spite of the parenthetical statement that the levelization period would reflect the full period covered by all of Portland’s existing long-term FT Contracts. The Commission will not overturn the specific rate levelization periods set out by Appendix D to the 2002 Settlement because a party to the instant proceeding asserts that the language to a settlement that the party agreed to years earlier did not precisely contemplate one contract in determining that the rate levelization period would encompass all contracts.

53. Section 3.1(b) of the 2002 Settlement, obligating Portland to use levelization “through March 31, 2020,”⁷⁴ also is contrary to PSG’s argument that the levelization

⁷⁴ Section 3.1(b) also refers to a March 31, 2020 levelization end date stating:

[Portland] shall continue to propose to design its FT rates based on the levelization methodology reflected in Appendix D for the entire period

(continued...)

period should run until March 2021. PSG argues that this should be discounted because the 2002 Settlement rates could be designed using levelization for one period, ending March 2021, as it suggests, while the pipeline's obligation to employ levelization ends at a different time, one year earlier. According to PSG, the levelization period employed, and the period for which Portland is obligated to continue utilizing rate levelization, are different and independent periods.

54. This line of argument lacks merit for two reasons. First, the 2002 Settlement required that the rates charged by Portland be levelized and set forth a specific levelization period for designing rates in Appendix D. There is no record evidence to suggest that the 2002 Settlement required Portland to use two separate levelization periods as suggested by PSG. Further, and perhaps more importantly, Appendix D to the subject Settlement sets forth a specific levelization period that reflects a zero balance for the deferred asset balance after the year 21 period. Under PSG's theory, Portland is obligated to continue using rate levelization beyond the period required for rate design. Given the fact, however, that the deferred asset balance reaches zero in the Year 21 period, the Commission finds that little would be accomplished by this continued levelization, particularly as the 2002 Settlement does not contemplate such action.⁷⁵

55. The Commission also finds that the ALJ was correct to discount the "2008 Case" tab exhibit in the electronic levelization model designed to implement the 2002 Settlement levelization methodology in the instant proceeding. As noted by the ALJ, the case tab contravenes Appendix D to the 2002 Settlement, which lists the DRA balance in Year 21 as zero (0). It also appears inconsistent with PSG Witness Briden's reformatted model presented in this proceeding to replicate the 2002 Settlement, which also shows a zero (0) balance at the end of year 21.⁷⁶

through March 31, 2020, subject to adjustments to the cost-of-service in accordance with this Settlement or in future proceedings following termination of this Settlement in accord with Article VI below. [Emphasis added].

⁷⁵ Levelized rates will continue in effect on Portland's system unless it files a new rate case pursuant to NGA section 4 and places new non-levelized rates into effect at the end of the Rate Levelization period. However, this would require a voluntary act by Portland that is not required by the 2002 Settlement.

⁷⁶ ID, 129 FERC ¶ 63,027 at P 69 (citing Ex. No. PSG-26 at 6). The Commission further finds that the ALJ was reasonable to hold that the parties to the 2002 Settlement did not need to adapt the RP02-13-000 electronic levelization model to correlate with an anticipated month-to-month effective rate period in the instant case that would be different from the effective rate period utilized in the RP02-13-000 proceedings, because
(continued...)

C. Escalation Clause in Levelized O&M Expenses

Initial Decision

56. In the ID, the ALJ rejected Portland's assertion that its operations and maintenance (O&M) expenses should be increased annually pursuant to an escalation clause in service contracts with American and Canadian subsidiaries of TransCanada Corp. (TransCanada), the majority owner in Portland.⁷⁷ According to the record, because Portland has no employees of its own, it contracts with the TransCanada subsidiaries for O&M work and administrative and general (A&G) services (such as accounting).⁷⁸ The contracts operate on a fixed fee basis and the fixed fee increases each year pursuant to a formula set forth in the contracts.⁷⁹ Portland argues that the increase in future years is a "known and measureable change" that is properly included in the cost-of-service, because the contracts providing for the annual increases were in effect during the test period.⁸⁰ Trial Staff challenged the escalator clause at hearing, claiming that it did not satisfy the inflation adjustment test established in *Kern River*. PSG also opposed the escalator, noting that it was the product of agreements between affiliates and should be subject to heightened scrutiny.

57. The ALJ ultimately relied on Portland's failure to satisfy the test established in Opinion No. 486 in rejecting the escalator. According to the ID, a pipeline has a two-fold

the 2002 Settlement provided the 2008 case would be filed with a proposed April 1 (2008) effective date to match the April 1 (2002) effective date of the rates in the Docket No. RP02-13-000 proceeding. *See* ID at P 70.

⁷⁷ ID, 129 FERC ¶ 63,027 at P 111. Portland identifies the two contracts at issue as its 92076670 Delaware Inc. Contract and its 1120436 Alberta Ltd. Contract.

⁷⁸ *Id.* P 99 (citing Exhibit No. PNG-31) and P 104.

⁷⁹ *See* Exhibit No. S-8. According to the respective "Schedule 'A' Fees for Services" for each agreement, the fee to be paid each year, following the year 2009, for services rendered and covered under the contract, is the Fee for the prior year plus "the Increase Factor" for the preceding year. Ex. No 3-8 at 22 and 47. According to the agreements, the "Increase Factor" is the sum of the "G&A Increase Factor" and the "Salaries and Benefits Factor." The "G&A Increase Factor" is based on any increase in the Consumer Price index multiplied by 0.25. Exhibit S-8 at 21. The "Salary and Benefit Factor" is defined as "any increase in TransCanada's average per capita salaries and benefits for employees..., expressed as a percentage, ...multiplied by 0.75." *Id.*

⁸⁰ ID, 129 FERC ¶ 63,027 at P 99 (citing Exhibit No. PNG-82 at 7).

burden under Opinion No. 486 to support a proposed inflation adjustment for its A&G and O&M costs by first showing that it has taken into account any existing excess recovery of A&G and O&M costs, and second by supporting its projection of inflation for the remainder of the levelization period.⁸¹ The ALJ found that the proposed escalation clause failed the *Kern River* test because the proposal did not address existing excess recoveries and did not support the proposed increase in relation to projected inflation. The ALJ notes that Portland's fixed fee contract has no true-up mechanism, and thus there is no way to show whether Portland overpaid or underpaid or correctly paid an amount associated with actual costs incurred.⁸² Thus, there appears to be no evidence to demonstrate the relationship between the fees to which the escalator were to apply and the costs actually incurred.

58. In addition, the ALJ found that Portland did not even address the argument that heightened scrutiny was warranted because the agreements are between affiliates of TransCanada.⁸³ Noting that the only justification that Portland provides is that the escalator clause is in the current agreements, the ALJ stated that there is no evidence to suggest the cost increases proposed are in line with those that may have been negotiated at arms-length.

Briefs on Exceptions and Opposing Exceptions

59. Portland objects to the ALJ's rejection of its proposal and claims that an increase in its O&M expenses in accordance with the terms of the service contracts with the affiliated TransCanada subsidiaries.⁸⁴ Portland attempts to distinguish reliance on *Kern River* by asserting that the adjustment specified in the contracts is not a generic inflation adjustment and instead is directly related to the cost of providing service. Portland characterizes the adjustment as "known, measurable, and reasonable contractually-mandated increases."⁸⁵ According to Portland the adjustment is weighted 75 percent for changes in TransCanada's average actual salary expense and 25 percent for Consumer Price Index (CPI) changes.⁸⁶ Portland characterizes its adjustments as reasonable and claims they were negotiated at arm's length. Portland points to the fact

⁸¹ *Id.* P 105-09 (citing Opinion No. 486, 117 FERC ¶ 61,077 at P 101).

⁸² *Id.* P 106.

⁸³ *Id.* P 109.

⁸⁴ Portland Brief on Exceptions at 12.

⁸⁵ *Id.* at 14.

⁸⁶ *Id.* at 12.

that voting restrictions in its partnership agreement preclude TransCanada from voting on the contracts, with contract approval coming therefore from the other partner, Gaz Metro Inc.

60. According to Portland, its expert testimony accounted for the direct costs incurred by the service companies and showed that Portland's expenses under the contracts would be less than the overhead that it would incur in the absence of such contracts.⁸⁷ Portland states that it acted reasonably in shifting the risk of unexpected cost increases by obtaining price certainty through the affiliate contracts. Therefore, it concludes that its entering into the contracts was reasonable and that the costs should be included in the levelized cost-of-service.

61. PSG supports the ALJ's exclusion of the increase factor. According to PSG, the increase factor may amount to over \$700,000 per year as a result of front-loaded costs in the levelization process, instead of the \$160,000 figure proposed by Portland (assuming traditional cost-of-service ratemaking).⁸⁸ PSG contests Portland's attempt to distinguish *Kern River*, claiming that the increase factor is similar to the 3 percent factor in *Kern River* because both are based on the consumer price index. According to PSG, the *Kern River* proceeding found that the CPI was a poor indicator of how a pipeline's A&G and O&M costs may increase.⁸⁹ According to PSG, Portland lacks a record of the actual operating expenses because the affiliates providing the service do not provide such data. Furthermore, PSG argues that Portland has ignored the second prong of the test because its proposal does not describe how it would take into account over collections of O&M costs that would occur in the first half of the levelization period. According to PSG, the levelization process causes the inflated O&M expenses occurring in later years to be "frontloaded."⁹⁰

62. PSG notes that Portland's original rates lacked the escalation clause. PSG also questions Portland's claim that the contracts were negotiated at arm's length. PSG asserts that nothing in the voting clause would preclude TransCanada from asserting influence over the contracts, such as by structuring, negotiating and drafting the

⁸⁷ *Id.* at 14 (citing Ex. PNG-9 at 8-9; Ex. PNG-10 and Tr. 1583:25-1584:6; Ex. PNG-9 at 8-9; Ex. PNG-10).

⁸⁸ PSG Brief Opposing Exceptions at 19-20.

⁸⁹ *Id.* at 21 (citing Opinion No. 486-A, 123 FERC ¶ 61,056 at P 119).

⁹⁰ *Id.*

agreements.⁹¹ PSG claims that Portland presented no evidence to rebut testimony that the contracts were not negotiated at arm's length.

63. PSG also contests Portland's cost savings claim as based on assumptions and unsupported cost data. PSG objects to Portland's cost support, which consists of a single page purporting to reflect TransCanada's costs, but fails to identify its source or the time frame it represents, or to provide comparative data to demonstrate that the costs are representative over time.⁹² PSG also questions the cost comparison allegedly showing savings under the agreement compared to the contract charges because it fails to compare Portland's costs, but instead compares Portland's 2003 costs adjusted by a CPI factor. According to PSG, Portland failed to establish any rise in its actual costs.

64. Trial Staff also supports the ALJ's determination on this issue. Trial Staff points to the ALJ's findings that the costs claimed were not supported because the base fixed fees have no relation to actual costs incurred and they lack a true up mechanism.⁹³ Trial Staff also contests Portland's assertion that the contracts were negotiated at arm's length, citing the lack of evidence describing either the negotiating process or the selection of TransCanada as the service provider, including evidence that other entities were considered.

Commission Determination

65. The Commission affirms the ALJ's decision to reject Portland's proposal for an inflation escalator for calculating its O&M and A&G costs reflected in the service contracts with its TransCanada affiliates, but for different reasons than those relied on by the ALJ. As discussed below, the Commission finds that the participants' position that Opinion No. 486 is controlling on this issue is erroneous and that Portland has not shown its proposed adjustment to be known and measurable.

66. First, the ALJ's and participants' reliance on *Kern River* in this proceeding is misplaced. The circumstances under which the Commission allowed Kern River an inflation adjustment for O&M and A&G costs were different than those in this case because in Kern River's original certificate proceeding, the parties all agreed that Kern River's levelized rate methodology would include a levelization of its O&M and A&G costs, based on a projection of future inflation of those costs. Kern River's levelized rates thus included levelized O&M and A&G costs from the time it went into

⁹¹ *Id.* at 23.

⁹² *Id.* at 26.

⁹³ Trial Staff Brief Opposing Exceptions at 12.

service. In Opinion No. 486, the Commission found that the pipeline could have an inflation adjustment to those costs because such an adjustment was part of the original risk sharing agreement which led to the construction of the pipeline.⁹⁴

67. By contrast, the record in this proceeding indicates that the levelization methodology approved in Portland's certificate and last rate proceedings did not include levelization of O&M and A&G costs and thus it appears that Portland is attempting to levelize these costs for the first time in this case. There is no comparable risk sharing agreement between the pipeline and the participants that was relied on by the parties in deciding to construct Portland's system.⁹⁵ Accordingly, the reason for allowing Kern River to attempt to justify its inflation adjustment does not exist in this proceeding, and Opinion No. 486 is inapplicable here.

68. Because there is no existing agreement to levelize Portland's O&M and A&G costs, these costs must be treated as any costs would be under a traditional test period method. Pursuant to the Commission's regulations, costs proposed to be included in a pipeline's cost-of-service must be based on a base period reflecting the 12 months of the most recently available actual experience, as adjusted for actual costs incurred for up to 9 months immediately following the base period.⁹⁶ As we have held previously, "[c]ost-of-service ratemaking seeks to establish a representative level of future costs based on historical cost and known and measurable changes."⁹⁷ Base period adjustments are only allowed for changes in revenues and costs that are known and measurable with reasonable accuracy and "will become effective within the adjustment period."⁹⁸ The Commission regularly permits cost changes occurring during the last twelve months of the test period to be annualized for purposes of projecting the pipeline's future costs.⁹⁹

⁹⁴ *Kern River*, Opinion No. 486, 117 FERC ¶ 61,077 at P 98-99.

⁹⁵ *See, e.g.*, PSG Brief Opposing Exceptions at 22 (noting that neither the levelization methodology approved in Portland's original certificate proceedings nor in the 2002 Settlement provided for any escalation of O&M expenses).

⁹⁶ 18 C.F.R. § 154.303(a) (2010).

⁹⁷ *Enbridge Pipelines (KPC)*, 102 FERC ¶ 61,310, at P 123-128 (2003) (*Enbridge KPC*).

⁹⁸ 18 C.F.R. § 154.303(a)(4)(2010).

⁹⁹ *Enbridge KPC*, 102 FERC ¶ 61,310.

69. Contrary to Portland's assertions, that Commission finds that the inflation adjustments sought by Portland are neither known nor measurable nor would they take effect during the test period in this case. According to the agreements, the "Increase Factor" only applies in "any year following 2009." The test period in the instant case ended on September 30, 2008. Thus, the adjustments did not take effect during the relevant test period.

70. Moreover, the inflation adjustments were not known and measurable during the test period. While the agreements contain provisions regarding how to calculate the increase each year, the "G&A Increase Factor" and the "Salary and Benefits Increase Factor" are based on inputs that are not currently known and measurable, namely the CPI and future salary and benefit increases. Moreover, the term provisions of the agreements are indefinite and either party can terminate the agreements.¹⁰⁰ Thus, there is no evidence to show how long the agreements will be in existence. Based on these facts, no inflation adjustments incurred by Portland after September 2008 relating to these contracts are "known and measurable," and Portland may not include them in the instant proceeding.

III. Cost-of-Service Issues

A. Overall Cost-of-Service

71. The ALJ identified the overall cost-of-service as the sum of the levelized cost-of-service discussed above and the non-levelized costs, as adjusted to address various rate issues.¹⁰¹ Portland excepts to the ID's findings with regard to the overall cost-of-service for Portland.¹⁰² Portland contends generally that the cost-of-service established in the ID is inadequate and faults the ID for failing to determine whether the charges established by the rate determinations meet Portland's revenue requirements and produce a just and reasonable result.¹⁰³

72. In opposing Portland's exceptions, PSG questions the credibility of Portland's claims, citing Portland's ability to disburse \$120 million in bankruptcy proceeds as evidence that it was able to obtain an after tax net income higher than the cost-of-service

¹⁰⁰ Agreements Section 10, Exhibit No. S-8 at 14 and 38.

¹⁰¹ ID, 129 FERC ¶ 63,027 at P 113-17 (summarizing cost-of-service totals proposed by Participants).

¹⁰² Portland Brief on Exceptions at 14.

¹⁰³ *Id.* at 4.

proposed in this proceeding. Also, PSG contends that Portland's claims of revenue inadequacy ignore both the bankruptcy proceeds and the short-term firm capacity resales of capacity that was previously dedicated to the customers declaring bankruptcy.¹⁰⁴

73. Trial Staff states that Portland provides no separate argument on its claim that the overall cost-of-service is lacking, and characterizes Portland's Exception No. 4 as an overall contention that encompasses its Exceptions No. 5 through 8.

Commission Determination

74. We agree with participants who note that Portland fails to argue this issue in its Brief on Exceptions and fails to demonstrate that its anticipated revenues under the overall rates developed in this proceeding would fall short of recovering its costs. Therefore, the Commission will not address overall cost-of-service as a separate issue but will instead address the specific issues argued in Portland's Brief on Exceptions.

B. Operations and Maintenance (O&M)

1. Pipeline Integrity Projects (PIP)/Maintenance of Mains Expenses

75. Portland records the costs of its Pipeline Integrity Projects (PIP) as expenses in its Account No. 863. It performs those projects in order to comply with the Pipeline Safety Act of 2002. In its section 4 filing in this case, Portland reflected actual PIP costs for the 12-month base period (calendar year 2007) of \$201,218, but projected that its PIP costs for the last 12 months of the overall test period (October 2007-September 2008) would be \$1,149,218.¹⁰⁵ In a July 2008 response to a Trial Staff data request,¹⁰⁶ Portland estimated that its PIP expenses for the period March 31, 2007 through 2011 would be as follows:

March 31-December 31, 2007	\$168,389
2008	\$1,354,000
2009	\$262,000
2010	\$248,000
2011	\$262,000

¹⁰⁴ PSG Brief Opposing Exceptions at 8.

¹⁰⁵ Portland 2008 Rate Filing, Schedule H-1(1)(b).

¹⁰⁶ Ex. S-7; ID at P 132..

76. At the hearing, Portland and Trial Staff proposed to use the annual average of these amounts (\$458,878) for the pipeline's PIP/Maintenance of Mains expenses.¹⁰⁷ Portland stated that it used the five-year average because Portland was projected to incur significantly higher PIP expenses during the test period as compared to its projected expenses through 2011.

77. However, PSG Witness Fink pointed out that Portland's 45-day update filing showed that it had actually incurred only \$818,727 during the last 12 months of the base period, which included the last three months of 2007 and the first nine months of 2008.¹⁰⁸ PSG's witness stated that this amount was substantially less than Portland's prior estimate of \$1,354,000 (relied on by Trial Staff) for all of 2008. Moreover, Portland's 2008 Form 2 indicated that its calendar year 2008 PIP costs were \$821,011. Because the projected 2008 costs relied on by Portland to calculate a five-year average of such costs was substantially in excess of its actual costs, PSG's Witness Fink proposed to rely on a combination of the actual cost data for the last twelve months of the test period (the year ending September 2008), in combination with Portland's projected data for years 2009-2011. Thus, PSG would average the available data for these four non-contiguous years to arrive at a proposed PIP expense of \$397,682.¹⁰⁹

78. The ALJ adopted Portland and Trial Staff's proposed \$458,878 amount for PIP expense. The ALJ rejected PSG Witness Fink's approach for calculating a proposed level of PIP expenses as improper because it used a non-contiguous data sequence, omitting cost data for October 2008 through December 2008, and thereby leading to a distorted result.¹¹⁰ The ALJ faulted this proposal as examining a particular time period, while failing to assess Portland's overall cost projection. The ALJ also rejected PSG's attempt to "cherry pick" certain of Portland's actual versus test period costs as improper.¹¹¹

79. PSG excepts to this finding, arguing that the \$458,878 figure is based on a 5-year average (2007-2011), which includes a substantially erroneous estimate of 2008 PIP

¹⁰⁷ ID, 129 FERC ¶ 63,027 at P 132.

¹⁰⁸ *Id.* P 135 (citing Ex. PNG-84 at 50 (Schedule H-1(1)(b))).

¹⁰⁹ The four years to be averaged are the test year, reflecting costs incurred in December 2007, as well as Jan. – Sept. 2008 (no costs were incurred in Oct. or Nov. 2007), and the years 2009, 2010, and 2011, reflecting the projected costs.

¹¹⁰ ID, 129 FERC ¶ 63,027 at P 138.

¹¹¹ *Id.* P 139.

expenses. According to PSG, Portland's calendar year 2008 estimate of \$1,354,000 greatly exceeded Portland's actual PIP costs, as reflected in Portland's 2008 Form 2 Annual Report. Portland's five year average is based on an estimate claiming \$1,354,000 in PIP for 2008 and amounts for the remaining years not exceeding \$262,000. According to PSG, record evidence demonstrates that the actual PIP costs reported in the 2008 Form 2 were \$500,000 less than the proposed figure for 2008.¹¹² PSG concludes that the ID relied on "an inaccurate and highly inflated [Portland] estimate of 2008 costs."¹¹³ PSG supports two alternate figures for PIP costs (1) the \$397,682 figure, based on a four year average advocated by its Witness Fink at hearing, or (2) \$358,846, calculated by averaging the actual cost figure for 2007 (\$201,218), the Form 2 data for 2008 (\$821,011), and the projected data for 2009 through 2011.

80. PSG addresses the ALJ's concern that it is relying on non-contiguous data noting that Portland's projection for 2008 was overstated and that Portland's cost update did not provide data for the last three months in 2008. According to PSG, to sustain the 2008 \$1,354,000 cost estimate would require an assumption that Portland would incur more costs in the remaining three months of 2008 than the \$617,509 incurred in the previous nine months. PSG notes that Portland's Form 2 reports \$821,011 for 2008 PIP (Account 863), and notes that this Form 2 is included in the record as Exhibit No. PSG-128. PSG states that taking that figure and averaging it with actual 2007 expense and the 2009 through 2011 estimates provides a five-year average of \$358,846. PSG claims that no participant challenged the accuracy of Portland's cost projections for 2009-11.

81. According to PSG, calculating average costs using actual 2007 and 2008 data and Portland's estimates for 2009-2011 provides an average PIP expense of \$358,846, which is below both the \$458,878 figure accepted by the ALJ, as well as the \$397,682 figure proposed by its Witness Fink.

82. Portland claims that PSG fails to recognize the reality that accompanies the long-term planning process for pipeline integrity projects. According to Portland, a long-term pipeline integrity project nearly always experiences changes in timing and execution, and a pipeline may modify its plans in response to inspections, contractor schedules, and other outside forces. According to Portland, the fact that actual costs in a given period differ from the original projection bears no direct correlation to the total costs expected to be incurred over the life of the project. Portland defends the \$458,878 figure as an average of PIP expenses anticipated to be incurred between 2007 and 2011.

¹¹² PSG Brief on Exceptions at 30 (citing PIP cost projections provided above).

¹¹³ *Id.* at 34.

83. Trial Staff supports the ALJ's determination that \$458,878 is the appropriate level for the pipeline's PIP/Maintenance of Mains expenses, based on Portland's identification of \$2,294,389 in PIP expenses for the five year period and the ALJ's conclusion that PSG improperly advocated the selective use of Portland's PIP cost projections for the years 2008-2011.¹¹⁴ Trial Staff also faults PSG for using non-contiguous data, noting that it could have sought discovery of such information or relied on projections.

Commission Determination

84. Based on the record in this proceeding, the Commission reverses the ALJ's determination to rely on the \$458,878 five-year average of Portland cost estimates for Portland's PIP/Maintenance of Mains expenses, and finds instead that a just and reasonable PIP/Maintenance of Mains expense for Portland in this proceeding is \$397,682. All participants agree that the costs to be recorded fluctuate, and, consequently, that the PIP/Maintenance of Mains costs should be projected based on a multi-year average of Portland's PIP costs, including its estimates for 2009-2011. Indeed, the record evidence indicates that Portland's actual PIP costs during the last 12 months of the test period ending September 30, 2008 were \$818,727, an amount that is significantly higher than Portland's projected PIP expenses for 2009-2011.¹¹⁵

85. The Commission's regulations require that a pipeline justify any proposed rate increases by filing cost and other information for a test period consisting of a base period of "12 consecutive months of the most recently available actual experience,"¹¹⁶ and an adjustment period of up to 9 months immediately following the base period. Rate factors established during the base period may be adjusted for changes, including costs, which are "known and measurable" and "which will become effective within the adjustment period."¹¹⁷

86. Portland's proposed PIP expense based on its five year projection is not consistent with the Commission's test period methodology described above because it includes projections of post test period costs that are not "known and measurable" because they did not become effective during the test period as required by the regulations. Nevertheless, all participants rely on the projected post-test period costs and agree that the actual costs during the last twelve months of the test period are not representative of

¹¹⁴ Staff Brief Opposing Exceptions at 15-17.

¹¹⁵ ID, 129 FERC ¶ 63,027 at P 135.

¹¹⁶ 18 C.F.R. §154.303(a)(1).

¹¹⁷ 18 C.F.R. §154.303(a)(4).

the costs expected to be incurred while the subject rates were in effect. Therefore, we find that considering the costs to be anticipated in future years for the PIP projects is a just and reasonable way to measure Portland's costs. In this instance, doing so results in a figure that is less than the actual costs incurred by Portland during the test period.

87. However, Portland's 45-day update filing and its 2008 Form 2 demonstrated that its projected 2008 PIP expense of \$1,354,000 was not accurate. Portland nevertheless argues that its overall projection may be relied on, based on general statements to the effect that "actions originally budgeted for 2010 might be accelerated or deferred, based on inspections and testing results."¹¹⁸ Whatever the appeal of this hypothetical notion, Portland has failed to back up its theory with an accounting of why costs that were projected for 2008 were not incurred. Portland's projected 2008 PIP expense was based on its estimated expense for eight specific projects it expected to complete in 2008.¹¹⁹ At the July 2009 hearing, Portland presented no evidence as to what had happened with respect to any of these projects during 2008 to cause Portland not to incur the full amount of its projected PIP expenses for that year. Thus, Portland has failed to demonstrate that the costs of any of the underlying projects not incurred in 2008 would in fact be incurred in later years, because those projects were delayed in 2008 and rescheduled into the later years. For all that appears on the present record, Portland's estimated costs may have exceeded the actual costs of the projects, or some of the projects may have been cancelled outright, deferred beyond the projection period, or displaced other projects in the later period. Portland bears the burden to support its cost figures and demonstrate that its proposed costs are just and reasonable. In light of the failure of the 2008 actual costs to meet expectations, it was incumbent on Portland to update its remaining data with revised cost estimates to reflect changed circumstances.

88. As for the contention that PSG's estimate is unreliable because it relies on a "non-contiguous data sequence," we find this concern unconvincing for two reasons. First, it is the fact that Portland's initial estimate is unreliable that creates the gap – because there is then no reliable data for the last quarter in 2008. Second, Portland has effectively rebutted any "cherry picking" argument, demonstrating that the result would be even lower if it filled the gap and averaged actual costs for all of 2008 with 2007 actual costs and the projected 2009-2011 costs. Consequently, we reverse the ID as to approval of Portland and Staff's calculation, which relies on the inflated 2008 figure. Instead, we find that the \$397,682 figure advocated by PSG before the ALJ is just and reasonable.

¹¹⁸ Portland Brief Opposing Exceptions at 28.

¹¹⁹ Ex. S-7 at 4.

2. Outside Services (Account 923)

89. In the ID, the ALJ adopted Portland's and Trial Staff's proposed Outside Service Expense (Account 923) figure of \$6,600,753. Portland incurs these costs under its 9207670 contract with Delaware, Inc. and its 1120436 contract with Alberta Ltd.¹²⁰ The annual fees paid by Portland pursuant to these contracts increased by \$26,012 on January 1, 2008, nine months before the September 30, 2008 end of the test period. The \$6,600,753 amount represents an annualization of the actual fees paid by Portland during the last nine months of the test period after the fee increase. The ALJ found that the \$26,012 contractual fee increase was a "known and measurable" change which became effective during the test period, and therefore the ALJ approved Portland's proposed outside service expense as representative of Portland's cost levels going forward.¹²¹

90. PSG excepts to the ID, claiming that figure adopted by the ALJ is based on a demonstrably inflated cost estimate. PSG also faults the ALJ's decision to permit Portland to reflect the increase stemming from charges by its affiliates in its Account 923. According to PSG, these cost increases occur beyond the end of the Test Period and were not negotiated at arm's length.¹²² PSG states that the ID elsewhere rejected reliance on the affiliate agreements to escalate levelized costs and observed that the fixed fees on which the annual increases are based have no relationship to the actual costs incurred by Portland's affiliates in providing service under the contracts.¹²³ PSG concludes that the cost escalation provisions should be rejected when annualizing Portland's post test period costs, in particular when the increase is extended to include three months falling outside the test period.

91. Trial Staff and Portland oppose PSG's exception.¹²⁴ Trial Staff argues the fact that costs attributable to the inflation escalator discussed above were proposed to commence outside the test period distinguish that escalator from the annual increase in fixed fees for the Account 923 Outside Services, which commenced on January 1, 2008, in the middle of the test period. Trial Staff also notes that no participant challenged the increase for nine months of the test period, and thus, the only issue is whether it is

¹²⁰ These are the same contracts that are discussed above with respect to Portland's proposal to rely on the escalator clause to update its levelized costs.

¹²¹ ID, 129 FERC ¶ 63,027 at P 146.

¹²² PSG Brief on Exceptions at 35.

¹²³ *Id.* at 35-36.

¹²⁴ Trial Staff Brief Opposing Exceptions at 17-20.

appropriate to annualize the increase for the three months that fall outside of the test period. In addition, according to Trial Staff, PSG does not contest that Portland has paid the increase. Consequently, Trial Staff supports the ALJ's decision.

92. Portland emphasizes that the expenses represent costs that were actually incurred, and that, because the costs are incurred on an annual basis, it is rational to include the entire fee, even though a portion of the fee was incurred outside the test period.¹²⁵ Portland asserts that use of the 2008 cost increase is a conservative measure of future costs and defends the agreements as shifting the risks of cost increases beyond the cost increase in the contracts to the service provider rather than rate payers.

Commission Determination

93. The Commission affirms the ALJ's decision to recognize the \$26,012 contractual fee increase which took place on January 1, 2008, during the twelve months of the test period in the calculation of Test Period Outside Service Expense (Account 923).¹²⁶ Unlike the situation with respect to review of Portland's levelized O&M and A&G cost projection, which relied on an inflation adjustment to project cost increases occurring after the end of the test period, the cost increases at issue here became effective during the test period. As Trial Staff notes, PSG does not contest that Portland paid the amounts in question, and thus those amounts are "known and measurable." Furthermore, PSG's data, which purportedly show appropriate costs levels for the services rendered, do not demonstrate that Portland's proposed level of the costs is unreasonable. The Commission regularly permits cost changes occurring during the last twelve months of the test period to be annualized for purposes of projecting the pipeline's future costs.¹²⁷

94. Finally, we find that the ALJ's determination is adequately supported by record evidence. The ALJ found that "the contractual fee increase was 'known and measurable' during the test period, and the increase is clearly representative of PNGTS' cost levels going forward."¹²⁸ The fact that Portland incurred the costs under its contract for nine months is sufficient for the ALJ to determine that that level of charges will continue under the contract. Consequently, we reject the suggestion that it was necessary for the

¹²⁵ Portland Brief Opposing Exceptions at 15 (Portland also reiterates its earlier positions with respect to the escalation clause as to arm's length negotiation, and protections afforded by the voting rights provisions).

¹²⁶ ID, 129 FERC ¶ 63,027 at P 146.

¹²⁷ *Enbridge Pipelines (KPC)*, 102 FERC ¶ 61,310 at P 123-28.

¹²⁸ ID, 129 FERC ¶ 63,027 at P 146.

ALJ to consider costs outside of the test period in order to predict that a similar level of charges will continue as known and measurable charges in the future.

3. Ad Valorem Tax

95. Portland excepts to the ALJ finding that its ad valorem taxes should be set at \$6,055,858, asserting that the appropriate level of ad valorem taxes for this case should be adjusted upwards by \$62,701, to \$6,117,559, to reflect the actual level of taxes Portland paid. For the reasons discussed below, we agree and reverse the ALJ as to rejecting this \$62,701 adjustment.

96. The ALJ found the appropriate level of ad valorem taxes to be \$6,055,858, which consists of the base value listed in Portland's 45-day update filing (\$5,193,761), with an upward adjustment of \$862,097 to offset an over accrual in ad valorem taxes that occurred prior to the test period.¹²⁹ The ALJ permitted Portland to increase the 45-day update figure by \$862,097 to reflect that a December 2007 adjustment was made to reflect activity for an earlier period, because the over accrual was attributable to a period prior to the test period.¹³⁰

97. Portland refers to an exhibit provided with its Witness Sieppert's rebuttal testimony and states that the latest actual tax incurred during the test period is the best evidence of future tax expense.¹³¹ Portland explains that the 45-day update reflects the test period tax expense recorded in the general ledger based on estimates that are updated as better data becomes available. Portland's Witness Sieppert describes the updated figures as representing the "actual ad valorem tax payments made during the test period of October 1, 2007 to September 30, 2008" and is based on actual tax bills received. According to Portland, the updated figure meets the known and measureable standard because it is the actual total ad valorem tax paid during the test period, as opposed to the estimate in the 45-day update filing, which may be "obscured by adjustments for out-of-period items."

98. Trial Staff supports the ALJ's determination and opposes Portland's exception on this issue. According to Trial Staff, the record supports reliance on Schedule H-4 of

¹²⁹ ID, 129 FERC ¶ 63,027 at P 161. *See* Ex. PNG-82 at 10. The total (\$6,055,858) is cited as being reflected in Ex. PNG-84 at 64 (presenting Schedule H-4 (work papers) for "Adjusted Test Period Expense").

¹³⁰ ID, 129 FERC ¶ 63,027 at P 160.

¹³¹ Portland Brief on Exceptions at 15 (citing Ex. PNG-82 at 10-11; *Northwest Pipeline Corp.*, 77 FERC ¶ 61,326, at 62,472 (1996)).

Portland's 45-day update filing which provided a \$5,193,761 balance for ad valorem taxes for the 12 months ending September 30, 2008 (adjusted by the \$862,097 out of period adjustment to which Trial Staff does not except). Trial Staff opposes Portland's claim that ad valorem taxes should be set as \$6,117,559, to reflect additional adjustments that were not incorporated into the 45-day filing.

99. Trial Staff argues that the Commission's regulations require use of the data contained in the 45-day update filing, which are to reflect the pipeline's costs and were relied on by participants.¹³² Trial Staff challenges Portland's reliance on the *Northwest* order, noting that the earlier order quoted *Williston Interstate Pipeline Co.*,¹³³ which cited section 154.63(e)(2) of the Commission's regulations and permitted changes that are "known and measurable at the time of the filing, and which will become effective within nine months after the last month of available actual experience utilized in the filing."¹³⁴ According to Trial Staff, Portland is seeking to increase its ad valorem tax using amounts that were not known and measurable at the time of filing, or at the time of the 45-day update filing (made a month and a half after the close of the test period). Therefore, Trial Staff concludes that Portland's proposal fails the known and measurable test.

Commission Determination

100. The Commission reverses the ALJ's decision to rely on the cost data provided in the 45-day update filing, rather than Portland's updated cost data, which presented actual taxes paid during the test period and was based on actual tax bills received. The Commission's regulations permit parties to include changes in costs that are "known and measurable with reasonable accuracy at the time of the filing and which will become effective within the adjustment period."¹³⁵ Portland testified that the ad valorem tax

¹³² Trial Staff Brief Opposing Exceptions at 23 (citing 18 C.F.R. § 154.311).

¹³³ *Williston Basin Interstate Pipeline Co.*, Order on Initial Decision, 72 FERC ¶ 61,074 (1995), *order on reh'g*, 76 FERC ¶ 61,066 (1996) (order on rehearing and remanding issue on subsequent review); *order on initial decision*, 79 FERC ¶ 61,311 (1997), *aff'd in relevant part sub nom.*, *Williston Basin Interstate Pipeline Co. v. FERC*, 165 F.3d 54, at 57 (D.C. Cir. 1999); *order on remand*, 87 FERC ¶ 61,265 (1999) (setting DCF data issue for hearing) (*Williston II*).

¹³⁴ *Id.* at 61,383-84 (citing 18 C.F.R. § 154.63(e)(2)); see also 18 C.F.R. § 154.303(a)(4) ("The rate factors (volumes, costs, and billing determinants) established during the base period may be adjusted for changes in revenues and costs which are known and measurable with reasonable accuracy at the time of the filing and which will become effective within the adjustment period.").

¹³⁵ 18 C.F.R. § 154.303(a)(4).

figure in its 45-day update filing was incorrect, and did not reflect the actual ad valorem taxes that it was billed, and that it paid, during the last twelve months of the test period; therefore, such costs were known and measurable and took effect during the test period.¹³⁶ Accordingly, we reverse the ALJ's decision not to permit Portland to rely on the updated figures showing taxes actually paid during the test period, and find that such an adjustment should be added to the approved ad valorem tax figure, \$6,055,858.

4. Regulatory Commission Expenses (Account 928)

101. In the ID, the ALJ approved \$314,500, the amount proposed by Trial Staff, for Portland's Account 928, regulatory Commission expenses. The ALJ stated that the Commission requires that "regulatory Commission expenses must be based on actual costs incurred during the test period."¹³⁷ In addition, the ALJ agreed with Trial Staff's calculation of \$1,572,501 for regulatory Commission costs during the test period and with the uncontested proposal to amortize, or average, the costs over a five-year period.

102. The ALJ reviewed Trial Staff testimony starting from Portland's updated balance of \$668,340 for regulatory Commission expenses, Account 928, from the 45-day update filing.¹³⁸ Witness Sosnick also accepted Portland's proposed transfer of rate case costs recorded in Account 923, but excluded amounts outside of the test period. Trial Staff defended its proposal to spread the costs over five years, reasoning that Portland is not likely to file a rate case more frequently than every few years. PSG Witness Fink's approach is similar, except that he chose not to exclude \$49,287 from Account 928, as being outside the test period, as Trial Staff's witness did.

103. Portland's Witness Sieppert also applied a five-year averaging period, but derived his base dollar figure by counting rate case expenses incurred during the base period coupled with expenses "expected to be incurred during the test period." Portland proposed an expense of \$2,132,595, amortized to \$426,519 per year to account for the five-year recovery period. Portland's witness defended this figure claiming that the actual costs incurred in this rate case have already exceeded the estimated costs it

¹³⁶ *Williston II*, 76 FERC at 61,384.

¹³⁷ ID, 129 FERC ¶ 63,027 at P 171 (citing 18 C.F.R. § 154.303(a)(4); *Iroquois Gas Transmission System, L.P.*, Initial Decision, 81 FERC ¶ 63,012, at 65,087-88 (1997), *aff'd as to regulatory expenses*, 84 FERC ¶ 61,086, at 61,432 (1998), *order on reh'g*, 86 FERC ¶ 61,261 (1999) (*Iroquois*); *Williston Basin Interstate Pipeline Co.*, 67 FERC ¶ 61,137, at 61,364 n.51 (1994), *aff'd*, 71 FERC ¶ 61,019 (1995) (*Williston I*)).

¹³⁸ *Id.* P 169-70.

previously claimed.¹³⁹ As noted in the ID, Portland defends its higher figure as a conservative measure of regulatory expense.¹⁴⁰ The ALJ rejected Portland's proposal.

104. Portland excepts to the ALJ finding and claims that its annual Account 928 regulatory Commission expense should be set at \$426,519.¹⁴¹ According to Portland, the ALJ's focus on test period costs ignores its actual pre- and post-test period regulatory expenses and argues that actual rate case costs have already exceeded the cost total used in the ID. Portland argues that it is entitled to recover the entire cost of pursuing the pending rate case through a final Commission order, which it estimates at \$2,132,595. Portland states that Commission policy generally requires cost data for an annual period, but notes that rate cases occur less frequently than every year and last more than a year. If the goal is to amortize the total cost of a rate case over a reasonable number of years, the total costs incurred should be used, rather than a mere fraction of that cost.¹⁴² Portland cites *Kern River*, where the Commission noted "[t]he Commission's general approach to Regulatory Commission Expenses is to look at a historical three or five-year period in order to establish a representative level of a pipeline's future expense level during the period the rates are effective."¹⁴³

105. According to Portland, previous Commission policy measured regulatory Commission expenses by averaging three years of expenses,¹⁴⁴ but recognized that "regulatory expenses fluctuate, rising during the time of a major rate case and falling thereafter until another rate case is instituted" and determined that an average of the three year data was necessary "to take account of the fluctuation."¹⁴⁵ Portland claims that there is no reason to restrict the costs being considered to those incurred in the test period, because the costs will be spread over five years.

¹³⁹ *Id.* P 164.

¹⁴⁰ *Id.* (citing PNG Initial Brief at 37; Ex. PNG-88; Ex. PNG-82 at 8).

¹⁴¹ Portland Brief on Exceptions at 15.

¹⁴² *See* Ex. PNG-82 at 8.

¹⁴³ Portland Brief on Exceptions at 16 (citing *Kern River Gas Transmission Co.*, 117 FERC ¶ 61,077, at P 278 (2006), *order on reh'g*, 123 FERC ¶ 61,056 (2008), *order on reh'g*, 126 FERC ¶ 61,034, *order on reh'g*, 129 FERC ¶ 61,240 (2009)).

¹⁴⁴ *Id.* (citing *Iroquois*, 81 FERC at 65,087-88; *Williston I*, 67 FERC at 61,363-64, *aff'd*, 71 FERC ¶ 61,019 at 61,077).

¹⁴⁵ *Id.* (citing *Southern Natural Gas Co.*, 41 FERC ¶ 63,030, at 65,213 (1987)).

106. Portland states that the Commission has recognized that data outside of the test period may be used when “there is good reason to use other data,” and cites Trial Staff testimony to the effect that a pipeline could properly recover “additional cost levels of litigation expense that happened outside of the test period.”¹⁴⁶ Portland also cites PSG’s proposal to include pre-test period costs to support its position.¹⁴⁷

107. Trial Staff objects to Portland’s proposed out of period adjustments, noting that, although Portland proposes such adjustments for this cost item, it declines to update other cost items.¹⁴⁸ Furthermore, Trial Staff notes that Portland correctly acknowledged that Commission precedent generally requires cost data limited to an annual period. According to Trial Staff, when departing from that general rule, the practice is to look at an historical period, not a future period.¹⁴⁹ Trial Staff claims that Portland’s cited support is taken out of context. For instance, Trial Staff notes that, though *Williston* indicated that circumstances may support use of data outside the test period, the facts in *Williston* showed that the test period data was “not produced or supported.”¹⁵⁰ Trial Staff asserts that in this instance Trial Staff and PSG supported the test period amounts. Trial Staff clarifies its Witness Sosnick testimony, relied on by Portland, by noting that Portland may seek to show additional litigation costs at the compliance phase. In addition, Trial Staff also notes that Mr. Sosnick testified earlier that a pipeline “should be able to recover what costs have been incurred for a rate case during the base and test period” but affirmed that this did not include costs “outside of the base and test period.”¹⁵¹

108. PSG supports the ALJ’s decisions to amortize the Account 928, regulatory Commission expense over five years and exclude post test period expenses from the amount of regulatory Commission expense. PSG states that no participant excepts to the decision to amortize over five years and also that Portland fails to cite authority to support including post-test period costs. PSG objects to Portland’s proposed expense, noting that Portland’s witness admits that the figure includes expenses expected to be

¹⁴⁶ *Id.* at 17 (citing *Williston I*, 67 FERC at 61,364, n.51 and hearing transcript, Tr. 2084:21-2085:7).

¹⁴⁷ *Id.* (citing Ex. PSG-1 17).

¹⁴⁸ Trial Staff Brief Opposing Exceptions at 27 (noting disparity in approaches of Portland Witnesses Sieppert and Lovinger).

¹⁴⁹ *Id.* (citing *Kern River*, 117 FERC ¶ 61,077 at P 278 n.137).

¹⁵⁰ *Id.* (citing *Williston I*, 67 FERC ¶ 61,137 at 61,364 n.137).

¹⁵¹ *Id.* at 27.

incurred in the test period.¹⁵² However, PSG notes that the Commission's regulations permit adjustments to base period costs for changes in costs which will become effective within the adjustment period, defined as a period up to nine months following the base period.¹⁵³ According to PSG, Portland fails to reconcile its proposal to collect post-test-period costs with the Commission's regulations.

109. According to PSG, the precedent cited by Portland fails to support its case. PSG states that *Iroquois* accepted an amortization proposal based on expenses "ending with the last month of the test period."¹⁵⁴ PSG agrees that *Williston Basin* stands for the Commission's long-standing principle that "the Commission's policy is to use test-period amounts unless there is good reason to use other data," but states that Portland has failed to provide a good reason to use other data. PSG counters Portland's suggestion that PSG and Trial Staff may have been supportive of such a proposal, citing testimony clarifying that those participants' witnesses were considering costs incurred during the test period.¹⁵⁵

Commission Determination

110. The Commission affirms the ALJ on this issue and denies Portland's exception to the ALJ's decision adopting Trial Staff's proposal to include in Portland's cost-of-service regulatory expenses of \$314,500. We find that Portland has failed to support its exception. Portland reports that its actual rate case costs have already exceeded the costs on which the ID based its determination. However, the exhibits that Portland cites in its Brief on Exceptions fail to explain how Portland developed its cost data, or to include the analysis necessary to determine whether the additional expenses that Portland seeks to account for occurred in, or prior to, the test period.

111. Portland cites Commission precedent addressing regulatory expense costs that fluctuate over time. The orders cited by Portland reflect the Commission's approved methodology and hold that a pipeline may project the annual regulatory expenses it will incur during the period its proposed rates are in effect by taking an average of its expenses from the previous three year period, ending with the end of the test period.¹⁵⁶

¹⁵² PSG Brief Opposing Exceptions at 27.

¹⁵³ *Id.* (citing 18 C.F.R. § 154.303(a)(2), (4)).

¹⁵⁴ *Id.* at 28 (citing *Iroquois*, 18 FERC ¶ 63,012 at 65,087 *see n.130*).

¹⁵⁵ *Id.*

¹⁵⁶ Portland Brief on Exceptions at 16. *Williston Basin Interstate Pipeline Co.*, 84 FERC ¶ 61,081 at 61,364-66 (1998) (*Williston III*). *Iroquois*, 81 FERC at 65,087-88,

(continued...)

However, Portland's briefs and exhibits cited therein fail to apply this methodology to its cost data or cite any exhibit in the record setting forth its regulatory expenses during the three years preceding the end of the test period. Therefore, Portland has failed to show that it is even possible on this record to determine its regulatory expenses in a manner consistent with the precedent Portland cites. Instead, Portland attacks the ID at least partly on the ground that it failed to take into account Portland's post-test period regulatory expenses. However, the Commission's approved methodology for determining a pipeline's regulatory expenses only looks at historical regulatory expenses during the preceding three years, not estimates of post-test period regulatory expenses. The Commission concludes that the ALJ's determination of Portland's regulatory expenses based on its actual test period expenses provides the best estimate of Portland's regulatory expenses possible on the current record.¹⁵⁷ Portland has failed to sustain its section 4 burden to show that a higher amount would be just and reasonable. Accordingly, we find that Portland has failed to support its exception on this issue and affirm the ALJ.

C. Negative Salvage

Initial Decision

112. The ALJ determined that Portland is warranted a negative salvage value¹⁵⁸ and adopted Trial Staff's proposed negative salvage rate of 0.13 percent, based on Trial Staff's estimate that Portland's net negative salvage expense would be \$20.4 million.¹⁵⁹ The 0.13 percent negative salvage rate is added to Portland's depreciation rate and should permit Portland to recover sufficient funds during the life of the system to cover its net negative salvage expenses incurred in retiring the plant. Portland had proposed a negative salvage rate of 0.32 percent to recover final abandonment estimates of

aff'd in pertinent part, 84 FERC at 61,432; *Williston I*, 67 FERC at 61,363-64, *aff'd*, 71 FERC at 61,077.

¹⁵⁷ See *Kern River*, Opinion No. 486, 117 FERC ¶ 61,077 at P 275-280, where the pipeline also failed to provide the historical data needed to apply the Commission's usual methodology for determining regulatory expenses and the Commission accordingly approved a regulatory expense based on the same methodology as used by the ALJ in this case.

¹⁵⁸ Net salvage value means the salvage value of property retired less the cost of removal (18 C.F.R. Part 201, Definition 23 (2010)). When the revenue realized from the sale of the property is less than the cost of removal, the net salvage value is negative.

¹⁵⁹ ID, 129 FERC ¶ 63,027 at P 242.

approximately \$37 million. The ALJ relied on Trial Staff's interim retirement, end of life,¹⁶⁰ and labor wage rate figures in finding that the 0.13 percent rate was appropriate.

Briefs on Exceptions and Opposing Exceptions

113. Portland on exceptions states that the ALJ erred by endorsing Trial Staff's negative salvage approach regarding: (i) expenses related to interim retirements; (ii) an appropriate end of life; (iii) labor wages; and (iv) a failure to update data to the test period.¹⁶¹

1. Treatment of Interim Retirement Costs

Initial Decision

114. The ALJ rejected Portland's proposal to include expenses related to interim retirements of plant during the life of the system in the calculation of a negative salvage rate. The ALJ found that Trial Staff's approach not to include such expenses was consistent with Commission precedent in *Iroquois Gas Transmission System, L.P.*,¹⁶² and Opinion No. 486.¹⁶³ In these cases, the Commission held that when a company does not experience any actual negative salvage expense on its experienced interim retirements, it is not entitled to recover estimated negative salvage expenses on future estimated interim retirements.¹⁶⁴

Briefs on Exceptions and Opposing Exceptions

115. Portland on exceptions states that in *Iroquois*, as clarified in Opinion No. 486, the Commission established that a negative salvage allowance can include the costs of interim retirements if the cost projections are based on the historical costs of retirements that have actually taken place.¹⁶⁵ Portland states that basing projections of interim

¹⁶⁰ The ALJ accepted Trial Staff's economic end of life of 35 years as opposed to Portland's proposed 23-year "Weighted Average Economic Life."

¹⁶¹ Portland Brief on Exceptions at 32-36.

¹⁶² *Iroquois*, 84 FERC ¶ 61,086, *order on reh'g*, 86 FERC ¶ 61,261.

¹⁶³ Opinion No. 486, 117 FERC ¶ 61,077.

¹⁶⁴ ID, 129 FERC ¶ 63,027 at P 239-241 & n.27.

¹⁶⁵ Portland Brief on Exceptions at 33 (citing *Kern River*, Opinion No. 486 at P 455).

retirement costs on historical costs apparently was driven by fears that removal costs might be less than the gross salvage of the facilities subject to interim retirement. Portland argues that circumstances have changed since *Iroquois* and Opinion No. 486. Portland argues that environmental concerns have increased the cost of the removal of pipeline facilities.¹⁶⁶ Portland argues that as a result, there no longer should be a requirement to present cost projections for interim retirements based on historical costs of retirements that actually have occurred on the specific pipeline whose rates are at issue.

116. Trial Staff in its Brief Opposing Exceptions states that the ALJ correctly adopted Trial Staff's position as consistent with the facts at issue as well as applicable Commission precedent. Trial Staff notes that the ALJ correctly found that when "a company does not experience any actual negative salvage expense on its interim retirements, it is not entitled to recover any of its estimated negative salvage expenses related to future estimated interim retirements."¹⁶⁷ Trial Staff argues that Portland acknowledges that under *Iroquois* interim costs can be included in calculating negative salvage only when there is a record of actual historical costs, yet Portland did not introduce evidence relating to such costs. Trial Staff concludes that the ALJ was correct in finding that Portland was not entitled to recover any estimated negative salvage expenses related to future estimated interim retirements because there is no record evidence that Portland has experienced any actual negative salvage expense on its interim retirements.

Commission Determination

117. The Commission affirms the ALJ's decision to accept Trial Staff's approach not to include expenses related to interim retirements occurring before the end of Portland's life for calculating a negative salvage rate. Both *Iroquois* and *Kern River* hold that where a company does not experience any actual negative salvage expense for interim retirements, it is not entitled to recover any of its estimated negative salvage expenses for such retirements. We find that Portland has not provided evidence to demonstrate it has incurred any actual costs for interim retirements, and thus it fails to satisfy the *Iroquois* requirements. The Commission does not dispute that there may be environmental costs associated with retiring plant, and that environmental costs may change over time. However, this argument presumes that there are interim retirements for which there may be associated environmental costs. The Commission's interim retirement criteria that there be a history of interim retirements helps the Commission determine whether the

¹⁶⁶ Ex. PNG-52 at 80:1-2.

¹⁶⁷ See ID, 129 FERC ¶ 63,027 at P 239 & n.27 (citing *Iroquois*, 84 FERC at 61,441, *order on reh'g*, 86 FERC ¶ 61,261; *Kern River*, Opinion No. 486, 117 FERC at 61,398; Ex. S-1 at 73).

nature of the total plant and the company's plant management permits and provides (respectively) for interim plant retirements, and thus the legitimacy of including such costs as part of negative salvage. Companies cannot simply include interim retirements as a cost without demonstrating that such costs actually exist. The record demonstrates Portland has not incurred any interim plant retirements. Accordingly, there is no need to evaluate how such non-existent retirements should be valued. Therefore, we affirm the ALJ's decision not to include interim retirement costs in determining negative salvage expenses.

2. Labor Costs

Initial Decision

118. The ALJ accepted Trial Staff's labor wage rate figures, which consisted of a blended and weighted mix of union and non-union labor, for projecting the labor costs Portland will incur when it retires its plant.

Briefs on Exceptions and Opposing Exceptions

119. Portland takes exception to the ALJ's adoption of Trial Staff's proposal to use a blended and weighted mix of union and non-union labor wage rates. Portland proposed using union-only wage rates calculated from a proxy area consisting of Syracuse, New York. Portland states that, contrary to the ALJ's finding that Portland provided no actual contractual evidence to support its use of union-only labor rates or its Syracuse proxy area, it did provide such evidence, and that the ALJ failed to discuss Portland's evidence that: (i) supports use of labor wage rates from Syracuse, New York; and (ii) shows that Trial Staff used labor wage rates that understate the actual wages Portland will have to pay.

120. Portland further argues that its testimony used September 2007 union labor rates for Syracuse, New York, including a 25 percent factor for labor overhead and an adjustment factor of 1.17 for overtime pay.¹⁶⁸ Portland argues that union labor rates for Syracuse are a good proxy for labor rates of pipeline contractors that Portland will employ as Syracuse union labor rates are generally 25 to 50 percent lower than that found in Boston, Massachusetts. According to Portland, Trial Staff asserted that the percentage of union labor in the terminal salvage of Portland would be minimal.¹⁶⁹ Portland argues that Trial Staff's labor rates were heavily weighted toward non-union labor and ignored

¹⁶⁸ See Ex. PNG-16 at 15; *see also* Ex. PNG-18 at 66 for a summary of the labor rates that Mr. Taylor used in each option.

¹⁶⁹ Ex. PNG-27 at 4

specialized skills of pipeline industry work and the limited number of qualified contractors.¹⁷⁰ Portland states that pipelines will not select a contractor without regard to quality and experience of the contractor and that past contractor performance and quality of work would also be key considerations during a bid-evaluation process.¹⁷¹

121. Trial Staff, in its Brief Opposing Exceptions, argues that the ALJ fully addressed the record evidence and found that “the Trial Staff relied on a blended and weighted mix of union and non-union labor wage rates extant in the states where Portland actually has facilities and operates.” Further, Trial Staff claims that the ALJ carefully examined and weighed the record evidence and made an informed and objective determination.

Commission Determination

122. The Commission affirms the ALJ’s findings concerning the proper mix of labor and the associated costs.

123. The ALJ relied on Trial Staff Witness Bieltz’s testimony, which included a blended and weighted mix of union and non-union labor wage rates in the states that Portland bases its operations. The ALJ noted that these states are Maine, New Hampshire, Massachusetts and to a limited extent Vermont. Trial Staff Witness Bieltz analyzed the percent of union labor in Maine, Massachusetts, and New Hampshire and demonstrated that the percent of union labor in these states in the private construction sector is only 4.2 percent, 16.1 percent, and 9.5 percent, respectively. Trial Staff Witness Bieltz then weighted by mileage per state the combined percentage of union labor in the states where Portland operates and determined the percentage of union labor to be 6.9 percent. Trial Staff Witness Bieltz made the same analysis for non-union labor and determined that 93.1 percent of the private construction sector in these states was non-union labor.

¹⁷⁰ Ex. PNG-27 at 5.

¹⁷¹ Portland also asserts that the ID fails to note that Trial Staff did not adjust its final abandonment estimate to reflect updated construction costs. Portland Brief on Exceptions at 35. According to Portland, Trial Staff’s estimate was based on construction costs at the end of the base period, and record evidence shows construction costs increased following the base period. Portland argues that failure to reflect that increase produced artificially low rates that the ID fails to address. Trial Staff responds in its Brief Opposing Exceptions that its Witness Bieltz did in fact update his final abandonment estimate and thus the ALJ considered the correct information. Trial Staff Brief Opposing Exceptions at 36 & n.12. Based on a review of this evidence we see nothing to compel us to question the ALJ’s determination on this point.

124. Trial Staff's analysis, which the ALJ adopted, analyzed and rebutted Portland's evidence. Portland assumed that it would use union labor drawn from sources outside of New England. However, Portland presented no evidence that labor will have to be imported into New England to perform these retirements. Nor does Portland contend that skills needed to retire plant requires imported labor, and it further makes no showing that non-union licensed contractors with similar labor skills could not perform the act of decommissioning Portland's pipeline in the same safe and skillful manner as union laborers. Therefore Trial Staff's assumption that decommissioning a pipeline can utilize a significant proportion of local labor is reasonable. Trial Staff's use of a blended labor rate is also reasonable. Based on current labor percentages, to meet Portland's union-only labor mix, it would need to utilize almost 100 percent of the available union labor force in the decommissioning of its pipeline. This is not a realistic scenario. The Commission therefore, finds that Trial Staff Witness Bieltz's labor analysis correctly recognized the actual make-up of union and non-union workforce to develop the actual wage rates.

3. Appropriate Recovery Period for Negative Salvage

125. The ALJ's findings and the exceptions for the appropriate recovery period of negative salvage are the same as those for depreciation rates. The Commission addresses that issue below, and finds that Portland should retain its existing depreciation rate of 2.0 percent. As the negative salvage allowance in a pipeline rate case recovers costs the pipeline will incur upon retirement of plant, negative salvage costs need to be recovered over a term consistent with the expected plant retirement date. In Portland's case, where there is a history of limited changes to gross plant and no interim retirements, the two percent depreciation rate provides a good estimate of the remaining life over which to recover negative salvage costs. In this proceeding, the remaining life for Portland is 38 years.¹⁷² The Commission finds that the appropriate recovery period for Portland's negative salvage costs is 38 years.

¹⁷² The 38 years is arrived at by taking the total years that Portland has been in service and subtracting that number from the estimated life of Portland when service began. Portland has been in service for approximately 12 years (from March, 1999 through March 2011). The estimated life of Portland was 50 years based on the 2 percent depreciation rate. 50 years of estimated life less the 12 years of service arrives at a remaining life of 38 years.

D. Depreciation Rate Increase

Initial Decision

126. The settlement of Portland's last rate case provided for a composite transmission depreciation rate of 2.0 percent.¹⁷³ In this rate case, Portland filed tariff sheets containing rates reflecting a continuation of the existing 2 percent depreciation rate, and that depreciation rate is thus also reflected in its currently effective rates following the five-month suspension of this section 4 rate increase filing. However, in its testimony in this rate case, Portland proposed to prospectively increase its composite depreciation rate on depreciable transmission plant to 3.53 percent following approval by the Commission. No other party proposed to change Portland's currently effective composite depreciation rate, and Trial Staff and PSG opposed Portland's proposal as unsupported. However, each presented testimony and evidence in support of alternative depreciation rates in the event the Commission permits a prospective depreciation rate increase.

127. The ALJ's analysis of the record found that Portland's evidence, as a matter of fact and of law, was lacking. However, the ALJ relied on Trial Staff Witness Bieltz's testimony in recommending a "prospective increase to the filed-for 2.0% depreciation rate for transmission plant to a rate not exceeding 2.41%."¹⁷⁴ The ALJ explained:

For the reasons discussed above, Trial Staff witness Bieltz's gas supply projections and his attendant depreciation and negative salvage rate recommendations are fully supported and I recommend the Commission permit a prospective increase to the filed-for 2% depreciation rate for transmission plant to a rate not exceeding 2.41%.¹⁷⁵

The ALJ rejected PSG's recommended end-life of 40 years for Portland's system, finding it extended beyond the Commission's standard of 35 years, and is inconsistent with Commission precedent indicating that reserve estimates projected beyond 35 years are speculative.¹⁷⁶

¹⁷³ The two percent rate was agreed to as part of the 2002 Settlement, Article 5, and approved in the 2002 Settlement Order, 102 FERC ¶ 61,026 at P 6.

¹⁷⁴ ID, 129 FERC ¶ 63,027 at P 298.

¹⁷⁵ *Id.*

¹⁷⁶ *Id.* P 299.

128. For the reasons discussed below, the Commission adopts the ALJ's analysis of the evidence submitted in this proceeding finding that Portland's evidence was insufficient to support an increased depreciation rate. The Commission also finds, however, that the ALJ provided no compelling arguments or analysis as to why Trial Staff's evidence supporting its alternative position supports Portland's proposal to change its composite depreciation rate. Thus, the Commission rejects the ALJ's recommendation to prospectively increase Portland's depreciation rate.

1. Adequacy of Portland's Depreciation Study

129. The ALJ states that Portland's proposed depreciation rate (like Portland's proposed negative salvage rate) is predicated on its testimony that the average remaining economic life of Portland is only 23 years, based primarily upon a study allegedly demonstrating that all natural gas supplies potentially accessible to Portland's customers will be virtually depleted by then. According to Portland, the existing 2 percent rate assumes an untenable remaining economic life of 39 years. Further, according to Portland, a 3.53 percent depreciation rate for transmission plant (predicated on a 30-year economic end-life as modified to reflect a 23-year "Weighted Average Economic Life") is permissible and justified prospectively.¹⁷⁷

130. The natural gas supply study relied upon by Portland to forecast gas supplies potentially available to its customers in the future is set forth in Exhibit Nos. PNG-14 and PNG-15. The model underlying the study involves the relationship of natural gas drilling efforts to results, in terms of natural gas deposits discovered, over the course of a particular year in the Western Canadian Sedimentary Basin (WCSB), and is known as the "finding rate or effectiveness of exploration [E/fE]" model. Portland's E/fE model includes five key components. The model:

- Projects indefinitely into the future a constant drilling rate;
- Projects into the future a constant natural gas finding rate, until the projected future point when 90 percent of the total endowment of natural gas in the WCSB is expected to be depleted, at which point the finding rate is reduced by 10 percent per year going forward;
- Projects indefinitely into the future a constant estimate of the total endowment of natural gas in areas to which shippers on Portland have access;

¹⁷⁷ ID, 129 FERC ¶ 63,027 at P 243, 246.

- Projects indefinitely into the future a constant production rate, assuming arbitrarily an exponential depletion rate (or reserve/production ratio) of 10 percent per year; and
- Was expressly represented to be comprehensive in application, so as to project the time for depletion of all natural gas supplies potentially accessible to PNGTS' customers, including potential supplies throughout the United States as well as Canada.¹⁷⁸

131. In the ID, the ALJ notes that Portland's EfE model is similar to models the Commission and the courts have previously rejected in *Kansas Pipeline*,¹⁷⁹ *Williston Basin*,¹⁸⁰ *Kern River*¹⁸¹ and *South Dakota PUC v. FERC*.¹⁸² For each of these cases, the ALJ identified the issues that led to the Commission's or court's rejection of the model, and then identified how those same issues exist in Portland's EfE model.¹⁸³ The ALJ concluded that to satisfy its burden of proof on the depreciation issue, Portland must present substantial persuasive evidence of future gas supplies in the United States that may be available to Portland via the Dawn Hub,¹⁸⁴ as well as future gas supplies in the WCSB.¹⁸⁵

¹⁷⁸ ID, 129 FERC ¶ 63,027 at P 246-248.

¹⁷⁹ *Kansas Pipeline Co.*, 96 FERC ¶ 63,014 (2001) (*Kansas Pipeline*), *aff'd in relevant part in Enbridge KPC*, 100 FERC ¶ 61,260, *order on reh'g*, 102 FERC ¶ 61,310.

¹⁸⁰ *Williston Basin Interstate Pipeline Co.*, 95 FERC ¶ 63,008 (2001) (McCartney, Presiding Judge) (*Williston II*), *aff'd in relevant part*, 104 FERC ¶ 61,036 (2003), *order on reh'g*, 107 FERC ¶ 61,164 (2004) (*Williston IV*).

¹⁸¹ *Kern River*, 114 FERC ¶ 63,013 (2006), *aff'd in relevant part*, Opinion No. 486, 117 FERC ¶ 61,077.

¹⁸² 688 F. 2d 333, 341-42 (8th Cir. 1981).

¹⁸³ ID, 129 FERC ¶ 63,027 at P 249-256.

¹⁸⁴ The Dawn Hub is located in Ontario, Canada. Portland states that the Dawn Hub has become a very liquid trading hub where natural gas supplies from both Canada and the United States move freely across the United States/Canadian border to find the best market available, either transportation markets and/or storage markets in the United States or Canada. Ex. PNG-52 at 7.

¹⁸⁵ ID, 129 FERC ¶ 63,027 at P 253.

132. The ALJ found that Portland failed to meet this burden. The ALJ found that the E/e long term gas supply projections ignored changes in gas prices and technology. Thus, according to the ALJ, the E/e purports to project 30 years into the future, yet holds constant: (1) a gas price rooted in the past; (2) levels of gas exploration and drilling technology that are anchored in the past; and (3) an assumed fixed limit on the growth of natural gas reserves and production, based on estimates that have always proven transitory in the past. The ALJ found that Portland's E/e model amounts to a "depletion" model that assumes that gas supply in the lower 48 states will not be increasing over the next 30 years -- an assumption at odds with the most recent authoritative projections in the record. The ALJ states that an E/e "depletion" model is inherently implausible for the foreseeable future because in the event that a depletion scenario otherwise appeared to be a real possibility, any gas supply shortages would engender a commensurate increase in the price of gas such that "[p]roducers will drill to deeper and higher cost zones ... thereby increasing reserves."¹⁸⁶

133. Portland's E/e model's primary gas supply projections are for the WCSB. However, while Portland did include projections for future gas supplies from the United States, the ALJ found that Portland's underlying data for United States supply was significantly less than what it had attempted to show for the WCSB, and the analysis was lacking. The ALJ further held that because Portland's E/e model is a depletion model, Portland had the burden to show that all United States gas supplies would be depleted by the end of 30 years. The ALJ did not find the E/e projection of United States gas supply credible in light of other studies, especially the June 18, 2009, Potential Gas Committee's latest biennial assessment of the U.S. natural gas resources.¹⁸⁷

Portland's Brief on Exceptions

134. Portland claims that the ALJ failed to discuss Portland's evidence, made factual findings refuted by the evidence, made findings unsupported by the evidence, and reached illogical conclusions. Portland claims that the ID attributes to Portland several key purported admissions that in fact were neither admitted, nor reflect Portland's positions. Portland provides two examples in support of its claim. First, the ID states:

In order for PNGTS to satisfy its burden of proof on the depreciation issue, it was incumbent upon it to present substantial persuasive evidence of future gas supplies in the United States that may be available to PNGTS via the Dawn

¹⁸⁶ *Id.* P 260 (citing *Kansas Pipeline Co.*, 96 FERC at 65,097).

¹⁸⁷ *Id.* P 263-273.

hub, as well as future gas supplies in the WCSB. PNGTS *admittedly* failed to do so . . .¹⁸⁸

Portland states that it admits to no such failing. Portland states that it presented substantial evidence concerning future gas supplies available to it via the Dawn Hub.

135. Second, Portland contends the ID erroneously alleges that:

*PNGTS [Portland] recognized that its burden of proof in this regard required it to present substantial evidence supporting reliable long-term gas supply forecasts (which should include explicit variables for future changes in gas prices and technology) . . .*¹⁸⁹

Portland states that it does not, and did not, recognize the burden of proof as characterized in the ID. Portland claims that the Commission never has required nor, to Portland's knowledge, approved a gas supply forecast based upon a model that included an explicit variable for future changes in gas prices.¹⁹⁰

136. Portland also argues on exceptions that the Commission's determination in *Iroquois Gas Transmission System, L.P.*,¹⁹¹ is the controlling Commission precedent in support of Portland's proposed remaining life date of 2030.¹⁹² Portland states that the Commission tied Iroquois' remaining economic life directly to TransCanada's economic life because TransCanada was the primary upstream conduit for transporting volumes to Iroquois.¹⁹³ Portland contends the *Iroquois* precedent is directly applicable to itself because unlike pipelines enjoying gas supplies available from multiple fields or supply basins via different gathering systems or multiple intrastate or interstate pipelines, Portland relies upon supplies transported to it by TransCanada. Therefore, Portland continues, whether natural gas supplies originate in the WCSB, or from Lower 48 supply basins and are made available at Dawn Hub, they must be transported on TransCanada to

¹⁸⁸ Portland Brief on Exceptions at 36 (citing ID at P 253).

¹⁸⁹ *Id.* (citing ID at P 264).

¹⁹⁰ *Id.* at 36-37.

¹⁹¹ *Iroquois*, 81 FERC ¶ 63,012, at 65,092, *aff'd* 84 FERC ¶ 61,086.

¹⁹² Portland Brief on Exceptions at 37.

¹⁹³ The Commission notes that TransCanada's system is in Canada and its tolls are set by Canada's National Energy Board (NEB), not FERC.

reach Portland at Pittsburg. Thus, Portland concludes, the “NEB’s order is definitive for setting Portland’s remaining economic life.”¹⁹⁴

137. Portland argues that the ALJ completely ignored: (i) the holding of *Iroquois*; (ii) the legal arguments that Portland made concerning the applicability of *Iroquois*; and (iii) the evidence Portland submitted applying its so-called “Iroquois Rule” to the facts of this case. That clear error, Portland contends, requires rejection of the ID’s recommendation concerning depreciation.¹⁹⁵

Commission Determination

138. The Commission affirms the ALJ’s finding that Portland’s depreciation study does not support an adjustment to its remaining economic life and therefore rejects Portland’s claims regarding the sufficiency of its evidence. The ALJ discussed the evidence Portland submitted in support of its position in detail and properly rejected Portland’s model consistent with Commission precedent rejecting similar gas supply models. The ALJ also conducted an item by item comparison of the deficiencies identified in the prior Commission orders and concluded on point after point that those same deficiencies remained in Portland’s model.

139. In the examples provided by Portland on exception, the issue is the applicability of the E/fE model to a pipeline such as Portland. The Commission has never ruled that a fixed-reserve, depletion-based model such as the E/fE model is inappropriate in all circumstances. Rather, the cases analyzed by the ID go to the fact that the Commission believes long-term gas supply studies for pipelines that have access to several production areas need to take into consideration economic and technological factors. History has shown these factors do affect gas supply projections.

140. Portland states that it has access to multiple production areas in North America, including the WCSB and the Rocky Mountain, mid-continent and the Gulf Coast production areas of the United States through the Dawn Hub. As Portland notes, its E/fE model includes gas supply projections for all those areas. According to Portland’s witness, however, these projections are based on a “geological model ... not an

¹⁹⁴ Portland Brief on Exceptions at 39.

¹⁹⁵ Portland Brief on Exceptions at 37-39.

econometric model,” that does not have exogenous prices,¹⁹⁶ and the model did not incorporate “any rate of technological change and its effect on drilling.”¹⁹⁷

141. Portland also claims that the ALJ imposed an additional burden of proof. The Commission does not interpret the ALJ’s comment in that fashion. The Commission has previously documented the *EfE* model’s failure to recognize the impact that prices and technology have on gas supply results and how such an approach is not reasonable when compared to other gas supply models and compared to actual production data. It was incumbent upon Portland, as the proponent of the *EfE* model, to address the already known deficiencies of that model.

142. The Commission also rejects as misplaced Portland’s reliance on *Iroquois* as the standard for establishing its system remaining economic life in this proceeding. As noted, Portland, in its Brief on Exceptions, claims that in *Iroquois* the Commission approved the Presiding Judge’s findings that the remaining life of the *Iroquois* system could be tied to TransCanada’s economic life because TransCanada is the primary upstream conduit for transporting volumes to *Iroquois*’ system, and that a 2003 TransCanada depreciation study approved by the NEB dictates that Portland’s economic end-life must be 2027, the same as TransCanada. Contrary to Portland’s assertions, the Commission’s affirmance of the Presiding Judge’s ID in *Iroquois* did not establish a general Commission policy or rule requiring the use of an upstream pipeline’s depreciation rate or remaining life for all downstream pipelines as Portland appears to suggest.

143. In *Iroquois*, the pipeline proposed to continue its existing four percent rate of depreciation based upon a 25-year life. The *Iroquois* judge found that the pipeline’s depreciation rate should be reduced to 2.77 percent, based upon a 35-year life. *Iroquois* excepted to that holding, arguing that its existing four percent depreciation rate should be retained. In affirming the Presiding Judge, the Commission pointed out that the shippers advocating a 35-year life had presented “extensive and persuasive evidence” on gas supply in addition to a TransCanada study showing that *Iroquois*’ economic life would extend well beyond the 35-year life in the TransCanada study. However, the shippers reduced their proposed life for *Iroquois* to 35 years “based on a number of factors, primary among which was the fact that TransCanada’s most recent study produced a 35-year economic life for TransCanada—the system through which *Iroquois* accesses its Canadian supply.”¹⁹⁸

¹⁹⁶ ID, 129 FERC ¶ 63,027 at P 257 (citing Tr. 1796/7-9).

¹⁹⁷ *Id.* (citing Tr. 1773:14-15).

¹⁹⁸ *Iroquois*, 84 FERC ¶ 61,086 at 61,439.

144. Thus, in *Iroquois*, no party advocated a depreciable life in excess of the 35-year life in the TransCanada study, and the only exception presented to the Commission was the pipeline's contention that its depreciable life should be even shorter than the 35-year life in the TransCanada study. Thus, no issue was presented to the Commission concerning whether the depreciable life of an upstream pipeline should act as a ceiling on the depreciable life of a downstream pipeline, and therefore *Iroquois* cannot be cited as establishing any such policy. In this case, Portland's reliance on a TransCanada depreciation study is particularly inappropriate, because that study was conducted in 2003, six years before the hearing in this case. It is thus outdated and not probative on the issue of the remaining life of gas supplies available to the Portland system as of the time of this rate case.

145. The Commission affirms the ALJ's analysis that Portland's depreciation study in this case, particularly its EfE model for projecting gas supply, is deficient and does not produce reasonable results. As discussed above, because the EfE model is the primary supporting pillar of Portland's proposed depreciation rate, Portland has failed to support its proposed change.

2. ALJ's Depreciation Rate Recommendation

Initial Decision

146. The ALJ, after dismissing Portland's EfE model, states:

For the reasons discussed above, Trial Staff witness Bieltz's gas supply projections and his attendant depreciation and negative salvage rate recommendations are fully supported and I recommend the Commission permit a prospective increase to the filed-for 2% depreciation rate for transmission plant to a rate not exceeding 2.41%.

147. PSG's Brief on Exceptions notes that the ID found that Portland had failed to present credible evidence to support any increase in the 2 percent depreciation rate. Yet, PSG continues, the ID nevertheless went on to assert that regardless of the evidence of record, the Commission has somehow precluded as a matter of law any recognition of any pipeline's remaining economic life beyond 35 years for purposes of determining an appropriate depreciation rate under the NGA. PSG claims that it demonstrated that Portland had failed to meet its burden of justifying any increase in the 2 percent depreciation rate for mainline facilities, and in any event that no such increase could be justified beyond 2.15 percent.¹⁹⁹

¹⁹⁹ PSG Brief on Exceptions at 49.

Commission Determination

148. In *Western Resources Inc. v. FERC*, 9 F.3d 1568, 1579-1580 (D.C. Cir. 1993) (*Western Resources*), the court held that, before the Commission can impose its own tariff provision in a proceeding commenced under NGA section 4, the Commission first must find that the pipeline failed to carry its burden of proof to support its section 4 proposal. If the Commission wishes to impose its own rates, *Western Resources* states that the Commission had a dual burden under NGA section 5 in order to impose its own rates. The Commission must show that (1) the preexisting rate design is unjust and unreasonable and (2) the Commission's proposed rate design is just and reasonable.²⁰⁰

149. The ALJ satisfied the first part of the test by finding that Portland failed to carry its burden of proof to support its section 4 proposal. The ALJ, however, did not satisfy the next step: finding that Portland's existing depreciation rate of 2.0 percent is no longer just and reasonable. The ALJ simply adopted Trial Staff's position as the basis of her recommendation to permit Portland a changed depreciation rate. Trial Staff never purported to demonstrate that Portland's currently effective depreciation rate is no longer just and reasonable.²⁰¹ In fact, Trial Staff testified that it was fully supportive of an economic end-life of 40 to 50-year range.²⁰² Therefore, the ALJ's citation to Trial Staff's testimony is insufficient to satisfy the statutory requirement. The ALJ could have found that the record supported a finding that Portland's currently effective depreciation rate was no longer just and reasonable, but the ALJ did not. The Commission finds that the ALJ's recommendation that the Commission permit a change to Portland's depreciation is flawed. Portland will retain its currently effective depreciation rate of 2.0 percent.

150. All remaining depreciation rate issues raised on exceptions are dismissed.

²⁰⁰ *Western Resources*, 9 F.3d at 1578.

²⁰¹ Trial Staff testified that its recommended depreciation rate should apply only "if the Commission were to modify the existing depreciation rates...." Ex. S-1 at 5:21-22. Trial Staff never argues that Portland's existing depreciation rates are not just and reasonable.

²⁰² Ex. No. S-1 at 26:16-18.

IV. Return On Equity

A. Rate Base – Prepaid Taxes in Working Capital

151. The ALJ found that Portland had demonstrated \$330,056 of prepaid ad valorem taxes should be included in the working capital allowance included in rate base.²⁰³ The ALJ determined that the detailed information provided in Exhibit PNG-86 as part of Portland's rebuttal evidence enabled Portland to carry its burden for inclusion of prepaid taxes in rate base. The ALJ also found that PSG's position at hearing to exclude all prepaid taxes was overly harsh, particularly as PSG only challenged two prepayments as obligations outside the test period.²⁰⁴ During the post-hearing briefing stage, while Portland disagreed with PSG's contention that two payments were outside the test period, it revised its initial proposal for prepaid taxes downward from \$345,080 to the \$330,056 approved in the ID. The ALJ found that the relatively minor downward adjustment Portland made to account for the elimination of these prepayments was reasonable.

152. PSG excepted to this finding, claiming that procedurally the level of pre-paid taxes raises questions of fundamental fairness because Portland revised its initially supported figure downward at the briefing stage.²⁰⁵ PSG claims that because Portland did not disclose the figure until after the hearing no participants had an opportunity to review or question the derivation of the proposed figure. According to PSG, Portland's direct case contained no support for its prepaid tax amounts as it did not provide sufficient data to support its claim and thus all proposed amounts should be rejected.

153. Portland and Trial Staff oppose PSG's exception.²⁰⁶ Portland claims that its Witness Sieppert provided more than ample evidence in support of its request to include end of test period average balances for prepaid taxes in working capital, and that its Exhibit PNG-86 "shows in voluminous detail that the prepaid taxes were for the relevant time period, were required to be paid, and, in fact, were actually paid."²⁰⁷ Portland states

²⁰³ ID, 129 FERC ¶ 63,027 at P 127.

²⁰⁴ *Id.* P 128 (noting that PSG had not provided any evidence that any prepayments were outside the test period other than prepayments to Peru, Maine and Waterford, Maine).

²⁰⁵ PSG Brief on Exceptions at 25-29.

²⁰⁶ Portland Brief Opposing Exceptions at 11-13; Trial Staff Brief Opposing Exceptions at 13-15.

²⁰⁷ *Id.* at 12 & n.30 (quoting Initial Brief of Commission Trial Staff at 38).

that the fact it took into account PSG's criticisms of the originally proposed amount and made adjustments to eliminate two payments made in advance of their due dates does not warrant excluding all of the proposed prepaid tax amount. Portland asserts that Exhibit PNG-86 provides copious detail of the due date of each tax bill and the month and the year each bill was actually paid and that PSG acknowledges that fact. Portland also claims that PSG had ample time to review the data provided in Exhibit PNG-86. Portland claims that it is disingenuous for PSG to now claim that it did not have sufficient data to assess whether the invoices were properly included when PSG used the very data provided to challenge the invoices that Portland eventually withdrew.

154. Trial Staff agrees that Portland carried its burden to include the prepaid taxes in its rate base and PSG's fairness claims should be rejected as the changes made by Portland represent a concession by Portland, not a recalculation.²⁰⁸ Trial Staff concludes that where "the only prepayments challenged by PSG were voluntarily removed from the calculation, and where PSG has not specifically challenged any other prepayments, the ruling of the ALJ should be upheld."²⁰⁹

Commission Determination

155. We find that the ALJ was correct to determine that Portland met its burden for including the prepaid tax amount approved in the order in the working capital allowance included in rate base. At the July 2009 hearing, Portland submitted as Exhibit PNG-86 its January 29, 2009 response to Trial Staff's discovery request for a detailed listing of all prepaid taxes paid in calendar year 2007, together with supporting documentation to show the prepayment requirement. As noted by Portland, Trial Staff and the ALJ, Exhibit PNG-86 provided copious amounts of record evidence detailing the tax amounts and their due dates and the dates that Portland paid such taxes. Given that evidence, PSG challenged at the hearing only two of the relevant invoices, and Portland in its post-hearing brief voluntarily adjusted its originally proposed amount downward to account for prepayments made outside of the test period. We agree with the ALJ that it would be unjust to disallow all of Portland's proposed prepaid tax amounts as Exhibit PNG-86 clearly contains record evidence of properly included prepayments and PSG has not identified any further questionable invoices. Accordingly we find that it was reasonable for the ALJ to rely on that evidence to determine that the downward adjustment was reasonable.

²⁰⁸ Trial Staff Brief Opposing Exceptions at 14.

²⁰⁹ *Id.* at 15.

B. Derivation of ROE

156. As discussed in the Commission's *Policy Statement on the Composition of Proxy Groups for Determining Gas and Oil Pipeline Return On Equity*,²¹⁰ the Supreme Court has held that "the return to the equity owner should be commensurate with the return on investment in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."²¹¹ In order to attract capital, "a utility must offer a risk-adjusted expected rate of return sufficient to attract investors."²¹² In theory, this requires an evaluation of the regulated firm's needed return compared to other regulated firms of comparable risk.

157. Most natural gas pipelines are wholly-owned subsidiaries and their common stock is not publicly traded. Therefore, the Commission performs a discounted cash flow (DCF) analysis of publicly-traded proxy firms to determine the return the equity markets require a pipeline to give its investors in order for them to invest their capital in the pipeline. The DCF model is based on the premise that "a stock's price is equal to the present value of the infinite stream of expected dividends discounted at a market rate commensurate with the stock's risk."²¹³ With simplifying assumptions, the DCF model results in the investor using the following formula to determine share price:

$$P = D / (r - g)$$

where P is the price of the stock at the relevant time, D is the current dividend, r is the discount rate or rate of return, and g is the expected constant growth in dividend income to be reflected in capital appreciation.²¹⁴

158. Unlike investors, the Commission uses the DCF model to determine the return on equity (ROE) (the "r" component) to be included in the pipeline's rates, rather than to estimate a stock's value. Therefore, the Commission solves the DCF formula for the

²¹⁰ 123 FERC ¶ 61,048 (2008), *reh'g dismissed*, 123 FERC ¶ 61,259 (2008) (Policy Statement).

²¹¹ *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

²¹² *CAPP v. FERC*, 254 F.3d 289, 293 (D.C. Cir. 2001).

²¹³ *Id.*

²¹⁴ *National Fuel Gas Supply Corp.*, 51 FERC ¶ 61,122, at 61,337 n.68 (1990); *Ozark Gas Transmission System*, 68 FERC ¶ 61,032, at 61,104 n.16. (1994).

discount rate, which represents the rate of return that an investor requires in order to invest in a firm. Under the resulting DCF formula, ROE equals current dividend yield (dividends divided by share price) plus the projected future growth rate of dividends:

$$R = D/P + g$$

159. The Commission uses a two-step procedure for determining the constant growth of dividends, averaging short-term and long-term growth estimates. Security analysts' five-year forecasts for each company in the proxy group (discussed below), as published by the Institutional Brokers Estimated System (IBES), are used for determining growth for the short term; long-term growth is based on forecasts of long-term growth of the economy as a whole, as reflected in the gross domestic product (GDP).²¹⁵ The short-term forecast receives a two-thirds weighting and the long-term forecast receives a one-third weighting in calculating the growth rate in the DCF model.²¹⁶ The DCF methodology produces a zone of reasonableness in which the pipeline's rates may be set based on specific risks.²¹⁷

160. In the instant case the parties have not disputed this basic methodology. The ROE issues litigated by the parties center upon: (1) the composition of the proxy group; (2) the appropriate methodology for calculating dividend yield; (3) the appropriate placement of Portland in the range of reasonable returns developed using the Commission's constant growth DCF model; and (4) the appropriate data to use for calculating ROE. The ALJ adopted the proxy group proposed by PSG and adopted Trial Staff's ROE range, DCF methodology and median for those proxy group members. The returns for the proxy group adopted by the ALJ range from 8.7 percent to 16.09 percent and the median is 11.65 percent.²¹⁸ The ALJ determined that Portland's ROE should be placed at the median of the proxy group adopted in the ID, namely 11.65 percent.²¹⁹

²¹⁵ *Northwest Pipeline Corp.*, Opinion No. 396-B, 79 FERC ¶ 61,309, at 62,383 (1997); *Williston II*, 79 FERC ¶ 61,311, at 62,389 (1997); , *aff'd in relevant part*, *Williston v. FERC*, 165 F.3d 54 at 57.

²¹⁶ *Transcontinental Gas Pipe Line Corp.*, Opinion No. 414-A, 84 FERC ¶ 61,084 at 61,423-24, *reh'g denied*, Opinion No. 414-B, 85 FERC ¶ 61,323, at 62,266-70 (1998), *aff'd*, *CAPP v. FERC*, 254 F.3d 289 (D.C. Cir. 2001).

²¹⁷ *Williston v. FERC*, 165 F.3d 54, 57.

²¹⁸ *See* ID, 129 FERC ¶ 63,027 at P 567 (citing to Trial Staff Witness Keyton's Exhibit S-23).

²¹⁹ *Id.* P 638.

161. Portland excepts to the ALJ's holding with respect to the make-up of the proxy group, as do several other parties. Portland also excepts to the ALJ's failure to use the most current record data available for the DCF analysis and to Portland's placement at the median range in the zone of reasonableness. PSG asserts that Trial Staff made a calculation error in its dividend yield calculation and that the ALJ should have adopted PSG's proposed alternative methodology. CAPP argues that the ALJ should have acknowledged or evaluated CAPP's basis for a proposed 12-month dividend yield calculation.

162. As discussed in detail below, the Commission determines that the proxy group approved by the ALJ is not risk appropriate for Portland and thus in this order we approve a proxy group consisting of TC Pipelines LP (TC Pipelines), Southern Union Gas Company (Southern Union), Boardwalk Pipeline Partners (Boardwalk), Spectra Energy Corporation (Spectra Corp.), El Paso Pipeline Partners, LP (El Paso Partners), and Spectra Energy Partners, LP (Spectra Partners). The Commission conducted a DCF analysis based on the use of this proxy group, which establishes a zone of reasonableness of 12.18 percent to 14.89 percent, with a median of 12.99 percent.²²⁰ The analysis conducted uses Trial Staff's DCF methodology, which methodology was adopted by the ALJ in the ID,²²¹ and is based on a six-month dividend yield calculation using data for the six month period beginning November 2008 and ending April 2009.

C. Composition of the Proxy Group

163. As the court explained in *Petal Gas Storage, LLC v. FERC*,²²² the purpose of the proxy group is to "provide market-determined stock and dividend figures from public companies comparable to a target company for which those figures are unavailable. Market-determined stock figures reflect a company's risk level and when combined with dividend values, permit calculation of the 'risk-adjusted expected rate of return sufficient to attract investors.'"²²³ It is thus crucial that the firms in the proxy group be comparable to the regulated firm whose rate is being determined. In other words, as the court emphasized in *Petal v. FERC*, the proxy group must be "risk-appropriate."²²⁴

²²⁰ The results and workpapers relating to this DCF analysis are attached hereto as Appendix A.

²²¹ ID, 129 FERC ¶ 63,027 at P 567.

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

²²³ *Petal v. FERC*, 496 F.3d at 697 (quoting *CAPP v. FERC*, 254 F.3d 289 at 293).

²²⁴ *Id.*

164. In deciding the ROE issue in this case, the primary issue has been developing a representative proxy group used to determine a range of reasonable returns for setting Portland's ROE. Historically, the Commission required that each company included in the proxy group satisfy three standards: (1) the company's stock must be publicly traded; (2) the company must be recognized as a natural gas company and its stock must be recognized and tracked by an investment information service, such as the Value Line Investment Survey; and (3) pipeline operations must constitute a high proportion of the company's business.²²⁵ Historically, this last standard could only be satisfied if a company's pipeline business accounted for, on average, at least 50 percent of a company's assets or operating income over the most recent three-year period.²²⁶

165. In the last several years, the Commission has reexamined its policy concerning the composition of the proxy group, in light of the fact that few corporations have satisfied the Commission's historical proxy group standards. Mergers and acquisitions have reduced the number of publicly traded corporations with natural gas pipeline operations. Most of the remaining corporations have been engaged in such significant non-pipeline business that their remaining pipeline business accounts for significantly less than 50 percent of assets or operating income. At the same time, there has been a trend toward master limited partnerships (MLPs) owning natural gas pipelines.

166. On April 17, 2008, the Commission issued its Policy Statement concerning the composition of the proxy groups used to determine jurisdictional gas and oil pipelines' ROE under the DCF model.²²⁷ The Commission concluded: (1) MLPs could be included in the ROE proxy group for gas pipelines; (2) there should be no cap on the level of an MLP's distributions included in the dividend yield component of the DCF methodology; (3) the IBES forecasts would remain the basis for the short-term growth forecast used in the DCF calculation for both corporations and MLPs; (4) there should be an adjustment to the long-term growth rate used to calculate the equity cost of capital for an MLP; and (5) there would be no modification to the current respective two-thirds and one-third weightings of the short- and long-term growth factors. The Commission stated that the Policy Statement made no findings as to which particular corporations and/or MLPs should be included in the gas or oil proxy groups. The Commission left that determination to each individual rate case. The Commission did provide general criteria for the inclusion of MLPs in proxy groups, namely: (i) the MLP should be tracked by Value Line; (ii) the MLP should have been in existence for at least 5 years; and (iii) the

²²⁵ *Williston IV*, 104 FERC at P 34-43.

²²⁶ *Id.* P 35 n.46.

²²⁷ Policy Statement, 123 FERC ¶ 61,048.

MLP should derive at least 50 percent of its operating income from, or have 50 percent of its assets devoted to, interstate operations.²²⁸ The Commission further noted that there might be individual MLPs that do not satisfy the criteria described above but may still be appropriate for inclusion in the proxy group.

167. The Commission applied the Policy Statement in Opinion Nos. 486-B²²⁹ and 486-C.²³⁰ In those opinions, the Commission restated its preference that proxy firms satisfy the Commission's historical standard that 50 percent of their income or assets be in the pipeline business.²³¹ However, the Commission stated that, in order to achieve a proxy group of at least five firms, a diversified natural gas company not satisfying the historical standard could be included in the proxy group, but only if there is a convincing showing that an investor would view that firm as having comparable risk to a pipeline. The Commission explained that diversified natural gas firms not only have gas transmission operations, but engage in other aspects of the natural gas business, including (1) generally higher risk market-oriented exploration, production, and marketing businesses and (2) generally lower risk local distribution business. Therefore, the more the diversified natural gas firm is composed of functions other than a natural gas transmission function, the more difficult it is to assure that such a firm is risk appropriate under *Petal Gas v. FERC*. The Commission concluded that, while a diversified natural gas firm not satisfying the historical 50 percent standard may be considered for inclusion in the proxy group, such a firm should be excluded from the proxy group if either of its less risky distribution or more risky market-oriented functions substantially outweighs its transmission functions or each other.²³² Specifically, Opinion No. 486-C held that, in order to include such a firm in the proxy group, it must be shown that: (i) the combined natural gas pipeline and distribution businesses of the firm make up at least 50 percent of its total business; (ii) the natural gas pipeline business is at least equal to the distribution business; and (iii) the firm's more risky exploration, production, and other market-oriented businesses are no greater than the less risky distribution business.²³³

²²⁸ *Id.* P 79.

²²⁹ Opinion No. 486-B, 126 FERC ¶ 61,034.

²³⁰ Opinion No. 486-C, 129 FERC ¶ 61,240.

²³¹ Opinion No. 486-B, 126 FERC ¶ 61,034 at P 91; Opinion No. 486-C, 129 FERC ¶ 61,240 at P 60, 70.

²³² Policy Statement, 123 FERC ¶ 61,048 at P 51.

²³³ Opinion No. 486-C, 129 FERC ¶ 61,240 at P 71; *see also* Opinion No. 486-B, 126 FERC ¶ 61,034 at P 91-92, 94, 97-99.

168. In this case, the ALJ adopted the proxy group proposed by PSG, consisting of TC Pipelines, Southern Union, Boardwalk, Spectra Corp. and National Fuel Gas Company (National Fuel). The ALJ excluded alternative proxy group proposals by Portland, Trial Staff and CAPP. Portland's proxy group included El Paso Partners, Spectra Partners, Enbridge Energy Partners (Enbridge), Energy Transfer Partners (ETP), Enterprise Products Partners (Enterprise), Kinder Morgan Energy Partners, LP (KMEP), ONEOK Partners, LP (ONEOK), and the Williams Companies (Williams). Trial Staff's proposed proxy group included Williams, TransCanada Corporation (TransCanada), and NiSource Inc. (NiSource).

169. As discussed in detail below, we find that the ALJ's chosen proxy group is not risk appropriate as compared with Portland. Based on the Commission's preference that a proxy firm's natural gas pipeline business account for at least 50 percent of its assets or operating income, we determine that National Fuel is not an appropriate member of the proxy group for this proceeding. Further, based on the determination below that neither the language nor the intent of the Policy Statement established a strict five year test for the inclusion of MLPs in a natural gas pipeline proxy group, we find that Spectra Partners and El Paso Partners are appropriate members for the proxy group in this case. We also find that the ALJ's remaining proxy group choices were appropriate. Accordingly, we approve a proxy group consisting of TC Pipelines, Southern Union, Boardwalk, Spectra Corp., El Paso Partners and Spectra Partners. We approve this group because all the companies in the group meet the 50 percent threshold. Below we discuss in detail the parties' exceptions to the exclusion and inclusion of several of the entities chosen for the proxy group in this proceeding and provide our analysis of the firms the parties proposed to include in the proxy group.

1. TC Pipelines

170. The ALJ included TC Pipelines, an MLP, in the proxy group. The ALJ noted that each of the participants sponsoring ROE testimony in this proceeding agreed that TC Pipelines was an appropriate member of the proxy group and found that in 2007, 100 percent of TC Pipelines' operating income and 100 percent of its assets were associated with natural gas facilities.²³⁴ Thus, TC Pipelines more than satisfied the Commission's historical 50 percent threshold.

171. No Participant excepted to TC Pipelines' inclusion in the proxy group for this proceeding. According to the record, TC Pipelines is covered in the Value Line Small and Mid-Cap Edition.²³⁵ TC Pipelines has been in operation since 1991, with its primary

²³⁴ ID, 129 FERC ¶ 63,027 at P 333 & n.83.

²³⁵ See Ex. S-12 at 44; Ex. PSG-30 at 39-40.

business being interstate natural gas transportation. TC Pipelines owns 100 percent of Tuscarora Gas Transmission Company, 46.45 percent of Great Lakes Gas Transmission, LP and 50 percent of Northern Border Pipeline Company, all of which are regulated by this Commission. According to the record, TC Pipelines devotes 100 percent of its assets to, and derives 100 percent of its income from, interstate natural gas pipeline operations.

Commission Determination

172. The Commission finds that TC Pipelines is an appropriate proxy group member in this case. TC Pipelines satisfies the Commission's historic requirement that the natural gas pipeline business account for at least 50 percent of its assets or operating income. Through its ownership interests in Northern Border and Tuscarora Gas Transmission, 100 percent of TC Pipelines' operating income and 100 percent of its assets were associated interstate natural gas facilities in 2007. Further, all the parties sponsoring ROE testimony in this proceeding agree that TC Pipelines is an appropriate member of the proxy group for this proceeding.

2. Southern Union

173. The ALJ included this MLP in the proxy group, noting that all the participants submitting ROE testimony agree that Southern Union is an appropriate member of the proxy group.²³⁶ According to the record, Southern Union is categorized in Value Line as being in the Oil/Gas Distribution Industry, which encompasses both wholesale transmission as well as retail distribution activities, and over 60 percent of Southern Union's assets are devoted to, and about 75 percent of its income is derived from, its interstate natural gas pipeline operations. These operations are conducted mainly through its subsidiaries Florida Gas Transmission Company, Panhandle Eastern Pipeline Company and Trunkline Gas Company.²³⁷ No party objected to the inclusion of Southern Union in the proxy group.

Commission Determination

174. Based on the facts above we find that Southern Union is an appropriate proxy group member for this proceeding. As shown, Southern Union satisfies the Commission's 50 percent threshold test and all the parties that presented ROE testimony in this case agree that Southern Union should be included in the proxy group.

²³⁶ ID, 129 FERC ¶ 63,027 at P 335-36.

²³⁷ See Ex. No. PSG-30 at p.17. See also ID P 335 and n.84.

3. Boardwalk

175. The ALJ included Boardwalk, an MLP, in the proxy group. According to the record, Boardwalk is listed in Value Line as being in the Oil/Gas Distribution Industry. Moreover, about 94 percent of Boardwalk's assets are primarily dedicated to, and 100 percent of its operating income derived from, its interstate natural gas pipeline operations, namely Texas Gas Transmission Company and Gulf South Pipeline Company.²³⁸

176. Trial Staff filed an exception to the inclusion of Boardwalk in the proxy group.²³⁹ According to Trial Staff, Boardwalk does not meet the Policy Statement's criteria for the inclusion of an MLP in the proxy group because Boardwalk had not been in existence for five years in 2007 and thus was not "well established."²⁴⁰ Trial Staff argues that the criterion that an MLP should have been in existence for at least 5 years was a minimum and that there is no language in the Policy Statement to suggest that the Commission was merely advancing a broad, flexible guideline that could be discarded instead of a bright-line rule. Trial Staff also asserts that the ALJ was wrong in determining that Boardwalk was close to reaching the 5-year milestone because in 2007 Boardwalk had only been in existence for less than three years.

177. Portland and PSG oppose Trial Staff's exception to the inclusion of Boardwalk in the proxy group. Portland contends that the Policy Statement rejects a bright line five-year rule and instead states that MLPs that are "well-established can be included in a pipeline proxy group."²⁴¹ Portland asserts that the key to being considered "well-established" is the stability of a company's earnings and distributions and that Boardwalk's earnings and distributions have been stable since its establishment as an MLP, as have the earnings and distributions of Boardwalk's underlying assets for years prior to formation of the MLP. Portland notes that Boardwalk derives all of its operating income from the interstate pipeline operations of Texas Gas and Gulf South, assets that have been in operation for decades. Portland argues that Trial Staff's position, that Boardwalk is not "well established" because it has not been in existence for five years, is based on a presumption that the Commission did not adopt in the Policy Statement and that is belied by Boardwalk's stable earnings as reflected in its distributions and growth

²³⁸ Ex. PSG-30 at 16. *See also* Ex. PSG 33.

²³⁹ Trial Staff Brief on Exceptions at 23-26.

²⁴⁰ *Id.* at 25.

²⁴¹ Portland Brief Opposing Exceptions at 48-50.

rate.²⁴² PSG agrees with Portland, asserting that Boardwalk's steadily increasing earnings and distributions, and the fact that Boardwalk devotes more than 90 percent of its assets and derives all of its income from interstate natural gas pipeline operations, demonstrates that it is well established.²⁴³

Commission Determination

178. We find that the ALJ was correct to determine that Boardwalk should be included in the proxy group. As noted in the ID, Boardwalk has an ideal profile for a member of the proxy group because nearly all of its assets consist of interstate transmission pipeline operations and it derives all of its income from those operations.²⁴⁴

179. The opponents of including Boardwalk claim that Boardwalk is not well established because it does not meet the purported five years in existence requirement set forth in the Policy Statement. The clear language of the Policy Statement, however, indicates that the Commission did not establish a bright-line test as argued by Trial Staff. The Policy Statement states, in relevant part that:

The Commission agrees in principle ... that IBES forecasts should only be used for an MLP that is tracked by Value Line, has been in operation for at least five years as an MLP, and derives at least 50 percent of its operating income from, or 50 percent of its assets devoted to, interstate operations. Thus, when developing a proxy group, a pipeline should select MLPs that are well established and have assets that are predominately gas and oil pipelines.... However, there may be particular MLPs that do not satisfy these criteria but are still appropriate for inclusion in the proxy group.... Thus, while the Commission encourages pipelines to follow the [above] guidelines, it will not make them a condition of including a particular MLP in the proxy group.²⁴⁵

Nothing in the Commission's statements establish a bright-line five-year test for inclusion of an MLP in a proxy group. The Policy Statement clearly states that it

²⁴² *Id.* at 50.

²⁴³ PSG Brief Opposing Exceptions at 63-64.

²⁴⁴ ID, 129 FERC ¶ 63,027 at P 351.

²⁴⁵ Policy Statement, 123 FERC ¶ 61,048 at P 79.

encourages parties to follow the guidelines but explicitly declines to make the criteria a condition of inclusion in a proxy group, recognizing that some MLPs may not satisfy all the criteria but can still be included in the proxy group. Accordingly, we reject Trial Staff's arguments in this proceeding that the Policy Statement established a five-year in existence rule for the inclusion of an MLP in a proxy group, as well as the notion that an MLP must be in existence for five years to be considered "well-established."

180. Based on this clarification, the Commission finds that the ALJ was correct to find that the five-year guideline for MLPs is not a bright-line rule and that the Policy Statement allows for flexibility. As noted in the ID, Boardwalk has earned more than it paid in distributions each year and has demonstrated a sustainable growth rate since its inception.²⁴⁶ Further, as Portland points out, Boardwalk's underlying assets are well established interstate natural gas pipelines that have been in existence for decades and the earnings and distributions of the underlying assets have been stable for years. We find it reasonable to conclude that Boardwalk's earnings and distributions will continue to be stable and thus, that it is a well-established MLP for purposes of inclusion in the proxy group.

4. Spectra Energy Corp. (Spectra Corp.)

181. The ALJ included Spectra Energy Corp. (Spectra Corp.), a corporation formed at the beginning of 2007, in the proxy group.²⁴⁷ The ID notes that both Portland and PSG support the inclusion of Spectra Corp. in the proxy group because in 2007 it derived approximately 60 percent of its operating income from natural gas transmission pipeline operations, and thus meets the Commission's threshold standard.²⁴⁸

182. Trial Staff takes exception to the inclusion of Spectra Corp. in the proxy group.²⁴⁹ Trial Staff notes that its witness, Mr. Keyton, testified that to ensure that dividend yields of proxy companies are truly representative of future expectations, one criterion for inclusion in the proxy group is that the entity pay dividends for at least three years without making any dividend cuts.²⁵⁰ Trial Staff claims that the record evidence obtained from Value Line demonstrated that Spectra Corp. had not been paying dividends for a

²⁴⁶ ID, 129 FERC ¶ 63,027 at P 352 (citing Ex. S-14 at 152; Ex PNG 57 at 1).

²⁴⁷ *Id.* P 483.

²⁴⁸ *Id.* P 471.

²⁴⁹ Trial Staff Brief on Exceptions at 26-29.

²⁵⁰ *Id.* at 26 (citing Ex. S-12 at 35).

full three years, because as of the close of the record in July 2009, Spectra Corp. had only been paying dividends for about two and half years.²⁵¹

183. Trial Staff claims that the ALJ erred in finding that the three year requirement had not been previously used by the Commission. Trial Staff asserts that in *Golden Spread Electric Cooperative, Inc. v. Southwestern Public Service Company (Golden Spread)*,²⁵² the Presiding Judge adopted the criteria presented by Trial Staff in that case for inclusion in the proxy group, namely that the company was paying a dividend currently, had not cut the dividend level in the past three years, and Value Line did not expect a cut in its future dividend estimates. Trial Staff also argues that Mr. Keyton's position is supported by Opinion No. 486-C, where the Commission purportedly excluded NiSource from the proxy group in that case because it cut its dividend within six months of the beginning of the data period used for the DCF analysis.²⁵³ Trial Staff concludes that as the Commission found in Opinion No. 486-C that a company that recently cut its dividend should be excluded from the proxy group because it had not exhibited three years of stable dividend payments, the Commission should rule similarly here and exclude Spectra Corp., a new entity that does not have a track record of three years of dividends, from the proxy group.

184. Portland opposes Trial Staff's position regarding the inclusion of Spectra Corp.. Portland argues that while the Commission had excluded companies in the past that have cut their dividends, Spectra Corp. has not cut its dividend in the past three years. Portland contends that Trial Staff's evidence shows that Spectra Corp. had not paid dividends for a full three years, not that Spectra Corp. had cut its dividends. Portland states that the Commission has not analogized the consequences for a company that has cut its dividend in the past three years to those for a company that has not paid dividends for a full three-year period. According to Portland, the rationale for excluding a company that cut dividends, the instability of data inputs, does not apply to companies that first began to pay dividends less than three years ago.

185. Portland also argues that the Commission's DCF model requires only six months of data and notes that Spectra Corp. had been paying dividends for nearly three years at the time of the issuance of the ID. Thus, six months of data is available for Spectra Corp..

²⁵¹ *Id.* at 27 (citing Ex. S-14 at 154).

²⁵² *Golden Spread*, 115 FERC ¶ 63,043 (2006); *see also* Opinion No. 501, 123 FERC ¶ 61,047 (2008) (order on initial decision).

²⁵³ Trial Staff Brief on Exceptions at 28.

Commission Determination

186. The Commission finds that the ALJ correctly included Spectra Corp. in the proxy group for this proceeding and approves its inclusion herein. Spectra Corp. satisfies the Commission's historical threshold as 60 percent of Spectra Corp.'s assets are devoted to, and 60 percent of its operating income is derived from, interstate natural gas pipeline operations. Further, it is well established that the Commission requires six months of data for its DCF analysis.²⁵⁴ According to the record, since its formation in 2007 through April 2009, Spectra Corp. has paid nine consecutive and increasing dividends, and Value Line projects that Spectra Corp. will continue to do so.²⁵⁵ Moreover, we note that Trial Staff does not cite to Commission precedent or policy to support its position that a proxy group member must have paid dividends for three years without a dividend cut. While the Presiding Judge in the *Golden Spread* proceeding acknowledged that the Staff witness in that case used three years of dividends without a cut as one criterion for selecting the proxy group,²⁵⁶ the Presiding Judge did not adopt or endorse that criterion as a standard for selection, nor did the Commission do so in affirming the Presiding Judge's use of the Trial Staff's proxy group.²⁵⁷

187. We agree with the ALJ in this case that Spectra Corp. satisfies the Commission's preferred 50 percent threshold and that Trial Staff's purported three years of dividends requirement has not been used by the Commission as a criterion in a DCF analysis. Given that Spectra Corp. meets the 50 percent threshold, had been in existence for more than 2.5 years at the time the evidentiary record closed and paid dividends without cuts since its inception, we find that Spectra Corp. is an acceptable proxy group member for this proceeding.

5. Spectra Energy Partners (Spectra Partners)

188. The ID excludes Spectra Partners, a MLP, from the proxy group based on a finding that Spectra Partners was not shown to be "well-established" because it had not been in operation for five years. The ALJ also found that Portland had not shown that

²⁵⁴ See, e.g., Policy Statement, 123 FERC ¶ 61,048, Appendix A (providing sample DCF analysis relying on six months data); *Boston Edison Co.*, 42 FERC ¶ 61,374, at 62,093 (1988).

²⁵⁵ Ex. PSG-88 at 9; Ex. S-14 at 154.

²⁵⁶ *Golden Spread*, 115 FERC ¶ 63,043.

²⁵⁷ See *Golden Spread*, Opinion No. 501, 123 FERC ¶ 61,047 at P 62.

Spectra Partners' long existing components had the same risk as stand-alone entities as Spectra Partners does as an MLP.²⁵⁸

189. The record evidence shows that 100 percent of Spectra Partners' assets consist of interstate transmission pipeline operations and that Spectra Partners derives nearly 100 percent of its operating income from transmission pipeline activities serving interstate markets.²⁵⁹ Spectra Partners owns East Tennessee Natural Gas, (100 percent ownership), Saltville Gas Storage (100 percent ownership), Gulfstream Natural Gas (24.5 percent ownership), and Market Hub (50 percent ownership), long existing interstate natural gas facilities. The record also indicates that Spectra Partners was established in the second half of 2007 and is publicly traded.

190. Portland excepts to the exclusion of Spectra Partners from the proxy group.²⁶⁰ Portland argues that Spectra Partners clearly meets the Commission's primary 50 percent threshold test, and thus is more risk appropriate than National Fuel, because 100 percent of Spectra Partners' assets consist of transmission pipeline operations. Portland notes that the ALJ excluded Spectra Partners only because it had not been in operation as an MLP for 5 years, a standard Portland contends the Commission declined to adopt in the Policy Statement.²⁶¹ Portland also states that the statement in the ID that "the Commission has recognized that the risks of a new MLP may not be equivalent to the risks of the MLP's component parts" is unsupported and is not stated or implied by the paragraph in the Policy Statement to which the ID refers, nor in fact is the assertion made at all in the Policy Statement.²⁶² Portland argues that the conclusion reached in the ID is wholly unsupported by record evidence. Portland contends the record does show that Spectra Partners' growth rates are reasonable and no party has challenged them as irrational, that its assets are mature and have been providing consistent revenues, and that Spectra Partners' distributions have never exceeded their earnings. Portland also notes that no other party has provided evidence to support the conclusion that Spectra Partners is not "well-established" aside from the statement that it has not been in existence for five years.

²⁵⁸ ID, 129 FERC ¶ 63,027 at P 371.

²⁵⁹ See Ex. PNG-12S at 1.

²⁶⁰ Portland Brief on Exceptions at 70-72.

²⁶¹ *Id.* at 70.

²⁶² *Id.* (citing ID at P 371; Policy Statement, 123 FERC at P 79).

191. PSG, Trial Staff, CAPP and CES all oppose Portland's exception and support the exclusion of Spectra Partners from the proxy group. PSG asserts that the ID recognized the Commission's concerns regarding the potential unsustainability of MLP distributions in rejecting a company that was not formed until the second half of 2007.²⁶³ PSG argues that while the Policy Statement did not establish a bright line five year rule for MLPs, Spectra Partners had not been shown to be well established and thus was properly excluded. Trial Staff argues that Portland provided virtually no support for its inclusion of Spectra Partners or to demonstrate that Spectra Partners is well established.²⁶⁴ CAPP argues that the ALJ correctly determined that Spectra Partners did not have a sufficient operating record to consider it an established equity investment.²⁶⁵ CES makes similar assertions about the ALJ's correct decision in excluding Spectra Partners based on a lack of evidence demonstrating that Spectra Partners is "well established."²⁶⁶

Commission Determination

192. We find that the ALJ erred in excluding Spectra Partners from the proxy group in this case. None of the parties challenge the fact that Spectra Partners meets the Commission's preferred threshold that at least 50 percent of a firm's assets or income be related to the interstate natural gas pipeline business. The record shows that Spectra Partners' assets consist nearly 100 percent of interstate transmission pipeline operations and that Spectra Partners derives nearly 100 percent of its operating income from transmission pipeline activities serving interstate markets.²⁶⁷ Thus, Spectra Partners' business activities are made up almost entirely of the same unbundled interstate natural gas pipeline business as Portland. It follows that an investor would view an investment in Spectra Partners as an investment in the same line of business as Portland.

193. The ALJ nevertheless rejected Spectra Partners on the grounds that it was not well established because it had only been in existence for 2.5 years. The ALJ found that to allow such a short lived MLP into the proxy group would essentially "swallow" the "five year rule."²⁶⁸ As noted in our discussion concerning Boardwalk, however, the

²⁶³ PSG Brief Opposing Exceptions at 63-64.

²⁶⁴ Trial Staff Brief Opposing Exceptions at 61-65.

²⁶⁵ CAPP Brief Opposing Exceptions at 9.

²⁶⁶ CES Brief Opposing Exceptions at 47-48.

²⁶⁷ Ex. PNG-12S at 1.

²⁶⁸ ID, 129 FERC ¶ 63,027 at P 360.

Policy Statement did not establish a strict five-year rule for the inclusion of MLPs in a natural gas pipeline proxy group. The Policy Statement explicitly contemplates that certain MLPs that do not satisfy the general guidelines may still be appropriate members of a proxy group.

194. PSG argues that even if the five-year rule is flexible, Portland did not meet its burden of demonstrating that Spectra Partners was “well-established” because it provided no analysis of the risks of Spectra Partners as an MLP as compared to its component parts. PSG further argues that the ALJ was correct to include Boardwalk, a “well established MLP that had been in existence for nearly five years, while excluding Spectra Partners, which fell short of the guideline.

195. We find that, contrary to the ALJ’s determination, Spectra Partners has been shown to be well established. The vast majority of Spectra Partners’ assets, East Tennessee Natural Gas, Saltville Gas Storage, Gulfstream Natural Gas, and Market Hub, are established interstate natural gas facilities. Moreover, according to the ID, Spectra Partners has earned more than it paid in distributions for each year that it has been in existence.²⁶⁹ In addition, the record reflects five years worth of operational data for the components that make up Spectra Partners’ assets and that data demonstrates the consistent payment of distributions and profitability of the company. Finally, according to publicly available data, Spectra Partners paid seven increasing quarterly dividends through April 2009, similar to the nine increasing dividends paid by Spectra Corp., which was formed only about six months before Spectra Partners. Thus, while the risks of an MLP may not necessarily be equivalent to the risks of its component parts, here they have been shown to be nearly equivalent. The five years of operational data available for the component parts of Spectra Partners demonstrates that it is well established. In these circumstances, the advantage of including in the proxy group a firm whose business activities are so similar to Portland’s outweighs any concern about the relatively short period Spectra Partners has been organized as an MLP.

6. El Paso Partners

196. Portland proposed El Paso Partners as a risk comparable proxy group member but as with Spectra Partners the ALJ excluded the company because it is an MLP and at the time in question it had not been in existence for five years and thus was not “well established.” In rejecting El Paso Partners, the ALJ asserted that exceptions from the five year rule should not “swallow” the guideline.²⁷⁰

²⁶⁹ ID, 129 FERC ¶ 63,027 at P 362.

²⁷⁰ ID, 129 FERC ¶ 63,027 at P 360.

197. The record shows that nearly 100 percent of El Paso Partners' assets are composed of transmission pipelines that have been in operation for many years, namely Wyoming Interstate Company (WIC), Colorado Interstate Gas Company (CIG) and Southern Natural Gas Company (Southern). The record also shows that El Paso Partners was formed in the second half of 2007.²⁷¹

198. Portland excepts to the exclusion of El Paso Partners from the proxy group. Portland makes essentially the same arguments it made regarding the inappropriate exclusion of Spectra Partners, namely that El Paso Partners meets the 50 percent threshold because it is composed of 100 percent U.S. regulated natural gas transmission pipelines, that the Commission declined to adopt a minimum five-year rule in the Policy Statement, that the conclusion reached in the ID is wholly unsupported by record evidence, and that no other party has provided evidence to support the conclusion that El Paso Partners is not "well-established" aside from the statement that it has not been in existence for five years.

199. PSG, Staff, CAPP and CES all oppose Portland's exception and support the exclusion of El Paso Partners from the proxy group. PSG asserts that the ID recognized the Commission's concerns regarding the potential unsustainability of MLP distributions in rejecting a company that was not formed until the second half of 2007.²⁷² Staff argues that Portland provided virtually no support for its inclusion of El Paso Partners or to demonstrate that El Paso Partners is well established.²⁷³ CAPP argues procedurally that irrespective of its longevity, inclusion of El Paso Partners is not supported by record evidence because Portland did not propose it as a proxy group member until Portland's rebuttal testimony.²⁷⁴ CES makes similar assertions about the ALJ's correct decision in excluding El Paso Partners based on a lack of evidence demonstrating the El Paso Partners is "well established."²⁷⁵

Commission Determination

200. We find that the ALJ erred in excluding El Paso Partners from the proxy group in this case. El Paso Partners is similarly situated to Spectra Partners in relation to its status

²⁷¹ *Id.*

²⁷² PSG Brief Opposing Exceptions at 63-64.

²⁷³ Trial Staff Brief Opposing Exceptions at 61-65.

²⁷⁴ CAPP Brief Opposing Exceptions at 9.

²⁷⁵ CES Brief Opposing Exceptions at 47-48.

as a proxy group member. El Paso Partners more than satisfies the 50 percent test as its assets are composed nearly 100 percent of interstate natural gas facilities and nearly 100 percent of its operating income is derived from the those facilities. It follows that an investor would view an investment in El Paso Partners as an investment in the same line of business as Portland. Although El Paso Partners had not been in existence for five years at the time of the ID, as we have found above the Policy Statement did not establish a strict five-year test for inclusion in a natural gas pipeline proxy group.

201. The vast majority of El Paso Partners' assets, WIC, CIG and Southern, are established interstate natural gas facilities that provide a steady income stream. According to the record evidence, these mature assets are providing consistent revenues.²⁷⁶ Moreover, according to the ID, El Paso Partners has earned more than it paid in distributions for each year since it was formed in the second half of 2007.²⁷⁷ Moreover, the record indicates that El Paso Partners began paying dividends in January 2008 and has paid them consistently on a quarterly basis since then. During the time period adopted in this case for calculating ROE (November 2008 – April 2009), El Paso Partners paid increasing dividends for six consecutive quarters. Thus, while the risks of an MLP may not necessarily be equivalent to the risks of its component parts, here they have been shown to be nearly equivalent. In these circumstances, the advantage of including in the proxy group a firm whose business activities are so similar to Portland's outweighs any concern about the relatively short period El Paso Partners has been organized as an MLP.

7. National Fuel

202. The ALJ included National Fuel in the proxy group for this proceeding.²⁷⁸ About 23 percent of National Fuel's assets are devoted to natural gas pipeline operations, while 40 percent are devoted to local distribution and 34 percent to exploration and production (E&P).

203. The ALJ states she made her decision to include National Fuel in the proxy group with trepidation, because of the small percentage of its assets devoted to natural gas pipeline operations. Nevertheless, the ALJ found that National Fuel's less risky utility distribution operations and more risky exploration and production operations offset each

²⁷⁶ ID, 129 FERC ¶ 63,027 at P 355 (noting that El Paso Partners' revenues have increased for the past eight quarters).

²⁷⁷ *Id.* P 354.

²⁷⁸ *Id.* P 538. PSG was the only party to support the inclusion of National Fuel in the proxy group at the hearing.

other and thus it was appropriate to combine National Fuel's LDC and interstate transmission assets for proxy group purposes. According to the ALJ, this aggregation puts National Fuel over the 50 percent threshold. The ALJ concluded that the mix of National Fuel's diverse functions make it a reasonable reflection of the overall risk level facing an interstate pipeline.²⁷⁹

204. Trial Staff and Portland except to the inclusion of National Fuel.²⁸⁰ These parties argue that the ALJ failed to properly apply Opinion No. 486-C's criteria for including diversified natural gas companies in proxy groups. They claim that pursuant to Opinion No. 486-C, a diversified natural gas company may only be included in a pipeline proxy group if:

(1) the combined natural gas pipeline and distribution businesses of the firm make up at least 50 percent of its total business; (2) the natural gas pipeline business is at least equal to the distribution business; and (3) the firms' more risky exploration production and other market-oriented businesses are no greater than the less risky distribution business.²⁸¹

205. Trial Staff and Portland argue that using the data upon which the ALJ relied, National Fuel does not satisfy the second factor based on assets.²⁸² They state that while the first and third tests are met, the requirement that the natural gas business is at least equal to the distribution business is not met based on the ALJ's determination that for the relevant time period 40 percent of National Fuel's assets were devoted to distribution business while only 23 percent of its assets were devoted to natural gas pipeline operations.

²⁷⁹ *Id.* P 540. The ALJ stated that because of the "difficult and imprecise balancing of risk regarding National Fuel," however, that it is the weakest of the five members adopted for the proxy group, and proposed TransCanada as a substitute should the Commission disqualify National Fuel for the proxy group. ID P 544 and n.107.

²⁸⁰ See Staff Brief on Exceptions at 29-34; Portland Brief on Exceptions at 64-69. Portland also argues that because National Fuel is not risk appropriate, the Commission should not include National Fuel in the proxy group just to have a five member group. Portland Brief on Exceptions at 83.

²⁸¹ *Kern River*, Opinion No. 486-C, 129 FERC ¶ 61,240 at P 71.

²⁸² Portland notes that National Fuel fails all three factors of the test when applied to income.

206. The opponents of National Fuel's inclusion in the proxy group also argue that there was no record evidence for the ALJ's determination that the company's riskier exploration and production and its less risky distribution businesses offset one another. They note that the proponents of including National Fuel did not present any evidence that National Fuel's distribution and E&P operations' risk were equally lower and higher than its transmission operations' risks. They conclude that the ALJ's determination on this point is unsupported by any record evidence and thus, purely speculative.

207. PSG, CAPP and CES oppose Portland's and Trial Staff's exceptions to the inclusion of National Fuel.²⁸³ According to PSG, the opponents' exception is based on the single untenable ground that National Fuel's gas pipeline business must be at least equal to its distribution business, and cannot be any smaller. PSG claims that such opposition is at odds with Commission precedent, particularly the *Kern River* proceeding, where the Commission approved National Fuel as a proxy group member in circumstances similar to those here.

208. PSG argues that in Opinion No. 486-C, the Commission reiterated its Opinion No. 486-B finding that a diversified natural gas company that did not meet the historical 50 percent threshold could nonetheless be considered for the proxy group under general guidelines for a case-by-case evaluation of such diversified natural gas companies. PSG asserts those guidelines allow inclusion if the lower risk of utility or distribution assets are offset by the higher risk of market oriented components, as long as neither of those "substantially outweigh" the pipeline business.²⁸⁴ PSG contends that use of the general guidelines reduces the problem of assigning appropriate weights to the riskier and less risky business units. It also notes that the Commission included National Fuel in the proxy group in Opinion No. 486-B.

209. PSG also argues that the ALJ's analysis was correct and that the determination that the different risks of the distribution and E&P operations offset each other was based on the fact that the non-pipeline operations exceeded the company's transmission assets in roughly equal proportions. PSG also claims that the ALJ's decision recognizes that National Fuel's circumstances were essentially the same at the time of the *Kern River* case as they were in the instant proceeding.

210. PSG also takes issue with Portland's and Trial Staff's contention that Opinion No. 486-C established a more rigid and strict test for the inclusion of a diversified natural gas company in a proxy group than the general guidelines discussed in

²⁸³ PSG Brief Opposing Exceptions at 64-71.

²⁸⁴ *Id.* at 65 (citing Opinion No. 486-C, 129 FERC ¶ 61,240 at P 53).

Opinion No. 486-B.²⁸⁵ PSG asserts that the criteria discussed in Opinion No. 486-C simply set out a safe haven for inclusion in a proxy group but did not necessarily exclude companies that might not meet all three factors. PSG argues that as long as the less risky distribution business “does not substantially outweigh” the company’s pipeline business then it can be accepted in the proxy group.²⁸⁶ PSG concludes that National Fuel satisfies this standard and the Commission should include National Fuel in the proxy group in this case as it did in Opinion No. 486-B.

211. CAPP also advocates the inclusion of National Fuel in the proxy group.²⁸⁷ It contends that National Fuel is one of the core group that the Commission adopted for the proxy group in *Kern River* and that it remained viable as a proxy group candidate in this proceeding. CAPP argues that the ALJ was correct, and that the record supports her determinations regarding National Fuel’s offsetting assets and aggregation of National Fuel’s distribution and pipeline assets to exceed the 50 percent threshold.

212. CES, which originally urged that National Fuel should be excluded from the proxy group, states that the ID identifies creditable reasons for excluding certain proxy group proposals and thus no other superior alternative to National Fuel exists. Rather than proceed with a four member proxy group, CES now contends that the ID justified the inclusion of National Fuel in the proxy group. CES, like PSG, asserts that the proper test is whether the more or less risky business functions “substantially outweigh” the transmission function, and if not, then difficult determinations of relative risk can be made to assign appropriate weight to the non-transmission functions. CES further asserts that the ALJ properly performed such an analysis based on substantial evidence that National Fuel’s distribution and transmission assets combined exceed 50 percent of its total assets and that the portion of assets devoted to the riskier E&P operations does not exceed the less risky distribution operations.

Commission Determination

213. The Commission finds that the ALJ erred in including National Fuel in the proxy group.²⁸⁸ National Fuel fails to meet the Commission’s 50 percent threshold as the

²⁸⁵ PSG Brief on Exceptions at 68.

²⁸⁶ *Id.* at 70.

²⁸⁷ CAPP Brief on Exceptions at 2-4.

²⁸⁸ Based on our determination to exclude National Fuel from the proxy group, we dismiss Portland’s argument that a four company proxy group is preferable to a five member group that includes a company that is not risk appropriate as moot.

record demonstrates that only 23 percent of its assets are devoted to natural gas pipeline operations.²⁸⁹ This is in sharp contrast to the firms discussed above which we have included in the proxy group, all of which have 60 percent or more of their assets or income devoted to natural gas pipeline operations.

214. National Fuel also fails to satisfy the three-pronged test set forth in Opinion No. 486-C for the inclusion in the proxy group of diversified natural gas companies that do not satisfy the 50 percent threshold. That standard requires that:

- (1) the combined natural gas pipeline and distribution businesses of the firm make up at least 50 percent of its total business;
- (2) the natural gas pipeline business is at least equal to the distribution business;
- and (3) the firms' more risky exploration production and other market-oriented businesses are no greater than the less risky distribution business.²⁹⁰

While National Fuel's combined natural gas pipeline and distribution businesses make up about 63 percent of its assets, the distribution business accounts for almost twice as much of its business (40 percent) as its interstate pipeline business (23 percent) as measured by the value of its assets devoted to the two businesses. Thus, National Fuel fails the second prong of the above standard.

215. In any event, in Opinion Nos. 486-B and 486-C the Commission "returned to its preference for the historical standard of 50 percent of pipeline assets or income for inclusion in the gas pipeline proxy group."²⁹¹ While the Commission stated it would consider diversified natural gas companies not satisfying that standard "in order to achieve a proxy group of at least five firms,"²⁹² the Commission also stated that the more a firm's business profile diverges from the minimum 50 percent transmission rule, the more the Commission will have to make increasingly difficult determinations as to whether investors would view the non-transmission components of the firm's business as having comparable risk to its transmission components.²⁹³ Here, we are approving the

²⁸⁹ ID, 129 FERC ¶ 63,027 at P 538.

²⁹⁰ *Kern River*, Opinion No. 486-C, 129 FERC ¶ 61,240 at P 71.

²⁹¹ Opinion No. 486-C, 129 FERC ¶ 61,240 at P 70 (citing Opinion No. 486-B, 126 FERC ¶ 61,034 at P 91).

²⁹² Opinion No. 486-B, 126 FERC ¶ 61,034 at P 91.

²⁹³ Opinion No. 486-C, 129 FERC ¶ 61,240 at P 69.

adoption of a six company proxy group for which all the members amply satisfy the historical 50 percent threshold.²⁹⁴ Accordingly, a proxy group of more than five firms is possible, without the need to engage in the “difficult determinations of relative risk” that the ALJ undertook in the ID in an effort to determine whether investors would view National Fuel as having comparable risk to Portland, despite the fact 77 percent of its assets are devoted to non-pipeline business activities.

216. While the Commission included National Fuel in the proxy group in Opinion Nos. 486-B and 486-C, that case involved a significantly earlier 2004 test period, than this case. In that case, only four firms satisfied the Commission’s historical proxy group standards including the 50 percent transmission standard. Therefore, it was necessary to include a diversified natural gas company not satisfying the historic standards in order to achieve a five-member proxy group. Moreover, in that case, National Fuel did satisfy the three-pronged test for including such a company in the proxy group. Unlike here, National Fuel’s natural gas pipeline business was equal to its distribution business, since the record in that case indicated that during 2004 National Fuel’s net income profile was approximately 28 percent pipeline business and 28 percent distribution business.²⁹⁵

217. Thus, we reject National Fuel as an appropriate proxy group member for this proceeding.²⁹⁶

8. Remaining Proposed Companies

218. Based on the analysis above, the Commission approves in this order a six member proxy group for which all of the included companies satisfy the Commission’s preferred 50 percent threshold for inclusion in a natural gas pipeline proxy group. The proxy group is composed of TC Pipelines, Southern Union, Boardwalk, Spectra Corp., El Paso Partners and Spectra Partners. We find that the included entities, which all have 50 percent or more of their assets devoted to interstate natural gas transmission and or 50 percent of their operating income derived from such assets, are more risk appropriate

²⁹⁴ See Opinion No. 486-C, 129 FERC ¶ 61,034 at P 59-61 (re-affirming that the 50 percent threshold is the Commission’s preferred test for proxy group members because such firms are more likely to meet the risk comparability standards of *Petal v. FERC*).

²⁹⁵ Opinion No. 486-C, 129 FERC ¶ 61,240 at P 54.

²⁹⁶ Because we have determined that there are six appropriate proxy group companies that meet the historical 50 percent threshold, it is not necessary to engage in a deliberation as to whether the riskier E&P or less risky distribution operations “substantially outweigh” the pipeline operations.

to Portland than the other companies proposed by the parties, many of which do not meet the 50 percent threshold. We discuss the remaining proposed but excluded entities below.

a. Enbridge, ETP, Enterprise, KMEP and ONEOK

219. The ALJ excluded Enbridge, ETP, Enterprise, KMEP and ONEOK from the proxy group in this case because these MLPs did not clearly meet the Commission's 50 percent threshold.²⁹⁷ Because we are approving a proxy group that includes five members that meet the threshold, we agree with the ALJ that these MLPs, which hold significant assets that are not related to the interstate transportation of gas, were appropriately excluded from the proxy group.

220. With regard to Enbridge, Enterprise and ONEOK, the ALJ's decision ultimately relies on record evidence demonstrating that those entities own significant assets that are devoted to the transportation of natural gas liquids, gathering, processing and other non-interstate natural gas transportation operations. The ALJ correctly notes that the parties have not shown that these activities have risk levels that are similar to interstate natural gas transportation.²⁹⁸ The make-up of these entities is such that it is not clear that they meet the 50 percent threshold because to do so involves combining interstate natural gas transportation assets with non-transmission assets such as liquids handling and processing, E&P, and gathering. Because we approve a proxy group herein consisting of entities that meet the 50 percent standard based only on interstate natural gas transmission assets, there is no reason to engage in the difficult analyses required to complete risk assessments for these other entities.

221. Likewise, with regard to ETP and KMEP, the ALJ found that they owned significant assets devoted to the intra-state transportation of natural gas, and thus did not meet the 50 percent threshold.²⁹⁹ The ALJ also determined that because of the differences between interstate and intrastate transportation, the entities with significant intrastate operations had not been shown to be risk appropriate. We agree and thus exclude these parties from the proxy group in this proceeding. Because the entities in the

²⁹⁷ ID, 129 FERC ¶ 63,027 at P 399, P 417, P 432, P 449, and P 468-470.

²⁹⁸ See, e.g., *id.* P 469 (noting that Portland has not shown that gathering and processing are similar in terms of risk).

²⁹⁹ See *id.* P 418 (ALJ agreeing that interstate and intrastate service are distinct services and that the latter include gathering, processing, treatment, marketing and trading and other services that are typically riskier than interstate transportation).

chosen group meet the 50 percent threshold, there is no need to proceed to a second step to try to include companies that do not meet that test on their face.³⁰⁰

b. Williams, TransCanada, NiSource and El Paso Corporation

222. The ALJ excluded these companies from the proxy group again on the general grounds that they do not meet the 50 percent threshold.³⁰¹ Despite the parties' arguments for the inclusion of these companies, we find that the ALJ correctly excluded them from the proxy group.

223. With respect to Williams, the ALJ determines that the proponents of inclusion have not shown that Williams' midstream petroleum products and NGL pipeline assets have similar risks compared to Williams' interstate pipeline assets and that Williams lacks distribution assets to offset the higher risks of the midstream assets. The ALJ reasoned similarly with regard to NiSource, finding that it does not meet the 50 percent threshold because the record demonstrates that the majority of NiSource's operations are in lower risk gas distribution and electric operation segments, without any offsetting higher risk functions. We agree with the ALJ's determinations with respect to Williams and NiSource, particularly in light of the proxy group approved in this order.

224. As to TransCanada, the ALJ excluded it because although over 90 percent of TransCanada's operating income is derived from natural gas pipeline operations, only 51 percent of that is from U.S. pipeline operations and the non-U.S. assets are subject to a different regulatory structure. As we did in Opinion No. 486-B, we find that this regulatory structure renders TransCanada less comparable to U.S. pipelines that are regulated by the Commission, and thus approve the ALJ's decision to exclude TransCanada from the proxy group.³⁰²

³⁰⁰ See *id.* P 497, P 514-515, P 555 and P 562. In P 419 of the ID, discussing ETP, the ALJ notes that there may be merit to the arguments that Natural Gas Policy Act Section 311 service may have risks that could be considered similar to that of interstate transportation. We are not in this order foreclosing such arguments in the future. As noted, however, because we approve a proxy group where all the members meet the 50 percent threshold, there is no need to rule on this argument at this time.

³⁰¹ The record is unclear as to whether any party still proposes El Paso Corporation as a proxy group member in this case. In any event, we agree with the ALJ's decision to exclude El Paso Corporation on the grounds that its credit rating was not investment grade during the relevant time period. ID P 562.

³⁰² See *Kern River*, Opinion No. 486-B, 126 FERC ¶ 61,034 at P 60.

D. DCF Analysis

225. As stated above, the Commission adopts a six member proxy group for this proceeding consisting of TC Pipelines, Southern Union, Boardwalk, Spectra Corp., El Paso Partners and Spectra Partners. Below we address the two major issues raised by the participants relating to the DCF analysis in this case – the dividend yield calculation and the time period from which to draw the financial data for carrying out the DCF analysis. For the reasons presented below, the Commission affirms the ALJ’s decision to adopt Trial Staff Witness Keyton’s methodology for calculating dividend yield³⁰³ and determines that the appropriate time period for the DCF analysis in this proceeding is the six month period from November 2008 to April 2009. Based on these determinations, the Commission conducted a DCF analysis using the methodology, time period and proxy group adopted in this order. This analysis establishes a zone of reasonableness of 12.18 percent to 14.89 percent, with a median of 12.99 percent.

1. Dividend Yield Calculation

226. As noted above, the ALJ adopted Trial Staff’s methodology for calculating the dividend yield to be used in the DCF analysis for each proxy group member over that proposed by PSG. The ALJ stated that she agreed with Trial Staff that PSG’s method could lead to distorted stock price representations and distorted dividend yields.³⁰⁴ Trial Staff’s methodology involves calculating for each proxy group member a separate dividend yield for each of the six months and then averaging those six monthly dividend yields. Trial Staff Witness Keyton used a three step process that: (1) averaged the high and low stock prices for each of the reported six months; (2) divided the indicated annual dividend for each month³⁰⁵ by the average stock price for the same month calculated in step one (resulting in a dividend yield for each of the reported six months); and (3) averaged the monthly dividend yields calculated in step two.³⁰⁶

227. PSG excepts to the ALJ’s adoption of Trial Staff’s methodology for calculating the dividend yield. PSG Witness Neri proposed a different approach for calculating the dividend yield component of the DCF analysis whereby he calculated a single dividend

³⁰³ ID, 129 FERC ¶ 63,027 at P 567.

³⁰⁴ *Id.*

³⁰⁵ To determine the “indicated annual dividend” for each of the six months, Trial Staff used the most recent dividend declared by the relevant company.

³⁰⁶ Trial Staff Brief Opposing Exceptions at 78; Portland Brief opposing Exceptions at 38-39. *See also* Ex. S-22 at 4-5; Ex. S-23 at 2-6.

yield for each proxy group member by: (1) averaging the high and low stock prices for each of the reported six months; (2) averaging the average monthly stock prices calculated in step one (resulting in an average of the six monthly average stock prices); and (3) dividing the company's reported annual dividend in the final month by the average stock price calculated in step 2.³⁰⁷

228. PSG argues that Trial Staff Witness Keyton made a mathematical error in his calculation of monthly dividend yields for each proxy group member. PSG also claims that the different approach taken by its ROE Witness, Dr. Neri, is supported by recent Commission precedent, and thus the ALJ's adoption of Mr. Keyton's methodology was wrong. In its Brief Opposing Exceptions, Trial Staff counters that Mr. Keyton's approach has been routinely followed in natural gas and oil pipeline cases for decades and that PSG's exception to that approach should be rejected. Portland also opposes PSG's exception, arguing that Trial Staff's approach is consistent with Commission precedent and that PSG's approach overstates yields if a company had raised its dividends or distributions during the six month period because it uses only the dividend paid in the final month.³⁰⁸

229. According to PSG, Order No. 420³⁰⁹ and several other Commission decisions in the 1980s and more recently support the use of PSG's approach rather than Trial Staff's approach in this proceeding.³¹⁰ PSG contends that its approach, which focuses on most recent dividends or distributions, is appropriate from an investor's perspective to smooth transient market fluctuations that could otherwise distort the analysis. PSG argues that given the stock price volatility during the relevant period at issue in this case, Mr. Keyton's approach may lead to distorted payout yield because a dividend yield may be affected more by stock price changes than by a dividend increase during the relevant period. PSG asserts that its approach is superior because it takes the view of a forward looking investor, whereas Trial Staff's approach focuses on non-current yields for five of the six months in the relevant period, and is therefore backward looking.

230. Trial Staff counters that there is ample precedent to support Mr. Keyton's approach and that PSG's approach undermines the purpose of using a six month period to

³⁰⁷ PSG Brief on Exceptions at 75; *see also* Ex. PSG 30 at 24, Ex. PSG 35 at 1.

³⁰⁸ Portland Brief Opposing Exceptions at 39-40.

³⁰⁹ *Generic Determination of Rate of Return for Common Equity for Public Utilities*, Order No. 420, FERC Stats. & Regs. ¶ 30,644 (1985).

³¹⁰ PSG Brief on Exceptions at 76-79.

calculate payout yields, namely to smooth out any aberrations in the stock price.³¹¹ Trial Staff also argues that the cases relied upon by PSG do not necessarily track PSG's approach, or turned on a different issue than the one presented by PSG, while sustaining Trial Staff's proposed methodology.³¹²

231. Portland argues that PSG's approach is contrary to Commission precedent and that Trial Staff's calculation averages the actual dividend yields for each of the preceding six months while PSG's approach averages stock prices for the preceding six months to derive a single stock price and calculates an estimated dividend yield based upon the dividend in the final month.³¹³ Portland contends that Trial Staff's approach reflects the actual dividends paid for each of the preceding months and PSG's approach only uses the dividend paid in the last month. According to Portland, this is problematic when a company raises its dividends or distributions during the period because in that situation, "earlier months in which the entity's equity price would not be influenced by the enhanced dividend/distribution would be compared to a higher dividend/distribution from a later month."³¹⁴

Commission Determination

232. The Commission finds that the ALJ was correct to adopt Trial Staff Witness Keyton's methodology for calculating dividend yield and we do so here. As noted in Trial Staff's and Portland's Briefs Opposing Exceptions, there is ample Commission precedent supporting the approach used by Trial Staff and adopted by the ALJ and the cases cited by PSG do not appear to support its position.³¹⁵ In *New England Power Co.*,³¹⁶ the Commission stated that "[i]n order to ensure that consistent dividends and prices are used in the dividend yield calculations, we prefer...to calculate the dividend yield for *each* month of the period using the indicated dividend and the average of the high and low stock price for the month."³¹⁷ According to PSG itself, Trial Staff's method

³¹¹ Trial Staff Brief Opposing Exceptions at 81.

³¹² *Id.* at 80.

³¹³ Portland Brief Opposing Exceptions at 38-43.

³¹⁴ *Id.* at 40.

³¹⁵ *See id.* and cases cited therein; *see also* Trial Staff Brief Opposing Exceptions at 80-81.

³¹⁶ *New England Power Co.*, Opinion No. 158, 22 FERC ¶ 61,123 (1983).

³¹⁷ *Id.* at 61,188 (emphasis added).

calculates for each proxy group member a separate dividend yield for each of the six months, while PSG's approach calculates a single dividend yield for each proxy group member.³¹⁸ Approval of Trial Staff's approach was affirmed in *Allegheny Generating Co.*,³¹⁹ where the Commission directly addressed the dividend yield calculation issue and found that, "[e]ach month's dividend yield should be calculated by using that month's average stock price and the dividend expected to be received during the twelve months ensuing after that month."³²⁰ Further, as noted by Portland, the methodology used by Trial Staff in this case was in adopted in Opinion No. 486-B.³²¹

233. We find that the ALJ properly adopted Trial Staff's methodology for calculating dividend yield. The methodology is firmly grounded in Commission precedent for electric proceedings and no party cited to a natural gas case where the Commission has discussed the issue. Thus, while we are relying on precedent from electric proceedings for our determination in this case, the Commission finds that the methodology is appropriately applicable in natural gas proceedings as well. Trial Staff's methodology has been used consistently in the recent past, including in the Kern River proceeding that resulted in Opinion No. 486-B. Moreover, as noted by the ALJ, all the parties sponsoring ROE testimony, except for PSG, used the Trial Staff's methodology for calculating dividend yield.

234. Most importantly, the Commission approves the use of Trial Staff's methodology because it appears to be the more appropriate and correct way to calculate the average dividend yield. As noted by Portland and Trial Staff, this methodology matches each average monthly stock price with the actual dividend paid for that month to calculate the actual dividend yields for each of the preceding six months. PSG's methodology averages the stock prices for those months to arrive at a single stock price and calculates an estimated dividend yield based only on the dividend declared in the final month of the period. Using only the dividend declared in the final month results in a mismatch between the stock prices and the dividends used to calculate a firm's dividend yield. A

³¹⁸ PSG Brief on Exceptions at 75.

³¹⁹ *Allegheny Generating Co.*, Opinion No. 281, 40 FERC ¶ 61,117 (1987).

³²⁰ *Id.* at 61,316 & n.6.

³²¹ See Portland Brief Opposing Exceptions at 42 & n.170. The precedent cited by PSG for support of its position fails to do so. In Order No. 420, the Commission addressed the quarterly calculation of dividend yield for DCF purposes, not a six month calculation. Moreover, Order No. 420 predates the Commission's opinion in *Allegheny Generating Co.* (as is also the case with *Minnesota Power & Light Co.*, Opinion No. 86, 11 FERC ¶ 61,312 (1980)).

company's stock price is affected by dividends declared and expected by investors. Thus, the method using only the dividend declared in the final month of the period fails to account for the effect of prior period dividends on the earlier stock prices used in the calculation. As shown by Portland and Trial Staff, such an approach is especially problematic when a firm raises its dividends or distributions during the six month period. That is because earlier stock prices do not reflect the increased value of the stock resulting from the increased dividend or distribution. As a result, the calculated dividend yield would likely be overstated.³²² Accordingly, we find that the ALJ was correct to adopt Trial Staff's methodology for calculating dividend yield in this case.

2. Time Period for Calculating DCF

235. In the ID the ALJ adopted Trial Staff Witness Keyton's DCF methodology, including Mr. Keyton's data, which includes data for the six month period ending December 2008. On exceptions, the participants disagree as to the time period from which data should be used for the DCF analysis. According to Portland, the Commission should use the most updated market data in the record, which it contends includes a time period up to April 2009, as reflected in Mr. Moul's rebuttal Exhibit No. PNG-57. Trial Staff and PSG assert that the proper time period is that approved by the ALJ, six months prior to December 2008. CAPP proposed to use a 12 month (January 2007 – January 2008) dividend yield average for the DCF analysis in this case, which the ALJ rejected.³²³ CAPP and CES also oppose the ALJ's use of Portland's data on procedural grounds, claiming it was only introduced in rebuttal testimony.

236. Portland excepts to the ALJ's not using the most updated market data in the record for the DCF analysis. Portland notes that while the ALJ used Mr. Keyton's DCF analysis, which only included data through December 2008, Portland's Witness Moul provided data up to April 2009. Portland argues that the Commission prefers the use of the most recent financial data in the record for calculating ROE because "the market is always changing and later figures more accurately reflect current investor needs."³²⁴ Portland contends that Mr. Moul's Ex. PNG -57 contains the most recently available data in the record.

237. PSG, CAPP and CES oppose Portland's exception. CES argues that Portland's claim is procedurally deficient in that Portland had not advocated reliance on any set of DCF calculations prior to its Brief on Exceptions. CES contends that the Commission

³²² Portland Brief Opposing Exceptions at 39-40.

³²³ ID, 129 FERC ¶ 63,027 at P 568.

³²⁴ See Portland Brief on Exceptions at 84 & n. 525 and cases cited therein.

has held that arguments raised for the first time in Briefs on Exceptions are improper and should not be the basis for modifying an ID.³²⁵ Thus, Portland should not be allowed to challenge the ALJ's decision not to rely on data for which no party urged reliance and Portland's attempt to replace its direct case with the "most current DCF data" should be rejected, particularly when the "updated" data raises the ID's recommended ROE of 11.65 percent to 12.75 percent or even 13.725 percent. CAPP also opposes the use of the "updated data" on grounds that Portland should not be allowed to use data first presented in its rebuttal case when it has not requested the record be re-opened to cure the deficiency. CES also notes that using the latest data would combine information from different time periods rendering a meaningless result.

238. PSG asserts that the Commission should not use its discretion to use post test period data in this case because the pipeline has not met its burden to show that resorting to such data is necessary in this proceeding. PSG contends that the Commission should exercise such discretion only when "the results would otherwise be in substantial error," and that Portland has not made any such showing here.³²⁶

239. As noted, the ALJ also rejected CAPP's proposal to use a 12 month (January 2007 – January 2008) dividend yield average for the DCF analysis in this case. The ALJ found that CAPP's proposal is contrary to Opinion No. 486-B, the Policy Statement, and the Commission's preferred ROE policies.³²⁷

240. On exceptions, CAPP contends that the recent financial crisis warrants use of a 12 month period rather than a six-month period for the dividend yield average. According to CAPP, the six month dividend yield data utilized by the ALJ for the DCF analysis in this case are anomalous because the DCF returns for the proxy group have increased since the recession began, while general profitability has declined. CAPP argues that by expanding the range of yield data CAPP's ROE Witness Purcell made a deliberative adjustment to his DCF analysis designed to dampen purported distortions in the DCF analysis resulting from the financial crisis in the market.³²⁸ CAPP claims that Mr. Purcell's testimony shows that holding all other variables constant, the difference in

³²⁵ CES Brief Opposing Exceptions at 64-65 (citing *Bluegrass Generation Co., LLC*, 118 FERC ¶ 61,214 (2007)).

³²⁶ PSG Brief Opposing Exceptions at 86 (quoting *Enbridge KPC*, 102 FERC ¶ 61,310 at P 101).

³²⁷ ID, 129 FERC ¶ 63,027 at P 568.

³²⁸ CAPP Brief on Exceptions at 4.

the DCF results for two different six month periods differed by 140 basis points (or 1.4 percent).

241. Trial Staff, Portland and PSG all oppose CAPP's exception. Trial Staff notes that even CAPP acknowledges that its approach is contrary to the consistent approach used by the Commission for years. Trial Staff contends that the existence of a financial crisis alone is not a sufficient basis for a change from established Commission precedent, especially because such economic downturns have occurred in the past.³²⁹ Portland argues that CAPP's proposed adjustment undermines the Commission's attempt to balance the goals of dividend yields that reflect current market conditions and avoiding unnecessary volatility. Portland also claims that the Commission has consistently preferred the use of six month dividend yields to calculate DCF returns because the use of a 12-month moving average "would not provide a sufficiently current estimate of the dividend yield."³³⁰ Portland further argues that a simple rise in DCF returns does not prove that the data used were anomalous. According to Portland, the CAPP theory that the pipeline's cost of capital decreased because of the recession ignores the Commission's longstanding policy to set a pipeline's ROE at a market determined return.³³¹ PSG claims that CAPP essentially urges the Commission to average dividend yield data over a longer period that includes additional earlier months because the data for earlier months tends to overstate current ROEs because the stock prices in decline for those earlier months are now on a path to recovery.

Commission Determination

242. The Commission determines that the appropriate time period for the DCF analysis in this proceeding is the six month period ending April 2009, that is, November 2008 through April 2009. As discussed below and shown by record evidence, the use of this time period is consistent with the Commission's longstanding policy to use the latest six month dividend yields, growth rates and GDP data in the record for its DCF analysis in pipeline rate cases. As the Commission has stated previously, the Commission uses the most recent data in the record, even if such data is from outside the test period, "because the market is always changing and later figures more accurately reflect current investor

³²⁹ Trial Staff Brief Opposing Exceptions at 81-82.

³³⁰ Portland Brief Opposing Exceptions at 44.

³³¹ *Id.* at 46.

needs.”³³² Unlike cost-of-service and capital structure data, the Commission prefers the most recent financial data in the record for calculating a pipeline’s ROE,³³³ recognizing that updates are not permitted once the record has been closed and the hearing has concluded.³³⁴

243. In the instant proceeding, the ROE adopted by the ALJ used Staff Witness Keyton’s DCF calculation, which provided IBES growth rates, GDP calculation and stock and dividend data through December 2008.³³⁵ Portland’s Witness Moul’s DCF calculations provided data up to April 2009.³³⁶ Therefore, Portland’s ROE data are the most recent available data in the record and the use of this data for the ROE analysis comports with our policy to use the most updated record data for the DCF analysis in natural gas pipeline rate cases.

244. The Commission rejects PSG’s reliance on the March 2003 rehearing order in *Enbridge KPC* for the proposition that the Commission should not use post test period data in the calculation of ROE unless doing so is necessary to avoid “substantial error.” In that case, the Commission addressed a situation where the test period had ended on January 31, 2000 and a hearing was held in October 2000. In March 2002, KPC had filed a motion to reopen the record to allow it to introduce evidence regarding changes in the capital markets caused by Enron’s November 2001 bankruptcy. In its September 2002

³³² *Trunkline Gas Co.*, 90 FERC ¶ 61,017, at 61,117 (2000) (citing *Panhandle Eastern Pipe Line Co.*, 74 FERC ¶ 61,109, at 61,363-63 (1996) and *Boston Edison Co. v. FERC*, 885 F.2d 962, 966 (1st Cir. 1989)); *Williston II*, 72 FERC ¶ 61,074, at 61,373 and 61,375.

³³³ See *Williston IV*, 104 FERC ¶ 61,036, at P 20 (permitting updated cost of equity figures over Trial Staff’s objections); *Williston III*, 84 FERC ¶ 61,081, at 61,382 (“It is true that the Commission prefers to use dividend yield data from the most recent six-month period available”).

³³⁴ See *Enbridge KPC*, 100 FERC ¶ 61,260, at P 379-86 (2002), *reh’g denied*, 102 FERC ¶ 61,310, denying the pipeline’s motion to reopen the record after the hearing had concluded to consider the effects of Enron’s bankruptcy on pipeline capital costs. See also *Office of Consumers’ Counsel v. FERC*, 783 F.2d 206, 232 (D.C. Cir. 1986) (“In relying on ex parte submissions appearing in a post-hearing brief, the Commission violated fundamental canons of due process.”).

³³⁵ See Ex. S-23 at 2-7.

³³⁶ See Ex. PNG-57 at 1-2.

order on initial decision, the Commission denied the motion to reopen the record,³³⁷ noting that the “general rule is that the record once closed will not be reopened.”³³⁸ KPC sought rehearing and argued the Commission should take into account the Enron bankruptcy and the Commission’s approval of higher ROEs in other post-Enron orders. The Commission denied rehearing.³³⁹

245. Thus, *Enbridge KPC* was not addressing the issue of whether to use the latest financial data in the record for the DCF analysis; rather in that order the Commission was rejecting KPC’s contention that we should consider events occurring after the close of the record, which is contrary to Commission policy. Therefore, while the result in *Enbridge KPC* that the Commission will not consider post-record non-financial data is correct, that holding is inapplicable to the issue of whether to use most updated financial data in the record for the DCF analysis in natural gas pipeline rate cases. As stated above, the Commission’s policy is to use the most updated financial data in the record for determining a pipeline’s ROE, even if that data is post-test period. To the extent that the language in *Enbridge KPC* can be interpreted to mean otherwise, that language was overly broad and contrary to the policy the Commission has consistently applied in other cases.

246. Based on the record in this proceeding, we find, on balance, that it is better to use the updated record data submitted by Portland for the six month period ending April 2009, than to use the data for the earlier six month period ending December 2008 supported by the ALJ, Trial Staff, and PSG. The data for the later period captures not only the increases in dividend yield resulting from the financial crisis, but also at least some offsetting downward adjustments to other inputs to the DCF analysis. As discussed above, the dividend yield component of the Commission’s approved DCF analysis is essentially the monthly dividend divided by the average stock price for that month. When a financial crisis causes a sudden drop in stock prices, the immediate effect is to increase a proxy firm’s dividend yield, which significantly increases the ROE produced by a DCF analysis. The other inputs to the formula, which may have an offsetting downward effect, typically do not adjust as quickly to the changed circumstances produced by the financial crisis. For example, as the economic effects of a financial crisis become clear, financial analysts may reduce their five-year IBES growth projections for the firms in the proxy group, thereby lowering the growth component of the DCF analysis. Thus, the use of data from a later time period may capture some of

³³⁷ *Enbridge KPC*, 100 FERC ¶ 61,260 at P 379-386.

³³⁸ 100 FERC at P 382.

³³⁹ 102 FERC at P 98-105.

those delayed adjustments. In the instant case, for example, the record evidence shows that IBES growth projections declined between the period utilized by the ALJ and the time period ending April 2009.³⁴⁰ While the Commission realizes that the ROE arrived at based on using the most recent record data may not be entirely representative of a long term ROE that one would expect for natural gas pipelines, it appears to be the best analysis based on the record data available in this case, without having to divert from our longstanding policy of not using post-record data.

247. This result is particularly warranted in the instant proceeding, where the Commission is approving rates for a limited locked-in period ending November 30, 2010. Portland has filed the 2010 Rate Filing, and thereby initiated a separate rate case subsequent to the instant proceeding. Thus, the ROE and ensuing rates determined in this proceeding are effective only for a locked-in period from September 1, 2008 through November 30, 2010, after which date the rates from the new proceeding will go into effect, subject to refund.³⁴¹ Thus, the ROE approved in this order reflects the effects of the financial crisis that occurred in late 2008 and early 2009 during the locked-in period and yet is limited in its prospective application to a time period representative of the actual effects of that crisis.

248. Our decision in this case, to follow our longstanding policy of using the most recent financial data in the record and not use financial data for periods after the July 2009 close of the record, is also consistent with our determination below not to consider the July 2, 2010 post record reduction in Portland's credit rating to below investment grade.³⁴² On August 20, 2010, Portland filed a motion requesting that the Commission take official notice of that change in its credit rating, acknowledging that the

³⁴⁰ The IBES growth projections for four of the six proxy group firms declined during the period November 2008-April 2009 as compared to the time period adopted by the ALJ, and two remained the same. A comparison of Ex. No. S-23 to Ex. No. PNG-57 shows that TC Pipelines' IBES growth projection declined by 5.0 percent to 4.0 percent and Boardwalk's from 8.4 percent to 6.75 percent. The growth projections of Southern and Spectra Corp. remained the same. While Trial Staff's Ex. S-23 does not include data for El Paso Partners and Spectra Partners, a review of publicly available information shows that their growth projections fell from 9 to 7.5 percent and from 8.0 to 6.5 percent respectively.

³⁴¹ See Hearing Order on 2010 Rate Filing, 131 FERC ¶ 61,230 (2010); *see also* Portland's Motion to Place Suspended Rates and Tariff Sheets into Effect, Docket No. RP11-1541-000 (Nov. 22, 2010).

³⁴² See the Commission's determination below, denying Portland's motion.

information is post hearing, out of test period data. If the Commission were to take the post hearing change in credit rating into consideration for the DCF analysis, then it would be necessary to reopen the record to allow other post-record developments to be considered, including post-record changes in DCF inputs such as stock prices, dividends and growth projections.³⁴³ . Because, as noted above, Portland has filed a new rate case, and the instant case only sets rates for a locked in period ending November 30, 2010, we find that all such developments since the close of the record in this case should be addressed at the hearing in the new rate case, where all interested participants will have an opportunity to develop a full record concerning how such developments should affect Portland's ROE.

249. We affirm the ALJ's decision to reject CAPP's argument that the Commission should use a 12-month dividend yield analysis. CAPP argues that the Commission should use an extended period to account for the aberrant market conditions that occurred in the fall of 2008. As discussed above, however, we approve the use of Portland's proposed most recent record data because that data accurately reflects the actual market conditions during the locked-in period. Moreover, as even CAPP agrees, using a 12 month period is contrary to the Commission's established methodology.

E. Portland's Placement in the Proxy Group

250. The ALJ determined that Portland's ROE should be placed at the median of the proxy group adopted in the ID (11.65 percent), finding that Portland had not overcome the "heavy presumption" that it has average risk, as would be necessary for a pipeline to justify an ROE above the median for the proxy group.³⁴⁴ The ALJ determined that Portland's failure to compare itself to each of the proxy group members in a comprehensive manner was by itself fatal to Portland's argument that it should receive an ROE that deviates from the median. The ALJ also determined that Portland had approximately the same business risk as the proxy group members because Portland's credit rating was within the range of credit ratings of the proxy group.³⁴⁵ The ALJ found

³⁴³ An updated DCF analysis using data for the six month period January – June 2010 would result in a reduced zone of reasonableness of 10.02 percent to 13.39 percent, and a reduced median of 11.23 percent. *See* Appendix B, containing the Commission's DCF analysis using data for the six-month period beginning January 2010 and ending June 2010. There is insufficient record data for Spectra Partners and El Paso Partners to conduct a DCF analysis for the time period approved by the ALJ.

³⁴⁴ ID, 129 FERC ¶ 63,027 at P 632.

³⁴⁵ *Id.* P 634 (noting that Portland's credit rating is BBB- while the credit ratings in the adopted proxy group range from BBB- through BBB+).

unpersuasive the reasons and circumstances that Portland gave in support of its claim of high business risk because those reasons and circumstances were not unique to Portland.³⁴⁶ The ALJ also found that many of the risk factors that Portland raised were a result of Portland's own business choices.³⁴⁷

251. Portland excepts to being placed at the median of the proxy group. Portland argues that the ALJ's finding with regard to a lack of a comparative analysis is simply wrong because it ignores the detailed comparative risk analyses provided by Portland and the other participants in the proceeding.³⁴⁸ Portland argues that it compared its circumstances with respect to major business segments, natural gas operations and recent financial disclosures to those of other proxy group candidates and that its witnesses analyzed its risk as compared to those candidates. Portland also challenges the ALJ's reliance on credit ratings. Portland argues that a credit rating, which measures the financial health of an entity, is not the sole indicator of an entity's overall risk. According to Portland, financial health does not necessarily decrease as risk increases and in some instances an entity with a high risk profile may be required by its lender to be financially strong exactly because of the high level of business risk. Thus, Portland argues, the ID erroneously presumed that a good credit rating is synonymous with low risk without conducting an independent analysis of the individual risks facing Portland and each of the proposed proxy group members. Portland further argues that even if corporate credit ratings were an adequate measure of risk, the ID's failure to reconcile, or even discuss, Standard and Poor's (S&P) negative assessment of Portland was a critical error.

252. Portland claims that it has an "anomalously high risk profile" based on purported increased risk as a result of the MFN clauses, contract reduction, and free off-peak

³⁴⁶ *Id.* P 635 (noting that factors such as the seasonal nature of Portland's system, its market change due to the bankruptcy of two of its shippers, and the competition in Portland's market area are also faced by other interstate natural gas pipelines).

³⁴⁷ The ID lists long-term FT contract limitations with "most favored nation" (MFN) clauses, decontracting options, free off-peak transportation, and certain joint facilities agreements as examples of risk factors that were a result of Portland's own contract negotiations. *Id.*, P 636. In rejecting Portland's claims the ALJ observed that, "Business remorse does not equal business risk". CES Brief Opposing Exceptions at 73 (quoting ID at P 636).

³⁴⁸ Portland Brief on Exceptions at 86.

transportation provisions of its long-term firm contracts.³⁴⁹ Portland also contends that it has significant risk as a result of its shared ownership of certain joint facilities with Maritimes/Northeast, its primary competitor.³⁵⁰ Portland claims that shared ownership of those joint facilities restricts Portland's operational flexibility, provides Maritimes/Northeast with advance notice of certain business development initiatives undertaken by Portland,³⁵¹ and puts Portland at risk for by-pass by Maritimes/Northeast.³⁵²

253. Portland asserts that its market characteristics also increase its risk as compared to the proxy group members because its market is seasonal and its lacks integrated storage. Portland claims that significant new capacity has been created, or is planned to be built, in its market area without any increase in demand. Portland further claims that increased competition from LNG and stagnant growth of natural gas consumption increase the risk of its already difficult competitive position.³⁵³

254. Portland argues that the ALJ's determination that the reasons Portland provides to support a high risk profile are not convincing because they are faced by other interstate pipelines and that some of its risks factors are the result of the pipeline's own choices do not justify placing Portland at the median of the range of reasonable returns.³⁵⁴ With respect to the former finding, Portland claims that the ALJ misses the point that there is no evidence to suggest that any other pipeline faces the combination and severity of risk it faces. Portland claims that taken together the risk resulting from ownership of joint facilities with Maritimes/Northeast, the combination of contractual clauses and limitations and the severe and abrupt reduction in long term contract demand levels places it at a much higher risk level than the other companies in the proxy group.

255. With respect to the finding in the ID that many of the risk factors of which Portland complains are of Portland's own making, Portland asserts that many of the items were the result of extensive negotiations and provisions that were required by certain

³⁴⁹ *See id.* at 88 & n. 547 (citing Ex. PNG-1 at 8:5-23; Ex. PNG-13 at 61:16-63:8; Tr. 1518:5-7, 1816:20-24).

³⁵⁰ *Id.* at 88 & n.548 (citing Ex. PNG-1 at 9:1-14).

³⁵¹ *Id.* at 88 and n.549 (citing Ex. PNG-1 at 9:7-11).

³⁵² *Id.* at 88 and n.550 (citing Ex. PNG-1 at 9:2-4).

³⁵³ *Id.* at 88-89.

³⁵⁴ *Id.* at 89-93.

shippers as a pre-requisite for signing up for capacity on Portland's system. Portland claims that it had to accept some of the conditions requested by potential shippers for the long term firm contracts in order to sign those shippers. Portland contends that the same is true for many provisions in the operating agreements related to the jointly owned facilities with Maritimes/Northeast. Portland states that the agreements are based on a series of compromises that were necessary to enter into an "uneasy commercial marriage" at the Commission's request.³⁵⁵ Portland concludes that any suggestion that Portland is primarily or exclusively responsible for its competitive circumstances is simply incorrect.

256. Portland also challenges the ID's claim that Portland should be placed at the median of the range of returns because "bankruptcy proceeds [Portland] has received ...have] in some ways served to reduce [Portland's] risk, as the proceeds have provided the pipeline with guaranteed, upfront revenues."³⁵⁶ According to Portland, that claim misrepresents and incorrectly suggests that Portland's bankruptcy recovery is comparable to revenue it lost as a result of the underlying bankruptcies. Portland contends that when evaluated on a net-net-net basis, it has not recovered anywhere near the revenue it was entitled to collect over the remaining years of the contracts rejected by the bankruptcy court, nor has it obtained significant revenue from the firm contracts formerly held by the bankrupt parties. Portland concludes that it is therefore unreasonably optimistic to presume that Portland's recovery of bankruptcy proceeds reduces its risk.

257. Trial Staff, PSG, CAPP and CES all claim that the ALJ was correct to set Portland's ROE at the proxy group median.³⁵⁷ These parties argue generally that Portland did not meet the high standard of showing highly unusual circumstances or anomalously high risk as compared to other pipelines required for an above average ROE. Trial Staff asserts that Portland does not challenge the ALJ's ruling that Portland had not overcome the heavy presumption required for any participant seeking to justify an ROE at other than the median of the zone of reasonableness and that Portland does not even acknowledge that it must overcome such a presumption. CAPP also notes Portland's failure to meet this standard. CES argues that Portland failed to provide a "persuasive case in support of the need for an adjustment and the level of the adjustment proposed" because it failed to provide the requisite nexus between the business risks

³⁵⁵ *Id.* at 92.

³⁵⁶ *Id.* at 93 (quoting ID at P 635).

³⁵⁷ *See* Trial Staff Brief Opposing Exceptions at 82-95; PSG Brief Opposing Exceptions at 89-99; CAPP Brief Opposing Exceptions at 10-13; CES Brief Opposing Exceptions at 70-74.

outlined by its Witness Haag and the upward adjustment it seeks.³⁵⁸ According to CES, the pipeline made no attempt to explain how the business risks discussed by its witnesses translate into an 85 basis point increase in ROE.

258. As to whether it was appropriate to compare credit ratings as a means of assessing whether the proxy group members reasonably reflect the business risk of the pipeline, Trial Staff contends that the ALJ was correct to compare credit ratings because Opinion No. 486-B reiterated that corporate credit ratings are an important tool for evaluating relevant risk.³⁵⁹

259. The opponents of Portland's placement at the high end of the zone of reasonableness also challenge Portland's arguments as to the uniqueness of its competitive circumstances. Trial Staff points out, for example, that while Portland's market is highly seasonal, Portland did not explore or present evidence as to whether that circumstance exists on the proxy group members' systems. Trial Staff argues that other pipelines have seasonal markets and that Portland's Witness Haag conceded that other pipelines have experienced plant closures and had bankrupt customers. PSG contends that the circumstances here are similar to those faced by the Commission in *Mojave Pipeline Company*,³⁶⁰ where the Commission rejected the pipeline's assertion that it faced extraordinary risk as "unsustainable" because a high percentage of the pipeline's capacity was reserved under long term firm contracts and because the pipeline's economic viability could not be determined in isolation of its parent company. PSG argues that Portland likewise cannot be deemed to be high risk because "practically all of its firm capacity is subscribed under long-term firm contracts that extend for another 10 years" or has been prepaid as a result of bankruptcy settlements. PSG also argues that Portland's economic status cannot be viewed in isolation of its parent, TransCanada. CAPP argues that Portland presents nothing to demonstrate that joint ownership of facilities is inherently risky or that it is so anomalous to warrant an upward risk adjustment for ROE.³⁶¹

³⁵⁸ CES Brief Opposing Exceptions at 71 (quoting Opinion No. 486-B, 126 FERC ¶ 61,034 at P 140).

³⁵⁹ Trial Staff Brief Opposing Exceptions at 86.

³⁶⁰ *Mojave Pipeline Co.*, 81 FERC ¶ 61,150 (1997), *reh'g denied*, 83 FERC ¶ 61,267 (1998).

³⁶¹ Trial Staff also counters Portland's argument that it has faced increased delivery capacity in Portland's market area due in primary part to expansion of Maritimes' system by noting that Portland eventually withdrew its protest to Maritimes' proposed expansion and entered into a settlement with Maritimes. Trial Staff argues that
(continued...)

260. The parties opposed to placing Portland at the high end of the range of reasonable returns agree with the ALJ that Portland should not be granted a higher ROE based on risks it knowingly assumed. As discussed above, the ALJ found that many of the contract limitations identified by Portland as risk factors were the result of its own contract negotiations. Trial Staff argues that the Commission should reject Portland's argument that while it did not negotiate the subject contracts under duress, the agreements were not purely voluntary because they did not reflect only the terms and conditions that Portland desired. Trial Staff notes that the very nature of contract negotiations is that no one side will receive all of the terms it desires and that Portland could have declined to enter into the agreements, but instead freely entered into them. CES agrees that terms and conditions negotiated freely by the pipeline but which now appear inconvenient or unprofitable are no reason to increase the pipeline's ROE.

261. On August 20, 2010, Portland filed a motion to request that the Commission take official notice under Commission Rule No. 508 of a confidential, July 22, 2010 S&P report that downgraded its BBB- corporate credit rating to BB+ Stable.³⁶² According to Portland, S&P specifically identified the rates approved in the ID as the main factor in the downgrade. Portland argues that the S&P downgrade is relevant to Portland's risk compared to the proxy group and states the credit rating can be used to determine whether the rates approved in the ID provide a rate of return that Portland suggests is constitutionally-required to maintain its credit standing.³⁶³

262. CAPP, PSG and CES, and Trial Staff oppose Portland's motion, and contest whether the confidential S&P report is suitable for official notice under the Commission's rules. In its answer to Portland's motion, Staff states that Portland is correct that pursuant to Rule 508, the Commission may "take official notice of any matter that may be judicially noticed by the courts of the United States, or of any matter about which the Commission, by reason of its function, is expert."³⁶⁴ Staff also notes that in

Portland's rate payers should not bear the expense of any increased risk associated with the Maritimes expansion because Portland now regrets not obtaining adequate tangible benefits in that settlement. Trial Staff Brief Opposing Exceptions at 91.

³⁶² 18 C.F.R. § 385.508(d) (2010). The original motion was filed on Aug. 20, 2010; Portland refiled a public version of the motion on Jan. 19, 2011.

³⁶³ Portland Motion at 3, 5 (as refiled) (citing *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1994) (*Hope*); *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679, 692-93 (1923) (*Bluefield*)).

³⁶⁴ Trial Staff September 7, 2010 answer in opposition to motion for official notice (September 7 Answer), at 3.

exercising its authority to take official notice, the Commission has referenced Rule 201 of the Federal Rules of Evidence, which provides that a fact may be judicially noticed if it is “not subject to reasonable dispute in that it is either (1) generally known within the territorial jurisdiction of the trial court or (2) capable of accurate and ready determination by resort to sources whose accuracy cannot reasonably be questioned.”³⁶⁵

263. Trial Staff contends that the credit analysis is not relevant because it was issued some 21 months after the test period ended, and that Portland must show a change in circumstance that is “more than material” to justify reopening the record.³⁶⁶ Staff notes that rates are developed using cost data available at the time of the filing, and that the utility has the burden to prove that its estimates were reasonable when made.³⁶⁷ Staff indicates that Portland should file a new rate case, if circumstances change after a rate case is filed and adjudicated, and notes that Portland did just that in May 2010.³⁶⁸

264. PSG and CES object to Portland’s motion, claiming that the credit analysis does not establish facts that are generally known or beyond controversy because the confidential credit rating goes to a hotly contested issue in this proceeding, is not subject to review through responsive testimony or cross-examination, and is based on undisclosed assumptions.³⁶⁹ In particular, PSG and CES question whether the credit report takes into account the financial security offered by Portland’s receipt of substantial bankruptcy proceeds. CAPP likewise states that the credit analysis is unsuitable for official notice, because it should be subject to responsive testimony and cross-examination, as was the prior credit rating that Portland submitted with its testimony.

³⁶⁵ See *AES Ocean Express LLC*, 119 FERC ¶ 61,075, at P 87 (2007).

³⁶⁶ Trial Staff September 7 Answer at 6 (citing *CMS Midland, Inc.*, 56 FERC ¶ 61,177, at 61,624 (1991)).

³⁶⁷ Trial Staff September 7 Answer at 7 (citing *Exxon Corporation v. FERC*, 114 F.3d 1252, 1263 (D.C. Cir. 1997) and *Indiana & Michigan Mun. Dist. v. FERC*, 659 F.2d 1193, 1198 (D.C. Cir. 1981) to the effect that the Commission “rightly does not require that history prove the accuracy of the utilities’ estimates, but rather that the utility prove that the estimates were reasonable when made”).

³⁶⁸ See Hearing Order on 2010 Rate Filing, 131 FERC ¶ 61,230 (accepting May 2010 rate filing subject to refund effective Dec. 1, 2010 in Docket No. RP10-729-000).

³⁶⁹ PSG and CES Answer at 4 (citing *Louisiana Public Service Comm. v. Entergy Services, Inc.*, 106 FERC ¶ 63,012 (2004); *Northeast Utilities Service Co.*, 62 FERC ¶ 63,013 (1993)).

Commission Determination

265. We find that the ALJ was correct to set Portland's ROE at the median of the proxy group range. The Commission's traditional assumption with regard to relative risk is that pipelines generally fall into a broad range of average risk absent highly unusual circumstances that indicate an anomalously high or low risk as compared to other pipelines. Thus, unless a party makes a very persuasive case in support of the need for an adjustment and the level of the adjustment proposed, the Commission will set the pipeline's return at the median of the range of reasonable returns.³⁷⁰ We reiterated this policy in Opinion No. 486-B and the Policy Statement.³⁷¹ Based on the record in this proceeding, we determine that Portland has failed to overcome the presumption that its ROE should be set at the median of the proxy group.

266. As noted in the ID, Portland effectively fails to present a comprehensive analysis comparing its risk to that of each of the proxy group members. Portland argues that the testimony of its various witnesses, when taken as a whole, provide such an analysis and thus the determination in the ID is based on a "faulty premise" and should be rejected.³⁷² A review of the exhibits cited by Portland, however, indicates that while those exhibits do include information regarding the different operations and business segments of proxy group candidates and general supply studies and data meant to support Portland's claims of high business risk, they do not provide more than a generalized comparison of Portland's risk to the general risk of the proxy group candidates.³⁷³ Whether or not Portland's general comparisons or lack of a more detailed comparative analysis is "fatal" to Portland's case, Portland's failure to compare itself to each of the proxy group candidates in a comprehensive manner is detrimental to its attempt to overcome the heavy burden of justifying its placement at the high end of the zone of reasonableness.

267. Further, we find persuasive the ALJ's and other parties' arguments with regard to Portland's failure to justify an above average ROE. First, with regard to the ID's reliance on credit ratings to evaluate relative risk, Trial Staff is correct that in Opinion No. 486-B, the Commission affirmed that it is well established Commission precedent that a pipeline's credit rating is "an appropriate part of the risk analysis...."³⁷⁴ Portland argues

³⁷⁰ *Transcontinental Gas Pipeline Corp.*, 90 FERC ¶ 61,279 (2000).

³⁷¹ Opinion No. 486-B, 126 FERC ¶ 61,034 at P 140 (quoting the Policy Statement at P 7).

³⁷² Portland Brief on Exceptions at 86.

³⁷³ See e.g., Ex. PNG 13 at 62-65.

³⁷⁴ Opinion No. 486-B, 126 FERC ¶ 61,034 at P 137.

that credit ratings, which evaluate the financial health of an entity, are not the sole indicator of an entity's overall financial risk, and thus the ID erroneously presumed that a good credit rating is synonymous with low risk without conducting an independent analysis of the individual risks facing Portland and each of the proposed proxy group members. The ALJ, however, does not conclude that because the credit rating of Portland is within the range of credit ratings of the proxy group members that a good credit rating means low risk. The ID states rather that it is appropriate to compare credit ratings to assess whether the proxy group members reasonably reflect the business risk of Portland, and that the similar credit ratings of Portland and the proxy group members indicate that they have approximately the same business risks.³⁷⁵

268. Further, the ALJ's analysis with regard to the other risk factors presented by Portland to show its purportedly anomalous high risk profile shows that credit ratings were not the only factors relied on in placing Portland's ROE at the median. The ALJ notes that factors such as the seasonal nature of Portland's system, the market change due to bankruptcy of two of its shippers and competition in its market area, are hardly unique to Portland and are also faced by other interstate pipelines. Moreover, the ALJ specifically points out that Portland received considerable proceeds from the referenced bankruptcies that provide Portland with guaranteed upfront revenues.³⁷⁶ Portland's argument that the ALJ misses the point because there is no evidence to suggest that any other pipeline faces the combination and severity of the risks that Portland faces is not compelling. It is incumbent upon Portland to provide support to overcome the heavy presumptive burden that it is an average risk pipeline. As argued by the other parties, Portland did not explore or present evidence as to whether circumstances such as seasonal markets exist on the proxy group members' systems. As Trial Staff points out, other pipelines have seasonal markets and Portland's own witness concedes that other pipelines have experienced closure of plant and bankrupt customers. Further, as argued by PSG, the record evidence indicates that a high percentage of Portland's firm capacity is subscribed under long-term firm contracts that extend for another 10 years or have been prepaid as a result of bankruptcy settlements. In addition, Portland has not presented evidence to demonstrate that joint ownership of facilities is inherently risky or that such arrangements are so anomalous as to warrant an upward risk adjustment for ROE.

269. The Commission also finds compelling the argument that many of the factors upon which Portland relies for its high risk claim are effectively the result of its own business decisions. The MFN clauses, the decontracting options, free off peak transportation

³⁷⁵ ID, 129 FERC ¶ 63,027 at P 634.

³⁷⁶ *Id.* P 635.

provisions and the joint facility agreements are consequences of Portland's own contract negotiations and there is no evidence to indicate that Portland was under duress when it made those contracting decisions. While Portland claims that those provisions were only entered into as a series of compromises during the negotiation of the agreements at issue, such compromises are the very epitome of contract negotiations and are not unique in that respect to Portland. As Trial Staff points out, despite Portland's alleged unease with some of these provisions, Portland nevertheless voluntarily entered into the agreements. The fact that Portland may now regret those business decisions does not warrant an upward adjustment to Portland's ROE.

270. Based on the reasons discussed above, the Commission finds that Portland has not met its burden to overcome the heavy presumption that its ROE should be set at the median of the range of reasonable ROEs, and affirms the ALJ's determination to place Portland's ROE at the median.

271. The Commission denies Portland's request for official notice of S&P's July 22, 2010 downgrade of Portland's corporate credit rating in this proceeding. As Staff notes, this event occurred approximately 21 months after the close of the test period in this case and thus any possible effect of the downgrade is irrelevant to the determination of Portland's ROE and ensuing rates as it does not reflect Portland's risk during the period considered to calculate Portland's rates in this proceeding.³⁷⁷ As noted above, Portland has filed an updated rated case and the downgrade at issue occurred during the test period in that proceeding.³⁷⁸ Thus, any effect from Portland's downgrade is best addressed in that proceeding.

V. Rate Design

Background

272. In the July 1997 Certificate Order, the Commission directed Portland, among other things, to revise its initial rates to reflect billing determinants of 178,000 Mcf per day for the first year of service and, in subsequent years, 210,000 Mcf per day, even though Portland only had firm contracts for 170,200 Mcf per day during the winter (November-

³⁷⁷ See *Enbridge KPC*, 100 FERC ¶ 61,260 at P 383 (general rule is that record will not be reopened once closed).

³⁷⁸ See May 2010 Rate Filing at 2. According to Portland, its cost-of-service and determination of rates in that proceeding reflect the costs and throughput for a Base Period of twelve months ended February 28, 2010, as adjusted through the Test Period ending November 30, 2010.

March) and 96,600 Mcf per day during the summer (April-October).³⁷⁹ These billing determinants reflected the winter-day design capacity of Portland's system in the first year and its estimated increased capacity in subsequent years. Recognizing that Portland would have unsubscribed capacity for both the winter and summer months based on these figures, the Commission expressly placed Portland at risk for the recovery of costs based on 178,000 Mcf per day for the first year of operation and 210,000 Mcf per day in subsequent years.³⁸⁰ In addition, the Commission approved Portland's proposal to allocate costs to its Rate Schedule IT service and retain its Rate Schedule IT revenues and not credit them to firm shippers, as the Commission had required in the 1996 Certificate Order.³⁸¹

273. Following the July 1997 Certificate Order, Portland sought rehearing of the Commission's decision to require Portland to revise its rates to reflect 210,000 Mcf per day of capacity after the first year of operation and be placed at risk for the increased unsubscribed capacity. Portland argued that it was uncertain when additional compression would go into service or the actual amount of increased compression and its effect on the capacity of the Portland system. In an order issued on September 24, 1997 (the September 1997 Certificate and Rehearing Order), the Commission issued certificates of public convenience and necessity allowing Portland to construct its proposed interstate pipeline system and granted Portland's rehearing request.³⁸² The Commission agreed with Portland that it was premature, based on the current facts, to require Portland to revise its rates and to be placed at risk for higher capacity after its first year of operation. Instead, the Commission stated it would review the matter when Portland made its first NGA section 4 rate filing within three years of its in-service date.³⁸³

274. Thereafter, on October 1, 2001, Portland made a section 4 rate filing in Docket No. RP02-13 as required by the certificate orders. The rate filing ended in an

³⁷⁹ July 1997 Certificate Order, 80 FERC ¶ 61,134 at 61,448.

³⁸⁰ *Id.*

³⁸¹ *Id.* at 61,451. In its first application, Portland did not allocate any costs to its IT service. Consistent with the Commission's policy regarding interruptible service, Portland was therefore directed to credit 100 percent of the IT revenues to its firm shippers. 1996 Certificate Order, 76 FERC at 61,661.

³⁸² September 1997 Certificate and Rehearing Order, 80 FERC ¶ 61,345.

³⁸³ *Id.* at 62,147.

uncontested settlement, which the Commission approved on January 12, 2003.³⁸⁴ The instant proceeding is Portland's first section 4 rate case since the settlement.

A. At-Risk Condition

Initial Decision

275. Among the issues raised before the ALJ at the hearing was the appropriate level of Portland's at-risk condition. In this proceeding, while Portland proposed billing determinants of 210,840 Dth per day (approximately 210,000 Mcf per day) for rate-making purposes, it asserted that its at-risk condition should remain at the 178,712 Dth per day (178,000 Mcf per day) level established in its certificate proceeding. Portland based its billing determinants for ratemaking purposes on its system's current firm capacity of 210,840 Dth per day. On the other hand, Portland proposed an at-risk condition of 178,712 Dth per day, arguing that "the Commission's 178,000 Mcf/day at-risk condition was the final determination of this matter in the certificate proceedings."³⁸⁵ Portland asserted that none of the participants in this proceeding had demonstrated that an increase in the at-risk condition was justified or required by Commission precedent.

276. Trial Staff recommended that the at-risk condition be set at the current firm system capacity of 210,840 Dth per day (210,000 Mcf per day). PSG Witness Fink, on the other hand, argued that the billing determinants for the at-risk condition should be established at a level of 217,405 Dth per day. Mr. Fink argued 217,405 Dth per day better represented current capacity on Portland's system.

277. In the ID, the ALJ agreed with Trial Staff that the Commission should set the at-risk condition at a level of 210,840 Dth per day.³⁸⁶ The ALJ found that the Commission, in both of the 1997 certificate orders, intended to base the at-risk condition on the actual capacity of the pipeline and to place Portland at risk for any unsubscribed capacity. In doing so, the ALJ stated, the Commission recognized that Portland would have significant unsubscribed capacity for both the winter months and the remainder of every year and nevertheless placed Portland "at-risk for the recovery of costs for the unsubscribed capacity."³⁸⁷

³⁸⁴ 2002 Settlement Order, 102 FERC ¶ 61,026.

³⁸⁵ ID, 129 FERC ¶ 63,027 at P 304 (citing Ex. PNG-1 at 6).

³⁸⁶ *Id.* P 311.

³⁸⁷ *Id.* P 314 (citing July 1997 Certificate Order, 80 FERC at 61,448).

278. Disagreeing with Portland, the ALJ stated the September 1997 Certificate and Rehearing Order only delayed increasing the at-risk condition to a figure above 178,000 Mcf per day until Maritimes/Northeast's upstream facilities went into service and its capacity actually increased. By deferring its decision until the first section 4 rate case (now this case, since the first such case was settled), the ALJ stated that the Commission clearly placed the burden of proof on Portland to confirm that the compression had been added and its effect upon the post-first year capacity of the pipeline.³⁸⁸ Further, the ALJ stated that Portland does not and cannot deny that the compression was added, thus eliminating the impediment, as expressed by the Commission in the rehearing order, to placing the pipeline at risk for a higher capacity. The ALJ stated that Portland's admission that its system capacity at the end of the test period was 210,840 Dth per day is consistent with the Commission's initial finding in the certificate proceedings that it "will place Portland at risk for the recovery of the *off-peak costs*."³⁸⁹

279. The ALJ also rejected PSG's arguments to impose an at-risk condition based on billing determinants at a level in excess of 210,840 Dth per day. The ALJ stated that PSG was attempting to place Portland at-risk for its winter peak capacity, not its off-peak capacity, which the ALJ found was inconsistent with the language from the Commission's 1996 Certificate Order.³⁹⁰ The ALJ also stated that PSG failed to present any engineering analyses or studies of its own to support its thesis.³⁹¹ In addition, the ALJ noted Portland Witness Haag's statement that the "Definitive Agreements" between Portland and Maritimes/Northeast, which were accepted by the Commission and govern the operation of the Joint Facilities, provide that Portland has a maximum capacity entitlement of 210,840 Dth per day on the Joint Facilities.³⁹² Lastly, the ALJ stated that PSG's position for a higher at-risk condition ignored the unchallenged testimony of Portland Witness Haag that although operational capacity may exist from time to time that could permit service above 210,840 Dth per day, Portland had no entitlement to sustain those deliveries on a year-round basis.³⁹³

³⁸⁸ *Id.* P 320.

³⁸⁹ *Id.* P 321.

³⁹⁰ *Id.* P 323.

³⁹¹ *Id.* P 324.

³⁹² *Id.* P 325 (citing *Maritimes & Northeast Pipeline, L.L.C.*, 81 FERC ¶ 61,166, at 61,724-25 (1997) (*Maritimes I*)). As discussed earlier, the Joint Facilities consist of 101 miles of pipeline from Westbrook, ME to Dracut, MA, and three laterals.

³⁹³ *Id.* P 325.

Briefs on Exceptions

280. Portland argues that the ALJ incorrectly held that Portland's at-risk condition should be set at its system capacity of 210,840 Dth per day (or approximately, 210,000 Mcf per day). Portland argues that the NGA assigns the burden of proving that a change is just and reasonable to the party seeking such a change and, because Trial Staff and PSG are seeking to change Portland's current at-risk condition of 178,000 Mcf per day, which was the Commission's last word on the matter in the September 1997 Certificate and Rehearing Order, they bear the burden of proof.³⁹⁴

281. Portland also argues that there is no record basis for the ALJ's assertion that "[Portland] does not (and cannot) deny that compression was added, thus eliminating the impediment...to placing the pipeline at risk for a higher capacity."³⁹⁵ Portland states that since 1999, no compression has been added either to Portland or Trans-Quebec & Maritimes to serve Portland's shippers.³⁹⁶ Further, Portland states that when Maritimes/Northeast adds compression on its facilities upstream of the Joint Facilities, the result is a higher pressure at Westbrook that upstream flows on Portland must buck to be able to deliver gas into the downstream Joint Facilities. Portland states that, all other things being equal, a higher pressure at Westbrook means reduced capacity north of Westbrook on Portland. Portland states that Maritimes/Northeast ultimately did install more compression on its facilities before they were placed in service than had been expected when Portland was certificated³⁹⁷ and thus, the presumption that 210,000 Mcf per day would be an appropriate at-risk level was further undermined by subsequent developments.

282. PSG argues that the ALJ refused to consider a wealth of record evidence that conclusively establishes that Portland constructed, offered and maintained sustainable year-round capacity greater than 210,000 Mcf per day throughout its system's operational history, including during the test period. According to PSG, such evidence includes: (a) the Annual System Capacity Reports which Portland has filed with the Commission every year since its system inception;³⁹⁸ (b) capacity reported in Portland's Form 2

³⁹⁴ Portland Brief on Exceptions at 57.

³⁹⁵ *Id.* at 58 (citing ID at P 321).

³⁹⁶ *Id.* at 58.

³⁹⁷ *Id.* at 59 (citing *Maritimes & Northeast Pipeline, L.L.C.*, 89 FERC ¶ 61,123, at 61,338-39 (1999) (*Maritimes II*)).

³⁹⁸ PSG Brief on Exceptions at 53 (citing Ex. PSG-15).

covering the Base and Test Periods;³⁹⁹ (c) engineering studies applicable to the test period which Portland submitted in sworn filing in its declaratory order proceeding at Docket No. CP08-70-000, and which the Commission relied on in issuing a final order in that proceeding;⁴⁰⁰ (d) Index of Customer reports submitted by Portland periodically pursuant to Commission regulations and reflecting Portland's firm service commitments throughout its operational history;⁴⁰¹ and (e) the Operationally Available Capacity Reports posted by Portland on its interactive website every day of the Test Period Year.⁴⁰²

283. While PSG concedes that Portland's contractual volumetric capacity entitlement on the Joint Facilities is 210,000 Mcf per day, it does not believe that this precludes Portland from making additional deliveries off its Northern Facilities upstream as well.⁴⁰³ For Portland's entire system capacity to be limited by its Joint Facility capacity entitlement, PSG argues, Portland would have to be operationally incapable of receiving more than 210,000 Mcf per day into its Northern Facilities at Pittsburg and delivering more than that volume out into either the Joint Facilities or other Northern Facilities delivery points. PSG argues that this is not the case, as demonstrated by the evidence cited above.

284. PSG also excepts to the ID's suggestion that PSG Witness Fink was attempting "to place [Portland] at-risk for its winter peak capacity, not its off-peak capacity." PSG states that, to the contrary, PSG Witness Fink discussed the certificate orders and concluded that the Commission in those orders intended that Portland be held at-risk for what the Commission believed would be "the total constructed firm capacity of the [Portland] system."⁴⁰⁴ PSG states that the 1996 Certificate Order placed Portland at-risk for its off-peak capacity costs precisely by requiring that rates be designed "based upon a winter-day capacity design of 178,000 MMBtu per day," and that was not Portland's peak throughput capability, but its firm capacity in the winter. PSG states that the fact that PSG Witness Fink advocated establishing billing determinants and Portland's at-risk

³⁹⁹ *Id.* (citing Ex. PSG-128; PSG-131).

⁴⁰⁰ *Id.* (citing Ex. PSG-85 Protected).

⁴⁰¹ *Id.* at 54 (citing Ex. PSG-17).

⁴⁰² *Id.* (citing Ex. PSG-133).

⁴⁰³ *Id.* at 61. As described above, the Northern Facilities consist of 142 miles of mainline from the Canadian border at Pittsburg, New Hampshire to Westbrook, Maine.

⁴⁰⁴ *Id.* at 55 (citing Ex. PSG-1 at 26/16-27/8).

condition at only 217,405 Dth per day while expressly recognizing that Portland had been able to achieve system peaks as high as 395,592 Dth per day, and report firm delivery obligations as high as 273,405 Dth per day, disproves the statement that Mr. Fink was “attempting to place [Portland] at-risk for its winter peak capacity.”⁴⁰⁵

Briefs Opposing Exceptions

285. Trial Staff argues that, even if there was merit to Portland’s argument that the burden of proof switched to Trial Staff and PSG, that burden has been readily met.⁴⁰⁶ First, Trial Staff state that Portland previously conceded (Initial Brief at 60) that in 1999, well after the certificate orders were issued, compression was added to serve Portland’s shippers. Second, Trial Staff states its witness Steffy testified, without dispute by Portland, that the “Commission placed Portland at risk for the recovery of costs of the unsubscribed firm capacity.”⁴⁰⁷ Third, Trial Staff states that it is undeniable that Portland’s current firm system capacity is 210,840 Dth per day⁴⁰⁸ and Portland designed its rates based on billing determinants of 210,840 Dth per day.

286. Similarly, PSG contends that Portland claim that “since 1999, no compression has been added either to Portland or TQM [Trans-Quebec & Maritimes] to serve Portland’ shippers,” appears to be for the purpose of creating the misleading impression that Portland capacity did not actually increase to 210,000 Mcf per day following its first year of operation, as had originally been anticipated. PSG argues that that statement ignores record evidence establishing that since its very first year of operation, Portland has consistently reported and maintained system capacity of 210,000 Mcf per day and more, just as had been anticipated at the time of its system certification. Therefore, it argues, regardless of whether Trans-Quebec & Maritimes actually installed further compression “since 1999” or not, the record establishes that Portland has nonetheless been able to achieve and maintain physical capacity in excess of 210,000 Mcf per day throughout its operational history.

287. Portland argues that PSG’s claim that Portland’s at-risk condition should be set at 217,405 Dth per day is not supported by the evidence and should be rejected. First, Portland states that there is a direct relationship between its total firm system capacity (including both the Joint Facilities and the Northern Facilities) and the distribution of

⁴⁰⁵ *Id.* at 56 (citing Ex. PSG-1 at 32).

⁴⁰⁶ Trial Staff Brief Opposing Exceptions at 54.

⁴⁰⁷ *Id.* (citing Ex. S-9 at 7; Tr. 2056-57).

⁴⁰⁸ *Id.* (citing Ex. S-9 at 5).

deliveries on Portland's system.⁴⁰⁹ Thus, its firm system capacity must be determined by reference to the pipeline as a whole, and cannot be derived simply by adding the deliveries on the Northern Facilities to the capacity of the Joint Facilities. This is especially true because approximately 95 percent of Portland's firm contracts have delivery points on the Joint Facilities.

288. Second, Portland states that the sources cited by PSG reflect Portland's operationally available capacity, not its firm system capacity. Portland states that the Commission's order requiring the filing of Operationally Available Capacity report, i.e., Order No. 637, recognizes this fact by noting that natural gas pipelines can use at least three different measures of capacity: available capacity, scheduled capacity, and design capacity.⁴¹⁰ Moreover, Portland argues, because "the Commission's regulations do not allow for flexible compliance [with the posting regulations] due to weather conditions, holidays, or other such circumstances,"⁴¹¹ some of the sources cited by PSG as evidence of Portland's purported firm system capacity do not necessarily take into account the impact of those types of changing conditions that affect maximum capacity available from time to time. Portland states that, as a result, reports of a pipeline's operationally-available capacity may reflect capacity numbers which far exceed the pipeline's firm, sustainable capacity. For this reason, Portland argues, the Commission has held that it is inappropriate to hold a pipeline at risk for its operationally- or temporarily-available capacity.⁴¹² Portland states that, while operational capacity may have existed based upon operating conditions that could have permitted Portland to provide a total amount of service above 210,840 Dth per day, those levels were simply not sustainable by Portland on a consistent, year-round basis.

289. Portland also objects to PSG's claim that Portland's at-risk condition should be permanently established in this proceeding on the basis that it constitutes a collateral attack on the Commission's determination in Docket No. CP08-70-000 that once

⁴⁰⁹ Portland Brief Opposing Exceptions at 34 (citing Tr. 1135:22-1136:2).

⁴¹⁰ *Id.* at 32 (citing *Regulation of Short-Term Natural Gas Transportation Services and Regulation of Interstate Natural Gas Transportation Services*, FERC Stats & Regs. ¶ 31,091, at 31,321 (2000)).

⁴¹¹ *Id.* at 32 (citing *Natural Gas Pipeline Co. of America*, 82 FERC ¶ 61,038, at 61,163 (1998)).

⁴¹² *Id.* at 33 (citing *Gulfstream Natural Gas System, L.L.C.*, 98 FERC ¶ 61,349, at 62,479 (2002) (citing *Maritimes II*, 87 FERC ¶ 61,061 (1999), *order on reh'g*, 89 FERC ¶ 61,123 at 61,334 & n.9 and 61,337, *order on reh'g*, 93 FERC ¶ 61,117 (2000)); *Gulf Crossing Pipeline Co.*, 123 FERC ¶ 61,100, at P 36 (2008)).

Maritimes/Northeast placed its Phase IV Expansion into service, Portland's firm year round capacity would be no more than 168,000 Mcf per day on a firm year-round basis.⁴¹³

Commission Determination

290. For the reasons discussed below, we affirm the ALJ's decision to establish Portland's at-risk condition at a level of 210,840 Dth per day. We agree with the ALJ that in both the July 1997 Certificate Order and September 1997 Certificate and Rehearing Order, the Commission intended to base Portland's at-risk condition on the actual capacity of the pipeline and to place Portland at-risk for any unsubscribed capacity. As the ALJ stated, the Commission in the September 1997 Certificate and Rehearing Order "only delayed increasing the at-risk condition to a figure above 178,000 Mcf/day ... until Maritimes' upstream facilities went into service and the capacity actually increased."⁴¹⁴ Given that the Commission only deferred the issue until Portland's next section 4 case (now this case because the first such case was settled), the burden of proof was squarely on Portland in this case to confirm its current firm system capacity for at-risk purposes.

291. We also agree with the ALJ that 210,840 Dth per day is the appropriate level at which to set the at-risk condition. Portland readily admits that its firm system capacity at the end of the test period is 210,840 Dth per day.⁴¹⁵ Trial Staff also agrees that this figure represents firm system capacity at the end of the test period.⁴¹⁶ While PSG concedes that Portland's contractual volumetric capacity entitlement on the Joint Facilities is 210,000 Mcf per day,⁴¹⁷ PSG argues that 217,405 Dth per day better represents current sustainable capacity on Portland's system and therefore, should determine the at-risk level.

292. As explained by Portland, there is a direct relationship between Portland's total firm system capacity (including the Joint Facilities and Northern Facilities) and the

⁴¹³ *Id.* at 35 (citing *Portland Natural Gas Transmission System*, 123 FERC ¶ 61,275, at P 28, *reh'g denied*, 125 FERC ¶ 61,198, at P 15 (2008); *PNGTS Shippers' Group v. FERC*, 592 F.3d 132 (D.C. Cir. 2010)).

⁴¹⁴ *Id.*, 129 FERC ¶ 63,027 at P 320. *See also Portland Natural Gas Transmission System*, 123 FERC ¶ 61,275, *reh'g denied*, 125 FERC ¶ 61,198.

⁴¹⁵ *Id.*, 129 FERC ¶ 63,027 at P 321.

⁴¹⁶ *Id.* P 302-303.

⁴¹⁷ *See* PSG Brief on Exceptions at 61.

distribution of deliveries on its system. Portland Witness Haag described this relationship stating that, “as North System deliveries fall off, our total end to end firm system capacity approaches – or it becomes the 210,840.”⁴¹⁸ In light of this, we believe that for purposes of determining Portland’s at-risk condition, the ALJ was correct to determine Portland’s firm system capacity based on the pipeline as a whole. This is especially true because, as Portland points out, approximately 95 percent of Portland’s firm contracts have delivery points on the Joint Facilities.

293. With respect to the level of billing determinants for ratemaking purposes, the Commission finds that Portland must recalculate such determinants consistent with the discussion below.

B. Credit for Interruptible Transportation (IT) or Parking and Lending Revenues (PAL)

Background

294. The Commission’s “long-standing policy regarding new interruptible services requires either a 100 percent credit of interruptible services, net of variable costs, to firm and interruptible customers or an allocation of costs and volumes to such services.”⁴¹⁹ In its original certificate application, Portland proposed not to allocate any costs to its interruptible services. Therefore, the Commission required Portland to credit 100 percent of its interruptible revenues against its cost-of-service.⁴²⁰ However, in its amended certificate application, Portland allocated costs and volumes to its Rate Schedule IT service.⁴²¹ Accordingly, the Commission accepted Portland’s proposal, stating that “[b]ecause Portland has now allocated costs to Rate Schedule IT service, we will allow Portland to retain its Rate Schedule IT revenues, and not credit them to firm shippers as we had formerly required.”⁴²² Portland’s settlement of its last rate case continued to allocate costs and volumes to its interruptible services.

⁴¹⁸ See Tr. 1135:22-1136:2.

⁴¹⁹ *Wyoming Interstate Co., Ltd.*, 121 FERC ¶ 61,135, at P 9 (2007).

⁴²⁰ See, e.g., ID at P 228 (citing PSG Initial Brief at 6 (citing 1996 Certificate Order, 76 FERC at 61,661)).

⁴²¹ July 1997 Certificate Order, 80 FERC at 61,451.

⁴²² *Id.*

Initial Decision

295. In this rate case, Portland has proposed to design its rates based upon its design capacity of 210,840 Dth per day, without any express allocation of costs to its Interruptible Transportation (IT) and Parking and Lending (PAL) services. It also proposed not to credit its cost-of-service with any test period IT or PAL service revenues. While acknowledging that Commission policy requires IT customers to contribute to the recovery of a pipeline's fixed costs based on an estimated volume of interruptible transportation,⁴²³ Portland argued that policy is inapplicable in this case. It explained that it is already "at risk" for any under collection of its costs, as it has derived its rates using full year round capacity in effect at the end of the test period without seeking an adjustment for unsubscribed capacity. Specifically, Portland stated that under its proposed billing determinants of 210,840 Dth per day, it is at risk for all capacity between 210,840 Dth per day and what it can actually sell in the market as discretionary or firm transportation capacity. Portland stated that requiring it to credit the IT/PAL revenues would double-count the revenue it receives from these services. Further, Portland stated that if it were required to credit the IT/PAL revenues, it "would not be able to recover its cost-of-service unless it sells 100 percent of its unsubscribed capacity at full, non-discounted rates and collects IT and PAL revenues over and above the proposed credit amount."⁴²⁴ Portland asserted that because Portland has never been able to sell all of its unsubscribed capacity at full, non-discounted rates, crediting the pipeline's cost-of-service with the IT/PAL revenues is unjust.⁴²⁵

296. CES, PSG and Trial Staff argued at hearing that Portland's assertion that its IT/PAL revenues should not be credited against its cost-of-service is without merit.⁴²⁶ PSG and Trial Staff pointed out that the Commission has traditionally employed two methods to account for the revenues that a natural gas pipeline receives for non-firm services: (a) the Commission has required the pipeline to allocate costs to interruptible pipeline customers based on an estimated volume of interruptible transportation; or (b) in the alternative, the Commission has required the interruptible service revenues be credited against the pipeline's cost-of-service.⁴²⁷ CES, PSG and Trial Staff stated that

⁴²³ ID, 129 FERC ¶ 63,027 at P 223 (citing PNG Initial Brief at 44-45; Ex. PNG-60 at 5-6).

⁴²⁴ *Id.* (citing PNG Initial Brief at 44-45).

⁴²⁵ *Id.* P 223-24 (citing PNG Initial Brief at 45; Ex. PNG-60 at 4).

⁴²⁶ *Id.* P 226-234.

⁴²⁷ *See, e.g.,* ID at P 227 (citing PSG Initial Brief at 91 (citing *AES Sparrows Point LNG, LLC*, 126 FERC ¶ 61,019, at P 52 (2009))).

Portland proposed neither a cost allocation to IT and PAL services nor a revenue crediting mechanism for Portland's IT/PAL revenues. Accordingly, they propose that Portland's cost-of-service be credited with its Test Period IT/PAL service revenues. PSG asserted that during the test period Portland's IT revenues were \$2,814,550 and its PAL revenues were \$545,972, and thus PSG proposed a total revenue credit of \$3,360,522.⁴²⁸ Trial Staff witness Steffy recommended that \$3,360,528 be credited to the firm shippers in the form of a cost-of-service credit, which is a six dollar discrepancy from PSG witness Fink's recommendation of \$3,360,522.⁴²⁹

297. CES, PSG and Trial Staff argued that a credit for IT/PAL service revenues against Portland's cost-of-service is consistent not only with longstanding Commission policy, but also with the earlier certificate order permitting construction and operation of the Portland system. PSG and Trial Staff stated that the Commission's 1996 Certificate Order required Portland to credit 100 percent of the IT revenues to its firm shippers because Portland did not allocate costs to the IT service.⁴³⁰ PSG and Trial Staff stated that, in the subsequent July 1997 Certificate Order, the Commission reiterated its policy that Portland must either allocate IT costs or credit all of IT revenues to its cost-of-service, but allowed Portland to forego revenue crediting because Portland proposed a specific allocation of costs and volumes to IT services.⁴³¹ Further, PSG noted that in addition to requiring Portland to credit 100 percent of its IT revenues to its cost-of-service, the 1996 Certificate Order placed Portland at-risk for its total annualized capacity,⁴³² a fact that Trial Staff contended was conceded to by Portland Witness Haag.⁴³³

298. PSG argued that it is not punitive both to hold the pipeline at-risk for system capacity and to require a credit for its interruptible revenues. PSG stated that such a

⁴²⁸ ID, 129 FERC ¶ 63,027 at P 226 (citing PSG Initial Brief at 90, 92 (citing Ex. PSG-1 at 34-35; Ex. S-9 at 8-9)).

⁴²⁹ *Id.* P 233.

⁴³⁰ *See, e.g.*, ID at P 228 (citing PSG Initial Brief at 6 (citing 1996 Certificate Order, 76 FERC at 61,661)).

⁴³¹ *See, e.g.*, ID at P 228 (citing PSG Initial Brief at 8 (citing July 1997 Certificate Order, 80 FERC at 61,447-51)).

⁴³² *Id.* P 228 (citing PSG Initial Brief at 6 (citing 1996 Certificate Order, 76 FERC at 61,664-50)).

⁴³³ *Id.* P 234 (citing Trial Staff Initial Brief at 55 (citing Tr. 1500-01)).

requirement is no more punitive than the conditions accepted by Portland as part of its original certificate authorization which both held Portland at-risk and required Portland to credit 100 percent of the IT revenues to its firm shippers. CES also stated that Portland's "double-counting" argument regarding the IT/PAL revenues was rejected by the Commission in *Trailblazer*.⁴³⁴

299. PSG and CES also argued that Portland improperly relies on *Kern River*. PSG contends that the passage of the *Kern River* opinion that Portland relies on, including succeeding paragraphs, does not support the elimination of all IT revenue credits. PSG stated that, because Kern River included in its billing determinants the 90,000 Dth per day of capacity that was associated with the bankrupt shipper, Mirant Corporation (Mirant), Kern River was permitted to reduce — though not to eliminate — its market-oriented revenue credit⁴³⁵ by the \$5.185 million in IT revenue attributable to the remarketing of the 90,000 Dth per day of capacity.⁴³⁶ Thus, PSG argues, "*Kern River* does not support elimination of all interruptible or discretionary service revenue credits, just reductions of those credits to the extent associated with revenue attributable to the capacity held by its bankrupt former shippers."⁴³⁷ Further, CES noted that the \$5.185 million was only a fraction of the approximately \$20.2 million in market-oriented revenues that Kern River obtained during the last 12 months of the test period.⁴³⁸ CES

⁴³⁴ *Id.* P 231 (citing CES Reply Brief at 25; *Trailblazer*, 80 FERC ¶ 61,141).

⁴³⁵ *Kern River*, Opinion No. 486-A described the market-oriented revenue credit as follows:

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

123 FERC ¶ 61,056 at P 277.

⁴³⁶ *Id.* P 230 (citing PSG Reply Brief at 39 (citing Opinion No. 486, 117 FERC ¶ 61,077 at P 370, 385)).

⁴³⁷ *Id.*

⁴³⁸ *Id.* P 232 (citing CES Reply Brief at 25 (citing Opinion No. 486-A, 123 FERC ¶ 61,056 at P 278)).

stated that this meant that about \$15 million flowed back to the pipeline's firm shippers as a cost-of-service credit.

300. In the ID, the ALJ found that Portland's cost-of-service should be credited by \$3,360,522, the IT/PAL revenues during the Test Period.⁴³⁹ The ALJ agreed with PSG, CES and Trial Staff that the Commission's 1996 and 1997 Certificate Orders already addressed this issue making clear that Portland must either allocate some of its costs to IT service or credit its IT/PAL revenues to FT customers.⁴⁴⁰ Further, the ALJ agreed that Portland witness Haag had conceded in his testimony that these same orders, in addition to requiring Portland to allocate some of its costs to IT service or credit its IT/PAL revenues to its FT customers, also held Portland at risk for its unsubscribed firm capacity.⁴⁴¹

Briefs on Exceptions and Opposing Exceptions

301. Portland excepts to the ALJ's decision, arguing, as it did previously, that setting its rates based on its full year round capacity negates any justification for crediting IT/PAL revenues and that *Kern River* supports this result. Portland claims that the Commission's policy goal behind crediting IT/PAL revenues to the firm cost-of-service – namely, to prevent the firm customers from paying all of the system's fixed costs – has already been achieved by Portland's proposed billing determinants of 210,840 Dth per day, without crediting IT/PAL service revenues, including those revenues obtained from service using some of the capacity that was de-contracted as a result of the bankruptcy of Calpine Corporation (Calpine) and its affiliates.

302. Furthermore, Portland argues that since the Commission's 1996 Certificate Order, the circumstances surrounding the operation of Portland have changed dramatically given changes in market circumstances and loss of long-term FT contracts. The crediting of the IT/PAL revenues, Portland contends, not only denies Portland a realistic opportunity to recover its costs and revenue requirements, particularly when combined with the requirement to credit a portion of its bankruptcy proceeds to cost-of-service, but also imparts an unjust gain to the remaining shippers on Portland. Portland argues that this again would violate the *Hope/Bluefield* standard (discussed [above] at [P 73]), as well as

⁴³⁹ *Id.* P 235.

⁴⁴⁰ *Id.* (citing 1996 Certificate Order, 76 FERC at 61,661; July 1997 Certificate Order, 80 FERC at 61,447-51).

⁴⁴¹ *Id.* P 235 (citing Tr. 1500-01).

the holding in *Trailblazer*, and prevent Portland from earning a reasonable amount on its investment.⁴⁴²

303. Portland maintains that Portland's retention of IT/PAL service revenues is supported by *Kern River* which allowed the pipeline to retain discretionary service revenues from remarketing capacity because the pipeline included the related billing determinants in its derivation of rates.⁴⁴³ Portland states that the IT/PAL revenue earned by Portland helps to replace, in part, revenue lost due to rejected contracts that would have otherwise been earned from Portland's firm year-round capacity had the rejected contracts not been lost through the bankruptcy of Calpine. Therefore, Portland states, crediting the IT/PAL service revenues will effectively prevent Portland from recovering its costs. Portland states that it would be unduly punitive to require Portland to credit revenue proceeds simply because the capacity was sold on an interruptible, rather than firm basis, particularly when that revenue is necessary to achieve Portland's revenue requirements.⁴⁴⁴

304. CES, Trial Staff and PSG argue that Portland's exceptions should be rejected, for reasons similar to those described in the ID.⁴⁴⁵ CES argues that Portland's witness Haag's admission that the same Commission order that imposed the pipeline's at-risk condition also required the pipeline to either allocate costs to IT service or credit those revenues to its FT customers negates Portland's contention that its at-risk condition eliminates the need for IT/PAL revenue crediting in this case.⁴⁴⁶ PSG argues that Portland's exception to the ALJ's decision amounts to a collateral attack on the rate design terms of its certificate order.

305. CES, Trial Staff and PSG also maintain that Portland misreads *Kern River*. PSG argues that, in *Kern River*, the Commission made clear that even though Kern River was required to design its rates using billing determinants equal to 100 percent of its design capacity, it was nonetheless required to credit IT revenue of \$20.2 million reduced by

⁴⁴² Portland Brief on Exceptions at 31 (citing *Hope*, 320 U.S. 591, 603; *Bluefield*, 262 U.S. 679; and *Trailblazer*, 81 FERC ¶ 61,032 at 61,172).

⁴⁴³ *Id.* at 31-32 (citing *Kern River*, Opinion No. 486, 117 FERC ¶ 61,077 at P 382-84).

⁴⁴⁴ *Id.* at 32 (citing Tr. 2054:21-2055:3).

⁴⁴⁵ CES Brief Opposing Exceptions at 39; Trial Staff Brief Opposing Exceptions at 29; PSG Brief Opposing Exceptions at 44.

⁴⁴⁶ CES Brief Opposing Exceptions at 39-40 (citing Tr. At 1500-1501).

\$5.2 million attributable to the remarketing of bankruptcy-related capacity on an interruptible basis.⁴⁴⁷ Thus, in *Kern River*, PSG argues, the pipeline was still required to credit significant IT revenue to its cost-of-service, but was permitted to reduce that credit to reflect the remarketing of bankruptcy-related capacity in a circumstance in which it had not already received compensation for that capacity through the recovery of substantial bankruptcy proceeds. PSG argues that Portland ignores the facts that in that *Kern River*: (i) the pipeline had remarketed its bankruptcy-related capacity as IT service (not short-term firm service, as Portland has done); (ii) the pipeline had not also received substantial compensation for the bankruptcy-related capacity through the recovery of bankruptcy proceeds prior to the end of the Test Period; and (iii) the pipeline was nonetheless required to credit all of its substantial IT revenues remaining after reduction for those attributable to bankruptcy-related capacity.

306. Regarding Portland's assertion that the crediting of \$3.6 million in IT/PAL revenues to its shippers would deny it a realistic opportunity to recover its cost and revenue requirements, Trial Staff states that Portland has made no showing that by following applicable Commission precedent with respect to IT/PAL revenues, the ALJ contravened the standards set forth in *Hope* and *Bluefield*. Trial Staff states that Portland's catch-all generic argument should be afforded no credence. Similarly, PSG states that the record does not support any such violation, as it establishes that during the Test Period, in addition to its long-term firm contract revenues, Portland also recovered well over \$100 million in bankruptcy proceeds as well as approximately \$12 million in short-term firm contract revenues.

Commission Determination

307. Prior to this rate case, Portland allocated costs to its interruptible IT and PAL services based upon projected volumes of interruptible transportation. Portland did not credit any interruptible revenues against its cost-of-service. In this section 4 rate case, Portland has proposed to design its rates based upon its design capacity of 210,840 Dth per day, without any express allocation of costs to its IT and PAL services based upon projected volumes of interruptible transportation. Portland has also proposed to continue its preexisting practice of not crediting any interruptible revenues against its cost-of-service. For the reasons discussed below, the Commission reverses the ALJ's recommendation that Portland be required to credit its IT/PAL revenues against its cost-of-service. Instead, the Commission will require Portland to allocate costs to its IT/PAL service based upon a projected volume of interruptible transportation, consistent with the cost allocation and rate methodology underlying its preexisting rates, subject to the

⁴⁴⁷ Opinion No. 486-A, 123 FERC ¶ 61,056 at P 74, 277-284.

condition that Portland's overall rate design volumes must satisfy the at-risk condition discussed in the previous section.

308. In this case, Portland has the burden under NGA section 4 to show that its proposal to design its rates based upon its design capacity of 210,840 Dth per day without any express allocation of costs and volumes to its IT and PAL services is just and reasonable. That proposal represents a change from Portland's prior practice of allocating costs and volumes to its IT and PAL services. However, if the Commission finds that Portland has not satisfied its section 4 burden of proof, the Commission would have to satisfy a dual burden under NGA section 5 before it can require Portland to credit interruptible revenues against its cost-of-service. Because Portland has not previously credited interruptible revenues against its cost-of-service and did not propose to do so in the rate case, any requirement that Portland credit such revenues against its cost-of-service would constitute a change in its existing rate design of allocating costs and volumes to interruptible services without any revenue credit. As the court held in *Western Resources*, before the Commission can impose its own rate design, it must show that: (1) the default position, the preexisting rate design, is unjust and unreasonable; and (2) the Commission's proposed rate design is just and reasonable.⁴⁴⁸ Accordingly, in this case, in order for the Commission to require Portland to credit its interruptible IT and PAL revenues against its cost-of-service, the Commission would have to show not only that Portland failed to support its section 4 proposal, but also: (1) that its preexisting rate design of allocating costs to interruptible service without a revenue credit is unjust and unreasonable; and (2) that a revenue credit is just and unreasonable.

309. Portland has sought to satisfy its section 4 burden of justifying its proposed rate design volumes of 210,840 Dth per day based solely upon the fact those rate design volumes equal its firm system capacity. Portland has made no effort to show what its rate design volumes would be under its preexisting method of allocating costs to its interruptible IT and PAL services based upon projected volumes of interruptible transportation. The mere fact, standing alone, that Portland's proposed rate design volumes equal its design capacity is not sufficient to show that those rate design volumes are just and reasonable. The Commission's Part 284 regulations generally require that a pipeline design its rates based upon its projected units of service for all its services.⁴⁴⁹ It is not unusual for a pipeline's rate design volumes to exceed its design capacity. To take a simple example, a pipeline's capacity may be fully subscribed by long-term firm

⁴⁴⁸ *Western Resources*, 9 F.3d at 1578.

⁴⁴⁹ 18 C.F.R. § 284.10(c)(2) (2010), requiring that pipelines to design their rates based on projected units of service. See also *Panhandle Eastern Pipe Line Co.*, 74 FERC at 61-385-86.

shippers paying the maximum rate, but the pipeline may also provide interruptible service when its firm shippers are not making full use of their capacity. In that situation, the pipeline's total firm and interruptible billing determinants would exceed its design capacity. Therefore, in a case such as this, where the pipeline is subject to an at-risk condition, Commission policy generally requires that the pipeline's rates be designed based upon the greater of its projected billing determinants or the volumetric level of the at-risk condition.⁴⁵⁰

310. It follows that Portland's proposed rate design volumes of 210,840 Dth per day are only just and reasonable if its projected units of service for all firm and interruptible services are 210,840 Dth per day or less. Therefore, determining whether Portland's proposed rate design volumes are just and reasonable requires that its interruptible billing determinants be projected, along with its firm billing determinants. The Commission generally projects interruptible billing determinants based upon its interruptible throughput during the last twelve months of the base period.⁴⁵¹ Portland's actual IT volumes during the last twelve months of the test period were 8,063,673 Dth and 1,325,677 Dth for IT and PAL services, respectively.⁴⁵²

311. Portland states that in order to obtain this interruptible throughput it had to offer significant discounts. PSG and Trial Staff, in their examination of Portland's IT and PAL revenues, did not object to any of these discounts,⁴⁵³ and the ALJ recommended that all IT and PAL revenue (including revenue from discounted services) be credited to the cost-of-service. The Commission has held that qualified discounting benefits all customers by allowing the pipeline to spread its fixed costs across more units of service. Therefore, in order to avoid a disincentive to discounting, the Commission has stated that, in the next rate case after giving discounts, the pipeline need not design its rates on the assumption that the discounted volumes would flow at the maximum rate. Rather the pipeline is permitted to reduce the discounted volumes used to design its rates so that, assuming market conditions require to continue giving the same level of discounts when the new rates are in effect that it gave during the test period, the pipeline will be able to recover 100 percent of its cost-of-service (subject in this case to compliance with Portland's at-

⁴⁵⁰ See *Kern River*, Opinion No. 486-A, 123 FERC ¶ 61,056 at P 86, citing.

⁴⁵¹ *Trunkline Gas Co.*, Opinion No. 441, 90 FERC ¶ 61,017 at 61,081-82 (2000) (*Trunkline*).

⁴⁵² Ex. S-10.

⁴⁵³ Ex. PSG-1 at 34:22 and Ex. S-9 at 9:7-9.

risk condition).⁴⁵⁴ The discount adjustment to projected billing determinants may be carried out using what is referred to as the ratio method. Under that method, the volumes that flowed at a discount are adjusted by multiplying them by the ratio of the pipeline's average discounted rate to its just and reasonable rate established in the subject rate case.⁴⁵⁵ Accordingly, consistent with Commission policy, Portland may reduce the projected interruptible IT and PAL annual volumes that underlie the PSG and Trial Staff exhibits showing Portland's IT and PAL revenues to account for discounting.⁴⁵⁶ This adjusted amount is converted to a daily amount by dividing it by 365, and then adding it to Portland's projected firm billing determinants (which may also be discount adjusted) to determine whether its overall projected billing determinants are less than or greater than its design capacity of 210,840 Dth per day.

312. We recognize that as of the end of the test period, Portland had long-term maximum rate firm contracts for only 156,600 Dth per day in the summer and 170,200 Dth per day in the winter of its 210,840 Dth per day design capacity,⁴⁵⁷ because of the loss of the Androscoggin Energy LLC (Androscoggin) firm contract (Androscoggin Agreement) and the Rumford Agreement due to Calpine's bankruptcy.⁴⁵⁸ However, as discussed in the next section, in light of the substantial bankruptcy award received by Portland, the Commission is requiring the 62,000 Dth per day of contract demand associated with the Androscoggin and Rumford Agreements to be included in Portland's rate design volumes, subject to a discount adjustment to reflect the fact the bankruptcy award only partially compensated Portland for loss of those maximum rate contracts. In addition, Portland performed some short-term firm service during the last twelve months of the test period. Portland's projected units of service should also include projected

⁴⁵⁴ *Rate Design Policy Statement*, 47 FERC ¶ 61,295 at 62,056-57 (1989). *Williston I*, 67 FERC ¶ 61,137 at 61,379. *Trunkline*, Opinion No. 441, 90 FERC ¶ 61,017 at 61,086.

⁴⁵⁵ *See Williston III*, 84 FERC ¶ 61,081 at 61,401-02, for a description of the somewhat complicated iterative mathematical computation used to carry out the ratio discount adjustment method.

⁴⁵⁶ Ex. S-10 and PSG-1 at 34:19-21. The ID at P 233 noted a six dollar discrepancy between the exhibits, which the Commission does not view as significant. *See also* Portland 2008 Rate Filing, Schedule G-1; and Ex. PNG-84, Portland's 45-day update filing, Schedule G-1.

⁴⁵⁷ Ex. PNG-26 at 3, Table 1.

⁴⁵⁸ The Rumford Agreement was discussed above in relation to the Levelization Deferral Period in this proceeding.

short-term firm billing determinants as adjusted to account for any discounts necessary to obtain the short-term firm service.

313. As in other cases involving discount adjustments using the ratio method, Portland will have to calculate the actual discount adjustments in the compliance filing required by this order.⁴⁵⁹ That is because the calculations must be based on all the findings in this order concerning Portland's costs of service. If Portland's total adjusted projected billing determinants, as determined in that compliance filing are less than or equal to its design capacity of 210,840 Dth per day, then consistent with the at-risk condition, its rates should be designed using total billing determinants of 210,840 Dth per day. If Portland's total adjusted projected billing determinants exceed 210,840 Dth per day, then those projected billing determinants should be used to design its rates.

314. In either case, Portland's rates should be just and reasonable, without the need to take action under section 5 to require Portland to credit its interruptible revenues against its cost-of-service (or its bankruptcy revenues, as discussed in the next section). That is because in both cases, Portland's rates will already reflect a full allocation of costs to its interruptible services. If Portland's total billing determinants equal or exceed 210,840 Dth per day, that allocation will be based on its actual projected IT and PAL billing determinants. If Portland's total billing determinants are less than 210,840 Dth per day, then the at-risk condition will effectively require a greater allocation of costs to interruptible services than required by a traditional projection of interruptible billing determinants. The Commission's policy is "to require a pipeline *either* to allocate costs to interruptible service *or* to credit revenues from such service."⁴⁶⁰ Therefore, because Portland will be allocating costs to its interruptible service, Commission policy does not require that it also credit revenues from that service to its cost-of-service. Accordingly, there is no basis for section 5 action to require such crediting.⁴⁶¹

⁴⁵⁹ *Id.* The Commission recognizes that the iterative ratio and iterative revenue credit discount adjustment methods lead to identical results. However, in this case, the Commission requires Portland to use the ratio method in its compliance filing for all its billing determinant discount adjustments. This requirement will simplify the review process for both the public and the Commission.

⁴⁶⁰ *Overthrust Pipeline Co.*, 83 FERC ¶ 61,003 at 61,014 (1998) (emphasis supplied).

⁴⁶¹ Some parties appear to equate the Commission's initial rate revenue credit condition with the rate design technique of crediting interruptible revenue to the revenue requirement. These are not equivalent tools and they do not lead to identical results. The initial rate revenue credit condition calculates the maximum recourse rate with either total
(continued...)

C. Androscoggin and Rumford Bankruptcy Proceeds

Background

315. Also among the issues raised before the ALJ at hearing was to what extent, if any, Portland should be entitled to retain the \$119,761,258 in gross bankruptcy proceeds that it received from the termination of the Androscoggin and Rumford Agreements (the rejected contracts). Prior to the base period (12 months ended December 31, 2007) in this case, Portland had 20-year firm transportation (FT) agreements in effect with Androscoggin and Rumford. The Androscoggin Agreement covered 18,000 Dth per day and was to run through October 31, 2019; the Rumford Agreement covered 44,000 Dth per day and was to run through October 31, 2020. The Androscoggin and Rumford Agreements were terminated as part of the bankruptcy proceedings of Calpine and its affiliates, resulting in the aggregate termination of 62,000 Dth per day of maximum firm delivery commitments on the Portland system.⁴⁶² Portland filed bankruptcy claims as a result of those contract terminations and on the basis of such claims, recovered a net total of \$119,761,258 in bankruptcy proceeds before and during the test period (period ending September 30, 2008) in this case.

316. The \$119,761,258 in net proceeds consisted of the sums of \$16,460,850 of cash distributions from the Androscoggin estate, \$2,250,000 of credit collateral posted by Androscoggin, and \$103.1 million obtained from the sale of stock of the reorganized Calpine distributed as part of the Rumford bankruptcy proceeding, minus \$2,088,742 of Portland legal fees related to the bankruptcy recoveries. The Androscoggin recoveries occurred largely during 2006 and 2007. The \$103.1 million in recovery from Rumford occurred in February 2008, during the test period in this case. Portland expects to receive further recoveries — up to \$125 million in total recoveries — as a result of the Rumford bankruptcy, but the exact time and amount of the future recovery is currently unknown.

firm or design capacity billing determinants. This rate may be higher than what is just and reasonable as it lacks any allocation of costs to interruptible services. Maximum rate customers receive, as a credit to their bills, *actual* interruptible revenues, which lowers their effective maximum rate. The rate design technique, in contrast, credits *projected* interruptible revenue to the revenue requirement – which lowers the maximum recourse rate. However, as actual revenues will rarely equal projected revenues, the resulting maximum rates and revenue responsibility will rarely, if ever, be the same.

⁴⁶² Portland Witness Haag testified that the remaining term of the Androscoggin and Rumford Agreements at the time of their rejection were 171 and 172 months, respectively. Ex. PNG-60 at 16.

317. Portland and Trial Staff argued Portland should be entitled to retain all of the bankruptcy proceeds because, among other things, Portland developed its rates based upon its year-round firm system capacity, including 62,000 Dth per day of capacity associated with the rejected contracts. On the other hand, PSG and CES proposed that one half of Portland's bankruptcy proceeds, \$59,880,669, be credited to Portland's rate base. PSG argued that a pipeline does not have a right to recover windfall profits or double-recover capacity costs from its customers and, unless the Commission credited Portland's rate base, Portland would substantially over-recover the costs of capacity associated with the rejected contracts and receive a windfall.

318. As further justification for their position, Portland and Trial Staff argued there was a lack of any identifiable harm to shippers as a result of the bankruptcies and, in fact shippers benefitted from additional capacity made available by the rejected contracts. Portland also argued that PSG's proposal to credit the bankruptcy proceeds to rate base did not consider Portland's generally unsuccessful attempts to re-market the bankruptcy-related capacity, despite holding several open seasons and making daily postings on its electronic bulletin board.

319. Portland acknowledged that it was able to obtain contracts with the new Androscoggin and Rumford generators for two of the approximately 100 months of potential service during the 4 years since the first bankruptcy occurred and that those contracts were obtained at about a 70 percent discount from the maximum tariff rate.⁴⁶³ Portland also acknowledged that it was able to execute four short-term firm contracts during the test period at a level that would not have been possible had the rejected contracts still been in place, but noted that these contracts were in place for only a few months and three of the four contracts were discounted significantly.⁴⁶⁴

320. Portland and Trial Staff also argued that the Commission's decision in *Kern River*⁴⁶⁵ establishes that Portland is entitled to retain the bankruptcy proceeds. Portland stated that in *Kern River* contracts between Kern River and Mirant were rejected during the bankruptcy of Mirant. Portland stated that, because Kern River included the

⁴⁶³ ID, 129 FERC ¶ 63,027 at P 183 (citing PNG Initial Brief at 43; Ex. PNG-60 at 12-13).

⁴⁶⁴ *Id.* P 183-184.

⁴⁶⁵ *Kern River*, Opinion No. 486, 117 FERC ¶ 61,077, *order on reh'g*, Opinion No. 486-A, 123 FERC ¶ 61,056, *order on reh'g*, Opinion No. 486-B, 126 FERC ¶ 61,034, *order on reh'g*, Opinion No. 486-C, 129 FERC ¶ 61,240.

bankruptcy-related capacity in its billing determinants, it was entitled to keep the revenues garnered by the re-marketing of that capacity.⁴⁶⁶

321. As stated above, PSG proposed that one half of Portland's bankruptcy proceeds, \$59,880,669, be credited to Portland's rate base. PSG witness Fink characterized the \$119,761,258 in bankruptcy proceeds Portland received as a prepayment of future revenues that Portland would have received had the rejected contracts remained in effect.⁴⁶⁷ Mr. Fink explained that PSG's proposed credit to rate base is one-half of Portland's net bankruptcy proceeds because over the remaining years of the rejected contracts, Portland will draw on the proceeds to replace the revenues it lost because of the bankruptcies until the balance of the proceeds is zero.⁴⁶⁸ PSG witness Fink testified that this prepayment treatment was similar to the inclusion in rate base of insurance premiums and other costs paid prior to the period in which they are applicable.⁴⁶⁹ CES supported PSG's proposal.

322. Contrary to Portland and Trial Staff, PSG and CES argued that Portland was successful in remarketing the bankruptcy-related capacity, as evidenced by the \$1 million per month Portland collected on average under shorter-term firm contracts.⁴⁷⁰ CES estimates that, when both the bankruptcy proceeds and the shorter-term firm contract revenues are considered, Portland realized an annual over-recovery of about \$9,624,760 from the bankruptcy-related capacity. CES explained the derivation of this \$9,624,760 figure as follows. First, to price the capacity remaining under the rejected contracts, CES argued that it was appropriate to use the rates in effect prior to the rejection of the contracts, as opposed to the rate proposed in this proceeding of \$27.4017 Dth per month. CES argued that using such rate reduces the nominal amount owed Portland from \$287,101,559 to \$268,602,692.⁴⁷¹ Then CES applied a 9 percent NPV discount rate to

⁴⁶⁶ ID, 129 FERC ¶ 63,027 at P 178 (citing Portland Initial Brief at 40 (citing Opinion No. 486, 117 FERC ¶ 61,077 at P 382-384)).

⁴⁶⁷ *Id.* P 186 (citing Ex. PSG-1 at 23-24; PSG Initial Brief at 85).

⁴⁶⁸ *Id.* P 187 (citing Ex. PSG-1 at 24; PSG Initial Brief at 85).

⁴⁶⁹ *Id.* P 186.

⁴⁷⁰ *Id.* P 189 (citing PNG Initial Brief at 21 (citing Ex. PNG-84 at 34-45; Tr. 1312-13, 1340-52, 1368; PSG Initial Brief at 81)).

⁴⁷¹ Androscoggin: 18,000 Dth x \$25.8542/Dth/month x 10 months = \$4,653,756; 18,000 Dth x \$25.2631/Dth/month x 160 months = \$72,757,728. \$4,653,756 + \$72,757,728 = \$77,411,484. Rumford: 44,000 Dth x \$25.2631/Dth/month x 172 months

(continued...)

\$268,602,692 to calculate a total NPV claim of \$150,925,880. CES then subtracted Portland's bankruptcy-related legal fees of \$2,088,742 from its bankruptcy proceeds of \$119,761,258 to arrive at a net recovery for Portland of \$117,672,516. Subtracting this amount from the total NPV claim of \$150,925,880, CES calculated a remaining claim of \$33,253,366 and divided it by 14 (number of years left on the rejected contracts) to calculate Portland's annual revenue shortfall caused by the bankruptcies of \$2,375,240. When CES subtracted this figure from the shorter-term firm revenues of approximately \$12 million per year, CES arrived at \$9,624,760 million in annual over-recoveries.

323. PSG and CES also argued that Portland and Trial Staff misapplied *Kern River*. PSG and CES stated that in none of the Commission's three separate decisions in *Kern River*, Docket No. RP04-274-000, does the Commission address the proper cost-of-service treatment for pipeline bankruptcy proceeds. PSG and CES concluded that the absence of bankruptcy proceeds during the test period in *Kern River* differentiates the *Kern River* proceeding from the instant proceeding.

324. Moreover, CES argued, like PSG, that Portland's receipt of bankruptcy proceeds is more analogous to the Commission's decisions in *Trailblazer Pipeline Co.*⁴⁷² and *Wyoming Interstate Co. (WIC)*⁴⁷³ than to *Kern River*. CES argued that Commission precedent has made clear that payments made to extinguish long-term firm contractual obligations — such as bankruptcy payments, exit fees, or buyout payments — should result in some form of cost-of-service credit to prevent the pipeline from reaping a windfall. CES also argued that these prior Commission decisions reject the contention that retaining the billing determinants associated with terminated shipper contracts eliminates the need for a credit. Citing the Commission's decision in *Algonquin Gas Transmission Co.*, 105 FERC ¶ 61,180 at P 21-22 (2003), CES stated that the Commission agreed with protesters that the pipeline's proposed crediting mechanism should also extend to encompass damages that Algonquin might obtain through a bankruptcy proceeding. CES added that the Commission also stated its general policy on prohibiting a pipeline from receiving a windfall through the retention of buyout payments in *Overthrust Pipeline Co.*, 83 FERC ¶ 61,003 at 61,013 (1998).

= \$191,191,140. Total Lost Revenues: \$77,305,086 + \$191,191,140 = \$268,602,624. ID, 129 FERC ¶ 63,027 at P 204 (citing CES Reply Brief at 20 n.51).

⁴⁷² *Trailblazer Pipeline Co.*, 80 FERC ¶ 61,141 (hearing order), *order on reh'g*, 81 FERC ¶ 61,032 (1997); *see also Trailblazer Pipeline Co.*, 88 FERC ¶ 61,168 (1999) (rehearing order on subsequent settlement) (*Trailblazer*).

⁴⁷³ *Wyoming Interstate Co. Ltd.*, 87 FERC ¶ 61,339 (1999) (*WIC*).

Initial Decision

325. In the ID, the ALJ found that “Portland is recovering twice for capacity associated with the rejected contracts: once through its considerable bankruptcy proceeds and again through its shorter-term firm revenues.”⁴⁷⁴ Accordingly, the ALJ found that, based on Commission precedent, “there should be some recognition of the receipt of these double-collected revenues in the Portland rate structure such as a credit to account for the over-recoveries that Portland has received for the capacity related to the rejected contracts.”⁴⁷⁵ Accordingly, the ALJ recommended that a credit of \$4,886,978 be directly applied to Portland’s cost-of-service to reflect one-half of the estimated annual amount of Portland’s over-recovery.⁴⁷⁶

326. In addition to permitting the sale of the associated capacity twice, the ALJ stated that failing to recognize this benefit in Portland’s rate structure would render the pipeline’s at-risk condition ineffective regarding its bankruptcy-related capacity. The ALJ stated that Portland accepted the expedited certificate proceedings’ conditions, which included the at-risk condition, and Portland’s receipt of the bankruptcy proceeds should not afford it a release from this certificate condition.

327. The ALJ also found with PSG that the fact that the bankruptcy proceeds are taxable does not affect the analysis because Portland’s claimed revenue shortfall of \$1.6 million per month was also based on a pretax revenue calculation.

328. Like PSG and CES, the ALJ did not believe that *Kern River* was analogous to the instant proceeding. The ALJ found that Portland’s attempt to demonstrate that the Commission in *Kern River* considered the pipeline’s receipt of bankruptcy proceeds was unpersuasive. As PSG and CES pointed out, the ALJ stated that the Commission never addressed Kern River’s receipt of substantial bankruptcy proceeds in any of the three

⁴⁷⁴ ID, 129 FERC ¶ 63,027 at P 213.

⁴⁷⁵ *Id.*

⁴⁷⁶ \$4,886,978 is one half of the ALJ’s estimate of Portland’s annual over-recovery of \$9,773,956. The ALJ arrived at the \$9,773,956 figure by making one adjustment to CES’ \$9,624,760 estimate for Portland’s annual over-recovery. The ALJ found that that Portland witness Haag improperly double-counted the \$2,088,742 in legal costs that Portland incurred to obtain the bankruptcy proceeds, as this amount was already factored in Portland’s net proceeds of \$119,761,258. Accordingly, the ALJ divided \$2,088,742 by 14 years (approximate number of years left of rejected contracts), and added that amount (\$149,196) to CES’ estimate of Portland’s over-recovery of revenue of \$9,624,760 to reach \$9,773,956. ID at P 216.

Kern River orders in the Docket No. RP04-274 proceeding. The ALJ stated that the bankruptcy proceeds in Kern River had not been awarded until after the end of the test period and had not been received until after the evidentiary record had closed.

Briefs On Exceptions

329. Portland and Trial Staff contend that the decision to credit any bankruptcy proceeds was in error. Among other things, they argue that: (a) the ID improperly relies upon untimely arguments presented by CES; (b) it has not double-collected the value of bankruptcy-related capacity; (c) the ID contravenes standards established by the Supreme Court; and (d) the ID is contrary to Commission precedent, in particular, *Kern River*. In support of these exceptions, Portland and Trial Staff advance several of the same arguments that they raised previously.

330. First, citing Rule 706(b)(1)(iii) of the Commission's regulations,⁴⁷⁷ Portland argues that the ALJ erred to the extent she relied upon the arguments presented for the first time in CES' reply brief. Portland states that, prior to its Reply Brief, CES at no time addressed the disposition of bankruptcy receipts. Portland also states that CES did not take any position on the issue of bankruptcy proceeds in the Joint Statement of Issues presented by the participants. Accordingly, Portland argues that CES' arguments were untimely and deprived the other active participants of an opportunity to respond consistent with the procedural schedule adopted in the case.

331. Second, Portland argues that the 4.9 million annual credit is unsupported by the record. Portland argues that the ID did not demonstrate how bankruptcy proceeds recovered by Portland and remarketed bankruptcy-related capacity have equaled or exceeded the amount of revenue that would have been due to Portland in the absence of the bankruptcy.

332. Portland also argues that the ALJ erroneously presumed that the tax consequences of receiving bankruptcy proceeds is the same as those applicable to the stream of revenues that Portland would have received had the rejected contracts remained intact. Portland states that bankruptcy proceeds are treated entirely as income by the Internal Revenue Code, and therefore the proceeds yielded roughly \$71 million after recognition of income tax liability.⁴⁷⁸ Portland contends that, on the other hand, had it received the revenue it was due pursuant to the rejected contracts a substantial amount of that revenue

⁴⁷⁷ Portland Brief on Exceptions at 18 (citing 18 C.F.R. 385.706(b)(1)(iii) (2009)).

⁴⁷⁸ Portland notes that the composite tax rate is roughly 40.6471 percent and $\$119,761,258 - (\$119,761,258 * .406471) = \$71,081,780$. Portland Brief on Exceptions at 19 & n.85.

would not have been subject to any income tax. Specifically, Portland states that while 100 percent of the bankruptcy proceeds are treated as taxable income, only 40 percent of the cash stream would have fallen into that category had the contracts been honored.

333. Trial Staff also contends that there was no evidentiary basis for the ALJ's assumptions that Portland will continue to remarket the capacity sufficient to collect the same revenues as it did during the test period (approximately \$1 million per month) until 2020. Similarly, Portland states that its ability to remarket this capacity at even vaguely compensatory rates over the period associated with the rejected contracts has not been demonstrated (only assumed) and the record reflects that it has no realistic expectation that it will be able to successfully re-contract all of the bankruptcy-related capacity on a non-discounted firm basis for the balance of the terms on the rejected contracts.

334. Third, Portland asserts that if the holdings of the ID are allowed to stand, it would not only fail to recover a reasonable return on its investment, but would also fail to recover its out-of-pocket costs to operate the pipeline. Portland states that using the iterative model found in Ex. PSG-28 and the inputs as determined by the ID, Portland calculated that the total cost-of-service would be \$58,379,351. Portland states that, using the rates set by the ID, it also calculated its projected revenues to be \$37,228,221.⁴⁷⁹ Portland states that even if one were to attribute earnings on bankruptcy proceeds using a hypothetical 10 percent return (which is well in excess of both the after-tax cost of capital set for Portland in the ID and current interest rates),⁴⁸⁰ the result would be only \$41,446,915 in revenue.⁴⁸¹ Portland states that, given these results, it is nevertheless clear that Portland would still operate with an annual cost-of-service shortfall of \$16,932,436 (roughly 29 percent of the cost-of-service) under the ID.⁴⁸² This shortfall, Portland contends, conflicts with Commission precedent that requires Portland be afforded at least a reasonable opportunity to recover its cost-of-service, including a

⁴⁷⁹ Projected revenues = (Net FT Recourse Rate * Annual FT capacity * 365 days) + (Net FT Recourse * 1.9 * Winter FT capacity * 151). \$37,228,221 = (\$0.7586 * 76,600 * 365 days) + (\$0.7586 * 1.9 * 73,600 * 151). Net FT Recourse Rate = Total Cost-of-service / 365 days / billing determinants. \$0.7586 = \$58,379,351 / 365 days / 210,840 Dth per day. Portland Brief on Exceptions at 23 n.114.

⁴⁸⁰ Net bankruptcy earnings = (10% * \$71,078,154) - (40.6471% * (10% * \$71,078,154)) = \$4,218,694. Portland Brief on Exceptions at 23-24 n.115.

⁴⁸¹ Projected revenues + Bankruptcy earnings = \$37,228,221 + \$4,218,694 = \$41,446,915. Portland Brief on Exceptions at 24 n.116.

⁴⁸² \$58,379,351 - \$41,446,915 = \$16,932,436. \$16,932,436 / \$58,379,351 = 29%. Portland Brief on Exceptions at 24 n.117.

reasonable return on its investments. Portland states that it also performed a cash analysis based upon the holdings of the ID. Portland states that it calculated its out-of-pocket expenses to be \$42,262,989, based upon the levelized cost-of-service (net of return), ad valorem taxes and O&M expenses.⁴⁸³ Portland states that even when compared to the hypothetical total revenue of \$41,446,915 (which includes both projected revenues based on the ID and an assumed 10 percent return from bankruptcy proceeds), it is left not with income, but with an out of pocket expenditure of \$816,074. Therefore, Portland contends, if the results of the ID stand, operation of the pipeline would create a loss on a cash basis.

335. Portland argues that given these results, the ID fails to meet the *Hope/Bluefield* standard.⁴⁸⁴ Under this precedent, Portland states that the Commission must consider whether the revenues generated under the ID allow Portland an opportunity to make distributions to equity investors. Furthermore, Portland contends that the ID would cause Portland to fail the S&P credit metric criterion regarding funds from operations (FFO) and interest payments⁴⁸⁵ and its credit rating may therefore also be negatively impacted if the ID is adopted.

336. Fourth, Portland and Trial Staff maintain that *Kern River* fully supports Portland's retention of bankruptcy proceeds for generally the same reasons they argued before. Portland and Trial Staff also argue that *Trailblazer* and *WIC* are distinguishable because, as Portland states, those cases dealt with exits fees, as opposed to bankruptcy proceeds which are uncertain and inherently risky.⁴⁸⁶ Portland argues that *WIC* is also distinguishable because the pipeline admitted that it had remarketed all of the bankruptcy-related capacity at rates close to the maximum rate.⁴⁸⁷ Portland also points

⁴⁸³ Levelized Cost-of-service Net of Return + Ad Valorem Taxes + O&M Expenses = Total Expenses. \$28,833,000 + \$6,055,858 + \$7,374,181 = \$42,262,989. Portland Brief on Exceptions at 24 n.119.

⁴⁸⁴ Portland Brief on Exceptions at 24 (citing *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) and *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679 (1923)).

⁴⁸⁵ *Id.* at 24-25 (citing Ex. PNG-60 at 27:13 (Protected Materials)). Portland states that the S&P metric for FFO/Interest payments would fail at 2.79. Portland states that this figure is calculated based upon the prospective rate determined by the ID (\$0.7586/Dth) and Portland's 2009 *pro-forma* budget. Portland Brief on Exceptions at 25, n.122 (citing Ex. PNG-73 (protected materials)).

⁴⁸⁶ *Id.* at 27.

⁴⁸⁷ *Id.* at 28 (citing *WIC*, 87 FERC at 62,309).

out that in *WIC* the Commission did not determine the amount of the credit, as the order addressed a proposed settlement and merely severed a contesting party.⁴⁸⁸

337. Portland argues that *Trailblazer* is also distinguishable because in that case the Commission determined that a credit was required in order to prevent “[the pipeline’s] customers from paying rates that cover costs [the pipeline] has already recovered in the buyout payment.”⁴⁸⁹ In contrast, Portland states, it used billing determinants of 210,840 Dth per day, its test period firm capacity, and thus is economically responsible for remarketing the bankruptcy-related capacity.

338. In their brief on exceptions, PSG and CES object to the ALJ’s decision to allow Portland to retain 50 percent of the Portland’s annual revenue over-recovery or approximately \$4.9 million. PSG and CES contend that affording Portland a 50 percent stake in approximately \$9.8 million of annual revenue over-recoveries violates both Commission precedent and policy. Further, PSG and CES argue that the ALJ’s basis for allowing Portland to retain 50 percent of the annual over-recoveries, i.e., that shippers “have also benefitted from the Androscoggin and Rumford bankruptcies” because they “have been able to resell their Portland capacity to service the Androscoggin and Rumford generators,”⁴⁹⁰ has no evidentiary support.

339. If Portland is permitted to retain any portion of its annual revenue over-recovery, PSG and CES argue, such share should not exceed 10 percent of that over-recovery, as opposed to 50 percent. Alternatively, PSG and CES argue that the Commission could adopt the rate base crediting approach advanced by PSG witness Fink, which they argue is the only evidence of record advancing a specific methodology for factoring Portland’s bankruptcy proceeds into the determination of its cost-of-service and rate design.

340. If the Commission determines that Portland should retain some share of these over-recoveries, PSG and CES urge the Commission to apply the same 90/10 sharing mechanism applied to excess pipeline IT revenues.⁴⁹¹ CES contends that the

⁴⁸⁸ *Id.* (citing *WIC*, 87 FERC at 62,310).

⁴⁸⁹ *Id.* (citing *Trailblazer*, 80 FERC ¶ 61,141 at 61,518).

⁴⁹⁰ CES Brief on Exceptions at 17 (citing ID at P 215).

⁴⁹¹ PSG Brief on Exceptions at 48 (citing *Algonquin Gas Transmission Co.*, 65 FERC ¶ 61,019, at 61,257 (1993), which states “[W]e have permitted the pipeline to retain 10 percent of all revenues collected in excess of allocated costs as an incentive for the pipeline to market interruptible service. However, the pipeline is required to credit

Commission has consistently rejected the type of 50/50 sharing of excess IT revenues proposed by the ALJ for Portland's bankruptcy-related over-recoveries. Instead, CES contends, the Commission has implemented a sharing mechanism under which 90 percent of excess IT revenues were flowed back to firm shippers.⁴⁹² Under this approach, CES states that Portland would be authorized to retain approximately \$980,000 of the annual revenue over-recoveries related to the bankruptcy proceeds. CES submits that this approach would better accomplish the twin policy goals of incenting Portland to continue aggressively remarketing capacity that has been turned back due to the bankruptcies and fully protecting shippers from a windfall over-recovery by Portland.

341. Finally, in order to avoid relitigation of this issue, PSG requests that, if the ID's approach is adopted, the ID should be clarified to provide that such a credit will be applicable for the remaining duration of the rejected contracts.

Briefs Opposing Exceptions

342. Portland and Trial Staff argue that PSG and CES's exceptions should be denied. Portland maintains that, even when accounting for the short-term and discounted recontracting of the bankruptcy-related capacity, it is in an under-recovery position. Portland also maintains that the firm shippers on Portland's system received incremental revenue by releasing capacity to serve the Androscoggin and Rumford generators.⁴⁹³ Portland also argues that the policy of crediting excess IT revenues is irrelevant.

343. In their Briefs Opposing Exceptions, PSG and CES argue that no prejudice resulted from the ID's consideration of arguments advanced by CES. PSG and CES state that Portland never explains precisely how it was disadvantaged or prejudiced by CES addressing this issue in its Reply Brief and CES states that Portland fails to specify the "set of issues" or "new theories or arguments" supposedly introduced by CES' Reply

90 percent of the revenues which it collects that are in excess of the allocated costs. This requirement ensures that customers are protected from windfall profits going to the pipeline....").

⁴⁹² CES Brief on Exceptions at 18 (citing *Colorado Interstate Gas Co.*, 63 FERC ¶ 61,101, at 61,545-46 (1993), *Iroquois Gas Transmission System, L.P.*, 63 FERC ¶ 61,285, at 61,905-06 (1993), *Wyoming Interstate Co., Ltd.*, 63 FERC ¶ 61,284, at 62,889-90 (1993)).

⁴⁹³ Portland Brief Opposing Exceptions at 20-21 (citing Ex. PSG-129; Portland Brief on Exceptions, Attachment B; and Tr. 1355:20-1356:3). Portland states that Ex. PSG-129 does not reflect total revenue, but this figure is easily calculated by multiplying the delivered quantity and rate, which is reflected in the exhibit.

Brief. CES asserts that its Reply Brief supported the rate base credit sponsored by PSG witness Fink and at no point did CES recommend the crediting method adopted by the ID. CES also contends that the ALJ's rules did not require that the parties' state positions regarding the bankruptcy proceeds issue or any other issue as part of the Joint Stipulation of Issues or otherwise, waive the right to do so on brief.⁴⁹⁴

344. PSG contends the ID was correct in concluding that tax effects should not impact a legitimate economic analysis of Portland's bankruptcy receipts and any ultimate revenue shortfall attributable to the bankruptcies. PSG states that Portland's purported after-tax comparison is distorted by its implicit suggestion that the benefits of future tax deductible expenses will be forever lost to Portland because those expense deductions were not accelerated in tandem with Portland's accelerated receipt of bankruptcy-related revenues. PSG states that while Portland could not take deductions for future tax deductible expenses at the time it received its bankruptcy proceeds, Portland will nonetheless be able to capture the tax-reducing benefits of those expense deductions in the future (i.e., throughout what would have been the remaining terms of the rejected contracts). PSG states that the fact that their availability was not accelerated with the Androscoggin/Rumford revenue streams does not support the contention that Portland has been ultimately tax-disadvantaged by having received those revenue streams up-front.

345. PSG also argues that the ID was correct in according Portland's claims of tax consequences little weight because Portland failed to introduce any tax analysis into the evidentiary record. PSG states that, although Portland Witness Lovinger made the bald assertion "[t]he bankruptcy proceeds are clearly taxable ...,"⁴⁹⁵ neither Mr. Lovinger nor any other Portland witness presented any analysis of the alleged tax implications associated with Portland's receipt of such. Thus, PSG argues that the evidentiary record contains no quantification or analysis of the tax consequences which Portland now alleges, leaving only four footnotes in Portland's Brief on Exceptions which Portland attempts to rely on as constituting such an analysis (Br. at 19-20, nn. 85-87 and 90).

346. Regarding Portland's claim that the ID violates *Hope/Bluefield*, PSG states that Portland's analyses are predicated on the false assumption that Portland's only source of revenue is revenue attributable to its current long-term FT contracts. PSG states that Portland ignores revenues achievable from short-term firm sales (which, as noted, amounted to \$1 million per month during the test period) and any drawdowns of the

⁴⁹⁴ CES Brief Opposing Exceptions at 13 (citing Joint Statement of Issues at 1 n.3).

⁴⁹⁵ PSG Brief Opposing Exceptions at 34 (citing Ex. PNG-31 at 34).

\$119.8 million in bankruptcy-related. PSG states that neither *Hope/Bluefield* nor any other authority requires or permits the Commission to engage in the pretense that Portland did not recover those substantial bankruptcy proceeds or \$12 million in short-term firm revenues during the test period, when considering the adequacy of Portland's revenues and rates.

347. PSG and CES continue to argue that *Kern River* does not support Portland's retention of bankruptcy proceeds for generally the same reasons cited by the ID. PSG and CES also argue that, contrary to Portland's and Trial Staff's contentions, *Trailblazer* and *WIC* are not inapposite. PSG states that, while there may be some question as to how much of the capacity attributable to the terminated contracts each pipeline in *Trailblazer* and *WIC* had successfully remarketed,⁴⁹⁶ the holdings of those cases do not hinge on the demonstrated ability of the pipelines to have fully remarketed all of the affected capacity. Rather, PSG contends, both expressly state that "to the extent [the involved pipeline] has remarketed that capacity to other shippers, [it] is effectively selling the same capacity twice" [emphasis added].⁴⁹⁷ Further, PSG maintains that the fact that the lump sum contract termination payment is received in the form of bankruptcy proceeds rather than a contract exit fee or buyout payment also provides no relevant basis for distinguishing Portland's circumstances from the holdings of *Trailblazer* and *WIC*.

348. In addition, PSG states that, in both *Trailblazer* and *WIC*, the pipelines had included in their rate design volumes the billing determinants attributable to the contracts terminated as a result of the exit fee payments, yet the Commission found that fact did not eliminate the need for a cost-of-service credit.⁴⁹⁸ PSG states that the pivotal factor distinguishing those two cases from *Kern River* was that, although all three pipelines included in their rate design volumes the billing determinants attributable to the capacity covered by the terminated contracts and then remarketed that capacity, in *Trailblazer* and *WIC* the pipelines had also received contract termination payments related to that capacity, in addition to remarketing revenues. Thus, PSG argues, those circumstances –

⁴⁹⁶ PSG states that, contrary to Trial Staff's assertions that the pipelines "had both fully remarketed the [former customer's] capacity," in *WIC* the Commission observed that "WIC states that it still has not remarketed the capacity for the full term of [the] former contract" PSG Brief Opposing Exception at 41 (citing *WIC*, 87 FERC at 62,309).

⁴⁹⁷ PSG Brief Opposing Exceptions at 36 (citing *WIC*, 87 FERC at 62,309; *Trailblazer*, 88 FERC ¶ 61,168 at 61,566 (rehearing of order accepting settlement)).

⁴⁹⁸ *Id.* at 41 (citing *Trailblazer*, 80 FERC ¶ 61,141 at 61,518; *WIC*, 87 FERC at 62,309).

not those set forth in *Kern River* (where no contract termination payment was involved) – drive the need for a cost-of-service credit for Portland.

349. CES also disputes Portland’s and Trial Staff’s argument that *Trailblazer* and *WIC* involved “concrete” exit fees as opposed to the uncertainty and inherent riskiness of bankruptcy proceeds. CES states that there is nothing uncertain about the Portland bankruptcy recoveries, as the record reflects not only that Portland received those monies, but that it passed those recoveries on to its corporate parents. CES states that the only uncertainty that remains is whether Portland will receive up to an addition \$5 million increment of bankruptcy proceeds.

Commission Determination

350. While the Commission agrees with the ALJ that there should be recognition of the receipt of the bankruptcy award for the rejected contracts in Portland’s rate design, we disagree with the ALJ’s decision that such recognition should take the form of a credit to Portland’s cost-of-service in the amount of one-half of the estimated annual amount of the pipeline’s over-recovery. Instead, consistent with our determination in the foregoing section, Portland must include in its rate design volumes both: (1) the 62,000 Dth per day of contract demand associated with the Androscoggin and Rumford Agreements, subject to a discount adjustment to reflect the fact the bankruptcy award only partially compensated Portland for loss of those maximum rate contacts; and (2) the interruptible and short-term firm billing determinants associated with its remarketing of the capacity formerly held by Androscoggin and Rumford. In addition, Portland must reduce rate base for the bankruptcy proceeds.

351. Consistent with the ALJ, we find that *Kern River* is not analogous to the instant case. In *Kern River*, contracts between Kern River and Mirant were rejected during the bankruptcy of Mirant. Following the bankruptcies, the Mirant capacity had been used for interruptible transportation and contributed to what was termed in that proceeding as “market oriented revenues.”⁴⁹⁹ In its rate case, Kern River proposed to retain the portion of the market oriented revenues deemed associated with the turn back capacity and credit its overall cost-of-service by the remaining amount. Kern River argued, and the Commission agreed, that this was reasonable given its proposed billing determinants reflected the capacity associated with the Mirant capacity though it had been unable to contract that capacity to a new long-term firm shipper. However, no issue arose in the *Kern River* proceeding concerning the treatment of any bankruptcy award related to the

⁴⁹⁹ *Kern River*, Order No. 486, 117 FERC ¶ 61,077 at P 370. Market oriented revenues were revenues derived from interruptible, authorized overrun, and short-term firm services. Order No. 486-A, 123 FERC ¶ 61,056 at P 277.

Mirant capacity, because Kern River did not receive any bankruptcy award until after the end of the test period and after the close of the evidentiary record.⁵⁰⁰ As the ALJ stated, in its decision to accept Kern River's proposal, "the Commission never addressed Kern River[']s receipt of substantial bankruptcy proceeds in any of the three Kern River Orders in [the] Docket No. RP04-274 proceeding."⁵⁰¹

352. Thus, as the ALJ stated, *Kern River* is unpersuasive because, at the time of the close of the evidentiary record, Kern River had received only one revenue stream with respect to the turned-back capacity, a portion of the so-called market oriented revenues. For this reason, the Commission allowed Kern River to retain the portion of the market oriented revenues that was deemed associated with the turned back capacity.⁵⁰² In this case, on the other hand, the record shows that Portland received within the test period more than one revenue stream with respect to the turned-back Androscoggin and Rumford capacity: the bankruptcy proceeds and the shorter-term firm and interruptible sales.

353. As argued by PSG and CES, these facts make Portland's situation more analogous to the pipelines' in *Trailblazer* and *WIC*. In *Trailblazer* and *WIC*, unlike *Kern River*, the pipelines received contract termination payments related to that capacity, in addition to remarketing revenues. Thus, both *Trailblazer* and *WIC* raised a similar issue to that presented here: how to account for the fact that a pipeline has received compensation for payments a shipper would have made in the future pursuant to a firm contract that has been terminated before the end of its term. In *Trailblazer*, for example, the Commission considered whether to credit Trailblazer's cost-of-service with a \$16.4 million exit fee that the pipeline received from Columbia Gas Transmission Company (Columbia) for the early termination of a firm transportation service agreement. The capacity associated with the Columbia contract was fully resubscribed and Trailblazer argued that no credit

⁵⁰⁰ ID, 129 FERC ¶ 63,027 at P 221. As one party pointed out, the fact that the Commission did not address the receipt of bankruptcy proceeds is made clear in Opinion No. 486-C, where the Commission observed, in relation to another issue in the case, that while Kern River ultimately did receive substantial bankruptcy proceeds, it was after the test period in the case: "Because the bankruptcy settlement occurred after the test period in this case, it is not relevant to a determination of Kern River's relative risk in this case." PSG Brief Opposing Exceptions at 39 (citing Opinion No. 486-C, 129 FERC ¶ 61,240 at P 115, n.175).

⁵⁰¹ *Id.*

⁵⁰² *Id.* (citing *Kern River*, Opinion No. 486, 117 FERC ¶ 61,077, at P 370, 382-386).

was warranted, as the capacity associated with the Columbia contract was still reflected in the pipeline's billing determinants.⁵⁰³ Trailblazer explained that it had reflected in its rate filing "the volumes formerly held by Columbia under the names of shippers currently holding the abandoned Columbia capacity."⁵⁰⁴ Like Portland in this case, Trailblazer asserted that crediting the Columbia exit fee "would effectively require Trailblazer to double count the volumes for rate design purposes" and that the Commission should consider "the fact that Trailblazer received less than dollar for dollar in exit fee payment."⁵⁰⁵ Despite Trailblazer's contentions, the Commission determined that a credit against Trailblazer's cost-of-service was warranted. The Commission stated that, "Failure to credit some or all of the buyout payment to the cost-of-service ... would result in Trailblazer's customers paying rates that cover costs Trailblazer has already recovered in the buyout payment. This would result in a windfall to Trailblazer...."⁵⁰⁶ The Commission set for hearing the issue of the level of the credit, and the case subsequently settled.

354. Similarly, in *WIC*, the Commission considered whether it should credit the pipeline's cost-of-service for an exit fee paid to the pipeline by Columbia. As in *Trailblazer*, the pipeline proposed to include the volumes associated with the capacity formerly held by Columbia in its rate design volumes. The Commission nevertheless determined that a credit to the pipeline's cost service seemed to be necessary:

The fact that *WIC* has not removed the volumes associated with the former Columbia capacity from the volumes used to design its rates does not, by itself, eliminate the need for a credit. Columbia's exit fee compensates *WIC* for revenue it would have collected from Columbia if Columbia's contract had remained in effect through January 1, 2004. Therefore, to the extent *WIC* has remarketed that capacity to other shippers, *WIC* is effectively selling the same capacity twice, once to Columbia and once to the new shippers. That would inevitably lead to an over-recovery of its cost-of-service.⁵⁰⁷

⁵⁰³ *Trailblazer*, 80 FERC ¶ 61,141 at 61,518.

⁵⁰⁴ *Id.*

⁵⁰⁵ *Id.*

⁵⁰⁶ *Id.* See also *Trailblazer*, 81 FERC ¶ 61,032 (order denying rehearing).

⁵⁰⁷ *WIC*, 87 FERC at 62,309.

As in *Trailblazer*, the Commission established further procedures to resolve what the level of the credit should be, but the case subsequently settled.

355. We also disagree with Portland that the fact that its lump sum contract termination payment is received in the form of bankruptcy proceeds rather than a contract exit fee or buyout payment distinguishes Portland's circumstances from the holdings of *Trailblazer* and *WIC*. In each case, the pipeline is receiving revenues for services not yet provided and the pipeline is in a position to remarket that capacity to a third party. Therefore, the fact that Portland has included in its rate design volumes the billing determinants attributable to the rejected contracts, does not in and of itself obviate the need for some recognition of the bankruptcy proceeds in Portland's rate design.

356. However, contrary to the ALJ's decision on how to recognize the lump sum payment, we find that, in this case, Portland's receipt of the bankruptcy award should be accounted for: (1) in Portland's rate design volumes; and (2) a reduction to rate base. First, the Commission requires Portland to include in its rate design volumes both: (1) the 62,000 Dth per day of contract demand associated with the rejected contracts in Portland's rate design volumes, subject to a discount adjustment to reflect the fact the bankruptcy award only partially compensated Portland for loss of those maximum rate contracts; and (2) the interruptible and short-term firm billing determinants associated with its remarketing of the capacity formerly held by Androscoggin and Rumford. Including both sets of billing determinants in the design of Portland's rates should avoid requiring Portland's shippers to pay rates that cover costs Portland has already recovered in the bankruptcy award.

357. As discussed in the previous section, it is currently unclear if Portland's proposed rate design volumes of 210,840 Dth per day are just and reasonable given that it is unknown whether Portland's adjusted projected units of service for all firm and interruptible services satisfy its 210,840 Dth per day at-risk condition. If Portland's total adjusted projected billing determinants, as determined in its compliance with that section, are less than or equal to its design capacity of 210,840 Dth per day, then consistent with the at-risk condition, its rates should be designed using total billing determinants of 210,840 Dth per day. If Portland's total adjusted projected billing determinants exceed 210,840 Dth per day, then those projected billing determinants should be used to design its rates. Our requirement that Portland account for the bankruptcy award through an adjustment to its billing determinants, rather than a credit against Portland's cost-of-service, will assist in making the determination whether Portland has satisfied the at-risk condition. Therefore, consistent with our other determinations in the preceding section concerning interruptible billing determinants, Portland must include the 62,000 Dth per day of contract demand associated with the rejected contracts in Portland's rate design volumes, but subject to a discount adjustment to reflect the fact the bankruptcy award only partially compensated Portland for loss of those maximum rate contracts.

358. The bankruptcy award that Portland received as a result of the Androscoggin and Rumford Agreements being terminated reflected only a portion of the revenue to which Portland would have been entitled had the contracts remained in effect. Therefore, it is appropriate that Portland be entitled to a discount adjustment to reflect the fact that the bankruptcy award equated to Portland receiving an amount per Dth that was less than the maximum rate it would have otherwise received had the contracts remained in effect.⁵⁰⁸ Accordingly, consistent with Commission policy, as discussed in the previous section, Portland may reduce the firm billing determinants associated with the rejected contracts to account for the discounted revenues. The discount adjustment to projected firm billing determinants is carried out using what is referred to as the ratio method. Under that method, the volumes which flowed at a discount are adjusted by multiplying them by the ratio of the pipeline's average discounted rate to its just and reasonable rate established in the subject rate case.⁵⁰⁹ Accordingly, consistent with Commission policy, Portland may reduce its projected contract demand billing determinants associated with the rejected contracts to account for discounting. This amount may then be added to Portland's other projected firm billing determinants to determine whether its overall projected billing determinants are less than or greater than its design capacity of 210,840 Dth per day.

359. Whether or not Portland's total billing determinants calculated in this manner satisfy its at-risk condition, Portland's rates should be just and reasonable. That is because in both cases, Portland's rates will already reflect an allocation of costs to both the rejected contracts and the new short-term firm and interruptible contracts obtained by remarketing the subject capacity. If Portland's total adjusted billing determinants equal or exceed 210,840 Dth per day, a portion of Portland's cost-of-service will be allocated to the rejected contracts consistent with Commission policy. If Portland's total billing determinants are less than 210,840 Dth, then the at-risk condition will effectively require a greater allocation of costs to the rejected contracts than required by a traditional projection of billing determinants for those contracts. Therefore, because Portland will be allocating costs to the rejected contracts, Commission policy does not require that Portland also credit the bankruptcy award to its cost-of-service. Accordingly, we reject the ALJ's finding requiring Portland to directly credit one half of the estimated annual

⁵⁰⁸ The unit rate of the rejected contracts to be used in Portland's discount adjustment calculations is equal to the bankruptcy proceeds (\$119,761,258) divided by total contract volumes over the number of years left of the rejected contracts when they were rejected. As most of these proceeds were received within the test period, there is no need to make adjustments to reflect the time value of the money.

⁵⁰⁹ See *Williston III*, 84 FERC ¶ 61, 081 at 61,401-02, for a description of the somewhat complicated iterative mathematical computation used to carry out the ratio discount adjustment method.

revenue over-recovery of \$9,773,956 attributable to the bankruptcy and transportation revenues to Portland's cost-of-service.⁵¹⁰

360. Second, the Commission finds that a reduction to Portland's rate base is justified to account for the fact the bankruptcy award allowed Portland to recover immediately costs that would otherwise have been recovered only over the remaining terms of the Androscoggin and Rumford Agreements. Based on the facts presented in this proceeding, the Commission will require Portland to use the full bankruptcy proceeds, net of legal costs incurred by Portland in the bankruptcy proceeding,⁵¹¹ as a reduction to rate base.⁵¹²

361. We find this rate base adjustment to be a reasonable approach since it provides recognition that Portland received significant lump sum payments for early contract termination. At the same time, consistent with our prior findings in *Trailblazer* and *WIC*, a pipeline should not over-recover its cost-of-service by selling the same capacity twice.⁵¹³ The lump sum payment is an early recovery of future costs. Reducing the rate base by the net lump sum bankruptcy proceeds reduces the return allowance that would otherwise be included in Portland's rates, thereby mitigating cost over-recovery. Further, the Commission believes this approach simplifies what is an inexact projection of calculating benefits to the pipeline, simplifies the estimate of the potential over-recovery of revenues⁵¹⁴ in this proceeding, as the bankruptcy proceeds were largely received in a lump sum and within the test period, and eliminates the need to develop an appropriate discount rate factor and NPV calculation of revenue lost under the terminated contracts.

362. Finally, the Commission's holdings concerning the treatment of the bankruptcy award do not violate *Hope/Bluefield*. Except to the extent Portland's projected units of service are less than its at-risk condition, its rates will be designed to provide it an

⁵¹⁰ ID, 129 FERC ¶ 63,027 at P 213.

⁵¹¹ *Id.* P 216.

⁵¹² Since the revenues received by Portland are subject to income taxes, Portland should reflect the appropriate deferred income taxes in rate base. Portland estimates that the after tax amount of the bankruptcy proceeds totals \$71,081,780, indicating that the tax liability totals \$48,679,478 (\$119,761,258 – (\$119,761,258 x 40.6471 percent)). *Id.* P 181 & n.18. Further, these adjustments should be reflected in the remaining levelization period.

⁵¹³ *Trailblazer*, 80 FERC ¶ 61,141; *WIC*, 87 FERC ¶ 61,339 at 62,309.

⁵¹⁴ ID, 129 FERC ¶ 63,027 at P 218.

opportunity to recover its full cost-of-service, taking into account its receipt of the bankruptcy award. Portland having accepted its certificate subject to the at-risk condition, it is just and reasonable to continue to require that it design its rate consistent with the at-risk condition.

The Commission orders:

- (A) The Initial Decision is affirmed and modified as discussed in the body of this order.
- (B) Within 30 days of the issuance of this order, Portland must file revised tariff sheets and rates, including proposed accounting and workpapers, reflecting the Commission's rulings in this order.
- (C) Within 30 days of a final order in this case, Portland must refund amounts recovered in excess of the just and reasonable rates approved by the Commission.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Appendix A

APPENDIX A

RP08-306-000 PORTLAND NATURAL GAS TRANSMISSION SYSTEM
 FERC DCF Analysis: Natural Gas Model Using Data for the Six-Month Period Beginning November 2008 and Ending April 2009

<u>Ticker</u>	<u>Company Name</u>	<u>6 Mos. Avg</u> <u>Div. Yield</u>	<u>I/B/E/S</u>	<u>Growth Rate ("g")</u>		<u>Adj. Div.</u> <u>Yield</u>	<u>DCF</u> <u>Result</u>	
BWP	Boardwalk Pipeline Partners, LP	9.22%	6.75%	<u>GDP</u>	<u>Composite</u>	9.46%	14.70%	
EPB	El Paso Pipeline Partners, L.P.	7.28%	7.50%	2.21%	5.24%	7.49%	13.22%	
SUG	Southern Union Co.	4.34%	9.30%	4.42%	7.67%	4.51%	12.18%	
SE	Spectra Energy Corp.	6.75%	6.50%	4.42%	5.81%	6.94%	12.75%	
SEP	Spectra Energy Partners, LP	7.15%	6.50%	2.21%	5.07%	7.33%	12.40%	
TCLP	TC Pipelines, LP	11.30%	4.00%	2.21%	3.40%	11.49%	14.89%	
Zone of Reasonableness							---	14.89%
							Median:	12.99%
							Midpoint:	13.54%

Appendix B

APPENDIX B

RP08-306-000 PORTLAND NATURAL GAS TRANSMISSION SYSTEM
 FERC DCF Analysis: Natural Gas Model Using Data for the Six-Month Period Beginning January 2010 and Ending June 2010

Ticker	Company Name	6 Mos. Avg Div. Yield	I/B/E/S	Growth Rate ("g")		Adj. Div. Yield	DCF Result	
				GDP	Composite			
BWP	Boardwalk Pipeline Partners, LP	7.18%	4.50%	2.30%	3.77%	7.32%	11.08%	
EPB	El Paso Pipeline Partners, L.P.	5.55%	9.00%	2.30%	6.77%	5.73%	12.50%	
SUG	Southern Union Co.	2.54%	8.77%	4.60%	7.38%	2.64%	10.02%	
SE	Spectra Energy Corp.	4.62%	10.56%	4.60%	8.57%	4.82%	13.39%	
SEP	Spectra Energy Partners, LP	5.47%	6.17%	2.30%	4.88%	5.60%	10.48%	
TCLP	TC Pipelines, LP	7.82%	4.00%	2.30%	3.43%	7.95%	11.38%	
Zone of Reasonableness							---	13.39%
							Median:	11.23%
							Midpoint:	11.70%