UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
Nora Mead Brownell, Joseph T. Kelliher,
and Suedeen G. Kelly.

Williston Basin Interstate Pipeline Company Docket Nos. RP00-107-003 and RP00-107-004

ORDER ON REHEARING AND COMPLIANCE
AND REMANDING CERTAIN ISSUES FOR HEARING

(Issued May 11, 2004)

1. On July 3, 2003, the Commission issued its Order on Initial Decision in this proceeding (July 3 Order),[1] which involves a general rate increase filed by Williston Basin Interstate Pipeline Company (Williston) on December 1, 1999 pursuant to section 4 of the Natural Gas Act. The July 3 Order affirmed in part and reversed in part the initial decision of the Administrative Law Judge (ALJ).[2] On July 23, 2003, Williston filed to comply with the Commission's July 3 Order. Thereafter, on August 4, 2003, Williston and Northern States Power Company (Northern States or NSP) filed requests for rehearing of the July 3 Order. As discussed below, Williston's compliance filing is insufficient, and the requests for rehearing are granted in part and denied in part.

I. Background

2. Williston's December 1, 1999 general rate increase filing raised numerous issues with respect to the justness and reasonableness of the rate increase sought by Williston. The ALJ's initial decision dealt with those issues in detail. In large part, the Commission approved the initial decision, and on those issues where the Commission approved of the reasoning and the result of the initial decision, the Commission declined to elaborate further. However, on certain issues, the Commission stated that further discussion was necessary, and on other issues, the Commission reversed the ALJ.[3] The July 3 Order then proceeded to discuss those issues.

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[1] Williston Basin Interstate Pipeline Company, 104 FERC ¶ 61,036 (2003).

[2] Williston Basin Interstate Pipeline Company, 95 FERC ¶ 63,008 (2001).

[3] 104 FERC at 61,098 P 5.

A. Compliance Filing

3. On July 23, 2003, Williston submitted two separate sets of pro forma tariff sheets to comply with the July 3 Order. Volume I reflects Williston's refund rates purportedly based on the July 3 Order requirements and "other adjustments" to become effective August 1, 2001. According to Williston, such other adjustments include "previously approved" methods for calculating depreciation and negative salvage rates, calculating discount adjustments, and allocating cushion gas costs. Williston states that Volume II reflects prospective rates based on the adjustments required by the July 3 Order that will become effective "at the appropriate time." Both volumes include cost of service and rate design schedules and workpapers, except for the workpapers showing the iterations used to calculate discount-adjusted volumes.

4. Williston made its filing without prejudice to its request for rehearing discussed supra, and requests waiver of any regulations the Commission deems necessary to implement the proposed tariff sheets.

5. Protests, motions or notices to intervene were due on Williston's compliance tariff filing no later than August 4, 2003. No new motions or notices to intervene were filed. State Agencies filed a late protest. Williston filed a response to the protest on August 15, 2003. The untimely filed protest will not delay, disrupt, or otherwise prejudice this proceeding. The Commission's findings below respond to State Agencies' objections. For this reason, the specific objections in State Agencies' pleading will not be discussed. Williston's response reiterating its "section 5" argument for prospective treatment of the refund rates is discussed, infra.

B. Requests for Rehearing

6. On August 4, 2003, Williston and Northern States filed requests for rehearing of the July 3 Order. Williston raises fourteen points of error, some of which were discussed in the July 3 Order. A number of those issues raised as error by Williston had been fully and adequately addressed by the Administrative law Judge (ALJ) and were summarily approved by the July 3 Order. Northern States raises several points of error in the July 3 Order concerning its service under Rate Schedules X-13 and FT-1. All of the claimed points of error are described and discussed below. To the extent any point is not discussed below, it should be considered denied.

II. Discussion

A. Compliance Filing

7. The Commission finds that neither set of pro forma tariff sheets fully complies with the Commission's July 3 Order. As more fully explained below, Williston used: (i) inappropriate effective dates for calculating annual depreciation expenses and base tariff rates; and (ii) cost allocation and rate design methodologies that were previously argued but not sanctioned in this proceeding. Williston is required to file actual tariff sheets and comprehensive workpapers, including an iterative process used to calculate discount adjustments, within 30 days of the issuance of this order to reflect the Commission's final orders in this proceeding.

8. With respect to the Volume I data, Williston calculates revised rates based on an August 1, 2001 effective date rather than the June 1, 2000 effective date determined in the initial order in this proceeding.[4] Further, the Volume I data reflect adjustments contrary to the July 3 Order. Specifically, Williston uses expense levels and allocation methods based on alleged "previously approved" rates and methodologies. Such adjustments include: (i) Annual Depreciation Expense of $6,671,533 rather than $5,676,864; (ii) Storage Negative Salvage of $106,143 rather than $57,052; (iii) Allocation of 160 Bcf of Cushion Gas using an allocation method allegedly determined in Williston's Docket No. RP95-364-000 rate case; (iv) Rate Schedule IS-1 volumes reflecting a cost allocation and rate design allegedly approved in Williston's RP92-236-000 rate case; and (v) the calculation of discounts including the GRI surcharge in the maximum rate for Rate Schedules FT-1 and IT-1 allegedly "consistent with [Williston's] previous discount methodology." Because the expense levels in Volume I exceed the levels mandated in the July 3 Order, and the cost allocation and rate design methodologies and adjustments are not consistent with our July 3 Order, the resulting rates are overstated, unjust and unreasonable, and result in understated refunds.

9. With respect to Volume II data, Williston claims to use expense levels and allocation and rate design methodologies mandated by the July 3 Order. However, contrary to the initial suspension order in this proceeding, Williston derived its revised rates on a prospective basis. The suspension order in this proceeding is clear. Williston's proposed tariff sheets were accepted and suspended pending further investigation, to be effective June 1, 2000. As a result of Williston's attempt to characterize this section 4 rate case as a section 5 matter requiring only prospective rate adjustments, the calculation

[4] Williston, 89 FERC ¶ 61,330 (1999).

of the annual depreciation expense is skewed and results in inflated revenue requirements, and thus, overstated base tariff rates.

10. Because neither set of tariff sheets fully complies with the July 3 Order, we require Williston to file, within thirty days of this order, workpapers and tariff sheets to be effective June 1, 2000, consistent with the discussion in this order. Williston must therefore recalculate its refunds and rates.

B. Requests for Rehearing

1. Amortization of Intangible Plant

11. Williston first claims that the July 3 Order erred by affirming the Initial Decision concerning the amortization of intangible plant.[5] Noting that the Commission had approved a ten-year period for amortization of most of Williston's intangible plant, the ALJ found that Williston failed to provide a compelling argument as to why the remaining $2,969 of intangible plant should be amortized over a three-year period. The ALJ required that Williston amortize the $2,969 over the same ten-year period previously approved by the Commission for this type of plant.[6]

12. Williston seeks rehearing of the Commission's affirmation of the ALJ. Williston argues that the Commission has approved a three-year amortization period in the past, citing Williston Basin Interstate Pipeline Company, 84 FERC ¶ 61,081 at 61,372-73 (1998). However, that case involved the amortization of SFAS 106 costs during a transition period, not intangible plant costs as is the case here. Williston has made no showing why these types of costs should be treated in a similar fashion.

13. Williston acknowledges that, in previous rate proceedings, intangible plant was amortized over ten years. Williston attempts to distinguish the ten-year treatment because the intangible plant balance there was $101,789, larger than the $2,969 in this case. Williston contends that a three-year period in that case would have had a much greater rate impact than in this case. However, in the very Williston case cited above, Staff argued for a five-year period instead of the three-year period found to be reasonable by the ALJ in that case and supported by Williston for the amortization of SFAS 106 costs. Staff based its argument on the proposition that a five-year period would have a lesser impact than would a three-year period. The amount involved there was in excess

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[5] 104 FERC ¶ 61,036 at 61,098 (2003).

[6] 95 FERC ¶ 63,008 at 65,077 (2001).

of $1.7 million, and the Commission determined that the three-year period was appropriate based on the facts of that case. Certainly, the rate impact on customers would have been less had the Commission chosen to use a five-year amortization period. Therefore, the dollar amount involved is not necessarily the controlling factor, and given the general use of a ten-year period for amortizing intangible plant costs adopted by the ALJ and affirmed by the Commission, rehearing is denied on this issue.

2. Accumulated Deferred Income Taxes in Account No. 190

14. The July 3 Order affirmed the ALJ on this issue without further discussion. Williston seeks rehearing. The issue regarding the level of ADIT that should be included in rate base concerns deferred taxes associated with excess contributions[7] made by Williston to an external trust fund for Post-retirement Benefits other than Pensions (PBOPs). Commission policy is to allow prudently incurred costs of PBOPs. Williston represented that every year it estimates the level of contributions that will not be tax deductible and accrues the estimated amount on its books. During 1999 and 2000, Williston estimated that none of its contributions would be deductible, resulting in estimated calendar year 1999 excess contributions of $1,174,585, and calendar year 2000 excess contributions of $415,892. During the course of the proceeding before the ALJ, Williston provided actual amounts of such excess contributions for calendar year 1999 - $163,124 actual opposed to the estimated $1,174,585. The ALJ found that the actual amount for 1999 related to excess contributions should be adopted for calculation of the deferred taxes. The ALJ also stated that, ideally, actual data should also be used for calendar year 2000, but that Williston had not provided that data. The ALJ concluded that, since Williston's estimates of excess contributions related to PBOPs for calendar year 1999 were substantially greater than its actual amount of excess contributions for 1999, and since its estimates of excess contributions for calendar year 2000 were well in excess of any "excess contribution" ever shown to have been made by Williston in this record, Williston's estimates for 2000 had not been shown to be known and measurable with a reasonable degree of accuracy at the time of filing, and the amounts claimed by Williston for year 2000 were rejected. The ALJ therefore adopted Staff's $82,739 ADIT for Account No. 190 as the best proxy for PBOPs as of the end of the test period.[8]

15. On rehearing, Williston argues that the estimates for both 1999 and 2000 should be allowed, because they were reasonable when made. It contends that the difference

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[7] Excess contributions are defined as amounts that are funded to a trust but are not deductible for Federal Income tax purposes.

[8] Id. at 65,084.

between the estimated amounts included in Williston's filing and the actual amounts for 1999 provided in 2000 before the hearing were the result of higher returns being earned on the money invested by the external trust, and a change in assumptions by the actuaries regarding the level of future medical expenses. Williston argues that it had made its estimates on the basis of then-current assumptions regarding medical costs from previous actuarial estimates and known earnings on the trust fund assets.

16. Rehearing is denied on this matter. Williston provided actual data for excess contributions for calendar year 1999, and that amount was accepted by the ALJ. It would be unreasonable for the Commission to allow Williston to use estimates known to be substantially inaccurate when actual data were available to all the parties before the hearing, especially so when the amount claimed as an estimate for that year is so materially in excess of the actual amounts. Williston apparently used the same methodology for estimating the year 2000 amounts, and did not purport to change its estimates for the year 2000 to reflect the so-called "changed actuarial assumptions." It would likewise be unreasonable to accept Williston's estimates of excess contributions for calendar 2000 unless the same corrected assumptions were used in deriving that figure. Williston did not attempt to update its year 2000 numbers. Moreover, Williston's estimates for 2000 were well in excess of any "excess contributions" ever shown to have been made by Williston.[9] Williston has presented nothing new in its request for rehearing that was not already considered by the Commission in affirming the ALJ on this issue.

3. Correct Level of Storage Royalties

17. Williston pays royalties to the Mineral Management Service (MMS) for the right to store gas under federally-owned land. In late 1994, the MMS audited Williston and assessed $1.6 million in underpaid storage royalties during the period from March 1988 through August 1991. In this proceeding, Williston proposes to expense the remaining audit-related installment of $727,160 paid in August 1997, prior to the base period, plus recovery of one-half of that amount in rate base.

18. The ALJ rejected the audit-related payment because it was paid outside the test period. In the July 3 Order, the Commission affirmed the ALJ's decision, and denied the pre-base period payment as a nonrecurring expense and not representative of the pipeline's costs to provide service during the rate period at issue.[10]

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[9] Id. at 65,084.

[10] July 3 Order at P 66-69.

19. On rehearing, Williston repeats its earlier argument that this proceeding is its first opportunity to recover the remaining installment of the assessment for the March 1988 through August 1991 audit period. Williston contends that its recovery of the 1997 payment is consistent with the Commission's approval in past Williston proceedings.[11] Williston is mistaken. In its previous rate case in Docket No. RP95-364-000, the record shows that the ALJ only allowed the MMS payments actually paid within the test period. In this case, Williston's 1997 payment was clearly made prior to the base period beginning August 1, 1998.

20. For ratemaking purposes, the Commission does not permit pipelines to accrue expenses between test periods for recovery in future periods, nor do we permit past expenses that are not representative of the period the rates are in effect. Here, the pre-base period payment applies to services provided by Williston from seven to ten years prior to the rate period, and no evidence suggesting a similar expense for the test period in this proceeding was produced by Williston. We find that the inclusion of an expense related to services rendered more than seven years prior to the rate period is contrary to sound ratemaking principles, and would result in an unjust and unreasonable rate. Williston's request for rehearing on this issue is denied.

4. Depreciation Expense

21. In filing its section 4 rate increase in this proceeding, Williston did not propose to change the depreciation rate component from that underlying its previous rates. At hearing, the ALJ found that Williston had not proved that retaining the extant depreciation rates and rate methodology produced just and reasonable rates, and adopted depreciation rates proposed by Commission staff. In the July 3, 2003 Order, the Commission affirmed that decision.

22. Williston maintains specific accounts for depreciation and categorizes them by Plant Function (General, Underground Storage, Transmission and Gathering). On rehearing, Williston objects to Commission staff's General and Storage depreciation rates, but did not contest Staff's Gathering function depreciation rates. As to the Transmission function, Williston only contests the economic life of 35 years estimated by Commission staff.

23. Williston asserts that because Williston did not propose any change to depreciation methodology or depreciation rates in the instant proceeding, the

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[11] Williston Request for Rehearing at 8-10, citing Williston, 84 FERC & 61,081 at 61,362-63 (1998); see also Williston BOE at 16-17.

Commission must act under NGA section 5 to change the proposed depreciation rates.[12] Williston argues that pursuant to section 5, the Commission bears the burden of proof for such depreciation rate changes, and any rate change must be given prospective effect.[13]

24. Where the pipeline proposes an overall rate increase, the burden of proving that unchanged depreciation rates are just and reasonable is on the pipeline. Since each item in the pipeline's proposed cost of service is a part of the pipeline's proposed rate increase, the pipelines' section 4 burden to support the proposed general rate increase includes the burden of supporting the dollar amount of each item in the cost of service, including unchanged items.[14] As the Commission held in Northwest Pipeline Corp. [15] and Northern Border Pipeline Co.,[16] it may act under section 4 of the NGA to reduce a depreciation rate and order refunds, even where the pipeline has not proposed a change in its depreciation rate, as long as the as-filed depreciation rate is a part of a proposed overall rate increase.

25. The Commission's finding is consistent with case law. In Laclede Gas Company v. FERC, [17] the Court held that, by filing for a rate increase under section 4, the pipeline

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[12] Williston makes a related argument that there are no changed circumstances that warrant a reassessment of existing depreciation rates. However, there is no statutory or regulatory threshold requirement that the Commission demonstrate "changed circumstances" in order to reject a pipeline's proposal to maintain the same depreciation rates. As discussed herein, the only requirement is that the pipeline proposes an overall rate increase.

[13] Section 4 authorizes the Commission to suspend a filed rate subject to refund beginning with the effective date of the rate and puts the burden on the pipeline to prove the rate increase is just and reasonable. In contrast, under section 5, if the Commission finds a rate to be "unjust, unreasonable, unduly discriminatory, or preferential," the Commission determines the just and reasonable rate "to be thereafter observed and in force" and fixes the new rate by order. 15 U.S.C. § 717d.

[14] Pursuant to 18 CFR §§ 154.301(c) and 154.312(l) (2003) the pipeline must submit materials to support the depreciation rates underlying a proposed rate change.

[15] Northwest Pipeline Corp., 87 FERC ¶ 61,266, at 62,038 (1999).

[16] Northern Border Pipeline Co., 88 FERC ¶ 61,201, order on reh'g, 89 FERC ¶ 61,185 (1999).

[17] 670 F.2d 38 (5th Cir. 1982).

opened to scrutiny under that section all practices that are "an integral part of the manner in which rates are charged."[18] Thus, a purchased gas clause was reviewable under section 4 although the pipeline had not sought to change the provision. Similarly, in Cities of Batavia, et al. v. FERC,[19] the court explained that the Commission is not precluded "from reviewing a revised rate completely to assure that all its parts--old and new--operate in tandem to insure" a just and reasonable rate.[20] Similarly in the instant case the depreciation rate determines the amount of allowed depreciation expense, which is a significant part of the cost of service. Consequently, the Commission is authorized to order refunds of excess depreciation so long as Williston's resulting revenues for the periods at issue are equal to or greater than the revenues under the last approved rate.[21]

26. Since Williston bore the burden of proving that its depreciation rates were just and reasonable, it was not necessary for Commission staff to prove that Williston's existing rates were unjust and unreasonable. In the hearing below, Commission staff submitted testimony and evidence supporting its proposed depreciation rates and the Commission has properly affirmed the ALJ's finding that Commission staff's proposed depreciation rates are just and reasonable.[22]

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[18] 670 F.2d at 42.

[19] 672 F.2d 64, 77 (D.C. Cir. 1982).

[20] Tennessee gas Pipeline Company, Opinion No. 190, 25 FERC ¶ 61,020 at 61,108. (1983).

[21] Williston also argues on rehearing that on "equitable" grounds, the Commission should be estopped from ordering refunds because Commission staff had earlier thought that section 5 governed this issue and gained substantial benefit from filing surrebuttal testimony and exhibits on that basis. This argument is without merit. In addition to the hearing, Williston had ample opportunity to present any arguments in its brief on exceptions and request for rehearing. The Commission is not convinced that any procedural disadvantage that may have occurred at hearing has resulted in an insufficient record upon which to reach its conclusions herein. In any event, had a procedural error actually caused an insufficient or incorrect record, the defect would be resolved by rehearing the effected issues, not by adjusting the just and reasonable rates to the customers.

[22] See, Trunkline Gas Company, 90 FERC ¶ 61,017 at 61,051 (2000).

27. The dominant factor in determining the useful life, and therefore, the depreciation rates for gas facilities is the amount of reserves. The Commission must estimate the potential recoverable natural gas reserves available to the pipeline within a "zone of reasonableness."[23] Commission staff proposed a 35-year economic life based, in part, on the remaining life for the Western Canada Sedimentary Basin (WCSB) and the U.S. domestic supply. Williston maintains a 23-year average economic life based on two methodologies, the Effectiveness of Exploration Model (EHF)[24] and the R/P Ratio Model.[25]

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[23] The Commission has used the following definition of depreciation for gas plant for many years: Depreciation, as applied to depreciable gas plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities, and, in the case of natural gas companies, the exhaustion of natural resources. Accordingly, pipeline facilities are considered to have a service life or useful life and depreciation is the loss in service value. Trunkline, at 61,054. The depreciation rate is a measure of the loss in service value on an annual basis. Prior to the 1970's, it appears that the factors most significant in determining the useful life of facilities were those having to do with the physical life of the facilities. During the 1970's, however, available gas reserves appeared to decrease and the amount of reserves became the dominant factor in determining the useful life, and therefore, the depreciation rates for gas facilities. Memphis Light, Gas and Water Division v. FPC, 504 F.2d 225, 229-30 (D.C. Cir. 1974). This type of analysis, the examination of gas reserves to determine depreciation, has been widely used ever since. In South Dakota Public Utilities Commission v. FERC, 668 F.2d 333, 345 (D.C. Cir. 1981) (South Dakota), the Court, sitting en banc, stated that to set appropriate rates, the Commission must determine depreciation rates, and to do that it "must estimate the potential recoverable natural gas reserves available to pipeline companies." It went on to say that courts have recognized the difficulty of estimating reserves and "have permitted the Commission to develop estimates within a 'zone of reasonableness.'"

[24] The Effectiveness of Exploration Model (EHF) is a theory that by comparing the level of exploratory drilling in a particular year with the associated discoveries, annual discoveries of natural gas can be forecasted.

[25] The R/P Ratio Model is a theory that the relationship of remaining proven gas

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28. Williston complains that Commission staff witness Mr. Pewterbaugh, in his February 1996 testimony in Williston's previous proceeding, endorsed the continued use of Williston's existing depreciation rates. But in the instant proceeding in which the same domestic supply area has indicated an 8% decline from 93,860 Bcf as of 12/31/94 to 87,176 Bcf as of 12/31/98, Mr. Pewterbaugh recommends an increase in Williston's economic remaining life from 25 to 35 years.

29. Mr. Pewterbaugh's testimony indicates a remaining life of 45 years for the Western Canada Sedimentary Basin (WCSB) and 62 years for the U.S. domestic supply, from which he developed an average of 53.5 years. Therefore, the Commission finds an estimate of 35 years to be very conservative (even with the 8% decline in the updated data of the domestic supply) and consistent with the 35-year remaining economic life based on the WCSB adopted by the Commission in Iroquois Gas Transmission System.[26]

30. Williston claims that Iroquois is a bad precedent to justify Williston's 35-year economic life, since Iroquois receives all its supply from TransCanada while Williston receives none from TransCanada and 10% or less from the WCSB. Williston also questions the availability of gas supplies in parts of Montana and Wyoming from which it currently does not receive any gas.

31. Williston correctly states that it currently receives only minimal gas from nearby gas supplies. However, proper consideration must be given to gas supplies beyond the reach of Williston's pipeline available by direct transportation or exchange services. Williston acknowledges that it may have interconnections with pipelines that could deliver these supplies to its pipeline system. As stated in South Dakota, the Commission finds that this is well within the "zone of reasonableness" of available gas reserves and, further, the Commission "must estimate the potential recoverable natural gas reserves available to pipeline companies." Therefore, Commission staff correctly considered these supply areas because, as a result of open access under the Commission's Order No. 636 and its impact on the availability of future gas supplies and developments, Williston can now deliver, receive, or exchange gas on behalf of its customers from Northern

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reserves to its related annual production can forecast the economic life of natural gas reserves.

[26] Iroquois Gas Transmission System, L.P., 86 FERC ¶ 61,261, at 61,943 (1999) (Iroquois).

Border Pipeline, Kansas-Nebraska Gas Company, Colorado Interstate Gas Company, and Montana Power Company.[27]

32. On rehearing, Williston complains of defects in Commission staff witness Mr. Pewterbaugh's presentation, such as an allegedly limited sample of historical data to determine a final ultimate recovery quantity of gas supplies using the least squares curve-fitting technique to fit an S-curve to the pattern of historical data. However, Williston is wrong. Mr. Pewterbaugh used 22 data points representing a span of 22 years creating a reliable study.

33. Williston also claims that staff witness Mr. Pewterbaugh added remaining reserves to his cumulative production total, which is a misuse of ultimate recovery data because of the use of mismatched data. However, Mr. Pewterbaugh acknowledged his mistake and recalculated his S-curves using only remaining reserve data, which leaves the new reserve discoveries in the year in which they were discovered.[28] This correction removed the problem of using mismatched data, but did not change Mr. Pewterbaugh's recommended 35 years for Williston's remaining economic life. Exhibit No. 38, Schedule Nos. 4 through 8, indicate a minor decrease for the WCSB area to a 31-year supply life from the 33.5-year supply life in Mr. Pewterbaugh's original study. But as shown on Exhibit No. S-38, Schedule No. 13, the average life for the Domestic Supply Area (Williston's main supply area) is longer than before and, therefore, the corrected exhibits do not indicate a decrease in Williston's economic life is warranted.

34. Finally, Williston questioned the use by Mr. Pewterbaugh of the bell-shaped S-curve. Williston's assertion that this method is fundamentally unsound and untested before the Commission is incorrect. The Judge and the Commission adopted the use of the Hubbert methodology in Wyoming Interstate Company.[29]

35. Williston maintains that its witness Mr. Feinstein's models are consistent with Commission precedent and produce reliable results. Mr. Feinstein determined a 23-year average economic life based on two methodologies, the Effectiveness of Exploration Model (EHF) and the R/P Ratio Model. The Commission, like the Presiding Judge, is

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[27] See Ex. S-67.

[28] Surrebuttal Testimony, Exhibit Nos. S-37 through S-39.

[29] Ex. S-37 at 42-46. Docket No. RP85-39, 67 FERC ¶ 63,015 at 65,081 (1994), affirmed, 69 FERC ¶ 61,259 (1994).

"not persuaded that Mr. Feinstein's models are consistent with Commission precedent or entirely reliable as a basis for establishing just and reasonable depreciation rates."[30]

36. Although more than 25 years ago, the Commission accepted the EHF Model in Northern Natural,[31] it was reversed by the Court of Appeals. In the court's view, neither the validity nor the reasonableness of the EHF Model was sustained by substantial evidence on the record. Specifically, the court found: (1) The model unduly minimized the importance of developmental drilling during a period when rising prices led to increased drilling activity; (2) The study imputed results of studies of nationwide gas production to the Hugoton-Anadarko and Permian basins; (3) The results gave the impression of facial absurdity by assuming large percentages of reserves would be undiscovered 20 years in the future; (4) The EHF Model ignored current governmental policies expressed in the NGPA and Northern natural's expansion activities and other actions likely to increase gas supply for the future; and (5) The model did not consider reserves in the two basins below the level of 15,000 feet.[32]

37. The EHF Model Mr. Feinstein used for the WCSB ignores developmental drilling and focuses on experimental drilling,[33] which is erroneous as "most analysts now believe that most undiscovered gas reserves will be the result of expanded exploratory areas, more sophisticated estimating techniques and technological advances in petroleum engineering as well as the traditional development of existing fields and pools."[34] The EHF Model as applied by Williston ignored potentially vast unconventional resources of deep gas and estimated a much lower total reserve additions of 111 TCF for the WCSB than the high National Energy Board of Canada (NEB) estimate of 176 TCF and closer to the low NEB estimate of 105 TCF.[35] Therefore, the Commission finds that the EHF Model as applied here does not produce a reasonable result.

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[30] 95 FERC at 65,104.

[31] 8 FERC ¶ 61,123 (1978), affirmed, South Dakota Public Utilities Comm. v. FERC, 643 F.2d 504 (8th Cir. 1981), reversed, 668 F.2d 333 (8th Cir. 1981).

[32] South Dakota, 668 F.2d 333, 341-344.

[33] Exhibit WBI-20 at 33-34.

[34] Exhibit S-37 at 6.

[35] Ex. WBI-2,1 Schedule 25 revised.

38. Mr. Feinstein's R/P Ratio Model was submitted to further support Williston's proposed 23-year average remaining economic life of natural gas reserves. The R/P Ratio Model incorporates the historical statistics of gas reserves to its related production. The R/P ratio is the relationship of gas reserves to its annual production.[36] Based on 1989-1999 data on annual reserve additions,[37] Mr. Feinstein assumed reserve additions in the WCSB at 4.1 TCF per year which are unsupported. Also, when the R/P Ratio Model was applied to the Northern Rocky Mountain Area,[38] the result was an unlikely higher production and reserves for 2022 than those in 2000.[39] Despite the estimated increased production and higher reserves, Mr. Feinstein claims an economic life ending in 2022 (23 years from 1999). However, several leading authorities also predict increased supply, as well as demand, of natural gas through the year 2020.[40] Because of these discrepancies and the fact that the R/P Ratio Model, unlike the EHF Model, has no precedent in any hearings before the Commission, the Commission is not persuaded that the R/P Ratio Model is appropriate to establish just and reasonable depreciation rates.

39. Further on rehearing, Williston argues that since the Presiding Judge relied on Iroquois, to adopt a 35-year life based on the WCSB supply, it follows that we must also adopt the depreciation rate of 2.77% for Transmission plant, to be consistent with the Iroquois precedent.

40. Commission Staff's depreciation rates were developed examining Williston's gas supply, demand, competition and the use of Iowa curves,[41] and therefore Williston's suggestion that the Presiding Judge only considered the remaining life of the WCSB and past proceedings is incorrect. In any event, we are not convinced that the same depreciation rate must be adopted simply because the same 35-year remaining life is being adopted.[42]

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[36] Exhibit WBI-20 at 43.

[37] Exhibit WBI-20 at 30.

[38] Exhibit WBI-20 at 43.

[39] Exhibit S-72.

[40] Exhibit S-75.

[41] Exhibit Nos. 10-12 and revised in Exhibit Nos. 37-39.

[42] A depreciation rate (DR) is derived by subtracting the accumulated reserve for

(continued)

41. On rehearing, Williston disagrees with Staff's proposed depreciation rates for its General Plant subaccounts: 391.1, 391.2, 391.3, 397.3, 397.5, 397.6.

42. The Commission staff witness and the Williston witness both produced depreciation studies, and in fact used many of the same Iowa survivor curves such as S5, S6 and R5.[43] But, only the Commission staff witness properly utilized the latest ten years of historical additions and retirements of General Plant in his calculations. This is significant as the General function's gross plant has increased from $8.437 million in 1990 to $21.151 million as of February 2000.[44] In addition, Williston supplied the latest ten years of historical additions and retirements used by Commission staff in its CADLAS computer program.[45] Williston's witness' calculations, however, inexplicably did not include such latest ten years of data (an increase of nearly $13 million in plant), but used outdated 1990 data and the previously discussed 23-year average economic life. Williston's resulting calculations are therefore flawed.

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depreciation (ARD) from the gross plant (GP) to obtain the net plant (NP), and then dividing by the average remaining life (ARL). Depending on how fully an account is depreciated, the depreciation rate can vary greatly. For example, using GP = $100 and ARL = 35 years we'll use ARD = $5. Therefore, DR = (100-5)/35 = 2.71% or similar to the 2.77% for Transmission plant adopted above in Iroquois. However, when the account is more fully depreciated and ARD = $95, DR = (100-95)/35 = 0.14%. Though the same ARL of 35 years is used in both calculations, the difference is evident as the 2.71% rate is nearly twenty times greater than the 0.14% rate.

[43] Iowa-type survivor curves, developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property has been retired, are appropriate tools to account for the normal retirements that occur over the life of a specific type of facility so that the account will be fully accrued when its life is over. These smoothed curves are widely accepted and employed throughout the pipeline industry.

[44] Exhibit S-32, Page 77 of 521; Exhibit S-31, Schedule No. 1, Sheet No. 2 of 4.

[45] Computer Assisted Depreciation and Life Analysis System, software developed by the Interstate Commerce Commission, which accounts for transfers of plant investment among different accounts or subaccounts that occur in a particular year by adjusting the addition and retirement amounts in each of the previous years in proportion to the dollar amount being transferred into or out of the account/subaccount prior to generating synthetic plant balances and fitting different survivor curves.

43. On rehearing, Williston claims that if Commission staff's 4.40% depreciation rate is applied to Account No. 391.1 (Computer equipment), it would take nearly 23 years for Williston to recover its investment. That would only be true if the equipment were new and undepreciated. But, in fact Account No. 391.1 is nearly 81% depreciated and Williston will recover its remaining investment in approximately 4.3 years.[46]

44. Similarly, Account Nos. 391.2 and 391.3, Williston's two other computer equipment accounts in General Plant, are 61% and 95% depreciated, respectively. Therefore, Commission staff reasonably estimated that Williston will recover its investment in 4.2 years and 2.7 years, respectively, which is consistent with Williston's witness' assessment of replacing property (four years for Acct. No. 391.1, seven and a half years for Acct. No. 391.2, and three years for Acct. No. 391.3).[47] Williston's SCADA system master station and display station hardware and operating software booked in Acct. No. 397.5 was replaced in 1995 and the depreciation reserve book balance (as of April 30, 2000) for this account is a negative balance. Commission staff analyzed the supervisory and telemetering equipment in this account with the associated telephone communication equipment in Acct. No. 397.3. Exhibit S-31 also shows that Commission staff's estimated remaining life (6.8 years) for Williston's SCADA equipment in Account No. 397.6 is comparable to (and more conservative than) Williston's assessment that the expected service life of field equipment that supports the SCADA system is effectively eight years.[48] On rehearing, Williston argues that Commission staff did not study different time periods (analysis bands) to see whether the data evidenced any trend toward shorter average service lives. (Tr. 937). Although Williston witness Link claims there has been a recent trend toward more rapid obsolescence for the plant additions to these General Plant subaccounts, no detailed analysis was provided, and he accepts Williston witness Strand's depreciation rate calculations using data that ended in December of 1990. Therefore, the Commission finds that the depreciation rates calculated by Williston may not be just and reasonable and rehearing is denied. The depreciation rates calculated by Commission staff for Williston's General Plant function are accepted.

45. On rehearing, Williston argues that the Commission staff's survivor curve selections for Storage function plant accounts are not supported by substantial evidence. In its analysis of the physical life of Account No. 352, Storage Wells, Commission staff

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[46] See Exhibit S-31, Schedule No. 2, Sheet 4 of 4.

[47] Page 30 of Williston's request for rehearing.

[48] Ex. WBI-22, pp. 13-14.

used data consisting of 80 years of historical plant additions.[49] For Acct. No. 354, Storage compressor station equipment, Williston witness Feinstein claimed that American Gas Association (AGA) depreciation data refuted the reasonableness of Commission staff witness Greene's average physical life of 57 years, yet the AGA data included Koch Gateway Pipeline Company (Koch Gateway) facilities with an average service life of 55.6 years.[50] Mr. Feinstein states the survey data for Koch Gateway should be disregarded as too long, but Mr. Greene maintains that Koch Gateway is more similar to Williston in its operation and configuration than any of the other pipelines referred to in Mr. Feinstein's testimony.[51] Therefore, Williston's assertion that Mr. Greene's selection of survivor curves was purely mechanical and exclusively dependent on the CADLAS[52] computer program, which incorporated historical data supplied by Williston, is incorrect. As with General Plant, Williston's selection of a 23-year economic life versus Commission staff's 35-year life in the calculation of an estimated average remaining life has a greater impact than the choice of the survivor curves, some of which were used both by Williston and Commission staff.[53] Therefore, rehearing is denied and the Commission accepts the depreciation rates calculated by Commission staff for Storage Plant.

46. Net salvage value means the salvage value of property retired at the end of its service life, less the cost of removal.[54] Pipelines may be permitted to include in their cost of service a charge for negative net salvage to compensate for costs to be incurred in the future associated with the retirement of facilities. Williston has supported its negative salvage rate with a study by Mustang Engineering (Mustang study). The Presiding Judge adopted Commission staff's estimated economic end-life of 35 years through 2033 and negative salvage proposal of 0.20% for transmission plant. The Presiding Judge also

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[49] Staff BOE at 44.

[50] Ex. WBI-20 at 132-133.

[51] Ex. S-43 at 7-8.

[52] A computer software program to assist in selecting Iowa survivor curves developed by the Interstate Commerce Commission and currently used by the Safety Transportation Board.

[53] Ex. S-31, Sch. 2, sheet 3 and Ex. S-32 at 75.

[54] 18 C.F.R. Part 201, Definitions, 23 (2003).

adopted Staff's proposal of 0.85% for FERC Account No. 352, a reduction from Williston's existing negative salvage rate of 1.60%.

47. On rehearing, Williston continues to support the net negative salvage cost of $41,347,675 (expressed in April 2000 dollars) in connection with the retirement of its existing transmission function facilities, which Williston proposes to collect from ratepayers over 20.7 years through the use of a negative salvage rate of 1.18%.

48. The Presiding Judge found Williston's proposed 20.7 year life of the pipeline unsupported by substantial evidence, and held that Williston's witness's work determining Williston's end-life was based on outdated data (ending in 1990). Williston has not provided any new evidence to support its proposed 20.7 year life (ending in 2011).

49. The Presiding Judge, citing one of the criteria for receiving a negative salvage allowance in Iroquois is the consideration of interim retirements: "the evidence is persuasive that interim retirements have been taken into account in computing negative salvage costs," adopted Commission staff's use of historical data reflecting interim retirements. The Commission affirms the Presiding Judge's decision, as Williston did not perform an interim retirement analysis, which would show the existing property in place at the termination of the pipeline's operation,[55] and the end-year remaining life of 2033 is consistent with that used in the depreciation section.

50. On rehearing, Williston also claims Staff's adjustment to the Mustang study net negative salvage amount concerning Acct. No. 369's measuring and regulating (M&R) equipment salvage value should have been rejected. The Commission staff witness based his assessment on historical gross data of M&R equipment, which indicated gross salvage of 33% for the period 1992-1999, and 26% for the period 1995-1999. Williston asserts that Commission staff has over-valued such M&R equipment and that the Company would have to sell the used equipment and facilities at low prices outside of its area. However, Williston has not produced record evidence that interim retirements have been taken into account in computing negative salvage costs.

51. Williston argues that in SERI, the Commission agreed that the expected net negative salvage amount applicable at the time of decommissioning should not be adjusted based on historical experience related to interim retirements.[56] The Commission

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[55] See Staff Initial Br. at 82; Tr. 329.

[56] System Energy Resources, Inc., 92 FERC ¶ 61,119, at p. 61,451 (2000) (SERI).

so held because SERI's use of parts, salvaged from the cancellation of a planned second unit and placed in inventory, caused the historical experience to be unrepresentative of the net negative salvage amount that would be expected at the time of final decommissioning. We are not persuaded that the temporary bookkeeping anomaly of nuclear spare parts in SERI is at all similar to Williston's situation here. As noted above, evidence showed a pattern of successful use of salvaged M&R equipment, based on historical data on the record, and one may reasonably expect this will continue in the future. Williston's witness, by not adjusting for the sales and reuse of M&R equipment in his negative salvage estimate, has derived a negative salvage allowance that may not be just and reasonable. Therefore, Williston's arguments on M&R equipment are unavailing.

52. Finally, on rehearing, Williston complains that although Williston's transmission plant was updated to reflect year-2000 dollars, the calculated negative salvage rate of 0.21% was reduced to a recommended negative salvage rate of 0.20% because this was the methodology used in Commission staff's original calculations. We agree with Williston that the rate of 0.21%, the calculated rate before rounding, should be used as the negative salvage rate. In the other rate determinations for both depreciation and negative salvage in this proceeding, the calculated rates were not rounded to a recommended rate. Therefore, to be consistent, the use of a 0.20% negative salvage rate which was a rounded figure is rejected, and a 0.21% negative salvage rate for transmission M&R equipment shall be used. Rehearing is granted on this issue.

5. Ad Valorem Tax Rates

53. Each year, Williston pays property-related taxes (ad valorem taxes) on its facilities in the Dakotas, Montana, and Wyoming. The individual states calculate the taxes by multiplying the assessed value of Williston's property by the established tax rate, generally each year. The states base the tax on the assessed value of Williston's property as of the end of the preceding year.

54. The remaining contention on this issue is whether to allow Williston's payments to Montana and Wyoming for taxes assessed over an 18-month period or 12 months of ad valorem taxes accumulated during the test period. In the July 3 Order, the Commission affirmed the ALJ's decision to adopt Staff's use of the total test period ad valorem payments of $5,222,090, less the additional 6 months of accumulated payments to Montana and Wyoming totaling $1,317,347.35, with one exception. The Commission found that Staff overstated the Montana production plant by $136,561, and required an

upward adjustment to the $3,904,742.65 in tax payments incurred during the test period.[57] On rehearing, Williston agrees with the Commission's $136,561 adjustment, but maintains that rejection of the additional tax payments paid during the test period is contrary to prior Commission holdings.[58]

55. In its rehearing request, Williston broaches no new arguments from those previously raised and addressed in this proceeding. Williston repeats its proposal to include tax payments assessed for a previous tax year and held for payment during the test period. This proposal would place 18 months of tax expense in Williston's "annual" cost-of-service. As stated earlier, the Commission does not permit pipelines to accrue expenses between test periods for recovery in future periods; nor do we permit past expenses that are not representative of the period the rates are in effect. For these reasons, we will allow Williston to recover the latest actual ad valorem taxes incurred and accrued during the annual test period, and affirm our rejection of the additional 6 months of accrued ad valorem payments ($1,317,347.35) for taxes assessed prior to the test period. This finding is consistent with our treatment of other expenses in the cost of service that are accrued outside the test period, and the precedent we have consistently applied with respect to ad valorem taxes.[59] Accordingly, Williston's request for rehearing is denied.

6. Labor Costs

a. Proposed Labor Capitalization Percentages

56. In the July 3 Order, we affirmed without further discussion the ALJ's conclusion that Williston should capitalize 14.76% of labor expense rather than 12.635% proposed by Williston. Labor capitalization expenses are those expenses that should be capitalized to reflect the time spent by employees on construction projects. The amounts to be capitalized are reflected as a percentage of total allowable labor costs. The parties

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[57] July 3 Order at P 82-84.

[58] Williston Request for Rehearing at 70-72.

[59] Williston, 72 FERC & 61,074 at 61,362-63 (1995); 76 FERC & 61,066 at 61,383-84 (1996); and 84 FERC & 61,081 at 61,369-70 (1998). The 1992 rate proceeding cited by Williston is irrelevant in this case. The issue involved "anticipated" increases in ad valorem tax assessments as a result of plant additions occurring within the test period, and not pre-test period payments.

stipulated that total labor expenses of $10,738,016 should be allowed, based on a payroll run for the last pay period of the test period.

57. Staff and Williston agreed that a three-year average should be used to calculate the percentage of labor costs devoted to construction, since the amount of construction-related activity varies from year to year, as does the resultant capitalization percentage. Williston used a three-year average of this percentage for 1996, 1997 and 1998, the most recent year prior to the filing of this case, by taking the total construction-related and other non-operation and maintenance-related payroll, as a percentage of total payroll. The parties agreed that this averaging technique was appropriate since the amount of construction-related activity varies from year to year. This average resulted, according to Williston, in a proposed labor capitalization percentage of 12.635%, based on the average of the years 1996-1998.

58. Staff argued that, having updated test period labor expense to 1999, it was appropriate that the labor capitalization percentage also be updated. Therefore, Staff's three-year average is based on the years 1997, 1998 and 1999, the last year for which a full year's data was available in the test period. In addition, Staff excluded any labor costs for WBI Holdings Company (WBI Holdings), asserting that WBI Holdings' labor dollars have nothing to do with Williston's labor dollars, and that their inclusion merely serves to dilute the otherwise applicable labor capitalization percentage.

59. The ALJ found that Staff's proposed percentage of labor costs that should be capitalized, 14.76%, was fully supported by the record. The ALJ also agreed with Staff that the labor expense related to WBI Holdings should be excluded from the calculation of the labor expense capitalization percentage. The ALJ stated that the WBI Holdings' labor expense is more properly an overhead charge to Williston. We affirmed the ALJ.

60. On rehearing, Williston reiterates the same arguments it used in its brief on exceptions to the ALJ's initial decision. It claims that it did not seek to include WBI Holdings' labor expense in Williston's labor expense. Williston explains that WBI Holdings was not formed until July 1998, and that the employees of WBI Holdings had been Williston employees until that time. Whether the three-year period 1996-1998 or 1997-1999 is used, Williston claims that it is necessary to include the WBI Holdings' labor expense until the end of the period in order to get a valid comparison. Williston further claims that the only percentage figure supported by the record is the 12.635% that it proposed, but that the 14.76% figure is derived only from cross-examination of Williston's witness and the exclusion of WBI Holdings.

61. The Commission denies rehearing on this issue. The purpose of adjusting the three-year average is to obtain a number which will be representative of the future. The Commission is persuaded that the WBI Holdings costs should be excluded. It is

appropriate to reflect Williston's labor expense on a forward looking basis, and, since WBI Holdings was not a part of Williston's labor costs during the test period, their inclusion merely serves to dilute the otherwise applicable labor capitalization percentage. Since Williston's test period labor expenses – i.e., the stipulated $10,738,016 - reflects WBI Holdings' employees, they should likewise be excluded developing the historical three-year average of labor cost to be capitalized.

62. Moreover, updating the numbers to be averaged to the later period (i.e., the three-year period ending 1999 rather than 1998) is consistent with annualizing labor expense based on the last payroll run of the test period. As to Williston's contention that rehearing should be granted because there is no affirmative Staff testimony which takes issues with Williston's 12.635% capitalization percentage, nor any staff testimony why any different percentage should be used, the Commission finds that the ALJ's 14.76% is a legitimate calculation of a percentage from numbers which are in evidence, through a Staff-sponsored exhibit and through the cross-examination of Williston's witness.[60] As such, there is ample record evidence to support the use of 14.76% rather than the 12.635% claimed by Williston. Therefore, rehearing is denied.

b. Proposed Inclusion of Open Positions in Test Year Labor Expense

63. The July 3 Order affirmed the ALJ on this issue. The ALJ rejected Williston's claim for $150,197 relating to authorized employee positions that were not filled as of April 30, 2000, the end of the test year in this proceeding. The ALJ stated that Williston has failed to justify departure from the reasoning relied upon by the Commission in considering, then rejecting, the identical proposal in its last rate case.[61] Further, the ALJ found that these proposed expenses were not effective prior to the end of the test period.

64. On rehearing, Williston again merely reiterates the same position and arguments it raised on exceptions to the ALJ's decision. It argues that an employee who worked every day for the prior year up to the date of the last payroll run but who was not on the payroll then, would be excluded from the labor costs. It says that only by adding in the annualized wages associated with any open positions which the company is actively pursuing to fill will Williston be allowed to include in its cost of service the total wages associated with all authorized employee positions.

65. The Commission affirmed the ALJ on this issue. Williston recognizes that its

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[60] See Id. at 65,112, note 434.

[61] Williston Basin Interstate Pipeline Co., 84 FERC ¶ 61,081(1998) at 61,367-68.

claim is substantially the same as the one the Commission had already disallowed in its prior rate case. In effect, Williston is contending that the Commission should reverse its prior policy respecting open positions. Williston has provided nothing to indicate that our reasoning in the prior rate case is wrong, and Staff is correct in stating that it has never been Commission policy to allow as an expense the costs of all authorized but unfilled positions, even if the company is trying to fill those positions.[62] As Williston's witness himself conceded, there are frequently times when positions go unfilled for various periods of time. Rehearing is denied on this issue.

7. Non-Labor O&M Expenses

66. Williston seeks rehearing of the Commission's affirmation of the Initial Decision holding that all operating costs to be included in the cost of service should be the test period amounts, rather than Williston's projected amounts.[63] Williston states that, when it made its filing, it included $5,926,963 of non-labor O&M expenses.[64] Williston states that this amount was derived by using the twelve months ending July 31, 1999 (the base period), and projecting certain adjustments through April 30, 2000 (the end of the test period). Williston states that it "made these specific adjustments to its base period actual expenses to account for known and measurable changes through the end of the test period…." Williston notes that the adjustments it proposed are for expenses associated with the cost of service portion of the MMS royalty payment and the Billy Creek compressor.[65] Williston states that the ALJ did not make required adjustments to the end of test year figures adopted, and cites two examples where the end of test year figures must be adjusted. The first of these has to do with "Storage" expense, where the ALJ allegedly would allow $650,489 compared to Williston's filed proposed level of $1,015,716. Williston states that the ALJ's figure did not include $242,387 for the expense portion of the MMS royalty payment Williston made. The second example concerns mainline transmission. Williston claimed expense is $4,514,016, whereas the ALJ number is $4,244,631. Williston claims that the ALJ figure includes only $87,500 for expenses related to the Billy Creek compressor, yet the ALJ states that the correct

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[62] See Staff Brief Opposing Exceptions at p.102.

[63] Id. at 65,113.

[64] Williston Rehearing at 75.

[65] Ibid., at 75-76, and fn. 87.

expense level is $150,000.[66] Williston contends that these two items alone would raise the expense level approved by the ALJ to $5,502,825.[67]

67. The Commission agrees in part with Williston's analysis. The ALJ was correct in her statement that the Commission has a clear policy preference that the determination of "just and reasonable" rates be based on the most accurate and current information available within the test period. Here, that information is the end of test year amounts reflected on Williston's books, adjusted to reflect the approved adjustments contained in the Commission's orders in this proceeding. For example, the amount claimed for regulatory expenses approved by the ALJ was $826,815, representing the three-year average of such expenses for Account No. 926 for the three years ended February 2000. There are other instances where Williston or other parties may have justified departure from the end of test year general principle and where the ALJ or the Commission has approved such departure. Thus, Williston is partly correct that the end of test year numbers should not be used in all situations.

68. As to the Billy Creek compressor, the approved cost is $150,000, which is the annual lease cost for the unit, and was found by the ALJ to be a representative level on which to base rates. This amount was agreed to by the parties and should be used by Williston in calculating its rates resulting from this proceeding. However, as to the expense portion of the MMS royalty payment made by Williston, the Commission has already disapproved the inclusion of the MMS royalty amounts claimed by Williston (supra, PP 17-20). Consistent with that action, Williston may not include the expense portion of the MMS royalty payment associated with the disapproved royalty amounts in its cost of service. Therefore, Williston must calculate its cost of service based on the end of test period (i.e., April 30, 2000) amounts, excluding the amounts claimed for the expense portion of the MMS royalty payments and including an amount of $150,000 for the Billy Creek compressor, unless a departure from the end of test period has been specifically approved.

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[66] Id. at 65-115.

[67] This amount is derived by adding the two adjustments claimed by Williston ($242,387 for the effect of MMS royalty payments plus $62,500 difference between the Billy Creek compressor cost as approved by the ALJ) to what Williston claims is the amount approved by the ALJ of $5,197,938 (see id. at 56,113).

8. Correct Level of Rate Schedules FT-1 and IT-1 Volumes and Quantities

69. In the July 3 Order, the Commission affirmed the ALJ's decision to use test period actual volumes as representative of the throughput levels for Rate Schedules FT-1 and IT-1.[68] On rehearing, Williston argues that the Commission should have adopted the volume levels originally proposed by Williston. Williston adds that even if it is correct to use test period actual volume levels they should be adjusted to reflect nonrecurring transactions and should be annualized for other transactions.[69] Williston presents no new arguments on rehearing. As a general practice, the Commission accepts the most recent actual test period data as the best evidence of what volumes are expected to be once the rates take effect.[70] For this reason, the Commission affirms its findings in the July 3 Order and denies Williston's rehearing requests as discussed below.

a. Rate Schedule FT-1

70. The issue here is whether to accept the FT-1 volume levels originally proposed by Williston or whether to use actual volume levels as a basis for the design of FT-1 rates. These are the two positions advocated at the trial in this proceeding. Williston claims that because its original projections are so close to the end of test period actual volumes and that it has complied with section 154.303(4) of the Commission's regulations, its volume projections rather than the test period actual levels should be adopted. [71] Williston offers the comparison below.

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[68] July 3 Order at P 85-87.

[69] Williston Request for Rehearing at 77-82.

[70] See, e.g., Stingray Pipeline Co., 98 FERC ¶ 63,004 at 65,011 (2002); citing Williston, 165 F3d 54 at 64-69 (D.C. Cir. 1999) (the Commission re-affirmed this point on remand from the D.C. Circuit Court of Appeals, which had granted in part and denied in part the petition for review of Williston, 72 FERC ¶ 61,074 (1995), and order on rehearing, 76 FERC ¶ 61,066 (1996).

[71] Williston Request for Rehearing at 78.

	Williston Projections	FT Test Period Actuals
MDDQ Eqv. Dth	311,513	317,826
ADQ Eqv. Dth	61,140,997	62,017,164
Commodity Dth	39,409,803	42,210,071

71. In addition, Williston contends that the Commission's adoption of the ALJ's decision to use the actual volume levels at the end of test period is not appropriate because the Commission failed to follow its own regulations by not conducting an analysis to determine whether the test period contains non-recurring events or transactions that need to be annualized. Williston suggests that this claimed shortcoming could be remedied by adjusting the test period actual volume levels downward to remove volumes related to two short-term contracts terminated by ONEOK in April 2000, and by adjusting the test period volumes upward to include a long term contract with Prairielands Energy Marketing Inc. (PEMI).

72. Specifically, Williston argues that the ONEOK volumes must be eliminated as nonrecurring because ONEOK, a marketer, has chosen not to do business on Williston's system. Williston contends that ONEOK's decision essentially creates a by-pass situation because the result is the same as if a producer had built facilities to by-pass Williston.[72] Williston attempts to justify the adjustment for ONEOK volumes, by stating that the adjustment would be consistent with the Commission's findings in Williston's 1992 rate case. In particular, Williston points to the Commission's statement:

> Had the bypasses taken place in the test period, as Williston had expected, the adjustment would have been permitted.[73]

73. Preliminarily, we note that section 154.303 of our regulations sets forth the filing requirements that interstate pipelines must follow when proposing changes in rates. These regulations do not dictate how the Commission should decide an issue after a hearing record has been developed.[74] In addition we do not agree with Williston that if a

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[72] Williston Request for Rehearing at 79.

[73] Citing Williston, 76 FERC ¶ 61,066 (1996).

[74] See, e.g., Williston, 72 FERC ¶ 61,074 (1995); and Williston, 87 FERC ¶ 61,265 (1999).

pipeline's originally proposed volume levels are close to the ultimate test period actual volumes, then we must adopt the originally proposed levels for rate making purposes. Moreover, what Williston characterizes as "close" is not insignificant. For instance, the MDDQ difference shown above when applied to the refund rates in Williston's compliance filing generates over $660,000 in revenue alone.

74. We generally use end of the test period actual information because we find it provides the best evidence of what can reasonably be expected to occur once the rates take effect. [75] Notwithstanding that general rule, adjustments to the end of test period information may be reasonable in certain circumstances. For instance, a legitimate bypass situation is an event that the Commission may consider when developing rate design volume levels on which to design future rates just as we may consider markets lost to plant closings or similar events that would suggest traditional load may be lost for a considerable time period. However, the hearing record in this case does not support such an event. In prepared testimony Williston's witness merely states that ONEOK has chosen not to do business on Williston's system and no other shippers have contracted with Williston for the capacity. [76] There is no mention of the nature of the market, if it continues to be served by other means and, if so, by whom. In other words there is insufficient information in the record for the Commission to determine if the volume associated with the terminated ONEOK contracts is nonrecurring and actual test period levels should be revised accordingly.

75. In order for adjusted end-of-test-period levels to be superior to the actual levels for the period, one would have to investigate each service contract underlying the actual levels to determine whether there are any trends that are evident that suggest whether or not each contract should be adjusted. Based on the evidence, Williston has not performed such an analysis in this case.

76. We also find Williston's reliance on the Commission's finding in its 1992 case misplaced. In that case, the Commission did not make a finding on the legitimacy of adjustments for "bypasses," it merely rejected Williston's throughput adjustments related to bypasses that occurred on its system because they occurred after the test period.

77. Therefore, we affirm our decision to accept the actual test period volumes shown above, reflecting the most current volumetric data in the record for the test period which consists of the twelve-month base period ending July 31, 1999, and the nine-month

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[75] Williston, 72 FERC at 61,382.

[76] Rebuttal testimony of William D. Kickert, II Heraing Exhibit No. WBI-49.

adjustment period ending April 30, 2000. This results in rates which reflect costs and volumes that best represent the throughput volumes for the period the rates are effective.[77]

b. Rate Schedule IT-1

78. The July 3 Order affirmed, without discussion, the ALJ's decision to use Staff's 28,864,459 dkt actual test period volumes as opposed to Williston's use of 26,155,001 dkt adjusted base period volumes. On rehearing, Williston broaches no new arguments to grant rehearing but merely reiterates the same arguments it raised before the ALJ in its earlier pleadings in this proceeding. For the reasons discussed earlier we reject Williston's arguments with respect to the firm transportation volumes, and we deny rehearing on Williston's parallel arguments regarding its interruptible transportation (IT-1) volumes.

9. Discount Methodology and the Allocation of Storage Costs

79. In our July 3 Order we summarily affirmed the ALJ's decision on this matter without discussion. The ALJ concluded that Williston's adjustment of storage allocation units and subsequent re-allocation of storage costs performed as part of its discount adjustment calculation was inconsistent with Commission policy. As a result the ALJ adopted Staff's proposed methodology. On rehearing Williston argues that we erred because the ALJ's claim was incorrect and that, in fact, Williston's methodology conforms to Commission precedent. We deny rehearing for the reasons below.

80. Williston provides both firm and interruptible storage services and in order to retain certain interruptible storage customers it provides service to them at a discounted rate.[78] As a result, in order to design maximum tariff rates for storage service a discount adjustment must be performed. One way of adjusting the maximum rate for the effects of discounting is the ratio method, under which a percentage of the volume attributable to discounted service is included in the volumes used to design the pipeline's rates based on the ratio of the pipeline's discounted rates to its new just and reasonable rates. Application of this method requires the use of a somewhat complicated iterative mathematical computation, since the final just and reasonable rates cannot be known until a proper discount adjustment is calculated, but the proper discount adjustment cannot be

[77] See Northwest Pipeline Corp., 82 FERC ¶ 63,012 at 65,071 (1998); citing Williston, 52 FERC ¶ 61,170 at 61,648 (1990).

[78] See WBI-46 Lawrence Rebuttal Testimony at page 3, line 20.

known until a final just and reasonable rate is calculated.[79] Under this process the service units used for designing rates are reduced with each iteration and divided into the cost of service to arrive at a new, higher, maximum rate. The process continues through a number of iterations. When the rate does not change from the rate derived in the immediately preceding iteration the process is over and the last rate calculated is the maximum tariff rate for the services in question. Also, the rate design derivation units for the last iteration should be the same as those used in the immediately preceding iteration. Staff performed a discount adjustment using this method and presented it at the trial in this proceeding.[80] Williston claims it performed an iterative discount adjustment as well and presented the results of the process in Schedule J-1(e) of its original filing and motion filing in this docket.[81]

81. The primary difference between the method presented by Staff and the method used by Williston is a storage cost allocation difference. Whereas staff allocates storage costs once at the beginning of the iterative discount adjustment process, Williston claims it re-allocates storage costs each time it performs an iteration using the same service units that it uses for the design of rates for the iteration being performed.[82] Williston claims its reallocation step is consistent with Commission policy and Staff claims it is not.

82. Generally speaking, the allocation of costs is a separate step in computing rates for services. For instance, on long-line pipelines that have rate zones, transmission costs are allocated or proportioned among the zones based on contract demand weighted for mileage. Contract demand is used because it provides a relative measure of the service levels that cause the company to incur the fixed costs associated with its system. In other words, a customer demanding twice as much service as another customer would be expected to pay twice as much for its service assuming the same distance haul. Once costs are allocated there is usually no need to revisit this step in the process of designing the pipeline's per unit rates because the allocation step apportions the cost responsibility to the classes of customer based on cost causation principles and the recovery of those costs is achieved through a subsequent rate design step.

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[79] Williston, 67 FERC at 61,381-82.

[80] Staff exhibit No. S-42.

[81] Tiggelaar Cross-Examination Vol. 13, Tr. 1519, lines 4-9.

[82] Tiggelaar Cross-Examination Vol. 13, Tr. 1517-1518.

83. Williston is not a zoned pipeline, but the principles of allocation apply here as well when Williston allocates its storage costs. Williston must perform an allocation of its storage function costs because its storage facilities not only allow Williston to provide firm and interruptible storage service, but they also perform a valuable function for transportation services offered by Williston. Storage provides balancing and line pack functions for transportation services.[83] Consequently, storage costs must be allocated to the storage services and to the transportation services that benefit from Williston's storage operation. Both Staff and Williston performed an allocation of storage costs. The allocation was done once by Staff, following the usual practice, and many times by Williston. In fact, to the extent Williston re-allocated storage costs each time it performed a discount adjustment iteration, in this proceeding Williston re-allocated storage costs 66 times. [84]

84. The Commission affirmed the ALJ's decision to adopt the Staff's method for the allocation of storage costs and designing storage rates because it follows sound ratemaking principles and the result appears reasonable. There is no need, based on this record, to re-allocate costs while performing the iterative rate design process. The staff's one-time allocation is the usual manner to establish cost responsibility based on cost causation principles. Second, a review of the iterative process presented by staff shows that, with each of the six iterations performed by the Staff's witness, the maximum rate increased and the difference between the rate and the one that immediately preceded it became smaller and smaller until the computed rates converged, a result that seems reasonable.[85] Staff's presentation shows what one would expect to see when applying a discount adjustment.

85. On the other hand, other than the end result summary contained in Schedule J-(e), the record in this case appears not to contain the iterative process Williston claims to have performed. As a result, it is impossible for the Commission to test the reasonableness of the result. The reasonableness of Williston's iterative process could be assessed by examining whether the maximum rate computed by Williston increased after each iteration. Then we would check to see if the rate derivation units for the last iteration are the same as those used in the immediately preceding iteration. Because

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[83] Tiggelaar Cross-Examination Vol. 13, Tr. 1490, line 16.

[84] Tiggelaar Cross-Examination Vol. 13, Tr. 1521, lines 1-6.

[85] Williston's witness Lawrence recognized the convergence aspect of the iterative process as a natural result. See Tiggelaar Cross-Examination Vol. 13, Tr. 1518, citing to WBI-13 Testimony of Dale R. Lawrence at page 20, line 14.

Williston shows only the result of the last iteration, we are unable to determine if Williston's iterative process is reasonable. In fact, based on the number of iterations Williston's witness claims were required to develop a maximum rate sufficient to accommodate the discounts permitted by Williston, its process seems unreasonable.

86. Earlier we stated that the usual practice is to allocate costs once with no need to revisit this step in the process of computing rates. On rehearing Williston claims we erred by not accepting its proposal to re-allocate costs with each iteration of the discount adjustment process essentially re-allocating storage costs 66 times. Williston claims that our precedent on this issue supports its position and it cites four proceedings.

87. We are not inflexible with regard to any of the steps that culminate in final rates for pipeline services. At times, for equity reasons, we may deviate from usual practices in response to an alleged anomaly or unexpected result. For instance, in the Southern[86] case cited by Williston the Commission agreed that Mississippi Valley Gas Company (Mississippi Valley) had identified a problem with Southern's rates that should be corrected. Mississippi Valley contested the settlement in the case and argued, among other things, that the mismatch of cost allocation factors and rate design volumes used by Southern resulted in more costs being allocated to Southern's traditional Production Area Zone than could be recovered in that zone due to the disproportionate amount of discounting in that zone compared to other zones. The Commission held that the appropriate remedy was to revise Southern's cost allocation methodology to reflect the effects of discounting. However, because the settlement did not purport to resolve cost allocation issues, the Commission decided the remedial issue should be addressed in the parties' briefs to the Commission on cost allocation and rate design issues. Later the issue ultimately settled in Docket No. RP90-139-000, and the proceeding terminated, on June 19, 1997, in Docket No. RP89-224, et al.

88. Our initial reaction to Mississippi Valley's claim was an attempt to address a dilemma specific to Southern's zoned-rate structure, wherein the application of the traditional cost allocation methodology could result in unjust and unreasonable rates. Because the issue later settled we had no opportunity to review Mississippi Valley's concerns in the context of the briefing schedule set in the case and determine if the problem could be fixed by matching allocation and rate design units. Consequently, we do not believe the Southern case can be used to identify any general Commission policy regarding discount adjustments. More importantly, Williston has not supported or identified any unique circumstances on its system that might suggest that traditional cost allocation methods would render unexpected results. The Southern case is therefore, sui

[86] Southern Natural Gas Co., 65 FERC ¶ 61,348 (1994).

generis, and Williston has made no showing that it is in the same straits as Southern, so that an exception should apply to it.

89. Williston also claims that our decision in a Northern [87] case supports its position to match cost allocation volume level with those used to compute rates through the discount adjustment process. Williston cites the following language from the order to support its position:

> Northern is not following standard Commission practice in designing the FDD [Firm Deferred Delivery] rates … In addition, Northern is not using the same volumes for allocating costs to the FDD service that it uses for billing the FDD service. If it uses the same units for rate design and billing it will have a reasonable opportunity to recover its entire allocated storage costs of service via the FDD and SMS [System Management Service] rates.

90. In this case, Northern allocated costs to its FDD service based on the ratio of the service level it expected to sell (49.2 Bcf) to total storage capacity available (63.2 Bcf). The remaining 14 Bcf was earmarked for another service – its System Management Service. However, when designing its rates Northern used all 63.2 Bcf for FDD service. As indicated in the above passage from the order, the Commission thought Northern should use the 49.2 Bcf for designing its rates rather than the 63.2 Bcf so that its billing units would match the level of service it expected to sell. That would give Northern a reasonable opportunity to recover its allocated costs. The Commission does not say that the allocation units must match the rate derivation units, as Williston suggests. Moreover, the facts in the Northern case match allocation units with billing units (49.2 Bcf). The rate derivation units used in a discount adjustment process are not the same as the billing units. Williston acknowledges this difference in its Schedule J-1.[88]

91. Williston also claims that a Panhandle case[89] allowed discount adjustments to be reflected in the MMBtu/Mile cost allocation factors so that there will be a match between the volumes used for cost allocation and those used for rate design.[90] To the extent Panhandle and also Southern may be read as stating a general policy that discount

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[87] Northern Natural Gas Company, 62 FERC ¶ 61,075 (1993).

[88] Compare columns (A) and (B) of Schedule J-1.

[89] Panhandle Eastern Pipe Line Co., 74 FERC ¶61,109 (1996).

[90] Williston Request for Rehearing at 94.

adjusted volumes must be used for allocation as well as rate design, the Commission does not believe such a policy is correct.[91] For the reasons discussed above, we find that the cost of service should generally be allocated based upon non-discounted volumes in order to properly match cost incurrence to cost causation.

92. Finally, Williston claims that the Court in 1987 rejected Staff's allocation methodology in the process of affirming Order No. 436.[92] In Associated Gas Distributors v. FERC (AAGD@), Williston states that the Court discussed the impact of discounting on pipeline solvency and concluded that the Commission could not employ rate calculations based on a procedure that uses unadjusted throughput units. The Court interpreted the language from the Commission=s regulation (which refers to the revenue requirement allocated to firm and interruptible services) as proof that the Commission agreed to use maximum rate (i.e., discount-adjusted) throughput quantities. Williston contends that Staff's use of unadjusted units of service to allocate costs violates the holding in AGD.

93. We find Williston misreads the Court's 1987 decision, whose core concern was rate design – whether to allow a discount adjustment – and did not reach the mechanics of any particular cost allocation methodology. The Commission responded to the court's concern by allowing discount adjustments, but never mandated iterative reallocations of costs. Rather, as a general rule such cost reallocations would be unfair to customers, save where they are agreed to as part of a settlement, or in exceptional circumstances, such as presented in Southern, supra, where the viability of the pipeline itself would be threatened, were such reallocative adjustments not permitted.

94. To allow Williston to implement discount adjustments combined with iterative shifts in allocation factors may understate the correct allocation of storage costs to interruptible service and unreasonably overstate costs to firm service, to the detriment of users of firm service who would have such costs shifted to them. Since this issue has not been settled, and Williston has presented no convincing rationale or extreme economic circumstance to support its deviation from the Commission's generally applied discount adjustment methodology, Williston's request for rehearing on this issue is denied.

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[91] We also note that the Panhandle case settled while rehearing of the order cited by Williston was pending. Accordingly, it has been held that the Panhandle case must be treated as only a tentative statement of the policy the Commission intended to apply in future cases. See Panhandle Eastern Pipe Line Co. v. FERC, 198 F.3d 266 (D.C. Cir. 1999); Pacific Gas & Electric Co. v. FERC, 506 F.2d 33 (D.C. Cir. 1974).

[92] See AGD, 824 F.2d 891, 1012 (D.C. Cir. 1987).

10. Limitation on Northern States Power's Annual Volumes for FT-1 Service

95. In the July 3 Order, the Commission affirmed the ALJ's rejection of contentions made by NSP that it has been treated unfairly by Williston with respect to service under Williston's Rate Schedules FT-1 and X-13. The ALJ determined that NSP has been given the use of all the firm capacity on the Mapleton Extension (the portion of Williston's system where deliveries are made for NSP's account) with an effective load factor total ADQ of over 97%. NSP seeks to convert X-13 service to Part 284 service, and challenges the 50% limitation on its FT-1 service entitlement that Williston has imposed. The ALJ denied NSP a forum in which to examine the X-13 conversion issue, and further concluded that Williston had established that the 50% limitation on NSP's FT-1 service had not been imposed for valid operational reasons.[93]

96. NSP seeks rehearing of the July 3 Order. NSP contends Williston should be required to convert its individually certificated X-13 service to Part 284 open access service under Rate Schedule FT-1 on a revenue-neutral basis. It contends that the ALJ's decision to strike NSP's testimony on the conversion issue and the Commission's unstated affirmance thereof was error and was based on a misreading of decisions that had nothing to do with the X-13 conversion issue. Further, NSP contends that the Commission erred in adopting the the ALJ's acceptance of the 50% ADQ limitation on NSP's service under Rate Schedule FT-1, contending that the "operational reasons" relied on by the ALJ are illogical, and that the record does not demonstrate that WBI, with respect to the ADQ issue, has treated NSP fairly and in a manner consistent with Commission policy.

97. In the proceedings before the ALJ, NSP proffered testimony in support of its position that Williston should be required to convert, on a revenue-neutral basis, its individually certificated service under rate Schedule X-13 to Part 284 Open access service. The ALJ struck the NSP testimony, based on the ground that the matter had already been decided by the Commission and the Courts. In its exceptions to the ALJ's treatment of this matter and in its request for rehearing, NSP pointed out that there are in effect two issues involved in consideration of the X-13 service. One issue is whether Williston has overrecovered its cost of service to the detriment of NSP, and the other is whether, as a matter of policy, Williston should be required to convert this individually certificated service to an open-access transportation service. According to NSP, the ALJ mistakenly relied on a court ruling[94] having to do with the cost recovery issue in ruling on

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[93] Id. at 65,123.

[94] Williston Basin Interstate Pipeline Co. v. FERC, 215 F.3d 875 (8th Cir. 2000).

Williston's motion to strike all of NSP's evidence, failing to distinguish between the cost recovery issue and the conversion issue. NSP contends that it is fully entitled, in this general rate proceeding, to pursue the X-13 conversion issue. NSP asks that the Commission either reinstate the stricken testimony and remand the issue to the ALJ for further proceedings, or alternatively, remand the issue for resolution through the Commission's Dispute Resolution Service.

98. NSP points out that it has long sought resolution of the conversion issue in various proceedings before the Commission, yet has been stymied in its attempts to get a hearing on this issue.[95] Indeed, in the Commission's biennial orders on the restatement of rates for Williston's Rate Schedule X-13, the Commission has recognized NSP's protests and its plea to convert the certificated Rate Schedule X-13 service to open-access service under Part 284 of the Commission's regulations, and has agreed with NSP that the Commission wants pipelines and their customers to pursue the issue of converting Part 157 services to Part 284 services to promote as competitive an environment as possible for natural gas. However, the Commission has stated in those orders that the biennial restatement proceedings were not the proper forum for resolution of this issue.[96]

99. Upon review of this matter, the Commission finds that NSP is entitled to a forum for resolution of this conversion issue, and that the bases for striking NSP's testimony and argument on this issue were flawed. We shall therefore remand the issue to the ALJ for consideration of the proffer of testimony and issues raised by NSP regarding Rate Schedule X-13. The Commission has consistently encouraged pipelines and customers to pursue the issue of converting Part 157 services to Part 284 service to promote the most open competitive market possible for natural gas. NSP has offered to pay Williston the incremental rate that Williston would be entitled to under Rate Schedule X-13 even if it converts to Part 284 service, which conversion would enhance NSP's capacity release opportunities. [97]

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[95] NSP Request for Rehearing at 2-7.

[96] See 102 FERC ¶ 61,327 at 62,119 (2003); 94 FERC ¶ 61,392 at 62,472 (2001).

[97] This conversion issue was not rendered moot by Williston Basin Interstate Pipeline Co. v. FERC, 215 F.3d 875 (8th Cir. 2000), which dealt only with the proper calculation of the incremental rate under rate schedule X-13, as some of the components would now be known with finality at the time the rate was restated every two years, and therefore would necessarily need to be retroactively adjusted in order to be calculated accurately.

100. NSP also objects to the 50% take restriction on its FT-1 service contract with Williston. Williston argues that the restriction is justified for operational and maintenance reasons, but NSP counters that Williston's tariff gives the pipeline the right to perform necessary maintenance without triggering a breach of contractual obligations even if a customer had a 100% call on service on a particular segment. Since neither the possibility of converting the X-13 service to Part 284 service, nor the 50% limit on NSP's FT-1 service on the Mapleton extension have been heretofore closely examined by the Commission, the ALJ is directed, as part of the determination whether the X-13 rate should be converted to Part 284 service, to re-examine whether the 50% limit on NSP's FT-1 ADQ is just and reasonable under the circumstances presented.

101. Resolution of the X-13 issues and NSP's objections to the 50% restriction on NSP's service under Rate Schedule FT-1 appear to be interrelated (as the combined X-13 and FT-1 capacity NSP holds amounts to 97% of the capacity on the Mapleton Extension), and the resolution of the X-13 conversion issue may help in resolving whether or not remedial action need be taken with respect to the 50% restriction on NSP's service under Rate Schedule FT-1. In any event, both the customer and the pipeline are entitled to a forum in which their arguments and evidence may be fully tested. It appears that nascent settlement discussions on these issues may have been truncated by the Order on Initial Decision in this case.[98] The parties are free to consider alternative methods of dispute resolution or settlement in order to avoid the expense and uncertainty of litigating these issues. The Commission will defer to the presiding judge whether the hearing on the remanded issues should be held in abeyance if the parties jointly request that hearing be delayed in order to pursue resolution by settlement judge proceedings or by alternative dispute resolution through the Commission's Office of Dispute Resolution Services.

11. Storage Cost Allocation of Cushion Gas and Related Rate Design

102. The July 3 order generally affirmed the ALJ's Initial Decision on cost allocation and rate design issues without comment. In its rehearing request Williston continues to re-work earlier arguments in support of its own allocation method.

103. As a general matter, when allocating costs among classes of customers the allocation factors or percentages are developed using determinants that are the same as, or are based on, the service levels of the customers. This is a fundamental principle of cost allocation because, in the case of fixed costs, it reasonably distributes the costs among services based on the customers' relative rights to use the facilities to which the

[98] See NSP Request for Rehearing at 4.

costs pertain. The method used by litigation staff follows this principle. Williston's method corrupts this fundamental principle of cost allocation by essentially adding the 160,000,000 equivalent dekatherms of stored cushion gas to the portfolio of capacity rights held by its storage customers. Williston offers no support for this, except to refer to a statement made in an ALJ's initial decision in one of Williston's earlier cases before us which is totally irrelevant to the allocation issue here. Williston argues that the statement:

> cushion gas is used to maintain the integrity of storage field operations and support the maximum deliverability of the entire designed working gas volume from a given reservoir. (citing KN Energy, Inc., 66 FERC ¶ 61,037 at p. 61,067 (1994))

stands for the proposition that cushion gas costs may be allocated to both firm and interruptible storage services. Williston adds that the Commission affirmed the ALJ's statement in its subsequent Order on Initial Decision at 84 FERC ¶ 61,081.[99] Williston also states that it complied with the Commission's order by allocating the cost of the cushion gas to all storage services.[100] Williston is correct on all counts. However, the relevant issue here is not whether costs were allocated to all storage services, but whether costs are allocated to the services in accordance with long-applied allocation principles. Nothing in the ALJ's statement or the subsequent order affirming the ALJ's initial decision in that case suggests that cushion gas quantities should be added to service level rights in order to develop factors for the allocation of fixed storage costs. Such a requirement would radically diverge from the established methodology for allocating costs among pipeline services.

104. Williston attempts to draw another inference from the ALJ's statement that also has no bearing on the cushion gas issue here. In its request for rehearing, Williston states the Commission held that:

> cushion gas is needed to make interruptible storage delivery possible as well as firm storage deliverability" and that in a KN Energy, Inc. order at 66 FERC ¶ 61,037 we held that cushion gas supports the maximum deliverability of the entire storage reservoir. (emphasis added by Williston)

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[99] Williston Request for Rehearing at 87.

[100] Williston Request for Rehearing at 88.

105. Williston implies that this statement requires that cushion gas quantities be included in "its storage capacity volumetric determinants." [101] Presumably, Williston emphasizes the words "delivery" and "deliverability" to lend support to its use of its deliverability function allocation factors to allocate the 160,000,000 equivalent dekatherms among the various storage services' and add the allocated portions to each of the service-level based capacity allocation factors it has otherwise computed. Here too, Williston's position on these matters is flawed. That is, if Williston believes that cushion gas supports storage service deliverability, why has it allocated cushion gas quantities to the capacity cost allocation factors which are used to allocate storage capacity related costs? In addition, all of the passages Williston refers to for support deal with the allocation of cushion gas costs. What Williston is attempting to advance here is the notion that these passages require the allocation of cushion gas volumes. The result of Williston's position is that storage capacity costs would not be allocated on the basis of relative rights to use the storage facilities, but on some other basis.

106. Williston claims it has used the Equitable method, [102] and in its rehearing request argues that the Equitable method requires 50% of storage fixed costs to be classified to the storage capacity function and the other 50% to the storage deliverability function and also that it requires that storage costs be apportioned between system storage and contract storage on the basis of capacity quantities, deliverability quantities, and injection and withdrawal quantities. [103] We agree with Williston's assessment of what the Equitable method requires and we acknowledge that the Equitable method has long been used by the Commission for the design of storage rates. However, except for correctly classifying fixed costs 50% to capacity and 50% to deliverability, Williston has not followed the Equitable method because it has not apportioned the fixed storage costs on the basis of capacity and deliverability. The Equitable method is best explained in a Consolidated Gas Transmission Corporation case. There, referring to an earlier Tennessee case, the Commission stated: [104]

> Equitable relied on Tennessee Gas Pipeline Co. [fn: Tennessee Gas Pipeline Co., 56 FPC 120 at pp. 161-162 (1976).] In Tennessee the Commission adopted the

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[101] Id.

[102] Equitable Gas Company, 36 FERC ¶ 61,147 (1986).

[103] Williston Request for Rehearing at 88.

[104] Consolidated Gas Transmission Corporation, 47 FERC ¶ 61,171 at 61,562 (1989).

> view that contract storage customers should be charged for costs related to the percent of storage units used for the storage service out of the total storage units available … Accordingly, it determined that storage function fixed costs should be allocated between the different uses of such facilities on the basis of the proportion of units contracted for by specific customers to the total number of units available. (emphasis added)

107. Cushion gas quantities are never contracted for or available for contracting. Because of its purpose, cushion gas cannot be considered capacity available for customers because it is gas that is not cycled and must remain in the storage reservoir. This purpose is confirmed by Williston's witness Tiggelaar both in his original and rebuttal testimony in this case when he states, "[t]he cushion gas is not cycled out of Williston Basin's storage fields." [105] Thus, the space that cushion gas occupies is not available to provide service.

108. In its rehearing request Williston again argues that it has included cushion gas volumes in the firm, interruptible, and line pack and balancing storage capacity allocation quantities, pursuant to the Commission's holding in Docket No. RP95-364-000. The storage cost allocation issues in that case were the subject of a hearing, an Initial Decision, and a subsequent Commission Order on Initial Decision. Nothing in those orders supports Williston's claim. Rather, the facts presented in that case support the opposite conclusion – that cushion gas volumes should not be used to develop capacity cost allocation factors. As the ALJ in that case stated: [106]

> Cushion gas is defined as the gas within a system which provides the minimum pressure necessary for operation. Transwestern Pipeline Co. v. The United States, 639 F.2d 679 (Ct. Cl. 1980); Arkla, Inc. v. The United States, 592 F. Supp. 502 (U.S.D.C. W.D.L.A. 1984). As the Commission noted in KN Energy, Inc., 66 FERC & 61,037 at p. 61,067, A[c]ushion gas is used to maintain the integrity of storage field operations and support the maximum deliverability of the *entire* designed working gas volume from a given reservoir.@ (emphasis added). Without cushion gas a facility would be nonfunctional. Arkla, Inc. v. The United States, 592 F. Supp. at p. 511.

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[105] Prepared Direct Testimony of Keith A. Tiggelaar, Exhibit No. WBI-18, p. 26, and Rebuttal Testimony of Keith A. Tiggelaar, Exhibit No. WBI-52, p. 27.

[106] 79 FERC ¶ 63,010 at 65,168 (1997).

109. While Williston bears the burden of proof on this issue, it has presented no persuasive record evidence and has cited no authority directly supporting its position.

110. Our subsequent Order on Initial Decision[107] affirms the ALJ's decision and states:

> In response, Staff points out that cushion gas is needed to make interruptible storage delivery possible as well as firm storage deliverability. The Commission finds that Staff's point is well taken, in that Williston's methodology treats interruptible storage service as if such interruptible customers provided their own cushion gas or somehow did not need cushion gas, and this is not the case. Staff also challenges Williston's assertion that the issue was first raised by Staff on brief, as the issue appears in the Joint Statement of issues submitted by the participants. We find that the issue was thus joined early on, and that Staff has better supported its position than Williston. [84 FERC at 61,391]

111. These holdings indicate that it was staff's methodology that we affirmed in Docket No. RP95-364-000, not Williston's. Staff's method as presented at the hearing in the RP95-364-000 proceeding clearly indicates that the allocation of storage capacity costs performed consistent with our holding there does not incorporate cushion gas quantities in the capacity cost allocation factors but instead uses storage service levels.[108] Rehearing is therefore denied.

12. The GRI Surcharge and Discount Adjustments

112. The Commission affirmed, without discussion, the ALJ's ruling that Aconsistent with Commission policy and the Commission=s prior ruling on this issue, that there may be no commodity surcharges, other than Order Nos. 500/528 take or pay surcharges, in calculating discounting adjustments.@[109] On rehearing, Williston argues that the inclusion of the GRI surcharge in its discount adjustment calculations is consistent with the iterative discount methodology approved in Northwest and in Williston's previous RP92-

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[107] Williston Basin Interstate Pipeline Co., 84 FERC ¶ 61,081 (1998).

[108] Compare Revised Staff Exhibit No. S-9, Revised Statement K-1, page 5 of 20 to page 6 of 20, in Docket No. RP95-364-000, showing that firm and interruptible storage service levels (billing determinants) are identical to the quantities used to develop storage capacity cost allocation factors for firm and interruptible storage service. Thus no cushion gas volumes are used for the allocation of storage capacity costs.

[109] 95 FERC at 65,127-28.

163-000 and RP95-364-000 rate proceedings.[110] For the reasons discussed below, we affirm our decision in the July 3 Order requiring Williston to remove GRI surcharges from the rates used to calculate its discount adjustments, and deny Williston's request for rehearing.

113. Williston broached its iterative process to calculate discount-adjusted volumes for use in designing its rates in its Docket No. RP92-163-000 rate case. In that case, the ALJ followed precedent set forth in a Southern case, and required Williston to remove the "take-or-pay" surcharge from its discount adjustments.[111] The Commission subsequently reversed the ALJ by Order on July 25, 1995, finding that the discount ratio should not only reflect the take or pay surcharges, but fuel, Annual Charge Adjustments (ACA), and GRI surcharges consistent with its finding in Northwest.[112]

114. On rehearing in Williston's RP92-163-000 case, the Commission further considered this issue in light of a second Northwest case.[113] In the second Northwest case, the Commission determined that, because the ACA and fuel charges are designed outside the pipeline's rate case, their inclusion in the discount adjustment results in the

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[110] Williston Request for Rehearing at 85-87. Citing Northwest Pipeline Corp., 71 FERC ¶ 61,253 (1995). In its pleading, Williston refers to a GTI surcharge. On April 24, 2000, The Gas Research Institute (GRI) and the Institute of Gas Technology combined to form The Gas Technology Institute (GTI). The institutes exist as separate entities within the GTI organization. Annually, the GRI files for approval of a separate volumetric surcharge which allows the organization to fund its Research, Development, and Demonstration Programs, in part, through member pipelines. The pipelines recover their GRI funding costs entirely through a volumetric surcharge (referred to as the "GRI surcharge") applied to each unit of throughput.

[111] Williston, 68 FERC ¶ 63,007 at 65,067 (1994) (the July 29, 1994 Order); citing Southern Natural Gas Co., 65 FERC ¶ 61,347 at 62,832-33 (1993).

[112] Williston, 72 FERC & 61,074 at 61,379 (1995); citing to Northwest Pipeline Corp., 68 FERC ¶ 61,309 at 62,277 (1994), reh'g denied, 71 FERC & 61,174 (1995). The issue in that case was whether the take-or-pay surcharge design throughput should be adjusted to reflect discounts. The Commission adopted Staff's recommendation to use discounted adjusted volumes to calculate the take-or-pay surcharge, and required Northwest to include the take-or-pay surcharge in the calculation of the ratio to calculate its discount adjusted throughput volumes.

[113] Williston, 76 FERC ¶ 61,066 at 61,389 (1996) (the July 19 Order).

pipeline underrecovering its costs.[114] For this reason, the Commission in the RP92-163-000 rate case required the exclusion of commodity surcharges (such as, the ACA and fuel charges) from the discount adjustment calculation. Although, no specific mention was made with respect to the GRI surcharge in Williston's rate case, the GRI surcharge, like the ACA and fuel charges, is not designed based on rate case volumes. However, unlike the pipeline's underrecovery of costs by including the ACA and fuel charges in its discount adjustments, the inclusion of the GRI surcharge results in the pipeline overrecovering its costs. Accordingly, we find Williston's reliance on the July 19 Order on Rehearing in Docket No. RP92-163-000, misplaced, and agree with the ALJ's distinction in the instant case, that the "prior ruling on this issue, [dictates] that there may be no commodity surcharges, other than Order Nos. 500/528 take or pay surcharges, in calculating discount adjustments."[115]

115. Williston also cites to its RP95-364-000 rate case, where gas supply realignment (GSR) surcharges were added to the list of surcharges to be excluded from discount adjustments.[116] Williston notes that no mention was made in that proceeding to exclude the GRI surcharge from the calculation of discount adjustments. Again, we cite to the Commission's findings in the second Northwest case, which effectively excluded all commodity surcharges from the discount adjustment process because such charges are "designed outside the pipeline's rate case, [and] their inclusion in the discount adjustment results in the pipeline underrecovering its costs." If in fact, as stated by Williston, its compliance filing in that proceeding included the then-GRI surcharge in the discount adjustment, Williston's settlement base rates for the period January 1, 1996 through May 31, 2000, are in error.

116. Lastly, Williston points to the Initial Decision in the instant proceeding citing to Staff's statement that the Commission's Order Approving Settlement in Gas Reasearch Institute, Docket Nos. RP97-149-004, et al., requires that "GRI surcharges are first to be discounted; and that member pipelines are only to remit to GRI the revenues collected."[117] Williston's interpretation of this language is incorrect. Under the GRI

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[114] Northwest, 74 FERC ¶ 61,234 at 61,799 (1996).

[115] Williston, 95 FERC ¶ 63,008 at 65,127 (2003).

[116] GSR surcharges, implemented for a pipeline's recovery pursuant to Order No. 636, were excluded from discount adjustments under the precedent set forth in Natural Gas Pipeline Company of America, 69 FERC ¶ 61,029 (1994).

[117] 95 FERC ¶ 61,093 at 61,453-54 (1998).

Settlement, on discounted transactions, the pipelines remit to GRI only the amount, if any, by which the GRI surcharge exceeds the amount of the discount. Therefore, the GRI surcharge is removed from the discounted rate prior to the calculation of the discount adjustment. Accordingly, we affirm our July 3 Order and require Williston to remove the GRI surcharges from its discount adjustment calculations when it makes its compliance tariff filing.

The Commission orders:

(A) The pro forma tariff sheets submitted by Williston in compliance with the Commission's July 3 Order in this proceeding are rejected.

(B) Williston is directed to recalculate the cost of service underlying its rates to reflect the determinations in this proceeding and to file tariff sheets to conform to this order within 30 days of the date of this order, except with respect to Rate Schedule X-13.

(C) The issues raised by Northern States Power Company (NSP) respecting Rate Schedule X-13, and the 50% ADQ restriction on NSP's FT-1 service are remanded to the Presiding ALJ as discussed in the body of this order. Within 30 days of the date of this order, the Presiding ALJ is directed to convene a conference of the parties to establish a procedural schedule for resolution of the remanded issues. Within six months thereafter, and every three months following the date of the initial report, the Presiding ALJ shall report to the Commission the progress toward resolution of these issues until said issues are either settled or decided.

(D) Rehearing of the July 3 Order is granted in part and denied in part, as discussed in the body of this order.

By the Commission.

(S E A L)

Linda Mitry,
Acting Secretary.