LEXSEE 74 F.E.R.C. 61109

Panhandle Eastern Pipe Line Company

Docket No. RP92–166–000

FEDERAL ENERGY REGULATORY COMMISSION – COMMISSION

74 F.E.R.C. P61,109; 1996 FERC LEXIS 486

OPINION NO. 404OPINION AND ORDER ON INITIAL DECISION

February 5, 1996

PANEL:
[**1] Before Commissioners: Elizabeth Anne Moler, Chair; Vicky A. Bailey, James J. Hoecker, William L. Massey, and Donald F. Santa, Jr.

COUNSEL:

APPEARANCES

Lawrence Acker, David P. Sharo, Raymond Shibley, John R. McDermott, Merlin E. Remmenga and James J. Valentino on behalf of Panhandle Eastern Pipe Line Company.

James W. McTarnaghan, Gregory Grady, Luke A. Mickum and David B. Shoper on behalf of Phillips Petroleum Company and GPM Gas Corporation

John R. Schaefgen, Jr., Alan Lescht, Kevin J. McIntyre and Glen S. Bernstein on behalf of Panhandle Customer Group.

Jeffrey A. Keevil, Anne W. Yates, Eric Eisen and Penny G. Baker on behalf of Missouri Public Service Commission.

Leja D. Courter and Ronald E. Christian on behalf of Indiana Gas Company, Inc.

Mark R. Haskell, Gordon Gooch, Glenn S. Benson, J. Stephen Martin, and Michael Pate on behalf of Indicated Shippers.

Steven M. Sherman on behalf of Citizens Gas & Coke Utility.

Charles F. Wheatley, Don Uthus, Timothy P. Ingram, Philip B. Malter and Mark W. Floersheimer on behalf of Municipal Gas Commission of Missouri.

Arthur L. Smith, Robert C. Johnson, and Diana M. Schmidt on behalf of Missouri Gas Users, Anheuser–Busch, [**2] et al.

Carolyn Y. Thompson, Donna J. Bobbish and Martin V. Kirkwood on behalf of East Ohio Gas Company.

Deborah A. Moss, Renee Hamilton Gwaltney and William M. Lange on behalf of Michigan Gas Storage Company.

Cheryl L. Jones, and Barbara K. Hefferman on behalf of The Providence Gas Company.

Steven Howe, John Staffier, and George McHenry on behalf of Pan Alberta Gas Ltd. and Foothills Pipeline Ltd.

Katherine L. Henry on behalf of ANR Pipeline Company.

Glen S. Howard and Roger D. Williams on behalf of Association of Business Advocating Tariff Equity.

Steven H. Haake on behalf of National Steel Corporation.

R. Brian Corcoran on behalf of Bethlehem Steel Corporation.

Roy R. Robertson on behalf of Narthern Indiana Public Service Company.

James Howard on behalf of Colorado Interstate Gas Company.

Gary Himes on behalf of Omega Pipeline Company.

Letitia Lee and James D. Senger on behalf of Martin Exploration Management Company and Colorado Energy Corporation.

Steven J. Kalish on behalf of Michigan Gas Utilities Division of Utilicorp United, Inc.

Laurence Skinner on behalf of Midland Cogeneration Venture.

Joel Kaufman, Ronald D. Eastman, Henry J. [**3] Boynton and Don L. Keskey on behalf of the State of Michigan and Michigan Public Service Commission.

Craig A. Marks and Mary Ann Walker on behalf of Southeastern Michigan Gas Company and Michigan Gas Company.

Steven A. Adducci and Richard F. Powers, Jr. on behalf of Tejas Power Corporation.

Jerry W. Amos on behalf of United Cities Gas Company.

Vera Callahan Neinas and John B. Randolph on behalf of Western Gas Resources, Inc.

Deborah B. Lawrence and Lois McKenna on behalf of Williams Natural Gas Company.

Thomas J. Burgess, J. Carmen Castilo, JoAnn Levegue and Kathleen M. Dias on behalf of Federal Energy Regulatory Commission.

OPINION:
[*61,353] **[Note: The Initial Decision, issued December 12, 1994, appears at 69 FERC P63,013.][Opinion No. 404 Text]**This order reviews an initial decision n1 concerning the general rate filing made by Panhandle Eastern Pipe Line Company (Panhandle) in Docket No. RP92–166–000. The filing proposed rates that were in effect for the six months preceding the commencement of Panhandle's restructured services under Order No. 636 [*FERC Statutes and Regulations* P30,939], and included the cost of service that was used to establish rates for those restructured services. The rates, as revised during restructuring, remain in effect. The Commission affirms, modifies, and reverses the initial decision for the [**4] reasons discussed in this order. In addition, the Commission remands to the ALJ the issue of the appropriate adjustment to Panhandle's rate design volumes to reflect non–affiliate discounts.

n1 69 FERC P 63,013 (1994).

I. BackgroundPanhandle filed its proposed rates in this proceeding May 1, 1992. The filing proposed to collect approximately $475 million in revenues, which represented an increase of about $80 million over Panhandle's previous rates in Docket No. RP91–229–000. n2 The rates were based on costs during a base period of twelve months, from March 1, 1991, to February 29, 1992, adjusted for changes over the next nine months which ended November 30, 1992. The Commission accepted motion rates Panhandle filed on December 8, 1992, and March 1, 1993, and made the rates effective November 1, 1992. n3

n2 59 FERC P 61,243 (1992).

n3 62 FERC P 61,152 (1993), 63 FERC P 61,129 (1993).

The Commission has determined some of the issues in this case in other proceedings. The use of straight fixed variable rate design for the period prior to restructuring was determined [**5] in Docket No. RP88–262–000. n4 The refunctionalization of some facilities from gathering to transportation has been determined in Docket No. CP90–1050–000. n5 Other issues related to gathering and whether certain compressors are used and useful were decided in Opinion No. 395 in Docket No. RP91–229–000. n6

n4 Opinion No. 369, 57 FERC P 61,264 (1991), reh'g denied, Opinion No. 369–A, 59 FERC P 61,244 (1992).

n5 70 FERC P 61,178 (1995).

n6 71 FERC P 61,288 (1995).

The Commission made the cost of service of Panhandle's rates in its restructuring proceeding subject to the outcome of this proceeding. n7 Panhandle's restructured rates went into effect May 1, 1993. The determinations in this proceeding thus apply to two periods, a pre–restructuring period from November 1, 1992, through April 30, 1993, and a post–restructuring period beginning May 1, 1993, and continuing to the present.

n7 61 FERC P 61,357 (1992); 62 FERC P 61,288 (1993); 64 FERC P 61,009 (1993). The cost of service in Docket No. RS92–22–000 was about $335 million, about $143 million less than the approximately $475 million cost of service in Docket No. RP92–166–000 because Panhandle removed the direct costs of sales service from Docket No. RS92–22–000.

[**6] Following a hearing, the ALJ issued his initial decision on December 12, 1994. A number of parties have filed briefs on exceptions and briefs opposing exceptions. n8 The Commission affirms in part and reverses in part the ALJ's decision.

n8 The parties filing briefs on exceptions are Association of Businesses Advocating Tariff Equity (ABATE), Citizens Gas & Coke Utility (Citizens), State of Michigan and Michigan Public Service Commission, Missouri Gas Users (MGU), Missouri Public Service Commission (MoPSC), Municipal Gas Commission of Missouri (MGC), Panhandle Customer Group (PCG), Panhandle, Phillips Petroleum Company and GPM Gas Corporation (Phillips/GPM), and the Staff.

[*61,354] II. DiscussionA. Rate BaseThe ALJ found the amount of gas plant was $1,426,055,140. He included the Higgins Gathering System and certain farm taps which Panhandle sold after the end of the test period. As components of working capital, the ALJ included $22,004,941 for materials and supplies (based on 13 monthly balances ending November 30, 1992); prepaid interest of $170,500 consisting of a discount on Panhandle's sale of its accounts receivable; $1,230,813 in gas prepayments; $121,934,713 in accumulated [**7] federal and state income taxes; and volumes of gas stored underground calculated by the North Penn method. He held Panhandle must value the volumes stored underground using the LIFO method. He found the value of the volumes in the pre–restructuring period was $74,301,396 and their value in the post–restructuring period was $19,392,664. The ALJ found the amount of depreciation was $821,680,265.1. Facilities sold to othersPanhandle sold the Higgins gathering system and certain farm tap facilities on January 1, 1993, and March 31, 1993, respectively. The ALJ held that Panhandle could nevertheless include these facilities in its rate base, because these facilities had been sold after the November 30, 1992 end of the test period. IS excepts to the inclusion of these facilities. IS relies on KN Energy, 63 FERC P 61,155 (1993) and Northwest Pipeline Corp., 59 FERC P 61,115 (1992).The Commission affirms the ALJ. Both the cases relied on by IS involved proposals to transfer all of the pipeline's gathering facilities to an affiliated company. In Northwest, these facilities had a book value of over $300 million. There were protests [**8] in both filings concerning the removal of the costs of the facilities that would be abandoned from the pipeline's rates. The Commission approved the entire conveyance requested in Northwest and a portion of the request in KN Energy. In both cases, the Commission required the pipelines to file revised rates to remove the costs of the facilities that were abandoned.The original cost of the farm tap facilities Panhandle sold was $2,205,725 and the amount of depreciation was $1,671,881. The salvage value (proceeds received) of the facilities was $675,000. Panhandle recorded a gain on the sale of $126,155. There were five interventions to the filing, but no protests. 61 FERC P 62,025 (1992). The Higgins gathering system was abandoned automatically under 18 C.F.R. § 157.216(a). IS–16. Neither of these transfers involved a corporate reorganization or a large portion of Panhandle's plant. They were some of many sales and purchases or construction projects that Panhandle undertakes on a regular basis. Given the routine nature of the transactions at issue here, unlike those in Northwest and KN Energy, the Commission sees no reason to depart from its test period [**9] regulations in this case. Consequently, Panhandle may include in rate base these facilities, which were not sold until after the test period.2. Drip fluidsThe ALJ held that Panhandle appropriately included in rate base $3.8 million of

drip fluid collecting equipment necessary for the safe and efficient operation of [*61,355] Panhandle's system. He also held that for the pre-restructuring period, Panhandle correctly credited revenues from the sale of drip fluids, amounting to about $82,000, to sales customers. He held that for the post-restructuring period, Panhandle must continue to credit these revenues to its customers, rather than retaining them.Panhandle objects to the ALJ's finding that it must continue to credit the revenues from the sale of gas volumes removed by the drip fluid equipment to its customers during the post-restructuring period. It asserts that, since its PGA was terminated as part of restructuring, the costs of the volumes of gas removed through operation of the drip fluid equipment are no longer included in its cost of service, as shown in its exhibits, PE-21 and PE-25. It states that it must replace these volumes itself, and so is entitled to revenues from the [**10] sale of the drip fluid volumes.The Commission's examination of Exhs. PE-21, PE-25 and also PE-19 shows that Panhandle included $1,751,492 in purchased gas expenses (Account Nos. 807.2 - 807.5) in its post-restructuring cost of service. Therefore, it is not clear that the costs of the drip fluid volumes are not included in the cost of service. Accordingly, the Commission affirms the ALJ's requirement that Panhandle credit the revenues from volumes removed by the drip fluid equipment to its customers.3. Working Capital—Prepaid interestStaff excepts to the amount of $170,500 included as prepaid interest in working capital. This amount consists of a discount Panhandle gave on its sale of its accounts receivable. As the Commission held in Opinion No. 395 in Docket No. RP91-229-000, a discount on accounts receivable is not prepaid interest, and thus is not eligible for treatment as working capital. n9 These costs should be included in the determination of the gain or loss on the sale of receivables, and charged to Account 426.5, Other Deductions. Id. Consequently, Panhandle must remove $170,500 from rate base.

n9 71 FERC P 61,228 (1995).

4. Storage [**11] working gasa. Pre-restructuring(i) BackgroundPanhandle used the North Penn method for the valuation of gas stored underground. This method consists of taking the average of thirteen monthly balances of storage gas. n10 Panhandle used a beginning balance as of December 31, 1991, and an ending balance as of December 31, 1992. It originally calculated the average volume of storage working gas over the 13 months as 46,929,688 Mcf with a LIFO value of $95,972,141, or $2.045 per Mcf. Exh. PE-4. It later revised this figure by subtracting the value of 10,000,000 Mcf of storage gas to reflect a sale on November 1, 1992. n11 It calculated the value of the 10,000,000 Mcf to be $20,982,000 based on the weighted average cost of gas stored underground as of October 31, 1992, of $2.0982, rather than on a LIFO method. n12 Exh. PE-10 at p. 4; Exh. PE-13. Panhandle then claimed an allowance of $74,990,141.

n10 North Penn Gas Company, 14 FERC P 61,033 (1981), affirmed, North Penn Gas Company v. FERC, 707 F.2d 763 (3rd Cir. 1983).

n11 59 FERC P 61,206 (1992).

n12 In cross-examination, it appeared that the sale consisted of 10,364,000 Dt and the sale price was $21,277,292 (Tr. 216-17).

[**12] The ALJ accepted the North Penn method for the valuation of gas stored underground. He did not find that there were any unusual circumstances which would [*61,356] render that method inappropriate. He reasoned that even if the average volumes for December 31, 1991 through December 31, 1992 were unrepresentative of the volumes that remained in storage during the November 1, 1992 through April 30, 1993 pre-restructuring period, they would be balanced out by other periods with low allowances. He thus accepted Panhandle's proposal to use 36,929,688 Mcf as the average storage gas volumes for the pre-restructuring period. Exh. PE-4; Exh. PE-13. The ALJ did not accept Panhandle's method of valuing those volumes, however. He held that the average storage gas volumes should be valued using the LIFO method to determine the value of the 10,000,000 Mcf sold on November 1, 1992 as well as the value of the average amount in storage over the 13 months and not, as Panhandle had done, by subtracting the weighted average cost of the gas sold November 1, 1992, from the previously derived LIFO figure for the average of the 13 monthly balances. He stated that the Commission orders authorizing the use of WACOG [**13] applied to the pricing of the gas to be sold, not to the general valuation of gas in Panhandle's books of account. Accordingly, he accepted staff's figure which was based solely on the LIFO method. Exh. S-1 at p. 12; Exh. S-4 at p. 11. Staff valued the 10,000,000 Mcf which Panhandle sold at its LIFO value of $21,670,745 and then subtracted that figure from Panhandle's LIFO value for the total volumes, $95,972,141, to give a value of $74,301,396 for the remaining volumes.PCG claims that North Penn is not applicable because it does not give representative results for the November 30, 1992 through April 1993 period. PCG asserts that Panhandle liquidated its storage gas inventory starting in November 1992 and continuing through March 1993. It cites the actual amounts of storage gas inventory during that time as declining from 26,059,737 Mcf to zero. Tr. 832-34; Exh. PE-161. PCG asserts that, based on the actual amount of gas in storage, the value of Panhandle's average storage gas inventory during the 7-

month period was $24,492,759, not $74,301,396. Panhandle claims that the ALJ improperly valued its pre-restructuring storage volumes by applying the LIFO method and that the allowance [**14] should be $74,990,141.(ii) DiscussionWe affirm the ALJ on the method he used for inventory valuation for the pre-restructuring period. The rates for the pre-restructuring period will be in effect from November 1, 1992 through May 1, 1993, a period of 6 months. During the period at issue Panhandle was a merchant and maintained an inventory of current working gas. It has long been the Commission's policy to value the rate base amount of current working gas using the "North Penn" methodology, and the Last In, First Out (LIFO) accounting valuation method. Here, the ALJ decided that the "North Penn" method was still the appropriate methodology for the pre-restructuring period. We agree.PCG argues that the ALJ erred in not determining that an extraordinary circumstance occurred requiring him to depart from the test period and change the traditional valuation methodology. We disagree and find that the watershed date of the extraordinary circumstance is after the test period in this proceeding and ultimately not until May 1, 1993, the effective date of the new services. We acknowledge that Panhandle's restructured services and storage gas levels were in the planning stages during the [**15] latter part of the test period, and that sales of storage gas under Rate Schedule ISS commenced around the end of the test period, August 1992. n13 However, during the [*61,357] winter of 1992 and 1993 Panhandle was still a merchant with an inventory to manage. We find no compelling argument to go outside the test period and attempt to capture events that were short lived, less than a couple of months. We find that for the locked-in 6 month pre-restructuring period it is reasonable to accept the test period concept and continue the traditional time tested valuation methodology known as "North Penn", utilizing the historically approved LIFO accounting method. We find that the valuation change argued for by the PCG occurs after the effective date of the new services and has been provided for herein by a change in valuation methods between the test period and the post-restructuring period discussed below.

n13 The sale of 10 Bcf which occured in August 1992 is reflected in the reduced current working gas balance accepted by the ALJ. The rate base impact of that reduction was $25 million from the as filed amount of $96 million.

Panhandle argues on exception that we should change the accounting [**16] valuation basis to use an averaging basis rather than LIFO. Panhandle asserts that since the Commission accepted its sales rate for Rate Schedule ISS based on the average WACOG, the Commission should accept the average pricing method here as well. We disagree, and will reject Panhandle's proposed averaging methodology. We find that Exhibit PCG-2 specifically demonstrates that Panhandle's historical storage inventory accounting methodology is LIFO. A company may not continually, from rate case to rate case, change its accounting method for inventory. The Commission's regulations indicate that a pipeline should file in advance with the Commission for the authority to change inventory valuation methodologies. Accordingly, we will affirm the ALJ and use the LIFO method for the locked-in period.b. Post-restructuring(i) BackgroundThe Commission approved Panhandle's retention of 15.1 Bcf of storage capacity after restructuring. n14 This was 26.1 percent of the storage capacity it had previously. n15 Panhandle claimed that it was retaining the same proportion of storage gas inventory as it was of maximum storage capacity. Accordingly, it claimed that the value of gas stored underground [**17] after restructuring should be 26.1 percent of its LIFO value prior to both restructuring and the sale of the 10 Bcf. The value of the storage gas after restructuring, according to Panhandle, was thus .261 x $95,972,151, or $25,048,729. Exh. PE-20 at pp. 8-9.

n14 61 FERC P 61,357 at p. 62,400 (1992). The Commission stated it would evaluate whether that amount was necessary after one year of operations under restructured services. It required Panhandle to file a study within 90 days of that date showing the amount of storage actually used for authorized and unauthorized balancing and for hourly swings. That study, which Panhandle filed on July 29, 1994, is pending in Docket No. RP94-344-000.

n15 15.1 Bcf/57.8 Bcf = 26.1 percent.

The ALJ found that Panhandle had correctly used 26.1 percent to calculate the change in average inventory balance and Panhandle's maximum storage capacity after restructuring was 15.1 Bcf. The ALJ again held, however, that Panhandle had to value the volumes using the LIFO method and that it had not done so. The ALJ applied the 26.1 percentage to the LIFO value of the storage gas before restructuring with the value of the [**18] 10 Bcf removed. He thus found that the correct allowance was 26.1 percent of $74,301,396, the amount he had determined for the pre-restructuring allowance, or $19,392,664.PCG states that Panhandle's only uses for storage after restructuring are for managing monthly imbalances (2.7-3.0 Bcf) and hourly swings (9 Bcf). It states that Panhandle might have to invest in storage inventory to handle monthly imbalances, [*61,358] but would not have to do so to handle hourly swings in receipt and delivery of customer gas. PCG asserts that Panhandle has not shown that its post-restructuring use of retained storage capacity will involve investment in an inventory of working gas or what the magnitude of that investment is. PCG points out that Panhandle's retained storage capacity must be available to absorb excess receipts of gas from shippers, as well as to supplement deficient receipts. It states that it is reasonable to assume that storage capacity serves these purposes equally, so that, on average, half of its storage capacity would be used for working inventory. PCG states that the Commission should use the information in Panhandle's FERC Form No. 8, Gas Stored Underground filings from the end [**19] of August, 1993 to the end of December, 1994, to compute the amount of Panhandle's working gas in storage. PCG asserts that the average Form No. 8 amount for this period was 7,352,878 Mcf. B.E., ADD. B.Staff argues that it is more appropriate to use the LIFO valuation of 15.1 Bcf, which it assumes to be stored gas inventory, as opposed to a percentage of the pre-restructuring allowance. It states that this is the amount of storage capacity the Commission approved for Panhandle after restructuring (61 FERC P 61,357 at p. 62,400 (1992)), and, so, is the amount that should be used here. Staff proposes a post-restructuring allowance of $20,102,972.Panhandle excepts to the ALJ's use of his pre-restructuring allowance, which was based on the LIFO method, to determine the post-restructuring allowance. It also claims that the post-restructuring allowance should be 31.6 percent of the pre-restructuring allowance. In Panhandle's view, 31.6 percent, which represents the ratio of the 15.1 Bcf in retained storage capacity to Panhandle's pre-restructuring storage capacity of 57.8 Bcf minus the 10 Bcf of storage gas sold in November 1992, takes into account the November [**20] 1992 sale of storage gas. The correct post-restructuring allowance would then be .316 x $74,301,396, or $23,479,241. Last, Panhandle states that Form No. 8 amounts show only Panhandle's net storage gas inventory and do not show storage gas on loan to shippers to make up negative imbalances.(ii) DiscussionThe Commission will affirm the ALJ on this issue. The ALJ was correct in accepting the 15.1 Bcf level of capacity and then valuing this capacity using the LIFO methodology. The 15.1 Bcf level was previously approved by the Commission in Panhandle's restructuring proceeding. n16 It is appropriate to use the LIFO methodology to value this gas because that is the methodology that has been previously approved for Panhandle to use to value its gas inventory. To change here to an averaging methodology would require prior approval from the Commission or a showing here as to why averaging should be used instead of the previously approved LIFO method. Panhandle has not sought approval from the Commission nor has it made a sufficient showing why such a change is appropriate. Panhandle merely uses the averaging method for its convenience and states that it is appropriate. Accordingly, [**21] Panhandle's proposal to use an averaging method is rejected.

n16 61 FERC P 61,357 at p. 62,400 (1992).

However, Panhandle is correct that the judge has made a mistake in developing his post-restructuring valuation. To calculate that valuation, the ALJ needed to convert the pre-restructuring valuation, calculated on a LIFO basis, into the post-restructuring valuation, also based upon the LIFO methodology. To do this the ALJ multiplied the pre-restructuring balance by 26 percent. This 26 percent figure was [*61,359] based upon a ratio of remaining capacity to pre-restructuring capacity. However, the ALJ's calculation does not recognize that there was an adjustment made to the pre-restructuring balance, reflecting Panhandle's sale of 10 Bcf of top gas. Accordingly, while we accept the ALJ's use of the LIFO method to value inventory, but we will use staff's actual calculation of the LIFO balance of $20,102,757 because it is the most accurate information on the record (Exh. S-4, p. 11).B. Return on common equityThe ALJ used Panhandle's own capital structure in which common equity was 59.97 percent of capitalization. He accepted Panhandle's cost of debt of 10.17 [**22] percent, as adjusted for a reduction in the discount rate from 11.625 percent to 7.6 percent on the amortization of debt costs incurred in the issuance of debentures that were subsequently reacquired. The ALJ found the preferred equity return should be 7.61 percent and the common equity return, 11.79 percent.1. Capital structureThe ALJ held that Panhandle could use its own capital structure, of which about $600 million, or 59.97 percent, out of $1 billion was common equity; 0.19 percent was preferred stock and the remaining 39.84 percent was long-term debt. Staff, Municipal Gas Commission of Missouri (MGCM), the Missouri Public Service Commission (MoPSC), and Indicated Shippers (IS) assert that Panhandle should use its parent company's, Panhandle Eastern Corporation (PEC), capital structure. They argue that PEC runs its subsidiaries as one business and Panhandle is not a separate unit for purposes of obtaining financing. PEC's capital structure was about 45 percent common equity and 55 percent long-term debt. Exh. S-5 at p. 4. Panhandle counters that it obtains its own financing and should be permitted to use its own capital structure.The Commission's policy is to use the actual [**23] capital structure of the entity that does the financing for the regulated pipeline, whether that entity is the regulated pipeline itself or its parent, with an exception discussed below. n17 Hence, the first step in our analysis is to determine whether Panhandle or PEC does Panhandle's financing. Since PEC owned all of Panhandle's stock and Panhandle's stock was not traded publicly, the manner in which Panhandle obtained its debt financing determines whether it did its own financing. n18

n17 Arkansas-Louisiana Gas Co., 31 FERC P 61,318 at pp. 61,728-9 (1985). Transcontinental Gas Pipe Line Corp., 60 FERC P 61,246 at p. 61,823 (1992), reh'g denied, 64 FERC P 61,039 (1993), reversed and remanded on other grounds, North Carolina Utilities Commission v. FERC, 42 F.3d 659 (D.C. Cir. 1994), order on remand, Transcontinental Gas Pipe Line Corp., 71 FERC P 61,305 (1995).

n18 Panhandle Eastern Pipe Line Co., 71 FERC P 61,228 at p. 61,828.

Based on his review of the record developed in this proceeding, the ALJ found that Panhandle [**24] issues its own debt and accordingly does its own financing. The Commission holds that the record adequately supports this finding. There is record evidence that Panhandle can and does issue its own debt to the public. For example, Panhandle sold two issues of debt during 1993, including $100 million of 7.95 percent debentures in March maturing in 2023 and another $100 million of 7.2 percent debentures in August maturing in 2024. n19 PEC did not guarantee either of those issues. PE-94 at p. 2. While it is true, as staff states, that Panhandle obtained a reduction in the commitment fee for a term loan due in 1996 because PEC guaranteed the loan (Exh. PE-79 at p. 2, col. 8; Exh. PE-86 at p. 11), the record supports the ALJ's finding that the PEC guarantee was not a requirement for obtaining the loan, but was solely for the purpose of [*61,360] obtaining a lower interest rate (Exh. PE-86 at pp. 10-11). Moreover, in Opinion No. 395 in Docket No. RP91-229-000, the Commission rejected a similar contention that PEC's guarantee of the term loan required a finding that Panhandle does not obtain its own financing. n20 The short-term intracorporate loans to which MoPSC points (MoPSC-29) are not part of Panhandle's [**25] capital structure and are not directly related to Panhandle's operations (Exh. PE-79; Exh. IS-17).

n17 Arkansas-Louisiana Gas Co., 31 FERC P 61,318 at pp. 61,728-9 (1985). Transcontinental Gas Pipe Line Corp., 60 FERC P 61,246 at p. 61,823 (1992), reh'g denied, 64 FERC P 61,039 (1993), reversed and remanded on other grounds, North Carolina Utilities Commission v. FERC, 42 F.3d 659 (D.C. Cir. 1994), order on remand, Transcontinental Gas Pipe Line Corp., 71 FERC P 61,305 (1995).

n18 Panhandle Eastern Pipe Line Co., 71 FERC P 61,228 at p. 61,828.

n19 Exh. PE-86 at p. 10.

n20 71 FERC P 61,288 at p. 61,828 (1995). The Commission also found that the reduction in the commitment fee, which in that case occurred after the test period, was too small (from 0.375 percent to 0.3125 percent) to warrant a departure from the Commission's test period regulations in order to reflect the reduction in rates. 71 FERC at p. 61,830.

The record also supports the ALJ's finding that the [**26] bond rating services give Panhandle a separate and different bond rating from PEC. n21 This fact also supports a finding that Panhandle does its own financing. Staff, however, points out that Standard and Poor's, in its June 21, 1993 Credit Review, n22 stated:

> The credit quality of Panhandle Eastern Pipe Line Co. (PEPL), a natural gas pipeline unit of Panhandle Eastern Corp., is strongly influenced by the consolidated parent due to significant financial, operational, and managerial relationships. This is highlighted by the corporate strategy to physically connect all affiliated pipelines and conduct an extensive marketing effort to move gas throughout the consolidated system.

IS, MoPSC, and Staff also point to the fact that Panhandle lends money to, and borrows from, its affiliates. n23 But these facts do not undercut the ALJ's finding that Panhandle has an independent status in the financial markets and sells it own debt. Staff's Exhibit S-9, at 2, shows that Standard and Poor's rated Panhandle's debt at BBB-, but PEC's debt at BB+, thus recognizing a difference between the credit quality of the two entities. Corporate subsidiaries commonly have significant financial, [**27] operational, and managerial relationships with their parents. Therefore, if the existence of such relationships were to prevent use of the subsidiary's actual capital structure, that would be contrary to the Commission's preference to use the subsidiary's capital structure where, as here, it issues its own debt and has its own bond rating.

n21 Exh. PE-86 at p. 12.

n22 Exh. S-5 at p. 6.

n23 Exh. IS-17. Panhandle is a net lender to its affiliates.

Of course, while the Commission prefers to use the actual capital structure of the entity that does the financing, it may use a different capital structure where the actual capital structure is not representative of the pipeline's risk profile. Alternatively, in such a situation, the Commission may, in certain circumstances, follow its preferred course of using the actual capital structure but adjust the rate of return on equity to account for the skewed capital structure. n24

n24 See Transcontinental Gas Pipe Line Corp., 71 FERC P 61,305 at pp. 62,194-5 (1995).

The ALJ accepted Panhandle's capitalization with 59.97 percent common equity. As in the previous rate case, the excepting parties argue [**28] that Panhandle's own capital structure is atypical, because its equity ratio is significantly higher than the equity ratio of the four pipeline parent corporations included in the comparison group of companies used by Panhandle's witness as part of his DCF study. However, as the Commission found in Opinion No. 395, the fact other companies may have lower equity ratios than Panhandle does not require rejection of Panhandle's equity ratio. The parties have provided no basis for concluding that Panhandle's equity ratio is excessive [*61,361] simply because it is higher than the companies used in the comparison. For these reasons, the Commission affirms the use of Panhandle's capital structure.2. Rate of return on equityPanhandle proposed that it have the opportunity to earn a 14.25 percent return on common equity. In addressing this issue of the appropriate return on equity, the ALJ used the Discounted Cash Flow (DCF) methodology often relied upon by the Commission to resolve this question. The DCF method hypothesizes that the current cost of equity capital is the sum of the current dividend yield as a percentage of the stock's market price plus the growth in dividends. n25 The ALJ determined [**29] that Panhandle faced the same risks after restructuring as it did before restructuring, so that the rate of return on common equity should be the same for both periods. He found that the dividend yield and growth rate for PEC should be used as a proxy for Panhandle rather than those of a group of companies. He held that the most representative dividend yield in the record was that for the period June, 1993, through November, 1993, 3.4 percent. With regard to the growth rate, he decided not to use historical data because they were so low as to be unrepresentative of future growth. He adopted the projections provided by Panhandle—8.25 percent to 8.75 percent—which were in the middle of a number of short and long-range growth projections. To these he added the dividend yield adjusted for the payment of quarterly dividends to obtain a range for rate of return on common equity of 11.79 to 12.30 percent. He held that the just and reasonable return was at the bottom (11.79 percent) of the range because of Panhandle's relatively high equity ratio (relatively low financial risk) compared to PEC and the average proxy company.

n25 The DCF method can be expressed algebraically by the formula $K = (D/P) + G$, where K is the cost of common equity, D is the current annual dividend amount, P is the current market price of the stock, and G is the dividend growth rate of the stock.

[**30] The Commission recently considered the return on common equity for Panhandle in Opinion No. 395. As many of the facts and some of the testimony are the same here as they were in that case, the Commission will follow the approach it used in that opinion.Since Panhandle is not publicly traded, it is necessary to use a proxy to determine its cost of equity capital using the DCF method. The ALJ and Panhandle chose PEC as a proxy. IS and staff object. They claim a group of companies with gas transmission activities should be used instead. The Commission agrees with IS and staff. As the Commission determined in Opinion No. 395, a proxy group should be used since it is more likely to reflect the risks facing Panhandle than PEC alone. The parties in this case used a number of different proxy groups. IS used a proxy group consisting of Coastal Corporation, Enron Oil and Gas Company, Transco Energy Company, The Williams Companies, Inc., and PEC. Exh. IS-2, 15/111. Staff used the same five companies, plus El Paso Natural Gas Company and Sonat, Inc. Exh. S-5 at p. 13. Panhandle used the proxy group as an alternative method in determining the rate of return on common equity. It included Coastal [**31] Corp., Enron Corp, Transco Energy Company, and The Williams Companies in its proxy group. Exh. PE-93, Sch. No. 3. As the Commission determined in Opinion No. 395, it is appropriate to exclude companies for which no Merrill Lynch steady state growth is in the record since, for the reasons discussed below, the determination of the long-term growth rate in this case depends, in part, on this data. Thus, the Commission will use the proxy group proposed by IS [*61,362] consisting of Coastal, Enron, PEC, Transco, and Williams, and excluding Sonat and El Paso.However, as the Commission held in Opinion No. 395, it cannot accept the proxy group analyses of the parties. IS adopted its testimony in Docket No. RP91-229-000 in this case. It is thus subject to the same infirmities the Commission found earlier, namely, some of the individual cost of equity estimates for companies in the proxy group do not reasonably reflect the cost of common equity for the companies analyzed. The Commission will not adopt the growth factor recommended in staff's analysis since the suggested growth rate depends largely on Value Line's average internal growth estimates for the 1996-98 period. The Commission believes that [**32] there is a better long term growth forecast (Merrill Lynch's long term steady state earnings growth) in the record.Panhandle insists that the ALJ only used growth rate projections in the DCF analysis based on five-year projections. Panhandle asserts that the ALJ should have used growth rate projections for periods longer than five years and that these projections were 9.3 and 11.2 percent. (Exh. MoPSC-1 at p. 43; Exh. MoPSC-14, Sch. 13 at p. 4.) According to Panhandle, use of long-term projections is required by the Commission's decisions in Wyoming and Ozark. n26 MGCM and IS counter that the ALJ took long-term growth factors into account, including the twenty-year long-term growth rate of seven percent of the general economy. IS also supports the initial decision. Staff asserts that the ALJ should have used its growth rate. S. Br. at p. 39.

n26 69 FERC P 61,259 (1994) and 68 FERC P 61,032 (1994).

The Commission agrees the ALJ considered long–term growth data. But he used the data to obtain a middle range of long–term growth rates—8.25 to 8.75 percent—and then added them to the dividend yield for Panhandle to create a range [**33] of returns. As the Commission determined in Opinion No. 395, the long–term growth rate should be added to the dividend yield of each company in the proxy group to create the range. Here, the most appropriate growth rates for use in the DCF methodology are found by averaging Merrill Lynch's long term steady state growth rates provided by IS (Exh. IS–2 at p. 74) and the IBES growth forecasts provided by staff. Exh. S–6 at p. 2. The Commission adopts the IBES data to establish growth rates for the proxy companies for the first five years while the Merrill Lynch steady state data provides the growth rate for the subsequent ten year period, consistent with Ozark Gas Transmission System n27 and Opinion No. 395. The staff IBES data ranges from a low of 8.00 percent for PEC to a high of 15.00 percent for Enron. The Merrill Lynch steady state data provided by IS varies from a low of 6.00 for Enron to a high of 9.00 for Coastal. Averaging the IBES data and the Merrill Lynch data leads to composite growth rates ranging from 7.50 for PEC to 10.50 for Coastal and Enron.

n27 68 FERC P 61,032 (1994).

The Commission will now determine the dividend yield for the DCF formula. [**34] The Commission will not use the data provided by Panhandle to make that determination. Panhandle used dividend yield data from November 1991, through April 1992. Exh. PE–93, Sch. No. 4. On exceptions, Panhandle supports using the actual dividend yield of 5.35 percent for November 1, 1991, through April 30, 1992, for the pre–restructuring period (Exh. PE–93, Sch. 2) and the actual dividend yield of 4.16 percent for December, 1992, through March, 1993, for the post–restructuring period (Exh. S–11). These data are too old. The Commission finds that the most appropriate dividend data is that for the most recent six months available. The Commission uses the most recent data [*61,363] because the market is always changing and later figures more accurately reflect current investor needs. n28 In this case, the best dividend yield data are the average dividend yield figures for June, 1993 through November, 1993 provided by staff. Exh. S–5 at p. 17; Exh. S–6 at p. 2. These range from 1.45 percent for Coastal to 3.66 percent for Transco. Using the methodology described in Opinion No. 395, the Commission will establish average annual dividend yields for the proxy group companies using the composite growth rates [**35] determined above. These calculations are shown in the following table and result in a low average dividend yield for Coastal of 1.53 percent and a high for Transco at 3.81 percent.

n28 Boston Edison Company v. FERC, 885 F.2d 962, 966 (1st Cir. 1989).

Derivation of Average Dividend Yield n29

Coastal	[1.45 + 1.45(1.1050)] / 2 =	1.53%
Enron	[2.15 + 2.15(1.1050)] / 2 =	2.26
PEC	[3.32 + 3.32(1.0750)] / 2 =	3.44
Transco	[3.66 + 3.66(1.0810)] / 2 =	3.81
Williams	[2.77 + 2.77(1.1040)] / 2 =	2.90

29 In this table, the growth rates for the proxy group companies previously determined in this order appear to the right of the decimal point in the parenthetical.

Combining these average annual dividend yields with the growth rates establishes a range for the total cost of equity capital with PEC at 10.95 percent at the bottom and Williams with 13.30 percent at the high end. The range mid point is 12.13 percent.Panhandle excepts to the ALJ's setting the growth rate at the lowest point of the zone of reasonableness. As the Commission stated in Opinion No. 395, Panhandle's high equity ratio is not reason enough to set the return at the lower [**36] end of the zone and Panhandle remains at risk for cost recovery since its contracts may terminate. Consequently, the Commission will set the return on common equity at the mid–point (12.13 percent) of the range.C. Cost of service1. Gathering plant depreciation rateThe ALJ adopted Panhandle's proposed depreciation rate for onshore gathering plant of 2.4 percent. n30 This rate assumes a ten–year life for remaining gas reserves. Exh. PE–26 at p. 46. He found that there was no substantial evidence to support a longer life of twenty years which IS had proposed.

n30 In Docket No. RP91–229–000, the parties stipulated to a gathering depreciation rate of 2.5 percent. 68 FERC P 63,008 at p. 65,090 (1994).

IS claims that the onshore gathering depreciation rate should be 1.2 percent instead of 2.4 percent. IS bases its rate on a 20–year remaining life for gathering plant. IS claims that Panhandle's reserves are being maintained and augmented by the activities of Centana Energy Corporation which makes new well connections to Panhandle, by new discoveries in the area, and by a lack of meaningful competition. Panhandle argues in opposition that IS's estimated reserve [**37] life is not supported by substantial evidence and is based wholly on past reserves without any showing of what they demonstrate about future reserves.The Commission affirms the ALJ's holding. After examining the record, the Commission finds that IS's evidence consists of reviewing the level of reserves in the past. Exh. IS–2. IS showed that this level had remained constant for periods in the 1980's. IS thus argued that it is reasonable to expect that some additions would be [*61,364] made to reserves in the future. But IS then simply assumed that additions would be one–half the existing reserves. Exh. IS–2 at p. 10. It presented no evidence as to where future reserves were likely to be discovered; the amounts remaining to be discovered; or whether upward revisions of existing estimates were likely. It presented no geological data and no testimony of geologists, economists, or other experts that additional reserves exist and are likely to be discovered. IS did not prove that its proposed depreciation rate was just and reasonable.2. Adjustment to Administrative and General Expenses due to Formation of Panhandle Service CorporationThe ALJ accepted approximately $53.6 million in administrative [**38] and general expenses, exclusive of labor, office consolidation, workforce reduction, and office configuration amortizations. Staff claims that some of these expenses n31 should be based on data for Panhandle after the formation of Panhandle Service Corporation (PSC) in January 1992, consisting of Panhandle's annualized expenses for the eleven months from January 1992, through November 1992. Staff believes that the formation of PSC made a material change in Panhandle's expenses.

n31 Staff claims that the affected accounts are Nos. 921, office supplies, 922, outside services (discussed further below), 924, property insurance, 926, pensions and benefits (discussed further below), and 931, rents. The net reduction from staff's adjustment for these accounts is about $2.5 million. Exh. S–2, Sch. H(1)–3, Part 4; Exh. S–3, Sch. H(1), Part 1. Account No. 926 is discussed further under the 1992 union workforce reduction program. Panhandle claims that the affected accounts are Nos. 921, 922, 923, 924, 926, 930, and 931. Staff's proposed net reduction for these accounts was about $15.3 million. Exh. S–2, Sch. H(1)–3, Part 4.

The Commission rejects staff's arguments as it did in Opinion [**39] No. 395 in Docket No. RP91–229–000. 71 FERC P 61,228 at p. 61,836 (1995). The record does not show that the actual level of Panhandle's expenses has changed due to this reorganization. Consequently, there is no reason to reduce Panhandle's administrative and general expenses because of the change in organization to PSC as the accounting entity for group costs.3. Employee Pensions and Benefit ExpenseThe ALJ accepted Panhandle's Account No. 926, employee pensions and benefit expense, less the amount of $869,131 which he found was interest expense related to deferred executive compensation. n32 The ALJ rejected Citizens' proposed Account No. 926 reductions of over $2 million which it based on the 1992 union workforce reduction. He found that Citizens used inflated salary reductions and also that the workforce reduction did not affect Account No. 926 either directly or proportionately. On exceptions, Citizens still objects that Panhandle should make an adjustment in Account No. 926 for the 1992 union workforce reduction. It contends that this account should be the amount shown on Panhandle's books as of November 30, 1992, $18,762,795 (Exh. PE–40 at p. 1). This [**40] would be a reduction of $1,286,197. Panhandle counters that the ALJ has already removed interest on deferred executive compensation in the amount of $896,131 and that Citizens is seeking to remove this same amount twice.

n32 This was the as–filed amount for the base period. Exh. S–4 at p. 21. The annualized amount for the twelve months ending November 30, 1992, was $1,252,997. Id. Staff argued that this interest on deferred executive compensation should not be included because

> the cost of service in previous rate cases included this deferred salary as a part of annual labor expense. Since the ratepayers paid for this compensation through past rates and the pipeline had the use of the money . . . this revenue should have been invested in order to pay the interest. [Exh. S–1 at p. 20.]

[*61,365] We will not require Panhandle to remove the same amount twice. Account No. 926 includes pensions, group and life insurance premiums, payments for hospital and medical services, payments for accident, sickness, hospital, and death benefits or insurance; payments to employees incapacitated for service or on extended leave of absence; and expenses for educational and recreational activities [**41] for employees. Panhandle's witness Mr. Tindall testified that certain items—the Equalization and Executive Service Plan, Deferred Compensation Benefit, Safety Program Expenses, and the Houston office cafeteria—were unrelated to workforce reductions. Exh. PE–26 at p. 34. He testified that there were no significant reductions for medical coverage during the test period because most union employees could retain benefits up to eighteen months. He stated that there was a reduction in the cost of the Stock Purchase and Savings Program of $151,932 because this expense does vary with labor.Panhandle's estimates of Account No. 926 expenses also included an item for accrued Post Employment Benefits Other Than Pensions (PBOPs). n33 Panhandle began recording these expenses on January 1, 1993, a month after the November 30, 1992 end of the test period. Therefore, the issue here is

whether to allow in rates an expense for PBOPs, even though the expense did not occur until after the end of the test period. This issue was not addressed in the PBOPs Policy Statement. n34 However, we believe that the amount is known and measurable and was certain to occur January 1, 1993, just a month after the end [**42] of the test period. Moreover, the expense is significant. Therefore, in these circumstances we will waive our ordinary test period rules and affirm the ALJ on this issue as to what amounts Panhandle may include in its rates commencing January 1, 1993.

n33 Mr. Tindall's end of test period figure of $18,762,795 includes a post-test period addition for PBOPs (retirees' health insurance and miscellaneous benefits other than pensions (Exh. S-1 at p. 7.) of $1,141,713. It appears that Panhandle used this figure for PBOPs in estimating its as-filed Account No. 926 expenses as well. Exh. PE-14 at p. 12, line 7, col. 9; Exh. PE-14 at p. 13. Mr. Tindall calculated this figure by removing interest expense incurred on deferred executive compensation from the cost of service. This amount is shown as ($ 1,252,888) on line 16. He also stated that Panhandle's pension trust currently required no additional funding from Panhandle, so that the amounts shown adjusted pension trust expense to zero. He included the $1,141,713 of PBOPs (line 15) and removed workforce reduction related amortizations because separate provision was made for these costs. (Line 23, ($ 695,200).) The result was a total of $18,762,795. (Line 32.)

Panhandle's original as-filed amount of Account No. 926 expenses was $21,092,051. Panhandle removed $1,043,059 for workforce amortization costs to be treated separately for a total of $20,048,992. Exh. PE-40. The ALJ excluded $869,131 of this amount as interest on deferred compensation for a total of $19,179,861. A further $151,932 would be excluded because of the reduction in labor expense for a total of $19,027,929. If PBOPs were subtracted from this amount, the result would be $17,886,216.

[**43]

n34 Statement of Policy, Post-Employment Benefits Other Than Pensions, 61 FERC P 61,330 (1992), reh'g denied, 65 FERC P 61,035 (1993).

4. Bad debt expenseThe ALJ held that Panhandle must exclude bad debt expense of $968,000 from its cost of service, but only because it had not proved that the level of this expense was recurring. Panhandle states that the ALJ was correct in finding that Panhandle was not barred by Williston Basin Interstate Pipeline Co. n35 from including bad debt expense in its cost of service, but incorrect in excluding its proposed bad debt reserve on the grounds that it was not shown to be recurring. IS supports the ALJ's decision.

n35 67 FERC P 61,137 at p. 61,360 (1994).

The Commission has held that bad debt expense may not be included in the cost of service, but must be compensated through the pipeline's rate of return. Williston Basin Interstate Pipeline Co., 67 FERC P 61,137 at p. 61,360 (1994). The ALJ found that [*61,366] Panhandle had distinguished its situation from Williston by showing that its bad debt expense was not compensated through its [**44] rate of return and by characterizing its bad debt expense as a bad debt reserve rather than a write off. The ALJ's reasoning conflicts with the Commission's holdings in Williston and the Commission rejects it.

As the Commission stated in Opinion No. 395,

> It is the pipeline that decides who to contract with based on the creditworthiness provisions it establishes in its tariff. If those customers then turn out to be uncreditworthy, the pipeline should bear the risk rather than its other customers, particularly since Panhandle's tariff allows it to terminate service to uncreditworthy shippers. n36

Allowing Panhandle to include bad debt expense in its cost-of-service would, contrary to that holding, shift the risk that some customers will be uncreditworthy from Panhandle to its other customers. In addition, a bad debt reserve would burden other customers to the same extent as a write off by creating a subsidy for non-paying customers. As the Commission suggested in Williston, if a particular pipeline faces significant risk that customers will be uncreditworthy that fact may be taken into account in establishing the pipeline's rate of return. But, for the reasons stated above, [**45] the Commission will not permit the pipeline to include bad debt as an expense in its cost of service under any circumstances.

n36 71 FERC P 61,288 at p. 838.

5. Charitable contributionsThe ALJ approved $613,355 in charitable contributions, but recommended that the Commission reexamine its policy of allowing these costs in light of changing regulatory practice. Staff, IS, and the State of Michigan and the Michigan Public Service Commission urge the Commission to exclude these costs from the cost of service. Panhandle claims that they should be included. Consistent with its determination in Opinion No. 395, the Commission will permit the inclusion of these costs as a reasonable cost of doing business.6. Downsizinga. 1992 union workforce reduction programThe ALJ held that Panhandle could include the cost of its 1992 union workforce reduction program, $5.4 million (including carrying costs) (Exh. PE-39 at p. 1), in its cost of service. He found that amortizations of past years' programs had not compensated Panhandle for the costs incurred for the 1992 union workforce reduction program. Staff opposes the inclusion of these costs. Staff asserts that [**46] ratepayers have paid for three Panhandle reorganizations in 1988, 1989, and 1991, and should not have to pay for any more. Panhandle asserts that without downsizing costs, there would be no reduction in labor costs and that the reduction in labor costs is beneficial for many years to come. n37 As the Commission did in Opinion No. 395, 71 FERC at p. 61,837, it will deny recovery of these expenses because they are the kind of expense that should be borne by Panhandle's shareholders.

n37 Panhandle described the result of the 1992 union staff reduction as a gross reduction of $3,111,773 in annual labor expense, with a net reduction of $1,317,564 over the originally proposed three-year amortization period. (Exh. PE-38 at p. 1, line 19; I. Br. at p. 92.) Panhandle's original as-filed labor expense was $72,438,123. Panhandle subsequently used its payroll as of November 30, 1992, and adjusted its claimed labor expense by $3,111,773, to $69,326,350. 69 FERC P 63,013 (1994).

[*61,367] b. Years prior to 1992The ALJ held that Panhandle could continue to amortize the costs of the prior workforce reductions. He held that the amortization of the [**47] 1988 workforce reduction was included in the stipulation in Docket No. RP88-262-000 and that the Chief Accountant permitted Panhandle to defer the costs remaining at February 29, 1992. (Letters of January 12, 1990 and January 7, 1992.) He also held that Panhandle could recover the remaining balances of the other workforce reduction costs. He found that the balances were $2,819,966 for the 1988 workforce reduction, $1,236,779 for the 1989 workforce reduction, and $402,873 for office reconfiguration.Staff asserts that these prior downsizings have no current beneficial effect for ratepayers. It claims that Panhandle's alleged savings of $23.5 million in labor expense is offset by an increase in overtime expense that is indefinite. It also asserts that the Chief Accountant's deferral does not guarantee rate recovery. Citizens contends that the ALJ erred with regard to the 1988 workforce reduction. It states that these costs are outside Panhandle's base period in this case and claims that the stipulation in Docket No. RP88-262-000 did not address the amortization of these expenses. Citizens also asserts that if Panhandle failed to collect these costs during the Docket No. RP88-262-000 [**48] rate period, this issue should have been determined in the previous case, Docket No. RP91-229-000, not in this proceeding.The Commission finds, as it did in Opinion No. 395 in Docket No. RP91-229-000, that Panhandle's proposed downsizing expenses should be excluded from the cost of service. As it stated there, these costs were incurred during 1988, 1989, and 1991, well before the test period in this proceeding. Thus, they are beyond the scope of this proceeding. In addition, they, like the 1992 workforce reduction costs, should be borne by shareholders. 71 FERC P 61,288 (1995).Panhandle erroneously attempts to defend its out of period inclusion of costs on a letter received from the Office of Chief Accountant as its authorization to defer and collect these costs in its Docket No. RP92-166 cost of service. The letter received from the Chief Accountant explains very clearly that it is approving accounting entries, not the collection of costs. Further, the Chief Accountant's letter specifically states that Panhandle should immediately seek rate approval, and explains what accounting entries are necessary should rate approval be denied by the Commission. [**49] The letter expresses no opinion on the recognition in rates of the amounts at issue. In any event, the opinion of the Chief Accountant is not binding on the Commission as to whether test period regulations should be waived, or whether proposed costs may be recovered in rates. The Chief Accountant merely determined that, if Panhandle chooses, it may defer financial statement recognition of these amounts until the Commission acts. The letter is very clear on this and is not subject to multiple interpretations. Therefore, Panhandle's reliance on the letter is misplaced and misrepresents the intention of the Chief Accountant in writing that letter.7. Additional overtimeThe ALJ excluded $453,465 of overtime, of which $428,993 was allocated to Operations and Maintenance. He found that this amount was based on overtime for the period December 1992, through November 1993, (Exh. PE-37; Exh. PE-38), which was outside the test.period. Panhandle claims that this overtime expense should be included in its labor expense because it was necessary to achieve cost reductions. The Commission affirms the ALJ's decision. Panhandle has not supported a departure from the test [*61,368] period methodology and [**50] the amount involved is insufficient to justify an exception to that methodology. Panhandle has 57,496 hours of transmission overtime in its cost of service. Exh. PE-37 at p. 2. The additional amount Panhandle proposes to include is 16,795 hours. Including this extra amount in Panhandle's cost of service would mean building in increased overtime indefinitely, since there is no requirement that Panhandle file

another rate case. Panhandle may propose in a new rate case to recover the costs excluded here. However, the Commission will not use data from outside the test period to support their inclusion here.8. Federal income tax rateThe ALJ held that Panhandle could not use the thirty-five percent federal income tax rate which went into effect January 1, 1993, for either the pre-or post-restructuring periods because this change was not known and measurable at the time of filing and did not become effective during the test period. Formerly, the rate was thirty-four percent. The ALJ held that the change was not of sufficient magnitude to require a change to the cost of service. Southwestern Public Service Co. v FERC. n38 Village of Chatham and Riverton v. FERC. n39 Panhandle asserts that [**51] this denial prevents it from collecting about $2 million in federal taxes and that its flowback of excess deferred taxes (reverse South Georgia) would also be excessive. Panhandle insists that the increase in tax rate is required by Southwestern Public Service Co. (Southwestern). n40

n38 952 F. 2d 555 (D.C. Cir. 1992)

n39 662 F.2d 23, 35 (D.C. Cir. 1981).

n40 60 FERC P 61,052 (1992), aff'd in relevant part, 63 FERC P 61,295 (1993).

In Southwestern, the Commission's decision to change the federal tax rate from forty-six percent to thirty-four percent to correspond to post-test period changes ultimately resulted in the Commission's reopening the record and requiring that all post-test period changes be considered. 60 FERC P 61,052 (1992). The Commission agrees with the ALJ that, in this case, Panhandle should make a new rate filing if it is dissatisfied with the federal tax rate that existed during the test period. The Commission can then consider all post-test period changes in the context of the new rate filing. Accordingly, the [**52] Commission affirms the ALJ's decision to adopt the federal tax rate of thirty-four percent in existence during the test period for both pre-and post-restructuring periods.9. Federal income tax — meals and entertainment expense deductionThe ALJ removed $324,187 of meal and entertainment expense (Exh. PE-7; Exh. PE-26 at pp. 41-2) from Panhandle's tax allowance. This was the twenty percent of such expense that was made non-deductible by the Tax Reform Act of 1986 (Tax Reform Act). The ALJ stated that this result was in accordance with the Commission's holding in Williston Basin Interstate Pipeline Co., 56 FERC P 61,104 at pp. 61,378-79 (1991), order on reh'g, 60 FERC P 61,162 at pp. 61,594-95 (1992).Panhandle maintains that Williston is wrong, arguing that the Tax Reform Act did not preclude the recovery of the income tax expense associated with the non-deductible meals and entertainment expense in rates. It also asserts that non-regulated companies can raise prices to cover the extra tax cost, while the Commission is prohibiting it from doing so.The intent of making a portion of meals and entertainment expense non-deductible was [**53] to make that portion taxable. An ordinary company in an efficient market would have to pay the tax out of its earnings, and, as a result, its earnings would be [*61,369] lower. The result of the Tax Reform Act should be the same for Panhandle. Panhandle should have to pay this tax cost out of its earnings. If Panhandle can pass through the tax cost, it avoids this result. Its earnings remain the same, in spite of the lowering of the deduction. The loss of a portion of the deduction would then have no deterrent effect on the incurrence of meals and entertainment expenses, contrary to the intent of the Tax Reform Act. The holding in Williston puts pipelines in the same position as non-regulated companies paying federal income tax that are operating in efficient markets. Consequently, consistent with Williston, the Commission affirms the ALJ's decision to exclude twenty percent of Panhandle's meal and entertainment expense from Panhandle's tax allowance.10. Labor expense and FICA taxThe ALJ approved a labor expense allowance of $68,897,357. n41 This figure was based on an annualization of Panhandle's wages as of November 30, 1992, the end of the test period. Exh. PE-38 at p. 1. It included certain [**54] accrued labor expenses (amounts Panhandle asserts it owes but has not yet paid) and a May 1992, wage increase. It excluded $453,465 in overtime expenses, an exclusion which the Commission has affirmed above. Staff excepts to the allowance on several grounds and seeks a reduction of about $759,666.

n41 Panhandle originally proposed a total labor expense of $72,438,123. Exh. PE-5 at p. 5, col. 9, line 24. Panhandle subsequently used its payroll expansion as of November 30, 1992, and adjusted its claimed labor expense by $3,111,973 to $69,326,350.

Staff asserts that accruals are only estimates of future expenses and that the accrual for Vacation and Bank Time (Exh. PE-38 at p. 1, line 9) should be eliminated as unknown and unmeasurable. Panhandle answers that it is proper to include accrued expenses.Staff contends that Panhandle is recovering some accrued items like vacation pay twice because such an expense is already included in employees' salaries. Panhandle asserts that staff has not borne its burden of proving this claim and that nothing supports it. On Panhandle's exhibit PE-38, Panhandle lists an item of $56,665,053 for annualized wages as of November 39, 1992, direct [**55] payroll, and a separate item of $303,000 under supplemental payments for accrued vacation and bank time. Panhandle's witness, Mr. Tindall, testified that Panhandle accrued bank time and vacation pay in accordance with Financial Accounting Standard No. 43. He stated that:

bank time was earned by employees who did not use their sick pay and is paid if the employee requires additional sick leave because of an extended illness or, if it is not used, upon retirement. In accordance with FAS 43, each year Panhandle accrues the Bank Time owed to vested employees 55 years of age or older. When these employees receive Bank Time payments at retirement, no labor expense will be recorded; these amounts will be charged to the liability account, instead. FAS 43 also provides for Panhandle's increased liability to its employees for vacation accruals earned in the current year.

Exh. PE–26 at p. 30. Mr. Tindall testified that the amounts for accrued vacation and bank time had only been recorded as expenses once.Panhandle proposes to include accrued vacation liabilities in its annualized wages. These amounts represent accruals which Panhandle may have to pay in the future. The Commission [**56] will not set rates here for a potential liability which may occur when some [*61,370] employee retires being owed sick leave. The Commission has consistently set rates based upon actual annualized test period labor costs. An employee's annual salary is therefore provided for. We will not provide extra amounts for an unknown and unmeasurable amount to be incurred in the future, unless Panhandle wishes to, as with PBOPs, establish an outside trust fund and make non–refundable contributions to the trust for these accruals. Since Panhandle has not proposed this in the instant case, we will adopt Staff's position with regard to labor expenses and require a reduction in Panhandle's claimed labor expense equal to the amount it proposed to include for these accruals.On May 1, 1992, Panhandle gave its field employees a four percent hourly wage increase. Staff claims that this increase should not be included in labor expense on an annualized basis, but only for the seven months of the test period in which it was effective. Staff's position would exclude $47,557 from labor expense. n42 Panhandle asserts that the annual effect of this wage increase must be included in labor expense. The Commission agrees [**57] with Panhandle that the annual effect of the wage change should be included in labor expense. This change, which was known and measurable, should be included in its entirety. This is a permanent change, and the estimate of this expense is meant to be forward looking and to establish rates for the future. The increased wage cost is an expense to Panhandle in each month after the rates go into effect and is properly included in labor expense as a yearly amount.

n42 The wage increase for the additional five months is $46,557. Exh. PE–38 at p. 1, line 10 and 2, line 10.

As the Commission has made changes to Panhandle's labor expense, there are changes to the FICA tax, other than that already determined by the ALJ relating to the disallowed increased overtime. Panhandle must reduce the amount of FICA tax accordingly.11. Miscellaneous fuel accounts (company use gas)The ALJ approved inclusion of $2,012,325 in miscellaneous fuel accounts (Exh. S–3 at p. 19) for the post–restructuring period. The ALJ found that Panhandle was not recovering any of this amount through its fuel reimbursement percentage. He also held that staff's argument that these accounts should be adjusted was not [**58] explained through expert testimony and so had no support. On exceptions, staff urges a reduction to $1,538,506, which is obtained by eliminating two accounts, Nos. 818 and 823, adjusting the fourteen remaining accounts, and using a three–year average. Staff believes that this level of expenses is more representative than Panhandle's because the test period level is higher than the company's recent actual experience.In his testimony, Mr. Reed, Panhandle's witness, testified that miscellaneous fuel accounts were not included in the fuel reimbursement percentage and that these accounts were Nos. 753, 754, 759, 764, 765, 807.3, 817, 818, 823, 852, 853, 855, 856, 857, 863, and 864. Exh. PE–74 at p. 2. Nonetheless, staff removed Account Nos. 818 and 823. Account No. 818, compressor station expenses, consists of labor, materials used, and expenses incurred in operating underground storage compressor stations. Account No. 823, gas losses, consists of the cost of gas lost or unaccounted for in underground storage operations. From Mr. Reed's testimony, it appears that neither of these items were included in the fuel reimbursement percentage. They are thus properly included in the miscellaneous [**59] fuel accounts and charged to operation and [*61,371] maintenance expenses. The Commission also rejects staff's argument that a three–year average from November, 1990 to November, 1992 should be used to calculate the amount of these expenses.A review of the record shows that the three year amounts of $1,332,798, $1,588,596, and $1,694,125 are escalating. While the Commission does not as a general matter endorse trend analyses, the evidence in this case supports the inclusion of $2,012,325. Historically, the Commission has used averaging methodologies when the data demonstrates swings between periods. Here, Staff has not shown that any swings are present so that averaging is required. Accordingly, the Commission accepts Panhandle's proposal to include $2,012,325 for this item.12. Kansas ad valorem taxThe ALJ held that in the pre–restructuring period, Panhandle could include in its cost of service increases in the Kansas ad valorem tax of about $2 million consisting of taxes on gas inventory and a three percent increase in the state rate. He found these changes, which were approved by voters on November 3, 1992, and which went into effect during the test period, to be known and measurable [**60] at the time of filing.The State of Michigan and the Michigan Public Service Commission (Michigan) urge the Commission to exclude this tax increase. Michigan argues that the changes in the Kansas ad valorem taxes did not occur until after the test period. It states that these changes were effective January 1, 1993, and were not paid by Williams Natural Gas Company, which subsequently billed them to Panhandle), until the latter part of 1993. Exh. S-1 at p. 36. Michigan states that, if the ALJ's approach is adopted, then any legislatively mandated changes enacted and any contracts executed within the test period would result in known and measurable test period expenses, regardless of their effective dates or the point at which expenses are incurred in relation to them. Michigan also states that the inclusion of these tax increases is inconsistent with the ALJ's refusal to exclude the costs of the Higgins gathering system on the grounds that this sale was not effective until January 1, 1993, and so was a post-test period event.Staff takes differing positions with regard to these tax increases depending on the period in question. For the pre-restructuring period, it states that the Kansas [**61] ad valorem tax increases should not be included because they were not effective until after the start of the pre-restructuring period and were to be paid in the latter part of 1993, during the post-restructuring period. For the post-restructuring period, staff states that the increases in the Kansas ad valorem tax should be included in the cost of service because Panhandle will actually be paying these increases during the post-restructuring period.Panhandle argues that the increase in the Kansas ad valorem taxes should be reflected in its tax allowance as of January 1, 1993, because voters approved the law on November 3, 1992, which was during the test period. It also states that the Commission's policy is to adjust for known tax rate changes occurring within a reasonable time after the end of the test year. United Gas Pipe Line Co., Opinion No. 428-A, 32 FPC 687 (1964). Panhandle faults staff for allegedly taking a position contrary to the one it took in Trunkline Gas Co. (Trunkline). n43 which, Panhandle asserts, favored the inclusion of a post-test period tax change. Panhandle maintains that staff's position is just [*61,372] another attempt to institute cash [**62] accounting which is neither required nor permitted by the Commission's regulations.

n43 41 FERC P 63,011 (1987).

In seeking inclusion of the increase in the Kansas ad valorem taxes, Panhandle relies on testimony of a staff witness in Trunkline. The staff witness' testimony there was that a tax rate change which was known and measurable during the test period and became effective after the end of the test period should be included in rates. Exh. PE-42 at p. 4; I.Br. at p. 143. Panhandle also argues that the ALJ in Trunkline adopted staff's position and required the pipeline to modify its rates in accordance with a tax change.The Commission finds that Panhandle should not be permitted to reflect the increased Kansas ad valorem taxes in its cost of service for either the pre-or post-restructuring periods. The initial decision in Trunkline stated that the parties stipulated to the amount of other taxes, which would have included the Kansas ad valorem tax and any increase in that tax. In its order on the Trunkline initial decision, the Commission also stated that the parties stipulated to the issue of other taxes. Thus, the Commission did not address the [**63] issue of tax changes in that case. Consequently, there is no support in Trunkline for including the increase in the Kansas ad valorem tax in Panhandle's pre-restructuring rates.In any event, the changes in the Kansas ad valorem tax do not meet the requirements of the Commission's regulations for inclusion in Panhandle's cost of service in this rate case. The Commission's regulations require a pipeline's costs to be based on a test period. The test period consists, first, of a base period of 12 months of most recently available actual experience. This period may be adjusted for changes in revenues and costs which meet certain criteria. The changes that are acceptable are changes

> which are known and are measurable with reasonable accuracy at the time of the filing, and which will become effective within nine months after the last month of available actual experience utilized in the filing . . . . [18 C.F.R. § 154.63(e)(2)]

The change in the Kansas ad valorem tax was not known and measurable at the time of the filing. The filing was made on May 1, 1992. In addition, the changes in the Kansas ad valorem tax did not become effective within nine months after the last month [**64] of available actual experience. The base period ended March 1, 1992, and the nine months completing the test period ended on November 30, 1992. The increases did not become effective until January 1, 1993, and Panhandle did not have to pay the increase in the tax until after January 1, 1993.In sum, excluding the increases in the Kansas ad valorem tax is consistent with the Commission's regulations and also with other holdings in the initial decision which are affirmed here. The ALJ excluded an increase in Federal tax from cost of service and a decrease in gathering facilities (Higgins) from rate base because these events took place after the close of the test period. In the same way, the increases in the Kansas ad valorem tax should be excluded from rates because they became effective after the test period. As the ALJ noted, and as discussed elsewhere in this order, Panhandle may file a general rate case under section 4 to accommodate these changes in its costs. The amount of Kansas ad valorem tax to be included in the cost of service for both the pre-restructuring and post-restructuring periods is that proposed by staff, $2,828,799. Exh. S-2, Sch. H(4)-

1; Exh. S–4 at p. 32.13. Outside [**65] services, Account No. 923 [*61,373] The ALJ accepted Panhandle's allowance of $15,416,943 (Exh. PE–14 at p. 5) for outside services for both the pre–and post–restructuring periods. Staff argues that the allowance should be based on an annualization of actual costs incurred during the eleven–month period from the formation of the Panhandle Service Company (PSC) in January, 1992, until the end of the test period in November, 1992. Staff proposes a total allowance for Account No. 923 of $10,177,896 for both pre–and post–restructuring periods.Staff also proposes to remove accruals for legal expense and directors' fees from the cost of service. According to staff's exhibits (Exh. S–4 at pp. 14–20), Panhandle proposed a legal expense component in Account No. 923 of $6,820,676, of which $1,097,361 were accrued expenses. n44 Staff argues that accounting should not dictate ratemaking. It states that those accruals were only estimates of future expenses and so were not costs that were known and measurable in conformance with the Commission's regulations. 18 C.F.R. § 154.63(e)(2) (1995). Staff proposes an allowance for legal expenses within Account No. 923 of $3,660,761 for both periods. Panhandle [**66] asserts that using accruals conforms to the Commission's regulations (General Instruction 11), and that staff has not shown that its accruals are unreasonable.

n44 According to staff's exhibits, Panhandle proposed directors' fees of $189,751 of which none were accrued. Exh. S–4 at p. 17.

The Commission reverses the ALJ on this issue and adopts Staff's position. Staff argues that the accruals are only estimates of future expenses and are not known and measurable in conformance with the Commission's regulations. Panhandle has not met its burden of showing that all the legal expense costs it claims here were incurred during the test period. Historically, the Commission has only allowed rates to be set based upon known and measurable costs. Panhandle's claimed legal expense costs within Account No. 923 were not known and measurable during the test period. Therefore, we will only allow Panhandle legal expenses based on its actual legal expenses during the eleven month period January through November 1992, annualized, or $3,660,761.14. PCB expensesThe ALJ approved the inclusion of $615,937 for polychlorinated biphenyl (PCB) investigation and clean up expenses in the cost of service. [**67] n45 Most of these expenses were for testing and analysis. Exh. PE–26 at p. 27. Staff objects on the ground that PCB contamination testing is not normal maintenance testing and was thus not normal and usual to the operation of the system. Staff maintains that these PCB procedures are unique and non–recurring. It also claims that Panhandle should seek reimbursement from manufacturers and its insurance companies before seeking payment from ratepayers. Panhandle states that staff seeks only the deferral of these expenses and does not oppose their recovery. Panhandle asserts that it does not have insurance coverage for these costs. It alleges that its PCB clean–up costs will be continuing in nature.

n45 These expenses consisted of $400,450 of Account No. 850 operation supervision and engineering expenses and $215,487 of Account No. 923 outside services expenses. Exh. S–3, Schedule H(1)–1, Parts 7 and 8.

The Commission has previously determined that PCB expenses are maintenance expenses: "For accounting purposes, PCB decontamination is maintenance. PCB decontamination is done for the purpose referred to in the USofA's [Uniform System of Accounts] Operating Expense Instruction 2(3), [**68] Maintenance: 'Work performed specifically for the purpose of preventing failure, restoring serviceability or maintaining life [*61,374] of plant.'" Unison Transformer Services, Inc. n46 The Commission agrees with the ALJ that investigative as well as actual clean up expenses may be included. It appears that Panhandle does not have insurance for these expenses (Exh. PE–26 at p. 28) and litigation against the manufacturers could be costly and is uncertain. Staff has not shown that these costs are non–recurring. These or other maintenance costs may be incurred in the future. Therefore, they are includable in Panhandle's cost of service as normal maintenance costs.

n46 48 FERC P 61,327 (1989).

15. Post–employment benefits other than pensionsPBOP costs were to be accrued as of January 1, 1993, and are included in both the pre–and post–restructuring costs accepted here. The ALJ held that it was not necessary for Panhandle to establish a regulatory asset or liability for changes in the amount of PBOPs between rate cases. On exceptions, Staff requests that the Commission require Panhandle to establish such a regulatory asset.The Commission established the conditions [**69] under which a pipeline could include PBOPs in its rates in its policy statement issued in 1992. n47 Panhandle proposes, consistent with the Commission's policy statement, to place PBOP amounts equal to the amounts included in rates in an external trust. Exh. PE–26 at pp. 7–8; Tr. 1058–62; 1804–08. There is no requirement in the policy statement for the creation of a tracker or regulatory asset or liability for PBOP costs. After the pipeline includes its PBOP costs in its rates, as we permit Panhandle to do in this rate case, the pipeline is at risk for any subsequent undercollection between rate cases. Since Panhandle has not asked for relief from this risk and since such relief is not provided for in the policy statement, we will not add such relief here through establishment of a regulatory asset. Consequently, since Panhandle is using the accounting method prescribed by the Commission, it is not required to establish a regulatory asset

or liability for its PBOPs expense.

n47 Statement of Policy, Post–Employment Benefits Other than Pensions, 61 FERC P 61,330 (1992), order denying reh'g, 65 FERC P 61,035 (1993).

16. Purchased [**70] gas expense and compressor fuelFor the pre–restructuring period, the ALJ found that Panhandle's purchased gas costs were $53,259,099. This figure was derived from staff's proposed level of firm sales, 25,881,572 Dt, multiplied by the WACOG for July 31, 1992, of $2.0578/Dt. Exh. S–23.In its brief opposing exceptions, staff states that the level of purchased gas costs should be increased to include interruptible sales (ISS) which occurred during the test period. Staff asserts that ISS sales amounted to 23,315,224 Dt worth $47,978,067 at the same WACOG, for a total level of $101,237,167 for purchased gas costs. Exh. S–16 at pp. 11–12; B.O.E. at p. 33 n. 92. Panhandle refers to this addition as a conforming change. Panhandle contends, however, that the ALJ did not include sufficient compressor fuel for ISS, non–jurisdictional, and off–system sales, and that compressor fuel use increases geometrically with increased system throughput. Staff maintains that no increase for compressor fuel is necessary, or, if it is, it is up to Panhandle to prove the amount.The ALJ included 23,315,224 Dt of ISS volumes in sales throughput. A corresponding dollar amount should be included in pre–restructuring [**71] purchased gas expense. The Commission adopts staff's addition of $47,978,067 to purchased gas expense. The Commission agrees with Panhandle that compressor fuel expense (Account Nos. 755, [*61,375] 819, and 854) for ISS, non–jurisdictional, and off–system sales should be included in the cost of service. The Commission finds, however, that the burden of showing the amount of the increase in compressor fuel use was Panhandle's. Panhandle failed to provide any testimony as to the amount of the increase, so there is no basis on which to determine the extent of any such increase. Finally, changes in compressor fuel use were tracked through Panhandle's PGA (Exh. PE–68 at p. 3), so that Panhandle collected the compressor fuel costs associated with these sales.17. Revenue crediting for non–jurisdictional salesThe ALJ determined that the allocation of costs to non–jurisdictional sales was an issue to be heard in this proceeding. He decided that Panhandle bore the burden of proving that revenue crediting rather than three–day peak should be used, and that Panhandle had failed to bear this burden. He held that the revenues credited to non–jurisdictional service should be increased by $669,686, from [**72] $1,463,767 to $2,133,453.Panhandle asserts that this issue was not set for hearing in this docket, but was to be decided in the previous rate case, Docket No. RP91–229–000. Panhandle also states that any change in its revenue crediting method could only be implemented prospectively, and, that since this is now impossible, the issue is moot. Citizens contends that non–jurisdictional service can be considered here because it was not addressed in any of the orders in Panhandle's restructuring proceeding. It urges the Commission to determine non–jurisdictional sales costs based on its allocation which includes the use of three–day peak.The ALJ rendered his decision before the issuance of Opinion No. 395 in Docket No. RP91–229–000. In that order, the Commission held that Panhandle had shown that revenue crediting should be used to calculate the costs of non–jurisdictional sales. Thus, Panhandle bore its burden of proof in that case. The question here has become whether Citizens' evidence shows that Panhandle's costs for non–jurisdictional sales are unjust and unreasonable, and that its own figure is just and reasonable.Citizens presented its allocation of costs through its witness [**73] Mr. Saunders. Mr. Saunders adjusted Panhandle's final compliance rates n48 by reducing them by about $7 million and then by allocating these revised costs between jurisdictional and non–jurisdictional services. Exh. C–1 at p. 2 and Exh. C–17 at p. 2. He used an MFV type of cost allocation to allocate gas supply and transmission demand costs in which he allocated half the demand costs for these functions on the basis of three–day peak and the other half based on annual volumes.

n48 63 FERC P 61,129 (1993).

Mr. Saunders' allocation method differs from Panhandle's, but in ways that allocate fewer costs to non–jurisdictional sales service. n49 Mr. Saunders' calculations show that if costs are allocated to non–jurisdictional sales service, that service would be responsible for a greater share of Panhandle's revenue requirement. The Commission finds that the difference of over $600,000 between Panhandle's proposed revenue credit to non–jurisdictional sales and Mr. Saunders' allocation is significant and that Citizens has shown jurisdictional sales customers are subsidizing non–jurisdictional sales customers. [*61,376] The facts here differ from those [**74] in Docket No. RP91–229–000. There the difference between allocating costs to non–jurisdictional sales customers and the revenue credit was in the $200,000 range, rather than over $600,000. In addition, in Docket No. RP91–229–000, Citizens' calculation of the amount to be allocated to non–jurisdictional sales service was unclear, while here it is possible to follow Citizens' calculations. Consequently, in this proceeding, the Commission will require Panhandle to allocate $2,113,278, the costs supported by Citizens, to non–jurisdictional sales service. n50

n49 Mr. Saunders seems to have allocated gathering demand costs based on annual volumes and underground storage demand costs based solely on three–day peak. Exh. C–17 at p. 2. Panhandle used contract demand to allocate gathering D1 costs and the Opinion No. 369 factors to allocate storage demand costs (i.e., 78 percent to winter sales and 22 percent to transportation). Exh. PE-55 and-56. Mr. Saunders' variations from Panhandle's allocation factors reduced the costs allocated to sales, and hence to non-jurisdictional sales.

n50 This is the difference between the total cost of service, $378,629,340 put forward by Citizens and its total jurisdictional cost of service, $376,516,062. Exh. C-17 at p. 2.

[**75] 18. Revenue crediting of off-system salesThe ALJ held that Panhandle had not credited sufficient revenues from off-system sales to its jurisdictional sales customers. He held that the amount of the credit, $5,078,801, must be increased by $550,571. He found that the increase was necessary because Panhandle had used a different commodity purchased gas cost for the off-system sales, $1.8359/Mcf, than it had used for all other commodity purchased gas costs, $2.1489/Mcf.Panhandle excepts, asserting that it has credited the correct amount. It states that for off-system sales, the average rate for revenue collected was $1.9387 per Mcf. It credited an amount equal to this per Mcf rate multiplied by the test period volume of off-system sales of 2,619,653 Mcf. Statement G-3 at p. 4; Exh. PE-59 at p. 6. It states that the actual cost of gas during the six-month pre-restructuring period was $1.8359/Mcf. Exh. PE-59 at pp. 5-6; Exh. PE-61. The result, it alleges, is that it credited revenues from off-system sales that exceeded the cost of the gas.Citizens counters that sales customers were subsidizing off-system sales in the amount of $0.2102/Mcf because the off-system sales customers are [**76] paying less than Panhandle's then current commodity costs for gas. Citizens states that the then current commodity cost of gas was $2.1489/Mcf, the cost which Panhandle used in its Revised Schedule H(1)-2 for the commodity cost of gas. (Motion Rates, October 1, 1992, and March 1, 1993.) It asserts that there is a subsidy of $2.1489/Mcf minus the amount credited, $1.9387/Mcf, or $0.2102/Mcf. Citizens also argues that Panhandle's reliance on its cost of gas for off-system sales during the 6-month pre-restructuring period is incorrect because it is based on only six months of data of which five are outside the test period. Citizens claims that there is no reason to depart from test period data. Citizens also faults the derivation of Panhandle's actual cost of gas for the six-month period because the $1.8359/Mcf figure was not based on factors comparable to those used to derive the unit of sales rate for the PGA.The Commission rejects Citizens' arguments. Panhandle filed the $1.8359/Mcf cost figure in Exh. PE-61 as rebuttal testimony in answer to Citizens' contention that the credited revenue from the off-system sales customers was less than the commodity cost of gas. Exh. PE-59 [**77] at pp. 5-6. Panhandle showed the actual cost of gas for the pre-restructuring rate period, November 1992, through April 1993. Regardless of the commodity gas cost that was adopted for purposes of base rates in this proceeding, the crux of the matter is the actual commodity cost of the gas. This is what sales customers ultimately paid, since gas costs were flowed through the PGA. Therefore, this is the appropriate figure to compare to the amount paid by the off-system sales customers. Consequently, the Commission finds that Panhandle's reliance on the actual costs for the rate period was a reasonable means of rebutting Citizens' contention that the [*61,377] commodity cost of gas during this period was greater than the revenues from the off-system sales customers, which Panhandle credited to the jurisdictional sales customers.Citizens also objects, however, to the way in which Panhandle calculated the cost of gas for the rate period in Exh. PE-61. Citizens claims that Panhandle calculated the unit cost of gas purchased and that this figure did not show off-system sales customers paid the commodity cost of gas. It claims that Panhandle uses the cost of the unit sold in its PGA and that is what [**78] sales customers pay.The difference between the two costs is primarily that some gas is lost and unaccounted for and that some is used for compressor fuel, both of which are included in the fuel reimbursement percentage. The Commission finds that Panhandle has shown the commodity cost of gas during the locked-in period was $1.8397/Mcf per unit purchased. It is also a matter of record that Panhandle's fuel reimbursement percentages were 0.25 percent for the gathering area, 2.05 percent for the field zone, and 2.35 percent for the market area. Exh. PE-67. If the fuel reimbursement percentage for off-system sales was the maximum of 4.65 percent, then the cost of an Mcf of gas sold to an off-system sales customer would be $1.9254/Mcf. n51 This is within the amount of revenue Panhandle credited for off-system sales, $1.9387/Mcf, and shows that the revenue from the off-system sales covered the commodity cost of the gas. In any event, Citizens did not put forward any alternative figures for the cost of gas sold for off-system sales. Thus, the best evidence of record as to the cost of the gas and the justness and reasonableness of the off-system sales revenue credit was that provided by [**79] Panhandle. The Commission reverses the ALJ and accepts Panhandle's revenue credit for off-system sales of $5,078,801.

n51 $1.8359/.9535 Mcf = $1.9254/Mcf.

19. South Georgia adjustmentThe ALJ accepted Panhandle's South Georgia adjustment to normalize deferred taxes of $1,506,993 as the overfunded revenue amount to be used in the flow-back calculation for ratepayers and $5,123,385 as the underfunded revenue amount to be used in the calculation to determine recovery from ratepayers. Exh. PE-41. Staff urges that its method of making this adjustment be accepted because it is simpler and makes clear what the individual

components of the tax allowance are. Exh. S-4 at pp. 28-31. Staff's method consists of offsetting excess Federal deferred income taxes by the deficiency in the state deferred income taxes, resulting in a single flow-back in the cost of service of $1,490,355 over the remaining depreciable life of 16.60 years for the pre-restructuring period and $671,529 over the remaining depreciable life of 17.24 years for the post-restructuring period.The Commission reverses the ALJ and accepts staff's composite method. As the Commission stated in Opinion No. 395, staff's [**80] proposal is consistent with the Commission's general policy in applying the South Georgia method. Staff's proposal is appropriate because Panhandle's federal Accumulated Deferred Income Taxes (ADIT) account is overfunded while its state ADIT account is underfunded. "The use of a composite rate to net the two is the simplest and most effective method to solve this problem . . . ." n52 Consequently, the Commission adopts staff's flow-back adjustments.

n52 71 FERC P 61,228 at p. 61,840 (1995).

D. Functionalization, classification, allocation, and rate design1. Functionalization of Administrative and General Costs to Gathering [*61,378] IS asserts that the initial decision functionalizes too large a share of Panhandle's administrative and general (A&G) expenses to gathering. Panhandle included its A&G expenses in eleven accounts. n53 Panhandle used the Kansas-Nebraska method n54 to functionalize $84,817,022 of A&G costs among its various functions, including gathering. n55 It allocated Property Insurance and Maintenance of General Plant based on gas plant. It allocated Outside Services Employed, Regulatory Commission Expenses, and Miscellaneous General Expenses [**81] on a combination of direct labor and gas plant. It allocated the other costs based on direct labor. The total amount of A&G expenses allocated on the basis of gas plant was $2,877,821, while the total amount allocated on the basis of direct labor was $81,939,201. n56

n53 No. 920, Administrative and General Salaries; No. 921, Office Supplies & Expenses; No. 922, Admin. Expenses Transferred; No. 923, Outside Services Employed; No. 924, Property Insurance; No. 925, Injuries and Damages; No. 926, Employee Pensions and Benefits; No. 928, Regulatory Commission Expenses; No. 930, Miscellaneous General Expenses; No. 931, Rents; and No. 935, Maintenance of General Plant. Exh. PE-5 at p. 5.

n54 Kansas-Nebraska Natural Gas Company, Inc., Opinion No. 731, 53 FPC 1691, 1721, order on reh'g, 54 FPC 923 (1975), aff'd, 534 F.2d 227 (10th Cir. 1976). In Kansas-Nebraska, the Commission held that seven of eleven items included in administrative and general expenses were related primarily to the expenditure of direct labor and should be allocated on that basis; two items, "Fire and Other Insurance" and "General Plant Maintenance Expenses," were related to plant and should be allocated to plant; and "Outside Services Employed" and "Miscellaneous General Expenses" were related to both labor and plant so they should be allocated based on direct labor and gas service ratios. 46 FERC P 61,183 (1989).

Thus, in the Kansas-Nebraska method, A&G expenses are classified to labor, plant, and other. The expenses classified as "other" are allocated to labor and plant pro rata on the basis of the ratio of the total labor-related A&G expenses and the total plant-related A&G expenses to the total of both plant and labor-related A&G expenses. After the "other" expenses have been allocated to labor and plant, they are added to the total labor-related and plant-related A&G expenses. The labor-related A&G expenses are then functionalized on the basis of direct labor ratios (the direct labor devoted to each function divided by total direct labor other than A&G labor). The A&G expenses related to gas plant are functionalized on the basis of gas plant ratios (the gas plant devoted to each function divided by total gas plant in service).

[**82]

n55 Exh. PE-11; Motion Rates (March 1, 1993), Statement A, Statement H(1) at p. 7. For the pre-restructuring period, Panhandle allocated A&G costs $10,014,031 to gathering, $3,935,540 to gas supply, $2,990,182 to underground storage, and $67,877,269 to transmission.

For the post-restructuring period, Panhandle allocated A&G expenses $10,014,031 to gathering, $2,990,182 to underground storage, and $71,812,809 to transmission. July 12, 1993, Motion Rates, Docket No. RS92-22-009, et al., Appendix 2 at pp. 21-5.

n56 Motion Rates (March 1, 1993), Revised Statement H(1), Workpaper at p. 2.

The ALJ approved Panhandle's allocation method as just and reasonable. He also found that Panhandle had used the correct amount of direct labor expenses in calculating the allocation using this method. n57 The amount of direct labor was $51,712,779, of which $6,123,462 or 11.841 percent, was direct labor for gathering. n58 This amount consisted of $4,757,116 identified as labor expenses for gathering and $1,366,346 of purchased gas expense allocated to gathering.

n57 See Motion Rates (March 1, 1993), Revised Statement H(1) Workpapers at pp. 1–3.

n58 Motion Rates (March 1, 1993), Statement H(1), Workpaper at pp. 1 and 3.

[**83] a. Allocation factorsIS objects that too many A&G costs are allocated to gathering. IS contends that the direct labor expense for the gathering area in Panhandle's Kansas–Nebraska method formula is too high. IS states that direct labor expense in the gathering area includes well connection, but that a Panhandle affiliate, Centana Energy Corporation (Centana), has assumed the function of well connection in the gathering area. Exh. IS–12; Tr. 76, 79–80. IS asserts that Centana acts as an agent for Panhandle. Consequently, it claims that Panhandle's direct labor expense for well connection improperly includes expenses for work done by Centana employees. IS asserts that Panhandle has the burden of proof on this issue and has failed to carry that burden. The result, [*61,379] according to IS, is that the increase in the gathering rate attributable to the increased allocation of A&G costs should be rejected.Staff contends that the Kansas–Nebraska method is not responsible for the large amount of A&G costs allocated to gathering. It explains that this is primarily due to the amount of direct labor costs booked to the operation and maintenance accounts for the gathering function. Staff states [**84] that although IS claimed Centana performed some of these tasks, like well connection, IS did not quantify the specific costs that were not incurred by Panhandle. Panhandle claims that labor costs related to the construction of new well connections are chargeable to gas plant accounts and are not included in labor in the allocation factors used in the Kansas–Nebraska formula.Panhandle's witness Mr. Tindall testified that one of the functions Panhandle performed in the gathering area was the connection of new wells to Panhandle's system. Tr. 76. However, a marketing brochure for a "SwiftConnect" program (Exh. IS–12), indicates that Centana, a subsidiary of Panhandle Eastern Corporation (Tr. 80), was connecting wells to the Panhandle system in the gathering area. Mr. Tindall testified that he understood that Centana "does operate in some instances as an agent for Panhandle." Tr. 80. Panhandle's 1993 Annual Report indicates Centana assisted in connecting more than 400 Bcf of additional natural gas reserves to the pipeline network and completed receipt interconnections with pipelines and plants representing new deliverability in excess of 140 MMcf per day. Exh. IS–14 at p. 25.The Commission [**85] agrees with Panhandle that direct labor costs for new well connections would be capitalized whether the service was performed by Centana or by Panhandle itself. They would thus be recorded in gas plant accounts, not in direct labor accounts and would not be part of the direct labor allocation factor. They would still be included in the Kansas–Nebraska formula in the gas plant allocation factor and would affect the four items that are allocated in whole or in part based on gas plant. This would include any expenses incurred by Centana as Panhandle's agent. There is nothing in the record to indicate that Panhandle's dealings with Centana were not arm's length transactions, and thus no reason to exclude these expenses from an allocation factor in the Kansas–Nebraska formula.b. Kansas–Nebraska methodIS contends that the Kansas–Nebraska method is unjust and unreasonable. It claims that it allocates to gathering a disproportionate amount of A&G costs and costs that are not uniquely related to gathering. IS supports the method proposed by its witness, Mr. Chalfant, which would allocate corporate overhead costs in the same ratio as all other costs. Exh. IS–5 at pp. 6–7.Staff, Panhandle [**86] and Phillips/GPM support the Kansas–Nebraska method. They state that A&G costs cannot be assigned to any specific function, whether gathering, transportation, or storage; thus, the fact that they are not uniquely related to gathering is not relevant. They assert that the Commission established the Kansas–Nebraska method precisely for the purpose of distributing such non–specific costs among the various functions. Panhandle states further that the Commission required it to use the Kansas–Nebraska method (46 FERC P 61,183 at p. 61,615 (1989)) and has recently reaffirmed the method. Arkla Energy Resources Co., 67 FERC P 61,208 (1994). Phillips/GPM and Panhandle also argue that IS did not bear its burden of proving the Kansas–Nebraska method is unjust and unreasonable or of proving that its own method was just and reasonable. Panhandle claims that IS's method is unjust and unreasonable [*61,380] because it does not remove gas purchase expense from base operations and maintenance, it tilts A&G expenses toward the storage and transmission functions because of the inclusion of contract storage expenses and Account No. 858 expenses, and it uses net [**87] plant rather than gross plant as the allocation base, which, in turn, undervalues gathering since gathering has been depreciated at higher rates than transmission or storage plant. Exh. PE–26 at pp. 40–1.The Commission has already rejected IS's argument concerning a disproportionate amount of costs being allocated to gathering in the discussion above about well connection costs. The Commission also rejects IS's argument that the Kansas–Nebraska method is unjust and unreasonable. A&G expenses are, as they are denominated, "administrative" and "general." They are not uniquely related to any function. Given the nature of A&G expenses, IS's contention that these expenses are not uniquely associated with gathering has no meaning. They are not uniquely associated with any function.

Therefore, they must be allocated to all functions, including gathering. The Commission has determined that a reasonable method of doing this is to use direct labor ratios for labor–related A&G expenses, gas plant ratios for gas plant–related A&G expenses and, in some instances, a combination of the two. IS has not shown that the Kansas–Nebraska method is unjust and unreasonable. Since IS has not borne the burden [**88] of proof on this issue, there is no need to consider whether its proposed method is just and reasonable. n59

n59 Western Resources, Inc. v. FERC, 9 F.3d 1568, 1579–80 (D.C. Cir. 1993); Tennessee Gas Pipeline Co. v. FERC, 860 F.2d 446, 456 (D.C. Cir. 1988); Sea Robin Pipeline Co. v. FERC, 795 F.2d 182, 184 (D.C. Cir. 1986); ANR Pipeline Co. v. FERC, 771 (D.C. Cir. 1985).

2. Functionalization of Facilities between Gathering and Transmission and its Effect on Fuel ReimbursementPanhandle used the same functionalization of facilities in this case that it used in Docket No. RP91–229–000. This included a refunctionalization of approximately 1,800 facilities from gathering to transportation which was first proposed in the settlement of Docket No. RP87–103–000. Tr. 446–7. n60 The Commission considered whether to approve the refunctionalization in Docket No. CP90–1050–000 and issued an order in that docket on February 14, 1995. n61 The February 14 order approved the refunctionalization of only about 50 gathering facilities. The other facilities thus remain functionalized as transmission. In the meantime, [**89] in this docket, Panhandle collected a gathering fuel reimbursement percentage of 0.12 percent for fuel use and 0.25 percent for lost and unaccounted for gas. Exh. PE–156; Tr. 438.

n60 71 FERC P 61,288 (1995)

n61 70 FERC P 61,178 (1995).

Phillips/GPM argues that fuel use should reflect the functionalization finally approved in Docket No. CP90–1050–000. Otherwise, Phillips/GPM states, the gathering fuel use percentage will be too low and the field zone transportation use percentage will be too high. n62 It states that the ALJ did not rule on this issue. Phillips/GPM seeks both a refund and a revised fuel use study based on the outcome of Docket No. CP90–1050–000. Panhandle states that it should be required to re–perform its fuel use study only after the implementation of the Commission determination in Docket No. CP90–1050–000.

n62 Phillips/GPM claims approximately eight compressors were functionalized as gathering and 87 as transmission facilities. Exh. PH–5 (compressors are marked "F" or "G" in handwritten letters).

[*61,381] In its February 14, 1995 order in Docket No. CP90–1050–000, the Commission approved the refunctionalization [**90] of 50 facilities from gathering to transmission. 70 FERC P 61,178 (1995). On May 25, 1995, the Commission held that the rate case immediately preceding this one, Docket No. RP91–229–000, was subject to the outcome of Docket No. CP90–1050–000. 71 FERC P 61,228 (1995). As indicated above, Panhandle's rates in Docket No. RP91–229–000 were based on the proposed refunctionalization of 1,800 facilities. The Commission required Panhandle to identify the facilities included in its field zone transportation rate pursuant to its refunctionalization proposal which ultimately were not refunctionalized. The Commission found that Panhandle must make refunds to its field zone transportation customers in Docket No. RP91–229–000 to the extent that the proposed refunctionalization was not approved. The refund was the excess of the field zone transmission rate over that same rate after removal of the costs of the facilities whose refunctionalization was not approved. This holding included fuel reimbursement percentages. The Commission held that Panhandle must refund to its field zone transportation customers any fuel reimbursement overcharges resulting [**91] from those portions of its refunctionalization proposal which were not accepted.Panhandle must revise its functionalization in this docket to conform to the Commission's orders in Docket Nos. RP91–229–000 and CP90–1050–000. It must file the same report identifying facilities that were not approved for refunctionalization as required in Docket No. RP91–229–000. It must then refund the excess of the field zone transmission rate over that rate with the costs of the unapproved facilities removed. It must also refund overcharges for fuel reimbursement that were due to the inclusion of unapproved facilities in the field zone transmission rate. In addition, since this is an on–going rate case in which the rates are still in effect and not, like Docket No. RP91–229–000, a locked–in rate period, Panhandle must revise its rates to reflect the functionalization the Commission approved in Docket No. CP90–1050–000 and charge rates prospectively based on that functionalization.On December 21, 1993, Panhandle requested authorization, pursuant to section 7(b) of the NGA, in Docket No. CP94–151–000 to abandon most of its gathering facilities, which are located in Colorado, Kansas, Oklahoma, and [**92] Texas and known as the West End System, by transfer to Panhandle Field Services Company (Field Services). In December, 1994, when the ALJ issued his decision in this docket, the Commission had not yet issued a merits decision concerning the abandonment application. The ALJ found that there would be cost of service changes arising from the

abandonment and that Panhandle had no obligation to file a new rate case in the future. Tr. 687–8, 1036. The ALJ held that the rate effects of the abandonment were not ripe for decision and recommended that the Commission re–examine them when it acted on the spin–off application. In particular, he recommended that the Commission consider whether Panhandle should refund the amount of money collected in this proceeding for Panhandle's staff reduction program related to the spun–off facilities.Panhandle argues that the proper forum to consider the effects of the spin–off on cost of service is the abandonment proceeding and that it is inappropriate to do so in this proceeding. Phillips/GPM and Citizens assert that the effect of Docket No. CP94–151–000 must be reflected in the rates in this proceeding. Citizens asserts that costs associated with the [**93] spun–off facilities should not be part of the cost of service in this case. Citizens states that the Commission should remove such costs from transportation rates just as it removed the costs of FS storage in Docket Nos. RP92–233–000 and CP92–462–000. 61 FERC P 61,133 (1992). [*61,382] In February 1995, the Commission made a preliminary determination that Panhandle may abandon the facilities. n63 In a rehearing order issued May 23, 1995, the Commission reiterated that it would not require a revision of Panhandle's rates as a condition of abandonment of facilities. The Commission stated:

> We affirm our February 14 finding that it is appropriate to address rate issues associated with Panhandle's abandonment of facilities in a future NGA section 4 rate proceeding. We will not require Panhandle, as a condition of its requested abandonment, to make a limited section 4 filing at this time. We note that in the event Panhandle does not submit its section 4 filing in a timely fashion, the Commission, the Customer Group, Citizens Gas, or any other interested party may initiate an NGA section 5 proceeding to examine Panhandle's existing rates in light of its abandonment [**94] of its facilities. We reiterate our February 14 decision that such a future section 4 proceeding, in which evidence can be presented regarding the impact of the spin down on the operation of Panhandle's remaining system, would be the appropriate forum to consider whether Panhandle's current rates include costs (including labor–related costs and overhead expenses) associated with facilities which Panhandle intends to abandon by transfer to Field Services or which Panhandle has previously transferred to other entities. n64

Accordingly, the Commission will not consider the effects of the holdings in Docket No. CP91–154–000 in the instant general section 4 proceeding.

n63 70 FERC P 61,178 (1995); 71 FERC P 61,201 (1995). "A final determination on Panhandle's request for abandonment authorization in Docket No. CP94–151–000 will be issued after Panhandle submits evidence demonstrating that Centana Energy Corporation and Centana Gathering are not marketing affiliates pursuant to section 250.16 of the regulations."

n64 71 FERC P 61,201 (1995).

3. Load Factor for Design of Interruptible Transportation [**95] RateThe ALJ found that the interruptible transportation rate should be the 100 percent load factor rate which Panhandle had proposed. He rejected arguments that interruptible transportation had been degraded by the availability of released capacity under restructuring or that any degradation, if it had taken place, warranted a lower rate.Phillips/GPM contends that released capacity has reduced the availability and quality of interruptible transportation service in the field and market zones because firm holders of capacity now operate at a higher load factor. Phillips/GPM asks the Commission to set interruptible transportation rates at a higher load factor, 150–200 percent, to reflect the alleged reduced quality of service. Panhandle argues that Phillips/GPM has not shown released capacity has reduced the quality of interruptible transportation service. It states that it incurs the same fixed costs regardless of whether firm or interruptible service is performed and that the rate for each service should recover all those costs entailed in constructing, operating, and maintaining the pipeline. Mobil Oil Corp. v. FERC, 886 F.2d 1023, 1030 (8th Cir. 1989). [**96] Panhandle argues that restructuring has affected only the availability of interruptible service, not its quality. It states that if the rate is reduced for interruptible service, then the firm customers will subsidize the interruptible customers. Last, it notes that Commission policy favors the 100 percent load factor rate for interruptible transportation. Interstate Natural Gas Pipeline Rate Design, 47 FERC P 61,295 at p. 62,057, reh'g denied, 48 FERC P 61,122 (1989). [*61,383] In Opinion No. 369, n65 the Commission held that Panhandle's interruptible transportation rate should be designed based upon a 100 percent load factor of its firm transportation rate. Panhandle has continued that design of its interruptible rate in both Docket No. RP91–229–000 and the present rate case. Thus, the Commission would have to act under NGA section 5 in order to require Panhandle to design its interruptible rate in the manner suggested by Phillips/GPM. The Commission sees no basis in the present record for such action.

n65 57 FERC P 61,164 at pp. 61,833-4 (1991).

In several recent cases, the Commission has approved 100 percent [**97] load factor interruptible rates over objections similar to those raised by Phillips/GPM in the present case. n66 Phillips/GPM suggests that, after restructuring, interruptible service in both the field and market zones is more likely to be interrupted than before. However, in both Southern and South Georgia, the Commission held that evidence of interruptions of interruptible service supports use of a 100 percent load factor maximum rate for purposes of rationing capacity during periods when interruptible capacity is available but scarce. Moreover, the Commission pointed out that the pipeline can discount the 100 percent load factor maximum rate when necessary to maximize throughput during off-peak periods. As the Commission also explained in Southern and South Georgia, a 100 percent load factor maximum rate does recognize the lower quality of interruptible service, since the per unit 100 percent load factor maximum rate for interruptible service is less than the per unit maximum rate for firm service in all instances, except if a firm customer paying the maximum rate takes its full contract demand every day of the year.

n66 Southern Natural Gas Company, 72 FERC P 61,322 at pp. 62,336-40 (1995). South Georgia Natural Gas Company, 73 FERC P 61,354 (1995).

[**98] Finally, the fact interruptible service competes with capacity release supports continuation of a 100 percent factor maximum interruptible rate. A higher load factor would set the maximum interruptible rate below the maximum volumetric rate for released capacity. That would give the pipeline an unfair competitive advantage in marketing its interruptible service. n67 Consequently, the Commission affirms the 100 percent load factor rate for interruptible transportation service.

n67 See Arkla Energy Resources, Inc., 67 FERC P 61,208 at pp. 61,646-7 (1994).

4. Revenue crediting for Interruptible TransportationIn Panhandle's restructuring proceeding, the Commission required Panhandle to credit to firm shippers 90 percent of the revenues it received for interruptible transportation in excess of the costs allocated to that service. 62 FERC P 61,288 at p. 62,847 (1993). The Commission adopted the crediting mechanism because of the uncertainty surrounding the amount of interruptible transportation after restructuring.The ALJ held that the Commission set excess interruptible transportation revenues for hearing in Panhandle's next rate [**99] case, not in this one. 64 FERC P 61,009 at 61,049 (1993). He found that Panhandle had not raised this issue because it had introduced no direct testimony concerning it, and held that Panhandle's rebuttal testimony on this issue was improper. However, in response to direct testimony from Missouri Gas Users (MGU) that Panhandle keep all excess interruptible transportation revenues, the ALJ affirmed the uncertainty of interruptible transportation volumes, relying on figures provided by the party itself (MGU Post-Trial Memorandum), and hence the necessity of retaining the interruptible transportation crediting mechanism. [*61,384] At the same time, the ALJ expressed his view that estimates of interruptible transportation were less than Panhandle's actual experience (Exh. MGU-1 at p. 4) and that this resulted in excessive costs being attributed to firm transportation which, in turn, lead to excessive maximum rates for interruptible transportation since these are based on firm rates.On exceptions, Panhandle urges the Commission to eliminate interruptible transportation revenue crediting. It states that this crediting was meant to be an interim measure, and that Panhandle [**100] is now beyond the interim stage of operations. Panhandle argues that there is sufficient experience in the record for projections of interruptible throughput, citing Exhs. PE-135 at p. 23 and PE-143. Panhandle also states in a footnote (B. on E. at p. 84 n.59) that revenues from interruptible transportation, as shown in a compliance filing it made on July 1, 1994, were more than 20 percent below the allocated level. Docket No. TM94-6-28-000, 68 FERC P 61,151 (1994). n68 Panhandle insists that, in any event, Panhandle Eastern Pipe Line Co. v. FERC (Panhandle), 613 F.2d 1120, 1129 (D.C. Cir. 1979) and Northern Natural Gas Co. v. FERC (Northern Natural), 827 F.2d 779 (D.C. Cir. 1987) (en banc), prohibit revenue crediting. MGU believes that interruptible transportation revenue crediting can be considered in this proceeding and, like Panhandle, that there is sufficient experience to project interruptible transportation so that crediting should be terminated.

n68 The tariff sheets in that docket are subject to the outcome of this proceeding.

IS, MoPSC, PCG, and Citizens contend that Panhandle must continue [**101] to credit revenues from interruptible service. They argue that the Commission determined in Panhandle's restructuring proceeding that elimination of interruptible transportation revenue crediting would be considered in Panhandle's next general section 4 case—the case filed to supersede the rates in this docket. They assert that Panhandle's projections of interruptible transportation are uncertain. They claim that MGU's witness Mr. Mallinckrodt used only four months of summer experience under post-restructuring rates (Exh. C-22), that his testimony conflicted with actual volumes where those were available (comparing Exh. C-38, App. D at p. 4, based on nine months of actuals, with Mr. Mallinckrodt's estimates (Exh. C-22)), and that estimates of interruptible transportation varied among the witnesses. Tr. 1545-47. They argue that the Commission should reject the request for termination of revenue crediting just as it did in Trunkline Gas Company, 67 FERC P 61,249 (1994), because here, as there, the pipeline does not have substantial actual experience under its restructured tariff representative of the full range of annual operating conditions. n69 They assert [**102] that it is irrelevant whether Panhandle has recovered all of the costs allocated to interruptible transportation because there has been an economic incentive for Panhandle to market short-term firm transportation rather than interruptible transportation. Citizens and IGC argue that Panhandle and Northern Natural are inapplicable in this proceeding because it is being conducted pursuant to sections 4 and 5 of the NGA.

n69 See also KN Interstate Gas Transmission Co., 66 FERC P 61,318 (1994).

The ALJ correctly held that, in Panhandle's restructuring proceeding, the Commission required that the interruptible transportation revenue crediting mechanism must be included in Panhandle's rates until it files its first rate case after restructuring. In the Commission's July 2, 1993 order in Panhandle's restructuring proceeding, the Commission stated,

> In Order No: 636-B [61 FERC P61,272], we stated that if the Commission allows revenue crediting in a pipeline's compliance filing, we will evaluate any such [*61,385] mechanism in the pipeline's next rate case after the parties have experience with capacity releasing. Thus, the issue of the operation of Panhandle's interruptible allocation/revenue [**103] crediting mechanism may be reexamined in Panhandle's next general rate proceeding after Panhandle has obtained operating experience under restructured services. n70

Because of the "uncertainty surrounding interruptible transportation in the capacity release era," 64 FERC P 61,009 at p. 61,049, it would be impossible to reliably project interruptible throughput in a rate case such as this, filed before Panhandle's restructuring took effect, without test period data reflecting actual operating experience under restructured services.

n70 Id. at p. 61,049 (emphasis supplied).

Moreover, since the above order in Panhandle's restructuring proceeding, the Commission has considered other pipelines' requests to eliminate IT crediting in circumstances similar to those here and has rejected them. In ANR Pipeline Co., 66 FERC 61,335; 69 FERC P 61,322 (1994), the pipeline contended it had reasonable experience in predicting the amount of interruptible transportation service under its restructured services and that such data would be available by the time its rate case was decided. [**104] ANR filed its rate case the same day its restructured services became effective (November 1, 1993) and four months after the end of its base period, June 30, 1993. The Commission found ANR had no operating experience under Order No. 636 at the time it filed this rate case. The Commission found ANR did not have enough operating experience to make an allocation of costs to its interruptible transportation service. The Commission required ANR to reinstate its IT revenue crediting.In Trunkline Gas Company, 66 FERC P 61,386, reh'g denied, 67 FERC P 61,249 (1994), the Commission also required the pipeline to retain an interruptible transportation revenue crediting mechanism. Trunkline proposed to allocate 8.5 percent of its costs, or $15.2 million to IT service. The Commission found this amount was based on actual operating experience under restructuring limited primarily to the winter months. The Commission found that during this period firm services tend to be at a maximum level and IT services tend to be at a minimum level. Thus, the Commission concluded Trunkline's experience had been limited only to the winter season and did [**105] not include the off-peak season. As such, the Commission found it was not representative of the level of IT service throughout the entire year. The Commission held the pipeline must have substantial actual experience under its restructured tariff representative of the full range of annual operating conditions. It stated that the policy of crediting is necessary until sufficient operating experience is gained.Here, Panhandle filed its rate case on May 1, 1992, based on a test period which ended November 30, 1992. Panhandle's restructured services commenced May 1, 1993. Actual operating experience was not available on which Panhandle could base its rate filing and the allocation of IT costs. Moreover, the Commission agrees with the ALJ's assessment that the limited data that was presented at the hearing concerning interruptible transportation throughput after restructuring was inadequate for purposes of making a reliable projection. n71 Consequently, as in ANR and Trunkline, the Commission rejects the elimination of IT crediting here. However, our holding here is based solely on the circumstance that this rate case was filed before restructuring, and the test period therefore reflects [**106] no experience with post-restructuring services. When Panhandle files its next rate case, it will have had substantial post-restructuring [*61,386] experience and the Commission's normal policy that rates be based on projected units of service, without any revenue crediting, will apply. n72

n71 69 FERC at p. 65,103.

n72 18 C.F.R. § 284.7(c)(3) and (d) (2) (1995).

The Commission also rejects Panhandle's argument that Panhandle and Northern Natural bar revenue crediting in this case. As the ALJ stated, those cases were concerned with certificate proceedings. They prohibited crediting revenues from new services to existing services when the Commission was proceeding under section 7 of the NGA. They reasoned that if the Commission could alter existing rates in a section 7 proceeding, it could emasculate the role of section 5 in the ratemaking scheme and circumvent the section 5 requirements of a hearing and specific findings as to the justness and reasonableness of existing rates. They explained that these actions would destroy rate stability and dilute the pipeline's protections against revenue loss caused by administrative delay. 827 F.2d 779 at p. 792. [**107] Both this proceeding and Panhandle's restructuring proceeding were conducted pursuant to sections 4 and 5 of the NGA. To unbundle pipelines' sales service, the Commission acted pursuant to section 5 of the NGA. Order No. 636, 57 Fed. Reg. 13,267, 13,279 (April 16, 1992). n73 The Commission reviewed Panhandle's restructuring filings under section 5. 62 FERC 61,288 (1993). This proceeding is a general section 4 rate filing which the Commission is reviewing under sections 4 and 5 of the NGA. Consequently, there has been and can be no circumvention of section 5 in this proceeding or in any of the arrangements in this proceeding that stem from Panhandle's restructuring. The Commission may require revenue crediting and finds it is just and reasonable to do so here.

n73 Order Nos. 636 and 636-A also contained certificate authorizations such as a blanket certificate for unbundled sales and abandonment authorizations of service necessary to implement restructured services. Order No. 636, 57 Fed. Reg. at p. 13,299; Order No. 636-A, 57 Fed. Reg. 36,128, Section A.2 Natural Gas Act Authority (August 12, 1992).

[**108] 5. Revenue credits and demand determinants for short-term firm transportationa. The Initial DecisionAt the time it filed this rate case in May, 1992, Panhandle did not have a separate rate schedule for shortrterm firm transportation. Nor did it propose such a rate schedule in its rate filing in this case. However, such service can be performed pursuant to its generally applicable firm transportation rate schedule, and, to the extent such service is performed, Panhandle would include firm contracts with a duration of less than twelve months in the design of that firm transportation rate. Tr. 1063-64.Until its restructuring, Panhandle appears not to have performed a significant amount of short-term firm transportation service. However, after restructuring, Panhandle's firm capacity was not fully subscribed and Panhandle began marketing its excess capacity on May 1, 1993, as the Commission anticipated in Order Nos. 636 and 636-A. These contracts could be for less than a year. n74 The Commission regarded short-term contracts of one to three months as part of the secondary market in pipeline firm capacity. n75

n74 In Order No. 636, 57 Fed. Reg. 13,267, 13,300 (April 8, 1992), the Commission defined firm transportation with a duration of less than one year as short-term firm transportation. ("The nature of these services is such that customers selecting these options [interruptible and short-term firm transportation] do not rely on continued service at the expiration of the contract. . . . Short-term transportation customers choose the flexibility of short-term service rather than the stability of long-term commitments."). Cf. 18 C.F.R. § 284.221(d) authorizing pre-granted abandonment for transportation services of less than one year.

[**109]

n75 Order No. 636-A, 57 Fed. Reg. 36,128, Section V.C.3.a, Exceptions for Short Term or Small Volume Transactions (August 12, 1992).

[*61,387] Panhandle described as short-term certain of the firm transportation contracts in existence on May 1, 1993, which it included in its billing determinants for the post-restructuring period. The ALJ found, however, that these were replacement contracts for regular long-term firm service that had less than one year of their terms remaining as of May 1, 1993, and that they would probably be renewed. The ALJ found that these contracts were not for short-term firm transportation of the kind competing with released capacity and interruptible transportation in the secondary market. Exhs. PE-153; PE-154; PCG-18; PE-138 at p. 24. The ALJ thus held that Panhandle had not taken into account in establishing its demand determinants for the post-restructuring period any of the short-term agreements it markets in the secondary market. Consequently, he determined that Panhandle had not included a representative level of short-term firm transportation determinants for secondary market transportation in its post-restructuring billing determinants. [**110] He also found that Panhandle had not included determinants for this type of short-term firm transportation in its post-restructuring commodity units because it had not estimated short-term firm transportation throughput. Tr. 956; MoPSC-33.The ALJ determined, in addition, that, since restructuring, Panhandle has been offering short-term firm transportation in a way that undercuts interruptible transportation and released capacity. He found that two of Panhandle's

tariff provisions, General Terms and Conditions, sections 15.3(a) and (c), may result in a lag of four or five days in providing service for capacity release contracts while there was no lag for short-term firm transportation or interruptible transportation offered by the pipeline. He cited section 15.3(c), because it provides that released capacity for less than one year must be posted on Panhandle's electronic bulletin board for at least two business days, while short-term firm transportation does not have to be posted. He cited section 15.3(a) because it provides that Panhandle need not tender the service agreement for released capacity until two days after the close of the posting period.The ALJ found that it was [**111] not possible to determine representative levels of short-term firm transportation for the secondary market. He concluded, however, that the parties had presented convincing facts and arguments to demonstrate that it was necessary to deviate from the Commission's policy of not requiring crediting of revenues from firm transportation. n76 He held that "imposing the revenue crediting mechanism on the short-term firm service will pass on to customers an appropriate share of revenues from a service whose costs they, rather than Panhandle, have borne, and will put that service on a level playing field with the other services in the secondary market in which they compete." n77 The ALJ found that Panhandle's failure to allocate costs to short-term firm transportation was unjust and unreasonable. As a remedy, he adopted crediting to firm customers of ninety percent of the revenues from all short-term firm transportation contracts Panhandle entered into after May 1, 1993.

n76 65 FERC P 61,130 at p. 61,644 (1993); 66 FERC P 61,141 at p. 61,263 (1994).

n77 69 FERC P 63,013 (1994).

b. ExceptionsPanhandle [**112] asks the Commission to vacate the short-term firm transportation revenue crediting requirement. Panhandle states that it is the Commission's policy to permit pipelines to retain revenues from additional sales of firm capacity, and that the Commission twice rejected revenue crediting of new firm transportation revenues in its restructuring proceedings on these grounds. 65 FERC P 61,130 at p. 61,644 (1994); 66 FERC P 61,141 at p. 61,263 (1994). Panhandle contends that the parties have not [*61,388] provided any new proof that would warrant reversing these decisions. Panhandle asserts that, if a crediting requirement were adopted, it could only be effective after the Commission has approved compliance tariff sheets. Electrical District No. 1, v. FERC, 774 F.2d 490 (D.C. Cir. 1985). n78 Panhandle also asserts that its short-term firm transportation does not undercut capacity releases. Tr. 1029-33; sections 6.2, 6.9, 6.11 of the General Terms and Conditions. It states that section 15.5 (a) of its tariff requires it to provide a contract to a replacement shipper "as soon as practical, but in no event later than two (2) Business [**113] Days." n79 Panhandle says that if it does have a tariff advantage in marketing its services, then the remedy is to correct the tariff.

n78 Panhandle's exceptions relating to Panhandle and Northern have been addressed above.

n79 Panhandle actually cites section 15.1(c)(1); however, this does not appear to be the section it means as it contains criteria for becoming a replacement shipper. B. on E. at p. 90.

The replacement shipper has up to two days to execute and return the contract. Section 15.5 (a).

MoPSC, IGC, PCG, IS, and Citizens all support crediting for short-term firm transportation revenues. IS and PCG state that short-term firm revenue crediting should be implemented to prevent circumvention of interruptible transportation revenue crediting. They state that Panhandle does not attempt to project short-term firm transportation throughput. Exh. MoPSC-33, Tr. 956. They assert that Panhandle did not include any billing determinants for short-term firm transportation marketed in the secondary market, and so failed to allocate any costs to short-term firm transportation transactions. They say that the same uncertainty exists with regard to short-term firm transportation [**114] as interruptible transportation so that projections cannot be made. Exh. MoPSC-23 at pp. 22-3. They assert that short-term firm transportation competes with capacity release sales in the secondary market (Tr. 956; Exh. PE-138 at p. 24), and that Panhandle has approached some former interruptible transportation customers with offers of short-term firm transportation. They claim that Panhandle can sidestep the Commission's revenue crediting mechanism for interruptible transportation by selling short-term firm transportation for which there is no crediting. They assert that there are a growing number of short-term firm transportation contracts in the post-restructuring period, and that these indicate that Panhandle is circumventing the interruptible transportation crediting mechanism. Exh. MoPSC-23 at pp. 26-7; Exh. MoPSC-27. IGC characterizes crediting as a prospective remedy because it is the only available remedy for customers who would otherwise overpay for long-term firm transportation and finance Panhandle's short-term firm arrangements.In addition, IGC argues that the Initial Decision is correct in finding that short-term firm transportation is offered in a manner that undercuts capacity [**115] release because for capacity release, two days are required for posting (General Terms and Conditions, Section 15.3) and up to two days are allowed for Panhandle to deliver service, while short-term firm transportation can be provided immediately. IGC states that the provisions on minimum creditworthiness add additional delays. Tr. 1027; General Terms and Conditions, Section 6.2. IGC states that these inequalities are a compelling reason for adopting short-term firm transportation crediting that was not presented in Panhandle's restructuring proceeding.c. DiscussionThe Commission's regulations prefer rates based on projected volumes and costs rather than on crediting. 18 C.F.R. § 284.7 (d)(2) (1995). As discussed previously, crediting is used only in unusual circumstances. Panhandle has used its unadjusted demand determinants effective May 1, 1993. This is in accordance with the Commission's [*61,389] requirement that Panhandle use its actual contract demand as of the effective date of restructured firm services for its firm service billing determinants. 64 FERC P 61,009 at p. 61,054 (1993). The Commission believes that the short-term firm service does replace some [**116] historical service. To that extent, short-term firm service is reflected in Panhandle's May 1, 1993 demand determinants. Moreover, the short term firm service at issue here is performed under Panhandle's generally applicable open access firm rate schedule. The Commission finds that the determinants used by Panhandle reflect all the demand units in existence in that rate schedule on May 1, 1993. There may have been changes thereafter, as stated by the parties. The Commission finds, however, that these changes are not of sufficient magnitude to merit a departure from the Commission's established policy of basing rates on contract demands in effect on the last day of the test period or the date the rates go into effect. In any event, this issue can be addressed in Panhandle's next rate case. The Commission determines that crediting for short-term firm revenues is unnecessary and reverses the ALJ on this issue.6. Backhaulsa. Backhaul ratesIn Opinion No. 369, issued in November 1991, the Commission found that Panhandle's system is, at times during the winter, constrained in the segment that runs from a compressor station at Haven, Kansas to a compressor station at Tuscola, Illinois. [**117] Accordingly, the Commission held that backhauls that consist of delivery of gas at or west of Haven during the peak period and receipt of gas at or east of Tuscola during either the peak or off-peak periods create usable capacity in the constrained segment and thereby benefit Panhandle. The Commission concluded that the rate for such backhauls should be lower than the full forward haul rate. The Commission adopted the suggestion of Kansas Power and Light Co. (KP&L), an individually certificated backhaul customer served under Rate Schedule T-53, that the rate for its backhaul service, as well as other backhauls, be set at one-half the forward haul rate for open access transportation under Rate Schedule PT-Firm. In an order in Panhandle's previous rate case in Docket No. RP87-103-000, issued the same day as Opinion No. 369, the Commission reached the same result with respect to the issue reserved by settlement in that case of the appropriate rate for KP&L's backhaul service.The Commission's decision in Docket No. RP87-103-000 concerning KP&L's T-53 backhaul rate was appealed to the United States Court of Appeals for the District of Columbia Circuit. The court held that the Commission [**118] had not validly adopted the Rate Schedule T-53 50 percent backhaul rate. Western Resources, Inc. v. FERC. n80 The court held that, since the Commission had gone beyond rejecting Panhandle's proposal to increase the T-53 backhaul rate from one cent to a rate equal to the open access transportation forward haul rate, the Commission had to proceed under section 5 of the Natural Gas Act to adopt its own rate. The court found, however, the Commission had not met the requirements of section 5 because it had not shown either that the pre-existing, one-cent backhaul rate was unjust and unreasonable or that the Commission's substitute rate was just and reasonable. Thus, the court held the Commission had not properly approved the 50 percent backhaul rate under section 5. The court remanded the backhaul rate so the Commission could reconsider how it wished to proceed under the statutory scheme.

n80 9 F.3d 1568 (D.C. Cir. 1993).

[*61,390] On remand, n81 the Commission reaffirmed that Panhandle's proposal to increase the T-53 backhaul rate to a level equal to the forward haul rate was unjust and unreasonable because it did not recognize the benefits created by T-53 backhaul [**119] transportation. The Commission stated that it had previously found that the subject backhaul service, in which Panhandle delivered gas to Western Resources, Inc. (the successor to KP&L) at Reno, Kansas, west of Haven, and, in turn, received gas west of Tuscola, conferred a substantial benefit to Panhandle. It did that by reducing peak period capacity constraints on the Haven to Tuscola segment and saving costs of compression. Therefore, the Commission held that it is appropriate that the T-53 backhaul rate be lower than the forward haul rate. However, the Commission pointed out that, as it had previously held, no party offered at the hearing any means of quantifying the precise benefits involved. The Commission concluded that as a result it could not make the necessary findings to replace the existing presumptively just and reasonable one-cent rate with a new rate. The Commission concluded that the pre-existing backhaul rate must remain in effect for the subject locked-in period.

n81 66 FERC P 61,329 (1994); reh'g denied, 73 FERC P 61,366 (1995).

In Panhandle's May 1992 filing in this case, Panhandle proposed to continue [**120] the backhaul rates resulting from Opinion No. 369. Thus, its rate filing set the rate for backhauls in which gas was delivered at or west of Haven and received at or east of Tuscola at one half the rate for forward hauls. However, the rate for all other backhauls was set at a level equal to that for forward hauls. n82

n82 The rate for these backhauls was one-half the forward haul rate. Substitute Original Sheet No. 33.

In Panhandle's restructuring proceeding, it also proposed no change in these backhaul rates. However, PCG sought a lower rate for certain additional backhauls. Panhandle's mainline telescopes down (gets smaller) from Haven to Tuscola, decreasing from about 1,500 Mmcf/d at Haven to 900 Mmcf/d at Tuscola. n83 Much of the reduction in capacity occurs between Haven and Glenarm, the last compressor station before the mainline reaches Tuscola. PCG asserted in the restructuring proceeding that backhauls in which Panhandle delivered gas to the customer at or west of the Glenarm compressor station and, in turn, received gas at or east of Tuscola would also create usable capacity and should be charged a lower rate. However, in response to a staff data request, Panhandle [**121] stated that a backhaul from Tuscola to Glenarm would only create usable capacity if there were receipt points between Haven and Glenarm. Panhandle stated that currently there are no such receipt points. The Commission held that it had no reason to question Panhandle's explanation and therefore the Commission did not require Panhandle to offer a lower rate for the backhauls described by PCG. However, the Commission stated that PCG and other parties had not had an opportunity to make factual showings supporting the appropriate rate for this backhaul. The Commission therefore stated that this issue should be addressed in the instant section 4 rate case.

n83 Tr. 856, 858, 896; 57 FERC P 61,264 at p. 61,840 (1991).

At the hearing in this case, neither Panhandle nor any other party presented evidence opposing the continuation of the reduced backhaul rate for backhauls in which gas is delivered by the Panhandle at or west of Haven and received at or east of Tuscola. Nor is there any exception to the ALJ's holding that a reduced rate should be maintained for those backhauls. However, at hearing, PCG again argued that backhauls in which gas is delivered between [**122] Haven and the downstream Glenarm compressor station (or north of that station on the Peoria lateral) and received at or [*61,391] east of Tuscola also create usable capacity. PCG argued that Panhandle can schedule up to 1,500 Mmcf/d of service at Haven, if the customers between Haven and Tuscola take deliveries of about 600 MMcf/d. Otherwise, the capacity at Haven is about 1,150 MMcf/d. Exh. PCG-12; Tr. 859-60. Therefore, deliveries at or west of Glenarm, as well as deliveries at or west of Haven, should create usable capacity.PCG proposed that, where shippers are attempting to schedule (or Panhandle has confirmed transportation for) more than 900 MMcf/d of Field Zone gas supplies for deliveries east of Tuscola, backhaul transactions of gas supplies received at or east of the Tuscola compressor station for redelivery west or north of the Glenarm compressor station should receive a reservation charge credit for freeing the capacity that permits increased deliveries. That credit should be equal to the fixed cost component of the rate, at 100 percent load factor, otherwise applicable to the backhaul quantity on that day.The ALJ rejected PCG's contention, and upheld Panhandle's proposal that [**123] the rates for backhauls should be the same as the rates for forward hauls, with the one exception noted above. The ALJ found that delivery for both backhauls and forward hauls is effected by displacement. He reasoned that backhauls do not create capacity, but enable the pipeline to transport additional volumes. He found that the system should be treated as a whole and that these additional volumes should be rolled-in with all other transportation volumes. Otherwise, he felt, one group of shippers would subsidize another. The ALJ did require a backhaul rate for backhauls in which gas is received at or east of Tuscola and delivered at or west of Haven of one-half the forward haul rate citing the Commission's order in Docket No. RP87-103-000. n84

n84 59 FERC P 61,245 (1992), remanded sub nom. Western Resources, Inc. v. FERC, 9 F.3d 1568 (D.C. Cir. 1993), on remand, 66 FERC P 61,329 (1994), order on rehearing pending.

PCG excepts to the ALJ's holding. PCG claims that backhauls in the Haven-Tuscola segment increase the capacity of the system by increasing the amount of gas that can be flowed through [**124] Haven and by allowing the pipeline to deliver more than 900 MMcf/d of gas supplies to points east of Tuscola. Tr. 897. Panhandle responds that forward hauls and backhauls are both accomplished by displacement and are thus indistinguishable forms of service. Williams Natural Gas Co., 59 FERC P 61,306, reh'g denied, 61 FERC P 61,205 (1992). Panhandle states that backhauls allow additional volumes to be transported in some instances and that system benefits from backhauls are recognized by rolling the additional volumes in with forward haul volumes to determine rates. Panhandle points out that backhaul service could not be performed without forward haul service. Last, Panhandle asserts that the Commission's determination that a backhaul rate could be set below a forward haul rate in Docket No. RP88-262-000 was overturned in Western Resources.The Commission affirms the result reached by the ALJ, but for somewhat different reasons than those relied on by the ALJ. In Algonquin Gas Transmission Company, 70 FERC P 61,310 (1995), the Commission discussed backhauls in detail. It stated that in the Rate Design [**125] Policy Statement, it had suggested that a backhaul could provide a benefit to others on the system by creating "additional capacity on the pipeline between the exchange (receipt and delivery) points."

The reason for this was that the delivery of gas to the backhaul customer at its upstream delivery point meant that from that point to the downstream receipt point where the backhaul customer replaces the gas that it took at its delivery point the actual amount of gas flowing on the system would be less than it would be in the absence of the backhaul. This, the Commission [*61,392] stated, had the effect of creating capacity that would not exist without the backhaul, thus potentially creating a positive benefit for the system to the extent that the additional capacity is actually usable by other customers. n85 The Commission reaffirmed its policy that, where the additional capacity is usable by others, that fact should be reflected in the rates for that backhaul service. However, the Commission held that the particular backhaul service at issue in Algonquin did not create capacity usable by third parties, because there were no receipt points on Algonquin's system over the segment where the backhaul [**126] occurred. Therefore, the Commission refused to take section 5 action to order a reduced rate for that backhaul.

n85 The Commission also discussed the effect of backhauls on capacity upstream of the delivery point and downstream of the receipt point. It stated that a backhaul would not increase capacity in these pipeline segments because gas flow would not be reduced by the backhaul, but would remain the same.

In our orders on remand from the Western Resources decision, the Commission reaffirmed that Rate Schedule T–53 backhaul service, in which Panhandle delivers gas to west of Haven (at Reno Kansas) and receives gas east of Tuscola does create additional capacity over the constrained segment from Haven to Tuscola, that is usable by third parties, and thus, consistent with the Rate Design Policy Statement, that service should have a rate lower than a forward haul. PCG seeks in this case to show that backhauls in which Panhandle delivers gas downstream of Haven and west of Glenarm create similar benefits, and therefore should also receive a reduced rate. Since in this rate case Panhandle has proposed to continue the preexisting rate for such backhauls, which is equal to the [**127] forward haul rate, PCG bears the burden under NGA section 5 of proving that Panhandle's existing rates for those backhauls are unjust and unreasonable and that PCG's suggested lower rate is just and reasonable.The Commission finds PCG has not borne its burden of proof. PCG has not shown that backhauls of the type it describes create usable capacity in the Haven to Tuscola segment in accordance with the Rate Design Policy Statement and Algonquin. The mainline decreases in size from Haven to Glenarm and Glenarm to Tuscola. Thus, it is unclear that any additional capacity results when gas is delivered to a backhaul customer between Haven and Glenarm. Even if there were additional capacity, Panhandle stated in the restructuring proceeding that there is no receipt point between Haven and Glenarm which would enable a shipper to take advantage of it, and PCG at the hearing in this case did not contend that there were receipt Points in that area. In addition, as in Algonquin, the backhaul does not reduce the amount of gas flowing upstream of the backhaul delivery point or downstream of the backhaul receipt point. Consequently, available capacity is not increased upstream of Glenarm or downstream [**128] of Haven when Panhandle performs a backhaul of the type described by PCG.In the rehearing of Algonquin, 72 FERC P 61,050 (1995), the Commission discussed other kinds of benefits that might result from backhauls, with reference to Texas Eastern Transmission Corp. n86 In Texas Eastern, Hamilton, Ohio, performed a backhaul which increased pressure in the mainline and ensured the delivery of gas downstream. n87 The Commission found that this backhaul contributed to the operational flexibility of the pipeline and hence to the service of downstream customers. Here PCG contends that its backhauls increase the amount of gas that is flowing between Haven and Tuscola. If PCG did not do a backhaul, however, Panhandle would still be able to deliver 900 MMcf received at Haven to Tuscola. In addition, if there were no PCG [*61,393] backhaul, customers in the Haven to Tuscola segment would still receive gas. The Commission finds PCG has not shown that its backhauls create operational benefits that would justify a lower rate than the forward haul rate for its backhauls. So far as appears from the present record, the only benefit arising from backhauls of the type described by PCG [**129] is the addition of the backhaul customer to the system and the additional revenue contribution that always accompanies the addition of another customer to the system. However, in Algonquin, the Commission held that was not a sufficient benefit to justify a lower backhaul rate. n88

n86 63 FERC P 61,100 (1993); 64 FERC P 61,305 (1993).

n87 The Commission also held this backhaul created usable capacity in a constrained pipeline segment—Joaquin to Lebanon.

n88 Algonquin, 72 FERC at p. 61,286.

On the record before it, the Commission finds PCG has not shown that its backhaul transactions or other such transactions in the Haven to Tuscola segment create benefits that can be used by other customers. Accordingly, PCG has not shown that existing backhaul rates are unjust and unreasonable as it is required to do under section 5, and the Commission affirms Panhandle's existing backhaul rates.b. Fuel reimbursement for backhaulsThe ALJ also determined that backhaul transactions should continue to pay for fuel reimbursement. He reasoned that less compressor fuel is needed and unit costs are less [**130] for all shippers if they are determined based on the combined total of both forward and backhaul volumes. PCG claims that the Commission should eliminate the fuel reimbursement charge for backhauls and exchanges. It claims that such transactions do not consume fuel, yet Panhandle charges for them based on mileage in the market zone. Panhandle contends that its fuel charges are correctly based on all customer nominations as required by 18 C.F.R. §§ 284.7(d)(1) and (4). Panhandle also argues that backhauls, like forward hauls, occur by displacement, which is made possible by compression which, in turn, requires fuel.PCG did not offer testimony of its own, but cross-examined Mr. Kelly, the Director of the Technical Services Division in Panhandle's Transmission Department. Tr. 474-80. Mr. Kelly testified that in certain hypothetical circumstances, where there were only a backhaul and a forward haul on the system and both used receipt and delivery points west of Illinois and east of Indiana, it would not be necessary to expend fuel in Illinois and Indiana. He testified, however, that this was an oversimplification and that the system did not work that way. Mr. Kelly also testified that [**131] the amount of throughput, and hence the amount of fuel used, might be reduced due to a backhaul. The Commission finds the evidence of record on this issue conflicting and insufficient. There is simply not enough evidence of a clear and positive nature to warrant a finding that backhauls use less fuel and should, accordingly, be charged less for fuel reimbursement. n89

n89 Cf. Trunkline Gas Company, 64 FERC P 61,030 (1993) (requiring identification of backhaul transactions that save fuel and appropriate level of lost and unaccounted gas for such transactions).

E. Rate Design DeterminantsBecause this case involves both a six-month period before Panhandle's May 1, 1993 restructuring, as well as a post-restructuring period, separate rate design determinants must be developed for the two periods. In the suspension order in this case, the Commission suggested that the same overall throughput would be used for commodity billing determinants after restructuring, as before. However, the throughput mix [*61,394] between services would be subject to change to reflect restructuring. n90 In addition, in Panhandle's restructuring proceeding, the Commission required that [**132] Panhandle must use its actual contract demands as of the May 1, 1993 effective date of its restructuring for its post-restructuring firm service billing determinants. n91

n90 Panhandle Eastern Pipe Line Co., 59 FERC P 61,243 at p. 61,831 (1992). See also Panhandle Eastern Pipe Line Co., 59 FERC P 61,366 at p. 62,399 (1992). In Panhandle's restructuring proceeding, the Commission noted that Panhandle's total throughput was at issue in this case, and the Commission made the throughput mix accepted there subject to the outcome of this case. The Commission also expressly encouraged the parties in this proceeding to establish different interruptible throughput levels for the pre-and post-restructuring periods. Panhandle Eastern Pipe Line Co., 61 FERC P 61,357 at p. 62,407 (1992).

n91 64 FERC P 61,009 at p. 61,054 (1993).

At the hearing in this case, Staff proposed to develop commodity billing determinants for the November 1, 1992 through April 30, 1993 pre-restructuring period based on actual throughput for the last twelve months of the test period, December 1, 1991 through November [**133] 30, 1992. Staff proposed to develop demand billing determinants for the pre-restructuring period based on actual contract demand as of November 30, 1992. n92 Staff's proposed total commodity billing determinants for the pre-restructuring period were 1,345,443,743 Dt and its demand billing determinants 55,037,631 Dt. n93 Staff proposed to use the same total commodity billing determinants for the post-restructuring period as for the pre-restructuring period. However, it proposed to recalculate the mix of those determinants among services based upon each restructured service's proportionate share of total actual throughput during the first six months after restructuring (May through October 1993). As directed by the Commission, Staff proposed to use contract demand as of May 1, 1993 to develop the post-restructuring demand billing determinants, or 44,589,501 Dth. n94

n92 The demand units for interruptible services reflect the 100 percent load factor of the recommended commodity volumes for these services.

n93 Staff I. Br. at p. 133, App. A; Tr. 1877-86; S-20; C-30.

n94 Exhibit S-18(a). Again, the demand units for post-restructuring interruptible services reflected the 100 percent load factor of the recommended commodity volumes for those services.

[**134] Panhandle, by contrast, proposed to develop commodity billing determinants for the pre-restructuring period based on actual throughput for the twelve-month period ending April 30, 1993. Panhandle proposed to develop demand billing determinants for the pre-restructuring period based on its firm customers' November 30, 1992 contract demands,

with contract demands imputed for interruptible service based on interruptible throughput for the 12 months ending April 30, 1993. Panhandle appears to have developed its proposed commodity billing determinants for the post-restructuring period by adjusting the billing determinants it proposed for the pre-restructuring period to reflect, among other things, the termination of its sales service and the reduced capacity it expected to be available for interruptible service. Finally, Panhandle, like Staff, proposed to use contract demand as of May 1, 1993 to develop the post-restructuring demand billing determinants.Panhandle proposed to adjust certain of its commodity and demand billing units downward to reflect discounts. It proposed to do this based on the ratio of actual discounted revenues under the relevant transactions to the revenues that [**135] would have been collected under the maximum rates proposed by Panhandle in this proceeding. Staff did not oppose a discount adjustment, but stated that any discount adjustment should be based on the ratio of actual discounted revenues to the final just and reasonable rates, based on the finally approved cost of service. Since those rates had not yet been determined, Staff did not include a proposed calculation of the discount [*61,395] adjustment in its testimony. Other parties opposed any discount adjustment, generally on the ground that Panhandle had inadequately explained or justified its discounts.The ALJ adopted staff's proposal to use test period actuals to establish commodity and demand billing determinants for the pre-restructuring period. The ALJ rejected Panhandle's proposed use of data for the year ending April 30, 1993, since that period included five months of data beyond the end of the test period. For the post-restructuring period, the ALJ also adopted staff's proposed design determinants. The ALJ also held that Panhandle should not be permitted to adjust any of its commodity or demand billing determinants for discounts. The ALJ held that Panhandle had to prove the discounts [**136] it gave affiliated entities were justified by market conditions. He found Panhandle had not borne this burden of proof. In addition, he found Panhandle had not distinguished affiliate discount transactions from other discount transactions. n95

n95 This holding included ISS volumes if any of these discounts were given to affiliates.

Below, we consider first the parties' exceptions to the ALJ's rulings concerning the unadjusted volumes to be used to develop commodity and demand billing determinants before any discount adjustment is made. We then consider issues concerning what, if any, discount adjustments should be permitted.1. Unadjusted Volumesa. Pre-restructuring volumesPanhandle does not object to the ALJ's decision to base commodity billing determinants for the pre-restructuring period on throughput during the twelve month period December 1, 1991 through November 30, 1992. However, Panhandle does object to the ALJ's failure to adjust those commodity billing determinants to reflect the effect on throughput of conversions of contract demand from sales to transportation that were made by certain Rate Schedule G, LS, SSS and SG customers during the December 1, 1991 through [**137] November 30, 1992 period and before the November 1, 1992 effective date of the rates in this docket. Panhandle claims that the volumes sold to converting customers before their conversions should be treated as firm transportation rather than sales volumes for purposes of determining commodity units. Panhandle says that it made such adjustments for sales commodity volumes in its own projections of pre-restructuring sales commodity throughput and cites its exhibits, Exhs. PE-101 at pp. 13-4, 16; PE-109; and PE-123. Panhandle states that Appendix B to its Brief on Exceptions shows that twelve customers converted from sales to transportation between March 30 and November 1, 1992, and the associated sales commodity volumes that must be considered transportation volumes. In Appendix B, Panhandle shows these commodity volumes amount to 4,354,600 Dt.Staff opposes any revision of the pre-restructuring design determinants. Staff claims that while Panhandle's projected test period figures did not reflect all the conversions, the actual volumes for the twelve months ending November 30, 1992, did reflect all the conversions. The Panhandle Customer Group also opposes Panhandle's exception. It states [**138] that the information contained in Appendix B to Panhandle's brief on exception does not appear to have been part of the evidentiary record developed at the hearing. It also points out that Panhandle's witness Grygar did not identify the need for this adjustment to Staff's proposed commodity billing determinants in his rebuttal testimony, n96 and he made no adjustment to actual throughput for the 12 months ending April 1993 which he supported as the proper basis for commodity billing [*61,396] determinants even though all but one of the twelve conversions listed on Appendix B occurred during that period.

n96 Exhibits PE-118 at pp. 2-3 and PE-139 at pp. 2-3.

The sales demand determinants adopted by the ALJ reflect all conversions up until November 30, 1992. The sales commodity determinants, however, may not reflect the entire effect of the conversions until that date. The reason is that the sales commodity determinants are the actual commodity units for the twelve months ending November 30, 1992. If a contract is terminated after the beginning of this twelve-month period, then the sales commodity units for the period would not reflect the full effect of the conversion.The Commission does not [**139] necessarily agree with Panhandle that the commodity units associated with the converted contracts should all be treated as transportation commodity units rather than sales commodity units. During the test period, volumes sold under converted contracts were a mix of sales and transportation volumes, depending on the time when the conversion took place. But even if the Commission did agree with Panhandle that all volumes sold under contracts converted prior to November 1, 1992, should be treated as firm transportation volumes for commodity purposes, there does not appear to be any evidence in the record to indicate the amount of these volumes. Appendix B in which Panhandle recites the terminated contracts and associated volumes does not appear to have been introduced in evidence in any form. Panhandle does not describe the provenance of its Appendix B nor provide any citations to the record where the information it contains might be located. The evidence of record Panhandle does cite does not contain information on terminated sales contracts for the twelve months ending November 30, 1992. PE–109 states that an adjustment was made for conversion of sales service to transportation service, [**140] but does not describe the conversions or indicate the size of the adjustment. Exh. PE–123 contains a list of active sales customers, but does not describe terminated customers. Exh. PE–101 at pp. 13–4 and 16 states that adjustments were made to base sales rates to reflect conversions in contracts, among other things, but does not describe these conversions. Under these circumstances, there is no basis in the record on which the Commission can make any further adjustment for the commodity volumes associated with contracts that were converted to transportation during the twelve months ending November 30, 1992.b. Post–restructuring volumesMissouri Gas Users (MGU) n97 believes that the ALJ established design determinants only for the pre–restructuring period, and asks the Commission also to set levels for the post–restructuring period. MGU wants the Commission to use post–test period data, consisting of throughput for the initial twelve months after restructuring (May 1, 1993 through April 30, 1994), to determine post–restructuring commodity billing determinants, and, in particular, to use interruptible throughput for this purpose, because, in its view, restructuring has completely changed [**141] business patterns on Panhandle and pre–restructuring data is irrelevant to a determination of post–restructuring throughput. In the alternative, MGU urges the Commission to adopt its position at hearing for interruptible throughput of 109,856,169 Dt or to annualize actual interruptible [*61,397] throughput for the eleven months ending March 1994, which it claims can be found in the record in exhibits C–38 and MGU–6, and comes to 111,145,046 Dt. n98

n97 This group consists of end use consumers of natural gas with facilities in Missouri and includes American National Can Company; Anheuser–Busch Companies, Inc.; A.P. Green, Inc.; McDonnell–Douglas Corporation; Monsanto Company; and MEMC Electronic Materials, Inc.

n98 Exhibit C–38 is Panhandle's filing in Docket No. TM94–5–28–000 concerning the flow–back of cash–out and scheduling revenues. Appendix D to the filing contains information on the actual commodity volumes for interruptible transportation from May 1993, through January 1994. Exhibit MGU–6 is Panhandle's response to a data request in which it provides the commodity volumes unadjusted for discounting for all services for the five months ending March 31, 1994.

Panhandle counters [**142] that the ALJ adopted staff's volumes for the post–restructuring period, carrying forward the ISS volumes (to which it objects). Panhandle asserts that the Commission has determined in prior orders that only the throughput mix, and not the total amount of throughput, should change for the post–restructuring period. 61 FERC at p. 62,407; 61 FERC P 61,241 at p. 61,786 (1992). It also states that the record does not contain the evidence to implement MGU's proposals.Staff states that the ALJ adopted its proposal to use the same overall throughput level for the post–restructuring period as for the pre–restructuring period, with the mix among services adjusted to reflect restructuring. It says that his discussion of ISS sales presumes the use of staff's post–restructuring period throughput. Staff insists that its projections do incorporate post–restructuring experience because the throughput mix is based on the first six months' of the post–restructuring period (May 1 through October 31, 1993), even though the overall throughput level is based on data for the year ending November 30, 1992. Staff states that demand determinants must be those [**143] existing on May 1, 1993, by Commission order.The Commission agrees with Panhandle and staff that the ALJ adopted staff's volumes for the post–restructuring period. As staff indicates, this holding is implicit in his discussion of the ISS volumes, which he describes as being carried forward into the post–restructuring period. Thus, the ALJ adopted, as indicated above, 1,345,443,743 Dt of commodity units and 44,589,501 Dt of contract demand for the post–restructuring period. The contract demand figure was derived from Panhandle's contract demand on the May 1, 1993 effective date of restructuring. The estimate for commodity units was based on test period throughput, i.e., commodity units for the twelve months ending November 30, 1992, but revised by allocating these units to the different services using the mix of throughput on Panhandle from May 1, 1993, through October 30, 1993. Exhs. S–16 at pp. 27–8, S–19, and S–18. n99 Thus, the determinants take into account post–restructuring changes on Panhandle's system. Using this method, 107,789,109 Dt was allocated to interruptible transportation in the field and market zones on an annualized basis, unadjusted for discounting. Staff I. Br., [**144] App. B.

n99 In his direct testimony filed January 10, 1994, staff's witness Mr. McDaniel stated that he believed that it was appropriate to use these percentages because "they are based on actual volume activity experienced by Panhandle since the restructured services became effective May 1, 1993." Exh. S–16 at p. 28.

In any event, the Commission will not adopt MGU's proposals. The actual throughput for the twelve months ending April 30, 1994, is not in the record. For interruptible throughput, Exh. MGU–6 shows total commodity volumes for the five months November, 1993, through March, 1994, and Exh. C–38, App. D at p. 4, shows total commodity volumes for the nine months May, 1993, through January, 1994. MGU does not explain how it combined these two data sources, nor is it clear it would be reasonable to do so. The data on which MGU relies are fragmentary and incompatible. [*61,398] For these reasons, the Commission affirms the ALJ's determinations of pre–and post–restructuring throughput, including interruptible transportation in the post–restructuring period of 84,630,296 Dt in the field zone, 23,158,813 Dt in the market zone, and 68,075,071 Dt in the gathering area.c. ISS volumes [**145] Panhandle made interruptible sales (ISS) during the test period. It continued to make such sales during the pre–restructuring period, but ceased all such sales after restructuring. n100 Tr. 1883–86; C–30; PCG–8; PCG–9. n101 Since Staff used actual throughput during the last twelve months of the test period to develop the commodity billing determinants for the pre–restructuring period adopted by the ALJ, those commodity billing determinants reflected 23,315,244 Dth of ISS sales, n102 and 766,528 Dth of demand determinants were imputed from the commodity determinants. In addition, since staff used the same overall throughput for the post–restructuring period as for the pre–restructuring period, the ISS sales also underlay Staff's development of post–restructuring commodity billing determinants. However, as discussed above, Staff assigned the overall post–restructuring commodity billing determinants among post–restructuring services based on each service's share of actual throughput during the first six months after restructuring. Since there were no ISS sales after restructuring, Staff assigned no post–restructuring commodity billing determinants to ISS sales. Nor were any post–restructuring [**146] demand determinants imputed to ISS sales.

n100 This was an interruptible sales service. The transportation component of these sales was usually discounted.

n101 For the twelve months ending April 30, 1993, Panhandle claimed total ISS volumes were 36,948,640 Dt and that the discount adjustment to those volumes should be 27,975,138 Dt, so that ISS volumes adjusted for actual discount experience would be 8,973,502. Exh. PCG–8.

n102 This was the amount of ISS sales for the twelve months ending November 30, 1992, according to staff. Exh. S–16 at pp. 11–12; Staff I.B. at p. 133 and App. A.

The ALJ adopted the Staff's commodity and demand billing determinants for both the pre–and post–restructuring periods. Thus, he held that the ISS volumes actually sold during the test period must be included in design determinants for the pre–restructuring period. In adopting Staff's proposed post–restructuring commodity billing determinants, the ALJ refused to reduce the overall commodity billing determinants for the post–restructuring period to reflect the fact that Panhandle no longer performed ISS sales service. He reasoned that "if those transactions had not taken place, equivalent [**147] volumes would have been sold or transported that were displaced by the ISS volumes . . . ." In other words, customers would now "transport their former [ISS] purchase volumes." n103 The ALJ held that Panhandle could make discount adjustments to the ISS volumes if none of the ISS sales had been made to Panhandle affiliates.

n103 69 FERC P 63,013 (1994).

Panhandle does not object to the ALJ's inclusion of ISS volumes in pre–restructuring period actual volumes, as long as it can make a discount adjustment to these volumes. The Commission finds that ISS volumes are appropriately included in the pre–restructuring period since they occurred during the test period and the pre–restructuring period, and affirms the amounts adopted by the ALJ. The issue whether these amounts may be adjusted downward to reflect discounts is discussed in the next section.Panhandle excepts to what it describes as the ALJ's inclusion of ISS volumes in the post–restructuring billing determinants. It states that these volumes should be excluded from the determination of post–restructuring billing determinants because it no longer [*61,399] provides a sales service and that Rate Schedule [**148] ISS has been removed from its tariff. Panhandle claims that these sales should not be included in design determinants primarily because ISS sales were made solely to reduce Panhandle's gas supply inventory in anticipation of terminating its sales service (Exh. PE–138 at p. 6). Panhandle claims that it made no ISS sales until it began the orderly disposition of its gas supply inventories (Exh. PE–138 at p. 6) and a significant portion of ISS sales were made to customers who were not Panhandle's traditional sales customers. Exh. PCG–7. Panhandle urges that ISS sales were thus of a non–recurring nature.The Commission rejects this exception. First, as Staff points out in its brief on exceptions, under the ALJ's decision, no commodity or demand billing determinants are actually assigned to the terminated ISS sales service for the post-restructuring period. Rather, consistent with the Commission's previous orders that the same overall throughput level be used for the post-restructuring period as for the pre-restructuring period, the overall level of commodity billing determinants used for the pre-restructuring period is carried forward to the post-restructuring period. However, those determinants [**149] are then assigned among the various restructured services based upon each service's share of overall throughput during the first six months after restructuring. Since no ISS sales service was performed during that period, no commodity billing determinants are assigned to ISS sales. Nor are any demand billing determinants imputed to that service.What Panhandle is seeking though its exception to the ALJ's holding concerning ISS sales is, in essence, to base its post-restructuring commodity billing determinants on a projection of less overall throughput for that period than for the pre-restructuring period. It would do this by taking the overall throughput projected for the pre-restructuring period based on the last twelve months of the test period, subtracting the ISS volumes that flowed during that period, and using the result as the projected overall throughput level for the post-restructuring period.The Commission affirms the ALJ's holding that Panhandle has failed to support a lower projection of overall throughput for the post-restructuring period, than for the pre-restructuring period. Panhandle may have used the ISS service, terminated as part of restructuring, to sell off [**150] its gas inventory. The purchasers of that gas, however, were Panhandle's usual customers. The Commission has examined the ISS purchasers listed on Exh. PCG-7 and compared them to the customers listed on Exh. PE-139 which shows jurisdictional sales, firm transportation, interruptible transportation, and gathering for the twelve months ending April 30, 1993. The Commission finds that, with two exceptions, the ISS customers consist of entities that were customers of Panhandle for sales, firm transportation, interruptible transportation customers, or some combination of these services. n104 The ISS customers used ISS sales to make up some portion of the gas supplies they needed. It is reasonable to assume that they will need equivalent gas supplies in the post-restructuring period. Consequently, the ISS volumes should be included in Panhandle's design determinants for this period. (See discussion of the MMBtu/Mile study below for ISS volumes as part of allocation factors.)

n104 The only two ISS customers on PCG-7 who are not found on Exh. PE-139 are Columbia Gas Development and West Ohio Gas.

2. Should Commodity and Demand Determinants Be Adjusted for Discounts? [*61,400] At the hearing [**151] in this case, Panhandle proposed to adjust both throughput and demand billing determinants downward to reflect discounting. The discount adjustments that Panhandle sought appear to be contained in Exhs. PE-135, PE-139, PE-140, PE-141, and PE-143. In developing its proposed commodity billing determinants for the pre-restructuring period, Panhandle proposed to reduce its actual interruptible throughput during the year ending April 30, 1993 to reflect discounts given during that same period to its interruptible customers. n105 Panhandle did not propose any discount adjustment to firm throughput. However, Panhandle did propose to adjust for discounting its demand billing determinants for Rate Schedule PT-Firm service in the Field and Market Zones as well as in the gathering area. n106 Panhandle appears to have based that discount adjustment on its firm discount agreements in effect on November 30, 1992. It imputed its proposed demand units for interruptible transportation from the adjusted commodity determinants proposed for interruptible service. Thus, the interruptible demand determinants also reflected a discount adjustment. n107

n105 Panhandle proposed to reduce actual Rate Schedule PT-Interruptible throughput in the Field Zone of 219,780,774 Dt by 81,985,583 Dt to 137,795,191 Dt. It proposed to reduce Market Zone interruptible throughput of 135,888,018 Dt by 58,520,395 Dt to 77,367,623 Dt. It proposed to reduce gathering interruptible throughput of 104,670,420 Dt by 24,346,543 Dt to 80,323,877 Dt. Exhs. PE-139 at p. 1 and PE-140. See also Exhs. PE-122 at p. 10 and PE-123.

[**152]

n106 It proposed to adjust contract demand of 11,840,392 Dt in the Field Zone down by 721,701 Dt to 11,118,691 Dt. It proposed to adjust contract demand of 21,194,784 Dt by 3,714,577 Dt to 17,480,207 Dt. It proposed to adjust contract demand of 1,108,164 Dt by 97,124 Dt to 1,011,040 Dt. Exhs. PE-141 and PE-142.

n107 This resulted in unadjusted imputed Field Zone interruptible demand units of 7,225,669 Dt being reduced by 2,695,416 Dt to 4,530,253 Dt. The unadjusted imputed Market Area interruptible demand units of 4,467,551 Dt were reduced by 1,923,958 Dt to 2,543,593 Dt. Unadjusted gathering imputed interruptible demand units of 2,836,836 Dt were reduced by 800,434 Dt to 2,640,785 Dt. Exh. PE-141 at p. 1.

Panhandle sets forth its proposed commodity billing determinants for the post-restructuring period, on a customer-by-customer basis, in Exh. PE-132. See Exhs. PE-122 at p. 12 and 15 and PE-138 at p. 10. Panhandle compares its proposed throughput mix for the post–restructuring period with that for the pre–restructuring period in Exh. PE–133. According to Panhandle, its proposed throughput mix for the post–restructuring period reflects "the discounting which is necessary to perform" its level of post–restructuring services. [**153] n108

n108 Exh. PE–122 at p. 15.

Panhandle also proposed to adjust for discounting its demand billing determinants for Rate Schedules FT and EFT firm service in the Field and Market Zones, as well as in the gathering area. n109 Panhandle, like Staff, proposed to use contract demand as of May 1, 1993 to develop the post–restructuring demand billing determinants. Panhandle appears to have based its proposed discount adjustments on its firm discount agreements in effect on May 1, 1993. Also, it imputed its proposed demand units for interruptible transportation from the commodity determinants proposed for post–restructuring interruptible service, which it states reflect a discount adjustment. Thus, the post–restructuring interruptible demand determinants also reflected a discount adjustment.

n109 After these discount adjustments, the proposed demand billing determinants for Rate Schedule FT in the gathering area are 819,275 Dt (Exh. PE–135 at p. 19). As shown on Exh. PE–135 at p. 20, that number reflects a discount adjustment of 218,701 Dt. The proposed demand billing determinants for Rate Schedules FT and EFT service in the Field Zone are 3,571,206 Dt and 8,211,478 Dt respectively (Exh. PE–135 at pp. 17–18), following a discount adjustment applicable to both Rate Schedules of 706,244 Dt (Exh. PE–135 at p. 21). The proposed demand billing determinants for Rate Schedules FT and EFT service in the Market Zone are 3,705,860 Dt and 17,488,548 Dt respectively (Exh. PE–135 at pp. 13–15), following a discount adjustment of 3,491,762 Dt (Exh. PE–135 at p. 22).

[*61,401] [**154] At the hearing, Staff did not oppose Panhandle adjusting its throughput and demand units to reflect discounts. However, Staff pointed out that Panhandle's proposed discount adjustments were based on the ratio of actual discounted revenues under the relevant transactions to the revenues that Panhandle would have collected under the maximum rates it proposed in this proceeding. Citing Williston, 67 FERC P 61,137 (1994), Staff stated that any discount adjustment should be based on the ratio of actual discounted revenues to the final just and reasonable rates, based on the finally approved cost of service. Since those rates had not yet been determined, Staff did not include a proposed calculation of the discount adjustment in its testimony. However, it did present an exhibit showing, for illustrative purposes, the iterative process that would be necessary to properly calculate the discount ratio. Exh. S–21. Citizens, IS, and MGCM opposed any discount adjustment.The ALJ held that if any discount adjustments were permitted, they would have to be calculated pursuant to Staff's proposed iterative method, consistent with Williston. However, the ALJ held that no [**155] discount adjustment would be permitted in this case. He held that a substantial number of Panhandle's discounted transactions involved affiliates. He further held that Panhandle had failed to present sufficient evidence to meet its burden of showing that its discounts to affiliates were required by competition. Therefore, none of the affiliate discounts were allowed to be taken into account in adjusting rate design volumes. The ALJ then stated that, if Panhandle had satisfactorily distinguished affiliate transactions from non–affiliate transactions, only the affiliate transactions would need to be excluded. But, the ALJ stated, Panhandle had not distinguished the two types of transactions, and therefore he held that no discounts could be taken into account, except for ISS discounts if none of those involved affiliates.On exceptions, Panhandle asks the Commission to allow discount adjustments for the pre–and post–restructuring periods and various parties oppose such adjustments. Staff supports the ALJ's adoption of the iterative discount method in Williston, but did no analysis of the discounts claimed by Panhandle, and does not recommend any specific level of discounts. B. Op. [**156] E. at p. 49. Citizens, IS, and the Municipal Gas Commission of Missouri (MGCM) support the ALJ's decision to eliminate a discount adjustment from design determinants. IS argues that Panhandle did not show that its discounts provided benefits to ratepayers, because any addition of contract demand or throughput or firming up of load on the system would not be included in customers' rates until Panhandle filed a new rate case and Panhandle is no longer under any obligation to file such a case.a. Affiliate discountsThe ALJ held that Panhandle had to prove that the discounts it gave to affiliated entities were justified by market conditions, and that Panhandle had not borne this burden of proof. He found, in addition, that Panhandle had not distinguished affiliate discount transactions from other discount transactions. As a result, he held that Panhandle could not use any discounts in computing throughput. n110

n110 This holding applies to ISS volumes if any of these discounts were given to affiliates.

Panhandle claims that it should be permitted to include its discounts to affiliates in its discount adjustment. Panhandle states that it is Commission policy to permit discounting to affiliates as well as to others [**157] as long as a pipeline does not unduly [*61,402] discriminate in favor of its affiliates. Panhandle insists that the evidence shows that affiliate transactions were required to meet competition, which it claims it faces in both its market and production areas. Panhandle also claims that it requires shippers to provide information concerning competitive rates at which they can obtain fuel and transportation when they make a request for a discount (form at Exh. PE-145). n111 Panhandle contends that it provided evidence to distinguish between affiliate and non-affiliate discounting in Exhs. PE-140 and PE-142 for the pre-restructuring period, in Exh. PE-135 at pp. 15-6 for the post-restructuring period, and in Exh. PE-144 for both periods.

n111 On this form the shipper is to report the total cost per MMBtu of gas transported on another pipeline and the total cost per MMBtu equivalent (commodity plus transportation) of alternate fuel.

Citizens, IS, and MGCM assert that Panhandle has the burden of proving that its discounts to affiliates were justified, and that Panhandle did not provide evidence to show that they were required by market forces. n112 They also claim that Panhandle did not identify [**158] all affiliate transactions. In particular, IS claims that Panhandle did not identify post-restructuring affiliate discounts on its exhibit PE-144, and does not believe that all affiliate discounts have been identified on the other Panhandle exhibits. Citizens states that future compliance filings cannot make up for the failure to identify affiliate transactions in the record.

n112 These parties cite Southern Natural Gas Co., 65 FERC P 61,347 (1993); order on reh'g, 67 FERC P 61,155.

As discussed in more detail in the next section on non-affiliate discounts, the Commission's established policy is to permit adjustments to volumes for discounts. The Commission also permits discounts to affiliates to be included in the discount adjustment. However, the Commission carefully scrutinizes discounts to affiliates, since pipelines do have incentives to offer affiliates discounts not required by competition. n113 The Commission has drawn a distinction between the pipeline's burden to justify discounts to affiliates and those to non-affiliates, with a much heavier burden to justify that its discounts to affiliates were required to [**159] meet competition.

n113 Southern, 65 FERC at p. 62,831.

Thus, under established Commission policy, Panhandle had the burden at the hearing in this case of showing that its discounts to affiliates were required by competition. Panhandle had to provide information concerning how the level of the discounts to affiliates was determined and why it was necessary to grant those discounts, for example, by identifying the transportation and/or fuel alternatives available to the affiliated customer that gave rise to the decision to discount. The record, however, does not contain any of this information for affiliate discounts. Panhandle testified as to the kind of information it collects (Exh. PE-145) and entered the form for collecting the information in the record, but it did not offer any of the information actually collected from the affiliates as evidence. Thus, the record contains no specific evidence as to what alternatives were available to the particular affiliates given discounts. The fact that the level of the discounts given to the affiliates in question is similar to that of discounts given to some other shippers is not sufficient to show the competitive [**160] circumstances under which the affiliate discounts were given. It does not show that affiliate and non-affiliate shippers were in the same competitive circumstances.Since Panhandle did not prove its discount adjustments were required to meet competition, it may not make discount adjustments to billing determinants or throughput for discounts given to affiliated shippers. This requirement applies to all of [*61,403] the affiliate discounts that were identified in the record of this proceeding and any other affiliate discounts that Panhandle may identify in subsequent submissions required by this order, as discussed below.We now turn to the issue of whether Panhandle should be permitted a discount adjustment for its non-affiliate discounts.b. Discounts to Non-AffiliatesThe ALJ's sole discussion of the reasons for his holding concerning the exclusion of non-affiliate discounts was as follows:

> Had Panhandle satisfactorily distinguished the transactions involving affiliates from the others, only the discounting in those transaction would be eliminated from the computations. As it has not, none of the discounts may be taken into account, except for the ISS volumes, if none involved affiliates." [**161] n114

n114 69 FERC at p. 65,097.

Panhandle excepts to this holding. Panhandle first asserts that the holding that Panhandle did not distinguish between affiliate and non-affiliate discounts is incorrect. It states that, with the concurrence of the parties and the ALJ, it attempted to provide a modicum of confidentiality for all shippers regarding their commercial transactions by substituting a code number for the shippers' names in its exhibits supporting its proposed discount adjustments. Thus, Panhandle contends, participants in this proceeding with access to the shipper codes, pursuant to the protective order issued by the ALJ, could identify which transactions involved affiliates and which did not. Moreover, Panhandle points out that established Commission policy permits pipelines to adjust rate design volumes for discounts so as to avoid a disincentive to discounting. Therefore, Panhandle concludes that the ALJ's denial of a discount adjustment for its non-affiliate transactions is unsupported by the record, contrary to Commission policy, and inequitable.In its brief opposing exceptions, Citizens objects to the adequacy of Panhandle's support [**162] for its proposed discount adjustment for reasons in addition to that provided by the ALJ, especially with regard to the post-restructuring period. Citizens claims that under Williston, n115 Panhandle must use actual discounted revenue from the base or test periods to determine the discount adjustment, and that Panhandle did not do so for the post-restructuring period, at least for its discounts to firm customers. Citizens asserts that, instead, Panhandle used firm discounted rates and volumes existing during one month, May, 1993, for the post-restructuring period and projected these figures forward. Tr. 696-99. Citizens contends that the number of firm shippers, the discount rates, and the discounted volumes change over time so that it is not reasonable to use the figures for only one month as the basis for a discount adjustment. Exhs. PE-123, PE-135, PE-140, PE-142, Tr. 688-700. For example, Citizens points to the variation in the number of shippers in Panhandle's different calculations of the discount adjustment. Exhs. PE-123 and PE-142. n116 IS argues generally that Panhandle has not shown that its past discounts would form a reliable basis for a prospective discount adjustment. [**163]

n115 Williston Basin Interstate Pipeline Co., 67 FERC P 61,137 (1994).

n116 Citizens also claims that Panhandle included contracts in its exhibit PE-123 that terminated before the end of the test period without any evergreen provision, and that these contracts should not be included in any discount adjustment.

[*61,404] The Commission has consistently held that, to the extent a pipeline was required during the test period to give discounts either to attract or retain load, it need not design its rates on the assumption that such discounted volumes would flow at maximum rates. Otherwise, there would be a disincentive to pipelines' discounting their rates to capture marginal firm and interruptible business. The Commission has held that such discounts benefit all customers by allowing a pipeline to maximize throughput and thus spread fixed cost recovery over more units of service. n117

n117 Southern Natural Gas Co., 65 FERC P 61,347 at pp. 62,829-30 (1993), reh'g, 67 FERC P 61,155 at pp. 61,456-7 (1994).

The Commission has also stated that the pipeline has the ultimate burden of proving that all discounts [**164] reflected in its discount adjustment were appropriate and that its throughput projections are reasonable. However, the Commission has stated that, in contrast to the situation with respect to affiliate discounts discussed above:

> it is a reasonable presumption that a pipeline will always seek the highest possible rate from non-affiliated shippers, since it is in its own economic interests to do so. n118

Accordingly, once the pipeline has explained generally the basis for its discounts to non-affiliated customers and thus met an initial burden of demonstrating that the discounts were proper, those opposing a discount adjustment have the burden of demonstrating that the discounts to non-affiliates were discriminatory, i.e., were not justified by competition. n119

n118 Southern, 65 FERC at p. 62,831.

n119 Williston, 67 FERC at p. 61,379.

The primary data concerning the discount transactions underlying Panhandle's proposed discount adjustments are set forth in Exhs. PE-140 and PE-142 for the pre-restructuring period and Exh. PE-135 at pp. 15-16 for the post-restructuring period. The portion of the hearing transcript cited [**165] by the ALJ n120 for his finding that Panhandle failed to identify a number of affiliated transactions contains cross-examination of Panhandle's witness Grygar concerning Panhandle's Exh. PE-140. That cross-examination establishes, as is apparent from the face of Exh. PE-140, that footnote 2 of the exhibit identifies by name of affiliated shipper only the transactions involving Panhandle's affiliate, the Panhandle Trading Company, despite the fact there were other transactions which involved other affiliated shippers. However, the exhibit also includes a column setting forth the contract codes for each discount transaction. With those contract codes, it was possible for participants in the proceeding to identify which transactions involved affiliates other than Panhandle Trading Company. n121 Similar contract codes are also included in Exhs. PE-135 and PE-142. Thus, contrary to the ALJ's finding, distinguishing the affiliate and non-affiliate transactions listed in the primary exhibits supporting Panhandle's proposed discount adjustment does not appear to be an insurmountable problem.

n120 Tr. 790-96. See 69 FERC at p. 65,096.

n121 The cross-examination also included questions concerning the difficulty of identifying which transactions involved non–affiliated shippers transporting gas on both Panhandle and a pipeline affiliated with Panhandle. However, as discussed below, the Commission holds that such transactions need not be excluded from the calculation of the discount adjustment.

[**166] In addition, as the ALJ appears to have recognized, Panhandle met its initial burden of explaining generally the basis for the discounts to non–affiliated customers, and no party opposing a discount adjustment even attempted to meet its burden, thereafter, of demonstrating that any of the discounts to non–affiliates reflected in Panhandle's exhibits were not required by competition. Panhandle's witness Grygar [*61,405] stated that "Without these discounts, Panhandle could not have attained the contract demand and throughput levels which are reflected in [this case]." Exh. PE–138 at p. 11. Moreover, he stated that Panhandle requires appropriate documentation justifying discounts requested by customers n122 and that Panhandle's marketing department verifies all requests for discounts. In Opinion No. 395, the Commission held that similar evidence presented by Panhandle in its previous rate case was sufficient to meet its initial burden of explaining generally the basis for discounts to non–affiliates. n123

n122 Grygar's testimony was supported by an exhibit showing the type of information which Panhandle requires that its customers submit for this purpose.

n123 As discussed above, such evidence is not sufficient for the pipeline to meet its heavy burden of justifying discounts to affiliates.

[**167] However, there are two gaps in the information which Panhandle has provided to support its discount adjustment. First, the data provided in Exh. PE–140 to justify Panhandle's discount adjustment for its pre–restructuring interruptible throughput is for the twelve month period ending April 30, 1993, consistent with Panhandle's proposal to determine unadjusted interruptible throughput based on those same twelve months. However, as discussed above, the ALJ, without exception from the parties, adopted the Staff's proposal to determine unadjusted interruptible throughput for the pre–restructuring period based on the last twelve months of the test period, the year ending November 30, 1992. Moreover, use of post–test period data that includes discounts during the entire pre–restructuring period at issue here would be at odds with the concept behind permitting discount adjustments. Such adjustments are permitted to ensure that pipelines are not penalized for past discounting, but the adjustment is not intended to insulate pipelines from the risk of future discounting.Therefore, Panhandle's adjustment to interruptible throughput for the pre–restructuring period must be based on discounts [**168] given to non–affiliates during the same year ending November 30, 1992, that is being used to project its unadjusted interruptible throughput. Moreover, the Commission believes that any discount adjustment of the unadjusted interruptible throughput established above for the post–restructuring period should be based on the same discount ratio used for the pre–restructuring period. There is no reliable basis to determine a different discount ratio for the post–restructuring period than the pre–restructuring period. Therefore, both discount ratios should be calculated using discount data for the last twelve months of the test period, the year ending November 30, 1992. While the discount data in Exh. PE–140 does include the last seven months of the year ending November 30, 1992, and other exhibits include discount data for some of the earlier five months, it does not appear possible from the present record to reliably construct precisely what discounts Panhandle gave to interruptible shippers during the year ending November 30, 1992.The second gap in Panhandle's data supporting a discount adjustment concerns its proposed adjustment of firm contract demand volumes for both the pre–and [**169] post–restructuring periods. In both Exh. PE–142 setting forth the data supporting the discount adjustment to pre–restructuring contract demand and Exh. PE–135 setting forth the data supporting Panhandle's proposed discount adjustment for post–restructuring contract demand, Panhandle chose the discounted firm volumes and rates for a month or a specific point in time and projected these forward instead of using actual discounted volumes and rates for a base or test period. n124 Thus, the record shows that, [*61,406] initially, Panhandle filed discount adjustments to firm contract demand for the pre–restructuring period based on "end of test period certificated levels" and discounted rates in effect in April, 1992. n125 It then revised this discount adjustment based on contract demand and discounted rates, both at the end of the test period. n126 The record also shows Panhandle based its discount adjustment for the post–restructuring period on contract demand as of May 1, 1993, and projected discounted revenues based on discount agreements in effect on that same date. n127

n124 Tr. 688–700; C–34; C–35; and C–36.

n125 Exhs. PE–122 at p. 10; PE–123, Tr. 698.

n126 Exhs. PE–142; C–36; C–39; Tr. 698.

[**170]

n127 Exhs. PE-122 at p. 14; PE-135; Tr. 694, 698.

The Commission finds that any discount adjustment to Panhandle's firm contract demand volumes for both the pre-and post-restructuring periods should be based on the ratio of discounted reservation charge revenues collected during the entire course of the last twelve months of the test period to the revenues that would have been collected on those volumes at the just and reasonable maximum reservation charges determined in this rate case. As Citizens showed, discount rates given to particular firm customers varied both during and after the test period. n128 Also, the number of firm shippers receiving discounts changed during the test period. n129 Thus, a more reliable discount adjustment can be determined based on data for a full year, than on data for any particular point in time. However, the current record does not contain data showing Panhandle's discounted firm revenues for the last twelve months of the test period.

n128 For example, Citizens traced discounts to East Ohio Gas for firm transportation and showed that the discount rate to this shipper was $3.35 in April, 1992 (Tr. 698; Exh. PE-123; and Exh. C-34); $3.11 on November 30, 1992 (Tr. 696; Exh. PE-142; and Exh. C-36); $2.83 on May 1, 1993 (Tr. 699; Exh. PE-135; and Exh. C-35); and $3.63 in November, 1993 (Exh. C-37).

[**171]

n129 For example, the number of shippers receiving a discount on firm transportation in the market zone was 23 in Exh. PE-123, which was based on discounts in April, 1992; it was 51 in Exh. PE-142, which was based on discounts on November 30, 1992; and it was 40 in Exh. PE-135 at p. 17, which was based on discounts in effect on May 1, 1993.

Thus, the instant record does not contain all the data necessary to calculate a discount adjustment, based on non-affiliate discounts, either for Panhandle's interruptible throughput or for firm contract demand volumes. However, the Commission does not believe it equitable or appropriate to deny Panhandle any discount adjustment at all, due to the gaps in the data necessary to calculate the discount adjustment. As already discussed, the Commission's policy is to permit discount adjustments so as to avoid a disincentive to discounting, since the Commission has held that discounting benefits all customers by spreading the recovery of fixed costs over more volumes. Panhandle's failure to provide revised information for calculation of a discount adjustment to interruptible throughput based on the year ending November 30, 1992, used by Staff to [**172] project unadjusted interruptible throughput, may have been due in part to Staff's position that it was premature to calculate a discount adjustment until after a final Commission decision on all the other cost-of-service and rate design issues necessary to determine Panhandle's final just and reasonable rates. Moreover, with respect to Panhandle's failure to provide information concerning firm discounted revenue over the year ending November 30, 1992, this is the first Commission order in which the Commission has expressly addressed, and decided, the issue whether the discount adjustment to firm contract demand volumes should be based on actual discounted revenues over a full year during the test period, rather than a projection of discounted revenues based solely on discount agreements in effect on the last day of the test period, as proposed by Panhandle. [*61,407] In these circumstances, the Commission believes that the most appropriate approach is to remand this case to the ALJ for the purpose of enabling Panhandle to fill in the gaps in the information it has provided concerning non-affiliate discounts described above. This will also give the other parties an opportunity to respond to [**173] the additional information provided by Panhandle. As discussed above, the Commission in this order has already held that Panhandle failed to meet its burden to support the inclusion of any discounts given to affiliated shippers in the calculation of its discount adjustment. The Commission sees no reason to give Panhandle any further opportunity to support inclusion of affiliate discounts, and no issue concerning affiliate discounts is to be considered in the remanded proceeding.The additional data to be provided by Panhandle in the remanded proceeding for firm and interruptible n130 discounted transactions performed during the twelve months ending November 30, 1992 must show the volumes, discounted rates, and total revenues collected in each such transaction and identify the shipper. n131 Because the additional information to be provided by Panhandle will likely include discount transactions not reflected in the exhibits previously filed by Panhandle, the other parties must be given an opportunity to rebut the presumption that the non-affiliated transactions were required by competition. Finally, in the remanded proceeding, once the ALJ has determined the non-affiliated transactions [**174] which may be used in adjusting Panhandle's rate design volumes, the ALJ should proceed to determine the discount adjusted commodity and demand billing determinants pursuant to the iterative method approved in Williston and outlined in staff's testimony in this case. See Opinion No. 395, 71 FERC at pp. 61,870-1, describing the iterative methodology for determining discount adjustments. Since this order contains the Commission's findings on all other cost of service and rate design issues necessary to determine Panhandle's final just and reasonable rates, it is now possible to perform the various calculations required by the iterative methodology.

n130 Consistent with the ALJ's determination that Panhandle should be permitted a discount adjustment to its pre-restructuring ISS sales throughput, Panhandle may provide the information specified here for ISS sales throughput, as well as interruptible transportation throughput.

n131 In addition, consistent with Opinion No. 369, 57 FERC at p. 61,842, the data should show the transactions by month, type of receipt point, and delivery location. Panhandle included such information in its Exh. PE-144. However, the information presented in that exhibit was not presented in a form in which it could be correlated with the transactions reflected in Panhandle's other discount exhibits. Panhandle must correct this deficiency on remand.

[**175] c. Pooling, multi-pipeline, and no revenue transactionsIS claims that certain transactions are not eligible for a discount adjustment, even if one is permitted. It states that it is the Commission's policy to permit discount adjustments only for discounts that are required to meet competition. Pacific Gas Transmission Co., 68 FERC P 61,215 (1994); Southern Natural Gas Co., 67 FERC P 61,155 (1994). IS claims that discounts that facilitated pooling (Tr. 778-90) and discounts related to transactions on Panhandle and its affiliated pipelines (multi-pipeline transactions) were not required to meet competition and should be excluded. Citizens also objects to discount transactions involving Panhandle and its affiliated pipelines and asserts that, in these transactions, the affiliated companies are free to allocate the discounts between themselves as they desire. Therefore, Citizens argues, these discounts do not reflect market conditions. Last, Citizens states that customers did not receive any benefits from eleven demand discount transactions for which Panhandle received no revenue. Exh. PE-142 (these transactions do not appear to [**176] involve affiliates). It asserts that these firm contracts provide no benefit to other [*61,408] customers by lowering their contribution to fixed costs and, therefore, should be excluded from any discount adjustment. n132

n132 Citizens also asserts that Panhandle received no revenue in one transaction in which the shipper received gas from a Panhandle affiliate and had it delivered to a Panhandle affiliate. Citizens is referring to Exh. PE-123 on which Panhandle no longer relies and does not identify the transaction.

In Opinion No. 395, the Commission considered IS's contention concerning discounts given to non-affiliated shippers in transactions involving transportation of gas on both Panhandle and other pipelines affiliated with Panhandle. For the reasons stated in Opinion No. 395, 71 FERC at pp. 61,869-70, the Commission holds that such discounted transactions may be reflected in Panhandle's discount adjustment. The Commission also holds that Panhandle may include in its discount adjustment discounts given to non-affiliated shippers to facilitate pooling. The Commission encourages pooling. Since pooling often involves a large number of very short haul transactions, [**177] discounts may be necessary to make pooling economic. Therefore, the Commission sees no reason to exclude such transactions from Panhandle's discount adjustments. Finally, transactions in which Panhandle receives no reservation charge revenue should be excluded altogether from the design of Panhandle's rates.d. SCT ratesWhile the ALJ had disallowed discounting on most volumes, he gave his opinion in dicta concerning discounting and SCT rates in the post-restructuring period. The ALJ stated that, if Panhandle had not already done so, it should allocate discounts to all firm customers as a group in the post-restructuring period, i.e. to FT and EFT customers, rather than only to FT customers. This would, in his opinion, avoid the shifting of costs to captive EFT customers which would result from a discount adjustment that decreased only the throughput of FT customers. It would also, he stated, spread the benefits of discounting to all customers, including captive customers who had not received discounts, which he believed to be the intent of Williston. 67 FERC at p. 61,378.On exceptions, MGCM supports the ALJ's finding that Panhandle failed to prove its proposed [**178] discount adjustments were appropriate. If discounting adjustments are approved, however, MGCM insists SCT customers would have a disproportionate rate increase when compared to PT-Firm customers in the pre-restructuring period and FT customers in the post-restructuring period due to Panhandle's treatments of discounts. MGCM insists that Panhandle allocates discounts only to FT customers and that this shifts costs to SCT customers. It argues that Panhandle's discount adjustments should reduce SCT determinants as well as FT determinants. MGCM asks the Commission to apply any discounts equally to all customer classes for both the pre-and post-restructuring periods.Panhandle and Citizens claim that there is no disproportionate increase in SCT rates. Panhandle explains that discounted volumes are used to design the base rates for all three rate schedules, FT, EFT, and SCT. Exh. PE-135. It states that "the rate for Rate Schedule EFT is merely the rate for Rate Schedule FT with a storage add-on. The rate for Rate Schedule SCT is the 52.5% load factor equivalent of Rate Schedule EFT rates." B. On E. at p. 40. Panhandle also asserts that the SCT rate design conforms to the requirements of [**179] the settlement in Docket No. RP88-262-000 and to Panhandle's restructuring proceeding in Docket No. RS92-22-000. 61 FERC P 61,357 at p. 62,407. [*61,409] Panhandle's explanation adequately demonstrates that it uses discounted volumes in the design of all three post-restructuring firm rate schedules, and therefore its treatment of discounted volumes does not result in unreasonable cost shifts among those rate schedules.e. MMBtu/Mile StudyThe

ALJ held that it was improper to use discounted volumes, as Panhandle proposed, to allocate costs. Accordingly, he adopted staff's proposed MMBtu/Mile study which used undiscounted volumes. Exh. S–14 at pp. 6–9; Exh. S–15, schs. 3 and 4. Staff's study assumed that all sales volumes during the pre–restructuring period were received in the field zone (at the West End). Exh. S–15, Sch. 3 at pp. 36–7. The ALJ found that some sales volumes might have been delivered from market storage, and that some of the market storage volumes might have been received in the market area. If that was the case, then, he reasoned, staff's MMBtu/Mile study overstated the distance of haul of such volumes. But the ALJ could not find evidence of record indicating [**180] the amount of market storage gas that had been received in the market area. Consequently, he held that there was insufficient evidence to adjust staff's MMBtu/Mile factors for sales service in the pre–restructuring period.Both Panhandle and Citizens assert that Panhandle's MMBtu/Mile study with its discounted volumes should be used. Panhandle claims that it is the Commission's policy to use discount adjustments in both cost allocation and rate design. PCG asserts that if any discount adjustments are permitted, they must be reflected in the MMBtu/Mile cost allocation factors. The Commission agrees that the discount adjustments determined in the remanded proceeding should 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. n133

n133 See Southern, 65 FERC at p. 62,842.

PCG excepts to the MMBtu/Mile factors the ALJ adopted because they assume that all sales gas originated in the Field Zone. n134 PCG states that this increases the MMBtu/Mile allocation units for sales service and leads to an overallocation of Field Zone costs to sales service. [**181] PCG claims that some sales gas originated in the market zone because some sales gas came from market storage. PCG states that Panhandle intended to use market storage to satisfy its firm sales obligations and to make sales to ISS customers. It claims that Panhandle had about 30 million Dt of storage inventory for these purposes on November 1, 1992, n135 and that this amount constituted 73 [*61,410] percent of system supply in the pre–restructuring period. n136 PCG argues further that this storage gas was injected prior to 1983 or 1984 because later LIFO layers had been sold off. PCG then claims that 33.7 percent of the storage gas was received in the market area. It bases this argument on the fact that Panhandle received 33.7 percent of its supplies at Tuscola during the period November 1980 to November 1982, when a large amount of gas, 15.3 Bcf, was injected. n137 PCG concludes that, given that storage gas was 72.7 percent of system supply and that 33.7 percent of storage gas was received in the market area, 24.5 percent of sales volumes should be considered as being received in the market area and should be excluded from the MMBtu/Mile sales commodity factors in the Field Zone and 26.3 percent [**182] of sales demand determinants should be excluded from the MMBtu/Mile demand factors in the Field Zone. n138

n134 Staff's MMBtu/Mile factors resulted in field zone annual demand units being attributed about 16 percent to sales and 84 percent to transportation. These units would be used to allocate mileage–related D1 costs. Staff's MMBtu/Mile factors resulted in field zone annual volumes being attributed about 5 percent to sales and 95 percent to transportation. These units would be used to allocate mileage–related D2 costs and commodity costs other than fuel. Exh. S–15, Sch. 3 at pp. 33 and 37; Exh. PE–126 at p. 1.

PCG objects to Panhandle's allocation factors on the same grounds. Panhandle's MMBtu/Mile factors resulted in field zone annual demand units being attributed 19.353 percent to sales and 80.647 percent to transportation and field zone annual volumes being attributed 5.296 percent to sales and 94.704 percent to transportation. Exh. PE–126 at p. 1; Motion Rates, Revised Sch. I–1 at p. 1 (March 1, 1993).

n135 PCG claims that this is the amount of storage gas Panhandle had at the end of October, 1992, less 10,364,000 Dt which it sold on November 1, 1992. PCG asserts that the exact amount is 29,733,218 Dt (or 29,882,631 Mcf). B. on E. at p. 47 n.71. However, PCG derived this number by subtracting 10,364,000 Dt (for the amount sold on November 1, 1992 (PE–160)) from 40,246,631 Mcf (for the amount in storage at the end of October, 1992 (Exh. PE–161)) to get 29,882,631 Mcf and then converting this number to dekatherms. See Exh. PE–161 and PCG B. on E. at p. 15. If the units are kept the same, the amount available is 40,045,398 Dt of storage gas at the end of October, 1992, minus 10,364,000 Dt, the amount that was sold, which gives 29,681,398 Dt. (The heat content of storage gas was 995 Btu per cubic foot. Tr. 829.)

[**183]

n136 PCG states that the storage gas available for delivery was 29,733,218 Dt, actual gas purchases for the pre–restructuring period were 11,162,267 Dt (Exh. PE–61), and the ratio of storage gas to the total supply was thus 72.7

percent. B. on E. at pp. 37-8 nn. 72 and 73. This ratio is not changed by using the corrected figure for storage gas on November 1, 1992, of 29,681,398 Dt.

n137 Citing 27 FERC P 61,345 at p. 61,675 n. 10 (1984). In the alternative, PCG argues that since 39 percent of Panhandle's capacity was at Tuscola, it would be reasonable to find 39 percent of Panhandle's gas in storage at November 1, 1992, was received at Tuscola.

n138 PCG also argues that 68.4 percent of Panhandle's gas purchase volumes entered the system at transmission points in Illinois in the six months before the pre-restructuring period (citing Exh. PCG-5) and that the MMBtu/Mile allocation factors should reflect this test period receipt point mix. Exh. PCG-5, which is a portion of Panhandle's Annual PGA Filing to be effective March 1, 1993, shows only transmission line purchases (Account No. 803), not transmission line purchases in Illinois. It is also unclear that any of these purchases were net injections to storage.

[**184] In response, Panhandle argues that no study of receipt points of sales Volumes was needed because all sales volumes were received on the West End. Panhandle states that it terminated the contracts for Trunkline and Canadian gas as of November 1, 1992, and that there were no alternative supplies from Canada or the Gulf Coast available in the period immediately preceding the pre-restructuring period. Panhandle argues that market area storage only serves peak demands of relatively short duration, not annual sales requirements. It also contends that the content of storage cannot be analyzed using the LIFO method. According to Panhandle, LIFO is a method of book valuation only and does not trace molecules of gas to their source. n139

n139 Panhandle also argues the Commission has held storage is not to be included in the allocation of transmission costs and the design of transmission rates because it is not mileage-related and cites Opinion No. 369-A in Docket No. RP88-262-000, 59 FERC P 61,244 at p. 61,849 (1992). That order, however, allocated storage costs to transmission service as part of a non-mileage unit cost component (or access fee) for Panhandle's 100-mile segment rates. Id. The Commission eliminated Panhandle's access fee but continued to allocate 22 percent of storage costs to transmission service for the duration of the period in which Panhandle had a sales service.

[**185] The Commission agrees with PCG that an adjustment in MMBtu/Mile sales factors should be made to reflect gas received in the market area. As shown by Panhandle's November 1992 sale of gas from market area storage before the November 30, 1992 end of the test period, Panhandle's test period data suggested that at least some of its pre-restructuring sales would not be of gas originating in the Field Zone. The Commission finds Panhandle intended to and did use storage gas to make firm and interruptible sales during the pre-restructuring period and that some of the storage gas was received in the market area. Therefore, we agree with PCG that performing the MMBtu/Mile Study based on the assumption that all sales gas orignates in the Field Zone would lead to unreasonable results.It is not possible to trace molecules, but, contrary to Panhandle's assertion, gas volumes are treated as being received in specific years for accounting and ratemaking purposes. Panhandle itself regards them in this way when it claims that working gas [*61,411] should be included in rate base and it should receive a return on this gas. It was not PCG's responsibility to show receipt points. The Commission placed that burden [**186] on Panhandle. 61 FERC P 61,352 at p. 62,376. n140 Panhandle provided no evidence of this kind in its direct testimony. When PCG asked Panhandle for receipt point data during discovery, Panhandle did not provide it, citing the Commission's system of accounts. n141 Consequently, the best evidence of record is a reasonable approximation of the amount of gas in storage that was received in the market area.

n140 In Docket No. RP91-229-000, the Commission directed Panhandle "to revise its mileage study to reflect all receipt points and the volumes received at those points in calculating the weighted average point of entry of gas into its transmission system." 61 FERC P 61,352 at p. 62,376. In designing rates, Panhandle was to comply with the point-to-point directives of Opinion No. 369. Subsequently, Panhandle filed a revised MMBtu/Mile study which resulted in a reduced allocation of cost responsibility to the sales service for gathering. 68 FERC P 63,008 at p. 65,103, citing Exh. P-120 at pp. 8-9.

n141

> [Mr. Schaefgen for PCG] Q. . . . . Has . . . . anyone . . . at Panhandle attempted to determine what the volumes were that were purchased and received . . . at transmission receipt points?
>
> [Mr. Grygar] A. No. Mr. Schaefgen, we don't maintain our system supply purchases by receipt point. We maintain them by FERC account designation well head, field lines, plants, transmission, which are

> the designations for accounts 800, 801, 802, and 803, respectively. And I believe, we furnished to you, in a data request, the -- that particular breakout for the six-month period covered by these rates.
>
> Q. It wasn't terribly helpful, as far as identifying transmission receipt points, versus gathering receipt points, was it, Mr. Grygar?
>
> A. No, Mr. Schaefgen. As I explained, we do not maintain our system supply receipts by plant functionalization.

Tr. 908-09.

[**187] The Commission finds that PCG has provided an approach for making such an approximation. The Commission agrees with PCG that 72.7 percent of Panhandle's sales gas came from storage during the pre-restructuring period and that 33.7 percent of gas in storage was received in the market area. However, these percentages apply to storage used for both firm and ISS sales. PCG did not distinguish between the two. Exhibit PCG-9 shows ISS sales, which were sales from storage gas, for the months November 1992, through April 1993, were 18,977,897 Dt. After the ISS sales, there were 10,703,501 Dt of storage gas left for sale to firm sales customers. There was a total of 21,865,768 Dt of system gas that was used for firm sales, of which 10,703,501 Dt, or 49 percent was storage gas. Of this amount, 33.7 percent was received in the market area. Thus, 16.5 percent of firm sales volumes (.49 x .337) were received in the market area. Consequently, 16.5 percent of firm sales volumes should be considered as being received in the market area and should be excluded from the MMBtu/Mile sales commodity factors in the Field Zone and 16.5 percent of firm sales demand determinants should be excluded from the [**188] MMBtu/Mile demand factors in the Field Zone.Panhandle did not include ISS volumes in throughput and did not use ISS volumes to derive allocation factors. When Panhandle does provide allocation factors using ISS volumes in accordance with this order, it should regard 33.7 percent of the ISS volumes as received in the market area since all of these sales were made from storage.F. Tariff matters-force majeureIn its restructuring proceeding, Panhandle proposed the force majeure provision which is currently in effect in its tariff. Section 20 of its General Terms and Conditions of its tariff provides that if Panhandle or the shipper is unable to perform the service agreement because of force majeure, n142 the obligation to pay reservation fees or [*61,412] capacity fees continues, but all other obligations are suspended and neither party is liable to the other for damages. The Commission reviewed and accepted Panhandle's force majeure tariff provision in Panhandle's restructuring proceeding. n143 It declined to require Panhandle to refund reservation charges when it was excused from performance due to force majeure. The Commission followed its holding in Northern Natural Gas Company. n144 [**189] There it stated, "We agree that if the interruption is [the pipeline's] fault the fees should be credited. However, all parties bear the risk of force majeure events and in such cases no fees should be credited." The Commission stated, however, that the parties could raise this issue in this proceeding.

n142 "Force majeure" is defined as

> any cause, whether of the kind herein enumerated or otherwise, not within the control of either Panhandle or Shipper claiming suspension, and which by the exercise of due diligence, either Panhandle or Shipper has been unable to prevent or overcome, including without limitation acts of God, the government including the issuance of rules or orders which serve to frustrate or prevent the performance of Panhandle, or a public enemy; strikes, lockouts, or other industrial disturbances; wars, blockades, or civil disturbances of any kind; epidemics, landslides, hurricanes, washouts, tornadoes, storms, earthquakes, lightning, fires, explosions, arrests, and restraints of governments or people; freezing of, breakage or accident to, or the necessity for making repairs or alterations to wells, machinery or lines of pipe; partial or entire failure of wells; and the inability of either Panhandle or Shipper to acquire, or the delays on the part of either of Panhandle or Shipper in acquiring, at reasonable cost and after the exercise of reasonable diligence: (a) any servitudes, rights of way grants, permits, or licenses; (b) any materials or supplies for the construction or maintenance of facilities; or (c) any permits or permissions from any governmental agency; if such are required to enable either of Panhandle or Shipper to fulfill its obligations hereunder.

Original Sheet No. 323, First Revised Volume No. 1.

[**190]

n143 61 FERC P 61,357 at p. 62,431; 62 FERC P 61,288 at p. 62,878 (1993); 64 FERC P 61,009 at p. 61,067 (1993).

n144 59 FERC P 61,379 (1992).

In the Initial Decision, the ALJ found that Panhandle had reduced its demand charges to its sales customers when force majeure events occurred (Exh. MoPSC-24) and that the Commission intended no-notice transportation to be comparable to the former sales service in this respect. Consequently, he held that it was unjust and unreasonable for Panhandle to impose this risk on affected no-notice transportation customers. n145 However, he viewed the Commission's decision in the restructuring proceeding that the risk of loss could not be transferred to the pipeline as dispositive. Accordingly, in order to ameliorate the situation of affected customers, he held that the risk of loss should be spread to all customers. The ALJ determined that Panhandle should give affected customers a credit for the demand charges for service they did not receive and impose a volumetric surcharge on all customers for the amount of the credit, less the return [**191] on equity and related taxes.

n145 Rate Schedule GDS, General Delivery Service, variously effective sheets numbered 81-85, First Revised Volume No. 1.

1. ExceptionsThe Association of Businesses Advocating Tariff Equity (ABATE) claims that the issue of demand charge credits was properly before the ALJ for a determination on the merits. It asserts that the Commission had clarified that the parties would be "free to raise this issue in Panhandle's current rate proceedings" n146 so that the ALJ should have reconsidered this issue.

n146 64 FERC P 61,009 (1993).

On the merits, ABATE and MGU object to both the ALJ's decision and Panhandle's tariff. They also take a broad view and consider interruptions of service in general. They claim that pipelines should be primarily responsible for their inability to provide service for any reason. They assert that a business expects to assume its own business risks and that it is unreasonable to require others to do so. They state that curtailing a firm customer's service creates an adverse financial impact on that customer and that it is unjust and unreasonable for the pipeline to curtail firm service but [**192] still collect revenues for service it has not performed. Thus, they claim that Panhandle should bear the risk of any service interruptions, just like any other business, and that it should do [*61,413] so with regard to all firm transportation, not just no-notice service. ABATE states that it is not aware of any force majeure provision in any commercial context that requires the performing party to continue to pay despite the other party's non-performance.ABATE claims that neither Panhandle's original tariff nor the Initial Decision carry out the Commission's policy in Northern Natural with regard to force majeure. Instead of all parties bearing the risk of force majeure events, it states that under Panhandle's original tariff, only customers bear the risk of force majeure events on both their own property and on Panhandle's system. Under the ALJ's credit/surcharge mechanism, ABATE states that only firm customers who are not no-notice customers bear the risk of force majeure failures to deliver their gas.ABATE suggests that the Northern Natural policy should be revised or clarified so that, in its view, all parties do, in fact, bear risk. ABATE advocates the following policy. Firm customers [**193] would continue to be obligated to pay demand charges if they are unable to take delivery of service due to a force majeure event occurring either downstream of the pipeline's delivery point to that customer or upstream of the pipeline's receipt point from that customer's gas seller or other transporter. Firm customers would not be obligated to pay demand charges when pipeline service is curtailed for any reason, including force majeure. The pipeline would be permitted to project force majeure-related losses as an expense as part of a general rate case based on test period experience and recover these costs in rates or factor the risk into its determination of return on common equity.Finally, ABATE, and MGU as well, object to the ALJ's demand charge credit/commodity surcharge as the wrong remedy for Panhandle's original tariff. They say it is unduly discriminatory. They point out that no-notice customers pay the same rates as other firm customers. n147 They argue that the Initial Decision relieves one class of customer from demand charge obligations while leaving other classes subject to those payments. In addition, it shifts financial responsibility for the unrecovered force majeure-related [**194] costs to other customers, including those who receive no demand charge relief. ABATE and MGU also claim that the credit/surcharge mechanism perpetuates undue preferences that were built into pre-Order No. 636 bundled sales service.

n147 No-notice customers receive combined firm transportation, gathering, and storage service. They are either EFT or SCT customers and have a storage agreement subject to Rate Schedule IOS. No-notice customers pay either EFT or SCT rates; IOS rates; and WS, PS, or FS rates as appropriate. Rate Schedule GDS, General Delivery

Servicer First Revised Sheet Nos. 81 and 83. The acronyms stand for: EFT–Enhanced Firm Transportation Service; SCT–Small Customer Transportation Service; IOS–In/Out Storage; WS–Winter Storage Service; PS–Peaking Storage Service; and FS–Firm Storage.

ABATE also addresses the policy concerns behind no–notice service. It states that no–notice service was intended to provide customers "the flexibility to meet unexpected changes in peak period needs by receiving gas up to daily contract entitlements on demand without nominating that amount or incurring penalties." B. on E. at p. 11. It sees the reason for no–notice service as providing [**195] "the flexibility to swing without adjusting nominations." Id. ABATE contends that the pipeline's ability to provide this flexibility and the customer's ability to swing are unaffected by the amount of demand charges a no–notice customer has to pay during a force majeure event. Therefore, it concludes that there is no need to provide no–notice service customers with demand charge relief during these events solely on the basis that they are no–notice customers.MoPSC seems to assert both that no–notice service customers should receive demand charge credits when Panhandle is unable to deliver gas for any cause and also [*61,414] that they should receive such credits when Panhandle is unable to deliver gas due to force majeure. It argues that the ALJ found that Panhandle had borne the risk of force majeure events under its pre–restructuring sales tariff (Exh. MoPSC–24) and that the Commission intended no–notice service to be comparable to the pre–restructuring sales service. It claims that these findings constitute good cause for modifying Panhandle's force majeure tariff.In its Brief Opposing Exceptions, MoPSC urges the Commission to affirm the Initial Decision's holding if it does not adopt [**196] demand charge credits. MoPSC claims that the Commission intended that no–notice service after restructuring should replicate the transportation service that was bundled with Panhandle's former sales service, and that Panhandle understood that "customers should be able to receive the same services [after restructuring], under the same economic conditions." Exh. MoPSC–29 at 0020859. It claims that prior to restructuring, Panhandle's sales tariff provided for reduced demand charges when Panhandle was unable to deliver gas. Exh. MoPSC–23 at p. 5; Exh. MoPSC–24, Rate Sch. G–2, Para. 6.2. It states that Panhandle's force majeure tariff provision (Exh. PE–171, General Terms and Conditions, para. 12) did not change that since it only provided for the payment of amounts that were "due" and the sales tariff provided that no demand charges were due if gas was not delivered. MoPSC also argues that under Panhandle's post–restructuring tariff, all parties do not bear the risk of force majeure events, as the Commission's policy requires, but that only Panhandle's customers bear the risk. At the same time, MoPSC alleges that Panhandle currently carries force majeure insurance which covers loss of revenue [**197] (Tr. 252–54) implying that it might recover demand charges and insurance proceeds at the same time.Panhandle claims that no–notice service customers should be required to pay demand charges when no–notice service is interrupted by force majeure events. It claims that affected sales customers have been obligated to pay demand charges under the force majeure provisions of its tariff for forty years. Exh. PE–171; n148 10 FPC 185, 220 (1951). It claims that it included this same policy in its open access transportation tariffs and PT–Firm and PT–Interruptible Rate Schedules, and continued it in its restructured tariff. Panhandle also states that the Commission held that its tariff is consistent with Commission policy. n149

n148 Paragraph 12, Force Majeure, General Terms and Conditions, (Original Sheet No. 40 (effective February 20, 1952) and First Revised Sheet No. 41 (effective July 1, 1991).)

n149 61 FERC P 61,357, accord, Florida Gas Transmission Company, 51 FERC P 61,309 (1990).

2. DiscussionThere are two procedural matters to resolve first. The Commission agrees with ABATE that the [**198] issue of demand charge credits for force majeure events was to be considered in this proceeding. The Commission stated as much in its July 2, 1993 restructuring order. n150 In addition, the Commission finds that the scope of the matter to be determined here is the payment of demand charges in the event of force majeure. The parties have concentrated primarily on the allocation of risk under force majeure, not under other circumstances. n151 Moreover, the Commission has already stated in Northern Natural that "if the interruption is [the pipeline's] fault the fees should be credited." n152

n150 64 FERC P 61,009 (1993).

n151 MoPSC's witness Mr. Rudolph testified on the "force majeure issue" which was the allocation of risk associated with force majeure events. Exh. MoPSC–23 at pp. 2–4.

n152 59 FERC P 61,379 at p. 62,461 (1992).

[*61,415] In addition, the Commission finds that its consideration here is not restricted by Northern Natural. Northern Natural is a pre–restructuring rate case. In part, it considered demand charge credits for firm transportation service that was available prior to the Commission's restructuring orders. [**199] Here, the service at issue is no–notice service. As discussed below, no–notice service is the transportation service that was embedded in bundled sales service. In addition,

unlike Northern Natural, here the Commission is considering the provision of transportation services in a restructured environment.Moreover, the entire discussion of such credits in Northern Natural reads as follows:

> Indicated Shippers request Northern be required to offer to credit reservation charges if the firm service is interrupted. We agree that if the interruption is Northern's fault the fees should be credited. However, all parties bear the risk of force majeure events and in such cases no fees should be credited.

Id. at p. 62,461. In this case, the Commission has a complete record and arguments on which to base a decision. Unlike Northern Natural, the record provides probative facts and argument as to why demand charges should be credited when Panhandle is unable to perform its obligations in force majeure situations.Mr. Rudolph, MoPSC's witness, testified that there is a risk of force majeure events on the Panhandle system. He cited flooding in the summer of 1993 and testified that it caused [**200] 300 feet of Panhandle's thirty–inch steel pipeline to float on top of Missouri flood waters. "As a result," he stated, "Panhandle removed approximately 8.5 miles of its pipeline from service." Exh. MoPSC–23 at p. 4. Panhandle's witness Mr. Grygar testified in rebuttal that these floods did not cause any interruption in firm service. Exh. PE–138 at p. 22. He also testified, "We have not had events of force majeure on the Panhandle system." Tr. 963. Although the risk to date has been small, the Commission finds that risk of force majeure events does exist on Panhandle's system. The question here then is how to allocate that risk.Prior to restructuring, Panhandle's bundled sales tariff read:

> 6. **ADJUSTMENT OF MONTHLY BILLS**. . . .
>
> 6.2 **Failure to Deliver Contract Demand.** If during one or more days in the billing month Seller is unable to deliver to Buyer, for any cause whatsoever, natural gas up to the Billing Demand established for the month, then the total Demand Charge shall be reduced by an amount computed as follows: Determine for each such day the number of Dt. which Seller was unable to deliver as above stated and multiply the sum of all such days' deficiencies by the [**201] currently effective charge (Sheet No. 3–A).

Exh. MoPSC–24, Rate Schedule G–2, Twentieth Revised Sheet No. 9, effective April 1, 1992 (emphasis supplied).At the same time, Panhandle's force majeure tariff read:**12. FORCE MAJEURE**

> Neither Seller nor Buyer shall be liable in damages to the other for any act, omission, or circumstances occasioned by or in consequence of any acts of God, [*61,416] strikes, lock–outs, acts of the public enemy, wars blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrests and restraints of rulers and peoples, civil disturbances, explosions breakage or accident to machinery or lines of pipe, temporary failure of gas supply, the binding order of any court or governmental authority, and any other cause, whether of the kind herein enumerated, or otherwise, not within the control of the one claiming suspension and which by the exercise of due diligence it is unable to prevent or overcome.Such causes or contingencies affecting performance shall not relieve Seller or Buyer of liability in the event of its concurring negligence or in the event of failure of either to use due diligence to remedy [**202] the situation and remove the cause in an adequate manner and with all reasonable dispatch, nor shall such causes or contingencies relieve either from its obligations to make payments of amounts then due hereunder.

Exh. PE–171, General Terms and Conditions, Original Sheet No. 40 (effective February 20, 1952) and First Revised Sheet No. 41 (effective July 1, 1991) (emphasis supplied).When read together, the Commission finds these tariff provisions excused a customer from paying charges during a force majeure event in which Panhandle was unable to deliver gas. Paragraph 6.2 of Rate Schedule G–2 excuses payment for any non–delivery at all. This would include non–deliveries due to force majeure. Paragraph 12 of the General Terms and Conditions requires a customer to continue to pay amounts that are due when a force majeure event occurs. No charges were due for gas that was not delivered. This result is bolstered by the standards for interpreting contracts. These standards give preference to an interpretation which gives a reasonable, lawful, and effective meaning to all the terms of a contract. Restatement (Second) of Contracts § 203 (a) (1981). If the force majeure provision were [**203] read as requiring payment of all charges, it would make Paragraph 6.2 of the rate schedule either ambiguous or void. Reading the force majeure provision as applying only to certain amounts—those due—enables both provisions to have meaning. In addition, specific terms are given greater weight than general language. Id. § 203 (c). Here, the terms in the rate schedule were specific terms that governed a particular service. The force majeure provision was contained in the General Terms and Conditions. The specific provisions of the rate schedule take precedence over the general provisions of the General Terms and Conditions. Consequently, the Commission finds that, prior to restructuring, the risk of non-delivery of gas to firm sales customers due to force majeure events was on Panhandle.The Commission finds that the cases on which Panhandle relies do not change this decision. Panhandle Eastern Pipe Line Co., n153 does not discuss Panhandle's force majeure provision. In the Appendix, however, it contains provisions regarding adjustments for sales demand charges in its Rate Schedules G-1, G-2, and G-3 n154 that reduce demand charges in the event Panhandle fails to deliver gas "for [**204] any cause whatsoever." These provisions are similar to those in Panhandle's Rate Schedules G-2 and SG-2, effective April 1, 1992. In Florida Gas, n155 shippers asked that they be excused from paying demand charges when they were unable to perform because of force majeure. The Commission determined that the pipeline should not have to forgo revenue in this [*61,417] situation because the events were unrelated to the pipeline's ability to perform. Florida Gas is concerned with force majeure events that prevent shippers from performing. It has no bearing on situations in which force majeure prevents the pipeline from performing.

n153 10 FPC 185 (1951).

n154 Rate Schedule G-1 is General Service-Eastern Zone (Indiana, Ohio and Michigan); G-2 is General Service-Central Zone (Missouri and Illinois); G-3 is General Service-Western Zone (Texas and Kansas).

n155 51 FERC P 61,309 (1990).

Should Panhandle's liability for force majeure events carry over to no-notice service? No-notice service is described in 18 C.F.R. § 284.8(a) (4). That section requires a pipeline that provided firm sales service on a no-notice basis on May 18, [**205] 1992, and now provides transportation to provide "a firm transportation service under which firm shippers may receive delivery up to their firm entitlements on a daily basis without penalty." Order No. 636, 57 Fed. Reg. 13,267, VII.D. "No-Notice" Transportation Service (April 16, 1992). n156

n156

> "Firm entitlements" refers to the firm shippers' daily right to receive transportation service . . . . Under 284.284(b) of the regulations adopted by Order No. 636, the sales customer's firm rights are converted to an equivalent amount of firm transportation service. Hence, firm entitlements means the converted firm entitlements to which a shipper is entitled to receive no-notice transportation service under Order No. 636.

Order No. 636-A, 57 Fed. Reg. 36,128, V.D.4. The Meaning of Firm Entitlement.

The Commission adopted no-notice transportation in Order No. 636 as a result of customer concerns about reliability. Order No. 636, 57 Fed. Reg. 13,267, 13,269 (April 16, 1992). No-notice service was formulated "in response to those who have expressed a particular concern about reliability during [**206] peakperiods." No-notice transportation provided for the delivery of gas on demand up to the amount of firm daily entitlements without nominations and without daily balancing and scheduling penalties. The Commission stated that no-notice service would "enable pipeline customers to continue to receive unnominated volumes to meet unexpected requirements" such as unexpected changes in temperature. Thus, stated the Commission, pipeline customers "will be able to receive varying volumes of gas to meet their fluctuating needs during a twenty-four hour period." 57 Fed. Reg. at p. 13,286. The Commission anticipated that no-notice service "will enable a customer to receive its natural gas supplies in a fashion as reliable as the customer had been receiving under a bundled, city-gate service . . . ." n157 Under no-notice transportation, the customer's ability to just "'turn on the valve' . . . would be the same as its current ability under bundled service." The result would be the customer could "meet the demand of its system as it has historically done . . . ." 57 Fed. Reg. at p. 13,288 (emphasis supplied).

n157

> The Commission, pursuant to NGA section 5, found bundled, city-gate, firm sales service to be unduly discriminatory and preferential. As a remedy, the Commission determined that a just and reasonable practice would be the separate provision of no-notice transportation service embedded within the bundled sales service. The Commission found that this requirement was necessary so that a customer could receive its natural gas supplies in a fashion as reliable as the customer had been receiving under

a bundled, city-gate service, with the added advantage of providing greater opportunities to purchase that supply at competitive prices from other sellers.

Order No. 636-A, 57 Fed. Reg. 36,128, III.A.2. Natural Gas Act Authority (emphasis supplied).
[**207] In Order No. 636-A, the Commission noted that the pipeline's transportation service obligation to its bundled sales customers continued. In other words, a pipeline had to provide no-notice transportation to a customer if it had provided that customer with bundled sales service. 57 Fed. Reg. 36,128, III.A.2 Natural Gas Act Authority. The purpose of this requirement was to "ensure that pipeline customers can continue to get guaranteed deliveries to meet their peak needs . . . ." Id., III. B.2. Anticompetitive finding. The Commission clarified that "former bundled sales customers are entitled to receive the same quality and quantity of transportation service they were previously receiving as part of their sales service before unbundling." Id. The central point, said the Commission, was that "the no-notice transportation must be at least as reliable as [*61,418] the service the bundled sales customers were actually receiving." Id. n158 The Commission noted in Order No. 636-A that it had subjected customers to risks associated with gas supply. It stated that "shippers must take the initiative in obtaining gas and therefore bear the responsibilities and risks of obtaining [**208] supply." n159 However, it was the pipeline's role to provide "the capacity and operational flexibility necessary to ensure no-notice delivery of gas supplies owned by the pipeline's customers." n160

n158 "To conclude, the Commission believes that through such measures [as operational flow orders], the no-notice transportation service will prove as reliable as the no-notice aspect of bundled, city-gate, firm sales service." 57 Fed. Reg. 57,911, II.A.1. Natural Gas Act Authority (December 8, 1992).

n159 57 Fed. Reg. 57,911, II.A.1. Natural Gas Act Authority (December 8, 1992).

n160 57 Fed. Reg. 36,128, V.D.1. Nature and Definition of No-Notice Transportation (August 12, 1992).
In its restructuring orders, the Commission regarded no-notice service customers as responsible for risks involving gas supply. It also regarded the pipeline as responsible for delivery of gas to no-notice customers. This was necessary to make the service as reliable as it was previously. The Commission finds that reliability is a definitive characteristic of no-notice service. The Commission also finds that liability [**209] for force majeure events is an essential aspect of reliability. If a force majeure event occurs on the pipeline and it is unable to deliver gas, the no-notice customer must obtain other transportation. The ability to obtain substitute transportation is crucial to the customer who does not receive gas because of a force majeure event on Panhandle's system. This ability would be diminished if the customer had to continue to pay Panhandle and also pay the alternate transporter at the same time. Having to make two such outlays simultaneously would thus decrease the reliability of the customer's gas service. As the Commission intended no-notice service to have the same reliability as the transportation component of the former bundled sales service, and as liability for force majeure events on the pipeline is significantly related to the reliability of transportation of gas, the Commission holds that the risk of non-delivery of gas to no-notice service customers due to force majeure events is on Panhandle, as it was when these customers received bundled sales service. This means that if a force majeure event occurs on Panhandle's system which makes it impossible for Panhandle to deliver [**210] gas to no-notice service customers, Panhandle must give these customers demand charge credits for transportation for the gas that is not delivered.The Commission agrees with ABATE and MGU that it would be unduly discriminatory for Panhandle to collect surcharges from all customers to support force majeure demand charge credits available only to no-notice service customers. Other customers would be charged for benefits that are received only by no-notice customers whose service is interrupted as a result of a force majeure event. Thus, the Commission reverses the ALJ's holding that Panhandle may recover the costs of any demand charge credits actually given to no notice customers through a special volumetric surcharge to its other customers. However, in its next rate case, Panhandle may seek to include in its cost of service, and allocate to its no notice service, a projection, based on test period data, of a representative level of costs resulting from offering demand charge credits to no notice customers. Such costs may be either the costs of credits actually given to no notice customers during the test period or the cost of insurance purchased by Panhandle to cover the loss of [**211] revenue during a force majeure event. n161

n161 Panhandle's witness Mr. Tindall indicated that in 1994, Panhandle obtained insurance to cover loss of revenue. Tr. 252-54. Mr. Grygar testified that this insurance was for catastrophic events that covered physical damage. Tr. 966-68.

[*61,419]

The Commission orders:(A) The exceptions are granted or denied as discussed in the body of this order.(B) The Initial Decision is affirmed, modified, or reversed, as indicated in this order.(C) The issue of the appropriate adjustment to Panhandle's rate design volumes to reflect non-affiliate discounts is remanded to the ALJ for further proceedings consistent with the discussion in this order.By the Commission. Commissioners Hoecker and Massey dissented in part with separate statements attached.Lois D. Cashell, Secretary.

DISSENTBY: HOECKER (In Part); MASSEY (In Part)

DISSENT:

William J. HOECKER and James J. MASSEY, Commissioners, dissenting in part:To the extent today's order reverses the Judge's Initial Decision to require 90 percent of the revenues from Panhandle Eastern Pipe Line Company's (Panhandle) short-term firm service to be credited to firm shippers, we dissent. On the basis of both the factual record and policy, [**212] the Judge made a thoughtful ruling and should be upheld. n162 The majority's discussion of the crediting issue, in contrast, is conclusory and not based on record support.

n162 69 FERC P 63,013 (1994) at pp. 65,103-06

Crediting of revenues serves a limited purpose. It is largely a transitionary tool by which the Commission can ensure that cost-based rates remain just and reasonable when a pipeline's use of its system is significantly changing between full section 4(e) rate proceedings. n163 We do not seek to inhibit development of innovative services but, so long as rates are based on costs, this Commission must be reasonably confident that the relationship between costs and rates is maintained. Here, Panhandle is charging for a service to which it assigns no costs or volumes in developing its rates. Short-term firm is thus a very lucrative service offering for Panhandle.

n163 The same issues arise in Docket No. RP95-397-000, where Panhandle proposes to implement a new Limited Firm Transportation (LFT) rate schedule. We approve LFT service without revenue crediting; however, unlike this case, there is insufficient record evidence to justify crediting, and it is uncertain that the service will even be utilized. As noted in the LFT order, the initiation of LFT service "does not appear to constitute a post-test period change of any greater significance than commonly occurs following the filing of a rate case . . . ." Slip op. at p. 9.

[**213] The Commission did not require crediting of short-term firm revenues in Panhandle's restructuring orders. However, it did invite Panhandle's customers to raise this issue in this rate proceeding, and those parties have convincingly demonstrated on this record that: (1) there are no costs associated with short-term firm represented in the existing firm rates; (2) short-term firm competes with IT and capacity release in the secondary market; and (3) without crediting, the Commission's goal of providing parties a means of mitigating the effects of straight fixed variable rates through capacity release would be frustrated. If, in Panhandle's next rate case, it were to allocate appropriate costs associated with its provision of short-term firm service, thereby reducing firm rates to all customers, crediting would arguably be unnecessary. Until then, crediting short-term firm revenues to other firm customers is appropriate.Short-term firm transportation service is an effective new response to an increasingly short-term market. Like other new pipeline services, this service increasingly competes with capacity release and interruptible service. Yet, under current posting and bidding requirements, [**214] for example, capacity release is disadvantaged in comparison [*61,420] to other services, that can be obtained directly from the capacity holder. Since no costs are assigned to short-term firm service, benefits that might otherwise go to firm shippers through lower rates, capacity release revenues, or crediting of interruptible revenues, will now remain with the pipeline. As the Judge found, absent crediting, Panhandle's accounting for short-term firm revenues is unjust and unreasonable. n164

n164 Id. at p. 65,106.

For these reasons, we respectfully dissent to the portion of today's order addressing short-term firm crediting. James J. HoeckerCommissioner William L. MasseyCommissioner

HOECKER, Commissioner, dissenting in part:Panhandle Eastern Pipe Line Company seeks to include charitable contributions in its rates. For the reasons articulated previously, I dissent to the flowthrough of such costs to ratepayers. n165

n165 See Panhandle Eastern Pipe Line Company, 71 FERC P 61,228 (1995) at pp. 61,872-73 and Williston Basin Interstate Pipeline Company, 72 FERC P 61,074 (1995) at pp. 61,387-89.

James J. [**215] HoeckerCommissioner