141 FERC ¶ 61,223
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

Texas Gas Transmission, LLC Docket No. RP12-820-000

Order Accepting Tariff Records Subject To Conditions

(Issued December 20, 2012)

1. On June 28, 2012, Texas Gas Transmission, LLC (Texas Gas) filed certain tariff records[1] to be effective August 1, 2012, to revise its tariff provisions pertaining to reservation charge credits to be consistent with Commission policy. Texas Gas's filing was protested by a number of parties, and Texas Gas filed an answer (July answer) and agreed to make certain modifications to address protesters' concerns. On July 31, 2012 the Commission issued an order[2] (the July 2012 Order) which set forth the issues raised by protesters and Texas Gas' response to these issues. The order accepted and suspended the tariff records, subject to refund and further Commission action, to be effective January 1, 2013, or an earlier date established in a subsequent Commission order in this proceeding. The order further provided that parties could file responses to Texas Gas' July answer. A number of parties filed responses, and on August 31, 2012, Texas Gas filed a motion to answer and answer to the responses.[3] For the reasons discussed below, the Commission accepts the revised tariff records effective January 1, 2013, subject to

[1] Texas Gas Transmission, LLC, FERC NGA Gas Tariff, Tariffs; Section 1, Table of Contents, 6.0.0; Section 5.12, Rate Schedules - FSS, 4.0.0; Section 6.9, GT&C - Fuel, and Other Rates and Charges, 9.0.0; Section 6.24.4, GT&C - Misc Provisions - Force Majeure, 2.0.0; Section 6.25, GT&C - Demand Charge Credits, 7.0.0; Section 6.26, GT&C - List of Non-Conforming Service Agreements, 0.0.0.

[2] *Texas Gas Transmission,* LLC, 140 FERC ¶ 61,083 (2012).

[3] Rule 213(a)(2) of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.213(a)(2) (2012)) prohibits answers unless ordered by the decisional authority. In this case, the Commission will accept Texas Gas's August Answer because it may assist the Commission in its decision-making process.

conditions. Texas Gas is directed to file revised tariff records or provide further information and, pursuant to section 5 of the Natural Gas Act (NGA), either to modify certain tariff provisions concerning reservation charge credits or show cause why it should not be required to do so, as discussed below.

I. Background

2. In *Natural Gas Supply Association, et al.*,[4] the Commission encouraged interstate pipelines to review their tariffs to determine whether their individual tariff is in compliance with the Commission's policy concerning reservation charge credits, and, if not, make an appropriate filing to come into compliance. In general, the Commission requires all interstate pipelines to provide reservation charge credits to their firm shippers during both *force majeure* and non-*force majeure* situations. The Commission requires pipelines to provide full reservation charge credits for outages of primary firm service caused by non-*force majeure* events. The Commission also requires the pipeline to provide partial reservation charge credits during *force majeure* outages, so as to share the risk of an event for which neither party is responsible. Partial credits may be provided pursuant to: (1) the No-Profit method under which the pipeline gives credits equal to its return on equity and income taxes starting on Day 1, or (2) the Safe Harbor method under which the pipeline provides full credits after a short grace period when no credit is due (i.e., 10 days or less).[5]

3. The Commission has defined *force majeure* outages as events that are both unexpected and uncontrollable. The Commission has held that routine, scheduled maintenance is not a *force majeure* event, even on "pipelines with little excess capacity"[6] where such maintenance may require interruptions of primary firm service. That is because, even if such outages are considered to be uncontrollable, they are expected. The U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) affirmed this policy in *North Baja Pipeline, LLC v. FERC*,[7] stating:

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[4] 135 FERC ¶ 61,055, at P 2 (2011) (*NGSA*).

[5] *See, e.g.*, *Tennessee Pipeline Co.*, Opinion No. 406, 76 FERC ¶ 61,022 (1996), *order on reh'g*, Opinion No. 406-A, 80 FERC ¶ 61,070 (1997), *as clarified by*, *Rockies Express Pipeline LLC*, 116 FERC ¶ 61,272, at P 63 (2006) (*Rockies Express*). The Commission has also stated that pipelines may use some other method which achieves equitable sharing in the same ball park as the first two methods.

[6] *El Paso Natural Gas Co.*, 105 FERC ¶ 61,262, at 61,350 (2003).

[7] *North Baja Pipeline, LLC v. FERC*, 483 F.3d 819, 823 (D.C. Cir. 2007), *affg*,

(continued…)

> Although some scheduled maintenance interruptions may be uncontrollable, they certainly are not unexpected. There is nothing unreasonable about FERC's policy that pipelines rates should incorporate the costs associated with a pipeline operating its system so that it can meet its contractual obligations.

4. As the Commission requested in *NGSA*, Texas Gas reviewed the reservation charge crediting provisions in its tariff. As a result of such review Texas Gas' June filing proposed to modify its tariff provisions related to reservation charge credits[8] to customers during instances of *force majeure* and all maintenance activities and other non-*force majeure* events, consistent with current Commission policy. The filing included a proposed modification to the definition of *force majeure* in section 6.24.4 of its General Terms and Conditions (GT&C) to address new pipeline safety and integrity management obligations, and a new proposed section 6.25[9] dedicated to reservation charge credits. Texas Gas asserted that its proposed changes are similar to those approved for other pipelines citing *Midwestern Gas Transmission Co.*[10]

5. Texas Gas stated that it was proposing to modify its tariff to provide reservation charge credits for *force majeure* events utilizing a modified version of the Safe Harbor Method.[11] Under its proposal the customer remains liable for all amounts due for the first

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North Baja Pipeline, LLC, 109 FERC ¶ 61,159 (2004), *order on reh'g*, *North Baja Pipeline, LLC,* 111 FERC ¶ 61,101 (2005) (*North Baja*).

[8] Texas Gas employs the term "demand charge credits" for reservation charge credits.

[9] This section was formerly the "List of Non-Conforming Agreements." Such list has been relocated to section 6.26 of the Tariff.

[10] *Midwestern Gas Transmission Co.*, 137 FERC ¶ 61,257 (2011) (*Midwestern*), *order on compliance*, Docket No. RP11-2254-002 (April 2, 2012) (unpublished letter order).

[11] The Commission permits pipelines to credit under two methods, the Safe Harbor method, and the No Profit method. Under the Safe Harbor method reservation charges must be credited in full to the shippers after a short grace period, 10 days or less, when no credit is due the shipper. Under the No-Profit method the pipeline provides for partial refunds starting on the first day of the interruption in service, covering the portion of the pipeline's reservation charge that represents the pipeline's return on equity and associated income taxes.

twenty days of a *force majeure* event. Following this twenty-day grace period, Texas Gas will provide reservation charge credits for the "Force Majeure Average Usage Quantity" as defined in new GT&C section 6.25 that Texas Gas failed to deliver to the customer's primary delivery point(s) due to the *force majeure* event provided that the customer was not utilizing such quantity for delivery on a non-primary basis. Texas Gas will determine the Force Majeure Average Usage Quantity based upon nominations over the seven gas days prior to the first gas day of the *force majeure* event.

6. Texas Gas stated that it was requesting a longer safe harbor period than the customary 10 day safe harbor period because it has a non-Straight Fixed Variable (SFV) rate design that includes almost seven percent of its transmission fixed costs in its usage rate. Since the usage charge is only billed on volumes actually transported, even with a safe harbor in place Texas Gas may not recover up to approximately seven percent of its fixed costs during the grace period because it will not be collecting some or all of its usage charge.

7. Texas Gas also proposed to provide full reservation charge credits for non-*force majeure* events, including maintenance events not included in the revised definition of *force majeure* described below. Texas Gas would provide reservation charge credits for any "Maintenance Average Usage Quantity" that it failed to deliver during a non-*force majeure* event provided the customer was not utilizing such quantity for delivery on a non-primary basis. Texas Gas would determine the Maintenance Average Usage Quantity based upon nominations over the seven gas days prior to the first gas day of the maintenance and non-*force majeure* event.

8. Texas Gas also proposed to change its definition of *force majeure* in section 6.21.5(2) to address new pipeline safety and integrity management obligations resulting from the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (2011 Act). Specifically, Texas Gas proposed to include in the definition of *force majeure* "any testing, repair, replacement, refurbishment, or maintenance activity, including scheduled maintenance, to comply with the [2011 Act] requirements issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA) [of the United States Department of Transportation (DOT)] pursuant to the 2011 Act, [and] requirements resulting from PHMSA's ongoing gas pipeline rulemaking proceedings." Texas Gas contended that these initiatives are expected to result in an increase in operations and maintenance costs and greater pressure on pipelines to perform upgrades and replacements. Texas Gas further contended that, while the exact nature of any additional pipeline safety requirements is undetermined, disruptions in service and pipeline infrastructure modernization costs are likely to be substantial.

9. Texas Gas stated that the Commission's current *force majeure* policy on reservation charge crediting stems from the D.C. Circuit's order in *North Baja* affirming the Commission's holding that scheduled maintenance is not a *force majeure* event. However, Texas Gas contended that recent pipeline incidents, new legislation, and

ongoing rulemakings have resulted in increased scrutiny of pipeline operations, and this scrutiny is evident in several DOT and PHMSA initiatives and actions by the Executive Branch.[12] Texas Gas argued that any resulting outages are not the routine scheduled maintenance considered in *North Baja*. Texas Gas asserted that such service disruptions are due to broad government-initiated actions that are not reasonably in control of pipelines and which represent a sea change for the natural gas industry. Texas Gas contended that, in *North Baja*, the court's rationale for upholding the Commission's general exclusion of routine maintenance and testing outages from the definition of *force majeure* was that a pipeline's rates "incorporate [the] costs associated with a pipeline operating its system so that it meet its contractual obligations."[13] Texas Gas argues that this rationale does not apply to these outages as pipelines' existing rates do not and cannot incorporate the costs associated with complying with the new requirements.

10. Protests to the June filing were filed by a number of parties.[14] The protests generally argued that Texas Gas' proposal conflicted with the Commission's policy and precedents regarding reservation charge crediting policy. On July 13, 2012, Texas Gas filed its July answer (Answer) and proposed several alternatives to its original proposal which are discussed below.

11. The July 2012 Order stated that since the protestors had raised a number of issues that warrant further consideration, and Texas Gas had filed a detailed Answer to the protests and had also proposed various modifications to its original proposal, protestors would be afforded an opportunity to respond to Texas Gas' Answer. Atmos, AEM, Devon, PSEG ERT, and SESC filed responses to that Answer. Texas Gas filed an answer to the responses limited to the definition of *force majeure*. We will address the issues in light of all the filings to date.

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[12] Transmittal Letter at 7-8.

[13] (Citing *North Baja*, 483 F.3d 819, 823).

[14] Atmos Energy Corporation (Atmos); Atmos Energy Marketing LLC (AEM); Devon Gas Services, L.P. (Devon); Indicated Shippers; PSEG Energy Resources & Trade, LLC (PSEG ERT); Tennessee Valley Authority (TVA); Duke Energy Ohio, Inc. (DEO); Southwestern Energy Services Company (SESC); and the Western Tennessee Municipal Group, the Jackson Energy Authority, City of Jackson, Tennessee, and the Cities of Carrollton and Henderson, Kentucky (Cities). Comments were filed by Louisville Gas and Electric Company (Louisville); Pivotal Utility Holdings d/b/a Elizabethtown Gas (ETG); and ProLiance Energy, LLC (ProLiance).

II Discussion

12. The Commission accepts the revised tariff record listed in footnote 1 of this order to become effective January 1, 2013, subject to conditions. As discussed below, the Commission requires Texas Gas to file revised tariff records and provide further information and, pursuant to NGA section 5, directs Texas Gas to make certain changes in the reservation charge crediting provisions in its tariff or explain why it should not be directed to do so.

A. Outages to Comply With the 2011 Act and PHMSA Rulemakings as *Force Majeure* Events

1. Texas Gas's Proposal

13. Texas Gas proposes to change its definition of *force majeure* in section 6.21.5(2) to include outages necessary to comply with the 2011 Act and PHMSA's ongoing gas pipeline rulemakings. Specifically, Texas Gas proposes to include in the definition of *force majeure* "any testing, repair, replacement, refurbishment, or maintenance activity, including scheduled maintenance, to comply with the [2011 Act] requirements issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the United States Department of Transportation (DOT) pursuant to the 2011 Act, [and] requirements resulting from PHMSA's ongoing gas pipeline rulemaking proceedings."

2. Positions of the Parties

14. In its transmittal letter and its Answer, Texas Gas argued that its proposal to amend its definition of *force majeure* to include service interruptions associated with compliance with the 2011 Act is just and reasonable.[15] Texas Gas asserted that it is appropriate for it and its shippers to share the risk of such service interruptions pursuant to the well-established Safe Harbor Method applicable to other *force majeure* outages. Texas Gas argued that the 2011 Act and PHMSA's ongoing rulemaking proceedings will result in significant, new safety requirements, increasing the risk of service disruptions which cannot be considered "routine" and over which the pipeline will have little control.

[15] Texas Gas contends that the Commission must accept Texas Gas' proposal, if the Commission determines that it is just and reasonable, regardless of whether other tariff or rate mechanisms are also just and reasonable or it has approved different provisions for other pipelines (citing *Columbia Gas Transmission Corp.*, 124 FERC ¶ 61,122, at P 26 (2008) (citing *Western Resources, Inc. v. FERC*, 9 F.3d 1568, 1578 (D.C. Cir. 1993), and *Consolidated Edison Co. v. FERC*, 165 F.3d 992 (D.C. Cir. 1999)), *reh'g denied*, 133 FERC ¶ 61,217 (2010)).

15. Texas Gas stated that in August 2011 PHMSA issued an Advance Notice of Proposed Rulemaking (ANOPR),[16] requesting comment on various potential changes in PHMSA's gas pipeline safety regulations. Texas Gas stated that PHMSA requested comment on strengthening of PHMSA's existing integrity management (IM) regulations, expanding the application of those regulations beyond High Consequence Areas (HCAs),[17] strengthening criteria for pipeline assessment tools, modifying repair criteria, and revising data collection requirements. PHMSA also requested comment on adding new requirements concerning corrosion control, weld seams, Maximum Allowable Operating Pressure (MAOP), and the use and location of certain mainline valves. Texas Gas stated that PHMSA is expected to issue multiple proposed rules on the issues covered by the ANOPR and these will likely require additional facility testing and upgrades, which will disrupt service.

16. Texas Gas also stated that the 2011 Act, which the President signed into law on January 3, 2012, will likely lead to significant service disruptions. Specifically, Texas Gas asserted that the provisions of section 23(a) of the 2011 Act adding section 60139, Maximum Allowable Operating Pressure, to Chapter 601 of Title 49 of the United States Code will likely cause PHMSA to take actions that will disrupt pipeline service. Texas Gas stated that new section 60139(a) requires pipelines to verify the records of pipeline segments in Class 1 and Class 2 HCAs and Class 3 and Class 4 locations[18] to confirm their established MAOP. New section 60139(b) requires pipelines to report by July 3, 2012 those pipeline segments for which MAOP cannot be confirmed with records. Texas Gas pointed out that new section 60139(c)(1) provides that, after receiving this information, PHMSA must require the pipeline to reconfirm a MAOP. Texas Gas asserted that reconfirmation could require in-line inspection, or other alternative tests of Texas Gas's pipeline which could result in disruptions to pipeline service. Texas Gas also pointed out that new section 60139(c)(2) authorizes PHMSA to take interim measures until MAOP can be reconfirmed and such actions could involve pressure cuts reducing the pipeline's capacity.

17. Texas Gas stated that section 23 of the 2011 Act also requires PHMSA to issue regulations to require strength testing of previously-untested gas pipelines in HCAs operating at a pressure of greater than 30 percent of specified minimum yield strength.

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[16] (Citing 76 FR 53086 (August 25, 2011)).

[17] An HCA is a location which is defined in the pipeline safety regulations as an area where pipeline releases would have greater consequences to the health, safety, or environment.

[18] Basically, these are areas with greater population density.

Texas Gas stated that such testing could include pressure testing, in-line inspections, and other alternative testing methods and could result in additional disruptions in pipeline service.

18. In addition to the 2011 Act's requirements concerning MAOP, Texas Gas maintained that PHMSA is required by the 2011 Act to conduct studies to help determine whether to expand the scope of integrity management requirements or to require the use of automatic or remote-controlled shut off valves. Texas Gas stated that PHMSA's existing integrity management program covers only about seven percent of all gas transmission pipelines, but portions of the 2011 Act have the potential to apply to all gas transmission pipelines. Texas Gas also maintained that, if PHMSA determines that such changes are appropriate, PHMSA has the discretion to initiate a rulemaking to implement them.

19. Texas Gas asserted that the risk of outages under the new pipeline safety requirements is sufficiently detailed to provide certainty as to the range of impacts and is not speculative. Texas Gas further contended that any such outages should be considered outside the control of the pipeline and thus qualify as *force majeure* events for which cost sharing is appropriate, contending that the costs of such outages are not currently included in their rates. Texas Gas further asserted that its proposed risk sharing mechanism will not provide an incentive to prolong outages because it will have an incentive to keep outages to the shortest possible duration to reduce the amount of reservation charge credits after the 10-day safe harbor grace period.

20. Texas Gas contended that the service disruptions anticipated to result from the 2011 Act and pending PHMSA rulemakings were not contemplated prior to the 2011 Act and are not accounted for in Texas Gas's existing rates or the Commission's existing *force majeure* policy. Texas Gas argued that any rate changes through a general section 4 rate case or adjustment of billing determinants and return on equity would only take place on a prospective basis. Texas Gas maintained that until it has operated under any increased regulatory requirements for a transitional period, including those costs in its rates would be difficult because the outages would not be reflected in test period data. Texas Gas asserted that the exact level of service interruptions resulting from the new requirements is unknown, and a proposal to include their costs in its rates could potentially be rejected on the ground that such interruptions are speculative and non-recurring events, i.e., such as interim pressure reductions. Texas Gas asserts that resolution through a general section 4 rate case ignores the realities of the current natural gas market, and it likely would be unable to recover any increased rate because of competitive circumstances.

21. In the alternative, Texas Gas offered to limit its equitable sharing proposals to a transitional period outside its *force majeure* provisions. Texas Gas proposes a transitional period when the costs of outages caused by increased regulatory requirements are not reflected in its rates. Texas Gas contended that treating outages due to the 2011

Act as *force majeure* events for at least a transitional period is necessary to address their cost recovery concerns.

22. In their Responses, the respondents generally argue that the proposal to modify the definition of *force majeure* conflicts with Commission and judicial precedents, including *North Baja*, that classify outages for scheduled maintenance as non-*force majeure* events. They also point out that PHMSA has not yet determined what requirements will be necessary for pipelines to comply with the 2011 Act and that the Act does not require PHMSA to issue any regulations until July 3, 2013. Therefore, the respondents contend that Texas Gas has not presented any evidence that it will be unable to provide primary firm service as a result of the possibility of future regulations which have not yet been enacted.

23. The respondents argue that Commission policy requires that *force majeure* events must be both uncontrollable and unexpected. They contend that outages for compliance with the 2011 Act are not unexpected, as evidenced by Texas Gas's instant request. The respondents also assert that the details of how Texas Gas manages compliance with any new requirements resulting from the 2011 Act, including when and where outages occur is likely to be in the control of the pipeline. The respondents further assert that testing and maintenance required by government regulation are part of a pipeline's duties under a certificate of service and are not appropriately considered a *force majeure* event. Some respondents argue that *North Baja* only stated that a pipeline's rates should incorporate the costs associated with meeting its contractual obligations but did not require including such costs as a requirement for crediting. The respondents also argue that, if Texas Gas's rates are insufficient to recover those costs it may file pursuant to section 4 for a rate increase.

24. Respondents also contend that, if Texas Gas is unable to verify its records and confirm the MAOP of certain pipeline segments, as required by section 23(a) of the 2011 Act, that could be the result of its own negligence in failing, for example, to keep proper records or conduct appropriate tests in the past. Respondents assert that, in such circumstances, any outages required to reconfirm MAOP could not qualify as no-fault, *force majeure* events for which only partial credits are required.

25. In its Answer to Responses, Texas Gas argues that its new obligations are not speculative since PHMSA is actively developing regulations to implement the 2011 Act. Texas Gas asserts that a significant expansion of PMSHA regulation is reasonably foreseeable and could result in service interruptions. Texas Gas further asserts that, in any case, shippers will not be harmed if there are no disruptions. Texas Gas argues that interruptions are not, and could not have been, included in its rates and, therefore, its proposal is not inconsistent with the outages considered in *North Baja* since these outages are not provided for in its existing rates.

26. Texas Gas also states that it could be required to reconfirm MAOP on certain portions of its system despite having followed all applicable regulatory requirements, and thus outages required for such reconfirmation would not be attributable to any negligence on its part. It points out that neither the pipeline safety laws nor PHMSA regulations required Texas Gas to retain record of the original design, installation, construction, initial inspection and initial testing specifications of pipeline facilities built before August 19, 1970.[19] It also stated that it has set the MAOP of some of its pre-1970 pipeline at historical high operating pressures, as permitted by PHMSA regulations.[20]

3. Commission Determination

27. The Commission finds that Texas Gas's proposal to revise its definition of *force majeure* to include all testing, repair, replacement, refurbishment, or maintenance activity required to comply with the 2011 Act and ongoing PHMSA rulemaking proceedings is overbroad. With one exception, the nature and timing of any new safety requirements PHMSA may adopt pursuant to the 2011 Act or ongoing PHMSA rulemakings is too speculative at this time to justify modifying Commission policy to treat any outages resulting from such new requirements as *force majeure* events. However, for the reasons discussed below, we will allow partial reservation charge crediting for a transitional two-year period for outages due to orders PHMSA may issue pursuant to section 60139(c) of Chapter 601 of Title 49, as added by section 23 of the 2011 Act. This determination is without prejudice to Texas Gas filing a proposal to allow equitable sharing of credits resulting from other new safety requirements PHMSA may adopt, after the nature and timing of such new requirements becomes sufficiently clear to allow consideration of whether such a proposal is just and reasonable.

Safety Requirements Other Than Those Related to MAOP

28. Aside from the 2011 Act's provisions concerning MAOP, Texas Gas focuses primarily on potential new regulations concerning integrity management programs and remote or automatic shut-off valves in order to support its proposal to revise its definition of *force majeure*. However, as discussed below, it is unclear at the present time what changes, if any, PHMSA may make with respect to its existing regulations concerning integrity management and shut-off valves. Nor do any such changes appear likely to take effect before 2014, at the earliest. In these circumstances, Texas Gas cannot show that its proposal to provide only partial reservation charges for outages that may result from whatever regulations PHMSA may adopt on these subjects is just and reasonable.

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[19] (Citing 49 U.S.C. § 60104(b)).

[20] (Citing 49 C.F.R. § 192.619(c) (2012)).

29. PHMSA adopted its first integrity management regulations pursuant to the Pipeline Safety Improvement Act of 2002 (2002 Act), which provided for PHMSA to issue regulations requiring pipelines to implement integrity management programs for pipeline segments in HCAs. Those regulations took effect on January 14, 2004,[21] and specify how pipeline operators must identify, prioritize, assess, evaluate, repair, and validate the integrity of gas transmission pipelines in HCAs as part of their routine, periodic maintenance activities. Shortly after those regulations took effect, the Commission rejected a pipeline's proposal to treat outages resulting from PHMSA's integrity management regulations as *force majeure* events.[22] The Commission held that an outage due to periodic maintenance required by government regulations for the safe operation of the pipeline "is a necessary non-*force majeure* event within the control of the pipeline."[23] In subsequent orders, the Commission has explained that testing and maintenance required by government regulation are a part of the service provider's duties under a certificate of public convenience and necessity and thus are not appropriately considered a *force majeure* event or otherwise exempted from the requirement for full reservation charge crediting.[24]

30. In the ANOPR, PHMSA sought comments on whether the existing integrity management regulations should be strengthened. For example, PHMSA requested comment on whether the definition of a HCA should be modified to include more miles of pipeline; whether some integrity management requirements should be imposed on pipelines outside of HCAs; whether repair criteria for both HCA and non-HCA areas should be strengthened; whether in-line inspection methods, including pigging, should be required whenever possible; revising the requirements for collecting, validating, and integrating pipeline data; requiring the use of automatic and remote controlled shut off

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[21] *See Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines),* 68 FR 69778 (December 15, 2003).

[22] *See Florida Gas Transmission Co.*, 107 FERC ¶ 61,074, at PP 19 and 28-29 (2004).

[23] *Id*., P 29.

[24] *Orbit Gas Storage, Inc.*, 126 FERC ¶ 61,095, at P 68 (2009); *See also Natural Gas Pipeline Co. of America*, 106 FERC ¶ 61,310, at P 15 (2004) (*Natural*); *Tarpon Whitetail Gas Storage, LLC*, 125 FERC ¶ 61,050, at P 5 (2008) (*Tarpon Whitetail*); *Tennessee Gas Pipeline Co*., 135 FERC ¶ 61,208 (2011), *order on reh'g*, 139 FERC ¶ 61,050, at PP 80-82 (2012) (*Tennessee II*); *Texas Eastern Transmission, LP*, 138 FERC ¶ 61,126 at PP 82, *order on reh'g*, 140 FERC ¶ 61,216, at P 88 (*Texas Eastern*); and *Rockies Express Pipeline Co*., 139 FERC ¶ 61,275, at P 19 (2012) (*Rockies Express*).

valves; and valve spacing. However, PHMSA did not propose any specific changes in its integrity management regulations in the ANOPR. Before making any changes to its integrity management regulations in response to the comments received in response to the ANOPR, PHMSA must issue a notice of proposed regulations (NOPR), proposing specific changes to those regulations and requesting comment. PHMSA must then analyze those comments and issue a final rule adopting revised regulations. Thus, at the present time, there is no certainty as to whether and how PHMSA may modify its integrity management regulations in the rulemaking proceeding initiated by the ANOPR. Moreover, because PHMSA has not yet issued a NOPR on this subject, it will likely be at least a year before any final rule can be issued in that proceeding.

31. In addition to the integrity management issues raised by the ANOPR, sections 5(a) and (b) of the 2011 Act require PHMSA to evaluate, by July 3, 2013, whether some or all of its integrity management requirements should be expanded beyond HCAs, taking into account various factors including "the need to perform integrity management assessments and repairs in a manner that is achievable and sustainable, and that does not disrupt pipeline service," and "the options for phasing in the extension of integrity management requirements beyond [HCAs], including the most effective and efficient options for decreasing risks to an increasing number of people living or working in proximity to pipeline facilities." Section 5(c) of the Act requires PHMSA to submit a report to Congress by January 3, 2014 on the results of its evaluation of expanding integrity management requirements. In order to give Congress time to review the report, section 5(f) of the Act prohibits PHMSA from issuing any final rule expanding IM requirements beyond HCAs until the earlier of one year after completion of the report to Congress or January 3, 2015, unless PHMSA determines such a regulation is necessary to address a risk to public safety, property, or the environment or an imminent hazard exists.

32. Thus, the 2011 Act does not require PHMSA to take any specific actions with respect to its integrity management regulations, apart from evaluating the need for expanding the existing requirements in its regulations and submitting a report to Congress by January 3, 2014. Moreover, the 2011 Act requires PHMSA to wait until the earlier of one year after submitting the report or January 3, 2015, to issue any final rule expanding integrity management requirements beyond HCAs, unless such a regulation is necessary to address a risk to public safety, property, or the environment. It thus appears unlikely that any such final rule could take effect before 2015.

33. Until there is some certainty as to what new integrity management requirements PHMSA may adopt for pipelines and when they will take effect, it is premature for the Commission to consider modifying its well established current policy that pipelines must provide full reservation charge credits for outages of primary firm service due to scheduled maintenance and repairs performed as part of an integrity management program and that these outages are not *force majeure* events. Because of the uncertainty as to what integrity management requirements may be adopted, it is uncertain how any

such new requirements will affect pipelines' ability to minimize outages due to their integrity management activities. For example, it is unclear whether, even if PHMSA adopts strengthened integrity management regulations, those regulations will significantly exceed the integrity management activities pipelines are already voluntarily conducting and would conduct in any case. The Interstate Natural Gas Association of America (INGAA) has reported to PHMSA that, while only about 4.5 percent of all member pipeline miles are included in HCAs, interstate pipelines have assessed and mitigated 53 percent of their pipeline miles pursuant to IM programs.[25]

34. Also, section 5 of the 2011 Act requires PHMSA to take into account "the need to perform integrity management assessments and repairs in a manner that . . . does not disrupt pipeline service" and to consider options for phased implementation of any new requirements. When PHMSA adopted the first integrity management regulations pursuant to the 2002 Act, it gave pipelines no later than one year after enactment to develop written integrity management plans and gave pipeline operators no later than five years after enactment to assess 50 percent of their covered pipelines and another five years to assess the remainder. There could be a similar phased implementation of any new requirements, which would give pipelines considerable control over when any necessary outages on particular pipeline segments occur. In light of the uncertainty concerning the nature and timing of any new integrity management requirements, the Commission lacks the information necessary to evaluate whether it would be just and reasonable to grant any relief from the present requirement that pipelines provide full reservation charge credits for any outages of primary firm service due to integrity management activities required to comply with PHMSA regulations.

35. With regard to Texas Gas's concern about shut-off valves, section 4 of the 2011 Act requires PHMSA, "if appropriate," to issue regulations not later than January 3, 2014, requiring automatic shut-off valves on pipelines constructed or entirely replaced after adoption of the regulation where economically, technically and operationally feasible. PHMSA has not yet issued any Notice of Proposed Rulemaking pursuant to section 4 of the Act. Therefore, PHMSA has not yet provided even a preliminary statement of its views concerning the appropriateness of requiring such shut-off valves. Moreover, even if PHMSA does determine such regulations are appropriate, any regulations it adopts would only apply to new construction occurring after adoption of the regulations and would not appear to be directly related to existing pipeline facilities. Accordingly, as with integrity management, it is premature to consider whether to permit

[25] *See* INGAA submission responding to *The State of the Natural Pipeline Infrastructure – A Preliminary Report, Progress Made with Integrity Management*, June 22, 2011, Docket No. PHMSA-2011-0127.

partial reservation charge crediting for outages of primary firm service related to the installation of shut-off valves.

36. The 2011 Act contains numerous other provisions requiring studies of various kinds, apart from the MAOP provisions discussed in the next section. For example, section 7 of the Act requires PHMSA by December 31, 2012, and every two years thereafter, to conduct surveys to measure progress in plans for safe management and replacement of cast iron (CI) pipelines. PHMSA must also submit a report to Congress not later than December 31, 2013, identifying all CI pipelines and evaluating the pipeline's safety programs. However, Texas Gas does not expressly rely on these other provisions to support their partial crediting proposal.

MAOP Requirements

37. We now turn to the new requirements concerning MAOP established by section 23 of the 2011 Act. As described above, section 23(a) of the 2011 Act added section 60139, Maximum Allowable Operating Pressure, to Chapter 601 of Title 49 of the United States Code. Section 60139(a) required each owner and operator of a pipeline to conduct a verification of its records of relating to pipelines in class 3 and class 4 locations and class 1 and class 2 HCAs by July 3, 2012. The purpose of the verification is to ensure that the records accurately reflect the physical and operational characteristics of the subject pipelines and to confirm their established MAOP. Section 60139(b) requires each owner or operator of a pipeline facility to identify and submit to PHMSA documentation relating to each pipeline segment for which its records are insufficient to confirm the established MAOP of the segment by July 3, 2013. Section 60139(c)(1) provides that, after receiving this information, PHMSA must require the pipeline owner or operator of a pipeline facility identified pursuant to section 60139(b) to reconfirm a MAOP "as expeditiously as economically feasible," and PHMSA must determine what interim actions "are appropriate for the pipeline owner or operator to take to maintain safety until a [MAOP] is confirmed." Section 60139(c)(2) requires that, in determining the interim actions for each pipeline owner or operator to take, PHMSA must take into account "potential consequences to the public safety and the environment, potential impacts on pipeline system reliability and deliverability, and other factors, as appropriate."

38. Section 60139(d)(1) also requires PHMSA to issue regulations by July 3, 2013, to require testing to confirm the material strength of previously-untested gas pipelines located in HCAs which are operating at a pressure greater than thirty percent of specified minimum yield strength (SMYS). This requirement includes both grandfathered pre-1970 pipelines and post-1970 pipelines. Section 60139(d)(2) requires PHMSA to consider safety testing methodologies, including at a minimum pressure testing and other alternative methods, including in-line inspections, determined by DOT to be of equal or greater effectiveness. Section 60139(d)(3) requires PHMSA, in consultation with the Chairman of FERC and State regulators, to establish time frames for completion of the

testing which "take into account potential consequences to public safety and the environment and that minimize costs and service disruptions."

39. For the reasons discussed below, we find it is just and reasonable for Texas Gas to provide partial reservation charge credits consistent with the Safe Harbor Method for outages of primary firm service required to comply with orders issued by PHMSA pursuant to section 60139(c) for a transitional two-year period starting on January 1, 2013. However, it is premature to consider any similar partial reservation crediting provision for outages that may be caused by any strength testing regulation PHMSA may adopt pursuant to section 60139(d).

40. Section 60139(c) provides that, if a pipeline is unable to confirm MAOP for a pipeline segment by July 3, 2013, PHMSA must require the pipeline to reconfirm the MAOP of the segment as expeditiously as economically feasible, and PHMSA may require the pipeline to take interim actions to maintain safety until MAOP can be confirmed. Unlike the other sections of the 2011 Act discussed above, all of which require PHMSA to conduct rulemaking proceedings before modifying current requirements, section 60139(c) does not require PHMSA to conduct any rulemaking proceeding before it orders particular pipelines to reconfirm MAOP and take interim actions to maintain safety until MAOP is confirmed. Rather, PHMSA may simply issue an order to a particular pipeline tailored to address the specific circumstances of its system. Therefore, unlike the non-MAOP provisions of the 2011 Act discussed in the preceding section, PHMSA actions pursuant to section 60139(c) of the Act are relatively imminent, and could take effect at any time without advance notice of the type that would ordinarily be provided in a rulemaking proceeding.

41. In addition, the Commission finds several other important factors which distinguish any outages resulting from actions PHMSA takes pursuant to section 60139(c) from the routine, periodic maintenance which the Commission has held are within the control of the pipeline and therefore must be treated as non-*force majeure* events for which full reservation charge credit must be given. First, whatever actions PHMSA takes pursuant to section 60139(c) of the 2011 Act would be one-time non-recurring events. Section 60139(c) does not create an ongoing requirement to reconfirm MAOP on a periodic basis comparable to ordinary integrity management programs. Section 60139 simply authorizes PHMSA to require a one-time reconfirmation of MAOP for the subject pipeline segments, pursuant to in-line inspection, hydrostatic testing, or other alternative tests.[26] Also, any interim safety measures, such as a requirement for the

[26] In this regard, PHMSA orders requiring a one-time reconfirmation of MAOP and interim safety measures may be considered comparable to the one-time requirement that a pipeline be relocated for highway construction, which the Commission held could

(continued…)

pipeline to operate at reduced pressure, would only be in effect until MAOP is reconfirmed. Moreover, the pipeline could have less discretion concerning the timing of testing to reconfirm MAOP or any interim measures to maintain safety until MAOP can be reconfirmed, than it has concerning the timing and location of routine scheduled maintenance.

42. Second, costs of outages for such one-time testing or reduced operating pressure would generally not be recurring costs eligible for inclusion in a pipeline's rates in a general section 4 rate case.[27] By contrast, as the court in *North Baja* emphasized in affirming our policy concerning full reservation charge credits for scheduled maintenance, that policy is premised on the ability of the pipeline to include the expected costs that would be incurred under that policy in its rates.[28]

43. The Commission also finds that a blanket authorization of partial crediting for outages required to reconfirm MAOP pursuant to section 60139(c) for a transitional period is consistent with Congress's determination that MAOP should be confirmed "as expeditiously as economically feasible." The Commission recognizes that there could be circumstances in which a pipeline's inability to verify its records concerning the MAOP of a particular pipeline segment could arguably be attributable at least in part to the pipeline's failure to maintain adequate records, at least for pipeline segments constructed after 1970. However, the Commission finds that, on balance, it is preferable to permit pipelines to include in their tariffs a bright-line rule that the pipeline will provide partial reservation credits for all outages resulting from PHMSA orders issued pursuant section 60139(c). Such a bright-line rule should minimize the need for burdensome case-by-case consideration of whether a pipeline's mismanagement may have contributed to its inability to verify the records for a particular pipeline segment and thus should expedite the resolution of what credits are due the shippers. Also, the requirement that the pipeline provide partial credits regardless of fault will ensure that pipelines share the risk of all outages of primary firm service resulting from compliance with PHMSA orders pursuant to section 60139(c).

44. The Commission will limit any authorization for partial crediting for outages resulting from section 60139(c) to a specified transitional period of two years. This two-year transitional period is consistent with the fact that actions by PHMSA pursuant

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be treated as a *force majeure* event in *Florida Gas*, 107 FERC ¶ 61,074 at P 32. *See also Tarpon Whitetail*, 125 FERC ¶ 61,050 at P 6.

[27] *See* 18 C.F.R. § 154.303(a)(4) (2012).

[28] *North Baja*, 483 F.3d 819, 823.

to section 60139(c) are only temporary in nature to reconfirm MAOP and require interim safety measures until MAOP is reconfirmed. After MAOP is reconfirmed, there should no longer be a need for such a special partial crediting provision. At the end of the transitional period, the Commission will reexamine whether there is any need to extend this tariff provision. Accordingly, Texas Gas may include in its tariff a provision permitting partial reservation charge crediting, for a transitional period of two years commencing on January 1, 2013, for outages resulting from orders issued by PHMSA pursuant to section 60139(c) of the 2011 Act. That tariff provision should include a requirement that, when Texas Gas provides notice of an outage required to comply with an order issued by PHMSA pursuant to section 60139(c), that notice identify the specific PHMSA order with which it is complying.

45. This allowance of partial crediting is limited to solely to outages resulting from section 60139(c). Unlike section 60139(c), section 60139(d) requires PHMSA to issue regulations by July 3, 2013, before requiring strength testing of previously-untested gas pipelines located in HCAs and operating at a pressure greater than thirty percent of specified minimum yield strength. Section 60139(d) also requires PHMSA, in consultation with the Chairman of FERC and State regulators, to establish time frames for completion of the testing which minimize outages. Therefore, it is possible that the pipelines will be permitted a longer period of time to conduct this testing, than any testing required to reconfirm MAOP or interim safety measures adopted under section 60139(c) of the 2011 Act discussed above. That would give the pipelines a greater ability to control outages due to the strength testing required by section 60139(d), than they are likely to have to comply with requirements issued under section 60139(c). Accordingly, the Commission finds that consistent with the discussion above, it is appropriate to await developments in the rulemaking proceeding required by section 60139(d) before permitting any special tariff provision with respect to outages resulting from strength testing under section 60139(d).

46. In summary, the Commission finds that Texas Gas has not shown that its proposal to revise its definition of *force majeure* to include all testing, repair, replacement, refurbishment, or maintenance activity required to comply with the 2011 Act and ongoing PHMSA rulemaking proceedings is just and reasonable. However, the Commission will permit Texas Gas to file revised tariff records which require the partial reservation charge credits for outages due to PHMSA orders pursuant to section 60139(c) of the 2011 Act for a transitional period of two years. We emphasize that our holding in this order is without prejudice to Texas Gas filing a proposal to allow equitable sharing of credits resulting from other new safety requirements PHMSA may adopt, after the nature and timing of such new requirements becomes sufficiently clear to allow consideration of whether such a proposal is just and reasonable. The Commission is aware of the possible impact of the 2011 Act and PHMSA rulemakings and will closely monitor the implementation of the new requirements. The Commission is tracking the impacts of the

2011 Act and understands the importance of these issues and will consider the need for further action as the impact of PHMSA's implementation process moves forward.

B. Reservation Charge Credits for *Force Majeure* Events

1. Texas Gas' Proposal

47. Texas Gas is proposing to modify its tariff to provide reservation charge credits for *force majeure* events utilizing a modified version of the Safe Harbor method. Under this proposal, Texas Gas will provide no reservation charge credits during the first twenty days of a *force majeure* event. After the first twenty days, the customer would receive full reservation charge credits until the *force majeure* event ended. Texas Gas states that its proposal differs from the ten day Safe Harbor period approved by the Commission in other proceedings. Texas Gas states it is requesting approval of a longer Safe Harbor period, because it does not use a Straight Fixed Variable (SFV) rate design, but rather includes 6.7 percent of its fixed costs in its usage charge.

48. In its transmittal letter as well as in its response to the protestors, Texas Gas states that Commission policy dictates that for *force majeure* events both the pipeline and its customers should share the risk when such outages occur because no blame can be ascribed to either party for such interruptions. Texas Gas notes that under an SFV rate design, 100 percent of a pipeline's transmission fixed costs, including its return on equity (ROE) and associated income taxes, are allocated to the pipeline's reservation charge. Thus, partial crediting is required for *force majeure* for SFV pipelines because they do not share any risk when an outage occurs because the usage charge which is not paid during an outage, does not include any transmission fixed costs. Texas Gas contends that for a pipeline with a non-SFV rate design, like Texas Gas, which places some portion of the pipeline's fixed costs in the usage charge, the Commission recognized that the risk of a *force majeure* event "was automatically shared between the pipeline and its shippers," since the pipeline was at risk for the costs included in the usage charge.[29] Texas Gas stated that the Commission has approved different *force majeure* reservation charge credits requirement for pipelines with a unique rate design, and Texas Gas' proposal is consistent with those decisions.

49. Texas Gas asserts that in *Tennessee,* where the pipeline's rate design provided for recovery of $79 million of its transmission fixed costs through usage rates representing 12 percent of its transmission cost-of-service, the Commission held that no crediting was required by the pipeline. The Commission found no crediting was needed because

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[29] *Tennessee Gas Pipeline Co.*, 80 FERC ¶ 61,070, at 61,198-99 (1997) (*Tennessee*).

Tennessee's rate design "accomplishes, in effect, our goal of ensuring that the risk associated with a *force majeure* interruption is shared, and that Tennessee not be guaranteed a profit when unable to provide service, without having to require Tennessee to provide partial credits."[30]

50. Texas Gas points out that in contrast to *Tennessee*, in *Northern Natural Gas Co.*,[31] cited by Protestors, the pipeline's non-SFV rate design included $16 million of fixed costs in its usage rates, which amounted to 3 percent of its cost-of-service. The pipeline sought similar treatment as the pipeline in *Tennessee*, namely, no reservation charge crediting during a *force majeure* outage. The Commission rejected the proposal, finding that 3 percent of fixed costs in the usage charge did not "equitably apportion the risk of curtailments during a *force majeure* situation" and was "not an amount that is in the same ballpark as the sharing in the approved methods, and does not satisfy the rationale in [*Tennessee*]."[32] Accordingly, the Commission required the pipeline to provide partial reservation charge credits for *force majeure* outage. However, the Commission added that the pipeline could "modify the usual provisions of the Safe Harbor or No-Profit methods to reflect that a certain portion of the fixed costs are included in the usage charge,"[33] such as an increase in the length of the Safe Harbor period, and the Commission would review any proposed modification.

51. Texas Gas contends that with nearly 7 percent of its fixed costs recovered in its usage charge, Texas Gas' rate design falls somewhere between the bookends of 3 percent found insufficient for an exemption from crediting in *Northern Natural* and the 12 percent found sufficient in *Tennessee*. Rather than requesting a full exemption from partial reservation charge credits for *force majeure* events, as was permitted in *Tennessee*, Texas Gas asserts it has modified the usual provisions of the Safe Harbor method by adding ten days to the safe harbor period to reflect the significant portion of its fixed costs included in its usage charge.

52. Texas Gas states that during the safe harbor period it is at risk for the transmission costs in the usage charge. In its Answer, Texas Gas refers to an NGSA Study, entitled "Actual Pipeline Rate of Return on Equity" which states that Texas Gas' return on equity for years 2006 through 2010 was respectively 10.7 percent, 12.2 percent, 9.3 percent,

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[30] *Id.* at 61,200.

[31] 137 FERC ¶ 61,202 (2012) (*Northern Natural*).

[32] *Id.* P 23.

[33] *Id.*

6.8 percent, and 9.7 percent, so the five-year weighted average return on equity for this period is 9.3 percent.[34] Texas Gas asserts that in any given year, Texas Gas' realized return on equity has been only a few percentage points more than the amount of transmission fixed costs that Texas Gas recovers under its usage charge. It states that for 2009, the NGSA Study shows Texas Gas' return on equity to be a mere 6.7 percent, the return on equity is almost exactly the same percentage as the transmission fixed costs recovered through Texas Gas' usage charge. Moreover, once the Safe Harbor period ends the shippers will receive the entire amount of the reservation charge. Accordingly, Texas Gas argues its proposal more than adequately balances the risk between the pipeline and its customers, and should be accepted. Texas Gas asserts that this is clearly consistent with Commission policy that the Commission is open to alternative methods that "achieve a similar sharing of risk as the two previously approved policies."[35]

2. <u>Protestors' Position</u>

53. Protestors object to the proposed twenty day grace period. Protestors state this is longer than any grace period the Commission has permitted, and is twice as long as the grace period the Commission indicated it will approve, namely ten days or less. Moreover they assert that Texas Gas has not provided adequate justification for such a deviation from Commission policy. They cite to *Northern Natural*, noting that there the Commission rejected a similar attempt by the pipeline to deviate from the approved 10-day Safe Harbor period because it had a non-SFV rate design. The Commission held that the pipeline's small departure from the SFV rate design, the inclusion of approximately 3 percent of fixed costs in the usage charge, did not justify deviation from the Commission's policy that the pipeline and the shipper share the risk of *force majeure* events.

54. Protestors state that the fact that Texas Gas has included approximately 6.7 percent of its fixed costs in the usage charge is insufficient to warrant a grace period twice as long as the 10 day grace period previously the Commission permitted. They argue that the proposal would make it highly unlikely that Texas Gas would ever be required to provide reservation charge credits for *force majeure* outages. Protestors note that the purpose of reservation charge credits is to provide impetus for the pipeline to expeditiously return the system to full operational status, and doubling the period when no credits would be due for a *force majeure* event sends the wrong signal to the pipeline.

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[34] Texas Gas Answer at 41.

[35] *Northern Natural*, 137 FERC ¶ 61,202 at P 23.

55. In their responses to Texas Gas' answer, Protestors reiterate that Texas Gas has not justified how doubling the length of time during which the customer bears 100 percent of the risk is the same type of risk-sharing the Commission has approved under a ten-day safe harbor period. They contend that while Texas Gas may be entitled to modify the Safe Harbor period, with 6.7 percent of fixed costs in the usage charge it is entitled to "at most, one additional day."[36]

56. Protestors also argue that Texas Gas' contention that it recovers 6.7 percent of fixed costs in the commodity usage charge is speculative. They note that Texas Gas's assertion that 6.7 percent of its fixed transmission costs are included in its usage charge is based on its originally proposed rates in its last general section 4 rate case in Docket No. RP05-317. However, that rate case was subsequently resolved by a black box settlement and thus the amount of fixed costs in the usage charge approved as part of the settlement is not specified.[37] Further, they refer to a clause in that settlement, Article XII, which states that no party has "consented to any fact, ratemaking principle or any method of cost of service determination, cost allocation, or rate design…."

3. **Commission Determination**

57. The Commission requires the pipeline to provide partial reservation charge credits during *force majeure* outages in order to share the risk of an event for which neither the pipeline nor its shippers are at fault. The Commission has approved two methods for pipelines with an SFV rate design to share the risk, the No Profit and Safe Harbor methods. The Safe Harbor method requires the pipeline to provide full reservation charges after a short grace period of 10 days or less during which no credit is required. The No Profit method requires the pipeline to grant partial credits equal to the pipeline's ROE and associated income taxes included in its reservation charge, thereby requiring the pipeline to forego its profit during the *force majeure* outage. This replicates the sharing of the risk that occurred automatically under the Modified Fixed Variable (MFV) rate design used before Order No. 636, under which the pipeline's ROE and associated taxes were included in the pipeline's usage charge.

58. In addition, as the court stated in *North Baja*, the Commission permits pipelines to use other cost-sharing formulas, so long as they achieve "an equitable sharing in the same ballpark" [38] as the Safe Harbor and No Profit Methods. When pipelines with SFV rates

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[36] DEO Protest at 8.

[37] *Texas Gas Transmission, LLC*, 115 FERC ¶ 61,092 (2006)

[38] 483 F.3d 819 at 822-23 (D.C. Cir. 2007). *See also Kern River Gas Transmission Co.*, 139 FERC ¶ 61,044, at PP 36-40 (2012) (*Kern River*) (rejecting

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have proposed mechanisms to share the risk of *force majeure* outages which differ from the approved methods, we have carefully analyzed whether those proposals provided for risk sharing in the same ballpark as the approved methods do for other pipelines using an SFV rate design. As illustrated by our orders in *North Baja* and *Kern River*,[39] we have rejected alternative proposals which we found were not in the same ballpark. It is reasonable to apply the same approach to all pipelines, regardless of their rate design, so that all pipelines are subject to similar risk sharing requirements with respect to *force majeure* outages.

59. In contending that its proposal for a 20 day safe harbor period, is reasonable, Texas Gas relies in part on a comparison of its proposal to the risk sharing the Commission approved in *Tennessee*. In that case, the Commission found that the pipeline's inclusion of 12 percent of its fixed transmission costs in its usage charge provided sufficient risk sharing, without the need for any reservation charge credits. In a contemporaneous order in *Northern Natural Gas Co.*,[40] the Commission concluded that it will no longer follow *Tennessee* as a precedent that arguably provides that a pipeline's allocation of 12 percent of its fixed costs (or any other percentage) will exempt it from granting partial reservation charge credits during a *force majeure* outage. The Commission stated that, consistent with *North Baja*, the issue of what crediting is appropriate for a pipeline with a non-SFV rate design must be resolved based upon a determination of whether the pipeline's tariff provides for a sharing of risk in the same ballpark as the risk sharing the two approved methods provide for SFV pipelines. For the same reasons, we find in this case, that *Tennessee* should not be used a base line for determining whether Texas Gas's alternative risk sharing proposal provides for sufficient risk sharing. Rather, the analysis of whether Texas Gas's proposed modified Safe Harbor method provides for an equitable sharing of the risk of *force majeure* outages must focus on whether that proposal provides for sharing in the "same ballpark" as the approved No Profit and Safe Harbor methods provide for pipelines using an SFV rate design. Otherwise, Texas Gas could receive more favorable treatment than SFV pipelines.

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alternative cost-sharing formula because it did not provide for sharing in the same ballpark as the No Profit or Safe Harbor methods).

[39] *Kern River Gas Transmission Co.*, 139 FERC ¶ 61,044, at PP 36-40 (2012) (*Kern River*) (rejecting alternative cost sharing formula because it did not provide for sharing in the same ballpark as the No Profit or Safe Harbor methods).

[40] 141 FERC ¶ 61,221 (2012).

60. Texas Gas asserts that its proposed modified Safe Harbor method provides sharing in the same ball park as the approved method does for SFV pipelines, because its usage charge includes about 6.7 percent of its total fixed costs. Thus, Texas Gas will forgo 6.7 percent of its fixed costs starting on Day 1 of a *force majeure* outage. By contrast, an SFV pipeline using the approved Safe Harbor Method does not forgo any fixed costs during the first 10 days of a *force majeure* outage, because its usage charge does not include any fixed costs. For the reasons discussed below, we find that there is some merit to Texas Gas' position, but find it goes too far in shifting the risk to Texas Gas' firm shippers under Texas Gas' tariff.

61. While some protesters question whether Texas Gas' usage charge includes any fixed costs, we accept its estimate of the percentage of its fixed costs included in its usage charge. As Texas Gas has explained, in its initial section 4 filing in Docket No. RP05-317, Texas Gas proposed "to move $16 million, or almost 20 percent of its return, from the demand component to the commodity component and to assume the risk inherent in this shift."[41] That amount represented 6.7 percent of its proposed transmission cost-of-service of $237,443,289. While the subsequent black box settlement reduced Texas Gas's proposed rates and does not identify a specific dollar amount of fixed costs included in the usage charge, the rates approved in the settlement include both a maximum and minimum usage charge. It follows that fixed costs are included in the usage charge.[42] The Commission finds it reasonable to assume that the usage charge approved in the settlement includes approximately the same proportion of Texas Gas's fixed transmission costs as it proposed in its original section 4 filing.[43]

62. However, that Texas Gas' usage charge includes about 6.7 percent of its fixed costs does not justify doubling the ordinary 10 day safe Harbor period to 20 days, as Texas Gas proposes. When a pipeline uses an SFV rate design, the Safe Harbor Method allocates the entire risk of *force majeure* outages of 10 days or less to the firm shippers. However, the requirement to provide full credits after Day 10 then allocates to the pipeline a progressively greater share of the risk of a *force majeure* outage the longer the outage lasts. For example, as shown on the Appendix to this order, an SFV pipeline, with full reservation charge credits under the Safe Harbor Method starting on Day 11 would

[41] April 29, 2005 Transmittal Letter at 3.

[42] *See* 18 C.F.R. §§ 284.10(b)(4)(ii) and (5) (2012), providing that a pipeline's minimum rate are based on its variable costs.

[43] *See* an affidavit of David J. Haag, attached to Texas Gas' July 13 answer in which he stated "there is no evidence that the settlement changed any of the underlying cost of service allocations."

provide credits equal to 9.09 percent of the cumulative reservation charges for the first 11 days of the outage, rising to 50 percent of the cumulative reservation charges for the first 20 days of the outage.[44] If the outage lasts 30 days, the Safe Harbor Method would require an SFV pipeline to credit to its firm shippers about 66.7 percent of the total reservation charges that would otherwise be due during that period and 75 percent of a 40 day outage.

63. Because Texas Gas' usage charge includes only 6.7 percent of its fixed costs, Texas Gas' proposal would place on its shippers 93.3 percent, or almost all, of the risk of short-term *force majeure* outages of 10 days or less. That is not much different than the Safe Harbor Method's imposition of 100 percent of the risk of short term-outages of 10 days or less on the pipeline's shippers.[45] However, after 10 days Texas Gas' proposal would place substantially more of the risk of the *force majeure* outage on its shippers than does the Safe Harbor Method. While the Safe Harbor Method requires a pipeline to start providing full reservation charge credits on Day 11 of the outage, Texas Gas does not propose to provide any reservation charge credits until Day 21 of the *force majeure* outage. Thus, under Texas Gas' proposal it would continue to bear only 6.7 percent of the risk of the *force majeure* outage through Day 20. By contrast, as stated above, an SFV pipeline would provide credits equal to 9.1 percent of the cumulative reservation charges for the first 11 days of the outage, rising to 50 percent of the cumulative reservation charges for the first 20 days of the outage.[46]

64. While Texas Gas would start providing full reservation charge credits after Day 20, it would continue to forgo a substantially lower percentage of its fixed costs during *force majeure* outages lasting more than 20 days than would an SFV pipeline using the standard Safe Harbor Method. The percentage of fixed costs forgone by Texas

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[44] *See* Appendix A comparing the pipeline's cumulative absorption of its fixed costs during outages of various lengths under the Safe Harbor Method, the No Profit Method, Texas Gas' proposed method, and the Modified Safe Harbor Method permitted by this order.

[45] In all cases where the Commission has approved a pipeline's use of the Safe Harbor Method, the no credit period has been limited to 10 days or less. *See, e.g., Midwestern*, 137 FERC ¶ 61,257 at P 20; *Tuscarora Gas Transmission Co.*, 123 FERC ¶ 61,109, at P 12 (2008); *Entrega Gas Pipeline LLC*, 114 FERC ¶ 61,326, at P 13 (2006); *Natural Gas Pipeline Co. of America*, 106 FERC ¶ 61,310, at P 24, *reh'g*, 108 FERC ¶ 61,170, at PP 8-11 (2004); *Texas Eastern Transmission Co.*, 62 FERC ¶ 61,015, at 61,090 (1993).

[46] *See* Appendix A.

Gas would gradually rise from 11.1 percent on Day 21 to 37.8 percent on Day 30 and to 53.4 percent on Day 40. By contrast, the percentage of fixed costs forgone by an SFV pipeline would rise from 52.4 percent on Day 21 to 66.7 percent on Day 30 and 75 percent on Day 40.

65. Texas Gas' proposal is also substantially less favorable to its shippers than crediting under the No Profit Method. That method requires the pipeline to bear the same proportionate risk, based upon the percentage of its fixed costs comprised of ROE and associated income taxes, starting on Day 1 until the outage ends. Using the same assumptions Texas Gas used in determining the percentage of its fixed costs included in its usage charge, we calculate that Texas Gas' ROE and associated income taxes represent 37 percent of its total fixed transmission costs.[47] Thus, if Texas Gas used an SFV rate design, it would provide credits equal to 37 percent of its total reservation charge, starting on Day 1 and continuing throughout the *force majeure* outage. By contrast, Texas Gas' proposal only requires it to bear 6.7 percent of the risk of any *force majeure* outage of 20 days or less. It would not absorb a similar amount of fixed costs as under the No Profit Method until the outage has lasted for 30 days. Accordingly, we will not accept Texas Gas' proposal for a 20 Day Safe Harbor period.

66. While the Commission rejects Texas Gas' proposal, the Commission finds that Texas Gas may modify the No Profit or Safe Harbor Methods to reflect that its usage charge includes 6.7 percent of its fixed costs, as follows. In order to provide risk sharing equivalent to that provided under the No Profit Method by a pipeline with an SFV rate design, Texas Gas could revise its tariff to provide reservation credits equal to 30.3 percent of the fixed costs in its reservation charge for every day of a *force majeure* outage. Those credits, combined with the fact Texas Gas would not be collecting the 6.7 percent of its fixed costs included in its usage charge, would result in Texas Gas forgoing the 37 percent of its fixed costs comprised of ROE and associated income taxes during the *force majeure* outage, consistent with the No Profit Method.

67. Alternatively, if Texas Gas desires to use the Safe Harbor Method, we find that the addition of one day to the 10-day Safe Harbor period would result in Texas Gas's risk sharing being in the same ball park as the risk sharing under the Safe Harbor Method for an SFV pipeline which does not allocate any fixed costs to the usage charge. On a cumulative basis, Texas Gas' loss of the 6.7 percent of its fixed costs included in its usage charge during each day of the first 10 days of a *force majeure* outage is the equivalent of providing the shippers a credit equal to 67 percent of the fixed costs

[47] *See* Statement A to Texas Gas' April 29, 2005 filing in Docket No. RP05-317. That statement indicates an ROE of $57.8 million, associated income taxes of $30 million, and total transmission cost-of-service of $237 million.

included in the charges for one day of service. This is about two thirds of the full reservation charge the Safe Harbor Method would ordinarily require for Day 11 of a *force majeure* outage. In light of this fact, together with Texas Gas's assertion that most *force majeure* outages on its system will last more than 10 days,[48] the Commission finds that adding one day to the Safe Harbor period provides a sufficient adjustment to account for the fact that Texas Gas bears 6.7 percent of the risk of the first 11 days of a *force majeure* outage. As shown on Appendix A, if the *force majeure* outage lasts more than 11 days, Texas Gas would bear somewhat less of the risk of longer *force majeure* outages than would an SFV pipeline using the Safe Harbor Method. For example, if the outage lasted 20 days, Texas Gas would forgo 48.7 percent of its fixed costs, whereas an SFV pipeline using the standard Safe Harbor Method would forego 50 percent of its fixed costs. Texas Gas' somewhat lower risk sharing during the longer *force majeure* outages it asserts are most likely on its system would offset its somewhat greater risk sharing for shorter term *force majeure* outages. Therefore, no greater adjustment to the Safe Harbor Method beyond the addition of one day to the Safe Harbor period would be justified.

68. Accordingly, Texas Gas must revise its proposal consistent with the above discussion.

C. Triggering Event for Providing *Force Majeure* Credits

1. Texas Gas' Proposal

69. Proposed section 6.25.1(a) provides that Texas Gas will provide reservation charge credits to the extent it "fails to deliver the Force Majeure Average Usage Quantity . . . on any day due to a Force Majeure event . . . that excuses performance under Section 6.24.4 of" the GT&C. Section 6.25.1(b) then defines how a customer's Force Majeure Average Usage Quantity will be determined. As discussed in more detail in the next section of this order, a customer's Force Majeure Average Usage Quantity for any Gas Day shall be determined based on its average nominated quantities or actual flow quantities during the seven days prior to the Force Majeure Event.

[48] Texas Gas states that in the last five years it has declared five *force majeure* events and only one was for less than 10 days. Its states that during Hurricane Ike in 2008 it had a *force majeure* outage which lasted 23 days, and it asserts that such hurricane-induced service interruptions may be the most likely *force majeure* events to occur on its system because of the location of its facilities in Louisiana. Answer at 47.

2. Positions of the Parties

70. Louisville states it is inappropriate for Texas Gas to use its failure to deliver the Force Majeure Average Usage Quantity as the triggering event for issuing reservation charge credits because Texas Gas's obligation to deliver gas is determined by the shipper's nomination. Louisville states that while it may be appropriate to use the seven-day average Force Majeure Average Usage Quantity to calculate reservation charge credits, the average should not be used to determine whether Texas Gas has curtailed service on a particular day.

71. In its Answer, Texas Gas states contrary to Louisville's contention, the triggering event for *force majeure* is controlled by existing section 6.24.4(1) of Texas Gas' tariff, where *force majeure* is defined, rather than new section 6.25, where the crediting mechanism is established. Under existing section 6.24.4(1), the triggering event for a *force majeure* occurs when Texas Gas or a customer provides appropriate notice that it "is rendered unable, wholly or in part, to carry out its obligations under this tariff." Under Texas Gas' proposal the Force Majeure Average Usage Quantity is used only to determine whether Texas Gas is required to provide reservation charge credits and the amount of such credits after a *force majeure* event has already been declared.

3. Commission Determination

72. The Commission agrees with Texas Gas that proposed section 6.25.1(a) provides that the triggering event for whether a *force majeure* has occurred requiring Texas Gas to provide reservation charge credits is Texas Gas's provision of notice of a *force majeure* event pursuant to section 6.24.4. Thus, Texas Gas's failure to deliver the Average Usage Quantity is not the triggering event for issuing reservation charge credits. That quantity is used only to calculate the level of reservation charge to be provided during the *force majeure* event.

D. NNS Shippers' Long Term Outages

1. Texas Gas' Proposal

73. Texas Gas proposed in section 6.25(1) concerning *force majeure* outages to calculate reservation charge credits for all firm services based on (1) the shipper's average nominated quantity during the seven days immediately before the *force majeure* outage for services requiring nominations and (2) the shippers actual flow quantity during the preceding seven days for services not requiring nominations. Texas Gas proposed in section 6.25(2) concerning non-*force majeure* outages to calculate reservation charge credits in a similar manner (except where it had not given advance notice of the outage before the timely nomination opportunity).

2. **Position of the Parties**

74. In its protest, Cities argued that the seven-day period immediately before an outage fails to accurately reflect a No Notice (NNS) shipper's loss of firm service during long-term outages. Cities stated that, while Texas Gas' proposal is a reasonable approach for short-term outages it fails to anticipate prolonged outages. Cities asserted that NNS Rate Schedule shippers have varying seasonal contact quantities and their usage is seasonal and typically weather driven, i.e., lower in the summer and higher in the winter with corresponding average usage. Therefore, Cities argued that Texas Gas should include an alternative calculation of Average Usage Quantities for outages lasting more than 28 days based on the level of service experienced in a comparable period in the prior year, presuming that the historical period was not subject to an outage.

75. In its Answer, Texas Gas acknowledged that a seven-day historical period may not be sufficient for NNS service during a long-term outage. Texas Gas asserted that, unlike its annual services, its seasonal NNS and STF services provide customers with a Maximum Daily Quantity (MDQ) that can change seasonally, i.e., during the Summer Season, Winter Season, and two Shoulder Months.[49] Texas Gas further asserted that when an outage extends into a new season, it may be appropriate to calculate the Average Usage Quantity based upon the average usage of that season from previous years. Texas Gas contended that because usage of seasonal service is highly weather dependent, an average of several past seasons will appropriately normalize any atypical usage data caused by unusual weather events, such as an extremely warm or cold winter. Texas Gas stated that it would be willing to modify its tariff to take into consideration the seasonal nature of NNS and STF service. Texas Gas accordingly proposed to add a subsection (iii) for *force majeure* events to proposed section 6.25(1)(b) that would provide:

> (iii) For NNS and STF customers with varying seasonal contract demands only, if the FM Event extends into another season, upon the first day of such season and throughout such season, Customer's average nominated quantity for Primary Firm Services requiring nominations and Customer's average actual flow quantity for Primary Firm Service where nominations are not required will both be determined based upon the applicable average nominated quantities in the respective seasons during the previous three calendar years.

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[49] Texas Gas states that, for the purposes of this provision, it intends extensions into "another season" to include extensions into a Shoulder Month.

Texas Gas also offered to make similar changes to proposed section 6.25(2), which addresses credits for non-*force majeure* events.

76. Texas Gas contended that, while it is economically incentivized to eliminate such interruptions as soon as possible; where a long-term interruption occurs, its modified proposal appropriately acknowledges the seasonality of certain services and establishes a calculation that reasonably accounts for the impact of weather conditions on usage.

3. Commission Determination

77. The Commission finds that Texas Gas' revised proposal for addressing long-term outages reasonably addresses the concern that the seven-day average usage immediately before the outage may become unrepresentative of the service a NNS or STF shipper would have used during a long-term outage. However, the Commission requires Texas Gas either to provide a further explanation of under what circumstances it is appropriate to use nominated quantities to determine reservation charge credits for No Notice service or revise its proposal to base such credits on actual deliveries.

78. Under the NGA, the Commission must accept a just and reasonable tariff proposal by a pipeline, regardless of whether other tariff provisions would also be just and reasonable.[50] The Commission recognizes that an NNS shipper's need to transport gas may change over time, with the result that a shipper's usage during the seven days immediately before an outage may not be representative of the service the shipper would have used during the latter part of a long-term outage.[51] Texas Gas proposes to address this problem by proposing that, when an outage extends into a new "season," it will determine an NNS and STF shipper's credits based on its average usage during the same "season" of the preceding three years. For this purpose, it proposes to use the same seasons as are used in its NNS and STF rate schedule for purposes of the seasonal changes to the MDQs of its NNS and STF shippers. These are a November through March winter season, an April shoulder season, a May through September summer season, and an October shoulder season.

79. Texas Gas' NNS and STF Rate Schedules assume that the major changes in the NNS and STF shippers' need to use these services occur when the seasons set forth in these rate schedules change, since these are the seasons when the shipper's MDQs are adjusted up or down. The Commission finds that Texas Gas' proposal to tie changes in the calculation of NNS and STF shippers' reservation charge credits to those same

[50] *Consolidated Edison Co. v. FERC*, 165 F.3d 992, 998, 1002-1004 (1999).

[51] *See Kern River*, 139 FERC ¶ 61,044 at P 49.

seasons is reasonable. While Texas Gas' proposal may produce only a rough estimate of the service a NNS or STF shipper would have used during the outage, there is no perfect method of estimating that usage.[52] Any inaccuracies in the estimate produced by Texas Gas' proposed methodology should even out over time, because that methodology could as easily overestimate, as underestimate, a shipper's need for NNS or STF service during the outage. Regardless of such inaccuracies, the credits calculated pursuant to Texas Gas' proposal should accomplish the basic purpose of the Commission reservation charge crediting policy: provide Texas Gas an incentive to minimize any outage of primary firm service and provide the shipper reasonable compensation for any inability to use the primary firm service.

80. While the Commission accepts Texas Gas' proposed method for accounting for seasonal changes in shippers' need for NNS and STF service, Texas Gas has not yet justified its proposal concerning the use of "nominated quantities" to calculate the NNS shippers' credits. Texas Gas proposes in sections 6.25(1) and (2) to calculate credits for all firm shippers based on "average nominated quantities" for "services requiring nominations" and based on "actual flow quantities" for "services "where nominations are not required." Texas Gas' proposed revised tariff language concerning credits to NNS shippers includes similar language. It is not clear how Texas Gas would apply its proposed distinction between "services requiring nominations" and services "where nominations are not required" in the context of No Notice Service.

81. Section 2.2 of Texas Gas' No-Notice Transportation Service Rate Schedule provides that "Customer's seasonal Contract Demands are thus supplied by a combination of Nominated (pipeline) and Unnominated (storage) quantities …" and section 9 requires the NNS shipper to nominate gas supply into Texas Gas' system up to the shipper's Nominated Daily Quantity. In addition, section 2.4 also provides that a NNS "Customer shall be required to nominate any Unnominated Daily Quantity at a primary delivery point where an Operational Balancing Agreement is in effect." It appears from these provisions that there could be days on which actual deliveries to an NNS shipper's primary delivery point vary from its nominations. As a general matter, an NNS shipper's actual need for, and use of, its NNS service would appear to be best represented by actual deliveries to that shipper at its primary delivery point. Therefore, arguably on days during the past period used to calculate reservation charge credits when there was a variation between an NNS shipper's nominations and deliveries to its primary delivery point, it would be reasonable to use the actual deliveries to calculate the average quantities on which reservation charge credits are based, rather than the nominated quantities if any. On the other hand, Texas Gas has not described the circumstances in

[52] *See Midwestern*, 137 FERC ¶ 61,257 at P 22.

which it believes use of an NNS shipper's nominated quantities would be appropriate. Therefore, in order to clarify this matter, the Commission requires Texas Gas to provide a detailed explanation of the circumstances under which it would use an NNS shipper's nominated quantities to determine reservation charge credits and when it would use actual deliveries.

82. In addition, the Commission requests that Texas Gas explain the extent to which it provides any firm services other than NNS service which do not require nominations. If there are no other services, the references to services "where nominations are not required" should be clarified to refer only to NNS service. If there other such services, Texas Gas should provide a similar explanation to that required above with respect to NNS service as to when it will use nominated deliveries and when it will use actual deliveries to calculate reservation charge credits.

E. Limit on Use of Seven Day Average Daily Quantity

1. Position of the Parties

83. In the interest of consistency across its affiliated pipeline companies, Texas Gas proposes in its Answer to add the following language proposed by Gulf South Pipeline Company, LP and Gulf Crossing Company LLC in responses to protests:

> "The previous seven (7) days' average daily quantity usage will only be used in the determination of the Maintenance Average Usage Quantity when Texas Gas has posted notice prior to the Timely Cycle nomination deadline that the capacity will be unavailable for the day in question."

84. Texas Gas also proposes to amend section 6.25.2(b)(ii), changing the 7:00 a.m. CCT deadline to conform to the deadline established above, which is tied to the Timely Cycle nomination deadline.

2. Commission Determination

85. Texas Gas is directed to modify its tariff accordingly.

F. Secondary Points

1. Texas Gas' Proposal

86. Proposed section 6.25.3 states that Texas Gas will provide reservation charge credits for Primary Firm Service only.

2. **Positions of the Parties**

87. PSEG ERT states that Section 6.25.3 implies that transactions involving secondary points would for some reason be automatically ineligible for reservation charge credits. PSEG ERT states Texas Gas blurs its use of the concept of primary capacity. On the one hand, when it is unable to provide full service no reservation charge credits will be made to nominations involving anything other than primary points. On the other hand, in determining the Average Usage Quantities in the seven days leading up to service limitations, only primary transactions will be counted. PSEG ERT requests that Texas Gas be required to revise its tariff such that for purposes of calculating the Average Usage Quantities, the average daily usages should include secondary receipt and delivery point transactions that are within the primary path and should not be limited to Primary Firm Service only. SESC also states the Commission should reject Texas Gas' proposal to exclude secondary points used in the base period calculation from the Average Usage Quantity calculations. SESC states there is no reason for distinguishing between primary and secondary firm capacity in the base period when determining the amount of curtailed service for which a shipper will receive reservation charge credits. SESC notes if a shipper has used its firm transportation capacity, albeit at secondary points, during the base period, it has established a legitimate base period requirement for gas which prevents any gaming. That shipper should then be free to submit nominations at its primary points and if Texas Gas curtails the shipper, the reservation charge credits should be based upon the shipper's nomination of firm transportation service, without regard to whether primary or secondary points were used during the base period.

88. Texas Gas states in its Answer the Commission has consistently held that reservation charge credits are only provided for primary firm service, not secondary service. This policy holds that pipelines are not required to provide reservation charge credits when they fail to provide service at non-primary points and that it is reasonable for a pipeline to calculate reservation charge credits based upon the shipper's utilization of primary firm capacity during the seven days prior to the outage.[53] In the latter case, the credit will apply to curtailed service between primary points, less any volumes transported on a secondary basis.

89. SESC states in its reply comments it is raising a different issue which was not explicitly raised in *Midwestern,* which Texas Gas relies on to dismiss its claims. SESC states that since the objective of using a base period is to minimize the potential for gaming, there could be no gaming if the shipper's base period reflected its actual use of the Texas Gas system, at primary and secondary points. SESC states a shipper should be

[53] *Midwestern Gas Transmission Co.,* 137 FERC ¶ 61,257, at P 17 (2011).

free to submit nominations at its primary points and if Texas Gas curtails the shipper, the reservation charge credits should be based upon the shipper's nomination of firm transportation service at *primary points only* up to its base period volumes, without regard to whether primary or secondary points were used during the base period.

3. Commission Determination

90. Commission policy is for the pipeline to provide reservation charge credits for the pipeline's failure to provide primary firm service. A firm shipper has a guaranteed firm contractual right to service only at its primary points, not secondary points. Pipelines design their systems in order to have the capacity to satisfy their primary firm obligations, and the Commission has never required pipelines to maintain sufficient capacity to give firm shippers a guaranteed right to service at secondary points.[54] The required reservation charge credit being granted is the amount of primary firm service the shipper nominated for scheduling but the pipeline is unable to deliver. Similarly, the intent of the seven-day average is to estimate the amount of primary service a shipper would have scheduled at primary points, not its total contract utilization during that period.[55] Therefore, it is reasonable to use the shipper's nominations of primary service during the seven-day past period to make that estimate.[56] Therefore, Texas Gas' proposed Section 6.25.3 complies with Commission policy and the Commission will not require further modification.

G. Outages Due to Acts of Shippers or Third Parties

1. Texas Gas' Proposal

91. Proposed section 6.25(4) provides that a customer's "Average Usage Quantity shall be reduced to the extent any curtailments are the result of Customer's negligence or intentional wrongful acts. Customer shall not be entitled to [reservation] charge credits as a result of loss of any of the following: (a) gas supply, (b) markets, or (c) transportation upstream or downstream of Texas Gas' system."

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[54] *Southern Natural Gas Co.*, 137 FERC ¶ 61,050 (2011).

[55] *Midwestern Gas Transmission Co.*, 137 FERC ¶ 61,257, at P 17 (2011).

[56] *Ibid.*, P 17.

2. **Position of the Parties**

92. Protestors argued that proposed section 6.25(4) conflicts with the Commission's policy which holds that a pipeline is exempted from providing reservation charge credits only where the outage is solely due to an upstream or downstream disruption or the conduct of a third party, including shippers, and not controlled by the pipeline.

93. Cities state it is inappropriate for Texas Gas to reduce a customer's Average Usage Quantity in Section 6.25.4 "to the extent any curtailments are the result of Customer's negligence or intentional wrongful acts." Cities state this kind of comparative negligence or portioning-out of blame has no place in tabulating reservation charge credits due to *force majeure* events, which are by definition uncontrollable and out of the control of either party. Therefore, Cities request the Commission reject Texas Gas' proposed provision regarding "curtailments due to customer or third-party action".

94. In its Answer, Texas Gas contended that its proposed section 6.25(4) is consistent with Commission policy. However, Texas Gas stated that it is willing to modify the second sentence of its section 6.25(4) with the following emphasized language:

> *Unless Texas Gas has declared a force majeure, maintenance, or non-force majeure event*, Customer shall not be entitled to demand charge credits as a result of loss of any of the following: (a) gas supply, (b) markets, or (c) transportation upstream or downstream of Texas Gas' system.

95. Texas Gas asserts that this clarification makes it clear that Texas Gas will not be exempt from providing credits if it cannot provide service due to an interruption on its facilities. Texas Gas contends that its proposed revision is more appropriate than limiting the exemption to circumstances solely due to others' operating conditions or the conduct not controlled by the pipeline since use of the term "solely" could be interpreted to require reservation charge credits when not appropriate. Texas Gas gave the following example of a situation where it asserted that reservation credits would be inappropriate, even though a party might contend that the inability to make deliveries was not due solely to another pipeline. In this example, Texas Gas has historically delivered gas into Pipeline X at a certain pressure. Pipeline X declares a *force majeure* but claims that the reason it cannot accept Texas Gas' gas is due to pressures provided by Texas Gas. However, Texas Gas stands ready and able to delivery gas at historical pressures. Texas Gas asserts in such a situation it should not be obligated to provide reservation charge credits because the cause of the interruptions is outside of Texas Gas' control.

96. Indicated Shippers assert there is no basis for Texas Gas' proposed exemption, because Texas Gas' proposal relates to the inability to deliver gas at the pipeline interconnect due to deviations in pressure from historical averages. Indicated Shippers further asserts that the pressure at an interconnection is solely an issue between the interconnecting parties and there are contractual remedies. SESC states that because

Texas Gas does not propose to revise the first sentence of proposed Section 6.25 – "The Average Usage Quantity shall be reduced to the extent any curtailments are the result of Customer's negligence or intentional wrongful acts" – a shipper would be denied any reservation charge credits in the event that multiple causes, including actions by Texas Gas or *force majeure* affecting Texas Gas, contributed to the curtailments.

3. Commission Determination

97. We find that Texas Gas's proposed crediting exemption must be revised to be consistent with Commission policy. Commission policy is to require the pipeline to provide reservation charge credits for outages where the failure to deliver is due to events within the pipeline's control. On the other hand, when a pipeline cannot deliver the service because of events not within the pipeline's control, i.e., due to the conduct of the shipper or the operator of upstream or downstream facilities, the pipeline should not be required to grant credits.[57] Therefore, Texas Gas' proposed exemption must be limited to include only those circumstances where its failure to provide service is due to events or conduct of others outside of its control which result in an outage of reserved firm service.

98. In addition, when *force majeure* events occur on both Texas Gas' facilities and the facilities of others, Texas Gas could not have provided service in any case. Therefore, as the Commission found in *Paiute Pipeline Co.*, in a *force majeure* event when both the pipeline's and the facilities of others are affected, then the traditional *force majeure* rule applies and the pipeline is required to provide partial credits.[58] Therefore, Texas Gas' tariff also must expressly provide that it is exempted from issuing reservation charge credits only when Texas Gas' failure to schedule or deliver gas is solely due to conduct of others not controllable by Texas Gas.[59]

99. Texas Gas' alternative also does not conform to the Commission policy discussed above. The additional language requiring a declaration of an outage by the pipeline must be eliminated to make clear that it is the pipeline's failure to deliver the nominated firm

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[57] *See, e.g., Natural*, 106 FERC ¶ 61,310 at P 15, n.10; *Tennessee*, 139 FERC ¶ 61,050 at PP 100-101; *TransColorado Gas Transmission Company, LLC*, 139 FERC ¶ 61,229, at P 50 (2012) (*TransColorado*).

[58] *Paiute Pipeline Co.*, 139 FERC ¶ 61,089, at PP 30-32 (2012). *See also* Rockies Express at P 12; *TransColorado Gas Transmission Co*., LLC, 139 FERC ¶ 61,229, at PP 51-52 (2012).

[59] *Rockies Express*, 139 FERC ¶ 61,275 at P 12; *TransColorado*, 139 FERC ¶ 61,229 at P 52.

service, not declarations by the pipeline related to the outage, that requires it to provide reservation charge credits.[60] Therefore, the Commission directs Texas Gas instead to limit the scope of the proposed section 6.25(4) exemption to make clear that Texas Gas is exempted from issuing reservation charge credits only when Texas Gas' failure to deliver gas was due solely to the conduct of others or events not controllable by Texas Gas, i.e., operating conditions on upstream or downstream facilities or a shipper's inability to obtain gas supplies or find a purchaser to take delivery of the supplies.

100. The Commission will not reject Texas Gas' tariff provision reducing its reservation charge credit requirement to the extent any curtailments are the result of customer's negligence or intentional wrongful acts. The Commission believes to the extent these acts contribute to curtailments Texas Gas should not be required to provide reservation charge credits.

H. Segmented Capacity, Capacity Release, and Partial Assignment

1. Positions of the Parties

101. Indicated Shippers argue that sections 6.25(1)(c) and 6.25(5)(d) both define the reservation charge credits owed for segmented capacity, capacity release, or partial assignment. Indicated Shippers contend that section 6.25(1)(c) should be eliminated as redundant to section 6.25(5)(d).

102. Texas Gas agrees in its July 13, 2012 Answer to delete both proposed section 6.25(1)(c) and section 6.25(2)(c) because they are redundant.

2. Commission Determination

103. We will accept Texas Gas' agreement to remove proposed sections 6.25.1(c) and 6.25.2(c). Therefore, we direct Texas Gas to file revised tariff records removing proposed sections 6.25.1(c) and 6.25.2(c), as proposed in its Answer.

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[60] When Texas Gas has an outage of primary firm service not due solely to the conduct of others, it must provide credits whether or not it has declared a maintenance or other non-*force majeure* event. The credits must be full credits, unless Texas Gas has declared a *force majeure* event pursuant to section 6.24.4. In that event, it need only provide the partial credits required during a *force majeure* outage, as discussed *supra* P 72.

I. Reservation Credits for Leased Capacity

1. Position of the Parties

104. DEO notes that Texas Gas offers Firm Transportation Service that includes transportation service on Gulf South Pipeline, which Texas Gas leases from Gulf South. DEO requests that it be made clear in Texas Gas' tariff that this leased capacity will be considered part of Texas Gas's system for determining whether or not reservation charge credits are due its shippers. DEO states that under the language proposed by Texas Gas, if Gulf South issues reservation charge credits for interruptions on the part of the system on which Texas Gas leases capacity, Texas Gas could keep those credits rather than passing them on to its shippers utilizing the leased capacity. Therefore, DEO requests Texas Gas be required to modify its proposal accordingly.

105. Texas Gas responded that DEO is not correct in its reading of the lease agreement between Texas Gas and Gulf South. Texas Gas states that under the terms of that lease Texas Gas in essence owns the Gulf South capacity and the capacity is subject to the Texas Gas tariff since Gulf South "no longer has any rights to use the leased capacity." [61] Thus, Texas Gas' customers who use the leased capacity take service under the Texas Gas tariff. Texas Gas further states that Gulf South would not provide reservation charge credits if there is interruption on the leased facilities because Gulf South does not have shippers taking service on those facilities under its tariff. When there is such an interruption of service on the leased capacity, Texas Gas states it would provide reservation charge credits to shippers that were curtailed pursuant to the terms and conditions of its tariff, the same as it would credit shippers for any other interruption of service on its system.

2. Commission Determination

106. The Commission will not require Texas Gas to modify its tariff as requested by DEO since Texas Gas' answer fully addresses DEO's concern.

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[61] *Gulf South Pipeline Co., LP, and Texas Gas Transmission,* LLC, 119 FERC ¶ 61,281, at P 36 (2007) (order certificating the Texas Gas lease of capacity from Gulf South).

J. Existing *Force Majeure* Definition

1. Existing Tariff Provision

107. Texas Gas' GT&C section 6.24.2 includes "the necessity of testing pipeline or other equipment as may be required by a governmental authority or as deemed necessary by the testing party for the safe operation thereof" as an instance of *force majeure*.

2. Positions of the Parties

108. Louisville, Indicated Shippers and SESC argue this existing definition of *force majeure* is overly broad, in that it may be read to cover routine testing, maintenance and repairs that are in the pipeline's control and the Commission has declared those actions are not *force majeure* events. Louisville states the definition also includes "shutdowns for purposes of necessary or required repairs, relocations, or construction of facilities" which does not comply with the Commission's *force majeure* policy for similar reasons. Therefore, protestors request the Commission require Texas Gas to revise these provisions to comply with Commission policy.

109. Texas Gas states in its Answer that its definition of *force majeure*, read as a whole with the proposed changes, makes clear that only non-routine maintenance and testing are included. Texas Gas states its existing tariff language does not classify scheduled maintenance as a *force majeure* event nor does it contemplate that all compliance activities carried out in accordance with a governmental order will be considered to be *force majeure* situations. Texas Gas states that not all pipeline testing, including testing in compliance with governmental orders and regulations is routine in nature or within the pipeline's control. Texas Gas suggests that existing section 6.24.2 should be read as limited primarily to outages necessary to comply with the previously unanticipated large-scale changes in PHMSA's pipeline safety regulations which are anything but routine and outside of the control of the pipeline. In such situations, it states, testing should appropriately be deemed a *force majeure* event.

3. Commission Determination

110. As discussed above, the Commission has held that outages for routine or scheduled maintenance do not constitute *force majeure* events which are both outside the pipeline's control and unexpected. Routine and scheduled maintenance may include testing of pipeline or other equipment. In any case, contrary to Texas Gas' assertions,

this provision is not limited to outages to comply with PHMSA regulations.[62] Therefore, this provision which defines all service interruptions for testing, repair, or alteration of certain pipeline facilities as *force majeure* events is overbroad and thus contrary to Commission policy. Accordingly, pursuant to section 5 of the NGA, Texas Gas is directed to file revised tariff records to eliminate this provision from its definition of *force majeure* or explain why it should not be required to do so.

The Commission orders:

(A) The tariff records listed in footnote 1 are accepted to become effective January 1, 2013, subject to conditions, as discussed in this order.

(B) Within thirty (30) days of the date of this order, Texas Gas is directed, to file revised tariff records, to be effective January 1, 2013, modifying the tariff changes it filed pursuant to NGA section 4, and provide further information concerning those proposals, consistent with the discussion in the body of this order.

(C) Within thirty (30) days of the date of this order, Texas Gulf is directed, consistent with the discussion in the body of this order, pursuant to NGA section 5, either to modify certain existing provisions in its tariff or explain why it should not be required to do so.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

[62] Any such provision would of course be subject to the Commission's determination of the related issues in this order.

APPENDIX A

Texas Gas Transmission, LLC
Docket No. RP12-820-000

Pipeline % of Cost Absorption

Duration of Force Majeure Outage (Days)	No Profit Method (SFV)	Safe Harbor Method (SFV)	Texas Gas Proposal	11 Day Safe Harbor (6.7% fixed costs in usage charge)
1	37	0.0	6.7	6.7
10	37	0.0	6.7	6.7
11	37	9.1	6.7	6.7
12	37	16.7	6.7	14.5
13	37	23.1	6.7	21.1
14	37	28.6	6.7	26.7
15	37	33.3	6.7	31.6
16	37	37.5	6.7	35.9
17	37	41.2	6.7	39.6
18	37	44.4	6.7	43.0
19	37	47.4	6.7	46.0
20	37	50.0	6.7	48.7
21	37	52.4	11.1	51.1
25	37	60.0	25.4	58.9
30	37	66.7	37.8	65.8
35	37	71.4	46.7	70.7
40	37	75.0	53.4	74.3
50	37	80.0	62.7	79.5
90	37	88.9	79.3	88.6