UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Interstate and Intrastate Natural Gas Pipelines;	)	
Rate Changes Relating to Federal Income Tax Rate	)	Docket No. RM18-11

MOTION FOR LEAVE TO ANSWER AND ANSWER OF THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

Pursuant to Rules 212 and 213 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") Rules of Practice and Procedure, 18 C.F.R. §§ 385.212, 385.213, the Interstate Natural Gas Association of America ("INGAA") hereby moves for leave to answer and answers the comments filed by various parties in this docket. Although the Notice of Proposed Rulemaking ("NOPR") does not expressly provide for reply comments, the Commission allows answers where a responsive pleading will assist the Commission's analysis, provide useful and relevant information, or otherwise facilitate a full and complete record for purposes of rendering a decision.[1] INGAA's response should be permitted as it will assist the Commission's analysis, provide useful and relevant information, and will otherwise facilitate a full and complete record on the important issues raised in the NOPR.

I. Comments on Negotiated Rate Agreements

In the NOPR, the Commission stated:

> In the Negotiated Rate Policy Statement, the Commission allowed pipelines to negotiate individualized rates that are not bound by the maximum and minimum recourse rates in the pipeline's tariff. Among

[1] *See, e.g., Tuscarora Gas Transmission Co*., 120 FERC ¶ 61,022 at P 4 (2007); *Transwestern Pipeline Co*., 109 FERC ¶ 61,062 at P 7 (2004); *Transcontinental Gas Pipe Line Corp*., 108 FERC ¶ 61,230 at P 3 (2004); *Algonquin Gas Transmission Co*., 108 FERC ¶ 61,195 at P 8 (2004); *ANR Pipeline Co*., 107 FERC ¶ 61,250 at P 11 n.4 (2004); *Columbia Gas Transmission Corp*., 106 FERC ¶ 61,128 at P 15 (2004); *El Paso Natural Gas Co*., 104 FERC ¶ 61,303 at P 11 (2003).

> other things, this permits pipelines, as a means of providing rate certainty, to negotiate a fixed rate or rate formula that will continue in effect regardless of changes in the pipeline's maximum recourse rate. Accordingly, unless a negotiated rate agreement expressly provides otherwise, the rates in such agreements will be unaffected by any reduction in the pipeline's maximum rate reductions resulting from the policies adopted in the rulemaking proceeding, whether in a limited or general NGA section 4 rate proceeding or a subsequent NGA section 5 investigation.[2]

Notwithstanding this clear statement, a few commenters request the Commission to clarify that negotiated rate contracts are subject to revision and allow rate reductions for shippers under such contracts.[3] Indicated Shippers argue that the Commission should allow negotiated rate shippers to share in the tax cost reductions through a negative surcharge where the contract includes a *Memphis* clause that would allow, or require, a change to rates.[4] Indicated Shippers further request the Commission to establish a process to review each negotiated rate contract entered into by every pipeline to determine whether the contract allows for such rate changes.[5]

These requests are contrary to well-established law and policy and should be soundly rejected. Shippers have two rate mechanism options for paying for natural gas transportation service. Shippers can choose a recourse rate option and pay the pipeline's maximum tariff rate or a discounted recourse rate that is linked to the maximum tariff rate. Maximum and minimum tariff rates must be filed and approved by the Commission as just and reasonable under Section 4 of the Natural Gas Act ("NGA"). If the pipeline and a

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[2] NOPR at P 45, *citing Northern Natural Gas Co*., 105 FERC ¶ 61,299, at PP 15-16 (2003). *Columbia Gulf Transmission Co*., 109 FERC ¶ 61,152, at P 13, *reh'g denied*, 111 FERC ¶ 61,338 (2005); *Iberdrola Renewables, Inc. v. FERC*, 597 F.3d 1299, 1305 (D.C. Cir. 2010).

[3] *See* Comments of Indicated Shippers at 3-13; Natural Gas Supply Association ("NGSA") at 7-9 and Independent Oil and Gas Association ("IOGA") at 6-11; Range Resources-Appalachia, LLC at 9-10.

[4] Indicated Shippers Comments at 7, *citing United Gas Pipeline Co. v. Memphis Light, Gas, and Water Div.*, 358 U.S. 103 (1958).

[5] *Id.*

shipper agree to a discounted rate, the rate is bound by the maximum and minimum tariff rates. As a result, a discounted contract receives the benefit of a lower rate if the maximum rate decreases below the contractual discounted rate. A shipper subject to the maximum tariff rates pays the maximum tariff rate as modified during the term of the contract through Section 4 or Section 5 proceedings.

The second option is to pay a negotiated rate which, unless otherwise specifically provided for in the contract, does not change with changes in the maximum recourse tariff rate. Rather, as the D.C. Circuit stated in *Iberdrola Renewables, Inc. v. FERC*, a negotiated rate is a contractually agreed to rate that "reflects FERC's assumption that sophisticated parties will bargain for rates that are just and reasonable."[6] Shippers with negotiated rates "remove themselves from any protection the Commission may give customers under recourse rates."[7] Shippers choosing negotiated rates bargain for the contractual protection against rate increases if the pipeline's maximum recourse rate increases, and forego the opportunity to lower their rates if the maximum recourse rate decreases. Thus, the fact that the shipper "in hindsight, considers its … bargain unwise is not reason to disregard the contract's clear meaning."[8] The primary benefit of negotiated rate agreements for both the pipeline and the shipper is that "they limit challenges to specific rate(s) so as to ensure rate certainty."[9] The rate certainty provided by negotiated rate agreements has been instrumental in facilitating the construction of natural gas infrastructure throughout the

[6] *Iberdrola Renewables, Inc. v. FERC*, 597 F.3d 1299, 1301 (D.C. Cir. 2010), *citing Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines*, 74 FERC ¶ 61,076, at 61,241-42 (1996).
[7] *Columbia Gulf Transmission Co.*, 78 FERC ¶ 61,262 at 62,124 (1997).
[8] *Iberdrola*, *supra*, 597 F.3d at 1305.
[9] *Columbia Gulf Transmission Co.*, 109 FERC ¶ 61,152 at P 13 (2004) ("to the extent a pipeline and its shipper want to obtain rate certainty by agreeing to a rate that will remain in effect throughout the term of the service agreement, the Commission provides them an opportunity to do so by entering into a negotiated rate agreement.").

country by allowing shippers to enter into long-term contracts without risking rate increases not permitted by their contracts. Shippers are never required to enter into negotiated rate agreements. The Commission has explained that shippers have the option, at the time of contracting, of obtaining service pursuant to the pipeline's recourse rates.[10]

The arguments made by commenters in support of abrogating negotiated rate contracts to reflect a lower federal tax rate have no merit. Indicated Shippers, for example, contend (at 5) that *if* the recourse rates had reflected lower tax costs at the time their negotiated rate agreements were executed, it would not be unreasonable to *assume* they would have agreed to lower negotiated rates. Therefore, Indicated Shippers argue, the recourse rate could no longer be said to be a viable alternative to the agreed-upon negotiated rate. Even accepting the assumption as to what these shippers would have done *had* the federal tax rate been lower at the time they entered into their contracts, the fact is the tax rates were not lower at that time. Reducing the rates under these contracts because the tax rate was reduced *after* the contracts were executed negates the very bargain reflected in the negotiated rate agreements. Accepting Indicated Shippers' argument would lead to the irrational conclusion that every negotiated rate contract could be abrogated if any of the pipeline's costs increase or decrease after the contract was executed because the pipeline or shipper might have negotiated a higher or lower rate had such costs been different at that time.

The commenters seeking rate reductions under negotiated rate agreements advance two legal justifications in support of their request. First, they argue that notwithstanding the bargain reflected in the negotiated rate agreements, the Commission has the authority

[10] *See Modification of Negotiated Rate Policy*, 104 FERC ¶ 61,134 at P 2 (2003).

to revise these contracts under the *Mobile-Sierra* doctrine if the public interest requires a modification.[11] However, the burden that must be met to modify freely-negotiated contracts is extraordinarily high in recognition of the importance of upholding the sanctity of contracts. As the Supreme Court stated, "uncertainties regarding rate stability can have a chilling effect on investments and a seller's willingness to enter into long-term contracts and this, in turn can harm customers in the long-run."[12] Consequently, to modify a contract rate, a challenger must show that the rate seriously harms the public interest, and the Commission must make a finding of "unequivocal public necessity."[13] The D.C. Circuit has characterized *Mobile-Sierra* as presenting a "practically insurmountable" barrier to contract reformation.[14]

Disrupting freely-negotiated contracts to reflect a lower federal tax rate is far from an "unequivocal public necessity." The interests that would be promoted by such action would be private interests of the shippers that seek to avoid their contractual agreements. In this instance, the primary parties that are requesting the Commission to lower their freely-negotiated rates - Indicated Shippers, NGSA, IOGA and Range Resources - are sophisticated companies that are fully capable of assessing the impacts of agreeing to fixed negotiated rate contracts. These same companies would have made every effort to argue that a change to their negotiated rate would be unjust and unwarranted had the tax rate increased rather than decreased. Weighed against the private interests of these

[11] *See* Indicated Shippers Comments at 6, IOGA Comments at 7, *citing United Gas Pipe Line Co. v. Mobile Gas Service Corp.,* 350 U.S. 332 (1956); *FPC v. Sierra Pacific Power Co.,* 350 U.S. 348 (1956).
[12] *Morgan Stanley Capital Group v. Pub. Util. Dist. No. 1 of Snohomish County*, 554 U.S. 527, 551 (2008).
[13] *Id.* at 548, 550.
[14] *Papago Tribal Util. Auth. v. FERC*, 723 F.2d 950, 954 (D.C. Cir. 1983).

sophisticated shippers is the paramount public interest in honoring and preserving the sanctity of contracts.[15] Commenters have failed to meet their heavy burden.

Second, these commenters argue that even if the Commission is not inclined to abrogate these contracts under *Mobile-Sierra, Memphis* clauses in pipeline tariffs would allow the Commission to indirectly achieve the same result by imposing a negative surcharge. These commenters cite to cases where the Commission has permitted pipelines to impose surcharges to recover certain costs in discounted or negotiated rate contacts based on a *Memphis* tariff clause incorporated into the contract.[16]

The commenters' reliance on *Memphis* clauses as justification to impose a negative surcharge under these contracts is misplaced. A *Memphis* clause "refers to an agreement between a shipper and a pipeline providing that the *pipeline* may change a rate during the term of the contract by making a rate filing under section 4 of the NGA."[17] A *Memphis* clause provides a unilateral right for pipelines to propose changes to their rates and terms and conditions of service and does not give shippers any right to propose such changes. Thus, even if a negotiated rate agreement incorporated the pipeline's tariff, which in turn, included a *Memphis* clause in its rate schedules, such a clause would not provide a basis for the *Commission* to change the rate negotiated by the parties absent a *Mobile-Sierra* showing.

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[15] The American Gas Association ("AGA") requests the Commission (at 6) to reduce a negotiated rate in the circumstance "where the interstate pipeline specifically required that the rate for capacity awarded under a negotiated rate agreement be no less than the interstate pipeline's otherwise applicable tariff rate such that the negotiated rate is now equal to the otherwise applicable tariff rate, and the tariff rate is reduced pursuant to proceedings related to the TCJA." The circumstances described by AGA are not clear and are best addressed in individual pipeline proceedings.
[16] *See* Indicated Shippers Comments at 7-12; NGSA Comments at 7-9; IOGA Comments at 5.
[17] Order Clarifying Statement of Policy, 90 FERC ¶ 61,128, at 61,391, n.2 (2000), *citing United Gas Pipeline Co. v. Memphis*, 358 U.S. 103 (1958).

In support of their argument that a *Memphis* clause allows the Commission to effectuate a rate reduction through a negative surcharge, the commenters rely on cases involving hurricane surcharges and reservation charge crediting tariff provisions. These cases are inapposite. In *High Island Offshore System, L.L.C.,* ("*HIOS*"),[18] the Commission permitted HIOS to include a Storm Event Surcharge to recover "extraordinary costs resulting from a future hurricane, tropical storm, or depression named or numbered by the U.S. National Weather Service through a surcharge."[19] The Commission found that the *Memphis* clause in HIOS' tariff permitted the *pipeline* to add this new charge to negotiated rate agreements. The Commission explained that allowing the new charge was consistent with the negotiated rate agreements, which expressly provided that the shipper was responsible for "all applicable surcharges."[20]

In a series of *Sea Robin* orders, the Commission similarly found that a proposed hurricane surcharge was consistent with discounted rate contracts because the language in the contracts allowed Sea Robin to add "applicable surcharges".[21] In Opinion No. 516-A, the Commission relied on the pipeline's right to add surcharges pursuant to the *Memphis* clause in the tariff to reject shippers' arguments that "applicable surcharges" were limited to either existing surcharges or those the Commission required the pipeline to propose.[22] Thus, the Commission found that the *Memphis* clause permitted the pipeline to add a surcharge that was not prohibited by the negotiated rate agreement. It was not found to be an independent justification for modifying the negotiated rate.

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[18] 145 FERC ¶ 61,155 (2013).
[19] *Id.* at P 19.
[20] *Id.* at P 20.
[21] *See* cases cited by Indicated Shippers in their footnote 25.
[22] *Sea Robin Pipeline Company, LLC,* Opinion No. 516-A, 143 FERC ¶ 61,129 at PP 124, 126 15 (2013).

Importantly, the Commission in both *HIOS* and *Sea Robin* contrasted the nature of the extraordinary costs that were the subject of those pipelines' hurricane surcharges with other proposals that sought to impose a surcharge for ordinary recurring costs that are typically included in pipelines' base rates. In distinguishing HIOS' Storm Event Surcharge from a surcharge proposed in *Bay Gas Storage Co.,* the Commission stated:

> Unlike *Bay Gas,* this is not a situation where the pipeline is shifting an ordinary, recurring cost formerly included in the base rate, such as the lost and unaccounted for gas at issue in *Bay Gas*, to a separate surcharge and trying to add that recurring cost to the previously-agreed upon discounted base rate. Here, HIOS has proposed a new rate mechanism which it will use solely to recover new, extraordinary one-time costs it may incur in the future to repair damage to its pipeline caused by future significant storm events. [23]

The proposals made in comments on the NOPR to add a negative surcharge to reduce shipper rates to reflect lower tax costs is a similar attempt to circumvent the negotiated rate through a negative surcharge. Unlike the extraordinary one-time hurricane costs at issue in *HIOS* and *Sea Robin,* taxes are ordinary recurring costs included in a pipeline's base rates. When sophisticated members of Indicated Shippers, NGSA and IOGA entered into their negotiated rate agreements, they accepted the possibility that these types of base rate cost components could either increase or decrease, and they bargained for the rate certainty of their negotiated rate. Stated another way, if a *Memphis* clause is interpreted to allow the Commission to impose a negative surcharge to reduce negotiated rates to reflect the reduction in the federal tax costs, that same clause would allow the Commission to add a positive surcharge to negotiated rates for every increase in cost

[23] *HIOS* at P 21, *citing Bay Gas Storage Co.*, 131 FERC ¶ 61,034 at P 45 (2010). Similar language is found in Opinion No. 516-A, 143 FERC ¶ 61,129 at P 40.

underlying a pipeline's base rates. Such a holding would eviscerate the purpose of negotiated rates.

The *Iroquois* and *Algonquin* cases involving reservation charge credits likewise do not support the imposition of a negative surcharge on negotiated rate agreements.[24] These cases arose from the Commission's clarification of its reservation charge crediting policies for outages that prevent the pipeline from providing firm service. Iroquois and Algonquin sought to exclude from their revised reservation charge tariff provisions negotiated rate contracts entered into prior to the Commission's orders implementing these new policies.

In both cases, the Commission held that the changed reservation charge crediting provisions of the tariff applied to the negotiated rate contracts through application of the *Memphis* clauses in the pipelines' tariffs. The Commission found that the *Memphis* clause incorporated the pipeline's general terms and conditions of service as they may change from time to time into the service agreement. Thus, when the tariff provisions governing reservation charge crediting for *force majeure* and non-*force majeure* events were changed to comply with Commission policy, the modified tariff terms and conditions applied to the negotiated rate contracts.[25]

These cases stand for the unremarkable proposition that pipeline service agreements incorporate the general terms and conditions of service found in the pipeline's tariff as they change from time to time. These cases do not provide shippers with the ability, or the Commission with the authority, to change a negotiated rate absent the

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[24] *Iroquois Gas Transmission System, L.P.*, 145 FERC ¶ 61,166 at PP 16-20 (2013); *Algonquin Gas Transmission, LLC*, 153 FERC ¶ 61,038 at PP 90-100 (2015).
[25] *Iroquois*, 145 FERC ¶ 61,233 at PP 67-68; *Algonquin*, 153 FERC ¶ 61,038 at P 91.

extraordinary showing required by *Mobile-Sierra* that the public interest requires such a change.

Indicated Shippers' reliance (at 9) on cases approving changes required by Order No. 636 is also misplaced. Neither *Natural Gas Pipeline Company of America*[26] nor *Kern River Gas Transmission Co.*,[27] which predated the Commission's Negotiated Rates Policy Statement,[28] involved negotiated rates. Moreover, Shippers' reliance on *Union Pacific*[29] is misleading. In the quote from *Union Pacific* appearing on page 8 of Indicated Shippers' comments, the Court stated that "parties may contract in such a way as to invoke *Mobile-Sierra….",* which may imply by negative inference that if parties do not explicitly invoke *Mobile-Sierra* in the contract, the Commission is free to modify contractually agreed-to rates. This construction of *Union Pacific* was expressly repudiated in *Texaco Inc. v. FERC*.[30] The law is clear that unless a modification to a rate is expressly permitted by the contract, the higher *Mobile-Sierra* standard applies.[31]

Finally, Indicated Shippers' request for the Commission to require pipelines to provide a "catalogue" of negotiated rate agreements to the Commission, and to specify the provision prohibiting modifications to the rate, should be denied. None of the commenters supporting a negative surcharge have provided any evidence that their negotiated rate agreements can lawfully be changed to reduce the agreed-to rate for reductions in tax costs.

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[26] *Natural Gas Pipeline Co. of America*, 70 FERC ¶ 61,317, at 61,967-68 (1995).

[27] *Kern River Gas Transmission Co.*, 62 FERC ¶ 61,191, at 62,258-62, *order denying reh'g*, 64 FERC ¶ 61,049 (1993), *order denying petition for review, Union Pacific Fuels v. FERC*, 129 F.3d 157 (D.C. Cir. 1997).

[28] A*lternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines and Regulation of Negotiated Transportation Services of Natural Gas Pipelines*, 74 FERC ¶ 61,076 (1996).

[29] *Union Pacific Fuels v. FERC*, 129 F.3d 157 (D.C. Cir. 1997).

[30] *Texaco, Inc. v. FERC*, 148 F.3d 1091, 1096 (D.C Cir. 1998), *interpreting Union Pacific* and *Papago Tribal Util. Auth. v. FERC*, 723 F.2d 950, 953 (D.C.Cir.1983) ("the court did not suggest that the parties' failure to explicitly foreclose the Commission's authority to replace rates would leave it intact.").

[31] *Id.*

As discussed above, the existence of *Memphis* clauses in pipeline tariffs does not justify such changes and explicit language prohibiting rate changes is not required for the *Mobile-Sierra* doctrine to apply.

Moreover, negotiated rate agreements are already either filed with the Commission or listed in pipeline tariffs.[32] Certainly, shippers are aware of the terms of their own negotiated rate contracts. If any shipper believes that it has a contract that permits a reduction in the negotiated rate for decreases in the federal tax rate, it can bring the contract to its pipeline provider's attention and file a complaint if the matter cannot be resolved. There is no need for the cumbersome and burdensome process of requiring all pipelines to submit their negotiated rate agreements to the Commission.

II. Comments on Settlements

A. Rate Moratoria

In the NOPR, the Commission acknowledged that a pipeline's rates will not be reduced if the rates are subject to a rate moratorium in a settlement. NOPR at P 49. The LDC Coalition correctly states (at 19) that the NOPR does not appear to contemplate any process other than Commission or customer initiated Section 5 complaints when a settlement moratorium expires in the absence of a come-back provision. It requests that the Commission either continue its current practice of reviewing pipeline Form 2s on an annual basis or continue the Form 501-G process beyond "one-time" and require the filing of a Form 501-G at the end of the applicable rate case filing moratorium.[33]

[32] *Natural Gas Pipeline Negotiated Rate Policies and Practices; Modification of Negotiated Rate Policy*, 104 FERC ¶ 61,134 at PP 31-34 (2003), *order on reh'g and clarification*, 114 FERC ¶ 61,042, *reh'g dismissed and clarification denied*, 114 FERC ¶ 61,304 (2006).

[33] Indicated Shippers make a similar request (at 14).

For the reasons stated in INGAA's comments, a Form 501-G should not be required for pipelines that have rate settlement moratoriums in effect. If the Commission nonetheless requires such filings, it should adhere to the one-time nature of the Form 501-filing in response to the Tax Cuts and Jobs Act ("TCJA"). Part and parcel of the Commission's NOPR is the option for pipelines to make a limited Section 4 rate filing to reduce the tax cost component at the same time the Form 501-G is filed. In other words, the One-time Report is the predicate for the one-time options set forth for addressing the TCJA. INGAA submits that the better course of action is to maintain the one-time nature of the Form 501-G filing and thereafter monitor pipeline rates through the current process of reviewing pipeline Form 2s on an annual basis.[34]

If, however, the Commission requires the filing of a Form 501-G after the expiration of settlements that have a rate moratorium but no comeback provision, the Commission should also extend the limited Section 4 rate option. In addition, the Commission should clarify that the requirement to file a Form 501-G at the end of such settlement *replaces* the requirement to file this form when currently required by the NOPR, instead of being in addition to such requirement. There is no reason to file a Form 501-G while a rate moratorium is in effect, and there is no basis to convert the One-Time Report to a Two-Time Report.[35]

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[34] *See* pages 25-27 of INGAA's Comments on the NOPR.

[35] If the Commission were to require two reports for pipelines with rate settlement moratoria, it would be required to update the Information Collection Statement submitted to the Office of Management and Budget to disclose the additional burden that would be created.

B. Exemption from the Form 501-G Filing Requirement for Uncontested Settlements

Proposed Section 260.402(b)(ii) states that a pipeline that files an uncontested settlement of its rates after the NOPR was published in the Federal Register on March 26, 2018, would not need to file the Form 501-G. INGAA requested in its comments to also apply this exemption to pre-packaged settlements filed after the enactment of the TCJA but before March 26, 2018. The Canadian Association of Petroleum Producers ("CAPP") appears to believe (at unnumbered 6-7) that the exemption from the filing requirement applies only when the pre-packaged settlement has been negotiated "following the release of the Final Rule in this proceeding." INGAA believes CAPP has misread the proposed regulation's reference to the date of publication of the NOPR to be the date of publication of a Final Rule. As INGAA explained in its comments, any settlement filed after the TCJA was enacted would have taken the tax rate reduction into account. Therefore, there is no need for pipelines with such settlements to file a Form 501-G.

Moreover, contrary to the suggestion of the Southern Companies (at 4-5), all uncontested settlements, including black-box settlements, filed after the enactment of the TCJA should be exempt from the filing requirement. There is no reason to distinguish between black-box and other uncontested settlements for purposes of this exemption. The parties' choice in black-box settlements to agree on rates without specifying agreement on individual cost components does not indicate inadequate attention to income taxes or any other specific cost component, as Southern Companies contend. Unless a black-box settlement entered after the enactment of the TCJA allows for a reopening of the settlement to address the impact of the TCJA, the settlement resolved all tax cost issues and the filing of a Form 501-G is unnecessary.

C. Submission of Settlement Agreements

Indicated Shippers (at 14) and NGSA (at 9) request that pipelines be required to provide evidence of a rate moratorium in settlements and that the Commission should examine the settlements to determine whether there are provisions that require rate changes related to tax reductions. The filing of settlements, like the filing of negotiated rate agreements discussed above, is unnecessary. All settlements are in the Commission's public records. Clearly, shippers who agreed to settlements would know if there is a provision in the settlement that provides an exception to a rate moratorium for changes in income tax rates. If a pipeline informs the Commission that a rate moratorium precludes rate changes, and a shipper disagrees, the shipper can bring the pertinent settlement provision to the Commission's attention.

III. Comments on the Filing Process and Content of Form 501-G

Commenters seek several clarifications and changes to the filing process and content of the Form 501-G. INGAA agrees with the following requests: (1) pipelines should be permitted to make limited Section 4 filings prior to the due date of their Form 501-G (APGA at 4-5); and (2) the filing of either the Form 501-G or limited section 4 pursuant to a Final Rule would not, by itself, constitute a "recent rate review" under the Commission's Modernization Policy Statement (LDC Coalition at 13-14; AGA at 7-8). INGAA, however, does not agree with other requested clarifications and proposed changes to the NOPR, as discussed below

A. The Schedule for Filing of the Form 501-G

Process Gas Consumers and American Forest and Paper Association ("PGC/AF&PA") request (at 4-8) the Commission to change the staggered schedule for filing the Form 501-Gs so that all pipelines are required to file the forms at the same time within 28 days of the Final Rule. INGAA opposes this request. The staggered schedules are needed to give both regulated pipelines sufficient time to prepare the Form 501-Gs and the Commission Staff sufficient time to review each form. As the Commission states, there are 133 interstate natural gas pipelines with cost-based rates. Dividing them into four groups and staggering the due dates for the Form 501-G submission is a reasonable way to provide both pipelines and Commission Staff sufficient time to prepare and review the forms, respectively.

PGC/AF&PA fail to acknowledge that many regulated pipelines are part of a group of pipelines under common or affiliated ownership. Thus, in many cases, the personnel responsible for preparing and reviewing the completed Form 501-Gs are tasked with doing so for a number of pipelines within the same organization. Staggering the due dates allows these personnel the time needed to devote to the individual pipelines in their regulated group.

Moreover, accelerating the filing of these forms will not produce the desired effect of achieving an end result sooner. Even if all Form 501-Gs were filed at the same time within 28 days of a Final Rule, Commission Staff could not possibly review all of them and make recommendations for all pipelines not choosing Options 1 or 2 without staggering its review over the longer time period contemplated by the staggered schedule included in the NOPR. In other words, under the timetable included in the NOPR, the last group of filings would be made 112 days after the Final Rule. Assuming it takes another 28 days for Commission Staff to review the forms submitted by this last group, Staff will have reviewed all the forms within 140 days of the Final Rule. Even if all the forms were filed within 28 days, as PGC/AF&PA proposes, it logically will still take Staff 140 days to review as many as 133 forms. The result of PGC/AF&PA's proposed change would be to create an unnecessary burden on pipelines for no gain.

B. The Content of the Form 501-G

Indicated Shippers make a series of requests to add more detailed requirements to the Form 501-G. These requests seek additional detail that is (1) unnecessary to calculate the Indicated Rate Reduction on the Form 501-G; (2) publicly available; and/or (3) would require pipelines to conduct studies that are more appropriately addressed in rate case proceedings. Moreover, many of these requests go beyond reporting the data in pipeline Form 2s and are inconsistent with the nature of these informational filings. INGAA's response to the specific requests for more information is as follows:

- Requests to break out gas fuel and electric power cost exclusions are unnecessary because the Form 501-G already excludes fuel and power from the cost of service. Breaking out these and other miscellaneous fuel costs would require a study that is inappropriate for an informational filing. Specifying whether a pipeline has a fuel tracker or stated fuel rates is also unnecessary because fuel is excluded from the cost of service. Which pipelines have fuel trackers is public knowledge;

- Storage gas losses in Account No. 823 are included in a pipeline's fuel and LAUF tracker and have no impact on the cost of service;

- ACA costs and revenues are publicly available and including both in the cost of service and tax adjusted cost of service would not impact the Indicated Rate Reduction;

- Negative salvage is included in depreciation expense and breaking it out will not affect the cost of service;

- Requests to show the impact of tax reduction and revenues reserved for refunds on accumulated deferred incomes taxes ("ADIT") are inappropriate because the NOPR deferred consideration of ADIT. Amounts related to the tax rate change in ADIT are already reflected in Accounts 182.3 and 254, and Page 3, Line 1 of the Form 501-G nets out refunds;

- The footnotes from the Form 2 related to Page 2, Lines 13-15, are publicly available and would not affect the Indicated Rate Reduction;

- The Form 2 does not reflect rate design. Shippers are aware of whether their pipelines utilize a traditional or levelized rate design;

- "Other interest" is separately stated in the Form 2. Amounts "properly included in a cost of service" would require a study and is more appropriately performed in rate case proceedings; and

- SEC Form 10K references, Ticker and Company Name and time periods relating to parent capital structures, as well as year or owner data and ownership percentages related to Page 5, Lines 11-24 reflect additional reporting requirements beyond the Form 2.

C. Docketing the Filings and Post-Filing Procedures

The NOPR states that the Commission will assign an RP docket number to each Form 501-G filing, and that parties will be permitted to intervene and file comments on the Form 501-G filings within the timeframe required by its regulations. NOPR at PP 29, 64. CAPP concurs (unnumbered at 7) with the assignment of an RP docket number for each Form 501-G filing. CAPP states that providing for intervention and protests "is sufficient to enable the Commission to fully consider whether to initiate an investigation under NGA section 5" of those pipelines not choosing Options 1 or 2.

In its comments, INGAA opposed the proposal in the NOPR to assign an RP (*i.e.*, Rate Proceeding) docket number for each Form 501-G filing. As INGAA explained, the proposed treatment of these informational filings as pipeline rate filings with attendant rights given to parties to intervene and protest, is contrary to the Commission's reliance on Sections 10 and 14 of the NGA, and inappropriately treats the filings as pipeline rate filings under Section 4 of the NGA.

If the Commission nonetheless adheres to its proposal to assign an RP docket number to these filings, it should clarify that procedures that may be available in its regulations for filings made under Sections 4 and 5 are not applicable to the proceedings established for the Form 501-G filings. The comments filed by the LDC Coalition on the process to be followed with respect to these informational filings underscore the need for such clarification. In direct contrast to CAPP's opinion that the comment process would be sufficient for the Commission to review the informational filings, the LDC Coalition contends that the process lacks sufficient procedures. It questions (at 12) whether discovery will be permitted before the Commission sets the Form 501-G for technical conference, hearing or settlement judge procedures.

The questions concerning hearing-type procedures raised by the LDC Coalition stem from the inappropriate use of a "rate proceeding" docket for these informational filings. These informational filings are not being made under NGA Sections 4 or 5, and procedures otherwise available under these statutory provisions are not applicable to these informational filings, which highlights the very issue with formally docketing the Form 501-G filings with an "RP" designation. If the information included in the informational Form 501-G for any pipeline indicates an investigation under Section 5 is warranted, a complaint may be filed and the appropriate procedures in the Commission's regulations will apply to any hearing established under Section 5.

In addition to improperly suggesting the use of discovery, conferences and hearings on the Form 501-G filings, the LDC Coalition also complains (at 11-13) about a lack of "specific procedural protocols" for addressing hypothetical inadequacies in the filings, and lists a series of questions it seeks the Commission to answer concerning the procedures the

Commission intends to utilize if certain events occur. The LDC Coalition's questions are based on a series of "what-ifs" that are speculative and premature, and its request for more detailed procedures is too prescriptive. If the Commission finds inadequacies in any pipeline filing, it can at such time determine the best procedure to follow based on the particular issue that arises. Attempting to address various "what-ifs" at the outset in a Final Rule would be premature, inefficient, and unnecessarily prescriptive.

IV. Comments on the Four Filing Options

A. Option 1 - The Limited Section 4 Filing

Commenters make two requests concerning the limited section 4 option. The LDC Coalition requests (at 15-16) the Commission to hold that neither the filing of the Form 501-G nor a limited section 4 filing in which only tax costs are addressed will satisfy a pipeline's "come-back" obligation under a settlement. The APGA notes (at 7) that not all pipelines employ Straight Fixed-Variable ("SFV") rates, and that as a result proposed section 154.404(c) of the Commission's regulations pertaining to limited section 4 filings should be amended to allow pipelines to reduce usage rates in addition to reservation rates if there are fixed costs in usage rates. INGAA does not oppose these requests.

B. Option 3 – The Explanatory Statement

In the NOPR, the Commission stated that one reason why an adjustment to a pipeline's rates may not be required is if the pipeline has a settlement with an expiring rate moratorium or a come-back obligation to file a new Section 4 rate case "in the near future." NOPR at P 28. The LDC Coalition asks (at 21) the Commission to specify what it means by "near future". There is no need for a specific deadline for a rate moratorium or come-back provision to justify the postponement of a Section 5 investigation. It is not yet known when the Commission will make these determinations for each pipeline. Therefore, the length of time from such a determination to the time a pipeline might otherwise adjust its rates is unknown. Other factors, such as the size of the pipeline and how long ago the settlement was executed could also affect this decision. The better approach is to address such explanations on a case-by-case basis.

Direct Energy Business Marketing and the Interstate Gas Supply ("DEBM/IGS") request (at 8) that when a pipeline chooses Option 3 and the Commission finds that the "pipeline's revenues are so far in excess of its actual cost of service," the Commission should find that the pipeline's rates are presumptively unjust and unreasonable under Section 5, and order an "immediate proportional rate reduction." DEBM/IGS seems to suggest (at 11) that the Commission's elimination of minimum bills in Order No. 380 could serve as precedent for such a summary reduction.

DEBM/IGS' proposal for immediate rate reductions is unlawful. Absent a Section 5 investigation and hearing into the justness and reasonableness of a pipeline's *overall* rates, there would be no basis for a finding that a pipeline's revenues are "far in excess" of its costs and presumptively unjust and unreasonable. Indeed, the purpose of the Form 501-G is to allow the Commission to "estimate" reductions in pipeline costs of service resulting from the TCJA and Revised Policy Statement ("RPS") and to "estimate" actual rates of return before and after the tax rate change and RPS. NOPR at P 32. Such estimates cannot provide a basis for immediate rate reductions. The reasonableness of a pipeline's rates depends on the resolution of numerous factual issues that cannot be resolved on a summary basis.[36]

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[36] *Cf. KN Interstate Gas Transmission Co.*, 87 FERC ¶ 61,267 (1999), cited by DEBM/IGC at n. 16 where the Commission granted summary disposition because there were no genuine issues of material facts in

As one example, the Commission has proposed to require pipelines to utilize a 10.55 percent return on equity ("ROE") to compute rates on the Form 501-G based on an ROE approved for one pipeline based on financial data from 2010-2011. What a reasonable ROE would be for any specific pipeline must be based on current data and would be dependent on the returns of proxy group companies with commensurate risks to that pipeline. These factual issues cannot be resolved absent a hearing.[37]

Order No. 380 lends no support for an immediate rate reduction for changes in the tax allowance afforded to individual pipelines. In that Order, the Commission found in a rulemaking that minimum bills were anti-competitive as a matter of law and policy.[38] A finding based on law and policy in a rulemaking is vastly different than summary action in an adjudication of the just and reasonable rates of pipelines, which depends on the resolution of numerous interrelated factual issues.

C. Option 4 - No Action

Several commenters propose to eliminate the "no action" Option 4 and/or fold that option into Option 3.[39] The justifications offered for eliminating this option are that the option is unproductive and may lead to the overwhelming majority of pipelines electing it. These commenters, however, ignore the reason the Commission provided this option. As the Commission stated, "[t]his option is consistent with the fact that the Commission lacks

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dispute concerning the treatment of expansion costs. *FPC v. Tennessee Gas Transmission Co.,* 371 U.S. 145, 155 (1962), cited in *KN,* is also inapposite. There, the Commission issued an interim order on the rate of return but only after a hearing was held on that issue. *Id.* at 148-49.

[37] DEBM/IGS' proposal is also vague and unworkable. How much would a pipeline's revenues have to exceed its costs to invoke this drastic remedy? What is meant by a "proportional" rate reduction, and how could such a reduction be allocated across rate classes and rate zones on a summary basis?

[38] *See Wisconsin Gas Co. v. FERC,* 770 F.2d 1144, 1166 (D.C. Cir. 1985) ("As we have established, substantial evidence supports the Commission's conclusion that minimum bills and minimum take provisions have two industry-wide effects: minimum bills can result in the recovery of unincurred costs and are anticompetitive.").

[39] Indicated Shippers at 13-14; DEBM/IGS at 8-9; NGSA at 6; Southern Companies at 5.

authority under the NGA to order an interstate pipeline to file a rate change under NGA section 4." NOPR at P 51. The Commission is correct that it cannot order pipelines to justify or explain why existing approved rates continue to be just and reasonable absent the protections afforded by NGA section 5. To the extent that pipelines do not commit to either Options 1 or 2, they should have the option to explain why a rate reduction is not necessary, or take no action.[40]

V. Comments on ADIT

In its comments, INGAA expressed the concern that the Commission's consideration of tax rate reductions and the impact of such reduction on ADIT on two separate tracks would create uncertainty and a lack of clarity. INGAA proposed that the Commission complete the rulemaking process in Docket No. RM18-12 before or at the same time as it issues a final rule in the instant proceeding.

Other parties also commented on the relationship between the tax rate reduction and ADIT. The LDC Coalition also refers to the two different proceedings established to address these two issues and requests the Commission to take certain action which suggest the Commission should address ADIT in this proceeding. Specifically, the LDC Coalition requests (at 23) the Commission to require pipelines to explain how they treated ADIT in their Form 501-Gs, including a requirement to attach a spreadsheet or explanatory statement to their filings showing the methodology used to recalculate ADIT and for calculating any related offsetting accounting entries. It also requests the Commission to

[40] IOGA argues (at 5) that if a pipeline elects the no action option, the Commission should "commit" to exercising its rate authority under Section 5. To the extent IOGA is suggesting that the Commission automatically initiate a Section 5 investigation for every pipeline that chooses the no action alternative, such request should be denied. A pipeline's data may on its face demonstrate no rate reduction is required without any explanation. IOGA's apparent assumption that a pipeline's silence demonstrates a rate reduction is required is unfounded.

revise proposed section 154.404 to include the calculation of ADIT in the scope of hearing issues for purposes of its FERC Form 501-G and concurrent limited section 4 filing.[41] APGA similarly requests (at 7) that parties be allowed to comment about the accounting treatment of ADIT.

These comments are premised on the relationship of the TCJA and ADIT referenced by INGAA in its comments. INGAA agrees the two issues should be addressed in a manner that efficiently takes into account both the tax rate reduction and its impacts on ADIT. For the reasons explained by INGAA in its comments, the review of rates contemplated in this proceeding should not occur before the issues surrounding ADIT are resolved.

Unless the Commission addresses issues related to ADIT at or before the Commission issues a final order in this proceeding, the LDC Coalition's requests are improper. The NOPR clearly states that it does not intend to take any action regarding the effect of the TCJA on ADIT. Thus, there is no need for Section 4-type explanations of ADIT treatment in this proceeding. The NOPR simply requires pipelines to populate the Form 501-G with data from their Form 2s. NOPR at PP 32-33. Nor is there any reason to revise proposed section 154.404 to include the calculation of ADIT in the scope of issues included in limited section 4 filings.

[41] The LDC Coalition's suggestion that proposed section 154.404 identifies the scope of hearing issues "for purposes of its FERC Form 501-G" is erroneous. That section applies only to limited section 4 hearings.

VI. Comments on MLPs and Other Pass-Through Entities

The NOPR proposes to implement the RPS through its instructions for pipelines to complete the Form 501-G. As INGAA has demonstrated in both its comments on the NOPR and its related request for rehearing of the RPS in Docket No. PL17-1-000, the RPS is legally deficient in several regards. Specifically, as it pertains to the NOPR, the Commission unlawfully proposes in the NOPR to implement the policies announced in a policy statement as if it were a rule by requiring pipelines to incorporate that policy in its Form 501-G. For the reasons INGAA explained in its comments, the Commission should remove the NOPR's proposal to address the income tax allowance of all pass-through entities in this rulemaking proceeding, and allow all such pipelines to propose tax allowances in their individual rate proceedings, where such issues could be adjudicated on a full evidentiary record.

To the extent parties have requested in their comments to require MLPs to assume a tax allowance of zero, they should be rejected for the reasons explained by INGAA.[42] To the extent parties have requested the Commission to clarify, rule on, or otherwise address the tax allowance to be afforded to pass-through entities that are not MLPs, such requests are premature. In the RPS, the Commission stated that the tax allowance for pipelines *organized as MLPs* will be addressed in the NOPR in this proceeding, but that *pass-through entities other than MLPs* will be addressed in subsequent proceedings.[43] The Commission should decline to address in this proceeding AGA's requests (at 5-6) to clarify the (1) treatment of MLP unit holders of non-MLPs; (2) the percentage of MLP ownership that will trigger the policies announced in the RPS; and (3) the level of upstream ownership

[42] *See, e.g.*, CAPP at 6.
[43] RPS at P 8.

that is relevant to these policies. Similarly, APGA's requests (at 6-7) that the Commission revise its proposed regulations to include all pass-through entities to justify the continuation of a tax allowance, and to allow parties to comment on such justification, should also be denied. As stated in the RPS, these issues should not be addressed in this proceeding, but should be addressed in response to pipeline filings in individual rate cases.

VII. Conclusion

WHEREFORE, INGAA respectfully requests that the Commission grant this motion for leave to answer and answer to the comments filed by various parties in this docket.

Respectfully Submitted,

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DATE: May 10, 2018

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing documents upon the parties designated on the official service list compiled by the Secretary of the Federal Energy Regulatory Commission for the above-captioned docket in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure.

Dated at Washington, D.C. this 10th day of May, 2018.

Ammaar Joya