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Independent and In-Depth Reporting on the Energy Industry

THE FOSTER REPORT

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FERC

FERC Cleans Up Some Pending Issues Governed by its Natural Gas Regulations, Including Lingering Questions Emerging from Orders 787 and 790, and PL15-1 (Pipeline Modernization Cost Recovery)

There was an unusually large batch of oil and gas industry orders voted by the FERC at its July 16, 2015 public meeting, the last "sunshine" meeting at the Commission until September. The synopsis below identifies the Commission's key decisions this week and offers a brief review. Some of the listed actions, such as order dealing with El Paso Natural Gas Co.'s rates, will be reviewed further in next week's Foster Report.

1. Communication of Operational Information between Natural Gas Pipelines and Transmission Operators. The Commission denied National Fuel Gas Distribution Corp.'s request for clarification of Order No. 787 (RM13-17) regarding communications between public utilities and local distribution companies. The Commission dismissed NFG Distribution's request for clarification as beyond the scope of the rulemaking. Order 787 provides explicit authority to interstate natural gas pipelines and public utilities that own, operate, or control facilities used for the transmission of electric energy in interstate commerce to share non-public, operational information with each other for the purpose of promoting reliable service or operational planning on either the pipeline's or public utility's system. NFG Distribution sought to persuade the Commission to permit sharing of information received from a local electric utility concerning impending or ongoing power outages in a National Fuel office building with potentially prohibited employees that work in the same building. The order dismissed the rehearing request, finding that it involves a matter unrelated to the type of wholesale transactions addressed in Order 787. The Commission stated that the regulations, including the No-Conduit Rule, are applicable to non-public, operational information being transmitted from interstate pipelines to public utilities and vice versa. The Commission, however, made clear that the rule does not affect the ability of an electric transmission operator to share its own information with an LDC, if otherwise permitted under its tariff. Based on the information provided by National Fuel Pipelines, FERC further concluded that its June 19 order found that good cause did not exist to justify granting a waiver of Order 787 to permit National Fuel Pipelines to communicate information received under the rule regarding electric service interruptions or impending power outages to affiliated non-shared employees.

2. FERC also dismissed a joint request of National Fuel Gas Supply Corp. and Empire Pipeline, Inc. (RP14-380) for rehearing regarding the scope of the No-Conduit rule adopted in Order 787 -- which prohibits subsequent disclosure of information received from a public utility or interstate pipeline with a third party or a marketing function employee of the public utility or pipeline.

3. In a Notice of Proposed Rulemaking (NOPR) (RM96-1), the Commission proposes to amend the regulations to incorporate by reference, with certain enumerated exceptions, the

latest version (Version 3.0) of business practice standards adopted by the Wholesale Gas Quadrant of the North American Energy Standards Board applicable to interstate natural gas pipelines. These revisions, in part, revise the codes used to identify receipt and delivery locations in the Index of Customers. The Commission also is proposing certain conforming changes to the regulations in section 284.13(c) and in regulations on exhibits and system flow diagrams.

4. FERC denied the pipeline's requests for rehearing regarding changes to its tariff provisions which govern reservation charge crediting and pipeline liability of Enable Gas Transmission, LLC (RP12-498, RP12-498). The order generally approved Enable's compliance filing, but directed Enable to make another modification.

5. An order on compliance and clarification addresses El Paso Natural Gas Co.'s (RP12-816, et al.) voluntary filing of revised tariff sheets to adopt the Commission's determinations made in Opinion No. 517, and responds to El Paso's request that the Commission clarify that no interim refunds or additional rate changes will be required until the Commission issues an Order on Rehearing in El Paso's 2011 Rate Case (RP12-1398).

6. Opinion No. 517-A generally rejected requests for rehearing relating to rate and settlement interpretation determinations made in Opinion 517, which addressed the rates of El Paso Natural Gas Co. (RP08-426, et al.) for the locked in period, 1/1/09 through 3/31/11. The opinion granted limited rehearing to permit El Paso to attribute $50 million of a $760 million capital structure adjustment to debt (resulting in an estimated 49.6% equity ratio). The order also generally accepted El Paso's compliance filing and directed refunds within 60 days.

7. An order denies requests for clarification of the Commission's April 16 Policy Statement regarding Cost Recovery Mechanisms for Modernization of Natural Gas Facilities (PL15-1). The order declined to set out the specific data that a pipeline must provide to justify existing base rates, and declined to adopt formal procedures for the collaborative process that pipelines must undertake prior to filing for a modernization cost tracker (see below).

8. The Commission dismissed High Prairie Pipeline, LLC's request for rehearing of a 5/18/12 order that accepted proposed revisions to the Nomination Verification Procedures of Enbridge Energy, LP (IS12-236). High Prairie contends that the Commission erred in the 5/18/12 order by imposing a new and unlawful litmus test for a protesting party, i.e., that a protesting party must be a shipper or potential shipper on the pipeline that filed the tariff. High Prairie also challenged (a) the Commission's determination that High Prairie does not have a substantial economic interest in the tariff filing, (b) the Commission's reliance *on Plantation Pipe Line Co. v. Colonial Pipeline Co.*, (c) the Commission's determination that it cannot order Enbridge Energy, LP to file a tariff containing a connection policy, and (d) the Commission's failure to address arguments that the tariff will allow Enbridge to unduly discriminate against new shippers. The Commission denied High

Prairie's premises and requests. FERC said that all issues raised by High Prairie on rehearing have already been addressed in the May 18 order and in related complaint proceeding orders issued 3/22/13 and 10/1/14 in Docket No. OR12-7. The March 2013 order dismissed a complaint by High Prairie, finding that Enbridge Energy did not unduly discriminate against High Prairie and its shippers by refusing to grant an interconnection at the Clearbrook, Minnesota origin point. Rehearing of the March 2013 order was denied in the order issued October 1.

9. FERC granted rehearing and clarified a Final Rule (Order No. 790-A, RM12-11) implementing Revisions to Auxiliary Installations, Replacement Facilities, and Siting Maintenance Regulations. Order No. 790-B (1) provides pre-granted authority under new subsection 2.55(a) (3) for companies to abandon auxiliary facilities, subject to certain conditions; (2) permits auxiliary facilities that cannot meet the conditions for the pre-granted abandonment authority to be abandoned under section 157.216, subject to those regulations' requirements; and (3) permits 2.55(b) replacements to be abandoned under section 157.216 of the blanket regulations, subject to those regulations' requirements.

Certificate Proceedings. Floridian Natural Gas Storage Co., LLC (CP13-541) gained FERC's approval to amend its certificate in order to construct and operate a liquefied natural gas (LNG) storage facility near Indiantown in Martin County, Florida. Floridian will modify the previously authorized Phase 1 facilities by substituting a 1 Bcf single containment LNG storage tank for the previously authorized 4 Bcf full-containment tank and reducing the associated Phase 1 vaporization capacity.

FERC also authorized the interstate pipeline facilities and abandonment request of Southern Natural Gas Co. LLC (CP15-23), clearing Southern to construct and operate the North Main Line Relocation Project that would be located in Jefferson County, Alabama. Southern is authorized to abandon in place three segments on its existing North Main Lines and one short segment on its Calera Branch Line, also located in Jefferson County.

Order No. 790-B. Staff explained to the Commissioners during the meeting that the rulemaking follow up Order 790-B was originally initiated by a petition filed by the Interstate Natural Gas Association of America (INGAA). Section 2.55 of the regulations govern the scope of auxiliary installations, which include activities ranging from the construction of very minor valves and station yard piping to pig launchers and gas conditioning, electrical and communication equipment. INGAA sought clarification because it disagreed with Commission staff's position that all section 2.55 construction activities, both of replacement facilities and auxiliary installations, must stay within existing rights-of-way and facility sites and use only those previously disturbed work spaces that were subject to the Commission's environmental review before the existing facilities were constructed.

In Orders No. 790 and 790-A, the Commission clarified and affirmed staff's position that spatial limitations do apply to auxiliary installations under these regulations, even if a landowner is willing to grant the company additional right-of-way or other area needed for a project. Now, staff asserted, "Order No. 790-B further streamlines the Commission's regulations by reducing the number of case-specific applications that companies would need to file to abandon auxiliary installations that meet the special limitations of section 2.55 and of auxiliary installations and replacement facilities that do not meet section 2.55's limitations." Order 790-B specifically amends section 2.55 to include pre-granted abandonment authority to abandon or replace auxiliary installations within existing rights-of-way and other previously reviewed areas.

In addition, the Commission's blanket certificate regulations – which are subject to environmental conditions and review – were amended to provide authorization for the abandonment of section 2.55 facilities in other instances. Companies will be able to use this new blanket authority to retire auxiliary facilities in situations where section 2.55(a)'s new pre-granted abandonment authority will not be available because the abandonment activities need to go outside existing rights-of-way or use other area that have not been reviewed by the Commission. The new blanket certificate authority also would apply to "replacement facilities", to which section 2.55(a)'s new pre-granted abandonment authority will not apply even if abandonment activities do not need to use new areas.

Cost Recovery Mechanisms for Modernization of Natural Gas Facilities (PL15-1). On April 16, 2015, the Commission issued a policy statement to provide greater certainty regarding the ability of interstate natural gas pipelines to recover the costs of modernizing their facilities and infrastructure to enhance the efficient and safe operation of their systems. Standards were adopted to govern simplified mechanisms, such as trackers or surcharges that will be used by interstate natural gas pipelines to recover certain costs associated with replacing old and inefficient compressors and leak-prone pipes and performing other infrastructure improvements and upgrades to enhance the efficient and safe operation of their pipelines. Process Gas Consumers Group (PGC) and the American Forest and Paper Association (AF&PA) requested clarification of the Policy Statement. FERC yesterday denied those requests. The Commission denied the requests for clarification and declined to adopt the suggested formal procedures.

The Policy Statement adopted five guiding standards a pipeline would have to satisfy for the Commission to approve a proposed modernization cost tracker or surcharge. Those criteria are (1) Review of Existing Base Rates; (2) Defined Eligible Costs; (3) Avoidance of Cost Shifting; (4) Periodic Review of the Surcharge and Base Rates; and (5) Shipper Support.

In their request for clarification the PGC and AF&PA asked FERC to affirm six points related to the Policy Statement, specifically: (1) that pipelines must provide actual cost and revenue information, based on twelve months of operation, including the type of data required; (2) the party responsible for paying modernization surcharges in existing capacity release arrangements; (3) the formal procedures for conducting the collaborative process to ensure all stakeholders are invited and included in meetings; (4) that the Commission intends the pipeline to work with each shipper sector in the collaborative process; (5) that if a pipeline has over-collected through a surcharge or tracker such that its rates are later found unjust and unreasonable the pipeline must pay refunds calculated from the date a protest or complaint was filed; and (6) that pipelines may not seek to implement a modernization tracker or surcharge until the October 1 effective date of the policy.

In answer, the Commission reaffirmed its fundamental objective to set standards that are "sufficiently flexible so as not to require any specific form of compliance but to allow pipelines and their customers to reach reasonable accommodations based on the specific circumstances of their systems." The Commission will evaluate any proposal for such a surcharge case by case. "The requested clarifications are antithetical to that approach."

Collaborative Process. It is the Commission's intention that the process be an "informal process" for parties to share information and negotiate absent Commission involvement. With respect to concerns that customers may not be aware of, or be made aware of, the initiation of the collaborative process to implement a modernization cost tracker, a pipeline will have to make an NGA section 4 filing to implement any cost modernization surcharge. That filing will be noticed the same as any other section 4 filing, and will provide all interested persons the opportunity to intervene in the proceeding and to protest. The burden in that instance will be on the pipeline to demonstrate that its proposal is just and reasonable.

In other words, it is in the proposing pipeline's best interest to resolve as many outstanding issues as possible through the collaborative process prior to filing a cost recovery mechanism proposal. In the Commission's opinion, the procedures as suggested by the requesters would thwart rather than facilitate this intent and the collaborative process.

Existing Rate Justification. Requesters asserted that the Policy Statement does not identify the data that pipelines must provide under the Commission's regulations to show that the rates are just and reasonable, and whether a cost and revenue study would need to include the information in the form required by the regulations. They asked the Commission to clarify that the pipeline must provide its most recent 12-months of actual costs and revenues and other information prior to engaging in any collaborative process with its shippers.

The Commission denies clarification. It was already determined neither to require a specific method by which the pipeline must show its existing rates are just and reasonable, nor to prescribe the specific data or form that the data must take if a pipeline chooses to justify its existing rates by a method other than a general section 4 rate case.

Rather, to the extent a pipeline seeks expedient approval of a modernization cost tracker, the Commission expects that the pipeline will freely share data and the results of its system testing to attempt to resolve as many issues as possible prior to filing for the tracker under the established section procedures.

Retroactive Refunds. If the Commission is unable to determine the justness and reasonableness of a proposed modernization cost tracker mechanism within 30 days after its filing pursuant to section 4, it will suspend the filing and it will remain subject to refund until the Commission determines whether it is just and reasonable. Further, once a modernization cost tracker mechanism has been approved, the requirement that such mechanisms include a provision for trueing up cost over and under-recoveries will ensure that the pipeline only recovers eligible costs approved for recovery in the tracker mechanism.

Each of the pipeline's periodic filings pursuant to its modernization cost tracker mechanism would include a comparison of the costs approved for recovery during the prior period with the amounts the pipeline actually collected from its shippers during that period.

To the extent the pipeline over-recovered or under-recovered costs during the relevant period, it would adjust the surcharge for the next period up or down so as to either return the over recovery to its shippers or collect any under-recovery from them. Accordingly, the Commission "finds no reason to condition the right to implement a modernization cost tracker mechanism on the pipeline's agreement to forego its NGA section 5 rights against retroactive refunds for amounts recovered pursuant to a modernization cost tracker mechanism that the Commission has approved as just and reasonable...."

Cost Responsibility in Capacity Release Agreements. In their answers to the clarification request, INGAA and the Natural Gas Supply Association (NGSA) opposed the requesters' proposal that cost responsibility for any modernization surcharge be placed on replacement shippers.

According to the Commission, the regulations state that unless otherwise agreed by the pipeline, the contract of the releasing shipper will remain in full force and effect during the release, with the net proceeds from any release to a replacement shipper credited to the releasing shipper's reservation charge. Therefore, "to the extent the releasing shipper's service agreement permits the pipeline to recover the surcharge from the releasing shipper, the releasing shipper would remain liable for the surcharge during the term of any temporary release." That is, the replacement shipper's liability for the surcharge would turn on the terms of its release.

If the release requires the replacement shipper to pay any portion of the surcharge, those payments would be credited to the releasing shipper. In short, cost responsibility for modernization costs during the term of a capacity release is a contractual issue between the relevant parties, and that issue cannot be resolved on a generic basis, the order stated.

Effective Date. The requesters stated that this effective date enforcement would provide the Commission time to prescribe the formal procedures they sought. But the Commission declined to provide the requested clarification. The Commission "has no authority to regulate a pipeline's discussions with its customers or the content of such discussions." Moreover, even if it had the authority, the Commission advocates active discussions between pipelines and their customers.

Additionally, the Commission lacks the authority to prevent a pipeline from making a section 4 filing to request approval for a modernization cost tracker. As INGAA notes, the Policy Statement did not permit pipelines to file for tracker mechanisms for the first time; it announced the Commission's policy for addressing such filings. There is nothing to prevent a pipeline from making a proposal consistent with the Commission's existing policy as set forth in *Columbia Gas Transmission, LLC* (2013), prior to October 1.

Finally, the Commission affirmed that as with any policy statement, this one is not a final action of the Commission but "an expression of our intent as to how we will evaluate proposals by interstate natural gas pipelines for the recovery of infrastructure modernization costs."

FERC Tech Conference on Oil Pipeline Index-Reset Will be Held on July 30 in Washington

FERC this week officially established a public technical conference to move forward its Five-Year Review of the Oil Pipeline Index (RM15-20) that it announced in a Notice of Inquiry issued on June 30. The conference will be held on July 30, from 2:00 pm to 3:30 pm (EST), at the offices of the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC, 20426. The conference will be led by Commission Staff and may be attended by one or more Commissioners.

The purpose of the conference is to gain an understanding of the positions of the parties in advance of the filed comments in this proceeding. Interested persons will be permitted to give brief presentations regarding the index level proposed and "alternative methodologies" for calculating the index level. Each presenter will be allowed up to 15 minutes as time permits based on the number of presentations.

Those interested in providing presentations are asked to submit a brief request to speak in this docket on or before July 15, a date already past. This conference is open to the public. Pre-registration for attending is not required, but is recommended. Registrations can be made at: (https://www.ferc.gov/whats-new/registration/07-30-15-form.asp).

The Liquids Shippers Group have already signed up. They include, Anadarko Energy Services Co., Apache Corp., Cenovus Energy Marketing Services Ltd., ConocoPhillips Co., Devon Gas Services, LP, Encana Marketing (USA) Inc., Marathon Oil Co., Murphy Exploration and Production Co.-USA, Noble Energy, Inc., Pioneer Natural Resources USA, Inc., and Statoil Marketing & Trading (US).

OIL PIPELINE RATES

FERC Trial Staff Raises Possibility that Buckeye Settlement with the Airlines Brings Contract Incentive Rates into Conflict with Non-Discrimination Provisions of Interstate Commerce Act

FERC Trial Staff, commenting on the Settlement Agreement filed on June 19 by American Airlines, Inc., Delta Air Lines, Inc., JetBlue Airways Corp., United Airlines, Inc., US Airways, Inc., and Buckeye Pipe Line Co., outlined the reasons it does not oppose certification to the full Commission and why the deal may be beneficial to all parties, but also expressed concern with two aspects. (Airlines v Buckeye Pipeline Co., OR12-28, et al.) It amounts to a reduction from Buckeye's current rates of 20% to JFK Airport and 40% to Newark International Airport for all shippers. Staff asserted, the settlement provides "significant benefits, including facility improvements that will provide greater flexibility to meet summer peak demand at J.F. Kennedy International Airport (JFK Airport)."

However, Staff expressed misgivings that, first, the Settlement specifically precludes third-party marketer shippers from direct participation in the settlement's newly-created volume incentive rate program. Second, even though the base rates that shippers other than the incentive-eligible jet fuel end-users will pay (and that all shippers will pay after termination of the settlement) represent a reduction from current rates, "they nonetheless are significantly higher than any participant, including Buckeye, proposed" as just and reasonable in the cost of service proceeding.

Trial Staff is concerned that this exclusion is at odds with the non-discrimination provisions of the Interstate Commerce Act (ICA). "There is a question of law and policy regarding whether disparate circumstances between shippers can justify disparate rates based on the end use by shippers."

The Commission has not previously, to Trial Staff's knowledge, approved of disparate incentive rate or contract programs for oil pipelines that specifically exclude certain shippers from the ability to participate. Therefore, "there is a substantial issue of law and policy as to whether an oil pipeline can exclude certain shippers from the ability to enter into volume, term, or other contract incentive rates without running afoul of the non-discrimination provisions of the ICA." In approving incentive contract rate structures under the ICA, the Interstate Commerce Commission, the courts, and this Commission have "from the beginning" based approval on the fact that they were offered to all shippers. "Whether it is appropriate to exclude certain shippers from incentive rates on the basis of whether the shipper is an airline or is a marketer to airlines," Trial Staff believes, is "a matter of first impression" for the Commission.

There are similar law and policy issues in approving settlement base rates that are substantially in excess of what any party proposed or supported in the cost of service proceeding, Trial Staff suggested.

Three dockets consolidated in the process will be resolved except for a part of the market-based rate application in Docket No. OR13-3. Buckeye will withdraw the portion of its market-based rate application related to jet fuel in the New York City market, but may seek approval or submit a revised or amended application to obtain market-based rate authority for non-jet fuel transportation to Inwood and Long Island City. And no initial decision will be issued in the cost of service docket.

Experimental Program and Challenges. A unique Experimental Rate Program proposed by Buckeye, and adopted by the Commission in 1990, adopted the current rates for the pipeline after it was determined that Buckeye lacked market power in the transportation of refined petroleum products in the majority of its markets. That program relied on the changes in rates in competitive markets, and subject to a cap and weighted based on volume, set the rate increases in non-competitive markets, which included the New York City market and Buckeye's service to JFK, Newark, and LaGuardia Airports. Therefore, Buckeye was permitted to increase the rates in its non-competitive markets, including the New York City market, by the increase in the rates in its competitive markets.

The Experimental Rate Program existed unopposed until 2011; on 3/30/12, the Commission rejected a proposal by Buckeye to increase its rates under that program for transportation of jet fuel to its New York City destinations. Buckeye had to show cause why the program should not be discontinued.

Later in 2012, the Airlines (with the exception of American Airlines, Inc.) initiated the cost of service complaint proceeding in Docket Nos. OR12-28 et al. The challenge questioned the lawfulness of Buckeye's rates for transportation of jet fuel from the Linden, New Jersey, area to Newark, JFK, and LaGuardia (NYC-area Airport Destinations). The Airlines requested prospective just and reasonable rates, and also sought reparations for the two years prior to the filing of their complaint through the date on which any new rate was set.

On 10/15/12, Buckeye filed an application to charge market-based rates in the New York City market, including the three NYC-area Airport Destinations, and the Inwood and Long Island City, New York, destinations.

Then in February, 2013, the Commission issued orders in the show cause proceeding, in the cost of service complaint proceeding, and on the market-based rate application. In the show cause proceeding, the Commission discontinued Buckeye's Experimental Rate Program. FERC directed that the rates for the New York City market "will be addressed in … pending filings before the Commission."

The order in the cost of service proceeding set for hearing the justness and reasonableness of Buckeye's rates for the transportation of jet fuel to the NYC-area Airport Destinations and set Buckeye's market-based rate application for hearing. The OR12-28 and OR13-3 dockets were consolidated for settlement purposes.

Then on 9/17/14, American Airlines filed a complaint (OR14-41) that also challenging the lawfulness of Buckeye's rates to the NYC-area Airport Destinations. This matter was set for hearing as well.

Trial Staff reviewed the settlement in principle, and apparently the parties resolved some but not all of Staff's concerns. Staff disclosed it determined not to oppose certification but reserved its right to address its remaining concerns.

Black Box Settlement. The "black box" settlement launched on June 19 establishes new base transportation rates for jet fuel that are different from, and higher than, the rates proposed by any of the participants in the cost of service docket. Those base rates, however, are lower than Buckeye's Experimental Rate Program tariff rates to JFK Airport and Newark Airport, and are available to all shippers, without acceptance of how or whether any cost of service principles or Commission policies should be applied. The rates would take effect July 1, to be adjusted going forward based on the Commission's indexing methodology.

Volume incentive contract rates for qualifying shippers, including airlines that are not settling parties, are significantly lower than the base transportation rates. To qualify for the incentive rates, generally the shipper must be an ultimate consumer of jet fuel (i.e., an airline) and transport a minimum of 3.3 million barrels of jet fuel annually to the NYC-area Airport Destinations. Airlines with smaller shipments of jet fuel are allowed to create an entity to aggregate shipments and thus qualify for the volume discount rate.

Non-airline shippers, that is, third-party marketers shipping in their own name, are not eligible for volume incentive rates.

Each complainant Airline will receive a settlement payment directly from Buckeye, while the amounts of the payments are confidential. The new base and volume incentive rates will be adjusted annually under the Commission's indexing methodology.

Pursuant to terms of the agreement, Buckeye will undertake a new capital project to improve delivery capability to JFK Airport by cross-connecting Line 602 and Line 601, which will enable both lines to deliver jet fuel to JFK simultaneously. While no new pipeline capacity will be created, it purportedly will increase flexibility by allowing simultaneous delivery into JFK from both lines where now only one line can provide service there at a time. This project will be completed approximately 9 months after approval of the settlement, and Staff says this "represents a major benefit for airlines at JFK Airport."

The cost of the Project will be $12,900,000. The Airlines have an option to invest in the project, and a surcharge to recover the additional costs, including a return on equity, is imposed. Specifically, the Airlines have the option to invest in the project up to an aggregate amount of 50% of the total costs. The increased operating and property tax expenses from the project are stated to be $609,792 annually. The capital costs and increased operating expenses will be collected through a surcharge of 7.233 cents per barrel on all jet fuel shipments to JFK Airport. The surcharge amount is designed to collect the total capital cost within 12 years based on historical and projected throughput, and also includes recovery for the increased operating expenses and a 10% overall rate of return.

The Airlines will receive a percentage of the surcharge revenues based on their level of investment, should they exercise the option. After the total capital costs are recovered, the surcharge will be terminated and the increased annual operating and property tax expenses will be treated as jurisdictional operating and tax expenses, but the capital costs will not be reflected in net plant.

Additionally, Buckeye committed to evaluate operating pressures and a midpoint booster for future capacity options. Buckeye pledged increased coordination and cooperation with the Port Authority of New York and New Jersey, the JFK Fuel Committee, and the JFK Working Group to maximize the efficient use of the existing delivery system for JFK and to plan for future jet fuel transportation needs for the NYC-area Airport Destinations.

The Settlement has a term of three years, after which the volume incentive rate would end. "To promote possible extension of the Settlement, Buckeye agreed to share cost, volume, and revenue data with the Airlines at the end of the Settlement Period."

As indicated above, to obtain the incentive rates a shipper must contract to ship a minimum of 3.3 million barrels of jet fuel annually for three years in aggregate to the three NYC-area destinations, subject to deficiency payments and other conditions. A shipper has 90 days after notice is posted to Buckeye's website to contract for these incentive rates. However, also as noted above, not all shippers are eligible, and not all volumes qualify, for the volume incentive program.

Buckeye is to provide the complainant Airlines with two years of cost, volume, and revenue data in a FERC Form No. 6, Page 700 format, showing separately the Long Island System and the Eastern Products System in the last year of the settlement period. This information-sharing "is designed to promote mutual understanding and possible extension of the Settlement," according to Staff.

First Impression Matter. While Trial Staff does not oppose certification, it raises two concerns for the Commission's consideration: (1) the exclusion of third-party marketer shippers from any participation in the volume incentive program; and (2) and the level of the base rates, which shippers that do not participate in the volume incentive program, including all third-party marketer shippers, will pay.

From the benefits perspective, FERC staff believes Buckeye's agreement to increase its capability to deliver jet fuel to JFK is important to enabling the future ability of airlines to meet summer peak travel demands and is an arrangement that could not have been imposed through litigation. Without the JFK Project, it is likely that shippers would have difficulty meeting the jet fuel needs of that airport in the summer of 2016. Moreover, with the rate reductions, the settlement provides benefits to non-party shippers, including those excluded from the new volume incentive rate program.

In addition, according to Staff, the settlement resolves the rate uncertainty and expense associated with the three proceedings, and removes the litigation risk faced by the parties. "If Buckeye were successful in its application for market-based rates, for instance, it is unclear what the level of rates would be to the NYC-area Airport Destinations."

Turning to its concerns, FERC's Trial Staff explained its reservation is not about the exclusion of third-party marketers on the basis of volumes shipped, which is consistent with past incentive programs, but is about the exclusion on the basis of the end use of those volumes and thus "the exclusion of certain shippers regardless of volumes."

The barrels eligible for incentive rates are limited to: a) those barrels shipped under a shipper's own name "provided that such Barrels are being shipped for ultimate consumption by Consumer;" b) barrels of an affiliate, commercial partner, or joint venture of a shipper with specific definitions; c) barrels sold to a third-party or other subsequent purchaser as part of emergency supply or inter-user balancing subject to a percentage limitation on the use of these transactions; and d) barrels shipped by a third party as shipper of record but title to those barrels is transferred to the "Consumer" at the delivery point or upon delivery into an airplane at the delivery point (the third-party shipper of record is charged the base rate and the ultimate consumer is credited back the difference between the base and incentive rate by the pipeline).[1]

The effect of these requirements, Staff explained, is that only airlines consuming the

[1] An "affiliate" is defined as one in which a shipper has control (more than 50% voting interests); a "commercial partner" is defined as one in which a "codeshare relationship," publicly declared marketing, or cooperative alliance exists; and a "joint venture" is an ownership interest by a shipper in a business enterprise or contractual enterprise with another air transportation company.

jet fuel (or their affiliates, joint ventures, or partners) are eligible for the volume incentive rates. Third-party marketers—who necessarily do not ultimately consume the jet fuel barrels—cannot participate in the volume incentive program and obtain the incentive rates.

Staff recites in its communication that the ICA prohibits undue discrimination or undue preference. In justifying incentive or contract rate structures (which necessarily discriminate against shippers that do not enter into the term or volume commitments) as not "unduly" discriminatory, the Commission and courts have required oil pipelines to offer such volume, term, and other contract incentive rates to all shippers. As the Court of Appeals for the District of Columbia Circuit summarized, "[a]lthough one normally regards contract relationships as highly individualized, contract rates can still be accommodated to the principle of nondiscrimination by requiring a carrier offering such rates to make them available to any shipper willing and able to meet the contract's terms."

FERC specifically has held that a fundamental requirement for the legality of discount rates under the ICA is that they be offered to all interested shippers.[2] Where an oil pipeline has not offered the incentive rate structure to all shippers, the Commission has required supplemental open seasons to allow for the inclusion of all shippers.[3]

According to Staff, differences in rates can be justified, however, where shippers are not similarly situated in the conditions or circumstances of service. "The core concern in the nondiscrimination area has been to maintain equality of pricing for shipments subject to substantially similar costs and competitive conditions, while permitting carriers to introduce differential pricing where dissimilarities in those key variables exist."

Staff reasons, given that the actual jet fuel transportation service provided to airline consumers and marketers is the same in this instance, the question, then, is whether there are different competitive circumstances among shippers and whether that permits disparate rates in this situation. The Interstate Commerce Commission and courts have approved disparate rates for railroads based on disparate competitive circumstances.

FERC has also done so in the context of discounted rates on natural gas pipelines. "The theory underlying this rate disparity allowance is that if carriers could not discount rates to shippers who have competitive alternatives, and who might otherwise leave the system by accessing those alternatives, all shippers would suffer from increased costs."

Here though, Trial Staff is "not aware of any competitive alternatives" to Buckeye or other competitive circumstances between airline shippers and marketers that could form the basis of a rate disparity.

Base Rates - Incongruity. Staff's second issue is that the agreed-to rates are in excess of the range of cost-supported rates proposed in the cost of service complaint proceeding, including the rates Buckeye proposed in that proceeding. In the cost of service proceeding, Trial Staff and Buckeye both submitted cost of service proposals.[4]

According to Trial Staff, when the Commission's indexing adjustments are removed from the 7/1/15 effective base rates in order to directly compare them to the 2012 test period proposals, the settlement rates are

2 Enterprise TE's open season for its Seymour Project failed to meet this fundamental requirement.

3 Enterprise TE was instructed to hold a supplemental open season and provide the same terms and conditions to contract for incentive rates, and information regarding those contract rates, to all potential shippers.

4 The Airlines proposed rates were based on a 2011 test period with an adjustment period and were lower than both Trial Staff and Buckeye's proposed rates.

up to 36% higher than what Buckeye proposed and up to 125% higher than what Trial Staff proposed.

In this case, while Trial Staff is not opposing the settlement, there appears to be "a significant incongruity between the Settlement base rates and the cost-based rates that even Buckeye proposed."

Familiar TAPS Rate Issues Emerge and Are Dusted Off In Latest Tariff Upgrade Lodged with FERC by ConocoPhillips Alaska

On July 16, FERC suspended a tariffed rate proposal of ConocoPhillips Transportation Alaska, Inc. (CPTAI) (IS15-522) representing an increase in its rate for interstate transportation of crude oil on its share of the Trans Alaska Pipeline System (TAPS) from $5.88 per barrel to $6.53/b. On July 1, the State of Alaska (Alaska) filed a protest, as did Anadarko Petroleum Corp. and Tesoro Alaska Co. (together, Anadarko/Tesoro). On July 6, CPTAI filed answers to the protests.

The proposed tariff was accepted, to become effective July 17, subject to refund. FERC will consolidate CPTAI's filing with the already-consolidated proceedings in Docket No. IS11-306-000, et al., which are being held in abeyance pending the outcome of the consolidated proceedings in Docket No. IS09-348-004, et al.

Besides the State of Alaska, the chief adversaries to this CPTAI rate proposal, like preceding ones, are Anadarko Petroleum and Tesoro Alaska.

The State had requested that investigation of CPTAI's latest tariff modification filing be consolidated with Docket Nos. IS11-306, et al., and held in abeyance pending resolution of the consolidated 2009 and 2010 TAPS rate proceedings in Docket Nos. IS09-348, et al. In is response, CPTAI said it does not object to those requests.

CPTAI says the State and Anadarko/Tesoro make the same arguments here that it put forward in prior protests of CPTAI's FERC tariffs in Docket Nos. IS14-596, IS13-480, IS13-125, IS12-498, IS11-306, IS10-476, and IS09-384. The State challenges (1) the cost of the TAPS Carriers' Strategic Reconfiguration Program (the "SR Program"), (2) treatment of dismantling, removal and restoration ("DR&R") costs, and (3) the operating expenses included in CPTAI's rate filing. Anadarko/Tesoro challenges the costs of the TAPS Carriers' SR program, operating expenses (including state ad valorem taxes), throughput, and rate of return. Anadarko/Tesoro also argues that CPTAI's tariff should be rejected for not explaining the rate change in the transmittal letter.

Strategic Reconfiguration. Recapping what has become an annual resurrection, the SR Program at issue with shippers consists of a series of projects that the TAPS Carriers have undertaken to reduce costs and increase efficiency, while claiming to be maintaining safety, pipeline integrity and environmental standards. The SR Program principally involves the electrification and automation of four TAPS pump stations. The State broadly challenges the SR Program's planning and execution and the prudence of the SR Program costs.

The State relies on the Initial Decision (IS09-348-004, et al.), which found that the TAPS Carriers imprudently planned and executed the SR Program. The TAPS Carriers have filed a brief on exceptions challenging various aspects of that decision, and the brief on exceptions is still pending before the Commission.

Conoco maintains that the fact that adjustments were made does not mean that costs incurred in connection with such adjustments were imprudent. Rather, the Commission has held that the prudence of management decisions is judged on the basis of what a reasonable pipeline manager would have done under the circumstances at the time the costs at issue were incurred, rather than using hindsight. Williams Natural Gas Co., (1997).

Further, the SR investment decisions of the TAPS Carriers are presumed by the Commission to be prudent, and the State bears the burden of raising a "serious doubt" with respect to the prudence of particular costs. So yet again CPTAI "strongly contests the broad and unsubstantiated allegations the State has made with respect to the SR Program." CPTAI continues to believe that, at the conclusion of the proceedings regarding these issues, the Commission will find that significant operational, environmental and cost savings benefits are (and will continue to be) achieved through the SR Program and that the State's claims lack merit.

DR&R Costs. The State's second chief allegation is that CPTAI may have improperly included some DR&R costs as operating expenses in its tariff filing. CPTAI declares that the State's "speculation" on this issue is entirely unsupported and without merit. The State's claims relate to the TAPS Carriers' obligation under the TAPS right of way agreements to dismantle and remove pipeline and related facilities, and to restore the condition of the right of way when TAPS eventually shuts down. But CPTAI says it did not include any DR&R costs in its rate filing.

Moreover, the State raised the exact same allegations regarding DR&R costs in its protests of the TAPS Carriers' 2009-2010 rate filings. According to CPTAI, in that proceeding the State did not present any argument or evidence supporting its DR&R allegations, despite having an opportunity to do so. There, as here, "there was simply no evidence to support the State's allegations.

Operating Expenses. Finally, CPTAI dismissed the State's challenge to the operating expenses included in its rate filing. Despite the SR Program, Alaska had claimed the "operating and maintenance costs appear to have substantially increased."

On the contrary, answers CPTAI, the SR Program has substantially reduced certain operating and maintenance expenses below the levels that would have been incurred without the SR Program. That said, CPTAI "never represented that all operating and maintenance expenses would necessarily be reduced below pre-SR levels." Rather, the TAPS Carriers' costs – like those of all businesses – are affected by a number of external factors. For example, the owner explained, a significant category of operating expenses that has increased is state and local ad valorem property taxes. During the applicable base and test period, the TAPS Carriers incurred approximately $267 million in pipeline taxes.

Anadarko/Tesoro's claims. According to CPTAI, the transmittal letter explained the proposed rate change and attached all of the schedules and workpapers required by the regulations to support a cost-of-service rate filing. CPTAI does not dispute that the proposed rates should be suspended subject to investigation and "looks forward to the opportunity to defend its rates at hearing. There is no justification, however, for summarily rejecting CPTAI's proposed rates as Anadarko/Tesoro proposes."

CPTAI said transportation of petroleum on TAPS between Prudhoe Bay, Alaska and Valdez Marine Terminal, Alaska, over CPTAI's share of TAPS capacity. Besides stating the rate change, the transmittal letter further explains that the new rate is calculated in accordance with the ratemaking methodology prescribed by the Commission for TAPS in Opinion 502.

Moreover, the schedules include significant detail regarding each of the required elements and set forth the precise calculations used to generate the proposed rates.

Anadarko/Tesoro's claim that it is required to "shoot in the dark" is "particularly disingenuous", fired back CPTAI, given that TAPS rates have been subject to extensive litigation during the past several years and Anadarko/Tesoro has been an active participant in those cases.

According to the owner, this time around, "far from waiting for its answer to justify the rate filing," it provided all of the required support for the proposed rate with the tariff filing." And the responses in the instant filing are not an attempt to make up for any deficiency in the rate filing, since that filing, including the transmittal letter and attached schedules and workpapers fully complied with the Commission's requirements.

Turning to Anadarko/Tesoro's concerns about the rate base, CPTAI explained that it did not include any additional test period retirements, since such retirements are not known and measurable at this time; defended its use of a base period ending March 2015 instead of a calendar year base period; rejected the shippers' charge that its costs are "excessive" or otherwise improper, or that costs were improperly "normalized."

CPTAI insisted its supplemental ad valorem tax amounts are properly included in rates. Anadarko/Tesoro does not dispute that the TAPS Carriers have already paid $377.7 million in supplemental ad valorem taxes attributable to recent reassessments of ad valorem taxes for the 2006-2009 tax years. CPTAI expects that additional supplemental tax payments will be required because the TAPS valuations used to determine the amount of ad valorem taxes owed for post-2009 tax years are also under appeal, and thus subject to reassessment in future years.

Additionally, several Alaska municipalities continue to challenge the assessed valuation of TAPS, advocating an increased valuation. "The municipalities have succeeded in these challenges in the past, and they may well succeed in the future." Accordingly, CPTAI claims it reasonably included in its test period rate calculation $75.54 million of supplemental ad valorem tax expense, representing the average of the annual supplemental tax payments made by the Carriers over the last 5 years.

"Amortization of the supplemental tax payments over a 5-year period will allow the Carriers to recover their costs, is fair to both shippers and the Carriers, and is fully consistent with Commission regulations and precedent."

Finally, CPTAI disputed Anadarko/Tesoro's challenge to its rate of return calculation, the throughput assumptions underlying CPTAI's rate, the DR&R costs (that CPTAI says it did not include in its rate filing), and the approach of charging a uniform rate (adopted in the Commission's Opinion No. 502, 2008).

On the latter issue, CPTAI stressed it was Anadarko/Tesoro that urged the Commission to adopt the uniform rate approach in the first place. Anadarko/Tesoro now claims that the uniform rate has proved to be "illusory" because in practice the TAPS Carriers' filed rates have not been uniform. That "circular argument", in the owner's opinion, does not demonstrate that the uniform rate approach is unreasonable.

Anadarko/Tesoro also claimed the uniform rate practice results in competitive harms because "the system-wide pooling the Commission required to facilitate the federal uniform rate has devastated competition in the state transportation market." However, Anadarko/Tesoro has already challenged the TAPS Carrier's pooling agreement in a lengthy proceeding, in which the Commission rejected Anadarko/Tesoro's position. Hence, CPTAI signed off admonishing FERC not to "entertain Anadarko/Tesoro's disingenuous attempt to reintroduce the pooling issue which has already been fully litigated."

INTERSTATE GAS PIPELINE RATES/TARIFFS

Texas Gas' Northern Supply Access Project Raises Red Flags for Municipals

A group of gas municipal distribution companies -- Western Tennessee Municipal Group, the Jackson Energy Authority, City of Jackson, Tennessee, and the Kentucky Cities (together, the Cities or municipals) -- recently aired various objections to Texas Gas Transmission, LLC's (CP15-513) proposed $149 million Northern Supply Access Project (NSAP), and especially questioning the pipeline's current fuel rate methodology and how it would apply to the project.

Given the structure of the fuel rate allocations, the Cities questioned whether or not the pipeline can financially support the project without relying on subsidization from existing customers. Texas Gas "must clarify how capacity from the project will be priced," the municipals demanded. The municipal customers also asked FERC to decline to grant the pipeline's requested predetermination of rolled-in rate treatment under its current rate design. They don't believe Texas Gas has shown it meets the standard for a predetermination decision, which requires showing that the projected revenues using actual contract volumes and actual maximum recourse rates would exceed estimated project costs. In dispute is over the pipeline's use of the recourse backhaul rates that actually would apply to the project's new capacity.

Furthermore, the municipals are not aware of any instance in which FERC granted a rolled-in rate predetermination based on a rate comparison using tariff recourse rates that are really "inapplicable to the new service."

The pipeline applied for a certificate on 6/5/15 (FR No. 3054, pp19-22), seeking authorization to build a project that will provide additional north-to-south transportation capacity on Texas Gas' system, while retaining the current capability to flow south to north. Texas Gas wants to accommodate customers who are seeking to transport Marcellus/Utica shale gas supplies from the northern end of its pipeline system to markets in the Midwest and along the Gulf Coast. The pipeline said the target in-service date is 4/1/17.

The municipals called the NSAP "a major endeavor," which along with Texas Gas' Ohio-Louisiana Access Project (OH-LA) (FR Nos. 3019, pp17-19, 3033, p33) will fundamentally alter the nature of the Texas Gas system. The company's planned expenditures on compressor facilities alone are considerable. Across it various projects, Texas Gas "is changing nearly every compressor on its mainline," the municipals warned. And the implications for operations and fuel consumption will be "substantial."

Cities, as captive customers who receive firm transportation and no-notice transportation service under Rate Schedules FT, NNS, STF, and/or SGT, do not want to be stuck with the costs. "Cities do not desire to be the last captive, maximum-rate shippers standing if the Project Shippers default and the costs of the project have been rolled in," the municipals blasted. Cities, therefore, urged FERC to proceed with caution to ensure that the risks are placed on the pipeline when appropriate and not on themselves, the captive customers.

Rationale of Current Fuel Rate. The Cities proffered that Texas Gas' intended reversal of system flows brings into question the pipeline's underlying rationale for its current fuel rate methodology. Historically, the pipeline's fuel costs mostly concerned the operation of storage fields in the middle of its system that were vital to operations.

The market area facilities served as surrogate pipeline capacity upstream of the storage, which allowed upstream facilities to be generally designed to meet demand based on the pipeline's daily average; whereas downstream facilities were designed on a peak-day basis, as well as for various operational purposes, including supporting system management and load balancing. The storage was also required to provide gas supply to the northern portion of Texas Gas' system during the winter.

After NSAP though, the storage needs and flows will be different, and fuel costs should not only decline but be reallocated, the municipals ventured. FERC should inquire whether a different fuel rate methodology than the one used in RP15-14 is required to determine whether the fuel costs of NSAP shippers will be subsidized. "The significance of the fuel issue is plain from the face of the pipeline's application, especially given the amount of money that is proposed to be expended on Texas Gas' comprehensive compressor changes."

In other fuel-use related matters, the municipals requested that the pipeline demonstrate that NSAP will not adversely affect fuel rates for existing customers. So far, Texas Gas has not explained the effect of the project on its fuel rates. FERC had to direct the pipeline (in CP14-553) to provide a fuel reimbursement study reflecting the revised in-kind reimbursement percentages that would result from OH-LA, and needs to do so again here.

"Despite this recent history, the application in the instant proceeding does not mention 'fuel,'" scolded the Cities. This time, FERC should have Texas Gas provide both a stand-alone study for NSAP plus a study that aggregates the impacts of both NSAP and OH-LA.

The pipeline also needs to explain why it uses Effective Fuel Rate Percentages (EFRPs) as the basis for comparisons instead of only the Projected Percentages (PRFPs).

Reject Rates Predetermination. The Cities next asserted that it is "premature" for FERC to allow a predetermination for a roll-in of the project's costs with system-wide rates in a future rate case. In response to such requests, the Commission usually compares the cost of a project to the project revenues, using actual contract quantities and the applicable maximum recourse rates (or the actual negotiated rate if the negotiated rate is lower than the recourse rate). But, this time Texas Gas did not compare the project's costs to the project revenues using applicable maximum recourse rates -- even though the negotiated rates are higher than the applicable recourse rates.

Instead, the pipeline supported its request "with an unprecedented comparison of rates," including: the negotiated rates to be paid by project shippers compared to firm transportation recourse rates for forward-haul service -- even though firm backhaul rates are the only recourse rates available to the respective project shippers."

In other words, reasoned the Cities, Texas Gas is using "the inapplicable forward-haul rates" because the project shippers agreed to pay a negotiated rate that is higher than the applicable currently effective backhaul rates. In instances like this, again, FERC generally compares project costs with the revenues that would be generated if all project services under contract were provided at the maximum recourse rate.

The municipals charged that Texas Gas is attempting to justify its approach by claiming that comparison of the project rate to its backhaul rates is inappropriate as the backhaul rates did not contemplate physical transport of any gas in a north to south direction and were solely meant to address backhaul by displacement. Those backhaul rates may indeed be obsolete, the Cities remarked, but Texas Gas is confined to the tariff that it has in place for purposes of its request for predetermination of rolled-in rate treatment.

As Texas Gas itself noted, the pipeline's current rate design assumes all gas is physically transported in a south-to-north direction and also assumes any backhaul transactions are performed by displacement. Of course, those assumptions no longer hold true, the municipals stated, and would be particularly inapplicable if the NSAP is placed into service. Under these circumstances, Texas Gas should have to redesign its rates to accommodate "the new reality," the Cities insisted.

Finally, the municipals also requested that FERC require Texas Gas to account for the construction and operating costs and revenues for NSAP separately from other costs. This accounting information would allow the Commission "and interested parties" to identify any change in material circumstances that may warrant a reexamination of rolled-in rate treatment in the pipeline's next rate case.

More Clarification. The Cities, in addition, asked the pipeline to clarify how excess and secondary capacity on NSAP will be priced, as the pipeline's submitted information on the matter "makes the answer uncertain." To the municipals, it appears there may be available unsubscribed capacity flowing north-to-south. If so -- or if there is "any other such excess that may result after this massive system change is complete" -- the pricing is not clear, and the pipeline needs to provide details on pricing for available north-to-south capacity that will be sold after NSAP is completed.

Also unclear to the Cities is how capacity releases will operate for NSAP capacity itself. Texas Gas needs to clarify which rate would apply for purposes of capacity release and explain why.

Whether project capacity release transactions would be deemed backhaul or forward haul is also important because capacity release applies differently to each, the Cities said. Forward-haul customers may release all capacity held under a particular service agreement, a percentage of such capacity or a segment of such capacity. Backhaul customers may release all capacity held under a particular service agreement or a percentage of such capacity from their primary receipt point zone to their primary delivery point zone. Which standard would apply to released project capacity?

Transwestern's Many-Faceted Rate and Tariff Settlement Appears Ready to be Certified to FERC For Approval

In initial comments addressed to the Presiding Administrative Law Judge Steven Glazer, this week FERC's Trial Staff offered its support of the Offer of Settlement filed by Transwestern Pipeline Co. LLC (RP15-23, et al.) last month in a rate case proceeding initiated by Transwestern on 10/1/14. The instant settlement resolves all of the rate issues and many of the tariff issues. For those non-rate issues that remain unresolved, Staff noted that the settling parties have established suitable procedures under which Transwestern, its shippers and the Commission can decide those issues. Trial Staff urged the Presiding Judge to certify the Settlement to the Commission and urged the Commission to approve it without modification or condition.

Apparently the settling parties agreed to "significant changes in the reservation, usage, and fuel rates for each of the destinations served by Transwestern." The parties also agreed to modify Transwestern's Rate Schedule FTS-1 service to allow the shippers a contractual right of first refusal (ROFR). Moreover, shippers using FTS-5 service can extend such service by a substantial number of years, add an additional FTS-5 contract, and potentially modify the contract quantity of existing FTS-5 contracts.

Transwestern would roll-in the costs of its San Juan expansion facilities and its New River Compressor Station. Various accounting issues are also addressed in the deal that will be subject to a moratorium until 10/1/19. According to staff, the terms will ensure more than four years of rate certainty on the Transwestern system. In addition, a comeback provision will require Transwestern to make a rate filing no later than seven years from now.

The parties have adopted procedures which could lead to the resolution of issues regarding maximum Btu levels, possible new peaking services, and flow control matters. Those procedures will follow on discussions between Transwestern and all interested shippers. If those efforts prove unsuccessful, then Transwestern will make limited NGA section 4 filings to implement their proposed solutions subject to shippers having the option to exercise their rights to support, oppose, or seek modification of Transwestern's proposal.

Finally, Transwestern and certain shippers did not resolve a matter dealing with Transwestern's current capacity release provision. A briefing process was devised to enable the Commission to resolve this issue. Any Commission-directed modification of Transwestern's current capacity release provision will be accomplished through a compliance filing.

Background. Transwestern's new general rate increase filed to comply with the terms of a 2011 settlement was met by a number of protests. On 10/30/14, the Commission issued its hearing order accepting the filing subject to refund, suspending for five months (until 4/1/15) certain tariff records, and setting Transwestern's rate increase application for evidentiary hearing.[5]

On 3/31/15, Transwestern made a filing moving the tariff records associated with its rate increase into effect. Also on that date, intervener New Mexico Gas Co. filed a "Motion for Stay, Interim Relief and Technical Conference and a Request for Expedited Treatment" with respect to Transwestern's tariff records, and especially addressing proposed maximum total heating value gas quality specifications. On 4/28/15, FERC accepted Transwestern's tariffs to be effective April 1, subject to refund and the outcome of the evidentiary hearing (those rates are referred to as the "Motion Rates.")

Terms of Settlement. The negotiated settlement rates cover the maximum and minimum Base Tariff rates and fuel percentages for all of Transwestern's services. Transwestern is ready to file to implement its settlement rates and remove the provision in its General Terms and Conditions (GT&C) of its rate increase application dealing with a maximum Btu level on the first day of the month. Transwestern will make refunds with interest for the amount by which the rates placed into effect 4/1/15 exceed the Interim Settlement Rates. However, there will be no refunds as a result of the implementation of the settlement fuel percentages.

Transwestern will add back a provision in its GT&C to post non-sustainable operationally available short-term capacity not available in Transwestern's Unsubscribed Capacity postings. However, if Transwestern has not made any postings for firm agreements for

[5] Indicated Shippers, one of the interveners, sought rehearing of the hearing order, asserting that the Commission should have rejected Transwestern's filed usage rates on the ground that they were based on an adjusted straight fixed variable (SFV) rate design. On 1/22/15, the Commission granted rehearing and rejected Transwestern's adjusted SFV rate design for its usage rates. Transwestern has made a compliance filing following the SFV rate design, which filing was accepted by the Commission. But the pipeline also filed a petition for rehearing of the rehearing order, and that petition is pending.

such capacity by 6/1/20, Transwestern can make a tariff filing to remove this provision and the settling parties agree not to oppose any such filing.

Procedures were adopted to address maximum Btu heating value, new peaking service and flow control. After the settlement is approved, Transwestern will meet with its shippers who either support or do not oppose the settlement to discuss: (1) the potential need for a maximum Btu limit; (2) the possible implementation of new peaking services; and (3) the implementation of flow control provisions in the GT&C. Transwestern and its shippers will seek to reach an agreement on the terms of forward looking tariff provisions dealing with each of these items. However, if the parties are unable to reach such agreement on one or more of these issues prior to 1/1/16, Transwestern will file to implement its proposed tariff provisions "on all unresolved issues." Transwestern will propose that those filings become effective following any suspension period and the Commission's review and approval. In any resulting proceedings, "all parties are free to take whatever positions they so choose."

In the interim period leading to FERC acceptance of the settlement agreement and the effective date of tariff records implementing flow control provisions, Transwestern will only implement any flow control (to control either daily or hourly takes): (1) in response to a threat to System Integrity; (2) following issuance of an Alert Day and/or and Operational Flow Order; and (3) on no less than two hours posted notice.

Transwestern will localize the imposition of flow control to the smallest affected area necessary to resolve the System Integrity problem. Following a Commission order establishing maximum Btu limits, a settling party may bring a limited proceeding under NGA section 5, regarding those maximum Btu limits.

The settlement next establishes procedures for the resolution of an issue involving Transwestern's capacity release provisions. There will be "a briefing procedure" to allow the Commission to adjudicate the following issue: "Is Section 30 of the GT&C ..., as interpreted and implemented by Transwestern, in compliance with Commission policy governing capacity releases?"

The settlement addresses future service agreements that may be filed. One provision applies to any shipper supporting the settlement and holding one or more Rate Schedule FTS-1 service agreements with a term extending to at least 3/31/17; another applies to any shipper supporting the settlement and holding one or more Rate Schedule FTS-5 service agreements with a term extending to at least the end of March 2017.

Among the additional issues addressed, Transwestern may roll into the rates for the San Juan lateral the capital and other costs for the San Juan expansion facilities constructed following Commission authorization in Docket No. CP06-459; Transwestern may roll into the rates for the Phoenix lateral the capital and other costs for the New River Compressor Station constructed following Commission authorization in Docket No. CP14-8.

The depreciation rate applicable to all of Transwestern's transmission plant facilities shall continue to be 1.20% per annum.

Transwestern will be authorized to include in its annual cost of service the Net Periodic Cost of $544,709 associated with the recovery of post-retirement benefit costs other than pensions. Transwestern may continue to include $48,528 in its annual cost of service to effectuate the collection of deficient deferred income taxes, due to the 1993 change in the corporate income tax rate, as approved by the Commission in 1994.

Transwestern will establish and commence amortization of a Reverse South Georgia deferred taxes regulatory liability "to effectuate the flow back to shippers of excess accumulated deferred income taxes resulting from the decrease in Transwestern's federal and state income tax rates." Transwestern will flow back an amount equal to $2,064,639 per year over the average remaining life of its depreciable plant, which is 56 years.

Transwestern also may, in its cost of service, reset its amortization expense associated with non-polychlorinated biphenyls (non-PCB) soil and groundwater remediation expenses to $488,128 annually. Transwestern agrees that in any future general rate change under section 4, it shall not include in such filing any remediation costs paid to third parties that are directly attributable or related to polychlorinated biphenyls (PCB) or PCB contaminated soils or liquids in, on or adjacent to the Transwestern pipeline system from Station 8 west to the Arizona/California border caused by the use of lubricating oil containing PCB at a turbine compressor unit between 1968 and 1972. Transwestern is allowed to seek recovery of any other PCB remediation costs in future filings.

Transwestern shall file a general section 4 rate case on or before 7/1/22, and in that filing shall file for a fuel tracker as part of its primary case, but it may also file to continue fixed fuel rates as an alternative. Transwestern will also include in its rate filing the most recently available three years of fuel data by month for each compressor station on its system and the most recently available twelve months of lost and unaccounted-for data. On or after 4/1/17, Transwestern may file to implement the fuel tracker.

Transwestern shall not file a general section 4 rate case to increase its Base Tariff rates prior to 10/1/19. Similarly, except for a limited section 5 proceeding with respect to maximum Btu limits, no settling party shall seek or solicit a change or challenge to any effective provision of the settlement through a complaint filed under section 5 prior to 10/1/19.

ALJ Reports Options the Commission Has to Address a Contested Settlement Offer Dealing with ANR's Costs and Impacts of Service Conversions Triggered by TransCanada's Reduction of its Contract Demand on Great Lakes Transmission

A comprehensive report delivered on or about July 13 to FERC by Presiding Settlement Judge David Coffman offers an insight and thorough airing of issues addressed in a contested settlement deal filed on April 20, 2015 by ANR Pipeline Co. in Docket Nos. RP13-743, RP14-650, RP15-138, RP15-139 and RP15-785. Commission Trial Staff, the Wisconsin Distributor Group (WDG) and ANR all filed comments in support, while DTE Gas Co. (DTE) filed comments opposing it. Northern States Power-Minnesota and Northern States Power Co.-Wisconsin (collectively, Northern States) submitted joint reply comments supporting the settlement.

On 2/6/15, all active participants except one reached an agreement in principle, which resolved the issues set for hearing in the Docket No. RP13-743 proceeding, and issues reserved in Docket Nos. RP14-650 and RP15-785.

The settlement provides for specific ceilings on the amounts of ANR's DTCA Costs (defined below) that shall be eligible for recovery during the term. For designated future periods, the settlement also provides for a sharing mechanism should ANR's actual DTCA Costs fall below their prescribed ceilings. In addition, the negotiated agreement: (1) specifies the circumstances in which increases in DTCA Costs arising under contract replacements entered into during the settlement's term may become eligible for recovery; (2) provides for the abandonment of the so-called T Agreements; and (3) reserves shippers' rights, once the settlement expires, to challenge ANR's recovery of costs incurred under the successor agreements.

ANR is obligated to share any benefits resulting from its reduction of its DTCA Costs below $56 million, allowing its ratepayers to keep 80% of any resulting savings. Overall, ANR contends, the settlement's incentive mechanism, operating in tandem with the prescribed ceiling on recoverable DTCA Costs, provides ratepayers with protection from DTCA Cost increases above the cap, while incenting ANR to reduce such costs below the cap.

ANR has contended moreover, that by permitting ANR to recover its storage costs through its transportation rates, the Commission will have recognized that the pipeline cannot meet its transportation service obligations without maintaining minimum volumes of gas in storage for balancing purposes. Any customer to which ANR provides transportation service benefits from ANR's utilization of its storage, regardless of whether that customer directly uses the storage. So the settlement will allow ANR to meet its system demands, which will benefit all of its shippers in the affected zones, including DTE, according to the pipeline company.

Background. By order in 1998, the Commission approved a Stipulation and Agreement that, among other things, permits ANR to adjust its rates each May 1 to recover "Qualifying Transportation Costs" (QTCs), which are transportation and compression costs incurred under certain contracts and recorded in FERC Account No. 858 for the previous 12-month period. ANR recovers QTCs through its Deferred Transportation Cost Adjustment (DTCA) tracker.

On 3/28/13, ANR filed under section 4 of the NGA for authority to impose a DTCA surcharge during the period 5/1/13 through 4/30/14 that would permit it to recover $51.4 million in DTCA Costs incurred or expected to be incurred during the prior year period. Of those costs, $19.3 million were incurred under Contract No. FT17593, which ANR and its affiliate, Great Lakes Transmission Limited Partnership, recently executed to replace an exchange agreement negotiated in 1970 between ANR, Great Lakes and a third affiliate, TransCanada Pipelines Ltd. Great Lakes implemented this agreement under its Rate Schedule X-1.

TransCanada initially was shipping large volumes of gas on Great Lakes' system. The X-1 Agreement required Great Lakes to deliver 506,500 Dth/d of TransCanada gas to ANR at Fortune Lake, located in the upper peninsula of Michigan, and required ANR to redeliver an equivalent amount of gas to Great Lakes at Farwell, located at a central point in the lower peninsula of Michigan. The volumes delivered by Great Lakes enabled ANR to meet its firm service obligations in Wisconsin and Michigan without having to build new facilities.

ANR and Great Lakes did not charge each other for the gas delivered under the X-1 Agreement, and ANR therefore incurred no DTCA Costs under that agreement.

In late 2012, though, TransCanada reduced its contracted demand on Great Lakes from 698,727 Dth/d to 100,000 Dth/d. This development rendered the X-1 Agreement inoperable, because Great Lakes no longer had sufficient TransCanada gas to meet ANR's needs at Fortune Lake. So ANR entered into Contract No. FT17593 with Great Lakes, which required the latter to transport 506,500 Dth/d to ANR at Fortune Lake under Part 284 (open access) of the Commission's regulations. ANR then incurred DTCA Costs under the new contract as it would under any firm transportation agreement.

ANR had explained to FERC that Contract No. FT17593 replaced the X-1 Agreement, and, therefore, was a “contract replacement” within the meaning of its tariff and therefore the DTCA Costs incurred thereunder were QTCs, eligible for recovery under ANR’s DTCA tracker.

Protesters, to the contrary, argued that Contract No. FT17593 did not qualify as a "replacement" for the X-1 Agreement, and that the DTCA Costs incurred were not QTCs. By order (RP13-743) dated 4/29/13, the Commission agreed, noting, among other things, that the two agreements bore “no resemblance” to each other, and that Contract No. FT17593 imposed “substantial new costs”.

ANR filed tariff revisions that complied and removed the DTCA Costs incurred under the new contract. The Commission accepted the tariff revisions by letter order, but ANR sought rehearing of the Docket RP13-743 Initial Order.

In May 2014, the Commission issued its order on rehearing and establishing hearing and settlement judge procedures. The Commission then concluded, among other things, that an "undefined phrase ‘contract replacement’ in the pipeline's GT&C is subject to interpretation.” The Commission found sufficient ambiguity as to the meaning of this phrase to establish hearing and settlement procedures to resolve the issue. In other words, the question remained “what may be considered appropriate replacement contract costs under the DTCA.”

One issue facing the ALJ involved interpreting “the meaning of the term ‘contract replacement’” and whether Contract No. FT17593 was “consistent with that meaning, given the nature and circumstances of the contract and the Commission’s long-standing policy to narrowly construe cost trackers.”

The other apparent issue involved “ANR’s burden to demonstrate that its proposal to track the costs of the [Great Lakes] contract through its Account No. 858 is just and reasonable.”

On 3/30/14 ANR made two filings seeking authority to recover DTCA Costs that it had incurred, or expected to incur during the period 5/1/13 through 4/30/14, and sought to impose a surcharge that would enable it recover these costs during the next period. In a primary filing, it sought a surcharge that would enable it to recover DTCA costs of $66.9 million, of which $34.2 million were incurred under Contract No. FT17593. The alternate filing sought a surcharge that excluded the contact costs, and sought recovery of only the remaining $32.7 million.

The Commission in April last year rejected ANR’s primary tariff filing, and accepted the alternative tariff filing subject to the outcome of the proceedings in Docket RP13-743.

Also wrapped up in this case are three transportation contracts with Great Lakes under Part 157 of the Commission’s regulations (under Rate Schedules T-8, T-9 and T-10). ANR in October 2014 advised Great Lakes that it wished to convert the T Agreements into contracts governed by Part 284. Subsequently, ANR converted the contracts, with Great Lakes’ consent, and last November ANR and Great Lakes (RP15-138, RP15-139) filed revised tariffs sheets removing references to the T Agreements from their respective rate schedules.

A number of protestors contended that if Great Lakes charged its maximum Part 284 firm transportation rate (a prerequisite to conversion under section 157.217(a) (2)) and ANR were to recover the resulting rate increase through its DTCA tracker, the collective rate increase to protestors would approximate $40 million. Because the conversion was a transaction between affiliates rather than an arm’s-length transaction, the protestors asked the Commission to reject the filings or, alternatively, suspend them and set them for hearing.

FERC suspended the effectiveness of Great Lakes' and ANR's proposed tariff changes for the maximum five-month statutory period (i.e., to be effective 5/3/15), and set them for hearing. In so doing, the Commission found that the filings were "not routine in the circumstances presented", reasoning that "the affiliate relationship between the parties to the subject contracts," and the likelihood of "the costs arising from the conversion" flowing through "to shippers under the same DTCA mechanism already subject to hearing and review" in Docket RP13-743 precluded "unconditional acceptance of the filings". On January 2, ANR and Great Lakes requested rehearing and clarification.

Now came two ANR filings on 3/31/15 seeking authority to recover via a surcharge DTCA costs that it had incurred or expected to incur during the period 5/1/14 through 4/30/15. The primary filing sought a surcharge that would enable it to recover costs of $86.2 million, of which $54.5 million were incurred under the Converted Agreements. The alternate filing sought a surcharge that sought recovery of only $31.7 million.

On April 30, the Commission rejected ANR's primary tariff filing, and accepted the alternative filing subject to the outcome of the consolidated proceedings in Docket No. RP13-743, et al.

Resolved. Based on the ALJ's report summed here, the deal on the table provides these resolutions:

(1) The settlement establishes the maximum amounts of QTCs ANR may recover through its DTCA tracker: For the period May 2013 through April 2014, covered by Docket RP13-743, the QTCs eligible for such recovery shall be $40,700,000; (2) For the period May 2014 through April 2015 period, covered by Docket RP14-650, the QTCs eligible for such recovery shall be $47,700,000; (3) For the period May 2015 through April 2016 period, covered by Docket RP15-785, the QTCs eligible for such recovery shall be $55,000,000; and (4) For the period May 2016 through April 2017, and for each subsequent twelve-month period, the QTCs eligible for such recovery shall be $56,000,000, "provided, however, that if the actual QTCs for any of those periods fall below $56,000,000, ANR shall be permitted to recover 20 percent of the shortfall."

(2) The settlement provides for the abandonment and conversion of the T Agreements, effective 5/3/15.

(3) An ANR rate moratorium prohibits ANR from placing new base rates resulting from a general filing under section 4 of the NGA into effect before 5/1/16.

(4) The transaction "restricts ANR's ability to recover increased QTCs that it may incur under valid contract replacements, amendments or conversions." If such cost increases cause an increase in the total QTCs from the prior year, the cost increases shall not be recoverable through the DTCA tracker unless they are lower than the cost increases that would have been incurred under any alternative, functionally comparable service available to ANR and are within other cost levels prescribed in the settlement.

(5) The settlement discusses how ANR shall calculate the surcharges used to recover the QTCs eligible for recovery.

(6) ANR and the parties are obligated to meet at least annually to discuss a long-term plan for meeting ANR's service obligations.

Opposing the Settlement: DTE. On May 11, DTE filed comments opposing the settlement. The critic represents that DTE and its ratepayers face over $900,000 in additional costs for the period 5/1/13-4/30/16, and over

$375,000 in additional costs per year thereafter, without receiving any corresponding improvement in service. Moreover, according to the ALJ report, DTE contends, it has not caused and does not benefit from these increased costs: ANR has admitted it needs the converted agreements to integrate its storage network, yet DTE does not use ANR's storage.

Among at least five issues that ANR and others are compelled to respond to due to DTE's dissent, ANR contends that it has demonstrated that the converted agreements qualify as "contract replacements", and that DTE has not rebutted that showing.

The ALJ concluded his report by presenting the "overarching issue" to the Commission: whether the Commission may approve the settlement under any of the four approaches outlined in Trailblazer for approving a "contested" settlement.

FERC Supports Gulf South Pipeline's Tariff Revisions Designed to Expand Ability to Offer Evergreen and Contractual Right of First Refusal (ROFR)

A FERC order issued July 10 approved tariff records filed on June 12 by Gulf South Pipeline Co., LP (RP15-1058) to expand its ability to offer evergreen and contractual Right of First Refusal (ROFR) contract terms, to be effective7/12/15. The company's existing evergreen and contractual ROFR clauses apparently differ from rate schedule to rate schedule. For example, some rate schedules require a shipper to choose either an evergreen or ROFR option, but not both; some allow a single term extension, while others allow multiple consecutive term extensions.

Gulf South proposes to adopt a uniform, "more liberal evergreen and ROFR clause" for its firm rate schedules. As proposed, the evergreen and ROFR clause would read: Gulf South and Customer may agree at the time of initial service agreement execution to (1) a contractual Right of First Refusal and/or (2) evergreen option(s) provided such option(s) shall not exceed the initial service agreement term and MDQ (Maximum Daily Quantity).

The United Municipal Distributors Group (UMDG) filed comments, asking that the Commission require Gulf South to clarify that the proposal does not discriminate against pre-existing customers. UMDG noted that the proposed evergreen and ROFR clause contains the phrase "initial service agreement." UMDG argued that pre-existing customers are capable of contracting for an "initial service agreement," but it expressed concern that Gulf South might claim that their "initial service agreements" are the decades-old agreements that each customer signed the very first time that it sought service on the Gulf South system.

FERC, though, found that the phrase "initial service agreement" must be read to cover any customer, old or new, who signs a new service agreement. The phrase "initial service agreement" was in virtually every Gulf South evergreen and contractual ROFR tariff provision before the instant filing. Since the phrase "initial service agreement" is not new tariff language proposed in Gulf South's instant tariff filing, "it suffices to note that the pre-existing tariff has been understood to allow both old and new customers to negotiate a new contract with term extension clauses. The instant proposal only expands that option, without placing any new restrictions on customers."

Separately, "we find that a restrictive reading of the tariff language would go against Gulf South's stated purpose of helping it to retain its long-term firm contracts." On either ground, then, the phrase "initial service agreement" should be read to include a new service agreement entered into by any firm shipper, regardless of whether that shipper was previously taking service on Gulf South, the order concluded.

GAS PIPELINE INFRASTRUCTURE

Transcontinental Gas Pipe Line Requests a Certificate from FERC to Allow for Significantly More Natural Gas Transportation to National Grid NY in New York City

On 7/8/15 Transcontinental Gas Pipe Line Co., LLC (CP15-527) filed for certificate approval at FERC to construct and operate a $112 million expansion in the New York City area. The New York Bay Expansion was designed to provide an additional 115,000 Dth/d of firm natural gas transportation service especially to the Brooklyn Union Gas Co. d/b/a National Grid NY (National Grid), in order to meet the local distribution utility company's supply needs for the 2017/2018 winter heating season. Brooklyn Union will take all of the capacity. Transco told the Commission that boosting the compression and installing related facilities could take place without installing additional pipeline or pipeline looping. Transco is proposing to make: (1) compressor station modifications and add horsepower (hp) at three existing compressor stations (Stations 207, 200, and 303, respectively); (2) minor pipeline replacements on the company's Lower New York Bay Lateral (LNYBL); (3) a pressure uprate of the LNYBL; (4) modifications at the Narrows, Morgan and Downingtown meter and regulating stations; and (5) modification to related appurtenant facilities. The pipeline requested FERC approval by 5/1/16 so that it can complete the expansion by the targeted in-service date of 11/1/17.

The project will allow Transco to boost capacity by (1) approximately 65,000 Dth/d firm transportation service from Transco's existing Compressor Station 195 in York County, Pennsylvania to an existing interconnection between the LNYBL and the Rockaway Delivery Lateral in New York state waters, and (2) 50,000 Dth/d from Compressor Station 195 to an existing interconnection with National Grid at the Narrows meter station in Richmond County, New York. Minor pipeline segments that will be replaced, include three segments of the LNYBL in Middlesex County, New Jersey, and the replaced segments will be abandoned by removal. The replacement allows for a pressure uprate of the LNYBL from 960 to 1000 psig.

The pipeline executed a binding precedent agreement with the utility for 100% of the project's firm capacity – and the parties will subsequently execute a long-term (15-year) firm service agreement. After it signed the precedent agreement with the utility, Transco held an open season last March to offer firm transportation to other shippers, but did not receive "acceptable" requests.

The utility will be responsible for contracting directly with suppliers of natural gas and arranging for the deliveries from Compressor Station 195 to Rockaway and Narrows meter station.

National Grid will pay the maximum recourse reservation rate and commodity rate and all other applicable charges, surcharges, and fuel retention under the FT rate. The incremental cost of service for expansion comes from calculations using the estimated cost of facilities, engineering estimates for operation and maintenance expenses and other cost factors, including a pre-tax return of 15.34%, the pre-tax return underlying the design of Transco's approved settlement rates in Docket Nos. RP01-245 et al., and a depreciation rate of 2.61% that is Transco's onshore transmission depreciation rate (including negative salvage) included in the settlement (RP12-993 et al.) approved in 2013.[6]

Because the pipeline is proposing an incremental rate, Transco said the project satisfies FERC's requirement that there be no subsidy from existing shippers. National Grid aims to use the additional capacity to serve incremental growth requirements in its markets.

Virtually all of the project activities are within the pipeline's existing rights of way and/or the property boundaries of Transco's existing facilities. Because the expansion does not include pipeline construction, the facilities will not have "a significant impact" on human health or the environment, the application

Natural Gas Producers/Marketers Urge FERC to Authorize Columbia's Leach XPress Project and Others Like It

The Natural Gas Supply Association (NGSA) once again lent its support for FERC's diligent attention to natural gas transportation infrastructure expansions in the U.S., most recently filing a letter with the Commission commenting on the Leach XPress Project that Columbia Gas Transmission, LLC (CP15-514) is planning. The letter, signed by Dena Wiggins, CEO of the gas producer/marketer association representing major integrated and independent companies, stated the group's support for "the pipeline industry in its efforts to build much-needed natural gas pipeline infrastructure. Our member companies supply trillions of cubic feet of natural gas each year to a growing number of power plants, local gas utilities, factories and other industrial users. Our commitment to our customers is why we are deeply invested in ensuring that there is adequate infrastructure in place for them to transport their natural gas," the July 10 letter declared.

"Access to abundant domestic natural gas has given U.S. industrial companies a competitive advantage over their global competition, leading to the resurgence of gas-intensive manufacturing in the United States and the creation of more jobs to construct and fill the resulting new and expanded industrial facilities."

"At the same time, demand from the power sector has also increased, driven by natural gas's low carbon emissions, retirements of older coal-fired plants, and the comparatively low cost and small footprint of natural gas-fired power plants," stated Wiggins. The letter declares that natural gas can help states meet their Clean Power Plan objectives in a reliable manner as greater levels of renewable forms of energy are included in their portfolios. NGSA anticipates that the Clean Power Plan will likely bring more intermittent renewable energy sources into the generating mix, which could require more available natural gas capacity, "particularly when the sun doesn't shine or the wind doesn't blow."

The letter cited a scientific study showing that greater use of natural gas has produced significant reductions in U.S. carbon emissions "because, over its lifecycle, natural gas emits only about half the carbon of other fossil fuels when combusted, whether to make electricity, forge steel or provide heat. Because of these advantages, along with its lack of sulfur dioxide (SO2) or mercury, very little nitrogen oxide (NOx) and no soot or volatile organic compounds, natural gas is poised to become an even more important part of states' energy portfolios as they seek cleaner energy

[6] Consistent with the methodology implemented by Transco in compliance with the Commission's order approving Transco's Leidy to Long Island Project (2006), the electric power costs for Stations 207 and 303 and the fuel burned at Station 200 will be allocated to the project based on certificated horsepower installed at each respective compressor station compared to the station's total certificated horsepower. Any difference, positive or negative, between the fuel and electric power costs allocated and the fuel retention and electric power costs retained/collected by applying the Zone 6-6 fuel retention and electric power rates will be deferred and directly assigned to National Grid NY in the form of fuel retention and electric power surcharges.

alternatives in order to comply with the Environmental Protection Agency's proposed Clean Power Plan."

"The forecasted growth in demand illustrates the need for increased flexibility in our pipeline systems to meet the anticipated variation in demand from the power sector. This flexibility can be achieved through the addition of new pipeline capacity, such as the Leach XPress Project. The power sector will benefit from a more resilient natural gas delivery system in times of system stress, such as severe weather events."

According to Wiggins, the natural gas industry is committed to "environmental stewardship" and has a track record of reducing methane emissions to prove it. Natural gas producers "are doing our part, making enormous investments in exploration and production of natural gas, while also financially committing to the pipeline projects that provide the capacity needed to bring gas from supply areas to market hubs. But more is needed."

From the producers/marketers' perspective, "the path ahead seems straightforward: ...additional natural gas infrastructure must be in place to transport natural gas from the wellhead to consumers. Unnecessary delays in building needed pipelines and related facilities will only hurt the American businesses and households."

For these reasons, the letter concluded, the Association encourages the Commission "to give this project and all pipeline applications serious consideration to ensure that natural gas infrastructure is built that will allow us to continue to provide natural gas to our customers and to help meet the country's need for reliable and clean energy."

Iroquois Gas Transmission Is In Improving Strategic Position As Outlet for Marcellus Basin Natural Gas

Moody's Investors Service recently affirmed Iroquois Gas Transmission System, LP's A3 senior unsecured rating and changed the outlook to positive. These rating actions reflect Iroquois' "improving strategic position as an outlet for gas from the Marcellus basin," the rater said. "Iroquois' strategic position is improving as a key intermediate pipeline between the Marcellus shale play and the attractive demand centers of the northeastern United States will soon come to bear" said Moody's Analyst, Lesley Ritter. Iroquois' positive outlook reflects its strategic position as one of the four pipelines transporting natural gas to the metro New York area, as well as its anticipated role as a key intermediate pipeline supporting the transportation of natural gas from the Marcellus region to the supply constrained markets of the northeastern US.

Headquartered in Shelton, Connecticut, Iroquois is a FERC-regulated interstate natural gas pipeline owned by subsidiaries of TransCanada Pipelines, Dominion Resources, National Grid USA, New Jersey Resources, and Iberdrola USA.

Moody's believes that projects like Constitution Pipeline and the Spectra Alliance, if constructed, would turn Iroquois into a key conduit to flow Marcellus gas to the supply constrained New England region.

The Service acknowledges that rising upstream transport costs and declines in natural gas receipts from TransCanada resulting from changing supply and market dynamics upstream of the pipeline, "have generated some headwinds for the pipeline." But Iroquois is developing various important projects "that leverage its strategic position as an intermediate pipeline located at the nexus of the high supply areas of the Marcellus Shale and the underserved, and highly attractive demand centers in the northeastern US."

Furthest along is the Wright Interconnect Project (WIP) that is being developed in conjunction with the proposed third-party Constitution Pipeline which, if and when constructed, will transport Marcellus gas from Pennsylvania to New England and interconnect with Iroquois at Wright, New York. WIP is expected to be on-line in 2016 and should begin generating incremental revenues at that time. Longer-term, Constitution Pipeline has the added benefit of completely offsetting any decline in receipts from TransCanada Pipelines that may occur in the coming years due to changing supply and market dynamics upstream of Iroquois.

Iroquois' record of conservative financial management gives us comfort that any capital outlay associated with these projects would be financed with significant portion of internal cash flow. Furthermore, Moody's noted that the company's leverage has already been declining according to its debt amortization schedule.

COLUMBIA GAS TRANSMISSION-NISOURCE

Columbia Transmission Asks FERC to Approve "Abandonment" of Facilities by Sale to Formerly Affiliated LDCs in Ohio, Pennsylvania

In a pair of virtually identical 7/14/15 filings, Columbia Gas Transmission LLC asked FERC to authorize the abandonment of facilities by sale to (1) Columbia Gas of Ohio (COH) and (2) Columbia Gas of Pennsylvania (CPA) (CP15-531; CP15-532). The moves were cast as part of a major corporate reorganization – and an opportunity for a long overdue reclassification of these facilities from "transmission" to "distribution." A key business development behind the twin filings was that NiSource, Inc., formerly the ultimate parent of Columbia Transmission (as well as these LDCs), ceased to be affiliated with Columbia Transmission effective July 1. However, NiSource remains the corporate parent of the two LDCs, COH and CPA.

The separation of Columbia Transmission from NiSource and the LDCs provided the occasion, the application explained, to correct the "shortcomings of the original [circa 1970] functional distinctions between distribution and transmission assets" on the pipeline system.[7] The system has "evolved," added the filing, especially since the FERC-engineered transition of the pipeline industry in the early 90s from bundled "merchant" activities to "almost exclusively transportation."

The July 14 application for abandonment authority under section 7(b) of the Natural Gas Act (NGA) also extended to (1) the abandonment of the services provided by the facilities being sold to the LDCs; and (2) a request for a finding that the subject facilities will "perform distribution activities," and hence are exempt under section 1(b) of the NGA from FERC jurisdiction. Moreover, Columbia Transmission asked for "expedited processing" to gain approval of its requests by 11/30/15, a timeline it says will "facilitate" its separation from NiSource.

Also noteworthy are the filing's requests for "privileged" or "confidential" treatment on two fronts. First, the company represented that the Purchase and Sale Agreements (PSAs)

[7] The application cites CP71-132 as the FERC docket where the organization of the original Columbia system – a rollup of several transmission and distribution companies operating in Kentucky, Maryland, New York, Ohio, Pennsylvania, Virginia and West Virginia – was approved. Columbia continues to operate transmission and storage facilities in all of those states plus Delaware, New Jersey, North Carolina, and Tennessee.

between it, Columbia Energy Group (CEG),[8] and the LDCs (COH/ CPA) contain "commercially sensitive information that provides the basis for the sale of assets" and, accordingly, should be exempt from "mandatory disclosure" under both the Freedom of Information Act and the Commission's regulations. Second, the company stated that certain "Critical Energy Infrastructure Information" (CEII) included in the filing should be shielded from public access, also pursuant to FERC regulations. Thus, these elements were not accessible on FERC's public website.

Corporate Reorganization and Facilities Sale. Although the current owner of the facilities, Columbia Transmission, was the filing entity, the application noted that Columbia Pipeline Group (CPG) is the parent of Columbia Transmission and that CPG is now independent from its former parent, NiSource. Since COH and CPA have remained subsidiaries of NiSource, the sale of facilities from Columbia Transmission to the two LDCs are presented as arms-length transactions negotiated among separate entities. The particular facilities conveyed are described as "certain pipelines, measurement facilities, appurtenances, and associated land rights" to be "incorporated" into the respective LDCs' distribution systems. The sale will further the Commission's policy in Order 636, the company suggests, by "establishing better defined jurisdictional demarcation points" for distinguishing transmission from distribution assets and activities.

The company estimated the net book value of the facilities being sold to COH at $18.1 million and to CPA about $6.2 million. As to rate implications, it proposed that the effects on Columbia Transmission's recourse rates should be reflected in the next Section 4 general rate case given the "*de minimis* impact" an adjustment of this magnitude would have on its transmission rate base.[9] The company added that it is "routine" Commission practice to permit adjustments to a pipeline's rate base, such as occur with abandonment or acquisitions, "without requiring a full scale review of the pipeline's rates."

For the sale to COH, the facilities are located entirely within Ohio and cover about 13.1 miles of pipeline, 594 measuring stations, 35 mainline consumer taps, and associated rights of way, etc. For the CPA sale, the facilities are similarly within one state (Pennsylvania) and include about 3.6 miles of pipeline, 213 measuring stations, 7 mainline consumer taps, and associated rights-of-way, etc.

Rationalizing the Service. The filing represents that the LDC, whether COH or CPA, will step into the shoes of Columbia Transmission in providing continuity of service from these facilities, and the change in ownership will result in a "more logical relationship" by removing Columbia Transmission as the "intermediary transporter directly connected to the consumer." The customers served directly off these facilities have been, and will remain, customers of the LDC. Given that the transactions will not result in any construction or facility removal, the company believes they qualify for a categorical exemption under section 380.4(a)(31) of FERC's regulations and that no environmental report by the company or Environmental Assessment by the Commission is necessary.

The filing also suggested that the "presence of 35 mainline consumer taps" on the facilities to be transferred to COH (7 taps on the facilities going to CPA) are a relic of a past era when Columbia Transmission performed gas merchant services. Now, each of the LDCs will be able to "integrate the facilities into its

[8] Under the structure of the transaction, CEG is an intermediary party in the ultimate sale of the facilities to the respective LDCs, COH and CPA.

[9] The net utility plant value set forth in the company's last FERC Form 2 (as of April 2015) was $3.7 billion.

current assets" and deliver natural gas to its retail customers from these delivery points.

Public Convenience and Necessity Threshold. The applicant contends that the divestiture of the facilities to the LDCs will satisfy the regulatory requirement of serving the public convenience and necessity. These facilities, stated Columbia Transmission, are no longer an "integral part" of its pipeline system and their retention would be "inconsistent" with the company's main purpose of providing transportation and storage service "in the most cost effective manner." Their transfer will obviate the need of Columbia Transmission to operate and maintain these "non-core" assets and would relieve Columbia customers of a potential $57 million in replacement costs, the company concludes.

The facilities to be acquired by the LDCs will be regulated by their respective state commissions, and service will be maintained by the LDCs, according to their representations.

OIL PIPELINE PROJECTS

FERC Grants Approval of Terms for Navigator's Big Spring Gateway Crude Oil Pipeline System in West Texas

On July 10 FERC issued a declaratory order (DO) for Navigator BSG Transportation & Storage, LLC (OR15-24) that approves the overall tariff, rate, and priority service structure for Navigator's proposed 140,000 b/d crude oil pipeline system in West Texas, called the Big Spring Gateway Crude Oil Pipeline. The pipeline filed the petition for the DO in April; Navigator expects transportation service to begin on Big Spring Gateway during "the second half" of 2015.

FERC's DO means that the transportation services agreements (TSAs) entered into between Navigator and Committed Shippers will be honored. The Commission's order signs off on various other aspects of Big Spring Gateway's terms of service: committed and uncommitted rates, priority service for committed shippers at a premium rate, 10% of capacity reserved for uncommitted shippers (with a clarification), and treatment of the committed rates as settlement rates with agreed-to adjustments.

Designed to serve oil producers and other shippers in the Permian Basin – which has seen "a substantial increase" in crude oil production -- Big Spring Gateway will include 250 miles of gathering pipeline and 200 miles of mainline pipe. The system will begin in the Basin and terminate near Colorado City, in Scurry County, Texas. Navigator will provide both interstate and intrastate transportation services using two segments of the project: the Big Spring Segment and the CC Segment.

The Big Spring Segment will include various subsets of pipelines (Segments A-G) with origin points in several West Texas counties; will have several truck injection stations along the segments; and would converge at Navigator's Big Spring Terminal in Howard County. From the terminal, the pipeline will run northeast to link Navigator's facilities in Colorado City. Near Colorado City, the system will interconnect with BridgeTex Pipeline, the Permian Express II Pipeline, and the West Texas Gulf Pipeline.

Through the interconnections, the project will provide West Texas producers with "a direct path" to approximately 950,000 b/d of takeaway capacity from Colorado City to the Texas Gulf Coast and Midcontinent market centers, according to the pipeline.

In 2013, following an open season offering a total of 75,000 b/d of capacity, the company received "sufficient shipper commitments" to proceed. Subsequently, Navigator was acquired by First Reserve, a global private equity and infrastructure investment firm. Then, following a re-evaluation the project First Reserve decided to increase the design capacity to 140,000 b/d. The pipeline held a supplemental open season between Feb. and April of 2015, again receiving sufficient shipper commitments to proceed. Navigator offered long-term minimum volume commitments for either five, seven or ten years.

Committed shippers on the pipeline were required to sign up for a minimum overall committed volume of 2,000 b/d in 1,000 b/d increments, or for transportation from a truck injection point were required to sign up for a minimum overall committed volume of 1000 b/d. Shippers were able to aggregate volume commitments from Segments A through G or the truck injection stations to qualify for the applicable tier rate. The committed rates were discounted below the uncommitted rates based on the volume commitment and time length of the executed TSAs.

As per regulations and the Interstate Commerce Act (ICA), Navigator reserved up to 90% of the capacity for priority committed service and reserved at least 10% of the capacity for use by uncommitted shippers. Even so, FERC pointed out that since the pipeline will be providing both interstate and intrastate transportation services, it is possible that it would not meet these interstate common carrier obligations.

Therefore, consistent with a recent determination in Panola Pipeline Co., LLC, FERC told the pipeline that it must reserve the minimum 10% of capacity for uncommitted jurisdictional shippers. To the extent there are service nominations from both intrastate and interstate uncommitted shippers that exceed the 10% of uncommitted capacity available, interstate uncommitted shippers "shall have the first right to service" from that 10% of uncommitted capacity, FERC explained.

The pipeline also offered priority service at a premium rate when the pipeline system is in allocation to all shippers that either (1) signed up for a seven- or ten-year term or (2) signed up for a five-year term and a committed volume of at least 30,000 b/d across both the Big Spring Segment and the CC Segment. Priority rates always will be at least $0.01 higher than the corresponding uncommitted rate, as is customary. The priority rates and committed rates are subject to increase (but not decrease) by the positive adjustment, if any, in the Commission's oil pipeline index from the immediately preceding year. Any such rate increase though is capped at 3%.

In addition, Navigator had requested FERC's permission to waive the per-barrel tariff pumping and truck unloading charges for certain committed shippers. To this, the Commission conceded the proposal does not constitute undue preference or discrimination because it was made clear during the open season that truck unloading or pumping charges would not be assessed as a benefit of being a Committed Shipper (who agreed to certain contractual terms). Moreover, Navigator has indicated that any costs associated with the waiver of the charge will be borne solely by Navigator and not any other shippers.

LNG

LNG Expert Goncalves Depicts Global Reverberations from U.S. Shale Boom

BRG consultant Chris Goncalves addressed a

Washington D.C. Energy Bar Association (EBA) lunchtime gathering on 7/14/15 on a subject he claims to have thought long and hard about: the impacts on the global LNG market of the U.S.

shale gas revolution that began in earnest around 2006. His talk to EBA was drawn from his fall 2014 *Energy Law Journal* article, "Breaking Rules and Changing the Game: Will Shale Gas Rock the World?"[10] But, in the volatile energy world, eight months can be a long time, and some of the speaker's projections were adjusted to deal with the ramifications of a prolonged oil price slump and the latest LNG market dynamics.

Goncalves' 2014 article revolved around the premise that (1) the surge in U.S. natural gas production and consequent reversal of this country from a prospective large-scale importer of LNG to a substantial exporter, coupled with (2) the pricing of U.S. LNG exports on a Henry Hub index basis (rather than being indexed to oil, like most global LNG) had the potential to "rock the world." He likened this phenomenon to "rules breaking" such as has been seen over the last generation in the computing and communications industries.

But that dramatic hypothesis had to be rethought in light of the sustained drop in world oil prices -- making global LNG indexed to the price of oil much cheaper and hence less vulnerable to displacement by exports from the North American shale "revolution."

The consultant's revised analysis indicates that additional U.S. LNG export projects (or for that matter, announcements of new projects from other international export epicenters) are likely to take a breather as long as oil prices remain in a lower channel, pushing down the world price of LNG. For the U.S.-based natural gas and LNG industries, the formerly generous "spread" between the Henry Hub gas price and the market-clearing price of LNG has diminished to the point that taking the large capital cost risk of incremental LNG liquefaction and export facilities simply isn't as alluring as it was just a year or two ago.

Other fundamental factors also highlighted in Goncalves' talk have contributed to lower LNG prices around the globe. These include the slowdown in the Chinese economy, Japan's attempt to reduce heavy reliance on LNG and take a harder tack in negotiating LNG prices, cheaper oil as a substitute for burning LNG, and more LNG liquefaction projects anticipated to come online in the near future, contributing to a "glut" of LNG.

Goncalves also underscored how the global LNG market has become more liquid, flexible, and nimble, compared to the rigid structure of the recent past, increasing its preparedness to combat new threats from North America.

Joined at the hip to any discussion about shale gas exports and their potential impact on the global LNG market is a secondary question: whether the favorable U.S. experience in using fracking and improved drilling technologies to unlock vast new stores of natural gas will itself spread to other corners of the world?[11] To the extent this does occur, it will dampen the indigenous demand for LNG imports.

However, Goncalves' expectations in this arena are modest, at least for the medium term, because you don't find elsewhere the remarkable confluence of so many U.S. advantages: e.g., abundant shale and water resources, existing infrastructure, accelerating domestic demand for natural gas in the face of falling conventional supplies, technical expertise, entrepreneurial culture, landowner royalty rights, and responsive capital formation. As the speaker put it, even where

[10] The journal is sponsored by EBA in conjunction with the University Of Tulsa College Of Law.

[11] The speaker cited China, Argentina, parts of Europe, Australia, and South Africa as examples of nations with considerable shale gas development potential. With respect to Europe, only England and certain Eastern European countries seem inclined to go ahead with fracking anytime soon, he noted; but with the much lower LNG prices now available, other countries in Europe can afford to "coast along."

some of these factors are found, there are "one or two screws loose."

Continuation of Strong Supply and Demand Trends in U.S. A predicate for growing U.S. LNG exports is the expectation for ever-larger production of domestic gas and the assumption that the boom will continue to outstrip growth in domestic demand. Here, Goncalves tweaked his outlook for continuing production surpluses to take account of the depressed price of natural gas liquids (part of the fallout of oil price declines). For "wetter" natural gas production, the substantial revenue contribution from extracted liquids was a spur to more aggressive gas well drilling. Without such a kicker, the net breakeven cost has increased, while lower natural gas market prices have prevailed in 2015. The result is that new drilling has been set back.

As a countervailing factor, however, the speaker noted that new shale gas wells are experiencing more enduring initial production: instead of a rapid tailing off of productivity, technological improvements have led to more sustained well output. In spite of the headwinds, he mused, U.S. shale production shows resiliency and, like the "Energizer bunny", seems to "keep on going and going." Shale gas is already providing over a third of total U.S. production and is expected to reach 51% by 2020.

A related and important observation by Goncalves is that setbacks in U.S. shale drilling activity are eminently reversible. The technological prowess remains, dormant wells and drilling projects can be resurrected, and capital can be raised as soon as market returns rebound – whether from natural gas prices, oil and natural gas liquids prices, or global LNG prices. It is difficult to overstate how nimble and adaptive the U.S. shale gas industry has become, Goncalves believes.

As far as U.S. demand goes, the outlook remains fairly upbeat. Attractively priced natural gas and the increasing effect of environmental regulations hitting coal generation the hardest are driving substitution of gas for coal at power plants, contributing to a steady upward march for gas consumption.

But, as noted above, an important takeaway from Goncalves' revised outlook is that the bright outlook for expanding U.S. LNG exports has dimmed somewhat, based on today's economics. New LNG projects appear "uncompetitive" when the all-in costs of shale gas production and transportation to export hubs, the cost of liquefaction and shipping terminals, and ocean transport to offshore destinations are added up and compared to the current prices of global LNG in key markets.[12]

Future of Global LNG Growth and U.S. Role. Goncalves likewise foresees a slowdown in new LNG projects beyond North America, as the multi-billion dollar investment cost is a deterrent no matter where the location. The high global LNG prices that prevailed before they turned south in 2014 led to increased end user efficiency and slackening demand. In sum, a surplus in global LNG capacity will be around for some time;[13] and that, coupled with less lucrative LNG prices because of slower demand growth and the linkage to depressed oil price indices, together point to less opportunity for investment in new infrastructure.

Eventually, though, the global surplus will be worked off – and, presumably, oil prices will rebound to the $80- $100 level that enticed the current round of LNG projects to come to fruition. With more robust international LNG prices, the significant Henry Hub "shale spread" could return and induce more U.S.

[12] However, the speaker noted, U.S. projects currently under construction are largely protected by long-term offtake contracts.

[13] Goncalves' outlook is five years of "surplus" with the LNG market returning to "equilibrium" by around 2020.

export projects to come back from the sidelines.

The upshot could be that Goncalves' "rock the world" scenario is realized. This could include, on a commercial level, eventual repricing of global LNG to reflect international "gas hubs," similar to the indexing of U.S. exports to Henry Hub transactions. Goncalves believes decoupling LNG "term" contracts from oil prices and relating them to market prices at gas hubs could provide a better reference, more meaningful price signals, and therefore sounder investment and transaction decisions in the long run.

CLIMATE CHANGE

Senate Environment and Public Works Committee Considers the Administration's International Climate Agenda -- Signaling "Ambition" May Be Positive Ploy in Diplomacy

The U.S. Senate Environment and Public Works (EPW) Committee discussed issues relating to President Obama's climate change policies and international agreements on greenhouse gas emissions (GHGs) during a hearing entitled, "Road to Paris: President Obama's International Climate Agenda and Implications for Domestic Environmental Law." The debate centered on whether or not the Obama Administration will succeed in reducing U.S. greenhouse gas emissions by 26-28% by 2025 compared to 2005 levels. The appropriate role of the U.S. on the world stage of climate negotiations was also an important topic at the Committee hearing.

In December, the United Nations Framework Convention on Climate Change (UNFCCC) is holding its international negotiations conference in Paris, France, where the U.S., along with other countries, will be forging climate change agreements known as "intended nationally determined contributions" (INDCs).

As of the beginning of July, UNFCCC has received 17 INDCs covering 45 countries and representing nearly 55% of global emissions. Countries will have until October 2015 to submit their pledges. The UN will then evaluate the INDCs to determine the overall emissions reduction to be expected post-2020.

The U.S.'s INDC will hinge on the 26-28% reduction in emissions. The stance on whether the Administration would be able to deliver on that promise was divided mostly along party lines. Committee Chairman Jim Inhofe (R-Oklahoma), a leading critic of the President's climate change policies, said he was holding the hearing to "take a closer look" at Administration's climate agenda. Inhofe took over the reins of the Committee from Sen. Barbara Boxer (D-California) at the start of the new Congress in January after Republicans assumed a Majority control.

"We've been here before, and I remember so well, that for the climate conference in Copenhagen five years ago, everybody went, including Obama, Clinton, Kerry, Pelosi, and Gore. They assured everybody that we were going to pass legislation in Congress to control our emissions. All these things were going to happen, they said. And I went over as the 'one-man truth squad' to let them know it wasn't going to happen, and it didn't," the contrarian Senator declared at the hearing.

Inhofe added that "the slightest level of scrutiny revealed a significant lack of authenticity, substance and merit" concerning the Administration's climate polices. "While the President is going around and lecturing everyone about credibility and transparency, he is going out of his way to write the U.S. Senate – and the American people -- out of the final climate agreement.'

In conjunction with the hearing theme, Inhofe also sent a letter to Obama – signed by 10 other senators -- requesting a detailed response for how the Nation will meet its pledge. The lawmakers want details on the economy-wide greenhouse gas reduction goal, the legal framework, the U.S.-China announcement and the corresponding INDC, and the regulatory impact on jobs and the economy. The members requested a response by July 22.

Sen. Boxer, distinctively, applauded the "serious steps" that the Administration has taken to address carbon pollution. She believes the reduction level set forth by the President is "an achievable goal," and the associated Climate Action Plan (CAP) contains "the tools necessary to get the job done." Boxer poses the U.S. and the leader that inspired the world. "We know that we must cut harmful air pollution to protect the health and welfare of the American people, and our resolve has brought other countries to the table to make their own domestic commitments to reduce carbon pollution."

Boxer attributed action taken by the Administration as prompting China to make its first commitment to reduce carbon pollution. Other countries, including those in the European Union (EU), and developing countries such as Mexico and South Korea, have pledged to reduce carbon pollution significantly.

Among the witnesses invited to the hearing, Jeff Holmstead, a partner in the law firm of Bracewell & Giuliani, and Sarah Ladislaw, director and senior fellow at the Center for Strategic & International Studies (CSIS) gave opposing perspectives on the President's climate-related actions.

In regard to the U.S.' emissions reductions commitment, Holmstead does not see how the Administration "could possibly fulfill" the pledge without new legislation. In addition, the government reportedly developed the target based on "a thorough interagency review of the available tools in each of the agencies," but Holmstead noted that no documents have been released that point to this type of "intensive analysis."

The Administration "has refused to provide anything" in disclosing how it intends to meet its commitment – or even to show that a 26% reduction is plausible under existing law. Holmstead ventured that it is "more likely" that the Administration "simply does not have a plan" for achieving even a 26% reduction in emissions by 2025.

Furthermore, the various actions that the Administration has taken (or will take) fall far short of what is needed to actually reduce emissions, Holmstead warned. "In my view, this is even more troubling, especially if other countries are counting on the U.S. commitment when they develop their own submissions for the upcoming Paris Conference. When a President makes a commitment on behalf of the U.S., this is not something that should be taken lightly. I think most Americans would be concerned to learn that the President is making a commitment to the international community that he does not intend to meet."

Essentially, Holmstead surmised that Obama is treating the INDCs as nothing more than aspirational goals, while the Paris Conference "will accomplish much less than meets the eye."

Moreover, Holmstead predicted that the U.S.'s commitment would fail given that the CPP: (1) rests on shaky legal footing and is likely to be invalidated by the courts; (2) can easily be rescinded or modified by the next President; and (3) has a questioned implementation schedule. "Thus, even in the unlikely event that the CPP is actually implemented, it will not achieve substantial emission reductions by 2025."

With another hat on, Ladislaw told the lawmakers that the U.S.' actions were "in line" with the actions of other major economies -- although exact comparability is difficult to assess on an "apples to apples" basis.

The U.S.'s initiatives are not contrary to the global trend with regard to mitigation activity; whether or not U.S. actions are more or less stringent or ambitious than other countries' efforts is another matter, "typically referred to in the negotiations as comparability," Ladislaw said.

According to Ladislaw, the U.S.'s commitment is arguably more stringent than the Chinese goals to reduce emissions intensity because one represents an absolute cap on emissions while the other represents an intensity improvement -- although the Chinese target is accompanied by a peaking of emissions by 2030. Both do represent "an increase in ambition."

The U.S. target implies a large reduction in emissions whereas the Chinese target requires peaking and an improvement of CO2 emissions intensity 60-65% below 2005 levels by 2030. The U.S. target doubles the pace of emissions reduction from 1.2% per year on average between 2005-2020, to 2.3-2.8% per year on average in the last five years of the goal.

The Chinese INDC target to produce 20% percent of its primary energy supply from non-fossil based energy resources by 2020 appears "quite ambitious," requiring them to deploy 800-1,000 GW of non-fossil energy capacity, close to the entire electricity capacity of the U.S.

Ladislaw offered that the establishment of "stretch goals" – or aggressive goals -- is actually "a key part of the international negotiation process and a key element" of U.S. leadership. "While this point has been used to criticize the administration's goal, it is not clear that it is a deal breaker for the international negotiations and in fact may be a helpful signal in support of conveying U.S. leadership," she told the Committee.

The thing is, countries want to see that other countries are working hard to meet their emissions reduction pledges, she said. "Signaling ambition" is important in the negotiations and entices participation from others, as well as greater ambition from some. "The idea that the U.S. and China are committed to emission control despite potentially having a hard time meeting their target (whether true or not) can be reassuring to those with whom they are negotiating," Ladislaw noted.

Moreover, that both countries even introduced some flexibility into their targets to make them more ambitious – such as the early emissions peaking by China and the 28% emissions reduction target from the U.S. -- signals to other countries that effort matters. Other countries are likely to defend their actions as ambitious in light of their national circumstances but may signal the same sort of message about ambition by providing stretch goals for themselves – though some of more ambitious efforts from developing countries will be tied to climate financing.

"Stretch goals walk a fine line between inspiring greater ambition from others and ultimately being achievable," she argued. "The process of setting and achieving or surpassing targets in a verifiable manner will be a critical component of the international climate regime going forward."

ENERGY NEWS ALERT

On 7/15/15 Kinder Morgan, Inc. and Shell concurrently announced that they have reached an agreement for Kinder Morgan to purchase 100% of Shell's equity interest in Elba Liquefaction Co., LLC (ELC), the owner of the Elba Liquefaction Project. The project is to be constructed and operated at the existing Elba Island LNG Terminal near Savannah, Georgia. Kinder Morgan currently owns 51% of the ELC joint venture. Shell which owned the remaining 49% subscribes to 100% of the liquefaction capacity. Kinder Morgan will purchase the remaining venture that it does not already own. Kinder Morgan's expected investment resulting from this transaction is approximately $630 million, bringing its total investment in all the liquefaction and terminal facilities at Elba Island to approximately $2.1 billion.

In 2012, the project received authorization from the Department of Energy to export to Free Trade Agreement (FTA) countries. An application to export to non-FTA countries is pending. Under full development, the Elba Liquefaction Project is expected to have a total capacity of approximately 2.5 million tons per year of LNG for export, which is equivalent to approximately 350,000 Mcf/d of natural gas. The project was first announced in January 2013 by Southern Liquefaction Co., LLC, a unit of Kinder Morgan, and Shell to add liquefaction and export capability to Southern LNG Co. LLC's existing liquefied natural gas regasification terminal at Elba Island in Chatham County, Georgia.

Permitting continues for the proposed Elba Liquefaction Project, which consists of 10 small-scale liquefaction units to be purchased from Shell. They will be integrated with the existing Elba Island facility and enable rapid construction compared to traditional large-scale plants. The next step in the regulatory approval process is for FERC to issue a draft environmental assessment. Subject to regulatory approvals, construction could begin in fourth quarter of 2015, with initial production expected to occur in late 2017.

"We are very pleased to purchase Shell's equity interest in the joint venture and advance the project with Shell's continued support and subscription to 100 percent of the capacity of our world-class Elba Island terminal," said Kinder Morgan East Region Natural Gas Pipelines President Kimberly Watson.

"This is a good opportunity to leverage the proven track record of both companies to deliver an innovative LNG export project in the United States," said Ton Ten Have, Shell Upstream Americas VP LNG Operations and Growth.

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Moody's Investors Service downgraded Sabine Oil & Gas Corp.'s Probability of Default Rating following the company's announcement that it had filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of New York to facilitate the restructuring of its balance sheet. Moody's "will withdraw all ratings for the company in the near future." The company "continues to engage in constructive discussions with its lenders and debt holders regarding the terms of a consensual financial restructuring plan and is focused on achieving a resolution as expeditiously as possible," Sabine said in a statement. Its problems stem from a recent and "dramatic decline in oil prices, the continued low prices of natural gas, and general uncertainty in the energy market." The company acknowledged "substantial debt obligations" as factors leading to its decision to file.

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According to Platts, meanwhile, Cameron LNG was issued a permit by the Department of Energy to export an LNG equivalent of 1.41 Bcf/d of natural gas from a proposed expansion project near Hackberry, Louisiana, to nations with free trade agreements with the US.

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Tulsa-based WPX Energy, a domestic energy producer with operations in the western U.S., announced a definitive merger agreement to acquire privately held RKI Exploration & Production, LLC for $2.35 billion plus the assumption of $400 million of debt. The majority of RKI's leasehold is located in the Permian Basin in Loving County, Texas, and Eddy County, N.M., where the company has four rigs deployed. RKI's liquids-rich assets in the Permian Basin include approximately 22,000 boe/d of existing production (more than half of which is oil), approximately 92,000 net acres in the core of the Permian's Delaware Basin(approximately 98% of which is held by production), more than 3,600 gross risked drilling locations and more than 375 miles of gas gathering and water infrastructure.

The merger announcement states "the acquisition metrics include approximately $1.1 billion for the existing production at $50,000 per flowing barrel, approximately $500 million for the established midstream infrastructure, which equates to an average of $12,500 per acre – or $1.15 billion – for the undeveloped locations."

Rick Muncrief is WPX president and chief executive officer. The company is pursuing a portfolio transition to more liquids. This deal is portrayed as an arrangement "that will have a deep oil inventory, massive natural gas optionality and long-term growth visibility." With the "transformative" RKI transaction, WPX expects oil to account for approximately 22% of equivalent production this year, 30% in 2016, and 36% in 2017. All of RKI's Permian properties are located in the Delaware Basin. RKI also has operations in Wyoming's Powder River Basin. Those assets, however, are not included in WPX's purchase. RKI said it will divest or transfer out its Powder River Basin assets before completing the merger with WPX. WPX has leading positions in the core of North Dakota's Williston Basin, New Mexico's San Juan Basin and Colorado's Piceance Basin.

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Moody's Investors Service, (Moody's) placed MarkWest Energy Partners, LP's ratings on review for upgrade. The outlook was previously stable. This rating action was in response to the announcement that MPLX LP will acquire MarkWest in a transaction valued at roughly $20 billion, including the assumption of MarkWest's debt of roughly $4.2 billion. The transaction is expected to close in the third quarter of 2015. The merger would create the nation's fourth-largest MLP with a $21 billion market capitalization and estimated 2015 EBITDA of nearly $1.3 billion, the two companies said. MPLX's sponsor, Marathon Petroleum, would contribute $675 million of cash to MPLX to fund the one-time cash payment. Upon closing, MarkWest would become a wholly owned subsidiary of MPLX, according to a joint statement.

Moody's review for upgrade is based on "the potential benefit of MarkWest's debt being supported by the stronger credit profile and greater financial flexibility of MPLX," said Moody's. MarkWest Energy Partners is a Denver-based publicly traded master limited partnership engaged primarily in natural gas and natural gas liquids gathering and processing and other midstream activities with principal operations in the Marcellus and Utica shales and in the U.S. mid-continent.

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On July 1, FourPoint Energy, LLC announced the signing of agreements to acquire oil and gas assets in the Western Anadarko Basin from Chesapeake Exploration LLC and CHK Cleveland Tonkawa LLC, whose preferred interest owners are funds managed by GSO Capital Partners LP, as well as other third party investors, and common interest owner CEX in three related transactions for a combined purchase price of $840 million. The assets to be acquired include an interest in approximately 1,500 producing wells primarily in the Cleveland, Tonkawa and Marmaton formations with average daily net production of approximately 21,500 Boe/d over the twelve months ended April 2015. The production mix is 7,000 b/d of oil, 5,000 b/d of natural gas liquids and 57 MMcfd of natural gas. The assets cover nearly 250,000 net acres centered in Roger Mills and Ellis counties, Oklahoma. Approximately 95% of the leasehold is held by production. FourPoint will assume full operations of the assets at closing which is anticipated to be 8/31/15.

FourPoint Energy is headquartered in Denver, Colorado. FourPoint's Western Anadarko footprint will exceed 400,000 net acres with net production estimated at 260 MMcf-equivalent/d from approximately 4,600 gross wells, with half of the production coming from oil and natural gas liquids.

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Black Hills Corp. entered into a definitive agreement to acquire SourceGas Holdings LLC from investment funds managed by Alinda Capital Partners and GE Unit GE Energy Financial Services. SourceGas operates four regulated natural gas utilities serving approximately 425,000 customers in Arkansas, Colorado, Nebraska and Wyoming and a 512-mile regulated intrastate natural gas transmission pipeline in Colorado. Black Hills is acquiring SourceGas for total consideration of $1.89 billion, including reimbursement of an estimated $200 million in capital expenditures through closing and the assumption of $720 million of debt projected at closing. The combined entity will serve more than 1.2 million electric and natural gas utility customers in 790 communities in eight Rocky Mountain and Midcontinent states. Black Hills Corp. will operate the acquired company under the name Black Hills Energy. Black Hills disclosed it is also developing new relationships in Arkansas. The acquisition is expected to be completed in the first half of 2016.

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Algonquin Gas Transmission's (CP14-96) Algonquin Incremental Market (AIM) pipeline cannot be stopped by a district court according to a ruling this week by a federal district court in Massachusetts. The court on Wednesday dismissed efforts by the Town of Dedham to put a hold on construction. FERC is considering its rehearing request in Washington D.C. The US District Court for the District of Massachusetts concluded that pursuant to the Natural Gas Act (NGA) it is the federal courts of appeals that have exclusive jurisdiction to review FERC pipeline certificate decisions. The AIM project would expand Algonquin's pipeline system by 37.4 miles from an interconnection at Ramapo, New York, and modify compressors to supply up to 342,000 dth/d of gas to local utilities in Connecticut, Rhode Island and Massachusetts. A expansion, approved by FERC on March 3 is slated to be in service next year.

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Earlier this month, FERC's Director of the Office of Energy Projects, Ann Miles, expressed misgivings after receiving from CE FLNG, LLC implications of continuing delays in its plan to file an application for its CE FLNG Project. Initially it was coming in May 2015. In subsequent status reports, CE FLNG indicated that it was pursuing additional funding and would begin updating field work in April, then May, and then June 2015. "Due to the changing schedule and the lack of a full set of draft resource reports," Director Miles stated in a letter to the company, "I am concerned about the viability of the Project and the use of Commission resources in support of the pre-filing process. Therefore, should CE FLNG be unable to provide draft resource reports in support of its project by August 1, 2015, I will suspend my staff's participation in the prefiling process." If this occurs, CE FLNG would then need to begin the pre-filing process anew once it is prepared to move forward.

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On 7/9/15 the staff of FERC announced it will prepare an environmental assessment (EA) that will discuss the environmental impacts of the Chicago Market Expansion Project involving construction and Operation of facilities by Natural Gas Pipeline Company of America, LLC (CP15-505) in Livingston County, Illinois. Comments are due on or before August 9, 2015. Natural proposes to construct and operate a new compressor station and associated facilities in Livingston County. The project would provide about 238,000 dth of incremental northbound firm transportation capacity to the city of Chicago, Illinois and neighboring areas.

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On 7/13/15 the FERC staff stated it has prepared an EA for the Kalama Lateral Project, proposed by Northwest Pipeline, LLC (CP15-8). Northwest requests authorization to construct and operate about 3.1 miles of natural gas transmission pipeline and associated facilities in Cowlitz County, Washington. The project would provide about 320 MMcf/d of natural gas to the NW

Innovation Works' (NWIW) proposed Kalama Manufacturing & Marine Export Facility Methanol Plant, a methanol production facility that would be located at the Port of Kalama, also in Cowlitz County. The FERC staff concludes that approval of the proposed project, with appropriate mitigating measures, would not constitute a major federal action significantly affecting the quality of the human environment.

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Equitrans, LP (CP15-528) recently submitted to FERC an abbreviated application for (1) a certificate authorizing Equitrans to construct, operate and maintain the proposed replacement facilities and (2) authorization to abandon an existing pipeline segment in place. In order for the Project to be completed and in-service by November 2016, Equitrans asked FERC to issue the approvals by 2/1/16. Equitrans proposes to replace approximately 21 miles of 12-inch diameter pipeline installed in the 1950s and 1960s on the TP-371 pipeline with 20-inch diameter new pipeline located in Armstrong and Indiana Counties, Pennsylvania. The purpose of the Project is to improve system integrity, reliability, and safety of the Replacement Segment. Equitrans, LP is a Pennsylvania limited partnership that owns and operates an interstate natural gas pipeline system. In addition, Equitrans leases and operates the Allegheny Valley Connector system pursuant to a lease agreement. Equitrans is currently owned 97.25% by Equitrans Investments, LLC, a subsidiary of EQT Midstream Partners, LP, and 2.75% by Equitrans Services, LLC, also a subsidiary of EQT Midstream Partners.

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By order issued 7/14/18, FERC approved an Addendum to the Stipulation and Consent Agreement it approved in March, 2005, between the Office of Market Oversight and Investigations (OMOI), now the Office of Enforcement (Enforcement), and Coral Energy Resources, LP (IN05-5), now Shell Energy North America. The approved addendum relieves Shell Energy of the requirement that it give the Commission advance notification if it decides to modify the Price Reporting Procedures it adopted in November 2004 to ensure the accuracy of the pricing information it provides to firms that report such information. The addendum "does not change the separate requirement that Shell Energy give the Commission advance notification if it decides to terminate the Price Reporting Procedures," the Commission noted. This order is in the public interest because it ensures that Shell Energy will continue to have procedures in place to ensure the accuracy of the pricing information it makes publicly available while relieving it of an administrative requirement that no longer contributes to achieving that purpose, the Commission ruled.

According to the order, "since entering into the Settlement Agreement in 2005, Shell Energy has demonstrated its compliance with its Price Reporting Procedures, and Enforcement has received no report from any source suggesting that Shell Energy or its predecessor has reported inaccurate pricing data. Furthermore, audits performed by Commission staff confirm Shell Energy's implementation of all other requirements of the Settlement Agreement and the accuracy of the pricing data that Shell Energy provides." Shell Energy represents that since entering into the Settlement Agreement there have been no substantive modifications of its Price Reporting Procedures, and that it currently has no intention to make any such modification in the future.

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The American Gas Association (AGA) this week filed comments in response to the U.S. Department of Energy's (DOE) Notice of Proposed Rulemaking on Energy Conservation Standards for Residential Furnace (3/12/15). The proposed rule would mandate that natural gas furnaces meet a 92% or higher specification for energy efficiency.

"At first glance, the rule appears to be a positive step forward for energy efficiency," but AGA holds that the proposal would create a number of counterproductive and unintended consequences that could increase energy use. "Natural gas utilities support energy conservation standards that are technologically feasible, economically justified, based on reasoned analysis and will result in significant conservation of energy as laid out in the Energy Policy and Conservation Act," said Kathryn Clay, vice president, Policy Strategy for the AGA. "This rule does not meet those standards. Due to flawed analysis and a raft of unintended consequences, this rule, if implemented, would place an undue burden on low-income customers and lead to an increase in carbon dioxide emissions. We have laid out this analysis in detail in our comments submitted today and we urge the Department of Energy to rethink this rulemaking."

In particular, the gas distributors organization argues that DOE's analysis of economic justification and energy savings has significant methodological and data flaws. A "corrected analysis", according to AGA, shows that a 92% AFUE (annual fuel utilization efficiency) standard is not economically justified and would impose significant costs on American consumers. DOE's analysis underestimates the number of consumers that are likely to switch away from natural gas heat and misidentifies which consumers are likely to switch due to the Proposed Rule. These flaws led DOE to overestimate the benefits, and underestimate the costs, of the proposed standard. Their analysis estimates that its proposed 92% AFUE standard would drive 16.3% of affected consumers that would otherwise purchase natural a non-condensing gas furnaces to shift to electric heat. Such fuel switching increases primary energy consumption. Under DOE's analysis, the direct energy savings and emission benefits of increased furnace efficiency requirements are offset in very significant part by increased electricity usage from fuel switching caused by the rule. Moreover, after correcting for DOE's analytical errors, the proposed standard results in increased source energy use and increased carbon dioxide emissions.

According to DOE's life-cycle cost analysis, many consumers are worse off under the proposed standard. DOE projects that the "middle" 41% of American consumers would receive no benefit from the proposed standard while 20 percent of households would face higher costs. In the replacement market, fully one quarter of all households would see a net cost increase. Low-income families and consumers in the Southern U.S. would be the hardest hit, with 39% of low-income households in the South bearing higher costs as a direct result of the proposed rule.

AGA included in its comments a recently completed study by the Gas Technology Institute (GTI) that provides "strong technical analysis and demonstrates that DOE's economic and energy impact analyses use a materially flawed methodology to estimate the costs and benefits of the proposed standard." These methodological flaws lead DOE to overestimate benefits, and underestimate the costs, of the proposed standard. Meanwhile, AGA reported it has been meeting regularly with environmental groups, efficiency advocates, furnace manufacturers and other stakeholders to try to come to an agreement on a standard that all parties believe will benefit consumers and our environment.

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This week the Independent Petroleum Association of America (IPAA) President Barry Russell released a statement after the Obama Administration secured the nuclear deferment agreement with Iran, which includes provisions that will soon lift global sanctions on Iranian oil sales. "Once oil sanctions on Iran are lifted, today's deal will soon put America's oil producers at a competitive disadvantage on the global marketplace. As soon as Iran is permitted to export its surplus oil on the world market, why can't we allow our own companies to do the same with their American-made surplus of crude oil? "

"It's past time to lift the 1970s-era ban on crude exports, which makes no sense for a nation that has surpassed Saudi Arabia and Russia as the world's leading oil producer in 2015. It's not only good national security policy, it's good for American energy self-sufficiency," declared Russell.

With no opportunity to export their crude oil surpluses to the world marketplace, American producers – companies that have been one of the most significant factors in America's economic recovery – are forced to sell their product at a significant discount, store their crude supplies, or slow production by laying down rigs and laying off American workers – the effects of which the U.S. economy is already starting to see."

According to Russell, IPAA and its member companies have made lifting the export restrictions on the United States' surplus of crude oil a top priority for 2015.

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On the international scene, Moody's assigned an Aa3 rating to the proposed senior unsecured US dollar notes to be issued by Korea Gas Corp. The rating outlook is positive. The rating reflects Moody's assessment of "a very high likelihood of government support to Kogas, if and when needed, because of its important strategic policy role in ensuring a stable natural gas supply and improving Korea's self-sufficiency for natural gas, and its close relationship with the Korean government," says Mic Kang, a Moody's Vice President and Senior Analyst. Kogas' ratings will remain closely linked to that of the Korean government over at least the next 2-3 years, because of its strategic importance as "an effective monopoly over the import, transmission and wholesaling of natural gas in Korea and the government's intention to maintain a close relationship with and significant influence over the company, which will remain strategically important to the country."

EIA'S WEEKLY GAS STORAGE ANALYSIS

WORKING GAS IN UNDERGROUND STORAGE FOR WEEK ENDING July 10, 2015						
Region	Current Week Stocks (Bcf)	Prior Week Stocks (Bcf)	Net Change (Bcf)	Year Ago Stocks (Bcf)	5-Yr Average Stocks (Bcf)	Cur Wk Difference from 5-Yr Avg (%)
East	1,235	1,178	**57**	1,035	1,300	-5.0
West	450	440	**10**	356	426	5.6
Producing	1,082	1,050	**32**	723	967	11.9
Total Lower-48	2,767	2,668	**99**	2,114	2,694	**3.2**

Working gas in storage was 2,767 Bcf as of Friday, July 10, according to EIA estimates. This represents a net increase of 99 Bcf from the previous week. Stocks were 653 Bcf higher than last year at this time and 73 Bcf above the 5-year average. In the East Region, stocks were 65 Bcf below the 5-year average, while stocks in the Producing Region were 115 Bcf above the 5-year average. Stocks in the West Region were 24 Bcf above the 5-year average.

Weekly Update (For the Week Ending Wednesday, July 15)

Natural gas prices increased at most market locations through the report week. The Henry Hub spot price began at $2.71/MMBtu and closed at $2.92/MMBtu. At the New York Mercantile Exchange (Nymex), the August contract began the week at $2.685/MMBtu and increased by 23¢ to settle at $2.918/MMBtu yesterday.

The total oil and natural gas rig count increased by 1 unit to 863 for the week ending Friday, July 10, according to data from Baker Hughes Inc. The oil rig count increased by 5 units, totaling 645, while the natural gas rig count decreased by 2 to 217. Miscellaneous rigs also decreased by 2 units down to 1.

EIA noted that even though this is the third consecutive week that the total rig count has increased, rig activity was mixed, with the Permian Basin in West Texas adding the most oil rigs - 7 - while other plays, such as Eagle Ford in South Texas and Marcellus in the Northeast, had rig counts that were down.

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