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Independent and In-Depth Reporting on the Energy Industry

THE FOSTER REPORT

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STATE OF THE UNION

In His Final State of the Union Address, U.S. President Obama Advised the Nation to "Not Fear the Future, But Shape it;" Among other Pledges, He Promised to Push for Changes in the Way Oil and Coal Resources Are Managed

President Barack Obama's final State of the Union (SOTU) speech to Congress and the Nation on Jan. 12 portrayed the U.S. as a nation weathering many headwinds but doing so successfully in most circumstances under his leadership. At the time he assumed the Presidency, Obama reminded the audiences that the country was facing the worst economic crisis since the Great Depression. "Seven years later, our businesses have created 14.1 million new jobs over the past 70 months. We've rebuilt our manufacturing base, reformed our health care system, and reinvented our energy sector. We've welcomed home more than 160,000 troops."

"We are living through an extraordinary moment in human history," he suggested, with technological and social change reshaping the way Americans live and work, deal with the environment, and make a place in the world. As Americans, "we should not fear the future, but shape it."

Obama acknowledged that because it was a presidential election cycle "expectations for what we'll achieve this year are low." Instead of presenting a laundry list of action items to Congress and the new Speaker of the House, Rep. Paul Ryan (R- Wisconsin), Obama mentioned a few priorities, including: fixing a broken immigration system; pursuing criminal justice reform; protecting kids from gun violence; equal pay for equal work; paid leave; raising the minimum wage; combatting prescription drug abuse; helping students learn to write computer code; and personalizing medical treatments for patients. "[Also], our foreign policy must be focused on the threat from ISIL and al Qaeda."

The President hoped "we can work together this year on bipartisan priorities," and praised the "constructive approach" Speaker Ryan and other Congressional leaders took at the end of last year to pass a budget and make tax cuts permanent for working families.

He stressed that the progress over the last seven years was "not inevitable," and that it was "the result of choices we made together." Now, going forward, the country is facing four "big questions" that it has to answer, Obama said – (1) how to give everyone a fair shot at opportunity and security in this new economy; (2) how to make technology "work for us, and not against us — especially when it comes to solving urgent challenges like climate change"; (3) how to keep America safe and lead the world without becoming its "policeman"; and (4) how to make our politics "reflect what's best in us, and not what's worst."

Obama claimed the U.S. -- right now -- has the strongest, most durable economy in the world. "We're in the middle of the longest streak of private-sector job creation in history," he said, citing "the strongest two years of job growth" since the '90s and an unemployment rate cut in half. "Anyone claiming that America's economy is in decline is peddling fiction."

The President proposed to "reignite the spirit of innovation" to meet the Nation's biggest challenges, including climate change. Citing the example of the Space Race, he urged the country to get onboard with climate measures. "Sixty years ago, when the Russians beat us into space, we didn't deny Sputnik was up there," he admonished. "We didn't argue about the science, or shrink our research and development budget. We built a space program almost overnight, and twelve years later we were walking on the moon. Look, if anybody still wants to dispute the science around climate change, have at it. You'll be pretty lonely, because you'll be debating our military, most of America's business leaders, the majority of the American people, almost the entire scientific community, and 200 nations around the world who agree it's a problem and intend to solve it."

The President said he doesn't want to the country "to pass up the chance for American businesses to produce and sell the energy of the future." He boasted that "seven years ago, we made the single biggest investment in clean energy in our history," resulting in "fields from Iowa to Texas, in which wind power is now cheaper than dirtier, conventional power. On rooftops from Arizona to New York, solar is saving Americans tens of millions of dollars a year on their energy bills, and employs more Americans than coal — in jobs that pay better than average. We're taking steps to give homeowners the freedom to generate and store their own energy — something environmentalists and Tea Partiers have teamed up to support. Meanwhile, we've cut our imports of foreign oil by nearly sixty percent, and cut carbon pollution more than any other country on Earth."

"Gas under two bucks a gallon ain't bad, either," he quipped.

"Now we've got to accelerate the transition away from dirty energy," Obama pressed on. "Rather than subsidize the past, we should invest in the future — especially in communities that rely on fossil fuels." He promised to "to push to change the way we manage our oil and coal resources, so that they better reflect the costs they impose on taxpayers and our planet. That way, we put money back into those communities and put tens of thousands of Americans to work building a 21st century transportation system."

Obama acknowledged there are "plenty of entrenched interests who want to protect the status quo."

The President lobbied Congress for the Trans-Pacific Partnership (TPP) "to open markets, protect workers and the environment, and advance American leadership in Asia." The agreement cuts 18,000 taxes on products "Made in America," and supports "more good jobs," Obama claimed. "With TPP, China doesn't set the rules in that region, we do. You want to show our strength in this century? Approve this agreement. Give us the tools to enforce it."

Lastly, he urged Congress to lift the embargo with Cuba. "You want to consolidate our leadership and credibility in the hemisphere -- recognize that the Cold War is over and lift the embargo."

Reaction from Energy Industry. Following the President's speech, segments of the energy industry and businesses continued to display skepticism toward the Administration's policies and Obama's outlook. The **Western Energy Alliance** (WEA), often critical of the government's actions that affect western Federal lands, claimed the President's final SOTU address only reaffirmed his "go-it-alone posture on key issues," including energy production and the environment. WEA warned that Obama would continue "side-stepping Congress" through the use of executive orders to implement his climate change goals, and change the rules targeting oil and natural gas producers across the West.

"The president still fails to accept one basic fact about climate change: The U.S. has dramatically reduced greenhouse gas emissions, more than other developed countries, primarily because of increased use of natural gas," said **Tim Wigley, WEA's president**. "It is not because of wind or solar."

Obama's legacy, WEA predicted, will be "overreaching regulations" designed to constrict production of oil and gas in favor of "unreliable" alternatives. "It's no coincidence there's a significant decline in production of natural gas on federal lands while it has soared elsewhere. Since 2008, production on public lands is down more than 19%," Wigley said.

Wigley harshly alleged that Obama didn't include a prescribed list of new policy goals to Congress "by design," since he has "no intention of working with elected leaders to implement his goals for energy and the environment." Obama will close out his term by continuing to issue new rules through the federal agencies "that kill jobs and economic growth in order to promote his climate change agenda, which he couldn't even pass when Democrats controlled both the House and Senate."

After the past seven years, Wigley suggested, "we need a president with a vision that embraces innovation, technology and the abundant oil and natural gas available in the West, not centralized Washington policies."

The **American Petroleum Institute's (API) president and CEO Jack Gerard** was not quite so strident in his posted response to the SOTU, but called on the President to "put consumers first and not disrupt America's energy renaissance with unnecessary, duplicative and costly" regulations. "The energy revolution has created a proven model to improve the environment while creating jobs and strengthening our national security and lowering consumer costs," Gerard stated. "We call it the U.S. model, and it can be achieved without over-regulating."

He complained that the oil and gas industry has had to address "nearly 100 regulations impacting all aspects of our business." API is going to urge the administration "to take a close look" at the regulations to see: (1) are the regulations necessary; and (2) what the cost will be to consumers.

"Instead of pursuing a barrage of job-crushing new regulations, many of which are duplicative and unnecessary, - President Obama has the opportunity to seize the initiative and embrace policies that recognize the value of the energy resurgence and acknowledge that the goals of environmental progress and energy production are not mutually exclusive," Gerard advised. "By looking to science and real-world proven results to guide the policy choices during his final year in office, the president can ensure that America's energy resurgence continues to provide economic growth, environmental progress and security benefits."

From the environmentalists' camp, the **Environmental Defense Fund** (EDF) applauded Obama's efforts. "President Obama has built an impressive environmental legacy during his seven years in office," said Fred Krupp, EDF's president. "Tonight's State of the Union address showed that climate change and clean energy will continue to be priorities for this White House in 2016, and that's good news for all of us. The President is right that working for a clean energy future, including giving families the freedom to generate and store their own energy, is an area where people should work together across the political spectrum."

The **American Gas Association's (AGA's) President and CEO Dave McCurdy**, in posted remarks, touted the successes accomplished by the natural gas segment of the energy industry. The direct use of gas was "helping to meet our national goals of boosting our economy, improving our environment and increasing our energy security." The U.S. has "a credible leadership role" on climate change, in part, because of the country's abundant supply of natural gas and the adoption of aggressive automobile fuel economy standards that have led to significant and continued declining emissions –allowing President Obama's "aggressive action at home and abroad to reverse the effects of climate change."

Natural gas remains "part of the solution to climate change" and the fuel will help the U.S.

make progress toward ambitious emissions reduction targets, McCurdy suggested. He offered that households with gas versus all-electric appliances save an average of $840/y, and that the low domestic gas prices have led to savings of almost $69 billion for residential natural gas customers over the past four years. "In addition, households with natural gas versus all-electric appliances produce 37% lower greenhouse gas emissions," McCurdy concluded.

FERC ENFORCEMENT

FERC Orders Coaltrain Energy, its Principals, and Staff Analysts/Traders to "Show Cause" Why They Shouldn't Be Liable for Major Civil Penalties for "Sham" Transactions in the PJM Market

On 1/6/15, FERC issued a "show cause" order treading the now familiar path of seeking major civil penalties (totaling $38.25 million plus $4.1 million in profits "disgorgement") against an energy trading firm for "market manipulation" involving PJM's "Up to Congestion" (UTC) market and its marginal losses refund pool (IN16-4). The respondents are Coaltrain Energy, LP, its owners Peter Jones and Shawn Sheehan, and staff analysts Robert Jones, Jeff Miller, Jack Wells, and Adam Hughes. The Commission has previously pursued similar allegations against two other financial trading firms – Powhatan Energy Fund and City Power – and issued final orders with penalty assessments likewise running into the tens of millions of dollars.[1]

The January 6 show cause order relates that, at this stage, the allegations are those of FERC's Enforcement staff, and its issuance "does not indicate [either] Commission adoption or endorsement" of the Enforcement staff report. It gives the respondents the opportunity to file an answer within 30 days, which FERC says it will take into account in formulating its final assessment. However, given the considerable bulk of the evidence, the lack of mitigating factors, and the precedential effect of two similar cases in which FERC has come down heavily on financial trading firms engaged in similar dealings, the outlook for amelioration of Enforcement's penalty recommendations cannot be bright.

The staff-proposed penalties break down as follows: $26 million for Coaltrain, $5 million each for owners Peter Jones and Shawn Sheehan, $1 million for Robert Jones, $500,000 each for Jeff Miller and Jack Wells, and $250,000 for Adam Hughes. For the two co-owners, Jones and Sheehan, the exposure is considerably larger than the $5 million directly proposed for them, because staff recommends they be held "jointly and severally liable" for the penalties assessed against their company, Coaltrain, as well as the profits disgorgement of $4.1 million. A secondary allegation against Coaltrain and its principals is that they gave false or misleading statements during the discovery phase of the FERC investigation to conceal the existence of documents responsive to data requests, in violation of section 35.41(b) of the regulations.

Pumping up Transaction Volumes to Tap the Marginal Losses Reimbursement Pool. The heart of the case against Coaltrain and the individual respondents is that they devised a trading scheme to gain eligibility for large cuts of what PJM calls "Marginal Loss Surplus Allocations" (MLSA) – the same temptation that purportedly lured Powhatan and City Power in their respective enforcement proceedings. The MLSA pool exists because PJM transmission services include a charge for

[1] Powhatan Energy Fund's proceeding, now in a federal district court in Richmond, Virginia, is covered in the adjacent article in this Report.

line losses on a "marginal cost," rather than average cost, basis, and these charges raise considerably more money than the actual cost of the line losses. PJM's tariff therefore includes a methodology for redistributing the excess to customers, and that method (including the relative size of one's allocation) is driven by the quantity of transmission services purchased by customers.

UTC transactions are a congestion hedging product on the PJM market that can also be legitimately used as an arbitraging vehicle.[2] At the time of the alleged market manipulation, PJM required non-physical (i.e., financial or "virtual") traders engaging in UTC transactions to reserve transmission. What Coaltrain (and several other market participants at the time) realized is that, by placing a large number of UTC transactions with little or no actual market exposure or "spread," a party could earn MLSA credits whose cash value would significantly exceed the minimized market risk plus the out-of-pocket cost of transmission.

Coaltrain's specific strategy, which it called its OCL Strategy ("OCL" is short for Over-Collected Losses, a reference to the MLSA payments), involved researching and then placing UTC transactions on paths that exhibited little or no congestion cost differential between the day-ahead and the real-time markets.[3] Referring to these as "sham transactions," FERC's show cause order states that Coaltrain deployed its OCL Strategy on some 40 different PJM transmission paths, although primarily on just two: the SouthImp-Exp and NCMPA Imp-Exp paths.[4]

The alleged violations of section 35.41(b) regulations requiring accurate and complete responses to information requests in the course of an investigation also figured prominently in the staff report. Staff asserted that the company withheld "thousands of communications and screenshots" that were relevant to the investigation and preserved by Coaltrain's computer security monitoring software (used to monitor all employees' transactions, whether at work or on their home computers). FERC staff only found out about this trove of documents "years after the investigation commenced" from a former employee. Coaltrain had breached its obligations under section 35.41(b), the show cause order asserts, by falsely attesting that its discovery responses were "true, complete, and accurate."

The show cause order itself is only five pages long, but attaches the staff report in excess of 100 pages detailing the investigation's findings and penalty recommendations. The order concludes with the standard provision that, in the event the Commission confirms the staff's proposed violations and penalty assessment, the respondents will have the option of requesting (1) a full evidentiary hearing before a FERC administrative law judge (subject to full Commission review and the right to appeal to a federal court of appeals), or (2) a more summary process whereby FERC issues a "prompt penalty assessment," followed by the Commission's initiation of an action in a federal district seeking to affirm the penalty.[5]

Details of the Alleged Transgressions. FERC Enforcement staff's extensive account of the

[2] Basically, a UTC transaction is a directional bet on whether the cost of congestion between Points A and B is greater in the day-ahead versus the real-time market. This differential is sometimes referred to as the "spread." A cleared UTC bid is profitable when the real-time market congestion price exceeds the day ahead congestion price (i.e., the spread increases) for the same set of PJM nodes. The arbitrageur loses money if the spread decreases.

[3] City Power followed this strategy, along with the alternative strategy of placing "round trip" transactions that offset market risk. That strategy was effective because the dollar exposure from a congestion cost differential between Points A and B would be cancelled out by placing an opposing UTC transaction between Points B and A.

[4] As FERC notes, these two paths were also involved in the City Power proceedings.

[5] The appropriate nature and structure of the latter option is the main subject of the article in this edition on the

genesis of Coaltrain's UTC trading scheme, how this allegedly violates the Commission's anti-market manipulation regulations, its allegedly misleading responses to discovery requests, and how staff views the severity of the misconduct and the appropriate penalty level comprises (as noted) well over 100 pages. However, the highlights of the report can be synopsized.

The staff report charges that the now-defunct Coaltrain Energy firm devised, in June 2010, a "trading scheme" which it executed from mid-June until early September 2010 whose "purpose" was not to profit from price differentials in the day ahead/real-time markets (i.e., to arbitrage them), but rather to "avoid or nullify" such price spreads while garnering profits from the MLSA payment pool. It accomplished this by placing voluminous "sham" UTC trades, the report alleges.

The respondents had previously engaged in UTC trades for conventional arbitrage purposes and made "tens of millions" of dollars over the years doing so. But its arbitraging "Spread Strategy" gave way to the new OCL Strategy in the summer of 2010 and took dead aim at the MLSA payment pool. Because the Coaltrain employees selected paths with "reliably zero or near-zero" price differentials, the OCL Strategy was "the very opposite of a legitimate arbitrage strategy," staff ventures. While the report contends that "voluminous evidence" demonstrates the improper, manipulative intent of the strategy, it suggests that one "contemporaneous comment" from the employee who designed the OCL Strategy software neatly "sums it up": "create an application to find deals for loss credits."

Conducting what seems at first blush to be unprofitable transactions is a prime signal of inappropriate trading under FERC's enforcement policy and surveillance practice. The report underscored that, on the transmission paths utilized, the company made either no money on the UTC spread or precious little (which was outstripped by the transaction costs, including the transmission purchases necessary to get MLSA payment eligibility). Moreover, staff found that <u>even on paths where there was free transmission,</u> the firm went ahead and purchased transmission – which could have no economic justification apart from compounding its eligibility for MLSA payments.

As the numbers fell out, Coaltrain executed 4.61 million MWh of trades over the summer of 2010, losing in the process a net $96,000 on UTC spreads and paying another $3.83 million in transaction costs (including some transmission reservation charges it had no obligation to pay). Its reward was collecting $8.05 million in MLSA payments, yielding a net profit of $4.12 million.

PJM Discovers Irregularities and Hands Off to FERC. It was in late July 2010 that PJM's independent market monitor discovered that some traders were engaging in high-volume UTC transactions with no evident economic rationale <u>except</u> to secure eligibility for MLSA payments.[6] It quickly obtained a tariff amendment to end the requirement that UTC transactions obtain transmission reservations, thus eliminating their eligibility for the payment pool. At that time, PJM also referred the market participants in question to FERC's Office of Enforcement for further investigation.

Powhatan proceeding, now pending in a federal district court.

[6] PJM was initially alerted by a market participant who questioned whether market participants engaging in high-volume UTC transactions were trying to "game the system" by locking people out of transmission service. PJM also became suspicious because it found the transmission service reserved in some cases was disassociated from the sink and source points of the UTC transaction.

That led to Enforcement's opening up an investigation in August 2010. A major breakthrough occurred in June 2012, when a former Coaltrain employee revealed the extensive recording of employees' keystrokes and periodic screenshots archived by the monitoring system the company's owners had installed.[7] That new documentation provided the investigators with an almost play-by-play account of the trading strategy's design and execution. Enforcement served the respondents with a notice of "preliminary findings" in September 2014, leading to written responses from the respondents in May 2015, supplemented in September 2015. When settlement discussions proved unavailing that fall, more notices and responses were exchanged, culminating in the January 6 order to show cause.

Sizing up the Evidence. The cataloguing and characterization of the extensive evidence secured by the discovery of the firm's employee tracking software constituted the majority of the staff report. Staff also noted a degree of hypocrisy implicit in Coaltrain's pleading submitted to FERC in a related matter. In a proceeding that considered modifications to PJM's methodology for crediting the MLSA back to market participants,[8] Coaltrain insisted, in a 6/9/10 request for rehearing, that there was "no merit to any claim that updating the allocation percentage will give market participants perverse incentives to engage in virtual transactions in order to capture a larger share of the [marginal losses] surplus. As always, market participants will conduct virtual transactions when they think they can profit from the difference between the day ahead LMP [locational marginal price] and the real-time LMP they expect." The staff report emphasizes that the company was telling the Commission "one thing while at the same time…privately planning to do the opposite."

Shortly after it was contacted by the independent market monitor, the Coaltrain owners agreed to stop the "uneconomic trades," which they conceded (at least for one major leg) were "inappropriate."[9] But, notes staff, they did some after-the-fact calculations in an attempt to discover historical instances of "some small price divergence" (i.e., an arbitrage opportunity) in the past, and pointed to some limited profit on price spreads during the investigation period. The respondents then used this information to justify their trades to PJM and Enforcement. But it was unconvincing to FERC staff because the "tiny gains" demonstrable on any price differentials were "more than cancelled out" by the "basic expenses associated with UTC trading" – as the traders' own research had concluded. The nodes chosen for the OCL Strategy, in short, were never ripe candidates for arbitrage-based trading.

Conclusions from the Evidence. Applying the analytical framework that the Commission has used in other market manipulation cases, including the similar fact patterns involving the PJM market and financial traders Powhatan and City Power, the staff report found that all the elements of intentional "market manipulation" were present in the Coaltrain case. Factors that stood out included (1) marked differences in trading patterns before the manipulative scheme was put in place versus after; (2) the persistent making of uneconomical trades (but for the MLSA payments); (3) contemporaneous or "speaking" documents that revealed the traders' fraudulent intent; (4) failure to give a plausible or credible explanation for the pattern of uneconomic trades; and (5) an

[7] The respondents, when confronted with this revelation, initially denied (incorrectly) that they could access the software system's recorded data. They "belatedly" produced the documents, however, notes the staff report.

[8] This was the *Black Oak* proceeding.

[9] The report later explains that the company did not cease all of the OCL Strategy trades at that stage.

inference of guilt from "evidence of lying or deceit."

The respondents offered one defense that has reverberated throughout all the recent market manipulation cases the Office of Enforcement has brought: that market participants have lacked "fair notice" that their practices would be deemed to run afoul of the anti-manipulation rules. In the context of UTC transactions on PJM, they argued that, in the *Black Oak* proceeding, the "MLSA trading scheme was squarely before the Commission," FERC realized that the incentive of MLSA payments would "change the overall economics" of conducting MLSA-eligible transactions, and yet it (and other market participants were "not put on notice that they could be prosecuted…for doing precisely what rational market participants were expected to do."

But the FERC staff shot back that the Commission's definition of "fraud" – i.e., "any action, transaction, or conspiracy for the purpose of impairing, obstructing or defeating a well-functioning market" – is not "ambiguous, vague, or overbroad," citing the Commission's rejection of the same contention by the respondents in the *City Power* case. It also repeated FERC's finding in *City Power* that nothing in the *Black Oak* proceeding or PJM's tariff condoned the placing of "uneconomic trades solely for the purpose of collecting MLSA payments." And, reiterating Coaltrain's assurance to FERC in the *Black Oak* proceeding that a virtual trader would <u>not</u> place trades based primarily on racking up MLSA payments, FERC staff branded that representation "knowingly false," since the firm was doing just the opposite in the same time frame.

As to the proposed section 35.41(b) violations, the staff report laid out in detail how the respondents deliberately hid the existence of the extensive employee computer use records and then, once discovered, dissembled about their ability to recover the recorded documents; yet, they attested that Coaltrain's data responses were "true, complete, and accurate."

FERC staff also rebuffed Coaltrain's assertion that no harm to the market had occurred as a result of its scheme. The report points to the company's having claimed a large share of PJM's MLSA payments by executing the scheme, depriving other market participants of what would have been their full shares.[10] Since some of the major dollar losers would by law have had to pass through the MLSA payments to consumers, end users also were harmed as a result of the scheme. Additionally, the report asserted that harm to the market was caused by the OCL Strategy reserving millions of MWh of day-ahead transmission, tying up capacity that otherwise would have been available to other market participants.

Remedies. The staff report noted that, while FERC "should disgorge" Coaltrain's net profits of $4.1 million stemming from the unlawful strategy, this is problematic because the two owners, Jones and Sheehan, "withdrew more than $33 million" from the company after the investigation was initiated, paying this money "to themselves and to other companies they jointly control." This led staff to recommend that Jones and Sheehan be held "jointly and severally liable" for the Coaltrain disgorgement, along with the civil penalty of $26 million proposed for Coaltrain (which has become asset-less and defunct).

Staff recommended such major penalties – though "well within the Commission's authority" to "impose $1 million per violation per day" – because the violations were "very serious" and "willful," because senior

[10] PJM calculated the "top 10" market participants in terms of dollars lost as a result of the scheme. The biggest loser lost over $1 million, while the tenth-place loser lost about $126,000.

management was implicated in the scheme, because the harm to the market was significant, and because the respondents "persisted in their scheme" even after the PJM market monitor contacted them and asked them to stop. The report also concludes that the cover-up when FERC staff requested documents responsive to the inquiry was aggravated, and directly the fault of senior management.

While penalty determinations are subject to several potential "mitigating factors," staff concluded that the respondents deserved no credit under any of these four mitigation categories: (1) commitment to compliance or actions taken to correct violations; (2) self-reporting; (3) cooperation; or (4) reliance on FERC staff guidance.

As for the severe penalties assessed individually to co-owners Jones and Sheehan ($5 million each plus "joint and several" liability for the disgorgement remedy plus the $26 million penalty assessed in the first instance to Coaltrain), the staff showed no compunction. Its report revealed that Jones had received more than $21 million in income in 2010-11, while Sheehan had more than $30 million. Staff therefore concluded these respondents had the ability to pay substantial fines. It made similar analyses of the personal culpability and ability to pay with respect to each of the four analyst/trader employees it proposes to penalize.

Powhatan Energy Fund, in an Appeal from Heavy Civil Penalties, Puts FERC's View of Adjudication Process on Trial

In a federal district court in Richmond Virginia, heavily penalized financial trader Powhatan Energy Fund and FERC duked it out on procedural issues of broad interest to the trader community through an exchange of "memoranda of law" on 12/31/15. The central question was whether the Commission's interpretation and implementation of its statutory authority in determining civil penalties for violations of its market manipulation prohibitions squares with Congressional intent and established administrative law precedents.

Powhatan, along with its co-defendants[11] Houlian Chen and two trading funds Chen directly controlled,[12] contended FERC's interpretation was significantly off the mark. These financial traders in the PJM organized electric market had been dealt a severe blow by FERC in a 5/29/15 decision that imposed, in the aggregate, nearly $35 million in penalties. The bulk of that total (almost $30 million) represented civil penalties assessed for the alleged misconduct, while the rest (almost $5 million) was for disgorgement of profits from the transactions at issue.

In contesting these misconduct charges, Powhatan had opted for an adjudicatory procedure that calls for the Commission to "promptly" issue its penalty ruling (without an evidentiary hearing), following which FERC must file an action in federal district court to further pursue the alleged violation and penalties. Importantly, under the procedure Powhatan elected, defendants are entitled to a "*de novo* review" by the district

[11] In contrast, FERC's pleadings call the charged parties "respondents" – more consistent with its view that this is an appellate-like procedure. Powhatan refers to the charged parties as "defendants," reflecting its view that the matter is like a civil trial.

[12] Chen was the lead advisor to the Powhatan Energy Fund as well as directly controlling two other trading firm funds, all employing essentially the same strategy which FERC challenged as fraud or market manipulation. Powhatan, Chen, and the Chen funds joined in the "memorandum of law", and for convenience of reference the entire group is combined here as "Powhatan."

court. FERC's filing of suit against Powhatan kicked off the Richmond federal district court proceedings in October and November of last year.[13] It also triggered a heated debate over the correctness and fairness of FERC's entire approach to penalty determinations and court review under the track for contesting that Powhatan elected.

Background. As noted, the immediate focus of the litigants' 12/31/15 memos of law was on whether the procedures FERC employs when an accused party elects a more truncated FERC penalty-setting process to advance to a court's "*de novo* review" are consistent with what the statute directs. This controversial procedural issue fits within a larger substantive debate being waged in the Richmond court over whether FERC has provided sufficient "notice" to PJM financial traders and arbitrageurs such as Powhatan that the types of transactions Powhatan engaged in would run afoul of the Commission's anti-fraud rules.

As to the larger question, Powhatan has argued, first before FERC and now the court, that market participants were entitled to more specific notice that Powhatan's complex trading strategy involving a particular PJM congestion hedging product (under which Powhatan became eligible for sizeable payments earmarked for transmission customers) crossed a red line. FERC has countered that (1) its general bar against transactions intended to defraud, manipulate, or disrupt the normal functioning of markets; (2) its 2003 Market Behavior Rules; (3) its Order No. 670 (implementing its enhanced statutory authority under EPAct 2005 to pursue fraudulent conduct); and (4) its precedents in pursuing misconduct cases collectively served to put financial traders on ample notice that "round trip" or "wash trade" transactions[14] that eliminate all or most of the exposure to market risk, and serve no "legitimate" business purpose (such as traditional hedging or arbitraging), are deemed forms of unlawful market manipulation.

A linchpin of FERC's policy argument is that it needs a "flexible" enforcement standard. In other words, FERC asserts, "fair notice" and "due process" principles should <u>not</u> require it to spell out in advance every conceivable variety of market manipulation that might cross the line, since human ingenuity to devise new or altered schemes is virtually boundless. Rather, FERC believes that its general anti-fraud regulations, coupled with a growing body of enforcement caselaw precedent, provide the industry with sufficient guidance; and, if a market participant is in any doubt, it should confer with the organized market, the market's independent monitor, or FERC itself before plunging ahead.[15]

"Alternative Paths" of FPA Section 31(d). The critical procedural issue on which the opposing parties are now clashing is whether FERC is correctly interpreting Federal Power Act (FPA) section 31(d), the provision which prescribes the two alternative "procedural paths" available for a respondent in an investigation contesting market misconduct allegations and civil penalties proposed by FERC's Office of Enforcement.

As mentioned above, the accused party gets to choose at the outset <u>which</u> procedural path it desires under section 31(d). One option is for a full-blown evidentiary hearing before a

[13] See FR No. 3075, pp. 16-20. For a detailed article on the underlying FERC determination, see FR No. 3053, pp. 1-8.

[14] Powhatan was found to have pursued a strategy of placing voluminous amounts of "Up to Congestion" (UTC) hedging positions on PJM and, at the same time, placing opposite and offsetting UTC transactions on the market to neutralize virtually all market exposure but obtain large allocations of PJM's marginal loss repayment fund because it had contracted for associated transmission. The traders' out-of-pocket cost for this transmission service was <u>less</u> than their marginal losses repayment fund allocation, making the strategy profitable.

[15] In the instant case, the accused parties did not seek an advance ruling from any institution on the legitimacy of its trading strategy.

FERC administrative law judge (ALJ), whose findings are then reviewed by the commissioners and either affirmed or modified.[16] The second option is designed to truncate the FERC administrative process. If that path is selected, the Commission must "promptly assess" the civil penalty and then (assuming the party declines to pay the penalty) file an action in federal district court (where the "review *de novo*" takes place). The Powhatan memo of law shorthands the first option under section 31(d) as "administrative procedures" and the second as "district court procedures."

Powhatan holds that the nature of the "action" FERC must pursue under the second statutory path (i.e., the "district court procedures") is a "plenary adjudication" of all disputed facts governed by the Federal Rules of Civil Procedure (Federal Rules), not a "summary review proceeding." In support, it cites cases holding that, if a statute is intended to provide for limited adjudicatory rights, Congress must clearly express that intent. It also suggests that the two-part structure of FPA section 31(d) reinforces the concept that the "district court procedure" entails a plenary trial, since the first alternative – the "administrative procedures" – also provides for a trial-type hearing, although before a FERC ALJ.

Powhatan charges that FERC's interpretation "defies this statutory structure." According to Powhatan, FERC posits that the district court judge has "unfettered discretion" to shortcut normal trial procedures and waive the Federal Rules by deciding to limit the "*de novo* review" to a "summary review" of the record compiled by FERC (a record, Powhatan underscores, that was not developed through formal, trial-type procedures).[17] The defendants suggest this would lead to a "patently absurd result," inasmuch as the "district court procedure" under section 31(d) would be "less robust" than the ALJ trial path.

FERC Going Too Far with its Administrative Record. A second prong of Powhatan's argument is that FERC's interpretation of section 31(d) (3)[18] takes it too far in the direction of compiling an administrative record when the respondent has opted for the shortcut, the "district court procedure." This is especially important because FERC argues that the district court judge should have the latitude to review and mainly rely on the extensive administrative record and decisional rationale the Commission has compiled, rather than conducting a new, full-blown trial.

Powhatan asserts that FERC has no business "adjudicating" the civil penalty proceeding or creating an administrative record where the respondent has elected, in effect, to head virtually straight for the court and bypass FERC adjudication. The statute normally indicates whether or not an administrative record should be compiled en route to making a determination, it argues, and in this context, FPA section 31(d), such an indication is given only for cases where the respondent opts for an ALJ-conducted hearing (i.e., the "administrative process.") For the district court path, the statute "never refers to, or authorizes FERC to create, an administrative record," Powhatan submits.

FERC's practice of compiling an administrative record even when the respondent opts for the district court route is also at odds, Powhatan suggests, with the statutory directive that the Commission "promptly" assess the penalty once the respondent has elected to forego the ALJ administrative process. Claiming the

[16] The final FERC order is subject to judicial review but in an appellate court with a more limited scope of review.

[17] Powhatan also argues that as a result of FERC's interpretation, the optionality built into the statute (allowing the accused party to choose between a trial before a FERC ALJ or a "*de novo* review" before a district court judge) would "not be meaningful" because the party would have no idea in advance whether the judge would choose to conduct a full trial or a "summary review."

[18] Section 31(d) (3) is the subsection outlining the second (or "district court") optional path.

authority to conduct an "adversarial proceeding" through a show cause order and thereby create a record – as FERC did in the Powhatan case and in similar cases where the respondent has selected the district court option – is not a reasonable construction of the statute, the defendants maintain.

Whether "*De Novo* Review" Means Starting Afresh. This is another critical issue where Powhatan and FERC part company. Powhatan is adamant that the statutory phrase "*de novo* review" means the district court must grant the defendants an entirely new trial on the facts and make its own determinations, with no deference to how the Commission interpreted the facts or concluded what was a just outcome. It cited similar phrasing construed by the federal courts to buttress its contention that a *de novo* review equates to a "new adjudication," plain and simple, including a new trial. It moreover points to instances over "at least two decades before espousing its current litigation position" where FERC itself, in various contexts, has treated the phrase "review *de novo*" as meaning a new trial before a court.

Powhatan also attempts to devalue the "supposedly 'extensive' administrative record" compiled by FERC. Its chief points are that (1) the factual evidence in the record was accumulated as part of an Office of Enforcement investigation, not an adjudicatory procedure, without the ability to test the materials therein "under any evidentiary standard"; and (2) the only FERC "process" occurring after Powhatan elected the district court path was briefing in response to the show cause order – a step "FERC acknowledges is not part of the statutory scheme."

The defendants conclude: "FERC cannot invent procedures that the FPA does not authorize and then assert that those procedures supplant the fundamental rights the statue and the Constitution confer."

For its part, FERC's memo of law offers a full-throated defense of its view that the FPA language at issue does not mandate a new, plenary trial conducted by the court. It explains the "*de novo*" statutory standard as prescribing a "review" of the "extensive findings of fact and conclusions of law" in the Commission's May 2015 order. Underscoring the extent of "factual development and legal argument" occurring over the five-year investigation period, FERC submits that the "most appropriate procedure" to litigate the case would be through a motion by FERC to affirm the May 2015 Order Assessing Penalties, followed by a "responsive briefing" phase.

The court's essential duty, as FERC sees it, is to determine if "the evidence supporting the Order is credible" and whether Powhatan "failed to rebut it." However, FERC does concede that the court "has discretion to craft the procedure that will best facilitate its review" as well as to determine if additional information is necessary (and, if so, to conduct additional fact-finding).

But there are limits, in FERC's view, to the court's discretion. It argues that discretion does not extend to "jettison[ing] years of investigation, fact-finding, and analysis" on the Commission's part by treating the very order "Congress directed the Commission to issue" as a "nullity" (which, says FERC, is precisely what the defendants suggest).

Staking a claim to precedent, FERC points out that the more limited *de novo* review model it is advocating the Richmond court adopt was, in fact, the procedure followed by the only court thus far to address the FPA section 31(d)(3) process in the context of FERC's market manipulation enforcement – a California federal district court in *FERC v. Barclays Bank PLC* (though FERC acknowledges *Barclays* has appealed the court's ruling on the issue).

FERC's Own Interpretation of the Relevant Language. FERC also contends, just like its adversary, that its interpretation is rooted in the "plain meaning" of the statutory language. The "relevant language" of the statute states the court "shall have authority to review *de novo.*" The implication of "authority," says FERC, is that the court has "substantial latitude" over the scope and depth of its "review" of FERC's work, and that a "review" does not necessarily mean or entail a "trial." The Commission also finds it telling that Congress employed the very same term – "review" – to describe the court's role for both procedural options available to parties charges with violations (i.e., an ALJ-conducted trial followed by a final FERC ruling subject to appellate "review," or a "prompt" FERC assessment followed by a "review *de novo*"). FERC observes that "identical terms should be read as having a consistent meaning."[19]

In addition, the Commission's memo of law drills down on the legal dictionary meaning of "review." The term, it reports, means a judicial re-examination or "second view…for purposes of correction," frequently by an appellate body, focused on "what came previously" – not a start-from-scratch approach. If Congress had intended a trial, insists FERC, it would have simply used that word (and has done just that – providing for a "*de novo* trial" – in other statutory contexts). Moreover, while section 31(d) (3) does direct the Commission to "bring an action" in court to enforce its "prompt" penalty assessment, FERC explains that an "action" in various federal agency statutory contexts does not necessarily imply a trial, but may also be a "summary proceeding."

In short, the Commission urges that the statutory directive that the court "shall have authority to review [FERC's order] *de novo*" means only that the court must assess FERC's penalty assessment order with "fresh eyes," and may but is not required to conduct new evidentiary proceedings to further develop the record. It explains the rationale behind the two procedural paths this way: a party charged with anti-fraud violations may opt for a full trial-type proceeding before a FERC ALJ ultimately subject to judicial review under the traditional (and deferential) "substantial evidence" standard[20]; or it may choose the shortcut to get to the court sooner and with a "less deferential" standard (i.e., "*de novo* review"), but, at the same time, waiving "the benefits of formal adjudication."[21] In other words, Congress intended major trade-offs in the two options afforded.

Whether FERC's Procedures Went Beyond the Statute. Finally, FERC also attempts to rebut Powhatan's charge that the extensive briefing stage FERC directed between its show cause order and its final penalty assessment was an "adjudication" in conflict with the basic statutory structure. The Commission counters that, since the statute requires it to issue a penalty "order" based on certain guidelines,[22] it was necessarily obligated to "find facts" and "adjudicate liability." And answering the respondents' assertion that it was not authorized to "create an administrative record," FERC cites general provisions of the FPA empowering it to conduct hearings, keep records, and issue "orders and regulations" to carry out its duties under the FPA. It then derides the respondents' implication that, in effect, "Congress intended to prohibit the Commission from engaging in thoughtful fact-finding prior to assessing penalties" under FPA section 31(d) (3)."

[19] FERC underscored that the two procedures, both employing the term "review," are in adjacent paragraphs of the statute.

[20] Under this "deferential" standard, the agency determination is upheld if the court finds it is supported by substantial evidence in the record, even if the court might have come to a different conclusion based on other evidence in the record.

[21] Presumably FERC here means waiving the benefit of a guaranteed formal adjudication, since it acknowledges that a court may craft an appropriate procedure including new fact-finding.

[22] These include under FPA section 31 the seriousness of the violation and the efforts of the accused party to remedy the violation in a timely manner.

NATURAL GAS PIPELINE RATES/TARIFFS

Statoil Natural Gas Cites a Flaw in Columbia Gas' Modernization II Settlement Offer in Which the Shipper Participated - Should Storage Modernization Costs Be Allocated to Transportation Customers?

Statoil Natural Gas LLC[23] launched an out-of-time protest regarding one aspect of Columbia Gas Transmission, LLC's (RP16-314) December 18 filing seeking approval of a Stipulation and Agreement of Settlement (called the "Mod II Settlement") to implement an updated version of its modernization efforts and to modify and extend its Capital Cost Recovery Mechanism (CCRM). Columbia is seeking an extension and modification of its original modernization settlement, which the Commission approved in 2013, this time identifying especially new developments with respect to its storage capabilities. Columbia plans to spend approximately $125 million on projects to improve storage integrity and reliability. Columbia notes that related projects include capital upgrades and replacements of specified wellheads and downhole tubulars, well treatments, drilling of new wells in existing filed to restore late-season deliverability, and other specified storage projects.

Statoil itself "actively participated in the Mod II Settlement negotiations and does not object in principle to a prudent extension of Columbia Gas' ongoing pipeline modernization efforts." The shipper conceded that the Mod II Settlement "represents a carefully crafted balance of competing interests that indivisibly and constructively extends the pipeline modernization program while providing certain financial benefits to shippers." But Statoil contends that "the recovery of storage-related improvements from firm transportation service customers does not find strong support in the Commission's cost causation principles."[24]

While Statoil "understands that improving storage deliverability on the Columbia Gas system may result in some general benefit to all of the pipeline's customers due to the system's reticulated nature," Statoil "questions whether it is appropriate to allocate storage modernization costs to Rate Schedule FTS customers here." Statoil insisted its acquiescence to the Mod II Settlement should neither be viewed as support for an allocation of storage modernization costs to firm transportation customers, nor as an endorsement of Columbia's claims that the Mod II Settlement conforms with the principles in the Commission's policy statement on modernization cost recovery.

The Mod II Settlement purportedly will preserve and extend the core elements of the original modernization settlement, including the CCRM, but with some added provisions that propose: (1) An additional reduction in base rates equal to approximately $8.4 million annually effective 1/1/16; (2) A further base

[23] Headquartered in Stamford, Connecticut, Statoil engages in the marketing and trading of natural gas produced by its affiliates in the Marcellus, Eagle Ford, Bakken and Gulf of Mexico, along with gas purchased from third-party producers and marketers. In support of these activities, Statoil noted it is a firm and/or interruptible shipper on the following pipelines: Central New York Oil And Gas Co. LLC (CNYOG), Columbia Gas, Discovery Gas Transmission LLC, Dominion Transmission, Inc. (DTI), National Fuel Gas Supply, Corp., Tennessee Gas Pipeline Co., Texas Eastern Transmission, LP, Transcontinental Gas Pipe Line Co., LLC ("Transco"), Nautilus Pipeline Co., LLC, Natural Gas Pipeline Company of America LLC, and Rockies Express Pipeline LLC. Statoil also holds storage capacity with Steckman Ridge, LP. Statoil is a project shipper on numerous expansion facilities, including projects by TETLP, TGP, National Fuel, Columbia Gas, and CNYOG. Statoil also imports liquefied natural gas (LNG) to the Dominion Cove Point LNG, LP, receiving facilities at Lusby, Maryland, and ships regasified LNG on a firm and interruptible basis to delivery points on DTI, Columbia Gas, Transco, and other pipelines.

[24] Statoil makes a point of noting that the principle of cost causation includes the concept that "rates should produce revenues from each class of customers which match, as closely as practicable, the costs to serve each class or individual customer."

rate reduction equal to approximately $12.2 million annually for a 6-year period beginning 1/1/16; (3) A reset of base rates effective 2/1/19, and simultaneous reduction in those base rates equal to $7.5 million annually; (4) A one-time settlement payment of $5 million; (5) A revenue-sharing mechanism under which Columbia will share 50% of its revenues above $750 million; (6) A moratorium through 1/1/22 to changes in base rates; and (7) A reduction in the pre-tax return allowed under the CCRM from 12% to 11.14%.

Within its filing, Columbia says that an extension for another term of the modernization elements is needed to provide for the continued integrity, safety, and reliability of its system. Columbia also states that it has identified a need to restore the late-season deliverability of several storage facilities. According to Columbia, this deliverability has declined due to the age and/or condition of the facilities, and that in certain storage wells gas has tended to migrate toward lower-pressure sections, creating obstacles in recovering the stored gas late in the withdrawal season.

According to Columbia, the decline in late season deliverability also is attributable to injected debris (scale, compressor oils, pipeline debris) that restricts from the reservoir into the well bore. The storage deliverability restoration work will improve the efficiency, flexibility, safety, and long-term reliability of its system.

Statoil's Narrow Protest. Statoil’s delay in submitting the intervention and associated comments was due to administrative error, the company explained. Statoil, too, stressed that it is basically on board with the Mod II Settlement insofar as it provides additional base rate reductions and other financial benefits and avoids the need for a protracted general section 4 rate case (or "pancaked" rate cases) that Columbia would otherwise be required to file at the end of the first modernization term (2/1/19). For these reasons, Statoil "is not contesting the Mod II Settlement."

However, Statoil argued that while the Mod II Settlement largely extends the key components of the original modernization settlement, "there is one notable exception." That is Columbia's proposal now to include in its Eligible Facilities certain projects aimed at improving late-season storage deliverability. Columbia states the main area of focus for the storage modernization program is storage field deliverability restoration, which will address safety, reliability and performance concerns, and these investments, as a by-product, also will increase system flexibility.

Statoil questioned Columbia's assertion that the storage projects will improve the long-term reliability of the transmission system and that the pipeline has historically allocated some storage costs to the transmission function, “recognizing that storage supports transmission on its vast reticulated system.”

Columbia claims the storage-related projects will cost approximately $125 million, or about 5% of the $2.6 billion spent on both the first and second modernization programs (although the $125 million represents approximately 11% of the $1.130 billion in "nominal Mod II Settlement expenditures"). The costs of these storage-related projects would be recovered through the CCRM, a surcharge applied to all transportation services, such as firm transportation service (Rate Schedule FTS), no notice transportation service (NTS), interruptible transportation service (ITS), general transportation service (GTS), off-peak firm transportation service (OPT), third party storage transportation service (TPS), and storage transportation service (SST).

Statoil’s protest emphasized that its "non-opposition to the Mod II Settlement" must be viewed "only in the narrow and limited circumstances of the Mod II Settlement and the careful balancing of interests that the settlement represents." Importantly, the shipper explained, the inclusion of capital storage improvements through a CCRM surcharge paid by transportation customer under the Mod II Settlement is counterbalanced only by provisions favorable to the transportation customers (e.g., further rate base reductions and the avoidance of the cost associated with pursuing a general rate case). Therefore, "despite the questionable departure from general Commission cost causation policies and the non-conformity with the principles in the Commission's Policy Statement, in this limited case, Statoil does not object to the Mod II Settlement."

FERC Addresses Rehearing Petitions With Regard to the Tuscarora Lateral Project Proposed Jointly by National Fuel and Empire Pipeline

Early last year on 3/10/15 FERC issued an order authorizing Empire Pipeline, Inc. and National Fuel Gas Supply Corp. (CP14-112) to construct and operate the Tuscarora Lateral Project. The Allegheny Defense Project filed a timely request for rehearing and, in a separate filing, a request for stay. Empire and National Fuel also jointly filed a timely request for rehearing and clarification. FERC's order issued on 12/30/15 granted and denied, in part, the requests for rehearing and clarification and denied the request for stay. Among other things, FERC declined to accept Empire's proposed flow-through mechanism and tracker filing.

Empire currently offers only firm and interruptible transportation services (Rate Schedules FT and IT) and has no storage facilities. The Tuscarora Lateral is designed to connect Empire's pipeline system to National Fuel's system, which will enable Empire to lease transportation and storage capacity on National Fuel and allow Empire to offer no-notice transportation and storage service to its customers. The capacity of the project is fully subscribed under long-term contracts with two of Empire's existing shippers.

The March 10 order last year conditionally authorized Empire to construct and operate, among other project components, 0.77 miles of 16-inch diameter pipeline and 16.23 miles of 12-inch diameter pipeline between a tie-in at the southern end of Empire's system in the Town of Jackson, Tioga County, Pennsylvania, and a tie-in at National Fuel's Tuscarora Compressor Station in Steuben County, New York. To enable Empire to use the storage and transportation capacity on National Fuel's system, the March 10 order authorized National Fuel to add a reciprocating natural gas-fired compressor unit to its existing Tuscarora Compressor Station and to lease to Empire capacity sufficient to provide 55,000 Dth/d firm transportation service and 3,300,000 Dth of firm storage. The lease provides for injection rights up to 27,500 Dth/d and withdrawal rights up to 55,000 Dth/d.

Empire was cleared to (1) to offer firm no-notice transportation service (FTNN), firm no-notice storage service (FSNN), and interruptible storage service (ISS); (2) to charge initial rates for those services; and (3) to revise its tariff accordingly.

Allegheny requested a stay of the March 10 order along with two other projects[25] and stay of "all construction activities that the Commission has authorized" since it issued the March 10 order. Among other things, it was Allegheny's position that a stay is appropriate because without it the parties would have no remedy at law to address its injuries and the public will lose significant

[25] *Niagara Expansion and Northern Access 2015 Projects and West Side Expansion and Modernization Project.*

environmental resources, together amounting to irreparable injury.

Injury. With regard to the stay petition, the rehearing order, premised on the Commission's standard for granting a stay (i.e. "whether justice so requires"), FERC found that Allegheny had failed to establish the most important showing that the movant will be irreparably injured without a stay. Moreover, the Commission's general policy "is to refrain from granting a stay." Allegheny provided only unsupported, generalized allegations about environmental harm resulting from the project, answered the Commission. Besides, it had fully considered and addressed the protest and comments of Allegheny, as well as the comments of other individuals and entities, both in the Environmental Assessment and in the March 10 order's environmental discussion.

Rates and Tariff Issues. National Fuel's concern with the March order was its failure to explicitly approve a proposed *pro forma* tariff revision regarding how National Fuel would reflect the capacity lease in its calculation of system fuel and lost and unaccounted-for (LAUF) gas retainages. In the application, National Fuel proposed to deduct the quantities of system fuel and LAUF gas attributable to the capacity lease from its experienced fuel and losses, before calculating the adjusted retainage factors for its existing system. In the instant order, the Commission granted clarification and approved National Fuel's *pro forma* tariff language.

Empire's rehearing request challenged the Commission's former refusal to allow Empire's proposed flow-through mechanism under which it would submit a tracker filing to modify its FSNN and ISS storage rates to reflect changes to National Fuel's rates and fuel retainages retroactive to the date of such change. The Commission had denied Empire's proposed flow-through mechanism for monetary rates and yet left intact the proposed tariff language describing the adjustment mechanism. Here, the Commission did not grant Empire's request for rehearing.

Empire contended that although the capacity lease will provide it with the ability to provide no-notice service, the Commission erred in finding that some lease costs may eventually be allocated to FTNN transportation service. Empire also contended that the Commission erroneously concluded that the flow- through mechanism for monetary rates could become a problematic fixed cost or plant tracker, or both.

According to the Commission, however, "though Empire diminishes its importance, the Commission is concerned about the fact that ... FTNN service includes the administrative provision under which receipts and deliveries will be balanced using storage service. This administrative provision may in the future be a basis for allocating some lease costs to Empire's FTNN transportation service."

Among other things, FERC reasoned that the proposed mechanism is not consistent with the regulations for changing a rate. Nevertheless, Empire is not blocked from revising its Rate Schedules FSNN and ISS in the event that National Fuel's FSS and FST schedules change so long as such revision is proposed in an NGA section 4 proceeding.

Empire next contended that the Commission erroneously rejected its proposed ISS capacity charge, which used a load factor of 50% based on the assumption that storage capacity used by an ISS customer will be, on average, half full. The March 10 order required Empire to recalculate the rate using a load factor of 100%.

Answering, the Commission ruled that Empire's "claimed distinction between precedent addressing interruptible transportation rates versus interruptible storage rates" is not relevant. Policy requires the use of a 100 percent load factor rate for interruptible service unless there are extenuating circumstances that would require an exception. Even if Empire's assumption were true that an ISS customer's storage balance will be on average half full, this does not justify use of a 50% load factor (which would result in a higher ISS capacity charge than if Empire used a 100 percent load factor) for a service, "which we note, is of lower quality than firm service."

Empire also argued that it should have been allowed to apply the ISS injection charge to quantities transferred from an FSNN shipper's storage balance to an ISS shipper's storage balance. Empire would also credit an amount to the ISS shipper equal to the maximum FSNN injection charge for each transferred dekatherm. All other storage balance transfers are subject to an identical storage balance transfer charge of $3.86/Dth.

The March 10 order found that Empire had not identified any additional costs that would be incurred by a storage balance transfer from an FSNN shipper to an ISS shipper, and thus had not justified why a different charge for this type of storage balance transfer is reasonable. The rehearing order leaned in the favor of Empire on this one.

FERC said Empire contends that because FSNN shippers pay capacity and demand charges based on contract quantities, not actual usage, they also pay a low maximum FSNN injection rate of $0.0526/Dth, reflecting only variable costs. ISS shippers, by contrast, pay a higher maximum ISS injection rate of $0.9601/Dth because the ISS injection rate reflects the allocation of fixed costs. Empire notes the disparity between FSNN and ISS injection charges is the intended result of the Commission's straight fixed variable (SFV) rate design. So, Empire contends the ISS injection charge must apply to quantities transferred from an FSNN shipper's storage balance to prevent gaming by ISS shippers to avoid responsibility for fixed costs allocated to the ISS injection charge and that its proposal to credit an amount to the ISS shipper equal to the maximum FSNN injection charge for each transferred dekatherm prevents any double-collection of fixed costs.

Upon review, the Commission agreed the ISS qualifier is necessary to prevent ISS shippers from avoiding the responsibility for the fixed costs allocated to the ISS injection charge.

The Commission also allowed Empire to reinstitute a limitation that an FTNN shipper must have an associated FSNN service agreement to use the no-notice adjustment described Rate Schedule FTNN. Empire had stressed that absent an FSNN service agreement, it has no ability to adjust an FTNN shipper's storage balance under a contract with a third-party, if weather or some other cause results in a mismatched schedule. FERC also acknowledged, as stated by Empire, a shipper with an FTNN service agreement is permitted to use contracts with third parties to resolve imbalances, but their use would require nominations submitted to Empire.

Next, Empire currently can require ISS customers to withdraw gas on 30 days' notice, if the storage capacity is needed to perform firm service obligations. The Commission in March required Empire to revise this provision to explicitly allow an ISS shipper to transfer quantities of gas. Empire then requested that the Commission clarify that an ISS shipper may accomplish a mandatory withdrawal by arranging a transfer of storage inventory only to a firm storage customer that has not exceeded its maximum storage quantity. The Commission agreed with Empire that allowing an ISS customer to transfer storage inventory to another ISS customer or an FSNN shipper whose maximum storage quantity would be exceeded as a result of the transfer would impact Empire's ability to make capacity available to firm customers.

With respect to addition admonitions from Empire, the Commission granted a clarification that if at the time that Empire makes its compliance filing to place the project into effect, Empire has not yet proposed to revise its tariff to include a new section addressing permissible discounts in its GT&C, Empire may submit a discounting section in each new Rate Schedule (FTNN, FSNN, and ISS) in the compliance filing. Also, Empire is permitted to acquire capacity on other pipelines for operational or other purposes but is prevented from doing so in a supposedly "hypothetical situation" in which Empire might enter a joint ownership agreement for capacity.

Empire must revise a tariff in order to clarify that no storage volumes that are also sold or transported by Empire would be counted twice in computing the ACA (annual cost adjustment). Other Empire requests for clarification regarding the revised tariff records were dismissed as moot.

FERC Tags Policy-Busting Tariff Provisions Still Retained by Cameron Interstate Pipeline

A FERC order issued on December 30 conditionally accepted proposals of Cameron Interstate Pipeline LLC (RP16-184) to revise (1) its reservation charge crediting provisions in the tariff and (2) the form of firm and interruptible transportation service agreements to dispose of inaccurate information and obsolete language relating to a disclaimer of liability section. These proposed revisions became effective 12/31/14. In addition, pursuant to section 5 of the Natural Gas Act (NGA), the Commission required that Cameron either file revisions to its tariff concerning force majeure, scheduling priority, and curtailment to conform to policy, or explain why it should not be required to do so.

The Commission approved in June 2014 Cameron's application to construct and operate new pipeline facilities that transport and deliver gas to the Cameron LNG terminal for liquefaction and export. Cameron expects to complete those facilities and initiate service in 2017. In the interim, Cameron and its long-term firm transportation customers that will receive service through the new facilities have agreed upon revised procedures for crediting reservation charges in the event that Cameron is unable to deliver firm primary contract quantities that the customer has scheduled.

Acting on the compliance proposals, the Commission specifically directed Cameron to revise one aspect of its proposed reservation charge crediting language. In addition, the Commission initiated the section 5 investigation as to whether Cameron's existing (1) definition of force majeure, (2) use of the term curtailment, and (3) scheduling and curtailment priorities for Authorized Overrun Service (AOS). FERC found these may be unjust and unreasonable and must be modified.

Among other recommendations, the Commission advised Cameron to clarify its proposed exemptions from the requirement to provide reservation charge credits, especially signifying that the conduct of others that would permit a reduction in credits must be a party "not controlled" by Cameron. The Commission has found that it is reasonable for a pipeline's tariff to include an exemption from providing full credits where its failure to provide service during a non-force majeure outage is due to the conduct of the upstream or downstream operator of facilities at a receipt or delivery point, if those operators are outside the control of the pipeline. However, the conduct of others that would permit an exemption from credits must be by a party "not controlled by the pipeline."

The Commission also has found that, when a third parties' facilities are affected by the force majeure event but the pipeline was ready and able to perform service, it is reasonable for the pipeline to be exempted from providing credits. However, when both the pipeline's facilities and the facilities of third parties are affected by the force majeure event, then the pipeline could not have provided service regardless of the situation on interconnecting facilities, and therefore the pipeline must provide partial credits in order to share the risk of the force majeure event. Thus, pipelines are required to limit exemptions related to events affecting the facilities of third parties to situations where the failure to deliver was due solely to the conduct of others.

According to the order issued, Cameron's existing tariff includes force majeure events which are foreseeable and, therefore, conflicts with the Commission's definition of force majeure. Further, Cameron's existing definition of force majeure events also includes "the binding order of any court or governmental authority which has been resisted in good faith by all reasonable legal means." The existing tariff language conflicts with policy because it can be interpreted to include regular, periodic maintenance activities required to comply with government actions as force majeure events. The Commission has previously clarified the basic distinction as to whether outages resulting from governmental actions are force majeure or non-force majeure events. Outages necessitated by compliance with government standards concerning the regular, periodic maintenance activities a pipeline must perform in the ordinary course of business to ensure the safe operation of the pipeline, including the Pipeline and Hazardous Materials Safety Administration's (PHMSA) integrity management regulations, are non-force majeure events requiring full reservation charge credits. Outages resulting from one-time, non-recurring government requirements, including special, one-time testing requirements after a pipeline failure, are force majeure events requiring only partial crediting.

Cameron's definition of force majeure which includes both foreseeable events and "the binding order of any court or governmental authority which has been resisted in good faith by all reasonable legal means" is unjust and unreasonable, because it appears to define all outages which are foreseeable or resulting from government action as force majeure events.

According to FERC, one remedial option that Cameron has is to include in its compliance filing a provision permitting partial crediting for a transitional period of two years for outages resulting from orders related to pipeline's maximum allowable operating pressure (MAOP) issued by PHMSA. This would be a one-time, non-recurring events distinguishable from the routine, periodic maintenance which the Commission has held must be treated as non-force majeure events for which full credits must be given.

The Commission next cited proposed language that permits Cameron to curtail scheduled service in non-emergency situations, including making modifications or operating changes to its system when it is desirable or necessary "in its sole judgement." Such allowances are unjust and unreasonable to the extent that they authorize Cameron to issue a curtailment order terminating service outside of the normal scheduling process in order to perform activities where there are no emergency circumstances or unexpected capacity loss which make it necessary to disrupt confirmed service in order to perform the activities.

The order also faulted Cameron's existing language that provides that gas nominated for transportation utilizing AOS service will be scheduled before gas nominated for interruptible transportation service is scheduled. Other policy-offending tariff language provides that AOS service at primary and secondary points will be curtailed after IT service has been curtailed. The Commission "has repeatedly held that AOS service and IT service are both interruptible services and must be treated as having equal priority for both scheduling and curtailment purposes." Cameron was directed to file tariff records which treat AOS service and IT service as having equal priority for both scheduling and curtailment purposes consistent with policy, or explain why it should not be required to do so.

Likewise, the order concluded that Cameron's existing tariff provides that secondary firm service will be curtailed before primary firm service. This scheduling priority is inconsistent with policy stating that, once scheduled, all firm service is assigned the same priority for curtailment purposes, irrespective of whether capacity is utilized on a primary or secondary basis.

FERC Addresses Viking's Fuel Over-Recovery Identified by Northern States Power Utilities

After filing corrected workpapers, Viking Gas Transmission Co. (RP16-15) was awarded on December 30 FERC's conditional approval of a contested report in lieu of its semi-annual fuel adjustment filing. Viking did not propose to change its Fuel and Loss Retention Percentages (FLRPs). Viking requested that the FLRPs remain at 0.00% for all zones in Rate Schedules FT-A, IT, and AOT until the next FLRPs tariff filing. The FLRPs include a 0.00% Gas Lost and Unaccounted-For rate for Zone 1-1, Zone 1 -2, and Zone 2-2. The Commission conceded that points made in a protest lodged by Northern States Power are valid, given Viking's persistent over-recovered GRO (gas required for operations) balance position since 2012, but allowed Viking's report to suffice anyway on condition that more information must be forthcoming with Viking's next fuel filing. Viking suggests the GRO over-recovered balance should significantly decline during this winter season. However, according to FERC, "While there may be some improvement, an over-recovered balance of three years duration is worthy of further examination, and a detailed explanation or remedial action, as necessary."

Viking's tariff contains the filing and computation procedures for Viking's FLRPs. Current FLRPs are computed by adding: (1) the fuel retention percentages calculated by zone with (2) the lost and unaccounted retention percentages computed by zone. Viking files to reflect net changes in the FLRPs at least 30 days prior to each April 1 and November 1, the beginning date of each seasonal period.

On 10/8/15, Northern States Power Co.-Minnesota and Northern States Power Co.-Wisconsin filed a joint protest in this case, contending that Viking failed to adequately support continuing its current FLRPs, notwithstanding the fact that Viking's cumulative deferred GRO balance has been in an over-recovered position since January 2012. Northern States Power had asked that the Commission require Viking in its next FLRP filing to: (1) provide a detailed explanation of the causes of the prolonged GRO balance; (2) explain why the over-recovery has persisted for such a lengthy period, including any previously undisclosed operational or accounting issues affecting the GRO balance; and (3) identify the steps Viking has taken, or plans to take, to resolve such issues.

Northern States Power added that if there is not a prompt reduction in the over-recovered GRO balance, the Commission should find that the true-up provisions in the Viking tariff are no longer just and reasonable and impose a cash-out procedure to eliminate the existing over-recovery, as well as provide a remedy to avoid sustained over-recoveries in the future. Alternatively, Northern States Power said it would not oppose a determination at the present time in the instant proceeding that the

FLRP provisions of Viking's tariff are no longer just and reasonable, and directing Viking to promptly amend its tariff to establish a cash-out mechanism for resolving over-recoveries.

Viking, in turn, asked the Commission to accept its report, and suggested there is no basis for taking action on the protesters' request. Viking stated it has sufficiently explained the factors contributing to the deferred GRO balance, its expectations for the reduction of the deferred GRO balance, and the timing in which that reduction will occur. Viking said it does not receive an economic benefit from an over-recovered position, contrary to Northern States' claim.

Here, FERC accepted Viking's report for information purposes, on the condition that with its next FLRP filing it shall provide the detailed information and explanation sought by Northern States. "Notwithstanding Viking's assertions to the contrary, the persistent GRO over-recovery balance for several years warrants a more complete and detailed explanation, including the specific steps taken to reduce it to more normal levels," the Commission agreed with the utilities.

The letter order issued by FERC noted further that a pipeline can also take pro-active steps to refund over-collected balances, which prevents persistent over-recovered GRO balance positions in its fuel tracker calculations. To the extent an over-recovered balance persists at the time of Viking's next semi-annual filing, it should explain why it should not be required to make such a refund, so as to clear the GRO balance, or modify or seek waiver of its tariff provisions in some manner in order to prevent in the future a substantial cumulative GRO over-recovery status that persists for several years.

"Although fuel trackers are conceptually intended to be revenue neutral, protracted deferral of reimbursement of over-collected shipper gas may, for practical purposes, become so long a delay in 'settling up' that it becomes unreasonable," stated the order.

NATURAL GAS PROJECTS/ ABANDONMENTS

Anti-Pipeline Activists Protest Tennessee's Planned Northeast Direct Project, Claiming it is an "Extreme Overbuild" of Gas Pipeline Infrastructure

According to a recent filing at FERC from an anti-pipeline activist group, the Pipe Line Awareness Network for the Northeast, Inc. (PLAN),[26] the application of Tennessee Gas Pipeline Co., LLC's (CP16-21) Northeast Energy Direct (NED) project at FERC raises all sorts of "red flags," represents an "extreme pipeline overbuild," and as such, should be denied. The proposed project's capacity is not appropriately subscribed, the pipeline's parent company has not even given corporate approval of part of the project, states have done a poor job of examining pipeline alternatives, and customers of the utility shippers in New England will be socked with the enormous costs. Moreover, Tennessee turned in a faulty application that should be denied. PLAN is protesting the project "as well as" FERC's acceptance of "an incomplete" application, the group said.

"Fundamentally, PLAN opposes the NED project as an extreme overbuild of gas infrastructure," the group told FERC. "Less

[26] PLAN is "a broad-based coalition" of organizations, municipalities, businesses, citizen groups, legislators, ratepayers and concerned citizens "working to prevent the overbuild of natural gas infrastructure" in the Northeast. PLAN "seeks to prevent the negative economic and environmental impacts associated with overbuild, and to promote lower-impact energy solutions."

than half of the capacity on the Market Path is subscribed – indeed, after more than two years of intense efforts by Tennessee, the company has added an inconsequential amount of subscribed capacity to the approximately .5 Bcf/d in 'firm commitments' they had secured by July 2013. The capacity that *has* been contracted for is being challenged in court as excessive and imprudent."

Tennessee submitted its certificate application for the project at FERC on 11/20/15, seeking authority to build 400 miles of pipeline and compression capable of handling 1.3 Bcf/d of natural gas in Pennsylvania, New York, Massachusetts, New Hampshire, and Connecticut, as well as permission to abandon certain facilities. NED includes (1) the Supply Path component from Troy, Pennsylvania, to Wright, New York and (2) the Market Path component from Wright to Dracut, Massachusetts. (See FR Nos. 3076, pp6-8 and 3077, pp1-6).

It appears to PLAN that market participants subscribed for substantially less than half of the capacity (only about .55 Bcf/d of contracts on Market Path), "all at a cost now estimated at $5.2 billion to be charged to Tennessee's shippers, and ultimately, their ratepayers (to the extent capacity is contracted for by regulated utilities)." The group further stressed that the board of directors of Tennessee's parent company, Kinder Morgan, Inc., had not authorized capital for or otherwise approved the Supply Path Project.

In addition, the pipeline has "not fully provided adequate data for alternative comparisons" as required by FERC's Minimum Filing Requirements – based on FERC's recent information request to the pipeline. According to PLAN, "this, and other violations" should have barred the Commission from accepting the pipeline's application. "As such, this proceeding should properly be terminated, and the intervention deadline should be voided."

The group noted that its members include commercial and residential ratepayers of the four Massachusetts and New Hampshire local distribution companies (LDCs) that signed precedent agreements to be shippers on the NED Market Path project. But these precedent agreements were entered into "based on unrealistic demand forecasts" of the LDCs and "inadequate alternative analyses" at the state level. The state regulatory approvals of the agreements are now the subject of ongoing judicial appeals by PLAN and others.

PLAN complained that ratepayers and potential ratepayers of the Berkshire Gas Co. in particular have been subjected to a moratorium on any new or expanded gas service in the LDC's eastern division (served by Tennessee's Northampton lateral), which Berkshire claims (on its customers' bills) will be in place until the NED pipeline "is permitted and built." Another utility, Bay State Gas Co. has also "imposed a moratorium" with respect to additional service off of the Northampton lateral. It is believed by its members that Berkshire is foregoing opportunities to resolve the moratorium with more expeditious supply options and system modifications, thus "holding customers and potential customers hostage" to the investment interests of its parent company, UIL Holdings Corp., which has an ownership interest in the NED project.

Tariff adjustments for other regulated shippers, such as the electrical distribution companies that Tennessee seeks as additional project shippers, would also ultimately be reflected in the utility bills of PLAN members.

The group is also concerned about the direct impacts to conservation land along the NED route, as well as the threat posed by the project to future conservation efforts. The group cited a statement from the Massachusetts Energy Facilities Siting Board, which warned that the use of lands for pipeline easements "could certainly send a detrimental message to donors and benefactors of future conservation lands."

PLAN foresees a "violation of the public trust" posed by the possible siting of the infrastructure on public or private lands "intended to be protected in perpetuity." Furthermore, drinking water supplies of the region "could be impacted by blasting, horizontal drilling, and the simple installation of the pipeline." In particular, a new pipeline corridor "could act as a conduit for groundwater contamination between aquifers, river basins, and other water sources that would normally be isolated from one another."

To fulfill its organizational mission, PLAN "seeks both a programmatic environmental impact statement (EIS) of all proposed natural gas expansion projects throughout the Northeast and a consolidated review for non-environmental issues." In their view, a programmatic EIS would allow for the adequate consideration of the cumulative impacts, pursuant to the National Environmental Policy Act, and to eliminate concerns about improper segmentation. The Commission should evaluate the impact of each project and multiple projects to the pipeline systems in the region and to minimize potential redundancies, excess capacity and stranded costs that could ultimately put ratepayers at risk.

"Also, in the event that offshore Canadian production is curtailed or halted due to a glut of Marcellus gas flooding the region, the result will be a reduction in supply diversity. Moreover, the anticipated export of Marcellus gas overseas is widely predicted to drive up domestic prices for gas, ultimately increasing energy costs for residential, commercial, and industrial ratepayers, including PLAN members."

High Island Offshore Maintains the Need To Abandon "Severely Underutilized" Gulf Facilities In Face of Stiff Opposition

High Island Offshore System, LLC (HIOS) (CP16-20) asserted that its recent application -- to abandon its Gulf of Mexico jurisdictional natural gas facilities to Delfin LNG, LLC to be Deepwater Port Facilities and export liquefied natural gas (LNG) (FR No. 3081, 19-21) -- meets the Commission's test for abandonment of depleting reserves. The proposal also satisfies the present or future public convenience or necessity standard, as it provides extensive benefits, including: extending the economic life of the reserves connected to HIOS, providing long-term environmental benefits, and repurposing of underutilized facilities, the company told FERC.

HIOS's two Indicated Shippers-- Exxon and Fieldwood Energy LLC --who hold secondary firm transportation (FT-2) and interruptible transportation (IT) services rights on HIOS, respectively, vehemently oppose HIOS's plan. In particular, HIOS is seeking to abandon to Delfin the HIOS 66-mile, 42-inch mainline, a 42-inch pig launcher at High Island Block 264 (HIA-264), and its platform at West Cameron Block 167 (WC-167 Platform).

HIOS disagrees with the contention of the protestors that instead of the abandonment it should file serial rate cases to adjust its rates to account for diminishing throughput. Moreover, HIOS argues that "less weight" should be given to the protesting shippers, as they do not hold major firm transportation contracts on the system. FERC should not allow "a single, rather small volume FT-2 shipper" (like protesting ExxonMobil Gas & Power Marketing) "to unilaterally block" an abandonment that is otherwise in the public interest, HIOS suggests.

The company told FERC it is seeking the abandonment because the facilities are "severely underutilized" with throughput less than 60,000 Dth/d, which is less than 4% of HIOS' peak in 1981. A significant percentage of existing HIOS production does not pay the recourse rate and the majority of shippers that protested do not pay the full recourse rates, the company said. The company expects "additional declines" to continue, forcing it "to repeatedly raise its rates" to cover its cost of service "until eventually no shipper will be willing to pay such costs to transport gas." It is "beyond reason" for the protestors to contend that HIOS will not have regular rate cases. "It is equally wrong for such protestors to make light of the reality that it will be difficult for HIOS to continue operations under its current trajectory," HIOS argues.

To HIOS, Delfin Deepwater Port presents "a unique opportunity" to repurpose a portion of its system "for the benefit of existing shippers, the energy industry and the nation by facilitating the development of a much-needed alternative means of exporting natural gas." FERC should reject the protests and grant the abandonment, reject the protestors' various allegations with respect to operations after the abandonment, and reject the request for refund any payments allegedly attributable to negative salvage and/or asset retirement obligation (ARO).

The Protests. The Indicated Shippers had argued that HIOS should not be permitted to abandon the facilities, most of which have been paid for by shippers, and should not be permitted to "shirk" its jurisdictional service obligations. Five other shippers – with IT service -- also filed protests: Arena Energy, LP; Castex Offshore, Inc.; M21K LLC; Walter Oil & Gas Corp.; W&T Offshore, Inc. (collectively, the Indicated IT Shippers).

HIOS' Answer. In a Jan. 6 answer, HIOS specified that it was responding to both sets of protesters. The abandonment would potentially benefit shippers "by prolonging the economic life" of the producing fields attached to HIOS by reducing the costs that must be borne by its shippers as a result of repeated rate increases. None of the protestors are disputing the fact that production has, and will continue to, rapidly decline, and none have offered claims—much less evidence—of additional production that would change this reality, HIOS stated. They have not contested that its system throughput is on pace to satisfy the "rate case trigger" of an NGA section 4 filing to change the settlement rates (in RP14-218). Going forward, dwindling throughput will require it to regularly file rate cases in order for it to be able to cover the cost of operations until HIOS will inevitably have no customers who are willing to ship at the rates required to cover such costs. "When this occurs, the opportunity to repurpose the relevant portions of the HIOS system for the Delfin Deepwater Port will no longer be available and shippers on HIOS and the public interest will be harmed by the loss of all the associated benefits that will result if the application is granted," HIOS reasoned.

HIOS said shippers are currently subject to a discounted rate or negotiated rate that is less than the recourse rate. Under FERC policy, a pipeline is not required to retain facilities "for the purpose of ensuring the continued availability of discounted service to those who do not place a sufficient value on the service to contract for it on a firm basis at the established recourse rate."

Additionally, the fact that the Commission has granted other abandonment applications unopposed by shippers does not mean that HIOS's application must be unopposed in order for the Commission to find for abandonment. "The protestors are relying on specific, but irrelevant, factual differences between the HIOS abandonment application and other cases where the Commission has granted abandonment application," HIOS charged.

The *Matagorda Offshore* (MOPS) proceeding was different in the above instance, and MOPS was distinguishable because the facts the Commission relied upon in denying MOPS's request for abandonment are not present with respect to HIOS, the company countered. FERC had denied the MOPS abandonment due to the lack of transportation alternatives and the presence of drilling near the system. The abandonment of the HIOS system will shut in approximately less than one percent of HIOS's current production because all other production can continue to flow as it does today, or "there exist alternate means for that gas to reach the interstate grid."

To the claims that existing firm shippers will be denied service or that replacement service will be inferior, HIOS clarified that after abandonment all but less than 1% of the gas that flows on the system will continue to have access either through Stingray or through Kinetica Energy Express, LLC and TC Offshore LLC at the WC-167 Platform.

And as for the entitlement of refunds, HIOS said it was not aware of any proceeding that does not involve the physical abandonment of a pipeline's facilities where the Commission conditioned approval of the abandonment on the pipeline's immediate refund of any collected, but unused ARO or negative salvage amounts. Moreover, no shipper has cited any Commission precedent that supports the notion that HIOS must refund unexpended accrued negative salvage and/or ARO amounts to its shippers in these circumstances.

HIOS added that while its rate settlement agreement indicates that current rates are assumed to incorporate a negative salvage rate of 0.24% for transmission and gathering plant, this does not mean that the amount collected will necessarily cover all of HIOS' costs once the system is actually physically abandoned. Since the system is seriously underutilized and a significant portion of its shippers already pay discounted rates, there is no guarantee that HIOS will be able to recover sufficient revenue to cover its cost of physical abandonment should the application be denied. Requiring HIOS to refund unexpended negative salvage and ARO amounts would be inconsistent with the Commission's last clean rate doctrine and the rule against retroactive ratemaking, which prohibit the Commission from requiring a pipeline to issue refunds below the last clean rates (i.e., the current rates) or adjusting current rates to make up for over-collection in prior periods.

Regarding HIOS's offer of a three-year rate freeze, HIOS pledged it would hold rates at a level that is no higher than the rate in effect for each shipper at the time jurisdictional service is discontinued on the HIOS 42-Inch Line. This is a "generous approach" to resolving any issues between HIOS and its IT customers, in the company's opinion. It is a *bone fide* opportunity for IT shippers -- for whom HIOS has no obligation to provide any specific level of service, much less at a rate that will restrict HIOS' opportunity to recover its costs. Moreover, the freeze is available to all shippers, including any protestors, and it "is also reasonable" for HIOS to not keep the offer available indefinitely.

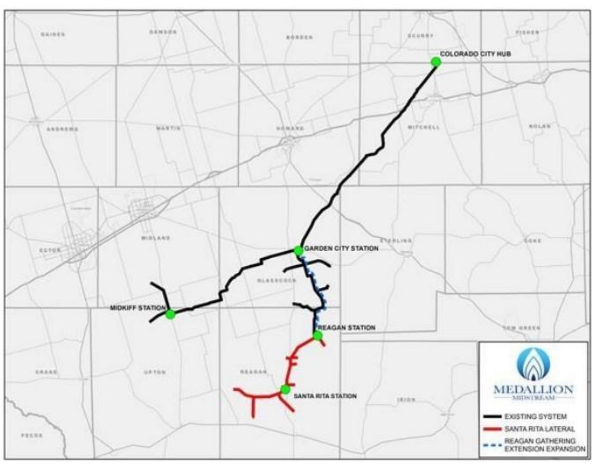
Lastly, contrary to Castex's claims, HIOS said it does not have an obligation to blend non-pipeline quality gas for customers. In HIOS' opinion, Castex's concern about its gas quality stems from Castex relying on the commingling of its non-pipeline-quality gas with the pipeline-quality gas of other shippers on the HIOS 42-Inch Line in order to meet the quality specifications of its downstream pipeline. The "commingling" is not a jurisdictional service HIOS provides, but is happening currently because sufficient quantities of gas are being delivered by other shippers at the WC-167 platform. The abandonment will not preclude Castex from continuing to deliver gas to TC Offshore and

Kinetica, assuming that Castex meets the quality specifications of those gas pipelines. Castex's inability—post-abandonment—to continue to utilize the pipeline-quality gas of other shippers to Castex's benefit "has no place" in the evaluation of the abandonment, HIOS insisted.

And, as noted, HIOS contended that FT-2 and IT shippers (like Exxon and Fieldwood) should be given "less weight" than traditional firm shippers in an abandonment proceeding. The majority of the 13 IT shippers and the one other firm shipper on its system have not protested the abandonment.

OIL PIPELINES

FERC Facilitates Medallion's Continued Rapid Expansion of its Wolfcamp Connector



Medallion Pipeline Co., LLC (OR16-4) recently was cleared by FERC to pursue a second round of expansion projects on its existing Wolfcamp Connector crude oil pipeline system in West Texas' Midland Basin. A declaratory order approved the pipeline's proposed expansion tariff rate structure and terms of service. The Commission's approval allows the pipeline to extend both the geographic reach of Wolfcamp in the Basin and "substantially" expand its capacity. The project adds (1) the Santa Rita Lateral (55 miles of pipe and approximately 65,000 b/d of capacity), which would run into central and southwestern Reagan County, Texas, and (2) the Reagan Expansion, adding 30,000 b/d capacity to the Reagan Gathering facilities from the existing Reagan station to the Garden City station.

FERC granted all of the expedited rulings requested by Medallion's unopposed petition, including confirming that: (1) Medallion's open season followed precedent, was widely advertised and gave interested shippers an opportunity to become committed firm shippers on the expansion; (2) Medallion's reservation of up to 90% of the projects' capacity allows at least 10% to remain available for walk-up shippers, allowing reasonable access for shippers that did not enter into Transportation Service Agreements (TSAs); (3) the committed rates and rate structure provided in the open season TSAs and *pro forma* tariffs are consistent with precedent; (4) the committed rates will be treated as settlement rates; and (5) the TSA rates will not be subject to modification or revision except as provided in the TSA.

FERC also approved the provisions of the TSA for committed firm shippers, which will pay premium rates compared to all other shippers -- their commitment as firm shippers agreeing to ship-or-pay certain volumes over the long-term provided support for the expansions' commercial viability. Other committed shipper provisions included: limiting annual index adjustments, offering contract extension rights, ramp-up elections for the initial years of service, and the opportunity to elect a new destination point on Santa Rita subject to a potential surcharge. The potential new destination point on the lateral will provide committed firm shippers "with greater flexibility" to tailor service to particular transportation requirements, according to the pipeline.

Originally built in 2014 as a 112-mile, 65,000 b/d mainline system (in OR15-10), Wolfcamp has grown quickly, first after an initial round of expansions by adding: (1) the Midkiff Lateral, a 40- mile long, 12-inch diameter, 75,000 b/d pipe, and (2) the Wolfcamp Expansion that added 30,000 b/d of capacity to the mainline, to total approximately 95,000 b/d. Wolfcamp pursued the second round of expansions five months after the company placed Midkiff and the first Wolfcamp Expansion into service on 6/1/15, petitioning FERC on 11/6/15 to pursue the additional Santa Rita and Reagan projects. (See FR Nos. 3034, pp14-16; 3040, pp24-25; and 3074, pp25-28)

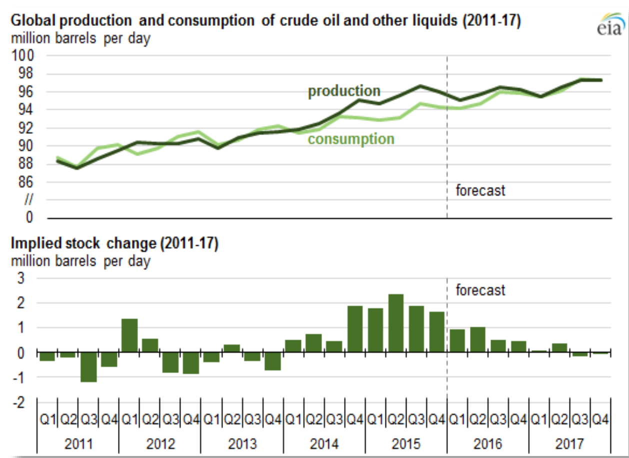
ENERGY FORECASTS/DATA

EIA's Short Term Outlook Anticipates Low Fuel Prices Through 2017

The Energy Information Administration's latest *Short-Term Energy Outlook*, the first to include forecasts for 2017, reports that North Sea Brent crude oil prices averaged $38/barrel (b) in December, a $6/b decrease from November and the lowest monthly average price since June 2004. Brent prices averaged $52/b in 2015, down $47/b from the average in 2014, as growth in global liquids inventories put downward pressure on prices. The analysis forecasts Brent crude oil prices averaging $40/b in 2016 and $50/b in 2017, while West Texas Intermediate (WTI) crude oil prices will average $2/b lower than Brent in 2016 and $3/b lower in 2017. However, there is a caveat -- "the current values of futures and options contracts continue to suggest high uncertainty in the price outlook."

For example, EIA cautions that its forecast for the average WTI price in April 2016 of $37/b should be considered in the context of recent contract values for April 2016 delivery (Market Prices and Uncertainty Report) suggesting that the market expects WTI prices to range from $25/b to $56/b (at the 95% confidence interval).

U.S. crude oil production averaged an estimated 9.4 million b/d in 2015, and it is forecast to average 8.7 million b/d in 2016 and 8.5 million b/d in 2017. EIA estimates that crude oil production in December fell 80,000 b/d from the November level.



"Crude oil prices are expected to remain low as supply continues to outpace demand in 2016 and more crude oil is placed into storage. EIA estimates that global oil inventories increased by 1.9 million b/d in 2015, marking the second consecutive year of inventory builds." Inventories are forecast to rise by an additional 0.7 million b/d in 2016, before the global oil market becomes relatively balanced in 2017. "The first forecasted draw on global oil inventories is expected in the third quarter of 2017, marking the end of 14 consecutive quarters of inventory builds."

A decline in power generation from fossil fuels in the forecast period is offset by an increase from renewable sources. The share of generation from natural gas falls from

33% in 2015 to 31% in 2017, and coal falls from 34% to 33%. For renewables, the forecast share of total generation supplied by hydropower rises from 6% in 2015 to 7% in 2017, and the forecast share for other renewables increases from 7% in 2015 to 9% in 2017.

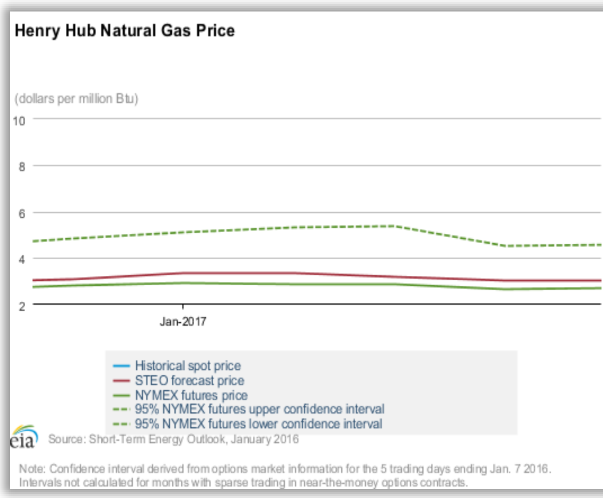
Natural Gas. Although annual average Henry Hub prices for natural gas for 2015 and 2016 are similar, prices are forecast by the agency to rise through much of 2016, from near $2/MMBtu. "Price increases reflect consumption growth, mainly from the industrial sector, that outpaces production growth in 2016," said EIA.

EIA expects production growth will be relatively flat in 2016, partly in response to lower prices and declining rig activity. With higher prices in 2017, and as new consumption and more export capacity comes online, EIA projects production will pick up slightly.

EIA's forecast of U.S. total gas consumption averages 76.6 Bcf/d in 2016 and 77.2 Bcf/d in 2017, compared with 75.5 Bcf/d in 2015. Increases in industrial sector consumption drive total consumption growth in 2016 and 2017. Industrial sector consumption increases by 3.5% in 2016 and by 2.5% in 2017, as new projects in the fertilizer and chemicals sectors come online. EIA expects a 0.1 Bcf/d (0.3%) decline in consumption of gas for power generation in 2016 and a 1.4% decrease in 2017. Consumption in the residential/commercial sectors is projected to increase in 2016 and 2017, however, reflecting slightly higher heating demand in those years.

In September, total marketed production of natural gas hit a record high of 80.2 Bcf/d before declining the following month, according to EIA's survey data. EIA estimates that marketed gas production averaged 79.1 Bcf/d in 2015, an increase of 4.2 Bcf/d (5.7%) from 2014. Growth is likely to slow to 0.7% in 2016, as low prices and declining rig activity begin to affect production. In 2017, however, forecast production growth increases to 1.8%, as forecast prices rise and more demand comes from industrial sectors and liquefied natural gas (LNG) exporters.

"Although demand growth levels off, production remains high, which is expected to reduce demand for natural gas imports from Canada and to support growth in exports to Mexico." EIA expects gas exports to Mexico to increase because of growing demand there from the electric power sector coupled with flat gas production in Mexico. EIA projects LNG gross exports will increase to an average of 0.7 Bcf/d in 2016, with the start-up of Cheniere's Sabine Pass LNG liquefaction plant planned for early this year. EIA projects gross exports will average 1.4 Bcf/d in 2017, as Sabine Pass ramps up.

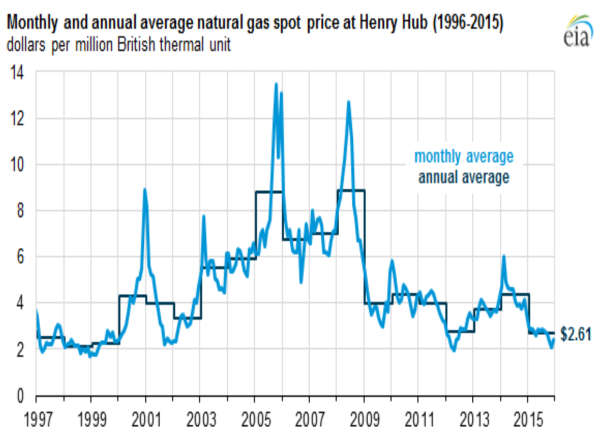


According to this *Outlook*, monthly average Henry Hub spot prices are forecast to rise through 2016, but they remain less than $3/MMBtu until December. Forecast Henry Hub prices average $2.65/MMBtu in 2016 and $3.22/MMBtu in 2017, compared with an average of $2.63/MMBtu in 2015. (see adjacent article).

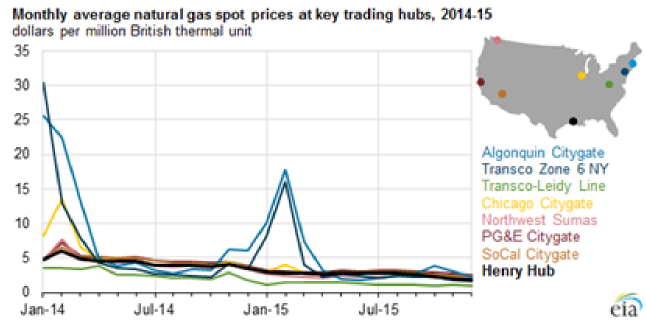
Natural gas futures contracts for April 2016 delivery traded during the five-day period ending January 7 averaged $2.38/MMBtu. Current options and futures prices "imply market participants place the lower and upper bounds for the 95% confidence interval for April 2016 contracts at $1.61/MMBtu and $3.52/MMBtu, respectively." In January 2015, the natural gas futures contract for April 2015 delivery averaged $2.88/MMBtu, and the corresponding lower and upper limits of the 95% confidence interval were $1.90/MMBtu and $4.36/MMBtu.

EIA predicts that if natural gas inventories end the winter heating season (March 31) at approximately 2,043 Bcf, as EIA projects, this would represent gas ready to deliver in the ground which would be 38% above the level at the same time last year.

Data Tracking Natural Gas Production and Use Shows Lowest Spot Prices in More than a Decade During 2015



From the U.S. Energy Information Administration (based on Natural Gas Intelligence), new data shows natural gas spot prices in 2015 at the Henry Hub in Louisiana averaged $2.61/MMBtu, "the lowest annual average level since 1999." The annual average spot price at Henry Hub was $1.78/MMBtu, or 41%, lower than the 2014 average. Daily prices fell below $2/MMBtu for the first time since 2012. Henry Hub spot prices began the year relatively low and fell throughout 2015, as production and storage inventories hit record levels and fourth-quarter temperatures were much warmer than normal.



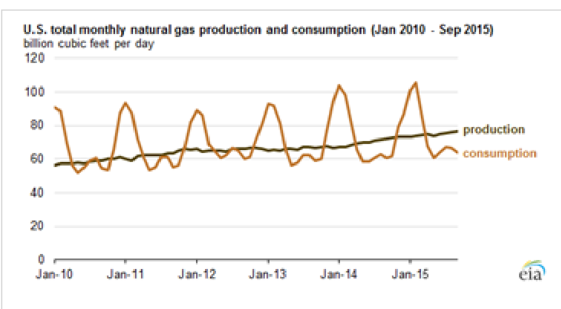
Natural gas prices at regional trading hubs ended the year lower than their starting point. At northeastern locations, where gas transmission infrastructure is often constrained, prices spiked in the early months of 2015, which were colder than normal compared to much of the U.S. Prices at the Algonquin Citygate, which serves Boston, and at Transcontinental Pipeline's Zone 6, which serves New York City, began the year much higher than the Henry Hub spot prices in early 2015, but then fell below the national benchmark for much of the rest of the year.

Despite declining prices, total "dry" natural gas production averaged an estimated 74.9 Bcf/d in 2015, 6.3% greater than in 2014. This increase occurred even as the number of natural gas-directed drilling rigs decreased. As of December 18, there were 168 natural gas rigs in operation, only about half the number of rigs at the beginning of 2015, according to data from Baker Hughes Inc. However, "the remaining rigs are among the most productive, and producers have continued to make gains in drilling efficiency."

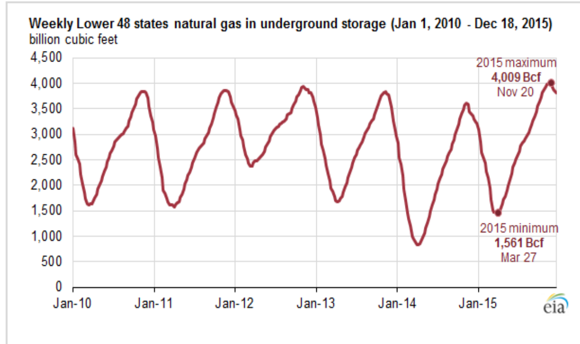
Low prices and strong production led to increased use of natural gas for electric power generation, which is projected to be about 26.5 Bcf/d in 2015, exceeding the 24.9 Bcf/d level in 2012. Gas surpassed coal as the leading source of electricity generation on a monthly basis for the first time in April, and again in each of the four months from July through October.

In the residential and commercial sectors, which use gas primarily for heating, consumption in 2015 declined 6.7% and 4.4%, respectively, from the previous year largely because of warmer weather. "Natural gas consumption in the residential and commercial sectors was particularly high in 2014 because of cold temperatures in the first and fourth quarters. Although 2015 had a cold start, temperatures in the fourth quarter were warmer than normal throughout most of the United States."

Growth in production also allowed for strong builds in working natural gas inventory. Inventories surpassed 4,000 Bcf for the first time, reaching 4,009 Bcf in the week ending November 20.



With much of the growth in gas production in the Marcellus and Utica shale regions in the Midwest, several major pipeline projects came online in 2015 to transport natural gas from these plays to consumers. In August 2015, the Rockies Express Pipeline (REX) reversal was completed. REX, one of the longest natural gas pipelines in the U.S., began service in 2009 to bring Rockies gas eastward. As Marcellus production increased, however, demand in the East for gas produced in the Rockies declined. The REX reversal added westbound capacity to enable the transport of Marcellus/Utica Shale supplies to markets in the Midwest.

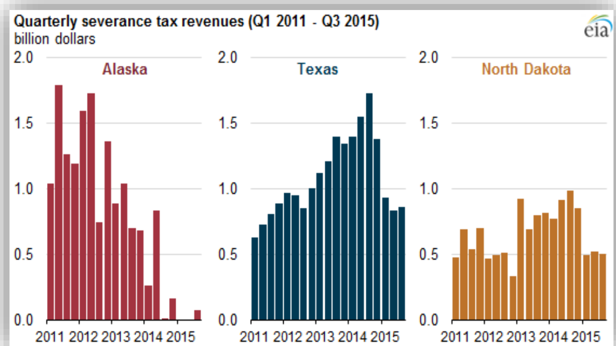


Six State Budgets Strained by Shrinking Tax Revenues Collected from Fuels Production

Several states that collect severance taxes on fossil fuel extraction are re-evaluating current and upcoming operating budgets and taxation structures to address revenue shortfalls, according to a report from the Energy Information Administration (EIA). Lower fossil fuel prices, and in some cases, lower production, have led to lower severance tax receipts than were expected when revenue estimates were developed. Six states strongly affected by this "budget squeeze" are Alaska, Texas, North Dakota, Wyoming, Oklahoma, and West Virginia.

Alaska's severance tax revenue "has fallen further and faster than other states" because "its tax is based on the operators' net income rather than on the value or volume of oil extracted." In 2015, when average net incomes after operating and capital expenses were near zero, the state derived practically no revenue from this tax, versus more than $5 billion in 2012. Based on 2014 data, severance taxes accounted for about 72% of the state's tax revenue. Given the sharp decline in tax revenues, the governor recently proposed a 6% state income tax as well as scaling back the payout of dividends to residents from Alaska's Permanent Fund.

At the other end of North America, the comptroller of Texas reports that, as of November, revenues from gas production and oil production and regulation were down 48% and 51%, respectively, from a year ago. EIA suggests that Texas's economy is more diversified than that of other major oil-producing states, so taxes account for a lower percent of its tax total receipts (11% in 2014), "meaning Texas can likely respond to the lower severance tax receipts without drastic changes to its enacted 2016 budget."

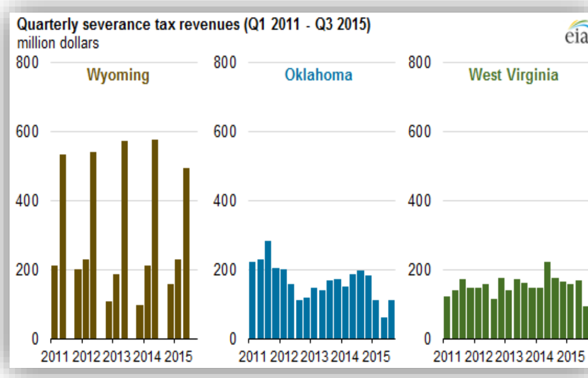


Despite oil production volumes remaining largely flat throughout 2015, total severance tax revenues fell in North Dakota from more than $3.5 billion in 2014 to $2 billion in 2015 as oil prices declined. The state's general fund budget collections from July through November 2015, the first five months of the 2015-17 two-year budgeting period, were $152 million, which was 8.9% below the budgetary forecast.

The below-budget revenue collected in North Dakota was attributed to weaker sales tax collections, which are in part driven by oil exploration and production in the Bakken region. If projected revenue remains 97.5% or less of the budgeted amount, across-the-board spending reductions would be imposed for most state agencies.

Mineral severance taxes from oil, natural gas, and coal production, along with associated federal mineral royalties, are the primary revenue sources for Wyoming. Severance taxes alone accounted for 39% of the state's receipts in 2014.[27] However, despite recent increases in oil production, EIA reported that Wyoming is seeing lower revenue projections in response to lower oil prices and declining gas and coal production. In October 2015, the state revised its 2015-18 severance tax projections downward by nearly $160 million from January 2015 projections.

Although severance taxes accounted for 8% of Oklahoma's revenue collections in 2014, collections from state sales taxes and individual and corporate income taxes are also significantly affected by oil and natural gas prices. That state faces a fiscal year 2017 budget deficit of $900 million on a general fund budget of nearly $7 billion.



In December 2015 the state of Oklahoma declared "a revenue failure," which requires state agencies to reduce spending, and allows for use up to 37.5% of the state's budget stabilization fund.

Finally, severance taxes accounted for 13% of West Virginia's tax revenues in 2014. There, a combination of falling coal production and low gas prices in the third quarter of 2015

[27] In Wyoming, revenue collections for the production year are due in February, and third quarter payments are not required.

resulted in "the lowest total tax collection since 2008, mostly as a result of decreased severance tax receipts." The shortfall helped create a projected fiscal year 2016 budget deficit of more than $250 million. West Virginia's coal production in 2015 was down more than 15% from 2014. Lower gas prices more than offset an increase in the state's gas production, resulting in lower natural gas severance tax receipts. In October 2015, the governor announced 4% reductions to budgets for most state agencies.

GAS AND OIL BUSINESS

EPA's Scientific Advisory Panel Raises Issues With Draft Agency Study on Effect of Hydraulic Fracturing on Drinking Water

An independent scientific panel, assembled to advise the Environmental Protection Agency (EPA) on its study of the potential impacts of hydraulic fracturing on drinking water, issued a draft review on 1/7/16 that challenges a key finding of the draft of that study (draft Assessment Report). In a 133-page report issued to EPA Administrator Gina McCarthy, the Science Advisory Board (SAB) called into question whether there were “no widespread, systemic impacts” to groundwater from fracking, one of the most significant findings in the draft report on the study the EPA released in June. The panel’s comeback also urged the EPA to release its findings on studies into incidences of groundwater contamination in places like Dimock, Pennsylvania. Citing data gaps and ambiguity on how the Assessment Report reached the conclusion it did, the 31-member SAB panel’s draft report is open to public comment until January 21. The science board will reconvene with public teleconference meetings February 1stto hear comments and review the draft report, and could make a second draft public by February 15th.

The draft Assessment Report that the SAB panel reviewed synthesized available scientific literature and data on the potential for hydraulic fracturing for oil and gas development to change the quality or quantity of drinking water resources, and identified factors affecting the frequency or severity of any potential changes. The SAB was asked to comment on various aspects of the EPA’s draft Assessment Report, including the descriptions of hydraulic fracturing activities and relationship to drinking water resources, the individual stages in the hydraulic fracturing water cycle (HFWC), and the identification and hazard evaluation of hydraulic fracturing chemicals.

The EPA's science advisers' panel said the widely-criticized finding that fracking poses "no widespread systemic risks” was “inconsistent” with the rest of the draft landmark study, released in June. Now, the public, affected communities, other scientists and public health experts can weigh in with EPA on the most comprehensive study to date on the controversial drilling technique.

“Communities on the frontline of fracking know how it harms water and public health, and as this science panel points out, EPA's main finding belies its own research,” said Rachel Richardson, director of Environment America’s Stop Drilling Program. “That's why EPA should revise its false conclusion, which flies in the face of fracking's dangerous reality." Reversal of the main finding of the congressionally-mandated study could increase pressure for regulations or limitations on fracking, which remains exempt from most major federal environmental laws and is linked to more than 1,000 cases of water contamination, according to Richardson.

“Panel member Dr. Scott Blair said it best,” said Richardson, “there are 700 pages that present ‘the potential impacts of hydraulic fracturing on water resources and human health, but only two lines concluding that it is not a universal problem. Talk about a surprise ending.'"

In addition to questioning the study's conclusion, the EPA's SAB pointed to the report's exclusion of Dimock, Pennsylvania, Pavillion, Wyoming, and Parker County, Texas, where water became so contaminated that residents could no longer drink water from their taps. "We urge EPA to listen to its science advisers," Richardson said. "The conclusion that fracking posed no widespread risk dominated media coverage, and was used as fodder by fracking proponents to excuse a practice that increases pollution and puts our communities at risk."

SAB Draft Review. In general, the SAB found the EPA's overall approach to assess the potential impacts of hydraulic fracturing for oil and gas on drinking water resources, focusing on the individual stages in the HFWC, to be "appropriate and comprehensive." The SAB also found the agency provided a generally comprehensive overview of the available literature that describes the factors affecting the relationship of hydraulic fracturing and drinking water, and adequately described the findings of such published data in the draft Assessment Report.

However, the SAB identified several areas of the draft Assessment Report "that can be improved."

The SAB specifically has concerns regarding the clarity and adequacy of support for several major findings presented within the draft "that seek to draw national-level conclusions regarding the impacts of hydraulic fracturing on drinking water resources." The SAB is concerned that these major findings are presented "ambiguously" in the Executive Summary and are inconsistent with the observations, data, and levels of uncertainty presented and discussed in the body of the draft assessment. Of particular concern in this regard is "the high-level conclusion statement" that "we did not find evidence that hydraulic fracturing mechanisms have led to widespread, systemic impacts on drinking water resources in the United States."

According to the SAB, the above statement does not clearly describe the system(s) of interest (e.g., groundwater, surface water) nor the definitions of "systemic," "widespread," or "impacts." The SAB is also concerned that this statement does not reflect the uncertainties and data limitations described in the body of the report associated with such impacts. "The statement is ambiguous and requires clarification and additional explanation."

The SAB recommended that the EPA revise the major statements of findings in the draft Assessment Report to be "more precise, and to clearly link these statements to evidence provided in the body of the draft Assessment Report." The SAB also recommended that the EPA discuss the significant data limitations and uncertainties, as documented in the body of the Report, when presenting the major findings.

While the EPA appropriately aimed to develop national-level analyses and perspective, the panel pointed out that most stresses to surface or ground water resources associated with stages of the HFWC are localized. For example, the impacts of water acquisition will predominantly be felt locally at small space and time scales. "These local-level hydraulic fracturing impacts can be severe." The draft Report "needs to do a better job of recognizing the importance of local impacts."

In this context, the SAB recommended that the agency include and explain the status, data on potential releases, and findings if available for the EPA and state investigations conducted in Dimock, Pavillion, and Parker "where hydraulic fracturing activities are perceived by many members of the public to have caused significant local impacts to drinking water resources. Examination of these high-visibility cases is important so that the public can understand the status of investigations in these areas, conclusions associated with the investigations, lessons learned for hydraulic fracturing practice if any, plans for remediation if any, and the degree to which information from these case studies can be extrapolated to other locations."

The SAB went on to recommend that sections of the draft Assessment Report should be revised to make these sections more suitable and understandable for a broad audience.

The SAB provides several suggestions to improve the agency's approach for assessing the potential for hydraulic fracturing for oil and gas to change the quality or quantity of drinking water resources.

Among other conclusions, the SAB found that the potential for water availability impacts on drinking water resources is greatest in areas with high hydraulic fracturing water use, low water availability, and frequent drought. The SAB agreed, however, that there are important gaps in the data available to assess water use that limit understanding of impacts on water acquisition.

The agency(EPA) should provide more information regarding the extent or potential extent of the effects of chemical mixing processes from fracturing processes; should provide additional detail describing the extent and duration of the impacts of spilled liquids and releases of flowback and produced waters when they occur; should include additional major findings associated with the higher likelihood of impacts to drinking water resources associated with hydraulic fracturing well construction, well integrity, and well injection problems, and from large spill events; and include an additional major finding that: (1) large severe hydraulic fracturing flowback and produced water-related contaminant release incidents such as blowouts, and smaller common incidents (usually containment leaks), may cause effects on drinking water resources on a volume basis, and (2) blowouts are more severe in terms of impact due to the high-volume, short-duration characteristics of the release.

The science panel, in addition to many other suggestions, asked the EPA to compile toxicological information on chemicals employed in hydraulic fracturing in a more inclusive manner, and not limit the selection of chemicals of concern to those that have formal non-cancer oral reference values (RfVs) and cancer oral slope factors (OSFs). "The agency should use a broad range of toxicity data, including information pertinent to sub-chronic exposures, from a number of reliable sources cited by the SAB in addition to those used in the draft Assessment Report to conduct hazard evaluation for hydraulic fracturing chemicals."

Environmentalist Concern Calls From Better Methane Disclosure From Oil and Gas Handlers

A new report by Environmental Defense Fund (EDF) finds that none of the 65 market leaders reviewed in the natural gas/oil production and midstream segments disclose targets to reduce methane emissions and less than a third report such emissions via accessible, investor-facing data sources. Based on its survey results, the Fund suggests that leading oil and gas companies "are putting themselves and their investors at financial and reputational risk by failing to adequately disclose meaningful information on emissions of methane, the heat-trapping pollutant that is drawing increased scrutiny from regulators and the public."[28]

"As a shareholder with a global portfolio, we have a financial stake in the long-term performance of the natural gas industry," said Jack Ehnes, CEO of CalSTRS, one of California's largest pension funds, and author of the report's foreword. "However, for the gas industry to be part of the solution in the needed transition to a low-carbon global economy, methane emissions – which reduce the potential climate benefits of natural gas over other fossil fuels – must be actively managed. Improved methane disclosure is one important piece of the climate change risk management puzzle."

The report, "*Rising Risk: Improving Methane Disclosure in the Oil and Gas Sector*," examines the current state of voluntary reporting on methane in the U.S. oil and gas sector. The authors found that data publicly disclosed through sources like CDP questionnaires, corporate sustainability/CSR reports and 10-K filings "is generally low in quality and lacks rigorous and standardized metrics, making comparisons among operators difficult."

The EDF report offered recommendations to improve methane disclosure "centered around four key methane metrics that aim to bring a level of standardization and quantitative rigor to methane reporting." The metrics include (1) emission rates, (2) reduction targets, (3) economic value of emissions, and (4) reporting on frequency, methodology and scope of a company's leak detection and repair programs. Operator and disclosure platform adoption of these metrics will help give investors much-needed meaningful information to properly assess risk from methane, the report concluded.

The report is premised in part on the realization that methane emissions from the oil and gas sector are increasingly viewed as a financially material issue for companies, and by extension, their investors. Every pound of methane allowed to escape represents not only a loss of sellable product, but also undercuts natural gas' climate benefits as a fuel source,[29] the report posits. Potential liability issues that can arise as a result of methane leaks are "starkly illustrated by the massive leak currently underway at the Aliso Canyon storage facility in California," which has cost $50 million for mitigation of environmental and community impacts, over $12 million in lost product to date and reputational damage. The Aliso Canyon leak "is a large example of the types of leaks that occur daily across the world's oil and gas infrastructure," according to EDF.

[28] The oil and gas industry releases seven million tons of methane annually in the United States alone, according to the Environmental Protection Agency (EPA).

[29] The EDF mentions a 2015 study by the Rhodium Group that found that the sector loses $30 billion globally each year from leaked or vented methane at oil and gas facilities.

ENERGY NEWS ALERT

Late in December the staff of the FERC prepared an environmental assessment (EA) for the Sunbury Pipeline Project, proposed by UGI Sunbury, LLC (CP15-525). Sunbury requests authorization to construct and operate a natural gas pipeline facility in Snyder, Union, Northumberland, Montour and Lycoming Counties, Pennsylvania. The project would provide 180,000 dth/d of natural gas to the Hummel Station Generation Facility in Snyder County.

Staff concludes that approval, with appropriate mitigating measures, would not constitute a major federal action significantly affecting the quality of the human environment. Sunbury proposes to: construct and operate a 34.4-mile-long pipeline from the Transcontinental Gas Pipe Line Co. LLC and MARC I Pipeline operated by Central New York Oil & Gas Co., LLC (CNYOG), both in Lycoming County, to the proposed Hummel Station Generation Facility. Comments are due on or before January 27, 2016.

At about the same time FERC staff issued notice of availability of an EA for the Loudon Expansion Project proposed by East Tennessee Natural Gas, LLC (CP15-91). East Tennessee requests authorization to construct, own, and operate a new pipeline, new mainline valve, and new meter station in Monroe and Loudon Counties, Tennessee and install a pressure regulator at an existing meter station in Loudon County. The Loudon Expansion would provide up to 40,000 dth/d of firm transportation service Tate & Lyle Americas Ingredients, LLC for its new natural gas fueled combined cycle electric power plant at its manufacturing facility in Loudon County. The proposed Loudon Expansion includes 10.2 miles of new 12-inch-diameter natural gas pipeline from East Tennessee's existing 3200 mainline in Monroe County, Tennessee to the Tate & Lyle in Loudon County, Tennessee. Comments here too are due on or before January 27.

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On 1/13/16 — BakerHostetler announced that Poe Leggette has been named Managing Partner of the firm's Denver office, succeeding Managing Partner Raymond L. Sutton Jr., who served in that role for 20 years and will continue representing certain clients. Leggette joined the firm in 2014 as co-leader of the firm's 80-member "multidisciplinary Energy team." Prior to joining BakerHostetler, he led Norton Rose Fulbright's Denver and Pittsburgh offices and served as regional head for that firm's Americas energy practice. "Poe's reputation as one of the country's preeminent energy lawyers and his experience as a former managing partner makes him an ideal leader to continue our growth in Denver," Sutton said. Leggette was named a 2015 "Colorado Lawyer of the Year" by Law Week Colorado. He was a former Assistant Solicitor for the U.S. Department of the Interior. BakerHostetler is celebrating the 100th anniversary of its founding this year. The firm's Denver office was established in 1980.

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Lloyd's Register Energy issued a finding and conclusion that Pacific Gas and Electric Co. (PG&E) meets requirements of the American Petroleum Institute's (API's) pipeline safety management system standard – Recommended Practice 1173 (RP 1173) – "giving confidence in the company's safety culture." The Register assessed PG&E under API RP 1173 and found no major non-conformances for its network of pipelines serving a 70,000-square-mile service area in northern and central California. The API-recommended practice "gives operators a holistic framework to identify and address safety concerns for a pipeline system's entire lifecycle." According to Lloyd's Register, PG&E wanted a thorough "deep dive" into their integrity systems for transmission and distribution pipelines. "We have assessed their safety management systems against the API requirements and they have made a lot of good progress over the past five years in making their pipeline systems safer." PG&E operates and maintains more than 6,750 miles of transmission pipelines and more than 40,000 miles of distribution pipeline. PG&E covers nearly half of California in its service area and is considered the second largest utility in the U.S.

Commenting on the audit, PG&E president Nick Stavropoulos said, "These recognitions are proof of our commitment to continually improve our safety culture and enhance our asset management program. I'm proud of the resolve of our Gas Operations team to become the gas company our customers want and deserve - the safest, most reliable gas company in the country. This is another superb recognition and validation that we continue doing the right work in the right way and we are determined to make even more strides towards world-class safety performance."

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A decision by Petróleo Brasileiro S.A. to sharply reduce its capital spending is positive, according to Moody's Investors Service, "as it helps the oil company preserve cash at a time when it is facing significant refinancing risk." The company's estimates of a limited decline in its production target for 2020 imply very low prices for equipment and services as well as continued operating productivity, says Moody's. Petrobras announced it would cut spending by 36% to an annual average of $19 billion from $28.8 billion for the period 2017 to 2019. The company has about $24 billion of debt maturing in the next two years. A weak Brazilian economy, volatile oil prices and local currency, difficult prospects for asset sales and political uncertainties are combining to limit the company's funding options. In addition, banks in Brazil are facing their own lending restrictions and will likely have much lower risk appetite in a contracting economy, according to the rating agency.

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EIG Pacific Holdings Ltd., a Cayman Islands limited company and subsidiary of Harbour Energy Ltd., has commenced tender offers and proposed to sponsor a restructuring of Canadian-based Pacific Exploration and Production Corp. (Pacific E&P). Harbour Energy, managed by EIG Global Energy Partners (EIG), believes that Pacific E&P faces significant near-term insolvency concerns and requires a large infusion of new capital in order to restructure its balance sheet, avoid value-destructive asset-level reorganizations or distressed sales, and degradation of Pacific E&P's assets through under-investment and deferred maintenance. As of September 30, Pacific E&P had approximately $5.4 billion of debt outstanding, including $4.10 billion aggregate principal amount of senior bonds that are trading at levels equivalent to approximately thirteen cents on the dollar (1/13/16), indicating that no value remains in its equity. R. Blair Thomas, CEO of EIG and Co-Chairman of Harbour Energy's Board of Directors, said, "We believe Pacific E&P is on the verge of insolvency and out of other options. We have an appreciation for the company and its operations, partners and stakeholders and are committed to shepherding the company through an expeditious reorganization that will permit it to continue operating, remain intact and thrive once again. We are offering to inject substantial capital by acquiring the senior notes of the company and sponsoring an overall reorganization of Pacific E&P."

Pacific E&P (formerly Pacific Rubiales Energy Corp.) is an oil and gas company incorporated in Canada and engaged in the exploration, development and production of crude oil and natural gas in Colombia, Peru, Brazil, Guatemala, Papua New Guinea, Guyana and Belize.

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According to FuelFix.com, BHP Billiton plans to book a $4.9 billion post-tax write-down on its U.S. shale assets, lowering the value of the operations to about $16 billion. The Australian company is the largest foreign investor in US shale, having spent $20 billion on shale oil and natural gas assets in Arkansas, Louisiana and Texas in 2011, according to the published news.

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RB Midstream, LLC, a Denver, Colorado-based midstream logistics and marketing company, has acquired InCorr Energy Group LLC, an established crude oil marketing and trading company also headquartered in Denver, Colorado. InCorr, a privately held crude oil marketing and trading firm established in 2011, currently markets crude oil from producing regions throughout the inland corridor of the U.S. including the Bakken, Powder River Basin, Uinta, and DJ Basins.

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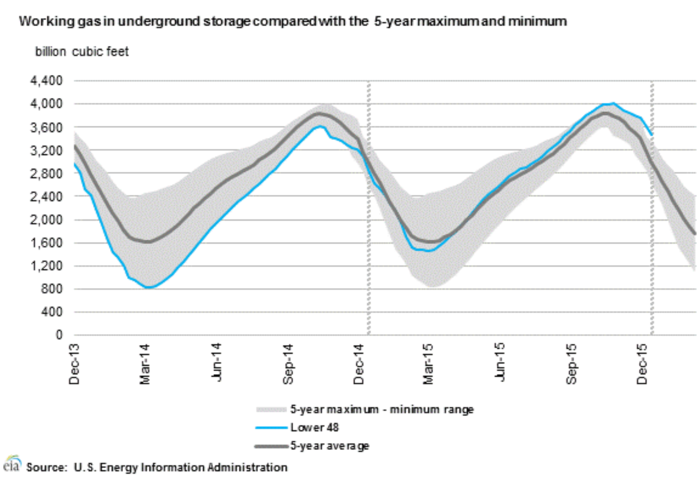
The International Association of Oil & Gas Producers (IOGP) has appointed Gordon Ballard to be its new Executive Director. He is succeeding Michael Engell-Jensen, who is retiring after five years. Ballard formerly worked with oilfield services company, Schlumberger, on four continents, and became Schlumberger's UK Chair in 2005. He has also served as Chair of the UK's Oil and Gas Industry Council and of OPITO International, the upstream oil & gas skills organization, and was Co-Chair of industry trade association Oil & Gas UK.

EIA'S WEEKLY GAS STORAGE ANALYSIS

WORKING GAS IN UNDERGROUND STORAGE FOR WEEK ENDING Jan. 8, 2015						
Region	Current Week Stocks (Bcf)	Prior Week Stocks (Bcf)	Net Change (Bcf)	Year Ago Stocks (Bcf)	5-Year Average Stocks (Bcf)	Current Week Difference from 5-Yr Avg (%)
East	802	857	-55	692	711	12.8
Midwest	942	983	-41	785	809	16.4
Mountain	177	185	-8	143	171	3.5
Pacific	295	313	-18	295	284	3.9
South Central	1,259	1,305	-46	971	1,026	22.7
Total Lower-48	**3,475**	**3,643**	**-168**	**2,888**	**3,001**	**15.8**

Working gas in storage was 3,475 Bcf as of Friday, Jan. 8, according to EIA estimates. This represents a net decline of 168 Bcf from the previous week. Stocks were 20% (or 587 Bcf) higher than last year at this time and 16% (or 474 Bcf) above the five-year average.



EIA reported that natural gas spot prices fell at most trading locations outside of the Northeast during the report week ending Wednesday, Jan. 13. The Henry Hub spot price fell from $2.35/MMBtu to $2.30/MMBtu. At the New York Mercantile Exchange (Nymex), the price of the near-month (February 2016) contract rose by less than a penny, from $2.267/MMBtu to $2.269/MMBtu.

The total oil and natural gas rig count declined by 34 units this week, with 664 units in service for the week ending Friday, Jan. 8, according to data from Baker Hughes Inc. The oil rig count decreased by 20 units to 516, and the natural gas rig count fell by 14 units to 148. The oil and natural gas rig count has not been this low since August 1999.

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