

Inside FERC

May 10, 2010

NorthernStar files bankruptcy, abandons Bradwood Landing LNG terminal plans

The collapse of NorthernStar Natural Gas last week marked a dramatic end to a five-year battle over the Bradwood Landing liquefied natural gas project near Astoria, Oregon.

Unable to pay \$129.5 million in debt, the Houston company and its subsidiaries filed for Chapter 7 bankruptcy protection Tuesday. The company said in a voluntary filing that its assets are worth \$165,900.

Among the debts, it owes the Bank of New York Mellon \$108 million for

exchange notes and \$20.9 million for senior convertible notes, all purchased in May 2009, according to documents signed by NorthernStar President Paul Soanes.

The bankruptcy also applies to NorthernStar subsidiaries Bradwood Landing, NorthernStar Pipeline, Clearwater Port Holdings, NSNG Management and Clearwater Port.

Soanes issued a statement late Tuesday blaming slow permitting for the

decision to drop the Bradwood project. The lengthy press release made no mention of bankruptcy papers filed earlier in the day.

"The extended delays in the processing of state and federal permits for Bradwood Landing and the difficult investment environment have forced us to suspend development," he said.

NorthernStar spokesman Charles

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Financial reform bill amendment would give CFTC final say on jurisdiction

An amendment to the financial reform bill under consideration in the Senate would give the Commodity Futures Trading Commission the final say in a jurisdictional dispute with FERC.

The financial reform bill (S. 3217) would, among other things, expand the CFTC's authority to regulate over-the-counter derivatives markets. In a months-long dispute, FERC has said that it should retain authority over certain transactions related to electric markets, such as finan-

cial transmission rights.

Under the amendment, the CFTC would determine whether it is in the public interest to exempt from its oversight "an agreement, contract or transaction" entered into under a tariff or rate schedule approved by FERC.

Senator Jeff Bingaman, Democrat-New Mexico, who joined six other senators in offering the amendment, said it would protect FERC's authority to look after rates.

"We're glad to have the [CFTC] have authority over all derivatives," Bingaman said during a meeting of the Energy and Natural Resources Committee, which he chairs. "We just don't want anything in the legislation interpreted in a way that would interfere with FERC's authority to continue doing what it's required to do and that is to ensure that rates are just and reasonable."

It's not clear, however, that the lan-

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LaFleur, Moeller cleared for vote by full Senate

The Senate Energy and Natural Resources Committee last week approved two nominees to FERC and sent their names to the full Senate for confirmation votes.

President Obama nominated Cheryl LaFleur of Massachusetts to a vacant seat on the five-member commission, and Commissioner Philip Moeller was tapped for a second term. If confirmed, LaFleur would serve until 2014, while Moeller's term would end in 2015.

LaFleur, a Democrat, has more than

20 years of experience in the electric and gas sectors. Until 2007, she was executive vice president and acting CEO of National Grid USA.

If confirmed, she would add a New England perspective to a commission that has a Western flavor. Chairman Jon Wellinghoff is from Nevada, Moeller from Washington, Commissioner Marc Spitzer from Arizona and Commissioner John Norris from Iowa.

A Republican, Moeller was nominated

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to his current term by President Bush. The term expires in June. He previously ran the Washington office of Alliant Energy.

During a confirmation hearing last month, the pair testified about their approaches to the controversial topic of who should pay for new transmission capacity and of whether to give states more say in permitting liquefied natural gas terminals (*IF*, 3 May, 1).

"I would be open to exploring whether there could be an expanded role for state regulators, particularly in cases where there are multiple proposals in a state, multiple options being considered," LaFleur said.

Moeller said that there's room for more input from local and state voices, but he's "not quite sure how to formalize that."

"We have constituents who feel at times that their voice hasn't been heard," he told Oregon Senator Ron Wyden. "We don't want that. We want to make sure the government should be responsive to constituent concerns." —*Meghan Gordon*

Senators talk but don't act on legislation to give states authority over LNG projects

Although senators behind a bill to give states final say in siting liquefied natural gas terminals insist they are serious about making the change, they haven't taken the first step to putting it on the Senate agenda.

The bill (S. 3056) was introduced in March by Democratic Senators Ron Wyden and Jeff Merkley of Oregon, Barbara Mikulski and Ben Cardin of Maryland, Maria Cantwell of Washington and Chris Dodd of Connecticut (*IF*, 8 March, 1). They represent states where LNG developers have clashed with vocal citizens groups who fear the terminals' repercussions for public safety and the environment.

Bill Wicker, spokesman for the Senate Energy and Natural

Resources Committee, said no one has asked to schedule a hearing on the bill targeting FERC's authority over LNG applications.

Wyden said Thursday he wanted to send a message to FERC. He said last week's abrupt demise of the Bradwood Landing LNG project shows that the commission doesn't give local perspectives a full vetting.

"Bradwood Landing is a good example of what can happen when FERC refuses to address the underlying issues that matter most to people affected by these sorts of projects," Wyden said. "The bill was intended to provide FERC with a wake-up call that the public and local governments were fed up with the process. Bradwood Landing has shown that the developers should be fed up with the process as well."

Merkley said last week that he remains committed to the bill. "Citizens in this state should have a voice in the process for siting this type of infrastructure," Merkley said.

The topic of LNG siting also bubbled up last month during the confirmation hearings for Cheryl LaFleur to the fifth FERC seat and Commissioner Philip Moeller to a second term.

"If we're going to get balanced approaches — LNG and natural resources — running roughshod over the states is not the way to do it," Wyden said during the Senate Energy and Natural Resources Committee hearing.

LaFleur and Moeller both said they would be open to examining how state and local interests could have a louder voice in federal reviews.

S. 3056 calls for administering the Natural Gas Act as if section 311 of the Energy Policy Act of 2005 had not been enacted. That section clarified that FERC had final say in siting LNG terminals.

Wyden introduced a similar bill in 2008, but it failed to move out of committee. According to a Senate Energy commit-

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tee source, the sponsors did not request a hearing for that version, either.

Industry groups have said the bill's backers are mistaken in believing that repealing the 2005 language would turn over the final decisions on LNG applications to states. They contend that section 311 simply clarified authority the commission has held since the first batch of LNG proposals in the 1970s. —*Meghan Gordon*

Federal court vacates FERC approval of station power charges tariff

FERC overstepped its authority by approving a tariff that preempts states from regulating retail sales of electricity to power plants, a federal appeals court has found.

The commission's order "does not just sideswipe state jurisdiction; it attacks it frontally," said the May 4 ruling by the DC Circuit Court of Appeals. The court overturned FERC approval of the station power charges in California Independent System Operator markets and remanded the case for further consideration.

At issue in the case (*Southern California Edison v. FERC*, 05-1327) is whether FERC went outside jurisdictional bounds when it approved changes to Cal-ISO's open-access transmission tariff to calculate generator station power on a one-month netting interval (*IF*, 12 April, 6).

The tariff provisions allow generators in California to net their monthly station power needs against their deliveries of power to the transmission grid. In one of two orders, FERC said load-serving entities may not impose retail and load-based charges on merchant generators that self-supply using monthly netting under to the ISO's station power protocol.

Station power is used by generators to meet lighting, heating and other electrical needs. Although some generators self-supply, there may be times when a plant is not operating and needs to pull power from the grid. Station power is considered retail load because it is not transmitted on an interstate basis, Southern California Edison argued before the court.

In response to a 2005 order, Cal-ISO revised its tariff to match FERC's station power policies, which were established in a series of orders involving other utilities and regional transmission organizations. Merchant generators, including NRG Energy and Constellation Generation Group, had argued that Cal-ISO's tariff was not in line with those policies.

The commission declared that if a generator's output exceeds demand for station power during a one-month interval, the generator would not be deemed to have made a retail purchase and could not be charged for retail energy or any other service subject to state jurisdiction.

While Cal-ISO calculates station power on a monthly basis, the California Public Utility Commission allows utilities to use 15-minute intervals to determine whether a generator has made a retail purchase of energy.

FERC failed to explain why the potential for undue discrimination in the way utilities treat affiliates versus merchant gener-

ators "can be grounds to preempt the state's authority to set the netting period for station power — *i.e.*, the pricing mechanism — in the retail market or to allow utilities to impose consumption charges," said the appeals court.

It also rejected FERC's assertion that to recognize the utilities' right to use a different netting period for station power as a retail sale under state law would cause a conflict with FERC's different netting period for transmission. "That is a familiar sort of preemption argument, but we do not see the conflict," the court said.

"After all, FERC has succeeded through its unbundling initiative in creating separate markets for wholesale sales, transmission and retail sales and distribution. Why should different pricing techniques cause a conflict?"

The court also determined that its related 2006 ruling does not control the SoCal Ed case. In *Niagara Mohawk Power Corp. v. FERC*, the court upheld FERC's station power policies as they related to New York Independent System Operator's tariff. Niagara Mohawk Power had asked the court to reject the station power provision, arguing that it violated the Federal Power Act by encroaching on state jurisdiction over local distribution service and retail sales.

While the court found FERC's rationale confusing, it allowed the decision because Niagara Mohawk conceded that an hourly netting tariff would not violate the power act.

"In this case, by contrast to *Niagara Mohawk*, petitioners have consistently maintained that FERC has no authority to set *any* netting period to determine whether a retail sale occurs" or utilities are permitted to impose consumption charges, said the May 4 ruling. —*Esther Whieldon*

Facing rate increase, Northern Natural customers ask FERC to drop investigation

A plea for FERC to drop its investigation into the rates of Northern Natural Gas last week came from an unlikely source — the pipeline's customers. In a May 5 motion, shippers holding a majority of Northern Natural's firm capacity rights called on the commission to terminate the high-profile Natural Gas Act section 5 proceeding.

The group wants action by May 28, "the date on which Northern has indicated it will file a section 4 rate increase if this proceeding is not terminated." The effect of the requested termination "would be to leave Northern's current rates in place, with Northern's agreement not to seek to implement higher rates prior to November 1, 2011," said the customer group.

The ad hoc group comprises Black Hills Energy, CenterPoint Energy Minnesota Gas, Metropolitan Utilities District, MidAmerican Energy, Northern States Power-Minnesota, Northern States Power-Wisconsin and Southwest Public Service.

Northern Natural is one of three pipelines charged by FERC with dramatically exceeding allowed return on equity (*IF*, 23 Nov, 1). Natural Gas Pipeline Co. of America and Great Lakes Transmission are the others. The Natural proceeding is in the

process of being settled.

According to FERC audits of data filed by the pipelines, their actual earned returns on equity were as high as 24.5% in 2008, well above the industry average ROE of roughly 12%.

The Northern Natural case (RP10-148) has taken several odd procedural twists and turns in recent weeks, with trial staff, the defendant and the administrative law judge going at each other over the level of detail included in a required report on privileged documents. Acting in his capacity as motions commissioner, Chairman Jon Wellinghoff late last month agreed to place before the full commission an appeal by trial staff of a series of directives by the ALJ (*IF*, 3 May, 1).

Procedural oddities aside, the customer group said that it “shares the commission’s concern that pipeline rates can become stale over time and that pipelines have no incentive to initiate a rate review under section 4 when the existing rates generate equity returns above the level the commission could be expected to approve.”

But the “sole purpose” of section 5 “is to provide rate relief for consumers if the investigation demonstrates that the existing rates are excessive or to leave the existing rates in place if . . . they are not excessive,” the group continued. Therefore, “should it become apparent at any point” during a section 5 proceeding that the end result of the process “may well be a rate increase,” the investigation should be brought to an end, it said.

Settlement talks “reached an impasse” on May 3, according to the motion, and Northern Natural is poised to file a full-blown section 4 rate case, with “substantially higher rates,” at the end of the month. The higher rates “will be driven to a significant degree by proposed changes in cost allocation that will seek to shift to Northern’s customers the risk that Northern currently bears for recovering costs of its underutilized Field Area facilities,” the group related.

Under current circumstances, “there is no period of time when any rate reduction deemed appropriate by the commission in the section 5 proceeding would be in effect,” it said. However, if FERC terminates the proceeding before May 28, the pipeline’s vow to postpone the rate hike is a “valuable consideration” that should be recognized by the commission.

Continuing the section 5 proceeding “would be contrary to the economic interests of the customer group and the consumers they serve as well as other shippers on Northern’s system,” the motion concluded. —*Chris Newkumet*

FERC approves SPP plan to standardize process for local delivery point changes

Southwest Power Pool may streamline transmission customers’ ability to alter, add to or abandon the local facilities where power is delivered to retail load, FERC has ruled.

Periodically, transmission customers must add, revise or cease use of already established delivery point facilities, said the April 30 order (ER10-550). For example, a customer might need to increase the capacity at a point or add new delivery points

for new residential or commercial retail customers.

SPP sought to standardize and specify all the actions that SPP, the transmission owner and the transmission customer would need to take when a customer seeks to change or remove delivery point facilities.

The proposal is just and reasonable and provides a “separate and more efficient standardized process for its transmission customers to add, modify or abandon delivery point facilities associated with growth or reconfiguration of existing load,” said the order.

Under the approved new process, effective May 1, the relevant transmission owner would review a delivery point modification request through a load connection study once the grid owner and customer agree on the study and a deposit has been received within 30 days. The grid owner would issue a report to the customer and SPP within 60 days, after which the owner and petitioner would need to reach a written agreement on paying for engineering, design, and construction needs for meeting the service modification.

Simultaneously, upon receipt of a customer request related to an existing delivery point, SPP would consider whether the project would have a significant impact on the SPP system.

If none is found, SPP would end its direct involvement in the process and allow the host transmission owner to complete the changeover. If the change would have a substantial impact, SPP would conduct a delivery point network study at the customer’s expense. —*Esther Whieldon*

Cal-ISO allowed to increase data, telemetry software requirements for wind and solar

California Independent System Operator has been given the green light to expand the scope of data that it requires from wind, small hydropower and solar project operators.

FERC on April 30 approved most of Cal-ISO’s plan to require intermittent resources with a capacity of more than 10 MW to report outages that affect more than 1 MW of its capacity.

The previous tariff required the operator of a plant to report an unanticipated forced outage that reduced the capacity of the unit by the greater of 10 MW or 5% of the unit’s total value, to the extent the outage lasts longer than 15 minutes.

Lowering the threshold from 10 MW to 1 MW for outage reporting “is a reasonable means to address variability and uncertainty in eligible intermittent resource output,” FERC found (ER10-319).

The commission disagreed with the assertions of Pacific Gas and Electric and NextEra Energy Resources that the change would result in undue discrimination. Prior FERC orders have recognized that some types of generation present unique circumstances and, therefore, dissimilar treatment of different resources does not constitute undue discrimination, it said.

Cal-ISO has explained its difficulty in forecasting intermittent resources, FERC said. The increased outage information requirement is reasonably designed to enable Cal-ISO to

account for those unique characteristics and produce more accurate forecasts, which will enhance grid reliability, said the order.

Also approved was Cal-ISO's proposal to require all eligible intermittent resources that have signed participating generator agreements or qualifying facility agreements with the ISO to install specific forecasting and telemetry equipment and to communicate relevant data to the grid operator. The requirement currently applies to generators in the participating intermittent resource program.

The telemetry and forecasting equipment requirement will help mitigate operational challenges related to intermittent resources by increasing the quality of data Cal-ISO receives from those resources, FERC found.

However, the commission directed the ISO to remove small conduit hydroelectric facilities from the definition of eligible intermittent resources "because installation of telemetry equipment will not provide the Cal-ISO with more accurate output forecasts."

The compliance filing is due within 30 days of the April 30 order. —*Esther Whieldon*

ELECTRIC POWER

Capacity markets performing as intended despite dearth of investment, officials say

Faced with an apparent evaporation of investment for new fossil fuel-fired generation, the capacity markets in New England and PJM Interconnection are working as designed and will be able to attract new capacity against the backdrop of expected coal-fired power plant retirements, industry officials said.

"Why would anybody be building anything? We are sitting on massive surpluses," said Robert Stoddard, vice president and leader of the energy and environment practice at Charles River Associates.

According to Stoddard, those capacity markets are designed to react to exactly the scenario in which the industry now finds itself — low demand, low fuel prices, surplus capacity and increasing state requirements for renewable energy and energy efficiency. "I have every confidence that [the markets] will do that," he said, adding that ratepayers could face greater risk if regulators and utilities second-guess the market instead of just letting it work.

ISO New England and PJM have robust capacity markets, while Midwest Independent Transmission System Operator still does not, Stoddard continued. Meanwhile, New York is looking at alternative solutions and trying to achieve a 15% reduction in energy use by 2015 to stave off the need for new plants, he said.

"In areas where we have low [capacity] prices, of course nobody will invest," agreed Andy Ott, vice president of markets for PJM. In parts of its footprint where the grid operator really

needs generation, the capacity prices are higher, he added.

A lot of different factors are playing into a company's decision to build power plants today, but investment in the industry has not dried up completely, Ott maintained. "I am not seeing complete silence in the generation queue," he said, adding that several significant traditional generation resources have been expressing interest in entering future capacity market auctions.

PJM's generation queue has some 41,877 MW of proposed wind generation and another 30,759 MW of proposed non-renewable energy projects.

Nor is PJM overly worried that a lot of coal units may retire because they are not covering their costs to stay in operation. PJM Market Monitor Joseph Bowring's 2009 state of the market report identified about 11,000 MW of coal-fired capacity that could potentially retire in PJM.

"This is not a problem," Ott maintained. Retirement of certain generators replaced by demand response and energy efficiency is not a "bad thing," he said.

If those coal plants in fact end up retiring soon or fall subject to more stringent environmental standards, the time-frame for when new capacity is needed could accelerate, Stoddard suggested.

Some critics of the current capacity markets assert that looking only three or four years ahead doesn't send a sufficient signal to investors to build new generation.

The original design of PJM's reliability pricing model was four years forward, explained Ott, who called the current three-year design a compromise. "Developers think they can do it" in three years, Stoddard said. That is adequate time to develop a peaking or smaller project, as well as demand response, he added.

Merchant power plant projects are still possible, Stoddard said, but the leverage financing model used in the past will not soon return. "If you have a long-term contract, and you can assume [a fossil fuel-fired project] is not susceptible to" carbon dioxide and other emissions restrictions, "you can find somebody to finance it," he said.

Once the credit market is on firm footing again and there is a need for capacity, the investment dollars will be available again, Stoddard said. In the meantime, money is available for some transmission projects, he added. —*Milena Yordanova-Kline*

Entergy Arkansas begins consideration of costs, benefits of MISO membership

Entergy Arkansas last week held the first in a series of internal technical conferences to examine third-party arrangements that could result in it becoming a full member of either Southwest Power Pool or Midwest Independent Transmission System Operator.

The Arkansas Public Service Commission, which previously told Entergy Arkansas to analyze joining SPP, in late April ordered the utility also to study joining MISO.

In testimony filed with the PSC last week, Entergy Arkansas CEO Hugh McDonald said the company has not yet met with

MISO representatives to discuss the option of joining that grid operator's markets.

The MISO study order noted that the Missouri service territory of Ameren, a MISO member, is next to Entergy Arkansas' footprint. Moreover, the fact that MISO has a day-ahead market may be the answer to a continuing concern of Entergy Arkansas and its parent company, Entergy, about SPP's lack of such a market structure.

SPP, which now serves as Entergy's independent coordinator of transmission, expects to launch a day-ahead market in 2014.

"Their plans for 2014 are too far out to be taken seriously," said James Carson, CEO of RisQuant Energy, which is in Minnesota in MISO's footprint. "The improvement in price transparency with a Day Two market structure is very valuable, and the adoption will yield substantial benefits."

Entergy Arkansas membership in MISO would lead to better integration of the transmission system in the Midwest and benefit renewable power, especially wind generators, he said.

"I do not anticipate any negative long-term repercussions for Entergy, should this occur," Carson continued. "Nevertheless, Entergy would lose significant control and influence that they have enjoyed for many years in their market," he said, and "it would definitely weaken SPP."

An industry consultant observed there is nothing preventing Entergy from reaching agreement with MISO, but said he would be "very surprised — shocked — if the stakeholders supported it." David Cruthirds, who publishes a bi-weekly report on Southeast power markets, said "nothing against MISO, but SPP has been on the ground working with Entergy, its system, stakeholders, regulators, etcetera, and has so much more knowledge than MISO possibly could have."

Thus, the MISO option "just doesn't seem credible to me," he said. "The need for an established Day Two market won't drive the train."

Another source agreed with Cruthirds that any possible MISO advantage is not definitive. Mike Proctor, a consultant to the SPP Regional State Committee and former Missouri Public Service Commission chief economist, said SPP's lack of a day-ahead market "is a short-term difference that will be resolved very soon and is not a reasonable basis for making a decision" about which regional transmission organization to join.

The Missouri PSC required all investor-owned utilities in that state to compare the costs and benefits of joining SPP with joining MISO, Proctor noted.

Benefits on the west side of Missouri were higher for SPP than MISO, with those utilities being more highly interconnected to other SPP members, but on the east side, benefits were higher for MISO than for SPP, with AmerenUE being more highly interconnected to other MISO utilities, Proctor said. "Whether or not this will be a determinative factor for Entergy Arkansas is yet to be determined," he added.

"Joining one or the other is a good idea, compared to staying isolated," said Neil McAndrews, an electric utility consultant. But he maintained that the day-ahead market access con-

cern is "basically not that relevant, because you can hedge bilaterally anyway in SPP."

The Entergy Arkansas cost/benefit analyses are to be add-ons to a broader study on the multi-state Entergy system joining SPP after the ICT arrangement ends in November. SPP, Entergy and the Entergy Regional State Committee are working on a modified agreement to serve until a permanent successor arrangement is implemented.

Funded by FERC, the cost-benefit analysis for all of Entergy to join SPP is being performed by Charles River Associates with a September deadline. —*Mark Watson*

Louisiana PSC calls on FERC for changes to Entergy system cost sharing formula

The formula for redistributing system production costs among Entergy affiliates needs to be reworked, the Louisiana Public Service Commission said in a complaint last week.

Production costs are shared among the Entergy units under a FERC-approved system agreement and rate schedule that was created as a way for the utilities to have access to a broad pool of affiliate generation resources.

In 2005, FERC determined that power production costs were not being allocated appropriately among the Entergy utilities. To equalize those costs, it imposed a bandwidth of plus-or-minus 11% of the system average production costs for each of the operating companies — Entergy Arkansas, Entergy Gulf States, Entergy Louisiana, Entergy Mississippi and Entergy New Orleans. Entergy Gulf States was the predecessor of Entergy Gulf States Louisiana and Entergy Texas.

FERC ordered Entergy to make annual filings applying that bandwidth to cost allocations, beginning with the 2006 calendar year.

The current bandwidth formula does not include the costs associated with a power plant that was planned for "system purposes" and owned by Entergy Louisiana, said the May 5 complaint.

The Little Gypsy Repowering Project was planned by Entergy to diversify the system's fuel requirements and provide baseload capacity, said the complaint (EL10-65). Falling natural gas prices and other factors drove Entergy to terminate the project in 2009, the PSC explained.

"The cost of this cancelled plant, to the extent recoverable from ratepayers, is a system production cost and needs to be included in the . . . formula to make the bandwidth calculation just and reasonable."

Additionally, the formula does not account for the actual costs of power plants Entergy purchased in recent years, the PSC continued. In three cases where the cost of a project has changed to be less or more than the original net book value, Entergy has not altered the depreciation expenses to reflect the new amount.

Adjustments are needed for Entergy Louisiana's upcoming purchase of Power Block Two of the Acadia Power Facility for more than net book value, Entergy Arkansas' acquisition of the

Ouachita Power Facility at less than net and Entergy Gulf States Louisiana's purchase of the Calcasieu Generating Facility for less than the original amount, said the complaint.

The PSC also seeks to resurrect arguments it made in a related case (EL08-51). In that proceeding, the PSC said Entergy Gulf States should have accounted for the lease of the Spindletop gas storage facility in Texas in its bandwidth formula. A FERC administrative law judge found that the expenses were out of period and that a regulatory asset such as Spindletop is not a production cost.

It was not until after discovery closed in that case that Entergy revealed the transaction had been accounted for as a capital lease by Entergy Gulf States and that the lease included a bargain purchase option, the PSC said in its recent complaint. Under FERC's accounting rules, the deal should have been amortized over the life of the facility because it provided for indefinite self-renewals and could be terminated through an option to buy at a lower-than-market price.

The PSC asked FERC to reclassify the capital costs of the plant, now on the books of Entergy Texas as a capital lease, as system production costs to the extent they are paid by ratepayers.

It also sought adjustments for accumulated deferred income taxes on a sale and leaseback of the Waterford nuclear plant unit in Louisiana, a matter also under consideration in another FERC proceeding (ER08-1056). Comments on the complaint are due May 25. —*Esther Whieldon*

FERC asked to find CPUC not preempted from making utilities offer certain contracts

Seeking to avoid a court fight with utilities over feed-in tariff requirements for cogeneration facilities, the California Public Utilities Commission last week asked FERC to declare that the state's actions were not preempted by federal law or regulations.

Pacific Gas & Electric, Southern California Edison, San Diego Gas and Electric and Southern California Gas have threatened to sue the CPUC over whether it had authority to require them to offer contracts to cogeneration facilities, also called combined heat and power (CHP) systems, said the May 4 petition for a declaratory order (EL10-64).

The CPUC asked FERC to find that the feed-in tariff decisions are not preempted by the Federal Power Act, the Public Utility Regulatory Policies Act or FERC regulations. The CPUC also wants FERC to grant waivers of its regulations, to the extent it deems necessary.

Under a state law on waste heat and carbon emissions reduction, the CPUC required utilities to offer contracts to combined heat and power systems of 20 MW or less. For cogeneration systems in congested areas, there is a 10% bonus to reflect the avoided costs of building additional distribution and transmission upgrades.

The CPUC does not dispute FERC's exclusive authority over wholesale rates under the FPA, said the petition. "The CPUC has only required that the retail electric utilities must offer contracts with certain prices to encourage CHP systems to be constructed,

but does not require a CHP system to accept that offer."

FERC repeatedly has recognized that states have authority over the discretionary procurement decisions of retail utilities, including the resource portfolios of those entities, said the petition.

Even if the petition raises issues that are a matter of first impression, FERC should find that the CPUC's decisions "are not preempted due to the compelling nature and urgency of reducing [greenhouse gas] emissions, the legal authority that the states already have over the resource portfolios and procurement of retail utilities" and the different purposes of the environmental protection objectives of the bill and the economic objectives of FPA and PURPA. —*Esther Whieldon*

MARKETS

ISO-NE would drop secondary FTR market mechanism, pending plan for long-term rights

The harm from potential unmitigated risk outweighs benefits to be derived from retaining the little-used secondary market for financial transmission rights that is now administered by ISO New England, the region's market participants have agreed. So the ISO filed May 5 to temporarily eliminate the mechanism.

Currently, secondary FTR market transactions can be conducted either without ISO involvement or through its bilateral trading system known as eFTR. But since inception of the FTR market in March 2003, the volume of trades through eFTR has been very small, with only 47 transactions for 2,712 MW-months of FTRs, explained the filing (ER10-1190).

That is a mere fraction of the 49,358.9 MW-months cleared in ISO-NE's most recent monthly FTR auction alone, the ISO said. And in the last three years, only one customer pairing used the eFTR system to conduct secondary trades on 11 paths for 67.8 MW-months of FTRs, it added.

Despite the insignificant volume of trades, however, the market administered by ISO-NE faces the risk of a significant default by a market participant, according to the filing.

That is because ISO-NE "has no authority through its market rules or system capabilities to verify that both parties to the trade are sufficiently collateralized prior to accepting the trade," explained testimony from Jeffrey Iafrati, manager of the ISO's market and credit risk department. While market participants must post sufficient financial assurance before acquiring FTRs in the ISO-run auctions, no such requirements exist for trades in the ISO-administered secondary market.

As a result, "unmitigated risk can be realized through the submittal of a single trade at any time" as long as the ISO-administered market remains available, Iafrati said.

Stakeholders considered two options to address that credit risk: implement necessary software enhancements to perform a credit check and confirm trades in the eFTR system, or remove the secondary FTR market provisions from the tariff until ISO-

NE implements a long-term FTR (LFTR) market, as all organized electricity markets must do under order 681 (*IF*, 24 July '06, 1).

The choice likely was made easy by the fact that dropping the tariff provision could take place immediately and at essentially no cost, while software enhancements could take as long as 13 months to complete at a cost of up to \$810,000. Moreover, those enhancements would be rendered obsolete when the LFTR market software is put in place.

In an update filed last month, ISO-NE said it expects to initiate stakeholder review of financial assurance policy alternatives for LFTRs in the fourth quarter of this year, setting in motion an implementation process that is likely to be completed no earlier than mid-2012.

While a financial assurance policy for the LFTR market has yet to be determined, it will “unquestionably include a provision to confirm sufficient financial assurance of secondary FTR trade participants prior to trade acceptance,” Iafrati said.

In the meantime, the market participants have an ability to trade FTR positions bilaterally without involvement by ISO-NE or its software systems, he noted. “Such activity will be unaffected by this filing.” —*Craig Cano*

Complaint slams ‘irregularities’ in auctions to integrate ATSI into PJM; remedies sought

An energy management company wants FERC to investigate “irregularities” that it says resulted in a competitive advantage for certain bidders in the recent capacity auctions to integrate American Transmission Systems Inc. into PJM Interconnection.

While not seeking to change the results of the auction “for the simple reason that this could cause still further disruption and uncertainty,” EnerNOC’s April 30 complaint calls for sanctions or remedies. If allowed to stand, the irregularities introduced by ATSI-parent FirstEnergy have the “potential to shatter public confidence in the integrity of other wholesale market competitive procurements,” the filing warned.

Because PJM’s reliability pricing model acquires capacity three years in advance, the special auction was conducted to allow load-serving entities in the ATSI zone to acquire capacity they will need once the transmission system is integrated into PJM on June 1, 2011.

In preparation for the integration auctions approved by FERC late last year (*IF*, 21 Dec, 1), there was an extensive stakeholder process to inform potential bidders and others of their rights and obligations, explained EnerNOC’s filing (EL10-63). To ensure that all potential bidders had access to the same information, it continued, communications were limited to open public stakeholder meetings and teleconferences, and the ATSI integration auction page on the PJM website.

But according to the complaint, some potential or actual bidders had access to relevant, market-sensitive information that was not available to all other bidders.

It said FirstEnergy made specific, material public statements in response to questions posted on the website that “became false prior to the auctions but were not corrected in a timely

fashion or appropriately qualified.” That information was maintained on the site even as FirstEnergy engaged in “private negotiations” with a subset of bidders that altered the facts, the complaint continued.

As a result, those bidders, including a FirstEnergy affiliate, had access to information that not only would allow them to tailor bidding strategies in ways denied to others, but also to influence changes to relevant market conditions in the ATSI auctions that other public bidders could not influence and were not told were subject to revision, the complaint said.

The failure “to abide by the letter, spirit and intent of the ATSI auction rules caused harm to the competitive market,” the filing asserted. Advocating sanctions or remedies rather than revisions to the auction results, EnerNOC said what it “seeks above all is non-repetition of similar scenarios” in the future.

“This situation was avoidable,” it went on, and could have been “largely cured by timely disclosure or even prudent measures” within the settlement process to mitigate the anti-competitive impact. The integrity of FERC’s bidding procedures and rules is “essential to maintain confidence in the competitiveness and fairness of the markets,” EnerNOC concluded.

Comments on the complaint are due May 20. —*Craig Cano*

Further changes to FCM rules could take more time than order allows, ISO-NE says

If ISO New England ultimately must make material changes to capacity market revisions that FERC accepted last month on an interim basis, there won’t be adequate time to implement those changes prior to the June 2011 capacity auction as required in the April 23 order, the grid operator says.

FERC acknowledged that some of the revisions filed by ISO-NE and the New England Power Pool participants committee were not shown to be just and reasonable, but it allowed them to take effect while a paper hearing is held (*IF*, 3 May, 6). With the next capacity auction to be held in August, the commission concluded that market participants needed certainty about the rules, explained that order (ER10-787, *et al.*).

But while accepting the full package of revisions, the order set some for hearing, including the modeling of capacity zones and the alternate price rule that triggers when an auction outcome is not competitive. Any revisions resulting from the hearing would take effect prospectively, beginning with the June 2011 auction that will be the fifth under the forward capacity market regime.

ISO-NE and the protesting parties must file briefs on July 1, with replies due by September 1.

Although that fifth auction is more than a year away, there are “several critical dates well in advance” of it, some as early as this October, ISO-NE said in a May 5 request for clarification or, in the alternative, rehearing. Even if the scope of changes resulting from the hearing is relatively narrow, “it will simply not be possible to complete the steps necessary” for new rules to take effect in time for June 2011 auction, the filing asserted.

The commission should clarify last month’s order to allow

the accepted revisions to remain in effect until any new rules are approved, ISO-NE maintained, and it should extend the implementation date for any ordered changes to no earlier than the sixth FCM auction now scheduled for April 2012.

Separately last week, ISO-NE also filed its proposed installed capacity requirement (ICR) as well as an informational report on resource qualification for the upcoming auction to procure capacity for the 2013-14 commitment period.

The ICR is a measure of installed resources that are projected to be needed to meet reliability standards based on total forecasted load requirements in the New England control area as well as to ensure sufficient reserve capacity.

The grid operator's May 4 filing (ER10-1182) proposed an ICR value of 33,043 MW. After subtracting 916 MW of Hydro Quebec Interconnection Capability Credits that allow certain entities in the region to move power across that interconnection, ISO-NE said it will need to procure 32,127 MW of capacity in the auction.

Capacity market rules also direct ISO-NE to calculate both a "local sourcing requirement," which is the minimum amount of capacity that must be electrically located within an import-constrained load zone, and a "maximum capacity limit," which is the maximum amount of capacity that can be procured in an export-constrained load zone to meet the ICR.

For the upcoming auction, ISO-NE proposed local sourcing requirements of 7,419 MW for the Connecticut load zone and 2,957 MW for the Northeast Massachusetts/Boston zone. In calculating the requirement, the ISO for the first time used a revised methodology accepted in the April 23 order, the filing noted. It also proposed a 3,187 MW maximum capacity limit for the export-constrained Maine load zone.

The May 4 informational filing (ER10-1185) reported that ISO-NE has 37,271 MW of qualified existing capacity resources: 32,776 MW of intermittent and non-intermittent generating capacity; 3,139 MW of demand resources; and 1,356 MW from import capacity. In addition, the ISO qualified 886 MW of new generating capacity resources, 1,244 MW in import capacity resources and new demand resources of 1,011 MW.

The result is 40,412 MW of qualified capacity to meet the ICR of 32,127 MW. "As the informational filing demonstrates, the FCM continues to attract resources" to participate in the auctions, ISO-NE said. —*Craig Cano*

SUPPLY & DEMAND

MISO sees 25.9% summer reserve margin owing in part to significant additions of wind

Midwest Independent Transmission System Operator expects to have a reserve margin of almost 26% this summer, well in excess of the 15.4% system planning reserve requirement. In its recently issued resource assessment, the grid operator projected coincident net internal demand of 104,288 MW against total

designated capacity resources of 131,284 MW.

Although the summer peak is expected to be up 4.2% from a year ago, that increase is attributable entirely to the integration of three Iowa systems, including MidAmerican Energy, last September 1, and the planned integration of Dairyland Power Cooperative on June 1. "Without the new membership, the net internal demand would have decreased by 1.7% primarily due to the economic downturn," MISO said.

Since last summer, the Midwest market has added 10,370 MW of nameplate capacity, including 7,822 MW associated with the Iowa and Dairyland integrations. Capacity retirements, on the other hand, "were nominal" with only 756 MW of nameplate capacity being shut down, the assessment noted.

Slightly more than 2,000 MW of the additional capacity is wind resources, the assessment continued, with 72% located on the systems of the new members. That represents a 36% increase in MISO's wind capacity since last summer, it said.

It is "always possible that a combination of high loads due to adverse weather, a lack of wind generation, a high rate of outages and a lack of external support could result in the curtailment of firm demand," MISO acknowledged. But that is considered to be a "low probability event" given the expected reserve margin of almost 27,000 MW and the fact that fuel scarcity "is not projected to be an issue." —*Craig Cano*

PJM sees adequate summer power supplies, expects demand response to play major role

Peak use of electricity in PJM Interconnection this summer is expected to increase 1.5% from last year, when adjusted for the relatively cool summer weather in 2009, and demand response is expected to play a significant role in reducing that peak, the grid operator said last week.

In a summer outlook released May 5, PJM said it has 162,903 MW of available generation to meet the forecast peak demand of 135,750 MW. Additionally, it anticipates cutting that peak by more than 6% through voluntary consumer demand reductions of about 8,525 MW.

"PJM and our members are ready to handle the expected summer conditions," said Senior Vice President of Operations Michael Kormos in a statement. "However, until transmission additions can relieve congestion, we expect we will continue to reschedule generation to accommodate peak load conditions," he observed.

Separately, in a May 4 presentation at PJM's annual meeting, Market Monitor Joseph Bowring noted that congestion charges on the grid in 2009 tumbled by two-thirds from the prior year, settling at about \$719 million. That's the lowest level since 2003 and represented just 3% of PJM total billings, compared with the 6% average for the 2003-2009 period.

Bowring, who is president of Monitoring Analytics, also noted that last year's average real-time load of 76,035 MWh dropped 4.4% from 79,515 MWh in 2008, which in turn was down 2.7% from the prior year. The real-time, load-weighted

average locational marginal price was \$39.05/MWh in 2009, a 45.1% drop from 2008.

According to Bowring, who re-iterated findings from his annual state of the market report for 2009 (*IF*, 15 March, 5), the total price for power in PJM was \$55.58/MWh. By far the largest component, representing 70.2% of the total price, was the load-weighted energy cost of \$39.05/MWh. Other major components were the \$10.75/MWh cost of capacity (19.3%) and \$4/MWh in transmission service charges (7.2%).

As for the summer outlook, PJM said the forecast was based on normal weather conditions. If the weather is unusually hot, air conditioning use could drive demand as high as 144,612 MW, it said. That would fall just short of the grid operator's all-time record demand of 144,644 MW reached in the summer of 2006.

Touting the role that demand response is expected to play, PJM noted that the 8,525 MW of available resources represents a five-fold increase since 2006. —*Craig Cano*

RENEWABLES

Electricity generation from ocean currents still down the road, reports industry expert

Technologies harnessing ocean currents and waves to generate electricity are a long way from being affordable enough to attract commercial investment, according to an ocean energy expert.

Key technologies are not yet cost-competitive and there is no timeline for when they will be, said Sue Skemp, executive director of the Center for Ocean Energy Technology at Florida Atlantic University. Further, the nascent renewable energy field faces numerous regulatory, policy and environmental hurdles, she added.

"We have to surmount the policy issues first" before the sector can develop, Skemp said last week in Houston at the Offshore Technology Conference focused mainly on technology for oil and natural gas exploration and production.

If that challenge can be met, however, the global potential for such technology could eventually reach about 38,000 MW, according to some estimates. That compares with US nameplate generating capacity of about 1.1 million MW.

Thus, ocean energy "is not the solution," Skemp said. "It's an additional solution."

A single offshore project using "underwater wind turbines" to harness the power of tides and currents or employing the ocean as a solar collector could require approval from multiple authorities, she continued. Offshore equipment, transmission lines, interconnection with the power grid and the staging area for construction each could fall under state, federal or even international jurisdiction with a host of administering agencies.

"Many of these agencies have their own mission, and decisions could be based on their singular missions instead of overall" objectives, Skemp said. Unlike oil and gas, where overlap-

ping authorities have to some extent been decided, this is a new area with little cohesive policy to guide developers, she added.

Moreover, ocean energy has only begun to scratch the surface in investigating possible environmental effects of the technologies. In Florida, for example, threatened sea turtles have been found in several promising areas for development. Aerial surveys of the habitats are set to begin soon for use in evaluating impacts of a project, Skemp said.

Wakes created by equipment, changes to the ocean floor and other sediment movements, as well as potential entanglement of animals or fishing lines with ocean power projects all raise concerns, she continued.

Ocean energy projects face many of the issues that the oil and gas industries had to deal with, including policy, environmental and even some technical considerations. Hopefully, she said, the new industry will learn from things that oil and gas developers "stubbed your toes on." —*Carla Bass*

Snohomish hydro license should provide for fish spawning sites, upstream paths, says staff

To reduce the environmental impact of relicensing a 112 MW hydropower project in Washington, FERC staff has recommended measures to increase fish spawning and rearing and require regular compliance reports from Public Utility District No.1 of Snohomish County, Washington.

Snohomish proposes no changes to the generation capacity of the Henry Jackson Hydroelectric project (P-2157) located on the Sultan River, east of Everett, Washington.

The primary issues to be addressed when relicensing the project include enabling upstream fish passage, restoring spawning and rearing sites for salmon on the Sultan River and establishing a water management and flow plan that balances hydro generation with the local waster supply, habitat, recreational and flood control needs, staff said in a draft environmental assessment.

Staff recommended that a license for the project include most of the measures outlined in a settlement between PUD Snohomish, federal wildlife agencies, Snohomish County, the cities of Everett and Sultan, environmental groups and the Tulalip Tribes of Washington.

In addition to activities intended to increase survival and production of eggs and growth into juvenile salmon, the plan would remove culverts the currently block upstream fish passage, said the assessment.

However, the staff alternative plan does not include Snohomish's proposed fish-habitat enhancement proposal. "The measures that would be implemented with the funds are not yet specifically defined, thus the exact benefits of these measures cannot be determined and we cannot evaluate whether the potential benefits of this measure warrant its substantial cost," said the assessment.

Also, instead of providing funds to the Washington Department of Fish and Wildlife to be used to stock steelhead smolts

in the Sultan River, Snohomish would be responsible for replenishing the population and file a report each year on its actions, staff suggested.

Other staff-recommended measures include an operational compliance-monitoring plan and modifying the proposed habitat enhancement and the March Creek Slide monitoring and modification plans to include a reporting requirement.

Staff also would require coordinated efforts with the US Forest Service for preserving habitats on federal lands and considering whether Culmback dam should be included in the National Register of Historic places when it is 50 years old.

The staff alternative would ensure the project provides a dependable source of power for the region, or about 402,540 MWh annually. It also includes measure to protect and enhance environmental and cultural resources affected by the project, staff said. —*Esther Whieldon*

Amendment would give CFTC final say on jurisdiction begins on page 1

guage would settle anything between the feuding agencies.

The amendment says “notwithstanding the exclusive jurisdiction of the (CFTC) with respect to accounts, agreements and transactions involving swaps or contracts of sale of a commodity for future delivery,” no provision in the reform package should supersede or limit FERC’s authority under the Federal Power Act or the Natural Gas Act.

Neither should those provisions restrict FERC “from carrying out the duties and responsibilities to ensure just and reasonable rates and protect the public interest.”

Chairman Jon Wellinghoff didn’t respond to a request for comment as of press time.

In addition to Bingaman, the amendment is sponsored by Majority Leader Harry Reid; Democrat Maria Cantwell of Washington; and Republican Senators Lisa Murkowski of Alaska, Sam Brownback of Kansas, Bob Corker of Tennessee and John Cornyn of Texas.

Separately, 10 utility and energy groups last week called on the Senate to make changes to the bill to ensure energy users are not inadvertently classified as swap dealers.

The bill would bring stricter regulation to over-the-counter products and require central clearing and exchange trading “for derivatives that can be cleared.” Senator Christopher Dodd, Democrat-Connecticut, who chairs the Banking, Housing and Urban Affairs Committee, unveiled the legislation in March (*IF*, 22 March, 7).

While the bill would exempt “end-users,” or physical hedgers such as energy producers and distributors, from the clearing requirements, who would qualify for the exemptions would be determined by the CFTC or Securities and Exchange Commission.

In a May 3 letter, the American Gas Association, Edison Electric Institute, Natural Gas Supply Association, Electric Power Supply Association, American Public Power Association and others urged the Senate to tweak the bill to exempt com-

mercial end-users.

“A clear commercial end-user exemption is absolutely critical for us to maintain stable and affordable rates while continuing to invest in America’s energy infrastructure,” the groups said.

To ensure that end-users can rely on the exemption, “it is critical that these commercial entities are not inadvertently misclassified as either a swap dealer or a major swap participant.”

The legislation should define swap dealer as any entity that describes itself as a dealer in swaps, makes a market in swaps, “regularly engages in the purchase and sale of swaps in the ordinary course of its primary business as a market maker or dealer” and engages in any activity causing it to be commonly known as a swaps trader or market maker, the groups said.

The bill also should create a definition for the term “substantial position” to be no lower than the hedge exemption granted to any other entity or speculative position limit or accountability level, for any contract, transaction or agreement at the time of the CFTC’s determination, the groups said.

In addition, the definition of swap should expressly exclude any sale of the non-financial commodity or security for deferred shipment or delivery.

Also, Congress should not mandate a fiduciary responsibility on swap dealers because that would prevent them from entering into swap transactions with state and local governments, the letter said.

Greater regulation of swap transactions entered into by governmental entities could be accomplished by requiring those entities to hire a CFTC-registered swap transaction dealer to perform a similar function to commodity trading advisers.

The groups also urged the Senate to clarify the jurisdictional authorities of the CFTC and FERC when it comes to derivatives markets stemming from FERC-approved tariffs.

The letter echoes concerns voiced in March by the Coalition for Derivatives End-Users, whose members include the American Petroleum Institute and National Association of Manufacturers. The groups warned that the language could have “harmful consequences” for end-users without a specific exemption. —*Meghan Gordon, Esther Whieldon*

NorthernStar files bankruptcy, abandons Bradwood Landing plan begins on page 1

Deister on Wednesday declined to comment further.

Mike Carrier, natural resources policy director for Oregon Governor Ted Kulongoski, said NorthernStar officials briefed him an hour before they issued a statement announcing the decision to suspend further work.

“The issue was that their investors had withdrawn their financing,” he said.

Carrier said he was surprised to read in the press release that the company was pinning the blame on slow regulators. He said the state’s review has taken much less time than the federal process.

“I acknowledge that it’s taking them six years from the time they started to get their FERC license,” he said. “Four-and-a-half

of those years were to get their federal license.”

In September 2008, FERC approved the Bradwood proposal for a 1.3 Bcf/d import terminal and 36-mile pipeline (*IF*, 22 Sept '08, 4). Developers were working through environmental and waterway permits and fighting opponents in the 9th US Circuit Court of Appeals.

Backers of two competing LNG projects in Oregon said Bradwood had a poor strategy for building local support and predicted that their projects wouldn't suffer the same fate.

Peter Hansen, CEO of Oregon LNG, said his team considered the same site in 2004 and decided it had too many challenges. Farther up the Columbia River, the Bradwood terminal would have been built within an active salmon rookery. On security, Hansen said it would have to rely on smaller tankers, given its proximity to Astoria's inner harbor.

“We have known for years that site had land-use issues,” Hansen said. “It was no surprise that eventually that would have to come to a head.”

Bob Braddock, project manager of the Jordan Cove LNG terminal approved by FERC in December, said Bradwood's developers would have been wiser to confront certain zoning issues years ago.

Last month, the state Land Use Board of Appeals ruled for a second time that the project didn't fit the current zoning restrictions allowing small- to medium-sized industry.

“It looked like they couldn't comply with zoning,” Braddock said. “You scratch your head. If they had to comply with zoning then it would mean it had to go back to the drawing board, redraw your whole facility.”

Hansen added that chances of success in appealing the decision were “slim to none.”

“Consequently, the system worked,” he said. “It was never the intent that this area was to accommodate large industry. In the end, they were not able to get the system to view a facility of this sort as small to medium.”

Hansen and Braddock said they remain optimistic about their projects, despite Bradwood's exit and growing concerns that El Paso's Ruby Pipeline from Wyoming to Oregon will make their proposals irrelevant.

Braddock added that one fewer competitor could be a good thing. “It might help from a standpoint of lowering the level of emotional and political rhetoric,” he said. “Maybe things will calm down a little bit.”

On the other hand, groups opposed to LNG can focus on two projects instead of three. “Certainly they will have more resources available to spend against us,” Hansen said.

But he predicted the Oregon LNG proposal, still under consideration by FERC, will withstand the scrutiny.

“It really is a good site. It's very well suited for this purpose,” he said. “Where they focused their fight with Bradwood was on land-use. We finished our land-use process back in 2006.”

The best organized opponent of all three projects is the Columbia Riverkeeper conservation group.

Executive Director Brett VandenHeuvel said Bradwood's demise represents a clear victory for grassroots efforts to protect

the Columbia River estuary.

“A lot of people believe it was simply a bad location that had too great an impact on salmon, on family farms, on forest lands,” he said. “It's very difficult to force a project down the throats of strong local opposition.

“There's no doubt in my mind that local citizens standing up to protect their values and their livelihoods defeated this project.”

VandenHeuvel said NorthernStar's exit has implications for the remaining two projects.

“It sends a strong message that LNG is not viable in Oregon,” he said. “The very same problems that caused Bradwood to pull the plug affect the other terminals.” —*Meghan Gordon*

PIPELINES

Trailblazer, Northern Natural gas quality dispute has shippers scrambling for capacity

Shippers in the middle of a dispute between Trailblazer Pipeline and Northern Natural Gas about carbon dioxide levels are losing money on some deliveries, according to market sources and regulatory filings.

Northern Natural implemented the limits at its interconnection near Beatrice, Nebraska, on April 8 because carbon-dioxide levels of Trailblazer gas exceeded Northern Natural's 2% tariff limit and were causing operational concerns. Northern Natural has limited receipts at that point since the announcement.

Throughput at the interconnection, designed to transport about 450,000 Mcf/d, has not exceeded roughly 223,000 Mcf since April 9, according to Northern Natural's website.

Because of Northern Natural limits on Trailblazer receipts, shippers cannot deliver the full volumes to their customers but still have to pay almost full rates because the situation does not constitute a *force majeure* event, market sources said last week.

In a recent FERC filing on a related matter (RP10-337), Shell Energy and Chevron — which are firm capacity holders on both pipelines — said that they must find alternatives to serve their customers on Northern Natural and that they “have not been afforded relief from reservation charges.”

Gas quality issues of this type “are very disruptive to gas marketing efforts because they undermine predictability and reliability” and “affect exploration and development of gas supplies,” the filing added.

Both companies urged FERC to look further into such gas-quality issues.

Northern Natural spokesman Michael Loeffler said the company has tried to resolve the issue with Trailblazer owner Kinder Morgan Energy Partners, to no avail. “Northern has been unsuccessful in facilitating upstream pipeline CO2 reductions at the interconnect,” he said.

“Obviously, customers aren't happy about the situation, but it appears, to date, that they have been unable to convince the

suppliers or upstream pipelines to modify the CO₂ levels in the gas stream,” Loeffler said.

He also said “the ability to accept quantities of this out-of-spec gas” could improve if “significant quantities of supply” are purchased at locations upstream of the Trailblazer receipt point and “depending upon other market dynamics that impact system flows.”

Kinder Morgan said Trailblazer’s tariff limit is 3% and that it will continue operating at that level. “Pipelines downstream of Trailblazer have different CO₂ tariff specifications and make independent decisions to curtail shipper nominations, and then work directly with shippers to implement the reduced nominations,” said spokesman Joe Hollier.

In addition, he said Trailblazer does not “have control over decisions made by downstream pipelines to curtail shipper nominations due to gas exceeding tariff gas-quality standards.”

After the Northern Natural limits went into effect, much of the gas from Trailblazer was diverted to Natural Gas Pipeline Co. of America, said Bernadette Molinar, an analyst with Bentek Energy. Flows increased at the Natural interconnection with Trailblazer by 238,000 Mcf/d on average from April 8 through April 30, she said.

On April 27, Natural also threatened to limit receipts from Trailblazer because of high CO₂ levels, according to a web site posting.

Natural said the gas it receives from Trailblazer is exceeding Natural’s gas-quality specifications at the receipt point in Gage County, Nebraska, and said it might limit the volume received at that point.

Kinder Morgan, a private entity, operates Natural, of which it owns 20%. Myria Holdings owns the other 80%. —*Eunice Bridges*

FERC denies Colorado driller’s complaint that pipeline should have sought certificate

The commission denied a complaint by a Colorado natural gas driller about whether the Bull Mountain Pipeline should fall under FERC’s jurisdiction.

Riviera Drilling and Exploration asked the commission in July to examine whether the pipeline’s owners should have sought a certificate of public convenience and necessity from the commission before building the system (*IF*, 27 July, 15).

Texas-based SG Interests I and Colorado-based Gunnison Energy co-own the 20-inch-diameter, 25-mile pipeline, compressor and processing plan.

Making a case that Bull Mountain should fall under FERC oversight, Riviera said the pipeline feeds directly into an interstate pipeline system and was designed to be more than just a stub-line extension of the processing plant (CP09-445).

Riviera added that pipeline operators have a history of upping prices for transportation on non-jurisdictional gathering lines, such as the Ragged Mountain Pipeline.

The pipeline argued, however, that Bull Mountain qualifies as a gathering system under the “primary function test” and that its length and diameter are consistent with a gathering function.

FERC agreed that Bull Mountain meets its six-pronged test for

identifying non-jurisdictional gathering facilities. The May 6 order found the pipeline’s “diameters and lengths are consistent with a system performing a gathering function” and that future looping is unlikely.

Congress gave FERC authority over interstate pipelines, but the Natural Gas Act doesn’t delineate interstate transportation from gathering pipelines. —*Meghan Gordon*

ENERGY PROJECTS

Ruby’s completion expected to cast shadow over Oregon LNG, Canadian gas imports

When El Paso’s Ruby Pipeline comes online in March 2011, it will usher in major changes to the Northwest gas market, likely reducing the need for pipeline imports from Canada and liquefied natural gas imports from abroad, industry sources agree.

Extending 675 miles from Kern River Gas Transmission’s hub at Opal, Wyoming, to Malin, Oregon, Ruby will bring a fresh supply of relatively cheap Rocky Mountain gas to Northern California, which has traditionally relied heavily on gas from Western Canada to meet its needs.

The pipeline’s initial 1.2 Bcf/d capacity, most of which has been contracted by Pacific Gas & Electric, will be “in direct competition with gas from Alberta,” explained Navigant Consulting Director Gordon Pickering.

“Modeling we did on the effects of Ruby were that it would have fairly high utilization rates given PG&E as anchor tenant, which would increase over time,” he said. Specifically, deliveries on TransCanada’s Gas Transmission Northwest pipeline — the only mainline delivering Alberta gas to Malin — would drop by about 500,000 Mcf/d, Pickering estimated.

Ziff Energy analyst Cameron Gingrich concurred. “Our view is that flows on GTN would be backed into Canada and move to the Upper Midwest or Eastern markets” via TransCanada’s mainline as Alberta gas is displaced by Ruby supplies, he said.

Currently, Western Canada produces roughly 15 Bcf/d, of which it exports approximately 8 Bcf/d across the border. But analysts say that with Alberta gas basins maturing and demand within Canada growing, exports to the US will continue to decline over the next five to 10 years.

Ruby will likely exacerbate that trend, Pickering said, and might even cause producers in Alberta to cut back on drilling.

“Ruby is likely to serve as a displacement to other gas supply that may have been developed but for the economic pressures of the market and, in the case of Alberta, of the regulators,” Pickering said. “Declines in gas production in Alberta occurred just as shale gas came on the scene elsewhere and as a result of the ‘punitive’ royalty structure that was implemented in 2007.”

The expected reduction in Canadian supply and greater reliance on Rockies gas will likely weaken Northern California

prices, Pickering said. A softening is already becoming visible, according to data from Platts ICE Forward Curve.

On April 29, summer 2011 and winter 2011-12 packages throughout the Northwest fell considerably in relation to the rest of the curve in a move that market sources largely attributed to expectations of Ruby's impact.

As of April 30, PG&E's summer 2011 basis had fallen to plus 28 cents/MMBtu, dropping 3.5 cents in just two days, vs. the 4.75-cent gain in PG&E's front-month package over the same period, Platts forward assessments showed.

While initial Ruby gas deliveries are planned for Malin, it seems inevitable that Ruby will play a large part in the energy future of the Pacific Northwest, according to traders and analysts.

For example, just as Canadian gas begins to see competition from Ruby, the Pacific Northwest will be facing an increase in gas demand for power generation, Northwest Gas Association Executive Director Dan Kirschner said.

"From our outlook study . . . we are seeing a pretty consistent, continued growth in gas demand for generation of about 1.5% per year," Kirschner said, with the most dramatic growth expected over the next five years.

That trend is one of the key drivers for the host of liquefied natural gas terminals that have been proposed for the Northwest. But analysts believe the Oregon LNG and Jordan Cove projects all could see their projected market niche thwarted by deliveries from Ruby.

Bradwood Landing abruptly backed out of the scene last week when its backers filed for bankruptcy (see story on page 1).

Jordan Cove received FERC approval in December, while Oregon LNG's application is pending.

"Ruby is apt to play havoc with the Oregon LNG facilities still being proposed," Pickering said.

Gingrich agreed with the sentiment. "When we think about bringing LNG into the West Coast" into a negative basis market that will be served by pipelines from Canada and the Rockies, "it doesn't make a lot of sense," he said.

The alteration of the Kitimat LNG terminal on Canada's western coast from an import to an export terminal is proof that the need to bring more LNG to the Pacific Northwest isn't there, he added.

Oregon LNG Senior Vice President Mohammed Alrai disagreed, saying the gap between demand and supply in the Northwest will be larger than expected by the time his company's terminal would come online in 2015.

According to Alrai, Canadian gas deliveries are expected to fall to 4 Bcf/d by then, and Ruby will not be able to cover the gap. "Ruby will not have an effect on Oregon LNG. It might on others, such as Jordan Cove, because that will be coming into Malin," he said, adding that he believes gas demand for electric generation will increase more than some have predicted. He also said Ruby gas will be used more for Northern California demand than for needs farther north in Oregon and Washington.

"Ruby will fill a gap starting next year, but beyond that into 2016 when Oregon LNG comes online, how will that decline in supply be filled?" Alrai asked. "That's when we see LNG as being really necessary." —*Joshua Starnes*

Senate committee approves \$30 billion loan guarantee for Alaska gas pipeline projects

The Senate Energy and Natural Resources Committee voted Thursday to increase a federal loan guarantee for builders of an Alaska natural gas pipeline to \$30 billion from \$18 billion.

The committee attached the new language to the American Clean Energy Leadership Act (S. 1462), a comprehensive energy package the committee approved in June.

The larger loan guarantee reflects the skyrocketing price tag for tapping North Slope gas reserves. The original \$18 billion limit was based on 2001 cost estimates for the massive 48-inch diameter, 1,700-mile pipeline.

Two teams hoping to build a pipeline put the latest costs at \$32 billion to \$41 billion for a proposal by TransCanada and ExxonMobil and \$36 billion for a competing proposal by BP and ConocoPhillips.

Administered by DOE, the loan guarantee would be available to developers of any project that ships Alaska gas to North American markets. But it wouldn't apply to TransCanada's alternative proposal to build a pipeline to Valdez, where a third party would build a liquefied natural gas terminal for export to Pacific markets.

Larry Persily, federal coordinator for Alaska gas projects, said the loan guarantee will help pipeline builders find financing on good terms, allowing them to keep the pipeline's rates as low as possible.

"It's good news, but not unexpected news," he said of the amendment supported by bipartisan senators and the White House. "Now we just need to wait while the Senate considers the bill in its entirety, and hope for a positive outcome." —*Meghan Gordon*

BRIEFLY . . .

NERC security chief leaving: The head of cybersecurity at North American Electric Reliability Corp. is leaving at the end of May. The departure of Michael Assante, vice president and chief security officer, "will not affect the momentum and initiatives that are under way" to address critical infrastructure protection, NERC President and CEO Gerry Cauley wrote in a May 4 letter to electric industry officials. No replacement has been named but the position will move to NERC's Washington office.

Accounting change prompts rehearing: Given FERC's recent change to an accounting policy, it granted rehearing to Midcontinent Express Pipeline's certificate for a system from Oklahoma to Alabama. In March, FERC started allowing pipeline developers to accrue allowance for funds used during construction (AFUDC) for expenses made before they file certificate applications (AD10-3). The funds were the subject of a conference convened after a string of complaints about the previous policy. In September, FERC turned down Midcontinent's request to accrue AFUDC (CP08-6). The pipeline returned to the commission after the policy change, and FERC agreed that it now qualifies for the accrual.

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