

## LNG Mitigation Costs

# WHO WILL PICK UP THE TAB?

FERC issues a surprising order regarding responsibility for LNG-related retrofit costs.



BY JAMES E. GODDARD

“The Federal Energy Regulatory Commission (FERC) will not accept requests from interstate natural-gas pipelines to compensate customers or other downstream entities for any costs they may incur in using gas supplies that include revaporized liquefied natural gas (LNG) that meets approved standards for gas quality and interchangeability.”

This is the lead paragraph from an April 19, 2007, FERC press release announcing FERC’s order in *AES Ocean Express LLC v. Florida Gas Transmission Co.*, which was issued one day later. FERC’s order, which many believed would answer some important questions regarding the introduction of LNG into the U.S. pipeline grid, thus left open the most important question on the topic: Who ultimately will be responsible for cost-mitigation measures to accommodate the introduction of large quantities of LNG into the U.S. pipeline grid?

### **LNG Is Coming, Like it or Not**

LNG is still an enigma to many. The term conjures up visions of exploding supertankers with nuclear bomb-like intensity. This is something experts say physically cannot happen. On the other end of the spectrum, some say that LNG will be the end-all to the problem of rising natural-gas prices in the United States. This is something that may be equally unlikely. No matter what your opinion regarding LNG, one thing is clear: LNG has started to wash ashore in the United States in increasing volumes and likely will continue to do so for many years to come.

In early 2007, there were five LNG regasification terminals in the United States, with a combined capacity of 5.835 billion cubic feet (Bcf) per day (see Fig. 1). Another 23 terminals, with a combined capacity of 34.72 Bcf per day, have been approved by the relevant U.S. agencies, and an additional 15 terminals, with a combined capacity of 17.3 Bcf per day, have been proposed. During the first quarter of 2007, the United States imported approximately 262.5 Bcf of LNG, a 60-percent increase over the volume of LNG regasified in the United States during the first quarter of 2006.<sup>1</sup> The U.S. Energy Information Administration (EIA) has projected that LNG imports into the United States in 2007 will rise to 790 Bcf and should surpass 1 trillion cubic feet (Tcf) in 2008.<sup>2</sup> EIA estimates that LNG imports into the United States will continue to increase over the next several years, with annual LNG imports reaching 4.5 Tcf in 2030.<sup>3</sup>

### **What’s the Big Deal? LNG Is Just Natural Gas, Right?**

While many consumers may cheer at the news that increased LNG supplies will be hitting U.S. shores, supplementing the

decreasing domestic supply of natural gas and, hopefully, mitigating the price volatility in the U.S. natural-gas market, technical issues arise with respect to the introduction of LNG into the U.S. pipeline grid. The biggest technical issue involving LNG is interchangeability, or the extent to which LNG can safely and efficiently replace gas normally used by an end-use customer in a combustion application. The measure most often used to calculate the interchangeability of natural gas is known as the Wobbe Index, which is determined by dividing the gross heating value (or higher heating value [HHV]) in Btu per standard cubic feet (scf) of a gas stream by the square root of the specific gravity of that stream. FERC has described the importance of the Wobbe Index as follows:

The formula for determining the Wobbe Index takes into account the fact that the heat release rates for a gas stream vary directly with its BTU content, but inversely with the gas’s specific gravity. That is because gas with a higher specific gravity has a lower volumetric flow rate. Therefore, if a gas stream with a higher gas gravity is substituted in a given burner with a fixed fuel-supply pressure, fewer cubic feet of gas will flow across the metering orifice. As a result, to ensure delivery of the same heat release rate to the burner, the substitute gas stream must have a higher heating value per cubic foot to offset the reduced volumetric flow rate. Conversely, if the substitute gas stream has a lower gravity, more gas volume will flow across the orifice during a given interval, and, hence, the heating value of the substitute stream must be lower to maintain the same Wobbe Index.<sup>4</sup>

Simply put, the introduction into the United States natural-gas pipeline grid of large quantities of LNG containing a materially different composition than that contained in historic domestic natural-gas supplies, could have serious consequences for end-use combustion applications. As reported by the NGC+ Interchangeability Work Group—comprising 76 participating members from various stakeholder groups across the country, including LNG suppliers, natural-gas pipelines, utilities, power generators, feedstock suppliers, appliance manufacturers, research organizations, gas processors, and state officials—“varying natural-gas composition beyond acceptable limits can

have the following effects in combustion equipment:

- a. In appliances, it can result in soot formation, elevated levels of carbon monoxide and pollutant emissions, and yellow tipping. It can also shorten heat-exchanger life, and cause nuisance shutdowns from extinguished pilots or tripping of safety switches.
  - b. In reciprocating engines, it can result in engine knock, negatively affect engine performance and decrease parts life.
  - c. In combustion turbines, it can result in an increase in emissions, reduced reliability/availability, and decreased parts life.
  - d. In appliances, flame-stability issues including lifting are also a concern.
  - e. In industrial boilers, furnaces and heaters, it can result in degraded performance, damage to heat transfer equipment and noncompliance with emission requirements.<sup>75</sup>
- After months of collaboration, the NGC+ Interchange-

ability Work Group published a set of guidelines regarding the quality of LNG received into interstate natural-gas pipelines to ensure that LNG can be received into the U.S. pipeline grid with minimal impacts on current end-user equipment. Specifically, the group recommended the following guidelines: (1) use of the local historical Wobbe Index average with an allowable range of variation of plus or minus four percent, with a maximum Wobbe Index of 1,400; (2) a maximum heating value limit of 1,100 Btu/scf; (3) a limit of butanes and heavier hydrocarbons of 1.5 mole percent; and (4) an upper limit on the amount of total inert gases (primarily nitrogen and carbon dioxide) of up to four mole percent.<sup>6</sup>

On June 15, 2006, FERC issued its *Policy Statement on Provisions Governing Natural Gas Quality and Interchangeability in Interstate Natural Gas Pipeline Company Tariffs* (the *Interchangeability Policy Statement*), wherein FERC strongly encouraged pipelines and their customers, in negotiating technically based solutions, to use the guidelines (*Cont. on p. 52*)

**FIG. 1 EXISTING AND PROPOSED NORTH AMERICAN LNG TERMINALS**

**CONSTRUCTED**

- A. Everett, MA : 1.035 Bcfd (DOMAC - SUEZ LNG)
- B. Cove Point, MD: 1.0 Bcfd (Dominion - Cove Point LNG)
- C. Elba Island, GA: 1.2 Bcfd (El Paso - Southern LNG)
- D. Lake Charles, LA : 2.1 Bcfd (Southern Union - Trunkline LNG)
- E. Gulf of Mexico: 0.5 Bcfd (Gulf Gateway Energy Bridge-Exceleerate Energy)

**APPROVED BY FERC**

- 1. Hackberry, LA: 1.5 Bcfd (Cameron LNG - Sempra Energy)
- 2. Bahamas: 0.84 Bcfd (AES Ocean Express)\*
- 3. Bahamas: 0.83 Bcfd (Calypso Tractebel)\*
- 4. Freeport, TX: 1.5 Bcfd (Cheniere/ Freeport LNG Dev.)
- 5. Sabine, LA: 2.6 Bcfd (Sabine Pass Cheniere LNG)
- 6. Corpus Christi, TX: 2.6 Bcfd (Cheniere LNG)
- 7. Corpus Christi, TX: 1.1 Bcfd (Vista Del Sol - ExxonMobil)
- 8. Fall River, MA: 0.8 Bcfd (Weaver's Cove Energy/ Hess LNG)
- 9. Sabine, TX: 2.0 Bcfd (Golden Pass - ExxonMobil)
- 10. Corpus Christi, TX: 1.0 Bcfd (Ingleside Energy - Occidental Energy Ventures)\*\*
- 11. Logan Township, NJ: 1.2 Bcfd (Crown Landing LNG - BP)
- 12. Port Arthur, TX: 3.0 Bcfd (Sempra Energy)
- 13. Cove Point, MD: 0.8 Bcfd (Dominion)
- 14. Cameron, LA: 3.3 Bcfd (Creole Trail LNG - Cheniere LNG)
- 15. Sabine, LA: 1.4 Bcfd (Sabine Pass Cheniere LNG - Expansion)
- 16. Freeport, TX: 2.5 Bcfd (Cheniere/ Freeport LNG Dev. - Expansion)
- 17. Hackberry, LA: 1.15 Bcfd (Cameron LNG - Sempra Energy - Expansion)
- 18. Pascagoula, MS: 1.5 Bcfd (Gulf LNG Energy LLC)
- 19. Pascagoula, MS: 1.3 Bcfd (Bayou Casotte Energy LLC - ChevronTexaco)

**APPROVED BY MARAD/ COAST GUARD**

- 20. Port Pelican: 1.6 Bcfd (Chevron Texaco)
- 21. Offshore Louisiana: 1.0 Bcfd (Main Pass McMoRan Exp.)
- 22. Offshore Boston: 0.4 Bcfd (Neptune LNG - SUEZ LNG)
- 23. Offshore Boston: 0.8 Bcfd (Northeast Gateway - Exceleerate Energy)

**CANADIAN APPROVED TERMINALS**

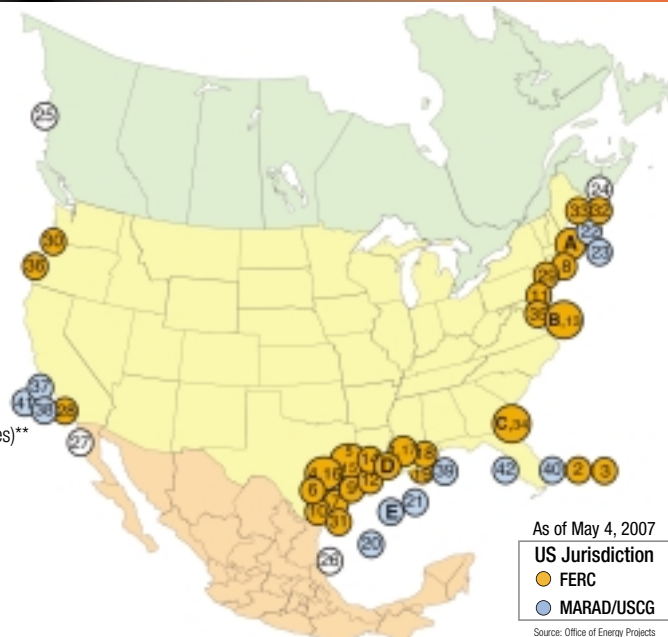
- 24. St. John, NB: 1.0 Bcfd (Canaport - Irving Oil/ Repsol)
- 25. Kitimat, BC: 1.0 Bcfd (Kitimat LNG - Galveston LNG)

**MEXICAN APPROVED TERMINALS**

- 26. Altamira, Tamulipas: 0.7 Bcfd (Shell/ Total/ Mitsui)
- 27. Baja California, MX: 1.0 Bcfd (Energia Costa Azul - Sempra Energy)

**PROPOSED TO FERC**

- 28. Long Beach, CA: 0.7 Bcfd, (Mitsubishi/ ConocoPhillips - Sound Energy Solutions)



As of May 4, 2007  
**US Jurisdiction**  
 ● FERC  
 ● MARAD/USCG  
Source: Office of Energy Projects

- 29. LI Sound, NY: 1.0 Bcfd (Broadwater Energy - TransCanada/ Shell)
- 30. Bradwood, OR: 1.0 Bcfd (Northern Star LNG - Northern Star Natural Gas LLC)
- 31. Port Lavaca, TX: 1.0 Bcfd (Calhoun LNG - Gulf Coast LNG Partners)
- 32. Pleasant Point, ME: 2.0 Bcfd (Quoddy Bay, LLC)
- 33. Robbinston, ME: 0.5 Bcfd (Downeast LNG - Kestrel Energy)
- 34. Elba Island, GA: 0.9 Bcfd (El Paso - Southern LNG)
- 35. Baltimore, MD: 1.5 Bcfd (AES Sparrows Point - AES Corp.)
- 36. Coos Bay, OR: 1.0 Bcfd (Jordan Cove Energy Project)

**PROPOSED TO MARAD/ COAST GUARD**

- 37. Offshore California: 1.5 Bcfd (Cabrillo Port - BHP Billiton)
- 38. Offshore California: 0.5 Bcfd, (Clearwater Port LLC - NorthernStar NG LLC)
- 39. Gulf of Mexico: 1.4 Bcfd (Bienville Offshore Energy Terminal - TORP)
- 40. Offshore Florida: 1.9 Bcfd (SUEZ Calypso - SUEZ LNG)
- 41. Offshore California: 1.2 Bcfd (OceanWay - Woodside Natural Gas)
- 42. Offshore Florida: 1.2 (Hoëgh LNG - Port Dolphin Energy)

\* US pipeline approved; LNG terminal pending in Bahamas \*\* Construction suspended

# THE CASE THAT MATTERED

## What's the story with *AES Ocean Express*?

In January 2004, FERC authorized AES Ocean Express LLC (AES) to construct and operate natural-gas pipeline facilities to transport revaporized LNG from an offshore receipt point at the boundary between the Exclusive Economic Zone of the United States and the Commonwealth of the Bahamas to onshore delivery points on the east coast of Florida. AES proposed to connect its planned pipeline to the pipeline system of Florida Gas Transmission (FGT). AES and FGT were unable to agree upon the terms and conditions to be included in FGT's tariff regarding the LNG delivered through AES' proposed pipeline, leading to AES filing a formal complaint with FERC, wherein it alleged that FGT sought to impose unreasonably restrictive gas quality and interchangeability standards on LNG delivered into the FGT system.

In response to AES' complaint, FERC ordered FGT to file quality and interchangeability standards to address the introduction of LNG into the FGT system. FGT subsequently filed its proposed tariff revisions with FERC, requesting, among other things, a Wobbe Index range for receipts of gas into the FGT Market Area between 1,340 and 1,396, which equated to plus or minus 2 percent of FGT's historic Wobbe Index of 1,368, and a minimum HHV of 1,025 Btu/scf and a maximum HHV of 1,100 Btu/scf. As a result of a number of interventions and comments filed with respect to FGT's proposed tariff provisions, FERC ordered a hearing before an administrative law judge (ALJ) to determine the appropriate natural-gas quality and interchangeability standards regarding the LNG delivered into FGT's system.

On April 11, 2006, after a lengthy and heavily contested hearing, the ALJ issued a 65-page initial decision, finding that FGT's proposed Wobbe Index range of 1,340 to 1,396 and proposed HHV limits

of 1,025 to 1,100 Btu/scf for deliveries into FGT's Market Area were just and reasonable. However, the ALJ found that the standards should be applied only to imported LNG and should not be extended to domestic natural gas. In addition, the ALJ found that mitigation costs downstream users may incur as a result of the introduction of LNG into FGT's system were speculative, but the ALJ left open the issue of whether actual mitigation costs attributable to the importation of LNG could be recovered in the future, stating: "To the extent that a participant may incur a cost which it attributes to the actual importation of LNG under this decision, it may make an appropriate filing, presumably under Section 5 of the NGA, to recover that cost."<sup>1</sup>

Most of the parties in *AES Ocean Express*, other than FGT and the LNG suppliers, requested that FERC establish some method for downstream gas users to recover their costs of testing, remediation, and repair to accommodate the introduction of LNG into FGT's system. The electric generators connected to FGT's system argued that the sponsor of the LNG should be required to bear any costs to install equipment necessary to protect their turbines. In making this argument, the electric generators pointed out that in a prior case, *Columbia Gas Transmission Corp.*,<sup>2</sup> FERC had approved a pipeline's proposal to compensate two sales customers for their costs of modifying equipment in order to accommodate the pipeline's purchase of LNG to serve its customers.

Local distribution companies (LDCs) connected to the FGT system, also relying on *Columbia Gas Transmission* and subsequent FERC rulings, similarly argued that FERC should rule on the cost responsibility for moderating the impact of interchangeability with respect to imported LNG. The LDCs urged FERC to confirm how the costs for necessary mitigation measures will be

allocated, and to specify the procedures by which the costs will be monitored, verified, and collected. Specifically, the LDCs argued that the mitigation costs should be borne by the LNG suppliers and project sponsors, because they are the parties that financially benefit from the importation of LNG.

FERC staff also argued that FERC should establish an appropriate mitigation cost-allocation methodology. Unlike the electric generators and LDCs that advocated that all mitigation costs be borne by the LNG sponsors and suppliers, staff recommended socializing the mitigation costs over all parties.

FGT strongly opposed the arguments that FGT include a mechanism in its rates to permit generators and LDCs to recover their mitigation costs from other parties. FGT stressed that FERC has no jurisdiction with respect to FGT's electric-generation customers and LDCs, adding that the mitigation costs sought to be recouped by the electric generators and LDCs related to facilities that are not used and useful for a pipeline's jurisdictional transportation service.

Not surprisingly, the LNG suppliers involved in the proceeding argued that they should not bear responsibility for mitigation costs because there was no showing that such costs were necessary. They argued that FERC lacks authority to direct payments among parties that are not subject to FERC's jurisdiction, lacks jurisdiction to order payments for equipment upgrades from jurisdictional customers, and lacks authority to award damages or reparations. On a final note, the LNG suppliers pointed out that, contrary to the assertions of the electric generators and LDCs, in *Columbia Gas Transmission Corp.* FERC found that the pipeline, not the supplier, should reimburse affected customers for their mitigation costs.

A little more than one year after the ALJ issued the initial decision, after considering the record and the various arguments of the parties, FERC issued its 126-page opinion and order on the initial decision in *AES Ocean Express*. In its order, FERC generally upheld the ALJ's decision to accept

FGT's proposed standards as just and reasonable, but found that the proposed standards are applicable to all gas tendered to FGT's market area, not just to LNG. In addition, although FERC acknowledged that "the adopted standards could require owners of downstream appliances to incur certain incremental expenses to enable their equipment to use the gas delivered off the Florida Gas system,"<sup>3</sup> FERC agreed with the ALJ that such mitigation costs were speculative. However, in an interesting turn, FERC disagreed with the ALJ regarding the future recovery of actual end-user mitigation costs.

Recognizing the importance of the cost-mitigation issue, and possibly recognizing the likelihood that no matter what FERC decided on the issue, FERC's decision probably would be met with an appeal, the commission spent nearly 20 pages (approximately one-sixth of its order)

addressing cost mitigation. FERC ultimately came to the conclusion that it has no jurisdiction to consider how mitigation costs should be allocated among non-jurisdictional customers. FERC noted:

The commission's only rate jurisdiction in this situation is over the rates Florida Gas charges its shippers for transporting their gas. The mitigation costs which Florida Gas's LDC and electric generator customers seek to recover from the LNG project sponsors, Florida Gas, or other shippers are not Florida Gas's costs, but are the customers' costs of testing and modifying their own equipment.<sup>4</sup>

FERC pointed out that the electric generators and LDCs, many of whom are subject to the jurisdiction of the Florida Public Service Commission (FPSC), were asking FERC to establish a mechanism under

which their mitigation costs would be allocated to other parties, some of whom were also regulated by the FPSC. FERC noted that it believed such a matter is more appropriately within the jurisdiction of the Florida regulatory bodies. Thus, it appears FERC has passed the buck to state regulators to address the issue of end-user cost mitigation resulting from the introduction of LNG into the U.S. pipeline grid.—**JEG**

### Endnotes

1. *AES Ocean Express LLC v. Florida Gas Transmission Co.*, Initial Decision, 115 FERC ¶ 63,009, at par. 225 (Apr. 11, 2006).
2. 13 FERC ¶ 61,102 (1980), opinion and order denying reh'g, 14 FERC ¶ 61,073 (1981), aff'd *Corning Glass Works v. FERC*, 675 F.2d 392 (1982).
3. *AES Ocean Express LLC v. Florida Gas Transmission Co., et al.*, Opinion and Order on Initial Decision, Opinion No. 495, 119 FERC ¶ 61,075, at par. 250 (Apr. 20, 2007).
4. *Id.* at par. 272.

(Cont. from p. 50)

established by the NGC+ Interchangeability Work Group. FERC also noted that, to the extent pipelines and their customers could not resolve disputes over gas quality and interchangeability, FERC would give significant weight to the NGC+ Interchangeability Work Group's guidelines.

While some commentators had asked FERC to address in the *Interchangeability Policy Statement* the issue of who should be responsible for mitigation costs resulting from the introduction of LNG into the U.S. pipeline grid, FERC declined to address the issue, stating that the issue "should be addressed, if and when problems are identified, in specific cases."<sup>7</sup> The industry has waited since the issuance of the *Interchangeability Policy Statement* for the specific case in which FERC would address the issue of who would be responsible for mitigation costs resulting from changes to pipeline tariffs in response to increasing LNG volumes reaching U.S. shores. Many thought that case was *AES Ocean Express* (see, "The Case That Mattered," p. 53), but even after FERC issued its opinion in that case on April 20, 2007, the question remained unanswered.

### Where Are We Left After *AES Ocean Express*?

Even after FERC's Order in *AES Ocean Express*, the question of who pays for mitigation costs resulting from the introduction of LNG into the U.S. pipeline grid remains. FERC suggested that state regulators are in the best position to make the

determination related to costs incurred by state-regulated entities. Thus, in the absence of an appellate court overturning *AES Ocean Express* on the issue of mitigation costs, it is likely that utilities that incur mitigation costs related to LNG will seek to recover such costs in state rate-making proceedings. Therefore, the ultimate answer to the question of who will bear the downstream costs resulting from the importation of LNG appears to be the ratepayers. ■

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### Endnotes

1. "U.S. overtakes Spain as largest LNG Importer in Atlantic Basin," *LNG Daily*, Vol. 4, No. 82, April 30, 2007, p. 1.
2. Energy Information Administration, "Short-Term Energy and Summer Fuels Outlook," May 8, 2007, <http://www.eia.doe.gov/emeu/steo/pub/contents.html>.
3. Energy Information Administration, "Annual Energy Outlook 2007," Feb. 2007, at 12, 94, [http://www.eia.doe.gov/oi/aeo/pdf/0383\(2007\).pdf](http://www.eia.doe.gov/oi/aeo/pdf/0383(2007).pdf).
4. *AES Ocean Express LLC v. Florida Gas Transmission Co., et al.*, opinion and order on initial decision, Opinion No. 495, 119 FERC ¶ 61,075, at par. 30 (Apr. 20, 2007).
5. NGC+ Interchangeability Work Group, "White Paper on Natural Gas Interchangeability and Non-Combustion End Use," Feb. 28, 2005, at p. 5.
6. *Id.* at p. 26.
7. Policy Statement on Provisions Governing Natural Gas Quality and Interchangeability in *Interstate Natural Gas Pipeline Company Tariffs*, 115 FERC ¶ 61,325, at par. 47 (June 25, 2006).