Cheniere Sells Out Two LNG Trains At Sabine Pass

Cheniere Energy is tantalizingly close to lining up the requisite commitments to underpin the first liquefaction phase at its Sabine Pass terminal in Louisiana, announcing a fully-termed sale and purchase agreement with BG Group for 3.5 MMt/y from train 1 on October 26 just as it puts the finishing touches on a second deal with Total for an equivalent amount from train 2. Unlike BG, who is buying its LNG on FOB terms and will not invest in the liquefaction facilities, Total will be both an offtaker and a partner in Sabine Pass Liquefaction LLC, apparently taking a material stake between 20% and 40% in the project. Phase 1 now involves the construction of two trains with nominal capacity of 4.5 MMt/y each, rather than the 3.5 MMt/y units cited by Cheniere as recently as August in a corporate presentation (see LNGWM, Sep '11). A lump-sum turnkey construction package for these two trains has been negotiated with Bechtel as part of the project's recently-completed front-end engineering and design. The results of the FEED exercise haven't been announced, but soundings suggest a capital cost for the two trains of about $3.75 billion, or a little over $415 per ton of installed capacity for the initial 9 MMt/y phase. With two large balance sheet customers in the bag, the developer should be able to secure the required financing. Total's partnership position will also provide added comfort that Cheniere can meet its performance obligations, including sourcing the 1.4 Bcf/d needed from the domestic grid and operating the plant to a high standard.

Both buyers will purchase output on FOB terms without any destination restrictions. BG will pay a contract sales price of 115% of Henry Hub plus a fixed charge of $2.25/MMBtu, about one-sixth of which represents variable costs associated with the operation and maintenance of the plant. This variable component of 34 cents/MMBtu escalates annually with the US Consumer Price Index. The 115% of Henry Hub covers the cost of buying the gas plus boil off and fuel use. BG can cancel cargo liftings provided it meets certain notice requirements. But it will have to pay a fixed amount each month irrespective of how much it loads, a portion of which is subject to annual escalation. This charge equates to approximately $34 million per month in the first contract year, or about $408 million over this 12 month period. Because Total already has a terminal use agreement covering 1 Bcf/d of regasification capacity at the existing import facility, the deal for train 2 is likely to be structured a bit differently. The French firm won't want to pay twice for shared infrastructure that it already utilizes under the terms of its TUA, for which it pays $125 million annually. While the same Henry Hub-related price may apply, fixed charges should be somewhat less for Total given its presence on the import side.

Later buyers in trains 3 and 4 almost certainly won't get the same consideration as the two foundation customers in phase 1, and will undoubtedly have to shell out higher fixed fees in order to score offtake contracts. The expected volume distribution between BG and Total in phase 1 suggests Cheniere will keep about 2 MMt/y from the initial two trains for itself, and it may also have rights to excess production beyond the nameplate capacity of 9 MMt/y. "Not only have Cheniere gotten BG to launch their first train and Total the second, but they've now got a bit of spare volume in train 1 and another bit in train 2 which they can use to play the spot market," comments one source admiringly. "They could sell some of this spare capacity to other players, but my sense is they want to keep it back for themselves." This could be quite lucrative if domestic gas prices remain depressed, as many commentators expect given forecasts for continued high shale gas output in the US. Henry Hub is currently hovering around $3.70/MMBtu, and it has not traded above $5/MMBtu since June 2010. But even if this benchmark were to rise to $6/MMBtu, one analyst says BG still stands to make a margin of $3.65/MMBtu on Sabine Pass deliveries to Asia assuming $1.50/MMBtu for shipping, a delivered cost of $10.65/MMBtu under the terms of its offtake arrangement with Cheniere and an LNG sales price around $14.30/MMBtu based on $105 per barrel oil. The low shipping cost presumably assumes passage through the Panama Canal, which is being expanded to accommodate larger vessels.

The deal with Cheniere does not mean BG is no longer interested in its proposed liquefaction venture with Southern Union at Louisiana's Lake Charles terminal. Indeed, both BG and Southern Union were at pains to reaffirm the British company's continued participation in Lake Charles Exports LLC after the announcement of the SPA at Sabine Pass. "BG are quite happy with Lake Charles as their investment position, it is just that Cheniere was able to offer them LNG at an earlier start date," explains one source. Cheniere hopes to sanction phase 1 in January followed by a formal notice to proceed under the engineering, procurement and construction contract with Bechtel soon thereafter. But this is subject to regulatory approval. The current schedule calls for Cheniere to begin making LNG at Sabine Pass in late 2015. This is about three years ahead of Southern Union, who only filed its initial export application with the Department of Energy in May. Lake Charles will probably be structured as a tolling operation with BG taking all of the capacity as well as an equity stake in the plant, rather than a straightforward FOB offtake deal. There could be space limitations at Lake Charles, as sources say the lay down area isn't very far from a residential area and will require rerouting of a road. "Liquefaction can be done at Lake Charles, no question, but they are going to have to shoehorn it into the existing site," comments one contracting source.

Cheniere is still awaiting approval from the Federal Energy Regulatory Commission, although it has obtained permission from the DOE to export to nations without bilateral free trade agreements with the US as well as those with such pacts. The delay on the FERC front is mostly beyond Cheniere's control, as its flammable vapor dispersion analysis could not be approved until the

Department of Transportation came up with alternative models to replace earlier versions no longer deemed scientifically acceptable. This consultative process with industry has taken nearly two years, although the DOT finally approved two models from Det Norske Veritas and GexCon earlier this month. The models are used to simulate LNG spills on water or land, into sumps and trenches as well as vapor dispersion from flashing and jetting releases. They apply to receiving terminals, liquefaction facilities, peak shaving plants and LNG storage tanks. "The industry has been scrambling for almost two years now to get a model approved, and it has held up the FERC authorization process for all projects involving large liquid transfer lines or storage facilities. Without an approved model, these projects can't simulate their largest credible spills," explains one source.

As liquefaction schemes proliferate, the DOE has launched a "cumulative" impact study to assess the potential effect of multiple export projects on domestic gas prices, job creation and balance of trade. The study, which is due to be completed by the end of November or early December, is holding up approval of several applications including one by Freeport LNG in Texas to export to non-free trade countries. According to Southern Union, four export plants totaling 6 Bcf/d on the US Gulf Coast would push prices up just 22 cents/MMBtu while moving from 6 to 12 Bcf/d would have no additional price impact. Oregon's Jordan Cove became the fifth developer to apply to the DOE to export domestically-produced LNG on September 22, following Dominion Cove Point in Maryland by just three weeks. Dominion is doing pre-FEED work with CB&I and KBR, including feasibility studies on possible driver configurations. But contractors say capital costs on the east coast are likely to be 20% higher than USGC projects, mostly due to the requirement for union labor. Altogether, the five applications involve the exportation of up to 7.6 Bcf/d. This is a drop in the bucket compared to total dry gas output in the Lower 48 states, which is running over 60 Bcf/d and could rise to nearly 70 Bcf/d by 2020. Another four projects totaling 4 Bcf/d are on the drawing board in Canada's British Columbia (see related story below).