Figure 1. Aerial view of Jordan Cove LNG facility.

UNIQUE GLOBAL MARKET IMPACTS OF NORTH AMERICAN LNG SUPPLY

Guy Dayvault, Veresen, Canada, discusses North American commercial impacts on global LNG markets, highlighting areas such as project finance and price risk management; followed by an overview of the proposed Jordan Cove LNG export facility in Southwest Oregon.

While analysts speculate about the ultimate amount of LNG volume to be exported from North America, anticipation of this new LNG supply source is changing the way buyers and sellers manage price risk and supply portfolios. North American LNG provides heretofore unavailable vertical integration for LNG buyers beyond the traditional step of controlling LNG shipping. It allows LNG buyers to establish the costs of liquefaction and gas transportation from wellhead to export facility, leaving only commodity price volatility exposure, which reflects geologic and other exploration and production (E&P) risks in the natural gas supply value chain.

Background

Decades ago, traditional LNG buyers bought supply on primarily Delivered Ex-Ship (DES) terms. Certain very large buyers evolved and took an initial step toward vertical integration by controlling LNG ships to buy LNG at the supply point and achieve savings through managing their own shipping fleets. Essentially, LNG buyers eliminated the excess returns on the shipping/delivery component of the LNG value chain.

The Tolling Commercial Model (TCM) being sold by US LNG export plants fixes the liquefaction cost component of LNG supply and has other risks and rewards set out in Table 1. It also provides the LNG buyer with an opportunity to further vertically integrate by reserving gas pipeline transportation capacity connected to gas trading hubs where they can access established gas supply markets with deep liquidity of multiple buyers and sellers. In contrast, traditional LNG supply categorised the liquefaction and pipeline costs (from wellhead to export site) in the E&P asset class even though these assets reflected more midstream than upstream costs and operating risks. As a result, the lower-risk, LNG-related midstream investments earned a higher return, normally achieved only by E&P assets.

Historical supply locations in areas such as Borneo (e.g., Bintulu, Brunei, Bontang), Australia (North West Shelf, Darwin) and coastal Algeria (Skikda, Arzew) were typically remote. There were no established midstream infrastructure owners locally positioned in these countries to independently provide pipeline and liquefaction services for prospective LNG buyers. In contrast, unconventional gas supply (shale and tight gas) in North America has changed this balance from upstream to midstream. Now midstream entities are developing LNG export infrastructure to provide services on fixed-fee-for-service terms rather than priced as an embedded portion of an E&P development.

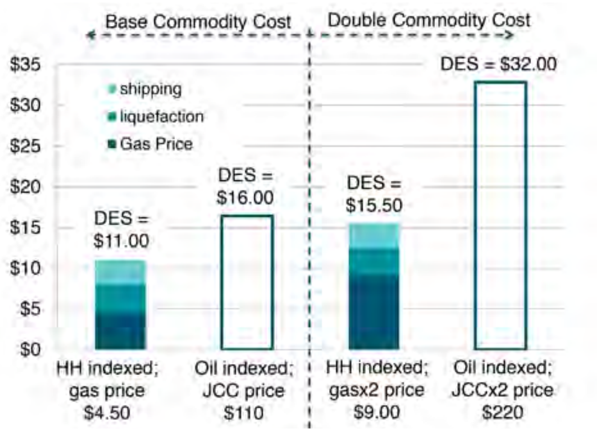

Figure 2. LNG cost resulting from doubling commodity index.

Table 1. Risks and rewards of LNG tolling commercial model

The risks	The rewards
Source, secure, nominate and schedule gas into pipeline and LNG plant	Long-term control of gas supply needs (up to 45 years through optional term extensions)
Contract for pipeline capacity from sufficient liquid market points to the LNG export plant to ensure competitive gas supply	Not competing with the plant owner in marketing LNG
Manage a new business model with value-chain-segments upstream of liquefaction to control	Avoid power cost exposure through dedicated power plant
Hurricane interruptions	HH – JCC arbitrage value
	Vertical integration beyond DES and FOB, back to wellhead

Lower fixed cost and Take or Pay (TOP) obligations

Among the many new rewards embedded in a tolling services model for LNG buyers is effectively a lower TOP obligation. By having the obligation to 'take-and-pay-for' only the liquefaction services, the gas commodity becomes the only variable cost component that floats with commodity price. This is possible because a tolling facility is supplied by liquid gas markets in contrast to traditional models supplied by a dedicated gas field(s). When a dedicated gas field(s) is devoted exclusively to an LNG liquefaction plant, gas must be produced continuously to avoid reservoir damage that can reduce gas productivity and ultimate gas recovery.

For example, consider a situation where an LNG buyer wants to greatly reduce LNG consumption in a particular year. In a traditional LNG sales and purchase agreement (SPA), TOP obligations prevent any substantial reduction beyond a limited Downward Quantity Tolerance because of both reservoir management and geologic constraints and the need to service the capital for liquefaction infrastructure.

In contrast, an LNG buyer's fixed costs are substantially lower under the TCM. Under a TCM, the fixed costs are similar to TOP obligations and continue with regard to shipping time-charter-party-agreements, liquefaction services and pipeline transportation services. However, the 70 billion ft^3/d liquid US gas market provides an LNG buyer with the choice of whether or not to pay for the commodity. An LNG buyer can sell feed gas to a multitude of buyers and sellers in the US market if the volume is not needed at the liquefaction plant given sufficient lead time. The LNG buyers' fixed costs might be further reduced by re-deploying its LNG fleet that has previously been dedicated to lifting US sourced LNG.

Buffered price volatility

Fixing liquefaction and gas transportation costs reduces the delivered LNG cost exposure for an LNG buyer because in the super-high-cost scenario, where the underlying commodity price index doubles, the Henry Hub (HH) indexed gas supply component under a TCM is a smaller portion of the DES cost of LNG than the oil indexed component of DES cost of LNG cost under traditional pricing terms.

Figure 2 shows the contrast between a TCM and oil indexed gas pricing. In a TCM example, the HH gas price is US$ 4.50/million Btu in the base case and doubles to US$ 9/million Btu in the 'double-commodity-cost-case'. This increases the DES cost of LNG from US$ 11 to US$ 15.50 (note a 12-month forward HH gas price strip captured in January 2014 was US$ 4.34/million Btu, anchoring this example base case gas price). In contrast, in the oil indexed example, the JCC oil price is US$ 110/bbl in the base case and doubles to US$ 220/bbl in the 'double-commodity-cost-case'. This increases the DES cost of LNG from US$ 16/million Btu to US$ 32/million Btu because all of the LNG costs are lumped into the pricing, which moves in totality with the commodity price (note 2013 JCC average oil price was approximately US$ 110/bbl and a 14.5% slope is assumed to anchor this example base case).*

Competition between proposed export plants in Australia, Canada and the US

While various supply locations for an LNG project appear similar on the surface, a comparison of the key features in the qualitative analysis below demonstrates that proposed LNG export projects of British Columbia (B.C.), and in some ways Australia, do not compete directly with those in the US. The differences between supply locations show that they will attract and serve LNG buyers with differing needs in addition to diversification-of-supply-region. Thus, while B.C., Australia and US proposals are all 'fit-for-purpose', they fit different purposes.

Booking gas reserves

Booking gas reserves is a priority for E&P companies as a financial metric of sustainability, however it is irrelevant for LNG buyers and midstream companies. TCM LNG plants do not directly monetise stranded gas reserves in the way that historically drove international oil companies (IOCs) to build LNG plants. In contrast, the proposed Australian and B.C. LNG plants are connected to dedicated gas fields to monetise stranded gas and may allow for gas reserves to be booked by E&P operators.

Access to E&P risk and reward

Access to E&P risk and reward can be achieved for LNG buyers investing in B.C. or Australia LNG export projects because they are directly connected to natural gas reserves. However, an LNG buyer taking equity in a US LNG export project is only investing in infrastructure and can avoid E&P risk through gas supply agreements in liquid gas markets.

Shipping

Shipping distances to LNG buyers' home delivery ports are equal from West Coast US and B.C. However, US Gulf Coast (USGC) LNG supply is almost double the distance from North Asian LNG markets compared to B.C. or US West Coast.

Startup

For several US projects, start-up is expected before 2020, while it appears more likely that the big B.C. projects will be commissioning after 2020.

Construction challenges

The remote location of B.C. LNG projects will make labour shortages perhaps analogous to Fort McMurray and the experience of oil sands in Alberta as well as Australian LNG projects. The conditions in these two locations are manageable, but have negative impact on cost as well as schedule, and they require the unique capabilities and strengths of an IOC.

Pipeline access to gas supply

US LNG projects will be connected through relatively short and accessible terrain via umbilical gas pipelines, connected to established dry gas infrastructure of the US gas grid, which starkly contrasts the new 500-mile pipelines needed across the challenging Canadian Rocky Mountains.

Tax uncertainty

Speculation abounds regarding the LNG export tax to be imposed by B.C. as a provincial tax. In contrast, it is beyond the jurisdiction of individual states in the US to impose an export tax on LNG.

Price risk diversification

For a traditional LNG buyer with a portfolio of supply indexed to JCC or other crude oil indices, price diversification and portfolio risk management benefits are achieved by re-aligning the supply portfolio to include LNG with the price indexed to a different underlying commodity price such as HH. An Asian LNG buyer with liquefaction tolling capacity begins to assume the characteristics of a US Local Gas Distribution Company (LDC) and can thus consider some of the gas supply strategies used by LDCs in the US. These include outsourcing gas supply to third party gas trading companies and using the Federal Energy Regulatory Commission (FERC) approved structure of an Asset Management Agreement (AMA) for operations, nominations, scheduling, balancing, etc. of pipeline transportation and storage capacity.

Managing gas supply risk for HH indexed LNG

LNG with gas supply price indexed to HH introduces new physical and financial risks for an LNG buyer as well as new tools to manage those risks. As summarised below, it is optional, though not imperative, for an LNG buyer under a TCM to secure multi-decade gas supply; just as LDCs based in the US generally buy gas on shorter term contracts than a traditional 20-year term of an LNG SPA. For example, many LDCs buy gas on 30-day or 3 - 6 month supply agreements that are renewed, restructured and re-priced regularly. Though LDCs are structurally always short of gas supply, they have found certainty in the liquid gas markets of North America to supply the gas they need without multi-year or multi-decade gas commodity obligations. However, these LDCs do make long-term, multi-year, transportation and storage capacity agreements that in some

What are the new challenges for project financing?

- New challenges = the old challenges.
    - Good deal fundamentals (customers, supply, constraints, complexity).
    - Financial engineering needed (existing and peripheral obligations).
    - "How many stars must be alligned to close the financing?"
    - Underlying value proposition (better value proposition wins in the long-term).
    - Gas supply (liquidity, diversity in supply basins).
    - Market access (canals, shipping distance, precedent trade).
- Better deals might leave project lenders wondering about earlier LNG deals.
- How to manage boom and bust cycle of high demand for new debt followed by insufficient good deals and too much debt hunting for a borrower.
- Cost over-run and delay risk (Australia-syndrome, Sakhalin-syndrome).

ways are structurally analogous to the long-term commitments made by LNG buyers for shipping.

LNG buyers will manage risks of LNG indexed to HH. Various strategies fit various LNG buyers. A few example concepts are listed below:

- Long-term gas suppy agreements with E&P producers or third-party gas marketing and trading companies.
- Buying resource in the ground as gas reserves and taking on E&P risks (e.g. through joint ventures with E&P operators or E&P ownership).
- Entering into a structured AMA with an established gas marketing and trading company for multi-year gas pipeline operations and gas supply solutions (these might be a single bundled AMA for delivered gas or multiple contemporaneous separate agreements). Benefits of an AMA and gas supply agreement include accessing an established gas desk for nominations, scheduling, balancing, and risk management to eliminate the need to directly hire gas trading and pipeline operations staff. Also there would be a gas volume economy-of-scale by leveraging an existing gas desk that trades much larger gas volumes than just the TCM customer needs. Effectively the established gas desk would probably not need to hire any more people or add any new systems or equipment in order to buy and manage the additional gas supply volume for a TCM customer, which means there would be relatively small incremental costs for the AMA provider in buying the incremental gas. Finally, an established gas desk will already have NAESB gas trading agreements with dozens of E&P producers and other gas traders to facilitate flexibility in buying or selling incremental gas if and when needed.
- Buying long-term gas transportation capacity e.g. Mitsubishi with 20 years of 600 000 million Btu/d on Tennessee Gas Pipeline (TGP) for supply to Cameron LNG.

Pacific connector gas pipeline

- 232-mile, 36 in. dia. (1480 psig MAOP), from Malin, or to Coos Bay.
- Initial design capacity of 1.1 billion ft^3/d.
  - Includes potential gas delivery within Oregon.
  - Serves 6 million tpy LNG exports, expandable to meet Jordan Cove's expansion to 9 million tpy LNG exports.
- Pipeline design and rights-of-way previously approved by FERC (2009).
- Owned equally by Veresen and Williams.

Jordan Cove LNG export terminal

- 6 million tpy facility expandable to 9 million tpy.
- 500-acre site includes:
  - Two 160 000 m^3 full contaminent LNG tanks.
  - Marine facility.
  - Liquefaction plant, gas treating.
  - 420 MW power plant.
  - Environmental reserve land.
- Berth design range: 89 000 m^3 - 217 000 m^3.
- Marine facilities, LNG tanks and site grading previously approved by FERC (2009).
- Owned 100% by Veresen.

New challenges for LNG project finance in North America

When it comes to project finance solutions for LNG facilities in North America, the new challenges are much the same as the old ones; essentially solid business fundamentals are key and many remain unchanged, as summarised in the sidebar 'What are the new challenges for project financing'.

Perhaps the biggest change for project finance, and in fact a simplifying factor, is the absence of natural gas reserves certification for an LNG tolling agreement. A traditional LNG SPA required a dedicated gas field(s) with a reserves certificate from a reservoir engineering expert firm. However, this is not the case for US facilities connected to multiple interstate pipelines that are supplied by a multiplicity of gas basins, which are operated by a plethora of E&P operators. In many cases the project finance lender can look to existing pipeline grids and liquid gas trading hubs with multiple decades of history of existing gas buyers and sellers for assurance that gas reserves exist and will be developed and delivered in a predictable manner.

On the other hand, a unique new challenge for project finance lenders is bi-directional import-export LNG facilities and integrating smoothly the rights and obligations of existing LNG import customers with the rights and obligations of new LNG export customers. The commercial and financing success of Cameron LNG, Freeport LNG and Sabine Pass LNG demonstrates that these challenges have been resolved.

Jordan Cove project overview

In order to highlight the above considerations, it is helpful to provide a brief overview of the proposed Jordan Cove LNG Export Project (Jordan Cove) in Southwest Oregon.

Jordan Cove energy project

Located midway between San Francisco and Seattle, Jordan Cove (owned by Veresen Inc.) will be connected by a new 230-mile pipeline (Pacific Connector Gas Pipeline – equally owned by Veresen and Williams), to the existing gas trading hub at Malin, Oregon. The Malin hub is supplied by the Ruby and Gas Transmission Northwest (GTN) pipelines with a total capacity approaching 4 billion ft^3/d (see Figure 3). Today, there is sufficient capacity on Ruby and GTN to supply Jordan Cove with the approximate 1 billion ft^3/d of gas required to produce the initial liquefaction capacity of 6 million tpy. Jordan Cove's business model is a tolling structure. The two sidebars 'Pacific connector Gas Pipeline' and 'Jordan Cove LNG Export Terminal' summarise the new pipeline and facilities (see also Figure 1, on the first page of this article, for visual).

Existing gas supply infrastructure

Jordan Cove and the associated Pacific Connector Gas Pipeline will provide a new gas market for oversupplied gas basins in the US Rockies and the Western Canadian Sedimentary Basin (WCSB). Connecting to a trading hub supplied by two major interstate pipelines provides LNG tolling customers of Jordan Cove with many options to ensure a consistent gas supply. They will have access to existing pipeline gathering systems including the TransCanada, Fortis and Spectra gathering systems to access gas in Alberta and B.C., as well as the extensive US Rockies gathering systems and natural gas liquids extraction plants to access US Rocky Mountain region gas. The net gas oversupply to Malin hub greatly exceeds the new gas

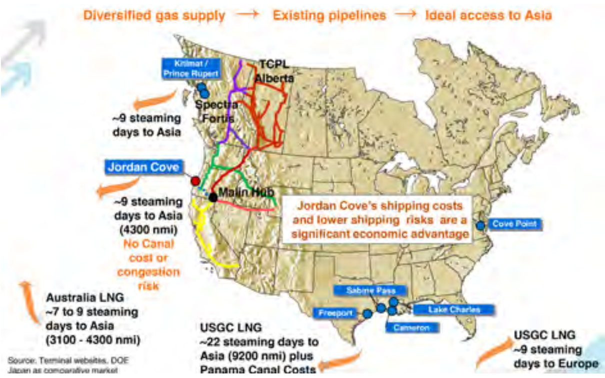

Figure 3. Jordan Cove is highly competitive with unique advantages.

Figure 4. Jordan Cove supply pipeline route map.

demand for Jordan Cove. The Jordan Cove business model is a TCM structure. Supply will come from countless gas fields and E&P operators underpinning upstream gas supply diversity for an LNG buyer. This upstream supply diversity is a unique benefit for LNG tolling customers who have traditionally relied on a single or few E&P operators to supply gas to a liquefaction plant. For example, at Bontang in Indonesia there are multiple gas suppliers and E&P operators while at Tangguh, Malaysia LNG, Brunei, Qatargas and RasGas there is a single E&P operator for each LNG facility (see Figure 4).

In summary, Jordan Cove is situated sufficiently close to Asian LNG markets that the incremental costs (above the costs of converting an existing brownfield LNG import terminal in the USGC to export service) are more than offset by the cost savings of the shorter shipping distance to North Asia. In addition, the location reduces shipping risks by eliminating LNG-shipping-fleet-operational uncertainties of congestion at the Panama Canal and uncertainties associated with the Panama Canal tolls (see Figure 3).

Facility layout

Jordan Cove has a dedicated combined cycle gas turbine co-gen power-plant integrated with a gas treatment facility as the steam-host to provide super high availability of electric-drive compression through four 1.5 million tpy liquefaction trains using proven Black & Veatch Prico technology. As an integrated facility, the overall fuel consumption is designed as less than 8% including all fuel used in power generation. The integrated process/power/steam-host fuel requirements are essentially only boil-off gas (BOG) for all fuel needs including power generation during steady state operations. Steam is used for regeneration of the gas pre-treatment plant to create excellent thermal-efficiency for the overall plant with minimal environmental impact in this thoughtful design integration.

The Jordan Cove location in southwest Oregon is industrially zoned and enjoys local community support.**

Existing deep water port

Jordan Cove will be situated on an existing deep water port that is federally maintained by the US Army Corps of Engineers. The port had some 300 large-vessel calls annually about 20 years ago, but due to timber-industry contraction it now has less than 50 large-vessel calls per year. This leaves plenty of room for the increased traffic of some 90 annual vessel calls by LNG ships. **LNG**

Notes

*The author would like to thank Poten & Partners for the reference JCC oil price and forward gas price strip.

**For more information, visit www.BoostSouthwestOregon.org