Generators’ Appetite to Finance Pipeline Capacity: New England and South Australia

By Nina Hitchins and Gabrielle Maguire

Introduction

Pipeline shippers, such as gas distributors and electricity generators, underpin investment in pipeline expansion by booking firm capacity. The commitment to pay for reserved capacity on the pipeline provides owners with the certainty required to invest in new or expanded pipelines. New England generators typically do not book firm capacity, but rather choose to rely on interruptible capacity. In recent years market commentators and policy makers expressed concern that New England generators’ reliance on interruptible capacity was exacerbating pipeline constraints into the New England during the winter. Some reporters implied that there was risk of a gas shortage in New England, citing the “inability” of gas-fired generators to secure gas supplies. In early 2014, the governors of New England temporarily pursued government intervention by the Independent System Operator (ISO-NE) to approve a tariff on electricity to pay for a pipeline expansion. Today, there is still support for government intervention. The Massachusetts Department of Public Utilities and New Hampshire’s Public Utilities Commission recently allowed electric distribution companies (EDCs) to recover the cost of pipeline capacity contracts, if they can demonstrate it would result in cost savings to ratepayers.

We counter this decision for government intervention by reflecting on the New England market and comparing its purported failures with the perceived success of a distant market: South Australia. In South Australia, gas-fired generators do more than just book firm pipeline capacity, they construct their own pipelines. We find that the cause lies in fundamental differences in weather, the availability of alternative fuels such as LNG and fuel oil, and differences in electricity market incentives (Table 1).
Table 1: Incentives to purchase firm capacity

<table>
<thead>
<tr>
<th></th>
<th>New England</th>
<th>South Australia</th>
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<tbody>
<tr>
<td>Weather related gas demand</td>
<td>Heavily seasonal</td>
<td>Intermittent, but non-seasonal</td>
</tr>
<tr>
<td>Dominant heating load</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>Availability of alternative fuels</td>
<td>Readily available</td>
<td>Limited</td>
</tr>
<tr>
<td>Electricity market price cap</td>
<td>US$1,000/MWh</td>
<td>US$10,300/MWh</td>
</tr>
<tr>
<td>Regulated pipelines</td>
<td>Yes</td>
<td>No</td>
</tr>
</tbody>
</table>

Contrary to some opinion, we find that New England’s gas pipeline market appears to function efficiently; in order to support fuel procurement incentives we recommend changes to the electricity market regulation. In contrast, Australia’s electricity market appears to function efficiently, and we recommend that policy makers reform the pipeline regulation in the image of the successful U.S. framework.

In New England, we find little justification for government intervention to finance pipeline expansion to serve power plants with firm capacity. Rather, we find cause to lift the price cap in the electric energy market to strengthen the market incentives for generators to secure fuel supplies. In this respect, South Australian market outcomes seem preferable. However, deeper analysis reveals an illiquid and inefficient market that can be cured through the creation of valuable and tradable capacity products. South Australia would benefit from adopting those U.S. regulatory principles to facilitate their own competitive pipeline capacity market.

Generators support pipeline expansions in South Australia, but not New England

All power supply choices trace back to incentives. Generators choose between firm capacity and interruptible capacity—pipelines prioritize firm capacity services above interruptible services and charge more for doing so. A generator’s optimal portfolio of capacity services depends on their relative cost and benefit at the margin. The benefits to gas generators of purchasing “firm” capacity are greatest when:

- the chance of the pipeline constraints is high;
- there are no other viable fuel substitutes; and
- the cost of forgone gas-fired electricity generation is large.

Assuming that the only source of generating fuel is pipeline gas, a profit maximizing generator will contract for additional pipeline capacity where the cost of an additional unit of capacity is less than the risked opportunity cost of not having that capacity to meet electricity demand. In other words, if the expected additional revenues from generating electricity are less than the costs of securing additional availability, there is no economic justification to securing that capacity. This is the case in New England.
New England generators take advantage of unutilized pipeline capacity during the summer months by purchasing inexpensive day-ahead gas upstream of the pipeline and utilizing capacity released by firm pipeline shippers for a fee. In the winter, firm shippers, particularly gas distributors, use their capacity themselves, so generators must procure fuel differently by purchasing LNG or fuel oil—or pay high delivered gas prices. South Australian generators have fewer fuel supply options. With no sizeable substitute fuels supplies and hefty penalties for failing to generate, South Australian generators have little choice but to secure gas via firm capacity.

Winter heating drives peak gas consumption and pipeline expansion in New England

The Tennessee Gas Pipeline and the Algonquin Gas Transmission pipeline deliver over half of New England’s gas. Their access to low-cost shale gas from the Marcellus region in Pennsylvania region makes firm capacity on these pipelines particularly attractive. Additional pipelines ship gas from New York and Canada. The New England market also has access to two LNG facilities, at Canaport LNG in New Brunswick and Everett LNG near Boston.

Gas distributors largely determine the capacity of New England pipelines. They must meet customer gas demand during the most extreme of winters (a 1-in-50 winter) to meet heating requirements. These distributors underpin pipeline expansion by signing long-term contracts to pay for firm capacity equal to their customer’s absolute maximum gas needs. Since distributors will not use their full contracted capacity on the vast majority of days, it is available to non-firm shippers, and firm capacity holders re-sell to those non-firm shippers in an unregulated market.
New England gas-fired generation constrains pipelines, eliciting electricity price complaints

New England gas consumption is highly seasonal, where the summer utilization on New England pipelines is about half the winter peak. In winter months gas is used to both heat homes and run generators. Gas consumption can reach 3.9 bcf per day—2.5 times larger than the lowest daily consumption in 2014. Electricity generators, who generally do not purchase firm capacity, benefit from distributors’ unutilized pipeline capacity during the summer months, when demand for heating gas is low (Figure 1).

Figure 1. Monthly New England Gas Consumption, by Sector

Over the past ten to fifteen years, New England’s total gas consumption has increased, expanding existing pipeline use. Gas-fired electricity generation represents a large portion of this growth. Since 2000, gas-fired generation has grown from 14 percent to 40 percent of total electricity generation.4

Since pipeline companies build additional capacity when shippers are willing to commit to long-term contracts, and only gas distributors traditionally make such a contractual commitment, New England’s pipeline capacity has not grown proportionately with total natural gas consumption.5 Generators rely on existing pipelines built only to meet maximum gas distribution demand.
Earlier this year, the Federal Energy Regulatory Commission (FERC) approved an expansion of the Algonquin pipeline, which was financed through precedent agreements with eight gas distributors and two municipal utilities. The pipeline operators proposed an incremental recourse reservation change of $42.57 per month per MMBtu of capacity for firm mainline expansion capacity. Table 2 shows the cost of this firm capacity, spread over throughput, assuming different levels of capacity utilization. At full utilization, the cost of firm capacity is modest. However, shippers realistically need the additional capacity for only short period of time each year.

Table 2: **Algonquin pipeline expansion: Firm capacity cost**

<table>
<thead>
<tr>
<th>Utilization</th>
<th>Load factor</th>
<th>$/MMBtu of throughput</th>
</tr>
</thead>
<tbody>
<tr>
<td>Full utilization all day, every day</td>
<td>100.00%</td>
<td>$1.42</td>
</tr>
<tr>
<td>Full utilization all winter only</td>
<td>25.00%</td>
<td>$5.68</td>
</tr>
<tr>
<td>Full utilization 1 month of the year only</td>
<td>8.33%</td>
<td>$17.04</td>
</tr>
<tr>
<td>Full utilization 10 days a year only</td>
<td>2.74%</td>
<td>$51.79</td>
</tr>
<tr>
<td>Full utilization 1 day a year only</td>
<td>0.27%</td>
<td>$525.61</td>
</tr>
</tbody>
</table>

It is not surprising that, given the other options available, electricity generators do not purchase the firm capacity to meet their needs. Instead, they often look to day-ahead markets to manage their gas needs. The consequence is that, during periods of peak consumption, released firm or interruptible capacity is hard to come by, and many generators must accept the New England delivered gas prices. Not surprisingly, winter pipeline capacity constraints put upward pressure on New England gas prices, such that the Algonquin Citygate (“Algonquin”) price (Boston) far exceeds the Marcellus price (in Pennsylvania) plus transportation costs during the winter. Only those customers with firm capacity on the pipeline can tap into lower prices upstream. Figure 2, below, shows the day-ahead prices in Algonquin and Marcellus (the Leidy hub). The price of transporting gas on an interruptible basis is far less than the price discrepancy in the coldest months.

These higher gas prices are reflected in the electricity market. Gas is the marginal generation technology in New England, and so the bids of gas-fired generators into the electricity spot market often set the market clearing price. As those generators face higher gas prices, they increase their bids and electricity prices increase (Figure 2).
Figure 2. Correlation between New England Gas and Electricity Prices

This situation has been reported widely in the trade press, with some market commenters citing the “inability” of gas-fired generators to secure gas supplies. They do not acknowledge, however, that those same gas-fired generators consciously decided not to purchase firm capacity, and instead choose to compete with other customers in the Algonquin day-ahead market for delivered gas during period of peak demand.

In 2014, the six governors of New England only temporarily advocated for ISO-NE’s intervention in the form of an electricity tariff to finance a pipeline expansion. More recently, however, the Massachusetts Department of Public Utilities and New Hampshire Public Utilities Commission allowed EDCs to recover the cost of pipeline capacity contracts, if they can demonstrate it would result in cost savings to ratepayers. For reasons set out in this paper, EDCs are highly unlikely to meet that condition—despite perceptions to the contrary—and so the intervention is misdirected.

The New England generators prefer substitute fuels to firm pipeline capacity

There is little value in securing firm capacity for generators in New England, due to the availability of LNG and fuel oil and low opportunity cost of forgone electricity generation. New England gas-fired generators have multiple fuel procurement options. While a gas pipeline is the primary source of fuel, generators can also purchase LNG, which is imported at the Everett and Canaport LNG terminals. Everett LNG deliveries nearly doubled in January and February of 2015, relative to 2014, reflecting higher gas prices in New England compared to other LNG consuming regions, such as Asia. About one third of gas capacity in New England is dual fuel, where fuel oil is a substitute for natural gas. The extensive oil pipeline network, liquid market and cheap storage options make oil readily available to New England generators, allowing them to rely on oil when gas is not available.
Indeed, the lower gas and electricity prices in the winter of 2014-2015 reflect increased gas availability relative to the previous year. Gas generators increased their purchases of LNG—instead of firm capacity—to secure fuel supplies. The gas prices in New England were sufficient to attract LNG shipments to the Everett facility in Boston (and away from customers in Asia). Despite 2014-15’s particularly harsh winter, electricity prices did not increase relative to the previous winter.

**The New England electricity market subdues incentives to secure fuel supplies**

The ISO-NE oversees New England’s electricity market, comprising energy and forward capacity markets. The former is designed to set the electricity price equal to the short-run marginal cost of generation. The latter is intended to deliver the long-term capacity requirements by allowing generators to compete to provide electricity generation capacity to the market three years in advance. Committed generators must meet their capacity commitments by bidding that amount into the day-ahead market, and are paid or penalized depending on performance. On the surface, this seems like a well-balanced approach that provides generators with incentives to ensure that there is sufficient generation to meet demand in both the short- and long-term.

However, while the forward capacity market results in sufficient electricity generation capacity to meet *future* load requirements, it does not provide generators with the incentives to secure long-term, gas supplies to fuel that capacity on an ongoing basis. Unlike the vertically integrated gas distribution market, generators do not have an obligation to serve and the capacity market does not correct for this. This results in idle electric capacity at periods of extreme peak electricity demand. In turn, the ISO-NE has attempted to further encourage securing fuel supplies by introducing changes to the forward capacity market with its pay-for-performance and winter reliability programs.

Energy markets, rather than capacity markets, would seem to create appropriate incentives for generators to secure fuel supplies. Generators will ensure that they have fuel available if they expect to capture revenues associated with high electricity prices, even if those high prices only occur for a very short period. These incentives tend to be eliminated if the possibility of high revenues is removed through a price cap.

The ISO-NE is responsible for enforcing an energy price cap set by the FERC of $1,000/MWh. The cap is substantially lower than the value of lost load (VoLL), which some analysts estimate is between $9,000–$14,000/MWh. With a price cap, generators are unable to bid into the energy market at prices which consumers are willing to pay, and there are minimal incentives for electricity generators to secure fuel supplies.

In recent years, the price cap has risked electricity market reliability. On several occasions the FERC granted requests by other ISOs and RTOs to lift the price cap, in response to surging natural gas prices resulting from peak heating and electrical demand. A permanently higher market price cap would encourage generators to secure fuel supplies and moderate these reliability issues.
South Australian insights shed light on New England realities

While there is some commonality between the New England and South Australian markets—the electricity, gas, and pipeline industries are not vertically integrated and both rely heavily on gas—South Australian generators purchase firm capacity on gas pipelines while New England generators do not.

Gas buyers in South Australia procure gas from two major sources and transport it on two major pipelines: the Moomba to Adelaide Pipeline (MAPS) and the South East Australian Gas (SEA Gas) Pipeline from the Cooper/Eromanga Basin and the Otway Basin, respectively (Figure 3).

Figure 3. Pipelines in South Eastern Australia

Major differences between New England and South Australia include (1) weather, (2) the rigidity of pipeline regulation; (3) electricity market structure; and (4) the availability of alternative fuel sources. These factors encourage generators to participate differently in the pipeline market.
Gas-fired generation supports renewables in South Australia

Pipeline flows in South Australia, as in New England, are also driven by the weather—but not freezing temperatures. South Australian residential and commercial consumption, which is generally for minimal heating and cooking needs, only comprises 11 percent of gas consumption. Instead, extreme high temperatures during the summer months drive the use of air-conditioners and the demand for gas-fired electricity generation, which accounts for 52 percent of South Australian gas consumption.

Gas-fired generation comprises half of the installed capacity in South Australia—the same penetration as New England. Solar and wind comprise the majority of the remaining installed capacity (30 percent of the total). Unfortunately, renewable generation output is minimal at times of cloud cover and still air. On those days, renewable generation is far less than installed capacity, and gas-fired generation makes up the difference. South Australian electricity generators’ gas demand fluctuates considerably, reflecting their constant ramp-up and ramp-down of generation to keep up with variations in renewable energy output. This means highly the utilization of the MAPS is highly variable, with the pipeline’s operator planning and contracting according to maximum hourly quantities, rather than maximum daily quantities. During peak utilization gas-fired electricity generators operate at full speed to meet the heightened electricity load from air-conditioners, while simultaneously supplementing generation from underperforming renewables.

South Australian generators finance pipeline expansions

South Australian generators are willing to purchase firm pipeline capacity because fuel substitutes are prohibitively expensive and the cost of failing to generate can be overwhelming. While gas-fired power stations may have dual fuel capability, fuel oil is considerably less accessible and transported by truck. Higher delivered fuel oil prices reflect Australia’s proximity to higher priced Asian crude markets and substantial transportation costs.

South Australian generators stand to profit a great deal from periods of peak electricity demand and low renewable energy output. South Australia’s electricity market is an energy-only market; generators receive revenues from the sale of their electricity in a spot market. The price cap is set at the VoLL, A$13,100 (US$10,300) and it is not unusual for the spot price in the South Australian electricity market to exceed $1,000/MWh. On the 28 January 2009, a heat wave caused the spot price to reach A$9,999.77 for 2.5 hours. During that period alone, a 1,000MW generator could have earned just under A$25 million (US$19.6 million). The opportunity cost of being unable to generate is extremely high, and generators have a strong incentive to secure fuel supplies for the generally non-seasonal peaks that they face (as compared to New England).
The incentives for electricity gas-fired generators to secure gas supplies extend beyond purchasing firm capacity to directly investing in said capacity. Electricity generators in South Australia have underpinned pipeline expansion and construction. Pelican Point Power, TruEnergy and Origin Energy, all electricity generators, formed a joint venture to construct the South East Australia Gas Pipeline (SEA Gas Pipeline). The 314TJ/day pipeline extends 680km, cost A$500 million and commenced operation in 2004. The cost of forgone gas-fired electricity generation was sufficient to motivate generators to invest in pipelines on their own.

**Beneficial regulatory reform in New England’s electricity market and Australia’s pipeline market**

Our analysis suggests that New England generators do not have strong incentives to secure firm transport for gas supplies. There is little evidence of a market failure in the pipeline market and therefore little evident justification for government intervention. Instead, the need for regulatory reform would appear to lie in the electricity market. New England policy makers need only look to South Australia to appreciate the incentives created by a high energy price cap. An upward revision to New England’s price cap would help to improve the security and reliability of both gas and electricity markets.

South Australian generators are readily purchasing and building pipeline capacity. On the surface, the lack of Australian pipeline regulation has supported pipeline use by allowing pipeline owners to grant shippers request for bespoke pipeline contracts. Pipelines operators in South Australia are not obligated to set prices according to the cost of service and instead, are able to negotiate the capacity contracts terms. However, this approach unintentionally hindered the secondary capacity market by limiting the availability of standardized capacity products. The absence of an open and efficient secondary trading stifled the development of a liquid and efficient gas market.

The Australian gas market would benefit from stringent U.S. inspired regulatory principles, which:

- mandate that pipelines operators have no conflicting interests elsewhere in the gas supply chain, such as gas production, distribution or retailing or consumption—fortunately, few such conflicts still exist in Australia;
- require that pipeline operators conform to a transparent “uniform system of accounts”;
- establish capacity licensing and cost-based tariff regulation of the pipeline industry;
- define the physical transport rights that pipeline companies sell with sufficient precision to allow those rights to become tradable property in a competitive market in those rights; and
- require that all capacity trades occur on a public platform with transaction details.
Combined, these components facilitate pipeline investment while permitting the whole pipeline system to embrace competition both in (1) the construction and expansion of licensed, regulated capacity and (2) the use or re-sale of that capacity by those connected to it. Such regulation facilitates pipeline investment to construct the efficient quantity of pipeline capacity by regulating new pipeline entry, preventing destructive rivalry and permitting pipeline owners reliable and compensatory profits based on long-term shipper commitments. At the same time, such regulation ensures that those who trade in the gas commodity pay the market price including the market price for transporting it from one location to another.

A proposal to overhaul the Australian pipeline regulatory framework is gathering momentum. A proposed revised framework resembles the U.S. market, which has proved to be fundamental to the establishment of a liquid market for gas, and derivatives markets that enable gas market participants to manage risk. Interestingly, some U.S.-based consultants advising the Australian energy market rule maker highlight the “market failure” observed in New England as evidence of that the U.S. regulatory approach to pipelines could be failing. We disagree and contend that Australian would benefit greatly from U.S.-style pipeline regulation.

**Conclusion**

U.S. gas pipeline markets would appear to function more efficiently than their Australian counterparts, however, U.S. electricity markets face somewhat of the reverse. Firm pipeline capacity provides a certain value to customers, and shippers will only purchase such capacity when benefits exceed costs. In New England, the benefits of firm capacity are squandered by an electricity price cap that does not come close to VoLL, misaligning incentives in the electricity, gas and pipeline markets. By contrast, the Australian pipeline system is appropriately utilized since its value determines the appropriate capacity to meet peak demand. Unfortunately, the Australian gas market is stifled by the limited secondary capacity trading—an unintentional result of light regulation that allows pipeline operators to sell non-standardized capacity products.

There appears to be little justification for government intervention to finance pipeline expansions in New England, but there is significant evidence to support straightforward regulatory intervention in the electricity sector. South Australia, for its part, would benefit from adopting a pipeline regulatory policy similar to that of the U.S. to facilitate a competitive gas market.
Notes


3. Alternatively, “interruptible” capacity may also be purchased from the pipeline company—a service that competes with released capacity.


5. Few generators have secured firm capacity on the major pipelines. Kleen Energy in Middletown Connecticut is one such generator. Kleen Energy has signed a fifteen year contract for differences with Connecticut Light and Power to provide capacity into the market that supports its purchase of 251 mmcf/day of firm Algonquin capacity.


8. Excluding a negative electricity price event in late 2014.


12. The New England Independent System Operator has introduced a “Pay for Performance” scheme for the capacity markets, which is designed to mimic an energy only market with a very high spot price cap. The plan is yet to be fully implemented and market participants are skeptical that design will deliver the intended incentives. Matthew White, “FCM Pay for Performance: Enhancing Capacity Markets to Improve Resource Performance and Investment,” May 2014, http://www.pjm.com/~media/committees-groups/task-forces/gestl/20140521/20140521-item-07-b-iso-ne-fcm-fpoverview.asx.

13. The energy price cap is determined by the FERC to protect against market power. “The mitigation procedures in the RTO and ISO energy markets, as set forth in the Commission-jurisdictional tariffs, are based on the premise that in a competitive wholesale electricity market, a resource’s offer will be approximately equal to its short-run marginal cost (including opportunity costs). All energy offers are capped at an administratively determined value of $1,000/MWh, such that, in the absence of market power mitigation, resources are allowed to offer at any price up to $1,000/MWh. If a resource does not have market power, competitive pressure should discipline the resource into bidding offer prices at or near its marginal cost.” FERC, “Price Formation in Organized Wholesale Electricity Markets: Staff Analysis of Energy Offer Mitigation in RTO and ISO Markets,” October 2014, https://www.ferc.gov/legal/staff-reports/2014/AD14-14-mitigation-rtiso-markets.pdf.


15. For example, in January 2014, the PJM requested a waiver to lift the cap last week after natural gas prices jumped to triple digits as heating and electrical demand for the fuel surged. It said that simple-cycle combustion turbines buying gas at those prices would have marginal costs of about $1,200/MWh. The FERC obliged, temporarily lifting the price cap to $1,800 /MW.


22. Australian pipeline operators have some interest in downstream distribution. However, distributors are not shippers. The reatailing function lies with third parties.

23. Such licencing and tariff regulation may not be the same as traditional Australian notions of “coverage”, which requires pipeline operators to submit an access arrangement, based on forecast cost estimates, for regulator approval, every five years.
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