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The Australian east coast gas supply cliff

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ABSTRACT

On Australia's east coast over the period 2013–2016, we forecast that aggregate demand for natural gas will increase three-fold, from 700 PJ to 2100 PJ per annum, while our forecast of system coincident peak demand increases 2.4 times, from 2790 TJ to 6690 TJ per day. This extraordinary growth is being driven by the development of three Liquefied Natural Gas plants at Gladstone, Queensland. In this article, we present our dynamic partial equilibrium model of the interconnected gas system and produce forecasts with daily resolution. We find that absent additional supply-side development, unserved load events will remain more than a theoretical possibility in the short-term due to inter-temporal spatial constraints. In the long-term, with appropriate policy settings in place, additional supplies will be brought to market, albeit at higher than historical prices.

1. Introduction

Australia's east coast gas market, which spans Queensland, New South Wales (NSW), the Australian Capital Territory (ACT), Victoria, South Australia and Tasmania, is undergoing a large demand-side shock. Over the past 10 years, the demand for natural gas has averaged year-on-year growth of 2.1%. In 2013, aggregate demand was about 700 peta joules per annum (PJ/a) with a coincident peak winter load of 2690 tera joules per day (TJ/d). By 2016, just three years later, we forecast gas demand to rise to 2100 PJ/a with a system-wide coincident peak winter load of 6690 TJ/d. This represents a three-fold increase in aggregate demand and a 2.4 *times* increase in peak load—driven by the development of three Liquefied Natural Gas (LNG) facilities in Gladstone comprising 6 trains, each with theoretical ex-field loads of between 250 and 290 PJ/a. We are unaware of any mature, large-scale national energy markets experiencing a three-fold increase in aggregate demand in such a short period of time. The first of the LNG trains will be commissioned in the fourth quarter of 2014, with the balance of the six trains commissioned in rapid succession thereafter.

The history of LNG developments can be traced back to discoveries of large reserves of Coal Seam Gas (CSG) in Queensland.[3] Queensland has been highly successful in developing its gas industry with proved plus probable (i.e. 2P[4])

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3 The CSG 'resources' were known to exist at least as far back as the 1980s. Advances in drilling technology enabled the resource to be booked as economically recoverable reserves during the 2000s.

4 1P or proved reserves are those thought to be *reasonably certain* (i.e. 90% confidence limit) of being recovered (i.e. production wells have been drilled). 2P or proved plus probable reserves have a 50% confidence limit (i.e. commercial gas flow from a pilot well has been demonstrated as a stabilised flow over several months for a CSG well). 3P or proved plus probable plus possible reserves have a 10% confidence limit of being recovered.

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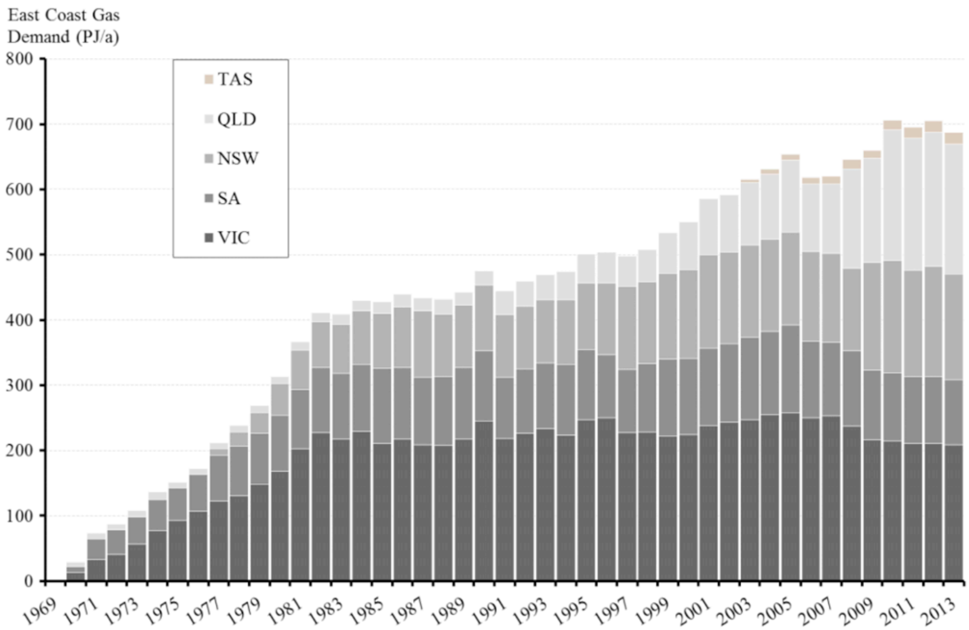

Fig. 1. East Coast aggregate final demand for natural gas—1969–2013.[8]
Source: AGL Energy, Core Energy, EnergyQuest, esaa.

reserves escalating dramatically from 3400 PJ in 2005 to 41,200 PJ by 2013. During this discovery and appraisal phase, it was evidently clear to resource owners that the east coast gas market was not sufficiently large enough to enable the monetisation of reserves in suitable timeframes and at the scale necessary to maximise profit, and so developing an export market for natural gas in the form of LNG was a logical strategic solution. Not only would it result in the rapid expansion of aggregate demand, but would also have the benefit of linking domestic gas prices, historically *ca*$3[5] per gigajoule (/GJ), to the north Asian export market price of *ca*$6–9/GJ equivalent ex-field 'netback price' over the medium term (Simshauser et al., 2011). The practical evidence is that this strategy has worked. Forward gas prices have risen beyond the top-end of this range, and aggregate demand is now trending towards 2100 PJ/a. For Queensland, LNG developments are forecast to produce $850 million per annum in state royalties and taxes once the industry is fully operational, along with 18,000 jobs and add $3 billion per annum to Gross State Product.[6]

There are two policy implications associated with these developments. First, Australia will become one of the world's largest exporters of LNG. As a highly capital-intensive industry with largely irreversible investments, the importance of stable and predictable policy frameworks and minimisation of regulatory risk (in order to maximise welfare) is heightened considerably. Second, large Commercial & Industrial (C&I) gas consumers on Australia's east coast are likely to be exposed to international gas prices for the first time. The development of the LNG industry has resulted in considerable debate on the potential impacts of higher prices on C&I gas consumers. Industry advocacy bodies such as 'Manufacturing Australia' – which represent these consumers – have argued forcefully for market interventions, principally the introduction of a domestic gas reservation policy which would have the effect of forcing gas producers to supply a certain percentage of their output to local industry. Gas producers, unsurprisingly, have argued against retrospective gas reservation policies. Thus far, policymakers on the east coast have not intervened in the market.

What has been missing from this debate is a quantitative assessment of the nature of the problem—virtually all forecast modelling of the gas system has been done on an annualised basis. In this article we present a dynamic partial equilibrium model of the east coast gas system with daily resolution over the five-year period 2014–2018. Our model solves for differential equilibrium conditions given binding constraints associated with maximum theoretical field production, shipper nominations, pipeline capacity and storage facility limits. We focus specifically on infrastructure augmentation and field production given our aggregate load forecast—thereby enabling us to identify any unserved loads. Our analytical procedure is consistent with what Joskow (1976) has loosely described as the 'British Approach' to energy system modelling.[7]

5 All financial data are expressed in Australian Dollars unless otherwise specified.

6 See Queensland Government at http://www.industry.qld.gov.au/lng/key-points.html.

7 As Joskow (1976) observed, the British approach tended to focus on optimising the supply-side for a given load curve. The American approach tended to use a homogeneous technology and focus on periodic and shifting loads. The French approach focused on optimising the supply-side given stochastic demand and hence represented a combination of the British and American approach (and pre-dated both). See for example Turvey (1968), Steiner (1957) and Boiteux (1949, 1956) respectively.

8 Note that Townsville demand, which is isolated from the existing east coast interconnected grid, has been excluded from this analysis.