Eastern Australian Gas Market Outlook: Options for Meeting Demand Growth

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INTRODUCTION

In recent times, a great deal of debate within the Australian gas industry has centred on the question of whether or not there is a genuine need—or indeed any economic justification—for the supply of natural gas from remote sources such as PNG or Timor Sea into eastern Australia. On the one hand, some have argued that supply from existing domestic sources and new field developments adjacent to existing sources, together with significant expansion of coal seam methane production, will be sufficient to meet Eastern Australia's requirements for many years to come. Others have put the case that, even allowing for substantial increases in production from existing conventional sources and coal seam methane fields, additional large-volume, low-cost sources of supply will be required to meet demand growth.

The answer depends fundamentally on the question 'How much is enough?'—a question for which the answer is far from clear. In the first place, one needs to think about the concept of *demand*. How much gas will the market 'need'? The question can only be answered in the context of assumptions regarding the *price* at which the gas is offered. It is a common enough concept—but often overlooked—that price and demand are inextricably linked: there is much more demand for cheap gas than there is for expensive gas. It is rare, in fact, to find demand forecasts that explicitly state the underlying assumptions about pricing.

The issue is important, because it is an economic truism that supply and demand will always find a balance: it is common to think of current demand as the amount that is currently being sold, but quite clearly that amount would change if the price at which supply were offered were to rise or fall. When available supply is limited, unmet potential demand will be dissipated through the operation of the price mechanism. The dissipation of excess potential demand occurs through a number of mechanisms: consumers switching to other, more cost-effective fuels; new gas-dependent projects failing to proceed, or moving ahead in modified form; end-users reducing their level of gas demand either by directly modifying their usage patterns or by pursuing more vigorously efficiency improvements aimed at reducing gas use.

This paper examines the question in terms of *potential demand*—that is, the amount of identified demand that could emerge *if sufficient supply were available at the prices required by the various market participants*. In developing our views on potential demand, ACIL Tasman has adopted a relatively conservative stance with regard to new project developments, and in particular concerning the extent and pace of growth in demand for gas-fired electricity generation. Our total potential demand forecast for the Eastern Australian states of some 1050 PJ/a by 2022 (compared with around 570 PJ/a at present) is conservative when viewed against official forecasts such as those published by the Australian Bureau of Agricultural & Resource Economics, ABARE (Dickson et al. 2003).

Drawing on extensive modelling of the gas supply-demand outlook for eastern Australia, this paper demonstrates that reliance on existing gas supply sources is unlikely to satisfy potential demand growth at these levels, even if augmented by new discoveries in established producing basins, anticipated new project developments in Southern Australia and expanded CSM production. We would expect under these circumstances to see supply peak at around 780 PJ/year.

The results of course depend on what is assumed about the capacity of existing supply provinces and CSM expansion to continue to increase output over the long term—in our analysis, a 20-year timeframe. The question is not so much whether production capacity can continue to grow, but whether it can do so and remain viable at the prices currently prevailing in the market.

MODELLING SCENARIOS

The analysis examines supply/demand and weighted average wholesale price outcomes for four different supply scenarios:

- A *Base Case*, under which there is significant expansion of production capacity from existing basins, new field developments in the Gippsland, offshore Otway and Bass Basins, and at least a five-fold expansion in CSM production capability in both Queensland and New South Wales. The Base Case assumes no connection of major new northern supply sources to Eastern Australia;
- A *'With PNG Case'* which adopts identical assumptions to the Base Case with the sole exception that gas from Papua New Guinea is assumed to become available through pipeline connections to Weipa, Townsville, Mt Isa, McArthur River and Gladstone (via a mid-line connection to the Duke pipeline) from 2007;
- A 'With Timor Sea Case' which differs from the Base Case only in that it assumes connection of a major new Timor Sea producer to East Coast markets via transmission pipeline links to Mt Isa and Moomba by 2009; and
- A 'Transcontinental Pipeline Case' which investigates the impact of a transmission pipeline connection from the NWS to Moomba by 2012.

MODELLING RESULTS

When compared with the Base Case results, each of the major northern supply options is found to significantly boost overall supply levels in Eastern Australian markets, and to impact positively on average cost of gas in those markets, particularly by enabling maintenance of supply to less price tolerant consumers such as intermediate load power generators and major industrial plant. The impacts are, however, quite different when viewed on a regional scale: because of the assumed configuration of the transmission pipeline system associated with the PNG gas project, the Queensland market is most strongly affected by this option. The Timor Sea and Transcontinental Pipeline Cases, on the other hand, have the most pronounced effects in South Australia and New South Wales.

Even in areas where a particular northern gas source may have little if any effect in terms of direct sales, it may boost total levels of market satisfaction in the area in question through displacement of gas from other sources, in other regions. Thus, for example, the uptake of northern gas in New South Wales may displace Gippsland Basin supply, making more Gippsland gas available to meet demand in Victoria or Tasmania.

Pricing impacts are less predictable because there are two potentially countervailing effects in play. The most commonly observed outcome is a lowering in average wholesale delivered gas prices brought about by increased competitive discipline in the market. Even where the northern gas source does not physically make the supply, its availability as an alternative commonly acts to constrain the prices sought by other suppliers. However, the modelling results also reveal circumstances where northern supply results in localized increases in average prices. This situation comes about where relatively high-priced loads, that otherwise would not be able to obtain gas at all, are supplied as a result of the introduction of the new source.

Of course, a lower average price does not mean that every consumer sees a price reduction. Under the modelled outcomes, the introduction of a northern supply source means that some consumers are able to obtain more gas than they otherwise could: no consumer pays more than they otherwise would; and some consumers obtain cheaper supply.

IMPLICATIONS

There is no doubt that, all else being equal, the economically rational development pathway for the Eastern Australian gas industry would see available sources near at hand developed in preference to those further afield. To do otherwise would result in needless costs incurred for transportation of gas over unnecessary distances. However, in this context, the qualification *all else being equal* has particular significance: the general principle holds true only if the costs of production of the nearby source are similar to the more distant alternative. Where the distant source can supply gas profitably at ex-field prices significantly lower than the nearby source, it has the capacity to absorb additional transportation costs.

The major challenge for any large-scale greenfields development distant from markets is to secure the necessary 'critical mass' of customer commitment. This has been clearly demonstrated in recent times by the difficulties experienced by the PNG gas project in bringing together sufficient foundation customer volumes to enable the project to move forward with confidence. Such difficulties are by no means exceptional: they are in fact the norm. The history of many large-scale resource projects (not only gas), both in Australia and overseas, has been one of repeated delays and deferrals while the project proponents attempt to aggregate sufficient market to proceed.

The problem is exacerbated in Eastern Australia because of the relatively immature nature of our gas market: a 200PJ/a project could be absorbed into the US market almost without being noticed, whereas in Eastern Australia such a project needs to assemble a customer base equal to around one-third of the total current market.

Thus, while it is clear that Eastern Australian gas consumers would benefit from access to large northern gas developments in terms of both competitive supply alternatives and price discipline in the market, the incremental development of supply from existing sources of conventional gas and CSM makes the task of achieving critical mass even more difficult.

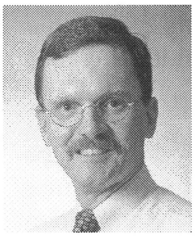
This is the conundrum faced by all the large incremental development projects: that while the market opportunities may look enticing when viewed in prospect, they constantly recede as incremental supply from proximate sources meets the most immediate market opportunities.

The 'easy' and low-risk option is to follow the incremental development pathway, accepting that long-term growth in the gas sector may be constrained as a result. The alternative will require a more risky, but potentially more rewarding 'leap of faith' on the part of those who stand to benefit from new large-scale supply developments. Those beneficiaries may include producers, consumers and governments.

REFERENCE

DICKSON, A., AKMAL, M. AND THORPE, S., 2003—Australian Energy: National and State Projections to 2019-20. ABARE Report 03.10 for the Ministerial Council on Energy, Canberra, June.

THE AUTHOR



Paul Balfe is an Executive Director of ACIL Tasman. He has more than 25 years experience in the energy and resources sectors, and has overall responsibility for ACIL Tasman's gas business including the development and commercialisation of ACIL Tasman's *GasMark* model and its application to strategic and policy analysis throughout Australia and in New Zealand. Prior to joining ACIL Tasman, Paul held a number of senior executive positions in the Queensland Department of Minerals and Energy. He has worked extensively on gas industry matters: particularly gas policy reform issues; gas market analysis; gas pipeline developments, acquisitions and disposals; and gas project commercial analysis. He has also acted as an adviser to both government and corporate sector clients on regulatory, technical, economic and commercial aspects of Coal Seam Methane development.