Energy Market Issues for Cogeneration, Project Development

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Abstract

The electricity and gas market deregulation, reform and open access to transmission (of gas and electricity) has encouraged substantial private sector investment. This is directly observable with some 1350 megawatts (MW) of new generation capacity committed, commissioned or under construction since 1995.

Cogeneration has played a significant role in this new investment bubble. Recent projects include Kinleith, Te Awamutu Dairy, Te Rapa Dairy, Bay Milk Dairy, BHP NZ Steel Limited, Kiwi Dairy and Kapuni Gas, a total of 264 MW. This sudden burst of interest and commitment to cogeneration raises a number of issues in regard to their commercial durability in what is now a very uncertain energy market.

The substantial surplus of new generation committed to the New Zealand market suggests that there will now be strong downwards pressure on electricity prices. This is a somewhat different prognosis for electricity pricing than may have been the case two or three years ago.

The potential for power companies to embed cogeneration plants within their networks, enhance the value of existing local hydro generation and reduce or avoid transmission charges has also encouraged cogeneration development. However, Transpower's pricing methodology raises a number of risks for embedded plants.

The rush to invest may also have been encouraged by uncertainty of gas reserves. On face value, the Maui field has dominated the expected economic life for gas fired projects and raised the spectre of a shortage pricing model for gas beyond 2000.

Finally, there are some challenging commercial optimisation trade-offs between the size of cogeneration plants to obtain optimal economic and technical efficiency and maximise value for the host, yet provide the necessary level of reliability to satisfy host process requirements and to avoid transmission charges.

In today's electricity and gas market cogeneration investments are not for the faint hearted.

Introduction

Cogeneration has raised its profile dramatically in the last five years. Prior to the energy sector reforms in 1987, there were relatively few cogeneration projects in existence and they were generally of limited scale. In 1987, with electricity deregulation, there was still no resurgence of interest in cogeneration investment even though private sector capital could readily flow to this sector. To some extent this may have been impeded by the presence of a large dominant generator. It may have also been impeded by the then, well publicised surplus generation capacity, and Electricity Corporation of New Zealand's (ECNZ) pricing policy of reducing wholesale electricity price levels in real terms.

The deregulation of electricity was followed more slowly by changes in the gas sector. Petrocorp, the state owned petroleum operation was privatised and Natural Gas Corporation (NGC) emerged as a separate gas wholesaler and transmission business. NGC began to prepare itself for unbundled tariffs for gas supply and transmission service, as well as developing industry debate on open access.

It was not until about 1994 that it became apparent that significant decisions on major cogeneration projects were in the offing. By this time the surplus in the generation system had largely been mopped up and ECNZ had been actively campaigning publicly that electricity prices would have to rise to justify the next investment in generation. Up to that time coal fired generation plants and even gas combined cycle technology, would have required significant real increases in wholesale electricity prices, lasting some 10-15 years.

Between 1994 and 1997 major cogeneration projects were announced. These included:

- A 34 MW plant at Kinleith pulp mill, constructed by ECNZ.
- A 52 MW peak (26 MW base load) plant at the Te Awamutu dairy factory, based on a relocated Whirinaki gas turbine, promoted by ECNZ.
- A 10 MW project at Bay Milk dairy factory sponsored by BOPE.
- A 40 MW joint venture between Todd and Kiwi at the Hawera dairy factory.
- A 65 MW project at BHP New Zealand Steel.
- A 40 MW project at the Te Rapa dairy factory to be built by Contact Energy.
- A 25 MW project at the Kapuni gas treatment plant sponsored by BOPE and NGC.

These projects added some 266 MW of new generating capability to the electricity system. During the same period a number of other major electricity generation projects were also announced. These included the Southdown 115 MW combined cycle project, the Taranaki 350 MW combined cycle project, Contact Energy's Otahuhu 400 MW combined cycle project and ECNZ's Manapouri Tunnel expansion of 160 MW.

It is curious to note that all of the cogeneration projects identified above were implemented at host sites that had been in existence for many years. Why had the projects not come forward earlier if they had sound economic fundamentals?

Maybe the underlying economic drivers to these projects were enhanced by optimistic future price expectations. Perhaps the risks of buying wholesale electricity were further sharpened with the split of ECNZ into Contact Energy. Buying risk was further identified by development of the wholesale market, coming into effect in 1996. Maybe the formation of a market allowed projects, whatever the reason, to reach an economic scale and obtain wholesale prices, rather than ECNZ marginal cost, for exported electricity. Security of supply and price risk hedging may well have been a significant stimulus in some of the above projects.

The New Electricity Market

With the spot market in 1996 came a fundamental shift in risk. Prior to 1996 ECNZ controlled 96% of the generation market and largely internalised hydrology and supply balance risk in its hedge pricing. Although a spot market existed it covered only a small quantity and was always under suspicion because it was based on an ECNZ administered price. However, the spot market was a genuine attempt to create a transparent price setting mechanism that would represent short, medium and long term supply risk.

The new fully developed electricity spot market has created a fundamental shift in risk from the `benevolent' ECNZ pricing mechanism to the purchaser. The purchaser now has to choose the extent to which spot price risk is covered by hedge contracts at fixed prices. When lakes are full and inflows are strong, there may be significant savings to be achieved through buying on the spot. However, the risks of getting caught unhedged when hydro inflows are low and lake levels fall is not symmetrical and spot prices can rise very high during hydro shortage.

Perhaps cogeneration host companies who have supported projects have been extremely aware of these risks and have covered these risks, not by a long term hedge policy, but by the contracting or investing in cogeneration plant on site.

Supply and Demand

The cogeneration investments, together with other industry investments have added some 1350 MW or more of new capacity to the electricity market. If the electricity market is working correctly, one would anticipate that this substantial capacity increase will put downwards pressure on both spot and hedge prices over time. There are growing signs that a downward trend in wholesale price is occurring.

It is worthwhile to examine the extent of the likely oversupply position in the New Zealand electricity wholesale market. The plant identified above is nearly all base load and will add some 10,000 GWh or more of baseload energy capacity to the market. New Zealand has never

experienced such an energy capability surplus, even during the post oil shocks of the 1970s. However, that capacity is liable to be substantially reduced as some older thermal plants become uneconomic as a consequence of the spot and contract market price reaction to such a surplus.

The advent of the spot market has allowed major consumers, who are aware of their electricity cost to take a direct stand in the electricity market for their wholesale supplies. The current investment cycle is a good example of the opportunity that such a buyer faces. However, cogeneration hosts who have contracted long term for electricity from their site plant may well be in a position where their contract prices are well above market trends for a period of some years. While the cogeneration plant may have looked attractive in 1994 or 1995, who could have anticipated such a significant burst of investment?

Reform Uncertainty

Also overhanging the current electricity market is a substantial degree of uncertainty as the government grapples with further electricity reform. The Energy Minister has repeatedly indicated his desire to undertake further break up of ECNZ and to separate power company line and energy charges by some form of structural regulation. At the time of writing this paper, the government's announcements are awaited with interest. However, should there be further disaggregation of power company functions, this will further unbundle line and energy charges for end consumers. Consumers will become even more aware of energy price risk and their relationship with spot prices, than they may be currently.

Further breakup of ECNZ is likely also to have a significant effect on the functioning of the spot market. The current oligopoly structure of ECNZ and Contact is regarded with some scepticism by major industry players. However, with four or five generators actively trading in the spot market and some of the new investments assuming greater significance, we are likely to see a more competitive spot price. Disaggregation of ECNZ on top of the current surplus supply situation, will put greater downwards pressure on prices at the wholesale level.

This is a two edged sword. Owners of cogeneration projects that have not succeeded in securing well hedged positions for their output may find income derived from the spot market falling for some years. On the other hand hosts who have contracted long may find their electricity costs well above market and more importantly, above their competitors.

Transmission Embedding

Cogeneration projects that have been undertaken within Power Company networks may be able to achieve significant transmission embedding benefits. For example, Transpower offers customers a nominated capacity and excess demand tariff structure for its transmission services. This may initially appear an attractive way of reducing Transpower transmission costs. In addition, Power Companies may be able to use their own generating plants and load management in conjunction with cogeneration, to manage transmission costs (and wholesale market peak prices) to achieve significant savings.

On the surface, Transpower savings may appear easily achievable, but in practice this is not always the case. For a start, the cogeneration facility must achieve a reliability level equivalent to the demand reliability required of their host, if it is going to avoid calling on grid capacity. If the cogeneration plant is unable to meet all of the host power requirements, there will be periods when the host may require substantial capacity from the grid. If these periods are significant, excess demand charges would be prohibitive and nominated capacity may therefore need to be sufficient to meet host peak demand. These issues must be considered carefully when designing the cogeneration plant configuration in order to maximise the reduction in nominated capacity, while maintaining a high level of reliability to the host. Clearly, with high levels of redundancy in cogeneration plant, nominated capacity must be sufficient to cater for full export. If the host shuts down, as is the case for seasonal operations such as dairy plants, during the winter, transmission connection costs must necessarily be incurred for export of electricity during peak price winter periods.

Transpower's implementation of its pricing policy is also important when identifying transmission embedding benefits. For example, prior to 1996, Transpower had a rolling 10 year pricing methodology based on historical consumption. This limited transmission bypass benefits in the early years of a project. Transpower now uses a forward looking pricing model. Transpower is still keen to limit bypass and reserves the right to change transmission service unit cost when nominated capacity is substantially at variance to expectation (and the assumptions used in their pricing model).

It is therefore not a simple case of reducing ones nominated capacity to collect embedding benefits when connecting a cogeneration facility into a distribution network.

The issues of transmission charging for embedded cogeneration facilities needs to be well canvassed with Transpower before committing to an investment that depends on transmission savings for a positive economic outcome.

The Gas Market

Most of the cogeneration plants recently committed have been based around natural gas as a fuel. These decisions have also been made based on reserves of the two major fields, Maui and Kapuni. In the case of Maui there has been much debate as to whether it will run its full contract term to 2009. In the case of Kapuni there has been significant uncertainty about access to the reserves during the litigation between the supplier and the buyer of that field. With Maui such a dominant gas supply in the gas market, and with its contract life due to expire in about 10 years time, the horizon for cogeneration investment is particularly challenging. While rising real electricity prices may have allowed project paybacks inside of 10 years, this may now not be the case. However, there are few gas contracts that have extended much beyond the life of the Maui/Crown contract.

Nevertheless there seems to be a high degree of optimism within the gas industry with regard to reserves. This can be evidenced from the recent major contracts emerging around the Mangahewa Field that is currently being developed by Fletcher Challenge Energy Limited. In addition, the active exploration programme appears to yield significant optimism for further reserve discovery. Even the Maui Field may yield sufficient gas to outlive its Crown contract.

There will be ongoing demand for gas with the presence of Southdown and the large Taranaki Combined Cycle (TCC) and Otahuhu gas fired combine cycle plants. These plants will be looking for gas reserves beyond the life of Maui and cogeneration plants using gas will be looking to do the same.

The long term market appetite for gas is therefore well established and the active exploration programme offers a real prospect of adding further gas reserves.

Reserve life is a critical issue in cogeneration project economics. When the latest burst of electricity generation investments were committed, reserve life appeared quite short as Maui was projected to run out about 2006. However, if further reserves can be proven, there are a number of other cogeneration projects not yet committed that would be economic with secure 10-15 year gas supplies. This is even the case under the current electricity pricing prognosis.

Cogeneration Host Value

The underling reason for implementing a cogeneration project is to create value for the host by either reducing the cost of energy supplies to the host or improving site reliability, or both. However, cogeneration plant is not core business for host operations and, when it involves complex technology, it is not always easily understood. Furthermore the gas and electricity market risks, that must be managed carefully if a project is to produce a successful long term outcome, are not necessarily well understood by the host.

Cogeneration projects involve a tied dependency and a long term relationship between host and sponsor. It is therefore critical, in my view, that the plant should be configured to maximise total value and the commercial contracts around the plant should share that value equitably.

These reasons alone justify the use of a partner skilled and competent in the energy markets in which their cogeneration business must compete.

It is therefore disappointing to see a number of projects that have not created as much value for the host as was potentially available. It is my experience that where hosts have not been fully informed on the nature of the project or the market opportunities that the project might create, the host has invariably created value for the project sponsor and has not captured as much of that value as it might be due. Having participated in a number of projects, on both sides, it is my observation that the project sponsor is often focussed on technical and thermal efficiency to the exclusion for creating value for the host.

There have been cases where small, lower efficiency gas turbines have been used for reasons of reliability and to more closely match host heat and electrical requirements. It is my contention that such projects suffer from a loss of economies of scale and do not realise full potential value.

Larger more efficient gas turbine generator sets, sized, or oversized, to provide the heat energy requirements of the host, necessitate the export of electricity. However this electricity is more likely to be competitive in the market and in addition provides opportunities for the host and sponsor to extract maximum value from the project. This value may have been forgone by the host through a lack of project understanding.

As the competitive market for generation investment re-emerges from the current surplus, I would anticipate further cogeneration projects also emerging. However, the host sponsor of such a project will need to become well informed on the nature of the project, the prevailing conditions in the gas and electricity markets and the potential for the project to create value if value is to be equitably split.

Conclusion

Cogeneration projects have made a significant contribution to the latest burst of private sector investment in electricity generating facilities. While they offer a significant opportunity to create value for the host, some of the current projects have not delivered on this goal to the extent they are capable of. However, I remain confident that as new gas supplies emerge in the market, and the current electricity surplus creates a more realistic perspective on forward price electricity prices, that further cogeneration projects will emerge. They will only be successful where

they confer substantial value on the host and where they manage the significant market risks now prevalent in both the gas and electricity markets.

Author

Dr Keith Turner has a PhD in Electrical Engineering and 28 years experience in the New Zealand energy sector, holding senior executive positions in Electricity Corporation of New Zealand to 1995. He has participated widely in the Government's reform programme as a member of the 1989 Industry Task Force, member of the Transpower Establishment Board, director of Electricity Market Company and as a member of the Contact Energy Development Group. He is currently a member of the Market Surveillance Committee for the electricity market and runs his own consultancy specialising in the energy sector.