Review of the treatment of embedded generation

REPORT PREPARED FOR THE ENERGY MARKET AUTHORITY AND THE ECONOMIC DEVELOPMENT BOARD

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1 Introduction

Presently in the National Electricity Market of Singapore (NEMS), the *Electricity Act* (the Act) requires that generators equal to or above 10 MW capacity are licensed. For non-exempt generators (embedded or otherwise), licensing imposes a number of obligations and costs. For load customers with embedded generators, many of these costs are imposed on their 'gross' MW or MWh load and generation rather than the 'net' load they take from the system. Some industrial companies have argued that embedded generators should either not be subject to these obligations or should be charged costs on a net load basis only.

Given such feedback, Frontier Economics (Frontier) was engaged jointly by the Singapore Energy Market Authority (EMA) and the Economic Development Board (EDB) (together, the Clients) to undertake a review of the treatment of embedded generation (the Review). Frontier in turn engaged Sinclair Knight Merz (SKM) to assist in certain technical power system engineering aspects of the Review. A Draft Report was prepared and circulated to the industry for comment. These comments have been taken into account and Frontier and SKM are now pleased to present this Final Report.

Tables & figures

2 Framework for the Review

The scope of this Review required Frontier to consider the appropriateness of the treatment of embedded generation in the NEMS on the basis of a 'user pays' principle, using cost-benefit analysis. Both these concepts derive from the requirements of economic efficiency.

Frontier's approach to the review was to focus on whether existing *market* prices and charges adequately reflect the *social* benefits and costs of a decision. Frontier considered appropriate methodologies and options for ensuring this occurs.

Frontier also considered a range of options for the treatment of embedded generation. This included an analysis of 'gross' versus 'net' treatment of various market charges, such as transmission charges, reserve charges and market administration fees. However, we also considered alternative means of supplementing market signals applicable to embedded generation where existing signals do not reflect the wider benefits or costs of embedded generation.

3 Current treatment of embedded generation in Singapore

3.1 WHAT IS 'EMBEDDED GENERATION'?

This report considered 'embedded generation' as referring to generation principally for internal purposes. While this includes on-site generation on the same premises owned by the same party as a large load, various other ownership and locational structures will also be considered. Such generation would typically use an external fuel source (eg gas or distillate). 'Embedded cogeneration' is taken to refer to embedded generation that provides electricity as well as other products such as process steam, hot water and/or chilled water. Such generation may use an external fuel source (eg gas or distillate) or within plant fuel (eg non-saleable refinery product).

3.2 THRESHOLDS AND REQUIREMENTS

If a generating unit is 10 MW or more, it must be licensed and centrally dispatched. Licensing sets minimum standards for participation and can be used to impose obligations. The most relevant obligations for dispatched generators are contained in the Transmission Code, Market Rules and System Operation Manual.

The requirements contained in these instruments may make it difficult for embedded cogenerators to target their maximum level of output, say, for the purposes of producing steam or other industrial processes. This is because the provision of regulation or spinning reserve basically involves changes to generation output that may not serve the needs of the cogenerator's primary purpose, which is to serve an industrial process. As such embedded cogenerators may not wish to provide these services such as regulation and spinning reserve.

3.3 APPLICABLE COSTS AND CHARGES

Under current arrangements for (non-exempt) embedded generators, if a generator is licensed, it and its accompanying load are required to pay a number of fees and charges in the NEMS.

The value of the difference between a fully gross and fully net treatment of embedded generation is estimated to be worth approximately:

- $4.03/MWh on generation output per annum[1]; and
- $140,000 fixed fees per annum (treating the regulation charge on generators as a fixed cost and assuming the customer has one unit).[2]

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1 This is made up of $1.61/MWh (MSS metering data fee), $0.82/MWh (regulation charge), $0.22/MWh (MEUC), 2*$0.208/MWh (PSO fee on generation and load), 2*$0.39/MWh (EMC fee on generation and load) and $0.18/MWh (approximate license fee). NB This calculation excludes an additional $0.82/MWh regulation charge on the first 5 MWh of generation per half hour.

3.4 STAKEHOLDER VIEWS ON CURRENT TREATMENT

Companies with embedded generation or considering investment in embedded generation believed that they should be entitled to a fully net treatment on all embedded generation (ie not just their existing exempt embedded generation) based on the general principle that net metered consumption is the appropriate indication of burden a consumer imposes on the system. These companies also argued that they are 'forced' to sell electricity they produce to the pool, subsequently buy it back and in the process incur market charges for both production and consumption of electricity for self consumption and that electricity generation was not their core business. Finally, they argued that the price of electricity was already very high in Singapore. As businesses, they faced international competition that had access to lower prices.

The licensed generators argued that embedded generators should be treated in a similar manner to standalone generators because they effectively compete to supply (or self-supply) load. There was also a more widespread concern that embedded generators should not be able to avoid paying for the costs they imposed on the network and on system operation. Some were satisfied that load limiter devices (LLDs) would ensure embedded generators could not 'free-ride' on the system, while others were not convinced LLDs would be effective in actually limiting demand in the event of an embedded unit outage.

The EMC was in favour of retaining the current approach towards licensing and charges for embedded generation. This was because the EMC saw most system costs and charges as fixed charges that did not vary according to the activities of embedded generators. In the EMC's view, allowing embedded generators and their on-site loads the benefit of a full net treatment could lead to perverse incentives to embed.

PSO were also consulted to provide technical input but did not express views on the fees and charges applicable to embedded generators. PSO's main concern was that all generators connected to the power system did not compromise power system security and reliability. Increasing numbers of non-centrally dispatchable and non-frequency sensitive generators could impact system security and reliability if they led to insufficient regulation or spinning reserve.

PowerGrid noted that in certain circumstances embedded generators could help avoid or defer the need for network augmentation.

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2 The $140,000 fixed charge was based on the approximate sum of:

- the average 2004 regulation charge applied to a generator running at more than 10 MW output with one unit ($0.82*5MWh*2*8760 = $71,832); plus
- fixed component of annual licence fee ($50,000); plus
- approximate benefit of avoiding spinning reserve charge based on 2004 charge of $16,425/unit/year.

If a load with an embedded generator was regarded purely as a net load, it would avoid these charges.

SP Services had concerns about the metering, settlements and billing implications of certain treatments of embedded generation. In particular, they did not think existing market systems could handle net treatment of network use of system (UoS) charges and gross treatment of market charges. SP Services intended to seek advice on the cost and system implications of such a change.

Appendix A contains more detail on stakeholder initial comments on this review and Frontier's responses to those comments.

Appendix D provides a summary of stakeholders' comments on Frontier's Draft Report and Frontier's responses to those comments.

4 Treatment of embedded generation in other jurisdictions

Generally speaking, most advanced electricity markets (in Britain, Australia and PJM) apply net treatment to loads with embedded generators, at least to some extent. The main reason for net treatment seems to be to avoid or defer network investment and to encourage 'demand-side' response in order to reduce the need for new generation investment. In the case of Australia and Britain, net treatment of some kind has operated since their respective market starts, whereas in PJM it was implemented in 2004.

In addition, Britain offers separate benefits outside its market, to efficient cogenerators to promote fuel efficiency and greenhouse gas reductions. We are not aware of cogenerator-specific incentives to the same extent in Australia and PJM.

4.1 AUSTRALIA

Market fees in the NEM are based on metered (ie net) load or generation at the transmission connection point. Shared network costs in the NEM are recovered almost entirely from loads, although generators do pay shallow connection costs. Under the NEM Rules, embedded generators (those embedded in distribution networks) get paid rebates by distributors for 100% of the avoided customer transmission usage charge that the distributor saves by virtue of the embedded generator reducing the need for electricity to be provided through the transmission network (it is distributors who are billed for transmission charges). The rationale for the 100% requirement is the distributors have a high degree of market power and could otherwise withhold the savings in transmission charges that embedded generators provide to them. For embedded generators serving on-site loads, the savings available are even greater because *all* shared customer transmission charges (ie not just the usage charge) are based on metered (net) load.

Charges for ancillary services are also generally on a net load (or generation) basis. There are eight types of frequency control ancillary services (FCAS) – regulation raise and lower services and fast, slow and delayed contingency raise and lower services. The system requirements for each FCAS service must be forecast by NEMMCO each week in advance for the following week. All of these services are procured through eight separate real-time markets operating through NEMMCO's SPD dispatch engine. The Fast, Slow and Delayed Raise and Lower services are recovered from market participants on a net load or net generation basis. The costs of regulation raise and lower services are recovered from participants through the 'causer pays' methodology.

The cost of contracts for network control ancillary services (NCAS) is recovered only from loads on the basis of a participant's net load. The cost of contracts for system restart (black start) ancillary services (SRAS) is recovered half from loads and half from generators on the basis of the participant's net load/injection.

Therefore, embedded generators can help their loads reduce their non-market ancillary services charges.

There is a range of greenhouse gas reduction schemes in place in Australia. These include:

- Mandated Renewable Energy Target (MRET);
- New South Wales Greenhouse Benchmarks; and
- Queensland 13% gas scheme.

4.2 BRITAIN

In Britain, the British Electricity Trading and Transmission Arrangements (BETTA) commenced in April 2005. Prior to BETTA, the New Electricity Trading Arrangements (NETA) were implemented in 2001, taking the place of the original England and Wales Pool that had operated since April 1990. At the switch to NETA, small generators considered themselves disadvantaged by the new rules. A number of modifications have occurred to lessen this problem and a significant degree of trading consolidation has occurred, but participation in BETTA still remains more onerous for small generators than larger trading units.

As in the Australian NEM, a distinction is made between:

- Generators embedded within distribution networks; and
- Generators not embedded within distribution networks but that serve an on-site load.

Generally speaking, embedded generators enable loads (distributors or on-site loads) to pay lower charges for:

- Transmission Network Use of System (TNUoS);
- Balancing Services Use of System (BSUoS); and
- Elexon (BSC Co) charges,

up to a maximum of 100 MW of embedded generation.

Cogeneration (CHP) and other energy efficient technologies are eligible for a range of benefits in Britain. Some of the main benefits provided are:

- Exemption from the Climate Change Levy (CCL);
- Enhanced Capital Allowances;
- Capital grants for smalls-scale CHP (<1 MW); and
- CHP feasibility programme provides grants of up to 75% of the cost of a detailed feasibility study for projects of 1-20 MW.

A number of ancillary services are procured in BETTA. The key Frequency Response service is broadly equivalent to Singapore's regulation and spinning reserve requirements. Frequency Response requirements depend on:

- Largest infeed currently connected to the system – in other words, the largest contingency;

- Demand on the system – the response requirement is higher in overnight and/or summer, when demand is lower; and
- Dynamic/non-dynamic requirements – the largest loss can be met by dynamic or non-dynamic response, but there is a minimum dynamic response requirement of 300-500 MW dependent on the time of day. There is no specific non-dynamic requirement – non-dynamic response can be used when minimum dynamic requirements have been met and where cost-effective.

4.3 PJM

The Pennsylvania-New Jersey-Maryland market (PJM) has implemented a net load approach in relation to 'behind-the-meter' generation. In order to encourage demand response and the use of behind-the-meter generation in times of scarcity and reduce the cost to market participants that rely to a lesser degree on the PJM transmission system, the PJM Interconnection LLC (the Regional Transmission Organization that operates the PJM network) developed a 'total netting' proposal that was approved by the Federal Energy Regulatory Commission (FERC) in 2004. This allows qualifying market participants to net operating behind-the-meter generation against load at the same electrical location for purpose of calculating charges for energy, capacity, transmission service, ancillary service and PJM administrative fees.

In October 2005, PJM moved towards setting a 1,500 MW cap on the amount of behind-the-meter generation (connected at the distribution level – typically 69 kV and below) to be given net treatment.

4.4 NEW ZEALAND

The New Zealand Electricity Governance Regulations and Rules set out a number of obligations for embedded generators. Under the Electricity Governance Regulations, a business is exempt from registration as a market participant (although not exempt from the other obligations in the Regulations) if it only carries out certain activities set out in the *Electricity Industry Reform Act* (EIRA). These activities include generating solely for its own consumption or consumption of its associates. Therefore, embedded generators may not be required to be registered as a participant, although they must still comply with all the other obligations in the Regulations.

4.5 NETHERLANDS

Cogeneration or CHP plant play an important role in the electricity industry in the Netherlands, accounting for around 40% of installed capacity.

The market rules include a number of advantages for embedded generators:

- small embedded generators (below 10 MVA) do not pay connection or use of system charges, while large generators (including CHP plant) do;
- some small plants embedded within the distribution network sell their output directly to the local distributor, who is obliged to buy it; and

- rules relating to imbalance were adjusted, to enable producers to make final adjustments up to one hour in advance of real time, addressing concerns that embedded and renewable generators were unfairly disadvantaged by the market.

The Government has also provided a set of further measures:

- an increase in the tax credit allowed for new CHP;
- an exemption of CHP electricity consumption from the regulatory energy tax (subject to certain efficiency targets);
- financial support to CHP plant output; and
- an accelerated depreciation program for CHP investments that meet certain efficiency targets.

4.6 EUROPE

The regime for embedded generators and cogenerators varies across Europe (see also Britain and Netherlands above). However, most jurisdictions provide some sort of favourable treatment or benefits for CHP.

4.7 MALAYSIA

The Government of Malaysia expanded its Fuel Diversification Policy to add renewable energy as a fifth source (in addition to oil, natural gas, coal and hydro) in 1999. The 8th Malaysia Plan (2001-2005) announced the intention to generate 5% of electricity (about 600MW) from renewable sources by the end of 2005.

A number of programs have been introduced to encourage renewable and cogeneration, which are likely to benefit embedded generators:

- the Malaysia Electricity Supply Industry Trust Account (MESITA) fund;
- the Small Renewable Energy Program (SREP);
- the Biomass Based Power Generation and Co-generation (BioGen) project; and
- fiscal incentives such as investment tax incentives income tax exemptions and import duty or sales tax exemptions.

4.8 THAILAND

The small power producers (SPPs) program was established in 1992 with the aim of promoting the use of biomass and cogeneration. Under the scheme SPPs with a plant capacity of 90MW of less are entitled to sell their output under a common PPA. SPPs may also elect to sell their electricity to industrial customers located next to the SPP plant.

In July 2002, the Thai Government introduced rules to promote investment from very small-scale producers (less than 1 MW) by offering retail prices for their output and connection to the electricity grid.

Tables & figures

Overall, it can be seen that most advanced electricity markets offer some degree of net treatment for loads with embedded generators. Even in New Zealand, which applies gross treatment, on-site generators generating for self-consumption are not required to be registered as market participants, although they are required to comply with other regulatory obligations.

In summary, most jurisdictions with advanced electricity markets (Australia, Britain and PJM) offer net treatment of transmission and market charges to loads with on-site generators, at least up to particular limits. Most jurisdictions generally also offer some favourable treatment to cogenerators. Full details are attached in Appendix B and the table below outline the results.

Countries	**Net / Gross for Reserve, Ancillary & Market Admin Charges**	**Cap on Net Treatment**	**Date commenced**	**Other schemes/benefits**
Australia	Net	None	NEM start (1998)	MRET scheme NSW Greenhouse Benchmarks scheme Qld 13% gas scheme
Britain	Net	100 MW	Pool start (1990)	Exemption from Climate Change Levy Enhanced Capital Allowances Capital grants for CHP
New Zealand	Gross	-	NZEM start (1996)	Exempt for registration if unit is for self consumption
PJM	Net	1,500 MW cap across entire system	May 6 Order (2004)	NA
Belgium	Unknown	Unknown	NA	Fixed minimum prices for CHP output Priority grid access Moderate back-up network tariffs
Denmark	Unknown	Unknown	NA	Compulsory purchases of electricity from CHP Priority of dispatch for CHP

				Financial subsidies
France	Unknown	Unknown	NA	Long term PPAs Compulsory purchase of electricity from CHPs up to 12 MW
Germany	Unknown	Unknown	NA	CHP exemption from fuel taxes Grid operator required to purchase electricity from CHPs at fixed price Favourable UoS rates
Italy	Unknown	Unknown	NA	Compulsory purchase of electricity from CHPs Industrial gas prices lower than domestic CHP exempt from carbon tax Priority of dispatch
Malaysia	Unknown	Unknown	NA	MESITA financial assistance SREP renewables program Biomass project
Netherlands	Unknown	Unknown	NA	No connection or UoS charges for small CHP plant CHP tax credit Exemption from energy tax (subject to efficiency targets) Financial support for CHP output Accelerated depreciation program for CHP
Spain	Unknown	Unknown	NA	Spilled (exported) electricity paid a premium
Thailand	Unknown	Unknown	NA	SPP program for biomass and cogeneration

Table 1: International treatment of embedded co/generation

5 Generic benefits and costs of embedded generation

Proponents of embedded generators have argued that they should be encouraged due to the benefits they provide. These benefits are, broadly speaking:

- Enable their owners to optimise the production of various forms of utility streams (electricity, steam, chilled water/air), which translates into cost savings for these businesses (embedded **co**generators only);
- Reduce the system resources companies draw from the system, leading to a more efficient electricity system; and
- Provide wider environmental and fuel diversity benefits (embedded cogenerators only).

However, as discussed above, Frontier's approach in this Review was not to estimate *all* the benefits and costs of embedded generators but to evaluate to what extent the benefits and costs of embedded generation are not reflected in existing regulatory and market arrangements (including fees). Such divergences may arise from:

- Environmental benefits of embedded cogeneration;
- Fuel diversity benefits for the Singapore economy; and
- Benefits embedded generators *provide to* the system.

We distinguish between embedded generation and embedded cogeneration where relevant and also between different designs and configurations of plant.

Embedded generators may also *derive benefits from* the system.

5.1 ENVIRONMENTAL BENEFITS OF EMBEDDED GENERATION

The use of embedded generation and particularly cogeneration can provide environmental benefits. The amount of the benefits can vary widely – depending on the nature of the fuel and the extent to which waste heat can be captured. Because environmental costs do not tend to be internalised, the environmental benefits and costs of different energy supply options tend to accrue to or be borne by the community as opposed to the customer or the network/system.

Reductions in resource (fuel) usage and greenhouse gas (GHG) emissions are each a direct function of efficiency and depend on the scale of the plant and how closely matched the electricity and thermal loads are to the selected cogeneration configuration. It may be that GHG emissions either increase or decrease with the adoption of embedded generation: If the value of GHG emissions or GHG emissions savings were, say $26/tonne, an optimally fitted cogeneration plant saving 0.1 to 0.15T/MWh might be credited with an *additional value* of approximately $2.50-$4/MWh compared to buying from the grid. For a non-cogeneration embedded generator, or the limiting case of ill-fitted cogeneration, the plant might impose *additional costs* of $2.50-$4/MWh. Real-life cogeneration plants tend to be somewhere between these two extremes, which must be determined on a case-by-case basis. Details of the calculations are attached in Appendix C.

5.2 FUEL DIVERSITY BENEFITS

Embedded generation that uses waste by-product for fuel (instead of natural gas or distillate) could provide some benefit to Singapore in terms of increased fuel diversity

This benefit may be considered in the context of a gas supply crises in Singapore in which there was a partial reduction in the availability of gas for electricity generation. The ability of embedded generators to produce electricity from other sources could help avoid load shedding and maintain system security in such circumstances. While fuel diversity will certainly benefit the embedded generators (by being shielded from gas supply disruptions), there is a further system benefit relating to reductions in potential load shedding in the event of a gas supply shortfall.

However a detailed analysis of the benefits of fuel diversity is highly case-specific and difficult to fully quantify.

5.3 BENEFITS EMBEDDED GENERATORS PROVIDE TO THE SYSTEM

In general, the distribution of generation throughout the network will provide an enhanced voltage profile compared to the situation where there are only a few large generating centres. This will inherently reduce losses and reduce the requirement for additional voltage control devices.

Hence embedded generation, by virtue of being distributed at load locations, can improve system security by reducing the reliance on large generation centres, reduce network loading and provide local voltage support. Embedded generators may also assist system restart in some cases.

5.4 BENEFITS EMBEDDED GENERATORS DERIVE FROM THE SYSTEM

The network provides an alternate source of supply in the event that embedded generation fails. The network also inherently provides continuous voltage control by means of the Automatic Voltage Regulators on every generator. All of the generators in the network provide a high fault level to embedded generation. The network also provides a stable system frequency, which is essential for many industrial processes. Embedded generators may also benefit from connection to the power system following a system black.

6 Review and assessment of options

The Review and assessment considered:

- Implications of alternative regulatory treatments of embedded generation for the NEMS; and
- Broader implications of alternative regulatory arrangements for the Singapore economy and Singapore's international competitiveness.

6.1 ELECTRICITY MARKET IMPLICATIONS

This section discusses the economic efficiency and system security implications for the NEMS of current and alternative regulatory arrangements, including a comparison of 'gross' and 'net' treatments of market fees and charges.

6.1.1 Regulation

The requirement for regulation is currently a fixed amount, 100 MW based on 'system load'. This suggests that the supply of loads by (increased) embedded generation instead of standalone generation does not necessarily reduce the quantity of regulation that is required in the Singapore system. Similarly, if increased demand were met by more embedded generation, regulation requirements would increase by as much as if the extra load were served by standalone generation. For a given load, the replacement of standalone generation should not affect the need for regulation. Further, the quantity of regulation determined by PSO is in line with the approach used by NGC, in that the British requirement for dynamic response is usually based on a 0.2 Hz deviation (equivalent to about 300 MW change to the demand-supply balance), although it may be higher (up to 500 MW).

<u>Option 1: Gross load</u>

An approach based on gross load (without charging generators at all) would avoid the need to bill generators for a cost that they are likely to pass on through bids and wholesale prices in any case. It should not have any material adverse impacts on the competitiveness of the market or the final costs to consumers. However, it would be likely to require changes to the Market Rules.

<u>Option 2: Net load</u>

Given that regulation is currently charged on the basis of gross load and the first 5 MWh of generation per half-hour, a net load treatment would save loads with embedded generators between approximately \$0.82/MWh and \$1.64/MWh on the quantity of embedded generation compared to the current arrangements. Net treatment gives rise to two main concerns:

- First, a net load treatment may create an incentive for loads to (inefficiently) develop embedded generators instead of buying from the wholesale market. The maximum efficiency loss of a net treatment compared to the current gross treatment would be \$0.82-\$1.64/MWh – the value of the saving outlined above. This is because this is how much extra a potential investor would be willing to pay for an embedded generation option over purchasing from the wholesale market to enjoy the benefits of net treatment, other things being equal. However this is not to say a net treatment *will* lead to the inefficient development of embedded generation, but that it *could*; and

- Second, as the sum of money to be recovered is fixed in the short term, while a net load treatment would not initially affect the $/MWh charges for regulation, in the longer term as system load expanded, a net treatment would involve higher $/MWh charges than under a gross load treatment.

Nevertheless, we note that net treatment is applied in other deregulated markets, such as Britain and PJM. Finally, as with a gross load treatment, a net load treatment would require changes to the Market Rules, with a transitioning period.

<u>Option 3: 'Causer pays' treatment</u>

A more radical option would be to move to a 'causer pays' regime for regulation, as in the Australian NEM. Under this regime, the required quantity of regulation is procured in real time markets, with the cost allocated to those parties in accordance with their causer pays 'factor'. Participants can either have an individual causer pays factor or the residual averaged factor.

In order to have an individual causer pays factor, the participant must have the necessary monitoring and communication systems in place. This involves operating under NEMMCO's centralised Supervisory Control and Data Acquisition (SCADA) system.

For those participants with an individual causer pays factor, the treatment is really neither net nor gross – it is an absolute dollar value billed to the participant each 30-minute trading interval. This amount can typically vary from nil to several percent of the entire regulation procurement cost for the period.

Remaining (non-measured) participants are subject to the residual causer pays factor, which is the average factor for all those participants who either do not have the requisite equipment in place or are loads that choose not to opt into the regime. These participants are billed for regulation services costs on a $/MWh net basis.

The implementation of a causer pays cost allocation methodology for regulation costs in Singapore would raise a number of important issues:

- First, it would make more sense, from an economic efficiency perspective, to charge generators for some of the cost of regulation By way of example, in the NEM, measured generators pay approximately 20-25% of the cost of regulation; and
- Second, loads with on-site generators who chose to opt into the regime by requesting an individual causer pays factor should have that factor assessed – to the extent technically feasible and practicable – on their net load. This is because the monitoring arrangements that would need to be in place under such a regime would be capable of determining the combined (net) effect of that participant's load and generation activities on the overall system frequency and hence the need for regulation services.

Alternatively, if some simpler means of determining the impact or likely impact of a generator (whether embedded or otherwise) on system frequency can be developed and implemented, net treatment for those parties may also be appropriate. However, this would depend on the precise nature of the proposal.

6.1.2 Spinning reserve

The quantity of required spinning reserve in Singapore is based on the largest output of a generating unit. This is similar to the approach that NGC applies in Britain for determining the quantity of firm frequency response requirements, in that it is also based on the largest potential loss on the system.

<u>Options 1& 2: Gross and net cost recovery</u>

Both gross and net treatments are simpler than the current 'modified runway' method. However, given the small size of the Singapore system and the importance of ensuring sufficient spinning reserve, a shift away from the current regime may inappropriately encourage investors to develop larger generators. This could potentially impact system security in the longer run although it is difficult to predict when or by how much. In any case, it may be better to deal with requirements for spinning reserve directly through license conditions.

Net treatment would be more in line with existing treatments in Australia and Britain. It would also provide benefits to investors in embedded generation, which may reflect some of the wider benefits embedded generators provide.

However, as with regulation, net treatment creates two main concerns:

- First, a net treatment could again create incentives to embed when this would not reduce system costs. This could lead to inefficiency if standalone generation or buying from the market is a lower-cost option than embedding; and
- Second, it would benefit loads with embedded generators while impacting other electricity users who cannot use embedded generation.

One important exception to the possibility of inefficiency is if loads with embedded generators had LLDs that prevented loads from drawing power from the grid in the event of a planned or forced outage at the embedded generator. This would help justify a net treatment.

6.1.3 Other market fees and charges

There is a range of other market charges that apply to NEMS participants. These include the PSO and EMC administration fees (presently $0.208/MWh and $0.39/MWh respectively), as well as the MSS metering data administration charge ($1.61/MWh) and the MEUC uplift ($0.22/MWh). The EMC and PSO charges are recovered on a gross load and generation basis. The MSS metering data charge and the MEUC are recovered only from loads on a gross basis.

These costs do not vary significantly with the volume of power delivered through the market or the grid. Therefore, the current means of cost recovery may reflect an attempt to recover these generally fixed costs from as broad a base as possible.

Option 1: Net load

A net treatment of these charges would have two main disadvantages:

- First, a net treatment could again create incentives to embed as system costs are generally fixed. This could lead to inefficiency if standalone generation or buying from the market was a lower-cost option than embedding. In our view, the potential for inefficiency would be greater the larger the unit size that was eligible for net treatment. This is because investors tend not to develop very small units for standalone generation – therefore, the risk of distorting investment decisions at a small unit size is less than at a larger unit size; and
- Second, as the sum of money to be recovered is basically fixed, while a net load treatment would not initially affect the $/MWh charges, in the longer term as system load expanded, a net treatment would cause $/MWh charges to fall at a slower rate than under a gross treatment.

However we note that net treatment is applied in other deregulated markets, such as Britain, Australia and PJM.

Option 2: Price discrimination

Given the essentially fixed nature of EMC and PSO, MEUC, and MSSL costs with respect to system demand, Ramsey Pricing principles would suggest these costs be recovered from those customer groups that are unlikely to by-pass the Singapore market, such as existing loads and generators, particularly domestic loads. Such price discrimination raises high-level policy issues discussed further below.

6.1.4 Network charges

Option 1: Gross treatment

An obvious alternative means of implementing UoS charges is to set $/MWh tariffs on gross load and/or generation. However, such an approach would not recognise the benefits of embedded generation in reducing network loading and potentially deferring or avoiding the need for network augmentation in the long term. We do not think imposing UoS charges on generators is desirable either, because the basis of network planning in the Transmission Code is fundamentally to meet system demand and provide quality of supply to loads.

Option 2: Peak demand charging basis

One alternative to the existing transmission pricing regime is to have loads with embedded generators charged UoS charges on a peak demand (MW) basis rather than net consumption (MWh) basis. This would ensure that those loads that made use of the network – even if only occasionally – paid a charge that properly represented its implications for long run network costs.

We understand that the existing capacity charges (ie those based on MW) are intended to recover costs of the network close to the customer ('driveway' costs) while UoS charges (ie those based on net MWh consumed) are intended to recover more upstream ('meshed') costs. On this basis, it makes sense that UoS charges (recovering the costs of the meshed network) are based on net load, because if there are many embedded generators in operation, on average, only a proportion will be out of service while the remainder will be able to substitute for network expansion. Both Australia and Britain both impose their transmission UoS charges on the basis of net peak load and net peak consumption.

In our view, Singapore's current transmission pricing framework reasonably reflects economic efficiency objectives.

6.1.5 Market participation obligations and expenses

A significant complaint of companies wishing to develop embedded generation is the obligation to become a licensed and registered market participant. While these obligations may seem onerous, embedded generators can have implications for the operation of the overall power system in terms of the need for regulation and spinning reserve.

A key question is whether the registration threshold (1 MW) should be increased to the dispatch and licensing threshold (10MW) or whether all thresholds should be increased even higher. In our view, it seems reasonable for at least the registration threshold to be increased to the licensing and dispatch thresholds. If generators do not impose a material impact on the operation of the power system, such that they are not required to be centrally dispatched, there does not appear to be a strong case for requiring those generators to be settled through the market.

In addition, a specific license condition may be necessary for larger generators (including embedded generators) to remain frequency responsive and provide spinning reserve as well as have AGC if this is not already required by the Market Rules. The imposition of this requirement should be determined by the PSO on a case-by-case basis.

6.1.6 Relevance of ownership and proximity

We have considered the relevance of ownership and proximity for various configurations of embedded generation facilities for the discussion of charges discussed above. The configurations considered were:

- Generation and load on the same premises, with each facility owned by the same party;
- Generation and load on different premises, with each facility owned by the same party;
- Generation and load on the same premises, with each facility owned by different parties; and
- Generation and load on different premises, with each facility owned by different parties.

In our view, the merits and demerits of the various options discussed above for recovering costs do not depend on whether the embedded generator and load are located on the same premises or are owned by the same person. Ownership and proximity of the embedded generator are only relevant to the policy issue of 'what is transmission'.

A policy decision was made in the Singapore reform process for transmission to be separated from generation, to promote non-discriminatory access to the grid and competition. To enforce this Government policy, EMA currently impose the following conditions for a generator to be allowed to supply directly to loads:

(a) the generator and the loads must be located on the same contiguous piece of land; and

(b) the generator, the loads and the land on which the generator and loads are located, must be majority owned by the same party; and

Such conditions have the advantage of simplicity and ease of enforcement. Any further relaxation would be arbitrary and risk creating dispute and uncertainty; and hence should be carefully considered before effecting any change. That said, this is ultimately a policy issue and we do not believe that a small degree of relaxation need necessarily jeopardise the Government's original position.

6.2 WIDER IMPLICATIONS FOR THE SINGAPORE ECONOMY

6.2.1 Environmental and fuel diversity impacts

Many of the benefits of embedded generation are recognised in the regulatory arrangements. However, there are some areas where the benefits of (especially) embedded **co**generators are not reflected in the charges they pay or receive. The key areas where the NEMS does not reward embedded cogenerators for the benefits they could potentially provide are:

- Greenhouse gas emission reductions; and
- Fuel diversity during a gas crisis.

As discussed above, the benefits of greenhouse gas reduction could be worth as much as $2.50-$4/MWh (based on recent European data) for efficient cogenerators that optimally match their loads. That said, the value of GHG emission reductions may be different in Singapore depending on local conditions. The value of fuel diversity during a gas crisis is difficult to measure, because it depends on the probability of such an event occurring.

Nevertheless, whether such benefits should be recognised *at all* is a policy issue for the Singapore Government. However, if they were to be recognised, the options for recognising these benefits are as follows:

- Implement a more comprehensive GHG reduction scheme such as tradable permits or carbon tax;
- Provide an explicit subsidy to cogeneration;
- Offer reduced license fee for cogeneration; and
- Offer limited 'net' treatment of EMC, PSO, MEUC and MSS charges (depending on value of GHG & fuel diversity benefits).

Tables & figures

6.2.2 Competitiveness issues

A key issue raised by several of the companies seeking favourable treatment for embedded generation is the effect on the international competitiveness of Singapore businesses of high energy prices. Embedded cogeneration through its enhanced energy efficiency is presented as an option to help mitigate the high cost of energy. Favourable treatment of embedded generation – such as a net charging approach – was proposed as one means to enable companies implementing embedded cogeneration to partly overcome the cost disadvantage they face against international competitors.

From the perspective of the economy as a whole, it is desirable that investors are not deterred from investing in Singapore because of inefficient regulatory arrangements. Such a philosophy is typically behind moves to reduce tariffs and 'red tape' for business. However if attracting investments could potentially result in reduced economic efficiency, then careful policy considerations need to be made to achieve the optimal outcomes.

Singapore could choose, as a policy decision, to provide limited net treatment to recognise the benefits of embedded cogeneration outside the electricity market and to encourage more embedded cogeneration. Measures such as capacity limits or no export to the grid could be used as means to mitigate any potential distortions in the electricity market. Furthermore some form of net treatment is also in line with practices in other jurisdictions with deregulated electricity market such as Australia, Great Britain and USA (PJM).

Alternatively, given that many of the market fees and charges fundamentally involved the recovery of costs that were either fixed or sunk in the short to medium term, it may be fruitful to consider exercising a degree of price discrimination in recovering these charges. Two options may be worth considering:

- <u>Option 1</u>: Recover EMC, PSO, MEUC and MSS fees and even the bulk of license fees from existing NEMS participants only, and exempt all new participants, whether investors in embedded generation or otherwise; and
- <u>Option 2</u>: Recover EMC, PSO, MEUC and MSS fees and some license fees from domestic and small business consumers only, on the basis that these customers are unlikely to materially curtail their consumption due to higher final prices, and exempt large consumers and generators. In this context, we note that loads with embedded generators are almost certain to be amongst these larger customers.

Both of these options raise difficult policy and implementation issues, particularly option 1. Further, notwithstanding any overall efficiency improvements option 2 might bring, it would almost certainly result in aggregate transfers from smaller Singaporean consumers to larger ones.

7 Recommendations

Frontier has presented various options for the treatment of embedded generation. Ultimately it is a policy decision for the government whether to promote more embedded generation as means to address the high cost of energy in Singapore and to recognise the wider benefits of embedded cogeneration beyond the electricity market in line with practices in other deregulated markets.

In our view, the current arrangements for embedded generation in Singapore are broadly reasonable, within the context of the NEMS. One potential option for change is the introduction of a 'causer pays' mechanism (or something simpler) for allocating the costs of regulation, as has been adopted in the Australian NEM. However, we emphasise that such an approach may involve considerable design and implementation costs and it is not certain that the benefits will outweigh the costs.

Moving outside the NEMS and considering the welfare of the broader Singapore economy, the Government may wish to consider:

- Some sort of favourable treatment for new cogenerators, such as a GHG emissions scheme or limited net treatment to recognise the wider benefits of embedded cogeneration in line with practices in other advanced jurisdictions such as Britain, Australia and USA (PJM); and
- Recovering EMC, PSO, MEUC, MSS and license fee charges from smaller consumers rather than larger consumers, bearing in mind the equity issues this would raise.

Tables & figures

Appendix A – Stakeholder views and Frontier responses

This appendix tables stakeholders' initial comments on the treatment of embedded generation made in written submissions from market participants, as well as Frontier's responses to those comments.

Written submissions were received from the following market participants:

- ExxonMobil;
- Island Power;
- Linde Syngas Singapore;
- Power Seraya;
- SembCorp Utilities;
- Senoko;
- Singapore Refining Company; and
- Seraya Chemicals Singapore.

Stakeholder	Comments	Frontier Economics response
ExxonMobil	1. Embedded cogenerators provide a number of benefits to the system including energy efficiency, lower emissions and supply security. 2. Therefore, efficient embedded cogeneration should be encouraged but the current 'gross load' treatment penalises embedded cogeneration – the NEMS is one of the few markets that applies a gross treatment. 3. Embedded cogenerators are developed to generate power as well as other useful outputs, not to compete with licensed generators. Singapore should develop a non-market generator classification to reduce embedded cogenerators' costs of market participation. Embedded generation should also not be required to be centrally dispatched. 4. Embedded generators should contribute to reserve costs and market fees, but on the basis of net withdrawals from the power system, as this measures the burden a consumer imposes on the system. 5. Policies towards embedded generation applied in Europe should be considered for Singapore.	1. Agree, but the issue is whether these benefits can be captured by participants or whether other incentives need to be provided to encourage efficient investment in embedded generation. 2. See above. It is true that many other jurisdictions apply a 'net' treatment of embedded generation. However, Singapore's individual circumstances should be considered carefully – especially in terms of risks in ensuring sufficient quantities of spinning reserve. 3. We have considered whether a higher MW threshold should apply for registration and licensing and whether requirements should be imposed on embedded generators above a certain MW size to be frequency sensitive and have AGC. 4. See section 6 of this report. 5. It is a broader policy issue whether the benefits of embedded generation should be recognised in Singapore.
Island Power	Embedded generators should be treated and charged in the same way as standalone generators to ensure a level	Agree to some extent – see section 6 of this report.

	playing field in the NEMS.	
Keppel Energy	1. Exempt companies should be treated the same as other market participants. If they choose to invest in new capacity, their exempted status should be revoked. 2. Exempting embedded generators could produce market volatility if they withdraw capacity that is not subject to licensing requirements. 3. A level playing field is necessary so that all participants pay their share of transmission, spinning reserve, reserve fuel and fuel switching capability. A cross-subsidy may be created if a special class of participant is created and competition will be distorted.	1. This is the legacy issue that the EMA is considering separately. 2. Price volatility is a matter for market participants to manage – any plant, whether licensed or not, is free to bid and operate how it deems fit. 3. Agree it is important that competition is not distorted. However, cross-subsidies are unlikely to occur even with a fully net treatment because of the fixed and sunk nature of many relevant costs.
Linde Syngas Singapore	New embedded generating units should be exempt from licensing requirements because: 1. they do not inject into the system; 2. they are small and impose insignificant impact on the system; and 3. they are equipped with LLDs to avoid instantaneous power demand from the network.	1. Even if embedded generators do not inject into the system, they can have impacts on the system – such as the need for regulation and spinning reserve. Market costs also need to be recovered efficiently. 2. See above. 3. If a load with an embedded generator has an effective LLD, it should pay for spinning reserve on a net basis only.
Power Seraya	1. The current NEMS design is based on a gross pool and there is no reason to change to a net pool regulatory charging framework.	1. The terms ‘gross’ and ‘net’ pool are difficult to apply in this context – they are normally applied to whether all energy is traded through the pool (which is

	2. Embedded generators should be subject to the same charges as standalone generators to create a level playing field. 3. There are questions over whether embedded generators pose a risk to the system. If they do, they should pay for the costs of back-up electricity when they draw electricity at times their own generating plant are down. 4. It is not clear why Singapore should incentivise embedded generators. It is not clear whether they really cheaper than standalone generators. 5. Promoting embedded generation may strand grid assets. This could result in higher charges to consumers.	the case in Singapore as well as the Australian NEM). 2. Agree to some extent – see section 6 of this report. 3. Agree to some extent – see section 6 of this report. 4. Embedded cogenerators provide some benefits to the power system as well as environmental benefits (see section 5 of this report). Whether these benefits should be recognised is ultimately a policy issue. 5. Transmission assets are already 'sunk' but it is true that if some loads pay less due to embedded generation, other customers will have to pay more, at least in the short run until network augmentation costs are affected.
SembCorp Utilities	1. Agrees with user pays principle but it is necessary for some mechanism to allow participants to transparently review principles on a regular basis. 2. Pros and cons of embedded generation strictly within fence compared with possibility of export outside fence. 3. Impact of embedded generators on vesting regime. 4. Propose user pays principle should be applied to transmission lines.	1. Noted. 2. We have considered this in section 6.1.6. 3. We do not consider vesting contracts to be relevant. 4. Agree that the treatment of transmission charges should be in line with user pays/economic efficiency principles.
Senoko	1. Giving incentives to embedded generation must be justified on sound grounds, not just on the basis of	1. Agree. 2. The terms 'gross' and 'net' pool are difficult to

	what other jurisdictions do. 2. The gross pool design selected for Singapore should apply to embedded generation to ensure the benefits of the model are achieved, especially in relation to transmission charges, ancillary service charges and loss-of-load pricing. 3. The 'user pays' principle must be applied comprehensively across all assets/costs to ensure they pay for the burden they impose on the system. This should include the risk of creating stranded network assets. Risks of supply security should be considered, as well as price volatility risks caused by sudden injections or withdrawals of power. Also, subsidies would need to be paid for by participants or consumers. 4. Embedded generation should be subject to a size limit that is consistent with the original market design. 5. A specific code should be applied to govern embedded generation. 6. Exempted embedded generators complicate the treatment of new embedded generators. 7. Favourable treatment towards embedded generators calls into question the role of the NEMS.	apply in this context – they are normally applied to whether all energy is traded through the pool (which is the case in Singapore as well as the Australian NEM). But agree that treatment of embedded generators should reflect economic efficiency considerations. 3. As above. 4. We have considered whether existing thresholds are appropriate, as well as whether requirements should be imposed on embedded generators above a certain MW size to be frequency sensitive and have AGC. 5. See response to question 2. 6. The issue of exempt embedded generation is beyond the scope of this report. 7. Disagree – see response to question 2. The key is to ensure the treatment of embedded generators is consistent with the user pays/economic efficiency framework.
Singapore Refining Company (SRC)	1. Requiring participation of 'captive' cogeneration in the market will penalise new efficient cogeneration projects and discourage efficiency. 2. Refineries elsewhere in the world with embedded	1. We have considered whether a higher MW threshold should apply for registration and licensing and whether requirements should be imposed on embedded generators above a certain MW size to be

	generation are not required to participate in the wholesale market and pay licensing fees and other charges. 3. Other countries encourage cogeneration, which operates at a higher level of efficiency and provides higher environmental benefits than standalone generation. 4. Transmission charges based on declared contract capacity are unacceptable. 5. The alternative is to buy electricity from retailers. 6. SRC urges EMA to consider: • extending current exempt treatment to new embedded generators; • allow SRC not to participate in the wholesale market because we produce power not as our core business but for our own use. Requiring participation increases our costs because of the need to bid into the market, ensure regulatory compliance, have IT systems in place and become familiar with rules and regulations. These costs will be hard to justify; • not forcing SRC to pay for market and spinning reserve charges because we pay retailers for these when we purchase power from them; • not charging embedded generators for spinning reserve charges because they do	frequency sensitive and have AGC. 2. Noted. This factor could be taken into consideration but the key is to ensure embedded generators are treated appropriately within the Singapore context. 3. Embedded cogenerators provide some benefits to the power system as well as environmental benefits (see section 5 of this report). Whether these benefits should be recognised is ultimately a policy issue. 4. See section 6 of this report. 5. Noted. 6. We have considered all of these matters in this report. 7. Noted – see section 6.2 of this report.

	not contribute to the need for spinning reserve; • adopting the net load concept applied in Australia 7. The proposed treatment will jeopardise potential new investment in Singapore.	
Seraya Chemicals Singapore (SCS)	1. It is not SCS's core business to generate, sell and buy electricity. 2. Participation in the wholesale market would increase our variable costs and weaken Singapore's competitive position. The price of electricity in Singapore is already high. 3. Our cogeneration is highly efficient and environmentally friendly. 4. On spinning reserve, loads with embedded generation are just like loads with a high peak but low average consumption. 5. Singapore should encourage more efficient electricity generation, not penalise consumers.	1. Noted. However, the impacts of embedded generation on the Singapore system need to be taken into account. 2. We have considered whether a higher MW threshold should apply for registration and whether requirements should be imposed on embedded generators above a certain MW size to be frequency sensitive and have AGC. 3. Embedded cogenerators provide some benefits to the power system as well as environmental benefits (see section 5 of this report). Whether these benefits should be recognised is ultimately a policy issue. 4. Disagree – there are few if no loads in Singapore that spike from a low average to a high peak load virtually instantaneously (as do those customers with embedded generators that suffer an outage). 5. Agree, but the regulatory arrangements need to promote the user pays/economic efficiency principle.

Table 2: Market participant comments and Frontier responses

Appendix B – International arrangements for embedded generation

AUSTRALIA

Generator classifications

It is worth noting that in the Australian National Electricity Market (NEM), the term 'embedded generator' is normally used to describe generators embedded in distribution networks. However, it can also be used to describe generators serving an on-site load.

Under the National Electricity Rules (Rules), which govern the NEM, all generators that are connected to the transmission or distribution network must be registered with NEMMCO, the market and system operator. Generators can be licensed in one of several categories, depending on their size, characteristics and whether they send electricity into the network.

A *scheduled generator* (generally >30 MW nameplate capacity) must participate in the central dispatch process operated by NEMMCO, while *non-scheduled generators* do not participate in dispatch. A generator with capacity above 30 MW may be registered as a non-scheduled generator if its primary purpose is local use and it rarely, if ever, sends more than 30 MW into the network or if its output is intermittent (eg windfarms).

A *market generator* is a generator whose output is not purchased in its entirety by the local retailer or (large) customer located at the same transmission connection point. A *non-market generator* is a generator whose output is purchased in its entirety by the local retailer or customer. Non-market generators do not get paid for their generation by NEMMCO except in very specific circumstances.

Licensing is a State responsibility and is generally required of all generators. For example, in Victoria, section 16 of the *Electricity Industry Act* 2000 prohibits a person from engaging in the generation of electricity for supply or sale unless the person is licensed or has an exemption. However, a generator that is below 30 MW, non-scheduled and non-market does not usually need to be licensed. In Victoria, for example, generators that are non-scheduled under the National Electricity Rules (ie export less than 30 MW) receive a blanket license exemption. Even then, such generators must comply with State regulatory requirements (in Victoria, the Distribution Code). Further, a number of specific exemptions have been granted in respect of on-site generation plant.

The license (or the order granting an exemption) is normally the vehicle for various obligations to be imposed on the generator, such as compliance with the Rules, codes, standards and procedures, information provision and accounts. License fees are normally payable under each license.

The 30 MW threshold for a generator to be scheduled (ie to be dispatched by NEMMCO) was made fairly early in the reform process, and was not based on much science (or economics).

At the time (early 1990s) the reform was being driven by the CEOs of large vertically-integrated authorities and 30 MW was thought of as:

- Too small to be of concern to them in the context of the interconnected system capacity;
- Not very numerous at the time;
- Not thought of as becoming more numerous, because they could not possibly compete with the economies of scale and technologies of the incumbents.

However, above 30 MW, it was considered important for generators to participate in central dispatch in order to maintain the overall security and integrity of the interconnected system.

Fees and charges payable in relation to embedded generators

Market fees

Market fees in the NEM recover the cost of NEMMCO's establishment and operations. These fees are based on metered (ie net) load or generation at the transmission connection point. For example, aggregate market fees for customer loads for the current financial year is $0.24845/MWh of net load.[3]

Transmission charges

Shared network costs in the NEM are recovered almost entirely from loads, although generators do pay shallow connection costs.[4] Shared network costs are recovered through the following key charges:

- Customer transmission use of system (TUoS) usage charge – this varies on a locational basis based on the cost-reflective network pricing (CRNP) methodology;
- Customer TUoS general charge – this is designed to recover the outstanding (sunk) costs of the shared network;
- Common service charge – this is designed to recover overheads and other network costs that cannot be allocated on a locational basis; and
- Generator use of system charges – contributions to the shared network by generators. These are currently not in widespread use.

Under the Rules, embedded generators (those embedded in distribution networks) get paid rebates for 100% of the avoided customer usage charge. That is, to the extent that embedded generators that generate in excess of their owner's use reduce the 'usage' component of TUoS charges paid by the local distributor, the generators are entitled to receive the additional sum that the distributor would have had to pay to the transmission company. Note that this rebate does

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3 NEMMCO, *Schedule of Participant Fees 2005/2006.*

4 See *National Electricity Rules*, chapter 6, part C.

not include the TUoS general charge, which is about half the overall shared transmission charge payable by loads.

For embedded generators serving on-site loads, the savings available are even greater because *all* shared customer transmission charges are based on metered (net) load. Therefore, the load will effectively save on the usage charge, the general charge and the common service charge.

Embedded generators, or rather, their accompanying loads, can seek to negotiate 'standby' charges to accommodate outages of their generation plant. However, if they do not negotiate such charges, they will generally pay normal transmission charges on any excess supply they take when their generators are off-line.

Frequency control ancillary services

Charges for ancillary services are also generally on a net load (or generation) basis.[5] There are eight types of frequency control ancillary services (FCAS). These are:

- Regulation Raise;
- Regulation Lower;
- Fast Raise (6 second raise);
- Fast Lower (6 second lower);
- Slow Raise (60 second raise);
- Slow Lower (60 second lower);
- Delayed Raise (5 minute raise); and
- Delayed Lower (5 minute lower)

The regulation raise and lower services are broadly equivalent to Singapore's regulation while the fast, slow and delayed raise and lower services are contingency services that are broadly equivalent to Singapore's spinning reserve.

FCAS are procured through eight separate real-time markets operating through NEMMCO's SPD dispatch engine. The highest cost offer sets the marginal price for the service. The amounts of FCAS required depend on what is necessary to maintain the system frequency within the normal operating band of 49.85 Hz to 50.15 Hz.

The system requirements for each FCAS service must be forecast by NEMMCO each week in advance for the following week. The requirement for regulation services is normally set at a nominal value for the time and day of week unless prevailing system conditions dictate otherwise. Since a relaxation of frequency standards in 2001, the quantity of regulation required is approximately 270 MW, down from 300 MW. This is just over 1% of average system demand. The required amounts of raise and lower contingency services are based on the largest generation output or load blocks on the power system as well as the combined

5 NEMMCO, *Guide to Ancillary Services in the National Electricity Market*, Version 1.0, 24 August 2001.

system demand. In most cases, the largest generation and load blocks on the power system will be relatively constant so the contingency reserve requirements become a simple function of system demand.[6]

The Fast, Slow and Delayed Raise and Lower services are recovered from market participants on a net load or net generation basis. The cost of raise services is recovered from generators and the cost of lower services is recovered from loads. Therefore, embedded generation can help reduce a load's charges for Fast, Slow and Delayed Lower services.

The costs of regulation raise and lower services are recovered from participants through the 'causer pays' methodology. Under this methodology, the response of measured generators and loads to frequency deviations is monitored and used to determine a series of 'causer pays' factors. Those facilities that have appropriate measurement equipment in place (known as Supervisory Control and Data Acquisition or SCADA) are assigned a unique causer factor while those that do not are assigned a factor based on the averaged performance of non-measured facilities. The measurement involves NEMMCO remotely monitoring and measuring the generation and consumption levels of these participants through SCADA every 4 seconds. These factors are revised by NEMMCO every 4 weeks. Each market participant is allocated a particular sum to pay through this process.

Therefore, a load with an embedded generator that has a joint causer pays factor will only be required to pay for regulation services to the extent that its combined (ie load plus generation) performance contributes to frequency deviations. Consequently, if the operation of an embedded generator makes its accompanying net load cause the system frequency to deviate, it will incur high regulation charges for its load. However, if an embedded generator helps its net load assist in the correction of frequency deviations, it will help lower its load's regulation charges.

See the summary in Figure 1 below.

[6] NEMMCO, *Operating Procedure: Frequency Control Ancillary Services*, Document Number: SO_OP2708A, 1 July 2005.

(a) All scheduled generators are required to be assigned individual causer-pay factors based on their respective actual generation profile. Large loads connected to the transmission network may opt into the regime. To opt in, a prerequisite is the installation of SCADA equipment to enable NEMMCO to monitor and measure their respective generation/load.

(b) The individual causer-pay factor for a generator is determined by measuring the deviation of actual generation from scheduled generation every 5 minutes over a 4-week period.

(c) The individual causer-pay factor for a load is determined by measuring the deviation of actual load from their actual (ex post straight line) load trend every 5 minutes over a 4-week period.

(d) Generators and loads that do not have individual factors will be assigned the same residual causer-pay factor based on the system-wide deviation (specifically the deviation of actual demand from forecast demand) and the aggregate of the measured deviation of generators and loads.

(e) The causer-pay factors to be applied are fixed every 4 weeks.

(f) A company with embedded generation:

- May opt to have separate individual causer-pay factors assigned to its generating unit and to its load
- May opt to have a causer-pay factor assigned to its net import or export (as the case may be)
- That does not have any causer-pay factor assigned to it, will be assigned the residual causer-pay factor. All companies without individual factors will be assigned the **same residual factor** and hence pay the **same $/MWh charge** on a net basis for regulation.

Figure 1: Causer Pays in the Australian NEM

Appendix B – International arrangements for embedded generation

Non-market ancillary services

NEMMCO contracts for the provision of remaining 'non-market' ancillary services.[7] These are:

- Network control ancillary services (NCAS); and
- System restart (black start) ancillary services (SRAS).

The cost of contracts for NCAS is recovered only from loads on the basis of a participant's net load compared with total system net load. The cost of contracts for SRAS is recovered half from loads and half from generators on the basis of the participant's net load/injection compared with total system net load/injections. Therefore, embedded generators can help their loads reduce their non-market ancillary services charges.

Benefits available to embedded generators

There is a range of greenhouse gas reduction schemes in place in Australia.[8] These include:

- Mandated Renewable Energy Target (MRET) – this obliges retailers and other parties (on the pain of penalty) to purchase certain quantities of renewable energy. Cogenerators and other parties that produce electricity from renewable energy can create renewable energy certificates (RECs) to benefit from this obligation;
- New South Wales Greenhouse Benchmarks – this scheme obliges retailers and other liable parties to surrender NSW greenhouse abatement certificates (NGACs) each year. While similar to the MRET scheme, the key difference is that the NGACs can be produced not just through renewable energy but by any activity that reduces greenhouse gas emissions, such as improving the efficiency of existing (non-renewable fuelled) generators.
- Queensland 13% gas scheme – this scheme requires retailers and other parties to source at least 13% of their electricity from gas-fired generation, including natural gas, coal seam methane, waste coal mine gas and waste gases associated with petroleum refining.

There are various other smaller greenhouse gas reduction programs in operation. However, a key point to note about the schemes mentioned above is that they operate outside the NEM and do not apply to embedded generation *per se*.

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7 NEMMCO, *Guide to Ancillary Services in the National Electricity Market*, Version 1.0, 24 August 2001.

8 See, for example, Australian Business Council for Sustainable Energy, *Guide for the Connection of Embedded Generation in the National Electricity Market*, September 2003.

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BRITAIN

NETA and BETTA

In Britain, the British Electricity Trading and Transmission Arrangements (BETTA) commenced in April 2005. Prior to BETTA, the New Electricity Trading Arrangements (NETA) were implemented in 2001, taking the place of the original England and Wales Pool that had operated since April 1990. At the switch to NETA, small generators considered themselves disadvantaged by the new rules. NETA and BETTA require participants to 'self-balance' by entering into contracts to match their metered load or generation volumes. If a participant is not balanced, it is exposed to energy imbalance prices. This effectively amounts to a penalty for having actual load or generation different from the volume of notified contracts. A number of modifications have occurred to lessen this problem and a significant degree of trading consolidation has occurred, but participation in BETTA still remains more onerous for small generators than larger trading units.

Generator categories

Under BETTA small generators are entitled to some degree of favourable treatment, as discussed below. As in the Australian NEM, a distinction is made between:

- Generators embedded within distribution networks; and
- Generators not embedded within distribution networks but that serve an on-site load.

This report will also separately consider cogeneration (known in Britain as combined heat and power or CHP).

Benefits available

Distributed generators

With respect to the first category, embedded generators that are not directly connected to the transmission network are not subject to charges for:

- Transmission Network Use of System (TNUoS);
- Balancing Services Use of System (BSUoS); and
- Elexon (BSC Co) charges.[9]

Further, both the embedded generators and the distribution networks to which they are connected benefit from avoiding scaling of electricity volumes to reflect transmission losses. These are worth 1.5-2% of energy generated.

TNUoS charges recover the cost of the shared transmission network owned and operated by the National Grid Company (NGC). These charges apply to both

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[9] See Ofgem, *Charges and embedded benefits* (available at Ofgem website www.ofgem.gov.uk).

loads and generators on a partly locational basis. Generally speaking, TNUoS charges for load are higher in the south of Britain than in the north, and are higher for generators in the north than in the south (where they can be negative – ie rebates). TNUoS charges to loads are based on demand during system peak if a customer is half-hourly metered and on deemed peak (evening) consumption for customers that are not half-hourly metered. TNUoS charges to generators located in positive charging zones are based on the average of their three peak injections into the grid over the financial year.[10]

Meanwhile, BSUoS charges recover NGC's costs (as system operator) of keeping the system in electrical balance and maintaining the quality and security of supply. BSUoS costs include:

- The total costs of the balancing mechanism;
- Total balancing services contract costs;
- Payments and receipts from NGC incentives schemes;
- Internal costs of operating the system;
- Costs associated with contracting for and developing Balancing Services;
- Adjustments;
- Costs invoiced to NGC associated with manifest errors and special provisions; and
- BETTA implementation costs.[11]

These charges are levied on all parties to the Connection and Use of System Code (CUSC) and are based on energy taken or supplied to the NGC system in each half-hour settlement period.

Elexon's charges are designed to recover its costs of administering the Balancing and Settlements Code (BSC). These charges are levied on the basis of metered volumes.

Therefore, distributors with embedded generators incur reduced TNUoS, BSUoS and Elexon charges, since use of the locally generated electricity by that party reduces the extent to which they have to use NGC's transmission system and energy balancing services.

Initially, these savings were the subject of negotiation between distributors and the embedded generator. However, modifications to the relevant rules now mean that embedded generators can access these benefits directly, without negotiation with the retailer/customer: Embedded Licence Exempt Generators (ELEGs) that are registered in the Central Metering Registration Service (CMRS) automatically receive the reductions in TNUoS and BSUoS they provide to the distribution networks they are located in.

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10 National Grid, *The Statement of the Use of System Charging Methodology, Effective from 1 April 2005*, Issue 1, Revision 1, 8 August 2005.

11 *Ibid.*

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These benefits are limited to those generators eligible for license exemption. The threshold for exemption is currently 100 MW. However, larger generators may seek license exemption from the Secretary of State and the Department of Trade and Industry has indicated that it is broadly sympathetic to exemptions for generators exporting less than 100 MW to the system.[12]

Generators serving on-site loads

For generators that serve large on-site loads, many of the same benefits apply. Such generators are likely to reduce the net offtake of electricity at the relevant connection point. As noted above, NGC's TNUoS load charges are based on demand during system peak. Therefore, to the extent on-site generators help moderate a load's metered demand at these times, this will be reflected in lower TNUoS charges to the on-site load up to the same maximum of 100 MW of embedded generation referred to above.

Similarly, BSUoS charges are based on energy taken out or supplied to the NGC system in each half-hour. Therefore, generators with on-site loads can also reduce the load's BSUoS charges up to the same threshold.

Where a generator serves an on-site load, it is typical for one party to be party to the CUSC and BSC. Therefore, there is usually one connection agreement with NGC in relation to the 'site' rather than separate NGC agreements for the load and the generator.

However, where a small generator is separately connected to the transmission network, it is required to become a party to the CUSC and BSC itself. Therefore, if such generators inject into the transmission system from time to time, they will incur TNUoS and BSUoS charges. But if they do, they may benefit from a discounted TNUoS charge, as determined by Ofgem. This discount operates outside the use of system charging methodology.[13]

That said, there has been a license exemption regime of some sort for small generators in place since 1990. The threshold was originally 10 MW at privatisation, then relaxed to 50 MW in 1995. The logic behind the increased threshold was to remove unnecessary 'red tape' for small generators while maintaining the integrity of the system. In 1998, the threshold was relaxed again to 100 MW subject to a maximum export into the grid of 50 MW. In 2000, the exemption was extended to generators up to 100 MW exporting up to 100 MW (the current level – see above).[14]

We understand that the increase in the threshold to 100 MW was based on facilitating the aggregation of output for small generators, thereby reducing their

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12 Elexon, *Overview of Embedded Generation Benefits*, Version 1.0, August 2005, pp.2-3.

13 National Grid, *The Statement of the Use of System Charging Methodology, Effective from 1 April 2005*, Issue 1, Revision 1, 8 August 2005.

14 *The Electricity (Class Exemption from the Requirement for a Licence) Order* 2001 (No. 3270 of 2001). See also Elexon, *Overview of Embedded Generation Benefits*, Version 1.0, August 2005, pp.2-3.

costs and increasing the flexibility under which they may operate under the new arrangements.[15]

However, we stress that where a generator merely reduces the net load at the same connection, it can provide benefits directly through reduced TNUoS, BSUoS and Elexon charges, up to a cap of 100 MW.

Cogeneration and renewable generation

Cogeneration (CHP) and other energy efficient technologies are eligible for a range of benefits in Britain.[16]

Some of the main benefits provided are as follows:

- Exemption from the Climate Change Levy (CCL) – the CCL is levied on the use of energy by industry and government (ie not the domestic or transport sectors). The fuel used by certified 'good quality' CHP plant is exempt from the CCL. However, it should be noted that the fuel used by electricity-only generators is also exempt from the CCL. The use of electricity is subject to the CCL at a rate of 0.43p/kWh (about $12.50/MWh), except for electricity produced by new renewable energy (eg solar and wind). Therefore, non-renewable CHP receives only the incremental saving of avoiding the CCL on its heat production. It also worth noting that electricity used in electrolysis processes, such as aluminium smelting, is exempt from the levy;
- Enhanced Capital Allowances – firms making energy-saving investments, such as certified good quality CHPs are able to deduct the full cost of these investments in arriving at the corporate tax and income tax bills for the first year of the investment;
- Capital grants for smalls-scale CHP (<1 MW); and
- CHP feasibility programme provides grants of up to 75% of the cost of a detailed feasibility study for projects of 1-20 MW.

Although it is too early to assess the impact of these schemes on investment in CHP (for example, the CCL only came into effect in April 2001), the installed capacity of CHP in the United Kingdom rose from 3042 MW in 1994 to 6460 MW in 2000, an increase of over 100%.

Ancillary services procurement

This section briefly discusses how the requirements for ancillary services are determined and procured under BETTA.

A number of ancillary services are procured in BETTA.[17] These include those that are:

15 Proposed Revocation of the Existing Electricity (Class Exemptions from the Requirement for a Licence) Order 1997 (as amended) and Making of a New Electricity (Class Exemptions from the Requirement for Licence) Order 2001, Regulatory Impact Statement.

16 See Department for Environment, Food and Rural Affairs website at www.defra..gov.uk.

17 See NGC website at www.nationalgrid.com.

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- Mandatory – must be provided to NGC by the relevant market participants:
  - Frequency Response – to maintain system frequency within 1% of 50 Hz;
  - Reactive Power – to maintain stable voltage throughout the network;
- Necessary services – NGC contracts with participants for these:
  - Fast Start – fast start capability from open cycle gas turbines to provide frequency support within 5-7 minutes of a low frequency event;
  - Black Start – the ability to help NGC restore the system after a major system shut down;
- Commercial – procured by NGC under contract to meet its license obligations:
  - Enhanced reactive service – additional voltage support;
  - Frequency Response – additional frequency response to obviate the need to use the generally more expensive mandatory supply of frequency response;
  - Fast Reserve – the rapid delivery of active power output within 2 minutes of an instruction to help control frequency following sudden changes in load or generation;
  - Standing Reserve – extra power either as generation or demand reduction to deal with actual demand exceeding forecast demand;
  - Warming and Hot Standby – the ability of a generator to deliver an Offer into the Balancing Mechanism;
  - Intertrip – an automatic control arrangement where generation or load may be reduced or disconnected to maintain system or voltage stability;
  - Emergency Assistance – specific interconnector service to cover extreme major unforeseen circumstances;
  - Maximum Generation Service. – additional short term generation output during periods of system stress for system balancing.

The key Frequency Response service is broadly equivalent to Singapore's regulation and spinning reserve requirements, although Fast Start and Fast Reserve services also help provide spinning reserve.

Frequency Response is intended to deal with the largest loss on the system, given levels of demand. For this reason, according to NGC, frequency response requirements are continuously changing. They depend on:

- Largest infeed currently connected to the system – in other words, the largest contingency;
- Demand on the system – the response requirement is higher in overnight and/or summer, when demand is lower; and

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- Dynamic/non-dynamic requirements – the largest loss requirement can be met by dynamic or non-dynamic response, but there is a minimum dynamic response requirement.

Dynamic response is a continuously provided service used to manage normal second-by-second changes on the system. It is usually provided by generator governor control. There is a minimum dynamic requirement of 300-500 MW of response dependent on the time of day as measured at 0.5 Hz. Non-dynamic response is usually a discrete service triggered at a defined frequency deviation. There is no specific non-dynamic requirement – non-dynamic response can be used when minimum dynamic requirements have been met and where cost-effective.

Unlike the Australian NEM, there is no real-time market for Frequency Response. NGC tenders for these and other ancillary services following a pre-qualification assessment, with detailed offers from potential providers.

PJM

The Pennsylvania-New Jersey-Maryland market (PJM) has implemented a net load approach in relation to 'behind-the-meter' generation. Under the new market rules, the term behind-the-meter generation refers to generating units that are located with load at a single electrical location such that no transmission or distribution facilities owned by any transmission owner or distributor are used to deliver energy from the generating units to the load.

PJM filed proposed revisions to its Open Access Transmission Tariff (PJM Tariff) and related agreements on March 1, 2004 to implement market rules for behind-the-meter generation.[18] Under PJM's pre-existing market rules, market participants were charged for network service, energy, capacity, ancillary services, and PJM administrative fees based on their total load or scheduled load, as applicable. In order to encourage demand response and the use of behind-the-meter generation in times of scarcity and reduce the cost to market participants that rely to a lesser degree on the PJM integrated transmission system to serve load, PJM stakeholders developed a "total netting" proposal, which was approved by the PJM Members Committee, made up participants. The idea behind this proposal was to reduce certain costs to market participants that rely to a lesser degree on the PJM integrated transmission system to serve load.

The 'total netting' approach allows such qualifying market participants to net operating behind-the-meter generation (or behind-the-meter generation expected to be operating in the case of day-ahead markets) against load at the same electrical location for purpose of calculating charges for energy, capacity, transmission service, ancillary service and PJM administrative fees.

In PJM's filing dated 1 Mar 2004 to FERC to seek approval to implement net treatment, PJM stated the following:

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[18] See PJM Interconnection LLC, 107 FERC 61,113 (2004) (6 May 2004).

> "While the total netting approach may exempt participants from charges for some ancillary services that continue to benefit them (e.g., regulation, reserves), eliminating these charges for those relying on behind the meter generation administratively treats all of these charges alike, simplifying market administration, and, as noted, will further encourage demand response. Moreover, as noted, the PJM stakeholders have approved the total netting approach. PJM intends to monitor the impact of these proposed new rules to assess whether they fairly allocate costs and burdens among market participants."[19]

In October 2005,[20] PJM has moved towards setting a 1,500 MW cap on the amount of behind-the-meter generation (connected at the distribution level – typically 69 kV and below) to be given net treatment. This is about 1% of the 2005 system demand of about 130,000 MW in 2005.[21]

The required quantities of regulation and spinning reserve in PJM vary marginally according to location. In the key Mid-Atlantic zone:[22]

- The regulation requirement is 1.1% of the day-ahead peak load forecast for the on-peak period and valley load forecast for the off-peak period. This requirement may be adjusted by PJM if the adjustment is consistent with the maintenance of NERC control standards; and
- The spinning reserve requirement is the amount of 10-minute reserve that must be synchronized to the grid. This is currently set at 75% of the largest contingency in that zone, provided that double the remaining 25% is available as non-synchronized 10-minute reserves.

In the smaller Western zone:[23]

- The regulation requirement is determined for each hour of the operating day and is equal to 1% of the forecast peak load for the PJM West area for that day; and
- The spinning reserve requirement is defined as 1.5% of the peak load forecast of the Western Spinning Reserve Market Area for that day.

NETHERLANDS

Cogeneration or CHP plant play an important role in the electricity industry in the Netherlands, accounting for around 40% of installed capacity. This is in large part a response to the Government policies, introduced in 1989, to encourage entry by decentralised CHP plant for environmental reasons.

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19 See page 7, footnote 13

20 See PJM Filing of Settlement Agreement, October 24, 2005, pp.5-6.

21 PJM Market Implementation Committee, *Behind the Meter Generation Settlement Agreement*, December 14, 2005, Agenda Item #6.

22 PJM, *PJM Manual 11: Scheduling Operations*, Revision 22: Effective Date: 10/19/04, sections 3 and 4.

23 PJM, *PJM Manual 11: Scheduling Operations*, Revision 22: Effective Date: 10/19/04, sections 3 and 4.

CHP is used both by industry (for example, greenhouses) and district heating. Industry is the largest user, accounting for around 65% of installed capacity. Over two-thirds of CHP capacity is in units larger than 60 MW. In many cases the CHP producer is connected to the grid, but supplies power to other sites not connected to the grid. The municipal owned electricity distribution businesses actively participated with private sector investors in developing CHP plant prior to the reform of the electricity industry. More than half of CHP capacity is sold to or controlled by the major distribution and generation companies.

Stimulating embedded generation

A variety of mechanisms were used to stimulate investment in CHP plant, including:

- government investment subsidies of up to 17.5% (until 1995);
- an obligation for generation companies to purchase surplus power from CHP plant at the estimated full cost of new central generation facilities (until 1995);
- favourable natural gas prices from the partially Government-owned gas supplier (until 2000); and
- an exemption from paying for reserve capacity or ancillary services (until 1997).

These policies resulted in a doubling of CHP capacity over the ten years from 1990, resulting in excess generating capacity in the Netherlands.

Industry reform

The electricity industry in the Netherlands was reformed in the late 1990s. As part of these reforms a wholesale market was established and distributors were required to separate their distribution activities from other functions (such as retailing or CHP investments).

The presence of large volumes of CHP prior to the reforms means that the design of the electricity market had regard to the presence of distributed generation. The system operator coordinates the system and controls the dispatch of central generators, while the local network operators are involved in balancing their own systems having regard to production from CHP.

The market rules include a number of advantages for embedded generators:

- small embedded generators (below 10 MVA[24]) do not pay connection or use of system charges, while large generators (including CHP plant) do;
- some small plants embedded within the distribution network sell their output directly to the local distributor, who is obliged to buy it; and
- rules relating to imbalance were adjusted, to enable producers to make final adjustments up to one hour in advance of real time, addressing concerns that

24 International Energy Agency, *Distributed Generation in Liberalised Markets*, 2002, p.62.

embedded and renewable generators were unfairly disadvantaged by the market.

Following the liberalisation of the energy market in the Netherlands many embedded generators faced financial difficulties as a result of the combination of:

- falling electricity prices, as a result of excess capacity and relatively cheap imports from neighbouring countries;
- the requirement to purchase gas at competitive (rather than subsidised) prices; and
- the increase in natural gas prices (as a result of an increase in oil prices).

Recent developments

The Government responded to the financial difficulties in the CHP industry with a set of further measures in 2000:

- an increase in the tax credit allowed for new CHP;
- an exemption of CHP electricity consumption from the regulatory energy tax (subject to certain efficiency targets);
- financial support to CHP plant output; and
- an accelerated depreciation program for CHP investments that meet certain efficiency targets.

The Government has resisted pressure to waive network connection fees for large CHP.

EUROPE

The regime for embedded generators and cogenerators varies across Europe (see also Britain and Netherlands above). This section highlights some of the benefits offered to CHP plants in different European jurisdictions.[25]

Belgium

- Fixed minimum prices for electricity from CHP;
- Grid operators should strive to deliver green and CHP electricity;
- CHP has priority grid access;
- Distribution tariffs to be transparent and reasonable;
- Emergency back up electricity tariffs to be moderate;
- Funding for CHP associations; and
- Fiscal abatement for investment in energy efficiency including CHP projects.

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25 See, for example, Irish Energy Centre, *An Examination of the Future Potential of CHP in Ireland*, December 2001, Appendix 3.

Denmark

- Compulsory purchase of electricity from CHP;
- Obligation on municipalities to ensure CHP projects are developed;
- Planning guidelines for CHP;
- Priority of dispatch for CHP electricity;
- Financial subsidies for electricity production;
- Grants for district heating networks; and
- Green tax on trade and industry, which is returned in the form of grants and subsidies.

France

- Long term power purchase agreements; and
- Compulsory purchase of electricity from CHP up to 12 MW.

Germany

- CHP exemption from fuel taxes;
- Grid operator required to purchase electricity from CHP at a fixed bonus; and
- Favourable use of system rates.

Italy

- Compulsory purchase of electricity from CHP;
- Industrial gas prices lower than domestic prices;
- Taxation for CHP gas is reduced in proportion to electric efficiency;
- CHP exempt from carbon tax; and
- Priority of dispatch.

Spain

- Spilled (ie exported) electricity is paid a premium;
- Promotion of third party financing;
- Legislative adaptations; and
- Provision of technical advice.

Appendix B – International arrangements for embedded generation

MALAYSIA

Overview

The Malaysian electricity industry continues to be dominated by vertically and horizontally integrated utilities, responsible for electricity generation, system operation, transmission, distribution and retail supply. There are three main electricity supply utilities (the utilities) operating in different parts of the country, the largest of which is Tenaga Nasional Berhad (TNB) in Peninsular Malaysia. Separate utilities supply the States of Sabah and Sarawak. Unlike Singapore, there is no wholesale electricity market.

In addition to generating electricity, these utilities purchase output from Independent Power Producers (IPPs) and cogenerators. There are six main IPPs supplying electricity to TNB under long term power purchase agreements (PPAs), five in Sabah and two in Sarawak. Around 58% of electricity produced in Malaysia is supplied by IPPs. There was 800 MW of public and privately owned cogeneration facilities in operation throughout Malaysia in 2004, with a further 163 MW licensed but not yet operational. Over 1,600 self-generation licenses have been issued in Malaysia.

There are also several small distributors who buy electricity from the utilities, or generate their own power, for distribution to customers within industrial complexes (such as Petronas Gas who generates electricity by cogeneration to supply customers in two integrated petrochemical complexes). Owners or managers of large commercial complexes also often purchase electricity at high voltage for supply to tenants (such as the Kuala Lumpur International Airport which supplies tenants with electricity and chilled water from an onsite cogenerator).

Benefits available

The Government of Malaysia expanded its Fuel Diversification Policy to add renewable energy as a fifth source (in addition to oil, natural gas, coal and hydro) in 1999. The 8th Malaysia Plan (2001-2005) announced the intention to generate 5% of electricity (about 600 MW) from renewable sources by the end of 2005.

A number of programs have been introduced to encourage renewable and cogeneration, which are likely to benefit some embedded generators:

- the Malaysia Electricity Supply Industry Trust Account (MESITA) fund was set up to provide financial assistance to rural electrification, energy efficiency and renewable energy projects. IPPs and TNB contribute 1% of their annual audited revenue to the fund, which is administered by a special committee comprising representatives from Government, the Energy Commission (the industry regulator), TNB and the six mainland IPPs;
- the Small Renewable Energy Program (SREP) was introduced in 2001 to encourage the private sector to undertake small projects using renewable resources, such as biomass fuels like palm oil residues and wood waste. Under the SREP small power plants using renewable fuel can apply to sell electricity to TNB under a long-term take-or-pay PPA. Each project will be

given a license for up to 21 years to inject up to 10MW into the national grid. Under the SREP renewable producers will be responsible for all the costs of network connection, including reinforcement and metering equipment. No stand-by charges are levied, but any energy taken by developers is charged at the standard rates. Special preference is given to cogeneration projects. Progress under the project has been slow, with only six of the 52 projects approved in 2003 reaching implementation in that year. As of January 2005, 62 projects were approved with aggregate capacity of 355 MW. Two projects with total capacity of 12 MW were commissioned in 2004, bringing the total capacity of projects under the SREP to 51 MW;

- the Biomass Based Power Generation and Co-generation (BioGen) project was established in 2002 with the aim of reducing greenhouse gas emissions from fossil fuel-fired combustion processes, utilising waste residue from palm oil and stimulating other bio-mass based generation and cogeneration. The Government of Malaysia, United Nations Development Program, Global Environment Facility and the private sector, jointly fund the project. Funding can be used to cover up to 80% of total project cost; and
- fiscal incentives such as investment tax incentives have also been offered to stimulate investment in biomass, including income tax exemptions and import duty or sales tax exemptions.[26]

THAILAND

Overview

The Electricity Generating Authority of Thailand (EGAT) is responsible for electricity generation, transmission and system operation in Thailand. In addition to generating electricity, EGAT purchases power from its partly owned subsidiary Electricity Generating Company (EGCO), IPPs and small power producers (SPPs). EGAT acts the monopsony buyer in Thailand – all IPPs and SPPs must sell their output to EGAT. Together IPPs and SPPs accounted for just over half of the electricity generated in Thailand in 2003/04. EGAT sells the majority of its electricity purchases to the two major distribution companies in Thailand, and also sells a small volume direct to customers and as standby power.

Benefits available

The SPP program was established in 1992 with the aim of promoting the use of biomass and cogeneration. Under the scheme, SPPs with a plant capacity of 90 MW or less are entitled to sell their output to EGAT under a common PPA. The PPAs have durations of 5 to 25 years. EGAT and the Thai energy ministry set the terms and conditions of the PPAs. Both firm and non-firm contracts are offered. The prices under non-firm contracts are set with regard to EGAT's short-run avoided energy cost. Under firm contracts, SPPs must be able to guarantee supply during system peak months and prices are determined by

26 These exemptions were expected to expire on 31 December 2005.

EGAT's long-run avoided capacity and energy costs. The PPAs include both capacity and energy charges, with an 80% take-or-pay provision.

SPPs may also elect to sell their electricity to industrial customers located next to the SPP plant instead of, or in addition to, selling to EGAT. In contrast IPPs are obliged to sell their entire output to EGAT. There are no arrangements for SPPs to access the network to transport energy to customers that are not located adjacent to the SPP plant. Most industrial customers are in industrial estates that also house the SPP plants. In most cases, SPPs are built to meet EGAT's capacity requirements, rather than the requirements of customers. This means that many SPPs have unused electricity or steam producing capacity. Writing a contract directly with an SPP, rather than purchasing electricity from the grid, often results in a more reliable source of supply for industrial customers.

To be eligible to participate in the SPP program, generators must use one of the following fuels:

- hydroelectric, wind power and mini-hydroelectric;
- biomass; or
- thermal where at least 10% of steam is used for co-generation.

As of March 2005, EGAT had contracts with a total of 84 SPPs with a total installed capacity of around 4,600MW (around 15% of total capacity). Around 3,679 MW (80%) of this total is firm power, with the non-firm power the remainder. About 58% of firm power and one-third of non-firm power capacity is designated to EGAT, with the remainder supplied to industrial customers. In July 2002, the Thai Government has introduced rules to promote investment from very small-scale producers (less than 1 MW) by offering retail prices for their output and connection to the electricity grid.[27]

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[27] Probe International Briefing, *Small Power Producers in Thailand*, March 2005, p.2.

Appendix C – Greenhouse benefits of embedded generation

We assume that the base case involves electricity from the grid sourced from a CCGT plant supplemented with a gas boiler whereas embedded generator options would include:

- Cogeneration; and
- Standard embedded generation (eg open-cycle gas turbine (OCGT) combined with gas boiler).

For a large CCGT plant, efficiency tends to be 45-50% on a Higher Heating Value (HHV) basis. In Singapore, transmission and distribution losses of, say, 2% would also arise. For a generic medium sized industrial customer with a 20 MW electrical load and 50T/h of steam (approx 40 MW_{th}) the weighted average efficiency would be:

$$\frac{45\% x 20MW / 1.02 + 80\% x 40MW}{20MW + 40MW}$$

$$= \quad 68\%$$

Reciprocating engine and gas turbine cogeneration plants often have an overall thermal efficiency in the range 50-80% HHV.

A simple OCGT embedded generator (non-cogeneration) of 20 MW scale would have an efficiency of the order of 30-35% HHV[28].

Since the primary fuel in all cases is assumed to be natural gas, the fuel usage and GHG emissions are all directly (inversely) proportional to efficiency. Depending on the scale of the plant and how closely matched the electricity and thermal loads are to the selected cogeneration configuration, it can thus be seen that:

- non-cogeneration embedded generation using current OCGT technologies would tend to have poorer efficiency than the centralised large CCGT plant and result in *extra* fuel usage and GHG emissions of the order of 40%. This also represents the limiting case for cogeneration with very poor matching of the thermal load to the engine/gas turbine's capabilities;
- Cogeneration with good matching of the thermal usage to the capabilities of the engine/gas turbine can result in a fuel and GHG *savings* of the order of 10%-15%; and
- Cogeneration where the thermal load is less than optimally matched to the engine/gas turbine capabilities will have fuel and GHG emissions in between the two cases above.

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28 Small CCGT plants for embedded generation are technical possible but are seldom applied as the delivered electricity cost is high due to economies-of-scale factors.

Therefore, GHG emissions may either increase or decrease with the adoption of embedded generation depending on the relative overall efficiency differences considering the CCGT and boilers in the benchmark case as against the embedded generator/cogeneration efficiency:

- The GHG emissions of a large CCGT plant are approximately 0.4 T/MWh;
- For a non-cogeneration embedded generator using simple OCGT or gas engines, the GHG emission rate would be approximately 0.5T/MWh to 0.65T/MWh; and
- For a gas turbine or gas engine-based cogeneration plant that is optimally matched to the customer's thermal load, the GHG emission intensity (per MWh basis) would typically be in the range 0.25 to 0.3 T/MWh. To the extent that the cogeneration plant is not optimally fitted to the customer's thermal load the GHG emission rate is effectively higher. At the limit, this would be the same as the non-cogeneration embedded generator (that is, higher GHG emissions than the benchmark CCGT plant). Practical cogeneration plants tend to be somewhere between these two extremes, which must be determined on a case-by-case basis.

If the value of GHG emissions or GHG emissions savings were, say $26/T[29], an optimally fitted cogeneration plant saving 0.1 to 0.15T/MWh might be credited with an *additional value* of $2.50-$4/MWh compared to buying from the grid. For a non-cogeneration embedded generator, or the limiting case of ill-fitted cogeneration, the plant might impose *additional costs* of $2.50-$4/MWh compared to the benchmark base case on account of such a GHG price. Real-life cogeneration plants tend to be somewhere between these two extremes, which must be determined on a case-by-case basis.

[29] Presently in the EU carbon trading market the traded price is approximately €13/T, or approximately $26/T. It is difficult to forecast what might be the price for GHG emissions in a future market in which Singapore might participate. However, it may be a lot lower in Singapore.

Appendix D – Stakeholder comments on the Draft Report and Frontier responses

This appendix tables stakeholders' comments on Frontier's Draft Report on the treatment of embedded generation made in written submissions, as well as Frontier's responses to those comments.

Written submissions were received from the following stakeholders:

- Diamond Energy;
- EMC;
- ExxonMobil;
- Keppel Energy;
- Power Seraya;
- Singapore Refining Company; and
- Shell Eastern Petroleum.

Stakeholder	Comments	Frontier Economics response
Diamond Energy	1. Asks whether the $0.82/MWh regulation charge refers to the AFP wholesale market charge. 2. Argues that more information should be provided on the costs embedded generators impose on the system. 3. Supports review of registration and/or dispatch thresholds by the authority at the appropriate time. 4. Supports development of a tradeable greenhouse gas permit scheme in Singapore. 5. Supports a consistent licensing regime for all participants as opposed to charging existing and new participants differently.	1. The $0.82/MWh refers to the average 2004 charge for regulation based on information provided by the EMA. This charge is paid by generators on the first 5MWh of generation per half hour. 2. The report only identifies areas where the arrangements do not reflect the actual costs and benefits of embedded generation. In areas where the existing arrangements reflect the costs generators, including embedded generators, impose on the system (eg the need for spinning reserve) and this is reflected in the charging regime (eg the 'runway' method), there is no need to change the arrangements. 3. Noted – whether this is undertaken is a matter of policy. 4. Noted – this is a policy matter for the Government. 5. Noted. The report highlighted that price discrimination approaches to the recovery of certain market costs may promote efficiency in certain cases. However, whether such approaches should be adopted is a policy matter.
EMC	1. Notes that 'embedded generation' and 'cogeneration' are used interchangeably in the report (3.1). 2. Highlights various drafting and editing comments	1. Embedded generators refer to generators principally for internal purposes. Embedded cogenerators refer to cogenerators principally for internal purposes. The report will be reviewed to

	(3.3, 6.1.3, 6.1.4). 3. Corrects EMC and PSO fees and queries the appropriateness of describing license fees on a MWh basis (3.3 and 6.1.3). 4. Questions why report refers to exempted company (3.3). 5. Questions how $140,000 fixed fee figure was derived and particularly the treatment of regulation charges as a fixed cost. Also queries why an embedded generator under gross treatment would incur this fee but would not under net treatment (3.3). 6. Argues that the report's characterisation of EMC's views was inadequate (3.4). 7. Queries why other jurisdictions are referred to as 'advanced' given that no justification was provided. The treatment in other jurisdictions cannot by itself form the basis for Singapore to adopt net treatment (4). 8. Argues that the report should have included a full cost-benefit study of embedded generation. There was little mention of the costs of embedded generation (5). 9. Questions whether gross treatment for regulation charging would lead to material economic inefficiency (6.1.1). 10. Questions whether a net load treatment for regulation would initially affect the $/MWh charge (6.1.1).	ensure clarity. 2. Noted – report has been revised accordingly. 3. Noted – report has been revised accordingly. 4. Noted. 5. The $140,000 fixed charge was based on the approximate sum of: • the average 2004 regulation charge applied to a generator running at more than 10 MW output with one unit ($0.82*5MWh*2*8760 = $71,832); plus • fixed component of annual licence fee ($50,000); plus • approximate benefit of avoiding spinning reserve charge based on 2004 charge of $16,425/unit/year. If a load with an embedded generator was regarded purely as a net load, it would avoid these charges. 6. The EMC's views were fully taken into account in the report. By necessity, all stakeholders' comments were summarised. 7. The term 'advanced' was simply used to describe markets that were mature. Frontier agrees that international experience, by itself, does not justify particular regulatory treatment. However, other jurisdictions provide useful examples of how other governments and regulators have dealt with similar

	11. Asks whether it is likely if in Singapore, generators would be responsible for 20-25% of regulation costs (as in Australia). Also asks the set-up costs of a causer-pays regime (6.1.1). 12. Requests clarification for how 'gross and net treatments' of spinning reserve would work. Argues that recovering costs from load would lead to a rise in reserve costs and questions the relevance of simplicity in recovering reserve costs (6.1.2). 13. Argues that individual large embedded generators should not raise system security concerns because if larger than 10MW, the embedded generator would be centrally scheduled and required to generate at a level that ensured there was sufficient reserve. It is not clear how licence conditions for ensuring spinning reserve would work (6.2.2). 14. Expresses concerns about price discrimination option for recovering market fees with some users being charged nothing. Usage-based prices should be set to recover variable costs and it may be necessary to variabilise fixed costs to encourage participation. Ramsey prices must be based on estimated – not assumed – elasticities (6.2.2) 15. Argues that generator registration is necessary to impose the regulation charge and EMC and PSO fees. Unless the costs of imposing these charges on generators between 1 MW and 10 MW outweigh the benefits, the registration threshold should not be increased (6.1.5).	issues. 8. To the extent that the benefits or costs of embedded generation are reflected in existing regulatory arrangements, there is little value in quantifying those benefits and costs. The report sought to identify areas where the existing arrangements did not reflect actual benefits and costs. This could then be used as a basis for changing or augmenting the existing arrangements. 9. The report noted that regulation requirements are currently based on total system load. Therefore, whether generation is embedded or standalone would not affect the need for a certain amount of regulation. This suggests that charging for regulation on gross load would be unlikely to harm efficiency. 10. We understand there are no embedded generators in the NEMS currently subject to gross treatment. This means that a move to net treatment should not immediately affect the $/MWh charges. 11. We cannot say at this stage whether generators would pay a higher proportion of regulation costs under a causer pays regime. This would depend on the extent to which generators (and loads) deviated from target output (consumption). The costs of setting up a causer pays regime would partly depend on the equipment presently installed in the Singapore system. Therefore, estimating such costs would need to be undertaken as part of a separate exercise. The report simply recommended that the Government could consider such a regime.

	16. Questions the need for the electricity market itself to recognise the environmental benefits of embedded generators (6.2.1). 17. Criticises the report for only providing two options for improving economic efficiency (charging regulation on a causer pays basis and embedding generation to avoid network augmentation costs). The remaining options all involve wealth transfers and do not help address the high cost of energy in Singapore (7).	12. A gross treatment of spinning reserve costs could apply on the basis of gross MW or MWh load and generation (such as a charge in $/MW or $/MWh), whereas a net treatment could be on net MW or MWh. Simplicity is one factor in considering the appropriateness of a particular regulatory treatment. However, the report makes clear that a shift away from the current approach could lead to inappropriate incentives for investors to develop larger units. 13. The report notes that if a net treatment were adopted and many large embedded units were developed, licence conditions could help ensure sufficient spinning reserve. In other words, licence conditions could be used to overcome the incentives net treatment could create for the development of many large embedded units. 14. The EMC has itself noted that many market costs are almost wholly fixed with respect to system demand or output (see EMC, “Comments and relevant information/documents relating to the treatment of embedded generation”). Hence, these costs should be recovered in a way that influences (ie distorts) decisions least. One way of doing this is Ramsey pricing. The comments in the report on smaller customers having lower price elasticity were based on international experience. However, the report noted that such an approach would raise difficult policy and implementation issues. 15. The key implication of exceeding the registration threshold is centralised settlement. However, if a decision is made to continue the existing regime for

		regulation, EMC and PSO fees, generators between 1 MW and 10 MW could continue to be charged these fees using either some other mechanism or a different classification of registration that allows these fees to be imposed while exempting these parties from centralised settlement. 16. Whether and how any greenhouse benefits providing by embedded cogenerators should be recognised is a policy matter. The report noted that a variety of options for recognising these benefits are available to the Government. 17. The recommendations in the report note that "the current arrangements for embedded generation in Singapore are broadly reasonable, within the context of the NEMS" – hence the lack of recommendations for change. The areas where changes could be made are highlighted. Whether changes should be made is always a policy matter.
ExxonMobil	1. Argues that if there is inefficient embedded generation due to favourable treatment, there should be qualification criteria (eg efficiency target). There should not be restrictions on the unit size, system capacity or export of embedded generation. Setting such restrictions will not prevent inefficient embedded generation being added to the system and may prevent inefficient and beneficial embedded generation. But adding qualification criteria will promote efficient and optimally-sized capacity. Such criteria could involve a minimum efficiency target or absolute or relative (% of unit capacity) MW export	1. As noted in the report, favourable treatment of embedded generation may lead to an inefficient level of over-investment in embedded generation from the perspective of the NEMS – ie more embedded generation than is optimal. This may create concerns for system security in the longer term. One way of addressing this could be measures such as export limits, which may reduce the attractiveness of developing embedded generation notwithstanding the favourable treatment. However, this concern does not relate to the technical efficiency of embedded generators (as suggested by ExxonMobil). Ensuring

	limits. 2. Argues that physical system requirements should be kept separate from market participation and settlement requirements. Coordinating and cooperating on physical requirements with the PSO is reasonable, but imposing market participation and settlement obligations is inappropriate. 3. Disagrees that it may be necessary for larger embedded generators to be obliged through licence conditions to provide spinning reserve or frequency response.	the technical efficiency of embedded generation is a matter for the proponent – the proponent already has strong incentives to ensure the embedded generator minimises fuel use and provides the required amount of heat and power. Export limits should not prevent customers from developing embedded generators of sufficient and efficient size to serve their own needs. That said, there may be other reasons why the government might want to encourage embedded generation, such as greenhouse benefits or to assist industries overcome the high cost of electricity in Singapore. 2. Noted – any physical requirements would be a response to any signals for over-investment produced by the regulatory regime. On market registration and settlement, the report states that consideration should be given to raising the threshold to 10MW. 3. Embedded generators do not reduce the amount of regulation or spinning reserve required in the NEMS (subject to the installation of LLDs). Therefore, net treatment may inefficiently (from the perspective of the NEMS) lead to overinvestment in embedded generation and higher system costs. This will be more likely to occur if embedded generator is permitted to export as much as it wishes – it will effectively replace new standalone generation while escaping payment for regulation. One response to these incentives may be through licence conditions.
Keppel Energy	1. Notes that different jurisdictions may implement different arrangements for their own reasons and	1. Noted – agree, arrangements in other jurisdictions should not determine appropriate arrangements in

	these need to be taken into account to make a reasoned judgment. 2. Argues that parties invest in Singapore on the basis of a package of reasons. Other means are available for assisting embedded generators than tweaking the design of the NEMS. 3. Comments that it is surprising that Frontier suggests costs could be recovered from only domestic and small customers.	Singapore. However, they provide useful examples of how other governments and regulators have dealt with similar issues. 2. Noted – agree. The report provided a range of options for the Singapore Government to achieve similar ends. For example, a greenhouse tradeable permit scheme could be used to recognise greenhouse benefits, assuming the government decided, as a policy matter, that such benefits should be recognised. The report also discussed the option of basing certain charges in alternative ways (eg Ramsey pricing, gross load, charging etc). 3. These comments were based on Ramsey pricing principles. However, the report noted that such approaches would raise difficult policy and implementation issues.
Power Seraya	1. Argues that the NEMS was established on a 'gross pool' basis. Unlicensed generators could free-ride on the benefits provided by others and undermine the market. 2. Supports existing charging regime for regulation reserve. A 'causer pays' regime appears to be overly complicated for a small market like Singapore. 3. Supports existing 'modified runway' method for charging for spinning reserve costs, unless LLDs fitted. 4. Rejects net treatment for market fees and charges as this could lead to inefficiency. Price	1. The Australian NEM is also a 'gross pool', meaning that electricity traded through contracts is settled through the pool, but nevertheless provides for net treatment for embedded generators. Even if the NEMS was designed to treat embedded generators similarly to standalone generators, the report was commissioned to determine whether this was appropriate. 2. Noted – whether a causer pays regime is considered is a matter for the Government. 3. Noted. 4. Noted – price discrimination for market fees and

	discrimination would not be socially acceptable. 5. Supports existing transmission pricing regime. 6. Argues that the registration threshold for generators (1 MW) should not be raised. Supports Frontier's suggestion for an additional license condition for embedded generators to remain frequency sensitive and provide spinning reserve and have AGC.	charges is a policy matter. 5. Noted. 6. Noted – see also response to (1) above.
Senoko	1. Argues that the argument for net treatment does not stand. The report lacked specific recommendations for the equitable treatment of embedded generation in Singapore. 2. Argues that the reserve burden of embedded generation is not limited to the net amount injected or withdrawn. Frontier dismissed the risk of price volatility due to sudden withdrawal of embedded generation. 3. Argues that the NEM was established on a 'gross pool' basis. It would be inequitable to exempt embedded generation from this. 4. Criticises the report for not addressing the need for a maximum limit on the amount of embedded generation in the Singapore system, the imposition of a code of practice or the presence of exempted embedded generators. 5. Argues that environment-related benefits of embedded generation should be dealt with outside of the electricity market.	1. Noted – the report did not advocate net treatment as such but argued that net treatment was simply one way to recognise certain benefits of embedded cogeneration. 2. Agree that reserve requirement is based on gross system load rather than net system load. Price volatility is a matter for participant risk management. For example, standalone generators are not penalised by the regulatory arrangements if their plant experiences forced outages. However, the loss of market revenue from forced outages should incentivise reliable operation. Similarly, owners of embedded generators face commercial incentives for reliable operation. 3. The Australian NEM is also a 'gross pool', meaning that electricity traded through contracts is settled through the pool, but nevertheless provides for net treatment for embedded generators. Even if the NEMS was designed to treat embedded generators similarly to standalone generators, the report was commissioned to determine whether this was

	6. Argues that the report should contain tangible proposals for dealing with embedded generation.	appropriate. 4. The report notes that there may be a case for specific requirements for embedded generators to ensure system security. Exempt embedded generators are excluded from the scope of this report. 5. The report noted that a variety of options for recognising these benefits are available to the Government. 6. The recommendations in the report note that "the current arrangements for embedded generation in Singapore are broadly reasonable, within the context of the NEMS" – hence the lack of recommendations for change. The areas where changes could be made are highlighted. Whether changes should be made is always a policy matter.
Singapore Refining Company	1. Argues that embedded generators should receive net treatment for regulation and spinning reserve since they are too small to impact the network. 2. Asks whether embedded generators will have to sign a generation licence considering generation is not the core business of the owners. 3. Asks whether embedded cogenerators will be allowed to export surplus power on either a continuous or intermittent basis. 4. Requests the timeframe for ultimate resolution of the issue and clarity of specific regulations.	1. Noted – the report argued that net treatment may promote inefficient over-investment (in the context of the NEMS), even leaving aside system security issues. However, net treatment is one way to recognise other benefits of embedded cogeneration. 2. This is a policy decision. However, the report argued that licensing of embedded generators (above 10MW) was important to ensure obligations in the Transmission Code, Market Rules and System Operator Manual were obeyed to ensure system security. 3. Again, this is a policy decision. However, the report suggested that some limits on export could be imposed as one means of deterring excessive

		embedded generation. 4. This is a policy matter.
Shell Eastern Petroleum	1. Queries whether embedded cogeneration is a subset of embedded generation. If so, only embedded cogeneration should be rewarded for greenhouse gas savings (3.1). 2. Requests more information on the $0.82/MWh charge for regulation – 2005 costs were closer to $2.50/MWh (3.3). 3. States that Australia has RECS and other greenhouse schemes in place. Most countries referred to in the report as status 'unknown' offer net treatment for embedded generation (4). 4. Argues that embedded generation provides greater efficiency, lower greenhouse emissions and network benefits (5). 5. Argues that gross load treatment for regulation will not represent a change from the current situation except that generators will not have to incorporate these costs in their bids (6.1.1). 6. Argues that the cost of regulation is much higher than $0.82/MWh (6.1.1). 7. Argues that while a causer pays regime is fair in principle, the costs will be passed on to consumers (6.1.1). 8. Argues that LLDs effectively eliminate the incentive to be connected to the grid. However,	1. Embedded cogeneration is a subset of embedded generation. Agree that only embedded cogeneration should be rewarded for greenhouse benefits – this was noted in the recommendations of the report. 2. The $0.82/MWh refers to the average 2004 charge for regulation, based on information provided by the EMA. 3. Noted – RECS are part of the MRET scheme mentioned in the report. 4. Most of these benefits are already recognised by the regulatory arrangements. No documented information of arrangements in the 'unknown' jurisdictions was provided by stakeholders. 5. As generators' regulation costs do not change with increased output (after the first 10 MW), it is unlikely generators recover this cost through higher-priced bids than would otherwise be the case (ie it represents a fixed cost rather than a marginal cost). 6. See response to (2) above. 7. Noted – proper assessment of a causer pays regime for regulation is a matter for the Government. 8. Noted – however, connection with LLDs allow participants the ability to draw their surplus power needs from the grid (eg have a 100 MW load and

	island mode would create risks and disruption (6.1.2). 9. Agrees with peak charging for network costs. But queries why participants are charged for going beyond contracted capabilities (6.1.4). 10. Supports increases in the registration threshold to 10 MW or even 100 MW. This should be based on generator unit size rather than total sum of units at a site (6.1.5). 11. Argues that ownership and proximity rules for embedded generation should consider substance over form and examine on a case-by-case basis. Ownership restrictions will reduce opportunities for outsourcing (6.1.6). 12. Urges Frontier to consider comments of the National Environment Agency to ensure strategic alignment. Kyoto protocol should be taken into consideration. Recognition of greenhouse benefits should not be restricted to embedded cogenerators only, but also generators using non-saleable refiner process-steam (6.2).	install an 80 MW embedded generator). 9. Contracted charges are designed to recover the costs of the network near the load. If contracted capacity is exceeded, this may result in the need for network augmentation in the long term. 10. Noted. 11. Noted – this is a policy matter for the government. The report stated that a small degree of relaxation of the existing policy need not threaten the Government's original position. 12. Noted – the way in which any greenhouse benefits of embedded cogeneration are recognised is a policy issue. Generators using non-saleable refiner process steam are effectively cogenerators in the context of the report.

Table 3: Market participant submissions on Frontier's Draft Report and Frontier's responses

Appendix D – Stakeholder comments on the Draft Report and Frontier responses

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