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COAG Energy Council
SYDNEY NSW 2001

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SUBMISSION: NEG DESIGN FEATURES

Meta Economics welcomes the opportunity to comment on issues raised in the Energy Security Board (ESB) Consultation Paper of 15 February 2018, which seeks input on potential design elements of the proposed National Energy Guarantee (NEG). We endorse the aim of delivering abundant, reliable and low cost electricity to Australian energy consumers as part of a national framework that can also support significant future greenhouse gas (GHG) emission reductions in an affordable, efficient and equitable manner. Australia has a role in international efforts to reduce emissions and – like the international scene – all industries and activities have a role to play in achieving that outcome domestically. Individual costs and capabilities are key factors in determining the scope and extent of that role. The needs, abatement potential, economic contribution and technological capability of industries and activities can vary widely and change over time. Policy frameworks should have the flexibility to recognize and accommodate that.

We offer the following comments on issues raised in the ESB Consultation Paper under the broad headings of Emission requirements, Reliability requirements and Other design issues & features.

Emission requirements

We note that the greenhouse gas (GHG) emission reduction task set for the electricity sector to 2030 has not yet been defined, and the National Energy Guarantee (NEG) is being proposed as a framework to support reliable and low emission electricity supply. Although modelling for the NEG has focused on a sectoral emission target that parallels the national target proposed by Australia as part of the 2015 Paris Climate Agreement (ie. achieving a 26-28% reduction on 2005 over the decade to 2030), the appropriate emission outcome for the electricity sector should be less about its share of national emissions and more about its potential contribution to low cost abatement outcomes at a national scale. The electricity sector's contribution to Australia's GHG abatement task should reflect the cost and extent of abatement opportunities in all parts of the economy and the mix of activities that can deliver Australia's emission target at the lowest possible cost.

Meta Economics is supportive of a consistent national approach to GHG emission reduction, and features within the NEG that facilitate a 'joined up' approach. We would not wish to see the electricity sector (and downstream electricity consumers) bear an excessive level of costs in contributing to national abatement efforts, nor would we wish to see an uneven or inconsistent set of sectoral approaches emerge that led to excessive costs at a national level. Transparency around options and costs is essential to supporting well informed decision making. Program design should reflect expert and pragmatic advice on a wide palate of options and substantive empirical analysis of costs, benefits and risks.

We commend the Energy Security Board on the empirical analysis that it has released to date and encourage ESB to undertake and release more as a priority - particularly analysis that can help illuminate the full set of feasible options and outcomes, and which draws on a range of relevant expertise.

The ESB Consultation Paper seeks input on a range of potential design features and flexibility mechanisms that could be built into the NEG. In making those decisions it is vitally important to have good information on the likely and potential costs and benefits associated with each feature in order to determine its 'value' as a possible inclusion. In the absence of this information, the discussion of potential NEG design options threatens to become an exercise in theory or optics.

Meta Economics has undertaken some preliminary empirical analysis of a notional 26% (by 2030) GHG emission reduction target for the NEG (mirroring the national greenhouse target) that can help highlight what is at stake in deciding the features of the emission reduction regime that should be applied to the electricity sector. Our modelling suggests that the stakes are high, and some design decisions can be vital to limiting costs and ensuring the effectiveness of the mechanism.

Benefits from flexibility mechanisms are likely to be substantial

The inclusion of flexibility mechanisms is theoretically attractive, and this is borne out by the Meta Economics modelling. Crucially, the costs of achieving an emissions target for the electricity sector are dramatically reduced if abatement is drawn from least cost sources. Analysis indicates that these sources are much more abundant outside of the electricity sector. If policymakers are to ask electricity consumers to bear the cost of GHG emission reductions, it is reasonable that those reductions be sourced at the lowest cost possible – noting that the national GHG target for the decade to 2030 defines an emissions quota, and any offsets consumed should subtract from that quota if the target is to be achieved reliably and at least cost.

In recent analysis, Meta Economics applied marginal abatement cost estimates published in 2016 by the Commonwealth Department of the Environment and Energy (DoEE) to explore the costs of achieving a 2030 emissions target through abatement sourced from within and outside the electricity sector. The modelling (using our MACtrax model) depicts an abatement requirement equal to 40 million tonnes of carbon dioxide (40Mt CO_2e) over the period 2021-30 with emission reductions being sourced from electricity generation and transmission activities only, versus abatement action that draws on these sources plus emission reductions available in the mining, manufacturing and waste sectors. Abatement cost estimates are derived from linear decomposition of the DoEE estimates. That is, the reported abatement pool for each activity is assumed to display linearly increasing marginal abatement costs, with an equal quantity of abatement available above and below the average abatement cost reported for the relevant abatement pool.[1] This recognizes that reported average abatement costs for an industry or activity group actually reflect a range of individual cost outcomes distributed around an average value.

Using these disaggregated estimates, the Meta Economics MACtrax provides insights to the:

- likely cost of delivering emission targets through action focused in the electricity sector
- least cost mix of activities likely to be involved in that outcome; and
- savings that might be achieved by allowing the electricity sector to draw on lower cost abatement available elsewhere in the economy.

Importantly, and as an extension to the modelling released by ESB in October 2017, the MACtrax modelling captures a wide set of process, refurbishment and greenfields investment opportunities that can be drawn on by those with emission reduction obligations under the NEG. As such, the costs indicated for delivering the overall abatement target are likely to be substantially less than those implicit in the ESB's October 2017 modelling (noting that overall cost estimates were not released as part of that study).

Key cost outcomes under an 'electricity only' versus 'multi-sector' approach to abatement (ie. purchase or funding of emission offsets) are shown below in Table 1. Two response scenarios are examined.

[1] The source marginal abatement cost data appears in Energetics (2016), Modelling and analysis of Australia's abatement opportunities, Report to the Department of the Environment, May 2016. Appendix B, and a more detailed discussion of the Meta Economics MACtrax model which applies this data is available in Meta Economics Working Paper 18-01 (copy attached).

Table 1 **Cost of delivering a 40Mt CO_2e emission savings under an electricity only versus multi-sectoral approach**

	Electricity sector-only abatement		**Multi-sectoral abatement**	
Costs associated with 40Mt CO2e saving in 2021-30	Negative cost abatement accessed	Negative cost abatement excluded	Negative cost abatement accessed	Negative cost abatement excluded
Total cost	-$702.8m	+$1,750.8m	-$2,472.8m	+$116.1m
Marginal cost (cost of last unit of saving per tCO2e)	+$13.23	+$99.72	-$13.01	+$7.50

The first response scenario shows the implications of harnessing 'negative cost' opportunities as part of abatement efforts. These opportunities represent emission reductions that are associated with cutting costs or boosting productivity. They represent a win for both the economy and the environment and emanate from eliminating poor practices and decision making and doing things "smarter and better".

The other scenario assumes away these so called "no regrets" opportunities and focuses on the cost of the abatement task if every tonne of CO_2 (and its equivalent) saved involved a net cost to the emitter or enterprise undertaking the action. This type of emission reduction is not economically beneficial or attractive to the emitter unless some offsetting payment is provided. In essence, this scenario assumes that there are no "free lunches" or potential efficiency improvements in current processes available that could yield both cost and greenhouse savings. More importantly, it also recognises that a simple price based mechanism (particularly one yielding a relatively modest price) may not be sufficient to unlock significant efficiency gains that languish in the face of existing pressures from markets, pricing, incentives and performance management. If these kinds of efficiency gains are to be brought online, more tailored approaches are likely to be required.

Nevertheless, under either scenario the gains from opening the NEG up to abatement available beyond the electricity sector are likely to be substantial. If the NEG could activate "no regrets" abatement options in the upstream electricity sector, our modelling (based on the published marginal abatement cost estimates discussed above) indicates that a 40Mt emission reduction over the decade to 2030 could be achieved at a net cost saving of about $703m, with the most expensive tonnes of abatement required to achieve the target costing around $13.23. In contrast, a multi-sectoral approach could deliver the same target outcome with around three to four times the value of net savings, with each tonne of emission reduction being associated with in-house efficiency improvements worth a minimum of $13 (on a net present value basis).

The gains from offset trading and a multisectoral approach are magnified if negative cost emission savings cannot be harnessed. Delivering a 40Mt saving in the period 2021-30 using the NEG under an 'electricity only' scenario is estimated to have a net cost of around $1.75 billion compared to just $116m if extra emission savings from other sectors were counted under the scheme. That is, about a **fifteen fold cost reduction is feasible under an approach that allows NEG participants to source emission offsets from sectors beyond electricity.**

While all emission savings would need to be found within the electricity sector under an 'electricity only' approach, broadening the focus to allow offsets from other sectors would see generation and transmission carry a much lower abatement burden – with a substantial cost saving to the electricity sector and the economy overall. In the MACtrax multi-sectoral modelling, electricity suppliers account for about 8 of the 40Mt of abatement required to hit the emission target.

However, it is critical that ESB and other policymakers recognise that for offsets to be part of a coherent national greenhouse response it is necessary to ensure that any emission credits sourced by NEG participants represent a real reduction in the emission quota available to other part of the economy (in line with the 2030 national emissions target). Crediting emission savings derived from forecasts of 'business as usual' emissions output can easily result in a significant pool of emission offsets whose actual contribution toward national emission reduction aims is negligible. Uncertainty and generous judgement calls associated with forecast-based approaches can lead to the creation of credits based on elimination of a future tonne of atmospheric carbon dioxide that wouldn't have occurred anyway. They have little value in a serious system focused on minimising the cost of achieving real reductions in national greenhouse gas output.

Consider retailer AND generator offset purchases

Further, the ability to utilize emission offsets need not be restricted to energy retailers with obligations under the NEG. If offsets (or 'credits' or 'allowances') were sanctioned under the scheme, it can be beneficial to allow electricity generators to source them and bundle them with their product. This bundling approach would allow generators to effectively reduce the emission intensity of their product by negating part of the emissions output associated with creating a unit of electricity, and help with their transition into a low emission future by allowing them to participate in and benefit from investment in low cost abatement. The feasibility of this would be linked to the emission reporting and verification requirements established in support of the NEG.

Reliability requirements

The current reliability standard of 99.998% is not being met, as demonstrated by the Code Black in South Australia and the load shedding that has occurred in different jurisdictions. It is even less likely to be met with an increasing penetration of supply of intermittent non-dispatchable generators such as wind and solar.

A standard should be set that recognises the realities of the changes in the electricity market that is practically achievable, rather than aspirational. The current five 9's may not be achievable and two 9's or 99% reliability is unlikely to be acceptable. It is not clear how the reliability standard being targeted by the NEG compares with that being achieved today (or the five 9's 'gold standard').

No new dispatchable fossil fuel generators such as coal-fired or combined cycle gas turbines are likely to be built in Australia. They both have 30 year tax depreciation lives and the scientific and policy uncertainty cannot be priced into any business plan for potential future investment. As a data point on this uncertainty, note the statements of major corporate financiers that they will not be investing in coal-fired generation. This is not only due to public relations activities but also the economic risk associated with any long-term investment in this emission intensive activity.

According to the ESB Consultation Paper "*Modelling undertaken at the request of the Government suggests the Guarantee will deliver around 27-36% renewables (mainly hydro, wind and solar) by 2030, but with only 18-24% of that mix coming from variable generation that can cause reliability concerns.*"[2]

AER data has total generation capacity at 100 gigawatts (GW) currently, including dispatchable and non-dispatchable[3]. Assuming no growth in total demand, the 18 – 24% from intermittent generation could require a backup of a substantial proportion of the 18 -24 GW generation capacity for extreme weather events. The capital cost of open cycle gas turbines is around $1 million per megawatt (MW) – as a broad rule of thumb. Operating costs will depend upon how often and for how long they are used. Capital costs are therefore of the order of $1 billion per GW of generation capacity. In a perfect reliable world without extreme supply and demand imbalances, they would never be used and never return any income. The costs would still have to be borne by electricity consumers. It would be useful to have greater transparency around these costs to support the design and risk management task ahead.

Further, we foresee potential problems with meeting the reliability standard and accommodating demand growth.

[2] Energy Security Board (ESB) (2018), NATIONAL ENERGY GUARANTEE CONSULTATION PAPER, 15 FEB 2018, p.3

[3] https://www.aer.gov.au/wholesale-markets/wholesale-statistics/generation-capacity-and-output-by-fuel-source

ESB has stated in the Consultation Paper:

'AEMO will forecast whether the reliability standard is likely to be met in any NEM region over a forecast period. If there is a shortfall the market will be expected to react and start to invest in new capacity or offer existing additional capacity. If the gap doesn't look like it will be met there will be a trigger for retailers and some large energy users to contract for capacity depending on the size of their peak load requirements. This capacity could include fast response resources, such as batteries and demand response, or slow starting but longer running resources such as coal and gas'.[4]

An issue with this approach is that a retailer, operating on a commercially conservative basis, may have covered itself with enough reliable supply and seek to effectively 'close its books' to new customers as a way of avoiding new capacity requirements. With the expected expansion in smart meters and development of new contracts they may be capable of effectively supplying their customers and put in place hindrances for new customers to join them. There will no doubt be a price that these customers will have to pay for this reliability. If this strategy becomes widespread amongst retailers, who is going to be the retailer of last resort?

Expanded demand management presents challenges

A variety of demand management approaches can be integrated into the NEG. These span mechanisms that drop off specific consumer loads in response to unforeseen demand peaks and likely shortages and seek to shift the load (with compensation attached), to schemes that seek to reduce end user energy consumption commensurate with energy efficiency improvements and effectively reduce the load over time. As such they can have value from both a reliability and emissions perspective.

The easiest, simplest method of achieving a reduction in demand for electricity in peak periods is through large industrial consumers where coordination and transaction costs are minimised. However, this is likely to be a diminishing share of electricity demand in the future. Household demand management is feasible -but challenging.

The Finkel Report provides a case study of a small-scale experiment on demand management in NSW of 500 consumers for one afternoon in a heat wave period as a success. But the report also notes "*While some residential consumers are responsive to price signals, evidence from other countries suggests that this is difficult to maintain over time. Demand response is best achieved when the consumer is not required to manually respond, but the demand reduction is orchestrated by a service provider who has an agreement with the consumer covering the terms under which their demand can be curtailed or shifted*."[5]

There is scope for improving reliability through household demand management. Households are major contributors to peak load demands. A process can be put in place to develop methods and products that will enhance demand management. This is not to dispute that there are going to be some very difficult equity/efficiency issues to be resolved with customers.

One lesson for future programs is that mandatory rollouts of smart meters have not delivered the gains initially claimed as demonstrated by the Victorian example.

Experiments with new electricity supply offerings should be undertaken by retailers – in cooperation with distributors. They have the incentive to find the right mix of supply interruptions and pricing to achieve specific targets. There will no doubt be difficult issues to be worked through such as pricing of the meter and access to the grid. This is best left to private negotiation.

Improvements in energy efficiency will help to reduce demand and therefore improve reliability. This should be undertaken by the private sector as a means of reducing costs both for industrial and household customers. There have been claims that retrofitting of existing buildings for energy efficiency has been slow and therefore the government should provide taxpayer funded incentives to improve this efficiency. Most of these benefits are privately accrued and therefore should be substantially privately paid for, with policy focusing on correcting the structural failure in the market and allowing improved decisionmaking

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[4] ESB (2018) op cit, p.1

[5] (Finkel Review, 2017) The Independent Review into the Future Security of the National Electricity Market, p.147

to flow from that. There will no doubt be private sector organisations that will be able to search for products that will provide a net benefit to consumers in reduced electricity consumption. Electricity retailers themselves may be slow to embrace activities that run contrary to their traditional 'core business' – ie. selling electricity.

Other issues & features

While renewable technologies are moving ahead rapidly in terms of sophistication and cost competitiveness, there is a need for pragmatism in thinking through how they can best be integrated into our future energy mix. To maintain reliability and keep the risk of outages at tolerable and agreed levels a portfolio of technologies is needed accompanied by deep planning around locational and technological vulnerabilities, reserve capacity, back-up supply options, system resilience and consumption priorities.

Renewable generation and back-up technologies

Hydroelectric generation

Hydroelectricity provides the advantage of being a dispatchable, renewable generation source. There are studies and proposals suggesting that there is significant scope for expansion of pumped hydro. There are currently only 3 operating pumped hydro generators in Australia. Experience in Australia and the US shows that building new dams is difficult, even when the location is suitable, because they are likely to be in hilly or mountainous regions, and as has been noted in the US "potentially in areas of outstanding natural beauty, and therefore there are also social and ecological issues to overcome."

Seawater pumped hydro has also been suggested as a solution for Australia. There are currently no pumped seawater hydro commercial generators operating in the world. There has been one previously, but it was closed due to major technical problems.

The recharge rate of hydro schemes in terms of power use and time requirements can also emerge under circumstances of extreme demand and/or weather conditions.

This is not to dispute that at the margin additional hydro generation can help improve grid reliability, but it may not deliver sufficient quantities of power for long periods.

Biofuel generation

Electricity generated from biofuels is dispatchable. Much of this generation currently comes from sugar mills, wood waste, rubbish tips and piggeries. Possible expansions in biofuels production could occur through growing crops specifically for fuel production. This would then run into the problem of prioritising production of our agricultural products. Do we grow food to feed people elsewhere in the world or to provide electricity for Australians? Another option for increasing biofuel electricity production is using timber as the fuel for steam turbines. However, there may be objections to putting forests into furnaces.

Capacity expansions in this category can be problematic.

The Finkel Review does not forecast a major expansion in electricity generation from this source.

Wind and solar generation

These are the expanding generation technologies but no commercial, scale storage technology is currently available, and these are the obvious intermittent generators. Research is being undertaken on methods of storage such as molten salt but none of the technologies are currently commercially viable.

Further, the long term character of their intermittency is still not fully known as there are gaps in our knowledge of the duration and geographical extent of prolonged cloud cover or windlessness. Extreme weather events could have a major impact on the reliability of intermittent generators for extended periods of time. This needs to be factored into the reliability calculus, and subsequent planning and supply portfolio management.

Battery storage

This is a technology that can provide security to the grid and improve reliability over relatively short periods of time. At household level there are issues to be worked through that can hinder their uptake such as the draft ruling on lithium ion battery storage by Standards Australia. Though there has been much public discussion of large-scale battery storage, the storage capacities are only measured in hours and limited in scale. The largest battery storage facility in the world is located in Buzen Japan and, at 300MWh, is capable of delivering 50 MW or power for a period of 6 hours. It is a sodium-sulphur battery. Hornsdale in South Australia is home to the world's largest lithium-ion battery which can deliver 100MW of power and 129MWh of energy.

Much more research, experimentation and capacity is required before batteries become a major contributor to grid reliability – particularly over extended periods.

The role of gas

There is recognition of the linkage between gas availability and the reliability of electricity supply. This is nothing new. As Ross Garnaut noted in a previous review of Australia's energy policy settings:

"*When I was working on the first climate change review in 2007 and 2008, Australia had the developed world's cheapest natural gas available for domestic use—about one third of United States prices. The first climate change review recognised a major role for gas-fired electricity as a transitional fuel and for balancing the intermittency of renewable energy."*[6]

With current technology, the only generation options to back up intermittent supply with both the capacity and potential duration periods required are open cycle gas turbines and diesel generators. They both have the advantage of being fast start to provide reliability and are a complement to the intermittent generators in all aspects. Carbon emissions would only occur when they were called on to support regular supply.

There are certain issues that need to be resolved before these alternatives can be accepted as ensuring reliability in the grid:

- is there a reliable supply of gas to service urgent and unforeseen needs (possibly over an extended period, as required)?;
- how might changes in the price of gas affect supply and investment decisions?; and
- the current tax life for depreciation purposes is 30 years for open cycle gas turbine and 20 years for a diesel generator, is this still appropriate and what if the rules are changed against these technologies before they are fully depreciated? Unlike baseload generators which are physically fixed assets, the above peak generators can generally be relocated and sold to overseas buyers thus reducing some of the potential cost risks.

These are complex issues that will require much deeper consideration. It is essential to bring a balanced and pragmatic approach to analysis of Australia's energy needs and the development of measures that support the uptake and mix of technologies required by Australians as we progress into the 21st century.

We would be pleased to discuss these comments and insights further, and hope they are of assistance to the Energy Security Board and other stakeholders in the deliberations ahead.

Yours sincerely

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Attached: Meta Economics Working Paper WP18-01

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[6] Garnaut R, http://reneweconomy.com.au/the-economics-of-the-future-energy-system-75051/