Independent Review into the Future Security of the National Electricity Market

MARCH 2017
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Executive Summary

Our energy system is the cornerstone of our economy powering our industries, our cities and our homes.

Yet our homes consume less than 30 per cent of Australia’s electricity. The bulk of electricity is used in Australian businesses to support our competitiveness and to create jobs and prosperity for Australians.

And so we must get our energy supply right. But at the moment we’re not.

Our electricity and gas markets are undergoing substantial change and this has recently resulted in blackouts for South Australian customers and higher electricity and gas prices for all customers.

The current design of our electricity markets relies on a lot of flexibility from our electricity system.

We need electricity generation, networks, demand or storage that can provide services other than energy (such as inertia or fast frequency response) that can help to manage the operation of the system. This is often referred to as the security of the electricity system.

We also need enough generation available day in and day out to meet our average demand along with generation or demand response that can quickly switch on or off when demand peaks or if something in the system fails. This is often referred to as the reliability of the electricity system.

New sources of lower emissions electricity generation are less reliable and don’t provide the same level of flexibility

To date Australia’s electricity system has served us well and been a source of competitive advantage for Australian businesses. However, like other electricity systems around the world, our system is transitioning away from higher emission technologies and towards low or zero emission technologies. Some of these technologies, such as solar and wind, are intermittent and cannot be relied upon. They also don’t naturally provide system security services such as inertia. Although increasingly solar and wind, with additional technology, should be able to provide at least some of these services.

The integration of large volumes of intermittent wind and solar generation and the exit of a number of coal and gas-fired generators has therefore presented a series of challenges for the security, reliability and affordability of our electricity systems.

There are significant challenges with the availability and affordability of gas for electricity generation and for industry

The emergence of the LNG sector in east-coast Australia has significantly increased the volume of gas produced and contributed strongly to employment and export earnings. However, this growth, together with delayed or restricted access to new resources, has also created challenges for the domestic gas market with the price and terms of domestic gas contracts now very different, if available at all.
We must take immediate action to restore the security, reliability and affordability of our energy systems while delivering the long-term signals needed for investment

Our immediate focus must be on restoring the security, reliability and affordability of our energy systems. However, we cannot ignore the need for a more sustainable system as we transition towards a lower emissions economy.

Clear, stable energy and climate change policy will be critical to support much needed investment in the sector. Without new investment, we cannot deliver the security, reliability and affordability Australians expect.

The Business Council considers that the Independent Review into the Future Security of the National Electricity Market (the Review) should focus on the following five key reform priorities:

- Ensure security of electricity supply and restore community confidence in the operation of the National Electricity Market (NEM)
- Create conditions for investments necessary to support the reliability of energy markets
- Improve affordability of energy supply to drive a strong, internationally competitive economy
- Ensure the necessary incentives are in place for the energy sector to make its contribution to achieving the 2030 emissions reduction target
- Preserve optionality across all timeframes to achieve deeper reductions in emissions beyond 2030.

Governments collectively hold the policy tools to influence three critical levers within the energy system – market design, fuel supply and infrastructure investment.

Each of these levers must be pulled in a coordinated fashion if we are to deliver the stable, integrated energy and climate change policy that will secure investment across the short, medium and long term.

1. Ensure security of electricity supply and restore community confidence in the operation of the National Electricity Market (NEM)

Preserve the broad architecture of the NEM market design with specific changes to address security concerns

The failure to maintain a secure electricity system can leave a household stranded, cripple a business and significantly constrain economic activity.

In the main, the NEM continues to perform reasonably well in all states except South Australia, which is literally at the end of the line.

While the ‘system black’ event in South Australia in September 2016 was caused by an extreme weather event, the cascading failures that followed that day, along with the switching off of some customers in South Australia in summer 2016-17, highlight the need for some reform of the NEM’s current operation.

The Business Council supports the preliminary findings of the Australian Energy Market Commission and agrees that the ability to maintain power system security in an efficient manner could be enhanced by the development and introduction of a mechanism to
obtain inertia and support for the development of a fast frequency response (FFR) service. This work should be prioritised with recommended changes implemented as soon as possible.

2. Create conditions for new investment to support the reliability of energy markets

*Improved market information to manage transition and support electricity investment*

Information about the expected supply–demand outlook is a critical driver of electricity infrastructure investment decisions.

Currently, generators are only required to notify Australian Energy Market Operator (AEMO) about whether a generation unit will be physically available at a point in time. There is no indication of whether a generation unit has sufficient fuel to run for any period of time. The quality of information could be improved by publishing an aggregated energy (fuel) budget for each region over a period of time.

The electricity forward market extends out three years and significant, rapid changes in supply or demand can have huge impacts on the volatility and liquidity of the electricity contract markets.

In addition, it has been suggested that the timeframes for the announced closure of the Northern and Hazelwood power stations were insufficient to support system planning, community transition and to signal the need for new investment in electricity generation which has resulted in very high forward electricity prices.

To support a managed transition of the electricity sector, a three-year notice period for the withdrawal of registered market participants (both generation and load) could be considered.

*Measures to ensure adequate investment in ‘firm’ generation to manage increased intermittency*

Because of the intermittent nature of both wind and solar, additional ‘firm’ generation capacity (such as gas-fired electricity generation) may also be required as has been the case in South Australia since the closure of Northern power station. Additional measures should be investigated to ensure there is adequate ‘firm’ generation capacity to support increasing investment in intermittent renewable technologies.

*Stable policy frameworks with minimal government intervention in markets to support electricity investment*

With the Hazelwood power station in Victoria set to close in 2017 and the Liddell power station in NSW to close in 2022, substantial new investment will be required in the NEM to maintain system reliability.

The planning, permitting and construction of a power station (wind, solar or gas) can take several years with any new coal-fired generation facility (if it could indeed be financed) expected to take much longer than this.
Electricity infrastructure involves capital intensive, long-lived assets and stable policy settings, and clear market price signals are critical to support investor confidence.

Policies that suddenly shift from one place to another or see governments entering markets risk jeopardising, or at the very least confusing, this investment.

On the basis of this, there should be no further changes or extensions to the RET. Although renewable energy targets are a source of market distortion, the RET has underpinned significant investments and it should be left alone. To make further changes would have a chilling impact on investment right across the sector.

Similarly, governments should not enter the electricity market by offering contracts for difference for particular forms of energy or by directly contracting or acquiring sources of supply. These types of interventions undermine the price signals in the NEM and could be counterproductive to achieving our electricity market objectives.

Unilateral action by state and territory governments can also undermine investment. In particular, where state and/or territory governments implement policies that distort the operation of the NEM – such as state-based renewable energy targets – this can be particularly damaging to the investability, reliability, affordability and long-term transformation of the whole electricity sector, while actually increasing the costs of renewable energy projects.

There is no role for state-based renewable energy targets.

3. Improve affordability of energy supply to drive a strong, internationally competitive economy

In the face of multiple generator exits and record heat waves across summer, the NEM is now experiencing high wholesale prices which, in the face of stable, long-term policy settings and access to competitively priced fuel, should act as a sufficient incentive for new investment.

Current and future wholesale prices are currently above the long-run marginal cost of new generation. So new investment is needed to take some of the current heat out of wholesale prices.

However, the long-run marginal cost of all new generation technologies is higher than what we have experienced in the past. So while current and future prices may moderate they are unlikely to return to the levels we have experienced in recent years. Unless the long-run marginal cost of new entrant technology falls, wholesale electricity prices are expected to remain above their historical level for some time.

The international competitiveness of Australian industries depends upon our comparative advantage in energy resources. Restoring our comparative advantage in energy needs to be a core policy goal for all governments.
Deep, liquid and transparent gas markets critical to reducing long-run marginal cost of electricity

New investment in both gas-fired generation and renewables is likely to be required to manage the transformation of the electricity sector at lowest possible cost while maintaining system reliability.

Access to accurate and timely market information on the gas supply–demand balance and price outlook is a key characteristic of a well-functioning and efficient market.

This information enables market participants, planners and policymakers to develop a relatively informed view of forward market conditions. It also plays an important role in signalling new supply opportunities, informing risk-management strategies and negotiations, as well as stimulating timely investment.

COAG Energy Council should continue to advance gas market reform to:

- promote diversity of supply competition, market transparency, flexibility and liquidity
- improve the function of the east coast’s facilitated markets to allow for the development of secondary products
- support and implement the development of industry-led pipeline capacity trading and the gas supply hubs through the processes being led by the Gas Market Reform Group.

Increased gas supply critical to reducing long-run marginal cost of electricity

There are currently significant challenges in the domestic gas market with the price and terms of domestic gas contracts now very different, if available at all.

Increasing gas supply will be critical to all gas users and to reducing the long-run marginal cost of electricity. This is now an urgent national priority.

The policy challenge is to ensure that gas producers can access new gas resources to meet domestic and international demand at the lowest possible cost. Increasing Australia’s gas supply is the best way to ensure that Australia can access a reliable and competitively priced supply of natural gas.

It has been suggested that governments could reserve a portion of Australia’s gas for domestic use in an effort to boost the supply of domestic gas.

- To retrospectively force established gas projects, who have contractual commitments, to supply the domestic market would be to impose significant sovereign risk on the gas market. This could have a significant impact on future investor appetite for Australia’s gas sector.
- As part of their licencing regimes, state governments could choose to reserve a portion of future gas fields for domestic use on a case-by-case basis in an effort to boost the supply of domestic gas. If governments are considering this, then they should be mindful of two things:
  - the fields that could come on line are likely to have much higher production costs than Australia’s conventional fields.
  - restricting tenements to domestic use may actually deter investment in these fields, further tightening the supply–demand balance.
All governments should focus on the continued safe, environmentally responsible and timely development of Australia’s gas resources supported by a stable and efficient regulatory regime. Any regime should be risk-based and informed by science. Inappropriate barriers to natural gas development should be removed, including the immediate lifting of moratoriums on the development of unconventional gas reserves.

The regulatory frameworks that currently slow down or deter investments in major gas projects should also be reformed to ensure gas supply comes to market as quickly as possible.

The Business Council’s best practice model for major project approvals aims to encourage vastly better coordination and accountability, through a number of methods:

- A lead agency is assigned to oversee major project development assessments.
- A separate, dedicated assessment pathway is used for major projects.
- One project application, one assessment and one approval for a major project.
- A legislated, maximum umbrella timeframe for approval, ideally set at 12 months.
- Right of review is limited to judicial review, to determine whether the specific approval process was carried out in accordance with legislation (i.e. no merit review available).
- Government agencies involved in the planning and approval process for major projects are required to report on performance indicators relating to timeliness and adherence to best practice.

Network sharing and efficient prices critical to improving affordability

Australia has an already built network of electricity transmission and distribution assets that we must make efficient use of if we are to minimise the cost of electricity facing households and businesses. Advanced electricity meters which support demand-based, cost-reflective network pricing are a critical first step.

Encouraging greater energy efficiency to improve affordability

The lowest cost unit of energy is often the one we don’t consume. Increasing the energy efficiency of our built environment can reduce our energy costs, improve our energy security and reduce our greenhouse gas emissions.

Subject to a cost–benefit analysis, there are a number of opportunities for reducing our energy use in the built environment including:

- the construction and operation of residential and commercial buildings, and
- improving the efficiency of lighting and appliances that use a significant amount of energy.

Cutting the cost of regulation to improve affordability

Retailers play a crucial role in managing risk within the wholesale market and shielding business and household customers from the vagaries of volatile electricity spot prices. However, there are a number of complex obligations facing electricity market participants.
Our members who operate in the electricity sector advise that they are currently required to comply with 5500 different obligations across 250 instruments (state and federal) involving over 50 regulators.

To explore which aspects of the electricity regulatory frameworks could be improved, the electricity sector should be designated as one of the COAG’s Deregulation Priority Areas for 2017.

Furthermore, the AEMC should be asked to review and reduce ineffective, duplicative or inefficient rules. Finally, when the AEMC is considering new and amended rule changes, these rule changes should be assessed against an objective to decrease the regulatory burden across the sector.

4. Ensure the necessary incentives are in place for the energy sector to make its contribution to achieving the 2030 emissions reduction target

Australia’s 2030 emissions reduction target has been set. By 2030, Australia must reduce its emissions by 26-28% of 2005 level emissions. Using the National Greenhouse and Energy Reporting data we must continue to monitor our progress towards meeting this target.

What has not been set is the signal necessary to support the investment needed for the electricity system to move away from emissions intensive generation technologies and significantly reduce its emissions. Exactly how to do this has been the subject of significant debate for nearly 15 years.

The absence of stable, durable energy and climate change policies has made investment in long-lived, capital intensive generation assets more difficult and added to the increasing cost of electricity. However, without reform the sector is unlikely to be investable, reliable or affordable.

Establishing the necessary incentives to reduce electricity sector emissions could be achieved in a number of ways (or in a combination of ways). Each option though has its own set of costs and consequences that need to be understood. Ruling out options increases the cost, risk and complexity of transition.

**Emissions intensity scheme for electricity the best policy instrument for the medium to long term but could be challenging in the short term**

A signal such as an emissions intensity scheme for electricity is both fuel and technology neutral and preserves the broadest range of options to meet future emissions reduction targets. It also creates an incentive for investment in lower emissions generation technologies.

As demonstrated in numerous modelling exercises, an emissions intensity scheme for electricity would manage sectoral abatement objectives at least-cost. An emissions intensity scheme provides a subsidy for less emissions intensive generation with the cost of the scheme paid for by more emissions intensive generators. The net effect should be no increase in price for customers.
In the medium to long-term an emissions intensity scheme will be the lowest-cost way for the electricity sector to meet its abatement objectives and should be the principal policy tool.

However a closed-loop emissions intensity scheme, implemented in the short term, could lead to multiple closures within one region, placing pressure on system security and regional communities all at once.

In the absence of a closed-loop emissions intensity scheme, an emissions standard or emissions cap could be applied to coal-fired power stations based on their end of technical life (50 years). An emissions standard would require coal-fired generators to modernise or close their operations after 50 years. Whereas an emissions cap would allocate a certain amount of emissions to each generator based on 50 years of life but provide greater flexibility on the exact year of closure.

The requirement to close could be subject to a national interest test (undertaken at the point that three years’ notice is given for closure) if the generation capacity is required for system security and/or reliability.

Given the age profile of Australia’s coal-fired generation fleet, both brown and black coal-fired power stations would be expected to close in a staggered fashion across multiple regions over time. As the electricity market is already at prices that will encourage new supply, this type of regulation is unlikely to have a significant impact on price but would provide a strong signal for new investment which is ultimately what will ensure prices are as low as possible.

While less efficient than an emissions intensity scheme, the transition may be easier to manage and provide clearer signals for new investment in the electricity system in the short term.

Policy options that focus on particular technologies or operate outside the market, such as renewable energy targets, low emission energy targets or contracts for difference, should be avoided in the interests of preserving optionality and minimising costs to customers. The emissions reduction target is the target that should drive the reduction of emissions in the electricity sector.

5. Preserve optionality across all timeframes to achieve deeper reductions in emissions beyond 2030

There is a risk that Australia is putting all its eggs in one basket as it moves away from emissions intensive electricity generation.

A range of electricity generation technologies may be required to meet the government’s current emissions reduction targets and any future targets established under the Paris Agreement. It may be prudent to ensure that no generation options are ‘off the table’, including coal or gas-fired generation with carbon, capture and storage or nuclear.

All Australian governments should support the early and comprehensive development of new regulatory frameworks in relation to nuclear energy to preserve this optionality.
Support for research, demonstration and deployment of lower-emission and more energy efficient technologies will be critical to ensuring these technologies move down the cost curve. There is a role for government, in partnership with the private sector, in low-emissions research and development where the risks may be too great for the private sector to take on, on its own.

Section 62 of the Clean Energy Finance Corporation Act 2012 should be amended to remove any technologies from being ineligible for investments made by the Clean Energy Finance Corporation provided it meets its objectives.
The Business Council of Australia is a forum for the chief executives of Australia’s largest companies to promote economic and social progress in the national interest.

About this submission

Our energy system is the cornerstone of our economy powering our industries, our cities and our homes. It is critical that we get the settings for the energy system right to support investment so we can deliver four key goals:

- secure and reliable energy supply
- affordable energy supply
- strong, internationally competitive economy, and
- reduction in emissions intensity of the economy to meet future emission reduction targets.

This submission identifies five key priority areas and recommendations necessary to achieve these four goals for the consideration of the Independent Review into the Future Security of the National Electricity Market (the Review).

Key recommendations

The Business Council considers that the Review should recommend a number of key actions consistent with the following five key reform priorities:

- Ensure security of electricity supply and restore community confidence in operation of the NEM.
- Create conditions for new investment to support reliability of energy markets.
- Improve affordability of energy supply to drive a strong, internationally competitive economy.
- Ensure the necessary incentives are in place for the energy sector to make its contribution to achieving the 2030 emissions reduction target.
- Preserve optionality across all timeframes to achieve deeper reductions in emissions beyond 2030.

Governments collectively hold the policy tools to influence three critical levers within the energy system – market design, fuel supply and infrastructure investment.

Each of these levers must be pulled in a coordinated fashion if we are to deliver the stable, integrated energy and climate change policy that will secure investment across the short, medium and long term.
MARKET DESIGN
- Mechanism to obtain inertia and development of fast frequency response service
- MT PASA to publish aggregate energy (fuel) budget
- Three year notice period for the withdrawal of registered market participants
- Additional measures should be investigated to ensure there is adequate “firm” capacity
- COAG Energy Council should continue to advance gas market reform
- Demand-based, cost reflective network tariffs supported by advanced meter roll-outs
- Increase energy efficiency requirements in buildings and energy performance standards in appliances subject to cost-benefit analysis
- Electricity regulation one of COAG’s deregulation priority areas for 2017

FUEL SUPPLY
- Immediate lifting of moratoriums on the development of unconventional gas
- All Australian governments should, as soon as possible, support the early and comprehensive development of regulatory frameworks in relation to nuclear energy

INFRASTRUCTURE INVESTMENT
- Energy and climate change policy should be durable, national and complementary
- An emissions standard or cap should be applied to generators based on their end of technical life
- In the medium-long term, an emissions intensity scheme will be least cost and should be principal policy tool
- There should be no further changes or extensions to the existing RET
- There is no role for state-based renewable energy targets
- Governments should not buy or contract with generation assets
- COAG Energy Council to develop a long-term vision for the evolution of network infrastructure
- Australian Government to renew focus on research and development
- CEFC should not be precluded from investing in any technology provided it meets its objectives

Ensure security of supply and restore community confidence in operation of the NEM
Create conditions for new investment to support reliability of energy markets
Improve affordability of energy supply to drive a strong, internationally competitive economy
Ensure the necessary incentives are in place for the energy sector to make its contribution to achieving the 2030 emissions reduction target
Preserve optionality across all timeframes to achieve deeper reductions in emissions beyond 2030.
Discussion

Are there problems with our electricity and gas markets?

Our electricity and gas markets are undergoing substantial change and this has recently resulted in blackouts for South Australian customers and higher electricity and gas prices for all customers.

Our immediate focus must therefore be on restoring the security, reliability and affordability of our energy systems.

The current design of our electricity markets relies on a lot of flexibility from our generation fleet.

We need enough generation available day in and day out to meet our average demand along with generation or demand response that can quickly switch on or off when demand peaks or if something in the system fails. This is often referred to as the reliability of the electricity system.

We also need generation, networks, demand or storage that can provide services other than energy (such as inertia or fast frequency response) that can help to manage the operation of the system. This is often referred to as the security of the electricity system.

To date Australia’s electricity system has served us well and been a source of competitive advantage for Australian businesses. However, like other electricity systems around the world, our system is transitioning away from higher emission technologies and towards low or zero emission technologies. Some of these technologies, such as solar and wind, are intermittent and cannot be relied upon. They also don’t naturally provide system security services such as inertia. Although increasingly solar and wind, with additional technology, should be able to provide at least some of these services.

The integration of large volumes of intermittent wind and solar generation and the exit of a number of coal and gas-fired generators has therefore presented a series of challenges for the security, reliability and affordability of our electricity systems.

The emergence of the LNG sector in east-coast Australia has significantly increased the volume of gas produced and contributed strongly to employment and export earnings. However, this growth, together with delayed or restricted access to new resources, has also created challenges for the domestic gas market with the price and terms of domestic gas contracts now very different, if available at all.

Governments collectively hold the policy tools to influence three critical levers within the energy system – market design, fuel supply and infrastructure investment.
What are the drivers of the current problems in our electricity and gas markets?

Electricity

New investment in renewable energy, coupled with falling demand for electricity, have contributed to oversupplied electricity markets that until recently have delivered unsustainably low wholesale prices

- For 50 years electricity customers consumed increasing amounts of electricity in the face of greater reliability and falling prices (in real terms).
- From the early 2000s, decarbonisation was a new objective for the electricity system.
- In 2001, a Renewable Energy Target (RET) was introduced and then significantly increased in 2011 to drive investment in both large-scale and small-scale renewable energy. Additional generous subsidies were paid for rooftop solar with rapid uptake of the technology.
- In addition to these direct subsidies, electricity network tariff structures enable solar customers to avoid their electricity network costs, increasing the cost of the network for other customers.
- Investment in electricity networks increased dramatically in most jurisdictions during the same period due to forecast rising demand, population growth, ageing infrastructure, embedded generation and regulatory failure. As a result of this and the introduction of a range of green schemes, retail electricity prices doubled in the six years from 2008 to 2014.
- With mining, manufacturing and metal production accounting for around 50% of electricity demand, the closures at Port Kembla, Kurri Kurri and Point Henry had a significant impact on demand.
- Rising retail prices also put pressure on households making substitutes like energy efficiency and solar more attractive. As a result, grid demand fell by around 20 GWh in six years (equivalent to around two Hazelwood Power Stations).
- Yet as demand for electricity fell, new supply continued to enter the market with significant investment in new renewable energy generation (supported by the RET).
- The outlook for electricity demand over the next 20 years is now very flat despite a 30 per cent increase in population, average levels of economic growth and with more appliances being used in homes than ever.
- In the face of falling (or, at best, flattish) demand over the last decade, wholesale markets for electricity generation in both the National Electricity Market (NEM) and the South-West Interconnected System (SWIS) have been increasingly oversupplied.

Low wholesale prices coupled with rising gas prices and ageing coal-fired generators has seen the exit of a number of power stations and new investment will now be required to ensure a secure and reliable system

- The design of the NEM means that generators are only paid for the energy they produce and there is no real reward for being ‘available’ to produce electricity, should customers need it, or for providing services such as inertia.
- The NEM is also designed in such a way that generators often bid in at prices that would only cover their short-run costs like fuel (also known as short-run marginal cost).
In order to make enough money to cover their long-run fixed costs, generators rely on times when the supply–demand balance is very tight (like hot days) and prices are relatively high.

When supply–demand conditions are loose, as they have been in recent years, energy prices are weak. This has been further exacerbated by the subsidised entry of renewable technologies with zero short-run marginal cost.

Suppress electricity prices, coupled with rising gas prices and ageing coal-fired generation assets, has recently seen the exit (or mothballing) of a number of gas-fired and coal-fired power stations.

With significant volumes of energy leaving the electricity market, new investment in generation will be required over the next few years to ensure the security and reliability of the electricity system.

Wholesale prices have risen significantly in the NEM which should support new investment provided we have stable policy settings around which companies and households can invest.

The RET will continue to drive investment in wind and solar which will provide some of the energy we will need in coming years.

However, these technologies have a fundamentally different effect on the system than the fossil-fuelled generation they are replacing. Firstly, they are intermittent in nature and cannot always be relied upon.

Coal and gas-fired generation plants, along with hydro, provide firm generation to the market that also allows the system to address rapid changes in frequency due to significant changes in either supply or demand. At present, the installed solar and wind capacity does not offer these other ancillary services to the grid.

Gas

Following the discovery and development of conventional gas reserves in the 1960s, the gas industry on the east coast of Australia evolved from manufactured or ‘town’ gas.

The development of the basins and pipelines that dominated the supply of east coast gas until the early 2000s was largely delivered in the mid-1960s with significant direct and indirect state government support.

Under this framework, east coast demand for gas grew rapidly to over 350 PJ/annum by 1980 but then slowed for the next 10 years.

A number of key reports and working groups in the 1990s and 2000s identified a range of shortcomings in the gas markets and regulatory frameworks.

In 1995 the Gas Access Regime for natural gas pipelines established a right of access to transmission and distribution networks on a fair and reasonable basis.

In 1999, Victoria established Australia’s first facilitated gas market – the Victorian Declared Wholesale Gas Market.

In the mid-2000s there was significant unconventional gas exploration in response to the Queensland Gas Electricity Scheme which established a target for gas-fired electricity generation in that state. This scheme provided an initial market for the coal seam gas fields that later underpinned the LNG industry in Queensland.

Between 2006 and 2011 the recommendations of an industry-led Gas Market Leaders Group were progressively refined and implemented with the Bulletin Board established in 2008, AEMO taking on the role of Gas Market Operator in 2009 and short-term trading markets established in Adelaide and Sydney during 2010, and Brisbane in December 2011.
• In recent years, a range of gas market reviews have been undertaken with the aim of ensuring that supply is able to flexibly respond to market conditions and that the role of markets is promoted. The major focus of the work program has been the establishment of gas trading hubs to support the development of secondary markets and the need for further reforms to improve pipeline capacity utilisation through trading.

• The Australian east coast gas sector faces a number of powerful factors at the moment, including:
  – an unprecedented tripling of gas market volumes due to the emergence of an LNG industry in Gladstone
  – a consequent transformation of domestic market dynamics, including tightening supply conditions
  – a challenging social, political and regulatory environment for developing new supplies, in particular coal seam gas resources reflecting community concerns
  – persistent calls for gas market intervention, and
  – the rolling off of the long-term gas and transportation contracts that have underpinned gas supply for the last few decades.

• The price and availability of domestic gas is now a critical issue for both electricity generation and industrial users.

• Gas markets suffer from a lack of harmonisation due to three different facilitated market models for trading short-term gas and their varying interactions with the electricity market.

• An investment framework under contract carriage that does not provide ‘spare capacity’ in pipelines and limits the ability to trade firm rights and therefore the potential for competition.

• An investment framework under market carriage (in Victoria) that lacks incentives for efficient expansion for demand growth or to enable gas to transit through the system to other pipelines.

• Policy and regulatory processes that create unnecessary duplication and burdens on businesses (e.g. rule change processes and multiple gas market reviews).

• Limited support for current gas futures contracts in part due to additional uplift/imbalance charges and uncertainty that cannot be mitigated through use of this contract.
Five key reform priorities to improve the operation of our electricity and gas markets

In light of the current problems facing our electricity and gas markets, the Business Council considers that the Review should recommend a number of key actions consistent with the following five key reform priorities.

1. Ensure security of electricity supply and restore community confidence in the operation of the NEM

A secure and reliable energy system is the foundation of a productive and prosperous economy. As we have seen in South Australia over the past year, the failure to maintain a secure electricity system can cripple a business and significantly constrain economic activity. Maintaining the security of Australia’s electricity markets is also vital to ensure the Australian economy continues to attract private investment in the medium to longer term.

The NEM does continue to perform reasonably well in all states except South Australia. In early 2017, the system held up in the face of extreme temperature conditions in Queensland, New South Wales, the Australian Capital Territory and Victoria. Even with several generation units offline at critical peaks, involuntary load shedding (turning customers’ power off without their agreement) has been avoided in all states except South Australia.

The South Australian electricity market is literally at the end of the line and has long been subject to more volatile wholesale prices. With excellent renewable energy resources, South Australia has also seen the greatest penetration of wind and solar technologies of anywhere in the world. However, this rapid transition has exposed a range of weaknesses within the existing electricity market design.

While the ‘system black’ event in South Australia in September 2016 was caused by an extreme weather event, the cascading failures that followed that day, along with subsequent load shedding in South Australia in summer 2016-17, highlight the need for some reform of the NEM’s current operation.

An electricity system is secure when technical parameters such as power flows, voltage, and frequency are maintained within defined limits. Maintaining the frequency at a constant level involves balancing the supply of electricity against demand on an instantaneous basis. Any imbalance will cause the frequency to change and large deviations from the normal frequency level (50 Hertz in Australia), or rapid changes in frequency, can lead to instability in the system and cause the disconnection of generation or load.

The NEM is undergoing significant change as conventional, centrally dispatched and synchronous generation (coal and gas) is displaced by intermittent, non-synchronous generation (wind and solar). As has been noted by the Australian Energy Market Commission (AEMC) in its System Security Market Frameworks Review interim report, this is a new problem, which poses a unique challenge to the security and stability of the NEM:

Historically, in the NEM, plentiful inertia has been provided by conventional generators, such as coal and gas-fired power stations and hydro plant. However, many new generation
technologies, such as wind turbines and photo-voltaic panels, are not synchronised to the grid, have low or no physical inertia, and are, therefore, currently limited in their ability to dampen rapid changes in frequency. The shift in the generation mix towards non-synchronous generation consequently gives rise to increasing challenges in maintaining the system in a secure operating state.¹

To meet this challenge, the AEMC is undertaking a significant body of work to develop appropriate short- and long-term solutions. The Business Council supports the direction of this work and considers that the AEMC, assisted by the Australian Energy Market Operator (AEMO) and industry, is the appropriate body to develop the framework to ensure the security of the NEM.

*Preserve the broad architecture of the NEM market design with specific changes to address security concerns*

The electricity system requires sufficient flexibility to enable it to manage instantaneous changes in supply and demand while maintaining the system within its operational boundaries. This flexibility could come from a range of sources including generators, networks, storage or demand response.

As much as possible, the incentives to deliver these services should come from within – rather than outside – the market structure to preserve price signals for new investment.

The NEM market design needs to ensure that the full range of services required from electricity generators is adequately compensated and that there are sufficient signals for new investment when and where required.

The AEMC is currently considering a number of options for the procurement of inertia and fast frequency response. In conjunction with the System Security Market Frameworks Review, the AEMC is also considering a variety of National Electricity Rule change requests that are directly related to the system security challenges outlined above.

The Business Council supports the preliminary findings of the AEMC and agrees that the ability to maintain power system security in an efficient manner could be enhanced by the development and introduction of a mechanism to obtain inertia and support for the development of a fast frequency response (FFR) service.² This work should be prioritised with recommended changes implemented as soon as possible.

When developing such mechanisms however, it is important that short-term solutions are not prioritised at the expense of more well thought-out and durable policy solutions.

Electricity markets are particularly complex and their interaction with other markets such as renewable energy markets, carbon markets or even ancillary services markets can have unintended consequences. Tinkering with parts of the system should not be undertaken without a full review of the impact of any changes on investment and returns across the whole market. Any changes to the National Electricity Rules must also be in the long-term interests of consumers (that is, consistent with the NEM market objective).


² ibid., p. vii.
One important test for any action undertaken is that it should provide stable dispatch patterns that ensure there is sufficient firm generation available in the NEM at any time. As long as the constraints or changes to the market are effective and consistently applied, then the market price should rise by the minimum amount necessary to draw this service into the market. This helps to deliver security and reliability at the lowest possible price.

**Preserve the broad architecture of the NEM market design with specific changes to address security concerns**

The AEMC is currently considering a number of options for the procurement of inertia and fast frequency response. In conjunction with the System Security Market Frameworks Review, the AEMC is also considering a variety of National Electricity Rule change requests that are directly related to the system security challenges outlined above.

The Business Council supports the preliminary findings of the AEMC and agrees that the ability to maintain power system security in an efficient manner could be enhanced by the development and introduction of a mechanism to obtain inertia and the development of a fast frequency response (FFR) service. This work should be prioritised with recommended changes implemented as soon as possible.

The following criteria should be used when evaluating the suitability of any policy options that are being considered to improve the system security of the NEM:

- Mechanisms established to procure the relevant services need to be least-cost and fit for purpose.
- Mechanisms established to procure the relevant services should be technology, fuel and participant neutral.
- Market solutions that allow for innovation in the supply of the required services should be prioritised over non-competitive mechanisms.
- Wherever possible, price signals should be used to encourage efficient investment and operational decisions.
- Risk should be allocated to parties that are best able to manage them.
- Any solution should be adaptable and able to respond to changing market conditions.

In this context, there are a number of changes that should be considered:

- adequate demand and supply forecasting tools for AEMO, particularly wind and solar energy forecasting
- sufficient powers of direction for AEMO to manage credible and non-credible contingent events (the creation of protected events may assist this)
- creation of additional markets for inertia and fast frequency response to manage rapid fluctuations in frequency
- measures to ensure sufficient ‘firm’ capacity is available to the market to support increasingly intermittent sources of generation such as wind and solar.
2. Create conditions for new investment to support reliability of energy markets

With the Hazelwood power station in Victoria set to close in 2017 and the Liddell power station in NSW to close in 2022, substantial new investment will be required in the NEM to maintain system reliability.

*Improved market information to manage transition and support electricity investment*

Information about the expected supply–demand outlook is a critical driver of electricity infrastructure investment decisions.

AEMO currently produces a range of planning documents to assist with system planning and investment decision making. The short- and medium-term planning documents are the Projected Assessment of System Adequacy (PASA) while the long-term planning document is referred to as the Electricity Statement of Opportunities (ESOO).

Currently market participants are required to notify AEMO each week of their forecast availability for the next two years for the medium-term PASA. AEMO then uses this information to identify low reserve conditions for each region of the NEM.

However, generators are only required to notify AEMO about whether a generation unit will be physically available at a point in time. There is no indication of whether a generation unit has sufficient fuel to run for any period of time.

Fuel positions are commercially sensitive and can impact the bidding behaviour of generators. Any changes to the information required in the medium-term PASA would need to be carefully considered, but it does seem the quality of information could be improved to support decision making by publishing an aggregated energy (fuel) budget for each region over a period of time.

The ESOO is a longer-term planning document that provides technical and market data to inform the decision-making processes of market participants, new investors, and jurisdictional bodies over a 10-year outlook period. The ESOO includes information on the scheduled closure or mothballing of generation units.

The electricity forward market extends out three years and significant, rapid changes in supply or demand can have huge impacts on the volatility and liquidity of the electricity contract markets.

In addition, it has been suggested that the timeframes for the announced closure of the Northern and Hazelwood power stations were insufficient to support system planning, community transition and to signal the need for new investment in electricity generation.

To support a managed transition of the electricity sector, a three-year notice period for the withdrawal of registered market participants (both generation and load) could be considered. Generation closures within this period could not be addressed by new investment and could challenge the reliability of our electricity market. Equally, the sudden closure of a large source of generation load can undermine generation investments that are in train.
This type of obligation could be attached to market registration. While it may be hard to envisage an effective penalty regime to support this, this type of obligation would make the expectations of market participants very clear.

**Measures to ensure adequate investment in ‘firm’ generation to manage increased intermittency**

With the retirement of Hazelwood power station in 2017 and Liddell power station in 2022-23, the NEM will probably need around 15TWh more energy. Some of this energy will be provided by the 33TWh RET for 2020. However, because of the intermittent nature of both wind and solar, additional ‘firm’ generation capacity (such as gas-fired electricity generation) may also be required, as has been the case in South Australia since the closure of Northern power station. Additional measures should be investigated to ensure there is adequate ‘firm’ generation capacity to support increasing investment in intermittent renewable technologies.

This could happen within the contract market (requiring renewables to come to the market ‘firm’ or to offer swaps) or through changes to the market rules to require the electricity market to be cleared after taking account of the largest credible contingency event (covering energy and ancillary services markets). The cost of ‘firming’ intermittent generation could be met by intermittent generators or by customers. However, careful consideration would need to be given to the most appropriate mechanism in light of all the other changes proposed for the market.

Demand response can greatly assist with the integration of intermittent renewables. Intermittency is a challenge because of the existing paradigm, where supply meets demand and must be balanced at all times. More flexible demand (which includes storage behind the meter) can change this paradigm. The limitations of demand response are that customers will still ultimately want the amenity that their energy services provide, but this still leaves scope for progressively greater and more dynamic demand response in the system. The AEMC’s Power of Choice review and several subsequent rule change processes have been testing the current framework to see how it could be improved to facilitate more demand response.

**Stable policy frameworks with minimal government intervention in markets to support electricity investment**

Australian energy and climate change policies have been largely uncoordinated and often inconsistent, poorly costed, and, at times, have operated in conflict with each other.

This policy overlap and instability has created a volatile investment environment that has contributed to higher prices and hindered transformational change in Australia’s electricity system. Competing policies have also created complexity, cost and unintended consequences, leaving the enduring dysfunction we now see in the electricity sector.

Electricity infrastructure involves capital intensive, long-lived assets. Stable policy settings and clear market price signals are critical to support investor confidence.

The planning, permitting and construction of a power station (wind, solar or gas) can take several years with any new coal-fired generation facility (if it could indeed be financed) expected to take much longer than this.
Policies that suddenly shift from one place to another or see governments entering markets risk jeopardising, or at the very least confusing, this investment.

On the basis of this, there should be no further changes or extension to the RET. Although renewable energy targets are a source of market distortion, the RET has underpinned significant investments and will now need to support the additional investment required to replace assets such as the Hazelwood and Liddell power stations. To make further changes to the only energy and climate change policy instrument that has had some degree of bipartisan support would have a chilling impact on investment right across the sector – at a time when new investment is needed to ensure the security, reliability and affordability of our electricity system.

Similarly, governments should not enter the electricity market by offering contracts for difference for particular forms of energy or by directly contracting or acquiring sources of supply (unless they wish to do this to meet their own demand for electricity). These types of interventions undermine the price signals in the NEM and could be counterproductive to achieving our electricity market objectives.

The policy focus should be to ensure the smooth integration and digestion of the 33TWh of large-scale renewable energy to be delivered under the RET by 2020 and to create the conditions for new investment to ensure adequate firm capacity is available.

Unilateral action by state and territory governments can also undermine investment. In particular, where state and/or territory governments implement policies that distort the operation of the NEM – such as state-based renewable energy targets – this can be particularly damaging to the investability, reliability, affordability and long-term transformation of the whole electricity sector, while actually increasing the costs of renewable energy projects.

There is no role for state-based renewable energy targets.
**Improved market information to manage transition and support electricity infrastructure investment**

- To enable effective system planning and support efficient decision making, the medium-term PASA could be improved by publishing an aggregated energy (fuel) budget for each region over a period of time.

- To support a managed transition of the electricity sector, a three-year notice period for the withdrawal of registered market participants (both generation and load) could be considered. This would also facilitate community transition.

**Measures to ensure adequate investment in ‘firm’ generation infrastructure to manage increased intermittency**

- Additional measures should be investigated to ensure there is adequate ‘firm’ generation capacity to support increasing investment in intermittent renewable technologies. Careful consideration would need to be given to the most appropriate mechanism in light of all the other changes proposed for the market.

**Stable policy frameworks with minimal government intervention in markets to support electricity infrastructure investment**

- Wherever possible, energy and climate change policies should be durable, national and complementary.

- Governments should not distort investment signals as new investment will be critical to delivering a secure, affordable and sustainable energy system. There should be no further changes or extensions to the RET and governments should not buy or contract with generation assets (outside the normal operation of the National Electricity Market) to deliver electricity supply.

- There is no role for state-based renewable energy targets in national markets.
3. Improve affordability of energy supply to drive a strong, internationally competitive economy

**Long-run marginal cost of new entrant generation technologies**

In the face of multiple generator exits and record heat waves across summer, the NEM is now experiencing high wholesale prices which, in the face of stable, long-term policy settings and access to competitively priced fuel, should act as a sufficient incentive for new investment.

Current and future wholesale prices are currently above the long-run marginal cost of new generation. So new investment is needed to take some of the heat out of current wholesale prices.

However, the long-run marginal cost of all new generation technologies is higher than what we have experienced in the past. So while current and future prices may moderate they are unlikely to return to the levels we have experienced in recent years. Unless the long-run marginal cost of new entrant technology falls, wholesale electricity prices are expected to remain above their historical level for some time.

The international competitiveness of Australian industries depends upon our comparative advantage in energy resources. Restoring our comparative advantage in energy needs to be a core policy goal for all governments.

Bain & Company considered the levelised cost of electricity for a range of new technologies including ultra-supercritical coal-fired power stations, combined cycle gas-fired power stations and renewable energy technologies such as wind and solar. This work found that by 2020, all of these technologies could cost between $60/MWh-$75/MWh.

These costs are much higher than the prices we have seen in the wholesale electricity market in recent years and are more reflective of the prices we are seeing into the future.

However, a levelised cost assessment is not like comparing apples with apples. As noted previously, renewables such as wind and solar, currently don’t provide ‘firm’ (i.e. secure and reliable) energy to the grid. Similarly, even ultra/supercritical coal plants have twice the emissions of combined cycle gas-fired power stations and significantly more emissions than wind or solar. Given the emissions profile of coal plant, new investment in this technology (without government support) is unlikely to occur.

Highly efficient, combined-cycle gas turbines produce one-third of the emissions of brown coal-fired electricity generators and half the emissions of black coal-fired generators. These gas-fired generators (referred to as CCGTs) provide energy to the electricity system just like a coal-fired plant but with greater flexibility, making them a critical partner for renewables.

Open-cycle gas turbines (or OCGTs) are less efficient than CCGTs and have higher emissions. These types of generators tend to be required just when demand is at its peak. Some of these OCGTs might only run a handful of days each year, but they can be turned on quickly and play a really important role in ensuring the security and reliability of the electricity system as a complement to renewable generation.
New investment in both gas-fired generation and renewables is likely to be required to manage the transformation of the electricity sector at lowest possible cost while maintaining system reliability.

**Deep, liquid and transparent gas markets critical to reducing long-run marginal cost of electricity**

Because OCGTs only operate when the electricity price is very high (which is how they can afford to run only infrequently throughout the year) the availability of gas is far more important to their operation than the price of that gas.

The LNG industry in Queensland has driven considerable investment in new sources of gas. While the linking of our gas market to international markets has increased the domestic price of gas, it does mean that potentially more gas will be available for short-term supply in response to high electricity prices. This could further support the security and reliability of the electricity market. Improving access to short-term capacity and market-determined prices will help lift the liquidity of short-term traded markets and enable gas to flow to where it is needed most.

However, higher gas prices have made both energy generation from CCGTs more challenging and energy from gas for industry less affordable.

There are a number of key risks to investment in gas-fired generation, with access to a stable supply of competitively priced gas absolutely critical to support the transformation.

Access to accurate and timely market information on the gas supply–demand balance and price outlook is a key characteristic of a well-functioning and efficient market.

This information enables market participants, planners and policymakers to develop a relatively informed view of forward market conditions. It also plays an important role in signalling new supply opportunities, informing risk-management strategies and negotiations, as well as stimulating timely investment.

However, while bilateral contracts have been useful to underwrite the development of new gas resources and infrastructure and to manage risk, Australia’s gas markets continue to be dominated by bilateral, long-dated contracts; low levels of market transparency; and a contract carriage model for largely point-to-point pipelines.

Gas market information is currently provided by: the AEMO and Independent Market Operator; Geoscience Australia; the Bureau of Resources and Energy Economics; the Australian Energy Regulator; and through Gas Market Bulletin Boards and Short-Term Trading Markets.

The Declared Wholesale Gas Market in Victoria and the Short Term Trading Markets in Sydney, Adelaide and Brisbane play an important role, but currently act mostly as a balancing tool.

These trading hubs do not reflect underlying supply and demand conditions and have an absence of forward products, with minimum volumes traded.

The Vertigan Gas Market Reform Group should seek to streamline and improve the function of the trading hubs and, where possible, ensure greater integration with the
electricity spot market. The current number of fragmented and poorly designed trading hubs acts against the development of a viable forward market in gas, noting that, in a relatively small marketplace, gaining liquidity will always be a challenge.

The absence of standardisation across the east coast market is also a key issue. If the gas market is to have longer-term pricing information, it requires well-designed, consistent arrangements that will support secondary products that can be traded and settled off a representative and robust spot index. Without either of these, transparency will be limited to a number of short-term markets.

**Increased gas supply critical to reducing long-run marginal cost of electricity**

There are currently significant challenges in the domestic gas market with the price and terms of domestic gas contracts now very different, if available at all.

Increasing gas supply will be critical to all gas users and to reducing the long-run marginal cost of electricity.

The policy challenge is to ensure that gas producers can access new gas resources to meet domestic and international demand at the lowest possible cost. Increasing Australia’s gas supply is the best way to ensure that Australia can access a reliable and competitively priced supply of natural gas.

It has been suggested that governments could reserve a portion of Australia’s gas for domestic use in an effort to boost the supply of domestic gas.

- To retrospectively force established gas projects, who have contractual commitments, to supply the domestic market would be to impose significant sovereign risk on the gas market. This could have a significant impact on future investor appetite for Australia’s gas sector.

- As part of their licencing regimes, state governments could choose to reserve a portion of future gas fields for domestic use on a case-by-case basis in an effort to boost the supply of domestic gas. If governments are considering this, then they should be mindful of two things:
  - the fields that could come on line are likely to have much higher production costs than Australia’s conventional fields.
  - restricting tenements to domestic use may actually deter investment in these fields, further tightening the supply–demand balance.

All governments should focus on the continued safe, environmentally responsible and timely development of Australia’s gas resources supported by a stable and efficient regulatory regime. Any regime should be risk-based and informed by science. Inappropriate barriers to natural gas development should be removed, including the immediate lifting of moratoriums on the development of unconventional gas.

Moratoriums on hydraulic fracturing still exist in Tasmania and Victoria and it is possible that a ban on fracking could be implemented in the Northern Territory. The development of unconventional gas supplies in New South Wales has also proved extremely difficult.

However, even if these moratoriums are lifted, in 2015 the Productivity Commission pointed out the ongoing effect this policy will have for years to come:
There is typically a delay of 3–6 years between investments in gas exploration and production and the actual supply of gas to users, and such investments have large upfront costs. This means that moratoria could lock in some higher cost production and the effects could continue to play out for several years after the moratoria are lifted. 3

The regulatory frameworks that currently slow down or deter investments in major gas projects should also be reformed to ensure gas supply comes to market as quickly as possible.

Persisting with sub-optimal approvals processes for major projects is a major barrier to bringing more supply into Australia’s energy market. The societal cost of a one-year delay in approval of a project of average size (capex $473m) is $26 million to $59 million. For a large energy project like an offshore liquefied natural gas project, the cost can be between $0.5 and $2 billion. 4

In November 2016, the Business Council released the Competitive Project Approvals report. 5 In this report we set out a best practice model for project approvals that we would like to see included in planning and zoning reforms being considered by Australian governments in their response to the Harper review of competition policy arrangements.

The Business Council’s best practice model for major project approvals aims to encourage vastly better coordination and accountability, through a number of methods:

- A lead agency is assigned to oversee major project development assessments.
- A separate, dedicated assessment pathway is used for major projects.
- One project application, one assessment and one approval for a major project.
- A legislated, maximum umbrella timeframe for approval, ideally set at 12 months.
- Right of review is limited to judicial review, to determine whether the specific approval process was carried out in accordance with legislation (i.e. no merit review available).
- Government agencies involved in the planning and approval process for major projects are required to report on performance indicators relating to timeliness and adherence to best practice.

5 ibid.
Network sharing and efficient prices critical to improving affordability

Advancements in solar and battery storage technology now mean the potential for grid defection is real – for some customers. But grid defection is likely to increase total system costs. For example, for a household to go off-grid 90 per cent of the time today would cost around $35,000 in solar panels and batteries. For that same house to be off-grid 99.9 per cent of the time would cost them $70,000. However, if 20 households in a neighbourhood were willing to share their solar panels and batteries (for a price) and rely on the grid 10 per cent of the time, then this cost could be reduced to $17,000 for each household.

Australia has an already built network of electricity transmission and distribution assets that we must make efficient use of if we are to minimise the cost of electricity facing households and businesses. Advanced electricity meters which support demand-based, cost-reflective network pricing are a critical first step.

The opportunity for decarbonisation from new technology and innovation abounds, but a clear vision for the evolution of Australia’s electricity markets and network infrastructure will be critical to the continued dynamism of the customer revolution.

Access to data can empower consumers to make decisions that best suit them and help them save on their energy costs. For network providers, data can help ensure network investment is as efficient as possible. While interest in data is skyrocketing, this does not mean that regulations compelling data to be made available is prudent.

The best way to make data available to consumers, while still encouraging business investment in data-related innovation, is to allow for a well-functioning data market where consumers negotiate exchange of data and benefits, backed up by a light-touch regulated minimum. To that end, mandating further provision of data by businesses in the energy sector appears unnecessary, beyond the minimum required for markets to function.

In terms of protecting personal privacy, suitable protections already exist through the Privacy Act 1988 (amended recently in 2014). The AEMC’s 2014 rule change to improve the availability of information to customers found that no further privacy measures were
needed and that energy data privacy concerns are better addressed through the application of privacy legislation to the extent that meter data is personal information.\(^6\)

**Network sharing and efficient prices critical to improving affordability**

- Demand-based, cost-reflective network tariffs are essential to manage system costs supported by advanced meter rollouts on an opt-out basis.
- The best way to make data available to consumers, while still encouraging business investment in data-related innovation, is to allow for a well-functioning data market where consumers negotiate exchange of data and benefits, backed up by a light-touch regulated minimum. To that end, mandating further provision of data by businesses in the energy sector appears unnecessary, beyond the minimum required for markets to function.
- A long-term vision for the evolution of network infrastructure should be a key priority for the COAG Energy Council to ensure efficient utilisation of existing assets.

**Encouraging greater energy efficiency to improve affordability**

The lowest cost unit of energy is often the one we don’t consume. Increasing the energy efficiency of our built environment can reduce our energy costs, improve our energy security and reduce our greenhouse gas emissions.

There are opportunities to build on the National Energy Productivity Plan (NEPP) to better position Australia to meet our emission reduction targets and cut the cost of energy bills for households and commercial businesses.

A key focus for any new energy efficiency measures should be the residential and commercial sectors. Energy use is a significant input cost for industrial companies and is already tightly managed.

Subject to a cost–benefit analysis, there are a number of opportunities for reducing our energy use in the built environment including:

- the construction and operation of residential and commercial buildings, and
- improving the efficiency of lighting and appliances that use a significant amount of energy.

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**Encouraging greater energy efficiency to improve affordability**

- The Australian Government should examine the costs and benefits of increasing the energy efficiency requirements of commercial buildings and residences in the 2019 update of the National Construction Code.
- The Australian Government should increase the minimum energy performance standards of energy-intensive appliances (like HVAC systems) subject to a cost-benefit analysis.
- All governments should lead by example and set stronger energy efficiency targets for buildings where the government is a property owner of tenant.

**Cutting the cost of regulation to improve affordability**

Retailers play a crucial role in managing risk within the wholesale market and shielding business and household customers from the vagaries of volatile electricity spot prices. However, there are a number of complex obligations facing electricity market participants. Some are designed to ensure customers receive energy on fair and reasonable terms while others are duplicative or unnecessary and simply increase the cost of energy.

Australia’s electricity market is very highly regulated and while many of those regulations may be necessary, there is scope for regulatory reform to occur. Our members who operate in the electricity sector advise that they are currently required to comply with 5500 different obligations across 250 instruments (state and federal) involving over 50 regulators. Too often the first instinct of regulators and policymakers is to simply solve a problem by introducing a new regulation or rule.

To explore which aspects of the electricity regulatory frameworks could be improved, the electricity sector should be designated as one of COAG’s Deregulation Priority Areas for 2017. Furthermore, the AEMC should be asked to review and reduce ineffective, duplicative, inefficient rules. Finally, when the AEMC is considering new and amended rule changes, these rule changes should be assessed against an objective to decrease the regulatory burden across the sector.

**Cutting the cost of regulation to improve affordability**

- To explore which aspects of the electricity regulatory frameworks could be improved, the electricity sector should be designated as one of COAG’s Deregulation Priority Areas for 2017.
- The AEMC should be asked to review and reduce ineffective, duplicative or inefficient rules.
- When the AEMC is considering new and amended rule changes, these rule changes should be assessed against an objective to decrease the regulatory burden across the sector.
4. Ensure the necessary incentives are in place for the energy sector to make its contribution to achieving the 2030 emissions reduction target

Australia’s 2030 emissions reduction target has been set. By 2030, Australia must reduce its emissions by 26-28% of 2005 level emissions. Using the National Greenhouse and Energy Reporting data we must continue to monitor our progress towards meeting this target.

What has not been set is the signal necessary to support the investment needed for the electricity system to move away from emissions intensive generation technologies and significantly reduce its emissions. Exactly how to do this has been the subject of significant debate for nearly 15 years.

The absence of stable, durable energy and climate change policies has made investment in long-lived, capital intensive generation assets more difficult and added to the increasing cost of electricity. However, without reform the sector is unlikely to be investable, reliable or affordable.

Costs and consequences of various options to reduce the emissions intensity of the generation mix and create a stable, long-term signal for new investment

The electricity generation sector is Australia’s largest source of emissions and currently accounts for approximately 33 per cent of emissions. About one-third of those emissions come from Victoria’s brown coal-fired generators and most of the rest from black coal generators in NSW, Queensland and Western Australia.

Australia should manage the transition away from emissions intensive generation in an orderly manner that supports capital decision making.

Establishing the necessary incentives to reduce electricity sector emissions could be achieved in a number of ways (or in a combination of ways). Each option though has its own set of costs and consequences that need to be understood. Ruling out options increases the cost, risk and complexity of transition.

It is important to consider under each option the type and location of generators that are likely to close, what’s expected to replace it and who will pay for the transition. Risk is also an important consideration given the need for significant new investment. There are a range of risks facing new generation investments including market, policy, fuel and technology risks. Companies are generally well placed to manage market, technology and fuel risks except where governments restrict access to fuels. Policy risk is more challenging but is a key risk that can undermine investor confidence.
Emissions intensity scheme for electricity (EIS) is the best policy instrument for the medium to long-term but could be challenging in the short-term

- With a tight supply–demand balance in the electricity market, wholesale prices are relatively high. This has improved the profitability of existing coal-fired generators and relatively high carbon prices would be required in the electricity sector to manage the transition away from emissions intensive generation.

- An EIS provides a subsidy for less emissions intensive generation with the cost of the EIS paid for by more emissions intensive generators. The net effect should be no increase in price for customers.

- High carbon prices will significantly negatively impact emissions intensive generation. The consequence of this could be multiple closures within one region placing pressure on system security and regional communities all at once. It would also lead to significant asset value loss for the owners of those generators, potentially making it difficult to reinvest in replacement capacity.

- However, depending on how and where an emissions intensity baseline is set, an EIS should incentivise investment in generation below the baseline which is likely to be both gas and renewables in the short to medium term.

- As demonstrated in numerous modelling exercises, an emissions intensity scheme for electricity would manage sectoral abatement objectives at least-cost.

Emissions standard or emissions cap based on end of technical life

- An emissions standard or emissions cap could be applied to coal-fired power stations based on their end of technical life (50 years). This requirement could be subject to a national interest test (at the point that three years’ notice is given for closure) if the generation capacity is required for system security and/or reliability. This would send a strong signal for new investment in lower emission forms of generation.

- As the electricity market is already at prices that will encourage new supply, this type of regulation may not have any significant impact on price. The cost of the regulation
would be borne by the owners of individual power stations as they may lose some option value if prevented from extending asset life.

- Given the age profile of Australia’s coal-fired generation fleet, the consequence of the regulation would be both brown and black coal-fired power stations to close in a staggered fashion across multiple regions over time. Given the transition away from emissions intensive generation would be managed across multiple regions, this would relieve some pressure on system security and individual communities.

- While less efficient than an EIS, the transition may be easier to manage and provide clearer signals for new investment in the electricity system in the short term and provide greater certainty for local communities in which generators are situated.

Renewable energy targets (RETs)

- Between now and 2030, technological change is likely to see renewables become increasingly competitive against coal and gas. Bain & Company estimates that grid scale solar could become the cheapest source of generation by 2030. However, this does not reflect the change in total system cost as new technologies or other sources of generation are still required to manage intermittency and grid stability.

- The direct cost of RETs is usually borne by customers. With emissions intensive, trade exposed companies partially exempted from the RET, this cost falls disproportionately on households and small to medium businesses. To the extent that RET targets have contributed to higher wholesale electricity prices this cost is borne by all users.

- State-based RETs increase the cost of delivering renewable energy projects even further by specifying the state, timeframe and sometimes even the technology that needs to be built. State RETs can also distort the operation of the federal RET and the broader NEM further increasing costs.

- Policies that support the forced, subsidised entry of lower emission generation can reduce the emissions intensity of the electricity market but as a consequence do not manage the transition of the existing generation fleet. Solutions that specify a technology, location or timeframe tend to also be a higher cost way to reduce emissions.

Low emission energy targets

- A low emissions energy target (LET) enables a broader range of lower cost technologies to contribute towards meeting the target (such as HELE or gas-fired generation plants).

- This should reduce the costs of the scheme compared to the RET and support investment in both renewables and thermal generation which is a critical partnership if we are to deliver a secure, reliable and affordable energy system while reducing our emissions.

- As with the RET though, the cost of a LET would be borne by customers but it should be a lower cost way to reduce emissions than a RET.

- As with the RET, policies that support the forced, subsidised entry of lower emission generation can reduce the emissions intensity of the electricity market but as a consequence do not manage the transition of the existing generation fleet. Solutions that specify a technology, location or timeframe for investment tend to also be a higher cost way to reduce emissions than a market for emissions reduction might deliver.

Contracts for difference

- Governments can enter into contracts for difference with electricity generation developers to de-risk new generation investment. The ACT has done this with their renewables scheme and the Victorian Government is now proposing to do this to meet their renewable targets.
• Awarding of these contracts can be done by auction but generally would require governments to determine the choice of technology or emissions intensity of a technology, capacity, energy and potentially even the location of the generation.

• Customers and/or governments would need to underwrite risk and therefore bear the cost of policy change. This may be an appropriate risk allocation from a policy risk perspective but may undermine market mechanisms.

• The consequence of these instruments can be to shield market participants from policy risk but can have the effect of shielding them also from market risk. This could undermine the NEM market structure.

**Table 1: Comparison of options to reduce the emissions intensity of the electricity generation mix**

<table>
<thead>
<tr>
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<th>What closes?</th>
<th>What’s built?</th>
<th>Who pays?</th>
<th>Policy risk</th>
</tr>
</thead>
</table>
| EIS              | Brown coal first              | Renewables and gas until baseline reduces significantly | Higher emissions intensive generators | • Repeal  
|                  |                               |                                                 |                                 | • Sudden change in baselines                     |
| Emissions standard | Black and brown coal         | Whatever is economic and can be financed         | May not significantly change prices. Generators lose option value. | Closures don’t happen.                           |
| RET              | Existing gas and black coal (brown coal if state-based target) | Renewables                                     | SMEs and households            | Constant policy change                          |
| LET              | Existing gas and black coal   | Gas and renewables (possibly HELEs if future carbon risk can be managed) | Customers                       | Constant policy change                          |
| CFDs             | Existing gas and black coal   | Whatever is contracted                          | Customers or taxpayers          | • Specific generation investments secure  
|                  |                               |                                                 |                                 | • Broader market undermined                     |

A signal such as an emissions intensity scheme, is both fuel and technology neutral and preserves the broadest range of options to meet future emissions reduction targets. It also creates an incentive for investment in lower emissions generation technologies.

In the medium to long term an emissions intensity scheme will be the lowest cost way for the electricity sector to meet its abatement objectives and should be the principal policy tool.

However a closed-loop emissions intensity scheme, implemented in the short term, could lead to multiple closures within one region, placing pressure on system security and regional communities all at once.

In the absence of an effective price on carbon in the electricity sector, an emissions standard or emissions cap could be applied to coal-fired power stations based on their
end of technical life (50 years). An emissions standard would require coal-fired generators to modernise or close their operations after 50 years. Whereas an emissions cap would allocate a certain amount of emissions to each generator based on 50 years of life but provide greater flexibility on the exact year of closure.

The requirement to close could be subject to a national interest test (undertaken at the point that three years’ notice is given for closure) if the generation capacity is required for system security and/or reliability.

While less efficient than an emissions intensity scheme, the transition may be easier to manage and provide clearer signals for new investment in the electricity system in the short term.

Policy options that focus on particular technologies or operate outside the market, such as renewable energy targets, low emission energy targets or contracts for difference, should be avoided in the interests of preserving optionality and minimising costs to customers. The emissions reduction target should drive the reduction of emissions in the electricity sector.

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**Reduce the emissions intensity of the generation mix and create a stable, long-term signal for new investment**

- Australia should manage the transition away from emissions intensive generation and ensure electricity markets can provide adequate signals for new investment.

- An emissions standard or cap should be applied to generators based on their end of technical life. This will create a strong signal for new investment and ensure transition is not concentrated in one geographic region.

- However, in the medium to long term an EIS will be the lowest cost way for the electricity sector to meet its abatement objectives and should be the principal policy tool.

- Policy options that focus on particular technologies or operate outside the market such as RETs, LETs or CFDs should be avoided in the interests of preserving optionality.
5. Preserve optionality across all timeframes to achieve deeper reductions in emissions beyond 2030

A range of electricity generation technologies may be required to achieve emission targets

There is a risk that Australia is putting all its eggs in one basket as it moves away from emissions intensive electricity generation. Should the cost of solar PV and/or batteries not reduce as expected, or if gas is less available and/or more expensive than forecast, Australia may have insufficient electricity supply options in the face of binding emissions constraints.

A range of electricity generation technologies may be required to meet the government’s current emissions reduction targets and any future targets established under the Paris Agreement. It may be prudent to ensure that no generation options are ‘off the table’ including coal or gas-fired generation with carbon, capture and storage or nuclear.

To preserve optionality, our electricity markets also need to be fuel and technology neutral – that means not favouring one type of technology over another – but this must be in the context of the technology’s cost, operational performance and emissions intensity. The simplest way to do this would be to put a price on carbon emissions for the electricity system and to ensure all technologies face the cost of delivering a ‘firm’ product to market.

Support for research and development into lower emission technologies

Support for research, demonstration and deployment of lower-emission and more energy efficient technologies will be critical to ensuring these technologies move down the cost curve. There is a role for government, in partnership with the private sector, in low-emissions research and development where the risks may be too great for the private sector to take on, on its own.

The government’s overarching energy and climate change policy should be open to targeted support for all forms of emerging low-emission and energy efficient technologies that offer opportunities for least-cost abatement, not just support for renewable energy.

For example, section 62 of the Clean Energy Finance Corporation Act 2012 specifically lists carbon capture and storage and nuclear as ‘prohibited technologies’ that are ineligible for investments made by the Clean Energy Finance Corporation. Arbitrary restrictions on investments in potentially effective technologies like this should be removed, therefore allowing market participants to determine the most effective technology to invest in.

Adopting a technology-neutral approach in support of emerging technologies at the R&D stage will provide the opportunity for a greater mix of technologies to advance, so that Australia can preserve optionality and have a better chance of developing commercially successful lower-emission and more energy efficient technologies.
**Carbon Capture and Storage**

Although the Bain & Company analysis has shown that CCS is unlikely to play a key role in Australia’s emission reduction activity to 2030, beyond 2030 CCS is likely to be a key technology in enabling Australia to meet its longer-term emission reduction goals particularly in relation to industrial processes. The IPCC’s 5th Assessment Synthesis Report concludes that, without CCS, most models cannot meet the two degree global warming limit by the end of the century.

Achieving net zero emissions will likely require negative emissions, which CCS (with bioenergy) could provide at scale. It is therefore important that the foundations to allow commercial-scale deployment of this proven technology are put in place now to provide the right signal to investors; similar to the signals provided for other low-emission alternatives.

CCS will be critical in meeting emission reduction targets beyond 2030, with the IEA estimating that CCS will account for around 17% of global CO2e reductions by 2050. The financial costs of not including CCS in the energy mix are substantial, with the IPCC estimating that, without CCS, mitigation costs could increase by 138%. In the long term, a robust market-based CO2e price should drive sufficient CCS deployment. However, what is needed right now is a supportive policy framework that provides legal and time-limited fiscal support to facilitate innovative low-carbon technology projects in pre-commercial stages.

**Support for research and development into lower emission technologies**

- All Australian governments should support the early and comprehensive development of new regulatory frameworks in relation to nuclear energy.
- Section 62 of the Clean Energy Finance Corporation Act 2012 should be amended to remove any technologies from being ineligible for investments made by the Clean Energy Finance Corporation provided it meets its objectives.
- The Australian Government should renew the focus on research and development of technological advancements to support the lowering of emissions from all sources and adaptation to manage the long-term impacts of climate change.