CHAPTER 4: ELECTRICITY GENERATION

The activity under consideration is the establishment and operation of facilities to generate electricity from nuclear fuels in South Australia.

WHAT ARE THE RISKS?

34. **Nuclear power plants are very complex systems, capable of producing large amounts of energy. They are designed and operated by humans, who can make mistakes.**

Nuclear power reactors are carefully engineered vessels that enable the heat energy produced from the fission of uranium nuclei to be captured, through boiling water and creating steam, and transferred to a steam turbine electricity generating system. The electric power output of new light water reactors being deployed today is up to 1600 megawatts electric (MWe).[1] Modern reactor designs are described further in Appendix E: Nuclear energy – present and future.

The risks associated with generating nuclear power are fundamentally related to the large amount of energy produced in the relatively small volume of a reactor core. Hazards that must be managed and controlled in a reactor include the rate of fission heat produced and, in certain circumstances associated with the failure of equipment or control systems, the potential release of radioactive materials.[2] During normal operation, excess heat in a reactor is removed by a coolant, which in most modern reactors is water. When a reactor is shut down, whether for routine reasons or due to an accident, the fission chain reaction immediately stops; however, thermal energy remains in the fuel and the radioactive decay of fission products produces new heat.[3] This can cause damage to, and even melting of, fuel material if the heat is not removed by a coolant.[4]

Fuel cooling in all scenarios is of paramount importance as coolant loss can quickly develop into a serious loss-of-coolant-accident (LOCA). Nuclear engineers and safety analysts focus extensively on ways to avoid fuel damage in all credible and simultaneous LOCA pathways, including coolant pipe breaks and loss of power to coolant pumps.

While reactor design plays a significant role in overall safety, human operation is equally important: human error in management, control, maintenance and accident response can have severe consequences. Human error and reactor design flaws have been shown to be critical contributing factors to operating inadequacies, equipment damage and technical failures that can lead to major accidents.[5]

Modern reactor designs incorporate many safety mechanisms to protect against operator error, as discussed in Appendix E.

35. **There have been three major accidents in nuclear power plants involving the release of radioactive material into the environment: Three Mile Island in 1979, Chernobyl in 1986 and Fukushima Daiichi in 2011. Each accident has been thoroughly and credibly investigated to determine both the causes and lessons to be learned.**

The three major reactor accidents have been carefully analysed and better understood through root-cause investigations, resulting in numerous principles that could be applied to improve safety. Credible studies include those by the International Atomic Energy Agency (IAEA), the United Nations Scientific Committee on the Effects of Atomic Radiation (UNSCEAR) and the United States Nuclear Regulatory Commission (NRC).[6]

The broader health impacts are addressed in Chapter 7: Radiation risks.

THREE MILE ISLAND

In March 1979, one of the two Three Mile Island nuclear reactors in Pennsylvania, USA, suffered a serious loss of coolant. The combination of equipment failures and inadequate operator safety training and response led to a loss of water to remove heat from the reactor's core.[7] This caused the partial melting of fuel assemblies.[8] Primary water flow to the damaged core was eventually restored many hours later.[9] No deaths or injuries resulted. The vast majority of radiation released from the core was contained within the reactor containment building, with only insignificant amounts being released to the environment.[10] The reactor has remained out of operation since the accident.[11]

An initial inquiry[12] and subsequent analyses of the accident have led to many improvements in plant design and operation, as well as increased scrutiny and more stringent safety requirements from the regulator in the USA.[13]

CHERNOBYL

The Chernobyl reactor in Ukraine was a Russian RBMK design, unique to the former Soviet Union. Such a reactor used natural uranium for fuel, water as a coolant, and graphite as a moderator. This kind of reactor could be unstable in certain operating conditions. If an RBMK reactor lost its coolant its nuclear reaction proceeded faster, due to the greater moderating effects of graphite in the absence of water, rather than the reaction stopping itself as in the case of light water reactors. Also, RMBK reactors lack the level of containment that light water reactors have.

The accident at the Chernobyl reactor in April 1986 was due to this instability, combined with serious deficiencies in safety culture, operator experience and management capability.[14] Through bypassing safety systems during an unauthorised experimental test of the reactor control system, the core became unstable, leading to an increase rather than a decrease in fission heat production as the core temperature rose.[15] This induced two chemical explosions and a consequent fire that ultimately caused the death of two workers and the release of a significant amount of radioactive material into the environment over 10 days.[16]

FUKUSHIMA DAIICHI

In March 2011 the Great East Japan earthquake and tsunami triggered a nuclear accident at the Fukushima Daiichi nuclear power plant. The circumstances are explained in greater detail in Appendix F: The Fukushima Daiichi accident. In summary, the reactors at the Fukushima Daiichi plant were early-model boiling water reactors. Flooding caused a loss of both on-site and off-site electrical power and led to the loss of reactor core cooling capability in three reactors.[17] This ultimately resulted in a LOCA that caused fuel melting and fission product release.[18] The parallel generation of hydrogen gas resulted in chemical explosions, causing significant structural damage to plant buildings.[19] Thorough examinations of the incident identified various deficiencies including:

1. critical weaknesses in plant design and in emergency preparedness in the event of severe flooding.[20] These included an insufficiently high flood wall, emergency power supplies that were vulnerable to flooding, and a more limited form of primary containment compared to modern reactors
2. weaknesses in Japan's regulatory framework in both a lack of regulatory independence and multiple decision makers, which obscured lines of responsibility[21]
3. the absence of an appropriate safety culture within the reactor operator, the nuclear regulator and the government[22], resulting in a number of unchallenged assumptions[23], including that the plant was so safe that an accident of this magnitude was simply unthinkable, and that electrical power could never be lost at a plant for more than a short time
4. lower preparedness among plant operators for the conditions and stresses that could arise in the event of a severe accident.

Table 4.1: Environmental releases for specific radionuclides from the Three Mile Island, Chernobyl and Fukushima Daiichi accidents

Accident	Iodine-131 (PBq)	Caesium-137 (PBq)
Three Mile Island[a]	0.00055	–
Chernobyl[b]	1760	85
Fukushima Daiichi[c]	100–500	6–20

a. L Battist & HT Peterson Jr, 'Radiological consequences of the Three Mile Island accident', Office of the Standards Development, US Nuclear Regulatory Commission, Washington D.C., 1980, p. 264.
b. UNSCEAR, *Sources and effects of ionizing radiation*, vol. II, scientific annex D, 2008, p. 49.
c. UNSCEAR, *Sources, effects and risks of ionizing radiation*, vol. I, scientific annex A, 2013, p. 40.
Note: The becquerel (Bq) is the SI unit of radioactivity equal to one decay event per second. One petabecquerel (PBq) is equal to 10^{15} Bq.

RELEASES OF RADIATION

The major radioactive substances released into the environment during these accidents are summarised in Table 4.1. Two radionuclides, the short-lived iodine-131 (^{131}I), with a half-life of eight days, and the long-lived caesium-137 (^{137}Cs), with a half-life of 30 years, were particularly significant for the radiation doses they delivered to the environment. Strontium was also released, but the additional radioactivity associated with its release was negligible when compared with natural background levels.[24]

At Three Mile Island, although fission products were released from the damaged core into the containment vessel, only very small amounts of radioactive substances were released into the environment.[25] At Fukushima, considerable amounts of radioactive substances, predominantly caesium and iodine, were released into the environment.[26] The effective dose of radiation to the Japanese public was about 10–15 per cent of the comparable dose to the European populations affected by radiation from Chernobyl.[27]

36. The lessons learned from the design, siting and cultural factors that contributed to these accidents have been applied to new developments.

The three major nuclear accidents have shown that the numerous complex interdependencies at nuclear power plants need to be understood, monitored and controlled so that reactor cooling is maintained at all times. Many analyses of the accidents have advanced the industry's understanding of how accidents comprise a progression of events from an initiating incident.[28] This has helped to reduce the probability of LOCAs in modern reactors through improvements in physical engineering and design measures, sophisticated instrumentation, automated operational controls and interlocks, and strengthening safety cultures.[29] The establishment and subsequent updates of international nuclear safety reporting mechanisms through the Convention on Nuclear Safety (1994) have also fostered international cooperation and information sharing on lessons learned among nuclear power plant operators.[30]

In the year that followed the Fukushima accident, many countries cooperated in a comprehensive assessment of nuclear risk and safety (so-called 'stress tests') to review the design of nuclear power plants against site-specific extreme external hazards.[31] These tests have led to useful recommendations, including the installation of additional backup electrical power and cooling water sources.[32] To mitigate the potential release of radioactive materials, measures have been developed and implemented in many countries. These measures include improved emergency response planning, reactor operator training, human-factors engineering, and radiation protection strategies, including administering iodine tablets to potentially affected individuals.[33] Following the Fukushima accident, all of Japan's remaining nuclear reactors were shut down for a review of their safety. Reactors are permitted to restart only after these reviews and are subject to a new regulatory framework. The restarts are progressive and are proceeding slowly,[34] due primarily to community resistance. Three of 46 reactors have been restarted to date.

In September 2012, the IAEA Director General initiated an inquiry into the Fukushima Daiichi accident. The resultant report, *The Fukushima Daiichi accident: Report by the Director General*, and its associated technical volumes, released in 2015, identified a number of lessons for the global nuclear industry that built on those learned from the stress tests, previous nuclear accidents and other studies of the Fukushima accident.[35] Lessons presented in the report focused on:

1. the design of nuclear power plants and their safety systems
2. radiation containment
3. the need to properly prepare for multiple severe external hazards that simultaneously or in sequence affect operations at nuclear power plants
4. the need to strengthen regulatory oversight and assessment of plants
5. the need to create safety cultures in which stakeholders question basic assumptions and continually improve operational safety.[36]

While there can be no guarantee that severe accidents will not occur again, they are rare, given there have been 16 000 cumulative years of nuclear power plant operation in 33 countries. The risk of a nuclear accident should not of itself preclude the consideration of nuclear power as a future electricity generation option.[37]

If nuclear power were to be contemplated in South Australia, the responsible operator would be able to benefit from the accumulated safety knowledge of the global nuclear industry, including the lessons learned from prior accidents. As well, relevant local reactor safety expertise from the Australian Nuclear Science and Technology Organisation (ANSTO) and the Australian Radiation Protection and Nuclear Safety Authority (ARPANSA) is available.

IS THE ACTIVITY FEASIBLE?

37. Nuclear power is a mature, low-carbon electricity generation technology. Its deployment is characterised by large upfront capital costs and long periods of construction and operation. It offers high capacity and reliability, but does not efficiently follow the peaks and troughs of a highly variable demand profile.

The use of nuclear fission to commercially generate electricity was first achieved over 60 years ago.[38] Today the world's fleet of commercial nuclear power plants is predominantly made up of a small number of established water-cooled designs.[39]

Since the 1950s, reactor designs have continued to evolve to deliver increased efficiency and improved safety.[40] Large, modern designs incorporate independent safety systems that are both 'active', which include electrically powered pumps and valves, and 'passive', which take advantage of fundamental physical forces and mechanisms such as gravity and natural convection to maintain cooling to the reactor core.[41] 'Defence in depth' is another key safety feature of modern reactors; it ensures multiple barriers are in place to provide protection should a single barrier fail.[42]

Nuclear power plants are essentially baseload generators that run continuously. Their ability to operate flexibly to meet variations in demand depends on the reactor type and the refuelling cycle. The typical features of modern nuclear reactor designs are addressed in Appendix E.

In recent years, the complexity of some larger-capacity reactor designs and more stringent reliability and safety requirements have increased the difficulties of plant construction.[43] These have been key drivers of the cost and schedule overruns that have characterised recent construction programs[44], including several plants in Europe and the USA. Further, contemporary construction experience has declined given the lapse of time between current building programs and those undertaken decades ago.[45] Recent estimates of the cost of construction excluding finance (the overnight construction cost) in Europe and the USA range from A$9.25 billion for a Westinghouse AP1000 plant to A$14.8bn for an AREVA-designed EPR plant, with estimated construction schedules ranging from six to fifteen years, including cost and schedule over-runs.[46] The quoted contract price of the United Arab Emirates' current build program is slightly lower, at A$7.1bn for each of the four APR1400 reactors under construction. However, it is not known whether the vendor has been able to deliver the project within its contracted projection.[47]

Some evidence suggests that, for the current generation of large reactors, integrated construction programs involving multiple reactors of standardised design may have greater success in adhering to planned costs and achieving shorter build schedules.[48] The Commission's approach to estimating the capital construction cost of a nuclear power plant for the purpose of analysing its viability for Australia is explained in Finding 45 and in Appendix G: Nuclear power in South Australia—analysis of viability and economic impacts.

38. The technology to develop a nuclear power plant could be transferred readily from experienced commercial vendors. Careful consideration would need to be given to appropriate siting to ensure that water requirements for reactor operation could be met sustainably.

A number of commercial reactor vendors are capable of partnering with a South Australian entity for the construction and operation of a nuclear power plant. In nations new to nuclear power, partnerships for the development of a plant typically include arrangements to allow for knowledge transfer and local workforce training.[49] The lack of experience with nuclear power generation in South Australia would not preclude the development of a nuclear power plant at an appropriate site.[50]

The geophysical characteristics necessary for safe and efficient plant operation include low seismicity and ready access to adequate amounts of water for the current generation of large light water reactors.[51] While most parts of South Australia are geologically stable, sustainable access to water resources would need to be carefully assessed, given the reliance on water for cooling in most modern nuclear power plants.

In relation to the location for any potential large nuclear power plant in South Australia, a coastal site would be necessary to meet the significant water requirements for cooling using saltwater.[52] These requirements are addressed in detail in Appendix E.

Coastal siting might be a lesser consideration for future small modular reactor (SMR) designs, which have not yet been commercially developed.[53] Importantly, freshwater requirements for plant operation also need to be considered.[54]

39. If nuclear power were to be considered in South Australia, analysis should focus on a proven design that has been constructed with active and passive safety features. For commercial electricity generation in the foreseeable future this would include analysis of potential small modular reactors based on light water designs because of their suitability for integration in smaller markets, but not advanced fast reactors or other innovative reactor designs.

Any consideration of nuclear power in South Australia would need to focus on a reactor design with the following characteristics:

1. A proven design licensed by a reputable nuclear safety regulator. This would avoid project, technical and commercial risks and costs associated with construction of first-of-a-kind technology.[55] It also would increase confidence that the design would be able to be licensed in Australia, as it would need to comply with the relevant Australian licensing and regulatory framework. It may also reduce the level, and associated costs and timeframes, of the design assessment required.
2. A design previously constructed, ideally multiple times, would allow cost and schedule to be determined with greater certainty.[56] As nuclear power plant construction projects proceed overseas, reported construction costs should be monitored closely and independently verified.

3. A reactor design should be based on recent construction, with an experienced team and specialist workforce.[57]
4. The design should incorporate proven active and passive safety features for nuclear power plants (see Appendix E for a detailed explanation) that capture lessons learned from ongoing operations and fault scenarios.

Several proven designs incorporate the required and preferred design features identified above, and it is likely that more will become available in the next decade.[58] In particular, given the current maturity of the technology, it is likely that light water SMR designs will be available.[59] The smaller capacity of SMRs makes them attractive for integration in smaller electricity markets such as the National Electricity Market (NEM) in South Australia.[60] For this reason, it will be important to follow the development of such reactors.

Although there are no commercially operational examples of light water SMRs[61], several are in advanced stages of development and the early phase of licensing.[62] A study commissioned by the British government to address the potential availability of identified light water SMR designs confirmed the need for further detailed technical analysis. The study found SMRs would require A$1bn–2bn of development funding over five to seven years to be commercialised. Commercial deployment of a design would provide credible evidence of capability and cost.

In comparison, advanced fast reactors and other innovative reactor designs are unlikely to be feasible or viable in the foreseeable future (see Appendix E).[63] The development of such a first-of-a-kind project in South Australia would have high commercial and technical risk.[64] Although prototype and demonstration reactors are operating, there is no licensed, commercially proven design. Development to that point would require substantial capital investment.[65] Moreover, electricity generated from such reactors has not been demonstrated to be cost competitive with current light water reactor designs.[66]

The recent conclusion of the Generation IV International Forum (GIF)[67], which issued updated projections for fast reactor and innovative systems in January 2014[68], suggests the most advanced system will start a demonstration phase (which involves completing the detailed design of a prototype system and undertaking its licensing, construction and operation) in about 2021.[69]

The demonstration phase is expected to last at least 10 years and each system demonstrated will require funding of several billion US dollars.[70] As a result, the earliest possible date for the commercial operation of fast reactor and other innovative reactor designs is 2031.[71] This timeframe is subject to significant project, technical and funding risk. It extends by six years a similar assessment undertaken by GIF in 2002.[72] This means that such designs could not realistically be ready for commercial deployment in South Australia or elsewhere before the late 2030s, and possibly later.[73]

40. The future viability of nuclear power, as for any generation source, can only be analysed as part of the electricity supply system in which it would be integrated.

The potential viability of a new nuclear power plant in South Australia cannot be determined by simply comparing its associated costs with those of other electricity generating technologies.[74] Commercial profitability would be determined by the more complex issues of how, when, and at what price the electricity produced by any new generating plant would be made available to customers.[75] This requires an understanding of the established market structure, its rules of operation and its likely evolution.[76]

South Australia is part of the NEM, which is one of the longest continuous electricity transmission systems in the world. The NEM supplies electricity to about 10 million customers across the Australian Capital Territory, New South Wales, Queensland, South Australia, Tasmania and Victoria.[77] The main network is a legacy system—designed in the 1980s—comprising more than 300 generators that supply electricity via the transmission network.[78] Six cross-border interconnectors connect the transmission networks of the participating regions, with the amount of electricity imported or exported at any given time limited by the capacity of the transmission line.[79] Figure 4.1 shows the physical generating and transmission assets in the South Australian subregion of the NEM. The coal-fired power plant located at Port Augusta has been omitted as it will cease operation in 2016.

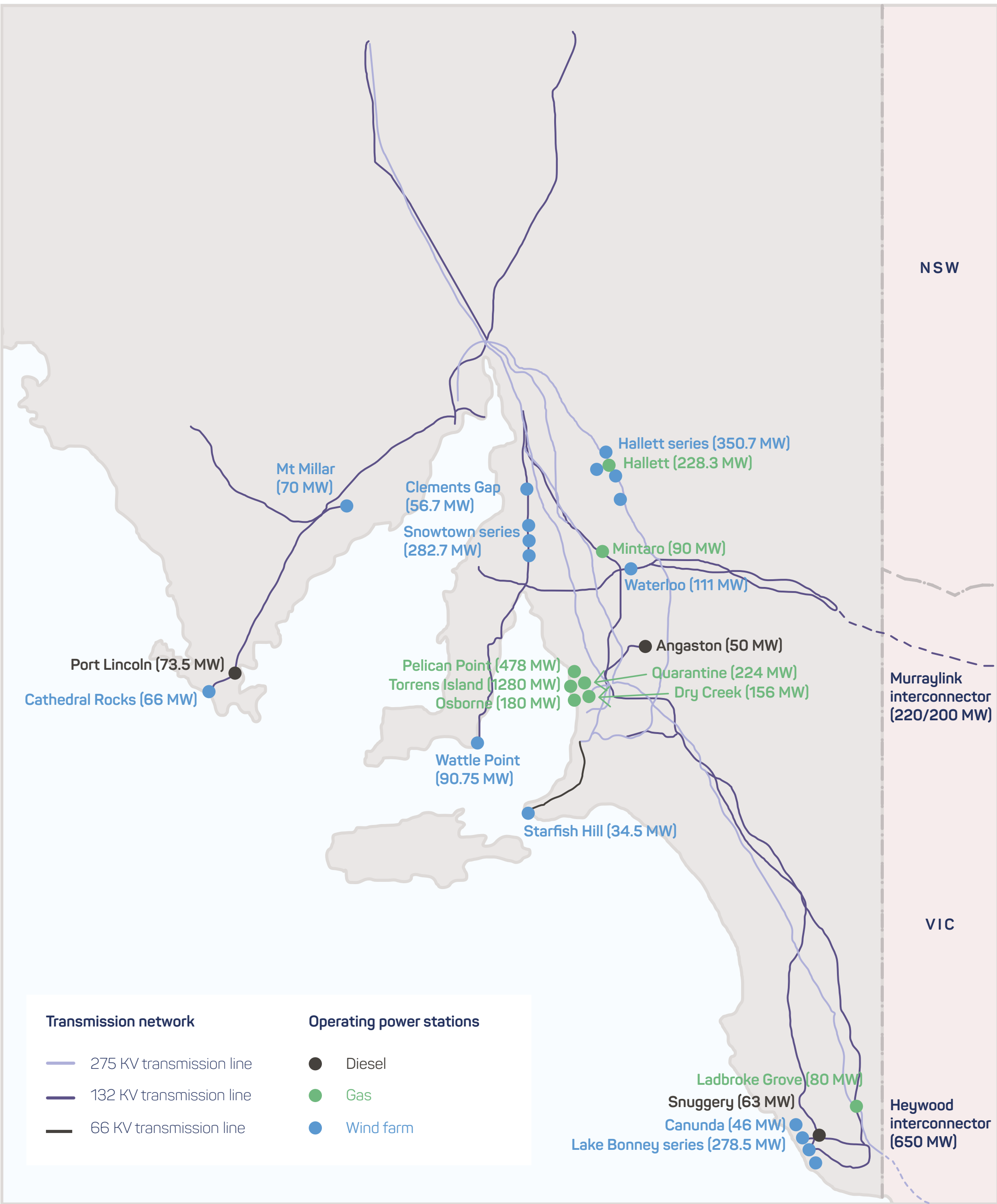

Figure 4.1: The South Australian region of the National Electricity Market (NEM), detailing power stations, transmission networks and interconnectors

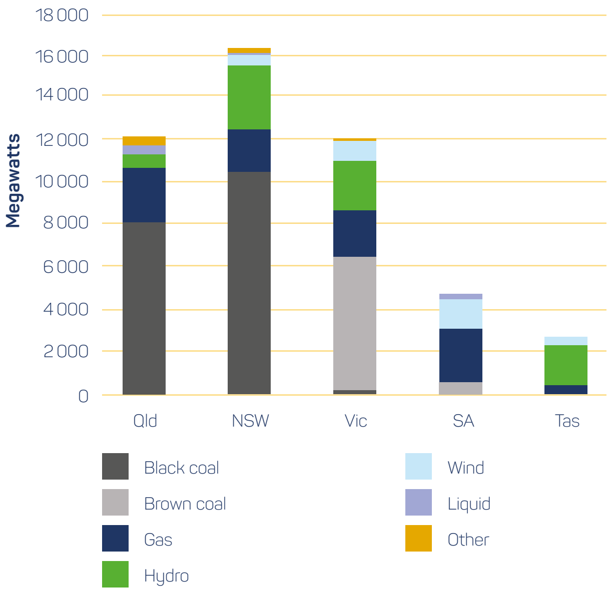

Figure 4.2: NEM generation capacity by region and fuel source, 2015

Data sourced from the Australian Energy Regulator (AER), *State of the energy market report*, 30 June 2015, p. 29

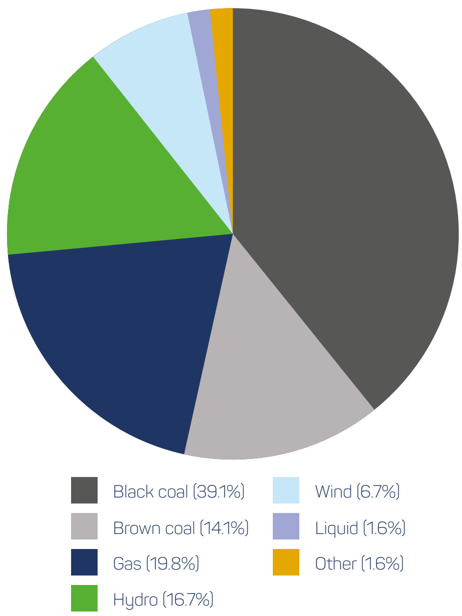

Figure 4.3: NEM generation capacity by fuel source, 2014/15

Data sourced from AER and Australian Energy Market Operator (AEMO)

41. The NEM is carbon-emissions intensive, does not require electricity generation sources to bear the full costs of their carbon emissions, and is subject to government interventions directed at lowering carbon emissions, which are not technology neutral and have not been demonstrated to achieve a low-carbon system with the lowest overall cost.

Black and brown coal-fired generators represented 53 per cent of installed generation capacity in the NEM in 2014/15 (see Figure 4.2 and Figure 4.3), but supplied 76 per cent of output.[80] This high share of coal-fired generation contributes more than one-third of national carbon emissions, and means the Australian electricity sector is one of the most carbon-intensive in the world (see Figure 4.4).[81]

The retirement of a significant percentage of that capacity is already planned over the next two decades.

There is currently no mechanism to impose the cost of emissions on generators, although this was enacted by carbon pricing from 1 July 2012 to 30 June 2014. During this time coal-fired generation output declined by 12 per cent, but it quickly recovered when carbon pricing was abolished. The Large-scale Renewable Energy Target (LRET) scheme, which was launched in 2001, aimed to decrease the carbon emissions intensity of the NEM by providing a financial incentive for renewable energy generation technologies to enter the market. The LRET is not a technology–neutral scheme: it offers incentives to develop a group of renewable technologies—most significantly wind and solar PV. Different policies are likely to have differing economic impacts and costs in reducing CO_2 emissions. They also have different effects in different NEM regions (see Box: South Australia's electricity price competitiveness to 2030 and beyond).
A review of policies, their effectiveness and economic impacts will be released by the Climate Change Authority in 2016.[82]

42. While the NEM predominantly comprises ageing centralised generators, low average wholesale prices and relatively flat average demand forecasts present challenges to the viability of any new electricity generation infrastructure suited to baseload supply.

Approximately 58 per cent of coal-fired and 24 per cent of gas-fired generation in the NEM was first commissioned more than 30 years ago, as shown in Figure 4.5, although this does not account for capacity expansions and upgrades after commissioning. Consequently, a significant number of generators have fully amortised capital costs, allowing them to operate at low short-run marginal costs and therefore offer low wholesale prices for the energy they generate. Any new capacity would be more expensive because capital costs would need to be recovered. At some stage, as the existing generators require replacement, incentives for investment in new generation capacity may need to be contemplated.

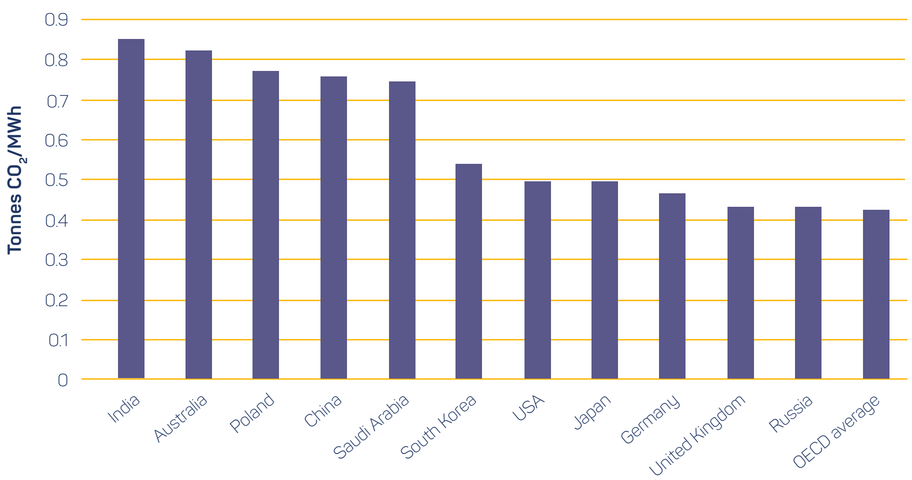

Figure 4.4: Electricity sector emissions for various OECD countries in 2011

Data sourced from A Stock, *Australia's electricity sector: Ageing, inefficient and unprepared*, Climate Council of Australia, 2014, p. 8

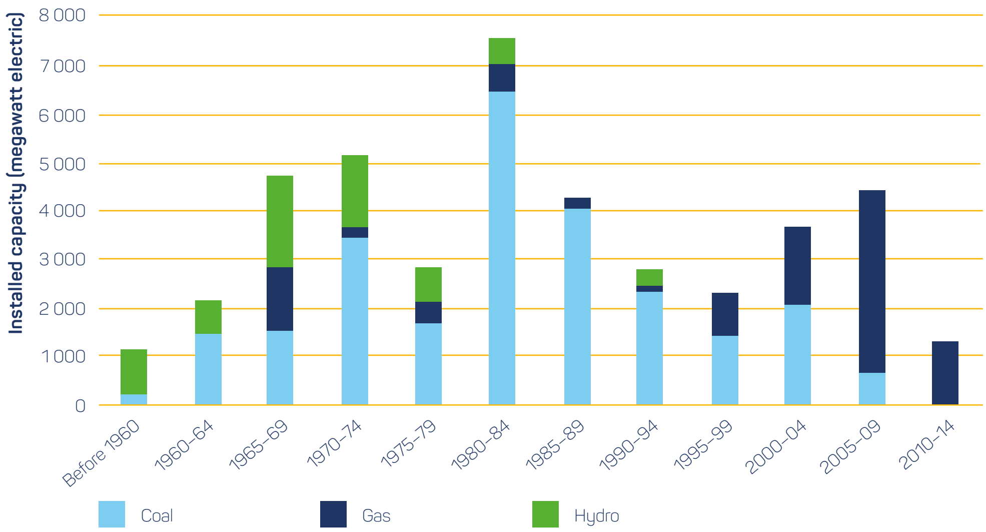

Figure 4.5: First commissioning date of operational baseload capacity in the NEM

Data sourced from the Chamber of Minerals and Energy of Western Australia, submission to the Nuclear Fuel Cycle Royal Commission, p. 22

A significant amount of generating capacity will be withdrawn from South Australia during the next few years due to the closure and mothballing of coal and gas-fired generators. This will place more reliance on importing electricity from Victoria through the interconnectors, unless generation capacity is replaced locally.[83]

Generators in the NEM sell electricity through a wholesale spot market. As an energy market, generators are paid based on the energy they supply, and the cheapest offers of electricity at any time are dispatched to meet demand.[84]

Generators need to be able to offer their electricity at a sufficiently competitive price to ensure selection for dispatch and are only able to sell electricity at very high prices when demand exceeds available supply.[85]

As shown in Figure 4.6, electricity demand in the NEM has declined during the past five years due to several factors including high electricity prices, penetration of roof-top solar photovoltaics (PV), increased energy efficiency and the closure of aluminium smelting and manufacturing facilities, for example, automotive factory closures in Victoria

BASELOAD VERSUS PEAKING GENERATORS

Generation technologies differ in terms of their flexibility of operation and consequently their ability to take advantage of fluctuations in the market.

Baseload generators such as coal and nuclear are typically operated to maintain a constant level of generation, and are therefore most profitable when required to meet a steady and predictable level of demand.

Peaking generators such as gas are able to start up quickly compared with other generation technologies, and therefore have the flexibility to react to sharp increases in demand. Peaking generators can still be profitable even though they may only operate for several days a year. Because they are the only source of supply at such times, they are able to charge large wholesale prices, enabling them to meet their costs despite their infrequent operation.

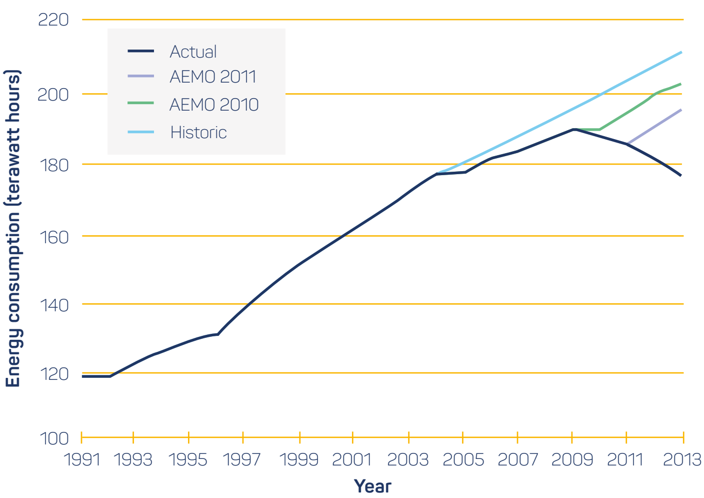

Figure 4.6: Energy consumption in the NEM—actual and predicted

and South Australia.[86] This decline, which was not predicted by the industry, has resulted in the temporary and permanent removal of some capacity from the NEM.[87]

The flat demand for electricity has negated the need for further generation investment in the near future, with the vast majority of new generation being LRET-incentivised wind energy.[88] However, the intermittent nature of wind generation can lead to it supplying a large amount of energy during low demand periods, resulting in low and even negative wholesale prices at these times. This presents a challenge for baseload generation technologies to compete financially.[89]

43. The following characteristics of the South Australian region of the NEM affect the viability of current or potential new baseload generators, such as a nuclear power plant:

a. The annual demand profile is characterised by peaks that substantially exceed average daily demand, which results in one-third of South Australia's generation mix being used less than 200 hours annually.

The South Australian region of the NEM is characterised by significant peaks in its demand profile on both short and long time scales. This is predicted to continue, with the maximum demand forecast to reach 2.2 times the average demand by 2024–25, easily the largest ratio of any region in the NEM, as shown in Figure 4.7 and discussed in Box: South Australia's electricity price competitiveness to 2030 and beyond.[90] This poses a significant challenge for the commercial viability of large-scale plant because although a large amount of capacity is needed to meet maximum demand, the amount of time this maximum capacity is used is limited.

b. The daily minimum demand for electricity has been falling as a result of increased penetration of solar PV. Yet solar PV has had little effect on peak demand requirements.

The minimum operational demand typically occurs in the middle of the day, and, given this coincides with the maximum operation of solar PV, has caused a steady decrease in operational minimum demand in South Australia during the past several years. By 2023–24, it is expected that solar PV will completely meet demand between 12:30 and 14:30 on particular minimum demand days.[91] Conversely, the uptake of solar PV has had little impact on operational maximum demand, particularly as peak demand typically occurs between 16:00 and 21:00 on hot summer days, when solar PV is past peak operation.[92]

c. Total demand is small, with low expected short- and medium-term growth, such that a very large generator would supply a large portion of demand.

As discussed, total demand in South Australia is relatively small compared with other regions in the NEM, with maximum demand between 2900 megawatts (MWe) and 3400 MWe.[93] Large-scale generators typically have capacity of about 1000 MWe, approximately one-third of current maximum demand in South Australia.

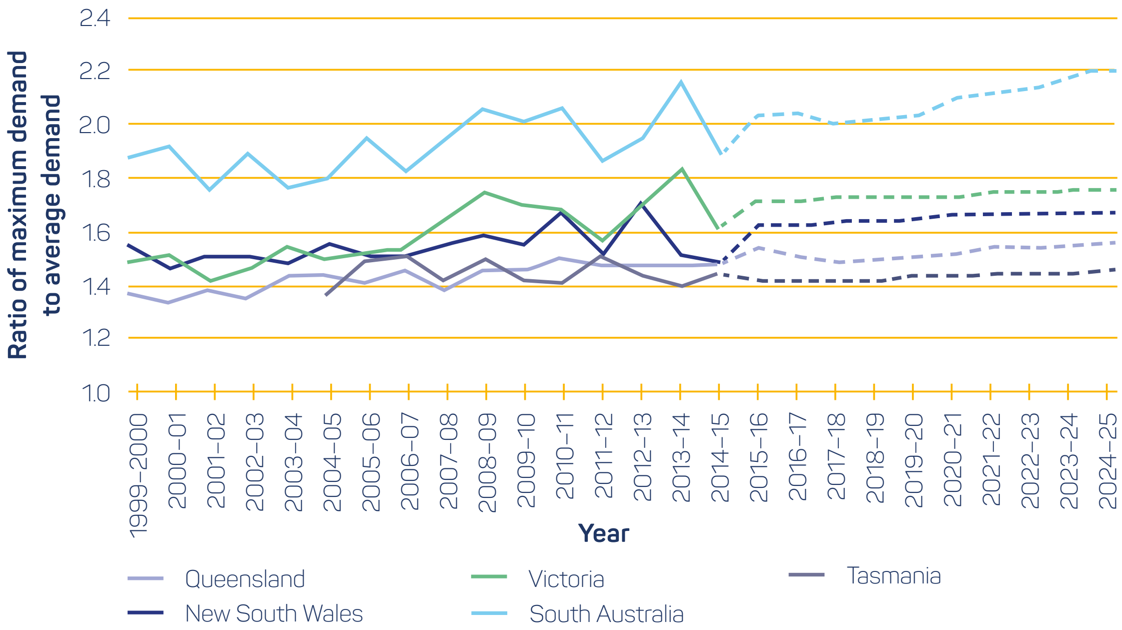

Figure 4.7: Ratio of maximum demand to average demand for each region in the NEM

Data sourced from AER, *State of the energy market report*, 30 June 2015, p. 26

d. There is substantial, and growing, intermittent generating capacity, which relies on interstate coal generation and peaking gas generation to continuously balance supply and demand.

In 2014/15, wind and solar PV made up 34 per cent and 7 per cent respectively of South Australia's total generation capacity. This high penetration of intermittent generation necessitates having a large amount of capacity that is ready to meet demand in periods of low wind and sunlight. Demand cannot always be met by local generation, requiring South Australia to import electricity from Victoria via the Heywood and Murraylink interconnectors.[94] This is typically sourced from coal-fired generation due to its low cost.[95]

e. The penetration of wind has altered the operational characteristics of existing gas and coal generation from baseload to load following.

Because wind farms typically have very low short-run marginal costs, they can place particularly low-cost bids in the NEM, which consequently sees all wind energy dispatched in South Australia when it is available.[96] As a result, fossil fuel plants that were historically operating as baseload generation are now operating as peaking generation, that is, periodically dispatched to meet peak demand rather than constantly supplying the minimum demand.

f. South Australia's relative isolation from the wider NEM due to limited transmission interconnection inhibits the import and export of electricity.

The import and export of electricity across state borders is limited by the physical constraints of the interconnectors—200/220 MWe for Murraylink and 460 MWe (currently being upgraded to 650 MWe) for Heywood.[97]

g. Relative to other regions of the NEM, South Australia has one of the highest average wholesale prices and some of the greatest price volatility.

South Australia has had either the highest or second-highest average annual electricity wholesale price in the NEM for each of the past nine financial years.[98] This has negatively affected the competitiveness of energy-intensive industries in the state. Additionally, South Australia has experienced significant price volatility (both highs and lows) in the past few years compared to other NEM regions. Price volatility in South Australia has been driven by coal and gas plant withdrawals, concentrated generator ownership (lack of competition), and limited capacity to import electricity via the interconnectors (see Box: South Australia's electricity price competitiveness to 2030 and beyond).[99]

SA'S ELECTRICITY PRICE COMPETITIVENESS TO 2030 AND BEYOND—POLICY IMPACTS

The Commission's modelling considered the effect on wholesale electricity prices in a scenario where there was no nuclear, but increasing renewable generation to 2030 and beyond. This assessment was necessary to both form a baseline against which the introduction of nuclear generation could be contrasted and identify any supply shortfall that a nuclear generator could fill.

This analysis offers some insights into the policy effects of reducing carbon emissions to South Australia's future electricity competitiveness relative to other regions of the NEM to 2030 and beyond.

Over recent years, the South Australian subregion of the NEM has had some of the highest average wholesale electricity prices in the nation. These prices make up part of the retail electricity price paid by businesses and households. The other parts are the cost of the transmission and distribution network, taxes, and subsidies paid to generators. Figure 4.8 compares South Australian wholesale prices with those of other NEM subregions since 2006/07.

The volatility in South Australia's wholesale electricity prices (the extent to which prices range from highs to lows) relative to the other NEM states is shown in Figure 4.9. South Australia experiences a much higher frequency of both negative and very high regional reference prices relative to the other NEM states. The very low price events are attributable to significant electricity supply from intermittent renewables during periods of low demand, whereas the very high price events are attributable to a combination of factors, including on occasion the need to rely on open cycle gas turbines when there is little or no supply from intermittent renewables.

The modelling undertaken for the Commission distinguished between two means of delivering low-carbon energy generation to meet abatement targets between 2017 and 2030:

1. continuing policies, such as the LRET scheme and emissions reduction fund, which is not technology neutral (a Current Policies scenario).
2. introducing market mechanisms, such as a carbon price, which is technology neutral (the New Carbon Price scenario).[1]

After 2030, the model assumed that a carbon price would apply. The scenarios and corresponding assumptions are explained in greater detail in Table G.2 and Figure G.2 in Appendix G: Nuclear power in South Australia—analysis of viability and economic impacts. The wholesale price was derived from the lowest-cost mix of technologies that was determined based on the current Australian estimates of the costs of renewables and storage shown in Figure G.3 of Appendix G. These assume subtantial cost reductions for both renewables and storage technologies.

Under both scenarios the average wholesale electricity price is higher in South Australia than it is now. However, the two policies had significantly different effects on electricity price competitiveness for South Australia.

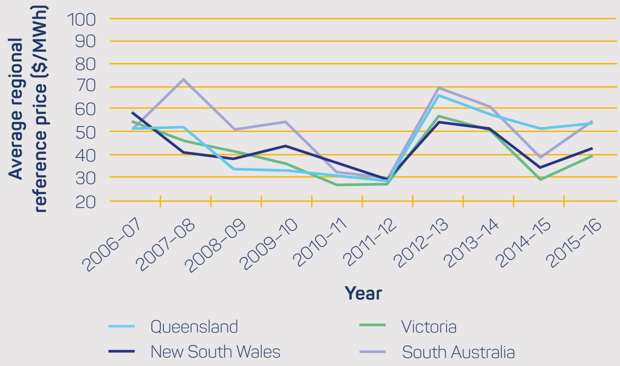

Figure 4.8: Annual average regional wholesale price across mainland NEM states from 2006/07 to 2014/15

Data sourced from Australian Energy Market Operator (AEMO), Average price tables

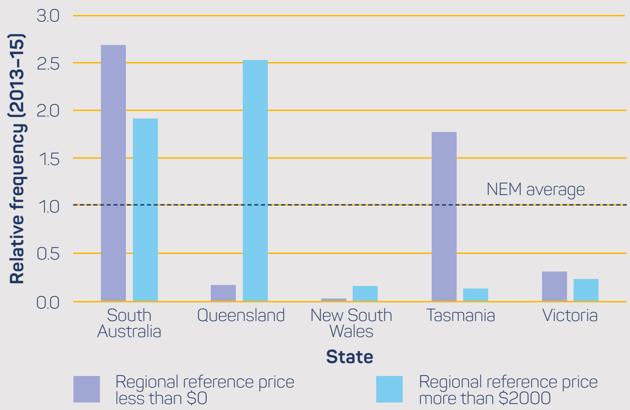

Figure 4.9: The frequency of negative and very high regional wholesale prices in NEM regions relative to the average, 2013–15

Data sourced from AEMO, Pricing event reports

SA'S ELECTRICITY PRICE COMPETITIVENESS TO 2030 AND BEYOND—POLICY IMPACTS (CONT'D)

Current policy mechanisms (not technology neutral)

A continuation of current policy interventions was shown to lead to continuing growth and relatively higher concentration of renewable generation in South Australia, compared to other regions (see Figure 4.10). The difference arises in the analysis as a result of better wind resources in South Australia; the presence of existing low-cost generation in some other regions, which diminishes the attractiveness of installing new capacity; and differences in state-based policies supporting new renewable capacity.

This policy has clear implications for wholesale price competitiveness in South Australia, as shown in Figure 4.11. In the period between 2017 and 2030, it leads to wholesale electricity prices in the state being 20 per cent higher than the NEM average. The comparatively higher price in the model arises from a combination of effects that includes the predicted high penetration of renewables in South Australia, the lack of diversity in the local generation mix to meet the balance of demand, and the lower shares of renewable generation in other regions of the mainland NEM.

Carbon price policy mechanism (technology neutral)

If a technology-neutral policy such as a carbon price were introduced to drive emissions reductions, there would be more uniform growth in the share of renewable generation across the mainland NEM states, as shown in Figure 4.10. This is because all generators must meet the full costs of their carbon emissions, including low-cost generators in other regions. Under this policy South Australia was still estimated to have the greatest share of renewable generation; however average wholesale prices in the state became similar to other regions as a carbon price leads to a rapid increase in renewable capacity from 2017, as shown in Figure 4.11.

Prices converge under both scenarios beyond 2030, as a carbon price is assumed to apply under both scenarios modelled.

1 Ernst & Young, *Computational general equilibrium modelling assessment*, report prepared for the Nuclear Fuel Cycle Royal Commission, Adelaide, February 2016, section 3.2, pp. 26-27.

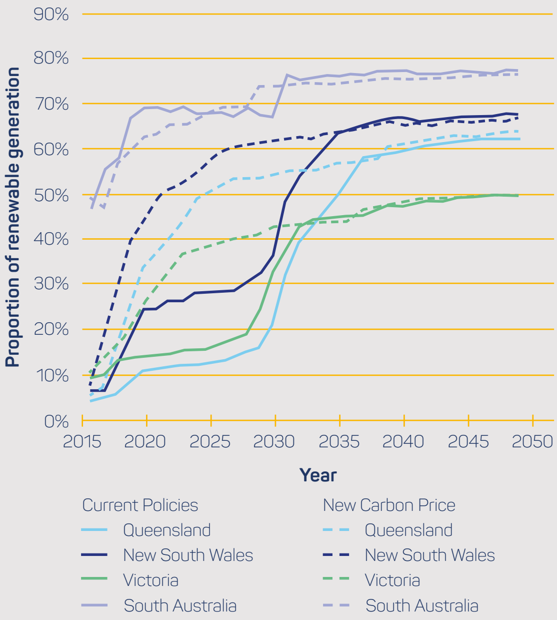

Figure 4.10: Renewable generation as a proportion of total generation by 2050 in the mainland NEM states under the Current Policies or New Carbon Price scenarios

Data sourced from Ernst & Young, *CGE modelling assessment*, underlying market model data

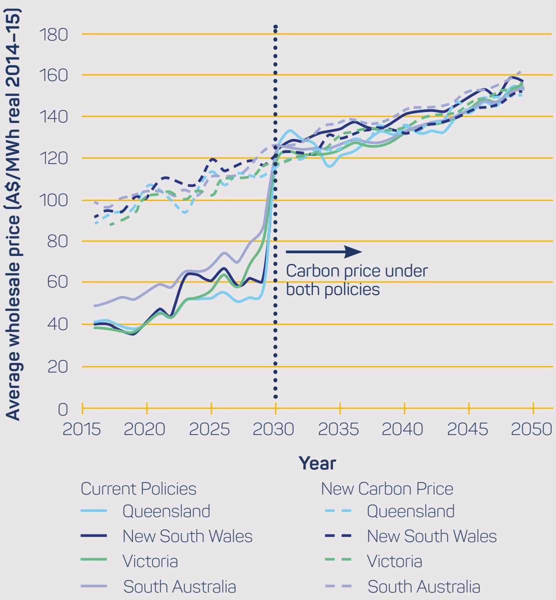

Figure 4.11: Annual average wholesale price of electricity to 2050 for all mainland NEM states under Current Policies and New Carbon Price scenarios

Source: Ernst & Young, *CGE modelling assessment*, underlying market model data

IN WHAT CIRCUMSTANCES IS THE ACTIVITY VIABLE?

44. An assessment of the viability of establishing a nuclear power plant in the South Australian NEM would require a full systems investigation.

Whether any additional electricity generator, including a nuclear power plant, would be able to deliver a sufficient return on investment in the South Australian NEM depends on whether it would be dispatched to supply electricity at a price that generates profits. This would require a full systems analysis of:

- the costs of establishing and operating a new nuclear power plant in South Australia[100]
- the levels of future demand in the South Australian NEM at the time that such a plant might be operating, which in turn would require an analysis of the earliest reasonable date of operation[101]
- the costs and outputs of the generators that would be competing to meet that demand—both existing generators and those likely to be integrated into the grid over the same time—which would inform analysis of the wholesale prices with which a new nuclear power plant might need to compete[102]
- the impact of carbon abatement policy measures on the electricity market[103]
- wholesale prices in the South Australian subregion following the introduction of any new generating capacity.[104]

45. Based on analyses addressing these issues, it can be concluded that, on the present estimate of costs and under current market arrangements, nuclear power would not be commercially viable to supply baseload electricity to the South Australian subregion of the NEM from 2030 (being the earliest date for its possible introduction).

The Commission did not find that nuclear power is 'too expensive' to be viable or that it is 'yesterday's technology'. Rather, it found that a nuclear power plant of currently available size at current costs of construction would not be viable in the South Australian market under current market rules.[105] The outcome of this analysis is consistent with a wide range of realistic scenarios. It does not necessarily apply to other jurisdictions in Australia. In fact, some of the modelling suggests that nuclear might well be viable elsewhere, as the challenges facing baseload generation in South Australia are not shared with other regions of the NEM. This is explained in more detail below, and in Appendix G: Nuclear power in South Australia—analysis of viability and economic impacts.

CAPITAL COST OF NUCLEAR

The development of a nuclear power plant involves a substantial upfront capital investment before operating revenues are earned. The amount of this investment is therefore critical to an analysis of viability. To have confidence in its estimated costs, the Commission applied the following criteria:

1. The reactor technology had to have been successfully constructed and commissioned elsewhere at least twice by 2022.
2. All cost estimates were to be based on realised-cost benchmarks or, if they were not available, independently verified estimates.

In terms of attempting to establish the likely capital costs of a new nuclear power plant, the Commission assessed that the most reliable data is recent, realised benchmarks in project development and construction timeframes. In the case of new technologies that have not been constructed, such as SMRs, the Commission considered that it was necessary to take a conservative approach to projected costs until they could be demonstrated. It did not consider the costs of advanced reactors that are not commercially proven and hence have no reliable bases for estimating costs.

The estimate of total costs used by the Commission for construction of a large pressurised water reactor (PWR) is set out in Table 4.2. The estimate is derived from known costs of the Westinghouse AP1000 PWR (1125 MWe) based on available realised costs for the four units (two each at Vogtle and VC Summer) under construction in the USA.[106] The known costs were adjusted as they relate to the construction of reactors in pairs, whereas the costs estimated in Table 4.2 are for a single reactor. The analysis sought to apply costs to local conditions by estimating additional expenditure associated with establishing supporting infrastructure such as electrical connection, reserve capacity, roads and wharf facilities, and water supplies. Separate estimates were made for greenfield and brownfield sites, which took account of the proximity of existing infrastructure.

Table 4.2: Capital and supporting infrastructure costs for a large nuclear reactor (PWR) at a brownfield and greenfield site

Site	PWR (1125 MWe) (A$ 2014[a])
Brownfield site	$8962m ($7966/kW)
Greenfield site	$9323m ($8287/kW)

a. Includes pre-construction, licensing, supporting infrastructure and connection costs.
Note: Megawatt electric (MWe); per kilowatt (/kW).
Data sourced from WSP/Parsons Brinckerhoff, *Final report: Quantitative analysis and initial business case – establishing a nuclear power plant and systems in South Australia*, report prepared for the Nuclear Fuel Cycle Royal Commission, Adelaide, February 2016, section 6.

Because of the potential for plants with smaller capacity to successfully integrate with the South Australian NEM, the Commission considered the viability of light water SMRs of less than 400 MWe. Because even the most advanced designs for such SMRs have not been commercially licensed, there are no available benchmarks.

The Commission undertook the analysis based on two of the more advanced SMR designs, which are in the process of licensing and appear to have prospects for commercial deployment.[107] In the absence of a demonstration of the SMR's actual costs, the Commission was not prepared to accept the projections of costs made by nuclear power plant vendors. These projections ranged from A$7000 to A$8000 per kilowatt, which is substantially lower than the Commission's analysis.[108] While the Commission accepts that the projections represent the target for vendors, and are in some cases their best estimate of costs, it could not confidently proceed on that basis.

Given this, the capital costs of SMR systems for the purposes of the Commission's study was estimated to be 5 per cent higher than that of the large-scale PWR costs presented in Table 4.2, on the basis that a small plant has not been demonstrated to achieve the economies of scale of a large plant.[109] The costs of licensing and project development were added to that. The cost estimates used by the Commission for constructing two types of SMR, including supporting infrastructure, on either a brownfield or greenfield site are set out in Table 4.3.

Table 4.3: SMR capital and supporting infrastructure for two designs

Site	SMR (285 MWe) (A$ 2014[a])	SMR (360 MWe) (A$ 2014[a])
Brownfield site	$2942m ($10 323/kW)	$3302m ($9173/kW)
Greenfield site	$3331m ($11 689/kW)	$3692m ($10 256/kW)

a. Includes pre-construction, licensing, supporting infrastructure and connection costs.
Note: Megawatt electric (MWe); per kilowatt (/kW).
Data sourced from WSP/Parsons Brinckerhoff, *Establishing a nuclear power plant*, tables ES1–8.

The cost estimates used by the Commission are, in the case of a large nuclear reactor (PWR), substantially higher than those used in the Australian Energy Technology Assessment 2013 Model Update (AETA 2013), but similar to those used in the Australian Power Generation Technology Report in 2015, set out in Table 4.4.[110] Internationally, the IAEA and the International Energy Agency (IEA) have published costs in the same order as the AETA 2013 costs. The Commission's higher costs are substantially explained by its use of a lower exchange rate (the long-term average), inclusion of pre-construction and project development costs (excluded in the AETA analysis), and supporting infrastructure such as port facilities.

Table 4.4: PWR and SMR capital and supporting infrastructure costs for a brownfield site

	PWR	SMR
***Australian Energy Technology Assessment 2013 Model Update* (first-of-a-kind costs)[a]**	$6392/kW	$11 778/kW
***EPRI/CO_2CRC Australian Power Generation Technology Report* (2015)[b]**	$9000/kW	N/A

a. Bureau of Resources and Energy Economics, Australian Government, Canberra, 2013.
b. Electric Power Research Institute, 2015, p. 127.
Note: Per kilowatt (/kW).

TIMEFRAME FOR INTRODUCTION AND LIKELY DEMAND AT THAT TIME

The Commission considers 2030 to be the earliest that a nuclear power plant could reasonably be expected to start operation in South Australia. This allows 14 years for establishing regulatory systems and expertise, undertaking a detailed assessment of the nuclear supply chain before pre-licensing activities, licensing, project development and construction for a large plant. This is an ambitious timeframe, but the Commission considers it reasonable if there were an imperative for development.[111]

Total network demand at that time will depend on the extent to which some renewable generation, energy storage and electric vehicle technologies are deployed. While increased roof-top solar PV would reduce demand, electric vehicles would both increase total consumption and change the demand profile. The extent to which these technologies may be deployed will be substantially driven by cost reductions that may be realised up to 2030.

To account for this uncertainty, the Commission's analysis of future demand in the NEM is based on separate projections for the residential, business and industrial sectors (incorporating network losses), including reducing demand to take account of solar PV generation and storage 'behind the meter', that is, local storage within businesses and residences. Different projections were made, taking account of growth in demand for electric vehicles, other economic activities (including population growth) and the effect on demand caused by consumers' response to increasing prices.

COMPETING GENERATION TECHNOLOGIES

To determine which technologies would be able to offer the lowest overall wholesale electricity prices to meet expected demand in 2030, the Commission used the most recent Australian estimates of costs published in the *Australian Power Generation Technology Report* (2015).[112] It also took account of expected reductions in cost previously published as part of the AETA 2013 update[113], as shown in Figure G.3 in Appendix G.

The cost of nuclear power plants is assumed to remain stable to 2050. Responses to the Tentative Findings have criticised that position, suggesting that cost reductions should have been assumed in response to rising global deployment. In the Commission's view there is significant uncertainty in relation to realising such cost reductions, given the lack of demonstrated evidence to date in Western democracies.

IMPACT OF CARBON ABATEMENT POLICIES

The mix of generation technologies likely to be competing with a nuclear power plant and their wholesale costs would also be affected by the scope and timing of policy measures to reduce the CO_2 emissions intensity of the energy sector. Such measures could affect the wholesale price of electricity and, if they are targeted, advantage particular technologies. The modelling undertaken for the Commission took this into account.

Significant uncertainty remains in relation to the policy measures that are likely to be implemented. To reasonably account for the likely impact of such measures, the Commission developed what it considers are plausible scenarios. These scenarios are based on existing measures (for example, the emissions reduction fund and LRET), recent policies (for example, a carbon price and emissions trading scheme), and the Australian Government's emissions reduction goals for 2030.[114]

Based on each of the above inputs, market modelling was undertaken to determine the lowest-cost mix of generation in the wholesale market that would make up the NEM to 2050. The model also determined the price of electricity that would correspond to this mix. This is discussed in further detail in Appendix G.

Nuclear power, on current costs, was not part of the lowest-cost mix.[115] Instead, significant growth in intermittent renewable generation was estimated to be supported by a combination of 900 MWe of combined cycle gas turbine capacity, the current level of peaking gas generation of 950 MWe and behind-the-meter energy storage. The mix of installed gas generation was found to comprise about 25 per cent of South Australia's total generation in 2030 and 22 per cent in 2050.[116]

46. The conclusion that nuclear power is not viable in South Australia remains the case:

a. on a range of predicted wholesale electricity prices incorporating a range of possible carbon prices

The Commission undertook analysis to determine whether the implementation of various carbon abatement policy measures could improve the viability of a nuclear power plant in South Australia. The analysis included hypothetical scenarios ranging from less stringent measures to more. They were:

- a continuation of the emissions reduction fund to meet abatement objectives of 26–28 per cent of 2005 levels by 2030 and implementation of a carbon price beyond 2030 to meet an emissions reduction of 80 per cent of 2000 levels by 2050 (Current Policies scenario)[117]
- the implementation of a carbon price in 2017 to meet the same emissions reduction objectives as those achieved under current policies (New Carbon Price scenario)[118]
- the implementation of a carbon price in 2017 to meet an emissions reduction objective of 65 per cent of 2005 levels by 2030 and complete decarbonisation by 2050 (Strong Carbon Price scenario).[119]

Only the Strong Carbon Price scenario would achieve emissions abatement consistent with the 'well below 2 °C' target affirmed at the 2015 United Nations Climate Change Conference in Paris.[120] Such a scenario significantly increased the wholesale price of electricity under current market rules (see Figure 4.12).

As would be expected, the potential viability of a nuclear power plant in South Australia improved under more stringent carbon policies, but remained unviable even under the Strong Carbon Price scenario.

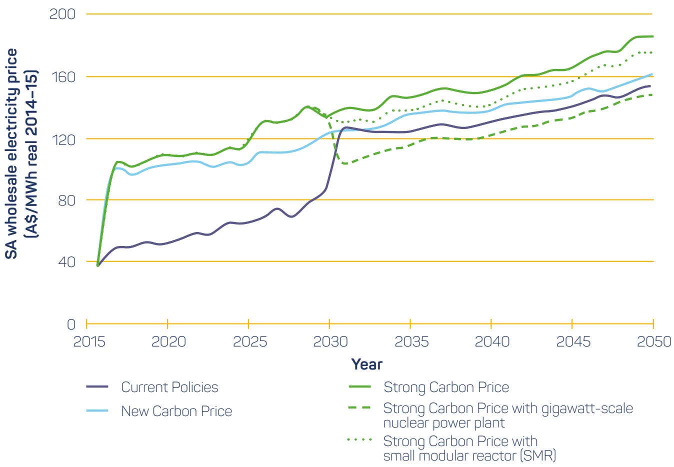

Figure 4.12: Annual average real wholesale electricity price in South Australia, 2014/15 prices

Data sourced from Ernst & Young, *CGE modelling assessment*, section 5.9, figure 47

Further, the construction and operation of a nuclear power plant were found not to have a positive rate of return at a commercial cost of capital of 10 per cent under any of the carbon abatement scenarios. The estimations of viability presented in Table 4.5 represent the best-case scenario for nuclear, operating as a baseload plant in South Australia with an expanded interconnection of up to 2 gigawatt electrical (GWe), if it were commissioned in either 2030 or 2050.

Table 4.5: Profitability at a commercial rate of return (10 per cent) of large and small nuclear power plants commissioned in 2030 or 2050 under the New Carbon Price and Strong Carbon Price scenarios

	Net Carbon Price Net present value (A$ billion 2015)		Strong Carbon Price Net present value (A$ billion 2015)	
Year of commission	**2030**	**2050**	**2030**	**2050**
Small modular reactor (285 MWe)	–2.2	–1.9	–1.8	–1.4
Large nuclear power plant (1125 MWe)	–7.4	–6.4	–6.3	–4.7

Data sourced from DGA Consulting/Carisway, *Final report for the quantitative viability analysis of electricity generation from nuclear fuels*, report prepared for the Nuclear Fuel Cycle Royal Commission, Adelaide, February 2016, section 6, tables 35–36).

b. for both large or proposed new small reactor designs

The establishment of a large nuclear power plant in the South Australian NEM was assessed to lead to an almost one-quarter decline in average wholesale prices (see Figure 4.12). While positive for South Australian consumers, this would dramatically affect the revenue earned and thus the viability of such a plant in this market.

This effect on wholesale prices is due to the relatively small size of the South Australian market. The introduction of a large nuclear power plant would be likely to have a much smaller impact on wholesale prices in Victoria and New South Wales because its output would form a much smaller portion of total demand. The modelling undertaken for the Commission indicated that a large nuclear generator in South Australia selling half its electricity in Victoria (through transmission) would only decrease wholesale prices in Victoria by 3 per cent.

A small nuclear power plant was not viable. This is not due to its effect on reducing wholesale prices, which fell by only 6 per cent (see Figure 4.12). Rather, its viability was mainly affected by its anticipated 15–30 per cent higher construction cost per kilowatt when compared with a large plant. This underscores the need to carefully follow the actual costs in small nuclear plant developments globally and any potential relevance to South Australia.

c. under current and potentially substantially expanded interconnection capacity to Victoria and NSW

Modelling showed that under current levels of interconnection, up to half of all nuclear generation from either a small or large nuclear power plant in South Australia would not be used (generation shedding). This would have a significant effect on the viability of a nuclear power plant, doubling the levelised cost of energy generation. It would also lead to the less efficient operation of the installed level of renewable generation, as about 40 per cent of output would be unused over a year unless grid storage systems were developed.[121]

However, as the penetration of intermittent generation in South Australia increases, so too will the viability of additional interconnection capacity between the state and the rest of the NEM.[122] This is to facilitate both the export of renewable electricity and the reduction of peak electricity prices in South Australia when there is reduced supply from intermittent sources. A joint AEMO/ElectraNet study in 2011 that assessed the viability of transmission upgrades found that only a relatively small upgrade to the Heywood interconnector was justifiable at that time. However, it anticipated that under some carbon abatement scenarios, consistent with the strong policies analysed by the Commission, an expansion of capacity to 2000 MWe would be viable in 2025.[123]

For those reasons the modelling undertaken for the Commission analysed the effects on viability of a South Australian nuclear power plant if transmission were substantially expanded to 2000 MWe, enabling the plant to export substantial additional electricity into the eastern regions of the NEM. Even with such exports, the analysis showed that a large nuclear plant was not viable.[124]

d. under a range of predictions of demand in 2030, including with significant uptake of electric vehicles.

Nuclear was not viable even on more optimistic views of future demand. The Commission analysed demand on a number of bases, including those with the largest forecast uptake of electric vehicles. Electric vehicles would be expected to add to grid demand through fuel switching from oil and to alter demand profiles depending on the time of charging, but also to contribute to storage in the network. Even in more optimistic scenarios of uptake, equal to 20 per cent of the light vehicle fleet in South Australia, neither a large nor small nuclear power plant in South Australia was assessed to generate a positive rate of return.

47. Off-grid nuclear power is also unlikely to be viable in South Australia in the foreseeable future because of low demand, even assuming optimistic growth of mining activities, and the likely location of that demand.

An off-grid electricity market, not connected to the NEM, supplies mining and remote communities in South Australia.[125] There is currently 77 MWe of installed off-grid generating capacity, dominated by diesel and natural gas generators, to meet 236 GWh of demand.[126] More than 80 per cent of the electricity consumed meets the requirements of industrial customers, predominantly mine operators.[127] However, the off-grid industrial sector is a small subset of the total electricity requirements of the mining industry in South Australia.

In 2014, studies undertaken at the request of the South Australian Government estimated that total electricity demand from the mining sector was 1.7 terawatt hours (TWh) and was estimated to rise to up to 6 TWh by 2023–32, under ambitious scenarios.[128] Even if those outcomes were realised, it is unlikely that new nuclear power plants would be the economic option to supply the required electricity, for three main reasons:

1. Mining operators require flexible energy systems that are able to scale up and down in response to fluctuations in operational requirements.[129] This affects the capacity utilisation of a generator. A nuclear power plant, because of its high capital costs, requires high levels of utilisation to be viable.
2. The construction and operation of a new nuclear plant in a remote location is likely to increase capital costs, making it less attractive than established alternatives.[130]
3. Even if a mining region were likely to generate the large and stable demand necessary to support a nuclear power plant, it may nevertheless be more cost effective to connect that mining region to the NEM for its power needs, the cost of which could be estimated with greater certainty than a nuclear power plant.[131]

48. While nuclear generation is not currently viable, it is possible that this assessment may change. Its commercial viability as part of the NEM in South Australia under current market rules would be improved if:

a. a national requirement for near-zero CO_2 emissions from the electricity sector made it impossible to rely on gas generation (open cycle gas turbine and combined cycle gas turbine) to balance intermittency from renewable sources

Gas-fired generation plays a significant role in providing reliable supply under all future low-carbon scenarios for the electricity sector. Under the Commission's model of a Strong Carbon Price scenario, gas was estimated to deliver more than 30 per cent of generation across the NEM by 2050.[132] Combined cycle gas turbine generation, even under a Strong Carbon Price scenario, was estimated to be profitable despite greater emissions intensity than nuclear.

However, implicit in the Commission's and other models of a future low-carbon electricity sector is that international carbon permits could be acquired to offset gas-fired generation emissions. The viability of gas-fired generation would be affected if either the cost or the credibility of emissions permits did not meet expectations.[133] Either outcome would result in a higher domestic carbon price that would improve the relative viability of nuclear power generation as part of the lowest-cost, low-carbon mix of energy generation.

SOUTH AUSTRALIA'S FUTURE ENERGY GENERATION MIX

There is considerable optimism about the potential of renewable technologies to meet South Australia's electricity needs. However, even with anticipated substantial reductions in costs, wind, solar PV and energy storage alone will not provide the lowest-cost mix of electricity generation.

Developments in renewable electricity generation technologies, particularly wind and solar, are of considerable interest and importance to the community. Reductions in the costs of such technologies during the past decade have been faster than anticipated, and further reductions are forecast. Modelling undertaken for the Commission and others suggests that intermittent renewable generation and storage technologies will make up a substantial share of the future lowest-cost mix of supply.[1]

However, the output of those models shows that even with expected cost reductions and favourable carbon emission abatement policies, the lowest-cost generation mix does not consist of wind, solar and storage alone.[2] In most cases, it also incorporates a significant level of firm, dispatchable fossil fuel-based generation capacity to constantly match demand with supply.[3] That is the case even under strong climate action scenarios.

This is due to a combination of our electricity demand profile, the intermittent nature of wind and solar generation, and the cost of installing new capacity. Given the demand peaks experienced in South Australia, the amount of wind, solar and storage capacity that would be required to reliably meet those peaks is substantial. However, as each additional wind, solar or storage unit is installed, it is likely to be required only to supply electricity to meet an increasingly smaller portion of demand.[4] Based on such limited utilisation, the revenue able to be achieved will eventually be insufficient to recover the costs of the unit's installation.

It is cheaper overall for gas-fired generation to be deployed to meet the highest peaks of demand, as gas plants are generally profitable as long as they can supply a sufficient level of demand at a higher price than the cost of fuel. This may have adverse implications for the cost of decarbonisation of the electricity sector if expected price reductions in renewable energy technologies are not realised.[5]

This is the reason future scenarios for an electricity system comprising only renewable energy sources often include a substantial share of geothermal and/or pumped hydro generation. The question remains as to whether either of these technologies is commercially feasible and cost effective at the required scale, as compared to gas-fired and/or nuclear, as discussed at Findings 51–54.

1 Ernst & Young, *CGE modelling assessment*, section 6.

2 DGA Consulting/Carisway, *Final report for the quantitative viability analysis of electricity generation from nuclear fuels*, report prepared for the Nuclear Fuel Cycle Royal Commission, Adelaide, February 2016, sections 4.6–4.7.

3 Ernst & Young, *CGE modelling assessment*, section 5.5.8.

4 Khalipour & Vasallo, 'Leaving the grid: an ambition or a real choice', *Energy Policy* 82, July 2015.

5 DGA Consulting/Carisway, *Final report*, section 5.2.2; Ernst & Young, *CGE modelling assessment*, section 5.5.8.

b. the intermittency of renewables could not be supported adequately by cost-effective storage at scale or by new demand sources such as 'power to fuel', which converts surplus power into a transport fuel source

Residential and grid-scale energy storage offers the potential to store surplus energy from intermittent wind and solar generation when supply exceeds demand, and to later release that energy when demand exceeds supply.[134] Although residential storage is not yet commercially viable[135], all current modelling assessments, including those undertaken for the Commission, see storage playing a significantly larger role in supporting the establishment and integration of additional intermittent renewable generation capacity.[136]

Similarly, other emerging technologies such as power-to-fuel arrangements may offer the potential to convert surplus electricity to a transport fuel in the form of hydrogen.[137] However, these technologies are yet to be demonstrated at scale in Australia.

Storage and power-to-fuel technologies also offer the potential to displace capital expenditure on the transmission and distribution networks. However, if the expected reductions in the cost of these technologies are not realised, the potential for nuclear power to provide reliable generation capacity to balance the intermittency of wind and solar would be improved.

c. system augmentations required to support substantially greater wind generation and commercial solar PV were more expensive than anticipated

Intermittent generation capacity requires electricity network support, therefore potentially increasing costs in several ways.

For example, it requires additional capacity to be installed that substantially exceeds the demand for energy from the network. That overcapacity is required to manage the intermittency of supply and allow for the storage of sufficient energy in the system so that it may be released during periods of low supply.[138]

Further, new wind and commercial solar PV generation plants need to be connected to the NEM. As the optimal locations for such plants within reasonable proximity to the existing transmission network reach capacity, extensions to the transmission network would be required to connect increasingly more remote locations.[139]

The increasing costs of that network augmentation have not been studied in detail.[140]

Integrating more intermittent generation in the NEM would also require augmentation of the transmission and distribution networks to reduce congestion during periods of peak supply from roof-top PV and wind generators when instantaneous generation exceeds transmission capacity. A 2013 AEMO study estimated that without such augmentation in South Australia, up to 15 per cent of the installed total energy output of wind generators may be curtailed by 2020–21 due to transmission constraints.[141]

If system augmentations are more expensive than current estimates, the cost of deploying additional wind and solar PV generation would increase. This would improve the relative viability of a large or small nuclear power plant because it is likely to be able to be integrated into existing networks without significant augmentation.

d. the costs and risks associated with demonstrating and integrating carbon capture and storage with fossil fuel generation at scale are greater than presently anticipated

Carbon capture and storage integrated with combined cycle gas turbine generation was estimated by both the Future Grid Forum's and ClimateWorks Australia's analyses of future low-carbon energy systems to meet a significant share of generation by 2050.[142] In the modelling undertaken for the Commission, the technology was also shown to be viable under current estimates.

However, as discussed at Appendix G, those outcomes are premised on cost projections assuming technical solutions that are yet to be realised. If these solutions do not eventuate, or their costs are more expensive than currently anticipated, the potential role of a nuclear power plant as a low-carbon source of reliable electricity generation would be greater.

e. current capital and operating costs of nuclear plants were substantially reduced, which would require overcoming complexities and inexperience in project construction. Some reductions in costs have been partially demonstrated for recent plants constructed in China, but not yet in Europe or the USA

The viability of a large or small nuclear power plant is highly sensitive to the cost of its construction. Capital expenditure including the cost of project development, licensing, construction, connection, ancillary infrastructure and accrued debt interest contributes to about three quarters

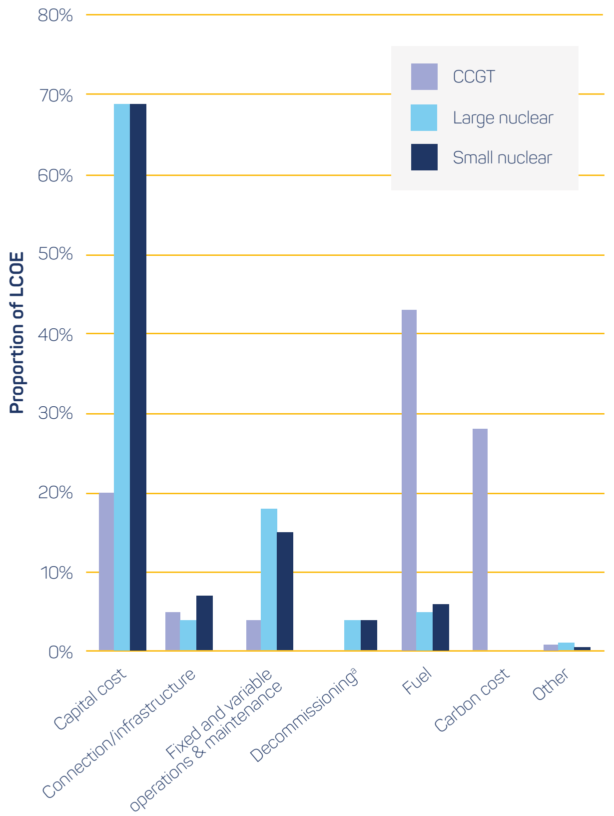

Figure 4.13: The contribution of cost components to the levelised cost of electricity (LCOE) from small and large nuclear power plants and combined cycle gas turbine (CCGT) generation[143]

[a]Decommissioning costs not included for CCGT

of the levelised cost of electricity (LCOE) generated by a nuclear power plant, as shown in Figure 4.13. The contribution of these elements to the LCOE is slightly larger for the small plant because of its lower energy output. Figure 4.13 also shows that more than 70 per cent of the LCOE of a combined cycle gas turbine generator is due to the cost of fuel (43 per cent) and carbon emissions (28 per cent), assuming a carbon price of about $120 per tonne (/t) in 2030 and $255/t in 2050.

Based on the Commission's analysis, for a nuclear power plant to achieve an LCOE competitive with a combined cycle gas turbine plant, capital and infrastructure costs for the nuclear power plant would need to decrease by about 25 per cent.[144]

Reductions in costs have been partially demonstrated for plants constructed in China, but this is not apparent in Europe or the USA. The feasibility of achieving such cost reductions for a nuclear power plant project in Australia is highly uncertain. It will be significant for South Australia to follow developments in international build programs that will show whether or not the nuclear energy industry is capable of applying lessons learned to reduce construction costs. Importantly, the conditions to make such reductions possible in the build country would also need to apply in South Australia.[145]

f. changes to government policy resulted in a combination of:

i. a price on carbon emissions in the economy (including from electricity generation)

The Commission's modelling suggested that a nuclear power plant would not be viable in South Australia even under carbon pricing policies consistent with achieving the 'well below 2 °C' target agreed in Paris in December because other low-carbon generation would be taken up before nuclear.[146] However, more stringent emissions abatement policies have the potential to improve the viability of nuclear power in combination with other measures.

ii. finance at lower cost than available on the commercial market (that is, a form of loan guarantee)

The Commission's analysis showed that the viability of a new nuclear power plant would be highly sensitive to the cost of capital. While not viable at a commercial weighted average cost of capital equal to 10 per cent, a large or small plant would offer a marginally positive return on investment assuming a cost of capital of 6 per cent, and the strongest emissions abatement scenario consistent with achieving the 'well below 2 °C' target.[147]

This is significant given that such a cost of capital is typical for the financing of public projects by government.[148] It can be obtained for the private sector in circumstances where a government guarantee is available. Such arrangements were used to secure the guarantee of the loan provided to develop the Vogtle 4 and 5 nuclear power plants in the USA.[149]

This observation is not a comment on the suitability of taking such a course. It would be a decision to be taken in the context of the commercial and public circumstances faced by a government were it seeking to secure particular types of electricity generation in the public interest.[150]

iii. **long-term revenue certainty for investors.**

For capital-intensive projects, in the absence of public funding, revenue certainty is important to secure investment.[151] In a market-based electricity system such as the NEM, revenue certainty could only be secured if a long-term power purchase agreement could be established.[152]

Such arrangements are in place in Australia for renewables (including most recently by the Australian Capital Territory Government in an auction for 200 MWe of wind generation capacity)[153] and internationally by other mechanisms such as the Contract for Difference model that was established in the United Kingdom to fund a range of technologies, including both renewables and the Hinkley Point C nuclear power project.[154]

49. The challenges to the viability of nuclear power generation under current market conditions in South Australia should not preclude its consideration as part of a future energy generation portfolio for the NEM. There is value in having nuclear as an option that could be implemented readily.

To achieve deep emission reductions, there is a need for substantial investment in low-carbon generation capacity between now and 2030.[155] The only low-carbon technologies that have been commercially deployed in Australia are wind and solar PV. With increasing reliance on such intermittent generation technologies, there will be a need for substantial investment in reliable generation supply to meet the balance of demand when sufficient wind or sunlight is not available.

Gas-fired technologies will continue to play a significant role in this respect.[156] However, an electricity system that relies only on intermittent renewables and gas risks depending on a single source of supply (gas) at an acceptable price. Gas-fired technologies are not, however, low carbon.

Other renewable technologies including enhanced geothermal systems, grid-scale energy storage, and carbon capture and storage could also play a significant role in helping to balance the intermittency of wind and solar, but their deployment would face significant technical and commercial challenges.

Nuclear power is a mature and deployable low-carbon option that provides reliable electricity supply at almost all times. It is therefore a credible alternative or complement to gas-fired generation in terms of assuring security of supply.[157] Although currently more expensive than combined cycle gas turbine generation, nuclear technologies may achieve cost reductions if expectations of increased global deployment were realised.[158]

50. A future national electricity supply system must be designed to be low carbon and highly reliable at the lowest possible system cost. Resolving this 'trilemma' will be difficult and will require carefully considered government policies.

To meet carbon abatement targets, the electricity sector will need to be one of the first sectors to be decarbonised. A low-carbon electricity system would also need to maintain current levels of reliability. It should be an objective of policy-makers to ensure that those outcomes are delivered at lowest possible cost.[159]

There is a substantial challenge in meeting the three requirements of low carbon, high reliability and low cost.[160] No single option for electricity generation currently commercially available in Australia meets all three criteria because of the intermittency of renewables, the emissions intensity of fossil fuel generation, and the high capital costs of developing nuclear power.

Policy interventions to deliver a transition from the current system to a future system would need to be planned carefully. There is a range of available options to achieve those outcomes, and lessons to be learned from past experience.[161]

The Australian Government has already intervened in the NEM to achieve emissions reductions by offering incentives to install new renewable capacity.[162] The LRET scheme provides an incentive to install new capacity by requiring retailers to purchase electricity from renewable generators[163], and has been successful in driving the installation of significant wind generation capacity. Substantial amounts of roof-top solar PV have resulted from feed-in tariff schemes and direct subsidies to households on the purchase costs of those systems.

While those interventions have reduced the emissions intensity of the electricity sector, they also have had significant effects on the market in the following ways:

1. Intermittent renewable generation capacity has contributed to increased price volatility in the NEM and risks to power system stability. The integration of significant intermittent generation affects the capability of the network to automatically and continuously match supply and demand.[164]

2. The profitability of gas generation has improved, given its ability to respond rapidly to meet shortfalls in supply.
3. The profitability of baseload forms of generation has decreased, thereby discouraging new entry for baseload capacity.[165]
4. The installation of roof-top solar PV has reduced operational demand from the network and required augmentation to the distribution network, as well as encouraged the installation of storage technologies.[166]

The likely impacts of any future energy policy options on the electricity market as a whole must be fully understood before implementation.

51. There are many combinations of generation technologies for a future low-carbon electricity system: it is not a simple choice between nuclear or renewables.

There are many possible combinations of technologies that could form a future low-carbon energy system.[167]

The view put to the Commission that 'we should develop our wind and solar power instead of nuclear' ignores the unique attributes of different generation technologies and their combinations in an electricity network.[168] While wind and roof-top solar PV will continue to play a significant role, their intermittency means they need to be combined with other technologies.[169] There is a wide range of choices of generating technologies to meet the balance of demand, including combinations of lower emission gas technologies, nuclear, geothermal, concentrated solar thermal and energy storage.[170]

Arguments that the choice is between renewables and nuclear fail to address the cost of each system, and the reality of which combination of particular technologies would meet reliability requirements in terms of being capable of deployment when needed.

The need for a combination of technologies is due to the characteristics of electricity demand.[171] The components of that demand (its minimum, average and peaks) dictate the necessary mix of generators. The suitability of generators depends on their operating characteristics and cost. Specifically, the viability of generators with high capital costs and low operating costs is driven by continuous operation or, in the cases of wind and solar PV, when the resource is available.[172] In comparison, the cost structure of gas generation is such that electricity is only produced when prices exceed their variable operating costs (based predominantly on the cost of fuel).

Based on a number of studies undertaken in Australia, including for the Commission, the mix of technologies that will make up the future electricity sector is diverse.[173] While the future market share of generating technologies modelled shows there are several options for achieving emissions abatement, it is equally important for decision-makers to contemplate how those technologies could be made available at scale, and the cost of doing so.

52. Identifying whether a particular generation portfolio would deliver electricity at the lowest possible cost requires an analysis of the future cost of the system as a whole.

Identifying which combination of technologies would be the lowest cost, including whether that mix included nuclear, would require an analysis of the future cost of the whole electricity system, that is, the total costs of electricity generation, transmission and distribution.

This would require a more sophisticated analysis than that advanced in numerous submissions by proponents of particular technologies based solely on the cost per unit of energy generated (LCOE). A variation on that argument was that, because a technology was expected in future to have a lower cost per unit generated, it would outcompete a rival. Such arguments were made both against and in favour of nuclear.[174]

These arguments fail to take account of the system costs of a technology, and also the varying value of electricity produced at different times depending on demand (and therefore customer willingness to pay). LCOE does not, therefore, reflect the revenues that a generator would receive, which is relevant to whether an investor would be willing to build new capacity. LCOE has limits as a tool for making decisions about the relative viability of different generators.[175]

LCOE does provide a baseline measure for comparing the competitiveness of different generating technologies.[176] It captures the cost of building, operating and decommissioning a generating plant over its financial life and its availability over that time (net of scheduled and unscheduled shutdowns).[177] However, LCOE does not take account of the costs of integrating that generation as part of the system, specifically the cost of:

- reserve generation capacity that may be required to meet total demand when the variable renewable energy technology is not available[178]
- additional inter- and intra-regional transmission, distribution and storage infrastructure to ensure generation from geographically disparate locations is transmitted to demand centres.[179]

For those planning a future electricity system (and the market in which it will operate), the relevant issue is the total systems cost, accounting for the cost of generation, connection, inter- and intra-regional expansion of transmission and distribution networks, and grid support costs.

AEMO's 2013 *100% renewables study* gave an indication of the potential total system costs of a hypothetical generation system comprising only renewable energy sources.[180] It was found that the total cost of developing such a system would be $250 billion, which is 200 times the annual value of electricity sold.[181] This assessment took into account anticipated reductions in the cost of renewables, and therefore their expected cost competitiveness with other generation options. How such a system could be funded, and whether it could be developed through private investment alone, is questionable.

53. At present, there is no analysis of a future NEM that examines total system costs based on a range of credible low-carbon energy generation options. Such an analysis would be required before it could be asserted that any option would deliver reliable, low-carbon electricity at the lowest overall cost—with or without nuclear power.

There have been few analyses of the total cost of developing a low-carbon future energy system in Australia, other than AEMO's *100% renewables study*. Other studies undertaken through the Future Grid Forum (FGF) in 2013 and 2015 and ClimateWorks Australia in 2015 have added significantly to discussion and understanding in this area.[182] However, none of these analyses was designed to provide the type of comprehensive investigation required. For policy-makers to consider the implications of different scenarios and avoid unintended consequences of policy interventions, assessments need to be undertaken on the basis of realistic expectations of technology deployment, taking into account the current level of investment and development.

Further study is needed into whether there will be sufficient returns in the electricity market to drive the commercial deployment of desirable, low-carbon energy generation technologies by the private sector. Many of the desirable types of generation technology have substantial upfront capital costs, making viability highly susceptible to the cost of finance.[183]

Further, the studies mentioned indicate that currently commercially unproven generation technologies will assume significant roles as part of a future energy system. In the case of the FGF and ClimateWorks studies, geothermal and/or carbon capture and storage paired with fossil-fuel technologies occupy more than one-fifth of generation by 2050.[184] The FGF and AEMO models assume a significant role for geothermal. Additional investigation is required into the impact of including and excluding those technologies to take account of the fact that they might not be available.[185]

The assessments to date also do not take account of the uncertainty surrounding assumed cost reductions in some technologies. While the costs of nuclear, solar PV and wind are based on established benchmarks, the same is not true for other technologies. Further analysis should be undertaken that includes the true cost of demonstrating technical feasibility, and thus enables 'like-for-like' cost comparisons with mature technologies. Such an approach would also enable certain classes of technologies to be excluded from system studies on the basis of expected costs of demonstration and the likely timeframe for availability.[186]

TIDAL AND GEOTHERMAL RESOURCES

Australia has no commercial-scale ocean energy projects at an advanced stage of development. Pilot-scale projects of less than 1 MWe, developed with substantial government support, are at an early stage of development and are yet to be demonstrated as commercially viable. Prospective reductions in cost depend on outcomes from research, development and demonstration. The deployment of tidal and geothermal technologies also is challenged by the remoteness of resources from grids and siting.[187]

There has been no commercial demonstration of enhanced geothermal systems in Australia. Following initial optimism, there has been substantial disinvestment given the failure to demonstrate permeability at depths suitable for electricity generation, high drill costs and the need to better understand the potential for induced seismicity. Direct-use geothermal, while it has cost advantages in specific settings, has to date had limited ability to contribute to electricity generation and supply in the NEM.[188]

BIOMASS

Existing commercial bio-energy applications are focused on the localised use of sugarcane residues and wood waste and the capture of gas from landfills and sewage plants. The expansion of the use of this resource is limited by a combination of economic factors: its seasonality, the value of biomass or the land on which it is cultivated for other uses, the energy consumed in its cultivation and transport, and its low-energy density.[189]

CARBON CAPTURE AND STORAGE

Carbon capture and storage (CCS) remains commercially unproven at scale in Australia and internationally. The retrofitting of capture systems with existing natural gas- or coal-fired power stations is not currently commercially viable and there are technical challenges in demonstrating the long-term stability of CO_2 in underground formations.[190] Optimism in the last decade about cost reductions in these systems has not been realised, despite the demonstration of the technical feasibility of injecting carbon dioxide into underground formations in the Boundary Dam (Canada) and the Gorgon Basin (Western Australia) oil recovery projects.[191]

While it is proposed that substantial investment in research and development may prove the feasibility of CCS in Australia[192], options modelling undertaken for the Commission suggested that a substantial portion of that investment would need to be publicly funded. A private investor would have insufficient revenue certainty from future generation plants integrating CCS to recover the capital and interest costs of research and development. In any event, the wide deployment of CCS also will be significantly affected by economic factors associated with the price of oil and gas, the efficiency of carbon dioxide separation, and constraints associated with siting and delivering community consent.[193]

ENERGY STORAGE

While battery storage technologies for a range of South Australian commercial and residential consumers are likely to be viable in the near future (particularly for those with time-of-use or capacity-based tariffs and who can integrate photovoltaic systems), the same is not true for on-grid storage. Battery, thermal or pumped hydro storage may have a future role by displacing additional transmission capacity and/or peaking generation capacity. A recent CSIRO analysis, based on expected declines in battery prices, concluded that the levelised cost of energy from lithium-ion batteries could be competitive with gas peaking power plants by 2035, but only in parts of the network such as South Australia and Queensland where there is a significant requirement for peaking capacity.[194]

54. A critical issue to be determined in a total systems cost analysis of a future NEM is whether nuclear could lower the total costs of electricity generation and supply.

Some of the additional systems costs required to support low-carbon electricity systems incorporating substantial market shares of wind and solar PV paired with storage capacity have been discussed previously. Other combinations of low-carbon generation may not impose the same costs.

Nuclear power may offer the potential to reduce total system costs by reducing the need for the measures discussed in Finding 52 and their associated costs. While nuclear power requires some reserve capacity to address outages during refuelling, it does not require measures to address intermittency and could if appropriately sited be integrated with the existing transmission network.[195]

In addition, nuclear power generation facilities have an expected operational life of at least 60 years, with possible extensions beyond that, whereas wind and other conventional renewable generation systems have asset lives of less than 25 years.[196] The extent to which the installation of nuclear may, over its lifetime, obviate the need for capacity that would otherwise have to be installed is an important consideration in an assessment of its value in a network.[197]

Whether nuclear would, in light of its current higher costs, result in lower total system costs is unknown. That would require further study including an analysis of a realistic timeframe of deployment in Australia in substitution for other technologies and system upgrades.

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