REVIEW

Australian Energy Market Commission

ADVICE TO THE COAG ENERGY COUNCIL

Barriers to efficient exit decisions by generators

16 June 2015

Reference: EPR0045
Advice to the COAG Energy Council

Inquiries

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

E: aemc@aemc.gov.au
T: (02) 8296 7800
F: (02) 8296 7899

Reference: EPR0045

Citation

AEMC 2015 , Barriers to efficient exit decisions by generators, Advice to the COAG Energy Council, 16 June 2015 , Sydney

About the AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

Executive Summary

The Australian Energy Market Commission (AEMC or Commission) has been asked to provide advice to the Council of Australian Governments Energy Council (COAG Energy Council) on barriers to generators exiting the National Electricity Market (NEM).

Having reviewed the factors that generators may consider in deciding whether or not to exit the market, the advice concludes that there is nothing in the National Electricity Law or Rules which would constitute a barrier to efficient exit decisions by generators.

The factors that inform generator exit decisions can be complex. They apply differently depending on the generator technology type and how the generator is structured. They also apply in a different way depending on the generator's location and the stage of exit being considered by the generator. Stages of exit can vary from merely reducing dispatch to full decommissioning of the generator.

Many of the factors represent costs generators would have to bear upon reducing participation in the market, or profits forgone. While they therefore represent barriers to exit for individual generators they are only a problem if they are a barrier to *efficient* exit decisions. In addition, it is not necessarily a problem if generators with lower running costs exit before generators with higher running costs. If the costs of exit of the lower cost generator are lower than those of the higher cost generator, this can be a rational decision.

The main factor determining if a cost is also a barrier to efficient exit decisions is certainty. Greater certainty of the costs incurred upon exit is more likely to promote efficient exit decisions.

Uncertainty manifests in two ways. The *current* costs to exit the market, such as site-specific remediation obligations, may not be specified and hence the associated costs are uncertain. Policy uncertainty will make *future* net revenues from remaining in the market or the consequences of exiting difficult to ascertain.

While it is possible the uncertainty around exit costs is creating a barrier to efficient exit, recent evidence suggests that generators are not deterred from exit. In 2012 to 2013 over 2000 MW of coal plant was shut down or periodically taken offline.[1] As recently as 11 June 2015 Alinta Energy announced the Northern and Playford B power stations would not operate beyond March 2018 and may be closed earlier.[2] Table 1 below summarises the total generation capacity that has entered and exited the NEM since mid 2011. Table 2 below summarises significant exit decisions and announcements in the NEM since mid 2011. This evidence further supports leaving the market to determine which plant should exit and when.

1 AER, State of the energy market 2013, p. 28, table 1.3.

2 Alinta Energy, "Flinders operations announcement", 2015, Alinta Energy press releases, https://alintaenergy.com.au/about-us/news/flinders-operations-announcement

The level of uncertainty involved in these exit costs means it is difficult for policymakers to know what costs are faced by which generators upon exit, and therefore what would be efficient in terms of the timing or order of generator exit from the NEM.

To promote efficient exit decisions where there is uncertainty in policy settings or remediation obligations, the uncertainty should be minimised to the extent possible. For example, governments can continue to stress that they do not support assistance to generators to exit the market as the COAG Energy Council did in its December 2014 Communique.

The Commission's view is that at this time further work is not required in respect of investigating barriers to exit.

Table 1 Generator entry and exit 2011-12 to 2014-15[3]

Generator entry 2011-12 to 2014-15	2600 MW
Generator exit 2011-12 to 2014-15	4600 MW

Source: AEMO; Company announcements.

Table 2 Generation exit since mid 2011 and announced exits after 2015

Year	Power station	Generation technology	Capacity (MW)	Stage of exit[4]
2023	*Mt Stuart (Qld)*	*OCGT*	*414*	*Retirement announced.*
2022	*Daandine (Qld)*	*CCGT*	*33*	*Retirement announced.*
2018	*Northern (SA)*	*Coal*	*540*	*Retirement announced.*
2018	*Playford (SA)*	*Coal*	*200*	*Retirement announced.*
2017	*Torrens Island A (SA)*	*Coal*	*480*	*Half mothball announced.*
2015	*Anglesea (Vic)*	*Coal*	*150*	*Decommissioning announced.*
2014-15	Wallerawang C (NSW)	Coal	1000	Decommissioning.
2014-15	Redbank (NSW)	Coal	144	Mothballed

3 The entry and exit figures here both include the withdrawal and re-instatement of 700MW of generation at Tarong, Queensland that was removed from the NEM for refurbishment from 2012 to 2014.

4 The term “retirement” reflects the terminology used in relevant company announcements. In these cases the precise nature of the exit decision has not been made clear

Year	Power station	Generation technology	Capacity (MW)	Stage of exit[4]
2014-15	Pelican Point (SA)	CCGT	249	Unit 2 mothballed on 48 hour recall.
2014-15	Swanbank E (Qld)	CCGT	385	Mothballed.
2012-13	Morwell, Brix (Vic)	Coal	25	Unit 2 mothballed and only operates when unit 1 is under maintenance.
2012-13	Morwell, Brix (Vic)	Coal	70	Unit 3 mothballed.
2012-13	Munmorah (NSW)	Coal	600	Retired.
2012-13	Tarong (Qld)	Coal	700	Closed for refurbishment 2012 to 2014.
2012-13	Collinsville (Qld)	Coal	180	Decommissioning.
2011-12	Northern (SA)	Coal	540	Seasonal (winter) shutdown. One unit returned to full service in 2014.
2011-12	Playford B (SA)	Coal	200	Seasonal (winter) shutdown and 90 day recall.
2011-12	Swanbank B (Qld)	Coal	120	Decommissioned.

Source: AEMO; *Company announcements.*

Approach

This advice is based on a “desktop” analysis of factors generators consider in exiting the market. In the time available it was not possible to formally consult generators or analyse specific exit decisions that have been observed in the NEM. Even if this was within scope, we do not expect it would have yielded any clearer outcomes. As a result, while we were able to consider in a general way the broad factors generators consider in making exit decisions, we could not consider matters such as the degree to which generators view costs as clear and reasonably certain.

Background to the advice

The context for the COAG Energy Council seeking the advice is the surplus of generation capacity in the NEM. Against this background, in December 2014, the COAG Energy Council stated that it is for the market to provide signals for investment and de-investment for generation, but that the Council will consider whether there are any barriers to orderly exit by generators.

The COAG Energy Council has asked the AEMC for advice on:

- The major factors to be considered by a generator when making a decision to de-invest (that is, retire or decommission assets); and
- Whether there is anything in the National Electricity Law or National Electricity Rules which might reasonably constitute a barrier to making an efficient de-investment decision.

Contents

1 Introduction

The AEMC has been requested by the COAG Energy Council to provide advice on potential impediments for generators in retiring or decommissioning assets in the NEM. This advice responds to that request.

This advice draws on analysis prepared for the Commission by Frontier Economics and Johnson Winter & Slattery (JWS) Lawyers. This report has been attached to this advice and contains further detail on some of the matters discussed here.

1.1 Scope of advice

On 13 April 2015, the COAG Energy Council's Senior Committee of Officials (SCO) sought advice from the AEMC on potential impediments for generators in retiring or decommissioning assets in the NEM.[5] SCO has requested the AEMC examine whether there are any material barriers to the orderly exit of generation plant. Specifically, SCO requested advice in relation to:

- The major factors to be considered by a generator when making a decision to de-invest (that is retire or decommission assets); and
- Whether there is anything in the National Electricity Law or National Electricity Rules which might reasonably constitute a barrier to making an efficient de-investment decision.

Furthermore, SCO requested that the AEMC's advice should identify, at a broad level, potential barriers outside the national energy legislation, including interactions with any other policy decisions. SCO requested that the AEMC also provide its views on whether further work is needed.

1.2 Background

The context for the COAG Energy Council seeking the advice is the surplus of generation capacity in the NEM. Against this background, in December 2014, the COAG Energy Council stated that it is for the market to provide signals for investment and de-investment for generation, but that the Council will consider whether there are any barriers to orderly exit by generators.[6]

The COAG Energy Council has separately asked the Australian Energy Market Operator to advise it on the implications for power system security and reliability of the exit of generators and the increase in penetration of intermittent renewable generation.

---

5 Under section 6 of the Australian Energy Market Commission Establishment Act 2004 (SA) the Ministerial Council on Energy (MCE) (now the COAG Energy Council) may request the AEMC to provide advice.

6 COAG Energy Council, Meeting Communique, 11 December 2014

Excess generation capacity may depress wholesale prices, place financial pressure on generators[7] and increase uncertainty for investors. These types of market signals are normal when new capacity with lower marginal costs has entered a market or when there is a general decline in demand. Depressed prices may signal to some generators to reduce their participation in the market if they can no longer cover the variable costs of generation. This advice is concerned with the decisions generators make to exit the market in these circumstances, including the relative order in which this occurs amongst generators.

1.3 Characterising barriers to exit

The decision by a generator to exit[8] the market is a form of investment decision. There are a range of factors generators take into account when making these decisions, which encompass both their variable costs of remaining in business and the costs involved in exiting the market.

A barrier to exit is any cost or foregone profit that a firm must bear if it leaves an industry. While these costs therefore represent barriers to exit for individual generators they are only a problem if they are a barrier to *efficient* exit decisions.

For example, based on this definition, it will not always be efficient for generators with the highest variable cost to exit the market first. Where generators with high variable costs have high shut down costs, it can be an optimal outcome for them to exit the market *after* generators with low variable costs but low shut down costs.

The main factor determining whether exit decisions are efficient or not is certainty of the costs incurred upon exit.

1.4 Uncertainty

Where a generator faces uncertainty in the costs that it would bear on exiting the market it would be more likely to defer any decision to exit the market until those costs become more certain. This uncertainty will impact the timing of the decision to exit the market such that it does not occur in a way that maximises the overall economic welfare.

This uncertainty can manifest in two ways. First, it can reflect a difficulty in ascertaining the *current* costs of exiting the market. For example, authorities may require a certain level of site remediation where a generator exits, but the precise level at which this is set may not be known until the exit decision is made. Second, it can reflect the way the costs of exiting the market may change in the *future*. For example, uncertainty with respect to Commonwealth and state climate change policy affects the level of certainty attached to expectations of net revenues forgone upon exit. Similarly,

7 Throughout this advice, the term "generator" refers to a generation business that may own and operate multiple plants, or just one.

8 The term "exit" is used to describe any of the ways a generator may withdraw capacity from the NEM, including on a partial, temporary, indefinite or permanent basis.

a generator may have an expectation that the current policy on contracts for closure may change in the future such that it will be paid for exiting the market.

Some level of uncertainty is expected; it can never be eliminated entirely. Where a generator makes a de-investment decision in the face of this uncertainty it may lead to an economically efficient decision to wait. However, uncertainty should ideally be reduced to the extent that the cost involved in reducing the uncertainty balances the benefits from having greater certainty.

1.5 Approach

In order to respond to the request for advice we have identified the key factors that generators would consider when making a decision to exit including those factors which are derived from the National Electricity Law or National Electricity Rules.

Critically, there are a number of complexities involved in the factors that generators consider when making a decision to exit. Three such complexities are particularly significant and are discussed below.

1.5.1 Stages of exit

First, generator exit is not a binary choice between staying in the market and exiting from it completely. In between these two extremes there are other options for reducing or suspending operation. In this advice we have used the term "stages to exit" to describe the various options generators have for reducing their participation in the market. These can be as simple as reducing the output of the generator in order to reduce variable costs, or can extend to shutting down plant indefinitely without actually decommissioning it. The exact option chosen by a generator will depend on its projections of future costs and revenues, as well as expectations of the behaviour of other generators. The stages to exit that we have examined are:

- dispatch at minimum stable generation;
- two-shifting (temporary shutdown);
- seasonal shutdown;
- mothballing; and
- decommissioning.

1.5.2 Generator technologies

Second, the characteristics of different generator types affect their options for exit from the market at any time. For example, coal generators are much less flexible in the way they can operate compared to gas-fired generators, so coal-fired generators have fewer options around reduced operation. This means that when considering the factors that a generator may take into account when considering exit from the market, it is necessary to look at different generator types separately. For the purposes of this advice, we have looked at:

- Coal-fired generators;
- Open cycle gas turbines;
- Combined cycle gas turbines;
- Hydro plants; and
- Other renewable generation plants.

1.5.3 Location and site specific factors

Factors considered upon exit will also vary by location and site requirements. For example, a coal-fired plant may be connected with a mine site such that the remediation requirements would be quite different from that required for a stand-alone coal plant. Similarly, remediation obligations could vary substantially between a plant located near an urban area and a plant that is located in a relatively unpopulated area. These differences in site and location drive some of the uncertainty faced by generators considering exit because there is no single approach that fits all locations.

1.5.4 Approach

Our approach to this advice is, first, to understand the relationships between the stages of exit, generator technology types and factors generators take into account when considering exit from the market. To do this we discuss the various stages of exit then describe, in general, what the factors are that most generators may consider before they make a decision to exit the market. We then map these factors against the generator types and stages to exit. Having understood how these factors may be considered by generators, we then consider whether they could constitute costs that are either inefficient or unnecessarily uncertain and therefore barriers to efficient exit decisions. To the extent such barriers exist, we identify whether they are a result of the operation of the National Electricity Law or Rules.

1.6 Structure of the paper

The remainder of this report is structured as follows:

- Chapters 2 to 4 summarise the stages of exit, factors taken into consideration in exit decisions and how these affect different types of generators.
- Chapter 5 considers implications for efficiency in the NEM.
- Chapter 6 provides conclusions for this advice.

2 Stages of exit

There are a number of different ways in which generators may reduce their participation in the market. Critically, generator exit is not an "all or nothing" decision. Generation plant may be able to continue operating periodically to take advantage of higher prices during peak times or peak seasons while reducing output or 'exiting' the market during times of low prices when generation becomes unviable. Some plant could be removed indefinitely, with the ability to restart generation with some notice period, if prices recover. Longer term, plants may be decommissioned entirely and sites rehabilitated.

The choice of strategy that a generator pursues depends upon expectations of future prices, the costs involved to maintain the integrity of the plant in shut-downs and restarts, the operating costs to remain generating at minimum output, the marginal cost of generation and a number of other market factors. These strategies are not clear cut defined limits, but a spectrum between continuous operation at minimum capacity and full site remediation. Figure 2.1 describes the range of strategies available to generators considering removing capacity from the NEM.

Figure 2.1 Stages of exit

Minimum reduced operation						Full Exit
Dispatch at minimum stable generation	Two-shifting	Seasonal shutdown	Mothballing of individual units	Mothballing of the entire plant	Power station decommissioning	Full site remediation for sensitive use

There are recent examples of partial operation or market exit from the NEM. These are set out in section 2.6 below.

The key stages of generator exit are described below.

2.1 Dispatch at minimum stable generation

If a plant is not recovering its variable costs of generation, a generator may still choose to keep the plant running to avoid shutdown and restart costs, delays and performance effects. The lowest level at which a plant can operate for a period of time without causing technical problems is described as minimum stable generation (MSG). This can occur where prices are only expected to be below a plant's variable costs for a period short enough that the overall losses from continued operation are still less than the expected costs of shutting down and restarting. While a generator could be making a loss over this period, the loss is minimised by continuous operation at MSG.

2.2 Two-shifting

If a generator expects its plant to not recover its variable costs for a period of time, the expected losses incurred from minimum stable generation accumulate over time but shutdown and restart costs remain constant. Therefore, expected losses could be minimised by temporarily shutting down the plant or specific units over the period that prices remain below their variable costs, such as afternoon or overnight shutdowns. This strategy is pursued if prices are expected to be below a generator's average variable cost, including its shutdown and restart costs, for the period of shutdown.

2.3 Seasonal shutdowns

Electricity demand typically follows a seasonal pattern.[9] As a result, it may be expected that wholesale prices would be higher during the peak season. A form of two-shifting, on an annual or biannual cycle, is more likely for power stations that have significant shutdown and restart costs such as base-load generators.

2.4 Mothballing

Mothballing refers to the techniques applied to prevent corrosion or deterioration when a plant is not operating for a period. When a generator expects prices to remain depressed for longer periods it may choose to mothball individual units or an entire power station so that less ongoing maintenance effort is required, but the generator retains an option to return to market with some notification period. These shutdowns may occur for an indefinite period.

Mothballing can be for short term periods of between three and 12 months, or longer than 12 months with different storage techniques applied depending upon the period. Mothballed plant may require additional maintenance and a longer notice period to bring a unit back into service. As such, a decision to mothball compared to two-shifting or seasonal shutdowns would suggest a generator expects prices to remain below variable costs for a long enough period to justify the costs incurred in preserving a plant for the mothballed period using different storage techniques.

A long-term mothballed unit also requires a longer notice period for restart than a short term mothballed unit. A mothballed unit is only likely to be brought back online where there is an expectation that prices will remain above variable costs for a long enough period to recover restart costs.

2.5 Power station decommissioning and site remediation

Power station decommissioning occurs when a plant is permanently shut-down and major items of plant and machinery are dismantled and removed from the site. The site may be developed for a new plant, some other industrial use or remediated for a completely different use. At least some level of remediation is typically required at decommissioning although the full extent of remediation depends upon the future use of the site. Where remediation is required it is typically the most significant cost faced by a generator on exiting the market.

---

9 In most NEM jurisdictions this is a summer peak due to increased use of air conditioning while in others it is a winter peak due to heating. It is also possible for there to be a two peaks per year, with off-peak periods in the shoulder seasons.

The costs incurred in remediation may be particularly uncertain due to a combination of policy uncertainty and site specific costs. Often these costs will not be clear until the generator has committed to the decision to exit. Efficient exit decisions may be promoted by governments that are able to clarify, to the extent possible, the costs involved and the approach to establishing remediation obligations upon plant exit. This is expanded upon in sections 3.1.2 and 3.3.2.

Decommissioning and remediation costs affect different plants in different ways according to contractual and jurisdictional obligations.

2.6 Recent evidence of generator exit in the NEM

Recent data has demonstrated the extent of the surplus of generation capacity in the NEM and the ways generators have responded to this.

AEMO has projected the NEM will have 7650–8,950 MW of surplus generation capacity in 2014–15, with around 90 per cent located in NSW, Queensland and Victoria.[10]

In response to this oversupply, in 2012 to 2013 over 2000 MW of coal plant was shut down or periodically taken offline.[11] AEMO reported a further 1385 MW of thermal baseload (mainly coal) capacity was placed in storage in 2013–14.[12] Table 2.1 summarises the total generation capacity that has entered and exited the NEM since mid 2011. More recently, other plant exit decisions have been announced. Recent generator exit decisions are summarised in Table 2.2.

Table 2.1 Generator entry and exit 2011-12 to 2014-15[13]

Generator entry 2011-12 to 2014-15	2600 MW
Generator exit 2011-12 to 2014-15	4600 MW

Source: AEMO; Company announcements.

10 AEMO, Electricity Statement of Opportunities 2014, p. 7-8, table 6.

11 AER, State of the energy market 2013, p. 28, table 1.3.

12 AEMO, Electricity Statement of Opportunities 2014, p. 10

13 The entry and exit figures here both include the withdrawal and re-instatement of 700MW of generation at Tarong, Queensland that was removed from the NEM for refurbishment from 2012 to 2014.

Table 2.2 Generation exit since mid 2011 and announced exits after 2015

Year	Power station	Generation technology	Capacity (MW)	Stage of exit[14]
2023	*Mt Stuart (Qld)*	*OCGT*	*414*	*Retirement announced.*
2022	*Daandine (Qld)*	*CCGT*	*33*	*Retirement announced.*
2018	*Northern (SA)*	*Coal*	*540*	*Retirement announced.*
2018	*Playford (SA)*	*Coal*	*200*	*Retirement announced.*
2017	*Torrens Island A (SA)*	*Coal*	*480*	*Half mothball announced.*
2015	*Anglesea (Vic)*	*Coal*	*150*	*Decommissioning announced.*
2014-15	Wallerawang C (NSW)	Coal	1000	Decommissioning.
2014-15	Redbank (NSW)	Coal	144	Mothballed
2014-15	Pelican Point (SA)	CCGT	249	Unit 2 mothballed on 48 hour recall.
2014-15	Swanbank E (Qld)	CCGT	385	Mothballed.
2012-13	Morwell, Brix (Vic)	Coal	25	Unit 2 mothballed and only operates when unit 1 is under maintenance.

14 The term “retirement” reflects the terminology used in relevant company announcements. In these cases the precise nature of the exit decision has not been made clear

Year	Power station	Generation technology	Capacity (MW)	Stage of exit[14]
2012-13	Morwell, Brix (Vic)	Coal	70	Unit 3 mothballed.
2012-13	Munmorah (NSW)	Coal	600	Retired.
2012-13	Tarong (Qld)	Coal	700	Closed for refurbishment 2012 to 2014.
2012-13	Collinsville (Qld)	Coal	180	Decommissioning.
2011-12	Northern (SA)	Coal	540	Seasonal (winter) shutdown. One unit returned to full service in 2014.
2011-12	Playford B (SA)	Coal	200	Seasonal (winter) shutdown and 90 day recall.
2011-12	Swanbank B (Qld)	Coal	120	Decommissioned.

Source: AEMO; *Company announcements.*

3 Factors considered by generators in reducing participation in the market

This chapter describes the different factors that generators may take into account when considering a decision to reduce participation in the market. While these factors may involve costs, which are a barrier to exit that each generator has to overcome in making a de-investment decision, each is not necessarily a barrier to efficient exit decisions.

In general, it should be borne in mind that who bears the costs described in this chapter will depend on the operational and organisational structures of a generation business.

3.1 Direct costs

Direct costs refer to a generator's actual expenditures that are incurred as a result of a decision to withdraw capacity from the market. The direct costs vary by generator technology as well as the extent of withdrawal.

3.1.1 Plant shutdown, preservation, reinstatement and staffing costs

Plant shutdown, preservation, reinstatement and staffing costs as well as any penalties associated with terminating commercial contracts are the operating costs that flow from the decision to withdraw capacity. The costs incurred vary depending on the extent of withdrawal or type of technology because each stage of exit and each generator type have differing implications for operational and staffing requirements.

Redundancy costs may also not be entirely known until after a decision to exit has occurred and the generator has entered negotiations with relevant union representatives.

3.1.2 Decommissioning and remediation costs

In all jurisdictions there is legislation that provides for a generator’s obligations when it is permanently shut down, including site remediation. In general, however, these obligations are only described at a high level in the legislation. The precise costs can only be known with certainty when a relevant authority issues a notice with respect to the contaminated land. The costs incurred to meet remediation obligations vary by jurisdiction, ownership structure and plant type, and can in some cases be large in magnitude.

Remediation costs may be borne by the registered market participant or they could be borne by the owner and operator of the physical plant, who could be an independent power producer. They may even be retained by previous owners of the plant, depending upon the organisational structures involved.

These costs are relatively uncertain prior to obligations being imposed by institutions such as environmental protection agencies. This is partly due to the fact that each site will have its own specific remediation requirements. For example, what is required will be different where a mine is involved compared to a site where there is no mine.

It is possible historic sites would also involve heritage obligations and that these costs may not be known until a site is closed.

3.2 Indirect costs

Indirect costs refer to the profits that a generator forgoes if it withdraws capacity from the market. The indirect cost of generator exit or reduced operation is:

- Operating profits (or losses) from continued operation

  less

- Capital that can be recovered[15] or the operating profits (or losses) from a reduced operation strategy.

3.2.1 Extent to which capital can be recovered

If a generator is able to sell its site and/or plant equipment after closure, then not all of its capital costs are entirely sunk.[16] The proceeds from recovering capital can be reinvested and a return made elsewhere. If the net return from an alternative investment is equal to the current return from continued operation of a plant, then there are no indirect costs from exiting the market.

Sunk costs may contribute to revenues from continued operation but cannot be recovered upon generator exit, thereby the indirect cost of generator exit increases with the extent of sunk costs.

3.2.2 Contracts for inputs and outputs

Generators typically manage risk by entering into contracts for both fuel and the electricity generated. These contracts do not have to be physical contracts and to make it easier to trade contracts generators can enter into derivative contracts based on market prices for inputs or the electricity spot price. If contracts can be sold for a fair market price then the generator's decisions to reduce operation or exit the market are still exposed to the market price of fuel or the electricity spot price, because the value of the contracts can be recovered. The costs of any contracts that are not tradeable and the transaction costs incurred by trading, could be considered sunk costs.[17]

---

15 the value of the site and any equipment that can be sold, and expected returns on capital.

16 Sunk costs refer to the costs that cannot be recovered at closure.

17 except where contractual obligations to pay can be avoided by claiming bankruptcy at exit.

3.2.3 Operational factors

Operational factors for different types of plant can affect the actual options available to a generator withdrawing capacity from the market. This is particularly relevant to options that require a plant to be operated flexibly. The fuel source can also affect the way it can be operated.

3.2.4 Government inducements

Payments or proposed payments by governments for generators exiting the market can be a factor a generator considers before exiting. An inducement improves the generator's ability to recover value upon exit and thereby reduce the indirect cost of exit. The uncertain prospect of inducements offered in future could also delay a decision to exit, as discussed in section 3.3.2.

3.3 Other factors

The above indirect costs rely heavily on expectations about the future. Expectations can be affected by the matters set out below.

3.3.1 First-mover disadvantage

Due to the lumpiness of electricity generation, the sudden removal of capacity from the wholesale market could put upward pressure on wholesale electricity prices. As a result, expectations about future electricity prices rely heavily on expectations about continued activity by all generators in the market.[18] If a generator expects that its continued operation would eventually induce a competitor to exit, this increases its expectations of future electricity prices, thereby increasing forgone profits if it does exit. This phenomenon is described as 'first mover disadvantage'. Conversely, if a generator expects a competitor would outlast it in such a waiting game, the generator would prefer to limit its losses by exiting as soon as possible, in order to minimise the disadvantage of being the first-mover to exit.

The lumpiness of generator exit decisions may be less significant than it appears due to generation plants containing multiple generating units. Mothballing or decommissioning single units at a time would reduce the effect on power prices therefore reduce the size of first-mover disadvantage. Similarly, a generator's other plants may benefit from the closure of its least efficient plant because of price rises for its remaining plants in operation. Finally, an exiting generator may likely receive the highest price for its plant by selling it to a competitor. For the new owner, if this plant is more efficient than its existing plant it would not make sense to close an efficient plant over an inefficient one.

18 This is characteristic of all markets. However reductions in capacity are less noticeable when capacity changes are less lumpy.

First mover disadvantage is a factor that is more likely to be considered at decommissioning than in respect of the other stages of exit where re-entry is possible.

3.3.2 Policy uncertainty

Policy uncertainty is a factor that is more likely to be relevant at decommissioning than in respect of the other stages of exit where re-entry is possible. Uncertainty about government policy or how it may be applied changes a generator's expectations about future costs or revenues. Furthermore, if policies have been changed on a regular basis, policy effectiveness may be reduced because the policy communicated may not be perceived as the credible long-term policy. Generators are affected by uncertainty regarding the following types of policies:

- Incentives for entry (such as the renewable energy target (RET)).
- Climate change policy.
- Inducements to exit (such as "contracts for closure").
- Environmental or remediation obligations.

4 Generation plant technologies and factors affecting operation and exit decisions

Generators considering reducing their participation in the NEM typically balance a combination of all the factors described in chapter 3 under different operational strategies in order to maximise profits or minimise losses. The costs and operational constraints vary for different types of generators.

4.1 Coal-fired generation

Coal-fired generators burn coal to produce steam used to drive a steam turbine. Thermal efficiency varies between coal generator types,[19] but the cost structures are relatively similar.[20]

In general, coal-fired generation is characterised by inflexibility of operation compared to other types of generators. This is partly due to the design of the boiler and furnaces as well as the impact of alternate heating and cooling on the boiler and steam turbine. They also have relatively low operating costs.

While two-shifting, seasonal shutdown or mothballing are technically possible operational strategies for coal-fired generators, the costs of shutdown and restart, delays, maintenance and performance effects are typically more significant for coal plants than other generator types. Coal-fired plants are not as suited to operate in a flexible manner. The low variable costs also make this a less attractive proposition. Therefore, they are typically suited to base-load operation and only operate at reduced capacity for relatively short periods such as overnight.

It is noted that there are also differences between types of coal generators. In particular, given the minimum stable generation is higher for brown coal generators than for black coal generators, operating at reduced dispatch is even less likely to be of benefit for brown coal plants than for black coal.

In general, two-shifting or seasonal shutdown is less likely with coal-fired plant.

4.2 Open cycle gas turbine

Open cycle gas turbine (OCGT) power stations are based on a gas-fired turbine. These plants are relatively simple and low cost, and can be built quickly but are not thermally efficient. As a result, these plants have lower fixed or sunk costs and greater variable generation costs than coal plants. These plants typically operate as peaking plants,

19 Subcritical and supercritical; and brown coal and black coal generators are collectively referred to as coal-fired generation.

20 Thermal efficiency refers to the ability of the plant to turn potential energy (chemical or otherwise) into heat and subsequently into electricity. Plants with high thermal efficiency have less waste heat and lower emissions intensity than plants with low thermal efficiency.

ramping up and down as demand requires, when prices are above variable generation costs.

Due to high fuel costs and poor thermal efficiency, a generator is unlikely to prefer to keep a plant running at minimum stable generation without relatively high spot prices. However, as the costs of shutdown and restart, maintenance and performance impacts are much lower for OCGT than other plant types, these plants are can be shut down for short, seasonal or longer periods.

Similarly, preservation and reinstatement costs incurred from mothballing are considerably lower for OCGT plant than for coal-fired plant. Therefore, it is more likely to be economic for OCGT generators to withdraw and reintroduce capacity from the market on a regular basis.

OCGT plant is suited to providing capacity during daily peaks, as well as seasonal peaks.

In general, OCGT plants can be decommissioned more quickly and cheaply than other generation technologies. They may also be able to be relocated with relative ease, meaning that capital costs may not be sunk to the same extent as for other types of generators.

4.3 Combined cycle gas turbine

Combined cycle gas turbine (CCGT) power stations are also based a gas-fired turbine, with a heat recovery steam generator capturing heat from the exhaust of the turbine to produce steam and drive an additional turbine. This additional process increases the fixed and sunk costs while improving thermal efficiency.

While start up times for CCGT power stations are relatively short, ramping up to full capacity can take significantly longer than for OCGT plant. Operating at minimum stable generation is therefore more likely for CCGT power stations than OCGT power stations. On the other hand, OCGT plants are more likely than CCGT plants to undertake a two-shifting operational strategy.

Similarly, mothballing and reinstatement time periods are longer for CCGT plants than for OCGT plants. Therefore CCGT plant is also less likely to be mothballed periodically, than OCGT plant.

Both types of gas-fired generation can be shut down and restarted, or mothballed and reinstated, more quickly and cheaply than coal-fired generation.

Decommissioning and site remediation costs for CCGT plants are also less than for coal-fired plants. Fuel supply agreements tend to be shorter in length and the workforce tends to be smaller than for coal generators.

4.4 Hydro-electric

These plants use the flowing water to drive a turbine and are a form of renewable energy. There are a number of different types of hydro electric generators with the most common being facilities that use dams to store water for release through a turbine. The main operational constraint for hydro plant is management of water resources.

Hydro plants are able to be operated very flexibly and there tend to be few obstacles to operating at reduced dispatch or shutting down for periods. On decommissioning the greatest challenge would be around removal of the dam and rehabilitating the dam site, if this is required.[21]

Hydro generators are built with very long usable lives and although avoidable costs are relatively small, the opportunity cost of water can be very high. As a result, these could be expected to be the last generators to exit in the market, although reduced participation in the short term is common.

4.5 Other renewable

Other renewable generation technologies include wind and solar. These types of plant involve high sunk costs but low variable generation costs. Low variable costs mean other renewable generation plants typically follow a strategy of being dispatched whenever available, rather than changing operating strategies in relation to price signals. These plants are typically funded by power purchase agreements that guarantee recovery of fixed and variable costs or the sale of renewable certificates which are less affected by the underlying price of electricity.

For these types of plant, exit decisions are likely based around the productive life of an asset. Exit would occur if it were not economic to replace an aged and deteriorating generating unit rather than as a consequence of low prices.

4.6 Summary of generation technologies and stages of exit

Table 4.1 summarises the relevant factors for each generator type.

21 Alternatively, remediation may involve leaving the dam in place and remediating the facility in a way that utilises the lake behind the dam.

Table 4.1 Decision factors at each stage of exit

	Stage of exit				
Generation Technology	**Dispatch at minimum stable generation**	**Two-shifting**	**Seasonal shutdown**	**Mothballing**	**Decommissioning and remediation**
Coal	• Reduced thermal efficiency at lower levels of output	• High shutdown and restart costs, and high wear and tear caused by shutdown	• High shutdown and restart costs, and high wear and tear caused by shutdown • Staffing costs	• High preservation and reinstatement costs • Staffing costs	• High decommissioning and remediation costs • Staffing costs • First mover disadvantage • Policy uncertainty: government inducements, climate change policy
OCGT	• Reduced thermal efficiency at lower levels of output	• Relatively low shutdown and restart costs • Relatively short shut down and restart periods	• Relatively low shutdown and restart costs • Relatively short shut down and restart periods	• Relatively low preservation and reinstatement costs • Relatively short shut down and restart periods	• Low decommissioning and remediation costs • First mover disadvantage • Policy uncertainty: government inducements, climate

	Stage of exit				
Generation Technology	**Dispatch at minimum stable generation**	**Two-shifting**	**Seasonal shutdown**	**Mothballing**	**Decommissioning and remediation**
					change policy
CCGT	• Reduced thermal efficiency at lower levels of output	• Relatively low shutdown and restart costs • Short initial start-up period • Long period to reach full capacity	• Relatively low shutdown and restart costs • Short initial start-up period • Long period to reach full capacity	• Relatively low preservation and reinstatement costs • Short initial start-up period • Long period to reach full capacity	• Low decommissioning and remediation costs • First mover disadvantage • Policy uncertainty: government inducements, climate change policy
Hydro-Electric	• Few obstacles, except where there are water flow obligations • Generators may benefit if reservoirs can be sustained for generation in future periods	• Few obstacles, except where there are water flow obligations • Generators may benefit if reservoirs can be sustained for generation in future periods	• Few obstacles, except where there are water flow obligations • Generators may benefit if reservoirs can be sustained for generation in future periods	• Relatively low preservation and reinstatement costs • A mothballed plant must still manage water flow obligations	• Few costs for the plant itself, but decommissioning the dam would be a significant factor • First mover disadvantage • Policy uncertainty: climate change policy
Other renewable	n/a	n/a	n/a	n/a	• Replacement cost and efficiency of replacement

	Stage of exit				
Generation Technology	**Dispatch at minimum stable generation**	**Two-shifting**	**Seasonal shutdown**	**Mothballing**	**Decommissioning and remediation**
					generating unit • First mover disadvantage • Ongoing maintenance costs • Policy uncertainty: climate change policy

Source: Frontier Economics, AEMC analysis.

5 Existence of barriers to efficient exit decisions

5.1 Distinguishing factors generators consider from barriers to efficient exit decisions

Costs faced by market participants at market exit are a natural part of market structures. Many of these cost factors are taken into account by market participants making both exit and entry decisions and can lead to optimal entry and exit decisions that are in the long term interests of consumers, such as the exit of an older less efficient plant rather than the exit of a newer more efficient plant. Barriers to exit can also be considered barriers to entry, as potential entrants are aware that these costs will be incurred at some point in future. Therefore, these factors may have a critical role when firms enter the market, by encouraging firms to make decisions that do not impose unnecessary costs.

On the other hand, barriers to exit that discourage less cost-efficient plant from exiting may place financial pressures on otherwise efficient generators. As a consequence, these generators may exit the market prematurely. This may result in less efficient outcomes for consumers.

In general, where the costs involved in exiting the market provide appropriate certainty, exit can occur at a time and in the manner that minimises the overall cost of generation. Where the cost is unable to be ascertained, or is subject to unnecessary changes, generators may be discouraged from taking a decision to exit, possibly in favour of a decision which delays exit until the cost is clearer.

The remainder of this chapter considers each factor identified in Chapter 3 and whether the factor could constitute a barrier to efficient exit decisions. Section 5.2 below relates to all stages of exit considered above while sections 5.3, 5.4 and 5.5 relate primarily to decommissioning decisions.

5.2 Typical operating and exit costs

Many of the factors identified in Chapter 3 are standard costs faced by operators of infrastructure. These factors include:

- plant shut down costs;
- preservation and reinstatement costs;
- staffing costs;
- decommissioning costs;
- contracts for inputs and outputs; and
- operational factors.

In many cases these costs are, appropriately, within the control of the generator. For example, a generator with multiple plants that has decided to decommission a plant would maximise profits (or minimise losses) by choosing to close and decommission the plant that incurs the greatest losses. Furthermore, a generator could save money by reallocating staff between plants to minimise the combination of redundancy costs and ongoing operational costs at their remaining plants.[22]

Generally, given these costs are common costs faced by generators (and in some cases the operators of other infrastructure) they should be sufficiently clear and certain. Therefore, these costs are unlikely to be a barrier to efficient exit decisions by generators. For example, where redundancy costs are described in an enterprise bargaining agreement they will be more easily ascertained.

5.3 Remediation costs

When a generator is being decommissioned, remediation costs are incurred because of the impact plant operation has had on the site during its lifetime. Remediation costs should generally not be considered a barrier to efficient decisions to exit if:

- remediation obligations are clear regarding which party has an obligation; and
- remediation obligations are clear about the level of remediation required.

Remediation costs are based on legislative obligations coupled with decisions of bodies such as environmental protection agencies. These costs are likely to involve a degree of uncertainty in many cases. First, the legislation where the relevant obligations are contained will not contain a high degree of specificity and in many cases a body such as an environmental protection agency will direct the remediation that should occur. Second, given that the remediation requirements will be specific to the particular site it will be difficult to predict how they will apply in individual cases.

If a generator expects that there is a chance that the remediation obligations imposed on it could be lower in the future, it will be more likely to delay a decommissioning decision. If a generator is uncertain about future obligations imposed by decommissioning, a generator may mothball a plant until such time that these costs are made clear or minimised by other government policies.

5.4 First mover disadvantage

First mover disadvantage is primarily relevant in respect of a decommissioning decision. It is possible that first mover disadvantage presents a barrier to exit for inefficient plants because a generator with an inefficient plant has limited incentive to exit the market prior to a more efficient plant, if the efficient plant owner is less financially resilient. If the efficient plant were to exit, conditions in the market would most likely become more favourable for the other generator. On the other hand, if the

22 This stylised example is a simplification in order to demonstrate how costs may be efficiently allocated.

generator with the inefficient plant expects that the owner of other plant is more financially resilient, the inefficient generator may prefer to exit sooner rather than later in order to minimise their disadvantage.

However, the extent of the issue depends upon generators' expectations that their continued operation would result in exit by other generators. Understanding these expectations would require a more in depth understanding of recent or pending generator exit decisions, particularly with regard to the exit of coal generators. It is possible that first mover disadvantage is sufficiently mitigated as a barrier to efficient de-investment decisions by the ownership structures of generation plant, the ability to close single turbines, the sale of efficient plants to alternative generators and the internal benefit of single plant closure for multi-plant generators.

5.5 Policy Uncertainty

Policy uncertainty may have the effect of increasing expectations that future revenues or costs may be different to the present. Even where policymakers have stated a particular policy position, if the generator does not think the position is credible, it may defer exit decisions. This may mean that firms are impeded in developing expectations of the indirect costs of exit. Policy uncertainty could therefore be a barrier to efficient de-investment decisions.

While operating under this uncertainty, it may be rational for generators to 'wait and see' with the intention of exiting in a future period when the net cost is more favourable. While reducing uncertainty may be difficult, to the extent that governments are able to clarify the factors concerned, barriers to efficient exit decisions may be minimised. Discussed below are key ways policy uncertainty could manifest for generation plant.

As a result, the barriers faced for an individual plant to make a de-investment decision are a combination of factors, many of which can only be evaluated when the decision to exit is already made. Some level of uncertainty is expected. Making these decisions in the face of uncertainty may lead to an economically efficient decision to wait. But to the extent that uncertainty is unnecessary, it may generate barriers to generators making efficient de-investment decisions.

5.5.1 Inducements to exit

If a generator expects that future governments may offer an inducement to exit the market completely, this increases forgone profits on exit. Therefore, a plant may remain in the market, or indefinitely mothballed, in the hope that it could benefit from changes to government policy in future.

Inducements reduce the net decommissioning and remediation costs and could be inefficient if the resulting net cost does not reflect the negative impacts caused by a plant's operation.

5.5.2 Climate change policy

Climate change policies affect all types of generators. Fossil-fuel-fired generators are affected because of the costs incurred to pay for or reduce emissions as well as financial pressures incurred by the ongoing entry of renewable generators. Renewable generators are affected in respect of their ongoing profitability under different policy scenarios.

If generators are uncertain about the direction of future climate change policy, this increases the risks of long-term operational decisions as well as changing the expectations of future costs and revenues. As a result, generators may delay a decision to reduce their participation in the NEM because they expect future costs to be lower or revenues to be higher than present.

While climate policy uncertainty can present a barrier to efficient de-investment decisions, recent agreement on the RET and the clear communique from the COAG Energy Council with regard to contracts for closure may have significantly reduced this uncertainty.

5.6 Conclusion

None of the factors considered in this chapter 5 are based on the National Electricity Law or Rules. Therefore, nothing in the National Electricity Law or Rules would constitute a barrier to efficient exit of generators.

We have also considered whether these factors would constitute a barrier to efficient exit of generation more generally. Across these different factors, the ease with which a generator could quantify the costs it would face if it were to exit the market will vary. As has been shown, some costs, such as operational matters, are relatively easier to quantify. Other costs, like remediation costs, are much harder to determine in advance.

In addition, policy uncertainty around matters such as climate change policy or inducements means generators may expect that other costs they might face on exiting the market could change over time.

To the extent possible, governments should take steps to reduce the uncertainty that generators face in this regard.

At the same time, the uncertainty means that it is difficult for policymakers to know what costs would be faced by which generators, and therefore what would be efficient in terms of the timing or order of generator exit from the NEM. In these circumstances, it would not be of benefit for governments to intervene in the market to influence how generator exit occurs.

It is also noted that a significant degree of generator exit is already being observed in the NEM as shown in Table 2.2. That is, if there are barriers to efficient exit of generators, they are not preventing generators from making decisions to exit.

6 Conclusions

This advice has described and analysed the factors that generators consider in making decisions around exiting the market.

The factors can be complex and apply differently depending on the generator technology type and how the generator is structured. They also apply in a different way depending on the generator's location and the stage of exit being considered by the generator. Stages of exit can vary from merely reducing dispatch to full decommissioning of the generator.

Therefore, while these costs represent barriers to exit for individual generators they are only a problem if they are a barrier to *efficient* exit decisions. The main factor determining if exit decisions are efficient is certainty. Greater certainty of the costs incurred upon exit is more likely to promote efficient exit decisions. In addition, it is not necessarily a problem if generators with lower running costs exit before generators with higher running costs. If the costs of exit of the lower cost generator are lower than those of the higher cost generator, this can be a rational decision.

Our analysis of the factors generators consider when exiting the market indicates that there is nothing in the National Electricity Law or Rules which would constitute a barrier to efficient exit decisions by generators in the NEM.

In terms of whether the factors that are considered by generators would constitute barriers to efficient exit more generally, the key driver is uncertainty.

Uncertainty manifests in two ways. First, it can reflect a difficulty in ascertaining the current costs of exiting the market. For example, authorities may require a certain level of site remediation where a generator exits, but the precise level at which this is set may not be known until the exit decision is made. Second, it can reflect the way the costs of exiting the market may change in the future. For example, a generator may have an expectation that the current policy on contracts for closure may change in the future such that it will be paid for exiting the market.

While it is possible the uncertainty around exit costs is creating a barrier to efficient exit, a number of generators have announced exit decisions in recent years. The evidence suggests that any barriers to exit have not deterred generators from commencing various stages of exit or the full retirement of plant. This would support leaving it to the market to determine which plant should exit.

On the whole, the level of uncertainty involved in these exit costs means it is difficult for policymakers to know what costs are faced by which generators upon exit, and therefore what would be efficient in terms of the timing or order of generator exit from the NEM.

To promote efficient exit decisions, where there is uncertainty in policy settings or remediation obligations, this should be minimised to the extent possible. For example, governments could continue to stress that there will be no contracts for closure, and the energy-only market will not be replaced by a capacity market.

The Commission's view is that at this time further work is not required in respect of investigating barriers to exit.