



**Australian Government**

**Department of the Environment and Energy**

# Regulation Impact Statement— Underwriting New Generation Investments Program



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Front—Gas fired power station in Dalby, Arthur Mostead © Department of Agriculture, Water and the Environment and Arthur Mostead

Front—Eraring Power Station near Morisset in New South Wales that is fuelled by black coal coming from the nearby Coorangbong Mine, Arthur Mostead © Department of Agriculture, Water and the Environment and Arthur Mostead

Front—Sunset over the Wattle Point Wind Farm near Edithburgh, © Department of Agriculture, Water and the Environment

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# The problem

In July 2018, the Australian Competition and Consumer Commission (ACCC) released its *Retail Electricity Pricing Inquiry—Final Report* (REPI) which investigated electricity pricing outcomes in the National Electricity Market (NEM).

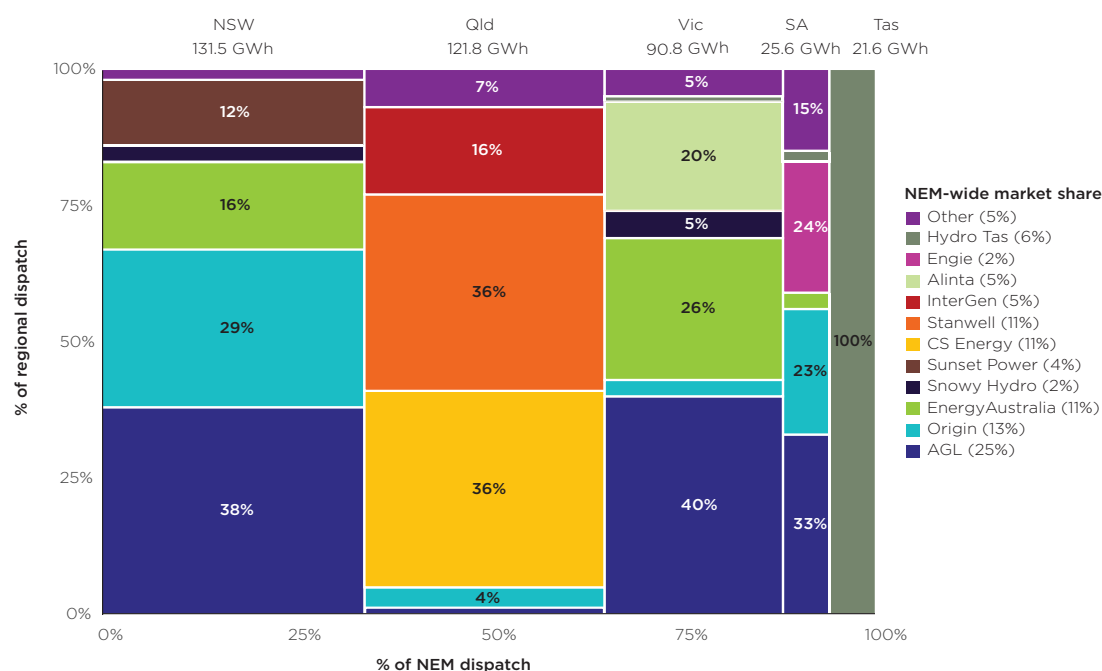
The ACCC’s overarching finding was that the market was not working in the best interests of consumers and reforms were needed.

In relation to the wholesale market, it found increases in the wholesale price of electricity had been the second largest contributor to consumer price increases in the NEM over the past decade, with network costs being the largest driver. Wholesale costs were particularly significant drivers of costs over the two years prior to the ACCC’s report, with wholesale prices increasing substantially during this time. Amongst other factors, the ACCC identified high levels of market concentration, the exit of some low-cost generation, and a tightening supply and demand balance as reasons for the higher wholesale prices. The ACCC’s view was that these factors have led to a lack of competitive constraint on market participants, which in turn has negatively affected electricity affordability.

## Market concentration drives elevated pricing

Generation ownership in the NEM has become increasingly concentrated over recent years, and is concentrated amongst a few key players in most regions (see Figure 1).

Figure 1: Market share by generation dispatched by region, year to April 2018



Source: ACCC analysis of AEMO data.

Note: Percentages in the chart represent the percentage share within the region; percentages in the legend represent the total NEM-wide market share for each company.

The closure of two, low-cost coal generators in 2016 and 2017 increased the concentration of generation ownership. The closure of the Northern Power Station in South Australia in May 2016 and the Hazelwood power station in Victoria in March 2017 removed more than 2000 megawatts (MW) of capacity from the market over a very short period, increasing the market share of other existing generators. The reduction in firm generation capacity<sup>1</sup> has also tightened the supply demand balance in the electricity market.

The ACCC concluded that:

*“[T]he current wholesale market structure is not conducive to vigorous competition. In an energy-only bidding market, it is particularly important that there is sufficient competition between generators to deliver efficient prices.”<sup>2</sup>*

and

*“[E]levated prices have generally been driven by high and entrenched levels of concentration in the market, combined with fuel source cost factors.”<sup>3</sup>*

## There are supply and demand pressures

Australia’s energy system is in transition. The coal generation fleet that has been the mainstay of Australia’s energy supply is aging, and many plants are reaching the end of their technical life. Since 2014, 4,200 MW of coal generation capacity has been withdrawn from the NEM<sup>4</sup>. The exit of large generators places pressure on remaining generators to meet the nation’s energy needs. In 2017–18, coal-fired generation accounted for 73 per cent of electricity output and had the highest summer output in a decade.<sup>5</sup>

During this transition, the NEM is continuing to experience significant supply and demand pressures. For example, on 25 January 2019, 200,000 customers across Victoria experienced blackouts when demand was greater than supply during hot summer conditions.

A number of coal plants are forecast to reach the end of their technical life in the next decade, including the Liddell Power Station in 2022–23, Vales Point in 2028–29 and Gladstone in 2029–30 (Figure 2). Further, Energy Australia has announced it will close Yallourn Power Station’s four units from 2029–2032.

1 Firm generation capacity, also known as dispatchable generation, is electricity generation that is able to be dispatched on request to meet demand. This could include coal-fired generation, combined cycle gas-fired generation, open cycle gas generation.

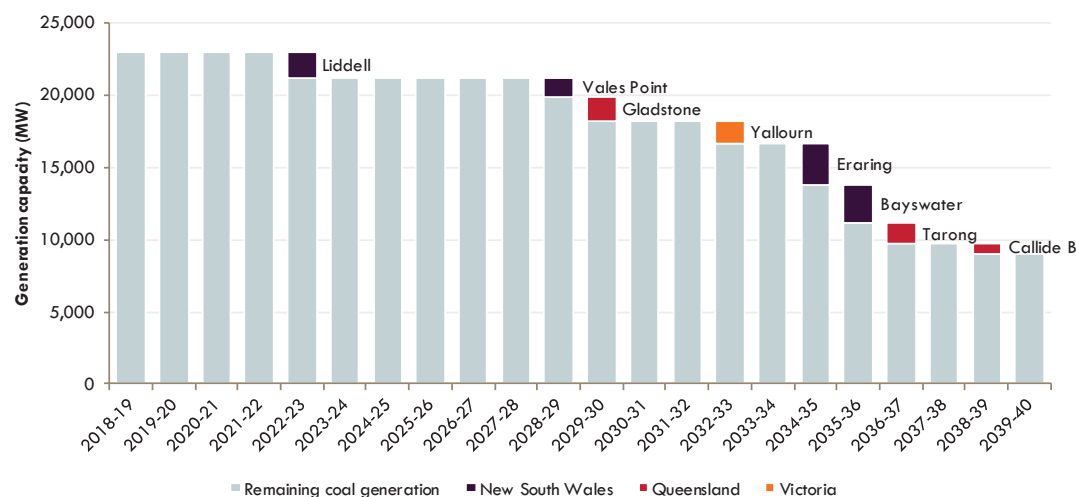
2 ACCC, REPI, July 2018, p. 88

3 ACCC, REPI, July 2018, p. vii

4 AER, State of the Energy Market 2018, p. 5

5 Ibid, p.15

Figure 2: NEM coal-fired generation fleet operating life to 2040, by 50th year from full operation or announced retirement



Source: AEMO, Integrated System Plan, July 2018, p. 22.

Maintaining existing coal-fired generation up to the end of its technical life is a key element of a least-cost approach outlined in the Australian Energy Market Operator’s (AEMO) Integrated System Plan.<sup>6</sup> However, aging plants can have increased reliability issues and may not operate as anticipated. This could lead to some closures occurring sooner, particularly if major maintenance and upgrades are delayed.

## The importance of reliability

The Australian Energy Market Operator (AEMO) currently identify 7.1 gigawatts (GW) of committed new generation, of which less than 2.3 GW could be considered dispatchable.<sup>7</sup> The amount of dispatchable generation scheduled to retire from the NEM over the next decade is 3,087MW, equivalent to two Hazelwood power stations. This includes: 1036 MW of gas (Torrens Island A, Osbourne, Swanbank, Tamar and Mackay); and 1800 MW of coal (Liddell).<sup>8</sup> The proposed Snowy 2.0 project, which would add 2,000 MW of fast-start, dispatchable capacity, will go some way to addressing this gap and AEMO has identified 53 GW of proposed generation developments for the NEM,<sup>9</sup> but there is uncertainty as to whether the private sector will build the additional estimated generation required.

Given these assumed exits, and other assumptions about future demand and market conditions, AEMO estimated the NEM could need up to 1160 MW of generation with ‘firming capability’ to enter the market in the next decade if the reliability standard is to be met. The reliability standard is set at 0.002 per cent of unserved energy (USE) per financial year.

Moreover, as mentioned above, much of the NEM’s dispatchable thermal generation fleet—coal and gas-fired generators that continue to provide the majority of electricity in the NEM—is old. The average age of coal-fired generation in 2017 was 33 years and, since 2012, the average retirement age of coal-fired

<sup>6</sup> AEMO, Integrated System Plan, July 2018

<sup>7</sup> AEMO, Generation Information, 8 August 2019, <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>.

<sup>8</sup> AEMO, 2019 Electricity Statement of Opportunities, August 2019, p.66

<sup>9</sup> AEMO, Generation Information, 8 August 2019, <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>.

generation has been 35 years.<sup>10</sup> The expected retirement dates for coal generators can be found at Figure 2 above. Consequently, the retirement of further generation in the short-term cannot be ruled out. And the amount of additional generation needed in the system may be higher than that outlined by AEMO.

There is a gap in the medium term on mechanisms to help address reliability issues. For in the short-term, reliability issues are managed through AEMO's Reliability and Emergency Reserve Trader (RERT) provisions and the Government's Retailer Reliability Obligation (RRO). For the longer term, the Energy Security Board (ESB) been tasked with developing a fit for purpose market framework to ensure investment signals and operational approaches can maintain a reliable system in the context of technological change and uncertainty.

## Investment is needed in dispatchable generation

In the NEM, generators bid their availability into the wholesale market at different price points. Generators are dispatched in order of lowest cost up to the amount required to meet demand. All generators dispatched receive the asking price of the marginal generator in that dispatch period, not according to their individual bids.

In the NEM, generators' revenues are almost entirely dependent on selling the electricity they produce, through the wholesale spot and contracts markets.<sup>11</sup> If a generator does not produce electricity it does not receive any revenue (with the exception of generators holding cap contracts, which are typically offered by open cycle gas generators operating as 'peaking plants').

Persistent high spot prices in the NEM would be expected to encourage new investment in generation in the market, which in turn would increase available supply and drive prices down.

Consistent with this, the market has been

responding to the recent high electricity spot prices by investing in generation. But the vast majority of the investment has been in the form of wind and solar generation. Over the last three years almost 5000 MW of intermittent renewable generation has come online.<sup>12</sup>

AEMO's Integrated System Plan has stated that almost 80 per cent of all currently announced, proposed, advanced or committed projects in the NEM are wind or solar generators.<sup>13</sup> This has been due to a range of factors including Commonwealth and State renewable energy schemes, the rise of corporate Power Purchase Agreements (PPA) and the declining cost of variable renewable energy (VRE) technologies.

While VRE investment has grown rapidly in the NEM over recent years, the growth in dispatchable technologies has been largely stagnant. Most of the investment that has occurred, such as the 100 MW/129 MWh Hornsdale Power Reserve 'big battery' and 262 MW of back up diesel generation in South Australia, has benefited from government underwriting. One exception is AGL's 210 MW Barker Inlet Power Station which is expected to commence operation in late 2019, replacing two of the four Torrens A turbines. The last significant large-scale firm generation built in the NEM was the 550 MW Mortlake gas power plant in 2012 in Victoria.

The levelised cost of electricity (LCOE) is an effective method of calculating the average return a new facility will need to make a return on the initial investment and ongoing costs over its lifetime. The average required rate of return for variable renewables has seen a rapid decline, as technologies improve and economies of scale come to bear. This trend is projected to continue, making variable renewables some of the cheapest investment opportunities (Figure 3).

However, the LCOE calculation is not designed to consider the effect the new capacity has on the grid. Dispatchable generation is able to provide additional value to the grid that is not measured

<sup>10</sup> <https://www.energycouncil.com.au/analysis/aging-generation-australias-coal-fired-fleet/>

<sup>11</sup> The NEM also has ancillary services markets through which generators can generate a small proportion of their revenue.

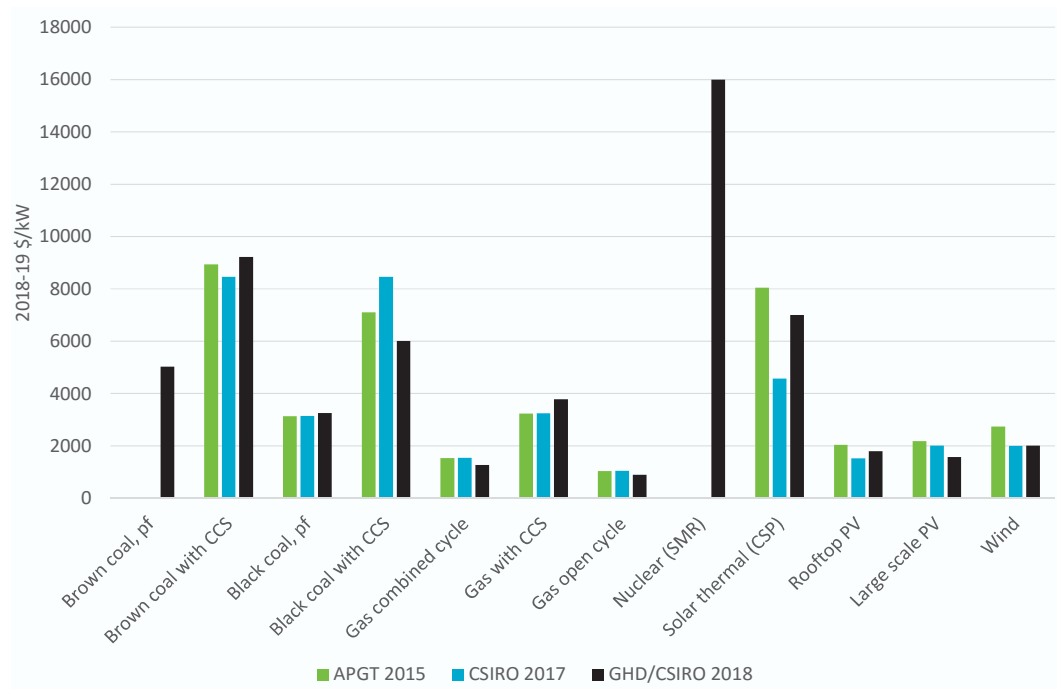
<sup>12</sup> Clean Energy Regulator, <http://www.cleanenergyregulator.gov.au/RET/About-the-Renewable-Energy-Target/Large-scale-Renewable-Energy-Target-market-data>.

<sup>13</sup> AEMO, ISP, July 2018, p. 22

explicitly, and which variable renewables cannot supply. This includes frequency services, response to changes in demand or supply, and inertia services that help the management of the grid.

There are currently no explicit signals in the NEM to provide dispatchable generation that is effective at responding to the peaks and troughs in supply which the growth in variable technologies is introducing to the grid (as opposed to explicit signals driving renewable investment through the Renewable Energy Target, and state and territory renewable energy policies).

Figure 3: Levelised Cost of Electricity (\$A2018/MWh)



Source: CSIRO, GenCost2018, Updated projections of electricity generation technology costs

Sufficient firm generation sources that can operate flexibly and provide power when needed—such as gas turbines, pumped hydro and battery storage—are critical to the future reliability and price outcomes in the market, particularly as the proportion of new renewables increases. Dispatchable generation can provide power when intermittent generators are not producing, and importantly can offer the market firm hedge contracts which are critical for retailers and large energy users to protect them from wholesale market volatility.

In relation to price effects, the ACCC noted that:

*“The [price] impacts of concentration are exacerbated by the tight supply-demand balance, particularly in South Australia and Victoria. While the supply demand balance will change as the committed and proposed new generation... enters the market, in the absence of further generation coming into the market, it is likely to tighten again as we see the further retirement of coal generation over the coming years.”<sup>14</sup>*

14 ACCC, REPI, July 2018, p. 88



## Some larger customers and smaller retailers cannot access affordable generation

The ACCC received confidential feedback from a number of market participants, including project developers and smaller retailers, that they were keen to invest in new generation projects but were unable to proceed due to an inability to secure project financing. A key barrier identified by the ACCC was a lack of long-term offtake agreements available to underwrite project debt. In relation to this, the ACCC noted that:

*“New large-scale generation projects require considerable upfront investment and carry significant risk. Where such projects are proposed by new entrants without a stable long-term downstream customer base, they are unattractive for traditional financing.”*

A PPA is a contract between the generator and customer where the customer agrees to purchase a certain amount of power over a period of time for a set price.<sup>15</sup> A PPA (or other forms of offtake agreement) gives new project proponents revenue stream certainty and provides the assurance that private financiers, including banks, need to underwrite an investment.

The ACCC identified that large commercial and industrial customers are often unable or unwilling to commit to a contract term that would provide investors with adequate certainty of long-term returns. These customers are sometimes able to sign up to shorter agreements (ACCC gave the example of 5 years), but only at prices which would be insufficient to finance the generation project.

The ACCC identified a market failure where some large industrial or manufacturing customers with high electricity needs are unable to invest in, or sponsor, low-cost sources of generation in the same way that major electricity retailers or some large corporate customers have done. As such, these customers are missing out on access to new low-cost generation in the market.

## The ACCC Retail Pricing Inquiry Recommendation

To address the problem of some project proponents being unable to attract sufficient debt financing for new generation capacity, the ACCC recommended the Australian Government operate a program under which it underwrite new generation investments in select circumstances (Recommendation 4). The full recommendation is at figure 4 below.

*“Where private sector banks are unwilling to finance projects... the ACCC considers there is a role for the Australian Government in providing support for such projects in appropriate circumstances.”<sup>16</sup>*

To help address the issue of market concentration, the ACCC also recommended that support under the program be limited to companies who did not have a significant market share of generation capacity in the relevant NEM region. The ACCC recommended support be provided through a mechanism to underwrite the future revenues of new generation projects for later years of operation. Proponents would need to have contracts with commercial and industrial customers for the first few years of operation, to demonstrate their commercial viability.

The ACCC considered this approach would encourage new entry, promote competition and enable commercial and industrial customers to access low-cost new generation. It noted:

*“The ACCC believes it is critical to ensure that challenges with project financing do not preclude large industrial and manufacturing customers from gaining access to the benefits of independent new low-cost generation in the market. As well as directly benefitting the business in question, such investments will support the development of a competitive market by introducing additional independent supply and reducing concentration.”<sup>17</sup>*

<sup>15</sup> The price may not be constant over the lifetime of the agreement.

<sup>16</sup> ACCC, REPI, July 2018, p. 99

<sup>17</sup> ACCC, REPI, July 2018, p. 99

Figure 4—ACCC Recommendation 4

The Australian Government should operate a program under which it will enter into low fixed-price (for example, \$45–50/MWh) energy offtake agreements for the later years (say 6–15) of appropriate new generation projects which meet certain criteria. In doing so, project developers will be able to secure debt finance for projects where they do not have sufficient offtake commitments from [Commercial & Industrial (C&I)] customers for later years of projects. This will encourage new entry, promote competition and enable C&I customers to access low-cost new generation.

The program should operate for at least a four-year period, with support provided for qualifying projects. To qualify, a project proposal must:

- have at least three customers who have committed to acquire energy from the project for at least the first five years of operation
- not involve any existing retail or wholesale market participant with a significant market share (say a share of 10 per cent or more in any NEM region)
- be of sufficient capacity to serve the needs of a number of large customers
- be capable of providing a firm product so that it can meet the needs of C&I customers.

## The Underwriting New Generation Investments program

On 20 August 2018, the Government announced it supported the ACCC's recommendation and would introduce a program to underwrite investment in new, competitive, dispatchable generation. The Underwriting New Generation Investments (UNGI) program is intended as an interim measure to reduce barriers to entry for new firm generation in the electricity generation sector in the medium-term.

This, in turn, is expected to increase supply, enhance competition and reduce power prices in the wholesale electricity market. The objectives of UNGI are to enable commercial and industrial customers and smaller retailers to access low cost generation, increase competition and improve reliability and system security across the NEM. This is not specific to regions or technologies. These outcomes are anticipated to happen over the next decade as new investment brought on by the program enters the market.

# Case for government action / Objective of reform

There are three objectives of the Underwriting New Generation Investments program.

## 1. To reduce wholesale electricity prices by increasing competition and supply

The ACCC identified that a lack of competitive pressure in the NEM is a contributing factor to recent increases in wholesale electricity prices. The inability of some generation projects to secure finance was identified as a market failure by the ACCC, creating a barrier to entry for new projects. Barriers to entry impede competition and place upward pressure on prices.

## 2. To assist commercial and industrial (C&I) customers and smaller retailers to access affordable energy supply arrangements

Government intervention will encourage new generation capacity where there is a demonstrated short to medium term demand for that capacity. The ACCC stated that generation projects must be capable of providing a firm product to meet the needs of C&I customers.

Stakeholder consultation identified that some smaller retailers also struggle to access competitively priced energy supply arrangements due to the relatively small size of their customer base and uncertainty around their future requirements. The program also has potential to provide small retailers with access to cheaper electricity contracts, which will provide increased competition in the retail market.

## 3. To improve reliability by increasing the level of firm capacity in the system.

The exit of the Northern and Hazelwood power stations, in addition to the planned closure of the Liddell power station in New South Wales in 2022-23, has reduced the amount of firm or dispatchable capacity in the NEM relative to demand, when compared to historic levels. Further, the amount of dispatchable generation scheduled to retire from the NEM over the next decade is 3,087MW, equivalent to two further Hazelwood power stations.

Investment in new generation is occurring, but much of this new generation is in the form of variable renewables, which generate intermittently and do not provide a direct substitute for the dispatchable generation capacity that is exiting the market. The proposed Snowy 2.0 project, which would add 2,000 MW of fast-start, dispatchable capacity, will go some way to addressing this gap but there is uncertainty as to whether the private sector will build the additional generation required.

There are existing or planned mechanisms to manage short-term reliability—ensuring there is enough generation in the market to meet demand—including the RERT and the RRO. However, supporting new dispatchable generation may reduce the likelihood of triggering these mechanisms, and the costs they impose. Further, intervention is needed to provide incentives which encourage new firm generation to be built, ensuring reliability for the long term.

# Policy options

## Option 1: Do nothing

Under a do nothing approach, the Government would continue to be reliant on the market to ensure that sufficient firm generation is developed by non-incumbents to meet the policy objectives. As noted, the market relies on high prices in the wholesale and contract markets to signal to investors to build new generation in the market.

## Option 2: Government funded new generation

The Government could directly provide the upfront capital to build new firm generation. This could mean funding a large generator or a series of smaller generators to address shortfalls in particular regions. It may also include targeting particular technology types that are identified to be most suitable, efficient and economical for addressing the market failure identified. For example, the Government could identify the need for a new 500MW combined-cycle gas turbine gas plant in a region and provide the estimated \$750 million to build the plant.

This option could result in sufficient firm capacity to meet the reliability issues identified in the market being built. The Government would effectively own the gas plant and could, as owner, ensure that generation from the plant is contracted with C&I customers.

## Option 3: Underwriting New Generation Investments (UNGI) program

Under an UNGI program the Government would support the development of new firm generation capacity by private entities through a range of financial mechanisms that help to address a market failure. In this instance there is a barrier to entry for new generation due to an inability to sign up C&I customers on long term contracts.

The program is intended to facilitate access to finance for projects that are otherwise economically viable but that are unable to secure the type of long-term customer offtake agreement required to underwrite debt finance. The program should not provide non-commercial projects with access to finance.

Possible mechanisms that could be used by the Government under the UNGI program are outlined below.

### Mechanism 1: Floor Price/ Revenue Floor

The ACCC recommended the introduction of a floor price mechanism, where there is a guaranteed minimum price that a generator will receive for any electricity generated and sold.

#### Price Floor

It would operate like a 'put option', with the Government agreeing to pay the generator the difference between an agreed price floor and the price they receive from selling electricity into the NEM (the settlement price) where the settlement price is lower than the price floor.

One approach would be to base the price floor on a project's weighted average dispatch price over a defined period (such as 3, 6 or 12 months, and subject to defined trigger thresholds being met) rather than a 30 minute (or 5 minute) settlement price (the price actually received by the generator for each unit of electricity delivered to the NEM).

Under such an approach, the Government would only make financial contributions to the proponent where the project's average weighted dispatch price over the defined period falls below the floor price, but not for individual trading intervals which fall below the floor price. This approach would limit the financial liability to Government because it is relatively

common for wholesale prices to fall to low levels in individual trading intervals (the price floor in the NEM is -\$1,000/MWh), but far less likely that prices for a period would on average be below an expected floor price.

The Government would only cover the price difference between zero and the floor price. It would not provide payments to cover negative average prices<sup>18</sup>.

The ACCC did not specify the level at which a low fixed-price floor should be set but suggested an example price floor of \$45-\$50/MWh. The price floor should be sufficient to ensure the project would be able to secure debt financing.

Price floors would need to be negotiated on a project-by-project basis. This creates flexibility for project specific factors such as capital costs, gearing ratios, and differences in wholesale price outcomes between regions.

## Revenue Floor

Differing technology types also require specific methodologies to determine the appropriate underwriting amount. For example, the type of price floor described above may be appropriate for traditional baseload generators, while peaking generators, such as open-cycle gas turbines and pumped hydro are sufficiently different in their output profile and revenue model to necessitate a variation on this approach.

Peaking generators generally make a significant portion of their revenue from selling cap contracts, which act as an insurance against high price events for the buyer. Peaking generators make money from charging a premium for these cap contracts, as well from the spot market when they generate electricity.

A floor price based only on average dispatch prices is not appropriate for peaking generators as this would not take into account revenue related to cap contract premium. In addition, the value of the cap contract premium is determined based on market volatility, not average prices, further reducing the appropriateness of a floor price for these generation types.

A price floor would also be of limited value to pumped hydro generators. Pumped hydro uses energy during low demand and lower cost periods to pump water uphill to a storage reservoir. The water is stored until needed to produce electricity during higher price periods and to defend contracts. Aside from contracts, pumped hydro generators' revenue comes from the price differential between the price of pumping water and the price received from producing electricity (less the efficiencies lost from pumping, which are typically 23 to 35 per cent). As such, storage revenues are highly correlated with price volatility and a wholesale floor price would be of limited assistance to this generation type.

A form of support more appropriate for peaking generators, including pumped hydro storage, is a revenue floor, whereby the total revenues of the generator (spot market revenues and contract market revenues) are assessed over a period (again, say 3, 6, or 12 months) to determine if project revenues are adequate to cover debt financing costs.

## Assessment periods for price and revenue floor

Seasonality of electricity revenues and electricity prices must be considered when determining the assessment period for each price or revenue floor agreement. This price seasonality in the NEM is most often seen over Quarter 1 where the price of electricity is often substantially higher than other quarters in the year. As such, a flat price floor settled quarterly could result in the project receiving significant market earnings over the

<sup>18</sup> The NEM spot market has a market price cap of \$14,500/MWh (for the period from 1 July 2018 to 30 June 2019) and a market floor price of -\$1,000/MWh. The negative market floor price allows generators to pay to stay online when the cost of staying online is lower than the cost of shutting down and re-starting their plants.

summer quarter but top up payments from the government over the winter quarters when spot prices are lower.

As the underwriting is focused on supporting debt and as different projects will have different repayment arrangements, the assessment period will need to be determined on an individual project basis. However, at a minimum the assessment period would be three months and additional options to address seasonality could include:

- Calculating settlements over a longer period of six to 12 months;
- Allow different strike prices or revenue floors over the four quarters;
- Allowing surpluses from previous periods to be considered before a top up payment can be made.

### Duration of support

Another variable to consider in designing a price floor mechanism is to consider when the price floor should apply. The ACCC recommended that for a project to qualify for support from the Government, the project should have contracts in place with C&I customers for at least the first 5 years of its operation. However, submissions received during the consultation process, as well as information provided by project proponents and financiers, suggest it may be necessary for Government support to commence prior to five years into a plant's operational life. For example, if construction of a new gas-fired project takes 2 to 3 years, a C&I customer would need to sign up for electricity 8 years in advance if the 5 year timeframe were imposed. The length of this timeframe has been noted as potentially prohibitive to new generation projects, as C&I customers may be unwilling to enter into offtake agreements of this duration.

The ACCC also suggested the price floor could be made available for a period of ten years after the end of a project's C&I contracts. An alternative approach could be to consider different periods of support for different projects. As with negotiating

price floors on a project-by-project basis, this could allow better targeting of assistance to take into account the need for specific types of generation capacity in different regions

## Mechanism 2: Loans

The Government could provide loans (including on concessional terms) to project proponents in order to get a generation project up and running.

Under this arrangement, the Government would provide upfront capital for projects and receive a return over a set repayment period, with terms to be agreed.

Project proponents would still be expected to offer contracts to C&I customers, but allow them to sign up to shorter term contracts than would normally be necessary to obtain private financing.

## Mechanism 3: Small grants

Small grants are another option that could be used to incentivise new firm generation capacity in the electricity market. Prior to the decision to build new generation, project proponents undertake feasibility studies and establish a business case to ensure an investment makes sense. Existing power stations can also undertake upgrades that deliver additional firm capacity.

The Government could provide direct funding to firms to undertake feasibility studies or minor upgrades to their power station through a small grants program. Project proponents who fulfilled a set of criteria would be given funds to undertake their projects. The Government would monitor progress against project milestones to ensure that the project is meeting the desired outcomes of the small grants program.

## Mechanism 4: Cap and floor (collar) contracts

An alternative to a floor price would be to use a collar contract where both a floor price and cap price would be enacted. Similar to the floor price contract, the Government would pay the project the difference when the spot price is below the floor price, but not below zero prices. However, if the spot price exceeded the cap price set, the project would pay the difference between the spot price and the cap to the Government. The project proponent would keep the gains between the floor and cap prices.

Under this mechanism, the Government would bear the risk that prices may fall below the price floor, but would also benefit when prices exceed the price cap. Because there are two variables—the floor and the cap—a collar contract is more complex to set than a floor contract. In addition to the specifics of the actual project, both the floor and cap prices will depend on where the other is set.

Similar to the floor price, a project proponent would need to have engaged with potential customers, demonstrating the project is economically viable. This would incentivise project proponents to contract with C&I customers and/or small retailers to meet the objectives of the reform.

## Mechanism 5: Contracts for difference

A number of governments use contracts-for-difference (CfD) to help finance renewable projects in Australia.<sup>19</sup> Under a CfD, the government agrees a strike price with the project proponent. The project then sells the electricity into the wholesale market. When the wholesale spot price is below the strike price, the government pays the project the difference. When the wholesale spot price is above the strike price, the project proponent pays the government the difference.

To ensure the program only targets firm generation, the strike price may be on the basis of:

- a pre-specified and fixed volume of output, akin to existing ‘flat’ baseload swaps, or
- a particular load profile, akin to existing ‘load following’ hedges.

A CfD provides revenue certainty to the project proponent in that they are guaranteed a set price for the electricity that they sell. The Government takes all the market risks (and benefits). The strike price and length of the contract would be dependent on the specific needs of the generation project.

To incentivise contracting with C&I customers and/or small retailers, the project proponent would be required to have contracts for at least three years prior to the contract with the government commencing.

## Mechanism 6: Capacity payments

The government could support new generation projects by providing capacity payments for the availability of firm generation. A number of electricity markets have capacity markets, including in Western Australia. In markets with a capacity market, generators receive payments to ensure capacity is available. Generators then receive additional revenue for the electricity that they sell.

Under this option, the Government would provide a direct payment to new projects for each megawatt of firm capacity available. The mechanism could stipulate that the generator must be available for dispatch at peak times—for example, over the summer period. The generator effectively receives a payment every year if it agrees to be available over the peak period.

The generator would also receive revenue from selling its electricity.

<sup>19</sup> In particular, the ACT and Victoria.

# Impact analysis

## Option 1: Do nothing

Current electricity prices have been high by historic levels since 2016 and are forecast to remain above historic levels. Under a do nothing approach, the Government would rely on these high prices to drive investment in new generation.

But, as noted, there has not been significant action in the market to commit to new, firm generation projects. Further, as noted in Chapter 1, there has been limited dispatchable generation build in the last 5 years and many of these investments only occurred with government support. The amount of dispatchable generation scheduled to retire over the next decade is 3,087MW.<sup>20</sup> Even with further expected withdrawals of firm generation, as outlined by the ACCC 2018 REPI, the market has not been responsive in commissioning new firm generation. The recent blackouts that occurred in Victoria on 25 January 2019 highlight the urgent need for new firm generation to ensure reliable supply. The proposed Snowy 2.0 project, which would add 2,000 MW of fast-start, dispatchable capacity, will go some way to addressing this gap but there is uncertainty as to whether the private sector will build the additional generation required.

It should be noted that, in response to concerns around the reliability of supply in the NEM, the Council of Australian Governments (COAG) Energy Council has agreed to introduce the Retailer Reliability Obligation (RRO). The RRO will impose an obligation on retailers to ensure they have access to sufficient generation—through ownership or contracting with the generator owner—to meet their customers' needs.

But the RRO is only triggered when there is a risk there will not be enough generation in the market to meet the reliability standard<sup>21</sup> based on a peak demand event which would be expected every one-in-two years, which may not deliver sufficient generation to maintain reliability in years when demand is above average.

Even if the market were to respond to price signals and bring on new generation in a timely fashion, the new generation may be owned by one of the existing big players in the market and not necessarily assist with addressing market concentration and competition concerns.

As a result, a do nothing approach is unlikely to address the objectives of the reform, and improve competition in the market to reduce electricity prices. Moreover, the market failure identified by the ACCC will not be addressed.

The benefit of a do nothing approach would be to avoid any potential adverse impacts on the market, such as reducing incentives for private investment in new generation. However, as noted above, there has been a lack of investment in new firm generation and there is a risk that the market will not address the shortfall in firm generation capacity in the short to medium term in the absence of government intervention.

Further, doing nothing will reduce the cost to taxpayers by reducing the impact on Government. However, no action will mean that consumers are not able to benefit from improved competition and reliability.

There are zero regulatory costs for businesses associated with the do-nothing option.

<sup>20</sup> AEMO, 2019 Electricity Statement of Opportunities, August 2019, p.66

<sup>21</sup> The reliability standard is currently set at the expectation that there be sufficient generation such that 99.998% of annual demand for electricity is expected to be supplied on a one in two year scenario.



## Option 2: Government funded new generation

The Government building and owning new generators could help address the objectives of the reform by ensuring there is sufficient firm generation in the market leading to improved reliability and reduced wholesale prices. Direct Government ownership could also ensure that generation is contracted with C&I customers.

The introduction of new generation could impact on higher cost generators. Additional lower cost generation could result in these higher cost generators either lowering their bid prices to keep getting dispatched or, if they keep their prices high, these generators would get dispatched less. In both situations, this would result in lower revenues for these higher cost generators. The lower revenues may mean some generators need to exit the market, but it is more likely to impact on profit margins. As highlighted by the ACCC in the 2018 REPI, there is a tightening of supply and demand which has driven up wholesale prices across the NEM in recent years. In this option, the new investment would help lower the wholesale market price through the increased competition.

But this option would not address competition concerns in the market as it may discourage new private entrants into the market. Action by the Government to fill firm generation needs is likely to crowd out private investment, making it less likely there will be new competitors in the market to create further competition and put downward pressure on wholesale prices. Direct Government investment will increase the perceived risk for private sector investors, and likely further suppress private investment in the market due to fears of further direct intervention in the market.

Moreover, the building of new generation would impose a significant upfront cost to taxpayers. Although there may be a dividend from the Government operating the new generation assets, there is no guarantee that this will provide benefits to taxpayers and taxpayers would bear the risk of the generation asset not operating at a profit. For example, the new generation asset may bid

low into the market at a price that would cover operating costs in order to address the objectives of the program to reduce wholesale prices. The building of a new generator may also create ongoing risks and liabilities for the Government in terms of the future management and maintenance of the facility.

Direct Government investment would present significant financial and reputational risks for the Government if the project failed. This risk could be managed by ensuring appropriate due diligence is undertaken as part of the program selection process. This risk could also be mitigated by the Government partnering with private investors, including leveraging off the due diligence and business risk assessment conducted by private investment partners.

There are zero regulatory costs for businesses associated with this option as Government would be making the direct investment.

## Option 3: The UNGI program

The Government has announced it supports the ACCC recommendation to underwrite new generation through the UNGI program. The impact of the program will be dependent on which mechanisms are used, which will be determined based on project details and timing.

The program will provide financial support to project proponents to bring new firm generation into the wholesale market to meet the objectives of increasing reliability; increasing competition and putting downward pressure on electricity prices; and assisting C&I customers access affordable energy supply arrangements.

As outlined in Option 2, the introduction of new generation could impact on higher cost generators. Additional lower cost generation could result in these higher cost generators either lowering their bid prices to keep getting dispatched or, if they keep their prices high, getting dispatched less. In both situations, this would result in lower revenues for these higher cost generators. The lower revenues may mean

some generators need to exit the market, but it is more likely to impact on profit margins. As highlighted by the ACCC in the 2018 REPI, there is a tightening of supply and demand which has driven up wholesale prices across the NEM in recent years. The new investment would help lower the wholesale market price through increased competition.

The provision of Government support to certain projects carries risks to the market, including over-investment in new generation capacity and crowding-out private sector investment.

These risks will be addressed in program design by ensuring that the level of support is determined on a needs basis, informed by expert advice, and ensuring the level and type of support is not such that it completely shields project proponents from market risk. Market impacts of the program will be affected by the support mechanisms provided. To minimise the potential for negative market impacts, the financial mechanisms used should be those which are least distortionary. In particular:

- The support provided should not create perverse incentives in terms of bidding and plant operation. Market signals which incentivise generators to be available when they are most needed should be preserved;
- Consistent with the ACCC recommendation, the support mechanisms used should aim to remove some, but not all, of the project risk. Underwriting debt but not equity will ensure project proponents retain a strong incentive to maximise profitability, thereby reducing the likelihood that support payments will be called on by the project proponent;
- Generators with a significant market share should not be eligible, by excluding applicants which currently hold a generation capacity market share of 10% or more across the project location in the NEM, or 20% or more in the interconnected system as a whole;
- For project financing the typical debt service coverage is usually set at a margin above one. However, a significant buffer above insolvency or to fund debt reserves is unnecessary and may lead to underwriting payments flowing

to equity. The underwriting should be limited to cash required to maintain solvency, and, as such, debt service providers should be prepared to accept a lower debt service coverage ratio compared to other projects; and

- The support mechanisms should not fully ‘shield’ generators from the operation of the market.

There is also the risk of creating an expectation of ongoing Government support for any new generation project. Ensuring long-term investment signals are adequate to maintain reliability is a key element of the program. The risk will be minimised by first ensuring the project has considered all commercial options and all available Government support options, including under the Clean Energy Finance Corporation. Further, as the UNGI program is an interim measure, it will be time-limited with no new support agreements entered into after 30 June 2023.

The Energy Security Board is currently designing a long-term market framework which will apply in the NEM from 2025 onwards. The UNGI program will bridge the gap until this framework is in place.

The provision of support also carries financial and reputational risks to the Government, including if projects fail or if government liabilities are higher than anticipated. These risks would be mitigated through rigorous due diligence and appropriate design of financial mechanisms based on expert advice.

To further limit the Government’s exposure, any potential UNGI support will be capped both at a project and a program level. Capping the risk to Government, will result in greater risk sharing with debt and equity providers. Through sharing the project risk, there will be improved incentives for generation projects to have robust business cases and revenue models. As the intention of the program is one of last resort, it is not intended to release information on specific project and program caps.

There will be ongoing monitoring of the impact of the program, including with reference to individual projects and the market as a whole. The Department will also conduct a full evaluation of the program after two years to assess the effectiveness and efficiency of the support provided.

The regulatory cost of this option for businesses is estimated to be \$573,253 per annum over 10 years. See Chapter 8 for more explanation.

The potential impacts of each of the mechanisms outlined in the Policy Options section are considered below.

### Mechanism 1: Price floor/ Revenue Floor

Introducing a floor price or revenue floor mechanism would address the problem identified by the ACCC, that some project proponents are having difficulties securing financing for new generation in the NEM. This is particularly an issue for new entrants, who are unable to fund new developments from their corporate balance sheet and instead must rely on project finance.

The floor mechanism would encourage the development of firm generation projects in regions where supply shortfalls exist or are reasonably likely to exist in the near future. It is intended to encourage new generation that is additional to that which is likely to come on stream in the future in the normal course of business. The new generation is expected to be viable in the longer term without the need for ongoing government support.

Providing support through a floor price involves risks to the market, including crowding out other project proponents who would otherwise be able to fund new generating capacity. It could also have unintended consequences in the market, such as increasing market volatility and creating stranded assets due to investment in inappropriate locations and types of generation.

Providing support through a price or revenue floor also has significant financial and reputational

risks for the Government. In particular, there are likely to be significant information asymmetries between the Government and the project developer which may make it challenging for the Government to determine the appropriate setting of the price or revenue floor.

Setting a price or revenue floor that is too high could mean a significant transfer of private investment risk to taxpayers and higher than expected future liabilities for the Government. On the other hand, setting a price or revenue floor too low may not provide sufficient support to facilitate new generation and will therefore not meet the Government's intended objectives. Consistent with the ACCC's recommendation, ensuring the floors are set appropriately is critical to the effectiveness of the mechanism and managing risks to the Government and the market.

#### Price floor risks

The risks of setting a price floor can be effectively managed in several ways. Firstly, price floors would be set on a project by project basis based on appropriate due diligence and expert advice. Providing a uniform floor price to successful applicants for a uniform length of time would be the simplest approach. However, a one-size-fits-all approach would not be suitable for the different needs of different market regions and of different technologies that may be required. Instead a tailored assistance package on a project by project basis will allow the Government to select projects that may fill particular expected shortfalls in particular regions, target particular technologies, and/or involve the Government taking on less financial risk.

The risks of a price floor can also be managed by requiring project proponents to demonstrate strong commercial support for their project. This will provide confidence in the commercial viability of the project and will help assess the appropriate level of assistance required to achieve the Government's objectives and to minimise potential distortion to the market and financial risk to the Government.

Over the life of the project, the Government should not be expected to underwrite all generation between zero and the price floor. As such the project, as well as equity providers and debt providers will need to share some of the project risks. This risk sharing will increase the incentive for robust revenue models and demonstration of the commercial case for this generation in the market.

It is intended that proponents of feasible projects will demonstrate purchase commitment from commercial and industrial customers and/or small retailers for a period of at least three years. This reflects feedback from stakeholders that a minimum period of five years, as suggested by the ACCC, does not consider the commercial realities of designing, building and commissioning new generation. This is particularly the case with long lead time generation projects, such as pumped hydro.

The price floor mechanism would only underwrite the revenues earned by generators (rather than set them, as is the case with a contract for difference). The risk that it will affect supported generators bidding behaviour would therefore be minimised provided it is set at an appropriate level. Supported generators would still have an incentive to offer hedging products (such as swaps and cap contracts to the market), increasing competition in the market consistent with the Government's objectives.

### Managing revenue floor risks

The revenue floor will provide top up payments if a generator's revenue (including revenue from both the spot and contract markets) falls below the level required to cover its debt obligations. As a generator's contract revenues are commercially sensitive and not publicly available, project proponents should be required to agree to an 'open book' process, whereby they will provide the Government with a range of commercial-in-confidence information.

Under the project finance 'cash flow waterfall', operating costs have priority payment ahead of debt service costs. Therefore, in order to guarantee a project's revenues are sufficient to meet debt

repayments, the price floor must also be sufficient to first cover variable and fixed operating costs.

Over the life of the project, the revenue needed to cover operating costs and debt service would be considerable. For the Government to assume the full risk would reduce the incentive of debt providers to undertake thorough due diligence on the project. Therefore, the Government should not bear the risks in full and it is reasonable to expect some risk sharing with debt providers.

Equity providers will retain the full risk of their investment which will help provide incentives to ensure there are robust revenue models for the proposed generation project.

In order to manage both the Government's and proponent's risk under a revenue floor agreement the following conditions should guide the agreement:

- The maximum length of the agreement to be in line with the proponent's debt agreement.
- The agreement can be structured as a series of back-to-back contracts of for example 2-3 years in duration to account for changing market conditions. The market conditions subject to reassessment and the methodology by which they are determined will be agreed at the project outset. Examples of contract terms for possible reset include interest rates, fuel costs and regulatory change events.
- The revenue assessment period is expected to be three to 12 months duration, to account for seasonal variation in earnings.
- Payments would be made to the project proponent if total revenues over the assessment period were insufficient to cover debt obligations over the same period.
- The Government's maximum liability will be capped at a pre-determined level across each assessment period as well as across the life of the agreement, including all back-to-back contracts. The cap will be determined on an individual project basis.
- All sources of a generator's revenue are included in determining the price floor to account for payments for the provision of ancillary services and future revenue streams.

- Related party contracts should also be interrogated to ensure no returns to equity through pre-debt revenue streams.

## Mechanism 2: Loans

A Government loan to support generation will address the Government's objectives if it is designed in a manner to ensure that only projects that were genuinely unable to attract sufficient debt financing were eligible. As with all support mechanisms, proponents will also be requested to demonstrate support for their project from commercial and industrial and/or retailer businesses.

There are likely to be significant information asymmetries between the Government and the project developer which may make it challenging for the Government to determine the actual level of assistance required to ensure additionality of generating capacity to the market.

This could have two consequences:

- Investment that would otherwise occur in the private sector would seek a Government loan. If those projects were to gain loans from the Government, the investment would not be additional to that which would occur under a business-as-usual scenario.
- Private sector investment may become depressed as project developers wait until the availability of Government loans. Even though a project developer may not initially be granted a loan, it may prefer to wait until subsequent rounds of the program rather than funding the investment privately.
- To mitigate these risks, it will be important that loans be designed in a manner that limits the concessionality. Government loans should ideally avoid non-commercial concessions such as interest-free periods.

The provision of loans also involves the Government taking on financial risks in the event the project defaults. Default could also result in the Government acquiring the asset. This risk can be managed by ensuring appropriate due

diligence is undertaken as part of the program selection process. The risk can also be shared by the Government being the sole debt provider to the project. In addition to sharing the risk, other debt providers also demonstrate that the project also satisfies the strict due diligence requirements of commercial banks.

## Mechanism 3: Small grants

Consultation with stakeholders identified that some project proponents are struggling to gain approval for undertaking feasibility studies owing to the current investment environment for electricity projects. Although feasibility studies cannot guarantee more capacity in the market, feasibility studies are an important step in the process to build new generation.

The provision of small grants to fund feasibility studies would assist some project proponents to firm up their projects and accelerate the process of bringing them to the development stage. As government support of a feasibility study will not impact on the manner in which a generator will operate if it proves to be feasible, supporting feasibility studies will not risk distorting the market.

Small grant programs to fund upgrades to existing power stations could quickly add capacity to the system, either through increasing the efficiency of the plant or through extending its life. Given the modest size of resulting capacity improvements, supporting upgrades through the provision of small grants is unlikely to distort the market, but could help meet some of the objectives of the Government, including increasing reliability. However, there is unlikely to be a material impact on competition in the market, regardless of the proponent's market share in the particular region of the market due to the modest size of the capacity improvements.

The grants mechanism may provide perverse incentives for existing generators to postpone routine upgrades in order to possibly have the Government fund these, thereby introducing further instability into the electricity network.

Grant funds will not cover the entire cost of the upgrades. The grants mechanism will only be used in instances where deemed appropriate and where the value of the grant is relatively small.

As mentioned above, the ACCC noted that large incumbents have limited incentive to invest in new capacity while they are reaping the benefits of higher spot prices and future prices. Small grants may not be attractive for large incumbents to undertake upgrade works as they may need to contribute significant finance to cover the cost. The Government would need to consider the size of a grant depending on the incentive needed for a specific project. The size of the grant proportional to the benefits of an upgrade will affect whether a grant is the most cost effective approach to achieve the outcomes of the program.

However, unlike other mechanisms which involve the Government taking on a contingent liability that may not crystallise by assuming some of the financing risk of a project (through a loan or floor price for instance), the provision of Government grants will have a direct and known cost to Budget.

#### Mechanism 4: Cap and floor (collar) contracts

A collar contract is similar to a floor contract and has similar advantages. But the existence of a cap, or ceiling price, means that Government could expect to receive some revenue if the average price exceeds the cap.

Effectively a collar contract will provide Government with a form of risk management in that, while it takes on some of the downside risk by imposing a floor price, it gains the upside benefit by imposing a cap. The floor price under the collar contract should be the same as under the floor price option. So while a collar contract will be less attractive to project proponents, it will provide less of a risk to Government finances.

Cap and floor contracts are already used in the market and industry is familiar with how they work. But they are currently used to manage day-

to-day fluctuations in prices and not the average price changes over a longer period as envisaged by this reform.

Unlike a floor price, a collar contract would involve an increased risk of altering the bidding behaviour of recipient generation projects. For example, a generator would have no incentive to bid into the market above the price set by the cap.

A collar contract is more complex to design because there are two variables for the Government to calculate and negotiate. This increases the likelihood that the prices set will not be accurate, potentially creating distortions in the market. It also potentially opens the Government to significant financial risks if the wrong parameters are set. Further, collar contracts usually require a higher floor price to compensate for the possible loss of revenue when the ceiling price is reached.

#### Mechanism 5: Contracts-for-difference

CfDs are a well-understood mechanism that has been utilised by many governments, including the Victorian and ACT governments in Australia. As the form and function of a CfD can mirror the PPAs used by the market, they are also well understood by industry.

CfDs are likely to be welcomed by industry players as they would provide projects with a guaranteed revenue stream. Projects would neither take the downside risk nor gain from any upside benefit. They would get a guaranteed price that should be sufficient to cover their fixed and marginal costs.

However, CfDs do not directly address the problem some stakeholders raised with the ACCC. A strike price under a CfD would provide little incentive for the project to seek out new commercial contracts given they would receive no benefit from striking a contract price higher than the strike price of the CfD. In effect, the Government would hold the swap contract, and so liquidity in the contract market would not be enhanced.

CfDs are also likely to distort the market, due to recipient generators altering their bidding behaviour. Output from the generators is set at a guaranteed price. So the incentive on the generator is to ensure that the electricity it generates is dispatched, earning it revenue. The best way to do this is by bidding into the market at zero (or lower), notwithstanding its short run marginal cost may be substantially higher.

## Mechanism 7: Capacity payments

Capacity payments would offer projects an alternative source of revenue, reducing generators' reliance on prices in the market and the risks that that brings to their revenue. Capacity payments would be highly likely to result in new generation entering the market.

But the NEM is designed to be an energy-only market. Introducing capacity payments would constitute a major change, with potentially significant consequences. Such a change may be a disproportionate response to the problem the program is trying to address.

A capacity payment—a payment direct from Government or consumers to a generator—would not automatically incentivise generators to contract with large industrial customers. But because of the upfront payment, generators may be able to offer businesses cheaper contracts than existing generators in the market.

Such an approach effectively gives new generation an advantage over existing generation, which will distort the market. One unintended consequence of such an approach could be to see new generation force existing generation out of the market. As such, serious consideration would need to be given to the impact capacity payments would have on the market prior to such an option being used to incentivise new generation.

# Consultation

## Overview

In October 2018, the Government released a consultation paper<sup>22</sup> on underwriting new generation investments. The consultation paper outlined the problem identified by the ACCC and suggested potential mechanisms that could deliver new investment. Submissions for the consultation paper closed on 9 November 2018.

The Government undertook further consultation during October and November 2018. The Minister for Energy hosted a roundtable in Sydney on Wednesday 7 November 2018, and the Department of Environment and Energy hosted a consultation forum in Melbourne on Friday 9 November 2018. Over 70 submissions were received in response to the Government's Underwriting New Generation Investments consultation paper. These submissions assisted in development of the Registration of Interest process and the design the program.

On 13 December 2018, the Government released a further paper calling for Registrations of Interest (ROI) in the program.<sup>23</sup> The paper asked for potential project proponents to submit ROIs outlining a description of the proposed project, participants in the project including any customers, the project's development status and which support mechanism would be most appropriate. ROIs were requested to be submitted by 23 January 2019. The intention of the ROI was to:

- Sound out the market to enable the Government to develop an understanding of the range of potential projects that are available and could be supported under the program.
- Inform the design of the program, including the eligibility and merit criteria to be applied in the current phase of the program.
- Develop an initial pipeline of projects that covers all firmed technologies.

<sup>22</sup> <https://www.environment.gov.au/energy/underwritingnewgeneration>

<sup>23</sup> <https://www.environment.gov.au/energy/underwritingnewgeneration/registration-of-interest>

- On 26 March 2019, the Government agreed to a shortlist of twelve projects<sup>24</sup>. The Department of the Environment and Energy also held targeted consultations with the short-listed project proponents as well as financiers in June 2019. These consultations were to discuss the shape of the program and potential mechanisms of support.

- During targeted consultation sessions in June 2019, project proponents noted support from the program may be required earlier than year five of a plant’s operational life.

## Key messages

### Program as a whole

- From the responses to the October 2018 consultation paper, support for the reform was mixed. Incumbent generation companies considered that Government intervention was not required, and raised concerns the program could distort the market and discourage private sector investment. A concern was also raised that the probable outcome of the program was that private investors would seek Government support before committing to any new investment.
- Against this, C&I customers, members of the business community, and potential new investors viewed the proposal favourably.
- Strong governance frameworks were considered vital to mitigating the risks of the program. It was argued that strong governance and a competitive process was needed to ensure that the best projects are funded. It was also argued that transparency and robust processes are key.

### Timing of support

On the timing of support for projects the ACCC put forward:

“Specifically, the ACCC proposes the government introduce a program under which it will guarantee offtake from a new generation asset (or group of assets) in the later years of the project (say years 6–10 or 6–15) at a low fixed price sufficient to enable the project to meet financing requirements.”<sup>25</sup>

The Department has received feedback which indicates the timing on the support is too restrictive and could create technology bias.

- Generation types with long construction periods of three or more years, such as pumped hydro, would be disadvantaged if support could only start from year 5. This is due to customers not being able to commit at final close for an energy supply agreement which would not commence for more than three years
- There is a lack of liquid electricity contract markets beyond three years.
- The later years of some generation types is not in the range of 6–15 years. Pumped hydro may have a life of 50 or more years and support covering longer than 15 years should be considered.

Generation project proponents have also provided feedback from customers which would prefer to sign only 1–2 years and are only willing to go up to 3 years. Further, some smaller retailers are asset poor and while generation projects can sign supply agreements with these companies, debt providers do not consider these firm revenue streams for debt repayment.

<sup>24</sup> Delivering Affordable and Reliable Power, Prime Minister, Media Release 26 March 2019.

<sup>25</sup> ACCC, REPI, 2018 pg. 99



## Support mechanisms

- In relation to the possible support mechanisms provided under the program, stakeholder views have been mixed.

### Floor price:

- The ACCC's recommendation for the Australian Government to introduce a price floor received support during the consultation processes. Some industry players described the price floor mechanism as being the one that provided the best-fit with the problem identified by the ACCC, and noted some other options carried much greater risks.
- Some submissions also noted that a floor price, if set appropriately, would minimise Government exposure, and that some of the other mechanisms (such as CfDs) did not provide projects with the incentive to contract with customers after the initial contracting period. Against this, others noted that a floor price, if set inappropriately, could result in supported generation pushing out existing capacity, and that a floor price based on electricity dispatched would favour generators with high capacity factors.
- It was noted that a price floor was a mechanism that could be designed to act as a 'safety net', effectively remaining unused if the market is functioning adequately, and minimising any distortions in the market.

### Loans:

- The use of Government loans was supported by some stakeholders. They considered it would directly address the problem faced by new entrants in accessing private financing and would avoid complexity. It was noted, however that setting competitive rates for loans is challenging and that there is the risk that Government provides overly concessional loans.

### Collar contracts:

- Limited comments were received in relation to the possible use of cap and floor contracts through the consultation. Some who commented suggested that such a mechanism could achieve a similar outcome to a floor price mechanism, but with greater risk-sharing between the Government and the proponent, albeit at the cost of greater complexity,
- Others, however, considered that a cap and floor mechanism would leave Government subject to much greater risk than a simple price floor because the strike price of the floor under a collar arrangement would need to be higher, and that it would go beyond what is needed to address the problem identified.

### Contracts for difference:

- CfDs received limited support in consultations. A few parties argued CfDs should be the preferred mechanism, on the basis that they are a well know mechanism for bringing on investment and that the strike price is the key to managing taxpayer cost and risk.
- Against this, other submissions noted CfDs would completely delink supported projects from risk and the operation of the market. Moreover, they noted that using such a mechanism would not increase contract liquidity, and so result in lower prices, as large customers and retailers would not be able to contract with generators with CfDs, unless the Government onsold the CfD.

#### Capacity payments:

- While some respondents considered capacity payments would be the best way of bringing on new investment, many others noted that the introduction of capacity payments would represent a dramatic departure from the energy-only market, and noted the use of such payments would involve transferring significant financial cost to the taxpayer.
- Others noted that, while international experience showed that capacity payments could reduce 'headline' energy costs, they can lead to inefficient investment and higher costs overall.

#### Small grants:

- Grants were not raised as a support option in the October 2018 consultation paper.
- Consultation with stakeholders identified that some project proponents are struggling to gain approval for undertaking feasibility studies owing to the current investment environment for electricity projects.
- Further, some generation projects expressed their preferred mechanism as grants where support is needed for a specific purpose. For example, for a small upgrade (such as components of a generator) where a revenue floor would underwrite the entire generator not just the upgrade. This in turn would reduce the Government's liabilities.

## Preferred option

The Government has announced it supports the ACCC recommendation to underwrite new generation through the UNGI program. This option represents the greatest net benefit to address the objectives of the reform. The UNGI program, as outlined in the impact analysis section above, represents the least risk approach to increasing firm capacity in the system, reducing wholesale electricity prices by increasing competition and supply, and assisting C&I customers to access affordable energy supply arrangements.

The do nothing option involves the highest risk that the market will not address the shortfall in firm generation capacity in the short to medium term. If no new investment is made under the do nothing approach or investment is undertaken only by the large incumbents, there will be no increase in competition and as a result little downward pressure in the wholesale market price or opportunities for C&I customers to contract with new generation.

The option for Government funded new generation could help address the shortfall in firm generation capacity which could lead to improved reliability and reduced wholesale prices. Direct Government ownership could also ensure that generation from the new generators is contracted with C&I customers. However, there is a high risk that this option would not address competition concerns in the market as it may crowd out private investment, making it less likely there will be new competitors in the market.

In order to provide flexibility and to ensure that the objectives of the reform are achieved, the UNGI program will be a multi-phase program that will open to agreeing to support for projects over a four year period up until 30 June 2023. The phased approach provides the program with the flexibility to respond to emerging market trends or changed market dynamics and reduce the risk of unintended market distortion.

The program will also undertake a flexible approach to supporting new generation, including price floors, revenue floors, small grants and government loans. For each phase of the program appropriate support mechanisms will be determined and a detailed assessment process will be undertaken to select the appropriate mechanism and level of support for each project to minimise risk to the taxpayer.

While the other mechanisms identified might also meet some objectives of the reform, they involve greater risks to the Government and the market. All identified mechanisms carry less risk than a do nothing or direct Government ownership approach as identified in section 4 of this RIS. Ongoing analysis will be used to assess the effectiveness of support provided, and determine if changed market dynamics mean an alternative support mechanism could result in lower-cost achievement of the program objectives.

Only Option 3 has any impact from a regulatory burden perspective. The estimated cost of \$573,235 per annum over 10 years is considered minimal in comparison to the expected benefits of the program, including enhanced competition. To constrain the burden, where possible, the Government should use standard project development reports, for example the legal and technical due diligence reports required by commercial banks, as part of the assessment process.

## Implementation and evaluation

The Underwriting New Generation Investments program will be a multi-phase program that will be open to agreeing to support for projects until 30 June 2023. As discussed in section 6 of this RIS, the program will take a flexible approach to supporting new generation, starting with the price floor, grants and government loans. In later phases of the program, other mechanisms may be made available dependent on further work occurring in developing those options and the needs of project proponents.

The program's objectives are to:

- reduce wholesale electricity prices by increasing competition and supply;
- assist commercial and industrial customers and small retailers access affordable energy; and
- improve reliability by increasing the level of firm capacity in the system.

Any program that seeks to deliver additional capacity creates risks for the market. Government intervention that is not tightly targeted risks drying up private investment, oversupplying the market and/or not providing any additionality. As such the program should:

- Be time bound. The program must have a clear end date. Consistent with the ACCC recommendation the program will be open over four years.
- Limit the level of assistance provided to what is necessary to meet the objectives of the program.
- Ensure the amount of additional capacity supported is appropriate to market conditions. The amount should take account of capacity gaps in the market, based on the best evidence available at the time decisions are made on preferred projects.
- Address the needs of customers. A pre-requisite of projects receiving Government support will be that they have in-principle support from large customers, either C&I or retailers.

- Ensure the generation supported is appropriate to changing market conditions. The projects supported by the program will be capable of providing firm generation to the market.

By adopting these parameters, the program will effectively target the objectives of the reform, while mitigating the risks that it will have a distortionary effect on the electricity market and the investment environment.

The implementation process commenced with the Registration of Interest (ROI) as explained in section 5 of this document. The ROI process was used to gain an understanding of the potential projects in the market, and to inform the design of the program and program guidelines, including the eligibility and selection criteria.

Ahead of project proponents submitting documentation against the eligibility criteria a screening process is planned to ensure the:

- Project is sufficiently advanced to be considering project financing
- Project revenue models are strong
- Project is technically feasible
- Project proponents and project partners are of sufficient reputational standing to have dealings with the Commonwealth
- Project proponents have been engaging or have a plan to engage in good faith with the local community
- Project proponents have pursued all other options available for Government support, including through ARENA.

To be eligible for support, projects proponents will have to demonstrate that the project will:

- Deliver firm new generation capacity of at least 30MW by 2025 for new projects or 15MW of additional generation capacity for upgrades or augmentation projects. Storage projects must be capable of delivering the required additional capacity for a period of no less than four (4) hours. Capacity is defined as the maximum power output (AC) that the system will produce, as measured at the metered point of connection to the interconnected network.

- Require Government support.
- Take place within an interconnected network within Australia.

To be eligible for support, a proponent must meet the following:

- Be a corporation to which section 51(xx) of the Constitution applies. Foreign investors can apply to the extent they meet the criteria, subject to normal Foreign Investment Review Board approval that must be obtained prior to lodging an application for support under the program.
- Neither as an individual company or in aggregate with all related bodies corporate as defined in the *Corporations Act 2001 (Cth)* (the Group), currently hold a generation capacity market share of 10% or more across the project location in the NEM, or 20% or more in the interconnected system as a whole.
- No Group entity has any outstanding amounts payable in relation to a judicial decision relating to employee entitlements made against it.
- Not named as an organisation that has not complied with the *Workplace Gender Equality Act 2012 (Cth)*.
- No Group entity is named as a person or entity designated as terrorists. The list and more information on the anti-terrorism requirements are available at [dfat.gov.au/icat/UNSC\\_financial\\_sanctions.html](https://dfat.gov.au/icat/UNSC_financial_sanctions.html)
- At the eligibility stage proponents should also be required to disclose any legal proceedings or investigation, or other material claims, including litigation, arbitration, mediation or conciliation that to the best of your knowledge, after having made proper enquiry are taking place, pending or threatened against any Group entity.

Once a proposal has been assessed to have satisfied the eligibility criteria, the project will be invited to submit evidence to support claims against the selection criteria.

To be successful, the project must be viable (Selection Criterion A), the proponent must have

the capacity, capability and resources to undertake the project (Selection Criterion B) and the project must contribute to one or more of the program objectives (Selection Criterion C).

The program will be run in phases. These may include ad-hoc work with proponents on individual projects as well as formal Requests for Proposals (RFPs). These processes will seek detailed proposals for projects to be considered for support under the program.

There will be multiple phases of the program. Each phase of the program will be determined by the identified future generation needs of the market, the requirements of individual project proponents and the needs of C&I customers.

The amount of support available under each phase of the program will be capped. This will include caps on both the amount of financial support/government liability available, and the amount of generation capacity that will be supported. These thresholds are yet to be determined. Upper limits will not be published in order to maintain competitive pressure under the program. The minimum eligible project size is anticipated to be 30 MW for new generation projects and 15MW for upgrades to existing generation.

Over its life, the program may offer support through a range of mechanisms including floor price contracts, revenue floors, cap and floor (collar) contracts, contracts for difference, underwriting of cap contracts, loans and grants. The range of support mechanisms available in each phase will be specified at the commencement of that phase. The support mechanisms available during the first phase of the program are anticipated to be limited to those that the government can implement quickly, such as a floor price, grants and loans. Other mechanisms not made available in phase one may be made available under subsequent phases after engagement with project proponents. These will be developed in parallel with the implementation of Phase One so they may be available in subsequent phases.

The program will be evaluated monitored during each phase of the program. The real time monitoring will provide further information for the design of future phases of the program and will include:

- identifying future generation capacity requirements over a ten-year period, considering generation incentivised by the program;
- undertaking a qualitative impact on the availability and price of contracts available to large C&I businesses; and
- undertaking an analysis of the impact of the program on relevant electricity systems and the investment environment for new generation.

In 2022, prior to the end of the four-year period, the program will be evaluated for its effectiveness and ongoing need and there will be a full evaluation at the end of the program.

# Regulatory burden

The preferred option has regulatory costs of \$573,235 per annum over 10 years.

## Task: Developing a project proposal

Consistent with investment in new generation projects, and the intention of this program, we assume proponents develop their projects primarily with a view to attracting private finance.

The UNGI program provides an additional avenue for financial support that proponents may seek to access. Participation in the program is likely to marginally increase proponents' costs, but the majority of costs associated with developing a project are business as usual and are unrelated to the program. In this context, an estimate of the regulatory burden of the program must focus on the marginal increase in costs due to participation in the program.

It is assumed that a project proponent will devote three people working for nine weeks to developing their proposal. This equates to 1,012.5 FTE hours per project proposal, assuming an FTE working week of 37.5 hours.

It is assumed that the hourly rate will be the Government approved labour rate of \$68.79 per hour.

Proponents are also assumed to spend around \$100,000 on consultants to assist with the proposal.

Over the four years of the program it is anticipated that the Government will run four RFP processes, one each year.

The recent Registration of Interest (ROI) process received 66 submissions but it is unlikely that all projects that have responded to the ROI will submit a proposal in the initial phase of the

program, as many are not sufficiently developed. We expect that the number of projects will be spread out over the course of the program, with limited new projects in later rounds given the time taken to develop a project to an advanced stage. It is also anticipated that some projects may apply to any RFP processes more than once. On this basis, it is assumed that there will be a maximum of 30 unique project proposals submitted over the four years the program is open to new support agreement. The minimum likely duration for any agreement is likely to 10 years, so the regulatory costs have been averaged against this time period.

The calculation for the annual regulatory burden of this task is:

$$[(\text{Time on proposal (1012.5 hrs)} \times \text{hourly rate (\$68.79)}) + \text{consultant fees \$100 000}] \times \text{submissions (30)}$$

*Divided by number of years of the program (10)*

On this basis, the annual regulatory burden for developing project proposals is \$508,950.

## Task: Complying with the program in the development phase

Successful applicants to the program will be required to provide regular reports back to the Government on progress towards the generation becoming operational. Reporting will focus on whether the project is meeting its milestones on being completed on time and assurances regarding the financing of the project. It is anticipated that a project will be required to report back to Government every quarter on the development of the process.

The number of projects that are successful at each phase of the program will be dependent on the reliability needs of the system at the time and the quality of project. For example, it may be that under some phase of the process four projects are chosen to progress and in others no projects meet the criteria. As such, over the phases it is assumed that a total of eight projects will be chosen.

It is assumed that a project proponent will devote one person working for two days on providing a compliance report to Government. This equates to eight days per project per year.

It is assumed that the hourly rate will be the Government approved labour rate of \$68.79 per hour.

The time between a project being approved under the UNGI program and being operational will differ depending on the type of technology and a stage of development it is at when it is approved. Some renewable projects can take under two years to be built, while a coal-fired power station can take up to seven years. It is assumed that, on average, each project will be in the development phase for four years. This equates to 32 days or 240 hours for each project, assuming an FTE working day of 7.5 hours.

The calculation for the annual regulatory burden of this task is:

$$\text{Time taken to undertake compliance reports (240 hours) } \times \text{ hourly rate } (\$68.79) \times \text{ number of projects (8)}$$

$$\text{Divided by number of years of the program (10)}$$

The annual regulatory burden for complying with the program during development is \$13,208.

## Task: Complying with the program in the operational phase

Some mechanisms that will be used under the UNGI program will require the program to regularly report back to Government for the mechanism to be effective.

Complying with the financial mechanism will be different depending on which mechanism is used. A Government loan should not provide any additional costs to a business than would occur under a business as usual approach.

A grant will require reporting according to the terms and conditions set out in the funding agreement, likely on a quarterly basis. This reporting could entail information on development applications, approvals, and information on whether the project is tracking to the intended timeline. At the end of the project there will be a final report (a more detailed and overarching report to determine that program objectives have been met). We assume the quarterly reports will be covered in the above task (complying with the program in the development phase), but the final report will take up to an additional three working days.

Under a price floor approach there may need to be at least monthly reporting to determine what, if any, money is to be paid to the project proponent. Even if the mechanism were not to be triggered there would need to be reporting on an at least annual basis that the requisite contracts with C&I customers and/or small retailers are in place.

We assume that the Government's commitment to the projects will be over a ten-year period, on average. However, it may be that the Government's commitment is for a shorter or longer time frame.

To be conservative we will assume that the project will be required to report to Government on a monthly basis under a floor price agreement. The needs for compliance will require one day of work every month. This will equate to 12 days of work per year over 10 years or 900 hours over the compliance period, assuming an FTE working day of 7.5 hours.

It is assumed that the hourly rate will be the Government approved labour rate of \$68.79 per hour.

The number of projects that are successful at each phase of the program will be dependent on the reliability needs of the system at the time and the quality of project put forward through the RFP. For example, it may be that under some phase of the process 4 projects are chosen to progress and in others no projects meet the criteria. As such, over the four phases it is assumed that a total of 8 new generation projects will be chosen (two per year), plus one efficiency upgrade. We assume that the new generation projects will be supported by a floor price, while an upgrade will be supported by a grant.

The calculation for the annual regulatory burden for the floor price projects is:

*Time taken to undertake compliance reports (900 hours) x hourly rate (\$68.79) x number of projects (8)*

*Divided by number of years of the program (10)*

*= \$49,529*

And for a grant:

*Time taken to produce final report (22.5 hours) x hourly rate (\$68.79)*

*= \$1,548*

The annual regulatory burden for complying with the program during operation is \$51,077.