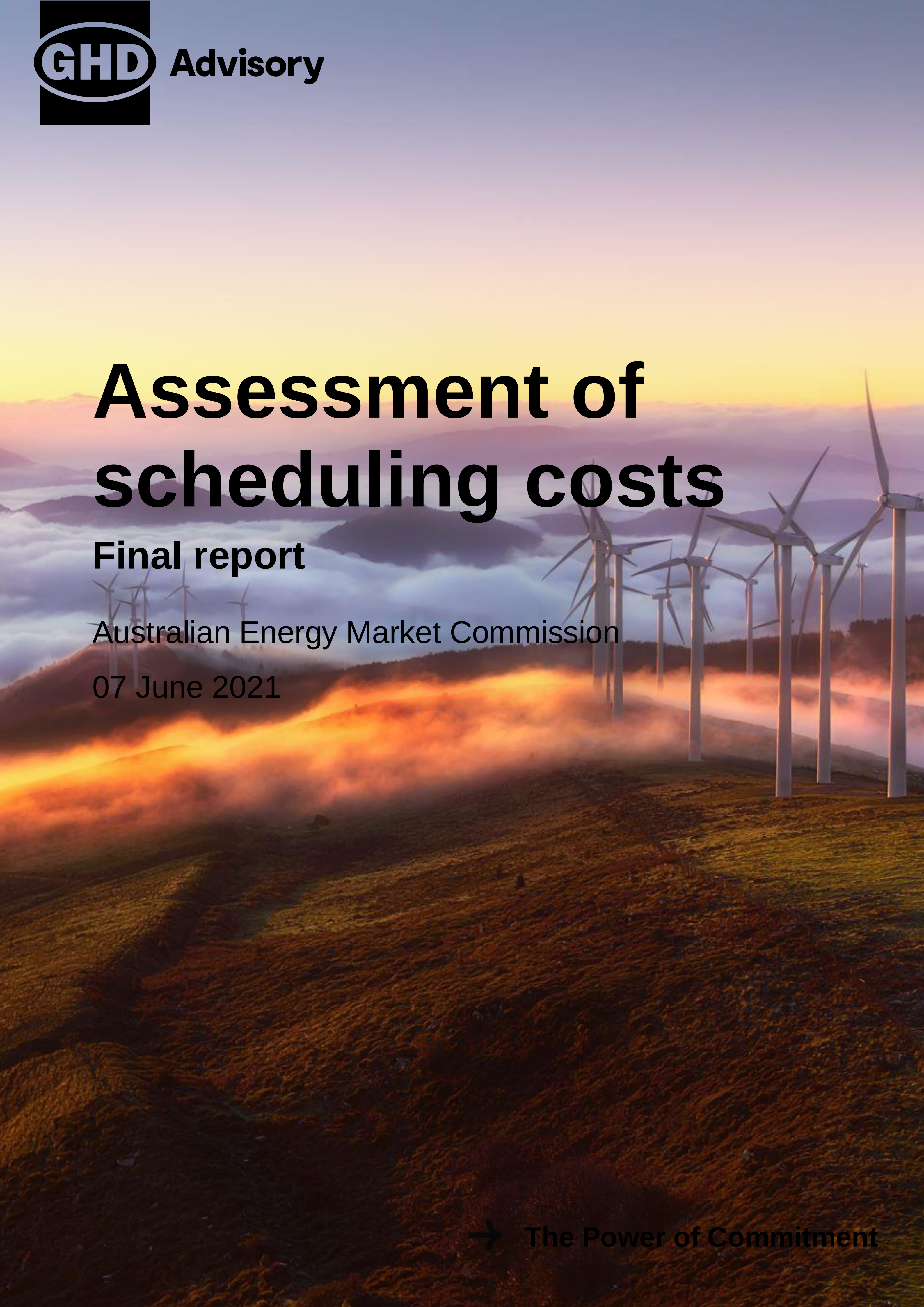

GHD Advisory

Assessment of scheduling costs

Final report

Australian Energy Market Commission

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The Power of Commitment

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Executive summary

The AEMC is assessing a rule change request from the Australian Energy Council (AEC) that seeks to increase the participation of smaller generators in central dispatch ('Generator registrations and connections rule change'[1]).

The AEC's rule change indicated that the costs of participating in central dispatch for these smaller generating units are unlikely to be appreciable, particularly as technology and communication costs continue to reduce[2].

To address the AEC's claim regarding costs to small generators and assist them in making a Rule determination, the AEMC engaged GHD Advisory and HARD software (referred to as GHD) to provide an independent assessment of the costs of registration and market participation by smaller generators.

Purpose of report

The purpose of this report is to inform the AEMC's determination on the 'Generator registrations and connections rule change'. Our report outlines the additional costs that would be incurred by small generators if they were required to participate in central dispatch as semi-scheduled or scheduled generator rather than being classified as a non-scheduled generator.

We do not provide a complete picture of the costs that would be incurred by small generators. However, we have provided commentary in some places about costs that are incurred regardless of the generator's classification.

The costs presented are estimates only and intended to inform policy outcomes. The costs presented do not represent a quote. Actual prices, costs and other variables may be different from those outlined in this report. Unless as otherwise specified in this report, no detailed quotation has been obtained for actions identified in this report.

This report is subject to, and must be read in conjunction with, the limitations set out in section 1.3 and the assumptions and qualifications contained throughout the Report.

Summary of cost changes

The total increase in **upfront project costs** for connecting and registering a scheduled plant compared to a non-scheduled plant is between $1.3 million and $1.8 million (for the same 5-30 MW plant). This can be compared with broad variations in total project cost for VRE plant in this capacity between $15 million to $100 million, depending on generation technology, manufacturer and Engineering Procurement and Commissioning (EPC) choice, location, complexity, and the size of the project. The below table gives a summary of upfront costs, noting that some items change from the low end of the scale to the high end when scheduling status changes. Further breakdown is provided in the report that shows more details of all costs.

Table 1 Summary of upfront costs

Upfront Cost	$ (Low)	$ (High)	Non-Scheduled	Semi-Scheduled	Scheduled
Generator connection	Same across all categories		✓	✓	✓
NSP connection agreement	$250,000	$400,000	✓	✓	✓
AEMO registration and Connection	$275,000	$536,000	✓	✓	✓
SCADA basic ^	$700,000	$1,000,000	✓	X	X
SCADA advanced ^ (PFR/droop controller,	$2,000,000	$2,500,000	X	✓	✓

[1] Refer to: https://www.aemc.gov.au/rule-changes/generator-registrations-and-connections
[2] AEC, *Generator Registration Thresholds Rule Change Request*, December 2018, p. 4. Available at: https://www.aemc.gov.au/sites/default/files/2020-10/Rule%20change%20request%20-%20AEC.PDF

Upfront Cost	$ (Low)	$ (High)	Non-Scheduled	Semi-Scheduled	Scheduled
ramping, multiple complex interface)					
Generation management system	$90,000	$340,000	X	✓	✓
Forecasting	$5,000	$30,000	X	✓	✓
Metering and metering provider	Same across all categories		✓	✓	✓
Contract management system and settlements	Same across all categories		✓	✓	✓

^ SCADA Basic and advanced is not an industry term and further explanation is provided on each term in section 3.4

✓ = Cost applicable, X = Cost not applicable

The estimated increase in upfront costs assumes the registration arrangements are known at project inception. Where projects are completed, and registration arrangements need to be varied and rework is required (including additional hardware or SCADA capabilities) these costs can be expected to be significantly higher.

Once a generator has been registered, commissioned, and placed in service there are **annual ongoing costs** applicable and range from $150,00 to $555,000 per annum. These costs include:

Table 2 Summary of ongoing costs (annual)

Ongoing Cost	$ (Low)	$ (High)	Non-Scheduled	Semi-Scheduled	Scheduled
Operational support 24/7	$100,000	$180,000	×	✓	✓
Ongoing system costs	$50,000	$150,000	×	✓	✓
NER obligations	$0	$200,000	×	✓	✓
AEMO Fees	Same across all categories		✓	✓	✓
Self-forecasting (optional)	$12,000	$25,000	×	✓	×

✓ = Cost applicable, X = Cost not applicable

Further financial expenditure due to becoming semi-scheduled (compared to non-scheduled) are **annual ongoing indirect costs** associated with being dispatched (and the continuing effect of these obligations on the generator's revenue). These costs are extremely variable and unique to individual projects and their location. Where estimates are provided in the table below, these are based on a selection of generators' experiences over the last financial year. It is highly uncertain as to whether these costs will materialise for any one project. However, we note curtailment costs are a growing area of concern amongst generators when it comes to evaluating their business case.

Table 3 Summary of ongoing indirect costs (annual)

Indirect Cost	$ (Low)	$ (High)	Non-Scheduled	Semi-Scheduled	Scheduled
Constrain/curtailment	$0	$1.5 million	×	✓	✓
Providing primary frequency response			×	✓	✓
Causer pays for regulation FCAS			×	✓	✓
AEMO fees increase associated with rule change	Same across all		✓	✓	✓

✓ = Cost applicable, X = Cost not applicable

From an individual participant perspective, the above indirect costs represent a significant change to the business case for new generators should the Rule change proceed. Noting the costs are incurred by the market and distributed amongst the generators that participate in dispatch.

Other potential costs relate to the individual circumstances of a project, its funding arrangements and the timing for commencement of any Rule change should it proceed. If affected, projects in progress will not have accounted for the requirement to participate in dispatch and this will affect the profitability of the project's business case. In particular, extensions to project durations driven by a need to meet increased requirements or revisit commercial agreements are likely to negatively affect new small generator connections.

Future changes

Looking back over the full period the National Electricity Market (NEM) has been in existence there have been significant decreases in the IT system, interfacing and communication costs for newly registering generator, particularly as standardised and generic products, software and TCP/IP communications became available and were more widely adopted. However, many of the real cost reductions have already been realised and in recent years the trend has been for increased specification and performance rather than changed costs.

Although trials are underway by AEMO and other parties to explore alternative arrangements that provide flexibility and options for interfacing and the transfer of data, there is no firm evidence to support a hypothesis that these costs will reduce for generators in the future. In our opinion, and from our experience providing, delivering and selling IT hardware, software and communication services over 20 years, we expect the costs associated with IT systems, interfacing and communication are likely to remain constant or increase regardless of these developments. The increasing sophistication of systems and increased requirements are likely to drive increases in costs that outweigh any gains from efficiencies associated with a broader range of options and different technology being made available. At least for the foreseeable future.

The trend identified in the market and supported through stakeholder engagement is to build a generator either below 5MW or go as large (>30MW) as feasibly possible. The connection process with AEMO and NSP is largely the same for generators >5MW and therefore the costs are similar. The cost for a connection agreement is substantial, which means a generator will try and connect the largest generator possible to offset this large upfront cost.

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1. Introduction

The AEMC is assessing a rule change request from the Australian Energy Council (AEC) that seeks to increase the participation of smaller generators in central dispatch (‘Generator registrations and connections rule change’[3]).

The AEC proposes to reduce the threshold for classifying generators as non-scheduled from 30 MW nameplate capacity to 5 MW. Doing this would make the default classifications for generators above 5 MW scheduled or semi-scheduled and narrow the grounds upon which generators can be exempt from scheduling obligations. The AEC considers this would improve the management of the power system and the efficient operation of the market.

Non-scheduled generators do not submit offers to signal market intentions, do not receive and respond to dispatch instructions, and are free to operate their generating units at any desired level under normal circumstances.

The rule change currently before the AEMC is very similar to the 2017 ‘Non-scheduled generation and load in central dispatch’ rule change[4]. The 2017 rule change considered an amendment to the NER to require the following load and generation to participate in the central dispatch process:

– loads above 30 MW that are or intend to be price responsive, and
– non-scheduled non-intermittent generating units above 5 MW nameplate rating.

In their 2017 final determination, the AEMC did not make a rule to reduce the threshold for participation in the central dispatch process for non-scheduled and non-intermittent generating units. Among other things, the AEMC’s analysis indicated that requiring non-scheduled generators (and loads) to be semi-scheduled, would place considerable costs and obligations on parties that were not justified by the limited benefits that may accrue. However, stakeholder estimates varied significantly on the potential magnitude of the costs.

In the AEC’s most recent rule change request, they indicated the cost to a smaller generating unit to install a generation control system is unlikely to be appreciable, particularly as technology and communication costs continue to reduce[5].

To address the AEC’s claim regarding costs to small generators and assist them in making a Rule determination, the AEMC engaged GHD Advisory and HARD software (referred to as GHD) to provide an independent assessment of the costs of registration and market participation by smaller generators.

1.1 Purpose of this report

The purpose of this report is to inform the AEMC’s determination on the ‘Generator registrations and connections rule change’.

In our report, we outline the additional costs that would be incurred by small generators if they were required to participate in central dispatch as semi-scheduled or scheduled generators rather than being classified as non-scheduled generator.

We have not provided a complete picture of the costs that would be incurred by small generators. However, we have provided commentary about some costs that are incurred regardless of the generator’s classification.

The costs presented are estimates only and intended to inform policy outcomes. The costs presented do not represent a quote. Actual prices, costs and other variables may be different from those outlined in this report. Unless otherwise specified in this report, no detailed quotation has been obtained for actions identified in this report.

[3] Refer to: https://www.aemc.gov.au/rule-changes/generator-registrations-and-connections
[4] Refer to: https://www.aemc.gov.au/rule-changes/non-scheduled-generation-in-central-dispatch
[5] AEC, *Generator Registration Thresholds Rule Change Request*, December 2018, p. 4. Available at: https://www.aemc.gov.au/sites/default/files/2020-10/Rule%20change%20request%20-%20AEC.PDF

1.2 Terminology used in this report

In this report, we use the following terminology, which is broadly consistent with the NER[6]:

- **Non-market** – All electricity produced by the Generator is sold to a Market Participant who is financially responsible for the generating unit's connection point.
- **Market** – All electricity produced by the Generator is sold through the spot market at the applicable spot prices.
- **Non-scheduled** – A generator that does not participate in central dispatch. Currently, these are generating units with a nameplate rating of less than 30 MW (not being part of a group of generating units described in clause 2.2.2(a) of the NER).
- **Semi-scheduled** – A generator that participates in central dispatch in specified circumstances, including receiving and responding to dispatch instructions and have an intermittent output. Currently, these are generating units that have a nameplate rating of 30 MW or greater or are part of a group of generating units connected at a common connection point with a combined nameplate rating of 30 MW or greater.
- **Scheduled** – A generator that participates in central dispatch and does not have an intermittent output. Currently, these are generating units that have a nameplate rating of 30 MW or greater or are part of a group of generating units connected at a common connection point with a combined nameplate rating of 30 MW or greater.
- **Small generator** - Unless otherwise specified, small generators refer to generators with a capacity of 5 MW to 30 MW (i.e., those likely to be affected by the Rule change before the AEMC).

A list of acronyms and abbreviations used in this report is provided in Appendix A.

1.3 Limitations

This report has been prepared by GHD for AEMC and may only be used and relied on by AEMC for the purpose agreed between GHD and AEMC as set out in section 1.1 of this report. GHD otherwise disclaims responsibility to any person other than AEMC arising in connection with this report. GHD also excludes implied warranties and conditions, to the extent legally permissible.

The services undertaken by GHD in connection with preparing this report were limited to those specifically detailed in the report and are subject to the scope limitations set out in the report.

The opinions, conclusions and any recommendations in this report are based on conditions encountered and information reviewed at the date of preparation of the report. GHD has no responsibility or obligation to update this report to account for events or changes occurring after the date that the report was prepared.

GHD has prepared this report based on information provided by AEMC and others who provided information to GHD (including Government authorities), which GHD has not independently verified or checked beyond the agreed scope of work. GHD does not accept liability in connection with such unverified information, including errors and omissions in the report which were caused by errors or omissions in that information.

[6] Terminology as defined in: https://www.aemc.gov.au/sites/default/files/content//NER-v71-Chapter-02.PDF

2. Scope of costs considered

Our report outlines the additional costs that would be incurred by small generators (5 MW to 30 MW) if they were required to participate in central dispatch and no longer be classified as a non-scheduled generator.

This section sets out the scope of generators that have been considered in developing cost estimates in the report. We also outline several excluded costs and assumptions that should be considered when interpreting the numbers presented in this report.

As outlined in section 1.1 of this report, we do not provide a complete picture of the costs that would be incurred by small generators. The information in this report is intended to inform the AEMC's determination on the AEC's rule change request only.

2.1 New market generators only

In developing this advice, we have considered costs from the point of view of a new market entrant that is a market participant and is considering being either non-scheduled or scheduled. We have **not** considered the costs likely to arise if:

– the rule change was to apply to existing generators.

– the rule change was to apply to non-market generators.

AEC's proposed their rule change apply to new generators at the time of their registration only. For existing plant registered inconsistently with the provisions set out in the Rule change, AEMO's existing practice of grandfathering following changes to registration rules would apply.[7]

Consistent with the AEC's rule change request, we have considered costs for **new market entrants only**. Modifying legacy systems of existing non-scheduled and exempted generators will largely depend on the age and type of generator controller, and existing SCADA and communications systems. Whereas for a small new generator, connecting a basic controller and SCADA system can be selected, allowing them to have a cheaper control scheme capable of running the generator without the option of complex control functions to meet semi-scheduled and scheduled requirements.

Non-scheduled and scheduled generators can choose whether they participate in the market. Our focus is on markert generators that will be affected by this rule change as these comprise the majority of new potentially non-schedule generators. As such the non-market generator category is not considered for cost itemisation purposes.

2.2 Excluded costs

We focus on costs that directly affect generators' participation in dispatch (as a scheduled generator). The following costs are not covered in our report:

– **The cost associated with the provision of ancillary services.** Ancillary service provision by generators is optional. As such, these costs may not be incurred by generators even if they are required to be scheduled. We note these costs will vary depending on the selected participation and the type of plant.

– **Indirect non-market system costs** include costs like the upgrade of a connected enterprise asset management system, risk/portfolio management, or financial system. These costs will vary widely between participants and it is difficult to disaggregate which of these costs is attributable to the scheduling component.

2.3 Applicability of rule change to small generators

Not all generators in the 5 MW to 30 MW category meet the requirements of being non-scheduled. Clause 2.2.3(b) of the NER limits the eligibility for small generators to be non-scheduled. Further, AEMO has powers under clause

[7] AEC, *Generator Registration Thresholds Rule Change Request*, December 2018, p. 4. Available at: https://www.aemc.gov.au/sites/default/files/2020-10/Rule%20change%20request%20-%20AEC.PDF

3.8.2(e) of the NER to require a generator, at any time, to participate in central dispatch where it is necessary for adequate system operation and the maintenance of power system security. Each clause is discussed in turn.

2.3.1 Limited eligibility to be non-scheduled

Clause 2.2.3(a & b) of the NER limits the eligibility of generators to be non-scheduled. This clause states:

> (a) A generating unit with a nameplate rating of less than 30 MW (not being part of a group of generating units described in clause 2.2.2(a) of the NER) must be classified as a non-scheduled generating unit unless AEMO approves its classification as: (1) a scheduled generating unit under clause 2.2.2(b); or (2) a semi-scheduled generating unit under clause 2.2.7(b) (of the NER)
>
> (b) A person must not classify a *generating unit* as a *non-scheduled generating unit* unless the person has obtained the approval of AEMO to do so. AEMO must approve the classification if it is satisfied that:
>
> (1) the primary purpose for which the relevant generating unit operates is local use and the aggregate *sent out generation* at its *connection point* rarely, if ever, exceeds 30 MW; or
>
> (2) the physical and technical attributes of the relevant *generating unit* are such that it is not practicable for it to participate in *central dispatch*.

In practice, this clause means that dispatchable generators above 30 MW (other than fuel limited generating systems such as at sugar mills and those supplying local load) are unlikely to meet the requirements to be classified as a non-scheduled generating unit.[8]

2.3.2 AEMO has power to require generators to be scheduled

At the time of registering a non-scheduled generator, AEMO has the power, under clause 2.2.3(c) of the NER, to make the generator comply with obligations of a scheduled or semi-scheduled generator for any reason if it deems necessary.[9]

AEMO can exercise its power at any time following registration under clause 3.8.2(e), requiring a non-scheduled generator to undertake central dispatch obligations to the extent and in the capacity specified by AEMO if AEMO considers it reasonably necessary for adequate system operation and the maintenance of power system security.[10]

In recent times, several non-scheduled generators have been issued with requests by AEMO under clause 3.8.2(e) of the NER. Further, we note the AEMC has previously guided this clause, stating it ‘provides AEMO with a reasonably flexible way of dealing with issues that may compromise system operation and security.’[11]

2.4 Factors driving cost differences

In developing this report, we have considered the factors that drive cost differences and whether these are related to a generator becoming scheduled. The following factors are key drivers of overall costs differences for generation projects, but **do not** drive material cost differences when considering non-scheduled compared to scheduled arrangements, particularly at the 5 MW to 30 MW range:

– MW size of the generator

– Location of the site

[8] Refer to https://aemo.com.au/-/media/files/electricity/nem/participant_information/new-participants/generator-exemption-and-classification-guide.pdf?la=en for further explanation on exemptions.

[9] 2.2.3(c) of the NER states: “If, in relation to an application under paragraph (b), in AEMO's opinion it is necessary for any reason (including power system security) for the relevant Generator to comply with some of the obligations of a Scheduled Generator or Semi-Scheduled Generator for that generating unit, AEMO may approve the classification on such terms and conditions as AEMO considers reasonably necessary.

[10] 3.8.2(e) of the NER states: If *AEMO* considers it reasonably necessary for adequate system operation and the maintenance of *power system security*, *Registered Participants* who may otherwise be exempted from participating in the *central dispatch* process must do so to the extent and in the capacity specified by *AEMO.”* This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations.

[11] AEMC, Non-scheduled generation and load in central dispatch, Rule Determination, 12 September 2017, p. 49. Available here: https://www.aemc.gov.au/sites/default/files/content/0bcaf68c-8449-4ce0-aaa6-da223ca6e01c/Final-Determination-ERC0203-Non-scheduled-generation-and-load.pdf

– Manufacturer and engineering, procurement, and construction (EPC) contractor choice
– Connection arrangements, including the site location concerning the existing network, the capacity of the existing network at the connection point, and distribution versus transmission voltage levels
– Funding arrangements.

2.4.1 Portfolio versus standalone

Preferences around generator management systems and SCADA arrangements may differ depending on whether the generator is a standalone development or is forming or will form part of a larger portfolio of power assets.

Where participants operate or plan to operate a portfolio of power assets the level of system sophistication desired may be higher than would otherwise be the case. In particular, a desire for portfolio management, trading and monitoring capabilities will be higher.

While increased sophistication typically means higher costs (including on a per MW basis), the increased costs may be offset by benefits from economies of scale across achieved by the participant. Economies of scale may include reusing existing MarketNet connectivity arrangements, leveraging relationships with vendors for preferential pricing for technology products.

2.4.2 Passive versus active market participation

Generators may choose to undertake very passive participation in the market, operating largely as a price taker and not often varying their energy offer to the market. On the other end of the scale, generators may choose to take very active participation in the market, utilising either a trading function resourced by skilled traders, sophisticated and powerful system driven automatic trading or a combination of both, where the generators bidding strategy and market conditions are reviewed each interval and the generation market offer regularly varied.

Typically, the decision for market participation by a small generator is driven by the specific obligations imposed by secured power purchase agreements (PPAs), organisational appetite for merchant risk, availability of skilled trading resources, and access to established systems for trading/bidding.

2.4.3 Economies of scale & the future of small generation

Through stakeholder engagement, a common theme has been expressed regarding the cost of connecting small versus large generators. The way the connection agreement and registration process have been set up, the costs to connect and register a 5 to 30 MW generator is similar to connecting generators 30 MW and above (excluding the plant requirements). The actual cost for the network studies, NSP negotiations, AEMO's involvement, the control schemes and most of the SCADA requirements are similar. It takes the same control scheme and Power Park Controller (PPC) to manage a small generator as it does for a large site.

Most of the SCADA and connection agreement costs are comparable for large versus smaller generators, making it more economical to build a larger generator than a smaller generator. Some smaller generators at the lower end of the 5 to 30 MW range can opt to install a less advanced control scheme. This choice to install a basic control scheme is driven more by cost constraints on a smaller revenue returning generator at the lower end of the 5-30 MW range and not driven by the non-scheduled, semi-scheduled or scheduled status

3. Upfront participant costs

The substantial direct, upfront costs involved in connecting and registering a market generator in the NEM include:

– NSP connection agreement (NSP costs passed through to the generator)
– Registration and connection costs (AEMO costs passed through to the generator)
– SCADA
– Generation management system
– Metering and metering provider
– Contract management & settlements
– Forecasting

The following sections describe each item and indicate whether and how the cost is relevant for each category of a generator. The additional costs that would be incurred by generators if they are required to be semi-scheduled or scheduled are identified.

3.1 Generator connections cost

Generator grid connection costs are unique for each project and do not vary based on the scheduling requirements or generator registration category. As such we have not provided a total estimate of these costs. However, discrete items that are well defined and have the potential to vary with scheduling arrangements are identified as appropriate in the subsequent sections.

3.2 NSP connection agreement costs

A connection agreement is initiated when the generator submits a connection inquiry to the relevant NSP. This will then start the negotiations between the proponent and the NSP. If the proponent wishes to proceed, they will submit a connection application to the NSP. This is the same process for non-scheduled, semi-scheduled and scheduled Generators. Through the connection application, the NSP will work with the proponent to model the connection and perform steady-state and dynamic studies to determine the impact the Generator will have on the network. These studies are performed by the proponent and submitted to the NSP, who will then conduct due diligence on the studies and accompanying report.

The outcome of the connection application is a connection agreement that outlines the agreed Generator Performance Standards (GPS) and the approved scope of works required to connect the Generator. If a generator has been exempted from registration with AEMO, the negotiations are between the NSP and the proponent only. However, if a Generator is not exempt from registration and is non-scheduled, semi-scheduled or scheduled it will require input from AEMO regarding the connection. AEMO will also review the preliminary impact assessment results and determine if any remediation works are required. They will also review the network studies that demonstrate that the generator meets the proposed GPS.

For complex exempt connections, the NSP will consult with AEMO regarding the connection. AEMO will perform a Preliminary Impact Assessment (PIA) that will determine if any remediation works will be required as part of the connection.

A typical connection agreement with an NSP can cost from $250,00 to $400,000 for the NSP portion. This does not include AEMO's costs and is standard for non-scheduled, semi scheduled and scheduled generators. All AEMO's incurred costs are passed through to the proponent via the NSP as a separate charge to the connection agreement.

Table 4 NSP connection agreement costs

Item	$ (Low)	$ (High)	Non-Scheduled	Semi-scheduled	Scheduled
Connection agreement (NSP costs)	$250,000	$400,000	✓	✓	✓

3.3 AEMO registration and connection costs

To participate in the NEM a generator is required to register with AEMO. Through the registration process, AEMO assesses the application to determine the operational and system readiness of the generator.

They will need to demonstrate they can meet all the obligations set out in the NER. Generators can apply to register as non-scheduled, semi- scheduled or scheduled and this relates to the extent to which the Generators participate in central dispatch.

– Non-scheduled – The generator does not participate in central dispatch.
– Semi-scheduled – The generator participates in central dispatch under specified circumstances.
– Scheduled – The generator participates in central dispatch.

The type of registration the Generator is seeking will determine the connection process, requirements and costs. The typical types of fees will be outlined below with a description of when they are relevant.

The typical fees involved in registration with AEMO include the time and expenses for the following:

– Registration/Application fee
– Grid connection and modelling team
– Congestion and grid modelling team
– Forecasting team
– Commissioning activities

The majority of these costs are relevant for all registered generators regardless of the scheduling arrangements. We outlined each of these fees and when they apply below.

3.3.1 Registration / application fee

AEMO charges a standard registration or application fee to generators to register with AEMO. The registration fee is dependent on the classification you wish to register under.

The registration team assesses the registration application and coordinates with other AEMO teams to determine if the information provided is complete and assessed as suitable for approval. The AEMO registration process usually occurs towards the end of the connection process as many items need to be supplied by the generator to support their application. Supporting documents include evidence that the applicant has executed a connection agreement with the relevant NSP.

For semi-scheduled generators, a portion of the registration fee is for AEMO to review the generator's Energy Conversion Model (ECM) and ensure it meets the requirements set out in AEMO's energy conversion model guidelines[12]. More information about the ECM requirements including the direct costs to the generator is outlined in section 3.3.6. Information in section 3.3.4. indicates the cost to AEMO for assessing additional ECMs, noting that assessment of one ECM is included in the semi-scheduled registration free, but that some sites may require multiple ECMs depending on the configuration.

[12] https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/dispatch-information/policy-and-process-documentation#forecasting

3.3.2 Grid connection and modelling

This team is responsible for modelling the new connection and assessing the impact on system security. This requires intensive dynamic modelling to determine how the generator responds to various system disturbances and how the new connection interacts with other control systems on the network.

Another responsibility is adding the PSCAD model of the new generator to the network-wide PSCAD model. AEMO is the owner of the network-wide PSCAD model, as there is confidential information contained within the various generator control systems, AEMO is the only party allowed to hold this model. This means AEMO takes the proponents model and includes it within the network-wide model to carry out the various PSCAD Studies. These are complex studies and can take many iterations depending on the quality of data and where the proposed connection point is located.

There are a large number of generator applications underway at any one time and these are assessed in order of application. Sometimes a Generator may need to repeat their connection assessment if another generator is connected before them and that connection has not been considered in their application process. This results in additional time and expenses.

The cost to undertake AEMO's assessment is passed on to the proponent via the NSP, although it could also be recovered directly from the applicant. The cost for this depends on the connection but anecdotally the range is $250,000 to $500,000. If a generator has a poor quality or incomplete application with inconsistent data and they revise their application information numerous times, this cost can be closer to the higher end of the cost range.

3.3.3 Congestion modelling

Generators applying for semi-scheduled or scheduled status are required to participate in central dispatch. This means AEMO will be dispatching the generator and therefore the Congestion and Grid Modelling team will need to include the generator in AEMO's National Electricity Market Dispatch Engine (NEMDE) process. This process often involves complex constraint equations that are used to manage the supply and dispatch of electricity in the NEM. Non-scheduled Generators are not required to participate in the market dispatch. However, AEMO's Congestion and Grid Modelling team still assesses these types of connections to understand their output into the network. To help balance supply and demand these non-scheduled generators' output is factored in and therefore, regardless of scheduling status, this team will require input into a generator application. The cost of these works is passed on to the applicant via the NSP.

3.3.4 Forecasting

One of the responsibilities of the forecasting team is to perform a due diligence check on the applicant's Energy Conversion Model (ECM). This model is relevant to semi-scheduled generators and is used to predict the energy output from intermittent generation at a particular location based on ambient conditions. The cost for AEMO to review the ECM is included in the registration fee as outlined in section 3.3.1

3.3.5 Commissioning

AEMO will be notified once the connection agreement has been finalised between the participant and the NSP. The participant will be required to submit a commissioning plan to AEMO and the NSP who will review and approve. The generator will then commence commissioning which involves hold point tests at pre-defined output levels. Many tests will be performed at each hold point to confirm the generator can meet its GPS and the results match the modelling that informed the GPS. AEMO and the NSP will review the results of each hold point test and provide approval to proceed to the next hold point. There might be a requirement for AEMO or the NSP to witness the commissioning test.

The cost of AEMO to be involved in commissioning is passed on to the proponent, however, this is the same process for all generator classification and therefore a change in scheduling status will not affect this aspect.

3.3.6 Summary of costs

Table 5 AEMO registration /application fees

Cost item	$ (Low)	$ (High)	Non-Scheduled	Semi-Scheduled	Scheduled
Registration as Non-Scheduled Market Generator	$20,600	$20,600	✓	X	X
Registration as Semi-Scheduled Market Generator	$31,930	$31,930	X	✓	X
Registration as Scheduled Market Generator	$23,690	$23,690	X	X	✓
Additional ECMs	~$5,000 per DUID (note: one DUID included in semi-scheduled registration fee)	~$5,000 per DUID (note: one DUID included in semi-scheduled registration fee)	X	✓	X

Source: AEMO Schedule of Registration Fees 2020-21[13]
✓ = Cost applicable X = Cost not applicable

Table 6 AEMO grid connection and modelling fees

Cost item	$ (Low)	$ (High)	Non-Scheduled	Semi-Scheduled	Scheduled
Grid connection and modelling			✓	✓	✓
Congestion and grid modelling	$250,000*	$500,000*	✓	✓	✓
Forecasting			X	✓	
Commissioning			✓	✓	✓

✓ = Cost applicable X = Cost not applicable
End to end cost for AEMO connection (not including registration fee)

3.4 SCADA

Supervisory control and data acquisition (SCADA) is used by generators, NSPs and AEMO to manage the grid's power operations. All generators require SCADA to be implemented as part of their connection. Many SCADA points/signals need to be brought back to the NSP for control, operation and reporting purposes. These points are largely the same for all generators above a threshold outlined in the relevant NSPs guidelines. Some DNSPs require the same SCADA arrangement for connections sized 200 kW and greater.

As more DER and VRE connect into the network, there is a great requirement for remote control, operation and visibility of these sites. Once a generator becomes semi-scheduled and scheduled they are required to interface with AEMO via the NSP and this introduces some extra SCADA points and testing, which adds additional costs. These costs are from additional labour for a tester to commission and test the additional points and the physical hardware that is required for these additional measurement data. This results in a cost difference for SCADA for a non-scheduled generator to become semi-scheduled or scheduled.

[13] https://aemo.com.au/-/media/files/about_aemo/energy_market_budget_and_fees/2020/fy21-final-aemo-electricity-revenue-requirement-and-fee-schedule.pdf?la=en

The commonly used communication protocol used in the NEM is DNP3, an industry-standard, and is transmitted via various communication pathways including fibre, 3G, satellite and others depending on the location.

Section 3.4.3 outlines the various SCADA elements that generators require under the three scheduled classifications.

3.4.1 Balance of plant control system

A balance of plant control systems is required by all generators. However, this may be minimal in the case of non-scheduled generators. This system controls all the supporting components and auxiliary systems of the power plant needed to deliver electricity, other than the generating unit itself. For example, the balance of plant control system may be used to control transformers, switches, inverters and circuit breakers. These particular components of a generator site will not change for a 5-30 MW generator if they change from non-scheduled to semi-scheduled or scheduled.

For semi-scheduled and scheduled generators, the balance of the plant control system incorporates an additional NSP interface with AEMO. This is a three-way interface between the generation plant, the NSP and AEMO. The generator provides DNP3 format data to the NSP. The NSP aggregates the generator's data with data from surrounding SCADA and then supplies the data to AEMO.

The equipment required for the DNP3 interface to the NSP is not significant and the majority of the interface is already required for non-schedule, semi-scheduled and scheduled. However, as the set up for semi-scheduled and scheduled involves a three-way test between the generator, the NSP and AEMO, then significant costs can be incurred due to testing of each point with the three parties.

3.4.2 Primary frequency response

Droop control is one of the most used types of primary frequency control that regulates the frequency by changing the active power output of the Generator. As per the AEMC Primary Frequency Response (PRF) Rule determination[14] all semi-scheduled and scheduled generators are required to provide PFR. However, non-scheduled generators are not required to provide primary frequency response and therefore do not need a droop controller.

The droop controller is managed through the control system and specifically the Power Park Controller (PPC). Even though a non-scheduled generator does not require PFR, a PPC are commonly installed to manage other control functions. If a PCC is installed for a non-scheduled Generator and it now becomes semi-scheduled, it will only incur the cost to configure PFR in the existing PCC and the associated labour costs for testing the PFR.

For non-scheduled generators on the smaller end of the 5 MW to 30 MW range, they may not install a PCC and hence would need more advanced control systems if they are now required to become semi-scheduled or scheduled.

3.4.3 Summary of costs

Through discussion with industry experts and SCADA suppliers, it is clear that the amount of required SCADA is not driven solely by the classification of the generator and that many other factors contribute to SCADA requirements. There are SCADA requirements already been installed as part of the NSP requirements and the addition of a droop controller and extra generation management functions, required for semi-scheduled and scheduled is a marginal increase to the total SCADA costs.

With non-scheduled generators still required to meet a range of GPS clauses, the generator will still need an advanced control system. These control systems are capable of the extra requirements imposed on semi-scheduled and scheduled generators; however, these functions do not get implemented and tested. Smaller generators may opt to install a more basic control system not capable of the semi-scheduled and scheduled control requirements, again this is not driven by the generator classification.

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14 https://ris.pmc.gov.au/sites/default/files/posts/2020/04/national_electricity_amendment_mandatory_primary_frequency_response_rule_2020_-_final_rule_determination_0.pdf

Table 7 SCADA requirements

Cost item	$ (Low)	$ (High)	Non-scheduled	Semi-scheduled	Scheduled
Balance of plant control system	Varies per site		✓	✓	✓
SCADA basic* ^	$700,000	$1,000,000	✓	X	X
SCADA advanced* (PFR/droop controller, ramping, multiple complex interface)	$2,000,000	$2,500,000	X	✓	✓

✓ = Cost applicable X = Cost not applicable

*SCADA basic and SCADA advanced are not defined terms nor do they represent industry terminology. The terms are used in this report for ease of reference only.

^ SCADA Basic will not be an option for 5-30MW generators if they are required to become semi-scheduled or scheduled

3.5 Generation management system

Semi-scheduled generators require a generation management system to be dispatched by AEMO[15]. At a minimum, the generation management system must comply and be consistent with AEMO's power system operating procedure for dispatch (SO_OP_3705).[16] Generators are required to demonstrate this compliance to AEMO through the registration process.

A GMS is capable of handling complex dispatch instructions, monitoring and reporting on generator performance, status and availability. AEMO's NEMDE issues dispatch instructions to generators based on a complex set of constraint equations. Dispatch instructions required response from generators across a range of attributes such as MW output values, linear ramp rates, the number of inverters or turbines permitted to be online and VAr setpoints.

Dispatch instructions have evolved and are likely to continue to evolve as the power system needs and risks change.

While all semi-scheduled generators required a generation management system, they can select the functionality from the system to suit their requirements. At a minimum, the system will facilitate and execute dispatch. Additional functions that may be implemented include:

- Bidding and trading, which may be manual or automatic.
  - Manual options involve a user interface and require resources to execute.
  - Automatic options are inclusive of price forecasting, strategy optimisation based on market movements and automatic execution of compliant bids and rebids.
- Monitoring and internal business reporting. This functionality is used to analyse the performance of the generator by recording factors such as generator output, revenue, wind speed/sun irradiance, number of constraint instances, performance against set vendors and manufacturer performance standards, performance against technical obligations (e.g., GPS) and market compliance as well as other useful data.
- Settlement reconciliation (discussed in section 3.8)
- Availability submissions (discussed in section3.5.1), including analysis of plant availability history, such as a comparison of availability submission compared to actual availability
- Self-forecasting (discussed in section 3.5.4), including analysis of self-forecasting outcomes and performance against actual.

The requirement for the functions beyond facilitating and executing dispatch are driven by business needs and are not affected by this rule change.

[15] Scheduled generators can be dispatched using automatic generator control (AGC) systems so may not need a generation management system (although they may elect to have one).
[16] AEMO, SO_OP_3705 - Dispatch, 31 March 2021. Available at: https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/procedures/so_op_3705-dispatch.pdf?la=en

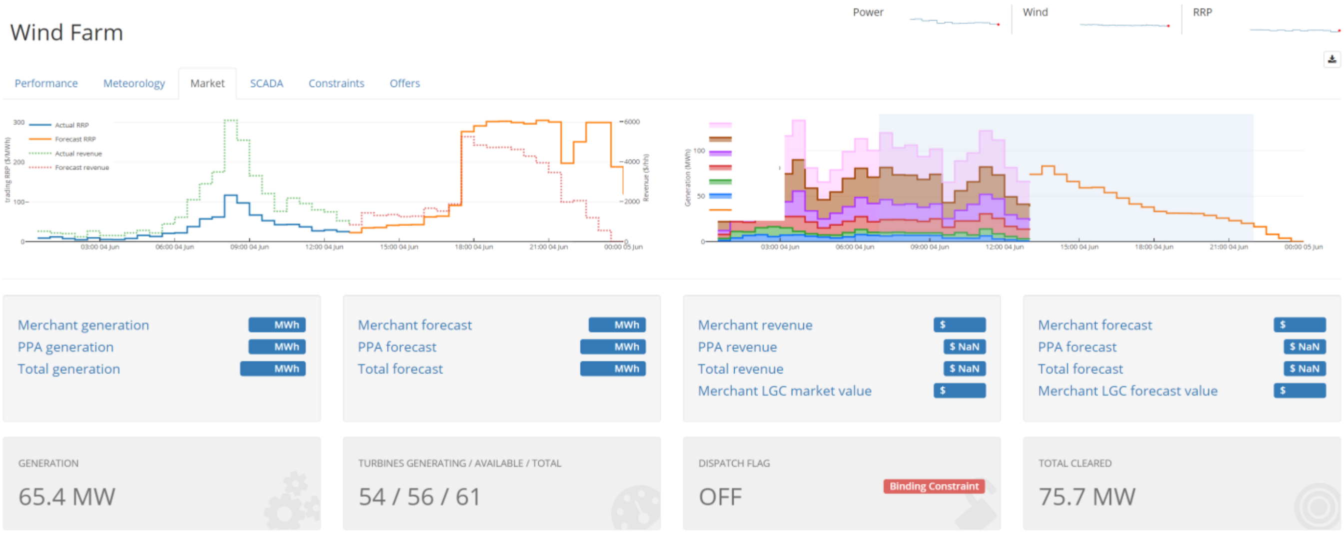

Figure 1 Example user interface from generation management system

3.5.1 Availability submissions

All units with semi-scheduled obligations (but not scheduled)[17] must submit plant availability as per clause 3.7B(b) in the NER to ensure the accuracy of Pre-Dispatch and PASA is maintained. The plant availability is input to AEMO's forecasting model when AEMO preparing the unconstrained intermittent generator forecast (UIGF) in the pre-dispatch and PASA timeframes as AEMO is required under NER clause 3.7B(c)(2).

Generators must update their availability submission when there is an expected or actual change in plant availability due to events including, but not limited to:

- An unplanned or planned outage of the semi-scheduled generator or its elements.
- Environmental conditions such as forecast high ambient temperatures causing possible de-rating effects on turbines, modules, and inverters, in addition, to forecast high wind speeds causing possible de-rating or cut-out effects on turbines.
- GPS requirements, operational arrangements between the generator and NSP/AEMO, and changes in commissioning hold point levels.
- Transformer outages or provision of reactive power.
- Changes in the number of elements available to generate.[18]

3.5.2 MarketNet

MarketNet is AEMO's secure network for market participants. It is used to facilitate access to AEMO market systems, dispatch instructions, market data and participant portals.

All semi-scheduled generators receiving dispatch instructions are required to interface with MarketNet. The generator's GMS will interface with AEMO market systems via MarketNet. There is a cost involved in setting up the secure connection to MarketNet and this cost is normally included in the cost of implementing the GMS.

3.5.3 Telecommunication site connectivity

All generators need to have some level of communication and connectivity for operational monitoring and management purposes. However, as dispatch information for semi-scheduled generators is sourced from AEMO

[17] This includes both on-scheduled units with semi-scheduled obligations and all semi-scheduled participants.
[18] AEMO, NEM Operational Forecasting and Dispatch Handbook for wind and solar generators, April 2021, p. 8-9. Available at: https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/dispatch/policy_and_process/nem-operational-forecasting-and-dispatch-handbook-for-wind-and-solar-generators.pdf?la=en

market systems, a requirement exists for connectivity and communications to be provisioned that complies with AEMO's Power System Communications Standard[19].

The Power System Communications Standard requires generators to implement redundant reliable connectivity. In practice, this involves establishing two internet connections to the generator site comprising of a primary and secondary connectivity method. The setup needs to provide support for and capability to manage failover and failback in the event of a service interruption of the primary service.

The communication and connectivity options available to generators vary significantly between sites. Differences are largely driven by how remote or isolated the site location is from the existing telecommunication network and the options available from the local NSP. For some generators, straightforward and relatively inexpensive options are available such as the provision of fixed-line NBN services or 4G/3G services. However, sites that do not have these services available will need to rely on more expensive options, such as microwave or satellite services. Alternatively, the generator may need to negotiate the use of the NSP's grid connection optical ground wire for communication purposes (where this is available).

While estimates are provided in section 3.5.4 below, it is noted that these costs are often included in the broader EPC or generation management vendor costs. As such, it is difficult to itemise these costs with a high degree of accuracy. Further, as all sites need some level of telecommunication connectivity, the costs could be marginal for scheduled generators if the site already needs extensive telecommunication installations.

3.5.4 Summary of costs

A summary of costs is tabled below that shows that for VRE generators the costs are at the higher end of the cost range. These figures demonstrate that for a non-scheduled generator now being required to become semi-scheduled or scheduled there will be a cost increase in the range of $80,000 - $340,000.

Table 8 Summary of costs for Generation Management System (GMS)

<table>
<tr><th>Cost item</th><th>$ (Low)</th><th>$ (High)</th><th>Non-scheduled</th><th>Semi-scheduled</th><th>Scheduled</th></tr>
<tr><td>Generation management system</td><td rowspan="3">$80,000</td><td rowspan="3">$280,000</td><td>X</td><td>✓</td><td>X</td></tr>
<tr><td>Availability submission</td><td>X</td><td>✓</td><td>X</td></tr>
<tr><td>MarketNet</td><td>X</td><td>✓</td><td>✓</td></tr>
<tr><td>Telecommunication site connectivity (marginal cost)</td><td>$10,000</td><td>$60,000</td><td>✓*</td><td>✓</td><td>✓</td></tr>
</table>

* Cost is at the lower end of the cost range as only minimal telecommunications required compared to other statuses

3.6 Forecasting

A forecast of expected energy output is a requirement of AEMO to participate in dispatch as a semi-scheduled or scheduled generator and does not apply to non-scheduled generators. There are a couple of options available as outlined in this section.

3.6.1 AEMO forecasting systems

AEMO has a forecasting system that semi-scheduled generators are required to use however, generators can opt for their own forecasting system if it proves (over 10 weeks) to be equal to or more accurate than AEMO's. AEMO's forecasting systems are called, Australian Wind Energy Forecasting System (AWEFS) and the Australian Solar Energy Forecasting System (ASEFS). Both systems require two inputs:

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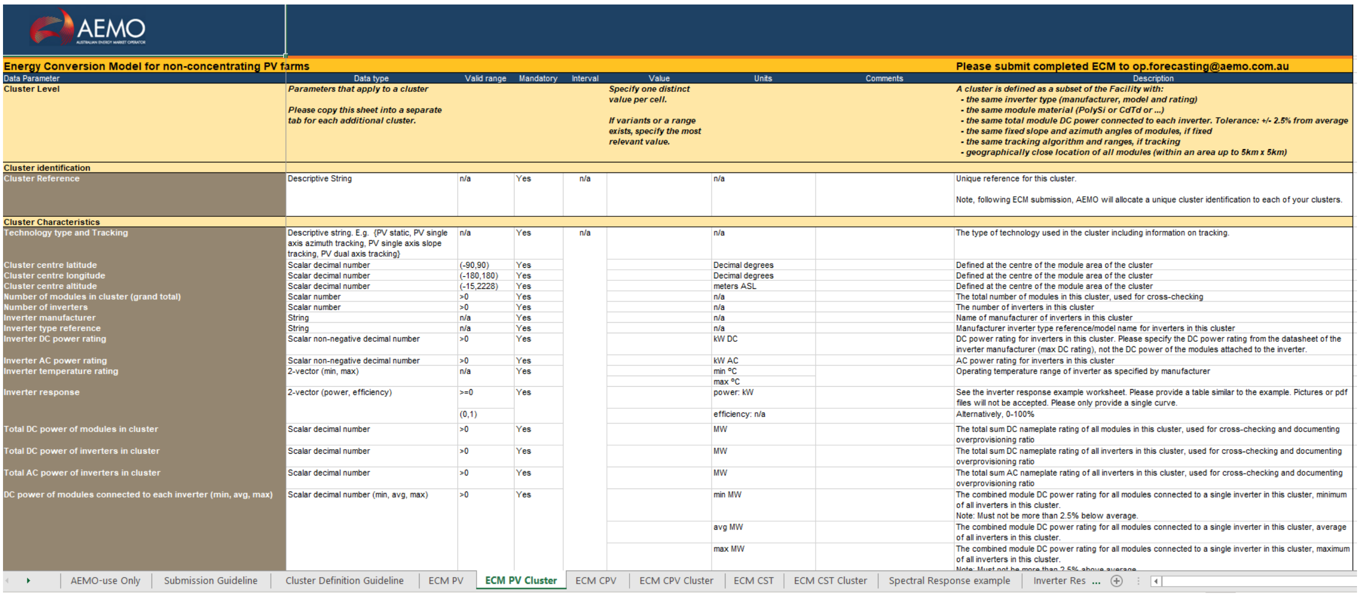
[19] AEMO, Power System Communications Standard, 1 December 2017. Available at: https://aemo.com.au/-/media/files/electricity/nem/network_connections/transmission-and-distribution/aemo-standard-for-power-system-data-communications.pdf?la=en&hash=9D6BCA32B459E2CF98A67CF89E43CC63

1. Energy Conversion Model (ECM)
2. Additional SCADA data

An ECM is a model of the energy output that can be expected from a semi-scheduled wind or solar farm based on ambient conditions at the farm's location. It takes into consideration ambient temperature, wind speed and solar irradiance predictions. The model is reviewed by AEMO and must be submitted as part of the registration as described in section 3.3.4. Information from the model feeds into AEMO's data systems for forecasting purposes.

Generators are required to produce the model at their own cost. Estimated costs for developing the model on a standalone basis are outlined in 3.6.3**Error! Reference source not found.**. However, the model is often d eveloped by the EPC, in which case these costs are included within and not distinguishable from broader project costs.



Energy Conversion Model for non-concentrating PV farms — Please submit completed ECM to op.forecasting@aemo.com.au

Data Parameter	Data type	Valid range	Mandatory	Interval	Value	Units	Comments	Description
Cluster Level	*Parameters that apply to a cluster* *Please copy this sheet into a separate tab for each additional cluster.*				*Specify one distinct value per cell.* *If variants or a range exists, specify the most relevant value.*			*A cluster is defined as a subset of the Facility with:* *- the same inverter type (manufacturer, model and rating)* *- the same module material (PolySi or CdTd or ...)* *- the same total module DC power connected to each inverter. Tolerance: +/- 2.5% from average* *- the same fixed slope and azimuth angles of modules, if fixed* *- the same tracking algorithm and ranges, if tracking* *- geographically close location of all modules (within an area up to 5km x 5km)*
Cluster identification								
Cluster Reference	Descriptive String	n/a	Yes	n/a		n/a		Unique reference for this cluster. Note, following ECM submission, AEMO will allocate a unique cluster identification to each of your clusters.
Cluster Characteristics								
Technology type and Tracking	Descriptive string. E.g. {PV static, PV single axis azimuth tracking, PV single axis slope tracking, PV dual axis tracking}	n/a	Yes	n/a		n/a		The type of technology used in the cluster including information on tracking.
Cluster centre latitude	Scalar decimal number	(-90,90)	Yes			Decimal degrees		Defined at the centre of the module area of the cluster
Cluster centre longitude	Scalar decimal number	(-180,180)	Yes			Decimal degrees		Defined at the centre of the module area of the cluster
Cluster centre altitude	Scalar decimal number	(-15,2228)	Yes			meters ASL		Defined at the centre of the module area of the cluster
Number of modules in cluster (grand total)	Scalar number	>0	Yes			n/a		The total number of modules in this cluster, used for cross-checking
Number of inverters	Scalar number	>0	Yes			n/a		The number of inverters in this cluster
Inverter manufacturer	String	n/a	Yes			n/a		Name of manufacturer of inverters in this cluster
Inverter type reference	String	n/a	Yes			n/a		Manufacturer inverter type reference/model name for inverters in this cluster
Inverter DC power rating	Scalar non-negative decimal number	>0	Yes			kW DC		DC power rating for inverters in this cluster. Please specify the DC power rating from the datasheet of the inverter manufacturer (max DC rating), not the DC power of the modules attached to the inverter.
Inverter AC power rating	Scalar non-negative decimal number	>0	Yes			kW AC		AC power rating for inverters in this cluster
Inverter temperature rating	2-vector (min, max)	n/a	Yes			min °C max °C		Operating temperature range of inverter as specified by manufacturer
Inverter response	2-vector (power, efficiency)	>=0 (0,1)	Yes			power: kW efficiency: n/a		See the inverter response example worksheet. Please provide a table similar to the example. Pictures or pdf files will not be accepted. Please only provide a single curve. Alternatively, 0-100%
Total DC power of modules in cluster	Scalar decimal number	>0	Yes			MW		The total sum DC nameplate rating of all modules in this cluster, used for cross-checking and documenting overprovisioning ratio
Total DC power of inverters in cluster	Scalar decimal number	>0	Yes			MW		The total sum DC nameplate rating of all inverters in this cluster, used for cross-checking and documenting overprovisioning ratio
Total AC power of inverters in cluster	Scalar decimal number	>0	Yes			MW		The total sum AC nameplate rating of all inverters in this cluster, used for cross-checking and documenting overprovisioning ratio
DC power of modules connected to each inverter (min, avg, max)	Scalar decimal number (min, avg, max)	>0	Yes			min MW avg MW max MW		The combined module DC power rating for all modules connected to a single inverter in this cluster, minimum of all inverters in this cluster. Note: Must not be more than 2.5% below average. The combined module DC power rating for all modules connected to a single inverter in this cluster, average of all inverters in this cluster. The combined module DC power rating for all modules connected to a single inverter in this cluster, maximum of all inverters in this cluster. Note: Must not be more than 2.5% above average.

AEMO-use Only | Submission Guideline | Cluster Definition Guideline | ECM PV | ECM PV Cluster | ECM CPV | ECM CPV Cluster | ECM CST | ECM CST Cluster | Spectral Response example | Inverter Res ...

Figure 2 Example ECM (ASEFS)

Additional SCADA data is required by AEMO for forecasting purposes. SCADA parameters that feed into AWEFS or ASEFS are outlined in the Guide to Data Requirements for AWEFS and ASEFS. The costs associated with the setup of this system are included in the SCADA Advanced cost items outlined in section 3.3.6.

3.6.2 Self-forecasting (optional)

Generators may elect to implement their own forecasting system in addition to the above AEMO requirement to provide an ECM as well as AWEFS and ASEFS data. Having an inaccurate forecast can result in less than optimal dispatching by AEMO and ultimately a reduction in possible revenue. Self-forecasting can help reduce causer pay penalties if it proves more accurate than AEMO's systems. Generators at the lower end of the 5-30 MW range may not benefit as much from improved forecasting as their causer pay factor will be less and so a self forecasting system is unlikely to be chosen.

AEMO allows the use of a self-forecasting system as long as the generator proves it is consistently accurate. This validation process is completed over 10 weeks. If AEMO's forecasting system proves to be more accurate then it will default back to the AEMO systems.

Commercially self-forecasting services are available for generators to procure. For solar farms, these typically consist of a Cloud-based service and the installation of one or more sky-cameras, which monitor cloud cover in real-time.

Self-forecasting systems are less common for wind farms as the technology can be more expensive and is less mature than equivalent systems for solar. The systems involved in installing meteorology measurement instruments (such as sodars) can be installed that captured data higher resolution data feeds.

Self-forecasting systems are charged on a subscription cost basis and may involve an upfront cost depending on factors such as the size of the installation (i.e., number of measuring instruments) and the subscription period. Potentially set-ups are outlined in section 3.6.3 and the ongoing subscription cost is covered in section 4.4

In addition to the set-up costs, self-forecasting involves going resource costs to manage, audit and review the forecasting tool for accuracy. These costs are typically included in an ongoing operational cost and so are not itemised separately.

This option is entirely optional (only if it is more accurate) as semi-scheduled generators can opt to only use AEMO's forecasting.

3.6.3 Summary of costs

The below summary shows that if non-scheduled generators are required to become semi-scheduled or scheduled there will be a cost impact of $5,000- $10,000, this is assuming the generator does not opt for a self-forecasting system.

Table 9 Summary of costs for forecasting systems

Cost item	$ (Low)	$ (High)	Non-scheduled	Semi-scheduled	Scheduled
ECM development	$5,000	$10,000	X	✓	X
AEMO forecasting (SCADA parameters)	Included in SCADA costs		X	✓	X
Optional Self-forecasting (set up)	$0	$30,000	X	✓	X*

✓ = Cost applicable X = Cost not applicable

* Alternative system used

3.7 Metering and metering provider

Any connection into the NEM requires metering and metering reading must be provided by an accredited provider. The list of accredited metering providers is maintained by AEMO[20].

While the metering arrangements may vary between generators (e.g., based on the site setup), these costs are not dependent on scheduling arrangements. As such, we have not itemised cost differences and do not expect costs to change should the rule change proceed.

3.8 Contract management system & settlements

Contract management and settlement system requirements and processes are driven by participant preferences and contract arrangements (e.g., power purchase agreements). These costs are not dependent on scheduling arrangements. As such, we have not itemised cost differences and do not expect costs to change should the rule change proceed.

[20] Refer to; https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/retail-and-metering/accreditation-and-registration

4. Ongoing participant costs

If non-scheduled market generators are required to be semi-scheduled or scheduled, there are extra requirements placed on the generator that will have ongoing costs associated with it. The following outlines these costs that need to be considered as costs. These include:

– Operational support 24/7 & additional compliance
– Ongoing system costs
– Ongoing NER obligations
– AEMO ongoing fees
– Self-forecasting (optional)

These ongoing costs that will be introduced as part of being reclassified from non-scheduled to scheduled are discussed below. Our research indicates that these costs, much more so than marginal costs itemised in section 2, will drive the viability of small generator projects. Moving from unrestrained export to being dispatched and potentially constrained, adds another cost/loss of revenue that needs to be factored in.

Due to the nature of these costs, we are not able to provide firm estimates on cost levels. However, we discuss each of these costs in turn below and provide broad ranges where possible.

4.1 Operational support 24/7 & additional compliance resources

Semi-scheduled and scheduled generators are required to have a contact person available 24/7 to answer phone calls and act on instructions given from AEMO. Advice from the stakeholder engagements indicates this could be the cost of half a full-time employee, required on an ongoing basis.

In addition to operational support, ongoing additional compliance obligations are likely to require, on average, half a full-time employee. Additional activities include:

– Monitoring of bids and dispatch
– Monitoring of more complex SCADA and control systems
– Monitoring of generator compliance with semi-scheduled or scheduled obligations (e.g., linear ramping, voltage response etc)
– Attendance at forums and events to keep up to date with ongoing changes to compliance obligations.
– Responding to AEMO request including providing information for audits and explaining any incidents around any potential non-compliance.

A generator's performance and ability to meet dispatch targets will be monitored for nonconformance and penalties applied if a generator does not meet its dispatch target. This presents a monetary risk to generators changing from non-scheduled to scheduled.

4.2 Ongoing system costs

Once the generation management system, SCADA and communications links are established, there will be ongoing system costs for the delivery, provision of support, and upkeep of these systems. Ongoing costs include (but are not limited to):

– Minor additional costs associated with small system changes
– Service provider costs for hosting, data transit
– SCADA service provider support including help desk functions
– Site telecommunication service provider costs
– Generation management system support, help and software maintenance

Variation in ongoing system costs is driven by factors such as:

– Minimum support/response resolution requirements
– Support availability (e.g., 24 hours support)
– Complexity and capability of systems, i.e., more complex systems typically require more support

4.3 Management and monitoring of NER obligations

Semi-scheduled and scheduled generators must have ongoing dedicated resources to manage and monitor:

– compliance with NER obligations – Any new rule changes.
– changes to NER requirements, including participation in industry forums and regulatory reform process.
– change processes progressed in response to changed NER requirements.

The actual costs will vary. Where the generator is going to be part of a portfolio of power assets and the marginal increase in costs is very low. However, for new standalone generators required to register a semi-scheduled rather than non-scheduled, these costs could be substantial compared to their total project costs.

4.4 Self-forecasting (optional)

Where semi-scheduled generators elect to have self-forecasting systems, they will have ongoing subscription costs. As described in section 3.6.2, self-forecasting systems have the potential to reduce a generator's causer pay costs; however, the smaller the generator the less of an issue this becomes. Costs associated with causer pays are calculated differently between non-scheduled and semi-scheduled generators. A non-scheduled generator is not overly concerned about its forecast, unless it becomes dispatched and there are penalties for not matching your forecast generation to your target dispatch level. For this reason, a non-scheduled generator my chose a self-forecasting system if it is required to be semi-scheduled. A generator can always default to AEMO's forecasting system at no extra cost

4.5 Summary of costs

There are several ongoing costs associated with a non-scheduled participant becoming semi-scheduled or scheduled as described above, these are in the order of $150,000 - $551,000.

Table 10 Summary of ongoing participant costs

Cost item	$ (Low) (Per annum)	$ (High) (Per annum)	Non-scheduled	Semi-scheduled	Scheduled
Operational support & compliance resources	$100,000	$180,000	X	✓	✓
Ongoing system costs	$50,000	$150,000	X	✓	✓
Ongoing NER obligations	$0	$200,000	X	✓	✓
Optional Self-forecasting (subscription)	$12,000	$21,000	X	✓	X

✓ = Cost applicable X = Cost not applicable

5. Indirect participant costs

Substantial costs from becoming semi-scheduled (compared to non-scheduled) are indirect costs associated with being dispatched (and the continuing effect of these obligations on the generator's revenue). These costs include:

– Constraint or curtailment costs (heavily variable depending on the location and may range from close to $0 up to hundreds of thousands of dollars per year)
– PFR delivery costs and lost energy production opportunity costs
– Causer pays (for regulation FCAS)

From an individual participant perspective, the above indirect costs represent a significant change to the business case for new generators should the Rule change proceed. The indirect costs mentioned above are apportioned amongst all semi-scheduled and scheduled generators, increasing the pool will decrease the cost per generator.

5.1 Constraint or curtailment costs

Non-scheduled generators do not submit offers to signal market intentions, do not receive and respond to dispatch instructions, and are free to operate their generating units at any desired level under normal circumstances. Non-scheduled generators can take full advantage of changes in the market price by behaving in a way that sees their full power output paid when prices are high, and constraining generation to avoid any low or negative market prices.

Once a generator becomes semi-scheduled or scheduled it is dispatched by AEMO according to network conditions and NEMDE's constraint equation results. This means that AEMO may not dispatch a generator's full capacity (or at all) depending on NEMDE's instructions. When this occurs, depending on the wholesale market price and it's contractual arrangements, the generator misses out on revenue (or costs in the case of negative prices)

Historically, larger wind farm's annual lost revenue due to constraints has ranged in the hundreds of thousands of dollars per year. Of the samples reviewed, costs ranged from close to zero to may hundreds of thousands of dollars for the 2020 financial year.

Depending on the location of the generator, curtailment costs could represent a significant change to the business case for new generators should the rule change proceed.

For completeness, it is noted that scheduling arrangements do not protect a generator from constraints driven by local network requirements.

5.2 Primary frequency response delivery costs

In March 2020, the AEMC made a rule change to introduce mandatory Primary Frequency Response (PFR) for semi-scheduled and scheduled generators[21]. The changed requirements mean these generators must change their MW output to meet PFR requirements, with the changed MW output being subsequently reflected in wholesale market payments. While this rule change was introduced to improve the overall system stability, it does require generators to adjust their MW output in response to frequency.

The PFR requirements affect semi-scheduled and scheduled generators differently. While scheduled generators can provide PFR support in both directions by increasing or decreasing their outputs as needed, semi-scheduled generators can only provide PFR in one direction – by decreasing their output and a lost opportunity cost.

[21] Refer to: https://www.aemc.gov.au/rule-changes/mandatory-primary-frequency-response

Should the rule change proceed, there will be two counteracting effects:

1. New small generators that would have been non-scheduled but are now semi-scheduled will receive marginally less revenue than they would otherwise as they reduce MW output to help meet PFR requirements.
2. There will be more generators contributing to PFR requirements. As PFR requirements are shared, there would be a proportionally less PFR burden for all generators (so less loss revenue for other generators).

Similar to the curtailment cost discussed above, PFR delivery costs are borne by generators who participate in dispatch. The costs may be material to the business case for an individual generator. This rule change would see this cost spread amongst a larger number of generators.

5.3 Causer pays for regulation FCAS

A feature of the ancillary service market is that costs for frequency control regulation services (regulation FCAS) are allocated to Market Generators (as well as Market Customer and Market Small Generation Aggregators). Costs are allocated in accordance with Contribution Factors, as set out in clause 3.15.6A of the NER and detailed in AEMO's causer pays procedure[22]. A generator's Contribution Factor is assessed at their connection point based on their contribution to recent variations on system frequency causing the need for regulation FCAS.

All non-scheduled, semi-scheduled and scheduled generators are responsible for the recovery of the FCAS regulation costs in the NEM through an allocation process based upon their participant contribution factors. The different calculation of the contributing factors for non-scheduled and scheduled generators produces a significantly increased risk when a generator is not classified as non-scheduled.

Regulation costs for all generators are distributed based on a "causer pays" principle where their individual contribution factor is pooled with all the other generator's factors and costs allocated as a proportion of the individual factor with that pool. Non-scheduled generators are allocated costs from a separate proportion of the FCAS regulation cost pool to either form of scheduled generator.

All generators' contribution factors are determined during an AEMO defined 28-day period, and the factors are then used for the next subsequent 28-day settlement period. This pre-calculation of the factors used in the allocation of the regulation costs can lead to perverse outcomes where generators can be liable for high regulation costs during a settlement period in which they may not even be operating and therefore not causing any of the actual market outcomes.

For a semi-scheduled generator, the contribution factors are based on the difference between the actual generation at the end of the five-minute Dispatch Interval compared with the forecast generation using a simple persistent forecast, where the measured generation in the previous Dispatch Interval is used as the forecast for the current Dispatch Interval. For non-scheduled generators, the contribution factor is little more than a measure of consistent generation.

In contrast, the semi-scheduled and scheduled generators FCAS causer pays contribution factor calculation is determined by calculating the difference between the unit's generation and the linear interpolation of the current and previous dispatch interval TOTALCLEARED values used as a measure of expected dispatch on a four-second basis, as shown in the following figure.

[22] Refer to AEMO website: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services/ancillary-services-causer-pays-contribution-factors

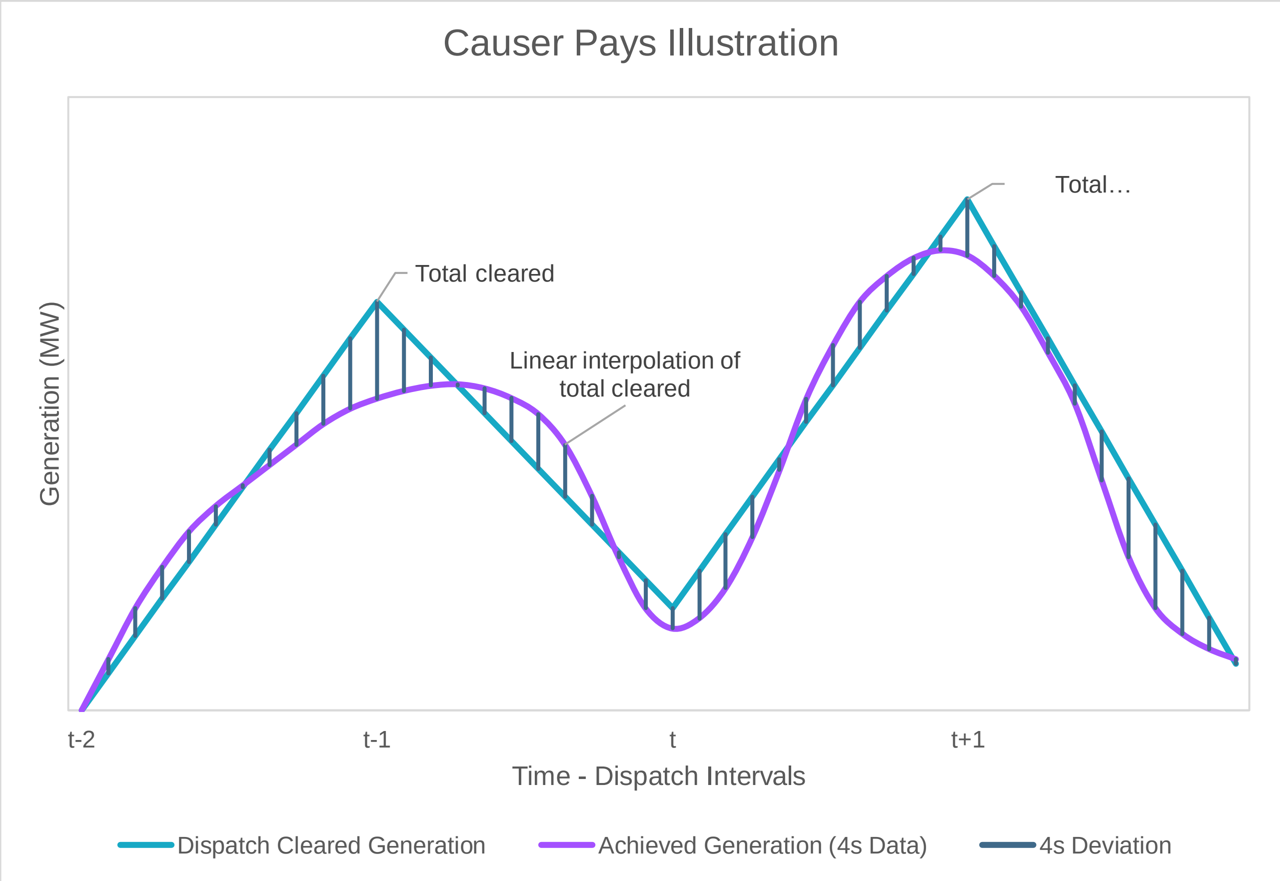


Figure 3 - Concept of four-second causer pays deviations

The four-second deviations, determined by measuring the difference between the units' four-second generation to the interpolated TOTALCLEARED values (see above Figure 3), are then multiplied by a factor, FI, that represents the raise or lower MW requirements in either the mainland or TAS regions for that four-second interval. The four-second factors are then categorised and averaged for that five-minute Dispatch Interval and then all of the categorised five-minute Dispatch Interval averages are averaged again over a four-week defined measurement period and a unit contribution factor is determined and scaled according to the respective proportions of demand for the mainland and the TAS regions.

The FCAS causer pays settlement factor is, therefore, a measure of the deviation of generation from the linear interpolated TOTALCLEARED values in the NEM dispatch process where the values of the TOTALCLEARED values are the dispatch targets produced by the NEMDE dispatch process.

For Variable Renewable Generation (VRE) generators, the TOTALCLEARED values are determined from the Unconstrained Intermittent Generator Forecast (UIGF) when not constrained due to price or market constraints. The UIGF is either a direct output of the AEMO forecasting system or a calculated self-forecast by the individual generator and input to the AEMO dispatch process.

Historically, the AEMO algorithm for the calculation of the generator contribution factors was developed without consideration of the different nature of VRE generators and was simply adopted without change for VRE generators. Whereas scheduled generators are dispatched to a target TOTALCLEARED value and measured against the standard of meeting that target, VRE generators have no requirement to meet that target as they are subject to the variation in the input variable solar irradiance or wind speed. Therefore, the semi-scheduled VRE generators share a disproportionate market risk for exposure to high regulation costs with no ability to actively manage that risk during a period of high regulation costs due to the predetermined factors for each settlement period.

There are many issues associated with the calculation of FCAS causer pays factors for all generators as detailed in “NEM FCAS Causer pays procedure”[23]. Although that document mostly considers the FCAS causer pays risks from a wind generator perspective, many of the identified weaknesses apply to all scheduled and semi-scheduled generators in the NEM, such as:

1. mathematically incorrect averaging of average deviations leads to a biased measure that is significantly over-influenced by large deviations and outlier measures not removed through the SCADA filtering process,
2. measured lags of up to 16 seconds between plant SCADA data and the calculation of the generation deviation, and
3. no way of minimising exposure to costs during high regulation cost periods.

Due to the indirect means of calculating contribution factors and the frequency of measurement of deviations, it is very difficult to quantify the increased costs associated with the scheduled and semi-scheduled causer pays methodology across a broad cross-section of the market.

The previously cited report attempts to conduct a sensitivity analysis to various aspects of the calculation for some representative generator types, to determine the significance of issues with the algorithm, but as factors only have relative significance to other factors in the same calculation period, it is difficult to determine actual costs to any individual generator. There have been some market events, especially when the SA region has been islanded or within FCAS markets with little competition such as TAS, that caused huge costs to be allocated to individual generators just because they randomly had a non-zero contribution factor in a period when other generators in a region randomly had zero factors, and the event was determined to have been caused by a local requirement.

In conclusion, if a generator's classification changes from non-scheduled to scheduled or semi-scheduled status, it will substantially increase the risk of exposure to high regulation FCAS costs. The way that causer pays contribution factors are calculated by AEMO, especially for VRE generators, and the pre-calculation of the factors from a previous measurement period prevents any generator from effectively mitigating or managing these increased risks.

5.4 AEMO fee increases associated with the rule change

AEMO fees for new generators affected by this rule change are not expected to be different based on scheduling arrangements. However, generators are likely to be indirectly affected by increases in AEMO’s fees should the rule change proceed.

While we have not itemised the costs to AEMO for implementing this rule change, we note the following changed requirements are likely to drive cost that would ultimately be recovered from participants (including generators):

– Increased numbers of semi-scheduled generators driving up the cost of AEMO systems. The rule change may result in increased numbers of semi-scheduled generators using AEMO’s systems. The scalability of existing systems, including ASEFS/AWEFS, would also need to be reviewed to account for the increased volume of data and processing required. While not itemised for this report, it could be assumed that increased costs will be passed on to generators.
– Increased modelling requirements as lower, distribution voltage modelling will need to be validated by AEMO. With non-scheduled generators now been semi-scheduled or scheduled AEMO would be required to model more of the DNSP network. The increased requirement of larger network models would require an increase in hours to maintain the model.

5.5 Summary of costs

A summary of the **annual ongoing indirect costs** associated with being dispatched is shown in Table 11. These costs are extremely variable and unique to individual projects and their location. Where estimates are provided in the table below, these are based on a selection of generators’ experiences over the last financial year. It is highly

[23] https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/Electricity_Consultations/2017/CPPC/Wind-Coalition-consultant-submission.pdf

uncertain as to whether these costs will materialise for any one project. However, we note curtailment costs are a growing area of concern amongst generators when it comes to evaluating their business case.

Table 11 Summary of ongoing indirect costs (annual)

Indirect Cost	$ (Low)	$ (High)	Non-Scheduled	Semi-Scheduled	Scheduled
Constrain/curtailment	$0	$1.5 million	×	✓	✓
Providing primary frequency response			×	✓	✓
Causer pays for regulation FCAS			×	✓	✓
AEMO fees increase associated with rule change	Same across all		✓	✓	✓

✓ = Cost applicable, X = Cost not applicable

6. Summary of costs and changes over time

6.1 Summary of changed costs

The total increase in **upfront project costs** for connecting and registering a scheduled plant compared to a non-scheduled plant is between $1.3 million and $1.8 million (for the same 5-30 MW plant). This can be compared with broad variations in total project cost for VRE plant in this capacity between $15 million to $100 million – dependant on generation technology, manufacturer and EPC choice, location, complexity and the size of the project.

The estimated increase in upfront costs assumes the registration arrangements are known at project inception. Where projects are completed, and registration arrangements need to be varied and rework is required (including additional hardware or SCADA capabilities) these costs can be expected to be significantly higher.

Increased **ongoing costs** range from $150,00 to $555,000. These costs include:

– Operational support 24/7 & additional compliance resourcing
– Ongoing system costs, for example, hosting, support and software maintenance costs paid to vendors
– Ongoing NEM fees, which are not expected to be significant regardless of scheduling status
– Ongoing changes to NER requirements that result in operational or software/hardware changes. This includes resources to monitor and remain up to date with changes as well as costs associated with implementing changes when needed.

Substantial costs from becoming semi-scheduled (compared to non-scheduled) are **indirect costs** associated with being dispatched (and the continuing effect of these obligations on the generator's revenue). These costs include:

– Constraint or curtailment costs (heavily variable depending on the location and may range from close to $0 up to hundreds of thousands of dollars per year)
– Causer pays (for regulation FCAS)
– PFR delivery costs

From an individual participant perspective, the above indirect costs represent a significant change to the business case for new generators should the Rule change proceed. These costs are incurred by the market and distributed amongst the generators that participate in dispatch. If the Rule change were to proceed, these costs would be distributed over a greater number of participants and will reduce the cost per generator.

Other potential costs relate to the individual circumstances of the project, its funding arrangements and the timing for commencement of any Rule change should it proceed. If affected, in-progress projects have not adequately accommodated and accounted for the requirement to participate in dispatch this could fundamentally affect the project's business case. In particular, extensions to project durations driven by a need to meet increased requirements or revisit commercial agreements are likely to significantly negatively affect new small generator connections.

6.2 Comparison with historical costs

Looking back over the full period the National Electricity Market has been in existence there have been significant decreases in the IT system, interfacing and communication costs for newly registering generator, particularly as standardised and generic products, software and TCP/IP communications became available and were more widely adopted. However, many of the real cost reductions have already been realised and in recent years the trend has been for increased specification and performance rather than changed costs. In our opinion, and from our experience providing, delivering and selling IT hardware, software and communication services over 20 years, we expect the costs associated with IT systems, interfacing and communication are likely to remain constant or increase regardless of these developments.

By counterbalancing any reduction in system connection costs, the requirements for market participation, dispatch and compliance for generators have increased. For example, primary frequency response obligations, dynamic linear ramping dispatch requirements, increased complexity of connection and registration processes.

As the connection process has evolved over time, there has been a larger amount of <30 MW connections and the impact of these connections is beginning to harm system stability. This has led to generators between the 5-30 MW range having to comply with the same connection requirements of >30 MW connections and therefore the costs to register and gain an executed connection agreement have become comparable.

6.3 Future market changes

While IT cost are generally expected to decrease in the future, there is no guarantee that the costs for specialist systems used by generators will decrease. The systems involved are highly specialist and are continually improving in functionality.

Hardware costs, such as servers, switches and routers, are likely to continue to decrease on a like-for-like basis. However, in practice, the specification of hardware will continue to evolve, and costs will remain constant or increase. Manufacturers make available the hardware of today, meaning that the current specifications will be surpassed and no longer available for routine procurement in the future.

Software costs are driven by increases in complexity of requirements, specifications and labour cost inputs. These costs are expected to remain the same or increase.

The technical requirements to connect into the NEM and participate in the market are becoming more rigorous over time and the requirements on generators are more onerous. For example, some recent changes, which are aimed at improving the NEM and the security of supply, include:

– system strength requirements have evolved
– the requirement for PSCAD modelling at lower voltage levels is reasonably new
– introduction of mandatory PFR in 2020 adds additional cost to generator connections
– changes to the semi-scheduled generator dispatch obligations[24]

In the future, changes aimed at providing overall benefits, but may increase complexity and costs include:

– the planned move to 5-minute settlements
– the potential move to a financial transmission right and locational marginal pricing (being progressed through the transmission access reform)

Ultimately, any reduction in hardware costs (if like-for-like replacements remain available) will be outweighed by increased requirements and more advanced control systems being used to meet these requirements, along with the increased labour costs to commission these complex control systems.

6.4 Scheduled-lite / SCADA-lite

AEMO is actively exploring several proof-of-concept studies and undertaking testing for new or alternative technical solutions for participants to interface with AEMO systems. These projects (and others) are in progress with industry stakeholders, involving the physical deployment of test devices and software, allowing simulated testing and performance analysis to be undertaken. Once this work is complete, the additional interfacing options will enable participants to interface directly with AEMO systems, potentially utilising internet connectivity secured with standardised communication security arrangements such as SSL certificates rather than via the current set NSP interface pathway and interface technology. This can be expected to provide more flexible data transmission and interface options for participants that utilise standard, common and current technology, formats and security arrangements.

The recent implementation of interfacing between participants and the market operator for VPP (Virtual Power Plan) successfully demonstrates Web APIs for the transmission of some data. However, we note that this does not include dispatch data. Ancillary services dispatch and enablement for VPPs is executed via AEMO market systems interface, using the same pathways, formats, and technology as it is for semi-scheduled plant. Similarly, the use of APIs for VPPs does not involve the frequency of data transmitted as currently occurs for Semo-Scheduled plant via NSP ICCP interfaces.

[24] Refer to: https://www.aemc.gov.au/rule-changes/semi-scheduled-generator-dispatch-obligations

Publicly announced broader collaborative projects that are currently underway within the energy industry, including Project EDGE[25] (Energy Demand and Generation Exchange) and Project Symphony[26] in Western Australia, encompass work on the options and methods for facilitating data transfer between generators and the market operator. AEMO has a significant stake hold and involvement in each of these projects. These prominent projects are expected to drive further development and options in this area

In light of these activities, the AEMC requested we consider if alternative, less onerous interfacing arrangements could be developed in the future to support dispatch, scheduling and data transfer for small generators.

Figure 4 provides a highly simplified illustration of the interfaces between generators and AEMO. AEMO interfaces directly with generators via MarketNet for dispatch, bidding and self-forecasts. Availability submissions are provided via aseXML or manually via an AEMO portal.

The SCADA interface for semi-scheduled plant is DNP3 interface from the local plant control system to the NSPs SCADA. The DNP3 interface takes data from the plant to support pre-dispatch and ASEFS/AWEFS functions (e.g., active power, possible power, element availability/status, irradiance, wind speed). Once the plant data is received by the NSP, it is aggregated with data from other plants and participants into an ICCP interface and sent to AEMO SCADA. This process is bi-directional, i.e., data can originate from the plant or from the NSP or AEMO. Updates to ICCP interfaces can be time-consuming and expensive exercises because any changes need to follow a change control and regression testing process involving a range of stakeholders.

We note that the dispatch and market obligations for semi-scheduled plant cannot currently be facilitated via APIs. Currently, semi-scheduled plant communicates via NSP SCADA (four-second interval DNP3 interface) and AEMO market systems (CSV files, MMS data model).

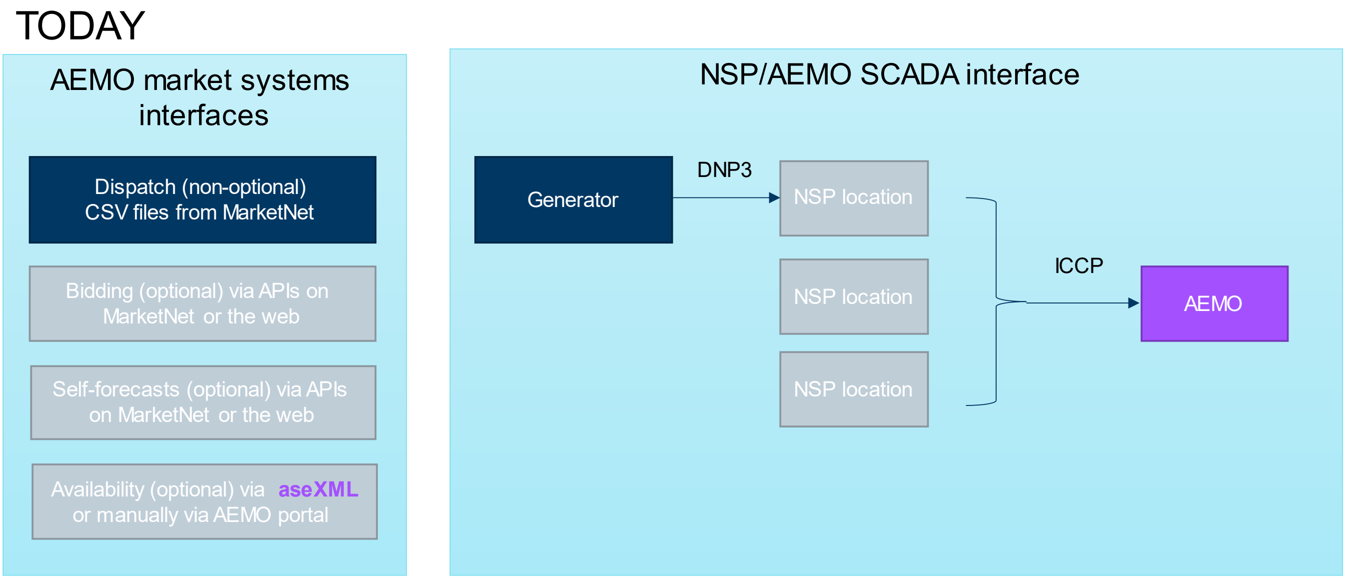


Figure 4 Current interface arrangements for semi-scheduled generators

While AEMO has confirmed they are actively working on providing additional flexibility in the interface option available to generators, no decisions have been made in respect to the technology options, the timeline or the extent of the potential scope of new data transmission options. Any new interface options (e.g., APIs or DNP3 direct to AEMO) would need to satisfy and fulfill the data requirements for both ASEFS/AWEFS and pre-dispatch (which is a subset of the ASEFS/AWEFS requirement).[27] Significant infrastructure and systems investment would be needed by AEMO to enable a new system or altered version of the current system to be adopted.

Figure 5 provides a highly simplified illustration of the interface options that could be developed in the future. The interfaces shown in the diagram include an option to retain the current interface arrangements where SCADA data

[25] Refer to: https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge
[26] Refer to: https://aemo.com.au/en/initiatives/major-programs/wa-der-program
[27] ASEFS and AWEF requirements are here: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Guide-to-Data-Requirements-for-AWEFS-and-ASEFS.pdf

is provided to AEMO via the NSP. It is likely NSP's will continue to need similar or the same data as AEMO to fulfill their obligations; as such, bypassing the NSP is not currently a credible option.

One of the challenges to be overcome for more flexible options to be accepted is for there to be agreement on the type and regularity with which data is interfaced from the various parties. Presently the DNP3/ICCP interface architecture supports data being transferred on a four-second basis.

While the extent of development activity and associated progress in this area is promising, it is likely to be 12 months or more before impacts to generator costs, if any can be extrapolated.

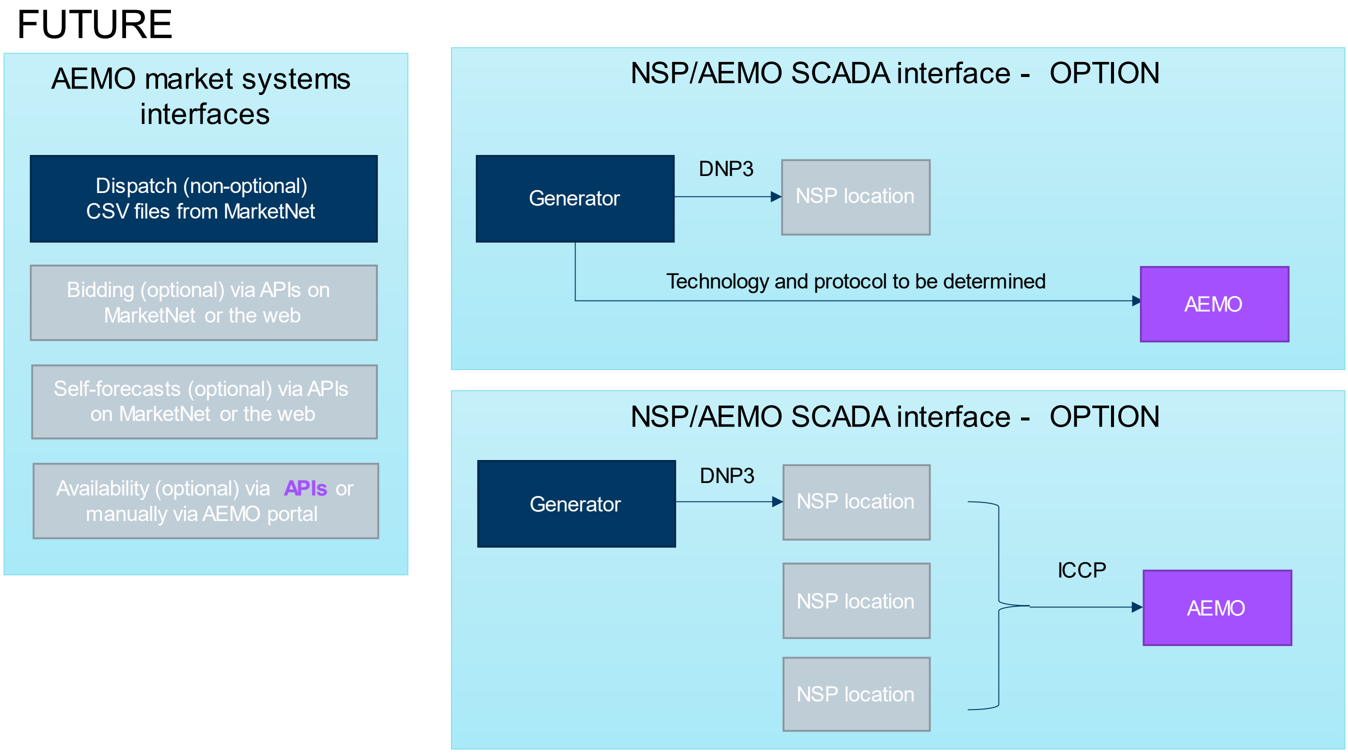


Figure 5 *Potential future interface arrangements for semi-scheduled generators*

Appendices

Appendix A

Acronyms and abbreviations

Acronyms and abbreviations

The following acronyms, terms and abbreviations have been used in this report.

Table 12 Acronyms and abbreviations

Acronym / term / abbreviation	Meaning
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
ASEFS	Australian Solar Energy Forecasting System
AWEFS	Australian Wind Energy Forecasting System
BESS	Battery energy storage systems
CCGTs	Combined cycle gas turbines
COAG	Council of Australian Governments
DER	Distributed energy resources
DERMS	Distributed Energy Resource Management
DNSP	Distribution network service provider
ECM	Energy Conversion Model
EPC	Engineering, procurement, and construction
GMS	Generation Management System
Hz	Hertz
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IPS	Individual power systems
kV	Kilovolt
ms	Millisecond
MW	Megawatt
MWh	Megawatt hour
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NER	National Electricity Rules
NSP	Network service provider
PFR	Primary Frequency Response
PSC	Power conversion systems
PV	Photovoltaic
TNSP	Transmission network service provider

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