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Intermittent generation forecasting arrangements – review of international jurisdictions

Prepared for the Electricity Authority

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1 Executive summary

This report describes arrangements used in five overseas electricity systems to create forecasts of intermittent generation for use in scheduling and dispatch processes. Each jurisdiction has its own unique approach, and this paper provides a high-level thematic overview.

For three of the systems (Alberta, Australia, Texas) we were able to talk to market operators/monitoring agencies, as well as review public documents. The discussions were very helpful to better understand the arrangements and design philosophies.

For two other systems (Ireland and Great Britain) we relied on published documents for information. Finally, we were able to discuss forecasting arrangements in European Union countries with the European Agency for Cooperation of Energy Regulators (ACER).

1.1 Centralised forecasting is prevalent

All three systems that were examined in detail use a centralised process to prepare short-term forecasts of intermittent generation. In each case, a service provider contracted to the market or system operator prepares forecasts of intermittent generation quantities available in the coming hours/days. The service providers' costs are recovered from market participants via fees or levies. To the extent that performance standards/incentives are used, they apply in the contracts between the service provider and the market/system operator.

We also examined arrangements in Ireland and Great Britain based on a review of published information. Our understanding is that both utilise centralised processes to compile the intermittent generation forecasts used in the scheduling and dispatch processes.

1.2 Decentralised approach preferred in principle by ACER

While centralised approaches appear to be relatively common, we understand that the European Agency for Cooperation of Energy Regulators (ACER)[1] prefers decentralised approaches in principle. ACER's preference appears to be based on a view that generators will have access to better information sources than a central agent. In ACER's view, provided generators have robust incentives, a decentralised approach should yield accurate forecasts.

ACER noted that ahead markets are compulsory in the European Union (EU) and that in principle, these should create robust incentives on generators to provide accurate forecasts. This is because generators become financially committed to sell the generation quantity cleared in the ahead market, with any deviation being settled at the balancing price. In short, an accurate quantity forecast will reduce the generator's exposure to being cashed out at the balancing price.

While ACER prefers decentralised approaches in principle, we note that EU member states do not necessarily follow ACER's guidance (for example as noted above Ireland uses a centralised forecasting process). Furthermore, as we discuss in the body of the report, a compulsory ahead market may not necessarily provide incentives for accurate generation forecasts.

[1] ACER is an umbrella body that seeks to harmonise energy regulation across European Union members, with the objective of facilitating cross border competition and trade.

1.3 Generator discretion to over-ride central forecasts

Although generators are not required to forecast their generation levels in systems that utilise a centralised forecasting approach, they may still choose to do so for other reasons. For example, they may prepare their own forecasts to help with contracting decisions.

In addition, some jurisdictions (for example, in the NEM) allow generators to 'overwrite' the quantity associated with their plant that was compiled in a centralised forecast. Such provisions are intended to provide discretion for generators to submit more accurate information where it is available. However, the discretion to substitute generator data for central forecast data is not unfettered.

1.4 Generation quantity information and price offers

Irrespective of whether a centralised or decentralised approach is used, there is a need to convert wind/solar energy levels into electricity equivalents, and account for any plant outages or deratings. All of the systems we examined have mechanisms to allow for this. Decentralised approaches rely on generators to do this, while centralised approaches typically obtain plant data (such as capacity and power curves) from generators as an input to the forecasting process.

Finally, both centralised and decentralised approaches can make provision for generators to nominate offer prices for tranches of generation output. This provision allows generators to reduce the likelihood of being dispatched at prices that are unacceptable to them (e.g. negative spot prices).

1.5 Forecast information that is provided

Our review indicates that centralised forecasts include a mid-point (typically a P50 value) estimate of generation quantities, as well as other quantity information. The additional information varies by system, but can include matters such as the estimated maximum and minimum levels.

Forecasting horizons typically extend up to a week, and have more granularity as real-time approaches. For example, the Alberta system operator publishes a week ahead forecast at the hourly level, and also publishes a 12 hour-ahead forecast which is updated more frequently (every 10 minutes).

1.6 Wind and solar generation

Our review indicates that arrangements for preparing wind and solar generation offers are consistent with each other within each jurisdiction we examined. Indeed, the only differences we identified were in the underlying methodology for compiling forecasts of actual energy levels for wind and solar. Our understanding is that this is because solar arrangements were developed based on wind arrangements which were already in place in each system.

1.7 Relative advantages of centralised and decentralised approaches

In theory, generators have the best information (or at least access to information) on projected generation from their plant. In particular, they should best understand idiosyncratic factors that affect their own intermittent generation plant, such as the effect of wind direction on energy conversion rates due to turbine shadowing, etc.

Decentralised approaches can more readily allow such 'distributed' knowledge to be reflected in forecasts used for scheduling and dispatch. They could also limit the impact of a forecasting error or bias to a single generation resource, rather than having a bias affect the forecasts for the entire system.

However, decentralised approaches rely on some form of incentive on generators to provide accurate forecasts. It is difficult to create appropriately balanced incentives using administrative tools (such as standards and penalties) in practice for the reasons discussed in the body of this report.

Centralised approaches still face an incentive issue, but it is focussed on the forecasting service provider contract and the quality of inputs provided by generators (e.g. SCADA data). The former can be addressed in the service provider's contract terms. Such contracts can reward providers for accuracy and encourage effort to be applied to aspects of forecasts which are most important (for example, the relative effort to be applied to mid-point versus sensitivity ranges). Having made these points, some level of forecasting error will be unavoidable so incentives will only be useful up to a point in reducing forecast errors.

In respect of input data provided by generators, it is more straightforward to define quality standards and incentives for these matters, and to monitor performance.

Centralised approaches may also allow faster adaption to reflect evolving system needs. For example, if there was a desire to introduce P90 estimates, this should be easier to achieve via an amendment to a single service provider contract than via market rule changes and subsequent amendments to individual generators with a need to cascade these to individual forecasting arrangements.

Hybrid approaches are also possible. For example, some systems with centralised approaches allow generators to overwrite the central forecast with their own information where this is expected to be more accurate.

Finally, in both approaches there is a need to monitor the quality of forecasts and address any problems, such as bias.

1.8 Comparison with New Zealand arrangements

New Zealand's arrangements are based on the decentralised approach, with generators having the responsibility to provide forecasting information for scheduling and dispatch purposes.[2]

New Zealand's arrangements have a relatively light-handed approach to the issue of incentives. New Zealand does not have a compulsory ahead market, and the Code does not include strong provisions in relation to forecast accuracy.

Overall, New Zealand's arrangements appear to be unusual because they allocate forecasting responsibility to generators, but there are no strong incentives to encourage accurate forecasts.

[2] The Code prescribes some aspects of the process.

2 Background

2.1 Purpose

This paper describes forecasting arrangements for intermittent generation in a range of overseas electricity systems and compares them to New Zealand arrangements.

2.2 "Forecasting arrangements"

For the purposes of this paper a 'forecasting arrangement' refers to the approach used to create projections of intermittent generation *for use in scheduling and dispatch processes*.

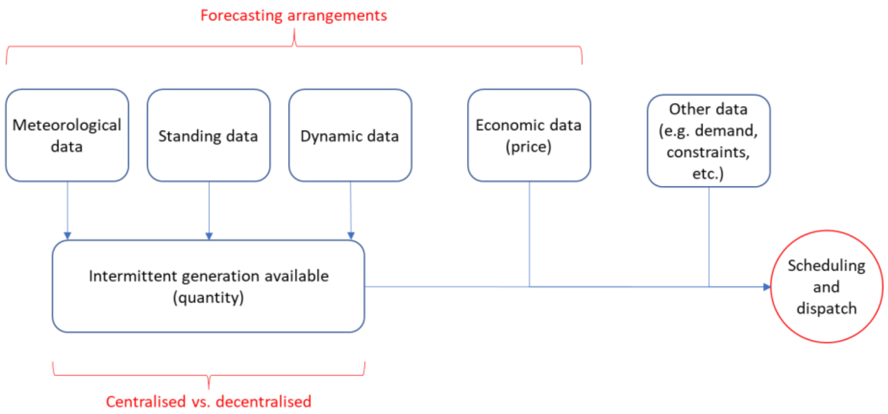
These inputs include:

- the primary wind and solar energy available at each generator site (based on wind speed and direction, solar irradiance, etc.)
- how adjustments are made for physical availability of generation plant (based on standing data such as installed capacity and power curves and dynamic data like SCADA)
- how intermittent generation owners signal their willingness to sell their generation volumes (based on offer prices).

Exactly what these inputs are, and how and by whom they are collected, processed and produced, varies between jurisdictions. Such arrangements are typically defined in market rules or codes.

In broad terms, the arrangements define the processes and responsibilities for combining meteorological data and plant data to project the likely quantity of intermittent generation output available at each generation site. This quantity data is then combined with economic data to forecast how much of this output will be offered at each price (see Figure 1 below).

Figure 1: Overview of forecasting process



As we discuss later, arrangements fall into two main camps: centralised arrangements where *a service provider is responsible* for forecasting the likely intermittent generation quantities available (albeit with extensive data inputs provided by generators); and decentralised approaches where *individual generators are responsible* for their own forecast in its entirety (i.e. both price and quantity elements).

The issue of forecasting *responsibility* is the key issue explored in this paper. Under our terminology, a system that places the quantity forecasting responsibility on individual generators would be decentralised, even if all generators contracted the forecasting task to the same service provider.

Similarly, a system in which all generators prepared forecasts for other purposes would still be categorised as centralised if the responsibility for preparing the quantity forecasts *for scheduling and dispatch processes* is allocated to one party. These distinctions are important because the forecasting arrangements for scheduling and dispatch purposes may differ from those used for other activities, such as to guide participant contracting and trading decisions.

2.3 Which jurisdictions were examined

This report describes forecasting arrangements used in five overseas electricity systems. For Alberta, Australia, Texas we were able to talk to market operators/monitors, as well as review public documents. The discussions were very helpful to better understand the arrangements and design philosophies that have been applied.

For two other systems (Ireland and Great Britain) we relied solely on published documents for information.[3] We also sought to review documents for some other systems with moderate/high levels of intermittent generation (e.g. Spain). In the event this proved to be impractical given language barriers and time constraints. However, we were able to discuss forecasting arrangements at a high level across European Union members with the European Agency for Cooperation of Energy Regulators (ACER).

All of the jurisdictions we examined in detail use an 'energy-only' design[4] for their wholesale market. New Zealand also uses an energy-only design, which suggests the lessons from those systems should be relatively applicable in New Zealand.

However, we also wanted to ensure some diversity in the jurisdictions that were reviewed. The information from Great Britain and Ireland is useful in this respect because these systems have capacity mechanisms, rather than energy-only designs. Finally, we note that EU members use a mix of approaches including energy-only and capacity mechanism approaches.

2.4 Structure of report

This report covers three jurisdictions (the Australian National Energy Market, Alberta, and Texas) in detail. We outline the forecasting arrangements, including:

- what data inputs are used
- who produces the forecasts and how
- what forecasts are produced and how they are used in dispatch
- what incentives are in place to encourage accurate forecasting.

We also briefly outline some key findings from our more high-level review of forecasting arrangements in various European jurisdictions, particularly the United Kingdom and Ireland.

We then set out some concluding remarks on the pros and cons of various systems, and make some comparisons with arrangements in New Zealand.

2.5 Acknowledgements

We wish to record our appreciation for the information provided by the Australian Energy Market Commission (AEMC), Alberta Market Surveillance Administrator (MSA), Alberta Electricity System Operator (AESO), Electricity Reliability Council of Texas (ERCOT), and European Union Agency for the Cooperation of Energy Regulators (ACER).

Any errors or omissions are the responsibility of Concept.

[3] Despite efforts to do so, it was not possible to arrange interviews with regulators/market operators in these systems as personnel were focused on responding to the energy market disruptions following the Russian invasion of Ukraine.

[4] This means that the energy spot market is compulsory for wholesale consumers and suppliers, and forward contracting is voluntary. By contrast, some systems have a capacity mechanism where forward contracting is also compulsory.

3 Australia: National Electricity Market

3.1 System characteristics

The Australian National Energy Market (NEM) is the wholesale electricity market for the Australian Capital Territory, New South Wales, Queensland, South Australia, Victoria and Tasmania. It is a standalone system, with no transmission interconnections to the Northern Territory or Western Australia grids. It supplies around 204TWh of electricity to customers every year.[5]

Like New Zealand, the NEM is an energy-only market, although authorities are considering whether to adopt a capacity mechanism. It also has no compulsory[6] ahead markets. However, unlike New Zealand's locational marginal pricing (LMP) system, the NEM is zonal, with each of the interconnected states effectively acting as a price region.

The system operator is the Australian Energy Market Operator (AEMO). Other key bodies are the Australian Energy Market Commission (AEMC) and the Australian Energy Regulator (AER).

Generation in the NEM is generally categorised in one of four ways:[7]

- Scheduled generation is non-intermittent generation above 30MW that must comply with dispatch instructions.
- Semi-scheduled generation is usually intermittent generation above 30MW that can be dispatched down.
- Non-scheduled generation is generation between 5MW and 30MW. AEMO generally does not generally constrain output from this type of generation.
- Exempt generation is generation less than 5MW. It does not participate in central dispatch.

The NEM is a thermal-based system, with nearly half of its capacity and over two-thirds of its energy coming from coal-fired and gas-fired plant. However, renewable penetration has increased in recent years. Combined wind and solar output has increased in energy terms from 3% to 24% in the decade leading to 2021.[8]

In particular, the NEM has a (relatively) very high penetration of solar generation. Most of this solar generation comes from rooftop solar, which is likely to be non-scheduled or exempt generation. As discussed below, intermittent generation forecasts are used differently depending on whether they are for non-scheduled or semi-scheduled generation.

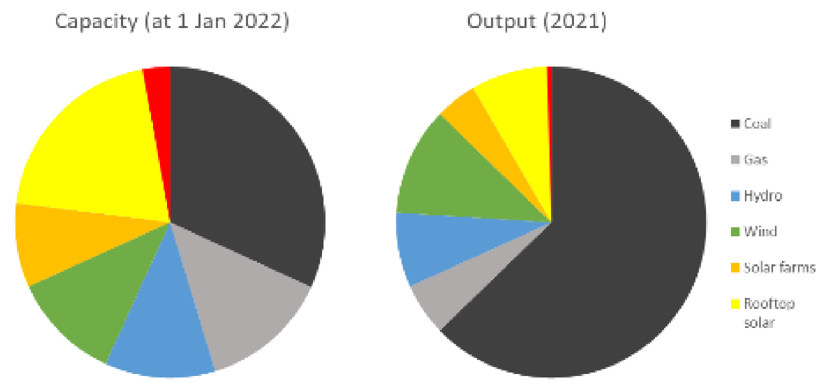
[5] See National Electricity Market Fact Sheet (aemo.com.au).

[6] Most electricity systems have mechanisms that allow short-term trading of contracts in the days and hours leading up to real-time. However, in some systems there are formalised 'ahead markets' in which participants are required to incentivised to contract all of their forecast load and generation. We refer to these as 'compulsory ahead markets'.

[7] See Rule Determination - National Electricity Amendment (Non-scheduled generation and load in central dispatch) Rule 2017 (aemc.gov.au).

[8] See State of the Energy Market 2022 - National Energy Market (aer.gov.au).

Figure 2: NEM generation by fuel type



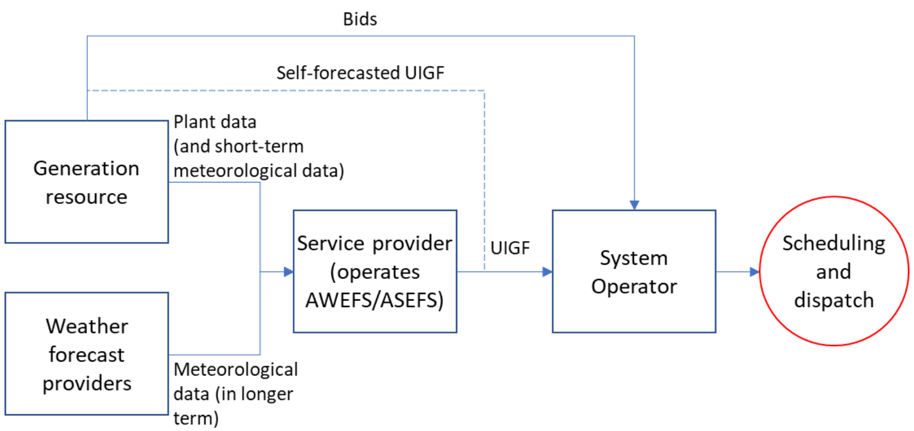
Source: AER State of the Market 2022

3.2 Outline of forecasting process

The NEM uses a centralised generation forecasting arrangement, albeit with individual generators providing multiple data inputs. AEMO contracts with a single service provider to develop and manage the Australian Wind Energy Forecasting System (AWEFS) and Australian Solar Energy Forecasting System (ASEFS). These systems produce an unconstrained intermittent generation forecast (UIGF) for individual generation resources and for the system as a whole. We understand that the service provider's costs are spread across all market participants (i.e. including load customers and non-intermittent generators).

For semi-scheduled resources, the UIGF of each resource is deemed to be its availability. AEMO determines dispatch based on demand levels (net of non-scheduled and exempt generation) and the price bands and availability of scheduled and semi-scheduled generation.

Figure 3: NEM simplified forecasting and dispatch process for semi-scheduled generation



3.2.1 Input data

The AWEFS/ASEFS process requires two sets of inputs:

- Static data – this includes technical specifications of the generation resource such as installed capacity and power curves for converting wind/solar energy into electrical energy.
- Dynamic data – this includes variable data regarding the generation resource and local actual and forecast meteorological conditions.

As discussed below, the AWEFS/ASEFS processes produce multiple forecasts across different timeframes. Different dynamic data inputs are required depending on how close to real-time the forecast is.

In the short term (i.e. real time dispatch and 5 minute pre-dispatch), forecasts depend on SCADA data. This includes wind or solar farm SCADA data (e.g. active power generation) and meteorological SCADA (e.g. wind speed and inclined irradiance).

Longer-term forecasts (i.e. pre-dispatch and short-term projected assessment of system adequacy) still use farm SCADA, but meteorological data comes from several contracted weather providers. This data contains additional information, including wind direction, ambient temperature and satellite imagery.

Not all data that could be relevant to the forecast is currently provided to the service provider. For example, we understand solar farms do not provide data as to dust levels (which can cover panels and reduce electrical conversion efficiency). Data regarding network congestion behind the meter is also not provided.

Economic data inputs (i.e. offer price bands) are provided to AEMO by generators for the dispatch process.

3.2.2 Forecasting process

AWEFS and ASEFS produce the following UIGFs:[9]

Table 1: NEM forecasts produced

Forecast	**Horizon**	**Update frequency/ resolution**	**Usage**
Dispatch	5 min ahead	5 min	Generation capacity available for dispatch (for semi-scheduled forecasts)
5 min pre-dispatch	2 hours ahead	5 min	Generation capacity available for dispatch (for semi-scheduled forecasts)
Pre-dispatch	Up to 40 hours ahead	30 min	Generation capacity available for dispatch (for semi-scheduled forecasts)
			Negative demand for reserve assessment (for non-scheduled forecasts)
Short-term Projected Assessment of System Adequacy (ST PASA)	8 days ahead	30 min	Generation capacity for reserve assessment (for semi-scheduled forecasts)
			Negative demand for reserve assessment (for non-scheduled forecasts)

Different forecasts are used for different purposes. In general, shorter forecasts (i.e. coming hours) for semi-scheduled generation are used for dispatch purposes, while longer term forecasts over coming days (for both semi-scheduled and non-scheduled generation) are used for coordination of scheduling and reserve assessments.

The UIGF is a forecasted central estimate value, but AWEFS and ASEFS also produce uncertainty forecasts (in pre-dispatch and ST PASA timeframes). These are P10/P90 forecasts that are a useful indicator of how accurate the UIGF is likely to be.

As well as system-wide forecasts, AWEFS and ASEFS produce forecasts for each individual generation resource, as well as by region and generation type.

The UIGF is the "forecast of electrical power output from a generating unit, or aggregated unit, based on the forecast amount of energy available for

[9] See Australian wind energy forecasting solar energy forecasting system (aemo.com.au).

conversion into electrical power."[10] It does not take into account network constraints or economic factors. Instead, these factors are dealt with at the central dispatch process which considers network and other operational data and the price/quantity offer bands that generators submit, along with the UIGF.

3.2.3 Wind and solar dispatch

AEMO determines dispatch based on price/quantity offers from scheduled and semi-scheduled generators. For semi-scheduled generation, the "quantity" component of its offer is derived from its availability (i.e. the UIGF).

Since January 2019, semi-scheduled generators have the ability to substitute their own 5 minute pre dispatch forecasts into the dispatch and scheduling process.[11] Such forecasts will then be used as an input into the UIGF in place of the AWEFS/ASEFS forecast for that semi-scheduled generator. Generators must get approval to be able to do this, and there are benchmarking processes in place which could result in this approval being revoked if generators' own forecasts are systematically and consistently wrong.

Once dispatched, a semi-scheduled generator must produce as close as possible to the forecasted quantity. The exception to this is during "semi-dispatch intervals" where the generator must cap output due to either network/ancillary service constraints or an offer/market-related limitation (i.e. uneconomic price bands).[12]

Non-scheduled and exempt generation does not participate in dispatch, so generation from these sources is effectively treated as negative demand. Their contribution to net demand is forecasted using a persistence model rather than the UIGF (although they still use the UIGF for reserve assessment purposes).

3.3 Incentives to forecast accurately

We have been unable to locate any specific information on the terms of the service provider contracts for the provision of AWEFS and ASEFS services. To the extent that incentives apply in relation to accuracy of forecasts, we assume these would be included in the service provider contracts.

For self-forecasting semi-scheduled generators, a different incentive exists. In the NEM, frequency keeping costs are allocated on a causer-pays basis – i.e. if the system is running below target frequency, intermittent generators that are generating less than forecasted (and are thus contributing to system underfrequency) will be allocated more of these costs, and vice versa.

If a generator can successfully predict that the system will be running below frequency, they will be incentivised to forecast conservatively so that they end up generating above this forecast. They would then be deemed to be making a positive contribution to system frequency, so their allocation of costs would be decreased. The reverse is also true – if system over-frequency is expected, a generator will be incentivised to forecast

[10] See National Electricity Amendment (Central Dispatch and Integration of Wind and Other Intermittent Generation) Rule 2008 (aemc.gov.au).

[11] See Semi-Scheduled Generation Dispatch Self-Forecast Assessment Procedure (aemo.com.au).

[12] See Dispatch operating procedure (aemo.com.au).

ambitiously so that they actually generate below this forecast and contribute to keeping frequency down.

At first glance this behaviour could appear to be gaming of the system. However, in reality it is likely to yield system benefits to the extent that it results in fewer under or over frequency events. Furthermore:

- This incentive can only be taken advantage of if the generator can accurately predict that the system is going to be over or under frequency.
- As more generators become aware of this opportunity and begin to implement it, frequency deviations will presumably become less common and predictable, so the incentive diminishes.
- The AEMC is currently working on making sure that the incentives to self-forecasting generally are correctly calibrated.

4 Canada: Alberta electricity market

4.1 System characteristics

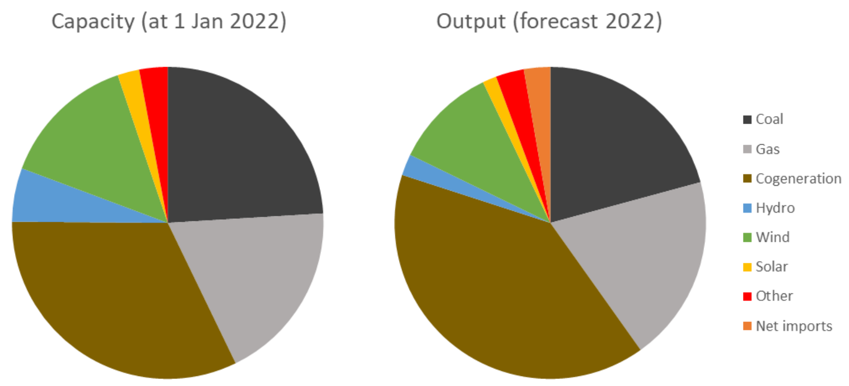
The Alberta Electricity System Operator (AESO) manages and operates the power grid and electricity market. Other agencies include the Balancing Pool, the Alberta Utilities Commission and the Market Surveillance Administrator (MSA). AESO is an independent system operator, but the Alberta grid has interties connecting it to British Columbia, Saskatchewan and Montana.

Like the NEM, the Alberta market is an energy only market with no compulsory ahead markets and no nodal pricing.

The Alberta electricity market is predominantly thermal-based, with approximately 75% of capacity and 80% of energy being provided by fossil fuels. A large proportion of this thermal generation is cogeneration. Most renewable generation comes from wind farms (14% of capacity and 11% of energy), with some hydro (6% and 2%) and a small amount of solar (2% and 1%).

However, substantial growth in wind and solar generation is expected in the next few years, with capacity expected to increase by nearly 120% by 2030.[13]

Figure 4: Alberta generation by fuel type



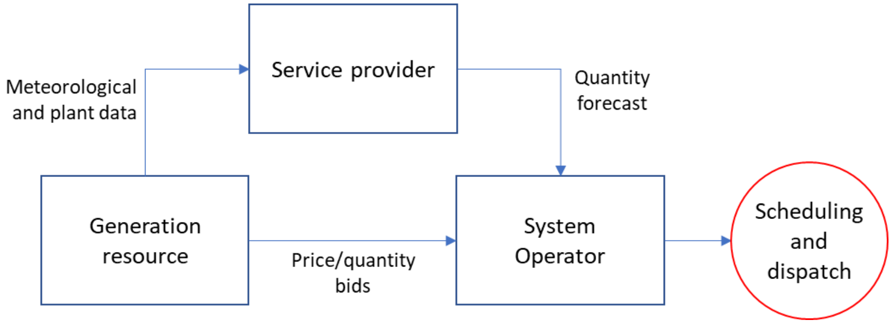
Source: AESO

4.2 Outline of forecasting process

Alberta uses a centralised process to forecast intermittent generation levels for scheduling and dispatch processes. The forecast is prepared by a third-party service provider using plant and other local physical data provided by generators. The forecast quantities are used in daily grid operation and assist the AESO to run an efficient system dispatch process. The cost of producing this forecast is recovered from wind and solar generators in a way that is proportional to the energy output of each generation resource.

[13] See AESO Net-Zero Emissions Pathways Data File (aeso.ca).

Figure 5: Alberta simplified forecasting and dispatch process



4.2.1 Input data

AESO collects a lot of data from generators on a routine basis, which is then used by the service provider for forecasting. The three main categories of data include:

- Facility data – this includes site location, meteorological tower information and data regarding wind turbines/panel arrays (e.g. height from ground, power limits, power curves). This data is provided upon connection and must be updated when changes occur (e.g. if additional turbines are added to a wind farm).
- Meteorological data – this includes wind speed and direction, barometric pressure, temperature, dewpoint, humidity, precipitation, ice-up parameter (wind-only), and panel temperature and irradiance levels (solar only).
- Power capability data – this includes net-to-grid real power, real power limit data and gross real power capability. Data requirements for power capability are the same for wind and solar generation.

Price and quantity data inputs are provided to the system operator by the generators.

4.2.2 Forecasting process

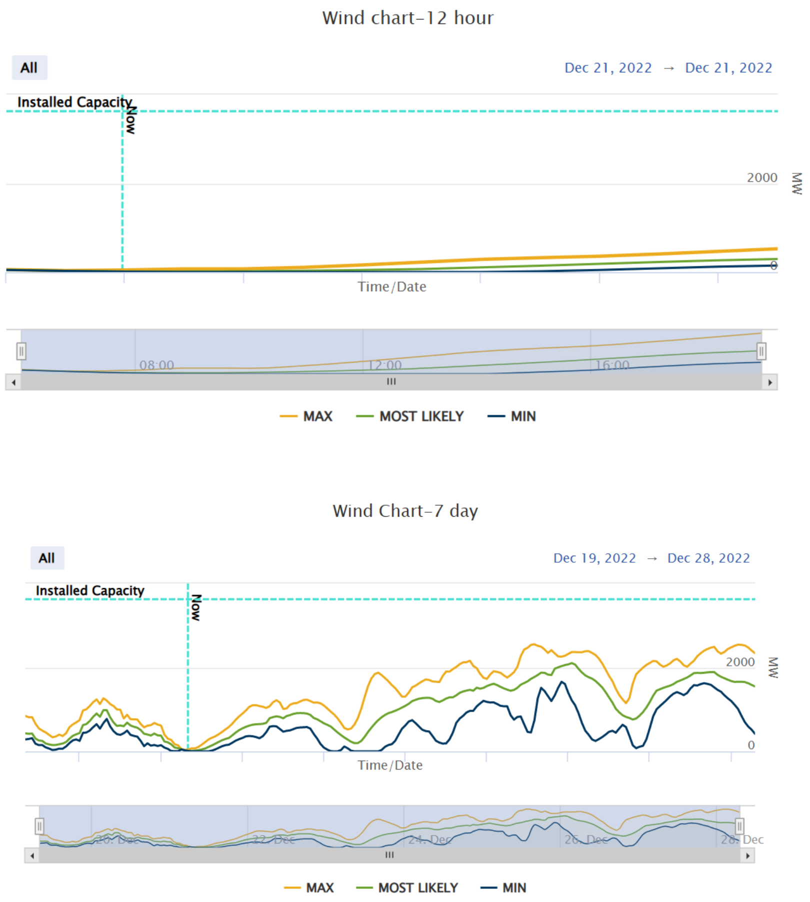
AESO contracts with a service provider to provide the following forecasts, which are published on its website.

Table 2: Alberta forecasts produced

Forecast	**Horizon**	**Update frequency/ resolution**	**Usage**
Wind/solar 12 hour	12 hours ahead	10 min	Anticipating net demand for dispatch purposes
Wind/solar 3 day	3 days ahead	1 hour	
Wind/solar 7 day	7 days ahead	1 hour	

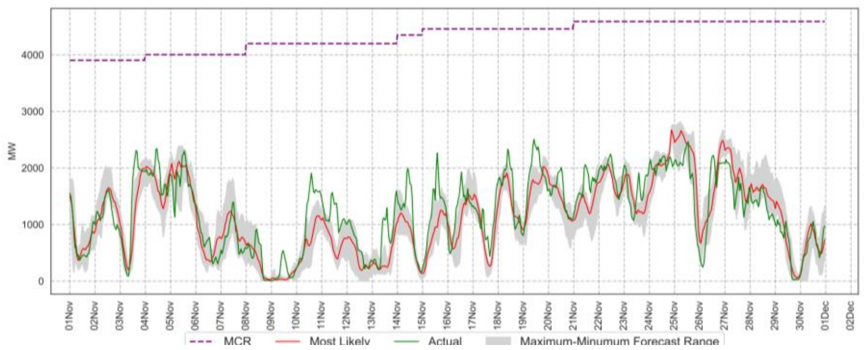
For each forecast interval, AESO provides a most likely (P50), and a ‘maximum’ and ‘minimum’ forecast. An example is shown in Figure 6 below.

Figure 6: Alberta examples of forecast information



Each month AESO publishes a comparison between the forecasts and actual wind and solar generation on its website.[14] An example is shown in Figure 7 below.

Figure 7: Alberta example of wind forecast vs actual comparison



In the dispatch process, the forecasts are not used as direct inputs in intermittent generation offers as a default or maximum quantity. Rather, they are used to anticipate net demand (i.e. demand less non-dispatchable generation) so that dispatchable generation can be ramped up or down as needed. Only the central forecast is used in this process – generators cannot submit their own forecasts.

Among the forecasts AESO produces is also a short term (i.e. 2 hours ahead) forecast of the pool price. This forecast uses persistence data (rather than modelled data from the service provider) as the input for intermittent generation quantities, which is updated every 5 minutes.[15]

[14] See [Wind and Solar power forecasting (aeso.ca)](#).

[15] See [Pool price forecast calculation methodology (aeso.ca)](#).

4.2.3 Wind and solar dispatch

Intermittent generators must submit offers in price/quantity pairs for all available capacity.[16] However in practice, wind and solar generation almost always offer all available generation into the market at $0/MWh.

Once intermittent generation is dispatched, it is expected to generate energy equal to either the amount dispatched in the merit order or their physical generating potential (whichever is lower). It must not vary its output outside of the allowable dispatch variance, which is ±5MW from the dispatch quantity. However, if the real power capability is lower than the dispatch quantity, the generator may reduce its output below the dispatch quantity, but must ensure output is not less than 5MW below this real power capability.[17]

4.3 Incentives to forecast accurately

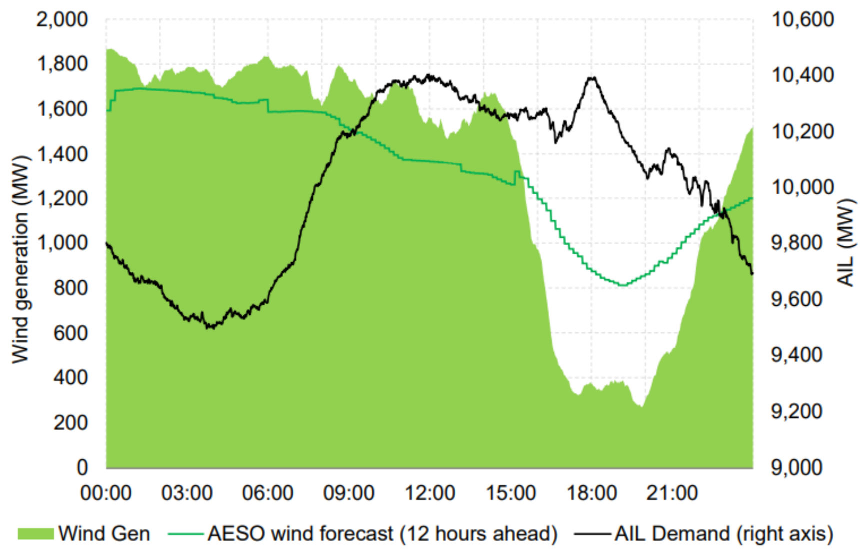
We have been unable to locate any specific information on the terms of the service provider contracts for the provision intermittent generation quantity forecasts. To the extent that incentives apply in relation to accuracy of forecasts, we assume these would be included in the service provider contracts.

4.4 Performance

We understand that this forecasting regime has generally worked well for Alberta. However, this is not always the case.

In February 2022 pool prices increased from $84.20/MWh to $999.64/MWh within three hours because of inaccurate forecasting. High wind generation forecasts had led to 1,800MW of gas-fired plant being taken commercially offline, but as shown in Figure 8 below, actual wind generation dropped sharply, causing the system supply cushion to reach 0MW for a short time and prices to spike.[18]

Figure 8: Alberta wind generation, wind forecast and Alberta Internal Load on 5 February 2022



[16] "Available capacity" refers to maximum potential generation irrespective of weather conditions.

[17] For generation resources with a capacity of 200MW or greater, the allowable dispatch variance is ±10MW. See [ISO Rules v7 (aeso.ca)] and [Consolidated Authoritative Document Glossary July 1 2021 (aeso.ca)].

[18] See [Quarterly Report for Q1 2022 (albertamsa.ca)].

5 United States: Texas electricity market

5.1 System characteristics

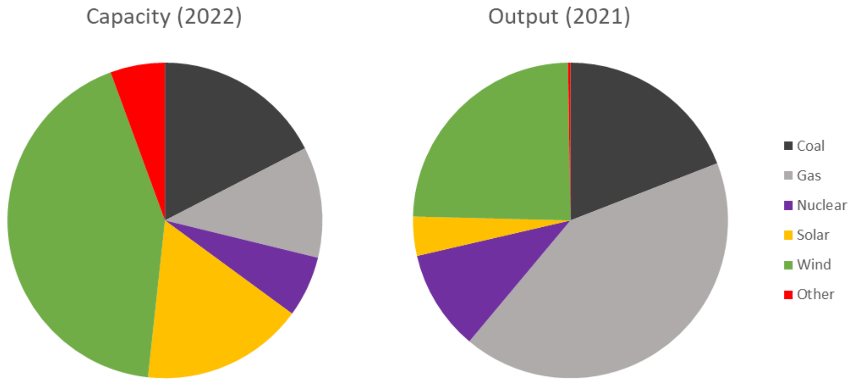
The Electricity Reliability Council of Texas (ERCOT) manages the grid that covers approximately 75% of Texas land area and serves about 90% of Texas' electrical load. ERCOT is the independent system operator for this grid, and also manages financial settlement of the wholesale market and administers retail switching for consumers.[19]

Like New Zealand, the ERCOT market is an energy-only market. It also has locational marginal pricing, where the price at each node is determined by the marginal cost of providing an additional unit of energy at that node. This marginal cost is based just on constraints, unlike in New Zealand where it also accounts for energy losses.[20]

While ERCOT also runs a day-ahead market, some resources (such as intermittent generation) do not typically participate in it.[21] For this reason we do not classify the ERCOT day ahead market as compulsory.

The ERCOT market is mostly fossil fuel-based, with over 60% of electricity coming from coal and gas generation. However, it has a high penetration of wind generation (24% of energy, 43% of installed capacity) and a reasonable solar generation base (4% of energy, 17% of installed capacity).[22]

Figure 9: ERCOT generation by fuel type



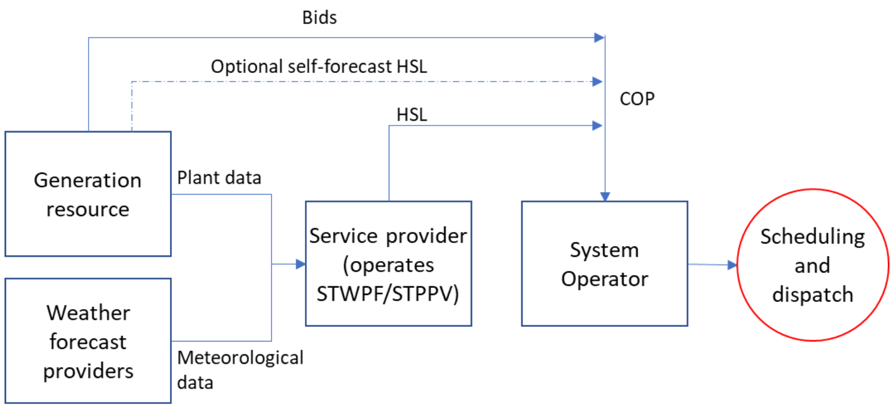
Source: ERCOT

5.2 Outline of forecasting process[23]

The Texas electricity market uses a centralised forecast of intermittent generation for scheduling and dispatch purposes. ERCOT uses third party service providers to produce short term wind and solar forecasts. These forecasts limit the energy quantities generators can offer, as generators must submit a Current Operating Plan with a High Sustained Limit that does not exceed the short-term forecast. The service providers' costs are covered by ERCOT's operating budget, which is funded by a charge on consumers and generators.

[19] See ERCOT Fact Sheet (ercot.com).
[20] See ERCOT marginal losses outcomes Nov 2017 (icf.com).
[21] See 2021 State of the Market Report (potomaceconomics.com).
[22] See Capacity Demand and Reserves Report (ercot.com) and Interval Generation by Fuel Report (ercot.com).
[23] See High level overview of ERCOT Wind Power Forecasting and Conceptual System Design PVGR Power Forecasting (ercot.com).

Figure 10: ERCOT simplified forecasting and dispatch process



5.2.1 Input data

Two service providers produce short-term wind and solar forecasts using the following data inputs:

- Registration data – this includes the precise locations and heights of turbines and meteorological towers, type and model of turbines, manufacturer's power curve, date of operations, etc. ERCOT provides the service providers with updated registration data weekly.
- Outage scheduler data – this includes any scheduled outages or deratings of generation resources.
- Real-time telemetry/operational data – this includes current resource status, current output and HSL and detailed weather data. For example, in Texas the potential effect of icing of wind turbines is a concern, and telemetry data includes information on temperature and humidity to assess the potential for icing to reduce wind farm output.[24] The data is telemetered via SCADA from the generator to ERCOT, and then provided to the service provider every 5 minutes.

Generators add economic data inputs (i.e. offer price bands) into the dispatch process by including them in their COPs along with the HSL.

5.2.2 Forecasting process

ERCOT engages external service providers to provide intermittent generation forecasts. Due to the critical nature of wind forecasting in Texas and the continued growth of wind generation, from 2018 ERCOT engaged a second service provider to provide an alternative wind forecast. A single service provider is used for solar forecasting. Each service provider produces several different types of forecasts.

Table 3: ERCOT forecasts produced for dispatch

Forecast	Horizon	Resolution	Usage
Short-term wind power forecast/short-term photovoltaic power forecast (STWPF/STPPF)[25]	7 days ahead	1 hour	Used in dispatch and in the day-ahead and hour-ahead reliability unit commitment (RUC) processes

[24] Icing of turbine blades reduces the power conversion of wind energy into electrical power (reducing accuracy of forecasts) and can cause turbines to be shut down to avoid damage if icing is sufficiently severe.

[25] The STWPF/STPPF is a P50 forecast. Service providers also produce wind powered/photovoltaic generation resource production potential (WGRPP/PVGRPP) forecasts, which are more conservative forecasts showing an 80% probability of exceedance. We understand that WGRPP/PVGRPP forecasts are used in financial settlements but we have been unable to obtain more information on how this information is used.

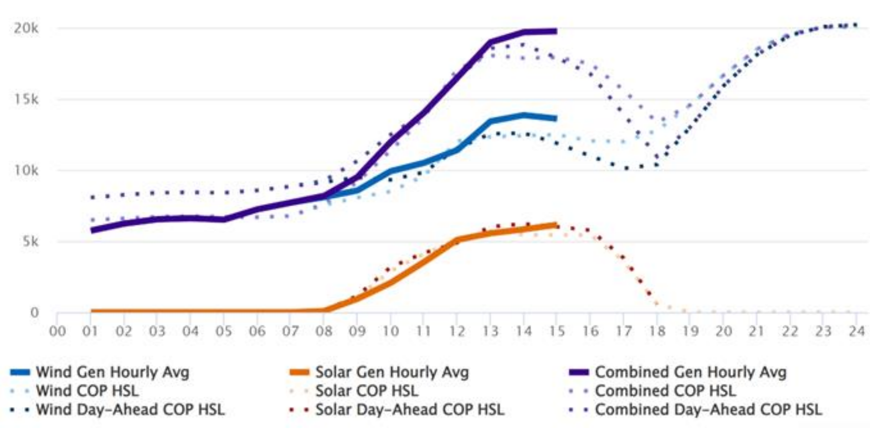
Extreme weather forecast (wind only)	7 days ahead	1 hour	Alternative forecast for dispatch. Predicts risk of extreme weather events occurring and likely impacts at a resource, regional and system-wide level. Includes 2 scenarios, "worst icing scenario" (all impacted turbines out of service) and "more likely scenario" (50% of impacted turbines out of service).
Intra-hour wind/photovoltaic power forecast (IHWPF/IHPPF)	2 hours ahead	5 min	Incorporated into the "Generation To Be Dispatched" (GTBD) calculation to allow for more efficient dispatch and better management of regulation resources.

For dispatch, ERCOT uses the STWPF/STPPF as a cap on a generator's offer quantity (see discussion about High Sustained Limits below). For wind generation, ERCOT has discretion to choose which service provider's forecast to use for this purpose, and also whether to use an extreme weather forecast in place of the STWPF.

All forecasts are delivered at different levels, i.e. for individual generation resources (published internally only), wind/solar regions (public) and system-wide (public).

ERCOT publishes these forecasts on its website. It also shows how actual generation compares to the forecasted generation, as shown below.

Figure 11: ERCOT example of forecast information



5.2.3 Wind and solar dispatch

Generators must submit a Current Operating Plan (COP) that reflects expected operating conditions for each generation resource for each hour in the next 7 days. These include the High Sustained Limit (HSL) for each generation resource, as well as each generator's price/quantity offers for the next 168 hours.

For intermittent generation, the HSL is the current net output capacity of the generation resource based on current weather and plant conditions (i.e. wind/irradiance and turbines/inverters online).[26] Unlike the nameplate capacity of the generation resource, the HSL will vary over time.

Previously, intermittent generators had to submit a COP with an HSL that did not exceed the STWPF/STPPF. However, this resulted in different generators updating their HSLs inconsistently, which led to reliability

[26] See Intermittent Renewable Resources (ercot.com).

challenges where HSLs did not closely match the forecast. This problem was expected to worsen as wind and solar penetration increased, so ERCOT now synchronises COPs with these short-term forecasts by automatically populating the HSL with the STWPF/STPPF figure. Intermittent generators now have the option to submit the COP with this pre-populated HSL or to amend it to a lower figure if necessary due to operating conditions. The HSL cannot be amended to be higher than the STWPF/STPPF.

ERCOT issues dispatch instructions known as "base points". We understand that deviations by an intermittent generator from its base point are not penalised unless the generator's output is capped (i.e. its base point is below its HSL) due to uneconomic prices or network constraints.[27] If generation is capped but output still exceeds the base point by more than 10%, then the generator is charged a base point deviation charge. However, we understand that this may be refunded if ERCOT is satisfied that the generator was taking all necessary actions to produce at/below the base point, but could not solely due to increasing energy output.[28]

5.3 Incentives to forecast accurately

The forecasting service providers are incentivised to forecast accurately due the contracts negotiated with ERCOT, which have performance-based payment structures.

Generators that do their own forecasting have a more limited incentive to be accurate, as self-forecasts can only cause the HSL (and therefore the dispatch base point) to be reduced. If a generator self-forecasts a higher output, that cannot be used in the dispatch process. If they incorrectly self-forecast a lower output, the main consequence will just be that they are dispatched a lower quantity, so they may have to reduce output to avoid a base point deviation charge (although this only applies if generation is capped).

5.4 Performance

We understand that there have not been any serious issues with the forecasting process in the ERCOT market at this stage (i.e. blackouts due to actual wind/solar generation being materially lower than forecasted). However, there have been some cases where forecast inaccuracies have required Texas' gas generation fleet to be ramped up at short notice, which resulted in higher prices and lower operating reserves.

[27] See Elements of Market Design that Support High Renewable Penetration - ERCOT (esig.energy).

[28] See Settlement guide BPD example (ercot.com).

6 Europe: various electricity markets

European Union (EU) member states have responsibility for regulating their electricity systems, subject to umbrella arrangements set at the EU level that are intended to foster pan-European competition.

This section briefly comments on the approach favoured by the European umbrella regulatory body, and arrangements in two member states.[29]

6.1 European Union – ACER view

The European Union includes many separate electricity markets. However, there is physical trade between member states and coordination of regulation across these markets, overseen by the Agency for Cooperation of Energy Regulators (ACER).

ACER's preferred approach is for forecasting arrangements to be decentralised, with strong incentives on generators to submit accurate forecasts.

In this context, it is noteworthy that electricity markets in EU member states all have a compulsory day ahead market.[30] This effectively makes their real time spot market a balancing market.

In ACER's view, this ensures that generators have strong incentives to provide accurate forecasts of the generation quantities they have available for sale.

[29] Technically speaking, the United Kingdom is no longer an EU member state. However, it was a member until recently, and its arrangements have not changed materially post-Brexit. It also retains physical interconnections with some EU member states.

In particular, any differences between actual generation and quantities cleared in the day ahead market will be cashed out in the balancing market.

For example, if an intermittent generator over-forecasts they will end up selling more generation in the ahead market than they actually produce. This means that they will need to purchase the shortfall on the balancing market. On the other hand, if a generator under-forecasts they will end up generating excess electricity that then needs to be sold on the balancing market. As forecasts change over time, generators are incentivised to trade away any imbalances right up to gate closure.[31]

While ACER prefers the decentralised approach to forecasting arrangements, we note that member states do not necessarily follow that guidance. As illustrated below, some member states have adopted centralised arrangements for forecasting intermittent generation for scheduling and dispatch purposes.

6.2 Ireland[32]

Wind and solar generation forecasting for electricity systems on the island of Ireland is undertaken on a unified basis across both the Republic of Ireland and Northern Ireland (part of the United Kingdom). The Irish system uses two external service providers to provide forecasts of generation quantities.

The two service providers produce forecasts using:

[30] These ahead markets have been standardised across the EU – see Single Day-ahead Coupling (SDAC) (entsoe.eu).

[31] However, as discussed in section 7.3 below, ahead markets do not always provide incentives for intermittent generators to forecast accurately.

[32] See Wind and Solar Forecasting Methodology (sem-o.com).

- standing data regarding the generation resource (provided prior to connection and as updated)
- SCADA and meteorological data (provided every 15 minutes)
- numerical weather prediction models.[33]

Table 4: Ireland forecasts[34]

Forecast	Horizon	Resolution	Usage
Unit level	4 days ahead	1 min for 4 hours ahead 15 min for up to 4 days ahead	Scheduling and dispatch Calculating unit lower operating limits
Aggregated system level (also Ireland and Northern Ireland)	4 days ahead	5 min	Information and display purposes (published every 6 hours)

The forecasts provided by the service providers do not initially consider outages. The System Operators incorporate plant, distribution and transmission outages to produce outage adjusted forecasts that are loaded into the scheduling and dispatch system.

Network and economic constraints are not incorporated into the forecasts, only for real-time operation.

In the dispatch process, a weighted average of the two outage adjusted forecasts is calculated, and schedulers review the forecast and can adjust it based on several factors (including flatness/variability of forecast, confidence interval, and direction of weather front).[35]

6.3 Great Britain

There are several different markets operating across Great Britain's electricity system. For the present purposes, the most relevant are:

- Day ahead electricity market – this is a financial market for trading on a short-term basis. It provides information for participants to help with commitment and other planning decisions.
- The balancing mechanism market – this refers to how the electricity system operator (ESO) balances real-time supply and demand through the Balancing Mechanism. In effect, the Balancing Mechanism acts as a spot market for cashing out imbalances.[36]
- The balancing services market – this includes various forms of reserve services to maintain security and power quality.

Our understanding is that forecasting of intermittent generation quantities is undertaken via a centralised arrangement, under the auspices of National Grid ESO. The extent to which forecasting is undertaken by service providers or by the ESO itself is unclear. It also appears that forecasting processes are currently undergoing significant development, with the objectives of materially improving the usefulness of information and

[33] For wind generation only, as an enduring solar forecasting solution is still in development.

[34] See Business Process BP_SO_04.3 Wind-Forecasting.pdf (sem-o.com).

[35] Adjustments are often made to forecasts to flatten peaks and raise troughs. See The EirGrid Journey (eirgridgroup.com).

[36] See Electricity markets explained (nationalgrideso.com).

forecast accuracy.[37] The modified process appears likely to retain a centralised approach to forecasting intermittent generation quantities.

In terms of the forecasts themselves, these include information on available quantities of intermittent generation (in MW) over the coming 14 day period, estimated 'usable' day-ahead quantities at half-hourly resolution, forecast outturn quantities (presumably after constraints and other factors are accounted for) and forecast peak wind generation for the next 24-48 hours.[38]

[37] See Platform For Energy Forecasting (PEF) Strategic Project Roadmap Update June 2020 (nationagrideso.com).

[38] See Generation Forecasts BMRS (bmreports.com).

7 Concluding observations

In this section we draw together some observations based on our review of forecasting arrangements for intermittent generation in certain other jurisdictions and discussions with overseas regulators.

These observations are relatively high-level in nature and are not intended to provide any formal evaluation of the regimes, as that was outside the scope of our brief.

7.1 What should 'good' forecasting arrangements strive for?

It might be tempting to think that forecasting arrangements should strive to achieve the greatest possible level of forecast accuracy. However, that goal may not necessarily be desirable because there are costs associated with improving forecast accuracy.

Put simply, the real goal should be to minimise the sum of forecasting costs and the cost of forecast errors. For example, in a system with very low intermittent generation penetration, forecast errors will impose little or no cost. Hence there would be few benefits from improving forecast accuracy. Likewise, if flexibility from other generation sources was free, forecasting would be of little or no benefit. Naturally, the reverse is also true – more accurate forecasts will have greater benefit in systems with high intermittent penetration or where flexibility from other sources (e.g. demand response or thermal generation) is relatively more expensive.

These observations haves some important implications for the design of forecasting arrangements. First, the aim should be to produce the types of forecast information that benefits the electricity system. For example, in systems that are heavily reliant on slower-starting thermal generation, accurate 12-24 hour ahead forecasts of intermittent generation could be more important than forecasts with shorter horizons. Conversely, for systems that have resources that can respond with little notice but which are energy constrained (such as those with a large volume of battery storage), forecasts over shorter horizons could be more important.

Second, the forecasting needs in coming years could be different from past years. This is because the scale and cost of forecasting errors will likely change as the system evolves. In particular, as intermittent generation becomes an increasing proportion of total supply, the effect of errors will be magnified. All other things being equal, this will increase the benefits from improving the accuracy of forecasts.

In summary, it is important to ensure that forecasting arrangements focus on producing the type of information of greatest benefit for scheduling and dispatch purposes, and that arrangements are flexible so they can evolve to meet changing needs over time.

7.2 Incentives matter with decentralised approaches

The quality of forecasts will be influenced by the incentives on the parties responsible for compiling those forecasts. While this observation may seem obvious, it is important to keep in mind.

For example, if the responsibility for forecasting rests with generators, it is important to consider the incentives they have to submit accurate forecasts for scheduling and dispatch purposes. Dealing first with their commercial incentives, these may be quite weak or even absent if the generator[39] is selling the generation output on a fixed price variable quantity basis. This is because the variable quantity aspect of the sale contract makes generators largely indifferent to spot prices and hence there is little direct interest in short-term forecasting accuracy.

Even if the generator is exposed to spot prices, it may not bear the full cost of errors in its own forecasts. For example, if a generator over-estimates its output and in real-time a more expensive source of supply is required, the additional cost is unlikely to fall on the generator.[40]

This necessitates other forms of incentives being required if a decentralised approach is used. One option is to apply forecasting standards, backed by penalties for non-compliance. However, this presupposes that the desired level of accuracy can be specified in workable terms and monitored against.

As noted above, the definition of 'desirable' is likely to vary according to system conditions. For example, in some trading periods an error will not matter much but in others it could have very significant consequences. More generally, the effects of errors are likely to change over years as the system evolves. These factors make it hard to prespecify penalties that match the level of harm from forecast errors.

In addition, from a system perspective, what really matters is the accuracy of overall forecasts. If two intermittent generators have forecast errors that are the same size but in opposite directions, there is no particular harm from a system perspective. However, a standards-based approach could end up penalising both generators for their errors.

7.3 Ahead markets may provide robust forecasting incentives

In principle, compulsory ahead markets provide a means to create forecasting incentives that are robust and will scale according to system conditions. This is because intermittent generators (along with all other wholesale participants) must submit an offer into the ahead market for their expected level of generation. Any difference between the ahead quantity and their output is settled at the balancing market price, which will reflect conditions in real-time.

For example, an intermittent generator that over-forecasts its output will pay the balancing price for the shortfall generation quantity (i.e. the generator's quantity cleared in the ahead market less its actual production). If the intermittent generator's shortfall occurs at a time of very tight supply, the balancing price will be high, and vice versa. This has the desirable property that the 'penalty' for forecast errors should scale up and down to reflect system conditions.

Another desirable feature is that offsetting forecasting errors tend to net out. For example, consider the case where two intermittent generators have equal and opposite forecast errors, but every other party produces and consumes the quantities cleared in the ahead market. In that situation, the ahead-market and balancing prices will be the same, so although one generator will receive cash for its extra production while the other pays for its quantity shortfall, their final positions will be the same as if they had forecasted their output accurately initially.

[39] In this context, generator should be read as the party which determines the price and quantity offer for the plant. In some cases this could be a buyer of the plant's output rather than the party that directly operates and maintains the plant.

[40] The intermittent generator may even benefit if the more expensive source of supply increases the system marginal price that the generator receives.

While ahead markets can be viewed as solving many of the incentive challenges in relation to forecasting, there are some important caveats. Firstly, retro-fitting a compulsory ahead market would be a significant undertaking and introduces additional complexity for market participants. Second, some market participants may be reluctant to participate in the ahead market because their output (or demand) is very uncertain. If participation is compulsory, they may seek to counter this by biasing their generation offers downward (effectively reducing their participation). This means their ahead market offer will not represent a central estimate of output. Buyers may likewise reduce their demand bids.

To counter this type of behaviour, some jurisdictions apply a penalty to the balancing market price (a discount for cashing out positive imbalances, and a premium for cashing out negative imbalances) to incentivise participants to use the ahead market and minimise their balancing market exposure. However, such penalties may also create an unintended bias in ahead market offer quantities, especially if they are not symmetrical.

Another issue with ahead markets is that they lock-in quantities for a particular time horizon (or horizons if they have multiple cycles). The choice of time horizon(s) can reflect the particular needs of the system, but once set it can be difficult to readjust them.

Lastly, ahead markets require participants (including intermittent generators) to lock-in a single estimate for their forecast level of output. As noted earlier, other types of forecast information may also be very useful for scheduling and dispatch purposes, such as the forecasts of P10 or P90 level of output. Those other types of information will typically not be revealed via ahead market offers.

7.4 Incentives with centralised forecasting approaches

Incentives are important with centralised approaches. They are typically focussed on the service provider(s) that compile the forecasts.

Incentives can be explicit (e.g. financial rewards for accuracy as in ERCOT) or implicit (e.g. loss of contract when the term is complete). There also need to be incentives on generators to ensure they provide accurate plant information to the service provider (such as planned outage schedules), but this is easier to define and monitor.

Finally, it is important to avoid any bias in incentives for the forecaster (or party engaging the forecaster). Such a bias could lead to reliability problems or undue costs for consumers. For example, a downward bias in forecasting intermittent generation output could lead to over-procurement of other resources and additional constrained-on costs. To minimise the scope for unintended bias, the forecasting objective (e.g. P50) should be clearly specified with regular reporting to measure performance.

It is worth noting that system operators often have a mandate and an operational ethos that focuses on reliability. Reliability failures are also more high-profile than cost inefficiencies. As such, forecasts prepared or procured by a system operator may be biased towards under-forecasting intermittent generation in order to prioritise system reliability over cost efficiency. On the other hand, electricity regulators tend to have a more balanced mandate that includes cost efficiency as well as reliability,[41] so forecasts prepared or procured by regulators may not have such biases.

7.5 Pros and cons of decentralised / centralised approaches

Decentralised arrangements have the advantage that they provide more scope for generators to apply localised knowledge and information that may be difficult for a centralised arrangement to capture.

Examples of such information in overseas jurisdictions were the effect of dust levels on photovoltaic panel efficiency for some solar farms, and the impact of blade icing on wind turbine generator performance. While centralised arrangements can take account of such factors, they may not necessarily be recognised when arrangements are first designed because they have localised impacts. Decentralised approaches are likely to allow such 'distributed' knowledge to be reflected more quickly into forecasts used for scheduling and dispatch purposes than centralised processes which by nature must be more standardised.

Decentralised approaches may also reduce the impact of any forecasting methodology biases on forecasts. This is because generators are less likely to apply a uniform methodology if arrangements are decentralised. As a result, any biases will affect only the relevant generators' forecasts rather than the entire class of intermittent generation on system (assuming a single provider is used in a centralised approach).

However, decentralised approaches rely on generators having a robust incentive to provide accurate forecasts for scheduling and dispatch purposes. For the reasons discussed in section 7.2, it would be very challenging to create such incentives via penalties in the market rules.

In principle, systems with compulsory ahead markets would provide a way to create robust financial incentives on generators to accurately forecast their intermittent generation output. However, as discussed in section 7.3, compulsory ahead markets increase the complexity of arrangements and would need to be carefully designed to yield unbiased forecast estimates. Furthermore, by their nature, ahead markets create a single central estimate for forecast output. Other measures of forecast generation such as likely minimum or maximum levels may also be important for scheduling and dispatch processes.

Centralised approaches also face incentive issues, but they are focussed on the forecasting service provider and the quality of inputs provided by generators (e.g. SCADA data). The former can be addressed in the service provider's contract terms. Such contracts can reward providers for accuracy, and encourage effort to be applied to aspects of forecasts which are most important (for example, the relative effort to be applied to mid-point versus sensitivity ranges). Having made these points, some level of forecasting error will be unavoidable so incentives will only be useful up to a point in reducing forecast errors.

In respect of input data provided by generators, it is more straightforward to define quality standards and incentives for these matters, and to monitor performance.

[41] For example, the main statutory objective of the Electricity Authority in New Zealand is to "promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers".

Centralised approaches may also allow faster adaption to reflect changing needs, once a need for change has been identified and accepted. For example, if there was a desire to make forecasts more granular (such as by moving to shorter intervals), this should be easier to achieve via an amendment to a single service provider contract than via market rule changes and subsequent amendments to individual generator/forecaster arrangements.

Finally, hybrid approaches are also possible. For example, some systems (for example Australia and Texas) with centralised approaches allow generators to overwrite the central forecast with their own information where this is expected to be more accurate, subject to some conditions and restrictions.

Finally, in both decentralised and centralised approaches there is a need to monitor the quality of forecasts and address any problems such as bias.

7.6 Comparison with New Zealand arrangements

We have not assessed New Zealand's arrangements as that is not part of the scope of this project. Nonetheless, it is useful to briefly comment on how New Zealand's arrangements compare to those found overseas.

In summary, New Zealand uses the decentralised approach, with generators having the responsibility to provide forecast generation levels for scheduling and dispatch purposes.[42]

In terms of incentives on generators, New Zealand's arrangements have a relatively light-handed approach. New Zealand does not have a compulsory ahead market, and the Code does not include strong provisions in relation to forecast accuracy.

The system operator does not have any formal responsibility for forecasting intermittent generation. However, we understand that it procured wind forecasts during the 2022 winter on a trial basis, and shared the information with the market when there were material divergences between the forecast commissioned by the system operator and generation offers. We understand this has led to generators to revise offers at times.[43]

Overall, New Zealand's arrangements appear to be unusual because they allocate forecasting responsibility to generators, but there are no formalised arrangements to strongly incentivise accurate forecasts.

[42] The Code prescribes some aspects of the process.

[43] See Driving efficient solutions to promote consumer interests through winter 2023 (ea.govt.nz).

8 Summary table

Jurisdiction	Responsibility for forecast quantities	Responsibility for economic inputs (offers)	Key usage	Forecast horizon
Australia	Centralised	Decentralised	• Generation capacity available for dispatch • Reserve requirements	Up to 40 hours ahead (dispatch) and 7 days ahead (reserve assessment)
Alberta	Centralised[44]	Decentralised	• Anticipating net demand for dispatch process • Forecast pool prices	Up to 7 days ahead
Texas	Centralised (two forecasters)	Decentralised	• Default (or maximum) capacity available for dispatch • Reliability unit commitment	Up to 7 days ahead
UK	Centralised	Not entirely clear but expect it will be decentralised	• Publication for market participants • Scheduling of generation	Up to 14 days ahead
Ireland	Centralised (two forecasters)	Decentralised	• Scheduling and dispatch • Calculating unit lower operating limits • Publication for market participants	Up to 4 days ahead
EU	Decentralised	Decentralised	• Positioning in ahead markets	Depends on participant

[44] See discussion at section 4.2.2.

9 Glossary

ACER	Agency for the Cooperation of Energy Regulators
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AESO	Alberta Electric System Operator
ASEFS	Australian Solar Energy Forecasting System
AWEFS	Australian Wind Energy Forecasting System
COP	Current Operating Plan
ERCOT	Electric Reliability Council of Texas
ESO	Electricity System Operator
EU	European Union
GTBD	Generation To Be Dispatched
HSL	High Sustained Limit
IHPPF	Intra-Hour Photovoltaic Power Forecast
IHWPF	Intra-Hour Wind Power Forecast
LMP	Locational Marginal Pricing
MSA	Market Surveillance Administrator
NEM	National Energy Market
PVGRPP	Photovoltaic Generation Resource Production Potential
RUC	Reliability Unit Commitment
SCADA	Supervisory Control and Data Acquisition
ST PASA	Short-Term Projected Assessment of System Adequacy
STPPF	Short-Term Photovoltaic Power Forecast
STWPF	Short-Term Wind Power Forecast
UIGF	Unconstrained Intermittent Generation Forecast
WGRPP	Wind Powered Generation Resource Production Potential