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Energy
Policy WA

Operational Forecasting in the WEM Review

Consultation Paper

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Abbreviations

Term	Definition
ADER	Aggregate Distributed Energy Resource
AEMO	Australian Energy Market Operator
ALFS	Automated Load Forecasting System
ASEFS	Australian Solar Energy Forecasting System
AWEFS	Australian Wind Energy Forecasting System
BRP	Balance responsible party
CAISO	California Independent System Operator
DA	Day Ahead
DER	Distributed energy resources
DERMS	Distributed Energy Resource Management System
DFS	Demand Forecasting System
DPV	Distributed Photovoltaics
DSPs	Distribution Service Providers
DWD	German Meteorological Service
ECM	Energy Conversion Model
EMS	Energy Management System
EPWA	Energy Policy WA
ERA	Economic Regulation Authority
ERAA	European Resource Adequacy Assessment
ERCOT	Electric Reliability Council of Texas
ESOO	Electricity Statement of Opportunities
ESS	Essential System Services
FCESS	Frequency Co-optimised Essential System Services
FRP	Flexible Ramp Product
GB	Great Britain
GSP	Grid supply point
GTBD	Generation To Be Dispatched
HA	Hour Ahead
IHWPF	Intra-Hour Wind Power Forecast
LSEs	Load Serving Entities
LTS	Long-term scheduling
MAE	Mean Absolute Error
MAPE	Mean average percentage error

Term	Definition
MMS	Market Management System
MTLF	Mid-Term Load Forecast
NEM	National Electricity Market
NESO	National Energy System Operator
NWP	Numerical Weather Prediction
Ofgem	Office of Gas and Electricity Markets
ORDC	Operating Reserve Demand Curve
PASA	Projected assessment of system adequacy
PN	Physical notifications
POE	Probability of Exceedance
PUCT	Public Utility Commission of Texas
QSEs	Qualified Scheduling Entities
REPs	Retail Electric Providers
RERT	Reliability and Emergency Reserve Trader
REZs	Renewable Energy Zones
RMSE	Root Mean Squared Error
RTC	Real-time commitment
RTD	Real-time dispatch component
RTM	Real-time market
RUC	Reliability Unit Commitment
SCED	Security-Constrained Economic Dispatch
SEM	Ireland and Northern Ireland
STLF	Short-Term Load Forecast
STPASA	Short term projected assessment of system adequacy
STWPF	Short-Term Wind Power Forecast
SWIS	South West Interconnected System
TEWPF	Total ERCOT Wind Power Forecast
TSO	Transmission system operator
UIF	Unconstrained injection forecast
UIGF	Unconstrained intermittent generation forecasts
UKPN	UK Power Networks
UOD	Unscheduled operational demand
US	United States
WEM	Wholesale Electricity Market
WEMDE	WEM Dispatch Engine

Term	Definition
WPMS	Wind Power Management System

Executive summary

Operational forecasting in the WEM

As the SWIS undergoes a transition towards net zero, the operational forecasting challenge evolves with increasing demand and supply side uncertainty. Accurate operational forecasting is a prerequisite for a secure, reliable and efficient energy market.

The Operational Forecasting Review (Review) aims to ensure that operational forecasting practices in the Wholesale Electricity Market (WEM) are fit-for-purpose and align with best practices in the National Electricity Market (NEM) and internationally.

Operational forecasting in the WEM is a 'centralised' process (i.e. undertaken by the Australian Energy Market Operator (AEMO)) with the exception of utility intermittent generation forecasting, which is partially decentralised. Operational forecasting in the WEM can be thought of as a two stage process.

- In the first stage, AEMO produce forecasts of demand for energy and ancillary services and for intermittent generation (which are based on market submissions made by participants).
- In the second stage, these forecasts are used in the dispatch and pre-dispatch processes along with other market data (e.g. participant real-time market submissions) to produce 'forecasts' of market outcomes, which AEMO and participants base operating decisions on.

There are many similarities between jurisdictions' approaches (of which seven were reviewed in this study) to operational forecasting and some key differences. The WEM stands out in this review in that participant self-forecasts for intermittent generators are relied upon, but incentives for participants to produce accurate self-forecasts for intermittent generators are weak. Other practices in reviewed jurisdictions form the basis of the recommendations arising from the Review.

Electricity forecasting of both the demand and supply side is driven by weather forecasts. Therefore, there are two ways to improve electricity forecasting accuracy:

- improve the input forecasts into demand/supply forecasts (i.e. weather forecasts including temperature, wind speed, irradiance); or
- improve the forecasting models themselves.

The recommendations arising from the Review target both of these aspects.

Forecasting error may also arise in different components of the forecasting process. For example, forecasts of demand during evening peaks may be a problem, or forecasting of rooftop PV may be a particular problem. This Review assesses the impact of different components in the forecasting processes against inefficient outcomes observed in the market.

Intermittent generation (particularly wind) forecasts are identified as a key problem, in that wind forecast error is often identified as a potential contributor to inefficient outcomes observed in the market. The wind forecasts in the lead up to extreme peak demand days have been particularly problematic.

Call for Submissions

Stakeholder feedback is invited on the Operational Forecasting in the WEM proposals that are outlined in this paper. The consultation period closes at **5:00pm AWST on 28 August 2025.**

Submissions can be emailed to energymarkets@deed.wa.gov.au.
Late submissions may not be considered.

Any submissions not marked as confidential will be published on www.energy.wa.gov.au.

Design Proposals and Rationale

Table 1 lists the proposals arising from the Operational Forecasting Review, along with a summary of the rationale for each proposal.

Table 1: Operational Forecasting Review Proposals

Proposal	Rationale
Proposal 1: Reconsider Blending Parameters. AEMO should review its approach to persistence forecasting and how these forecasts are blended with foundation forecasts. AEMO should consider shortening the period over which it blends these forecasts, blending differently for different sites, or not blending at all and adopting an alternate approach.	Current blending parameters drive material forecast errors when there are fast changes in demand or supply. For periods such as the "solar shoulders" this is predictable and can be better accounted for in forecasts.
Proposal 2: Enhance Collaboration with weather providers. AEMO should enhance collaboration with a number of weather providers to improve weather forecasts used in demand forecasting and especially for intermittent generation resource availability forecasts. Specifically, the focus should be on improving the quality, frequency, and understanding of uncertainty of weather forecasts, and enabling delivery of these forecasts in a state that can inform market forecasts.	Limitations to weather data inputs restrict the granularity and accuracy of operational forecasts produced by AEMO. Ways to drive improvement in these outputs should be investigated in collaboration with weather information providers as they could materially improve market outcomes. This is common practice in other jurisdictions.
Proposal 3: Enhance documentation and processes. AEMO should develop documentation of its forecasting process, including how it is implemented in its forecasting model, as well as a technical specification for the model. AEMO should review the use of its separate development and production environments for its forecasting system and the change management processes in place.	Model documentation, including a detailed technical specification, is important for operability, transparency and reproducibility. This should also minimise institutional knowledge loss and improve effective onboarding. AEMO should minimise risk where possible by ensuring a robust change management system for its operational forecasts.
Proposal 4: Address the lack of incentive to produce accurate intermittent generation forecasts. Intermittent generation forecasts used in WEMDE should be produced by AEMO. Participants should be required, under the rules, to provide necessary information for AEMO to produce these forecasts.	Participants with intermittent generation currently have limited incentive to forecast accurately or improve forecasts over time. Clause 7.4.2 of the ESM Rules requires that participants use "reasonable endeavours" to provide accurate forecasts. "Reasonable endeavours" is difficult to monitor and enforce, and the nature of intermittent generation

	forecasting is complex. Both of these aspects would likely make enforcement of this clause difficult. Consequently, this provides little to no incentive for participants to produce accurate forecasts and improve them over time.
Proposal 5: Publish operational forecasting metrics. A rule obligation should be introduced for AEMO to publish metrics for the tracking of forecast and backcast errors for its operational forecasting.	Transparency in operational forecasting accuracy would benefit all energy market stakeholders. Allowing participants to better understand forecasts and providing evidence of a need for change to commence any future upgrades to the forecasting system. Including through errors in forecasting driven by the increased uptake of DER, and being able to address these as they arise.
Proposal 6: Formalise large load information provision. Operators of large loads should be obligated to provide AEMO with consumption forecasts and notify AEMO of unexpected changes to forecast schedules as they arise.	Based on the undertaken materiality analysis (covering approximately one year of data), which did not find evidence of errors, EPWA considers that this voluntary approach has worked to date and may continue to work in the future. However, this approach may also present a risk – there is nothing preventing these loads from deciding to not provide, or limit, the information provided to AEMO. This presents a low probability but high impact risk to the WEM. This risk would be greatly increased if a large flexible load were to connect to the system.

2. Introduction

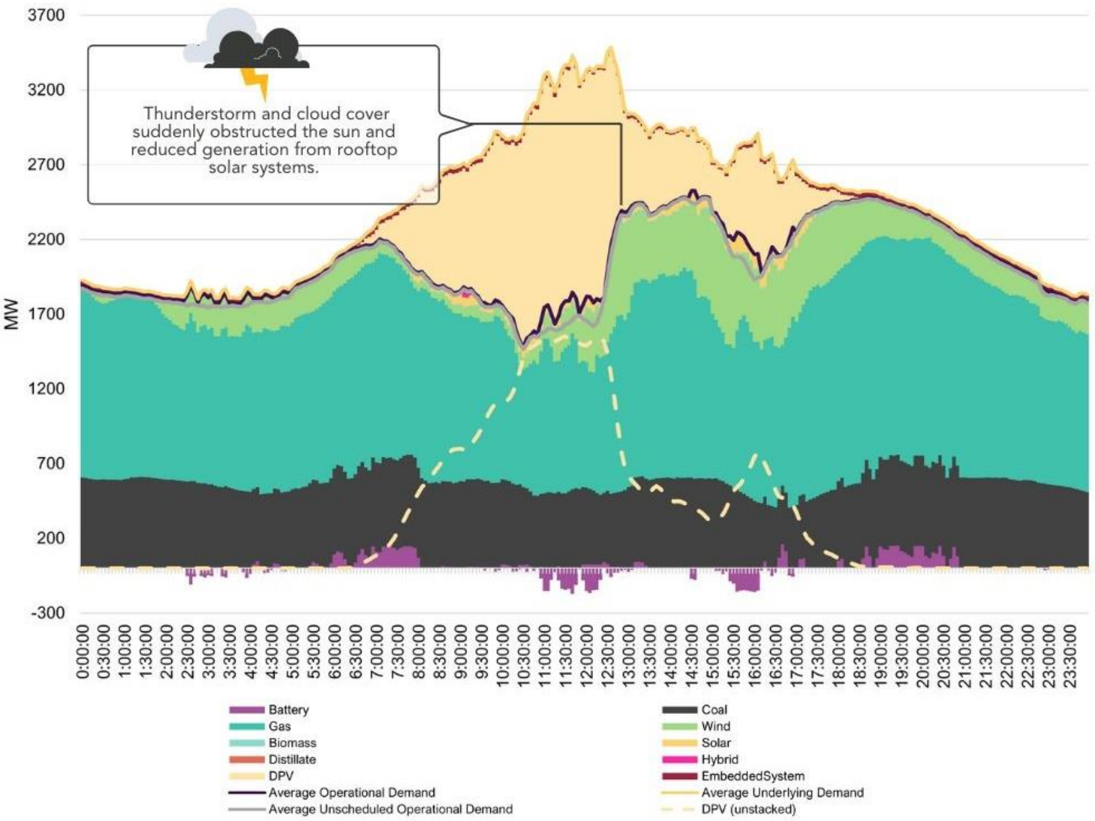
2.1 Background

2.1.1 The Need for Review

Accurate operational forecasting is a prerequisite for a secure, reliable and efficient energy market. As the South West Interconnected System (SWIS) undergoes a transition towards net zero, the operational forecasting challenge evolves with increasing demand and supply side uncertainty. Intermittent renewable generation and distributed energy resources (DER) represent growing shares of the energy mix and present their own forecasting challenges.

By way of example, Figure 1 shows the effect that shocks in rooftop solar output can have on demand, driving a sudden and significant increase in operational demand. These challenges exist for all intermittent resources that may change output unexpectedly as the weather changes. In these cases, dispatchable assets must be ready to fill the gap, and accurate forecasts ensure the lowest cost mix of these assets are available when required.

Figure 1: Change in operational demand caused by DPV



Source: AEMO LinkedIn, https://www.linkedin.com/posts/australian-energy-market-operator_western-australias-power-system-is-rapidly-activity-7308000587839590400-j_Kr?utm_source=share&utm_medium=member_desktop&rcm=ACoAADlHNmABVsQ6mRqzCG8FsoBsKmsf9EdbESE

Following implementation of the WEM reform, there have been frequent short-lived incidences of unforeseen high price events, which are indicative of potential inefficient outcomes. With better market signals through improved forecasting accuracy, these events may be avoidable. This could reduce resource costs and lower market prices.

New technologies, such as Artificial Intelligence, present opportunities for improving the ability to produce accurate forecasts. In particular, these technologies are being experimented with in other jurisdictions to improve the frequency and accuracy of weather forecasts, and to reduce the computational complexity of weather models, which inform electricity demand and supply forecasts.

Stakeholders have raised concerns with the quality of forecasts in the WEM and the uncertainty this presents for their market participation. Greater forecast accuracy can reduce the likelihood of shortfalls that cause significant spikes in market prices.

As the WEM continues to evolve it is paramount that the operational forecasting used to determine dispatch is as accurate as possible.

2.1.2 Scope of the Review

The Operational Forecasting Review aims to ensure that operational forecasting practices in the WEM are fit-for-purpose and align with best practices in the NEM and internationally.

Here, ‘operational’ refers to the operational time scale, which in the WEM spans from the current period to seven days ahead. Forecasts of demand and supply are produced and used in the scheduling, pre-dispatch and dispatch processes. These forecasts are the basis of market signals, indicating expected prices and dispatch[1], and inform decisions of both the market operator and market participants. Inaccurate forecasts may drive inefficient market outcomes as AEMO and/or participants make decisions on factors that do not eventuate, increasing resource costs (e.g. by burning higher-cost fuels than necessary) and creating transfers from consumers to producers (e.g. through higher market prices).

In the WEM, operational forecasts are produced for demand (mass market, some large loads, and some Essential System Services (ESS)) and supply (intermittent generation). These forecasts are then used as inputs in market dispatch and pre-dispatch processes to produce market forecasts (including prices).

A workshop and several meetings were held early in the review with Frontier Economics, Energy Policy WA (EPWA) and AEMO to consider which specific elements of operational forecasting should be considered in the review. Forecasts of ESS requirements and constraints were not included, except for Distributed Photovoltaics (DPV) forecasts that inform contingency requirements.

This review does not consider forecasts of ESS requirements or constraints. These are considered by a separate review currently undertaken by EPWA. This separate review of the ESS Process and Standards is assessing the ESS framework under the ESM Rules to ensure that it is functioning efficiently, and maintaining power system security and reliability at the lowest cost to consumers.

2.2 Purpose and Structure of this Paper

This Consultation Paper sets out the findings and recommendations for the operational forecasting review. It presents proposals to change operational forecasting practices to better align the WEM with best practices in other jurisdictions.

This Consultation Paper is structured as follows:

- Chapter 3 covers current operational forecasting practices in the WEM and provides a comparison with practices in selected jurisdictions;

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[1] As well as many other market outcomes

- Chapter 4 covers the assessment of materiality of sources of forecasting error in the WEM; and
- Chapter 5 covers proposals for change arising from the review.

3. Operational Forecasting

This chapter:

- discusses operational forecasting practices in the WEM at a high level, with a detailed description in Appendix A;
- summarises operational forecasting practices in other jurisdictions, with a detailed review in Appendix B; and
- compares operational forecasts in the WEM with other jurisdictions.

3.1 In the WEM

Operational forecasting in the WEM is a 'centralised' process (i.e. undertaken by AEMO) with the exception of utility intermittent generation forecasting, which is partially decentralised. Intermittent generation potential (i.e. unconstrained output) forecasts are required from participants via real-time market (RTM) offers, and AEMO is required to use these or better information available to produce forecasts.

AEMO produce the following market forecasts (including forecasts of prices and dispatch) utilising its market dispatch software called the WEM Dispatch Engine (WEMDE):

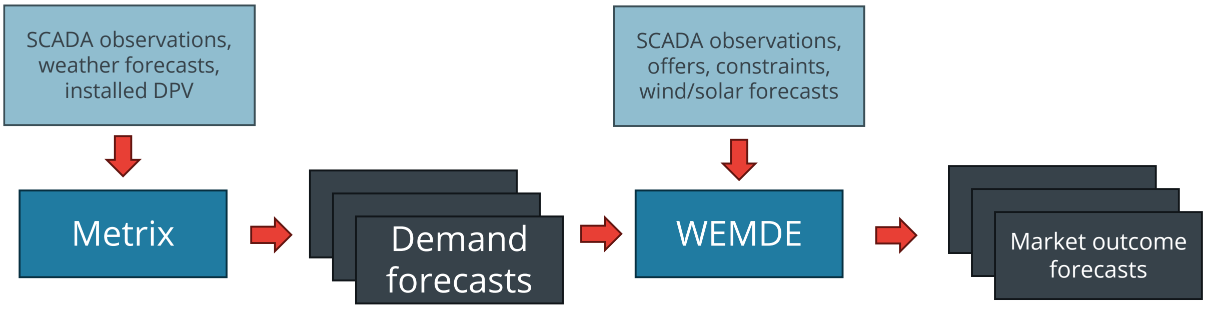
- dispatch: 5-minute frequency, 5-minute granularity, two hours ahead;
- pre-dispatch: 30-minute frequency, 30-minute granularity, two days ahead; and
- short term projected assessment of system adequacy (STPASA): Daily frequency, 30-minute granularity, seven days ahead.

Each of these market forecasts incorporates (i.e. WEMDE takes as input):

- An unscheduled operational demand forecast, which is prepared prior to the market forecast. Demand forecasts account for the impact of rooftop solar PV and movements of unscheduled large loads.
- Forecasts of utility-scale intermittent generation, which are in practice a blend of persistence forecasts and Real Time Market offers made by respective participants.

The forecasting process is illustrated at a high level in **Figure 2** and in detail in **Figure 6**.

Figure 2: High-level schematic of relevant components of AEMO's forecasting process



Source: Frontier Economics

A detailed overview of AEMO's approach to the relevant components of operational forecasting is presented in Appendix A and summarised as follows.

Demand forecasts are made up of two key components:

- Unscheduled mass-market load net of embedded generation. Weather forecasts are a key input to this model, including temperature for demand level and irradiance/cloud cover for contribution from DER.
- Unscheduled large loads, for which forecasts are provided voluntarily by the load participants themselves.

Intermittent generation forecasts of ‘unconstrained injection’ potential are provided by participants via RTM submissions in the first instance. AEMO is required to use these forecasts or alternative forecasts, if AEMO reasonably considers these alternatives to be more accurate. In practice, due to issues with accuracy of these forecasts and in accordance with clause 7.2.4A of the Electricity System and Market Rules (ESM Rules), AEMO overwrites the first two hours of a participant’s RTM unconstrained injection forecast (UIF) with the current UIF linearly blended (i.e. 100%-0% over two hours) with the RTM offers.

AEMO implicitly forecasts the impact of DPV in the mass-market demand forecasting process mentioned above, and also explicitly forecasts DPV for determining ESS contingency requirements. These explicit DPV forecasts rely on different input data to the implicit forecasts of mass-market demand.

3.2 In other jurisdictions

A detailed review of operational forecasting practices in other jurisdictions is available in Appendix B. Key themes from this review are noted as follows:

- The demand forecasting process for operational demand is generally the responsibility of the market operator and produced in a centralised fashion. The exception to this is Germany, which considers bottom-up forecasts from ‘balancing responsible parties’ (BRPs).[2]
    - Larger markets typically have more resources invested in the demand forecasting process. For example, both Texas and California employ meteorologists on their energy forecasting teams and also have the benefit of numerous sources of weather forecasts that can be used to produce probabilistic forecasts.
    - Transmission System Operators (TSOs) in Germany and the National Energy System Operator (NESO) in Great Britain have collaborated with meteorological services to improve weather forecasts that are used by energy forecasting processes.
- The forecasting process for intermittent generation can be either centralised (market operator or transmission system operator) or de-centralised (participant), or both. Where the process is de-centralised (or partially decentralised), there is typically a certification process (e.g. California Independent System Operator (CAISO), AEMO (NEM)) and/or incentives are in place for accurate forecasting (Germany and the NEM).
- The most important determinant of electricity demand forecasts is weather, and it is common to procure multiple weather forecasts from different providers, and break up forecasting regions into smaller weather- or network-related regions.

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[2] BRPs in Germany do not have a direct equivalent in the WEM. BRPs are responsible for a balancing group, which is a portfolio of generation and load. A balancing group might include power stations, individual customers or the entire generation and load of a retailer. Every generator and consumer in Germany is included in a balancing group. A BRP is responsible for preparing forecasts of feed-in and off-take for the balancing group and is responsible for shortfalls or surpluses within their balancing group, including through exchange of electricity with other balancing groups.

- Where DPV penetration is significant, forecasting cloud cover is a difficult and ongoing issue. Visibility of DPV and increasing DER is also an ongoing concern.
- Jurisdictions seek to improve their forecasting model performance by improving the models themselves, but importantly also by improving the quality of the data that is input into the model. There are numerous examples of Energy System Operators (ESOs) or TSOs partnering with meteorological services to improve the frequency and/or quality of weather observations and forecasts with the explicit purpose of improving energy forecasting.
- Many jurisdictions have developed probabilistic forecasting approaches to reflect uncertainty in demand and intermittent generation. These probabilistic forecasts may be based on multiple input weather forecasts from different providers (e.g. Texas with 14 different forecasts) or from a static analysis of historical uncertainty (e.g. AEMO in the NEM). Probabilistic forecasts are used in different ways, from procuring ramping services (e.g. CAISO) to providing situational awareness to market operators.
- If relevant information is available, those responsible for producing forecasts generally have incentives to produce accurate forecasts. For example, the funding for NESO in Great Britain is tied to its ability to produce accurate forecasts (as determined by the regulator). In California, participants can pay to use the market operator's forecasts or can provide their own forecasts subject to an accreditation process. In the WEM, participant self-forecasts are accepted, but these are not subject to any performance criteria, and participants are not subject to strong incentives for accurate forecasts.

3.3 Comparison between the WEM and other jurisdictions

The WEM is the smallest market considered in the inter-jurisdictional review by a significant margin and is somewhat unique in its high DPV penetration. Operational demand forecasting in the WEM is centralised and utility intermittent generation forecasts are partially decentralised in the form of persistence forecasts blended by AEMO with RTM offers.[3]

The approach to intermittent generation forecasting in the WEM is an outlier. For forecasts that are used in WEMDE, the current practice is that AEMO receives UIF information from participants in their RTM submissions, and modifies the first two hours of the forecast to carry forward the initial SCADA UIF value with decreasing significance.

In essence, AEMO in accordance with clause 7.2.4A of the ESM Rules, overwrites the participant forecast in the short term (favouring 100% persistence of the initial SCADA UIF value), and then progressively gives more weight to the participant forecast in the longer term. This is directionally opposite to AEMO's practice in the NEM, which provides the option of participant self-forecasts in the very short term (next five-minute dispatch interval), but produces centralised forecasts beyond that.

Participants in the WEM have little incentive to forecast accurately - Clause 7.4.2 of the ESM Rules requires participants to use "reasonable endeavours" to provide accurate forecasts. There is no way for the Economic Regulation Authority (ERA) to automatically detect whether this clause has been breached or administer a penalty. A suspected breach would require the ERA to undertake an investigation and then decide if a penalty is applicable.

AEMO produces centralised forecasts of intermittent generation output for its Control Room, which are based on wind speed and solar irradiance forecasts and facility level power curves. AEMO has indicated that the use of this internal forecasting approach is for 'visibility purposes' and that the Control Room considers participant RTM offers for comparison.

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[3] Centralised intermittent forecasts are produced for the control room, but these are not used in dispatch.

The WEM is an outlier in that it relies on participants to produce intermittent generation forecasts with little incentive for accurate forecasting and no accreditation processes. All jurisdictions reviewed with decentralised intermittent generation forecasting include one or both of these controls. Where incentives apply to the accuracy of forecasts, they apply very close to dispatch, i.e. to short-term forecasting.

While the jurisdictions reviewed make incremental improvements to forecasting methodologies (including specifications, processes and adjustments) over time[4], there is a recent emphasis on improving the quality of input data in collaboration with national and/or private weather services, particularly as the intermittent generation output shares increase.

The objective of these improvements is to increase the accuracy, frequency and/or understanding of uncertainty associated with the weather forecasts. For jurisdictions with significant penetrations of DPV and/or utility PV, improving the quality of inputs relating to solar forecasting has been a key focus, and cloud cover forecasting is recognised as a particularly difficult problem[5].

A 2024 United States (US) Department of Energy workshop on solar forecasting[6], discussed how different organisations in the US are tackling the solar forecasting problem and its key challenges. There is a suggestion that deep learning approaches will be able to replace Numerical Weather Prediction (NWP)[7] approaches at lower cost[8], although the evidence is not yet clear. There is also evidence of deep learning approaches to blend outputs of physical models significantly improving forecast accuracy[9] (25% is quoted, although it is unclear what this means in practice).

Based on publicly available information, larger markets (e.g. Texas and California) employ meteorologists directly in their electricity forecasting teams. EPWA understands that AEMO, in both the NEM and the WEM, have embedded meteorologists or have introduced priority access to meteorologists to assist with electricity-forecasting related matters. For example, EPWA understands that the level of collaboration between AEMO in Western Australia and weather providers – in terms of developing new forecasts or improving the accuracy/frequency/understanding of uncertainty for the purpose of electricity forecasts – is lower than of the reviewed jurisdictions (noting that these are generally larger markets).

Of the reviewed jurisdictions, only Texas regularly reports on operational forecasting[10] accuracy measures. Electric Reliability Council of Texas (ERCOT) publishes rolling forecast accuracy measures of short-term forecasts including back-cast accuracy results, and the data and calculations behind the metrics. This is helpful in providing confidence that model specifications and modelling processes are appropriate.

In the NEM, AEMO produce an annual ‘Forecasting Accuracy Report’, which focuses on longer-term forecasting. EPWA understands that the WEM Electricity Statement of Opportunities (ESOO) reports will report on the accuracy of previous long-term forecasts in

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[4] For example, CAISO has developed a ‘mosaic’ model – a quantile regression model based on component forecasts – for assessing uncertainty. The NEM forecasting team at AEMO appears to be adopting something similar for its ‘Forecast Uncertainty Measure’ – see ‘Operational Forecasting Fusion Platform project’, slides 29th October 2024.

[5] See, for example, “Best models still don’t capture ramps”, slide 138, https://www.energy.gov/sites/default/files/2024-07/SETO%20-%20Solar%20Forecasting%20Workshop%20-%20Day%202.pdf

[6] Slides for both days are available: https://www.energy.gov/eere/solar/2024-solar-forecasting-workshop

[7] Numerical Weather Prediction is a method of forecasting weather that uses mathematical models and simulations to predict weather. NWP computer models process current weather observations, which are assimilated into the model’s framework and used to produce forecasts.

[8] Slides 76 and 77, workshop Day 1

[9] Slide 8, workshop Day 2

[10] Operational forecasting here referring to the period, not the measure of demand.

the previous ESOO.[11] Other jurisdictions occasionally produce accuracy metrics in various reports, but nothing formalised and regular.

Improving forecasts by acknowledging the probabilistic nature of demand and intermittent generation has been another key focus area for improvement in most jurisdictions. Approaches to probabilistic forecasting differ. The ERCOT approach is to procure many (14) weather forecasts and use samples from the resulting distribution to produce forecasts which represent probabilistic outcomes. CAISO and AEMO, in the NEM and the WEM, use observed historical uncertainty in forecasts (i.e. historical inaccuracy) to project forward uncertainty.[12] This approach has the advantage of identifying potential error relating to inputs as well as model specifications and processing, whereas the Texas approach will only include errors related to inputs.

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[11] See bullet on p14, “For the WEM, the forecast accuracy of the past ESOO forecast will be assessed in the following ESOO.” https://www.aer.gov.au/system/files/2024-08/AEMO%20-%20Electricity%20Demand%20Forecasting%20Methodology%20-%20August%202024.pdf

[12] Noting that CAISO has more recently also incorporated weather forecast information into this measure.

4. Assessment of materiality of sources of forecasting error in the WEM

This chapter outlines the approach taken in the review to assess which sources of forecast error are related to the most material market inefficiencies. Results of the assessment are presented, and have guided priority areas for assessment and proposals for change.

Specifically, this chapter includes:

- a discussion of the sources of forecast error;
- a discussion around assessing materiality of forecast error, and the approach taken in this review; and
- findings from the assessment of operational forecasting error and inefficiency.

4.1 Sources of forecast error

Sources of forecast error may relate to:

- Input error: e.g. the weather forecasts used in demand forecasts may be inaccurate.
- Model misspecification: e.g. irrelevant variables may be used, relevant variables may be omitted, or the functional form of the model may be inappropriate.
- Model implementation: e.g. the model may be trained on out-of-date information, or trained on a very long horizon which masks recent trends.
- Pre- and post-model calculations: e.g. smoothing and blending processes may increase, rather than decrease, error.

Each of these areas may contribute to forecasting error in different ways. It is important to distinguish between the sources of error to ensure that the problematic forecast areas are addressed. For example, spending a lot of effort improving input forecasts to a demand forecasting process may not be of much benefit if the actual source of the error is a mis-specified model.

Ultimately, there are two important questions which help in diagnosing where forecast error arises from. These are:

1. Given correct inputs, does the model produce accurate predictions?
2. Can the quality, frequency, and/or understanding of uncertainty of inputs be improved?

If the model produces accurate forecasts when given accurate inputs, any forecast error is likely driven by issues with model inputs, for example the weather forecasts that inform electricity consumption forecasts. If the model does not produce accurate forecasts with accurate inputs, forecasts can be improved by addressing issues with the model itself.

More broadly, these types of forecast error may arise in different components of AEMO's forecasting process. These components (outlined in detail in Appendix A) include:

- 'baseload' demand forecasts;
- large load demand forecasts;
- utility-scale intermittent generation forecasts; and
- DPV forecasts.

In this section, the primary focus is on identifying the sources of forecasting error as they relate to these different components.

4.2 Materiality of forecasting errors

For this assessment, the ‘materiality’ of a forecast error is assumed to mean its effect on wholesale market outcomes, and in particular whether the forecast error results in market inefficiencies.[13]

There are three types of economic (in)efficiency:

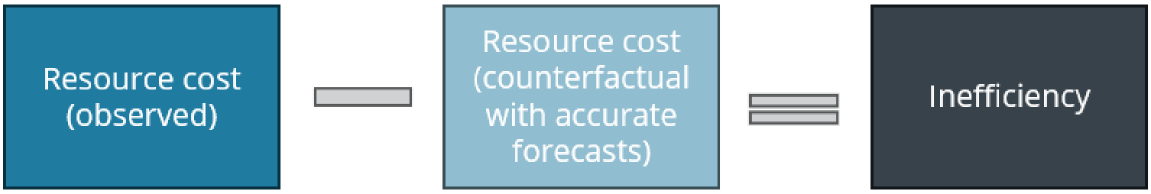
- Productive: are we operating the system at lowest cost?
- Allocative: are resources allocated to their highest value uses?
- Dynamic: is productive and allocative efficiency maintained over time?

When we think about market inefficiencies arising from forecasting error, we need to consider each of these aspects of efficiency. Given the short-term nature of operational forecasting and the nature of electricity dispatch, the primary focus is on productive efficiency. However, questions of allocative efficiency (e.g. do forecast errors facilitate gaming) or dynamic efficiency (e.g. do forecast errors send inappropriate price signals) are also important considerations.

Importantly, the materiality of forecasting errors depends on more than just the magnitude of the forecasting error itself. It also depends on the context in which it occurs. For example, forecast errors that occur during the time of peak demand may have more implications for inefficient outcomes than forecast errors made at other times.

Measuring the materiality of forecast errors is conceptually simple. The obvious approach to this would be to compare the resource cost of actual outcomes with the resource cost of a counterfactual outcome in which forecasts were accurate. Subtracting one resource cost from another would identify the inefficiency arising from inaccurate forecasts. This is illustrated in Figure 3.

Figure 3: Conceptual method of measuring inefficiency



Source: Frontier Economics

In theory, one could use WEMDE and information gathering powers to reconstruct counterfactuals substituting inaccurate forecasts for accurate forecasts. If participant behaviour could be induced[14] given counterfactual WEMDE forecasts with accurate components (e.g. a more accurate demand forecast), re-run WEMDE outputs could be compared with actual outputs and the difference in resource cost compared.

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[13] Another interpretation of materiality may be the numerical error in the forecast, as measured by forecasting accuracy metrics such as Mean Average Percentage Error.

[14] Meaning that participants would provide honest and accurate accounts of behaviour when presented with alternative scenarios.

Given the complexity of re-running dispatch, the inability to accurately induce participant behaviour, and the frequency of dispatch, this approach is not a practical one. For this review, the methodology described in the following section was adopted.

4.2.1 Assessment methodology

To assess the relationship between forecast errors:

- WEMDE input and output files from 1 Jan 2024 to 23 Jan 2025 were processed and detailed 'dashboard' style collections of charts were generated, with one dashboard for each day. These figures show forecasts, behaviour and outcomes in the RTM at a high granularity. Forecast evolutions charted against actual values show forecast error over time, and outcomes like price and dispatch provide 'markers' of potential inefficient outcomes.
- Each day's chart was inspected and a corresponding table row was filled out. The following assessment process was undertaken:
    - Are inefficient outcomes present? For example, are there high-cost liquid fuel generators operating prior to the start up of cheaper gas-fired generators that run for the remainder of the evening?
    - If yes, are there contemporaneous forecast errors in the 'right' direction (i.e. an under-forecast of demand or over-forecast of supply).
    - If yes, the sources of this forecast error and the magnitude of the inefficiency were noted.

As noted, these assessments are necessarily high-level, somewhat subjective and not privy to full information.[15] However, by analysing many forecasts across various scenarios over many days, recurring patterns and themes over the period became apparent, which are discussed in the following sections.

EPWA also notes that the new WEM is an evolving market and there have been significant changes made to the market over the period analysed in this Review. In particular, changes around scheduling for Frequency Co-optimised Essential System Services (FCESS) services and the treatment of 'in-service' components of submissions are likely to have materially improved efficiency. Despite these changes, the recurring themes identified above generally persist throughout the period observed.

4.3 Findings on operational forecasting error and inefficiency

4.3.1 Prioritising sources of forecast error

Sources of forecast error were prioritised based on their frequency relative to different magnitudes of inefficient events. This data is tabulated in Figure 4. Market outcomes are graded from least impact (light purple) to most impact (dark purple). For each level of impact, the frequency of events attributable to a source of forecast error is indicated by a colour scale ranging from green (least frequent) to red (most frequent).

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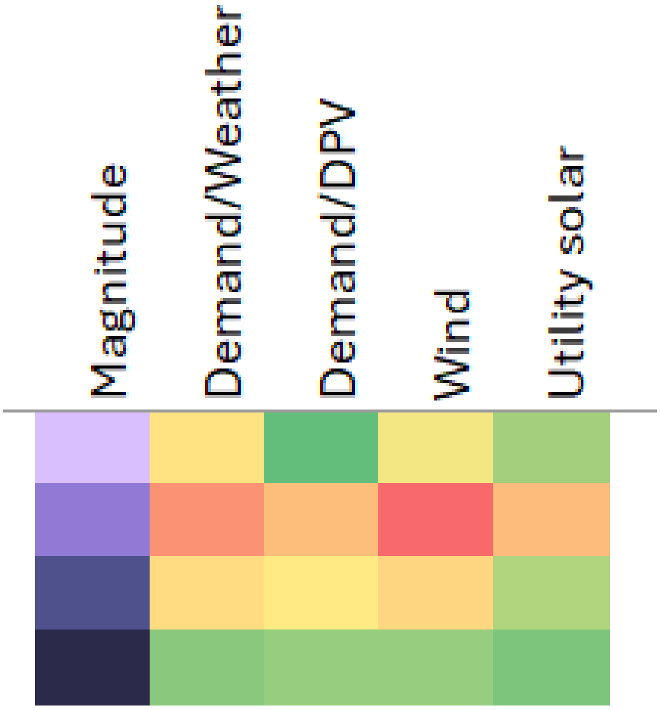
[15] The public WEMDE data doesn't include all component forecasts, forward-looking case input files, or any case input files for pre-dispatch. This means, for example, that changes in RTM offers leading up to particular intervals were not considered.

Figure 4: Tabulation of sources of forecast error related to different magnitudes of inefficient events



Source: Frontier Economics

Based on this table, the following areas were identified in order of priority:

- wind facility generation forecasts;
- weather inputs to demand forecasting;
- DPV inputs to demand forecasting; and
- utility solar facility generation forecasts.

Due to the similarities in the way wind and utility solar forecasts are sourced, any rule or policy change that affects wind forecasting is likely to affect utility solar forecasting in a similar manner.

4.3.2 Materiality of sources of forecast error

Figure 4 illustrates the result of the assessment of the sources of forecast error that are related to inefficient outcomes at different materiality levels. As noted, this is a challenging exercise with numerous and significant limitations. However, the analysis does identify patterns which may be useful in highlighting priority areas for consideration of forecast improvements.

In particular, in undertaking the analysis, it was noted that there are frequent events where:

- high prices are not forecast in dispatch;
- high-cost generation is dispatched (leading to high market prices);
- this high-cost generation is then displaced by lower-cost generation coming online shortly after; and
- there are coincident forecast errors that either understate demand or overstate generation for the relevant period.

There are similar and related events in which:

- high prices are not forecast in dispatch;
- low-cost generation de-commits;
- high-cost generation is dispatched (leading to high market prices); and
- there are coincident forecast errors that either understate demand or overstate generation for the relevant period.

Given the publicly available information, and considering the project timeframes and effort required for the analysis, it is not possible to definitively link forecast errors to these outcomes. However, these events are frequent, and EPWA considers that the analysis does provide some evidence that addressing the most frequent and significant forecast errors will improve outcomes by providing better price signals – and hence improved commitment/de-commitment outcomes – in the future.

5. Proposals for change

5.1 Reconsider blending parameters

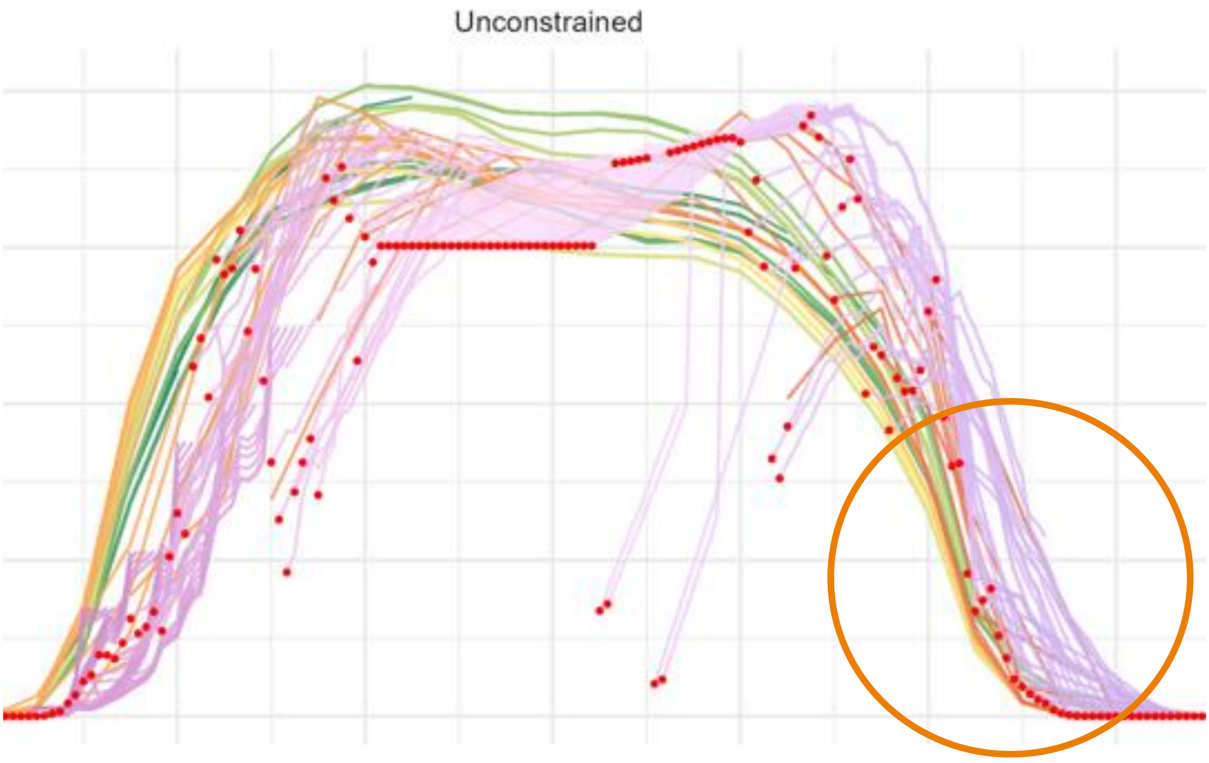
This recommendation is relevant to intermittent generation forecasts and large load forecasts, which both use blending parameters to implement a persistence forecasting approach, in accordance with clause 7.2.4A of the ESM Rules.

AEMO uses blending parameters to combine a persistence forecast and foundation forecast, or to blend different foundation forecasts of different time scales.

For intermittent generation forecasts, AEMO uses blending parameters to combine a persistence forecast and RTM offers over a span of two hours. This approach prevents ‘step changes’ in forecasts, where participant forecasts are substantially different from current production. While there may be circumstances in which this improves the accuracy of forecasts (e.g. when participant RTM forecasts are inaccurate), this approach also limits the ability of the forecast to adjust to real changes in supply (e.g. when wind speeds are forecast to drop off rapidly) and leads to other systemic errors in the forecasts even when good information about resource is available.

This is commonly observed in solar production in the morning and evening, when forecasts lag actual demand as persistence prevents values from reaching actuals. This is illustrated in Figure 5, showing various solar forecasts over the course of a day. There is good information about when solar PV is likely to stop generating (based on the time of sunset), but the persistence/blending approach continues to forecast output later into the evening.

Figure 5: Unconstrained solar generation forecasts



Source: Frontier Economics’ analysis of WEMDE data

Proposal 1:

AEMO should review its approach to persistence forecasting and how these forecasts are blended with foundation forecasts. AEMO should consider shortening the period over which it blends these forecasts, blending differently for different sites, or not blending at all and adopting an alternate approach.

Consultation Questions:

(1)(a) Do stakeholders have any concerns with AEMO altering its approach to blending forecasts?

This change will be increasingly important as forecasts improve. As a general principle, the better the forecast, the more inaccuracy is introduced by the use of a persistence/blending methodology. For example, if a forecast accurately predicts a shock in the output of a resource (e.g. a large load planning an outage period), the persistence blending will incorrectly keep the final forecast near its current level.

On presenting this proposal, AEMO informed EPWA that it was examining changing blending parameters and is considering reducing the solar PV blending window.

5.2 Investigate collaboration with weather providers

Improving electricity forecasts requires improving the forecasting models and processes, and/or improving the inputs to the forecasts, i.e. the weather forecasts that inform electricity forecasts. This recommendation focuses on the latter.

Limitations of input (weather) forecasts are a barrier to improving energy forecasting outcomes. For example, solar irradiation forecasts are published infrequently with four updates a day. Given cloud cover can change rapidly, and be hard to predict, the solar PV forecasts are often relying on ‘stale’ data (albeit the best data available).

AEMO informed EPWA that it is having ongoing discussion with weather providers, on improving forecasts. EPWA notes that collaboration between ESOs and weather services for improving electricity forecasts in the manner proposed here is common internationally. This reflects the fact that weather forecasting is a key component of electricity forecasting.

International examples tend to focus on intermittent generation forecasting. Recent examples, potentially of interest, include using deep learning to improve output of NWP models, combining output of multiple NWP models or replacing NWP models (DOE Solar Forecasting Workshop).

Recent initiatives observed in other markets – for example those described in the DOE Solar Forecasting Workshop[16] and cloud forecasting initiatives in the NEM[17] – could provide a starting point for discussion with weather providers.

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[16] https://www.energy.gov/sites/default/files/2024-07/SETO%20-%20Solar%20Forecasting%20Workshop%20-%20Day%201.pdf and https://www.energy.gov/sites/default/files/2024-07/SETO%20-%20Solar%20Forecasting%20Workshop%20-%20Day%202.pdf

[17] For example, https://arena.gov.au/assets/2021/02/solcast-nowcasting-lessons-learnt-report-3.pdf

Proposal 2:

AEMO should enhance collaboration with a number of weather providers to improve weather forecasts used in demand forecasting and especially for intermittent generation resource availability forecasts. Specifically, the focus should be on improving the quality, frequency, and understanding of uncertainty of weather forecasts, and enabling delivery of these forecasts in a state that can inform market forecasts.

Consultation Questions:

(2)(a) Do stakeholders see a role for participants to provide or utilise additional site-specific data in forecasting?

5.3 Enhance documentation and processes

Model documentation, including a detailed technical specification, is important for operability, transparency and reproducibility. The documentation should explain what the underlying approach is (including model structures, parameters, and pre- and post-model adjustments) to improve institutional knowledge and for training purposes.

Model documentation should be written so that parties unfamiliar with the model can understand how it works at a reasonably detailed level. This should minimise institutional knowledge loss and improve effective onboarding.

AEMO advised that it does have separate development and production environments, however, a more detailed examination of these indicated that AEMO should review its use of these different environments. Appropriate change management processes should also be implemented to prevent accidental or unintended changes.

Proposal 3:

AEMO should continue to develop documentation of its forecasting process, including how it is implemented in its forecasting model, as well as a technical specification for the model.

AEMO should review the use of its separate development and production environments for its forecasting system and the change management processes in place.

Consultation Questions:

(3) Do stakeholders have any concerns with AEMO enhancing documentation and reviewing internal forecasting practices?

5.4 Address the lack of incentive to produce accurate intermittent generation forecasts

Intermittent generation (particularly wind) forecasts are identified as a key problem, in that wind forecast error is often identified as a potential contributor to inefficient outcomes observed in the market. The wind forecasts in the lead up to extreme peak demand days have been particularly problematic.

Participants with intermittent generation currently have limited incentive to forecast accurately or improve forecasts over time. Clause 7.4.2 of the rules requires that participants use “reasonable endeavours” to provide accurate forecasts. “Reasonable endeavours” is difficult to monitor and enforce, and the nature of intermittent generation forecasting is complex. Both of these aspects would likely make enforcement of this clause difficult. Consequently, this provides little to no incentive for participants to produce accurate forecasts and improve them over time.

In the inter-jurisdictional review, it was observed that there are three ways in which the accuracy of intermittent generation forecasts is encouraged:

- Forecasts are produced by market operators or transmission service operators (i.e. centralised). These operators may have regulatory and/or financial incentives to produce accurate forecasts.
- Participants self-forecast and are incentivised to produce accurate forecasts, including through balancing payments tied to inaccurate forecasts. These incentives are short-term in nature (i.e. the following trading period or dispatch interval) and do not incentivise long-term forecast accuracy.
- Participants are ‘certified’ to self-forecast based on a benchmark or approval process determined by the system operator.
    - **In the NEM:** Participants are permitted to self-forecast for the next 5 minutes, and have an incentive to produce accurate forecasts. This incentive is based on Frequency Performance Payments (implemented June 2025, formerly incentivised through ‘causer pays’ ancillary service cost recovery) which reward/penalise participants for their impacts on system frequency. AEMO reverts to its Australian Wind Energy Forecasting System (AWEFS) and Australian Solar Energy Forecasting System (ASEFS)[18] for forecasts of intermittent generation in the longer term.
    - **In California:** Participants who are certified by the system operator must provide forecasts up to three hours ahead, at 15-minute granularity. The certification monitoring process constantly monitors the accuracy of the forecasts. Participants are still required to provide on-site meteorological data to CAISO, and CAISO reserves its right to suspend certification if forecast performance drops to worse than that of CAISO, or if CAISO reasonably believes that forecasts are being made with any intention other than being an unbiased representation of future output. This recognises the risk of gaming by participants.

The current arrangement in the WEM, namely the regulatory (“reasonable endeavours”) obligation for accurate information is another option for encouraging accuracy of intermittent generation forecasts.

EPWA notes that, even when self-forecasting of intermittent generation occurs, system operators also produce forecasts of intermittent generation. This may be for assessing a balancing requirement (Germany), for certification (the NEM), and/or to provide a forecasting service if participants do not forecast themselves (California and the NEM).

EPWA has considered each of the options listed above as well as other incentive-based schemes for self-forecasting (e.g. incentives over longer forecast horizons, payments/charges for improvements/regressions over time) for the WEM. EPWA considers that the best solution for the WEM is a centralised arrangement i.e. AEMO produces intermittent generation forecasts. This is for the following reasons.

- Intermittent generation forecast accuracy in the WEM is important at all points in the operational forecasting horizon, and it is difficult to design appropriate incentives for anything but the very short term. For incentives to be effective, they should be proportional to the harm that they cause or avoid, and harm is difficult to measure over the longer term. Large incentives for minor harms will lead to inefficient behaviour, and vice-versa.

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[18] AWEFS and ASEFS produce wind or solar generation forecasts, respectively, for all semi-scheduled wind and solar generating units, and for significant non-scheduled generating units, in the NEM. The forecasts are generated for dispatch, 5-minute pre-dispatch, pre-dispatch and short-term PASA processes.

- Harm in the very short term (i.e. the next trading period) can be measured by a participant's contribution to (or avoidance of) balancing energy utilisation.[19] Harm in the longer term is considerably more difficult to measure for the same reasons outlined in Section 4.2 – counterfactual outcomes based on alternative forecast error scenarios are extremely difficult to quantify.
- For longer-term self-forecasting incentives to persist would, therefore, require the following to determine the incentive.
    - The size of an incentive, which would necessarily be arbitrary; and
    - The benchmark against which forecasts are assessed, which could be:
        (i) actuals, against a centralised forecast;
        (ii) a nominal target; or
        (iii) based on improvement over time.

    Each of these options has non-trivial equity challenges.
- Participant self-forecasting creates the possibility of gaming - participants could bias forecasts to produce high intermittent generation output forecasts during key periods, such as periods of low demand, discouraging commitment of generation and leading to higher prices overall. It would be difficult to design a certification scheme and/or incentives that can effectively combat gaming of the forecasts. This is because it can be very difficult to identify what is genuine error in forecasts, and what is participant driven gaming of submitted forecasts.
- Centralising forecasts has economies of scale benefits but trades off the diversity-of-thought benefits of self-forecasting. That is, in the centralised approach, AEMO can efficiently improve its forecasting methodology which applies to all intermittent facilities, lowering the per-facility forecasting cost. However, this loses the benefit of having multiple parties thinking about the same problem and bringing different – and potentially better – data and approaches to the table. Individual participants may be able to forecast intermittent generation output better than AEMO.
- From the jurisdictional review, EPWA understands that the most important limiting factor in accurate intermittent generation forecasting is the input forecasts, i.e. forecasts of wind speed and solar irradiance. Power conversion models and intermittent generation forecasting techniques (using weather forecasts as inputs) are well understood; the key parameters in these models are static parameters relating to the properties of the facility (number of turbines, type of turbines etc) and weather forecasts. System operators collect detailed information relating to the static parameters from participants. It is unclear that diversity-of-thought benefits will improve these models or techniques meaningfully, and participants are not well placed to drive improvement in weather forecasting[20].

AEMO produces forecasts for each large intermittent generation facility in the WEM for the control room 'visibility purposes'. Clause 7.2.4A of the ESM Rules provides that AEMO can use alternative forecasts if AEMO considers that these will be likely more accurate. It can be

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[19] This is what currently occurs in the NEM. Participants can opt to self-forecast for the following dispatch interval, in order to avoid the (measurable) impact they have on ancillary service requirements. AEMO's centralised forecast determines the remainder of the forecast horizon.

[20] EPWA notes that incentives for accurate forecasts may drive participants to install additional resource metering to improve short-term forecasts, e.g. by installing private wind meters in the outer vicinity of their project. This may be efficient for short-term (next trading period) forecasts but is unlikely to be efficient for longer- term forecasts. In other jurisdictions, this on-site weather telemetry must be provided to the operator to assist in the development of their short term forecasts.

inferred that AEMO produces at least some better information than participant forecasts alone.

This proposal will likely require a rule change. Currently, AEMO has the option of using participant forecasts or their own forecasts in WEMDE. A centralised forecast approach will likely require additional information about intermittent generation facilities to be provided to AEMO. This additional data is likely to include:

- Static registration information including facility capabilities and equipment used to capture weather data.
- Outage/de-rate schedules including plans for scheduled outages, and live updates on unplanned outages.
- Real-Time Meteorological Information, including weather data collected at the site of wind and solar resources.
- In the case of hybrid facilities, additional information relating to the dispatchable component of the facility (see discussion below).

The timely provision of this information will be required for AEMO to produce forecasts.

Rules about intermittent generation RTM submissions will likely also need to be changed. This should not override the proposal in the WEM Deviation Method process to allow participants to self-forecast[21] for the next dispatch interval.

Hybrid facilities which do not distinguish between dispatchable and non-dispatchable components present a problem for any forecasting arrangement, including the status quo and the proposal for change. Having a facility which can submit a dispatchable bid as a UIGF is an undesirable outcome as it may have incentives to misrepresent available output through these bids. A centralised forecaster has limited ability to forecast what a dispatchable component of a hybrid facility may do.

Ideally, regardless of the forecasting arrangements, there should be separate visibility of co-located IGR and ESR facility output and forecasts, with renewable resource availability and ESR offers both visible separately in dispatch. Where this is not possible under existing arrangements, a centralised forecaster will require separate visibility of co-located IGR and ESR facility output and capability (including UIGF and storage levels). Further, the centralised forecaster will require an understanding of how participants intend to use dispatchable components of these facilities. Participant submissions regarding intentions for dispatchable components and behaviour will need to be monitored for compliance to prevent gaming.

AEMO, raised concerns that this proposal would present significant risk for AEMO, and that there will be potentially substantial implementation costs, because additional data would be required from participants and IT systems would need upgrading.

EPWA acknowledges that there may be additional costs in moving away from the current method. However, this review has demonstrated that accurate intermittent generation forecasting is an important competency for system operators, even when participants self-forecast. While AEMO would be assuming reputational risk for producing accurate forecasts, this creates an incentive to produce accurate forecasts and improve them over time. This proposal should reduce price spike events and FCESS/energy shortfalls that impose a significant cost to the market. EPWA also acknowledges that there will be some level of forecasting error regardless of who produces forecasts. However, this Review has found:

- There is room for improvement in forecasting accuracy in the WEM, particularly with regards to intermittent generation forecasting. Exactly how much room for improvement exists is unquantifiable prior to implementation.

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[21] https://www.wa.gov.au/system/files/2023-06/cost_allocation_review-information-paper-final.pdf

- There are significant potential efficiency gains to improving forecasting accuracy in the WEM. Even if a small fraction of inefficient events are avoided, the benefits of implementing the proposed change are likely to exceed expected costs of implementing the proposed change.[22]

Proposal 4:

Intermittent generation forecasts used in WEMDE should be produced by AEMO. Participants should be required, under the rules, to provide necessary information for AEMO to produce these forecasts.

Consultation Questions:

(4)(a) Do stakeholders support introducing a centralised forecasting approach with AEMO producing intermittent generation forecasts for use in WEMDE?

(4)(b) Do stakeholders have concerns about providing the required information to enable AEMO to produce intermittent generation forecasts to be used in WEMDE?

(4)(c) Do stakeholders have any views on the allocation of the implementation costs to move towards a centralised forecasting approach?

(4)(d) Do stakeholders anticipate challenges in providing the type of data required to AEMO in a timely manner?

(4)(e) Do stakeholders have any views on the proposed treatment of hybrid facilities?

5.5 Publish operational forecasting metrics

Transparency in operational forecasting accuracy would benefit all energy market stakeholders. Publishing forecast and backcast accuracy metrics would:

- Provide a benchmark for AEMO’s operational forecast accuracy, and information on how this benchmark changes over time. Where appropriate, this benchmark could be compared to other jurisdictions.
- Ideally, improve stakeholder confidence in AEMO’s forecasts and forecasting capability, and demonstrate that AEMO’s forecasting models are fit-for-purpose. Accuracy metrics using backcasts have good predictive power and would indicate to stakeholders that AEMO’s models are fit-for-purpose.
- Enable monitoring of the impact of DER on forecast accuracy over time. For example, a forecast accuracy by time-of-day metric may indicate that forecasts are becoming increasingly unreliable in the evening as a result of additional load from EVs. If forecast approaches are not keeping up with underlying system changes, these should manifest itself in forecast error metrics.
- Provide an incentive for AEMO to monitor, continually improve, and address specific issues in forecasts that manifest in these metrics. AEMO would have a reputational incentive to maintain and improve public accuracy metrics over time.
- Provide evidence for a need for change. If backcast metrics are accurate and forecast metrics are inaccurate, and forecast error is identified as a material issue, these metrics would provide evidence of a case for additional investment in weather forecasting,

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[22] While there were no quantified benefits readily available in the inter-jurisdictional review, there were some indications. See for example CAISO’s expected benefits from procuring flexible ramp services based on probabilistic solar forecasts: https://docs.nrel.gov/docs/fy21osti/80108.pdf

monitoring or reporting processes (e.g. investment in input weather forecasting processes, visibility of new DER activity).

In the NEM, cl 3.13.3A(h) of the NER obligates AEMO to publish information on the accuracy of the ESOO forecasts. These are planning-level forecasts (i.e. not operational) forecasts. This proposal is for frequent publications of operational forecasting accuracy.

The forecasts accuracy measures and methodologies published by ERCOT (see Figure 16) provide an indication of the metrics under consideration.

EPWA is not aware of anything limiting AEMO from making this information available on a voluntary basis. However, a rule change would create an obligation and improve transparency around a critical market function. EPWA considers that a rule change is required to ensure transparency and enable the monitoring of AEMO's operational forecasting capability.

Proposal 5:

A rule obligation should be introduced for AEMO to publish metrics for the tracking of forecast and backcast errors for its operational forecasting.

Consultation Questions:

(5)(a) Do stakeholders support the introduction of an obligation for AEMO to publish a metrics of forecast and backcast errors?

5.6 Formalise large load information provision

Some large loads currently provide self-forecasts to AEMO on a voluntary basis via email or by phone to AEMO personnel. These forecasts are an important component of system-level demand forecasting, with load sizes in the order of approximately 40-130 MW. AEMO collects self-forecasts from the operators of these loads and maintains separate forecasting model for each load.

Based on the undertaken materiality analysis (covering approximately one year of data), which did not find evidence of errors, EPWA considers that this voluntary approach has worked to date and may continue to work in the future. However, this approach may also present a risk – there is nothing preventing these loads from deciding to not provide, or limit, the information provided to AEMO. This presents a low probability but high impact risk to the WEM.

If this information is not provided, this could have negative consequences for market outcomes as it would limit AEMO's ability to accurately forecast large load segments in the WEM. This risk would also be increased if a large flexible load connects to the network, as the current practices would be potentially unable to cater to this type of participant.

EPWA notes that there are potential benefits to formalising the existing information provision arrangements for large loads. AEMO has confirmed that there would be benefits to moving away from an informal arrangement if the data from large loads could be explicitly used in constraint equations.[23] AEMO advised that "block load forecasts are taken in good faith as [they] are not required to inform AEMO of real time changes. AEMO and the market would benefit from having access to the major changes block loads make to improve the dispatch schedule".[24]

This change would require a rule change, likely to include a definition of 'large load' and an obligation for large loads to provide forecasts. EPWA does not expect that requiring loads to

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[23] AEMO, "Operational forecasting in the WEM – AEMO Response"

[24] *Ibid*

provide self-forecasts will change costs significantly for AEMO or for the load participants. Rather, this proposal would formalise the existing practice.

EPWA understands that the existing large loads are not weather sensitive, and so ‘self-forecasting’ is essentially a process of converting short-term operational plans into electricity consumption levels. For this reason, EPWA does not consider that an incentive scheme for accurate self-forecasting is currently necessary.

Proposal 6:

Operators of large loads should be obligated to provide AEMO with consumption forecasts and notify AEMO of unexpected changes to forecast schedules as they arise.

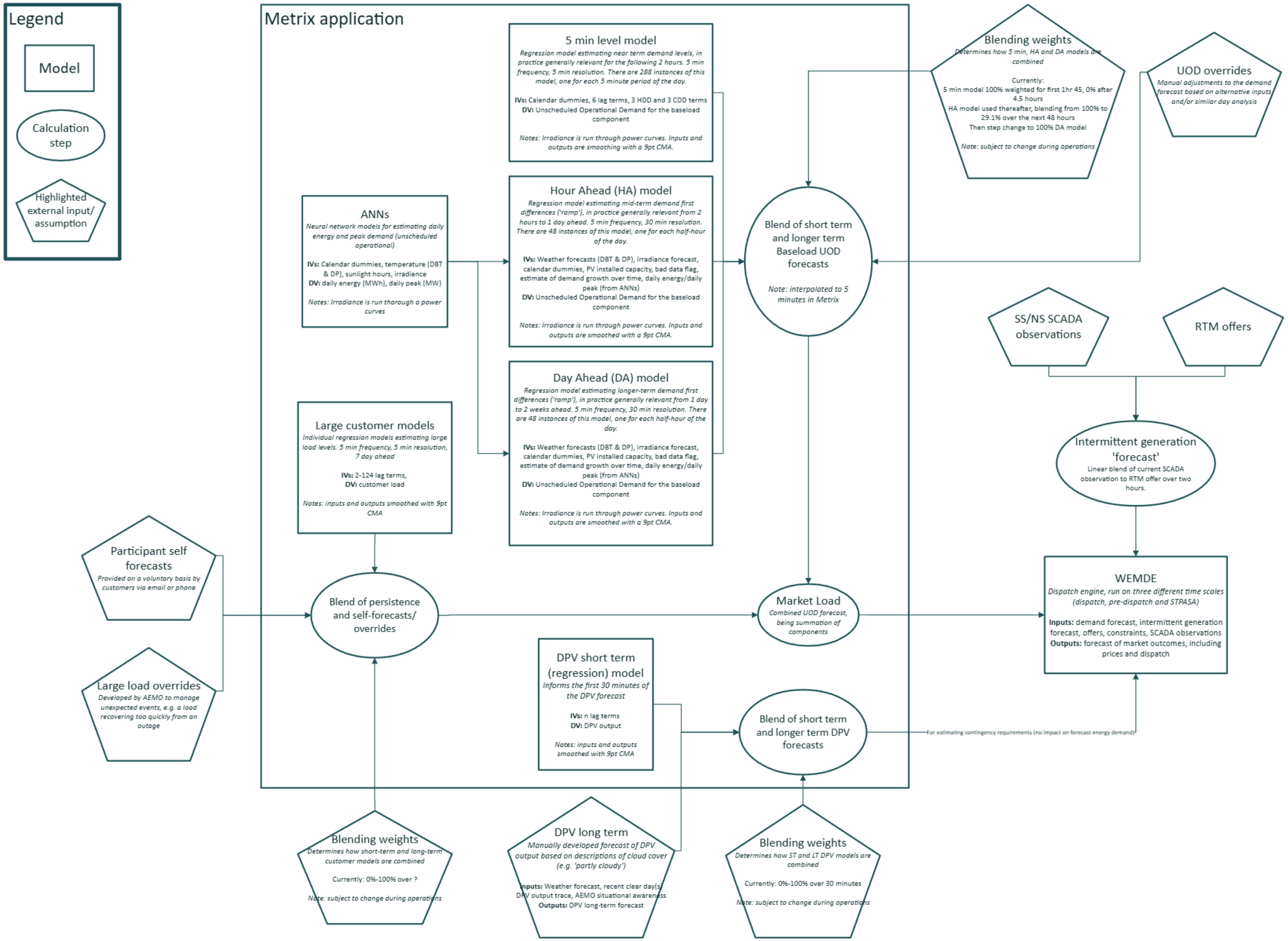
Consultation Questions:

(6)(a) Do stakeholders have any concerns with the proposal to formalise a requirement for large loads to provide consumption forecasts?

Appendix A. Detailed overview of AEMO’s forecasting methodology

AEMO uses an application called “Metrix” to produce operational forecasts. Metrix is a third-party application designed to produce energy forecasts. It is configurable, so AEMO is able to set up forecasting methodologies and procedures to produce forecasts for various components of supply and demand at different timescales and intervals. It enables AEMO to configure forecasts based on neural-network and regression-based models, and additionally facilitates data cleaning (e.g. smoothing, identification of bad observations), transformation (e.g. power curves), and manual intervention steps in the forecasting process.

Figure 6: Schematic of AEMO’s operational unscheduled operational demand and DPV forecasting methodology



Source: Frontier Economics, developed over a series of consultations with AEMO

A.1 Demand

Final unscheduled operational demand (UOD) forecasts are represented by the 'Market Load' oval in Figure 6. This forecast is based on several component forecasts:

- Forecast of unscheduled large loads: individual large loads are forecast based on autoregressive forecasts in the short term and large-load self-forecasts in the longer term. Large load self-forecasts are submitted to AEMO on a voluntary basis.
- Forecasts of unscheduled temperature-dependent load, net of embedded generation which is generation behind the meter. In practice, this includes metered loads not including large loads, and the models take into account the impact of behind the meter generation (e.g. solar PV).

A.2 Large loads

Unscheduled large load forecasts are included in demand forecasts based on the voluntary submissions by the large loads, with no formal requirement in place for these loads to inform AEMO of their operations. Currently, participants disclose their plans to AEMO in good faith, however, this information is confidential, and this information, therefore, cannot be disclosed to the market. Participants typically disclose these plans to AEMO via phone or email, and AEMO manually inputs the data into its demand forecasting system Metrix.

A.3 Temperature dependent loads

Forecasts of temperature dependent load are developed through a series of models and transformations within Metrix. Temperature forecasts are sourced from various providers. The weather forecasts are incorporated into the demand forecasts on a regular basis.

Three separate temperature dependent load forecasts are produced at different time scales for each weather provider's input forecasts. The shortest-term forecast takes a primarily autoregressive approach (predicting demand based on recent observations), and the longer-term forecasts take a fundamental approach (predicting demand based on drivers of demand, primarily weather).

These forecasts are then blended into a single forecast using weights on each data source over time. Forecasts based on different input weather forecasts are also blended together. EPWA understands that an even blend is the default, but in certain circumstances, such as on extreme days, this may be manually altered. EPWA was advised by AEMO that one weather provider tends to be conservative about maximum temperatures on extreme days, and so during these periods other forecasts may be given higher weighting.

A.4 DPV

The impact of DPV is implicitly forecast in the longer-term temperature dependent load forecasts. Irradiation forecasts are fed through power curves (developed with the assistance of Western Power prior to 2020) and included as terms in the Hour Ahead (HA) and Day Ahead (DA) models. AEMO receives week-ahead irradiance forecast at half-hourly resolution, which are updated several times a day.

Explicit DPV forecasts are made independently, but these independent forecasts are used in determining contingency requirements and do not affect forecast unscheduled demand levels. These forecasts are produced by blending two sub-forecasts:

- A short-term autoregressive forecast, and
- A longer-term forecast based on expected output given actual output on a recent non-cloudy day, adjusted for expected cloud cover (e.g. 'partly cloudy').

A.5 Intermittent generation

AEMO determines forecast intermittent generation unconstrained availability for use in central dispatch (WEMDE) and for situational awareness and planning (used by the Control Room).

For intermittent generation unconstrained availability, under rules 7.2.4(cA) and 7.2.4A, AEMO is required to use unconstrained injection forecasts (UIF) and unconstrained withdrawal forecasts specified in RTM submissions or alternative forecasts if AEMO "*reasonably considers that the alternative forecast quantities are likely to be more accurate*". In a response to an EPWA data request, AEMO submitted that "*MP RTMS were so inaccurate that the approach below using Unconstrained Injection Forecasts (UIF) from SCADA were used in place of their RTMS for the dispatch schedul*e."[25] The approach referenced is a blending approach where UIF SCADA values from participants are linearly blended with RTM UIF submissions over the course of two hours. That is, AEMO overrides participant UIFs with a blend of the most recent UIF SCADA value and the participant's submitted UIF over a two-hour period.

Market participants have a weak incentive to provide accurate unconstrained injection forecasts. This is discussed further in Section 5.4.

For the Control Room, intermittent generation forecasts are produced using weather forecasts (wind speed or irradiance) and power curves. The Control Room also looks at facility RTM offers for comparison.

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[25] AEMO, "Operational forecasting in the WEM – AEMO Response"

Appendix B. Operational forecasting in other jurisdictions

B.1 Eastern Australia (the NEM)

B.1.1 Key points

Stat	Value
Markets	Energy, forward/future
Annual electricity consumption	Around 180 TWh
Renewable energy share	Around 40%[26]
Rooftop PV penetration	Around 12.5%[27]

Box 1: Eastern Australia: key points

- Demand forecasting in the NEM is centralised and produced by AEMO on several different time scales. AEMO produces demand forecasts using its Demand Forecasting System (DFS).
- AEMO has a dedicated model for small-scale PV systems called the ‘Australian Solar Energy Forecasting System Phase 2’ or ASEFS2. The output of ASEFS2 is an input to the DFS to account for the impact of DPV. AEMO forecasts non-scheduled wind and larger solar using similar models.
- AEMO uses an autoregressive approach for short-term demand forecasts (dispatch and five-minute pre-dispatch (5MPD)) and a fundamental approach for longer term demand forecasts.
- AEMO produces uncertainty forecasts (POE10- 10% probability of exceedance and POE90- 90% probability of exceedance) as well as a baseline forecast (POE50- 50% probability of exceedance). This is based on a static scaling factor determined from a review of historical data. Different half-hours may have different scaling factors.
- Intermittent generation forecasting in the NEM is a mix of centralised and de-centralised. AEMO produces forecasts of intermittent generation output, but intermittent generators can provide their own short-term forecasts (5 minutes ahead) if they can meet minimum performance criteria. Participants have the incentive to improve intermittent generation forecasts to avoid causer-pays allocations of regulation service costs (an ancillary service).
- Forecasts of demand (including large loads and DPV) and intermittent generation are input into a centralised dispatch algorithm for predispatch which provides forecast price signals which can influence participants’ commercial behaviour and decisions.

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[26] https://cer.gov.au/markets/reports-and-data/quarterly-carbon-market-reports/quarterly-carbon-market-report-december-quarter-2023/state-of-total-renewables

[27] https://explore.openelectricity.org.au/energy/nem/?range=1y&interval=1M&view=discrete-time&group=Detailed

B.1.2 Market design

The NEM is a gross pool energy only market. AEMO conducts the market through a centrally coordinated security-constrained economic dispatch process. AEMO forecasts inputs to the dispatch process (including demand and intermittent generation) and outcomes from the dispatch process to inform the market of upcoming conditions.

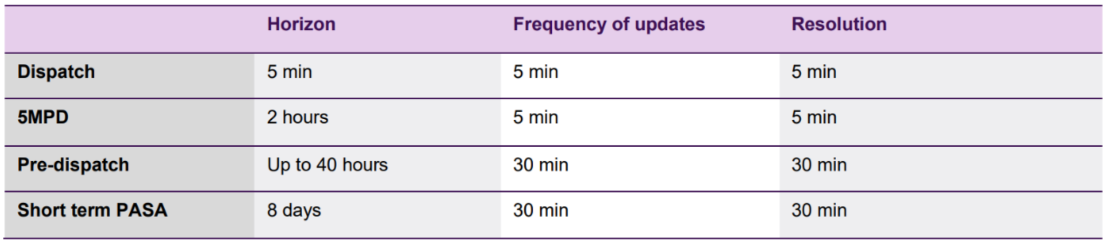
B.1.3 Operational forecasting

AEMO produces the following operational forecasts:

- Dispatch, a forecast of outcomes over the next five minutes.
- Five-minute pre-dispatch (5MPD), a five-minute forecast covering the following two hours (of which one hour ahead is published).
- Pre-dispatch (30 minute), a 30-minute forecast covering until at least the end of the next trading day.
- Short term projected assessment of system adequacy (STPASA) forecasts, a 30-minute forecast for the following seven trading days. Eight calendar days are required to fully cover the seven trading days of the forecast period.

Figure 7 summarises the timeframe details associated with each of these types of forecasts.

Figure 7: AEMO NEM forecast horizons



	Horizon	Frequency of updates	Resolution
Dispatch	5 min	5 min	5 min
5MPD	2 hours	5 min	5 min
Pre-dispatch	Up to 40 hours	30 min	30 min
Short term PASA	8 days	30 min	30 min

Source: p7, https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/dispatch/policy_and_process/australian-wind-energy-forecasting-solar-energy-forecasting-system.pdf?la=en

AEMO prepares each of the forecast timeframes listed above using its Demand Forecasting System (DFS) as described in the power system Operating Procedure SO_OP_3710.[28]

B.1.4 Demand Forecasting System

AEMO's DFS uses a collection of statistical models to generate forecasts for all timeframe listed above.[29]

The major factors considered within these statistical models vary based on the timeframe of the specific forecast being produced. For pre-dispatch and 5MPD, the statistical models consider actual real-time metered loads, weather and type of day. For pre-dispatch and STPASA, the key factors include the following:

- Historical actual metered loads
- Real-time actual metered loads (SCADA data from immediately preceding intervals)
- Historical and forecast weather data (temperature and humidity)
- Significant non-scheduled wind generation forecasts

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[28] https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/procedures/so_op_3710-load-forecasting.pdf?la=en

[29] *Ibid*

- Significant non-scheduled solar generation forecasts
- Small-scale (rooftop) solar generation forecasts
- Type of day (weekday/weekend), school holidays, public holidays and daylight savings
- Reliability and Emergency Reserve Trader (RERT) schedules, and
- Historical Wholesale Demand Response (estimated from unit SCADA data and dispatch targets).

Forecasts are generated automatically and do not usually require manual intervention. If forecasts are considered unreasonable or inconsistent by AEMO, they will be manually adjusted. Forecasts are also adjusted during periods of RERT activation and load-shedding.

The DFS generates demand forecasts for all NEM regions for all forecast timeframes listed above. For pre-dispatch and STPASA, the DFS generates 10%, 50% and 90% POE demand forecasts with the 10% and 90% forecasts produced by applying a scaling factor to the 50% forecast. The 10% and 90% scaling forecasts are based on statistical analysis of historical load and forecast data. The scaling factors are static and determined for each half-hour of the short-term period.

Forecasts are also produced on a sub-regional basis, with several states split up into multiple sub-regions.

B.1.5 Weather forecasts

Readings of historical and forecast weather data (temperature and humidity) for a given sub-region are identified at specific weather stations. In the DFS, NSW, VIC and SA are each forecast as single areas. In contrast, forecasts for QLD and TAS are aggregated from forecasts of multiple subareas.

As of September 2024, AEMO has been receiving hourly temperature forecasts from three separate weather service providers and has been working with the providers to ensure that weather forecast tools are fit-for-purpose to support load forecasting.[30] Relevant initiatives include:

- Redeveloping the projected assessment of system adequacy (PASA) to incorporate probabilistic methods and weather uncertainty margins in reserve calculations
- Establishing new weather stations in Renewable Energy Zones (REZs), near remote renewable generators and in metropolitan heat islands
- Accessing a range of probabilistic weather forecasts, and
- Considering a fourth provider which utilises AI-powered models with higher spatial and temporal resolution than conventional models to forecast wind speed, irradiance and temperature.

AEMO have made several public observations on the impact of weather forecasts in operational demand forecasting:[31]

- Operational demand is more sensitive to temperature during hot summer and cold winter periods (see **Figure 8**)
- Residential sensitivity to temperatures has risen since 2020 due to increases in the proportion of people working from home (see **Figure 9**)
- Humidity exacerbates demand sensitivity when dry bulb temperatures (one measure of air temperatures) are high. The relationship between the need for cooling and humidity is the ‘dew point’, which is state-specific, and

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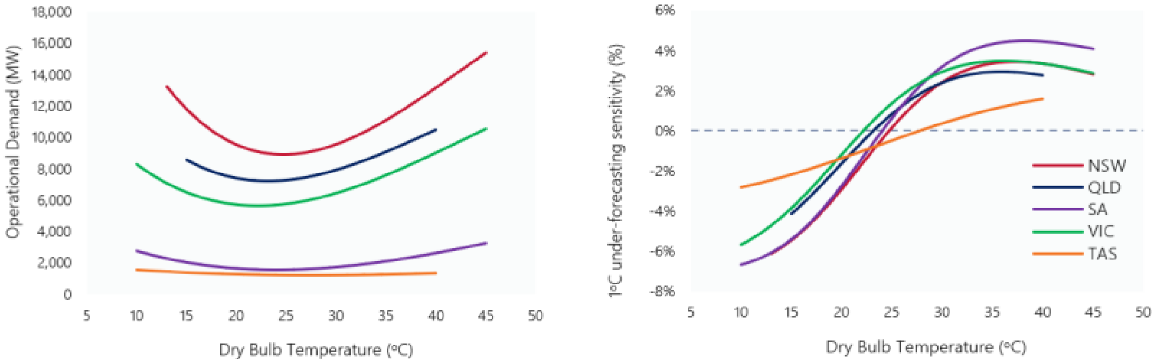
[30] https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/load-forecasting/temperature-forecast-analysis-for-summer-2023-24.pdf?la=en

[31] https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/load-forecasting/temperature-forecast-analysis-for-summer-2023-24.pdf?la=en

- Forecasting can be difficult due to due global warming and weather events such as El Nino which generally increase the chances of warmer and drier conditions across Australia.

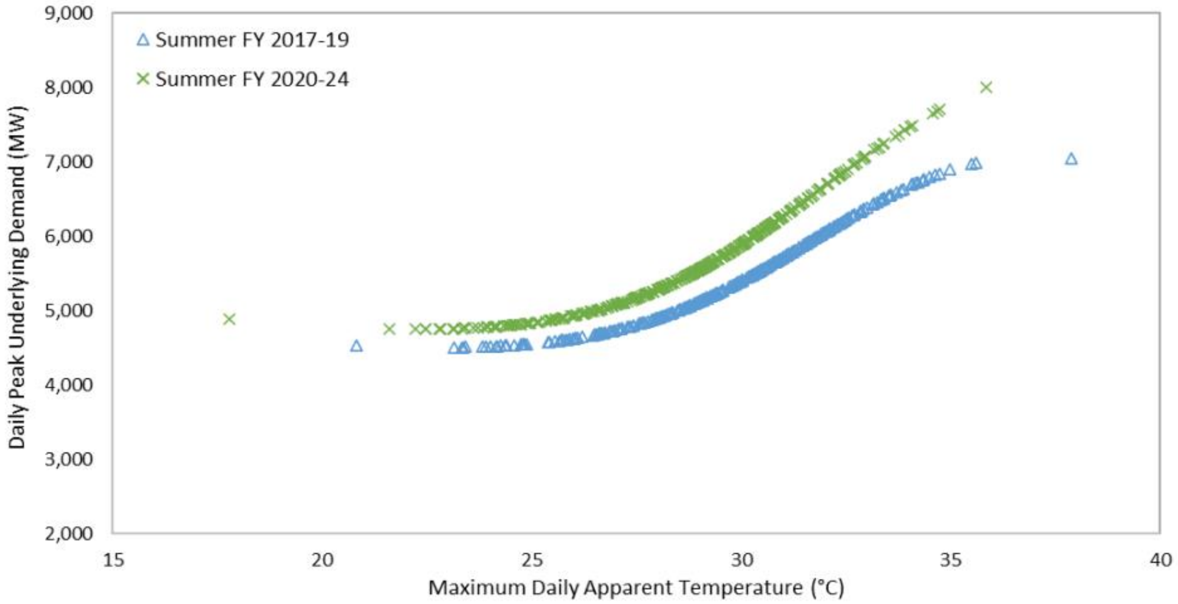
Figure 8: Operational demand and dry bulb temperature

Figure 2 **Weekday maximum daily operational demand against maximum dry bulb temperature (left) and the percentage change in operational demand for a 1°C under-forecasting error (right) for each NEM region.**



Source: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/load-forecasting/temperature-forecast-analysis-for-summer-2023-24.pdf?la=en

Figure 9: Impact of working from home on underlying load growth, Queensland



Source: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/load-forecasting/temperature-forecast-analysis-for-summer-2023-24.pdf?la=en

B.1.6 Large load forecasts

Scheduled large loads (i.e. registered Market Customers) bid in to the NEM and so forecasts of scheduled large loads are outcomes of the projected dispatch resulting from actual participant bids.

The treatment of large loads that do not participate in central dispatch is not explicitly discussed in AEMO’s forecasting operating procedures. However, it can be inferred that AEMO’s forecasting models likely incorporate both historical data and real-time metered loads for large loads that are not Market Customers, as listed above.

B.1.7 Wind and solar forecasts

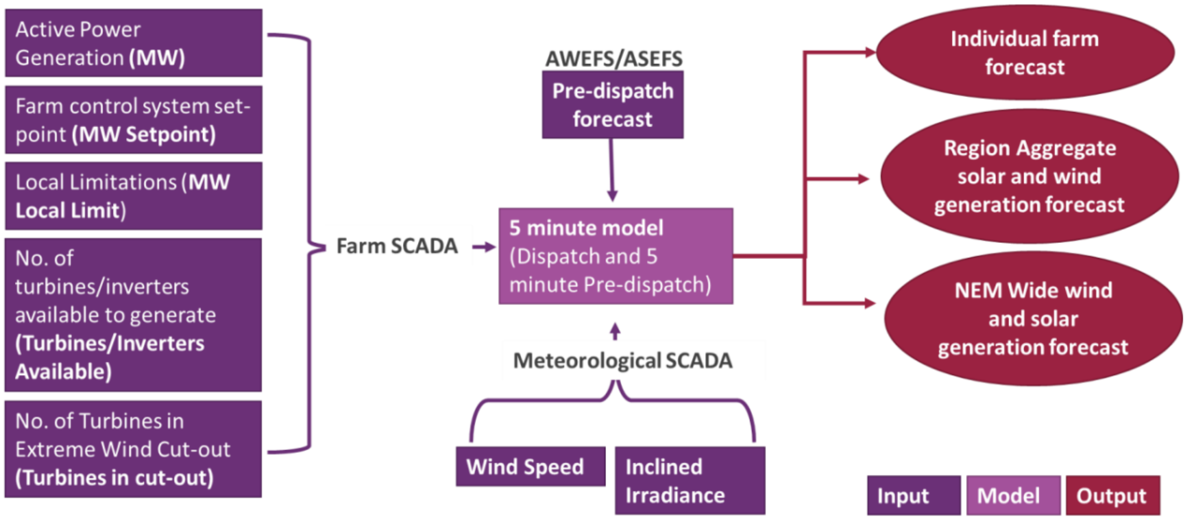
Wind and solar forecasts are produced by the Australian Wind Energy Forecasting System (AWEFS) and Australian Solar Energy Forecasting System (ASEFS) respectively. These systems forecast *unconstrained* generation capacity available from each facility. These systems are provided by a vendor, except in the dispatch timeframe where they are now developed in-house at AEMO, which has improved forecast accuracy.[32]

Both models use two types of inputs:

- Static data – semi-scheduled generators connected to the NEM and some intermittent non-scheduled generators must submit an Energy Conversion Model (ECM). Utilising these models, generator-specific forecasts are determined which consider each asset's location and technology.
- Dynamic data – dynamic information used in forecasts that varies based on timeframes.[33]

For **short-term forecasting** (namely dispatch and 5MPD) processes, this dynamic data includes recent SCADA and meteorological observations for each facility, as illustrated in **Figure 10**. If the facility is constrained (e.g. if it is curtailed by NEMDE), the SCADA observation for current generation is ignored and an unconstrained value is calculated from the relevant ECM and meteorological observations. AEMO's methodology paper does not describe exactly how 5MPD forecasts are produced (only the dispatch process is described). Based on the provided figures it is possible this is an autoregressive methodology.

Figure 10: Inputs and outputs for AEMO's NEM dispatch and 5MPD processes



Source: https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/dispatch/policy_and_process/australian-wind-energy-forecasting-solar-energy-forecasting-system.pdf?la=en

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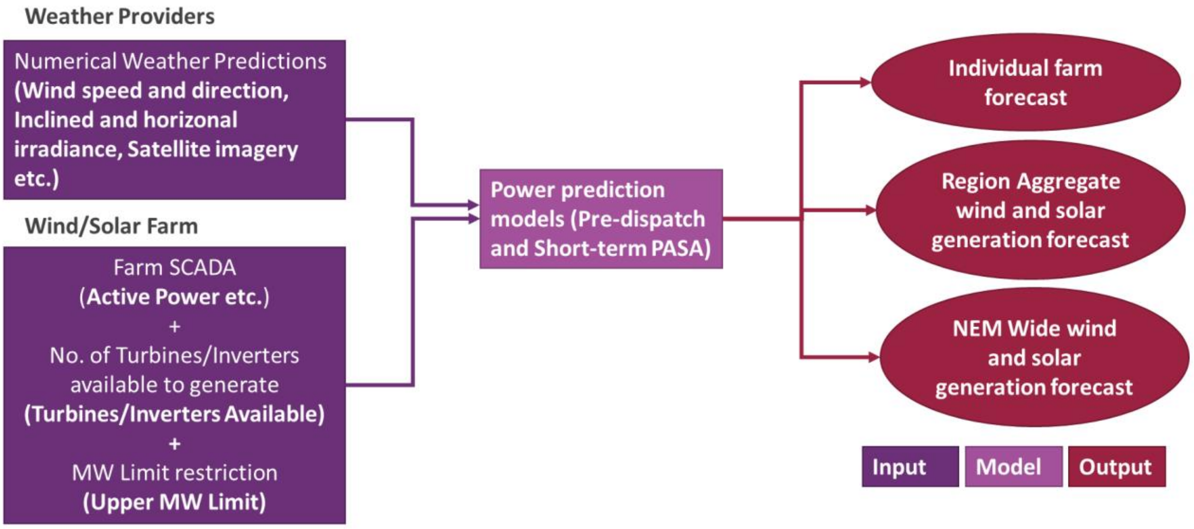
[32] https://aemo.com.au/-/media/files/stakeholder_consultation/working_groups/other_meetings/awefs-asefs/2022/intermittent-generator-session---presentation-slides-29-july-2022.pdf

[33] This is specified in detail in a document titled 'Guide to Data Requirements for AWEFS and ASEFS', September 2022, available https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/dispatch/policy_and_process/guide-to-data-requirements-for-awefs-and-asefs.pdf

For **longer-term** operational forecasting (namely 30-minute pre-dispatch and STPASA) these models use a combination of SCADA values and weather forecasts from Numerical Weather Predictions (NWP) models, as illustrated in **Figure 11**. AEMO contracts with several[34] commercial weather forecast providers for forecasts, and notes the most important of the predictions it receives are wind speed and global inclined irradiance. The specific methodology (i.e. model specification) for each of the models is not made public by AEMO, but likely makes use of the ECM and forecast values.

Figure 11: Inputs and outputs for AEMO's 30-minute pre-dispatch and ST PASA processes



Source: *https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/dispatch/policy_and_process/australian-wind-energy-forecasting-solar-energy-forecasting-system.pdf?la=en*

The AWEFS/ASEFS generates four types of unconstrained intermittent generation forecasts (UIGF):

- Individual wind/solar generation forecasts for both semi-scheduled and non-scheduled generators
- NEM-wide solar and generation forecast
- Region-specific forecasts for wind and solar i.e., for NSW, QLD, VIC, SA and TAS separately, and
- Uncertainty forecasts for pre-dispatch, and short term PASA timeframes for the above three forecasts. The specific methodology used to determine uncertainty forecasts is unclear.

These forecasts are used in dispatch and pre-dispatch processes in different ways. Semi-scheduled wind/solar generation unconstrained forecasts are used in conjunction with the bid energy Maximum Availability (bid Max Avail) to calculate available capacity for dispatch. Non-scheduled wind/solar generation is subtracted off operational demand forecasts produced by the DFS, as illustrated in **Figure 12**.

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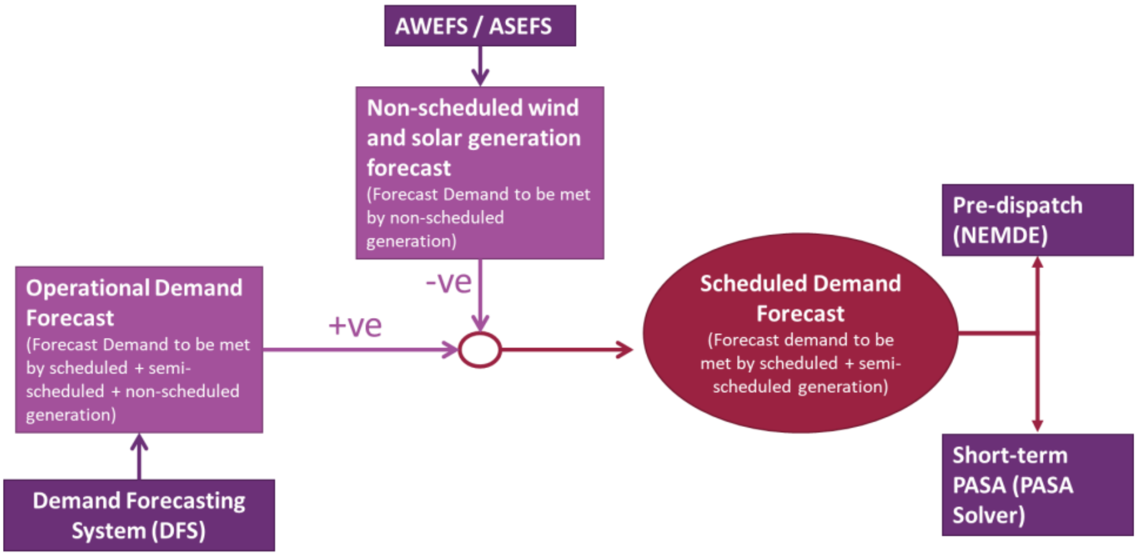
[34] A recent analysis by AEMO suggests three providers. See p4 https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/load-forecasting/temperature-forecast-analysis-for-summer-2023-24.pdf?la=en

Figure 12: Usage of non-scheduled forecasts



Source: *[https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/dispatch/policy_and_process/australian-wind-energy-forecasting-solar-energy-forecasting-system.pdf?la=en]*

B.1.8 Participant self-forecasting

AEMO have also implemented an opt-in self-forecasting program after an ARENA-funded trial[35]. This allows participants to provide their own forecasts of their semi-scheduled generating unit's UIGF 5 minutes ahead, providing a singular value for the next dispatch interval which, once accredited, will override the first entry of the AWEFS/ASEFS forecast.[36]

To become accredited for this, participants must meet minimum performance criteria by providing a reasonable level of assurance that their self-forecasts will not be materially worse than current forecasts. To establish this, AEMO conducts weekly assessments of participants' self-forecasts against those already produced by AWEFS or ASEFS over an eight-week period.[37] Participants' self-forecasts will then continue to be accredited provided that they remain above the minimum performance criteria and that AEMO does not find they are impacting system security. Performance is assessed against measures of Mean Absolute Error (MAE) and Root Mean Squared Error (RMSE)[38], which are metrics commonly used for assessing forecast accuracy.

Renewable generators have the incentive to make accurate self-forecasts in the next dispatch interval timeframe. If generators do not meet their dispatch targets, they incur regulation FCAS costs under the causer-pays FCAS cost recovery procedure[39]. Accurate self-forecasts mean that generators are more likely to perform to their dispatch targets, and incur less FCAS costs.[40]

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[35] See https://arena.gov.au/assets/2020/01/short-term-forecasting-on-the-nem-progress-report.pdf

[36] https://wa.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

[37] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Semi-Scheduled-Generation-Dispatch-Self-Forecast---Assessment-Procedure.pdf

[38] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Semi-Scheduled-Generation-Dispatch-Self-Forecast---Assessment-Procedure.pdf

[39] https://aemo.com.au/-/media/files/electricity/nem/data/ancillary_services/2023/settlements-guide-to-ancillary-services-payment-and-recovery.pdf?la=en

[40] Evidence for this during 2023 is provided here: https://wattclarity.com.au/articles/2024/05/regulation-fcas-costs-in-2023/

B.1.9 Distributed PV forecasts

The ASEFS2 forecasts output for small-scale distributed PV systems that have a system capacity of less than 100 kW. It does so for both the pre-dispatch and STPASA forecast timeframes.

The ASEFS2 requires the following inputs:

- Static data related to inverter size and model for selected systems from PvOutput.org and Solar Analytics, and aggregate kW capacity by installed postcode as recorded by the Clean Energy Regulator, and
- Dynamic data in terms of numerical weather prediction from multiple weather data providers and output measurements from selected household rooftop PV systems from PvOutput.org and Solar Analytics.

B.1.10 Other DER forecasts

From publicly available information, it appears that AEMO does not currently forecast impacts of other DER (e.g. batteries) or EVs in its operational forecasts outside of its usual weather-dependent forecasts. However, effects of these resources will be implicitly included in the forecasts.

To enable future development of DER resources, AEMO has developed “SCADA Lite”, a less cumbersome SCADA system designed for use by DER aggregators. This will facilitate their participation in the market, and allow AEMO to use live telemetry from aggregated facilities to inform its market forecasts.

B.2 Germany

B.2.1 Key points

Stat	Value
Markets	Day ahead, intra-day, forward
Market type(s)	Energy only
Annual electricity consumption	Around 450 TWh[41]
Renewable energy share	Around 57-59%[42]
Rooftop PV penetration	Around 2% of electricity demand[43]

Box 2: Germany: key points

- Germany has many (almost 900) distribution areas and four main transmission areas (Control Areas). The majority of intermittent generation is distribution connected.
- Forecasts for generation and load are made in a bottom-up fashion by 'Balancing Responsible Parties', which are responsible for one or more transmission connection points. The four transmission service operators aggregate these forecasts and publish them on the German electricity market data portal 'SMARD'.
- Transmission service operators are responsible for resolving differences between forecast generation and load and actual generation and load. They do this by buying energy in intraday markets and procuring balancing capacity. Balancing services are not co-optimised with energy.
- Balancing Responsible Parties are required by a standard contract to take due care in preparing accurate forecasts. Balancing responsible parties are also incentivised to produce accurate forecasts to minimise their exposure to balancing costs.
- Transmission service operators also have an interest in producing accurate forecasts as they need to procure energy and ancillary services to correct imbalances due to forecast error.
- There is limited information about the specific methodologies employed in forecasting demand and intermittent generation in Germany. However, there is information on various initiatives taken to improve forecasts.

B.2.2 Market design

The German wholesale electricity market is an energy only market. It features four 'control areas', each with its own transmission system operator (TSO). Electricity trade can occur within and between control areas as well as interconnected countries.

Germany has a forward market, a day-ahead market and an intraday market, although most volumes are sold OTC in long-term bilateral contracts[44]. The intraday market is 'real-time', with gate closure for intraday trading being five minutes within local control areas, 30 minutes between

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[41] https://ag-energiebilanzen.de/daten-und-fakten/auswertungstabellen/

[42] https://www.ise.fraunhofer.de/en/press-media/press-releases/2024/public-electricity-generation-2023-renewable-energies-cover-the-majority-of-german-electricity-consumption-for-the-first-time.html

[43] Calculated from https://www.ise.fraunhofer.de/content/dam/ise/de/documents/publications/studies/Photovoltaics-Report.pdf

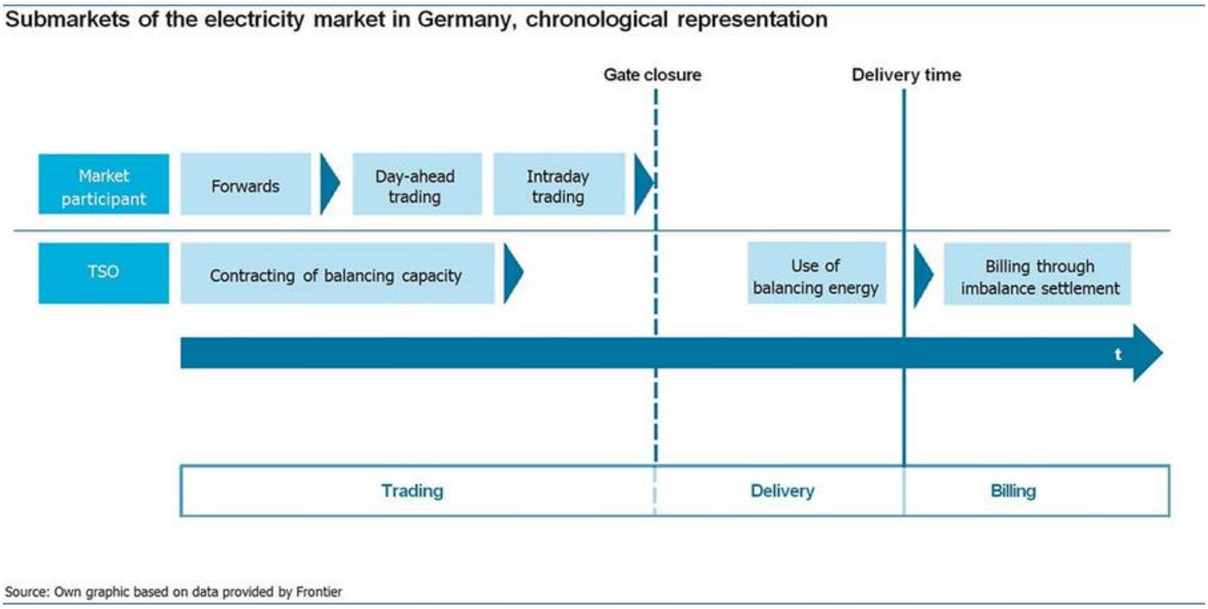
[44] https://www.lexology.com/library/detail.aspx?g=7c115c26-2be2-4ff6-8916-a929c90b7b6d

control areas, and 60 minutes across borders[45] to interconnected regions (i.e. other countries)[46]. Futures and forward products can be traded on exchanges or OTC respectively up to six years in advance.

Germany is subject to European network codes and guidelines which places some obligations on DSOs and TSOs with respect to operational forecasting[47]. Forecast errors in demand and renewable dispatch are managed by TSOs trading in intraday markets and procuring balancing capacity[48]. Balancing services in Germany are not co-optimised with energy dispatch[49], but procured by the TSOs in a separate process, and recovered by TSOs on a causer-pays basis. The rise of intermittent generation and related forecast errors has increased the amount of intraday trading significantly in Germany[50], but at the same time, the amount of balancing capacity required has reduced (known as the 'German Balancing Paradox')[51]..

Submarkets of the German electricity market are illustrated in **Figure 13**.

Figure 13: German electricity submarkets



Source: smard.de

The four TSOs in Germany are Amprion GmbH, TransnetBW GmbH, TenneT TSO GmbH and 50Hertz Transmission GmbH. Bundesnetzagentur, the Federal Network Agency in Germany, helps to oversee the operation of the German electricity market. SMARD is an electricity market data

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[45] https://www.smard.de/page/en/wiki-article/6076/5976

[46] https://www.smard.de/page/en/wiki-article/6076/5976

[47] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32017R1485

[48] See, for example, p18 THE GERMAN ELECTRICITY SYSTEM: OPERATIONAL CHALLENGES IN A EUROPEAN WIDE COUPLED SYSTEM, TransnetBW, 2022, available: https://cnostatic.s3.amazonaws.com/cno-public/archivosAdjuntos/mem_schlipf.pdf

[49] https://www.smard.de/page/en/wiki-article/5884/5840

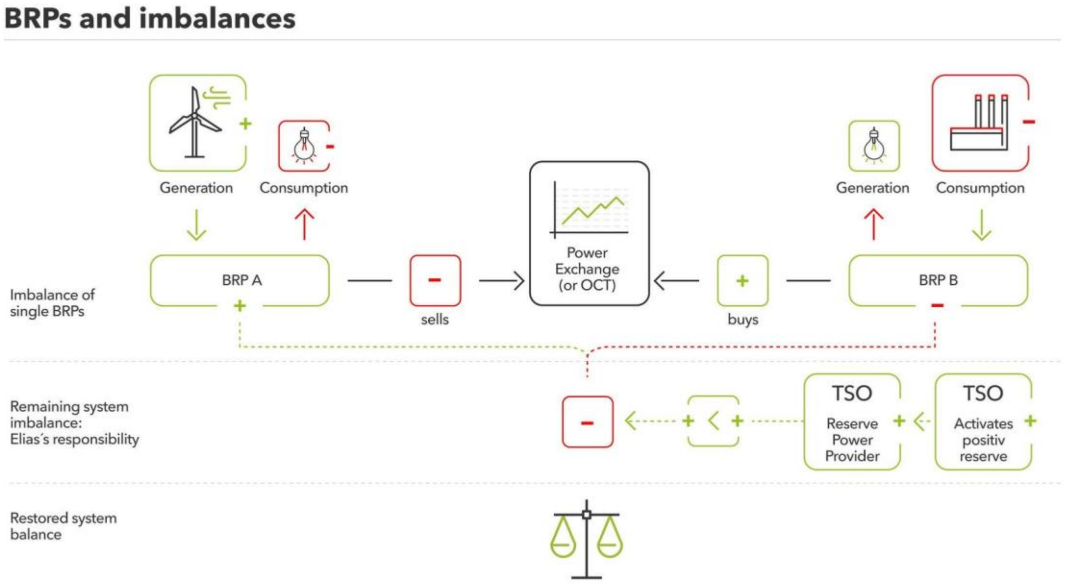
[50] https://journals.sagepub.com/doi/full/10.5547/01956574.45.3.shir

[51] There are a number of reasons suggested for this including more advanced weather forecasting techniques. See Short-term electricity trading for system balancing: An empirical analysis of the role of intraday trading in balancing Germany's electricity system, Koch & Hirth, 2019, available https://neon.energy/Koch-Hirth-2019-Trading-balancing.pdf

system operator in Germany, which displays data for Germany's energy network provided by TSOs.

In Germany, around 95% of renewable generators are connected to the distribution network[52], and there are over 800 DSOs.[53] Each transmission connection point has a balance responsible party (BRP), which is a private entity that is responsible for the load and generation connected to the connection point.[54] Each load or generator is required to have a contract with a BRP, and the BRP manager has a contract with the TSO.[55] BRPs may be responsible for more than one connection point. **Figure 14** illustrates how BRPs trade and how imbalances are resolved by TSOs.

Figure 14: BRPs and imbalances



Source: https://www.next-kraftwerke.be/knowledge-hub/balancing-responsible-party-brp

B.2.3 Operational forecasting

Operational forecasting is a fragmented process in Germany. Rather than a single market operator making a forecast, each BRP produces a forecast for the connection points for which it is responsible, which are aggregated by TSOs for the market as a whole.

Specifically, each BRP is required to produce a schedule of net feed-ins and withdrawals for each connection point it is responsible for the following day at fifteen-minute granularity. These schedules are essentially day-ahead forecast of load and generation. Under the BRP/TSO contract (cl 5.2), the BRP manager is obliged to take reasonable measures to produce an accurate forecast to keep balance deviations as low as possible. BRP managers and generators and loads are also incentivised to produce accurate forecasts to reduce exposure to imbalance price risk. Germany

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[52] https://www.bdew.de/presse/presseinformationen/fast-zwei-millionen-erneuerbare-energien-anlagen/

[53] https://www.cleanenergywire.org/factsheets/set-and-challenges-germanys-power-grid

[54] https://www.next-kraftwerke.be/knowledge-hub/balancing-responsible-party-brp

[55] The standard contract is available (in German) at the following link. EPWA has a translated copy if required. https://www.bundesnetzagentur.de/DE/Beschlusskammern/1_GZ/BK6-GZ/2023/BK6-23-102/BK6_23_102_bkv_kons_lesefassung.pdf?__blob=publicationFile&v=4

has been adjusting these incentives in various reforms from 2010-2022[56]. Some of these (now revoked) reforms had the effect reducing this incentive.[57]

Due to the fragmented nature of these load and generation forecasts, there does not appear to be well-documented forecast methodologies for these loads or intermittent generators.

TSOs also have an interest in forecasting load and particularly intermittent generation (including DPV). Because TSOs are responsible for correcting imbalances and procuring ancillary services, TSOs trade in intraday markets and procure balancing services, and so also need to take a view on future short-term supply and demand outcomes. SMARD publishes provisional figures which are aggregated by TSO Amprion and distributed to SMARD as well as TSO Swissgrid for wider European use. These figures are across key horizons:

- Intraday forecasts: Ranging from 5 mins to 6 hours and updated at 15 min or 1-hour intervals.
- Day-ahead and two-day ahead forecasts: Published at 6pm the day prior. Forecast horizon up to 48 hours.
- Short-term forecasts: Up to 7 days

TSOs are included under the ENTSO-E (European Network of Transmission System Operators for Electricity). ENTSO-E produces electricity demand forecasts for planning purposes for many parts of Europe, in line with the European Resource Adequacy Assessment (ERAA). The ENTSO-E forecasting methodology is well documented58, but not relevant here given the focus on operational forecasting.

B.2.4 Weather forecasts

German TSOs primarily rely on weather forecasts from external providers. Fraunhofer IWES and the German Meteorological Service (DWD) are in collaboration with TSOs, providing them with weather and power forecast data. Numerical weather prediction systems specifically optimised for renewable energies are at the centre of the forecasting.

Germany has conducted several research projects aimed at improving the accuracy of renewable energy forecasts. The German meteorological service (the DWD) has been working on optimising its weather forecasts for renewable energy applications in projects called EWeLiNE and ORKA/ORKA2, Gridcast, and PerduS[59]. In particular:

- EWeLiNE focused on improving the numerical weather prediction models COSMO-DE, COSMO-DE-EPS and ICON. These improvements included integration of new data sets, optimised model physics, and improved ensemble generation. An important contribution of this project was the development of probabilistic weather forecast products for the energy sector, as illustrated in **Figure 15**.[60]
- Gridcast uses real-time generation data to produce more accurate forecasts, and includes better weather warnings particularly under extreme weather conditions. The Gridcast system calculates solar irradiation data every 15 minutes (since 2014), and aims to integrate satellite images for solar forecasts in the future.

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[56] Information on the balancing energy price, Ampiron website, available https://www.amprion.net/Energy-Market/Balancing-Groups/Balancing-Group-Price/Important-Information.html

[57] See section “The mixed price system”, Lessons learnt from Germany’s mixed price system, Next Kraftwerke, available https://www.next-kraftwerke.com/energy-blog/lessons-reserve-power-market

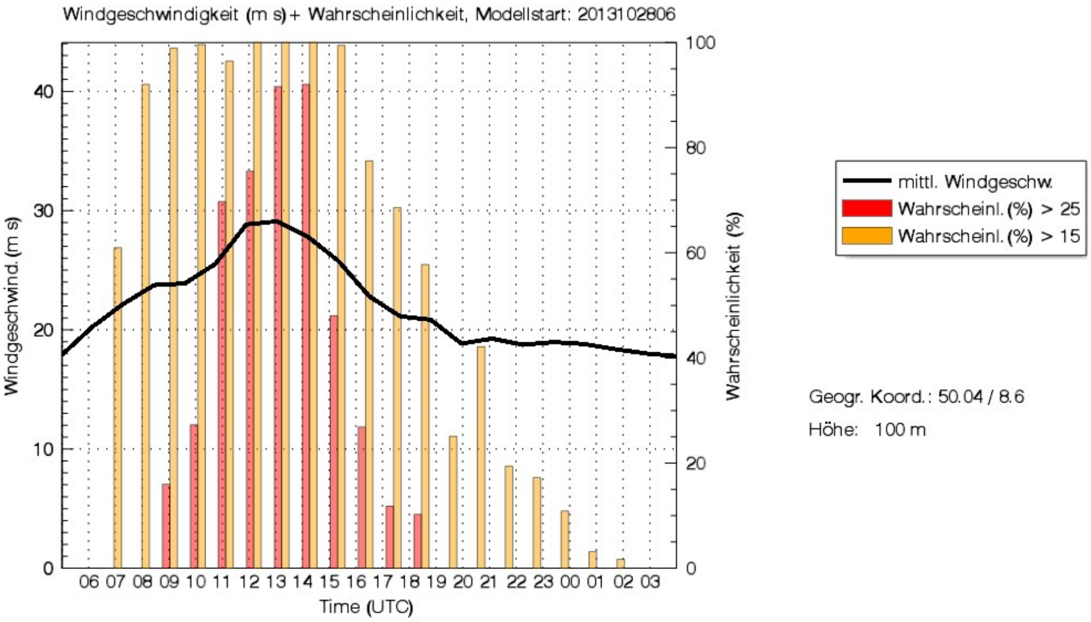
[58] Demand forecasting methodology

[59] IRENA, ADVANCED FORECASTING OF VARIABLE RENEWABLE POWER GENERATION, 2020, p17 available https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Jul/IRENA_Advanced_weather_forecasting_2020.pdf

[60] https://www.dwd.de/EN/research/weatherforecasting/num_modelling/07_weather_forecasts_renewable_energy/weather_forecasts_renewable_energy.html

- PerduS focused on accounting for Saharan dust and its implication for DPV forecasts[61].

Figure 15: Probabilistic wind forecast from COSMO-DE-EPS



Source: [dwd.de]

B.2.5 Wind and solar

German TSOs have used a neural network model combined with NWP forecast data to forecast wind output since at least the early 2000s, called the Wind Power Management System (WPMS) developed by ISET.[62] There are also independent commercial systems available in Germany, for example the Previento model which is based on NWP forecast data and solar and wind generator properties (e.g. capacity, location, hub height, panel angle etc).[63]

ParkCast is a relatively recent (2018-2021) initiative by the University of Stuttgart to improve forecasting of offshore renewables. The project focused on forecasts in a time range of up to 60 minutes and uses long-range lidar measurements combined with local weather models based on machine learning.[64]

For residential solar, forecasts from TSOs and DSOs are calibrated and evaluated against estimations of the solar power production on a postal code level. IRENA notes that "*forecasts of aggregated distributed solar PV production are developed and validated by upscaling the output from a subset of representative solar PV sites.*"[65]

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[61] https://www.dwd.de/EN/research/weatherforecasting/num_modelling/07_weather_forecasts_renewable_energy/weather_forecasts_renewable_energy_node.html

[62] https://publica-rest.fraunhofer.de/server/api/core/bitstreams/1cc7d355-27ad-4758-80f5-4fb0aa7cb03d/content

[63] https://www.get-transform.eu/wp-content/uploads/2024/01/GET.transform-Brief_VRE-Forecasting-Solar-Wind.pdf

[64] https://rave-offshore.de/en/parkcast.html

[65] https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Jul/IRENA_Advanced_weather_forecasting_2020.pdf

B.2.6 Consumer Energy Resources

Germany has seen significant investment in consumer energy resources, with around 580,000 battery systems installed in residences in 2024.[66] In part to respond to this, Germany updated its electricity industry act to mandate all newly-installed potentially flexible resources such as batteries, EV chargers and heat pumps to be controllable by their distribution network.[67] This may also facilitate future aggregation of CER by aggregators, facilitated by the distribution network.

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[66] https://www.cleanenergywire.org/news/german-battery-storage-capacity-increases-50-2024-report

[67] https://www.esig.energy/germanys-paragraph-14a-enwg/

B.3 The US: Texas

B.3.1 Key points

Stat	Value
Markets	Day ahead, real time
Market type(s)	Energy only
Annual electricity consumption	Around 460 TWh (native)
Renewable energy share	Around 27%[68], primarily wind
Rooftop PV penetration	<1% of electricity demand[69]

Box 3: Texas: key points

- Texas is a large electricity market with a significant renewable share (mostly wind) and a small share of rooftop solar PV. The Texas grid is operated by ERCOT.
- ERCOT produces centralised forecasts of demand and intermittent generation which are used in dispatch and for forecasting market outcomes in advance. Forecast outcomes are used for operational decisions including bringing additional units online in addition to self-committed units in a process called ‘Reliability Unit Commitment’.
- ERCOT procures weather forecasts from a significant number of providers (up to 14) for different sites and zones across Texas. This data is used to forecast different POE outcomes and extreme outcomes in different regions.
- Rooftop PV is only a recent focus of ERCOT’s given its low penetration. Behaviour of flexible loads receives significant attention from ERCOT in the presence of demand tariffs during the four hottest months and a current lack of visibility of large loads.
- ERCOT’s demand forecasting process is broadly similar to that of AEMO’s in the WEM, with a mix of autoregressive and foundation forecasting over different timescales.
- ERCOT employs two meteorologists on their forecasting team.
- ERCOT produces detailed and updated metrics on different aspects of forecast error.

B.3.2 Market design

The Texas market is an energy-only market that balances competitive wholesale and retail electricity markets within the Texas grid. Wholesale market participants include generators and Qualified Scheduling Entities (QSEs), while retail customers are served by Retail Electric Providers (REPs). ERCOT is independent of federal oversight and governed by the Public Utility Commission of Texas (PUCT), managing the grid’s reliability, operations, and market functions.

ERCOT features both a Day-Ahead Market and a Real-Time Market (RTM). The Day-Ahead Market allows participants to schedule electricity and ancillary services a day in advance, while the

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[68] EIA data browser, available: https://www.eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=vvg&geo=0000000002&sec=g&linechart=ELEC.GEN.ALL-TX-99.A&columnchart=ELEC.GEN.ALL-TX-99.A&map=ELEC.GEN.ALL-TX-99.A&freq=A&ctype=linechart&ltype=pin&rtype=s&pin=&rse=0&maptype=0

[69] https://environmentamerica.org/texas/center/resources/rooftop-solar-on-the-rise/

RTM addresses real-time adjustments to supply and demand using Security-Constrained Economic Dispatch (SCED).

ERCOT incorporates scarcity pricing through mechanisms like the Operating Reserve Demand Curve (ORDC), which increases prices during low reserve conditions to incentivise supply and demand adjustments. The grid integrates significant renewable resources, primarily wind, with specialised forecasting and ancillary services to manage variability.

B.3.3 Operational forecasting

ERCOT has a dedicated forecasting team and employs two staff meteorologists.[70] ERCOT produces forecasts for operational and planning purposes.

B.3.4 Demand

ERCOT produces centralised operational demand forecasts for Texas. These include:[71]

- A Short-Term Load Forecast (STLF), with a 5-minute frequency, 5-minute granularity, and two-hour window. The STLF model contains autoregressive and recent observation terms (i.e. previous day load shape).[72]
- A Mid-Term Load Forecast (MTLF), with an hourly frequency, hourly granularity, and seven-day window. The MTLF model has two sub-models, combining a short-term “Hour Ahead” model with autoregressive terms, and a “Day Ahead” model without autoregressive terms.[73]

ERCOT also produces a Long-Term Load Forecast for planning purposes which goes out 10-30 years and is updated annually.

Key focuses of ERCOT’s operational demand forecasts recently have been[74]:

- Controllable/price responsive demand behaviour. The Large Flexible Load Task Force was established to improve forecasting of large flexible loads. A key issue is visibility of these loads to ERCOT.
- Improving its “4 Coincident Peak” (4CP) forecasts. ERCOT administers peak demand charges for the four hottest months of the year (June through September). Customers are charged based on their consumption at the time of system peak (i.e. their coincident peak demands), and customers respond to these price signals, which presents a forecasting challenge.
- Developing a rooftop solar forecast. Rooftop solar penetration is limited in Texas, hence has not received much attention until recently.

Mid term load forecast

As of June 2024, the mid-term load forecasting process utilises both an in-house model and a vendor supplied forecast. The internally developed model:

- Is run multiple times with different weather forecasts in different configurations. These include:
  - Two runs based on two different forecasts respectively, using the same forecast for all Texas subregions.
  - One run using the most extreme forecast for each subregion for the day ahead.
  - One run using the most extreme forecast for each subregion 4+ days into the future.
- Is based on neural network and linear regression models.

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[70] https://www.ercot.com/files/docs/2022/08/09/6%20Load%20Forecasting%20Overview.pdf

[71] Available at the following link. ERCOT links require geolocation in the US. EPWA can provide copies of these public documents on request. https://www.ercot.com/files/docs/2022/08/09/6%20Load%20Forecasting%20Overview.pdf

[72] https://www.ercot.com/files/docs/2019/02/05/10.1_Load_Forecasting_Overview.pdf

[73] https://www.ercot.com/files/docs/2019/02/05/10.1_Load_Forecasting_Overview.pdf

[74] https://www.ercot.com/files/docs/2022/08/09/6%20Load%20Forecasting%20Overview.pdf

- Includes weather variables (dry bulb temperature, dew point, cloud cover, wind speed, irradiance) based on the month and season.
- Uses 49 weather stations across Texas.
- Includes other relevant variables such as calendar day flags (e.g. day of week, holiday).

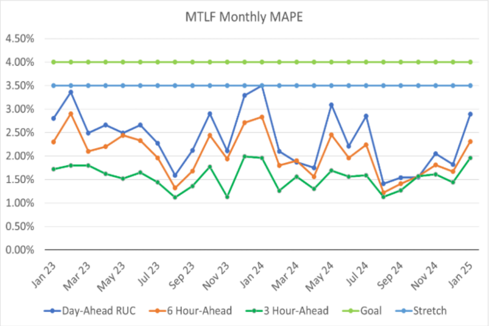
ERCOT uses four global weather models and three vendor-supplied weather forecasts, and has contracted for additional global forecasts which would result in 14 weather forecasts in total.[75]

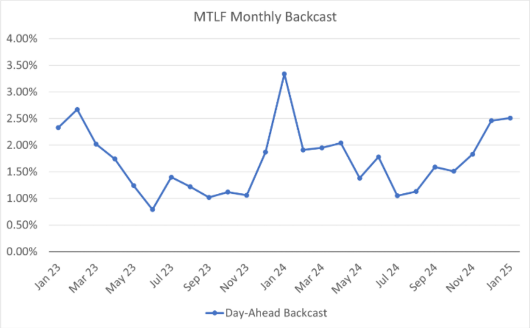
ERCOT publishes various forecast accuracy measures for the MTLF, as illustrated in **Figure 16**. These include:

- Mean average percentage error (MAPE), currently around 1.5% on a 3-hour ahead basis and 2.5% on a day-ahead basis.
- A 'backcast' day-ahead MAPE, where actual weather values are used in the model instead of forecast values. This is currently sitting around 1.75%.
- Average forecast error by hour of day.
- Frequency of over and under-forecast by hour of day.

ERCOT publish an accompanying spreadsheet showing how these metrics are calculated.

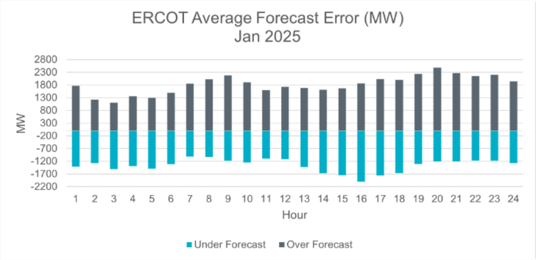
Figure 16: ERCOT's MTLF forecast accuracy measures

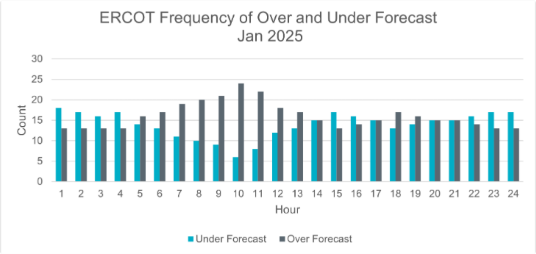




See MTLF Monthly MAPE **MTLF Monthly Backcast**

*Click the button to view the image in greater detail.





See Average Forecast Error **See Frequency Over Under Forecast**

*Click the button to view the image in greater detail.

Source: https://www.ercot.com/gridinfo/load/forecast

Short-term load forecast

The STLF model variables include:

- Previous actual load values and previous day load shapes (i.e. an autoregressive component).

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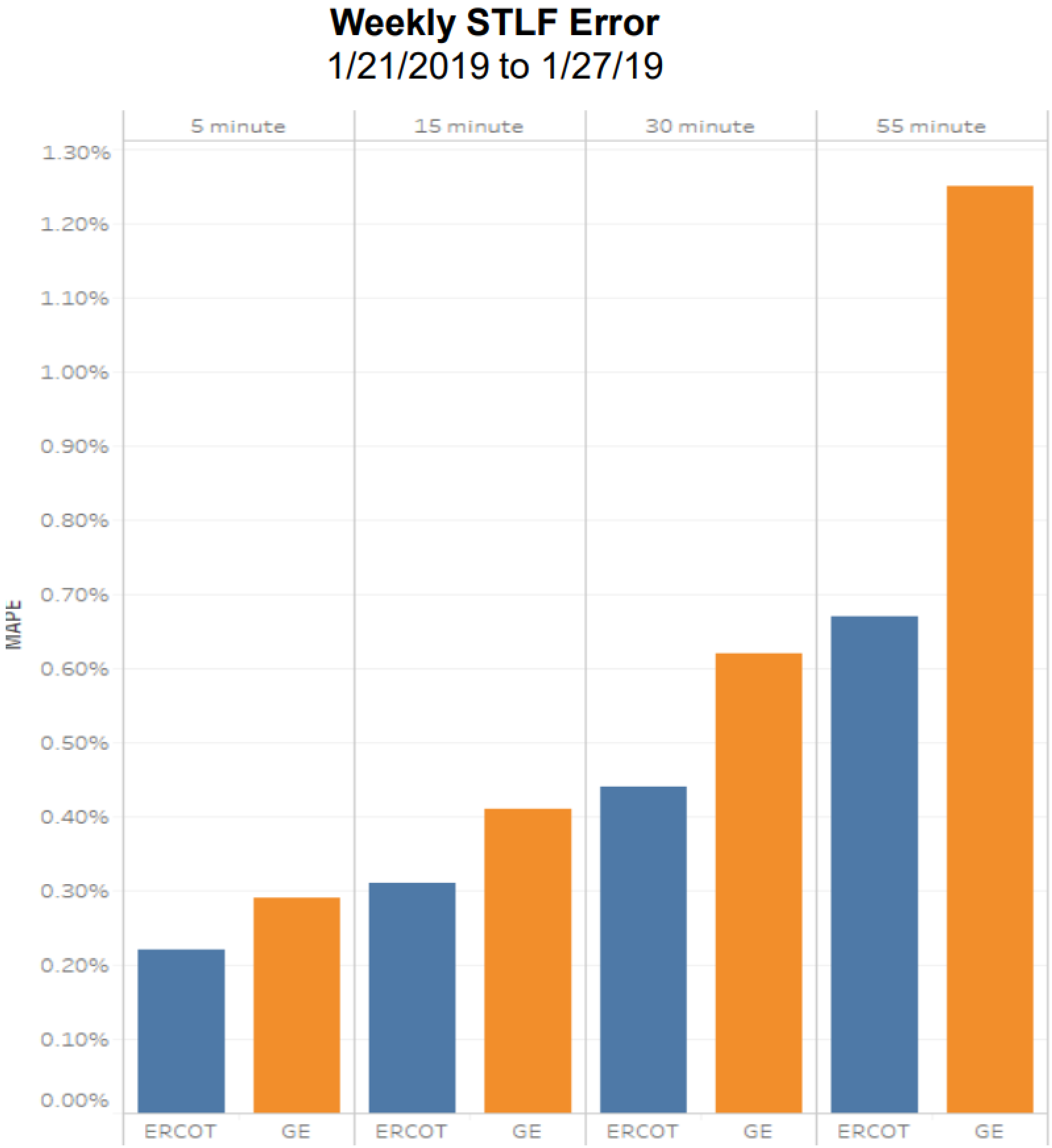
[75] Available https://www.ercot.com/files/docs/2024/06/11/7%20Board%20Education%20%E2%80%93%20Load%20Forecasting.pdf

- Calendar variables (e.g. day of week, holiday, season).
- Weather variables: dry bulb temperature, dew point, cloud cover, wind speed, heat index, wind chill, wet bulb temperature, sunshine minutes, irradiance, relative humidity, precipitation.

ERCOT does not routinely publish STLF errors, but has presented forecast errors in public documents, for example in **Figure 17**.

Figure 17: Example publication of STLF error



Source: *https://www.ercot.com/files/docs/2019/02/05/10.1_Load_Forecasting_Overview.pdf*

B.3.5 Grid scale renewable forecasts

ERCOT is responsible for intermittent generation (known as Intermittent Renewable Resources) forecasting in Texas.[76]

Wind

ERCOT produces four wind generation forecasts, including:

- An Intra-Hour Wind Power Forecast (IHWPF) that is a rolling two-hour, five-minute forecast of ERCOT-wide unconstrained wind output, produced every five minutes. This forecast is used in the 'Generation To Be Dispatched' (GTBD) calculation (i.e. in dispatch).[77]
- A Total ERCOT Wind Power Forecast (TEWPF), representing a probability distribution of the hourly production potential from all wind-power for each of the next 168 hours.
- A Short-Term Wind Power Forecast (STWPF) that is a rolling 168-hour, hourly forecast of individual wind facilities' production potential[78], produced every hour. The STWPF is a 50% Probability of Exceedance (POE) forecast based on the TEWPF. These forecasts are used for Reliability Unit Commitment (RUC) purposes, which is a process that enables ERCOT to bring additional capacity online (above the self-committed level) if a shortage is forecast.
- A Wind Generation Resources Production Potential forecast, representing an 80% POE forecast based on the TEWPF. This forecast is used by the Control Room.

Participants (known as Qualified Service Entities or QSEs) including wind resources must offer a 'Current Operating Plan' that includes a 'High' and 'Low' 'Sustained Limit' which represents their generation potential over time in addition to an energy offer curve[79]. Wind generators are exposed to Base Point Deviation Charges (penalties for missing dispatch targets) for deviations of more than 5% of the acceptable range under certain conditions.[80]

Solar

ERCOT produces solar PV forecasts for Texas which are analogous to the wind forecasts listed above, but for solar instead of wind.[81]

There is more public information on ERCOT's solar forecasting process than its wind forecasting process relating to a two-day 2024 DOE Solar Forecasting Workshop.[82] ERCOT's solar forecasting model and inputs are described on the slide copied in **Figure 18**.

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[76] https://www.ercot.com/files/docs/2024/07/30/2024_07%20IRR.pdf

[77] https://www.ercot.com/files/docs/2024/08/21/August%2023,%202024%20Nodal%20Protocols.pdf

[78] https://www.ercot.com/files/docs/2024/08/21/August%2023,%202024%20Nodal%20Protocols.pdf

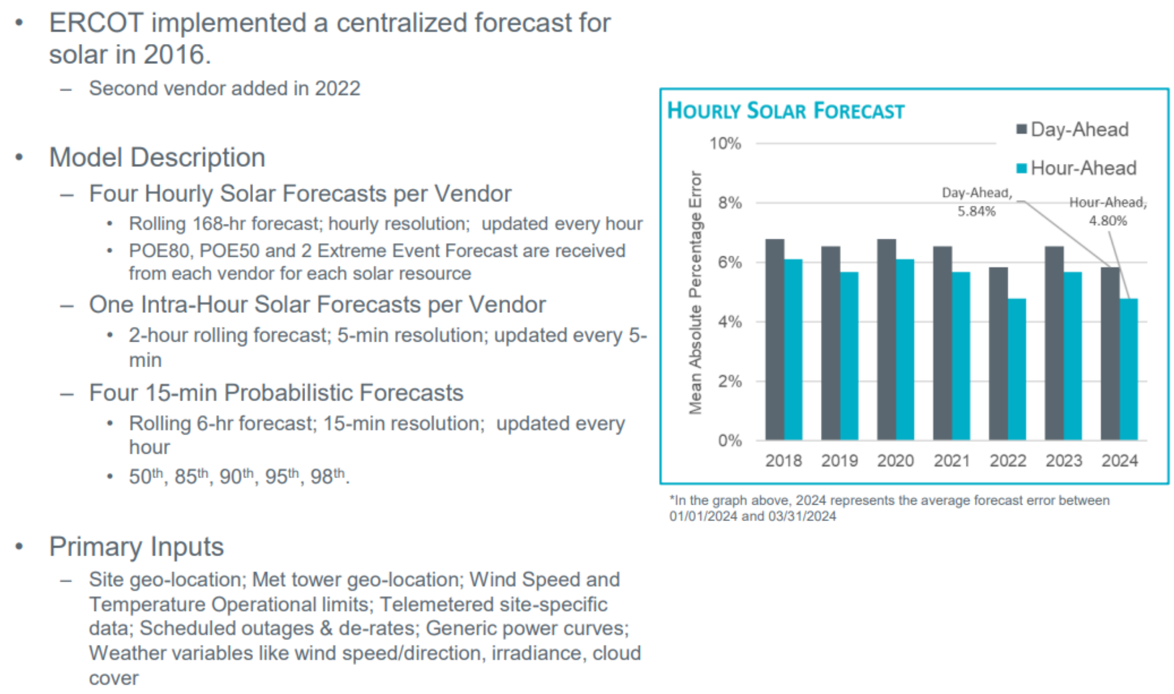
[79] https://www.ercot.com/files/docs/2024/07/30/2024_07%20IRR.pdf

[80] See slide 87: https://www.ercot.com/files/docs/2024/07/30/2024_07%20IRR.pdf

[81] https://www.ercot.com/files/docs/2024/08/21/August%2023,%202024%20Nodal%20Protocols.pdf

[82] This may be of wider interest to EPWA/AEMO. ERCOT's slides begin on slide 41 of Day 2. Slides for the respective days are available https://www.energy.gov/sites/default/files/2024-07/SETO%20-%20Solar%20Forecasting%20Workshop%20-%20Day%201.pdf and https://www.energy.gov/sites/default/files/2024-07/SETO%20-%20Solar%20Forecasting%20Workshop%20-%20Day%202.pdf.

Figure 18: ERCOT's solar forecasting model and inputs



- ERCOT implemented a centralized forecast for solar in 2016.
  - Second vendor added in 2022
- Model Description
  - Four Hourly Solar Forecasts per Vendor
    - Rolling 168-hr forecast; hourly resolution; updated every hour
    - POE80, POE50 and 2 Extreme Event Forecast are received from each vendor for each solar resource
  - One Intra-Hour Solar Forecasts per Vendor
    - 2-hour rolling forecast; 5-min resolution; updated every 5-min
  - Four 15-min Probabilistic Forecasts
    - Rolling 6-hr forecast; 15-min resolution; updated every hour
    - 50th, 85th, 90th, 95th, 98th.
- Primary Inputs
  - Site geo-location; Met tower geo-location; Wind Speed and Temperature Operational limits; Telemetered site-specific data; Scheduled outages & de-rates; Generic power curves; Weather variables like wind speed/direction, irradiance, cloud cover

*In the graph above, 2024 represents the average forecast error between 01/01/2024 and 03/31/2024

Source: https://www.energy.gov/sites/default/files/2024-07/SETO%20-%20Solar%20Forecasting%20Workshop%20-%20Day%202.pdf

ERCOT has also developed a number of dashboards and tools for monitoring, reviewing and making risk-based assessments based on renewable generation forecasts.

With funding from the US Solar Energy Technologies Office, ERCOT partnered with energy business Maxar to develop advanced probabilistic solar forecasts on a sub-hourly basis.[83] Maxar is one of the vendors ERCOT uses for its regular solar forecasting.

B.3.6 Consumer Energy Resources

Texas has experienced an influx of distributed solar and battery installations. To explore the future integration of these resources through VPPs, ERCOT commenced its Aggregate Distributed Energy Resource (ADER) pilot project in 2022. The objectives of this pilot include: [84]

- Assess the operational benefits and challenges of heterogeneous Distributed Energy Resource (DER) aggregations which are net generator or net load, and address those challenges to allow meaningful use of DER aggregation
- Understand the impact of having market services - Ancillary Services and energy, delivered by ADERs and assess how ADERs can best be used to support reliability.
- Assess challenges to incentivising competition and attract broad DER participation through Load Serving Entities (LSEs), while ensuring adequate customer protections are in place.
- Allow Distribution Service Providers (DSPs), the Commission, and others to study distribution system impacts of ADERs which inject to the grid.
- Evaluate the impacts to transmission system congestion management associated with the dispatch and settlement of ADERs at a zonal level.

This project intended to deliver 80MW of flexible resources and is currently providing approximately 25MW of energy and 20MW of other services. One takeaway from phase one was that there was difficulty in obtaining accurate telemetry from VPPs that would allow them to

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[83] https://www.energy.gov/eere/solar/articles/success-story-novel-approach-solar-forecasting-delivers-improved-reliability

[84] Page 5, https://interchange.puc.texas.gov/Documents/53911_72_1369652.PDF

participate in ERCOTs markets. Phase two of this pilot commenced in 2024, continuing with similar objectives and aiming to expand participation in the scheme.

B.4 Great Britain

B.4.1 Key points

Stat	Value
Markets	Capacity, balancing
Market type(s)	Capacity, net pool
Annual electricity consumption	Around 317 TWh[85]
Renewable energy share	Around 43%[86]
Rooftop PV penetration	Around 1% of electricity demand[87]

Box 4: Great Britain: key points

- The Great Britain (GB) market is a self-dispatch market with the exception of the balancing mechanism, which is centralised.
- The National Energy System Operator (NESO) began operating the GB system on 1 October 2024. It was formerly known as National Grid ESO and owned by National Grid plc. NESO is obligated to produce centralised demand forecasts.
- There is little transparency on forecasting in the GB market and centralised forecasts play a less-significant role in the GB market than in other jurisdictions considered. Forecast errors are managed through the balancing mechanism at different time scales.
- There is little public detail on the forecasting methodologies employed by NESO for demand and intermittent generation. NESO has collaborated with the national meteorological service (Met Office) to improve energy forecasting outcomes, although specific details are limited.
- NESO is implementing a new platform for energy forecasting and the most recent evidence indicates it is about a third of the way through implementation.
- NESO's funding and licence conditions are tied in-part to its ability to produce accurate forecasts.

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[85] P1 https://assets.publishing.service.gov.uk/media/66a7da1bce1fd0da7b592f0a/DUKES_2024_Chapter_5.pdf

[86] *Ibid*

[87] Calculated from the official statistics on solar photovoltaics deployment, using an average capacity factor for rooftop solar of 10%, available https://www.gov.uk/government/statistics/solar-photovoltaics-deployment

B.4.2 Market design

The relevant components of the GB market are as follows:

- NESO operates a capacity market to ensure there is sufficient capacity available to meet demand.
- Forward bilateral trades occur between or exchange traded contracts between suppliers, generators, and/or speculators (non-physical traders). Most energy is bought and sold in this way. Contracts must be notified to NESO by the submission deadline (currently at the start of a settlement period).[88]
- Forward bilateral trades are negotiated between NESO and counterparties under a “Grid Trade Master Agreement”[89]. NESO procures specific services (e.g. generation in a specific location) as part of its function as grid operator.
- NESO operates a balancing market to ensure supply meets demand in a particular settlement period (30 minutes). The auction gate opens 60 to 90 minutes before real time.[90]

The rules that govern electricity trading in GB are covered in the Balancing and Settlement Code.[91]

The GB electricity system currently operates under a ‘self-dispatch’ regime, where the only centralised dispatch component takes place in the balancing mechanism that operates after gate-closure.[92]

B.4.3 Operational forecasting

NESO is obligated to produce operational forecasts which include demand forecasts as well as the contribution of intermittent generation to the system. These forecasting processes are described below, although there is little public information on the methodologies. NESO has been criticised recently for a lack of transparency in reporting errors in demand and related component forecasts.[93]

B.4.4 Demand

The NESO is in the process of implementing its new Platform for Energy Forecasting, which replaces two legacy systems for forecasting – the Operational PEF which provided solar, demand and supply forecasts, and the EFS which was used for wind forecasting. As of July 2024, this process was 34% complete.[94]

Information is not readily available for NESO’s new system nor its old system. However, there are several relevant documents that provide some insight into how operational forecasting takes place in GB:

- OC1 of the Grid Code relates to demand forecasts.[95] OC1.6.1 outlines the things that NESO must take into account in producing demand forecasts. These include *inter alia* historic demand, weather, major events/activities, anticipated interconnector flows, demand control and demand management. How these elements are to be used are not specified in the code.

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[88] https://bscdocs.elexon.co.uk/guidance-notes/the-electricity-trading-arrangements-a-beginners-guide

[89] https://www.neso.energy/industry-information/balancing-services/trading#Trading-Requirements

[90] https://www.neso.energy/what-we-do/systems-operations/what-balancing-mechanism

[91] https://bscdocs.elexon.co.uk/bsc

[92] https://www.frontier-economics.com/media/exbbbduy/central-dispatch-summary-170624-final-stc.pdf

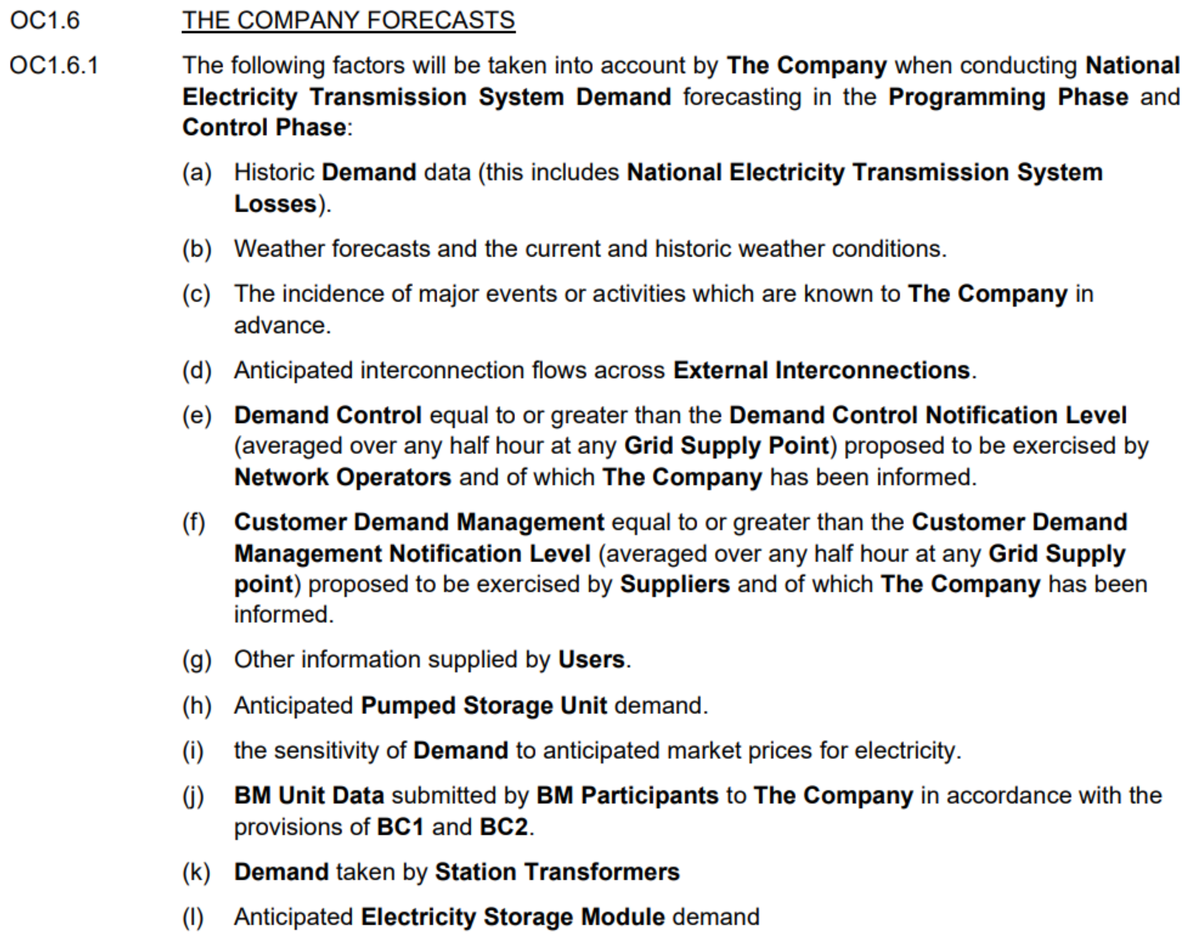
[93] https://watt-logic.com/2025/01/13/neso-forecasting-errors/

[94] https://www.ofgem.gov.uk/sites/default/files/2024-08/Coforge%27s_BP2_midscheme_review_of_ESO_Digital_Data_and_Technology_performance.pdf

[95] https://dcm.nationalenergyso.com/

- NESO has published several documents relating to its Platform for Energy Forecasting program. This includes a roadmap document in 2019[96] and an update document in 2020[97]. These documents appear to be the best descriptions of NESO's demand forecasting process publicly available. Updated or similar recent versions of these documents are partially visible in a review of NESO's data and technology performance.[98]

Figure 19: Forecast factors required to be taken into account by NESO



OC1.6 THE COMPANY FORECASTS

OC1.6.1 The following factors will be taken into account by **The Company** when conducting **National Electricity Transmission System Demand** forecasting in the **Programming Phase** and **Control Phase**:

(a) Historic **Demand** data (this includes **National Electricity Transmission System Losses**).

(b) Weather forecasts and the current and historic weather conditions.

(c) The incidence of major events or activities which are known to **The Company** in advance.

(d) Anticipated interconnection flows across **External Interconnections**.

(e) **Demand Control** equal to or greater than the **Demand Control Notification Level** (averaged over any half hour at any **Grid Supply Point**) proposed to be exercised by **Network Operators** and of which **The Company** has been informed.

(f) **Customer Demand Management** equal to or greater than the **Customer Demand Management Notification Level** (averaged over any half hour at any **Grid Supply point**) proposed to be exercised by **Suppliers** and of which **The Company** has been informed.

(g) Other information supplied by **Users**.

(h) Anticipated **Pumped Storage Unit** demand.

(i) the sensitivity of **Demand** to anticipated market prices for electricity.

(j) **BM Unit Data** submitted by **BM Participants** to **The Company** in accordance with the provisions of **BC1** and **BC2**.

(k) **Demand** taken by **Station Transformers**

(l) Anticipated **Electricity Storage Module** demand

Source: NESO Grid Code, Issue 6 Revision 21, 04 March 2024, p576

EPWA notes that NESO publishes a document relating to its Future Energy Scenarios modelling methodology, however, the purpose of this is long-term and not operational demand forecasting.[99]

Forecast timescales pre and post implementation of the Platform for Energy Forecasting are illustrated in **Figure 20**. At the time of publication (June 2019), intraday forecasts were published 5 times a day and day-ahead forecasts were published twice daily.

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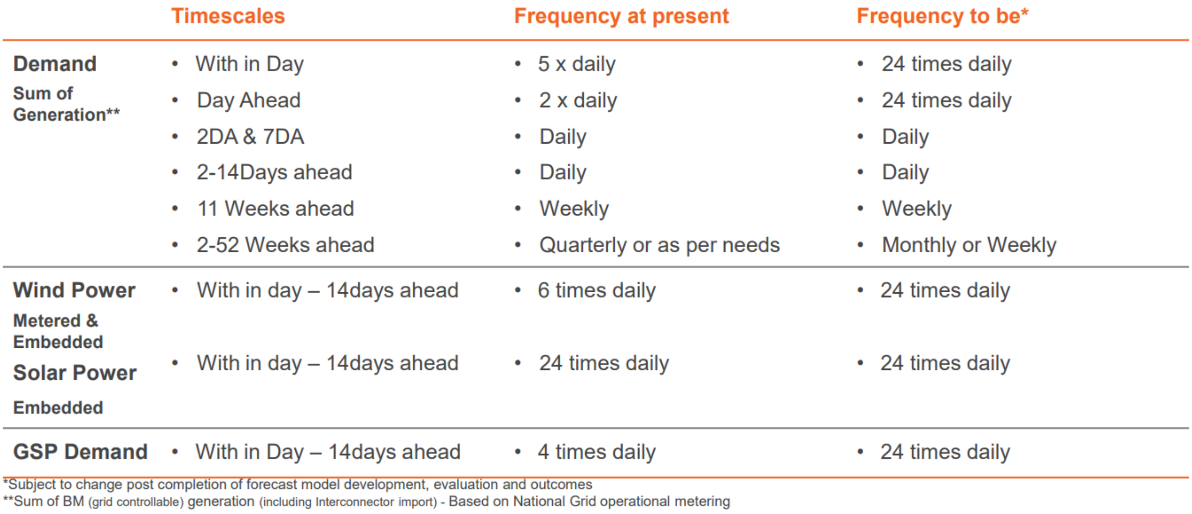
[96] https://www.neso.energy/document/145941/download

[97] https://www.neso.energy/document/172076/download

[98] https://www.ofgem.gov.uk/sites/default/files/2024-08/Coforge%27s_BP2_midscheme_review_of_ESO_Digital_Data_and_Technology_performance.pdf

[99] See https://www.neso.energy/publications/future-energy-scenarios-fes/fes-documents

Figure 20: Forecast timescales and frequency



	Timescales	Frequency at present	Frequency to be*
Demand Sum of Generation**	With in Day	5 x daily	24 times daily
	Day Ahead	2 x daily	24 times daily
	2DA & 7DA	Daily	Daily
	2-14Days ahead	Daily	Daily
	11 Weeks ahead	Weekly	Weekly
	2-52 Weeks ahead	Quarterly or as per needs	Monthly or Weekly
Wind Power Metered & Embedded	With in day – 14days ahead	6 times daily	24 times daily
Solar Power Embedded	With in day – 14days ahead	24 times daily	24 times daily
GSP Demand	With in Day – 14days ahead	4 times daily	24 times daily

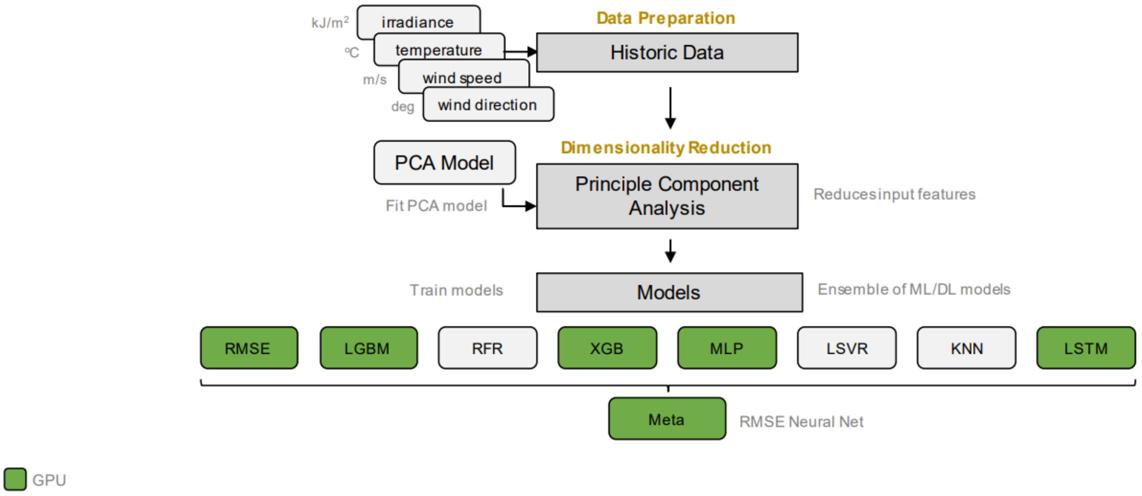
*Subject to change post completion of forecast model development, evaluation and outcomes
**Sum of BM (grid controllable) generation (including Interconnector import) - Based on National Grid operational metering

Source: https://www.neso.energy/document/145941/download

Demand forecasts for intra-day, two week ahead, and 1 year ahead forecasts are published on the Balancing Mechanism Reporting Service.[100]

There is little detail available publicly on the methodology employed by NESO to forecast demand. There are several schematics of the new machine learning modelling approach for the Platform for Energy Forecasting, which were at the time 'undergoing internal validation'. An example of one of these schematics is provided in **Figure 21**. This model is designed to forecast electricity demand for a single grid supply point (GSP). The model incorporates around 10 machine and deep learning models and predictions are made every hour using the model.

Figure 21: Machine Learning Model Training Single GSP



Source: https://www.neso.energy/document/172076/download

This new approach includes embedded generation, and takes irradiance and wind speed and direction as inputs in addition to temperature.

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[100] https://bmrs.elexon.co.uk/demand-forecast

The GB energy regulator, the Office of Gas and Electricity Markets (Ofgem), track NESO's forecasting performance because NESO's performance is related to funding. In its Mid-Scheme review of ESO Performance 2021-2023, Ofgem found that wind forecasting performance exceeded expectations and demand forecasting performance met expectations.[101] Improving electricity forecasting is expected to be part of NESO's licence expectations for 2025-26.[102]

B.4.5 Weather forecasts

NESO collaborates with the national meteorological service (the Met Office) to improve energy forecasting outcomes.

EPWA notes two relevant programs:

- The Met Office has invested in a supercomputer to enable "ensemble data"[103] to improve accuracy and detail of weather forecast data for use in energy forecasting models. The Met Office is collaborating with NESO to identify necessary data for energy modelling across different timescales. EPWA understands that the main focus of this is for longer-term forecasting.[104]
- The Met Office and NESO teamed up to improve solar irradiation forecasts to better forecast the impact of solar PV on the grid. The Met acknowledged that the local influence of clouds made longer-term forecasting of irradiance difficult. One of the work packages under this project focused on forecasting the very short term (several hours), called a 'Nowcast'. The result of the program brought an improvement of between 5% and 10% in solar radiation forecast mean absolute error.[105]

B.4.6 Renewable forecasts

There is little detail available on the methodology employed by NESO for wind and solar forecasts. Wind generation forecasts produced by NESO's wind power forecasting tool are published on the Balancing Mechanism Reporting Service up to eight times a day at 3:30am, 5:30am, 8:30am, 10:30am, 12:30pm, 4:30pm, 7:30pm, and 11:30pm.[106] These are four-day ahead forecasts at a one hour granularity, and include wind farms which are visible to NESO and have operational metering. Other forecasts are published on the NESO's data portal.[107]

B.4.7 Consumer Energy Resources

The UK's largest distribution system operator, UK Power Networks (UKPN) has implemented its Distributed Energy Resource Management System (DERMS) to optimise participation of DER in minimising grid and energy costs.[108]

The National Electricity System Operator in the UK has developed a demand flexibility service, that incentivises households to reduce demand and peak periods, and potentially increase demand

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[101] P10 https://www.ofgem.gov.uk/sites/default/files/2022-07/Ofgem%20Mid-Scheme%20Report%202021-23.pdf

[102] P19 https://www.ofgem.gov.uk/sites/default/files/2025-02/Draft_NESO_Licence_Expectations_Document.pdf

[103] EPWA interprets this to mean ensemble models, which involve combining a range of models to predict outcomes rather than using a single model.

[104] https://www.metoffice.gov.uk/blog/2024/collaborating-for-energy-network-resilience

[105] https://www.metoffice.gov.uk/binaries/content/assets/metofficegovuk/pdf/services/industry/energy/eso-teams-up-with-met-office-on-solar-forecasting.pdf

[106] https://bmrs.elexon.co.uk/wind-generation

[107] https://www.neso.energy/data-portal

[108] https://dso.ukpowernetworks.co.uk/curtailment-and-derms

during periods of high renewables.[109] This is similar to a wholesale price tariff, however, it does not appear there is a penalty for not participating.

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[109] https://www.neso.energy/industry-information/balancing-services/demand-flexibility-service-dfs

B.5 The US: California

B.5.1 Key points

Stat	Value
Markets	Day ahead, real time
Annual electricity consumption	Around 281 TWh[110]
Renewable energy share	Around 48%[111]
Rooftop PV penetration	5-7% of electricity demand[112]

Box 5: California: key points

- The CAISO operates the California system as well as day-ahead and real time markets for several western states.
- CAISO gathers historical data from around 63 weather stations across six climate zones from two different weather providers, and employs an internal meteorological review team to analyse data collected and assist in producing demand forecasts.
- Generators in California have the following options with respect to forecasting generation:
  - They can pay CAISO $0.10/MWh to forecast on their behalf, or
  - They can certify their forecasting accuracy with CAISO and provide self-forecasts.
- CAISO have a dedicated model for predicting short-term net load uncertainty for the purpose of procuring ramping services, called the Mosaic Quantile Regression Model.
- CAISO outsource forecasts of behind-the-meter generation and there is little public information on the methodology.

B.5.2 Market design

The CAISO operates both a day-ahead market and a real-time market within the Western Interconnection, a grid spanning from Western Canada to Baja California in Mexico. CAISO is the largest of about 38 balancing authorities on the Western Interconnection, responsible for matching generation with load and maintaining grid frequency in its transmission control area.[113]

The day-ahead market allows participants/'Load serving entities' (LSEs) to submit offers and bids to schedule generation for the following day based on demand forecasts up to seven days earlier. The real-time market allows participants to balance deviations from their day-ahead schedules by making adjustments based on actual physical outcomes.

In addition to this, CAISO operates the Western Energy Imbalance Market and extended day-ahead market, which are essentially extensions of the real-time and day-ahead markets respectively across multiple western states. While CAISO does not operate a capacity market, its resource adequacy framework requires LSEs to procure sufficient capacity on a monthly basis.

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[110] https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2023-total-system-electric-generation

[111] *Ibid*

[112] Calculated from https://www.caiso.com/Documents/2023SolarEclipseFAQ.pdf

[113] https://www.caiso.com/about/our-business/balancing-authority

B.5.3 Operational forecasting

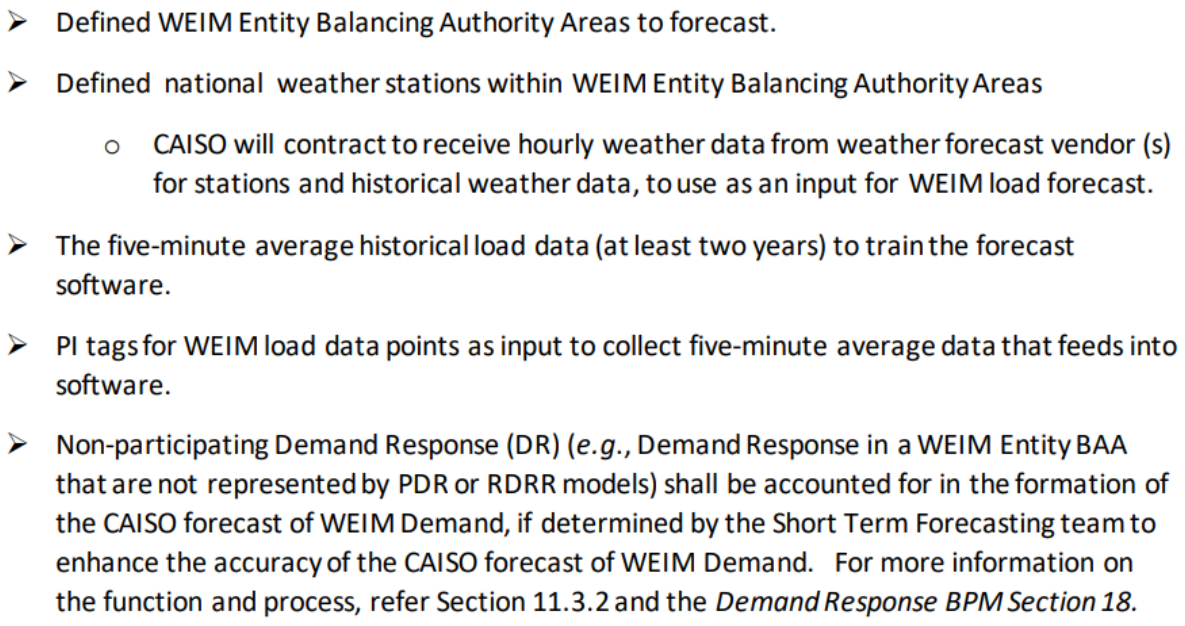
CAISO provides several documents relevant to operational demand forecasting:

- A Computer-Based Training Course on Forecasting, published May 2024[114].
- The Business Practice Manual for Market Operations (revised December 23 2024)[115]

CAISO use their “Automated Load Forecasting System” (ALFS) to provide load forecasts, described as follows. “*The automated load forecasting System (ALFS) is an application based on advanced neural network and regression models that is designed to capture linear and non-linear interactions between load, weather and calendar information. It uses five-minute averages of actual Load from the Energy Management System for the last 3 years as input for training the neural network. ALFS can generate a forecast for different time intervals and time horizon.”*[116]

The current business practice manual for the Energy Imbalance Market lists the elements in **Figure 22** as inputs to the AFLS[117].

Figure 22: AFLS software requirements



- ➢ Defined WEIM Entity Balancing Authority Areas to forecast.
- ➢ Defined national weather stations within WEIM Entity Balancing Authority Areas
  - o CAISO will contract to receive hourly weather data from weather forecast vendor (s) for stations and historical weather data, to use as an input for WEIM load forecast.
- ➢ The five-minute average historical load data (at least two years) to train the forecast software.
- ➢ PI tags for WEIM load data points as input to collect five-minute average data that feeds into software.
- ➢ Non-participating Demand Response (DR) (*e.g.*, Demand Response in a WEIM Entity BAA that are not represented by PDR or RDRR models) shall be accounted for in the formation of the CAISO forecast of WEIM Demand, if determined by the Short Term Forecasting team to enhance the accuracy of the CAISO forecast of WEIM Demand. For more information on the function and process, refer Section 11.3.2 and the *Demand Response BPM Section 18.*

Source: https://bpmcm.caiso.com/BPM%20Document%20Library/Energy%20Imbalance%20Market/BPM_for_Energy%20Imbalance%20Market_V33_Redline.pdf

CAISO prepares demand forecasts over the following set of horizons:

- Day-ahead forecasts: Updated at 9 am each day for the next day; look out 7 days.
- Real-time forecasts: Updated every 5 minutes; rolling 24 hours at a 5-minute granularity.

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[114] https://www.caiso.com/content/cbt/forecasting/story.html

[115] https://bpmcm.caiso.com/BPM%20Document%20Library/Market%20Operations/BPM_for_Market%20Operations_V100_Redline.pdf

[116] P379

[117] Noting that it is referred to in the BPM as the “**Advanced** Load Forecasting System”. See p129-130, https://bpmcm.caiso.com/BPM%20Document%20Library/Energy%20Imbalance%20Market/BPM_for_Energy%20Imbalance%20Market_V33_Redline.pdf

From EPWA's understanding, CAISO can use a number of statistical and/or machine-learning models to formulate key relationships between known explanatory variables and demand. Key inputs to these models include the following:

- Weather: CAISO gathers historical data from around 63 weather stations across six climate zones from two different weather providers. CAISO employs an internal meteorological review team to analyse data collected and assist in producing demand forecasts.
    - CAISO explicitly cite 'cloud cover' as one of the most important factors in short-term load forecasts.[118]
- Factors that drive behind the meter solar (as CAISO has limited visibility of BTM solar generation). These factors are included in the demand model to account for the impact of behind-the-meter solar.
- Time of day, day of week, month of year, special day
- Historical estimated gross load (observed demand plus estimates of BTM generation, demand response, batteries and hydro pumps). CAISO use 'at least two years' of five-minute historical data to train the forecast software[119].
- Non-participating Demand Response, *if* determined by the Short Term Forecasting team to enhance the accuracy of the forecast.[120]

CAISO relies on an external vendor to provide behind-the-meter solar forecasts.[121] However, it has flagged DER visibility as an important part of maintaining load forecasting accuracy as behind-the-meter solar, batteries and EVs increase in number.[122],[123]

Two of the markets CAISO administers are 'Flexible Ramp Product' (FRP) markets (including a 5-minute and 15-minute product) which ensure there is ramp capacity available in the short term. CAISO have used a model called the 'Mosaic Quantile Regression Model' to predict uncertainty in short-term net load ('mosaic' because it is a blend of different component forecasts) to determine the requirement for FRP.[124] That is, CAISO have a dedicated model to predict short-term uncertainty net load to help manage near-term ramp requirements. In 2023-2024, based on stakeholder feedback, CAISO have updated the mosaic approach to incorporate weather forecast information in lieu of only historical values to better account for uncertainty in short term net load.[125] CAISO has found that this has improved estimates of uncertainty and has led to lower cost outcomes in the market. A related diagram is copied in **Figure 23**.

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[118] See slide 4, https://www.westerneim.com/Documents/Presentation-Forecasting-CAISO.pdf

[119] P130 https://bpmcm.caiso.com/BPM%20Document%20Library/Energy%20Imbalance%20Market/BPM_for_Energy%20Imbalance%20Market_V33_Redline.pdf

[120] *Ibid*

[121] https://www.caiso.com/documents/april-2024-eclipse-post-analysis-report.pdf

[122] https://www.energy.gov/sites/default/files/2024-07/SETO%20-%20Solar%20Forecasting%20Workshop%20-%20Day%202.pd

[123] https://www.caiso.com/documents/dec-6-2024-comments-on-the-alj-ruling-seeking-comments-regarding-future-grid-study-report-high-distributed-energy-resources-r-21-06-017.pdf

[124] https://stakeholdercenter.caiso.com/initiativedocuments/analysis-flexiblerampinguncertaintycalculationinthewesternenergyimbalancemarket.pdf. See also https://www.sciencedirect.com/science/article/pii/S2667113122000122 and https://docs.nrel.gov/docs/fy21osti/80108.pdf

[125] https://www.caiso.com/Documents/BriefingonMosaicQuantileRegressionAnalysis-Feb2024.pdf

Figure 23: Mosaic quantile regression model flow chart

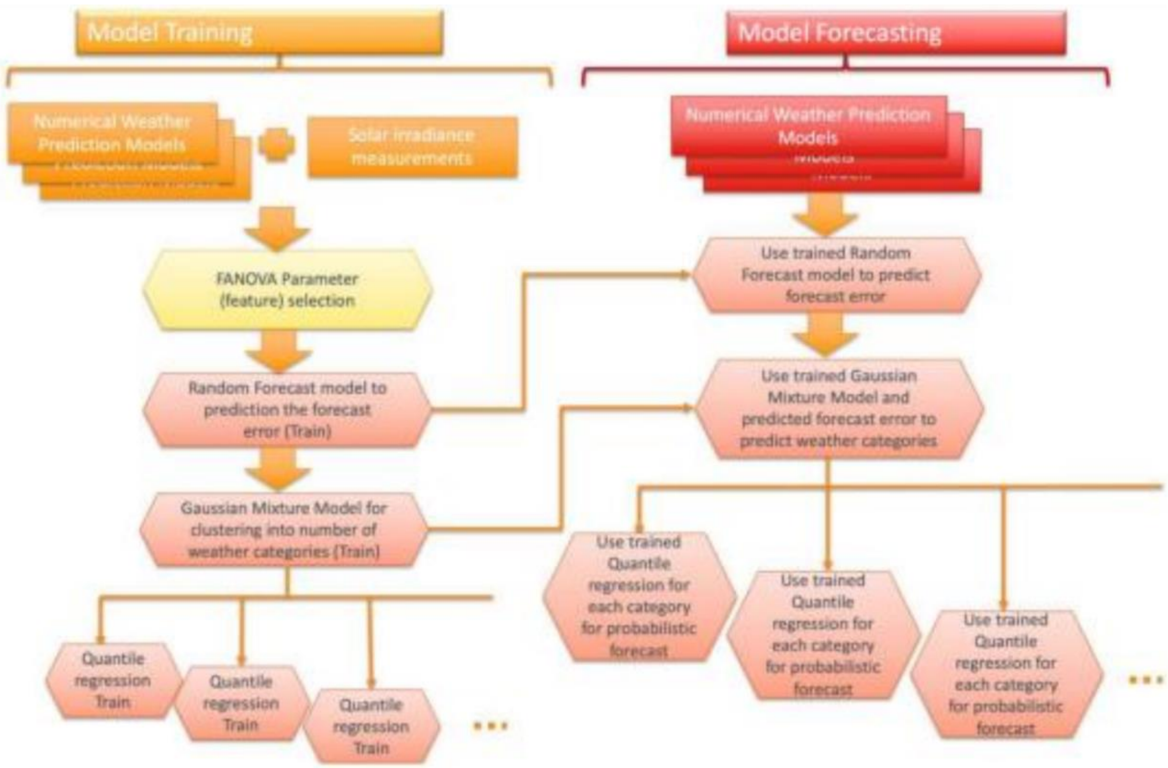

Fig. 9: Model blending Flow chart Overview

Source: https://www.energy.gov/sites/default/files/2024-07/SETO%20-%20Solar%20Forecasting%20Workshop%20-%20Day%202.pdf

CAISO's operating procedure documents suggest it uses the Metrix forecasting software.[126]

B.5.4 Grid scale renewable forecasts

CAISO prepares renewable forecasts over the following set of horizons:

- Day-ahead forecasts: Updated at 9 am each day for the next day; look out 7 days.
- Real-time forecasts: Updated every 5 minutes; rolling 9 hours at a 5-minute granularity.
- Persistence based forecast: a short-term alternative to the real-time forecast that does not rely any external forecast service providers, and hence provides a more accurate forecast in the very short term. Using external service providers introduces a lag of 6-12 minutes which can be avoided with persistence forecasts. Unlike the previous forecasts noted, this methodology just relies on historical recent output observations from generators.

Key inputs for CAISO's day-ahead and real-time renewable forecast models include:

- Asset Registration Information including Pmax/Pmin, site location, topography and equipment used to capture weather data.
- Outage/De-rate Schedules including plans for scheduled outages to prevent the ISO from committing resource during these periods.
- Real-Time Generation Telemetry (MW) information including actual MW generation for input in the forecast model.

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[126] CAISO, Real-Time Market Activities Operating Procedure, p2https://www.caiso.com/documents/2210.pdf

- Real-Time Meteorological Information, including weather data collected at the site of wind and solar resources.

CAISO employs two forecast service providers to use the above inputs as well as the latest available weather forecasts to create day-ahead and real-time forecasts.

- Day-ahead forecasts use long-term historical production data and weight the weather forecast heavily to produce a renewable forecast.
- Real-time forecasts weight very recent production data more heavily particularly in the short range (e.g. for the next 15 minutes), while also accounting for the weather forecast.

Renewable generators can either use the CAISO forecasts as forecasts of their generator or provide their own[127]. Use of the CAISO provided forecasts incurs a fee of up to $0.10 per MWh[128]. As of 2021, all participants were providing their own forecasts. Regardless of whether self-forecasting or using CAISO forecasts, participants must provide outage and meteorological data to CAISO. In order to qualify to use their own forecasts, participants must be certified by CAISO. In addition, CAISO holds the right to suspend the use of participant forecasts at any time if they believe a participant is "engaged in strategic forecasting for purposes other than accuracy"[129], showing that they appreciate the risk of participants having incentives to misrepresent output.

CAISO also procures a probabilistic forecast used for risk assessment from one provider.[130]

B.5.5 Participant self-forecasting

Renewable generators can either use CAISO forecasts as forecasts of their generator or provide their own. When providing their own forecast, these are typically developed by a 3rd party vendor who submits the forecasts on behalf of the participant.[131] Use of the CAISO provided forecasts results in a fee capped at $.10 per MWh[132]. As at 2021, all participants were providing their own forecasts. Regardless of whether self-forecasting or using CAISO forecasts, participants must provide outage and meteorological data to CAISO.

In order to qualify to use their own forecasts, participants must be certified by CAISO. In addition, CAISO holds the right to suspend the use of participant forecasts at any time if they believe a participant is "engaged in strategic forecasting for purposes other than accuracy"[133], showing that they appreciate the risk of participants having incentives to misrepresent output.

B.5.6 DER visibility

CAISO recognises that it will need to gain visibility to DERs to manage distribution level system constraints. This will feed as a new input into their ALFS as the real time behaviour of these participants must be forecast if they are not actively dispatched.[134] Currently this is an indication of where future investment should be directed, and not an active program. In addition, Southern California Edison, a utility within the CAISO region that serves 15 million customers, is investing

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[127] https://www.westerneim.com/Documents/Presentation-Forecasting-CAISO.pdf

[128] See Schedule 4, https://www.caiso.com/documents/appendixf-rateschedules-asof-jan1-2024.pdf

[129] Section 4.8.2.1.1 Use of Own Forecast, https://www.caiso.com/documents/drafttarifflanguage-participatingintermittentresources-fercorder764marketchanges.doc

[130] https://www.westerneim.com/Documents/Presentation-Forecasting-CAISO.pdf

[131] https://www.westerneim.com/Documents/Presentation-Forecasting-CAISO.pdf

[132] See Schedule 4, https://www.caiso.com/documents/appendixf-rateschedules-asof-jan1-2024.pdf

[133] Section 4.8.2.1.1 Use of Own Forecast, https://www.caiso.com/documents/drafttarifflanguage-participatingintermittentresources-fercorder764marketchanges.doc

[134] Solar forecasting workshop 2024, page 23, https://www.energy.gov/sites/default/files/2024-07/SETO%20-%20Solar%20Forecasting%20Workshop%20-%20Day%202.pdf

resources into forecasting behaviour of distributed resources, applying economic optimisation models that inform markets of expected DER behaviour.[135]

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[135] Solar forecasting workshop 2024, page 179, https://www.energy.gov/sites/default/files/2024-07/SETO%20-%20Solar%20Forecasting%20Workshop%20-%20Day%202.pdf

B.6 Ireland and Northern Ireland (SEM)

B.6.1 Key points

Stat	Value
Markets	Capacity, forward, day-ahead, intra-day, balancing[136]
Annual electricity consumption	Around 35 TWh[137]
Renewable energy share	Around 41%[138]
Rooftop PV penetration	126 GWh/a[139] (< 1%)

Box 6: Ireland and Northern Ireland: key points

- Demand and intermittent generation forecasting is centralised in Ireland and Northern Ireland by its two TSOs. The TSOs use an in-house model to forecast demand and procure forecasts from two vendors for intermittent generation. Intermittent generation facilities may submit forecasts ('physical notifications' of production), but these are not used by the TSOs.
- There is a mandatory balancing market and the TSOs are responsible for procuring balancing capacity.
- Public information on forecasting methodologies in Ireland and Northern Ireland is limited.

B.6.2 Market design

Participants in the SEM are required to participate in its capacity market wherein they receive payments in return for delivering on their capacity market obligations up to five years in advance of the trading day. This ensures sufficient generation capacity to meet forecast demand. The SEM then has a day-ahead market and an intra-day market that allow participants to trade on their positions and a balancing market to manage any differences between the market schedule and actual system demand. In particular:

- The day-ahead market is pan-European and has 24 hourly delivery periods[140].
- The intraday market has multiple auctions throughout the day closing up to one hour before real time.
  - Continuous trading occurs throughout the day on a half-hourly basis up to one hour before real time. Continuous trading is SEM only.

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[136] SEM Annual Report 2022-23 (latest published), available https://www.semcommittee.com/files/semcommittee/2024-03/SEM%20Annual%20Report%202022-2023.pdf

[137] First Look: Renenewable Energy in Ireland 2023, p8, available https://www.seai.ie/sites/default/files/data-and-insights/seai-statistics/key-publications/renewable-energy-in-ireland/First-Look-Renewable-Energy-in-Ireland-Report.pdf

[138] First Look: Renewable Energy in Ireland 2023, p8, available https://www.seai.ie/sites/default/files/data-and-insights/seai-statistics/key-publications/renewable-energy-in-ireland/First-Look-Renewable-Energy-in-Ireland-Report.pdf

[139] https://www.energyireland.ie/meeting-irelands-2030-solar-targets/

[140] SEM Annual Report 2022-23 (latest published), p10, available https://www.semcommittee.com/files/semcommittee/2024-03/SEM%20Annual%20Report%202022-2023.pdf

  - The IDA-1 and IDA-2 auctions include the SEM and the GB market via interconnectors. IDA-1 closes at 5:30pm the trading day prior. IDA-2 closes at 8am on the trading day. The IDA-3 auction is SEM only and closes at 2pm on the trading day.
- The balancing market also closes up to one hour before real time but includes actions taken by the TSO to keep the system balanced and secure, and includes five-minute imbalance pricing periods within each half-hour.

Most energy (around 84%) is traded on the day-ahead market[141].

B.6.3 Operational forecasting

Ireland and Northern Ireland's TSOs, EirGrid and SONI (the TSOs), publish a document called the "Balancing Market Principles Statement: A guide to Scheduling and Dispatch in the Single Electricity Market"[142]. This document sets out how the TSOs run the scheduling and dispatch process, including the forecasts that feed into this process.

B.6.4 Demand forecasting

The TSOs provide several relevant documents for operational demand forecasting, as follows. However, none provide a technical description of how the models are constructed or operate.

- Section OC1 (OC standing for 'Operating Conditions') deals with demand forecasts.[143]
- The Short-Term Demand Forecasting Methodology for Scheduling and Dispatch document[144], which provides an overview of the demand forecasting methodology.
- The Business Process 4.2: Demand Forecasting for Scheduling and Dispatch document[145], which provides more detail on certain parts of the demand forecasting methodology and process.

The TSOs are required to produce demand forecasts for operational planning through to scheduling and dispatch. The focus here is on forecasts prepared for scheduling and dispatch. These include forecasts produced by the TSOs' Energy Management System (EMS) and Market Management System (MMS).

The EMS forecast is a half-hourly resolution model of system demand for fourteen days ahead, although only four days ahead are published once a day[146]. The model is run every half-hour of the day. Forecasts are made for Ireland and Northern Ireland separately given different load shapes (e.g. public holidays are different, large industrial customer distributions) and limitations of the circuits that connect Ireland and Northern Ireland (the 'tie lines').[147]

The inputs are and outputs are shown in **Figure 24** below. Importantly, the EMS demand forecast tool operates 'predominantly' on the last two weeks (the "hot history") to produce the demand forecast. The EMS demand forecast model is part of the TSOs' proprietary system.

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[141] SEM Annual Report 202-23 (latest published), p18, available https://www.semcommittee.com/files/semcommittee/2024-03/SEM%20Annual%20Report%202022-2023.pdf

[142] The most recent published version of this document is from 29 July 2024, available https://cms.eirgrid.ie/sites/default/files/publications/EirGrid-and-SONI-Balancing-Market-Principles-Statement-V8.0.pdf

[143] https://cms.eirgrid.ie/sites/default/files/publications/Grid-Code-Version-13_0.pdf

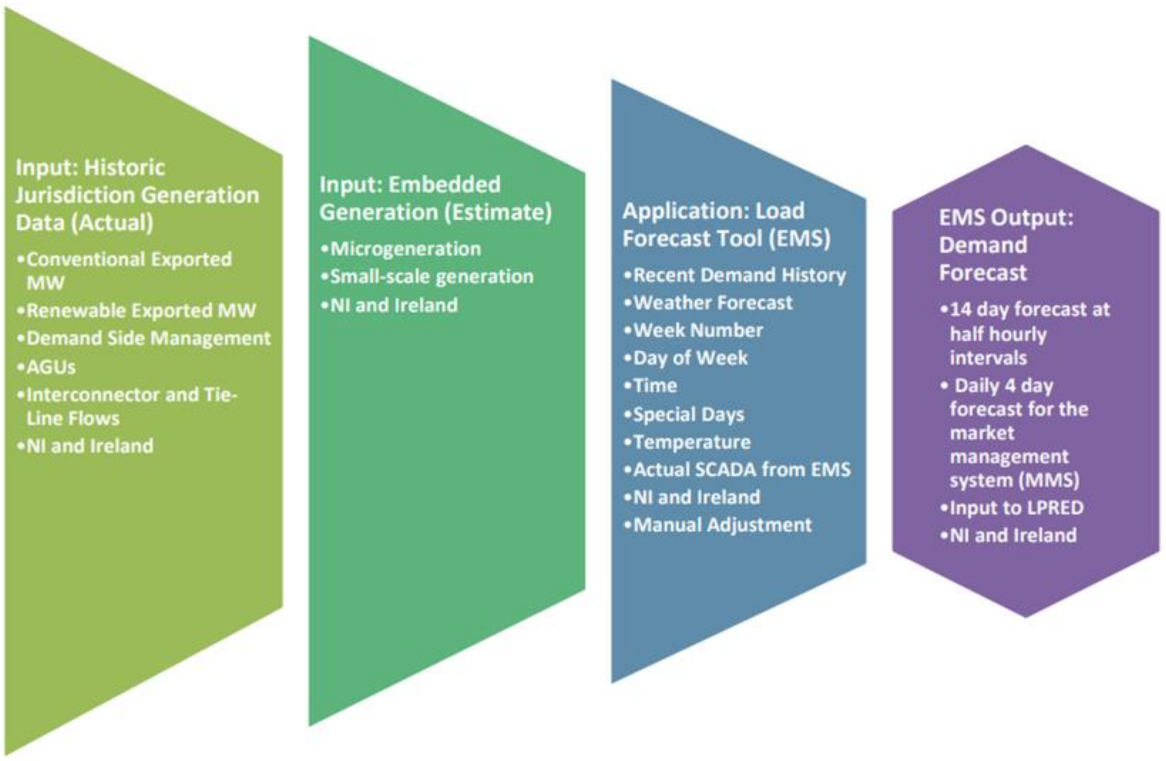
[144] available https://www.sem-o.com/documents/general-publications/Short-term_Demand_Forecasting_Methodology.pdf

[145] Available https://www.sem-o.com/documents/general-publications/BP_SO_04.2_Demand_Forecasting_for_Scheduling_and_Dispatch.pdf

[146] See Business Process 4.2: Demand Forecasting for Scheduling and Dispatch, available https://www.sem-o.com/documents/general-publications/BP_SO_04.2_Demand_Forecasting_for_Scheduling_and_Dispatch.pdf

[147] P3 https://www.sem-o.com/sites/semo/files/documents/general-publications/Short-term_Demand_Forecasting_Methodology.pdf

Figure 24: Summary of EMS Demand Forecasting Process



Source: Short-Term Demand Forecasting Methodology for Scheduling and Dispatch, p5, available https://www.sem-o.com/documents/general-publications/Short-term_Demand_Forecasting_Methodology.pdf

There are various manual adjustments that can be made to the EMS forecast shape and/or level after the EMS as post-model adjustments.

The EMS forecast is then fed into the MMS forecasting process (called Load Predictor or LPRED). This has three components:

- A long-term scheduling (LTS) component which forecasts up to 30 hours,
- A real-time commitment (RTC) component which forecasts up to 3.5 hours, and
- A real-time dispatch component (RTD), which forecasts up to 1 hour.

The RTC and RTD forecasts are at one-minute resolution and are used for commitment and dispatch scheduling applications.

The TSOs' highlight several features of LPRED used for the RTC and RTD forecasts, including "Load Shape Management", "Frequency Deviation Load Adjustment", "Load Prediction" and "Load Blending". These are described at such a high level that they are not enlightening. The Business Process document[148] describes the mechanical process of forecasting, but not how the models in any level of detail.

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[148] Available https://www.sem-o.com/documents/general-publications/BP_SO_04.2_Demand_Forecasting_for_Scheduling_and_Dispatch.pdf

EPWA further notes that:

- The TSOs' state they are further investigating options for better forecasting of the output of small-scale generation on the system as a whole. As of July 2024, the TSOs state "*The impact of solar micro generation is having a material impact on demand profiles and more generally on the scheduling and dispatch process. The forecasting and treatment of this embedded generation is in development.*"[149] Also to note is that Ireland has a small amount of rooftop solar PV.
- The TSOs are currently consulting on additional demand forecasting processes for ancillary services (in addition to energy).[150]

B.6.5 Renewable forecasts

The TSOs provide several relevant documents for operational renewable forecasting:

- The Wind and Solar Forecasting Methodology for Scheduling and Dispatch document[151], which provides an overview of the demand forecasting methodology.
- The Business Process 4.3: Wind Forecasting for Scheduling and Dispatch document[152], which provides more detail on certain parts of the wind forecasting methodology and process.

The TSOs procure wind and solar forecasts from two independent forecast providers for facilities with capacities of 5MW or above, although there are several exceptions to this rule. At a high level, forecast providers are provided with information about the location, unit properties (e.g. hub height), and recent SCADA data is provided to these operators, which forecast weather outcomes and output traces for each facility at a time resolution of 15 minutes over 4.5 days. These forecasts are provided every six hours.

The TSOs provide forecast providers with standing data (incl. installed capacity, coordinates, nearest transmission station, turbine information, permissible capacity, etc.), as well as historical SCADA and meteorological data to train wind power models specific to each wind farm. These models are trained for various weather conditions and rely on high-quality historical data. Forecast providers update the power curve models for winds periodically to ensure that forecasts are more precise, particularly when facing uncommon wind directions or changing terrain characteristics that might affect wind behaviour.

Forecast providers use proprietary Numerical Weather Prediction models and other modelling and processing to predict future weather conditions, such as wind speed and direction, based on current meteorological conditions. Feeding these future weather conditions into the trained wind power models, forecasts of wind power output are then determined.

The TSOs combine the two forecasts from the forecast providers using a "Wind Predictor"[153] function (a weighted average), adjusts these forecasts for relevant scheduled and forced outages, blends the forecast in with current conditions, and interpolates the forecast to a one-minute resolution for use in the scheduling and dispatch process. The TSOs may make manual adjustments in some circumstances (e.g. for adverse weather events).

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[149] https://cms.eirgrid.ie/sites/default/files/publications/EirGrid-and-SONI-Balancing-Market-Principles-Statement-V8.0.pdf

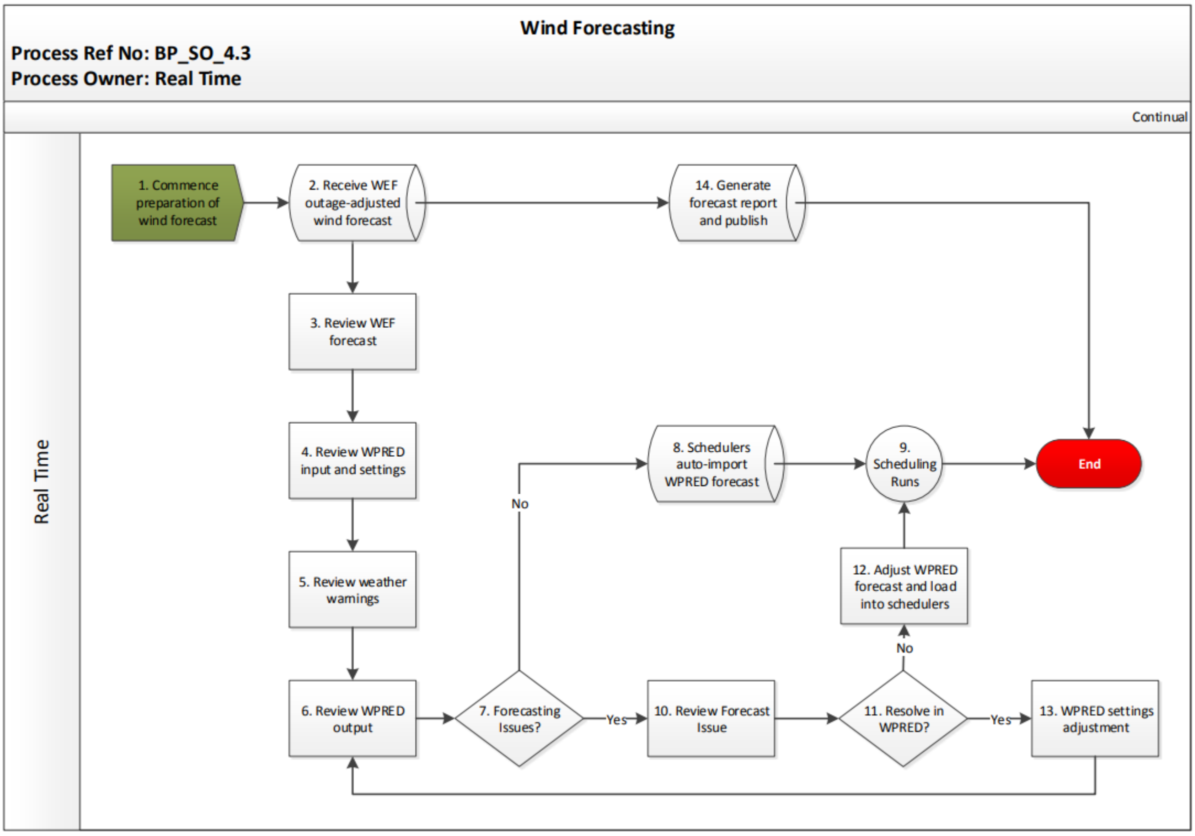
[150] https://cms.eirgrid.ie/sites/default/files/publications/FASS-DASSA-Volumes-Consultation-Paper-September-2024-EirGrid.pdf

[151] https://www.sem-o.com/documents/general-publications/Wind_and_Solar_Forecasting_Methodology.pdf

[152] Available https://www.sem-o.com/documents/general-publications/BP_SO_04.3-Wind-Forecasting.pdf

[153] It is unclear whether solar forecasts are treated in the same manner.

Figure 25: Wind Forecasting Process



Source: https://www.sem-o.com/documents/general-publications/BP_SO_04.3-Wind-Forecasting.pdf

The TSOs use their own forecasts of renewables in priority of information received from participants: “*Note that while wind participants may submit physical notifications (PN) representing their forecast production, these are not used in the scheduling and dispatch process. Rather we develop schedules that utilise our own forecast of renewables. This approach is driven by the priority dispatch categorisation of renewable generation.*”[154]

B.6.6 Consumer Energy Resources

There is relatively low uptake of CER in the SEM, with rooftop solar accounting for less than 1% of demand. Whilst the uptake is increasing, with a range of subsidies in place on rooftop solar and household batteries, this is not yet at the point of materiality. To achieve its renewable energy goals, Ireland is focusing on offshore wind resources, likely paired with grid scale BESS.

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[154] https://cms.eirgrid.ie/sites/default/files/publications/EirGrid-and-SONI-Balancing-Market-Principles-Statement-V8.0.pdf

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