Demand, Energy Delivered and Customer Forecasts

18 December 2023

Part of Energy Queensland

CONTENTS

Network Forecasting

Forecasting is a critical element of Ergon Energy's network planning and is essential to the planning and development of the electricity supply network. Due to the growth in peak demand and the expansion of the network into new areas, both locally and regionally, forecasting is a key driver for investment decisions leading to augmentation of the network.

Ergon Energy has adopted a detailed and mathematically rigorous approach to forecasting peak demand, electricity delivered (energy), DER generation and customer numbers with methods described in the following sections. Audits on the Ergon Energy forecasting models are regularly undertaken by external forecasting specialists with suggested improvements to forecasting methodologies continually being made.

Ten-year energy forecasts are prepared at a system level, at customer category levels and for certain individual network tariffs. Energy forecasts are used to determine annual network losses and to establish network tariff prices, and are developed using the latest economic, electricity consumption and technology trend data. Key assumptions used in the development of these forecasts are documented and updated regularly.

Electrical demand and DER forecasts are not only undertaken at the system level but are also calculated for all zone substations and feeders for a period of 10 years. Growth in peak demand and DER integration is not uniform across the state of Queensland, therefore electrical demand and generation forecasts are used to identify emerging local network limitations and network risks needing to be addressed by either supply side or customer-based solutions. Electrical demand forecasts therefore guide the timing and scope for capital expenditure (to expand or enhance the network), the timing required for demand reduction strategies to be established, and for risk management plans to be put in place.

A Strategic Forecasting Annual Report will also be available in detailing further discussion on the methodology and assumptions applied in the peak demand forecasts and including:

- Minimum demand forecasts
- Energy purchases and energy sales forecasts
- Customer number forecasts
- Distributed Energy Resources (DER) forecasts (solar PV, Electric Vehicles (EVs) and energy storage systems)
- Economic and demographic forecasts and commentary relating to population growth, Gross State Product (GSP) and the Queensland economic outlook.

1.1 Forecasting Assumptions

There are several factors which influence the forecasts assumptions used in the development of the peak demand and DER forecasts. These are discussed in the following sections.

1.1.1 Economic Growth

The level of economic activity is a major influence on many aspects of our industry. While the impact of economic growth is felt most directly at the individual household and business level, it is not possible to build a model which takes every one of these into account. As such, higher level measures of economic activity are used where measures of current activity and forecasts are available. GSP projections are a key driver to many of our forecasting models.

Ergon Energy utilises Deloitte Access Economics to provide detailed economic forecasts for the Australian and Queensland economies – extending out to a 10-year forecast horizon. They report that the outlook for the global economy has improved since last year's DAPR, inflation and energy prices have eased, and the labour markets have remained surprisingly resilient in the face of interest rate increases by the central banks. The recovery is expected to be gradual rather than a boom though, as inflation (globally) is remaining above the bank's targeted ranges.

For the Australian economy, the key risks are seen as being that the Reserve Bank of Australia (RBA) may have increased interest rates too much (given that the source of the inflation was imported & supply side pressures and are little impacted by higher interest rates), and the subdued economic restart in China (following the end of COVID-19 restrictions there) given that around 30% of Australia's exports are bound for China.

One of the many supports for the Australian economy is population growth, which is expected to be strong, with an extra 450,000+ people expected over 2023/24. Deloitte expects the Australian economy to grow by 0.9% in 2023/24, before increasing to 1.7% in 2024/25. These figures are well down on the 2.4% average economic growth in the decade up to 2022.

Queensland's export market share exposure to China is relatively lower at around a 15% – as the Japanese, Indian and Korean markets are more important for Queensland. The Japanese, and Indian economies are looking relatively healthy at this point in time. Deloitte expects the Queensland economy to grow by 0.5% over 2022/23 and 0.7% in 2023/24. Like the rest of Australia, Queenslanders are yet to experience the full effect of the interest rate increases to date, with inflation expected to be elevated for the next couple of years.

The Queensland government launched the Queensland Energy and Jobs Plan (QEJP), setting out a number of targets including 70% renewables by 2032. Energy Queensland / Ergon Energy will be involved in many of the plan's initiatives, with the DER forecast taking into account factors like the acceleration of the electrification of transport.

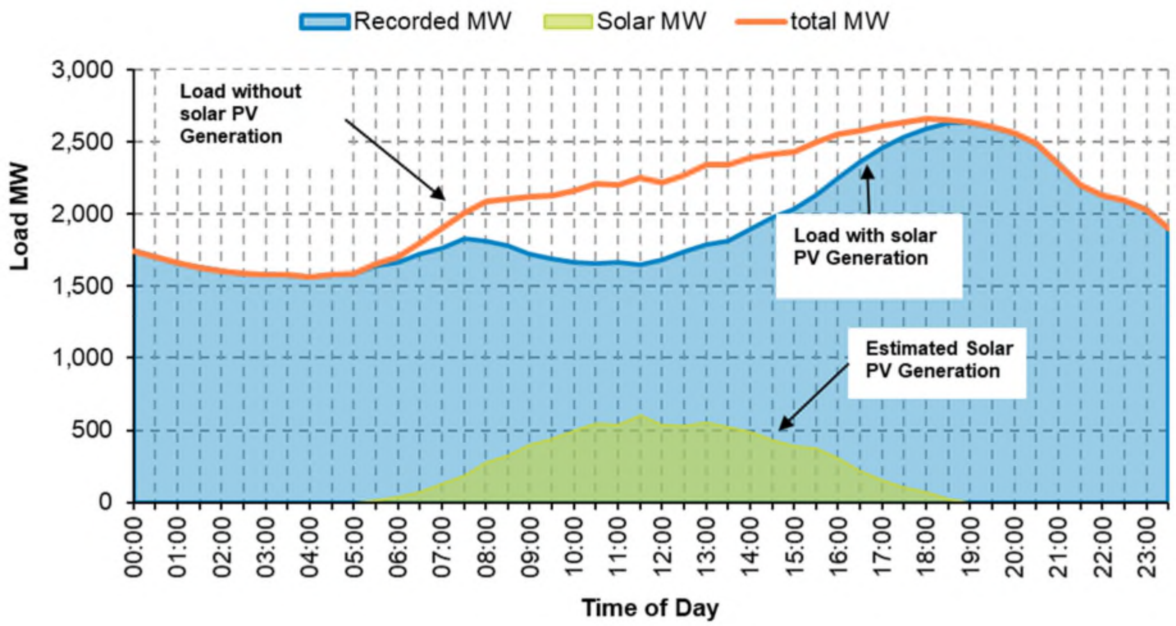
1.1.2 Solar PV

Solar PV has a significant load impact on our network, typically affecting the energy forecast outlook. The impact of solar PV is based on profiles which have been constructed to predict generation (and export) for rooftop systems for all forecast scenarios. In 2022, Energy Queensland had engaged Blunomy Consulting to provide a Distributed Energy Resource (DER, which include solar PV, Electric Vehicles and Energy Storage Systems) forecast for both Energex and Ergon Energy networks respectively.

A 0.5% per-annum degradation factor was used for solar PV systems. Small systems are designed to generate energy for the home with excess energy exported. Commercial-scale installations are larger and may or may not export to the grid. Utility-scale solar farms are designed to export.

Ergon Energy's 2022-23 summer system peak of 2,637 MW occurred between 6:30 pm and 7:00 pm on the 13th of February 2023 and it was estimated without PV generation, the peak would have occurred at 6:00 pm and would have been 23 MW higher. As battery storage becomes more affordable and therefore widely used, daily peaks may revert to mid-to-late afternoons, as less PV generation is exported in preference for re-charging storage batteries, refer to Figure 1.

Figure 1: System Demand – Solar PV Impact, 13 February 2023



Solar PV's impact on system peak demand is modelled separately by estimating and removing its historical impact, forecasting its future impact, and re-incorporating it into the overall system forecast.

Historically, temperature was the major variable on peak demand (after systematic factors such as time of day and day of year). However, the scale of solar PV generation means that cloud cover can create variations in generation output (thereby changing the source of supply to Powerlink) greater than what would be seen from temperature changes.

1.1.3 Electric Vehicles and Energy (battery) Storage

Mainstream uptake of Electric Vehicles and Plug-in Hybrid Electric Vehicles (PHEVs) will increase energy and demand forecasts over the forecast horizon. The uptake rate of EVs and PHEVs has historically not been high due to a combination of factors including the high initial cost and low availability of various vehicle types. However, it is anticipated that EV is likely to have a significant increase through time with as more various vehicle types are on offer in the market, and the EV cost creeping closer to price parity with its Internal Combustible Engine (ICE) counterpart. Therefore, the impact factored into the System Demand forecast has been relatively small in the earlier years of the forecast but increases over time with the growing population of vehicles. Nonetheless, it is expected that a major part of the uptake of EV will be in South-East Queensland (SEQ).

Customer interest in energy storage systems (batteries of various kinds) continues to increase. The number of known energy storage systems in the Ergon Energy network is approximately 5,118 as of end of June 2023. Over the next five to ten years energy storage will continue to grow with:

- Falling prices as battery storage production increases in scale
- New technology (safer, higher energy densities, larger capacities), and
- Package-deals of solar PV and battery storage systems promoted by major retailers and solar PV installers.

Ergon Energy's forecasting model is based on an average typical hot summer day demand profile for residential, and business customers. These assumptions are refined over time as more customers adopt EV and storage systems, and their usage data becomes available. The impact of energy storage on the customer's energy consumption profile is 'behind the meter' which means that it cannot be directly measured.

Historically, there has also been little high-quality data surrounding the number and size of batteries being installed, all of which makes forecasting the larger scale impact over time more difficult.

1.1.4 Temperature Sensitive Load

Temperature sensitive loads from electrical appliances like air conditioning and refrigeration, are major drivers of peak demand on the network. The most extreme loads seen on the network over a year are typically driven by a combination of hot (and usually humid) weather conditions during times of high industrial and commercial activity (although the scale of solar PV generation now creates other possibilities for extreme loads due to cloud cover). At the system level, the modelling process has continued to be refined over the years, with population replacing air-conditioning as a variable used in the equation as it is better able to represent the impact of broader range of electrical appliances during the extreme conditions.

Given the vastness of the Ergon Energy network, a number of weather stations are required to capture the variability of weather conditions across the network. The process also requires a long history of quality weather data – eliminating many candidate stations. Weather data from the following stations has been sourced from the Bureau of Meteorology (BOM), based on their representativeness of the weather in key population regions, and the quality of their extended weather history:

Table 1: Listing of Weather Station locations for temperature correction

Weather Stations used in the substation temperature correction process			
Applethorpe	Gatton	Mackay	Rolleston
Ayr	Gayndah Airport	Mackay Airport	Roma
Blackall	Georgetown	Mareeba	St George
Bundaberg	Gympie	Maryborough	St Lawrence
Cairns	Hamilton Island	Miles	Thargomindah Airport
Charleville	Hervey Bay	Mount Isa	Toowoomba
Clermont Airport	Hughenden	Normanton	Townsville
Cloncurry	Julia Creek	Oakey	Warwick
Cooktown	Kingaroy	Proserpine	Winton Airport
Dalby	Longreach	Richmond	
Emerald	Low Isles	Rockhampton	

If a small proportion of observations were missing, they were either estimated or substituted with data from nearby stations. The zone substation forecasting methodology also utilises weather data, with a process to identify the most relevant weather station to relate to a zone substation's load – further details of the substation forecasting process are detailed below.

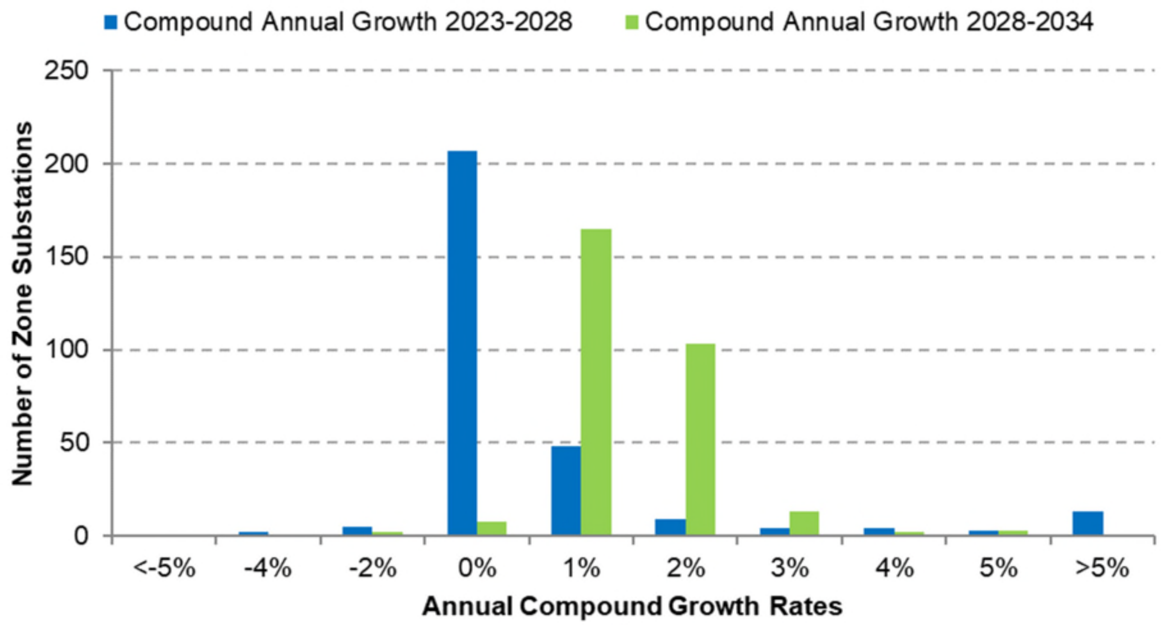
1.2 Zone Substation and Feeder Maximum Demand Forecasts

The forecasting process provides the ability to predict where extra capacity is needed to meet growing demand, or new assets are required in developing areas. Ergon Energy reviews and updates its temperature-corrected system summer peak demand forecasts after each summer season and each new forecast is used to identify emerging network limitations in the sub-transmission and distribution networks. The bottom-up substation peak demand forecast is reconciled with the system level peak demand forecast - after allowances for network losses and diversity of peak loads. This process accounts for drivers which only become significant at the higher points of aggregation (e.g. economic and demographic factors), while also enabling investment decisions to be based local factors. Hence individual substation and feeder maximum demand forecasts are prepared to analyse and address limitations for prudent investment decisions.

The take-up of solar PV is continuing as electricity prices rise and the cost of solar PV falls, and the emerging influence of electric vehicles and battery storage systems has been incorporated at the system and substation levels of forecasting.

Balanced against this general customer trend, the forecasts produced post-summer 2022-23 have provided a range of demand growth rates, with many established areas remaining static while other areas are growing strongly (refer Figure 2). The forecasts are used to identify network limitations and to investigate the most cost-effective solutions which may include increased capacity, load transfers or Demand Management alternatives.

Figure 2: Zone Substation Growth Distribution 2023-2034



While growth in demand is around 1% at a system level over a 10-year horizon, there can be significant variations in growth at a localised substation level.

In the 2023-28 period, the percentage compound growth rates of substations were as follows:

- 73% have an average compound growth rate at or below 0%
- 19% have an average compound growth rate between 0% and 2%
- 4% have an average compound growth rate between 2% and 5%
- 4% have an average compound growth rate of more than 5%.

Demand management initiatives have an impact on peak loads at a number of zone substations. The initiatives include broad application of air conditioning control, pool pump control and hot water control capability. Demand management is also being targeted at substations with capacity limitations in an effort to defer capital expenditure. The approach used is to target commercial and industrial customers with incentives to reduce peak demand. The resulting reductions are captured in the Substation Investment Forecasting Tool (SIFT) and in the ten-year peak demand forecasts.

The ten-year substation peak demand forecasts are prepared at the end of summer and are produced within SIFT. To enable appropriate technical evaluation of network limitations, these forecasts are completed for both existing and proposed substations. The forecasts are developed using data from internal sources as well as the ABS, AEMO and the Queensland Government. Economic and demographic influences are incorporated via the system demand forecasts. Independently produced forecasts for economic variables and photovoltaic installations, Electric Vehicles (EVs) and battery storage systems uptake are also sourced from Deloitte's and the Blunomy Consulting respectively.

Output from solar PV is generally coincident with Commercial and Industrial (C&I) peak demands, and there has been a significant uptake in solar PV for C&I premises. While this will provide benefits for those parts of the network which peak during times of significant PV generation, there are many other areas of the network which peak later in the afternoon/evening, where the impact of PV generation on the peak may either be limited or non-existent.

1.2.1 Zone Substation Forecasting Methodology

Ergon Energy employs a bottom-up approach, reconciled to a top-down evaluation, to develop the ten-year zone substation peak demand forecasts. Validated historical peak demands and expected load growth based on demographic and Distributed Energy Resource (DER – solar PV generation, Electric Vehicles, and un-aggregated battery energy storage capacity) are used as data inputs into the forecasting model. The planning team provides local insights where relevant, as well as project, block load and load transfer information.

The peak demand forecasts are produced for:

- 50 Probability of Exceedance (PoE) and 10 PoE levels
- Each zone substation
- Summer and winter, and
- Base, Low and High scenarios.

Zone substation forecasts are based on a probabilistic approach using a multiple regression estimation methodology. This approach has the advantage of incorporating a range of variability into the predictions.

A Monte Carlo simulation using BOM daily minimum and maximum temperature history is used to calculate the 10 PoE and 50 PoE maximum demands for each zone substation. Growth rates are then calculated using a separate model for summer and winter. Growth rates, load transfers and new major customer loads are then incorporated into the future load at each zone substation.

The zone substation forecasts are successively aggregated up to the bulk supply, and transmission connection points, to create forecasts at those levels – after taking diversity and losses into account. This aggregated forecast is then reconciled with the independent system demand forecast and adjusted as required.

The process sequence used to develop the ten-year substation demand forecast is briefly described as follows:Validated uncompensated substation peak demands are determined for the most recent summer and winter seasons

- These loads are then associated with minimum and maximum temperatures at the relevant weather stations, to calculate the substation's temperature demand relationship
- Many industrial substations tend not to have much temperature sensitivity, as their load can vary due to a range of other factors. As a result, these 50 PoE and 10 PoE values tend to be based on sets of business rules chosen to reflect these expected load variations
- Previous substation peak demand forecasts are reviewed against temperature-adjusted results as part of a process looking for the causes behind individual variations
- Starting values for apparent power (MVA), real power (MW) and reactive power (MVAr) are calculated for the key benchmarks of "summer day", "summer night", "winter day", and "winter night"
- The predicted impact of solar PV, battery storage, and Battery Electric Vehicles and Plug-In Hybrid Electric Vehicles are incorporated into year-on-year peak demand growth profiles and population forecasts
- The size and timing of block loads, transfers and projects are reviewed and validated with

Grid Planning and Network Management asset managers before inclusion in the forecast

- The different elements of the forecast – growth rates, block loads, transfers are combined and applied to the starting values to produce a 10-year demand forecast
- The substation peak demand forecasts are reviewed extensively and compared with previous forecasts, with a focus on the relative error between recorded demand and the forecast for the most recent season. If necessary, adjustments are made to incorporate late information or factors not able to be included in the forecasting model
- Zone substation forecast peak demands are aggregated up to bulk supply substation, and transmission connection point levels (after allowing for coincidence and losses) to produce forecasts at those network levels
- The zone substation forecast is "reconciled" against the system peak demand forecast to ensure that factors only evident at the distribution level (e.g., load increases driven by expected economic growth), are incorporated into zone substation forecasts. This is done by calibrating relevant zone substations' growth rates so that the sum of the forecasts equals the system – at the time of the coincident peak, this then flows through to an adjustment of the zone substation's local peak – which can occur at a different time.

Zone substation forecasts are based upon a number of inputs, including:

- Network topology (source: corporate equipment registers)
- Load history (source: corporate SCADA/metering database)
- Known future developments (new major customers, network augmentation, etc.) (source: Major Customer Group database)
- Customer categorisation (SIFT)
- Temperature-corrected start values (calculated by the FLARE forecasting model)
- Forecast growth rates for organic growth (calculated by the FLARE forecasting model), and
- System maximum demand forecasts.

The impact of Embedded Generation (EG) on the Ergon Energy forecasted peak and minimum demand are estimated for each zone substation using the solar PV and Battery Energy Storage Systems uptake forecast and their corresponding demand load profiles. This is based on the medium Distributed Energy Resource (DER) uptake scenario for solar PV and battery storage systems forecast, sourced by Blunomy Consulting for all zone substations. The forecasted EG for each zone substation is disaggregated from the systems level forecast based on the historical DER penetration rates across each individual zone substation in the forecast. The demand load profiles for solar PV are then estimated by modelling the historical relation between available solar PV inverter capacity and the measured solar irradiance hourly profiles based on a typical peak demand and minimum demand day.

Electric vehicles are not considered as part of the embedded generating unit category as the Vehicle to Grid (V2G) technology is at its infant stage, and the DER forecast suggests that EV would have an impact on the network from a peak demand perspective rather than generation. The forecast use of distribution services (export) by embedded generating units are estimated from each zone substation's load profile forecast. The uptake of solar PV systems is pushing the middle of the day load towards zero and causing reverse power flow in some parts of the network. This reverse power flow has been utilised to represent the zone substation export caused by the EG.

The EG export for each zone substation is forecasted on both peak and minimum demand events using the medium DER uptake scenario forecast and demand profiles.

1.2.2 Transmission Feeder Forecasting Methodology

A simulation tool is used to model the 110 kV and 132 kV transmission network. The software was selected to align with tools used by Powerlink and the Australian Energy Market Operator (AEMO). Powerlink provides a base model on an annual basis. This base model is then refined to incorporate future network project components. Two network loading scenarios have been considered: native load and load with DER. For the load scenario peak forecast loads at each bulk supply, zone substation and connection point are loaded into the model from SIFT. For the DER scenario, the DER forecast is determined and integrated into the SIFT loading. Registered generators have been excluded from the models as their dispatch is managed by AEMO and control schemes are in operation to limit their impact to the network.

Twenty models for each scenario are created using this simulation tool, with each model representing the forecast for a particular season in a particular year. The models have five years of summer day 50 PoE and 10 PoE data and five years of winter night 50 PoE and 10 PoE data.

1.2.3 Sub-transmission Feeder Forecasting Methodology

Forecasts for sub-transmission feeders are produced for a five-year window, which aligns with the capital works program. The forecasts identify the anticipated maximum forward and reverse loadings on each of the sub-transmission feeders in the network under a normal network configuration.

Modelling and simulation are used to produce forecasts for the sub-transmission feeders. The traditional forecasting approach of linear regression of the historical loads at substations is not applicable since it does not accommodate the intra-day variation. The modelling approach enables identification of the loading at different times of day to equate to the line rating in that period. A software tool models the 33, 66 and 110kV sub-transmission network. The simulation tool has built-in support for network development which provides a variable simulation timeline that allows the modelling of future load and projects into a single model.

Ergon Energy combines the substation maximum demand forecasts and the daily load profiles of each individual substation to produce a forecast half-hour load profile for the maximum demand day at that substation. This is produced for each substation in the network. A series of load flows are then performed for each half-hour period of the day using these loadings. The forecast feeder load for each period is the maximum current experienced by the feeder in any half-hour interval during that period.

There are two network load scenarios that have been considered, native load and loading with DER. The native load scenario provides indication of areas of the network may require augmentation due to load, impacts of phenomenon like solar masking being considered. The DER scenario highlight areas of the network that have high penetration of generation and capacity constraints or areas where capacity for EG remains.

1.2.4 Distribution Feeder Forecasting Methodology

Distribution feeder forecast analyses carry additional complexities in comparison to sub-transmission feeder forecasting. This is mainly due to the impact of block loads, variety of loading and voltage profiles, lower power factors, peak loads occurring at different times/dates and the presence of phase imbalance. Also, the relationship between demand and average temperature is more sensitive at the distribution feeder level.

Forecasting of distribution feeder loads are performed bi-annually on a feeder-by-feeder basis. The summer assessment covers the period of November to March, and the winter assessment from

June to August. The key forecasting drivers are like those related to substations, such as population and distributed energy resources growth.

In summary, the steps and sources used to generate distribution feeder forecasts are as follows:

- The historic maximum demand values, in order to determine load starting point by undertaking bi-annual 50 PoE and 10 PoE temperature-corrected load assessment. These historical maximum demands have been extracted from feeder metering and/or Supervisory Control and Data Acquisition (SCADA) systems and filtered/normalised to remove any abnormal loads and switching events on the feeder network. Where metering/SCADA system data are not available, maximum demands are estimated using After Diversity Maximum Demand (ADMD) estimates or calculations using the feeder consumption and appropriate load factors
- The weather data, used to model the impacts of weather on maximum demand, is supplied by Weather Zone, which sources its data from the Bureau of Meteorology. This is used to determine approximate 10 and 50 PoE load levels
- Customer growth on feeders is estimated by using the Queensland Government Statistician's Office spatial population projections, combined with Ergon Energy's customer number forecasts by residential and business customer segments
- The EQL's scenario-based forecast for distributed energy resources that includes solar PV capacity, battery storage capacity and Electric Vehicle (EV) uptake is used as one of the growth drivers at distribution feeder level. The average per-unit day load profile per customer segment for each DER technology is estimated to calculate the DER impact on maximum day load profile forecast for each feeder
- After applying the growth rates from customer and DER forecast, specific known block loads are added, and events associated with approved projects are also incorporated (such as load transfers and increased ratings) to develop the feeder forecast.

Similar to the zone substation forecasting methodology under Section 1.2.1: While growth in demand is around 1% at a system level over a 10-year horizon, there can be significant variations in growth at a localised substation level.

In the 2023-28 period, the percentage compound growth rates of substations were as follows:

- 73% have an average compound growth rate at or below 0%
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Zone Substation Forecasting Methodology, the demand of EG on the Ergon Energy forecasted peak and minimum demand are also modelled for each distribution feeder. The medium DER uptake scenario was used for solar PV and Battery Energy Storage Systems along with their corresponding demand load profiles. EVs are not considered as part of the embedded generating unit category as described in Section 1.2.1.

The forecasted EG for each distribution feeder substation is disaggregated from the systems level forecast based on the historical DER penetration rates across each individual feeder. The demand load profiles for solar PV are then estimated by modelling the historical relation between available solar PV inverter capacity and the measured solar irradiance hourly profiles based on a typical peak demand and minimum demand day.

The forecast use of distribution services (export) by embedded generating units are estimated from each feeder distribution load profile forecast. The uptake of solar PV systems is pushing the middle of the day load towards zero and causing reverse power flow in some parts of the network. This reverse power flow has been utilised to represent the distribution feeder export caused by the EG. The EG export for each distribution feeder is forecasted on both peak and minimum demand events using the medium DER uptake scenario forecast and demand profiles.

1.3 System Maximum Demand Forecast

Ergon Energy reviews and updates its ten-year 50 PoE and 10 PoE system summer peak demand forecasts after each summer season and each new forecast is used to identify emerging network limitations in the sub-transmission and distribution networks. For consistency and robustness, the substation peak demand forecast ('bottom-up') is reconciled with the system level peak demand forecast ('top-down') after allowances for network losses and diversity of peak loads. A new regional approach has been developed to provide the 'top-down' forecast. Each of six regions half hourly trace is modelled separately with a semi parametric model and the sum of each of these regional peak demands at network peak coincidence provides a distribution of max demand for each of the ten-years future total system maximum demand. 50 PoE and 10 PoE maximum demand are then calculated for each year for their respective distribution.

Inputs for the maximum demand forecast for each region include:

- Economic growth through the GSP and Population1
- Weather variables2 (e.g. temperature, rainfall, Global Horizontal Irradiance - GHI)
- Load history
- Solar PV generation, Electric Vehicles and Energy Storage.[3]

The 'bottom-up' forecast consists of a ten-year maximum demand forecast for all zone substations (also described as 'spatial forecasts') which are aggregated to a system total and reconciled to the econometrically derived system maximum demand. These zone substation forecasts are also aggregated to produce forecasts for bulk supply substations and transmission connection points. For further details are available in the Zone Substation Forecasting Methodology section.

In recent years, there has been considerable volatility in Queensland economic conditions, weather patterns and customer behaviour which have all affected total system peak demand. Weather patterns have moved from extreme drought in 2009, to flooding and heavy rain in recent years, to extended hot conditions over the past several summer periods. Both Covid and La Nina conditions had also contributed to a lower peak demand in recent years.

1.3.1 System Demand Forecast Methodology

Naturally, there is a level of uncertainty in predicting future values. To accommodate the uncertainty, forecasting at differing levels of probability have been made using the Probability of Exceedance (PoE) statistic. In practical planning terms for an electricity distribution network, planning for a 90 PoE level would leave the network far too vulnerable to under-capacity issues, so only the 10 PoE and 50 PoE values are considered relevant for planning purposes.

[1] Source: Queensland Government Statistician's Office and Deloitte

[2] Source: Bureau of Meteorology (BOM)

[3] Source: Blunomy Consulting

The methodology used to develop the system demand forecast is comprised of:

- Actual half-hourly recorded demand at the legacy regions for historical years is extracted from the Ergon Energy demand data
- Historic PV generation is then added back to the load traces
- System forecasts are obtained from modelling a temperature-corrected semi parametric model using economic and population variables
- Simulation of future PV generation as well as other DER components are added in to predict future demand
- 50 PoE level — this best estimate level is obtained from a maximum demand distribution such that 50% of the values are on each side of this value, and
- 10 PoE level — this highest level is obtained from a maximum demand distribution such that 10% of the values exceed this.

The nature of the system maximum demand methodology and the resulting forecast is such that it is considered the most accurate and reliable indicator of future demand in the network.

The system-wide 2022-23 peak was 2,637 MW between 6:30 pm and 7:00 pm on 13th February 2023.

1.3.2 Medium, high and low case scenarios

Peak demand is impacted significantly by weather and economic conditions, population growth and technology adoption. Base, high and low scenarios are created by combinations of the economic forecasts, simulations on summer daily temperatures and the DER post-model adjustments. While higher or lower levels of the individual DER components can vary positively or negatively with peak demand, the DER factors are incorporated as an aggregate impact with the DER scenario aligning with the corresponding peak demand scenario. The results of the forecasts are compared in Figure 3. Demand management load reductions are included in the forecast. The scenario's presented are based partly on DER scenarios developed by Blunomy Consulting. The medium, high and low cases and are designed to capture future uncertainties and risks.

Figure 3: Trend in System-wide Peak Demand

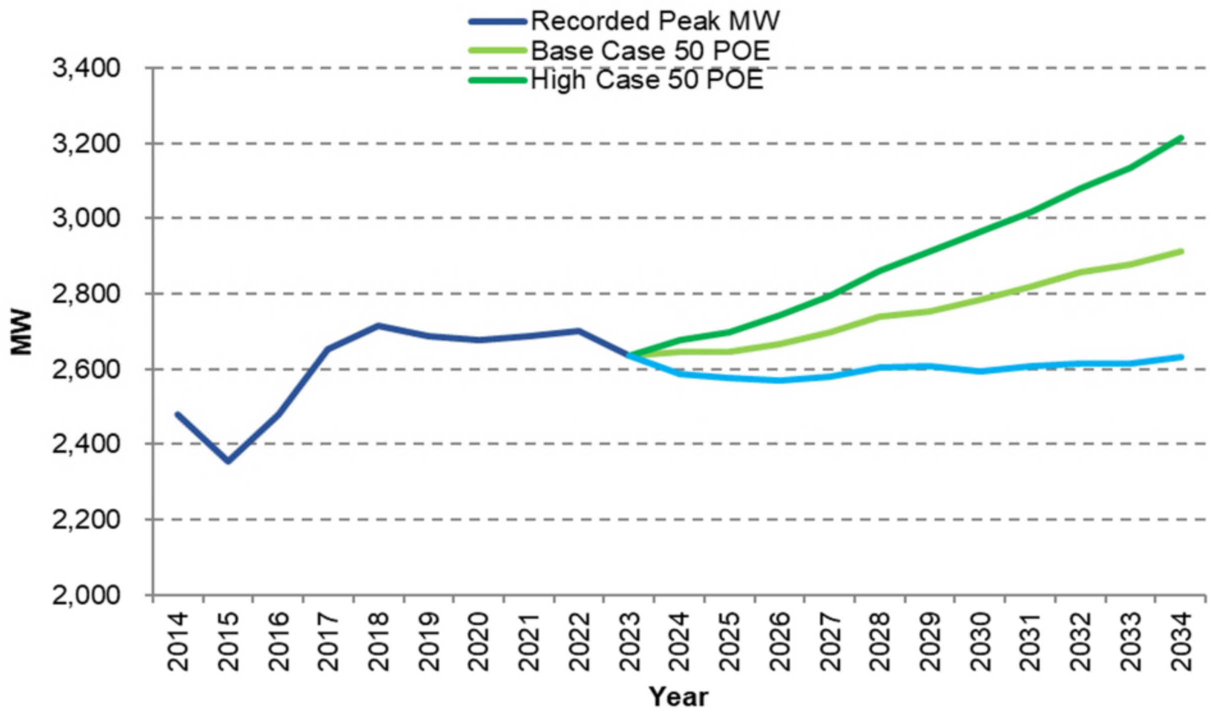

Table 2 summarises the historical actual demands.

Table 2: Actual Maximum Demand Change

Actual Maximum Demand Growth					
Demand	**2018-19**	**2019-20**	**2020-21**	**2021-22**	**2022-23**
Summer Actual (MW) [1]	2,689	2,677	2,688	2,702	2637
Annual (%) Change	1.0%	-0.5%	0.4%	0.5%	-2.4%
	2018	**2019**	**2020**	**2021**	**2022**
Winter Actual (MW) [1]	2,227	2,263	2,192	2,158	2,212
Annual (%) Change	3.6%	1.6%	-3.1%	-1.5%	2.5%

[1] Native Demand

Furthermore, Table 3 lists the maximum demand forecasts over the next five years for the 50 PoE and 10 PoE cases.

Table 3: Maximum Demand Forecast

Maximum Demand Forecast (MW)					
Forecast [1, 2]	2023-24	2024-25	2025-26	2026-27	2027-28
Summer (50% PoE)	2,647	2,645	2,667	2,698	2,741
Growth (%)	-	-0.1%	0.8%	1.2%	1.6%
Summer (10% PoE)	2,970	2,982	3,008	3,043	3,077
Growth (%)	-	0.4%	0.9%	1.2%	1.1%

[1] The summer actual demand has been adjusted to take account of embedded generation operating at the time of system peak demand.
[2] The demand forecasts include the impact of the forecast economic growth as assessed in March 2023.

Table 4: Contribution of Solar PV, EVs and Battery Storage Systems to Summer System Peak Demand

Impact on Summer System Peak Demand (MW)										
Category	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Solar PV Generation	-9		-7				-39	-18		-13
Electric Vehicle Load	1	1	2	2	4	4	6	9	16	16
Battery Storage Systems Load	-3	-4	-3	-4	-3	-5	-6	-6	-6	-7