Draft maximum and minimum demand forecasts

For the 2023 NEM ESOO

14 June 2023

Forecasting Reference Group Meeting

Purpose and agenda

The purpose of this presentation is to *consult* with the FRG on the draft maximum and minimum demand forecasts* for the 2023 Electricity Statement of Opportunities (ESOO) for the National Electricity Market (NEM).

Today's Agenda includes:

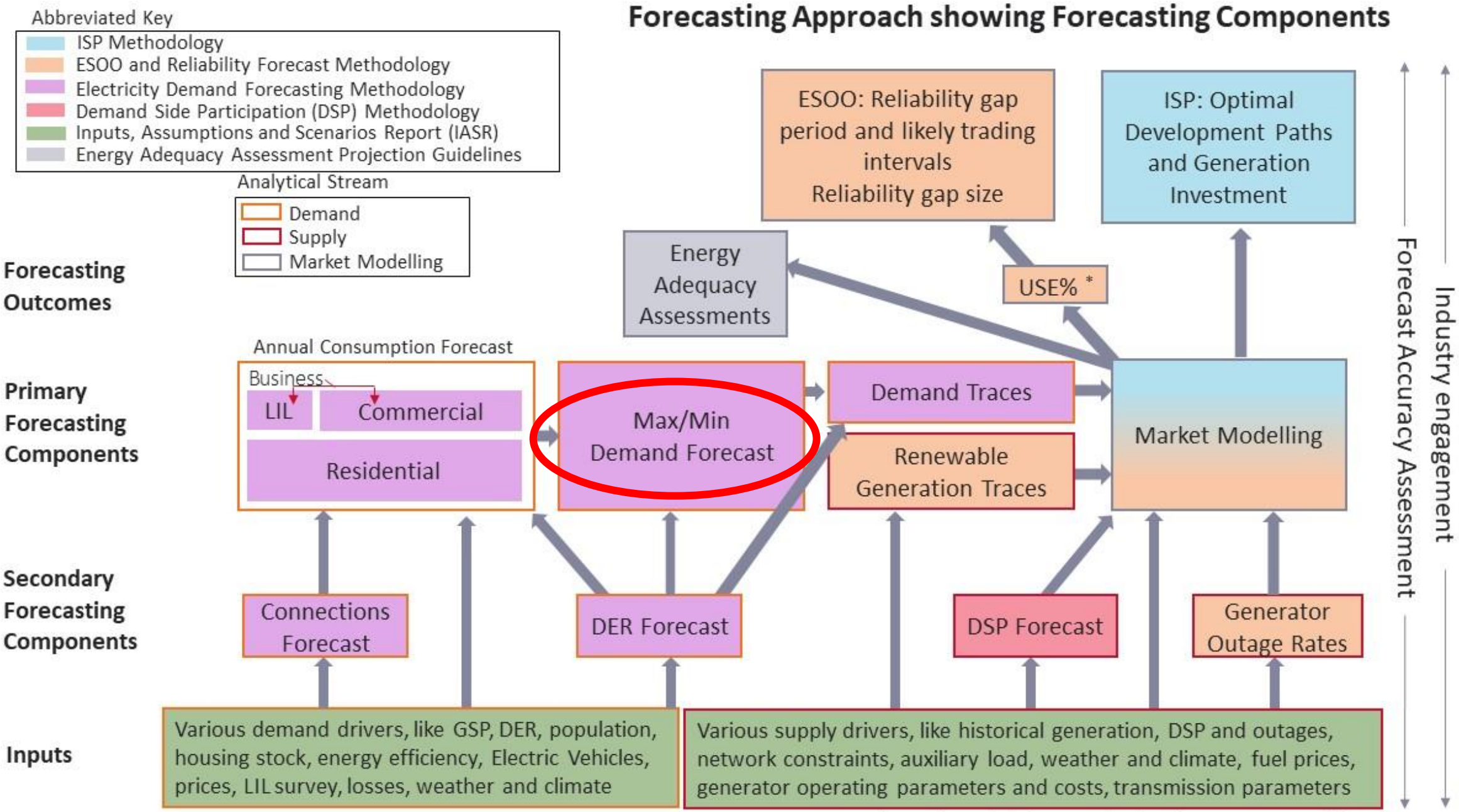
- Demand definitions
- Process
- Review and methodology changes
- Maximum and minimum demand forecasts by region
- Feedback and next steps

*Forecasts are non-coincident. They cannot be added together to give a total forecast for the NEM.

Relevant engagement includes:

Timing	Relevant topic	Responsible
Dec 22	2022 Forecast Accuracy Report (FAR) and consultation on 2022 Forecast Improvement Plan (FIP)	Stakeholders, AEMO
Dec 22 - Feb 22	Inputs, Assumptions and Scenarios Report (IASR) consultation	Stakeholders, AEMO
Mar 23	FRG presentation on Summer 2022/23 maximum demand performance	AEMO, FRG
Apr 23	FRG presentation on FIP progress	AEMO, FRG
Today	**FRG discussion on draft forecasts**	**AEMO, FRG**
End Aug	2023 ESOO publication	AEMO

Forecasting Approach showing Forecasting Components



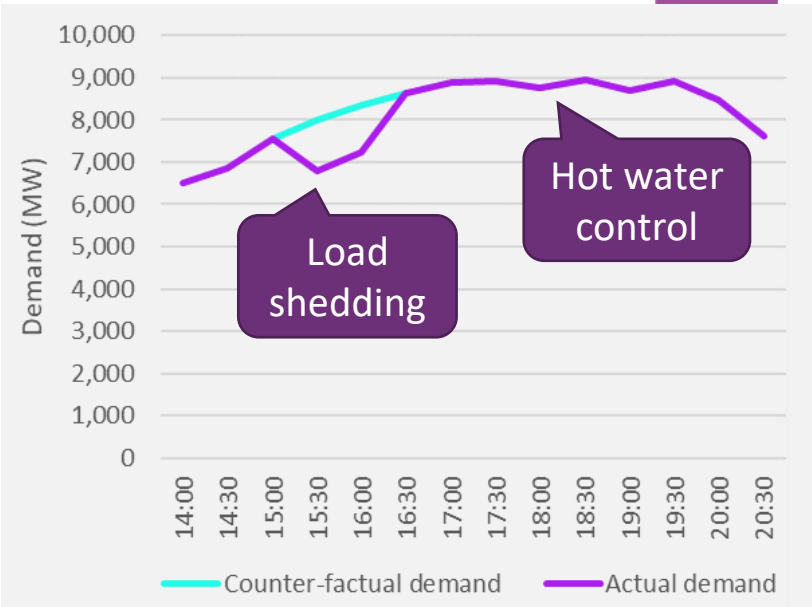
See AEMO's Forecasting Approach

Measuring maximum and minimum demand

AEMO's maximum and minimum demand forecasts represents forecast demand in the absence of:

- Directed load shedding
- Network outages
- Mandatory restriction schemes in effect
- Call for voluntary reduction in demand
- Demand side participation (DSP) including any under RERT

It does account for daily operation of load control, such as timer controlled hot water, or ripple controlled hot water/pool pump loads.



Any load shedding or atypical reduction in demand should be added back to the actual demand (counterfactual) when comparing with the forecast. For peak demand days, any such adjustments are accounted for and documented in the annual Forecast Accuracy Reports.

Note that "demand" refers to the "*as-generated*" definition (including generation aux load) and is *half-hourly* average values.

Time reference is NEM-time (AEST) unless otherwise noted.

Modelling maximum and minimum demand

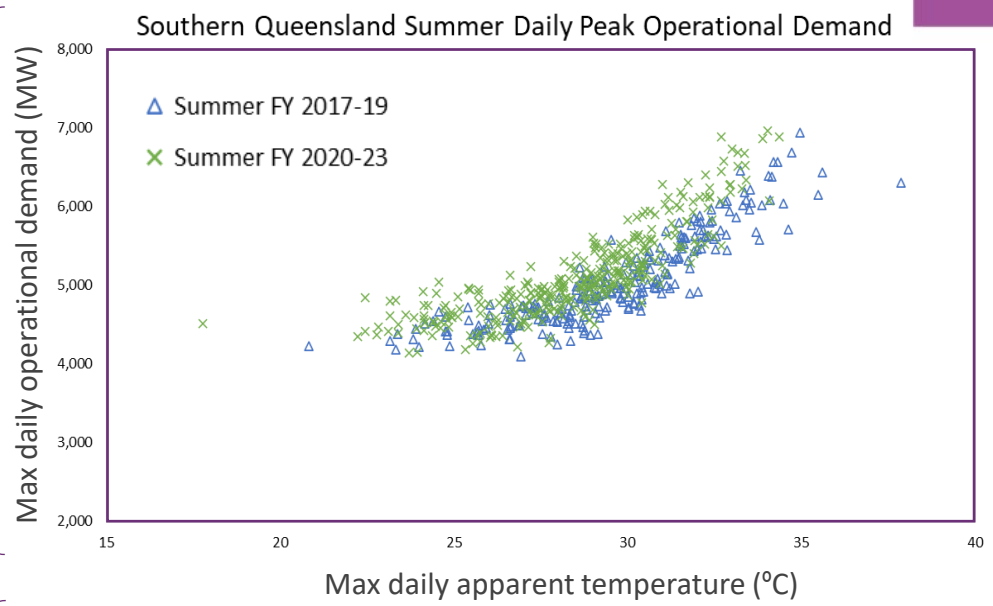
Maximum demand depends among other things on temperature*. The realised temperature outcomes differ from year to year.

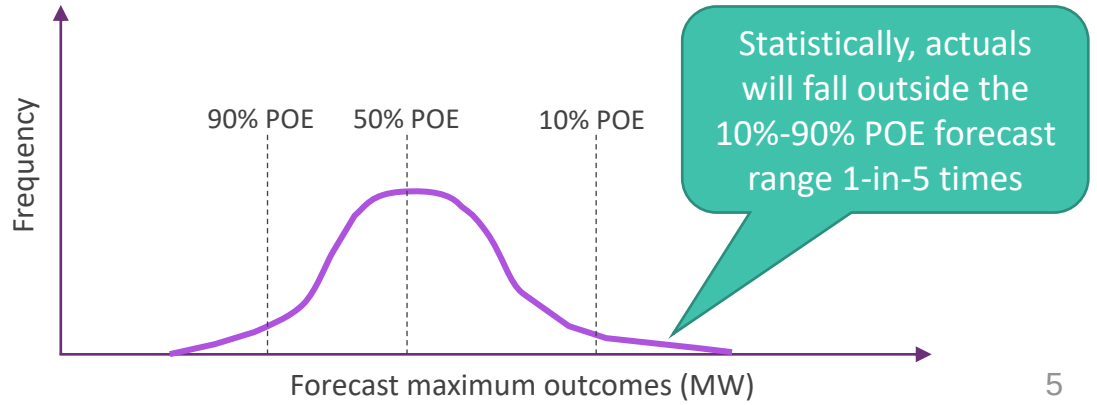
AEMO therefore applies a probabilistic forecast to account for difference in weather, among other things. This results in a forecast distribution of max (and min) demand outcomes.

AEMO publishes different points of the forecast distribution to stakeholders.

Typically, the 10%, 50% and 90% probability of exceedance (POE) values are provided. The 10% POE forecast represent a forecast value that only will be exceeded across the season with a probability of 10%.

* Minimum demand is temperature dependent too, typically occurring during weekends with high PV generation and mild weather, so without any significant cooling/heating load.



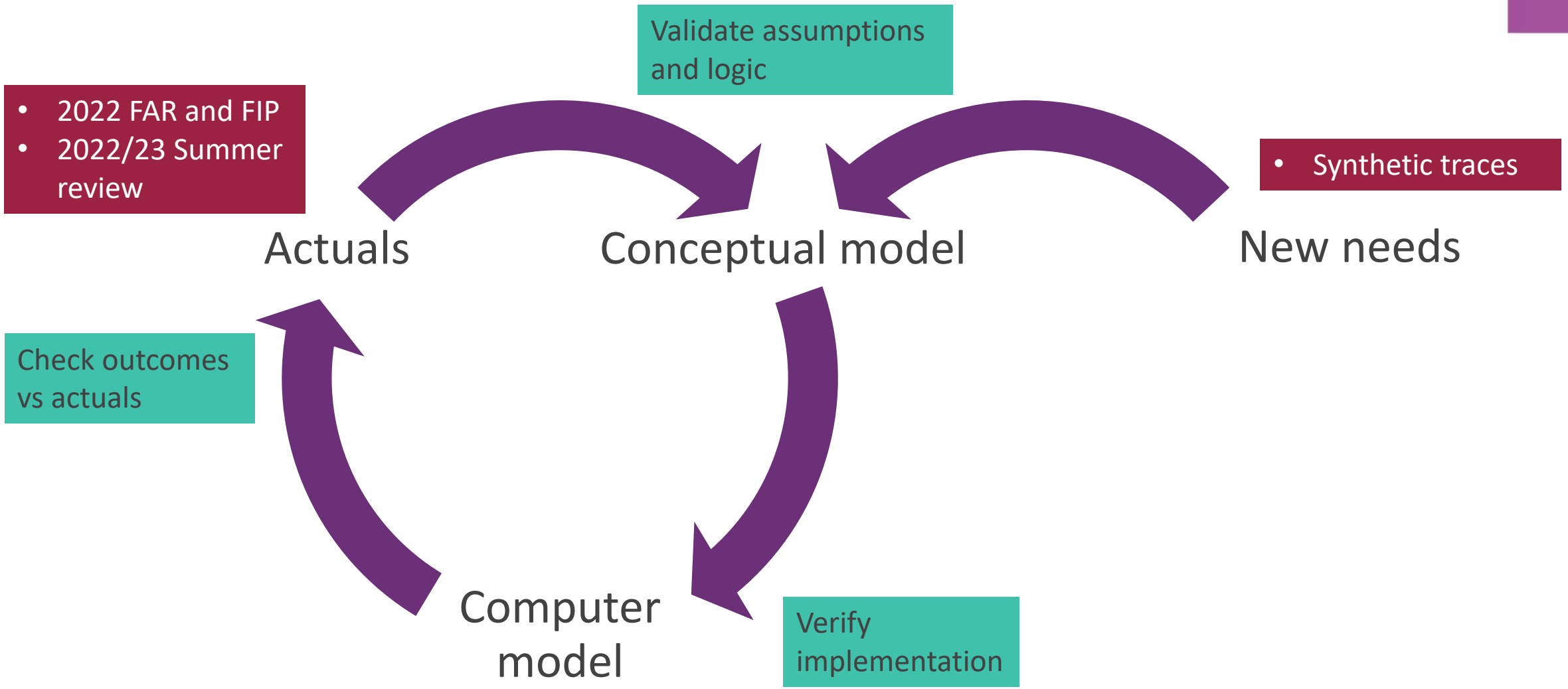


Demand forecast timeline and process

- Oct-Dec: Review accuracy of last year's forecast in Forecast Accuracy Report (FAR) and propose refinements in the included Forecast Improvement Plan (FIP).
- Nov-Mar: Observe ESOO forecast accuracy during summer.
- April: Collect historical data series till end of summer to (re)train model and consolidate forecast performance review findings.
- May: Retrain models and implement improvements based on FIP and observed summer forecast accuracy.
- June: Finalise forecast for use in ESOO and/or ISP and produce traces.

Forecast improvements overview

Forecast improvement cycle: Concept



Forecast improvement cycle: Improvement needs

- The appendix shows the findings of the 2022 FAR and 2022/23 summer review.
- 2021 ESOO forecast performance as presented in the 2022 FAR showed a need to:
  1. Review how the forecast distribution for the initial year is set.
     - As explained in the Forecast Improvement Plan update at the April 23 FRG, some improvements related to this were implemented to inform the 2023 WEM ESOO and would be used to improve the NEM ESOO as well.
  2. Review LIL and ONSG component forecasts
  3. Delivering more weather reference years – strong synergies from doing this together with forecasting demand
- 2022 ESOO forecast generally performed well for this summer, though outcome for Tasmania couldn't be fully explained.
  - The review of the initial forecast year distribution and the LIL component forecast will address this too.

Key methodology changes

- Large Industrial Load (LIL) sub-model: 2 3
  - Review showed most difference were due to unplanned outages or unexpected delays in commissioning of new LILs. More scrutiny on which LILs to include in this year's forecast.
  - The LIL impact at time of peak has changed to use a Random Forest machine-learning (ML) model to account for diversity in LIL contribution to peak rather than a fixed value (applied to all mainland regions) or simple scaling based on standard deviation as used for Tasmania.
- Other non-scheduled generation (ONSG) sub-model: 2
  - Reviewed ONSG list and found small differences in how it was applied between how actuals were calculated and how forecast was calculated. This has been fixed for 2023. Further work remains for synthetic traces.

- Half-hourly model: 1 3
  - Trained on shorter period (4-6 years, normalised) rather than longer period (11 years, detrended).
  - Include new variables that reflect impact of humidity ("feels like temperature" and "wet-bulb temperature").
- Revised residual model
  - Minor changes to address heteroscedasticity. 1 3
  - Application in simulation stage changed to use percentage scaling rather than MW scaling. 3
- Annual bootstrapping 1 3
  - Fortnightly bootstrapping averaged simulated years too much resulting in no extreme El Nino or La Nina years. This has been changed to annual (with dayshift) to improve the POE distribution.

All three items will lower the need for generalised extreme value (GEV) model rebasing.

Half-Hourly Model accuracy (underlying minus LIL)

Randomly selected 70% data and the rest 30% data

Mean absolute percentage error

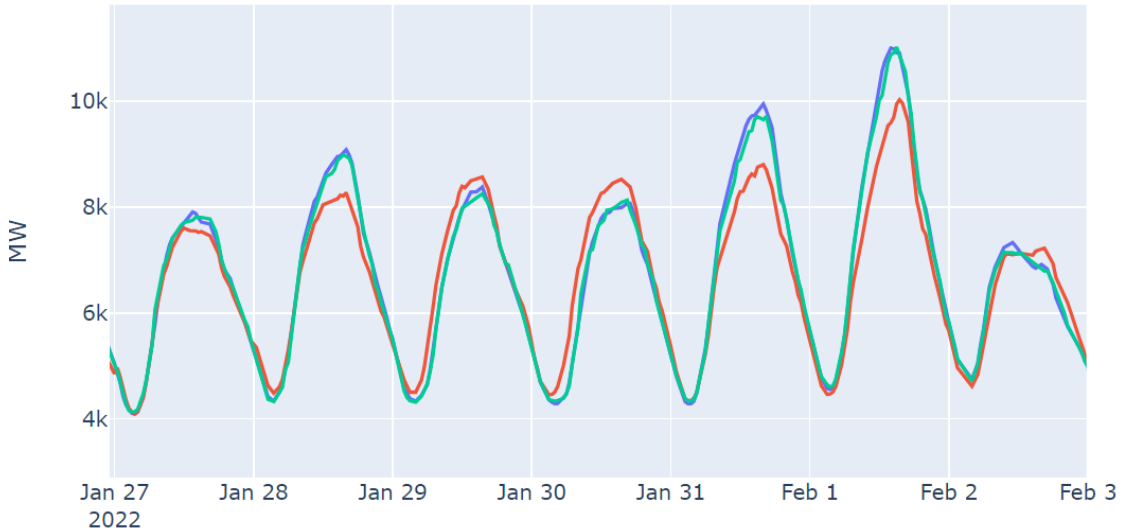
Typical time of OPSO max

Typical time of OPSO min

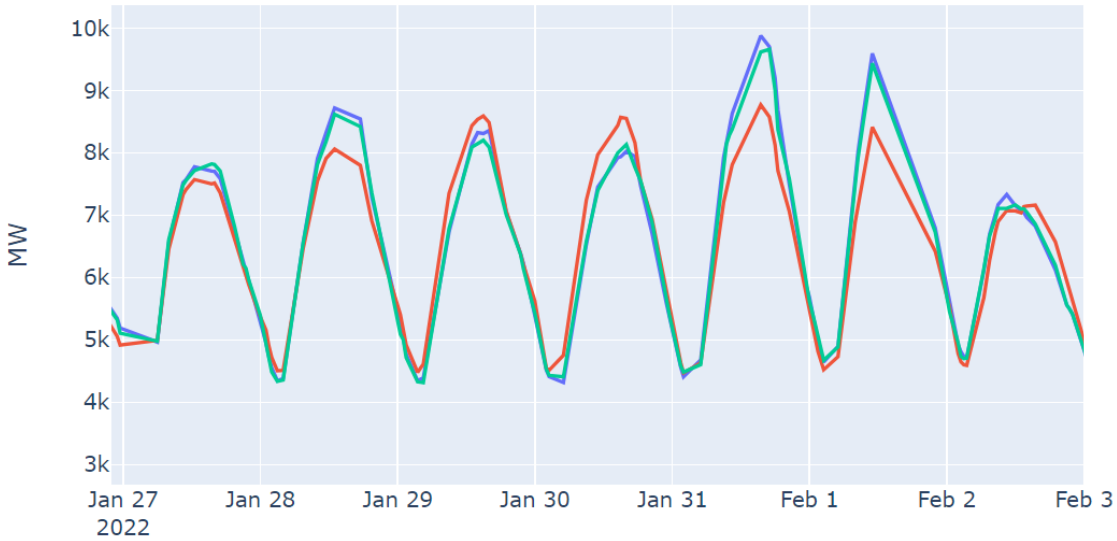
Average of error

TYPE	MAPE	MAPE TOP 1%	MAPE BOT 1%	MAPE 5:30PM-7:30PM	MAPE 5:30PM-7:30PM top 1%	MAPE 12:00PM-4:00PM	MAPE 12:00PM-4:00PM bot 1%	BIAS
Incumbent - Training set	5.386	8.241	5.368	5.552	8.229	5.857	8.580	0.280
Incumbent - Testing set	5.406	9.076	5.692	5.606	8.933	5.828	8.706	-3.401
Contender - Trainning set	1.377	1.317	1.273	1.549	1.247	1.422	0.987	-0.056
Contender - Testing set	1.781	2.276	1.546	2.015	2.075	1.786	1.550	1.068

Training set – Forecasts vs Actuals*



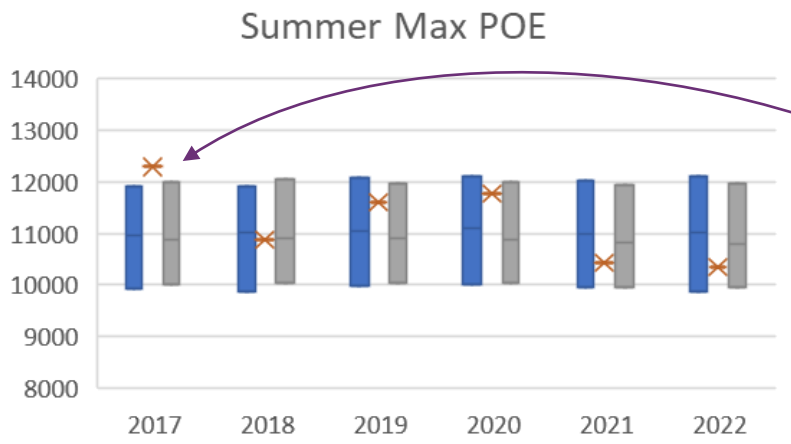
Testing set – Forecasts vs Actuals*

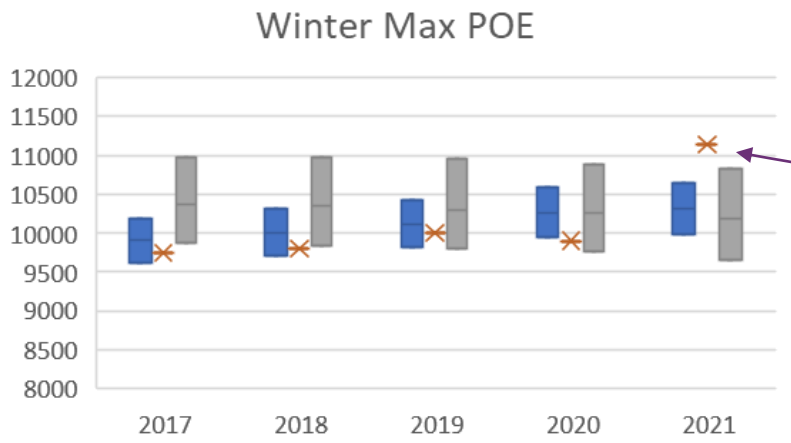


Underlying no LIL
Backcast – Incumbent
Backcast – Contender

*Results are based on New South Wales

Max/min demand accuracy (OPSO minus LIL)





MPE_YEAR	SUMMER Max Daily FL	WINTER MIN TEMP at 6-7pm	WINTER MIN of Daily MAX TEMP
2003	43.08	9.30	11.30
2004	40.61	9.70	12.60
2005	40.30	8.30	11.60
2006	42.95	8.60	12.30
2007	37.38	6.50	12.30
2008	36.22	7.70	11.40
2009	40.19	9.30	13.50
2010	42.46	6.70	11.90
2011	40.09	8.30	12.10
2012	38.16	7.70	13.40
2013	43.09	9.20	13.60
2014	37.43	9.10	14.40
2015	37.10	8.20	11.90
2016	38.98	9.30	12.00
2017	45.92	7.60	12.80
2018	40.62	9.70	14.60
2019	40.20	9.30	14.00
2020	40.22	9.80	13.10
2021	38.26	8.10	9.60
2022	36.73		
10th	37.06	7.42	11.38
50th	40.20	8.60	12.30
90th	43.08	9.70	14.08

Actual
New model
2022 ESOO

10% POE
50% POE
90% POE

*results are based on NSW ESOO22

Forecast improvements – Conclusion

- More improvements to the methodology than usual, but considered necessary to address issues with initial year of forecast and especially seems to affect winter max demand.
- Significant improvements have been made to improve accuracy and reduce bias in half-hourly model – at the same time making it fit for purpose for creating synthetic traces.

- The GEV model was superior to the "old" model, but current indications are showing the new forecasting model performs just as well, if not better.
- As foreshadowed in the April 2023 FRG, AEMO proposes to use the improved half-hourly forecast distributions directly rather than rebasing with the GEV model.
- **AEMO seeks FRG feedback on this proposal.**

Initial year – additional analysis pointing towards additional NEM model changes

2022 Forecasting Improvement Plan:

The distribution of the initial year of the forecast horizon requires review. Consider improvements to the GEV model or alternatives to it if required.

- **Review starting point of distributions for winter maximum and annual minimum forecasts.** Previous years' focus has been on improving the inputs, with the distributed PV forecast in particular being an issue. With that now improved, there is a need to improve the broader model performance. AEMO proposes to review the models used to set the starting points of the distribution, including whether additional weather variables like dew point (humidity) can improve model performance. Observed differences could also reflect an underlying change in customer behaviour, for example increased usage of heating/cooling load from customers that have invested in rooftop PV, that the modelling is not adequately picking up in maximum and minimum demand forecasting. This should also be investigated.

- Additional investigations undertaken along with the Synthetic trace initiative has shown improvements from adding additional variables related to reflecting humidity and impacts of heat waves.
- AEMO will continue the investigations, including whether the improvements (including reduced bias) can remove the need for the GEV model to set the starting point.
- AEMO will use this approach in the 2023 ESOO if same or better outcomes can be achieved.

FRG April 2023 – Forecast Improvement Plan update

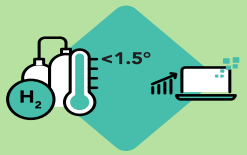
Forecast results summary and regional overview

Step Change forecasts to 2043

ESOO forecasts

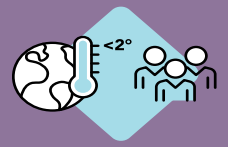
- The forecasts presented today is for the central 2023 ESOO scenario, which is the 1.8ºC Step Change scenario from the Draft 2023 IASR.
- Two other scenarios will feature in the ESOO:

High



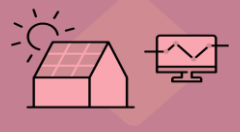
1.5ºC Green Energy Export

Central



1.8ºC Step Change

Low



2.6ºC Progressive Change

- Similar to last year, the forecasts shown exclude any coordinated EV charging demand and demand from hydrogen loads, as the dispatch of these loads is optimised in the subsequent market modelling.

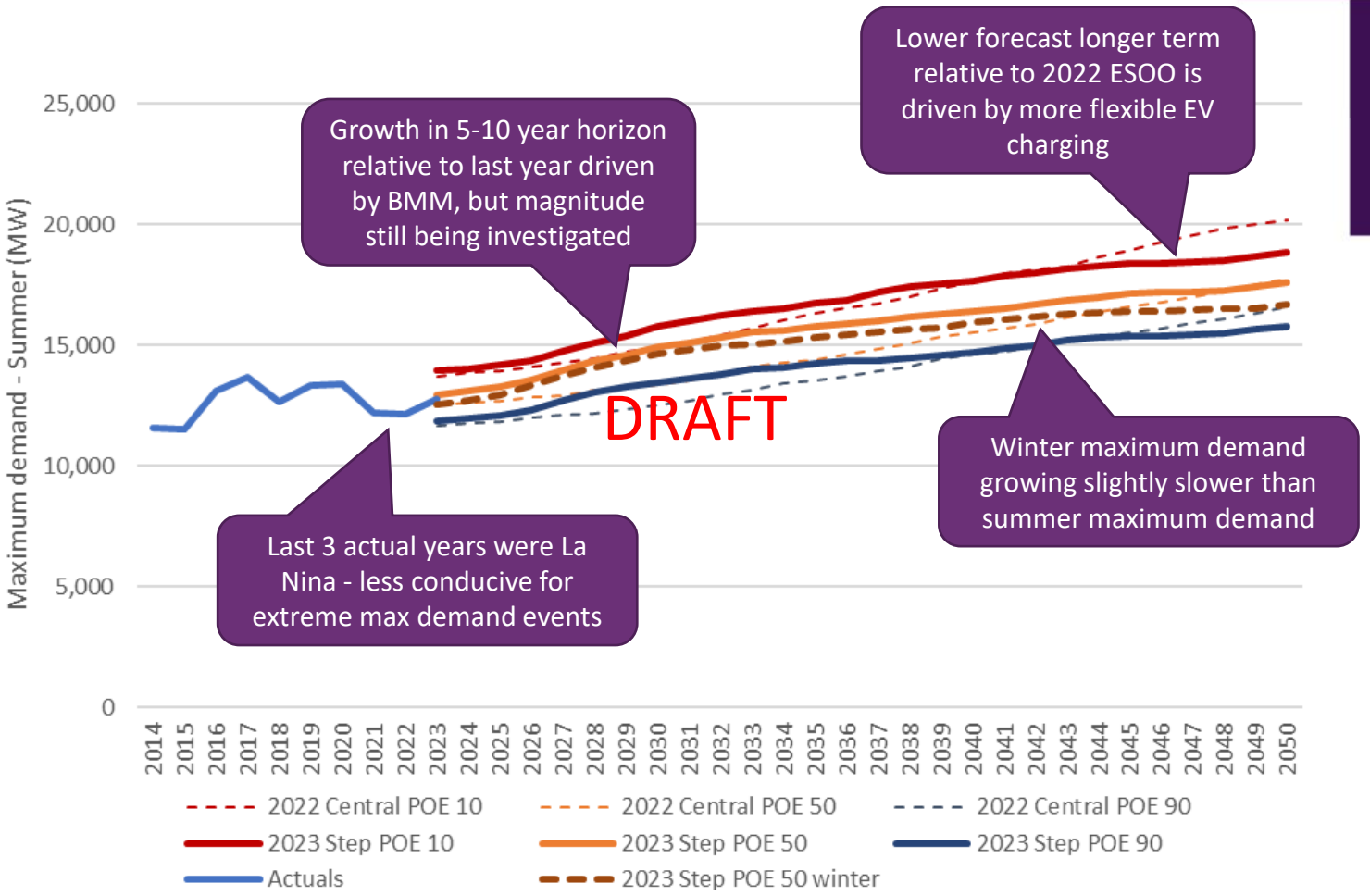
New South Wales maximum – summer

Short term (first 5 years):

- Relatively steady for the first two years, then growth picking up due to business mass market (BMM) growth.
- Somewhat higher compared to ESOO 2022 due to stronger forecast BMM growth.

Long term (5-30 years):

- Steady growth to the early 2040s, then growth slows down. Key reasons for growth are underlying BMM growth as well as electrification overall (including EVs).
- Initially slightly higher forecast compared to ESOO 2022 due to BMM growth (mainly driven by lower energy efficiency) and higher EV forecast. But towards the end, the 2023 forecast overall becomes lower due to more “peak-friendly” EV charging.



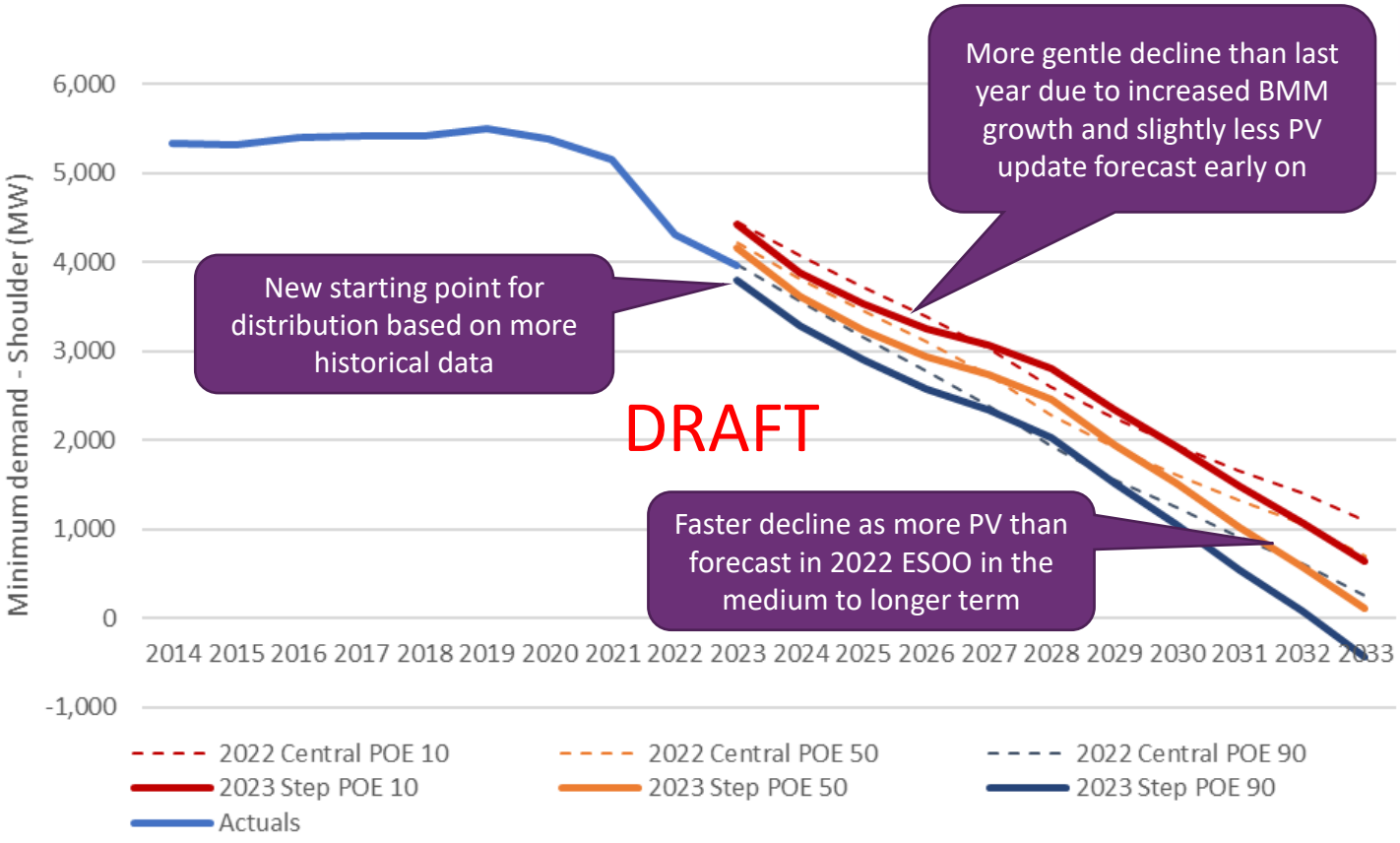
New South Wales minimum – shoulder

10 year outlook:

- Slight reduction in decline over the first three years due to BMM growth and slight reduction in PV uptake. Then a return to the recent rate of decline as PV uptake increases again.

Comparison with 2022 ESOO forecast:

- Recalibrated starting point lower based on more historical data.
- Slower decline early on due to higher BMM growth and a slightly lower rooftop PV forecast.
- In the medium to longer term, forecast minimum demand declines faster than in 2022 due to less forecast BMM electrification and more PV uptake.



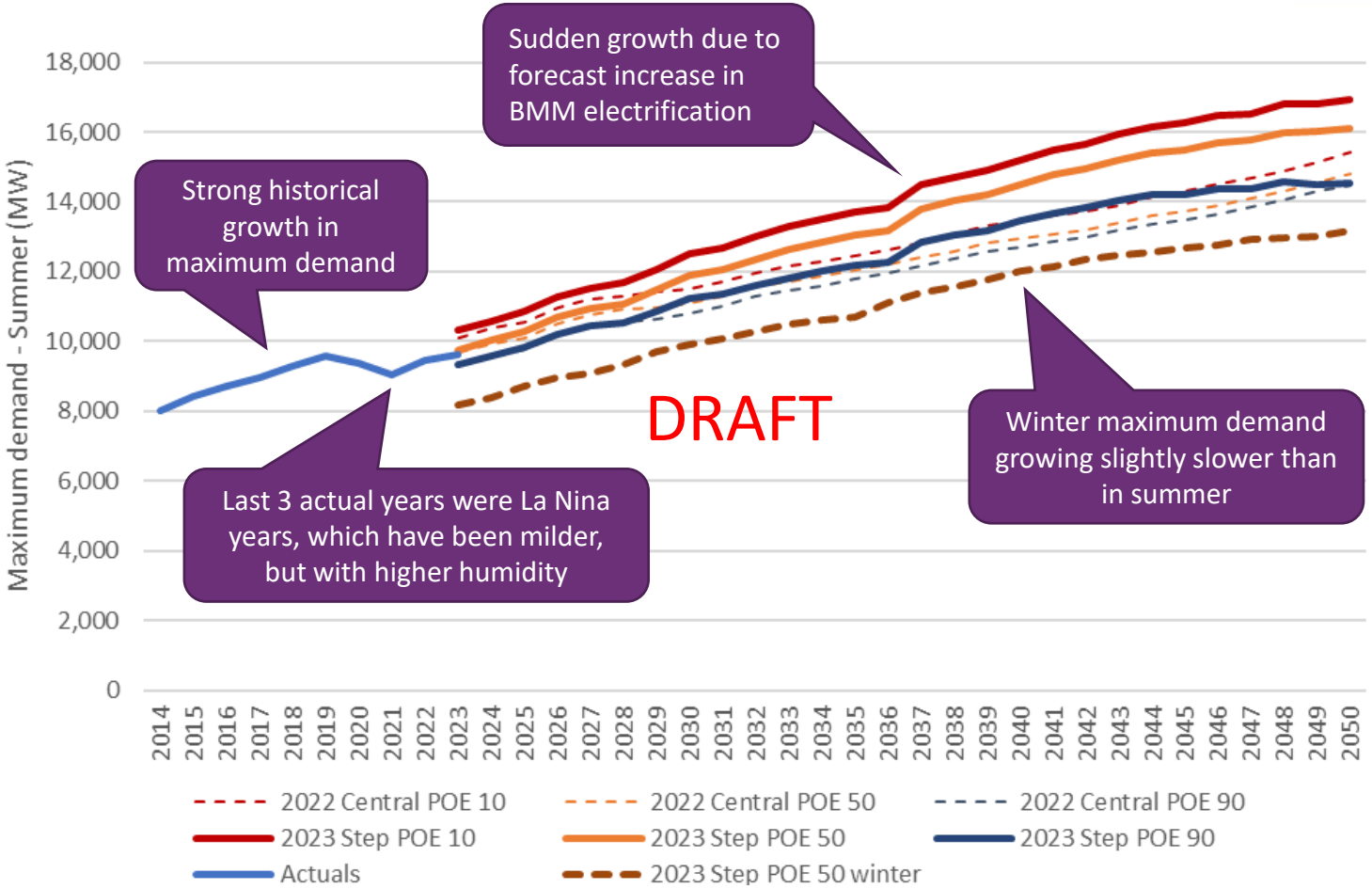
Queensland maximum – summer

Short term (first 5 years):

- Steady growth in line with history driven by underlying BMM and residential growth.
- Similar growth compared to ESOO 2022 but slightly higher starting point.

Long term (5-30 years):

- Steady growth to the mid-2040s driven by underlying BMM and residential growth (including electrification) as well as LIL growth from 2030 onwards. During the 2040s growth tapers off, mainly due to forecast reduction in LNG operation.
- Higher forecast compared to ESOO 2022 across the horizon due to lower energy efficiency forecasts and growth from LILs.



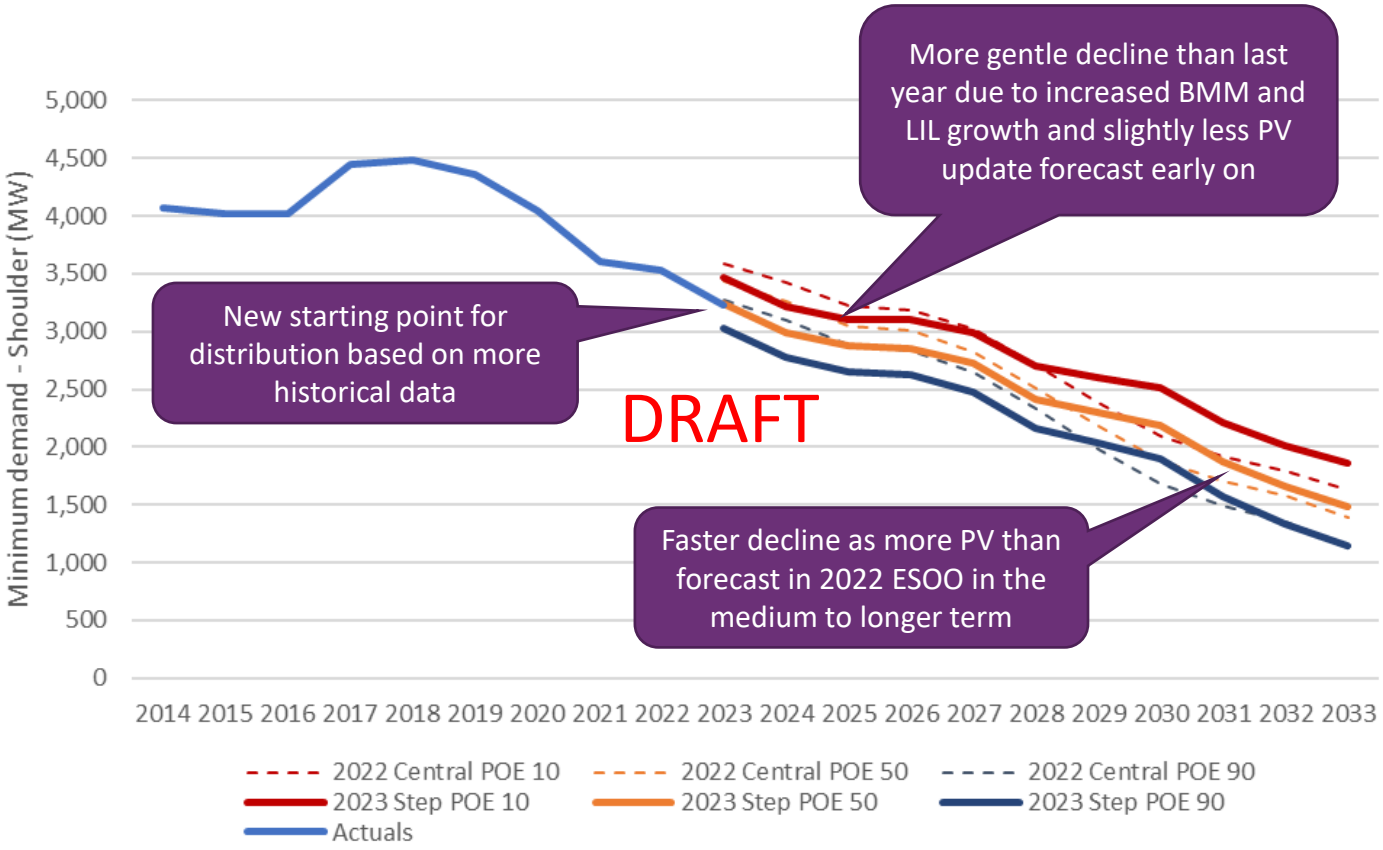
Queensland minimum – shoulder

10 year outlook:

- Slight reduction in decline over the first three years due to strong underlying BMM, LIL and residential growth and slight reduction in PV uptake.
- Then a small increase in the rate of decline in the late 2020s as PV uptake increases again.

Comparison with 2022 ESOO forecast:

- Recalibrated starting point lower based on more historical data.
- Slower rate of decline due to higher BMM, LIL and residential growth.



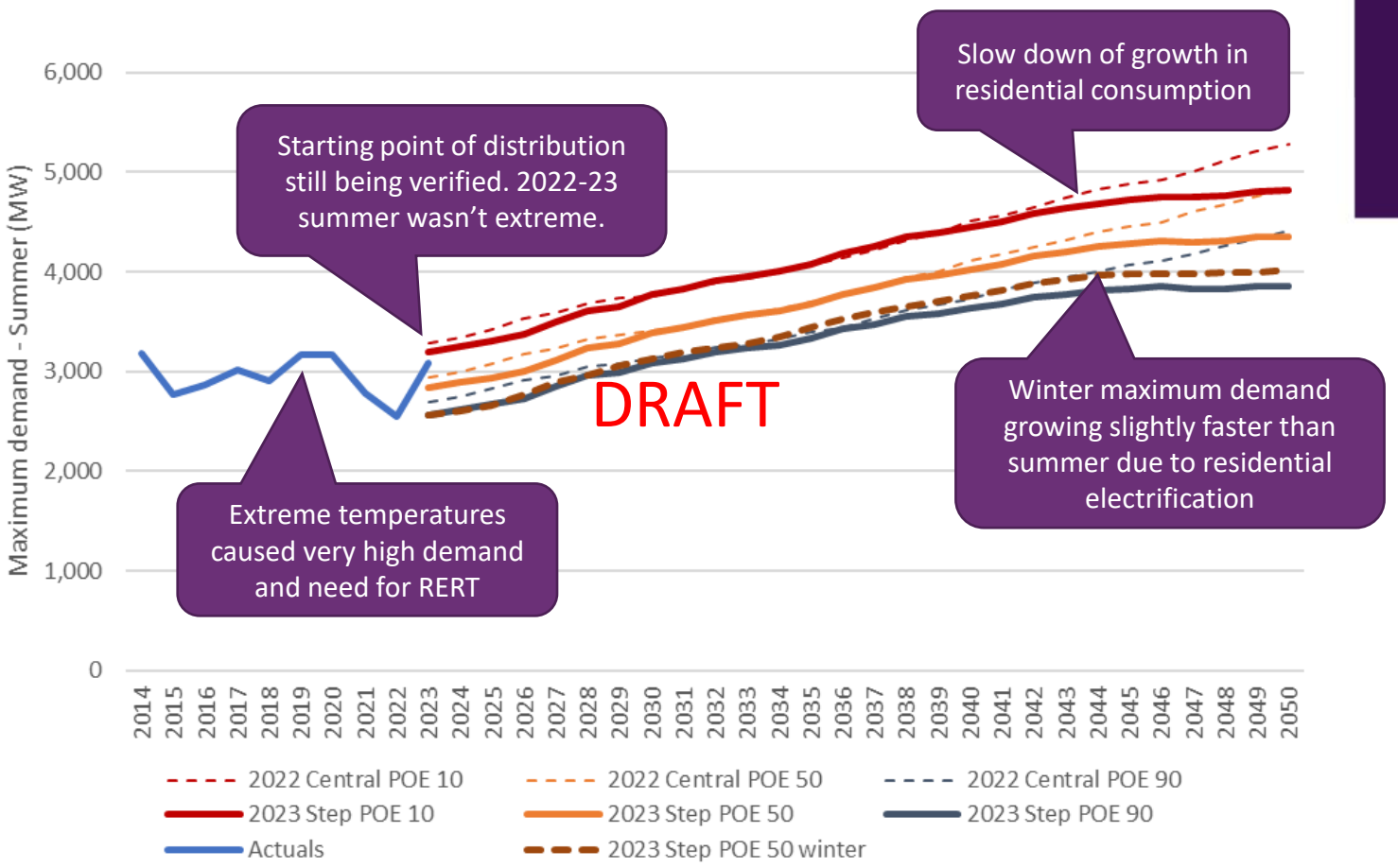
South Australia maximum – summer

Short term (first 5 years):

- Steady growth driven by underlying growth for BMM, residential and LILs.
- Sightly lower starting point from retrained model. Slightly higher growth compared to ESOO 2022 driven mainly by growth from LILs.

Long term (5-30 years):

- Steady growth to the mid-2040s driven by underlying growth for BMM, residential sector and LILs. From that point, residential growth tapers off.
- Similar forecast compared to ESOO 2022 till the early 2040s. Difference at the end is due to slow down in residential use and increase in BMM load in the 2022 forecast towards the end of the forecast.



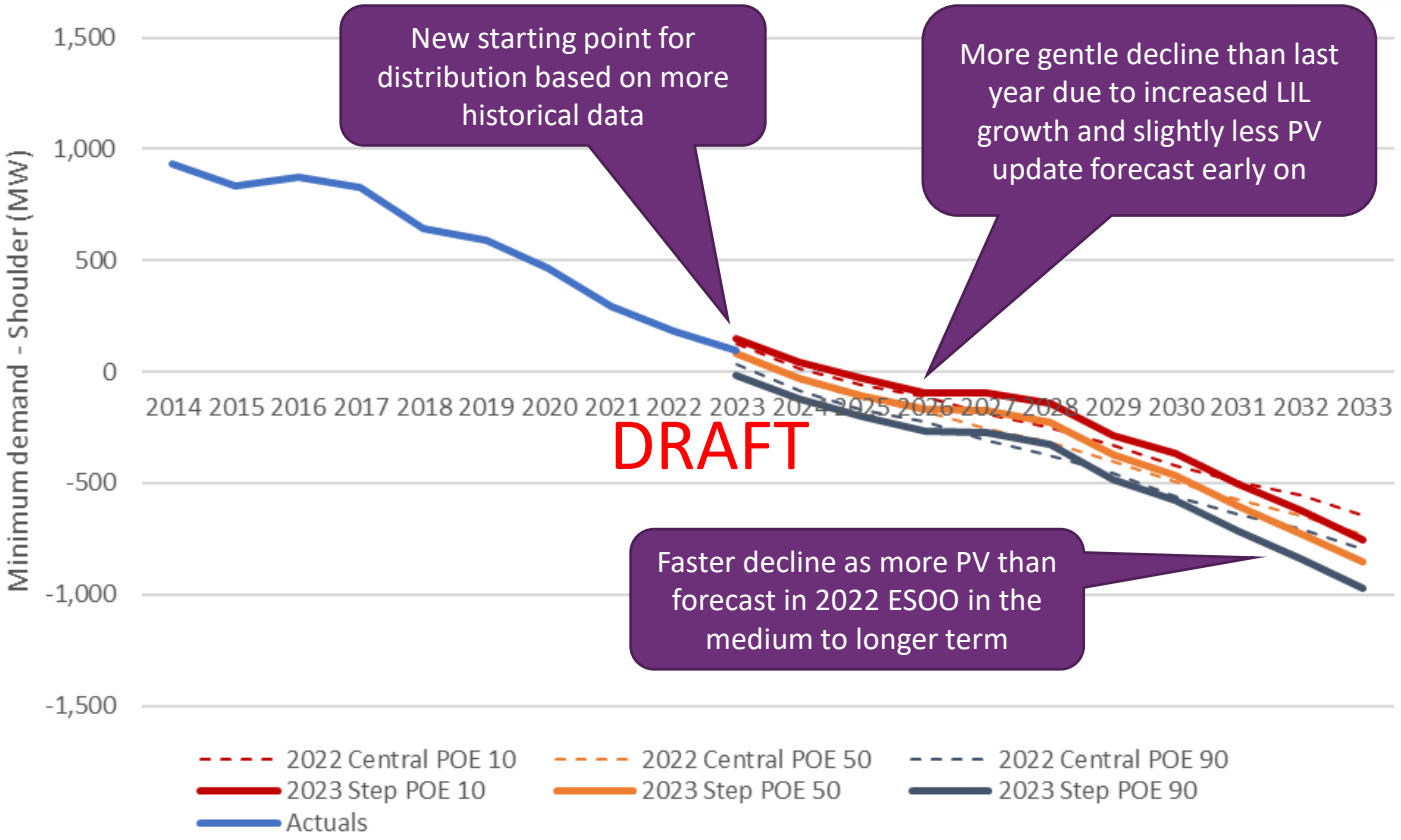
South Australia minimum – shoulder

10 year outlook:

- Slight reduction in decline over the first three years due to LIL growth and slight reduction in PV uptake. Then a return to the recent rate of decline as PV uptake increases again.

Comparison with 2022 ESOO forecast:

- Recalibrated starting point lower based on more historical data, though still subject to further investigation.
- Slower decline early on due to higher LIL growth and a slightly lower rooftop PV forecast.
- In the medium to longer term, forecast minimum demand declines faster than in 2022 due higher forecast PV uptake.



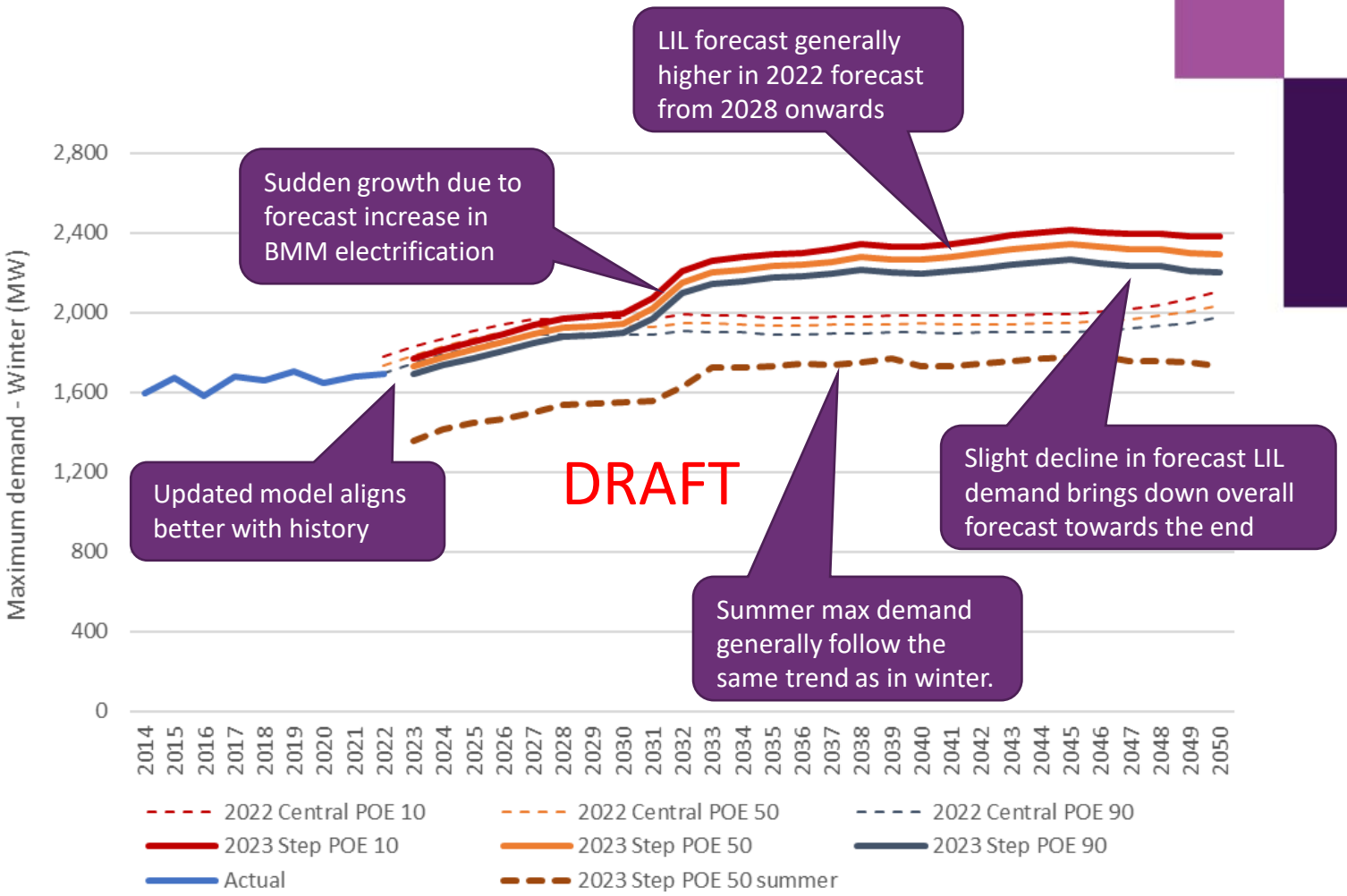
Tasmania maximum – winter

Short term (first 5 years):

- Steady growth driven by growth from BMM and LILs.
- Sightly lower starting point from retrained model and lower BMM initially. Then similar growth compared to ESOO 2022 driven by same factors (as above).

Long term (5-30 years):

- Step up in demand around 2032 due to forecast growth in BMM electrification. Then relatively flat till mid-2040s followed by slight decline in demand driven by downward trend in LIL consumption.
- Main difference compared to ESOO 2022 is the step up in early 2030s from the BMM electrification forecast. Forecast remains at that higher level due to higher LIL forecast.



Tasmania minimum

Tasmanian minimum demand forecast is highly dependent on variability in large industrial load and the forecast is still under development.

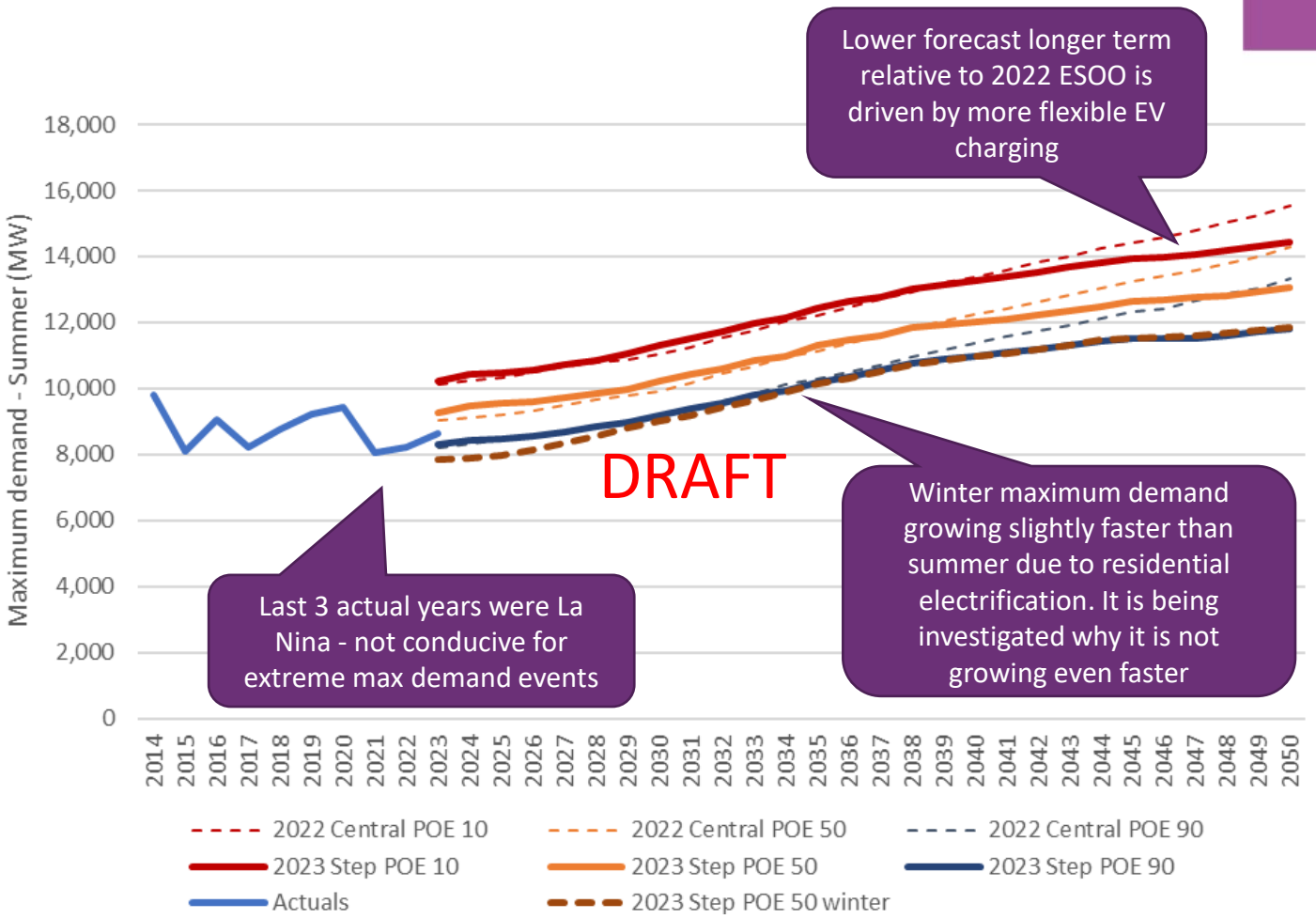
Victoria maximum – summer

Short term (first 5 years):

- Steady growth driven by underlying BMM and residential growth.
- Similar growth compared to ESOO 2022.

Long term (5-30 years):

- Steady growth to the early-2040s, then growth slows down. Key reasons for growth are underlying BMM and residential growth (including electrification).
- Similar forecast compared to ESOO 2022 till the late 2030s, then lower. Difference at the end is due to more flexible EV charging profiles.



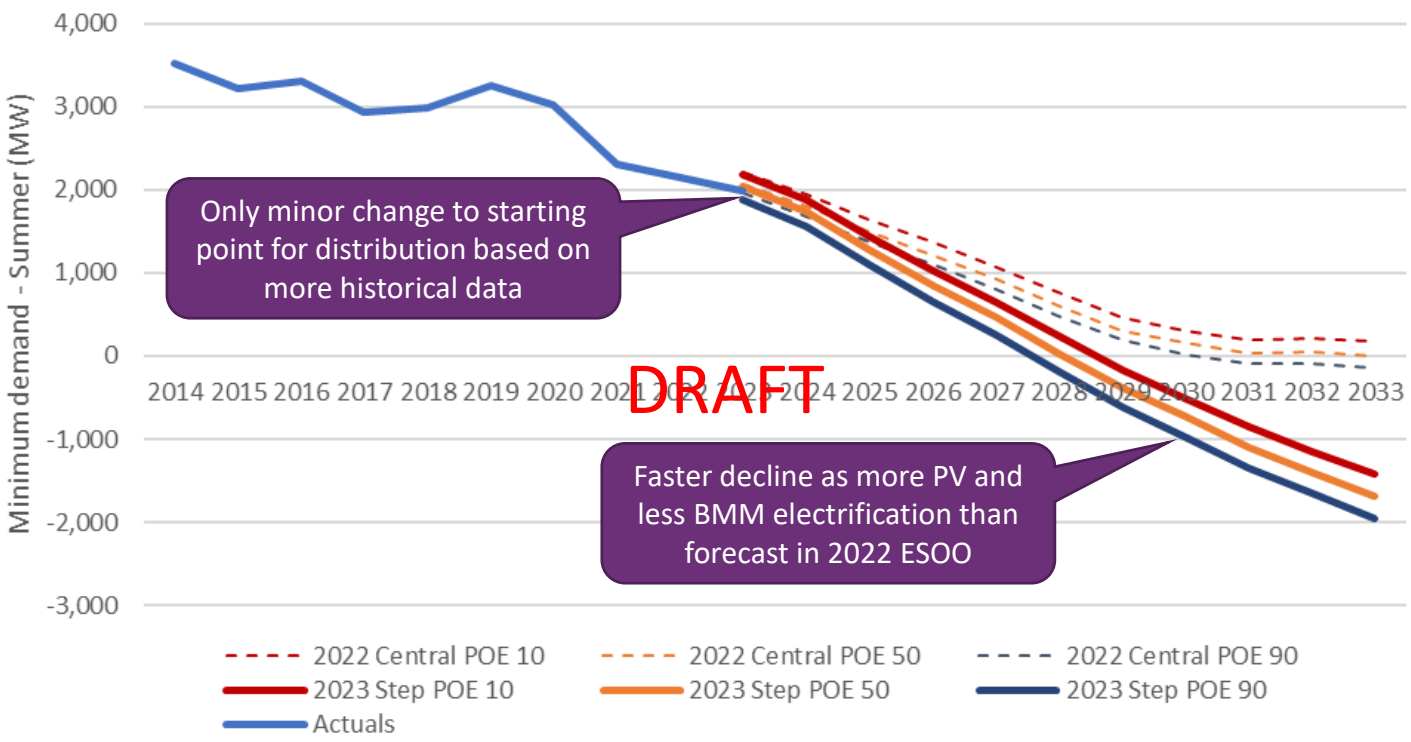
Victoria minimum – summer

10 year outlook:

- Steady decline as growth in rooftop PV more than offsets growth in underlying demand.

Comparison with 2022 ESOO forecast:

- Recalibrated starting point lower based on more historical data.
- Throughout the horizon, forecast minimum demand declines faster than in 2022 due higher forecast PV uptake and lower BMM electrification forecast.



Discussion and next steps

- Seeking FRG feedback on draft forecasts:
  - Are the implemented changes sufficient to address the issues observed in the 2022 FAR and the summer 2022-23 review?
  - Do the draft forecasts seem reasonable, based on the drivers?
    - (see Appendix B for May 2023 FRG Draft Consumption forecast by region, updated where relevant)

- Next steps:
  - Finalise 2023 ESOO forecast taking onboard any feedback from FRG and additional internal reviews.
  - Provide forecasts for use in 2024 ISP.
  - Finalise development of synthetic traces.

Appendix A: Improvement plan

Understanding the language of forecasting electricity demand

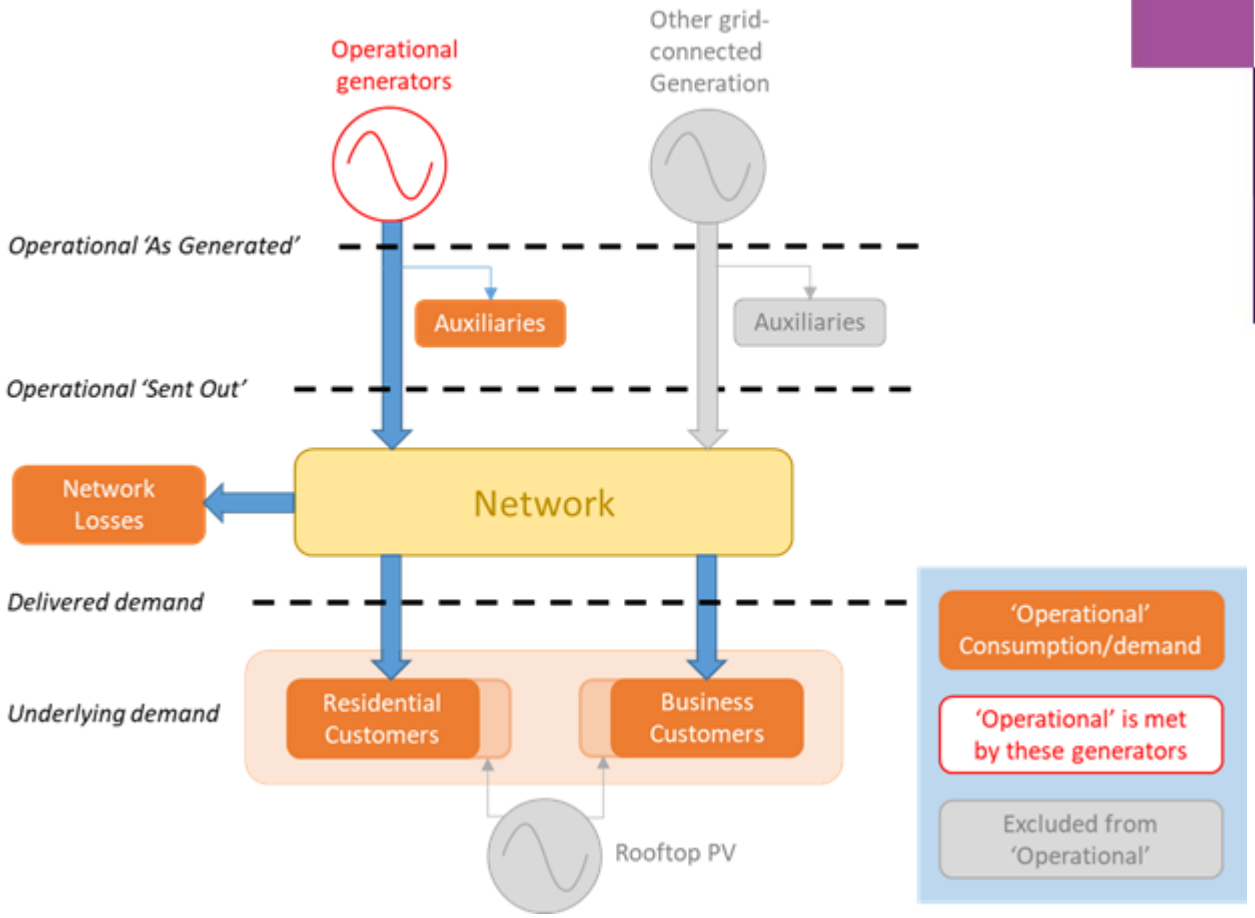
Pre-reading

Key forecasting definitions in use today:

- **Underlying Demand:**
  - Underlying demand is the "power point" demand of consumers, irrespective of where that power is generated (from the grid or within the home).
- **Delivered Demand:**
  - Delivered demand is the demand that is met from the transmission grid, net of any distribution-generated energy such as rooftop PV
- **Operational Demand**
  - What is consumed by consumers, as supplied by scheduled, semi-scheduled and significant non-scheduled generating units >= 30MW (with some exceptions).

Key demand measurement points:

- **"Sent Out"**
  - Electricity supplied to the grid by scheduled, semi-scheduled and significant non-scheduled generators (excluding auxiliary loads)
- **"As Generated"**
  - As per Sent Out, but including auxiliary loads (that load which is used within a power station)



For detailed definitions, see: demand-terms-in-emms-data-model.pdf (aemo.com.au)

Background

Overview of max/min demand results: Summer 2022/23 review

Status as of 31 March 2023, compared with ESOO 2022 forecast

Region	Summer maximum	Summer minimum
Queensland	Just under 50% POE	Just below 90% POE
New South Wales	Just above 50% POE	Between 90% and 50% POE
Victoria	Between 90% and 50% POE	Between 90% and 50% POE
South Australia	Between 10% and 50% POE	Between 10% and 50% POE
Tasmania	Below 90% POE	Between 10% and 50% POE
Western Australia	Between 90% and 50% POE	TBA

Note that green and red colours simply represent whether the forecast falls within the 10%-90% POE interval. Being red may not be due to input/model error, but due to more extreme drivers than usual.

Background

Overview of max/min demand results: 2022 Forecasting Accuracy Report

Forecast Component	NSW	QLD	SA	TAS	VIC	Comments
Summer maximum demand	🟢	🟡	🟡	🟢	🟢	Good alignment across most regions except Queensland and South Australia. Actual maximum demand in Queensland fell just above the forecast range, driven by very high humidity well into the evening. South Australia had an unusually low maximum demand outcome driven by very mild weather across the summer due to the La Niña climate conditions and fell just under the forecast range.
Winter maximum demand	🟢	🟡	🟢	🟡	🔴	Winter maximum demand outcomes in Queensland and Victoria were above forecast distributions and Tasmania below. While the reasons for the deviation for Queensland and Tasmania are known, a review of how the initial year of the forecast is set is required.
Annual minimum demand	🔴	🔴	🟢	🟢	🟢	Three regions showed good alignment, while New South Wales' actual minimum demand was lower than the forecast distribution and Queensland's actual minimum demand was above the forecast. With distributed photovoltaic (PV) installations showing good alignment, the forecast model requires review.

Background

2022 Forecast Improvement Plan:

- Initiative 3: Review initial year of forecast maximum and minimum demand distribution:

Review starting point of distributions for winter maximum and annual minimum forecasts. Previous years' focus has been on improving the inputs, with the distributed PV forecast in particular being an issue. With that now improved, there is a need to improve the broader model performance. AEMO proposes to review the models used to set the starting points of the distribution, including whether additional weather variables like dew point (humidity) can improve model performance. Observed differences could also reflect an underlying change in customer behaviour, for example increased usage of heating/cooling load from customers that have invested in rooftop PV, that the modelling is not adequately picking up in maximum and minimum demand forecasting. This should also be investigated.

The investigation may lead to proposed changes for the Generalised Extreme Value (GEV) model used to set the starting point of the maximum and minimum demand distributions, which in the published forecast are expressed as the 10%, 50% and 90% POE forecasts[36]. It may also reveal alternatives to use instead of the GEV model; if so, testing will be undertaken to ensure the best approach is identified and consulted on ahead of use in the 2023 ESOO.

Background

2022 Forecast Improvement Plan:

- Initiative 4: Review subcomponent forecasts of large industrial loads (LIL) and other non-scheduled generation (ONSG):

Review sub-component forecasts for LILs and ONSG. These should be reviewed both in terms of their impacts on consumption and their contributions at time of maximum and minimum demand. With minimum demand declining, even a smaller component like ONSG may impact forecast accuracy.

- Initiative 1: Improve representation of weather by modelling additional weather years:

Improve representation of weather by modelling additional weather years. The growth in new generation capacity driven by new large-scale wind and solar projects, along with the projected decommissioning of dispatchable thermal generators, increases the importance of weather when assessing future reliability outcomes. For the 2021 ESOO, AEMO used 11 reference weather years to assess the impacts of different weather patterns on reliability. For increasing shares of variable renewable generation, this may be insufficient to identify high risk periods of coincident low availability of renewable generation, and AEMO plans for more weather reference years to be available for the 2023 ESOO.

No recommendations for improving max/min demand, but strong synergies of building this into demand forecast process

Initial year – additional analysis pointing towards additional NEM model changes

April FRG recap

2022 Forecasting Improvement Plan:

The distribution of the initial year of the forecast horizon requires review. Consider improvements to the GEV model or alternatives to it if required.

- **Review starting point of distributions for winter maximum and annual minimum forecasts.** Previous years' focus has been on improving the inputs, with the distributed PV forecast in particular being an issue. With that now improved, there is a need to improve the broader model performance. AEMO proposes to review the models used to set the starting points of the distribution, including whether additional weather variables like dew point (humidity) can improve model performance. Observed differences could also reflect an underlying change in customer behaviour, for example increased usage of heating/cooling load from customers that have invested in rooftop PV, that the modelling is not adequately picking up in maximum and minimum demand forecasting. This should also be investigated.

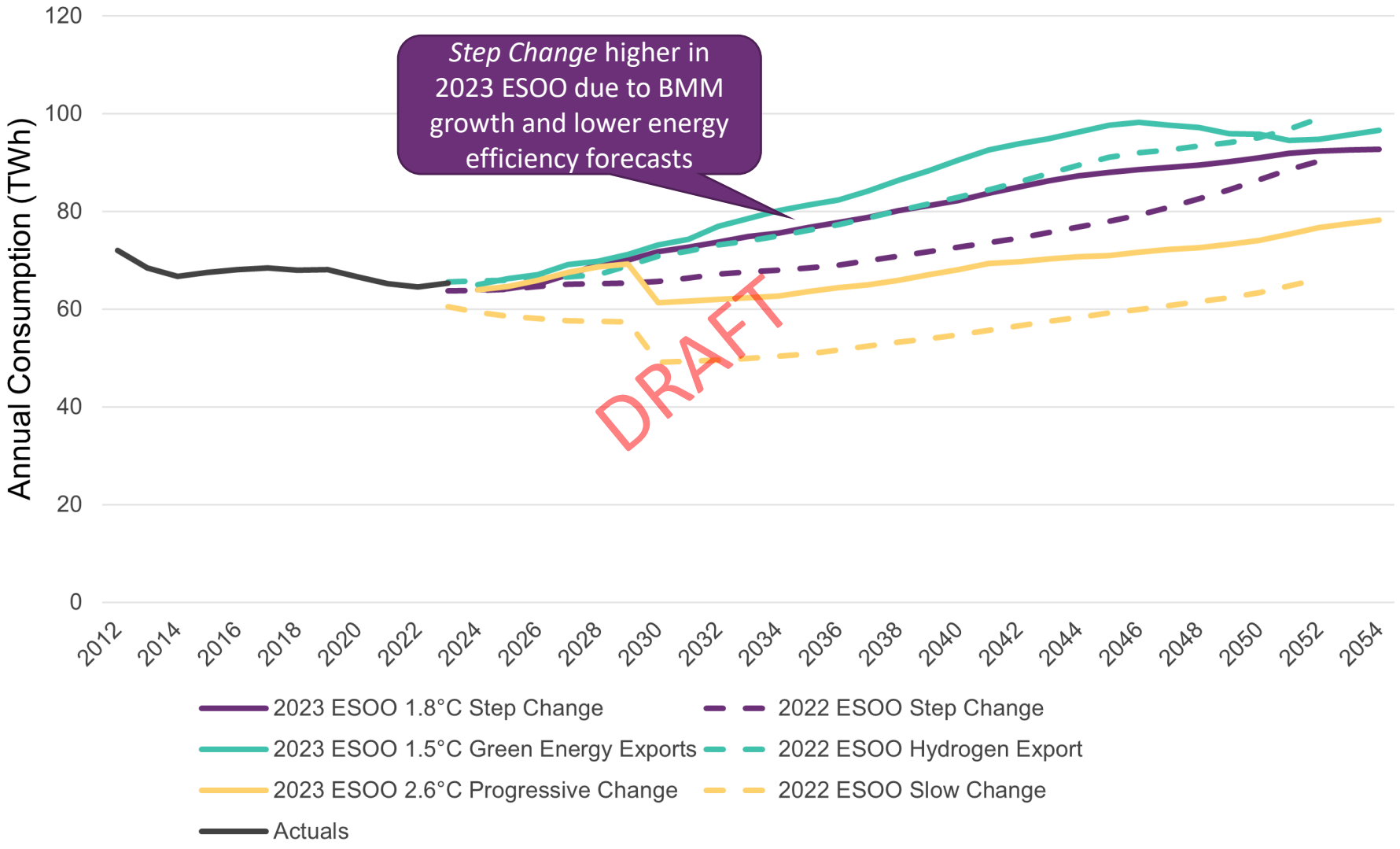
- Additional investigations undertaken along with the Synthetic trace initiative has shown improvements from adding additional variables related to reflecting humidity and impacts of heat waves.
- AEMO will continue the investigations, including whether the improvements (including reduced bias) can remove the need for the GEV model to set the starting point.
- AEMO will use this approach in the 2023 ESOO if same or better outcomes can be achieved.

Appendix B: Consumption drivers

presented at the May Forecasting Reference Group meeting

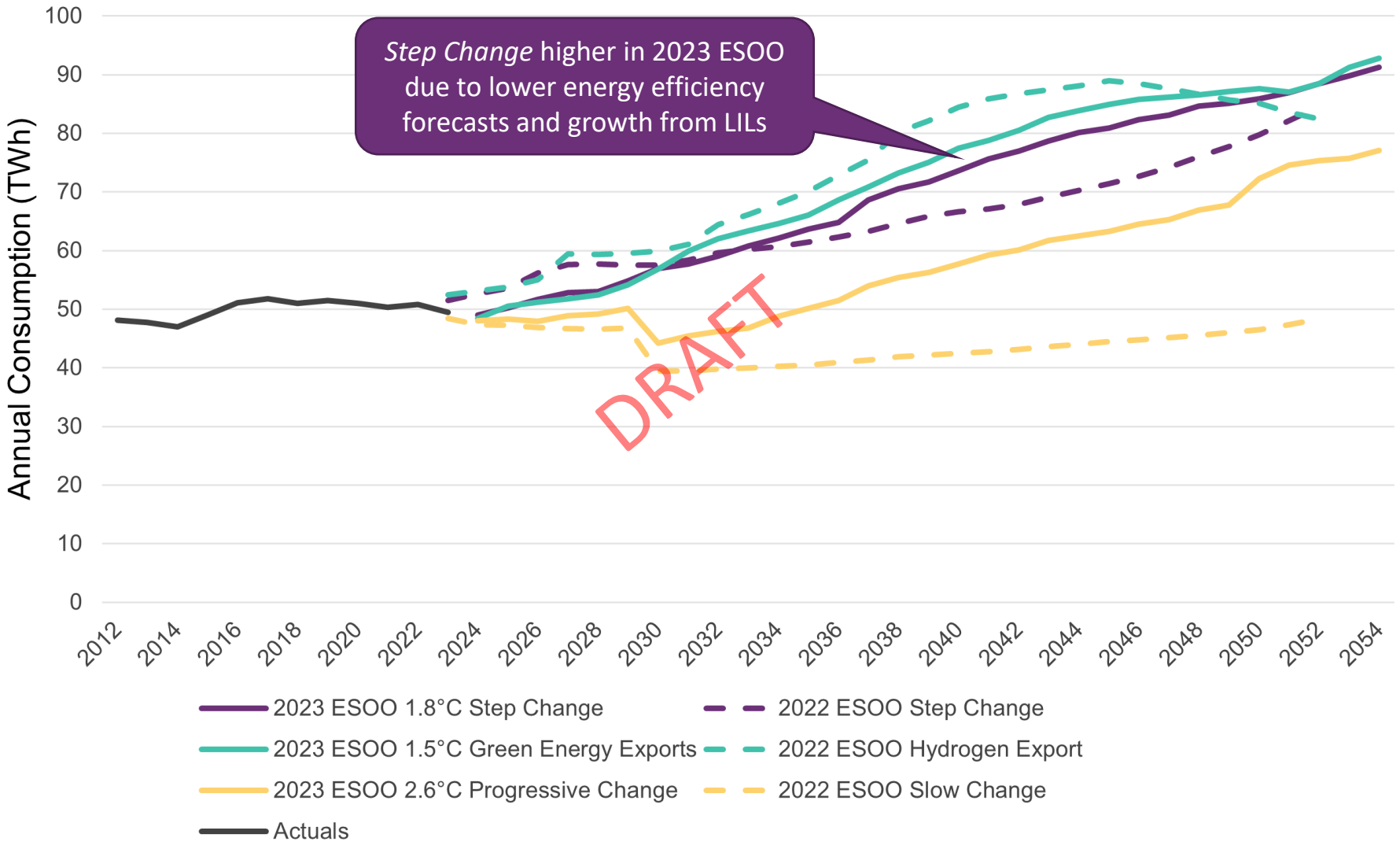
May FRG recap

NSW consumption (OPSO)



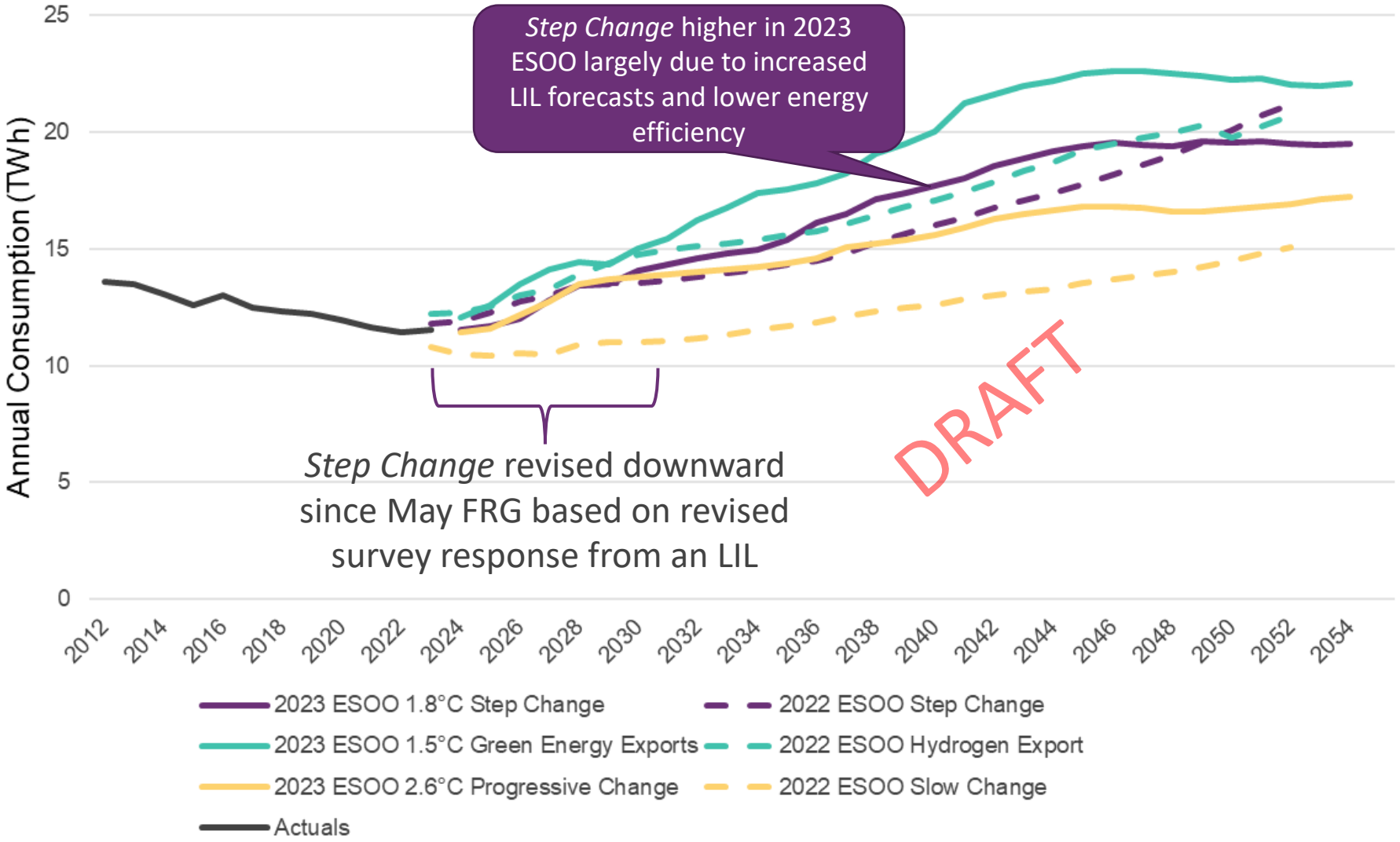
QLD consumption (OPSO)

May FRG recap



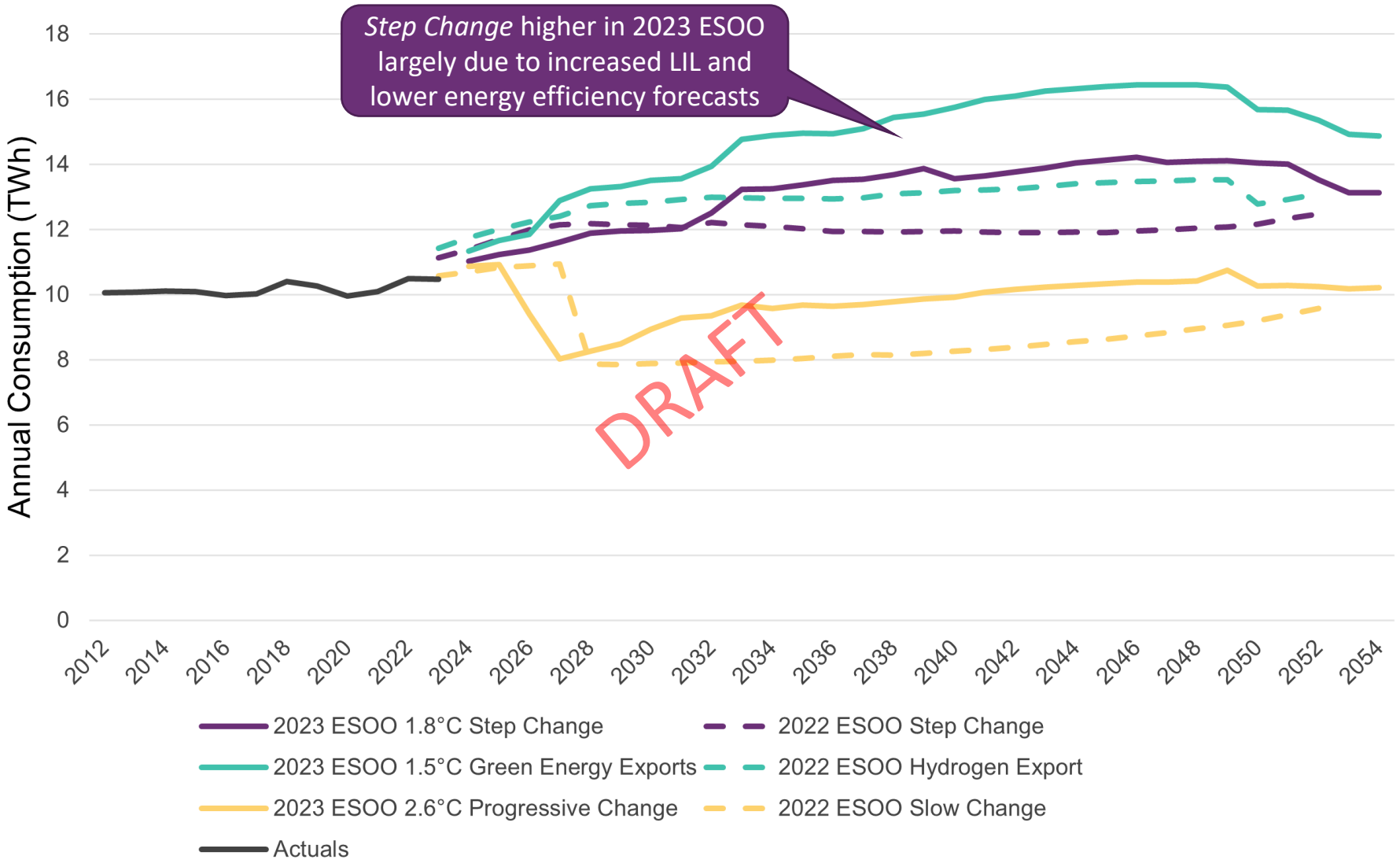
SA consumption (OPSO)

Updated since May FRG



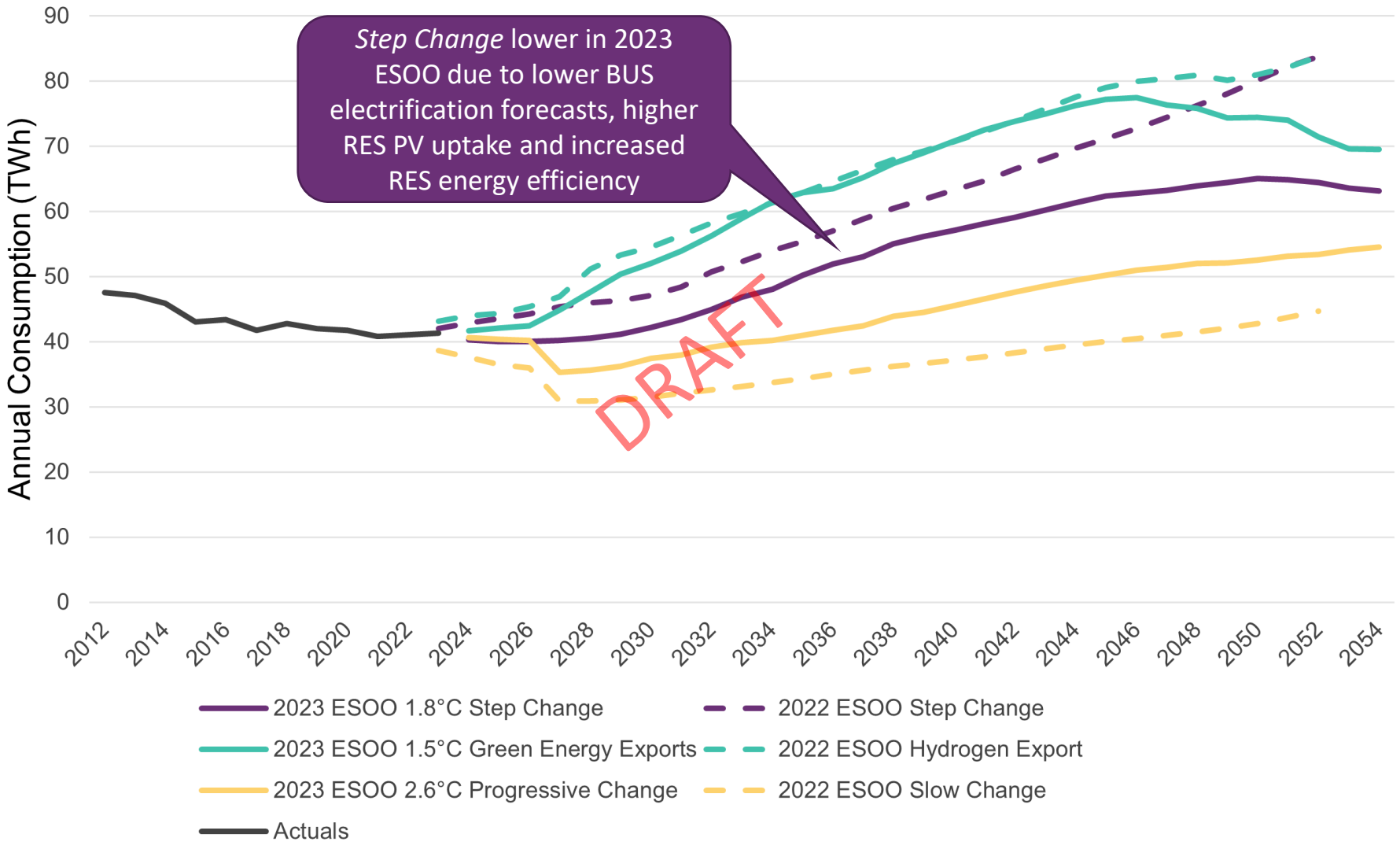
TAS consumption (OPSO)

May FRG recap



VIC consumption (OPSO)

May FRG recap



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