Minimum Connection Point Forecasts

July 29th FRG meeting

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Background

Timing	Implementation stage of CPF	Responsible
April 2019	Methodology workshops with Oakley Greenwood	AEMO, OG
Feb 2020	Commenced implementation	AEMO
Today	**FRG: Briefing on approach and current progress**	**AEMO**
Sep - Oct 2020	Forecasts published	AEMO
Oct 2020 onwards	Forecasts used in MLF's, VIC transmission planning	AEMO & Stakeholders

Today is a briefing on AEMO's progress implementing a new Connection Point Forecasting (CPF) methodology

Agenda includes:

- Definition and Purpose of CPF
- The need for a revised methodology
- Improvements in the methodology
  - Defined periods & contribution factors
  - Spatio-temporal population projections
- Top-down reconciliation
- Discussion

Background: decreasing minimum demand impacts power system stability

- Connection Points are the physical points at which Transmission assets meet Distribution assets
- Understanding minimum demand is essential for Network Planning. Unmanaged lower demand will lead to over voltage events and thus need to be addressed.
- Excessive over voltage events risk damage to the network and/or customer installations.

The challenge in forecasting minimum demand is that the timing of the minimum can shift significantly with society and technology.

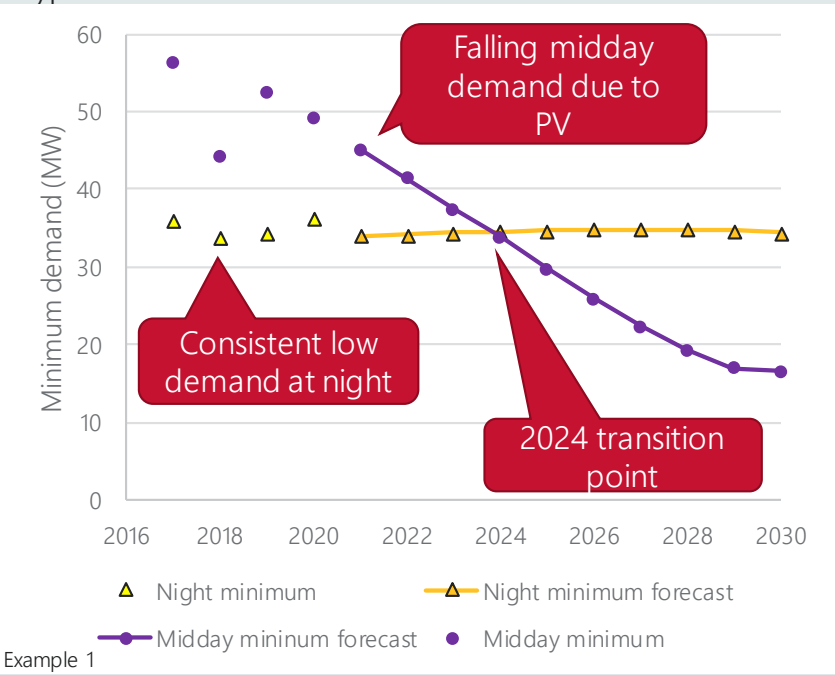
The methodology for connection point-level forecasting needs to capture shifting minimum demand and be practical to implement.

Components of the forecast that capture growth and intra-day dynamics:

Transition point: minimum demand time shifts from night to day

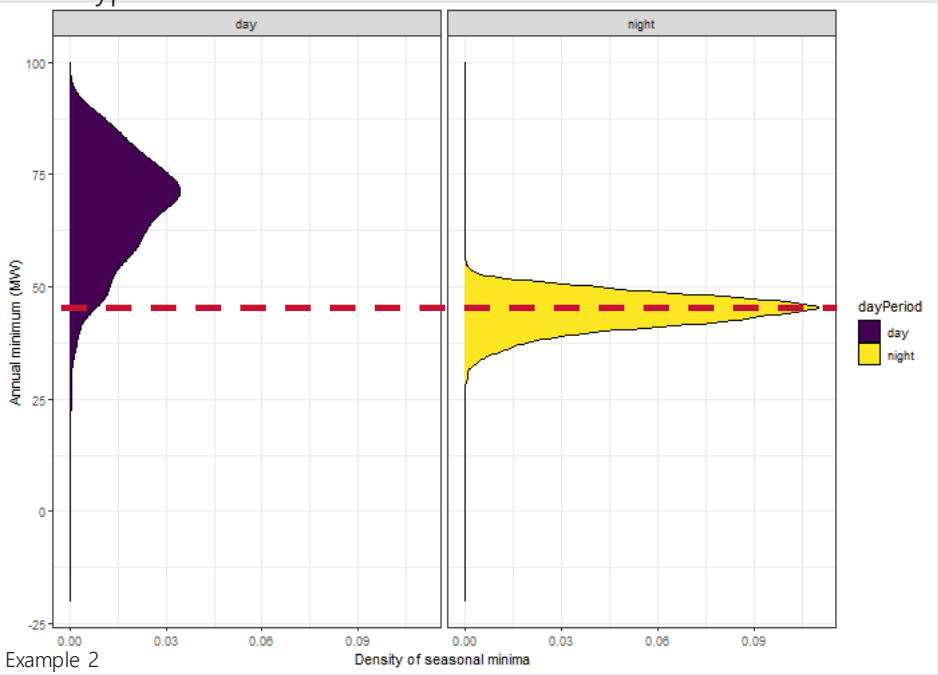
As minimum demand transitions from consistently occurring at night, our forecasting methodology must model multiple times of day (defined periods) and select the minimum.

Typical residential Connection Point minimum transition



Example 1

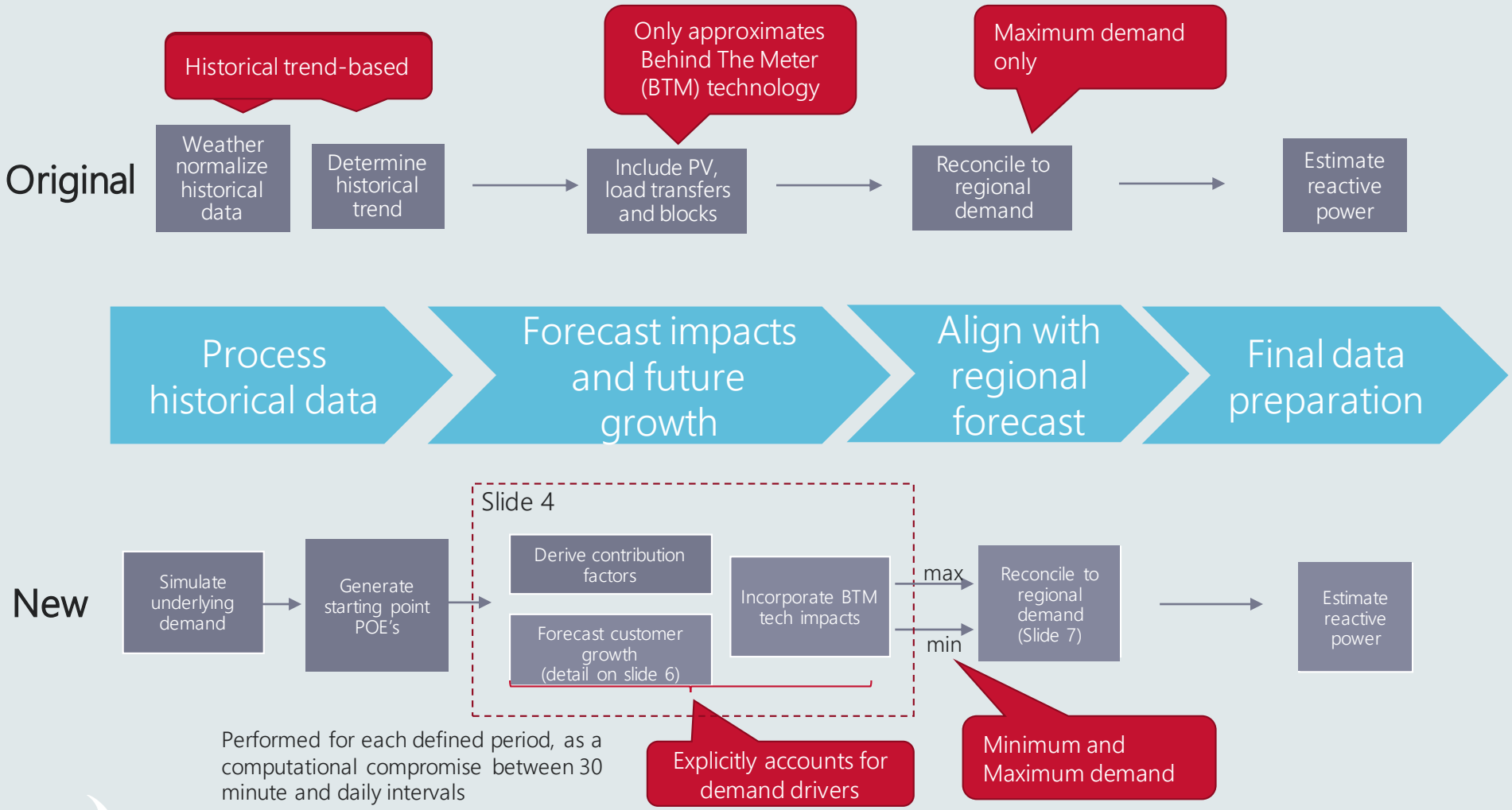
Typical residential Connection Point minimum demand



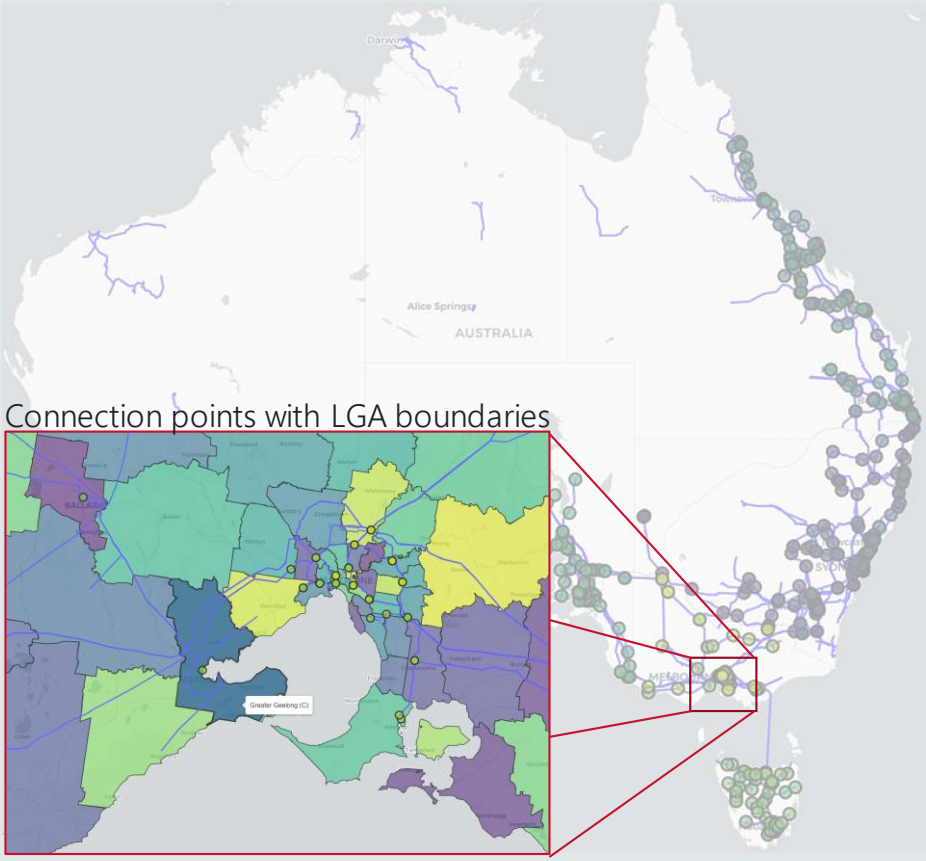
Example 2

Contribution factors apply technology trends (PV, EV, battery etc) to each defined period's demand.

Improved CP forecasting methodology supports minimum demand forecasts



Spatio-temporal projections improve on simple trend



Connection points with LGA boundaries

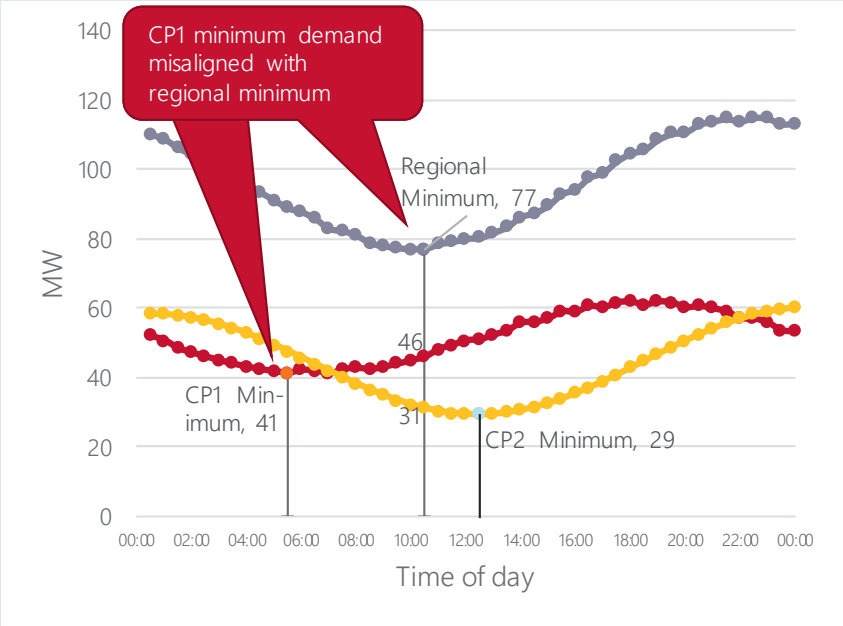
The former historical trend method projected forward CP demand history, with the regional reconciliation incorporating drivers not modelled at the CP level.

The new method links CP demand growth to:

- a spatial population forecast (typically LGA), paving the way for factoring in customer composition (residential, business, industrial, agricultural).
- Spatial DER projections at postcode level.

COVID19 brings new challenges to reconciliation methodology

Example 2020 CP and regional demand



Network planners require both:

- Individual CP demand (non-coincident means independent of the rest of the network)
- CP demand coincident with regional demand

Basic reconciliation

By design, the CP forecast produces non-coincident CP demand, so historical diversity factors are used to calculate coincident demand in future years:

Diversity factors 41/46 = 0.89 29/31 = 0.93

If CP1 Yr 2021 non-coincident forecast = 40, then

2021 CP1 unreconciled coincident demand = 40/0.89 = 45MW

If 2021 CP2 unreconciled coincident is 30 MW, the total is 75 MW. This must be adjusted to match a 2021 regional forecast of 72 MW, requiring an adjustment down by 3 MW overall.

Additional reconciliation step to reflect COVID-19

The above basic reconciliation should be enhanced to reflect spatially diverse impacts from COVID-19, such as changed res/bus demand (the work-from-home phenomenon) and differing industry impacts (example: heavy industry vs tourism)

The plan

AEMO will release a draft CP forecast, and with it a strawman approach to addressing COVID19, and then work with NSPs to jointly confirm the reconciliation methodology.

Stakeholder discussion

- (Slide 6) FRG feedback/experience on population growth as spatial demand driver?

- (Slide 7) Feedback on allocating regional COVID-19 impact to CP's via allocation of CY2020 CP specific impacts

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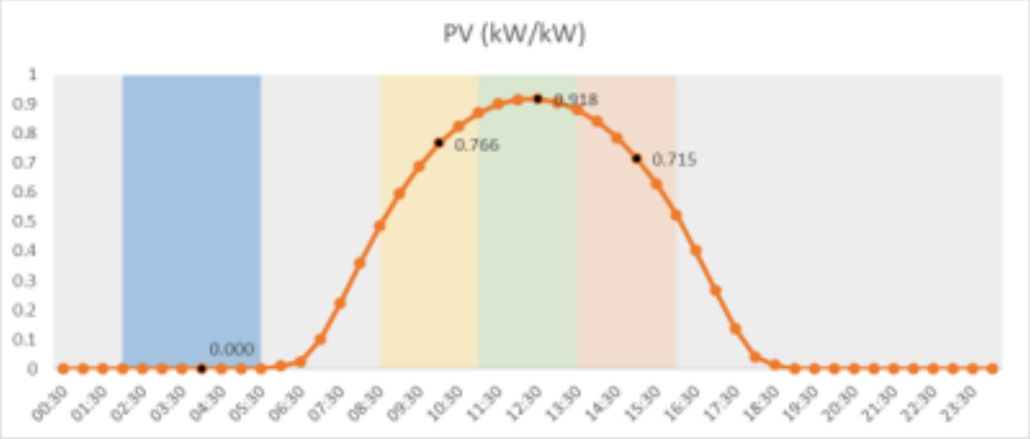
Appendix

How the CP demand model differs from the Regional demand model

The regional demand uses a single model to simulate demand for every future half hour for 30 years. But the method doesn't computationally scale well to connection points.

In contrast, the new connection point demand methodology breaks up demand into combinations of five defined periods and three seasons, to simulate demand for ten years.



Example: Seasonal {Summer, Winter, Shoulder}
+ Time of day {02:00 - 06:00, 06:00 – 11:00, 11:00 – 13:00, … }

Defined periods efficiently accommodate impacts of behind the meter generation and new technologies. It's expensive to simulate every half hour.

Multiple 'defined periods' allows the timing changes of maximum or minimum demands to be explicitly assessed.

A contribution factors rates what proportion of a 1 kW capacity applies during a defined period. It differs by technology (PV, EV, battery etc).

Method performance will be tracked via FAR