Meeting Notes: Network Planning and Demand Forecasts

Date: 1:30pm, Friday, 16 October 2015

Location: Ann Street, Fortitude Valley and Lake Street, Cairns

Invitees:

Ergon Energy: Graeme Finlayson – General Manager AER; Blake Harvey – Strategy & Policy Engineering Manager; Peter Kane – Network Forecasting Manager; Shane Brunker – Lead Econometrician/Forecasting; Sara Collins – Community Strategy Manager; Rubina Smith – Community Engagement Manager.
IN CAIRNS: Julie Heath – Community Strategy Advisor.

External Stakeholders: Bruce Cooke – Solar Citizens; Jonathan Pavetto – SAS Group; Sharon Denny – Australian Sugar Milling Council; Ian Johnson – Queensland Farmers Federation; Rose McGrath – Queensland Council of Social Services; Jennifer Brownie – Far North Queensland Electricity Users Network; Phil Pollard and Des Reppel – Australians in Retirement; Jan Crase – Regional Development Australia Far North Queensland & Torres Strait Inc

MEETING ITEMS

Our annual planning review

An overview was provided of Ergon Energy’s Distribution Annual Planning Report 2015-16 to 2019-20 (DAPR) published online at the end of September. The DAPR provides information around: load forecasting, demand management, new capacity investments, asset renewals, reliability, and supply quality in operating and managing the network. It aims to provide stakeholders with an insight into the key challenges Ergon Energy faces and the responses planned for the next five years.

These challenges were discussed in the context of our strategic themes: to support an ‘effective market’ and deliver an ‘efficient service’. We went over our new planning criteria (the shift away from asset duplication towards maintaining reliability standards through response/restoration management), the impact solar energy is having on the daily demand profiles of the network (system-wide and feeder level) and the potentially hidden demand, and the important role the energy services market is playing (through incentives/tariffs) in helping us respond to demand in a more cost effective way (non-network alternatives).

The DAPR is an important document for increasing the transparency of our investment decisions, with considerable data now available for interested parties to utilise via the links.

Action: To ensure the DAPR is a useful document for stakeholders going forward, we are keen to receive any feedback on the content/presentation of the data.
The future outlook in demand

With summer peak demand our key driver of augmentation investment, we invest significant time in forecasting demand growth. In the meeting we discussed our ‘top down’ / ‘bottom up’ approach.

The ‘top-down’ forecast is an econometric ten-year (but updated annually) system maximum demand forecast (inputs include economic growth through the Gross State Product, temperature and air conditioning sales). This is used to test our demand forecasts at the zone substation level: using the sum of these spatial ‘bottom up’ forecasts. This allows adjustments to be made to get the most accurate and reliable indicator of future demand in the network. This is then used to assess the potential for a constraint in future years on a specific network area. This supports the investment planning process that determines the best possible network or non-network solutions.

The regional level, spatial forecasts consider such things as solar PV take up, the local load history and any customer intelligence. Ergon Energy has a dedicated team who engage with large energy users, and those who are proposing major developments, to ensure we are anticipating any potential new ‘block’ load or other changes that could impact upstream demand.

The trends in peak demand experienced across the network over recent years were discussed. There has been significant change in the way the network is being used and looking forward we expect further changes with the two-way flows of electricity on the network increasing. Ergon Energy is expecting the number of solar systems to increase from 110,000 to at least 162,000 (or 518MW) over the next five years (note number corrected as accumulative from the meeting).

As a slowdown in the state’s economic indicators (a key indicator of electricity demand) was apparent when we were preparing our Regulatory Proposal for submission in October 2014, Ergon Energy used the lower range of our 2014 demand forecasts to formulate our investment plans (an average low growth rate of around 0.5 to less than 1%). This meant we did not need to revise our augmentation investment plans as our formal demand forecasts were adjusted and we revised our Regulatory Proposal (in June 2015), we did however put forward cost savings. Our current best estimate in our 2015 forecast is in line with the Australian Energy Market Operator’s (AEMO) base forecast – both are predicting slightly stronger growth outcomes than the low growth scenario that we have used to develop our capital investment forecasts.

The data in the link Transmission Connection Point Forecasts.xls (MS Excel Document) provides the 50% Probability of Exceedance (PoE) of demand in MW for each of our 61 Transmission Connection Points. Aggregated forecasts per region are not provided, but these forecasts can be summed to provide demand forecasts for each of our six planning regions.

**Action:** Ergon to confirm the forecasts used in the calculation of Long Run Marginal Costs.

The demand charges in Ergon Energy’s network tariffs are linked to the incremental network costs associated with catering for the peak in demand in the summer months. These charges are currently based on a proportion of these Long Run Marginal Costs (LRMC), calculated at the time of the October 2014 Regulatory Proposal. The value is based on the demand forecast used for the October proposal.

**Action:** Ergon to consider a request to provide further information about our energy, customer connection and other forecasts. Please let us know if you have specific areas of interest in these topics.

**Australian Energy Regulator’s (AER) Final Determination**

Network augmentation (made as a result of demand) is only a proportion of Ergon Energy’s overall investment program, which has been reviewed by the AER in order for it to determine Ergon Energy’s distribution revenue allowance for the period from 2015 to 2020. Since this meeting the AER has published its final decision on our revenue allowance (29 October 2015).
Follow Up Briefing
Our Distribution Annual Planning Report and Demand Forecasts 2015-20
16 October 2015

Agenda

Our annual planning review
Blake Harvey
Strategy & Policy Engineering Manager

The future outlook in demand
Peter Kane
Network Forecasting Manager

AER’s Final Determination
Shane Brunker
Lead Econometrician/Forecasting

Graeme Finlayson
GM AER
This DAPR presents the outcomes from Ergon Energy’s distribution annual planning review for the forward planning period 2015-16 to 2019-20.

It details planning outcomes for:

- subtransmission and distribution augmentation
- demand management
- asset replacement and refurbishment
- reliability and quality of supply.
The DAPR highlights

- Reduction in forecast expenditure
- Steady forecast in low load growth
- Significant reductions in augmentation
- Improved distribution feeder performance
- Strong progress in alternative investment
- Sustained renewal investment
- Strong reliability performance

Strategy Map 2015-2020

Value Creation

Financial & Shareholder
- Aligning strategies to the expectations of our shareholders

Customer
- To provide a uniquely satisfying customer experience

Internal
- To drive efficient processes...

People, Culture, Learning & Growth
- To help our people...

Effective Market

- Achieving competitive and affordable electricity market

Efficient Service

- Delivering customer value through consistent and strong performance
- Productivity improvements to deliver sustainable Financial return
- Reducing network charges to below inflation
- Reducing network operation expenditure to balance service and customer satisfaction
- Efficient project delivery and timely delivery of capital and operating programs

 ALWAYS SAFE

Success is built on our Values: Safety, Professionalism, Integrity, Respect, Innovation and Teamwork
Network optimisation

Elements of performance:
- Security
- Quality
- Reliability
- Availability
- Safety
- Efficiency
- Profitability
- Customer value

Customer feedback driving approach

<table>
<thead>
<tr>
<th>Importance</th>
<th>Performance</th>
</tr>
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<tbody>
<tr>
<td>Jan - Jun 11</td>
<td>9%</td>
</tr>
<tr>
<td>Jul - Dec 11</td>
<td>23%</td>
</tr>
<tr>
<td>Jan - Jun 12</td>
<td>23%</td>
</tr>
<tr>
<td>Jul - Dec 12</td>
<td>11%</td>
</tr>
</tbody>
</table>
New planning criteria

Focus has shifted away from asset duplication towards response and restoration management.

The new criteria comprises two parts:

- mandatory investment, for a base level of network security, known as the Safety Net
- reliability based investment, for security improvements above the Safety Net requirements, based on a Value of Customer Reliability (VCR) approach.

Service Safety Net targets

<table>
<thead>
<tr>
<th>Area</th>
<th>Targets for restoration of supply following an N-1 Event</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regional Centre</td>
<td>• Less than 20MVA after 1 hour;</td>
</tr>
<tr>
<td></td>
<td>• Less than 15MVA after 6 hours;</td>
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<tr>
<td></td>
<td>• Less than 6MVA after 12 hours; and</td>
</tr>
<tr>
<td></td>
<td>• Fully restored within 24 hours.</td>
</tr>
<tr>
<td>Rural Areas</td>
<td>• Less than 20MVA after 1 hour;</td>
</tr>
<tr>
<td></td>
<td>• Less than 15MVA after 6 hours;</td>
</tr>
<tr>
<td></td>
<td>• Less than 6MVA after 18 hours; and</td>
</tr>
<tr>
<td></td>
<td>• Fully restored within 48 hours.</td>
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</tbody>
</table>

Reliability of supply

![MSS SAIDI Rolling 3 Year Average Network Performance](chart1)

![MSS SAIFI Rolling 3 Year Average Network Performance](chart2)
Our average daily load shape

Feeder profile changing over time
Storm event exposing hidden demand

Residential energy usages – solar part of the future

During the year the fall in the amount of electricity being used by the average household without solar energy systems (Households without solar) has continued. At the same time, the energy being used by the households with solar has continued to increase on average as the profit of the households with solar has increased.

* The average residential consumption is based on Ergon Energy Queensland Pty Ltd accounts on a combination of regulated tariffs, existing household with solar energy systems installed. The second trend line shows households with solar energy systems installed.

Ergon Energy has seen a dramatic increase in the number of residential solar energy systems connected to the grid over recent years, with over 50,000 new connections in 2018. We remain committed to ensuring the network is more valuable in supporting the network in the future.
Risk Identified, quantified
Time of day and year quantified
Deemed products quantified
DM achievements quantified
Forecast correlated with DM outcomes

Market engagement

Responsibility planning
Responsibility Partners
Responsibility Forecasting

Cashback Incentive Search
Please enter your 11 digit National Hering Identifier (NHI) in your area.
Note: search


Mapping

In development:
- State incentive map, Ergon Incentives apply, customer side incentives
- State capacity map, where capacity limits may apply
- Other maps are also in development.

Note: maps are examples, data validation under way to ensure visualisation is accurate, i.e. capacity constraints have not been verified
Peak demand reduction

Achievements of the Non-Network Alternative program included:
• 13.6MVA of demand reduction achieved in 2014-15
• 139MVA of demand reduction achieved for the 2010-15 regulatory control period
• use of market mechanisms to engage the energy services market.

Our asset renewal plans (>$2million)

• Refurbish Middle Ridge-Yarranlea 110kV Feeder 734
• Rebuild East Warwick 33kV substation.
• Replace Pioneer Valley substation load control injection equipment.
• Frenchville RTU Age Replacement.
• Replace Biloela substation load control equipment with 66kV injection unit.
• Replace Gladstone South substation load control equipment.
• Marian South substation establishment
• Marion South feeder exits development
• Replace Mackay bulk supply substation RTU
• Refurbish Jarvisfield substation switchboard, RTU and protection
• Replace Dan Gleeson substation RTU and Protection
• Replace Macknade Transformer and associated switchgear.
• Replace Hartley Street substation aged RTU, protection and 22kV switchboard
• Biloela Bulk Supply Point - Substation Augmentation
• Gladstone South Substation - Install 2x20MVA transformers
**Network forecasting**

The Ergon Energy Network Forecasting team produce a number of standard forecasts for operational and regulatory purposes:

**Demand Forecasting**
- System
- Transmission-Distribution Connection Points (TNSP interface)
- Spatial (Zone Substation)

**Customer Numbers**

**Energy Forecasting**
Demand forecasts – Growth and Risk

Growth

• Ergon Energy is taking a conservative approach to economic growth (GSP - Gross State Product)
• Consistent with Queensland Treasury forecast (Budget 2014) until post 2017 except for one period (2015-16)
  o 2015-16 LNG projects responsible for increase in balance of trade
  o primary connections in off Ergon Energy Network supply resulting in EE using lower economic forecast in 2015-16 (Treasury’s 6% to EE 4% GSP)
• Current medium peak demand forecast same as last year’s low growth forecast for years 2014-15 through to 2018-19
• 4% (~100MW) drop in peak demand 2015-16 forecast (medium growth) compared to last year’s peak demand forecast (medium growth) due to softening economy
• AER accepted that Ergon’s system demand forecast reflected a "realistic expectation of demand" as per NER criteria

Risk

• Conservative approach moves risk from customers to Ergon Energy
• Risk is better managed by Ergon Energy through best business practice
• Improved utilisation and flexible security measures

1 Queensland Treasury 2014 Budget-Tuesday, 3 June 2014

Forecasting process

• Ergon Energy uses a combination of ‘top-down’ and ‘bottom-up’ approaches to provide a robust forecast methodology.
• The ‘top-down’ forecast is an econometric ten-year system maximum demand forecast based on identified factors which affect the load at a system-wide level.
• The System Maximum Demand forecast provides a benchmark, against which the aggregated spatial forecasts ‘bottom-up’ are reconciled.
• Further to the System Maximum Demand, Ergon Energy also produce a ten-year maximum demand forecast for all zone substations which are aggregated to bulk supply substations and transmission connection points.
The Final Determination and forecast made by the AER in 2010 was much higher than the actuals over the five year forecast.

Significant changes in Ergon Energy’s network customer movement, behaviour, technology uptake (PV...), response to pricing and from the economy in general.

The system forecast reflects the economic position of Queensland as the Gross State Product is one of the key proven drivers of the system and regional network demand.

The network experience in recent years...

While the Queensland economy has slowed post the boom in resource investment, and this year’s coincident system-wide TC peak of 2,382MW showed demand overall largely flat, we are forecasting, in our best estimate, low level growth. The AER has accepted this forecast as reflecting a "realistic expectation of demand" as per NER criteria.
Reset RIN comparison demand forecasts

Comparison of Ergon Energy’s and AEMO System Demand Forecast

- AEMO MW
- EE Reset RIN Base Forecast
- EE Latest
- EE Reset RIN Low Scenario

2015 AEMO FORECASTING REPORT

Figure 2

Summer rates of change in MD

Detail available

**Bulk Supply Substations Forecasts.xls** (MS Excel Document, 0.4MB)

**Zone Substation Forecasts.xls** (MS Excel Document, 3.5MB)

**Transmission Connection Point Forecasts.xls** (MS Excel Document, 0.1MB)

**Subtransmission Feeder Forecast.xls** (MS Excel Document, 0.4MB)

**Distribution Feeder Limitations.xls** (MS Excel Document, 0.07MB)

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**How to read the data**

![Image of data reading instructions]
How to read the distribution feeder limitations maps

HeatMapKmzFileHelp.pdf
Feeder_HeatMap_FN.kmz
Feeder_HeatMap_NQ.kmz
Feeder_HeatMap_MK.kmz
Feeder_HeatMap_CA.kmz
Feeder_HeatMap_WB.kmz
Feeder_HeatMap_SW.kmz

Agenda

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The future outlook in demand

AER's Final Determination

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Augmentation investment

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<thead>
<tr>
<th></th>
<th>2015-16</th>
<th>2016-17</th>
<th>2017-18</th>
<th>2018-19</th>
<th>2019-20</th>
<th>Total</th>
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<tbody>
<tr>
<td>Asset Renewal</td>
<td>305,512</td>
<td>289,124</td>
<td>253,566</td>
<td>278,571</td>
<td>277,071</td>
<td>1,403,845</td>
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<tr>
<td>Corporation Initiated</td>
<td>166,167</td>
<td>169,345</td>
<td>170,606</td>
<td>125,573</td>
<td>128,922</td>
<td>760,613</td>
</tr>
<tr>
<td>Augmentation</td>
<td></td>
<td></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Customer Connection</td>
<td>216,795</td>
<td>227,808</td>
<td>238,744</td>
<td>246,730</td>
<td>253,990</td>
<td>1,183,868</td>
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<tr>
<td>Initiated Capital Works</td>
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<tr>
<td>Reliability and Quality</td>
<td>3,133</td>
<td>3,235</td>
<td>3,317</td>
<td>3,347</td>
<td>3,365</td>
<td>16,396</td>
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<tr>
<td>of Supply</td>
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<tr>
<td>Other System</td>
<td>40,966</td>
<td>29,994</td>
<td>19,192</td>
<td>26,714</td>
<td>23,679</td>
<td>140,544</td>
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<tr>
<td>Non-System</td>
<td>144,433</td>
<td>101,095</td>
<td>91,179</td>
<td>77,618</td>
<td>66,641</td>
<td>482,965</td>
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<td>Gross capital expenditure</td>
<td>877,006</td>
<td>820,401</td>
<td>776,604</td>
<td>758,553</td>
<td>755,668</td>
<td>3,988,230</td>
</tr>
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</table>

Thank you