Quarterly Energy Dynamics Q1 2019

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Highlights for Q1 2019 included:

1. **Demand** – hot summer in the NEM increased electricity demand.

2. **Wholesale electricity prices** – record high spot electricity prices in VIC & SA.

3. **Electricity supply mix** – increased solar generation due to new capacity; hydro output reduced due to dry conditions.

4. **Wholesale gas prices** remained high as gas-powered generation and oil prices rebounded.
Summary

A Warmest summer on record across Australia. Multiple heatwave events leading to periods of high demand (i.e. 24-25 Jan).

B NEM op. demand increased by 243 MW on average compared to Q1 18 despite large increase in rooftop PV output (~300 MW). Largest increase in NSW primarily driven by warmer weather in Jan. Largest time-of-day increase in underlying demand occurred during early afternoon, corresponding with increased cooling load.

C Demand records:
   • QLD all-time max demand record = 10,044 MW (+246 MW)
   • SA Q1 min demand record = 695 MW (-25 MW)
Record high wholesale electricity prices in VIC & SA

Summary

A Highest quarterly price on record in VIC & SA.

Highest energy price (prices <$300/MWh) in VIC, NSW and second highest in QLD SA & TAS.

B Contributors included:
1. Extreme price volatility in SA & VIC on 24 & 25 Jan
2. High underlying energy price, with contributors including:
   1. Hydro - Reduced hydro output due to dry conditions. Shift of ~800 MW to prices above $100/MWh.
   2. Gas prices – gas prices remained high during the quarter influencing bidding from GPG and other fuel types.
   3. Black coal - further shift in black coal offers, with ~800 MW shifted to prices above $100/MWh.
   4. Increased demand – hot summer increased NEM average demand by 243 MW, with higher demand peaks.
Jan 24 & 25: extreme pricing and load shedding in VIC

Summary

A  **Confluence of events** led to extreme pricing outcomes in VIC & SA, and load shedding in VIC.

B  **Pricing**: 24 Jan 19: VIC daily average price of $3,378/MWh, its highest on record. On 25 Jan, CPT was enacted, limiting extreme pricing outcomes.

Prices on these days contributed to ~$41/MWh (80%) of VIC cap returns for the quarter.

C  **Load shedding and RERT activated**: ~266 MW load shed 24 Jan and ~250 MW shed on 25 Jan.

D  **Contributors to price volatility**:
   1) High demand across both VIC & SA (record temps).
   2) Unavailability of thermal capacity (up to 1,600 MW).
   3) Relatively low VRE output.
   4) Constrained imports from NSW.

E  **GPG & hydro** ran at very high levels – 25 Jan was the highest VIC GPG day on record and the 3rd highest NEM GPG day.
Electricity price outlook continues to rise

Summary

A  Since Sep 2019, Calendar year 2020 swap prices have increased, particularly in VIC (+35%) and NSW (+24%). Most of the increase has occurred in underlying energy (prices <$300/MWh).

B  Price increases coincided with:
1) Gas – Expectations of continuing tightness in domestic gas markets (as highlighted in GSOO).
2) Coal – Sentiment for thermal coal prices to remain comparatively high into 2020.
3) Hydro – Low hydro dam levels and generation.
4) Renewables – Concerns over delays to connection of new renewable projects and grid congestion.

C  Despite VIC price volatility this quarter, only moderate increases in CAL20 cap prices. NSW & QLD flat; VIC increased by ~$3/MWh.
Solar surges; hydro dries up

Summary

A Increases for grid solar (+394 MW) & rooftop PV (+273 MW), decreases in black coal (-133 MW) and hydro generation (200 MW).

B Despite higher spot prices, hydro output 200 MW lower than in Q1 2019, reflecting dry conditions.

C GPG returns: majority of GPG increase has occurred during evening peak, with higher spot prices and declining solar output.

D Reduced black coal generation reflects daytime displacement by solar and shift into higher priced bands.
Generation mix by time of day

Change in supply by time of day – Q1 19 versus Q1 18
Sun shines on solar

Summary

A Large-scale solar met 5% of total midday operational demand, contrasting its contribution of 1% in Q1 2018.

More than 2,000 MW of new grid scale capacity has commenced generation since Q1 2018.

B In SA & QLD ~8% of demand met by large-scale solar, compared to almost no contribution in Q1 2018.

C The shape of VIC’s solar generation profile illustrates the impact of solar tracking technology.

During summer tracking systems capture more direct solar radiation for longer periods of the day.
Gas prices remain high as GPG and oil rebound

Summary

A  Q1 2019 prices up in all wholesale markets relative to Q1 2018; small reductions compared to Q4 2018.

B  Contributors to continuation of high gas prices include:
   1) Increase in demand for GPG output, up 13% compared to Q1 18.
   2) Rebound in price of crude oil over Q1 2019 (+18%).
   3) Record daily average flows to Curtis Island despite falling ACCC netback price.
   4) Extended Longford maintenance in March.

Source: ACCC, Bloomberg
Gas-powered generation rebounds

Summary

A  GPG rebounded from record low quarterly output in Q4 2018. Drivers included:
   •  High NEM spot prices resulting from periods of high demand coinciding with coal generator outages.
   •  Comparatively low hydro output due to dry conditions.

B  Increased peaking role for GPG was particularly evident in January 2019, with six of the 20 highest GPG days on record.

C  25 Jan 2019 was the: third highest NEM GPG day on record; the highest VIC GPG day on record; and the 6th highest SA GPG day
**Gas flexibility on tight NEM days**

**Summary**

A. Record high GPG days in Vic on 24 & 25 Jan in response to high electricity demand (and unplanned thermal outages)) and resulting record high wholesale electricity prices.

B. Role of gas storage: Iona also provided supply with almost 1 PJ being withdrawn between the 22 and 25 Jan.

C. GPG able to quickly obtain gas – 123 TJ/day increase in gas transferred south on South West Queensland Pipeline on 24 & 25 Jan, corresponding with reduced flows to Curtis Island.

Potential that generators called on interruptible gas contracts – LNG producers selling to GPG owners on the GSH.

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*Source of additional gas on high GPG days*

<table>
<thead>
<tr>
<th>Source</th>
<th>Average (TJ/day)</th>
</tr>
</thead>
<tbody>
<tr>
<td>VIC &amp; SA GPG (Jan average)</td>
<td>300</td>
</tr>
<tr>
<td>Iona withdrawals</td>
<td>500</td>
</tr>
<tr>
<td>Additional flows south on SWQP</td>
<td>400</td>
</tr>
<tr>
<td>Additional Longford production</td>
<td></td>
</tr>
<tr>
<td>VIC &amp; SA GPG (24 &amp; 25 Jan)</td>
<td>800</td>
</tr>
</tbody>
</table>

Note: Data compares January average results (excluding 24 & 25 Jan) to results for 24 & 25 Jan.
AEMO’s market interventions decrease

Summary

A Level of directions for system security in SA declined, with directions in place for 4.4% of the time, compared to 13% during Q4 2018. This represents the least time directing (for a quarter) since SA system strength arrangements were introduced.

B Curtailment of SA wind generation reduced to around 1%, due to:

• Increased availability of synchronous generation in the region.
• Comparatively fewer periods of high wind conditions.
• Changes to operating guidance which allows dynamic levels of non-synchronous generation.
Summary

A  Lowest hydro output in two years due to dry conditions over the quarter and low storage levels.

B  Prevailing flow on VIC-NSW was 52 MW north on average, representing a 203 MW swing compared to Q1 2018. Transfers south on VIC-NSW restricted due to changes to Snowy’s generation profile (resulting from dry conditions).

C  92% increase in flows south on Basslink compared to Q1 2018, due to reduced Hydro Tas generation.
Newer technologies increase FCAS market share

Quarterly FCAS costs

- Batteries
- Coal
- DR
- Gas
- Hydro

Raise FCAS supply mix

- Batteries
- Coal
- DR
- Gas
- Hydro

Summary

A  FCAS cost reduced by 33% on Q4 2018 levels

B  Drivers of reduced cost included:
   - Increased supply from batteries, which almost doubled their share of Raise FCAS markets
   - Increased supply from hydro generators as some providers returned to the market or lowered the price of their offers
   - Decreased FCAS demand – Contingency Raise was 7% lower and Regulation FCAS was ~10% lower.
Discussion