FORECAST CONGESTION IN THE NATIONAL ELECTRICITY MARKET

9 SEPTEMBER 2021

PURPOSE OF SESSION

To inform stakeholders about how congestion is forecast to change as renewables replace thermal generation.

These changes are why the ESB considers it imperative that we reform the transmission access arrangements.

SPEAKERS

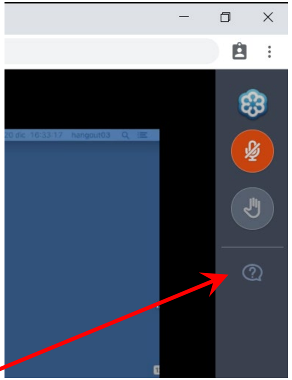
- Dr Kerry Schott, Chair, Energy Security Board
- David Swift, Deputy Chair, Energy Security Board
- Jason Mann, Senior Managing Director, FTI Consulting
- Jess Hunt, Senior Advisor, Energy Security Board

FACILITATOR

- Mark Paterson, Chief Strategy Officer, Strategen

WEBINAR LOGISTICS

- This public webinar is being recorded. The >500 registered participants are in listen-only mode.
- We will actively invite your clarifying questions at key points:
    - Please enter questions in this field as we proceed through the content (please double check clarity); and,
    - The expert panel will answer as many clarifications as possible in the time available.
- Following today's event, we will provide participants with:
    - A link to the event recording and a copy of the slides; and,
    - A thematic summary of questions and answers.



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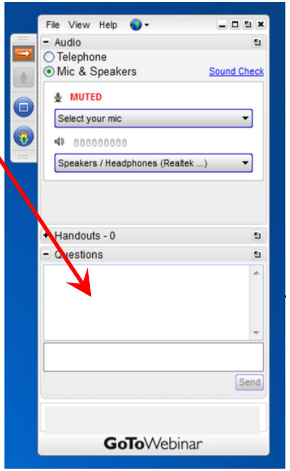

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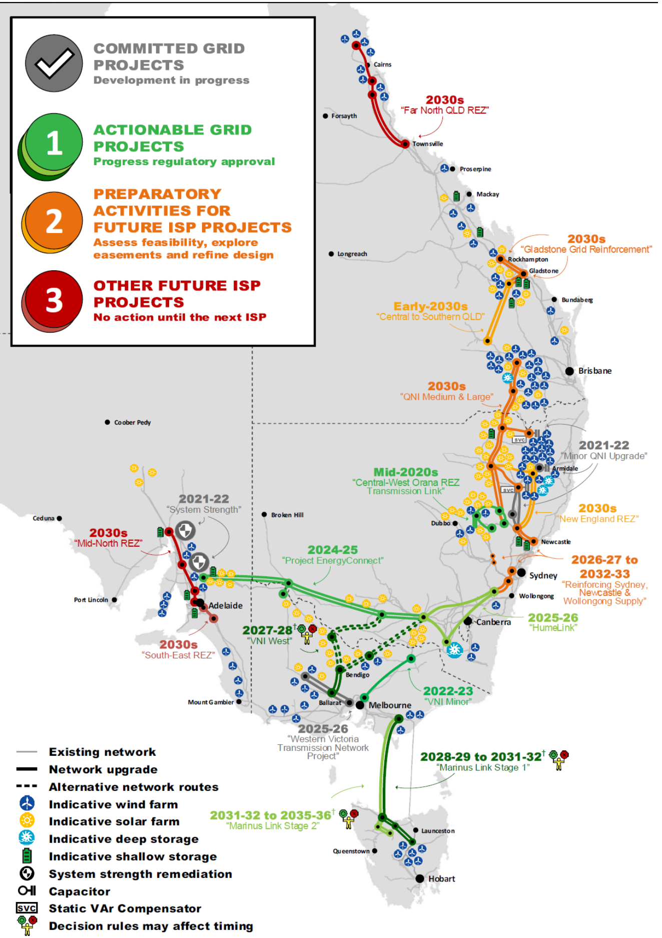
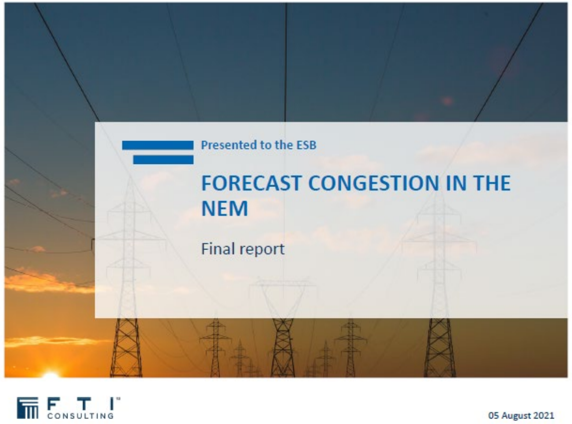


CONTEXT – THE AUSTRALIAN SITUATION AT A GLANCE

- Congestion is a normal feature of a power system with high levels variable renewable energy.
- It is inefficient to build a transmission system that could carry all the power generated at the most sunny and windy of times as there is more than enough electricity to meet demand at those times.
- The NEM access regime means that it can be profitable for new generators to locate in parts of the network that are already full
  - This is a very unusual feature of our market design.
- The challenge for Australia is to connect high levels of new generation, mainly renewables – it is a world leader in this.

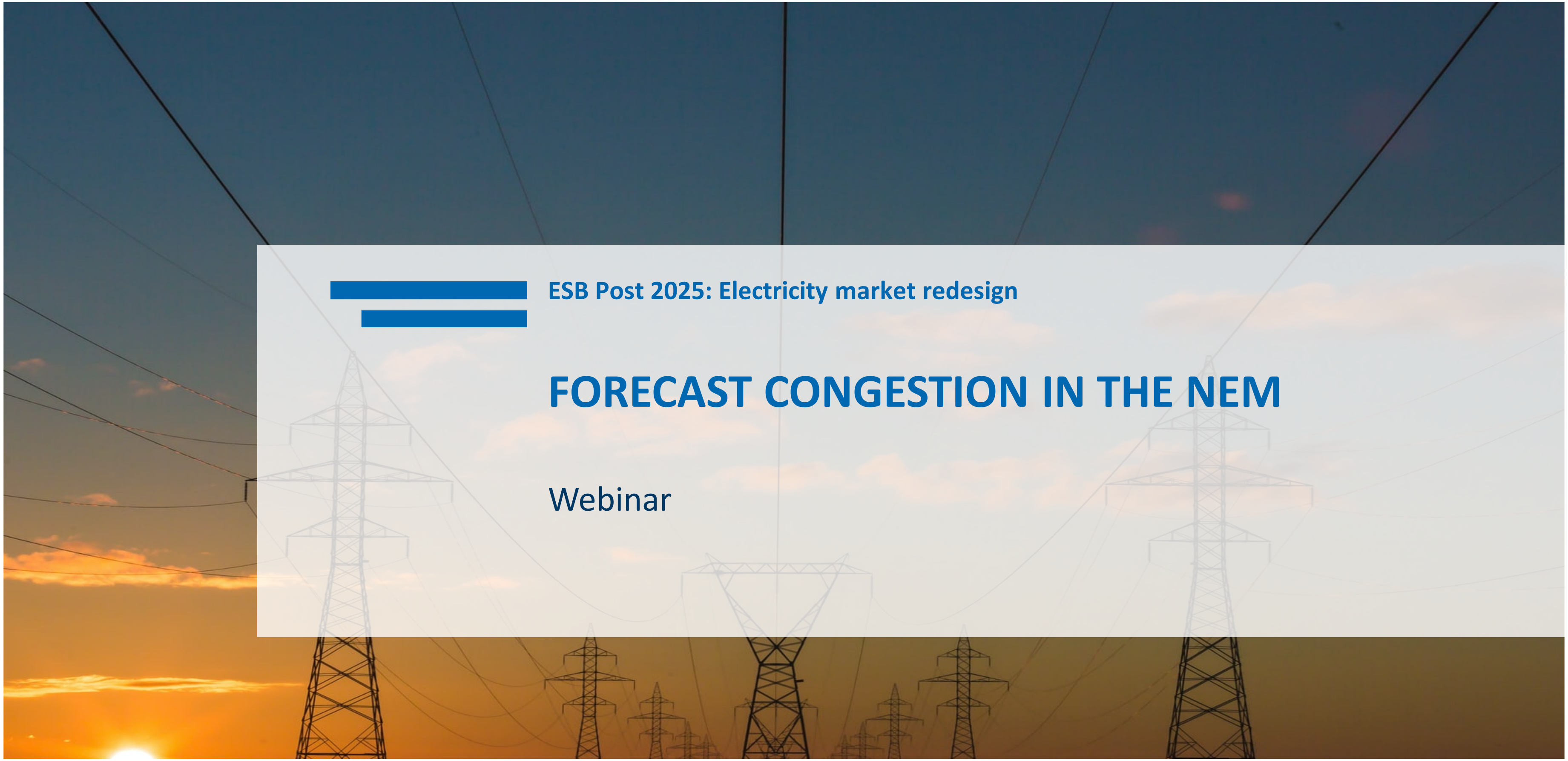
WHY DID THE ESB PROCURE THIS ANALYSIS?


Presented to the ESB
FORECAST CONGESTION IN THE NEM
Final report
FTI CONSULTING
05 August 2021

- Stakeholders have questioned whether congestion is a sufficiently large problem to warrant transmission access reform
  - Rather, we should focus on improving the connections regime and building new transmission
- Analysis aimed to explore the extent of congestion in 2030.
- A congested network is more likely to experience low marginal loss factors and technical difficulties in connections.

FTI's results reflect a best case scenario

- Generation and transmission from step-change scenario (2020 ISP). Current investment levels are 27% above the step-change scenario.
- Modelling assumes efficient placement of renewable generation and completion of network investment.
- Modelling assumes parties bid their short run marginal cost. Alternative bidding practices will increase the costs.
- Modelling excludes congestion associated with network outages, which account for a substantial portion of the costs of congestion.



ESB Post 2025: Electricity market redesign

FORECAST CONGESTION IN THE NEM

Webinar

FTI CONSULTING

9 September 2021

Agenda

Introduction to congestion in the NEM

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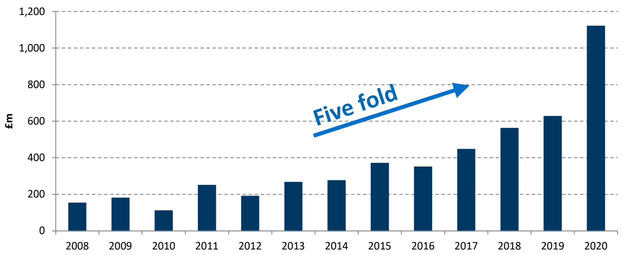
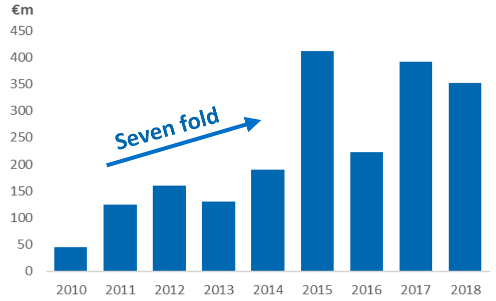
The increase in congestion cost is a global phenomenon – increasingly an issue as more distantly located renewables generation connects

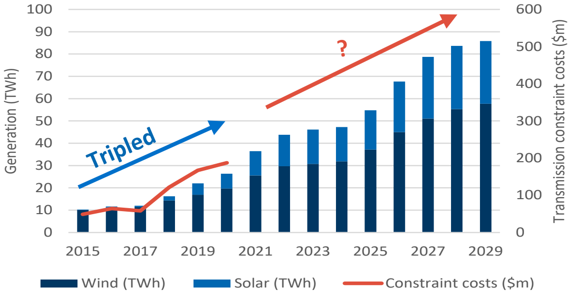
GB transmission constraint management costs



Germany congestion management costs



NEM constraint costs



Sources: 1) ESO MBSS data; Forecast based on ESO NOA6 modelling; 2) Bundesnetzagentur, Monitoring reports, 2010-2019, (link). 3) AEMO Quarterly Energy Dynamics - Q4 2020 for historical data; AEMO data dashboard for 2021 data; AEMO 2020 ISP generation outlook for forecast data.

Globally – two broad market design philosophies have emerged as the way to manage congestion

Congestion management approach #1:
"Leave to the SO"

- Wholesale electricity market is "unconstrained" and has single energy price…
- …market "ignores" transmission constraints.
- Congestion is resolved *outside* the wholesale market by local system operator….
- ….by making "constraint side payments" to chosen market participants located at certain critical points
- Costs of congestion resolution socialised across market

Congestion management approach #2:
"Price it in the market"

- US and NZ wholesale market are locational marginal pricing…
- ….market prices take account of transmission constraints.
- Prices vary by each node (with lower prices in export constrained areas)
- Market therefore resolves congestion – no need for additional SO interventions

…however, the NEM has an unusual approach to congestion management

Congestion management approach #3:
"Regional Reference Node"

- The wholesale price for each region is determined at the RRN which is sited at the point where demand is usually highest in the region.
- This price is then applied to the whole of the region.
- Participants behind a constraint are constrained off – but received no compensation

- **Unlike the European model**, the merit order and wholesale price includes some of the impact of transmission constraints (as constrained off plant cannot bid into the market)
- **Unlike the US/NZ model**, only one price is paid, - paid to most market participants that generate in that price region regardless which side of constraint located

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The congestion management approach in the NEM design is ill-suited to the large scale roll out of renewable generation

1 **Inefficient investment decisions**

- Because each region has a single clearing price, **investors may not consider the impact of the transmission network in siting decisions fully**…
- ….other policy measures (e.g. connection charges) unlikely to fully mitigate this
- This could lead to a higher cost to consumers, either through a higher transmission cost or a congestion impact on prices.

2 **Inefficient operational decisions**

- With congestion, generators will have an incentive to submit bids into the market that **diverge significantly from their marginal cost** to avoid being constrained off (this is known as “disorderly bidding” in the NEM).
- Highly unusual feature to design wholesale market that provides, in some circumstances, strong incentives for participants to not reveal marginal costs in bids (e.g. bidding -$1,000). Means will lose merit order and cause operational inefficiency.

3 **Transfer of rent from consumers to generators**

- The clearing price for the entire region is set by the **additional unit required to meet demand at the Regional Reference Node**.
- This likely leads to a higher price and thus cost to customers (i.e. an overall transfer of rent from generators to consumers, although specific generators may also be affected).

It is in this context where we have been asked to assess the likely materiality of congestion in the NEM in the year 2030

Overview of our methodology

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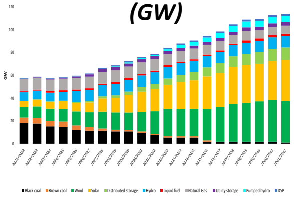
Our modelling approach includes two-stages: first to determine the optimal annual capacity mix and second to optimise the hourly dispatch

Inputs	**Long Term capacity expansion model**	**Short term dispatch optimisation model**	**Output**
AEMO's ISP and ESOO Step Change assumptions (demand, transmission, supply, costs, thermal retirements) **AEMO stability and thermal constraints**	**Our Long Term model determines the optimal capacity mix** to meet the capacity requirements minimum cost	**Our Short Term model determines generation profile and prices on an hourly basis** Model is run twice, with the second run incorporating stability and thermal constraints	**Net impact** equals difference between the models with constraints… …and version of the model without constraints

Most recent ISP and ESOO inputs

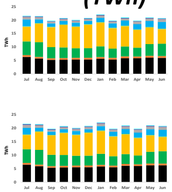
We rely on the ISP's Step Change scenario assumptions

NEM installed capacity (GW)



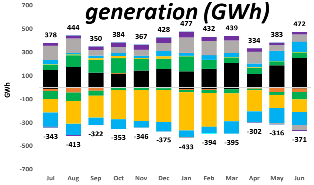
Up to 2042

NEM total generation (TWh)



2030 only

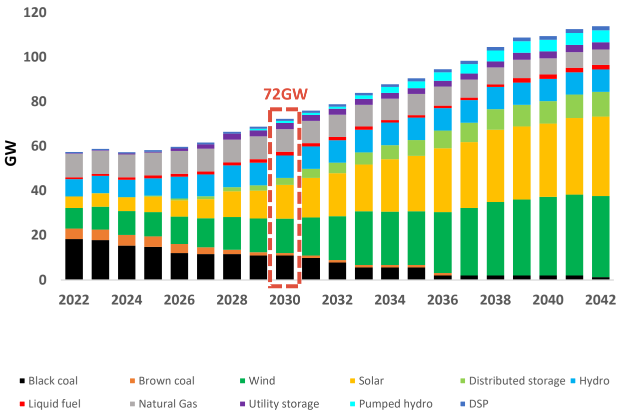
Net impact of constraints on NEM generation (GWh)



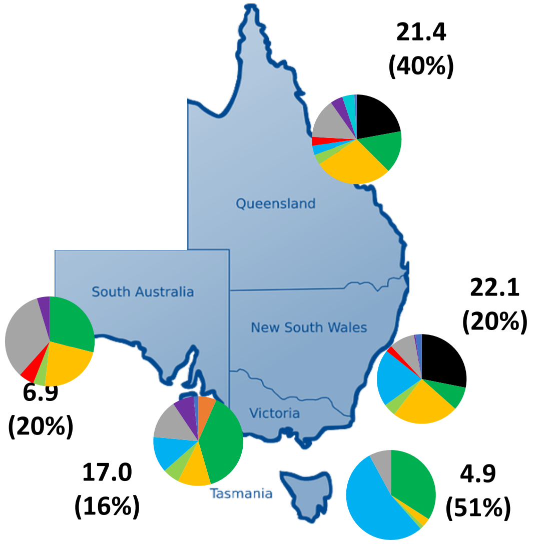
Notes: (1) Transmission investment profiles taken from the ISP; (2) All outputs from the model are presented in real 2020 terms; (3) the Short Term model calculates outcomes based on an SRMC basis.

We project that wind and solar capacity will increase by over 200% to 31GW by 2030 – this is consistent with AEMO's Step Change forecast

NEM installed capacity projected over 20 years, GW



2030 installed capacity by region and technology, GW (% increase from 2022)



- Installed capacity of 72GW in 2030.
- New wind and solar progressively replaces retiring coal capacity.
- Wind and solar constitutes over 40% of total installed capacity by 2030.

Note: (1) We have verified our long term forecast by comparing to AEMO's own forecast. The forecasts are broadly consistent, but small differences appear due to: i) updates to AEMO's ISP assumptions (July 2020) and AEMO's ESOO assumptions (December 2020); and ii) differences of categorisation (for example, Snowy is categorised as pumped hydro in our model and as utility storage by AEMO). Rooftop solar capacity is excluded.

Key results from our modelling

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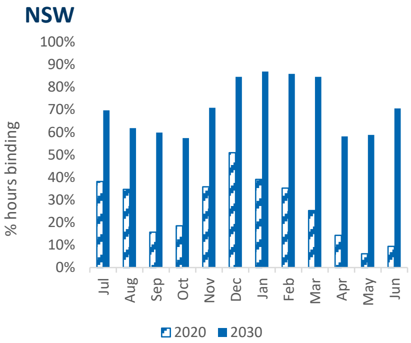
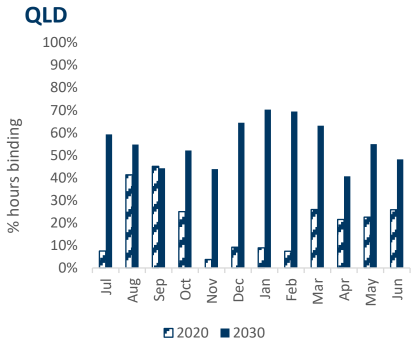
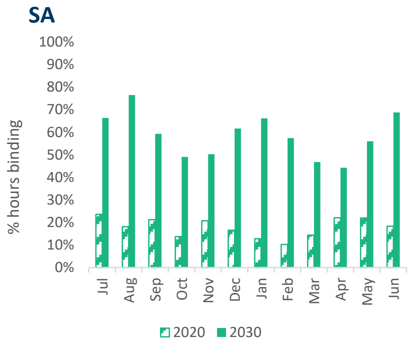
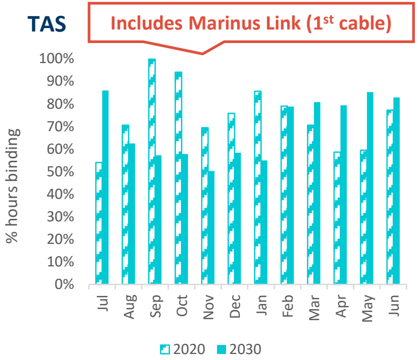
We project network constraints to occur frequently over the year, with peaks during summer periods

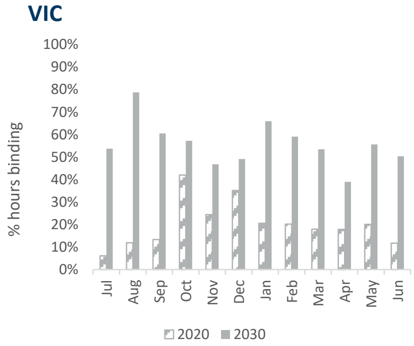
Percentage of hours per month with at least one constraint binding by state











- Congestion is expected to significantly increase in the next ten years in all states other than Tasmania.
- Excluding Tasmania, the average % of hours per month with at least one constraint binding is 60% in 2030 compared to 21% in 2020.

Note: Charts display the number of hours in a year in what at least one constraint binds; Both the 2020 and 2030 figures relate to System Normal conditions
Source: AEMO's monthly constraint reports 2019 & 2020. FTI analysis.

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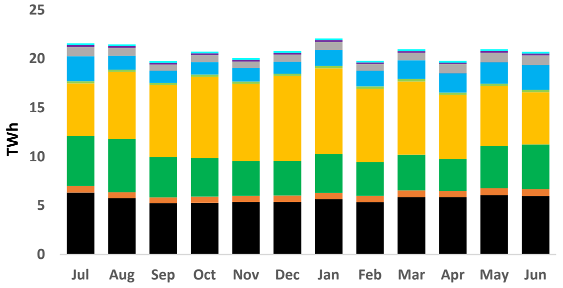
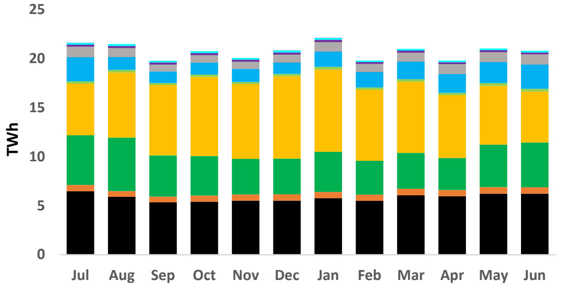
We assess which generator units would run in scenarios with and without constraints to show the difference in dispatch profiles

NEM total generation in 2030, TWh

Without network constraints

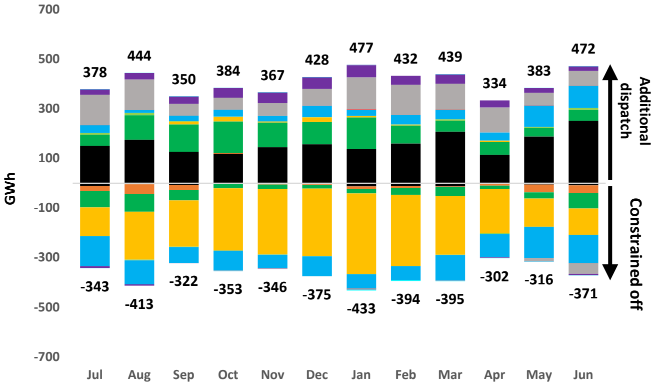


With network constraints



The impact of constraints on generation, GWh

With - without network constraints

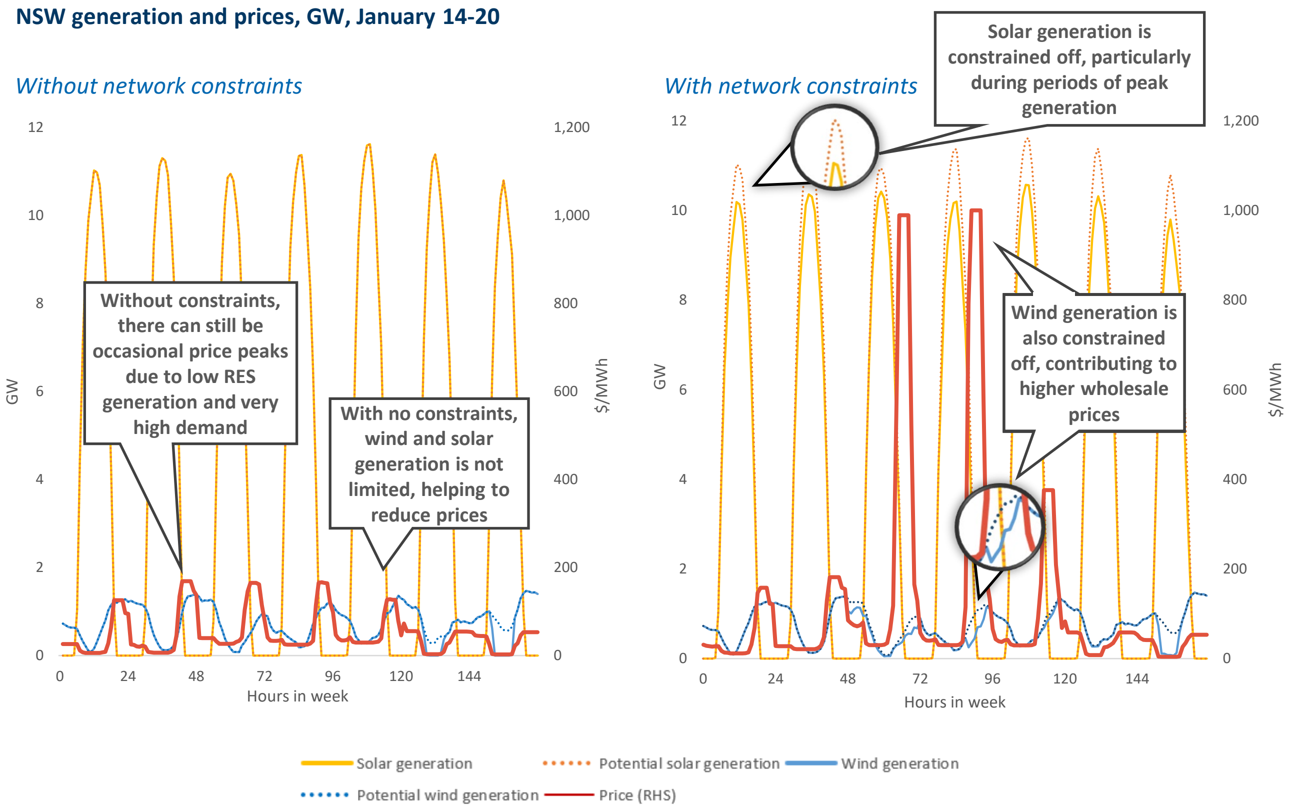


- With network constraints, solar is typically constrained off, while additional thermal generation is dispatched in its place.
- Approximately 2.5 TWh of solar is constrained off, in addition to 1.0 TWh of hydro…
- … compared to 3.0 TWh of thermal generation which is dispatched instead.

▪ Black coal ▪ Brown coal ▪ Wind ▪ Solar ▪ Distributed storage ▪ Hydro
▪ Liquid fuel ▪ Natural Gas ▪ Utility storage ▪ Pumped hydro ▪ DSP

Note: The total positive and negative values in each month are not exactly equal due to: (i) differences in storage (battery and pumped hydro) generation and load profiles, resulting in different charging requirements; (ii) differences in auxiliary loads; and (iii) losses on the system (grid and storage efficiency cycle).

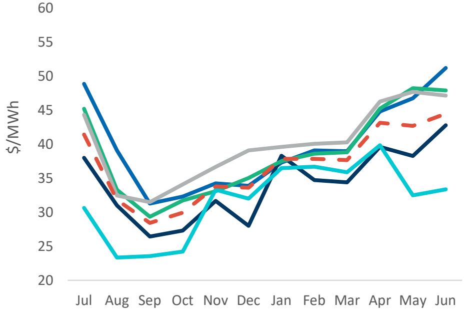
Wind and solar generation are key drivers of congestion, which may contribute to price spikes



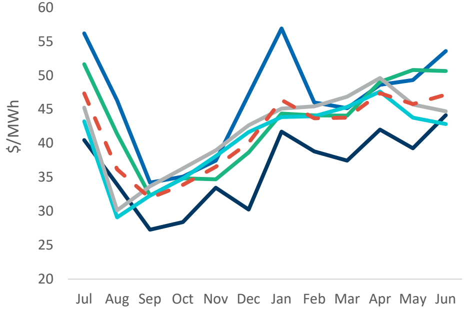
Constraints lead to higher prices, and may lead to price spikes in specific periods when the system is under stress

Time weighted prices, $/MWh

Without network constraints

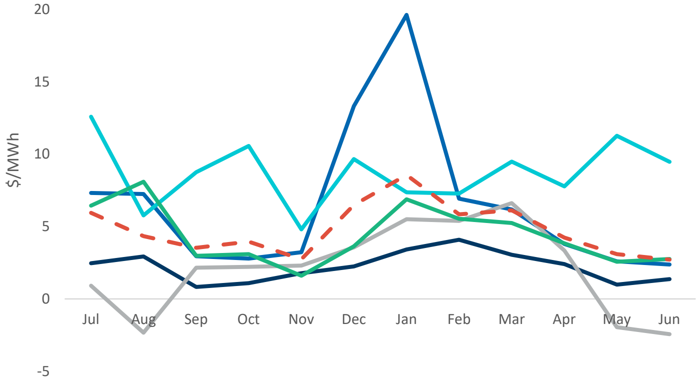


With network constraints



Impact of constraints on time weighted prices, $/MWh

With - without network constraints



- Constraints generally lead to higher prices in each state each month. The average increase in price across each state is $5/MWh.
- The prices presented are determined using SRMC bidding methodology and are therefore likely to be conservative.
- We also impose a price cap of $1,000/MWh to prevent infrequent but significant price spikes at the Market Price Cap from biasing the impact of congestion disproportionately.

QLD NSW TAS VIC SA Average

Note: *The negative price differentials observed in Vic are driven by differences in hydro behaviour in Tas. This arises as hydro units located in Tasmania optimise their water storage levels differently between the two scenarios which affects the water value (i.e. the future value of water held in storage). Without constraints, Tasmanian hydro units optimise to generate at its maximum capacity to serve peak demand. However, when constraints are introduced, hydro units generate less output per hour, meaning that it generates for more hours to utilise its fixed water resource. In turn, this results in lower water values which benefits Vic, particularly during winter peak periods when hydro output is higher.*

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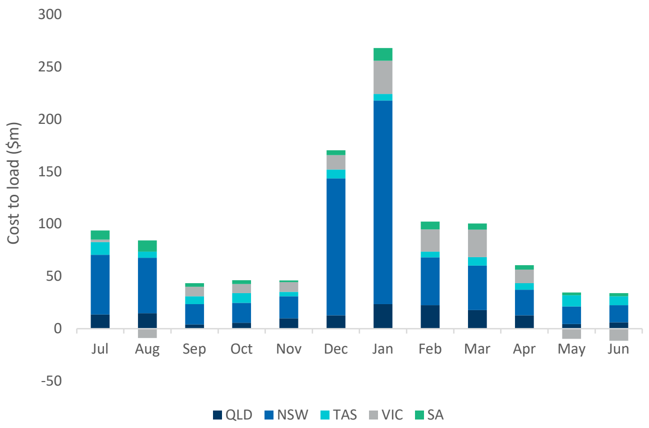
Constraints lead to higher consumer costs, in particular during periods of system stress

Increase in the cost to load by region in 2030

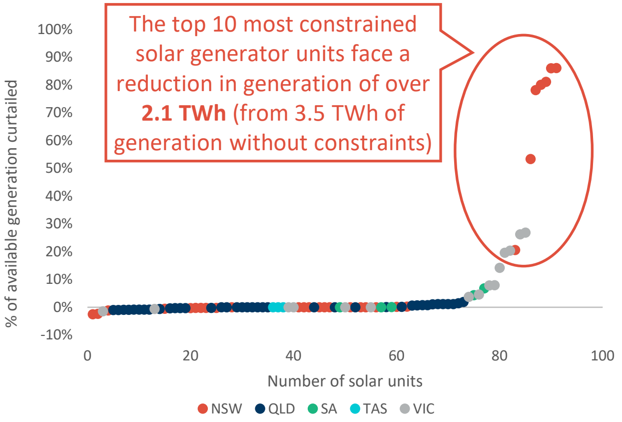


- Congestion increases cost to load consistently throughout the year, with an average increase of $18m per state per month.
- The total increase in cost to load due to constraints is **$1.05 billion** in 2030.

Note: *As stated previously, our modelling approach assumes that generators bid at their SRMC. If strategic bidding is included, the cost to load estimate is likely to be higher.*

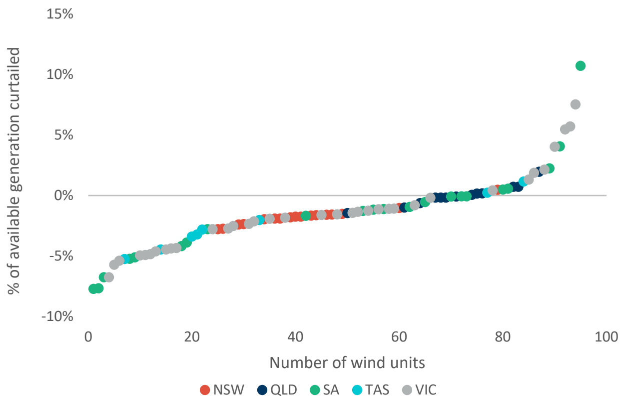
Additionally, generators may face significant loss of revenues depending on where they are located in the NEM

Solar curtailment by unit



- The majority of solar generators are not significantly affected by grid constraints and competition with other generators. However, a few units experience high curtailment indicating potential excess capacity or “solar spill”.
- The location of solar and/or combination with batteries are critical factors for investors. Locating behind a constraint could result in significantly lower output relative to available output.

Wind curtailment by unit



- Relative to an unconstrained scenario, wind generators experience less curtailment than solar due to a more diffused production during the day. The most adversely affected state is Queensland.

Note: *Impact on individual units are based on Plexos’ modelling using ESOO’s constraint assumptions, operational parameters, and SRMC bidding. This impact may differ with strategic bidding.*

Results of our sensitivity scenarios

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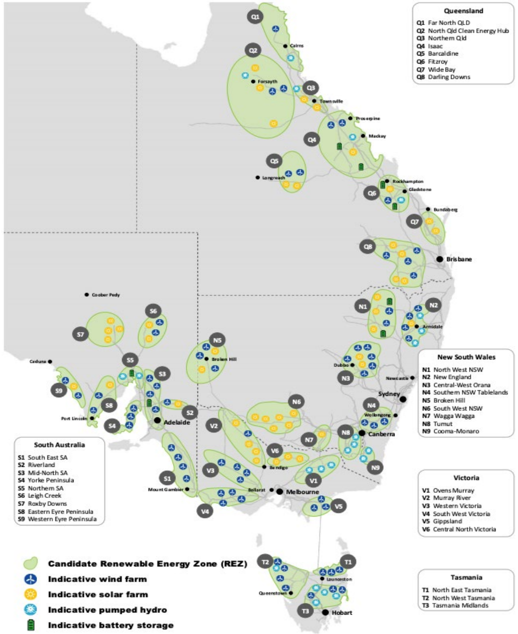
Sensitivity scenarios: We test the impact of additional renewable capacity and alternative battery placement on congestion

- The purpose of the sensitivities is to assess the incremental impact on congestion when market-driven investment in generation and storage deviates from the investment outcomes anticipated in the ISP.
- The modelled deviations are consistent with the incentive properties of the current market design and are already occurring in the NEM.

Sensitivity scenario	Solar	Wind	Location
Scenario 1	+300MW per region		Additional installed capacity is added to the most productive zone in each region
Scenario 2		+300MW per region	
Scenario 3	N/A		**NSW only:** move 35MW of total battery capacity located in the REZ to near the RRN (Eraring and Vales Point B)

Map of Renewable Energy Zones ("REZ") by state



Source: *AEMO.*

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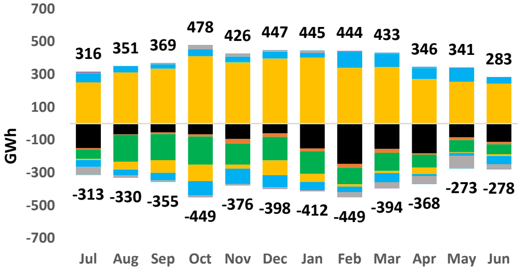
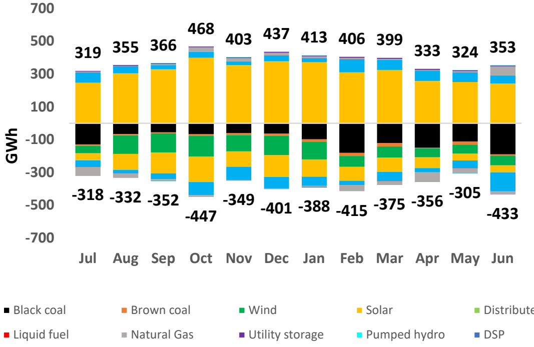
When additional solar capacity is added, the potential incremental output from solar generation is reduced by over 20% because of constraints

Change in generation mix, sensitivity – base, GWh

Without network constraints

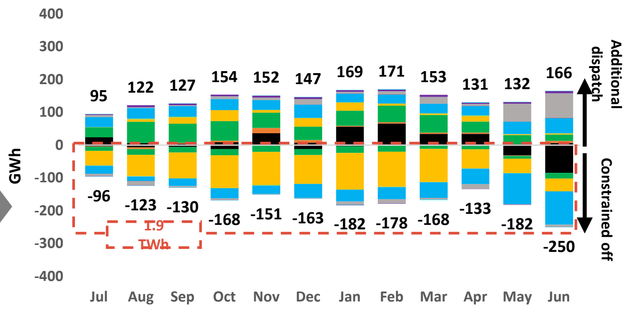


With network constraints



Change in total constrained generation given 1.5GW of additional solar capacity, sensitivity – base, GWh

With - without network constraints

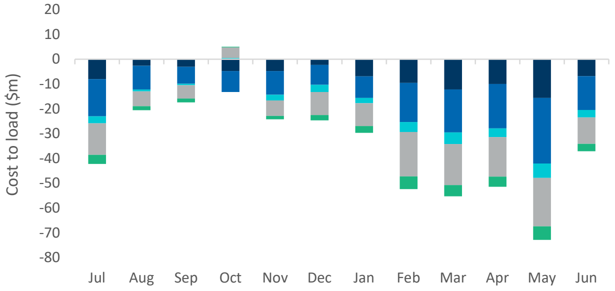


- Without constraints, the additional solar capacity increases total solar generation by 3,500 GWh. Additionally, 1,800 GWh of thermal generation is displaced, primarily black coal.
- However, with constraints, some of the additional potential solar generation is constrained off. Total solar generation therefore increases by 2,700 GWh. In this case, 1,500 GWh of thermal generation is displaced relative to the base scenario.

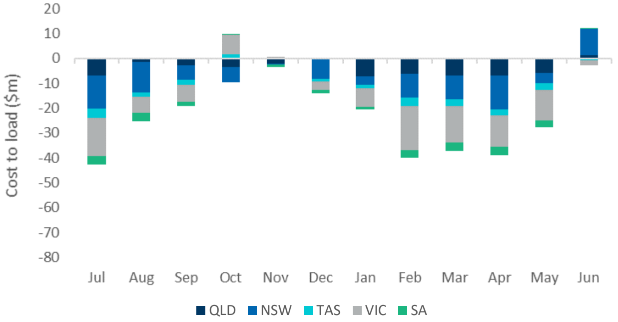
The cost of constraints also increases when additional solar capacity is introduced

Reduction in cost to load, sensitivity – base, $m

Without network constraints

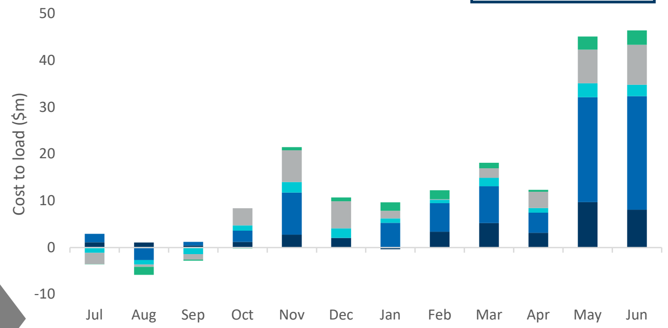


With network constraints



Impact of additional congestion on the cost to load, $m

$177 million / year



- Without constraints, the addition of 300 MW of solar capacity per state reduces total cost to load by $436m or 5.3% (from $8,266m to $7,830m).
- With constraints, the same addition reduces total cost to load by $259m or 2.8% (from $9,320m to $9,061m).

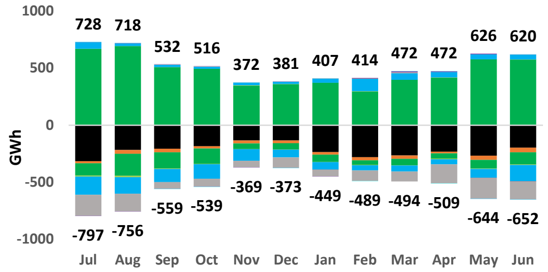
Note: *the Capex and transmission cost of the additional 1.5GW solar capacity is not considered.*

Note #2: *Additionally, total hours binding across all constraints increases by 5% after the additional solar capacity is added, from 32,300 to 33,900.*

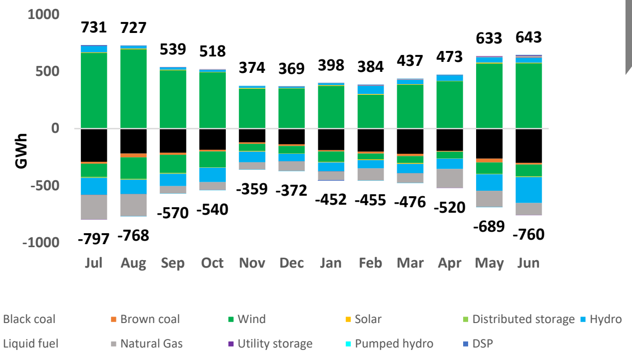
Constraints also limit the potential incremental output in wind generation associated with additional wind capacity, to a lesser extent than solar

Change in generation mix, sensitivity – base , GWh

Without network constraints

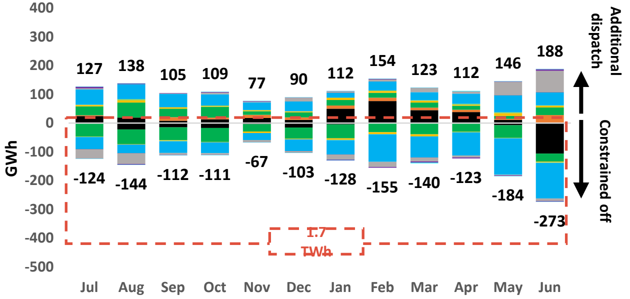


With network constraints



Change in total constrained generation, sensitivity – base, GWh

With - without network constraints

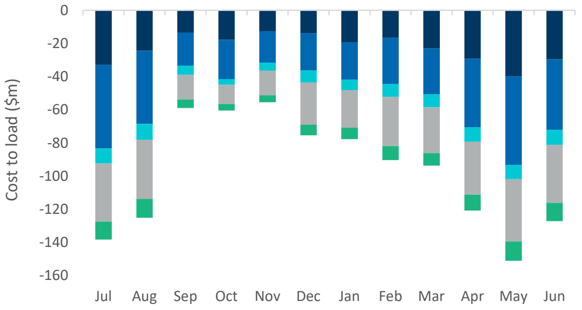


- <u>Without constraints</u>, the addition of 300 MW of wind capacity per state increases total net wind generation by 4,600 GWh. Additionally, 4,300 GWh of thermal generation is displaced, primary black coal and natural gas relative to the base scenario.
- <u>With constraints</u>, approximately 4% of the potential incremental increase in wind generation is constrained off, meaning total net wind generation increases by a smaller 4,500 GWh. 4,100 GWh of thermal generation is displaced, relative to the base scenario.

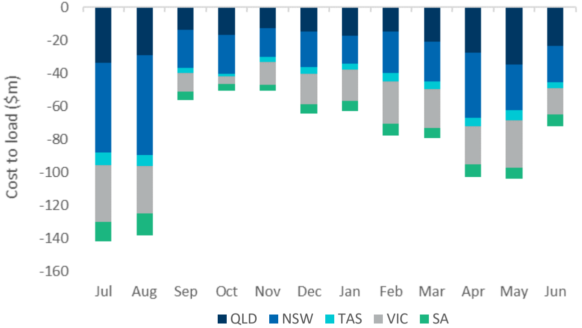
As with solar, additional wind capacity increases the cost of constraints

Reduction in cost to load, sensitivity – base, $m

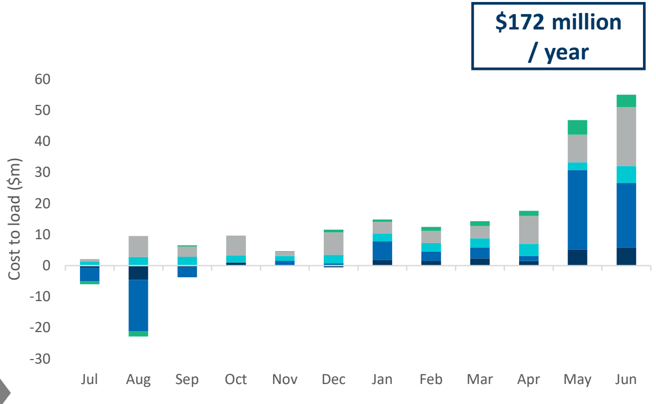
Without network constraints



With network constraints



Impact of additional congestion on the cost to load, $m



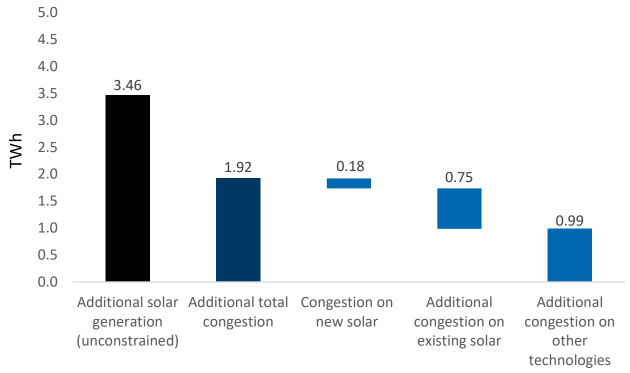
- Without constraints, the addition of 300 MW of wind capacity per state reduces total cost to load by $1,173m or 14.2% (from $8,266m to $7,093m).
- With constraints, the same addition reduces total cost to load by $1,001m or 10.7% (from $9,320m to $8,319m).

Note: *the Capex and transmission cost of the additional 1.5GW wind capacity is not considered.*

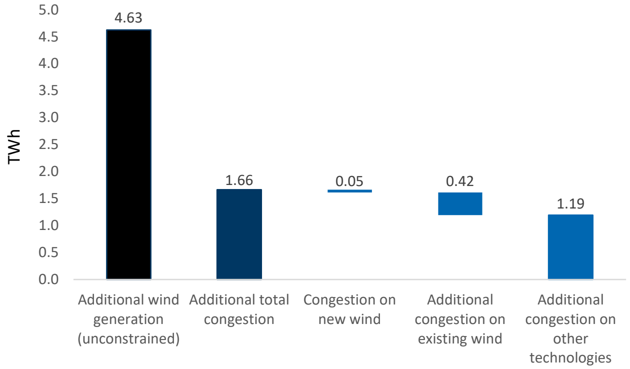
Note #2: *The total hours binding across all constraints remained stable when additional wind capacity is added at 32,300.*

In both scenarios, additional renewable capacity will increase congestion, and in turn, affect the revenue potential across different generators

Impact of 1.5GW of additional solar capacity



Impact of 1.5GW of additional wind capacity



- From an investor perspective, the forecast shows that that investments in additional renewable generation ahead of transmission development may result in an increase in congestion volumes across both new renewable capacity and incumbent generation capacity.
- In turn, this would lead to a fall in revenue potential across a wide range of market participants.

Note: *Congestion volumes for new renewable capacity appear relatively small in our forecast as we have sited the additional capacity in the most productive zones.*

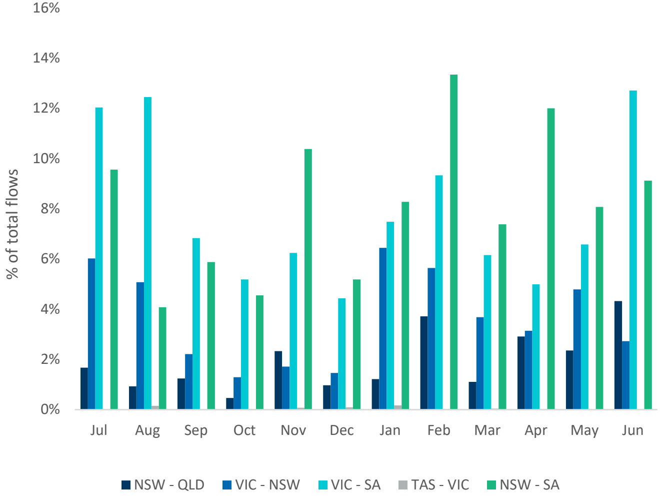
We anticipate that the propensity of loop-flows across the NEM will increase counter-price flows

Background

- In a system without constraints, electricity flows across interconnectors from a lower price region to a higher price region. These flows reduce the overall cost of meeting demand as imported low cost electricity displaces higher cost electricity.

- On some occasions, constraints in a particular region may lead to electricity flows across interconnectors from a higher price region to a lower price region (i.e. “counter-price flows”) due to market design idiosyncrasies. This represents a negative rent for consumers, that is, an additional cost.

Counter-price flow percentage of total flows



- Loop flows occur when electricity trades in one region impact the flow in a neighbouring region (i.e. when scheduled flows in one area leads to a divergence in scheduled and physical flows in another region). This feature of electricity markets is more prominent when there are multiple connection lines between two regions or a “triangle” connection between three or more regions.

- We forecast that the NSW-VIC-SA triangle will experience greater counter-price flows. This varies considerably across boundaries and months.

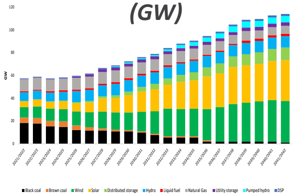
OUR MODELLING APPROACH INCLUDES TWO STAGES: FIRST TO DETERMINE THE OPTIMAL ANNUAL CAPACITY MIX AND SECOND TO OPTIMISE THE HOURLY DISPATCH

Inputs	Long Term capacity expansion model	Short term dispatch optimisation model	Output
AEMO's ISP and ESOO Step Change assumptions (demand, transmission, supply, costs, thermal retirements) **AEMO stability and thermal constraints**	**Our Long Term model determines the optimal capacity mix** to meet the capacity requirements minimum cost	**Our Short Term model determines generation profile and prices on an hourly basis** Model is run twice, with the second run incorporating stability and thermal constraints	**Net impact** equals difference between the models with constraints… …and version of the model without constraints

Most recent ISP and ESOO inputs

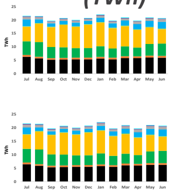
We rely on the ISP's Step Change scenario assumptions

NEM installed capacity (GW)



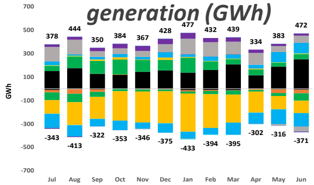
Up to 2042

NEM total generation (TWh)



2030 only

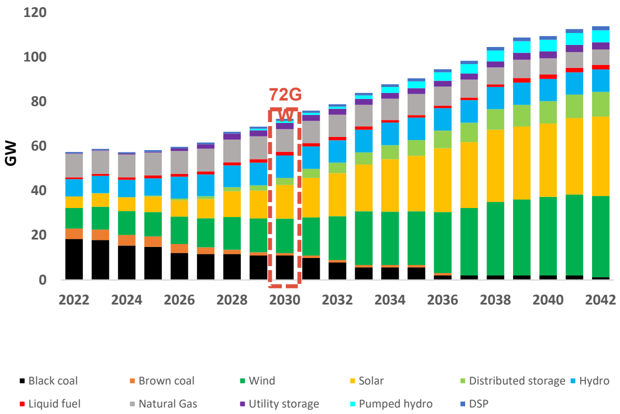
Net impact of constraints on NEM generation (GWh)



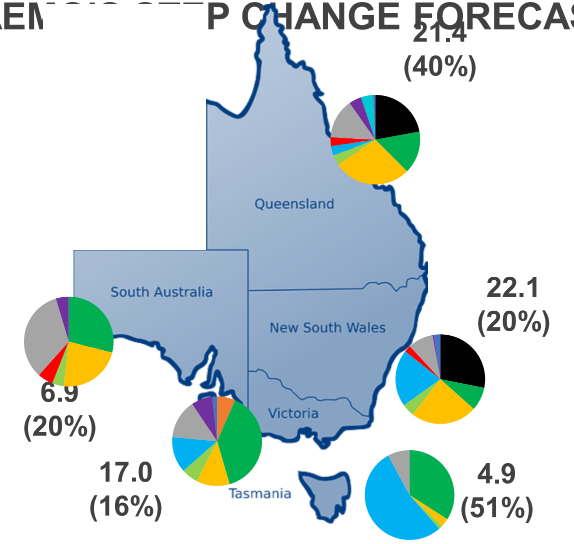
Notes: (1) Transmission investment profiles taken from the ISP; (2) All outputs from the model are presented in real 2020 terms; (3) the Short Term model calculates outcomes based on an SRMC basis.

WE PROJECT THAT WIND AND SOLAR CAPACITY WILL INCREASE BY OVER 200% TO 31GW BY [illegible] AEM[illegible]P CHANGE FORECAST

NEM installed capacity projected over 20 years, GW



2030 installed capacity by region and technology, GW (% increase from 2022)



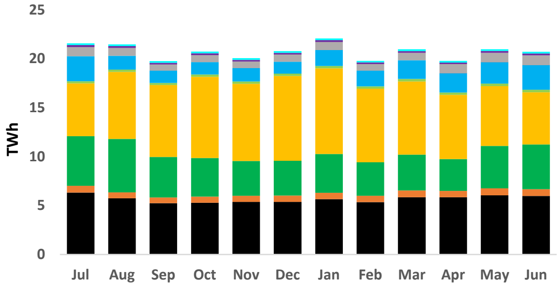
- Installed capacity of 72GW in 2030.
- New wind and solar progressively replaces retiring coal capacity.
- Wind and solar constitutes over 40% of total installed capacity by 2030.

Note: (1) We have verified our long term forecast by comparing to AEMO's own forecast. The forecasts are broadly consistent, but small differences appear due to: i) updates to AEMO's ISP assumptions (July 2020) and AEMO's ESOO assumptions (December 2020); and ii) differences of categorisation (for example, Snowy is categorised as pumped hydro in our model and as utility storage by AEMO). Rooftop solar capacity is excluded.

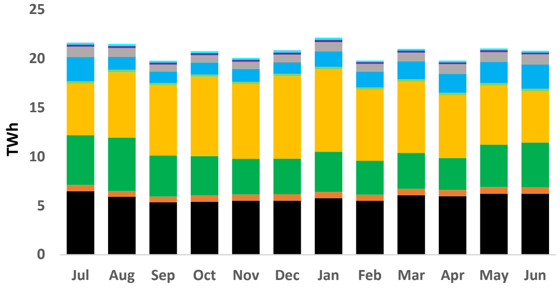
WE ASSESS WHICH GENERATOR UNITS WOULD RUN IN SCENARIOS WITH AND WITHOUT CONSTRAINTS TO SHOW THE DIFFERENCE IN DISPATCH PROFILES

NEM total generation in 2030, TWh

Without network constraints

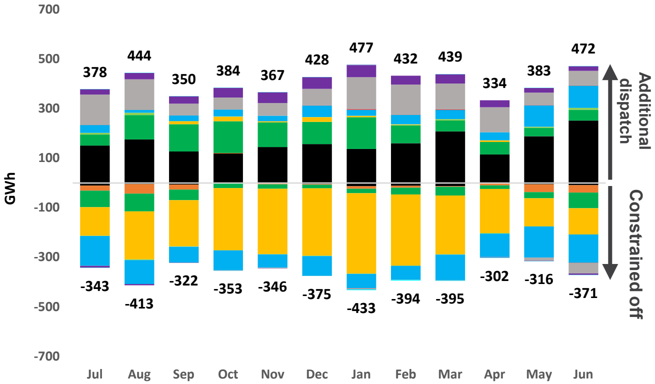


With network constraints



The impact of constraints on generation, GWh

With - without network constraints



- With network constraints, solar is typically constrained off, while additional thermal generation is dispatched in its place.
- Approximately 2.5 TWh of solar is constrained off, in addition to 1.0 TWh of hydro…
- … compared to 3.0 TWh of thermal generation which is dispatched instead.

■ Black coal ■ Brown coal ■ Wind ■ Solar ■ Distributed storage ■ Hydro
■ Liquid fuel ■ Natural Gas ■ Utility storage ■ Pumped hydro ■ DSP

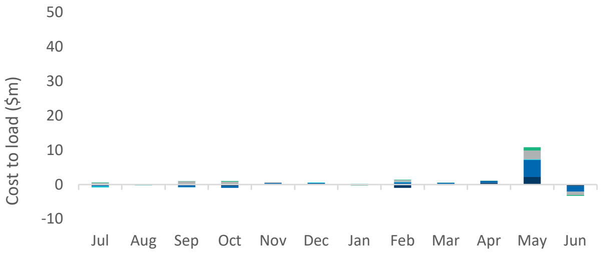
Note: The total positive and negative values in each month are not exactly equal due to: (i) differences in storage (battery and pumped hydro) generation and load profiles, resulting in different charging requirements; (ii) differences in auxiliary loads; and (iii) losses on the system (grid and storage efficiency cycle).

Appendix 1: Battery sensitivity

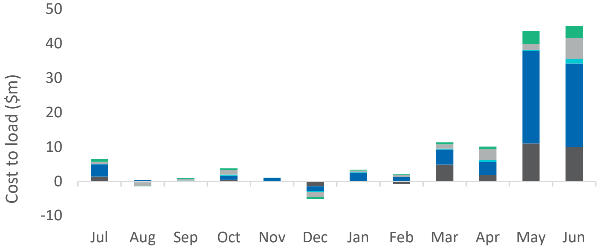
Relocating NSW battery capacity closer to the RRN increases the impact of constraints on cost to load

Change in cost to load, sensitivity – base, $m

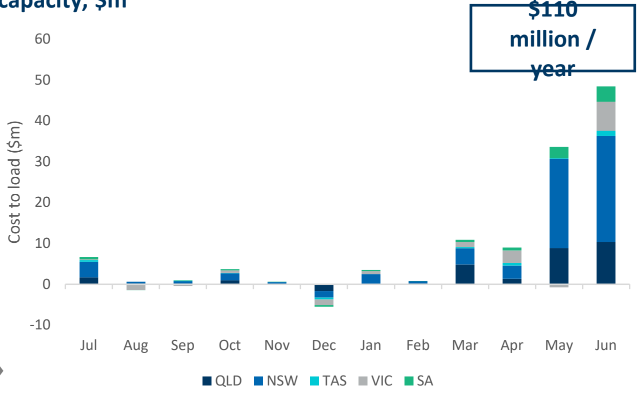
Without network constraints



With network constraints



Change in cost of constraints from relocating battery capacity, $m

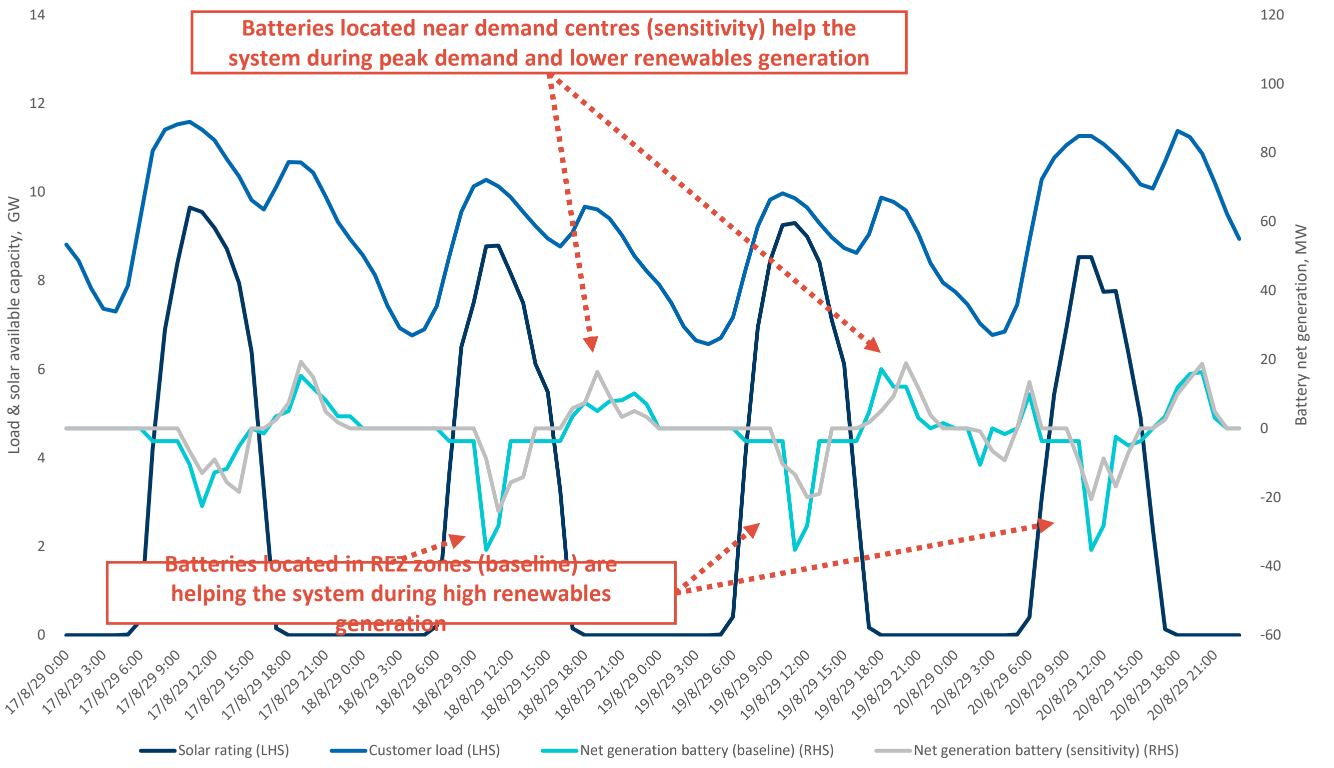


- Without constraints, moving 35MW of batteries in NSW towards the RRN increases cost to load by $11m.
- With constraints, cost to load increases by $121m.

***Note:** most of NSW's battery capacity are distributed storage capacities. The 35MW of battery capacity moved do not include these units nor storage capacities sited near Snowy 2.0.*

FTI CONSULTING

Battery location is important in determining whether benefits largely accrue during periods of high demand or high renewables generation



Appendix 2: Illustrative example on counter-priced flows

FTI CONSULTING

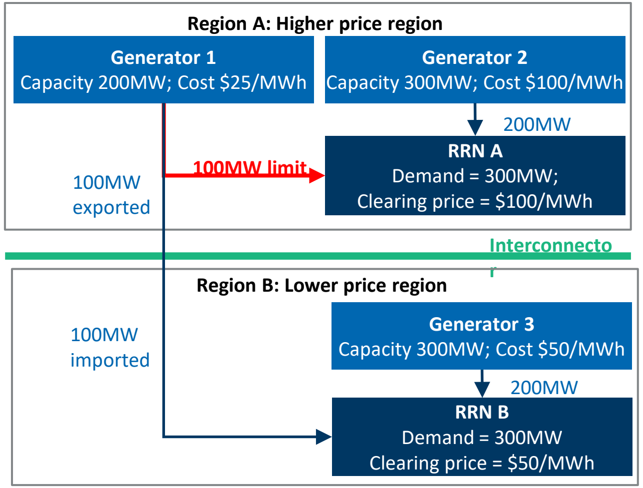
Intra-regional constraints could distort the flow of electricity across interconnectors from a high-priced region to a low-priced region

Explanation of counter-price flows across interconnectors due to intra-regional constraints

Background to counter-price flows due to intra-regional constraints

- In a system without constraints, electricity flows across interconnectors from a lower price region to a higher price region. These flows reduce the overall cost of meeting demand as imported low cost electricity displaces higher cost electricity. These flows also create a positive rent based on the difference customers pay for imports in the higher price region and the amount paid to generators in the lower price region for exporting. The positive rent is known as the positive inter-regional settlements residues (“IRSR”).
- On some occasions, constraints in a particular region may lead to electricity flows across interconnectors from a higher price region to a lower price region (i.e. “counter-price flows”) due to market design idiosyncrasies (as described in slides 5 and 6). This represents a negative rent for consumers, that is, an additional cost. We set out an example below.

Illustrative example



- Gen 1 is constrained and unable to generate at its full capacity to meet demand at RRN A. Nonetheless, it can operate at 200MW as 100MW is exported to meet demand at RRN B.
- Gen 1 is paid the clearing price at $100/MWh. However, consumers pay Gen 1 $50/MWh for the 100MW imported. This creates a **negative IRSR of -$5,000** for this hour (100MW x ($50 - $100/MWh)).
- In this example, the **allocation of capacity is efficient**; due to constraints, low cost Gen 1 is dispatched for Region B in place of more costly Gen 3. However, due to the congestion management approach, the **allocation of financial payments leads to a material transfer from customers to generators**. This is because Gen 1 receives $100/MWh instead of its value to Region B ($50/MWh) or its cost ($25/MWh).
- Additionally, **disorderly bidding** may arise where generators bid negative values as they compete to be exported instead of being constrained off. This “race to the floor” may lead to greater IRSR values.
- When the negative IRSR exceeds $100,000 in a dispatch period, AEMO is able to “clamp” the interconnector to prevent flows. While this reduces inefficient financial flows, this solution is suboptimal as it leads to capacity being allocated less effectively.

Note: *counter-price flows may also occur if the constraint is on the importing region. Illustrative example adapted from AEMC (2014) Management of negative inter-regional settlements residues.*

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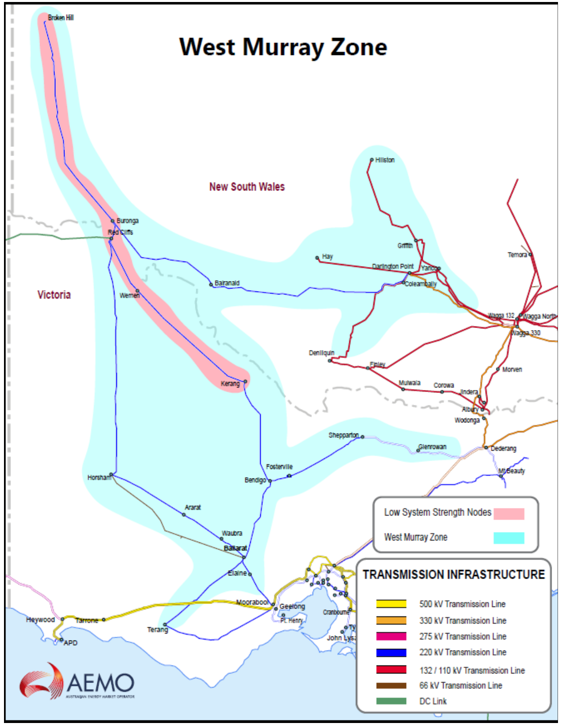
Q&A

CONCLUSIONS



- The level of congestion is much higher than we see today, but efficient given the high price of transmission.
- The effects of incremental additional generation without matching transmission are very severe.
- If generation and transmission investment remain out of sync, we can expect to see a range of congestion-related problems
  - Highly loaded lines will lead to low marginal loss factors.
  - Technical challenges during the connection process.

There is a need to coordinate transmission and generation investment and ensure that transmission upgrades are efficiently used.

CONCLUSIONS

Value of Australia's solar projects are being dented by growing curtailment issues

Michael Mazengarb 31 Aug 2021 0

New Energy Solar says curtailment issues complicated its exit from Australian market, particularly at Manildra solar farm where output fell 40pct.

- Current regime makes it profitable to invest in congested locations.
  - New generators cannibalise the profits of their neighbours.
- A 'tragedy of the commons' situation arises, with more generators seeking access in certain locations than is good for the system overall.
  - An analogous situation is global fish stocks.
- Given that the location of existing generators is locked in, it is highly likely that they will be worse impacted by congestion than those who come after them.
- Rational for new generators to pick locations where they congest others off, rather than being congested themselves.

CMM seeks to ensure that new investment adds usable MW rather than forcing existing renewables offline.

THANKS FOR ATTENDING

Please provide any feedback to **info@esb.org.au**