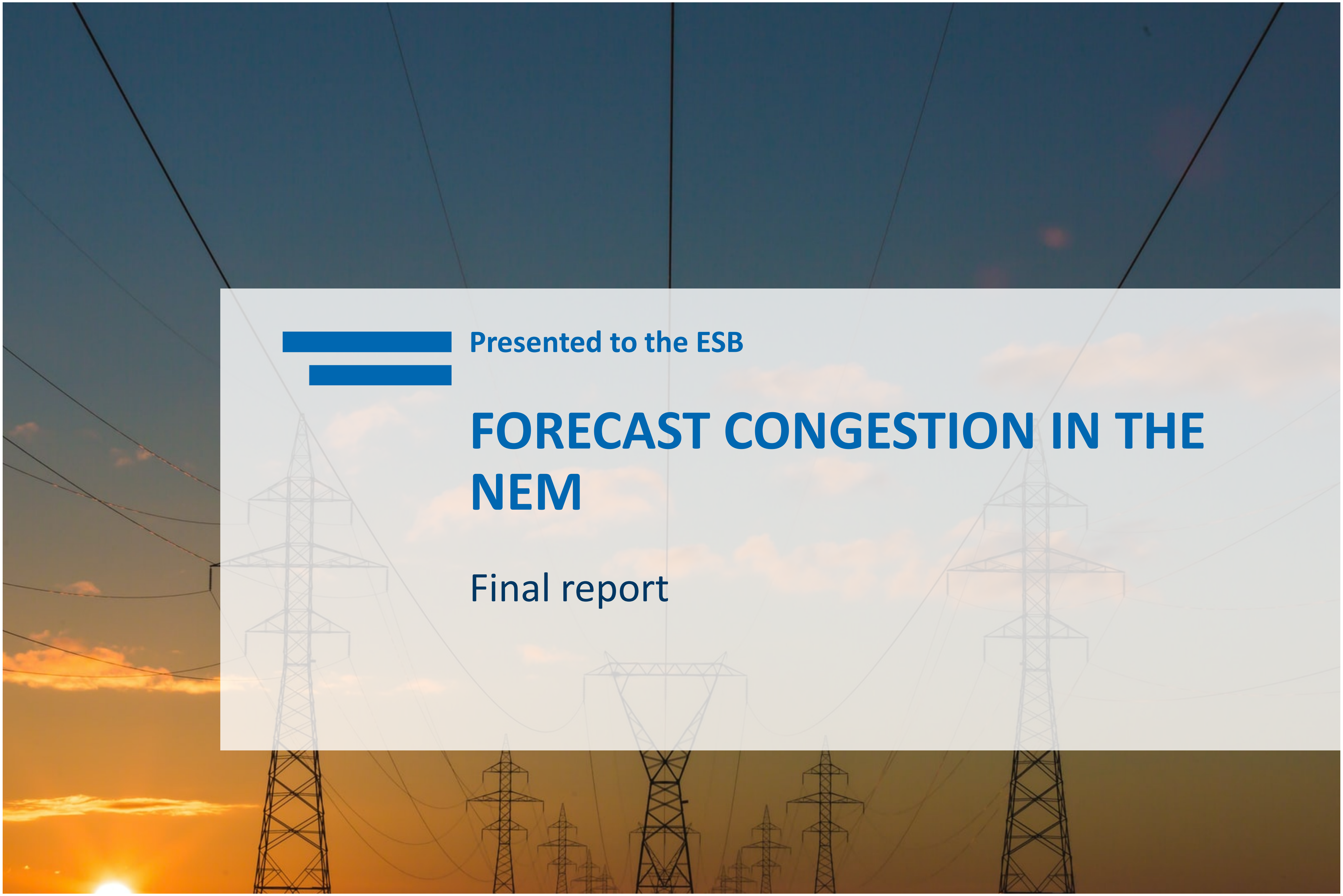


Presented to the ESB

FORECAST CONGESTION IN THE NEM

Final report

FTI CONSULTING

05 August 2021

FTI CONSULTING

FTI's modelling finds that the cost of network congestion to consumers in 2030 could be around $1.1 billion

Background and key findings

Background

- The Energy Security Board ("ESB") has commissioned FTI Consulting to forecast the impact of network congestion in the NEM in 2030.
- Congestion arises when transmission line constraints limit the flow of electricity from where lower cost generators are sited to where electricity is demanded (these generators are "constrained off"). Instead, a more expensive source of generation is required to be dispatched.
- Congestion therefore affects the generation mix in dispatch and can lead to higher prices and overall cost to consumers. Additionally, generators that are located behind constraints could experience significant impact and uncertainty on their revenues and profitability.
- However, resolving congestion typically requires additional transmission investment which would also cost consumers. As a result, the most efficient market outcome still typically contains some level of congestion.
- Congestion is expected to increase with greater renewable generation due to the unpredictability and variability in flows and as generation is often sited further from centres of demand. It is in this context where FTI is forecasting the impact of congestion on the NEM in 2030.

Key assumptions

- **Scenario:** AEMO's Integrated System Plan ("ISP") 2020 Step Change scenario (includes demand and commodity assumptions).
- **Constraint set:** AEMO's ESOO Thermal and Stability Constraints.
- **Interconnectors:** Follows the ISP 2020 Step Change scenario (VNI West assumed to be commissioned in 2035).
- **New build generation:** Determined by our model endogenously (this is cross-checked with the outcomes of AEMO's Step Change scenario and is broadly aligned).

Key findings from FTI's model

- We project capacity to reach 72GW by 2030, with wind and solar increasing by over 200% to 31GW by 2030.
- Across 2030, stability and thermal constraints lead to c.2.5 TWh of solar and c.1 TWh of hydro generation to be constrained off, with additional thermal generation dispatched in its place.
- Constraints generally lead to higher prices in each state. The average increase in price is $5/MWh, ranging from $3/MWh in November to $9/MWh in January.
- We estimate that the higher prices, along with spikes during periods of system stress which are worsened by constraints, result in **consumers paying an additional $1.05 billion over the year**.
- Additionally, investors of generation located behind frequently-constrained transmission lines could, because of curtailment, be prevented from earning a significant proportion of revenues.
- We also test the sensitivity of modifying the size and location of additional renewable capacity. These sensitivities show that:
    - Constraints limit the generation from any additional solar capacity, with over 20% of the potential increase in solar generation curtailed when constraints are introduced.
    - Constraints limit the generation from additional wind capacity, although to a lesser extent than solar as wind generation is typically less correlated with significant constraint periods.
    - Relocating batteries closer to the RRN has a small positive impact. While they are better placed to help the system during periods of high demand and prices, they are less beneficial to the system during periods of high renewable generation.

Congestion is a common feature of the electricity grid – it occurs when there is insufficient transmission capacity to convey electricity to demand

Introduction to congestion on electricity networks

Congestion occurs when electricity is unable to flow through a transmission line despite it being economic to do so

- In an efficient electricity system, demand is met by electricity produced by generators in order from the least cost to the highest cost generator. This is known as an "in merit" dispatch. The most expensive generator required to meet demand is known as the "marginal generator" which sets the clearing price paid to all plant that generate at that time.
- Electricity moves along a transmission line according to the path of least resistance. However, transmission lines have physical limits which may limit or "constrain" the flow of electricity. These constraints typically take the form of the following types (but not exclusively): (1) thermal constraints which sets the upper limit on the flow of power, (2) voltage limits which sets the operating bounds on the amount of power, and (3) stability limits which reflect the ability of the power system to return to stability after a relatively large disturbance.
- Congestion arises when these constraints limit the flow of electricity from where the lower cost generators are sited to all the locations where electricity is demanded. Instead, another source of generation is required to compensate, which is more costly.

Stylised worked example on congestion

- This simplistic illustration has two areas within a region: a low demand area with low cost production sources and a high demand area with higher cost production.
- A transmission line connects the areas but has a capacity limit which restricts the flow of low cost generation to Area B.
- It is assumed that each area has a competitive market with a linear supply curve (which means that generators are incentivised to bid at their true cost of production).

To meet 300MW of Demand A:

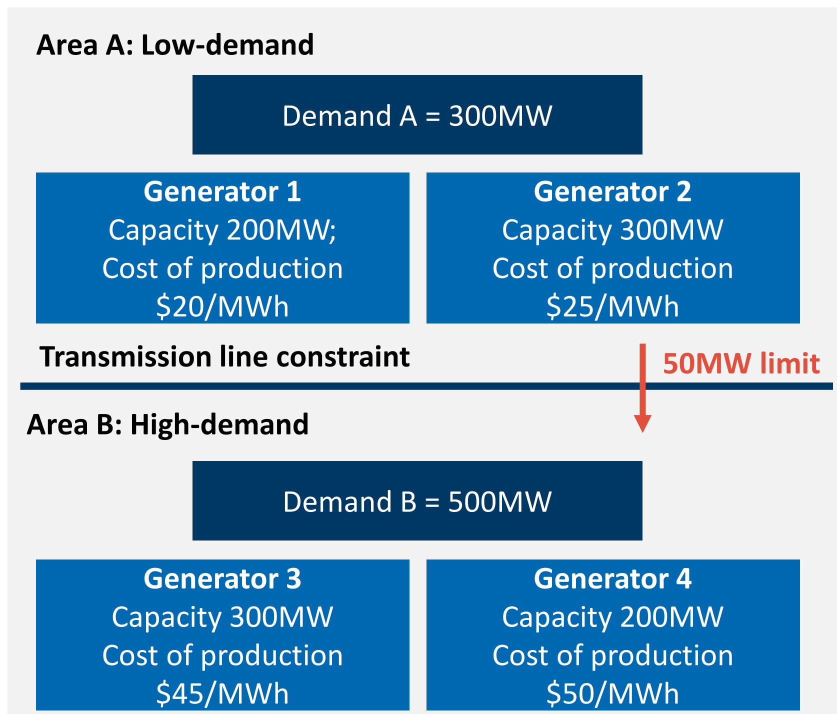
- 200MW is dispatched by Gen 1; 150MW is dispatched by Gen 2
- 50MW is exported to Area B (because of the constraint)

To meet 500MW of Demand B:

- 300MW is dispatched by Gen 3; 150MW is dispatched by Gen 4
- 50MW is imported from Area A

Impact of a 50MW transmission line limit

- Gen 2 cannot operate at full capacity of 300MW because of the transmission limit; instead, Gen 4 dispatches an additional 150MW.



To manage periods when transmission lines are congested, most electricity markets use one of two approaches

Common congestion management approaches

Worked example

Area A: Low-demand

Demand A = 300MW

Generator 1
Capacity 200MW;
Cost of production
$20/MWh

Generator 2
Capacity 300MW
Cost of production
$25/MWh

Transmission line constraint

50MW limit

Area B: High-demand

Demand B = 500MW

Generator 3
Capacity 300MW
Cost of production
$45/MWh

Generator 4
Capacity 200MW
Cost of production
$50/MWh

For ease of exposition we have incorporated simplifying assumptions:

- *Each area is competitive. Generators are assumed to be incentivised to compete by bidding their marginal cost of production.*
- *For example, Gen 3 bids at $45 as if it bids lower than $45 it risks setting the market price and not covering costs. If it bids higher than $45 it risks losing market share to Gen 4.*
- *In the example, Gen 3 might be expected to bid up to $49.99 if it learned Gen 4's costs, but we ignore that effect here.*

Congestion management through locational marginal pricing ("LMPs") (e.g. US, New Zealand)

- Some market designs have locational marginal pricing where the real-time price at each node *includes* the congestion impact. This means that each node has separate clearing prices revealing the value of congestion between two nodes.
- In this worked example, Areas A and B are individual nodes and cleared separately:
  - In Area A, Demand A pays $7,500:
    - Gen 1 sells 200MW at $25/MWh
    - Gen 2 (which sets the price) sells 150MW at $25/MWh
    - 50MW is exported
  - In Area B, Demand B pays $25,000:
    - Gen 3 sells 300MW at $50/MWh
    - Gen 4 (which sets the price) sells 150MW at $50/MWh
    - 50MW is imported
  - This results in a **total cost paid by customers of $31,250:**
    - $32,500 in the wholesale market (($25 x 300MW, paid by demand in Zone A) + ($50 x 500MW, paid by demand in Zone B))
    - $1,250 of congestion rent which is typically returned to consumers through network tariffs (50MW x ($50-$25))

Congestion management through constrained-on and off payments (e.g. most of Europe)

- In most European markets, congestion is resolved *outside* the wholesale market. This means that the wholesale market is first "solved" assuming no constraints. The SO then makes a series of payments to generators affected by constraints.
- In this worked example, Areas A and B are treated as a single market (800MW demand):
  - In Areas A & B, Demand A & B pays $36,000
    - Gen 1 sells 200MW at $45/MWh
    - Gen 2 sells 300MW at $45/MWh
    - Gen 3 (which sets the price) sells 300MW at $45/MWh
  - The SO resolves congestion outside the wholesale market:
    - The SO accepts the 150MW offer to *buy* power from Gen 4 at $50/MWh
    - The SO accepts the 150MW bid to *sell back* power to Gen 2 at $25/MWh
  - This results in a **total cost paid by customers of $39,750**:
    - $36,000 in the wholesale market ($45 x 800MW) plus $3,750 to resolve congestion (150MW x ($50-$25))

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

Congestion management in the NEM

Worked example

Area A: Low-demand

Demand A = 300MW

Generator 1
Capacity 200MW;
Cost of production
$20/MWh

Generator 2
Capacity 300MW
Cost of production
$25/MWh

Transmission line constraint

50MW limit

Area B: High-demand (RRN)

Demand B = 500MW

Generator 3
Capacity 300MW
Cost of production
$45/MWh

Generator 4
Capacity 200MW
Cost of production
$50/MWh

Assumptions:

- *As in the previous slide, each area has a competitive market with a linear supply curve; generators are incentivised to bid at its true cost of production.*
- *Area B is the RRN.*

Intra-regional congestion management in NEM

- In the NEM, the wholesale price for each region is determined at the regional reference node ("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.
- Unlike the two congestion approaches described in the previous slide, the NEM incorporates the management of congestion into the formation of market prices, where the same price is applied across each region. This differs from the two congestion management approaches described above in the following ways:
  - Unlike market designs with locational marginal pricing, the price for the entire region is set based on the clearing price at the RRN. This means that the value of congestion could not be revealed through separate wholesale prices within a region.
  - Unlike the European model, where the wholesale market price is cleared by the marginal cost of the generator in the unconstrained order (generator 3 in our example), the wholesale price in the NEM is set by the marginal cost of the generator at the RRN (generator 4 in our example) – which typically will include the impact of congestion in the merit order.
- In this worked example in the context of the NEM, Areas A and B are within a single region and so are treated as a single wholesale market with 800MW demand. It is assumed that Area B is the RRN and sets the clearing price for the entire region.
  - In Areas A and B
    - Gen 1 sells 200MW at $50/MWh
    - Gen 2 sells 150MW at $50/MWh (as the other 150MW is constrained)
    - Gen 3 sells 300MW at $50/MWh
    - Gen 4 (which sets the clearing price) sells 150MW at $50/MWh
  - This results in a **total cost of $40,000**:
    - $40,000 in the wholesale market ($50 x 800MW)

… which, in our view, leads to a number of problems and makes the NEM design ill-suited to the large scale roll out of renewables generation

Congestion management in the NEM

Worked example

Area A: Low-demand

Demand A = 300MW

Generator 1
Capacity 200MW;
Cost of production
$20/MWh

Generator 2
Capacity 300MW
Cost of production
$25/MWh

Transmission line constraint

50MW limit

Area B: High-demand (RRN)

Demand B = 500MW

Generator 3
Capacity 300MW
Cost of production
$45/MWh

Generator 4
Capacity 200MW
Cost of production
$50/MWh

Notes:
1. Other policy initiatives attempted to mitigate this issue (e.g. charging methodology for transmission losses, connection policies, as well as the perceived risk of being constrained off out of merit) are all still likely to impact siting decision.

2. As we discuss later in this pack, it is also likely to impact flows across interconnectors between regions (and revenues earned by an exporting generator that would otherwise be constrained-off).

Intra-regional congestion management in NEM

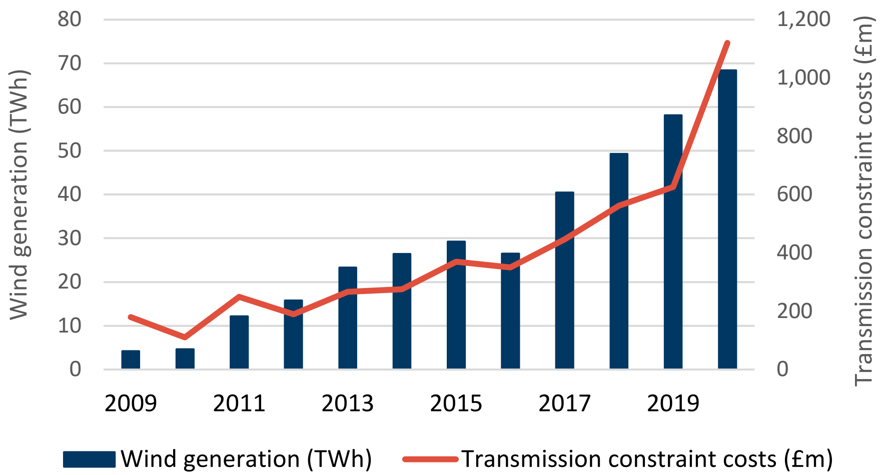
- Using the RRN price to clear the market in each region seems a potentially fundamental flaw in the design of the NEM. We are not aware of any other market design globally where the marginal cost of a generator sited at a particular location sets the price on both sides of a constraint. This means that the NEM price could be impacted when there is congestion – in contrast to the European approach (where the market price reflects the “unconstrained price”) and the LMP approach (where the market price varies by node to account for congestion).
- The NEM approach to congestion management has at least three key adverse implications:
  - **Inefficient investment decisions**: First, because each region has a single clearing price, investors may not consider the impact of the transmission network in siting decisions fully (this also applies to the European approach). This could lead to a greater number of generators being sited in areas with low cost of production but imposing a higher cost to consumers (either through a higher transmission cost or a congestion impact on prices).[1]
  - **Inefficient operational decisions**: Second, the NEM’s congestion management approach could lead to potential incentives to distort operational decisions. In particular, generators will at times of congestion 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). In our example, Gen 2 is incentivised to bid lower than Gen 1 on the hope it is dispatched ahead of Gen 1 and capturing the RRN price of $50. This could lead to the more costly Gen 2 displacing the less costly Gen 1 causing inefficient dispatch.[2] This incentive to not reveal marginal costs in bids (and ultimately the merit order) is, in our view, a particular failing of the NEM market design and is likely to cause further inefficiencies.
  - **Transfer of rent from consumers to generators:** Third, compared to other approaches, the NEM’s congestion management approach is likely to lead to higher cost to customers if Area B is the RRN, as the additional unit dispatched to resolve congestion (Gen 4 in our example) sets the clearing price for the entire region. In Europe the unconstrained price (Gen 3 in our example) sets the market price and in LMP markets set prices (Gen 2 and Gen 4). The NEM approach could lead to a significant transfer of rent from consumers to generators, whilst also causing distortion between price zones.

Congestion is expected to worsen over time as variable renewable generation increases

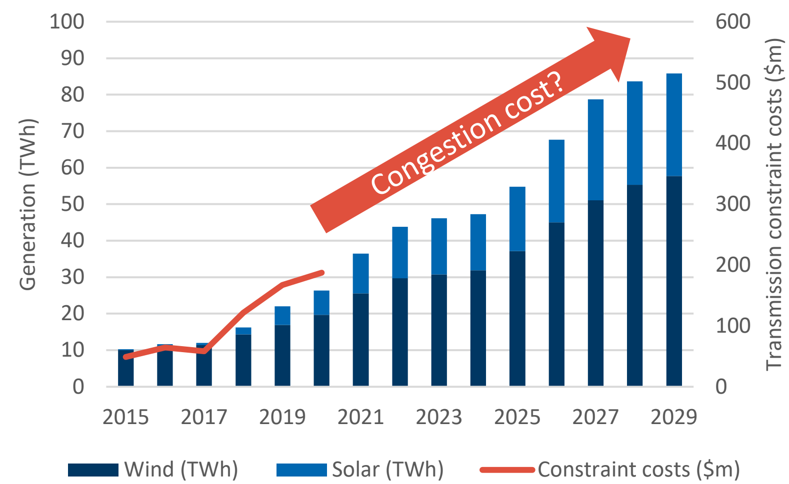
Trends in variable renewable generation and congestion costs

- Like the NEM, most jurisdictions globally have experienced an increase in congestion costs in line with an increase in variable renewable generation. Often this is because the best sites for renewables generation are distant from demand centres. We set out the historical trends for Great Britain below.

Great Britain (historical)



NEM (historical & forecast)



- Given projections in renewable energy sources and the current NEM market design, we have been commissioned to assess the likely impact of congestion in the NEM in the year 2030. This executive summary sets out our findings.
- We set out in the following slides:
  - Our modelling approach;
  - The impact of congestion on hours binding, generation mix, prices and consumer cost;
  - The results from three sensitivity analyses modifying the size and/or location of renewable capacity; and
  - Our analysis of counter-price interconnector flows caused by intra-regional constraints.

Source: FTI Analysis; AEMO Quarterly Energy Dynamics - Q4 2020 for historical data; AEMO data dashboard for 2021 data; AEMO 2020 ISP generation outlook for forecast data.

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

High-level modelling approach

Inputs

ISP and ESOO Step Change assumptions from AEMO (demand, supply, costs, thermal retirements)

AEMO stability and thermal constraints

Most recent ISP and ESOO inputs

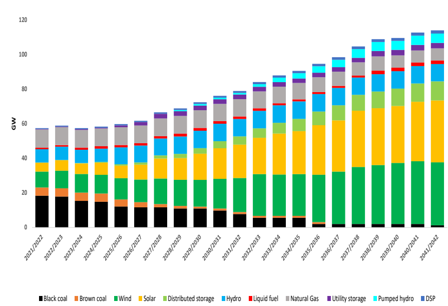
We rely on the ISP's Step Change scenario assumptions

Long term capacity expansion model

Optimal capacity mix for each region is determined by the Long Term model, based on capacity required to meet minimum capacity margins at minimum cost

This model is used to endogenously determine how much new capacity should be built over time

NEM installed capacity (GW)



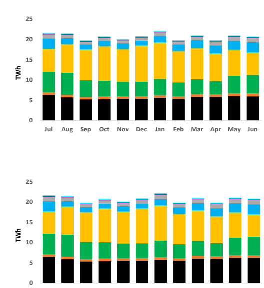
Up to 2042

Short term dispatch optimisation model

The Short Term model determines generation profile and prices on an hourly basis

This model is run twice, with the second run incorporating stability and thermal constraints. The capacity profile is the same in both runs

NEM total generation (TWh)



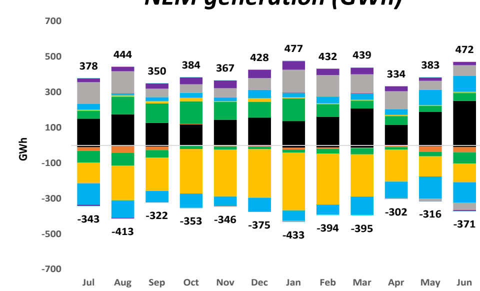
2030 only

Output

Net impact equals difference between version of the model with stability and thermal constraints…

…and version of the model without constraints

Net impact of constraints on NEM generation (GWh)



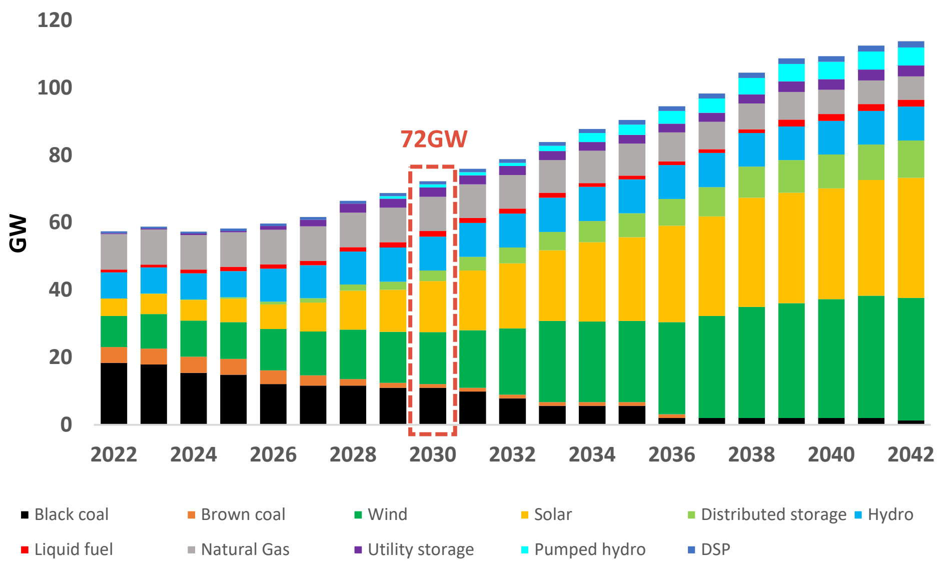
Note: All outputs from the model are presented in real 2020 terms.

FTI CONSULTING

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

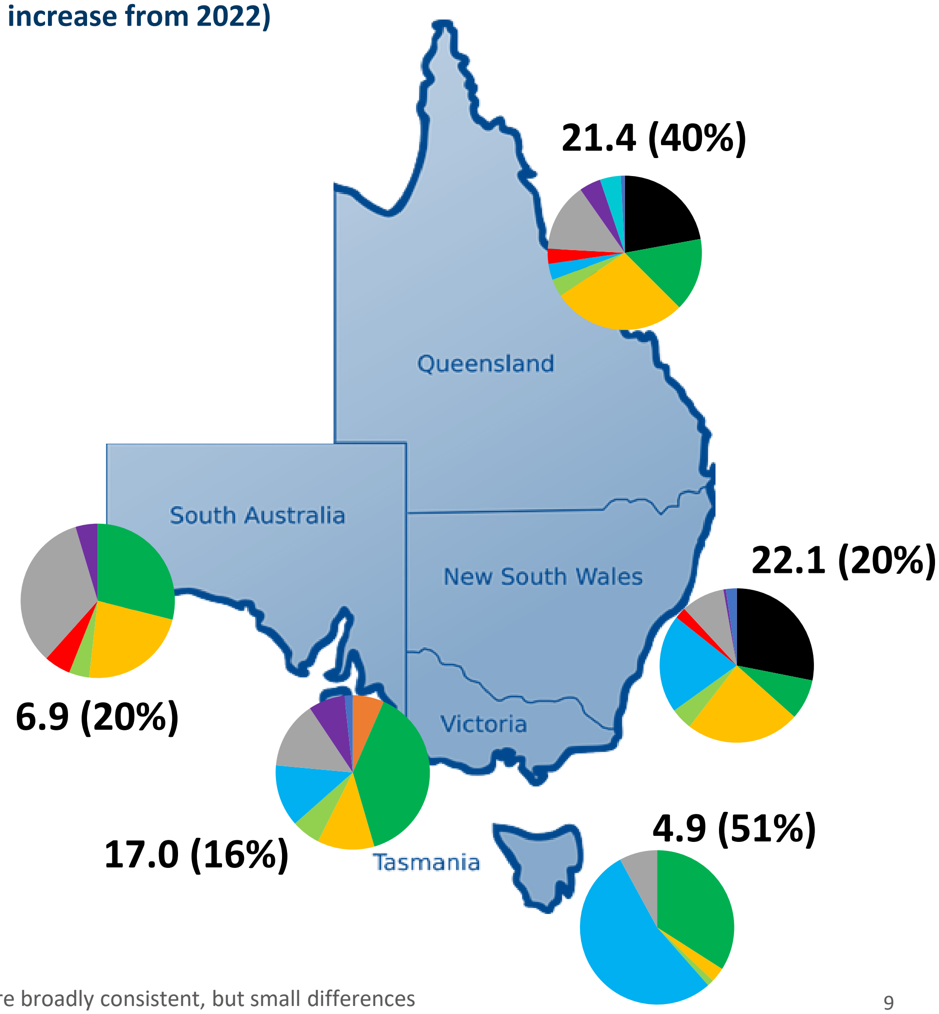
Results from our long term capacity expansion model

NEM installed capacity projected over 20 years, GW



- 2030, which is the focus of our analysis, has an installed capacity of 72GW.[1]
- Solar and wind capacity constitutes over 40% of total installed capacity in that year.
- The capacity mix in 2030 can be seen as "en route" in the energy transition, increasing steadily across the modelling period, with new wind and solar progressively replacing retiring coal capacity.
- Beyond 2030, solar and wind continues to grow as a share of total capacity.

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

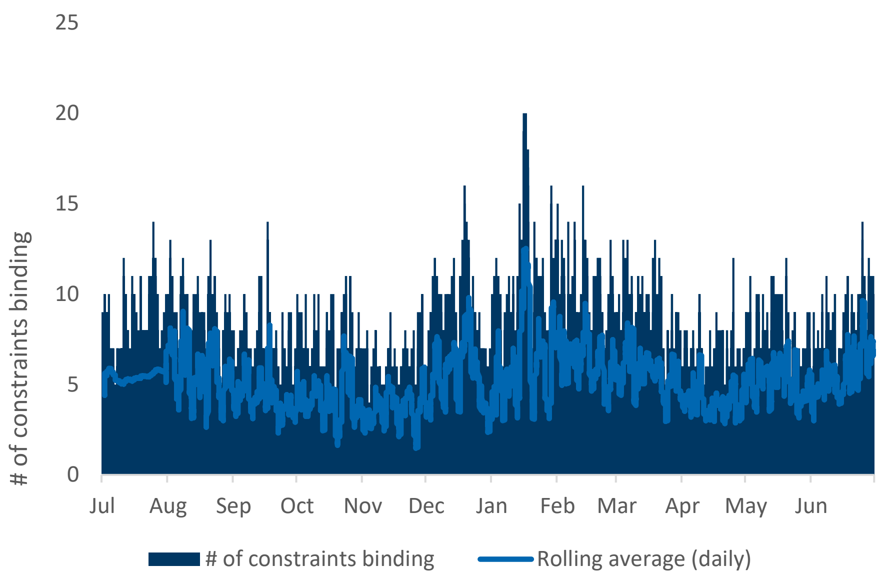


Note: (1) We have verified our long term forecast by comparing to AEMO's own forecast. The forecasts are broadly consistent, but small differences appear due to: i) updates to AEMO's ISP assumptions between July and December 2020; and ii) differences of categorisation (for example, Snowy is categorised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

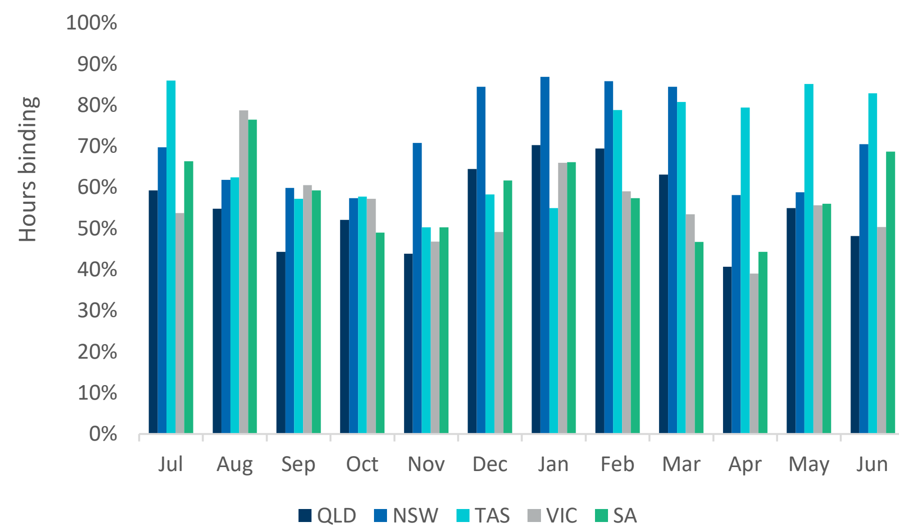
We project network constraints to occur frequently over the year, with peaks during summer periods

Volume of network constraints per hour

Number of constraints binding per hour in the NEM



Percentage of hours per month in which at least one constraint binds

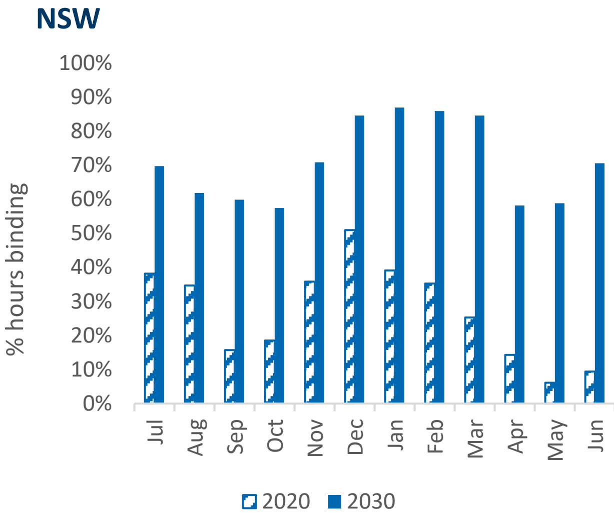


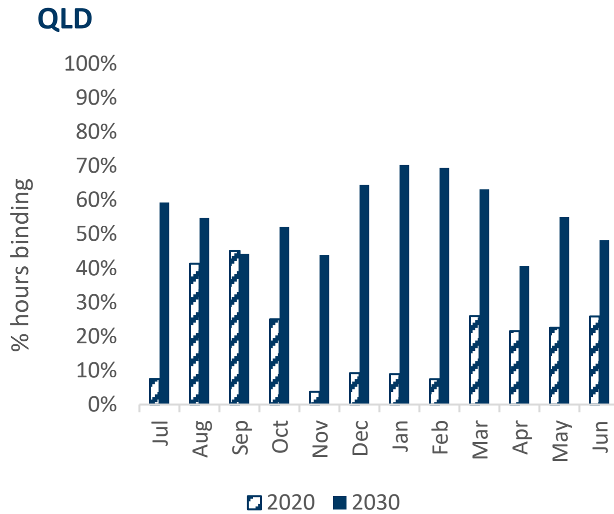
- Network constraints are a common feature in all electricity systems. In the NEM, they appear to be more prevalent in the summer, coinciding with higher demand periods and solar generation. Some periods have a surge in the number of constraints binding indicating system stress, with potentially higher prices and greater risk of outages.
- We project that over the year, over 99% of hours will have at least one constraint binding in any given hour across the NEM. On a state level, this is highest in New South Wales in January, with 87% of hours having at least one constraint binding.
- Hours of constraints binding is predicted to rise substantially from current levels. Our model estimates transmission constraints will bind for a total of **32,346 hours in 2030**, nearly a threefold increase compared to **12,310 in 2020**.[1]

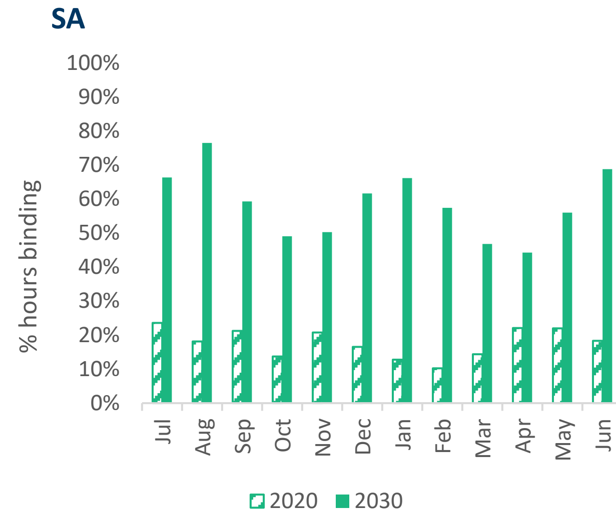
Notes: Network constraints include both thermal and stability constraints.
Source: (1) NEM Constraint Report 2020 Summary Data.

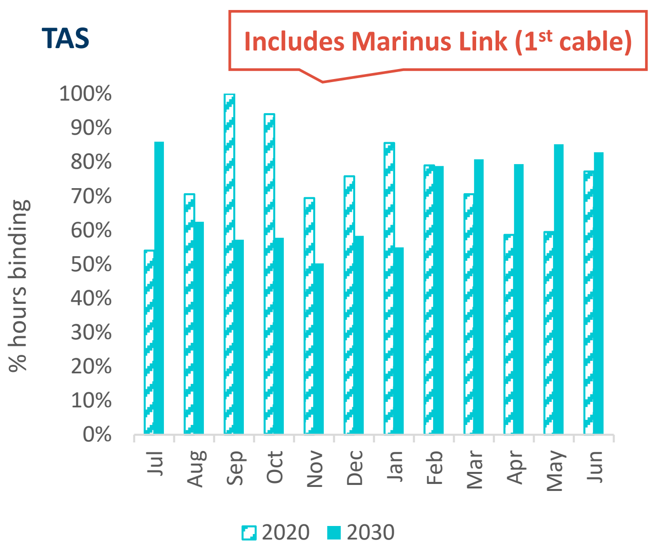
The number of hours with constraints binding is expected to increase in all regions except Tasmania

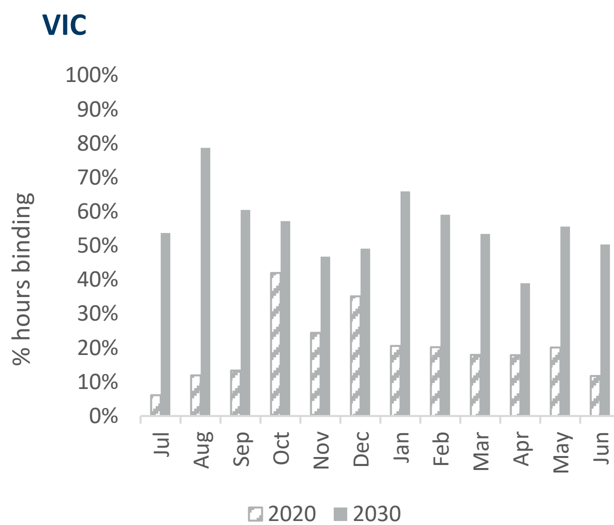
Percentage of hours per month with at least one constraint binding by state











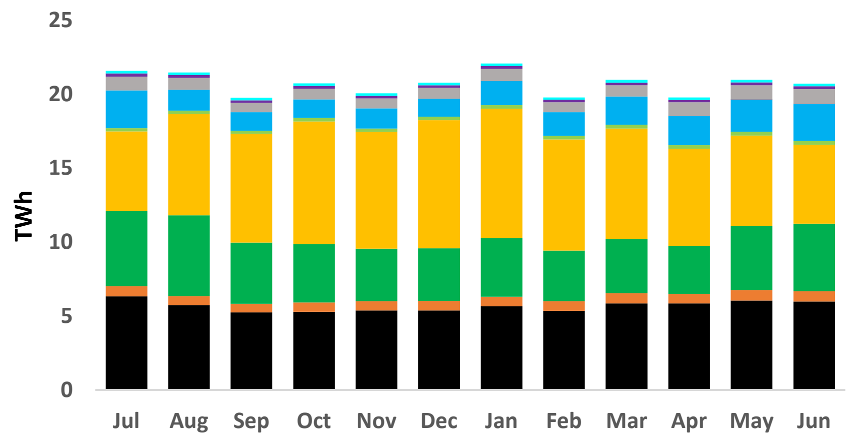
Source: AEMO's monthly constraint reports 2019 & 2020.

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

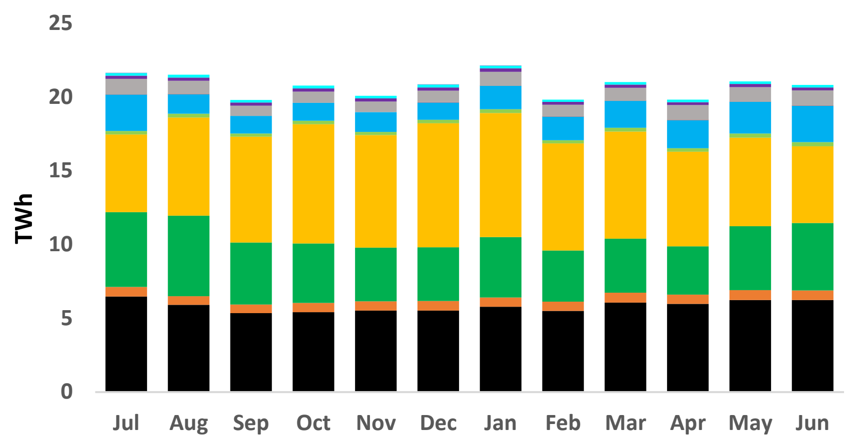
Impact of constraints on the generation mix

NEM total generation in 2030, TWh

Without network constraints

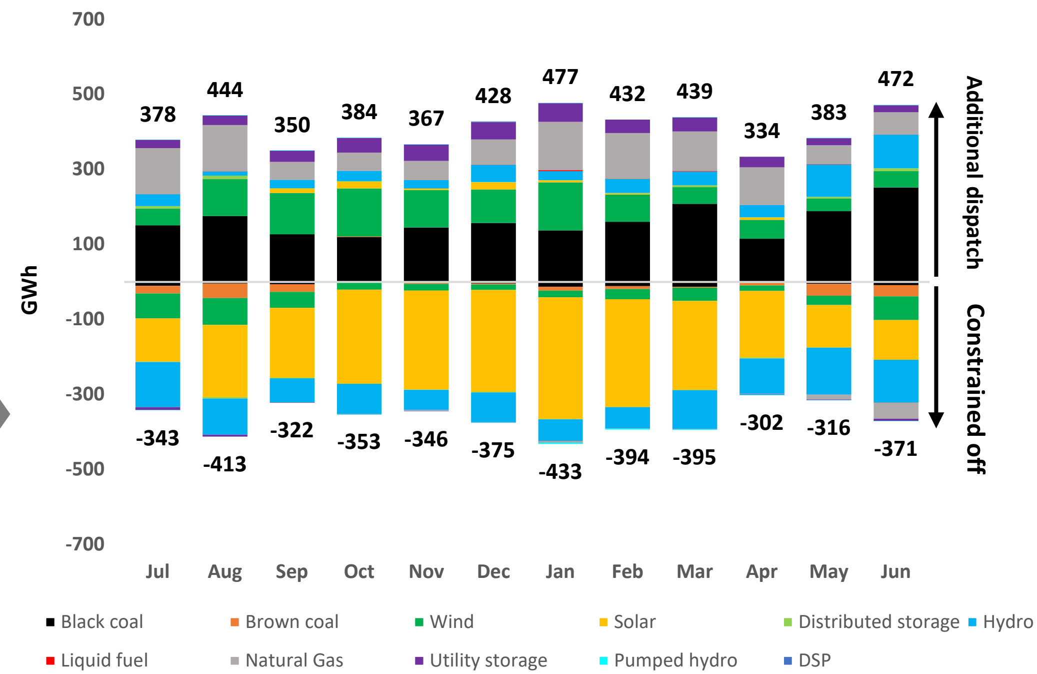


With network constraints



The impact of constraints on generation, GWh

With - without network constraints



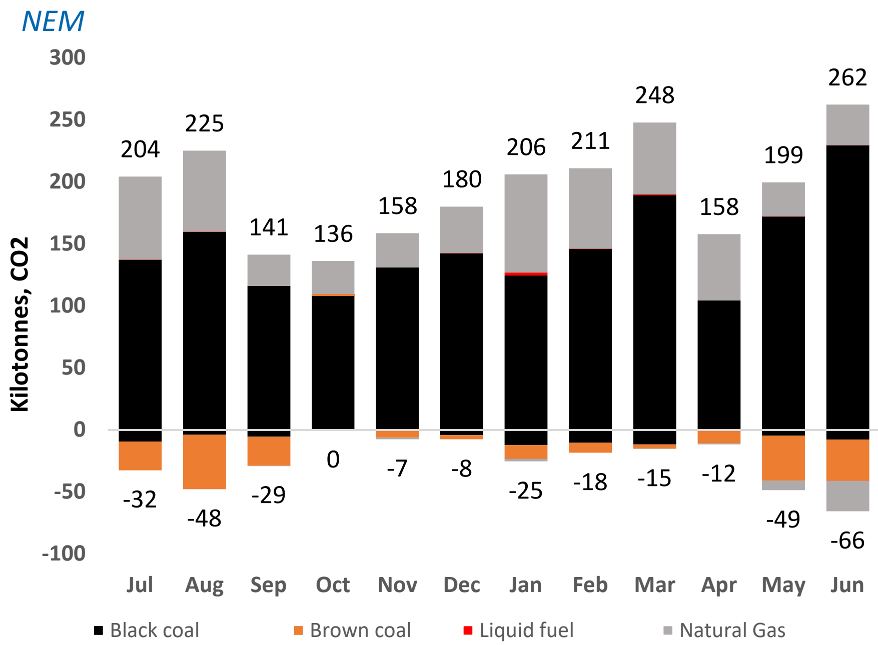
- Network constraints affect the generation mix of the NEM. Solar is typically constrained off, while additional thermal generation is dispatched in its place.
- Across the year, approximately 2.5 TWh of solar is constrained off, in addition to 1.0 TWh of hydro.
- This compares to 3.0 TWh of thermal generation which is dispatched instead.

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).

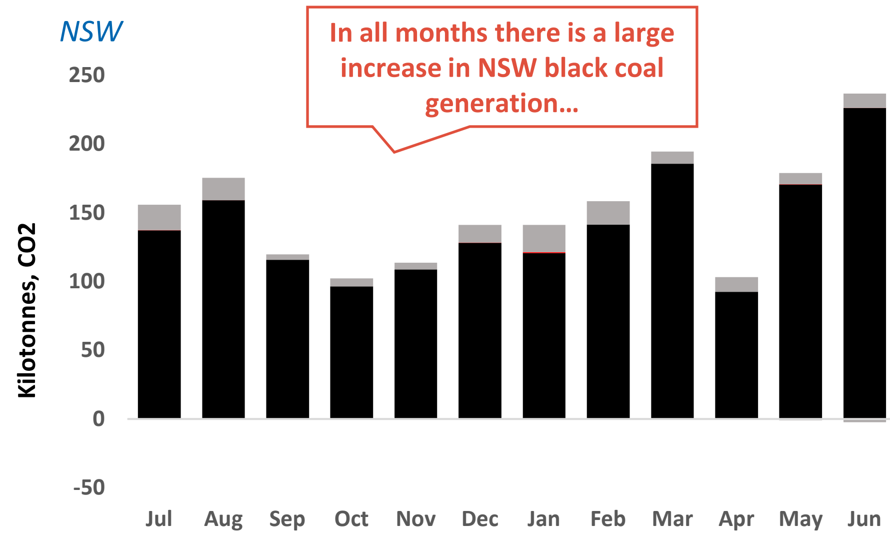
Constraints lead to higher emissions as dispatchable thermal generators are called upon to replace constrained off renewables

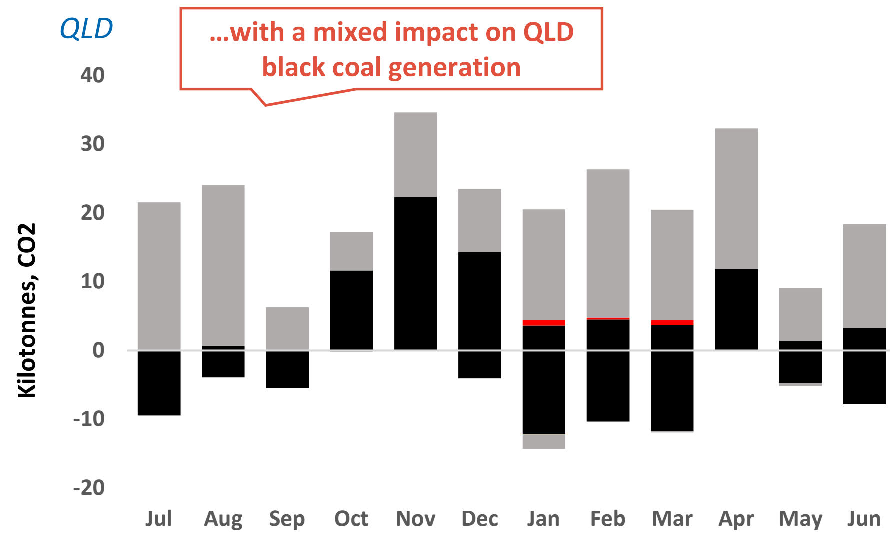
Impact of network constraints on emissions

The impact of network constraints on emissions, Kilotonnes, CO2



- As displayed on the previous slide, constraints typically lead to renewable generation being constrained off, with additional thermal plant being dispatched in order to meet demand.
- In 2030, the introduction of constraints results in an additional 2,020 kilotonnes of CO2 emissions, an increase of 2.7% over the annual unconstrained amount.
- Black coal is responsible for the largest increase, with over 1,690 kilotonnes of additional CO2 emissions.
- However, network-constrained brown coal generates less and produces fewer emissions. By 2030, only two units of brown coal (both from Loy Yang B) remain open in Victoria.



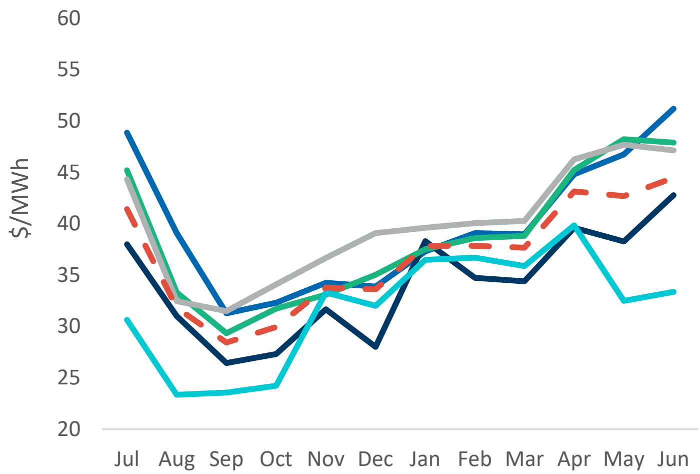


Constraints lead to higher prices, and may lead to price spikes in specific periods when the system is under stress

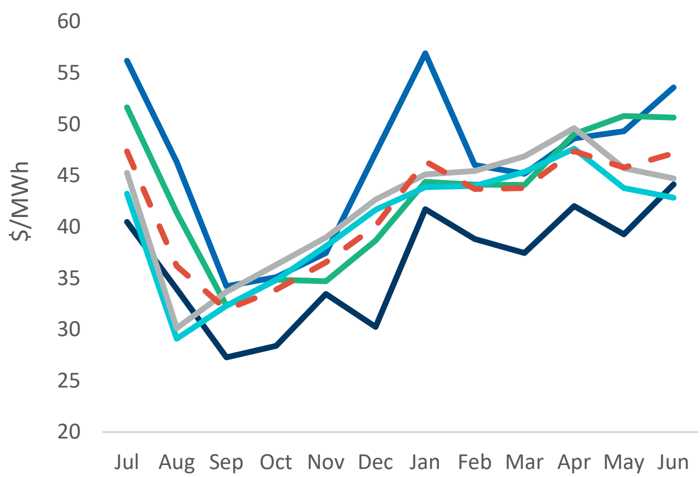
Impact of constraints on prices

Time weighted prices, $/MWh

Without network constraints

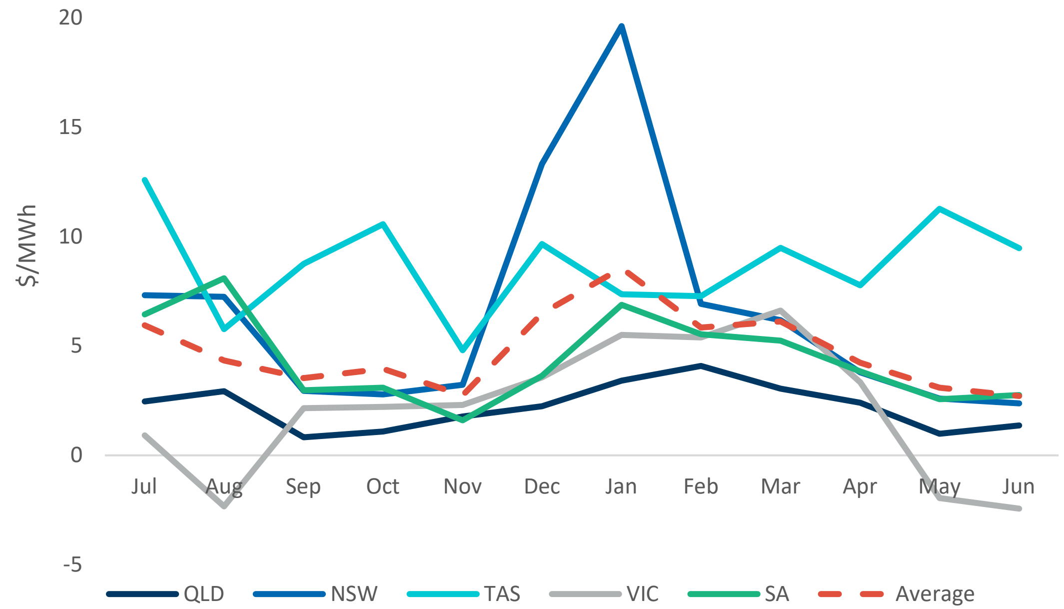


With network constraints



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.
- In high demand periods (for example during summer), constraints lead to further increases in prices. The average price difference in December and January is $8/MWh. Excluding these months, the price increase still averages $4/MWh.
- The prices presented are determined using SRMC bidding methodology. We also impose a price cap of $1,000/MWh to prevent infrequent but significant price spikes at the Market Price Cap ("MPC") from biasing the impact of congestion disproportionately. Prices are time-weighted monthly averages. Our results therefore are likely to be conservative.

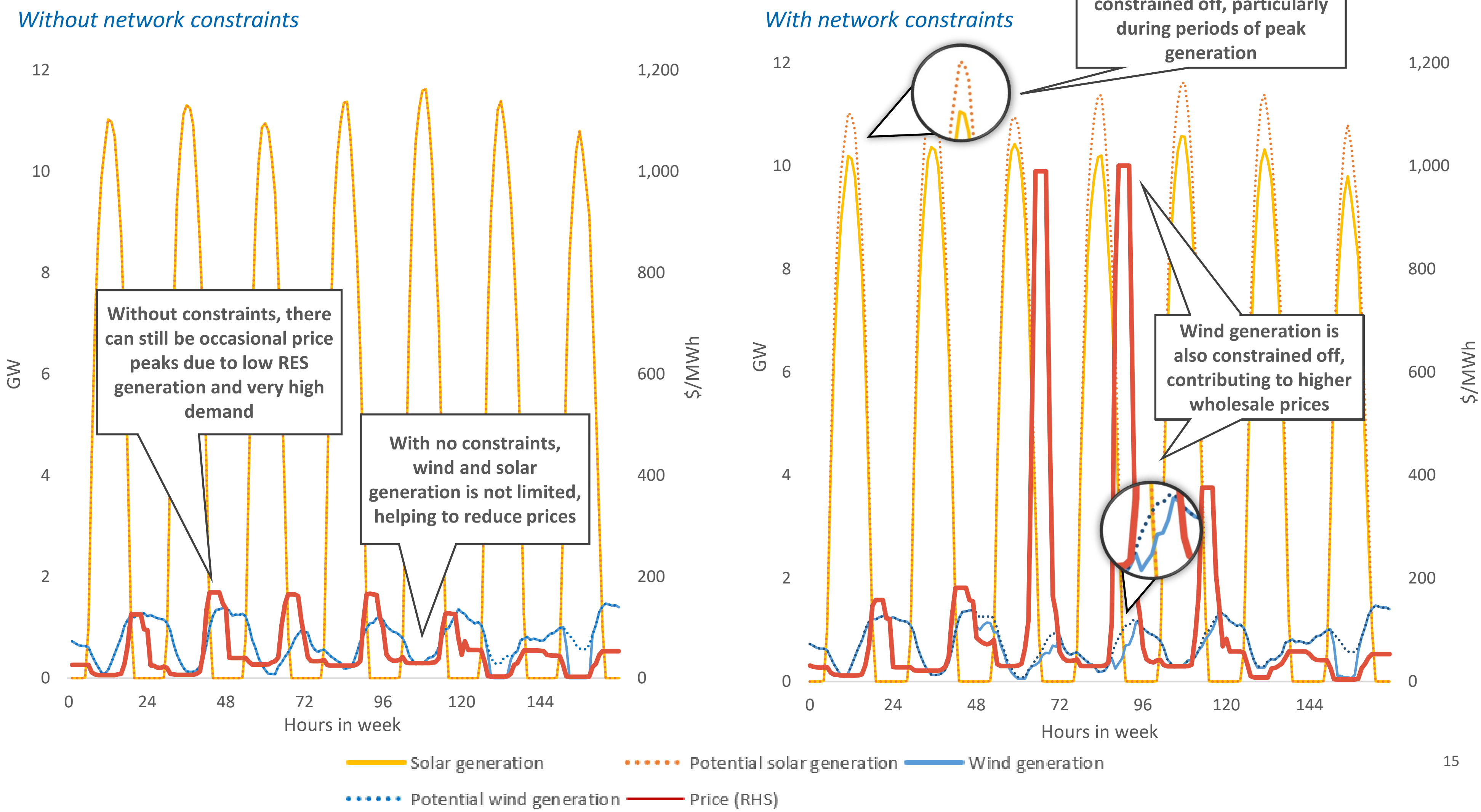
Note #1: *The negative price differentials observed in Vic are driven by differences in hydro behaviour in Tas. This arises as hydro units located in Tasmania optimise their water storage levels differently between the two scenarios which affects the water value (i.e. the future value of water held in 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.*

Note #2: *DSP prices lowered to the following bands Band 1 = $300/MWh, Band 2 = $300/MWh, Band 3 = $300/MWh, Band 4 = $500/MWh; Reliability response and MPC = $1,000/MWh.*

The impact on prices may be more susceptible to congestion as wind and solar generation increases

"Zoom-in" on the impact of constraints on wind and solar generation and prices in a high-demand week

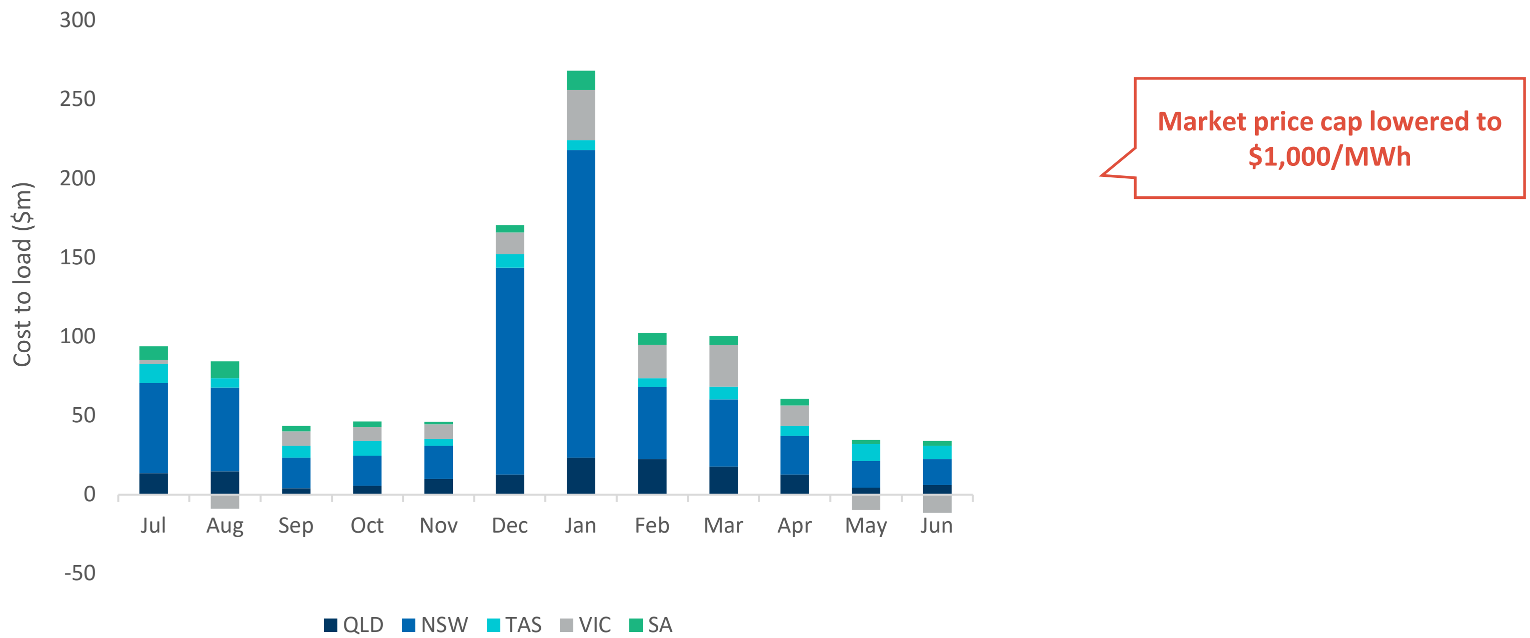
NSW generation and prices, GW, January 14-20



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

Increase in cost to load due to network constraints

Increase in the cost to load by region in 2030



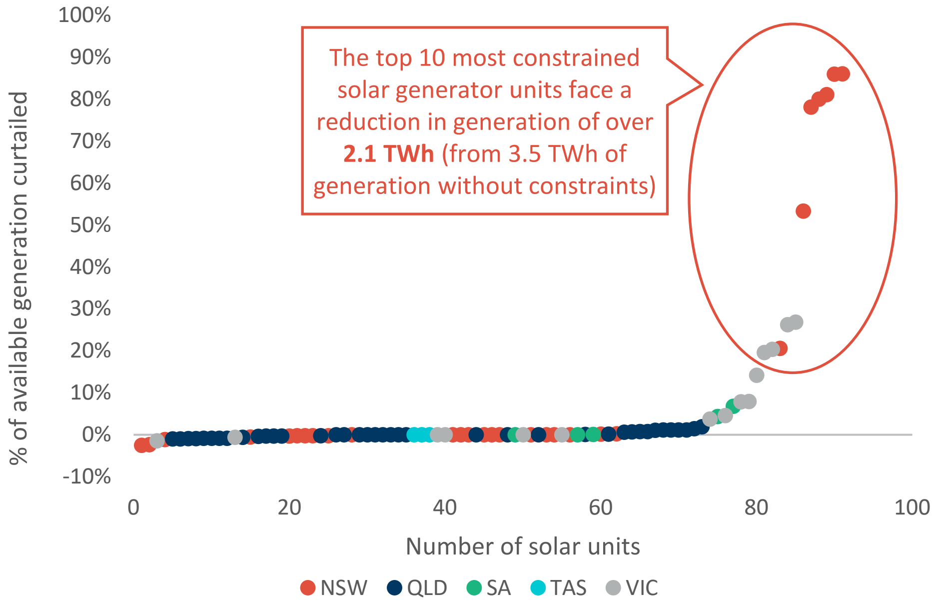
- Our forecasts indicate that system stress may occur in very high demand periods leading to very high prices, even in the unconstrained scenario. When constraints are introduced, the cost to load increases significantly based on these relatively infrequent periods.
- This is because there is insufficient dispatchable generation to compensate for the generation that is constrained off (mostly wind and solar).
- As in slide 14, in order to demonstrate the impact of constraints effectively without being disproportionately biased by extreme periods, we decrease the MPC of $15,000/MWh to $1,000/MWh. We also lower DSP activation prices (see footnote below).
- 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 #1:__ DSP prices lowered to the following bands Band 1 = $300/MWh, Band 2 = $300/MWh, Band 3 = $300/MWh, Band 4 = $500/MWh; Reliability response and MPC = $1,000/MWh.
__Note #2:__ Without lowering DSP prices and the MPC, the total increase in cost to load due to constraints is $4.8 billion in 2030.
__Note #3:__ 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.

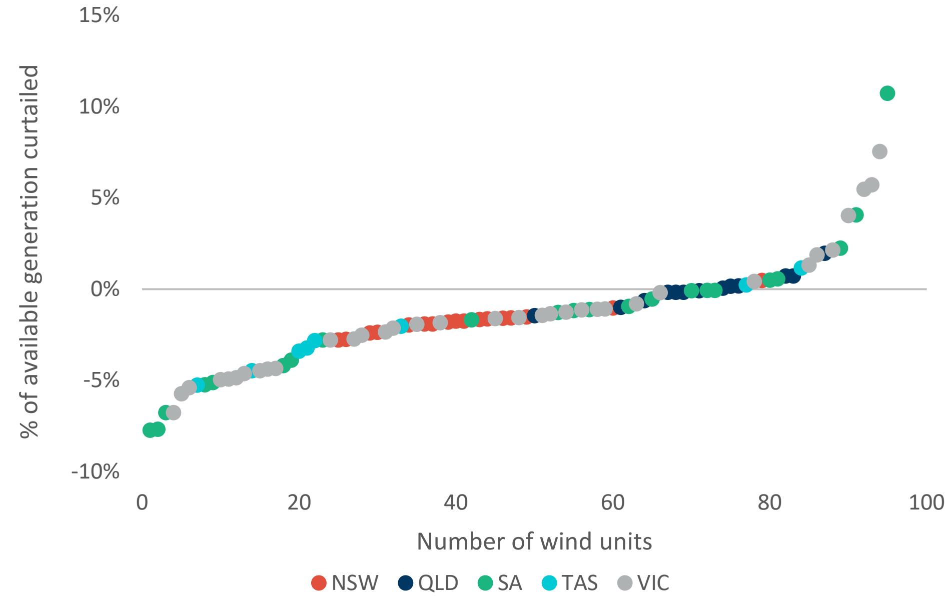
Additionally, generators may face significant loss of revenues depending on where they are located in the NEM

Percentage of curtailment for each renewable generator unit

Solar curtailment by unit



Wind 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 due to grid constraints and competition with other generators (indicating potential excess capacity or “solar spill” in some locations). The most affected states are New South Wales followed by Victoria.
- From a commercial perspective, 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.

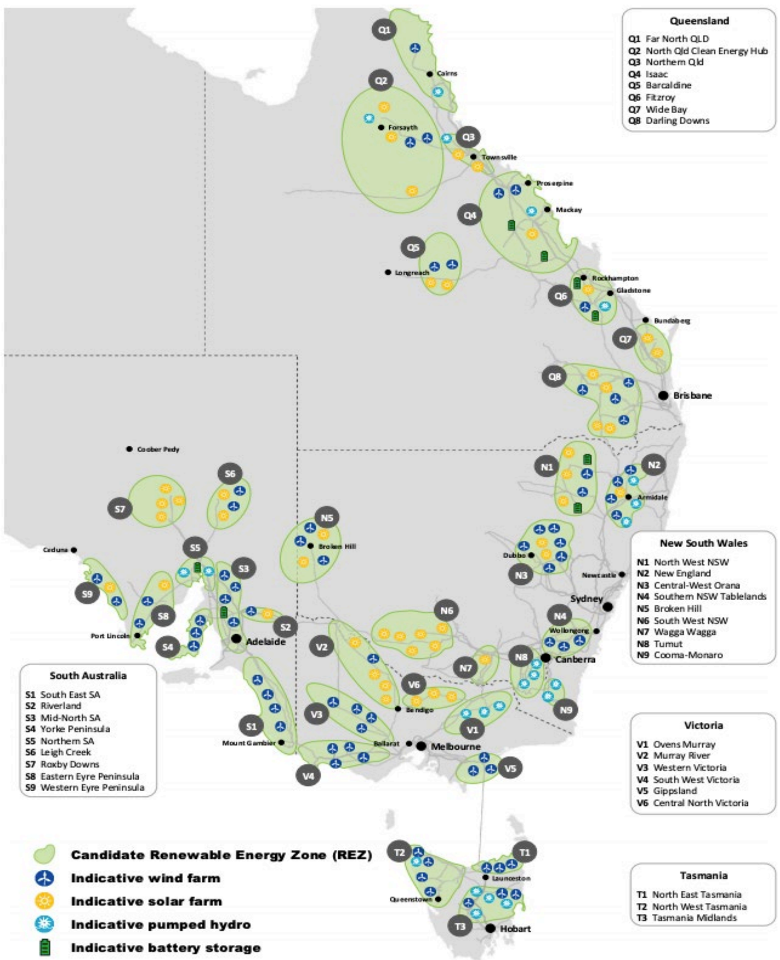
- Relative to an unconstrained scenario, wind generators experience less curtailment than solar due to a more diffused production during the day. The most adversely affected state is Queensland.
- Under a constrained scenario (relative to the unconstrained scenario), some wind generators produce more electricity as:
  - Some wind generators are displaced by solar generators in the “without constraints” scenario (with an average marginal cost of c.$2.8/MWh for wind compared to solar at $0/MWh);
  - In the “with constraints” scenario, more solar generators are curtailed in favour of wind generators.

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

Sensitivity scenarios

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.

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



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)

Approach to our sensitivity analysis:

- We have altered the capacity or location of capacity to our short term dispatch optimisation model to observe the impact on the system.
- The additional capacities in each REZ can exceed the REZ build limit fixed by AEMO to "stress test" the impact on the system.
- For Scenarios 1 and 2, we have added the same amount of capacity in each region for simplicity (instead of weighting by load).
- For Scenario 3, we relocate a share of NSW's battery capacity from the REZs to near the RRN.
- We reduce the MPC to $1,000 to avoid infrequent but significant price spikes from causing undue bias to the overall impact on congestion.

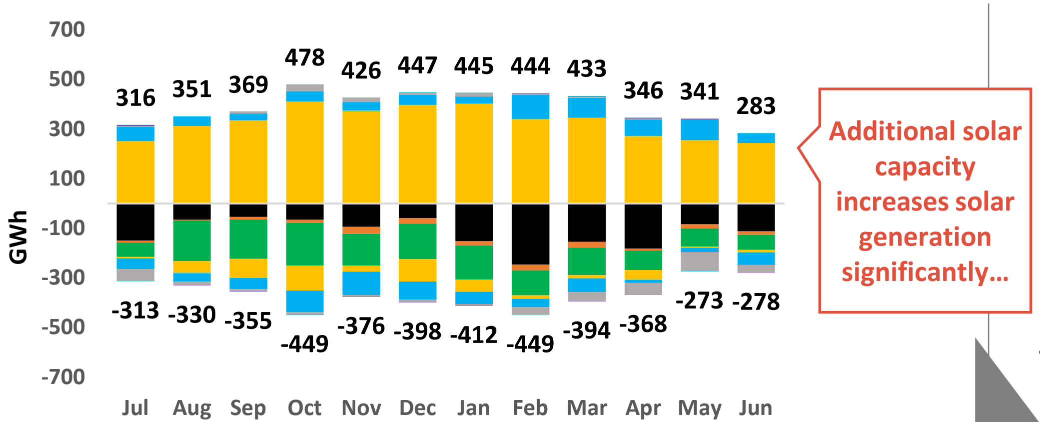
Source: *AEMO.*

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

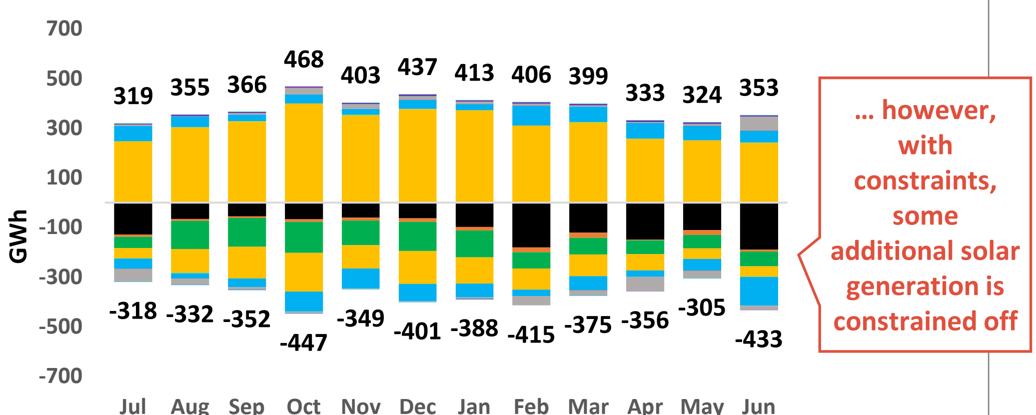
Impact of additional 1.5GW solar capacity on the generation profile

Change in generation mix, sensitivity – base, GWh

Without network constraints

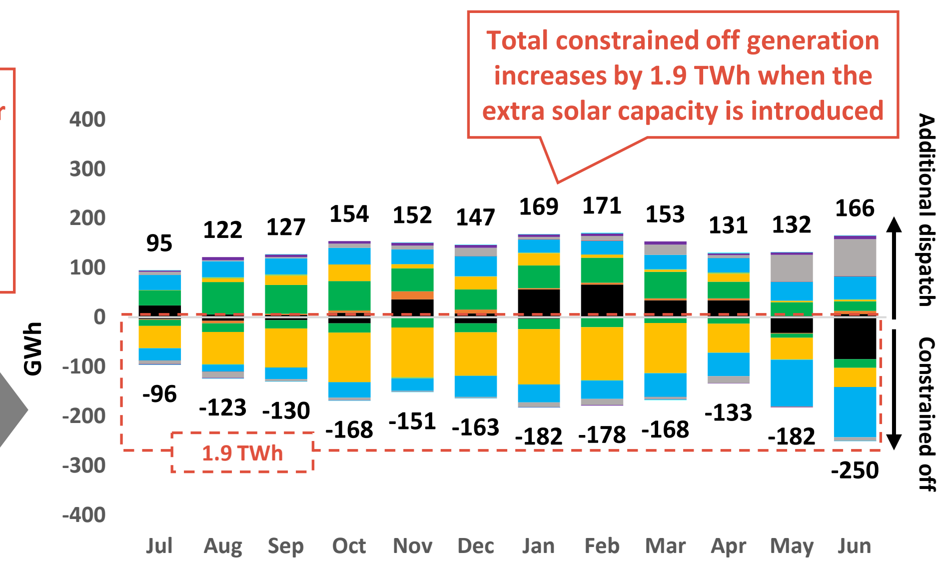


With network constraints



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

With - without network constraints



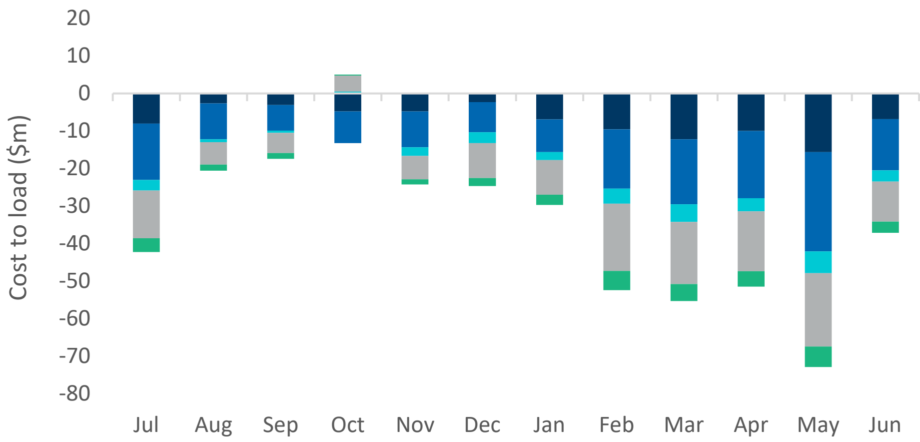
- Without constraints, the additional solar capacity increases total solar generation by 3,500 GWh. Additionally, 1,800 GWh of thermal generation is displaced, primarily black coal. Some wind is also displaced relative to the base scenario.
- However, with constraints, some of the additional potential 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.
- NEM-wide, the addition of 1.5GW of solar capacity increases total constrained off generation by 1.9 TWh across the year relative to the base scenario.

The cost of constraints also increases when additional solar capacity introduced

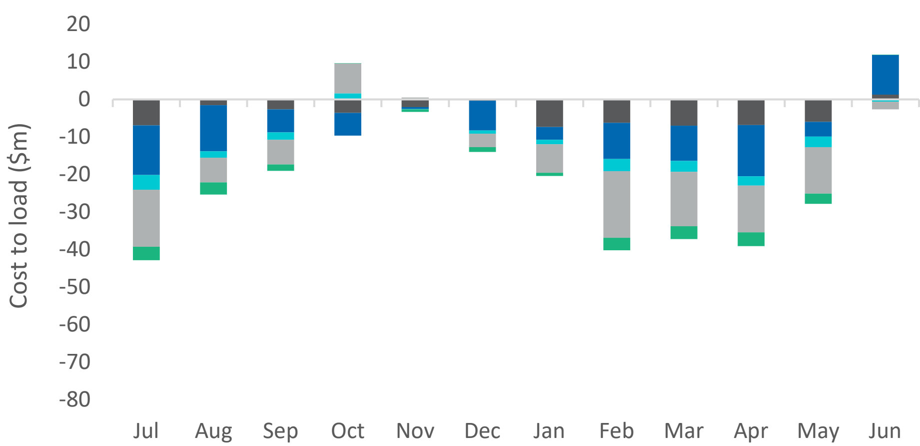
Impact of additional 1.5GW solar capacity on cost to load

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

Without network constraints

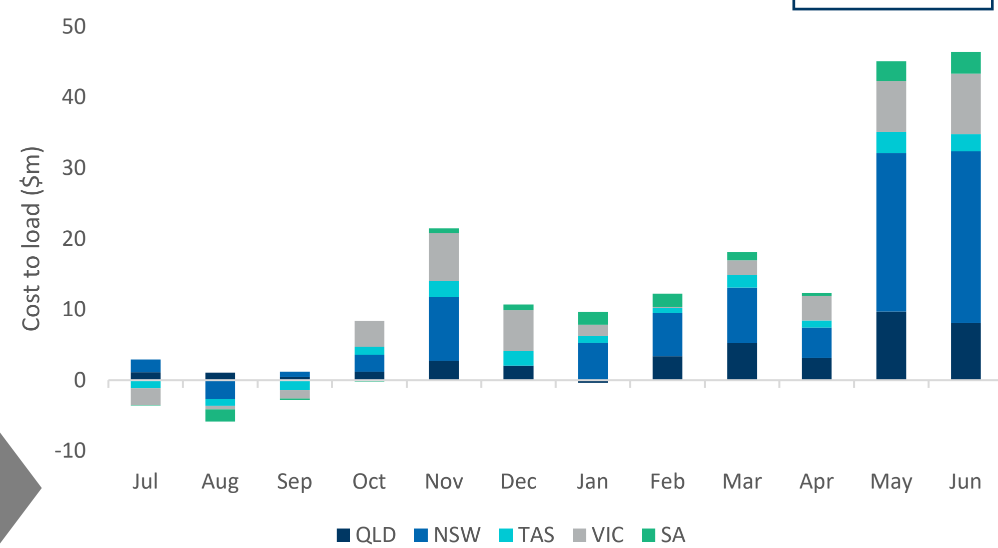


With network constraints



Change in cost to load from additional solar capacity, $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).
- Therefore, in this scenario with additional capacity, introducing constraints increases the cost to load by $1.23bn (from $7,830m to $9,061m). This is higher than the base scenario where constraints increase the cost to load by $1.05bn.

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.*

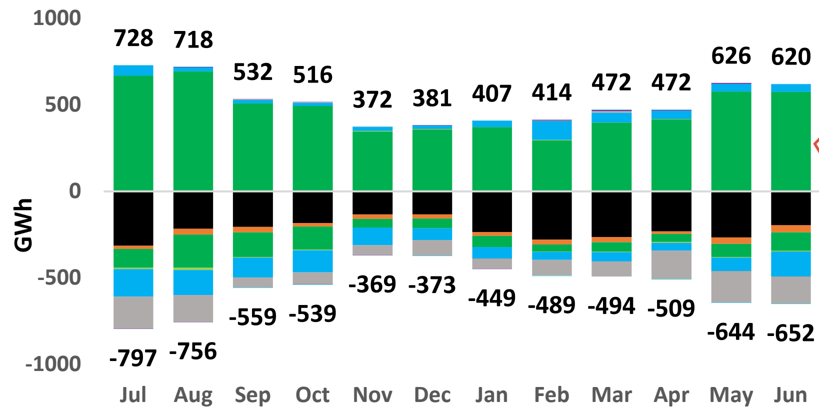
FTI CONSULTING

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

Impact of additional 1.5GW wind capacity on the generation profile

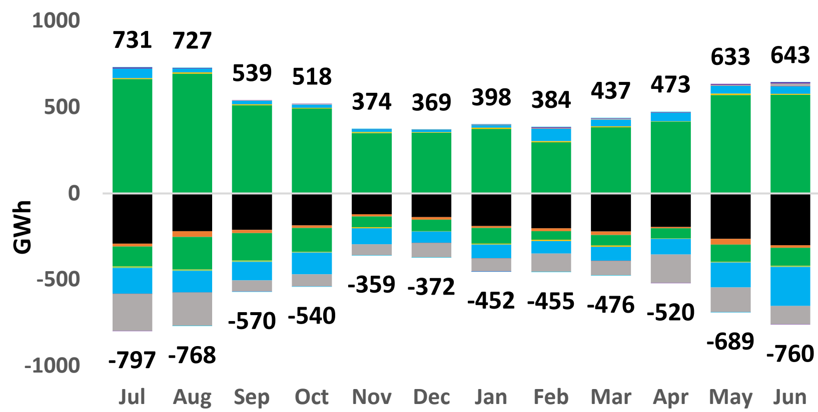
Change in generation mix, sensitivity – base , GWh

Without network constraints



Additional wind capacity increases wind generation significantly

With network constraints



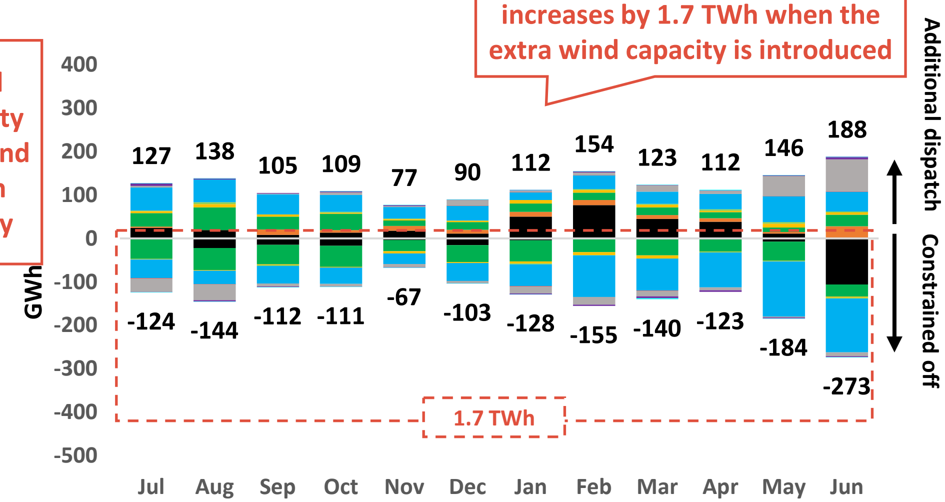
Constraints result in a small amount of extra wind generation being constrained

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

Change in total constrained generation, sensitivity – base, GWh

With - without network constraints

Total constrained off generation increases by 1.7 TWh when the extra wind capacity is introduced



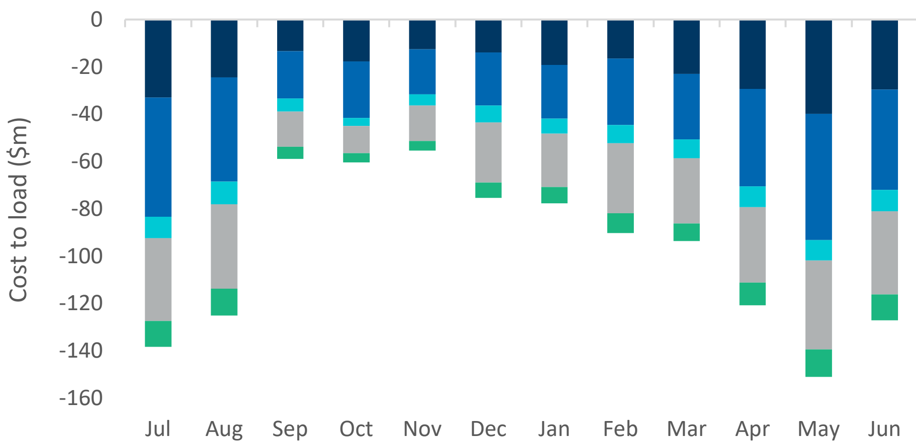
- Without constraints, the addition of 300 MW of wind capacity per state increases total net wind generation by 4,600 GWh. Additionally, 4,300 GWh of thermal generation is displaced, primary black coal and natural gas relative to the base scenario.
- With constraints, approximately 4% of the potential 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.
- NEM-wide, the addition of the wind capacity increases total constrained off generation by 1.7 TWh across the year, relative to the base scenario.

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

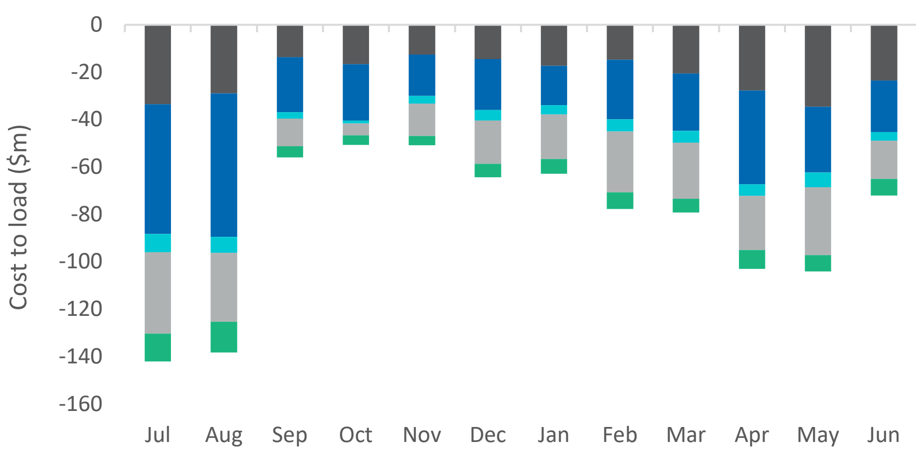
Impact of additional 1.5GW wind capacity on cost to load

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

Without network constraints

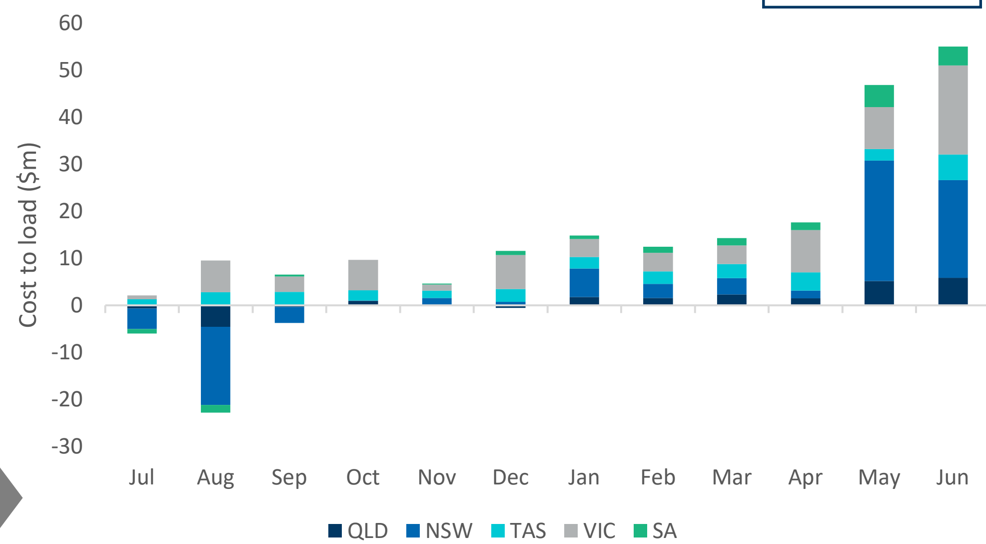


With network constraints



Change in cost to load from additional wind capacity, $m

$172 million / year



- 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).
- Therefore, in this scenario with additional wind capacity, introducing constraints increases the cost to load by $1.23bn (from $7,093m to $8,319m). This is higher than the base scenario where constraints increase the cost to load by $1.05bn.

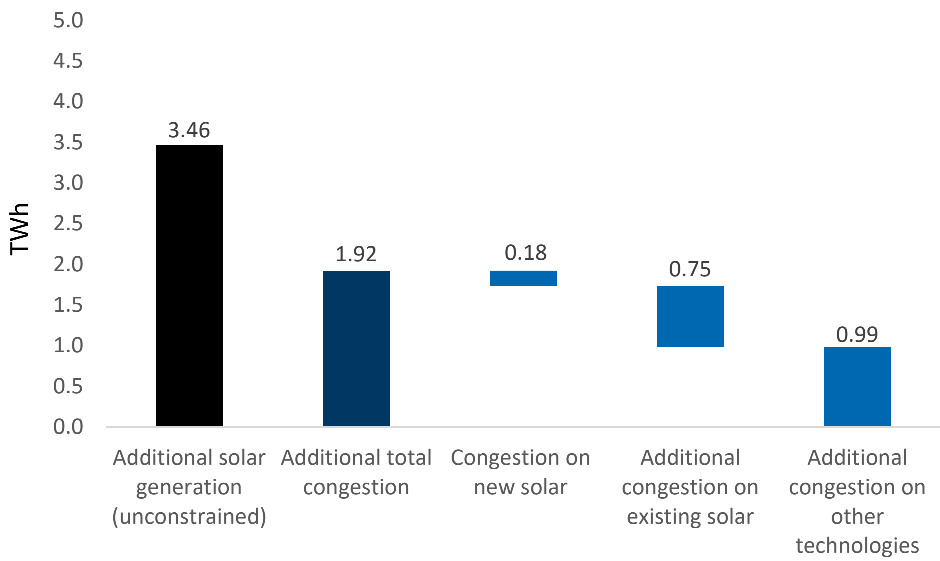
Note: *the Capex and transmission cost of the additional 1.5GW wind capacity is not considered.*

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

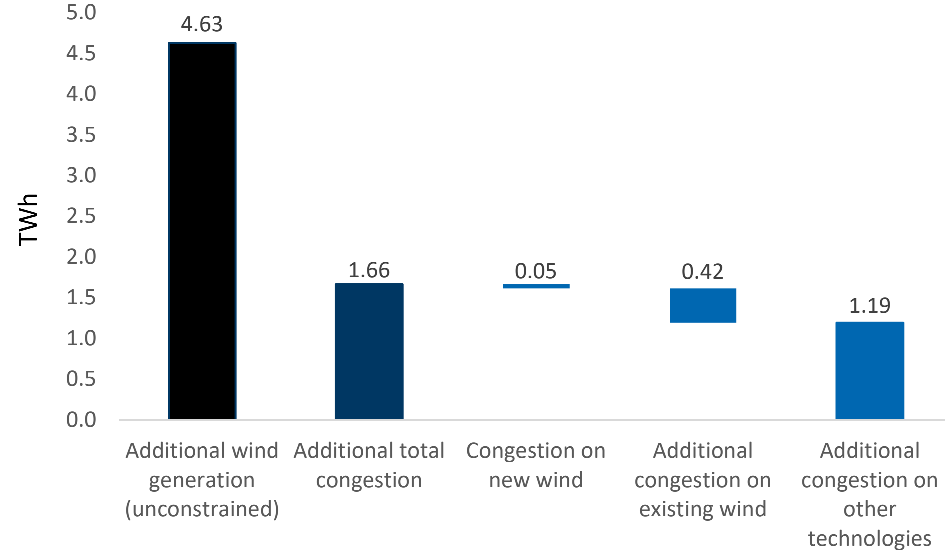
In both scenarios, additional renewable capacity will increase congestion, and in turn, affect the revenue potential across different generators

Impact of additional renewable generation capacity on congestion volumes

Impact of 1.5GW of additional solar capacity



Impact of 1.5GW of additional wind capacity



- In both scenarios, adding 1.5GW of solar or wind capacity leads to an overall increase in congestion volumes relative to the base scenario (see slides 19 to 22). This effect is expected given the considerable increase in additional renewable generation in the system.
- However, these sensitivities enable us to assess the impact on the system when investments are made ahead of transmission development (i.e. deviating from investment outcomes anticipated by the ISP). These deviations may be consistent with the incentives encouraged by the current market design of the NEM.
- 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.

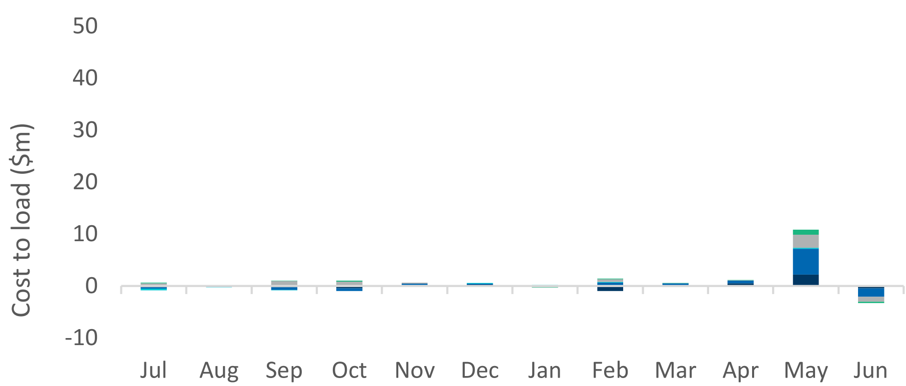
Note: *Congestion volumes for new renewable capacity appear relatively small in our forecast as we have sited the additional capacity in the most productive zones.*

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

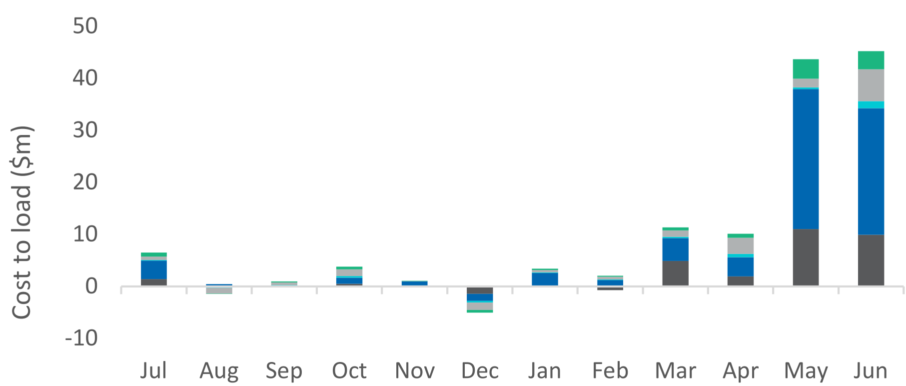
Impact of relocating battery capacity closer to the RRN on cost to load, NSW

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

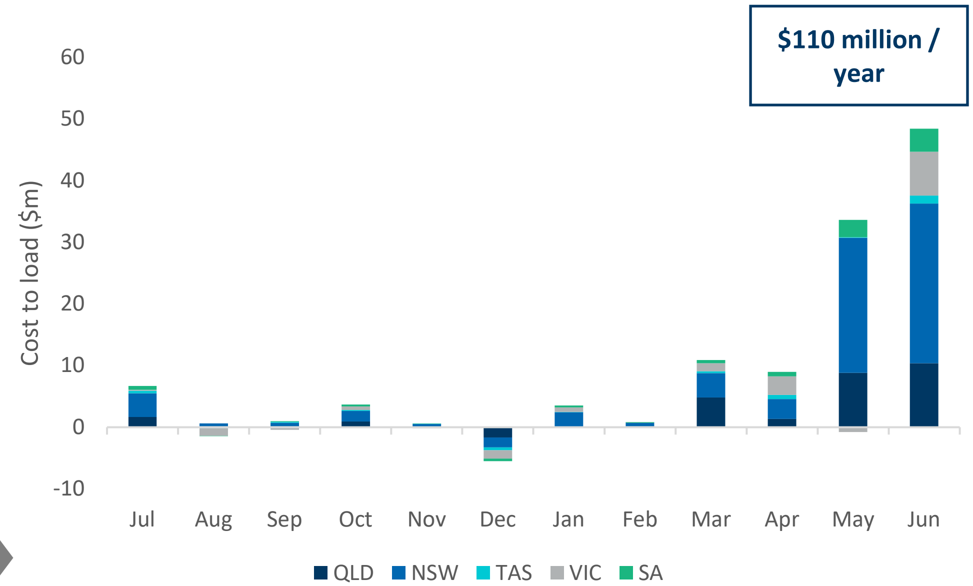
Without network constraints



With network constraints



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

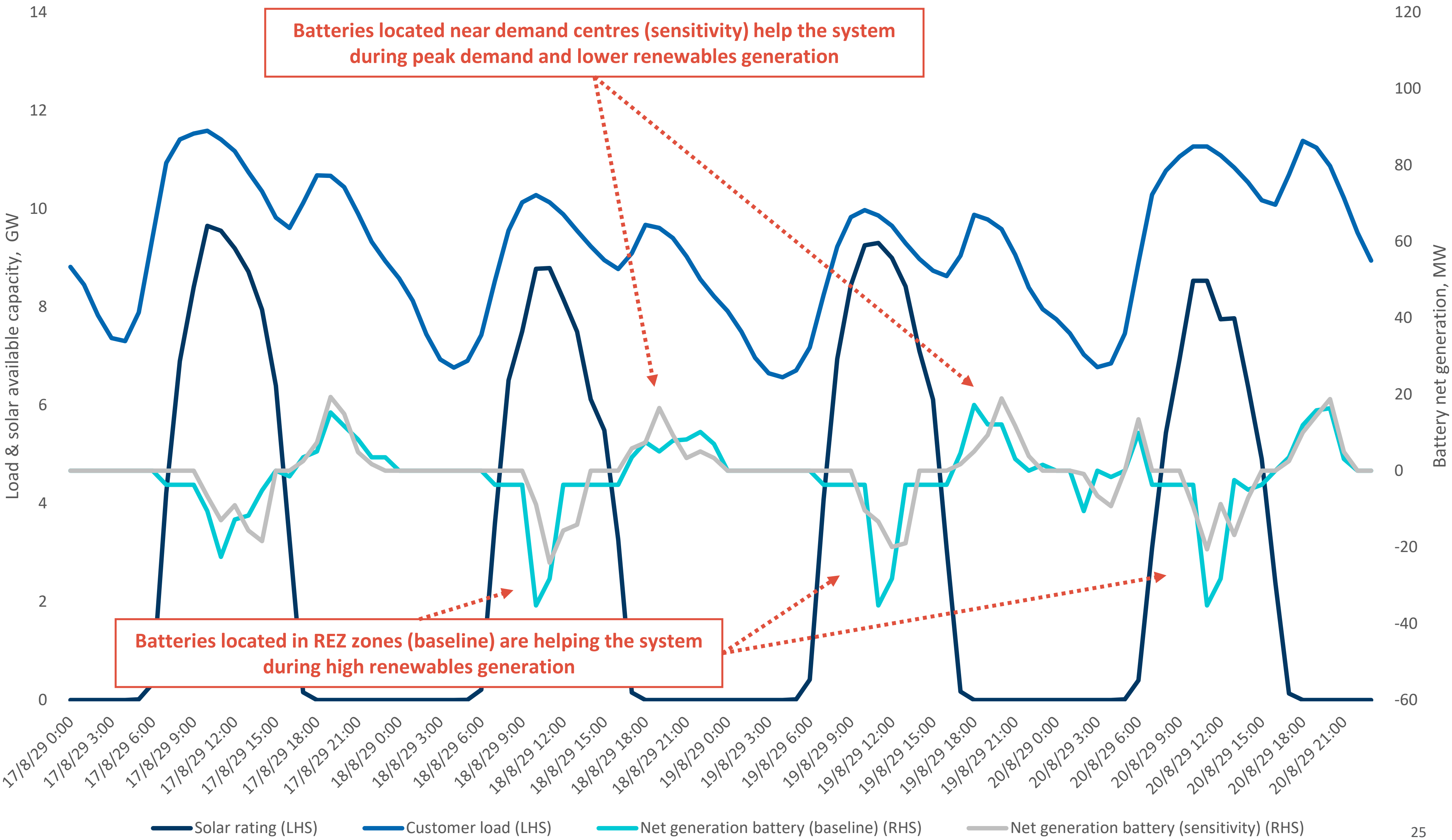


- Without constraints, moving 35MW of batteries in NSW towards the RRN increases cost to load by $11m.
- With constraints, cost to load increases by $121m.
- Therefore, in this scenario where batteries are moved towards the RRN, the overall the cost of constraints increases by $110m relative to the base scenario.
- The increased congestion around the REZ's outweighs the benefit of increased dispatch around the RRN.

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.*

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

"Zoom-in" on NSW battery behaviour, solar generation and demand



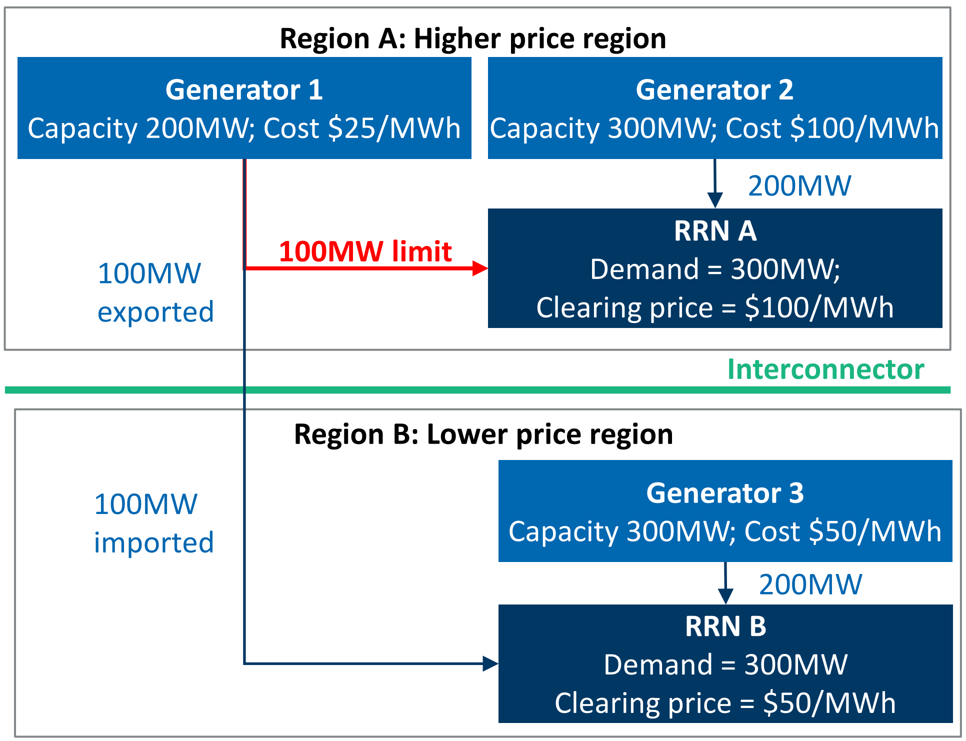
Intra-regional constraints could distort the flow of electricity across interconnectors from a high-priced region to a low-priced region

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

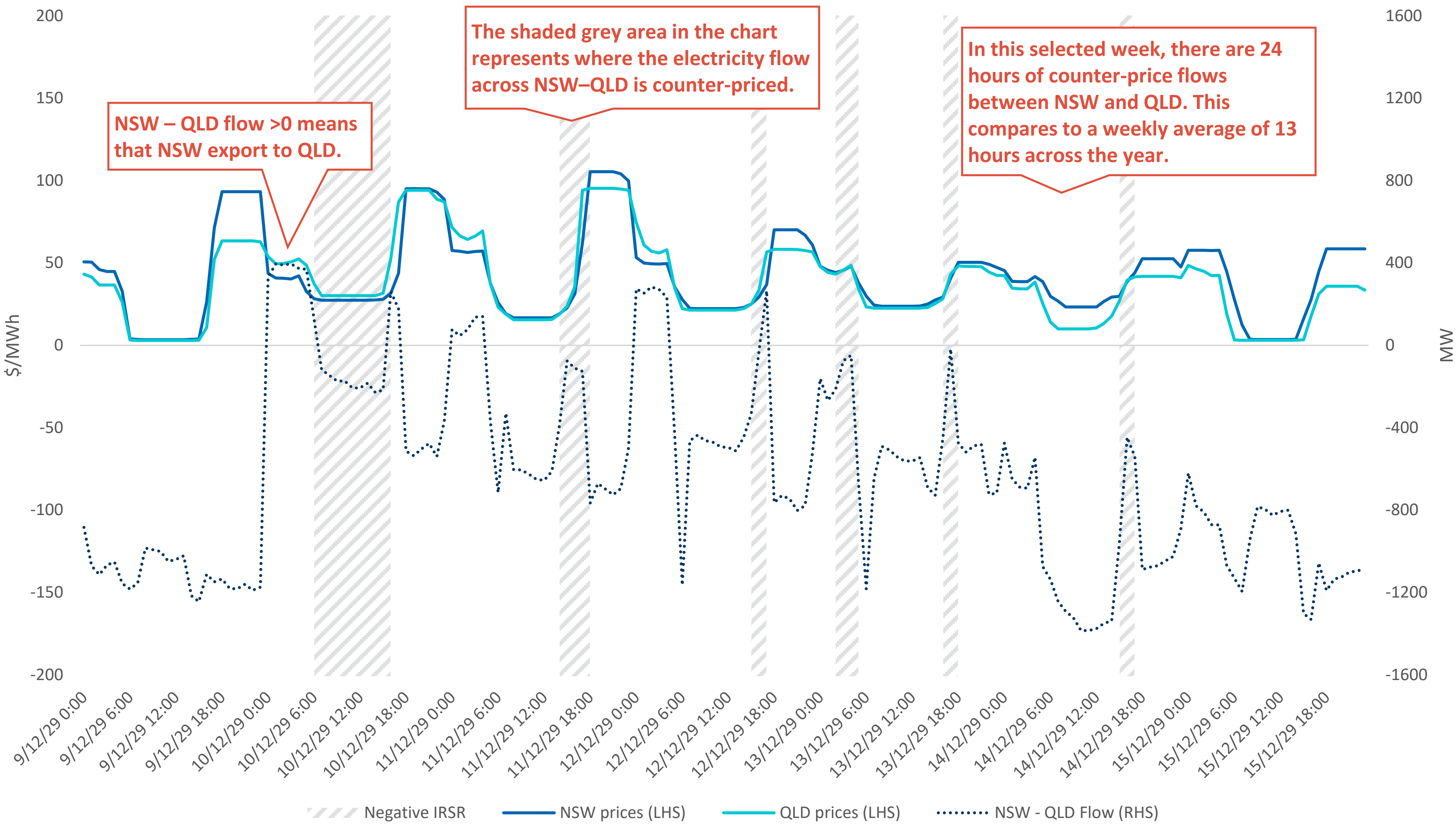


- Gen 1 is constrained and unable to generate at its full capacity to meet demand at RRN A. Nonetheless, it can operate at 200MW as 100MW is exported to meet demand at RRN B.
- Gen 1 is paid the clearing price at $100/MWh. However, consumers pay Gen 1 $50/MWh for the 100MW imported. This creates a **negative 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.

In our model, intra-regional constraints occasionally lead to counter-price flows across interconnectors

"Zoom-in" on hourly net flows between NSW and QLD and wholesale power prices

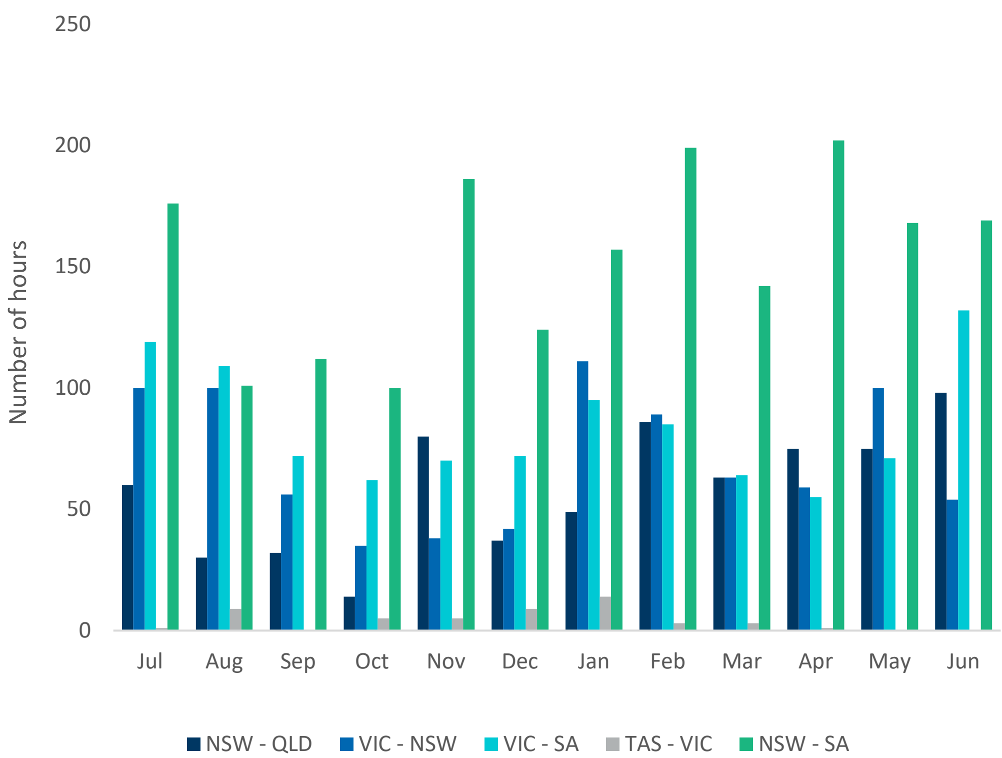


Note: *the model assumes SRMC bidding (with no strategic bidding) to calculate prices and flows. This means that prices here would be the minimum.*

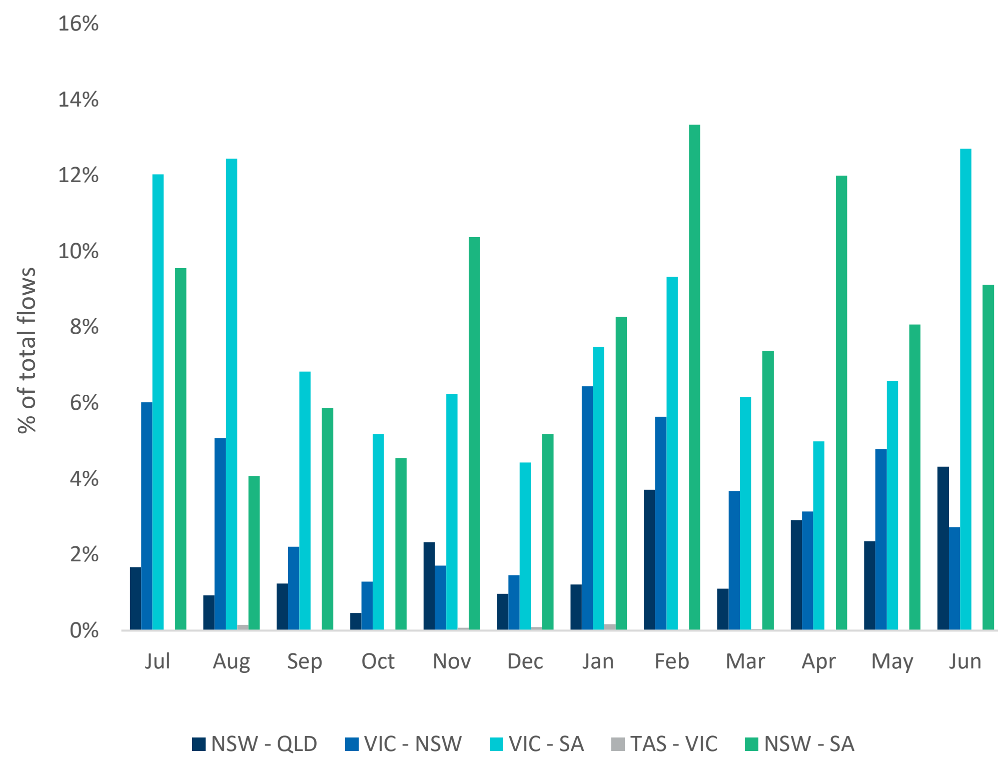
We anticipate that the propensity of loop-flows across the NEM will increase counter-price flows

Volume of counter-price flows

Number of hours of counter-price flows



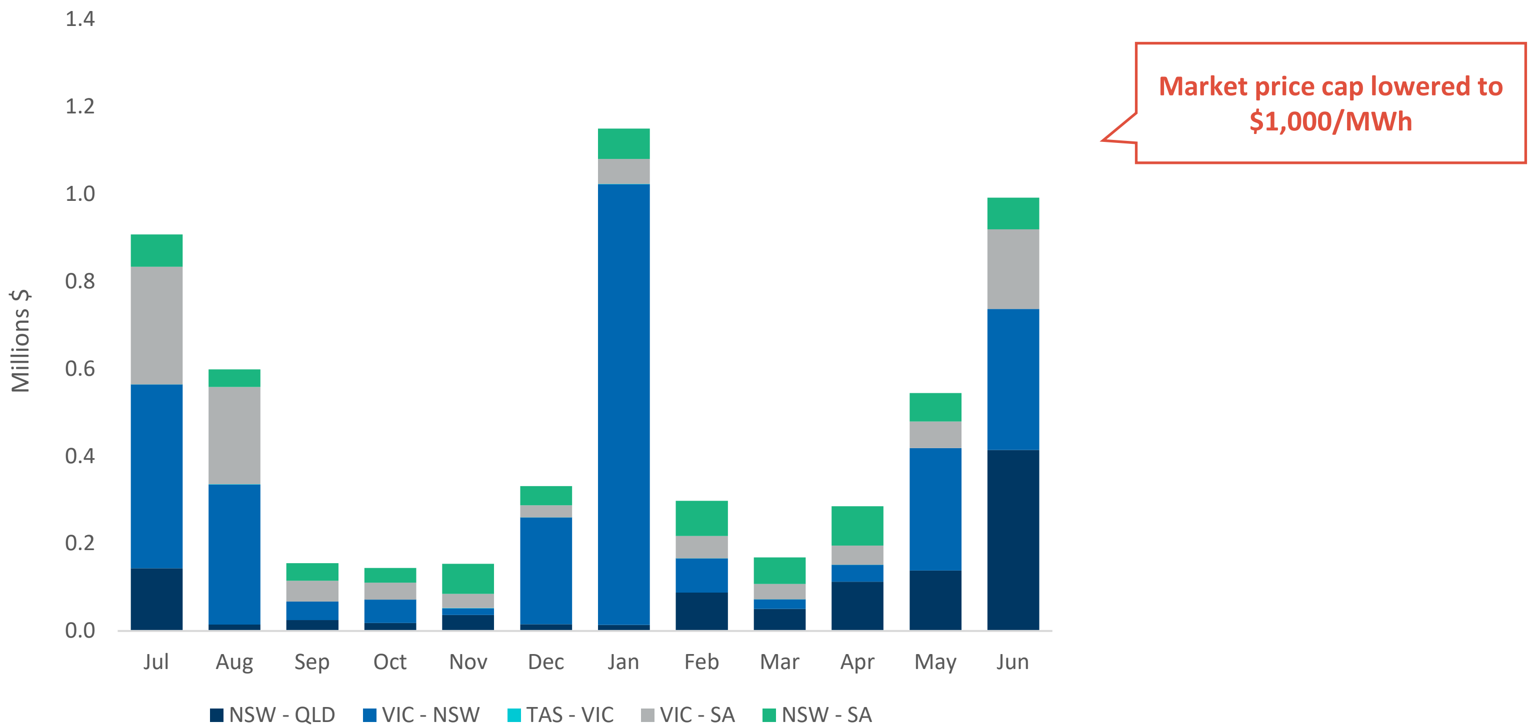
Counter-price flow percentage of total flows



- Loop flows occur when electricity trades in one region impacts 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 is 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 a high number of hours of counter-price flows. This varies considerably across boundaries and months.

Counter-priced flows due to intra-regional constraints occur across each regional boundary in the NEM, leading to greater consumer costs

Total negative IRSR for consumers by month



- We forecast that the total cost due to counter-priced flows is **$5.7m**. This is calculated as the flow through the interconnectors multiplied by the price difference between the regions.
- Given the current NEM market design, this estimate is likely to be the **minimum cost to consumers**. This is because it does not account for disorderly bidding which is difficult to measure and predict. However, we expect this effect to be relatively large due to the inherent incentives and assuming no change to the future market design in each region.
- Counter-priced flows with price differentials of below $0.15/MWh are not included in the analysis (as they may be attributable to interconnector losses instead of intra-regional constraints).

Disclaimer

This report has been prepared by FTI Consulting LLP ("FTI") for the Energy Security Board (the "Client") in connection with forecasting congestion in the National Electricity Market ("NEM") under the terms of the Client's contract with FTI dated 28 June 2021 (the "Contract").

This report has been prepared solely for the benefit of the Client in connection with forecasting congestion in the NEM and no other party is entitled to rely on it for any purpose whatsoever.

This report is not to be referred to or quoted, in whole or in part, in any registration statement, prospectus, public filing, loan agreement, or other agreement or any other document, or used in any legal, arbitral or regulatory proceedings without the prior written approval of FTI. FTI accepts no liability or duty of care to any person (except to the Client under the relevant terms of the Contract) for the content of the report. Accordingly, FTI disclaims all responsibility for the consequences of any person (other than the Client) acting or refraining to act in reliance on the report or for any decisions made or not made which are based upon the report.

The report contains information obtained or derived from a variety of sources. FTI does not accept any responsibility for verifying or establishing the reliability of those sources or verifying the information so provided.

This report is based on information available to FTI at the time of writing of the report and does not take into account any new information which becomes known to us after the date of the report. We accept no responsibility for updating the report or informing any recipient of the report of any such new information.

No representation or warranty of any kind (whether express or implied) is given by FTI to any person (except to the Client under the relevant terms of the Contract) as to the accuracy or completeness of this report.

Nothing in this material constitutes investment, legal, accounting or tax advice, or a representation that any investment or strategy is suitable or appropriate to the recipient's individual circumstances, or otherwise constitutes a personal recommendation.

This report and its contents are confidential and may not be copied or reproduced without the prior written consent of FTI.

Experts with Impact™