TRANSMISSION ACCESS REFORM

TECHNICAL WORKING GROUP

18 AUGUST 2022

AGENDA

Time	Topic
2:00	Welcome, objectives and agenda
2:10	Approach for modelling congestion management options • Scenario definitions and outputs • NERA inputs and assumptions
2:40	Investment timeframe considerations (focus area #2 for combined discussion) • Overview of transmission queue model • Incorporating transmission queue positions into dispatch • Allocating transmission queue positions including role of auctions • Scope for generator funded transmission • Signals for congestion relief
3:55	Next steps

REMINDER - ACCESS OBJECTIVES

Investment timeframes *The level of congestion in the system is consistent with the efficient level.*	Operational timeframes *When congestion occurs, we dispatch the least cost combination of resources that securely meets demand.*
1. Investment efficiency: Better long-term signals for generators, storage and scheduled loads to locate in areas where they can provide the most benefit to consumers, taking into account the impact on overall congestion. 2. Manage access risk: Establish a level playing field that balances investor risk with the continued promotion of new entry that contributes to effective competition in the long-term interests of consumers.	3. Operational efficiency: Remove incentives for non-cost reflective bidding to promote better use of the network in operational timeframes, resulting in more efficient dispatch outcomes and lower costs for consumers.

4. Incentivise congestion relief: Create incentives for technologies that can help to alleviate congestion (e.g. storage and demand-side resources) to locate where they are needed most and operate in ways that benefit the broader system.

REMINDER - ASSESSMENT CRITERIA

	Criteria	Description
1	Efficient market outcomes – investment	Better incentivises for generators, storage such as batteries, and load such as hydrogen electrolysers to locate in efficient areas.
2	Efficient market outcomes - dispatch	Better incentives for market participants to bid in a fashion that best reflects its underlying costs, resulting in more efficient dispatch outcomes and reducing fuel costs across the NEM. In turn, this may also reduce emissions.
3	Appropriate allocation of risk	Risk arising due to congestion in the NEM should be allocated, to the extent possible, to the party that is best placed to manage or otherwise bear that risk.
4	Manage access risk	Address the current market design features that amplify access risk to market participants above what would occur in a natural competitive market. Facilitate market participants' ability to manage access risk. Managing the risk arising from regulatory change, i.e. consider whether there are strategies to mitigate the impact of the changes on market participants.
5	Effective wholesale competition	Avoid creating barriers to new entry.
6	Implementation considerations	Cost, complexity, uncertainty of outcome, the likely timing of benefits versus costs.
7	Integration with jurisdictional REZ schemes	As requested by Ministers, the proposed rules must provide flexibility such that differences between jurisdictions' access schemes, including those without REZ schemes, can be integrated.

APPROACH FOR MODELLING CONGESTION MANAGEMENT OPTIONS

Purpose

The ESB has contracted NERA Economic Consulting (NERA) to perform an iterative market modelling exercise to quantify the outcomes resulting from different congestion management design options, focused on the operational timeframes.

Today's session is designed to facilitate TWG discussion and feedback on the proposed:

- structure of the modelling scenarios and outputs
- questions that will be informed / quantified by modelling
- summary of inputs and assumptions used in the congestion management nodal model (refer to companion memo from NERA).

Scope exclusions

- Cost benefit analysis (NERA modelling will provide some, but not all, inputs to the CBA)
- Congestion models addressing investment timeframes (modelling approach to be shared with TWG in future workshops)

Scenario definitions

- All model options will be compared to the following scenario to identify variances in cost and profit outcomes:
  - Status quo energy market structure with cost reflective bidding
- To date, modelling approach has considered two design options:
  - Congestion management model (CMM) with alternative rebate allocation methods
  - Congestion relief market (CRM)
- Rebate allocation methods for the CMM include (naming conventions are consistent with “20220721_TWG working paper_CMM allocation methods_final”)
  - Pro rata access
  - Pro rata entitlement
  - Winner takes all
  - Inferred economic dispatch
- CRM is structured as two dispatches (in accordance with “20220721_TWG working paper_CRM reference paper_final”). Variable inputs can be altered for each dispatch:
  - Access dispatch
  - Physical dispatch

Variable inputs for scenario definitions

- Period (start date – end date)
- Bidding behaviours (at cost, market floor price, unavailable, alternative bidding strategies)
- PPA assumptions (% generation output contracted, assumed strike price – wind, solar)
- Model design and variant (CMM with variant rebate allocation methods, CRM)
- Rounding of contribution factors (affecting calculation of rebates and outcomes of ‘access dispatch’, not physical dispatch)
- Inclusion / exclusion of out of merit generators from access dispatch
- Opt-in % of generators to the CRM (alternative % for thermal, storage and VRE)

Key outputs

- $/MWh - RRP by dispatch interval / volume weighted over period
- $/MWh - LMP by generator / node
- $ - Cost of generation by generator / node / region / NEM
- $ - Profit for generator / node / region / NEM
- MWh / % - Network curtailment

KEY QUESTIONS

The table below lists the key questions that will be informed by modelling outcomes. The model outputs will help to:

- understand the impact of design choices for individual participants
- forecast the impacts as the energy market transitions
- assess policy design choices in accordance with the transmission access reform objectives.

#	Question	Scenario definitions / model outputs
1	How are different market participants affected under different design choices?	Scenario outputs include the cost and profit variance by region and the profit variance by node compared to Scenario 1 (status quo - cost reflective bidding).
2	How are different market participants affected over time?	Intervals and time periods to be confirmed e.g. outputs for a full year at [5] year intervals, continuous modelling over [5-10] year period.
3	How will bidding strategies change depending on the policy option? Will generators face incentives to bid at cost in the CMM and CRM physical dispatch?	Scenario definitions include bidding strategies for unconstrained generators, constrained generators, contracted generators (PPA) and storage. The proposed inputs are based on working theories of bidding strategies in response to the policy design options. Model outcomes will refine these working theories. Scenario definitions include cost reflective bidding and disorderly bidding strategies (market price floor, MPF). Outcomes will identify if generators maximise profits by bidding at cost or disorderly.

KEY QUESTIONS (CONTINUED)

#	Question	Scenario definitions / model outputs
4	How are bidding strategies affected by PPA contracts?	Scenario definitions include assumptions for PPAs based on a contract for difference. PPA scenarios assume all renewable energy projects have PPAs, with variable % of generation contracted and variable PPA strike price.
5	Will market participants be incentivised to participate in the CRM?	Scenario definitions compare total cost and profit outcomes for participants if they do / do not participate in the CRM. Incentives to participate will depend on the financial upside available.
6	How are total cost outcomes / efficiency affected by varying levels of CRM participation?	Scenario definitions (and sensitivities) allow for varying levels of opt-in to the CRM in order to quantify the cost and profit outcomes in total, and by node.
7	How do the policy options provide signals for congestion relief? What is the potential size of increased profit available to batteries as a result of accessing LMPs?	Dashboard includes total cost and profit outcomes for storage under different policy options.

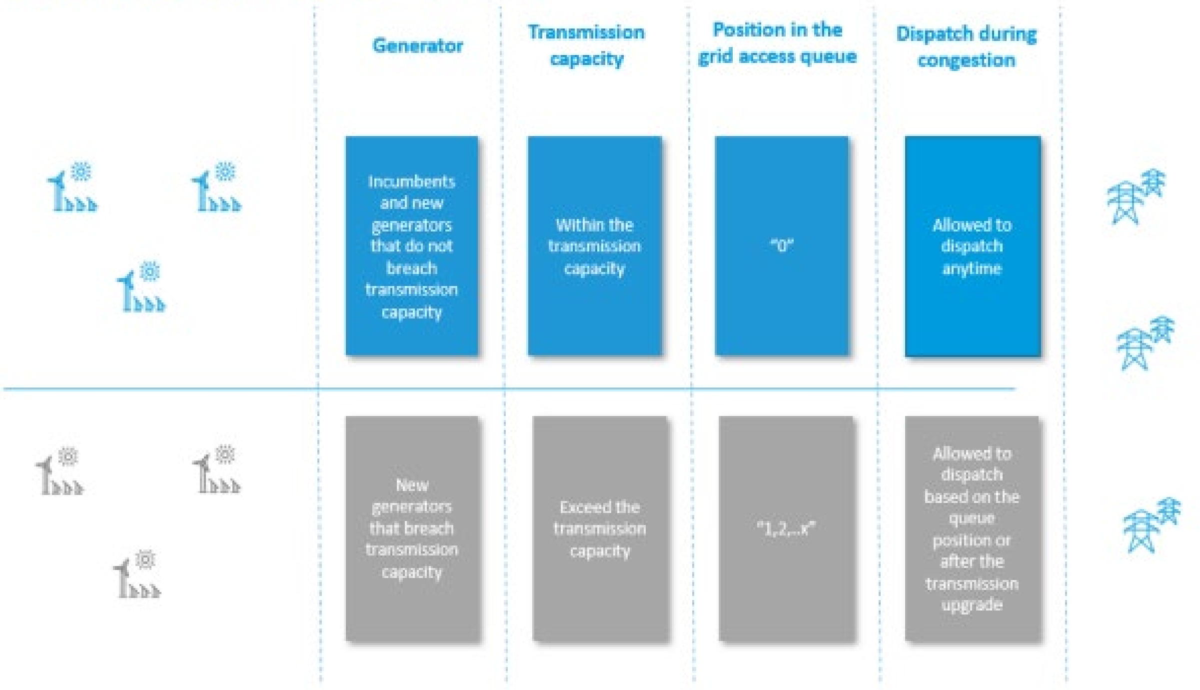
KEY QUESTIONS (CONTINUED)

#	Question	Scenario definitions / model outputs
8	Both the CMM and CRM raises issues for the treatment of out-of-merit (OOM) generators that may financially benefit from the access allocation method, despite not being in merit for physical dispatch. What is the potential size of this revenue transfer to OOM generators?	Scenario definitions include and exclude OOM generators to identify the materiality of the wealth transfer. This issue is not relevant to the 'inferred economic dispatch' method which already factors in assumed generation costs.
9	What is the impact on market participants if the policy design softens the knife-edge properties of contribution factors in access payments? [NB: We do not propose to change the treatment of generator coefficients in dispatch.]	Scenario definitions include an adjustment to the decimal places of contribution factors (coefficient a) to assess the impact on market participants from adjusting access payments.
10	NEMDE is a least cost solution. How will RRP be affected by the model options and bidding strategies?	Scenario outputs include RRP outcomes (by dispatch interval and volume weighted across periods).

TRANSMISSION QUEUE MODEL

OVERVIEW

Figure 3.1: Overview of the Transmission Queue

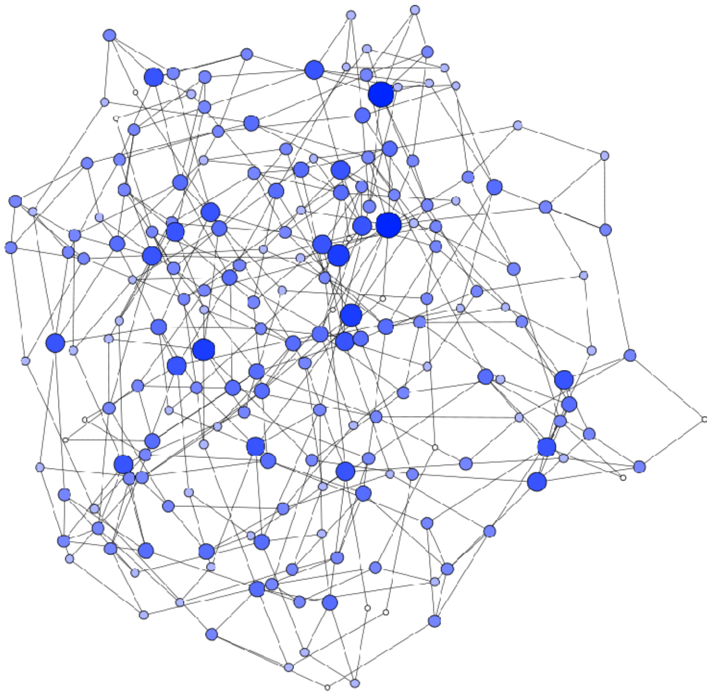


- Model creates a dispatch queue that will provide a firm and stable access right to local transmission capacity.
- When local constraints arise, generators are curtailed in queue order – last in, first curtailed.
- Queue positions are allocated either first come first served, or via auction if over-subscribed
- Encourages investors to build in locations
  - that will not have a negative impact on congestion or
  - where prospective curtailment is within acceptable level.

INCORPORATING TRANSMISSION QUEUE POSITIONS INTO DISPATCH

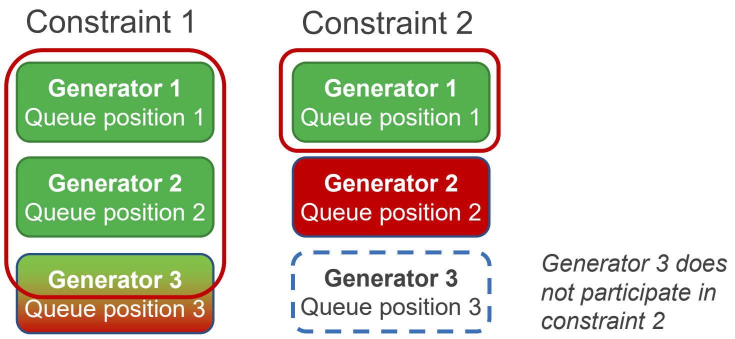
“LAST IN, FIRST OFF” IN A MESHED NETWORK

- On a meshed network, what happens on one part of the system affects what happens on every other part of the system
- Under transmission queue model, when local constraints arise, generators are curtailed in queue order – last in, first curtailed.
- Model is not designed to provide a firm physical transmission right to the whole of the meshed transmission grid.
    - Instead, it provides a much firmer access right to local transmission capacity.
- It is not clear that this approach can be generalised to a situation of multiple binding constraints and regions.
    - Some constraints include all the generators in a region
    - New connections can impact distant locations



Source: Pagani & Aiello (2012)

EXAMPLE – MULTIPLE BINDING CONSTRAINTS



- Not clear how to co-optimise dispatch by curtailing in reverse queue order.
- Low priority generator may get dispatched ahead of a high priority generator if the zero queue position generator needs to be curtailed due to a second constraint.
- For instance, generator 3 may be able to be fully dispatched notwithstanding Constraint 1 due to the impact of Constraint 2 on Generator 2.

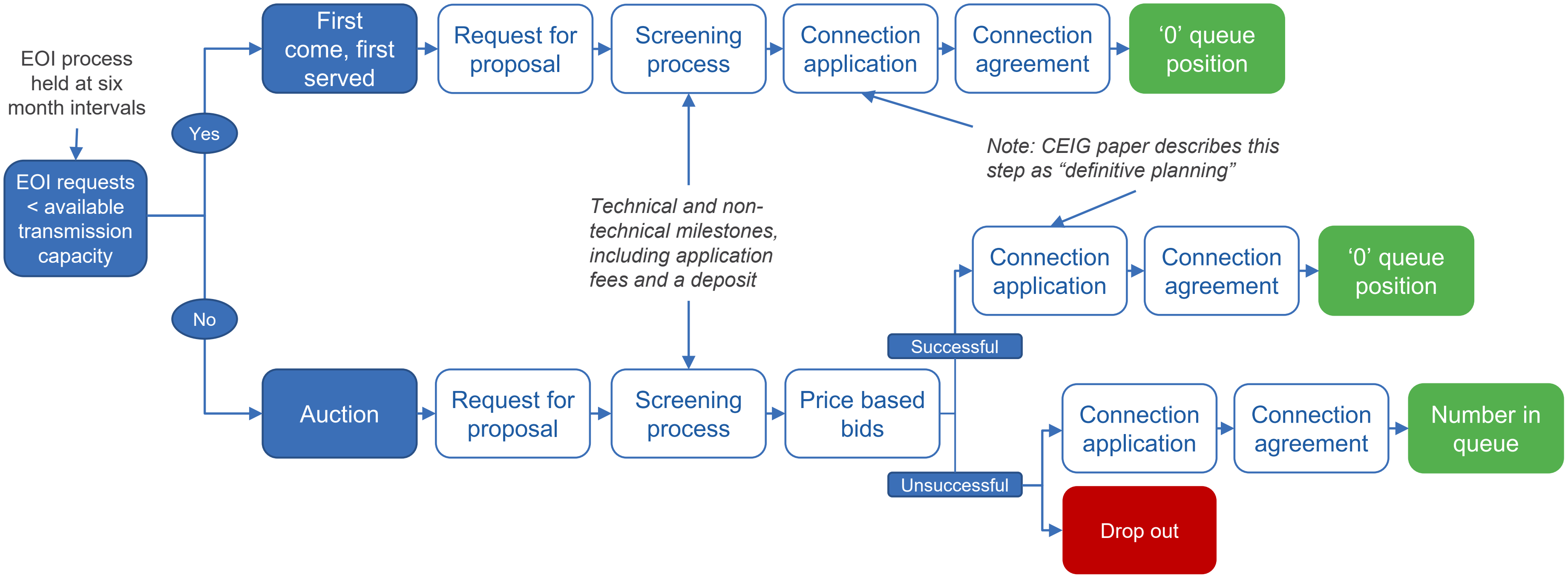
Possible solution – work up, not down, the queue

Dispatch generators at the front of the queue first, and then progressively add lower priority generators to the dispatch until the constraint is binding.

- Challenge: ESB's suggested solution requires multiple iterations of dispatch
  - Each dispatch is a complete, feasible dispatch, calculated using the dispatch algorithm.
  - If there are N queue positions, then N runs of the dispatch algorithm will be required to calculate the TQM dispatch.
  - If the CRM is added, one further run of the dispatch algorithm will be needed to clear this market.
- Computational complexity seems likely to limit number of queue positions on offer.

PROCESS FOR ALLOCATING TRANSMISSION QUEUE POSITIONS

TRANSMISSION QUEUE MODEL – AUCTION PROCESS



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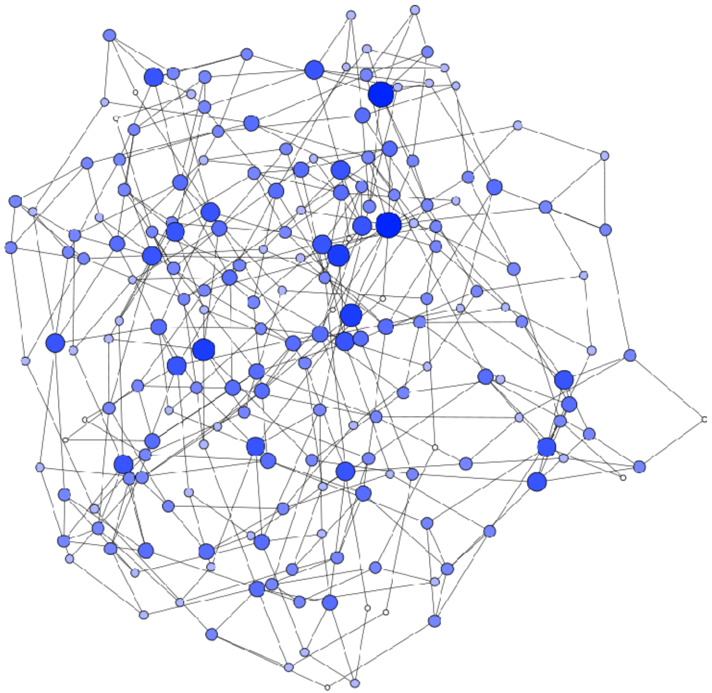

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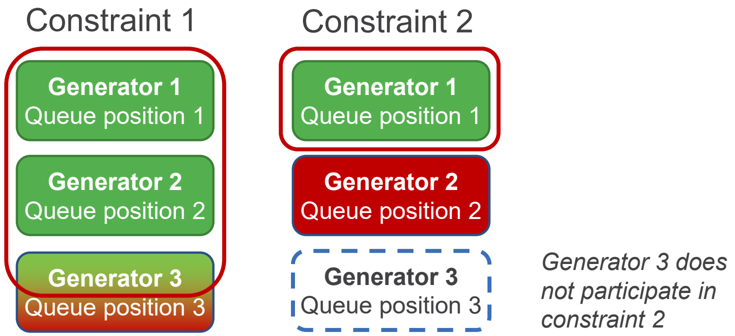

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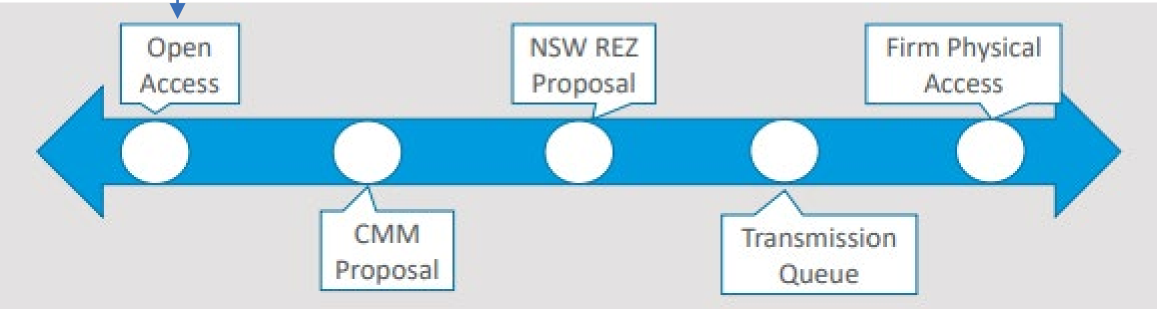
ROLE OF AUCTIONS

- If we shift away from current unlimited access model, some form of rationing mechanism is required
  - A queue is implicit in connection fees – the fees increase as more generators connect (and forecast congestion increases).
  - Alternative is first-come first-served
- How do generators form a view on the value of a firm queue position?
  - When we consulted on CMM, the ESB was told that generators can’t place a value on congestion rebates
  - Why is the transmission queue different?

Should the investment timeframe model use auctions when transmission capacity is over-subscribed?

SPECTRUM OF FIRMNESS

All parties have non-firm access



Source: Castalia

Some parties have firm access, some non-firm

- Transmission queue model adopts “last in, first curtailed” principle.
- When we consulted on CMM-REZ, the ESB was told that investors would be unwilling to go non-firm.

Will investors accept non-firm queue positions?

SCOPE FOR GENERATOR-FUNDED TRANSMISSION

GENERATOR FUNDED TRANSMISSION

Note: Regulatory framework for planning and investing in prescribed transmission assets is beyond scope. This is being considered in TPIR.

Status quo

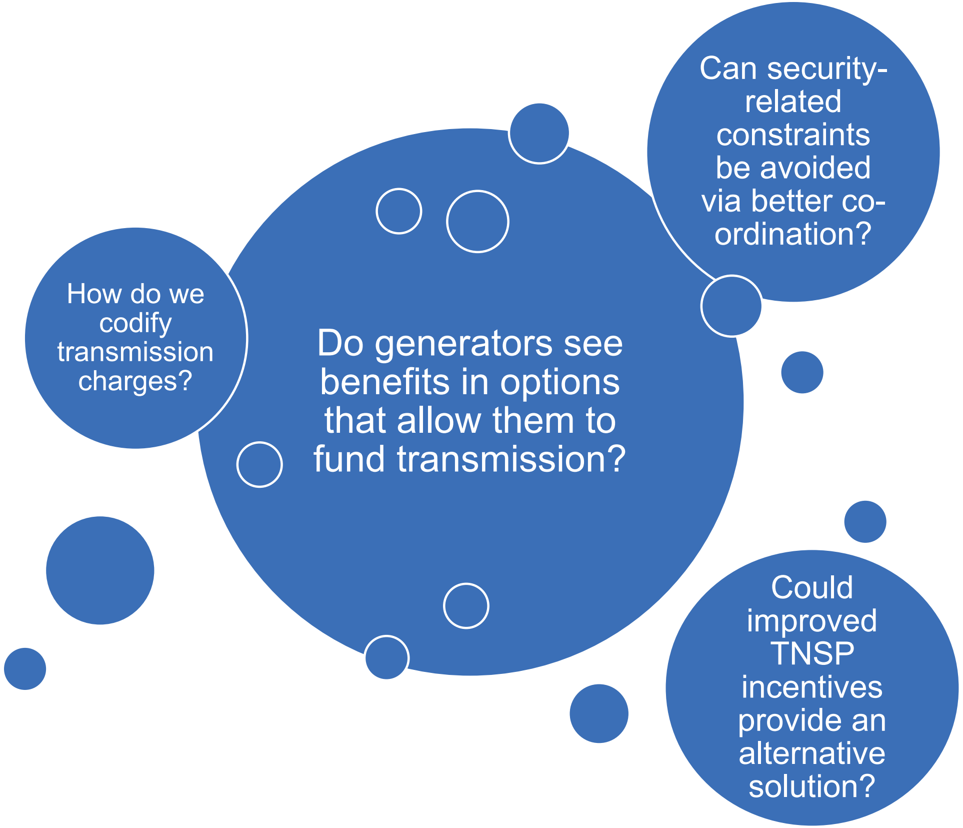
- Current access regime limits scope for generator funded transmission
- Subsequent entrants can free-ride, so no incentive to invest
- Scope for investment in designated network assets, limited to radial assets.

Transmission queue model

- New entrant can fund transmission investment to improve position in queue
- Pays a transmission charge to augment local transmission (note – not necessary to avoid creating congestion anywhere in the network)
- Formalised process for setting transmission charges
- Standardize generator-paid upgrades and allow for regulatory oversight.

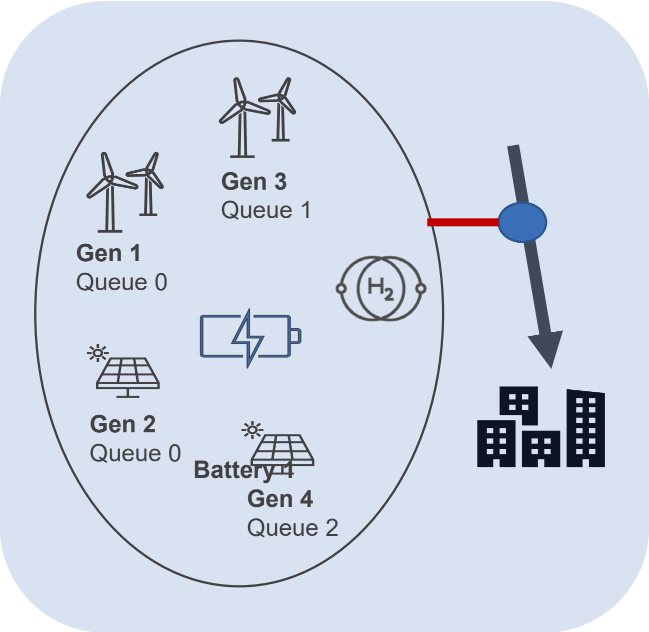
KEY CHALLENGES FOR DISCUSSION

- Safety valve gives generators more options when faced with transmission congestion
- Potential to drive efficient transmission investment, particularly where there are opportunities for incremental investments to release additional capacity
- However:
  - Investments to alleviate thermal constraints are very lumpy
  - Solutions to release additional capacity are likely to be bespoke depending on local network conditions
  - TNSPs may find it profitable to charge generators to provide services instead of seeking funding via the revenue determination



SIGNALS FOR CONGESTION RELIEF

GIVING EFFECT TO BILATERAL CONTRACTS FOR CONGESTION RELIEF



- Under current market design, batteries that provide congestion relief are often located behind the meter of the generator they are providing relief to.
- Under transmission queue model, generators may fund storage in return for a higher priority queue position
  - Generator enters into a contractual arrangement with storage to provide congestion relief
- ESB is exploring how a contracted generator can be assured that they will be dispatched when the battery charges, and not some other generator.
  - For instance, if Generator 1 enters into a contract with Battery 1, how do we know that Generator 1 gets the extra dispatch as a result of the battery charging, and not Generator 2?

Could the congestion relief market provide a solution?

APPROACH TO STORAGE AND DEMAND SIDE RESOURCES – CONNECTION FEES

- Previous TWG meetings have discussed the possibility of negative connection fees for parties that alleviate congestion
- Connection fees provide a once-off signal at the time of the investment decision.
- However, batteries can either exacerbate or alleviate congestion, depending on how they operate.

- Arrangements should be designed having regard to operational timeframes.
- If operational model provides correct signals, maybe the right answer is no connection fees for storage?

ESB is keeping the matter under review

NEXT STEPS

NEXT STEPS

Date	Investment	Operational	Description
25 August 2022		☑	Workshop: contract considerations, follow up on bidding strategies
1 September 2022	☑		Focus area 1 working papers
8 September 2022		☑	Workshop: signals for storage and scheduled load
15 September 2022	☑		Initial discussion of focus area 3 issues Focus area 2 working papers
22 September 2022		☑	*Workshop: to be confirmed (may be postponed in favour of combined TWG 29 Sept 2022)*
29 September 2022	☑	☑	Review outputs of NERA modelling Focus area 3 working papers (as necessary)
October 2022			*Draft report (date to be confirmed)*

Details of focus areas for investment timeframes are provided overleaf.

FOCUS ISSUES FOR DETAILED DESIGN

Focus area 1

Parties subject to the access arrangement

Quantifying available transmission hosting capacity

Process used to quantify transmission hosting capacity

Basis of connection fees

Focus area 2

Process for allocating transmission queue positions

Maximising hosting capacity of available transmission (incl. safety net)

Signals for congestion relief

Today's session

Focus area 3

Efficient retirement decisions

Treatment of pre-existing generators

Governance

Payment arrangements

Integration with jurisdictional schemes

Interaction with other schemes

Focus area 4

Modelling of impacts

Implementation

Transitional arrangements

Cost benefit analysis

Use of revenues