Grid access reform (COGATI) review – technical working group # 8
18 June 2020

The eighth technical working group meeting was held by Webinar on 18 June 2020.

The technical working group was formed by the Australian Energy Market Commission (AEMC) to provide advice and input into the progression of the grid access reform (COGATI) review (EPR0073).

All enquiries on this project should be addressed to Russell Pendlebury on (02) 8296 0620 or Tom Walker on 0410 764 175.

The attendees of the meeting are listed below.

Member	Organisation
Andrew Kingsmill	TransGrid
Angus Holcombe	Meridian Energy
Anh Mai	AusNet Services
Arista Kontos	Australian Energy Regulator (AER)
Ben Skinner	Australian Energy Council
Bill Jackson	ElectraNet
Dan Mascarenhas	AGL
Daniel Woodfield	Rio Tinto
Darryl Biggar	Australian Energy Regulator (AER)
David Havyatt	Energy Consumers Australia (ECA)
David Scott	Australian Energy Market Operator (AEMO)
Dean Gannaway	Aurizon
Donovan Marsh	Energy Security Board
George Anstey	NERA Economic Consulting – Conducting a cost-benefit analysis of reforms for the AEMC
Gordon Leslie	Monash University
Greg Hesse	Powerlink
Henry Gorniak	CS Energy
Jack San	Ausnet services
Jevon Carding	Lighthouse Infrastructure
Jill Cainey	Energy Networks Australia (ENA)
Joel Gilmore	Infigen
Jon Sibley	Australian Renewable Energy Agency (ARENA)
Kirsten Hall	Australian Energy Market Operator (AEMO)
Lawrence Irlam	Energy Australia
Lillian Patterson	Clean Energy Council (CEC)
Miyuru	PIAC
Nabil Chemali	Flow Power
Nishana Perera	Australian Energy Regulator (AER)
Panos Priftakis	Snowy Hydro

Peter Nesbitt	Hydro Tasmania
Rob Koh	Morgan Stanley
Robert Pane	Intergen
Ron Logan	ERM Power
Sam Ingram	Cleanco
Sally McMahon	Spark Infrastructure
Sarah-Jane Derby	Origin Energy
Sofia Birattari	NERA Economic Consulting – Conducting a cost-benefit analysis of reforms for the AEMC
Steven Nethery	Goldwind
Tim Astley	TasNetworks
Tom Geiser	Neoen
Verity Watson	Energy Networks Australia (ENA)
Will Taylor	NERA Economic Consulting – Conducting a cost-benefit analysis of reforms for the AEMC

The AEMC's project team attended and is listed below.

Name	Position
Victoria Mollard	Acting Executive General Manager – Security & Reliability
Orrie Johan	Adviser – Transmission and Distribution Networks
Russell Pendlebury	Senior Adviser – Retail and Wholesale Markets
James Tyrrell	Senior Adviser – Transmission and Distribution Networks
Ella Pybus	Consultant – Cambridge Economic Policy Associates
Tom Walker	Senior Economist
Jessica Scranton	Lawyer
Tom Meares	Graduate Advisor
Peter Thomas	Digital Communications Manager
Oliver Nunn	Senior Economist
Joseph Nunez	Quantitative Analyst

At the start of the meeting, the 'competition health warning' was read out, and copies of the protocol were sent out to each member of the working group in advance of the meeting.

After an introduction and recap to the project, the meeting focussed on four areas in relation to NERA Economic Consulting's modelling of grid access reform:

1) An overview of the approach to the modelling
2) The approach to modelling the impact of access reform on the efficiency of dispatch
3) The approach to modelling the impact on the efficiency of investment in generation and storage
4) The approach to modelling the impact on the efficient of investment in transmission

Introduction

- The AEMC introduced participants and the NERA team and outlined the purpose of the session, that is, to work through NERA's draft methodology for modelling the costs and benefits of implementing grid access reform in the NEM.
- Stakeholder questions and comments following the introduction (and responses from the project team) included:
    - Participants sought clarification on a statement made in TWG#6, questioning how FCAS and inertia markets fit into FTR payouts. The project team responded that these elements do not impact the FTR payouts and auction design. Participants

then queried whether residues created by co-optimised energy & FCAS constraints would be paid to those who hold FTRs or not, or whether FCAS terms in constraints equations would have to be rewritten to separate them? The project team noted that it is still considering this design question.
  - Participants asked when the technical working group would have the opportunity to work through a 'complete' LMP/FTR design in order to discuss and debate, including elements such as what the regional price is: VWAP or the RRP. The project team noted that we would consider this, but this would likely occur in Q3 2020.

Overview of modelling approach and assumptions

- The NERA team provided an overview of the analytical tools being used to conduct the modelling as well as key assumptions and the sources for those assumptions. NERA also discussed the list of tasks that the AEMC has requested NERA to complete over the course of the project.

- NERA have constructed a representation of the NEM using the PLEXOS model infrastructure and are using assumptions from the Electricity Statement of Opportunities (ESOO) and the Integrated System Plan (ISP) provided by AEMO. NERA noted that they have constructed the nodal model using AEMO data on a list of nodes, lines and interconnectors, as well as taking into account future projects.

- Further assumptions have been taken from the AEMO ESOO assumptions book.

- Stakeholder questions and comments on the overview of modelling approach and assumptions (and responses from the project team) included:
  - Participants queried whether NERA are modelling the transmission network as a DC load flow model based on thermal constraints. NERA responded that they intend to model a close physical representation of the network, and so are taking into account physics such as reactance, resistance, Kirchhoff's Law, springwasher effects and so on.

  - Some participants noted that in their view, the central ESOO scenario is not the most likely one.

  - Participants questioned whether the NERA model assumes dynamic marginal losses. The project team noted that this is a key design decision that we are asking NERA to test. So, the model will be run both *with* and *without* dynamic losses. This will allow us to assess the benefits and impact of implementing dynamic losses.

  - Participants queried what constraints were included in the model. NERA confirmed that the model does not include transmission line outages, but that contingency constraints are being modelled.

  - Participants questioned the use of high demand forecasts, known as POE 10 forecasts (which mean the probability that this maximum demand level will be met or exceeded is only 10 per cent), given that this is not the median expected outcome. The project team responded that the current proposal includes both POE 10 and POE 50 (the median expected outcome), and that feedback to this approach was welcome. Participants suggested that using both was appropriate, as well as a POE 90 forecast. The project team responded that due to computational limits an approach may be to use a POE 90 forecast with a weighting of 0 in order to capture the whole distribution. This was agreed as a reasonable outcome.

  - Some participants stated that POE 10 would overstate the benefits as that level of congestion is uncommon.

- Participants noted that the weighting applied to dispatch and dispatch pricing needs to be different to a weighting applied to a reliability forecast.
- Participants questioned what assumptions about LMP design were used in the NERA modelling, for example hedge tenure, grandfathering, dynamic loss factors and loss hedges. The project team noted that the modelling exercise is specifically considering the impact of LMPs (including moving to dynamically calculated marginal losses), but not FTRs. Other aspects of NERA's work (related, for example, to the impact on contract market liquidity and the cost of capital) considers the impact of FTRs.
- Participants asked whether NERA are using AEMO's draft 2020 ISP assumptions or final assumptions as the final has very different capital expenditure assumptions on cost of battery and pumped hydro energy storage (PHES) in particular. NERA responded that they are using draft ISP figures, given this was the most timely information available at the time the inputs into the modelled were prepared.
- Participants asked why NERA assumes wind is only built in REZs, but solar/ BESS (battery energy storage station) is both in and outside of REZs, why there is this distinction. NERA responded that this decision is driven by where there are reliable solar irradiation / wind strength traces and where it is thought construction is probable
- Participants asked whether the modelling would assume a difference in the cost of capital for new generation, between the status quo and the COGATI implementation, noting prior discussion about whether COGATI reduces or raises generator risk. NERA replied that the weighted average cost of capital (WACC) is simply an input into the modelling, but that they are seeking to test scenarios where the WACC may change and what the impacts / sensitivity of this are.

Benefits for short-term dispatch

- NERA outlined the ways in which benefits to short-term dispatch will be measured. Three tranches of benefits will be measured: generators bidding marginal cost, merit order dispatch and an efficient dispatch
- NERA continued with a discussion on the PLEXOS implementation of race-to-the-floor bidding, finding instances where generators' SMRC is lower than RRP, and making them bid to the price floor, and then comparing the outcomes under this distorted bidding behaviour to the base case.
- Stakeholder questions and comments on these areas (and responses from the project team) included:
    - Participants noted that if only expensive generators bid to the floor price, the inefficiency that exists will be overstated. NERA agreed that its method is not perfect, but not as inaccurate as suggested because only plants with marginal costs below the Regional Reference Price (RRP) would have their bids distorted. It agreed to consider how the approach might be improved.
    - Participants questioned the method for modelling fuel costs, NERA responded that fuel costs are assumed from the AEMO market modelling methodologies book.
    - Participants asked whether minimum generation levels are accounted for in the model. NERA confirmed they are.
    - Participants asked whether contractual positions including power purchase agreements (PPAs) are being taken into account and how this influences bidding.

NERA noted that contractual positions are not taken into account, consistent with cost-minimisation models such as PLEXOS.

- Participants requested that we look at historical data of disorderly bidding. Participants suggest that this costs about AUD20m per annum currently. The project team responded that this is a set of data we can look at. However, the NERA modelling is an exercise looking forward, that is the intent of the analysis.
- Participants discussed negative interconnector residues and whether they are included or excluded. The project team responded that this is not currently being modelled and is perhaps an issue that should be considered.

Generation and Storage Construction

- NERA outlined the incentives for investment in a specific location under both the status quo and the proposed changes. NERA noted that that there are locational signals currently in the NEM, but that they are incomplete.
- NERA outlined that under the status quo, all generators with a short run marginal cost that is less than the RRP receive an investment signal to invest at any node, whereas under locational marginal pricing, only generators with a short run marginal cost less than the locational marginal price receive a signal to invest at the node.
- NERA proposed that this inefficiency is quantified by calculating the subsidy (penalty) that generators receive under the regional reference price compared to the locational marginal price. This subsidy (penalty) is added to new entrant costs in the model. As a result, plant is encouraged to locate in sub-optimal locations in the status quo.
- NERA outlined the different locations where types of plant will be allowed to be built in the model. These assumptions include the following (and have been developed partly in discussion with AEMO):
    - No new coal is built
    - No gas generation can be built outside of urban area and REZs
    - Wind can only be built within REZs
    - Solar can be built within REZs, as well at locations outside REZs
    - Large scale batteries can be built at the same location as solar
    - Pumped hydro can be built at nodes with existing hydro capacity.
- NERA outlined that a series of PLEXOS runs are used to estimate costs and benefits, in which the plant is built out over the long term, and the model is run again with the same build plan in both the short term and the long term.
- In order to calculate the subsidy at each node, nodes without generators being built will have tiny “probe” generators to capture the impact of the subsidy, but not materially impact other outcomes.
- Stakeholder questions and comments on these areas (and responses from the project team) included:
    - Participants asked whether or not fuel costs vary based on location. NERA responded that fuel costs varied by location due to transport costs only.
    - Participants queried whether it was appropriate to model batteries as peaking generators, wondering this is too much of a simplification. Participants stated that peaking generators and batteries operate in fundamentally different ways in the

market. Participants also asked in relation to this point whether any benchmarking is done to the ISP to test the validity of the outcome. The project team recognises the issue, but the issue is with computational power, and that choices have been made due to the nodal nature of the model. NERA and the project team suggested that in order to compensate for the fact that batteries might be disadvantaged in the assumptions made, comparisons of the outcomes to the ISP could be made, which participants agreed could be a reasonable approach.

  - Participants noted the low number of load blocks may not be sufficiently robust. Participants commented that comparing outcomes with the ISP and running more blocks might help.

  - Participants noted that under the reform they consider that they will need to develop a similar model to that being developed by NERA. The project team commented that the models required by participants and by NERA serve different purposes. NERA noted that in making investment decisions, individual market participants would be more focused on a particular node or set of nodes, whereas the NERA modelling is looking at all nodes. Participants responded that under volume weighted average pricing for non-scheduled participants, participants may need to model pricing at all nodes.

    - The AEMC project team recognised this as a downside to volume weighted average pricing (VWAP), and something we could find out more about by looking at overseas jurisdictions and talking to overseas participants. Potentially we could discuss this at an upcoming technical working group meeting. The AEMC also noted that a decision has not yet been made on VWAP as opposed to the existing pricing for non-scheduled participants.

  - Participants noted that there may be impacts of the variability of LMPs with respect to the cost of capital. NERA noted that it will be looking at the extent to which variability of LMP, in conjunction with FTRs, has an impact on the absolute level of risk and as a result could cause credit problems.

Transmission Modelling Costs and Benefits

- The NERA team discussed the methodology for quantifying transmission costs and benefits. This involves linearising transmission benefits, assuming a constant transmission cost in $/MWh/km.

- NERA stated that the benefits of transmission expansion are likely to be larger in the status quo and the net benefits of transmission expansion will be (weakly) positive.

- Stakeholder questions and comments on these areas (and responses from the project team) included:
  - Participants queried what the role was between the ISP and LMPs. The project team noted that the introduction of LMPs and FTRs will provide additional information sources to AEMO in order to input into the ISP.

  - Participants also noted that there are already locational signals in the NEM that arise from MLFs and thermal constraints, and that the recent rule change on increasing transparency of new projects connecting to the system further sought to increase information. The project team noted that we agree that there are some locational signals at present, but that the signals that do exist are inefficient.

  - Participants noted that transmission investment is lumpy, i.e. it is in blocks of capacity. Sometimes the optimal investment will be smaller than what you would like, sometimes more. NERA agreed, and stated that the lumpiness of transmission expansion is something that could be taken into account in the modelling, for example, it could be assumed that expansions have to be made in discrete sizes.

- Participants questioned how much of the transmission expansion that is in the ISP is included in the modelling. NERA responded that ISP group one and two projects are included as well as the proposed Marinus link.
- Participants queried what the outputs of the model would be? NERA confirmed that the model would output LMPs, the RRP and VWAP price outcomes.
- Participants noted that the selection of transmission projects external to the ISP will be a significant factor in terms of what congestion there is. We agreed we would be transparent on that point.
- Participants asked whether implementation costs would be considered as part of the analysis. The AEMC responded that NERA has not been asked to do this in relation to this piece of work, however implementation costs are something we are currently considering. We also noted that certain design decisions, such as whether VWAP or RRP is the regional price, need to be determined first before considering implementation costs since this decision will have an impact on what the magnitude of implementation costs would be.
- Participants noted that it will be important to consider the other P2025 proposals alongside the COGATI benefits and costs. The project team agreed and noted that we are working closely with the ESB and the other p2025 MDIs on this matter.

Summary

- The project team outlined the next steps for the TWG process.
- It was queried whether a follow up session with NERA would be helpful. Participants responded that no additional session was needed at this stage. The project team noted that any additional feedback via follow up emails or discussions is always helpful.
- The project team noted that a copy of the presentation would be sent round the technical working group.
- Participants asked when they would get to see the entire transmission access reform design. The AEMC responded that we intend to have a session with the technical working group in Q3 to cover the whole design.