Chairman: Warren McNabb,
warren.mcnabb@altimarloch.com
Secretary: David Inch, david@nzenergy.co.nz

INDEPENDENT ELECTRICITY GENERATORS ASSOCIATION

20 October 2020

TPM Development Project Team
Transpower New Zealand Limited
PO Box
Wellington 6140

By email: tpm@transpower.co.nz

Dear team,

RE: Exploring a Transitional Congestion Charge

The Independent Electricity Generators Association Incorporated (IEGA) appreciates the opportunity to engage on the development of a possible congestion charge as part of the new TPM. The preparatory material and access to the workshops enabled limited engagement. The IEGA strongly requests continuing engagement as Transpower considers feedback it is receiving and works towards an approach that ultimately will be recommended to the Electricity Authority (EA). In the near-term we are available at your convenience to discuss our feedback in this letter.

The following information outlines a case for a peak charge to remain in transmission charging. While this information reflects the views of the IEGA, the case for and objectives of a peak charge below take into account our interpretation of the discussion at the workshops. We also suggest a methodology for determining where a peak charge is required (but not the quantum of this charge).

Problem definition

1. Agree there is an unquantified risk from removing the RCPD price signal in transmission pricing

Data examples:

- Transpower estimated gross demand 9 – 20% or 530MW to 1,345MW above volumes currently carried on the transmission grid (July 2016 submissions[1]).
- Transpower's submission on 2nd Issues Paper stated "the consequences of an LRMC [peak signal] not being implemented as part of a new TPM would, in our view, be a material increase in risks and costs across the power system and prices for consumers" …. "As we have previously submitted, we do not know what the impact of fundamental changes to the DGPPs and TPM will change market participant behaviour. However, we know that that those

[1] https://www.ea.govt.nz/assets/dms-assets/21/21135Transpower.pdf page 18-19 and https://www.ea.govt.nz/assets/dms-assets/21/21136TP-TPM-Appendix-E-Scientia-Analysis-AoB-method-Report-26July2016.pdf

participants currently combine to reduce peak demand on the grid by approximately one fifth (~1300MW).“ (February 2017[2]).

- Transpower's "The role of peak pricing in the TPM" report (November 2018[3]) included Grid Owner and System Operator analysis of the impact on investment need data of a removal of the RCPD incentive on EDBs to use load control to limit their offtake during regional peaks:
  - Grid Owner: Upper South Island voltage stability case study - $44.2m investment
    - 3% increase in demand bought forward investment by 2 years at a cost of $3.5m
    - 7% increase in demand bought forward investment by 4 years at a cost of $7.5m
  - Grid Owner: Waikato & Upper North Island voltage stability project
    - 3% and 7% increase in demand brings forward the need for this investment at a cost of $18m and $51m respectively
  - System Operator:
    - Adding back South Island EDB load control (182MW or 8.6% increase in SI load) during peak demand period increased nodal price by 6 times compared with status quo – to $794.40 at OTA2201
    - Adding South Island EDB load control (182MW) and North Island EDB load control (114MW) during peak demand period increased nodal prices by 11 times for a 4.6% increase in total load – to $6,682.14 at OTA2201
- Transpower's statement that "Peak pricing for transmission helps to preserve our option value into an increasingly uncertain future by providing downward pressure on peak demand growth. ... The faster peak demand grows in the short or medium term, the higher the risk we invest in new assets that become obsolete but must still be paid for.“[4]
- The Electricity Authority estimates ripple control at 800MW.
- 8 EDBs in USI managing 100MW of load – 3 EBDs doing it to manage RCPD only, the other 5 have other reasons for managing peak volumes.
- EnergyLink analysis of Upper South Island load control for Pioneer Energy (August 2016) revealed that the costs of settling the market on 22 June 2015 and 23 June 2015 increased by 32% and 72% respectively when the large amount of load control in operation those days was assumed to be unavailable.
- Network companies' comments about the flow on impact of changing peak demand volumes on their network capacity.
- NZ Steel's experience of managing a true co-gen operation, as discussed at workshop 2: in UNI NZ Steel's net demand (after co-gen is currently around 1% of ~2,000MW of peak demand compared with an AMD measure (ignoring co-gen) of 8%. NZ Steel raised the question - what is the impact on UNI transmission capacity if NZ Steel demand is 40-50MW from the grid or demand off the grid is the total 160MW of demand if the co-gen is on outage and the manufacturing process is operating at 100%?

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[2] https://www.ea.govt.nz/assets/dms-assets/21/21894Transpower-NZ.pdf page 17-19
[3] https://www.transpower.co.nz/sites/default/files/plain-page/attachments/Transpower_The_Role_of_Peak_Pricing_for_Transmission_2Nov2018.pdf pages C3 – C4 and C2 – C3
[4] https://www.transpower.co.nz/sites/default/files/plain-page/attachments/Transpower_The_Role_of_Peak_Pricing_for_Transmission_2Nov2018.pdf Page 4

Resulting in potentially:

- more and unpredictable constraints on the interconnected transmission grid
- risks of administrative curtailment of demand if generation is not on the right side of a constraint
- spring washer / infeasible nodal prices in wholesale market (until RTP is operational)
- more volatile and unpredictable nodal prices more generally
- higher hedge prices to reflect more volatile and higher spot prices
- negative consequences for consumers, especially those on spot prices and fixed price contracts will also incorporate these risks
- social and political response to these outcomes.

2. Acknowledge that the EA expects RTP to encourage / facilitate more responsive demand for electricity reflecting the levels of nodal prices (so that a peak demand price signal in transmission charges is a double up / no longer needed) but:
   - note the price signal from RCPD finishes on 31 August 2021 and RTP is currently forecast to start in October 2022 – leaving 12months+ before RTP encourages any benefits from demand response
   - uncertain how / if demand will respond to real-time prices
   - retailers are likely to require some time to take into account this new nodal price market environment and offer products to customers that meet customers' needs
   - new participants / technologies / business models will take time to enter / be engaged in this new RTP market

3. Agree that it is too risky to go 'cold turkey' with no RCPD charge (peak demand price signal) and complete reliance on RTP to manage congestion on the transmission grid.
   - Noting (again) that RCPD signal disappears before the RTP signal to manage demand starts

4. Agree a Transitional Peak Charge is required. Also it is uncertain how long it will be required to manage transmission capacity congestion in a responsible manner before the new participants / technologies / business models encouraged by RTP are sufficiently developed to be responsible for this. Five years may not be longer enough in certain parts of the transmission grid. Design of the TCC should ensure that this option is the least cost / most efficient way of managing transmission peak congestion.

Constraints on design of a Transitional Peak Charge

- EDBs and Direct Connect industrials are counterparties to the TCC (and residual charge)
- EDBs do tariff changes only annually
- Retailers are the counterparty to the RTP nodal prices
- The amount of transmission revenue recovered by the residual charge is the cap on any TCC charge over time
- EDBs pass through transmission charges to retailers and these are currently predominately repackaged by retailers – is this approach likely to change to influence consumer demand?

Objective of a Transitional Peak Charge

1. Agree that the objective of the Transitional Peak Charge is to transition:

   FROM: an RCPD price signal in transmission charges to manage peak demand on the transmission grid to avoid transmission constraints / avoid or defer transmission investment / signal the need for new transmission investment. The current nodal wholesale market also prices real-time transmission constraints (ultimately resulting in spring washer prices)

   TO: Only real-time prices in the wholesale market showing in real-time where there are constraints on the transmission grid and solving these constraints by applying scarcity values of $10,000 to $20,000/MWh

2. Note prices, generation investment and demand response activity under RTP (and the Benefits-based transmission charge) may not be sufficient to manage / alleviate / eliminate transmission capacity constraints in some parts of the transmission grid, and also:
   - taking into account the length of time it takes to plan, design and construct transmission infrastructure
   - noting the lack of experience with Grid Support Contracts thus far (first one to be signed in late 2020 when supposed to have been available in 2016 and prior)
   - being aware of the social and political appetite for consumers to be subject to potentially more frequent administrative load control or nodal prices of $10,000 to $20,000/MWh

Therefore, a Transitional Peak Charge must also be able to be:

- operative for longer than 5 years in particular parts of the grid
- introduced in particular parts of the grid if constraints consistently occur for the period until the required infrastructure or demand response investment is completed

Design of Transitional Peak Charge

Our design of a Transitional Peak Charge notes that:

- RCPD used to manage load in 4 course / large regions currently – there may be smaller areas within these regions that need / don't need to manage peak demand.
- Transpower (and EDBs) are indifferent to / not impacted by the level of nodal prices – they manage their infrastructure to ensure secure and reliable electricity supply, at the same time working to defer or avoid new infrastructure investment.
- It is assumed Transpower can plan, design, consult and construct a new transmission investment within 5 years. If this timeframe is too short then the 5 years mentioned in the following steps should be extended to the appropriate timeframe.

Transpower has analysed the power system to determine whether its Grid Reliability Standard (n-1) is met at each GXP using a 'with and without' distributed generation test. The results of this analysis show the sensitivity of the grid to changes in MWs of generation (or an increase in load would have the same impact) that will result in not meeting the GRS of n-1.

IEGA suggests that meeting the GRS is the same as the transmission grid being constrained (when the constraint is included in nodal prices)? Both indicate that demand exceeds available reliable supply of electricity and a need for investment to meet demand – either an increase in transmission capacity, or a reduction in demand or output from distributed generation behind the GXP.

Step 1: Information from the power system analysis can be used as a starting point to identify where a Transitional Peak Charge is required immediately:

- the list of GXPs where the absence of DG results in Transpower not meeting it's GRS
- the capacity of DG at those GXPs

Step 2: Group these GXPs into appropriate regions taking into account planned or potential transmission capacity investment to ensure n-1 is maintained.

Step 3: Transpower calculates the sensitivity of the timing of this transmission investment to a change in DG / load / ripple control / industrial load. That is, what percentage change in DG or load results in this investment being bought forward to within 5 years and is it prudent for Transpower to <u>not</u> start planning to make that investment. For example, if a 5% change in DG output or increase in load results in the planned transmission investment bought forward to within 5 years then it is prudent for Transpower to start planning that investment straight away.

Step 4: If transmission investment is now required within 5 years a TCC must be applied to that region. This TCC will encourage DG / demand / grid connected generation to change their behaviour / locate in that region to defer the investment in transmission infrastructure to allow enough time for Transpower to plan, design and construct the required transmission investment or it could avoid the need for transmission investment indefinitely.

Steps 1 – 4 must be completed before the RPCD signal finishes on 31 August 2021.

Step 5: In addition, in each of the first five years of the new TPM Transpower should monitor if demand, DG output or grid connected generation investment has changed the expected timing of any planned transmission investment. If the timing has been bought forward to now be required within 5 years, then a TCC should be in place and remain in place until the investment horizon for that transmission investment moves to beyond 5 years.

The IEGA believes that proposing a peak charge developed using the above methodology is consistent with the EA's statutory objective – it will ensure security of supply of electricity at a price that enables retail competition as well as supporting the efficient operation of the market.

As discussed above, the IEGA would welcome the opportunity to discuss this submission with you in more detail.

Yours sincerely

Warren McNabb
Chair