AEMO TUOS Pricing Methodology Consultation Paper

November 2020

TUOS pricing for a changing transmission network

Victorian TUOS pricing keeping pace with a changing network environment

Important notice

PURPOSE

AEMO publishes this document to inform AEMO in the development of AEMO's revised *pricing methodology*.

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1. Need for Consultation

AEMO as the TNSP for the Victorian transmission system recovers the cost of the *prescribed transmission services* (except *prescribed exit services* and *prescribed entry services* which are recovered by AusNet Services) from *Transmission Network Users* in accordance with its *pricing methodology* which is approved by the AER in accordance with Chapter 6A of the *National Electricity Rules* (NER). The current AEMO *pricing methodology* is available on the AEMO website[1] and entitled "Approved amended Pricing Methodology for Prescribed Shared Transmission Services for 1 July 2014 to 30 June 2019". The validity of the methodology has been extended under an enforceable undertaking by AEMO initially to 30 June 2021 (available on the AEMO website[2]) to allow AEMO to conduct further analysis and consult on emerging developments in the NEM and their effect on network pricing and investment. A further extension to 30 June 2022 is also being discussed with the AER and the updated enforceable undertaking will be published on AEMO's website when formalised.

An issues paper was published on 16 September 2020 (Issues Paper) and considered significant questions that AEMO is facing in terms of setting transmission Transmisstion Use of System (TUOS) prices in a changing power system. No submissions were received to the Issues Paper.

2. General

The Issues Paper considered three main matters and asked several questions in relation to those and some other related matters. In summary, those three matters related to:

- The growing occurrence of measured negative energy and demand from connected systems caused by increasing penetration of distributed generation (primarily rooftop solar);
- TUOS treatment of batteries and other energy storage devices that are becoming an increasingly important part of the overall electricity delivery chain.
- Consideration of alternative methodologies to determe the locational price component of TUOS in response to more mixed set of transmission investment drivers than has historically been the case.

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[1] https://www.aemo.com.au/-/media/files/pdf/approved-amended-pricing-methodology--1-july-2014-to-30-june-2019.pdf

[2] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Participant_Information/Fees/2019/AEMO---NER-s59-Undertaking---12-June-2019_0.pdf

In addition to these issues, this Consultation Paper will detail amendments to the Pricing Methodology required to update it in light of changes to the regulatory framework, processes and other minor administrative matters since the current version.

3. Reverse Flows at Transmission Connection Points

3.1 Recap

The transmission system was originally conceived to deliver energy from large generators to the major load centres. This meant that Transmission Connection Points (TCP) were substantially always load points and generally no enegy flowed in the opposite direction.

The current power system now has TCPs that do not always behave as loads and so in the absence TUOS being levied against generators, the question remains as to what happens when TCPs or loads turn into generators (i.e. there is reverse flow at the TCP) as they do now with distributed energy generation, with storage devices and in some cases, directly connected loads with co-located excess generation or storage.

3.2 Overview

In the Issues Paper, we identified three options for dealing with negative flows at TCPs:

- Option 1 – Allow the negative energy to be subtracted from the load
- Option 2 – Treat the net negative value as zero at a TCP
- Option 3 – Only consider half-hourly consumption and treat all negative values as zero

In the Issues Paper, it was proposed to use Option 3. AEMO considers this is the preferred approach because it provides a more consistent pricing outcome from year to year than would ignore negative values by zeroing out any negative energy or demand amounts in any 30-minute period.

It is worth making the point that this approach is not designed to act as proxy TUOS charge on generators located in distribution networks. There are a few reasons for this:

- Distributed generators are charged a proportion of TUOS charges by virtue of the fact that TUOS charges are usually included in distributors' distribution tariffs. They don't pay TUOS directly.
- Distribution customers (including generators) will still receive the benefit of reduced overall charges even under Option 3 because the contribution of generation in lowering the overall reliance on the transmission network can potentially reduce

both locational and non-locational/common service prices and charges in the long run.

- Distributed generators are entitled to receive an avoided TUOS amount from its connecting distributor under clause 5.3AA(h) of the NER.

3.3 Proposed Treatment at Customer TCP

3.3.1 Non-Locational and Common Service Pricing:

Only consider half-hourly consumption and treat all negative values as zero

In calculating the price to be set and the charge at each TCP, the 30 minute periods where there was injection into the transmission network will be set to zero, and so the metered energy only reflects net energy consumption at the TCP without the injection into the transmission network.

3.3.2 Locational Pricing:

Only consider positive half-hourly demand and treat all negative values as zero

In calculating the price and the charge at each TCP, the negative 30 minute demand and energy periods will be set to zero and not be included in any averaging.

4. Energy Storage Systems (ESS) and Payment for Transmission Usage

4.1 Recap

AEMO proposes to continue its current practise of not charging directly connected ESSs. To recap, AEMO's proposal for a rule change "Integrating Energy Storage Systems into the NEM"[3] has recommended that ESSs should not pay TUoS charges. The AEMO rule change proposal does point out that a hybrid load which consists of an ESS and a load should not use the ESS to avoid payments by the load and this may require additional metering behind the TCP.

AEMO's enforceable undertaking provided to the AER on the AEMO pricing methodology has a clause 6.2 which explicitly states that "…transmission use of system charges will not be determined or charged in respect of existing or new connection points at which large scale batteries are connected, either is respect of supply (discharging), or consumption (charging),…..".

Despite the above, not all ESS should be exempted and this has been clarified in the proposed draft Pricing Methodology.

[3] https://www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem on page 2 of rule change proposal

4.2 Proposed Treatment

In general, transmission connected ESS are not end users and therefore, consistent with the approach applied to generators, ESS that are directly connected to transmission networks should not be charged TUOS when withdrawing from (or injecting to) the transmission network.

Accordingly, for the purposes of this Pricing Methodology, AEMO proposes that consistent with its previous statements, it does not intend to charge TUOS to stand alone ESS that are directly connected to the transmission network. This is subject to the following exceptions:

- Where electrically powered pumps are used to recharge pumped hydro storage systems, the pumps will only be exempted from TUOS where the pumps are used exclusively for the pumped storage system and the proponent agrees to maintain that exclusivity in it Use of System Agreement with AEMO for the duration of the agreement.
- ESS used as part of a transmission connected load drawing facility (e.g. manufacturing factory, metal processing facility, wood and paper processing facilities etc) and located behind the load drawing facility's meter will be treated as part of the load drawing facility for TUOS purposes. The measurement of the combined operation of the load facility and ESS will be conducted by the energy meter located at the TCP and prices and charges determined in the same way as any other TCP for TUOS purposes. This includes treatment of negative 30-minute energy and demand readings (see section 3 above).
- For embedded ESS, it is up to the DNSP to determine how they will treat these for DUOS purposes but they will not attract discrete TUOS charges as they are not themselves connected to the transmission network. The charges (to the DNSP) will therefore rely on flows at the TCP with the treatment of flows into the transmission network treated as per section 3 above. Similar to distribution connected generators, ESS that are distribution connected might qualify for payments under the avoided TUOS regime under clause 5.3AA(h) of the NER.

In recognition that this is a fast developing technology which can be packaged up with technologies in any number of ways, AEMO will determine whether the ESS is elegible for an exemption at the time that the connection application is made by the proponent.

The question as to whether ESS that are directly connected to transmission should be charged any type of transmission charge (e.g. congestion charge etc) is a question that is preferably dealt with at a policy level in the same way as consideration of generator transmission/congestion pricing.

5. Peak Day (MD10) versus 365 Day Method for Locational Prices

5.1 Recap

The current location pricing methodology uses the average of the 10 weekday maximum demand half-hours on the system wide maximum demand days to allocate usage of the transmission system assets to TCPs and therefore set the prices. As asserted in the Issues Paper and citing the RIT-T for the Western Victorian Transmission Network Project as an example, choosing a subset of conditions that occur at peak demand times during a year is now problematic because the period "of greatest utilisation of the transmission network" isn't simply the maximum demand of the power system.

Unlike most previous RIT-Ts the Western Victorian Transmission Network Project was justified on the basis of unlocking renewable energy in Western Victoria rather than being biased towards the reduction in unserved energy at peak demands, so that maximum demand days is not the driver for this new augmentation.

Another option in determining the locational prices is the 365 day method which looks at all hours during the year and finds the one with the maximum utilisation of each element. This means that if a customer's maximum demand coincides with high wind speeds at 10pm on a winter's night then a high proportion of cost of elements transmitting energy from the wind resource area should be used in the allocation of the locational price compared to elements from dispatchable thermal generation in the LaTrobe Valley.

5.2 Proposed Treatment

It is proposed that the allocation of the *adjusted locational component* of *prescribed TUOS services* to each TCP moves from using an MD10 methodology to a 365 maximum demand method. The MD10 method has been fit-for-purpose in an era when generation met load requirements according to a relatively predictable dispatch sequence. AEMO could be relatively sure that high demand days that reached network limits could be met by the generation fleet on a relatively small subset of days in the year using the same network elements for a given load profile to do so. To a large degree, most TCPs' maximum demand coincided with full or near full utilisation of the network to supply them. Historically, in Victoria, where dispatchable generation was predominantly located in the La Trobe Valley and the major load centre located in Melbourne, the subset of 10 high demand days between December and March of each summer would have yielded relatively consistent asset cost allocations to TCPs as the same network elements would be subject to similar loadings under similar conditions year on year.

This is unlikely to continue to be the case going forward. As the network changes to accommodate zero marginal cost generation such as wind and solar[4], it is highly likely that network elements will be subject to different loadings under a more diverse set of circumstances. Overall high demand may not be determinant of a particular TCP's asset utilisation and therefore cost allocation. It is more likely that wind or solar output will be a major contributor to the TCP's allocation as different network elements contribute to an individual TCP's supply under different conditions.

The MD10 methodology becomes less relevant as the times of each individual network element's utilisation may not coincide with high system demand but with say, high wind penetration where energy will need to be transported from other parts of the network.

That is not to say that demand is irrelevant and indeed, both the Rules and the AER's Transmission Pricing Guidelines require that locational prices "must be based on demand at times of greatest utilisation of the *transmission network* by *Transmission Customers* and for which *network* investment is most likely to be contemplated".[5] With high penetration of roof top solar, daily summer peaks are generally moving from early afternoon to late afternoon/evening as roof top solar's contribution to energy dimishes, thereby offloading the burden on the network during the middle of the day. This peak shift is also being seen in other seasons, not just summer. At these times, load must be met from generation sources (wind and/or other dispatchable sources) which increases utilisation of different network elements.

This all suggests that measuring a TCPs' maximum demand for the purposes of deriving allocations based on ten top sytem peak days is becoming less indicative of the utilisation of the network and another method would be better reflective.

AEMO considers that the 365 day peak method is becoming a more appropriate method of allocating network costs to TCPs than MD10 as new network and generation mix take hold.

AEMO considers that as the generation technology mix broadens and generation location becomes less geographically concentrated with less dispatch certainty, trying to pick generalised peak periods (such as time of day or seasons) to inform pricing decisions becomes much harder to justify. A more generalised approach where average maximum demand measured over all hours of the year is preferable.

Other reasons for adopting the 365 day peak method include:

- Consistency with practise by other TNSPs in other regions.
- Consistency with the the methodology adopted in the NER for calculating inter-regional TUOS and the resulting MLEC.

[4] For instance, on 25 October 2020, Victorian demand was met 68.4% by zero marginal cost generation located on more remote parts of the DTS.

[5] Clause 6A.23.4(b)(1) National Electricity Rules and clause 2.2(a) of the AER's Transmission Pricing Guidelines.

- It enables AEMO to meet new timeframes necessitated by the Victorian DNSP pricing determination legislation.[6]

AEMO proposes to use either a TCP's CAMD (where a customer has agreed one) or average maximum demand readings (financial year t-2) for setting the locational price. However, it proposes to use the higher of the two measures to derive the customer's locational charge rather than the current formulation where the lower of the two has been used. This will align more consistently with the concept of a maximum demand that has been agreed between the customer and AEMO and the allowances AEMO makes in its network planning and connection activities to accommodate load requirements.

6. Other Amendments

The PM has also been revised to harmonise terminology more closlely with definitions and provisions under the NEL, the NER and the AER Guidelines.

6.1 Equalisation Adjustment Scheme Derogation

The Equalisation Adjustment Scheme Derogation ended at the end of the 2020 financial year. The provisions in Section 8 are no longer relevant but have been retained to carry over the mechanism contained in .

6.2 Change in timing of publication of transmission pricing

Under legislation recently passed the Victorian Parliament[7], Victorian DNSPs' "regulatory year" for the purposes of distribution determinations will transition from a calendar year to a financial year cycle. By virtue of the new legislation, the AER must approve the DNSPs' proposed distribution prices by 1 July each year. in order to allow DNSPs to factor in transmission charges into this new regulatory cycle, AEMO seeks to publish its prices by 15 March i(as opposed to the current 15 May).

The revised publication date is a whole two months earlier than usual and will require that older historical data sets be used to determine prices and charges. Historically, the data sets were closed off at the end of February preceding the financial year from which the new prices were to take effect. Consistent with the NER and other TNSPs' practice, AEMO now proposes to use earlier data sets extending back to the last full financial year before the new prices take effect. The will give AEMO sufficient time to settle and confirm meter data

[6] This has been necessitated by the fact that in order to allow the Victorian DNSP and the AER time to set annual regulated distribution prices, TUOS prices should be fixed and published by 15 March of each year. If the current method of including maxiumum demands from December to February is maintained, there will be insufficient time to calculate the allocations to each TCPS using TPRICE and meet that new publication date.

[7] National Energy Legislation Amendment Act 2020, section 16VB.

required to calculated locational and non-locational prices prior to receipt of information that allow for the adjustment factors such as MLEC, intra-regional settlement residues etc.

As an example, AEMO currently uses maximum demand data for setting locational prices in respect of the most recently past summer season. This means that the last data set won't be available until the end of February and that won't allow sufficient time to run TPRICE and calculate allocations and locational prices by the new, proposed publication date of 15 March. Where allowable under the NER and the Guidelines, AEMO proposes to use full financial year data sets and has made changes to the Pricing Methodology accordingly.

6.3 National Transmission Planner Costs

The allocation of National Transmission Planner costs in respect of Victoria applicable under clause 2.11.3(ba) are recoverable under clause 6A.23.3(e)(6) as an adjustment to the *pre-adjusted non-locational component* and contributes to the setting of non-locational prices.

6.4 Cost under Ministerial Order under section 16Y of the National Electricity (Victoria) Act (NEVA)

Subsequent to the passing of an amendment of the NEVA, the Minister may by Ministerial Order require AEMO to procure an augmentation or non-network service in respect of the Victorian declared transmission system and allow the costs to be recovered through TUOS. Minor changes have been made to reflect this recovery. The Second VNI SIPS Ministerial Order requires 'AEMO contracting costs' to be allocated to *prescribed common transmission services*.

7. How we will Consult on these Matters

7.1 Requirement to consult

Under the National Electricity Rules, the AER must approve AEMO Pricing Methodology and is required to consult. AEMO is consulting with participants to inform AEMO's revised Pricing Methodology to be submitted to the AER. AEMO intends to provide the AER with the revised Pricing Methodology on or before May 2021 so that the AER has sufficient time to consult before approval.

Network users who would like to discuss the potential impact of the proposed changes in the Pricing Methodology on their pricing and charging outcomes should contact AEMO on pricing.methodology@aemo.com.au to request a short meeting.

7.2 Timing

According to the consultation schedule that was proposed at the time of the release of the Issues Paper, the indicative dates for consultation on the proposed draft methodology was scheduled to take place between 26 October and 27 November 2020. In light of the delay in publication of this consultation, AEMO will extend the consultation period until 5pm on 7 January 2021. Similar to the previous stage, stakeholders are requested to forward their response to this Issues Paper to pricing.methodology@aemo.com.au by the time and date stated above.