TPM submission, and next steps

MEUG, September 2016

Jeremy Cain, regulatory affairs & pricing manager

Agenda

1. Introduction and context
2. Comment on May TPM proposals
3. Simplified, staged approach
4. Other matters
5. Next steps

1.1 Purpose of the TPM

- The purpose of the TPM, consistent with clause 12.78 of the Code, is to
  - ensure that the full economic costs of Transpower's services, as established by the Commerce Commission under Part 4 Commerce Act, are recovered, and
  - do so in a way that is in accordance with the statutory objective in section 15 of the Electricity Industry Act

1.2 Transpower's role

- To ensure services are provided efficiently and excessive costs (including excessive investment) are avoided or minimised
- The TPM is one of the tools to help ensure efficient service provision
- We are also in the unique position of having to codify and implement any EA decision on the TPM
- That’s why our submissions have focussed on achieving a workable solution, and ensuring the TPM sends efficient price signals

1.3 What isn't part of our role

- We do not see our role as making judgements about large wealth transfers amongst our customers
- Changes that predominantly impact on wealth transfers – such as reallocation of HVDC – are a judgement for the regulator
- Our 2014/15 TPM Operational Review purposely targeted changes that would improve efficiency, but avoided adverse wealth transfer impacts

2.1 Areas of common ground

- We agree prices could be more cost-reflective
- We agree RCPD currently sends peak-usage signals that are too strong
- We agree there is scope to adopt more targeted price signals
- We agree with the emphasis in the distribution pricing consultation that networks should consider peak-usage and LRMC pricing
- At least some amendment of the TPM Guidelines is likely to be beneficial

2.2 Key concerns with EA proposals

- We do not know whether we could develop a robust method for calculating AoB charges under the EA's proposals
  - Different methods and assumptions could result in a customer being determined as a minor or principal beneficiary
  - This is highlighted by the variance in benefit calculations in the 1st and 2nd Issues Paper
- Potential for increased disputes from application of AoB to each new eligible investment (each investment would require bespoke application of the AoB method)
- Complete removal of the existing dynamic price signals would risk a surge in peak-demand and trigger regretful investment

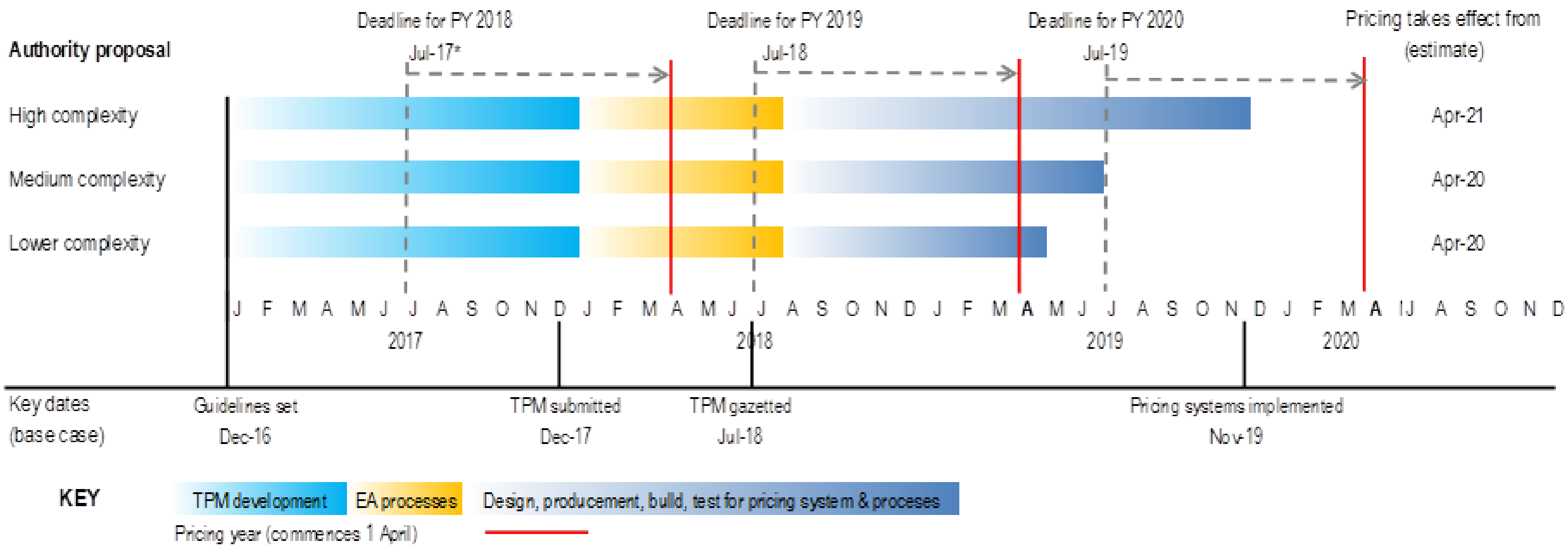
2.2 Key concerns … continued

- We are concerned about wholesale electricity market impacts (higher prices), and 'wrong' locational signals may be sent
- We do not support discriminating against some of our customers solely (and arbitrarily) on the basis of asset age
- We are concerned about the number of 'fixes' the Authority has incorporated into its proposal to address anomalies
- The price impacts would be substantial relative to the prospective efficiency gains

2.3 Timing for implementation

- Implementation by 2019 is not realistic for the proposals in their current form, even if a decision were made in October (which we understand has slipped)
- Even with a 12 month period, PWC conclude the scale and sequential nature of TPM development, approval and implementation tasks make April 2019 "improbable" at best
- A key question is the task presented to Transpower (how much development work we need to do) and the level of customer consultation that we undertake.
- For the operational review customer input was vital (improved decision quality and customer buy-in) and expect the same would be true in developing a new TPM.

2.4 Timings



* Deadline for completion of **major changes** to the TPM systems. Prices are notified to customers in November to take effect for the next pricing year (PY starts 1 April each year). This allows distributors to reflect transmission pricing in their own tariffs and in turn to notify retailers. This lead time also permits necessary customer consultation on the most complex aspects (connection charges), external audit and approval by Transpower's Board.

2.5 There may be better alternatives

- There is broad agreement that no TPM is perfect
- Our Operational Review and EA's process has highlighted there are opportunities to improve the TPM
- The nature and scale of change have been debated extensively (we think changes should be proportionate to identified problems/potential efficiency gains)
- Many submitters, including Transpower, have advocated moderated reform options through this process
- In essence, we believe the key issues with TPM could be addressed faster, with less disruption and risk, including of price shocks

3.1 Simplified, Staged Approach*

Stage (and timing)	Existing Component	New component
Stage I: target 2018	Postage Stamp cost allocation for interconnection	**Simplified AOB charge:** Replace with regional (area) allocation, based on asset location and value as a proxy for benefit
Stage II: target 2019	RCPD charges	Introduce **LRMC or LRMC-like charges** and a **Residual Charge** to recover the AOB allocation
Stage III – Additional component A: target 2019/2000	New investments (over Capex IM thresholds)	Transpower to review whether a **non-simplified cost allocation** should be applied, which estimates benefits in a more sophisticated manner
Stage III – Additional component B: target 2019/2000	Interconnection and HVDC link	Transpower to develop **locational pricing for generation** (this could replace the current HVDC charge)

* Some activities can be undertaken concurrently, timing reflects relative difficulty and priority of each task. Proposals are consciously high level to allow development through consultation with affected parties.

3.2 Stage I: Apply simplified AoB

- For Stage I we propose to allocate interconnection assets on a regional basis, using asset location and replacement cost as a proxy for benefit
- This could be done using the existing four regions or potentially a more granular approach.
- This would address the Authority's concern about the impact of investment in UNI on prices in the rest of the country

3.3 Stage II: LRMC-charges

- For Stage II we propose to replace the RCPD charges with LRMC or LRMC-like charges
- Any shortfall between the regionalised (area) allocation and LRMC charges would be recovered through Residual Charges in each area.
- We would investigate the least disruptive/distortionary way Residual Charges could be set.
- This would address the Authority's concern RCPD sending too strong/the wrong peak-usage signals, without relying on novel and uncertain implicit 'shadow prices'

3.4 Stage III – Part A: Investigate non-simplified AOB charge options

- Under Stage III(A) Transpower would review adoption of a non-simplified AoB cost allocation (which estimates benefits in a more sophisticated way) for future investments over a certain threshold.
- We would test whether a non-simplified method could be developed that is fit-for-purpose
- We would also test whether this would be better than the simplified regional (area) allocation.

3.5 Stage III – Part B: Investigate locational pricing for generation

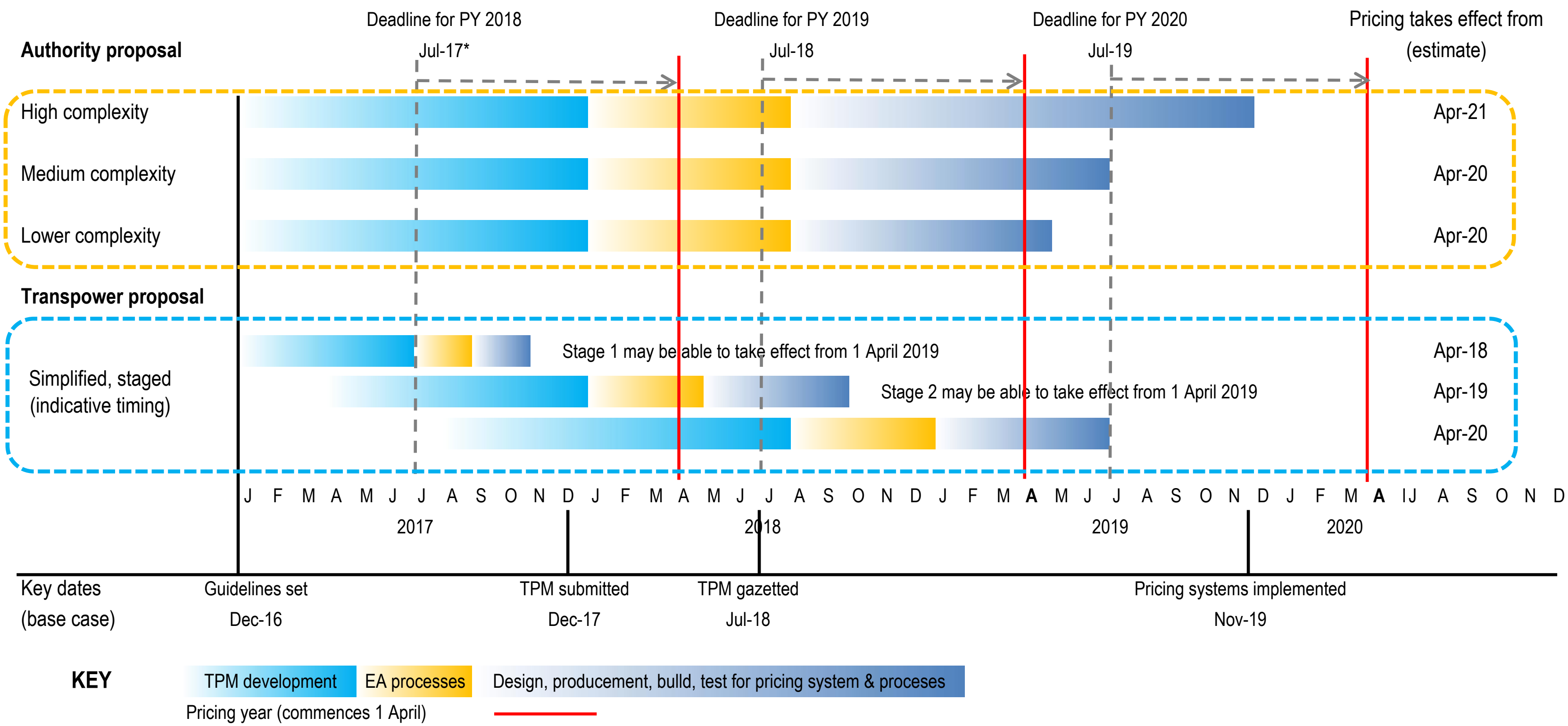
- Under Stage III(A) Transpower would review adoption of a non-simplified AoB cost allocation (which estimates benefits in a more sophisticated way) for future investments over a certain threshold.
- We would test whether a non-simplified method could be developed that is fit-for-purpose
- We would also test whether this would be better than the simplified regional (area) allocation.

*HVDC revenues are forecast to decline from ~$150m now to <$100m by the early 2020s.

3.6 Why did we make this proposal?

- It directly tackles the EA problem definition and reflects a natural progression of the current method
- It would treat customers equivalently regardless of asset age (and reduce price shocks and treats customers)
- Wider application of the regional (area) allocation better satisfies "beneficiaries-pay"
- Provides conventional explicit ex ante dynamic pricing signals – OGW CBA is based a simplified LRMC
- It is simpler and pragmatic and changes are likely to occur sooner than otherwise

3.7 Timetable comparison



* Deadline for completion of **major changes** to the TPM systems. Prices are notified to customers in November to take effect for the next pricing year (PY starts 1 April each year). This allows distributors to reflect transmission pricing in their own tariffs and in turn to notify retailers. This lead time also permits necessary customer consultation on the most complex aspects (connection charges), external audit and approval by Transpower's Board.

4.1 Options if our SSA is rejected

- The status quo, or incremental reform thereof should remain an option
  - Most of our customers consider that it has worked well for the last decade and is efficient relative to alternatives considered
  - OGW only estimated potential efficiency gains of 2.5% (relative to TPM revenue) and 0.75% (for HVDC) from replacement
- If the Authority adopts its proposals we have proposed a number of refinements to improve their workability and efficiency
- Regardless of what reforms are undertaken to the TPM we consider it imperative that an explicit, dynamic peak-usage charge is included or retained

4.2 Proposed changes to EA draft Guidelines

- Focus on simplification, more realistic implementation timeframe
- Allowing for pre and post-2004 assets to be included in the AOB charges (and use of replacement cost to value assets for pricing purposes)
- Providing a clearer basis for the simplified and non-simplified methods and capping AOB charges at aggregate benefit
- Making LRMC a required part of the TPM – i.e. retaining an ex ante peak price signal
- Moderating the price adjustment mechanisms (optimisation, marginal savings adjustments, and PDP)

5.3 Next steps

- Continue dialogue with our stakeholders (and use feedback to inform our thinking)
- Assist EA as it considers submissions and formulates decision
- Prepare for the next stage

5.1 Code process

Code part	Action
12.82 (3)	EA considers submissions (by 20 business days or longer as Authority allows) (20 business days is ~ mid August, EA has 'indicated' October)
12.88	EA writes letter of request to TP to develop methodology in '90 days or longer as Authority allows' (anticipate this by end of 2016)
12.89 (1) and (2)	TP to develop TPM consistent with guidelines, Part 4 and Statutory Objective and include indicative prices; submit
12.90	EA can decline submission if insufficient information, advise additional information required and resubmit by specified date
12.91 (1)	May approve or refer back, if latter then TP has 20 business days to resubmit
12.91 (2)	If EA considers that resubmitted TPM still does not conform to 12.89 (1) then it makes necessary amendments
12.92	EA to consult on TPM, minimum 15 business days for submission
12.93	Within 40 business days (or longer as Authority may allow) for consideration and decision
12.94	EA must consult with TP on commencement date of new TPM

Additional slides

Table 2 from Transpower submission

Table 2: Indicative price regional price impacts

Region	Status Quo interconnection (IC) $	Status Quo IC %	AoB for all IC assets	Residual (using GAMD)	Regional allocation (AoB + Residual) $	Regional allocation (AoB + Residual) %	Change from Status Quo
UNI	$218m	33%	$142m	$99m	$241m ($266m)*	36%	+10% (+22%)*
LNI	$217m	33%	$113m	$104m	$217m ($257m)*	32%	-1% (+17%)*
USI	$112m	17%	$55m	$53m	$108m	17%	-4%
LSI	$114m	17%	$52m	$45m	$97m	15%	-15%

Notes: For the scenario modelled in this table we assign $360m via the AoB charge using asset location and value (Replacement Cost[14] – indexed to 2012) and $302m[15] via the Residual charge using gross anytime maximum demand (GAMD) as the allocator. *Bracketed numbers include the Authority's modelled allocation of HVDC costs to NI consumers.

Excerpts from Transpower submission

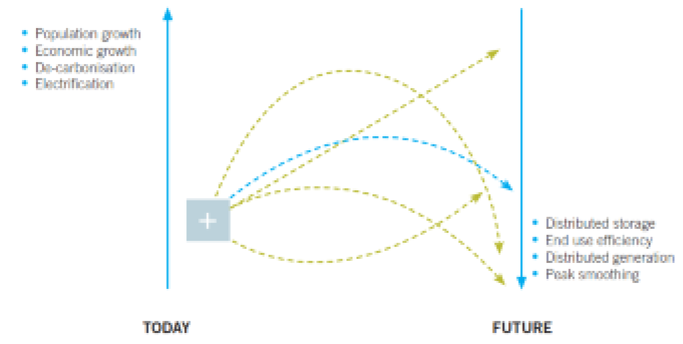
(excerpts highlight concerns with removal of peak price signals)

Our recent Transmission Tomorrow work has informed our view about future grid demand. It has highlighted the potential for pressures on grid capacity to 'wax and wane' – to grow strongly then to ease. In this context the option value of deferring investment (transmission and generation remote from load) is elevated (suggesting a strong price signal is optimal).

Absent an explicit ex ante price signal, the Authority's proposals will 'over-correct' resulting in an under-signalling of forward looking transmission costs.

Under-signalling could shift us from the blue line to the most parabolic (and regretful) trajectory depicted in Figure 1.

Figure 3: Capacity pressure trajectories (source: Transmission Tomorrow)



Avoiding this over-correction is essential. In this respect, we recognise that the proposal includes the option of introducing an LRMC charge. In our view, if the RCPD is abandoned, an LRMC charge should be mandatory.

This is because, at present, the RCPD price signals are a key component of, if not the main driver for, a proportion of demand response and regional (including distributed) generation. Table 4 shows the high level results of our analysis of the role existing distributed generation and demand response play in meeting the gross peak demand (metered consumer demand).

Table 4: Establishing a picture of 'gross system demand'

Scenario	Demand (MW)	% above net load
Net GXP demand	6200	0%
Net GXP + DG only	6730	9%
Net GXP + DG + DR[35]	7420	20%