

TPM Issues and Proposal Discussion Forum

19 October 2012

Agenda

1. Chapters 1-4: Introduction, Context, Decision-making about TPM, Problem definition
2. Proposal, including CBA (Chapter 5)
3. Evaluation of alternatives (Chapter 6)
4. Draft Guidelines and Process (Chapter 7 and 8)

The Authority regulates the allocation of transmission revenue

The current TPM has three main charges

1. Connection charges (approximately 14% of total)

- Paid by parties connecting to the transmission grid (generators, distributors and some large consumers)

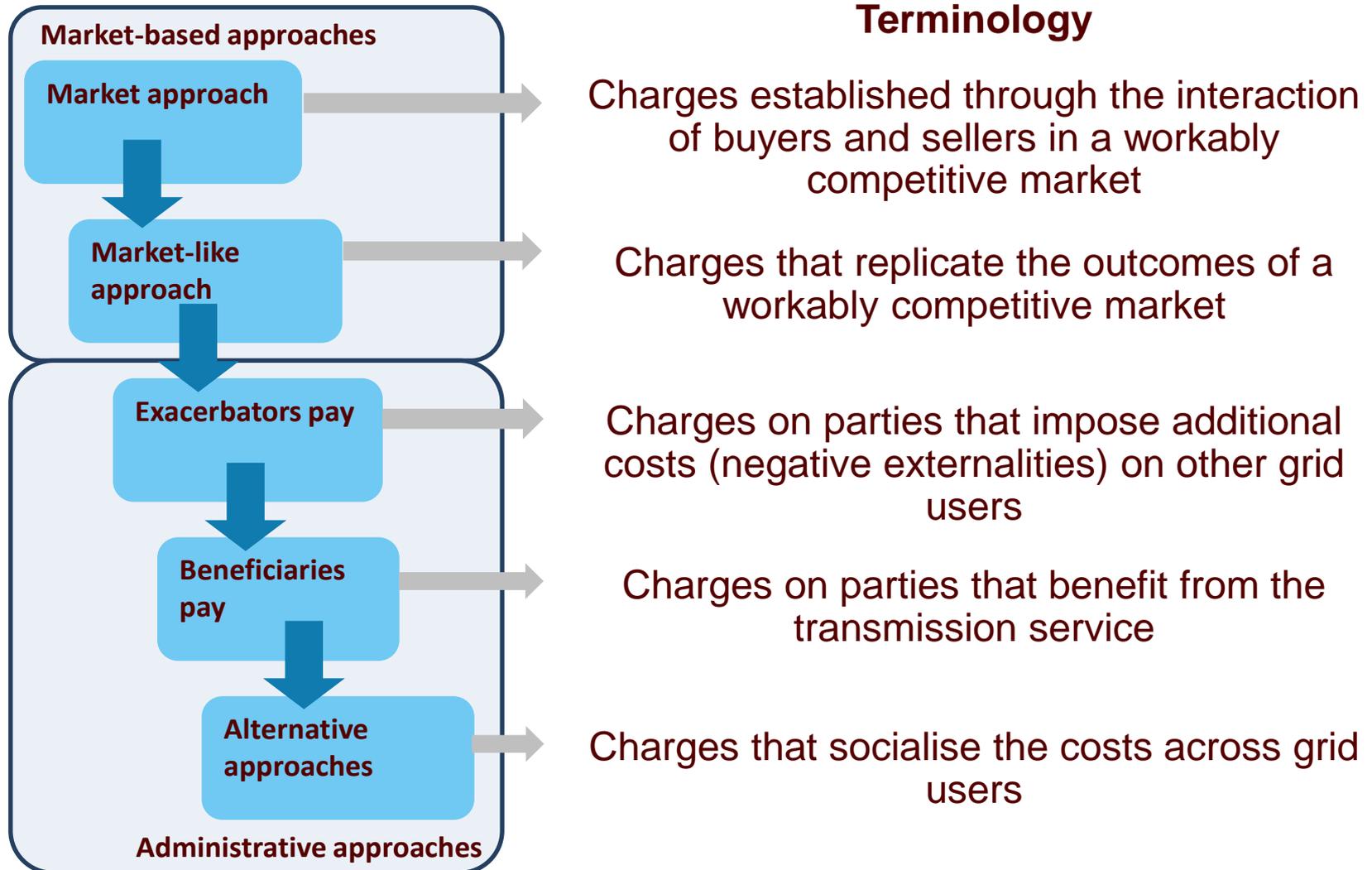
2. HVDC charges (approximately 16% of total)

- Paid by South Island (SI) generators according to their share of historical peak injection to the grid

3. Interconnection charges (approximately 70% of total)

- Largely paid by distributors and large consumers (those directly connected to the national grid)

We finalised the following decision framework



Reason for Reviewing TPM

- ❑ Fundamental reason to review the TPM is to promote the Authority's statutory objective:
 - Most relevant is efficiency criterion – efficient operation and efficient investment
- ❑ Material change (Clause 12.86) for the following reasons:
 - Significant amount of new investment
 - Changes to regulatory framework
 - Advances in technology enable more sophisticated means of allocating transmission costs

Problem definition

- ❑ Connection charge: generally efficient but loopholes mean connecting parties can inefficiently shift costs into interconnection charge
- ❑ HVDC charge: inefficient because it:
 - Disincentives efficient South Island generation investment
 - Is not durable as not all beneficiaries pay and, for those that do, charges do not necessarily = private benefit
 - Encourages on-going lobbying and review → does not promote efficient investment
- ❑ Interconnection: Inefficient because:
 - Does not promote efficient transmission investment
 - Disincentives efficient peak demand reduction
 - Disincentives efficient location of major new load

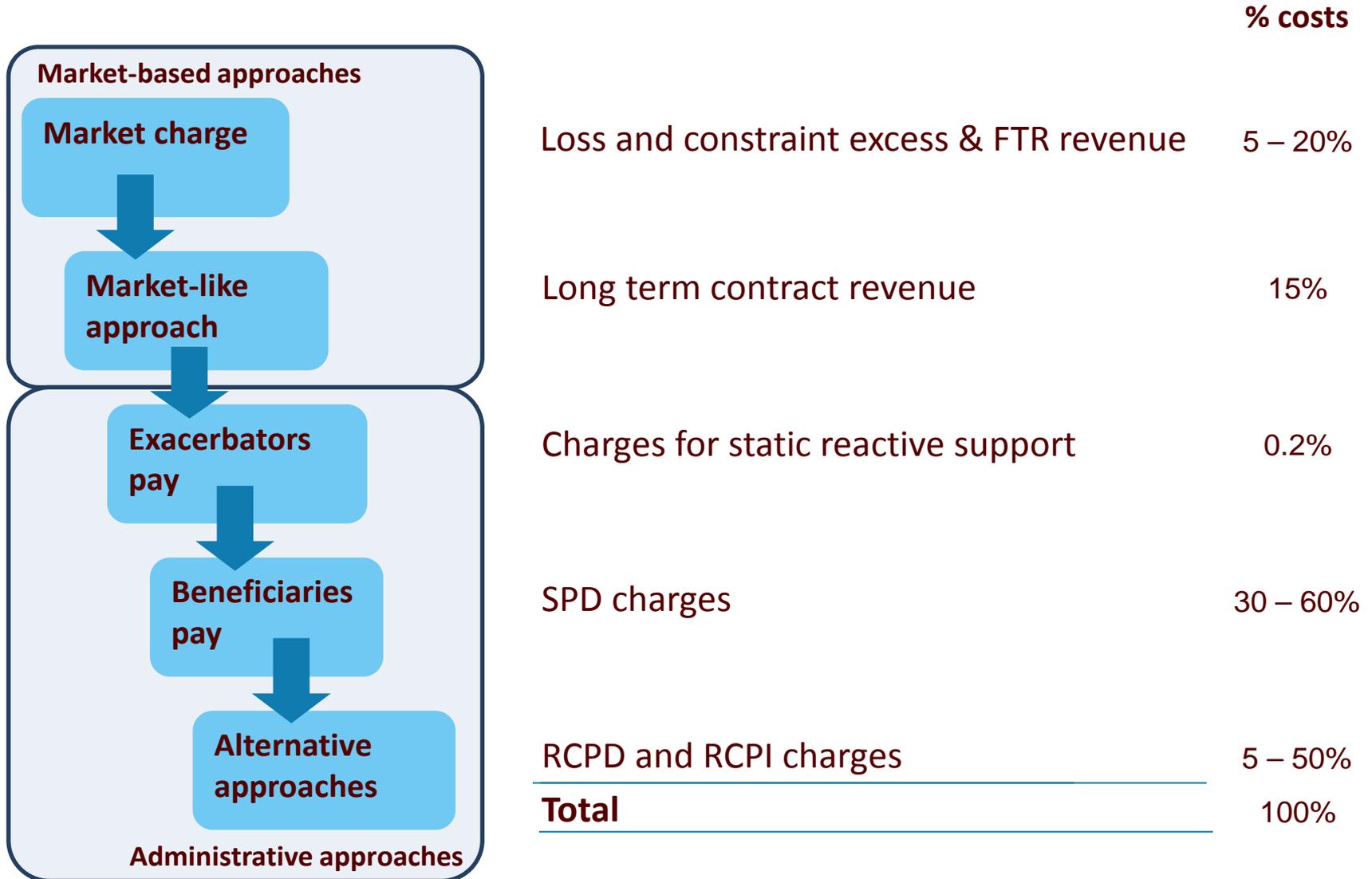
Problem definition cont.

- ❑ Quantitative assessment of problems with HVDC and interconnection:
 - \$30 million NPV - HVDC
 - \$12-170 million NPV - Interconnection
- ❑ Static reactive support: costs arise because of an externality but exacerbators do not pay as costs recovered through interconnection charge
- ❑ Dynamic reactive support: costs arise because of an externality (contingent events) but also enables greater power transfer into a region
- ❑ Prudent discount policy (PDP): exists to mitigate inefficient bypass or disconnection of the grid as a result of transmission charges. Need for and design of PDP depends on implications of proposed charging arrangements

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3. Chapter 6: Evaluation of alternatives
4. Process

Overview of Authority proposal



LCE provides a market approach to funding transmission

- ❑ Transpower currently pays the loss and constraint excess (LCE) to transmission customers in proportion to their transmission charges
- ❑ Effectively, LCE reduces the net amount they pay to Transpower
- ❑ The Authority proposes to codify the current arrangements
 - LCE received by Transpower is to be used to fund transmission costs that correspond to the origin of the LCE
 - e.g. LCE arising on the North Auckland and Northland (NAaN) project would be used to offset the cost of the NAAAN assets

LCE provides market approach to funding transmission, continued

- ❑ In principle, LCE could fully fund the costs of transmission assets
 - This would occur if grid investments exhibited constant returns to scale (CRS)

- ❑ But in practice, a large funding deficit (or residual) occurs because grid investments
 - Often have large economies of scale
 - Or are made earlier than is justified on economic grounds

- ❑ Need to recover this deficit through other charges

Connection charges

- ❑ We are proposing only minor refinements to connection charges
 - The current connection charge regime is a market-based charge, promotes efficiency, and is widely supported
 - Will allow surplus loss and constraint excess and FTR revenue to offset connection charges

- ❑ Minor problem with current connection charge
 - Connecting parties have inefficient incentives to shift some connection costs into the interconnection charge
 - Reflects minor drafting deficiencies (loopholes) in the current TPM

Connection charges

- Proposing to limit the shifting of connection costs by
 - Amending the TPM to require that current connection assets be treated as connection assets until replaced or decommissioned
 - Amending the TPM to require that replacement assets are valued for charging purposes at the actual replacement project cost, and
 - Introducing a mechanism to refer to the Authority disputes between Transpower and a connecting party about the level of connection charges following connection asset replacement

Network reactive support (NRS) services

- The need to invest in **static reactive support** equipment is the result of an externality
 - Arises because parties are using power in a manner that results in a poor power factor for other transmission users

- Propose to address this by applying **exacerbators-pay** charge to recover the costs of static reactive support services
 - TPM to include a kvar charge based on the aggregate kvar draw of off-take transmission customers, at times of regional coincident peak demand, in areas of the grid where investment in static reactive support is likely to be required
 - Set the kvar charge at LRMC of grid-connected static reactive support investment

Network reactive support (NRS) services, continued

- ❑ Dynamic reactive support is needed to deal with voltage instability caused by contingent events on the grid
 - e.g. a helicopter flying into power lines or a generator tripping
 - These events can lead to a sudden voltage collapse
 - This is an externality but it is not practicable to recover costs of dynamic reactive support through an exacerbators-pay charge

 - ❑ Dynamic reactive support enhances power transfer by making it more robust to contingent events
 - The Authority therefore proposes to recover the costs of dynamic reactive support on the same basis as for HVDC and interconnection
-

Network reactive support (NRS) services, continued

- ❑ Also proposing to amend the Connection Code to set a minimum power factor of 0.95 lagging for all regions
 - Retains clear signal to offtake customers that it is undesirable to operate their GXPs at below this power factor in any region.
 - This was the minimum power factor recommended by TPAG, on the basis that this requirement is:
 - a backstop measure,
 - it corresponds to a long-established benchmark; and
 - would provide alignment across the grid.
- ❑ The exacerbators-pay charge for static reactive support provides parties with incentives to
 - Draw reactive power only when and where this is efficient
 - Or to invest in equipment to manage their reactive power use

HVDC and Interconnection

- ❑ The Authority proposal is to use the Scheduling, Pricing and Dispatch (SPD) model to identify the beneficiaries of recent and future grid investments
 - The SPD model is used to set prices and quantities in the market now, worth about \$4b per year
 - Using it to estimate private benefits requires additional computations, but doing that is feasible now
 - The Authority has done simulations on historical market data to check it's feasible

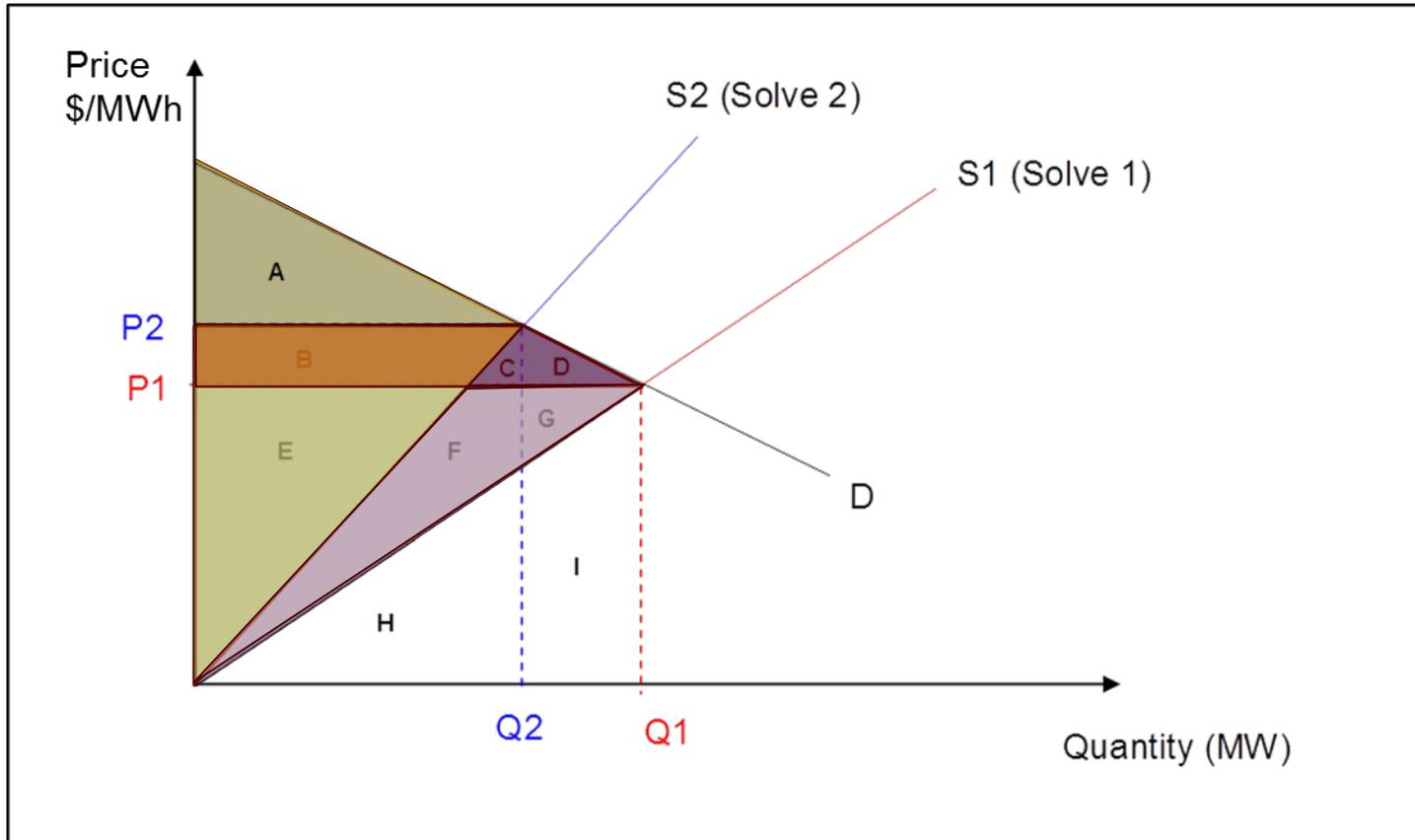
- ❑ The proposal is to apply “the SPD method” to selected grid investments
 - And allocate the cost of each investment to beneficiaries in proportion to their share of private benefits (capped at their level of private benefit)

Overview of the SPD method (e.g. for pole 3)

- Step 1: Calculate consumer and producer surpluses arising from market prices and quantities used to settle the spot market
 - This SPD solve contains all available assets including pole 3

- Step 2: Re-run SPD without the asset (e.g.) pole 3 and calculate consumer and producer surpluses based on simulated market prices and quantities
 - Private benefit of pole 3 to a consumer = its consumer surplus in step 1 minus its consumer surplus in step 2 (provided this difference is positive)
 - Same approach for generators but calculation is of producer surplus
 - Charge the half-hourly cost of pole 3 in proportion to parties' share of total half-hourly private benefits
 - Charge is capped at lesser of half-hourly private benefits or asset costs
 - Sequence of calculation does not matter except for Pole 2 and Pole 3: calculate for Pole 3 first, then Pole 2.

Calculation of benefit using the SPD method



	Solve 1	Solve 2	Change
➔ Demand (offtake)	$A + B + C + D$	A	$B + C + D$
➔ Supply (injection)	$E + F + G$	$B + E$	$F + G - B$

Application of the SPD charge

- Propose to apply SPD charge to any assets added to Transpower's regulated asset base with a cost of more than \$2m (at the time the assets are added) after 28 May 2004 + Pole 2.
 - 28 May 2004 was the date when Part F of the Electricity Governance Rules 2003 came into force
 - Date after which major uplift in transmission investment occurred
 - The more historic the investment the more diffuse the gains from applying beneficiaries pay
 - Captures investments that will soon be completed – benefits starting to flow
 - A threshold of \$2 million will capture transmission investments from which parties participating in the wholesale market benefit, including connection parties - effectively an automatic “but for” approach to determining connection charges. Seamless with connection
 - The cost and date thresholds limit the implementation cost of the SPD charge

Application of SPD charge continued

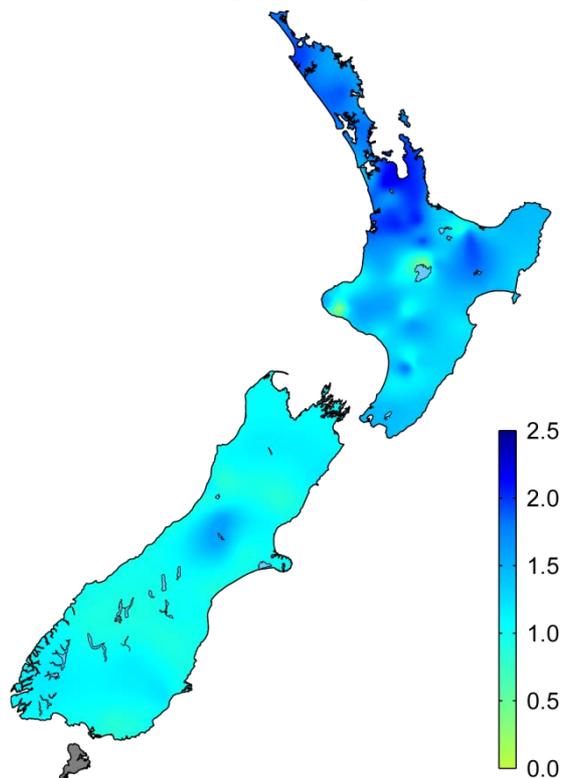
- Propose to levy SPD charge on those who benefit from access to the grid and wholesale market:
 - generators
 - direct connects
 - retailers, and
 - distributors - to the extent they provide interruptible load or offer to wholesale market

Private benefit rates for load from selected grid investments

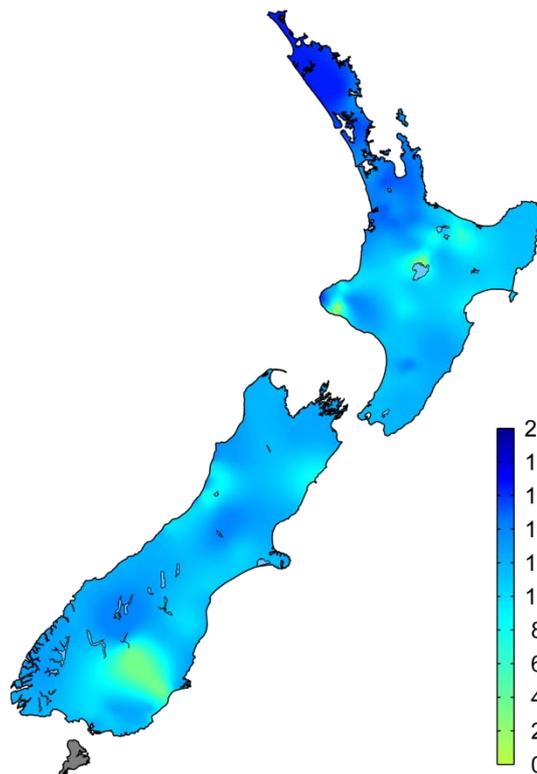
Heat maps showing private benefits in \$/MWh for period 1 July 2010 – 30 June 2012

(Note: these are benefit rates, not total benefits and not charges. Charges are to be determined using annualised cost of relevant assets)

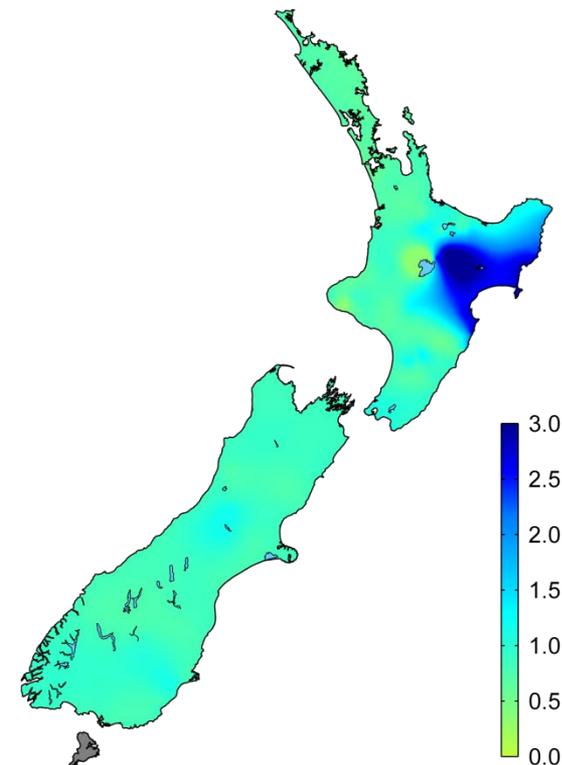
North Island grid upgrade



HVDC Pole 3

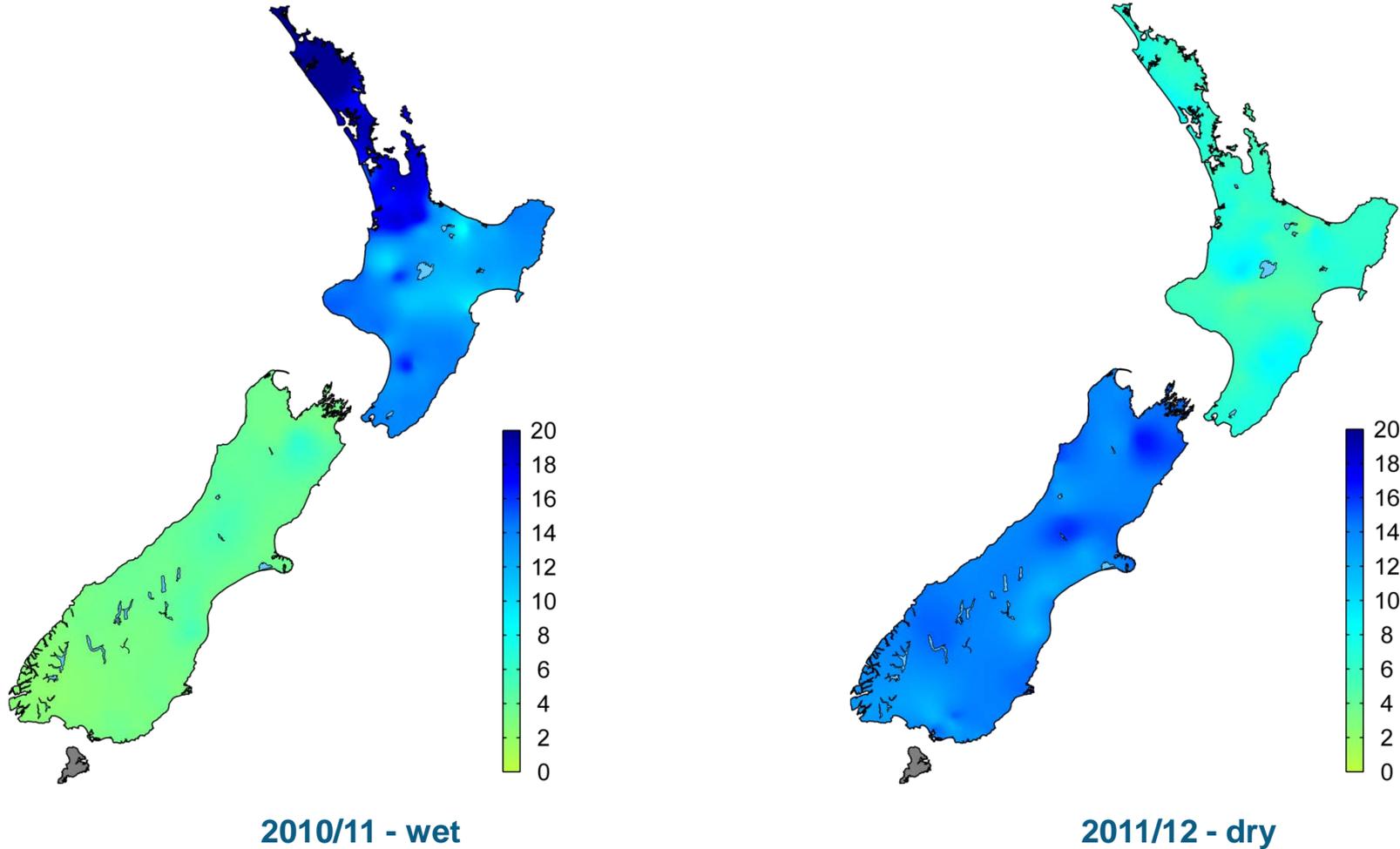


Wairakei ring



Benefits of Pole 3 change with hydrology

Heat maps showing private benefits to load from Pole 3 in \$/MWh



Proportion of private benefit by region

(excluding generators and 5 major direct connect customers)

Transmission region	NIGUP	Pole 3	Wairakei Ring
Auckland	25.8%	16.0%	14.0%
Bay of Plenty	2.1%	3.5%	3.1%
Canterbury	3.3%	5.5%	3.6%
Central	2.5%	3.3%	2.4%
Hawkes Bay	1.4%	2.4%	1.5%
Nelson/Marlborough	0.9%	1.6%	1.0%
North Isthmus	15.5%	10.2%	8.7%
Otago/Southland	2.1%	3.7%	2.3%
South Canterbury	0.5%	0.8%	0.5%
Taranaki	1.6%	1.8%	1.3%
Waikato	10.5%	8.4%	8.1%
Wellington	4.9%	6.5%	4.9%
West Coast	0.3%	0.5%	0.3%
Total	71.3%	64.1%	51.7%
Balance from others (see next slide)	28.7%	35.9%	48.3%

Proportion of private benefit for generators and large load

(note: the figures for generators relate to their generation activity, not their retail activity)

Generator	NIGUP	Pole 3	Wairakei Ring
Contact Energy	3.7%	6.2%	12.3%
Genesis	3.5%	4.2%	8.8%
Meridian	1.9%	9.4%	4.1%
Mighty River Power	6.5%	2.7%	11.0%
TrustPower	1.7%	1.3%	1.9%
Todd Energy	0.4%	0.2%	0.4%
Other Generators	2.8%	0.8%	1.5%
Large Load			
New Zealand Steel	3.5%	2.4%	2.1%
Norske Skog Tasman	0.7%	1.1%	1.2%
Winstone Pulp	0.3%	0.5%	0.4%
Pacific Aluminium	3.3%	6.5%	4.2%
Pan Pac	0.4%	0.6%	0.5%
Total	28.7%	35.9%	48.3%

SPD charge may not cover all costs (projections for 2015 based on 2010-12 data)

\$ million	Pole 3	NIGUP	WRK Ring	Islington-Kikiwa	Woodville-Masterton	Pole 2	NAaN
Expected cost	101.12	116.93	20.01	4.50	2.47	70.00	58.89
Revenue from SPD charge	37.40	15.78	8.96	1.40	0.70	64.26	5.54
Residual	63.71	101.14	11.05	3.10	1.77	5.74	53.35
Percent covered by SPD charge	36.99%	13.50%	44.78%	31.11%	28.34%	91.80%	9.41%

Re “Rate shock”

- ❑ Can’t get “rate shock” from:
 - Residual charge as roughly uniform
 - SPD charge on retailers/consumers because that reflects lower spot prices

- ❑ Very unlikely to get “rate shock” from SPD charge on generators because the charge reflects private benefits from the generator accessing a high-price area, not from increasing prices in an area it exports to

This approach is flexible and durable

□ Flexibility

- We are proposing to use the SPD model to calculate private benefits every half-hour: hence it will be very dynamic and flexible
- Changes in generation and demand patterns across the grid (eg. changes with Norske Skog, Pacific Aluminium) will immediately alter private benefits and the distribution of transmission charges

□ Durability

- HVDC and interconnection assets are shared assets – it's very difficult to set charges reflecting the full costs a grid user imposes on the grid
- The SPD method should be durable as charges will be explicitly linked to benefits actually accruing to parties on a half-hourly basis

Although variable, SPD charges may reduce overall risk

- ❑ Increasing international focus on beneficiaries-pay approach to transmission charges (eg. New York and Argentina)
- ❑ The flexibility of the SPD approach means that parties won't know for sure their future SPD charges
 - But this is the same for spot market prices and revenues, which are 5 to 10 times larger than SPD charges
 - Parties will invest in systems to estimate their future charges
- ❑ In reality the SPD charge may reduce profit volatility because co-varies with revenue
 - High SPD charges come from high private benefits (= high profits) and vice versa

Avoidance of SPD charge reveals investment efficiency

- ❑ Parties may be able to alter their offers to avoid the charge
 - e.g. South Island generators could reduce their beneficiaries-pay charge for Pole 3 by offering as if only Pole 2 was available
- ❑ To the extent parties can do this it would reveal the asset is not economically justified unless the SPD charge recovered costs from other beneficiaries
 - e.g. costs of Pole 3 may be able to be recovered through the SPD charge from consumers
 - If not, the costs would be recovered through the residual charge

Sequencing

- ❑ Only ever take one “project” out at a time
- ❑ Sequence of calculation does not matter except for Pole 2 and Pole 3: calculate for Pole 3 first, then Pole 2.
- ❑ Treat refurbishment as a new “project”

A residual charge is needed to ensure full revenue recovery

- ❑ Residual charge levied on both demand (using RCPD) and generators (RCPI)
 - Extending residual charge to generation consistent with good economic policy: broadens the base, lowers the rate → minimise distortions
- ❑ Costs split 50/50 between load and generation:
 - On the basis that, excluding losses, load \approx generation

Residual charge design

- ❑ Designed to encourage efficient avoidance of peak regional use of the grid
- ❑ Transpower would determine:
 - The optimal regions for applying these charges
 - The number of regional coincident peaks in each region to determine the charge that would apply
 - The number of peaks should reflect what is necessary to encourage efficient avoidance of peak use of transmission in each region
- ❑ Also considered flat MWh charge but this would not encourage efficient avoidance of peaks. The issue is whether the SPD charge provides efficient avoidance of peaks
- ❑ A judgement call whether RCPI or flat MWh charge

Distributors could opt-out of this charge

- ❑ The residual charge would be applied to generators, direct-connect customers and distributors (or retailers)
- ❑ Propose to give distributors the ability to opt out of the residual charge
 - Retailers operating on affected networks would pay the residual charge
 - Distributors' ability to opt out subject to consulting with retailers on their network
- ❑ But distributors would still incur any SPD charge arising from offering to or purchasing from the wholesale electricity market (eg. for interruptible load)

Load management

- ❑ Distributors still incentivised to undertake load management because RCPD retained
- ❑ To the extent that distributors opt-out of the residual charge and retailers therefore bear it, the distributor can provide load management services to retailers – explicitly provided for under the Model Use of System Agreement

Proposing to refine the prudent discount policy

- ❑ Proposing to extend the prudent discount policy (PDP)
 - To cover inefficient disconnection from the grid – this is because transmission costs rising about 79% over next 10 years
 - To cover the life of the bypass or disconnected asset (not just 15 years)
- ❑ In principle, PDP could apply to retailers where distributors opt-out
- ❑ Distributors would need to consider implications of PDP in any decision to opt-out of the residual charge

Comparison with Transmission Pricing Advisory Group (TPAG)

	TPAG minority view	TPAG majority view	EA proposal
Connection	Current approach	Current approach	Slight enhancement to current approach
HVDC	Current approach: charge all HVDC costs to SI generators	Transfer HVDC costs to interconnection charge (paid by distributors & consumers) over 10 year period	Clarify allocation of loss and constraint rentals/FTR revenue
Inter-connection	<p>Introduce NRS charge</p> <p>Retain RCPD charge</p> <p>Retain prudent discount</p>	<p>Introduce NRS charge</p> <p>Retain RCPD charge</p> <p>Retain prudent discount</p>	<p>Introduce NRS charge</p> <p>Introduce SPD charge</p> <p>Refine RCPD charge</p> <p>Introduce RCPI charge</p> <p>Allow distributors to opt out</p> <p>Refine prudent discount</p>

Cost-benefit analysis: overall

Present value of costs and benefits	Authority proposal (\$ million)	TPAG majority view (\$ million)
Economic costs	\$50.1	\$0.9
Economic benefits	\$223.3	\$50.2
Net economic benefit	\$173.2	\$49.3

Cost-benefit analysis: Economic benefits by asset class

Present value of economic benefits	Authority proposal (central case) (\$ million)	TPAG majority view (central case) (\$ million)
Interconnection & HVDC	\$208.3	\$37.2
Network reactive support	\$13.0	\$13.0
Connection	\$2.0	\$0
Total	\$223.3	\$50.2

❑ Source of gains for interconnection and HVDC:

- ❑ Avoided disputation gains: \$36.5 million PV
- ❑ Dynamic efficiency gains: \$171.8 million PV

❑ Dynamic efficiency gains estimated by multiplying sector revenue baseline (2011 baseline = \$6.493b) by a factor estimated from qualitative information. Approach used by Commerce Commission and upheld by High Court

- ❑ Assumed 10-year average growth of 3.8%, efficiency improvement of 0.3%

Cost-benefit analysis: Costs

PV of development costs	Pricing design	Pricing implementation (central systems)	Participant implementation	Totals
Authority's proposal (central)	\$0.5m	\$3.3m	\$1.8m	\$5.6m
TPAG majority view (central)	\$0.4m	\$0m	\$0.6m	\$0.9m

PV of on-going costs	Pricing party	Participant parties	Totals
Authority's proposal (central)	\$20.5m	\$24.0m	\$44.5m
TPAG majority view (central)	0	0	0

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Evaluation of alternative options

Option	Nature of option	Lawful	Practicable	Efficient	Potential to recover costs
Long-term contracts	Market	Y	N	✓✓	Partially
Capacity rights or offer rights	Market	Y	N	✓	Partially
Merchant transmission investment	Market	N	Y	✓✓✓	Partially (new)
Vote-based transmission investment	Market-like	N	Y	✓✓	Partially (new)
Economic model	Beneficiaries pay	Y	Y	✓✓	Depends on whether investments are efficient
Flow tracing	Beneficiaries pay	Y	N	✓	Depends on whether investments are efficient
Zonal uniform charge	Beneficiaries pay	Y	Y	✓✓	Depends on whether investments are efficient
Current RCPD charge	Alternative	Y	Y	✓	Yes
MWh charge	Alternative	Y	Y	✓✓	Yes
Incentive-free	Alternative	Depends	N	✓	Yes

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TPM, Code amendments, Connection Code and Benchmark Agreement

- ❑ TPM amendment – changes to connection charges and referral mechanism for connection; static reactive support charge; SPD method; and residual charge (RCPD and RCPI) and PDP
- ❑ Code amendments – LCE and designated transmission customer
- ❑ Connection Code amendment – 0.95 lagging
- ❑ Benchmark agreement amendment – may be required for aspect of LCE and to facilitate retailers as transmission customers

Briefing and consultation process

□ Consultation

- Initial consultation closes **30 November 2012** – 7 weeks & two days
- Cross submissions closes **21 December 2012** – three weeks
- Chair and CE meeting with chairs and chief executives of major participants
- One-on-one meetings available on request
- Parties can contact Market Performance team with requests for Authority to undertake modelling but results would be put on Authority's website

- Aim is to have new pricing approach in place for April 2015 pricing year

Indicative timeline as at 9 Oct 2012

