Transmission Pricing Methodology

A Review of Transpower's proposal to the Electricity Commission

For: Rio Tinto Aluminium New Zealand Limited

Author: Robert Reilly

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Preface

Strata Energy Limited specialises in providing services relating to the energy industry and energy utilisation. The company was established in 2003. Strata Energy provides advice to clients through its own resources and through a network of associate organisations. Strata Energy's consulting division, Strata Energy Consulting, has completed work on a wide range of topics for clients in the energy sector in both New Zealand and overseas.

The report was written by:
Robert Reilly

John Stephenson of NZIER has provided mathematical formula development and analysis.

For further information please contact:

Robert Reilly
Director
Strata Energy Consulting Limited
Level 2
95 – 99 Molesworth Street
PO Box 12332
Thorndon
Wellington

Phone: +64 4 473 6798
Fax: +64 4 471 0319
Mobile: 021 428 268
Email: robert.reilly@strataenergy.co.nz

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Executive Summary

Rio Tinto Aluminium New Zealand Limited (RTANZ) has commissioned Strata Energy to provide a review and analysis of the impact of the proposed Transpower Transmission Pricing Methodology (TPM). This report provides that review and considers, in particular, those customers who will be affected by the outcomes of the proposed methodology.

The Electricity Commission (EC) has only released analysis concerning the immediate (first year) changes that will occur upon introduction of the proposed methodology, and has not released any analysis of the forward impact on transmission customers. It is recommended that a further, more detailed, analysis is undertaken in order to fully assess the overall impact of the TPM.

However, in order to review, and provide analysis of, the proposed TPM, we have examined the impact of a change from the current 'Anytime Maximum Demand' (AMD) pricing methodology to a 'Regional Coincident Peak Demand' (RCPD) pricing methodology (as is being proposed), for the recovery of Transpower's interconnection revenue.

In particular, the effect on the changes to the interconnection and connection charges for the proposed regions and individual customers as shown in Annexure 1 have been examined.

A number of scenarios have been used to illustrate the effect of changing from an anytime demand pricing regime to a coincident demand pricing regime. The scenarios have been developed using a simple model that provides insights into the impact of Transpower's proposal on transmission customers and the regions.

Transpower's proposed TPM has some benefits and in general complies with the EC's guidelines. However, our analysis has identified a number of potential shortcomings in the proposed TPM. We consider that the main issues are as follows:

1. Introducing the new TPM as planned, with no transitional arrangements, will transfer wealth from one group of transmission customers to another, without any change in costs of supply or customer behaviour.

2. Within unconstrained regions there will be shifts in the interconnection charges that will place incentives on some customers to manage load unnecessarily and inefficiently.

3. Coincident peak demand pricing will tend to transfer interconnection charges from customers with low load factors to customers with high load factors, irrespective of whether they are in constrained or unconstrained regions.

4. In particular, some customers will face higher charges due entirely to the actions of others.

5. Differentiating capacity constrained regions from unconstrained regions by applying different values of N leads to lower average coincident demands for customers in the unconstrained regions (because N=100) and higher average coincident demands for customers in the constrained regions (because N=12). This effectively increases the interconnection rate in constrained regions and could therefore be considered to breach the postage stamp rate guideline.

6. The impact of the above is to increase the interconnection rate for all customers.

7. Increasing the interconnection rate has the effect of:

    - Encouraging load management by customers in regions that are not capacity constrained;
    - Transferring interconnection costs from customers that can reduce demand and have low load factors, to customers with high load factors, irrespective of whether the customers are in constrained or unconstrained regions; and
    - Transferring costs from those that make inefficient use of the system to those that have the highest load factors and therefore make the most efficient use of system capacity.

8. Customers with zero demand during the regional peak periods can use the transmission system free of interconnection charges. We consider that this breaches the 'User Pays' principle.

We consider that it is possible to address the above shortcomings and construct an alternative TPM that more closely complies with the guidelines and has greater alignment with the EC's efficiency objectives.

The alternative TPM we have developed (Strata alternative) has the following features:

1. Transpower's required interconnection revenue is divided by the sum of the anytime maximum demands of all customers, nationwide. This leads to a lower interconnection rate than would be obtained using Transpower's proposed TPM.

2. Once calculated, the revenue requirement for each region will be fixed for that pricing year.

3. Customers in constrained regions will be charged on the basis of their average regional coincident peak demands, the interconnection rate, and a regional diversity factor. The diversity factor adjustment ensures that the regional revenue requirement is met.

4. The locational price signal will be based on the diversity factor adjustment to the interconnection rate.[1]

5. The Strata alternative calculates each customer's interconnection charge using the same interconnection rate (the postage stamp) and tailors the charge according to whether the customer is in a constrained or unconstrained region. In this regard it is identical in structure to Transpower's proposal.

The benefits of the Strata alternative include:

- the interconnection rate is much easier to calculate and predict as it is the same as that used in the current methodology and thus is much more transparent than Transpower's proposal;

[1] Whilst this approach may still be considered to breach the postage stamp guideline requirement, we consider that the distortionary effects on nodal pricing and the incentives to avoid sunk costs are lower than in Transpower's proposed TPM.

- customers in unconstrained regions have their interconnection charges calculated in the same way as the current methodology which promotes consistency and certainty;
- stronger signals are sent to customers in constrained regions to shift load away from the system peaks, which Strata understands to be one of the major aims of the Commission;
- wealth transfers are minimised;
- cost increases for customers that occur not through their own actions, but through the actions of others, are also minimised;
- customers in unconstrained regions will be charged at similar levels to the existing pricing methodology and will not see a major shift in their interconnection charges just because a new pricing methodology has been implemented;
- inefficient signals to manage load will be minimised in unconstrained regions;
- a locational price signal in each constrained region will encourage more efficient investment in load management by those customers causing the regional peak demand; and
- efficient users of system capacity in unconstrained regions are not penalised, but the "causers" of capacity constraints in constrained regions are provided with higher incentives to reduce their coincident peak demands because the inter-regional transfer of charges is removed.

6. A transitional period before full implementation of the Strata alternative will provide an opportunity to customers in constrained regions to develop new load patterns.

An assessment of the proposed Strata alternative against the Regulatory Framework included in the EC's consultation document has been included as Annexure 3.

In summary, we consider that the Strata alternative method of recovering the interconnection charge revenue and implementation approach will:

- More closely meet the EC's guidelines for transmission pricing and its other evaluation criteria;
- Eliminate transitional issues for transmission customers;
- Provide improved focus for investment and more efficient price signalling in constrained regions and avoid inefficient price signals in unconstrained regions; and
- Reduce inefficient and distortionary wealth transfers between transmission customers.

We recommend that the amended TPM proposed in this paper is given serious consideration by the EC.

1. Introduction and purpose

The purpose of this paper is to provide advice to RTANZ regarding aspects of the Electricity Commission's (EC) consultation paper on Transpower's proposed Transmission Pricing Methodology (TPM). It is not intended that this paper provide a point by point response to the questions posed by the EC. Rather, this paper will:

1. Explore the consequences of the proposed TPM and raise issues relating to the impact of the proposed changes, particularly as they relate to interconnection charges.

2. Comment on the impact of the change in methodology on the charges to customers and to the regions that Transpower has identified in attachments to the TPM proposal (this information has been used to develop the tables and charts in Annexure 1).

3. Develop a set of scenarios using a simple model of a power system, to illustrate the effect of changing from interconnection charges based on anytime maximum demand to charges based on regional coincident peak demand pricing.

4. Set out proposed amendments to the TPM (Strata alternative) that would address the shortcomings of the proposed change and achieve outcomes that would have a higher level of compliance with the guidelines and principles that Transpower and the EC have used to evaluate the proposed change.

5. Present a comparison of the Strata alternative in relation to the Regulatory Framework used by the EC.

PART ONE: CRITIQUE OF TRANSPOWER'S PROPOSED TPM

2. Definitions and Interpretation

The following definitions, terms and formulae under paragraphs 2.1 and 2.2 have been obtained, verbatim, from the proposed Transpower Pricing Methodology, dated June 2006, and have the meanings stated unless the context otherwise requires.

2.1 Definitions

- *anytime maximum demand* or *AMD* means the average of the 12 highest net offtake quantities for an offtake customer at a connection location during the capacity measurement period for the relevant pricing year. This definition is subject to section 7 of the transmission pricing methodology and any prudent discount agreement;

- *capacity measurement period* means, for any pricing year, the period identified by Transpower as the capacity measurement period for that pricing year, being a period that commences not more than 24 months prior to the start of the pricing year and ends prior to the commencement of the pricing year;

- *connection location* means the substation or other location at which a customer's assets are directly connected to the grid;

- *customer* means a person who has or controls assets directly connected to the grid and, in relation to a connection location, means a person who has or controls assets directly connected to the grid at that connection location. A customer may be both an offtake customer and an injection customer at the same connection location.

- *region* means a group of connection locations, being one of the groups identified as:
  - Upper North Island;
  - Lower North Island;
  - Upper South Island; and
  - Lower South Island.

- *regional demand* means, in any half hour, the sum over all customers at all connection locations in a region of all net offtake quantities at those connection locations;

- *regional peak demand period* means:
  - in relation to the Upper North Island and the Upper South Island regions, a half hour in which any of the 12 highest regional demands occur during a capacity measurement period; and
  - in relation to the Lower North Island and the Lower South Island regions, a half hour in which any of the 100 highest regional demands occur during a capacity measurement period.

- *regional coincident peak demand* or *RCPD* means a customer's net offtake at a connection location during a regional peak demand period.

2.2 Terms and Formulae

- **Interconnection Charge**: The purpose of the interconnection charge is to recover the remainder of Transpower's AC revenue that is not recovered via connection charges. Interconnection charges are paid by offtake customers in respect of each connection location.

- **Interconnection Revenue**: The portion of AC revenue to be recovered by the interconnection charge is calculated as the difference between Transpower's AC revenue and the amounts recovered by the connection charges for that pricing year as follows:

  $$R_{IC} = \text{AC revenue} - \sum \text{connection charges}$$

  Where:
  AC revenue is Transpower's **AC revenue** for the relevant **pricing year**; and
  Σconnection charges is the sum of all connection charges calculated for the relevant **pricing year**

- **Interconnection Rate**: The interconnection rate used to determine the interconnection charge is referred to as IR and is the same for all offtake customers at all connection locations in all regions. The IR is calculated by dividing the interconnection revenue by the sum of the average of the RCPDs for each customer at a connection location for all customers at all connection locations for all regions as follows:

  $$IR = \frac{R_{IC}}{\sum_{regions} \sum_{cust} \sum_{loc} \frac{1}{N_{reg}} \sum_{i=1}^{N} RCPD_i}$$

  Where:

  R_{IC} is the interconnection revenue as calculated above; and,

the term $\sum_{regions} \sum_{cust} \sum_{loc} \frac{1}{N_{reg}} \sum_{i=1}^{N_{reg}} RCPD_i$ is the sum of the average **RCPDs** for each customer at a connection location for all customers at all connection locations for all regions.

- **Calculating the Interconnection Charge**: An interconnection charge is calculated for each offtake customer at a connection location by multiplying the interconnection rate by the sum of the customer's RCPD at a connection location as follows:

  $$IC = IR \times \frac{1}{N_{reg}} \sum_{i=1}^{N_{reg}} RCPD_i$$

  Where:

  IR is as defined above; and

the term $\frac{1}{N_{reg}}\sum_{i=1}^{N_{reg}} RCPD_i$ is the average **RCPD** for the offtake customer, i, in respect of whom the interconnection charge is being calculated at the relevant connection locations

2.3 Diversity and Load Factors

The diversity and load factor attributes of customers and regions are explained below, as these terms will be used to illustrate the impact of changing from an AMD pricing regime to a RCPD pricing regime.

2.3.1 Diversity

Electricity transmission enables power stations and loads to be interconnected. This achieves economies of scale, as well as diversity between the times of maximum demand of various loads and the need for available generation.

The diversity can be expressed as a factor relating the peak demand of the system to the sum of the maximum demand of the customers (or regions) of the interconnected system. Where diversity exists, the ratio of the sum of the individual maximum demands to the peak demand will always be greater than unity.

The diversity factor can be expressed as: $DF = \frac{\sum AMD}{\sum RCPD}$

where ΣAMD is the sum of the anytime maximum demands and ΣRCPD is the system peak demand.

2.3.2 Load factor

The load factor of a system is the ratio of the average demand of the system to the peak demand. If the system has a constant demand then the average demand will be the same as the peak demand, and the load factor will be unity.

The load factor can be expressed as: $LF = \frac{\frac{1}{N}\sum_{i=1}^{N} D_i}{\sum MD}$

where MD is the maximum (or peak) demand and $\frac{1}{N}\sum_{i=1}^{N} D_i$ is average demand.

If all the customers in a region have unity load factors, then each customer's maximum demand will coincide with the regional peak demand. The diversity factor and the load factor of the region will each be unity.

Current and historical pricing methodologies have encouraged customers to aim for high load factors as this allows a high capacity utilisation of the installed infrastructure. A high load factor system can spread the costs per kW over a larger number of kWh than a low load factor system with the same peak demand. Customers with high load factors pay a lower average c/kWh charge using the overall charges that include energy rates as well as demand charges. The system benefits from a high level of usage in that electricity can be more competitive than it otherwise would be in relation to other fuels. Customers benefit because the average price is lower than it would be in a low load factor system.

3. Managing Demand

The following points are important when considering price signals that provide incentives for the management of demand.

1. The revenue requirement is largely a fixed amount that Transpower will recover. The interconnection charge revenue is obtained by applying an interconnection rate to the demand in kW (the demand charge). That rate will vary according to the total level of demand – if the sum of customer AMD is used, the rate will be lower than if the sum of customer RCPD is used. If the level of revenue recovered is less than that required due to a reduction in demand (be it anytime or peak), then the rate will have to be increased in the next pricing year to ensure full recovery.

2. Under the present methodology, distributors use ripple control to manage their AMD and to improve their load factors. A distributor who reduces their interconnection charges by shifting load transfers the cost from themselves to other customers. It has been proposed that the existing methodology enable customers with multiple points of supply to be charged on their aggregate demands. Such an approach reduces the chargeable demand and the diversity of the system, and it will increase the interconnection rate in subsequent years. Increasing the rate increases the incentive for customers to manage demand to reduce interconnection charges.

3. A reduction in demand is required where capacity constraints exist but it is inefficient where the capacity of the region is unconstrained. Load management in those regions would be better used for other purposes – e.g. contributing to frequency management.

The proposed methodology makes provision for aggregation. However, it should be noted (as has been pointed out by Transpower[2]), that moving from charging on the basis of AMD to RCPD eliminates any advantage gained from aggregating demand. This is because the sum of a customer's coincident peak demands will either be equal to, or greater than, the aggregate maximum demand of a number of locations.

4. Transpower's TPM

The Transmission Pricing Methodology (TPM) comprises connection charges, interconnection charges and HVDC charges. Transpower recovers its revenue requirement for AC assets by applying connection charges and interconnection charges, whilst HVDC charges recover Transpower's HVDC revenue.

The new methodology proposed by Transpower has some significant changes to the existing method:

- It introduces a 'deeper' connection asset definition;
- It introduces regional coincident demand pricing for the recovery of the interconnection revenue;
- It identifies four regions for charging purposes;
- It introduces differentiation in the method for measuring chargeable demand for the four regions and
- It will be applied retrospectively.

[2] Paragraph 3.10 of Transpower's "Transmission Pricing Methodology Supplementary Material" , June 2006

4.1 Impact of proposed TPM

4.1.1 Connection charges

The definition of connection assets has been amended to include more assets – that is, the 'deep connection' method enables more assets to be classed as connection assets. The allocation of the costs of shared assets is on an anytime maximum demand basis, ensuring that there is a fair allocation based on usage. The valuation method for assets has been amended to a replacement cost (RC) basis but an adjustment factor has been introduced to maintain the optimised replacement cost (ORC) for assets that have ORC less than RC. This adjustment factor will prevent customers losing the benefits of the previous optimisation. This approach contrasts with that for the interconnection charge regime where no adjustment has been allowed for the transition to the new methodology.

4.1.2 Interconnection charges

Based on the analysis of the effect of changing from an AMD to a RCPD pricing regime described later in this report, we have drawn the conclusions below.

1. **Increased Costs:** The proposed TPM will lead to a higher interconnection rate through the introduction of RCPD pricing and differential N values for determining the number of coincident peaks to be used for calculating the rate. This will raise charges to all customers who cannot reduce their demand at the times of regional peak demand, even customers in unconstrained areas.

2. **Inefficient Incentives to Reduce Demand:** The proposed TPM will lead to a higher incentive for customers to shift their demand in all regions, due to the higher interconnection rate. This will result in inefficient incentives to reduce demand during regional peaks in unconstrained regions where this is clearly unnecessary.

3. **Breach of Postage-Stamp Guideline:** The proposed TPM will lead to a possible breach of the postage stamp rate guideline because, the lower the sum of the regional average coincident peaks, the higher the effective interconnection rate. Therefore the effective interconnection rates in unconstrained regions will be lower than those in constrained regions.

4. **Cost Transfers:** The proposed TPM will result in the transfer of charges from low load factor customers to high load factor customers (whose peaks are more likely to be coincident with regional peaks) and to other customers with coincident peaks (generally the largest customers in the region).

5. **Breach of the User-Pays Principle:** It will be possible for customers with maximum demand outside the regional peak periods to totally avoid interconnection charges if their demand falls to zero at the time of the regional peak. Although this is unlikely for many customers, it is conceivable that it could happen to irrigation, dairy processing and meat processing loads that may not be operating (or operating minimally) during a region's winter system peak. Under the proposed TPM, such loads would obtain free use of the interconnection assets. This would breach the user pays principle. Also, the avoided charges of these customers would be transferred to other customers, not necessarily those in constrained regions.

4.1.3 Regional effects

In regions subject to capacity constraints, a strong signal to reduce regional peak demand will affect the timing of transmission investments, and will also contribute to reducing energy prices by reducing or avoiding high regional spot prices. It will also reduce the level of loss and constraint rentals paid by customers in regions subject to constraints.

In regions with no capacity constraints, increasing the interconnection rate may be counterproductive because it would encourage unnecessary load management. The postage stamp approach will lead to charges being immediately transferred from customers with low load factors to customers with high load factors in both constrained and unconstrained regions. Such customers will also be penalised when charges are transferred from constrained regions if, and when, customers in those regions reduce their coincident peaks.

The apparent benefit of high N values for regions with high load factors is problematic, because high load factor invariably means high coincidence factors and those regions are liable to attract a great deal of any transfer of charges. The high N values contribute to higher interconnection rates, which will penalise the high load factor customers.

Customers who have achieved high load factors through the judicious use of load management, or efficient production, have limited potential for further improvement and their costs of shifting or reducing load are likely to be high. The incentive on high load factor customers in unconstrained regions of a move to coincident regional peak demand pricing will be to reduce their load factors in order to reduce the level of their coincident peak demand. It is likely this will lead to an increase in the overall average price in the unconstrained regions.

4.2 Retrospective application

The retrospective application of the new methodology will have the effect of transferring wealth among customers. A transitional arrangement would allow the new pricing signals to be anticipated so that in the following year the rewards or penalties will be based on the rules of the game that have been published in advance.

4.3 Summary of disadvantages of proposed TPM

In summary, we consider that the disadvantages of the proposed TPM are as follows:

1. Introducing the new TPM as planned, with no transitional arrangements, would transfer wealth from one group of transmission customers to another, without any change in costs of supply or customer behaviour.

2. Within unconstrained regions there would be shifts in the interconnection charges that will place incentives on some customers to manage load unnecessarily and inefficiently.

3. Coincident peak demand pricing will tend to transfer interconnection charges from customers with low load factors to customers with high load factors, irrespective of whether they are in constrained or unconstrained regions.

4. Differentiating capacity constrained regions from unconstrained regions by applying different values of N will lead to lower average demands for the unconstrained regions and higher average demands in the constrained regions.

This would effectively increase the interconnection rate in constrained regions and could, therefore, be considered to breach the postage stamp rate guideline.

5. Using lower average customer demands (through the higher N and the RCPD approach) when calculating the interconnection rate increases the average rate for all customers.

6. Increasing the interconnection rate would:

    - Encourage load management by customers in regions that are not capacity constrained.
    - Transfer interconnection charges from customers who can shift demand and have low load factors, to customers with high load factors, irrespective of whether the customers are in constrained or unconstrained regions.
    - Transfer costs from those that make variable use of the system to those who have the highest load factors and therefore make the most efficient use of system capacity, especially in unconstrained regions.

7. Customers with zero demand during the regional peak periods could use the transmission system free of interconnection charges. We consider that this would breach the 'User Pays' guideline.

4.4 Expected cost impact of proposed TPM

Attachment 1 to the TPM proposal (included in Annexure 1) provides a high level comparison of the impact of the proposed regime. It indicates that connection charge revenue is reduced, interconnection charge revenue is increased, and interconnection charge revenue in one of the constrained regions (USI) decreases at the expense of an unconstrained region (LSI).

The next sections briefly analyse possible reasons for the impacts but a more robust cost benefit analysis by the EC is required to provide a fuller explanations for the results.

4.4.1 Connection charges

The consequence of the amended approach to connection charges is to decrease the overall expected revenue from connection assets and to increase the revenue from interconnection charges by some $8.3 million. This outcome seems counterintuitive because why should the revenue decrease when more assets are included in the cost recovery process? The change from optimised to physical assets may account for this, but again, one would expect there to be an increase in the value of assets through the removal of the optimisation process.

Closer examination of the impact on customers reveals that the vast majority of customers experience a decrease in connection charges. However, there are some notable increases.

The charts below show the impact of the deeper connection charges definition. A large number of customers experience decreases, some experience increases, but the overall result is that a small number of large customers are affected. As can be seen from the data in Annexure 2, the most significant impact is the reduction for Meridian at Tiwai of $5.4 million which counterbalances the very significant increase of $4.58 million for Meridian's other connection points.

While the EC has explained why it believes the components of the TPM meet the guidelines and principles, it would be useful for it to explain why the connection charge revenue has decreased when the deeper connection definition captures more assets.

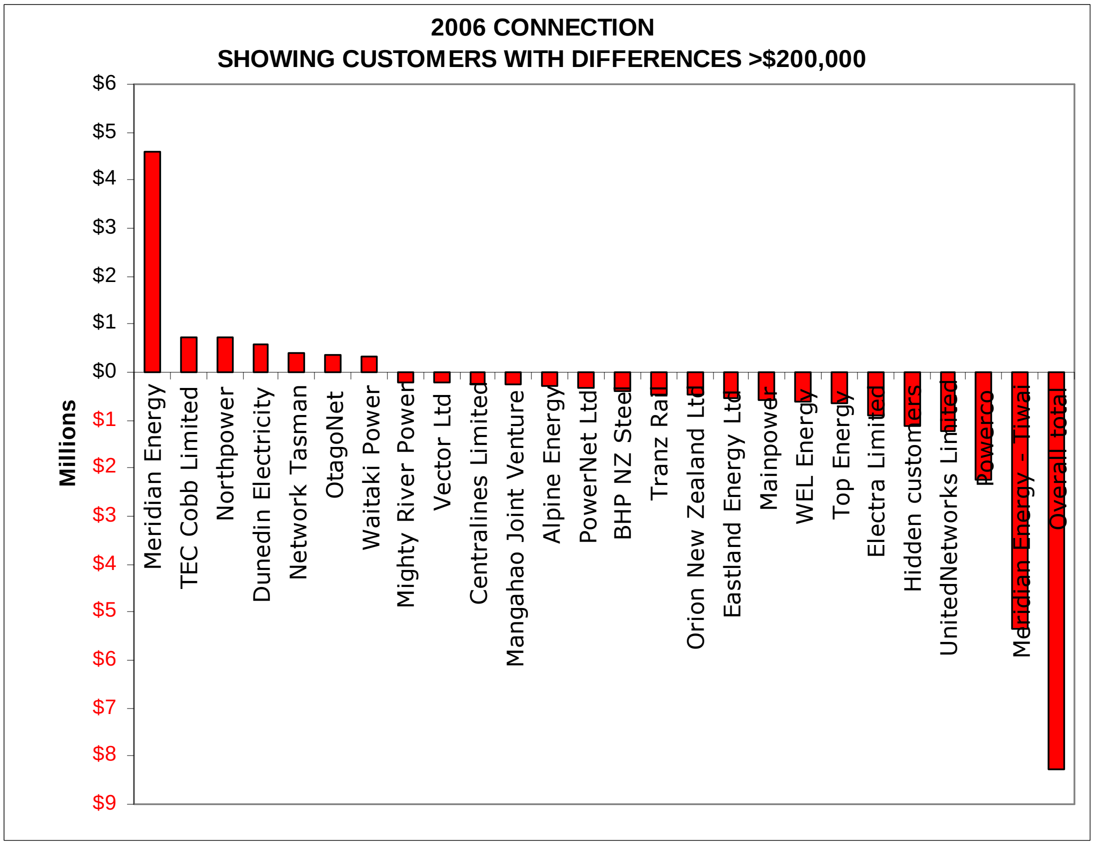


Figure 1: Impact of deeper connection charges – customers with differences > $200,000

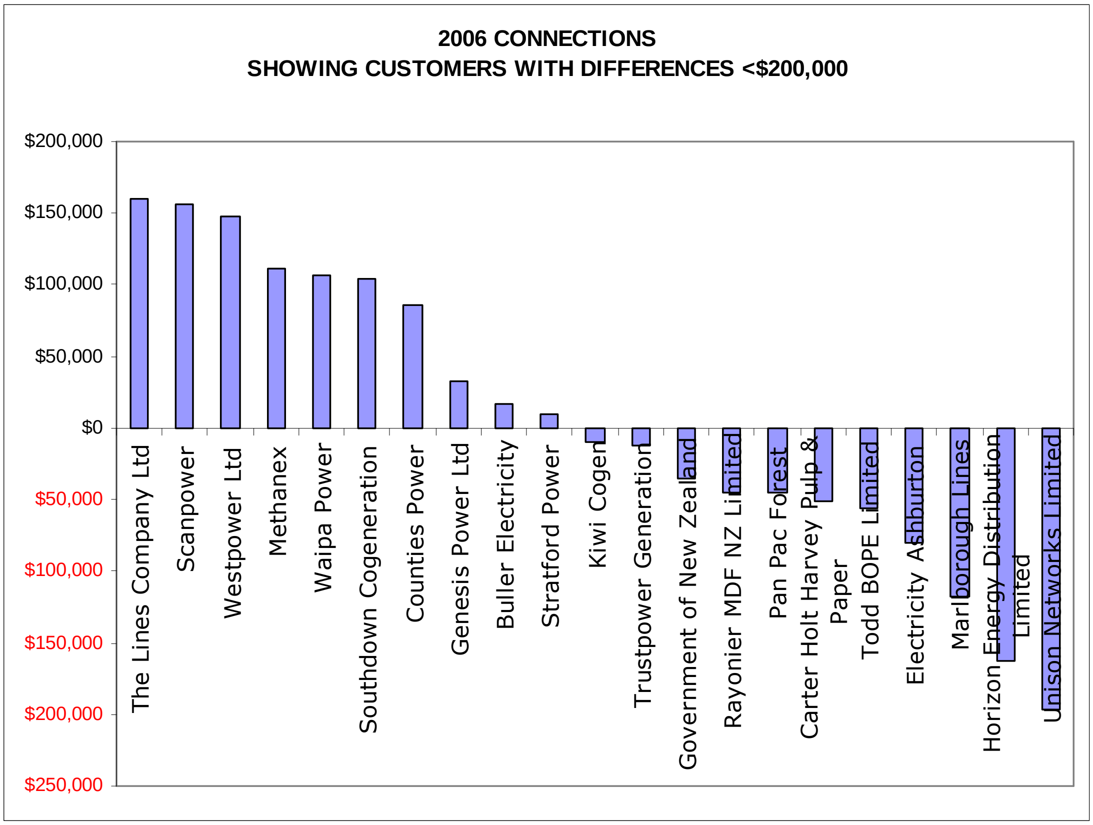


Figure 2: Impact of deeper connection charges – customers with differences < $200,000

4.4.2 Interconnection charges

The changes that have been made to the methodology in terms of interconnection charges are:

- The introduction of regions.
- The use of N=100 or N=12 for averaging the demands.
- The introduction of regional coincident peak demand charging.

The following 2 charts show the impact of the changes and (as per the result for connection charges) a large number of customers experience decreases, some experience increases, but the overall effect is that a small number of large customers are affected.

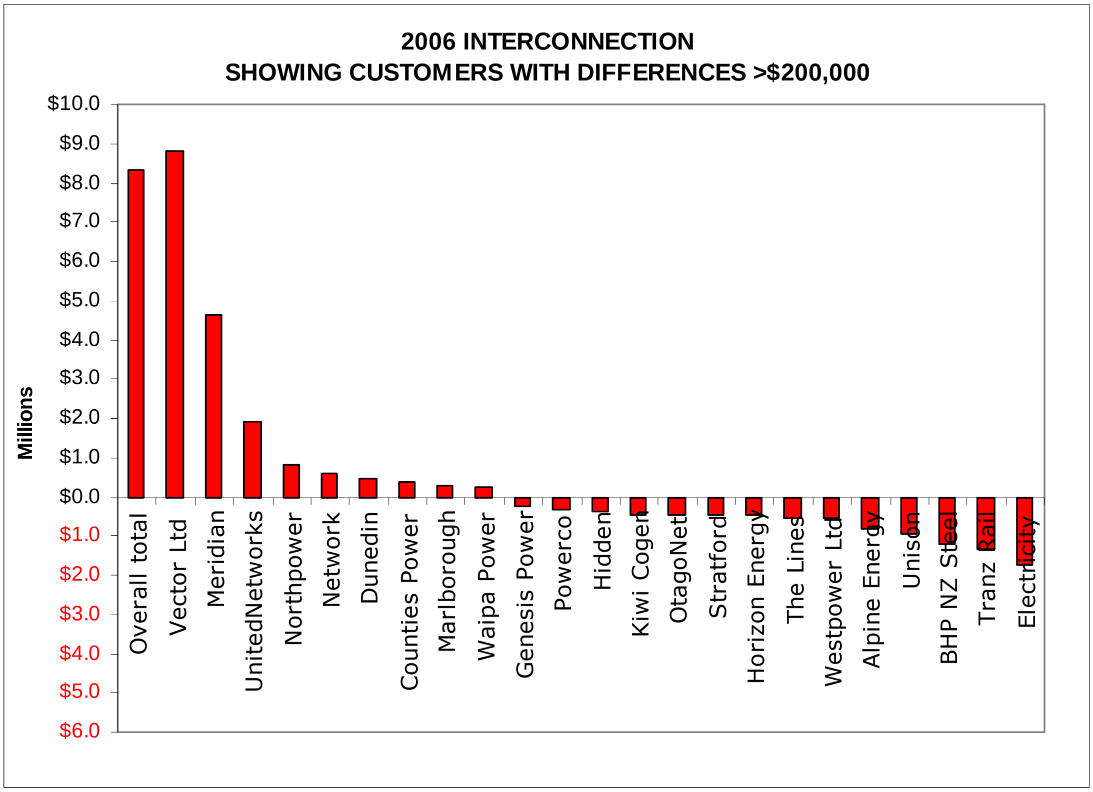


Figure 3: Impact on interconnection charges – customers with differences > $200,000

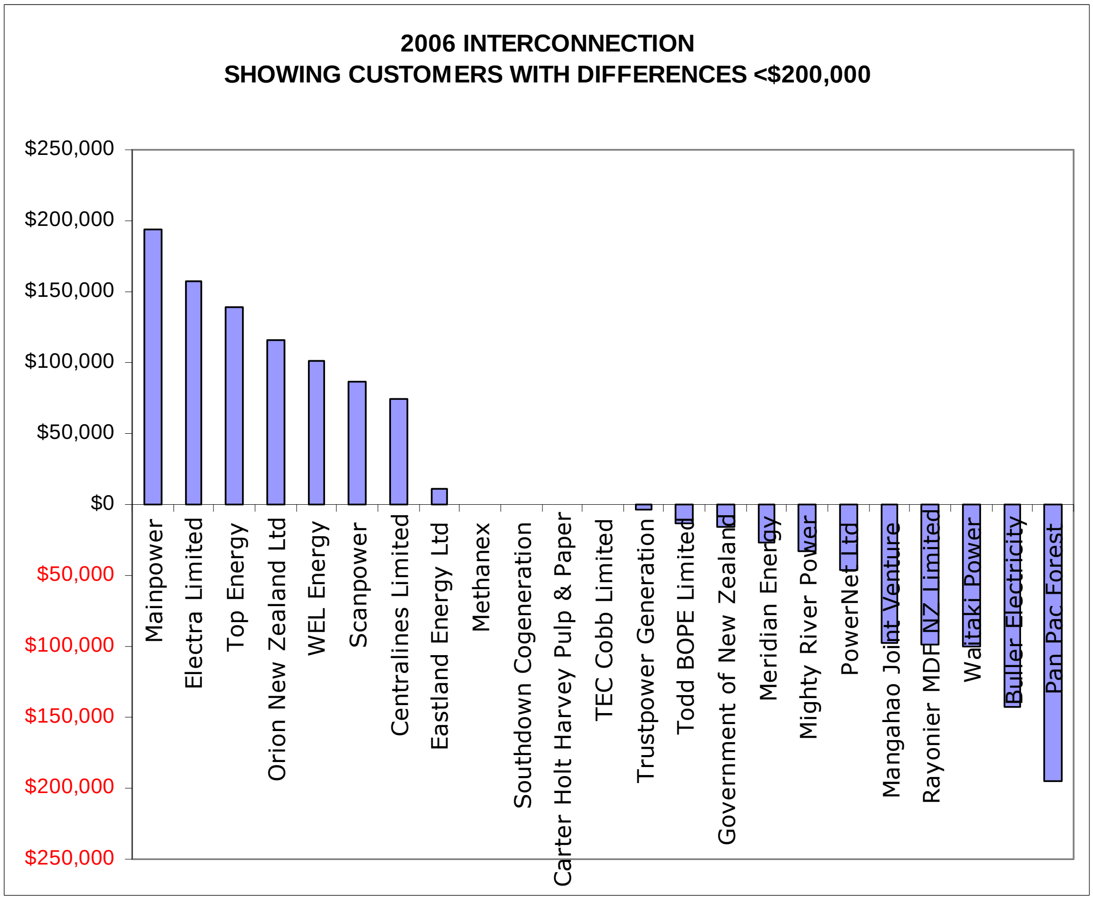


Figure 4: Impact on interconnection charges – customers with differences < $200,000

As can be seen from the table in Annexure 1, the consequence for lower South Island (LSI) customers is deleterious, regardless of the reason for the increase in interconnection charges. The regional connection charges revenue drops by a mere $431,000 while the regional interconnection charge revenue increases by $4.2 million. The beneficiaries of the reductions appear to be the lower North Island (LNI) and the upper South Island (USI).

The increase in interconnection charges for Meridian at Tiwai point is $4.64 million, which is more than 50% of the total increase in charges for all customers of $8.3 million. Closer examination reveals an interesting pattern. While the majority of customers actually experience a decrease, there are some notable exceptions:

- Vector: increase of $8.8million;
- United Networks (Vector): increase of $1.9million; and
- Meridian: increase of $4.64million.

Given that there is a postage stamp rate for recovering interconnection costs in both the current and proposed methods, it would be reasonable to assume that the allocation of the interconnection revenue across all customers would change each customer's charges by the change in the level of the required revenue, if there were no other changes. That is, if the AMD method using the average of the 12 highest peaks continued, then the relative increase for each customer would be of the order of 2.3% (i.e. the percentage increase in the required interconnection revenue).

Given the postage stamp interconnection rate is spread over all connection locations in all regions, differences in charges between the current and the proposed methodologies can be attributed to the impact of the change in N and the difference between the sum of the anytime maximum demands and the sum of the regional coincident peak demands in each region.

In the case of the LSI, the value of N in determining the interconnection charge will change from 12 to 100. This would tend to decrease the average customer coincident demand and thus increase the effective interconnection rate. In relation to a region with a similar demand pattern and a lower N value, the LSI would expect to see a lower charge. However, charges would decrease more in regions with low load factors, and that would transfer some charges to the LSI.

As explained in section 2.3.1 the ratio of the sum of the anytime maximum demands at each connection point in the region to the peak demand in a region is the diversity factor (DF). The change in revenue resulting from a change in the pricing methodology is attributable to the differences in the DF for each region. If each region had a DF of 1, the interconnection rate for the proposed method would only differ from the current method as a result of the revised N values. The LSI would then expect to have lower interconnection charges under Transpower's proposed methodology.

As can be seen below in an extract from Attachment 1 of the TPM proposal (full attachment is at Annexure 1), the interconnection charge revenue required from the LSI under the proposed method is $65.6 million compared with $61.4 million with the existing methodology. Some of the increase is due to the decrease in connection charges of $0.4 million. So the net increase is $3.8 million or 6.2%. The average increase in interconnection charge revenue over all regions is 2.3%.

		TPM 2005 (Indicative)		Current 2005		TPM 2005 – Current 2005	
Region	**Price Component**	**Charge**	**% of total**	**Charge**	**% of total**	**$ Change**	**% Change**
LSI	Connection	$20,002,674	12.6%	$20,433,275	13.2%	($430,601)	-2.1%
	Interconnection	$65,582,526	41.4%	$61,376,824	39.7%	$4,205,702	6.9%

Table 1: Extract from Attachment 1 of TPM Proposal

In effect, the LSI has a higher than average increase and this can probably be attributed to the nature of its load. The presence of the smelter will increase the regional coincident demand relative to other regions due to its high load factor and lower diversity factor and that may be the reason for the greater than average increase. The lower diversity also dilutes the impact of the higher N value.

Another feature of the interconnection charges in the LSI is that the interconnection charges to the smelter have increased more than those for the region. This confirms that the high load factor, low diversity customers will see higher increases under the new regime. A similar impact occurs in the UNI where Vector sees a higher increase than the average for the region (as seen in the table in Annexure 2).

5. Interconnection revenue recovery

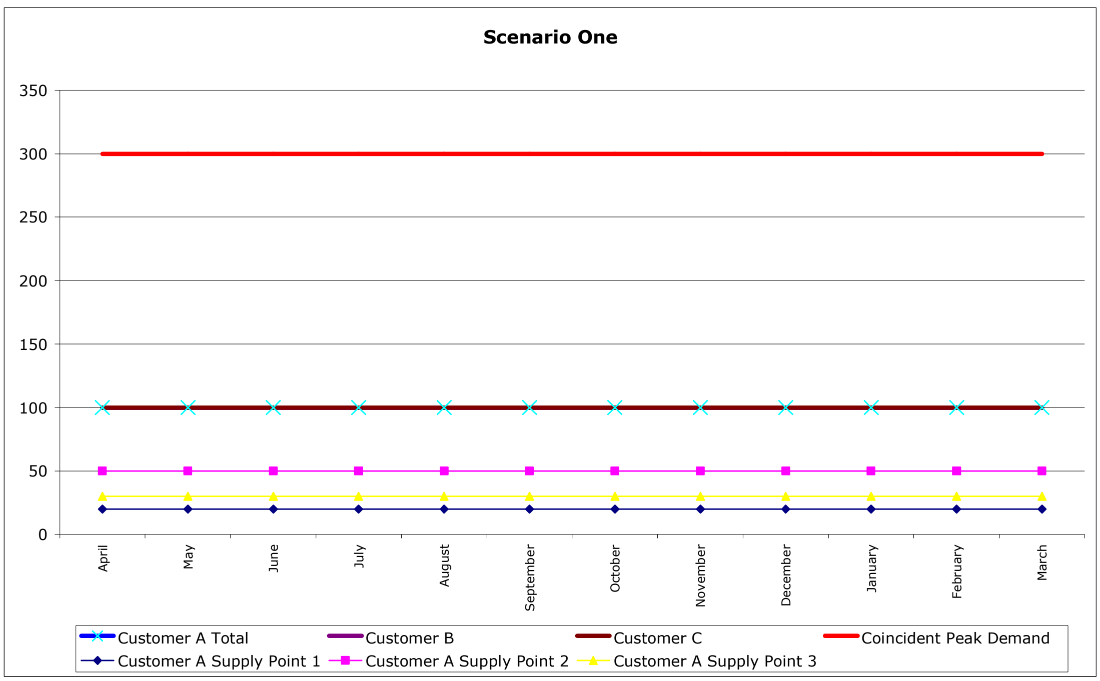
This section outlines a number of scenarios that illustrate the impact on customers of the 2 alternative ways of recovering interconnection revenue using a simplified model as follows:

- All scenarios have 3 customers;
- Customer A has 3 points of supply and a winter peak load profile;
- Customer B has a flat load profile;
- Customer C has a flexible load profile which is summer peaking;
- The revenue requirement is $30,000,000; and
- The interconnection rate (demand charge or IR) is determined by dividing the revenue requirement by either the anytime maximum demand (AMD) or the regional coincident peak demand (RCPD).

The scenarios are used to illustrate some of the effects of a change from AMD to RCPD pricing on customers with different diversity factors. They are not meant to model all the aspects of the TPM. Annexure 4 contains further detail of each scenario.

5.1 Scenario 1

This scenario assumes that all customers have 100% load factors. In this situation the rate for the AMD pricing is the same as for RCPD pricing. The same situation would apply if all customers had their maximum demand coincident with the regional peak. The revenue requirement of $30,000,000 is achieved with a $100/kW demand charge.

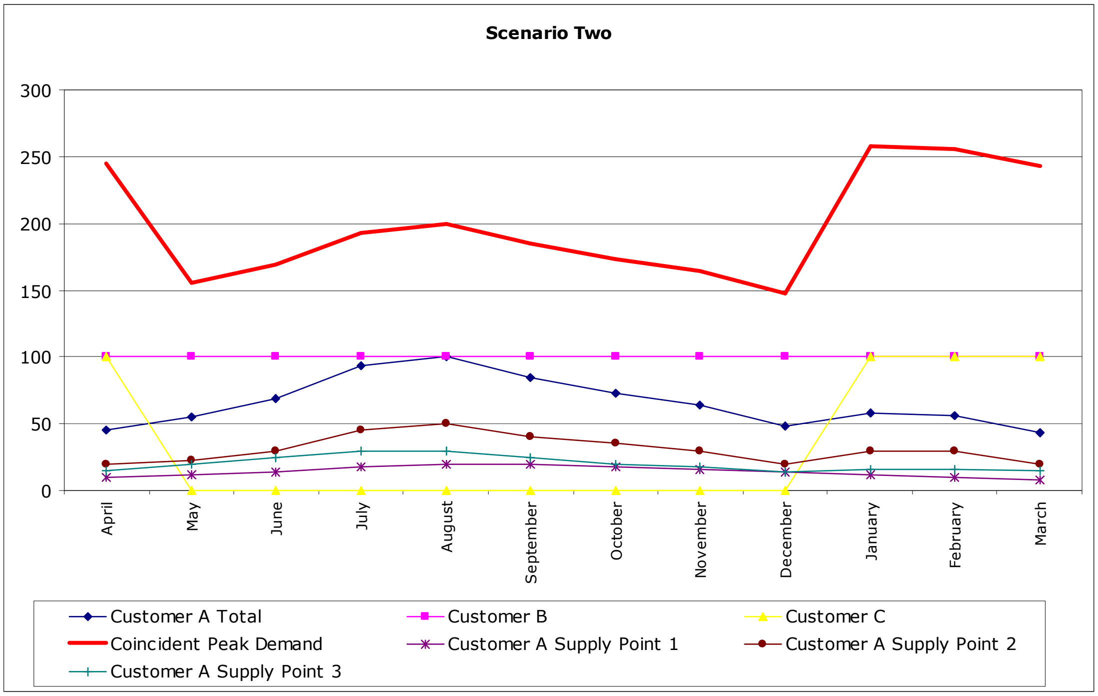


Customer	AMD (MW)	RCPD (MW)	Load Factor	Diversity Factor	AMD Pricing	RCPD Pricing
A	100	100	1.00		$10,000,000	$10,000,000
B	100	100	1.00		$10,000,000	$10,000,000
C	100	100	1.00		$10,000,000	$10,000,000
Region	300	300	1.00	1.00	$30,000,000	$30,000,000

This scenario illustrates that the AMD and RCPD methods produce exactly the same revenue when all customers are using their capacity in the most efficient manner. This is the ideal situation.

5.2 Scenario 2

In this scenario Customer C has a summer peak which is coincident with the regional peak and Customer A has a winter peak. The regional revenue requirement of $30,000,000 has to be met, so the demand charge for the RCPD has to increase.



Customer	AMD (MW)	RCPD (MW)	Load Factor	Diversity Factor	AMD Pricing	RCPD Pricing
A	100	58	0.66		$10,000,000	$6,744,186
B	100	100	1.00		$10,000,000	$11,627,907
C	100	100	0.33		$10,000,000	$11,627,907
Region	300	258	0.77	1.16	$30,000,000	$30,000,000

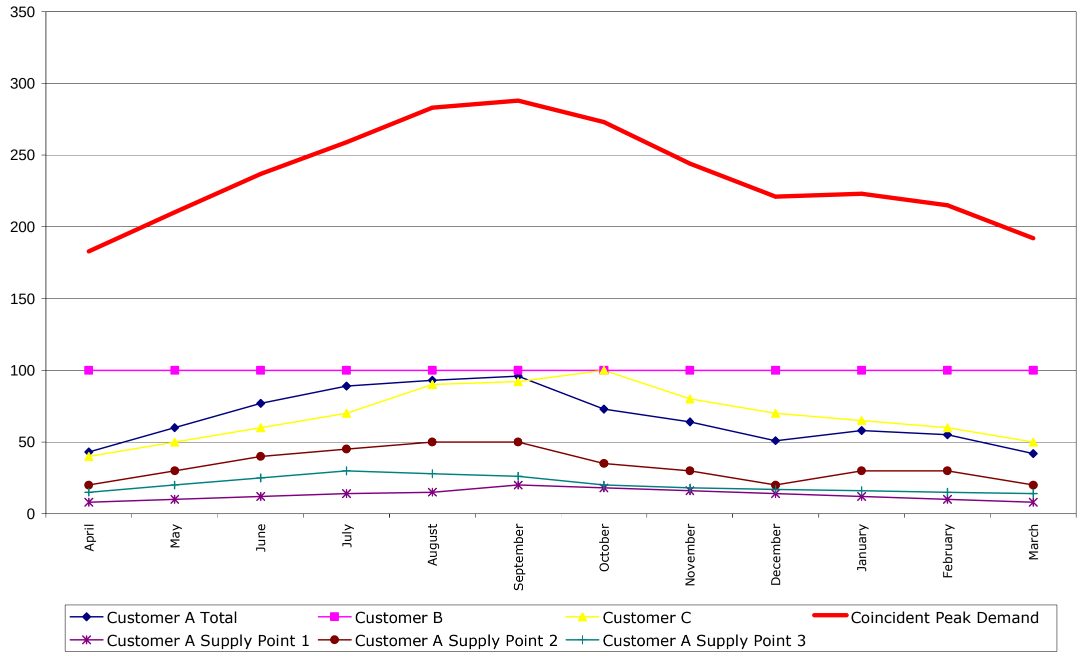
In moving from the AMD allocation method to the RCPD:

- The demand charge increases from $100 to $116;
- The new charge is the DF*$100 or (IR*AMD/RCPD) i.e. $100*1.16;
- The revenue from A decreases and the cost is shared between B and C;
- B is a 100% load factor customer so cannot avoid the peak; and
- Customer C has a low load factor and a coincident peak, but if the number of highest coincident demands were taken into account, C would benefit more than B.

Generally speaking, low load factor customers have high diversity factors. This example illustrates that cost redistribution is not proportional to load factor. But it is fair to say that high load factor customers generally incur higher charges under a RCPD system. The example also illustrates that the timing of the peak demand is determined by the low load factor customer.

5.3 Scenario 3

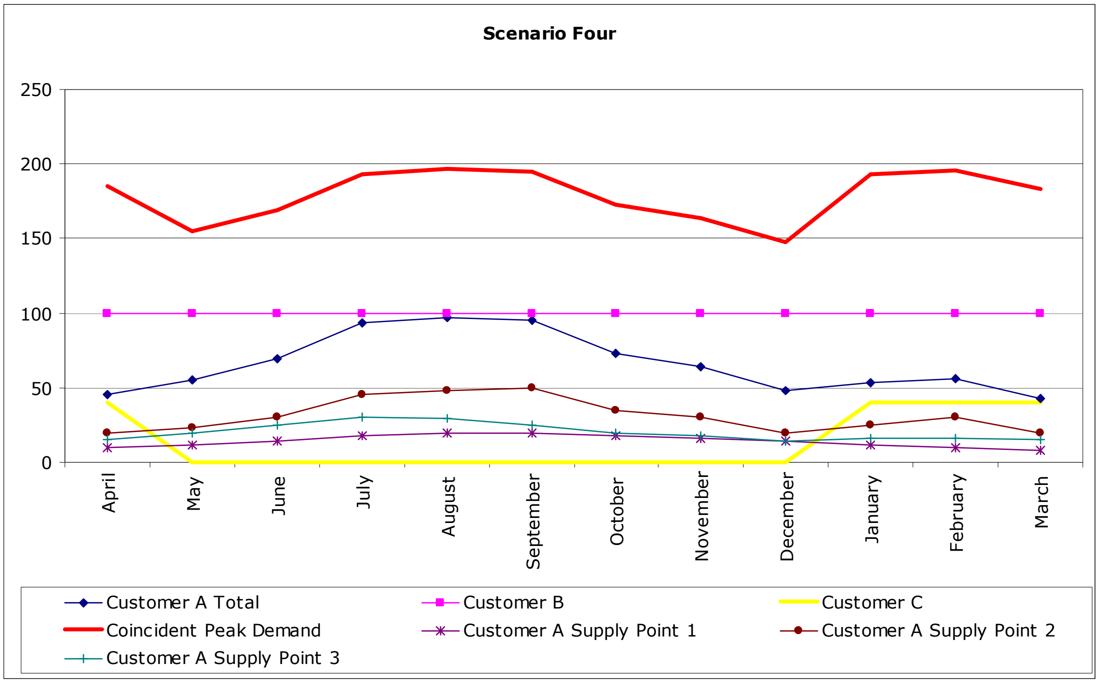
In this scenario Customers A and C have winter peaks, but A and C have coincident peaks lower than B, which is the dominant load. The charges shift between B and C but remain unchanged for A, as it has the same diversity factor as the region.



Customer	AMD (MW)	RCPD (MW)	Load Factor	Diversity Factor	AMD Pricing	RCPD Pricing
A	100	96	0.70		$10,000,000	$10,000,000
B	100	100	1.00		$10,000,000	$10,416,667
C	100	92	0.69		$10,000,000	$9,583,333
Region	300	288	0.82	1.04	$30,000,000	$30,000,000

5.4 Scenario 4

This scenario has Customer C reducing its summer peak from 100 MW to 40 MW, thereby causing the peak to shift to winter and the sum of the anytime maximum demands to reduce and the regional peak to reduce.



The AMD demand charge has to increase to $125 and the RCPD demand charge increases to $152 in order to meet the revenue requirement. The change between the two methods is determined by DF*IR (1.22*125 = $152).

Customer	AMD (MW)	RCPD (MW)	Load Factor	Diversity Factor	AMD Pricing	RCPD Pricing
A	100	92	0.66		$12,500,000	$14,771,574
B	100	100	1.00		$12,500,000	$15,228,426
C	40	0	0.33		$5,000,000	$0
Region	240	192	0.91	1.22	$30,000,000	$30,000,000

There is a significant transfer of charges from C to A and B, with B carrying the higher proportion due to its low diversity factor.

C obtains access to the interconnection assets at no charge.

If this were a system with no capacity constraint the increase in the demand charge would provide a significant price signal to B and A to reduce their demands.

PART TWO: AN ALTERNATIVE APPROACH

6. An alternative TPM

6.1 Interconnection charges

The requirements set out in the EC's guidelines do not eliminate the AMD approach from consideration. However, developing a pricing methodology for interconnection charge revenue recovery with locational price signals and postage stamp prices using a regional coincident peak pricing method presents a challenge.

Transpower has attempted to meet the challenge by introducing regions and manipulating the postage stamp rate by applying different quantities using N=100 in unconstrained regions and N=12 in constrained regions to provide the locational price signal.

The following sets out a proposed amendment to the TPM proposed by Transpower by suggesting an alternative method for recovering the interconnection charge revenue. It attempts to meet the principles and guidelines by using a more effective method for achieving locational pricing signals. This amendment also reduces the incentive for inefficient load management in unconstrained regions.

As for the existing method and the method proposed by Transpower, national interconnection revenue is determined as follows:

$$R_{IC} = \text{AC revenue} - \sum \text{connection charges}$$

Where:
AC revenue is Transpower's **AC revenue** for the relevant **pricing year**; and
Σconnection charges is the sum of all connection charges calculated for the relevant **pricing year**.

The required interconnection revenue is then fixed on a regional basis for each pricing year. This is done by calculating the interconnection rate using the current AMD methodology and using that rate to apportion revenue on the basis of a region's AMD.

$$R_i = \frac{R_{IC}}{\sum_{regions}\sum_{customers}\sum_{loc} AMD} \times \sum_{customers}\sum_{loc} AMD$$

Where:

R_i is the regional revenue requirement;

R_{IC} is as defined in the preceding paragraph; and

$\sum_{regions}\sum_{customers}\sum_{loc} AMD$ is the sum of the anytime maximum demands (AMD) across all locations, customers, and regions – i.e. the national aggregate of AMD; and,

$\sum_{customers}\sum_{loc} AMD$ is the anytime maximum demand across all connection locations and customers within region i;

and noting that the term $\frac{R_{IC}}{\sum_{regions}\sum_{customers}\sum_{loc} AMD}$

is simply the interconnection rate used to determine interconnection charges in the current pricing methodology.

For each region, the interconnection rate, IR, which is the same across all regions, is set using the AMD methodology by dividing the regional revenue requirement (denoted R_i) by the sum of AMD in that region:

$$IR = \frac{R_i}{\sum_{customers}\sum_{loc} AMD}$$

Note that the interconnection rate is exactly the same as under the existing AMD calculation method. However, a two-stage process has been detailed here to make it clear that the revenue requirement is fixed on a regional basis.

Calculation of a customer's interconnection charges then depends on whether the customer is in a constrained or an unconstrained region. Customers in unconstrained regions face a charge equal to the interconnection rate multiplied by the 12 month rolling average of their AMD. Customers in constrained regions are charged based on the interconnection rate multiplied by their contribution to average RCPD and by the regional diversity factor. Thus:

$$IC_{un} = IR \text{ x } AMD$$

$$IC_{con} = IR \text{ x } \frac{1}{N}\sum_{j=1}^{N} RCPD_j \text{ x } DF_i$$

where:

IC_{un} is the interconnection charge per customer in unconstrained regions,

IC_{con} is interconnection charge per customer in a constrained region;

AMD is the twelve month rolling average of the AMD for a customer;

the term $\frac{1}{N}\sum_{j=1}^{N} RCPD_j$ is the average RCPD for each offtake customer in respect of whom the interconnection charge is being calculated at the relevant location. Otherwise depicted more simply as RCPD; and

DF_i is the diversity factor for region i, calculated by dividing the region's AMD by the region's RCPD, i.e.

$$DF_i = \frac{\sum_{cust}\sum_{loc} AMD}{\sum_{cust}\sum_{loc}\frac{1}{N}\sum_{j=1}^{N} RCPD_j}$$

This method means, in effect, that a customer in an unconstrained region faces a charge equivalent to the charge they face under the existing AMD methodology, while a customer in a constrained region will face a charge equivalent to the charge calculated using Transpower's proposed RCPD methodology.

The methodology outlined above effectively changes the relevant quantities used to calculate the interconnection charge. The initial split of national interconnection revenue into regional shares is necessary to facilitate these changes. This is because, in keeping with the "postage stamp" principle, a customer's interconnection charges are simply a function of that customer's share of some quantity, i.e.

$$IC_i = R_{IC} \times Q_i/\sum Q_i$$

Where IC_i is the connection charge of customer i, and R_{IC} is the (exogenous) required interconnection revenue, and Q_i is customer i's demand quantity – whether calculated by , RCPD, or AMD.

The quantity unit chosen for a particular Q_i in the numerator of the above equation must be the same as the quantity unit for its counterpart in the denominator. If it is not, then revenue will either be under or over collected, in which case an adjustment factor will be required to restore the revenue.

6.2 Impact of the alternative methodology

As already mentioned, the alternative methodology outlined above effectively means that customers in constrained regions face an interconnection charge equivalent to that calculated under Transpower's RCPD methodology. On the other hand, customers in unconstrained regions will face a charge equivalent to that calculated under the existing AMD methodology. The impact of this variation in charging methods is shown in the following table with reference to scenario 3 as discussed earlier. The far right column of the table shows the price paid by each customer under the proposed Strata alternative depending on whether the customer is in a constrained or unconstrained region.

Customer	AMD (MW)	RCPD (MW)	Load Factor	Diversity Factor	AMD Pricing	RCPD Pricing	Proposed Strata alternative
Interconnection charges if region is **unconstrained**							
A	100	96	0.70		$10,000,000	$10,000,000	$10,000,000
B	100	100	1.00		$10,000,000	$10,416,667	$10,000,000
C	100	92	0.69		$10,000,000	$9,583,333	$10,000,000
Region	300	288	0.82	1.04	$30,000,000	$30,000,000	$30,000,000
Interconnection charges if region is **constrained**							
A	100	96	0.70		$10,000,000	$10,000,000	$10,000,000
B	100	100	1.00		$10,000,000	$10,416,667	$10,416,667
C	100	92	0.69		$10,000,000	$9,583,333	$9,583,333
Region	300	288	0.82	1.04	$30,000,000	$30,000,000	$30,000,000

The Strata alternative calculates each customer's interconnection charge using the same interconnection rate (the postage stamp) and tailors the charge according to whether the customer is in a constrained or unconstrained region. In this regard it is identical in structure to Transpower's proposal, but has significant advantages, which include:

- the interconnection rate is much easier to calculate and predict as it is the same as that used in the current methodology and thus is much more transparent than Transpower's proposal;

- customers in unconstrained regions have their interconnection charges calculated in the same way as the current methodology which promotes consistency and certainty;
- sharper signals are sent to customers in constrained regions to shift load away from the system peaks, which Strata understands to be one of the major aims of the Commission;
- wealth transfers are minimised; and
- cost increases for customers that occur not through their own actions, but through the actions of others, are also minimised.

6.3 Transitional arrangement

Transpower has indicated that there is no need for a transitional arrangement but to be fair to all existing customers, there should be no transfer of wealth as a result of a structural change that uses the past to determine current prices. Customers cannot change their past behaviour and load patterns.

The transfer of charges caused by the structural change is entirely related to the ratio of the coincident maximum demand totals to the anytime maximum demand totals.

It is therefore proposed that the implementation of the new pricing methodology be delayed to allow customers who will be subject to the RCPD method an opportunity to adjust their load patterns before the charges apply.

Going forward, the customer can see the price signal but is not penalised for its previous load pattern.

6.4 Additional Comments

The EC's analysis of the proposed pricing methodology is based on the philosophy that the whole is equal to the sum of the parts. If all the components meet the criteria set out for the pricing methodology then the pricing methodology itself will comply with the criteria. Its analysis examines each component against the complex set of guidelines and principles.

This results in conclusions relating to the parts rather than the whole. There is no analysis of the overall impact on customers of the changes.

Nothing in the guidelines excludes the possibility of having some regions with coincident demand pricing and others with anytime maximum demand pricing to recover interconnection revenue.

7. Answers to specific questions from the consultation document

The following table sets out answers to the relevant questions in the EC's consultation document on interconnection charges.

Q 25	Do you agree that the proposed regional definition is the best alternative? If not, why not, and what would be a more suitable alternative?	Yes
Q 28	Is it appropriate for the value of N to remain fixed or should there be some mechanism for regions to transition between N=12 and N=100? If so, what should that mechanism be and how would it line up with the Guidelines and Pricing Principles?	The value of N should be fixed and the price differentiation between constrained and unconstrained regions should be on the basis of diversity and not the average coincident peak demand. The alternative mechanism is described in section 7 above and it better meets the pricing principles and also meets the Guidelines.
Q 29	Do you agree that the proposed coincident peak allocation is the best alternative? If not, why not, and what would be a more suitable alternative?	No. The Strata alternative described above allocates the interconnection revenue on the basis of anytime maximum demands. This will lead to a lower interconnection rate and therefore less incentive for demand reduction in unconstrained regions. It will only use coincident peak pricing in constrained regions and restrict the transfer of costs arising from diversity to intra regional transfers.
Q 39	Do you consider that there should be transitional measures put in place and, if so, how would this be implemented?	Yes. The increases for some customers are caused by the structural change, yet their load patterns are historical and cannot be changed. The new structure should encourage changes in the behaviour of customers in constrained regions. That can only occur over time and with incentives going forward. The implementation of the new pricing methodology should be delayed to allow customers who will be subject to the RCPD method an opportunity to adjust their load patterns before the charges apply.

A full assessment of the proposed alternative is shown in Annexure 3 where the alternative is measured against the Regulatory Framework contained in the EC's consultation document.

8. Conclusions

Based on the analysis shown in this paper, we have reached the following conclusions:

1. Analysis of the outcomes of the proposed TPM as shown in Appendix 1 has given rise to a question as to why the expected connection charge revenue will be lower under the proposed TPM than the current methodology. It would be expected that the deeper connection definition would lead to more assets being included as connection assets, resulting in a corresponding increase in the connection charges.

2. The proposed TPM has shortcomings with respect to the method used to recover interconnection revenue. These shortcomings will lead to the expected revenue from interconnection charge revenue in the unconstrained LSI increasing and the interconnection charge revenue in the constrained USI decreasing.

3. Strata has developed an alternative method for recovering the interconnection charge revenue which has the following benefits:

   - Customers in unconstrained regions will be charged at similar levels to the existing pricing methodology and will not see a major shift in their interconnection charges on implementation of a new pricing methodology;
   - Inefficient signals to manage load will be minimised in unconstrained regions;
   - A locational price signal in each constrained region will encourage efficient investment or load management by those customers causing the regional peak demand; and
   - Efficient users of system capacity in unconstrained regions are not penalised but the "causers" of capacity constraints in constrained regions are provided with higher incentives to reduce their coincident peak demands because the inter-regional transfer of charges is removed.

4. The Strata alternative calculates each customer's interconnection charge using the same interconnection rate (the postage stamp) and tailors the charge according to whether the customer is in a constrained or unconstrained region. In this regard it is identical in structure to Transpower's proposal, but has significant advantages, which include:

   - the interconnection rate is much easier to calculate and predict as it is the same as that used in the current methodology and thus is much more transparent than Transpower's proposal;
   - customers in unconstrained regions have their interconnection charges calculated in the same way as the current methodology which promotes consistency and certainty;
   - sharper signals are sent to customers in constrained regions to shift load away from the system peaks, which Strata understands to be one of the major aims of the Commission;
   - wealth transfers are minimised; and
   - cost increases for customers that occur not through their own actions, but through the actions of others, are also minimised.

9. Recommendations

It is recommended that the EC:

1. Investigate the reasons why the connection charge revenue is lower under the proposed TPM than the existing TPM before implementing the connection charge proposal; and

2. Consider the Strata alternative method for recovering the interconnection charge revenue before implementing the interconnection charge proposal.

Annexure 1: Attachment One of the TPM Proposal

Attachment 1:

Comparison of Charges by Region for the Current Transmission Pricing Methodology (CPM) and Proposed Transmission Pricing Methodology (TPM)

		TPM 2005 (Indicative)		CPM 2005		TPM 2005 - CPM 2005	
Region	**Price Component**	**Charge**	**% of Total**	**Charge**	**% of Total**	**$ Change**	**% Change**
UNI	Connection	$ 14,306,313	11.1%	$ 15,711,961	13.1%	($ 1,405,648)	-8.9%
	Interconnection	$ 114,324,754	88.9%	$ 104,664,679	86.9%	$ 9,660,075	9.2%
	HVDC	-		-		-	
	Total	$ 128,631,067		$ 120,376,640		$ 8,254,427	6.9%
LNI	Connection	$ 37,837,319	22.7%	$ 44,013,882	24.9%	($ 6,176,563)	-14.0%
	Interconnection	$ 129,093,756	77.3%	$ 132,706,636	75.1%	($ 3,612,880)	-2.7%
	HVDC	-		-		-	
	Total	$ 166,931,075		$ 176,720,518		($ 9,789,444)	-5.5%
USI	Connection	$ 16,120,935	19.8%	$ 16,389,181	19.7%	($ 268,247)	-1.6%
	Interconnection	$ 62,230,233	76.6%	$ 64,134,229	76.9%	($ 1,903,996)	-3.0%
	HVDC	$ 2,867,254	3.5%	$ 2,867,254	3.4%	$ 0	0.0%
	Total	$ 81,218,422		$ 83,390,664		($ 2,172,243)	-2.6%
LSI	Connection	$ 20,002,674	12.6%	$ 20,433,275	13.2%	($ 430,601)	-2.1%
	Interconnection	$ 65,582,526	41.4%	$ 61,376,824	39.7%	$ 4,205,702	6.9%
	HVDC	$ 72,733,000	45.9%	$ 72,733,000	47.1%	$ 0	0.0%
	Total	$ 158,318,200		$ 154,543,099		$ 3,775,101	2.4%
Total Connection		**$ 88,267,240**	**16.5%**	**$ 96,548,299**	**18.0%**	**($ 8,281,059)**	**-8.6%**
Total Interconnection		**$ 371,231,269**	**69.4%**	**$ 362,882,368**	**67.8%**	**$ 8,348,900**	**2.3%**
Total HVDC		**$ 75,600,254**	**14.1%**	**$ 75,600,254**	**14.1%**	**$ 0**	**0.0%**
Grand Total		**$ 535,098,764**		**$ 535,030,922**			

Annexure 2: Comparison of Customer Charges for the Current Transmission Pricing Methodology (CPM) and Proposed Transmission Pricing Methodology (TPM)

	2005 Connection				2005 Interconnection				2005 HVDC				2005 EVA	Total		Total			
Customer	**Current**	**RPCD**	**Diff**	**%**	**Current**	**RPCD**	**Diff**	**%**	**Current**	**RPCD**	**Diff**	**%**	**Current**	**Current incl EVA**	**Current**	**RPCD**	**Diff**	**Diff inc EVA**	**%**
Overall total	$96,548,299	$88,267,240	$8,281,059	0.0%	$362,882,368	$371,231,269	**$8,348,900**	2.3%	**$75,600,254**	**$75,600,254**	**$0**	0.0%	$35,167,027	$499,863,895	$535,030,922	$535,098,764	$67,842	$35,234,868	0.0%
Vector Ltd	$4,744,343	$4,533,191	$211,152	-4.5%	$57,821,504	$66,652,155	**$8,830,651**	15.3%	$0	$0	$0	0.0%	$5,818,624	$56,747,223	$62,565,847	$71,185,346	$8,619,499	$14,438,123	13.8%
Meridian Energy - Tiwai	$6,072,100	$714,443	**$5,357,657**	-88.2%	$33,394,918	$38,033,980	**$4,639,062**	13.9%	$0	$0	$0	0.0%	$3,670,433	$35,796,585	$39,467,018	$38,748,423	$718,595	$2,951,838	-1.8%
UnitedNetworks Limited	$8,121,767	$6,893,572	**$1,228,195**	-15.1%	$54,891,535	$56,814,955	**$1,923,420**	3.5%	$0	$0	$0	0.0%	$5,860,237	$57,153,065	$63,013,302	$63,708,527	$695,225	$6,555,462	1.1%
Northpower	$2,717,409	$3,424,216	$706,807	26.0%	$7,599,145	$8,425,967	$826,822	10.9%	$0	$0	$0	0.0%	$959,440	$9,357,115	$10,316,554	$11,850,183	$1,533,629	$2,493,069	14.9%
Network Tasman	$1,343,554	$1,738,936	$395,382	29.4%	$7,671,810	$8,269,263	$597,453	7.8%	$0	$0	$0	0.0%	$838,429	$8,176,935	$9,015,364	$10,008,199	$992,835	$1,831,264	11.0%
Dunedin Electricity	$2,929,986	$3,522,978	$592,992	20.2%	$12,364,371	$12,833,121	$468,750	3.8%	$144,671	$144,671	$0	0.0%	$1,407,908	$14,031,120	$15,439,028	$16,500,770	$1,061,742	$2,469,650	6.9%
Counties Power	$736,632	$822,188	$85,556	11.6%	$4,632,900	$4,999,701	$366,801	7.9%	$0	$0	$0	0.0%	$499,366	$4,870,165	$5,369,532	$5,821,889	$452,357	$951,723	8.4%
Marlborough Lines	$357,285	$239,884	$117,401	-32.9%	$3,102,590	$3,390,718	$288,128	9.3%	$0	$0	$0	0.0%	$321,768	$3,138,106	$3,459,874	$3,630,602	$170,728	$492,496	4.9%
Waipa Power	$1,159,780	$1,265,943	$106,163	9.2%	$3,227,716	$3,459,896	$232,180	7.2%	$0	$0	$0	0.0%	$408,037	$3,979,458	$4,387,495	$4,725,839	$338,344	$746,381	7.7%
Mainpower	$2,684,078	$2,117,135	$566,943	-21.1%	$4,518,099	$4,712,442	$194,343	4.3%	$0	$0	$0	0.0%	$669,802	$6,532,374	$7,202,176	$6,829,578	$372,598	$297,204	-5.2%
Electra Limited	$1,446,683	$534,949	$911,734	-63.0%	$4,884,435	$5,042,346	$157,911	3.2%	$0	$0	$0	0.0%	$588,794	$5,742,324	$6,331,118	$5,577,295	$753,823	$165,029	-11.9%
Top Energy	$2,373,004	$1,716,128	$656,876	-27.7%	$2,926,509	$3,065,801	$139,292	4.8%	$0	$0	$0	0.0%	$492,855	$4,806,658	$5,299,513	$4,781,929	$517,584	$24,729	-9.8%
Orion New Zealand Ltd	$7,215,319	$6,740,684	$474,635	-6.6%	$35,528,088	$35,644,545	$116,457	0.3%	$0	$0	$0	0.0%	$3,975,137	$38,768,270	$42,743,407	$42,385,229	$358,178	$3,616,959	-0.8%
WEL Energy	$1,922,223	$1,309,138	$613,085	-31.9%	$10,845,501	$10,946,533	$101,032	0.9%	$0	$0	$0	0.0%	$1,187,398	$11,580,326	$12,767,725	$12,255,671	$512,054	$675,344	-4.0%
Scanpower	$420,758	$577,438	$156,680	37.2%	$910,317	$997,255	$86,938	9.6%	$0	$0	$0	0.0%	$123,790	$1,207,285	$1,331,075	$1,574,693	$243,618	$367,408	18.3%
Centralines Limited	$560,924	$325,470	$235,454	-42.0%	$1,036,727	$1,110,675	$73,948	7.1%	$0	$0	$0	0.0%	$148,582	$1,449,069	$1,597,651	$1,436,145	$161,506	$12,924	-10.1%
Eastland Energy Ltd	$2,820,434	$2,273,819	$546,615	-19.4%	$2,781,291	$2,791,713	$10,422	0.4%	$0	$0	$0	0.0%	$520,960	$5,080,765	$5,601,725	$5,065,532	$536,193	$15,233	-9.6%
Methanex	$346,255	$457,768	$111,513	32.2%	$0	$0	$0		$0	$0	$0	0.0%	$32,202	$314,053	$346,255	$457,768	$111,513	$143,715	32.2%
Southdown Cogeneration	$0	$104,680	$104,680	-	$0	$0	$0		$0	$0	$0	0.0%	$0	$0	$0	$104,680	$104,680	$104,680	
Carter Holt Harvey Pulp & Paper	$122,931	$71,258	$51,673	-42.0%	$0	$0	$0		$0	$0	$0	0.0%	$11,433	$111,498	$122,931	$71,258	$51,673	$40,240	-42.0%
TEC Cobb Limited	$32,729	$768,533	$735,804	2248.2%	$167	$0	$167	-100.0%	$776,532	$776,532	$0	0.0%	$74,594	$884,023	$809,429	$1,545,065	$735,636	$661,042	90.9%
Trustpower Generation	$79,129	$66,944	$12,185	-15.4%	$4,186	$0	$4,186	-100.0%	$1,196,292	$1,196,292	$0	0.0%	$111,881	$1,391,487	$1,279,607	$1,263,235	$16,372	$128,253	-1.3%
Todd BOPE Limited	$391,783	$335,777	$56,006	-14.3%	$13,897	$0	$13,897	-100.0%	$0	$0	$0	0.0%	$37,728	$367,951	$405,680	$335,777	$69,903	$32,175	-17.2%
Government of New Zealand	$66,648	$31,826	$34,822	-52.2%	$16,297	$128	$16,169	-99.2%	$0	$0	$0	0.0%	$7,714	$75,230	$82,944	$31,954	$50,990	$43,276	-61.5%
Meridian Energy	$5,753,229	$10,336,194	**$4,582,965**	79.7%	$60,889	$34,205	$26,684	-43.8%	$56,508,343	$56,508,343	$0	0.0%	$5,110,121	$67,432,582	$62,322,460	$66,878,741	$4,556,281	$553,840	7.3%
Mighty River Power	$2,742,571	$2,542,225	$200,346	-7.3%	$50,117	$16,943	$33,174	-66.2%	$0	$0	$0	0.0%	$259,720	$2,532,968	$2,792,688	$2,559,167	$233,521	$26,199	-8.4%
PowerNet Ltd	$1,800,173	$1,467,762	$332,411	-18.5%	$9,099,541	$9,053,040	$46,501	-0.5%	$0	$0	$0	0.0%	$1,013,673	$9,886,041	$10,899,714	$10,520,802	$378,912	$634,761	-3.5%
Mangahao Joint Venture	$486,178	$218,057	$268,121	-55.1%	$97,947	$0	$97,947	-100.0%	$0	$0	$0	0.0%	$54,324	$529,801	$584,124	$218,057	$366,067	$311,743	-62.7%
Rayonier MDF NZ Limited	$141,388	$96,942	$44,446	-31.4%	$519,479	$420,563	$98,916	-19.0%	$0	$0	$0	0.0%	$61,461	$599,407	$660,867	$517,505	$143,362	$81,901	-21.7%
Waitaki Power	$552,190	$875,040	$322,850	58.5%	$2,001,347	$1,900,782	$100,565	-5.0%	$0	$0	$0	0.0%	$237,479	$2,316,058	$2,553,537	$2,775,822	$222,285	$459,764	8.7%
Buller Electricity	$1,056,898	$1,073,976	$17,078	1.6%	$877,110	$734,035	$143,075	-16.3%	$0	$0	$0	0.0%	$179,863	$1,754,145	$1,934,008	$1,808,011	$125,997	$53,866	-6.5%
Pan Pac Forest	$794,583	$749,111	$45,472	-5.7%	$4,377,346	$4,182,551	$194,795	-4.5%	$0	$0	$0	0.0%	$480,989	$4,690,939	$5,171,929	$4,931,661	$240,268	$240,721	-4.6%
Genesis Power Ltd	$1,543,261	$1,575,346	$32,085	2.1%	$261,358	$0	$261,358	-100.0%	$0	$0	$0	0.0%	$167,830	$1,636,790	$1,804,619	$1,575,346	$229,273	$61,443	-12.7%
Powerco	$13,324,839	$11,078,929	**$2,245,910**	-16.9%	$39,905,210	$39,578,198	$327,012	-0.8%	$0	$0	$0	0.0%	$4,950,395	$48,279,655	$53,230,050	$50,657,127	$2,572,923	$2,377,472	-4.8%
Hidden customers	$5,254,580	$4,141,101	$1,113,479	-21.2%	$12,947,471	$12,590,231	$357,241												
Kiwi Cogen	$39,338	$28,913	$10,425	-26.5%	$444,806	$3,964	$440,842	-99.1%	$0	$0	$0	0.0%	$45,025	$439,119	$484,144	$32,877	$451,267	$406,242	-93.2%
OtagoNet	$1,388,169	$1,742,758	$354,589	25.5%	$3,086,014	$2,639,292	$446,722	-14.5%	$0	$0	$0	0.0%	$416,099	$4,058,084	$4,474,183	$4,382,051	$92,132	$323,967	-2.1%
Stratford Power	$0	$9,279	$9,279	#DIV/0!	$473,269	$0	$473,269	-100.0%	$0	$0	$0	0.0%	$44,014	$429,255	$473,269	$9,279	$463,990	$419,976	-98.0%
Horizon Energy	$1,591,252	$1,428,191	$163,061	-10.2%	$2,414,564	$1,936,713	$477,851	-19.8%	$0	$0	$0	0.0%	$372,541	$3,633,275	$4,005,815	$3,364,904	$640,911	$268,370	-16.0%
The Lines Company Ltd	$1,200,064	$1,360,177	$160,113	13.3%	$2,872,485	$2,343,914	$528,571	-18.4%	$0	$0	$0	0.0%	$378,747	$3,693,802	$4,072,549	$3,704,090	$368,459	$10,288	-9.0%
Westpower Ltd	$322,710	$470,440	$147,730	45.8%	$1,683,788	$1,113,425	$570,363	-33.9%	$61,020	$61,020	$0	0.0%	$180,502	$1,887,016	$2,067,518	$1,644,884	$422,634	$242,132	-20.4%
Alpine Energy	$2,396,033	$2,119,441	$276,592	-11.5%	$6,591,719	$5,768,389	$823,330	-12.5%	$111,442	$111,442	$0	0.0%	$824,717	$8,274,478	$9,099,194	$7,999,273	$1,099,921	$275,204	-12.1%
Unison Networks Limited	$3,840,619	$3,643,915	$196,704	-5.1%	$15,104,642	$14,173,642	$931,000	-6.2%	$0	$0	$0	0.0%	$1,761,909	$17,183,352	$18,945,261	$17,817,556	$1,127,705	$634,204	-6.0%
BHP NZ Steel	$1,842,157	$1,450,008	$392,149	-21.3%	$5,254,232	$4,048,927	**$1,205,305**	-22.9%	$0	$0	$0	0.0%	$659,964	$6,436,425	$7,096,389	$5,498,935	$1,597,454	$937,490	-22.5%
Tranz Rail	$1,266,145	$806,900	$459,245	-36.3%	$1,597,896	$251,711	**$1,346,185**	-84.2%	$0	$0	$0	0.0%	$266,356	$2,597,685	$2,864,041	$1,058,611	$1,805,430	$1,539,074	-63.0%
Electricity Ashburton	$546,168	$465,637	$80,531	-14.7%	$4,989,135	$3,249,550	**$1,739,585**	-34.9%	$136,063	$136,063	$0	0.0%	$501,177	$5,170,189	$5,671,366	$3,851,250	$1,820,116	$1,318,939	-32.1%

Annexure 3: Regulatory Framework Criteria

	Regulatory Framework Criteria	Proposed Strata alternative for Interconnection charges
GUIDELINES		
9	A definition of deep connection should be developed and applied consistently and transparently. The definition of deep connection must avoid subsidisation of interconnection assets to the extent practicable.	The following does not apply to the Strata alternative but is mentioned for consideration. The outcome of the application of the deeper connection definition is that the connection charges decrease and the interconnection charges increase. This seems counter-intuitive as it could be expected that the connection charges would increase due to the greater number of assets being defined as connection assets.
10	The costs of connection assets are to be recovered from those connected to them.	N/A
11	Where parties share the use of connection assets then the costs should be allocated among them on a peak demand or injection basis, in a manner than maximises efficiency.	N/A
12	Charges for existing and new interconnection assets should be on a postage stamp basis. This is similar to the current interconnection charges.	The proposed Strata alternative uses the current pricing methodology to calculate the interconnection rate (the postage-stamp). In unconstrained regions the interconnection charges are calculated exactly the same way as under the current pricing methodology. In constrained regions the same interconnection rate is used to calculate the regional revenue but the rate is applied to the customer's average contribution to the regional peak demands with a regional adjustment factor equal to the regional diversity factor. This contrasts with Transpower's proposal where the adjustment factor is related to the quantities used to calculate the average contribution to the regional coincident peak demand i.e. either N=100 or N=12.

	Regulatory Framework Criteria	Proposed Strata alternative for Interconnection charges
13	Transpower should review the existing basis on which it calculates the interconnection charges at a grid exit point. Specifically, Transpower should review whether using the 12 highest half hour offtake peaks in the 12 months up to and including the current month is the most consistent with the pricing principles in rule 2 of section IV of part F. This review includes consideration of anytime versus regional or national coincident peaks.	The Strata alternative agrees with the use of regional coincident peaks to recover interconnection charges in constrained regions as the "causers" can be allocated costs and those who reduce their demand at the times of the regional demand peaks are only charged for their coincident demand, which may be lower than their AMD. However, the Strata alternative proposes to use the current pricing methodology to recover interconnection revenue from customers in unconstrained regions, as this will be less distortionary. The Strata alternative uses N=12 for regional coincident peaks and for the anytime maximum demands.
14	Transpower should also review whether permitting greater aggregation across GXP loads for the purpose of calculating interconnection charges to encourage peak load management within regions would produce prices more consistent with the pricing principles in rule 2 of section IV of part F.	Aggregating demands for customers with multiple connection points in regions with regional coincident peak demand pricing is not necessary. The Strata alternative achieves a better signal for load management. Aggregating demands in unconstrained regions will provide an incentive to manage load unnecessarily as there will be an immediate benefit to customers with multiple points of supply at the expense of those with single points of supply. As there is no need to increase the signal for load management, this will result in a wealth transfer and a signal to decrease load unnecessarily.
15	The costs of the HVDC link and any replacement of or upgrade to it should be charged to all South Island generating stations that inject into the grid.	N/A
16	In allocating those costs, Transpower should consider the linkages with other elements of market pricing, and in particular, with the allocation of loss and constraint rentals or any revenue from financial transmission rights for transmission assets covered by the charge.	Similar to the proposal.
PRICING PRINCIPLES		
2.1	the costs of connection and use of system should as far as possible be allocated on a user pays basis;	The Strata alternative meets the principle more fully in that customers in unconstrained regions will be unable to avoid payment for use at anytime. In constrained regions both methods will meet a "causer pays" interpretation of user pays. The Strata alternative will avoid the situation of transfer of charges from constrained regions to customers in unconstrained regions.

	Regulatory Framework Criteria	Proposed Strata alternative for Interconnection charges
2.2	the pricing of new and replacement investments in the grid should provide beneficiaries with strong incentives to identify least cost investment options, including energy efficiency and demand management options;	The Strata alternative meets this principle more fully as the charges in constrained regions will be sharper and thus will provide stronger incentives.
2.3	pricing for new generation and load should provide clear locational signals;	The Strata alternative provides clearer signals as the charges in constrained regions will be sharper.
2.4	sunk costs should be allocated in a way that minimises distortions to production/consumption and investment decisions made by grid users;	The Strata alternative allocates the costs in a less distortionary manner as the sunk costs in unconstrained regions are allocated on the basis of anytime demand and recovered on that basis from customers.
2.5	the overall pricing structure should include a variable element that reflects the marginal costs of supply in order to provide an incentive to minimise network constraints;	Both options are based on a postage stamp rate but the Strata alternative provides a stronger price signal concerning the marginal cost of transmission during system peak demand in constrained regions and an appropriately lower signal in unconstrained regions.
2.6	transmission pricing for investment in the grid should recognise the linkages with other elements of market pricing (including the design of the financial transmission rights regime under section V, and any revenues from financial transmission rights);	No difference between the options.
3.1	In applying the Pricing Principles, Transpower and the Board should take into account practical considerations, transaction costs and the desirability of consistency and certainty; and	The Strata alternative has higher transaction costs in that diversity factors are required in constrained areas. The Strata alternative will reduce the uncertainty of the timing of the peak demand for customers in unconstrained regions and their interconnection charge calculation is consistent with the current methodology.
3.2	Where conflicts arise in applying the Pricing Principles set out in rule 2, they should be resolved with the objective of best satisfying the Board's principal objective.	The Strata alternative provides a fairer method for recovering the interconnection revenue as it does not transfer costs from customers in constrained regions to customers in unconstrained regions.
PRACTICAL CONSIDERATIONS		
a	make it difficult for parties to game the pricing signal;	The Strata alternative has no greater incentives than Transpower's proposal.
b	provide accurate signals;	Signals are more accurately provided as there are no inter-regional transfers that could lead to higher prices in unconstrained regions. The Strata alternative reduces signals to inefficiently shift load in unconstrained regions and thus improves the accuracy of the signal.

	Regulatory Framework Criteria	Proposed Strata alternative for Interconnection charges
c	provide predictable/stable signals;	The existing method remains in place for calculating the interconnection rate. The uncertainties associated with coincident demand pricing are restricted to constrained regions.
d	provide effective signals;	The signals in the constrained regions will provide effective signals for load management. The signals in the unconstrained regions will not encourage unnecessary load management.
e	provide signals to small and large participants;	The Strata alternative will provide signals that directly connected parties can respond to and which can be passed through to retail customers.
f	transparent and understandable calculation mechanism; and	The calculation of the pricing is similar to the existing methodology and the quantities to be used in the constrained regions will be calculated on the same basis as the proposal.
g	transaction costs.	The Strata alternative will have higher transaction costs as Transpower will have to continue with the AMD method for all regions as well as introduce the RCPD method and diversity factors for constrained regions. These costs are not likely to be excessive and are far outweighed by the benefits.
PRINCIPAL OBJECTIVES		
a	to ensure that electricity is produced and delivered to all classes of consumers in an efficient, fair, reliable, and environmentally sustainable manner; and	The Strata alternative is fairer as the low diversity high load factor customers in unconstrained regions will not incur increased costs attributable to structural change or the actions of other customers.
b	to promote and facilitate the efficient use of electricity.	The Strata alternative will provide greater incentives on customers in constrained regions to improve the efficiency of their electricity usage and to reduce system losses by reducing their demand at the time of the regional system peak demands.
SPECIFIC OUTCOMES		
a	energy and other resources are used efficiently;	The Strata alternative will encourage load management and the use of transmission alternatives to avoid unnecessary investment in transmission infrastructure. It will do so in constrained regions but still maintain a consistent price signal in unconstrained regions.
b	risks (including price risks) relating to security of supply are properly and efficiently managed;	The Strata alternative will provide a stronger signal about the risk of transmission capacity constraints in constrained regions

	Regulatory Framework Criteria	Proposed Strata alternative for Interconnection charges
c	barriers to competition in the electricity industry are minimised for the long-term benefit of end-users;	No difference between the proposals.
d	incentives for investment in generation, transmission, lines, energy efficiency, and demand-side management are maintained or enhanced;	The incentives for investment will be stronger as the signals in the constrained regions will encourage investment in those regions to a greater extent than Transpower's proposal.
e	the full costs of producing and transporting each additional unit of electricity are signalled;	Neither Transpower's proposal nor the Strata alternative signal the LRMC of transmission.
f	delivered electricity costs and prices are subject to sustained downward pressure; and	The Strata alternative produces a lower interconnection rate as the revenue requirement is spread over a larger number of kW. The average price in each region will be unchanged. Transpower's proposal will result in higher charges in the Lower South Island, which will flow through to customers purely as a result of the structural change.
g	the electricity sector contributes to achieving the Government's climate change objectives by minimising hydro spill, efficiently managing transmission and distribution losses and constraints, promoting demand-side management and energy efficiency, and removing barriers to investment in new generation technologies, renewables, and distributed generation.	The Strata alternative targets constrained regions better than Transpower's proposal with the result that investment in demand side management, generation and energy efficiency can be focused to where the need is greatest. The Strata alternative will contribute to loss management incentives in the constrained regions.
CONSISTENCY		
a	between elements (internal component consistency);	
b	between components (internal TPM consistency);	Transpower's proposal has more component consistency in that the components are common for all regions except the value of N. The Strata alternative retains the current pricing methodology components and introduces coincident peak charging and diversity factors for constrained regions.
c	with the wider transmission contracting/regulatory framework;	The Strata alternative is similar to Transpower's proposal.
d	with the treatment of assets under the proposed interconnection rules;	The Strata alternative is similar to Transpower's proposal.
e	between charging for existing and new assets;	The Strata alternative is similar to Transpower's proposal.
f	with nodal pricing and the grid investment test (GIT);	The Strata alternative is similar to Transpower's proposal

	Regulatory Framework Criteria	Proposed Strata alternative for Interconnection charges
g	with the current charging methodology (while recognising that current methodology was set on a transitional basis); and	The Strata alternative is more consistent with the existing methodology as it retains the same basis for the calculation of the interconnection rate and the same method for calculating interconnection charges in unconstrained regions.
h	with the treatment of similar participants in the market (for example, a dissimilar treatment would be to apply a charge to one participant and not to another equivalent one).	Similar to Transpower's proposal because customers in constrained regions will experience different charges from customers in unconstrained regions for similar load patterns.
REGULATORY CERTAINTY		
a	the desirability of regulation being stable and not changing frequently, suddenly, or in unpredictable ways;	The Strata alternative is more stable for customers in unconstrained regions and has less uncertainty for those customers. There is less transfer of charges from constrained to unconstrained regions under the Strata alternative.
b	the desirability of predictable and rational decision-making in relation to regulation; and	The Strata alternative is more rational as it does not provide incentives to manage load in unconstrained regions to the same extent as Transpower's proposal and it complies better with the Guidelines and Pricing Principles than Transpower's proposal.
c	the impact of regulatory changes on prices.	The Strata alternative is superior in that the average prices in all regions remain unchanged whereas the charges in the unconstrained lower South Island are increased and those in the constrained upper South Island decrease under Transpower's proposal.

Annexure 4: Scenario Data

Scenario 1

The coincident demand for each customer is 100 MW
The sum of maximum demands at all GXPs is 300 MW
Month

Month		A1	A2	A3	A	B	C	Coincident Peak Demand
April	1	20	50	30	100	100	100	300
May	2	20	50	30	100	100	100	300
June	3	20	50	30	100	100	100	300
July	4	20	50	30	100	100	100	300
August	5	20	50	30	100	100	100	300
September	6	20	50	30	100	100	100	300
October	7	20	50	30	100	100	100	300
November	8	20	50	30	100	100	100	300
December	9	20	50	30	100	100	100	300
January	10	20	50	30	100	100	100	300
February	11	20	50	30	100	100	100	300
March	12	20	50	30	100	100	100	300
MD		20	50	30	100	100	100	300
CMD		20	50	30	100	100	100	300
								1
AMD					100	100	100	300
Load Factor		1.00	1.00	1.00	1.00	1.00	1.00	1.00
Diversity Factor					1.00	1.00	1.00	1.00

Customers treated individually

	Customer A	Customer B	Customer C	Total
Sum of Maximum Demands at GXPs	100	100	100	300
Anytime Maximum Demand	100	100	100	

Regional Demands			
Sum of Maximum Demands at GXPs	100	100	100
Coincident Maximum Demand	100	100	100

Existing TPM			New TPM			
Original Revenues		IR	New Revenues	IR	LF	DF
Customer A	$10,000,000	$100	$10,000,000	$100	1.00	1.00
Customer B	$10,000,000	$100	$10,000,000	$100	1.00	1.00
Customer C	$10,000,000	$100	$10,000,000	$100	1.00	1.00

This scenario has the regional system fully loaded and utilised 100% at 300 MW total demand. Moving from existing to new TPM has no affect.
Interconnection Rate per kW = $100

Total Revenue Requirement	$50,000,000
Connection Revenue	$20,000,000
Interconnection Revenue	$30,000,000
Existing Pricing Method	
Total Demand MW	300
Interconnection Rate per kW	$100
Charges	
Customer A	$10,000,000
Customer B	$10,000,000
Customer C	$10,000,000
Total Charges	$30,000,000
Coincident Demand Pricing	
Regional Peak Demand (MW)	300
Interconnection Demand Charge per kW	$100
Charges	
Customer A	$10,000,000
Customer B	$10,000,000
Customer C	$10,000,000
Total Charges	$30,000,000

Scenario 2

The sum of maximum demands at all GXPs is 300 MW but C is an irrigation consumer causing a summer peak.
Month

	Month	A1	A2	A3	A	B	C	Coincident Peak Demand
April	1	10	20	15	45	100	100	245
May	2	12	23	20	55	100	0	155
June	3	14	30	25	69	100	0	169
July	4	18	45	30	93	100	0	193
August	5	20	50	30	100	100	0	200
September	6	20	40	25	85	100	0	185
October	7	18	35	20	73	100	0	173
November	8	16	30	18	64	100	0	164
December	9	14	20	14	48	100	0	148
January	10	**12**	**30**	**16**	**58**	**100**	**100**	**258**
February	11	10	30	16	56	100	100	256
March	12	8	20	15	43	100	100	243
MD		20	50	30	100	100	100	258
CMD		12	30	16	58	100	100	258
								10
AMD					100	100	100	300
Load Factor		0.72	0.62	0.68	0.66	1.00	0.33	0.77
Diversity Factor					1.72	1.00	1.00	1.16

Customers treated individually

	Customer A	Customer B	Customer C	Total
Sum of Maximum Demands at GXPs	100	100	100	300
Anytime Maximum Demand	100	100	100	

Regional Demands

Sum of Maximum Demands at GXPs	100	100	100
Coincident Maximum Demand	58	100	100

Existing TPM			**New TPM**			
Original Revenues		**IR**	**New Revenues**	**IR**	**LF**	**DF**
Customer A	**$10,000,000**	**$100**	**$6,744,186**	**$116**	**0.66**	**1.72**
Customer B	**$10,000,000**	**$100**	**$11,627,907**	**$116**	**1.00**	**1.00**
Customer C	**$10,000,000**	**$100**	**$11,627,907**	**$116**	**0.33**	**1.00**
Total	**$30,000,000**		**$30,000,000**			**1.16**

This scenario has the regional system fully loaded and utilised 77% at 300 MW total undiversified demand. Moving from existing to new TPM has the effect of transferring charges to the B and C.

Interconnection Rate per kW = $116

Total Revenue Requirement	$50,000,000
Connection Revenue	$20,000,000
Interconnection Revenue	$30,000,000
Existing Pricing Method	
Total Demand MW	300
Interconnection Rate per kW	$100
Charges	
Customer A	$10,000,000
Customer B	$10,000,000
Customer C	$10,000,000
Total Charges	$30,000,000
Coincident Demand Pricing	
Regional Peak Demand (MW)	258
Interconnection Demand Charge per kW	$116
Charges	
Customer A	$6,744,186
Customer B	$11,627,907
Customer C	$11,627,907
Total Charges	$30,000,000

Scenario 3

The sum of maximum demands at all GXPs is 300 MW. Both A and C have lower coincident maximum demands than B

Month

	Month	A1	A2	A3	A	B	C	RCMD
April	1	8	20	15	43	100	40	183
May	2	10	30	20	60	100	50	210
June	3	12	40	25	77	100	60	237
July	4	14	45	30	89	100	70	259
August	5	15	50	28	93	100	90	283
September	6	**20**	**50**	**26**	**96**	**100**	**92**	**288**
October	7	18	35	20	73	100	100	273
November	8	16	30	18	64	100	80	244
December	9	14	20	17	51	100	70	221
January	10	12	30	16	58	100	65	223
February	11	10	30	15	55	100	60	215
March	12	8	20	14	42	100	50	192
MD		20	50	30	96	100	100	288
CMD		20	50	26	96	100	92	288
								6
AMD					100	100	100	300
Load Factor		0.65	0.67	0.68	0.70	1.00	0.69	0.82
Diversity Factor					1.04	1.00	1.09	1.04

Customers treated individually

	Customer A	Customer B	Customer C	Total
Sum of Maximum Demands at GXPs	100	100	100	300
Anytime Maximum Demand	100	100	100	

Regional Demands

Sum of Maximum Demands at GXPs	100	100	100
Coincident Maximum Demand	96	100	92

Existing TPM			New TPM			
Original Revenues		IR	New Revenues	IR	LF	DF
Customer A	$10,000,000	$100	$10,000,000	$104	0.70	1.04
Customer B	$10,000,000	$100	$10,416,667	$104	1.00	1.00
Customer C	$10,000,000	$100	$9,583,333	$104	0.69	1.09
Total	$30,000,000		$30,000,000			1.04

This scenario has the regional system fully loaded and utilised 81% at 300 MW total undiversified demand. Moving from existing to new TPM has the effect of transferring charges to B from A and C.

Interconnection Rate per kW = $104

Total Revenue Requirement

Connection Revenue

Interconnection Revenue

Existing Pricing Method

Total Demand MW

Interconnection Rate per kW

Charges

Customer A

Customer B

Customer C

Total Charges

Coincident Demand Pricing

Regional Peak Demand (MW)

Interconnection Demand Charge per kW

Charges

Customer A

Customer B

Customer C

Total Charges

Scenario 4

The sum of maximum demands at all GXPs is 240 MW but C is an irrigation consumer with no coincident peak.
Month

	Month	A1	A2	A3	A	B	C	Coincident Peak Demand
April	1	10	20	15	45	100	40	185
May	2	12	23	20	55	100	0	155
June	3	14	30	25	69	100	0	169
July	4	18	45	30	93	100	0	193
August	5	**20**	**48**	**29**	**97**	**100**	**0**	**197**
September	6	20	50	25	95	100	0	195
October	7	18	35	20	73	100	0	173
November	8	16	30	18	64	100	0	164
December	9	14	20	14	48	100	0	148
January	10	12	25	16	53	100	40	193
February	11	10	30	16	56	100	40	196
March	12	8	20	15	43	100	40	183
MD		20	50	30	97	100	40	197
CMD		20	48	29	97	100	0	197
								5
AMD					100	100	40	240
Load Factor		0.72	0.63	0.68	0.68	1.00	0.33	0.91
Diversity Factor					1.03	1.00		1.22

Customers treated individually

	Customer A	Customer B	Customer C	Total
Sum of Maximum Demands at GXPs	100	100	40	240
Anytime Maximum Demand	97	100	100	240

Regional Demands

Sum of Maximum Demands at GXPs	100	100	40
Coincident Maximum Demand	97	100	0

Total Revenue Requirement		$50,000,000
Connection Revenue		$20,000,000
Interconnection Revenue		$30,000,000
Existing Pricing Method		
Total Demand MW	240	
Interconnection Rate per kW	$125	
Charges		
Customer A		$12,500,000
Customer B		$12,500,000
Customer C		$5,000,000
Total Charges		$30,000,000
Coincident Demand Pricing		
Regional Peak Demand (MW)	197	
Interconnection Rate per kW	$152	
Charges		
Customer A		$14,771,574
Customer B		$15,228,426
Customer C		$0
Total Charges		$30,000,000

Existing TPM			**New TPM**			
Original Revenues		**IR**	**New Revenues**	**IR**	**LF**	**DF**
Customer A	**$12,500,000**	**$125**	**$14,771,574**	**$152**	**0.68**	**1.03**
Customer B	**$12,500,000**	**$125**	**$15,228,426**	**$152**	**1.00**	**1.00**
Customer C	**$5,000,000**	**$125**	**$0**	**$152**	**0.33**	
Total	**$30,000,000**		**$30,000,000**			**1.22**

This scenario has the regional system utilised 91% at 240 MW total undiversified demand. Moving from existing to new TPM has the effect of transferring charges to A and B..

Interconnection Rate per kW = $152

The region is unconstrained compared to other scenarios but the demand charge has increased from $125 to $152 giving an increased incentive to manage load.

Customer C now pays no interconnection charges