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Review of Transmission Pricing Methodology

Report prepared for Vector

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Executive summary

The New Zealand Electricity Authority (EA) has released the report "Transmission Pricing Methodology: issues and proposal" dated 10 October 2012 (the EA Report) that presents its proposed electricity transmission pricing methodology.

We first note that the proposed TPM methodology is without precedence anywhere in the world and as such, is untested and unproven. Proper practice dictates a cautionary approach to this, and that a proper assessment of the proposal should be undertaken prior to any decision to introduce the proposal.

This report developed by Marsden Jacob Associates (MJA) has independently reviewed the proposed TPM methodology, the justification presented by EA regarding the inefficiencies of the current HVDC charging arrangements, and the proposal to include only post 2004 assets in the new arrangements (with the exception of the HVDC link).

The report reviewed the economics of "beneficiaries pay" which showed that there is no basis for improved efficiency by allocating sunk costs on this or any other approach. MJA is not aware of any literature that supports the principle of economic efficiency being achieved through beneficiaries pay. This is also a position adopted by Darryl Biggar in his paper 'Independent Review of "Transmission Pricing Advisory Group: Transmission Pricing Discussion Paper: 7 June 2011"', 14 July 2011.

The modelling presented by the EA in this regard for the HVDC link was shown, among other issues, to compare a case with fixed cost allocation as currently done to one with no fixed cost allocation. This meant the quantitative analysis presented in Appendix C of the EA report regarding the current inefficiency of the current HVDC charging arrangements was not considered sound and consequently should not be used as support for the beneficiaries pay approach. The EA's assessment of current HVDC costs also adopts a static approach, which ignores the long-run transmission cost/investment implications of decisions by generators to build generation plant in the South Island and export electricity to the North Island.

The SPD Methodology as presented in the EA report was reviewed and a number of matters identified. Foremost of these is that benefits as calculated via the SPD methodology would not be representative of outcomes in a functioning market - they would not be an accurate reflection of what the benefits would be if assessed by an investing party. In particular, they would result in an overstatement of benefits to consumers and understate benefits to generators. The key issues here were identified as:

- A counterfactual (i.e. the without asset case) that is materially different than would be used in an investment analysis – the EA has adopted a short-run calculation of benefits rather than a long-run calculation;
- Total reliance on actual spot market outcomes compared to a hedged forward expectation that would be used in an investment decision;
- Filtering of benefits through capping that significantly modifies the profile of benefits. This means that:
  - assets providing capacity services, as characterised by high value for a low number of half hours each year, would tend to be undervalued

  - the value of assets is not additive - combining two assets would have lower assessed benefits than if considered separately.

Section 4.1 of the EA report provided very little discussion on the proposal to restrict assets subject to the proposed TPM to those of commissioning dates post May 2004 and the HVDC link. While the EA Report recognises that introducing a cut-off date would introduce price distortions, Paragraph 5.6.30 states that "signalling benefits are likely to become more diffuse the more historic the transmission investment". This assertion was unsupported. A moderate outlook for new transmission build and a recognition that transmission assets in general are not used less due to age, would suggest that such distortion would remain a permanent feature of the market for many years into the future. MJA is concerned that the discriminatory treatment of pre-2004 (Residual charges) and post-2004 assets plus Pole 2 (SPD charges) will send distortionary signals to market participants that they should avoid using newer assets. This would be particularly perverse as newer assets would tend to be less capacity constrained.

Modelling of the proposed TPM methodology was undertaken to explore the dynamics of the SPD methodology and residual allocation. The modelling illustrated the substantially increased uncertainty in cost allocation associated with the proposed TPM due to factors such as generator outages, hydro lake levels and water inflows. Further to this, no instruments to manage such uncertainty in cash flows were identified. This would increase the risk associated with the purchase of transmission services.

The modelling illustrated that the HVDC and intra-island assets would respond differently to the SPD benefit assessment:

- Pole 2 of the HVDC lines has full cost recovery and a cost allocation variation to the generation and load sectors of about 20% due to market conditions over the period (the counterfactual has Pole 3 not in service). Sustained dry or wet hydrological conditions could result in variations substantially larger than this;
- Pole 3 of the HVDC line has less than 1% cost recovery through the SPD approach due to the fact that its counterfactual has Pole 2 in service (and flows rarely exceed the capacity of Pole2). Consequently its allocation would be managed almost entirely through the residual;
- MJA considers the differential treatment of Pole 2 and 3 to be arbitrary. Pole 2 and 3 both serve the same function. If the benefit of Pole 3 was calculated with the assumption that Pole 2 did not exist, the benefits calculated would far exceed the cost. If the benefit of Pole 2 and 3 are calculated jointly, the total benefits far exceed the costs. Notable also the benefits to South Island generators also far exceed the costs.
- The intra-island assets show a large variation in cost recovery through the SPD approach. However after allocation of the residual the variation in cost allocation was about 5% on a generator and load sector basis. Within each generator and load sectors there could be a wider allocation uncertainty due to generator dispatch and nodal price variations.

The results of the modelling indicated that outcomes that would approach that expected from the SPD methodology and residual allocation, at least from a generator and load sector basis, could be obtained using simpler allocation approaches. The report noted the differences between the intraregional transmission assets and HVDC link, which supports separate cost allocation approaches, as is done now.

A number of criteria were forwarded on which the proposed TPM should be assessed.

These were economic efficiency, benefits reliability and stability, cost recovery, market risk and impact to consumers. On all counts the proposed TPM was seen to be deficient.

This lead to a conclusion that the complexity and increased risk associated with the SPD methodology was not supportive of economic efficiency and was not supportive of lower costs to customers.

The report did not consider matters such as the impact on lobbying and dissatisfaction with the arrangements that in all probability would arise due to reasons such as those described above.

Glossary

AC	Alternating Current
CVP	Constraint violation penalty
EA Report	Transmission Pricing Methodology: issues and proposal 10 October 2102
HVDC	High Voltage Direct Current
MJA	Marsden Jacob Associates
NI	North Island
SI	South Island
SPD	Scheduling, Pricing and Dispatch
TPAG	Transmission Pricing Advisory Group
TPM	Transmission Pricing Methodology

1. Introduction

1.1 Background

The New Zealand Electricity Authority (EA) has released the report "Transmission Pricing Methodology: issues and proposal" dated 10 October 2012 (the EA Report) that presents its proposed electricity transmission pricing methodology.

The draft proposal addresses the three charging types (connection, HVDC and interconnection). The proposed Transmission Pricing Methodology (TPM) brings the costing arrangements of the HVDC and interconnection assets under a common methodology based on a dynamic assessment of private benefits ascribed to each asset in the spot market. This is undertaken through the change in spot market settlements that would occur had the asset not been in service. It has also been proposed that not all assets would be subject to the proposed TPM based on a threshold commissioning date.

Vector has concerns that the proposed TPM will not achieve its objectives and would in fact be counterproductive to the efficiency of the industry and ultimately would not be to the long-term benefit of consumers.

Given the significance of the proposed changes, Vector is of the view that the analysis undertaken to date has been insufficient and unproven, and that a proper and rigorous assessment of the proposed TPM is required prior to any decision being made in this regard.

To investigate the issues associated with the TPM, Vector commissioned Marsden Jacob Associates (MJA) to undertake an independent review of the proposed TPM with an emphasis in three key areas. The review was to be supported by modelling to illustrate matters that had not yet been canvased.

1.2 Terms of Reference

The Terms of Reference for this study comprised three tasks as follows.

Task 1: Review of Methodology

A review of the Authority's methodology for determining consumer/producer surplus, including:

- Efficiency and wealth transfer impacts;
- Identification of potential alternative options for a "beneficiaries pay" methodology; and
- Modelling of the proposed SPD charging arrangements and potential refinements.

Task 2: HVDC Charging

A review of the Authority's claimed "Problems with the HVDC charge" (Section 4.3 and Appendix C). Vector has concerns about the Authority's criticism of the current HVDC charges as has been reflected broadly in previous submissions by Vector that have supported the HVDC charges.

The alternative options identified in Task 1 should be tested on the HVDC link cost allocation.

Task 3: Post-2004 Asset Inclusion Criterion

A critique of the Authority's proposal to apply the SPD charges to post-2004 assets, including consideration of alternatives such as: (i) post 1 April 2015; and (ii) all major transmission assets (regardless of age). Vector has concerns about the impact of this on allocation of cost given a substantial amount of new (post-2004) investment is in the Auckland region, and about the potential efficiency distortions on discriminating between pre/post-2004 transmission investment.

1.3 Report Structure

This report is structured as follows:

Chapter 2 reviews the established principles of transmission pricing for improving transmission operations and development efficiency. The issue of wealth transfers to efficiency is also addressed.

Chapter 3 presents the matters relevant to beneficiaries pay. Matters of principle include the EA's rationale for beneficiaries pay and the theoretical basis in economics. Economic and private benefits of transmission assets are described.

Chapter 4 presents the SPD methodology. Described are the calculation steps, the delta surplus, and importantly the design choices made and what this is likely to mean to the nature of the resulting cost allocation.

Chapter 5 reviews Section 4.3 and the analysis undertaken (in Appendix C) of the distortionary impact of the current HVDC charging arrangements. **Appendix A** presents a review of Appendix C in terms of the approach taken, its findings, and the reliability of the assessment. The EA report placed considerable weight on the efficiency benefits presented in Appendix C in the justification of the proposed TPM;

Chapter 6 presents a review of the proposed 2004 cut-off date.

Chapter 7 presents a model of the New Zealand market and proposed TPM. The chapter then presents the results of modelling undertaken of the proposed SPD methodology for a number of different assets under a number of different assumptions.

Chapter 8 presents a quantitative assessment of the proposed SPD approach against a set of developed criteria, and suggests possible alternative charging refinements to the proposed TPM. The basis of the analysis is the review undertaken and modelling results presented.

2. Established Principles of Transmission Pricing

The proposed Transmission Pricing Methodology (TPM) is intended to promote, among other objectives, 'the efficient operation of the electricity industry for the long-term benefit of consumers'.

The EA's position is that a beneficiaries pay principle implemented through the described Scheduling Pricing Dispatch (SPD) methodology would promote the efficient operation of (and investment in) electricity transmission assets.

The robustness of EA's assertion has been discussed in the literature reviewed by MJA. This section outlines the concept of economic efficiency and the various forms of efficiency, and provides a summary of relevant discussions from the literature.

2.1 Efficiency

Economic efficiency refers to the optimal use of scarce resources to maximise the benefit to society as a whole. In the context of the TPM, this could be interpreted as pricing electricity transmission services so as to maximise the benefits gained by users of those services, whilst still recovering the cost of providing those services. Maximising benefits to transmissions system users should be distinguished from, and importantly is not the same as the EA's assertion that, pricing should be proportional to benefits.

The various forms of economic efficiency include:

- Productive efficiency – where a given output is produced using the least amount of inputs. For example, where supplying a load (within specified reliability constraints) at a certain point in the network is achieved using the most cost effective infrastructure (e.g. centralised generation, transmission assets or embedded generation etc.) possible.
- Allocative efficiency – where, assuming productive efficiency holds, the scarce resources are allocated to their highest value uses. For example, where the available transmission capacity is allocated to network users so as to maximise the total benefits to all users; and
- Dynamic efficiency – where allocative efficiency is achieved over time, taking into account the timing of new investment, innovation and changes in the relative prices of goods and services over time. For example, where there is allocative efficiency of transmission capacity over time and where the type, location and timing of new investment maximises benefits to users.

2.2 Monopoly pricing

Markets that are competitive tend to set prices and allocate goods and services so as to achieve economic efficiency. However, monopoly markets, where there is only one provider of a given good or service, in the absence of price regulation tend not to. Industries, such as transmission services, considered 'natural monopolies', are those where there are significant economies of scale and therefore the most efficient industry structure is where there is only one firm providing those services.

There is a branch of economic theory dealing with the pricing of natural monopoly services to achieve economic efficiency. In particular, to maximise benefits to society, services should be priced at marginal cost. In the context of the TPM, this is where the price reflects the marginal cost of electricity losses and congestion on the network.

This is consistent with 'nodal pricing' where the price of energy at a particular point in the network, reflects the marginal cost or value of electricity at that node. While this is allocatively efficient, it tends to result in the transmission system operator recovering less revenue than required to cover costs and therefore where additional charges are required, these charges should aim to result in the least amount of distortion (i.e. deviation from economic efficiency) possible.

2.3 Nodal pricing

The efficient use of the existing transmission network requires that network users pay and receive prices that reflect the (short run) marginal cost of electricity at different points on the network. This ensures users implicitly face the marginal cost (or value) of the transmission network at any point in time and at any given location on the network when making consumption or production decisions.

In nodal pricing electricity markets wholesale spot prices tend to reflect the marginal cost or value of electricity at each node. So long as there is adequate competition at each node (in some cases, an inappropriate assumption), and prices are not capped below market-clearing levels, participants will have incentives to make efficient operating decisions. By implication, they will also have incentives to make efficient use of the existing network. For example, where undistorted nodal pricing applies, generators will produce to the extent that their avoidable costs of generation are no greater than the marginal value of electricity at their location. Similarly, (dispatchable) loads will consume up to the point where their willingness to pay for electricity is at least as high as the marginal cost of electricity at their location.

Due to the large lumpy nature of transmission investment, the transmission system has associated significant economies of scale and scope. It is in this regard that theory can depart significantly from practice.

Absence of economies of scale and scope

Biggar explains[1] that in the absence of economies of scale and scope, full nodal pricing, when coupled with this simple rule for efficient transmission investment, will ensure the fully-efficient electricity market outcome. That is, full nodal pricing will ensure both efficient short-run operational decisions, and efficient long-run investment/location decisions in both transmission and generation. Full nodal pricing ensures that generators continually face the short-run marginal cost (SRMC) of use of the transmission network, while the transmission augmentation rule ensures that the transmission network is augmented to the point when the long-run marginal cost (LRMC) of transmission expansion is equal to the average SRMC arising from generator re-dispatch. No further investment/location signals are required.

Economies of scale and scope

However, assets such as transmission lines and transformers on the high voltage transmission system are not developed in 1MW increments but in large "lumpy" sizes. As a result, the

[1] Reference xxxx

conclusions of an idealised model that has the LRMC of transmission expansion equal to the average SRMC arising from generator re-dispatch is not realised. The implications of this are that an approach to the allocation of (fixed) transmission costs is required.

Economic efficiency is achieved when decisions minimise costs. The costs that are variable and that can be minimised are those that are not already sunk. These costs are the SRMC of operation and future capital expenditure. To the extent the allocation of sunk (fixed) costs is influenced by decision making will introduce inefficiency. As a result a tension can arise between allocative efficiency and longer term dynamic efficiency.

2.4 Wealth transfers

The EA does not consider wealth transfer as relevant to efficiency. This observation is also supported by Biggar who quotes from an EA publication:

For example, NZEA (2010a), 'The Authority interprets 'competition for the benefit of consumers' to mean the efficiency benefits of competition. This interpretation excludes wealth transfers' (A.10, emphasis added). In assessing the benefits of transmission investment the Authority takes an 'aggregate consumer interpretation of the benefits to consumers, which excludes wealth transfers to consumers' (NZEA 2011a, A.39, emphasis added).

However, we note that consumers can be made worse off if efficiency gains associated with a proposed cost allocation methodology are offset by wealth transfers from the consumer sector.

MJA agrees that avoiding wealth transfers, unless they are justified by efficiency benefits, is consistent with good regulatory practice. As Biggar points out, the Authority's discussion paper notes that wealth transfers could "undermine confidence in the pricing process" or "inhibit entry and investment decisions" (A.17b). Optimal timing of investment decisions is a requirement for dynamic efficiency. Undermining confidence in the pricing process could, in MJA's opinion, detract from achieving efficiency, and is therefore relevant for efficiency considerations. The degree of relevance will depend on the magnitude of changes to prices.

3. Beneficiaries pay

This chapter presents the EA basis for adopting a beneficiaries pay framework for the proposed TPM, the theoretical basis for this, the conditions that need to be met and how this relates to transmission assets.

It is not the intention of this report to criticise the beneficiaries pay framework adopted by the EA in the proposed TPM. However it is the intention of this paper to consider the stated conditions and performance criteria that need to be met for the approach to be considered applicable. This relates to the SPD methodology that will be reviewed in the next chapter.

The fundamental premise of the SPD methodology as expressed in the EA report is that economic efficiency will be achieved through *aligning benefits achieved and costs incurred* by the uses of transmission services. The rationale is that efficiency will be improved through increased participation in decision making[2].

Consistent with the description provided by the EA is that this can be expressed as ***the investment a participant would be willing to make in the transmission asset*.**

3.1 Energy Authority's Rationale for Beneficiaries pay

Chapter 3 of the EA report "Decision-making about the TPM" presents the Authority's objective and describes the economic framework for the TPM. The economic framework sets out a hierarchy of approaches which in order of preference are market-based charges, exacerbators-pay charges, beneficiary pay charges, and other options.

The beneficiaries pay approach is described in paragraph 3.3.12 which says:

The beneficiaries-pay approach involves using a method or methods to determine the parties that benefit from a transmission service, and each party's private benefit. A beneficiaries-pay approach is most likely to be required where parties to a transaction will not self-identify ….

Paragraph 3.3.17 notes:

The key advantage of assigning beneficiaries some decision rights is that the beneficiaries are the best ones placed to determine whether the expected benefits (to them) of the proposed investment exceed the costs (to them) of the proposed investment. If the benefits do not exceed the costs, the beneficiaries are unlikely to be willing to pay the costs and the investment should not happen. .

Paragraphs 3.3.15 and 3.3.16 present justification for the approach based on this approach as "emerging a common practice internationally". However the evidence presented does not support this.

The beneficiaries pay approach was supported in the report by the Transmission Pricing Advisory Group (TPAG) to the EA entitled "Transmission Pricing Analysis" dated 31 August 2011 (the TPAG Report). The TPAG Report emphasised a number of conditions that are required to be met for a beneficiaries pay approach to improve durability of the methodology and economic efficiency. These conditions include:

- Beneficiaries can be clearly identified;

[2] In relation to the HVDC link this is discussed in paragraphs 4.3.7 and 4.3.8.

- Charges determined do not exceed beneficiaries private benefits;
- Incentivises the provision of quality information to the planning and investment approval process;
- Cost of identifying beneficiaries does not outweigh the benefits of doing so.

We observe that the second condition above was presented in the EA report.

3.2 Theoretical Basis of Beneficiaries pay

While this report addresses transmission pricing arrangements within a beneficiaries pay framework, this should not be interpreted as support for the principle of beneficiaries pay as an approach to economic efficiency. As previously noted, the TPAG and EA have put forward beneficiaries pay as a principle consistent with achieving economic efficiency.

MJA is not aware of any literature that supports the principle of economic efficiency being achieved through beneficiaries pay. Theory recognises that sunk / fixed cost allocation is by nature arbitrary, and when done should be in a manner that does not close or impact any parties operations. Allocation of such costs in accordance with assessed benefits provided no additional guarantee of being non-distorting than any other allocation approach.

This is also a position adopted by Darryl Biggar in his paper 'Independent Review of "Transmission Pricing Advisory Group: Transmission Pricing Discussion Paper: 7 June 2011"', 14 July 2011. In particular, Biggar makes the point that beneficiaries pay has no basis in neo-classical economic theory and is not in any textbook as a form of solving the transmission pricing problem. However, there are principles of good public policy analysis that do have a basis in neo-classical economic theory. Biggar also makes the comment that incentivising parties to participate in transmission development decisions does not require benefits and costs to be aligned, but only that parties be allocated enough of the cost to attract their interest.[3]

The EA paper makes reference to emerging regulatory practice for beneficiaries pay (sections 3.3.15 and 3.3.16).

3.3 Benefits of Transmission Assets

The principle of beneficiaries pay requires an understanding and definition of the benefits a transmission asset would bring to the market and the associated private benefits. This is addressed below in terms of:

- The economic benefits (as would be assessed through the Investment Test); and
- As would be assessed by an investing party through a comparison of private benefits and costs.

3.3.1 Economic benefits

The economic benefits provided by transmission assets relate to resource impacts and exclude wealth transfers. These benefits are well established and include:

[3] In a similar vein, we consider that the risk that the TPM could change may attract similar interest e.g. when considering HVDC investment decisions, consumer know there is a risk they could have to contribute to the cost in the future if the TPM changes.

- Change in capital expenditure (generation, other transmission etc);
- Change in generator dispatch costs (mainly fuel costs and variable operating and maintenance costs). This includes the impact of changes in transmission losses;
- Change in unserved energy valued at the value to consumers;
- Change in other costs such as the provision of ancillary services, environmental requirements etc.

3.3.2 Private Benefits

The assessment of private benefits involves the allocation of the economic costs described above and the addition of wealth transfers due to price changes (usually based on spot price). Assets developed contingent on the transmission asset (such as new generator) were referred to in the EA report as "existence benefits"[4].

Thus the determination of the private benefits a transmission asset would bring to individual market participants requires a determination of the changes the asset would bring to the market that would impact participants operations and prices received. Key issues here are impacts to competition and generator offer prices and new generation assets.

3.3.3 Transmission Value Profile

The economic value of transmission assets through time varies with factors such a locational demand levels, generator availability and dispatch levels. The service provided by a transmission asset has a very high economic value when it is required to maintain power supply to loads, and a lower economic value when there is surplus capacity.

The profile of economic value varies with different types of transmission services / assets. Here we distinguish two categories:

- Assets that provide a bulk energy transfer service. Assets providing this service could be transmission lines from a group of power stations to the main load centre or the HVDC link connecting the two islands in New Zealand;
- Assets that provide a capacity service during times of load peaks and/or generator unit outages. Assets providing this service usually have value for a limited number of hours each year (typically less than 2 to 5% of the time[5]).

Transmission assets usually provide value (to varying degrees) in both the above categories.

[4] EA Report Appendix C Section C3.2.2 Paragraph 43.

[5] The assessed time assets provide a capacity service has been assessed through observations of electricity market operation.

4. The Proposed SPD Approach

The objective of the SPD approach is to calculate in an automated (and objective) manner the benefits each transmission asset brings to each market participant (i.e. the private benefits). This must be understood to be a metric for the actual benefits that would be derived as would be assessed in an investment decision.

4.1 Explanation of the change in surplus

The EA report fully described the SPD approach and this is not reproduced here.

However given the importance of the change in surplus in the SPD approach this is briefly reviewed here for completeness.

The proposed SPD method (described in Appendix E of the Authority's consultation paper) is designed to apportion the costs of transmission assets in proportion to the benefits users derive from them. The benefits to each market participant of a particular transmission asset is calculated by considering the outcome for a market participant with the asset in place compared with the hypothetical situation where the asset does not exist (counterfactual).

Using this "with and without" approach, the benefit for each market participant during a given time period is taken to be the change in surplus (Δ surplus), with and without the asset. Surplus, by definition, is the benefit to a market participant derived from a market transaction. Assuming market participants in this context are rational profit maximising firms, surplus is an appropriate financial measure of benefit.

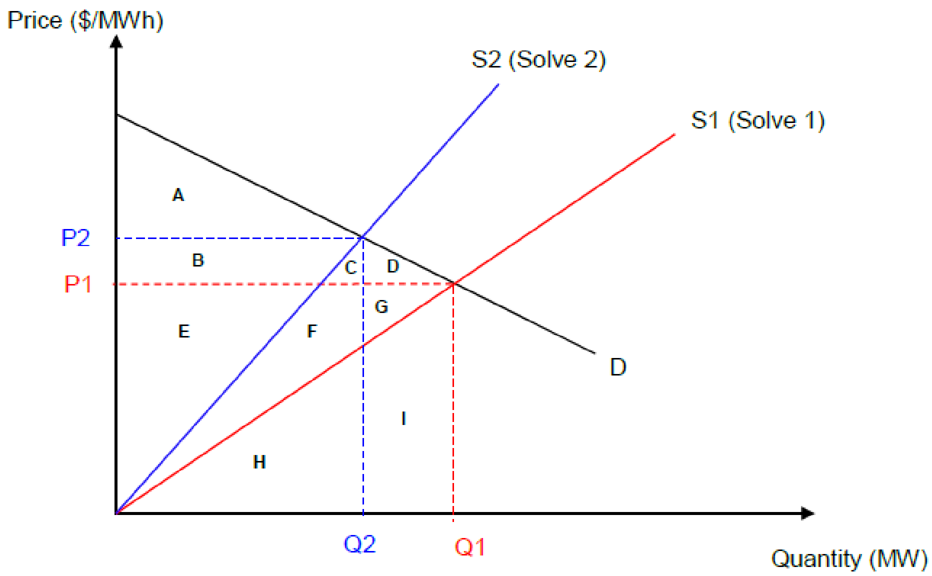
Figure 1 below presents Figure 1 from Appendix E of the EA Report. This illustrates the EA's proposed approach to calculation of surplus.

As illustrated above, the Δ surplus for generators and loads respectively is calculated as:

- The difference in area above the producer supply curve up to the market clearing price level between the "with and without" asset cases; and
- The difference in area below the consumer demand curve down to the market clearing price level between the "with and without" asset cases.

Figure 1 Explanation of Delta Surplus (taken from Appendix E of the EA Report)

Figure 1 Illustration of calculated benefits from vSPD solve



	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

4.2 Implementation issues identified by the Authority

Appendix E discusses a number of implementation issues. Some of these are technical in nature and the consultation paper should be referred to for a fuller explanation. In summary these are:

- **Allocation to intermittent generation -** if represented as negative loads the estimated benefit to intermittent generation using the SPD method would be understated. This issue could be overcome, as is being considered by the Authority, if intermittent generation are treated as dispatchable generation.
- **The effect of embedded generation** – if net demand (i.e. net of embedded generation) is used this could lead to an understatement of benefits (i.e. price reduction) to loads. This could be adjusted by using gross demand and modelling the embedded generation with a fixed output.
- **Value of unserved energy** – the constraint violation penalty (CVP) of $500,000/MWh used in the market clearing engine is not appropriate for the estimation of benefits. The Authority has considered a reduced value of $3,000/MWh (the cost of a diesel generation alternative) to be more appropriate for this purpose.
- **Counterfactual security limits** – the EA notes that removal of a transmission link would result in different sets of transmission security constraints. Therefore, the Authority has identified options to recalculate constraints in the counterfactual.
- **Recalculation of reserve requirements** – similarly, reserve requirements would be different in the counterfactual and require recalculation.

- **Final pricing schedule quantities compared with actual quantities** – the EA recognises the SPD approach is based on price schedule quantities (i.e. those determined by the SPD engine) compared with actual quantities (which may differ due to constraints). The Authority has proposed an alternative method for 'constrained off' generators to address this.

The above issues illustrate the complexity of the proposed SPD methodology and the array of issues and assumptions that would be required to operationalise this approach. This has consequences to any assessment of private benefits and consequential cost allocation.

While MJA agrees with the authority that these issues can be addressed, they raise many issues in relation to the meaning and appropriateness of benefits calculated via this approach

4.3 Value Profile and Charging Dynamics

4.3.1 Value Profile

The uniform allocation of asset cost over each half hour period in a year is not consistent with the profile of asset economic value as discussed in Section 3.3.3.

The consequences of this would likely be:

- For assets associated with the provision of capacity (usually at times of high demand) the SPD runs for the "with and without" cases may be very similar most of the time (except for small changes to transmission losses). This would result in significant under recovery of costs via the SPD approach with the bulk of costs being managed through the residual mechanism;
- For assets associated with bulk energy transfers a greater number of hours would show differences between the "with and without" SPD runs. Consequently the percentage cost recovery could be significant.

Calculated benefits of an asset to an investor would be different than what would be determined through the investors assessment of private benefits (through a financial model). This is because an investor's assessment would be based on the sum of all benefits (negative and uncapped) and would also account for how the transmission asset could change the future operation and development of the market (such as deferring new generation) i.e. a long-run approach to calculation of benefits.

This raises the important question of whether the SPD Method can reliably estimate private benefits and in particular not overstate them.

Section E7 of Appendix E discussed the impact of using different time periods in the SPD method[6]. Specifically, alignment of costs and benefits can be undertaken by trading (half-hourly) period or over a longer period (e.g. daily, monthly or annually etc.). The EA notes that extending the time period reduces the risk of revenue shortfall.

[6] Presumably, this is because a shorter time period is likely to result in more frequent capping and therefore lower revenue.

4.3.2 Financial Outcomes versus Economics

The distinction between financial outcomes (participant cash flows) versus economics can be illustrated through a hypothetical example. Assume an asset is being valued that that did not result in any change in generator dispatch but had the effect of having some generators increase their bids in a significant number of time periods and decrease their bids in other time periods. The result was that average prices were unchanged and that some generators made a substantial profit when prices were high and some loads a profit when prices were low. The SPD methodology would ascribe benefits to these parties. However, the Investment Test would show no benefits.

A similar matter to the above arose in the Australian National Electricity Market when the test for the development of transmission assets was initially proposed to be based on Customer benefits. It was found that the volatility of spot prices to changes in market condition made the test not practical and also that the results did not align with economics. The Customer benefits test was replaced with a Regulatory Investment Test similar to that in New Zealand[7].

4.3.3 Risk and Potential Gaming by Generators

The added risk to market participants resulting from the proposed TPM would likely vary depending on participant size, natural hedging due to vertical integration, and the location of customers and generators in the network. The behavioural response to this is uncertain but would likely have a proportionally larger impact on small retailers.

With SPD allocating benefits based on uncertain changes to surpluses as determined through participant behaviour (esp. bidding), raises the question of risk and the potential for gaming by generators. Gaming by generators is possible to the extent their bidding behaviours can influence spot price outcome sensitivity to transmission asset removal and consequently the calculation of delta surplus. The potential to game would be greater for larger players and would depend on the degree to which the proposed SPD method can be manipulated in order to minimise the allocation of transmission costs.

An example of a gaming strategy by a NI generator to the allocation of Pole 2 costs is to bid in a manner that reduces the NI spot price increase to the removal of Pole 2. This would lower the delta surplus benefit to that generator.

While the potential to game is uncertain, this also presents added risk and uncertainty to the market which should be tested. Such increased risk would likely be reflected in market efficiency and consumer costs.

[7] While no reference exists on the AEMO website, Andrew Campbell was involved in this work at the time. The comments are his recollection of the process.

5. The HVDC Charge

The impact of the proposed SPD cost allocation methodology on the HVDC charge is critical aspect of the EA charging proposal and one that the EA report placed a high level of importance. Shifting the allocation of the HVDC from South Island generators to a split between generators and load could create substantial winners and losers potentially well in excess of any efficiency impact (whether positive or negative).

Section 4.3 of the EA report is labelled "Problems with the HVDC Charge". It presents analysis to support the contention that the current arrangements are distortionary and do not align benefits with costs. Section 4.3 is brief and does not contain the detail and qualifications on the matter of efficiency gain through aligning benefits and costs as was addressed in the TPAG report.

Section 4.3 refers to[8] and uses the analysis presented in Appendix C of that report. Consequently this chapter is organised by first presenting a review of Appendix C for the purpose of assessing the reliability of the modelling presented in that appendix. Following this the substance of Section 4.3 is reviewed with reference to qualifications made in the TPAG report.

The current HVDC arrangements are not described as these are assumed known.

5.1 Review of Appendix C

Appendix C of the EA Report is entitled "Assessment of materiality of problems with HVDC charges under the current TPM". It is a long and complex document composed

The two themes of Appendix C were (1) how the current HVDC charging arrangements introduce economic distortion and (2) how the current HVDC charging arrangements misalign benefits and costs. The assessments made in Appendix C appear to have been relied upon in the EA Report as key reasons for the proposed change.

The two sections below present a brief review of the analysis undertaken in Appendix C to arrive at the conclusions made. A detailed review of Appendix C is presented in Appendix A of this report[9].

The conclusions of the review below are that the quantitative analysis presented in Appendix C of the EA report is not considered sound and consequently should not be used as support for the beneficiaries pay approach.

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[8] The EA report refers to Appendix C in Paragraphs 4.3.6, 4.3 12, 4.3.13, 4.3.15.

[9] We also note that Appendix F of the EA report presents an economic assessment of the benefits that a beneficiaries approach would bring to the market and arrives at an estimate of $173.2M (of this $158.2M being for interconnection and HVDC). The assessment approach used was stated as "multiply total revenue by a factor estimated from qualitative information". While not within the scope of this review, we note that this estimate as presented is not consistent with that presented in Appendix C.

5.1.1 Economic distortion introduced by the current HVDC charging arrangements

Section 4.3 refers to the assessment presented in Appendix C of $30M economic distortion associated with the current arrangements. The $30M efficiency loss associated with the current HVDC charges was derived by comparing the current arrangements that allocates sunk costs to existing and new SI generators to a counterfactual that had no allocation of HVDC costs to any generators. In both these cases the generation development program was based on a least cost generation development. The existing arrangements resulted in more expensive NI generation being developed at the expense of lower cost SI generation.

The logic of the argument presented is that allocating sunk costs to potential new generators will disadvantage these compared to others unless this is done in a non-distortive manner[10]. However the analysis makes no assessment of the level of distortion that would be introduced through allocating HVDC costs based on some form of beneficiaries pay methodology. The issue of HVDC cost allocation efficiency being regardless of associated HVDC benefits was made in the TPAG report (paragraph 4.5.8).

Further to this, the methodology used for assessing the efficiency loss was based on a number of arbitrary assumptions within a least cost investment framework that are subject to very considerable uncertainty. These included arbitrary assumptions of the profile of prices with and without the asset and how benefits would decay after the 2014 year. These assumptions and not the cost allocation methodology being tested dictated the results of the analysis.

These issues put in question the basis of the modelling presented in Appendix C that assessed the $30M efficiency loss.

5.1.2 Alignment of Benefits and Costs

The assessment of benefit/cost alignment presented in Appendix C was developed through a consideration of how the HVDC link capacity would impact a least cost generation development supported by spot prices that have all generators (new and existing) covering all costs.

The modelling ignored the competitive nature of the market and assumed that all generators recovered all their respective costs in the spot market. This assumption alone invalidates any conclusions drawn from the modelling.

Further, this is very different to the private benefits that would be assessed through the proposed SPD approach, as the SPD approach would have:

- Potential for significant delta spot price changes between the with and without cases;
- Many hours where the removal of the asset being considered would have only a minor impact on generator dispatch levels.

As a consequence (and as shown through the modelling presented) there is a very significant disconnection between the realised benefits and SPD assessed benefits.

These issues also put in question the basis of the modelling presented in Appendix C regarding cost / benefit alignment.

[10] A non-distortive manner would have no sunk costs allocated to generators.

5.2 Section 4.3 of the EA report

The issues addressed in Section 4.3 of the EA Report regarding economic efficiency and benefit / cost alignment are presented in turn below.

5.2.1 Economic Efficiency

The key statements / arguments in relation to economic efficiency were as follows:

- The current design of HVDC charges reflects mid-1990's thinking that efficiency would be enhanced if South Island (SI) generators pay HVDC costs (paragraph 4.3.3) and that this is no longer the case; and
- Paragraph 4.3.5 states "The Authority has identified three problems with the current HVDC charge resulting in a net cost of an estimated $30 million NPV";

The validity of these statements relies on the assessment presented in Appendix C, which has been shown to be unproven. As shown above, the estimated $30 million NPV is the cost of less SI generation compared to NI generation due to HVDC costs of $23/kW/Yr being imposed on new SI generators compared to new NI generators, where the counterfactual has no sunk HVDC charges being allocated to any generators.

We also note that the $30M assessment can be considered "in the noise" of the cash flows associated with the functioning of the market.

5.2.2 Alignment of Benefits and Costs

Section 4.3 presents a number of statements regarding benefit / cost alignment that require close review. To do this, this section is structured as follows:

- The key statements of Section 4.3 of the EA report are presented;
- Qualifications of alignment of benefits and cost presented in the TPAG report are presented;
- Issues with the arguments are noted.

Key Statement in Section 4.3

The key statements of Section 4.3 in relation the alignment of benefits and costs yet were as follows:

- The current design of HVDC charges does not align private benefits with HVDC cost allocation. This is shown in the table below (paragraph 4.3.9). This is stated as "the Authority's analysis" in the report;
- Paragraph 4.3.7 states "The allocation of costs based on private benefits derived from the HVDC link should promote investment efficiency through improved decision making and provide benefits from improved durability of the cost allocation methodology.";
- Paragraph 4.3.8 notes that parties paying a HVDC charge commensurate with their private benefits will have a number of incentives, namely to participate in decision making, make trade-offs between benefits and costs, and negotiate separate commercial agreements.

Table 1: HVDC Pole 2 + Pole 3 Benefits and Costs

	Benefits	Costs
SI Generators **	$695M	$1470
SI Consumers	$460	-
NI Generators	($1200)	-
NI Customers	$1380	-

Source: Energy Authority report Transmission Pricing Methodology, 2012.

** Pole 2 has Benefit of $540M and Cost of $500M.

The EA Report identified three problems (listed below) with the current design (due to the mismatch between the private benefits from the HVDC link and the current charges). These are:

- Dynamic inefficiency:
  - generators declining to carry out efficient investment in the SI
  - consumers (SI and NI) lobbying for more HVDC link capacity upgrades;
- Inefficient generation investment:
  - discourages investment in SI generation relative to NI generation even when SI generation is lower cost. The estimated cost of this is $30M NPV albeit with considerable uncertainty (paragraph 4.3.5)
  - flow on effect for transmission investment;
- Inefficient operation of electricity assets:
  - inefficient use of the grid due to HAMI discouraging SI generators operating at full capacity. The economic cost of this is estimated at $5M PV.

TPAG Report Qualifications

The TPAG report placed significant importance to the qualifications presented in relation to beneficiaries pay and are considered most relevant to an appreciation of the proposed TPM. The qualifications presented in the TPAG report, all of which were not included in the EA report, included the following:

- Table 8 describes the conditions under which a beneficiaries pay approach is applicable. These are:

– where beneficiaries can be clearly identified and charges can be determined which do not exceed the beneficiaries private benefits

– where the cost of identifying does not outweigh the benefits of doing so, and

– to incentivise participants to provide quality information to the planning and investment approval process;

- If the grid investment decision does not substantially rely on private information then charging beneficiaries is less likely to improve decision making (paragraph 4.5.5);
- Where beneficiaries can be clearly identified and are not charged more than they benefit, this can lead to improved durability of the methodology and improved regulatory certainty, through reduced disputes and interventions (paragraph 4.5.7);
- Applying a beneficiaries approach requires a robust method for identifying beneficiaries that can be applied consistently across the grid. The benefits of improved investment efficiency and durability will be compromised if beneficiaries cannot be cost-effectively and clearly identified (paragraph 4.5.8 (a));
- After an investment has been made, there is less value to be obtained in allocating sunk costs to beneficiaries, unless doing so impacts on future investment decisions, not only in transmission but in generation and load. …. Assessing potential beneficiaries before an investment will involve controversial analysis … Ex-post allocation of sunk costs is by contrast done on the basis of data rather than projections of these variables, but has the drawbacks above. (extracts from paragraph 4.5.8 (d)).

Assessment of Section 4.3 Conclusions regarding benefit /cost alignment

The review of Appendix C showed that no conclusions can be made regarding the alignment of benefits and costs and in particular how benefits and costs would align under the proposed SPD methodology. Given this, no conclusions regarding how the SPD approach would promote investment efficiency through improved decision making or the like can be made.

There were a number of key issues identified in the TPAG report that are unproven in the EA Report, namely:

- Beneficiaries need to be clearly identified;
- This requires a robust and cost-effective method without which the value of a beneficiaries approach would be compromised;
- After an investment has been made, there is less value to be obtained in allocating sunk costs to beneficiaries, unless doing so impacts on future investment decisions.

6. The Proposed Post-2004 Cut-off Date

The EA report presents a proposal whereby transmission assets commissioned ***before*** May 2004 would not be subject to the proposed SPD cost allocation methodology. Pre-2004 assets will be assumed to have no SPD cost allocation and costs will be totally allocated as per the residual cost allocation (50/50)[11]. Post May 2004 assets of capital value greater than $2M would be subject to the cost allocation as determined by the application of the SPD approach. The HVDC link is exempted from this proposal and would be subject to SPD cost allocation.

The clear implication of this proposal is that generators and consumers that are located near post-2004 transmission assets will be subject to higher change in transmission costs than generators and consumers that are located away from post-2004 transmission assets. Expressed another way, consumers in areas where there has been inadequate investment will be disadvantaged relative to consumers in areas where investment has been sufficient.

To review this matter this chapter:

- Presents and notes the limited consideration of this proposal in the EA Report;
- Presents matters that suggest a high degree of uncertainty in the potential economic distortion associated with this proposal.

6.1 Discussion in the EA report

The only discussion of the May 2004 cut-off date proposal presented in the EA report is that contained in Paragraphs 34, 35 and part of 5.6.30 which are reproduced below. There is no discussion of this in the TPAG report as the SPD methodology had not been published at the time the TPAG published its report.

The EA Report does recognise that introducing a cut-off date would introduce price distortions. This recognition is provided in Paragraph 5.6.28 which is reproduced below.

> 5.6.28 As foreshadowed in the framework consultation paper, the Authority considers that there are efficiency benefits from applying beneficiaries pay to assets already in place, as well as new investments. In particular, this ensures that existing and new assets are charged on a broadly comparable basis, thus providing pricing signals to parties considering investments that would be affected by transmission investment. It should also assist in making the charge more durable since assets providing similar services in different areas and implemented at different times would be charged on the same basis.

However the EA report goes on to say in Paragraph 5.6.30 that "signalling benefits are likely to become more diffuse the more historic the transmission investment".

It is not clear precisely what is meant here. The nature of transmission is such that transmission assets are not used less due to age, in fact if anything, they are used more with age. Depreciated cost may reduce with age, but the costs to be recovered from pre-2004 assets represent the majority of costs to be recovered. This would mean that pre-2004 transmission assets could have significant beneficiaries under an SPD approach.

[11] Based on RCPD and RCPI for individual loads and generators.

Additional information to this was provided in a communication from the EA "Transmission pricing methodology review Questions and answers" dated 10 October 2012. This is contained in Question 16 a copy of which is presented in Figure 2 below.

Figure 2 References to the May 2004 Cut-off dates in the EA report.

34. The Authority proposes to apply a cut-off date before which the beneficiaries-pay charge would not apply to existing transmission assets. The Authority proposes the cut-off date be 28 May 2004, the date on which the Electricity Commission first began approving transmission investments. The one exception to this is pole 2 of the HVDC link, which the Authority considers should also be subject to beneficiaries pay so that the charging basis for pole 2 is broadly consistent with the basis for pole 3.

35. The Authority proposes an investment cost threshold for application of the SPD method of $2 million. It is proposed that this threshold would apply for any assets added to Transpower's regulated asset base after 28 May 2004. The cost would be assessed as at the time the assets are added. The threshold is set so that the benefit derived from identifiable interconnection assets is attributed to beneficiaries by applying the SPD method. The costs of interconnection assets not covered by the beneficiaries-pay charge (i.e. assets built before 28 May 2004 (but not replacements or refurbishment of these assets) or since 28 May 2004 but with a cost below $2 million) would be recovered through the residual charge. HVDC and interconnection costs would also be recovered through a residual charge.

5.6.30 The Authority considers that these signalling benefits are likely to become more diffuse the more historic the transmission investment. Accordingly, the Authority proposes that the beneficiaries-pay charge would apply to assets added to Transpower's regulated asset base from 28 May 2004, the date when Part F of

Figure 3 Energy Authority Response to the May 2004 Date

16. **Why has the Authority proposed to apply the SPD beneficiaries-pay charge to assets after 28 May 2004 and pole 2?**

The Authority considers that there are efficiency benefits from applying the SPD-beneficiaries-pay charge to assets already in place, as well as new investments. In general, this is because:

- it ensures that existing and new assets are charged on a broadly comparable basis, thus providing pricing signals to parties considering investments that would be affected by transmission investment;
- it assists in making the charge more durable since assets providing similar services in different areas and implemented at different times would be charged on the same basis; and
- it provides information on the efficiency of investment decisions, thus helping inform future investment decisions.

These signalling benefits are likely to become more diffuse the more historic the transmission investment, so the Authority has proposed that the SPD charge would not apply to investments built before 28 May 2004, which is when the Electricity Commission was first able to approve transmission investment. Pole 2 was implemented before this date but the Authority considers that to promote the durability of the charge it is appropriate that it is charged on the same basis as pole 3. Using a "cut-off" date of 2004 will mean that the SPD beneficiaries-pay approach applies to the numerous large transmission investments made in recent years.

While not specifically discussed in the EA report, it is understood from EA presentations that computational constraints would limit the number of assets that can be managed under the SPD methodology. Each asset requires a separate solution of SPD with appropriate security constraints (which may take a number of solves), storage of the solution outputs and computation. The limit of the number of assets is understood to be about 80.

6.2 Potential Economic Distortion

The potential level of economic distortion would depend on the relative economic impact the post-2004 cut-off date would have to new generator investments compared to that with all assets included.

This relates to the assets that would qualify for SPD cost allocation. A significant amount of post-2004 transmission assets of capital cost greater than $2M are located in the Auckland region. This necessarily means that a May 2004 cut-off date would potentially introduce efficiency distortions by disproportionately impacting North Island generation and consumer costs.

The removal of such distortions was a key reason the SPD cost allocation method has been proposed. However here has been no analysis presented on the level of distortion that would be associated with a post-2004 threshold date. Given that the 2004 threshold date is independent of the proposed SPD methodology such as analysis should be and must be fundamental to any final decision on the proposed TPM. The assessed efficiency benefits of the proposal may be contingent on a decision in this regard.

This cannot be assessed without detailed analysis and modelling. Such modelling would need to recognise the considerable uncertainty that exits due to issues such as the future sensitivity of spot prices to the removal of each asset in the SPD solution.

7. Modelling of the Proposed Arrangements

This chapter presents a model of the New Zealand electricity market and the operation of the proposed SPD charging methodology. This model was then used to model the proposed SPD charging methodology for a number of different assets under a number of different market scenarios.

7.1 Description of the New Zealand Model

A model of the New Zealand electricity market was established using the electricity market model PROPHET. PROPHET is a model that is widely used in the Australian National Electricity Market (NEM) and has also been used in other markets including New Zealand, Singapore, Vietnam and the Philippines. PROPHET provides for detailed half hourly simulation of the physical power system and market operations, including the linear program System Pricing and Dispatch (SPD) engine.

The model was set-up to represent the New Zealand market as it operated in 2012. The information used in construction of the New Zealand electricity market model was sourced from WITS Free to air (http://www.electricityinfo.co.nz/comitFta/ftaPage.main) and the Electricity Authority (http://www.ea.govt.nz/) .

The key features of the New Zealand Energy electricity market model established were as follows:

- Two islands connected by a HVDC link;
- A HVDC interconnector repressing Pole 2&3 linking the north and south islands;
- Flows limits on the HVDC link;
- 196 individual nodes with all schedulable generators assigned to their respective nodes;
- 206 individual modelled links. These were lossless with no associated flow constraints. As a result spot prices were the same across all nodes in each island;
- Generator bidding as observed in the New Zealand market;
- Dynamic hydro-electricity pricing based upon island wide reservoir storages;
- Hydrological inflows based upon NZ long term averages;
- Load data for each hour at a nodal level based upon demands in 2011/12;
- Prices calibrated to the 2011/12 financial year for both North and South islands;
- Benefits calculated for each individual generator and nodal load;
- Monte Carlo simulation of generator availability.

The model also provided for changes to be made in assumptions such as hydro water inflows and changes in transmission and generation.

The arrangements for the SPD determination of transmission asset benefits and the allocation of these to market participants were established. This involved rerunning the market model with the target asset removed and processing the “with and without case” data generated in an Access model. The model developed ascribed benefits to four classes of participant, namely NI Loads, NI generators, SI load, and SI generators.

7.2 Cases Modelled

To explore the issues identified in this study a number of cases were modelled. These cases were developed through combinations of the following parameters:

- Transmission Asset subject to SPD benefit determination:
  - Pole 3
  - Pole 2
  - NI transmission line that resulted in a high number of high constraint hours when removed (hypothesised constraint equation)
  - NI transmission line that resulted in a low number of constraint hours when removed (hypothesised constraint equation);
- Hydro water inflow scenarios:
  - Medium
  - Wet
  - Dry;
- SPD Rule - capping total participant benefits at the asset cost each hour:
  - Capped (Benefits Scaling Factor used to ensure total benefits do not exceed asset cost allocated to each hour period)
  - Not capped (Benefits Scaling Factor not used);
- SPD Rule – market participants that are subject to benefit assessment and associated costs:
  - Loads and Generators (current proposal)
  - Generators only (loads excluded);
- SPD Rule – time period the benefit calculation is performed:
  - Hourly (current proposal is half-hourly)
  - Monthly (negative benefits are summed with positive during each month, but negative monthly benefits are set to zero);
- Alternative generation – these cases had generation in the North Island added in the without Pole 2 or Pole 3 cases equal to the foregone capacity (of Pole 2 or Pole 3 respectively). The reason for this was to replace the reduced capacity into the NI associated with Pole 2 or Pole 3 being assumed not developed. This is not presented as a potential SPD rule change, but rather it was done to better represent what the actual "without case" would be. This without case would better align with benefit calculations as would be undertaken in the Investment Test. The cases here were labelled:
  - No alternative generation
  - Alternative generation.

The cases modelled together with case names are shown in Table 2 overleaf.

For each asset the **base** set of assumptions were capped, medium hydro, benefits determined for both loads and generators, no alternative generation, and hourly aggregation.

For ease of reading, cells in bold show changes from the base assumptions, and spare rows in the table are included to separate groups of cases.

Table 2 Cases Modelled

Case Name	Asset	Cap in	Hydro	Benefits	Alt Gen	Aggregation
Pole3 Base	Pole 3	Capped	Medium	Loads and Gens	None	Hourly
Pole2 Base	Pole 2	Capped	Medium	Loads and Gens	None	Hourly
Pole2 Wet	Pole 2	Capped	**Wet**	Loads and Gens	None	Hourly
Pole2 Dry	Pole 2	Capped	**Dry**	Loads and Gens	None	Hourly
Pole2 No Cap	Pole 2	**No cap**	Medium	Loads and Gens	None	Hourly
Pole2 Monthly	Pole 2	Capped	Medium	Loads and Gens	None	**Monthly**
Pole2 Gens No Cap	Pole 2	**No cap**	Medium	**Gens**	None	Hourly
Pole2 Wet Gens No Cap	Pole 2	**No cap**	**Wet**	**Gens**	None	Hourly
Pole2 Alt Gen	Pole 2	Capped	Medium	Loads and Gens	**Yes**	Hourly
Pole2 No Cap Gens, Alt Gen	Pole 2	**No Cap**	Medium	**Gens**	**Yes**	Hourly
NI High Base	NI AC Line	Capped	Medium	Loads and Gens	None	Hourly
NI Low Base	NI AC Line	Capped	Medium	Load and Gens	None	Hourly

7.3 Summary of Modelling Results

A summary of the results is shown in Table 3 and Table 4 below. These tables respectively show:

- The SPD assessed benefit of the named asset ($M) to each of the four participant groups and the annualised cost of the asset;
- The benefit of each participant group as a percentage of the total benefit assessed by the SPD approach.

Table 3 Summary of Modelling Results – Benefits $M

Case	Description*	North Island Generation	North Island Load	South Island Generation	South Island Load	Total Recovery	Asset Cost $m
1	Pole 3		.02		.06	.08	47.90
2	Pole 2	1.84	29.44	15.85	0.39	47.53	47.90
3	Pole 2: Wet	0.01	31.75	16.07	0.04	47.87	47.90
4	Pole 2: Dry	6.37	22.28	11.72	7.17	47.54	47.90
5	Pole 2: No cap	5.66	1734.83	677.76	1.83	2420.08	47.90
6	Pole 2: Monthly aggregation	0.00	33.54	14.35	0.00	47.89	47.89
7	Pole 2: Gens only, no cap	5.66	0.00	677.76	0.00	683.42	47.90
8	Pole 2: Wet, gens only, no cap	0.02	0.00	593.67	0.00	593.70	47.90
9	Pole 2: Alt gen	5.36	22.60	19.35	0.31	47.61	47.90
10	Pole 2: Alt gen, gens only, no cap	45.30	0.00	677.76	0.00	723.06	47.90
11	NI Low Base	0.00	1.89	0.00	0.98	2.88	16.95
12	NI High base	0.00	10.30	0.00	5.33	15.63	16.95

* Description refers to any differences from the base scenario assumptions- medium hydro, capped benefits, both loads and generators benefits, no alternative generation, hourly benefits

Table 4 Summary of Modelling Results – Benefits as a % of total assessed benefits

Case	Description*	North Island Generation	North Island Load	South Island Generation	South Island Load	Total Recovery	Asset Cost # $m
1	Pole 3	0.00%	0.04%	0.12%	0.00%	0.16%	47.90
2	Pole 2	3.84%	61.47%	33.09%	0.82%	99.23%	47.90
3	Pole 2: Wet	0.03%	66.28%	33.56%	0.08%	99.95%	47.90
4	Pole 2: Dry	13.30%	46.51%	24.48%	14.97%	99.26%	47.90
5	Pole 2: No cap	11.82%	3622.11%	1415.07%	3.83%	5052.82%	47.90
6	Pole 2: Monthly aggregation	0.00%	70.04%	29.96%	0.00%	100.00%	47.89
7	Pole 2: Gens only, no cap	11.82%	0.00%	1415.07%	0.00%	1426.88%	47.90
8	Pole 2: Wet, gens only, no cap	0.05%	0.00%	1239.51%	0.00%	1239.56%	47.90
9	Pole 2: Alt gen	11.18%	47.18%	40.40%	0.64%	99.40%	47.90
10	Pole 2: Alt gen, gens only, no cap	94.59%	0.00%	1415.07%	0.00%	1509.65%	47.90
11	NI Low Base	0.00%	11.17%	0.00%	5.80%	16.97%	16.95
12	NI High Base	0.00%	60.74%	0.00%	31.46%	92.21%	16.95

*Description refers to any differences from the base scenario assumptions- medium hydro, capped benefits, both loads and generators benefits, no alternative generation, hourly benefits

The costs shown have been assumed based on an understanding of asset costs of this type.

Further details of the modelling results are presented in Appendix B which shows for each case modelled:

- A graphical display of the weekly asset costs allocated via the SPD approach to the four categories of market participants;
- The distribution of weekly costs recovered via the SPD approach;

Selected results for each of the cases modelled are presented below.

7.4 Pole 3

Pole 3 was modelled with only the base set of assumptions. The counterfactual has Pole 2 in service. The modelling found total benefits of $0.8M against an assumed annual cost of $47.9M.

This was not surprising as the EA Report had foreshadowed that an assessment of Pole 3 that has Pole 2 in the "without" case would be very low. We also note that historically the number of hours that flows on the HVDC line have exceeded the capacity provided by Pole 2 is very low.

The obvious question is the economic basis of the Pole 3 investment decision.[12] This question is beyond the scope of this report other than to add that risks associated with prolonged dry inflow conditions would add to the economics of Pole 3.

7.5 Pole 2

Pole 2 was modelled under a number of different assumptions ranging from hydrological conditions to SPD rule changes. These are presented below.

7.5.1 Pole 2 - Base set of Assumptions

Figure 4 below shows the weekly benefits for the four participant groups over the study year. The particular points of note are as follows:

- The sum of participant benefits is capped at the asset cost for most of the year;
- The split is mostly between SI generators and NI loads. This is because benefits to loads in one island are usually accompanied by negative benefits to generators at that location;
- The emergence of NI generator benefits is due to the seasonal nature of lower SI hydro generation (lower in September – October) resulting in hours where flows are southwards. When this occurs benefits also appear to SI loads. This also results in more hours of negative benefits and the total benefit assigned being below the asset cost.

Table 5 below presents the SPD assessed benefits and the relative percentage allocation of benefits between the four parties. The total recovery of asset cost was 99.23%. The profile of benefits also indicates that the sensitivity of level of asset cost recovery to asset cost is low.

The difference in benefits between Pole 2 and Pole 3 could be considered as due to definition only. Given that both assets provide a similar service, why should commissioning date

[12] Although we note the pole was universally endorsed including by South Island generators during the Electricity Commission's approval process.

determine that one has benefits and the other does not (under the SPD methodology). This raises the question of grandfathering benefits against new assets which is not proposed as part of the TPM methodology.

Figure 4 Case 2: Pole 2

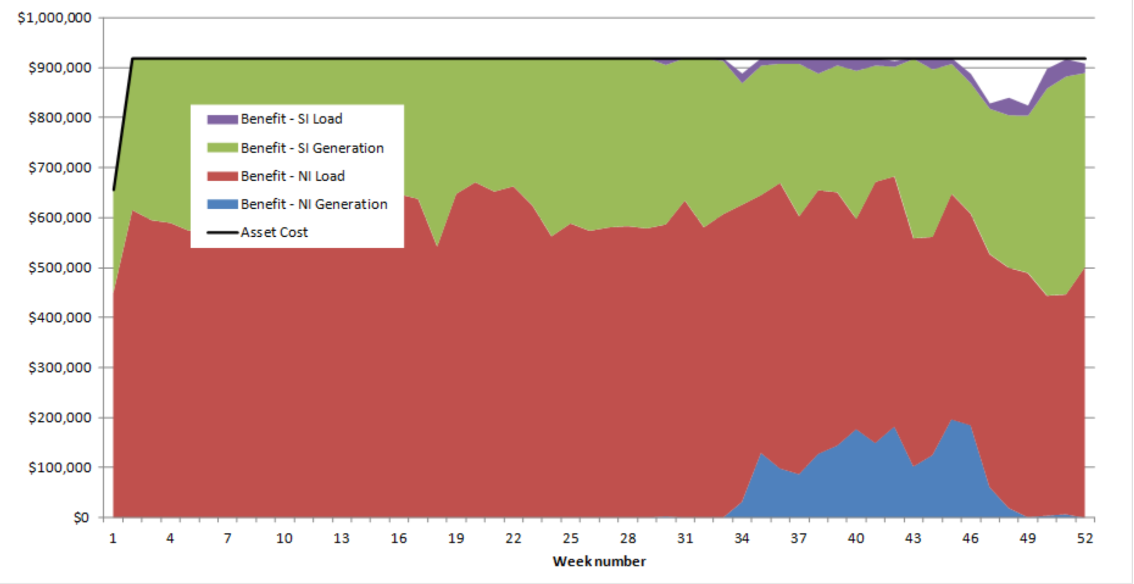


Table 5 Case 2: Pole 2 Benefits by Stakeholder

Benefit	North Island Generation	North Island Load	South Island Generation	South Island Load	Total
$m	1.84	29.44	15.85	0.39	47.53
%	3.9%	62.0%	33.4%	0.8%	100.0%

7.5.2 Pole 2 – No Cap of Benefits

To investigate the impact of removing the cap on total benefits at the asset cost each hour, the case above was rerun with the cap removed. The results are shown in the same format as above in Figure 5 and Table 6 overleaf.

The results indicate that the benefits as assessed by SPD are 48 times the asset cost, and 71.7% of this is ascribed to NI loads. This very large multiple of asset cost illustrates the extreme sensitivity of asset valuation when total wealth transfers based on spot price changes are involved. Although not demonstrated in the modelling, changes in bidding patterns as might result from a change in industry ownership could also significantly impact valuation.

While the actual assessed dollar benefit of NI generation and SI load increased with the removal of capping, their percentage allocation was proportioned down to very low percentages. This would mean they would pay less if these proportions were used to assign costs.

The question may be asked about the benefits of Pole 2 and Pole 3 treated as a single asset. The dynamics of capping means that the benefits of Pole 2 and Pole 3 treated as a single asset would necessarily be less than there individual benefits. This means the benefits of Pole 2 and Pole 3 treated as a single asset would at most be $0.8M greater than that of Pole 2.

Figure 5 **Pole 2: No Cap**

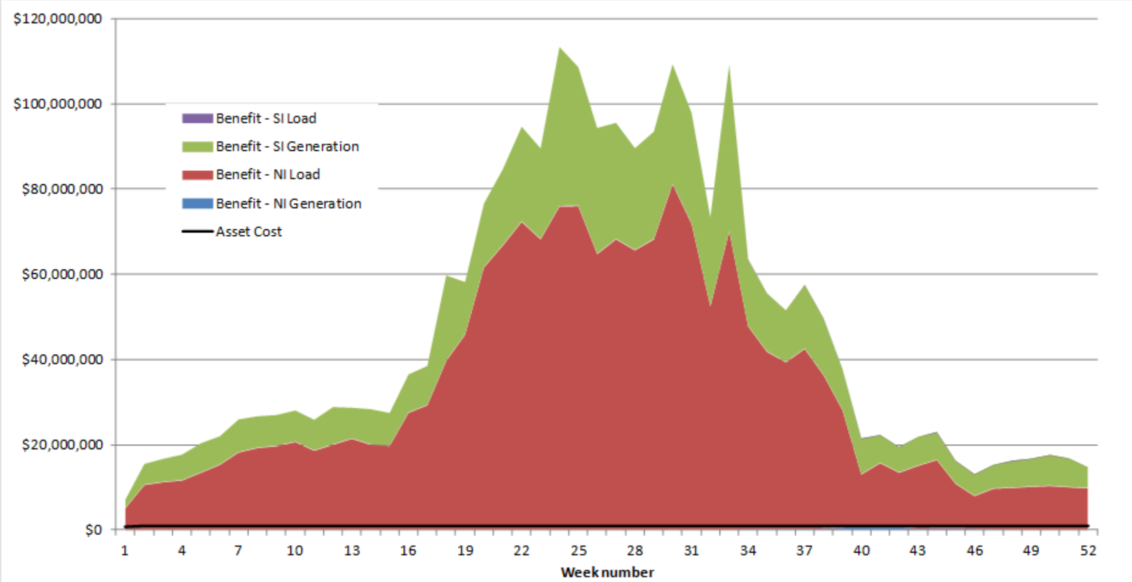


Table 6 **Pole 2, No Cap** **Benefits by Stakeholder**

Benefit	North Island Generation	North Island Load	South Island Generation	South Island Load	Total
$m	5.66	1734.83	677.76	1.83	2420.08
%	0.2%	71.7%	28.0%	0.1%	100.0%

Source: MJA Modelling

7.5.3 Pole 2 - No Capping, Generators Only

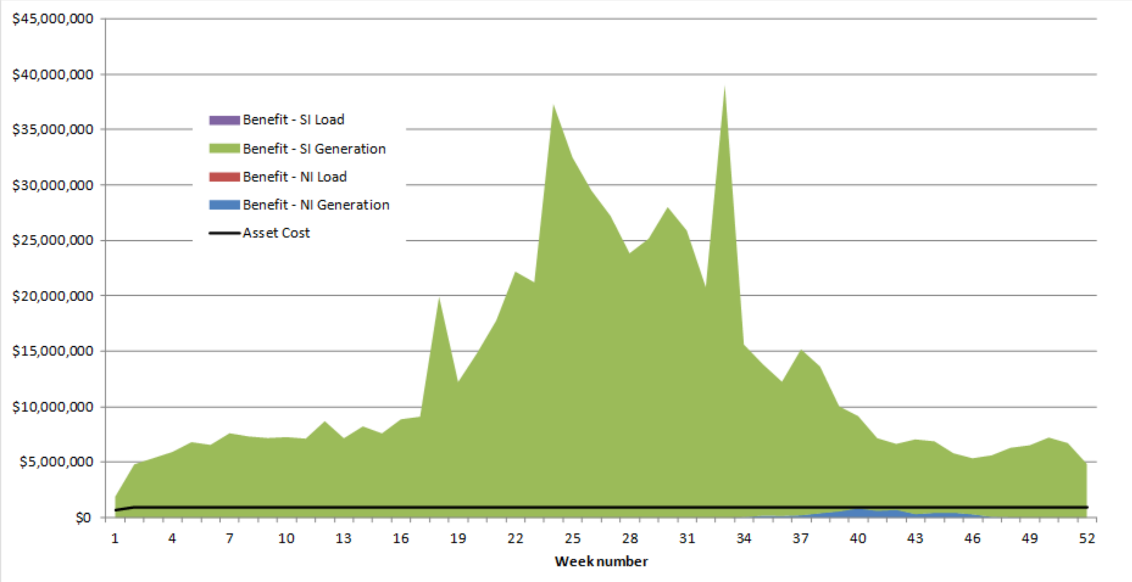
To investigate the impact of restricting benefits to generators and with no capping of benefits each hour at the asset cost, the base above was rerun with generators only being allocated benefits and associated charges. This was naturally the same as the No Cap case above but with the benefits ascribed to loads set to zero.

Given that SI generation has a benefit of $677.76M and NI generation $5.66M, almost all benefits were ascribed to SI generation. The $677M represented a value 13.5 times larger than the annualised asset cost. This illustrates two things:

- As for the previous case, the size and sensitivity of the benefit assessment when total wealth transfers based on spot price changes are involved;
- Based on the benefits assessment approach, generators receive benefits significantly greater than the annualised asset cost of Pole 2.

The graph of weekly generation benefits over the year is shown in Figure 6 below.

Figure 6 **Pole 2: No Capping, Generators Only**



7.5.4 Pole 2 – Monthly Aggregation

The impact of monthly aggregation was examined by summing up SPD benefits over each month and setting monthly benefits less than zero to zero. The summation of hourly benefits during each month included negative hourly benefits. The results of this are shown in Figure 7 and Table 7 below.

Figure 7 **Pole 2 – Monthly Aggregation**

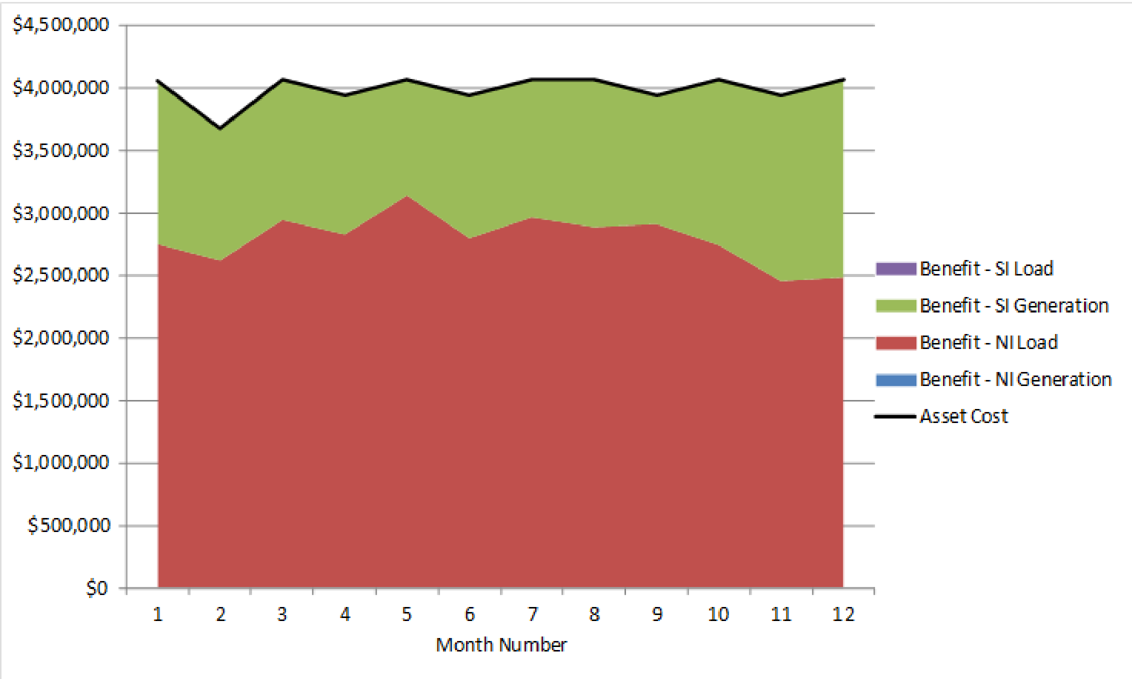


Table 7 Pole 2 – Monthly Aggregation Benefits by Stakeholder

Benefit	North Island Generation	North Island Load	South Island Generation	South Island Load	Total
$m	0.00	33.54	14.35	0.00	47.89
%	0.0%	70.0%	30.0%	0.0%	100.0%

Interestingly the percentage split of benefits is again close to the 70% NI customers and 30% SI loads. With negative hourly benefits included in the monthly summation we observe that:

- 100% of asset costs are recovered;
- The yearly pattern may be more stable and predictable;
- High benefits at times of system stress are recognised;
- SI load and NI generation have no assigned benefits.

The results are also consistent with the EA comment that extending the assessment period reduces the risk of revenue shortfall

7.5.5 Pole 2 – Alternative Generation Included

As previously discussed in this report, the analysis undertaken by an investor assessing private benefits of investing in a transmission asset, or as would be undertaken in the Investment Test, would account for dynamic changes in the market that would result from the investment[13]. For an interconnector such as Pole 2 this would be additional generation in the NI.

To investigate this, a case was run with "Alternative Generation" assumed to be developed in the NI had Pole 2 not been developed. The capacity of this alternative generation was set to maintain the same generator reserve margin in the NI. The results of this model run are shown in Figure 8 and Table 8 below.

Of particular note is that the benefits ascribed to NI loads have decreased and SI generators increased. The increased benefit to NI generators reflects the seasonal nature of SI hydro generation and includes that to the new "alternative generator". The total level of asset cost recovery was 95.4%.

[13] While both a private investor and the Investment Test would account for alternative generation had an asset not been built, the two assessments are very different. An investor would consider the impact to his own financials while the Investment test would consider total system economic costs.

Figure 8 **Pole 2 – Alternative Generation**

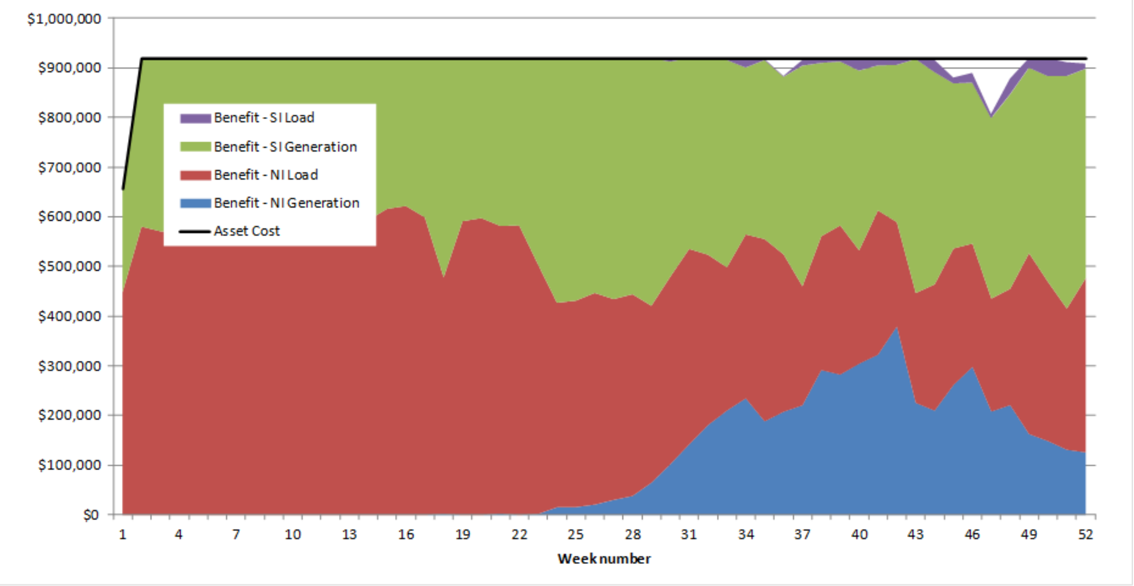


Table 8 **Pole 2 – Alternative Generation** **Benefits by Stakeholder**

Benefit	North Island Generation	North Island Load	South Island Generation	South Island Load	Total
$m	5.36	22.60	19.35	0.31	22.60
%	11.3%	47.5%	40.6%	0.6%	100%

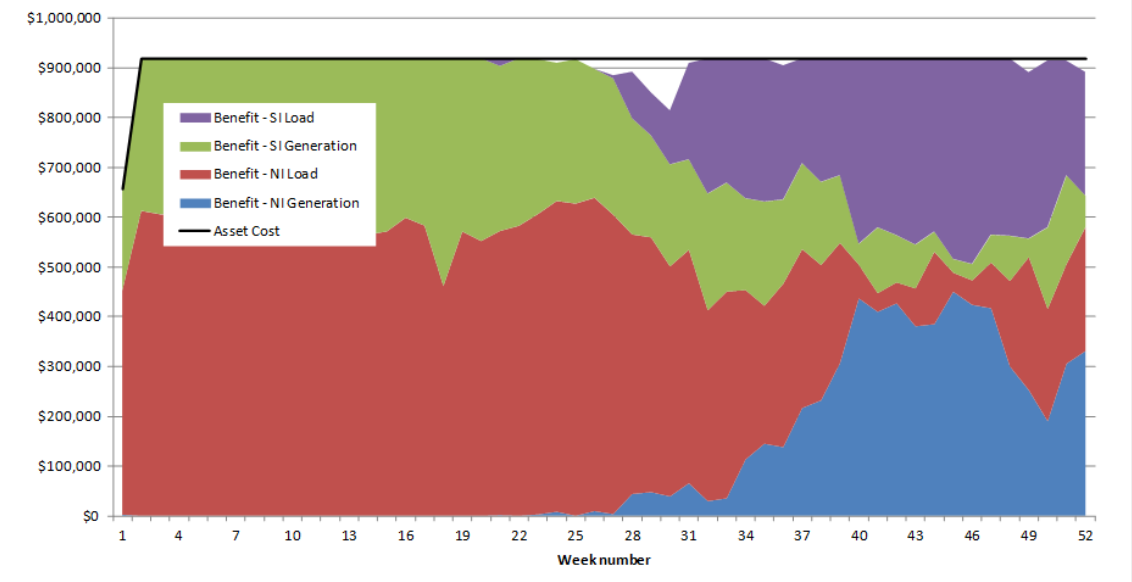
7.5.6 Pole 2 – Varying Hydro Inflow Conditions

To investigate the impact of varying hydrological conditions, the model was run assuming dry and then wet conditions. The outcome for the Dry case is shown in Figure 9 below.

The pattern reflects dry conditions "biting" in the second half of the year as lake levels decrease and flows on the interconnector change direction. If dry conditions were to continue over one or more years then the pattern observed in the later part of the year would expected over the entire year. If this was the case then the cost allocation to NI loads would be less than 10% and the main beneficiaries would be NI generation and SI loads, in roughly equal proportion.

This demonstrates the significant uncertainty that exists in the benefit allocation due to uncertain hydrological conditions and any uncertainty in the strategies employed by the SI generators.

Figure 9 **Pole 2 – Dry Conditions**



7.6 Meshed AC Lines in the North Island

This section presents modelling undertaken to investigate the SPD benefit assessment dynamics of meshed AC[14] lines in the NI. This is particularly relevant given the profile of post 2004 assets in the system.

Because the security constraints imposed by any of the transmission lines in the New Zealand market are not published, the study investigated two assumed NI AC transmission lines. These lines were represented in the modelling through assumed security constraints imposed on the dispatch solution in the "with and without" line in service cases.

The two cases were established assuming the NI AC line addressed different locations in the network and that with each respective line removed the time period of constraint was different:

- The first NI AC line was assumed to impact Maraetai and Waipapa generation and to have a moderate level of constraint hours when the line was assumed not in service. This constraint was named NI Low Constraint;
- The second NI AC line was assumed to impact Huntly, Huntly e3p and Huntly p40 generation and to have a high level of constraint hours when the line was assumed not in service. This constraint was named NI High constraint.

The assumed security constraints for these two lines and the hours the limits were binding (as a percentage of the year) are shown in Table 9 below.

[14] AC meaning alternating current transmission lines.

Table 9 Security Constraint Equations assumed for the NI AC Lines

Case	Constraint Equation	Hours Binding
Low Constraint		
With case	1.0 * Maraetai + 1.0 * Waipapa <= 215MW	6.8%
Without case	1.0 * Maraetai + 1.0 * Waipapa <= 110M	49.85%
High Constraint		
With case	1.0 *Huntly + 1.0 * Huntly e3p + 1.0 * Huntly p40 <= 1200MW	4.55%
Without case	1.0 *Huntly + 1.0 * Huntly e3p + 1.0 * Huntly p40 <= 600MW	93.9%

The following explanation is provided in relation to each of the constraint cases:

- Each constraint represents the limit of power flow on a certain section of the transmission system that the line has been developed to support;
- The "Right Hand Side" (RHS) of each constraint equation represents the power flow limit (through a section of the transmission network);
- The removal of each respective line has the effect of reducing the RHS of the respective constraint (the coefficients would also normally be impacted);
- The "with and without" cases respectively represent the limit with the line in and with the line out.

The results of the modelling are shown in Table 10 below. The graphs of the benefits are contained in the appendix of results.

Table 10 SPD Calculated Benefits for Example NI Transmission Lines

Benefit	North Island Generation	North Island Load	South Island Generation	South Island Load	Total	% Cost Recovered
Low Constraint						
$m	0.0	.28	0.0	.15	0.43	17%
%	0%	65.2%	0%	34.85%	100%	
High Constraint						
$m	0.0	10.3	0.0	5.33	15.63	92%
%	0%	65.9%	0%	34.15%	100%	

The results show that intra-island constraints that mainly result in generation dispatch changes within that island and associated spot price changes result in the demand sector being the net beneficiary.

The generation sector is likely to have small if any net benefits. The reason for this is that within the generation sector there will be some generators that have benefits (through higher dispatch levels and prices) and some generators that have no benefits (through reduced dispatch levels and lower prices).

These observations would be expected to remain valid for constraints in the SI and for actual constraints.

8. SPD Evaluation and Potential Refinements

The previous chapters described the basis and issues with the beneficiaries pay approach, summarised the proposed SPD methodology and the basis of its design, and presented modelling of the proposed SPD charging regime on a number of different assets under different conditions.

This chapter presents a comparative review of the finding presented in the previous chapters including modelling results, for the purpose of deriving conclusions on the application of the proposed SPD charging arrangements and suggesting potential refinements to the approach.

This has been undertaken by first assessing the proposed SPD methodology against developed criteria and then developing potential refinements to the SPD approach.

8.1 Comparison to Evaluation Criteria

8.1.1 Evaluation Criteria

Fundamental to any final decision on the SPD methodology (within the proposed TPM) is a full understanding of its performance in relation to a number of key criteria. From the review of the EA and TPAG reports suitable evaluation criteria have been assessed by MJA to be:

- Economic Efficiency – this relates to the impact the charging arrangements would have to the efficient operation of the market;
- Benefit Reliability - this relates to the reliability of the proposed approach to quantify the benefit that each market participant would receive and that would be the basis of any investment decision;
- Benefit Stability - the stability of assigned benefits from the proposed SPD method;
- Asset Cost Recovery - the level of costs that would be recovered from the proposed approach;
- Wealth Transfer Impacts – the impact of the proposed TPM on consumer costs;
- Market risk – the level of risk introduced to market participants and the ability to manage this risk.

8.1.2 Comparison to Criteria

Economic Efficiency

This relates back to the review presented in Chapter 3 and the analysis of economic efficiency presented in Appendix C of the EA report. Here we note:

- Observation by Biggar (presented in Section 3.2 of this report) that incentivising parties to participate in transmission development decisions does not require benefits and costs to be aligned, but only that parties be allocated enough of the cost to attract their interest;
- There is no evidence that a 50/50 allocation would be any more or less distortive than any other allocation of fixed costs.

There is no evidence that the allocation of costs as developed through the SPD approach would be any more or less efficient that that currently done. However what can be said is that the complexity and uncertainty of the proposed TPM would add risk that would be reflected in costs throughout the supply chain. .

SPD Benefit Reliability

The reliability of the SPD approach to quantify the private benefit that each market participant would assess in an investment decision was discussed in Section 4.4.1. This indicated that the SPD approach was likely to be a poor indicator of private benefits for the following reasons:

- No account is taken of the dynamic response that the market would have had a transmission asset not been developed;
- Assets providing capacity services are likely to be undervalued (such assets have very high value in a small number of half hour periods);
- Cash flows on the spot market are naturally volatile and value assessments are usually undertaken based on expected outcomes and more particularly locking in value through appropriate contracting.

The modelling results supported the above assessment. The modelling showed that:

- The dynamics of the HVDC and intra-regional transmission assets were observed in the modelling to be different. The HVDC showed both generation and load benefits while the NI AC lines showed net benefits to the load sector, reflecting spot price and generation dispatch characteristics. The economics of these two types of assets appear to have different dynamics;
- The benefits derived from the SPD calculation could be far in excess of the associated transmission cost, reflecting the natural volatility of cash flows based on spot price changes. This indicated that the underlying SPD methodology is not a reliable metric of benefits as would be assessed or captured by participants;
- A profile of SPD calculated benefits for the HVDC showed a strong seasonal pattern and a large portion of the assessed benefit was removed via the capping;
- The inclusion of alternative generation reflecting a market response to the asset resulted in a significant change to the SPD benefit assessment. In particular the value to SI generation increased such that the proportion of benefits to SI generators and NI loads were about equal.

SPD Benefit Stability

This refers to the sensitivity of calculated private benefits to the conditions of the market in each hour, and the resulting cost allocation that would be derived on an annual basis.

The modelling illustrated the potential for volatility in assessed benefits and also showed different dynamics for the HVDC and NI AC lines:

- The SPD calculated benefits for the HVDC link were extremely sensitive to hydrological conditions;

  It could be argued that the SPD methodology is recognising how benefits change with conditions such as hydrology, but this can be considered as taking an overly narrow view.

- The NI AC lines showed considerable variability in cost recovery although the ratio of NI to SI load benefits remained about the same. From experience in other power grids the binding hours on particular security constraints within a meshed network lines can vary considerably from one year to the next (due to factors such as nodal load distribution and generator dispatch changes due to changes fuel costs).

Asset Cost Recovery

The modelling showed that only Pole 2 would be expected to have near full cost recovery. Pole 3 would virtually have no benefits assessed through the SPD calculation and the NI AC lines could have benefits ranging from less than 10% to near 100%.

Market Risk

The introduction of an uncertain cost to market participants each year introduces risk to these parties. This risk is potentially substantial given that the level of costs involved is the annualised cost of all the transmission assets in the scheme.

Instruments to manage the risks introduced may be limited. In particular, the ability to set-up hedging arrangements between market participants and a transmission provider would appear very limited, as fixing the cash flow stream to a participant would simply transfer the risk to the transmission provider.

This is a key issue but a fuller consideration is outside the scope of this report.

Consumer Costs

As discussed in Section 2.4, considerations of wealth transfers are considered irrelevant to efficiency, and that improved efficiency should reflect to lower consumer costs.

The analysis and modelling has demonstrated that the proposed TPM will impose higher costs, increased uncertainty and higher risks in the value chain. Also shown is that there is no evidence that the proposed arrangements will improve efficiency, on the contrary the uncertainty would likely be detrimental.

Consequently the proposed TPM would likely increase consumer costs.

8.2 Dynamics of Intra-island assets and the HVDC Link

The analysis and modelling has demonstrated that transmission assets within an island and that connecting the islands are likely to behave differently to the SPD cost allocation methodology. This should be a consideration to any proposed transmission cost allocation methodology.

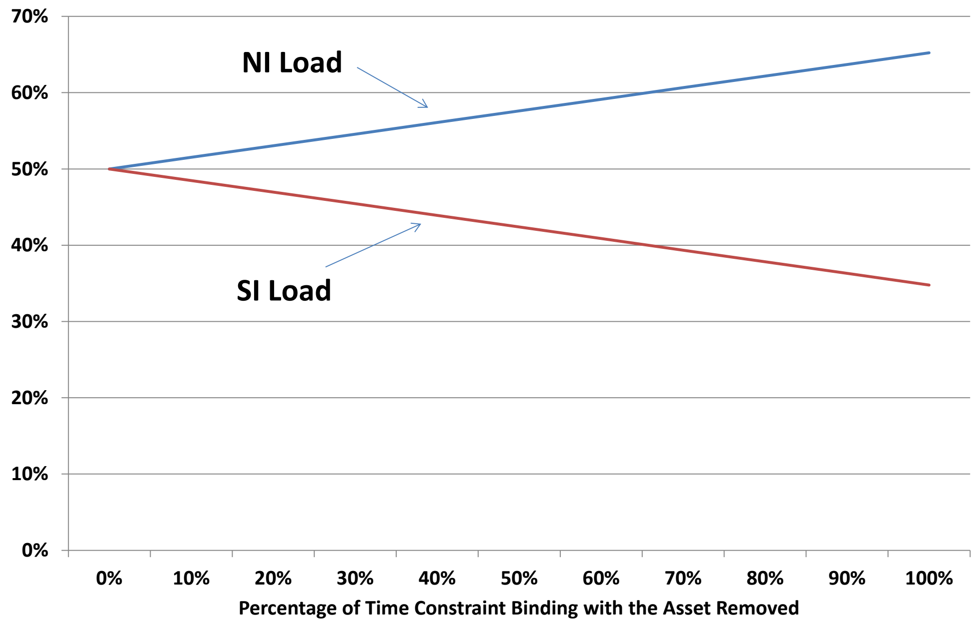
The following subsections illustrate these differences.

8.2.1 Intra-island Transmission Assets

The majority of the transmission assets that are proposed to be subject to the SPD methodology are intra-island assets that have only a minor impact on SI - NI island power flows. For NI AC lines the modelling indicated a split of 2:1 (NI:SI) in benefits and a recovery percentage that could vary significantly.

Based on this finding the charging for NI AC assets under the proposed TPM is illustrated in Figure 10 below. This shows the allocation of costs to NI and SI loads based on the percentage of hours the removal of the asset would result in a binding security constraint. The shown costs are after the application of the 50/50 split of the residual. The figure shows the spread is 50/50 for no binding hours to 65/35 for 100% binding hours (in the "without" case). For most assets the number of binding hours (in the without case) would be expected to be less than 30% of hours, which would imply that the split in costs (of NI / SI loads) would be expected to be between 50/50 and 45/55. This is not a large spread.

Figure 10 SPD Charging for NI AC Assets



8.2.2 HVDC Link

The analysis of modelling of the HVDC link showed that:

- Pole 3 charges would almost entirely be managed through the residual (50/50 split);
- Pole 2 charges would almost entirely be managed through the SPD cost allocation, and that:
  - the split of benefits would be highly dependent on hydrological conditions
  - accounting for the need for additional generation in the NI without Pole 2, the split of benefits would be expected to be roughly the same for NI load and SI generation.

8.3 Potential Refinements to the SPD Approach

The analysis and modelling presented has demonstrated the different dynamics that exists for the intra-island assets and the HVDC link. This suggests that any charging arrangements should consider these two classes of assets separately.

For the purposes of this assessment two types of charging arrangements are considered, these being:

- "Broad Base" equivalent to how the residual allocates costs (50% loads and 50% generation); and

- "SPD or Variant" this being the proposed SPD methodology or variations to this.

Error! Reference source not found. presents these potential options and their applicability to he HVDC link and intra-island assets. Only three of the cells are considered viable.

Table 11 Options for HVDC and Intra-island Assets

Intra-island / HVDC	Broad base	SPD or Variant
Broad base	• Simplest and low risk. • Appropriate treatment of intra-island assets. • Expected benefits for HVDC are near 50/50 split.	Not Suitable.
SPD or Variant	• Appropriate treatment of intra-island assets. • Potential variations possible for HVDC link. Issue of treatment of Pole 2 and Pole 3.	• Value for intra-island assets questionable. • Potential variations possible for HVDC link. Issue of treatment of Pole 2 and Pole 3.

A discussion of each of these cost allocation approaches to intra-island and the HVDC link follows.

8.3.1 Intra-island Assets

Broad Base

This option proposes that all intra-island assets have a cost allocation of 50% loads and 50% generators. The rationale for this option is as follows:

- The likely spread to load and generators of intra-island assets is most likely to be close to 50/50 due to the reasons noted above;
- Places the cost of all intra-island assets on an equal basis and without evidence to the contrary minimises the potential for economic distortion. This assessment of minimum distortion is consistent with the review presented in this report on Appendix C of the EA report;
- Provides stability and minimises the risk to market participants;
- Is the lowest cost option.

SPD or Variation

Application of the SPD methodology to intra-island assets would in all probability result in a change in allocation of less than 5% from that of the residual. Further as noted above, the SPD methodology appears not well suited to intra-island assets for the reasons of benefit reliability, stability and cost recovery. Potential variations to the SPD approach for these assets may not be a significant issue.

8.3.2 HVDC Link

Broad Base

The rationale for a board base for the HVDC link is that the expected allocation of costs via the SPD methodology across both Pole 2 and Pole 3 is likely to be close to 55% NI loads, 43% SI generation and 2% NI generation. This option provides certainty and stability. Without evidence to the contrary, it is also likely to be the least distortive of the identified options

SPD Methodology or Variant

The principle of a dynamic beneficiaries approach has been supported by the EA and also the TPAG. The dynamics of the current proposed SPD arrangements have been reviewed in this report together with some refinements.

There are a number of ways that the SPD methodology could be refined when applied only to the HVDC link. These include:

- Increase the time period of aggregation
  - ensures full cost recovery
  - more fully accounts for times of high benefits
  - will most likely result in increased stability of charging.
- Limit benefits allocation and charging to generators:
  - in the long run NI and SI spot prices should equilibrate at the cost of the marginal generator in each island respectively. This recognises that power flows across the HVDC link will become intra-marginal;
  - the HVDC link would determine composition of generation capacity between the NI and SI;
  - the likely consequence of this is that SI generators would continue paying 90% of the HVDC costs.

9. Appendix A Review of Appendix C of the EA Report

Appendix C is entitled "Assessment of materiality of problems with HVDC charges under the current TPM". Appendix C was concerned with two main issues these being (1) the alignment of HVDC benefits and costs and (2) efficiency impacts of aligning benefits and costs.

This appendix reviews the modelling presented in that appendix that was aimed at quantifying the efficiency benefits that the proposed TPM would deliver in relation to treatment of the HVDC assets.

As an overall comment the appendix was poorly structured and difficult to read which obscured the arguments and analysis presented. The summary below is intended to provide a clear description of the approach used and the reasons why the analysis presented is not considered meaningful.

Analysis of benefits and costs

The approach to determine benefits from the existing HVDC link was to determine a generator development and corresponding spot price profile with the HVDC link assumed in and then assumed out.

The modelling of generation investment and dispatch was done using a least-cost modelling approach (and thus corresponded to what would be done in the Investment Test). The basis of spot prices was a hypothetical price duration curve (PDC) based on generators receiving their long run marginal cost (LRMC). The PDC approach was based on many arbitrary and unsupported assumptions, such as existing generators to receive their LRMC.

From this the change in benefits as measured through change in generator dispatch levels and spot prices was developed. The benefits as developed did not correspond to the benefits as would be assessed under the proposed TPM methodology.

Efficiency Impacts

The assessed efficiency improvement was based on the distortion that allocating $23/kW/yr of sunk HVDC charges to SI (new and existing) generators would have. The counterfactual to this was no HVDC costs allocated to any generators. This assumed that allocating sunk HVDC costs via a beneficiaries pay approach is non-distortive and equivalent to the counterfactual used.

While not said directly, the $30M efficiency benefit aligns with that in the TPAG report, and thus it is concluded that the results presented are in fact those developed for the TPAG report (which was developed prior to the publication of the proposed TPM arrangements).

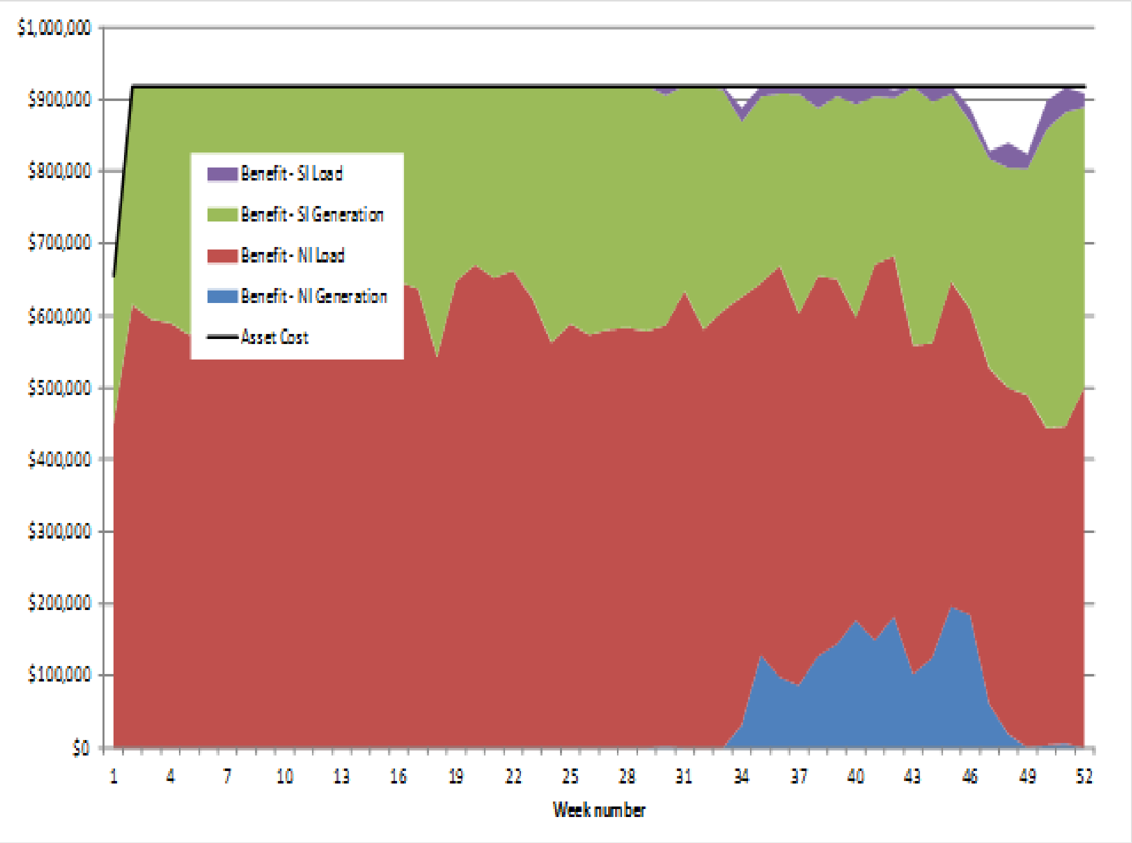
10. Appendix B Modelling Results

This appendix presents the modelling results of the casss modelled. A number of these graphs are also shown in the main body. Shown are:

- Graphs that display the hourly profile through time of asset cost allocation by the four categories of NI load, NI generation, SI load and SI generation;
- For assets that have a low level of cost recovery, the distribution of hourly cost recovery over the year.

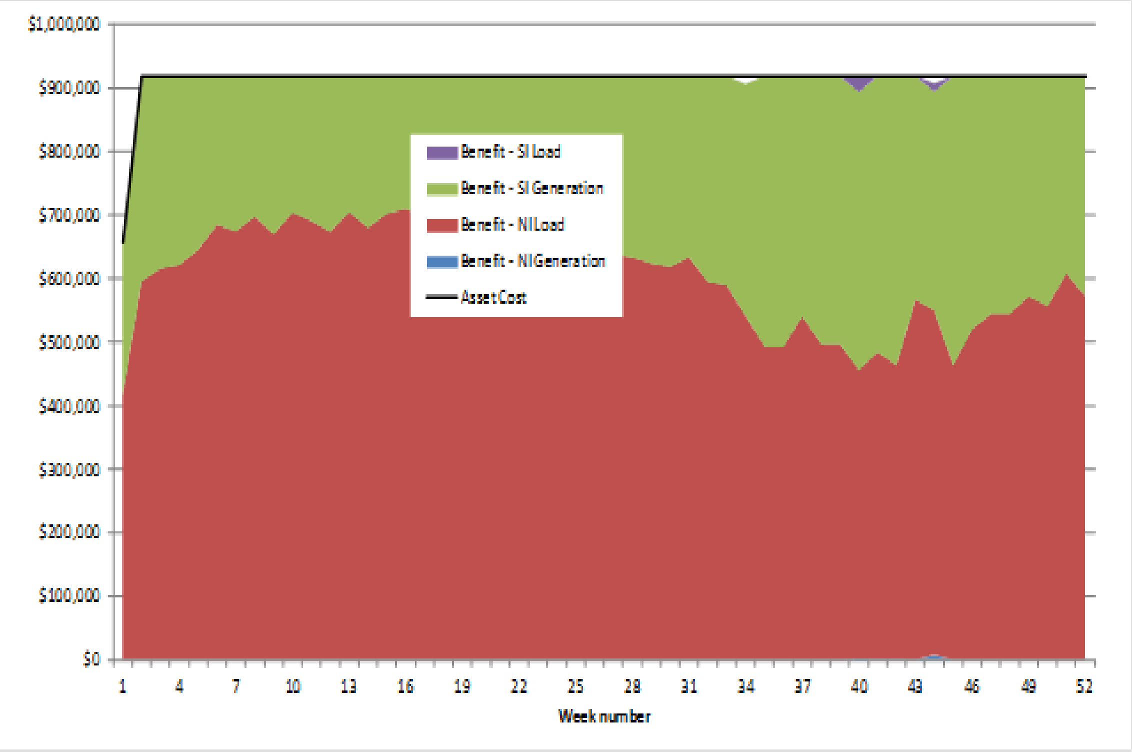
Pole 3 that had almost no cost recovery is not shown.

Pole 2 – Base Scenario

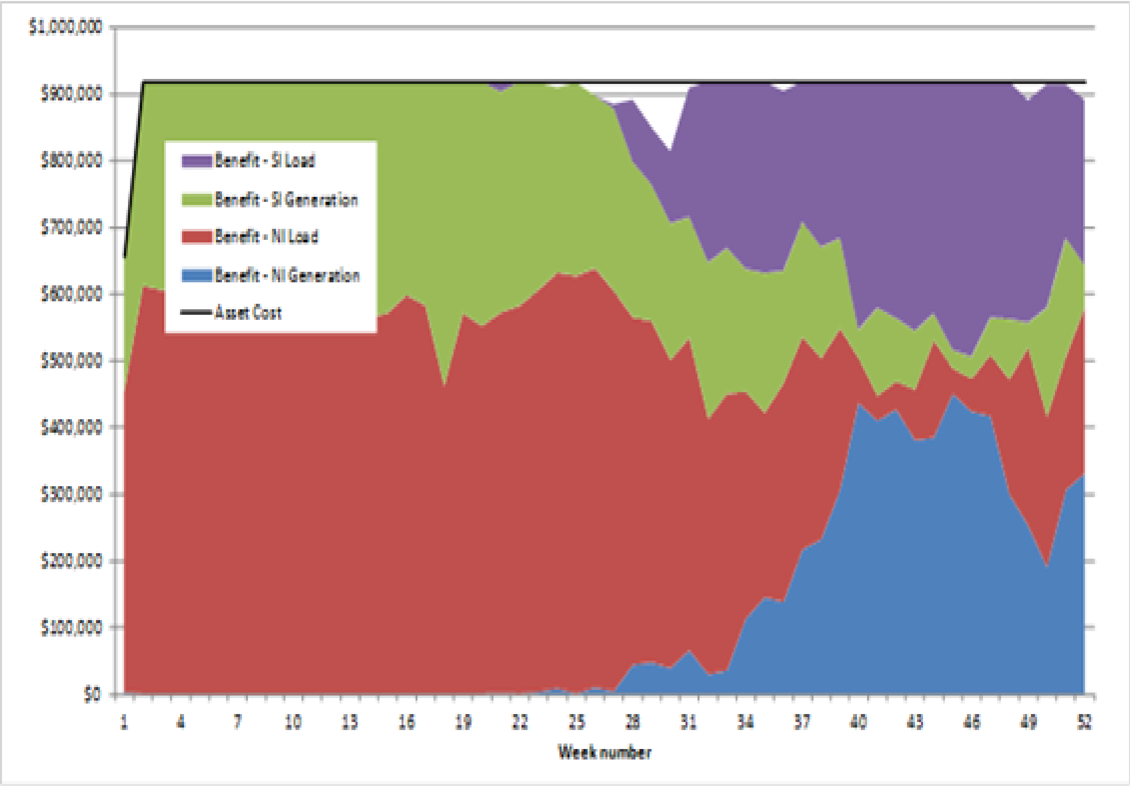


Pole 2 – Wet

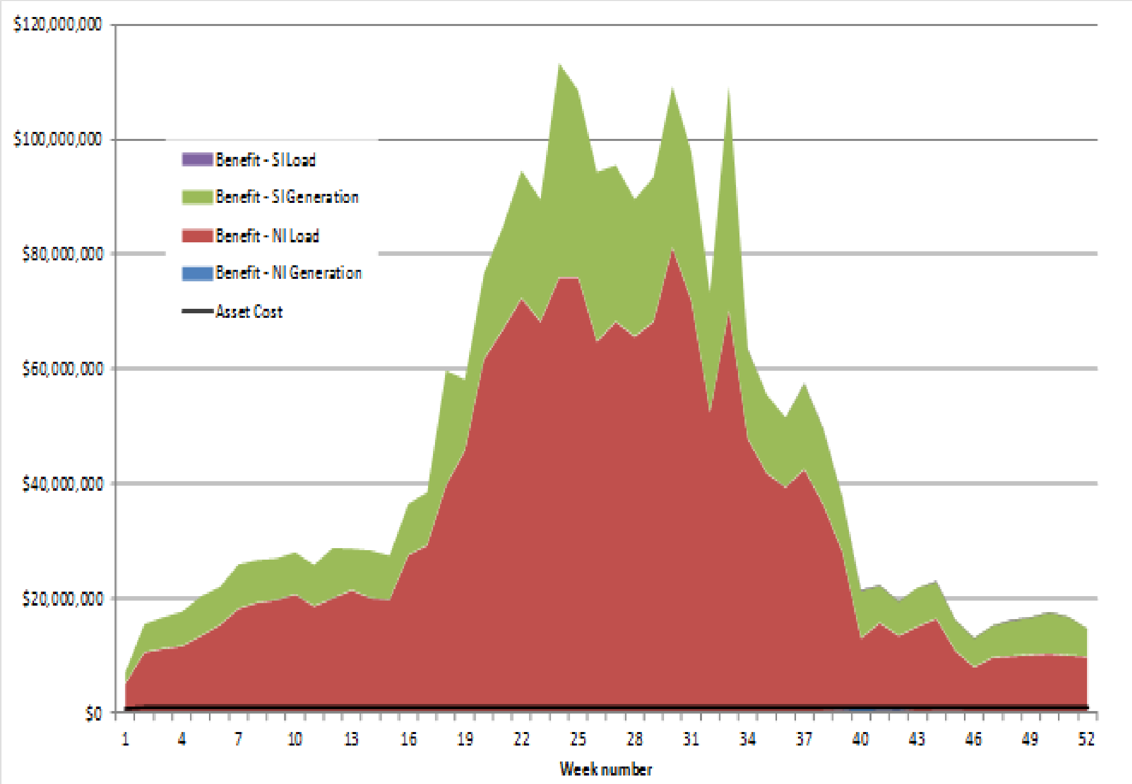
Level of recovery and distribution of charges to stakeholder groups



Pole 2 – Dry

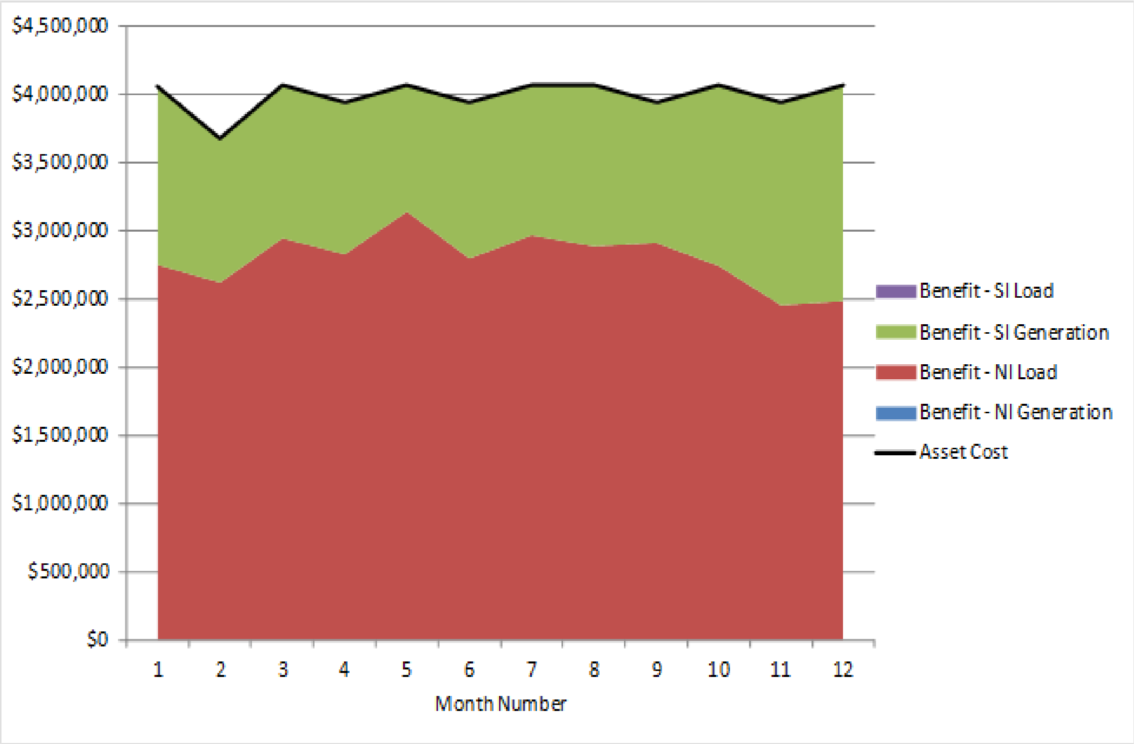


Pole 2 – No cap



Pole 2 – Monthly aggregation

Level of recovery and distribution of charges to stakeholder groups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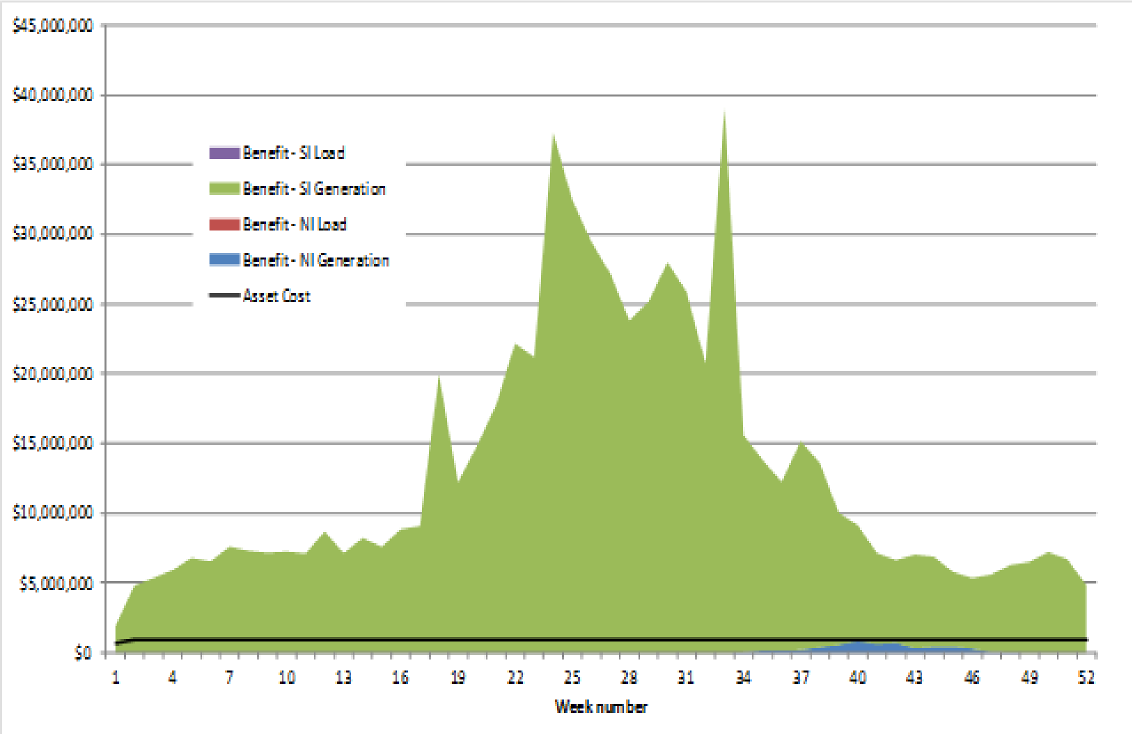
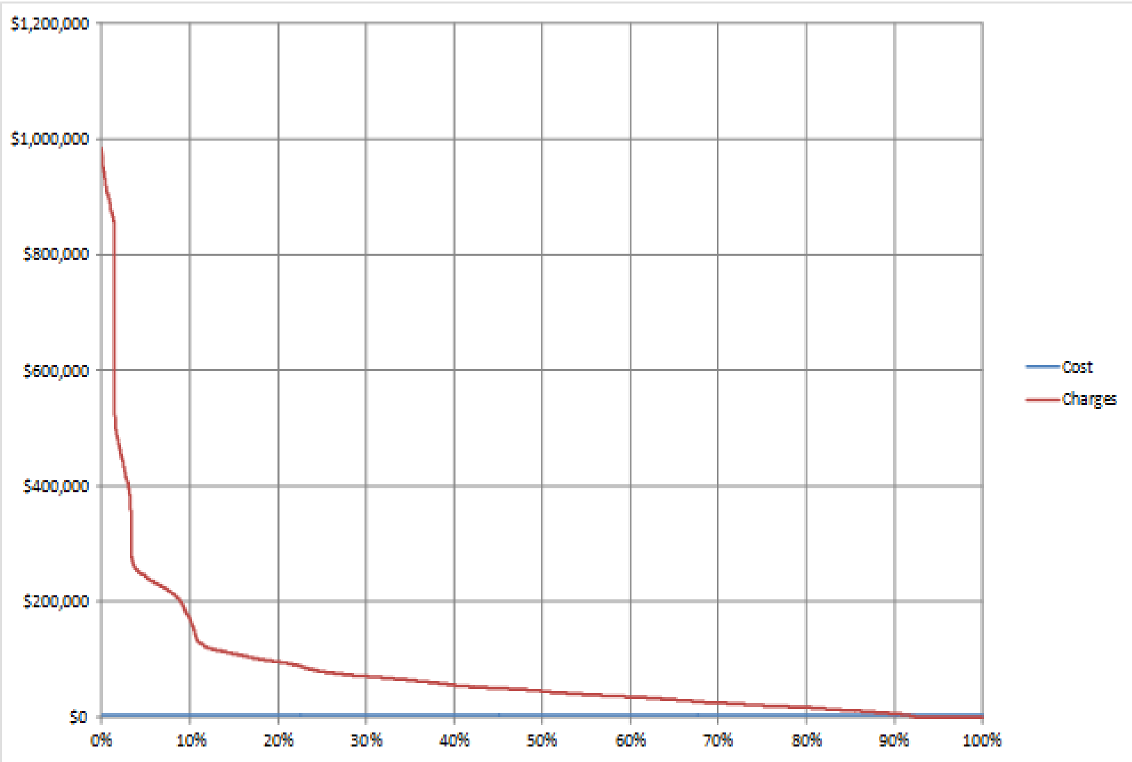
11
12
Month Number
Benefit - SI Load
Benefit - SI Generation
Benefit - NI Load
Benefit - NI Generation
Asset Cost

Pole 2 – Gens only, no cap

Level of recovery and distribution of charges to stakeholder groups

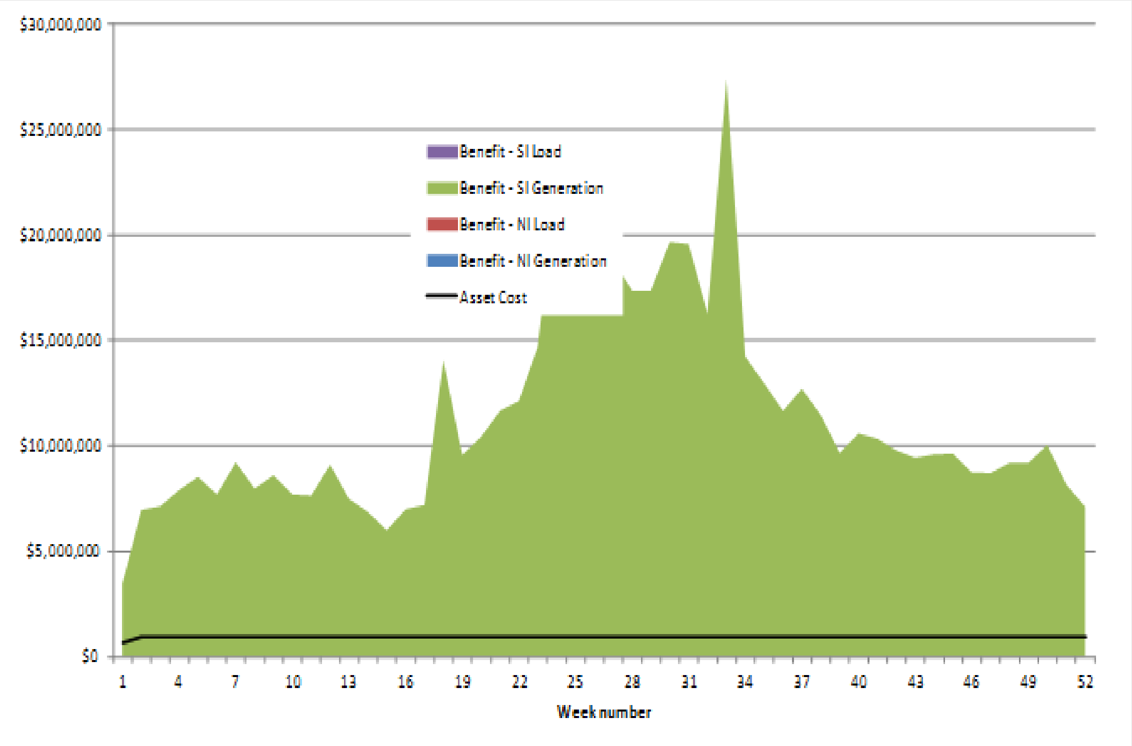


Distribution curve of cost recovery

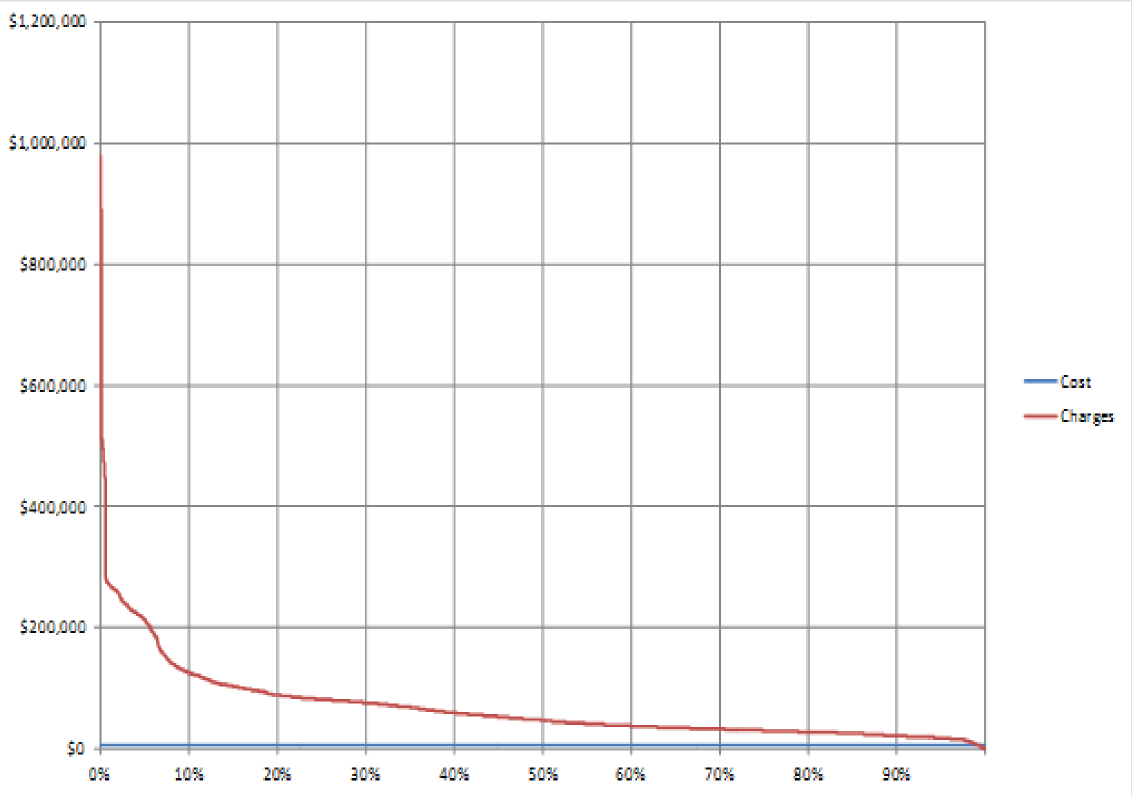


Pole 2 – Wet, gens only, no cap

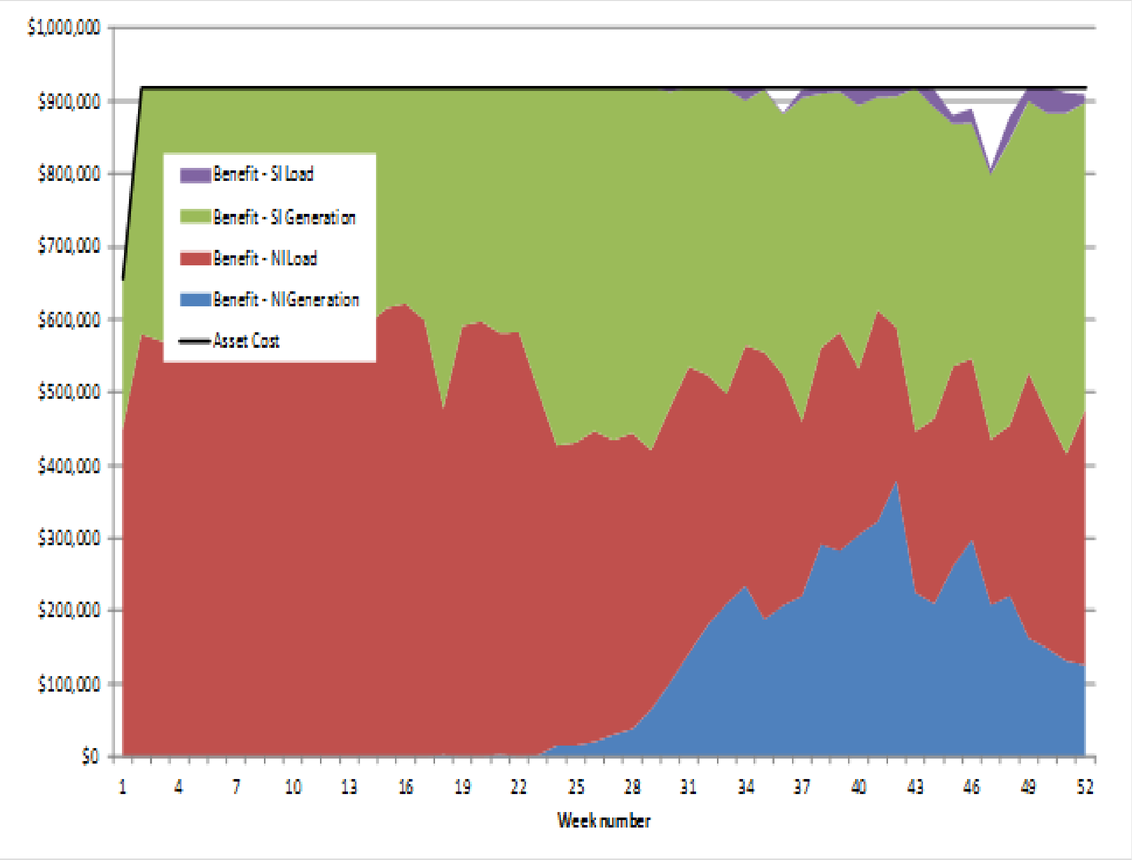
Level of recovery and distribution of charges to stakeholder groups



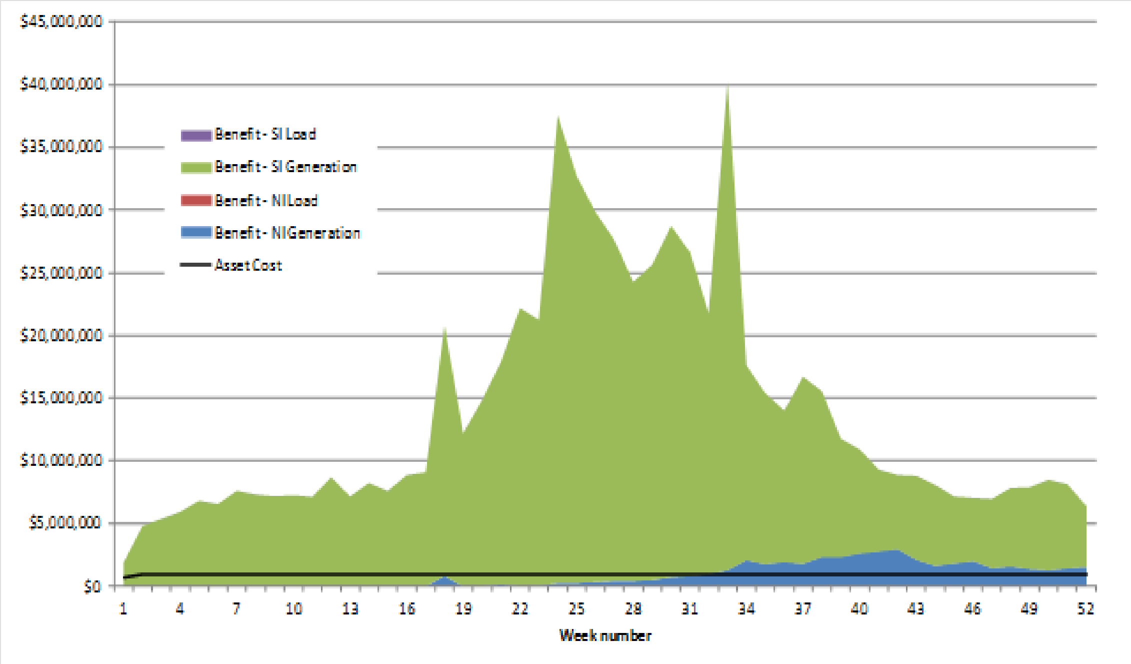
Distribution curve of cost recovery



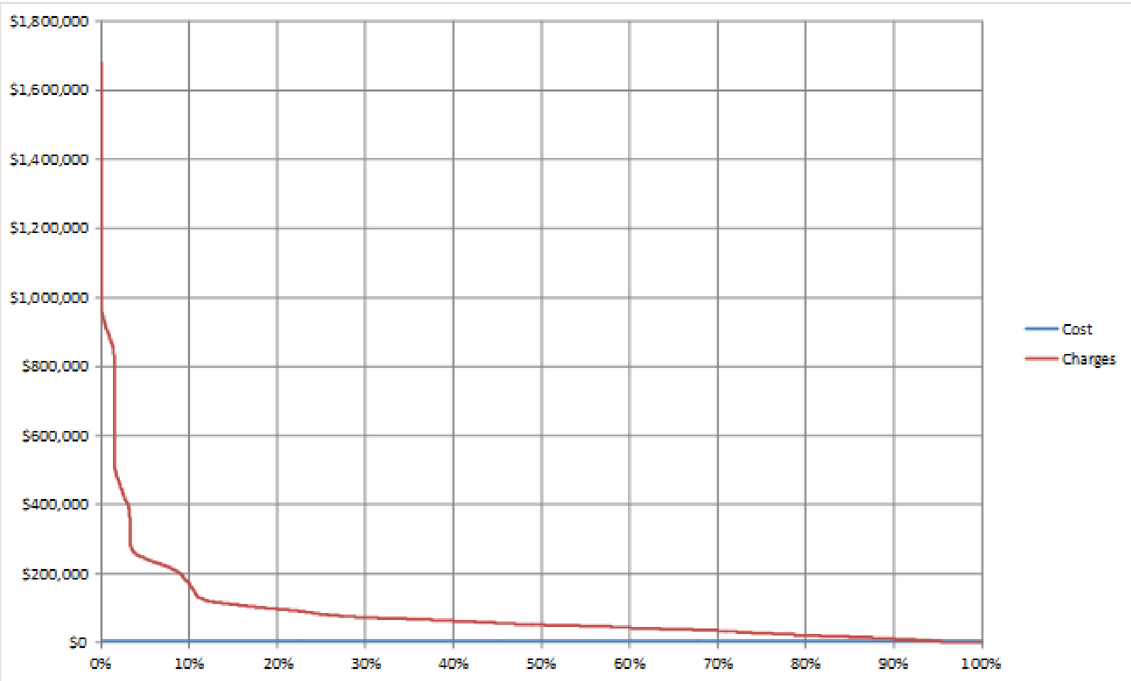
Pole 2 – Alternative Generation



Pole 2 – Alt gen, gens only, no cap

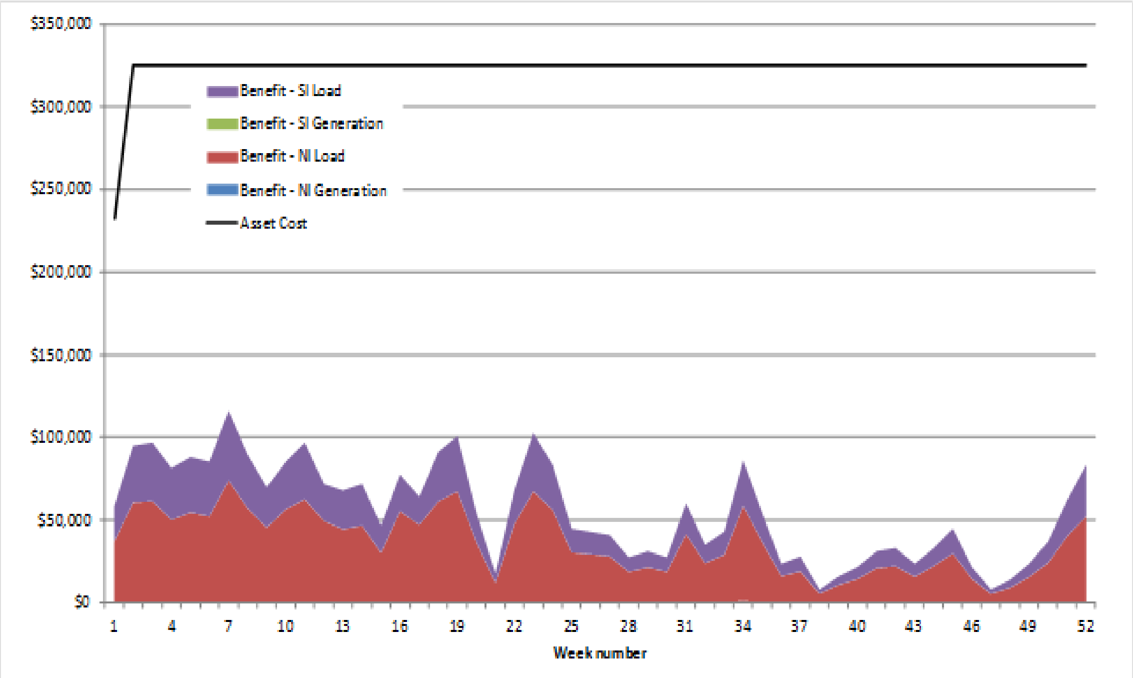


Distribution curve of cost recovery



NI AC line low - Base

Level of recovery and distribution of charges to stakeholder groups



NI AC line - Heavily constrained

Level of recovery and distribution of charges to stakeholder groups