# Inter-Island HVDC Pole 1 Replacement Investigation

# HVDC-TRAN-DEV-01

# GIT Consultation Document – Attachment G

# Further Information – PLEXOS Results

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## Document Revision Control

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| Rev A | PLEXOS Reports<br>Appendix G1 - Dated 29 February 2008<br>Appendix G2 - Dated 20 February 2008<br>Appendix G3 - Dated 3 October 2007 | 2007-02-29 |
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Changes made to this document since its last issue, which affect its scope or sense, are marked in the right margin by a vertical bar (|).

## Appendices

| Ref | Title |
|---|---|
| G1 | Market benefit analysis of short listed HVDC Options |
| G2 | PLEXOS New Zealand Database Assumptions Report |
| G3 | Capacity Expansion Planning for the New Zealand Electricity Market |
| G4 | Competition Benefits of Short-Listed HVDC Options |

 

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# Summary

Transpower employed McLennan Magasanik Associates (MMA) to undertake an independent GIT analysis of the short-listed HVDC Pole 1 replacement options, using PLEXOS, an integrated generation expansion planning and dispatch model. Four reports detailing this analysis and its results are presented within this document:

- a report of the GIT results (Appendix G1)
- a report describing the New Zealand PLEXOS model and assumptions used for the GIT modelling (Appendix G2)
- a background paper on generation expansion modelling and the PLEXOS approach, including a list of the actual model equations (Appendix G3)
- a report on the competition benefits and consumer benefits of replacing Pole 1 versus the Base Case of no replacement (Appendix G4)

The MMA GIT analysis concludes that installing 700 MW converters at Benmore and Haywards have the highest expected net market benefit (ENMB), which is the same as Transpower's conclusion in its own GIT analysis using GEM and SDDP. MMA's calculated ENMB for 700 MW converters is higher than in the Transpower analysis, but the ENMB for 500 MW and 700 MW converters are closer than in Transpower's analysis.

These reports are published for information.

  

# APPENDIX G1 MARKET BENEFIT ANALYSIS OF SHORT-LISTED HVDC OPTIONS

**Report to**

# Transpower

## Market benefit analysis of short-listed HVDC options

29th February 2008

McLennan Magasanik Associates

Ref: J1503 Final Report v1.0

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# ACRONYMS AND GLOSSARY

| Term | Meaning |
|---|---|
| $ | New Zealand dollars |
| 0-700 | The base case augmentation alternative in which the 500 MW Pole 1 link is not replaced |
| 1000-700 | The augmentation alternative in which the 500 MW Pole 1 link is replaced with a 1000 MW link |
| 500-700 | The augmentation alternative in which the 500 MW Pole 1 link is replaced with a 500 MW link |
| 700-700 | The augmentation alternative in which the 500 MW Pole 1 link is replaced with a 700 MW link |
| AC | Alternating current |
| Base case | The 500 MW Pole 1 link between the North Island and the South Island is not replaced |
| CC | Capacity constraint |
| CCS | Carbon capture and storage |
| DC | Direct current |
| DSR | Demand side response |
| FO&M | Fixed operations and maintenance |
| GEM | Generation expansion model |
| GIT | Grid investment test |
| HVDC | High voltage direct current |
| IGCC | Integrated Gasification Combined Cycle |
| KKT | Karush-Kuhn-Tucker conditions |
| LCP | Linear complementarity problem |
| LDC | Load duration curve |
| LT | Long-term |
| MDS | Market development scenarios for generation |
| MIP | Mixed integer program |

| | |
|---|---|
| MMA | McLennan Magasanik Associates |
| MT | Medium-term |
| MW | Megawatt |
| MWh | Megawatt hour |
| N-1 | N is the full capacity of the local assets and minus 1 refers to diminishing the asset capacity by the largest single component |
| N-2 | N is the full capacity of the local assets and minus 2 refers to diminishing the asset capacity by the two largest components |
| NI | North Island |
| NPV | Net present value |
| NZEM | New Zealand Electricity Market |
| O&M | Operations and maintenance |
| OCGT | Open cycle gas turbine |
| OPF | Optimal power flow |
| PLEXOS | Electricity market simulation software |
| RSI | Residual supply index |
| SI | South Island |
| SRMC | Short run marginal cost |
| ST | Short-term |
| USE | Unserved energy |
| VO&M | Variable operation and maintenance |
| WACC | Weighted average cost of capital |

# EXECUTIVE SUMMARY

Transpower is considering replacing the recently retired 540 MW Pole 1 HVDC equipment that links the North Island and the South Island. Transpower has undertaken its own market benefit analysis on a short list of options to identify whether any of those options would meet the requirements of the Grid Investment Test (GIT). McLennan Magasanik Associates (MMA) has been engaged by Transpower to conduct an alternative and independent market benefit analysis of the same short list of possible HVDC Pole 1 replacement alternatives. The use of two different and independent models is intended to test the robustness of any preferred grid investment option to various models.

The short list options are:

- To not replace the retired Pole 1 (0-700)
- To replace Pole 1 with a 500 MW link (500-700)
- To replace Pole 1 with a 700 MW link (700-700)
- To replace Pole 1 with a 1000 MW link (1000-700).

This report compares the costs and benefits of the proposed augmentation options. The non-competition benefits of the four augmentation alternatives have been assessed under high, medium, and low load growth scenarios and five different market development scenarios (MDS). These 60 scenario combinations are consistent with the scenarios used in Transpower's analysis.

MMA conducted its simulations of the New Zealand electricity system using the PLEXOS modelling suite. For each augmentation option, for each market development scenario, and for each demand growth scenario, market benefits were calculated by PLEXOS following a three-staged process.

- First, an optimal capacity expansion plan was obtained, taking into consideration the commercial incentives of private operators and using a drier-than-average hydro year.
- Then, additional capacity (OCGT and DSR) was added, if necessary, to ensure compliance with the dry-year security requirement.
- Finally, detailed market simulations were carried out using the chosen capacity expansion plan, and net market benefits from the market simulations were calculated.

The size of the augmentation with the greatest net market benefit is highly dependent on the capacity expansion plan used, which in turn depends on the particular combination of load growth and market development scenario. The augmentation option yielding the greatest net market benefit alternates between the 500-700 and the 700-700 augmentation alternatives. Considering the weighted average, the preferred option is to replace Pole 1 with a 700-700 augmentation in 2012, with the investment in an undersea cable to follow as required. Assuming the undersea cable is built in 2018, the expected net market benefit of this augmentation alternative is $399 million, compared to $380 million for the 500-700 alternative and $233 million for the 1000-700 alternative. The net market benefits in any given year are highly dependent on the hydro inflow for that year, being especially high in years that are higher-than-average in the South Island and lower-than-average in the North Island.

Because the 700-700 option can be staged, it can offer more flexibility than the 500-700 option in response to the actual capacity expansion plan that eventuates. Our analysis has demonstrated that, by deferring investment in the undersea cable until it is needed, beyond 2018 in most scenarios, an additional $27 million expected net market benefit may be extracted from the 700-700 alternative under medium demand conditions. There appeared to be no significant benefit in delaying the initial timing of the investment post 2012.

# 1 INTRODUCTION

Transpower engaged McLennan Magasanik Associates (MMA) to conduct a market benefit analysis of a short list of HVDC Pole 1 replacement alternatives for the 540 MW link that has been recently retired between the North Island (NI) and the South Island (SI).

MMA's independent analysis is intended to provide further information and to test Transpower's own application of the GIT.

The modelling considered four augmentation alternatives, which were:

- To not replace the retired Pole 1
- To replace it with a 500 MW link
- To replace it with a 700 MW link
- To replace it with a 1000 MW link.

These augmentation alternatives were assessed for combinations of scenarios which covered:

- Demand for electricity in response to economic growth
- Market development scenarios in response to the availability of gas for generation and various carbon charges, encouraging varying levels of renewable generation.

These scenarios are described in the following sections.

# 2 METHODOLOGY AND ASSUMPTIONS

The following sections briefly summarise the major market assumptions and methods used in the simulations. A more detailed review of the methodology and assumptions used in the PLEXOS database can be found in MMA's report titled *PLEXOS New Zealand Database Assumptions Report*, Feb 2008 ("Assumptions Report").

To comply with the Grid Investment Test (GIT), the market benefits of the four augmentation alternatives have been assessed under high, medium and low load growth scenarios and five different market development scenarios (MDS). These scenarios are consistent with the scenarios used in Transpower's analysis, and are also described in this section.

## 2.1 HVDC augmentation alternatives

Until recently, the NI and the SI of New Zealand were connected by a HVDC link consisting of a bipole arrangement. Pole 1 had a capacity of 540 MW and Pole 2 had a capacity of 500 MW. Pole 1 was retired late in 2007 (although Transpower are considering whether it could be recommissioned for limited emergency use,) and cables have now been re-arranged so that Pole 2 can operate at its maximum rating of 700 MW.

Transpower is currently investigating whether Pole 1 should be replaced. To assist with this investigation, the PLEXOS New Zealand database was used to assess the market benefits of various augmentation alternatives in a series of market simulations.

A number of Pole 1 replacement alternatives were considered, including a base case in which the Pole is not replaced. In the base case, the NI and the SI would still be linked by a 700 MW monopole. This alternative was termed the 0-700 alternative, the zero standing for no replacement for Pole 1 and the 700 for the existing 700 MW monopole.

There were three alternatives in which Pole 1 was replaced by a new link with capacities of 500 MW, 700 MW or 1000 MW. In the following sections, these alternatives are termed the 500-700, 700-700, and 1000-700 augmentation alternatives respectively.

### 2.1.1 Staging the augmentations

The 700-700 and 1000-700 alternatives may be considered as staged investment options. There are currently three subsea cables under the Cook Strait, each capable of transferring 500 MW. However, the cables cannot be shared between poles. Hence, one pole would have only one cable, limiting transfer on that pole to 500 MW. Under the 700-700 option, total northward transfer on the HVDC is therefore limited to 1,200 MW. To obtain 1400 MW of northward transfer would require investment in a second cable. Similarly, under the 1000-700 option, total northward transfer on the HVDC is limited to 1,500 MW until a second cable is built.

In reality, there are a number of additional staging options for all three alternatives, progressively increasing the capacity to the limits assumed in this analysis. However, most of these other stages involve relatively minor capital expenditure and for this analysis are assumed to occur at the time of the initial augmentation.

## 2.2 Market development and load growth scenarios

This section describes the market development scenarios and the load growth scenarios used in the modelling. These scenarios are consistent with those used in Transpower's own modelling.

### 2.2.1 Market development scenarios

Five market development scenarios were modelled:

- MDS1: High gas – Gas exploration is successful and therefore new generation is predominantly gas-fired. A low future carbon price is assumed.
- MDS2: Mixed technologies – A low future carbon price is assumed, but the gas price increases as less new gas is found than in MDS1. Coal-fired generation dominates new entry, but a mixture of gas, geothermal, hydro and wind technologies appears as well.
- MDS3: Primarily renewables – There is substantial development of new geothermal and wind resources. A moderate future carbon price is assumed.
- MDS4: SI surplus – This scenario is similar to MDS3, coupled with a progressive phase-out of the Tiwai Point smelter load between 2014 and 2019. A moderate future carbon price is assumed.
- MDS5: 90% Renewables – This scenario is similar to MDS3 above, but with the additional requirement that 90% of electricity generation is from renewable sources under average hydro-year conditions from 2025 onwards. Two units at Huntly Power Station are decommissioned in 2017, with the other two units shifting to dry-year reserve status in 2013 and 2015.

### 2.2.2 Demand growth scenarios

Three demand scenarios were used for the modelling, based on high, medium and low economic growth scenarios. The demand growth forecasts were identical to those underlying the generation expansion model (GEM) modelling. It should be noted that these forecasts only provided a single demand growth rate, and therefore a key assumption underlying the demand forecast formulated by MMA is that both the energy and the peak demand for each supply point, including AC transmission losses, grow at the same rate.

Table 5.1 in the Assumptions report summarises the average growth rates provided by Transpower at the zonal level over the 39 year modelling horizon for the three demand scenarios.

### 2.2.3 Combinations of market development and load growth scenarios

Table 2-1 shows the combinations of market development and load growth scenarios, and gives the probability of occurrence assigned to each combination.

**Table 2-1 Probabilities assigned to each combination of scenarios**

| | | Load growth scenario | | |
|---|---|---|---|---|
| | **MDS probability** | **High** | **Medium** | **Low** |
| **Load probability** | | 15% | 70% | 15% |
| **MDS1** | 20% | 3% | 14% | 3% |
| **MDS2** | 10% | 1.5% | 7% | 1.5% |
| **MDS3** | 15% | 2.3% | 10.5% | 2.3% |
| **MDS4** | 5% | 0.8% | 3.5% | 0.8% |
| **MDS5** | 50% | 7.5% | 35% | 7.5% |

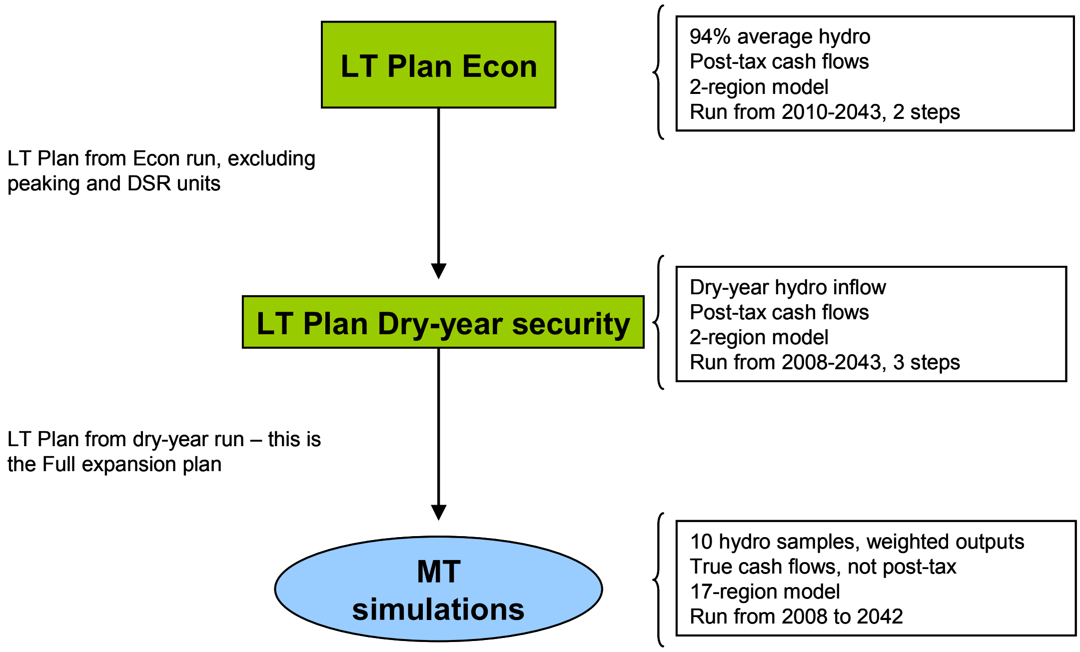
## 2.3 Methodology

For each scenario modelled, the determination of the net market benefit was a four phase process:

1. Determine the optimal capacity expansion plan, taking into consideration the commercial incentives of private operators.
2. Add additional capacity, if necessary, to ensure the dry-year security requirement is satisfied.
3. Undertake detailed market simulations using the chosen capacity expansion plan.
4. Calculate the net market benefits from the market simulations.

The first three steps in the process are modelled using the PLEXOS market simulation software, while calculation of net market benefits was undertaken using an Excel model. Figure 2-1 shows an overview of the simulation process.

**Figure 2-1 Diagram of the simulation process**




### 2.3.1 LT Plan

The LT Plan Econ module determined a capacity expansion plan based on a single hydro sample. This hydro sample was drier than average in an attempt to better capture the skewness of the underlying price distribution, which would impact on both generation and transmission investment decisions. New hydro generation projects were also assumed to have drier than average inflows, and were modelled by constraining annual production.

In order to capture some of the commercial incentives, post-tax cash flows were used and the tax impacts of depreciation were accounted for. A real post-tax weighted average cost of capital (WACC) of 8% was used to annualise the capital costs of generation projects, and a social discount rate of 7% was used to determine the net present value (NPV) of total system costs.

Transpower's HVDC charge is imposed on new SI generation projects. The allocation of costs to new entrants is based on assumed company ownership, and the company's existing market share of SI generation capacity.

PLEXOS uses a mixed integer program (MIP) to determine the optimal capacity expansion plan, with new generation projects selected to minimise total system costs. To manage the size of the MIP, monthly load duration curves were used with five load blocks modelled per month. Due to the number of years modelled, the number of load blocks used, and the number of annual hydro energy constrained units, solving all thirty-four years in one MIP proved intractable. Consequently, the capacity expansion plan was determined using two steps of 17 years, with the costs in the last year treated to perpetuity. The length of a single step was sufficient to account for any changes in carbon price or fuel price over the planning horizon. However, given that the capacity expansion plan was determined over two discrete steps, it is unlikely that the optimal expansion plan would be the same as for a model which solves in a single step (such as GEM).

The size of the MIP was also controlled by modelling the NZ system as only two regions: the NI and the SI. Moreover, most investment decisions were linearised, with only the large thermal units remaining integerised over the entire horizon. It was important to keep these decisions integer, since any decision to build a large thermal unit would have an impact on the amount of instantaneous reserve that would also need to be carried on the system. The impact of instantaneous reserve requirements was modelled in PLEXOS' LT Plan.

Capacity constraints were imposed on the MIP to ensure that there was sufficient capacity to supply the prudent peak load in the event that either the largest unit or the largest HVDC pole was out of service.

### 2.3.2 LT Plan – dry-year security

The NZ market has a dry-year security requirement that all loads should be supplied even in the event of a one-in-sixty-year drought. It is assumed that, if there was not sufficient capacity available to meet this security requirement, the Electricity Commission would secure either demand-side response (DSR) measures or peaking generation capacity to cover the shortfall. Once committed, this additional capacity would be available to compete in the market in all future years.

To model this dry-year security requirement, a second LT Plan is run using the second driest hydro year on record (1974). The new generation projects determined in the first LT Plan are assumed to be committed, but additional peaking or DSR options may be built. This LT Plan is run in three steps of twelve years, using eight load blocks per month, to better assess the likely capacity factors of the DSR or peaking generation options.

### 2.3.3 MT simulations

Having determined a capacity expansion plan, more detailed market simulations are undertaken within PLEXOS. A 17-region network topography is used, ten different hydro samples are simulated and 17 load duration curve blocks are used per month. The hydro samples used are discussed in more detail in Section 3.1.3.

Generation costs and pricing outcomes are important in these simulations, so the true pre-tax generation costs are used. Internally, PLEXOS formulates bids based on the short-run marginal cost of generators, and generators are dispatched according to these bids, subject to operating constraints and generation profiles assumed. Hydro generators are energy constrained, and the water value is internally calculated based on the shadow price of the energy constraint.

#### 2.3.4 Assessment of market benefits

To evaluate the economic benefits of the Pole 1 investment alternatives, a number of key measures are compared against the base case including:

- Benefits of savings in fuel consumption
- Benefits of reductions in voluntary or involuntary load shedding, based on an assumed $/MWh value of customer reliability of $20,000/MWh[1]
- Benefits in capital deferrals caused through deferral of new entry plant[2]
- Benefits of cost savings arising from changing the mix of new entrants required
- Benefits of reduction in transmission losses across the HVDC link
- Benefits of reductions in ancillary services.

These market benefits are calculated as the difference between the total system cost of the augmentation alternative and the costs associated with not building a replacement line. Total system costs for each scenario and for each hydro sample are determined by extracting capital cost, fixed and variable operating and maintenance costs, fuel cost, and unserved energy figures from the MT simulations.

For the purpose of calculating economic costs and benefits for the GIT, the capital costs of new generation projects are annualised using a 7% discount rate, as advised by Transpower.

Furthermore, emission cost comparisons are included in determination of market benefits. Emission costs are not often included directly in cost benefit analysis as the carbon price is considered a transfer of wealth, similar to a tax. Rather, the impact of any emission impost is reflected through increases in capital costs and operating costs. For this analysis, it is our understanding that $CO_2e$ is considered a limited resource with an associated cost equal to the carbon price, and hence is to be included in the GIT analysis.

The full AC network is not represented. Instead, major congestion areas are represented via key interconnectors between a 17-region network. Key AC network upgrades provided by Transpower are assumed to occur under all scenarios so there are no variations in the AC transmission investment resulting from different capacity expansion plans. Moreover, the load projections provided by Transpower included AC

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[1] Sensitivity of benefits to this assumed value of customer reliability has not been tested in this analysis as it is understood that this sensitivity has been assessed in Transpower's own analysis.

[2] Benefits from deferral of new transmission investment in the AC network have not been included in this analysis, but are included in Transpower's analysis.

losses, and are therefore assumed to remain static irrespective of the scenario being simulated.

Due to these AC network modelling limitations, the following measures are not included in the calculation of economic benefits:

- Benefits in capital deferrals caused through deferral of new AC transmission investment
- Benefits of reduction in AC transmission losses.

Market costs are calculated as the difference between the investment costs and fixed costs of the augmentation alternative, and the corresponding costs associated with not building the line (0-700). The capital expenditure assumed for each alternative, and the streaming of this expenditure, is summarised in Table A- 1 of Appendix A.

## 2.4 Optimal timing and staging of alternatives

The market benefit analysis has been conducted assuming that any Pole 1 replacement is built in 2012. For the 700-700 and 1000-700 alternatives, an additional undersea cable is assumed to be built in 2018 to allow the link to reach its full capacity potential. These timing assumptions are consistent with the assessment of annual HVDC revenue requirements provided by Transpower.

Under some market development scenarios, there may be benefit in deferring investment in the undersea cable beyond 2018. Therefore, for the preferred alternative, the optimal staging of the undersea cable was determined by sequentially delaying the investment, year by year, until the net market benefits decline two years in a row.

In determining the staging of the undersea cable, no further capacity expansion planning analysis was undertaken. Consequently, the deferral of the cable was not permitted beyond any period where significant differences in the capacity expansion plan were detected between the 500-700 and 700-700 links. Doing so might cause the capacity constraint to be violated.

The optimal timing of the initial Pole 1 replacement was also reviewed using a similar process to see whether there would be any benefit in delaying this investment.

## 2.5 Revenue adequacy

The capacity expansion plans developed for this analysis assumed that the capacity reserve margin in the NI must be sufficient to cover the loss of either the largest NI generator or the largest HVDC pole. Capacity constraints were imposed on the system to ensure that there was sufficient generation capacity built in the NI to cover these contingencies.

Concerns have been expressed that, if such a constraint were imposed on the system, this could result in an over-supply of capacity. In such a case, the revenue received by incumbent and new generators may not be adequate to cover all fixed and variable costs.

This concern would be valid if the capacity factors of incumbents and new thermal generators indicated that the units were not operating within a range expected for that technology. For example, if the capacity factor for a plant that was expected to operate in base-load mode was very low, then it is unlikely that the pool revenue received from this unit would be sufficient to cover the high capital costs typically associated with base-load generation. As part of this analysis, we have therefore reviewed the capacity factors of generators to ensure that there are no indications of probable revenue inadequacy.

## 2.6 National reserve market

PLEXOS market simulations co-optimise the energy and reserve markets in NZ, assuming one instantaneous reserve market in each island. It has been suggested that investment in a larger link may create the opportunity to develop a national reserve market, increasing the benefits of this investment.

To assess the magnitude of these additional benefits, PLEXOS market simulations were also undertaken for the 700-700 and 1000-700 alternatives, assuming that a national reserve market was formed. For these simulations, total reserve provision by SI generators was limited to the spare capacity available on the HVDC links. This ensured that if the largest generator in the NI tripped, the HVDC links could carry the additional load provided by SI generators in response to this outage event.

# 3 NON-COMPETITION BENEFITS

## 3.1 Preferred augmentation

The preferred replacement alternative is the alternative that yielded the greatest expected net market benefit, which is defined in Schedule F of the Grid Investment Test (GIT) as:

> *"the probability-weighted average of the net market benefit for each of the market development scenarios developed for the future with the proposed investment or alternative project."*

Based on this definition, our analysis indicates that the 700-700 augmentation is the preferred replacement of HVDC Pole 1, although there is little difference between the 500-700 and 700-700 alternatives. Table 3-1 shows the expected net market benefit for each of the augmentation alternatives.

**Table 3-1 Expected net market benefit of each alternative ($M)**

| | 500-700 | 700-700 | 1000-700 |
|---|---|---|---|
| NPV of net market benefits ($M) | 380 | 399 | 233 |

The expected net market benefit reported in Table 3-1 is derived assuming that the line is replaced in 2012 and, for 700-700 and 1000-700 alternatives, the undersea cable is built in 2018. This is consistent with Transpower's own modelling and the HVDC revenue charges used. Optimising the staging of the undersea cable will further increase the market benefit of the 700-700 and 1000-700 alternatives. For the preferred 700-700 augmentation alternative, the value of staging is discussed in Section 2.4.

Net market benefits for individual scenarios are presented in Appendix B.

There are predominantly two sources of non-competition market benefits associated with Pole 1 replacement:

- Market benefits associated with the ability to use the incumbent SI resources more efficiently
- Market benefits resulting from building more SI generation relative to the base case where the Pole is not replaced.

The majority of the benefits arise from increasing the new capacity that is built in the SI. For individual scenarios, the preference for one sized link over another depends on largely on the differential in capacity built in the SI. As discussed in the next sections, there is not always a one-to-one relationship between increases in the capacity of the link and increases in SI capacity built. Several factors influence the choice whether to build in the NI or the SI including, but not limited to the capacity of the HVDC link. Other factors include:

- The relative cost of SI capacity compared to the incremental new entrant in the NI, which varies over time and with different load assumptions
- Capacity constraints that may force capacity in the NI rather than the SI
- Addition of large thermal units which may result in over-supply of a particular region for a short period of time.

The interplay of these factors means that there is no guarantee that additional export capacity will be exactly matched by additional new entry in the SI. For example, in one scenario, with the 500-700 option being considered, a large thermal unit was built in the NI to satisfy one of the capacity constraints. The decision to build this unit was an integer decision that resulted in surplus capacity in the NI for several years. Because the capacity constraint was not binding for several years after this, small amounts of SI capacity were built as required. In contrast, under the 700-700 alternative, the decision to build the NI thermal generator was not made. However, the NI capacity constraint was binding in the future years and so increments of NI wind were built rather than SI capacity. This resulted in several years where there was actually more capacity built in the SI under the 500-700 alternative than under the 700-700 alternative.

While this expansion plan may in fact be commercially optimal, based on the drier than average inflow sequence used, the plan may not be optimising the use of the additional export capacity. Market simulations have demonstrated that the benefits of additional HVDC capacity are larger during wet years than during dry years. Therefore, once run through the market simulations using average hydro inflows, the net market benefits from the augmentation alternative with more SI hydro generation may be greater.

This demonstrates that the benefit of additional HVDC capacity, above 500 MW, is dependent on the capacity expansion plan and the set of potential projects identified.

This also highlights additional value that may be assigned to the 700-700 alternative. There is more flexibility available under the 700-700 option to respond to variations in the capacity expansion that actually eventuates. Investment in the undersea cable can be deferred if it becomes evident that it is not needed as early as first anticipated. This flexibility is not available under the 500-700 option.

### 3.1.1 Sensitivity to demand growth

The net market benefit of replacing Pole 1 increases as demand growth increases. Figure 3-1 indicates that under high demand growth, the expected net market benefit (weighted across all MDS) is approximately $300 million greater than the expected net market benefit under medium demand growth conditions. Conversely, under low demand growth, the expected net market benefit is $40 million lower on average.

There are a finite number of potential projects assumed to be available in each region. Without the link, under high demand growth conditions, it is necessary to build more costly NI plant towards the top end of the supply cost-curve. Under low demand conditions, the cost differential between incremental SI and NI projects is less pronounced and therefore the benefits of replacing Pole 1 are smaller.

**Figure 3-1 Expected net market benefit by demand scenario ($M)**

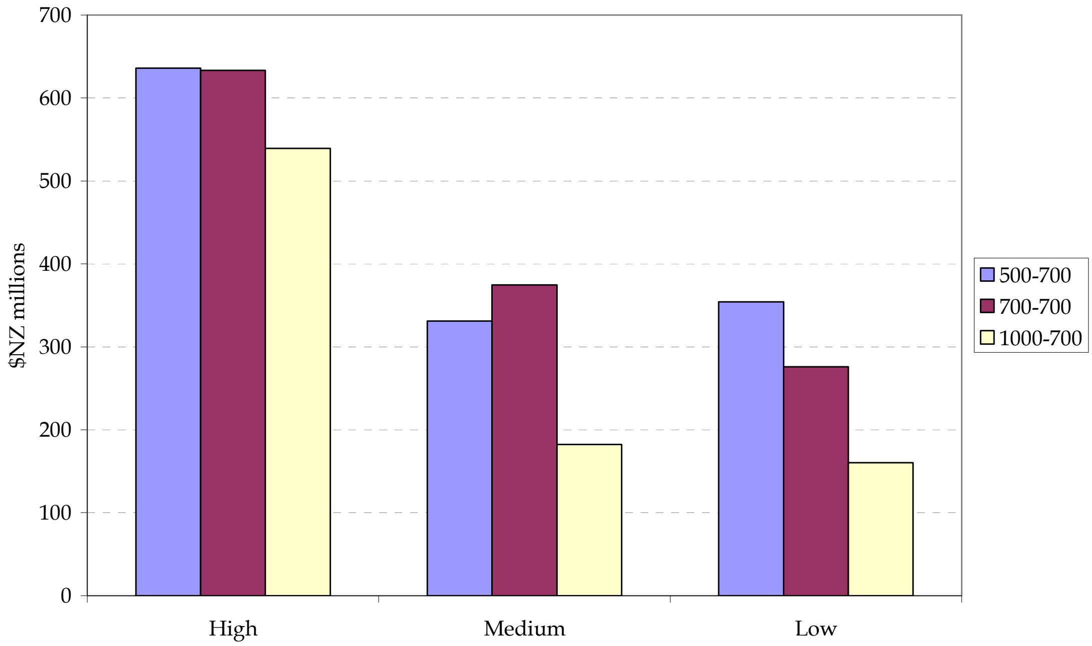



Figure 3-1 also indicates that the preferred augmentation option alternates between 500-700 and 700-700 depending on demand growth scenario.

Under high demand growth, the 500-700 augmentation option is preferable. Due to the increased demand in the SI, more SI capacity is built in the region, irrespective of whether Pole 1 is replaced or not. Furthermore, the difference in the volume of SI capacity built under the 500-700 and 700-700 alternatives reduces under all MDS as the incremental cost of additional SI capacity starts to increase. This combination of increased demand in the SI, and a reduction in the incremental SI capacity built in response to an additional 200 MW of export capacity, results in a reduction in net market benefits for the 700-700 alternative relative to the 500-700 option.

Under low demand growth, the 500-700 option is also favoured over the 700-700 alternative. Less generating capacity in general needs to be built and differences in the amount of SI capacity built are relatively small.

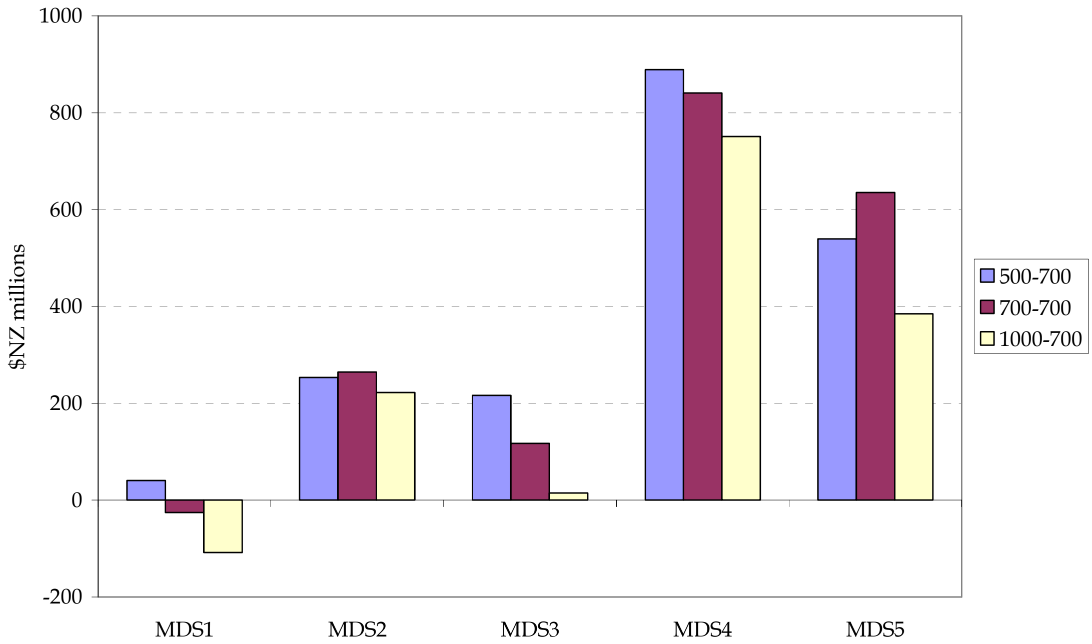
### 3.1.2 Sensitivity to market development

Figure 3-2 shows that the net market benefit of replacing Pole 1 (weighted across all demand growth scenarios) is significantly greater in MDS4 and MDS5 than in the other scenarios.

In MDS4, the phasing out of the Tiwai Point smelter results in a surplus of SI capacity that cannot be fully utilised in the short term without the additional export capacity. Without the HVDC augmentation, additional capacity is built in the NI that would otherwise not be needed.

In MDS5, the 90% renewable target and the higher carbon price increases the value of SI capacity relative to other new entry options. If Pole 1 is not replaced in this scenario, additional capacity must be built in the NI to cover the event that the HVDC link is out of service. Furthermore, without pole 1 being replaced more NI wind farms are built to meet the renewable target. While the wind farms do not have considerably higher capital costs than the SI renewable alternatives, the low peak contribution factors result in even more additional NI capacity needing to be built. In total, an additional 400 MW of capacity is built by 2030 if Pole 1 is not replaced.

**Figure 3-2 Expected net market benefit by market development scenario ($M)**




When looking at the net market benefit by MDS it becomes apparent that the 700-700 augmentation yields a greater expected net market benefit than the 500-700 alternative under MDS2 and MDS5 only. However, the high weighting applied to MDS5 makes this augmentation the preferred option overall. The individual differences between the 500-

700 option and the 700-700 option can be explained by variations in the capacity expansion plan.

In MDS1, two new SI lignite plants are built in 2030 to take advantage of the additional 200 MW of export capacity provided by the 700-700 augmentation alternative. However, market benefits resulting from building this capacity are not sufficient to warrant the additional transmission investment costs. Indeed, the increased availability of gas and correspondingly lower fuel prices in this scenario mean that the value of replacing Pole 1 at all is marginal.

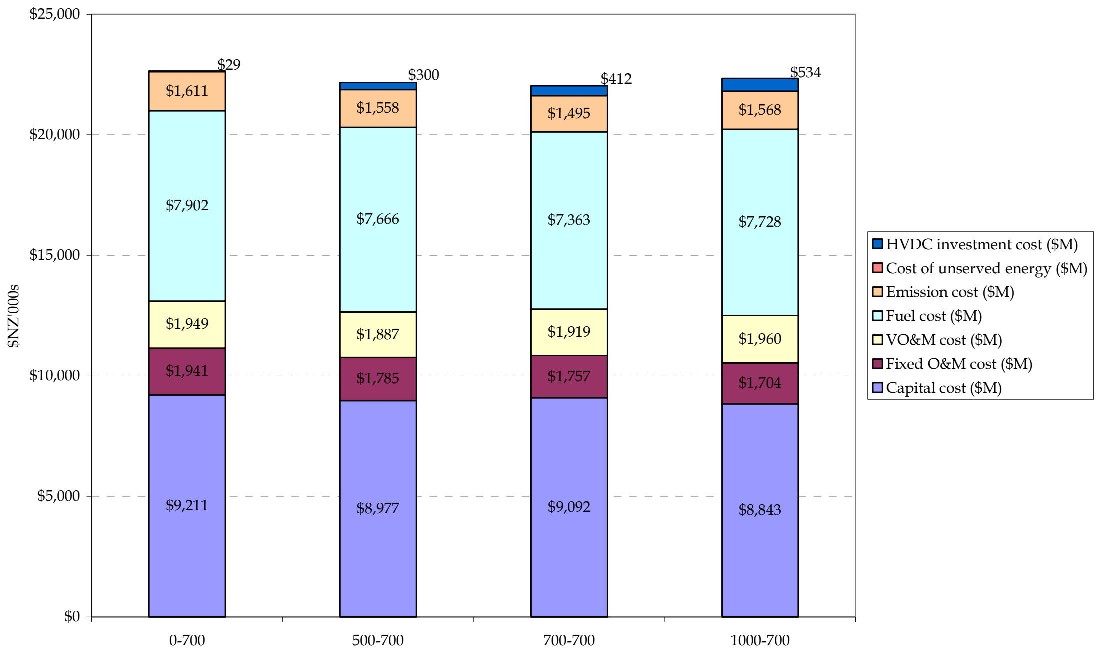
In MDS2, gas is not so readily available and hence the value of being able to build new lignite plants in the SI is greater. Under medium growth conditions, approximately 70 MW of additional SI hydro is built if the 700-700 is built rather than the 500-700 line. This is sufficient to yield a slightly greater market benefit for the larger line under this scenario. However, under the high demand scenario there is little difference in the SI capacity built between the two options – the next increment of SI capacity is more expensive and as such has not been selected by the capacity expansion plan. Consequently, benefits of the larger line do not outweigh the additional augmentation investment costs under high demand conditions.

In MDS3 and MDS4 there is no discernable difference in capacity expansion plans, whether the 500-700 alternative or the 700-700 alternative is considered. The flexibility of SI hydro is favoured over SI wind farms, with the most expensive SI wind farms not being built under either augmentation scenario. When considering the 500-700 option, slightly more DSR is built in the first LT Plan run to meet the capacity constraint; however, this DSR is also built with the 700-700 augmentation due to dry-year security considerations. While there are some market benefits associated with the larger link, these benefits are not sufficient to justify the cost of the investment.

In MDS5, medium growth, there is slightly more SI hydro built under the 700-700 alternative than under the 500-700 alternative. Additionally, more NI wind is built with the larger link to satisfy the capacity constraint. In the 500-700 case, the more stringent capacity constraint is satisfied by building more DSR. The benefit of building DSR in this case, rather than NI wind, is that every MW built can contribute fully to both the capacity constraint and the 90% renewable target.

Figure 3-3 shows the total system cost breakdown by augmentation alternative under medium growth conditions for MDS5. Most attention has been focused on medium growth as it carries the highest probability weighting. The 700-700 alternative has higher capital costs, fixed costs and VO&M costs, but lower fuel costs and emission costs than the 500-700 alternative. In total, the 700-700 alternative yields a net market benefit of $605 million under MDS5; $136 million more than the 500-700 alternative.

**Figure 3-3 NPV of cost breakdown by augmentation alternative – MDS5 medium growth ($M)**




### 3.1.3 Sensitivity to hydro inflows

In our market simulations, ten hydro inflows are sampled from the historical set of 74 annual inflow profiles. The characteristics of this sample are summarised in Table 3-2.

**Table 3-2 Hydro sample used for market simulations**

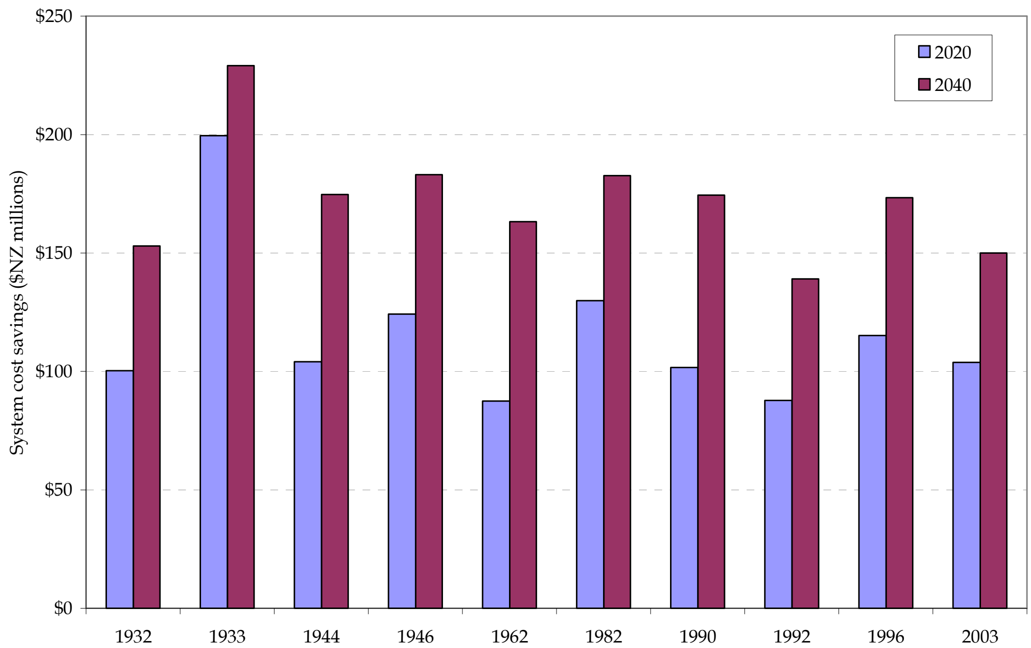
| Hydro year | Average annual cumecs | SI inflow relative to average | NI inflow relative to average | Weighting applied |
|---|---|---|---|---|
| 1932 | 1579 | 0.79 | 0.83 | 17% |
| 1992 | 1698 | 0.82 | 1.02 | 2% |
| 2003 | 1844 | 0.94 | 0.92 | 2% |
| 1962 | 1980 | 0.91 | 1.34 | 16% |
| 1944 | 1980 | 1.01 | 0.98 | 4% |
| 1990 | 1991 | 1.00 | 1.04 | 10% |
| 1982 | 2066 | 1.11 | 0.79 | 16% |
| 1933 | 2107 | 1.11 | 0.89 | 12% |
| 1946 | 2113 | 1.08 | 1.03 | 12% |
| 1996 | 2170 | 1.06 | 1.26 | 10% |

This sample is selected as being representative of the generation cost distribution associated with using all 74 samples in the market simulations. Weights are applied to the outcomes of each hydro sample so that the mean and standard deviation of the generation costs derived from this sample match the moments of the underlying distribution derived from using all 74 samples.

The net market benefits in any given year are highly dependent on the hydro inflow for that year. Figure 3-4 shows the system costs savings resulting from building the 700-700 alternative under medium growth conditions, MDS5, for two years: 2020 and 2040.

When looking at the results of individual hydro samples, it is apparent that the benefits of additional HVDC capacity are greater in years of high rainfall in the SI, as the water can be used more efficiently to supply both islands. In Figure 3-4, the 1933, 1982, 1946 and 1996 have the greatest SI inflows. Of these three samples, 1933 had the most rainfall in the SI and at the same time the NI was drier than average. 1932 and 1992 were the driest in the SI.

**Figure 3-4 System cost savings of individual hydro samples – MDS5 700-700 ($M)**




### 3.1.4 Revenue adequacy and capacity constraints

Capacity factors have been used as a measure of revenue adequacy, in an attempt to demonstrate that the imposed capacity constraint does not result in over-supply that is not economically viable. Capacity factors for wind, hydro, geothermal and cogeneration units are fixed based on the generation profiles that are used. Therefore, attention was focused on new thermal generators; particularly those which, due to their cost structures, should operate as intermediate or base-load generators in order to generate sufficient pool revenue to cover the fixed and capital costs of investment.

For these plants, assuming investment in the preferred 700-700 augmentation, capacity factors have been calculated at intervals of five years across the planning horizon. Table 3-3 and Table 3-4 report these capacity factors for MDS1 and MDS5 respectively, the market development scenarios with the highest probability of occurring.

**Table 3-3 Capacity factors for new thermal plant, MDS1, 700-700, medium growth**

| | 2015 | 2020 | 2025 | 2030 | 2035 | 2040 |
|---|---|---|---|---|---|---|
| Generic coal 6 Huntly stage 2 | | | | | | 97% |
| Generic gas 2 Taranaki | | | | 95% | 91% | 90% |
| Marsden Coal | | | | | 97% | 97% |
| Otahuhu C[3] | 72% | 64% | 76% | 47% | 34% | 31% |
| Taranaki CC 2 | 96% | 96% | 96% | 95% | 85% | 85% |
| Taranaki CC possible replacement | | | | | 88% | 87% |
| Generic lignite 1 Southland | | | | 96% | 96% | 97% |
| Generic lignite 2 Otago | | | | 96% | 96% | 97% |
| Generic OCGT NI 1 | | | | | 0% | 0% |
| Generic OCGT NI 3 | | | | | | 1% |
| Generic OCGT NI 4 | | | | | 0% | 0% |
| Generic OCGT NI 5 | | | | | | 1% |
| Generic OCGT NI 6 | | | | 0% | 0% | 1% |

**Table 3-4 Capacity factors for new thermal plant, MDS5, 700-700, medium growth**

| | 2015 | 2020 | 2025 | 2030 | 2035 | 2040 |
|---|---|---|---|---|---|---|
| Generic gas 1 Auckland | | | | | | 23% |
| IGCC coal plant with CCS 2 | | | | | 91% | 96% |
| Otahuhu B possible replacement | | | | | | 21% |
| Coal seam gas plant | | | | | 90% | 90% |

[3] Otahuhu C is actually forced into the expansion plan in this scenario, consistent with GEM assumptions

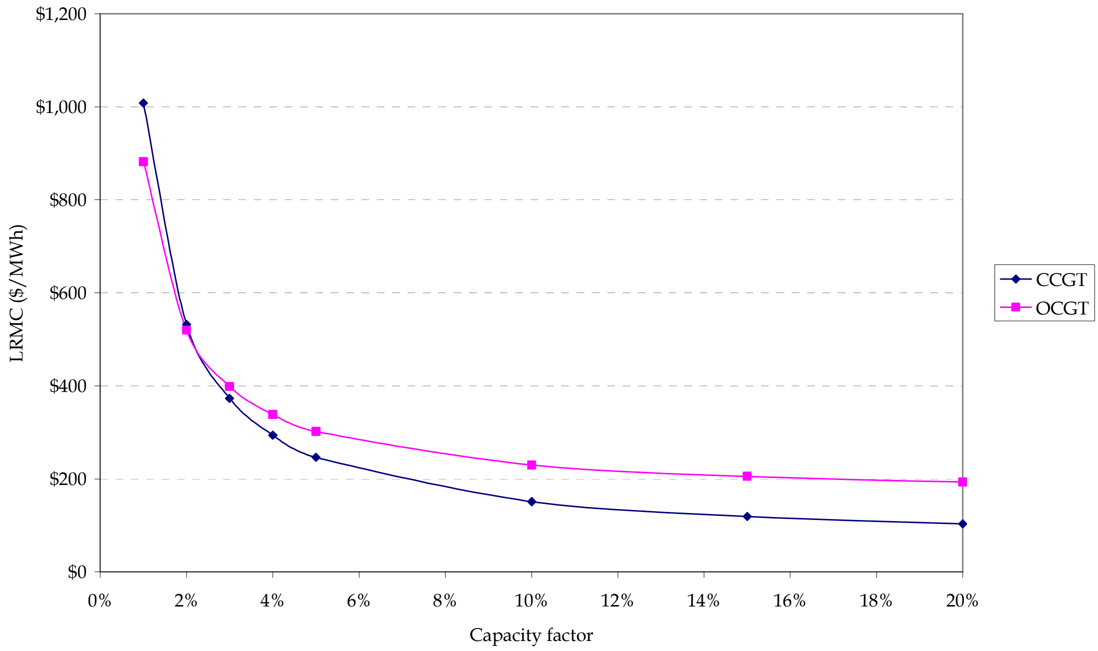
| | 2015 | 2020 | 2025 | 2030 | 2035 | 2040 |
|---|---|---|---|---|---|---|
| Generic OCGT NI 1 | | | | 0% | 0% | 0% |
| Generic OCGT NI 3 | | | | | | 0% |
| Generic OCGT NI 4 | | | | | | 0% |
| Generic OCGT NI 5 | | | | 0% | 0% | 0% |
| Generic OCGT NI 6 | | | | | 0% | 0% |

Typically, in MDS1, new coal plant operate at a capacity factor of at least 90%, generation volumes that should enable them to recover any fixed costs of investment. In this scenario, new combined cycle gas turbines (CCGTs) such as Otahuhu C, Taranaki CC and Generic gas 2 Taranaki, operate at levels between 30% and 90% utilisation which should also ensure revenue adequacy for these technologies.

In MDS5, with more wind and hydro technologies being built, the capacity factors of new CCGTS are generally lower. Both the generic Auckland gas plant and the Otahuhu B possible replacement operate at capacity factors just over 20% in 2040. These levels are relatively low for new CCGTs, however, it is more efficient to operate these technologies at this level of utilisation than to build open cycle gas-turbines (OCGTs) that run on diesel. Figure 3-5 shows a screening curve comparing the post-tax long-run marginal cost of CCGTs and OCGTs at capacity factors of up to 20%. Due to the high cost of diesel, CCGTs are cheaper to run than OCGTs above a capacity factor of 2%. Naturally, there may be technical restrictions that prohibit such low operation of CCGTs and start-up costs have not been considered in this analysis. However, this figure demonstrates that the thermal plant selection is efficient given the operational constraints considered, despite the imposition of capacity constraints.

At a capacity factor of 20%, the generic CCGTs would need to receive an average price of $146/MWh in order to break even, assuming a pre-tax WACC of 10%. If, in a perfectly competitive energy-only market, this revenue requirement can not be achieved, generators may need to exercise some market power to push pool prices up to levels that will provide an adequate return on investment. Alternatively, some other market mechanism, such as a capacity payment, may be required to supplement the revenue received from the pool.

**Figure 3-5 Screening curve for generic CCGT and OCGT options**




Interest has been expressed in the impact that the N-1 capacity constraint has on the net market benefits of the various augmentation alternatives. To test this impact, we ran the LT Plan without these capacity constraints. Because PLEXOS co-optimises energy and reserve, the capacity expansion plan is still likely to build some reserve capacity to ensure that the instantaneous reserve can be met. However, the amount of capacity built will still be lower without the N-1 constraints imposed because:

- The N-1 capacity constraints are formulated to ensure that the prudent peak demand can be met with reserves intact. The load forecasts used in the LT Plan are based on median peak demand projections rather than the prudent peak demand (which is expected to be exceeded ten percent of the time), and consequently the perceived need for additional capacity will be less.
- The LT Plan assumes average deratings for wind and hydro units and does therefore not reflect the non-firm nature of these resources. The N-1 capacity constraint accounts for this non-firm capacity by assuming a peak contribution factor. For wind, this is assumed to be 20%, and for run-of-river hydro, a peak contribution factor of 65% is assumed.

Figure 3-6 shows the NI reserve margins for all augmentation alternatives under MDS5, medium demand growth, with capacity constraints. The reserve margin has been calculated as the ratio of total firm capacity, including DSR, the capacity on the HVDC link and interruptible load, over the prudent peak demand in the NI. Applying N-1 capacity constraints, the NI reserve margin reduces over time from a current level of around 1100 MW to either 750 MW or 1050 MW, depending on the size of the largest HVDC link.

**Figure 3-6 North Island reserve margin, MDS5 with capacity constraints**

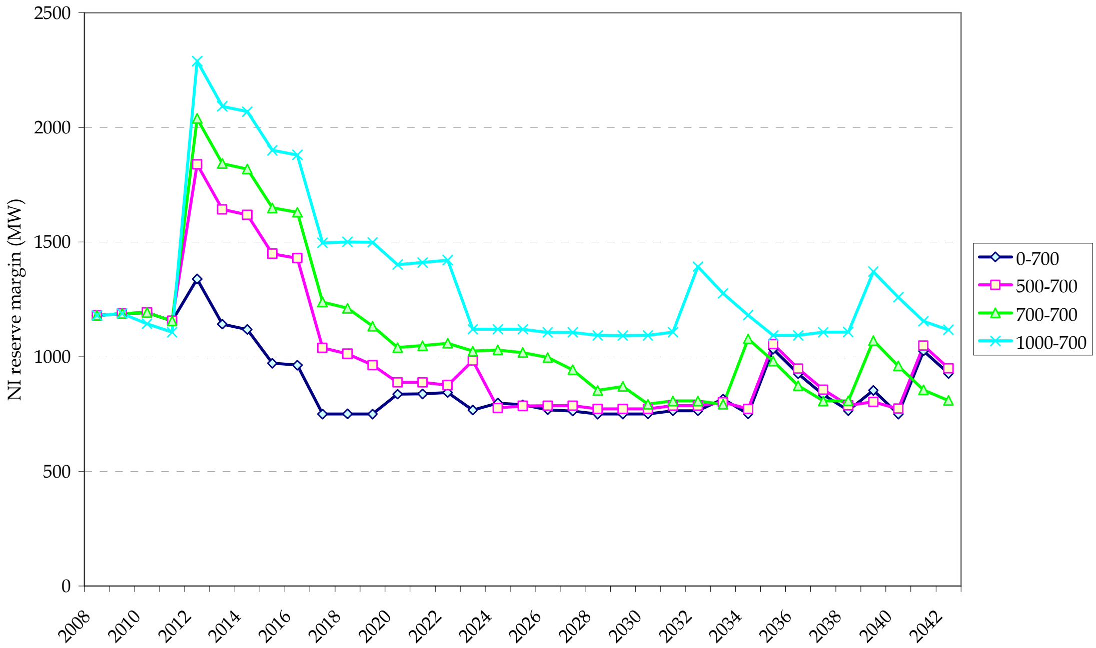
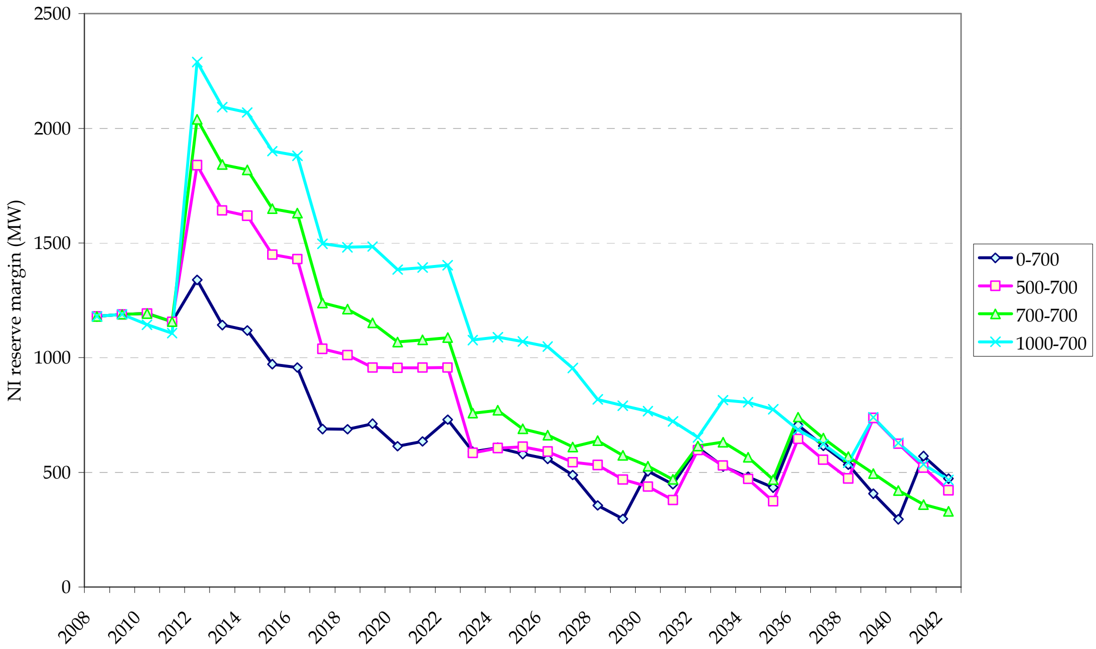



**Figure 3-7 North Island reserve margin, MDS5 without capacity constraints**



Without capacity constraints, the reserve margin reduces further over time to approximately 500 MW, as shown in Figure 3-7. With this low reserve margin, prudent peak demand in the North Island would not be able to be supplied in the event that the largest HVDC link was out of service. Due to reliability concerns, it is highly unlikely that the system would ever operate with such a low reserve margin.

For medium demand growth, MDS5, removing the capacity constraints tended to decrease the net market benefit of replacing Pole 1. As expected, total system costs reduced for all augmentation alternatives when the capacity constraint is removed. This cost reduction was more prominent for the 0-700 and 500-700 alternatives than for the larger links as the capacity constraints were more stringent and tended to bind more often with these smaller link alternatives. Consequently, without capacity constraints, for MDS5 medium growth, when compared against 0-700, the net market benefits are slightly greater for the 500-700 alternative than the 700-700 alternative, as shown in Table 3-5.

However, as already discussed, this scenario is not credible from a reliability perspective. Without running a large number of Monte Carlo simulations under various peak demand assumptions and forced outage states, the unserved energy impact of this reserve margin shortfall cannot adequately be captured in this net market benefit analysis. Moreover, variability in wind profiles and run-of-river hydro inflows would also need to be modelled to provide a more accurate assessment of the expected generation costs and unserved energy costs that may arise under this scenario.

**Table 3-5 Impact of capacity constraints on net market benefit – MDS5, medium demand growth ($M)**

| | With capacity constraints | Without capacity constraints |
|---|---|---|
| 500-700 | $469 | $455 |
| 700-700 | $605 | $450 |
| 1000-700 | $305 | $251 |

## 3.2 Optimal timing and staging for preferred augmentation

The net market benefits presented thus far assumed that, for the 700-700 alternative, the undersea cable was built in 2018.

However, under some market development scenarios and some load growth scenarios there is little, if any, difference in the capacity expansion plan, regardless of whether the 500-700 or the 700-700 augmentation is built. In these scenarios, there would be value in deferring the investment in the undersea cable. There is therefore, essentially, an "option value" associated with the 700-700 augmentation that does not exist to the same extent for the 500-700 option.

It has already been highlighted that the preferred size of the HVDC link is highly dependent on the capacity expansion plan selected. Based on the capacity expansion plans developed in this analysis, assuming medium growth, there is little benefit from building an undersea cable under MDS3 or MDS4 until around 2040, when differences in the SI capacity become apparent. Hence, if the 700-700 grid investment proceeded and MDS3 or MDS4 eventuated with a similar capacity expansion plan, one may reasonably say that there is no benefit from the additional 200 MW capacity obtained from the undersea cable.

Similarly, in MDS1, medium growth, the addition of an extra 200 MW encourages the building of a 400 MW lignite plant in the SI in 2030. However, prior to that time, the differences in SI capacity between 500-700 and 700-700 are relatively small. Hence, one may argue that the undersea cable could be deferred until 2030 in this scenario, unless the additional 200 MW allows for better utilisation of the SI resources that justifies this investment.

On the other hand, in MDS2 medium growth, additional hydro is built in the SI in 2018, yielding benefits from then on. Hence, it would be reasonable to build the undersea cable at that time. For MDS5, additional SI capacity is built in 2023 under the 700-700 alternative and therefore the undersea cable would need to be built by then.

To determine the optimal staging of the undersea cable for the 700-700 alternative, the investment was sequentially delayed for each market development scenario until either:

- The net market benefits reduced for two years in a row, or
- There was a significant SI capacity differential compared to the 500-700 alternative.[4]

For medium growth, based on the capacity expansion plans developed and the process described above, the optimal staging for the undersea cable is summarised by market development scenario in Table 3-6. This table also compares the NPV of net market benefits with and without deferring the undersea cable beyond 2018. For medium growth, an additional $27 million of market benefits may be extracted by optimising the timing of the undersea cable. The expected net market benefit of this alternative would increase further if we also deferred investment in the undersea cable in the low demand growth scenario.

[4] The timing of the undersea cable was not deferred beyond this point while using the capacity expansion plan developed for the 700-700 case, as this might result in violation of the NI capacity constraints.

**Table 3-6 Optimal staging of undersea cable: 700-700 medium demand growth**

| MDS | Year of investment in undersea cable | Net market benefits – optimised staging ($NZ million) | Net market benefits – staging in 2018 ($NZ million) |
|---|---|---|---|
| MDS1 | 2030 | $-11 | -$57 |
| MDS2 | 2018 | $302 | $307 |
| MDS3 | Not built | $156 | $85 |
| MDS4 | Not built | $820 | $797 |
| MDS5 | 2023 | $619 | $605 |
| Weighted average | | $402 | $375 |

For the purpose of the GIT, the optimal timing of the initial grid investment must also be determined. For the preferred 700-700 augmentation, the optimal timing of the Pole 1 replacement was tested by moving back the replacement date one year at a time until there were two years in a row that did not yield a greater net market benefit. This analysis indicated that there was little additional benefit from delaying the replacement date.

**Figure 3-8 Costs and benefits of delaying the replacement date – medium growth**

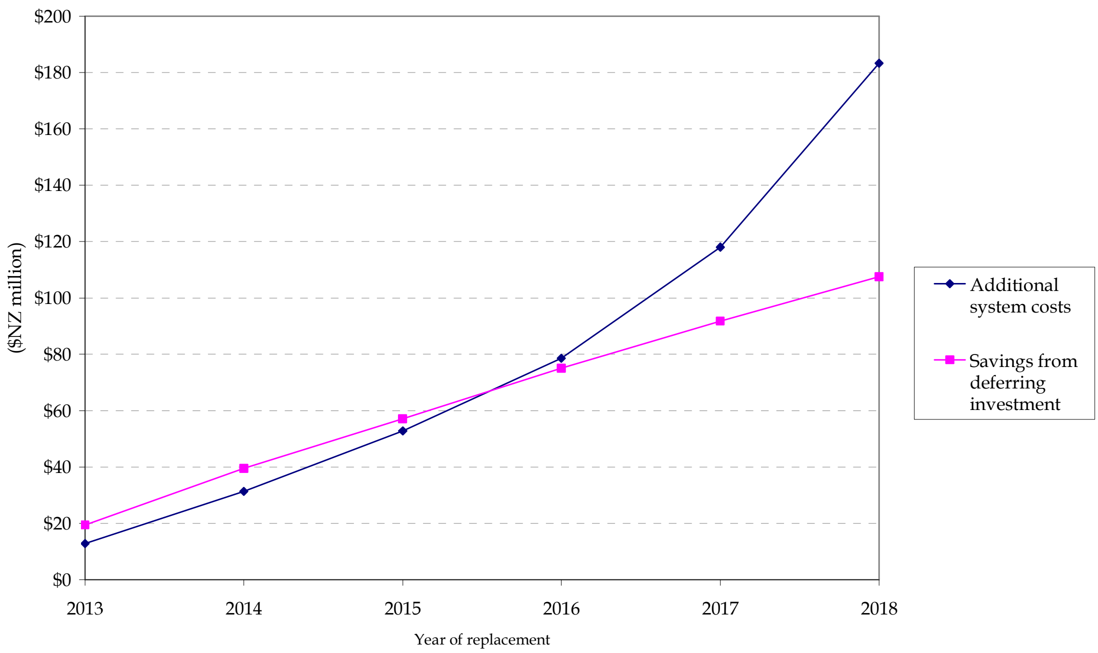



Figure 3-8 shows the weighted average costs and benefits of delaying the initial investment date for the 700-700 alternative, medium demand growth scenario, assuming a monopole (0-700) configuration prior to replacement. From 2012 to 2015 deferral of investment may lead to benefits of up to $8 million under average hydro conditions, however for heavier than average rainfall, or higher than expected demand, delaying the replacement could prove costly due to the asymmetry of risk.

## 3.3 Other benefits

In addition to the economic benefits already discussed, and the "option value" associated with the 700-700 augmentation alternative, there may be other benefits associated with investing in the larger line, including:

- Benefits from switching to a national instantaneous reserve market
- Benefits from enabling more wind diversification
- Cost effectiveness of emission abatement
- Competition benefits (discussed in a future report).

### 3.3.1 National instantaneous reserve market

With larger link sizes (700-700 or 1000-700) there may be value in switching to a national instantaneous reserve market. To estimate this value, we ran each market development scenario under medium growth conditions with a single national reserve market, limiting the SI contribution to the spare capacity on the HVDC link in any given period. It was found that switching to a national instantaneous reserve market produced additional benefits, compared with two single reserve markets, ranging from an NPV of $3 million to $28 million across the market development scenarios.

However, it should be noted that the implementation of ancillary service modelling for this analysis was rather rudimentary, as detailed unit commitment and minimum stable levels were not modelled. While PLEXOS has the capability to model extremely detailed ancillary service markets, this has not been the emphasis of this study. Therefore, further detailed analysis should be undertaken before assessing the merits of switching to a national reserve market.

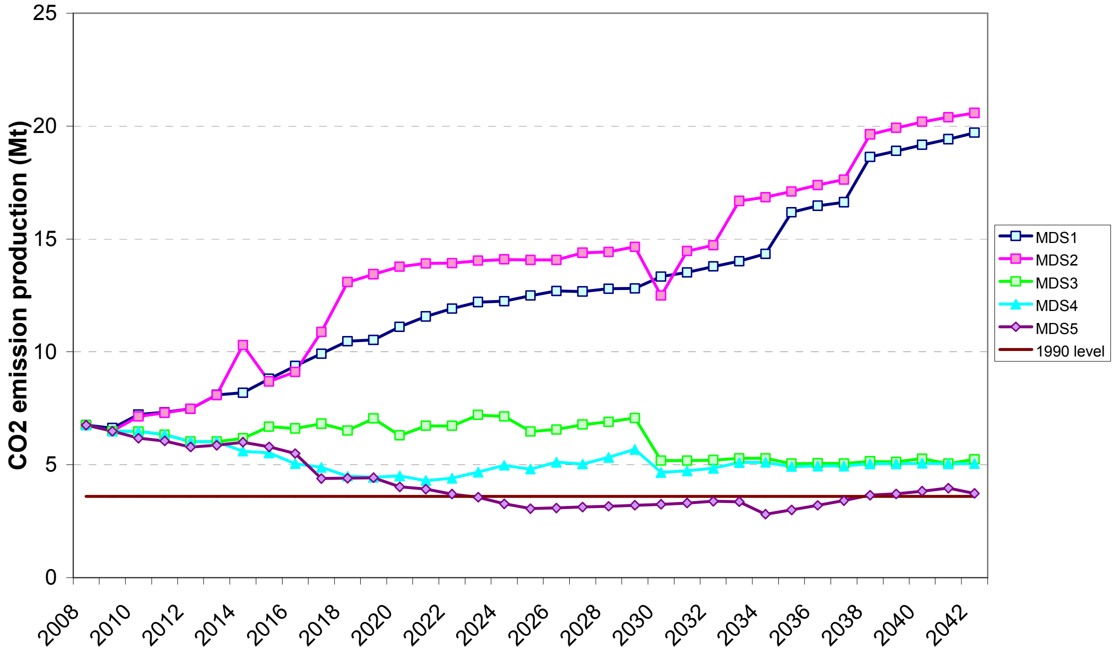
### 3.3.2 Enabling wind diversification

As more and more wind farms are built in the NI, the non-firm nature of this resource is likely to put a strain on the rest of the system from a reliability perspective. When the wind is not blowing, there still needs to be sufficient capacity to cover demand. Over time, an additional reserve market may emerge to back up the wind. With a larger link capacity, there is potential for more SI hydro capacity to be built, resulting in less reliance on wind capacity in the NI. Furthermore, if more SI wind capacity is built as a result of the larger link, the geographical diversity of this resource may help smooth out the intermittency.

### 3.3.3 Cost effectiveness of emission abatement

The Government's emission abatement target to return to 1990 $CO_2$ production levels by 2025 would only be achievable for the stationary energy sector under MDS5, as shown in Figure 3-9. Even then, if the cost of abatement in the stationary energy sector is lower than in other sectors, such as transport, deeper cuts in emission production may be required.

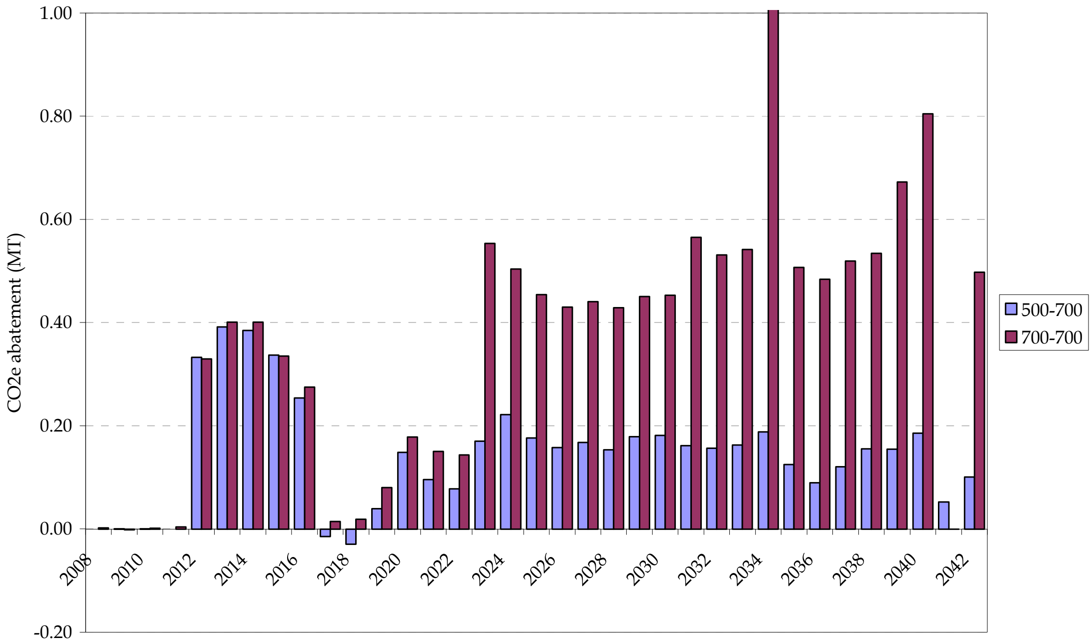
**Figure 3-9 $CO_2$ emission production, medium demand growth**




The 1990 target could be met in 2025 under all four augmentation alternatives, although it cannot be sustained for more than five years under the 0-700 and 500-700 replacement alternatives. The 700-700 option is the most cost-effective $CO_2$ emission abatement alternative, as it produces fewer emissions than the other augmentation alternatives in addition to yielding the greatest net market benefit.

Figure 3-10 shows the emission abatement from the 500-700 and 700-700 alternatives relative to the 0-700 no replacement option for MDS5, medium growth. From 2024 onwards, emission abatement under the 700-700 option is nearly double the abatement from the 500-700 alternative. This is largely driven by the additional NI wind that is built in the 700-700 option, compared with other thermal and DSR technologies chosen under the 500-700 option. It is conceded that the emission abatement is highly dependent on the capacity expansion plan chosen. However, under medium growth conditions, in all but MDS1, the emission costs are lower and hence the emission abatement is higher under the 700-700 alternative than the 500-700 alternative.[5]

**Figure 3-10 Emission abatement – MDS5, medium growth**




## 3.4 Differences between Transpower and MMA results

While we have arrived at the same conclusion as Transpower regarding the preferred augmentation alternative, it is our understanding that Transpower's results were more conclusively in favour of the 700-700 alternative under a wider range of scenarios.

Moreover, the magnitude of the net market benefits varies between the two sets of analysis, as shown in Table 3-7 below.

**Table 3-7 Comparison of net market benefit for MDS5, medium demand growth ($M)**

| | MMA | Transpower | MMA using Transpower's expansion plan |
|---|---|---|---|
| 500-700 | 469 | 275 | 572 |
| 700-700 | 605 | 379 | 740 |
| 1000-700 | 305 | 296 | 599 |

[5] It should also be noted that the emission abatement benefits have already effectively been included in the economic assessment, with the value of abatement assumed to be equal to the carbon price assumed.

There are a number of differences in the modelling methodology that may account for the variations in results, as discussed in the following sections.

### 3.4.1 Capacity expansion plan

The net market benefit of various HVDC Pole 1 replacement alternatives is dependent on the capacity expansion plan selected; particularly the location of new capacity and the technology chosen. Our analysis is based on capacity expansion plans developed using PLEXOS, software developed by Energy Exemplar. In contrast, Transpower's analysis relied on the Electricity Commission's Generation Expansion Model (GEM) to determine an expansion plan. Both models have been reviewed and compared by EGR Consulting in *GEM and PLEXOS in the SOO/GIT Process: Conceptual Commentary,* Oct 2007. For a more detailed description of the PLEXOS capacity expansion formulation, readers are referred to MMA's report titled *Capacity Expansion Planning for the New Zealand Electricity Market,* Oct 2007.

There are several notable differences between the two capacity expansion modelling formulations that may result in different plans being developed:

- In GEM, a single hydro sample was used representing 97% of average hydro yield, whereas in PLEXOS, a single hydro sample was used representing 94% of average hydro yield. It has already been demonstrated that the market benefits of the HVDC replacement are more favourable in high hydro inflow years. Therefore, the drier the year used in the capacity expansion plan, the more likely that the resulting plan, while perhaps optimal from a commercial perspective, may not optimise the market benefits from the link. This could explain why there is a more consistent pattern or trend in Transpower's results than in MMA's.
- In PLEXOS, the annual energy production from new hydro units is similarly varied assuming a drier than average hydro yield. It is understood that this is not done in the GEM formulation.
- In PLEXOS, monthly load duration curves were modelled, whereas GEM modelled quarterly load duration curves. There is slightly more resolution in the PLEXOS formulation. However, this results in a larger problem to be solved which must be split into two steps of 17 years, rather than being able to span the entire horizon in one solve as GEM can do.
- In PLEXOS, energy is co-optimised with instantaneous reserve, whereas this is not considered in GEM. Operating a larger HVDC link at full capacity would result in more instantaneous reserve needing to be carried in the NI. Therefore, there may be disincentive to fully load the HVDC link, resulting in similar capacity plans under the 500-700 and 700-700 alternatives, as observed.
- In GEM, Transpower has randomly varied the relativity of costs for wind and hydro projects to create a steeper cost curve for these generic new entrants. Moreover,

locational factors are used, modifying the capital costs to reflect expected variations in the nodal prices. PLEXOS does not vary the capital costs in this way. Capital costs are assumed to remain static between market development scenarios and no locational factors are used.

Despite these differences, the capacity expansion plans from GEM and PLEXOS are reasonably well aligned, particularly for the MDS5 scenario. Appendix C provides a comparison of the GEM and PLEXOS expansion plans for each market development scenario, focusing on the no replacement (0-700) and 700-700 augmentation alternatives.

Furthermore, when running the GEM expansion plan for MDS5 medium growth through the PLEXOS market simulations, the 700-700 link still yielded the highest net market benefits. As shown in Table 3-7, the NPV of net market benefit for the 500-700 link was $572 million, whereas for the 700-700 link the net market benefit was $740 million.

The difference in net market benefits between the two augmentation alternatives is larger using the GEM expansion plan than using the PLEXOS expansion plan, and the magnitude of the benefit is also greater than when run through SDDP. This indicates that variations in the market simulation models used are also impacting on the net market benefits determined.

### 3.4.2 Market simulations

At MMA, we have used PLEXOS to assess the market benefits of the various expansion options, whereas Transpower has used SDDP. There are some notable differences between these two software systems that may also have an impact on the assessment of market benefits, such as:

- Hydro samples - In PLEXOS, ten deterministic hydro samples are used to represent the underlying distribution of generation costs, whereas it is understood that Transpower used 6 hydro sequences, modelled stochastically.
- AC network representation - The PLEXOS formulation of the NZ system set up for this analysis does not utilise the linearised DC approximation of optimal power flows. A 17-region network is modelled and AC losses are assumed to be included in the load forecasts provided by Transpower. Only DC losses are modelled. Furthermore, a single AC network development plan has been used, as provided by Transpower, which is assumed to apply regardless of capacity expansion plan, augmentation alternative, or demand scenario being modelled. SDDP, on the other hand, uses a nodal representation of the network, DC load flow and loss approximations, and the network upgrades are modelled dynamically.

- Load representation - Both MMA and Transpower used monthly load duration curves to represent load. In PLEXOS, 17 LDC blocks were used to represent the monthly load duration curve, whereas 5 LDC blocks were used in SDDP.
- Instantaneous reserve - In PLEXOS, energy and reserve markets are co-optimised, whereas in SDDP the instantaneous reserves are not modelled explicitly. When co-optimising energy and reserve, the flow on the HVDC link tends to be reduced when there is only a 700 MW monopole, to reduce the amount of reserve that needs to be carried in the NI. Therefore, the benefits of augmentation are likely to be greater when instantaneous reserve is considered. This may explain why the magnitude of net market benefits is higher under MMA's analysis than under Transpower's.

These differences, and their likely impact, are summarised in Table 3-8.

**Table 3-8 Differences in market simulation models**

| | PLEXOS | SDDP | Likely impact |
|---|---|---|---|
| Regional representation | 17 zones | nodal | Little difference in market benefit, assuming that intra-regional congestion is alleviated through AC network developments. The cost of any AC network developments is included in Transpower's analysis but not in MMA's. |
| Load representation | 17 load blocks per month | 5 load blocks per month | Greater resolution in the load duration curve is likely to provide more realistic capacity factors for peaking generation. Water may also be better utilised, increasing the value of the replacement options. |
| Hydro modelling | 10 deterministic hydro samples used | 6 stochastic hydro sequences used | Impact depends on how representative each sequence or sample is. Preliminary analysis indicated that market benefits are quite sensitive to the choice of hydro sample used. |
| Instantaneous reserve | Energy and reserve are co-optimised | Dispatch of reserves is not considered | Modelling reserves may increase the value of replacing the link, relative to the 0-700 no replacement case. In the 0-700 case, flow on the line is likely to be backed off to reduce the reserve that must be carried in the NI. |
| Power flow model | Transportation model used to determine flow between zones. DC losses modelled, AC losses assumed to be included in load | DC load flow model used, with loss approximation. | Impact depends on how close the AC losses estimated in the load forecasts match the losses calculated in SDDP. |

# 4 CONCLUSION

The preferred option under the GIT is to replace Pole 1 with a 700-700 augmentation in 2012, with the investment in an undersea cable to follow as required. Assuming the undersea cable is built in 2018, the expected net market benefit of this augmentation alternative is $399 million, compared to $380 million for the 500-700 alternative and $233 million for the 1000-700 alternative.

The size of the augmentation yielding the greatest net market benefit under individual scenarios is highly dependent on the capacity expansion plan used, and alternates between the 500-700 and the 700-700 augmentation alternatives. In this independent analysis, a single, drier than average hydro sample was used for capacity expansion planning purposes in an attempt to better represent the underlying price distribution that would drive investment on a commercial basis. In contrast, the market benefits of any HVDC expansion are most prominent in years in which the SI is experiencing higher than average hydro inflows. This highlights the fact that new entry may well be driven by commercial incentives that will not necessarily guarantee maximum utilisation of the link or maximum net benefits from a grid investment perspective. Consequently, under some scenarios, the additional 200 MW export capacity available from the 700-700 augmentation option does not always prompt additional investment in SI generation.

Because the 700-700 option can be staged, it can offer more flexibility than the 500-700 option in response to the actual capacity expansion plan that eventuates. Our analysis has demonstrated that, by deferring investment in the undersea cable until it is needed, an additional $27 million of expected net market benefits may be extracted from the 700-700 alternative under medium demand growth. Deferral benefits would also exist under low demand growth. There appeared to be no significant benefit in delaying the initial timing of the investment post 2012.

# APPENDIX A CAPITAL EXPENDITURE

Table A- 1 shows the spread of capital expenditure assumed for each augmentation alternative. The initial replacement of the link is assumed to occur in 2012. For the 700-700 and 1000-700 options, the undersea cable is assumed to be built in 2018, with a salvage value included at the end of the horizon to reflect its residual asset life.

**Table A- 1 Streaming of capital expenditure for the four augmentation alternatives ($M)**

| Year | No replacement | 500-700 | 700-700 | 1000-700 |
|---|---|---|---|---|
| 2008 - NPV | 29 | 300 | 412 | 534 |
| | | | | |
| 2008 | 0.0 | 0.3 | 0.3 | 0.3 |
| 2009 | 2.3 | 27.7 | 15.7 | 20.2 |
| 2010 | 1.6 | 69.8 | 87.2 | 109.7 |
| 2011 | 3.3 | 120.8 | 149.8 | 185.9 |
| 2012 | 16.6 | 105.3 | 113.8 | 133.5 |
| 2013 | 0.1 | 36.3 | 40.4 | 51.6 |
| 2014 | 0.1 | 27.7 | 31.8 | 33.9 |
| 2015 | 0.1 | 1.4 | 4.7 | 9.7 |
| 2016 | 0.1 | 1.4 | 41.5 | 51.7 |
| 2017 | 19.8 | 1.4 | 77.9 | 132.9 |
| 2018 | 0.2 | 1.4 | 15.8 | 40.4 |
| 2019 | 0.2 | 1.4 | 7.0 | 7.7 |
| 2020 | 0.2 | 1.4 | 2.2 | 2.8 |
| 2021 | 0.2 | 1.4 | 2.2 | 2.8 |
| 2022 | 0.2 | 1.4 | 2.2 | 2.8 |
| 2023 | 0.2 | 1.4 | 2.2 | 2.8 |
| 2024 | 0.2 | 1.4 | 2.2 | 2.8 |
| 2025 | 0.2 | 1.4 | 2.2 | 2.8 |
| 2026 | 0.2 | 1.4 | 2.2 | 2.8 |
| 2027 | 0.2 | 1.4 | 2.2 | 2.8 |
| 2028 | 0.2 | 1.4 | 2.2 | 2.8 |
| 2029 | 0.2 | 1.4 | 2.2 | 2.8 |

| Year | No replacement | 500-700 | 700-700 | 1000-700 |
|---|---|---|---|---|
| 2030 | 0.2 | 1.4 | 2.2 | 2.8 |
| 2031 | 0.2 | 1.4 | 2.2 | 2.8 |
| 2032 | 0.2 | 1.4 | 2.2 | 2.8 |
| 2033 | 0.2 | 1.4 | 2.2 | 2.8 |
| 2034 | 0.2 | 1.4 | 2.2 | 2.8 |
| 2035 | 0.2 | 1.4 | 2.2 | 2.8 |
| 2036 | 0.2 | 1.4 | 2.2 | 2.8 |
| 2037 | 0.2 | 1.4 | 2.2 | 2.8 |
| 2038 | 0.2 | 1.4 | 2.2 | 2.8 |
| 2039 | 0.2 | 1.4 | 2.2 | 2.8 |
| 2040 | 0.2 | 1.4 | 2.2 | 2.8 |
| 2041 | 0.2 | 1.4 | 2.2 | 2.8 |
| 2042 | 0.2 | 1.4 | -21.1 | -46.1 |

SOURCE: Transpower “GIT-Results.xls”

# APPENDIX B NET MARKET BENEFIT BY SCENARIO

**Table B- 1 Net market benefits for individual scenarios – 500-700 alternative**

| | High | Med | Low |
|---|---|---|---|
| MDS1 | $174 | -$9 | $135 |
| MDS2 | $398 | $258 | $88 |
| MDS3 | $319 | $195 | $212 |
| MDS4 | $1,010 | $859 | $907 |
| MDS5 | $926 | $469 | $482 |

**Table B- 2 Net market benefits for individual scenarios – 700-700 alternative**

| | High | Med | Low |
|---|---|---|---|
| MDS1 | $55 | -$57 | $41 |
| MDS2 | $356 | $307 | -$24 |
| MDS3 | $283 | $85 | $101 |
| MDS4 | $996 | $797 | $887 |
| MDS5 | $989 | $605 | $421 |

**Table B- 3 Net market benefits for individual scenarios – 1000-700 alternative**

| | High | Med | Low |
|---|---|---|---|
| MDS1 | -$11 | -$139 | -$63 |
| MDS2 | $497 | $240 | -$137 |
| MDS3 | $167 | -$13 | -$6 |
| MDS4 | $916 | $710 | $775 |
| MDS5 | $841 | $305 | $297 |

# APPENDIX C GEM/PLEXOS CAPACITY EXPANSION COMPARISON

In this Appendix we compare the generation expansion plans derived from GEM and PLEXOS using the 0-700 and 700-700 augmentation alternatives to demonstrate similarities and differences. The PLEXOS and GEM results for the 0-700 and 700-700 alternatives are shown for each MDS in Figure C- 1 to Figure C- 20.

GEM and PLEXOS are both MIPs that select generation expansion plans to minimise total system costs using post-tax cash flows subject to:

- N-1 capacity constraints
- renewable energy constraints, where applicable
- annual maximum gas constraint, and
- operational constraints.

However, there are differences in the formulation of the MIP that lead to variations in the resulting expansion plans. Some of these differences have already been discussed in the body of this report, and a detailed comparison of these models has been made by EGR Consulting in *GEM and PLEXOS in the SOO/GIT Process: Conceptual Commentary*, Oct 2007. Table C- 1 summarises the key formulation differences that are likely to impact on the capacity expansion plan selected.

Despite these differences, there are many similarities that can be observed when comparing the resulting capacity expansion plans. MDS5 is a prime example, where PLEXOS tends to build more DSR and GEM builds more NI thermal, but overall the capacity expansion plans look very similar (Figure C- 17 to Figure C- 20). The total capacity built is also comparable between the two models.

When comparing a market development scenario heavily reliant on renewable technologies, such as MDS5, against a scenario favouring thermal generation, such as MDS1, it is also evident that both models are making sensible plant selections. In MDS1, new NI thermal generation dominates both expansion plans. With the 0-700 augmentation option, more NI wind and hydro is built in GEM than PLEXOS, possibly due to the random variations in capital costs imposed (Figure C- 1 and Figure C- 2). Due to wind's low peak contribution factor, the total capacity built in GEM in this scenario is higher than in PLEXOS.

Moreover, with the 700-700 augmentation option, both models build more SI capacity, as expected. PLEXOS builds new SI thermal generation, whereas GEM builds more SI hydro capacity (Figure C- 1 and Figure C- 4). Once again, these build differences may be attributable to the random capital cost variations applied in GEM. Moreover, as noted in Table C- 1, a drier hydro yield is used by PLEXOS for both existing and new hydro projects. Accordingly, it is expected that more hydro would be built in GEM and more mid-merit or base-load generation would be built in PLEXOS, as observed.

**Table C- 1 Key formulation differences between GEM and PLEXOS**

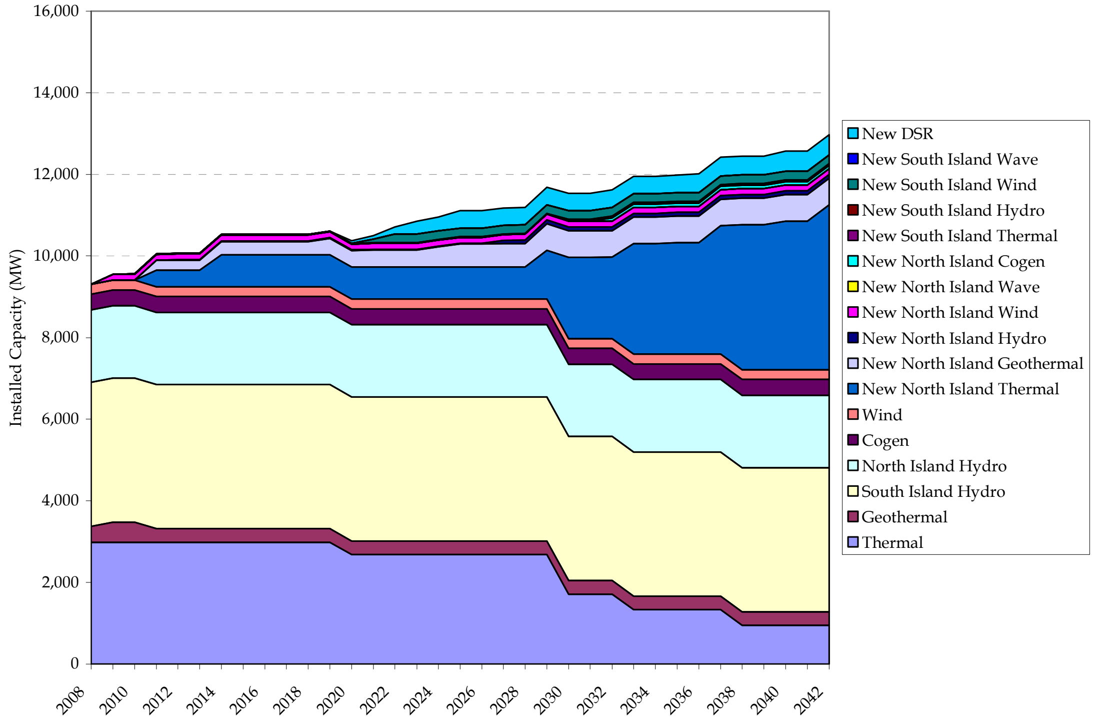
| | GEM formulation | PLEXOS formulation | Likely impact |
|---|---|---|---|
| Hydro inflows sample | 97% of average hydro yield | 94% of average hydro yield | Both models use a drier than average hydro yield in an attempt to reflect the underlying generation costs. Using an average hydro yield would under-estimate generation costs and hence tends to under-build capacity. The drier the hydro inflows sample the more base-load and intermediate generation plant will be favoured over peaking capacity. Moreover, the annual gas constraint will effectively be more limiting using a drier hydro yield, and hence more gas plant may be built in GEM than PLEXOS. |
| New hydro projects | Average yield assumed | 94% of average yield assumed | Hydro projects are likely to be favoured more in GEM than PLEXOS. |
| Load representation | Quarterly load duration curves using 5 blocks | Monthly load duration curves using 5 blocks | If there are few seasonal load variations within each quarter, this is unlikely to have a large impact on choice of expansion plan. |
| Forced outages | Average derating assumed | Represented by convolution of load duration curve | Convolution of the load duration curve essentially makes the load duration curve peakier, making peaking capacity and DSR more attractive. |
| Horizon | One optimisation spanning entire horizon | Two separate optimisation runs joined together | Breaking the horizon in two removes some of the perfect foresight available to GEM and hence is not guaranteed to provide an optimal solution over the entire horizon. For example, investment decisions made in the first step will not be informed of the fact that Huntly units are assumed to retire early in the second step. On the other hand, one might argue that perfect foresight is not available in reality and therefore investment decisions should be modelled assuming limited future knowledge. |
| Instantaneous reserve | Not modelled | Co-optimises energy and reserve | From an operational perspective, the modelling of instantaneous reserve may result in the HVDC link not being operated to full capacity, to minimise the cost of covering this risk in the reserve market. New plant that can provide reserve at low cost may also be favoured when co-optimising energy and reserve requirements in the capacity expansion plan. |

| | GEM formulation | PLEXOS formulation | Likely impact |
|---|---|---|---|
| Capital cost assumptions | Random variations in relativities of generic wind and hydro capital costs between scenarios | Capital costs of generic technologies not varied between scenarios | Similar cost structures were assumed for all generic wind and hydro units. Therefore, the purpose of randomising capital costs of generic wind and hydro units was to make the supply curve steeper and hence provide a greater mix of renewable technologies. Unfortunately, by randomly varying the cost assumptions between market development scenarios it made it more difficult to compare the different capacity expansion plans. In PLEXOS, without these random variations, there was a more noticeable switch from one technology to another. Using a flatter generic cost curve meant that additional HVDC link capacity did not necessarily facilitate more SI new capacity. For example, a corner solution may have already been reached whereby all available low-cost SI hydro had been built, and NI generic wind was the next-best technology. |
| Locational factor | Applies a locational factor to capital costs to reflect expected nodal price differentials | No locational factors used | The use of locational factors may favour plant on the periphery of the network, where it is assumed the nodal prices are relatively higher. Plants built at these locations have their capital costs reduced as a proxy for receiving higher nodal prices. |
| Dry-year security run | Driest hydro year on record (1932)<br>Only thermal peaking plant added/advanced | Second driest hydro year on record (1974)<br>Both thermal peaking plant and DSR added/advanced | More DSR is likely to be built in PLEXOS than in GEM. More capacity in total may be built in GEM as a drier hydro year is being used. |

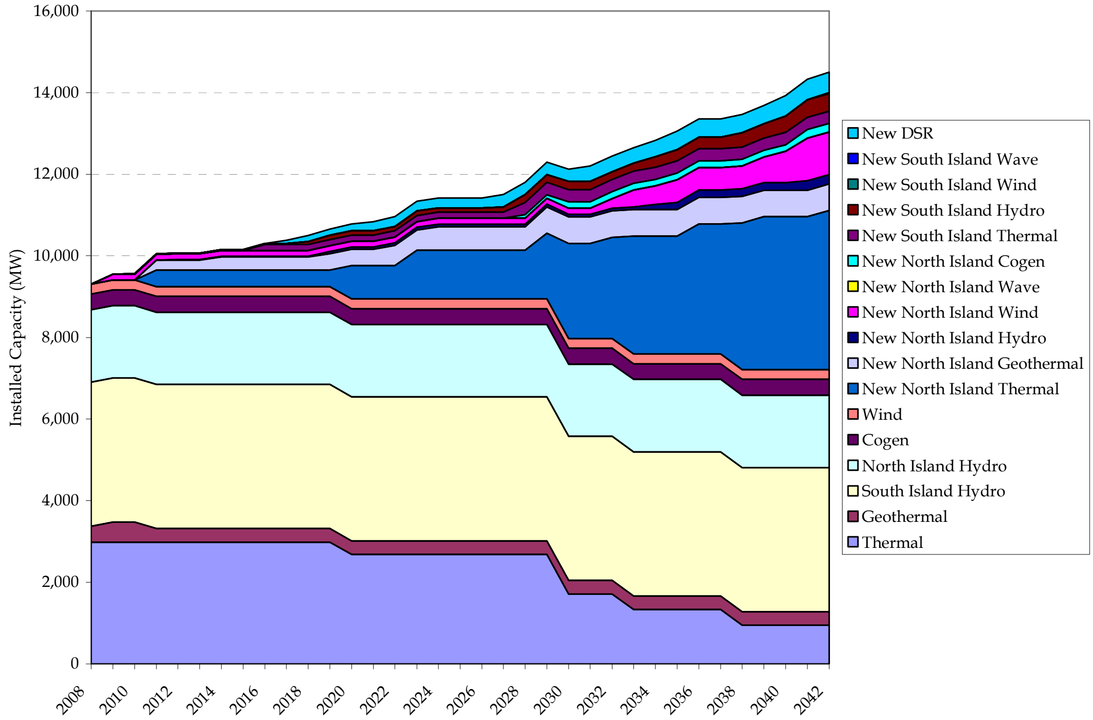
For individual scenarios, the following observations can be made:

- In MDS1, for the 0-700 case, GEM builds more NI wind and SI hydro, while PLEXOS builds more NI thermal. In the 700-700 case, as expected, more SI generation is built, but while PLEXOS relies more on new SI thermal generation, GEM builds more SI hydro and wind generation. PLEXOS results are consistent with the cheaper natural gas available in MDS1.
- Results for MDS2 are similar to those for MDS1 in the sense that PLEXOS relies more on thermal generation to supply the demand. While no wind generation is being built by PLEXOS in the SI, GEM is building some in the final years. In the 0-700 case, more thermal generation is built by PLEXOS both in NI and SI, compared with more SI and NI wind generation built by GEM. In the 700-700 case, GEM relies more on SI hydro and wind in both the NI and the SI, but no SI thermal generation, while PLEXOS results show the early entry of SI thermal generation.
- For MDS1 and MDS2 the total capacity built by PLEXOS is less than the total capacity built by GEM (about 1000 MW). This is partly justified because wind and hydro generators contribute less to the capacity requirements than thermal generation.
- In MDS3, PLEXOS builds more NI and SI hydro generation than GEM, and GEM relies more on SI wind and more NI thermal generation and less on SI hydro generation. The 700-700 case for GEM is the only case of wave generation being built.
- In MDS4, neither PLEXOS nor GEM build much SI generation, because of the SI surplus as a result of the progressive phase-out of the Tiwai Point smelter. In the 0-700 case, PLEXOS delays the building of new NI thermal generation until 2031, replacing it with earlier entry of more NI renewable generation (hydro and wind). GEM, on the other hand, starts building NI thermal generation from 2020. In the 700-700 case, PLEXOS replaces the NI thermal and wind generation built by GEM with more hydro. Less capacity is built overall by PLEXOS because of the possibility of exporting the energy surplus from the SI using the HVDC link.
- In MDS5, the 90% renewable scenario, PLEXOS builds little SI thermal generation (none in the 0-700 case) and instead builds more SI hydro and NI wind, while GEM relies more on thermal generation in both the NI and the SI. In the 700-700 case, as expected, more SI generation is built to take advantage of the cheaper renewable resources there. However, while PLEXOS builds almost exclusively hydro and wind generation, GEM builds some SI thermal generation. More DSR is commissioned by PLEXOS than by GEM, possibly to cover dry-year security constraints.
- There are no significant differences in total geothermal generation built by PLEXOS and GEM for any of the market development scenarios, with the only differences being small variations in the date of commissioning of the units.

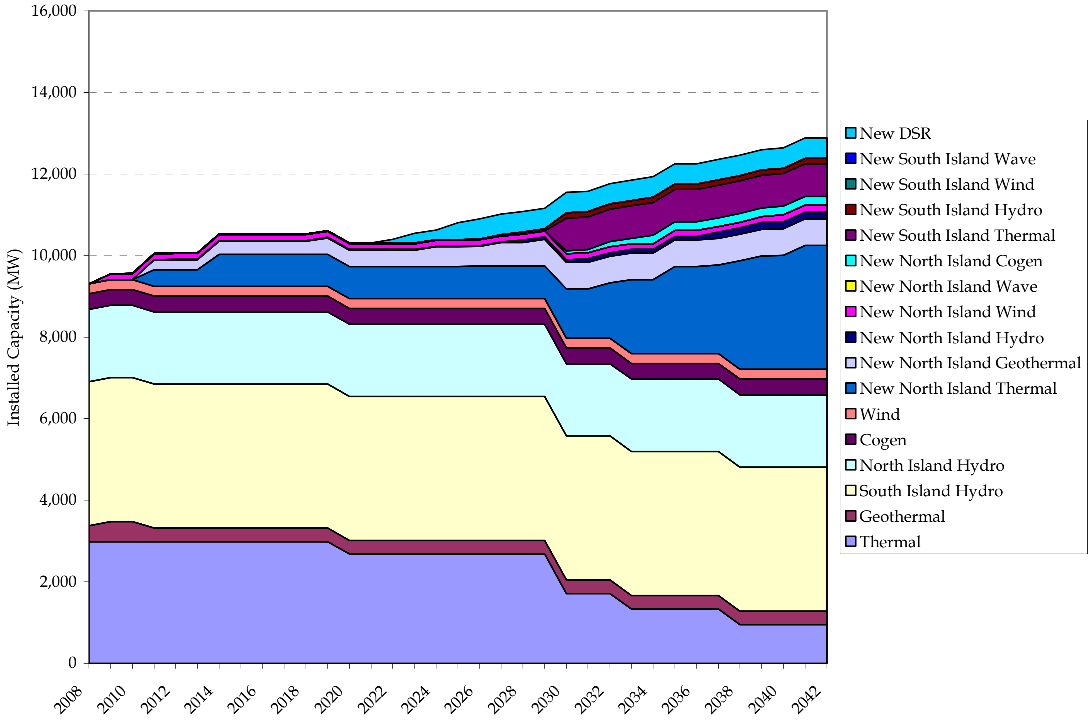
## Figure C- 1 MDS1 0-700 PLEXOS



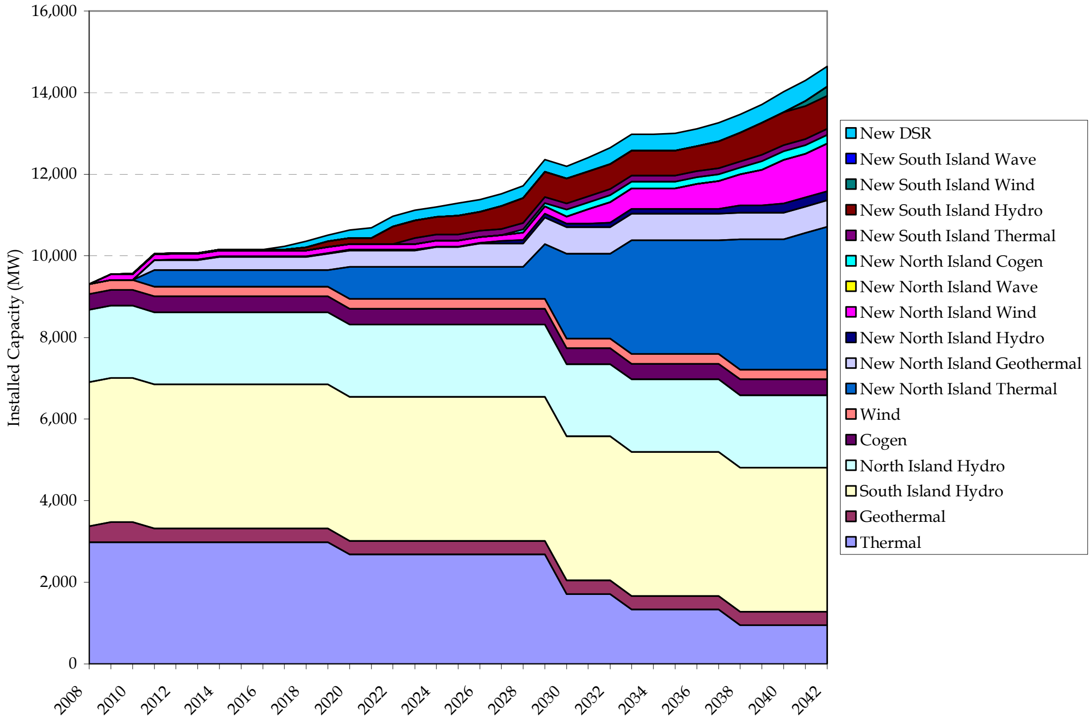

## Figure C- 2 MDS1 0-700 GEM



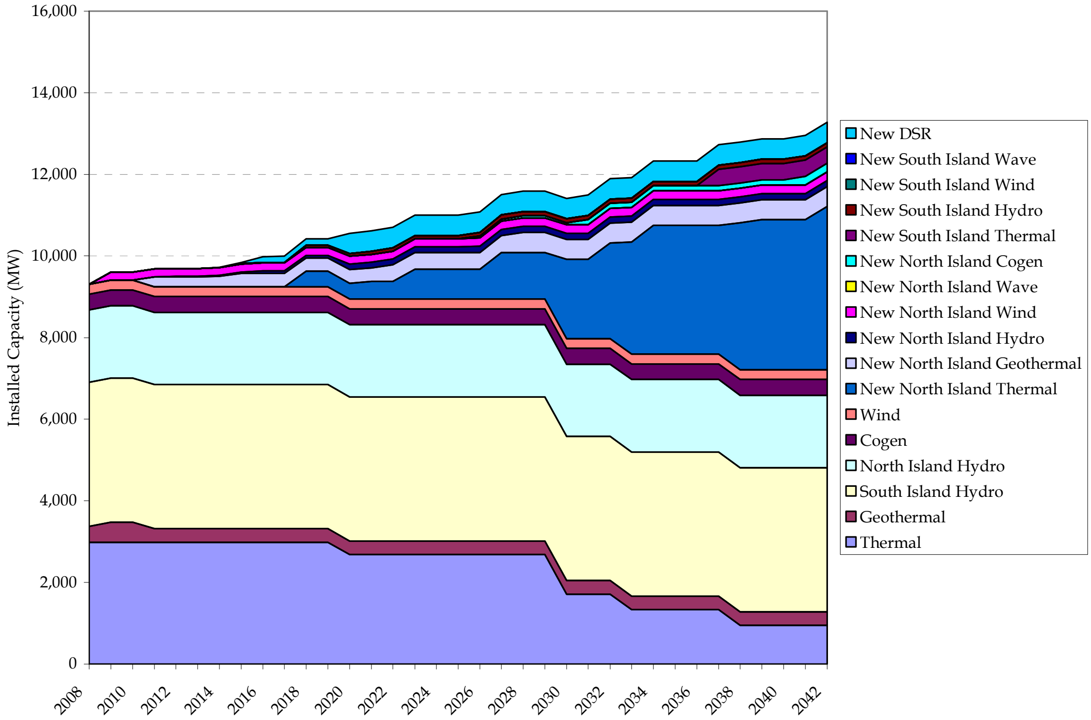
## Figure C- 3 MDS1 700-700 PLEXOS



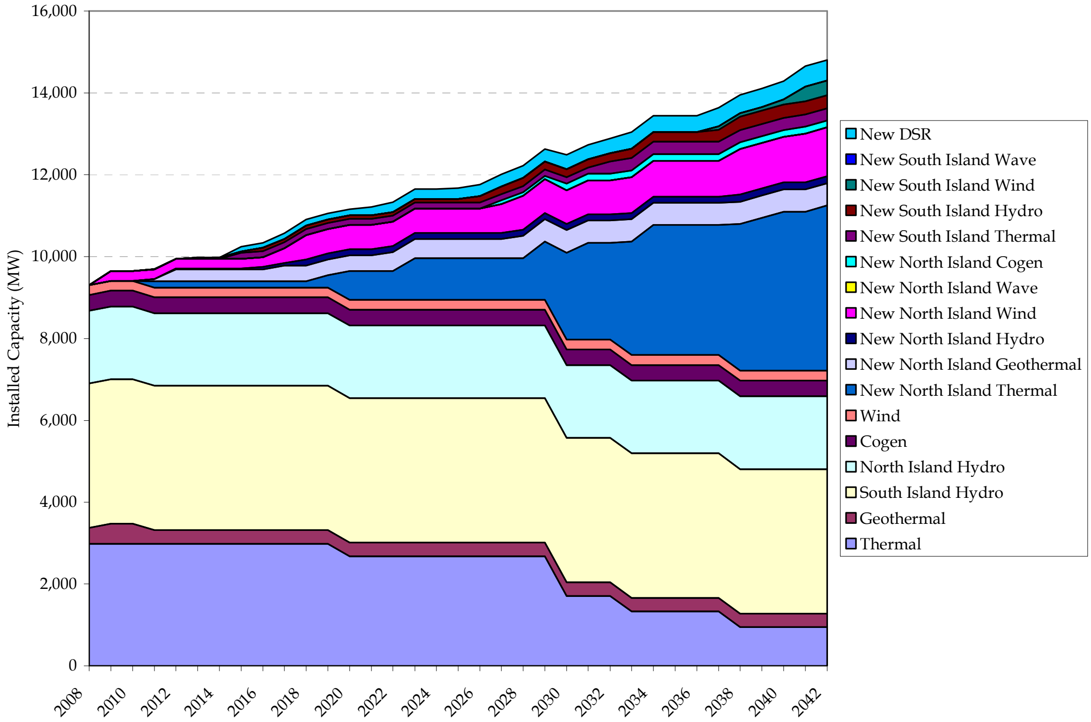

## Figure C- 4 MDS1 700-700 GEM



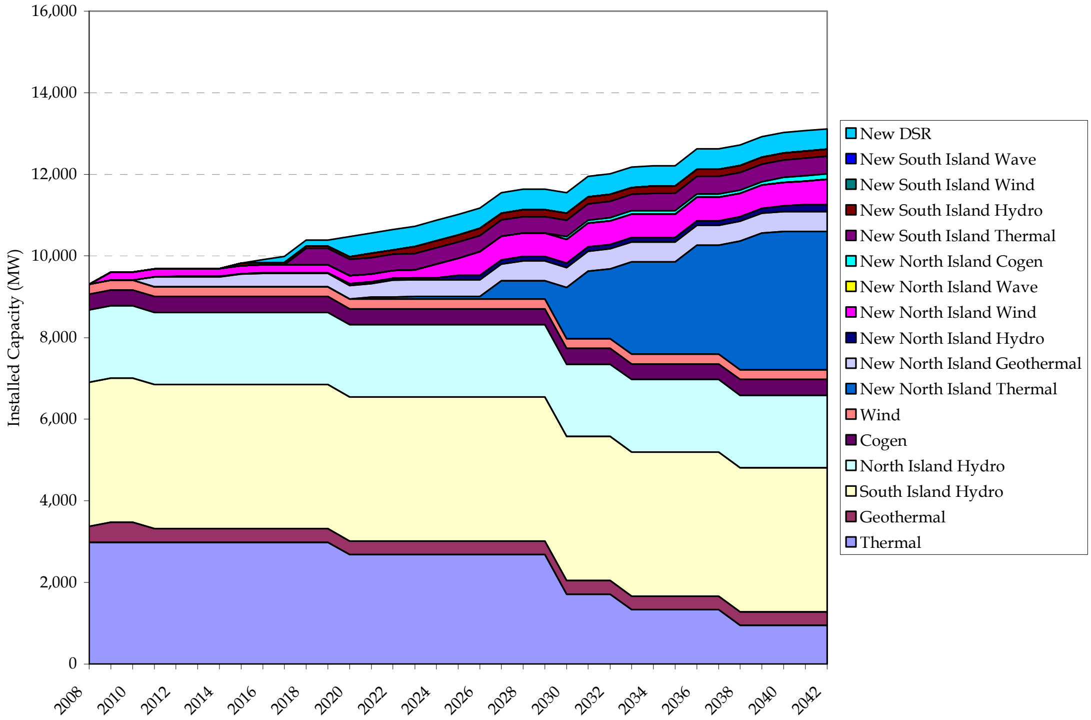
## Figure C- 5 MDS2 0-700 PLEXOS



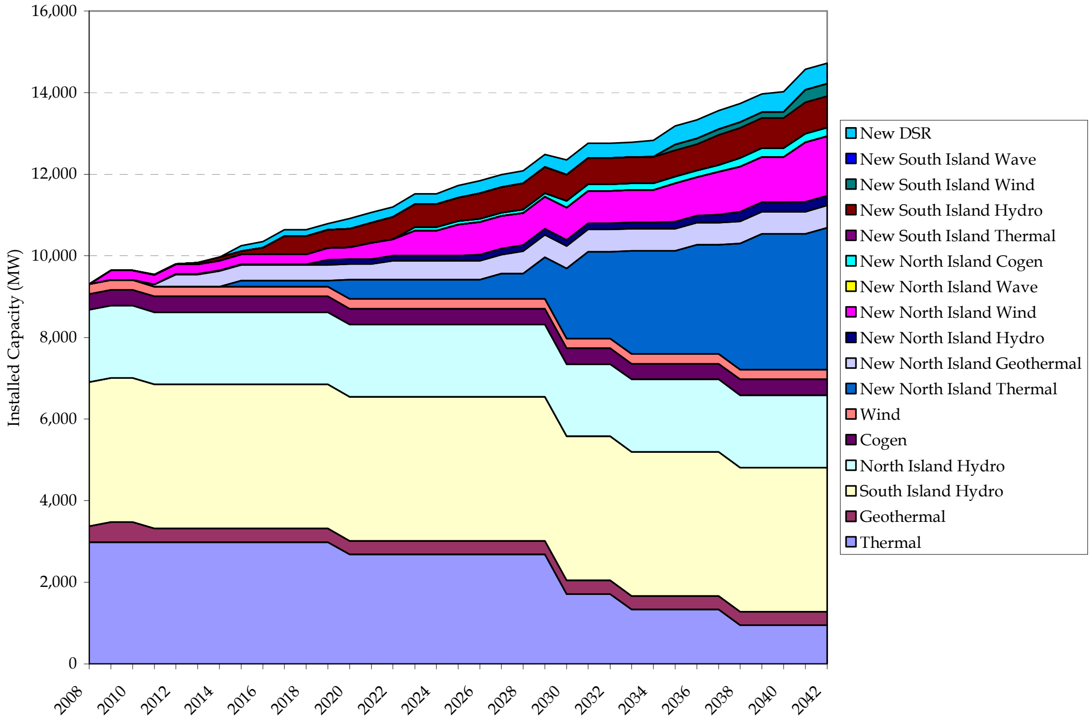

## Figure C- 6 MDS2 0-700 GEM



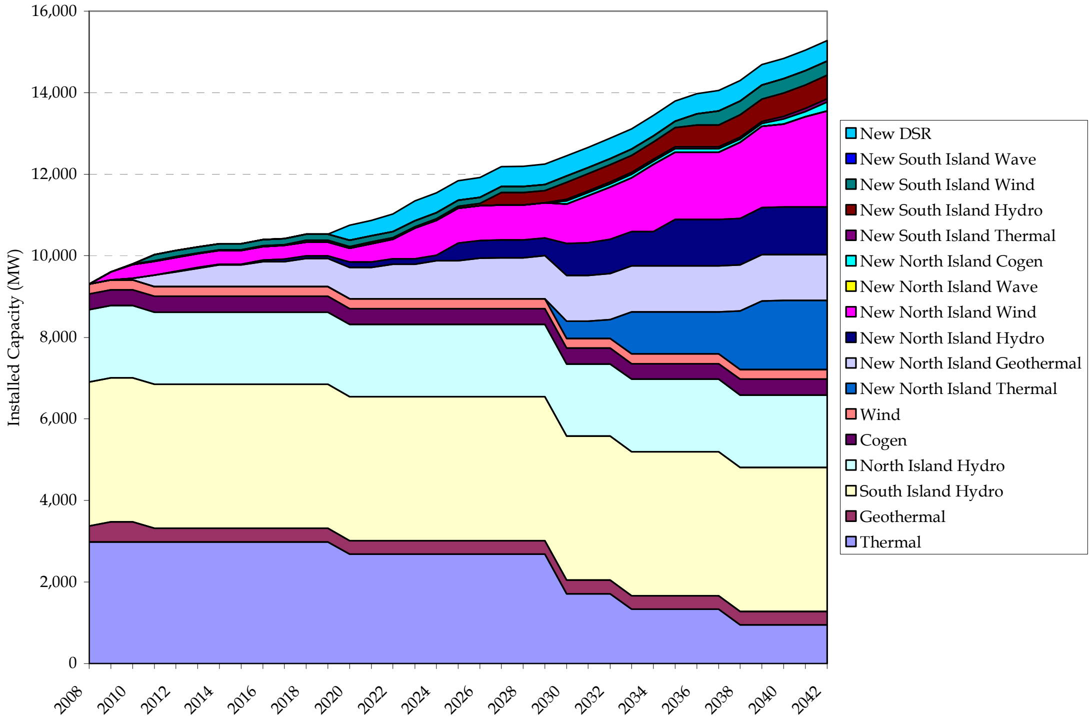
## Figure C- 7 MDS2 700-700 PLEXOS



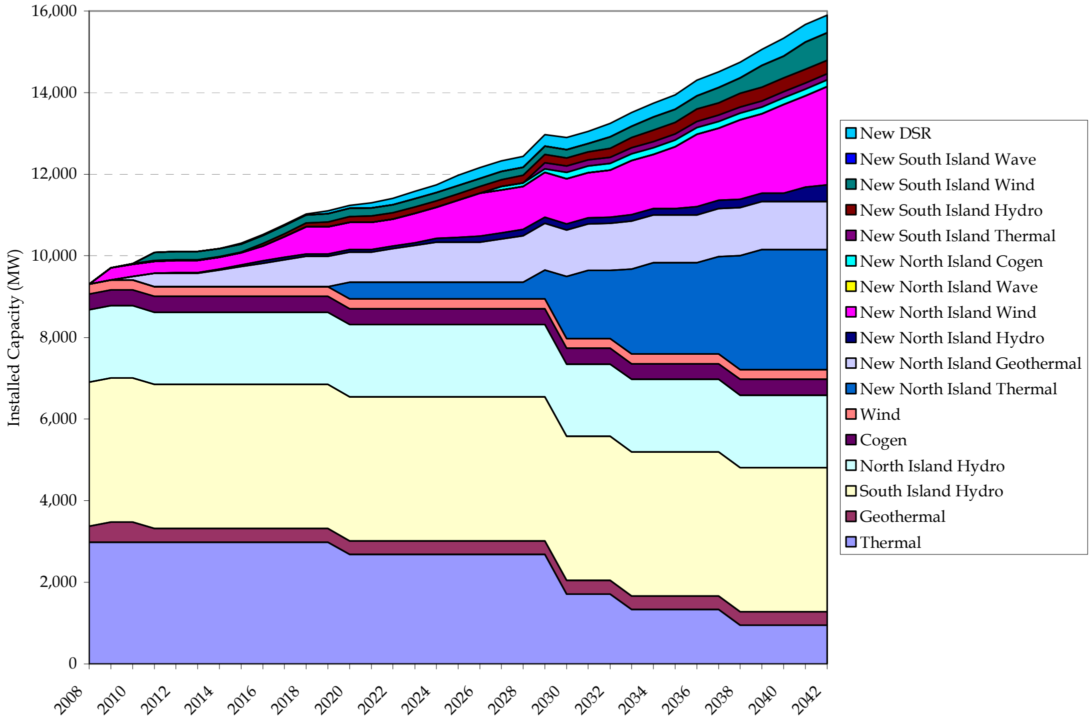

## Figure C- 8 MDS2 700-700 GEM



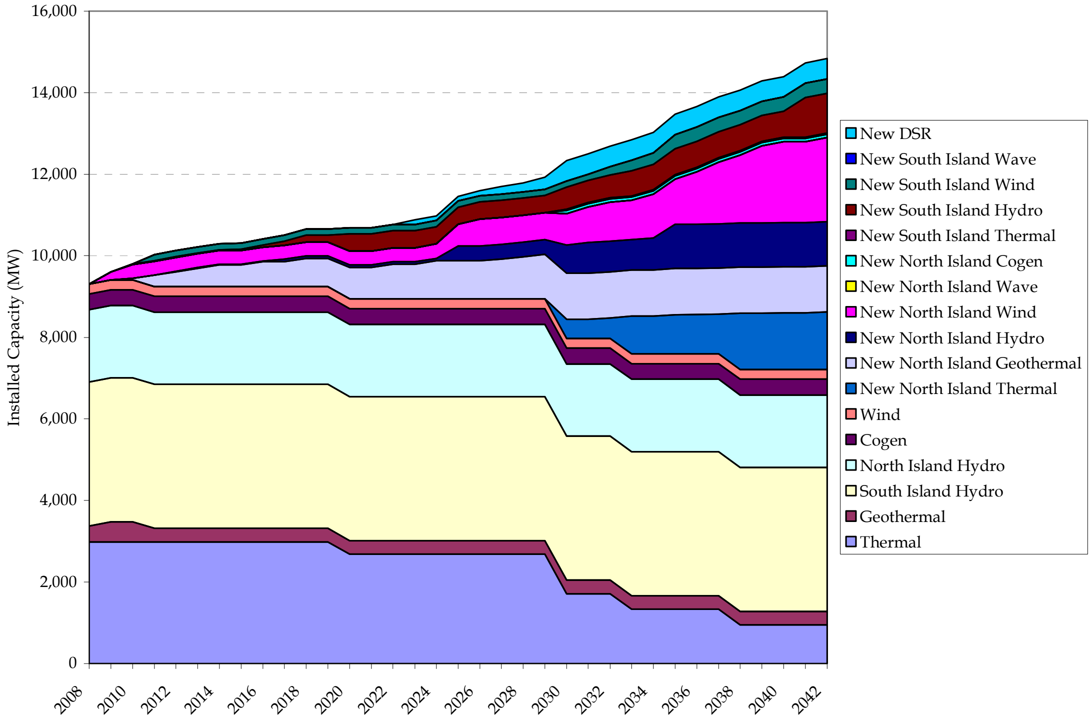
## Figure C- 9 MDS3 0-700 PLEXOS



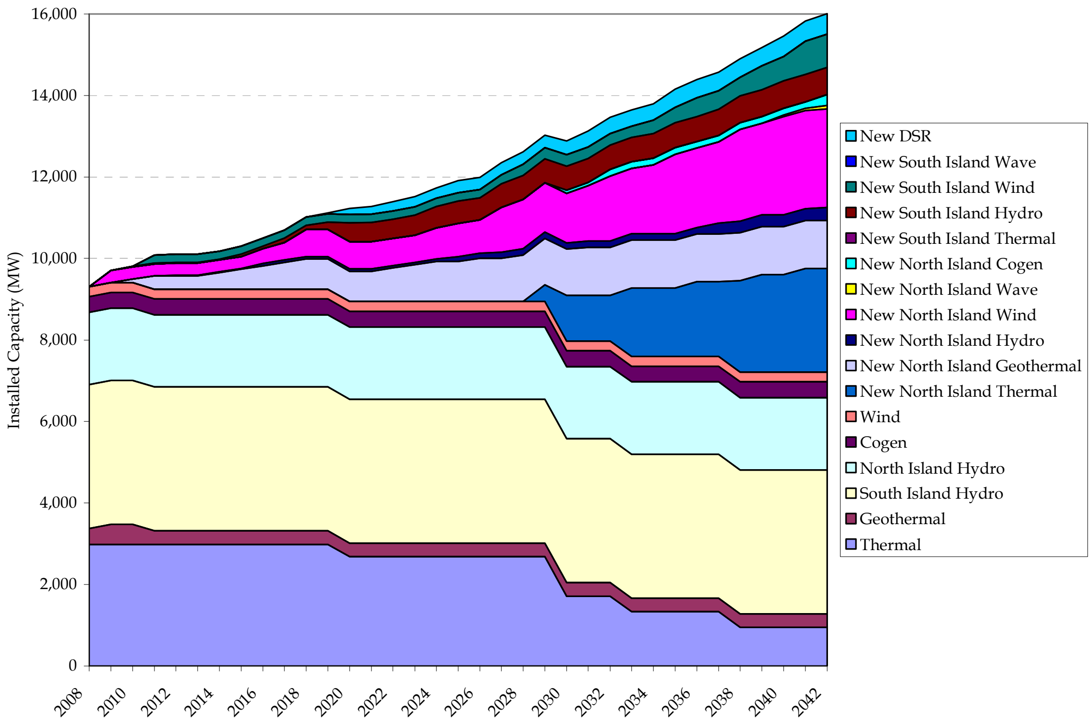

## Figure C- 10 MDS3 0-700 GEM



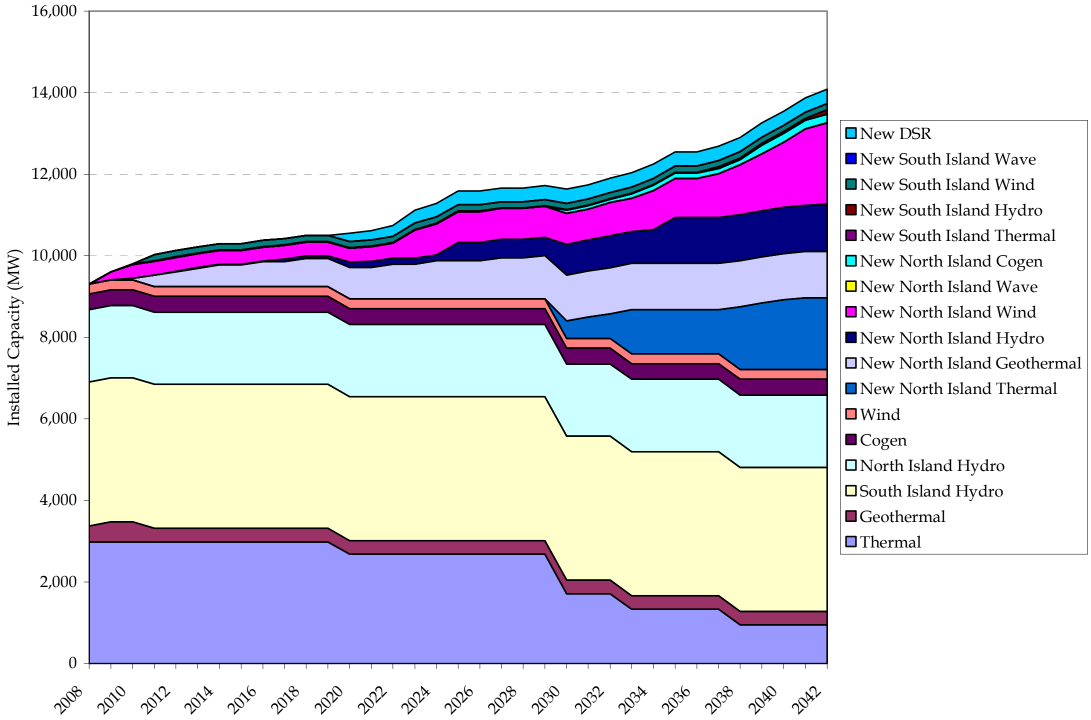
## Figure C- 11 MDS3 700-700 PLEXOS



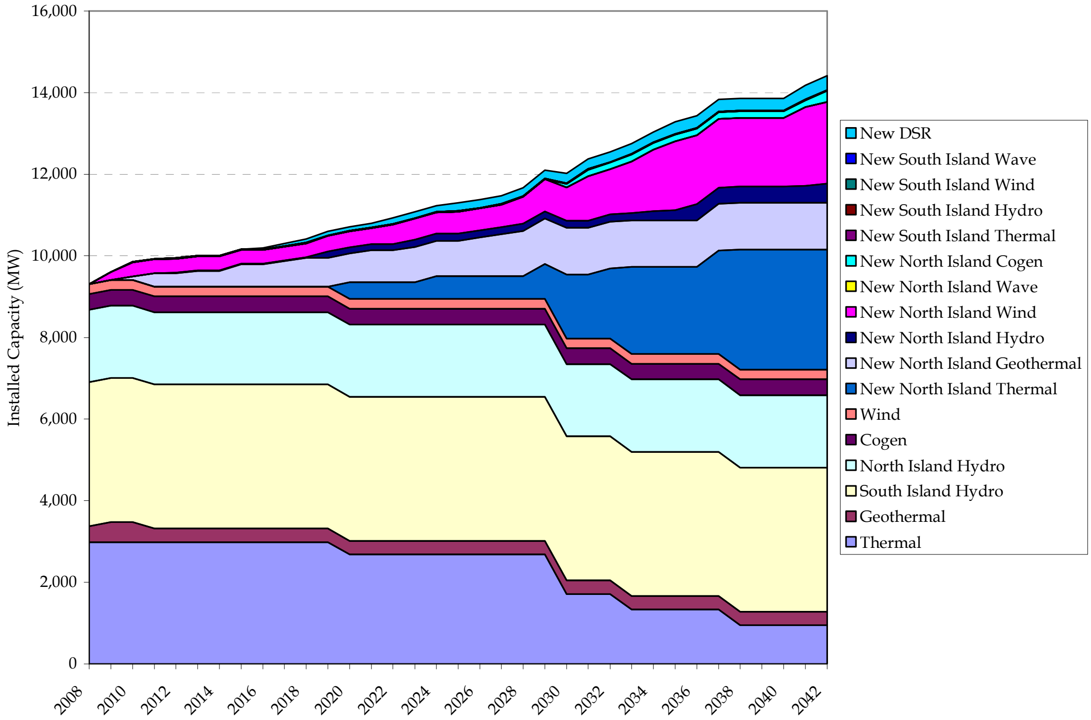

## Figure C- 12 MDS3 700-700 GEM



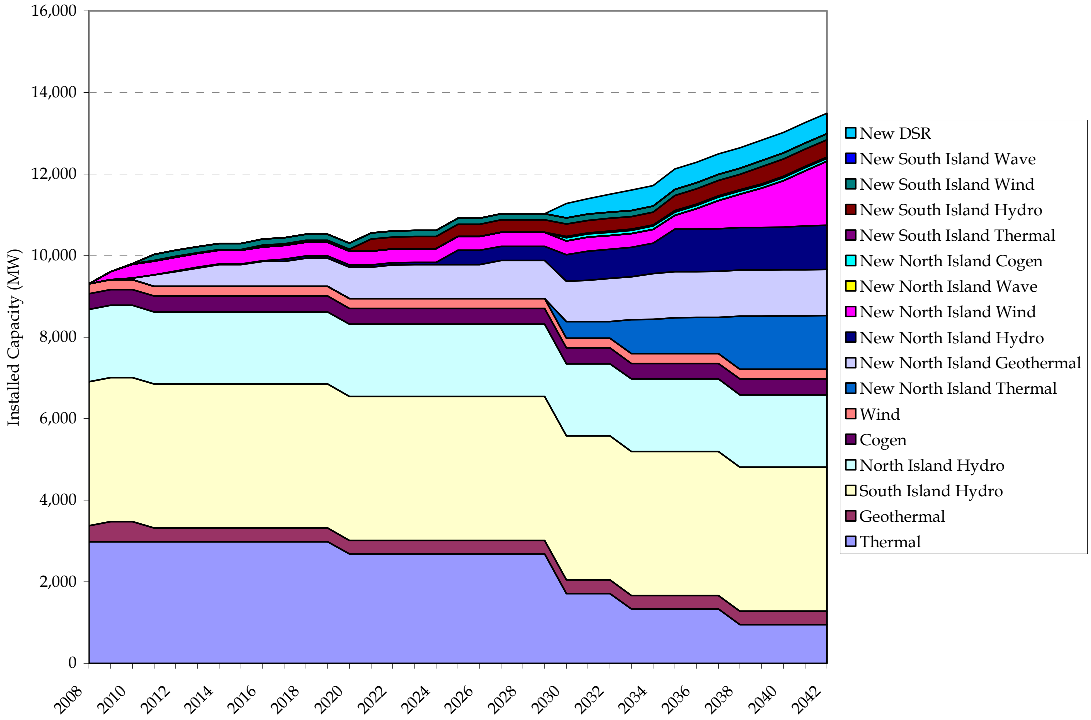
## Figure C- 13 MDS4 0-700 PLEXOS



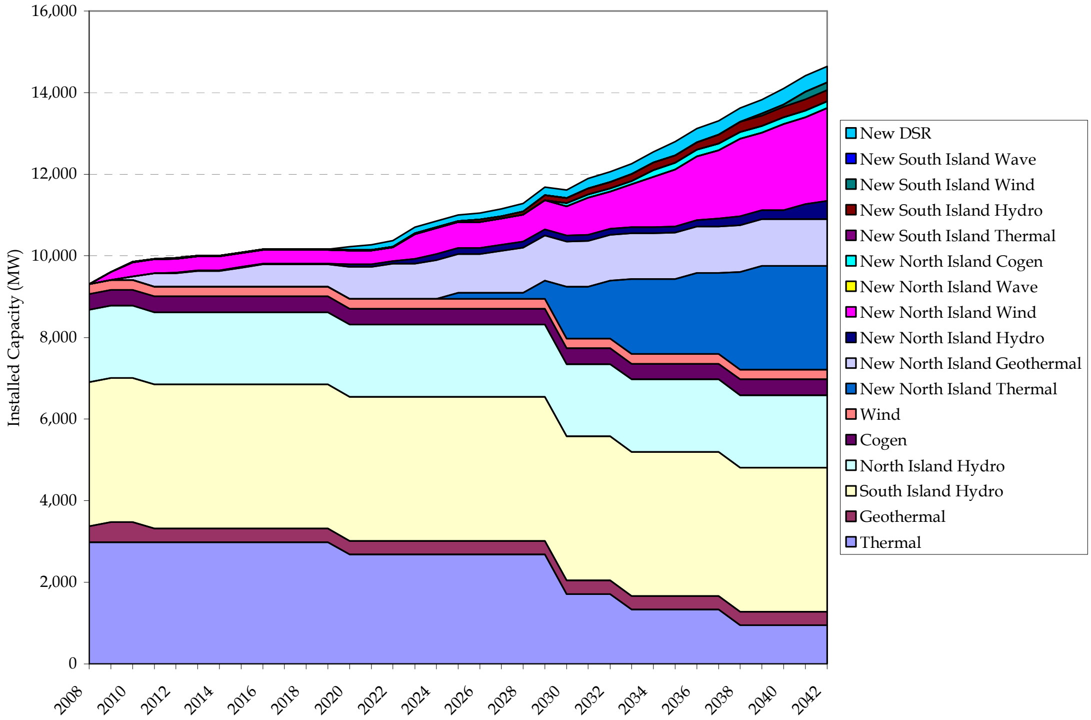

## Figure C- 14 MDS4 0-700 GEM



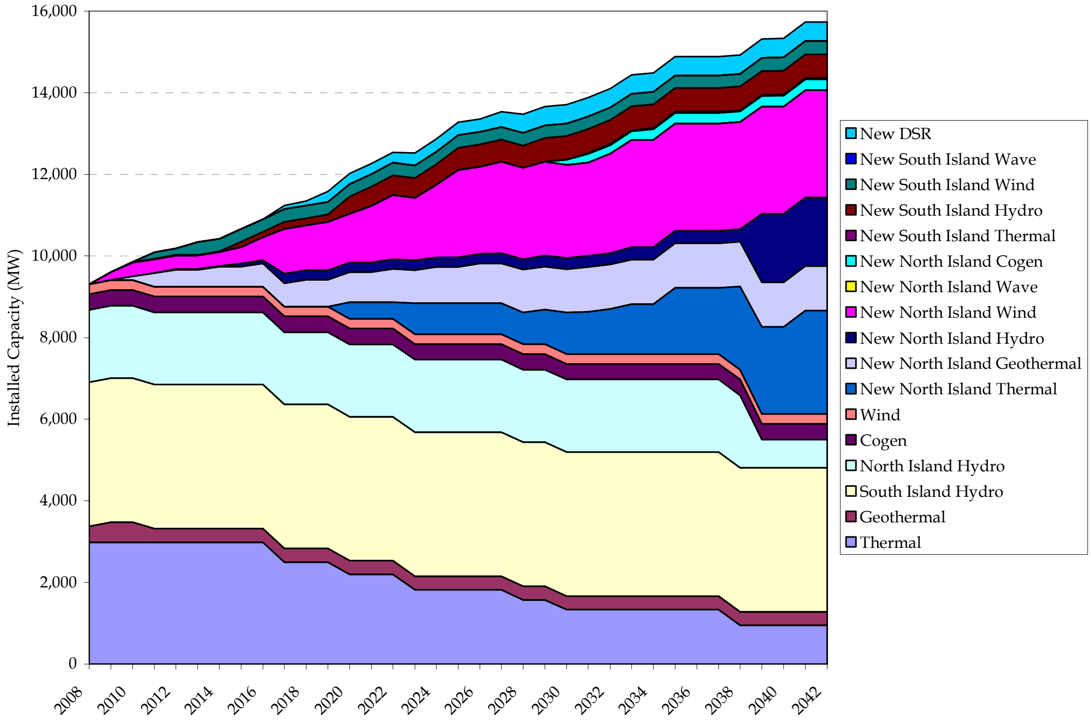
## Figure C- 15 MDS4 700-700 PLEXOS



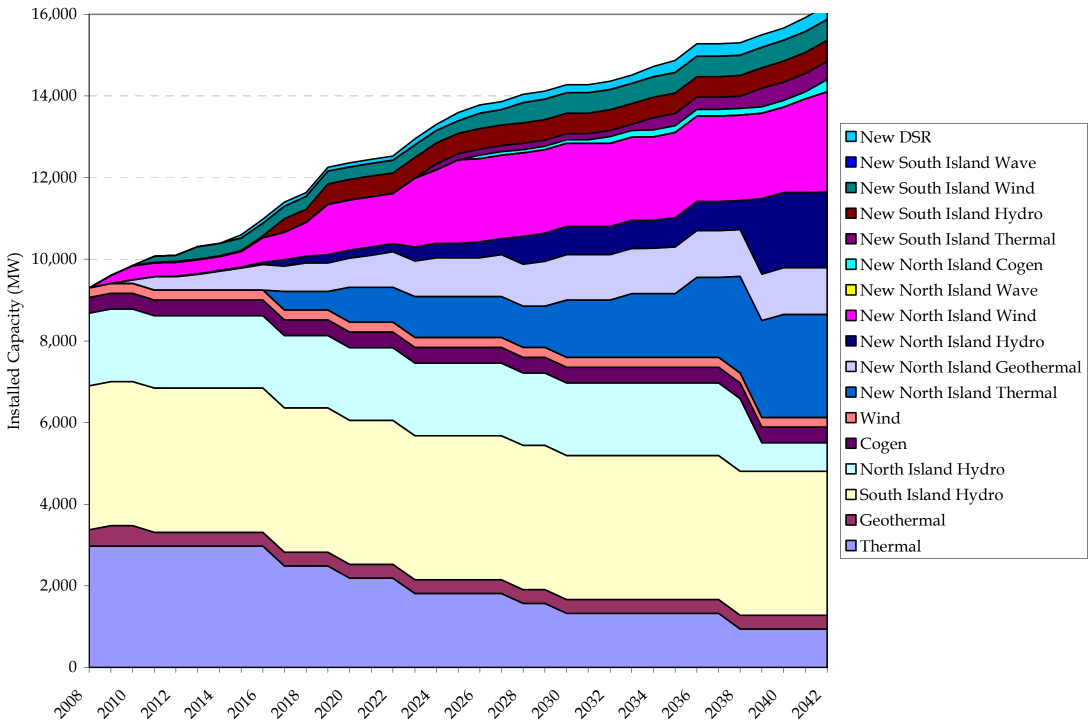

## Figure C- 16 MDS4 700-700 GEM



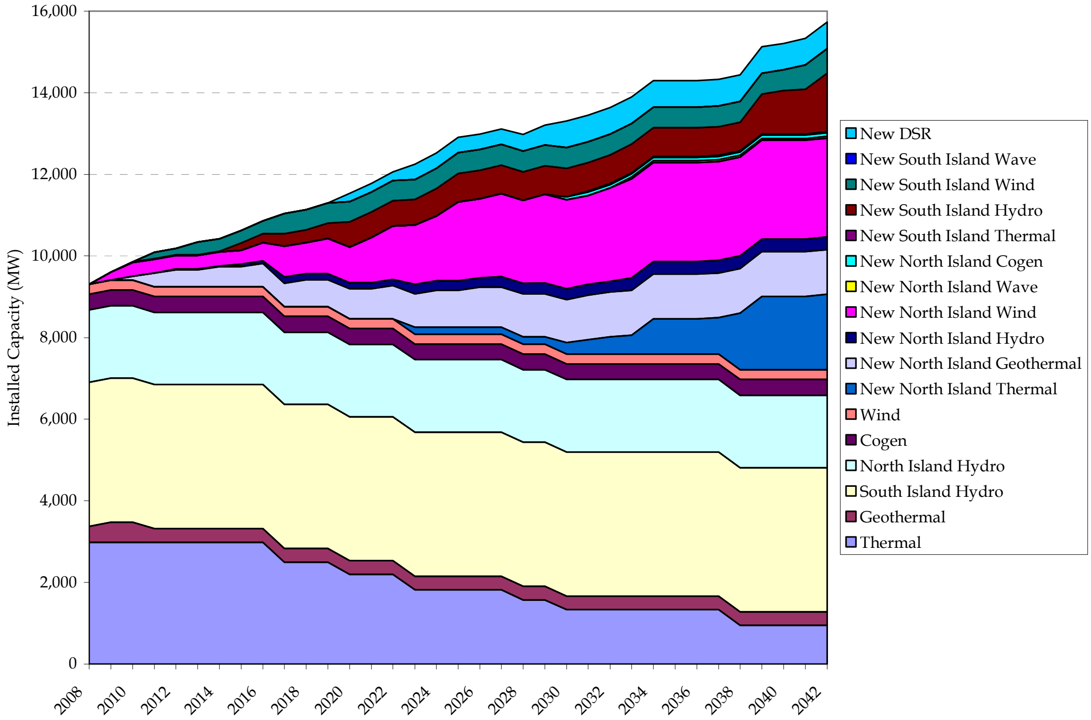
## Figure C- 17 MDS5 0-700 PLEXOS




## Figure C- 18 MDS5 0-700 GEM



## Figure C- 19 MDS5 700-700 PLEXOS




## Figure C- 20 MDS5 700-700 GEM