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FTR MANAGER

FTR GRID POLICY – SUPPORTING ANALYSIS

24 NOVEMBER 2014

Disclaimer

1.

EMS, as FTR Manager, will only accept a person as an FTR participant, and will only offer and issue FTRs to that person, if the person meets all of the following requirements:

(a) Meets the prudential requirements in relation to FTRs set out in Part 14 of the Electricity Industry Participation Code 2010 (**Code**), as determined by the Clearing Manager under the Code.

(b) Is a natural person resident in New Zealand, a body corporate that is incorporated in New Zealand, or a person with a branch office or other substantial physical presence in New Zealand through which it conducts its FTR participation.

(c) Has provided EMS as FTR Manager with either:

(i) a current and valid eligible investor certificate under clause 41 of Schedule 1 of the Financial Markets Conduct Act 2013 (FMCA) in respect of the issue or sale of FTRs; or

(ii) a current and valid wholesale investor certificate under clause 44 of Schedule 1 of the FMCA.

(d) Is registered by the Electricity Authority as an Industry Participant under section 9 of the Electricity Industry Act 2010 as a trader in electricity.

(e) Agrees to the standard FTR participation agreement,

(**authorised persons**).

2. Information about FTRs made available by EMS through any medium (**FTR information**) is not:

(a) advice on, or a recommendation of, FTRs or any other investment, financial product or risk management arrangement;

(b) an offer or solicitation by EMS to issue or deal in FTRs or any other investment, financial product or risk management arrangement; or

(c) directed to any person who is not an authorised person.

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4. Prior to any person acquiring, entering into or dealing in any investment, financial product or risk management arrangement they should obtain their own tax, legal and financial advice.

5. The FTR auction, reconfiguration auction and assignment facilities provided by EMS as FTR Manager are not licensed financial product markets under the FMCA or otherwise. However, those facilities and the FTR Manager are regulated under the Electricity Industry Act 2010, Electricity Industry (Enforcement) Regulations 2010 and Electricity Industry Participation Code 2010.

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Document History

Version	Date	Status	Edited By	Revision Description
1.0	7 March 2013	Draft	EMS	Initial draft to FTR Users Group
2.0	15 April 2013	Released	EMS	Feedback incorporated
2.1	26 June 2013	Released	EMS	Updated analysis of bipole outages
2.2	26 Sept 2013	Released	EMS	Updated to post HAY statcom HVDC limits
2.3	24 November 2014	Released	EMS	Updated Disclaimer to reflect FMCA changes

1 Introduction

The FTR Allocation Plan 2012 provides in section 1.6 that the FTR Manager will develop, publish apply and regularly review FTR Policies detailing how it will implement the FTR Allocation Plan, including an FTR policy on Determining the FTR Grid (the Policy). The Policy is formally titled *FTR Policy: FTR Grid and Auction Data*, and is available at *http://ems.co.nz/ftr/ftrlibrary*.

The Policy is critical because the choice of FTR Grid determines the volume of FTRs that can be awarded in the FTR Auction, which in turn determines both the total net capacity available to FTR Participants for hedging, and the likelihood of Revenue Adequacy or Revenue Inadequacy. There are some parameters in the Policy that justify significant care in their choice.

1.1 Scope

The purpose of this supporting analysis is to provide the justification for the parameters reflecting:

- Outages
- Losses
- Capacity scaling factor
- Contingencies
- Permanent security constraints
- HVDC representation and constraints

The contingencies, permanent security constraints and HVDC representation are required also by the Rentals Amount Calculation, also described in the Policy.

The reasons that the Supporting Analysis is presented separately to the Policy, rather than say as appendices to it, are:

- To focus the Policy on the 'what' rather than the 'why'
- To keep detailed technical analysis out of the Policy
- To simplify version control, as some reviews of the supporting analysis may not result in a change to the Policy, and some reviews of the Policy may not affect those areas covered by the supporting analysis.

The Policy describes (in section 1.4) when reviews will occur.

1.2 Glossary

Please refer to the FTR Glossary for an explanation of terms used in this document[1]. The following terms used in this document are not currently in that glossary:

Term	Meaning
AUFLS	Automatic Under-Frequency Load Shedding
CDS	Centralised Data Set
DCCE	DC Contingent Event
DCECE	DC Extended Contingent Event
LPRTG	Locational Price Risk Technical Group
P2, P3	Pole 2, Pole 3
RHS	Right hand side (of a constraint)
RMT	Reserves Management Tool
SFT	Simultaneous Feasibility Test
SPD	Scheduling, Pricing and Dispatch
SVC	Static Var Compensator

1 Available at *www.ftr.co.nz*

2 Approach to the analysis

This supporting analysis aims to quantify the various parameters in the FTR policy on the FTR Grid (the Policy) affecting FTR capacity of the FTR Grid.

2.1 Revenue Adequacy Objective

This supporting analysis assumes the FTR Allocation Plan of December 2012, available in the FTR library.

The FTR Allocation Plan requires (in section 4.8) that in developing the FTR Policy:

> The FTR Manager will target a balance between ensuring that there is revenue available sufficient to settle the FTRs, and ensuring that sufficient volume of FTRs are available so that participants who wish to purchase FTRs are able to obtain them.
>
> The FTR Manager will develop the FTR policy on the FTR Grid such that, in its reasonable opinion at that time, it is expected that the primary objective will be achieved, with consideration given to also achieving the secondary objective:
>
> - The primary objective is for Revenue Inadequacy to occur one month in twelve
> - The secondary objective is for the annual average scaling factor to be 98%
>
> Collectively, these primary and secondary objectives are referred to as the Revenue Adequacy Objective.

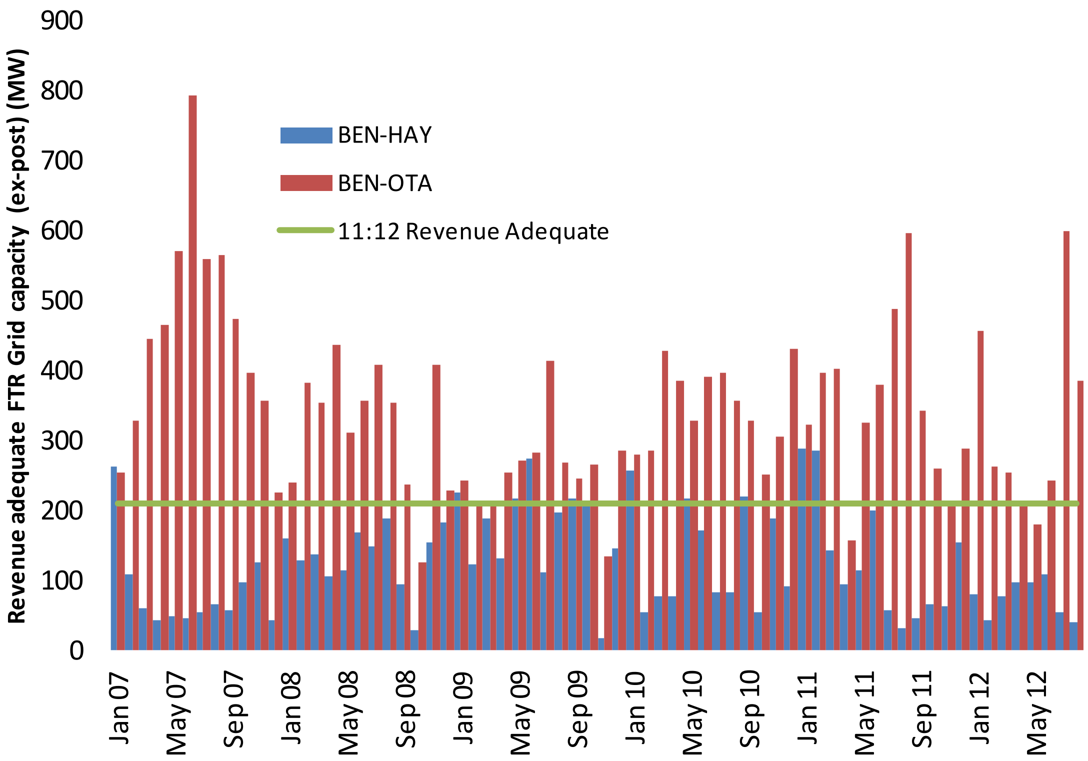
2.2 The historical overview

By way of background, it is revealing to consider what FTR capacities could have been awarded historically to achieve revenue adequacy.

Figure 1 illustrates the capacities of FTRs between BEN and OTA that could have been awarded monthly that, given the final prices that transpired, would have achieved precise monthly revenue adequacy. It assumes that all rentals are used to fund the FTR market and ignores the use of auction income. If a fixed FTR Grid capacity was used for all months, the Revenue Adequacy target would have been met at around 210 MW (the green line).

The blue bars illustrate the equivalent for FTRs between BEN and HAY using only the HVDC rentals. It illustrates, for this retrospective analysis, that historically shortfalls in HVDC analysis could have been made up by rentals excesses in the HVAC system. In other words, HVDC capacity while critical needs to be considered as part of the bigger BEN to OTA picture.

Figure 1 – Overview of historical rentals and ex-post revenue adequacy[2]



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[2] This analysis assumes:

- Actual rentals amounts from Transpower (from HistoricLCEBreakdown.xlsx as published on *www.transpower.co.nz*), using the HVDC and the total (HVDC, connection and interconnection).
- No reduction in this amount to allow for the effects of the FTR Rentals Amount calculation, and no additiona assumed for FTR auction income
- BEN, OTA and HAY final prices from the CDS
- Determines what capacity X would have been revenue adequate for that month against an FTR award scenarios of X MW of Option FTRs southwards and X MW of Option FTRs northwards

2.3 Treatment of uncertainty in approaching the Revenue Adequacy Objective

There is considerable uncertainty over many factors that will affect this balance, including:

- The FTR market is new to New Zealand, so there is no prior experience of how it will affect the behaviour of participants in the energy and reserves markets. However, overseas experience has been that the introduction of an FTR market can have material effects on energy market behaviour
- The commissioning of HVDC Pole 3 is planned for just before the FTR market opens. Pole 3 will have a significant impact on inter-island capacity, and on the energy and reserves markets. There is no prior experience of what the market effects will be
- Within the first year of FTR market operations, other major grid investments will be commissioned
- Even without these, the future is never certain

These uncertainties, or at least the first three, can be expected to diminish significantly as the FTR market progresses and matures.

There is also the issue of market confidence. If the FTR Manager has perfect information and foresight, then even then there would be, in accordance with the specification of the Revenue Adequacy Objective, an 8% chance of Revenue Inadequacy in the first auction. If an expected value approach were used, then given the real uncertainties, the probability would be much greater.

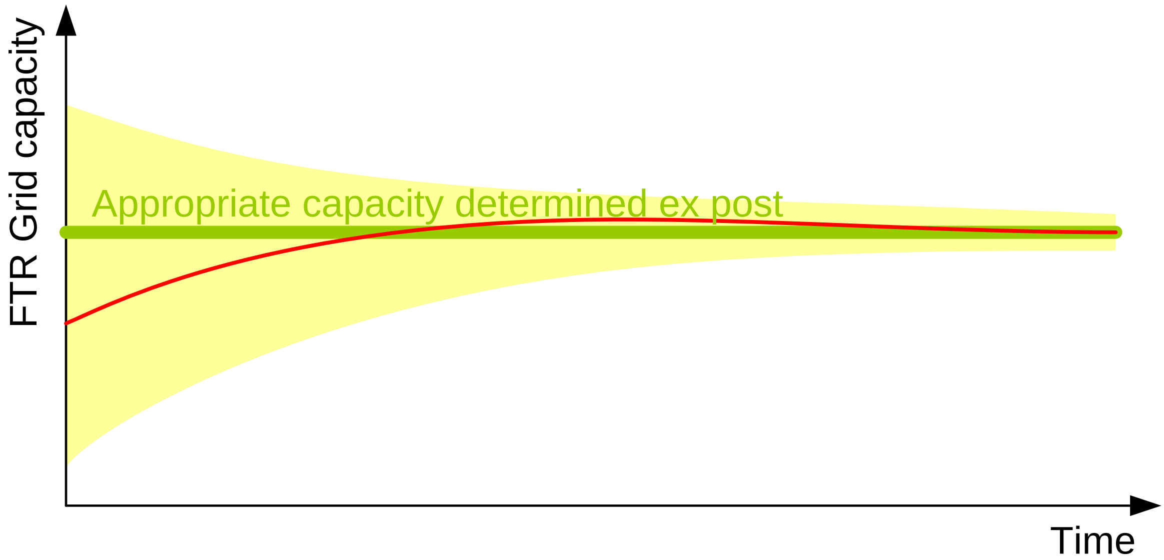
Another relevant issue is that the first FTR Auction will be for one FTR Period, the second for three, the third for five etc. as the FTR auction horizons build up. Thus, a wrong assumption in the FTR Grid Policy could have ramifications over many FTR Periods before being identified and addressed.

Given these uncertainties, and that the Revenue Adequacy Objective is expressed over a twelve month timeframe, the FTR Manager proposes being initially conservative in specifying the FTR Grid, and equilibrating the capacity to the Revenue Adequacy Objective over time.

This approach is illustrated conceptually in Figure 2, in which:

- the green horizontal line denotes the FTR Grid capacity that would, determined ex post, have exactly met the Revenue Adequacy Objective
- the yellow cone illustrates the amount of uncertainty, initially large but diminishing with market experience
- the red line the FTR Manager’s proposed initially conservative approach, to minimise the risk of being in the ‘upper yellow’ for the first FTR Periods

Figure 2 – Approach to conservatism in FTR Grid definition



Rule 1 – Approach

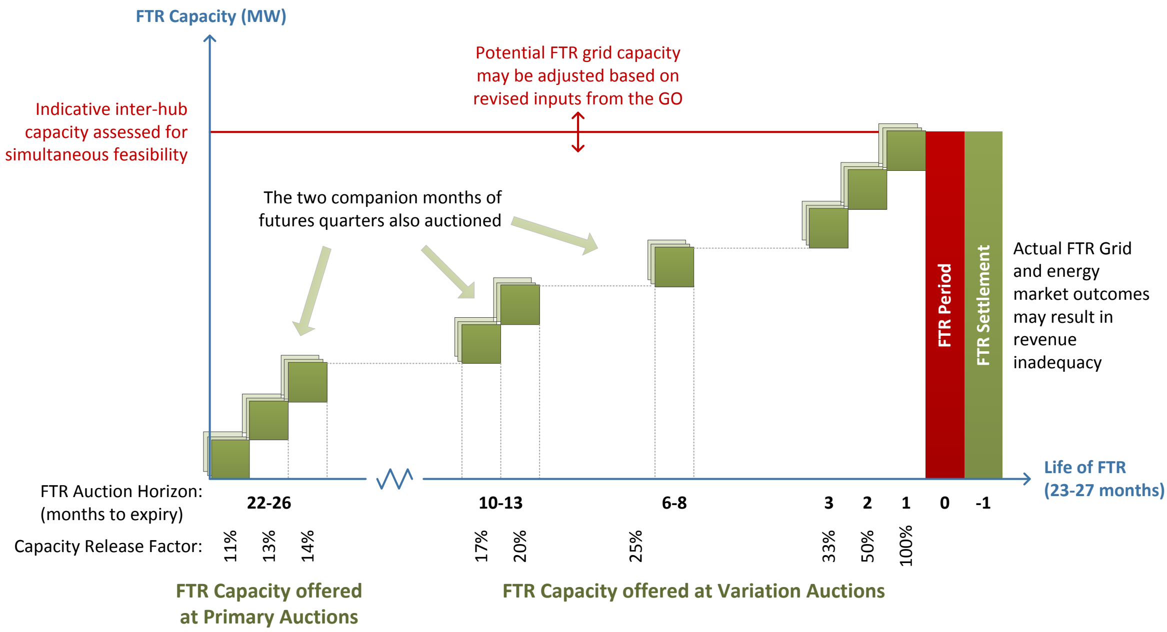
FTR Manager proposes being initially conservative in specifying the FTR Grid, and equilibrating the capacity to the Revenue Adequacy Objective over time as better information becomes available

Each FTR Grid parameter discussed below will be assessed in terms of its expected impact on the Revenue Adequacy Objective, with a view to ensuring that in aggregate a conservative approach is taken.

2.4 Progressive release of FTR Grid capacity

In accordance with the FTR Allocation Plan, and as explained in the FTR Calendar, as FTR horizons build up after the first auction FTR Grid capacity will be released progressively. Once steady state is reached, the amount released will be approximately 11% per auction, as illustrated in Figure 3 (which is from the FTR Calendar):

Figure 3 – FTR Auction build-up



The auctions that most affect Revenue Adequacy risk are therefore those with shorter horizons, especially the last auction. Auctions in the 23-27 month horizon have a risk 'buffer' of 2/3 of the capacity. That is, the FTR Grid would have to reduce to a third of its capacity between then and real time to result in an over-allocation of FTRs, an unlikely scenario. Similarly, auctions in the 9-14 month horizon a buffer of some 1/3, three month 22% and two months 11%[3].

This buffer is particularly relevant then to the treatment of long-range impacts, such as the treatment of unplanned outages when there are no planned outage data (section 3.3.3).

2.5 The Revenue Adequacy cycle

Classic FTR theory has it that, if the FTR Grid and the dispatch and pricing grid are the same, then if the set of FTR awards are 'simultaneously feasible' (on the FTR Grid), then rentals (from the dispatch and pricing grid) will cover FTR payments, and there will be guaranteed Revenue Adequacy.

The classic problem is that, with outages (and any grid reconfigurations, commissionings and decommissionings) the FTR Grid as forecast at the time of auction will rarely be exactly the same as the actual grid for every Trading Period in the FTR Period. Where the capacity of the latter is less, simultaneously feasibility no longer implies Revenue Adequacy, and Revenue Inadequacy can occur. This is why reflecting outages in FTR markets are so important. Outages are addressed in section 3.

In the New Zealand FTR market however, there are additional complications that can drive Revenue Adequacy.

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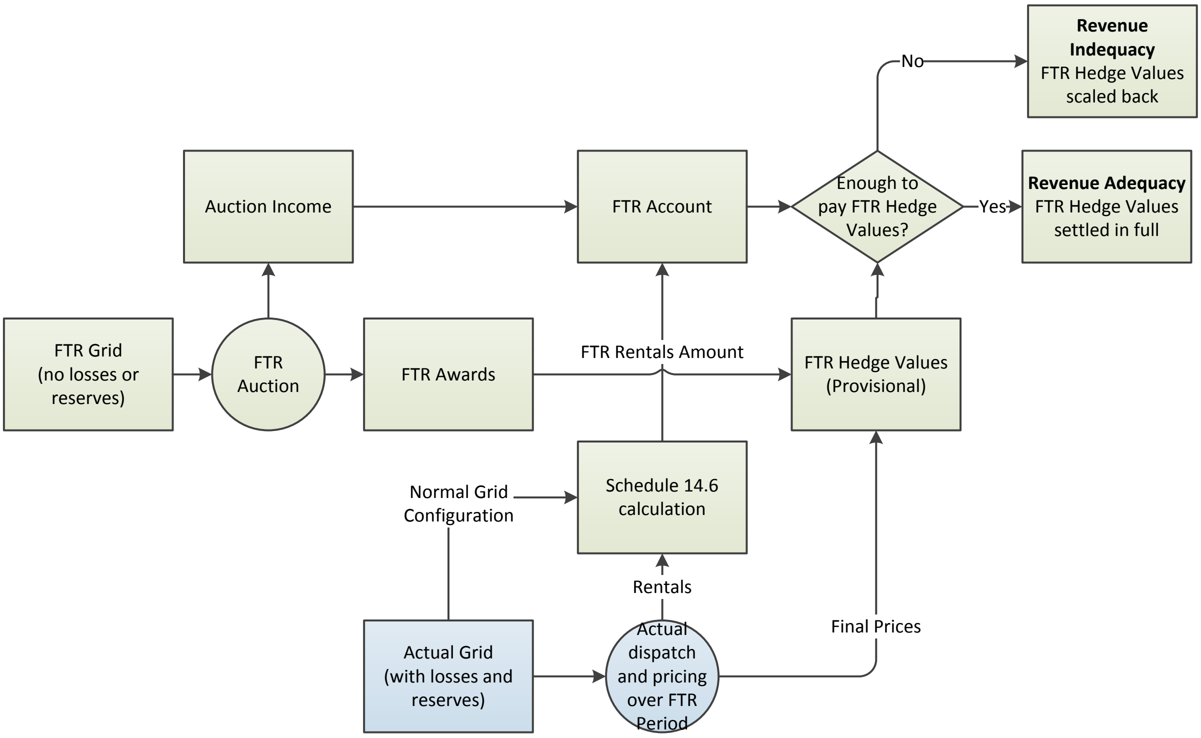
[3] These percentages are nominal, as they assume that the Indicative Inter-Hub Capacity remains the same between different FTR Auctions of the same FTR Period. If the Indicative Inter-Hub Capacity changes between different FTR Auctions of the same FTR Period, it will affect the percentages.

Two of these are losses and reserves, that are represented in dispatch and pricing but cannot be represented explicitly in the i-HEDGE™ auction model and hence in the FTR Grid and FTRs. How these effects are approximated is the subject of sections 6 and 4.

The two other drivers of Revenue Adequacy that are in effect external to the FTR Grid definition: Schedule 14.6 and the FTR Rentals Amount, and the use of auction revenue.

These many drivers of Revenue Adequacy are illustrated in Figure 4:

Figure 4 – The Revenue Adequacy cycle

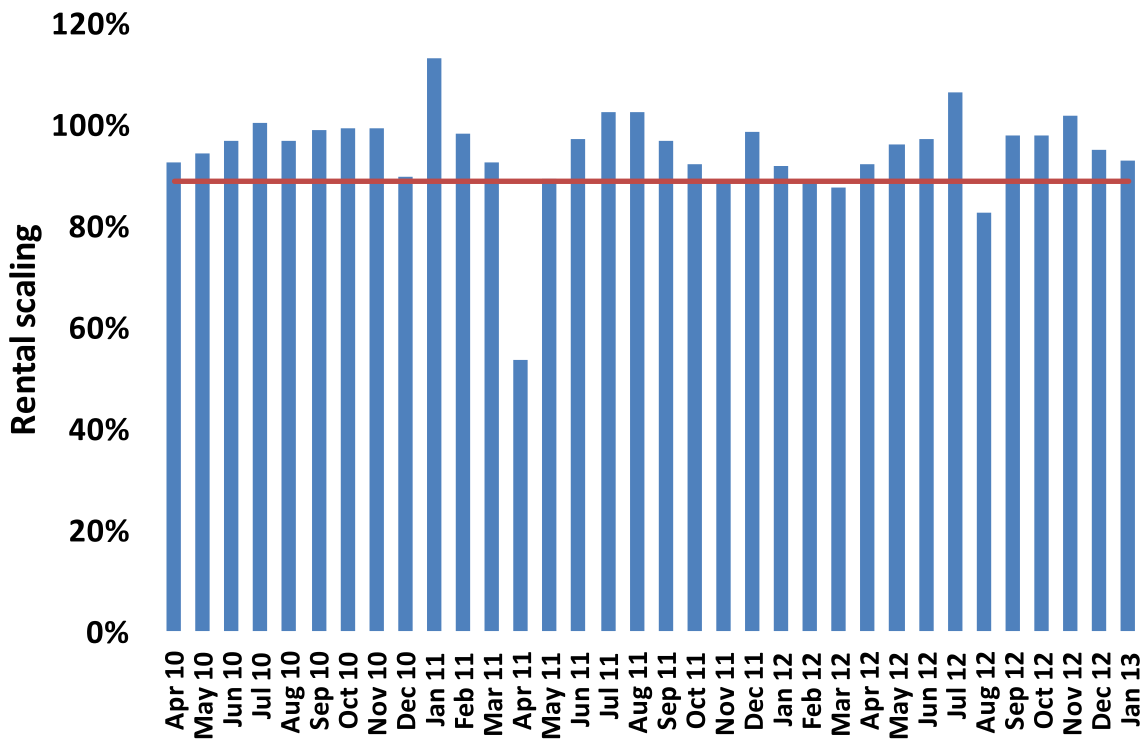


2.5.1 Schedule 14.6 and the FTR Rentals Amount

Schedule 14.6 determines the amount of the total market surplus or rentals to be allocated to the FTR Account to fund FTR settlement, known as the FTR Rentals Amount. Schedule 14.6 is designed to support the FTR market through collecting all the rentals corresponding to maximum FTR flows between the FTR hubs. It is assumed that the Schedule 14.6 algorithm will deliver the requisite rentals to fund the FTR market, as if the FTR market was a stand-alone sub-grid with its own rentals..

There have been differences in the amounts of rentals as calculated as the market surplus (as the difference between purchaser receipts and generator payments), and the actual amount collected by the Clearing Manager and (currently) passed to the Grid Owner. This proportion was analysed for the LPRTG last year for twelve months of data, and recently updated as shown in Figure 5. There was one major scaling, at 54% due to a major wash-up[4]. In other months, scaling ranged from 83% to 113%.

Figure 5 – Historical scaling of rentals[5]



To have achieved the Revenue Adequacy Objective on this alone would have required a scaling of between 54% and 89%. The use of the Auction Revenue, as discussed in the next section and later in this document, will be used for covering losses, and so cannot be relied on to fill any shortfalls in the FTR Rentals Amount.

Rule 2 – Assumption on FTR Rentals Amount

A Capacity Scaling Factor component of 0.85 will be applied to allow for monthly wash-ups in the rentals amount.

The expected effect of this on the Revenue Adequacy Objective is neutral.

4 Reportedly a one-off wash-up against the old Electricity Governance Rules (EGRs)

5 This compares the unscaled rentals total as calculated arc-by-arc from the Final Pricing SPD results by Transpower's rentals allocation methodology, with the actual amount received by Transpower from NZX

2.5.2 Auction revenue

In the New Zealand FTR market, revenue from the FTR auction (i.e. the FTR Participants' purchase costs of FTRs awarded at the auction) is added to the FTR Account, along with the FTR Rentals Amount.

Use of the auction income is discussed in the section on losses (section 4) and in the summary and conclusions (section 0).

2.6 Price as a proxy for capacity

The initial FTR market is for balanced, lossless FTRs between Benmore and Otahuhu only. The FTR Hedge Value, at least over a period when all flow is either northwards or southwards, is then proportional to the price difference between Benmore and Otahuhu. Thus, when we are considering scaling factors, which affect the FTR Grid capacity by scaling down every individual asset capacity by the same ratio, we can as a good approximation equate capacity with price difference. This enables in some cases the simplification of using Benmore and Otahuhu price differences ratios as a proxy for capacity[6].

[6] This simplification will not apply, or at least not be as powerful, if and when additional hubs are introduced, or losses are introduced (unbalanced FTRs)

3 Outages

Outages are described in section 3.3 of The Policy.

The Grid Owner will provide an Outage File listing all relevant outages planned for the FTR Period. The Outage File is used by i-HEDGE to remove specific assets from the basic network for the FTR Period. The assets in this file are removed for the entire FTR Period.

The rule for whether a planned outage is relevant and therefore included by the Grid Owner in the Outage File is the subject of this section.

3.1 Outage durations

This section described the analysis undertaken to determine the duration-based rule for including or excluding an outage, which consisted of the following steps:

3.1.1 Analysis of historical outages

The analysis used as its foundation a Transpower database of all outages that have occurred on the Transpower grid from 1 January 2007 to 30 June 2012, which is 63,038 outages.

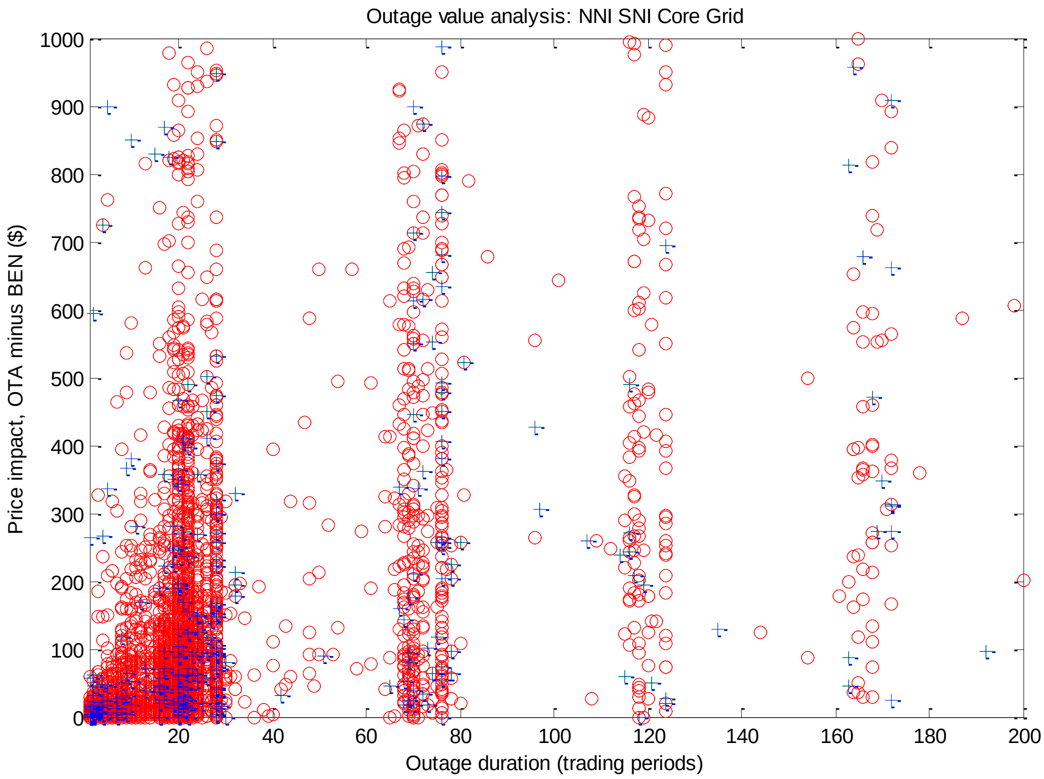
These include both planned and forced outages. The planned outages include both those planned 8-10 week ahead as normal, and those planned at shorter notices, down to around two days. Forced outages are those at or close to real time. While the aim of the analysis is to determine the impact that a planned outage might have, unplanned outages were included because the impact of unplanned outages provides useful information on the impact of the outage had it been planned, albeit that market participants might have less time to adjust their bidding and hedging strategies.

The data base included outages across New Zealand. Only North Island outages were considered, and only outages on circuits or interconnecting transformers. This is because, while South Island outages could impact on the BEN – OTA price difference, they would not impact on the BEN – OTA capacity, and thus their inclusion or not in the FTR Grid would have no impact on FTR capacity.

Each outage had a start time and end time to the nearest second, albeit that most start or end at the hour or half-hour to align with Trading Periods. Start and end times during a Trading Period were rounded to the nearest full Trading Period, e.g. if a start was up to 15 minutes into a Trading Period it was assumed to apply for the full Trading Period, if later it was assumed to start in the following Trading Period.

The price difference between OTA2201 and BEN2201 for each Trading Period during the outage duration was then applied to the duration to give a total price difference during that outage. This was compared to the average price across all Trading Periods (10 $/MWh), to give a price impact, being the total $ impact of that outage above average price differentials. The results are plotted in Figure 6:

Figure 6 – Outage price impact plot[7]



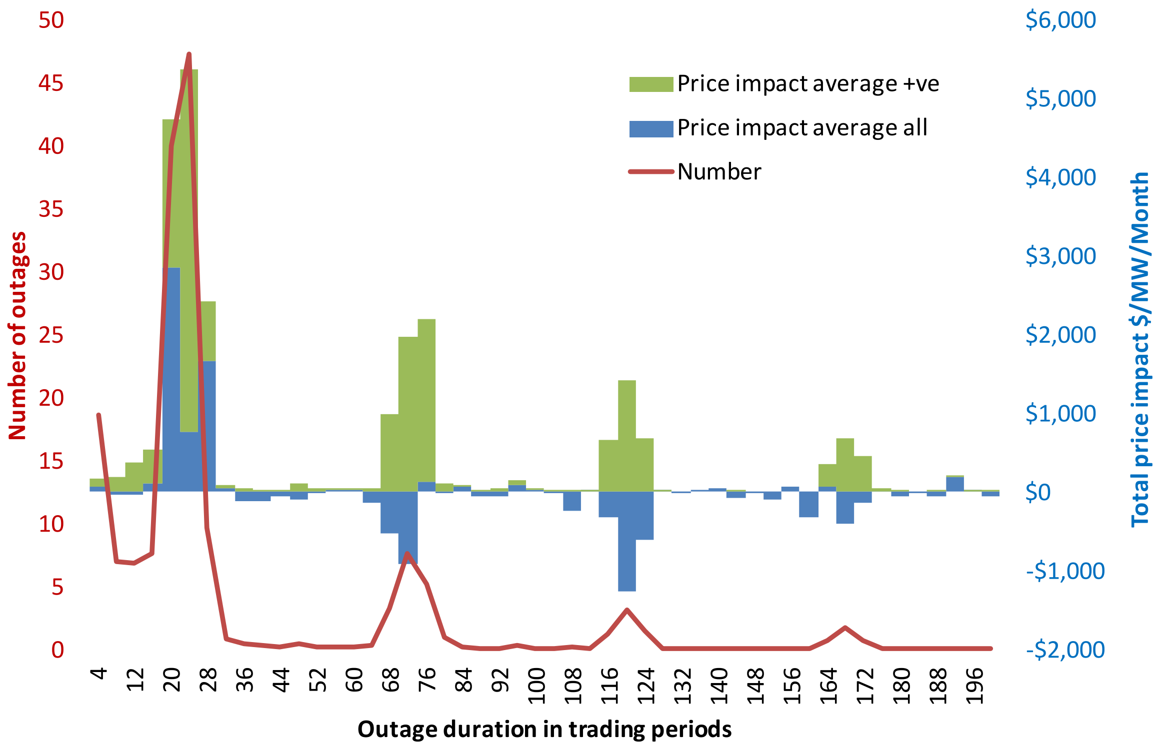
Red circles are individual circuit outages, blue crosses are individual interconnector transformer outages

As this plot indicates, there is (historically) a significant risk of increase in price separation relative to average price separation for outages with duration greater than around 15 Trading Periods, for both circuit and interconnector transformer outages.

Figure 7 presents the same data with circuit and interconnector transformers combined as an histogram of both number of outages and their price impact. The number of outages is averaged per month in the analysis period, and the price impact is a total price impact per MW per month, again averaged over the months of the analysis period. The steps in this plot are in 4 Trading Period increments.

7 The vertical axis to this graph is calculated as ([sum of OTA-BEN price differences ($/MWh) over the outage duration, rounded to nearest trading period at each end] / 2) – ([average price] × [outage duration in trading periods] / 2).

Figure 7 – Outage analysis in steps of four Trading Periods[8]



This illustrates that:

- Longer outages tend to clustered around common durations, of around 24 periods (=1 working day), 72 periods (2 working days, continuous), and so on.
- Only the first cluster has significant average price impact – longer duration outages have on average little adverse impact relative to the average price differential, but can still have a significant risk.

The reason that longer duration outages have on average little adverse impact relative to the average price differential is believed to be that such outages tend to be planned around low price periods. However, as a clear conclusion is that the duration threshold needs to be based around the first cluster, the reason for this has not been analysed further.

Figure 8 presents the same data again but in steps of one Trading Period, thus focusing on the first cluster of outage durations:

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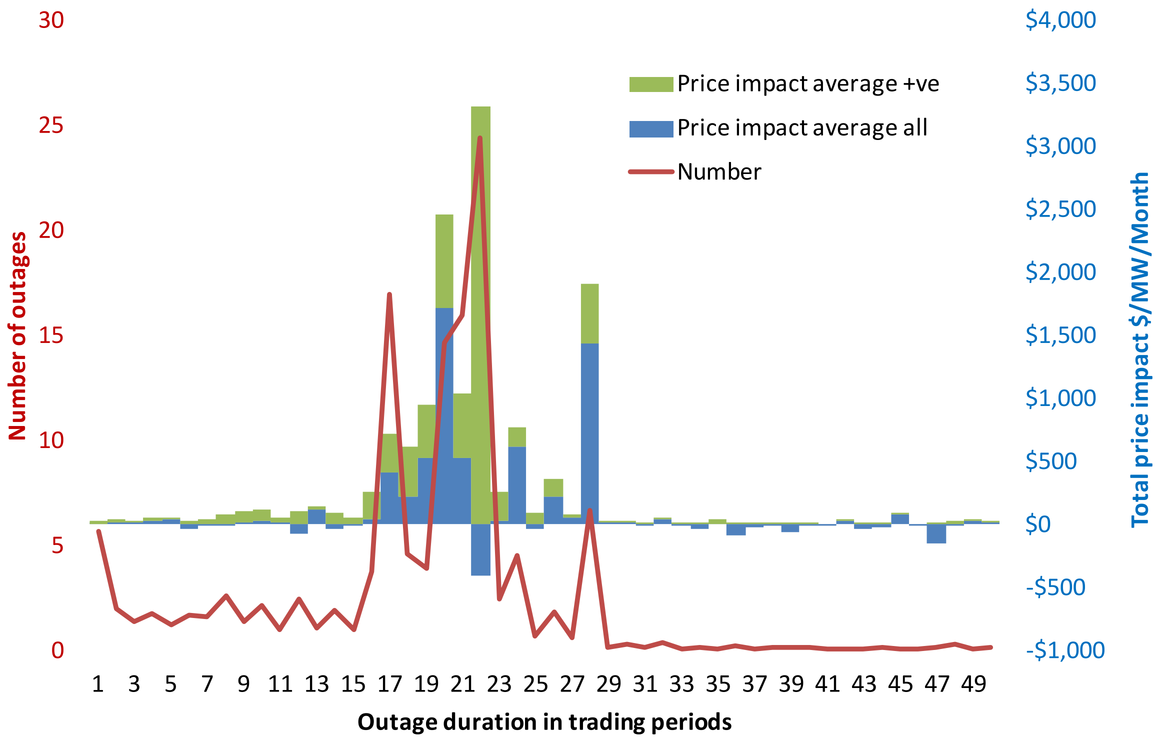
8 This graph takes data for every outage (illustrated by the circles in Figure 6) and sorts it by duration, with durations grouped in to blocks of x half-hours, to turn it into a histogram. Price impacts are average over all outages, and over all outages with positive price impact.

Figure 8 – Outage analysis per Trading Period



This graph suggests that an appropriate threshold would be at around 16 Trading Periods. Broadly, this means outages that are out for a full a working day.

Analysis for HVDC outage reveals similar patterns around one day, so there is no compelling reason to consider different outage duration thresholds for different asset classes.

The FTR Allocation Plan requires that the FTR Manager shall define in its Policy what planned outages are relevant, as a function of their asset type, outage duration and distribution of multiple outages across parallel circuits.

With regard to outages of parallel circuits, this is standard practice, as lines often carry two circuits and maintenance outages are often conducted first on one circuit and then the other. The same sometimes occurs for parallel lines.

Rule 3 – Relevant outages

Outages are considered relevant if they both:

- Satisfy the outage duration threshold as:
  - being out or open 16 half-hours (not necessarily consecutive) or more during the FTR Period
  - separate outages on circuits between the same buses (e.g. ABC-DEF-1 and ABC-DEF-2) are considered as a single-circuit outage for this purpose
- Are flagged as Confirmed or Tentative in POCP

Other outages, of shorter duration, not so flagged in POCP, or from other sources inconsistent with POCP, will not be considered relevant

The expected effect of this on the Revenue Adequacy Objective is conservative, as while some outages of lesser duration will be excluded (subject to the conclusions of section 3.3.1), those outages of longer duration are removed from the FTR Grid not just for their duration, but for the entire FTR Period of a month.

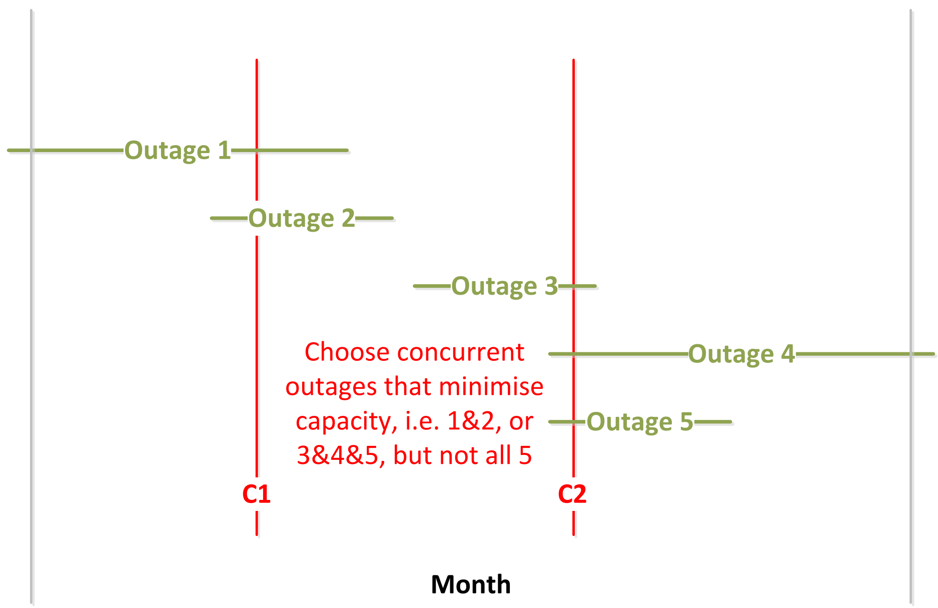
3.2 Allowing for temporally separate outages

However, in instances strict application of the relevant outages rule (**Rule 3**) may be too conservative. In particular, two problems could occur whereby strict application of a threshold outage rule could cause significant under-capacity:

- Firstly, if major outages of different circuits occurred at different times in the same month, then all those circuits would be removed, when ideally only that or those causing the biggest reduction on BEN-OTA capacity should be removed
- Secondly, some circuits, especially on the 110kV system, use inter-trips to provide the 'N-1' protection. Outages, combined with the automated contingency analysis to ensure robustness against removing each 110kV or 220kV circuit (**Rule 13**), could through loop-flow effects overly constrict BEN-OTA capacity

The first issue is illustrated in Figure 9:

Figure 9 – Allowing for temporally separate outages



There is no automatic process for identifying such instances, but nevertheless they may on occasion be identified by the Grid Owner or System Operator, or the FTR Manager may raise concern with the Grid Owner over the low capacity observed on the FTR Grid due to the Outage File.

Rule 4 – Allowing for temporally separate outages

HVAC outages assessed as relevant under **Rule 3** may be excluded from the Outage File if the Grid Owner or FTR Manager (on advice from the Grid Owner or System Operator) believes that the effects of that outage on BEN-OTA capacity are less than that of another relevant outage that does not overlap it in duration, or are negated by inter-trip arrangements.

The Grid Owner or FTR Manager as the case may be will publish any such decision with its reason.

The expected effect of this on the Revenue Adequacy Objective is neutral.

3.3 Impact of other outages

Taking account of outages according to the above rule will remove a planned outage from the FTR Grid for the whole FTR Period, even if it is only planned to be out for 8 hours (16 Trading Periods). This is conservative and thus provides a buffer.

The FTR Allocation Plan requires (in section 4.5) that the FTR Manager apply a Capacity Scaling Factor in the FTR Grid to allow for the expected, average impact of (*inter alia*):

- Planned outages that are not 'relevant' (e.g. of shorter duration)
- Unplanned outages

When the FTR grid is determined before Confirmed or Tentative outages are scheduled in POCP, then all outages are by definition unplanned outages (in the sense of being unconfirmed – some may still be in the draft outage plan). When Confirmed and Tentative outages are available in POCP for preparing the FTR Grid, then as well as planned outages at the time of determining the FTR Grid, there can also be (then) unplanned outages in the FTR Period.

3.3.1 Planned outages that are not 'relevant'

Inspection of Figure 7 and Figure 8 illustrates that the average price impacts of outages of less than 16 Trading Periods' duration are minor, albeit that Figure 6 illustrates that some individual short-duration outages can still have significant price impact.

Those figures illustrate also that outages of 16 Trading Periods' duration or over can have significant average and extreme price impacts. The average duration of such outages is 250 Trading Periods, which is one sixth of a month.

In the FTR auction, outages of 16 Trading Periods' duration or over are removed from the FTR Grid not just for their duration, but for the entire month of the FTR Period.

The conservatism inherent in this is such that the price impact 'cost' of outages of less than 16 Trading Periods' duration can be expected to be more than offset by the price impact 'benefit' of outages of less than 16 Trading Periods' duration. This of course is not guaranteed: there could still be high value short duration or unplanned outages.

Rule 5 – Allowance for planned outages that are not 'relevant'

No allowance will be made in the FTR Grid for such effects

That is, the Capacity Scaling Factor component is unity.

The expected effect of this on the Revenue Adequacy Objective is neutral.

3.3.2 Unplanned outages when there are planned outage data

Where an unplanned outage in the FTR Period is the result of shifting a previously planned outage, many shifts will be within a month, but some can be to change durations or to move to different months. On average, these effects are assumed to cancel out.

Rule 6 - Allowance for unplanned outages when there are planned outage data

No allowance will be made in the FTR Grid for such effects

That is, the Capacity Scaling Factor component is unity.

The expected effect of this on the Revenue Adequacy Objective is neutral.

3.3.3 Unplanned outages when there are no planned outage data

Unplanned outages are to be managed as part of the Capacity Scaling Factor. The purpose of this section is to derive a Capacity Scaling Factor component for unplanned outages when there are no planned outage data.

In the period analysed, in only 23% of Trading Periods were there no outages. When there were no outages, average price difference was -1.8 $/MWh, and when there were outages, it was +1.8 $/MWh[9]. This indicates that there is an 'average impact', as one would expect, but does not help determine the relevant Capacity Scaling Factor. If we split the results by Trading Periods in which the OTA price was higher (northwards flow), and the BEN price was higher (southwards flow), then we see the results shown in Figure 10 and Figure 11[10]:

[9] Start 2007 to end June 2012, core grid outages of circuits or interconnector transformers. Price differences OTA less BEN.

[10] Bars are the 50th, 75th and 95th percentiles of price difference. Each half-hour of an outage duration is considered as an independent outage. Price impacts are in $/MWh but time units are half hours: as the analysis is to produce ratios, the factor of 2 to normalise has been omitted for simplicity.

Figure 10 – Price differences by number of outages in Trading Period – Northwards flow

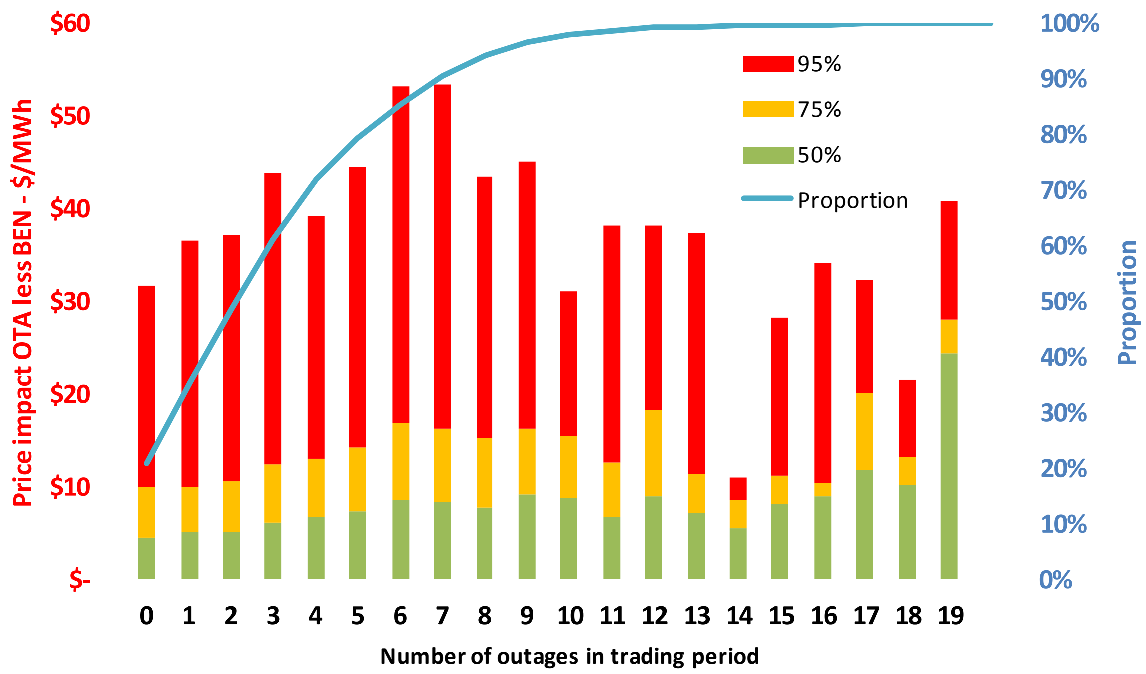
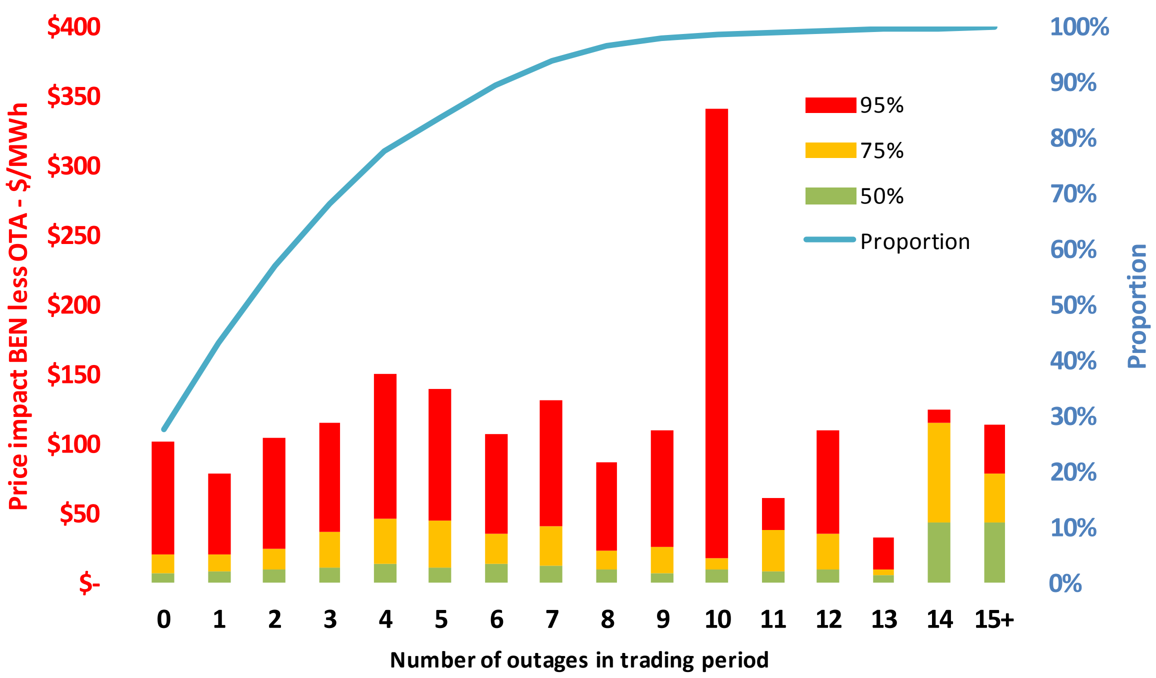


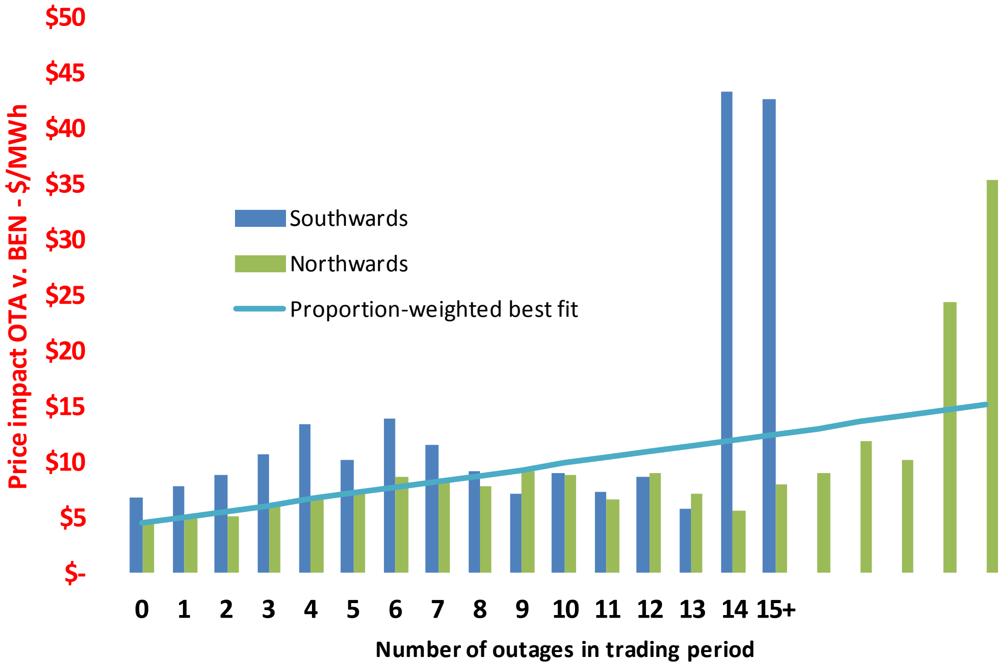
Figure 11 – Price differences by number of outages in Trading Period – Southwards flow



Interpretation of these results need to take into account that the periods of no or few outages are biased towards overnight periods when price differences would tend to be lower.

If we then consider what the best fit would be to that data, taking into account the proportional preponderance of Trading Periods with no outages, we get a proportion-weighted best fit of $4.5 + $0.50 per outage[11], as illustrated in Figure 12:

Figure 12 – Effect of number of outages on average price



The average number of outages in a Trading Period (considering each half-hour of an outage duration as an independent outage) is 3[12].

We can then estimate the average effect if all Trading Periods had no outages on the price difference, as 4.5 relative to 6 (4.5 + 3×0.5), or 3:4, or 75%. This will be an underestimate (i.e 75% is too high), because of the over-night correlation between low prices at times of low outage, mentioned above. It is difficult to calculate or estimate the scale of this effect, and where it might drive the true value in the 75% to 100% range.

This Capacity Scaling Factor component is not critical to Revenue Adequacy because it is not relevant to the longer auction horizons and has a safety buffer of some 33%. We therefore do not believe that this parameter requires more detailed analysis at this stage.

We have therefore assumed a figure of 85% as on the conservative side of the midrange.

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[11] These are the parameters that minimise the sum of absolute differences to the 50th percentile values, weighted by the proportions of trading periods with that number out outages, weighted by the 67604:35394 of nortwards:southwards, optimised using Excel's Solver. Precise calculated coefficients 4.47 and 0.53.

[12] Calculated number is 3.1.

Rule 7 – Allowance for unplanned outages when there are no planned outage data

The Capacity Scaling Factor component for unplanned outages when there are no planned outage data is 85%

The expected effect of this on the Revenue Adequacy Objective is neutral.

3.4 Identifying periods with no planned outage data

There are three levels of planned outage information:

- **Confirmed**, if a plant request has been created, normally 8-10 weeks prior to the outage occurring
- **Tentative**, if in POCP but not confirmed. POCP is populated by 19 May for the next July-June year
- **Draft** if not in POCP but in the draft Outage Plan, which is published by the Grid Owner by 31 January for the next July-June year, following consultation with affected customers and the System Operator.

The FTR Allocation Plan requires (in section 4.3) that "*the FTR Manager will use the relevant planned outages provided by the Grid Owner to develop the FTR Grid for each FTR Period offered in each FTR Auction. The source for these will be the public information posted on the POCP site pocp.redspider.co.nz*."

Outages are initially entered as Tentative with a time and window, which is then confirmed (or not), with the same or a revised time and window. While occasionally an outage will be moved to a different month at this stage, the usual case is a straight confirmation.

Rule 8 – Outage information sources

- The draft Outage Plan will not be used, as the source needs to be POCP
- Tentative and Confirmed outages will be considered the same

The expected effect of this on the Revenue Adequacy Objective is neutral.

Figure 13 illustrates, in the format of the FTR Calendar, how this relates to which FTR Auctions will have what level of outage information available, at the time that the Grid Owner prepares its Outage File:

Figure 13 – Relationship between FTR and Outage planning horizons

Outage information avalable for FTR Grid: POCP outage information available for FTR Grid

Information may sometimes be available in POCP earlier than shown

	Auction month		Primary auctions			Variation auctions					
Buildup	1	Jun-13	Jul-13			Jul-13					
	2	Jul-13	Aug-13	Sep-13						Sep-13	Aug-13
	3	Aug-13	Oct-13	Nov-13	Dec-13				Nov-13	Oct-13	Sep-13
	4	Sep-13	Jan-14	Feb-14	Mar-14				Dec-13	Nov-13	Oct-13
	5	Oct-13	Apr-14	May-14	Jun-14				Jan-14	Dec-13	Nov-13
	6	Nov-13	Jul-14	Aug-14	Sep-14				Feb-14	Jan-14	Dec-13
	7	Dec-13	Oct-14	Nov-14	Dec-14				Mar-14	Feb-14	Jan-14
	8	Jan-14	Jan-15	Feb-15	Mar-15	Jul-14	Aug-14	Sep-14	Apr-14	Mar-14	Feb-14
	9	Feb-14	Apr-15	May-15	Jun-15	Jan-15	Feb-15	Mar-15	May-14	Apr-14	Mar-14
	10	Mar-14	Jul-15	Aug-15	Sep-15	Jan-15	Feb-15	Mar-15	Jun-14	May-14	Apr-14
	11	Apr-14	Oct-15	Nov-15	Dec-15	Oct-14	Nov-14	Dec-14	Jul-14	Jun-14	May-14
	12	May-14	Jan-16	Feb-16	Mar-16	Apr-15	May-15	Jun-15	Aug-14	Jul-14	Jun-14
	13	Jun-14	Apr-16	May-16	Jun-16	Apr-15	May-15	Jun-15	Sep-14	Aug-14	Jul-14
Steady state	14	Jul-14	Jul-16	Aug-16	Sep-16	Jan-15	Feb-15	Mar-15	Oct-14	Sep-14	Aug-14
	15	Aug-14	Jul-16	Aug-16	Sep-16	Jul-15	Aug-15	Sep-15	Nov-14	Oct-14	Sep-14
	16	Sep-14	Jul-16	Aug-16	Sep-16	Jul-15	Aug-15	Sep-15	Dec-14	Nov-14	Oct-14
	17	Oct-14	Oct-16	Nov-16	Dec-16	Apr-15	May-15	Jun-15	Jan-15	Dec-14	Nov-14
	18	Nov-14	Oct-16	Nov-16	Dec-16	Oct-15	Nov-15	Dec-15	Feb-15	Jan-15	Dec-14
	19	Dec-14	Oct-16	Nov-16	Dec-16	Oct-15	Nov-15	Dec-15	Mar-15	Feb-15	Jan-15
	20	Jan-15	Jan-17	Feb-17	Mar-17	Jul-15	Aug-15	Sep-15	Apr-15	Mar-15	Feb-15
	21	Feb-15	Jan-17	Feb-17	Mar-17	Jan-16	Feb-16	Mar-16	May-15	Apr-15	Mar-15
	22	Mar-15	Jan-17	Feb-17	Mar-17	Jan-16	Feb-16	Mar-16	Jun-15	May-15	Apr-15
	23	Apr-15	Apr-17	May-17	Jun-17	Oct-15	Nov-15	Dec-15	Jul-15	Jun-15	May-15
	24	May-15	Apr-17	May-17	Jun-17	Apr-16	May-16	Jun-16	Aug-15	Jul-15	Jun-15
	25	Jun-15	Apr-17	May-17	Jun-17	Apr-16	May-16	Jun-16	Sep-15	Aug-15	Jul-15
	26	Jul-15	Jul-17	Aug-17	Sep-17	Jan-16	Feb-16	Mar-16	Oct-15	Sep-15	Aug-15
	27	Aug-15	Jul-17	Aug-17	Sep-17	Jul-16	Aug-16	Sep-16	Nov-15	Oct-15	Sep-15
	28	Sep-15	Jul-17	Aug-17	Sep-17	Jul-16	Aug-16	Sep-16	Dec-15	Nov-15	Oct-15
	29	Oct-15	Oct-17	Nov-17	Dec-17	Apr-16	May-16	Jun-16	Jan-16	Dec-15	Nov-15
	30	Nov-15	Oct-17	Nov-17	Dec-17	Oct-16	Nov-16	Dec-16	Feb-16	Jan-16	Dec-15
	31	Dec-15	Oct-17	Nov-17	Dec-17	Oct-16	Nov-16	Dec-16	Mar-16	Feb-16	Jan-16
	32	Jan-16	Jan-18	Feb-18	Mar-18	Jul-16	Aug-16	Sep-16	Apr-16	Mar-16	Feb-16
	33	Feb-16	Jan-18	Feb-18	Mar-18	Jan-17	Feb-17	Mar-17	May-16	Apr-16	Mar-16
	34	Mar-16	Jan-18	Feb-18	Mar-18	Jan-17	Feb-17	Mar-17	Jun-16	May-16	Apr-16
	35	Apr-16	Apr-18	May-18	Jun-18	Oct-16	Nov-16	Dec-16	Jul-16	Jun-16	May-16
	36	May-16	Apr-18	May-18	Jun-18	Apr-17	May-17	Jun-17	Aug-16	Jul-16	Jun-16
	37	Jun-16	Apr-18	May-18	Jun-18	Apr-17	May-17	Jun-17	Sep-16	Aug-16	Jul-16
	38	Jul-16	Jul-18	Aug-18	Sep-18	Jan-17	Feb-17	Mar-17	Oct-16	Sep-16	Aug-16
	39	Aug-16	Jul-18	Aug-18	Sep-18	Jul-17	Aug-17	Sep-17	Nov-16	Oct-16	Sep-16
	40	Sep-16	Jul-18	Aug-18	Sep-18	Jul-17	Aug-17	Sep-17	Dec-16	Nov-16	Oct-16
	41	Oct-16	Oct-18	Nov-18	Dec-18	Apr-17	May-17	Jun-17	Jan-17	Dec-16	Nov-16
	42	Nov-16	Oct-18	Nov-18	Dec-18	Oct-17	Nov-17	Dec-17	Feb-17	Jan-17	Dec-16
	43	Dec-16	Oct-18	Nov-18	Dec-18	Oct-17	Nov-17	Dec-17	Mar-17	Feb-17	Jan-17
	44	Jan-17	Jan-19	Feb-19	Mar-19	Jul-17	Aug-17	Sep-17	Apr-17	Mar-17	Feb-17
	45	Feb-17	Jan-19	Feb-19	Mar-19	Jan-18	Feb-18	Mar-18	May-17	Apr-17	Mar-17
	46	Mar-17	Jan-19	Feb-19	Mar-19	Jan-18	Feb-18	Mar-18	Jun-17	May-17	Apr-17

It can be seen that the horizon over which outage information is available vary significantly during the FTR build-up, and in steady state with the outage cycle.

This leaves the issue of how the FTR Manager identifies whether an FTR Grid (for a particular FTR Auction and FTR Period) should have the 'allowance for unplanned outages when there are no planned outage data' applied. Options for the FTR Manager for this are:

- Use relationship between FTR and Outage planning horizons (Figure 13) as the guide. The risk of this is that there might be planned outage data of longer horizon in POCP, in which case both an Outage File and an allowance for no planned outage data would be applied[13].
- Inspect POCP to determine whether planned outage data exists for the FTR Period. The risk of this is that the FTR operator is not an expert in interpretation of outage planning information, so differences in interpretation (or human error) could arise between the FTR Manager and the Grid Owner
- Use the existence or not of an Outage File to identify which state applies.

The last approach is preferred as least risk, and avoiding process duplication between the FTR Manager and the Grid Owner. The process would then be:

Rule 9 – Identification of planned outage periods

- The Grid Owner provides an Outage File whenever there are outages that satisfy **Rule 3 – Relevant outage**.
- The Grid Owner provides a nul (empty) Outage File when there are no outages that satisfy **Rule 3**, but confirmed or tentative outage information is available (e.g. there are planned outages for that period, but they are all short duration ones)
- The Grid Owner does not provide an Outage File when there is no confirmed or tentative outage information available, i.e. outside the outage planning horizon
- The FTR Manager uses the existence or not of an Outage File to determine whether the FTR Grid is inside our outside the outage planning horizon, and hence whether **Rule 7 – Allowance for unplanned outages when there are no planned outage data** is applied

The expected effect of this on the Revenue Adequacy Objective is neutral.

Transpower is planning changes to its outage planning tools, with a view to introducing them in early June 2013. This may extend out the horizon of confirmations beyond 8-10 weeks, and change some terminology. This will not affect the Policy required for the first FTR Auction in June 2013, but may result in this document and perhaps the Policy being updated as soon as changes to the outage planning process are confirmed.

13 Also, the Grid Owner will have its internal timeline for developing the Outage File and may have a cut-off time different from the assumptions of the FTR Manager, which risks the FTR Manager assuming that planned outage information is available, so no extra capacity scaling applied, when the Grid Owner actually prepared the Outage File before the planned outage information became available. That is, Figure 13 is not exact as it makes assumptions on the Grid Owner's cut-off date, and on precise timings on the part of the outage planners (e.g. POCP could be populated earlier than the required time).

3.5 Outage summary

The proposed approach to allowing for outages is summarised in Figure 14.

Figure 14 – Summary of allowances for different types of outage

	Outside outage planning horizon	In outage planning horizon
Situation	When the FTR Grid is determined before outages are scheduled in POCP Usually for Auction Horizons exceeding three months. At this horizon, all outages in the FTR Period are unplanned	When outages are available in POCP for preparing the FTR Grid Usually for Auction Horizons less than three months
Identification	By Grid Owner: inspection of POCP By FTR Manager: No Outage File (**Rule 9**)	By Grid Owner: inspection of POCP By FTR Manager: Existence of Outage File (**Rule 9**)
Planned outages	N/A	Outages with a cumulative duration of 16 Trading Periods or more in the FTR Period (allowing for parallel circuit outages) removed from the FTR Grid (**Rule 3**), subject to allowing for temporally separate outages (**Rule 4**) Outages below the threshold not allowed for* (**Rule 5**) Expected effect: Conservative
Unplanned outages	Use a Capacity Scaling Factor component of 85% (**Rule 7**) Expected effect: Neutral	Not allowed for* (**Rule 6**). Expected effect: Neutral

** Capacity Scaling Factor component of unity*

These allowances for outages apply to both HVDC and HVAC assets. However, the mechanisms for including them in the FTR Grid are different:

- HVAC outages are included in the Outage File
- HVDC outages are included in the HVDC configuration flag in the Network File, which are then used to set appropriate constraints

4 Losses

The theory of FTR is that, as long as they are awarded against the same grid as used for final pricing, the rentals that accrue will always be sufficient to pay out the FTRs in full. This rule is known as simultaneous feasibility implies Revenue Adequacy.

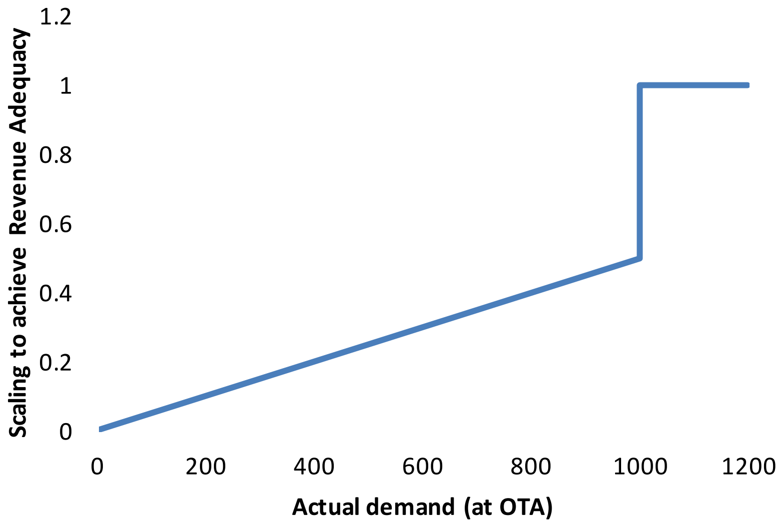
Unfortunately this rule does not apply perfectly to the design of New Zealand's FTR market because the FTRs are lossless, but dispatch and pricing includes losses. A possible development of the FTR market and the Nexant i-HEDGE engine that supports it is to include losses in FTRs, but at least for the time being we need to work around having lossless, balanced FTRs.

The mathematics of the inequality in this relationship of having lossless FTRs funded through a lossy energy market is that to achieve Revenue Adequacy in the absence of constraints, awarded FTR capacity must be less than half the actual flow[14]. This is doubly problematic – the halving would be a major reduction in FTR capacity, and the actual flow that will eventuate in the FTR Period is unpredictable.

On the other hand, in a situation where the price difference was entirely due to constraints, not losses (for example one in which there were two marginal generators, one close to BEN and one close to OTA), then classic simultaneous feasibility implies Revenue Adequacy would apply and no capacity scaling for loss effects would be required.

This relationship is demonstrated in Figure 15, for an example of a 1000MW transfer limit BEN-OTA:

Figure 15 – Relationship between loss capacity scaling component and actual flow[15]



[14] The mathematics of this, for a simple two-node, one circuit model, has been neatly expressed by the Electric Power Optimization Centre (EPOC) in one of their submissions on FTRs: http://www.epoc.org.nz/submissions/FTRappendix-12May.pdf

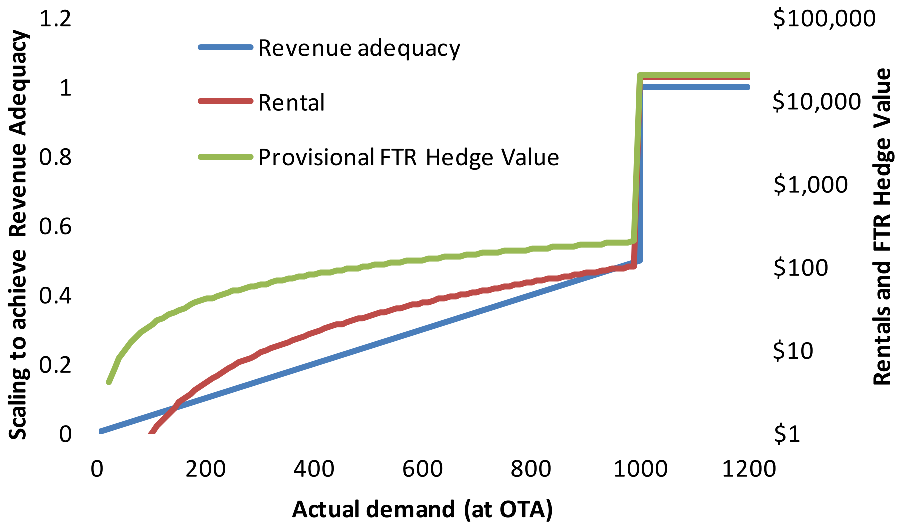
[15] Assuming a 1000MW transfer limit for dispatch and FTR grids, quadratic losses modelled in dispatch, shared between ends of line, northwards flow, and that if BEN-OTA goes into constraint then OTA will be supplied by more expensive local generation.

There are two conclusions from this:

- First, losses can be critical to FTR Revenue Adequacy, to the point that one could construct scenarios where the loss capacity scaling component would have to be close to zero, in which case minimal FTR capacity would be available
- Second, resolving the issue through use of a scaling factor would have to be empirically rather than theoretically based

Fortunately, the overall Revenue Adequacy situation over multiple Trading Periods, e.g. a month, is much improved, as the higher Revenue Adequacy Trading Periods correspond to the higher rentals and Provisional FTR hedge Values. That is, if there are no constraints, the value-weighted loss capacity scaling component approaches the 0.5 end of the 0 to 0.5 spectrum, and if there are constraints, these rapidly dwarf the loss effects, as illustrated in Figure 16 (note that the vertical, right-hand value axis is logarithmic):

Figure 16 – Relationship between Revenue Adequacy ratios and quanta[16]



Considering Revenue Adequacy per Trading Period, we do not know in advance whether that Trading Period will be constrained or not, and if not constrained, what the flow will be. To further complicate the issue, when there is a constraint in the system that drives some price separation between BEN and OTA, there will inevitably be both a loss and a constraint component to the total price separation, as the loss and constraint effects interact. However it is not possible to separate the total into these two components, without arbitrary assumptions.

If the actual flow will reach the capacity limit often each month, then the constraints effects will dominate and the loss effects will be less significant. However, in a month where the actual flow never or rarely reaches the capacity limit there could be very material loss effects. The FTR market will be operating with much expanded capacity between BEN and OTA following the commissioning

16 Same assumptions as for Figure 15: the revenue adequacy line is identical. Added are the rentals and provisional FTR Hedge Value lines. Assumed bid prices are $10 at BEN and $30 at OTA.

Note also that the revenue adequacy is a fraction less than one (0.99 in this example, but varies with the bid price assumptions). This is an artefact of sharing losses between the two ends of a circuit. It is a small effect and fully covered by **Rule 11** below, so is not considered further here.

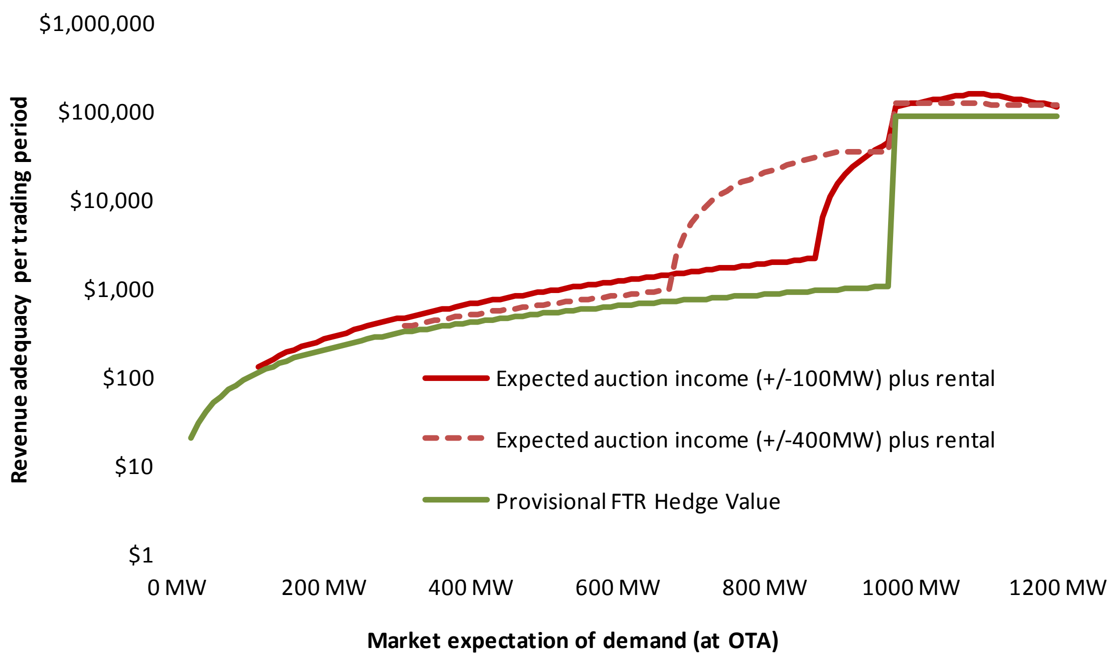
of HVDC Pole 3 and the recent commissioning of the North Island Grid Upgrade (NIGU), increasing the likelihood of such months occurring. Further, the issue with reduced Revenue Adequacy with losses when capacity is not reached is related not to capacity but to actual flow, and actual flows will change in unpredictable ways as the market adapts itself to the new grid configuration and capacity.

Consider how an FTR Participant would value an FTR from OTA to BEN when actual flow might not be constrained, but rather be below capacity and subject only to loss effects. We will assume that there is no loss capacity scaling component. Further, lets us conservatively consider only the expected cash value of the FTR, not any additional insurance or hedge premium that the participant might place on it. All else equal, the participant would take into account the risk that the Provisional FTR Hedge Value would be scaled down to only 0 to 0.5 of its value, and bid somewhere in the range of 0 to 50% of the expected Provisional FTR Hedge Value, according to what actual flows they consider might eventuate.

Now consider what that participant would bid if they knew that the FTR would not be scaled down: they would of course bid the full expected Provisional FTR Hedge Value. Under that scenario, of no scaling, the auction clearing price of that FTR would then equal the market's expectations of the expected Provisional FTR Hedge Value.

If we then apply the share of the FTR auction revenue attributable to awards of that FTR type, then it will be sufficient to compensate for the loss effects. This is illustrated in Figure 17, which assumes that participants' have a market expectation of demand that has some uncertainty:

Figure 17 – Relationship FTR Hedge Value and auction income with losses 1[17]



[17] Same assumptions as for previous figures: the Provisional FTR Hedge Value line is identical. Added are two lines that represent the expected auction income plus rentals. A uniform distribution of uncertainty from –X MW to + X MW is assumed. Note the change in the label of the horizontal axis – now market expectation of demand, rather than demand.

Under this scenario, there are always sufficient funds to cover the Provisional FTR Hedge Value without scaling, through use of the auction revenue as well as rentals. The closer to the point of constraint the more excess there is, as one would expect: under pure constraints, the auction income is purely additional. The close to the lower flows, the less the excess, but still sufficient.

These conclusions are robust to uncertainty in future flow and future constrained prices. However, they are not robust to uncertainty in future unconstrained prices, for which the corresponding figure is Figure 18:

Figure 18 – Relationship FTR Hedge Value and auction income with losses 2[18]

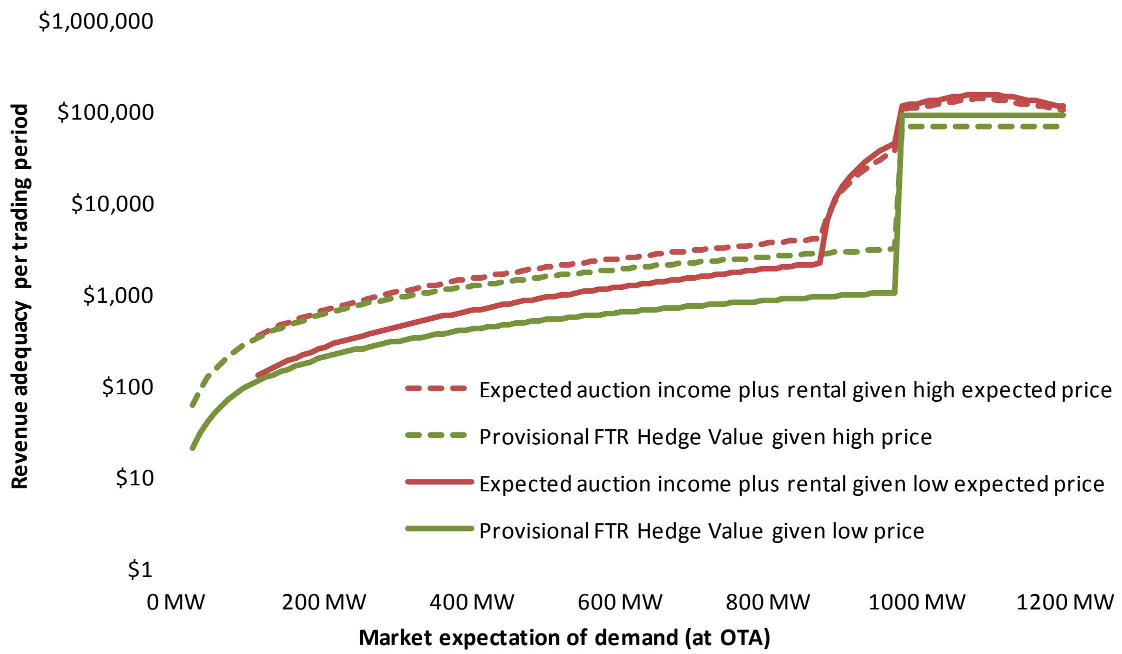


Figure 18 illustrates that in this case the market's expectations of hedge value can be below that observed. This is readily understandable: if the market expects loss values to be driven by an average marginal generation price of $30, but in the FTR month the actual average marginal generation price were $60, then loss values would be double that expected, and auction income (in the case of no constraints) would be insufficient to cover it.

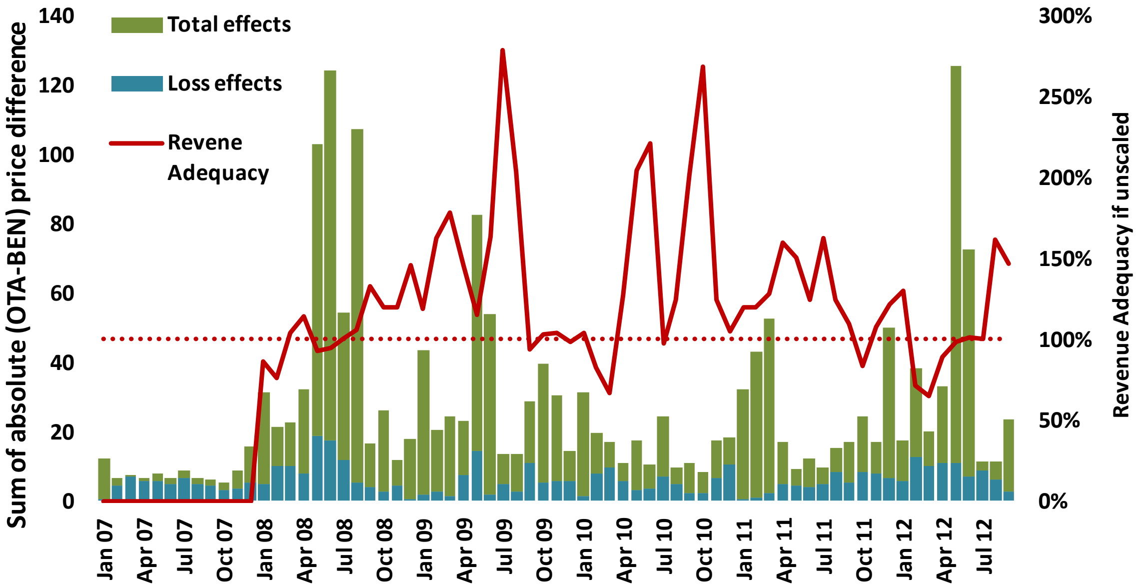
Typically, within an FTR month there will be some constrained periods when revenue adequacy will (within the context of this discussion) be assured, and some unconstrained periods where the above problem with covering loss values could occur. There is no theoretically correct way to compensate for the loss issue within the domain of simultaneous feasibility and capacity scaling factors. An empirical, quantitative estimation needs to be made.

If over a recent historical period we determine for each trading period wether the OTA-BEN price differential was caused by a constraint or only by loss effects, then we can sum the price differences per month in each category. We sum absolute price differences, to cover the case of full awards of Option FTRs in both directions. We then assume that FTR Participants value future loss effects based

18 Same assumptions as for previous figures, for the +/- 100MW case, but uncertainty in the assumed bid price at BEN is explored.

on recent historical loss effects. Assuming revenue adequacy in constrained periods, overall revenue adequacy would then be achieved if the total price difference for the month does not exceed the auction income related to losses (which might be an underestimate) and that related to constraints (which can be assumed to be adequate). We can then determine what overall revenue adequacy would accrue:

Figure 19 – Relationship FTR Hedge Value and auction income with losses 2[19]



From such analysis, we can determine what scaling factor would need to be applied to meet the 11 in 12 month revenue adequacy target. Assuming that FTR Participants value future loss effects based on historical loss effects for the previous 1, 2, … 12 months, gives a range of scaling factors from 98% to 75% with an average of 84%[20]. This will be an overestimate in that FTR Participants can be expected to take forward-looking valuations into account rather than just backward-looking. On the other hand, loss effects are expected to increase and constraint effects decrease with the commissioning of Pole 3.

Rule 10 – Allowance for losses impacts

The Capacity Scaling Factor component for losses is 80%

[19] Assuming loss effects estimated at time of auction as an average of the previous 12 months, and applied to an FTR Period of the next month, as that is the most critical auction. The bars represent the actual historical sum of absolute OTA-BEN price differences, split into loss and constraint effects through assuming a cutoff OTA/BEN price ratio of 1.2 in both directions. The line represents the resulting overall revenue adequacy, assuming no other scaling factors applied.

[20] Results:

Lookback months	1	2	3	4	5	6	7	8	9	10	11	12
Factor	87%	85%	84%	86%	89%	85%	86%	83%	89%	85%	79%	75%

The expected effect of this on the Revenue Adequacy Objective is neutral with regard to loss impacts, conservative with regards to constraint impacts.

This approach relies on the FTR auction reaching its market value. This is considered valid in the long run, but in the short run, it may take some time for the FTR auctions to find their market value. From a Revenue Adequacy point of view, the risk of an FTR auction not reaching its market value is that, in the case of an FTR Period in which loss effects dominate, there may not be sufficient Auction Income to cover the loss impacts. One way of approaching this would be to have a Capacity Scaling Factor component for losses that built up to unity over time.

Rule 11 – Allowance for auction learning

The Capacity Scaling Factor component for auction learning is:

- 80% for the first Auction Month
- 90% for the second Auction Month
- Unity for the subsequent Auction Months

The expected effect of this on the Revenue Adequacy Objective is neutral.

5 Capacity scaling factor

The Capacity Scaling Factor is described in section 4.3 of The Policy. The Capacity Scaling Factor is the product of the Capacity Scaling Factor components for:

- Rentals amount calculations (section 2.5.1)
- Planned outages that are not 'relevant' (section 3.3.1)
- Unplanned outages when there are planned outage data (section 3.3.2)
- Unplanned outages when there are no planned outage data (section 3.3.3)
- Losses (section 4)
- Auction learning (section 4)

Under the rules derived above, four of these will have a Capacity Scaling Factor component less than unity:

- Allowance for monthly wash-ups in the rentals amount, for which a Capacity Scaling Factor component of 85% will be applied (**Rule 2**)
- Unplanned outages when there are no planned outage data, for which a Capacity Scaling Factor component of 85% will be applied (**Rule 7**)
- Losses, or which a Capacity Scaling Factor component of 80% will be applied (**Rule 10**)
- Auction learning, for which a rising Capacity Scaling Factor component will be applied (**Rule 11**)

Taking into account that the identification of planned outage periods by the FTR Manager will be through the existence or not of an Outage File (**Rule 9**), we have, rounding to two significant figures where required:

Rule 12 – Capacity Scaling Factor

The Capacity Scaling Factor will be:

FTR Periods for which there is an Outage File	FTR Periods for which there is no Outage File
68%	58%

The expected effect of this on the Revenue Adequacy Objective is neutral to conservative.

6 Contingencies

Contingencies are described in section 4.1 of The Policy. The FTR Allocation Plan requires (in section 4.4) that "*The FTR Manager will apply contingent security constraints to the network model, net of the relevant planned outages, when determining the Indicative Inter-hub Capacity and clearing an Auction. These constraints will be consistent with the System Operator's Policy Statement, which is included by reference in the Code (clause 8.10)*".

The FTR Grid includes transmission assets but does not model generation or load, and the i-HEDGE model (in common with the SPD model) does not model voltage.

The Policy Statement[21] describes what 'contingent events' the System Operator dispatches to be robust to. This is commonly referred to as 'N-1' security. The Policy Statement defines the loss of the following transmission assets other than reactive power assets as contingent events:

- a transmission circuit
- an HVDC link pole
- both transmission circuits of a double circuit line, under certain defined conditions

The HVDC links will be modelled in the FTR Grid as HVAC circuits with the contingent event related security limits on the HVDC circuits as constraints rather than contingencies within i-HEDGE, as described in section 8.

i-HEDGE models contingencies as a list of monitored assets, and ensures that the auction solution is robust to the removal of each monitored asset in isolation. This is designed to ensure tractable solutions and reasonable computation time for the huge US FTR grids, as monitoring every asset for FTR purposes would be impractical.

As the New Zealand grid is much smaller, Nexant and EMS have customised i-HEDGE to create the list of monitored assets directly from the Network Model. This would reduce the risk of human error, and be a closer approximation of the System Operator's security processes for dispatch and pricing.

The list of monitored assets is created automatically through a business rule defining the voltage and types of assets (circuits and/or transformers) to be monitored. System testing has concluded that we can achieve satisfactory run times for the New Zealand system with a business rule that includes every 220kV and 110kV circuit in the contingency analysis. Including lower voltage circuits is not seen to have any merit for FTRs between Benmore and Otahuhu (but could be considered for future FTR nodes or hubs that might be materially affected by such lower voltage contingencies).

Rule 13 – HVAC contingency analysis

The following contingencies will be allowed for to ensure that the solution is robust to them:

- All circuits of 110kV and over
- Except the proxy HVDC circuits (any circuit between BEN and HAY)

These contingencies will be applied to the FTR Grid, as well as to the FTR Rentals Amount calculation

[21] Current version is 1 September 2012, available at http://www.systemoperator.co.nz/n1699.html

The expected effect of this on the Revenue Adequacy Objective is neutral to conservative[22].

The solution time of i-HEDGE increases with the number of monitored assets. For this reason, the huge US FTR grids have relatively few, carefully selected, monitored assets rather than a blanket rule such as the above. This rule will therefore be subject to run-time testing.

The FTR Manager is aware that the System Operator is tasked with managing pre-contingent flows on those interconnector transformers that are assessed as posing a cascade failure risk, but the process has not yet been finalised. The FTR Manager will monitor this situation and reflect it as necessary once finalised.

[22] In particular, the approach may be conservative where Transpower uses special protection schemes to assist in maintaining N-1 security. The i-HEDGE contingency analysis will not take account of the varying levels of security applied by the system operator where special protection schemes exist. For example the grid may be constrained to a 15 minute offload time for one contingent asset but only to 30 seconds for another where there is an associated special protection scheme.

7 Permanent security constraints

Permanent stability constraints are described in section 4.2.1 of The Policy. The FTR Allocation Plan requires (in section 4.4) that "*The FTR Manager may include additional security constraints in the FTR Grid to reflect constraints that the System Operator applies or might in future apply to manage, for example, voltage or transient stability*".

Most constraints in SPD are generated by SFT's contingency analysis, and similarly most constraints applicable to the FTR Grid will be generated by i-HEDGE's contingency analysis (see section 4). SFT cannot however produce all security constraints that might be required, and others are prepared manually through System Operator studies.

These additional (not SFT-generated) security constraints are published by the System Operator as periodic updates to its manual constraints list[23]. That list is updated from time to time, and applies from the time of update. Constraints in it are not time-stamped, but deemed to apply from then until removed or changed in any future update.

There are two types of constraints in the list: permanent and outage.

The permanent constraints are designed to be robust to a variety of power system conditions. They are long-lived and applicable to future periods, at least until updated or changed. These need to be included in the FTR Grid, and in the FTR Rentals Amount calculation. The permanent constraints from the latest list will be assumed to apply to all future FTR Periods.

The outage constraints are designed for specific anticipated power system conditions, are updated often to reflect differing expected system conditions, and are short-lived. Given this, the extended horizon of most FTR Auctions (and that outages are excluded form the FTR Rentals Amount calculation), and the built in conservatism in removing outages above the threshold duration for the entire month of the FTR Period, it is proposed not to included manual outage constraints in the FTR Grid.

The System Operator's manual constraints list includes a right hand side (RHS, which quantifies the limit of the constraint) value for each constraint. Some permanent constraints have RHSs that, as noted in the manual constraints list, can be modified by the System Operator in real time to reflect varying power system conditions[24]. Such events have in recent history been rare, and this is expected by the System Operator to continue, so the published 'default' RHS will be used.

The System Operator's constraints list refers to assets using SPD terminology. For the FTR Grid, this will need to be translated to the Grid Owner's terminology, as defined in the latest Asset Mapping File. Within the FTR Grid, the permanent security constraints will be included in the nomograms file.

As the effect of such constraints is to potentially limit capacity between BEN and OTA capacity, constraints affecting only the South Island AC system need not be included.

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[23] Published at *http://www.systemoperator.co.nz/n4681*, with the relevant spreadsheet being 'Manual constraints post SFT".

[24] There is currently only one such constraint, being WELLINGTON_STABILITY_P_1.

Rule 14 – Allowance for permanent security constraints:

- Permanent security constraints will be applied to all FTR Grids and FTR Periods, as well as to the normal grid configuration for the FTR Rentals Amount calculation
- The source of permanent security constraints will be the System Operator's latest published manual constraints list
- Other constraints in that list (e.g. outage constraints) are not to be included
- Permanent security constraints affecting only the South Island AC system need not be included

The expected effect of this on the Revenue Adequacy Objective is neutral.

In addition to these security constraints published by the System Operator in its manual constraints list, some stability constraints can be applied in real time to the HVDC. These HVDC stability constraints are addressed in section 8.4.

8 HVDC representation and constraints

The inter-island HVDC link needs to be considered in detail and treated differently from HVDC assets, as it is controlled differently, directional, critical to the capacity available between BEN and OTA, and can have significant impact on the BEN and OTA price differential.

The HVDC asset includes the overhead circuits and the undersea cables between BEN and Haywards, close to Wellington in the lower North Island. It has two separate 'poles'. By the time the FTR Market is operating, Pole 3 will be in service, and Pole 2 will be continuing in service. Pole 1 has recently been decommissioned.

The introduction of Pole 3 with its new control systems is a significant change in the ability to import power to and export power from the North Island, and will make a major difference to the energy market. For that reason, historical analysis of flows, prices and constraints is of little value in predicting how the system will operate in its normal configuration of both poles in service. Pole 2 is losing one of its cables to Pole 3, reducing its capacity, so historical analysis of Pole 2 operation is not necessarily relevant to future Pole 2 operation.

Further, as discussed in previous sections:

- any outages of the HVDC will not be reflected in the Outage File, but rather through configuration and constraints
- the HVDC link will not be included in the internalised contingency analysis within i-HEDGE, but rather HVDC contingencies will be treated as constraints

This section discusses HVDC representation and constraints under the headings of:

- configuration and representation
- capacity limits
- contingency and reserve constraints
- stability constraints
- constraints summary

8.1 HVDC configuration and representation

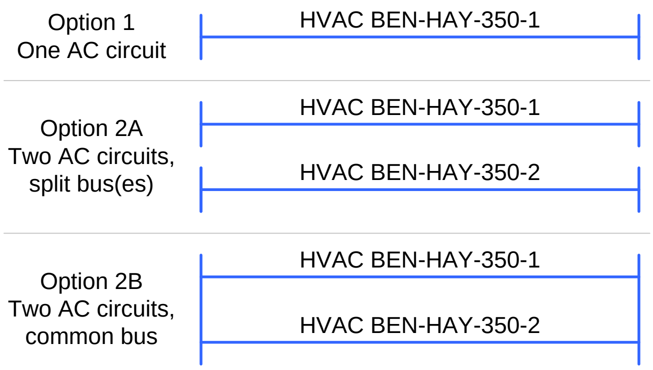
This appendix provides some background discussion supporting section 3.1.3 of the Policy.

i-HEDGE represents all assets as if they were HVAC assets. In the time frame of FTRs, typically there will be two poles in service, Pole 2 (P2) and Pole 3 (P3). When both poles are in service, they must therefore be represented either by:

- A single AC circuit (Option 1), or
- Two AC circuits (Option 2)

For Option 2, there are sub-options of a split or common bus.

Figure 20 – Possible representations of HVDC P2 and P3



A key issue in HVDC representation as AC circuits is that HVDC is controllable. So, if there are two poles in service with different ratings e.g. 500MW and 700MW, then it is possible to get 1200MW through them (ignoring any security or other constraints).

With a two AC circuits representation (Option 2), admittance[25] for each circuit would have to be set carefully (e.g. proportional to capacity) to ensure full capacity is available. In addition, if (as a sub-option) the BEN hub was modelled as separate buses for each pole, then the bus participation factors would have to be weighted commensurately. (Similarly for the Haywards (HAY) bus at the North Island end of the HVDC link if HAY ever became an FTR hub).

With a single AC circuit representation (Option 1), the circuit's admittance values do not matter, as long as they are within a solvable range, as the circuit effectively forms a single radial link between BEN and the inter-connected North Island system.

The disadvantage of representing multiple HVDC assets as a single AC circuit is that information on the capacities of individual HVDC circuits can be lost, that is relevant to the setting of security or reserve constraints (see below). However, the configuration can be signalled through other means, and capacities of different configurations are known, being a standing set of possible offers by the Grid Owner.

Representing multiple HVDC assets as a single AC circuit rather than separate AC circuits in i-HEDGE is thus preferred. This approach has the advantage also of consistency with the requirements of the FTR Rentals Amount calculation regarding the normal grid configuration[26], which will reduce the workload and risk of human error by both the grid owner and FTR manager.

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[25] Admittance is a measure of how easily a circuit or device will allow a current to flow

[26] Clause 6 of Schedule 14.6 (paraphrased):

- The set of inter-island HVDC links must be replaced by a single AC line with a nominal susceptance value between the Benmore and Haywards HVDC terminal nodes
- This nominal susceptance value determined under paragraph may be any suitable value that will avoid numerical difficulties
- Any switches between the Benmore HVDC terminal node and other Benmore nodes operating at the same nominal voltage that are normally closed must be treated as closed
- Any switches between the Haywards HVDC terminal node and other Haywards nodes operating at the same nominal voltage that are normally closed must be treated as closed

Rule 15 – HVDC representation

The HVDC link will be represented in the Network Model as a single AC circuit

The Network Model will include a flag reflecting the HVDC configuration (P2 & P3, P3 only, P2 only, no poles) allowing for any relevant HVDC outage (**Rule 3**).

The expected effect of this on the Revenue Adequacy Objective is neutral.

The Grid Owner has agreed with the FTR Manager that the Grid Owner will do the required conversions from HVDC to AC and from multiple circuits to a single, and include the configuration flag.

8.2 HVDC capacity limits

The simplest of the HVDC constraints is their capacity limits, which depend on both configuration and direction. The limits have both a send (higher) and receive (lower) figure, the difference being the losses at maximum flow. As we have lossless, balanced FTRs and a conservative approach, we assume the lower of the two figures, being the maximum receiving flow.

The source used for HVDC capacity information post Pole 3 is Transpower's HVDC Bipole Operating Policy, February 2013. The continuous ratings are used. Those for both Pole 2 and Pole 3 include the effects of the static stability constraints discussed in section 7.

The grid owner has advised the FTR Manager that, after the static var compensator (statcom) at Haywards is commissioned, the sent capacity of the bipole will increase to 1200 MW northwards and 850 MW southwards, as per Transpower's HVDC Bipole Operating Policy (TP.OG 48.02). The FTR Manager understands from the Grid Owner that the Haywards statcom is on schedule to be commissioned, and integrated into HVDC operation, by the end of November 2013[27].

[27] . See for example the test plan at https://www.transpower.co.nz/projects/hvdc-inter-island-link-project/pole-2-control-system-commissioning/pole-2-re-commissioning.

Rule 16 – HVDC capacity limits for the FTR Grid

The HVDC capacity limits for the FTR Grid will be Transpower's continuous ratings taking the received quantity, for each HVDC configuration and direction:

Up to November 2013 inclusive	HVDC configuration			
	P2 and P3	P2 only	P3 only	No poles
Northwards	954 MW	475 MW	655 MW	0
Southwards	724 MW	465 MW	655 MW	0

From December 2013 inclusive	HVDC configuration			
	P2 and P3	P2 only	P3 only	No poles
Northwards	1134 MW	475 MW	655 MW	0
Southwards	817 MW	465 MW	655 MW	0

The expected effect of this on the Revenue Adequacy Objective is slightly conservative.

The capacity implication in cases of planned bipole outage is discussed in section 8.5.

In dispatch and pricing, it is expected that in many cases the actual capacity will be constrained by contingency, reserve or stability constraints:

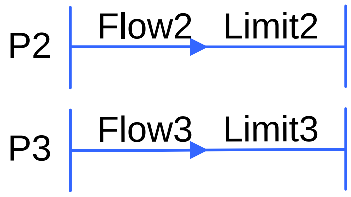
8.3 HVDC contingency and reserve constraints

In the New Zealand electricity market, energy and instantaneous reserves are co-optimised, to ensure that there are sufficient reserves available to meet the highest risk. The risk is typically the largest dispatched generation unit in an island. Sometimes the HVDC import into an island might exceed the size of the largest dispatched generation unit, in which case SPD determines the most economic dispatch of the HVDC, which might for example by full if reserves are relatively cheap (compared to energy), or constrained back if reserves are expensive.

The consequence of this is that the HVDC capacity can be constrained depending on the interplay between the energy market, reserves market, the grid and demand. The results of the energy and reserves co-optimisation affect not only HVDC capacity but prices[28] and hence rentals and Provisional FTR Hedge Vales. As only the grid part of this is explicitly modelled in the FTR market, we need to approximate the impact of such constraints on HVDC capacity in the FTR Grid.

For a particular direction of flow, we have flow and thermal limit parameters as illustrated here in Figure 21:

Figure 21 – HVDC configuration in SPD



There are two levels of HVDC (DC) risk are modelled in SPD:

- Contingent event (DCCE), being the failure of one pole, which is covered principally by instantaneous reserves
- Extended contingent event (DCECE), being the failure of both poles, which is covered principally by instantaneous reserves and AUFLS[29]

The formulae for DCCE risk are (in each direction):

Flow2 + Flow3 – Limit2 ≤ Reserves (for the P3 contingency)

Flow2 + Flow3 – Limit3 ≤ Reserves (for the P2 contingency)

These can be combined as:

Flow2 + Flow3 – Minimum(Limit2, Limit3) ≤ Reserves

In SPD, RampUp is fixed to Minimum(Limit2, Limit3) and so the DCCE constraint in SPD is written in the form:

Flow2 + Flow3 – RampUp ≤ Reserves

Reserves is the amount of net free reserve (NFR) as calculated in real time by the System Operator's Reserve Management Tool (RMT), plus the amount of instantaneous reserves available, in the receiving island.

For DCECE Risk we have similar constraint:

Flow2 + Flow3 – AUFLS ≤ Reserves

AUFLS is the amount of Automatic Under-Frequency Load Shedding available. This is calculated in real time by RMT also.

These two risk equations both involve 'Flow2 + Flow3'. That is, constraints can be meaningfully defined relative to a single AC line representation of the HVDC links.

28 The Electricity Authority has observed that inter-island price separation, when it occurred in 2008 and 2011 (the two years examined), was closely related to the price of fast instantaneous reserve (FIR). As the reserves market including the FIR price is not modelled in i-HEDGE, such effects will have to be approximated by an externality.

29 Automatic Under Frequency Load Shedding

For the parameters, we use the following assumptions:

- Ramp-Up is, when both Poles are in operation, the lowest of the two individual pole capacities
- Reserves, given the problems in forecasting net free reserves, and that they tend to be zero for Fast Instantaneous Reserves (FIR), we replace by the largest contingent risk in each island, which is assumed to be the largest typically dispatched generation unit in an island, being a 380 MW gas turbine in the North Island, or a 120 MW hydro unit in the South Island, plus a deminumus of 60 MW
- AUFLS as 30% of the average load, of 1500MW and 2500MW in the South and North Islands respectively.

The steps of this analysis are shown in Figure 22 at the end of this section, resulting in:

Rule 17 – HVDC contingency and reserve constraints

The HVDC DCCE and DCECE constraints will be:

	DCCE				DCECE
	P2 and P3	P2 only	P3 only	No poles	
Northwards	915 MW	440 MW	440 MW	0	1190 MW
Southwards	645 MW	180 MW	180 MW	0	630 MW

The expected effect of this on the Revenue Adequacy Objective is neutral.

8.4 HVDC stability constraints

Some stability constraints are included as permanent security constraints, discussed in section 7. In addition to these, for the new HVDC system there will be:

- Static HVDC stability limits
- Dynamic HVDC stability constraints that are created dynamically in the market systems

The static HVDC stability limits are 1000MW and 750MW sent, 954MW and 724MW received for northwards and southwards respectively, to reflect reactive power/voltage stability at HAY.

Once the new SVC is commissioned around December 2013, these limits are both expected to increase by around 200 MW. The first auction for an FTR Period in December 2013 is currently scheduled for September 2013, so this analysis and probably the Policy will need to be revised by then.

The dynamic HVDC stability constraints are calculated in a complex manner taking into account many system conditions, including:

- Wellington demand
- Outages on key 220kV lines in the central North Island
- Outages on regional transformers and reactive power equipment
- HVDC cable configurations (a level below pole configurations)

Of these, only the circuit outages and interconnecting transformers are modelled in the FTR Grid. As in the FTR Market all power flow is between BEN and OTA, such outages restrict that capacity even though they do not restrict the capacity of the HVDC link per se.

However the other system conditions of Wellington demand and the status of reactive power equipment is not explicitly modelled in the FTR Grid. As these stability constraints are designed for the new HVDC configuration and control systems, there is no history of their use.

Rule 18 – HVDC stability constraints

The static HVDC stability limits are 954MW and 724MW received for northwards and southwards respectively up to November 2013 inclusive, and 1134MW and 817MW received for northwards and southwards respectively from December 2014 inclusive.

The impact of dynamic HVDC stability constraints will be reflected by scaling the static HVDC stability constraint down by 20%

The expected effect of this on the Revenue Adequacy Objective is neutral.

The dynamic HVDC stability constraints are likely to be critical to HVDC capacity when Pole 2 and Pole 3 are in operation, but there is no data on their use, and they would be very uncertain to model as they depend on so many factors as above. In effect, the intention here is to use an estimate scaling factor (80%) and start collecting relevant data (Appendix A), and improve this rule when data is available to support it.

8.5 HVDC bipole outages

The FTR Manager's role is to set the FTR capacity made available to meet the revenue adequacy objective set in the FTR Allocation Plan (rather than say to maximise nor minimise the FTR capacity made available). With zero capacity offered for the life of the FTR, revenue adequacy is assured. Therefore to meet the revenue adequacy objective at least some capacity needs to be offered in cases of planned HVDC bipole outages.

The capacity offered should be such that there is a reasonable likelihood that excess revenue adequacy in trading periods with the HVDC operational would compensate for any lack of revenue adequacy during bipole outages, with 'reasonable likelihood' being an expectation of meeting of the revenue adequacy objective.

In principle, the capacity applied by the FTR Manager in such cases should not be zero but a proportion 'X' of the HVDC capacity for the remainder of the month. The proportion X could be calculated as the ratio of durations and price differences between periods of bipole outage and no bipole outages (discussed in greater detail in the consultation paper), but there are two problems with this:

- The ratio of price differences when there is a bipole outage is particularity difficult to estimate as the two islands are 'islanded' with independent price formation at BEN and OTA
- Historical analysis of bipole outages indicates that the value of X is not strongly correlated with the duration of historical bipole outage, at least for outages of two days or over.

Historically, values of X of around 60% would have met the revenue adequacy objective. Looking forward, using ASX hedge information a value of X of around 25% would. The FTR Manager consulted on this issue in June 2013, including this analysis: see *http://ems.co.nz/ftr/ftrconsultation*.

The counterfactual should be the HVDC configuration in service in the parts of the FTR period when there is no planned bipole outage.

The FTR Manager's approach is to be initially conservative in specifying the FTR Grid (Rule 1), and equilibrate the capacity to the Revenue Adequacy Objective over time as better information becomes available. In balance, weighing up this approach and the following factors:

- The need to provide some capacity to meet the revenue adequacy objective
- The difficulty in ddetermining the appropriate amount given all the uncertainties
- The benefits to the FTR Market of certainty over how FTR capacity will be calculated

the FTR Manager has decided to use the lowest indicated value of 25%.

The FTR Manager regularly reviews its policies including whether this factor will be increased (or decreased) over time as and when experience with actual revenue adequacy in periods of planned bipole outages eventuates.

Rule 19 – HVDC bipole outages

When there is a relevant bipole outage planned for the FTR Period, the HVDC capacity relevant to the remaining parts of the period will be used, multiplied by 25%.

8.6 HVDC constraints summary

The FTR Grid needs a capacity constraint for the single modelled HVDC line, which will depend on the HVDC configuration and direction.

Rule 20 – HVDC constraints for the FTR grid

The HVDC constraints for the FTR grid will be the minimum of the capacity limit (**Rule 16**), DCCE and DCECE reserve constraints (**Rule 17**) and HVDC stability constraints (**Rule 18**), **allowing for HVDC bipole outages (Rule 19)**. This gives:

Up to November 2013 inclusive	HVDC configuration						
	No bipole outages			Bipole outages, with configuration otherwise:			
	P2 and P3	P2 only	P3 only	No poles	P2 and P3	P2 only	P3 only
HVDC flag	1	2	3	4	5	6	7
Northwards	763 MW	440 MW	440 MW	0	191 MW	110 MW	110 MW
Southwards	579 MW	180 MW	180 MW	0	145 MW	45 MW	45 MW

From December 2013 inclusive	HVDC configuration						
	No bipole outages			Bipole outages, with configuration otherwise:			
	P2 and P3	P2 only	P3 only	No poles	P2 and P3	P2 only	P3 only
HVDC flag	1	2	3	4	5	6	7
Northwards	907 MW	440 MW	440 MW	0	191 MW	110 MW	110 MW
Southwards	630 MW	180 MW	180 MW	0	145 MW	45 MW	45 MW

The calculation of the HVDC constraints prior to allowing for HVDC bipole outages is summarised in Figure 22.

Note that the Capacity Scaling Factor (section 5) will apply to the HVDC as well as HVAC assets.

Figure 22 – HVDC constraints calculation summary

Figure 22a – Pre statcom

	Northwards			Southwards			
	HVDC configuration			HVDC configuration			
	P2 & P3	P2 only	P3 only	P2 & P3	P2 only	P3 only	
Capacity limits							
Sent	1000 MW	500 MW	700 MW	750 MW	489 MW	700 MW	*a*
Received	954 MW	475 MW	655 MW	724 MW	465 MW	655 MW	*b*
HVDC Flow Max <=	**954 MW**	**475 MW**	**655 MW**	**724 MW**	**465 MW**	**655 MW**	*c*
Contingency and reserve constraints							
Ramp-up	475 MW	0 MW	0 MW	465 MW	0 MW	0 MW	*d*
Deminimus	60 MW			60 MW			*e*
DCCE Island gen risk	380 MW			120 MW			*f*
HVDC Flow Max <=	**915 MW**	**440 MW**	**440 MW**	**645 MW**	**180 MW**	**180 MW**	*g*
DCECE AUFLS	750 MW			450 MW			*h*
HVDC Flow Max <=	**1190 MW**			**630 MW**			*i*
Stability constraints							
Static stability limit	954 MW			724 MW			*j*
Dynamic stability effect	0.8			0.8			*k*
HVDC Flow Max <=	**763 MW**			**579 MW**			*l*
FTR Grid constraint							
	Northwards			Southwards			
	HVDC configuration			HVDC configuration			
	P2 & P3	P2 only	P3 only	P2 & P3	P2 only	P3 only	
HVDC Flow Max <=	**763 MW**	**440 MW**	**440 MW**	**579 MW**	**180 MW**	**180 MW**	*i*

a *P2&P3 figures include static stability limit (j)*
b *P2&P3 figures include static stability limit (j)*
c *= b, use received rather than sent*
d *= c(other pole, or zero if none)*
e *Assumed*
f *Assumed typical largest plant*
g *= d + e + f*
h *Assumed 30% of average load*
i *= e + f + h*
j *1000 and 750 sent, converted to received*
k *Assumed*
l *= j * k*
i *= min(c, g, i, l)*

Figure 22b – Post statcom

	Northwards P2 & P3	Northwards P2 only	Northwards P3 only	Southwards P2 & P3	Southwards P2 only	Southwards P3 only	
Capacity limits							
Sent	1200 MW	500 MW	700 MW	850 MW	489 MW	700 MW	*a*
Received	1134 MW	475 MW	655 MW	817 MW	465 MW	655 MW	*b*
HVDC Flow Max <=	**1134 MW**	**475 MW**	**655 MW**	**817 MW**	**465 MW**	**655 MW**	*c*
Contingency and reserve constraints							
Ramp-up	475 MW	0 MW	0 MW	465 MW	0 MW	0 MW	*d*
Deminimus	60 MW			60 MW			*e*
DCCE Island gen risk	380 MW			120 MW			*f*
HVDC Flow Max <=	**915 MW**	**440 MW**	**440 MW**	**645 MW**	**180 MW**	**180 MW**	*g*
DCECE AUFLS	750 MW			450 MW			*h*
HVDC Flow Max <=	**1190 MW**			**630 MW**			*i*
Stability constraints							
Static stability limit	1134 MW			817 MW			*j*
Dynamic stability effect	0.8			0.8			*k*
HVDC Flow Max <=	**907 MW**			**653 MW**			*l*

FTR Grid constraint

	Northwards P2 & P3	Northwards P2 only	Northwards P3 only	Southwards P2 & P3	Southwards P2 only	Southwards P3 only	
HVDC Flow Max <=	**907 MW**	**440 MW**	**440 MW**	**630 MW**	**180 MW**	**180 MW**	*i*

a *P2&P3 figures include static stability limit (j)*
b *P2&P3 figures include static stability limit (j)*
c *= b, use received rather than sent*
d *= c(other pole, or zero if none)*
e *Assumed*
f *Assumed typical largest plant*
g *= d + e + f*
h *Assumed 30% of average load*
i *= e + f + h*
j *1000 and 750 sent, converted to received*
k *Assumed*
l *= j * k*
i *= min(c, g, i, l)*

8.7 HVDC constraints for the rentals amount calculation

Schedule 14.6 requires in clause 5(2) that HVDC link capacity limits are applied, risk and reserve constraints are disabled, and losses are set to zero.

For the FTR Grid, the HVDC constraints derived above are a mixture of capacity limits and risk and reserve constraints, and are based on receiving end figures and so include losses.

For the rentals amount calculation, we need the send rather than receive capacity limits, which using the same sources as described in section 8.2 are:

Rule 21 – HVDC capacity limits for the normal grid configuration

The HVDC capacity limits for the normal grid configuration will be Transpower's continuous ratings taking the send quantity, for each HVDC configuration and direction:

Up to November 2013 inclusive	HVDC configuration			
	P2 and P3	P2 only	P3 only	No poles
Northwards	1000 MW	500 MW	700 MW	0
Southwards	750 MW	489 MW	700 MW	0

From December 2013 inclusive	HVDC configuration			
	P2 and P3	P2 only	P3 only	No poles
Northwards	1200 MW	500 MW	700 MW	0
Southwards	850 MW	489 MW	700 MW	0

As the normal grid configuration excludes outages, there is no need for the HVDC bipole outage columns in similar tables in preceding sections.