Review of price separation during HVDC reversal

Market Performance Report

6 October 2011

Market Performance

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Investigation stages

An in-depth investigation will typically be the final step of a sequence of escalating investigation stages. The investigations are targeted at gathering sufficient information to decide whether a Code amendment or market facilitation measure should be considered.

Market Performance Enquiry (Stage I): At the first stage, routine monitoring results in the identification of circumstances that require follow-up. This stage may entail the design of low-cost ad hoc analysis, using existing data and resources, to better characterise and understand what has been observed. The Authority would not usually announce it is carrying out this work.

This stage may result in no further action being taken if the enquiry is unlikely to have any implications for the competitive, reliable and efficient operation of the electricity industry. In this case, the Authority publishes its enquiry only if the matter is likely to be of interest to industry participants.

Market Performance Review (Stage II): A second stage of investigation occurs if there is insufficient information available to understand the issue and it could be significant for the competitive, reliable or efficient operation of the electricity industry. Relatively informal requests for information are made to relevant service providers and industry participants. There is typically a period of iterative information-gathering and analysis. The Authority would usually publish the results of these reviews but would not announce it is undertaking this work unless a high level of stakeholder or media interest was evident.

Market Performance Formal Investigation (Stage III): The Authority may exercise statutory information-gathering powers under section 46 of the Act to acquire the information it needs to fully investigate an issue. The Authority would generally announce early in the process that it is undertaking the investigation and indicate when it expects to complete the work. Draft reports will go to the Board of the Authority for publication approval.

The outcome of any of the three stages of investigation can be either a recommendation for a Code amendment, provision of information to a Code amendment process already underway, a brief report provided to industry as a market facilitation measure, or a no further action.

From the point of view of participants, repeated information requests are generally concerned with Stage II; trying to understand the issue to such an extent that a decision can be made about materiality.

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Executive summary

Following the introduction of the new market system project (MSP) by the system operator in mid 2009, the modelling practice for the HVDC in the final pricing schedule has changed. The new practice is to apply to the dispatch schedule, a maximum constraint of 0 to pole 1 or pole 2 when either pole is scheduled to operate below its minimum operating level in real time. If the constraints occur across a trading period boundary, it is also applied to the final pricing schedule. The effect is to constrain out the HVDC. Prior to the MSP being implemented, this practice was only applied to pole 1.

The Electricity Authority's (Authority) analysis shows that when the HVDC is constrained to zero (approximately 2% of the time), the electricity markets in the North and South islands become independent of each other, with associated risk of price separation between the two islands.

Incidents of this nature occurred on 14 August 2011 and 26 September 2011. On both occasions prices separated to a significant level. This would not have occurred to the same extent under the modelling practice of the HVDC prior to MSP.

The Authority is currently implementing a financial transmission rights (FTR) market, covering price differences between Benmore (BEN) in Otago and Otahuhu (OTA) in Auckland. The system operator's practice of constraining out the HVDC has a potential future impact on the revenue adequacy of option FTRs and therefore the number of option FTRs that can be offered by the FTR Manager. Once pole 3 is commissioned, with the round power functionality (currently scheduled for 2013/2014) this issue will be significantly reduced.

The change from the practice that prevailed prior to MSP has increased the risk of price separation. The Authority believes it is important that market participants are made aware of the change in the modelling of the HVDC post MSP and of its effect on price volatility.

1 Introduction

1.1 The system operator's new market system project (MSP) went live on 21 July 2009. Since MSP went live, the modelling practice for the HVDC in the final pricing schedule has changed. Prior to MSP, the system operator's practice was to constrain out pole 1 when it was scheduled below its minimum operating limit in real time. This modelling technique was not applied to pole 2. During the MSP review, the system operator decided that in order to provide consistency in the treatment of the HVDC in the various schedules and also due to operational/technical factors, it would apply the same modelling technique to both poles. Consequently, since the market systems were introduced in 2009, the system operator's practice is to apply a [DCmax = 0] constraint (HVDC maximum constraint) to pole 2 (or pole 1 as the case may be) when it is scheduled below its operating limit in real time. The system operator advised the Authority of this by email on 14 September 2011.

1.2 While this practice provides a more accurate representation of HVDC capacity in the dispatch schedule, it is a change from the practice that prevailed prior to MSP. This report will discuss the possible impacts of the current practice on final prices and financial transmission rights (FTRs).

2 Background

2.1 During trading period 35 on 14 August 2011, the final price at Haywards (HAY) reached $657/MWh with the highest price in the North Island reaching $8,569/MWh at Waipawa (WPW). This was primarily due to an extreme high load in the Wellington region causing the transmission security constraint between Bunnythorpe (BPE) and Woodville (WDV) to bind.

2.2 In the final pricing schedule, the HVDC flow had also been constrained to zero during this trading period. The system operator confirmed this was due to the HVDC flow being below the minimum operating limit (30 MW) for a short time before the power flow changed direction in real-time. This occurred across a trading period boundary (between trading period 34 and trading period 35) and therefore this constraint was also applied to final pricing. It is standard practice to use assets available at the beginning of each trading period in final pricing.

2.3 The Authority has analysed its final pricing data sets for the period 21 July 2009 to 28 August 2011. A total of 703 trading periods (2% of the total trading periods over this timeframe) have resulted in the HVDC being constrained out due to the flow being below the minimum operating limits. No instances of this occurring were identified for pre-MSP cases.

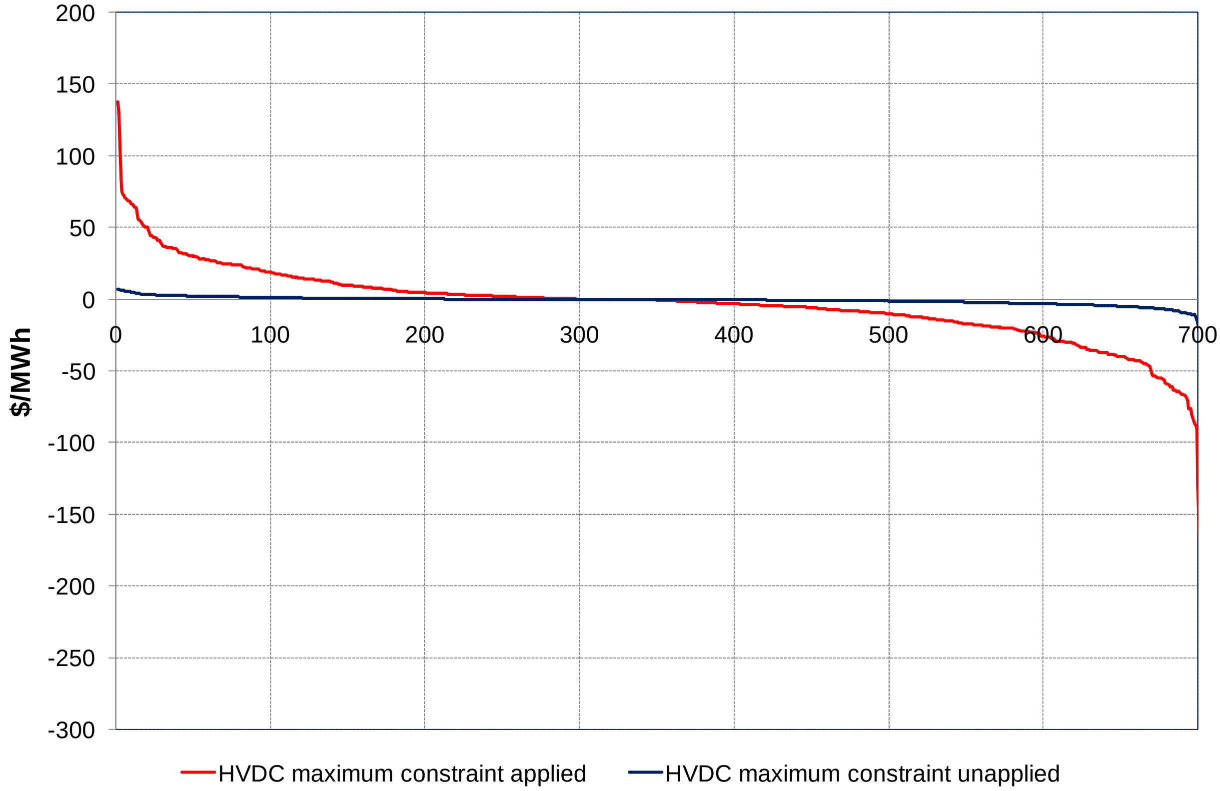
2.4 On 14 September 2011, the Authority queried with the System operator whether there was a change in the HVDC modelling practice. The system operator responded to the Authority's queries about HVDC modelling practice on 21 September. In particular the system operator confirmed that there was a change in HVDC modelling practice since MSP was introduced. The system operator stated that it "*believes the current modelling practice provides a more accurate representation of HVDC capacity in the dispatch schedule but [the System Operator is] comfortable that the practice prior to the implementation of the new market systems was also within the rule requirements that applied to the System Operator at the time (the EGR's).*"

2.5 The subsequent analysis undertaken by the Authority shows that the impact of the system operator's HVDC modelling practice on total system cost is minimal. However, the risk of price separation between the two islands has increased as a result of this change in modelling practise. The Authority considers it is important that market participants are made aware of this change in the modelling of the HVDC and of its effect on price volatility.

3 Impact of current HVDC modelling practice on price

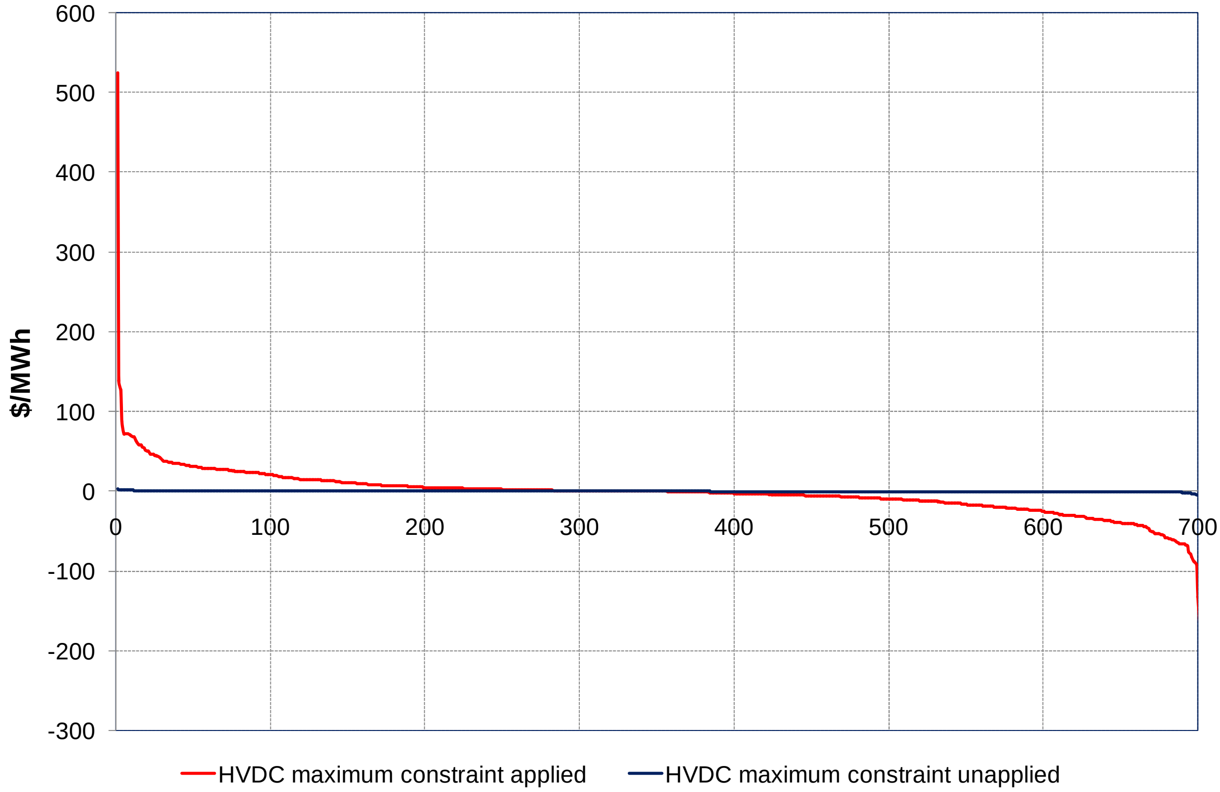
3.1 When the HVDC is constrained to zero, the electricity markets in the North and South islands become independent of each other. The risk of price separation between the two islands increases. The impact this constraint has on price separation between the two islands is shown in Figure 1 and Figure 2. Both figures show that the current HVDC modelling practice (with the HVDC maximum constraint applied) creates greater price separation between the North and South islands in both directions.

Figure 1 Impact of HVDC maximum constraint on OTA-BEN price difference between 21 July 2009 and 28 August 2011 (horizontal axis is the sorted 703 incidents).



Notes: 1. The comparison is based on 703 trading periods in which HVDC is constrained to zero according current HVDC modelling practice.

Figure 2 Impact of DC max constraint on HAY-BEN price difference between 21 July 2009 and 28 August 2011 (horizontal axis is the sorted 703 incidents).



Notes: 1. The comparison is based on 703 trading periods in which HVDC is constrained to zero according current HVDC modelling practice.

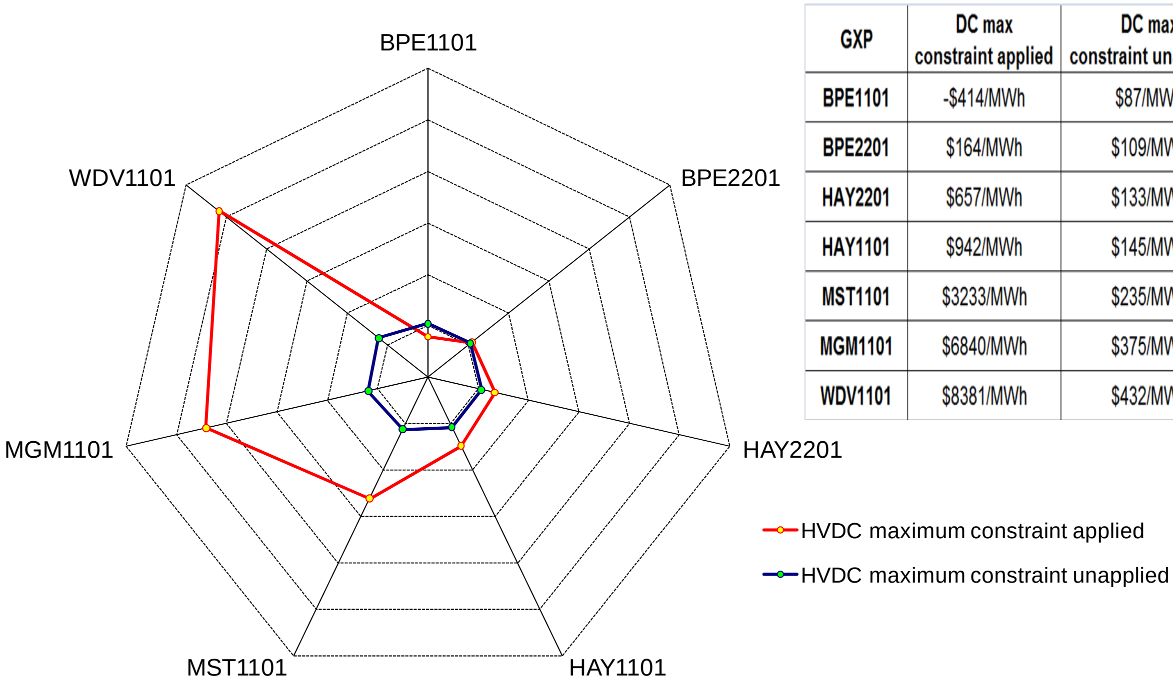
3.2 Even though the HVDC maximum constraints are applied only 2% of the time, the impact of HVDC max constraints on prices is considerable. This means that market participants are facing a risk that they may not be aware of.

3.3 An example of this pricing impact occurred during trading period 35 on 14 August 2011. During this trading period, the HVDC was constrained to zero and caused a high spring washer (HSW) price situation in the Wellington and Bunnythorpe regions. The price at the Haywards node (HAY) in Wellington rose to $657/MWh while the price at Benmore (BEN) was only $132/MWh.

3.4 The Authority's analysis[1] shows that if the HVDC had not been constrained to zero in final pricing, the spring washer's effect on prices would have been greatly reduced. Figure 3 below illustrates the impact of HVDC maximum constraints on prices in the Wellington and Bunnythorpe regions during trading period 35 on 14 August 2011.

[1] performed using final pricing data set and the Authority's vSPD model

Figure 3 Impact of HVDC maximum constraint on prices on 14 August 2011 TP35



GXP	DC max constraint applied	DC max constraint unapplied
BPE1101	-$414/MWh	$87/MWh
BPE2201	$164/MWh	$109/MWh
HAY2201	$657/MWh	$133/MWh
HAY1101	$942/MWh	$145/MWh
MST1101	$3233/MWh	$235/MWh
MGM1101	$6840/MWh	$375/MWh
WDV1101	$8381/MWh	$432/MWh

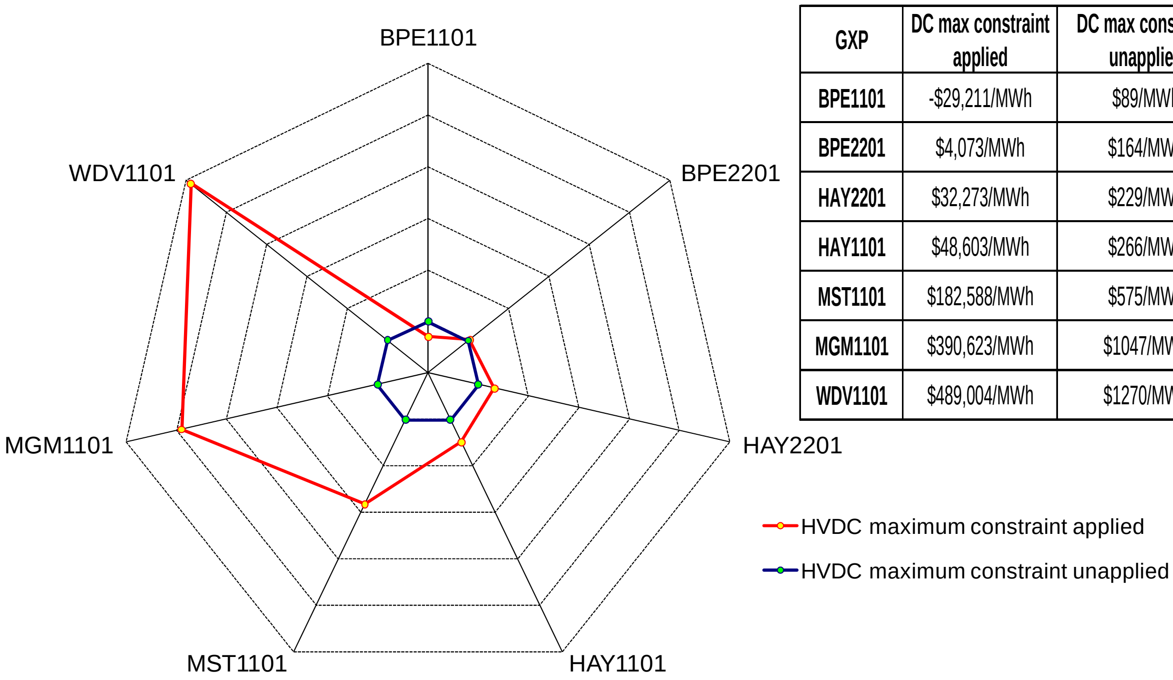
Notes:
1. HVDC maximum constraint is the constraints that limit energy flows on HVDC to zero.
2. If HVDC maximum constraint is removed, HVDC transfer will be 17.74 MW from South to North to supply The Wellington region and therefore, lessen the effect of binding constraint.

3.5 Without the application of the HVDC maximum constraint, the price at HAY would be reduced by 5 times and the price at WDV would be reduced by 20 times.

3.6 Another such pricing event occurred on 26 September 2011 during trading period 16. During this trading period, the HVDC was constrained to zero and again caused a HSW price situation in the Wellington and Bunnythorpe regions. The price at HAY rose to $32,273/MWh while the price at BEN was only $226/MWh. On this occasion there was also an infeasible solution for the trading period, with Waipawa (WPW) price at $500,000/MWh (infeasible price).

3.7 If the HVDC was not constrained to zero in final pricing, neither the infeasibility nor HSW price situation would have emerged. The price at WPW would have been at $1,293/MWh. Figure 4 below illustrates the impact of the HVDC maximum constraints on prices in the Wellington and Bunnythorpe regions on 26 September 2011 for trading period 16.

Figure 4 Impact of HVDC maximum constraint on prices on 26 September 2011 TP16



GXP	DC max constraint applied	DC max constraint unapplied
BPE1101	-$29,211/MWh	$89/MWh
BPE2201	$4,073/MWh	$164/MWh
HAY2201	$32,273/MWh	$229/MWh
HAY1101	$48,603/MWh	$266/MWh
MST1101	$182,588/MWh	$575/MWh
MGM1101	$390,623/MWh	$1047/MWh
WDV1101	$489,004/MWh	$1270/MWh

Notes:

1. HVDC maximum constraint is the constraints that limit energy flows on HVDC to zero.
2. If HVDC maximum constraint is removed, HVDC transfer will be 72 MW from South to North to supply The Wellington region and therefore, lessen the effect of binding constraint.
3. The prices for "HVDC maximum constraint applied" case is provisional prices

3.8 The two examples above illustrate how extreme the impact of HVDC maximum constraint can be on prices. The examples show that retailers in the Wellington region are facing a considerable pricing risk.

4 Impact of current HVDC modelling practice on FTRs

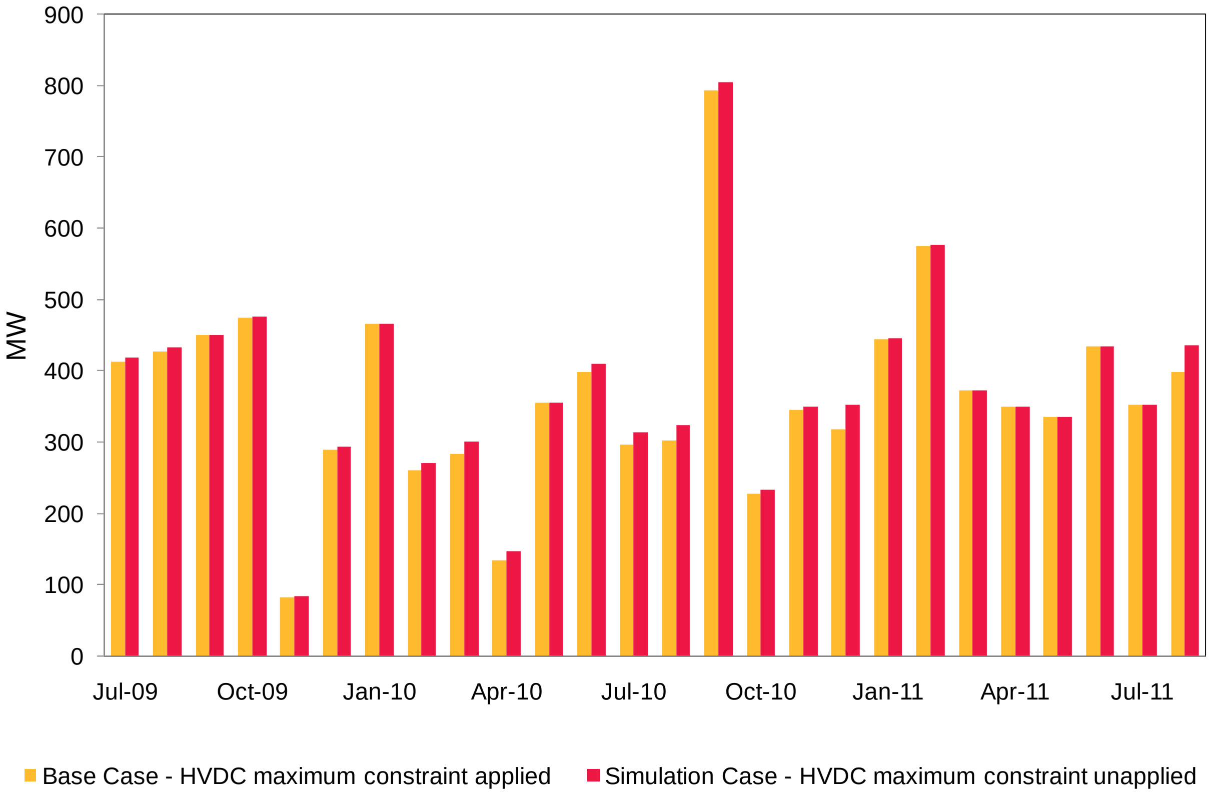
4.1 An additional impact of the HVDC maximum constraint is the impact on FTR revenue adequacy. The impact could be significant because the HVDC link is assumed by the FTR model to be in service for a whole FTR period but is actually intermittently "switched-off" when the HVDC flow is changing direction. This divergence between the actual and expected HVDC availability could exacerbate any FTR revenue adequacy issues.

4.2 The Authority has estimated the potential impact this may have on FTR revenue adequacy. This was done by calculating the available market surplus from the North Island and the HVDC and calculating the expected FTR capacity that could be supported between BEN and OTA at these observed price differences. This was done with (base case) and without (simulation case) the HVDC constraint.

4.3 Our analysis shows that if the HVDC maximum constraint is not applied, the amount of market surplus available for FTRs can increase or decrease, but the absolute price difference between OTA and BEN always decreases. In the case of a decreasing amount of available rent for FTRs, the reduction of absolute price difference between OTA and BEN is greater. Consequently, the amount of option FTRs that can be supported increases if the HVDC max constraint is removed.

4.4 Figure 5 compares the amount of option FTRs that can be supported under the base case and the simulation case. The base case presents the current HVDC modelling practice and the simulation case assumes the HVDC modelling practice prior to MSP.

Figure 5 Number of option FTRs that can be supported under base case and simulation case modelling practices.



4.5 The result of the analysis is shown in more details in Table 1. The data shows that if the HVDC maximum constraint is removed then the amount of option FTRs that can be supported increases by up to 10% (December 2010 data) or up to 37 MW (August 2011 data).

Table 1 Base case and simulation result for amount of option FTR supported.

Month	Available Rent for FTR		Sum of absolute OTA-BEN price difference		Amount of option FTR supported (MW)		Increase in option FTR amount.
	Base Case	Simulation Case	Base Case	Simulation Case	Base Case	Simulation Case	
Jul-09	$2,784,632	$2,785,771	$13,509	$13,307	412	419	-2%
Aug-09	$2,876,467	$2,876,573	$13,459	$13,289	427	433	-1%
Sep-09	$6,357,714	$6,357,714	$28,222	$28,222	451	451	0%
Oct-09	$9,405,407	$9,405,571	$39,684	$39,491	474	476	0%
Nov-09	$1,229,686	$1,230,883	$30,193	$29,652	81	83	-2%
Dec-09	$2,067,139	$2,067,141	$14,341	$14,091	288	293	-2%
Jan-10	$6,999,101	$6,999,101	$30,062	$30,062	466	466	0%
Feb-10	$2,532,541	$2,533,652	$19,477	$18,749	260	270	-4%
Mar-10	$2,380,084	$2,385,192	$16,795	$15,839	283	301	-6%
Apr-10	$730,352	$730,586	$10,921	$9,940	134	147	-9%
May-10	$3,086,936	$3,086,936	$17,354	$17,354	356	356	0%
Jun-10	$2,049,699	$2,049,949	$10,299	$10,021	398	409	-3%
Jul-10	$3,290,597	$3,291,438	$22,193	$20,962	297	314	-6%
Aug-10	$1,739,872	$1,738,997	$11,541	$10,751	302	324	-7%
Sep-10	$2,442,100	$2,441,728	$10,848	$10,697	450	457	-1%
Oct-10	$903,934	$903,936	$7,973	$7,764	227	233	-3%
Nov-10	$2,890,975	$2,891,066	$16,776	$16,554	345	349	-1%
Dec-10	$2,691,175	$2,692,433	$16,965	$15,271	317	353	-10%
Jan-11	$7,302,002	$7,301,489	$32,861	$32,789	444	445	0%
Feb-11	$12,242,702	$12,242,700	$42,530	$42,444	576	577	0%
Mar-11	$65,214,146	$65,214,184	$350,779	$350,713	372	372	0%
Apr-11	$2,976,482	$2,976,482	$17,075	$17,075	349	349	0%
May-11	$1,484,188	$1,484,188	$8,877	$8,877	334	334	0%
Jun-11	$2,547,177	$2,547,177	$11,746	$11,746	434	434	0%
Jul-11	$1,609,423	$1,609,423	$9,131	$9,131	353	353	0%
Aug-11	$2,914,804	$2,755,165	$14,655	$12,661	398	435	-9%

Source: Electricity Authority

Notes:
1. Base case means HVDC maximum constraint is applied
2. Simulation case means HVDC maximum constraint is removed.

5 Conclusion

5.1 The introduction of the HVDC maximum constraint into final pricing post MSP has significant impacts on both price volatility and the number of option FTRs that can be supported once FTRs are introduced.

5.2 While claiming that the current HVDC modelling practice provides a more accurate representation of the HVDC capacity in the dispatch schedule, the system operator appears to have under-estimated the impact of this modelling practice on several aspects of the electricity market, such as price volatility and FTRs. Consequently, market participants were not clearly informed and consulted about this change in HVDC modelling practice.

5.3 It is questionable that the current practice better represents conditions in real time, since the reversal takes place in only a small fraction of a trading period. Furthermore, it is doubtful if the price separation resulting from the practice provides an efficient signal for investment or coordination of generation and demand.

5.4 Once pole 3 is introduced with round power operation, which will allow for minimum interruption to the HVDC flow when changing HVDC flow direction, the requirement for HVDC maximum constraints will be reduced. However, round power operation will not be available until the national frequency and reserves market is implemented in 2013/2014.

5.5 The Authority anticipates that the FTR market will be operational from October 2012. This implies that there could be approximately 1-2 years when the FTR market is in operation without round power operation.

6 Next steps

6.1 The Authority is currently negotiating a Technical Advisory Services Contract (TASC) request with the system operator to report back on options for removing the application of the HVDC maximum constraint from final pricing when HVDC is available.

6.2 The Authority would anticipate the report cover:

a) solution options, including process changes;

b) cost estimates;

c) systems requiring change;

d) core implementation tasks, such as coding, testing, auditing; and

e) timeframes to implement.

Glossary of abbreviations and terms

Authority	Electricity Authority
vSPD	Vectorised schedule, pricing and dispatch