Under Frequency Management – Appendix 3

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National Instantaneous Reserve Market in the NZEM

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System Operations

Executive Summary

The Scheduling Pricing and Dispatch (SPD) model is used in the New Zealand electricity market (NZEM) to produce optimal security constrained dispatch. Energy and two types of instantaneous reserve (further reserve) are offered and dispatched at the market taking into account a full nodal DC approximation of power flow model with security constraints and a reserve model. The SPD model is based on a configuration that consists of two separate multi nodal AC systems connected by a DC link. The reserve market consists of two zones, North and South Islands. Reserve cleared in each zone has to cover biggest risk identified in the same zone.

The paper analyses the ability of the DC link to transfer reserve between Islands.

Simulation of the SPD with HVDC reserve transfer model has shown a reduction of total market cost (value of objection function) or increase in national benefit by 0.39% in March, 1.04% in April, 1.56% in May and 1.3% in June of 2004, which is about $0.68m overall. A reduction overall Energy and Reserve revenue for the same period by $9.6m compared to real data has seen. Forecast for one year could give about $29m reduction in energy and reserve revenue for market participants and $2.1m of net economic benefit increase.

Acknowledgement.

I am very grateful to Roger Miller for advice and for providing technical details of NZ power system and HVDC operation.

1. Introduction

The New Zealand electricity market uses the Scheduling Pricing and Dispatch (SPD) model to produce an optimal solution for energy and instantaneous reserve.

In the reserve model of SPD there are two reserve collecting areas (North and South Islands). Two classes of reserve (Six-second and Sixty-second) are kept in each area to stabilise the system in case of an under frequency risk event. Reserve is divided into Partly Loaded Spinning Reserve (PLSR) and Tail-Water Depressed Reserve (TWD) provided from generators and interruptive load Reserve (ILR) provided from the demand side. The amount of reserve cleared has to be greater then or equal to every identified risk in each island. There are two variable types of HVDC (CE and ECE) risk in each island, Manual constant risk in South Island and a few variable generation unit risks in the North Island. The SPD model co-optimises reserve with energy by minimising the total cost of energy and reserve.

The HVDC reserve sharing ability is analysed and presented in Appendix A. We can see from Figures A1 A2, Tables A1, A2 that the HVDC can provide ability to share reserve between islands by up to 250 MW over a significant time duration.

This ability is not fully modelled in the SPD at present. Only a small amount of reserve transfer is currently added as a hard number to the Net Free Reserve (NFR) parameter by RMT. Defining reserve transfer as a variable would co-optimize energy and reserve to use common resources like HVDC link capacity (Reserve transfer and Energy transfer bundled) and generator unit capacity (Generation and PLSR reserve bundled). The proposed model would include other constraints for reserve transfer like HVDC modulation limit and conservation constraints for transfer of reserve from one reserve zone to another

The purpose of this paper is as follows:

- develop reserve transfer model.
- analyse its effects on energy and reserve prices.
- explain problems of implementing the HVDC reserve transfer model into the real SPD model.
- build the SPD prototype (SPDP) in order to analyse the model's impact on SPD solutions.

Simulating the SPDP over a substantial period of time gives us the Cost and Revenue saving statistics that would be used for the development and implementation justification.

Section 2 describes a national reserve market with reserve transfer model. It also defines the formula for reserve cost (Reserve revenue) calculation. Section 3 describes an implementation of the reserve transfer model into the SPD code and the problems involved. Section 4 describes the analysis of the SPDP solutions and result of SPDP simulations over March-June 2004 in order to estimate an economic effect. Section 5 describes result summary, issuers and recommendations. Appendix A contains the statistical analysis of the HVDC sharing abilities.

2. Modelling of National reserve market.

2.1 National reserve market basics.

In the existing reserve model we have currently two separate reserve zones or two separate reserve markets.

A national market becomes operational when reserves from one zone are used to cover risks in another zone. Consider how this affects the overall solution. Cheaper imported reserve substitutes for more expensive local reserve. The main economic effect is depicted in Figure2.1. The Red Square is equal to net reserve revenue saving in either zone as a result of reserve import from other zone. The picture captures only the economic effect caused by reserve import given other parameters constant. A real picture is more complex. Imported reserve have a price, which depends on marginal price in exporting zone and shadow price of various constraints that limit HVDC reserve transfer. Other complication is that an imported reserve can not be used to cover any of the HVDC risks.

Further in the Appendix B a simplified SPD model is developed and analysed. A functional relationship between Energy, Reserve prices and other dual variables is derived.

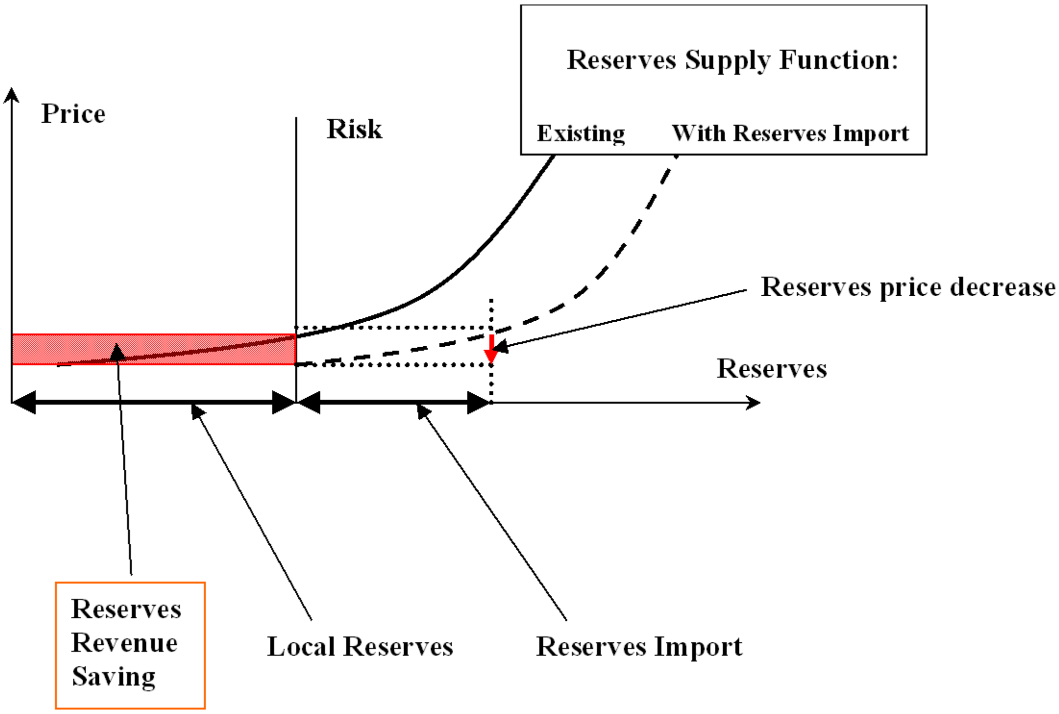


Figure 2.1. Reserve revenue saving caused by reserve import into zone.

2.2 The HVDC reserve transfer model.

The HVDC link has some capability to share reserve between islands. This capability depends on many factors.

Frequency Stabiliser and Instantaneous Reserve Sharing

The technical ability of HVDC to share reserve is restricted by the frequency stabiliser and reserve sharing functionalites. These functionalites are primarily designed to reduce the frequency fall due to a sudden loss of generation by sharing the loss between both the North and South islands.

Both functionalites measure the Haywards and Benmore frequency and then modulate the DC power to compensate for frequency changes. The frequency stabiliser component is fast reacting with no deadband and washes out with a time constant of 30 seconds. The reserve sharing function is slower with a 30-second time constant lag and a deadband of +/-0.2 Hz.

The conceptual relationship between the frequency stabiliser and the instantaneous reserve sharing is that the frequency stabiliser should assist management of small and temporary frequency fluctuations in an island(that compensated by the increased production from instantaneous reserve on the same island). If there is insufficient reserve to restore the frequency to within 0.2 Hz of nominal then the instantaneous reserve function will allow extra power to be contributed from unaffected island in the steady state, thereby “sharing” the total spinning reserve between islands. The frequency stabiliser and instantaneous reserve sharing functions may modulate the DC power up to +/-250 MW. The performance of the frequency stabiliser and Instantanious Reserve sharingl can be seen on Figure 2.4 below.

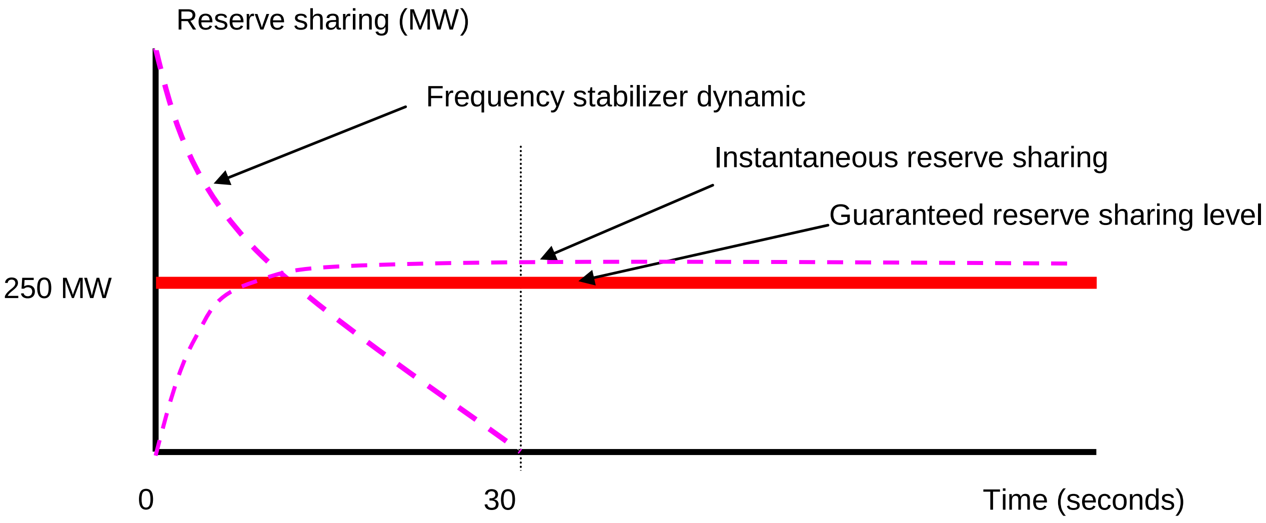


Figure 2.2 DC frequency stabiliser and instantaneous reserve sharing dynamic.

HVDC Reserve transfer modelling.

For simplicity we do not consider DC losses. So, import to one zone is equal to export from other zone. There are several constraints that restrict reserve transfer ability between islands.

First group is the HVDC modulation limit. The HVDC control system allows reserve transfer up to 250MW in both directions and this does not depend on power flow direction.

Second group is HVDC ability to ramp-up and ramp-down. These values are equal to difference between pre-contingency DC power flow and post contingency DC power flow. Shape of these constraints depends on power flow direction. DC power flow has positive lower and upper pre-contingency and post-contingency flow limits.

Third group of constraints restricts reserve transfer from zone by local reserve available in this zone.

In the Figure 2.3 we see a graphical representation of energy flow and reserve transfer ability of the DC line where pre-contingency energy flow is a bold arrow and a directional reserve flows are dashed arrows. In this particular example reserve import into SI zone is restricted by HVDC modulation limit but reserve import into NI zone is restricted by SI local reserve limit. Neither of any ramp-up or ramp-down constraints are binding there.

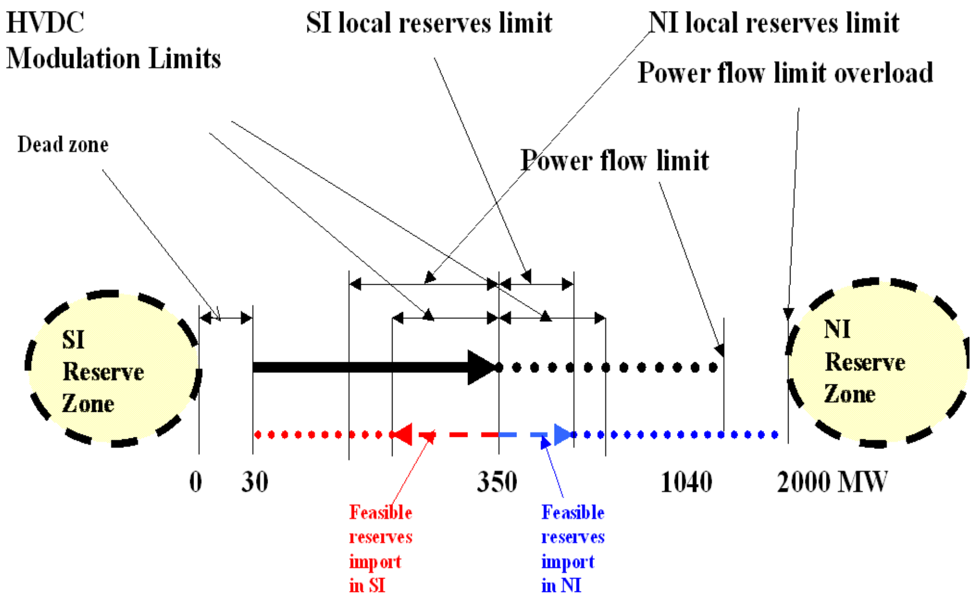


Figure 2.3 Graphical representation of energy and reserve flow on DC line (Limits are estimated and depend on the HVDC configuration).

3. Reserve price and revenue definition in the SPD.

Reserve is not a uniform product. IL reserve is used to cover any risk and PLS reserve is used to cover any risk except itself. Figure 3.1 depicts how reserve is collected and used to cover each risk in the existing SPD,

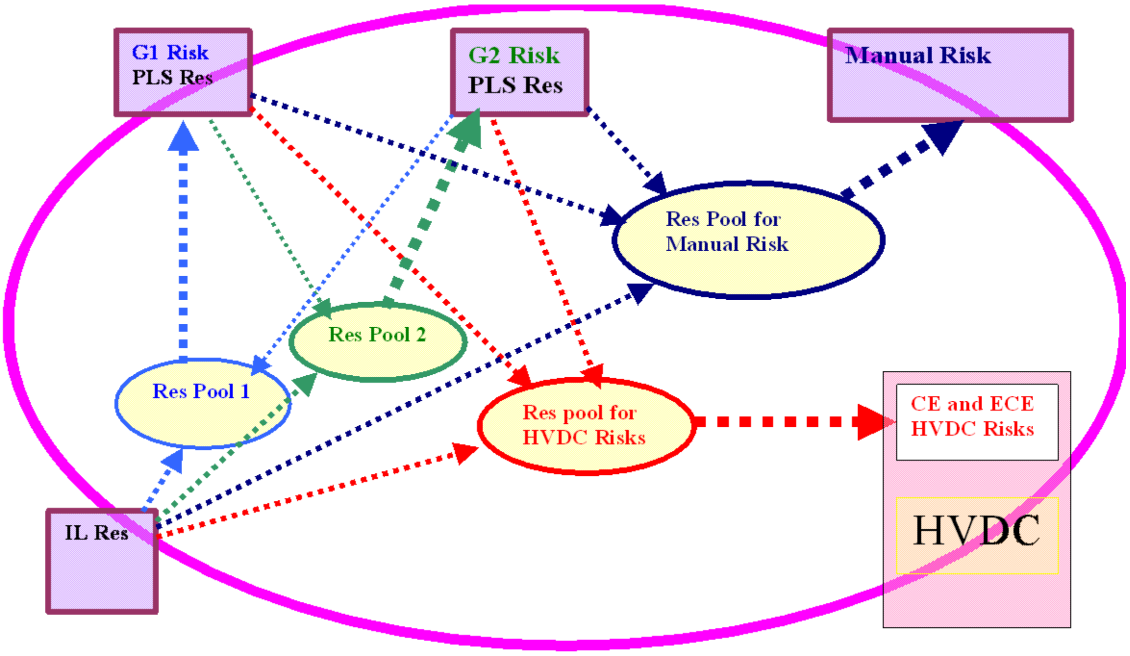


Figure 3.1. Reserve flows in the existing model.

where G1,G2 are generator's risks,

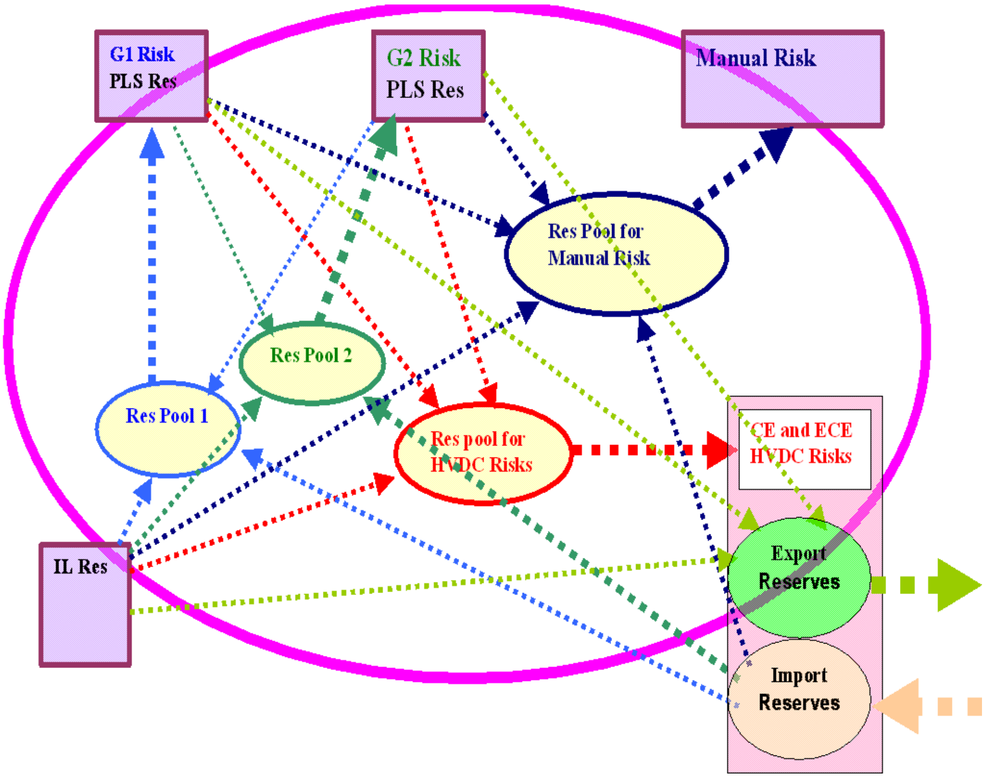


Figure 3.2. Reserve flows in the proposed SPD model.

Figure 3.2 shows flow of reserve in the case of HVDC reserve transfer. Reserve transferred to import zone can not be used to cover HVDC risks and only go to reserve pools that cover generation and manual risks.

So, we can write the part of new SPD model where reserve transfer quantity is taken into account;

Total reseve in zone is greater then manual constant Risk

$$R_{a,rt}^{Tot} \geq Risk_{a.rt}^{ManRisk} \qquad : \lambda_{a.rt}^{ManRisk} \qquad (3.1)$$

Local reserve in zone is greater then DC risk.

$$R_{a,rt}^{Tot} \geq DC\_Risk^{rst}{}_{a,rt} + R_{a,rt}^{IM} \qquad : \lambda_{a.rt}^{rst} \qquad (3.2)$$

Total reserve in zone is greater then generator’s risk less generator’s reserve

$$R_{a,rt}^{Tot} - R_{a,rt,k}^{Gen} \geq GenRisk_{a,rt,k} \qquad : \lambda_{a.rt,k}^{GenRisk}\,. \qquad (3.3)$$

Definition of total reserve in zone

$$R_{a,rt}^{Tot} = \sum_k R_{a,rt,k}^{Gen} + R_{a,rt}{}^{NonGen} + R_{a,rt}^{IM} \qquad : \lambda_{a.rt}^{R\_Tot} \qquad (3.4)$$

where

$R_{a,rt}^{IM}$ is an imported reserve of type **rt**, in the zone **a**.

$R_{a,rt}^{Tot}$ -cleared total reserve of type **rt**, in the zone **a**.

$R^{Gen}_{a,rt,k}$ -cleared reserve of type **rt**, in the zone **a**, from generator **k**.

R^{NonGen} -cleared reserve of type **rt**, in the zone **a** from non generation sources.

$Risk^{ManRisk}_{a.rt}$ -manually entered risk for reserve type **rt**, in the zone **a** (applies only in South Island at present).

$DC\_Risk^{rst}{}_{a,rt}$ -HVDC risk of type **rst** for reserve type **rt**, in the area **a**.

$GenRisk_{a,rt,k}$ -Generation risk for unit **k**, in the area **a**, for reserve type **rt**.

Note, that in the new reserve model we have to exclude imported reserve from total reserve for HVDC risk equations (see 3.2).

In optimisation models, the shadow price of any constraint defines a marginal cost of the particular resource. So, the total revenue of reserve in area **a**, reserve type **rt** can be calculated as

$$\begin{aligned} \mathrm{Re}\,v\_R_{a,rt} = {} & R^{Tot}_{a,rt} \times \lambda^{ManRisk}_{a.rt} + \sum_{rst} (R^{Tot}_{a,rt} - R^{IM}_{a,rt}) \times \lambda^{rst}_{a.rt} + \\ & \sum_{k} (R^{Tot}_{a,rt} - R^{Gen}_{a,rt,k}) \times \lambda^{GenRisk}_{a.rt,k} \end{aligned} \tag{3.5}$$

Given result from duality theory (Equation (B.30) we have pricing relationship among risk-reserve constraint (3.1-3.3) shadow prices $\lambda^{ManRisk}_{a.rt}\ \lambda^{rst}_{a.rt}\ \lambda^{GenRisk}_{a.rt,k}$ and total zonal reserve conservation equation (3.4) shadow price $\lambda^{R\_Tot}_{a.rt}$:

$$\lambda^{R\_Tot}_{a.rt} = \lambda^{ManRisk}_{a.rt} + \sum_{rst} \lambda^{rst}_{a.rt} + \sum_{k} \lambda^{GenRisk}_{a.rt,k} \tag{3.6}$$

The definition of reserve revenue in the existing SPD model is

$$\mathrm{Re}\,v\_R^{SPD}_{a,rt} = R^{Tot}_{a,rt} \times \lambda^{R\_Tot}_{a.rt}\ , \tag{3.7}$$

So, we can find the revenue difference between existing and new models:

$$\begin{aligned} & Del\_\mathrm{Re}\,v\_R_{a,rt} = \mathrm{Re}\,v\_R^{SPD}_{a,rt} - \mathrm{Re}\,v\_R_{a,rt} \\ & = \sum_{k} R_{a,rt,k} \times \lambda^{GenRisk}_{a.rt,k} + R^{IM}_{a,rt} \times \sum_{rst} \lambda^{rst}_{a.rt} \end{aligned} \tag{3.8}$$

Value (3.8) is always non-negative and presents revenue difference, which would be paid by participants if we used the existing revenue calculation methodology. It is strictly positive in case of multiple Risk_Reserve constraints binding with non-negative shadow prices if non-zero quantity of reserve is cleared from particular risk (reserve $R_{a,rt,k}$ from risk generator or reserve import $R^{IM}_{a,rt}$ into zone **a** via HVDC).

4. Implementation of HVDC reserve sharing model into the SPD code.

4.1 Aggregation of HVDC configuration and adjustment for losses.

HVDC link in the SPD model consists of two poles and four half poles as shown in Figure 4.1. Pole1 and Pole 2 branches have dynamic losses. Half-pole branches are loss-less.

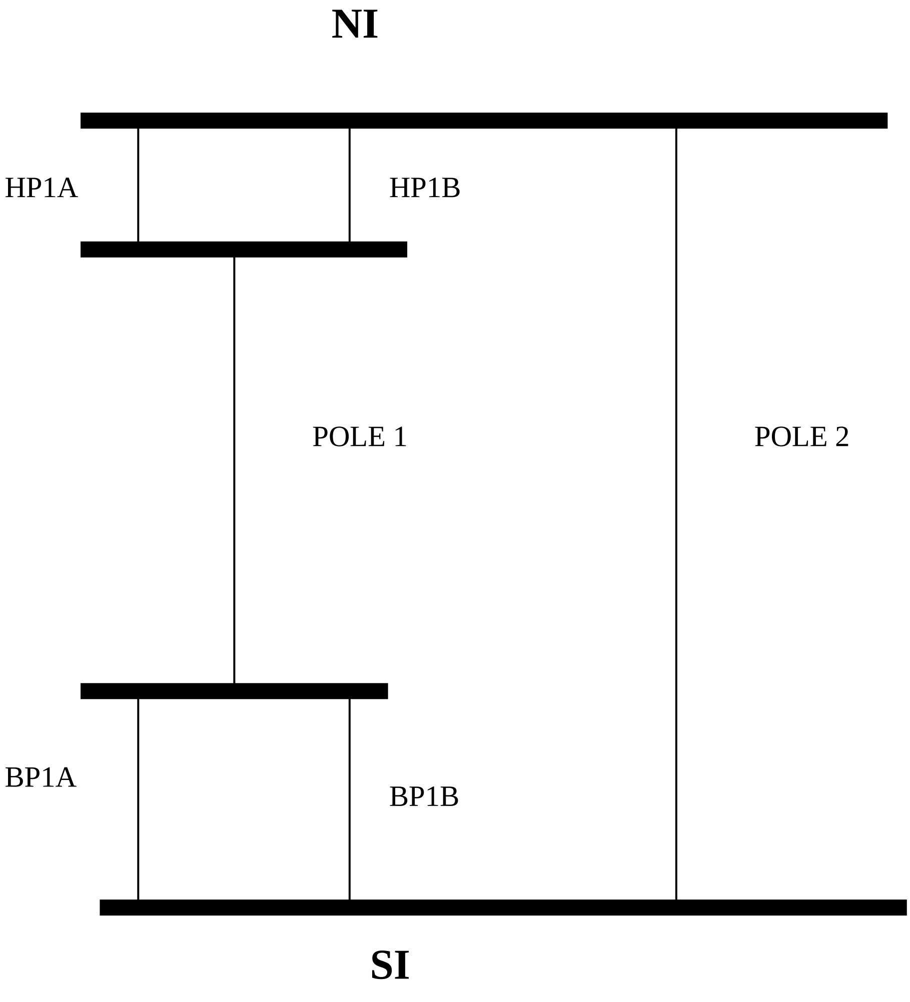


Figure 4.1. The existing HVDC configuration.

Pre-contingency power flow is modelled in the SPD according to configuration depicted on Figure 4.1. A detailed modelling of post-contingency power flows using formulation from Appendix B for every DC branch would complicate an implementation of reserve transfer model into the SPD code significantly. The model in the Appendix B is a non-convex one, so a mixed integer programming (MIP) model has to be build and MIP solver has to be used in every run which would take more time at programming and simulation stages.

So, reserve transfer model is based on a simplified HVDC configuration that consists on one HVDC loss-less link. Total HVDC power flow is follows

$$HVDCLinkFlow = Pole1Flow + Pole2Flow \qquad (4.1)$$

The post-contingency power flow limit is limited by

$$\begin{aligned} &HVDCLinkFlowLim = sum(Pole2FlowLim \\ &+ \min(Pole1FlowLim, HP1ALim \\ &+ HP1BLim, BP1ALim + BP1BLim) \end{aligned} \quad . \qquad (4.2)$$

Reserve transfer model does not have explicit post-contingency flow variables. Reserve import variables are used instead.

The HVDC losses account for significant part of HVDC reserve transfer. We take a conservative approach and estimate HVDC reserve transfer losses by a difference between post-contingency HVDC losses and pre-contingency losses that would occur at a given HVDC configuration (see Figure 4.1). So, HVDC Reserve transfer adjustment factor is presented by formula

$$\begin{aligned} &HVDC\,\mathrm{Re}\,sAdj = \max(L_1(Pole1FlowPostContLim) \\ &- L_1(Pole1FlowPostContLim - HVDCModLim), \\ &L_2(Pole2FlowPostContLim) \\ &- L_2(Pole2FlowPostContLim - HVDCModLim)) \end{aligned} \qquad (4.3)$$

where $L_1(Pole1FlowPostContLim)$ and $L_2(Pole2FlowPostContLim)$ are max post contingency losses at pole 1 and pole 2 accordingly. The above formula is derived given that losses are increasing functions, a difference between pre and post-contingency flow is equal to max of the HVDC modulation limit and HVDC power flows over the pole with max resistance.

Reserve transfer to import area is less then reserve transfer from export area by $HVDC\mathrm{Re}\,sAdj$ if reserve transfer and energy transfer directions are the same.

If reserve transfer and energy transfer have different directions the loss adjustment factor is negative and their conservative estimation is zero.

Total HVDC upper 6second and 60second post-contingency flow limits and total HVDC lower limit are calculated based on SPD solution without the reserve transfer model and adjust for HVDC losses. This two step approach is used because we have a Final pricing solution where HVDC lower limits are removed and because an exact HVDC configuration can not be identified properly from input data if any HVDC branch is taking out of service via using group constraint mechanism. So, the HVDC configuration is identified using HVDC branch's power flow data from a first run. Total HVDC upper limits and total HVDC lower limit are depicted in Table 4.1 and Table 4.2('*' –branch in service, 'X' – either of two half-pole branches in service). For example, the column with: Pole2-blank; Pole1 – ‘*’; B1PA, B1PB, H1PA, H1PB branches – ‘X’ consists of four HVDC configurations: Pole2 is out of service, either of B1PA, B1PB half poles in service and either of H1PA, H1PB half poles in service.

North Transfer. 60s reserve HVDC
post-contingency limits (MW)

Name	Branch Up Limit	Branch Up Limit	HVDC Configurations								
Pole2	30	500	*		*				*	*	*
Pole1	172	540	*	*		*	*	*	*	*	*
B1PA	86	324	*	*		X	*	X	X	*	X
B1PB	86	324	*	*		X	*	X	X	*	X
H1PA	86	303	*	*		*	X	X	*	X	X
H1PB	86	303	*	*		*	X	X	*	X	X
TotUpLim			1040	540	500	324	303	303	824	803	803
TotLoLim			202	172	30	172	172	86	202	202	116

North Transfer. 6s reserve HVDC
post-contingency limits(MW)

Name	Branch Up Limit	Branch Up Limit	HVDC Configurations								
Pole2	30	700	*		*				*	*	*
Pole1	172	605	*	*		*	*	*	*	*	*
BH1PA	86	356	*	*		X	*	X	X	*	X
BH1PB	86	356	*	*		X	*	X	X	*	X
HH1PA	86	332	*	*		*	X	X	*	X	X
HH1PB	86	332	*	*		*	X	X	*	X	X
TotUpLim			1240	605	700	356	332	332	1056	1032	1032
TotLoLim			202	172	30	172	172	86	202	202	116

.

Table 4.1 HVDC Upper and lower limits as functions of HVDC poles configuration (North power transfer).

South Transfer. 60s reserve HVDC post-contingency limits(MW)

Name	Branch Up Limit	Branch Up Limit	HVDC Configurations								
Pole2	29	489	*		*				*	*	*
Pole1	260	427	*	*		*	*	*	*	*	*
BH1PA	130	202	*	*		X	*	X	X	*	X
BH1PB	130	202	*	*		X	*	X	X	*	X
HH1PA	130	308	*	*		*	X	X	*	X	X
HH1PB	130	308	*	*		*	X	X	*	X	X
TotUpLim			842	427	489	202	308	202	691	797	691
TotLoLim			289	260	29	260	260	130	289	289	160

South Transfer. 6s reserve HVDC post-contingency limits(MW)

Name	Branch Up Limit	Branch Up Limit	HVDC Configurations								
Pole2	29	666	*		*				*	*	*
Pole1	260	427	*	*		*	*	*	*	*	*
BH1PA	130	202	*	*		X	*	X	X	*	X
BH1PB	130	202	*	*		X	*	X	X	*	X
HH1PA	130	308	*	*		*	X	X	*	X	X
HH1PB	130	308	*	*		*	X	X	*	X	X
TotUpLim			842	427	666	202	308	202	868	974	868
TotLoLim			289	260	29	260	260	130	289	289	160

Table 4.2. HVDC upper and lower limits as functions of HVDC poles configuration (South power transfer).

Let’s write the HVDC reserve transfer formulation in terms of the SPD model formulation.

HVDC reserve import constrained by technical HVDC ability to ramp-up if energy and reserve have the same direction

$$\begin{aligned} R^{IM}_{a,rt} &\le HVDCLinkFlowUpLimit_{a,rt} \\ &- HVDC\,\mathrm{Re}\,sAdj_{a,rt} - HVDCLinkFlow_{a} \end{aligned} \tag{4.4}$$

HVDC reserve import constrained by technical HVDC ability to ramp-down if energy and reserve have different directions.

$$R^{IM}_{a,rt} \le HVDCLinkFlow_{a1} - HVDCLinkFlowLoLimit_{a1,rt}, a1 \ne a \tag{4.5}$$

HVDC reserve import constrained by HVDC modulation limits

$$R^{IM}_{a,rt} \le HVDC\,\mathrm{Re}\,sModLimit_{a,rt} - HVDC\,\mathrm{Re}\,sAdj_{a,rt} \tag{4.6}$$

HVDC reserve import into one zone is less or equal to available reserve in the other zone:

$$R_{a,rt}^{IM} \le \sum_k R_{a1,rt,k}^{Gen} + R_{a1,rt}{}^{NonGen} - HVDC\,\mathrm{Re}\,sAdj_{a,rt}, a \ne a1 \qquad (4.7)$$

4.2 Simulation experiments with the HVDC reserve transfer model.

The experiments consist of two SPD simulations (with and without reserve transfer model). The first run is a base case. It is used to identify HVDC configuration, to calculate its upper and lower post contingency limits and to calculate HVDC loss adjustment parameters. In the second run the reserve transfer model is switched on. We can use conditional constraints but this would lead to introduction additional integer variable and to MIP formulation in every run which significantly complicate a problem and increase overall time of the project.

The following economic indices are calculated in each run:

Six second reserve revenue (see (3.5))

Res6sRev= $\sum_{a \in \{SI,NI\}} \mathrm{Re}\,v\_R_{a,rt=6s}$, (4.8)

Sixty second reserve revenue (see (3.5))

Res60sRev= $\sum_{a \in \{SI,NI\}} \mathrm{Re}\,v\_R_{a,rt=60s}$, (4.9)

Demand energy revenue (System energy revenue at demand side).

DemEnRev= $\sum_{n \in AllNodes} \lambda_n^E \times Load_n$, (4.10)

where λ_n^E is energy price at node n, $Load_n$ is load at node n.

Total system revenue

TotDemRev= Res6sRev+Res60sRev+ DemEnRev, (4.11)

Total value of Objective function, which is a sum of Generation, six second and sixty second reserve costs.

TotIntCost =Res6sCost+Res60sCost+GenCost. (4.12)

Differences of indices (4.8-4.12) between runs (“with reserve transfer” minus “without reserve transfer”) are aggregated for every day over March, April, May and June 2004-year period. Figures 4.2-4.9 depict these differences.

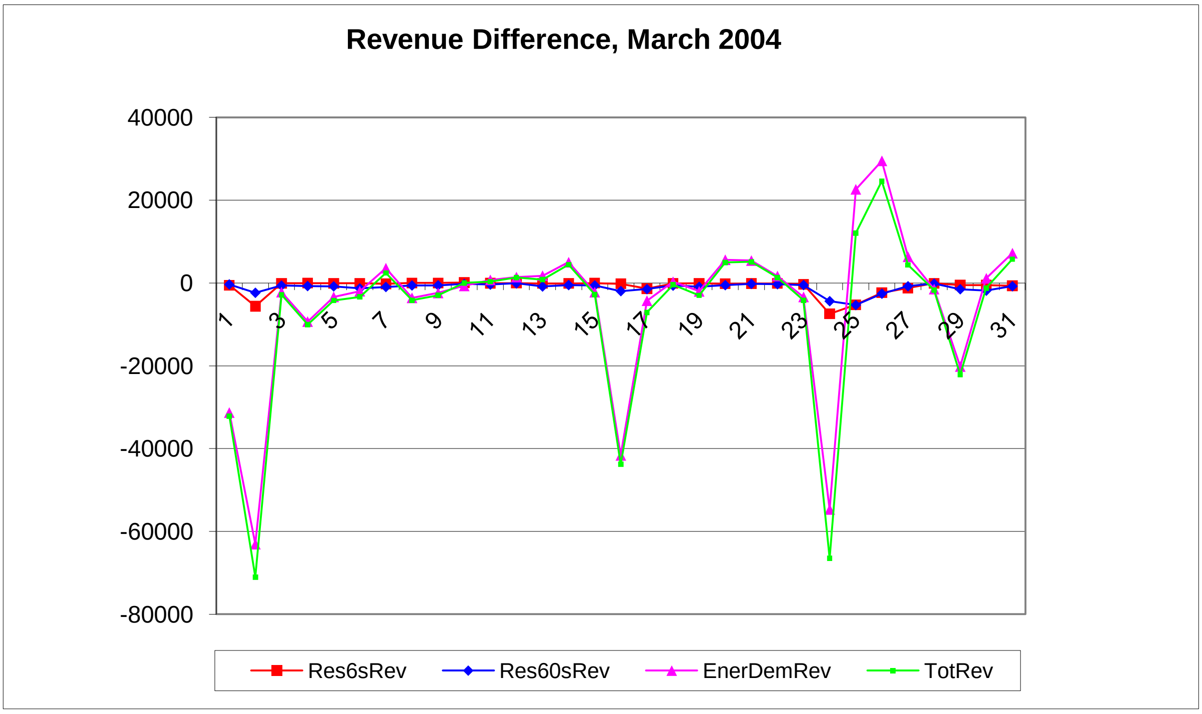


Figure 4.2. Daily aggregated Revenue Difference in March 2004.

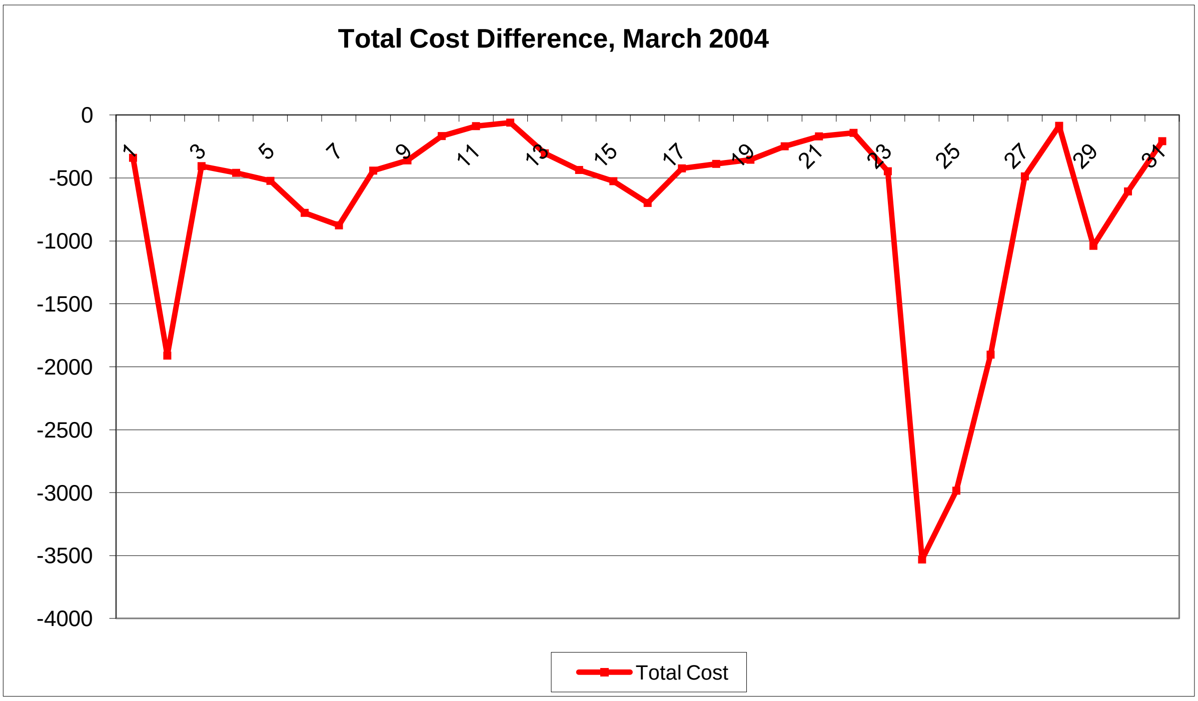


Figure 4.3. Daily aggregated Total Cost Difference in March 2004.

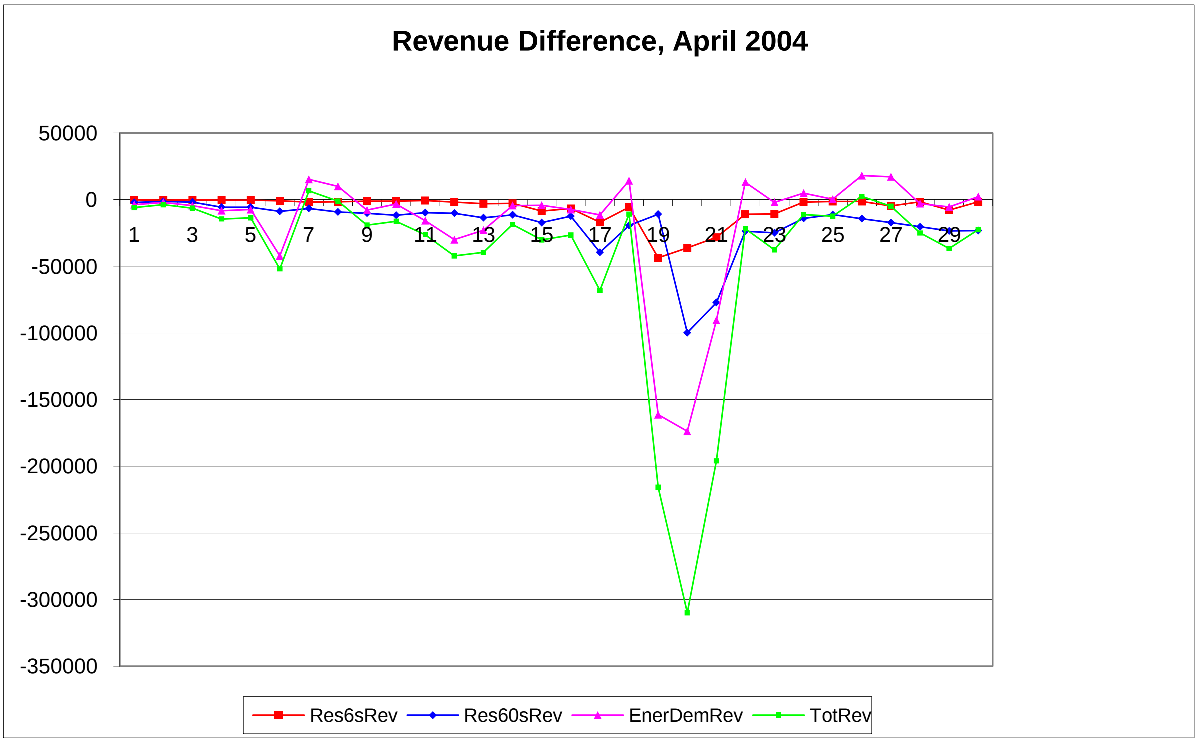


Figure 4.4. Daily aggregated Revenue Difference in April 2004.

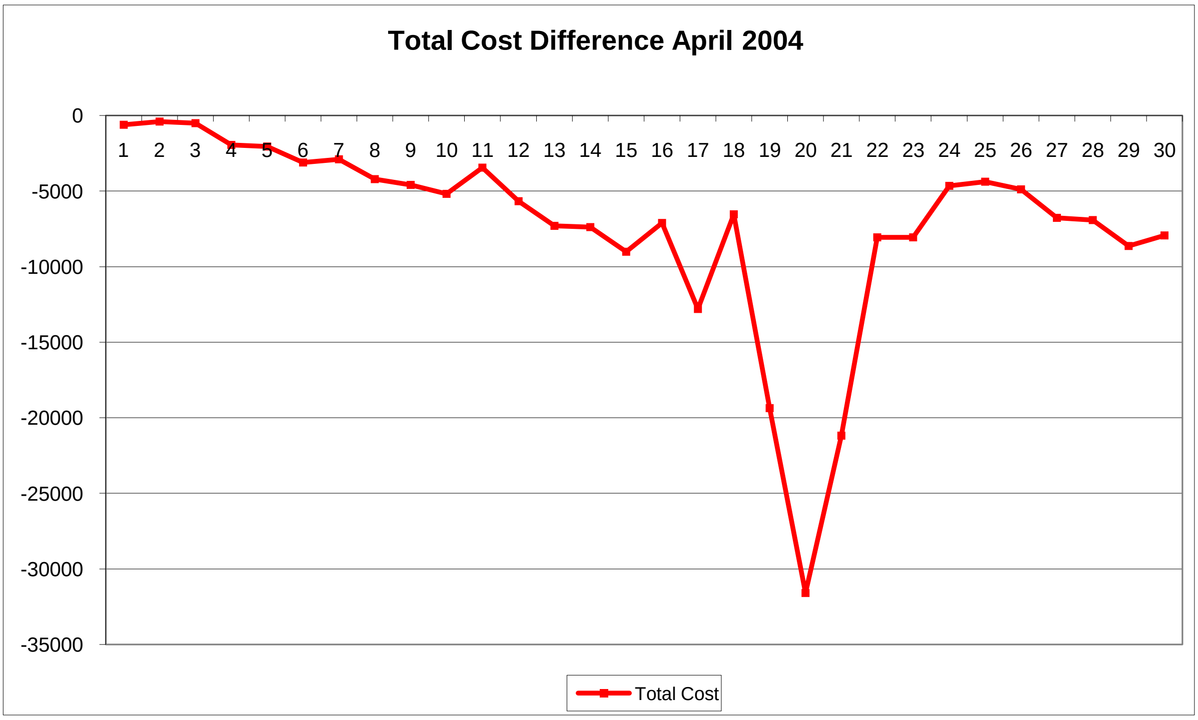


Figure 4.5. Daily aggregated Total Cost Difference in April 2004.

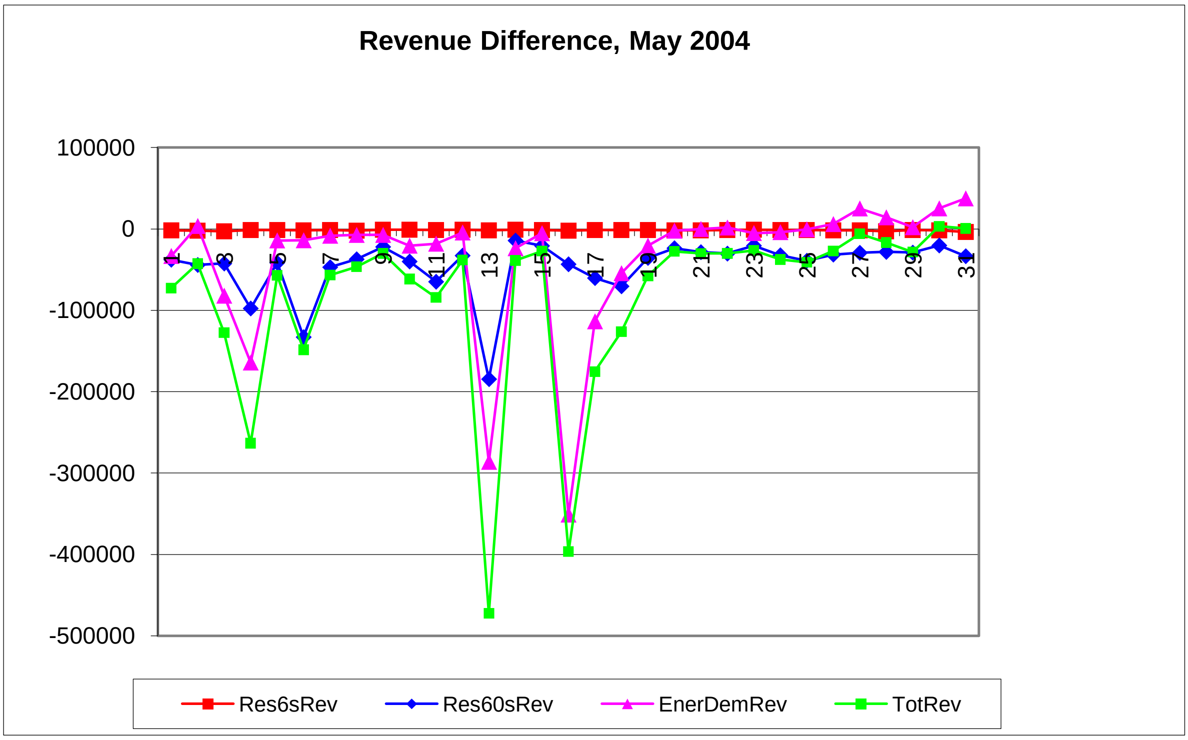


Figure 4.6. Daily aggregated Revenue Difference in May 2004.

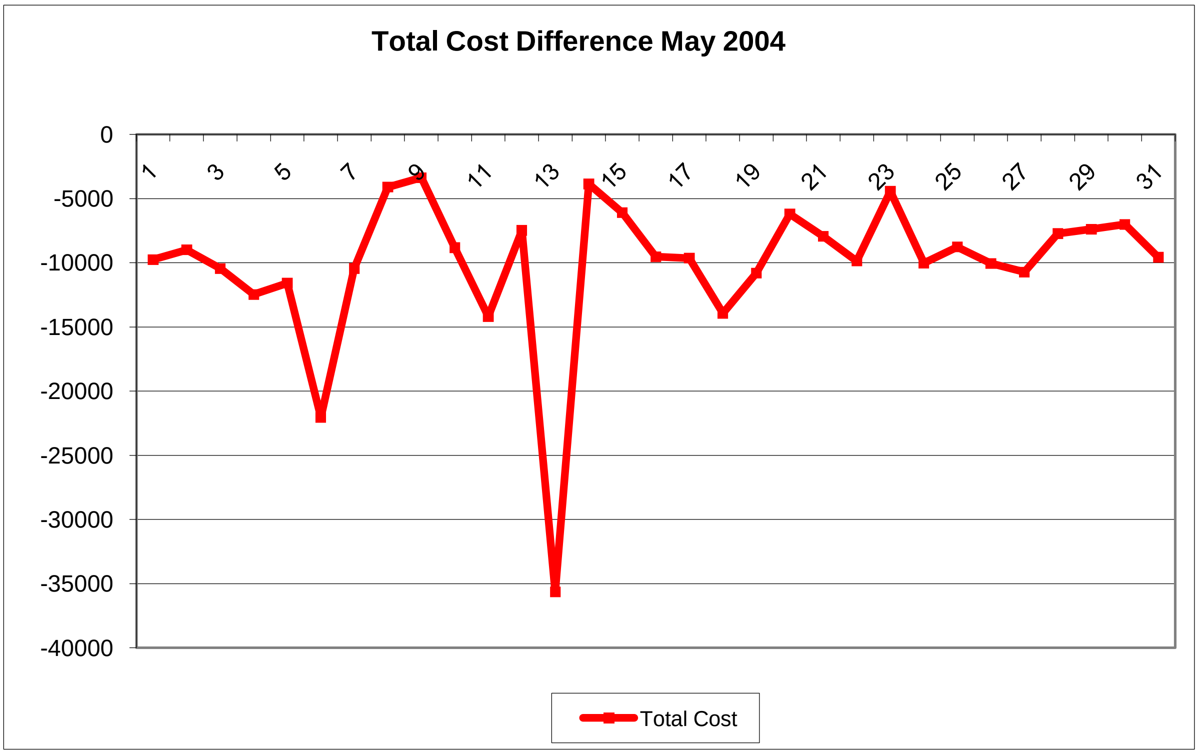


Figure 4.7. Daily aggregated Total Cost Difference in May 2004.

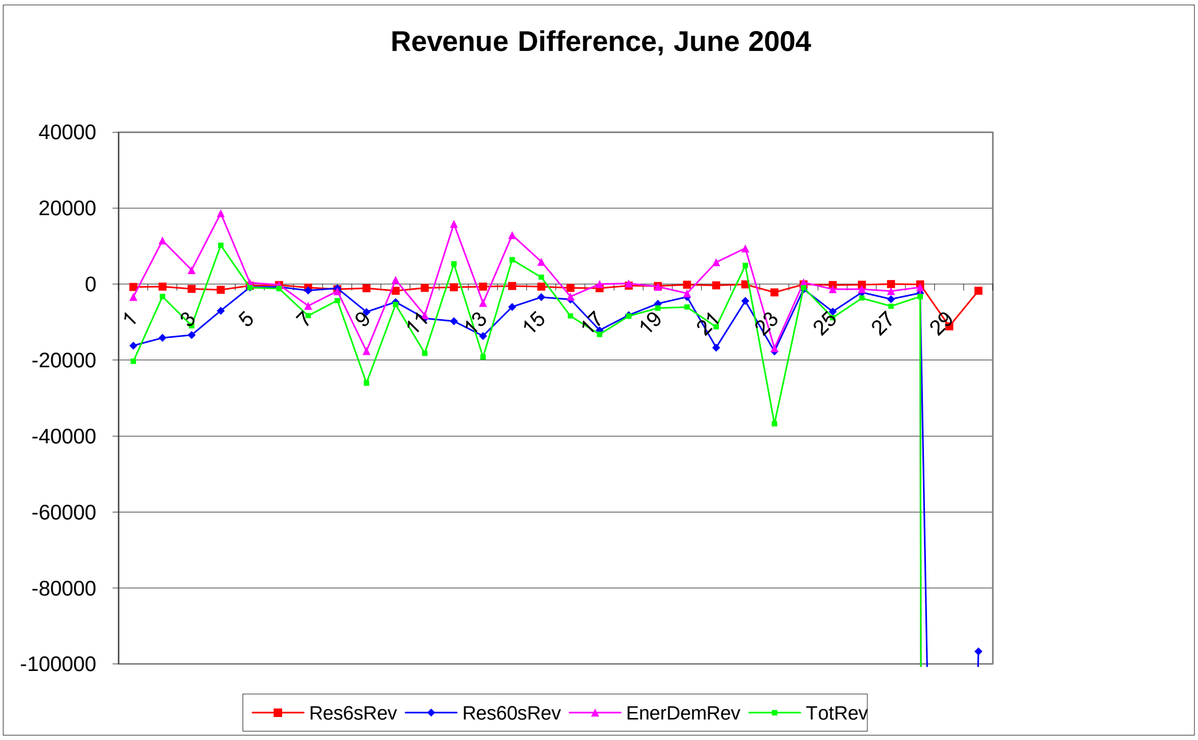


Figure 4.8. Daily aggregated Revenue Difference in June 2004.

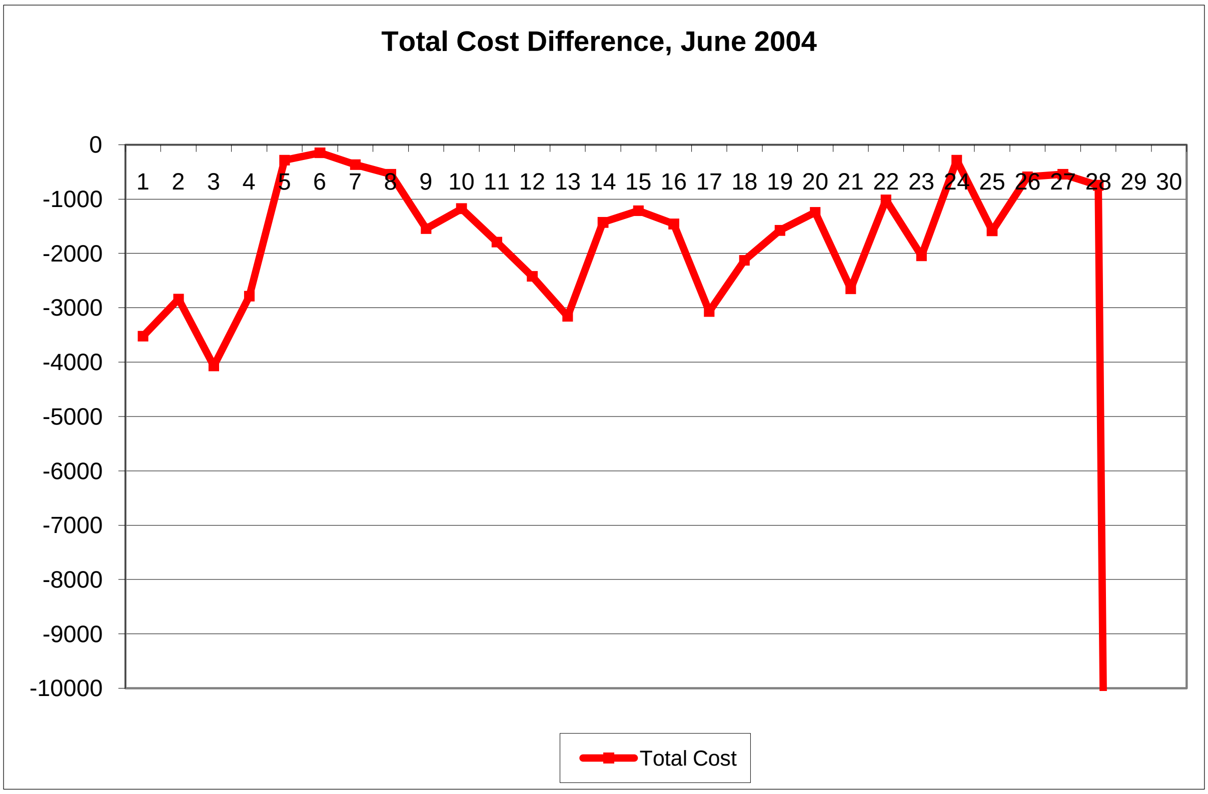


Figure 4.9. Daily aggregated Total Cost Difference in June 2004.

Analysis of indices for each day shows that there are days when Energy revenue differences are positive making the total revenue difference positive for some of those days.

According to optimisation theory a Total Cost of any SPD with reserve transfer model solution must be less or equal then Total Cost in the basic run. This is because introduction of reserve transfer model only increase a feasible area and a new objective function can only decrease its value. This property is observed in simulation experiments for every trading period. From Figures 4.3, 4.5, 4.7 and 4.9 we can see this tendency from a daily aggregated Total Cost statistics.

The explanation of Reserve and Energy revenue statistics is not straightforward. While Six and Sixty second reserve revenue are almost always decreased, but the Energy revenue is not. It increased in a few trading periods almost in every trading day. Daily aggregated statistics shows that Energy Revenue difference is positive for a few days in each month. Only a very few days with positive Total Demand Revenue difference are identified.

One explanation is that there is trade off between energy and reserve. While Reserve revenue difference decreased the energy revenue sometimes increased and the total revenue decreased.

Less understandable results for some periods when reserve revenue decreased, energy revenue increased and total revenue increased (Note that total cost decreased in every simulation). Detailed analysis has to be done in order to understand this sort of solutions. There is one suggestion that this is the effect of piece-wise linear approximation of smooth in theory transmission losses, energy and reserve supply curves. If it is true that over long period of time aggregated indexes would show decreasing tendency. Analysis of aggregated statistics depicted further in the Table 4.3 will prove this.

Indices in the Table 4.3. are further aggregation of indices (4.3-4.9) over trading periods for every March, April, May and June months in 2004 year.

Aggregated monthly revenue statistics from table 4.3 shows decrease in energy revenue, Six and Sixty second reserve revenue and Total Cost. Total cost is reduced by 0.39% in March, 1.04% in April, 1.56% in May and 1.30% in June. In absolute numbers the total revenue is reduced by $216,000, $1,280,000, $2,588,000 and $5,545, respectively. Smaller revenue numbers in March and April reflect a big HVDC energy transfer level (smaller reserve transfer window) to the most needed North Island together with more often HVDC risk binding, which is not covered by the transferred reserve.

Scenarios	Indices	March	April	May	June	Total
Base						
	Res6Rev	3,708,141	348,928	96,967	62,429	4,216,464
	Res60Rev	564,658	754,290	1,488,363	1,136,293	3,943,604
	DemEnRev	89,043,286	149,158,338	154,057,046	115,508,739	507,767,409
	TotalIntCost	5,456,204	20,802,472	20,050,995	10,922,237	57,231,908
	TotDemRev	93,316,084	150,261,556	155,642,375	116,707,460	515,927,476
with Res Transfer						0
	Res6Rev	3,680,943	143,630	46,672	29,621	3,900,867
	Res60Rev	530,127	195,862	74,606	426,873	1,227,468
	DemEnRev	88,888,125	148,641,412	152,932,600	110,704,996	501,167,133
	TotalIntCost	5,434,812	20,585,334	19,738,169	10,780,382	56,538,697
	TotDemRev	93,100,031	148,980,904	153,053,879	111,161,491	506,296,304
Diff(Res-Base)						0
	Res6Rev	-27,197	-205,298	-50,295	-32,807	-315,597
	Res60Rev	-34,531	-558,428	-1,413,757	-709,420	-2,716,135
	DemEnRev	-155,161	-516,927	-1,124,446	-4,803,743	-6,600,276
	TotalIntCost	-21,392	-217,138	-312,826	-141,855	-693,212
	TotDemRev	-216,053	-1,280,653	-2,588,497	-5,545,970	-9,631,172
(Diff/Base)*100%						
	Res6Rev	-0.73%	-58.84%	-51.87%	-52.55%	-7.48%
	Res60Rev	-6.12%	-74.03%	-94.99%	-62.43%	-68.87%
	DemEnRev	-0.17%	-0.35%	-0.73%	-4.16%	-1.30%
	TotalIntCost	-0.39%	-1.04%	-1.56%	-1.30%	-1.21%
	TotDemRev	-0.23%	-0.85%	-1.66%	-4.75%	-1.87%

Table 4.3. The monthly aggregated Revenue and Total Cost indices for 2004 year for the base run and for the run with reserve transfer model.

Total revenue saving reaches $9.6m over 4 month. This number presents $6.6m benefit for the energy and the rest for the reserve consumers. They can be overlapped.

The net benefit for the economy is presented by TotalIntCost saving. It reaches $0.68m over 4 months.

Extrapolation of the above results shows that annual saving could be of the order of $29m in revenue saving and $2.1m in net economic benefit. This should be confirmed by more extensive analysis as part of the development of the new SPD model.

Above results are obtained under assumption that all wholesale energy and reserve market transactions are done with wholesale energy and reserve prices.

5. Result Summary and Recommendations.

Results.

- The national reserve market methodology is developed.
- The HVDC transfer capability is analysed.
- Analysis of the existing SPD model with local reserve abilities has been done.
- A new SPD model with HVDC reserve transfer abilities is designed and developed.
- New reserve revenue calculation methodology is proposed.
- A new SPD model prototype, which is based on the SPD AIMMS2 code, has been built.
- Simulation experiments over every trading period since 01 march 2004 to 31 May 2004 have done. The SPD model runs twice: without (base run) and with reserve transfer model.
- Objective function (TotIntCost) decreases in every trading period, which is necessary condition to justify a reserve transfer model.
- Indices of monthly aggregated Reserve and Energy revenues decreased in March, April and May 2004, which is an indication of relaxation of the system.
- Total revenue saving reaches $9.6m over 4 months and could reach $29m over one year.
- Net economic benefit reaches $0.68m over 4 months and could reach $2.1m over one year.

Issues.

- The above results are obtained under assumptions that participants would not change their bidding behaviour. In reality they change there behaviour in order to maximise their profit. So, we would have revenue reduction less than we calculated. But because new reserve market would contain new participants the competition would be increased and new equilibrium would be set at lower objective function value.
- At the moment reserve transfer is not considered in the SPD model, therefore the system has some free reserves available. With implementing of HVDC transfer model these free reserves would be counted. A cheaper reserve would substitute for more expensive one. Some reserve providers with high reserve cost could decide not to offer reserve to market. So,

overall security would be reduced. Management of the system with reduced reserve abilities would cost more for System operator. One of possible way of solving this problem is to offer reserve transfer limits to market. Equilibrium established in this case would benefit all participants.

- Capacity of reserve transfer on AC lines connected to the HVDC link needs to be taken into account, especially configuration around Benmore generation nodes. This has not been covered in the paper.

Recommendations.

- Overall dynamic study has to be conducted to be sure that HVDC reserve transfer is utilised in the imported island.
- The RMT algorithm has to be corrected.
- It is recommended to implement the HVDC reserve transfer model into the SPD model and software.

Appendix A. Analysis of the HVDC sharing abilities during May 2001 to April 2002.

The HVDC sharing available is a function of the actual HVDC transfer at a particular time. Table A1 summarises the sharing assumed available at different HVDC transfer levels

Table A1.

HVDC transfer Received at HAY	South Island Sharing	North Island Sharing
-600 to –450	600 + transfer	250
-350 to -450	600 + transfer	-200 - transfer
-200 to –350	250	-200 - transfer
-112 to -200	250	-112 - transfer
-112 to –30	250	-30 - transfer
-30 to 30	0	0
30 to 200	Transfer – 30	250
200 to 323	Transfer – 73	250
323 to 715	250	250
715 to 965	250	250 (overload allowed)

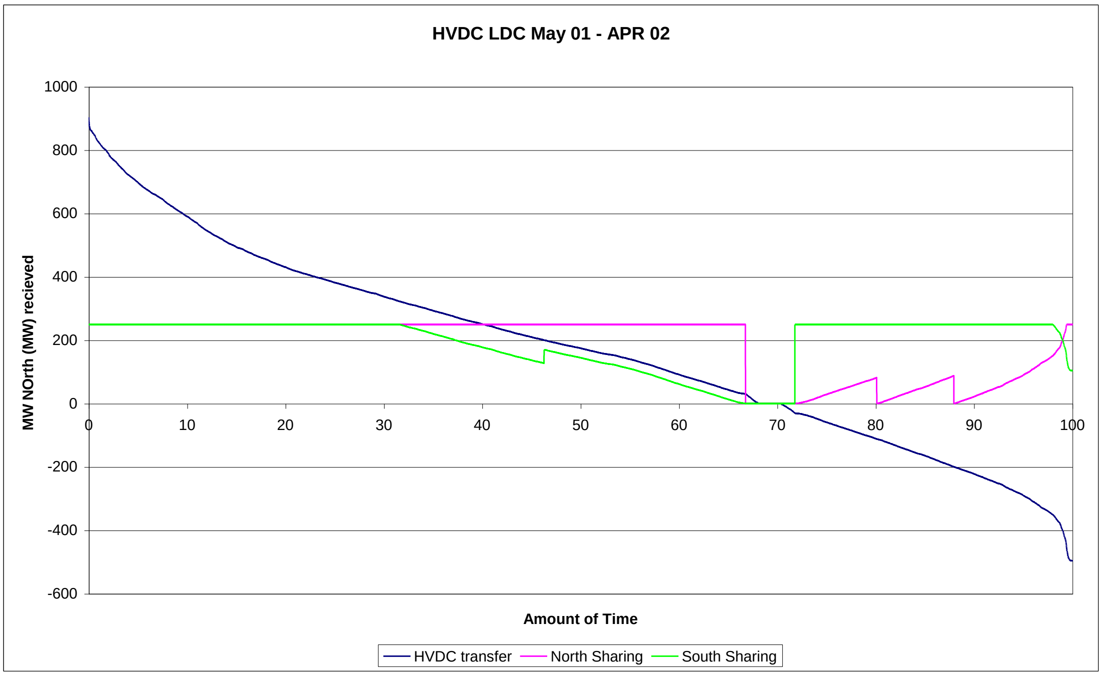
Note: Number in the Table A1 might have changed since.

This assumes

- All HVDC equipment is available
- Standard HVDC loading is assumed
- The HVDC current limiters do not limit the transfer

Figure 1 shows the HVDC transfer duration curve for the calendar year May 01 to Apr 02 inclusive. Also shown on the figure is the reserve sharing available for the North and South Island at each transfer point.

Figure 1:



The transfer available at each point is plotted as a LDC in figure 2. This shows the expected reserve available from the HVDC to each island. Table 2 summarises key data from the LDCs in figure 2

Figure 2:

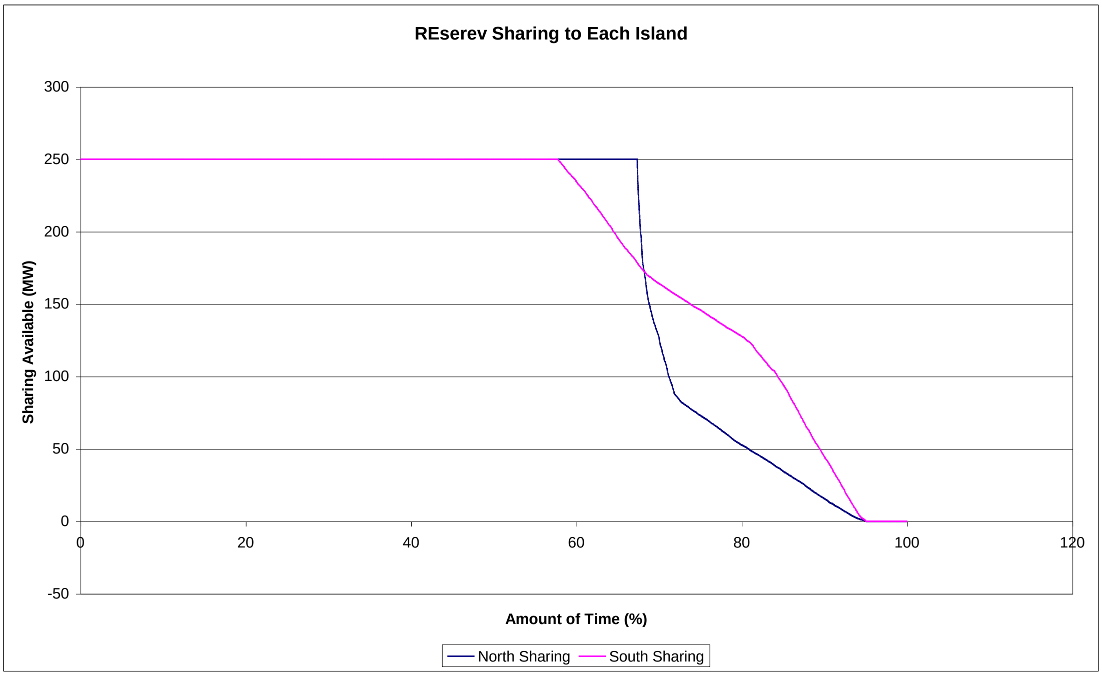


Table 2: Summary of Sharing Available

Quantity of Reserve available	North island - % of time	South Island - % of time
250	70	60
200	71	65
150	72	75
100	75	85
50	90	90