A SECURITY-CONSTRAINED BID-CLEARING SYSTEM FOR THE NEW ZEALAND WHOLESALE ELECTRICITY MARKET

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ABSTRACT - This paper reports upon the mathematical models and implementation of the Scheduling, Pricing, and Dispatch (SPD) application for the New Zealand Electricity Market (NZEM). SPD analyzes bids for energy offers, reserve offers and energy demands, and recognizes explicitly the effects on bid clearing due to transmission congestion, network losses, reserve requirements, and ramp rate limits. Advanced LP solution methods are utilized to solve the large-scale constrained optimization problem. Results on a 67-bus test system and the NZEM are included.

Key words: Electricity market; Energy and reserve market; Bid-clearing; Enhanced DC network models; Advanced LP techniques.

I. Introduction

The NZEM introduces competition within the wholesale electricity sector through creation of a national electricity pool and a spot market for electricity. Two organizations have key responsibilities for operation of the wholesale electricity market. The Electricity Market Company operates the market through a bidding system and is the clearing house for market transactions. Trans Power, the operator and developer of the national grid, performs the following services to the wholesale electricity market:

- Provide a reliable national grid and coordinate grid operation to minimize grid costs consistent with secure operation of the power system.
- Schedule and dispatch generation to satisfy market demand for electricity at minimum price while taking into account the security of the power system.
- Purchase for the benefit of the power system the ancillary services and resources that are necessary for economic and secure delivery of electricity.
- Provide information to grid users in an open, non-discriminatory manner to help them make consumption and production decisions.

The NZEM is a national market for centralized clearing of energy generation and demand, and for determining reserve requirements and prices. Other electricity services (frequency-keeping reserve and reactive support) are handled through standing contracts with the grid operator outside the market. The North and South Island are electrical regions (Figure 1) for which market prices cannot be always equalized due to finite transmission capability of HVDC links between islands. NZEM operation is sensitive to the location of market participants and the characteristics of the transmission system. Locational (nodal) pricing is included in the market model, meaning that the effects of losses and transmission constraints are reflected in the price at each node of the power system.

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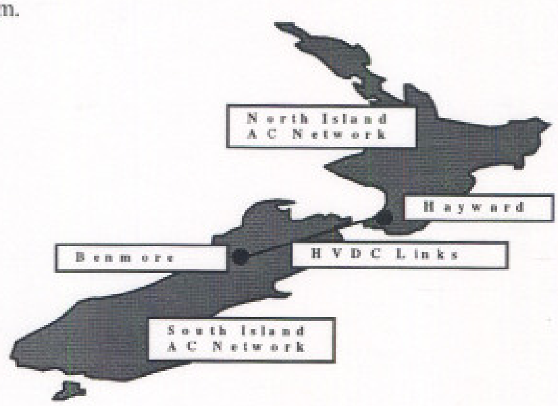

Figure 1 The NZEM Territory

NZEM market rules require concurrent dispatch of energy and reserve bids, and meeting various types of security constraints. This makes optimal power flow (OPF) based technology an important part of the solution process. Moreover, market requirements for pricing nodal injection and other constraints can draw on much of the work that has been done in applying formal optimization theory to OPF and related areas [1-5].

This paper reports upon the design and implementation of the Scheduling, Pricing, and Dispatch (SPD) application as a security-constrained bid-clearing system for the NZEM. In compliance with NZEM market rules [6], the problem is formulated as a linear-programming (LP) problem. Linearized power flow modeling with network losses is adopted to represent the transmission network. Advanced Dual Simplex and Interior Point algorithms are utilized to solve the problem. Special provisions for handling infeasible conditions are an integral part of the SPD application design and have been a key factor contributing to its robust performance. The NZEM began operation on 1 October, 1996.

Mathematical models and implementation of the SPD system are presented in the following sections of the paper. Section II provides a highlight of the NZEM market rules. Section III & IV presents terminology and the mathematical formulation of the SPD application. Simulation results are presented on a 67-bus test system and the NZEM in Section V. Conclusions follow in Section VI.

II. Highlights of NZEM

Figure 2 illustrates the basis of bid-clearing optimization, which is represented by the classic demand-supply balance model. Many important market rules have been temporarily ignored in this simplified illustration. For example, it assumes that there are no reserve capacity, no security constraint and no losses. Intersection of the demand and supply curve defines the marginal price and the transaction volume (i.e., cleared MW quantities.) Demand bids having higher price than the marginal price, and generation bids having lower price than the marginal price, are accepted by the bid-clearing process. This model is very similar to the classical merit-order economic dispatch.

More complex rules are defined for the NZEM to ensure a competitive electricity market and secure power system operation. Key characteristics of the rules affecting bid-clearing are highlighted below.

- A trading day begins at midnight, and there are 48 half-hourly trading periods in a trading day. Trading is based on bids made by traders (e.g., Generators and Purchasers). A bid can include up to 10 trader blocks. A trader block is a fixed quantity at a fixed price for a specified commodity (energy or reserve), trader, trading period, and trading location.
- Energy and reserve, which compete for the same resource (generation capacity), are cleared simultaneously based on location, quantities, and prices offered by market participants.
- Self-commitment of generating units. Each market participant is responsible for making its own commitment decision. This allows the Pool operator to maintain a higher focus on meeting overall system security requirements. Generator ramp rate limits are specified as part of the bid and respected by the bid-clearing process.
- Detailed transmission network is represented by the linearized power flow model; losses are modeled as piecewise linear functions of individual branch flows.
- Market is cleared by maximizing the cumulative benefit of feasible transactions (bids) within each trading period while observing the security constraints of the power system:
  - Branch flow limits
  - Generating unit min/max MW limits
  - Branch group MW flow min/max limits
  - Bus group MW generation min/max limits
  - Up- and down-ramp limits
  - Reserve requirements for *Fast* (6 second) and *Sustained* (60 second) classes of reserve in each island. The requirements are dynamically calculated to cover three specific risk criteria (Details in Section IV.5)
  - Maximum sum of generation and reserve cleared at a generator location
  - Maximum reserve capacity for each type of reserve at a location. (Details in Section IV.6)
  - Proportionality constraint between generation bid cleared and Partially Loaded Spinning Reserve (PLSR) bid cleared (Details in Section IV.6)
- Provisions for scheduling transmission outages and time-varying security constraint limits.
- For each trading period, the optimization process clears bids according to user-specified modes of MW scheduling:
  - PDS (Pre-Dispatch Schedule): maximizes market benefits by matching bids by generators with bids by purchasers, while meeting all constraints.
  - DS (Dispatch Scheduling): Minimizes the cost by matching generators bids to supply estimated demand while meeting all constraints.
- Calculation of nodal prices for each trading period and each bus in the study. For ex-post pricing runs, the optimization process calculates nodal prices by dispatching generation bids against metered demands.

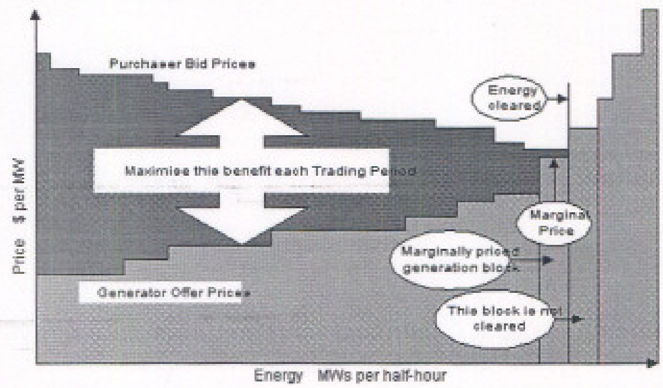

Figure 2 A Simple Pre-Dispatch Scheduling

III. Terminology

mi: Index of market nodes. A market node defines the location (bus) of a market participant.
MN: Number of market nodes
n: Number of network buses
i: Index of buses
Ntt: Number of bid types
$tt \in \{ENOF, ENDE, PLOF, TWOF, ILOF\}$
Nti: Number of traders
ti: Index of traders
T: Number of study intervals
t: Index of study intervals
NS: Number of MW blocks of a bid
ns: Index of bid blocks
bs: Index of piece-wise branch loss segments
Nbs: Number of piece-wise branch loss segments
BMW(mi,i,tt,ti,t,ns): Block MW, to be determined by the clearing system, of block *ns* of bid type *tt* at commercial market node *mi*, network bus *i* at time *t* by trader *ti*. BMW is negative for demand bids and positive for all generation and reserve bids.
BP(mi,i,tt,ti,t,ns): Block Price ($/MW) of block *ns* of bid type *tt* at commercial market node *mi*, network bus *i* at time *t* by trader *ti*.
$P_{t,i}$: Net MW injection at bus *i* at time *t*
S_B: MVA base value
B_{ij}: The *ij*th element of network admittance matrix
$Plss_{t,i}$: Equivalent loss at bus *i* at time *t*
$\theta_{t,i}$ Angle in radian of bus *i* at time *t*
$PG_{t,i}$: MW generation at bus *i* at time *t*
$PD_{t,i}$: MW demand at bus *i* at time *t*
l: Index of branches
b_l: Admittance in pu of branch *l*
f(*l*) and *t*(*l*): from-bus and to-bus buses of branch *l*

$BFlow_{tl}$:MW flow through branch l at time t

$BFlow_{tl}(bs)$: Segment flow through branch l at time t

$LF_l(bs)$: Loss factor of branch l on segment bs

UpRR(mi,ti,t): Up-ramp rate limit (MW/Hour) for unit of trader *ti* at market node *mi* at time *t*.

DnRR(mi,ti,t): Down-ramp rate limit (MW/Hour) for unit of trader *ti* at market node *mi* at time *t*.

K(mi,i,tt,ti,t): Proportional coefficient of PLSR reserve block *(mi,i,tt,ti,t,ns)* w.r.t. energy at *(mi,ti,t)*.

PLS1(mi,ti,t): *Fast* PLSR reserve cleared at market node *mi* at time *t* by trader *ti*

TWD1(mi,ti,t): *Fast* TWDR reserve cleared at market node *mi* at time *t* by trader *ti*

MNG(mi,ti,t): Energy offer cleared at market node *mi* at time *t* for trader *ti*.

$MNG^{max}(mni,ti,t)$: Max capacity at market node *mi* at time *t* by trader *ti*.

ENOF: Set of generation bids

ENDE: Set of demand bids

PLR1: Set of *fast* PLSR reserve offers

TWR1: Set of *fast* TWDR reserve offers

ILOF1: Set of *fast* ILOF

IV. Mathematical Formulation of the SPD for Bid-Clearing

The objective of an EM is to maximize market benefits. This is equivalent to minimizing the sum of payments to energy/reserve offers and the revenues from demand bids (*BMW* is negative for demand bids). The objective function of the bid-clearing problem is defined in (1).

$$(1)\quad Min \sum_{mi=1}^{MN}\sum_{i=1}^{n}\sum_{tt=1}^{Ntt}\sum_{ti=1}^{Nti}\sum_{ns=1}^{NS} BMW(mi,i,tt,ti,t,ns) * BP(mi,i,tt,ti,t,ns)$$

Constraints to the above objective function are described in the following sub-sections.

IV.1 Bid block MW Limits

For energy and reserve bid blocks (positive MW):

$$(2.1)\qquad 0 \le BMW(mi,i,tt,ti,t,ns) \le BMW^{\max}(mi,i,tt,ti,t,ns)$$

For energy demand bid blocks (negative MW):

$$(2.2)\qquad 0 \ge BMW(mi,i,tt,ti,t,ns) \ge BMW^{\max}(mi,i,tt,ti,t,ns)$$

IV.2 Network Constraints

For the linearized power flow model with network losses, bus generation-load balance at bus i is described in (3).

$$(3)\qquad PG_{t,i} - PD_{t,i} - Plss_{t,i} = S_B \sum_{j=1}^{n} B_{ij}\theta_{t,j}$$

In terms of MW bid blocks, $PG_{t,i}$ and $PD_{t,i}$ are calculated as follows:

$$(4)\qquad PG_{t,i} = \sum_{mi=1}^{MN} \sum_{\substack{tt=1 \\ and \\ tt\in ENOF}}^{Ntt} \sum_{ti=1}^{Nti}\sum_{ns=1}^{NS} BMW(mi,i,tt,ti,t,ns)$$

$$(5)\qquad PD_{t,i} = -\sum_{mi=1}^{MN} \sum_{\substack{tt=1 \\ and \\ tt\in ENDE}}^{Ntt} \sum_{ti=1}^{Nti}\sum_{ns=1}^{NS} BMW(mi,i,tt,ti,t,ns)$$

With bus angle and branch admittance, branch flow is expressed as in (6).

$$(6)\qquad BFlow_{tl} = S_B b_l(\theta_{f(l)} - \theta_{t(l)})$$

Branch flow is constrained by branch capacity MW limit.

Using the piece-wise linear loss model, branch losses are modeled as a piece-wise linear function of branch flows as in (7).

$$(7)\qquad BLoss_{tl} = \sum_{bs=1}^{Nbs} BFlow_{tl}(bs) \times LF_l(bs)$$

Branch losses are translated as an equivalent load, $Plss_{t,i}$, at the receiving-end bus i. $Plss_{t,i}$ is the sum of losses on branches that are connected to bus i and flows on the branches are flowing to bus i. The loss model is based on the premise that PDS/DS/Pricing optimizations would naturally favor reducing losses. When this premise is not valid, alternative rules for clearing bids are required.

IV.3 Outage Schedules and Time-Varying Limits

The security-constrained bid-clearing system supports scheduling outages and various time-varying network constraint limits. On an half-hourly basis, branch MW limits, bus min/max MW generation, Branch Group MW flow min/max limits, and Bus Group MW generation min/max limits can all be scheduled.

Constraints on Branch Group are modeled as linear functions of MW flow on one or more branches. Constraints on Bus Group are modeled as linear functions of MW generation injection at one or more buses.

IV.4 Ramp-Rate Constraints

Up-ramp rate constraints:

$$(8)\qquad MNG(mi,ti,t) - MNG(mi,ti,t-1) \le \tfrac{1}{2} UpRR(mi,ti,t)$$

Down-ramp rate constraints:

$$(9)\qquad MNG(mi,ti,t-1) - MNG(mi,ti,t) \le \tfrac{1}{2} DnRR(mi,ti,t)$$

where

$$(10)\qquad MNG(mi,ti,t) = \sum_{i=1}^{n} \sum_{\substack{tt=1 \\ and \\ tt\in ENOF}}^{Ntt} \sum_{ns=1}^{NC} BMW(mi,i,tt,ti,t,ns)$$

The initial conditions of generating units for the first trading period are determined with actual historical generation MW from the EMS.

IV.5 Reserve Requirements based on Island/Area Risks

The amount of reserve required is based on the type of risks that must be covered. The risks are evaluated according to the following three criteria:

- Manually Entered Reserve Risk
  Island reserve cleared must be greater than or equal to the manually entered MW reserve requirement.
- Island Generation Risk
  Island reserve MW actually cleared must be greater than or equal to the largest generation plus reserve cleared for each of the risk-setting generators.
- HVDC Link Risk
  Two models are implemented for HVDC link risk evaluation: (a) Island reserve bid actually cleared must be greater than or equal to net HVDC import MW into the island. (b) Single pole outage risk for paired HVDC links, meaning that actual island reserve must be greater than or equal to the MW difference between the actual MW flow of the pole out of service and the

spare capacity of the pole in service. Either model can be activated by toggling a flag.

IV.6 Other Reserve-Related Constraints

For presentation clarity, the models below are described for *fast* reserve constraints. The models for *sustained* reserve are similar.

- <u>Proportional PLSR Reserve Bid Cleared</u>

PLSR reserve capability of a unit is affected by its actual generation level. This implies that each block of PLSR reserve cleared cannot be greater than a pre-defined proportion of the total generation bid cleared for that unit. The constraint applies for both *fast* and *sustained* reserve. Expression (11) defines this type of constraints for *fast* reserve bid block.

(11) $BMW(mi,i,tt,ti,t,ns) \le K(mi,i,tt,ti,t) * MNG(mi,ti,t)$,
$tt \in PLOR1, i \in mi$

- <u>Market Node Capacity Limits</u>

This set of limits defines the total capability of a generator to be cleared for the combined sum of energy and reserve bids at a market node. The constraint is:

$$PLS1(mi,ti,t) + TWD1(mi,ti,t) + MNG(mi,ti,t) \le MNG^{max}(mi,ti,t) \tag{12}$$

where

$$PLS1(mi,ti,t) = \sum_{i=1}^{n} \sum_{\substack{tt=1 \\ and \\ tt \in PLOR1}}^{Ntt} \sum_{ns=1}^{NS} BMW(mi,i,tt,ti,t,ns) \tag{13}$$

$$TWD1(mi,ti,t) = \sum_{i=1}^{n} \sum_{\substack{tt=1 \\ and \\ tt \in TWOR1}}^{Ntt} \sum_{ns=1}^{NS} BMW(mi,i,tt,ti,t,ns) \tag{14}$$

In addition, variables *PLS1(mi,ti,t)* and *TWD1(mi,ti,t)* (*PLS2(mi,ti,t)* and *TWD2(mi,ti,t)* for *sustained* reserves) are constrained by their respective upper limits.

- <u>Interruptible Load Reserve Bids</u>

Interruptible load can be a major contribution to the reserve market. Reserves representing interruptible loads may be directly bid into the market. However, interruptible load reserve bid cleared for a trader cannot be greater than the total energy demand cleared for the same trader, as in (15).

$$\sum_{mi=1}^{MN} \sum_{i=1}^{n} \sum_{\substack{tt=1 \\ and \\ tt \in ILOF1}}^{Ntt} \sum_{ns=1}^{NS} BMW(mi,i,tt,ti,t,ns) \le -\sum_{mi=1}^{MN} \sum_{i=1}^{n} \sum_{\substack{tt=1 \\ and \\ tt \in ENDE}}^{Ntt} \sum_{ns=1}^{NS} BMW(mi,i,tt,ti,ns) \tag{15}$$

IV.7 Marginal Prices

The bid-clearing problem described above is solved via the LP method. One advantage of the LP solution is that various marginal prices (MPs) are by-products of the solution to the constrained optimization problem. For instance, the MP at bus i is the marginal value of equation (3), the MP for market node capacity constraints are equal to the marginal value of (12), the MPs of reserve constraints are determined by the marginal values of the corresponding reserve constraints, and so forth.

V. Test Results

This section demonstrates the results using a 67-bus test system and the NZEM. The 67-bus system is used to demonstrate some basic features of the SPD system. Results are also reported on the NZ NZEM system. The PDS-mode of scheduling, in which demand bids are cleared against generation and reserve bids, is used to demonstrate the results throughout this section.

V.1 67-Bus Test EM

The test data contains a set of generation bids priced from \$2/MW to \$27/MW, and reserve bids at 10% of the generation bid prices, and demand bids priced from \$13/MW to \$50/MW. Each bid contains only one bid block. The total generation bid is 6335MW, which is also the sum of PLSR and TWDR reserve bids. The total demand bid is 6255MW. Without considering constraints, generation is sufficient to meet load.

V.1.1 Conventional Dispatch without Reserve

Without consideration of reserve requirements, losses, and other security constraints, this simple dispatch can be performed manually by matching generation bids stacked at increasing prices to demand bids stacked at decreasing prices. This is schematically shown in Figure 3a. As described in Section 2, the intersection point of the generation bid price curve and demand bid price curve determines the marginal price of the market. The results were confirmed by the SPD solution: a uniform system marginal price of \$27/MW was found at all buses. Generation bids priced higher than \$27/MW or demand bids priced lower than \$27/MW were not cleared. Next, the impact of transmission losses is presented. Figure 3b demonstrates the effect of network losses on marginal prices. The spatial nature of marginal prices is seen.

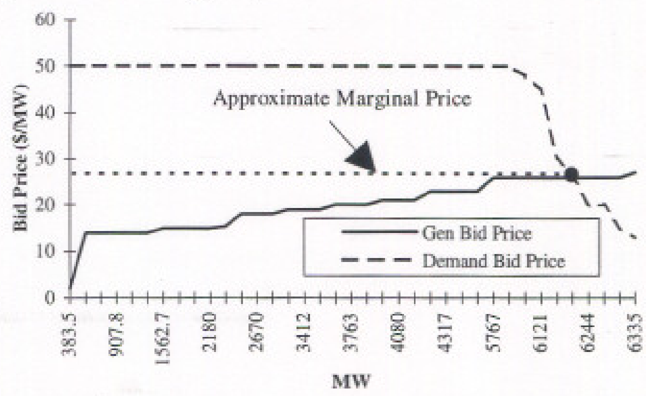

Figure 3a Illustration of Conventional Dispatch w/o Reserve

V.1.2 Concurrent Dispatch with Reserve

In this case, reserve constraints are enforced and reserve bids are cleared concurrently along with generation and demand bids. Nodal prices of the case are presented in Figure 4 against the case in Section V.1.1. It is interesting to note that nodal prices increase from around \$27/MW in the case without reserve to about \$50/MW with reserve. This is explained as follows. When reserve constraints are enforced, a total of 5261MW demand was cleared against 5304MW of generation and 961MW of reserve. From Figure 3a it can be seen that the price at 5261MW (which is the last MW demand bid cleared) is $50/MW. Because part of generating capacity is used to provide reserve, the total amount of the demand cleared has to be backed off to meet limited generation and reserve available.

Generation/reserve dispatches for the cases without and with reserves are displayed in Tables 1 and 2. Table 1 shows that without reserve constraints, generations are dispatched in their merit order. This is consistent with the concept of conventional economic dispatch. Table 2 shows that generations are dispatched out of merit order when generation and reserve bids are concurrently cleared. Significant differences in generation and reserve MW between the two cases are observed.

As previously stated in Section IV, system reserve requirements are determined by the largest of three quantities: Manually entered reserve requirement, generation risk, and HVDC link risk. In this case, the required system reserve is determined by unit 10 generation and reserve capacity dispatched. It is 961MW as is shown in Table 2.

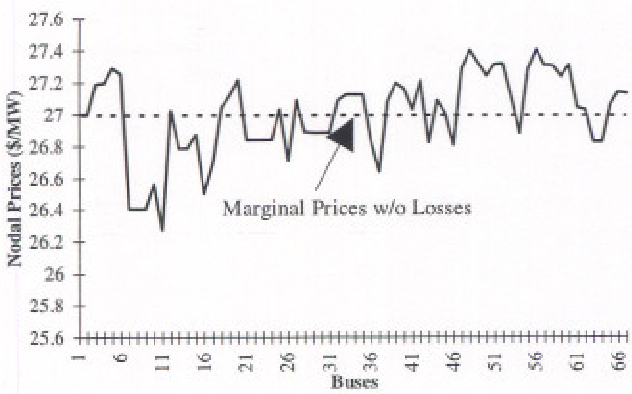

Figure 3b Effects of Network Losses on Nodal Prices

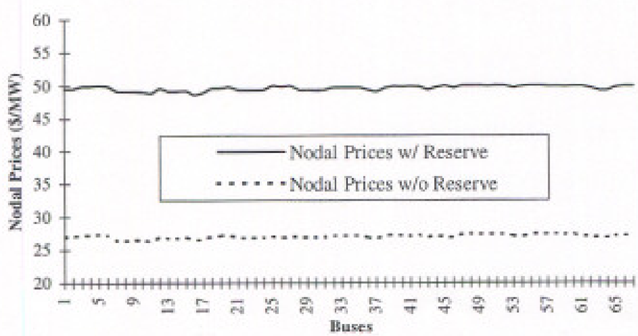

Figure 4 Effects of Reserve Constraints on Nodal Prices

V.1.3 Effects of Security Constraints on Nodal Prices

Branch flow limit constraints are applied in this example. Compared to the case in Section V.1.2, MW limits on three branches (D-H, L-R, and K-H) are reduced to 300, 200, and 200 MW respectively (initial MW flows over these lines without enforcement of branch limit constraints are 399, 287, and 271 MW). In this case, the flows over branches D-H and L-R are binding. Effects of security constraints on nodal prices are shown in Figure 5.

It is observed in Figure 5 that nodal prices dropped significantly at

Table 1 Generation Dispatch in Merit Order w/o Reserve

Unit	Capacity (MW)	Gen Price ($/MW)	MW Cleared	Loading (%)
1	383.5	2	383.5	100
2	961.0	14	961.0	100
3	218.2	15	218.2	100
4	774.2	15.4	774.2	100
5	218.4	18	218.4	100
6	569.5	19	569.5	100
7	599.5	20	599.5	100
8	292.5	21	292.5	100
9	719.6	23	719.6	100
10	1031.1	26	1031.1	100
11	567.3	27	456.2	80.4
Total	6334.6		6223.6	

Table 2 Generation Dispatch with Reserve

Unit	Capacity (MW)	Bid Price ($/MW)		MW Cleared (MW)		
		Energy	Reserve	Energy	Reserve	Total
1	383.5	2	0.2	383.5	0.0	383.5
2	961.0	14	1.4	613.7	347.3	961.0
3	218.2	15	1.5	218.2	0.0	218.2
4	774.2	15.4	1.54	613.7	160.5	774.2
5	218.4	18	1.8	218.4	0.0	218.4
6	569.5	19	1.9	569.5	0.0	569.5
7	599.5	20	2.0	599.5	0.0	599.5
8	292.5	21	2.1	292.5	0.0	292.5
9	719.6	23	2.3	613.7	105.9	719.6
10	1031.1	26	2.6	613.7	347.3	961.0
11	567.3	27	2.7	567.3	0.0	567.3
Total	6334.6			5303.6	961.0	6264.5

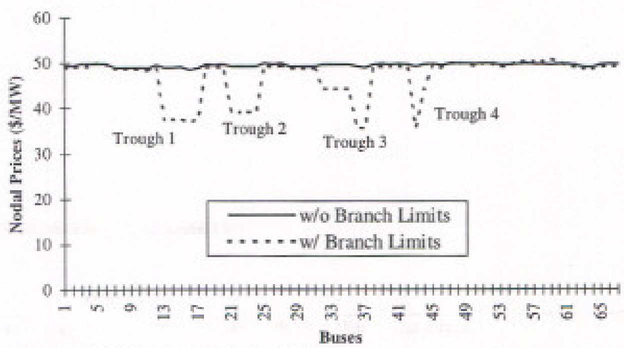

Figure 5 Effects of Branch Limit Constraints on Nodal Prices (w/ reserve)

several buses, increased slightly at a few buses, and changed little at many other buses. Explanations for this phenomenon follow.

This is a case where there is insufficient generation to meet price-sensitive demand. In such an under-supply case, marginal prices are affected more by demand bid prices, which is $50/MW at its maximum, and less by generation offer prices. This effectively prevented nodal prices from rising above the demand bid price. Hence, in Figure 5, there was no significant rise in nodal price when branch flows were constrained.

Next, we explain why nodal prices dropped at several buses.
Trough 1 represents nodal prices at buses in generation station D, which is the sending end of the constrained branch D-H that radially connects station D to the rest of the system. Constraining flow on branch D-H reduces MW generation from station D. The drop in nodal prices at station D reflects lower MW generation being dispatched at the station (Table 3).

The same reason applies to Trough 3, with station L situated at the sending end of the constrained branch L-R. (Station K is connected to station L via station H1.)

Trough 2 represents prices at Station H1, which is electrically close to Station L (of Trough 3) and thus exhibits the same characteristic as Station L. The same reason applies to Trough 4 where Station M is connected directly to Station L.

Table 3 Highlights of the 4 Price Troughs in Figure 5

	Nodal Prices		EnergyOfferCleared		DemandBidCleared		
Bus	Base	Cons'ed	Base	Cons'ed	Base	Cons'ed	Notes
13	49.05	37.46	0	0	0	0	Trough 1
14	49.05	37.46	0	0	0	0	(buses in
15	49.21	37.59	0	0	489.2	489.2	station
16	48.54	37.07	599.5	599.5	0	0	D)
17	48.89	37.49	292.5	193.4	0	0	
21	49.31	39.19	0	0	0	0	Trough 2
22	49.31	39.16	0	0	0	0	(buses in
23	49.31	39.19	218.4	218.4	0	0	station
24	49.31	39.19	218.2	218.2	0	0	H1)
32	49.69	44.27	0	0	0	0	Trough 3
33	49.73	44.31	0	0	189.6	189.6	(buses in
34	49.71	44.30	0	0	0	0	Sta. K)
35	49.72	44.30	0	0	0	0	
36	49.33	35.79	0	0	254.2	254.2	(buses in
37	48.98	35.69	569.5	399.90	0	0	Sta. L)
48	49.33	35.79	0	0	0	0	Trough 4
49	49.68	44.27	0	0	0	0	Sta. M

In summary, generation outputs at the sending area of the flow-constrained branches are reduced, hence dropping previously served demand bids. The reduced generation level enables these generators to provide more reserves, which in turn frees up generation capacity for units in the receiving area to serve more demand bids. In both cases, the same amount of demand bids are cleared. But, the re-dispatch of generation, reserve, and demand causes the market revenue to decrease from $134687 (w/o constraints) to $131271 (w/ constraint). Network losses increases from 42.4MW to 44.1MW.

V.2 The NZEM System

The NZEM network model consists of 473 buses, 755 branches, and two HVDC links. A typical daily bid-clearing involves about 40,000 bid blocks. With sophisticated reserve and ramp-rate models, the numbers of constraints and variables for a typical one trading-period solution are about 8,600 and 30,000 respectively. Solving the bid-clearing for one trading period takes about 40 seconds on a Pentium Pro 6/200 machine using the Dual Simplex method. *(The solution time reduces to about 6 seconds if network models are excluded from the formulation.)*
The HVDC link has significant impact on NZEM operations. Simulation studies for one day in October 1996 were performed to quantify the effects of one HVDC pole outage on the North Island region. The outage of the HVDC pole was scheduled from 00:00am to 12:00pm of the same day. Demand bids cleared in the North Island region for the cases with and without the HVDC pole outage are plotted in Figure 6. Because the capability of HVDC links to transfer energy from South Island to North Island was reduced, the demand bids cleared in North Island were also reduced. The effect of the HVDC pole outage on North island is more significant during peak hours (e.g., 09:30 - 11:30) than during non-peak hours, as shown in Figure 6.

According to the bid-clearing mechanism, it can be expected that the outage will cause increases in nodal prices at North Island and decreases at South Island. Figure 7 plots the changes in nodal prices at all system buses at 10:00am on the day of study. Higher nodal prices in North Island are observed.

Marginal prices for *fast* and *sustained* reserves are presented in Figure 8 for a 48 trading-period market clearing. Non-zero reserve prices are seen only at a few trading periods. This is because the amount of zero-priced reserve offers is sufficient to meet reserve requirements most of the time on the study day.

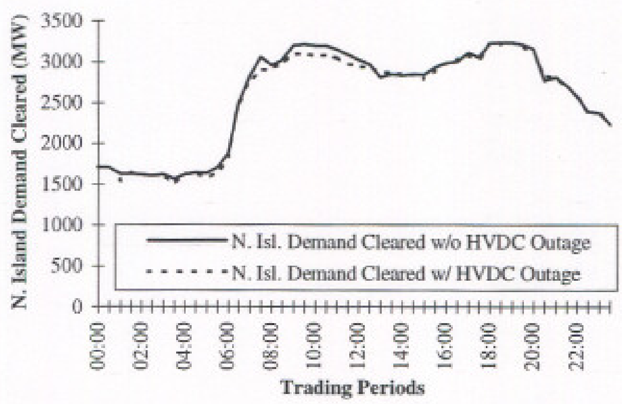

Figure 6 Effects of the HVDC link on North Island Demand

VI. Conclusions

This paper presents the implementation of a bid-clearing methodology that extends classical demand-supply balance in a competitive market to allow secure and economic operation of the NZEM. Key features of the SPD application for bid-clearing are:

- Concurrent dispatch of energy supply, energy demand, and reserve.
- Explicit enforcement of transmission congestion, reserve requirements, and ramp rate limits.
- Marginal price calculation for all constrained quantities: nodal price, reserve price, and so forth.

It was a challenge to start the SPD project on 1 June 1996 and have it ready for NZEM operation on 1 October , 1996. SPD solutions may not always be intuitively obvious at the first glance, but they have successfully withstood inquiries and scrutiny from the market, and increased our understanding of the market design and their implications. As the NZEM continues to mature, experiences gained from SPD will help refine operation of the physical market, and facilitate enhancements to market rules in the future.

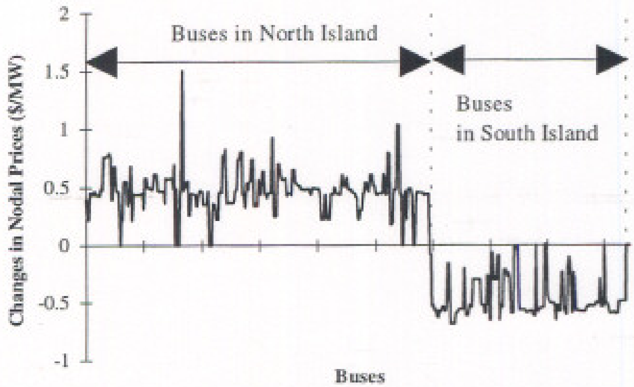

Figure 7 Changes in Nodal Prices due to HVDC Outage

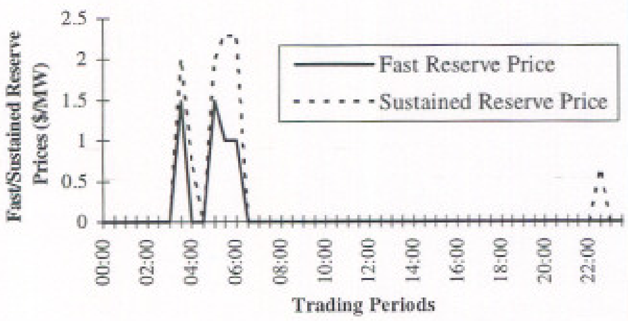

Figure 8 Marginal Prices for *Fast/Sustained* Reserves

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