Influence of HVDC Operation on Deregulated Markets

Nalin Pahalawaththa¹ Derrick Westenra Conrad Edwards Mohamed Zavahir
Transpower New Zealand Limited
New Zealand

1 Introduction

At the CIGRE Paris Session 2002 in a paper by the authors, the impact of the deregulated market on HVDC operation has been addressed from the perspective of asset operation and management [1]. The presence of a large power flow controlling device such as an HVDC link can also have a significant impact on the development and operation of the electricity markets. In this paper, the authors’ experience on the influence of the New Zealand HVDC transmission link in developing and operating the New Zealand electricity market is discussed.

New Zealand presently operates a mature deregulated electricity market. The size and the location of the HVDC inter island link in New Zealand is such that it has a significant influence on the successful and efficient operation of the physical power system as well as the electricity market.

2 Influence of HVDC on electricity markets

In operating HVDC transmission links in a fully deregulated market, the power system planners, market designers and the system operators need to address issues in three important dimensions: market, operational and financial. The generic issues in these dimensions are respectively:

• defining and pricing the services HVDC offers to the market,
• defining and pricing the services HVDC needs to procure from the market,
• dispatching the HVDC assets in the market and,
• operation and maintenance of the assets.

In grid planning and operation in vertically integrated power utilities, the cost of developing and operating HVDC transmission assets are often justified based on the economics of energy transmission. The ancillary services consumed or produced by the HVDC links receive little or no attention. However, in deregulated markets, these services are unbundled and separated to a significant extent.

¹ Nalin.pahalawaththa@transpower.co.nz
In relation to operation of HVDC links, the unbundled services it produces and which could be offered to the market include the following:

- Point to point energy transmission
- Instantaneous reserve sharing between the interconnected HVAC systems
- System frequency regulation and stabilisation
- Black start support
- Control of the ac grid voltage through reactive power modulation
- Directional power flow control

For successful and efficient operation of an HVDC link, the system operator or the HVDC asset owner needs to procure services from the other market participants. These services include:

- Synchronous reactive power support for maintaining the stability of the operation of HVDC links
- Instantaneous reserves covering the risk of reduction in power injection to an area following a single or bi-pole trip
- When connected to weak power systems, services for reducing the frequency excursions during switching on/off of the HVDC links

In summary, in developing and operating deregulated electricity markets, the benefits that can be provided through operation of the HVDC links as well as the huge technical demands (and constraints) it places on the power system for its successful operation require special attention. In New Zealand, while some of the benefits and constraints of operation of the HVDC link have already been identified through market mechanisms, the full effect on the market is still unfolding.

3 New Zealand’s HVDC Transmission System

The ac systems in the South and the North Islands of New Zealand are interconnected by a 1040 MW, bi-pole HVDC inter-island link. Power is transmitted from Benmore in the central South Island to Haywards at the southern tip of the North Island. The link allows the New Zealand grid to be operated as one single power system, taking advantage of the generation capacity and diversity of the primary energy sources in the two islands. The HVDC transmission link consists of two overhead line sections, one in each island, and a submarine cable between the islands (figure 1).
A schematic representation of the link is shown in figure 2. The 270 kV pole of the link consists of two mercury arc converters (built in 1965) connected in parallel whereas the 350 kV pole consists of thyristor converters (built in 1992). At the time of the thyristor converter commissioning in 1992 the link had the capacity to transfer 1240 MW. The failure of the old cables during the period 1991 - 1996 forced the link to be operated at a reduced link capacity of 1040 MW.

In addition to providing a means of electricity transmission between the two islands, the HVDC link is built with control mechanisms enabling it to provide many of the ancillary benefits outlined above to the New Zealand electricity market [2].

4 New Zealand Electricity Market (NZEM)

Presently in New Zealand, a lightly regulated electricity market is in operation. The electricity market can be characterised as a gross pool where spot market trading takes place in half hour periods. Generation offers are received in advance (with offers finalised two hours in advance of the trading period) and demand is forecast based on historical information. Optimum dispatch is determined and carried out taking into account the generation offers (quantity and price), demand forecast, transmission and grid operating constraints and transmission losses. The locational energy prices are calculated as the marginal cost of satisfying demand at each location.

The system operator is responsible for determining the level of ancillary services required for operating the grid to achieve economic dispatch with an agreed level of security and power quality. The system operator procures ancillary services outside the NZEM. Presently the ancillary services of frequency regulating, over-frequency arming and black start are procured through annual tenders. Instantaneous reserves are traded in the spot market and co-optimised with the energy dispatch. Presently there is no mechanism available for trading of reactive power. Where the reactive power requirement is beyond what can be reasonably expected from the dispatched generators, the system operator procures reactive power through annual contracts or will constrain on generators outside the dispatch merit order. The reactive power costs are allocated to the customers in the respective region. In 2002, the approximate cost of providing the ancillary services were frequency keeping - NZ$ 21 million, instantaneous reserves - NZ$ 12 million, black start – NZ$ 115,000, and over-frequency arming - NZ$320,000 compared to an energy market of NZ$ 1.5 billion (note: 1 NZ$ ≈ 0.6 US$).

Generation is dispatched ensuring agreed security levels to all the connected customers, in most cases (n-1). While a failure of a single pole of the HVDC link is considered as an (n-1) contingency, a bi-pole failure is considered as an (n-2) contingency. Although bi-pole failures are rare, given that a bi-pole failure would often lead to a system collapse, the risk of a bi-pole failure is managed through automatic under-frequency load shedding (AUFLS), which is mandated through regulation (further described in section 5.3 below).

5 HVDCC related market developments

5.1 National frequency regulating market

The HVDC link provides power transfer modulation functionality for stabilisation of the frequency in either island, following a system disturbance. The controller performance is such that the HVDC is effectively presented to either of the islands as the equivalent of a large generator with large inertia. Hence, the level of frequency excursion following a system disturbance is significantly reduced

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2 As at the time of writing in late 2003. The New Zealand government is reforming the lightly-regulated voluntary pool into a regulated mandatory pool, intended to start operating in early 2004. Although this heralds a major change in governance of the rules, the market rules themselves are being carried over with little immediate change.
compared to a situation where HVDC modulation is not available. When the HVDC frequency modulation is not available, in order to provide the same frequency quality a higher quantity of frequency regulating reserve is required to be carried, using partially loaded responsive generators.

Therefore, the utilisation of instantaneous reserve available in the system can be significantly increased by developing a market which enables
(a) generators in both islands to contribute commercially as well as physically to the frequency keeping of both islands
(b) The HVDC link’s contribution to combine the reserves in both the islands is recognised commercially as well as physically.

While the ancillary service market existing in either island for frequency keeping can be readily extended to a national market, an outstanding issue is how to value and reward the contribution of the HVDC link.

5.2 National under-frequency management reserve market

In order to manage the under-frequency performance of the power system, instantaneous reserves are procured as two ancillary service products
(a) Fast instantaneous reserves (FIR) – reserves that are available within 6 seconds of an under frequency event and sustained for at least 60 seconds
(b) Sustained instantaneous reserves (SIR) – reserves that are available within 60 seconds and sustained for at least 15 minutes

The two HVDC control functions, which would significantly influence the under-frequency performance of the power system, are frequency stabilisation control and spinning reserve sharing control. In its present form while HVDC frequency stabilisation controls will substantially supplement the fast instantaneous reserves, it will not be sustained for 60 seconds and therefore will not qualify as FIR. On the other hand the spinning reserve modulation function could sustain a modulation in power flow as long as there is a difference in frequency between the two islands. Therefore, through the HVDC link, the generators in both of the islands can provide SIR into the market and contribute to under-frequency management.

Presently, in the NZEM, instantaneous reserves are procured independently within each island for managing the under-frequency performance of the respective power systems. Future market developments may take into consideration the value of the HVDC link in combining and co-ordinating the reserves available in each island. Further, the future market may also have more flexibility in defining reserve products that recognise the physical contribution of the HVDC frequency stabilisation control function in supplementing the fast instantaneous reserve and financially reward this functionality.

5.3 Emergency load shedding market

A bi-pole failure is a rare event but could lead to catastrophic consequences. Hence the management of system security in the event of a bi-pole failure is given special attention. In the past bi-pole failures causing sudden interruptions to the power transfer have taken place on average once in every 5 years. The worst case scenario amounts to the HVDC link transmitting power to the North Island at close to full capacity (1040 MW) during a light load period in the North Island (e.g. night trough), when the total load could be as low as 1800 MW. A bi-pole failure under this scenario would reduce the power injection to the system by more than 50% and hence will cause a power system collapse unless mitigation actions are taken.

Instantaneous reserves are carried in each island for managing a single contingency. In order to cater for a bi-pole failure with instantaneous reserves, a reserve above that required for a single contingent event would have to be carried. Given the rarity of a bi-pole event this extra reserve is carried as
automatic under-frequency load shedding (AUFLS). The regulation presently in place requires that
two blocks of connected load, each block consisting of at least 16% of the supplied load, be made
available as AUFLS. Wherever possible, commercial and industrial loads are exempt from
participating in AUFLS. Instead, residential loads are targeted as much as possible.

Given that there is sufficient potential competition to provide AUFLS, economic efficiency can be
enhanced by replacing these mandatory arrangements with market mechanisms. A market where
consumers can offer appropriate loads for under frequency load shedding would replace a regime
based on administrative convenience by one based on the discovery of least-cost solutions. The cost of
load shedding would then better reflect the true value of power transmission through the HVDC link.

5.4 Power flow control

As a result of vertically integrated utility planning, when the HVDC link was first built, the six
generators at Benmore (6 x 112 MVA) were directly connected to the HVDC converter transformers
with the expectation that their generation would mainly be transferred to the North Island. The
Benmore generator and Pole-1 output is connected to the ac grid in the South Island through two 16
kV/220 kV interconnecting transformers. However the capacity of the transformers (2 x 240 MVA)
falls short of the total capacity required for transferring the total Benmore generation and HVDC Pole-
1 injection into the South Island during southward transfer.

A solution for relieving this transmission constraint is to operate HVDC Pole-1 and Pole-2
unbalanced, by reducing the HVDC transfer through Pole-1 while increasing the transfer through Pole-
2. The extreme would be the total capacity of the inter-connector being used by Benmore generation,
while total HVDC transfer takes place via HVDC Pole-2 (ie. Pole-1 transfer of 0 MW, Pole-2 transfer
of 600 MW). Such highly unbalanced transfer would incur costs in two areas:
• increase in instantaneous reserve required to be carried in the South Island to manage the risk
  of tripping of Pole-2
• increased operational cost on the HVDC asset owner to compensate increased erosion of the
electrodes

The market dispatch algorithm (the scheduling, pricing and dispatch algorithm “SPD”) will co-
optimise energy and instantaneous reserve dispatch, and so appropriately constrain the level of HVDC
transfer to achieve the minimum overall costs (energy and the reserve costs) taking into the account of
increased reserve costs due to unbalanced operation. However, the increased operation and
maintenance costs due to erosion of the electrodes etc. are not presently captured through the market
mechanisms.

5.5 Black start

New Zealand’s HVDC link has built-in capability to maintain the system stability and voltage in the
Wellington area if the southern part of the North Island ac grid becomes isolated from the rest of the
North Island grid. This capability could replace the need for maintaining a black start plant in the
Wellington area.

Although this functionality could theoretically provide a small saving in system operating costs, the
risk associated with relying on the HVDC link (together with the connected synchronous
compensators) for providing the black-start security to the region is considered to be too high. Hence
at present, this functionality is not considered to have any marketable value.

5.6 Voltage support

HVDC converter operation is inherently associated with poor power factors and hence a significant
reactive power supply is required at the link terminals for power factor compensation. Usually the
reactive power requirements are met by the capacitors in the harmonic filters. The control of ac supply voltage to the converters is normally carried out through transformer tap changers but in some schemes is carried out through voltage regulation of connected synchronous compensators (at Haywards) or synchronous generators (at Benmore).

During some trading periods in order to retain the voltage control ability and the system strength (ie. short circuit level) required for operating Benmore Pole-1 converters, the generators connected to the converter have to be scheduled out of the merit order, incurring significant “constrained on” cost. This scenario highlights the need to either recognise the constrained on costs in scheduling the HVDC transmission asset through dispatch tools (SPD), or to enter into a contract with the generator owners to provide the synchronous support when necessary. Presently in New Zealand the required synchronous support is obtained through a bilateral contract and the cost is considered as an integral part of the annual HVDC operating costs.

The reactive power absorption capability of the converters and its controllability via the firing angle allow the HVDC links ideally to be used as possible grid reactive power control devices (similar to Static Var Compensators). While it was possible to control the voltage at Haywards (the northern end of the HVDC link) through the HVDC firing angle control (in conjunction with the synchronous compensators), the designers have elected to provide 2x40 MVAR reactors for that purpose.

5.7 Minimum HVDC constraints

The loading of the HVDC link is determined by the dispatch schedule and conversely the availability of the HVDC link significantly influences the generation dispatch. Varying generation offers for each trading period (half hour) make the level of power transfer through the HVDC link highly volatile. It is not uncommon for HVDC transfer to reduce to zero or reverse the direction of the flow during low load periods. The best technical performance with mercury arc valves is achieved when they are continuously loaded at medium to high load for considerable periods of time. Frequent start/stops of the mercury arc valves increase the risk of arc-backs. Hence, for the operation of New Zealand HVDC Pole-1, the following constraints are imposed:

- MAV restart within 10 minutes of stopping or wait for restart for two hours (to reduce the risk of arc-backs)
- The minimum run time of the MAVs must be no less than four hours
- Each half pole may be started and stopped subject to a maximum of twice per 24 hour period.

There are no similar constraints on the operation of Pole-2. However, Pole-2 operation is subject to a minimum limit of 30 MW.

In order to run the converters above their minimum current level and in order to keep both the poles in balanced current operation, the loading guidelines shown in the Table 1 are mandated.

<table>
<thead>
<tr>
<th>Converter Poles</th>
<th>Bi-pole threshold for switching (MW)</th>
<th>Poles already in operation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pole-2 (P2)</td>
<td>30</td>
<td>None</td>
</tr>
<tr>
<td>Pole-1, 1st Half Pole (HP-1)</td>
<td>86-117</td>
<td>P2</td>
</tr>
<tr>
<td>Pole-1, 2nd Half Pole (HP-2)</td>
<td>117-203</td>
<td>P2 + HP-1</td>
</tr>
</tbody>
</table>

While the Pole-1 operating restrictions some times may cause Pole-2 to carry load outside the specified bi-pole operating guidelines, they have a significant impact on the electricity market under
certain circumstances. For an example, for southward transfer the reserve cost could be quite significant if only Pole-2 is in operation and Pole-1 is not available due to switching restrictions.

However, the above operating constraints are in-effect soft constraints where the HVDC link could be operated outside the above loading guidelines provided the asset owner is financially compensated for extra asset wear and tear and resulting extra maintenance. Therefore in the future, market mechanisms could be developed so that mandatory operating constraints are relaxed and costs associated with inefficient operation of market due to HVDC transmission constraints is traded against the cost of asset wear and tear and maintenance.

5.8 Management of frequency excursions during HVDC switching on/off

HVDC link operation is constrained with respect to the level of minimum HVDC transfer, where it must be maintained above 30 MW. Therefore, during switching on/off of the HVDC link a load disturbance of a 30 MW step is created in either of the islands. Considering the small amount of load connected to the South Island power system during the trough load periods (approximately 1000 MW), a load change of 30 MW is sufficient to create a significant frequency disturbance forcing the system frequency to deviate outside the normal operating band of 49.8 Hz – 50.2 Hz.

At present the impact on system frequency of HVDC switching on/off is managed by co-ordinating the switching with ramping up/down of the frequency keeping generator, through a loose ad-hoc arrangement.

In a market environment where frequency keeping costs are recovered on a “causer pays” basis, the HVDC asset owner would either be required to pay his relevant contribution to the frequency keeping costs or have a bi-lateral contract with a generator who could ramp up/down generation nullifying the effect of HVDC switching.

6 Modelling of HVDC in dispatch tools

As the HVDC link has such a large impact on the outcomes of the market, it requires accurate modelling within the market “scheduling, pricing and dispatch (SPD)” tools to ensure an optimal and transparent economic outcome. Ideally, the SPD tool should model the following features of the HVDC link and co-optimise the costs associated with HVDC operation together with the cost of scheduled generation:

- the power transfer capability of individual poles taking into consideration the constraints imposed by the connected ac and dc equipment (e.g. reactive support and interconnecting transformer constraints)
- the power system security risks due to operation of the link (e.g. instantaneous reserve required to be carried for ensuring power system security following a single or bi-pole HVDC failure)
- the inter temporal constraints associated with operation (e.g. minimum down time associated with mercury arc valves)
- the power flow control capability of the HVDC link

In New Zealand, the concerns associated with the energy security to the South Island during dry years have highlighted the need for improvements to HVDC and ac configuration modelling within SPD. Improvements already carried out include a more accurate representation of the HVDC pole configuration and optimisation of power flow in individual poles. The optimisation takes into account the ac grid configuration and constraints, power system losses and the level of risk due to the failure of a pole or the bi-pole. The NZEM dispatch tool does not explicitly optimise the on / off status of the HVDC link, as inter-temporal optimisation is limited to continuous ramp rates. However, at every trading period, as the generation offers and bids are adjusted for the future seven trading periods, the
market offers/bids will have a significant lead-time to settle taking into account the on/off status of the HVDC link.

7 Conclusions

In developing and operating deregulated electricity markets, the benefits offered by the HVDC links as well as any constraints imposed by them need to be clearly understood. The inter-island HVDC link in New Zealand has a significant influence on the successful operation of the physical power system as well as the electricity market. While at present New Zealand operates a mature electricity market, only some of the benefits and constraints of operation of the HVDC link have been identified and accommodated in the market rules and tools.

The controllability of power flow through each HVDC pole is represented in the market “scheduling, pricing and dispatch” tool. The generation and HVDC dispatch is optimised taking into consideration generation offers, ac grid constraints, power system losses (ac as well as dc), supply security and the cost of instantaneous reserves required for managing the under-frequency performance of the power system. Market policies are being developed recognising the ability of the HVDC link to modulate the power transfer between the islands which benefit in stabilising and controlling the power system frequency of the islands. While the risk of an HVDC bi-pole failure is presently managed through a mandatory under-frequency load shedding scheme, it is also conceivable that such mandatory arrangements will be replaced in the future with appropriate market mechanisms. Presently the reactive power support for successfully operating the HVDC link is ensured through bilateral contracts with the appropriate generators and such arrangements are likely to continue in the foreseeable future.

In summary, the HVDC link in New Zealand has influenced the development of the electricity market requiring it to implement least cost solutions for the operation of the HVDC link through market or contestable contract mechanisms. These market arrangements will expose the true cost of power transmission through the HVDC link and enhance the economic efficiency of the electricity markets.

8 References


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