Transpower HVDC Bipole – Transmission to Trading

Authors
Chris Otton, Transpower NZ Ltd
Bruce Mason, Reunion Asia Pacific
Dr Stephen Batstone, Reunion Asia Pacific

Presenter
Chris Otton, Transpower NZ Ltd

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Abstract

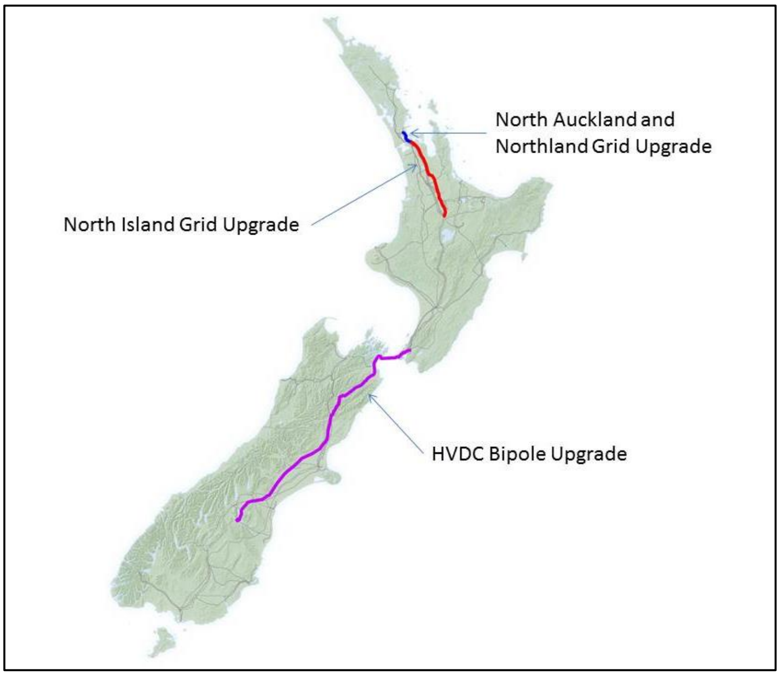
The HVDC link between Benmore, in the South Island, and Haywards in the North Island, is arguably the most important single piece of electricity infrastructure in New Zealand. In late 2007, Pole 1 of the HVDC asset was removed from regular service. This reduced the HVDC transfer capacity by approximately 50%. In September 2008, Transpower received regulatory approval to invest $672m in replacement HVDC equipment. The design and construction contract was awarded to Siemens. The commissioning of such a complex piece of electrical infrastructure was not trivial, requiring Siemens and Transpower to complete ~400 tests across the full range of the asset's capability. While not unique, this commissioning challenge was arguably one of the most complex in the world, in no small part due to Transpower's election to undertake these tests using market mechanisms, rather than regulatory power. As a result, Transpower needed to take an approach to the 400 tests which combined a prediction of likely system conditions, with financial mechanisms to incentivise generators to adjust their desired output to levels where needed, which created the correct HVDC flows required for each test.

In this paper, we describe the complexities of the testing regime, and how engineering requirements for the successful commissioning manifest in a highly prescribed set of tests. Many of these tests left little flexibility in terms of HVDC flow, and required market participants to deviate significantly from their preferred market positions in order to achieve the desired flow level and successfully complete the test. We then outline how Transpower used a novel combination of financial contracts and predictive modelling over a hydrologically-challenging 6 month period in 2013 to successfully commission the HVDC. This will include a description of how Transpower established a trading function which negotiated ~1100 financial contracts with market participants over the 6 month period.

Background

As part of Transpower's Grid Vision work in the early 2000s it was identified that Pole 1 of the HVDC link was nearing the end of its service life and would need replacement. A full Grid Upgrade Plan , or GUP, was developed and approved by the Electricity Commission in September 2008, although interim expenditure to continue work on identifying a replacement was approved as early as 2005.

Unlike AC grid upgrade projects, the HVDC GUP included new physical plant and control systems that required extensive in-situ testing under a wide range of operating conditions.



Transpower major grid projects

Many of these tests required particular levels of power transfer across the HVDC for short periods of time (usually less than one hour), and often needed to proceed in a precise order.

The central position of the HVDC within the New Zealand power grid and electricity market, combined with the sensitivity of HVDC transfer to the behaviour of market participants (largely driven by hydrological conditions), meant that waiting for 'natural' market conditions to provide the HVDC transfer required for many of the tests (particularly those requiring a high south or north flow) would be almost futile. Not only would the timing of the right conditions be difficult to predict in advance, there would be no guarantee that conditions would persist long enough to allow the required tests to proceed in the required order, let alone allow Transpower to manage the risk that the test may fail and need to be repeated. Thus, completing testing would be impossible within a reasonable commissioning time frame.

To ensure that test conditions could be met when required by the engineering team, the HVDC flows would have to be managed in some way. There were two approaches considered:

- Regulated management – Changes to the Electricity industry Participant's Code would be required to allow Transpower to physically constrain the HVDC (via the market dispatch model) to "force" the market to achieve the levels of transfer required for a test. This would have exposed industry participants to a significant level of price risk.
- Contracted management – this approach would require Transpower to contract directly with market participants in order to create the generation, reserve (and potentially demand) outcomes to achieve the required HVDC transfer, where natural flows did not provide it. This approach would dovetail into market participants' trading operations, and would compensate those market participants for the effects of changing their intended generation.

Given a desire to commission this critical asset in an industry-wide collaborative manner, Transpower decided to move ahead with the contracted management approach.

New Zealand Electricity Market

The New Zealand electricity market is primarily composed of two co-optimised markets; energy generation and reserve provision. Energy and reserves are offered by participants on a half hour basis. Market gate closure rules prevent changes to offers within 2 hours of the traded market period but participants are free to modify both offered quantities and prices outside of gate closure.

The System Operator uses an optimisation tool (known as the Scheduling Pricing and Dispatch model, or SPD) to produce an overall least-cost generation and reserve dispatch solution for the New Zealand market, with estimated flows on transmission lines, including across the HVDC. It also determines unique market prices at around 250 "nodes" around the grid, where power is bought and/or sold.

Forward looking market schedules (effectively forecasts which include expected price and HVDC transfer) are produced every half hour for up to 7 days ahead.

The tests

The testing regime required over 2,000 tests. The majority of these could be conducted at the Siemens factory in Germany. However, final commissioning and acceptance of the new equipment required that approximately 400 tests needed to be performed in the "live" environment.

The tests themselves ranged from relatively simple tests, such as to provide flows on the HVDC which could vary between upper and lower bounds, to far more complex specifications, requiring very precise flow levels, and/or ramping power flows up and down at quite precise rates. 70% of these tests were less than an hour in length, but a modest number exceeded 6 hours, with the longest being 26 hours.

Consistent with a normal approach to commissioning a complex asset, the testing programme required groups of tests, pertaining to different aspects of the HVDC's capability, to be performed repeatedly at gradually increasing power transfer levels. Further, the commissioning had two major stages – the commissioning of the new Pole 3 equipment ("Stage 1"), to be performed during autumn 2013, and then the commissioning of the upgraded Pole 2 control system to provide integrated bi-pole operation from a single control system ("Stage 2"). Stage 2 was performed over the spring and early summer period of 2013.

Approach

As indicated previously, Transpower pursued an approach where, for as many of the 400 tests needed, it would negotiate contracts with market participants to achieve the range of HVDC transfer required for each test.

Setup

Transpower's roles as Grid Owner and System Operator have historically precluded the need for an active trading presence in the Electricity Market. The high number of HVDC tests, the MW transfer levels required, and the uncertain dynamics of the market environment, implied a capability needed to be established which would effectively mirror the trading operations that were present in generator-retailer market participants. This dynamic capability needed to cover analysis, negotiation, and communications.

The more substantive change for Transpower would be its exposure to financial risk as a result of the financial derivatives which formed the basis of the contract mechanisms (described in more detail below). This exposure to wholesale market risk required policies and processes, including delegated authorities, risk measurement and management, as well as a robust infrastructure for contract capture, approval, and settlement which could handle a number and frequency of contracts not experienced by Transpower previously[1]. This infrastructure would have to satisfy good industry practice requirements and subsequent audits that would be faced by any trading function[2].

To aid in the transition to the required capability, industry experts Reunion Asia Pacific were engaged to develop the infrastructure and provide skilled and experienced resource in key areas of the contracting process[3].

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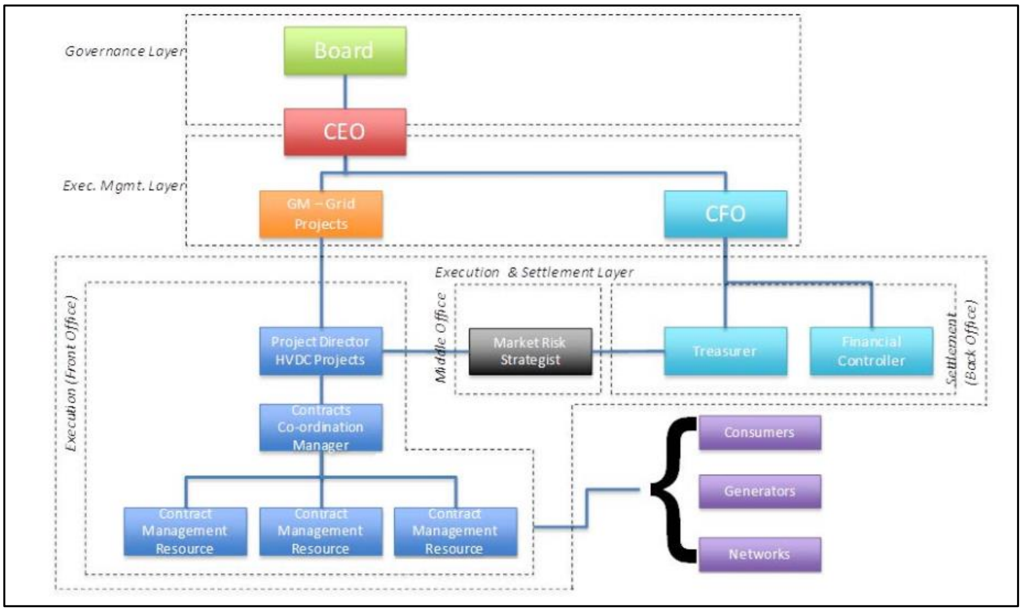
[1] It was our view at the time that the number and frequency of contracts required for the commissioning would exceed that experienced even by any established market participant, largely due to the fact that Transpower was contracting with multiple parties in a single trading period.

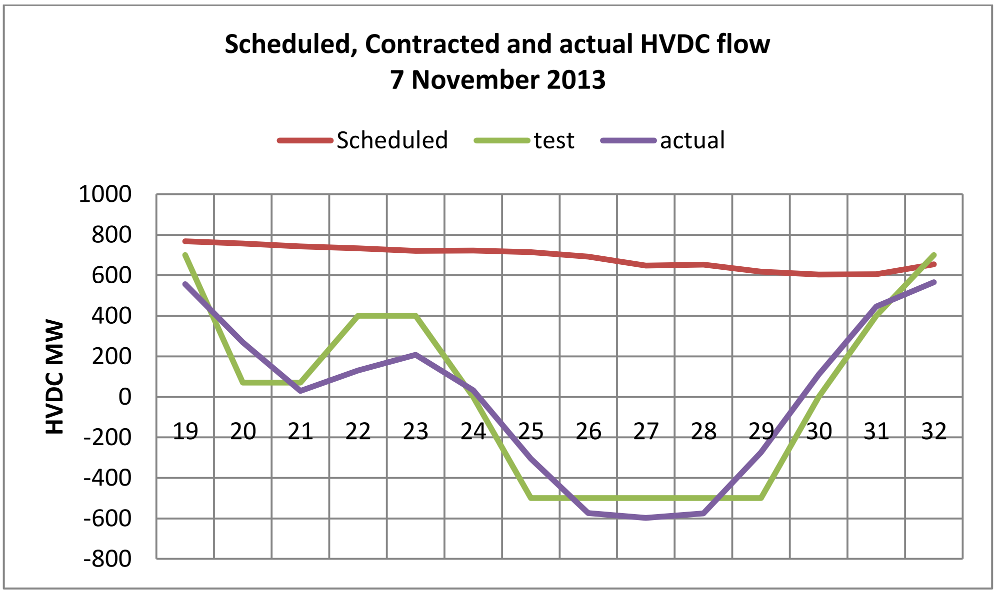
[2] Whilst Transpower had an existing Treasury function, it was not intended to manage the frequency and type of contracts envisaged for the HVDC commissioning.

[3] Reunion's Principals were made up of ex-senior managers of one of the market participants, and had extensive experience across wholesale markets, derivative trading and risk management, as well as transmission. Whilst Reunion resource would occupy a number of key positions within the contracting team, responsibility for the overall management



Transpower trading and governance structure for HVDC commissioning trading

The Trading Team consisted of a "front office" analytical team whose primary task was to predict what "natural" HVDC transfer would take place during an upcoming test, and thus deduce the degree of "shift" required (through contracting with market participants) in order to satisfy the test requirements. The team also included dealers, who gave effect to the recommendations of the analysts by negotiating the contract instruments with market participants to achieve the market change.



In line with good industry practice for trading operations, Transpower established two additional (separate) teams: a "back office" function which communicated with market participants to confirm the contracts engaged, as well as calculating the settlements due to

and approval of the trading would reside with Transpower (as it was Transpower that was exposed to the financial risk associated with the derivatives).

each party; and an independent “middle office” function which observed the trading undertaken by the front office, measured and reported risk, and provided an independent view of the value/risk trade-offs being undertaken by the front office.

Contract Forms

The contract forms needed to provide the correct incentives to generators to adjust their production plans with sufficient confidence that the test could be scheduled and completed. This included "fine tuning" contracts with those few participants in the wholesale market who were permitted to vary output in real time.

The main deal types enacted were:

- Contract for difference (CfD) – a pure financial contract where a contract quantity and price was negotiated for the period concerned. However, as pure financial arrangements, these instruments did not guarantee any particular physical outcome from a generator, but rather provided a financial incentive for generators to vary their output. The exact degree of variation depended on variables beyond the visibility and/or control of the trading team, for example; fuel position (including water value) and other financial commitments. These instruments were relatively imprecise in terms of achieving specific generator output.
- Contract for difference with physical condition (CfD with Physical) – a similar structure to the pure financial CfD but the contract price component depended on the counterparty meeting a physical condition on generator output or reserve offers. This was achieved by including two prices in the contract – a “knock in” price if the physical condition was achieved by the counterparty and a less favourable (to the counterparty) “knock out” price in the event that condition was not met. This provided a degree of precision and confidence for Transpower that was not provided by the pure CfD. Consequently, the cost of securing a CfD with Physical was generally higher.
- Capacity fee – a contract which provided a fixed fee for providing availability of a service, e.g. the operation of a large generating unit. Capacity fees were used to compensate counterparties for their fixed start-up costs associated with making plant available.
- Wind dispatch agreement –Wind generation was a source of significant real-time variability, but also was permitted under the Code to change its output within the 2-hour gate closure. This created a potential option to manage the effects of real-time variation in demand (and wind itself) on HVDC transfer[4].
- Fixed term agreement - These contracts were used for counterparties that were generally contracted less often and usually for a single service that did not require

[4] During the analysis phase, required levels of generation for hydro and thermal plant were determined assuming no wind generation. Thus, any wind generation in the sending island of the HVDC link would increase the HVDC transfer. If wind generation in the receiving island was too high, it could be managed down in real time to achieve the required test flow.

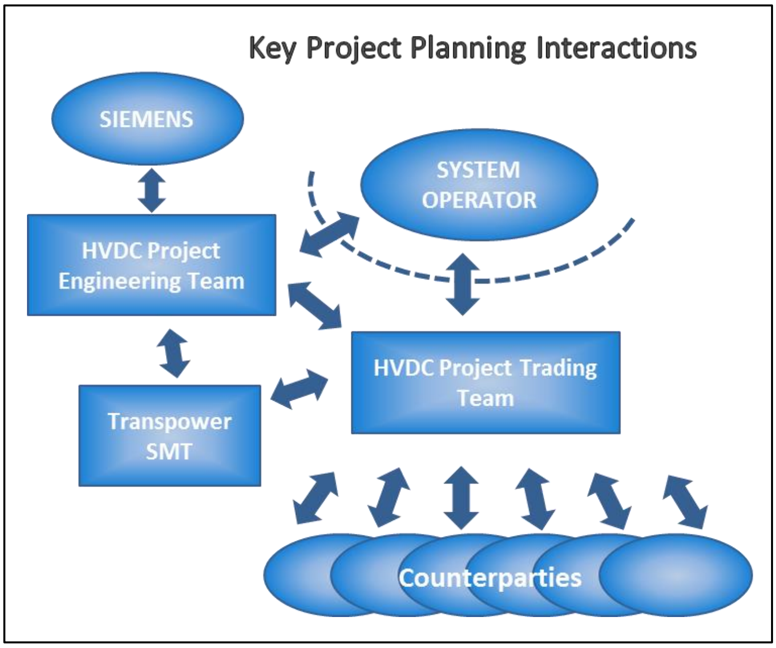
significant flexibility. These parties included load control participants (lines companies) and interruptible load reserve providers (industrial demand).

For the main counterparties, a standard International Swaps and Derivatives Association (ISDA) agreement was used; an agreement the counterparties traded frequently and were most familiar with. The ISDA set out a known and standardised framework under which each contract could be agreed, but was flexible enough to allow individual parameters (e.g., price, quantity) to be adjusted to suit the type of test and market conditions at the time.

Scheduling the Tests

Leading into the commissioning, there was a significant amount of planning and analysis required by a number of parties. Looking from the Transpower Trading team perspective, there were four key groups that were interacted with throughout the commissioning:

- Project Engineering Team (internal).
- Senior Management Team or SMT (internal).
- System Operator (external).
- Trading Counterparties/ market participants (external).



The critical document supporting the interactions was the Test Schedule. This set out the intended plan for testing over the commissioning period and was revised and republished to the industry throughout the project.

Beyond the schedule, each individual test had a detailed plan. Each test plan required review and sign-off in advance of testing (by the engineering team, Siemens, the System Operator and the trading team). The trading team in this process had to understand what was required from a market perspective, ensuring that it was achievable and seeking to understand and communicate market risks.

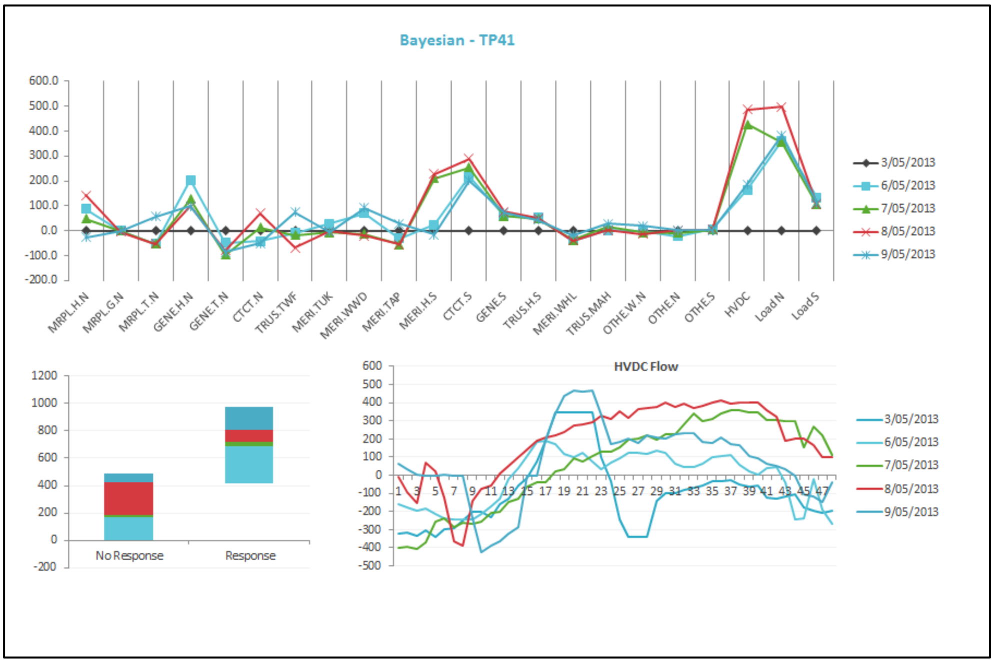
The schedule remained a ‘fluid’ document throughout each commissioning phase. This was driven by the level of re-testing required (24% and 13% of contracted tests were re-tests for Stage 1 and Stage 2 respectively) and the evolving test requirements as commissioning progressed.

Analysis

In a system where half hourly demand varied between 3,000 MW and 7,000 MW, achieving desired testing ranges of +/- 100 MW, even for short periods of time, proved challenging. Theoretically, if every generating plant in the system (except the frequency keeper) could be contracted to provide a specific output, the only residual variation would be demand, which – within each island – would be managed by the frequency keeper. However, such an approach would be immensely costly, time consuming and difficult to achieve in practice. The decision-making process became one of trading off the acceptable variation and uncertainty in HVDC flow for a given test, with the cost and difficulty of contracting. Hence the analytical process needed to highlight which generating plants, or demand regions, were creating the greatest uncertainty, implicitly generating a “merit order” of contracting.

One modelling challenge was that highly conditional nature of variability: variation in demand and wind output were highly contingent on the weather conditions persisting at the time, while hydro output was – to some extent – dependent on storage and the inflow patterns that had been present in recent weeks. For larger generators, their net financial position (which is not visible to the market) was equally important as a driver, and changed on a daily basis. This rendered much of the available historical data irrelevant to the prediction challenge.

An analytical tool, provided in Excel (illustrated below), was developed which attempted to capture this conditionality by isolating the variation caused in recent HVDC flow by each individual system element (demand, generation), thus establishing an a priori distribution.



This allowed the trading analyst to establish whether this prior distribution was reflective of the conditions expected for the test (e.g., by seeking weather forecasts, adjusting for plant outages etc.), thus providing posterior adjustments. Finally, if the level and/or variation in the resulting HVDC flow did not meet the requirements of the test, then contracting with market participants was necessary. The degree of change required of generators was provided to the dealers.

Real time monitoring

Another role of the trading team was to monitor the expected HVDC transfer as the test approached. All market participants can see forecast flows via the System Operator's published schedules. Schedule monitoring would start as soon as contracts with participants were confirmed and continue through the period of testing. Some contracts included the option to make limited adjustments to contracted physical volumes up to 2.5 hours ahead of real time. This gave the trading team the ability to adjust the generation levels prior to the test, and prior to gate closure, to allow for unexpected changes in forecast market conditions.

Contracts developed for real-time flow management (demand response and wind). These options had a short lead-time (between 5 and 10 minutes) and thus required a high degree of precision in terms of monitoring flow during the test.

Challenges

Stage 1 was largely conducted during autumn. During this time the inflows into the hydro reservoirs were very low, affecting the sustained availability of hydro generation needed to support high HVDC transfer tests. In contrast, Stage 2 was completed later in the year, by which time the hydro storage situation had turned around to the opposite – very full storage reservoirs. Where Stage 1 was impacted by scarce resources, Stage 2 was impacted by a relative surplus of water, with generators wanting to release water in advance of snowmelt and future lower demand in summer.

In order to prove the maximum capability of the HVDC, a number of tests required transfers of 700 MW or more in either direction. For Stage 2, these were scheduled for late spring when market conditions had substantially reduced the availability of thermal plant. In this environment, even relatively small changes in demand, due to e.g. irrigation, could significantly increase the risk of high flow tests being unachievable.

Substantial planning, analysis (and often re-work) was required for the tests, and a large number of contracts were negotiated with multiple parties, in some cases up to 10 parties were contracted for a single test.

Factors key to success were:

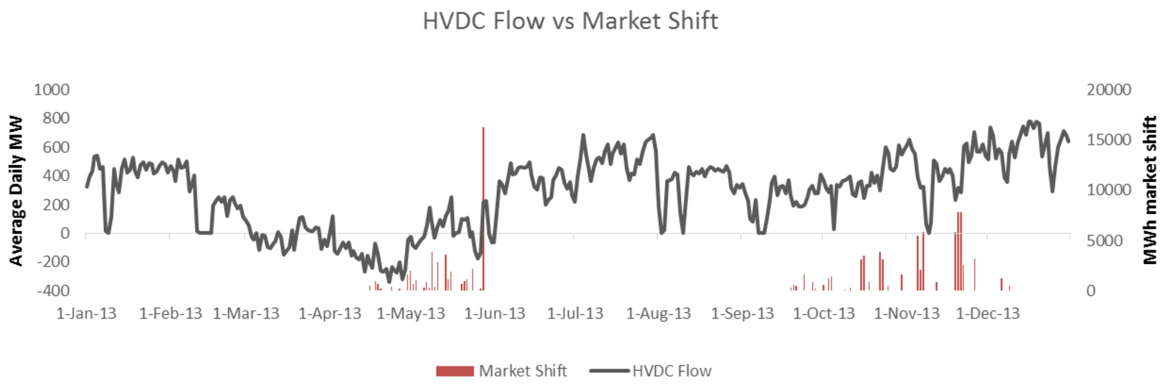
- Advanced planning and analysis – identifying the limitations on tests early.
- Freeing up constraints – where modelling analysis indicated that a test was limited by a transmission outage, deferral of such outages would be explored.
- Timely Communication – ensuring that all parties had a clear understanding of the targeted HVDC flows for the test and the contractual arrangement in place for them.
- Trusting the incentives – appreciating that the contractual arrangement with each party would provide sufficient incentive for them to deliver.
- Good will – the majority of parties being contracted for the testing were supportive of the HVDC upgrade project. Thus, there was a level of goodwill in the market to help ensure the successful delivery of test requirements.

The Outcome

In May 2013, after 163 contracted tests, Pole 3 was successfully commissioned into the market, in time for the critical winter period. Commissioning of the final Pole 2 interface and control system was achieved on 9th December 2013 after a further 165 contracted tests.

Over the combined 6 month commissioning period, the trading team successfully conducted 328 contracted commissioning tests, including 60 retests. This equated to around 5 tests for each day that testing took place – a high level of activity for the team given the amount of effort required to plan and execute each test. Only 3 tests needed to be repeated due to not achieving the required HVDC transfer. Despite some doubts from industry participants about the likely success of the contracted approach, the successful commissioning – with less than 1% failure rate resulting from inadequate contracting - showed it to be enormously successful.

In terms of the impact on the market, the contracted tests took a total of 270 hours, where the longest individual test was the heat run for Pole 3 in Stage 1 (26 hours). While a difficult metric to calculate, we estimate that a total of 120 GWh of "market shift" occurred (deviation of HVDC flow from its natural position), only 0.5% of national demand over the commissioning period. The greatest degree of market shift occurred during Stage 2, largely as a result of the much higher flow targets (north and southwards) that were required to test the Bipole control system. By the time these high-flow tests were required (November 2013) natural HVDC flows were strongly northwards as a result of hydrology. Hence, the high south-flow tests conducted between 7th and 21st November were challenging to contract. These 5 tests alone required 28 GWh of market shift. That said, the heat run alone at the end of Stage 1 required approximately 15 GWh of market shift.



Probably the most remarkable statistic is that 1,179 deals were negotiated over the commissioning period. This does not include standing arrangements for load control. This means that, on average, the trading team were concluding 5 deals per day for Stage 1, and a remarkable 8.3 deals per day for Stage 2. The higher Stage 2 figure partly reflects higher flow tests (since Pole 3 was already "proven") as well as the need for more reserve contracts at higher flows. As a counterpoint, the entire industry transacted 721 over-the-counter contracts in all of 2012[5], a rate of 2 per day spread across all market participants.

[5] Contracts disclosed to electricitycontract.co.nz. We used 2012 as a comparative metric, since the 2013 figures would have included all the commissioning contracts. As a reference, there were 1251 over the counter contracts disclosed in 2013.