SRC - Power System Performance

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System Operator

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SYSTEM OPERATOR

Keeping the energy flowing

TRANSPOWER

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1 Power system performance - strategic issues

The System Operator is pleased to present this briefing for the inaugural meeting of the Security and Reliability Council, April 2011. In this briefing we seek to outline the System Operator's view of the strategic drivers and issues that will impact the Electricity Supply Industry, power system performance and the System Operator's ability to deliver against its principle performance objectives in the medium term of the next 5 years. The briefing is divided into four sections two describing the System Operator's environment and two describing the issues and an overview of the System Operator's workplan in light of the environment and issues:

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2 Regulatory Context

The Electricity Industry Act 2010 establishes Transpower as the System Operator. The System Operator contracts to provide the services defined in the Electricity Industry Participant Code (the Code) through a service provider contract (System Operator Service Provider Contract, SOSPA) with the Electricity Authority (the Authority).

2.1 The System Operator role

The main roles of the System Operator are set out in the Electricity Industry Participation Code (the Code) and include:

- Part 7 (system operator), which covers the System Operator's principal performance obligations; the functions of the System Operator in relation to security of supply and supply emergencies; and the System Operator performance review.
- Part 8 (common quality), which covers the performance obligations of the System Operator.
- Part 9 (security of supply), which provides for the System Operator's management and co-ordination of planned outages as an emergency measure during energy shortages.
- Part 13 (trading arrangements), which provides that the System Operator prepares and implements schedules, and prepares and publishes forecast prices, forecast reserve prices, dispatch prices and real time prices.

The principal performance obligations of the System Operator under Part 7 are to act as a reasonable and prudent System Operator in:

- Dispatching assets made available in a manner that avoids cascade failure resulting in loss of demand

- Maintaining frequency and frequency time error within defined bands, and restoring it if necessary[1]

Notably these objectives are to maintain security as a priority over reliability, and as a priority over economics. However the System Operator must observe the dispatch objective in Part 13, of maximising the gross economic benefits to all wholesale purchasers of electricity, less the cost of generation and ancillary services, subject to the capabilities and offers of asset owners and subject to achieving the principal performance obligations.

The System Operator prepares also, through the Authority:

- A policy statement
- A security of supply forecasting and information policy
- An emergency management policy

that are incorporated by reference in the Code. The policy statement describes how the System Operator intends to meet its principal performance obligations and the dispatch objective, and addresses any conflicts of interest that arise.

2.2 Self-commitment market design

The Code defines a self-commitment market. The Code does not require generators to build or offer capacity, nor is there a requirement for market participants to contract for a predetermined portion of expected electricity demand. In other words attaining the desired security standard is dependent on the commercial incentives on generators to build and offer capacity or demand to respond to price. Historically, adequate generation capacity has been built to meet demand, but capacity has not always been offered when required.

3 The System Operator's Approach

In keeping with the Electricity Industry Act, the Code and SOSPA, the System Operator's stated purpose is:

'*To deliver a secure power system and an efficient electricity market to support New Zealand's economic and social wellbeing.'*

We acknowledge we will be judged on our results. In focusing on our approach and results, we abide by 'The SO Way', meaning that we:

- Make SO an excellent place to work
- Listen and talk with customers
- Know our stuff – we are competent
- Demonstrate leadership at all levels
- Are willing to be held accountable
- Demonstrate issue and subject ownership
- Are approachable, proactive, positive and innovative

4 Strategic Issues

A number of the grid owner's initiatives, identified in Transmission Tomorrow, and some market and industry trends, will require changes to System Operator software systems and procedures.

[1] *Also, to identify causes of participants' problems with harmonic levels, voltage flicker levels and negative sequence voltage.*

This section looks ahead into the medium term of around three to five years and beyond, and does not cover governance and commercial issues relating to the SOSPA.

4.1 Managing a more dynamic grid

As System Operator, we have to operate the grid as offered by the grid owner. Recent and planned grid investments, and the grid strategies outlined in Transmission Tomorrow, signal a move to a grid that runs closer to absolute thermal limits. It achieves this in large part through greater reliance on special protection systems to run-back generation automatically if required, and through much increased use of reactive compensation. The many new and planned reactive support devices will be managed by regional reactive power controllers (RPCs). These devices are reliant on the designer programming in the correct responses to all operating scenarios, and reprogramming them as the power system evolves. The technology is impressive, but an inevitable consequence is the future grid will contain incipient risks that will be difficult to manage as the power system evolves.

Other grid initiatives will allow and require the grid to be controlled more dynamically, that is, closer to real time. Variable, then dynamic line ratings will make determining security constraints more challenging. New HVDC control technologies will increase the linkages between the two island grids. This and automatic generation control (AGC) will provide new tools for the management of system frequency. As with the introduction of any technological improvements, the market must commit to using the technology to get the best outcomes.

One critical role the System Operator performs is the calculation of system constraints. The thermal security constraints are now performed automatically, following the recent introduction of the SFT tool. Voltage and transient stability constraints still have to be determined manually – as pseudo-thermal constraints – for the grid in steady state and for each significant outage. These constraints will become more critical as the grid is run closer to its limits. We are investigating tools to support and eventually automate the creation of these constraints.

4.2 Probabilistic or deterministic system operation?

Formerly under Part F of the EGRs and the Electricity Commission, and now under the input methodologies of the Commerce Commission, approvals for grid upgrades require a probabilistic approach. That is, there is no underlying standard (such as n-1, n-g-1 or n-2) for much of the grid. Economic models are used to trade-off capacity against modelled probabilities of unserved energy. In other words, in the planning timescale, material risk of non-supply is now designed into the grid.

At the operational end of the timescale, every effort is made by the System Operator, by the industry, and by politicians to keep the lights on. If necessary, we will run the system without reserves or constrain on expensive generation rather than turn lights off. The ‘bottom line’ is that the last thing we do is turn lights off, and we ignore price in doing so. Considerable efforts have been made to ensure continuity of supply in recent winters and for the Rugby World Cup.

Over time, these two approaches may conflict. How will we operate the system if and when the offered grid is insufficient to supply some load? Market measures such as dispatchable demand may help, but electricity is still regarded by many as an essential service. We could tighten the grid reliability standards, or we could move to more probabilistic system operation, perhaps shedding load against some necessarily averaged value of unserved energy. These are decisions the System Operator does not wish to make in real-time. Development of the Code will be required, involving substantial consultation with the industry and end-use consumers.

4.3 Support of the market

The System Operator manages security but also provides the platform for the electricity market.

Recent high price events have highlighted the volatility inherent in the nodal price system. Be that as it may, the system is optimal for dispatch – it is the only system that aligns commercial incentives on generators with their dispatch instructions. There would be clear security implications in diverging from it. It is the System Operator’s view that nodal dispatch be retained.

Regarding any fundamental changes to the dispatch or market systems, we are committed to a complex suite of automated market systems. Gone are the days of being able to dispatch and run the market manually. Developing the latest systems (introduced two years ago) to meet the requirements of the Code and of appropriate robustness took four years and in excess of $60 million. Any new market developments can in principle be accommodated, but it takes time and resource. Further, as such systems are sourced from a few international vendors, time and cost will escalate the further we deviate from international norms in market design. We are working to avoid such a ‘big bang’ approach to market systems again by progressively increasing the modularity of our systems.

The amount of data created in system and market operations is vast. Phasor measurement units (PMUs) are being introduced to measure grid performance at ever greater resolutions. Within the co-ordination centres we are exploring improvements to our already pioneering visualisation tools, to present the data in manners meaningful to the System Operator. Energy Market Services (part of the Transpower’s system operations division, but not funded through the SOSPA) is improving and expanding its ‘em6’ web information service. Turning the ever increasing quantities of data into information useful to decision makers will be a continuing challenge.

There is a welcome trend to market measures to enhance security. The System Operator supports the current initiatives to enhance the market design in this direction, namely the intended introduction of:

- a scarcity pricing regime
- demand side bidding and forecasting
- dispatchable demand

While still in the design stage and unproven, scarcity pricing is being designed to enhance incentives to build and offer capacity. While dispatchable demand is designed to help the market manage price, we hope it will also help the market attain chosen security standards.

As the financial market matures with increased hedging, and with the advent of FTRs, we expect to be under increased pressure from participants to adjust our actions to suit individuals’ commercial positions (as indeed happened during the recent high-price event). This, of course, we cannot do. We will need to be ever more black and white in our decision making as the financial consequences of our actions to the market increase.

4.4 The evolving generation mix

If significant penetration of wind or other intermittent generation occurs, this could cause problems in balancing the system, and there would need to be rapid evolution of security and market systems to accommodate it. Work to date indicates that up to 2000 MW of intermittent generation is able to be integrated into a 10,000 MW system (ours is currently 9000 MW) without substantial additional cost. While significant penetration of wind remains possible, recent trends indicate that other plant especially geothermal is likely to be next in line. Intermittent generation has its own issues such as reduced inertia, storage and firming requirements that must be assessed for future impact on system operations.

There remains a broader issue regarding the mix and location of generation in the fleet. This is exacerbated with concerns of the future of Huntly generation, which has long held a pivotal place in the system, and the aging of other key plant. The generation investment market is reliant on commercial, price-based incentives. To maintain security and reliability, these incentives need to result in an appropriate mix of base load and flexible, fast start plant, and at appropriate locations. Given the long lead time of generation investment decisions, consideration needs to be given to whether the current pricing incentives achieve this with sufficient certainty. From an overall energy and capacity perspective we agree with the Authority's intent to introduce scarcity pricing before further considering capacity markets, but remain concerned over issues of the evolving generation mix.

4.5 Enabling customer response

The System Operator is working with Transpower as grid owner to secure and operate some 60MW of responsive load in the upper North Island through grid support contracts, to assist with meeting load and managing outages as the new grid projects are commissioned. This load can be called by the System Operator in response to system conditions, an approach that builds on the upper South Island trials of 2007 and 2008. In addition, we have supported the introduction of load controllers in both regions.

We support the concept of dispatchable demand as not only a means for demand to manage price risk, but also as a security product, and are engaging with the Authority to help this product achieve its potential. Once implemented, we see grid support contracts evolving to contracting with parties to bid into the dispatchable demand market.

4.6 Industry organisation

The amount of embedded generation (such as cogeneration, medium-sized thermal plant and renewables) is increasing. Load characteristics are changing with increasing penetration of non-inductive load such as heat pumps and air conditioners. The future impacts of smart grid technologies at the retail and distribution level, and perhaps of electric cars, are unclear. Activities within distribution networks have increasing impact on the system, and the System Operator needs the tools and means to look beyond, and in some cases control beyond, the grid exit points.

The industry currently has many layers of control. The System Operator has one co-ordination centre, shared between Hamilton and Wellington. Transpower has three regional operating centres, and still operates some low voltage and customer-specific assets the natural owner of which would be the distributor. Most of the 28 distribution companies have their own control centres.

There would be significant gains in security and reliability - and probably in direct costs - in rationalising the levels of control within the industry, with a move to perhaps five distribution control centres (in addition to Transpower's), and extending the outreach of system visibility.

5 Overview of System Operator's Work Program

The following significant current or forthcoming initiatives are on the System Operator work program. It is not an exhaustive list of all projects.

These initiatives are additional to our main focus on the continuous operation and continual improvement of our business as usual activities. Much of the work, especially where Code change is involved, is carried out in close coordination with the Authority.

- Managing the grid owner's introduction of area-wide reactive power controllers (RPCs) and reactive power devices
- Managing the commissioning of the major grid investments, the most technically challenging of which is HVDC Pole 3, and introducing new HVDC controls to manage transmission north of Wellington
- Managing the introduction of variable and then dynamic line ratings
- Improving systems to monitor and manage voltages and transient stability issues and constraints , including optimising the use of new systems to monitor electricity system dynamics
- Updating our SCADA applications (which are approaching end of life)
- Improving under-frequency management, including AUFLS and instantaneous reserves products
- Improving our load and wind forecasting
- Introducing the systems and processes necessary to support the Authority's market development initiatives, including:
  - Demand-side bidding and forecasting (DSBF)
  - Dispatchable demand
  - Financial transmission rights (FTRs)
  - Scarcity pricing
- Supporting the systems and operational control of up to 60 MW of demand-side response in the upper North Island, and load controllers in the upper South and North Islands.
- Improving visualisation and information provision
- Introducing automatic generation control (AGC)
- Progressively improving the modularity of our market systems.

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