Automatic generation run-up to increase transmission capacity: A case study and lessons for the future

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Abstract

Transpower developed a scheme to increase the transmission capacity for power flow south from the Waitaki Valley to Roxburgh for use during the extended outages to reconductor the Clyde–Roxburgh circuits. The scheme automatically runs up generation at Manapouri if a circuit overloads. The scheme was developed in cooperation with Meridian and after industry consultation and agreement.

This paper describes the development of the scheme: system studies, checking equipment limits, changes to the tools and processes within the system control centre, generation and scheme testing, and implementation.

Issues with generation frequency response and managing the power system in real time means it is unlikely schemes which automatically run up generation will be widely applied at present. Technical and industry changes will be required before automatic generation run-up could be used more widely in future.

1. Introduction

Transpower has a project to increase the capacity of the Clyde–Roxburgh circuits by replacing the original simplex zebra conductors with duplex zebra conductors. Figure 1 shows a simplified representation of this part of the power system.

Replacing the conductors requires the circuits to be out of service for four – five weeks each, which reduces the transmission capacity. Therefore, to supply the load off-take in the Otago–Southland area, the minimum generation required within the area increases and the maximum possible generation export from the area decreases.

The greatest concern was the increase in the minimum level of generation required and the potential this had to delay the outages for replacing the conductors. Therefore, the option of operating the transmission system beyond its normal capacity by using a Special Protection Scheme (SPS) was investigated and implemented.

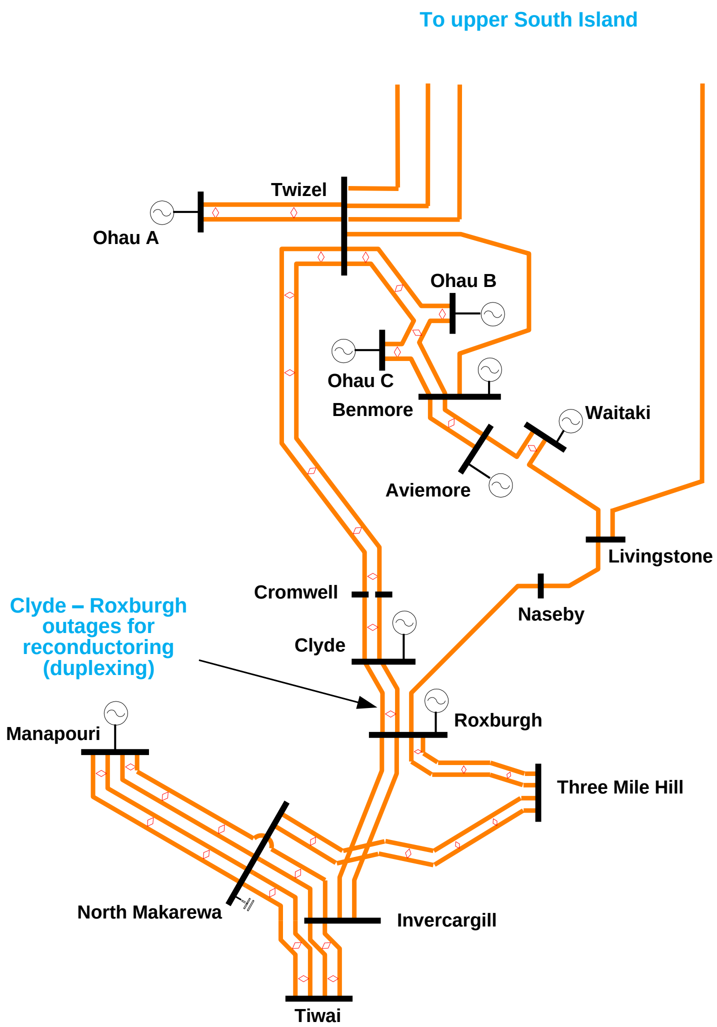

Figure 1: Lower South Island power system

2. Special Protection Scheme Concept

A number of obligations are placed on the System Operator to manage the grid. A simplified description of one obligation is to operate the power system so that, should a circuit trip, all other circuits remain within their capacity. The principal method to meet this obligation is to apply minimum and maximum generation limits.

With one Clyde–Roxburgh circuit out of service, generation is constrained so that should the second Clyde–Roxburgh circuit trip, none of the remaining in-service circuits overload. This is the most onerous contingency. Without a generation constraint, there is a risk the Livingstone–Naseby–Roxburgh circuits may overload, followed by the risk of overloading the Aviemore–Waitaki–Livingstone circuits. The transmission capacity is about 550 MW with all circuits in service and about 200 MW with a Clyde–Roxburgh circuit out of service.

The SPS concept is to relax the generation constraints and monitor the loading on the Livingstone–Naseby–Roxburgh circuits. If the loading exceeds a pre-defined value, automatically run up generation to reduce the loading on the circuit. Key aspects of the SPS concept were checked to be confident it would perform as desired, was practical to implement and would operate in the real world. These were:

- the system dynamics following the circuit trip and during the generation run up
- the short term rating of equipment during the generation run up
- integrating the special protection scheme into the planning and real time tools and processes used by the System Operator
- when to enable the special protection scheme and industry consultation
- practical implementation.

3. Dynamic Studies

A 1 MW generation increase in the Otago-Southland area will not reduce the loading on the Livingstone–Naseby–Roxburgh circuits by 1 MW due to governor action of all generating units connected to the power system. The change in circuit loading depends on which generating units are connected within the whole power system.

Dynamic simulation studies showed it was possible to increase the transmission capacity from approximately 200 MW to 300 MW. The 100 MW increase in transmission capacity required a 200 MW run up in generation. This result was stable for a representative range of load off-take and generation scenarios.

A representative result of a dynamic study is shown in Figure 2. A Clyde–Roxburgh circuit is out of service for reconductoring, the other circuit has a simulated fault and is tripped, and the current on the Livingstone–Naseby circuit is monitored (maximum steady-state summer rating 530 amps). Features to note from the figure are:

- the current prior to the simulated fault is only 270 amps
- the current has a high transient value (1240 amps) decaying in 20 seconds
- the current ramps down as the generation runs up to 200 MW in 60 seconds
- the final current is 580 amps

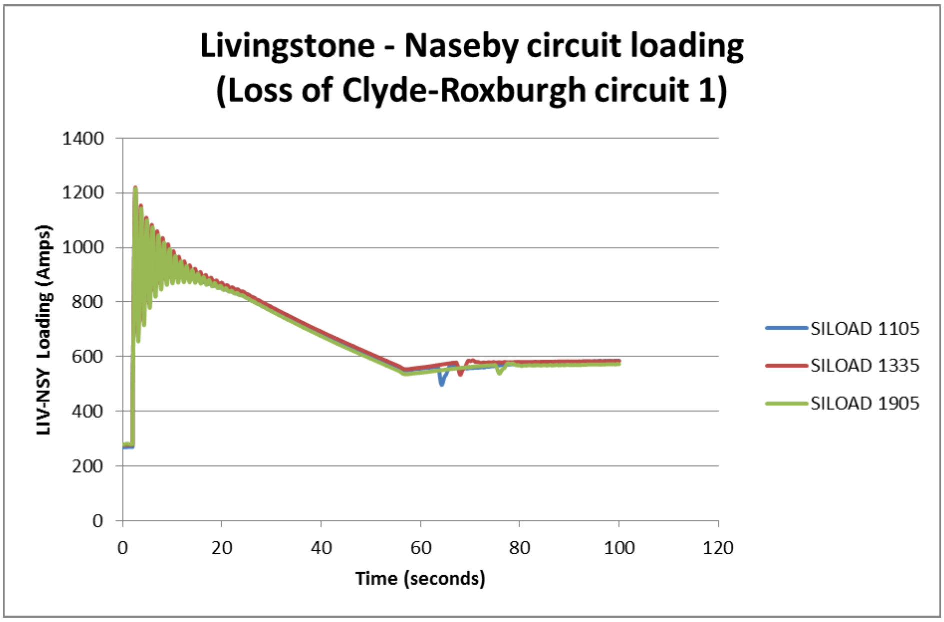

Figure 2: Livingstone–Naseby circuit loading during SPS operation

The line protection settings must be well above the transient current to prevent unwanted protection operation. The original protection settings on all circuits which could overload (Aviemore–Waitaki–Livingstone and Livingstone–Naseby–Roxburgh) were below the peak transient current. All line protections were reset to be well above the peak current without compromising protection setting standards.

The conductor is below its maximum operating temperature prior to the fault. Modelling the thermal inertia of the conductor showed it remained below its maximum operating temperature after generation run up. The current is above the steady-state rating, but there is sufficient time for the operator to take remedial action before the maximum operating temperature is reached.

Some substation components have a steady-state current rating less than the maximum current which flows during the generation run up (e.g. some current transformers and disconnectors). It is difficult to get good thermal models of these components. However, these components have a 31.5 kA / 3 seconds (2.98×10^9 Joules) fault current rating. The heating during the generation run up is comfortably less than the capacity of the equipment to absorb the heating due to fault current.

Therefore, the protection settings and the thermal rating of the line conductor and substation equipment did not prevent implementation of a generation run up scheme.

Increasing the transmission capacity more than 100 MW was not investigated to any great depth. This was principally because for some load off-take and generation scenarios the thermal capacity of the conductor was exceeded.

4. System Operator's Tools and Processes

Overview

A simplified description of the existing Market Systems and Security Tools used by the System Operator follow. The incompatibility of a generation run up SPS with the Market Systems and Security Tools is then described, followed by how the Manapouri generation run up SPS was managed by the System Operator.

The Market Systems consist of two main programs used to formulate dispatch: Scheduling Pricing and Dispatch (SPD) and Simultaneous Feasibility Test (SFT). Together, these two programs ensure generation is dispatched to supply the load at least cost, while respecting transmission constraints. Most of the process is a mixture automated and manual procedures, such as receiving generation offers and issuing generation dispatch instructions. Manual constraints need to be entered and enabled / disabled manually where SFT cannot model an SPS.

The Security Tools are a suite of programs, one of which is Real Time Contingency Analysis (RTCA). It runs in parallel with SPD/SFT. RTCA is one of the primary tools to ensure the power system is in a secure state in realtime. RTCA uses realtime data from SCADA and raises an alarm if a contingency (outage due to a fault) will result in equipment overloading. SPSs must be enabled / disabled manually in RTCA.

An enhanced application program, Remedial Action Scheme (RAS), provides detailed modelling of SPS actions in the Market Systems and Security Tools. RAS has been in 'parallel operation' for some time, where it receives all data but its output is only displayed to the System Operator and not inputted to SFT or RTCA. RAS will be connected to SFT and RTCA later this year.

Challenges to be addressed

It was identified early in the Manapouri generation run up SPS investigation that there were several challenges for the System Operator to resolve before Transpower could commit to implementing the SPS. These included:

- modelling the SPS in the Security Tools (RTCA)
- modelling the SPS in the Market Systems (SPD and SFT)
- determining criteria to enable the SPS
- managing offers for the SPS

These challenges are discussed below.

RTCA cannot differentiate between transmission constraints due to power flow into (import) or out of (export) the Southland area. A transmission constraint violation during generation export would be correctly identified. RTCA would then model operation of the SPS and increase generation export by 100 MW, worsening the violation even though the SPS would not operate in practice. Thus the output of the Security Tools would be invalid, which is not tenable. RAS can detect the direction of power flow and be used to control RTCA. Therefore, RAS was enabled for the Manapouri generation run up only, which resolved this issue. A second issue was that RAS/RTCA cannot model generation run up; it simulates a loss of load as a proxy.

For a generation run up SPS to operate within the Market environment, Meridian were required to have 200 MW of generation available to clear should a contingency occur. However, it was possible SPD would dispatch this generation pre-contingency and so not available to the SPS. Several options were considered, including creating a new market node or the use of Market node constraints. The most practical approach was for Meridian to manage its generation offers to ensure 200 MW of generation was always available, or otherwise withdraw the SPS offer.

RAS could not be linked to SFT in time, so the Market Systems would not correctly model transmission constraints. Therefore, 24 constraint equations were derived manually and enabled/disabled manually. Also, enabling/disabling the SPS was not linked to any other process, such as removing and returning a circuit to service, so a separate ad hoc manual process was created to manage the scheduling and modelling of the SPS.

The SPS could not be armed for the whole duration of the Clyde–Roxburgh outages as this would greatly restrict generation flexibility. Therefore, criteria for using the SPS were developed, discussed in Section 5.

To enable/disable the SPS requires a number of actions by the System Operator. The actions are mainly manual intervention in highly automated systems or standard processes. The SPS must be manually enabled/disabled in the Market Systems, which affects the market from two days before realtime to realtime operation. SPD and Meridian's generation offers should ensure the generating units controlled by the SPS are not incorrectly dispatched in the schedules, but this still needs to be checked manually by the System Operator. The instruction to enable/disable the SPS control system must be manually issued. RAS had to be manually enabled to monitor the SPS and the enabled/disabled status of the SPS needs to be updated in the Security Tools so that the System Operator can correctly monitor the system in realtime.

Learnings

Traditional special protection schemes such as system reconfiguration, load shedding or generation run back / tripping can be easily facilitated within the System Operator's existing automated tools and processes.

It was recognised that developing, managing and operating the Manapouri generation run up SPS would be technically and work intensive, because the SPS could not be easily facilitated within the System Operator's existing automated tools and processes. The System Operator agreed to implement the SPS as it was to be offered solely for the purpose of supporting the conductor replacement on the Clyde–Roxburgh circuits and the Grid Owner proposed to offer the scheme during these outages only.

Special protection schemes which automatically run up generation will continue to be technically and work intensive even after RAS is fully commissioned and integrated into the Market Systems later this year. This is because assessing the criteria when to enable a generation run up special protection scheme is not automated, managing the status of offers into the scheme requires a robust system to manage or significant simplification of the operational agreements. Checking that SPD does not dispatch generation available for run up is not automated. Given the significant economic value in the least cost dispatch of generation and other services in the market and the importance of system security, it is not desirable or sustainable at present for generation run up special protection schemes to become the norm. Significant development of the System Operator's tools would be required before generation run up special protection schemes could be routinely used.

5. Enabling and disabling the SPS – Industry advised criteria

The System Operator and Meridian formulated draft criteria to offer and enable the SPS for service. The aim was to not unduly restrict Manapouri generation, give advance notice to other market participants to ensure stability and certainty in the Electricity Market, and be practical for the System Operator to manage. Meridian determines when it offers two Manapouri units on TWD into the scheme.

The proposed enabling and disabling criteria for the scheme were:

- enabled where the daily average Manapouri generation is below 350 MW and forecast to remain below 350 MW in the forward schedules, and where the forward schedules indicate binding or near binding (i.e. >80%) constraints into the Southland region for consecutive days
- two business days' notice will be given when the scheme is to be enabled
- once enabled the scheme would be active for a minimum of 72 hours

- disabled only on one day's notice except in the event of a grid emergency, force majeure or other bonafide reason
- if Meridian withdraws the offer for units on TWD within two weeks of enabling the scheme, the scheme will not be re-enabled for at least three business days.

On receiving an offer from Meridian for two units on TWD for the SPS, the System Operator has 4 hours to assess if the criteria to enable the SPS is met. This was manageable for a 'one off' situation, but undesirable in normal day to day operations as there are often other changes in the power system and market in the same timeframe which must also be managed.

The criteria were notified to the industry via an industry briefing paper and forum (see https://www.transpower.co.nz/CUWLP consultation), with positive feedback.

The criteria were revised based on experience. Hydrological conditions were running dry and transfer into the area was becoming constrained, however, the criteria were still not met. Transmission constraints into Southland meant 420 MW was required for significant periods during the day. Also, the market produced varying outcomes for dispatch of the other generation in the Southland area, and both enabling criteria could not be consistently met regardless of the hydrological situation. The following revised criteria for enabling the SPS were proposed and an update issued to the industry on Transpower's website (no objections were received):

- enabled where the daily average of Manapouri generation is below 420 MW and forecast to remain below 420 MW in the NRSL schedules, or where the NRSL schedules indicate binding or near binding (i.e. >80%) constraints into the Southland region for not less than two consecutive days.

The need for a change reflects the complexity of defining such criteria in a market environment where many scenarios may present themselves in real time operation.

6. Generation Tests

The generating unit controls were modified for the SPS. Also, ramping generating units from Tail Water Depressed (TWD) to 100 MW at the required ramp rate of 1.8 MW/sec was a non-standard operating mode for the Manapouri generating units. System tests were required to prove the controls and confirm the units were 'fit for purpose' for the SPS. Testing was on a single unit; there was no need to test two units simultaneously ramping to 200 MW as per the SPS design concept.

The unit controller was programmed to change the set point at a rate of 2 MW/sec (rather than 1.8 MW/sec) as it was expected the unit response would lag slightly due to governor action, control logic limitations and the transition delay from TWD mode to generate mode. Two tests were done at a set point below 100 MW before the 100 MW test, to reduce the potential risk to both the generating unit and the system in the case of unexpected generation response or generation rejection/drop load.

The tests showed the unit did not respond as fully expected, with a considerable lag between generation set point from the controller and generation output as shown in Figure 3. The logic used to control the 2 MW/sec from 0–100 MW resulted in the generating unit output response being ‘dulled’ due to the low proportional and integral gain of the control logic. This resulted in an actual generation ramp rate of 1.62 MW/second instead of the desired minimum ramp rate of 1.8 MW/second.

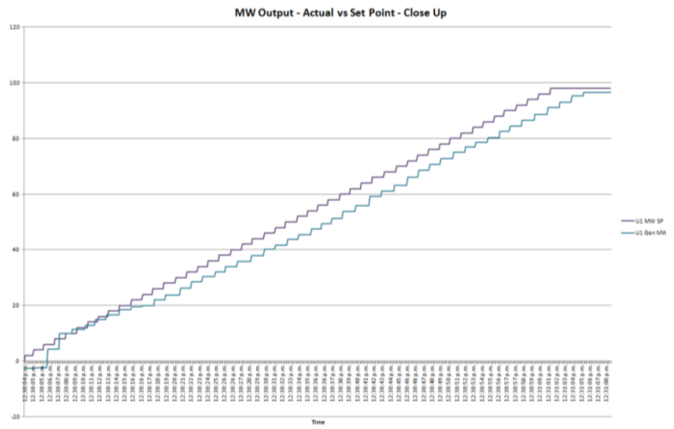

Figure 3: Actual vs Set Point Output for 100 MW test with a Set Point Ramp of 2 MW/s

In order to overcome the unsatisfactory ramp rate, three further tests were done with a 100 MW set point and varying the ramp rate from 2.3 to 2.8 MW/sec. The final test provided a satisfactory actual ramp rate of 2.38 MW/sec as shown by Figure 4. The higher than required generation ramp rate was accepted because it was within an acceptable range from the dynamic studies and it gave a slightly faster reduction in the loading on the transmission system.

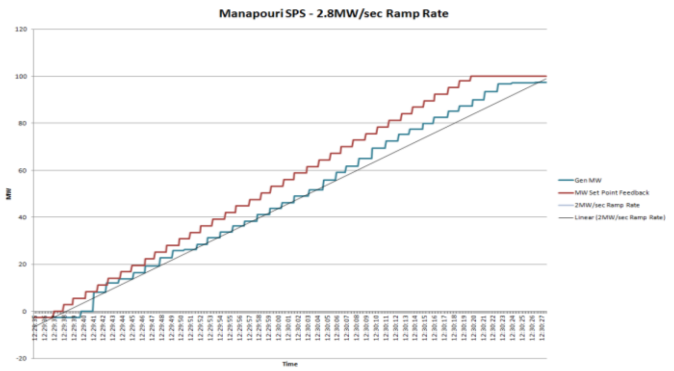

Figure 4: Actual vs Set Point Output for a 100 MW Test with a Set Point Ramp of 2.8MW/s

7. Implementing the Special Protection Scheme

There needs to be a very high level of confidence that the implementation of the SPS will operate as required, when required. This is achieved through a combination of duplicating the components of the scheme, monitoring the health of the components in the scheme, robust control action, and testing.

The full 200 MW of generation run up is used, even when a lesser amount is sufficient to ensure the power system ends up in a safe operating state. It was not practical in real time to match the generation for run up to the amount required to prevent the Livingstone–Naseby–Roxburgh circuit overloading for all operating conditions. The generation run up was most easily available from two of the seven 135 MVA units at Manapouri power station, rather than using more, lower capacity, units at another power station or from more than one power station. This simplified the SPS design.

The SPS at Roxburgh is directional, so it can operate only if power flow is from Naseby to Roxburgh. This System Operator does not need to enable/disable the scheme depending on the changes in direction of power flow during the normal course of a day, eliminating a potential source of error.

The Livingstone–Naseby circuit may overload before the Naseby–Roxburgh circuit, depending on the load at Naseby. The worst case Livingstone–Naseby current was inferred by assuming a worst case load off-take at Naseby and adjusting the over current set point at Roxburgh downwards. This could result in generation run up even with no circuit overload, but this action always leaves the power system in a safe state and, therefore, is a robust control action.

The Aviemore–Waitaki–Livingstone circuits are not monitored by the SPS, as they only overload after the Livingstone–Naseby–Roxburgh circuits overload.

Duplicate protection signalling from Roxburgh to Manapouri was implemented on Transpower's communication system.

The SPS had to be integrated within Meridian's existing generation control scheme and SCADA applications. There was confidence this could be done reliably because using unit(s) on TWD to provide FIR (Fast Instantaneous Reserve) was already implemented at Manapouri, whereby on receipt of a signal the units revert to generate and ramp up. This is implemented in the unit controllers and is separate to the station controller. The station controller holds all other units to their set point, except for small changes in output due to governor action, which is unavoidable. Post ramp up, the station controller automatically sets the current station output as the new station set point. Very similar controls and SCADA applications were used for units on TWD which are part of the SPS, which were proven through generation tests.

Any two of the seven units at Manapouri can be in TWD mode and selected for revert to generate to 100 MW each on receipt of a signal from the SPS. The SPS interface to the unit controller is not duplicated, because the signalling is continuously monitored and alarmed. The most common failure mode for a unit on TWD is to revert to 5 MW and hold, and will still respond to the SPS. Other failures result in a unit trip and alarm. Another unit can be quickly put into TWD mode and selected to the SPS. Therefore, it is not necessary to have three units in TWD mode and selected to the SPS to ensure 200 MW of generation run up.

8. Future Schemes – what would need to change

Automatic generation run up by an SPS changes the system frequency, which causes all other generators to respond through governor action. This in turn causes largely unpredictable changes to the current flow in circuits. A better approach is to coordinate an increase / decrease generation on both sides of the overloaded circuit so there is no frequency change and the overload can be reliably removed. This requires a sub-set of the functionality available from Automatic Generation Control (AGC).

For the System Operator the implementation and operationalization of the Manapouri generation run up SPS was complicated and required 'hands on' management using the current contingency analysis software. This will be partially mitigated when RAS is commissioned and linked to the SFT software later this year. However, RAS cannot directly simulate generation run up due to SPS operation (it simulates a loss of load as a proxy). RAS will need to be upgraded to directly simulate changes in generation due to SPS operation.

The most onerous part of managing SPSs with generation run up is monitoring which generating units are available for run up (i.e. monitoring when generator(s) offer their generation units for the SPS) and assessing when the criteria for enabling the SPS is met. The changes required to the short term planning process, the complexity of the criteria for enabling the SPS, and the need for manual procedures in Market Systems all mean that at present generation run up SPSs are undesirable and unmanageable on a permanent basis.

Therefore, future use of SPSs to run up generation will require:

- coordinated increase / decrease of generation so there is no change in frequency
- an upgrade of RAS to directly simulate generation run up
- industry agreement on simplifying the criteria for enabling the SPSs and upgrade of real time planning and operating tools and processes to automate the management of the SPS
- thorough consideration of what other changes may be required (e.g. perhaps market rules).

9. Acknowledgements

We wish to acknowledge the contributions from our colleagues in Meridian and Transpower in working through all the issues to make the Manapouri generation run up special protection scheme a success. Thanks also to Power Systems Consultants (PSC) for their work on modifying and testing the Manapouri generation controllers.