Multiple Frequency Keepers Project

21/04/2010

SYSTEM OPERATOR

Keeping the energy flowing

TRANSPOWER

Transpower New Zealand Ltd The National Grid

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1 Executive Summary

The Electricity Commission (EC) commissioned the System Operator (SO) to investigate the technical feasibility, cost and timeframe to implement Automatic Generator Control (AGC) in New Zealand. Overall the EC seeks to increase competition for provision of frequency keeping (FK) services through the use of AGC and the creation of a national FK market.

The EC have proposed a staged approach for implementing AGC, with the first stage AGC control of existing FK providers in each island followed by the introduction of a national market via the HVDC and co-optimisation of reserves at later stages. This report provides:

- Some “fleshing out” of assumptions on the strawman FK market design proposed by the EC which will require modification, that were necessary to develop this technical proposal;
- A strawman approach for implementing AGC with details of the proposed interface to generators and the HVDC, including:
  - An estimated time frame for the SO to implement the first stage of AGC (18 - 24 months);
  - A high level estimate of the time frame for the SO to implement the second stage of the multiple frequency keepers project (co-optimisation), (12 months); and
- Suggested next steps to progress this work.

1.1 Precursors to Successful AGC Introduction

1.1.1 FK Market Design Issues

Some significant market design issues need to be resolved before a national FK market can be implemented. These include:

- The specification of an AGC compatible interface; and
- The Rules for offering and settlement of FK services that will need to be incorporated in AGC and market systems.

These issues will need resolution before the AGC specification can be finalised and before we can commence AGC implementation.

1.2 FK Market Design

Inherent in the proposed implementation of AGC are assumptions regarding FK market design. The strawman market design proposed by the EC has largely been incorporated. However, important changes are recommended to make AGC work in the FK market. Suggested changes include:

- The two frequency transfer options for HVDC control (controlled by AGC or responding directly to frequency differences on its own control system) should be kept open;
- The HVDC “offer” into the FK market needs to be resolved with the asset owner;
- Block dispatch will continue as at present but AGC will need real time information at a unit level as to which units are providing the FK service[1]; and

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[1] A related issue, of how to co-ordinate station level dispatch of FK and overall block hydrology requirements also arises.

- Generator participation factors will be based on short term (10 second) ramp rates, determined in real time from generator technical characteristic, rather than offered ramp rates;

The overall FK market design, including the above suggested changes, needs to be accepted by the key players in the FK market (generators and HVDC asset owner) before the proposed FK market can be successfully implemented. It is noted that the proposed FK market may also need changes to the Rules to be implemented.

1.3 AGC Strawman Design

Assuming resolution of the above market design issues we propose an AGC strawman with the following main features:

- Designed for separate island FK markets and, when the HVDC is available, a national market;
- HVDC may be either directly controlled by AGC or act independently, using its own frequency controls:
- Generators provide real time information on unit level availability for FK provision;
- Co-ordination between station level dispatch of FK providers and overall block hydrology management;
- AGC output will account for 5 minute dispatch solutions;
- Absolute MW (setpoint) AGC dispatch instructions;
- FK output signals via ICCP interface is suggested[2]; and
- AGC accounts for generator actual response.

Once the EC has finalised the market design features, the SO can complete the AGC design, scope, costs and time to implement.

1.4 Next Steps

Transpower recommends the EC should:

- Resolve with the HVDC asset owner the frequency keeping “offer” for the HVDC;
- Confirm industry acceptance of the proposed market and AGC strawman designs; and
- Commence a work stream to implement necessary rule changes.

2 Introduction

The EC requested the SO to investigate costs and timing to implement a national frequency keeping market (FK) under the System Operator Service Provider Agreement (SOSPA) contract. The initial investigation is to scope the tools required for multiple frequency keepers, via AGC, in each island. The EC’s vision is that AGC would be a tool to allow the FK market to evolve towards a national market and that the increased competitive pressure from a national market would lower FK costs.

This report sets out a strawman proposal on how this initial (multiple frequency keepers in each island, via AGC) market might be implemented and the broad implications for development of the necessary SO tools. The strawman proposal includes timing to implement the proposed tools as well as details of how the technical interface with Generators and the HVDC might work.

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[2] The SO is interested in specific feedback from stakeholders concerning the preferred form of interface and how this might tie in with future direction for the energy dispatch interface.

This report also looks, in less detail, at how co-optimisation (of energy, reserves and frequency keeping) could be implemented and identifies some of the potential issues with implementing co-optimisation. It provides a strawman approach and time estimate for implementing co-optimisation.

3 Market Design Issues

This section identifies and further explains some of the market issues the EC needs to resolve before AGC is introduced.

3.1 Generator Participation Issues

The SO strawman AGC design proposed in section 4 covers how the SO might implement AGC and the SO's preferences for a generator interface. The EC needs to address generator commitment to the AGC design to ensure successful implementation of the frequency keeping market.

3.2 Co-optimisation Issues

Prior to introduction of co-optimisation (post stage 1) the following market design issues need to be considered:

3.2.1 Market Design - Pminfk, Pmax and FK Offer Form

One issue that may need consideration before co-optimisation is introduced is the form of the FK offer and whether minimum running constraints (to provide frequency keeping) are required.

The NZ energy market design philosophy has been to make minimum operating levels a generator decision rather than an SO decision in scheduling. This is consistent with the decision to have a single market rather than include a day ahead commitment market. So start up costs and minimum operating levels are addressed by generators in how they structure their offer.

However, a different approach has been adopted in the FK market, at present. Generators specify their minimum and maximum operating levels to provide FK (Pminfk, and Pmaxfk), and the SO then has to account for these in its FK selection process. This leads to needing to sometimes constrain on FK providers to provide FK, and hence to FK constrained on costs, or constrained off FK costs when a generator needs to be constrained back to provide FK. Recent changes to the FK selection process has reduced the associated FK constrained on costs by accounting for them in the FK selection process. This could be seen as a step towards co-optimisation.

3.2.2 Impact on of Pminfk and FK Offer Form on Co-optimisation Design

This approach, of requiring the scheduling and dispatch process to account for Pminfk, would require a mixed integer approach to FK co-optimisation (and possibly an iterative solution process as per Singapore). This would make the co-optimisation problem more complicated to implement and increase SPD solution times. This problem would be further complicated when we move to include the new HVDC bipole into SPD as this is likely to require more mixed integer programming (MIP) to account for different configuration options and associated loss and contingent reserve costs. As solution time goes up exponentially with the number of mixed integers included it is possible that the combination of a mixed integer approach for FK co-optimisation and for HVDC could lead to unworkable dispatch processes due to excessive solution times.

3.2.3 *Alternative - Make Pminfk a Generator Offer Problem*

An alternative approach would be for the Pminfk problem to be addressed by the generator in their offer. That is we could adopt the same approach as is currently taken for energy. That is generators would have to reflect the costs of getting up to Pminfk in their FK offer price. Just as they do for PminEnergy at the moment. (A constraint would still be needed in SPD to ensure a generators energy dispatch did not take it above the level it could provide FK). This approach would eliminate constrained on costs for FK altogether but the costs would simply be directly transferred to the FK costs. Overall market costs would not be reduced relative to the first approach.

This alternative approach would have the advantage of simplifying the SPD problem for co-optimisation of FK as mixed integers would no longer be needed and any potential problem, with excessive solve times (especially when we include mixed integers for the HVDC) would be avoided. This is our preferred approach and the strawman co-optimisation proposal is based on this approach.

3.2.4 *Market Structure*

Currently FK costs are very high due to a lack of competition in provision of FK services and resulting market power by the limited number of players.

Mostly this market power is currently manifest in constrained on costs. Improvements in the FK selection process, to include constrained on costs in the FK selection process may have reduced these costs temporarily. However, if the structural problems, in terms of lack of competition, are not addressed then it is likely that market power problems will simply re-emerge in a different guise eventually, such as in higher FK offer prices and costs. It is not clear that co-optimisation will markedly reduce FK costs much beyond what can be achieved by improvements in the current (external) FK selection process.

It is therefore suggested that the EC priority should be to address FK market structure issues, to reduce market power, before it addresses co-optimisation.

3.2.5 *Impact of Market Power on Co-optimised Markets*

The SO has some concerns that if structural market power issues in the FK market are not dealt with before co-optimisation is introduced then there could be potential adverse impacts on the total cost of procuring FK services. We have undertaken some brief studies of how market power in the FK market could impact on the market outcomes under both the current separate and proposed co-optimised energy and FK markets. See Appendix 3 for some worked examples. The following presents some high level results of this brief study.

3.2.6 *Constrained On Offer Price Continues to Impact FK Price*

Currently the constrained on energy offer impacts the FK price under the new FK selection process that takes account of constrained on offers. This will continue under any co-optimisation process that accounts for the need to constrain them up to their Pminfk to provide FK.

3.2.7 *Total Costs May Rise with Co-optimisation*

AGC is intended to allow multiple providers in each half hour and therefore increase competition. However it is not clear how the EC intends to increase supply of FK through AGC. The proposed stage 1 is based on existing suppliers only so may not increase supply sufficiently to markedly increase competition. If FK supply is not increased sufficiently to actually eliminate market power then potentially FK total costs could increase due to both accounting for constrained on in FK selection and possibly dramatically so under some forms of co-optimisation. Now that constrained on costs are included in the FK selection process the FK prices have increased as noted above. If this increased price is spread over multiple providers, rather than just the one provider that needs to be constrained on, then total FK costs may actually increase.

3.2.8 Constrained On Costs Remain

It appears the need to pay constrained on compensation for a generator constrained on to provide FK does not go away when we move to co-optimisation. At least it remains if we still have a constraint within the co-optimisation process in order to bring them up to their minimum operating level to provide FK. That is the constrained on cost arises due to the constraint. This is illustrated by the worked examples in Appendix 2 – Co-optimisation Worked Examples.

3.2.9 Impact Worse Without Pminfk Constraint

The strawman proposal for co-optimisation is that the generator is responsible for getting itself into a position to provide FK (one part FK offer). That is, there is no Pminfk constraint. This leads to them needing to account for any opportunity costs in getting to a position to provide FK within their FK offer, such as the costs of getting to Pminfk. This avoids the need for a Pminfk constraint in SPD and also avoids the need to pay constrained on compensation.

However, as shown the simplified examples in Appendix 2, if a generator has market power it would expect to then be able to be cleared for FK even if it offers at a price sufficiently high to cover the constrained on compensation it would otherwise have earned.

This can lead to very high FK prices with these prices spread across multiple providers, leading to a much higher overall cost.

3.2.10 EC Address Market Power before Implementing Co-optimisation

Overall our conclusion is that the EC needs to address market power issues in the FK market before it requests the SO to implement co-optimisation. That is it may be wise to develop some criteria or measure of market power in the FK market before we move to co-optimisation.

3.3 EC Need to Address Market Issues before AGC Introduced

Given the above key market issues it is strongly recommended that the EC address these market issues before AGC is introduced. Once a final market design is agreed on we could finalise the estimated cost and time to introduce AGC.

4 Strawman Market Design

In developing this strawman proposal for implementing AGC the design of the proposed frequency keeping market has also been considered. A strawman market design is proposed below, and the differences between this strawman and the EC's strawman design highlighted. The EC needs to review and discuss this strawman market design and address each of the market design issues raised by this strawman.

The design proposed in stage 1 the EC's strawman[3] has largely been followed. That is:

§ Implementing AGC as a means of co-ordinating between multiple FK providers in each island;
§ The SO sets technical requirements for FK providers (probably through ancillary service contracts);
§ The FK market is a voluntary market;
§ A half hour market for FK provision based on generator offers;
§ FK offers are multiple band;
§ FK offers are for symmetrical (raise or lower) service[4];
§ FK selection is outside SPD and results in constraints on generators in SPD (with an option for moving towards co-optimisation at a later stage).

However, some changes to the strawman market design proposed by the EC are proposed. These are as follows:

§ We should leave open both options for HVDC control, namely that the HVDC may either be controlled by AGC, or respond automatically to frequency differences between islands;
§ The commercial basis on which the HVDC is included in the FK market needs to resolved with the asset owner;
§ The SO technical requirement would not include any minimum capability (this was implied but not stated in the EC strawman);
§ Generator participation factors will be based on short term (10 second) ramp rates, determined in real time from generator technical characteristic, rather than offered ramp rates;
§ Payment for FK services should include a performance based element;
§ The form of FK offer would be the same as at present (band based, not fan based, and include a minimum and maximum operating level to be able to provide that band);
§ The FK selection process will need to account for energy ramping requirements over the 5 minutes (this was mentioned in the EC strawman but assumed to be taken care of as part of any co-optimisation process);
§ Block dispatch will continue as at present but AGC will need real time information at a unit level as to which units are providing the FK service;

The reasons for each of these proposed changes are outlined below.

4.1 HVDC Control

The currently proposed HVDC control system design includes automatic controls for frequency sharing between islands. Thus the HVDC does not need to be dispatched for frequency keeping by AGC. However there could still be merit in allowing the AGC to control the HVDC as:

§ It allows greater control over the use of the HVDC and potentially could be used to minimise wear and tear on the HVDC; and
§ It makes it easier to control time error in both islands if the HVDC is also controlled by AGC.

Details of exactly how the HVDC will be controlled for FK sharing will need to resolved in the detailed design phase.

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[3] http://www.electricitycommission.govt.nz/pdfs/opdev/comqual/consultationpdfs/freq-reg/AppendixA.pdf

[4] As noted by the EC there could be some merit in allowing separate raise and lower offers but we have not allowed for that in this strawman.

4.2 HVDC Use

The EC design has assumed the HVDC would be available, at no cost, for frequency keeping sharing between islands. The asset owner has already advised that pole 2 will not be available for FK sharing as the increased wear and tear from providing frequency keeping sharing imposes an unacceptable increase on the risk of failure while there is only one pole available.

The asset owner has also raised the issue of how they will be compensated, once the new pole 3 and bipole controls are available, for increased operating (and possibly capital) costs associated with use of the HVDC for frequency keeping sharing. This includes both the increased wear and tear on the equipment and some possible increases in instantaneous reserve costs.

The increased wear and tear arise from frequency keeping duties ramping the HVDC through converter transformer and filter bank breaker switching points[5].

The increased reserve costs that may arise depend on how FK transfer requirements impact HVDC scheduling and reserve risk assessments. For example if the scheduled maximum FK transfers across the HVDC impact reserve risk setting and reserve requirements then use of the HVDC for FK transfer could impact total reserve costs and impact the asset owner’s costs for reserves.

The asset owner currently has no mechanism for recovering these increased HVDC operating costs if the HVDC were to provide frequency keeping sharing between islands. This issue needs to be discussed with the asset owner, the EC and possibly the CC (as the party that regulates Transpower’s operating revenue).

The SO raises the issue of the commercial basis for the use of the HVDC with the EC and notes the need for further discussion. The SO would be happy to help facilitate this discussion in order to progress this project further.

4.3 No FK Minimum

It is assumed that the SO’s technical requirement for generators to provide FK, and sign an appropriate ancillary service contract, will no longer include a minimum FK provision capability. This is a key to increasing competition in the FK market and a key reason why AGC is required. It was not directly stated in the EC’s strawman proposal.

4.4 Short Term Ramp Rates Required

The EC’s strawman design assumed that 5 minute ramp rates will provide enough information for AGC to be able to control generators. Experience with the current (autonomous) FK providers suggests that dispatching on 5 minute based ramp rates could lead to generators fighting against each other or hunting.

The proposed strawman design is therefore based on generators providing information on their ramping capabilities at intervals less than 5 minutes, for example 10 second and 60 second ramping capabilities. The exact interval for these shorter term ramp rates would need to be determined, in conjunction with the AGC dispatch interval, in the detailed design stage.

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[5] This was explained in more detail, and quantified, in the asset owner’s letter to the EC of 24 December 2009, outlining why pole 2 was not available for frequency keeping sharing duties.

Two levels of ramping response information are needed as some generators may have delays in their response, e.g. due to inertia of water or boiler response times.

An unresolved issue is whether these ramp rates should be also be separated based on whether the generator is already ramping up or down, to take account of any inertia effects.

4.5 Performance Payment

Currently accountability for FK performance is simple because only one party is providing the FK service in each island in each half hour. Monitoring performance of multiple providers for each half hour gets much more complicated. Rather than try and design a complicated performance monitoring system it is proposed instead to include a performance based component in the ancillary services payment, probably via the ancillary services contract. That FK providers would be paid, at least partly, based on the actual level of FK service provided, rather than just availability, as at present. One possible form of performance payment would be a “mileage” payment whereby FK providers are paid based on how much they deviate (up and down) from their base point, in response to AGC set points. In theory this calculation should be possible based on 10 second SCADA snapshots of actual generator output and AGC dispatch instructions. In practice the calculation is likely to be complex. The detail of how to implement such performance payments needs to discussed, perhaps via the EC stakeholders advisory group process.

4.6 Retain Band Form of FK Offer

The EC strawman proposed changing the form of the FK offers to a fan type offer for FK, to accommodate block dispatch of FK offers for hydro generators. It is noted that this presumes FK is co-optimised with energy, and reserves, in SPD. However, as co-optimisation is not part of stage 1, we suggest the current (block) form of FK offer should be retained to maintain compatibility with the current FK selection process.

4.7 AGC Needs Unit Level Information

FK providers need to be offered at the unit level and AGC needs to know which particular units are providing AGC in real time. This is necessary for AGC to have any certainty about how they will respond in the 10 second AGC cycle.

5 Strawman AGC Design

This section proposes a strawman design for AGC, including how AGC would interface with generators and the HVDC.

5.1 Summary of Strawman Design

The key features of the proposed strawman AGC design are:

- It needs to be able to cope with separate island markets or a national market as the HVDC may not always be available or may be constrained in its ability to deliver frequency sharing between islands.
- HVDC control outputs may not be required as the HVDC bipole controls include frequency controls that respond automatically to frequency differences between islands.
- It is proposed that frequency keeping would be dispatched on the same level (block or unit) as energy is currently dispatched.

- It is proposed that the AGC output will account for the 5 minute energy dispatch solution in setting the AGC dispatch targets.
- AGC output dispatch instructions would be sent as absolute MW set points.
- The frequency keeping selection process would continue to account for constrained on costs, and short (10 second) and long (60 second) ramping capabilities. The output of the frequency keeping selection process would become a merit order for provision of frequency keeping services for the AGC for that trading period. The AGC would then dispatch providers every (10) seconds based on this merit order the required level of FK, and feedback from SCADA on how each provider is actually responding to FK orders.
- It is suggested that the generator interface for FK control could be via an ICCP interface between the generators SCADA system and the Transpower SCADA system. It is considered that the response times, security and reliability required for AGC control require direct SCADA to SCADA control and ICCP is a well proven industry standard interface for such controls. This could be implemented via the current EDF interface.
- The ICCP interface is only required for issuing AGC controls to FK providers. It is not required for energy dispatch. However, Transpower is considering the future of its current dispatch interface (Genco) and one possible option is to migrate energy dispatch for all generators to an ICCP interface. Feedback on generators' preferences for energy and FK dispatch interfaces would be welcome.
- AGC would account for actual generator response to previous orders in determining future orders, so that it can account for non-response of generators for any reason. The commercial consequences of non-performance of an FK provider would be dealt with via the performance component of the AGC procurement contract.
- It is noted that we will need to undertake some system simulation to tune AGC control loops and be confident that the proposed strawman design does not have any control stability problems. Such simulation would be part of the next phase of refining the strawman design once the EC have finalized the scope of AGC and contracted with the SO for delivery of AGC.

Each of these key features is explained in more detail in the following sections.

5.2 AGC Design

5.2.1 Control Philosophy

The proposed approach to AGC design is:

Able to Cope with Separate Island Markets or HVDC Constraints

Although the eventual market design may be for a national FK market, AGC needs to be able to cope with both separate island frequency control and national frequency control. It needs to be able to handle both a national market situation, where the HVDC is fully available for FK sharing and unconstrained, and where we do not have a full national market, e.g. the HVDC is either unavailable for FK sharing duties or constrained in its ability to share FK between islands[6].

HVDC Constraints Dealt with in FK Scheduling or SPD

It is assumed that constraints on HVDC availability or capability are dealt with in the FK scheduling process. Prior to full co-optimisation being introduced this will be dealt with by the FK selection process. In the interim, SPD will need to advise

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[6] Even when the new pole 3 and bi-pole controls are available the ability of the HVDC to transfer FK services between islands could be constrained due to capacity, risks of loss of capability due to a tripping, operational constraints around direction reversal (limitations in round power capability) etc.

the FK selection process of the expected HVDC FK transfer capability and the FK selection process will need to take this constraint into account in its FK selection for a half hour.

Prior to the new P3 and bipole controls being available this HVDC constraint will be quite simple (HVDC unavailable) but once the new bipole is available this calculation of HVDC FK transfer capability will be more complicated. Any necessary changes to SPD to calculate the HVDC FK transfer capability for a half hour is excluded from this strawman.

Once full co-optimisation is introduced these HVDC FK transfer constraints will need to be included in the co-optimisation process.

HVDC Control Outputs May Not be Required

The proposed HVDC frequency controls design includes an automatic frequency transfer function between islands (refer HVDC frequency control design review report by DC Consulting of January 2010). This approach assumes the HVDC control system is responsible for transfer of frequency between the islands. That is AGC would dispatch FK nationally and the HVDC controls would ensure the HVDC acts like and AC line to automatically transfer the energy from one island to the other if required to maintain a national frequency standard. If this control capability were used it is possible that an HVDC output may not be required from the AGC. It is noted that this approach differs from that proposed by KEMA in their earlier investigation for the EC. However, this design approach has not been finalised and the SO is still considering the best way to manage frequency keeping transfer between islands and proposes to finalise this during the detailed design stage.

Technical Requirements to Provide FK

The proposed approach to selecting FK providers is that they would have to meet certain technical requirements in order to be able to provide FK, including minimum ramp rate requirements, response times etc. This is similar to how the current FK procurement process works whereby the ancillary services contract specifies these technical requirements and then the SO monitors actual performance in real time. The key difference is that the required minimum capability band is likely to be smaller with multiple providers.

The alternative approach, of relaxing the technical ramping requirements but paying based on actual performance was considered but not taken further as it was considered too difficult to implement within a reasonable time frame. However, it may deserve merit for further consideration at some point.

FK Requirement Calculation and Selection

The FK provider selection process needs to take account of ramping requirements from both energy and frequency control. Significant changes will be required to the FK requirement calculation and FK selection tools.

Unit Information

AGC needs real time information at unit level about which generators are providing FK services. This is because AGC needs to co-ordinate response between multiple generators at a second by second basis to ensure stability and to avoid generators “hunting” each other.

Hunting Problems

Hunting problems can arise if generators have the same average ramp rates over say a 5 minute period but different delays in responding at the 10 second level. Generator offered ramp rates are hourly ramping capability. They do not reflect any delays in starting to ramp and so may be vastly different to their ramping capability at the 10 second level.

If AGC does not know about the delays it will see the lack of frequency response (due to the delay on one generator) and order both generators to respond further. Then the slow starting generator gets going but now overshoots the response. Then AGC responds by ramping both down and the delays cause over shoot the other way and the two generators hunt against each other.

So AGC needs to control generators at a sufficiently low level to know about response at say the 10 second level. This requires modelling generators at the unit level.

Unit Level Real Time Information

An implication of the need to know in real time which units are providing FK is that AGC will need a real time indicator, from generators via ICCP, of those which are actually providing the FK service in real time.

Interaction of Block Dispatch and AGC

It is proposed that AGC issue generator MW set points and controls FK providers at the station level. However where AGC is provided by a block river chain the generator will also want to manage the river chain as a block to manage hydrology and meet their overall block dispatch requirements. So some level of co-ordination between AGC station level control, and overall block management needs to occur. There are two options for such overall block co-ordination:

- AGC controls the FK providing station within the block and the generator manages the rest of the block to still meet their block dispatch requirements and manage river chain hydrology; or
- The generator tells the SO their overall station energy requirements every 5 minutes (to meet block dispatch and hydrology requirements) and AGC accounts for these in setting the energy set point for the FK providing station within the block.

Further discussion is required on this issue to determine the best way of managing both frequency control and hydrological management.

May Need Separate Unit Level Modelling Tool

The proposal is to use the AREVA RTGEN AGC tool for AGC as this is readily available, compatible with the SO’s other systems and reasonably well proven. RTGEN controls generators at the unit level and allows for separate short and long term ramp rates for raise and lower. So RTGEN is well suited to managing potential generator hunting problems.

However, until we have done detailed system simulation of how RTGEN will interact with the rest of the power system it is not clear whether we will need to account for delays as well as ramp rates in the information supplied to RTGEN. So it is possible that a separate tool may be required for modelling generator real time response rates and feeding these as inputs to RTGEN. These response rates may need to be modelled in real time because response rates, in MW/min, can vary depending on the generator state. Taking a hydro generator example again, once the penstocks are open and the water is moving its ability to ramp up is quite fast, but because of the inertia of the water, it may take some time to start ramping down. Similar problems can arise for thermal generators with any sort of inertia or delay in boilers.

For such reasons a separate module to calculate generator real time ramp rate responses, and feed these to RTGEN, may be required.

As we have not investigated in detail exactly how this module would work our estimate for this work is necessarily high level and would need to be confirmed at the detailed design stage.

The proposed approach is that actual generator responses to raise and lower instructions would be modelled off line, with detailed governor response models, and then input into a state dependent look up table for fast (10 second) and medium (90 second) ramp rate responses for each generator. The real time module would look at SCADA inputs and market information to determine generator status (including current direction of ramping) and use that status information to look up the relevant ramp rates, to pass to RTGEN.

This ramping calculation module also needs to take into account actual generators response and be able to determine and take account of situations where:

- Generators are not responding as expected;
- Generators are off line;
- Generators have advised operating restrictions in real time; and
- Information about a generator is unavailable for any reason.

Block Dispatch Tools Not Significantly Changed

An implication of the above approach, of making generators responsible for managing the rest of the block around FK dispatch, is that the current block dispatch process and tools are largely unchanged. It is noted that the alternative, of having the SO account for FK dispatch in how it issues the block dispatch instructions, would be much more complicated and expensive.

Absolute MW AGC Dispatch Instructions

It is proposed that the form of the AGC dispatch instruction will be an absolute MW set point target to be reached within the AGC dispatch period (assumed nominally 10 seconds). This implies the AGC system will need to account for energy dispatch targets, actual generator current outputs and ramp rate capabilities (all at a unit level). It also implies that AGC will need to know about 5 minute dispatch solutions at the unit level.

Output Signals Account for Energy Dispatch

AGC will need to account for the 5 minute energy dispatch targets from 5 minute dispatch and take account of these in issuing AGC dispatch targets. The aim is that that the AGC dispatch targets will oscillate (depending on actual frequency) around the 5 minute dispatch targets (taking account of ramp rates), so that if frequency were unchanged the AGC target at the end of the 5 minutes should match the 5 minute dispatch target.

AGC Economic Merit Order – Accounts for Offers and Constrained On

The AGC system will need an economic merit order for determining preferences of dispatch of FK providers in real time. It is proposed that this should be based on both the cleared FK offers, and any out of band costs (constrained on / off costs) derived from generator offers. However, prior to full co-optimisation these costs will be based simply on the existing (separate) FK selection algorithm. Noting that the current FK selection process accounts for constrained on costs by looking at the energy price and generator offers for each FK provider.

FK Output Signals Issued via ICCP Interface

It is assumed that AGC output control will be issued via an ICCP interface as this seems simple and provides an operational control level of reliability. We may need to confirm timing of such signals and whether the overall control loop is still stable with this level of delay in the loop.

The issues for generators to provide a control ICCP interface will need to be investigated.

SCADA Provides Feedback Loop

AGC needs real time SCADA feedback so it can see how each generator block is responding to orders and adjust for any non-response or slow response. Again in tuning AGC parameters we will need to check delays on feedback to check system stability with these delays.

Integral Controller

RTGEN has both proportional and integral control feedback loops, with different weightings available. It is assumed that the integral control feedback loop is likely to need to dominate in order to avoid instability and to maintain time error. However actual control loop settings will need to be set as part of the detailed design, including overall system stability simulation, and then tested during the commissioning phase.

Nominal 10 second FK Dispatch Period

It is not clear exactly what the time period of FK dispatch will need to be, but for this strawman proposal a nominal 10 second FK dispatch period has been assumed. This is based on the nominal 4 second SCADA analogue update period and the need for various other processing delays in the feedback loop. However the actual time interval for FK dispatch will need to be finalized as part of detailed design, including system stability modelling.

5.3 Need Detailed Design, System Simulation and Commissioning Tests

The above AGC control philosophy is based on assumptions around how generators will respond to AGC control signals and how the overall system will respond with some generators on AGC control and some having more independent control. This includes assumptions around a number of AGC parameters that are unknown at this stage (time delays in SCADA feedback loops, generator governor response characteristics, and inherent delays in some forms of generator response such as hydro penstock delay or thermal boiler delay). It is still not certain that, overall, AGC will achieve the level of frequency stability the SO is required to provide in its PPOs.

Once the overall design philosophy has been agreed with industry stakeholders, via the EC stakeholder consultation process, we will need to undertake a more detailed design. This will include simulation of the overall system control behaviour with this approach to confirm it works from a system stability view point and to set initial parameters of control loop to ensure overall system performance and stability.

We will also need to test actual generator response, and system response, as part of commissioning of the AGC system and tune the AGC to optimal performance.

5.4 Key Interfaces

Based on the above design philosophy the proposed key interfaces for AGC are as below.

5.4.1 Interface to Generator Capability Records

In order to calculate the 10 second level ramp rates of each unit offered for FK the AGC system will need to have access to generator technical capability information from their capability statements.

5.4.2 Interface to Offer Process

As at present, the FK selection process needs to know FK offers, generator energy offers and energy prices to calculate the economic merit order for FK selection that it passes on to AGC. AGC itself will also need to know generator total offered capacity from offers in order to calculate any constraints on generator operating bands (to ensure does not dispatch outside total offered capacity).

5.4.3 Interface to SPD – Half Hourly Schedule

As at present the FK selection process will need to know, from the half hour schedule, the forecast energy price at each node for determining the constrained on / off costs for its economic merit order for FK selection.

5.4.4 Interface to SPD – 5 Minute Dispatch

AGC will need to know the 5 minute dispatch targets from 5 minute dispatch. These then determine the central dispatch target about which the AGC frequency control signal will oscillate in determining the 10 second AGC dispatch orders. The ramp rates calculated in 5 minute dispatch will be used in the FK selection process to determine maximum requirements taking account of both energy and FK ramping requirements.

5.4.5 Interface to SCADA

The AGC system will need information from the SCADA, in real time, on:

- Line status and loading for the HVDC, so that it can avoid overloading; and
- Generators (at unit level) as they need to know when not responding to control signals or when near offered band limits.

5.4.6 Interface to Generators

Unit Level Information on AGC Provision

A key change for all generators will be the need for real time information on which units within a block are actually providing the FK service, as this information is not currently provided. Some kind of real time SCADA to SCADA information, perhaps via ICCP, on which units the generator has selected to provide FK will be needed. The aggregate level of FK service provided in real time needs to match their offered level. For example, if 4 units were offered and dispatched then in real time 4 units need to be available, even if not the same 4 units.

ICCP Preferred for FK Dispatch Interfaces

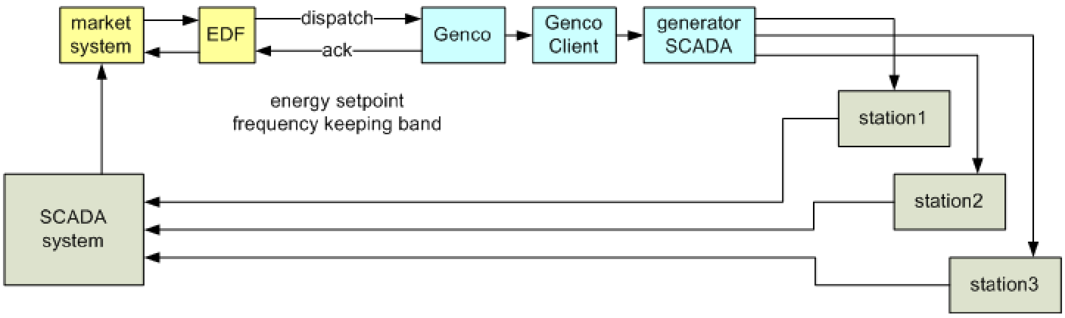
AGC will need a fast, secure and robust control loop response of units providing FK. Direct SCADA to SCADA ICCP links have been reasonably well proven as a means for such fast, secure and robust links and are the preferred means of providing FK dispatch instructions to FK providers.

So it makes sense for an ICCP based interface to be the preferred interface for AGC signals for generators that elect to participate in the FK market. Transpower would welcome any feedback on generators' preference for the dispatch interface for FK, and similarly views on where the energy dispatch interface should head over time. This will need to be discussed with the stakeholder group. Some possible approaches are outlined below.

Evolutionary Path for Generator Interface for AGC

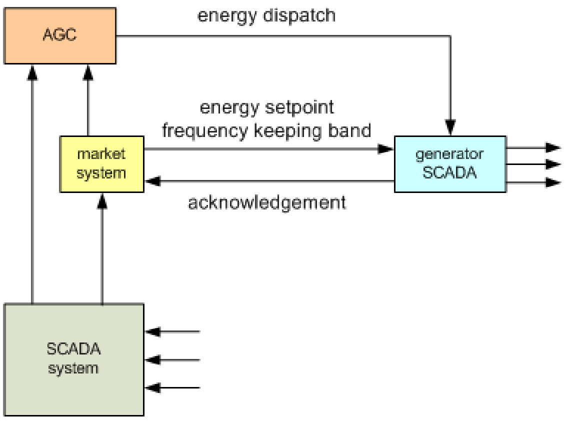
The current system looks like this:

Current electronic dispatch setup for generators where dispatch is sent directly to generator SCADA

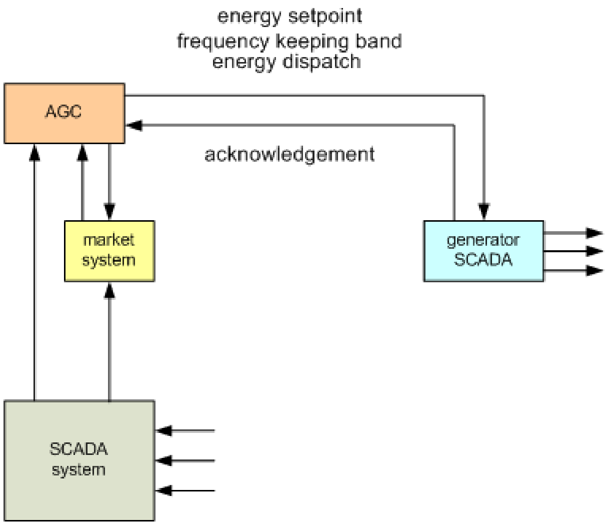


Given that AGC will need to know the dispatch instruction then it would seem to make sense that all dispatch instructions pass through AGC. This also provides AGC with the flexibility to vary not just the provider that it uses, but also the rate at which it sends the providers their set points. The generator could still receive advice of their target set point and their cleared frequency band from the market system, which it would then acknowledge in the existing way. The existing system then becomes more of an advice and acknowledgement rather than a control.

Example of how AGC could be interfaced, with existing electronic dispatch system still in place



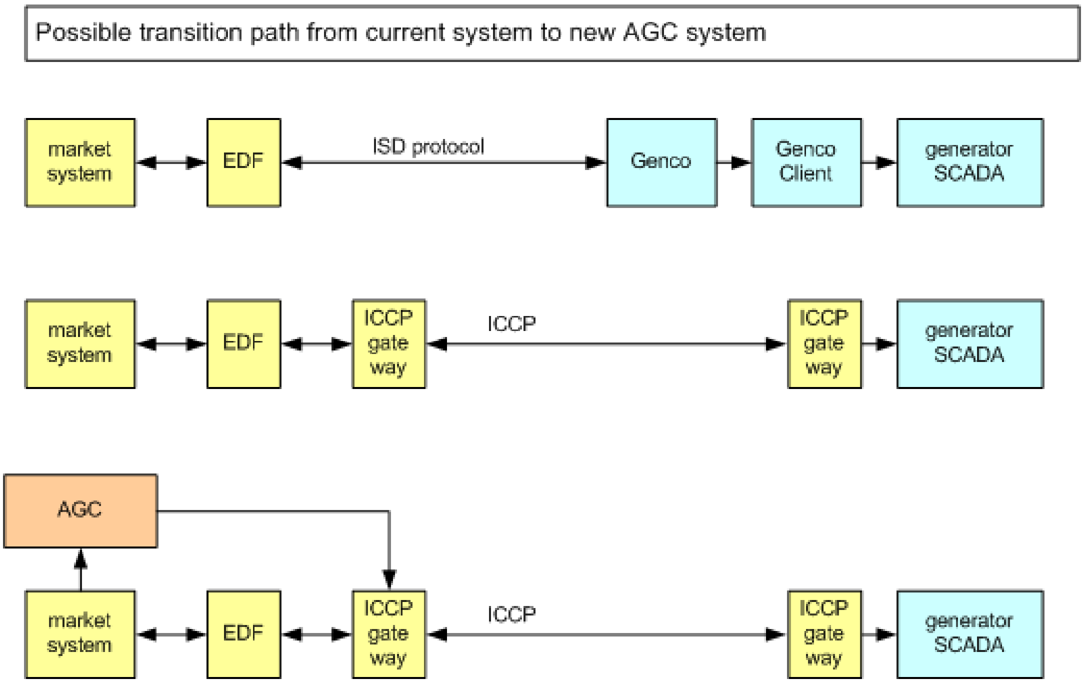
...or everything could all come and go through AGC



The SO is able to accommodate either approach and would like to engage with stakeholders on their preferences for provision of energy and FK dispatch instructions as whether these should all go via AGC or retain the market system for the acknowledgement loop.

ICCP staged implementation:

In order to implement the ICCP protocol a possible staged approach to implementing the change to ICCP, is suggested as below.


Possible transition path from current system to new AGC system

5.4.7 *Genco Retained*

As noted above provision of FK services is voluntary and generators that do not wish to provide FK services cannot be forced to accept and ICCP interface for their energy dispatch instructions. Therefore the Genco interface will need to be retained for some time. Replacement of Genco is not part of the AGC project. However, it is noted that the Genco interface could still be funnelled through the Electronic Dispatch Facility (EDF) which should be able to handle two different types of interface.

5.5 Co-optimisation

The EC also requested a high level estimate of the cost of implementing co-optimisation of FK with energy and instantaneous reserve in scheduling pricing and dispatch (SPD). This section looks at some possible market design issues involved in implementing co-optimisation and provides an estimated cost ($1.1 million) and timeframe (1 year) to implement co-optimisation.

5.5.1 Staged Approach to Implementing Co-optimisation

It is suggested that co-optimisation of FK be introduced in two stages with the first stage excluding HVDC and the second to bring HVDC into co-optimisation.

It is also suggested that the EC should consider the form of the current FK market arrangements before we introduce co-optimisation. That is, the EC should consider whether the minimum operating level problem is best dealt with by generators (as it is in the energy market) or by the SO as it is with current FK arrangements.

The reason for this proposed staged approach is:

§ The EC may wish to implement co-optimisation before the new HVDC bipole is available.

§ Including the HVDC in co-optimisation is complicated and trying to do both at the same time would be very complicated.

5.5.2 Stage 1 - Co-optimisation Excluding HVDC and Simplified FK Offers

Excluding HVDC

The first stage would be to implement co-optimisation at the generator level but treating the HVDC transfer capability as a fixed input set externally.

Consider Simplified FK Offers

It is suggested that the EC consider whether the FK market should be simplified to require suppliers to make a single FK offer before co-optimisation is introduced. That is they would offer a simple price quantity offer with no associated minimum operating level to provide FK. FK providers would have to account for their minimum operating level to provide FK (Pminfk) within their offering processes. They would need to account for any costs associated with getting to the energy level required to provide FK within their energy and FK offers, and their offer must represent their reasonable estimate of their ability to provide.

Advantages of Simplified FK Offers

From the SO's point of view the key advantage of such an approach is that it avoids the need for any mixed integer constraints for FK co-optimisation, and reduces solve time and the need for any sort of iterative solution process. Avoiding the use of mixed integer constraints is likely to be important as there are limits on how many mixed integer constraints we can use (due to exponential increases in solution time as we increase the number of mixed integer constraints) and we will almost certainly need more mixed integer constraints when we come to accommodate the new HVDC bipole in SPD (to account for round power etc). Using mixed integer constraints now, for FK co-optimisation, could limit future options for how we accommodate dispatch of the new HVDC bipole in future.

From the market’s point of view the advantages of the proposed approach are considered to be:

- It is likely to lead to a more optimal solution as it allows a fully linear optimal solution to be found.
- It makes constrained on costs more transparent as they are brought into the FK offer price.

Disadvantages of Simplified FK Offers

The disadvantage of this approach is that it places more risk on FK providers and could reduce the number of FK offers. This would potentially increase FK costs or, in the extreme case, endangering the SO's ability to achieve its frequency PPOs, if insufficient offers are available.

FK providers have more risk with this form of offer as they have to structure their energy offer to ensure they achieve their minimum operating level to provide FK (Pminfk) is dispatched. That is they have to offer this portion of energy at a sufficiently low price to ensure dispatch, e.g. $0. Any costs they incur in this energy offer strategy has to be recovered via their FK offer price. However they are not guaranteed FK dispatch with a very high price so they face higher financial risks in this offer approach.

This is analogous to the problem of recovery of start up costs that thermal generators have with the current energy market design.

Rough Order Costs and Time for Stage 1 of Co-optimisation

A rough order cost and time to implement such co-optimisation is estimated at $1.1 million and about 12 months, once the final scope is agreed with the EC and a commitment to pay, via SOSPA, is signed.

These costs and times are based on:

- 12 months of one FTE AREVA person at NZ$450/hr equivalent, plus 10 months of one FTE SO person at NZ$150/hr.
- Proposed plan would be 3 months' defining scope, 3 months' development, 3 months' integration and testing, and a 3 month roll out.

Further details of the timetable are provided in Appendix 1.

5.5.3 Stage 2 - Including New HVDC

It is proposed that including the new HVDC within the co-optimised solution should be decoupled from FK co-optimisation and delayed until the new HVDC bipole is available.

This is partly because it makes sense to de-couple these two processes and partly because there remain significant issues around how Transpower will offer the FK sharing capabilities of the new HVDC bipole into the market. De-coupling the two changes to SPD makes sense because both changes are significant in their own right. Coupling them together risks creating a change that would be too big to manage and would take a very long time to implement.

There are significant outstanding issues around how Transpower would offer the FK sharing capability of the new HVDC bipole into the market because:

- Transpower can incur costs in providing the FK sharing capability both in terms of increased wear and tear and in terms of increased exposure to instantaneous reserve event costs.
- There is currently no mechanism for Transpower to recover these costs (they were not included in the agreed regulatory return).

These issues need to be resolved before we can finalise how the frequency sharing capability of the new HVDC bipole should be treated in SPD for co-optimisation. For example one option could be for Transpower to offer the capability into the market at a cost. This would need to be accounted for in the co-optimisation process.

EC Resolution of Market Design Issues

An estimated cost or time for implementing the second stage of co-optimisation has not been provided. This is because some important market design issues on how Transpower charge for the FK sharing service need to be resolved before we can finalise how the HVDC, and its FK sharing capability, is treated in SPD. It is suggested that the EC resolve these issues, presumably via its stakeholder technical advisory group. The outstanding market design issues are detailed in section 3.2 Co-optimisation Issues.

6 Implementation Time

It is noted that implementation of AGC tools cannot commence until the scope and costs have been agreed with the EC and the EC have agreed to pay for AGC tools under the SOSPA contract. In turn the EC will need to agree the form of any changes to the FK market with participants, including the HVDC owner, and receive a commitment from participants to their willingness to provide FK services under the proposed FK market arrangements before it could commit to paying for the SO to develop the necessary AGC tools.

Given these constraints it is estimated that the SO would take approximately 18 - 24 months to develop the necessary AGC tools, once final agreement had been reached with the EC.

A high level project plan is provided in Appendix 1. Please note this is based on the proposed strawman and will need to be revised once the final details of AGC have been agreed with all parties.

7 Next Steps

The following next steps are suggested:

7.1 EC Discuss HVDC Access with Asset Owner

As noted above, although the new HVDC bipole is proposed to be designed with frequency keeping sharing capability, there is no commercial arrangement in place to access this capability. It is suggested that the EC, with possibly some involvement of the Commerce Commission, should engage in discussion with the asset owner about how this capability might be accessed for the market. This will have a significant impact on the overall national frequency keeping market design and should be resolved before the design is progressed too far. The SO would be happy to facilitate this discussion.

7.2 EC Discuss Strawman with Stakeholders

It is suggested that one way of resolving some of the outstanding market design issues that need to be addressed before AGC can be implemented, is for the EC to circulate this strawman proposal to industry stakeholders, perhaps via its industry stakeholder group. However the EC engagement with stakeholders will need to be much wider than this strawman (which only covers technical issues of how the SO could implement AGC) as they need to cover the wider aspects of how the FK market needs to evolve over time including:

- What form the future FK market might take and why generators would want to participate in this market?
- How the proposed SO AGC tools might be trialled and developed? and
- Generator views on the proposed AGC interface?

7.3 EC Develop Rules for FK Market

It is suggested that the EC may need to develop rules to support the proposed move to an AGC based FK market. Areas that the EC may need to consider include:

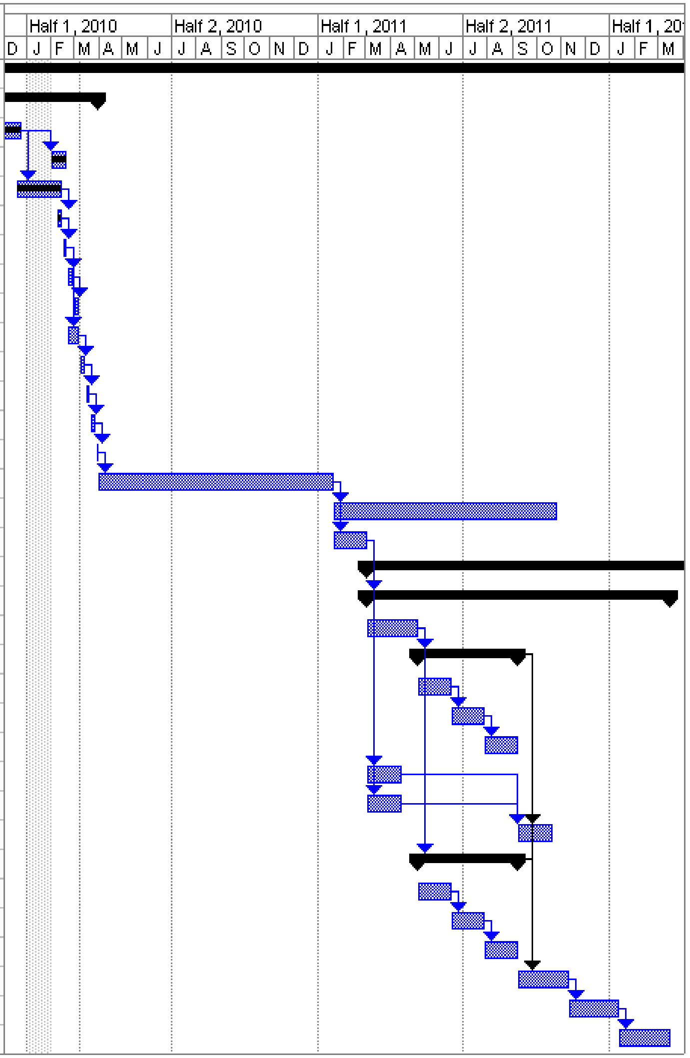
- Do the rules around FK ancillary service contracting need to reflect performance based payments?
- Do the rules need to be written for FK offering?
- How costs for FK are to be allocated?
- What performance incentives should exist for FK providers to deliver?
- Do the existing (manual based) dispatch rules need to be tightened with the move to AGC?

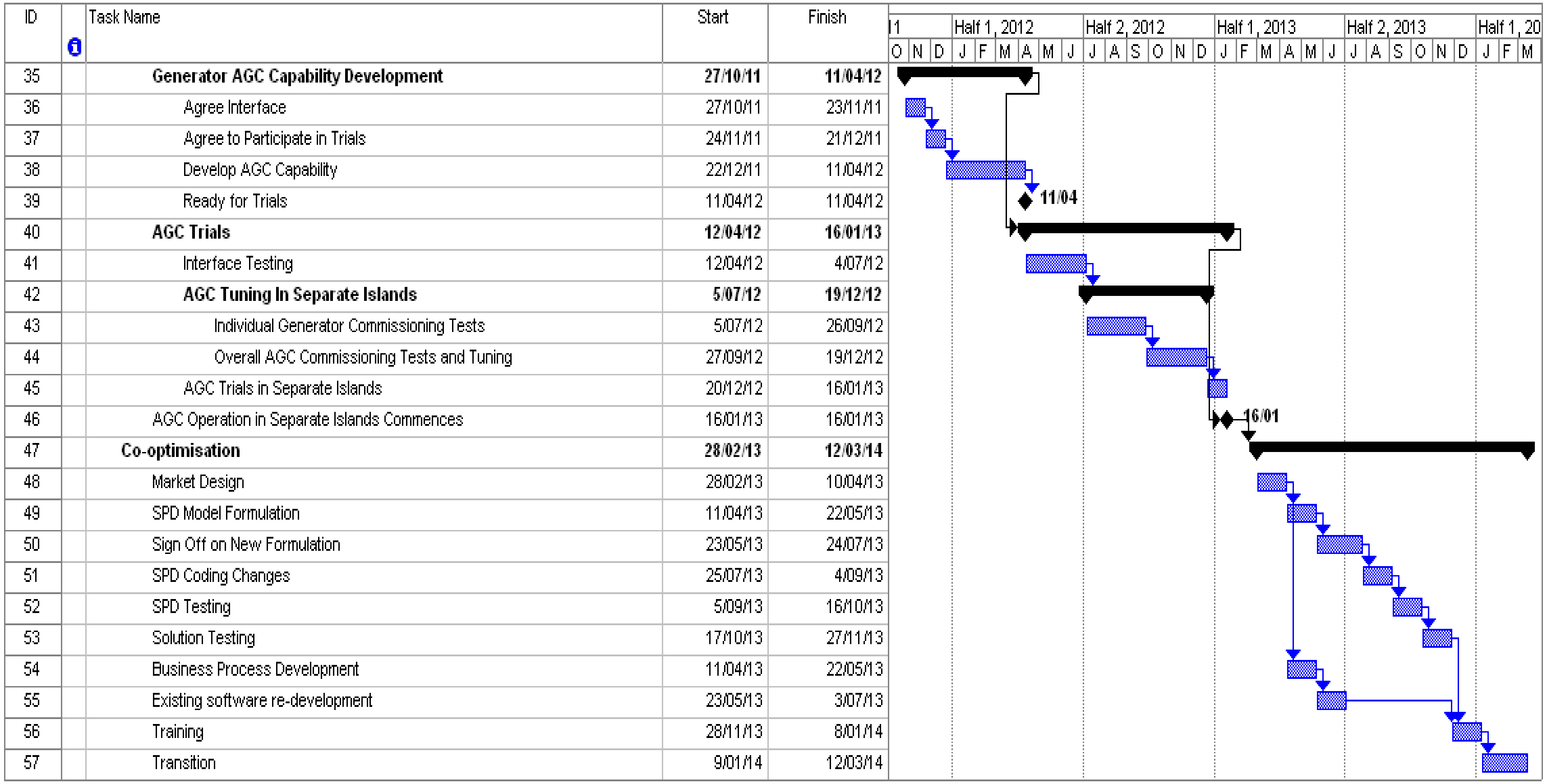
7.4 SO Finalise AGC Implementation Quote

The timeframes quoted in this strawman proposal are necessarily subject to a high level of uncertainty as the details of how AGC is to be implemented in the market have yet to be finalized by the EC. Once that above items have been finalized by the EC the SO will need to refine its quote to implement the final AGC design. This can then form a basis for the EC to contract the SO to implement AGC under the System Operator Service Provider Agreement (SOSPA) contract.

Appendix 1 – Project Plan

ID	ℹ	Task Name	Start	Finish
1		**National Frequency Keeping Market Development**	**1/12/09**	**12/03/14**
2		**Development of Scope Proposal**	**1/12/09**	**30/03/10**
3	✓	Review Impact on Current HVDC	1/12/09	24/12/09
4		Determine Compatibility with Future Bipole Controls	1/02/10	19/02/10
5		Investigate Options for Early Delivery of Increased Competition	18/12/09	12/02/10
6		Develop Strawman Proposal	8/02/10	12/02/10
7		TP Internal Review of Strawman Proposal	15/02/10	19/02/10
8		System Modeling on Strawman Proposal to Ensure Feasible	22/02/10	26/02/10
9		Refine Strawman Proposal	1/03/10	5/03/10
10		Determine Resourcing, Costing and Timing of Strawman Proposal	22/02/10	5/03/10
11		Initial Review of Strawman Proposal with EC	8/03/10	12/03/10
12		Refine Proposal Based on EC Feedback	15/03/10	19/03/10
13		Finalise Proposal	22/03/10	26/03/10
14		Present Final Proposal to EC	29/03/10	30/03/10
15		EC Agree Scope (Includes Industry Stakeholder Process)	31/03/10	19/01/11
16		EC Develop Rules for AGC Based FK Market	20/01/11	26/10/11
17		EC Commit to AGC Development via SOSPA Contract	20/01/11	2/03/11
18		**AGC**	**3/03/11**	**16/01/13**
19		**SO AGC Tool Development**	**3/03/11**	**14/03/12**
20		System Studies	3/03/11	4/05/11
21		**Core AGC Development**	**5/05/11**	**7/09/11**
22		AGC Modeling	5/05/11	15/06/11
23		AGC HVDC Customisation	16/06/11	27/07/11
24		TTSE Customisation	28/07/11	7/09/11
25		Redundant Frequency Telemetry (SCADA)	3/03/11	13/04/11
26		Control signal outputs via ICCP	3/03/11	13/04/11
27		Solution Testing (70 days)	8/09/11	19/10/11
28		**Other Process Developmemt**	**5/05/11**	**7/09/11**
29		Business Process Development	5/05/11	15/06/11
30		Training – Business Process	16/06/11	27/07/11
31		Existing software re-development	28/07/11	7/09/11
32		Testing	8/09/11	9/11/11
33		Training	10/11/11	11/01/12
34		Transition	12/01/12	14/03/12



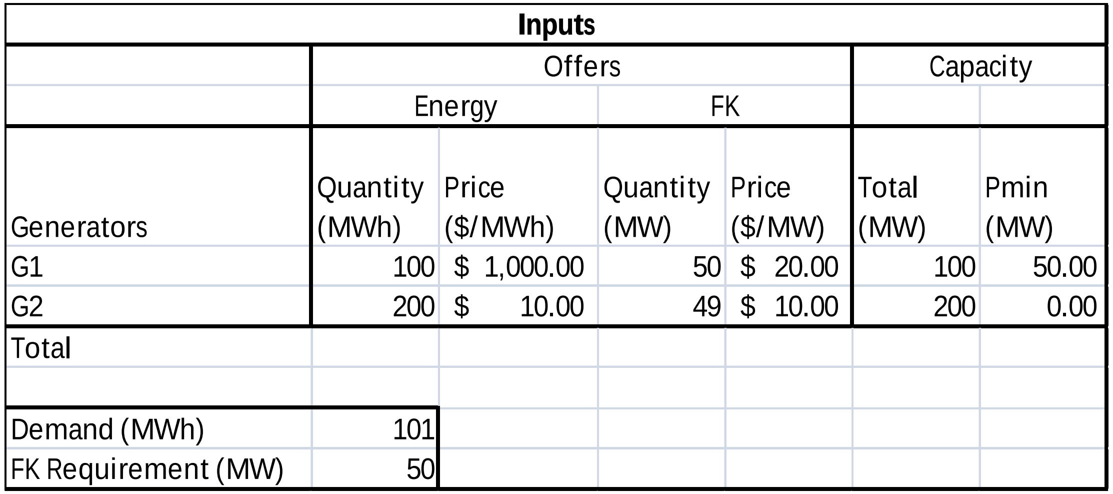


ID		Task Name	Start	Finish
35		**Generator AGC Capability Development**	**27/10/11**	**11/04/12**
36		Agree Interface	27/10/11	23/11/11
37		Agree to Participate in Trials	24/11/11	21/12/11
38		Develop AGC Capability	22/12/11	11/04/12
39		Ready for Trials	11/04/12	11/04/12
40		**AGC Trials**	**12/04/12**	**16/01/13**
41		Interface Testing	12/04/12	4/07/12
42		**AGC Tuning In Separate Islands**	**5/07/12**	**19/12/12**
43		Individual Generator Commissioning Tests	5/07/12	26/09/12
44		Overall AGC Commissioning Tests and Tuning	27/09/12	19/12/12
45		AGC Trials in Separate Islands	20/12/12	16/01/13
46		AGC Operation in Separate Islands Commences	16/01/13	16/01/13
47		**Co-optimisation**	**28/02/13**	**12/03/14**
48		Market Design	28/02/13	10/04/13
49		SPD Model Formulation	11/04/13	22/05/13
50		Sign Off on New Formulation	23/05/13	24/07/13
51		SPD Coding Changes	25/07/13	4/09/13
52		SPD Testing	5/09/13	16/10/13
53		Solution Testing	17/10/13	27/11/13
54		Business Process Development	11/04/13	22/05/13
55		Existing software re-development	23/05/13	3/07/13
56		Training	28/11/13	8/01/14
57		Transition	9/01/14	12/03/14

Appendix 2 – Co-optimisation Worked Examples

The impact of co-optimisation was studied by developing a simple optimal dispatch model and running it with and without co-optimisation. The same input assumptions (as listed below) were used for both the co-optimised and non co-optimised cases. In addition it was assumed that generator G1 has a technical requirement to run at 50MWs minimum (Pmin). For one case this was achieved by including a Pmin constraint in the optimisation problem. For another (comparison) case it was assumed there was no constraint in the optimisation but that the generator would need to achieve its Pmin operating level by its offer structure. In this second case it would need to recover these Pmin operating costs by structuring its offer in such a way to recover all its operating costs once it was dispatched.

The energy and FK prices were discovered by manually increasing the demand by 1MW (of energy and FK, separately) and measuring the change in total costs. Settlement at these prices was then compared between the three cases (non-co-optimised, co-optimised, and co-optimised with Pmin). (The spreadsheets behind these worked examples is provided separately)



Inputs						
	Offers				Capacity	
	Energy		FK			
Generators	Quantity (MWh)	Price ($/MWh)	Quantity (MW)	Price ($/MW)	Total (MW)	Pmin (MW)
G1	100	$ 1,000.00	50	$ 20.00	100	50.00
G2	200	$ 10.00	49	$ 10.00	200	0.00
Total						
Demand (MWh)	101					
FK Requirement (MW)	50					

Dispatch													
With Pmin													
	Energy				FK								
	Energy Quantity	Total Quantity (Energy + FK)	Price	Cost	FK Quanitity	Price	Cost	Total Cost	Total Quantity	FK Operating Range			
G1	50	51	$ 1,000	$ 51,000	1	$ 20	$ 20	$ 51,020	51	50	Base Case		
G2	20	69	$ 10	$ 690	49	$ 10	$ 490	$ 1,180	69	20			
Total	70	120		$ 51,690	50		$ 510	$ 52,200	120				
G1	50	51	$ 1,000	$ 51,000	1	$ 20	$ 20	$ 51,020	51	50	Energy +1	E Price	$ 10
G2	21	70	$ 10	$ 700	49	$ 10	$ 490	$ 1,190	70	21			
Total	71	121		$ 51,700	50		$ 510	$ 52,210	121				
G1	50	52	$ 1,000	$ 52,000	2	$ 20	$ 40	$ 52,040	52	50	FK+1	FK Price	$ 1,010
G2	19	68	$ 10	$ 680	49	$ 10	$ 490	$ 1,170	68	19			
Total	69	120		$ 52,680	51		$ 530	$ 53,210	120				
G1	50	53	$ 1,000	$ 53,000	3	$ 20	$ 60	$ 53,060	53	50	FK+2	FK Price	$ 1,010
G2	18	67	$ 10	$ 670	49	$ 10	$ 490	$ 1,160	67	18			
Total	68	120		$ 53,670	52		$ 550	$ 54,220	120				
Without Pmin													
	Energy				FK								
	Energy Quantity	Total Quantity (Energy + FK)	Price	Cost	FK Quanitity	Price	Cost	Total Cost	Total Quantity	FK Operating Range			
G1	50	51	$ -	$ -	1	$ 51,500	$ 51,500	$ 51,500	51	50	Base Case		
G2	20	69	$ 10	$ 690	49	$ 10	$ 490	$ 1,180	69	20			
Total	70	120		$ 690	50		$ 51,990	$ 52,680	120				
G1	50	51	$ -	$ -	1	$ 51,500	$ 51,500	$ 51,500	51	50	Energy +1	E Price	$ 10
G2	21	70	$ 10	$ 700	49	$ 10	$ 490	$ 1,190	70	21			
Total	71	121		$ 700	50		$ 51,990	$ 52,690	121				
G1	50	52	$ -	$ -	2	$ 51,500	$ 103,000	$ 103,000	52	50	FK+1	FK Price	$ 51,490
G2	19	68	$ 10	$ 680	49	$ 10	$ 490	$ 1,170	68	19			
Total	69	120		$ 680	51		$ 103,490	$ 104,170	120				

Settlement

Settlement - Co-optimised (G1 Constrained on to Pmin for FK)

	Energy Quantity	Total Quantity	Energy Settlement	FK Constrained On Settlement	FK Quantity	FK Settlement	Total		
G1	50	51	$ 510	$ 50,490	1	$ 1,010	$ 52,010	E Price	$ 10
G2	20	69	$ 690	$ -	49	$ 49,490	$ 50,180	FK Price	$ 1,010
Total	70	120	$ 1,200	$ 50,490	50	$ 50,500	$ 102,190		

Settlement - Separate (G1 Constrained on to Pmin for FK)

	Energy Quantity	Total Quantity	Energy Settlement	FK Constrained On Settlement	FK Quantity	FK Settlement	Total		
G1	50	51	$ 510	$ 50,490	1	$ 1,010	$ 52,010	E Price	$ 10
G2	20	69	$ 690	$ -	49	$ 49,490	$ 50,180	FK Price	$ 1,010
Total	70	120	$ 1,200	$ 50,490	50	$ 50,500	$ 102,190		

Settlement - Co-optimised Without Pmin Constraint

	Energy Quantity	Total Quantity	Energy Settlement	FK Constrained On Settlement	FK Quantity	FK Settlement	Total		
G1	50	51	$ 510	$ -	1	$ 51,490	$ 52,000	E Price	$ 10
G2	20	69	$ 690	$ -	49	$2,523,010	$2,523,700	FK Price	$ 51,490
Total	70	120	$ 1,200	$ -	50	$2,574,500	$2,575,700		

Appendix 3 – RTGEN Technical Summary

Areva RTGEN Summary

Introduction

This document summarises the useful capabilities of the Areva RTGEN application as may be applicable to the NZ situation. The summary draws primarily upon analysis of somewhat dated (EMP2.1) Areva functional design document, as this gives the best overview of the design capability as distinct from user-focussed operator guides typically delivered with later versions of the software.

Note presented like this are speculations on how pieces of AGC functionality might fit into the New Zealand puzzle. They do not represent an official position, or a recommended best practice.

RTGEN Overview

RTGEN is constructed as a 'one-size-fits-all' application to manage generation assets within a control area. Typically, & particularly in the North American context, this involves some knowledge of the surrounding control areas & management of the net energy exchanged with adjacent control areas via AC tie lines.

A number of functions are implemented by RTGEN & supporting software, including:

Automatic Generation Control (AGC)	Automatic control of generation within the control area to meet load while managing frequency & time error & meeting scheduled interchange with neighbouring areas,
Economic Dispatch (ED)	Determines the optimal economic basepoints for a (sub)set of controlled generators, consistent with the load demand & interchange requirements
Production Costing	Determines the actual production cost based on actual generation & the current cost or heat rate curves.
Reserve Monitoring	Monitor the quantity & type of 'spare' generation available to meet operating, regulating & spinning reserve requirements
Transaction Scheduling	Schedule energy exchanges with neighbouring utilities
Unit Scheduling	Schedule unit output, duration or fuel mix schedules for both AGC & ED

These functions & future references to Control Economic Dispatch are included for completeness of the overview: they would not necessarily form a part of the proposed solution.

Terminology

The following table gives definitions of terminology used in the RTGEN/AGC context, to improve the readability of the subsequent sections.

Term	*Meaning*
Operating Area	Top level area controlled by the AGC function, frequently corresponding to a utilities service territory. AGC can monitor multiple operating areas, but typically takes active control only with one.
Plant	Functionally equivalent to a (sub)station associated with one or more generating units
Plant Controller (PLC)	Control device within a plant that controls one or more units within the plant. This is the level at which AGC issues controls.
Unit	An individual generating unit within a plant. Every unit is associated with a plant controller, through which it receives control instructions. Unit have a number of nested limits, including economic, load-frequency control (LFC) & capacity limits.
Tie Corridor	A collection of (normally) AC lines interconnecting an operating area with another operating area.
Tie Line	An individual line making up part of a Tie Corridor
Economic Limits	The limits within which a unit can be dispatched by the economic dispatch algorithm
Load Frequency Control (LFC) Limits	The limits within which a unit can be ramped through its participation in regulation.

It is anticipated that larger units dispatched at unit level would be controlled by an individual PLC. Other units dispatched at the station (or block) level might be reasonably controlled by a single PLC.

AGC Functionality

AGC is capable of controlling generation within an operating area to meet load, manage frequency & time error and meet scheduled energy exchange with neighbouring areas by calculating & controlling a quantity called Area Control Error (ACE). When ACE is driven to zero, everything is in balance. A significant portion of AGC's work therefore centres on retrieving & processing telemetered data, at area, tie, PLC & unit levels to determine the level of control required.

AGC Control Status

AGC has 3 principal control statuses & two ancillary states:

AGC Status	*Functionality*
ON	AGC Active - real-time data retrieved & processed, area level calculations performed & control signals issued, performance monitoring enabled
MON	AGC Monitor – real-time data retrieved & processed, area level calculations performed, no controls issued, performance

AGC Status	*Functionality*
	monitoring enabled
OFF	AGC Off – real-time data retrieved & processed, area calculations performed, not controls issued & performance monitoring disabled
PAUSED	AGC Paused – AGC transitions into this state from ON when some abnormal condition occurs (e.g. loss of frequency measurements, no PLCs available for control, ACE out of band alarm). Area level processing is still performed, but no controls are issued. If the condition clears itself within a defined period AGC will automatically transition back to ON. However if the condition remains, then AGC will transition to SUSPEND mode.
SUSPEND	AGC enters this state when it fails to clear itself from the PAUSED state within a certain time, or when measured frequency exceeds the AGC trip frequency limit for two successive scans.

AGC Execution Control

Most RTGEN functions execute periodically based upon a base rate which is typically 2-4s. SCADA data retrieval & processing is performed at the base rate & alarms may also be issued. Other functions are performed at integral multiples of this rate, with typical rates as follows:

Function	*Typical rate*	*Notes*
Area AGC	4-10s	4s is typical if any units are controlled by raise/lower pulse width controls. 10s is typical where all units have setpoint controls
Reserve Monitor	60s	
Unit Tracking Test	20-120s	
Control ED	180-300s	
Advisory ED	300-600s	
Pond Monitor	450-900s	

ACE Calculation & Regulating Region

The makeup of ACE is:

$ACE = (I_A+I_M) – (I_S+I_D+I_{OFF}) + 10B(f_A-(f_S+f_{OFF}))$

Where

I_A = Actual nett interchange, based on measurement(s)
I_M = Miscellaneous interchange (manually entered, to allow for known metering error or unmetered ties)
I_S = Scheduled interchange
I_D = Dynamic Interchange (exchange due to transfer of MW between jointly owned units)
I_{OFF} = Interchange offset (manual or automatic) for payback of inadvertent energy exchange (used to redress previous imbalances in the interchange of energy)
B = Frequency Bias (MW/0.1Hz)

F_A = Actual Frequency based on measurement(s)
F_S = Scheduled Frequency (usually a constant – 50 or 60)
F_{OFF} = Frequency offset (manual or automatic) for time-error correction

For the New Zealand case there is the question of whether to treat the system as two independent areas (each having a distinct frequency), which then requires the treatment of the HVDC link as a tie corridor; or whether to follow the Australian model & simply combine the two ACE contributions into a 'global' ACE, dispatch regulation on that basis, and assume that some higher power (viz. the HVDC frequency controls) will deal with ensuring the island frequencies are appropriately managed.

However in any case where the HVDC is unavailable for regulation transfer, whether mediated by either AGC directly or by an internal frequency controller, AGC will need to be able to revert to independent island control, and the 'global' ACE will need to be managed as a pair of independent ACE values. Such situations would include the case of HVDC tripped, at a limit, or subject to a temporary delay in transitioning between normal & round-power modes in order to traverse the +/-35MW region.

It therefore seems inevitable that two areas will be modelled.

A further complication would be the case where one or both areas is required to run with a frequency offset, in order to perform time-error correction: an internal HVDC control function that applies integral control to null frequency differences would effectively interfere with this; however an AGC mediated function would at least be aware of the desire to run to different frequency schedules.

The components of ACE (interchange & frequency error) are only considered in the ACE calculation for specific AGC control modes:

Control Mode	*Uses Interchange*	*Uses Frequency*
Constant Frequency Control (CFC)		þ
Constant Net Interchange Control (CNIC)	þ	
Tie-line Bias Control (TLBC)	þ	þ

When controlling interchange an internal predictive ACE value is calculated based on the scheduled interchange at some point in the future. This enables AGC to anticipate the change & begin to position the generation to meet this.

The frequency bias value (B) represents the system frequency response characteristic, and may be an operator entered value, or computed based on system load & online generation.

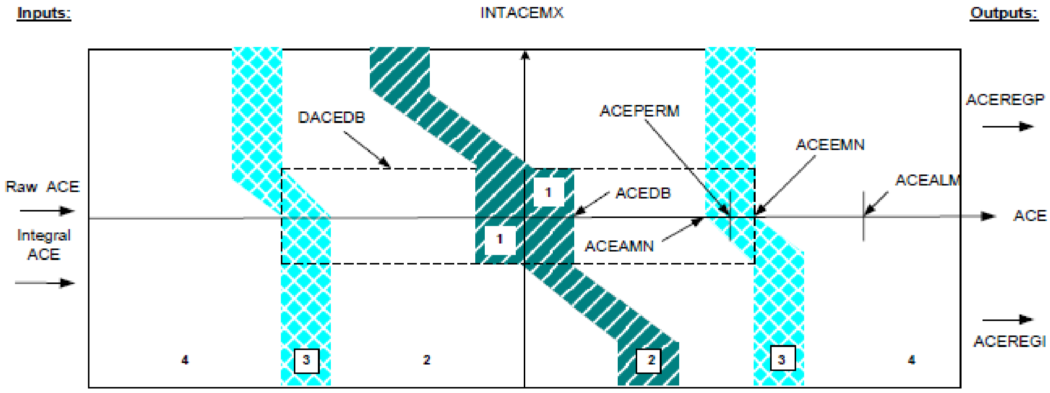
In addition to considering the immediate ACE value, AGC considers an integrated ACE value (ACEINT), which represents the accumulated ACE over time & provides an integral component to the resulting control signals.

AGC has 3 control 'regions' defined by the ACE & ACEINT values within which it may be operating. Each region has a separate set of gains for each of the ACE components which are applied to determine the regulating components of ACE & ACEINT that will be used for control purposes. The names of the regions indicate an increasing urgency of control action.

Deadband	§ No control action considered necessary (zero gains applied)
Regulating	§ Normal regulation gain parameters applied to ACE & ACEINT

	§ Dispatched via regulating units
Assist	§ 'Assist' gains applied to ACE & ACEINT § Dispatched by regulating & assist mode units
Emergency	§ 'Emergency' gains applied to ACE & ACEINT § Dispatched via all regulating mode units

The following diagram indicates how these regions relate to one another for various ACE/ACEINT values (ACE is horizontal axis, ACEINT is vertical axis).



Note the negative slope in the deadband region (dark hatching) – this indicates that for relatively large values of ACEINT, no action is required when ACE is also large but of the opposite sign (i.e. the situation is self correcting in the long term). A similar characteristic is present for the other control regions (notably the 'assist' region – cyan hatching). Tuning of these parameters is critical in providing a reliable control regime while minimising wear & tear on generator equipment.

The overall results of this process are the gain-weighted proportional & integral components of ACE used for regulation: ACEREGP & ACEREGI respectively.

Time Error Correction

Time error is still expected to accrue in an AGC controlled system – the presence of ACEINT in the control formulation is sufficient to drive frequency error to zero, but from a time error perspective (time-error being the integral of frequency error) it is only a proportional control element.

Time-error can be corrected in one of 3 ways:

- Manual modification of scheduled frequency entered directly by the operator (f_S in the ACE calculation) & remaining in effect until manually reset
- Manual specification of a frequency offset (f_{OFF}) & a period during which the offset is to be applied
- Automatic correction by specifying a period during which AGC should work to remove the time error by calculating & applying a frequency offset (f_{OFF}).

A similar set of regimes are available for the payback of inadvertent energy exchanged over AC ties between areas when in TLBC or CNIC modes; these are not discussed further here.

PLC/Unit Control

PLC/Unit Statuses & Modes

There are a number of control statuses & modes associated (primarily) with PLCs.

The control statuses determine how AGC will attempt to interact with the PLC & its corresponding units:

Control Status	*Description*
AUT (Automatic)	AGC calculates desired generation & issues controls
MAN (Manual)	AGC cannot control the unit(s) directly, but can calculate the desired generation & this can be communicated (verbally) to the plant operator
OFF	Unit(s) may be online but neither AGC nor the plant operator can control the plant out to a desired level
TST (Test)	AGC is issuing test controls to the PLC at an operator specified level & duration. When this completes the control status is returned to MAN (manual).
PAUSE	Similar to area control, PLCs in automatic mode can be paused due to a number of conditions, including: · Setpoint feedback telemetry failure · Unit(s) MW output(s) unavailable · Unit(s) all offline · Unit frequency differs from area frequency (implies a new island) · Remote/local status changes to local PAUSE mode automatically reverts to AUT mode if the initiating condition(s) clear within a defined period (typically 60s).
SUSPEND	A PLC that stays in PAUSE mode longer than a defined period will SUSPEND itself. This state is also entered if the PLC is deemed to be not tracking. Exit from the SUSPEND mode is manual.

In addition to this each PLC as a 3 character mode designation which determines (a) where its base-point generation comes from (first 2 characters), and (b) how it contributes to the management of ACE (last character). The following table describes both of these sets of characteristics:

Source of MW Basepoint		*Regulating Modes*	
CE	Control Economic Dispatch	O	Off-regulation
BL	Basepoint schedule function in RTGEN, or uses current telemetered generation if no base point schedule defined.	R	Regulated in Regulation, Assist & Emergency regions
BP	Operator entered manual basepoint	A	Regulates in Assist & Emergency regions only
EX	Externally telemetered basepoint	E	Regulates in Emergency region only

Source of MW Basepoint		*Regulating Modes*
EC	Energy constrained dispatch function (usually hydro)	
AV	Basepoint is average of economic high & low limits	
JU	Jointly owned unit – physical basepoint derived from non-physical share unit basepoints	

Thus a PLC in BPE mode will run to the operator entered base-point, and contribute to ACE management only when in ACE/ACEINT are in the ‘emergency’ region, while a PLC in CEO mode will track its economic setpoint & not contribute to regulation.

For the New Zealand scenario, assuming most units are not contributing to regulation but are still being dispatched directly via EDF, it is expected that most PLCs will be on MAN & BLO mode, with no defined schedules.

If generators were willing, schedules could presumably be transferred from SPD which would allow AGC to ramp the units appropriately, effectively automating their normal dispatch via AGC, potentially also regulating the ramping of the units over the 5 minute periods.

Units contributing to frequency regulation, assuming that they will have a defined symmetric band within which to operate, could be managed by setting the economic & LFC limits for the PLCs to the upper & lower limits of the band, and setting the PLCs onto AUT & AVR (so the units will regulate within their band, but in the absence of regulating allocation will sit mid-band.

A special case would exist where stations were providing regulation while being part of a larger hydro generation block (e.g. MTI or BEN). Ideally (from the generator’s perspective) the basepoint of the regulating station(s) would be consistent with the optimal hydraulic implementation of the block dispatch: however this would need to be calculated by the generator – not Transpower. Alternatively stations offered for frequency keeping could simply be dispatched out of block (but with an implicit hydraulic inefficiency).

Unit statuses are relatively simple by comparison:

Status	*Description*
OFFLINE	Unit not available for generation. If there is no SCADA telemetry available for this, then a unit is declared offline when its output falls below an analyst defined percentage of the unit LFC maximum.
SYNC	Unit running as a synchronous condenser (e.g. TWD). Determined by the unit being modelled as “syncable” & its MW output being below a threshold with the MVAr output being above a threshold. Note that once in SYNC mode a unit MVAr output can pass through 0 without it being declared out of SYNC mode (unless the MW output also increases).
PUMP	Unit running in pump-back mode (pumped storage). Unit must be modelled as “pumpable” & running with MW < 0.

PLC Basepoint Calculation

Given that AGC controls generators not only to manage ACE but also acts as a general dispatch mechanism, it is necessary to determine PLC/Unit basepoints. Basepoints are determined based on the PLC mode beginning with the AGC controlled PLCs not on economic dispatch (as these are largely pre-determined) and adding in the output of all PLCs not on AGC control. The difference between this total & the total generation requirement is allocated to the economically dispatched PLCs either by a Control ED, or a Tracking ED (which effectively distributes the change in economic dispatch requirement among those units on control).

This calculation takes into account units with scheduled ramps or with operator entered basepoints and ensures that the resulting change in generation is allocated appropriately to economically dispatchable units, and results in an updated set of basepoints for every controllable unit.

PLC Regulation Calculation

Area level regulation requirement is allocated to all PLCs providing regulation control for the current regulating region (Regulation, Assist or Emergency) using Regulation Participation Factors (Rpf), which can be calculated automatically based on unit ramp rates, or can be manually overridden by the operator. Overridden Rpfs take precedence & cause recalculation of the remaining non-overridden Rpfs.

The proportional component of ACE regulation (ACEREGP) is allocated directly based on participation factors. The integral component (ACEREGI) is allocated based on Economic Participation Factors (Epf) when these are available[7] (units on economic dispatch) and upon Rpfs otherwise.

PLC Desired Generation

The unconstrained desired generation for the PLC is simply the combination of the basepoint & regulation components as calculated above. This may be constrained by a number of considerations, including:

Forbidden Zones	A PLC controlling a single unit with a modelled forbidden zone will be constrained to one boundary of the forbidden zone until a zone crossing timer expires, when the unit is ramped quickly to the other side of the zone, thus minimising the time spent in the zone
High/Low Limits	PLCs exceeding their limits, which may be overridden, derated via a schedule or telemetered, are constrained at the limit and the difference reallocated to other PLCs.
Change Reversal Logic	This logic prevents issuing controls in the opposite direction to the previous controls for a preset minimum period.
At Min/At Max	Optional PLC telemetry can indicate that the plant is temporarily unable to move in one or other direction, and the PLC will respect this. Primarily protects against short term issues such as boiler imbalance.
Response Rate Constraint	PLC movement may be constrained by the dynamic selection of short term or maximum sustained response (MSR) rate.

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[7] Integral ACE components imply a sustained departure from plan, and should therefore be allocated on an economic basis in anticipation of the next economic dispatch.

The final PLC error (difference between constrained desired MW & current PLC MW) is input to a compensated (lead/lag) proportional controller and PLC error accumulation logic. The error accumulation logic accumulates PLC errors less than the PLC control error deadband, until such time as the accumulated error (plus any additional regulation) exceeds the error deadband & the values can be meaningfully issued.

Control Issue

A final permissive ACE check is performed to ensure that for values of ACE above a threshold controls which would tend to worsen ACE are suppressed. Controls which pass this test (or all controls, when ACE is below the threshold) are then issued as either raise/lower pulses or setpoint controls.

Raise/lower controls are converted via a calibration factor to a pulse length in milliseconds. Pulses with lengths less than the smallest meaningful pulse signal are accumulated until a meaningfully sized pulse has accumulated (perhaps over a number of cycles).

Setpoint controls are also subject to deadband check to ensure that the current setpoint differs significantly enough from the previously issued control.

PLC Not Tracking Test

A PLC response test is performed periodically (typically 2 minutes) to determine whether PLCs on control are tracking the issued controls. The test compares the total of the incremental change signals issued with the total change realised, with filtering introduced to minimise false alarms.

In additional to alarming changes of tracking status for a PLC, other actions can also be configured:

- Continue to use the PLC normally
- Continue to use the PLC but don’t consider it for regulation
- Suspend the PLC

Joint AGC Control

A relatively recent AGC development (with relatively scanty documentation) provides the ability for area ACE values to be shared between areas (i.e. one area contributes to the regulation of the ACE for a different area, in addition to its own).

This is modelled as a special tie between the areas whose scheduled flow is determined dynamically. Generally this is a fixed percentage of the requesting area’s ACE within some defined limits. It is not clear whether this can be performed bilaterally (i.e. two areas sharing reserve in one direction or the other depending on which has the greatest need).

Since in the New Zealand case this tie is physically represented by the HVDC link it is a promising way of managing area reserve sharing while meeting the individual areas’ control objectives (which may include a frequency offset for time-error correction).

HVDC operation regions where transfer of regulation is not feasible could be managed by forcing the ACE percentage values to zero.

Appendix 4 – AGC Implementation Issues List

Issue Number	Description	Section Reference
1	Generator participation	3.1
2	Co-optimisation	3.2
3	HVDC control	4.1
4	HVDC use	4.2
5	FK minimum	4.3
6	Short term ramp rate information	4.4
7	Performance based payment	4.5
8	Form of FK offer	4.6
9	Unit level information	4.7
10	Generator interface	5.4