Hydro Tasmania

21 October 2021

Anna Collyer
Chair
Australian Energy Market Commission (AEMC)
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SYDNEY SOUTH NSW 1235

Dear Ms Collyer

Synchronous services markets rule change (ERC0290)

Hydro Tasmania is Australia's largest producer of renewable energy, and is an active participant and significant contributor to the energy market reform agenda. Hydro Tasmania owns Victorian based electricity and gas retailer Momentum Energy and is a provider of specialist power and water professional services through our consulting business Entura.

Managing high levels of non-synchronous generation in Tasmania

Hydro Tasmania has had considerable experience in a region that has had very large proportions of inverter based and variable renewable energy (VRE) generation. In early 2021 Tasmania was briefly operated 92% from non-synchronous generation sources, which is the highest for any power system of this size. 100% instantaneous non-synchronous generation is expected to be reached on the island within a year, more than a decade ahead of the NEM. Given the rule change is attempting to facilitate this transition, it is important to draw on the successful Tasmanian experience.

Together with TasNetworks and AEMO, Hydro Tasmania has adapted plant and developed systems to provide essential system services during periods of low synchronous generation. A key element of the success in Tasmania has been our use generators of synchronous condenser mode to supply inertia and system strength, an option available to most peakers at very low conversion cost. It is from this practical and real experience that Hydro Tasmania proposed its Synchronous Services Markets rule change to benefit broader NEM objectives.

Market vs non-market ancillary services

Hydro Tasmania welcomes the opportunity to comment on the AEMC's directions paper on a Capacity Commitment Mechanism and Synchronous Services Markets. The focus of the AEMC's paper is on essential system services including inertia, frequency control and system strength. The AEMC argues that with increasing proportions of inverter based variable renewable energy (VRE) generation some of these services such as inertia and system strength will no longer be automatically provided in sufficient quantities, as a by-product of the dispatch of synchronous generators to meet the energy market's needs, to ensure secure operation of the power system.

The AEMC's paper sets out two broad options for how essential system services could be procured. These are: a **market ancillary services (MAS) approach, and a non-market ancillary services (NMAS) approach.** These two approaches are exemplified via the Rule changes proposed by Hydro Tasmania (a co-optimised market based approach) and Delta Electricity (a non-market day ahead commitment approach).

The AEMC has correctly outlined a long term vision for essential system services that where possible they are unbundled, explicitly valued, scheduled, dispatched and priced. The ESB has correctly stated that the direction for essential system services is to use co-optimised, market-based procurement where possible**. Hydro Tasmania considers that it would be better for these services to be unbundled from the start and co-optimised, which is consistent with the AEMC and ESB's vision. A MAS approach using co-optimisation in the spot market is more economically efficient than an NMAS approach** and better fits into the NEM's decentralised design philosophy and the AEMC's long term vision for ESS. A co-optimised MAS approach enables:

- The maximisation of the value of spot market trading (NER clauses 3.8.1 a and b) because it can enable the optimal spot market trade-offs between the dispatch of ESS, FCAS and energy depending on their costs (offers).
- Unbundling of services (some suppliers might provide multiple services but this is no different to what happens with energy and FCAS).
- The optimal use of existing resources to supply ESS, FCAS and energy.
- Marginal cost and transparent pricing of services which will encourage new entry and conversion of synchronous generators to be able to operate in synchronous condenser mode.
- Creates more transparent and efficient pricing and consequently better incentives for efficient operations and investments.
- Avoids issues of managing opportunity costs when spot market energy prices are very high or low because these are automatically accounted for in the ESS price.
- A MAS approach satisfies the National Electricity Objective (NEO) better than a NMAS approach.

Revised market approach

Since lodging its original rule change proposal in 2018, Hydro Tasmania has welcomed the opportunity to discuss our proposal with the AEMC, AEMO and the industry more broadly. Based on feedback received through these discussions, Hydro Tasmania has reviewed and revised our co-optimised approach. In this submission, **Hydro Tasmania outlines a revised approach that can be readily implemented using the current version of NEMDE with some additional generic constraints**. The revised co-optimisation approach addresses the issues of:

- yoyoing commitment decisions,
- compensating market participants who supply ESS for any opportunity costs,
- producing market clearing prices based on the marginal cost of meeting each ESS requirement,
- partial commitment dispatches,
- secure system configurations, and

– modelling of non-linear functions.

Non-market approach

One of the key arguments put forward for the NMAS approach, being that it can more accurately model essential system service constraints in an optimisation than the MAS approach, is incorrect. With increasing amounts of VRE generation at the grid and distribution levels forecast errors will inevitably increase. Further, the forecast errors are much larger a day ahead than one hour ahead. The optimal time to commit resources is therefore as late as possible such as through a market co-optimised approach.

A NMAS approach could create incentives for generators not to commit units for the energy market in the expectation that they will get paid start up and running costs and then be able to get the upside of participating in the energy market thus distorting the energy and FCAS markets. This has been observed in SA with AEMO directing units online for system strength/system inertia.

Hydro Tasmania has welcomed the chance to discuss these rule changes previously with market bodies and looks forward to ongoing dialogue with the AEMC and AEMO on these issues. Please contact John Cooper (john.cooper@hydro.com.au) should you have any questions.

Yours sincerely

John Cooper

JN Cooper

Manager Market Regulation

Capacity Commitment Mechanism and Synchronous Services Markets

Submission to AEMC

October 2021

Contents

1.0 Introduction

The AEMC's directions paper sets out two broad options for how essential system services could be procured. These are: a market ancillary services (MAS) approach, and a non-market ancillary services (NMAS) approach. These two approaches are exemplified via the Rule changes proposed by Hydro Tasmania (a co-optimised market based approach) and Delta Electricity (a non-market day ahead commitment approach).

The MAS approach is to co-optimise in the spot market the new ESS required to run the power system. These new services are inertia, system strength and a new fast FCAS. The Hydro Tasmania proposal initially focusses on system strength and inertia which can be managed via synchronous units (synchronous generators or synchronous condensers). The other new ESS, a new fast frequency control, can be managed just by extending the current FCAS definitions and included in the current energy and FCAS co-optimisation framework.

The NMAS approach, as exemplified by Delta Electricity's Rule change proposal, has a day ahead commitment process to provide system security and reliability services. In effect the proposal is for a day ahead commitment mechanism for system strength, inertia, "operational reserve" and any other required system security services. With the inclusion of "operating reserve" this approach is fundamentally shifting some of the energy spot market into a day ahead market. Further, this approach also envisages including Reliability and Emergency Reserve Trader (RERT) commitments and thus entangling "out of market" services with "in market" services and resulting in market prices not representing the marginal value of the energy, FCAS and ESS.

Hydro Tasmania considers that a MAS approach using co-optimisation in the spot market is more economically efficient than an NMAS approach and better fits into the NEM's decentralised design philosophy and the AEMC's long term vision for ESS. This submission:

- discusses and compares the MAS and NMAS approaches for ESS,
- provides a revised Hydro Tasmania proposal, which **can be readily implemented using the current version of NEMDE with some additional generic constraints**,
- and the rationale for why a MAS approach satisfies the NEO better than a NMAS approach

This submission includes two appendices:

- **Appendix A: Coordination in Electricity Markets.** Contains an excerpt from a report by SW Advisory for a group of generators which was submitted to the AEMC as part of its Reliability Frameworks Review.
- **Appendix B: Example ESS Co-optimisations.** Provides some simple examples of how co-optimisation of synchronous services can be done in the spot market for cases where there are existing generic constraints with unit connection statuses on their right hand sides (RHSs) and for situations where a least cost configuration of synchronous units is required to manage system strength and/or inertia.
  - The Excel spreadsheet that developed these examples is also provided to the AEMC for information.

2.0 Background

2.1 Changing Power System

Historically the NEM operated using large thermally fired dispatchable power stations, typically based around coal and gas hubs connected to the major load centres by major transmission lines. The requirement to mitigate greenhouse gas emissions and the accelerated development of energy technologies is driving a rapid shift away from this traditional form of generation to variable renewable energy (VRE) generation based primarily on solar PV, wind and storage systems. This is driving significant changes in the operation of the NEM and the investment environment.

VRE has increased rapidly over the last ten years. In total, grid and embedded VRE generation represents around 31 per cent of all generation in 2021. This is expected to increase to around two thirds of all generation by 2030. The likely dominance of VRE and its non-dispatchability are key areas of consideration with respect to the future NEM market design.

The increase in VRE is expected to drive an increase in the need for energy storage. This is likely to be in the form of battery and super capacitor energy storage systems and pumped hydro, but may also include other forms of storage including hydrogen, other chemical products, compressed air, etc.

Along with the increase in inverter based VRE generation, there will be explicit requirements for new ancillary services and variations to existing ancillary services in order to maintain the power system in a secure operating state. These ancillary services are referred to as the essential system services.

2.2 Post 2025 Market Design

Except for the planned introduction of five-minute settlements, the NEM has had minimal market design changes since the original FCAS spot markets were set up in 2001. However, since 2001 there have been substantial changes to the power system and the rate of change is increasing. There has been a substantial increase in large scale variable renewable energy (VRE) generation, a reduction in load growth, increased PV penetration at the household level, increased deployment of batteries at large and small scale and retirements of several coal power stations. These changes to the market have created issues of low inertia in regions and network zones, system strength problems, changes in network congestion and constraints, changing requirements for FCAS and governor like responses (primary frequency response) etc. In response to these changes the ESB has been working on a Post-2025 Market Design.

In its advice to Energy Ministers regarding market arrangements for essential system services (ESS), the ESB put forward the following objectives:

- new market-based arrangements to value the services needed to support the changing mix of resources in the NEM;
- new market mechanisms to support efficient scheduling and dispatch by AEMO; and
- to facilitate a range of supply and demand-based technologies and resources with capabilities to deliver these essential services.

In considering changes to the NEM, the ESB stated that: "**ideally spot market arrangements combined with co-optimisation should be used where possible**, and the market should progressively move towards spot market provision for services. However, there are some services that may be better suited to structured procurement where spot market arrangements may not be appropriate (either now or ever)."

2.3 Long Term Vision of an Efficient Power System

2.3.1 Introduction

With increasing penetration of VRE generation and retirements of coal and gas fired generation, increasing amounts of flexible generation and storage will be required to manage the demand and supply balances in real time. This new generation will need to be highly flexible to efficiently balance the randomness (unpredictability) of VRE generation. The new generation will be predominately composed of battery storage systems, pumped hydro systems and super capacitor storage systems. This new generation will be able to start and stop and ramp up and down very quickly.

In addition to systems that balance demand and supply in the energy market, new systems will be required to provide frequency management, inertia, system strength and voltage control.

2.3.2 Price durations curves

More VRE generation will certainly lower prices for large periods of time. The shape of the price duration curve will also be changed so that low prices account for much larger proportions of prices but there will still be periods of high prices. Thus, the average spot prices may go down, which will encourage the exit of baseload and inflexible generation but average spot prices attainable by flexible dispatchable resources may go up. Consequently, the change in shape of the price duration curve does not mean investments in flexible dispatchable resources will not proceed. On the contrary these investments will proceed as needed provided the Market Price Cap (MPC), Cumulative Price Threshold (CPT) and Administered Price Cap (APC) are allowed to rise to the levels required for investments in flexible resources such as batteries and pumped hydro generation and to meet the reliability requirements anticipated by governments.

2.3.3 Ideal dispatchable generation and essential system services

When discussing the future power system and how generation and essential system services should be optimally scheduled, dispatched and priced its worthwhile contemplating what would be the ideal dispatchable plant for providing energy, FCAS and any other essential services required to run the power system in an efficient, secure and reliable manner.

The ideal dispatchable generating unit would:

- be able to start up and shut down very quickly,
- be able to ramp up and down very quickly,
- have no minimum run times,
- have no minimum load,
- have no energy constraints,
- be able to provide FCAS, primary frequency control and very fast contingency FCAS,
- be able to provide inertia or equivalent (a linear response to the rate of change of frequency),
- be able to provide voltage control/reactive power, and
- be able to provide system strength.

The ideal dispatchable load would have similar capabilities and the ideal storage unit would combine the ideal dispatchable generator and load. Clearly none of the existing technologies meet these ideals. However, the market pricing system for energy, FCAS and ESS should encourage the investment in and operation of flexible technologies that are closer to the ideals rather than provide a crutch for less flexible technologies.

2.4 National Electricity Objective

The National Electricity Objective as stated in the National Electricity Law (NEL) is:

> *"to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:*
>
> > *price, quality, safety and reliability and security of supply of electricity*
> >
> > *the reliability, safety and security of the national electricity system."*

The AEMC views that the relevant aspects of the NEO that apply to Capacity Commitment Mechanism and Synchronous Service Markets rule change are the price, security and reliability of supply of electricity. In particular, the AEMC considers the approaches should be evaluated against the four criteria:

- efficient and secure dispatch
- market transparency and efficient long-term decision making
- transitional considerations, and
- implementation costs and timelines.

In principle, co-optimisation and marginal pricing across all ESS, FCAS and energy markets will lead to efficient operations via the maximisation of value of trade in the NEM's spot market. Efficient marginal prices that are published will lead to market transparency. In turn, published spot prices will lead to forward contracting and efficient investment.

A co-optimised spot market is more efficient for operations than forward markets or non-market arrangements. Thus, an efficient spot market with co-optimisation and marginal pricing across all ESS, FCAS and energy markets will satisfy the NEO better than any NMAS arrangements. The main issues are:

- how easy and costly it is to implement a co-optimised spot market in ESS, energy and FCAS, and
- what would be the transitional arrangements.

2.5 Decentralised Decision Making and NEM Design Principles

When the NEM was originally designed there was a concept that the market would operate via price signals rather than via a system operator controlling the market and that decision making would be decentralised to participants as much as possible. In particular, unit commitment decisions, management of fuel, water and energy constraints etc. were to be decided by the market participants not by the system and market operator (NEMMCO/AEMO). This was to be achieved via flexible rebidding and rolling pre-dispatch schedules and price sensitivities.

The decentralised approach to decision making in the NEM design is captured in the NER's clause 3.1.4, which states:

3.1.4 Market design principles

(a) This Chapter is intended to give effect to the following market design principles:

(1) **minimisation of *AEMO* decision-making to allow *Market Participants* the greatest amount of commercial freedom to decide how they will operate in the *market*;**

(2) **maximum level of *market* transparency in the interests of achieving a very high degree of *market* efficiency, including by providing accurate, reliable and timely forecast information to *Market Participants*, in order to allow for responses that reflect underlying conditions of supply and demand**;

(3) avoidance of any special treatment in respect of different technologies used by *Market Participants*;

(4) consistency between *central dispatch* and pricing;

(5) equal access to the market for existing and prospective *Market Participants*;

(6) ***market ancillary services*** **should, to the extent that it is efficient, be acquired through competitive market arrangements and as far as practicable determined on a dynamic basis.** Where dynamic determination is not practicable, competitive commercial contracts between *AEMO* and service providers should be used in preference to bilaterally negotiated arrangements;

When the NEM was being designed there was considerable debate about how to ensure an orderly decommitment of units when their minimum loading levels exceeded the regional demand and any possible exports. This was a problem from the Victorian market, VicPool. This issue was ultimately resolved by adopting a philosophy that the market should not reward generator inflexibilities and generators should determine whether their units are committed or decommitted. Thus, the NEM embarked on a decentralised approach whereby generators only offered simple price and quantity pairs, there were no start-up costs, minimum loads, minimum run times etc. To ensure units would reduce their minimum loads or decommit, when necessary, the negative price floor was implemented. Generators manage their minimum loading levels and commitment decisions via the offers they make in the energy market and via rebidding in response to the pre-dispatch prices and schedules.

In the NEM, co-ordination of energy and FCAS are managed via an iteration of pre-dispatch providing dispatch targets, prices and price sensitivities and market participants responding to this information via rebidding until the system converges to the real time dispatches and prices produced by the dispatch optimisation (NEMDE). This decentralised co-ordination process is outlined in Appendix A: Coordination in Electricity Markets and in the AEMC's Directions Paper. The process is a bit like the Dantzig–Wolfe decomposition algorithm in linear programming which is used to solve large optimisation problems with a special structure. In the NEM's case the 'master problem' is the pre-dispatch and price sensitivities and the subproblems are the market participants' optimisations of their own resources using their own private information and models. The subproblems interact with the master problem via their rebids.

Because the NEM has chosen the more efficient and flexible path of decentralised decision making, AEMO, either directly or via its market systems, should not be making unit commitment decisions for any market services (energy, FCAS and ESS) in the NEM. Proposals for ahead unit commitment processes for ESS, operating reserves and reliability services are incompatible with the NEM's decentralised electricity market design. AEMO should only be able to make any sort of commitment decisions for out of market resources such as for the RERT and only if this is absolutely necessary.

2.6 South Australia and Directions

With the increasing amounts of inverter based VRE generation across the NEM, SA was the first mainland region to experience obvious power system security issues due to the shortage of synchronous generation being dispatched via the energy market. At times this shortage of synchronous plant being dispatched was causing issues with low inertia levels that could not be managed with the existing contingency FCAS arrangements and system strength. To address these issues AEMO used its powers of direction to commit additional synchronous units.

The units that were directed to commit by AEMO received compensation for start-up and minimum loading costs but they also received the spot market revenues for energy and FCAS. This potentially created an incentive for generators with synchronous generating units to not commit these units in the energy market, then get AEMO to direct their units to commit and get paid their start up and fixed running costs and finally get the upside of energy and FCAS markets if the spot prices became high. Thus, this cycle of staying out of the market and AEMO interventions substantially disrupted the proper functioning of the energy and FCAS markets in SA at times. It is vitally important that any ESS arrangements do not cause similar distortions to the energy and FCAS markets. A day ahead commitment market for ESS and "operating" reserves has this potential.

2.7 Essential System Services

In the ESB's and AEMC's discussions of ESS they identify four key services:

- frequency control
- inertia
- system strength
- operating reserves

2.7.1 Frequency control

Clearly the issues with frequency control in an environment with high penetration of inverter based generation can be managed with the current FCAS framework by appropriately adding new FCAS services or possibly defining a new suite of services. Any new suite of FCAS services should be co-optimised with energy in the spot market as is currently done for the existing set of FCAS services. Any new FCAS services should not be bundled into an ahead mechanism for ESS. Such an approach would result in an overall loss of dispatch efficiency and efficient price signals since decision making is best done as close to real time as possible and thus would be contrary to the NEO.

2.7.2 Inertia

In the longer term, inertia can be co-optimised with energy and FCAS as inertia can affect the required amounts and costs of FCAS. Inertia, FCAS and energy can be jointly co-optimised via a linear programming optimisation via the use of the power system swing equation[1]. However, in the shorter term it would be sensible to manage inertia via a market based approach to ESS.

2.7.3 System strength

System strength is a characteristic of an electrical power system that relates to the size of the change in voltage following a fault or disturbance on the power system. System strength is the ability of the power system to maintain and control the voltage waveform at any given location in the power system, both during steady state operation and following a disturbance. The system strength at a given location is proportional to the fault level at that location, which in turn is inversely proportional to effective grid-following inverter-based generation penetration at that location.

With increased penetration of inverter based VRE generation system strength has become or is projected to become an issue in several areas of the NEM including SA, Tasmania, Victoria and northern QLD. System strength is largely a localised issue like voltage control. Clearly system strength will be an increasing issue for the NEM and should become a service that is paid for in the NEM.

2.7.4 Operating reserves

Operating reserve is a term commonly used in North American power systems. An operating reserve is a system of generating capacity available to the system operator within a short interval of time to meet demand in case a generator goes down or there is another disruption to the supply. The operating reserve is made up of the spinning reserve as well as the non-spinning or supplemental reserve:

- The spinning reserve is the extra generating capacity that is available by increasing the power output of generators that are already connected to the power system.

[1] George T, Wallace S, Crisp J, Mardira L and Leung J (2021) 'Exploring options for new frequency control ancillary service markets in the Australian National Electricity Market' IEEE PES Innovative Smart Grid Technology – Asia.

- The non-spinning reserve or supplemental reserve is the extra generating capacity that is not currently connected to the system but can be brought online after a short delay. This typically equates to the power available from fast-start generators.

Operating reserves correspond to the NEM's FCAS. On the other hand, some of the discussion about "ramping and operating reserves" is really a discussion about the energy market and the need to respond to the increasing generation and load variability in the power system due to increasing penetration of VRE generation at the grid and distribution level. This is really an energy market issue and is addressed in a later section. Consequently "ramping and operating reserves" should not be bundled in with other ancillary services, once the FCAS arrangements have been updated to meet the requirements of high VRE penetration then the residual issues for "ramping and operating reserves" need to be addressed in the energy market. They don't fit into the category of ESS.

Any issues with "ramping and operating reserves" should be addressed in the energy market via an increase in the market price caps (see discussion in section 2.9) and additional pre-dispatch runs which incorporate sensitivities based on forecast errors for loads and VRE generation and rapid ramping scenarios so that participants can make informed decisions about their operations and ultimately, their investments.

2.7.5 Synchronous services

For the shorter term, Hydro Tasmania suggests that system strength and inertia be managed by a synchronous services mechanism (SSM) which co-optimises the dispatch and pricing of these services. The method by which this can be done as a MAS is outlined in section 3.0.

2.8 Forecast Errors

With increasing amounts of VRE generation at the grid and distribution levels forecast errors will inevitably increase. Further, the forecast errors are much larger a day ahead than one hour ahead. For instance, in Figure 2-1 the forecast errors for SA for 24 hours ahead are about 3.5 times larger than for 1 hour ahead.

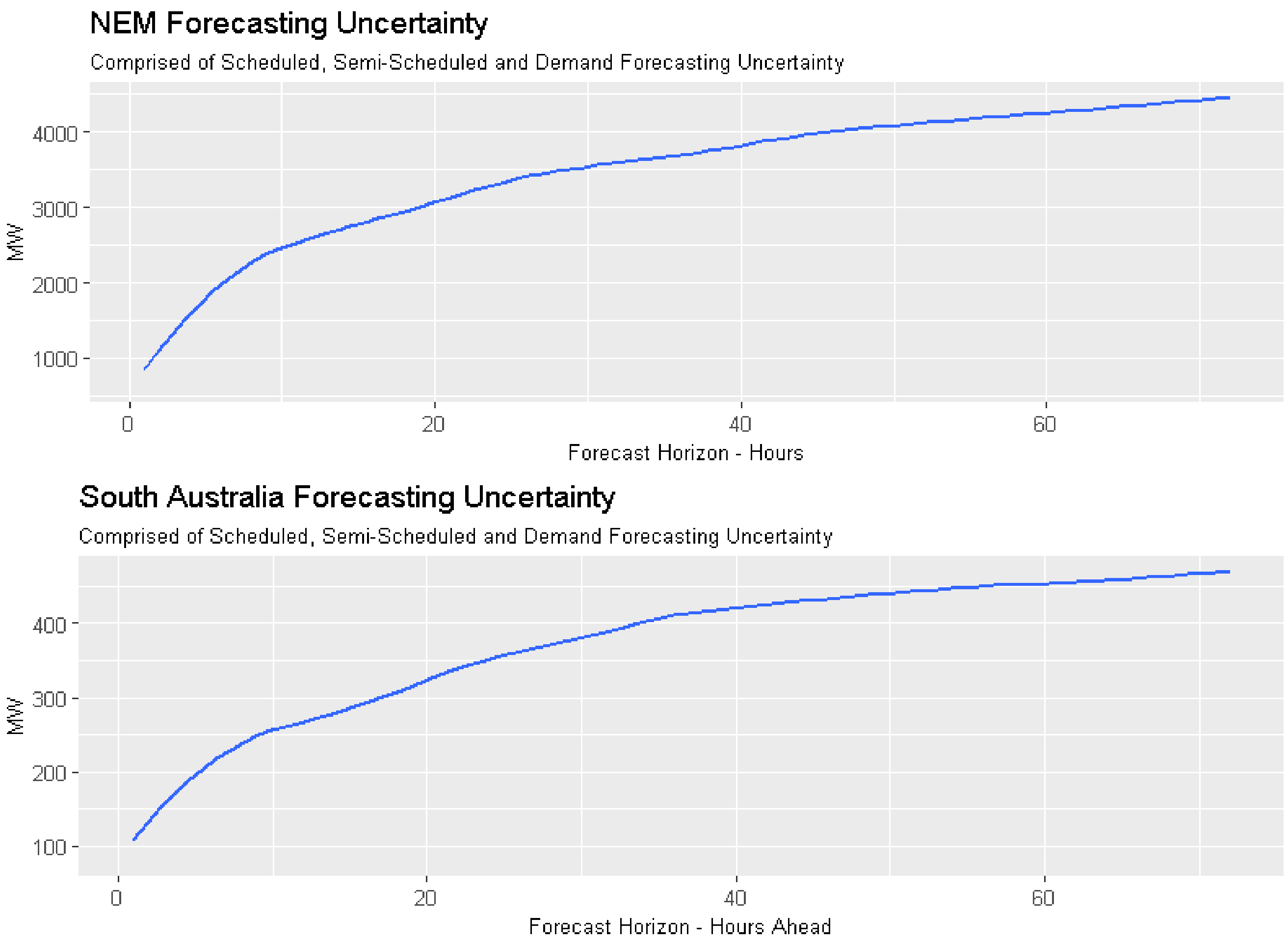


Figure 2-1 AEMO 98 percentile forecast error uncertainty measure (FUM), May 2018[2]

The implications of forecasts errors being much larger for forecasts many hours ahead compared to real time and for these errors to continue to increase with greater VRE penetration is that the optimal time to commit resources is as late as possible. The dispatchable generation resources that should be appropriately encouraged/incentivised in the NEM are the ones that can most quickly and flexibly respond to rapid changes in the demand and supply balance in the NEM. Focussing on ahead mechanisms for scheduling energy, FCAS or ESS does not seem to be the optimal direction to go. The focus should be on real time dispatch and the incentives for market participants to supply energy, FCAS and ESS when required, not day ahead scheduling.

2.9 System Reliability, Operating Reserves and Price Caps

As noted in Section 2.4, the NEM was based on the concept that the market would operate via price signals rather than via a system operator controlling the market and that decision making would be decentralised to market participants as much as possible. Following this logic, if there are reliability and security issues in the NEM then the NEM should be looking at:

- the price signals that drive generator operations and investment and where they are failing; and

[2] AEMO (2018) 'Determining Spinning Reserve Levels using Bayesian Belief Networks' presentation to Itron Forecasting Summit – San Diego, 15-17 May 2018

- the information provided to participants and where it is inadequate for efficient market operations.

As a first step, the NEM should not be looking at giving greater control to AEMO via ahead markets for operating reserves or reliability services. Ideally the NEM's market mechanisms for operations and investment should deliver a power system that meets the Reliability Standard without the intervention of AEMO in the market. The reliability settings for MPC, CPT, MFP and APC, particularly the MPC and CPT, are the key market parameters used to ensure that the Reliability Standard is met. The amount of intervention that is occurring in the NEM implies that the MPC should be higher.

Ideally all requirements for the NEM to run efficiently and reliably should be provided via market mechanisms; thus, in the longer term the reliability standard should be adjusted to the reliability that AEMO is using for the interim out of market reserves if that is the desired power system reliability and the MPC and CPT should be adjusted to match and AEMO's intervention in the market reduced.

Increases in the MPC, CPT, APC and a lowering of the MFP will encourage the flexible dispatchable generation technologies that are required for the NEM's future.

2.10 RERT, Directions and Reliability

AEMO's use of the Reliability and Emergency Reserve Trader (RERT) and directions are "out of market" mechanisms that should not be routinely used to manage energy reliability, FCAS and ESS. These services should be managed via market mechanisms including efficient pricing that creates the incentives to provide the services. In particular, these "out of market" mechanisms should not get incorporated into routine market mechanisms such the scheduling and dispatch of energy, FCAS and ESS unless absolutely necessary.

2.11 Tasmanian Experience with High VRE Penetration

The Tasmanian power system has been rapidly evolving over the past 15 years with increasing levels of renewables penetration. Tasmania has already had to address issues of increasing inverter based generation, low inertia and system strength that the rest of the NEM is only recently encountering.

The current position for Tasmania is that the minimum demand can be as low as 900 MW, whilst its DC interconnector, Basslink, may be importing over 400 MW and local wind can contribute over 500 MW. Under these conditions, there is little or no room left for synchronous generation. Additionally, Basslink power transfer during import is limited by a minimum required fault level and minimum inertia requirement to manage system rate of change of frequency (ROCOF). The ROCOF and inertia is managed by a limit/constraint equation and the interrelated availability of FCAS. Consequently, if these minimum system technical requirements cannot be met within the central dispatch process, constraints will limit Basslink flow and/or wind farm output so that more on-island synchronous generation is provided.

These constraints can also be alleviated by dispatching selected hydro generators in synchronous condenser mode.

Over the last decade, Hydro Tasmania, TasNetworks (formerly Transend) and AEMO have undertaken numerous initiatives to assist with managing and maintaining system security and stability. This has included significant capital expenditure to increase the capability of selected hydro and gas generation plant.

An outcome from this work is that a number of technical issues have been successfully addressed In Tasmania and the impacts of these issues on energy market outcomes are, in the most part, manageable. Consequently, there has been little impetus for addressing these issues in a more systematic, 'NEM focused' way until they surfaced as significant considerations for South Australia.

The initiatives that Hydro Tasmania, TasNetworks and AEMO have undertaken include the following:

- Hydro plant operating in synchronous condenser mode to support inertia and fault level requirements;

- Conversion of open cycle gas turbines (OCGT) to allow both generation and synchronous condenser operation;
- Generator governor modifications;
- Implementation of Frequency Control System Protection Scheme (FCSPS);
- Defining ‘region appropriate’ generator performance standards to maintain critical network capabilities;
- Network constraint formulation and optimisation; and
- Integrating new technologies to help manage high renewable penetration.

Hydro Tasmania has had very substantial experience in adapting plant and developing the systems to provide the ESS to run a power system with only a small proportion of the load being supplied by synchronous generation. A key component of what has been done in Tasmania is using generators running in synchronous condenser mode to supply inertia and system strength.

2.12 Conversion of OCGTs to Synchronous Condensers

As part of Hydro Tasmania’s strategy to address system strength and inertia issues in Tasmania we embarked on converting some GTs so that they could run in synchronous condenser mode.

Hydro Tasmania has four OCGT peaking plants located at Bell Bay in the state’s north. Three units were successfully modified to operate in synchronous condenser mode. They provide a very cost effective source of fault level support for the George Town area when compared to building new synchronous condensers. The units also provide some inertia, although being aero-derivative machines, the inertia contribution is significantly less than would be provided by a hydro unit of similar MVA rating.

The costs of the conversions of the GTs so that they could run in synchronous condenser mode was very low, less than $250k. In most OCGT cases it only involves control systems changes, compared to the very high costs of TNSPs purchasing dedicated synchronous condensers or the opportunity costs of restricting wind generation. It is notable that approximately half of NEM’s capacity is comprised of OCGT that are sitting idle during the time of high VRE penetration currently. Tasmanian OCGTs were continuously in synchronous condenser mode for the month preceding this submission. We are also aware of conversion of steam units in other markets, for a significantly higher cost, but with additional inertia benefits, offering salvage value to soon to be retired plant in the NEM.

3.0 Updated Hydro Tasmania Proposal

3.1 Introduction

This section outlines Hydro Tasmania's updated proposal for a market ancillary service (MAS) approach to the scheduling, dispatch and pricing of the ESS provided by synchronous units either operating in generating or synchronous condenser modes. The section builds upon Hydro Tasmania's original proposal and addresses some of the feedback provided by market bodies and market participants.

3.2 NEM Binding Constraints and Connection Statuses

Hydro Tasmania has undertaken an analysis of binding constraints from October 2020 to October 2021 and ranked them according to the hours that they were binding. Approximately a third of the top 50 constraints that were binding were quick constraints (the ones with a # at the start of the constraint ID). These were used by AEMO to constrain individual units at short notice. Of the remaining constraints, five contained synchronous generating unit's connection statuses on the RHSs that could be used to reduce level of constraint if incentivised through our proposal. Our analysis shows that NEM costs would have reduced by over $20m last year alone, primarily by increasing production at wind and solar farms in Queensland after the Callide explosion and increasing transfers from Victoria to NSW if peakers in respective regions were provided the incentive to come online in synchronous condenser mode or very low loads. These figures would be expected to grow considerably as VRE penetration increases in the coming years, demonstrating a net present value of hundreds of millions to the NEM if MAS approach is undertaken, and captured through modest investments as described in 2.12. In addition to the market efficiency benefits, the dynamic nature of MAS incentives would have increased system security by reducing constraint violation which were not anticipated (like the Callide incident) and hence would not have been catered for with a NMAS approach.

3.3 Original Approach

3.3.1 Overview

To optimise the connection statuses of synchronous units to address inertia, system strength and voltage control issues that would impact the amounts of inverter based generation that could be dispatched, Hydro Tasmania proposed a Rule change that would shift generator statuses from the right hand side (RHS) of constraint equations to the left hand side (LHS) of the equations. That is the connection statuses (commitment statuses) would move from being inputs to being decision variables (controllable variables). The proposal had a decision variable to close an open circuit breaker if this produced a more economic dispatch based on relaxing the relevant constraints and the costs of committing the unit.

3.3.2 AEMO and AEMC concerns

With this original proposal AEMO and AEMC were concerned with the potential for the dispatch process to commit units in one dispatch interval and because the unit's initial connection status for the next dispatch interval would then be connected then the optimisation would not recommit the unit and consequently the generator would decommit because it no longer had an incentive to remain on. If this happened there would be a yo-yoing of unit commitments and decommitments.

3.3.3 Market pricing issues and opportunity costs

Another problem with the original proposal was that generators would be paid as bid, not a clearing price. Given that most units would have a non-zero minimum loading level, if prices were very low, the pay as bid pricing could result in substantial opportunity costs that wouldn't be recovered. Further, the pay as bid approach would not result in clearing prices which in turn would substantial reduce market transparency and incentives for efficient new investments and operations.

3.4 Revised Approach

3.4.1 General approach

The general MAS approach proposed by Hydro Tasmania for synchronous services is to co-optimise these services with energy and FCAS. This would involve modest extensions to the NEM's dispatch engine for dispatch and pre-dispatch. In particular, the extensions to the market to include synchronous services and other ESS would comprise the following:

- Decision variables for commitment decisions for synchronous services (MAS) would be added to the NEMDE formulation. These variables would be real variables on the interval [0,1] rather than binary variables. The use of real [0,1] variables speeds up the optimisation solution times and enables synchronous service clearing prices to be determined.
- Decision variables to indicate whether a unit should run in generator mode or synchronous condenser mode if it was capable of both.
- Market participants could make offers to commit their synchronous units. Their offers to commit a unit would consist of an hourly commitment cost and a minimum loading requirement. The offers to commit their synchronous units would use just a single $/h price and a minimum loading level. The minimum loading level would have to correspond to the first band (price and quantity pair) in their energy offer or bid. These two requirements are necessary to reduce the potential for partial commitments.
- The additional costs for commitments would be added to the NEMDE objective function.
- Additional constraints would be added to NEMDE:
  - all generic constraints that had connection statuses (commitment statuses) on their RHSs and either significant numbers of hours binding or significant marginal costs (shadow prices) historically, would get converted to a co-optimised form with the commitment statuses moved to the LHSs as decision variables; and
  - minimum secure system configurations.
- Some of minimum secure system configurations and generic constraints might result in non-linear functions of the number of synchronous units committed in zones or regions in the NEM. In these cases, these non-linear constraints can generally be formulated as piecewise linear constraints. Often these constraints will not be convex but this can be addressed using special ordered set (SOS) variables. SOS variables are already used in NEMDE to model the quadratic transmission losses on interconnectors.
- The payments for a unit providing synchronous services would be based on all of the constraints in which its connection status appears as a decision variable. Its payment would be the sum, over all of the constraints in which it appears, of the shadow price of the constraint times the coefficient of the unit's commitment status in that constraint.
- In the cases of partial dispatches the market participants would be obliged to commit their units and would get paid the market clearing price as calculated above.

Some simple examples of how this MAS approach can be applied are in Appendix B: Example ESS Co-optimisations.

3.4.2 Scheduling, dispatching and pricing

Hydro Tasmania's proposal for developing a MAS approach to the commitment of resources for ESS is aligned with the NEM's current philosophy for scheduling, dispatching and pricing. Like what is currently done, pre-dispatch would be run on a rolling basis providing dispatch and pricing information and sensitivities, including ESS dispatches and prices, to enable market participants to optimise their own positions and for the market to co-ordinate in a decentralised manner. The actual dispatch and prices would be binding. AEMO would not be making any day ahead commitments for "in market" services or resources but could still make decisions about RERT and directions as is currently the case for out of the market resources.

3.4.3 Binary variables

Binary variables in optimisations are often used to model decisions such as whether to commit a unit or not, whether to make an investment or not etc. They are also used to model logical relationships.

A general problem with using binary variables in an optimisation is that you can't get any marginal cost information (shadow prices) for constraints. In some systems, where binary or integer variables are used, they will determine shadow prices for constraints by effectively doing a second optimisation run with all of the binary and integer variables fixed at their 'optimal' values and the real decision variables optimised in the new constrained problem. The draw back with this approach for commitment decisions and the provision of ESS is that the ESS will often not be priced correctly or priced at all. The market clearing price will often be estimated as zero if there are some decision variables remaining in the constraint equation. If there are no decision variables remaining in the constraint equation then no price will be computed.

An alternative approach to using binary variables is to use real variables on [0,1] interval. This is what is proposed in the Hydro Tasmania approach to MAS for ESS. This approach enables much faster computations and the determination of marginal cost prices but can result in partial commitments, a potential problem with is addressed in a later section.

3.4.4 System configurations

System configuration requirements might specify such things as the minimum number of synchronous units running in a region or more complex requirements such as at least two units from zone A and either one of the units from set B or two of the units from set C. These arrangements can generally be formulated in terms of binary variables and thus also formulated in terms of real [0,1] variables.

3.4.5 Nonlinear functions

Sometimes system configurations or generic constraint RHS may in effect specify non-linear function via a set of logical conditions. For instance, a set of secure operating requirements could be as follows:

- When there is between 0 – 1,200 MW of wind generation, South Australia must have three capable synchronous generating units available and in the market to maintain sufficient power system strength.
- When there is more than 1,200 MW of wind generation, South Australia must have four capable synchronous generating units available and in the market to maintain sufficient power system strength.

These requirements can be reformulated as the following constraints and non-linear function modelled as a piecewise linear function where:

N = sum X(i) where N is the number of synchronous units online and X(i) is a real [0,1] variable modelling the commitment status of unit i, and

Wind <= F(N) where F(N) is a piecewise linear function modelled using special ordered sets.

There are many non-linear functions that can describe the upper limits of wind generation at the integer number of committed units. Under Hydro Tasmania's proposal where partial commitments require the commitments of units and to facilitate marginal cost pricing the piecewise linear function has been chosen to be 0 MW for 2 synchronous units committed and 1,200 MW for three synchronous units connected and a much larger number for four synchronous units connected. An example of such a function is below in Figure 3-1.

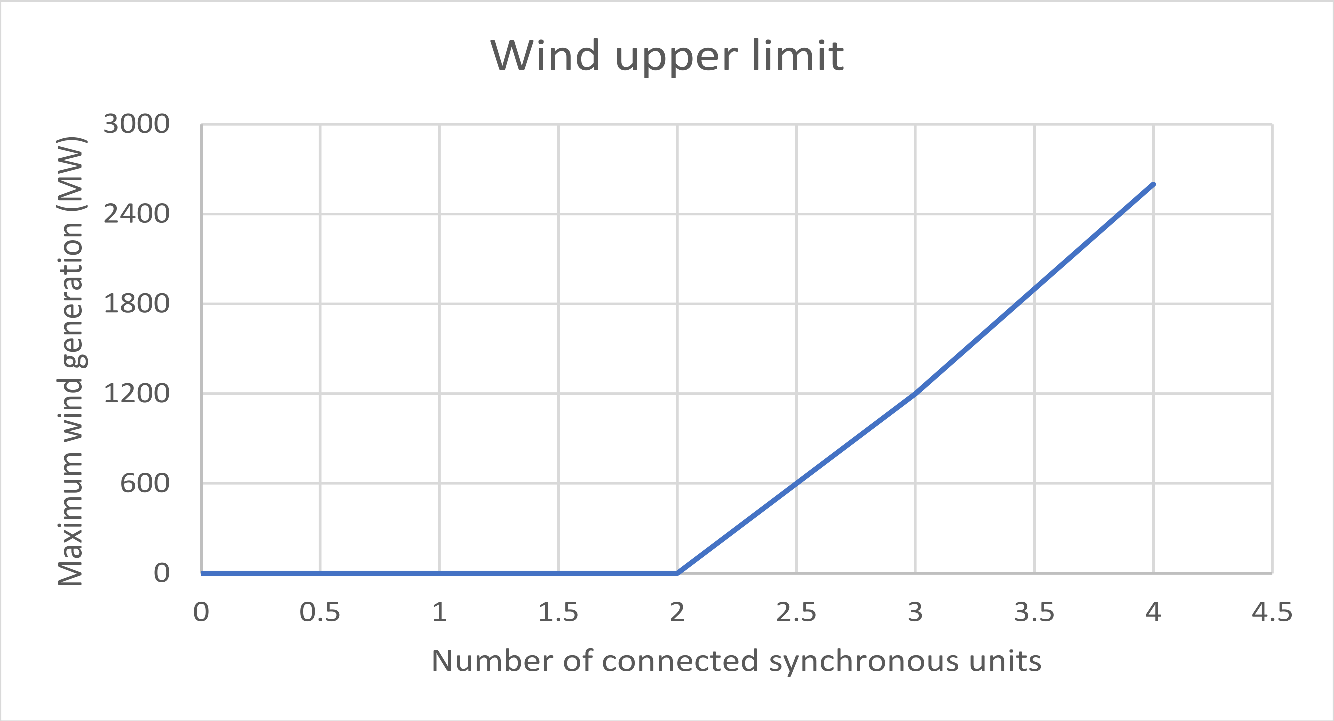


Figure 3-1 Example of piecewise linear model of non-linear function

3.4.6 Marginal pricing

Every constraint that has one or more unit commitment decision variable will have a shadow price as a result of the dispatch optimisation. If the constraint was not binding then the shadow price will be zero. If the constraint was binding then the shadow price will be non-zero. The relevant constraints for marginal pricing of ESS are the ones where the committed units satisfy a system configuration requirement or enable the relaxation of a generic constraint such as a maximum amount inverter based generation. Depending on whether the constraint is a less than or equal, greater than or equal or equality constraint and whether the optimisation is formulated as the maximisation or minimisation the shadow prices can be positive or negative.

The marginal contribution of a unit committed to relaxing a constraint is:

> the appropriate sign x the shadow price ($/h) x the coefficient of the unit commitment decision

The total marginal value of a committed unit is the sum of its marginal contributions for all of the constraints in which it appears. For each dispatch interval a unit would be paid the marginal value ($/h) x 1/12 h.

Lastly, if this marginal pricing approach is adopted, the marginal value calculations for each unit will ensure that the unit is compensated for all opportunity costs including for times when the unit is constrained on at times of low or negative prices.

3.4.7 Partial unit commitments

Any unit which was partially committed would be required to be committed for that dispatch interval. However, it should be noted that the unit will not require any constrained on payments or make good payments because the unit's total marginal value calculation will cover the full suite of its offered prices for energy, FCAS and ESS.

3.4.8 Power system security

Power system security will be fully satisfied even with partial commitments because a partially committed unit will be required to be online for the periods during which they are committed in the dispatch process. Thus, provided the power system security requirements are adequately captured in constraints, this approach will result in the same or more secure operations than an optimisation that just uses binary variables for the commitment decisions.

3.4.9 Modelling units that can operate in generator or synchronous condenser mode

Units operating in synchronous condenser mode can provide inertia and system strength services. When operating in synchronous condenser mode units consume power and thus when prices are negative and synchronous services are required it would be better to provide these services from units in synchronous condenser mode rather in generator mode with minimum loading levels.

Many hydro units can operate in generator or synchronous condenser mode. Also, gas turbines can be upgraded so that they can also operate in synchronous condenser mode. In the dispatch optimisation a unit which can operate in both modes would have a commitment variable for a generation commitment and another commitment variable for synchronous condenser commitment and an additional constraint that the sum of the generator commitment and condenser commitment variables is less than or equal to one.

3.4.10 Simple examples

Appendix B: Example ESS Co-optimisations provides a sequence of simple examples that illustrate the points outlined in the Hydro Tasmania MAS proposal for the dispatch and pricing of ESS.

3.4.11 Example of set up for a commonly binding generic constraint

The following is an outline of how to convert a constraint that involves the connection statuses of several synchronous units on the RHS of the equation. The constraint equation is identified as T::T_NIL_1 and the purpose of the constraint is to prevent a transient instability for fault and trip of a Farrell to Sheffield line. The constraint only becomes active if three or more west coast synchronous units are generating. In this case the default value for the RHS is 580 MW. The constraint needs to be inactive or swamped if less than 3 synchronous West Coast units are generating or the Farrell 220kV bus coupler is open or Hampshire 110kV line is closed.

For this example, the key issue is how to model the constraint being inactive if less than three West Coast units are running. If we use the notation of Xm = 1 if Mackintosh is online and 0 if not, Xb for Bastyan etc. then the part of the RHS related to the units being online becomes

Z= Sum Xi (number units online)

The swamping term Y is as follows

Y = 10,000 if Z < 3

0 if Z >= 3

Y can be modelled as the piecewise linear function as in Table 3-1 and Figure 3-2.

A key point to be remembered when using a piecewise linear approximation for logical or non-linear functions is that there is a requirement for partially committed units to commit, therefore it is necessary to have partially committed units when rounded upwards to conform to the underlying constraint. For instance, for the above swamping constraint the piecewise linear constraint could be constructed as Table 3-1. An alternative formulation that had the swamping term, Y, drop from 10,000 at 2 to 0 at 3 could result in a partial commitment giving a Y value of 2.4 say which would give a swamping term of 6,000 and result in three units being committed which would not be a correct representation of the constraint.

Synchronous units	Swamping amount limit	Swamping coefficient
0	10000	
1	10000	0
1.98	10000	0
2	0	-500000
4	0	0

Table 3-1 Example of piecewise linear function which can be used to model the swamping term

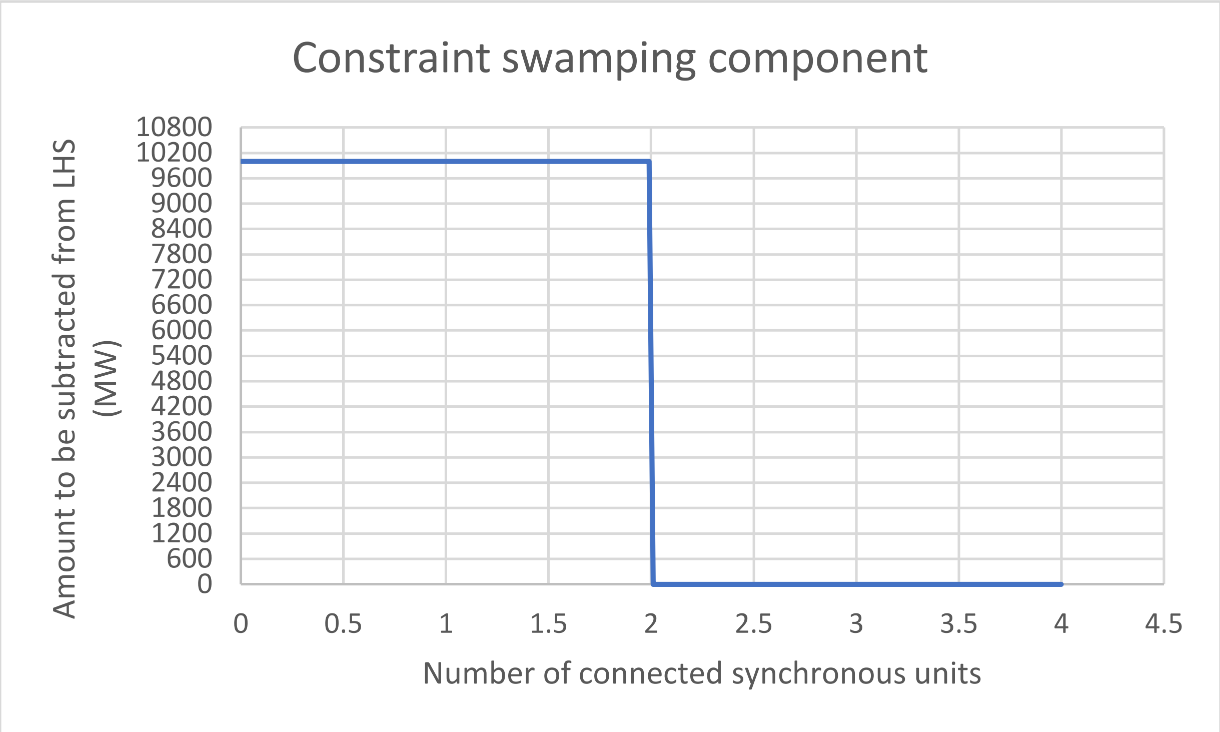


Figure 3-2 Example of piecewise linear function used to swamp a constraint

3.5 Addressing Previous AEMO and AEMC Concerns

Hydro Tasmania's revised MAS approach for ESS addresses issues previously identified by AEMO and AEMC, in particular:

- It addresses the potential yo-yoing problem;
- Partial commitments are managed to give secure dispatches; and

- Complex system configuration requirements and non-linear functions can be addressed using piecewise linear functions and special ordered set variables like what is done in NEMDE for quadratic losses on interconnectors.

3.6 Unbundling of Services

In their proposed initial reforms, the ESB assumed that services such as system strength and inertia would be bundled. We feel that, where possible, it would be better for these services to be unbundled from the start and co-optimised. Conceptually system strength and inertia are quite different. The only thing they have in common is that they can both be supplied by synchronous units. System strength is location specific and is related to the fault level at network nodes whereas inertia is either related to the whole power system or a potentially islanded portion of the power system. Further some resources may be able to provide one service and not the other.

Using a co-optimisation approach, some ESS resources may appear in some constraints and not others and thus it does not make any sense bundling the two services. The resources which can provide both services in the co-optimisation will generally be selected to provide both services, or no services, rather than just one service.

Fast response FCAS and inertia can be substitutes for each other and thus should in the longer term be co-optimised and priced together with energy. How energy, FCAS and inertia can be efficiently co-optimised and priced is outlined in a paper by Tim George et al to be presented at the Brisbane 2021 IEEE Innovative Smart Grid Technology conference[3].

Further, inertia is equivalent to a response to the rate of change of frequency which can be provided by some inverter based technologies as synthetic inertia. It does not have to be supplied by synchronous units.

3.7 Efficient Dispatch and Prices

Hydro Tasmania's approach of co-optimising ESS with energy and FCAS will result in efficient dispatches and prices and it does this in real time and thus does not have built into the process large forecast errors.

3.8 Incorporating TNSP and AEMO Contracts

Existing ESS contracts with TNSPs and AEMO can readily be incorporated into Hydro Tasmania's proposed framework. ESS providers with contracts with TNSPs and AEMO would offer their services at the contract prices and quantities into the ESS spot market. Further, to provide some financial incentives for the ESS providers to perform to their contracts with the TNSPs and AEMO, these contracts could be turned into swap contracts provided AEMO publishes the relevant ESS clearing prices.

3.9 Addressing Market Power

Given that some ESS such as system strength have a locational component and thus there could be a lack of competition to provide the service, a contracting approach could be used to mitigate any short term exercise of market power. Again, the contracts should oblige the ESS providers to offer their capabilities into the spot market at contracted prices. Also, the contracts could be set up as swap contracts.

[3] George T, Wallace S, Crisp J, Mardira L and Leung J (2021) 'Exploring options for new frequency control ancillary service markets in the Australian National Electricity Market' IEEE PES Innovative Smart Grid Technology – Asia.

4.0 NMAS Approach

4.1 Overview

The AEMC's proposed NMAS approach essentially envisages TNSPs and AEMO entering into contracts for ESS and AEMO scheduling the contracted ESS ahead of time, say a day ahead.

4.2 NMAS Optimisation

The proposed optimisation approach is to use an intertemporal optimisation with binary variables for the commitment of units. The optimisation would be run ahead of time with the objective of determining a schedule of ESS commitments that minimising the costs of the ESS. The proposed optimisation does not co-optimise the ESS with energy and FCAS.

The NMAS optimisation will not produce market clearing prices for ESS.

4.3 Problems with Approach

4.3.1 Not optimised with energy and FCAS dispatch

The proposed NMAS approach does not co-optimise the dispatch of ESS with energy and FCAS. Thus, the process when combined with the NEM's dispatch of energy and FCAS is unlikely to result in maximising the benefits of spot market trade.

The NMAS approach plans to use secure system configuration constraints and does not plan to incorporate generic constraints with unit connection states on the RHS. It will not be able to find the optimal trade-offs of the costs of ESS versus greater dispatch of more wind or PV generation.

4.3.2 Forecast errors

The proposed ESS optimisation is based on ahead forecasts which will have large errors for time periods many hours or days ahead. Thus, even though an intertemporal optimisation is planned to be used it will not result in the optimal real time dispatch of ESS.

4.3.3 Opportunity costs and make good payments

Since the proposed NMAS approach does not co-optimise the dispatch of energy and FCAS there will be situations where units are constrained on or off to provide ESS when the energy prices are very high or low. Under these circumstances ESS providers could suffer high opportunity costs. For instance, if a GT, with a minimum load of 10 MW and a fuel cost of $100/MWh, has an essential services contract for $1,000/h and is committed to provide system strength or inertia and the market price drops to -$60/MW then the unit will be losing $600/h. Unless the ESS arrangements allow for compensation for these losses through some form of 'make good' payments, ESS providers will be inclined to not follow their schedules. Alternatively, if 'make good' payments are part of the ESS NMAS approach then the intertemporal optimisation process is not even optimising the schedules ahead of time because it is missing a key source of costs.

4.3.4 Does not provide transparent and efficient prices

The NMAS approach contemplates that ESS prices would be determined via contract negotiations. There is no discussion of whether these contracts would be made publicly available. Because the NMAS approach proposes to just use binary variables it will not produce market clearing prices for ESS.

4.3.5 Does not create a clear path to unbundling services

The NMAS approach to ESS and the use of only secure system configurations does not provide a clear path for unbundling of system strength and inertia and facilitating the incorporation of inertia into the co-optimisation of the dispatch of energy and FCAS.

4.3.6 Contract mechanism are not as efficient as co-optimised spot market mechanisms

Prior to the NEM starting the co-optimised spot market in FCAS, there was a contract market in FCAS and NEMMCO scheduled the operations of the providers of these services. When the co-optimised spot market for FCAS was introduced the overall costs of FCAS dropped to about one third of what there were with the contract arrangements and the costs of some services dropped to about one tenth of what they were. Moving to a co-optimised spot market for FCAS resulted in very substantial cost savings and efficiency gains.

5.0 Comparison of MAS versus NMAS Approaches

5.1 Introduction

This section compares the MAS approach, as exemplified by the revised Hydro Tasmania proposal, to the NMAS approach, as exemplified by the AEMC proposal. In undertaking this comparison Hydro Tasmania has largely used the framework that AEMC used with a few additional criteria added to the analysis.

5.2 Unbundling of Services

The proposed MAS approach of Hydro Tasmania provides a simple framework in which the ESS can be unbundled. Over time, all of the constraints used to manage the dispatch of ESS could be identified as meeting inertia, system strength or other requirements. With this identification, different providers could be identified as being able to satisfy certain constraints and the marginal prices for these services determined. Further, in the longer term more sophisticated joint FCAS and inertia constraints could be constructed using the 'swing equation'.

5.3 Operating Reserves and System Reliability

Operating reserves and system reliability should not be considered as part of the new essential system services required to run the power system. They are either energy or FCAS services and should be addressed in those markets by looking at possibly new FCAS categories and aligning the market price caps to provide adequate returns for flexible plant that might operate at low capacity factors. These services should not be conflated into the ESS market.

5.4 Time of Decision Making

With increasing amounts of VRE at grid level and in the distribution system, load forecast and VRE generation forecast errors will increase over time. Further, forecast errors will be large 24 hours ahead and become quite small for forecasts five minutes ahead. Thus, in a rational decision analysis framework, decisions should be made as late as possible. With this uncertainty, the costs of making decisions a day ahead will on average be much higher than the costs of making decisions in real time.

5.5 What is an Optimal Schedule

In the AEMC's directions paper there is a lot of emphasis on producing an 'optimal' schedule. The intertemporal optimisation of the ESS does not produce an optimal schedule as it does not co-optimise energy and FCAS and it is based on forecasts many hours ahead. What is really required is the optimal dispatch (not schedule) of ESS, energy and FCAS. The MAS approach has more potential to produce dispatch results that are near optimal than the NMAS approach because it enables a feedback loop between the market pre-dispatch schedules, prices and sensitivities and market participants rebidding and doesn't rely on forecasts with potentially large errors.

5.6 Pricing of Services and Opportunity Costs

The MAS approach produces prices that take into account any opportunity costs via its co-optimisation of ESS, energy and FCAS. The NMAS approach doesn't take into account any opportunity costs such as being constrained on to generate at a minimum loading level when prices are low or negative.

5.7 Price discovery and Transparency

The NMAS approach is driven by contracts with AEMO and TNSPs. Will these contracts have confidential terms and conditions? Will they be published? Will all 'make good' payments be published? Will information be published in real time? Based on previous histories of similar contracting arrangements the NMAS approach is unlikely to result in very transparent and timely pricing information.

On the other hand, the MAS approach will provide transparent and timely pricing information just as now occurs with the energy and FCAS spot markets.

5.8 Interim Measures often Last Much Longer than Planned

There is some discussion that the NMAS approach would be just an interim measure. In the NEM, interim measures can last much longer than expected. For instance, the current 'causer pays' arrangement for regulation FCAS was meant to be an interim arrangement until a more efficient version was set up. The interim arrangement has now been running for 20 years.

5.9 Comparison

Table 5-1 is Hydro Tasmania's update of the AEMC's Table 5.1 of the Directions Paper. We have added a number of additional areas of interest and updated the comparisons based on our outlined MAS approach and our analysis of the NMAS and MAS approaches.

Area of interest	MAS	NMAS
Dispatch process		
Decision making	Decentralised to participants	Centralised in AEMO
Inter-temporal co-ordination of ESS, energy and FCAS	Managed via decentralised optimisation loop between pre-dispatch schedules, prices and sensitivities and market participants rebidding	Centralised ahead scheduling of ESS in AEMO optimisation
Management of forecast errors	Actual dispatch is determined in real time so the impact of forecast errors is minimal	Schedules are determined ahead of time based on forecasts. No explicit accounting for forecast errors
Co-optimisation of ESS, energy and FCAS dispatch	Yes	No
Optimisation engine		

Area of interest	MAS	NMAS
Single interval or inter-temporal optimisation	Single interval solve	Inter-temporal solve to schedule over multiple intervals
Objective function	To maximise the benefits of trade in ESS, energy and FCAS	To maximise the benefits that contracts could provide to the market less the cost of procuring them over multiple intervals. Effectively this is the minimisation of ESS costs because there is no trade-off (co-optimisation) with energy and FCAS
Controllable variables	Real time commitments and mode changes of ESS, energy and FCAS dispatches	The system service status of resources (commitments of ESS)
Coefficients in the objective function	Bids for energy and FCAS and bids for committing and operating ESS	Contract terms that potentially include information on start-up cost, running cost and start up times
Formulation of constraints	The use of real variables on the [0,1] interval for commitment decisions. Linear constraints for requirements that can be expressed as linear constraints. Use of piecewise linear constraints and special ordered sets for non-linear constraints and more complicated system configuration requirements. Generally, any constraints that can be formulated as binary variables can be formulated in terms of real [0,1] variables and piecewise linear constraints	System requirements included in constraints with binary variables, including system configurations

Area of interest	MAS	NMAS
Potential optimisation run time	Linear method and piecewise linear constraints would likely have short run times. Could be accomplished in times a little longer than current pre-dispatch timeframes but this possibly could be compensated for with the use of changed hardware and LP solver. Dispatch and pricing should run in similar times to current NEMDE dispatch and pricing runs.	Potentially long run time, increasing with complexity of binary constraints, but run separate to the pre-dispatch engine
Interaction with broader market scheduler ecosystem		
Required optimisation engine changes	Modifications to the dispatch engine to incorporate controllable variables and constraints for dispatching resources for system security support services. Could be completed in stages focusing on the most impactful constraints first.	Implementation of a new optimisation engine to schedule resources for system security support services via NMAS contracts
Re-bidding	Resources could rebid for ESS, energy and FCAS up until moments before real time, subject to re-bidding rules	Resources could re-bid for energy and FCAS up until moments before real time, subject to rebidding rules Resources cannot re-bid for system security support services past a certain gate closure
Binding instructions	As for energy and FCAS. Any units partially committed would be required to commit.	Binding instructions, i.e., calling the NMAS contracts
Timing of instructions	Dispatch instructions for system security support services would be given at the same time as the energy and FCAS targets.	Dispatch instruction for ESS would be provided ahead of time, likely at the latest possible moment to allow the resource to physically come online.

Area of interest	MAS	NMAS
Allows for changes in mode from generator to synchronous condenser	Yes	Not clear
Opportunity costs and 'make good' payments		
Compensation payments	Does not require any compensation payments as the co-optimisation determines ESS prices based on any lost opportunities or constrained on costs in the energy and FCAS markets	Requires compensation or make good payments in addition to the contract prices otherwise providers will have financial incentives not to follow instructions
Transparency and confidence		
Transparency to allow investment	Provides publicly available data for ESS in a similar way to energy and FCAS information. In particular, the ESS arrangements will provide efficient marginal cost and transparent price signals that may facilitate investment decisions.	Does not provide transparent price signals that may facilitate investment decisions. There is no guarantee all dispatches, contracts and compensation payments are going to be published in real time.
Operating confidence	Co-optimisation of ESS, energy and FCAS ensures that the resulting dispatch would be secure. Directions would also continue to be available.	Provides AEMO with some confidence that resulting dispatch would be secure but does not take into account forecast errors and rapid changes in the energy and FCAS markets. Directions would also continue to be available.

Table 5-1 Comparison of MAS and NMAS approaches

6.0 Conclusion

Hydro Tasmania's revised co-optimisation approach can address the concerns previously raised by AEMO and AEMC and that this approach can be readily implemented using the current version of NEMDE with some modest revisions and some additional generic constraints, although in the longer term it may be better to implement it via a modest reformulation of NEMDE. The revised co-optimisation approach addresses the issues of:

- yo-yoing commitment decisions,
- compensating market participants who supply ESS for any opportunity costs,
- producing market clearing prices based on the marginal cost of meeting each ESS requirement,
- partial commitment dispatches,
- secure system configurations, and
- modelling of non-linear functions.

Hydro Tasmania agrees that

- the ESB and AEMC have correctly outlined a long term vision for essential system services where they are unbundled, explicitly valued, scheduled, dispatched and priced;
- the ESB has correctly stated that the direction for essential system services is to use co-optimised, market-based procurement where possible; and
- defining ESS in terms of fundamental power systems attributes and the quantities required will be critical to achieving the ESB's vision and should be pursued as soon as possible.

An MAS approach using co-optimisation in the spot market is more economically efficient than an NMAS approach and better fits into the NEM's decentralised design philosophy and the ESB's and AEMC's long term vision for ESS. A co-optimised MAS approach enables:

- the maximisation of the value of spot market trading (NER clauses 3.8.1 a and b) because it can enable the optimal spot market trade-offs between the dispatch of ESS, FCAS and energy depending on their costs (offers),
- unbundling of services (some suppliers might provide multiple services but this is no different to what happens with energy and FCAS),
- the optimal use of existing resources to supply ESS, FCAS and energy,
- marginal cost and transparent pricing of services which will encourage new entry and conversion of synchronous generators to be able to operate in synchronous condenser mode, and
- avoids issues of managing opportunity costs when spot market energy prices are very high or low because these are automatically accounted for in the ESS price.

Hydro Tasmania thinks that the movement towards the NMAS approach may result in a move to centralised market operation. This should be avoided given the theoretical and practical deficiencies of centralised markets and their incompatibility with the current NEM design which has been remarkably robust and successful. What is required is the new ESS to be incorporated into the NEM's co-optimised dispatch process.

In summary, the MAS approach satisfies the National Electricity Objective (NEO) better than a NMAS approach.

7.0 Appendix A: Coordination in Electricity Markets[4]

This material is an excerpt from a report by SW Advisory for a group of generators which was submitted to the AEMC as part of its Reliability Frameworks Review. Stephen Wallace (2018) 'Critique of Day Ahead Markets and the NEM' chapter 3.3 https://www.aemc.gov.au/sites/default/files/2018-05/The%20Generator%20Group.PDF

Irrespective of the market design, all resources in an electricity market need to be co-ordinated on a range of timescales from days ahead, to hours-ahead and minutes-ahead. Electricity markets need to facilitate this co-ordination. There are two main ways this is done: centralised approach vs. decentralised approach.

- In a centralised electricity market, the system and market operator is responsible for more decisions related to co-ordinating resources, in particular, when to commit units; and
- In a decentralised electricity market, market participants are responsible for making more decisions on their own, in particular, when to commit units.

These two approaches are illustrated in Figure 7-1 and Figure 7-2. The centralised approaches tend to have been pursued as a carryover from what the system operator did prior to the development of an electricity market whereas the decentralised approaches are often explicitly pursued as part of the market design.

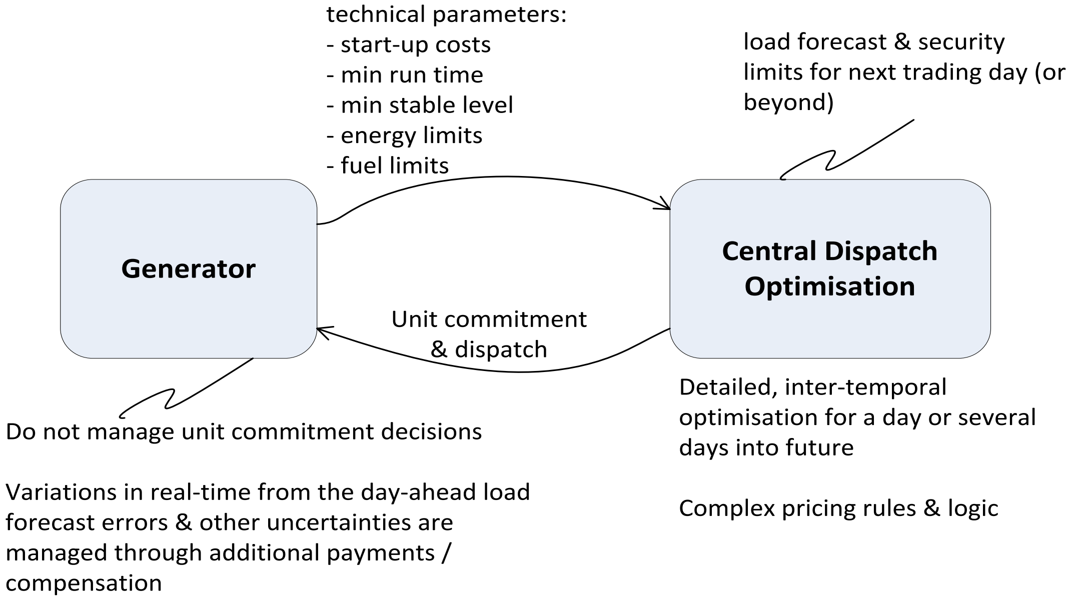


Figure 7-1 Centralised Electricity Markets (e.g. USA Standard Market Design)

[4] This material is an excerpt from a report by SW Advisory for a group of generators which was submitted to the AEMC as part of its Reliability Frameworks Review. Stephen Wallace (2018) 'Critique of Day Ahead Markets and the NEM' chapter 3.3 https://www.aemc.gov.au/sites/default/files/2018-05/The%20Generator%20Group.PDF

In the centralised approach, the system and market operator attempts to optimise the commitment and dispatch of units based on a number of parameters such as each unit's start-up costs and times, fixed running costs, minimum run times etc. as well as each unit's price and quantity offers.

Inevitably these parameters do not fully reflect the opportunity cost of running a unit. Units may have energy limitations such as is the case for many hydro units, gas units with gas usage restrictions and batteries.

Further, for most slow start units, such as coal units, their unit commitment decisions are made for months ahead rather than for one or two days ahead and are often based on planned maintenance programs.

Since the unit commitment decisions are made a day or more ahead, the actual loads, actual VRE generation and availability of dispatchable generators can be quite different to what was expected and used in the optimisation. System and market operators will try to address these uncertainties by requiring larger amounts of reserves to be committed than is strictly necessary for the forecast loads and VRE generation. In some markets the system and market operators are looking at stochastic optimisations of the unit commitment decisions. In the end, because a system and market operator does not pay the costs of committing additional units to what is required (the market does) there is great temptation for a system and market operators to over commit units to what is required to meet any reliability standards. The costs to the system and market operator of occasionally having curtailed loads are very much higher than the costs of over committing generation.

Lastly, when additional parameters are used to determine unit commitments, the start-ups costs, fixed loading costs etc. have to be recovered in some form of uplift to the spot price. This in turn creates risks for generators trying to hedge any contracts because even if they offer their capacity at prices below the spot price there is no guarantee that they will be dispatched. The market design of the NEM explicitly addressed these issues when the decision was made to have simple price quantity offers and decentralised unit commitment.

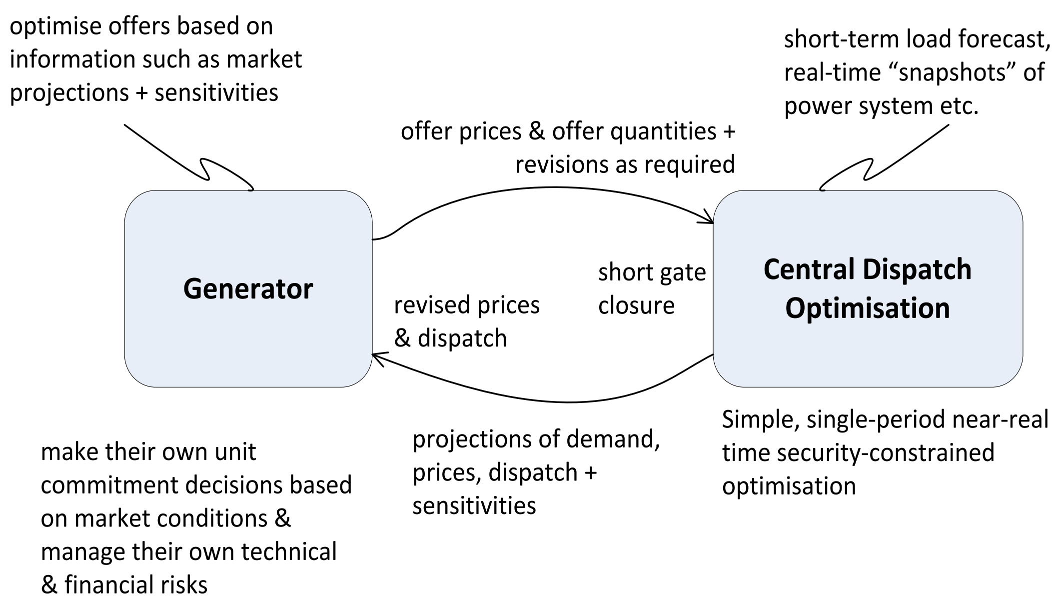


Figure 7-2 Decentralised Electricity Markets (Most Asia-Pacific Markets: NEM, NZEM, Philippines WESM, Vietnam VWEM etc. and Texas's ERCOT to some extent)

For a decentralised electricity market to work well requires the following:

- the system and market operator needs to provide generators with regularly updated information on projected: prices, dispatches, price sensitivities and other market conditions to ensure they can make informed commercial and technical decisions;
- generators need to have sufficient flexibility to respond to changes in market conditions and/or the conditions of the equipment they operate; and
- market interfaces between the system and market operator and generators need to allow for the timely transfer of the information that is needed to manage issues such as: power system security, dispatch of plant, management of ancillary services, management of fuels and hydro reservoirs etc.

8.0 Appendix B: Example ESS Co-optimisations

8.1 Introduction

This appendix provides some simple examples of how co-optimisation of synchronous services can be done in the spot market for cases where there are existing generic constraints with unit connection statuses on their right hand sides (RHSs) and for situations where a least cost configuration of synchronous units is required to manage system strength and/or inertia.

The examples were developed using Excel's Solver as the market clearing engine and are very simple stylised examples to illustrate the co-optimisation approach.

8.2 Example Spreadsheets

All of the examples can be found in the Excel workbook "Synchronous Unit Optimisation". They all use Excel's Solver to find a least cost dispatch including the provision of synchronous services. The spreadsheets illustrate how market clearing prices for synchronous service can be determined such that any provider of the service is compensated for any opportunity cost incurred in the energy spot market. This is analogous to what happens in the spot market where the prices for FCAS include any opportunity costs incurred by the optimal set of FCAS providers in the energy market. The efficient synchronous service prices are determined from models that use real variables between 0 and 1, [0,1], rather than binary variables. If binary variables are used, appropriate prices for synchronous services can't be determined. The use of [0,1] variables sometimes results in a partial commitment of a synchronous service. In these cases, the supplier would have to provide the service or rebid. This is no different to what currently happens to generators dispatched below their minimum loading levels.

There are some spreadsheets which use binary variables to able to determine what would have been the optimal unit commitments when there was a partial unit commitment. Some other spreadsheets which use piecewise linear functions use binary variables to locate the area in which the linear approximation is active because Excel's Solver does can't solve using special ordered stet (SOS) variables. The main stream solvers such as CPLEX, GUROBI and XPRESS can use SOS variables.

ID	Spreadsheet	Description
1	#1 SSG optimisation binary	Simple optimisation with a binary variable to determine whether it would be optimal to commit as an ESS a synchronous generator with a minimum load which would enable additional wind generation to be dispatched
2	#2 SSG optimisation	The same problem as the on above except that a [0,1] variable was used rather than a binary variable. With this formulation the result was the same but a market clearing price for a synchronous service generator (SSG) can be computed
3	#3 SSG pricing from binary opt	This model takes the commitment results from 1 and determines the market clearing price for energy but can't determine a price for the SSG

ID	Spreadsheet	Description
4	#4 SSG optimisation 2 SSGs	Extension of the approach in #2 to two SSGs
5	#5 SSG optimisation 2 SSGs	Same as #4 but with SSG having a much higher commitment price
6	#6 SSG optimisation partial	Same as for #5 but with lower wind generation potential which results in a partial commitment of the SSG
7	#7 SSG optimisation #6 binary	Same as #6 but uses binary commitment variables but can't produce a market clearing price of the synchronous service
8	#8 SSG optimisation SSGs fixed	Same as #5 but the SS commitments are fixed from #7. Results in 0 price for SS since wind constraint is not binding
9	#9 SSG and Synch Con	Has an additional unit that can operate in synchronous condenser mode. Unit commitments are managed using real [0,1] variables
10	#10 SSG Mode optimisation	Same as #9 except that the synchronous condenser operation is just an additional mode for unit SSG1. Unit commitments and selection of whether SSG1 is in generator or synchronous condenser mode are managed using real [0,1] variables
11	#11 SSG Mode optimisation	Same as #10 with different inputs
12	#12 SSG Mode optimisation	Same as #10 with different inputs
13	#13 SSG Mode Neg Price	Same as #10 but results in a negative energy price
14	#14 SSG System Configuration	Synchronous service optimisation where a system configuration of at least two synchronous units online is required
15	#15 Wind const + non linear	Non-linear wind constraint modelled as piecewise linear with binary variables for determining linear segments
	#16 Pricing NL + SOS fixed	Linear program and prices with the SOS variables from optimisation #16fixed (the choice of linear segments fixed)

ID	Spreadsheet	Description
	#17 Pricing NL + rounded up	Unit profits and costs when partial commitments rounded up to 1.

Table 8-1: Spreadsheet Examples

8.3 Optimisation Formulations

8.3.1 Generic constraint limiting wind generation

This group of problems represents the situations where there are generic constraints that have in their right hand side (RHS) calculation unit connection statuses. These statuses can be optimised by turning them into decision variables and in the NEMDE terminology putting them on the left hand side of the generic constraint.

The linear programming optimisation model for this set of problems was as follows:

Decision variables:

- Unit commitments for synchronous units including mode selection (generator or synchronous condenser)
- Dispatch levels for all units
- Zone variables (an approximation of SOS variables) for non-linear constraints that are non-convex

Parameters:

- Demand (MW)
- Unit capacities (MW)
- Unit minimum loads (MW)
- Energy offer prices ($/MWh)
- Commitment price ($/h)
- Dispatch levels for all units
- Wind constraint fixed coefficient
- Wind constraint coefficient for number of synchronous units online

Objective function:

- Minimise commitment and dispatch costs

Constraints:

- Total generation = demand
- Unit commitments >=0 and <=1
- Unit commitment gen mode + unit commitment sync con mode <=1
- Generating unit dispatch >= minimum load x unit commitment
- Generating unit dispatch <= capacity x unit commitment
- Wind generation <= wind security constraint = constant + SSG coefficient x number units committed
- Piecewise linear constraints to approximate non-linear funcrions

For some of the simpler cases some of the above constraints were not required.

8.3.2 Configuration commitment requirement

The optimisation for a configuration commitment requirement could largely the same as for the generic constraint optimisation model except that the wind generic constraint is replaced by a configuration constraint that requires a linear sum of unit commitments to be greater than a specified value. Alternatively, the configuration requirements might need to be represented as a piecewise linear constraint.

8.3.3 Binary variables

For the unit commitment decisions most of the examples use real [0,1] variables. To compare the results some of the examples use binary variables for commitment decisions. An optimisation which uses binary variables does not enable the correct prices for energy and synchronous services to be produced.

For situations where piecewise linear functions were required to model non-linear functions, binary variables were used to model the linear functions zones. This is a rough approximation to how SOS variables would operate. Once the optimal zones have been determined the model can be rerun a linear program and commitments, dispatches and prices can be determined.

8.3.4 Market clearing prices

If real [0,1] variables are used then sensitivity analyses can be computed which in turn can be used to calculate the marginal prices for energy and synchronous services.

The prices for energy can be determined from the shadow price of the total generation = demand constraint.

The prices for synchronous service commitments can be determined from the shadow prices of the wind or other ESS constraints.

The shadow price of the wind constraint is the amount that the objective function would change for a unit change in the right hand side (RHS) of the constraint. Thus, the shadow price will be negative or zero because if you relax the wind constraint more wind generation can be used. The value of a synchronous service unit committed is -shadow price x synchronous unit's coefficient in the wind constraint.

For some of the other constraints it is easier to get the value of the synchronous service from the reduced cost of the commitment variable.

8.3.5 Opportunity costs and any additional payments

If a linear programming approach with real [0,1] variables is used then every unit committed as a synchronous service, if it is paid according to the market clearing prices for energy and synchronous services, will always cover its offered prices for energy, FCAS and ESS commitments. This is an extremely desirable property and enables prices to drive behaviour.

There will be situations where the linear programming approach with real [0,1] variables will result in partial commitments. In these situations the proposed approach is for providers to commit units if they are partially committed. This problem of partial commitments can be mitigated if only one price is offered for commitments and if synchronous service prices are produced in a rolling pre-dispatch and rebidding is used. Further if only one price is offered for ESS commitments and one price for energy up to the minimum loading levels then a provider that has a unit that is partially committed will be fully compensated if they commit the unit and receive the market clearing price.

8.4 Examples

8.4.1 #1 Synchronous Service Generator (SSG) optimisation with binary variables

Demand									
300									
	Capacity / potential (MW)	Minimum load	Price	Unit commitment	Commitment price ($/h)	Minimum loading	Maximum loading	Dispatch	Cost
Wind	160	0	0	1	0	0	160	140	0
Gen 1	200	0	100	1	0	0	200	150	15,000
SSG	100	10	150	1	50	10	100	10	1,550
					Total			300	16,550

Constrained wind	Constant	SSG coefficient	Wind constraint value
140	120	20	140

The optimal solution is to commit the SSG unit and relieve the wind constraint by 20 MW.

8.4.2 #2 SSG optimisation with real [0,1] variables

Demand	Energy price														
300	100														
	Capacity / potential (MW)	Minimum load	Price	Unit commitment	Commitment price ($/h)	Minimum loading	Maximum loading	Dispatch	Cost	Energy revenue	SSG revenue	Total revenue	Unit "cost"	Unit "profit"	- Reduced cost (shadow price commitment)
Wind	160	0	0	1	0	0	160	140	0	14,000	0	14,000			
Gen 1	200	0	100	1	0	0	200	150	15,000	15,000	0	15,000	15,000	0	
SSG	100	10	150	1	50	10	100	10	1,550	1,000	2000	3,000	1,550	1450	1450
					Total			300	16,550						

Constrained wind	Constant	SSG coefficient	Value	Price (shadow price of wind constraint)	Value of SSG in relaxing constraint
140	120	20	140	-100	2000

The optimal solution is the same as for the optimisation using binary variables. The energy price is $100/MWh, the shadow price for the wind constraint is -$100/MWh and the marginal value of the SSG commitment is $2,000/h. Even though the market clearing price for energy, $100/MWh, is lower than the SSG unit's offer price, $150/MWh, this loss is automatically compensated for via the hourly synchronous commitment clearing price which also covers the unit's hourly commitment cost.

If market clearing prices from a linear program with no integer or binary variables are used then every dispatchable resource will always receive revenues that at least cover its offered costs.

8.4.3 #3 SSG pricing using commitment decisions from #1

Demand	Energy price													
300	100													
	Capacity / potential (MW)	Minimum load	Price	Unit commitment	Commitment price ($/h)	Minimum loading	Maximum loading	Dispatch	Cost	Energy revenue	SSG revenue	Total revenue	Unit "cost"	Unit "profit"
Wind	160	0	0	1	0	0	160	140	0	14,000	0	14,000		
Gen 1	200	0	100	1	0	0	200	150	15,000	15,000	0	15,000	15,000	0
SSG	100	10	150	1	50	10	100	10	1,550	1,000	2000	3,000	1,550	1450
					Total			300	16,550					

Constrained wind	Constant	SSG coefficiei	Value	Price (shadow price of wind constraint)	Value of SSG in relaxing constraint
140	100	20	140	-100	2000

This model takes the commitment results from 1 and determines the market clearing prices for energy and the SSG. In this case, because the wind constraint is binding at the commitment level determined from the binary variable optimisation a non-zero shadow price for the wind constraint can be determined.

8.4.4 #4 Extension of the approach in #2 to two synchronous generators

Demand	Energy price
300	100

	Capacity / potential (MW)	Minimum load	Price	Unit commitment	Commitment price ($/h)	Minimum loading	Maximum loading	Dispatch	Cost	Energy revenue	SSG revenue	Total revenue	Unit "cost"	Unit "profit"	- Reduced cost (shadow price commitment)
Wind	160	0	0	1	0	0	160	140	0	14,000	0	14,000			
Gen 1	200	0	100	1	80	0	200	150	15,080	15,000	2000	17,000	15,080	1,920	1920
SSG	100	10	150	1	50	10	100	10	1,550	1,000	2000	3,000	1,550	1,450	1450
			Total SSG	2			Total	300	16,630						

Constrained wind	Constant	SSG coefficient	Value	Price	Value of SSG in relaxing constraint
140	100	20	140	-100	2000

With two synchronous generators the linear programming approach produces optimal commitments and pricing.

8.4.5 #5 Same as #4 but quite different offered commitment prices

Demand	Energy price
300	100

	Capacity / potential (MW)	Minimum load	Price	Unit commitment	Commitment price ($/h)	Minimum loading	Maximum loading	Dispatch	Cost	Energy revenue	SSG revenue	Total revenue	Unit "cost"	Unit "profit"	- Reduced cost (shadow price commitment)
Wind	160	0	0	1	0	0	160	140	0	14,000	0	14,000	0		
Gen 1	200	0	100	1	80	0	200	150	15,080	15,000	2000	17,000	15,080	1,920	1920
SSG	100	10	150	1	1499	10	100	10	2,999	1,000	2000	3,000	2,999	1	1
			Total SSG	2			Total	300	18,079						

Constrained wind	Constant	SSG coefficient	Value	Price	Value of SSG in relaxing constraint
140	100	20	140	-100	2000

The reduced costs (shadow prices for a bound on a variable) for the commitment decision in the '#5 Sensitivity Report' spreadsheet indicate what the change in costs would be per unit if the commitment variables could be increased by a small amount. Note that the pricing still results in the SSG making a small "profit".

8.4.6 #6 Partial commitment

This example demonstrates how it is possible to get a partial commitment. The scenario is essential the same as for #5 but the potential wind generation is reduced. The SSG is partially committed.

Demand	Energy price
300	100

	Capacity / potential (MW)	Minimum load	Price	Unit commitment	Commitment price ($/h)	Minimum loading	Maximum loading	Dispatch	Cost	Energy revenue	SSG revenue	Total revenue	Unit "cost"	Unit "profit"	- Reduced cost (shadow price commitment)
Wind	139	0	0	1	0	0	139	139.0	0	13,900	0	13,900	0		
Gen 1	200	0	100	1	80	0	200	151.5	15,230	15,150	1719	16,869	15,230	1,639	1639
SSG	100	10	122	0.95	1499	9.5	95	9.5	2,583	950	1633.05	2,583	2,583	0	0
			Total SSG	1.95			Total	300.0	17,813						

Constrained wind	Constant	SSG coefficient	Value	Price	Value of SSG in relaxing constraint
139	100	20	139	-85.95	1719

8.4.7 #7 Partial commitment solved with binary variables

Demand	Energy price
300	NA

	Capacity / potential (MW)	Minimum load	Price	Unit commitment	Commitment price ($/h)	Minimum loading	Maximum loading	Dispatch	Cost	Energy revenue	SSG revenue	Total revenue
Wind	139	0	0	1	0	0	139	139	0	#VALUE!	0	#VALUE!
Gen 1	200	0	100	1	80	0	200	151	15,180	#VALUE!	#VALUE!	#VALUE!
SSG	100	10	122	1	1499	10	100	10	2,719	#VALUE!	#VALUE!	#VALUE!
			Total SSG	2			Total	300	17,899			

Constrained wind	Constant	SSG coefficient	Value	Price	Value of SSG
139	100	20	140	NA	#VALUE!

No price information can be gained from the linear program with binary variables.

8.4.8 #8 Pricing for #7 with commitments fixed

Demand	Energy price
300	100

	Capacity / potential (MW)	Minimum load	Price	Unit commitment	Commitment price ($/h)	Minimum loading	Maximum loading	Dispatch	Cost	Energy revenue	SSG revenue	Total revenue	Unit "cost"	Unit "profit"
Wind	139	0	0	1	0	0	139	139	0	13,900	0	13,900	0	
Gen 1	200	0	100	1	80	0	200	151	15,180	15,100	0	15,100	15,180	-80
SSG	100	10	122	1	1499	10	100	10	2,719	1,000	0	1,000	2,719	-1,719
			Total SSG	2			Total	300	17,899					

Constrained wind	Constant	SSG coefficient	Value	Price	Value of SSG in relaxing constraint
139	100	20	140	0	0

When the commitment decisions are fixed the wind constraint is no longer binding and thus its marginal price is 0. This results in units with negative profits, particularly the SSG which loses $1,719/h. If the partial commitment price is used then the SSG makes a small profit. If it is used but the payment is based on the partial commitment amount then the SSG makes a very small loss (this is not recommended as partially committed units will be obliged to commit).

8.4.9 #9 Addition of a synchronous condenser

This example is the same as #8 but adds the possibility of committing a synchronous condenser.

Demand	Energy price
300	100

	Capacity / potential (MW)	Minimum load	Price	Unit commitment	Commitment price ($/h)	Minimum loading	Maximum loading	Dispatch	Generation	Cost	Energy revenue	SSG revenue	Total revenue	Unit "cost"	Unit "profit"	- Reduced cost (shadow price commitment)
Wind	170	0	0	1	0	0	170	160.0	160	0	16,000	0	16,000	0		
Gen 1	200	0	100	1	80	0	200	135.0	135	13,580	13,500	2000	15,500	13,580	1,920	1920
SSG	100	10	150	1	1499	10	100	10.0	10	2,999	1,000	2000	3,000	2,999	1	1
Synch Con	5	5	-20	1	1399	5	5	5.0	-5	1,499	-500	2000	1,500	1,499	1	1
			Total SSG	3			Total		300.0	18,078						

Constrained wind	Constant	SSG coefficient	Value	Price	Value of SSG in relaxing constraint
160	100	20	160	-100	2000

8.4.10 #10 Optimal synchronous service mode selection

Same as #9 except that the synchronous condenser operation is just an additional mode for unit SSG1. Unit commitments and selection of whether SSG1 is in generator or synchronous condenser mode are managed using real [0,1] variables.

Demand	Energy price
300	100

	Capacity / potential (MW)	Minimum load	Price	Unit commitment	Commitment price ($/h)	Minimum loading	Maximum loading	Dispatch	Generation	Cost	Energy revenue	SSG revenue	Total revenue	Unit "cost"	Unit "profit"	- Reduced cost (shadow price commitment)
Wind	170	0	0	1	0	0	170	140.0	140	0	14,000	0	14,000	0		
Gen 1	200	0	100	1.0	80	0	200	165.0	165	16,580	16,500	2000	18,500	16,580	1,920	1,920.0
SSG 1 Gen mode	100	10	150	0.0	1499	0	0	0.0	0	0	0	0	0	0	0	0.0
SSG 1 Synch con mode	5	5	-20	1.0	1399	5	5	5.0	-5	1,499	-500	2000	1,500	1,499	1	0.0
			Total SSG	2			Total		300.0	18,079						

Constrained wind	Constant	SSG coefficient	Value	Price	Value of SSG in relaxing constraint
140	100	20	140	-100	2000
SSG 1 only 1 mode	1				

8.4.11 #11 Optimal synchronous service mode selection: higher demand and lower wind price

Demand	Energy price
400	150

	Capacity / potential (MW)	Minimum load	Price	Unit commitment	Commitment price ($/h)	Minimum loading	Maximum loading	Dispatch	Generation	Cost	Energy revenue	SSG revenue	Total revenue	Unit "cost"	Unit "profit"	- Reduced cost (shadow price commitment)
Wind	170	0	-60	1	0	0	170	160.0	160	-9,600	24,000	0	24,000	-9,600		
Gen 1	200	0	100	1	80	0	200	200.0	200	20,080	30,000	6300	36,300	20,080	16,220	16,220
SSG 1 Gen mode	100	10	150	1	1499	10	100	40.0	40	7,499	6,000	6300	12,300	7,499	4,801	4,801
SSG 1 Synch con mode	5	5	-20	0	1399	0	0	0.0	0	0	0	0	0	0	0	0
			Total SSG	2			Total		400.0	17,979						

Constrained wind	Constant	SSG coefficient	Value	Price	Value of SSG in relaxing constraint
160	100	30	160	-210	6300

SSG 1 only 1 mode	1

8.4.12 #12 Optimal synchronous service mode selection: lower demand

Demand	Energy price
220	100

	Capacity / potential (MW)	Minimum load	Price	Unit commitment	Commitment price ($/h)	Minimum loading	Maximum loading	Dispatch	Generation	Cost	Energy revenue	SSG revenue	Total revenue	Unit "cost"	Unit "profit"	- Reduced cost (shadow price commitment)
Wind	170	0	-60	1	0	0	170	160.0	160	-9,600	16,000	0	16,000	-9,600		
Gen 1	200	0	100	1	80	0	200	50.0	50	5,080	5,000	4800	9,800	5,080	4,720	-4,720
SSG 1 Gen mode	100	10	150	1	1499	10	100	10.0	10	2,999	1,000	4800	5,800	2,999	2,801	2,801
SSG 1 Synch con mode	5	5	-20	0	1399	0	0	0.0	0	0	0	0	0	0	0	0
			Total SSG	2			Total		220.0	-1,521						

Constrained wind	Constant	SSG coefficient	Value	Price	Value of SSG in relaxing constraint
160	100	30	160	-160	4800

SSG 1 only 1 mode	1

8.4.13 #13 Optimal synchronous service mode selection: negative energy price

Demand	Energy price
220	-60

	Capacity / potential (MW)	Minimum load	Price	Unit commitment	Commitment price ($/h)	Minimum loading	Maximum loading	Dispatch	Generation	Cost	Energy revenue	SSG revenue	Total revenue	Unit "cost"	Unit "profit"	- Reduced cost (shadow price commitment)
Wind	300	0	-60	1	0	0.0	300.0	225.0	225	-13,500	-13,500	0	-13,500	-13,500		
Gen 1	200	0	100	0.0	80	0.0	0.0	0.0	0	0	0	0	0	0	0	0
SSG 1 Gen mode	100	10	150	0.0	100	0.0	0.0	0.0	0	0	0	0	0	0	0	0
SSG 1 Synch con mode	5	5	-20	1.0	100	5.0	5.0	5.0	-5	200	300	0	300	200	100	100
			Total SSG	1			Total		220.0	-13,300						

Constrained wind	Constant	SSG coefficient	Value	Price	Value of SSG in relaxing constraint
225	200	30	230	0	0

SSG 1 only 1 mode	1

8.4.14 #14 Optimal synchronous unit commitments for desired system configuration

For this model each synchronous generator has system figuration coefficient and the units committed when multiplied by their configuration coefficients must exceed the system configuration requirement. In this example this simplifies to the number of synchronous generators committed must be at least 2.

	Capacity / potential (MW)	Minimum load	Price	Unit commitment	Commitment price ($/h)	Minimum loading	Maximum loading	Dispatch	Generation	Cost	Energy revenue	SSG revenue	Total revenue	Unit "cost"	Unit "profit"	- Reduced cost (shadow price commitment)
Wind	200	0	-60	1	0	0.0	200.0	200.0	200	-12,000	20,000	0	20,000	-12,000		
Gen 1	200	20	100	1.00	600	20.0	200.0	40.0	40	4,600	4,000	700	4,700	4,600	100	100
Gen 2	100	20	110	0.00	600	0.0	0.0	0.0	0	0	0	0	0	0	0	0
SSG 1 Gen mode	100	10	150	1.00	200	10.0	100.0	10.0	10	1,700	1,000	700	1,700	1,700	0	0
SSG 1 Synch con mode	5	5	-20	0.00	200	0.0	0.0	0.0	0	0	0	0	0	0	0	0
			Total SSG	2			Total		250.0	-5,700						

	Gen 1	Gen 2	SSG 1 Gen mode	SSG 1 Synch con mode	Configuration requirement
Configuration coefficient	1	1	1	1	2
Configuration	1.0	0.0	1.0	0.0	2.0
Value of SS to satsifying configuration	700	0	700	0	

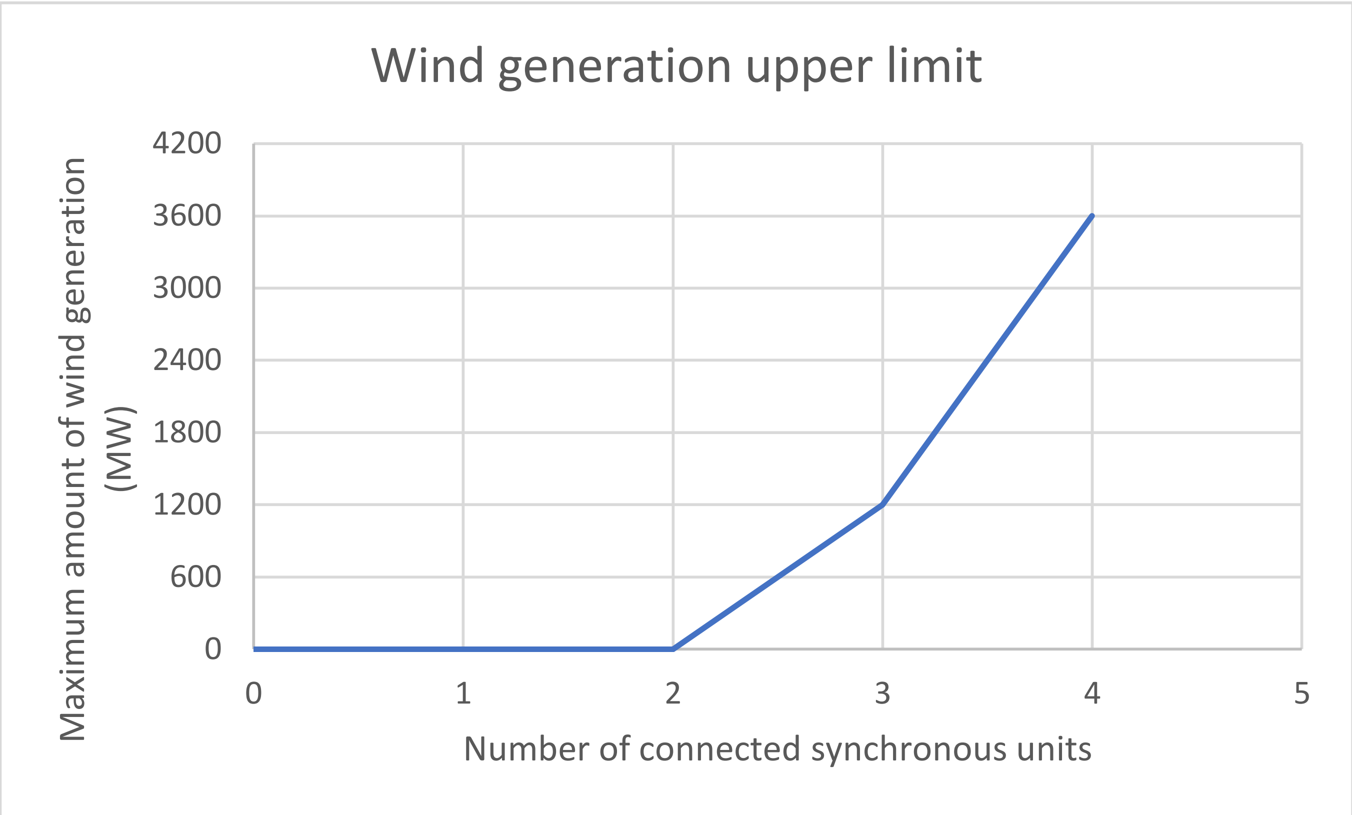
Marginal price of configuration	700
SSG 1 only 1 mode	1

The system configuration models tend to more often result in partial dispatches than constraints like the generic wind constraint model where there is a trade-off between the costs of committing more synchronous units and the ability to generate more power from cheap sources of generation.

8.4.15 #15 Optimal synchronous unit commitments for non-linear constraint

In this example in addition to a simple system configuration requirement of one synchronous unit online there is an upper limit to the amount of wind generation that can be dispatched due to inertia and system strength. The wind generation upper limit can be defined as a non-linear function of the number of synchronous units committed, see table and graph below.

Synchronous units online	Wind upper limit
0	0
1	0
2	0
3	1200
4	3600



The Excel Solver model uses binary variables rather than SOS variables to determine the optimal linear segment. Once the optimal linear segment is found then this value can be fixed and a normal LP can be run to produce prices.

Demand	Energy price								
2500									
	Capacity / potential (MW)	Minimum load	Price	Unit commitment	Commitment price ($/h)	Minimum loading	Maximum loading	Dispatch	Generation	Cost
Wind	3000	0	-60	1	0	0.0	3000.0	2,459.5	2,460	-147,570
Gen 1	300	20	100	1.00	600	20.0	300.0	20.0	20	2,600
Gen 2	200	20	140	0.52	600	10.5	105.0	10.5	10	1,784
Gen 3	100	15	110	1.00	500	15.0	100.0	15.0	15	2,150
SSG 1 Gen mode	100	10	250	0.00	200	0.0	0.0	0.0	0	0
SSG 1 Synch con mode	5	5	-20	1.00	200	5.0	5.0	5.0	-5	300
			Total SSG	3.52			Total		2,500.0	-140,736

8.4.16 #16 Pricing for non-linear constraint

Once the SOS variables are fixed from #15 then the marginal prices can be computed from the resulting linear program. The LP optimisation results in a partial dispatch of Gen 2. All synchronous units either break even or make a profit.

Demand	Energy price																
2500	-58.099																
	Capacity / potential (MW)	Minimum load	Price	Unit commitment	Commitment price ($/h)	Minimum loading	Maximum loading	Dispatch	Generation	Cost	Energy revenue	Constraint relief revenue	Configuration revenue	Total revenue	Unit "cost"	Unit "profit"	- Reduced cost (shadow price commitment)
Wind	3000	0	-60	1	0	0.0	3000.0	2,459.5	2,460	-147,570	-142,895	0	0	-142,895	-147,570		
Gen 1	300	20	100	1.00	600	20.0	300.0	20.0	20	2,600	-1,162	4,562	0	3,400	2,600	800	800
Gen 2	200	20	140	0.52	600	10.5	105.0	10.5	10	1,784	-610	2,394	0	1,784	1,784	0	0
Gen 3	100	15	110	1.00	500	15.0	100.0	15.0	15	2,150	-871	4,562	0	3,690	2,150	1,540	1,540
SSG 1 Gen mode	100	10	250	0.00	200	0.0	0.0	0.0	0	0	0	0	0	0	0	0	0
SSG 1 Synch con mode	5	5	-20	1.00	200	5.0	5.0	5.0	-5	300	290	4,562	0	4,852	300	4,552	4,552
			Total SSG	3.52			Total		2,500.0	-140,736							

Wind constraint			Value	Price	Value of synch service in relaxing constraint (- shadow price of wind constraint x coefficient of number of synchronous units in wind constraint or shadow price of Total Dispatched synchronous units)
2,459.5			2,459.50	-1.90	4,561.98
					4,561.98
SSG 1 only 1 mode	1.00				

Synchronous units	Wind upper limit	Wind coefficient	Special ordered set variable	Synchronous unit's lower limit	Synchronous unit's upper limit	Dispatched synchronous units	Wind enabled amounts
0	0						
1	0	0	1	1	1	1	0
2	0	0	1	1	1	1	0
3	1200	1200	1	1	1	1	1200
4	3600	2400	1	0	1	0.52479339	1259.5041
					Total	3.52479339	2459.5041

	Gen 1	Gen 2	SSG 1 Gen mode	SSG 1 Synch con mode	Configuration requirement
Configuration coefficient	0	1	1	1	0
Configuration	0.0	0.5	0.0	1.0	1.5
Value of SS to satsifying configuration	0	0	0	0	
Marginal price of configuration	0				
SSG 1 only 1 mode	1				

8.4.17 #16 Pricing and payments for when partial commitment rounded up

If the same prices are used as for #16 and the partial unit commitment is rounded up then the generator whose commitment was rounded up breaks even as was the case for the partial commitment. This will always be the case if only a single price is used for the commitment price and only one energy price is used for the minimum loading quantity.

Demand	Energy price
2500	-58.09917355

	Capacity / potential (MW)	Minimum load	Price	Unit commitment	Commitment price ($/h)	Minimum loading	Maximum loading	Dispatch	Generation	Cost	Energy revenue	Constraint relief revenue	Configuration revenue	Total revenue	Unit "cost"	Unit "profit"	- Reduced cost (shadow price commitment)
Wind	3000	0	-60	1	0	0.0	3000.0	2,450.0	2,450	-147,000	-142,343	0	0	-142,343	-147,000		0
Gen 1	300	20	100	1.00	600	20.0	300.0	20.0	20	2,600	-1,162	4,562	0	3,400	2,600	800	800
Gen 2	200	20	140	1.00	600	20.0	200.0	20.0	20	3,400	-1,162	4,562	0	3,400	3,400	0	0
Gen 3	100	15	110	1.00	500	15.0	100.0	15.0	15	2,150	-871	4,562	0	3,690	2,150	1,540	1,540
SSG 1 Gen mode	100	10	250	0.00	200	0.0	0.0	0.0	0	0	0	0	0	0	0	0	0
SSG 1 Synch con mode	5	5	-20	1.00	200	5.0	5.0	5.0	-5	300	290	4,562	0	4,852	300	4,552	4,552
			Total SSG	4			Total		2,500.0	-138,550							

Wind constraint			Value	Price	Value of synch service in relaxing constraint (multiply wind coefficient for marginal number of synchronous units or shadow price of Total Dispatched synchronous units)
2,450.0			3600	-1.90	4,561.98
SSG 1 only 1 mode	1.00				

Synchronous units	Wind upper limit	Wind coefficient	Special ordered set variable	Synchronous unit's lower limit	Synchronous unit's upper limit	Dispatched synchronous units	Wind enabled amounts
0	0						
1	0	0	1	1	1	1	0
2	0	0	1	1	1	1	0
3	1200	1200	1	1	1	1	1,200
4	3600	2400	1	0	1	1	2,400
					Total	4	3,600

	Gen 1	Gen 2	SSG 1 Gen mode	SSG 1 Synch con mode	Configuration requirement
Configuration coefficient	0	1	1	1	0
Configuration	0.0	1.0	0.0	1.0	2.0
Value of SS to satsifying configuration	0	0	0	0	
Marginal price of configuration	0				
SSG 1 only 1 mode	1				

8.5 Conclusions

The spreadsheet examples illustrate:

- how a co-optimisation approach can optimally determine synchronous service unit commitments,
- that if real [0,1] variables are used then market clearing prices for these synchronous services can be determined,
- if the market clearing prices are used then all providers receive as revenues at least there offered prices,
- non-linear functions can be modelled by piecewise linear functions, and
- if the market clearing prices are used, when partially committed units commit then they will breakeven based on their offered prices and thus there will be no incentive not to fully commit.