Dispatch Model for the All Island Market / Transmission System

November 2012

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Executive Summary

This paper is in response to a request by the Regulatory Authorities to provide further detail on the requirement for central dispatch in the All Island Market and determine the potential for self-dispatch in the All Island Market.

This request followed on from an analysis of the European Target Model requirements which showed that the current SEM design is not compliant with the European Target Model because SEM does not have day head trading and does not have continuous intraday trading, being currently an ex-post market without any form of market coupling in place. However, this does not mean that SEM per se can not be compatible with the target model. It simply means that changes are required to SEM to ensure the key features of the target model are adhered to, those changes may be a full redesign or changes based around existing core principles.

Self dispatch is not a requirement of the target model and any dispatch model can operate efficiently in compliance with the target model, both self dispatch and central dispatch are allowed for in the network codes. A large number of participants in their responses to the Regulatory Authority SEM Development consultation recognised the importance of central dispatch in the context of the All Island Market and have not sought a change. Other participants in seeking self dispatch seem to be seeking firmness of their dispatch positions. Self dispatch in Ireland will not offer this physical firmness to those market participants due to the level of intervention required (to maintain system security) which is a direct result of the physical and technical attributes of the All Island System.

There is a difference between scheduling and dispatch. Scheduling is the determination in advance of the expected running position of generation. Currently scheduling and dispatch are centrally decided. This could change such that market participants could self-nominate, determine their own expected schedule position, and the TSOs could then centrally dispatch, with a compensation mechanism for any deviations, this would in essence leave participants indifferent to the financial impact of the dispatch model chosen. These market design decisions can be made during detailed design analysis.

The nature of the Ireland and Northern Ireland power system is such that operationally managing the risk of loss of the single largest credible contingency requires retaining significant explicit margins of reserve and implicit ramping capability on the system. Given the nature of the portfolio where over 7,500 MW of conventional plant have start and notice times in excess of 1 hour, there is no obvious mechanism to efficiently access these margins for system benefit through “self” dispatch mechanisms. Participants who have excess generation will only have an incentive to manage their risk of not meeting their nomination, not covering the physical risk to the system. Given the risk is system wide and that the participants are relatively large this will lead to significant inefficiencies in providing the necessary margins to securely manage the system.

Self-dispatch is not practical for the all island system currently and will be even less so going forward with increasing renewable penetration, leading the TSO to intervene even more to maintain system security. If generators did self-dispatch, the TSO would have to intervene thus moving the generators away from their desired position. This independent moving up and down of generators would see the system frequency move around unacceptably.

The analysis included in this report shows the levels of intervention required to maintain system security would be very high taking away the self-determination and firmness of position that market participants were trying to achieve through self-dispatch thus rendering it unattractive and ineffective.

Intervention is required in the All Island Market more than in neighbouring markets. SEM is a market operating on a small island system with DC interconnection to its nearest neighbour and as such is not comparable to small systems in central Europe which operate in highly meshed AC networks. GB is also not a good comparison with Ireland because it is 10 times the size and the relative impact of a generation or system change in GB when compared to the All Island System is very small. The all island system has a specific combination of physical/technical attributes such as the type of interconnection, the relative size of individual generators, the number of generators, the size of the system and the penetration of renewables which together reinforce that central dispatch makes sense in the all island context.

Central dispatch is an efficient way to optimise a system such as the All Island system with its specific characteristics and it has proven cost effective. Central dispatch sees the TSO consider all generators and the needs of the system overall and then make a least cost dispatch decision. In a self dispatch model all generators dispatch to suit their own preferred profiles with no consideration of the overall system needs or interactions with system conditions or other generators. As such self dispatch will as a matter of course be more expensive than central dispatch on the All Island System and cannot be achieved without a greater degree of TSO intervention.

Dispatch (central or self) is but one of many factors in a market design, it is not a compliance issue for the target model and it can clearly work hand in hand with the target model requirements. Other markets such as Poland and Italy are addressing these very same issues while maintaining central dispatch for their own reasons. In addition central dispatch is in operation all over the USA, it is a commonly used model.

The current SEM design will need to change and adapt to facilitate continuous intraday trading which is a change all markets are facing particularly as the design for intraday remains open. It is not in question that SEM will change as a result of the move to the target model but central dispatch is not one of the factors that is required to change or for that matter sensible to change for the All Island Market. The TSOs can work with a decentralised model and would of course do so but we are at this early stage highlighting the issues with adopting this potential dispatch model for the All Island Market and the likelihood of higher dispatch costs if adopted.

1. Introduction

At the request of the SEM Committee, this paper has been written by the System Operators (SOs) and Market Operator (MO) to provide further evidence to support the view that central dispatch remains an important requirement of the Ireland and Northern Ireland electricity systems. This paper is intended to provide the SEM Committee with the necessary information to inform any future decisions on this matter that may arise as part of the process of meeting the requirements of the target model.

In early 2012, an options paper entitled, "SEM Integration Project - Pathways to the Target Model" ('Options Paper') written by the SOs and MO at the request of the RAs was published with the SEM Committee's broader consultation on options for meeting the challenging requirements of the 3rd legislative package for energy and associated network codes. In the Options Paper, consistent with the assumptions of the project, the current principle of central dispatch remained a requirement of the all-island system. Furthermore, the paper put forward the view that this requirement applies both now and, increasingly, in the future, as we strive to meet our 40% renewables targets.

The European electricity target model is quite different from the ex-post pricing and the gross mandatory nature of the SEM and is based on cross-border trading across four timeframes – the forward, day-ahead, intraday and balancing timeframes. In many ways, the target model reflects the current prevailing design in Central West Europe (CWE) and the Nordic region and has evolved from the various initiatives that have been established in these areas. As such, parts of the SEM will need to change to meet the target model.

The FG CACM makes no reference to central or self dispatch and therefore there is no requirement to change the dispatch model. It should be noted that any design process for a market that meets the requirements of the target model – be it a modified version of the SEM or a new set of arrangements - will firstly need to consider the finalised network codes as these will be the documents against which compliance will be assessed.

Nevertheless, the TSO view is that the question of self vs. central dispatch is less a function of the market arrangements that are in place and more a function of the physical and technical characteristics of the system being dispatched. With this in mind, this paper aims to provide evidence to support this view and we hope that it will provide the necessary support to the SEM Committee with regard to any future decisions in relation to this matter.

This paper gives consideration to different arrangements for dispatch, in particular “central” or “self” dispatch, that are available for market designs to meet the requirements of the All Island system and those of the target model. In putting this assessment together EirGrid has sought to consider the factors that market participants and the RAs have put forward during the workshops and the RA’s bilateral meetings. Some of the key issues this paper will consider are:

- What is meant by Central Dispatch and Self-Dispatch
- Central Dispatch and Self-Dispatch TSO considerations
- Factors requiring the TSO to deviate from market nominations
- GB and All Island system comparison
- Factors influencing a dispatch model
- Market firmness and physical firmness
- Compliance with the Target Model

2. Definition of Central Dispatch and Self-Dispatch

What is meant by the terms central dispatch and self dispatch is key to any discussion on the topic, below we provide definitions and in annex 1 we provide a further definition relevant to this discussion.

Dispatch here refers to two activities:

1. the determination of the operational schedule

2. the issuance of dispatch instructions to generators

Definition: Central Dispatch

A dispatch arrangement where the TSO determines the dispatch values and issues instructions directly to generators (or demand). The TSO determines the dispatch instructions based on prices and technical parameters provided by the participating parties in order to minimise the system production cost while meeting security requirements.

This is currently combined with centralised unit commitment scheduling in the SEM market. In a centrally scheduled market participants are given their position based on a central decision.

Definition: Self-Dispatch

A dispatch arrangement where generators determine a desired dispatch position for themselves based on their own economic criteria to provide commercial independence within a market. The dispatch determination may or may not have a requirement to have a balanced position with demand. The physical dispatch can be either carried out by the generators directly, tracking their desired output nomination or by following dispatch instructions from the TSO which have been determined based on generators' nominations.

Under this arrangement the generators nominations would become the starting point for the TSOs consideration of the dispatch required to meet security requirements. Sufficient resources need to be available to the TSO to be able to dispatch to achieve system security. The TSO would optimise the dispatch based on the minimum cost of moving away from generators' nominations rather than the minimisation of production costs under a centrally dispatched model.

Examples

Self-nomination could be combined with central dispatch, a change from the current central unit commitment scheduling and central dispatch market and it would give those generators who are seeking it more control. Table 1 below outlines the various combinations of dispatch and scheduling/nomination models that could be implemented.

Option	Who Dispatches?	Basis of Dispatch	Commercial Treatment
1. Centralised TSO scheduling and dispatch	TSOs issue all dispatch instructions.	TSOs schedule and dispatch all units to ensure system security and minimisation of production costs.	Participants are compensated for TSO instructed deviations from the market schedule through the constraint mechanism.
2. Self nomination and TSO dispatch	TSOs issue all dispatch instructions.	TSOs schedule and dispatch all units to ensure system security and minimisation of the cost of deviating from Participants nominated position.	Participants are compensated for TSO instructed deviations from their nominated position.
3. Self nomination and Self dispatch	Participants dispatch themselves with the TSOs only intervening for balancing purposes.	Participants determine their own dispatch position to follow their nomination. The TSOs only intervene to balance the system in short term timescales (typically one hour).	A balancing mechanism compensates participants for balancing actions instructed by the TSOs.

To put these definitions in context it is worth briefly looking at two well known markets which operate with a central and self dispatch model in place, i.e. the SEM and BETTA markets. The fact that BETTA is a bilateral market is not the key issue, central dispatch can work in conjunction with a bilateral market.

Central Dispatch Market Example

In a centrally dispatched market the TSO dispatches all plant, based on market Commercial Offer Data, to provide generation and demand balance, external transfers, reserve provision and transmission constraint management. This involves dispatch instructions being issued from up to 14 hours ahead of real time to connect off line plant (in particular plant with long start up times) to real time instructions for connected plant. In a SEM type pool market there is no inherent balancing link between generators and demand (suppliers). Generators bid into the market and become part of the market schedule if economic, suppliers buy at the resulting market price for their demand. The Grid Code stipulates the requirements for generators for following dispatch instructions. Differences between the market schedule and actual generation running as directed by the TSO to balance with reserve and constraint provision becomes a constraint cost to the end customers.

Self Dispatch Market Example

In a self dispatch market with generation and demand balancing requirements (e.g. in BETTA), the market design produces a balance between generation and demand (and external transfers) by requiring that both parties are in a balanced position (for trading periods) to participate in the market. Imbalance exposes the market parties to balancing charges, in some cases penal charges to commercially encourage accurate nominations. Lack of participation in the market will also lead to imbalance. Commitment decisions are made by the generators in conjunction with the demand elements they are balancing with; generators alter their output to maintain the balance between output and their expected demand. A deviation from the pre-declared balance position between the generator and its associated demand in the market results in a system imbalance that needs to be rectified to maintain overall system balance. The deviations can arise from incorrect demand forecasts, unexpected generation restrictions, wind forecast errors, non participation in the market etc. The actual system balancing is undertaken by the TSO to balance the entire system for real time operation. The TSO has to know the market position the generation intends to follow when dispatching themselves, in advance of real time and have the ability to dispatch generation to balance and secure the system. In self dispatch markets without a generation and demand balancing requirement the TSO would have to have the ability to dispatch generators to meet imbalances or would need to have sufficient reserves contracted to meet any potential imbalances. The balancing mechanism in BETTA does not take into account congestion on the transmission system and so, like the SEM, differences between market quantities and actual generation running due to transmission constraints are managed by National Grid, the GB System Operator. National Grid uses the balancing mechanism, bilateral contracts and TSO cross border trading to resolve constraints.

3. Central Dispatch and Self-Dispatch TSO considerations

In "self" dispatch models where it is assumed that the market determines the dispatch position of a generator, in real time there is invariably some level of TSO input, dispatch or step in rights required to ensure the security of the power system. All systems require the TSO to take responsibility for real time security and as such have obligations on all units to follow dispatch instructions from the TSO if required to do so. The differentiator between central and self dispatch is a question of the principle imposed on the TSO, the question is

Is the principle least cost dispatch or market position maintenance?

In the SEM today the principle is least cost dispatch and as such the TSO is able to dispatch a generating unit away from its market position to account for system conditions but does so to meet least cost dispatch, therefore to move to a more "self" dispatch model comes down to how often and to what level the TSO can step in to move a unit away from the market position and what benefits this will confer on the participants, the system as a whole and ultimately the cost and security of supply to the end consumer.

For the TSO the main difference between central and self dispatch, in practice, is the starting point for dispatch decisions to secure and balance the system. In a self dispatch market the starting point for the TSO is the generators' nominations i.e., the individual generators desired market position. In a central dispatch market the starting position for TSO dispatch decisions is the current state of the system and current position of the available generators. In order to secure and balance the system the TSO has to be able to call on generators to balance the system to account for system issues or generator outages etc.

There are a number of ways to do this:

1. TSO accepts generators nominations, which are balanced with demand, and uses a balancing market to secure the system, only deviating from market positions to ultimately balance and secure the system. Better suited to a self dispatch market

2. TSO accepts generators nominations, which are not balanced with demand, the TSOs can dispatch generation away from the nominated position, with payments provided for nomination deviations. The TSO dispatches to minimise the deviation cost and meet the system requirements. Suited to central dispatch or self dispatch market. We do not believe this model is sensible as participants in all other markets are required to balance and ours should be no different otherwise the TSO balancing cost will end up being extremely high.

3. TSO dispatches to secure and balance the system to minimise production costs without a pre determined starting point. Better suited to central dispatch

If, for example, one were to adopt model 2 in Ireland, because of the limited number of generators the TSO would need to dispatch generators away from their preferred schedule to balance the system starting from an inherently imbalanced position. In a self dispatch model generators will invariably seek to run at a level at odds to the system requirements to meet security needs. It is inevitable that the TSO will intervene and generators will not get to operate to their preferred schedule, thus rendering this form of self dispatch ineffective.

Under model 1 generator’s would be expected and responsible for being in balance. This model would disadvantage smaller units in Ireland as they wouldn’t have the plant portfolio required to easily keep them in balance. This kind of arrangement requires liquidity which would be an issue in a small market like the All Island Market.

Self dispatch Intervention

An important consideration and measure of market success for a self dispatch market is the magnitude of balancing that is required after market gate closure. This will be driven by the liquidity in the market and the degree of intervention, forced deviation from nominations, which would be required by the TSO to ensure system security and balance.
The degree of intervention required will be largely due to:

- the physical attributes of the system
- the market design
- engagement of participants.

The TSO will work with either model of dispatch, provided the TSO license obligations to be able to operate the system securely can be met (meaning the right to intervene where necessary to maintain system security), however a self dispatch market does cause significantly more concern for the TSOs.

4. Factors requiring the TSO to deviate from market nominations.

Following market development workshops and bilateral meetings with participants, the participants’ view of self dispatch is a model where they decide on a dispatch and follow it. What follows here describes that, in practice, it would be difficult to achieve secure system operation without TSO intervention. If in practice the TSO ends up having to carry out widespread intervention then the participants don’t actually achieve what they wanted. Under a model where participants know they will be moved away from their desired position at times (such as central dispatch), they can operate with this full knowledge. Compensation mechanisms for deviations from a desired position are required but the mechanism under a self dispatch model is likely to have to be at a higher cost.

What follows here is a discussion of the reasons why the TSO might diverge from the submitted profile of a generator and how often the divergence actually occurs in practice in SEM.

In a self dispatch market, with generators providing nominations, the TSO would expect to have to dispatch away from the nominations to balance and secure the system for the following reasons.

- System Services provision (Reserve and Reactive)
- System constraint management
- Wind and demand forecast errors
- Generator availability re-declarations
- Renewables

The following sections consider the impacts of these factors on system dispatch and conclude with a section entitled 'TSO Intervention in SEM' which analyses the impact of TSO dispatch decisions with respect to the unconstrained SEM schedule.

System Services provision

System (ancillary) services are managed and procured by the TSO to be able to operate the power system to the required security standards. The services do not normally exist as part of an energy market such as the SEM and are procured separately. At present the services procured that impact on dispatch are reserve and reactive services.

Reserve

Reserve is required in different time frames to control power system dynamics and re-establish a secure system due to a sudden loss in generation (or interconnection) or to react to a large forecast error in demand or wind generation. Fast acting reserves which react within seconds to the loss of generation and provide continuous system frequency regulation through governor systems are sourced from conventional generation and are classified as dynamic reserve. Other fast acting reserves which react only when a frequency threshold value has been reached and do not regulate frequency are classified as static reserve. The power system cannot be operated with only static reserve which is sourced from interconnectors and tripping demand, such as pump storage units when pumping. In order to provide fast acting dynamic reserve generation must be dispatched at less than its maximum output in order that its output governing system can increase output in reaction to a frequency fall. A unit not operating at full output may also be dispatched to a different output to provide more reserve. The total reserve requirement for the power system is dependent on the largest single credible contingency.

At present on the all island system the largest single credible contingency could typically be 450 MW or 20% of the minimum system demand, the equivalent GB figure for their largest single credible contingency would be 7%.

Following the major loss of generation (or interconnection) longer term reserves are utilised by the TSO to re-establish a secure system that will be able to sustain the loss of another generator. This involves dispatching on, normally expensive, quick start off line plant and re-dispatching connected generation until cheaper conventional generation can replace the quick start units. This would represent a major departure from a self dispatch market position for a period until the market can balance again, which may involve plant that takes hours to synchronise. In addition, the dispatch must take into account that any single unit that is dispatched away from its own self dispatch output will also require other units to be re-dispatched to rebalance generation and demand on the power system.

With the present SEM the TSO determines the required dispatch to meet the reserve requirements using the Reserve Constrained Unit Commitment (RCUC) tool. RCUC provides a minimum production cost dispatch to meet generation (and interconnector flows) and demand balance, reserve requirements and secure transmission constraints.
Reserve requirements cannot be determined by independent elements within the power system, it is a system wide requirement that is based on the actual real time status on any of the individual elements including interconnectors. If generators are determining a self dispatch position for their own market reasons the TSO will require the ability to redispatch in order to provide system reserves.

The largest single infeed on the island of Ireland will shortly rise from 450MW to 500MW on commissioning of EWIC. As a result the requirement for fast acting reserve will rise to 375MW (75% of the largest infeed), the majority of which must be sourced from online generation. This level of reserve (which is proportionally high with respect to system size) will at times require all capable generating units to be dispatched to a reserve providing position.

Reactive Power

Power system operation requires that voltage levels are maintained on the system both for normal operation as generation, demand and interconnection conditions change but also to ensure that post fault voltage changes meet security standards. To operate the system securely generation elements that can produce or absorb reactive flows are required to be dispatched. The requirements depend on the system demand, transmission system configuration, connected generation output, interconnector flows and transmission reactive device status. Reactive power cannot be transmitted over distance in the same way as active (MW) power hence the reactive requirements become a local transmission system issue. Some of these limitations are addressed by transmission devices such as Static Var Compensation (SVC) but not all and generation is still required in some areas to assist with low or high voltage issues.

As an example, generation in Dublin is required to be connected to absorb reactive power during periods of low demand.

An energy market does not take into account the reactive requirements of the power system. Similar to the reserve position, if generators are determining a self dispatch energy position for their own market reasons the TSO will require the ability to redispatch in order to provide system reactive requirements.

System constraint management

In an ideal world generation would be able to operate at any output at any time and not be subject to any limitation or constraint. Most constraints are produced for conditions that exist after a fault on the transmission system that would lead to an overload, voltage violation or stability issue which exceeds the system security standard. System constraints for generation exist as either inadequate transmission capacity to allow the export of generation from an area, an area requires local generation to support the transmission system or an area requires generation to provide system stability. The first two can be classified as forcing generation to be output limited and must run respectively. Security standards require the TSO to consider the system conditions post fault, normally a single credible fault. If a 200 MW generator is connected to the system by two 100 MW capacity lines and a line trips with the generator producing 200 MW the resulting overload will damage the remaining transmission line and create a safety hazard. In order to avoid this situation the generator output would be limited. Similarly if two 100 MW lines are connected to a 200 MW demand with local generation available the generation must be run to secure the demand i.e. the generation is constrained on. The constraints can be exacerbated by the requirement to do maintenance to the transmission equipment, where transmission equipment is required to be taken out of service for system re-enforcement or transmission investment has lagged behind generation establishment.

Examples of system constraints on the island of Ireland are:

- Generation limited in output – Aghada, Marina and Whitegate generators are limited by transmission congestion in the Cork area

- Generation that must run - Kilroot generators must run to support Belfast voltages

- Generation that is required for stability – Eight high inertia generators must run (3 in NI, 5 in IE).

A full list of current system constraints can be found in the EirGrid/SONI document 'Transmission Constraint Groups' at the following address:

http://www.eirgrid.com/media/Transmission%20Constraint%20Groups%20Version%201.3%2017%2005%2012.pdf

As noted in one of the examples above, to ensure post fault stability for Northern Ireland generation at least three generators must run at any one time. This is due to the limited transmission capacity between the North and South of Ireland. The SEM with no constraint recognised between North and South has scheduled zero generation in the North at times leading the TSO to dispatch on generation to ensure system security.

Wind and demand forecast errors

Forecasting errors will result in the TSO dispatching to balance in either direction depending on forecast error. To achieve a balanced nomination, self dispatching parties will be reliant on their own forecasts, any inaccuracy will lead to an imbalance in real time that will require TSO redispatch.

Generator Availability re-declarations

When unexpected changes of plant availability occur in short time frames, before a self dispatch market could react, the TSO re-dispatches to balance. The re-dispatch will move plant away from existing plant nominations. The market will react to these changes but only after the rolling gate closure time. For example, if the gate closure time was 2 hours, a change in availability could be rebalanced in the market, if another source is available, but it is at least 2 hours before the generator can re-nominate. During the intervening time the TSO must dispatch other plant to rebalance. On the All Island System (AIS), at minimum demand, the loss of 300 MW is 9% of demand, in GB at minimum demand 300 MW is 1% of demand.

To illustrate the degree and timing of unexpected changes in generation availability, the following describes details of generation availability re-declarations and trips for the All- island System during 2011. Generator availability is the MW value of plant capacity that can be utilised.

Short notice declarations (short notice is defined as changes in availability declared by generators to the TSOs with less than 8 hours notice) requires the TSO to dispatch generation on or increase output to balance. Calendar year 2011 produced 522 incidents of Short Notice Declarations (SNDs).

Unit Trips – requires the TSO to dispatch generation on or increase output to balance. Calendar year 2011 produced 80 incidents (the incidents recorded only include the loss of more than 100 MW) of generation trips.

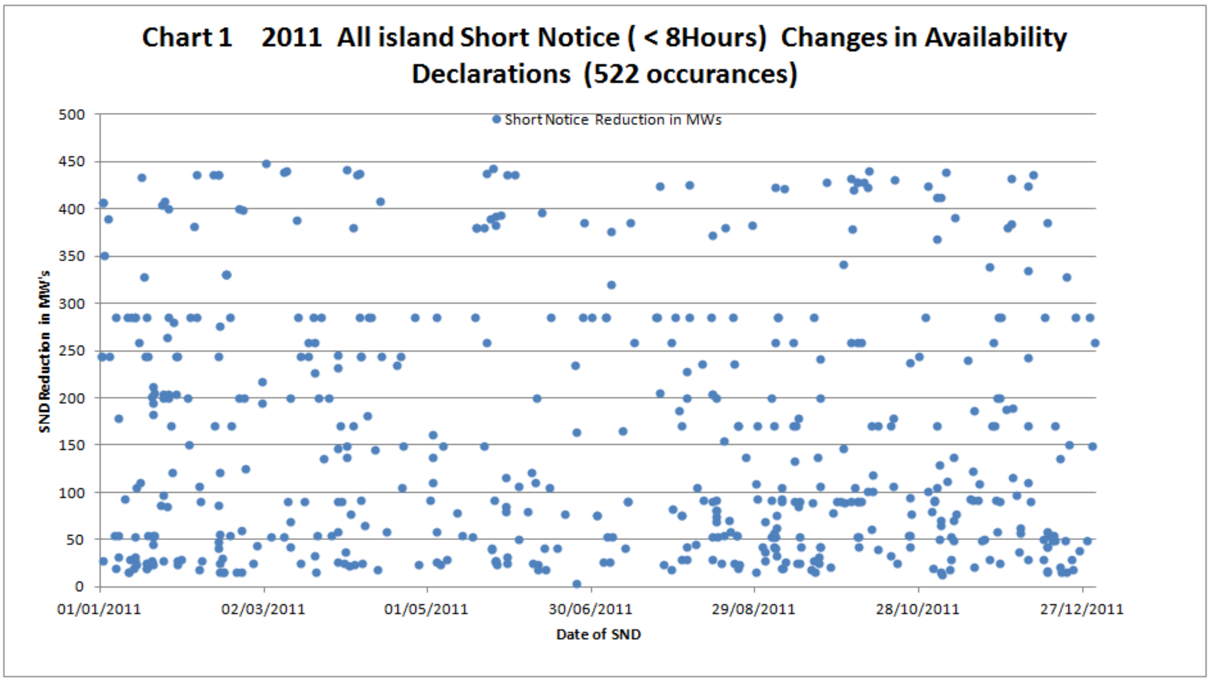


Chart 1 indicates the volume and magnitude of generation short notice re-declarations of availability throughout 2011. The X axis is time starting at 1/1/11 and finishing at 30/12/11. The Y axis is the reduction in availability in MW. Each point plotted represents an individual re-declaration. The system would need to be re-balanced for each of these occurrences.

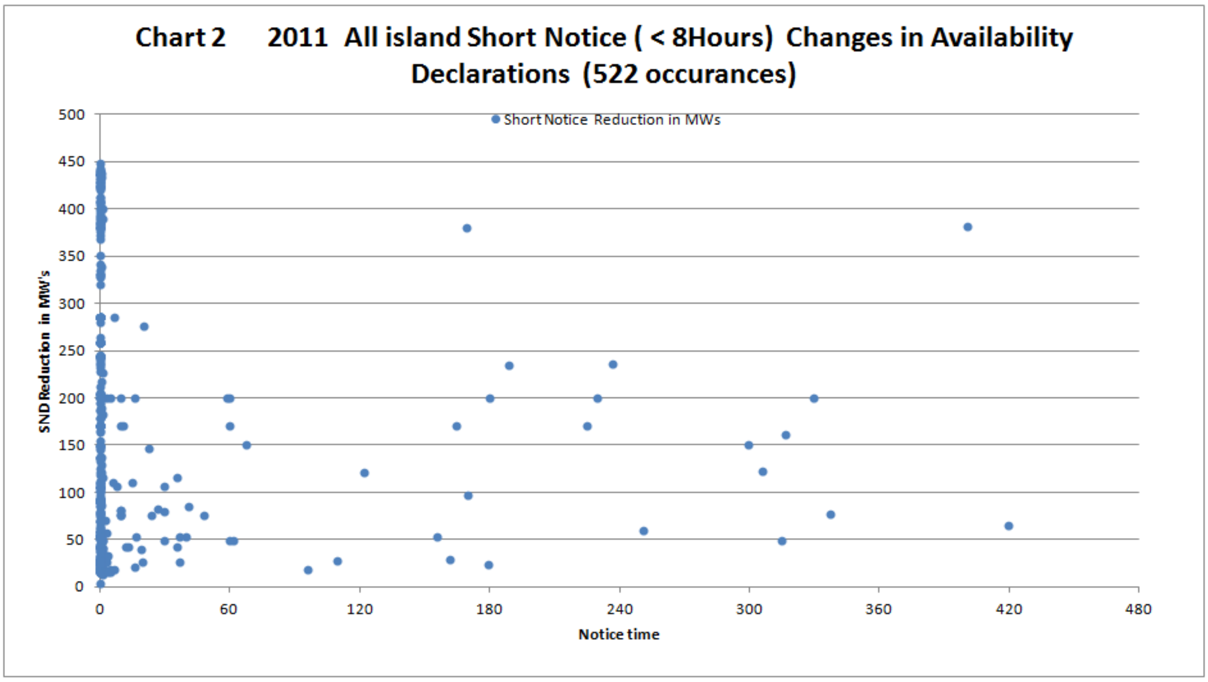


Chart 2 indicates the notice time and magnitude for generation short notice re-declarations of availability throughout 2011. The X axis is time starting at 0 minutes and finishing at 480 minutes. The Y axis is the reduction in availability in MW. Each point plotted represents an individual re-declaration. As can be seen from the chart the vast majority of re-declarations occur at less than one hour. The TSO reaction to re-declarations is dependant of the notice time given, where there is no notice or very short notice time given fast acting reserve holdings are used to balance and secure the system. With longer notice generation is ordered to replace missing capacity. The ability of a market to react to balance itself is dependent on the market gate time for unexpected changes in plant capacity.

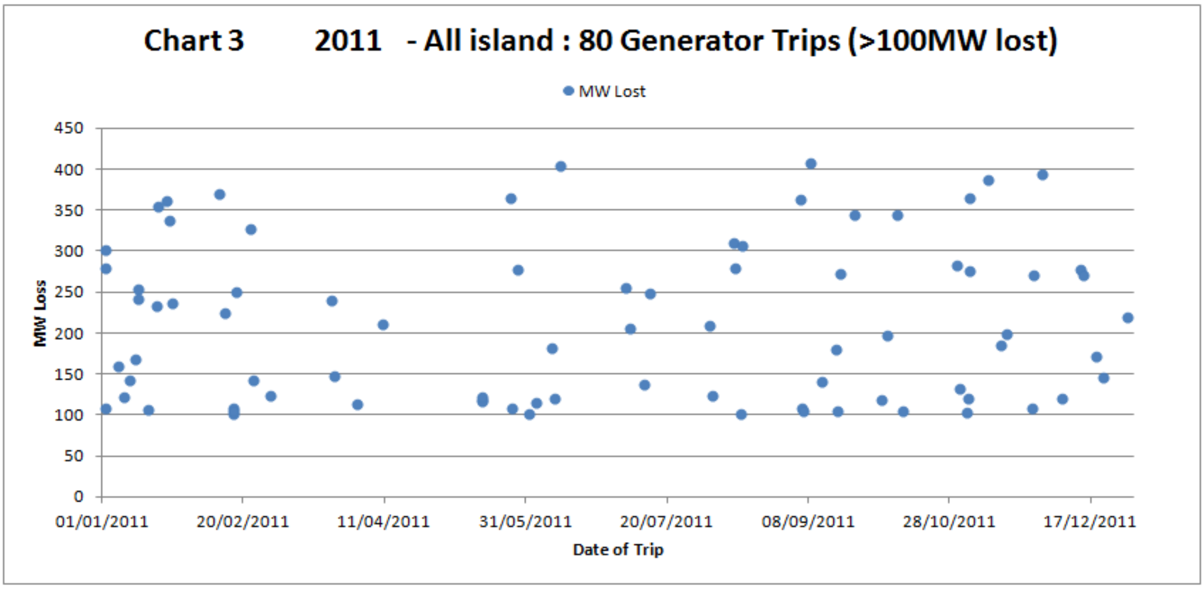


Chart 3 Indicates the MW value lost for each generation trip event (no notice) during 2011

The majority of unexpected changes in Generator availability occur with less than 1 hour notice.

Renewables

The governments in Ireland and Northern Ireland have set ambitious targets for electricity from renewable sources (RES) by 2020. Respectively this is 40% of final energy from RES by 2020. This target in Ireland translates to 37% of electricity from wind. While there is no similar explicit breakdown in Northern Ireland it is likely that wind will achieve comparable levels. These are the highest levels of wind generation in the electricity system for any Member State[1] from the 2011 National Renewable Energy Action[2] plans submitted to the EU. Notwithstanding this, when these figures are analysed with respect to distinct synchronous areas in Europe the scale of the challenge for Ireland and Northern Ireland as a small island system is even more significant. The majority of renewable energy will come from wind generation which is variable. Irrespective of the market/dispatch model that evolves, the volume of variable generation presents major challenges for secure system operation. Without variable generation, balancing a power system is the action of matching conventional generation sources to a predictable demand (and known interconnection flows). With increasing amounts of variable generation the role of conventional generation becomes the balancing entity between system demand, interconnector flows and the variable generation. The conventional plant will be subject to much more output ramping movement and cycling on and off to balance with the variable generation and demand. The high and mid merit portfolio of conventional plant of the island consists of thermal machines (200 to 450 MW) with synchronising times longer than an hour when hot, and much longer when cold. An informed TSO with the necessary tools and operational policies coupled with suitable incentivising of the appropriate portfolio performance would be the most efficient and effective means to manage these challenges going forward. The TSOs “Delivering a Secure Sustainable Power System (DS3)” programme is providing a multi-year, multi-stakeholder plan to achieve this and implicitly assumes that the TSO can co-ordinate its dispatch to accommodate evolving operational policy. The range of changing operational issues, identified by DS3 will need to be addressed and managed efficiently. This, in the first instance, requires significant research and development effort to fully understand these issues before any solutions can be developed. The Ireland and Northern Ireland power system is many years ahead of other systems in experiencing, managing and mitigating the challenges of high instantaneous penetrations of wind compared to other distinct synchronous areas in Europe. Given that new operational challenges are being experienced and analysed in the SEM that have not been thought about in other systems it is difficult to see how a self dispatch market can realistically and efficiently deal with these issues. It would not be possible within current timeframes to take into account the, not fully understood, changes in the underlying system described above and concurrently with this develop efficient and effective signals to accommodate self dispatch.

TSO Intervention in SEM

Justification for the use of the SEM schedule for comparison

In order to demonstrate the required degree of intervention i.e. the difference between market schedules and actual dispatch by the TSO, a comparison between a market schedule and an actual dispatch schedule has been analysed. The content of a self dispatch market schedule can only be guessed at this stage without any market design rules or knowledge of expected generator behaviour. A self dispatch schedule in a balancing market is the result of the contracts struck between the generators, suppliers and interconnector users prior to gate closure before real time. The schedule will be determined by the trading between market parties based on a variety of costs, plant availabilities, risks etc over a range of timescales. Not having a viable balancing market schedule available for analysis, the SEM market schedule was used. The SEM schedule represents a

[1] Northern Ireland is not a Member State but is a distinct power system and is used in this context here.
[2] Denmark has recently set a 50% target by 2020.

market schedule that has been produced using plant merit order and the majority of plant performance characteristics to balance generation and demand without any system constraints applied to produce a minimum cost schedule. Neither the SEM schedule nor a balancing market schedule would provide for reserve or respect transmission security constraints. The full differences between a SEM schedule and a balancing market schedule are unknown but differences that would result in a reduction in TSO intervention to secure the power system would be coincidental. Some differences are known or expected. The SEM schedule contains no wind or demand forecasting errors because the SEM schedule is produced after the event, the balancing market schedule would have errors because it is produced at a time before gate closure. Generators would be expected to reduce their existing level of two shifting in a balancing market to reduce their costs and operational risk, the SEM schedule applies only a financial consideration to two shifting; if it reduces the overall system cost the schedule will take the generator off and on again.

Constraint costs

Within SEM the TSO intervention results in a constraint cost, the difference between the SEM schedule and the dispatch position. The payment for the difference between dispatch and market schedule is paid for (or repaid) at the generators' actual production cost as required by the Bidding Code of Practice. The constraint cost is therefore based on the difference in price between generation being dispatched for security and the corresponding balancing generation. This provides a minimum cost solution for TSO intervention based on actual production cost. Additionally in a situation where the TSO requires to start or stop a generator from a selection of identical generators , for example within a power station with two or more identical units, the constraint cost is the same irrespective of which generator has been started or stopped in the SEM schedule. This allows flexibility for the TSO to; for example, avoid operating generators with declared inflexibilities such as the inability to two shift at no additional system cost.

In a balancing market the expectation is that balancing contracts with asymmetrical increase / decrease prices will be at a cost greater than generation production costs, TSO intervention would therefore be more expensive.

Comparison between SEM schedule and actual dispatch

The SEM produces, for settlement after the trading day with full hindsight, an optimised minimum cost unconstrained schedule for generator units based on actual generator availabilities and system demand. In this section the SEM Market Scheduled Qualities are compared to the actual dispatch quantities that the TSO had dispatched to illustrate the degree of intervention away from the market schedule carried out by the TSO.

Two full years of SEM data, calendar year 2010 and 2011, were selected and analysed.
For each Predictable Price Maker Generator (PPMG) and Predictable Price Taker Generator (PPTG) their Market Scheduled Quantity (MSQ) and Dispatch Quantity (DQ) for each 30 min Trading Period (TP) in the year was compared and recorded. For a TP which had a DQ greater than the MSQ this was recorded as a dispatched up positive value. For a TP which had a DQ less than the MSQ this was recorded as a dispatched down negative value.

For example for 3 sample Trading Periods -

			dispatched up	dispatched down
RESOURCE_N	MSQ	DQ		
GU_400180	0.00000	35.00000	35	0
GU_400180	0.00000	34.22700	34.227	0
GU_400180	35.00000	3.12000	0	-31.88

The 2010 and 2011 years data is summarised in table 1a and table 1b respectively.
Each TP value for MSQ, dispatched up and dispatched down values for the year have been summated and compared to the system demand as a percentage.

MWhr data 2010				
Market Generation	MSQ		dispatched up	dispatched down
PPMG	26115807		4874453	-5007842
PPTG	3985269		126934	-169985
Total	30101076		5001387	-5177826
		% of MSQ	17%	-17%
2010 demand MWhr				
36211000		% of demand	14%	-14%

TABLE 1a	Total intervention as % of demand	**28%**

MWhr data 2011				
Market Generation	MSQ		dispatched up	dispatched down
PPMG	24088083		5816480	-5696992
PPTG	3629911		28286	-225503
Total	27717994		5844766	-5922495
		% of MSQ	21%	-21%
2011 demand MWhr				
35143000		% of demand	**17%**	**-17%**

TABLE 1b	Total intervention as % of demand	**33%**

Wind generation and interconnector values have not been included. The PPMG, all conventional generation and PPTG, Peat and CHP generation, represent the plant dispatched by the TSO to balance and secure the system. The comparison of dispatched up and down quantities as a percentage of system demand indicates the degree of TSO intervention for the All Island system. The market schedule has been altered by a 28% volume in 2010 and 33% volume in 2011 to secure the system.

Further analysis was carried out for a sample week starting February 19th 2012, selected at random. The MSQs quoted are the summated half hour trading period MSQs for the week i.e. the energy that was scheduled in the market for that unit for the week. The difference between the MSQ and DQ for each trading period was recorded for each trading period with positive values (dispatched up) and negative values (dispatched down) separated. Table 2 below, in order of MSQ magnitude, lists a Unit Number, the total week's MSQ per unit, the quantity of energy that the TSO dispatched the unit down from its MSQ, the quantity of energy that the TSO dispatched the unit up from its MSQ, the dispatch down quantity expressed as a percentage of the system energy demand for the week and the dispatch up quantity expressed as a percentage of the system energy demand for the week.

During this week the TSO has intervened, by varying degrees, with almost all the machines that were available or running apart from the most expensive heavy fuel oil and distillate OCGT plant which would not normally be operating. The TSO intervention amounts to 30% of the total system energy demand for the period, i.e. in order to meet system security requirements while minimising production costs the TSO dispatch differed from an efficiently matched set of market transactions (market schedule) by a MW quantity equivalent to 30% of total system demand.

In a self dispatch market this intervention would have to take the form of balancing contracts which would have to be filled by the same units already operating in the market. The question is - would this be a more efficient model than the current one? We do not believe it would be.

UNIT	MSQ MWhr	dispatched down by TSO from MSQ MWhr	dispatched up by TSO from MSQ MWhr	dispatched down by TSO from MSQ as a % of total system demand	dispatched up by TSO from MSQ as a % of total system demand
Unit 1	65556	-6481	0	-0.92%	0.00%
Unit 2	56363	-45591	0	-6.46%	0.00%
Unit 3	56024	-9587	774	-1.36%	0.11%
Unit 4	42139	-7261	29	-1.03%	0.00%
Unit 5	42138	-6569	7	-0.93%	0.00%
Unit 6	41246	-6235	298	-0.88%	0.04%
Unit 7	40929	-5634	3275	-0.80%	0.46%
Unit 8	24337	-3371	2043	-0.48%	0.29%
Unit 9	23008	-2216	0	-0.31%	0.00%
Unit 10	21014	-1607	5380	-0.23%	0.76%
Unit 11	18816	-969	0	-0.14%	0.00%
Unit 12	15725	-1639	29872	-0.23%	4.23%
Unit 13	15288	-777	0	-0.11%	0.00%
Unit 14	12116	-421	6	-0.06%	0.00%
Unit 15	11383	-419	9	-0.06%	0.00%
Unit 16	9233	-6415	733	-0.91%	0.10%
Unit 17	3924	-220	90	-0.03%	0.01%
Unit 18	2883	-335	222	-0.05%	0.03%
Unit 19	2573	-288	351	-0.04%	0.05%
Unit 20	2315	-476	4891	-0.07%	0.69%
Unit 21	1999	-300	431	-0.04%	0.06%
Unit 22	1652	-5	2	0.00%	0.00%
Unit 23	1477	-285	565	-0.04%	0.08%
Unit 24	1462	-50	48241	-0.01%	6.84%
Unit 25	1165	-211	272	-0.03%	0.04%
Unit 26	1137	-214	278	-0.03%	0.04%
Unit 27	459	-44	112	-0.01%	0.02%
Unit 28	394	-146	6545	-0.02%	0.93%
Unit 29	260	-17	125	0.00%	0.02%
Unit 30	236	-67	129	-0.01%	0.02%
Unit 31	109	-74	65	-0.01%	0.01%
Unit 32	48	0	438	0.00%	0.06%
Unit 33	43	-20	40	0.00%	0.01%
Unit 34	23	-9	41	0.00%	0.01%
Unit 35	3	-3	0	0.00%	0.00%
Unit 36	3	-3	0	0.00%	0.00%
Unit 37	0	0	2192	0.00%	0.31%
Unit 38	0	0	2750	0.00%	0.39%
Unit 39	0	0	0	0.00%	0.00%
Unit 40	0	0	0	0.00%	0.00%
Unit 41	0	0	205	0.00%	0.03%
Unit 42	0	0	0	0.00%	0.00%
Unit 43	0	0	0	0.00%	0.00%
Unit 44	0	0	0	0.00%	0.00%
Unit 45	0	0	0	0.00%	0.00%
Unit 46	0	0	0	0.00%	0.00%
Unit 47	0	0	1	0.00%	0.00%
Unit 48	0	0	0	0.00%	0.00%
Unit 49	0	0	0	0.00%	0.00%
Unit 50	0	0	0	0.00%	0.00%
Unit 51	0	0	0	0.00%	0.00%
Unit 52	0	0	0	0.00%	0.00%
Unit 53	0	0	0	0.00%	0.00%
Unit 54	0	0	0	0.00%	0.00%
Unit 55	0	0	0	0.00%	0.00%
Unit 56	0	0	0	0.00%	0.00%
Unit 57	0	0	0	0.00%	0.00%
Unit 58	0	0	0	0.00%	0.00%
Unit 59	0	0	0	0.00%	0.00%
Unit 60	0	0	0	0.00%	0.00%
Unit 61	0	0	0	0.00%	0.00%
Unit 62	0	0	0	0.00%	0.00%
Unit 63	0	0	0	0.00%	0.00%
Table 2				-15.30%	15.65%

The contents of table 2 are presented graphically for all the units in the follow charts. The first 2 charts describe the chart information.

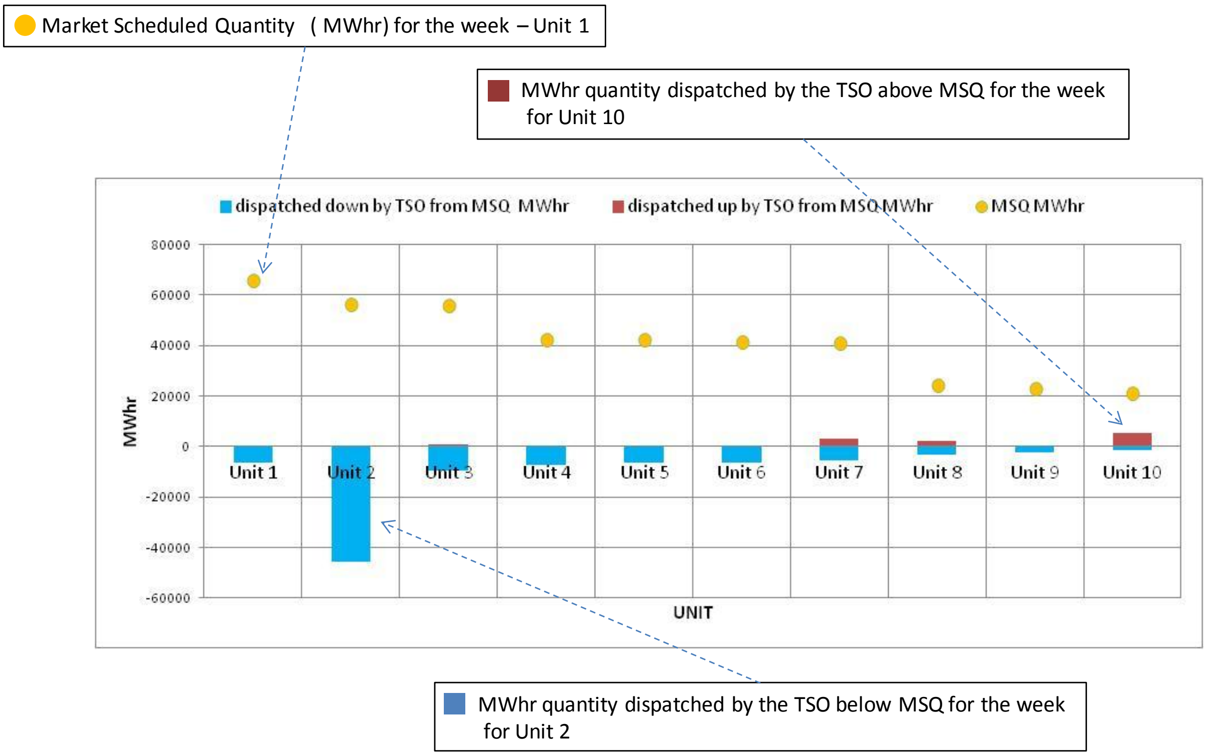


Chart 1 - Data from Table 1 expressed graphically - with MWhr values for MSQ and TSO dispatch deviations from MSQ values

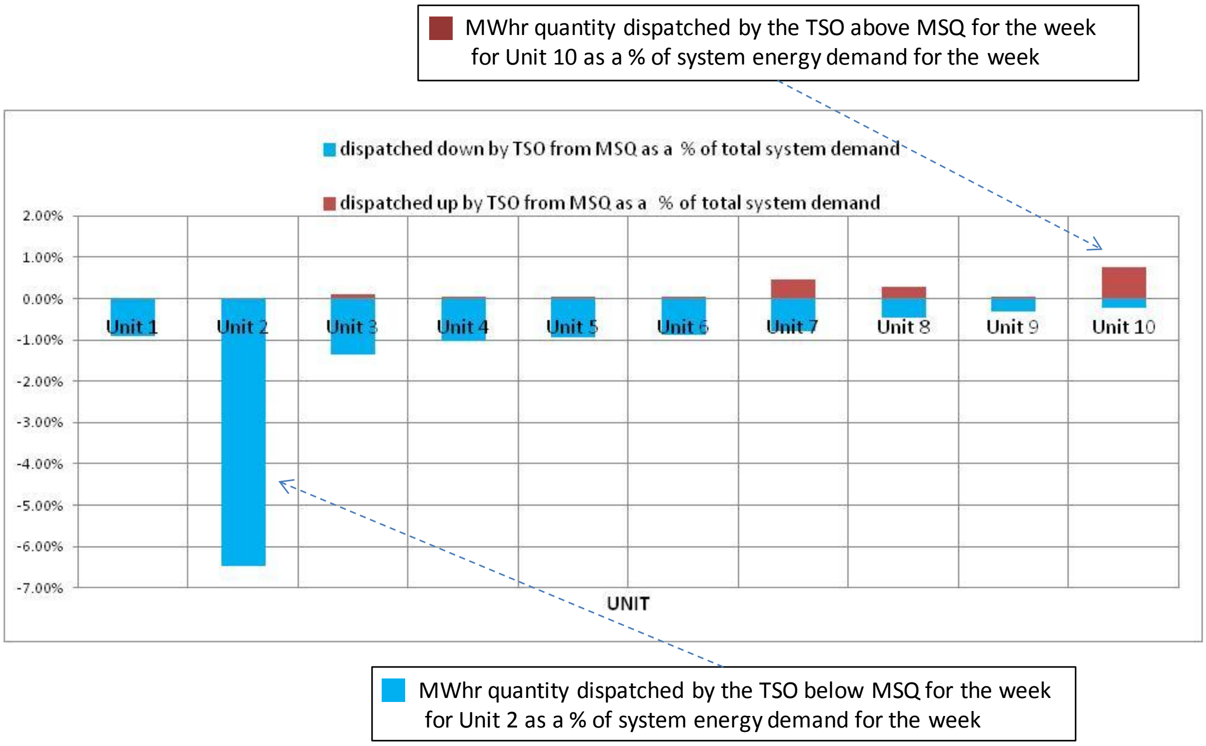
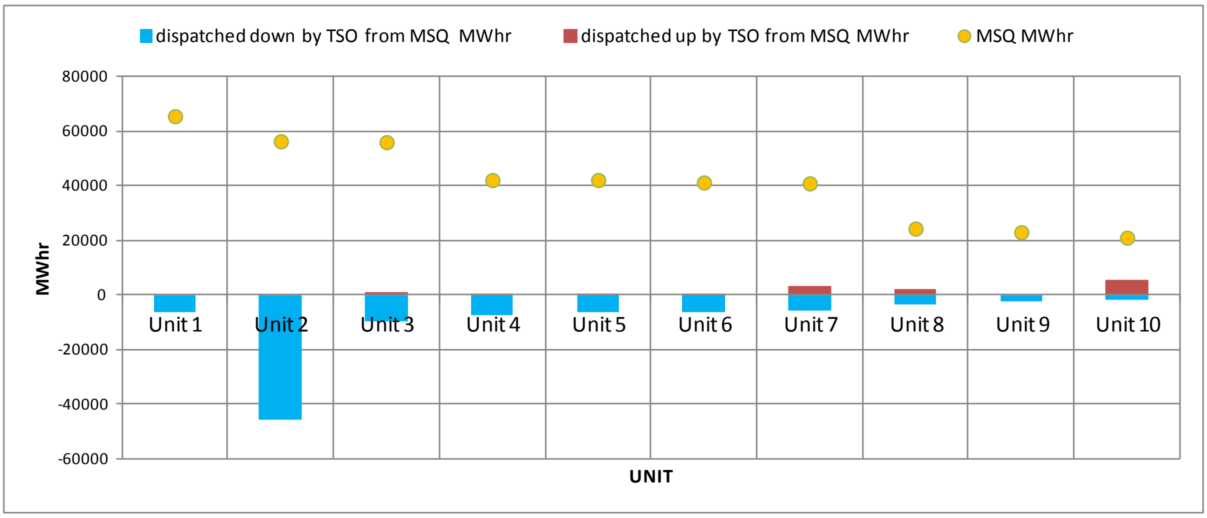
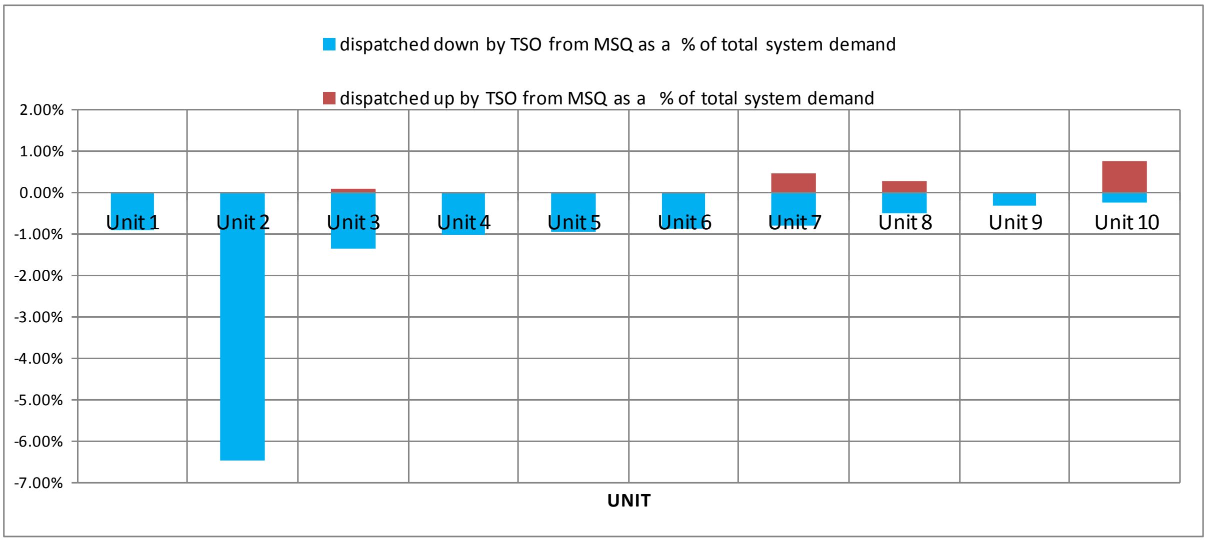


Chart 2 - Data from Table 1 expressed graphically - TSO dispatch deviations as a percentage of total system energy demand for the week

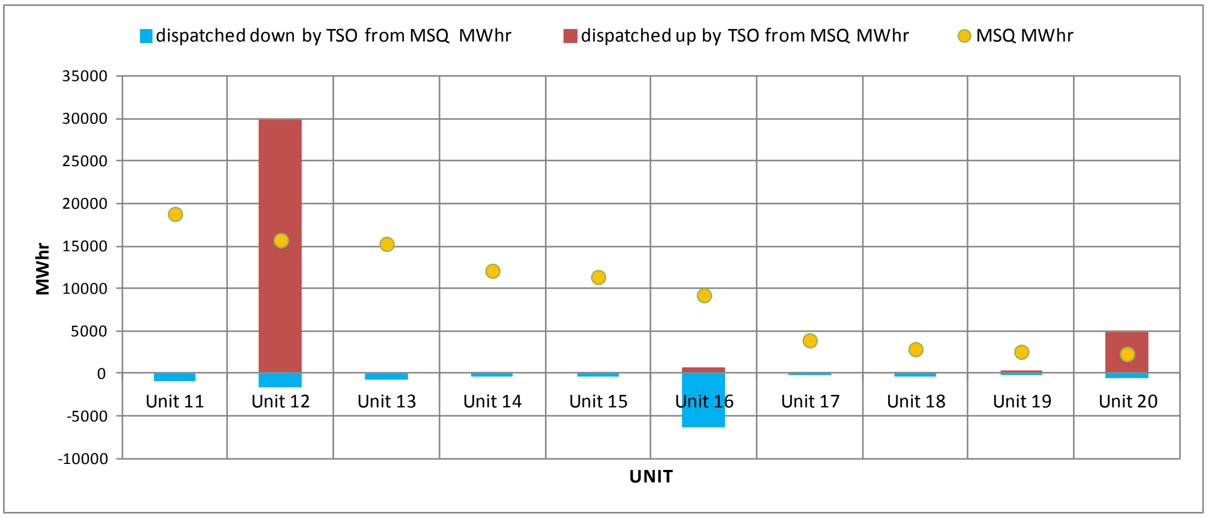




Charts 3 & 4 - This is the first ten units available in the market in order of the quantity of energy scheduled (MSQ) within the SEM.

It is not possible to break down the actual cause of constraints being applied in each case over a week but a commentary is provided in general terms, constraints vary from trading period to trading period, because this represents the summation of a whole week, a unit may, for example, have been constrained up over night and down during the day. The purpose of the analysis is to indicate the degree of intervention.

- The Unit 4, 5 and 6 were constrained down to provide reserve.
- The Units 8 and 10 have been constrained up or on overnight to reflect a minimum unit running constraint.
- The Units 2 and 3 have been scheduled down mainly due to a transmission area export constraint.



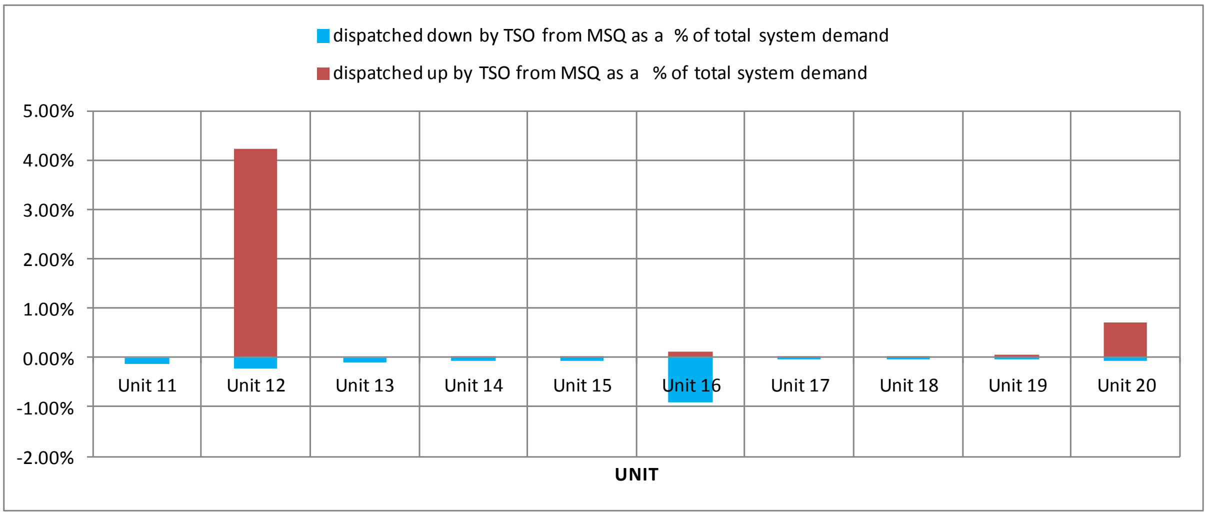
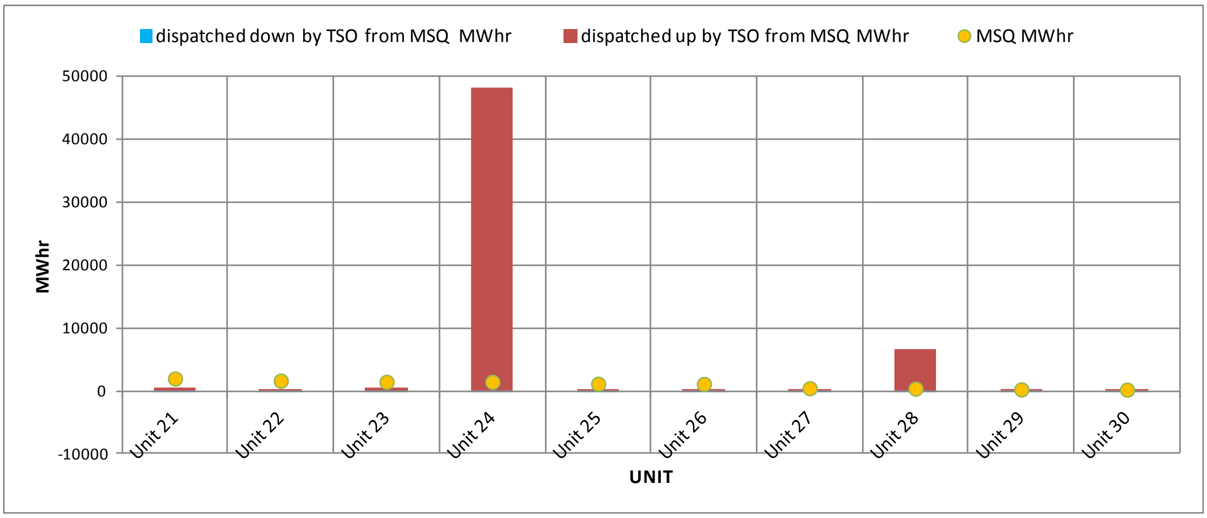


Chart 5 & 6 - This is the next ten units available in the market in order of the quantity of energy scheduled within the SEM.

- Unit 12 has been dispatched up for reserve and voltage support.
- Unit 20 was scheduled on six of the seven days to meet the evening peak and the all island reserve requirement over this period. The unit was then de-committed every night again.



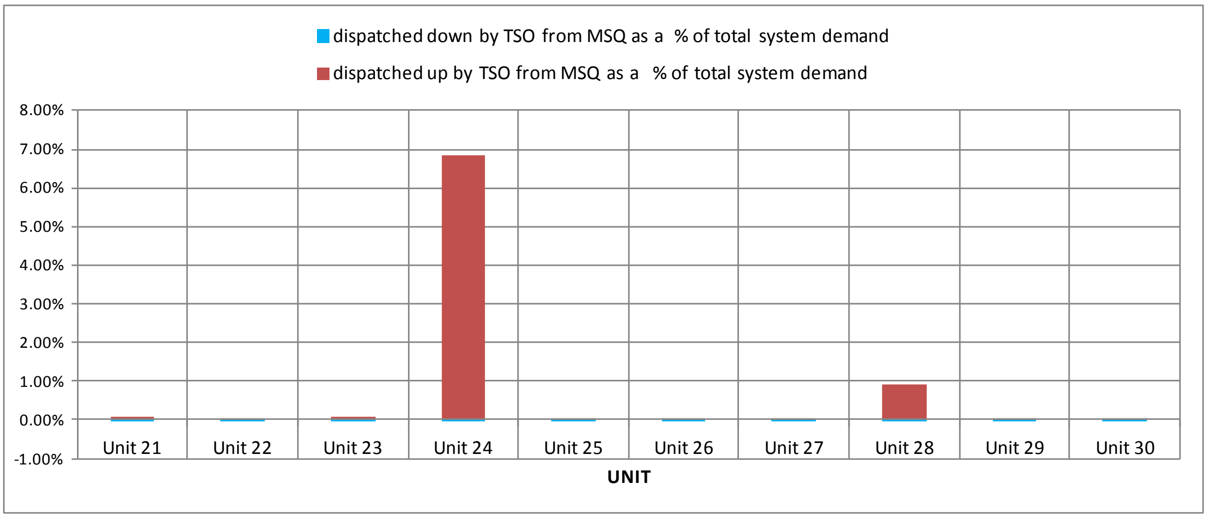
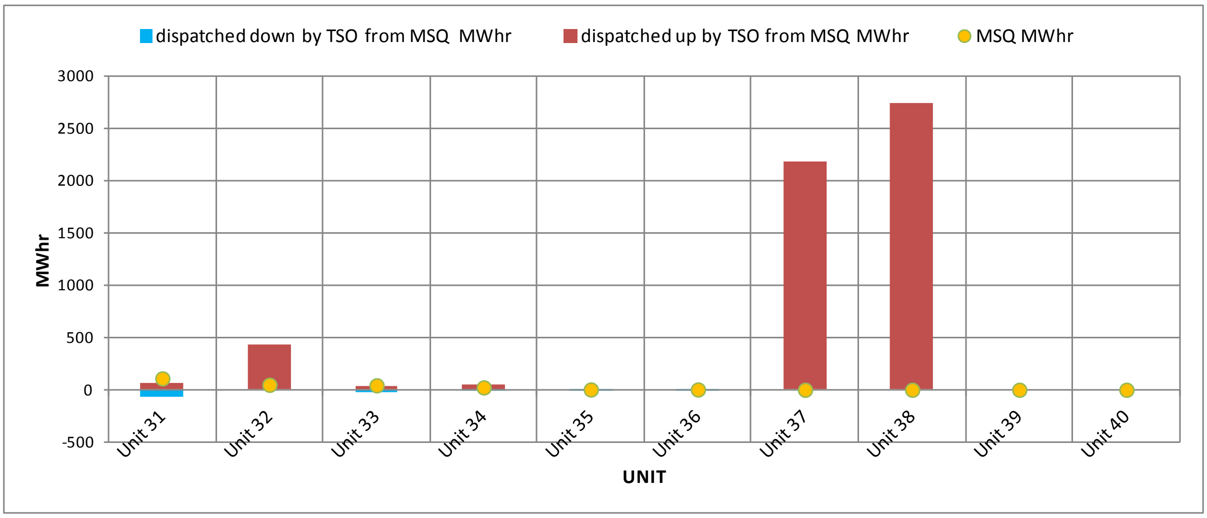


Chart 7 & 8 - This is the next ten units available in the market in order of the quantity of energy scheduled within the SEM

- Unit 24 has been dispatched up / on due to a minimum unit running constraint and for voltage support.
- Unit 28 was scheduled to meet the evening peak demand and the all island reserve requirements over this period. The unit was then de-committed each night.



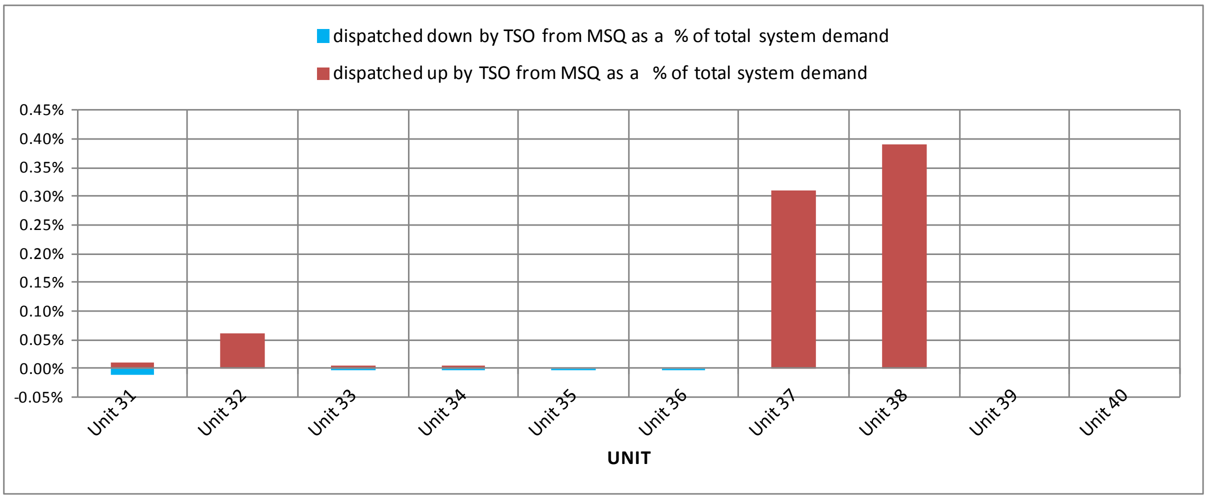
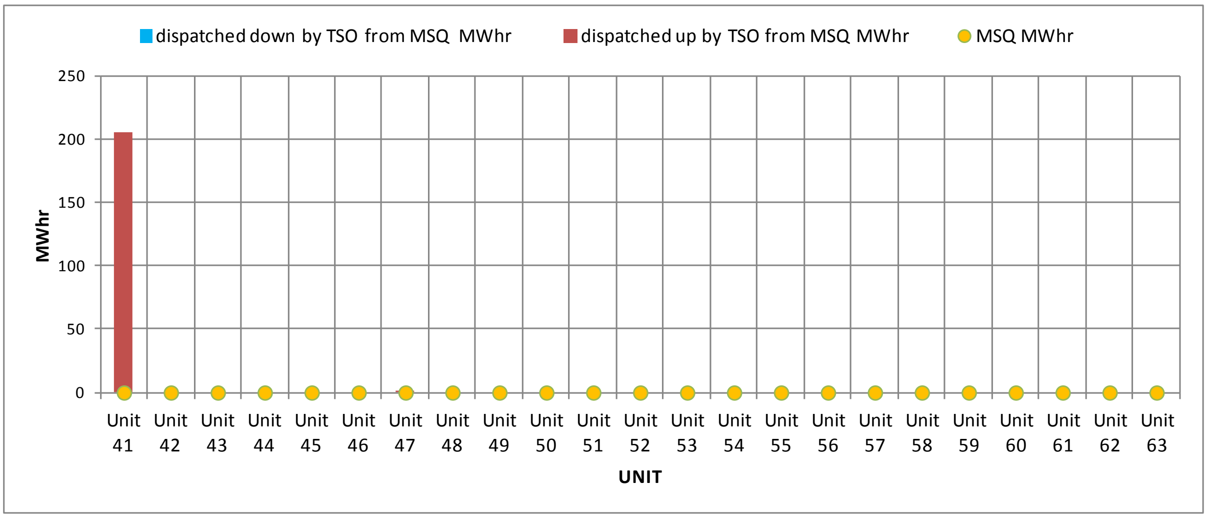


Chart 9 & 10 - This is the next ten units available in the market in order of the quantity of energy scheduled within the SEM (NB after Unit 36 none have been scheduled in SEM)

- Unit 38 has been dispatched up / on because of a transmission restriction
- Unit 37 has been dispatched up / on because of a transmission restriction



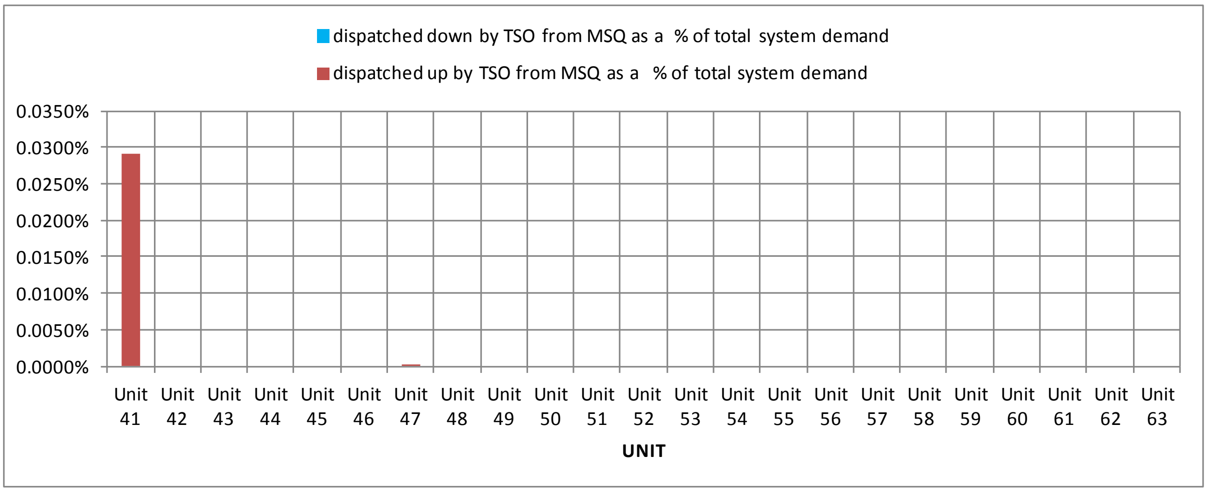


Chart 11 & 12 - This is the remaining 22 units available in the market

- Unit 47 has been dispatched on to provide reserve for short periods of time such as one trading period. If there is a potential for a reserve short fall for a short time, such as one trading period, it is more cost effective to run an OCGT which has a short notification period and will reach minimum generation (MSG) quickly rather than have to start a larger thermal unit with longer notification time and longer time to reach MSG. The OCGT also has the added benefit of a shorter period of running before it is allowed to be de-committed.

Analysis of National Grid Balancing Energy Volumes

The National Grid document 'Monthly Balancing Services Summary 2011/12' for March 2012[3] summarises the Balancing Services procured by National Grid (NG) either through market arrangements or bi-lateral contracts. These services, which mainly consist (by energy volume) of

[3] http://www.nationalgrid.com/NR/rdonlyres/3A6F00DE-6421-4A84-829E-5364DF91B4EB/53357/MBSS_MARCH_2012.pdf

various frequency response, reserve and system constraint management services, are procured for the purposes of operating the electricity transmission system in GB. Analysis of this document has been carried out by the TSOs for the purpose of determining the level of 'Balancing' actions taken by NG.

The analysis is based on the information provided in the March 2012 summary report (which contains summary information from April 2011 to March 2012) and the National Grid 2011 Seven Year Statement (Chapter 2, Table 2.4[4]) which provided the forecast total energy consumption for 2011/12 of 314,400 GWh. It should be noted that the analysis presented does not include the impact of commercially confidential contracts that National Grid enter into outside of the Balancing Mechanism to manage certain transmission system issues. These contracts are used by National Grid to (for example) cap the nominations of certain generators within constrained areas before actions are required in the Balancing timeframe – their impact is therefore not reflected in the reporting of Balancing actions by NG.

Page 29 of the March 2012 document summaries the 'Volume of BM Actions by Category' that provides a 'Year to Date Total' volume for the Balancing actions taken for the period April 2011 to March 2012. The table below summarises the various categories of Balancing actions reported in this table (a description of the categories is contained in the Glossary of the Monthly Balancing Services Summary[3] , 'Footroom' , for example, reflects the requirement for negative regulating reserve capability).

Category	Year to date total (MWh)	Absolute Value (MWh)	Include in Calc?	Absolute for Calc (GWh)
Energy Imbalance	-2,500,141	2,500,141	Y	2,500
Operating Reserve	4,714,526	4,714,526	Y	4,715
Absolute STOR	64,466	64,466	Y	64
Constraints By Area	5,465,660	5,465,660	Y	5,466
Constraint Margin Replacement	5,074,847	5,074,847	Y	5,075
Footroom	-1,186,921	1,186,921	Y	1,187
Fast Reserve	197,314	197,314	Y	197
Absolute Response	4,334,038	4,334,038	Y	4,334
Unclassified BM	-1,244,153	1,244,153	Y	1,244
BM General	21,680	21,680	Y	22
Transmission Losses	6,154,801	6,154,801	n	-
Total Projected 2011/12 BM Actions (A)	**21,096,117**	**30,958,547**		**24,804**
2011/12 Projected Energy Consumption (B)				**314,400**
BM actions as a percentage of Energy Consumption (A/B)				**8%**

National Grid Balancing Mechanism - March 2012 Report - Projected Total for Year 2011/12 (P29 of report)

The 'Year to Date Total' energy values were converted to absolute values as, consistent with the TSOs' own analysis of the SEM schedule versus actual dispatch, actions to reduce output as well as increase output are considered additive. Note that the transmission losses energy volume was excluded from the total to be consistent with the TSOs' own analysis. The total projected annual absolute volume of Balancing actions for 2011/12 is 24,804 GWh. With the projected energy consumption in 2011/12 being 314,400 GWh, the level of Balancing actions taken by National Grid corresponds to an energy volume equivalent to 8% of the forecast energy consumption in 2011/12

[4] http://www.nationalgrid.com/NR/rdonlyres/D4D6B84C-7A9D-4E05-ACF6-D25BC8961915/47015/NETSSYS2011Chapter2.pdf

As already noted this analysis does not include the impact of commercially confidential contracts taken by NG outside of the Balancing Mechanism to manage transmission system issues.

This analysis has been provided to NG for their review and comment however at the time of writing this report no formal response had been received.

5. GB System Comparison

Having considered how the choice of dispatch model affects everything from policy goals to system security it is worth looking at our nearest neighbour and considering their self-dispatch market and in particular pointing out the clear differences between the two island systems. The GB BETTA market is the most obvious source to compare the difference between operation of self and central dispatch on island systems of different sizes operating with similar individual generator sizes. Both systems have only DC interconnection to neighbouring systems. Small systems within Europe, which could be compared, are interconnected with AC interconnectors. The small systems in Europe become an area within a very large system as opposed to a synchronous island system which has to control frequency with its own indigenous plant. DC interconnectors are configured to provide external reserve but only as step changes in transfer flow that assists correction of frequency deviations but do not provide frequency regulation. In essence the small systems in Europe are part of one bigger system, on islands with DC interconnection we do not have this advantage.

The GB BETTA market has a well-established balancing mechanism, but not a perfectly functioning one as made obvious by the recent proposed changes to the cash out arrangements and the proposals for a capacity mechanism to secure additional capacity for system security -

- The principle of 'self dispatch' applies in BETTA.
- Generators nominate their position at day ahead and up to gate closure through their PNs (Physical Nominations) which include sync/de-sync times, target output, technical capabilities, balancing prices etc.
- The GB TSO takes a view if the market will be long or short at the day-ahead stage and initiates balancing actions if required to ensure system security.
- Generators will then 'self dispatch' and follow their PNs including syncing/de-syncing and ramping to their target output – The GB TSO will not instruct them to do this but operational conversations may occur on issues such as busbar selection prior to synchronising.
- The GB TSO may instruct generators to deviate from their PNs – this is the balancing mechanism.
- The majority of generation movement is a result of self dispatching to meet their PNs.

	SEM	BETA
System Size (max demand)	6500	60122
Number of Generators (excluding wind transmission connected)	75	391
Typical Unit size (MW)	400	400
Typical Unit Size as % of maximum demand (%)	6.15%	0.67%
System demand reduction with 0.2 Hz frequency drop (MW)	26	240
System demand reduction with 0.5 Hz frequency drop (MW)	65	601
Wind Generation Operational (MW)	2013	6580
Wind Generation (% max demand)	30.97%	10.94%
Wind Generation forecast error 10 % (MW)	201	658
Wind Generation forecast error 10 % as percentage of maximum demand (%)	3.10%	1.09%
Largest single credible contingency (MW)	450	1320
Largest single credible contingency (% max demand)	6.92%	2.20%
Interconnection (post EW)	1000	4000
Interconnection (% max demand)	15.38%	6.65%

The GB system demand is approximately 10 times the size of the All Island System (AIS). The largest infeed as a % of minimum demand on the AIS is 20% in GB it is only 7%.

The effect of imbalance between demand and generation on system frequency in GB is much less pronounced. Without any corrective generation action, an imbalance of 26 MW on the AIS will result in a 0.2 Hz frequency change (the normal operational limit), in GB, the imbalance would have to be 240 MW to produce the same frequency change**. System Imbalances have a much greater physical effect on the smaller system**.

The number of individual generators i.e. the number of parties self dispatching will make the larger system less prone to individual party balancing errors. The overall error produced by a large number of independent elements will be relatively smaller than from a smaller number when considered collectively. The number of units participating in GB would be many more than the number operating on the AIS with the total number available in GB nearly 400 and on the AIS 75. **With much fewer generators operating on the AIM the overall balancing error will be relatively greater.**

A 400 MW unit operating in GB represents 0.67% of the system (at peak demand) compared to 6.15% of the system for a unit the same size operating on the AIS. **Individual generators on the AIS form a much greater part of the system compared to GB, individual balancing errors have a greater effect on the smaller system**.

With three times the penetration of wind generation on the AIS, compared to GB, the influence of wind forecast errors are much greater. A 10 % forecast error, for example, would be 201 MW on the AIS and 658 MW in GB, although the GB MW error is larger, as a portion of the entire system it's three times smaller compared to the AIS. In addition, a power system with more wind penetration is substantially lighter and as a result it has a greater effect of system security. **The effect of Wind forecast errors has a much greater effect on systems with higher wind penetrations levels.**

6. Factors Influencing a Dispatch Model

The factors affecting the decision of which dispatch model to choose have been considered by many different markets across the world, however each market has made a decision on a model dependent on the one that best suits their own characteristics and policy goals. Factors to be considered include:

- System Frequency management
- System Size
- Plant Portfolio
- Size of the largest single credible contingency
- Capacity of the transmission network
- Renewables Penetration
- Level of Interconnection
- Commercial freedom

One would also have to consider the other factors (not considered here) such as:

- Self dispatch affords greater freedom to market participants
- Market power of individual generation portfolios
- Cost vs. laissez-faire attitude
- Policy objectives(Transparency, 20% penetration, demand-side penetration, - competition, minimise costs etc)
- Participant's appetite for risk in balancing their positions

We now discuss how each of the technical factors are relevant to the Irish system and the impact the dispatch model would have given these factors.

System Frequency

The control of system frequency, the outcome of generation and demand balance, is achieved by matching the system generation to the system demand on a continuous basis. Excessive frequency deviations high or low will result in system instability leading to power system failure. TSOs act as the balancing party in both self dispatch and central dispatch situations, with overall sight and control over individual generation (and some demand) elements, to direct their output to balance the system and control system frequency. The control of frequency is required for both normal system frequency regulation where the demand and generation are moving about the balance point slowly and during large sudden changes in balance such as experienced when generation units trip.
Frequency control and the reaction of the power system to generation trips are very different when comparing power systems of different sizes. The control of frequency is influenced by the effect of the connected demand, the number of connected generator elements and the relative size of the generation elements compared to the demand.

System frequency is the most important operational characteristic on the system, a continuous variation outside 4% will result in a power system failure. Therefore the management of frequency over all timeframes is essential; any structures that do not manage this correctly are ultimately very costly to consumers.

Demand

As system frequency changes there is a corresponding change in demand which is typically 2% per Hz, this tends to add to system frequency stability making a large system inherently less sensitive to generation and demand imbalances in terms of frequency deviation. On a large system frequency tends to move more slowly and within a smaller range compared to a smaller power system.

Size of the largest single credible contingency

A large power system having a greater number of small elements results in individual dispatch or balancing errors having less of an overall influence on frequency control compared to the effect the errors would have on a smaller system. The bigger the power system the more, relatively small, generation elements are connected as opposed to the situation on smaller systems, such as the Island of Ireland ,where the system comprises of a small number of relatively large elements. Reserve requirements are dependent on the largest single credible contingency for both large and small systems with the relative size of the reserve holding being much smaller on the large system. The loss of generation and the corresponding movement in frequency is much larger on the smaller system, requiring immediate re-dispatch. The generation balancing actions during trips are automatic initially, with generation providing reserve in the correct balancing direction. The automatic actions ensure the resultant frequency movement is limited and provides a limited control action which must be corrected shortly after the event. The correction requires multiple generation re-dispatch and commitment actions to revert to normal system conditions after the event to achieve a balanced position with reserves again.

Capacity of the transmission network

The AIS transmission network has a number of pinch points which until such time as the grid 25 programme and the additional North/South interconnector is implemented will remain problem areas on the network. For example the link from Dublin to Cork is limited. All plant along the corridor may want to run at full output but it may not be feasible because of the restrictions on the network along this corridor. The limited capacity between the North and South of the Island also restricts flows, in both directions.

Market participant behaviour

If, for example, all generators decided to self dispatch to base load, the system simply couldn't operate in this manner and the TSO would be forced to dispatch generators away from their preferred schedule, so as to maintain a viable, secure system. With a relatively small number of generators the likelihood of actions that would require action by the TSO is greater compared to a larger system with much more diversity of generation and generation ownership. The benefits of self dispatch can be afforded through a flexible market design which offers firmness. No one market participant will be able to consider what other market participants are doing in real time and therefore will never be able to dispatch as efficiently over the whole market, nor would they want to as they are interested in their own portfolio rather than the most optimal answer overall. There is no set of information that could be provided to generators that would see them dispatch optimally in consideration of system needs, nor would they ever want to as this would be counter to their desire to self dispatch.

7. Market Firm or Physically Firm

The decision of whether to have a central dispatch model or a self dispatch model does not decide the compensation model to be applied. It is possible to have a market position that is firm but a physical position that can change due to security issues. This is the very idea being considered now as part of the CACM network code.

Determining market firm prices and quantities

In the current SEM, generator units in the market schedule are paid by supplier units at the marginal price, SMP, whereas deviations between the market schedule and the dispatch schedule are pay-as-bid. The market design could have gone down the route of pay-as-bid in the market schedule; equally it could have contemplated settlement of constraints at marginal price.

In relation to revenue from the SEM, settling market quantities at a marginal price and dispatch quantities at a pay-as-bid price, leaves a generator largely indifferent to the actions of the system operator. Considering only SEM payments, the infra-marginal rent would be equal regardless of whether a generator unit is dispatched to zero or to its market schedule quantity[5]. On the other hand if a generator fails to deliver what it was instructed it is subject to uninstructed imbalances, which are more penal.

The Target Model allows generators (and suppliers) to determine their market schedule in a number of ways. Whereas the market schedule in the SEM is determined centrally ex-post by unit commitment and economic dispatch, the Target Model is built around a number of timeframes where participation is voluntary. This implies that a generator could trade some of its energy in the forward timeframe, some in the day-ahead price coupled auction and the rest through the continuous intraday arrangements. Day-ahead quantities will be settled at the marginal clearing price for bidding zone e.g. the SEM, intraday trades will be settled at the matched price, which will largely reflect the offer price. In this regard, taking the sum of all trade quantities in the forward, day ahead and intraday timeframes, generators and suppliers will arrive at the equivalent of their market schedule quantity and net demand respectively.

If a generator is dispatched away from its market quantity, regardless of whether self dispatch or central dispatch is in place, there will be some form of compensation mechanism e.g. the current system of pay as bid constraints payments could be implemented. The detail of this calculation would have to be considered however the principle of cost based compensation could remain.

[5] This assumes that generators' offers are cost reflective as required by the Bidding Code of Practice.

Alternatively, a different approach could be chosen. In any case, whether the unit has been self dispatched or central dispatched would not be relevant to the how the unit is compensated.

In the case where a generator or supplier unit fails to meet their firm quantity for reasons other than dispatch, similar to the current arrangements (for generators), the units would need to be subject to payments and charges that reflect the cost of balancing the system. Again, the detail of this calculation would need to be considered carefully with the overall design. Whether self or central dispatch was in place would not affect this; however, the nature of the balancing costs will have a significant influence on how much importance generators and suppliers place on arriving at accurate firm positions in advance of intraday gate closure and this in turn will determine the extent that the system operator has to re-dispatch the system for non-delivery of market quantities.

In two price balancing arrangements (e.g. in BETTA), balance prices are penal. As such, it is in the interest of all balance responsible parties to ensure that they are not trading in the balancing mechanism. This is commonly associated with self dispatch; however, it could also work just as easily with central dispatch. See below for how prices are calculated in BETTA:

		System	
		Long	Short
Party Imbalance	Long	Paid SSP (Main Price)	Paid SSP (Reverse Price)
	Short	Pay SBP (Reverse Price)	Pay SBP (Main Price)

It has been noted that this type of arrangement is not conducive to variable generation that does not have control over its availability in the same way that a conventional unit.

Target model compliance with central dispatch

In developing the evolution options for the recent market development RA consultation paper the SO/MO project team outlined a number of options for compliance with the target model. Each of these options considered that central dispatch would be maintained and all options were capable of being compliant with the target model. These options now seem less likely to proceed however they do show that central dispatch is compatible with the target model under a number of different scenarios.

We note that recently the Polish and Italian TSO/MO/RA'S have developed options to maintain intraday auctions while complying with the target model and also that these markets are centrally dispatched.

The SO's and MO are confident that there are many market design options which can be developed which will meet the target model and more than that are the best options for the all island market and can retain central dispatch if that is the decision that is made.

If central dispatch is maintained as a parameter/principle for the market design its exact interaction in the new market design and its interface with the target model elements in Europe would be worked out in design as would any other parameter such as renewables treatment for balancing or competitive bidding. The next phase of the project will be about investigating design options and it is at this stage that a high level and then detailed design would be fleshed out including the details of how the market principles and parameters interact with the European target model.

The goal of the internal market in electricity, as outlined in Directive 2009/72/EC concerning common rules for the internal market in electricity, which has been progressively implemented since 1999, is to deliver real choice for all consumers in the Community, be they citizens or businesses, new business opportunities and more cross-border trade, so as to achieve efficiency gains, competitive prices and higher standards of service, and to contribute to security of supply and sustainability. The SO's and MO consider that central dispatch is the optimal dispatch solution to achieve this goal in terms of efficiency gains and security of supply, given the characteristics of the all island market.

The purpose of the target model is not to create a "one-size-fits-all" for electricity in Europe but rather to provide a harmonised framework for cross-border exchanges of electricity. Regulation 714/2009 on conditions for access to the network for cross-border exchanges in electricity confirms this and does not go beyond what is necessary in order to achieve the objective of a harmonised framework for cross-border exchanges of electricity in accordance with the principle of subsidiarity and proportionality in Article 5 of the Treaty. The Regulation simply aims at setting fair rules for cross-border exchanges in electricity, thus enhancing competition within the internal market in electricity, taking into account the particular characteristics of national and regional markets. The particular characteristics of the SEM market indicate that central dispatch is the preferred solution for the reasons stated above and should be the dispatch model chosen for the all island market, so long as it does not hinder the development of a harmonised framework for cross-border exchanges of electricity.

Both dispatch models can be made to work within the confines of the CACM Network Code and Electricity Balancing Framework Guideline (EBFG). There is no explicit mention of the required dispatch model in the CACM Network Code therefore it does not preclude any dispatch model and central dispatch is not deemed to be incompatible with the target model. The EBFG does mention central dispatch and provides for a derogation given the prevailing characteristics of national or regional markets.

There are issues that need to be resolved with the introduction of continuous trading in the intraday timeframe as part of the development process for the SEM market design, these same issues are being considered by a number of markets but they can be resolved by appropriate design.

While the CACM Network Code does specify the gate closure time as one hour ahead of real time, it does not specify when the gate opening time needs to be, leaving it open to national markets to determine. Therefore, the duration between gate opening and gate closure times within the national markets across Europe may well be different. It is possible that SEM could operate with continuous trading within a shortened gate window. This would further mitigate any potential issues that might arise between central dispatch and continuous trading.

There is considerable uncertainty at present concerning the pricing of capacity intraday as continuous trading does not provide a means by which to price capacity. It is possible that an auction(s) may be required within the intraday timeframe to provide a reference price for capacity intraday. There is also considerable uncertainty over the final intraday model to be chosen for the intraday timeframe with EuroPEX power exchanges unable to agree on a preferred solution yet and delays now likely for the implementation of the interim solution for intraday trading in the North-West Europe pilot project. Given the level of uncertainty that currently exists in terms of how capacity will be priced in the intraday timeframe and what model will be used as Elbas is looking less fit for purpose as time goes on, it would seem pragmatic that while moving forward with developing the SEM market design across all timeframes we should not remove a key feature of the SEM design which has been considered to work well, In the context of our all island market when it remains unclear how exactly intraday will work in practice, regardless of this central dispatch can work with continuous intraday.

8. Conclusions

Self dispatch is not a requirement of the target model and central dispatch can operate efficiently in compliance with the target model. A number of participants in their responses to the Regulatory Authority development consultation recognised the importance of central dispatch in the all island market. Other participants in seeking self dispatch seem to be seeking firmness of their positions. Self dispatch in the All Island System will not offer this to those market participants due to the level of intervention required to maintain system security.

The SEM is currently designed such that dispatch decisions are made with all technical and cost characteristics in consideration to produce a least cost schedule. A self dispatch market would see participants making dispatch decisions on the basis of their own criteria. With each participant dispatching on the basis of their individual criteria it would seem obvious that this would not be as efficient as a solution that considers the criteria overall to produce a cost efficient schedule. This however depends on the other criteria which would not be included in a market design such as the one currently operating. One would need to consider the value of things such as:

- Participant freedom
- Overall social welfare
- Renewables policy
- Balancing requirements
- Available data
- Participant's attitude to risk in terms of balancing requirements

The TSOs are convinced that given the physical and technical characteristics of the all island market that central dispatch is an important principle to maintain for the new market design. The all island system is different to other small systems in Europe and very different to GB.

The TSOs believe market participants can be compensated such that they are kept financially neutral to the central / self dispatch question. The concept of market firmness as opposed to physical firmness is a common concept across the world in all market designs and has been addressed different ways in different places. Participants can be kept financially neutral to the central dispatch decision depending on market design.

There are numerous market designs that can be chosen as the way forward for the all island market, central dispatch is just one parameter to be considered and it is no less/more restrictive than any other parameter/principle that the market might seek to put in place.

Central dispatch can be maintained while delivering the right market design for the all island system , be compliant with the target model in Europe, and at the same time maintain system security while considering the unique characteristics of our market , system, island and generation portfolio.

The market can operate without central dispatch but the design required around it to maintain system security would seem unnecessary. TSO intervention in the market currently amounts to approximately 30% of the total system energy demand for the period analysed here which would be typical, i.e. 30% of what we believe to be a normal and efficiently matched set of transactions could not be physically delivered firm due to a mixture of system services provision, constraint management and plant unavailability. With this level of intervention self dispatch offers participants no extra firmness of their position and as such doesn't seem to add any real value for participants.

In a self dispatch market this intervention would have to take the form of balancing contracts which would have to be filled by the same units already operating in the market. The question would be if this a more efficient model than the current one? We do not believe it would be. It should be investigated as part of the detailed analysis of the market options if it remains an area of concern.

Self dispatch markets are desired for freedom and flexibility for generators, it is possible to afford much of this to generators regardless of the self dispatch question. Self dispatch must be viewed in the context of the other design principles, such as transparency, competitiveness and renewables policy all of which would be impacted by a decision on self dispatch. In addition practicality must be considered on a small system.

The market design principles/parameters will define the market design chosen and there would seem numerous reasons why central dispatch should be one of the parameters of that design. If it is not, the TSOs will engage fully on the requirements for a market without it.

This paper is a work in progress and the SOs see a need for further work as the other market parameters and principles become known which will interact with central dispatch and with each other. Central dispatch is simply one of the important factors that will influence this market design. The TSO/MO believe that more work on all the issues would need to be done through the HLD and detailed design and it is this process that can answer participants and RA's questions in further detail. The TSO/MO looks forward to working in an open and transparent way on the future designs.

Annex 1: Definitions

Dispatch

The process of determining individual generation output leading to the physical issuing of instructions to connect, disconnect, increase or decrease generators output.

Central Dispatch

A dispatch arrangement where the TSO determines the dispatch values and issues instructions directly to generators (or demand). The TSO determines the dispatch instructions based on prices and technical parameters provided by the participating parties in order to minimise the system production cost while meeting security requirements.

Self-Dispatch

A dispatch arrangement where generators determine a desired dispatch position for themselves based on their own economic criteria to provide commercial independence within a market. The dispatch determination may or may not have a requirement to have a balanced position with demand. The physical dispatch can be either carried out by the generators directly, tracking their desired output nomination or by following dispatch instructions from the TSO which have been determined based on generators' nominations. In either case if the system operator requires it the generator will have to follow instruction to maintain system security.

Nomination

Generators desired dispatch position, to inform the TSO of their anticipated output.

Central Unit Commitment

The TSO determination of when generators will be required to start /stop in advance of real time based on minimisation of production cost with prices and technical parameters provided by the participating parties.

Self–Unit Commitment

Generators determination of when they require to start /stop in advance of real time to meet their own commercial requirements