Commission for Energy Regulation

Operating Reserves in a Centralised Market

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1. INTRODUCTION

The procurement of and use of operating reserves is an important feature of the centralised electricity market that is proposed for Ireland. A part of the detailed design of the Irish electricity market will involve the approach to operating reserves.

This paper provides background on this issue and a detailed proposal for Ireland. The paper includes sections on:

- The concept of operating reserves in a centralised market
- A discussion of operating reserves
- A discussion on the current reserves situation in Ireland
- A detailed view of an approach to operating reserves that is coordinated with the electricity market
- A proposed way forward for operating reserves in the new Irish market

2. CENTRALISED ELECTRICITY MARKETS AND THE NEED FOR RESERVES

In centralised electricity markets, the SMO runs a bid-based spot market. All electricity is cleared through this spot market. Generators sell all power to the market and customers/ retailers participating in the spot market directly buy all power from the market. Electricity sold and bought through the spot market will be at the market-clearing price that may vary by location. In such a bid-based spot market, generators offer all their available capacity into the market. Generators are responsible for their own unit commitment and develop bidding strategies that are aimed at achieving desired generator operation levels and profitability.

For Ireland it is proposed that the real-time market will be an *ex ante* market that covers a 30-minute dispatch and trading interval[1]. The spot price will be set just prior to real time (*ex ante*), with dispatch and pricing based on demand bids from customers, supply offers from generators and SMO estimates of load at the end of each trading interval for each withdrawal node in the transmission network. Actual volumes cleared through the market will be determined by meter data and settled *ex post*.

In operating the real time market, the market will be cleared and the system dispatched using a computer programme called the dispatch engine or market-clearing engine (MCE). This program is designed to approximate the physical and economic system as closely as possible within a linear optimisation model[2]. It uses

- The generators' offers and customer bids taken from the last re-bidding,
- The load at each withdrawal node as estimated by the SMO for the end of the trading interval,
- The most recent estimate of reserve requirements, network data, system security constraints,
- The most recent status of the power system as determined by the SMO's Energy Management System.

The market will be cleared and the dispatch solution determined for the most current data just before the trading interval commences. The prices will then be immediately published.

The dispatch solution sets the "targets" that each generator has to meet at the end of the 30 minutes and the prices that apply to all dispatch during that period. The *ex ante* prices are applied to the metered generation and off-takes for the half-hour. The market has determined that those generators dispatched have the right to dispatch (except under special circumstances determined by the SMO) that quantity of electricity at the corresponding market price.

Inevitably, there will be discrepancies between the *ex ante* dispatch targets and actual events. These can occur because of inaccuracies in data especially the inability of the SMO to forecast load exactly, minor modelling imprecision, the need to constantly tune to system requirements and unanticipated events such as system breakdowns. The

[1] The length of the interval is a compromise between the precision of a short interval (say, 5 minutes) and the lower effort of operating in a less frequent market.

[2] While the power system is actually non-linear, acceptable formulations of the non-linear model are not yet available for market clearing purposes so non-linearities must be approximated linearly. Considerable research has enabled this to be done very satisfactorily in most circumstances.

potential for misalignment between *ex ante* and *ex post* assessments are very much less in a market that uses a short trading interval (eg, 5 minutes).

The SMO is responsible for maintaining the security of the system in real time. This responsibility commences with ensuring the model is accurate and that the data used for determining the dispatch instructions are the most current available so that the targets are set as reliably as possible. The dispatched targets are fixed and can only be deviated from by the SMO or the participant with good reason. As far as possible, the SMO handles discrepancies between the anticipated conditions and the actual events using ancillary services. Consequently, the SMO has the responsibility to acquire and use ancillary services to the best advantage of the market and the security of the power system.

It is within this context that we discuss how operating reserves may be obtained and scheduled in the centralised market. This report does not cover other ancillary services, such as reactive power/voltage support or black start. Nor does it discuss the question of capacity reserves.

3. OPERATING RESERVES

Most simple descriptions of electricity markets describe a situation where generators are loaded in order of increasing cost until demand is satisfied, the market price for electricity being the marginal cost of the most expensive generation used. In this case the price reflects the incremental cost of meeting one more unit of demand. However, electricity is not the only commodity that needs to be scheduled in an electricity market. Operating reserves also need to be scheduled, and these impose constraints on how we can schedule electricity, in much the same way that transmission constraints impact on the electricity dispatch.

3.1 WHAT ARE OPERATING RESERVES?

Operating reserves consist of spare capacity carried in an electric power system that is able to make up any loss of generation that may occur. Because electricity must be conserved at all times (ie, supply and demand must be equal), there must be a constant balance between the electricity which is supplied to a power system from the generators and that which is withdrawn by the connected loads and the losses in the transmission network. If this balance is suddenly upset, for example by a generation unit being tripped out of service, two things will happen that create a need for reserves:

- The frequency will drop, as a result of there being
- Insufficient electricity injected to meet demand.

3.1.1 Spinning reserves for frequency control

This is a critical issue for smaller power systems such as that in Ireland, but may be a less critical issue in large power systems, such as that in North America, Europe and (probably) that of Scotland, England and Wales.[3] When there is a sudden shortage of generation, the frequency will drop rapidly which can then lead to the collapse of the entire electricity system. Therefore, spare capacity is required which can rapidly replace the electricity that had been lost when the generation unit has tripped out of service. Some fast acting reserves are required to act within about 6 seconds, to arrest frequency drop, and further reserves are often needed within 30 seconds, to restore the electricity balance.

Because the additional electricity must be made available very quickly to prevent the frequency collapsing, these operating reserves are usually provided from generation units which are already in service and so are called "spinning reserves", because the generation units must already be up to speed, spinning at system frequency. The slower reserves required simply to ensure that the peak demand can be met can be often provided by generation units which are out of service, but which can be started quickly. This reserve is not spinning reserve but is often called fast start reserve or standby reserve.

[3] A simple reason for this is that that any individual unit is likely to be a small part of the total interconnected system and that the electrical "inertia" of a larger system provides a more stable frequency.

3.1.2 Fast-start reserves to meet demand

Immediately following the loss of generation, there will be insufficient generation to meet the present demand on an ongoing basis, and there may be insufficient committed generation capacity to meet the up-coming peak demand. Thus, operating reserves are carried to ensure that if there is a loss of generation then the peak demand can still be met without having to shed load. These operating reserves are usually required to act within either 10 minutes or 30 minutes.

Since operating reserves are required to correct an imbalance between the electricity supplied and the electricity withdrawn from the power system, the same effect can be achieved by reducing the level of demand to be met. Consumers in many power systems are increasingly willing to be disconnected under contract conditions so that they are able to provide operating reserves and be paid for this service. For example, current practice since the 1970s has used interruptible load as a source of operating reserve in Ireland.

The amount of reserve that must be carried is usually related to the size of the largest single contingency on the system, a "contingency" being the event that causes the loss of electricity. The single contingency might be the largest generation station, the size of an interconnector, or the size of a major transmission line. Some systems carry reserves for more than the single contingency, looking for reliability even when the worst two or three events happen simultaneously. As total system size becomes larger, the amount of reserves becomes smaller as a percent of the total demand. Smaller systems may need to carry a percentage reserve that is much greater than that carried in larger systems.

Where a portion of a power system is concerned – such as Ireland's power system that is a part of the entire island of Ireland power system – such a contingency can also occur if a major transmission line which can supply electricity from Northern Ireland to the South trips.

3.2 OPERATING RESERVES IN AN ELECTRICITY MARKET

Provision of operating reserves is one of the more important "technical" issues a market must address, as it goes to the heart of the question: can the market support the desired power system reliability and security standards?

The operating reserve requirement has three effects:

- In the short run, it requires some generators, which otherwise would be generating at full load, to be backed off and generate less, restricting their production and increasing operating costs; and thus
- It raises electricity prices by necessitating that more expensive generation capacity be run to ensure that the desired spinning reserve margin can be met; and finally
- In the long run, it increases the amount of generation capacity that must be built to accommodate growth in demand, thus forming an important part of the overall "investment signal" required in the industry over time.

Different approaches to managing and providing incentives for investment in operating reserve capability (or equivalent load reduction responsiveness) have been implemented in different markets.

We describe in this paper a market-based approach to reserve provision and how reserve and electricity can be procured simultaneously to ensure the best solution for the combined scheduling of both products.

The advantages of using a market-based approach are a long-term reduction in the total cost of providing operating reserve achieved as a result of clearer investment signals for the types of spinning reserve capability that are most valuable to the market, and for the development of demand side reserve response. In addition, a market-based approach facilitates the optimal use of existing plant for both electricity and reserve and makes transparent the cost of achieving a specific standard for security of supply.

This report considers the following questions:

- Have similar approaches been implemented successfully in other countries? Which countries have implemented such a market?
- More specifically, how does the reserve market work?
- Will it ensure adequate spinning reserve to meet the system reserve requirement?
- What will be the implication on co-generators or plants that cannot provide spinning reserve? Do they need to be centrally dispatchable?

A full and exhaustive treatment of these questions could fill volumes. This paper is a summary paper that combines economic logic, experience gained in other markets, and some technical detail to provide a general picture of what a market for operating reserves is, and how it might work to address issues relevant to Ireland. Experience in New Zealand is highlighted where relevant, given that New Zealand has implemented and now has more than six years experience with one of the most sophisticated (and successful) operating reserves markets in the world, and has an electrical system similar to Ireland.

4. CURRENT SITUATION IN IRELAND

This section outlines a preliminary understanding of the situation in Ireland based on discussions with CER and ESB National Grid.

4.1 DEMAND

The demand in Ireland varies between a minimum of 1500 MW and a peak (to date) of 4400 MW.

System Record	Value
Winter Valley	2555 MW
Summer Valley	1530 MW
Mid-day peak	3869 MW
Evening Peak	4400 MW
Daily Energy	82733 MWh

Source: ESB National Grid website. (www.eirgrid.com)

4.2 CONTINGENCY

The largest unit in the Irish Republic is Synergen (an ESB affiliate) at 400MW although there are other units over 300MW. The largest contingency for Northern Ireland is the Moyle Interconnector (500 MW) with Scotland of which 400MW is available for trade and therefore 400MW is the highest contingency on its system also.

The current primary reserve contingency is set at 80% of the largest unit in terms of the attached table.

The main reason for operating reserve is frequency control. Ireland also has significant voltage control issues.

4.3 INTERCONNECTOR

There is an AC line[4] (interconnector) with Northern Ireland:[5]

	North to South	South to North
TTC (total transmission capacity)	600MW	240MW
TRM (transmission reliability margin)	180MW	240MW

4 In fact there are two other lower voltage lines that are not considered here.

5 Source: Table above derived from IndicativeTransfer Capacity Report for the period 1/4/03 to 31/3/04.

NTC (net transmission capacity)	300MW*	0 MW

* The figure of 300MW is less than 420MW (600MW – 180MW) because SONI (SO Northern Ireland) is not inclined to have greater than 25% of their load being exported through the interconnector – if it were to trip the frequency effect would be too great[6].

The operating reserve contingency is spread with Ireland carrying 210MW and Northern Ireland carrying 110MW for a 320MW contingency.

4.4 CLASSES OF RESERVE

All dispatched and loaded units that are on free governor response[7] provide load following.

There are several classes of operating reserve as shown in the table. All plant is required by the Grid Code to be capable of supplying reserve at the percentages given below.

Reserve class	Response time	Reserve capability % of capacity
Primary	5 -15 sec	5%
Secondary	15 – 90 sec	5%
Tertiary 1	90 sec – 5 min	8%
Tertiary 2	5 – 20 min	10%
Replacement	> 20 min	

4.5 SOURCES OF RESERVE

Most thermal stations can provide both primary and secondary reserve. However, in practice the major sources of reserve are:

- The 292 MW pumped storage station (Turlough Hill) provides up to 35 MW primary and 292 MW secondary reserves while generating and 73 MW when pumping. It appears that it is used also for load following.
- Ireland and Northern Ireland form a reserve sharing group.

As has been noted, units currently are expected to provide reserve at levels designated in the code. In a reserves market the level of reserve is determined by the market rather than the code based upon generator offers. The generator offers for reserve provision

6 Note that this paper generally focuses on under-frequency problems, such as may occur following loss of generation or transmission import capacity. Although over-frequency can be a problem too, under-frequency is the main concern for Ireland.

7 "Free governor response" means that the output of the generation unit will vary automatically as the frequency changes.

may well be co-optimised with the energy market to allow the most efficient overall market clearing as signalled by all generators.

Examples of the type of data provided in market environments can be found at http://www.nemmco.com.au/ or http://www.comitfree.co.nz/fta/ftaPage.main. It is the intention for Ireland, in the current proposals, that there is as high level of data transparency as in Australia or New Zealand. This allows participants to gain a very accurate picture of the operating characteristics of the entire system and allows them to adapt their behaviours accordingly.

5. INTEGRATING RESERVES WITH THE ELECTRICITY MARKET

In many instances the same facilities are being called on to provide electricity and reserve. Traditionally the System Operator has been free to vary the allocation of plant to each duty, as and when required, so as to achieve an optimal overall result from a system perspective, while having regard to individual plant constraints and other impacts where appropriate. In a market environment, though, market participants will look for financial reward from provision of both of these services. Conflict and inefficiency may arise if market arrangements do not provide balanced incentives, or if market-clearing timescales preclude an efficient trade-off being achieved.

In older style markets reserves are provided in a similar way as for a traditionally regulated system. Typically:

- All plant is required to have reserve capability;
- All plant may be backed-off from full capacity by a given amount to ensure it is available for reserve if required;
- The System Operator uses its discretion as to which plant it will call for additional reserve;
- Plant may (or may not) be separately rewarded for being available for reserve, based either on a contract or on recompense for the opportunity cost of the generation foregone through the provision of the reserve..

In recent competitive markets, this approach has been refined to allow the offering of reserve as well as electricity into a spot or balancing market with two techniques:

- Electricity and reserves are offered into separate markets that are sequentially cleared with the results of the first market clearing being used as input into the remaining market(s)[8]; or
- Electricity and reserves are made as joint offers into the electricity and reserves markets simultaneously, with the allocation of the plant to each market being determined simultaneously – or “co-optimised”.

The co-optimisation of electricity and reserves does not necessarily imply that there is an active spot market in reserves. The benefit to be gained from co-optimisation is that the appropriate source of reserve and the quantity of reserve required is achieved at the least cost to the total market, given the “offers” provided to the market clearing software. Such “offers” need not be made by participants, but could be constructed by the SO to represent reserve capacity that is under contract.

This approach makes it possible for reserves to be procured under long-term contracts, thus providing greater assurance to the System Operator, and simplifying real time markets. Conversely, if a co-optimisation approach is to be employed, the advantage of moving all the way to implement a real time reserve market is that the latter allows more

8 If there are several classes of reserve, the markets for each class may be cleared sequentially if the classes are exclusive. So, for example, plant that has been cleared for primary reserve may not be available in the markets for secondary reserve or for electricity for the same capacity. However, capacity that can supply a fast class of reserve may also be able to supply slower reserve as well, so the classes may not be exclusive.

freedom for competition, innovation, and adaptation to real-time system conditions. These advantages have proved significant in markets where that approach has been employed[9].

Either way, though, the least cost calculation performed by the market clearing software can be made in terms of the electricity costs alone, or in terms of both electricity and reserves costs if the reserve "offers" involve direct cost terms.[10] Also, either way, electricity and reserve "prices" will be determined jointly by the market clearing software, but these notional "reserve prices" will have no commercial significance unless there is a reserve market, or contract payments are somehow linked to them.

The rest of this paper provides a more detailed exposition of the way in which:

- Reserves and electricity may be co-optimised;
- How co-optimised reserve markets work;
- How reserve is rewarded in such an environment.

9 It should be recognised, though, that the need to balance energy and reserve dynamically is much greater in a hydro based system such as New Zealand, than it may be in Ireland.

10 Co-optimisation actually employs joint energy/reserve offers, which specify joint limits, and limits on each, but need not specify any direct cost for reserve provision. If no direct reserve cost terms are involved then the market clearing software will only account for the indirect "opportunity cost" of denying plant the opportunity of profitable generation in order to provide reserve.

6. MODERN MARKETS FOR OPERATING RESERVES

Most modern electricity markets include a market for operating reserves, often including regulation[11], as an integral part of the electricity market. The table below summarises the characteristics of the operating reserve markets in seven jurisdictions. The markets included in this survey are those of which there is up-to-date knowledge, and include the markets in Australia, New Zealand and North America. The markets in England & Wales, Scandinavia and South America are not included, in this survey. Of the seven markets surveyed, all but two have a bid-based operating reserve market: the exceptions being PJM and New England, which are considering but have yet to move to a bid-based reserve market.

The main types of operating reserve considered are:

- Spinning reserves – reserves provided by generating units that are currently producing electricity, but are operating below their full capacity so as to maintain the ability to increase their output rapidly in response to the failure of another generating unit or transmission line;
- Interruptible load – load that can be reduced on very short notice to reduce the demands placed on existing generators during periods of system stress; and
- Stand-by reserves – reserves not currently synchronised but which can be synchronised within a period of minutes.

The mix of operating reserves required in a market depends upon the time frame required for a reserve response. In small isolated systems, like New Zealand, or Ireland, the size of risk being covered is large relative to the size of the system, and reserve response needs to occur within seconds requiring that most reserve be already spinning at system frequency.[12]

The issue in scheduling reserve is one of how to best utilise the available generation capacity so as to provide an appropriate mix of electricity and reserve, given the demand on the system and the security requirements of the system. In a simple world, one might load generators up in order of increasing cost so as to meet demand, and then use the remaining, unused generators to provide the operating reserve. However, in an all-thermal system, the “unused” generators must operate at or above their minimum operating level if they are to provide any spinning reserve, which means that some cheaper generators that would otherwise have been scheduled to provide electricity must reduce their output so as to provide reserve.

How is this scheduled? A simple approach would be to require that generators offer both generation and reserve from their units, with the obvious restriction that the same capacity cannot be offered for both. Thus a 100 MW generator might offer 80 MW for electricity at one price, and 20 MW of reserve at another price. The market would then have the option of using up to 80 MW of electricity and up to 20 MW of reserve from this generator.

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[11] Within this report, “Load following” is called “Regulation”.

[12] NZ covers the largest single contingency risk so that emergency load shedding is avoided if such contingency occurs, and also, at all times, makes sure that loss of both poles of the inter-island high voltage direct current transmission system (HVDC) are covered to the extent that once emergency load shedding has occurred the frequency does not dip below 47 Hz. That often means that sustained (60 second) reserve (typically from motored, tail-water depressed hydro units or slower interruptible load) is just as important as the faster (6 second) reserve.

Such an outcome, while seemingly logical (and indeed implemented in several markets) can be inefficient. This is because if the market decides to use all 80 MW of electricity, because it is cheap, but does not need the reserve, then 20 MW of cheap generation capacity will be idle. Further, the approach is not altogether workable, as the generator might only be scheduled for 0 MW of electricity and 20 MW of spinning reserve. But at 0 MW of electricity production the generator will generally be incapable of actually providing the 20 MW of spinning reserve if called upon during a contingency. These specification and feasibility limitations force market participants to bid in a very conservative fashion since they must decide beforehand how much electricity and reserve they are going to provide. In short, while such an approach at least partially reflects market forces, in that generators are bidding both electricity and reserve into the market, it does not capture potential "gains from trade" between the electricity and reserve capabilities of each unit.

The New Zealand electricity market addressed this problem by recognising that electricity and operating reserve are not independent commodities. In particular, a generating unit's responsiveness to provide spinning reserve is often quite restricted when the generator is providing very little electricity, and rises as the generator provides more electricity[13]. However, as the generator's output approaches full load, its ability to provide reserve declines again, since it cannot produce more electricity than its capacity.

Thus, the New Zealand market allows generators to offer electricity and reserve for the *same* capacity, while requiring that they also define a trade-off function that describes their ability to provide reserve at each level of electricity output. The market clearing software then trades between the amount of electricity and reserve across all generating units.

This gives the market clearing software considerable flexibility to find a lower cost solution, which might, for example, involve the 100% use of a particular unit for electricity, if that provides the least cost outcome, or it might involve a mix of electricity and reserve across a range of plant. Since the trade-off function is defined by the technical characteristics of the units and their owner's economic interests, the amount of reserve capability is no less than under a regulated approach – it is just that the price paid for reserves will be determined by the trade-off with electricity, and will more clearly reflect the economic interests of the plant owners – providing the correct signals to new investors and loads with respect to the timing of new investment in reserve capability or the worth of developing load reduction capability. The effect should be to reduce costs, and hence to enhance the net benefits from electricity production, both by improving utilisation of existing assets in the short term, and by reducing investment requirements in the longer term.

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[13] Alternatively, for some units it may merely be less efficient to provide reserves at lower load. Unless rewarded appropriately a generator is unlikely to incur unnecessary costs simply to provide greater levels of reserves. It is possible to operate a thermal unit at lower loads inefficiently (at higher steam pressure) to provide very good fast reserves. Similarly, with two units at low load, a station could incur a significant efficiency penalty (and potential maintenance cost if at very low loads) but could then produce substantially more reserves (fast and sustained) than a single unit at the same combined load.

However, without appropriate incentives why would one do this? Importantly, the NZ reserves market allows generators to make these tradeoffs now. Prior to the start of the NZEM in October 1996, without the ability to differentiate between fast and sustained reserves, and especially to value such reserves half hourly, there were few if any incentives for individual stations to increase operating costs, and potentially forego electricity revenues by limiting production to provide reserves, even if it reduced overall system costs. Similarly, when reserve prices are high, stations are often prepared to operate at up to their nominal capacity but – for short periods – are also prepared to go into overload for reserve purposes. Some have even been willing to go into overload for sustained periods if market prices for reserve reflect the increased plant risk they are inherently taking on.

New Zealand's specific situation is instructive, as it appears to be very similar to that which prevails in Ireland:

- In each of the two main islands there must be adequate reserve to stop frequency falling within 6 seconds, and to restore frequency to near normal levels within 60 seconds; and
- The reserve requirement is defined to be the greater of a fixed minimum level, the capacity of the largest operating generating unit, or the risk imposed by the failure of one of the poles of the inter-island HVDC link.

In each half-hour, the New Zealand market simultaneously determines a price for electricity and a price for each category of reserve (6 second and 60 second). The electricity price reflects the marginal cost of supplying an increase in load, and equals the cost of generating more electricity while respecting the reserve requirements. Each reserve price reflects the marginal cost of that type of reserve, and equals the cost of providing one more unit of reserve while satisfying the demand. In particular, the reserve prices at least cover the marginal opportunity cost incurred in backing off electricity generation to provide reserves. This means that any party that is making a loss in the electricity market on the margin because they are operating to provide reserve will be compensated via the reserve price. This allows those participants with reserve capable plant to make a profit in the reserve market. More importantly, the opportunity offered by a reserve market encourages the on-going construction of reserve-capable plant, while also giving an incentive for the demand-side to offer interruptible load.

By simultaneously scheduling electricity and reserve in this manner the New Zealand market achieves a highly efficient dispatch that ensures adequate reserve is available and provides long-run signals for market responses to reserve shortages. A similar model has been implemented in Australia, Singapore and in Ontario, Canada. The Ontario market will schedule and price 10, 30, and 60-minute reserve whereas the Australian and Singaporean markets require the faster acting reserves as in New Zealand. The Australian market involves four categories of "raise" reserve, and also four categories of "lower" reserve, to deal with over-frequency contingencies.

Alternative approaches to reserve are employed in the United States. The US markets tend to trade reserve in a simpler manner on an hourly basis separately from electricity. Consequently, the US markets do not achieve the same level of dispatch efficiency as New Zealand, though the sheer size of the US market undoubtedly reduces the incremental benefits of improving the efficiency of the reserve market. At times, however, the profile of reserve market issues has risen to a much higher level, as was the case in the early phase of the California market when reserve prices rose to several thousands of dollars, partly in response to a loophole (since partially closed) in the market rules between the electricity and reserve dispatches.

At times, market prices for reserves in the various jurisdictions have been quite high, sometimes attracting criticism. A commitment to tolerate occasional higher prices in the reserve market, however, is required for a reserve market to perform its core function: to manage existing reserves and to facilitate appropriate investment over time in new reserve capability. It is possible, of course, to exert market power in the reserve market – a generator could, for example, have a significant portion of the plant capable of providing a desired level of reserve response. However, higher prices in the reserve market will provide a signal to new investors on both the supply or demand side. In an appropriately designed market, generators exposed to high payments for reserves could also seek to hedge that risk by securing interruptible load contracts directly to reduce the net security risk that they impose and for which they are charged. New Zealand is introducing such arrangements.

6.1 OTHER ARRANGEMENTS

The existence of a spot market for reserve does not mean that complete reliance is necessarily placed on that market, just as the existence of an electricity spot market does not preclude contractual arrangements. Thus the "reserve market operator", typically the SO, may be empowered to enter into contracts with participants which:

- Give it the right to offer their reserve capacity into the market; or
- Require participants to offer their reserve capacity into the market, in an agreed manner; or
- Act as "contracts for differences", with respect to the reserve spot price, for an agreed reserve quantity.

Such contracts can be employed to provide the system operator with any assurance that may be required with respect to the availability of sufficient reserve to meet operational and/or regulatory requirements. In the New Zealand market, for example, extensive use was made of such contracting arrangements in the initial months of the market. But the need for them soon diminished as new reserve sources, such as interruptible load, entered a market that is now, if anything, over-supplied with reserve.

6.2 MARKET PERFORMANCE

Competitive market arrangements for spinning reserve are recommended on the same general grounds as for electricity, namely that both theory and experience suggest that:

- Such arrangements work; and
- Will create efficiencies which could lead to lower costs; and in particular
- Will lead to the kind of innovative response that will assist the power system in meeting its particular reserve requirements.

The New Zealand market arrangements described above are generally considered to have been successful, not only in terms of ensuring provision of reserve, but in reducing the overall cost of reserve provision. Innovation in the development of interruptible load as a substitute for traditional spinning reserve has been particularly important, reducing the overall requirement for generation capacity.

Typical reserve prices averaged around 10% of electricity prices at market start, but now average around 1% of electricity prices. It may be argued that, with such low prices, a reserve market is unnecessary. On the contrary, though, it is argued that low prices are the measure of a successful market, and the existence of the market has proven beneficial to the economy as a whole.

More recently, Australia has seen significant reductions in reserve prices in moving from a co-optimisation approach, based on reserve contracting, to a full market approach similar to that in New Zealand.

Market	Start	Bidding	Scheduling and Dispatch	Reserve requirement
New Zealand	1 October, 1996	Offered daily (half hour offers) for various classes of reserve and updated until 2 hours before real time.	An integral part of the NZEM scheduling and Transpower dispatch process, simultaneously optimising energy and reserve scheduling and dispatch with an energy/reserve trade-off function	Reserve ≥ f(largest generation in each island) Reserve ≥ f(largest inter-connector injection into each island)
Australia	13 December, 1999	Standing reserve offers made annually for various classes of reserve. May move to bid daily updated until 5 minutes before real time.	An integral part of the NEM scheduling and dispatch process, simultaneously optimising energy and reserve scheduling and dispatch with an energy/reserve trade-off function	Reserve ≥ f(largest generation in each region) (with transmission limited reserve trading between regions)
California ISO	1 April, 1998	Bid daily for various classes of regulation and reserves.	Uses a sequential optimisation of energy and reserve and then uses a "rational buyer price" optimisation of the various classes of regulation and reserves	Reserve ≥ x% of total load
PJM ISO	1 January, 1998	Not bid	Scheduled and dispatched through the normal economic dispatch software.	Reserve ≥ f(largest generation unit capacity and other system conditions)

Market	Start	Bidding	Scheduling and Dispatch	Reserve requirement
New York ISO	18 November, 1999	Bid daily for various classes of regulation and reserves. Check when their website is back up	Scheduled and dispatched through the normal economic dispatch software.	Reserve $\geq$ 100% $\times$ first contingency + 50% $\times$ second contingency
New England ISO	To start 1 March 2003	Not bid yet.	Scheduled and dispatched through the normal economic dispatch software.	Reserve $\geq$ 100% $\times$ first contingency + 50% $\times$ second contingency
Ontario, Canada	1 May 2002	Bid daily for various classes of regulation and reserves.	An integral part of the IMO scheduling and dispatch process, simultaneously optimising energy and reserve scheduling and dispatch with an energy/reserve trade-off function	Reserve $\geq$ 100% $\times$ first contingency + 50% $\times$ second contingency
Singapore	1 January 2003	Bid daily for various classes of regulation and reserves.	An integral part of the scheduling and dispatch process, simultaneously optimising energy and reserve scheduling and dispatch with an energy/reserve trade-off function	Reserve $\geq$ 100% $\times$ first contingency

7. RESERVE MARKET ARRANGEMENTS

7.1 MARKET REQUIREMENTS

The specific nature of reserve requirements varies significantly between markets, and reserve market arrangements vary accordingly. In New Zealand, Australia and other relatively small electricity systems that require operating reserves primarily for frequency management (stability) purposes, as well as for electricity replacement purposes, reserves required for frequency management must be fully activated within seconds of the loss of injection, typically within 5 to 10 seconds. Therefore the nature of the reserves, and their quantity, are paramount.

Thus, bids into a reserve market for frequency management must specify:

- Response time
- Capacity
- Price

A market allows a clearing price and requirement for reserve to be clearly determined and signalled so that:

- Reserve is provided by those participants best able to provide it, thus reducing cost to participants, and ultimately to consumers; while
- A shortage of reserve vis-à-vis the requirement will lead to an increased price for reserve, leading to new supplies of reserve entering the market, possibly from the demand side; whereas
- An excess of reserve will lead to lowering reserve prices and lower system operation charges to participants.

7.2 OPERATION OF THE RESERVE MARKET

To ensure that all participants in the reserves market know what will happen and why, the reserves market must have rules governing the management of operating reserves that are:

- Clear, unambiguous, open and transparent; and
- Defensible and appropriate in both a commercial and engineering sense.

Typically, an integrated market for operating reserves will follow the steps set out below.

1. The System Operator will determine an appropriate reserve requirement and advertise this to the market, providing justifications for that requirement.
2. Participants will offer operating reserves, together with their electricity offers to supply and/or bids to take load, either in the form of spinning or non-spinning reserve from generators, or interruptible load from loads/retailers. Each tranche of reserve offered is given a price that the supplier wishes to receive for that reserve. In the case of a generator, it is the fee that the generator wishes to

receive over-and-above the opportunity cost of the generation foregone.[14] For interruptible load, it is the fee they wish to receive for being available to be interrupted without warning[15].

3. The Market Operator will clear all electricity and reserve bids in a simultaneous optimisation. A clearing price for electricity and for each class of reserve is found, together with the appropriate dispatch schedule; that is, the dispatch schedule which minimises the combined cost of both electricity and reserve to meet the electricity requirements while respecting reserve constraints, and delivering accepted levels of system security. This will typically involve having some generation backed off to provide reserve, and, depending on the market arrangements, may also involve placing some interruptible load on standby and/or reducing the maximum injection into the system so as to reduce the reserve requirement[16].

4. Where there is a relative "shortage" of reserve at the initial scheduling stage, the shortage will be notified to the market through the publication of the pre-dispatch projection dispatch schedule and prices and the opportunity given for further offers to be made, just as for electricity.

5. Where there is a shortage of reserve at the dispatch stage only, several things may happen:
   - The reserve requirement can not be met, but the System Operator is satisfied that the system security is not at risk, possibly due to the small size and short duration of the reserve shortfall[17]. If this is reflected in a formal relaxation of operating constraints within the linear programme, then penalty values should be applied and reserve (and possibly electricity) prices may be very high[18]; or
   - The reserve requirement cannot be met, and the System Operator determines that system security is impaired. The market may be temporarily suspended, and the System Operator can exercise his/her discretion to then instruct one or more participants to provide reserve. Under these conditions the market rules would set out the additional compensation that the instructed participants should receive.

6. The system is dispatched, the prices and metered generation and off-takes read, and settlement payments calculated and made.

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14 This is a fee for being on standby, not a fee per incident. Once called upon, their energy profits will increase as their generation has been increased.

15 This is a fee for being on standby, not a fee per incident. Once interrupted, their energy costs decrease as their load has been reduced.

16 The latter can be optimal, even when there is ample reserve if the largest unit is on, or near, the margin. Compensation may be appropriate, or the reduction may be thought of as providing reserve, to be paid for in the market.

17 Interestingly, formalisation of reserve dispatch via the market often reveals that this "solution" has, in fact, been implicit in traditional, pre-market, operation procedures, particularly during times of rapidly rising load.

18 Relaxing constraints without the application of penalty values would create an inappropriate situation in which reserve prices would fall when the supply of reserve proved inadequate to meet normal standards.

7.3 SIMULTANEOUS ELECTRICITY/RESERVE OPTIMISATION AND PRICING

A reserve requirement implies a constraint on the generation dispatch that must be respected[19]. The System Operator uses the market-clearing software to determine the least cost dispatch and, in so doing, must implicitly calculate the marginal cost of meeting that constraint, together with the true marginal cost of electricity, after accounting for that constraint:

- Depending on the particular constraints and plant involved, the true marginal cost of electricity may be either more or less than the marginal cost of the most expensive generator operating. However, it will generally be higher than it would have been without the reserve requirement.
- The cost of spinning reserve is comprised of the payments to those who provide it. This price must reflect the marginal cost of providing that reserve, that is the reserve fee demanded by the marginal provider, plus, if the marginal provider is a generator, the opportunity cost of backing off/bringing on that generation relative to its optimal dispatch at the market clearing electricity price.
- The cost of spinning reserve must be covered by payments from those who require it. In the first instance, economic signalling may best be achieved by recovering these costs from generators.[20]

The key to calculating the cost of spinning reserve and, indeed, in determining the correct dispatch, is the *reserve capability function* of each generator. This is a curve that describes how much reserve can be provided at a given generator output (see Figure 2). The slope of this curve describes how many MW of reserve are provided for each MW of reduction in output.

7.3.1 Example

This section goes into a detailed example of reserve and electricity co-optimisation and electricity and reserve pricing in this situation. (Readers not wishing to become immersed into the intricacies of reserve allocation and pricing can go directly to Section 7.4.)

As an example, consider the simple power system below.

[19] Several such constraints may be binding simultaneously, but we will simplify the discussion by considering only one.

[20] Although note that these charges then become part of the cost structure which generators must ultimately recover from consumers, which is appropriate because the entire generation sector exists only to meet the needs of consumers. The market will ensure that, ultimately, they are recovered from consumers as electricity prices eventually rise to meet the total cost of generation entry.

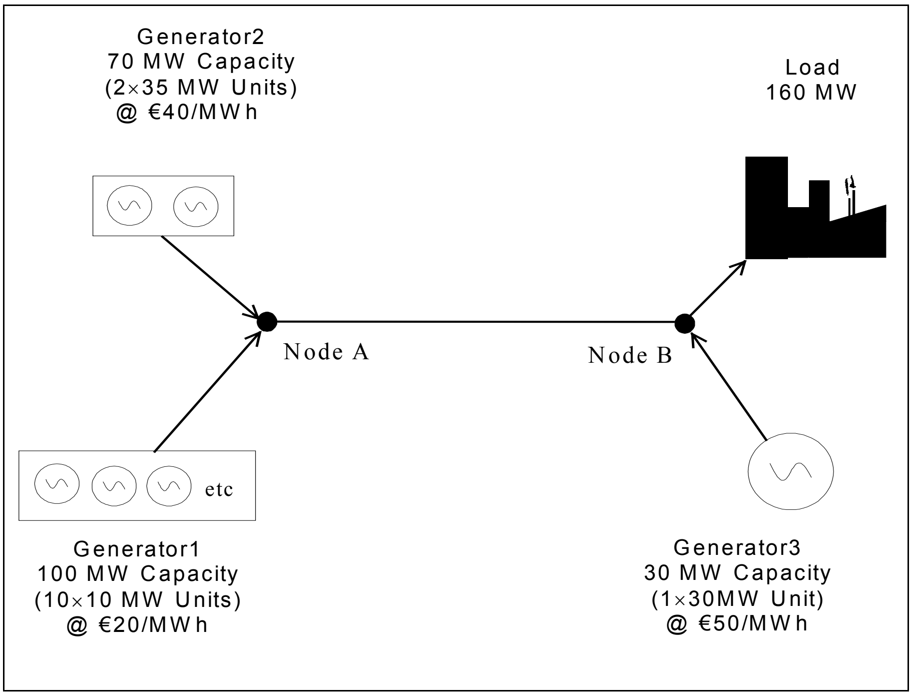

Figure 1: A simple reserve problem

Suppose that the load to be met is 160 MW, and that:

- Generator1 consists of ten 10 MW generation units;
- Generator2 consists of two 35 MW generation units;
- Generator3 consists of one 30 MW generation unit; and
- Enough spinning reserve has to be carried to cover the loss of any single generation unit[21].

The generation units have the reserve capability functions with the shapes shown below.

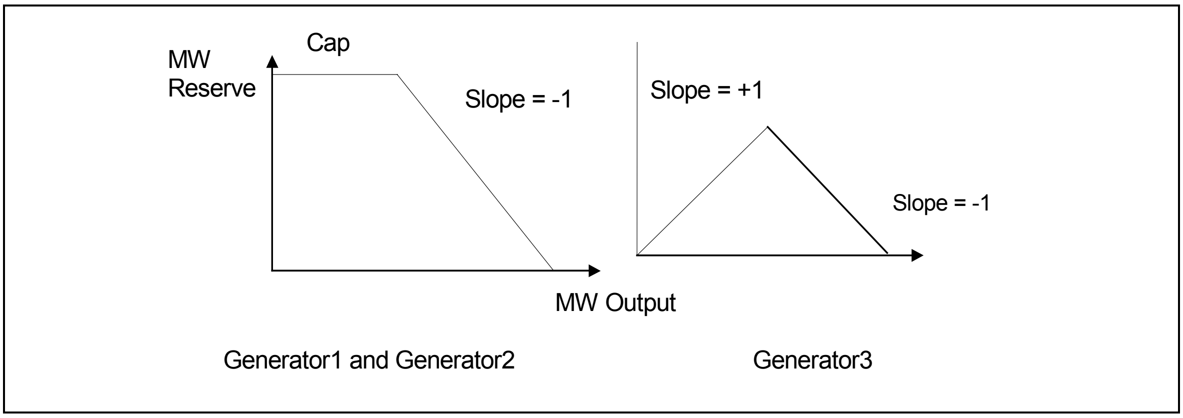

Figure 2: Generation unit reserve functions

21 Spinning reserve is not the same thing as spare capacity. The issue is whether there is enough spare capacity available to react in a short enough timeframe to cover the failure of the largest unit. If there is excess, then the reserve price will be zero, irrespective of how much spare capacity there may be. If there is insufficient, the reserve price may be very high, but it will only be paid to that capacity which can respond in the appropriate timeframe, not to other spare capacity.

Figure 2 shows that each MW of output backed off at Generator1 or at Generator2 provides 1 MW of reserve, while each MW produced at Generator3 provides an extra MW of reserve:

- The downward sloping line indicates that, as generation approaches maximum output, reserve contribution must fall to zero;
- The caps indicate a limit on ramping capability, and hence reserve provision, in the critical timeframe. For simplicity it is assumed not to be binding in this example; and
- The upward sloping line might indicate an increasing reserve capability with increasing output[22], but may approximate a situation in which no reserve is available at zero output, with maximum reserve being available at a minimum generation level. In this case the response must peak at 15, then decline to zero at full output.

The reserve offer form used in other markets includes response functions such as these, and we will assume that these generators have offered their plant in this fashion.

We will also assume that none of them has asked for a reserve fee over and above the opportunity cost that they will incur in being "mis-dispatched", with respect to the prevailing electricity price, in order to provide reserve.

Obviously, a unit cannot carry reserve to cover its own breakdown. Thus the dispatcher must cover the possible loss of output from any single unit operating with the reserve from other units.

For example, we could allow Generator2 to covers the breakdown of its own units and Generator1 and Generator3 to meet the remaining load at minimum cost:

Generator	Energy (MW)	Reserve (MW)	Energy Cost (€/MW)
1	10 each 100 total	0	2000
2	17.5 each 35 total	17.5 each	1400
3	25[23].	5	1250
Total	160	35	4650

[22] This may be as a by-product of the operating mode of a thermal unit, or of increasing unit commitment on a multi-unit hydro station.

[23] Note that even though Generator3 is the "largest" unit operating, in terms of MW loading, the critical contingency is still failure of a Generator2 unit, not so much because these units have the greatest capacity, but because we are relying on them for so much reserve, as well as energy. Thus the "largest" generator dispatched and loaded, as determined by its combined energy and reserve dispatch, sets the critical contingency size.

A better solution would be to reduce load on Generator3 (priced at €50/MWh) to 20 MW, and bring Generator2 (priced at €40/MWh) up to 20 MW per unit. Generator1 still produces 100 MW:

Generator	Energy (MW)	Reserve (MW)	Energy Cost (€/MW)
1	10 each 100 total	0	2000
2	20 each 40 total	15 each[24]	1600
3	20	10	1000
Total	160	25	4600

In fact, the least cost option would be to back off Generator3 further:

Generator	Energy (MW)	Reserve (MW)	Energy Cost (€/MW)
1	10 each 100 total	0	2000
2	23.75 each 47.5 total	11.25 each	1900
3	12.5	12.5[25]	625
Total	160	23.75	4525

The reserve requirement is still met, since the largest contingency, a failure of one Generator2 unit at 23.75 MW, can be covered by 12.5 MW of reserve from Generator3, plus 11.25 MW of reserve from the other Generator2 unit[26].

A. MARGINAL COST OF ELECTRICITY

We can calculate the marginal cost of electricity by looking at an increment of load. Any incremental load would be met by simultaneously increasing output at Generator2 and Generator3. For example, an increase in load of 4 MW would be met by 1 MW from each

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[24] Of course, one unit represents the contingency, so its reserve capability is not available to cover itself.

[25] Note that only 12.5 MW of reserve is available from Generator3 because of the shape of the reserve function.

[26] Backing off Generator 1 to provide reserve is not economic since each unit of reserve provided there costs€25/MWh (being the difference between the fuel cost saved at Generator 1 (€20/MWh) and the fuel cost incurred to make up the lost generation at Generator 2 and 3 (€45/MWh) but is only worth €5/MWh.

unit at Generator2 (24.75 MW each), plus 2 MW from Generator3 (14.5 MW) to meet the increased reserve requirement.

Generator	Energy (MW)	Reserve (MW)	Energy Cost (€/MW)
1	10 each 100 total	0	2000
2	24.75 each 49.5 total	10.25 each	1980
3	14.5	14.5[27]	725
Total	164	24.75	4705

The largest contingency is 24.75 MW at a Generator2 unit and reserve is supplied by 10.25 MW from the other Generator2 unit and 14.5 MW from Generator3. The marginal cost of electricity is (€4705 – €4525) / 4 = €45 / MW.

Note that both Generator2 and Generator3 are "on the margin" for electricity, but the electricity price does not equal the marginal cost of either, because incremental load is met equally from Generator2 and Generator3. The marginal cost, and hence the price of supplying an increment of electricity is actually €45/MWh the average of €40/MWh (Generator2) and €50/MWh (Generator3). This is the market price for electricity.

B. MARGINAL COST OF RESERVE

The marginal cost, and hence the price, of spinning reserve is €5/MWh. This is because:

- If another source (eg, interruptible load) were to provide 1 MW of reserve, this would allow Generator3 to be backed off a little further to 12 MW, thus allowing each Generator2 unit to come up by 0.25 MW to 24 MW.
- The net effect is to shift 0.5 MW from Generator3 to Generator2 at a saving of €5/MWh (= 0.5×€50 – 0.5×€40).
- The contingency is now 24MW. Reserve is met by the other Generator2 unit with 11 MW, Generator3 with 12MW and interruptible load with 1 MW

We need to consider why it is acceptable for the market price of electricity to be €45/MWh with Generator3 on the marginal at an offer price of €50/MWh. Generator3 is "on the margin" for *both* electricity and reserve so should not make a profit above its combined offers. This is the case:

- it makes a loss in the electricity market, generating 12.5 MW at a cost of €50/MWh but only receiving €45/MW,

[27] Note that only 12.5 MW of reserve is available from Generator3 because of the shape of the reserve function.

- this loss is exactly compensated by the payment it receives for 12.5 MW of reserve at €5/MWh.

7.4 PAYMENT FOR OPERATING RESERVES

Whereas there is an obvious buyer of electricity in the electricity market, the buyer of operating reserves is less obvious. In the first instance, the System Operator who requires the reserves to meet the obligations imposed by the Grid Code purchases the reserves. However, operating reserves are required to cover for the generation units and transmission circuits that are deemed to impose the contingencies that are to be covered by the operating reserves, and it may be argued that it is they who should then pay the cost of the reserves. This point is examined in more detail below.

A “causer-pays” approach to reserves may provide some price signals to the market that would not otherwise be present. For example, a new entry generator might find that it has two options for its new 500 MW CCGT – a single unit that would increase the system single contingency to 500 MW or a dual plant consisting of two side-by-side 250 MW units that would not increase the single contingency size. A “causer pays” approach to recovering the costs of additional reserves may well lead the power plant developer to opt for the 2 x 250 MW design, adding to system security rather than reducing it.

In principle:

- The price derived above should be paid by those requiring reserve to those supplying it; and
- It should ensure that the marginal electricity and/or reserve offers accepted just break even, while all others make a profit, as measured by the offered “costs”.

In most reserve markets the dispatch optimisation involves a significant degree of cost sharing, not only between those units that are assumed to jointly set the risk, but also with other, smaller units. Some variation of this position has been adopted in all cases, on the grounds that, if the larger units were not present, some reserve would still be required to cover breakdown of those smaller units. Thus it seems fair that they, too, should pay for reserve, at least in proportion to their generation capacity when dispatched. Put another way, system security is a common good from which all participants benefit, making it reasonable that all participants should share in the costs of providing that common good, roughly in proportion to the benefits received.

The implication of this cost sharing is that the generation sector as a whole gains from the economies of scope inherent in the fact that one reserve provision covers a multitude of generators[28]. In particular, the largest, or most marginal, units are guaranteed profitable operation, with respect to their market offers, after accounting for all spot electricity and reserve market transactions, **provided** the electricity and reserve prices (and quantities) are calculated appropriately. In the long run, these cost savings, by reducing the cost of generation, must also reduce prices to consumers.

[28] That is, until interruptible load enters the reserve market, after which the generation sector becomes a net buyer of spinning reserve, thus at least partially offsetting the effect.

Specifically, the cost of operating reserves is typically charged to the generators (although this is complicated by the existence of transmission links to other markets)[29]. The cost sharing approach is usually the "runway" model of the cost allocation.[30] This approach allocates the cost of reserves in proportion to the requirements for reserves that are deemed to be due to each plant and is best illustrated by an example.

The runway model is as follows: assume three generation units are to be covered by the operating reserves – one of 500 MW, one of 300 MW and one of 100 MW – and the level of operating reserve required is set by the largest generation unit. Therefore, there will be 500 MW of operating reserve scheduled at a price of, say, €2 /MW giving a total reserve cost of €1,000/hour. The operating reserve can be split into tranches required by each generation unit as shown below.

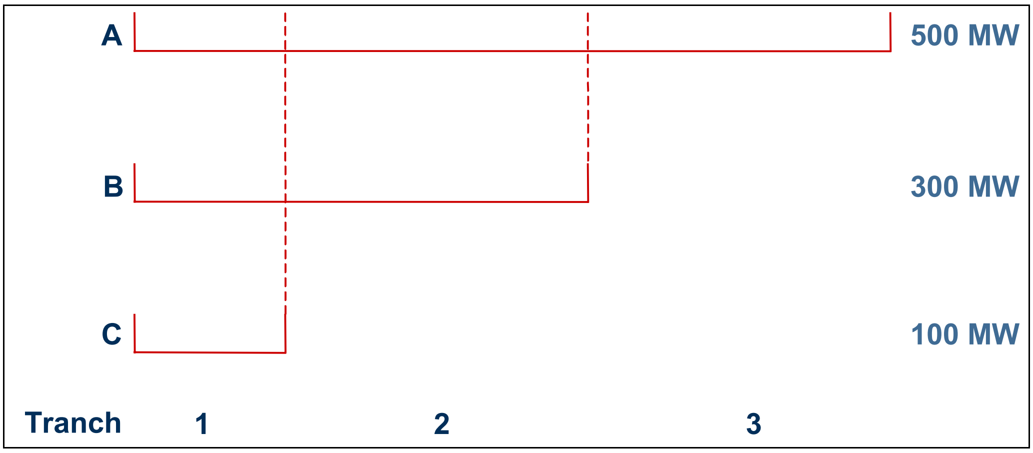

Figure 3: Allocation of operating reserves to participants

The cost of €1,000/hour is then spread across the three generating units as follows:

C pays for one third of tranche 1 only

$$\frac{1}{3} \times \frac{100}{500} \times €1{,}000 = €66.67$$

= €66.67

B pays for one third of tranche 1 and one half of tranche 2

$$\frac{1}{3} \times \frac{100}{500} \times €1{,}000 + \frac{1}{2} \times \frac{(300-100)}{500} \times €1{,}000 = €266.67$$

= €266.67

[29] In the Irish context, if transmission links form a part of the "risk" to be covered by the operating reserves, arguably the appropriate Transco would also be required to pay for necessary contribution to the cost of the reserves. Since the interconnector forms a major reserve source, it is paid for reserve. It is important to resolve how would that work if NI were not included in the market.

[30] At one stage, New Zealand charged the consumers the cost of the operating reserves on the basis that it was they who obtained the benefit of a good quality of supply. However, New Zealand has since moved to charging the generators as described above.

A pays for one third of tranche 1,	$\frac{1}{3}\times\frac{100}{500}\times €1{,}000$	*= €66.67*
one half of tranche 2, and	$+\frac{1}{2}\times\frac{(300-100)}{500}\times €1{,}000$	
all of tranche 3	$+\frac{200}{500}\times €1{,}000$	
	$= €666.67$	

Thus, although the largest generator still faces the largest cost, both in absolute and proportional terms[31], the total cost of €1000 is shared between all three units. This cost sharing effect would be substantially greater in a larger example, with more generators.

These arrangements are designed to share the cost equitably, as above, while ensuring that the last MW of generation from the largest contingency faces the marginal cost of reserve provision. This did not seem to be the case in the above example, because two generators shared the cost of the last reserve increment. But note that, if either had increased generation by 1 MW, they would have faced this price signal, both within the linear programming model and in the real market. This is the motivation for adopting the solution shown, both within the linear programming model and in the real market.

The cost allocation for load-following (or regulation) reserve has a different rationale. In that case the source of the risk is volatility in demand and variability in output from generators that cannot be dispatched reliably to a dispatch target or at a specified ramp rate. Consequently, the cost of regulation reserve should fall on load and certain generating units most usually in proportion to the risk they create. Removing "renewables" (e.g., wind and small hydro) from this obligation would be a policy decision to bias charging in their favour.

7.5 TREATMENT OF EMBEDDED GENERATION

It has been argued, above, that system security is a common good from which all participants benefit, making it reasonable that all participants should share in the costs of providing that common good, roughly in proportion to the benefits received. This implies that smaller generators should share at least some of the costs of reserve provision with larger generators. The net result is that all participants gain, in that they pay significantly less than they would have to if a secure system environment had to be provided to support their operation alone.

If accepted, this argument must apply with equal force to embedded generation of any kind, unless, of course, it is able to implement load shedding arrangements which ensure that the system experiences no disturbance as a result of that generator failing.

Ireland, as a matter of policy, may wish to exempt embedded generation from the obligation for its gross output, in order to favour this type of installation. This will not be of major importance when the units are small (no more than 20MW) but if large units are involved, the impact on the power system of a unit tripping may be significant.

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31 A proportional cost allocation would allocate €556, €333 and €111 respectively.

7.6 TREATMENT OF PARTICIPANTS EXACERBATING CONTINGENCIES

The situation may arise in which some participants choose to take their plant off-line, or the plant is automatically tripped, when frequency falls during a contingency. This exacerbates the situation, increasing the effective size of any contingency, and hence increasing reserve requirements, and costs. There may be good technical reasons for this, and it is not suggested that it be absolutely prohibited. However, the reference point against which such actions should be evaluated, and which is implicit in most reserve market arrangements, is that all participants should be assumed to at least maintain their generation levels during any contingency. Just as those participants that agree to increase output should be rewarded via the reserve market, those participants that decrease output should suffer penalties, not primarily as a matter of fairness, but of economic efficiency, providing incentives for efficient behaviour. Conceptually, this might be achieved in two ways:

Such generators could be treated as supplying negative reserve, in which case they would presumably be expected to **pay** the full market-clearing reserve price in each period when they operate. This is not advised for Ireland[32].

Alternatively, such generators could be treated as increasing the size of any contingency, in which case they would presumably be expected to pay for reserve according to some variation on the “runway” formula, discussed above.

In principle, the implications of these two approaches are slightly different, with the latter generally being somewhat less demanding, to the extent that the runway formula allows costs to be shared with other participants. But a proper application of the latter formula may actually give the same result as the “negative reserve” proposal.

Apart from any equity considerations, this latter proposal would give participants contemplating investment in such plant broadly appropriate economic signals to consider:

- Re-engineering plant to behave in a more stable fashion;
- Operating plant in a more robust fashion;
- Withdrawing such plant when reserve is tight, and prices high;
- Making physical arrangements with loads to ensure that their operations have no net adverse effect on system security; or
- Not proceeding with such plant if it appears to be uneconomic after consideration of the total cost, including whatever reserve mitigation measures are required.

7.7 MANAGING RESERVE IN PERIODS AFFECTED BY MINIMUM RUNNING CONSTRAINTS

Concerns are often expressed about the possibility that so much plant may declare itself to be inflexible that a situation will arise in which overnight load is met almost entirely from

[32] Ideally, one would like to include their “reserve response” in the market model, and take it into account when optimising their dispatch. Although we are not aware of such a formulation being attempted anywhere it does not seem difficult, in principle, and would automatically shut down such units when reserve prices were high enough to offset profits from continued energy generation. But such a formulation may not be effective if the main (potential) problem lies with non-dispatched plant.

such plant. We understand that this is not, of itself, considered to be a reserve problem. A problem will arise, though, if much of that inflexible plant is unsuitable for reserve purposes or, worse, may trip off during any contingency. It sometimes suggested that this problem could only be addressed by limiting the extent of such developments and/or prohibiting undesirable design features. We believe such intervention to be undesirable, in principle, and that the market can be designed to give appropriate incentives, and signals for participants to make decisions that are optimal from a system perspective.

First, a rational de-commitment market can be achieved by:

- Having generation units signal their "minimum running zones" with "negative offers", specifying the price which the generator is prepared to **pay** in order to keep on generating, rather than violate its minimum running zone, or shut down[33];
- Allowing market prices to become negative if the load is so low that some plant must be forced off; or, equivalently charging plant which wishes to continue generating in such circumstances; and
- Recognising that any plant which insists on defining a minimum running zone, or on "must run" status is effectively agreeing to pay whatever price the market determines for the privilege of maintaining generation in all circumstances.

Second, the reserve issues associated with such periods can be resolved by:

- Modelling plant which must be committed in order to provide reserve as having a rising reserve contribution, at least up to minimum load (as for Generator3 in Figure 2, of Section 7.3.1); and
- Ensuring that all plant pays its fair share of the reserve provision cost, as above.

The net effect of these arrangements will be that, in the situation described above:

- Electricity prices may become negative; and
- Loads will have incentives to rise; while
- All generating plant will have incentives to shut down[34]; except that
- Reserve prices will become high enough; so that
- Plant which can provide reserve will have sufficient incentive to keep generating; while
- Interruptible load will be encouraged.

Thus by co-optimising electricity and reserve the net effect of the electricity and reserve price signals, in combination, is to encourage a range of market responses, all of which can be expected to assist materially in solving this problem. We suggest, too, that such response will almost certainly be strong enough at moderate prices to avert the theoretical possibility that prices might reach very large negative values.

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33 This is standard in "self commitment" markets, such as Australia and New Zealand.

34 These incentives apply even to cogeneration plant that is not part of the pool, since the net load will face the pool price signal, opening up an opportunity to profit by shutting down the generation plant.

7.8 INTERRUPTIBLE LOAD AS OPERATING RESERVE

7.8.1 Motivation to Provide Interruptible Loads as Operating Reserves

The principal motivation on the part of consumers to offer interruptible load is financial reward; they have the chance to be paid for accepting that the System Operator may shed a contracted amount of their load, without warning. Because the probability of being shed is (generally) accepted as being small, they receive an income that is assured while they remain almost risk free. Put another way, they receive a slightly less reliable electricity supply for what may be a significantly lower net price. This opens up an important dimension for choice, and competition, in the market. The level of risk they face – the estimated number of times they can expect to the shed – would form a part of their contract with the System Operator (or with a third party). It would be expected to influence the price at which they offer their load into the operating reserves market. Should the risk of being shed rise to a level that is deemed to be unacceptable, the loads may either exit the reserve market, or increase the price at which they are prepared to accept that risk.

7.8.2 Control of Interruptible Loads

If interruptible loads are to be used as a contribution to operating reserves, the loads must be shed very rapidly. This may be accomplished by either:

- *SCADA* – which has been especially configured to provide a very fast broadcast of a trip signal to all interruptible loads. The use of such a dedicated SCADA system provides other advantages in that it allows the System Operator to readily signal that the load may be restored, as well as providing monitoring of the level of load available for shedding as noted below. Although it was installed in New Zealand, it eventually proved to be uneconomic;

- *Under-frequency relays* – have been used in New Zealand as the most economical means of shedding interruptible load, in addition to their use to provide second level emergency load shedding. The relays are set to a level that provides rapid shedding of load to a true low frequency incident but at a level which protects them against inadvertent nuisance tripping; or

- *Voice communications* – which, while obviously, not acceptable for shedding load in the timeframes required for quick acting reserve, are an appropriate means by which loads are instructed that they may restore their load. The distribution control centres have a role that they can play in this respect.

7.8.3 Monitoring of Interruptible Loads

A common concern expressed by all system operators which rely on interruptible loads which are counted as operating reserves is “How do I know how much interruptible load is actually there, both for dispatch purposes and for reserve market settlements purposes?”

The first concern may be covered by a variety of means, not all of which may be economic in a given situation:

- SCADA monitoring – is usually viable only for major demands that are associated with a grid supply point. However, this may be appropriate should there be a ready supply of low-cost communications channels available. The monitoring need not be on a second by second basis, as most loads that are appropriate for interruption tend to be comparatively steady, especially when compared to a dispatch period of 5 – 10 minutes. In many cases a 5-minute scan cycle is appropriate. SCADA monitoring can both inform the dispatcher of the load that is available for shedding, and measure and report the load that was actually shed;

- SCADA systems can also allow more interaction by the owner of the load by giving them the flexibility to withdraw their load from the reserve market, should they have a pressing manufacturing deadline, for example, without the System Operator having to go to the premises to switch a relay out. Because the level of load is constantly monitored, the System Operator is aware of the withdrawal, and is readily able to accommodate that withdrawal in the dispatch schedule; and
- Data recorders – can be built into under-frequency relays so that the relay both trips the load at the appropriate time and records, for settlement purposes, the load that was shed. For scheduling and dispatch purposes, the contracted level of load is assumed unless there is evidence that the contracted level is not available.

7.8.4 Duration of Load Shedding

The interruptible load is (usually) shed for a maximum period specified within the contract, with the proviso that, should the event be more major than expected, the System Operator has the ability to delay the restoration should restoration put the system security at risk. A 15-minute period usually gives the System Operator time to start other replacement reserves (such as open cycle gas turbines).

In time, given a fully functioning market featuring demand side bids (price based) and real time pricing available to participants, there would also be the prospect of longer term load reductions in response to prevailing spot prices if the system supply remained short following an incident. Thus demand side responses have the potential to supplement traditional open cycle peaking gas turbine plant, for example.

7.8.5 Communications

A most important part of any interruptible load scheme is communication with those whose load may be shed. When their load has been shed, a subsequent message advising them of the cause of the interruption, together with other relevant information, will make them feel a part of the power system and not just someone who is there to be shed. Generation stations are usually well informed of the events through continual contact with the System Operator. It can be easy to forget the less visible interruptible load.

7.8.6 Incentives to Make Offered Reserves Available in Practice

The System Operator would undertake monitoring the technical performance of reserve providers. Non-compliance could result in a variety of consequences for the provider, depending on the final design of the reserves market and any additional contractual arrangements entered into. The form of an interruptible load contract could be as simple as an agreement with the System Operator specifying the technical performance of any interruptible load offered into the half hourly reserves market at the discretion of the provider. A market compliance regime would inevitably take into account the consequences of failure to perform in accordance with interruptible load offered when establishing any penalties. That could of course be significant in commercial terms and would provide strong incentives to comply.

8. TOWARDS A RESERVES MARKET FOR IRELAND

A fully open, dynamic, half-hourly spot market for reserves is probably too much additional complication at the start of the new trading arrangements in Ireland. However, much of the benefit of efficient dispatch of plant for electricity and reserves can still be obtained.

It is suggested that initially:

- Ancillary services be obtained by contract, but that
- Contractual arrangements should be such that services such as spinning reserve and frequency control should be co-optimised in the dispatch, with participants being paid the corresponding market clearing price.

This should maximise the net value of such reserves, while providing for a basic spot market for reserves, which may become more dynamic as soon as the market is ready for it to be implemented. The software for co-optimisation would already be in place and giving benefit to the market.

In the simplest form of this arrangement:

- The System Operator would contract for reserve provision with reserve providers (both generators and interruptible load).
- The System Operator would offer the reserve into the market in terms of the contract (time of day, reserve price premium (if any), etc – which would be standing data in the market database).
- The spot price would be calculated from co-optimising electricity and reserve offers
- Each provider would be paid the "spot" reserve price for each half-hour that its reserve offer was cleared, and it was placed on reserve duty.
- Generation actually called on to generate in response to a contingency, would naturally be paid the market clearing price for the electricity it produced, in addition to its regular reserve payment.
- Interruptible load actually interrupted in response to a contingency, would naturally save the market clearing price for the electricity it would otherwise have consumed, in addition to its normal reserve payment.

This arrangement bridges between existing arrangements and a potential future reserves market, without imposing any undue additional burden on participants, in terms of requiring dynamic market interaction. A contract based regime also has distinct advantages in a situation where there is the likelihood of market power in the reserve market, as will be the case where there is a dominant reserve providing generation station (eg, Turlough Hill).

As the market matures, and a range of suitable reserve providers has emerged, participants in the market will wish to take more control of their reserve revenue. At that time the mechanism will already be in place for spot markets in reserves to be cleared simultaneously with the electricity spot market.