# Market Size, Market Structure & Market Power in the Irish Electricity Industry

ESRI

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# SECTION 1: INTRODUCTION

The literature on the recent liberalisation of electricity markets around the world discusses the successes and failures of the different approaches taken by many countries. All have common reasons and goals but the success of deregulation is a function of many factors, including the quality of all networks (transmission and distribution), the current economic environment and most importantly, country specific characteristics. In reality, the move from traditional state regulation to free market policies entails the swapping of one set of competitive issues for another. Governments entrust the market with the responsibility of ensuring a fair price for consumers. This paper examines some of these competitive concerns.

Previous to restructuring, national electricity industries were monopolies controlled by the incumbent, such as the Electricity Supply Board (ESB) in the Republic of Ireland. With a monopoly in place, there was an assumption of inefficiency tied to the incumbent, which was hard to validate and arose due to the lack of competitors in the marketplace. Key decisions required government approval since government and at times regulators, controlled the central planning of business and investment decisions. However, one side effect of deregulation more than any other, is causing concern for industry participants. Shifting the responsibility to produce electricity from the State to private enterprise introduces profit motivation[1] and requires new methods to ensure the abuse of market power is managed correctly. While regulation remains a key part of the new market for electricity, additional monitoring is required for two reasons; first, rather than one state-owned monopoly, there are now many more market participants that must be observed to prevent abuse of market power. Second, an increase in the number of players in the market means that tacit collusion as well as unilateral action is a now a genuine possibility for gaming the market.

The general goal of the liberalised electricity market is to provide a reliable electricity system at least cost to consumers by allowing competition to take place between rival

[1] ESB 1927 Mandate required that any profits earned by the company should be re-invested.

generators to produce electricity, which leads to improved efficiency and greater innovation[2]. The market for electricity production in Ireland, although liberalised six years ago, has not attracted many new entrants. Possible reasons suggested for this relate to the relatively small size of the market, lack of confidence in the regulatory regime and ESB dominance, which will be the focal point of the paper. There are numerous strategies that could be put in place to tackle an incumbent's dominant position, such as structural or regulatory solutions, but it is first necessary to assess the threat posed by a company since it is worth noting that EU Competition Law recognises that there is a very real distinction between dominance, abuse of a dominant position and even collective dominance.

The main focus of this paper is on market power in the Irish electricity market. However, first we examine issues relating to market size and market structure. The section of the paper dealing with market structure, examines the effects of different types of gaming on market participants. In dealing with market power we use the traditional indices to measure the potential threat presented by the abuse of market power. In each case we look at the market for electricity in the Republic of Ireland only and the "All-Island" case.

The plan of the paper is as follows. Section 2 conducts a literature review of the measurement of market power in the electricity sector. Section 3 builds a model of electricity supply that enables us to conceptualise how market power is exercised in the sector under a variety of market circumstances. Section 4 examines some simulation results with respect to the effects of different bid-price strategies. Section 5 considers model outcomes from a market dominance and market power perspective. Finally, Section 6 examines the main conclusions that arise from the paper.

[2] Reference to "Market Liberalisation and Regulatory Reform" by Isolde Goggin at http://www.tca.ie/speeches/10-05-01.pdf.

## SECTION 2: MEASUREMENT OF MARKET POWER IN THE ELECTRICTY SECTOR

The traditional assessment of market power has focussed on the supplier's ability to profitably alter prices away from competitive levels (Stoft, 2002). This interpretation is derived from the difference between the two polar cases of competition; perfect competition and monopoly. In perfect competition, many buyers imply that sellers are price takers. For this reason, the price of a homogeneous good is often very elastic and responsive to changes in price. Thus, in theory, the selling price is always close to or identical to its marginal cost. On the other hand, a monopolist is the sole seller. The lack of competition in the monopolist's market ensures an inelastic reaction to changes in price and consequently, raising the price will not cause a huge reduction in sales, which would be seen in a perfectly competitive market.

The extent to which price exceeds marginal cost is captured by the Lerner Index and is defined as;

$$LI = \frac{\text{Price} - \text{Marginal Cost}}{\text{Price}}$$

Since it is assumed that price is equal to marginal cost in a perfectly competitive market, the Lerner Index indicates the extent to which market performance deviates from the perfectly competitive benchmark. Firms that lack market power show ratios close to zero. As the ratio increases from zero to one, it is more likely that the firm possesses significant market power. Applying this technique to electricity markets and comparing a generator's bid with its marginal cost, proves useful in identifying those producers that are frequently bidding in prices in excess of their marginal cost. Many empirical studies have looked at generator bid and cost data to uncover abuse of market power. Von der Fehr and Harbord (1993) were one of the first to apply this method to electricity markets. They examined the bid prices and costs of the two largest generating companies in the England and Wales electricity pool (National Power and Powergen) from May 1990 to April 1991 and concluded that in the opening months of the pool's operation both companies bid very close to their marginal costs. However, after the first nine months bids started to rise above their costs.

Since electricity markets are more complicated than other markets, there are many criticisms of using the Lerner Index as a measure of market power in the sector. First and most importantly, the marginal cost used is generally estimated and derived from fuel prices and thermal efficiencies[3]. Variable fuel costs do not take account of very real decisions associated with fuel purchasing such as commercial constraints on interconnectors. In addition, fuel switching is common in electricity companies that have multiple generators, using a variety of fuels and so quantifying the exact marginal cost of each supply unit is difficult as this may change over the course of the day and year. Secondly, most studies that employ the Lerner Index will use the short run marginal cost, (e.g. Von der Fehr and Harbord) but due to the large amounts of capital that are required in electricity markets, the long run marginal cost may give a better indication of the actual overall level of market power evident in the industry.

In the electricity sector, above-cost pricing may not be a symptom of the exercise of market power since scarcity pricing is a characteristic of any market where the total available supply is capped in the short run. Scarcity pricing refers to those times of the day or year where demand is very close to the system's total capacity and so the price of electricity on the spot market will be exceptionally high to reflect this scarcity and the closeness to full capacity. Excess demand is not possible in an electricity market as it will cause a "blackout", so preventative measures must be taken before the equilibrium point is reached to maintain total available supply equal to demand. It must also be mentioned that many generators rely on these periods to recover the bulk of their fixed costs. More recent studies by Short and Swan (2002) and Evans and Green (2003) attempt to explain some of the variations in the Lerner Index with respect to structural and other factors.

Another general measure of market power, that is considered helpful in defining the relevant market, is based on market concentration. Structural indices such as market

[3] See Appendix B for model description

share[4] and the Herfindahl-Hirschman Index (HHI)[5] assess the ex-ante potential for market power. Studies of market power in electricity markets usually include at least one measure of market concentration. Schmalensee and Golub (1984) conducted a study of 170 generation markets operational in the United States in 1978 and concluded that 35 percent to 60 percent of these markets had HHI values in excess of 1800, which denotes highly concentrated markets, where abuse of market power is considered more likely. A similar and more up-to-date analysis, based on 1994 data, was conducted by Cardell, Hitt and Hogan (1997) and concluded that roughly 90 percent of the markets examined had HHI values in excess of 2500.

Although the HHI and market share indices are internationally recognisable standards, as static measures they do not represent the real-time aspect of electricity markets very well. Furthermore, they only examine the supply side of the market. For instance, there may exist some market with a HHI value below 1000. This figure would typically characterise an unconcentrated market where the threat of abuse of market power is low. However, even the smallest generator can possess some level of power to affect prices. This can be the result of harsh weather, breakdowns, transmission failures etc. When suppliers are essential for the certain and adequate provision of electricity, they possess significant market power regardless of their company size relative to the market. This occurs most often when the system is close to full capacity.

William and Rosen (1999) attempted to relax the static feature of the HHI, by using daily HHI values. Though they deduced that a daily HHI based on power delivered, had no ability to predict actual market power as measured by the price-cost margin index.

Finding suitable standards is not just a problem for market participants. Both the European Commission and the U.S. Federal Energy Regulatory Commission (FERC) employ tests based on behavioural and structural indices to assist in defining the relevant market. Currently the EU DG for Competition Commission relies on the

[4] The market share concentration ratio is the percentage of market share attributed to the largest firms. For example, the 4 firm concentration ratio refers to the total share of the largest 4 firms in the market.
[5] The HHI is the sum of the squares of all market shares in the industry. See Section 3 for a more detailed description.

“small but significant non-transitory increase in price” (SSNIP) test. This test asks the question, if all generators in a particular location combined into a single company, could a price rise of 5% in that region be sustained?

In the U.S., the “hub-and-spoke method”, which identified affected customers as those that are directly interconnected with the merging parties, was dropped in favour of a new method for determining market - the Supply Margin Assessment criteria. The hub-and-spoke analysis acknowledged potential suppliers as: (1) those suppliers that are directly interconnected with the customer (the "first-tier" suppliers); and (2) those suppliers that are directly interconnected with the merging parties and that the customer thus can reach indirectly through the merging parties' open access transmission tariff (the "second-tier" suppliers). This technique did not take account of the many other factors that affect the relative size of a market and resulted in markets that could be broader or narrower than those defined by the first and second tier analysis.

The Supply Margin Assessment (SMA) is also known as the Pivotal Supplier Indicator/Index (PSI) and is the first index to consider both demand and supply limitations. It examines whether a certain generator is necessary (or “pivotal”) in serving demand. The basis for the SMA compares the total capacity of a generator with the surplus supply[6]. Bushnell *et al.* (1999) characterise the PSI as a binary indicator for a certain supplier for a certain point in time. It is set equal to one if the supplier is deemed pivotal and zero otherwise. Aggregating over a period of time, say one year, provides a figure indicating the amount of time during the year that the supplier was pivotal and had the power to affect price. For example, if a supplier knows demand will be high and that their electricity will more than likely be required, they can effectively name their price. Vassilopoulos (2003) expresses criticism of this approach since it fails to take account of net buying or selling positions through contracting and also states that the measure is highly restrictive since only peak hours are examined. While Blumsack et al (2002) suggest supporting the SMA with a HHI applied specifically to groups of suppliers, who together, are pivotal.

[6] The difference between total supply and demand

The Residual Supply Index (RSI)[7] is a variation of the PSI, developed by the California Independent System Operator (CAISO) as a continuous metric that could better represent the potential for an abuse of market power by a generator. The RSI for a company X measures the percent of supply capacity remaining after subtracting company X's capacity of supply (less contract obligations). An individual company's RSI of above 100 percent implies that the company is not pivotal and *vice versa*. Therefore a low RSI is of more concern to the market than a high RSI. Sheffrin et al. (2001, 2002a, 2002b, 2002c, 2004) established the existence of a relationship between hourly RSI and hourly price-cost markup in the California market. Empirically, the correlation between the two indicates that on average, an RSI of approximately 120 percent will result in a market price outcome close to the competitive benchmark. While there is no doubt that the PSI captures many of the indications of market power, the RSI has the added advantage of flexibility in setting thresholds, compared to the PSI, which is set at 100 percent.

This paper attempts to analyse the issue of market power in the Irish electricity sector, using both a static and dynamic measure, namely, the traditional HHI index and the CAISO's RSI measure. The HHI will be employed to evaluate traditional market concentration and the CAISO's RSI will be used to assess the potential for market power in the Irish electricity system.

[7] $RSI_x$ = (Total Capacity – Company X's Relevant Capacity)/Total Demand. See Section 3 for a more detailed description.

# SECTION 3: MODELLING ELECTRICITY SUPPLY

## 3.1 Key technical features of electricity production

When analysing the electricity industry, it is important to first consider the characteristics of electricity. As the end product is always the same, electricity is a homogenous good and it has an inelastic demand since it is a necessary good for households and businesses. This gives electricity firms considerable market power and is one of the reasons for regulation of the industry. The success of any economy is very reliant on the adequate and certain provision of electricity. It is a capital-intensive industry and is characterised by significant initial investment costs and high costs of capital because of the high degree of technology, expertise and infrastructure required. However, the principal distinguishing characteristic of electricity and many other products is that it cannot be stored. Real-time dispatch must occur to prevent "blackouts". This means that at every second of every day the system operator is working to ensure that only the exact amount of electricity required is produced by generators. If excess electricity were produced it would increase thermal losses and could prove dangerous for the system. In electricity markets it is not possible for excess supply or excess demand to guarantee that an equilibrium point is reached for every minute of the day. In contrast to most forms of commodity trading, stocks of inventories cannot be kept on hand to balance the market. These standard market-clearing forces require a time dimension that is not feasible, as the market must be cleared in real-time. Thus, to ensure the least expensive outcome, it is necessary to employ the most efficient use of generation resources for that particular time of day.

Ireland currently uses the following fuels/technologies for electricity generation; Coal, Oil – Heavy Fuel Oil & Diesel Oil, Gas – CCGT & OCGT, Peat, Hydro, Wind and other renewables such as CHP, Biomass. Gas CCGT's are the most common new stations on the market. There are many reasons for this including; the fast-pace with which CCGT's can be built. It takes two-to-three years to commission a Gas-CCGT, whereas to build a coal-fired station usually takes four-to-five years. In addition, there are relatively low operation and maintenance costs associated with new CCGT's. Gas also has its advantages; it is a clean fuel with a low carbon content in comparison the other fossil fuels. With both Combined Cycle Gas Turbines (CCGT's) and Open

Cycle Gas Turbines (OCGT's), the engine produces its own pressurized gas by burning natural gas. The heat that comes from burning the fuel expands air, and the high-speed rush of this hot air spins the turbine.

Peat is a fuel native to Ireland and consists mainly of plant remains that have formed over many hundreds of years. Before indigenous natural gas came on stream in Ireland in 1979, peat was the most important indigenous energy resource in Ireland. Peat has been used for electricity generation since the 1950s[8]. However, is not widely used in electricity production since peat has a high carbon content, higher than coal, and the technology is not as cost-efficient. As a result the generator obtains less electricity per tonne of peat, than it would with a more efficient technology or fuel.

There can be many technologies capable of generating with each type of fuel and each of these technologies in turn possess different characteristics, relating to maximum capacity, efficiency, availability, costs, required ramp-up time[9] and Minimum Stable Generation (MSG). For example, a Gas-CCGT station would be the cheapest station to run at maximum capacity since gas is one of the cheapest fuels, the technology has one of the highest levels of efficiency and availability and labour costs are reasonable. However, if only a fifth of a station's capacity were needed and only for a short period of time, sometimes due to MSG, it is not efficient to turn the station on. Each type of technology has a minimum amount that it can be switched on to produce, anything less than this amount would be uneconomical. Usually in this situation, an oil-fired plant would be more suitable due to its quicker ramp-up time, although the cost per MWhr would be greater. So, in any electricity system a range of different types of generation is usually required. For simplicity these are characterised as; "Baseload", "Mid-merit load" and "Peak load".

Baseload refers to the cheapest forms of generation. It may be cheap due to the price of the underlying fuel, like renewables and coal-fired generation, or, it may be the newest, most efficient technology on the market, such as Gas-CCGT. These stations tend to run most of the day and therefore have the lowest cost per MWhr when total costs are spread out over the total electricity produced. Mid-merit load stations would

[8] For further information on peat see www.bnm.ie
[9] Time needed for electricity to be produced, that is, the time it takes to reach full capacity.

run for a considerable part of the day, usually based around the working hours, nine to five. These stations offer the next cheapest MWhr of electricity overall. The most expensive electricity, supplied by peak load generating stations, would only be used at the times during the day and year when demand is highest. These generators could be using a fuel such as oil and/or the technology may exhibit high operation and maintenance costs (O&M Costs), but usually they tend to be the generators with the shortest ramp-up time. Since these stations are aware that they will only be required for a small number of hours in the year and still must recoup all of their costs, the price that they charge for producing electricity can be extremely high. All stations rely on these peak-hours to recover their fixed costs.

## 3.2 A model of electricity supply

### 3.2.1 The Data

Modelling the electricity system of any country is difficult because in addition to the technical constraints that are embedded in the sector there are also country-specific regulatory and commercial constraints that must be taken into account. Given the range of complexities inherent in the sector, the aim was to construct a model that replicated the key features of the Irish electricity system for the 2003 supply year. Thus certain technical features, such as engineering constraints relating to ramp-up times (and costs) were excluded.

Populating the model with data required information from many sources, both national and international. Basic information on generators operational in the country was taken from Eirgrid's Generation Adequacy Report 2004-2010 and ESB's Annual Report 1992: type of fuel used, capacity, efficiency, availability. For example, Moneypoint is a coal-fired station with a total export capacity[10] of 855MW, at 34% efficiency and 90% availability (the other 10% is committed to scheduled maintenance). The marginal cost of production for each fuel was based on an average of fuel prices for the first three quarters of 2003 together with the efficiency of each station's technology. Operational costs were estimated using various sources including the CER's Best New Entrant 2004 paper.

[10] Refers to the maximum capacity of the stations less the MW it will take to produce that energy.

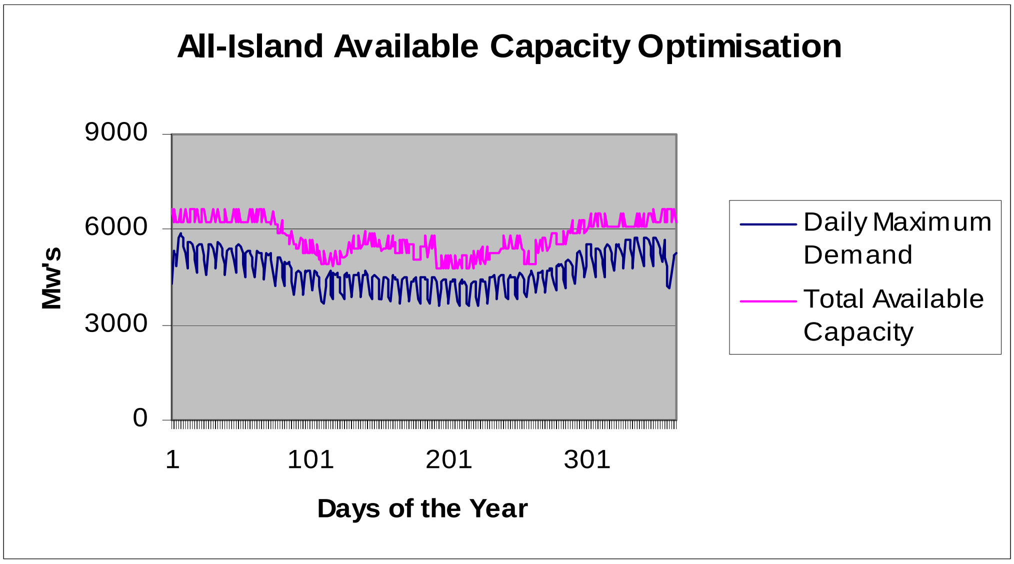


Figure 3.1: All-Island Capacity Optimisation Chart

Input data regarding levels of demand for the Republic and Northern Ireland were taken from the Eirgrid and SONI[11] websites respectively in the form of half-hourly data for 2003. For the purpose of modelling interconnectors to the U.K., it was necessary to obtain the wholesale sell prices for electricity for 2003[12].

Particular attention was paid to specific issues, such as the annual maintenance of all generators. In order to realistically optimise these scheduled outages it was necessary to create a timetable, indicating when generators were on or off, that reflected the percentage planned availability for each station. This was achieved using "educated guesses" such as, assuming that the larger baseload stations would be needed in winter and so would be scheduled for maintenance outages during the summer and hydro stations would be operational for only the peak times during the day, since they are physically constrained to a very low availability. This timetable was also constructed to roughly follow the annual load profile, which was assumed to remain unchanged from year to year.

Figure 3.1 illustrates the annual coverage in capacity in the All-Island electricity market, taking into consideration the scheduled outages of generators. The least

[11] System Operator of Northern Ireland.
[12] These were located on the website – www.bmreports.com in association with NETA.

amount of capacity is required in summer and so many of the larger stations are scheduled for maintenance from May to September.

The intermittency of wind means that it is hard to predict the amount of energy that wind will produce on any given day. For this reason, a random number generator with a normal distribution was chosen to model for the variability in wind. Wind was assumed to be available on average thirty-seven percent of the time, spread randomly over the year. Wind was also assumed to be either on or off for the entire day.

There is currently one interconnector on the island, which joins Northern Ireland to Scotland. The interconnector is only modelled when the All-Island scenario is being considered. The movement of electricity through the interconnector is limited to 500MW but it is assumed that there are no constraints pertaining to the direction of transfer. One other assumption that is only in force in the All-Island scenario, relates to NIE's Power Procurement Business. It is mentioned as part of the background[13], that the method of supply of electricity in the North differs from the South. Generators enter into short-, medium- and long-term contracts to supply electricity. This approach is one way of ensuring production at low/minimum cost, but it is not operational in the Republic of Ireland and so, in order to model the systems identically, it was assumed that Power Purchase Agreements do not exist and all market participants simply bid into an energy pool, where bids are ranked in order of preference, cheapest first – dearest last.

The model is capable of replicating the individual markets for electricity in the Republic and Northern Ireland, together with an All-Island system. It also has the capability to model the impact of different sized electricity interconnectors to Great Britain. Therefore, the model is capable of addressing various issues presently concerning the electricity market, such as the debate regarding the All-Island market, the effects of carbon taxation/emissions and other price shocks, and the consequence of different bidding strategies. Future years and fuel compositions can also be considered using a growth factor[14] for demand under the assumption that the load

[13] See Appendix A for Background of electricity markets in Republic of Ireland and Northern Ireland.
[14] Taken from the ESRI MTR and the forecast growth in electricity demand.

profile remains unchanged. This paper will use the model to examine the effects of different bidding strategies and market power.

### 3.2.2 The Modelling Process

Electricity demand is highly cyclical in nature. From winters to summers and even from nights to days, the amount of electricity needed by the country fluctuates on a moment-by-moment basis. Using historic demand data and weather information, it is possible to have a rough estimate of the quantity required and consequently electricity is sold hours in advance by generators. Each station bids into the market a price/volume combination, that is, the amount it can supply in the next half-hour period and the price per Megawatt-hour (MWhr) of that electricity. It is hard to estimate the bid-price, but one can assume that it should cover the fuel cost. In the medium-term, stations must also cover their operation and maintenance (O&M) costs, such as labour, and in the long-term they must be capable of repaying their capital debts.

The model first assumes that all plants bid in their fuel price per MWhr. In order to choose which stations will generate, the model ranks the generators. The cheapest bid is ranked first and the others follow in ascending order, this is known as a Simple Stack Model. Table 3.2 illustrates the model-generated marginal costs for different generating stations and capacities.

| **Generating Station** | **Capacity** | **Bid Price per MWhr (Marginal Cost)** |
|---|---|---|
| *Station A* | *5 MW* | *€10.50* |
| *Station B* | *50MW* | *€12.00* |
| *Station C* | *200MW* | *€12.10* |
| *Station D* | *100MW* | *€12.75* |
| *Station E* | *40MW* | *€15.00* |
| *Station F* | *160MW* | *€16.80* |
| Station G | 180MW | €17.30 |
| Station H | 2MW | €21.90 |

Table 3.2: Example of electricity generator bids in a Simple Stack Model

The next step is to offer contracts to those generators that fall within the level of demand required in that half-hour segment. If for example, 500MW were needed, Stations A to F (in italics) would be contracted to generate. It is important to note that Station F would be known as the "marginal station" and would not generate to its full capacity, since the cumulative total to Station F is 555MW and only 105MW of its potential capacity would be required to reach the 500MW target. The price that each generator receives is called the "system marginal price" and is determined by the bid price (marginal cost) of the marginal station. In the example above, Stations A to F would receive €16.80 per MWhr produced and each would make a straightforward surplus[15] with the exception of Station F, which would just break even. The system marginal price will vary over time depending on the cost of the most expensive station commissioned to generate. Consequently, the price of electricity is higher at peak times of the day and year.

Ranking the generators in this fashion and simulating the electricity system, basing the merit-order only on short-run marginal costs (fuel costs) represents the most efficient economic dispatch. The portfolio of generators at the disposal of the transmission system operator and the size of the margin between demand and total available capacity will have a significant effect on the outcomes. If demand is high, stations at the bottom of the stack model will be needed, which means that the revenue per MWhr that each station receives will also be substantial.

We now turn to the case of medium-run cost. In order to find a feasible medium-run cost, with which to compare the short-run cost of fuel cost, it was necessary to simulate the model to find those supply bids for each generator that allowed them to at least break even, whilst taking into consideration the bids of other generators. Hence the Medium-Run Marginal Cost (MRMC) equals the fuel cost plus an allowance for 'operational and maintenance' (O&M) costs. The required adjustment for O&M costs depends on the simulated break-even bid price.

[15] Defined as revenue minus cost.

This break-even[16] bid refers to the aggregate of all generating stations that may operate on a particular site. For example, in the case of the ESB's Moneypoint[17] generator the break-even bid price refers to the total of three separate generating stations that operate on the site. In relation to profitability and breaking even, this would mean that the surplus on the three units of Moneypoint would have to be greater than or equal to zero. Finally, the model allows us to identify the price-setting generators[18] and to compile indices of market power.

The operating profit that generating station i ($STP_i$) makes in a year is equal to its revenue minus its variable costs[19], defined as;

$$STP_i = \left( \sum_{j=1}^{17,520} (SP_j \text{ x } IC_{i,j}) - \sum_{j=1}^{17,520} (p_{i,j} \text{ x } IC_{i,j}) \right) - C_i$$

where i = 1,…,58 (number of stations).

j = 1,…,17520 (number of 30 minute periods in a 365-day year)

SP = "System" price (price bid by the marginal generator)

IC = Individual Capacity that each generator produces in each period

p = Price bid by each station

C = O&M costs of each station

Therefore, operating profit refers to the residual after all variable costs have been deducted. This figure may cover part, or, all of the capital repayments of the various technologies. The latter requirement has a major impact on any future investment decision in generating capacity regarding generation but in our case capital cost is sunk.

### 3.2.3 Modelling Limitations

As noted already, the model does not perfectly capture all of the operational features of the electricity market. For instance, normally when demand is high, supply is

[16] Defined as Total Revenue minus (Fuel Cost plus O&M Cost) > 0.
[17] Only coal fired power station in the Republic. Consists of three separate units.
[18] The marginal station; sets the price paid to all generators that make the cut to generate
[19] Fuel costs and O&M costs.

almost at its maximum and so the price per MWhr is very expensive and one often observes what are known as “price spikes”. This outcome arises because it is usually in these periods of high demand/short supply that generators recover their capital costs. In the model these price spikes are less pronounced they have been smoothed using a cap on the bid price. The bid price has been assumed to never go above €2,000 plus fuel cost/MWhr[20]. There are two main reasons for this model restriction. First, since some generators may not generate any electricity in the year, the model would not have been solvable had a suitable cap not been chosen. Secondly, €2,000 per MWhr is considered a reasonable approximation to the Value of Lost Load (VOLL)[21] for the system[22].

Economies of scale are ubiquitous in capital-intensive industries like electricity markets. However, research into the area of scale economies in electricity generation is not conclusive. It is not clear how important they are, or, at what scale they are exhausted (Joskow *et al*, 1985). Evidently, in the case of the Irish industry scale economies were not considered significant enough to support the proposition that the generation of electricity should be considered a natural monopoly (Massey, 2003). It is accepted, however, that economies of scale will exist at some level of output. Christensen and Greene (1976) believed that such economies of scale are fully exploited by generation companies with over 4,000 MW of capacity but due to information problems, could not give a comparable result for integrated utilities. It is worth noting that the ESB controls approximately 3,900 MW. Joskow *et al* (1985) discuss many studies that highlight the scale augmenting nature of technical change as one of the only clear-cut contributors to economies of scale. Typically, models that incorporate economies of scale do so as a maintained hypothesis of the model, which means that the relationship cannot be determined endogenously. There is little or no research on economies of scale in the generation sector for the Irish electricity system. On balance, therefore, we felt that it would not be unrealistic to attempt to model economies of scale in the case of the Irish electricity market.

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[20] CPB Study No. 60, “Capacity to spare? A cost-benefit approach to optimal spare capacity in electricity production” refers to a present value of 0.3million euro for the costs of 100MW outage of one hour.

[21] An estimate of customer valuation.

[22] See CPB document: “Capacity to spare? A cost benefit approach to optimal spare capacity in electricity production”.

# SECTION 4: EFFECTS OF BID-PRICE STRATEGIES AND THE CREATION OF THE ALL-ISLAND ELECTRICITY MARKET

## 4.1 Introduction

There are some major modelling differences between the Republic of Ireland and All-Island scenario that are worth clarifying. The All-Island perspective represents the inclusion of Northern Ireland and the interconnector to Great Britain. Northern Ireland consists of independent generators; Ballylumford and Kilroot, which also incorporate some independent OCGT's. While Coolkeragh is part of the ESB portfolio, it is still connected to and sells its electricity through the Northern Ireland grid. The demand profile in the North is not the same as in the South, as well as the spread of generators across the country and size of generation. Ballylumford is the largest generator in the North, contributing a total capacity of 774MW, split into five separate stations. Such a large contribution by any one generator is expected to cause at least some minor changes to the results.

Two features of the analysis should be noted. First, the iterative process associated with the MRMC bidding strategy would be different in an All-Island market since there are more stations to consider and the solution depends on the bids of other generators. Secondly, the markets in question are the Republic of Ireland market in isolation, versus an All-Island electricity market. Comparisons are done on this basis, as no modelling of the individual market for Northern Ireland was conducted.

Finally, as explained in the previous section, two types of bidding strategies are analysed in the paper. First, from an economic cost and social cost perspective, the fuel only bid price, or, the SRMC bid, ensures the most efficient dispatch of the available system, and, the second bid-price strategy, namely, the fuel plus allowance for O&M, or, the MRMC bid. It is worth noting that if economies of scale were present, they could have an effect on a generator's bid price, since a multi-generator company with significant contractual power may be able to obtain better terms of agreement than an Independent Power Producer (IPP).

Currently the Republic of Ireland operates a bilateral market. This means that the buyer and seller contract to supply a certain amount of electricity at some stage in the future or over a period of time. There is also a market for imbalances. The top-up and spill regime allows system shortfalls and surpluses to be managed. Usually, generators employ contracts to handle their price risk in the electricity market. Fuel purchasing using forward contracts helps to ensure individual security of supply and can generally offer more favourable pricing terms than relying on a spot market alone. Moving forward, the CER wishes to alter these trading arrangements such that electricity would be bought and sold in a "gross pool". This would be a centralised trading market. All physical power could be traded for the market as a whole, using uniform prices and a spot market. Bid prices submitted by generators would therefore include as much or as little of the true cost per MWhr as they wish. They may or may not include the full per unit O&M cost. Generators could still contract outside of the market. In addition to physical contracts, generators also use financial contracts to hedge the price of fuel. Interpreting these contracts as a form of guarantee on a generators cost stream, implies that if the same could be done for the revenue stream, it could reduce the price of risk and thus electricity, and be very attractive for generators.

Competition by generators ensures the cheapest price for electricity since each firm competes to supply each MWhr at its lowest possible price. The fuel cost in the model represents this price. Since all stations receive the price offered by the marginal station, there is still the possibility that a generator may cover its O&M costs, even if it did not specifically allow for them in the bid price. With the lowest possible price, the cost of fuel, the risk of not covering O&M costs depends on the type of generation, but there is a high risk of not meeting capital repayment obligations for all forms of generation. For this reason, the SRMC bid-scenario is only likely to transpire if some form of surety were offered on a generator's revenue stream, such as a capacity payment.

If large losses were to be observed, investment in new generation would be stifled. Therefore this is not an option. Thus, there are only two feasible solutions, normal profits or supernormal profits. Normal profits would refer to the case where all costs (fuel, O&M, annual capital repayments) are covered in the long run and the generator makes a small return for entrepreneurship. In this case, the market would only attract additional generation when it was profitable. Supernormal profits refers to all costs covered in the long run, however, some/all generators make large profits, such that the market attracts significant new investment. For price to return to a competitive level, a considerable amount of plant would have to be built, such that, the cost of this expansion would put the consumer at a further disadvantage, regardless of whether it was warranted on system security grounds.

## 4.2 The difference between the SRMC and MRMC bidding strategies

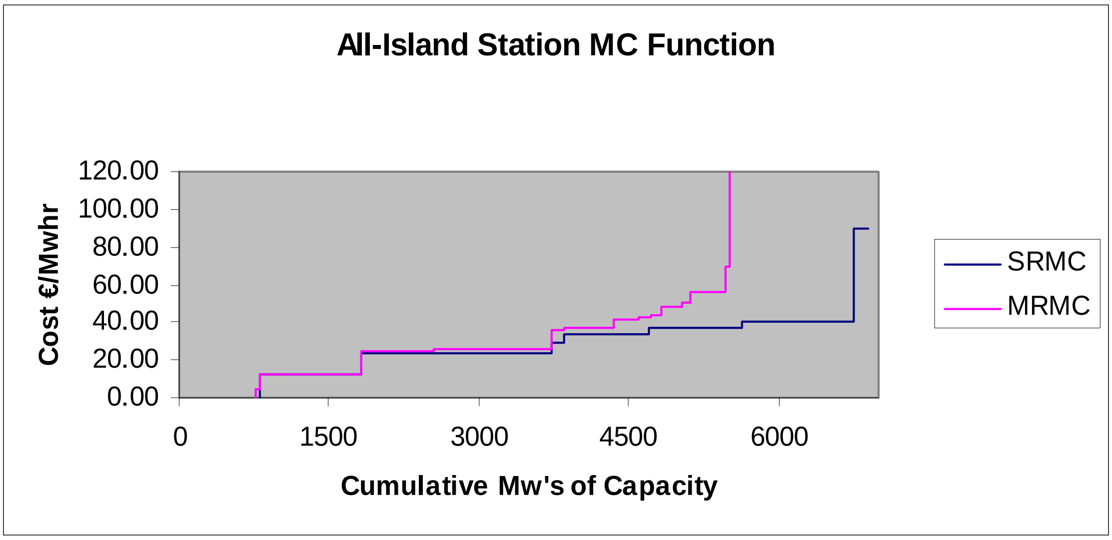


Figure 4.1: All-Island Station Marginal Cost Function

Figure 3 shows the deviation between the two different bidding strategies and demonstrates the basic principal of any bidding structure, that as demand for electricity increases, the price will also increase. The Station Marginal Cost Function shows how many megawatts can be purchased for up to a certain price. The diagram illustrates that under both bidding strategies, a small amount of power can be purchased at zero marginal cost. This output represents the renewable energy available, such as wind and hydro. Another 1,000 MW’s approximately can be bought for just less than €20 per MW. As the market gets closer to full capacity, the deviation between the two bidding strategies becomes more apparent. This arises because the peaking stations are bidding a much higher price per MWhr that to enable them to recoup their true variable costs.

If the generator had a choice between the two bidding mechanisms, short-run costs or medium-run costs, they would choose the strategy that offered the lowest risk and/or the highest return and/or the greatest freedom to act independently. Any one of those circumstances would be more closely associated with the MRMC bid price since it leaves the final decision in the hands of the generator. In addition, companies with multiple generators have a greater opportunity to take advantage of cross-subsidisation between stations and between times in the day. Stations will profit maximise regardless of the bidding structure, however, they would prefer to profit maximise using the MRMC bid price as it leaves a greater range of possible values that can be employed for extracting returns from the market. Nonetheless, from the regulators perspective, the first step should to ensure that the welfare of the consumer is maximised by the choice of strategy.

## 4.3 Effects of the SRMC bidding strategy

It has already been said that the energy industry is highly capital-intensive and can also have high maintenance costs. Consider according to their SRMC.

| | **RoI** | **All-Island** |
|---|---|---|
| Time Weighted Ave. Price[23] | € 34.43 | € 32.50 |
| Op. Profit[24] / Loss[25] Per MW Stations | 33% / 67% | 23% / 77% |
| Per MW Average | - €133.32 | - € 240.01 |
| ESB Per MW Average | - €171.95 | - € 305.75 |
| Non-ESB Per MW Average | €15.71 | € 13.57 |

Table 4.2: Table of Results for each market under the SRMC bidding structure

Table 4.2 illustrates that increased choice and intensified competition in an All-Island energy market, results in a reduction in the time weighted average price of producing

[23] Time weighted average price of one MWhr of electricity.
[24] Operational Loss = Where Total Revenue minus Total Cost (fuel and O&M) for a station is divided by the number of hours that the station generates, and the result is negative. Cannot cover its day-to-day costs of fuel and O&M and cannot make any contribution towards capital repayments.

[25] Operational Profit = Where Total Revenue minus Total Cost (fuel and O&M) for a station is divided by the number of hours that the station generates, and the result is positive. Can cover its day-to-day costs of fuel and O&M and can make some contribution towards capital repayments.

a MWhr of electricity. More efficient stations are being chosen to supply electricity, which reduces the cost of producing that power. This result is not dependent on which bidding structure under review and the same result, that is, a reduction in cost from increasing market size, is also observed for the MRMC bid-price strategy. Furthermore, from a social perspective, emissions are reduced.

The reduction in the cost of electricity production to the economy means that consumers are better off, however, this implies that generators are earning less. The average price of producing one MWhr of electricity has been reduced from €34.43 to €32.50 and therefore more stations are finding it harder to make ends meet. Consequently, the number of stations making an operational loss per MW rises from 67% to 77% in the Republic of Ireland and All-Island systems respectively, as the severity of these average losses also increases from €133.32 per MW to €240.01 per MW.

Most individual generators (both public and private) incur losses, with deficits rising to equal their complete[26] O&M cost for the year for stations that produce little or no electricity[27]. Most baseload plants make positive returns, with Moneypoint making the most operating profits. Baseload plant has the lowest per MWhr fuel cost of all fossil fuelled generation, since it generates a constant flow of electricity. These stations recoup enough on each unit to cover at least their day-to-day costs. Mid-merit stations are normally less efficient than baseload, and therefore, have higher marginal costs and lower operational profit. Some of these stations would see their operating profits go from positive to negative in the face of an All-Island market. Peaking stations that might only generate for a small number of hours in the year incur the biggest losses since their price is capped at €2,000 plus their fuel cost. Renewables[28] incur zero fuel cost and thus make an operational profit, but their high fixed costs have not yet been taken into account. Under current conditions, generators would be happier to operate with the SRMC bid price in the Republic of Ireland market since their operating profits are, on average, €106 per MW higher.

[26] Total Revenue minus Total Cost (fuel and O&M).
[27] Stations such as Lanesboro, Shannonbridge & Bellacorrick.
[28]In relation to small-scale independent renewables such as Wind, CHP, Biomass, Hydro – these independents have been grouped together for ease of modelling.

The ESB currently owns 73% of all generation in the Republic of Ireland and although it might be expected that the ESB's results for the above table would be more favourable, this is not the case. Due to an older portfolio of plant, the ESB had some stations operational in 2003 that might have cost a lot more per MW than the revenue they generated. These stations are old, oil-fired peaking stations that have become uncompetitive and therefore ran for very few hours in the year, but still had to cover O&M costs. Furthermore, even without including these stations, the ESB's figures were on average, 27% lower than the above economy-wide average. Also, the average change to ESB's earnings per MW was 3% lower, at 69% loss per MW, when moving from a Republic of Ireland market to an All-Island market.

In 2003, there are also several independent power producers (IPP's) operational in the Republic - Huntstown, Dublin Bay and Edenderry. Some have larger parent companies[29] and others are single-plant generators. Edenderry is the only independent station to make an operating loss[30] in the Republic of Ireland market. It is, however, the recipient of a Public Service Obligation (PSO) subsidy[31]. A PSO is similar to a grant for types of energy, such as renewables and peat, which would not be economically viable without some form of financial support. Each consumer pays an extra percentage on their bill to cover these extra costs (until such a time that they are no longer required). Most independent generators in the Republic of Ireland market operate at baseload, such as Viridian (Huntstown) and Dublin Bay. The modelling suggests that these stations make a small surplus that can contribute to capital costs.

The fact that these baseload IPP's can make only a small surplus highlights the level of uncertainty faced by investors in the Irish market. Investors understand that if all players bid in the smallest feasible amount[32], by force or freewill, only the cheapest baseload stations would recoup enough to cover day-to-day costs and make a small contribution to capital debts. This outlook is confirmed by the fact that baseload has

[29] Energia is the parent company of Viridian, Edenderry is owned by Finnish energy supplier Fortum
[30] Cannot cover its day-to-day costs of fuel and O&M and cannot make any contribution towards capital repayments.
[31] A detailed explanation of the purpose and workings of a PSO can be found at http://www.esbie.ie/energy_in_business/your_bill.html#PSOLevy.
[32] Assumed to be the fuel cost.

naturally attracted new competition. The CER has sought tenders for new generators in the baseload and peaking plant[33] divisions of the market.

## 4.4 Effects of the MRMC bidding strategy

In modelling the electricity system, the theory of producer surplus becomes much more apparent. It is the plants that can offer electricity cheapest that make the most money before capital remuneration. Although, it must be noted that these stations could also have the largest capital debts.

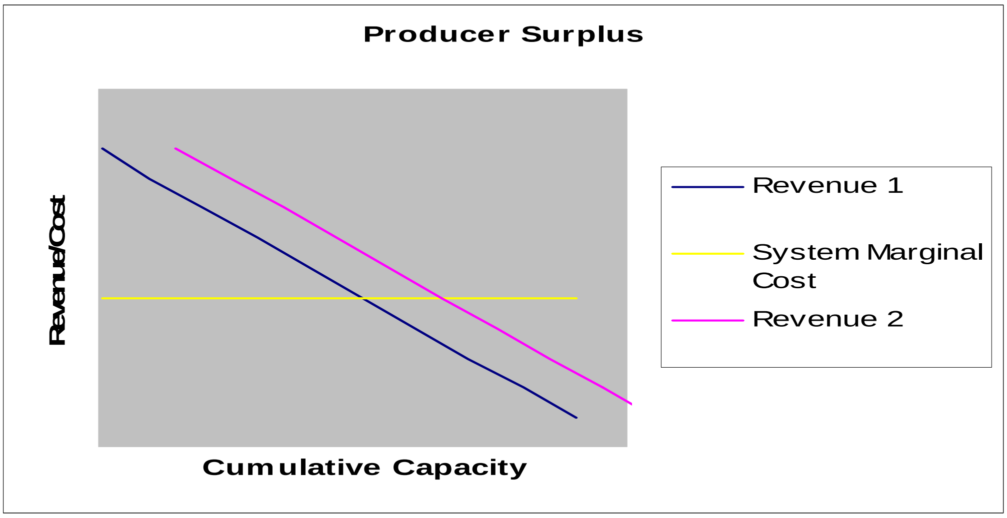


Figure 4.3: Theoretical Diagram of Producer Surplus[34]

Figure 4.3 shows that in each half-hour segment, the price setting station (system marginal cost line) determines who generates and how much surplus each station will make. Generating stations that can offer electricity at the cheapest prices, usually baseload plant, will make the most money. This corresponds to the top left of the Revenue 1 line, near the Y-axis. As the line descends towards the point of equilibrium, more mid-merit stations are in use and revenues are declining with respect to costs. Assuming that the marginal station bids in its cost for that period, it is the only station to just break even.

[33] Peaking plants would only be required for the most energy intensive hours in the day, usually around lunchtime. They would also use a fuel source and generator that allowed them to turn the station on and off rapidly, e.g. Diesel generators.
[34] Producer surplus is the excess of revenue over cost.

The concept of producer surplus makes it easy to see that there is a multiplier effect on the revenues to generators in energy markets. Consider again the marginal station that bids in its MRMC. It is bidding in enough such that it will recover its own medium-term per unit cost and will break even. This is acceptable, but the effect of this becomes inflated revenues for other generators, which would push the Revenue 1 line out to Revenue 2, where more can be earned for each MW. So, not only is the baseload station receiving the difference between the per unit fuel costs of the two generators (difference in SRMC bids), but it is also receiving the difference in the per unit O&M costs, which could be significant given that a baseload station would have one of the lowest per unit O&M costs. The number of units sold then multiplies this figure.

Mathematically, this could be considered as follows;

Recall that Operational Profit/Loss was defined as:

$$STP_i = \left( \sum_{j=1}^{17,520} (SP_j \text{ x } IC_{i,j}) - \sum_{j=1}^{17,520} (p_{i,j} \text{ x } IC_{i,j}) \right) - C_i$$

where i = 1,…,58 (number of stations).

j = 1,…,17520 (number of 30 minute periods in a 365-day year)

SP = System price (price offered by marginal station)

IC = Individual Capacity that each station produces in each period

p = Price offered by each station

Assume station X is a baseload generator, then the following is generally true;
*Baseload Bid Price < Mid-Merit Bid Price < Peaking Station Bid Price.*

Assuming that station X's bid price is equal to it medium-run marginal cost (MRMC), Then it is also true that both "SP" and "p" are made up of two elements; a fuel cost and an O&M cost.

Regardless of whether the price setting station is a Mid-merit or Peaking plant, on average both the fuel cost and O&M cost of the baseload generator will be equivalent or less than the costs of the marginal station. For example, comparing a baseload CCGT plant with a peaking plant oil generator and taking generator efficiencies into account, the per MWhr cost of oil is greater than that of gas[35]. A CCGT plant runs almost continuously compared to the peaking station that is only required for a small number of hours in the year, and so, the per unit O&M cost of a CCGT generator is much lower than that of the peaking plant.

Let $SP = SP^f + SP^o$ and $p = p^f + p^o$, where f = fuel and o = O&M

The Operational Profit/Loss figure under the SRMC bidding strategy is given by the differences in the fuel costs only;

$$STP_i = \left( \sum_{j=1}^{17,520} (SP^f_j \text{ x } IC_{i,j}) - \sum_{j=1}^{17,520} (p^f_{i,j} \text{ x } IC_{i,j}) \right) - C_i$$

Whereas, the Operational Profit/Loss figure under the MRMC bidding strategy is given by the differences in the fuel costs plus the differences in the respective O&M costs also;

$$STP_i = STP^f_i + STP^o_i - C_i$$

Where

$$STP^f_i = \left( \sum_{j=1}^{17,520} (SP^f_j \text{ x } IC_{i,j}) - \sum_{j=1}^{17,520} (p^f_{i,j} \text{ x } IC_{i,j}) \right)$$

$$STP^o_i = \left( \sum_{j=1}^{17,520} (SP^o_j \text{ x } IC_{i,j}) - \sum_{j=1}^{17,520} (p^o_{i,j} \text{ x } IC_{i,j}) \right)$$

Modelling the system using MRMC bids confirms this effect since total revenue on electricity production increases five fold in the Republic of Ireland model simulation and the Time Weighted Average Price in the Republic of Ireland increases from €34.43 to €162.12 under the SRMC/MRMC strategies respectively. Grossly inflated surpluses at a huge cost to the economy are observed for most generators. These excessive surpluses are more than adequate to cover any capital debts for all but the peaking stations.

[35] The marginal cost of fuel per MWhr is equal to the fuel price per MW divided by the efficiency of the generator.

| | **RoI** | **All-Island** |
|---|---|---|
| Op. Profit[36]/ Loss[37] Per MW Stations | 86% / 14% | 86% / 14% |
| Per MW Average | € 135.17 | € 192.10 |
| ESB Per MW Average | € 143.26 | € 222.41 |
| Non-ESB Per MW Average | € 103.97 | € 75.19 |

Table 4.4: Table of Results for each market under the MRMC bidding structure

Table 4.4 shows the comparative figures for the MRMC scenario with respect to average earnings. There has been a large reduction in the number of stations with operational losses. The remaining 14% are the old peaking stations that were referred to earlier as operating for very few hours in the year and restricted by the bid price threshold. Comparing average earnings and the relative changes in those earnings becomes more difficult as some stations make gains from increasing the market size, such as peaking stations that benefit from the new load profile. However, the fact that increasing the market size does not increase the number of stations earning an operational loss per MW, indicates that the operating profits must be sizeable, since they would certainly be diminished by the increased competition offered by the All-Island market.

## 4.5 Recovery of capital costs

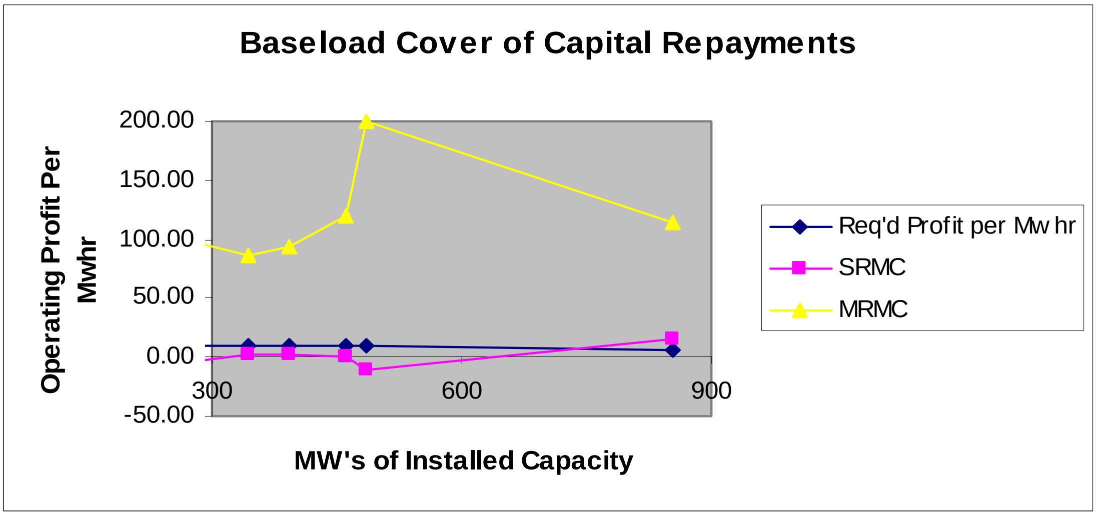


Figure 4.5: All-Island Baseload coverage of Capital Repayments

[36] Operating Profit. See footnote no. 28.
[37] Operating Loss. See footnote no. 27.

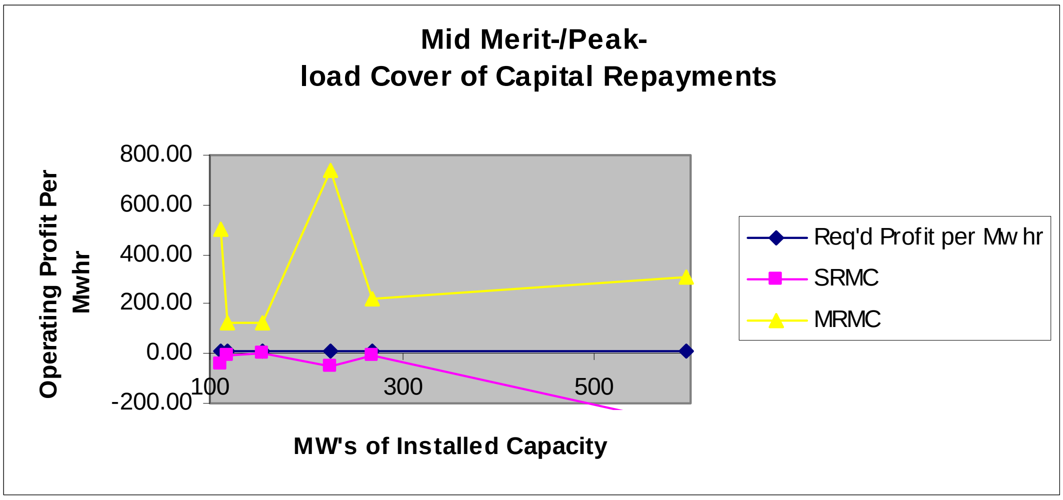


Figure 4.6: All-Island Mid-Merit/Peak load coverage of Capital Repayments

Each point in figures 4.5 and 4.6 represents a station. So, a station with an installed capacity of 300MW's would have corresponding markers in a vertical line to the 300MW spot on the X-axis representing capacity (not cumulative). The lines "SRMC" and "MRMC" represent the level of operational profit achieved by each generator under the respective scenarios and the line named, " Required Op. Profit per MWhr", gives the level of operating surplus per MWhr that is needed to recover a station's capital debts. From the diagram it is easy to see that with the SRMC bid price, most stations do not cover their debts, with the exception of a few generating stations that make a surplus. But there can be no doubt that the MRMC provides a return to generators that covers their capital costs and still leaves supernormal surpluses. Take the Great Island generators as an example, which are represented in total by the fourth point of each line in Figure 6(b). According to the graph, Great Island falls short of capital repayments by over €60 per MWhr with the SRMC bid price and exceeds its requirement by over €700 per MWhr with the MRMC bid price.

<u>4.6 An interesting implication of our simulations arises for the case of wind energy</u>

At present, another important point of concern for system operators and policymakers is the effect of the connection of additional wind to the system. The grid operator must ensure the reliability of the system at all times and this can prove difficult when variability in the level of wind energy is high. On the other hand, policymakers would like to see more wind energy, and renewables in general, on the system since wind and other renewables can offer security of supply by hedging the risk of fossil fuel price shocks. Generally speaking, renewables incur no costs other than its initial investment cost, which is usually high. In the case of wind energy, coupling this with its low level of availability means that the investor requires a return of approximately €45/MWhr to make the project viable. This is not a certainty in the energy market and so the government is supporting wind in the market through the Public Service Obligation. As expected, the model confirms that the return on wind is not sufficient to meet capital repayments. The per MW subsidies that would be required for wind to be commercially viable are as follows;

| | **RoI** | **All-Island** |
|---|---|---|
| **SRMC** | € 19.23 | € 20.91 |
| **MRMC** | € 7.85 | €10.25 |

Table 4.7: Subsidies Required For Wind

## 4.7 Economic effects of the bid-price strategy

Table 4.8 displays a table of the most salient results from our model simulations. Please note that all amounts are recorded in millions with the exception of Time Weighted Average price per MWhr, which is recorded in euros.

| | **RoI** | | | **All-Island** | |
|---|---|---|---|---|---|
| | ***SRMC*** | ***MRMC*** | | ***SRMC*** | ***MRMC*** |
| **Time Weighted Ave. Price/MWhr** | € 34.43 | €162.12 | | € 32.50 | € 115.07 |
| **Total Revenue** | € 862.33 | € 4060.05 | | € 1093.45 | € 3871.27 |
| **Total Cost** | € 488.92 | € 645.50 | | € 565.40 | € 696.53 |
| **Total Fuel Cost** | € 488.92 | € 489.98 | | € 565.40 | € 565.40 |
| **Total Operating Profit**[38] | € 108.05 | € 3149.20 | | € 197.27 | € 2843.96 |

Table 4.8: Results of Different Bidding Strategies under Different Market Structures

[38] Total Operating Profit = (Total Revenue minus Total Fuel Cost) minus O&M Costs

First of all, it is apparent from the table that overall, an All-Island market is extremely beneficial to the Republic of Ireland. Costs are lower than under a "stand-alone" Republic of Ireland market under both the short-run and medium-run bid-price scenarios.

The most notable feature of the table, however, is the difference in the Time Weighted Average Price. On average, it would cost almost five times as much to produce one MWhr of electricity with the MRMC bidding strategy than with the SRMC bid price in the Republic of Ireland, but only four times as much in the All-Island market. So, regardless of the market structure, the Time Weighted Average Price is more than tripled under the MRMC bid-price. The Total Revenues associated with each strategy and market also reflects these multiples.

Total Cost under the SRMC bid-price in each market represents only the cost of fuel, whereas Total Cost under the MRMC bid-price includes the total increases for all bid-prices such that they allowed all generators to break-even. These increases were considered to stand for some level of variable costs. The row "Total Fuel Cost" re-iterates the fuel cost for the SRMC strategy and includes the fuel cost for the MRMC strategy, highlighting any difference. No major changes to the merit order in the All-Island market indicate that the dispatch of plant is equally efficient under the two strategies. However, the Republic of Ireland figure indicates that the real increase in the cost of fuel from a less efficient dispatch is just over € 1 million per annum. This amount is model dependent and in actual fact could be larger since, unlike the real world, the model's bid prices cannot change from period to period. The difference arises because more costly generators are chosen to produce when there are more efficient stations available. The difference lies in the change that these bids make to the merit order dispatch (cheapest first, dearest last) and subsequently to the Station MC Function.

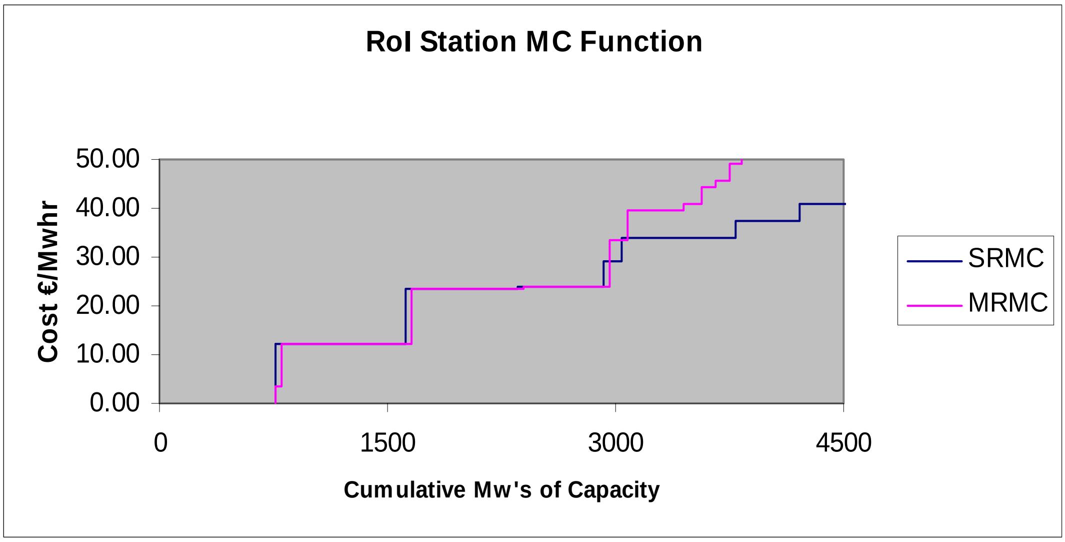


Figure 4.9: Republic of Ireland Station Marginal Cost Function

The large increases in bid prices only begin to occur in mid-merit stations and as the system gets closer to full available capacity, these variations over and above the fuel price reach their largest, with a cap on the bid price of €2,000 plus fuel/MWhr. Figure 4.9 highlights the difference between the two types of bidding strategies in the Republic of Ireland and illustrates that the changes in the bidding strategy do not cause any major differences in prices until the merit order reaches 3,000 cumulative MW's of capacity. The price then begins to rise more sharply in the MRMC bid scenario. It is worth bearing in mind that the graph only shows the relationship up to €50 per MW, whereas prices associated with the MRMC curve actually rise far higher and reach the pre-determined cap of €2,000 per MW plus fuel cost.

The disparity between the two strategies is more evident in the Republic of Ireland and one suggested reason for this could relate to how close the two systems are to full capacity. In 2003, the state of affairs in the two systems is very different; the South is in a position of under-capacity whilst the North has sufficient spare capacity and is exporting some electricity across the border. In a state of under-capacity, a system operator would need to employ nearly all of the available generation in the country and will therefore have to travel much further down the merit order of generators' bids. The last station on the list would be the most expensive and if it were deployed to produce energy all other stations would make significant gains. If this happened on a regular basis, it could have serious cost implications for the consumer.

The final row of Table 4.8, Total Operating Profit, illustrates again the multiplier effect of increasing costs/bid-prices under the MRMC strategy. Since, consider that in the Republic of Ireland market, when the multiplier between SRMC TWAP and MRMC TWAP is nearly five and costs are as low as possible, the multiplier on Operating Profits between the two strategies is nearly thirty. This number is reduced to fourteen in an All-Island market.

The process of rewarding inefficiency makes it harder to identify efficient dispatch and abuse of market power, as these inflated operating profits are better able to absorb losses. For instance, suppose that a generator bids in their MRMC cost. This price includes some or all of their O&M costs. Suppose also that, due to overstaffing, these day-to-day running costs are above the competitive level and could be considered inefficient. By including these costs in the bid price, not only does the company itself benefit from its own or any other company's inefficiency, but it is the consumer who pays. What is needed is a transparent bidding process, which makes it easier to detect firms who are using the market to pay for their inefficiencies.

It is accepted that, under the SRMC strategy, not all generators can cover their day-to-day costs. It is then worth comparing the following;

| | **RoI** | | | **All-Island** | |
|---|---|---|---|---|---|
| | ***SRMC*** | ***MRMC*** | | ***SRMC*** | ***MRMC*** |
| **Total Losses To Cover Costs** | € 100.28 | | | € 125.58 | |
| **New Total Revenue**[39] | € 962.61 | € 4060.05 | | € 1219.03 | € 3871.27 |
| **New Total Op. Profit**[37] | € 208.33 | € 3149.20 | | € 322.85 | € 2843.96 |

Note: All amounts are in millions

Table 4.10: Cost of Covering Variable Costs in Each Market

The first row of Table 4.10, "Total Losses To Cover Costs" highlights the total losses of all generators under the SRMC bidding structure in each market; €100.28m and €125.58m in the Republic of Ireland and All-Island markets respectively. These figures are the total O&M losses of all individual stations. They do not include

[39] Losses only added on to the SRMC Revenue and Surplus since this is the only loss-making scenario

remuneration of capital. If these figures are added to the SRMC Total Revenue and Total Operating Profit of all generators in the economy, then all stations are capable of at least covering their fuel and O&M costs. A comparison can be drawn since both strategies now ensure that all medium-term costs are covered. The final row of Table 4.10, New Total Operating Profit, shows that although the SRMC strategy only allows some generators to make a total contribution of approximately € 200m towards their capital repayments, it is possible to have a system that can support its own day-to-day costs for a fraction of the cost when compared with the MRMC situation, where all costs are extorted from the pool. The difference between the two is sizeable and therefore the cost to the economy could be substantial. Since if the aim is to produce energy at minimum cost to consumers, whilst also ensuring the viability of the companies producing the energy, the MRMC bidding strategy could be a massive overestimation, considering that a guarantee that all costs are covered in the long run could also be adequately provided by a payment for capacity mechanism.

Each bidding mechanism proposes a different possible equilibrium for the Irish electricity market. Neither strategy is dynamically stable, as they do not ensure that the right price signals are sent to the market to produce a realistic and efficient mix of generating technologies, nor do they tell a story that is likely to hold in the long run. The SRMC scenario without support for capital remuneration, suggests a market where day-to-day losses will result in a deficient level of investment that will not ensure future security of supply. While the large operating profits attainable using the MRMC bid price structure imply that a significant level of over-investment would occur in the years shortly following this static equilibrium, mostly in the baseload sector since this form of generation earns the most operating profits. This situation would come at a considerable cost to consumers since the adjustment process could take a very long time, leaving the time Weighted Average Price very high.

Lastly, in considering the two forms of bidding strategies, the nominal amounts of cost/revenue/operating profit are not as important as the relative difference between the SRMC and MRMC results. Contrasting the two as in Figure 10, reveals that it is possible to create a secure and transparent bidding-system with efficiency as the central premise. Consideration of a time dimension is also central to the investigation. Although the long run is not explicitly covered in this paper, the MRMC scenario can be considered a possible theoretical long-run situation since it would give rise to new investment that would only be realised in the long run, given that the time it takes to commission and build a new station is three to five years.

# SECTION 5: ASSESSING MARKET POWER & DOMINANCE

At present, the electricity market in the Republic of Ireland consists of one major player (the ESB) and a few substantially smaller players. The concern in the Republic of Ireland at the moment is that perceived dominance by ESB could discourage investment and lead to excessive prices. For the purposes of measuring the market power of the ESB and other industry participants, the model incorporates two exogenous indices, Herfindahl-Hirschman Index (HHI) and Residual Supply Index (RSI)[40], and one endogenous index, Price Setting Ability (PSA)[41].

## 5.1 Market Power Indices

The HHI is the sum of squares of market shares of all firms in the market[42]. If the HHI is in excess of 1,800, the market is generally considered highly concentrated and suppliers having an equivalent market share are believed to have potential market power. Both the number of firms and differences in their relative size influences the HHI.

In standard commodity markets, market concentration and market power are linked such that they are almost one and the same, but in electricity markets, this is not the case. The HHI does not take account of factors such as demand inflexibility and transmission limits that sometimes result in excessive market power (Sheffrin *et al*, 2004). Consequently, using only a static measure, such as the HHI, to calculate what is inherently a dynamic concept would not be optimal.

The RSI is defined as the ratio of residual supply to demand, for an individual supplier S,

$$RSI_S = (\textit{Total Available Supply} - \textit{Available Supply from Supplier S}) / \textit{Demand}$$

[40] See "Watching Watts To Prevent Abuse of Power" by Sheffrin, Chen & Hobbs – IEEE Magazine July/August 2004.
[41] PSA is a percentage indicating in how many half hour periods a station sets the system price.
[42] The total market share of independents was divided by the number of independent outlets and then squared and aggregated - all independents are assumed to be of equal size.

"The RSI measures how pivotal suppliers may be in setting prices based on the residual supply left, without their capacity, to serve demand. A supplier is deemed "pivotal" if it can withdraw its capacity from the market and induce a shortage" (Sheffrin *et al*, 2004). This tool was initially created to assess the Californian electricity crisis of 2000/2001.

"When a supplier is pivotal, its $RSI_S$ is less than 1.0 and the potential for market power abuse is most serious. When a supplier is not pivotal, the $RSI_S$ is greater than 1.0 and the supplier does not have absolute market power … The experience in California showed that when one or more $RSI_S$'s were below 1.2, there was significant market power. Only when all $RSI_S$'s were above 1.2 was there sufficient competition in the market place" (Sheffrin *et al*, 2004).

The RSI is a continuous metric and thus we can compute a RSI value for each period and for each supplier. However, for the purposes of this paper averages over the year have been calculated and the Sheffrin *et al* standard of 1.2 will be employed, against which all RSI results will be measured. The RSI is influenced by the size of the company but also by the reserve margin/tightness of the market.

The Price Setting Ability (PSA) of each generator refers to the percentage of periods in the year that each generator sets the price. It is apparent that a multi-generator company with some baseload and mid-merit plant has a better opportunity of setting the price, and thus the price paid to all generators, than a single-station company. In practice, either a baseload or mid-merit generator usually sets the price.

## 5.2 Market power indices for the ESB[43]

Six years ago, the ESB was a monopolist. Now, the company must compete with new more efficient generators whilst retaining its obligation as "seller of last resort". Tables 5.1 and 5.2 present ESB's market position, including estimates of its market power, for the SRMC and MRMC bidding strategies in respect of the "stand alone" RoI market structure and the hypothecated All-Island structure respectively.

[43] Synergen is not considered part of the ESB portfolio in any results for the ESB for this section.

| | SRMC | MRMC |
|---|---|---|
| Price Setting Ability | 91% | 91% |
| % Generation | 73% | 73% |
| % MW Generated | 64% | 64% |
| Ave. Utilisation | 35% | 36% |
| Operating Profit | € 36.12 m | € 2,306.97 m |
| RSI Ave. | 0.39 | 0.39 |
| HHI (RoI Market) | 5,309 | 5,347 |

Table 5.1: ESB's market position in the "stand alone" Republic of Ireland market

The ESB holds 73% of physical capacity, but in terms of actual megawatts generated this figure drops to 64%. The state-owned company has stated that it is committed to reducing its market share to 60% of all megawatts generated[44]. It is clear that the ESB is approaching this target. The HHI for the Republic of Ireland market is very high (5,309) and the RSI for the ESB (0.39) is only one third of what has been taken to represent a competitive market (1.2). In addition, an ESB plant sets the price 91% of the time during the year and with this ability comes the possibility of increasing the price even further.

The assessment for the ESB in a Republic of Ireland market must then be that it retains significant market power through its large portfolio of plant. The picture in the Republic of Ireland is similar regardless of the bidding strategy employed. The level of market power associated with each company under each bidding structure, expressed in terms of the RSI, is effectively the same since it solely depends on the amount of generation owned by a particular company and the level of demand. Nevertheless, the model does highlight the importance of ownership of baseload and mid-merit plant in a company's ability to set the price. Focussing on Moneypoint, it is easy to see that ownership of this 855MW[45] plant brings with it much power. Moneypoint is a baseload coal-fired station that generates roughly one third of all the energy produced in the Republic of Ireland. Even if the ESB owned only Moneypoint, they might still be considered to have a good deal of market power since industry

[44] See ESB Press Release No. 145
[45] Export capacity

participants may fear the outcome of a sudden breakdown of one or all of the three generating units on the site.

Table 5.2 demonstrates that moving to an All-Island integrated system reduces ESB's hold on the market.

| | **SRMC** | **MRMC** |
|---|---|---|
| Price Setting Ability | 67% | 73% |
| % Generation | 58% | 58% |
| % MW Generated | 45% | 44% |
| Ave. Utilisation | 30% | 31% |
| Operating Profit | € 5.35 m | € 4,420.73 m |
| RSI Ave. | 0.66 | 0.66 |
| HHI (Total All-Island Market) | 3,513 | 3,513 |

Table 5.2: ESB's market position in the All-Island Market

It is evident that the ESB's market share would be significantly reduced. The HHI and RSI have been halved and doubled respectively. Moreover, the ESB's price setting capability would have reduced to 67%-73%. The conclusion must therefore be that an All-Island system would greatly assist in addressing the dominance issue. However, it would not be enough.

## 5.3 The exercise of market power

In electricity markets there are generally two ways to increase the price paid to all generators. The direct method involves one/all generator(s) raising their bid-price. If only one generator raises its price, the only way that it can increase the price paid to all generators is, if it is the price setting station. This form of market power is hard to predict, as it is hard to pinpoint the exact level of demand required in a period and the bids of other generators. However, if a company owns many generators, it can increase the bid-price of all its generating units and subsequently increase its chances of increasing its revenues, or, generators could collude with one another to agree that each generator will raise its bid by a certain amount, therefore raising the system marginal price for all stations. The indirect method uses outages to disguise strategic unavailability. By claiming that a station is unavailable, a generator forces the System Operator further down the price-increasing merit order. This tactic ensures that all generators receive a higher payment per MW than would be secured if all operational generators were available. Only companies with a portfolio of generators would find it worthwhile to exploit this indirect course of action. It is also possible to combine both the direct and indirect methods by withholding a station from the market and simultaneously raising the price of the company's other generating units.

The possible outcomes associated with the direct method and a combination of the direct and indirect method, are endless since they are dependant on the prices involved and the size of the output that is withheld. For this reason, only the effects of withholding capacity from the market, holding everything else constant, can be examined with any transparency.

Table 5.3 illustrates the "withholding gains" for the ESB, that arise if it were to shut down some of its most marginal stations[46], in a Republic of Ireland market with a SRMC bid price strategy. This will be compared to the 2003 general base case of all generating stations being fully operational. In the table the base situation regarding costs and operating profits is set equal to 1.00

| Withdrawn generator | | **ESB** | **Edenderry** | **Dublin Bay** | **Viridian** | **Wind** | **Economy** | **PSA[47] of ESB** |
|---|---|---|---|---|---|---|---|---|
| **Aghada** | ***Total Cost*** | 1.01 | 1.00 | 1.00 | 1.00 | 1.00 | 1.01 | 1.02 |
| | ***Total Op. Profit*** | 1.37 | 1.33 | 1.59 | 1.71 | 1.03 | 1.21 | |
| **Poolbeg CCGT[48]** | ***Total Cost*** | 1.05 | 1.12 | 1.00 | 1.00 | 1.00 | 1.04 | 0.95 |
| | ***Total Op. Profit*** | 1.20 | 1.45 | 2.10 | 2.32 | 1.07 | 1.22 | |

[46] ESB plants which set the system price most often
[47] Price Setting Ability – % of periods in the year that an ESB station sets the System Marginal Price.
[48] Only 1 unit of Poolbeg CCGT is switched off i.e. 1 x 230MW plant

Table 5.3: Gains from withdrawing a station from the RoI market under the SRMC bidding strategy, relative to the base = 1.00

It must be mentioned that stations were withdrawn for the entire year to avoid any other factors contributing to the effect, such as time of year and scheduled outages by other larger stations. The stations chosen are of medium size; Aghada and Poolbeg CCGT are 258 MW's and 230 MW's respectively. So the system operator would have to go a good deal further down the merit order to make up for their withdrawal from the market. This in turn causes the cost to the economy and operating profits of the generators to rise.

Taking Aghada as an example; if the ESB switched off Aghada, their costs would increase by 1% since stations further down the merit order in their portfolio would be contracted to generate by the System Operator. However, this increase in costs would be more than offset by the 37% increase in operating profit that they would receive from having more expensive stations setting the system marginal price. Stations that are already working to full capacity such as Edenderry, Dublin Bay and Viridian, would see no increase in their costs but their operating profit would rise by 33%, 59% and 71% respectively. These figures also impact on the economy, where total cost to the economy would increase by 1% but overall total operating profit in the industry would increase by 21%. Finally, in relation to the parallel effects under the MRMC bid price, it is only worth mentioning that the increases associated wit the SRMC scenario are tiny in comparison.

## 5.4 Divestiture of generating assets

Economic theory suggests that four or five independent players in an oligopolistic market should be sufficient to prevent any player abusing its position. To test this assumption on the Irish electricity industry, an arbitrary method[49] was devised by which the ESB was broken up into smaller companies. These groups were tested for market power using the technique applied to the 2003 base case. The groups are then

[49] 1. ESB stations placed in groups based on site location.
2. All corresponding data summed together to give relevant data based on site
3. Rank sites by most to least profitable
4. Using this order, the plants are split into three, four and five companies.

tested for the effects of the strategic withholding of supply and their ability to set price, as well as compiling the associated market indices such as the HHI and RSI.

In view of the fact that the All-Island market contributes to the reduction of market power[50], only All-Island groups are considered here. As an example, the table below shows the ESB[51] split into three companies in an All-Island economy;

| **G1** | **G2** | **G3** |
|---|---|---|
| Moneypoint | Poolbeg CCGT | Poolbeg Steam |
| Aghada | Aghada CT | Ardnacrusha |
| Erne | Great Island | Marina |
| North Wall | Lee | Clady |
| Liffey | Coolkeragh | Tarbert |

Table 5.4: Assumed divestiture of ESB assets

| | **G1** | **G2** | **G3** |
|---|---|---|---|
| **RSI** | 1.2 | 1.32 | 1.29 |
| **% PSA** | 0.13 | 0.32 | 0.28 |
| **% Generation** | 0.23 | 0.16 | 0.19 |
| **Market HHI** | 1,300 | | |

Table 5.5: Market power outcomes following divestiture of the ESB's generating assets (All-Island market structure assumed)

These indices are consistent with the requirements for a competitive industry. All RSI figures are at or above the required 1.2 level, indicating that no one company is pivotal in the supply of energy. Group 2 sets the system price most often, 32% of the time. Summing the above % PSA's[52] highlights the fact that independents are setting the price 27% of the time. No one player is cornering the market and the HHI is below the required level of 1,800. Thus it seems that with three independent, roughly equally sized companies, that have a diverse portfolio, a competitive situation might exist.

[50] See Table 5.2.
[51] Shannonbridge, Lanesboro & Bellacorrick are always part of the ESB portfolio since they are due to be retired shortly after 2003 and would not be for sale. G1 will be considered to represent ESB for this purpose.
[52] Price Setting Ability – % of periods in the year that an ESB station sets the System Marginal Price.

It is accepted that, first, the results may be highly dependent on the way in which the groups were fashioned and second, the analysis is static and at best provides an underestimate of the competitive effects since we can expect technical and economic efficiencies to follow divestiture. However, considering these figures by way of assumption can only involve comparing the possible cost reductions due to divestiture with the possible savings credited to economies of scale.

## 5.5 The effect of withholding of supply under divestiture

Both the SRMC and MRMC pricing structures will be examined here with respect to the withholding of capacity from the market. The effects of withholding stations from the market are considered from two perspectives;

- If a company turns off one of its own stations, will its operating profits increase?
- If a company turns off one of its own stations, will it set the price more often?

If divestiture is successful and offers a first-best solution, the answer to both of these questions should be no. There should be a reduction in the company's operating profits and its ability to set price. This would ensure that there is no incentive to strategically withhold capacity from the market.

Using the SRMC prices gives the most efficient dispatch for generation and will therefore give the most economical answers. Thus, these outcomes will be used as the base case with which to compare the answers of the MRMC price strategy.

PRICE: SRMC

| | **G1** | | **G2** | | **G3** | |
|---|---|---|---|---|---|---|
| | Op. Profit | % PSA | Op. Profit | % PSA | Op. Profit | % PSA |
| **Group 1**[53] | **(-)** | **(-)** | (+) | (-) | (+) | (+) |
| **Group 2**[54] | (+) | (+) | **(-)** | **(-)** | (+) | (+) |
| **Group 3**[55] | (+) | (+) | (+) | (-) | **(-)** | **(-)** |

[53] Moneypoint was chosen from Group 1 for both SRMC and MRMC.
[54] Poolbeg CCGT (1 unit) was chosen from Group 2 for both SRMC and MRMC.

Table 5.6: Effects of abuse of market power on operating profits and price setting ability under divestiture, using SRMC prices.

Table 5.6 gives the results to the questions for the newly divested companies, under the SRMC bid price scenario. The first two columns of Figure 19 refer to the effects on Group 1, when each Group turns off one particular station in its portfolio. For example, if Group2[56] turns off Aghada, Group 1's Operating Profits will increase for two possible reasons; now a higher priced station is setting the system marginal price and/or more of Group 1's stations are required since Group 2's available capacity has been reduced. However, the interesting point relates to the effects of Group 2's strategic unavailability on itself. Not only will Group 2 lose money but it will also lose some of its power to set the price. This is also the case for Group 1 and 3 when one of their own stations is suddenly unavailable. This illustrates that it is possible to have a market where there is no incentive to game or exert market power. This approach makes the regulators job easier since the process is more transparent.

From Table 5.7 it is clear that this level of transparency is not obtainable with the MRMC bid structure under the same circumstances. The common result of a double-minus ((-),(-)) has been replaced mainly with a plus followed by a minus ((+),(-)). This means that under the MRMC bid, if a Group turns off one of its stations, although it will lose some of its price setting ability (-) it will make money (+). This is represented by an increase in its operating profits. This result is due to the inflationary effects of the MRMC bid, caused by the differences in the bidding prices. Therefore, under an MRMC bidding strategy, a second best solution may only be possible ((+),(-)). Even though Table 5.7 gives a second-best solution, ((+),(-)), the result could also be plus-plus ((+),(+)). This would indicate that it would be advantageous for Group 1 to switch off a station as it would increase Group 1's operating profit and the amount of times that it sets that system marginal price. This result is in no way desirable since it would encourage companies to game the market.

[55] Poolbeg Steam (1 unit) was chosen from Group 3 for both SRMC and MRMC.
[56] The stations chosen are the most marginal in each group, with the exception of Moneypoint, which was chosen for its significance.

PRICE: MRMC

| | **G1** | | **G2** | | **G3** | |
|---|---|---|---|---|---|---|
| | Op. Profit | % PSA | Op. Profit | % PSA | Op. Profit | % PSA |
| **Group 1** | **(+)** | **(+)** | (+) | (-) | (+) | (+) |
| **Group 2** | (+) | (+) | **(+)** | **(-)** | (+) | (+) |
| **Group 3** | (+) | (+) | (+) | (+) | **(+)** | **(-)** |

Table 5.7: Effects of abuse of market power on operating profits and price setting ability under divestiture, using MRMC prices.

# SECTION 6: CONCLUSIONS

We focus on three areas in drawing conclusions from our analysis

- An integrated All-island market structure versus the *status quo*
- SRMC versus MRMC bid-price strategies
- Divestiture of ESB generating assets

## 6.1 All-Island market structure option

The results of modelling both the bid structure and numeric indices representing market power, with respect to the Republic of Ireland and All-Island market, suggest that the All-Island energy market is a worthwhile initiative. This conclusion is based on figures that show that the new All-Island market would reduce the total cost of electricity production to the economy by at least 6%[57], which should result in lower prices to consumers. It is also worth noting that the All-Island market would offer improved security of supply[58]. With regard to the issue of dominance, the model estimates that the ESB's market share will be reduced to approximately 45% of all MW's generated[59], although they will retain almost 60% of physical capacity in the market. The Ballylumford generators in Northern Ireland play a vital role in these conclusions since together, they reduce the ESB's market share by 11% and the ESB's price setting ability by 21% - 27%. However, the solution regarding the specific design of the electricity market and the bid-price strategy is more complicated.

## 6.2 The preferred bid-price strategies?

If the goal is to produce electricity at least cost in a market where transparency exists for regulators and investors alike, then the SRMC bid structure is clearly preferred according to our simulations. This conclusion emerges because of the inherent

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[57] 6% difference in SRMC TWAP's / 29% difference in MRMC TWAP's
[58] For a detailed understanding of this topic, see "Generation Adequacy in an Island Electricity System", J. FitzGerald, ESRI Working Paper No. 161.
[59] Based on 2003 demand and station availability.

deficiencies in the MRMC strategy itself, but also because of the merits of the market characteristics that the SRMC strategy produces.

The MRMC bidding strategy makes available to generators the opportunity to recoup all forms of cost through the market. This formulation does not aid in the determination of “least cost” since less efficient stations are not openly penalised for their inefficiencies. This is left at the discretion of market participants, who can choose to act competitively and reduce the price until it reaches a competitive level, or, keep prices artificially high to the benefit of all generators. Either, all generators opt to keep bid-prices at a level such they cover at least their medium-run costs and all stations benefit equally. This is what the model has shown. Or on the other hand, since each generator knows that it could run for a lower bid-price in the short-run, generators may decide to undercut the MRMC price to ensure production. This form of competition would eventually results in the SRMC outcome. Essentially, without a benchmark cost that creates a competitive environment under which, all participants can compete equally, the market is more unstable than is necessary, and could possibly reach a point of equilibrium identical to the benchmark cost case.

The model demonstrates that a market with a SRMC bid-price structure would not be sufficient to allow generators to recover all of their costs. Some generators make enough to make a small contribution to capital remuneration, but some cannot even cover day-to-day O&M costs. This market is not sustainable and so additional mechanism(s) and/or incentive(s) would be required to ensure that each station could cover its costs in the long run. For example, using a capacity payment to affect market participants’ decisions would help to establish the appropriate environment by introducing a higher degree of certainty for generators and investors. However, the SRMC does succeed in producing a market at least cost. So coupling this with a capacity mechanism would help ensure a least cost competitive portfolio of plant for the economy. In addition, the SRMC bid structure also demonstrates that it is possible to have an outcome with little or no incentive to game and where abuse of a position can be identified and hence regulated. Therefore, a market based on the SRMC bid structure would facilitate regulation since it brings greater transparency to the cost structure and therefore increases the likelihood of identifying abuse of market power.

The extremity of the outcomes suggested by the alternative bid structures will, in some way create unstable equilibria. The SRMC structure will see problems incentivising new entry, as operating profits are minimal. Neither of these sub-optimal solutions is secure in the long-run, however, it is harder to recover from the MRMC outcome than it is to create a competitive mix of generation using the SRMC concept as the basis.

In essence, it is not the absolute level of costs that is worrying, but rather the effects on the economy of the ease with which it is possible for a generator to inflate their bid-price and thus conceal cost-based inefficiencies, if they are not tied to some benchmark cost. The conclusion must therefore be that the SRMC scenario offers the economy the best chance of providing a fair, least cost and secure electricity market, but only if this pricing system recognises that there must be support by means of some form of capacity payment.

## 6.3 Divestiture of ESB generating assets

Divestiture of ESB generators into smaller companies is considered by many to be the only way to ensure greater competition in the market. The model indicates that the ESB's dominance in the market at present is very strong, but, splitting ESB Generation into a minimum of three separate companies[60], would yield results consistent with a competitive market. Whether this route should be embarked on is open to several questions, many of which are outside the scope of this paper to consider. However, it will be helpful to consider some of the likely benefits and drawbacks of divestiture, as well as, looking at some of the alternatives.

Divestiture is likely to be a costly endeavour. Care would have to be taken when applying structural reform. In the production of electricity several resources are shared across generators within the same company and duplication of these services will prove to be expensive. In addition, some areas of the system may suffer from transmission inadequacy and be less attractive to investors, or, labour unions could make the situation even more complex. For these, and many other reasons, successful structural reform would be both difficult and costly. As against this, one would expect

[60] Using 2003 data and prices.

both technical and economic efficiency gains subsequent to divestiture, which could go some considerable way towards offsetting the costs that are likely to be involved.

There are a number of alternatives to the divestiture option considered here. We could instead allow the market to evolve which would permit the nascent competitive forces to assume a greater importance. As an exercise to illustrate the implications of what is effectively a “wait and see strategy” we use the model to simulate the outcomes for levels of concentration in the All-Island market for 2007 and 2010[61], if no divestiture takes place;

| | **Year** | **ESB[62]** | **Viridian [63]** | **Ballylumford** | **Kilroot** | **Indepts[64]** |
|---|---|---|---|---|---|---|
| **% PSA** | 2007 | 0.40 | 0.16 | 0.21 | 0.00 | 0.25 |
| | 2010 | 0.39 | 0.18 | 0.19 | 0.01 | 0.23 |
| **% Generation** | 2007 | 0.46 | 0.08 | 0.09 | 0.02 | 0.42 |
| | 2010 | 0.43 | 0.07 | 0.08 | 0.02 | 0.39 |
| **% Generated** | 2007 | 0.37 | 0.12 | 0.06 | 0.03 | 0.53 |
| | 2010 | 0.33 | 0.10 | 0.05 | 0.03 | 0.49 |
| **RSI (ave.)** | 2007 | 0.92 | 1.60 | 1.58 | 1.70 | |
| | 2010 | 0.96 | 1.57 | 1.55 | 1.66 | |
| **Market HHI** | 2007 | | | | | 2,332 |
| | 2010 | | | | | 2,053 |

Table 6.1: Indicators of electricity market concentration, 2007 and 2010 for the All-Island market scenario

While it is apparent that the market could still be considered highly concentrated in 2007 and 2010, there is nevertheless an appreciable improvement in the indices of market power. Moreover, the combined market share of Independent Power Producers (IPP’s) is growing. This is due to entry by new and existing IPP’s and increasing levels of renewables on the system. This simulation suggests that a strategy of “wait and see” may have some merit over a one-shot divestiture of the ESB’s generating assets.

[61] Using 2003 prices.
[62] Coolkeragh CCGT is part of the ESB portfolio, whereas Synergen is not considered part of the ESB portfolio.
[63] Huntstown 2 presumed operational by 2007.
[64] Includes Interconnector of 500 MW’s in 2007 and 1000 MW’s in 2010.

It is evident, however, that the ESB will still retain considerable market power by 2007 or 2010, as judged, for example by the RSI, which is much lower for the ESB than for its multi-generator competitors. It will be useful, therefore, to consider a more modest divestiture of its assets. For instance, in Table 6.2 we consider the impact on the market for electricity in an All-Island context by 2010 of divesting the ESB of approximately 500 MW's of price-setting capacity.

| | **ESB**[65] | **Viridian** [66] | **Ballylumford** | **Kilroot** | **Indepts**[67] |
|---|---|---|---|---|---|
| **% PSA** | 0.32 | 0.18 | 0.19 | 0.01 | 0.30 |
| **% Generation** | 0.39 | 0.07 | 0.08 | 0.02 | 0.43 |
| **% Generated** | 0.29 | 0.10 | 0.05 | 0.03 | 0.52 |
| **RSI (ave.)** | 1.01 | 1.57 | 1.55 | 1.66 | |
| **Market HHI** | | | | | 1,793 |

Table 6.2: Projected All-Island Market Concentration in 2010 where ESB has shed some price setting capacity

The simulation confirms that if the ESB were to shed approximately 500 MW of price-setting capacity, this together with the adoption of a "wait and see" strategy – would be likely to result in a competitive outcome by 2010. The resulting RSI of 1.04, although below the advised rate of 1.2, is not dependant on the type of generation sold and so taking into consideration that the stations being considered for divestiture often set the system marginal price, in terms of market power, the conclusion must be more favourable than the original 1.04. Even if not, the outcome illustrates that limited/targeted divestment is a credible alternative to complete divestment. This more gradual model of structural reform evidently takes much longer to achieve than a "one-shot" divestiture of the ESB assets, but it may prove more attractive to all involved, as it ensures stability in a core part of business activity for all consumers of electricity in the economy. It is worth noting that a similar outcome could also be achieved if one or more of the existing IPP's increased their market share.

[65] Coolkeragh CCGT is part of the ESB portfolio, whereas Synergen is not considered part of the ESB portfolio.
[66] Huntstown 2 presumed operational by 2007.
[67] Includes Interconnector of 1000 MW's in 2010 and the 500 MW's of capacity shed by the ESB to the Independent Sector.

Interconnection plays a key role in the above results. It is anticipated that by 2010, a second East-West interconnector will provide an additional 500MW of capacity. In an All-Island market this would mean a total of 1,000 MW's of interconnection to the U.K. Since the Irish market is relatively small compared to mainland Europe, it is possible that at some stage the Irish market may become part of the electricity market in Great Britain. This would come about if sufficient interconnection between the two islands meant that the cheapest price in the Irish market was actually the price of electricity delivered from the UK via the interconnector.

Since our model excludes the possibility of scale economies or "learning by doing" cost reductions, we overestimate the costs and underestimate the operating profits of any multi-plant company. The sub-additivity aspect of the cost function with respect to shared resources, however, cannot be overlooked. Taking this into consideration, it may seem that the ESB has extra benefits and reasons to hold onto older plant, but one must remember that although some independent generators may have only one station in Ireland, they too may belong to a bigger worldwide portfolio that can pool resources across countries or at least between their stations within a country. However, even if no actual scale economies are achieved, a company's ability to buy electricity or fuel in bulk, for security or discounting purposes, is based on its portfolio capacity. When buying fuel, small-scale generators are disadvantaged since they cannot contract to buy forward at the same rate as the multiplant company.

There may be lessons to be learned in this regard from the U.K. experience with the liberalisation of the gas and electricity markets. So far the UK has experienced problems relating to divestiture, given that the industry has witnessed the re-integration of many of the companies that were originally divested by region. When the Central Electricity Generating Board (CEGB) was divested in 1990, ownership of the transmission division, National Grid Company passed to twelve regional distribution companies (REC's) that were also created. Following this, these REC's were privatised. However, the Government retained the "golden share" in these companies to prevent any takeovers. In 1995 the Government sold its remaining shares. Acquisitions occurred in the form of mergers and many REC's integrated with U.K. generators to form vertically integrated companies. There is no doubt that some of these decisions were motivated by the benefits associated with economies of scale.

Besides this, many liberalised electricity industries have experienced problems relating to new investment in electricity generation. For instance, new entrants have mainly built baseload plant.

Finally, all markets depend on the life cycle of the commodity.  The product cycle in electricity industries relies on the life cycle of the generating asset, which is usually thirty years. As a result, decisions should be made with consideration for this timeframe. Applying this to the problem of ESB dominance in ownership of mid-merit plant means that this problem is partly time dependent. In other words, with careful planning of new investment and ownership, this problem could be reduced if not eliminated. Thus, in trying to ensure an outcome that is close to a competitive market structure and to reinforce the confidence of putative investors, there is much to be said for building on the dynamic that is in place.

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## APPENDIX 1:
## An Overview of the Market for Electricity in Ireland

The provision of electricity to an island, isolated and on the periphery of Europe can be difficult. Both parts of the island, North and South, have their own electricity system and are connected via one interconnector. Northern Ireland is further connected to Great Britain via another interconnector and the Republic of Ireland is considering the construction of an interconnector from the Republic to Great Britain. Previous to deregulation, the State in the Republic of Ireland and in Northern Ireland, was responsible for the provision of electricity in the respective countries. Electricity was provided by two state-owned monopolies, the Electricity Supply Board (ESB) in the South and Northern Ireland Electricity (NIE) in Northern Ireland. These companies had sole responsibility for all aspects of electricity production; transmission, generation and distribution.

In the 1980's the British Government slowly began opening up the energy market and other state monopolies to competition. In March 1991 the British Government published a White Paper entitled "Privatisation of Northern Ireland Electricity" and in June 1993 Northern Ireland Electricity was floated on the stock market[68]. Great Britain was one of the first countries to pioneer this and the European Union (EU) shortly followed suit. In December 1996, all EU countries adopted the European Community energy Directive 96/92/EC. In the Republic of Ireland, the European Electricity Directive was enacted through the Electricity Regulation Act 1999. This Act established an "independent body responsible for regulating and overseeing the liberalisation of Ireland's energy sector" to be known as the Commission for Energy Regulation (CER).

The CER – the Regulator – is responsible for the licensing of all electricity generation and transmission, whilst also ensuring free and fair access to the national transmission and distribution systems, as well as regulating charges for such access[69]. The Regulator also enforces Directive 96/92, which addresses the opening up of the Irish

[68] For a more detailed discussion see - ESRI PRS No.24 (Ch.3): "Electricity Privatisation: The Northern Ireland Experience", by Michael McGurnaghan.
[69] Taken from the CER website at http://www.cer.ie/about_us.asp.

electricity market to competition. In the Republic, the aim is to reduce the incumbents' (that is, the ESB's) market share to sixty percent[70] and also to allow non-domestic and domestic customers to choose their supplier by 2005 and 2007 respectively[71]. Since this process began much sooner in Northern Ireland, similar but not identical functions are performed by the Office for the Regulation of Electricity and Gas (OFREG), which is part of the Northern Ireland Authority for Energy Regulation (NIAER).

Prior to the changes imposed by the EU, the Electricity Supply Board (ESB) controlled one hundred percent of the consumer market and almost one hundred percent of electricity generation in the Republic of Ireland[72]. "ESB National Grid", "ESB Power Generation" and "ESB Customer Supply" were the respective divisions within the ESB accountable for transmission, generation and distribution. Following the EU Directive it became necessary for these three departments to become separate legal entities[73]. In Northern Ireland different companies perform these functions. The "System Operator of Northern Ireland (SONI)" is responsible for transmission and three generating companies have the right to produce electricity. The distribution of electricity differs slightly to that operating in the Republic of Ireland. "NIE Supply" is obliged under the terms of its licence to source its electricity from generators under contract to NIE's "Power Procurement Business (NIE PPB)"[74]. NIE Supply enters into short-, medium- and long-term contracts with the generators to supply electricity. These contracts are not statutory in the Republic. With regard to the actual distribution of electricity to customers, the two systems are similar. For example, if a consumer is large enough, it is possible to choose a supplier within its respective market.

Moving to a competitive market implies that governments will no longer be able to directly control such issues as type and location of generation. Yet it is still their responsibility to secure supply and ensure environmental targets are met. At present,

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[70] See ESB Press Release No. 145
[71] See ESB Press Release No. 108
[72] See Electricity Market Addresses Deregulation and Capacity Constraints at http://strategis.ic.gc.ca/epic/internet/inimr-ri.nsf/en/gr-81131e.html.
[73] For a brief overview of the ESB see http://www.esb.ie/main/about_esb/index.jsp.
[74] Market Opening in the North, brief overview by OFREG at http://ofreg.nics.gov.uk/Electicity%20Market%20Background.htm.

both electricity systems are at different stages of deregulation but looking forward, the problems they face are identical. Combining the two systems would give a larger single market where trading could be carried out systematically rather than opportunistically to take advantage of price differentials or congestion problems. The potential benefits from an integrated electricity system would include more competitive, secure and sustainable energy supplies. Both governments and regulators have cooperated extensively on an All-Island wholesale electricity market, and have produced a document outlining the development framework[75]. It is anticipated that the All-Island market will be fully functional by 2010.

[75] See "All-Island Energy Market Development Framework" accessible at www.dcmnr.ie

# APPENDIX 2

# A Formal Exposition of the Electricity Supply Model

## 2.1 Model variables

$i = 1,\ldots,58$ = number of generating stations

$j = 1,\ldots,17520$ = number of 30 minute supply periods in a year

$P_i$ : Price of fuel per MWhr (coal, oil, gas, peat)

$IP_j$ : Interconnector Price of electricity

- Sell price of electricity in great Britain
- Import price of electricity

$E_i$ : Station Efficiency (of technology)

- Affects the amount of fuel required by the station in order to produce electricity (in-house fuel requirement)
- High efficiency infers low in-house fuel requirement

$p_i$ : $P_i / E_i$ = price of fuel per MWhr

$\mathbf{p_{i,j}}$ :This column vector is repeated for every time period and altered such that the last row of $p_{i,j}$ is the $IP_j$ row vector of interconnector electricity prices

$C_i$ : Station Operation and Maintenance Costs

$\mathbf{CP_{i,j}}$ : Station Capacity: This column vector is repeated for every time period

$A_i$ : Station Availability

- A station is not available for 100% of the year
- (1 – x%) = time set aside for planned/scheduled maintenance

$D_j$ : System Demand

- the amount of electricity the is required in the Republic of Ireland, or, on an All-Island basis ( RoI + NI ) for each 30 minute period of 2003

T : Threshold

- a ceiling on the final price per MWhr
- limited to €2,000 + $p_i$

SF : Scale Factor

- facilitates studying future year such as 2007 or 2010
- load profile is assumed to remain unchanged

$A_{i,x}$ : Day Constraints

- Binary matrix: 0/1 = station Off/On for every 30 minute period of each day
- $A_i$ of hydro stations are also taken account of here

$B_{i,y}$ : Year Constraints

- Binary matrix: 0/1 = station Off/On for every day in the year
- $A_i$ of all stations with the exception of hydro stations taken account of here

$O_{i,j}$ : On Or Off

- Using $A_{i,x}$ and $B_{i,y}$
- Indicates whether each station is available or not for every 30 minute period of the year

$OP_i$ : Operational Cost per MWhr

- Vector created but remains empty until the end of the first iteration.
- Allows for an increase in $p_i$ if losses occur at the end of each iteration

2.2 Model computational process

$CC_{i,j}$ : Constrained Capacity
$SC_{i,j}$ : Summed/Cumulative Capacity
$TC_j$ : Total Capacity
$PC_{i,j}$ : Production Capacity
$RC_j$ : Residual Capacity
$IC_{i,j}$ : Individual Capacity
$SP_j$ : System Price

2.3 Model outputs

In each 30-minute supply period, the Model can compute

$RV_{i,j}$ : Revenue
$CT_{i,j}$ : Cost

For each station in the year, the Model can compute

$STG_i$ : Total electricity generated

$STR_i$ : Total Revenue

$STC_i$ : Total Cost

$STS_i$ : Total Surplus = total revenue minus total cost

$STP_i$ : Total Operating Profit = total surplus minus O&M costs

For the relevant market (or economy) in the year, the Model can compute

ETG : Total Generated

ETR : Total Revenue

ETC : Total Cost

ETS : Total Surplus

ETP : Total Operating Profit

For each MWhr that is produced by each generating station, the Model can compute

$RPM_i$ : Revenue per MWhr

$CPM_i$ : Cost per MWhr

$OPM_i$ : Operation and Maintenance Cost per MWhr

$PPM_i$ : Operating Profit per MWhr

$SU_i$ : Station Utilisation

## 2.4 An overview of how the model works

The most important variables in the model are the following

$p_{i,j}$ : matrix (58x17520) of bid-prices

$CP_{i,j}$ : matrix of capacities

$O_{i,j}$ : matrix of availabilities

$D_j$ : row vector of required system demand

The first and most significant component of the model is the simple stack model characteristic of supply in electricity markets. Put simply, this requires sorting $p_i$ for each j, such that the lowest price is first and the highest price is last. So within each time period (j), stations are ranked in ascending order, with the cheapest generator being first and the dearest last. Then for each j, the following is true;

$$P_{1,j} < P_{2,j} < P_{3,j} < P_{4,j} < \ldots \qquad \forall j \qquad (1)$$

Next, it is necessary to cross-reference the availability of a station with its capacity. This gives a vector for each j, indicating the Constrained Capacity that each station is capable of producing

$$CC_{i,j} = O_{i,j} \text{ x } CP_{i,j} \qquad (2)$$

It is important to note that all relevant station information must be in the same order. We then use the ranking for each j of $p_{i,j}$, obtained from the sort, and project it onto each j of $CC_{i,j}$.

The second part of the program uses binary relational operators of “greater than” and “less than” to identify all the generating stations that will be required to generate electricity such that supply is exactly equal to demand.

For each j, the Model creates the Cumulative Capacity vector, $SC_{i,j}$, associated with each j of $CC_{i,j}$. Then the following is true;

$$SC_{i,j} < SC_{i+1,j} \qquad \forall j \qquad (3)$$

Next, compare the system demand, $D_j$, with the cumulative capacity vector $SC_{i,j}$ for each j.

$$D_j > / < SC_{i,j} = 1 / 0 \qquad (4)$$

The binary matrix (Y) identifies all stations required by the System Operator, up to and including the “Marginal Station”, that is the last station required that is required to generate, which usually does not operate to its full capacity.

By multiplying $Y_{i,j}$ by $CP_{i,j}$ we can calculate many other important pieces of information.

The amount of electricity that each station will be requested to produce in each time period, with the exception of the marginal station, is given by the Production Capacity

$$PC_{i,j} = Y \text{ x } CP_{i,j} \qquad (5)$$

Labelling Total Capacity for each j, $TC_j$, as the sum to the second last non-zero figure of each column of $PC_{i,j}$, we can identify the Residual Capacity that must be produced by the marginal station in each period

$$RC_j = D_j - TC_j \qquad (6)$$

So, the Individual Capacity that each station must produce in each period is given by;

$$IC_{i,j} = RC_{i,j} + PC_{i,j} \qquad (7)$$

Finally, the System Price, $SP_j$, corresponds to the $p_{i,j}$ offered by the Marginal Station foe each j.

Before calculating various output variables, it is necessary to re-assemble the stations in their correct order.

In each period

- A station's revenue is; $RV_{i,j} = SP_j \text{ x } IC_{i,j}$ (8)
- A station's cost is; $CT_{i,j} = p_{i,j} \text{ x } IC_{i,j}$ (9)

For each station in the year

- Total electricity Generated is $STG_i = \sum_{j=1}^{17,520} IC_{i,j}$ (10)
- Total Revenue is $STR_i = \sum_{j=1}^{17,520} RV_{i,j}$ (11)
- Total Cost is $STC_i = \sum_{j=1}^{17,520} CT_{i,j}$ (12)
- Total Surplus is $STS_i = STR_i - STC_i$ (13)
- Total Operating Profit is $STP_i = STS_i - C_i$ (14)

For the market in the year

- Total Generated is $ETG_i = \sum_{i=1}^{58} STG_i$ (15)
- Total Revenue is $ETR_i = \sum_{i=1}^{58} STR_i$ (16)
- Total Cost is $ETC_i = \sum_{i=1}^{58} STC_i$ (17)
- Total Surplus is $ETS_i = \sum_{i=1}^{58} STS_i$ (18)
- Total Operating Profit is $ETS_i = \sum_{i=1}^{58} STP_i$ (19)

For each MWhr produced by each station

- Revenue per MWhr is $RPM_i = STR_i / STG_i$ (20)

- Cost per MWhr is $CPM_i = STC_i / STG_i$ (21)

- Operation & Maintenance Cost per MWhr is

  $OPM_i = C_i / STG_i$ (22)

- Operational Profit per MWhr is $PPM_i = STP_i / STG_i$ (23)

Each Station's Utilisation is given by; $SU_i = STG_i / (365 \times 24 \times CP_i)$ (24)