SEM Market Power & Liquidity

State of the Nation Review

An Information Paper

SEM-10-057

23rd August 2010

Contents

1. Introduction

1.1 Background

Since 1st November 2007 the Northern Ireland Authority for Utility Regulation (NIAUR) and the Commission for Energy Regulation (CER), together referred to as the Regulatory Authorities or RAs, have jointly regulated the all-Island wholesale electricity market known as the Single Electricity Market (SEM) covering both Northern Ireland and the Republic of Ireland.

The SEM includes a centralised gross pool (or spot) market which, given its mandatory nature for generators[1] and suppliers, is fully liquid. In this pool electricity is bought and sold through a market clearing mechanism, whereby generators bid in their Short Run Marginal Cost (SRMC) and receive the System Marginal Price (SMP) for each trading period for their scheduled dispatch quantities. Generators also receive separate payments for the provision of available generation capacity through a capacity payment mechanism, and constraint payments for differences between the market schedule and the system dispatch. Suppliers purchasing energy from the pool pay the SMP for each trading period along with capacity costs and system charges. The SEM rules are set out in detail in the Trading and Settlement Code (the TSC)[2].

In designing and developing the SEM in the lead-up to its go-live in November 2007, the RAs were aware of the fact that a key issue which needed to be addressed was the risk of the exercise of market power or abuse of dominance in the SEM. This was as a result of the existence of two large incumbent electricity groups on the island - ESB and Viridian - and their potential ability to exercise market power. In order to address this, the RAs decided that it was necessary to put in place a specific Market Power and Dominance Strategy as part of the regulation of the SEM. The market power mitigation measures are referred to in consultation AIP-SEM-02-06 [3] and decision AIP-SEM-31-0 [4] as well as consultation AIP/SEM/07/16[5] and decision SEM/304/07[6], as discussed in section 3 of this paper. Briefly, the measures are:

- Bidding principles for generators, i.e. a Bidding Code of Practice which states that generators must bid in the SRMC to the market;
- An RA Market Monitoring Unit to monitor adherence by generators to the bidding principles and to conduct market abuse investigations as needed;
- Directed Contracts (or DCs) to be offered to the market by incumbent generators with the potential to abuse market power, whose prices are based on the RAs' projected SMP in the SEM. DCs are forward contracts which help ensure that generators with market power do not have an underlying incentive to attempt to abuse their positions in the pool market. Together with other forms of forward contracts not directed by the RAs (see section 3), they also have the benefit of providing forward liquidity to the SEM by helping suppliers to manage the risk associated with movements in the SMP;

[1] Above 10 MW.
[2] Please see http://www.allislandproject.org/en/trading_and_settlement_code.aspx
[3] http://www.allislandproject.org/GetAttachment.aspx?id=5987ff76-0e0a-4d85-ad49-eb43dfe16dbf
[4] Please see http://www.allislandproject.org/en/market-power-decision.aspx?page=2&article=4cab0a1e-2e65-47a2-9585-67fca34ef586
[5] http://www.allislandproject.org/GetAttachment.aspx?id=e816446b-4653-4a9c-9522-ce528c727710
[6] http://www.allislandproject.org/GetAttachment.aspx?id=1f6c8708-b0a4-4db0-9afc-ce3722fc7aca

- Ring-fencing arrangements between affiliated generating and supply businesses within the ESB and Viridian groups, provided for in their licences. As part of these arrangements the RAs put in place for ESB Customer Supply (ESB CS) and NIE Energy Supply (NIE ES) an Economic Purchase Obligation (EPO) for them to purchase forward contracts in a manner that is economic, fair, transparent and non-discriminatory. Where regulated tariffs exist, without an EPO these suppliers could pay too much for contracts from their affiliates, resulting in their customers paying too much for their electricity and competition in the market being distorted; and,

- Local power mitigation measures, if deemed necessary.

1.2 Review of Market Power & Liquidity

On behalf of the SEM Committee[7], the RAs have committed to conducting a review of market power and contract liquidity within the SEM in 2010. The purpose of this Information Paper is to:

- Inform market participants of the scope of this review project and the timelines involved - see section 2;

- As the first part of this overall review project, inform market participants of the key findings from the RAs' "State of the Nation" review - see sections 3 and 4. This is a factual overview of:

  (A) The market power mitigation strategy adopted to date by the RAs; and,
  (B) The operation of the market since the inception of the SEM, particularly levels of market power in the spot and forward contract markets, as well as forward contract liquidity.

- Seek any initial ideas from market participants on the policy issues being examined as part of this review project. This includes initial thoughts that market participants may have in relation to a number of questions posed in section 2.3. This will then be considered by the RAs when developing a Consultation Paper on the matter (see section 2 for project timelines) for more detailed public responses and consideration.

- Comments from market participants in this regard are requested by 17:00 on **Monday 6th September** and should be sent to both Andrew Ebrill (aebrill@cer.ie) and Paul Bell (Paul.Bell@uregni.gov.uk).

[7] The SEM Committee is established in Ireland and Northern Ireland by virtue of Section 8A of the Electricity Regulation Act 1999 as inserted by Section 4 of the Electricity Regulation (Amendment) Act 2007, and Article 6 (1) of the Electricity (Single Wholesale Market) (Northern Ireland) Order 2007 respectively. The SEM Committee is a Committee of both CER and NIAUR (together the Regulatory Authorities) that, on behalf of the Regulatory Authorities, takes any decision as to the exercise of a relevant function of CER or NIAUR in relation to an SEM matter.

2. Scope *of* Project & Request for Comment

2.1 Project Aim

The overall aim of this market power and liquidity review project is to identify practical ways in which the RAs can further promote competition in the SEM by reducing/mitigating market power and/or improving contract liquidity over the course of the next 10 years. This includes a review of the performance of the market power mitigation measures in the context of experience to date and, looking forward, likely developments over the next 10 years which could alter market power. These developments include increased interconnection and new market participants (including, for example, wind generation). The project also examines measures which might be necessary to mitigate any potential adverse effects on market power and/or liquidity resulting from the various components of ESB's proposed re-integration.

2.2 Project Scope & Timelines

Scope

Following from the "State of the Nation" review in this Information Paper (see sections 3 and 4), as part of this review project the RAs will examine market power and liquidity in the SEM, both in the spot and contracts markets, taking into account that the SEM is a market with a gross mandatory pool and a capacity payment mechanism. In particular the review project will assess the following:

1. Identify the sources of market power in the SEM today together with methodologies to assess their potential effects

2. Review the degree and quality of liquidity in the SEM today and how liquidity might be dependent on the degree of market power.

3. Assess the likely changes to market power and/or liquidity in the SEM over the next 10 years resulting from (i) expected new entry and exits, and (ii) further interconnection.

4. Assess the effects in the SEM today on market power mitigation and/or the provision of liquidity, resulting from:

    a. The Bidding Code of Practice;
    b. DCs;
    c. Ring-fencing licence conditions on ESB affiliates and NIE affiliates; and
    d. The EPO on NIE ES and ESB CS (or any replacement measure following retail deregulation).

    Advise if any of the above measures should be relaxed or modified, over the course of the next 10 years, to better promote wholesale competition or the provision of forward contract liquidity and suggest any other measures (as applicable) to reduce market power and/or improve liquidity in the SEM.

5. ESB has proposed the removal of ring-fencing between its respective generation and supply businesses and their re-integration, both horizontal and vertical. This proposal is

currently under consideration by the SEM Committee[8]. By horizontal and vertical integration we refer to the integration of all ESB's generation and supply businesses into one unit, i.e. allowing ESB generation covering ESB Power Generation (PG) and ESB Independent Generation (IG) to integrate fully with a supply arm covering both ESB Customer Supply and ESBIE. This review will also assess the effects of the various components of the ESB integration proposal (including ESB's liquidity proposal) on market power, liquidity and wholesale competition in the SEM over the next 10 years.

6. Suggest other measures which should be employed to mitigate any adverse effects on market power and/or liquidity resulting from the various components of the ESB integration proposal.

Timelines

Taking on board comments received to this Information Paper, a Consultation Paper on the above issues will likely be published by the RAs in late September. A public workshop will likely be held during the consultation phase, to explain the paper and seek industry views. A decision is then expected in December.

2.3 Request for Comment

Comments from market participants on the policy issues being examined as part of this review project, including suggestions on how to promote liquidity and/or reduced market power, should be sent to the RAs by 17:00 on **Monday 6th September,** to both Andrew Ebrill (aebrill@cer.ie) and Paul Bell (Paul.Bell@uregni.gov.uk). This includes initial thoughts that market participants may have in relation to some or all of the following issues (which are in many cases discussed in section 3):

- How well are the market rules and monitoring arrangements working in terms of promoting contract liquidity, competition and market entry?

- Do SEM participants have the potential to exercise market power in the short and longer run? Please provide any evidence available.

- Do market participants face contract liquidity constraints? If so, how are these exhibited, what is their impact, and how could these impacts be addressed?

- How do you foresee the contracts market developing in the SEM, over the medium and long term?

- What are the costs and benefits of Directed Contracts (DC) as currently configured? How well does the current price setting mechanism of the DCs work in practice? Should alternative price setting mechanisms be considered and what would be the costs and benefits?

- Should the PSO-related contracts continue, taking account of the interests of the end customer?

[8] The SEM Committee minutes No. 25 state that "In relation to both the EPO condition on ESBCS and the ringfencing conditions between ESBCS and ESBIE, there was agreement that these conditions could be removed, subject to replacement by any new conditions which the SEMC may deem necessary to address wholesale market power or liquidity issues." And that any new conditions would be considered in this review of Market Power and Liquidity. See http://www.allislandproject.org/en/SEM_meeting_minutes.aspx?article=abc303f0-a541-4435-af58-fc654587d8a6

- In terms of liquidity and competition, what are the likely impacts on the SEM of the next interconnector and Ireland-UK market coupling?

- Are there locational constraints that could give rise to the potential to exercise market power? How is market entry best promoted where there is congestion?

- Is there a case to allow vertical or horizontal integration/re-integration of ESB? What would be the costs and benefits? What changes to market rules (especially market power mitigation measures), if any, should accompany further integration? These changes might either involve the relaxation of rules or addition to the rules. What other remedies should be considered?

- How would increased ESB integration impact the contracts market? If adverse impacts are anticipated, how would they be best mitigated?

- Are the current ring-fencing arrangements for ESB and Viridian adequate?

- Are there any other ways of addressing market power in the spot and/or contracts markets which you think should be considered?

Those respondents who would like certain sections of their responses to remain confidential should submit the relevant sections in an appendix marked confidential.

Please note that market participants will also have a further opportunity to comment on the matter when the detailed Consultation Paper is published.

3. State of the Nation Review - RA Policy to Date

3.1 Background

This “State of the Nation” review forms the first part of the market power and liquidity review project. Section 3 provides a factual overview of the market power mitigation strategy adopted to date by the RAs. Section 4 then provides information on the operation of the market since the inception of the SEM, including levels of market power in the spot and forward contract markets as well as forward contract liquidity.

3.2 SEM Market Power Definition & Measurement

3.2.1 Definition

Before examining market mitigation measures employed in the SEM, it is worth summarising what issues the RAs considered in relation to market power in the lead up to the SEM go-live in November 2007. Particular reference is made below to the RAs’ papers on market power mitigation in the SEM (consulted on in AIP/SEM/02/06 and decided on in AIP/SEM/31/06) and to papers which discussed the regulation of ESB and NIE in the SEM (consulted on in AIP/SEM/07/16 and decided on in AIP/SEM/304/07). A full list of relevant RA papers is provided in the Appendix to this paper.

There are many definitions of market power. Generally speaking, in developing the SEM, the RAs considered market power (see AIP/SEM/02/06) as the *capability* that a market participant has, acting independently, to consistently enhance its profitability by raising or reducing electricity prices in the all-island spot (wholesale) market from levels consistent with appropriate competition. Of course the market participant may or may not exercise that power - but the key issue is that it has the capability to do so.

The focus in AIP/SEM/02/06 and AIP/SEM 31/06 was on generator market power and its potential abuse in the spot market. In relation to the spot market, suppliers were not considered to have market power due to the market design which makes them price-takers, i.e. they pay the one SMP irrespective of their size in the market.

In entering into hedges such as financial contracts, the willingness of buyers to pay is based on expected spot market prices. If contracts are over-priced relative to the spot market, buyers can simply not purchase them and rely instead on the spot market. Hence, for the purpose of market power mitigation measures discussed in AIP/SEM/02/06, market power in the forward contract markets was primarily considered to be derived from market power in the spot market. It is for this reason that SEM market power concerns in AIP/SEM/02/06 were focused on the spot market. The EPO was designed to prevent market power abuse by a supplier in the forward contract market coming from the *supply* (or retail) market. This is discussed in section 3.8 of this paper.

The following were considered as key examples of the abuse of market power by generators in a spot market:

- Financial withholding: this is the practice of a generator bidding very high (i.e. higher than the unit would bid in an effectively competitive market) with the knowledge that there is likely to be little or no competition and having that bid set the market price;

- Physical withholding: this is the practice where a portfolio player can withhold some of their plant from the market, thereby driving up prices and revenue earned from the rest of their portfolio; and,

- Price suppression: this is broadly defined as pricing actions which reduce market prices either to yield long run profits by damaging current and future competitors, or to achieve other non profit-related goals.

These first two examples of spot market power abuse were considered to be the most common and of greatest potential in the SEM, and are discussed in more detail below.

Financial and physical withholding is a classic example of the exercise of market power by a generator in a spot market. Although these actions may reduce the profitability of the particular unit, the aggregate profitability of the other units under control of the bidder is enhanced by this action. Whether or not the net profitability is increased depends on the profits sacrificed at the particular unit, the increase in price achieved, and the quantity of other units generating to receive the higher price. In general, market power in electricity spot markets is exacerbated by the inelastic nature of demand in the short term. As demand is inelastic, generators who are not adequately constrained by supply competition can raise the spot price. Raising the spot price may well produce short run profits for generators and will also raise market expectations of future spot prices, thereby enhancing contract revenues. It is therefore essential that spot prices in the SEM be free of untoward market power both to control spot price and to ensure that competitively priced hedges (forward contracts) are available to suppliers in terms of forward products and contracts.

3.2.2 Market Concentration Metrics

The following measures of market concentration were considered by the RAs (in AIP/SEM/02/06) in developing a measure of market power for the SEM:

Installed Capacity

This looks at the market share of generating companies of the market by installed capacity and was considered a reasonable first-cut at the potential to abuse market power.

Residual Supply Index

The Residual Supply Index (RSI) measures the extent to which a generator's capacity is necessary to meeting demand after taking into account the capacity held by other suppliers.
The formula for the RSI is:

RSI = (Total Installed Capacity – Firm's Installed Capacity)/Total Demand

The California Independent System Operator (CAISO) first developed the RSI to measure the ability of a generating unit to set the prices and possibly abuse market power. The CAISO estimated that in general the RSI should not be less than 1.2 at the time of the peak, or less than 1.1 for more than 5% of the hours in a year. Thus, firms with an RSI of less than 1.2 are found to significantly influence the market price.

Price Setting Capability

Another indicator of market power is the ability of a firm to set the SMP of the market in a given half hour. If a firm can be certain of setting the SMP at certain times of the day or week, it may have the ability to bid in a price which is unreflective of their underlying costs.

Herfindahl-Hirschman Index

The Herfindahl-Hirschman Index (HHI) takes into account the relative size of the firms in the market. The HHI approaches zero when a market consists of a large number of firms of relatively equal size, while 10,000 is the maximum value and indicates a total monopoly. A market with a HHI between 1,000 and 1,800 would be considered to be moderately concentrated and above 1,800 indicates a significant potential for market power.
As discussed in section 3.7, this measure of market power was adopted by the RAs and used in relation to the provision of DCs as a market power mitigation measure. In particular the HHI was selected instead of the RSI as a measure of market concentration because:

1. It focuses on high market concentration throughout the price duration curve, while the RSI focuses only on the peak period (price spikes at times of scarcity), and is incapable of detecting potential for the exercise of market power in shoulder and off-peak periods;
2. The HHI is a more established and widely used index that has been applied to multiple industries; and,
3. The HHI measures competitiveness of an industry while the RSI measures only the power of the largest participant.

3.3 Features of SEM Which Deter Market Power Abuse

In developing specific regulatory mechanisms to mitigate market power and its abuse, the RAs were aware of the basic features of the SEM that already serve to mitigate market power. While the RAs recognised that given the high concentration of ownership of generation in the SEM, *specific* market power mitigation mechanisms would be needed (see next sections), they took account of the fact that there are significant features of the SEM, summarised below, which already help prevent the abuse of market power. It should be noted that these features were not designed primarily with market power mitigation in mind, but are rather inherent to the SEM.

Market Entry

Market entry is a deterrent to market power abuse in any market. That said, in electricity markets entry can take several years so it was not viewed as a sufficient stand-alone market power mitigation mechanism. Nonetheless, the potential for entry remains a powerful disciplining factor on the exercise of market power, especially given the SEM’s transparent pricing and signalling when new generation capacity is needed. The entry of new generators into the SEM since go-live is a demonstration of this.

Complex Bidding

The competitors in the SEM provide start-up, no load and minimal ramp costs, and the market software ensures that every plant running at least fulfils its stated bid costs. While this provision does not guarantee that marginal cost bidding for energy is optimal, it has two features which lower the possibility of the exercise of market power.

- First, participants will not have to intentionally skew their bids to get commitment and operational schedules to their liking, as happens in systems in which competitors bid only their energy prices and are required to modify these bids properly to commit themselves. Thus, for example, a generator who needs eight hours of operation to recover its start-up costs might have to bid well above its marginal costs in two or three peak hours to avoid the situation of being called on in those hours only and not making enough variable profit to recover its costs for the day.

- Second, since most of the complexity in bids is technical in nature, these parts of the bids would not be expected to change very often. Thus, the use of complex bids does serve an important monitoring function by allowing a focus on energy bids and attention to those times when other components of the bid change.

Single Daily Bids

Participants are allowed to bid only one energy price which covers an entire day, with the exception of interconnector users who bid in half hourly energy prices. This feature serves as a strong market power mitigation device. Hourly bidding allows participants to condition their bid on the expected level of load. Thus, a participant wishing to exert market power will, in general (when allowed to do so) bid higher when the supply-demand balance is tight than when it is slack. The single daily bid does not allow this conditioning, except through conditioning on the average expected load. But then high bids in one period will tend to lead to profits in the peak hours which are at least partially offset by losses in the off-peak hours, when the high bids force otherwise economic units out of merit. This is a strong mitigator in practical terms, particularly in systems with large diurnal variations in load.

Day-Ahead Gate Closing

Unit commitment is set day-ahead in the SEM. This mitigates market power by lessening the ability of competitors to condition bids on transient conditions that occur in real time. While it is certainly possible to anticipate a wide variety of next-day contingencies, one is less capable of doing so that one would be, say, four hours in advance. In general, uncertainty over demand or supply conditions weakens the ability to exercise market power by making it more difficult for the generator to precisely match its bid to system conditions.

It should be noted that the SEM Committee issued a decision[9] in March 2010 to implement arrangements for intra-day trading in the SEM, as required by Regulation (EC) 714/2009 (previously 1228/2003) on conditions for access to the network for cross-border exchanges in electricity. The SEM Committee Decision, determined that the RAs would bring a Modification to the TSC Modifications Committee to facilitate intra-day trading in the SEM and that a proposed means of intra-day trading should be brought to the SEM Committee by then end of 2010 to ensure intra-day trading in place in the SEM in advance of the commissioning of the East-West Interconnector in mid 2012. Accordingly, the TSC Modification Committee set up a Working Group on Intra Day Trading[10] that is currently proposing two additional gate closures for SEM generators and interconnectors users.

Capacity Payments

The current capacity scheme provides for an increased payment as the supply margin reduces. To some extent, this effect increases the cost of withholding a unit – not only does it sacrifice energy operating profits at times of high system demand, but it sacrifices capacity payments as well.

Dispatch of Wind Resources

[9] http://www.allislandproject.org/en/TS_Decision_Documents.aspx?article=beea10b1-a6c2-4993-8cfe-037a57dee8f9

[10] http://www.sem-o.com/MarketDevelopment/Modifications/Pages/Modifications.aspx?ModificationID=MOD_18_10

Any factor which increases uncertainty about load lessens the ability to exercise market power. The current dispatch of the wind units, in which they are assumed unavailable in the day ahead but then are dispatched as available in real time, leads to uncertainty. The more variable the wind conditions, the more difficult to condition bids on the existing state of net load, thus curtailing market power.

Current Ring-fencing Provisions

There were ring-fencing provisions between the generation and supply arms and between generation affiliates of both ESB and Viridian in advance of the SEM go-live, which includes an Economic Purchase Obligation (EPO) on ESB CS and NIE ES. If such ring-fencing did not exist, it would have been necessary to create it in advance of market opening to prevent large players in both the selling and purchasing arms jointly setting a strategy for bidding and purchasing in the SEM. Thus, the ring-fencing measures already in place which prevent that were taken into account when developing specific market power mitigation rules, in the context of a fully regulated retail market which prevailed at the time. This is discussed in more detail in later sections.

Ex-Post Pricing

The SEM market uses ex-post pricing, i.e. prices are adjusted based on measured quantities demanded after the fact. By itself this does little to deter the exercise of market power. However, the fact that all prices are determined ex-post gives scope, at least conceptually, for ex-post adjustments owing to the exercise of market power.

3.4 Market Power Mitigation Objectives

Due to the existence of two large electricity groups on the island - ESB and Viridian - the RAs considered that, in addition to the above standard features of the SEM, a specific strategy would need to be implemented to mitigate market power and its potential abuse. The objectives of this strategy, as referred to in AIP-SEM-31-06, are:

- To prevent market participants from abusing their market power; and,
- To maintain efficient incentives for new entry and exit. In particular, all market participants should see correct market signals and, where possible, have available to them a range of competitive strategies.

The secondary objectives are:

- To expose the incumbents to competitive pressure, which should lead to increased efficiencies; and,
- Not to unfairly discriminate between new entrants and existing players.

The RAs considered in AIP/SEM/02/06 that any market power mitigation strategy should meet the following criteria:

Effectiveness

The market power mitigation strategy should be effective at mitigating market power.

Feasibility

A market power mitigation mechanism which cannot be effectively applied by the RAs is of no value. For example it was considered that the RAs lack the power to order divestiture.

Retention of the Profit Motive at the Margin

Rate-of-return regulation eliminates the market power problem through elimination of the profitability of market power exploitation schemes. However it is the profit motive which in fact engenders improvements to customers which no regulatory scheme can achieve. Thus, whatever market power mitigation scheme is adopted, it should not eliminate the profit incentive.

Allows for Innovative Strategy

In order for competition to deliver benefits to consumers, market participants should have as wide a set of strategies to employ as possible. Any market power mitigation scheme will limit the strategies available to market participants to some extent but, ideally and where possible, only those strategies which are directed to the exercise of market power should be limited while allowing all others. Given a choice between two otherwise equivalent schemes in terms of their ability to control the exercise of market power, the RAs aim to choose the one which leaves the most scope for important economic choices to be made by all market participants.

Regulatory Efficiency

The selected market power mitigation scheme should not be an excessively difficult or expensive one to implement. More generally, any market power mitigation scheme ought to achieve benefits in excess of its costs.

Flexibility

The mitigation scheme must have the flexibility to deal with surprises in the SEM, whatever they turn out to be.

Transparency

As much as possible, the mitigation scheme should be transparent. Generators should know what is expected of them; whether or not they perform up to those expectations ought to be simple to monitor.

Ability to Sunset

If conditions warrant removal of a particular market power mitigation scheme, it should be removed and if possible, the conditions under which such a scheme will be removed should be stated in advance.

Impact on Retail Markets

The implementation of a market power mitigation strategy needs to take account of the method of Public Electricity Supplier (PES) regulation.

3.5 SEM Market Power Mitigation Strategy

After reviewing the market power mitigation measures available and evaluating them against the objectives and criteria above, as well as taking account of the design features of the SEM and international experience, the RAs developed a specific approach to the mitigation of market power in the SEM. This Market Power Mitigation Strategy developed for the SEM relies on a combination of the five measures summarised below - based primarily on consultation AIP-SEM-02-06[11] and decision AIP-SEM-31-0[12] for measures (1), (2), (3) and (5), as well as consultation AIP/SEM/07/16[13] and decision SEM/304/07[14] for measure (4).

(1) Bidding principles for generators that reflect an expectation that bids in the energy market should reasonably reflect marginal costs. Thus a Bidding Code of Practice[15] was developed, which are a set of principles upon which participants are required to build Commercial Offer Data (including energy bid prices) for their Generator Units. The principles state that participants must bid their SRMC in to the market, and are designed to help mitigate the potential abuse of market power by Generators.

(2) Market monitoring to monitor adherence to the bidding principles by generators and to alert regulators to problems with market rules that may create unintended pricing power or gaming opportunities primarily for generators with large portfolios. Thus the RAs' Market Monitoring Unit was created[16], which, among other activities, involves ex-post monitoring of the operation of the SEM to ensure that generators have submitted bids to the market in line with the Bidding Code of Practice. The Market Monitoring Unit also conducts investigations into the exercise of market power including but not limited to the violations of bidding principles or other market rules.

(3) DCs that incumbent generators with large shares of control over generation in the SEM will be required by the RAs to offer. DCs are essentially financial hedge contracts - Contracts for Differences (CfDs) – which exist outside of the physical electricity market and whose price are based on the projected SMP in the SEM. DCs help ensure that generators with market power do not have an underlying incentive to attempt to abuse their dominant positions in the SEM to the detriment of competitors or consumers (this is explained in more detail later). They also have the benefit of providing forward liquidity to the SEM by helping suppliers, especially those which are not vertically integrated, to manage the risk associated with movements in the SEM's SMP. As they are "directed", it is the RAs who decide upon the methodology, pricing and quantity of these DCs every year[17] .

(4) Ring-fencing arrangements between affiliated generating and supply businesses within the ESB and Viridian groups have been in place for many years. The main purpose of these arrangements is to ensure that, via licences, the ESB and Viridian businesses operate independently of each other. They feature separate management, separate accounts, as well as a prohibition of anti-competitive behaviour, cross-subsidies (either to or from their affiliate businesses) and contracts with affiliates other than those which are on an arm's length basis on normal commercial terms. This applies to both the generation and supply arms of the ESB and Viridian groups. As part of the licensing of ESB and Viridian for the SEM, the Regulatory Authorities revised their EPO requirements on ESB CS and NIE ES to ensure that they purchased forward contracts in a manner that is economic, fair and transparent. Without an EPO these suppliers could, resulting from market power in the supply market, pay too much for contracts from their affiliates, resulting in their customers paying too much for their electricity and competition

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[11] http://www.allislandproject.org/GetAttachment.aspx?id=5987ff76-0e0a-4d85-ad49-eb43dfe16dbf
[12] Please see http://www.allislandproject.org/en/market-power-decision.aspx?page=2&article=4cab0a1e-2e65-47a2-9585-67fca34ef586
[13] http://www.allislandproject.org/GetAttachment.aspx?id=e816446b-4653-4a9c-9522-ce528c727710
[14] http://www.allislandproject.org/GetAttachment.aspx?id=1f6c8708-b0a4-4db0-9afc-ce3722fc7aca
[15] Please see http://www.allislandproject.org/en/market-power-consultation.aspx?article=44d688de-8ac1-4bd3-846c-06d0f3b85ef8
[16] Please see http://www.allislandproject.org/en/market_monitoring_unit.aspx
[17] Please see http://www.allislandproject.org/en/market_modelling_group.aspx

in the market being distorted. This is in the context of a fully regulated retail market where tariffs are regulated, and the PES suppliers can recover the cost of energy purchases.

(5) A targeted package of certain local market power mitigation measures *if necessary* aimed solely at generators that must be operated for local transmission concerns and face no effective competition. These measures could be through the capping of constraint payments or full Reliability Must-Run (RMR) treatment which involves out-of-market contract payments to the generator.

Given that market mitigation measure (4) was already in place pre-SEM and measure (5) would only be applied as needed, on an ongoing basis measures (1) to (3) were the key new market power mitigation strategies adopted for the SEM, i.e. a Bidding Code of Practice with a Market Monitoring Unit and DCs. It was decided to rely on these twin strategies (rather than just one) for the following reasons:

- While bidding principles help control market power, they are more difficult to implement where there are strong incentives to exert market power. Regulators may be confronted with constantly changing rationales for what are purported to be bids based on SRMC, but are actually attempts to exert market power. By reducing incentives to exert market power, DCs subvert the incentives (this is explained later);
- While DCs reduce the incentive to exert market power, they do not eliminate the possibility of exercise unless the contracts are so pervasive as to eliminate profit motives in the SEM spot (pool) market altogether, i.e. if they cover 100% of the spot market volumes. Bidding principles allow the directing of fewer contracts to preserve pool incentives for profitability and price signals at the margin. In addition, the bidding principles are valuable in and of themselves in combating local market power.

In developing this package of measures, the RAs specifically rejected prescriptive bid controls whereby generators would be directed to specifically bid in a certain way based on cost formulae (and face sanctions for not bidding that way). This was in view of the difficulties with such an approach from both a regulatory and market efficiency perspective. It is, however, an effective means of controlling market power. Given the level of concentration in the SEM and the constraint that the RAs cannot impose a structural correction - i.e. reduction of concentration through divestiture - prescriptive bidding controls, despite their considerable drawbacks, were acknowledged as appearing necessary. However, applying DCs in a manner, price and quantity determined by the RAs removed the necessity for such prescriptive bid controls. With DCs used to reduce the effective concentration of generation control to levels that are not associated with significant market power (see more information on DCs later), the bidding principles and monitoring mitigation measures were implemented, via a Bidding Code of Principles that provides more room for competitive innovation and efficiency gains.

The RAs also considered and specifically rejected proposing a strategy which relied exclusively on aggregate revenue and/or profit controls applied retrospectively. It was considered that while these controls may well protect customers from average prices that are above competitive levels in the short term, they provide incumbents with unwarranted flexibility to use market power to damage competitors and discourage entry in the long term. Further, while average prices may well be reasonable, prices at various times and for various products may well be affected by market power and efficiency may suffer.

The Bidding Code of Practice (and Market Monitoring Unit), DCs and ring-fencing - i.e. market power mitigation measures (1) to (4) - are discussed in more detail in following sections.

3.6 Bidding Code of Practice & Market Monitoring

3.6.1 Bidding of Short-Run Marginal Cost

The requirement for Generators to submit bids that reflect their SRMC is enshrined in two places; the Generator Licences and in the Bidding Code of Practice. The Code is a legally binding document which is explicitly pointed to in the licences themselves.

This architecture was designed so that the detailed rules could be easily changed in one place subject to consultation with industry, rather than having to change every single licence should tweaks be required to the detail.

3.6.2 Bidding of Short-Run Marginal Cost – Principle

The SRMC Principle is defined broadly in the licences as 'the cost of generating electricity minus the cost of not generating electricity'. The residual of this subtraction yields obvious cost items such as fuel, carbon emission costs and variable operation and maintenance costs.

The Bidding Code of Practice goes on to explain the way that these elements should be priced with regard to the exploitation of an asset or resource. The Code states that:

7. The Opportunity Cost of any cost-item shall comprise the value of the benefit foregone by a generator in employing that cost-item for the purposes of electricity generation, by reference to the most valuable realisable alternative use of that cost-item for purposes other than electricity generation.

8. In calculating the value of the benefit foregone in employing a cost-item for the purposes of electricity generation, the following principles shall, unless it can be demonstrated to the satisfaction of the Authority or the Commission (as appropriate) that there is good cause not to, be applied:

    (i) where there exists a recognised and generally accessible trading market in the relevant cost-item, the Opportunity Cost of that item should reflect the prevailing price of the cost-item, which may be for immediate or future delivery or use as appropriate to the circumstances of the relevant generator, having regard to:

        (a) costs the relevant generator would incur in offering that cost-item for sale, or acquiring that cost-item, on a recognised and generally accessible trading market;

        (b) reasonable provision for the variability of the prevailing price of a cost-item on a recognised and generally accessible trading market;

    (ii) where no recognised and generally accessible trading market exists in the relevant cost-item the Opportunity Cost of that item should reflect the costs which would be incurred by the relevant generator in replacing that cost-item; and

    (iii) reasonable provision for increased risks to plant and equipment as a result of the operation of a generation set or unit may be included.

This essentially means that commodities such as gas should be referenced to the prevailing spot price of gas on a liquid accessible market. Should a generator have a gas supply contract struck at a fixed price, this should in no way inform the true economic cost of burning gas and should have no bearing on the bid submitted to the market.

3.6.3 Market Monitoring – Focus

The chief focus of the Market Monitoring Unit (MMU) has remained over the 2.5 years as the testing, checking, investigation and enforcement of compliance by Generator participants with the Bidding Code of Practice. The Unit also has a role in monitoring the performance of the market and system, and circulating relevant ground-level information to the Regulatory Authorities, as well as participating in SEM policy development.

The MMU tests for compliance by continually ranking commercial offer data against its own internal costing models. These models are fed real commodity prices by a data service (Platts). A combination of this analysis and complaints or queries from competitors has ensured that the unit has been able to detect excursions or 'behaviour of interest' relatively quickly; though work is currently underway to improve the speed of this process further.

3.7 Directed Contracts

This section explains how DCs work in mitigating market power, where the risk lies between the various market participants with regards to DCs and the relationship between DCs and Non-Directed Contracts (NDCs) and contract liquidity more generally.

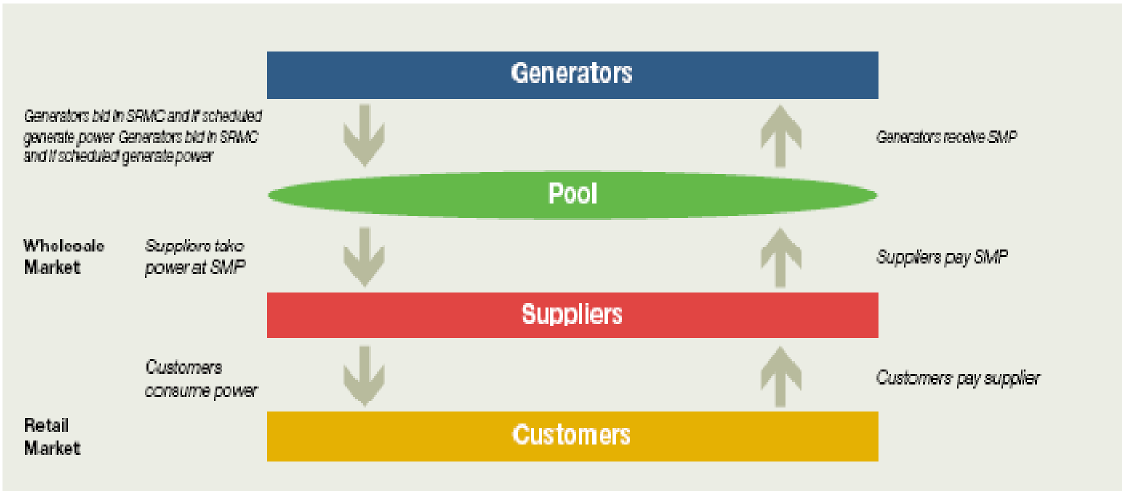
3.7.1 Pool & DCs

In order to explain how DCs work, it is first necessary to provide an overview of the workings of the SEM spot (pool) market and how CfDs (of which DCs are a type) fit into it. DCs themselves will then be explained.

All generators were issued with a revised licence before the beginning of the SEM which includes a condition that generators must adhere to the Bidding Code of Practice. As discussed earlier this sets out what generators should include in their bids into the market, is based on one of the key principles of the market: generators must bid their short-run marginal cost (SRMC) into the market. A market clearing mechanism operated by the Single Electricity Market Operator matches these SRMC bids with electricity demand across the island on a half hourly basis based on ex-post optimised schedule for the whole trading day, to derive a single System Marginal Price (SMP) that is set for each half hour. The ex-post SMP for each half hour trading period will therefore be based on an unconstrained (i.e. without network constraints and reserve issues) stack of available generation optimised over the trading day, taking account of the plant on the system and the actual demand which occurred during that trading day. The SMP has two components: (1) Shadow Price, which is set by the plant with the highest SRMC required to meet demand; and, (2) Uplift, which ensures that each station recovers their start up and no-load costs over their contiguous period of operation.

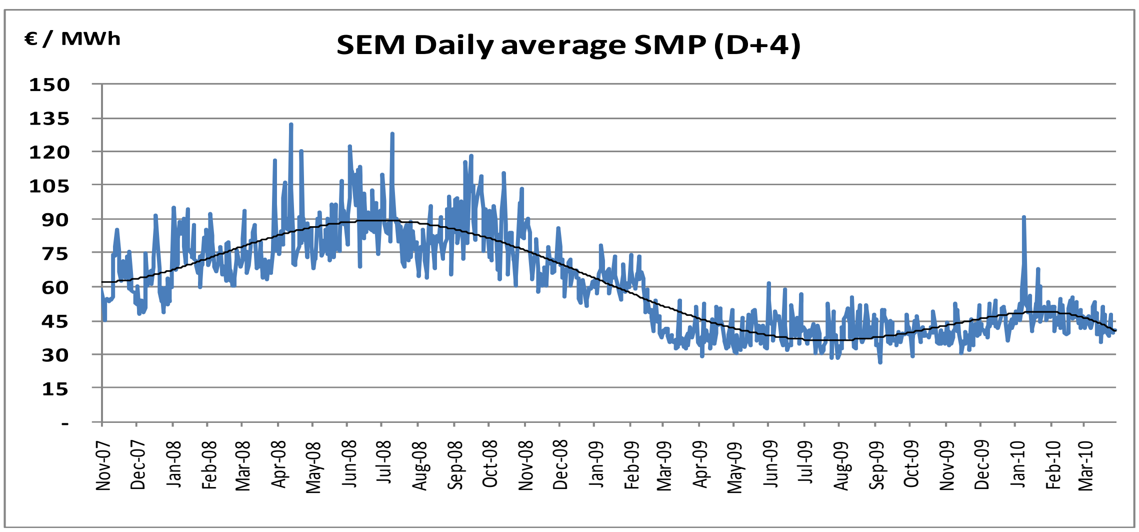
Generators receive the SMP for each trading period for their market scheduled quantities, which is paid for by electricity suppliers with respect to the electricity they supply to end customers. This is illustrated below. Please note that there is also a capacity payments mechanism in place for generators in SEM which is designed to contribute towards the fixed costs of a generator - details are available at www.allislandproject.org.

Figure 1



Given that the SMP is derived every half hour, and is largely driven by international fuel prices, it is volatile as illustrated in the following graph. This means that the income generators receive, or conversely the cost that suppliers pay, is volatile.

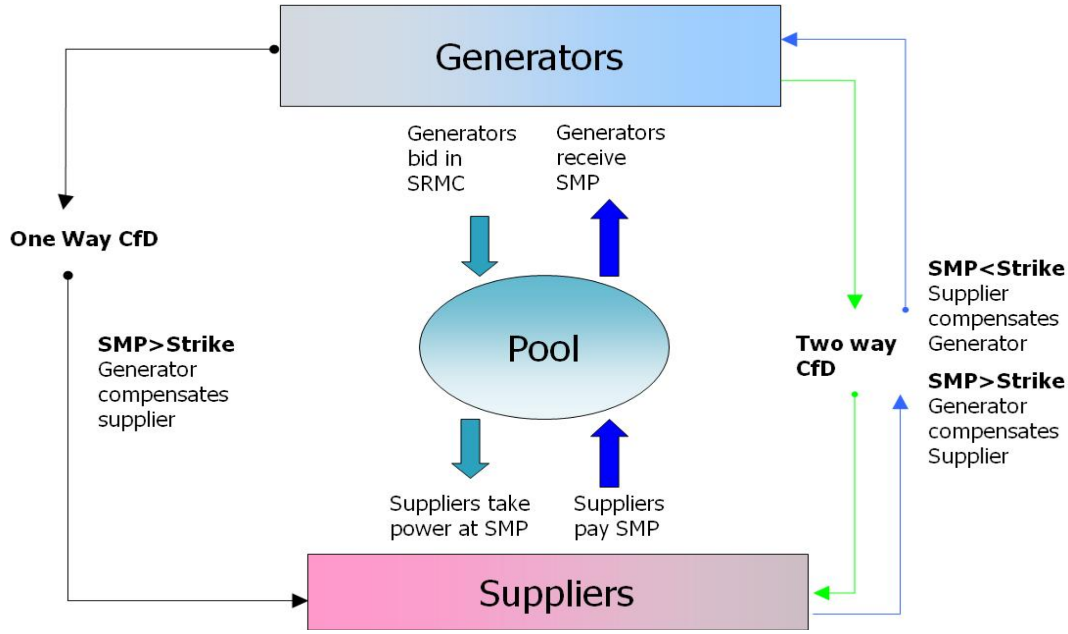
Figure 2



As a result of this volatility forward contracting around future predictions of this wholesale price in one form or another is a feature of many wholesale electricity markets around the world. CfDs are financial instruments often referred to as “hedging” or “hedge contracts” in that they are a form of contract between an electricity generator and an electricity purchaser/supplier that are designed to allow both parties to mitigate or “hedge” their risk in relation to the SMP. In this case risk refers to their exposure to a significant price change over which they have little or limited control or, in the case of market abuse, deliberate pricing above SRMC by a generator.

CfDs ensure that the two parties to the contract (the Generator as the seller and the supplier as the buyer) are not exposed to volatile price movements in the SEM pool market, be they due to market conditions or market abuse, the latter which is where DCs have a particular role (see later). If the average SMP in the market is lower than this agreed price then the supplier compensates (pays) the generator the difference. If the average SMP in the market is higher, then the Generator pays the Supplier the difference. This is illustrated below, followed by a numeric example.

Figure 3



So through CfDs both parties transfer risk and achieve price certainty for the volume agreed. However both have lost the opportunity to make additional profits when prices move contrary to market expectations. This is especially the case with DCs where the prices for the CfDs are set by the RAs based on their forward prediction of the SMP. For example, say the CfD price between a generator and supplier for 2011 are set at €80/MWh based on predicted fuel prices. If a dominant generator decides to exercise market power and increase the spot prices to €90/MWh, the generator will then have to pay the supplier the difference, i.e. €10/MWh, making the exercise fruitless. Thus the incentive for a generator to increase the market price is removed with DCs as the generator will not gain from the exercise, for the volume of contracts sold.

Exactly how DCs are determined is discussed in more detail below.

3.7.2 How DCs Work

Overview

DCs are CfDs which are imposed on the incumbent generators with market power in the SEM by the RAs as part of the RAs' Market Power Mitigation Strategy.

DCs are a mandated set of CfDs implemented at the direction of the RAs on entities with large shares of control over generation. As they are "directed", it is the RAs who decide upon the methodology, pricing and quantity of these DCs every year. The intent of these contracts is effectively to reduce the amount of generation that such entities will be receiving spot-based prices for through the SEM. The quantity of generation that the entities will offer to the market and receive spot-based prices for will therefore be the difference between the generation that they control and the directed contract quantities - i.e., the "uncontracted generation position". The quantity of contracts directed by the RAs is determined, via the HHI, so that the concentration of this "uncontracted generating position" is likely to result in a competitive market outcome given the other elements of the mitigation package, the design features of the SEM, effectiveness of ring-fencing measures, normal long-run economic incentives and the resulting concentration of the uncontracted generation position. Further, this concentration of the "uncontracted generation position" is examined by the RAs by generation market segment, i.e. by baseload, mid-merit and peaking generation.

The DCs mitigate market power by reducing the incentive, for the generators deemed to have market power (PPB and ESB PG - see next), to submit bids into the market above competitive SRMC levels, for the purpose of influencing either pool (SMP) prices or future contract prices. This is because the RAs set the DC price, quantity and eligibility and so if they do this, they will then lose money on the CfDs which are attached to these bids (see illustration and example in previous section) and so are no better off setting the price higher than SRMC. Thus, as referred to in section 3.5, DCs and the Bidding Code of Practice are complimentary in mitigating market power - DCs mean the bidding code does not need to be too prescriptive, principally because DCs reduce the incentive to exercise market power in the spot market, while bidding principles allow the directing of fewer contracts so as to preserve pool incentives for profitability and price signals at the margin.

DCs - Quantities

The RAs calculates the quantity of DCs that ESB PG and NIEE PPB are be required to make available to eligible suppliers each year using the Herfindahl Hirschman Index (HHI) as a measure of market concentration. DC quantities are determined using the HHI for 3 different generation market segments: baseload, mid-merit and peaking, with each examined by quarter in the tariff year. The target HHI for each of these segments is set by the RAs and for each year since the SEM has been set at 1,150. The DC quantities for ESB PG and NIEE PPB are set such that market concentration in the SEM (as calculated by the model) is below this threshold. The process works as follows:

- The RAs input fuel data into a validated Plexos model to give a forecast of half-hourly SMPs and Wind/Hydro Generation. For each half hour the "Market Concentration" is calculated. Only potentially competitive capacity is counted, defined as capacity with cost less than or equal to 1.05*SMP - essentially each generator's market share is based on the generator's running which in turn is based on whether it is within the 1.05*SMP threshold.

- Based on this the HHI is determined for the market to determine its concentration, divided into baseload, mid-merit and peaking by quarter.

- If the HHI exceeds the HHI threshold level of 1150 for these segments, the incumbent with the largest baseload market share in that month (ESB PG or NIEE PPB) is allocated 1% of said share as a DC quantity. This is repeated, with allocated DC quantities not contributing to the HHI, until the monthly baseload HHI is below this threshold level.

DCs - Eligibility

The RA determine the eligibility of each supplier for DCs each year, calculating separately for each quarter and each product-type (baseload, mid-merit and peak). The volume of DC contracts by product type (baseload, mid-merit, peaking by Quarter) is allocated to suppliers based on their share of customers' in each category in the market in the previous year. Essentially a supplier's eligibility for a DC product calculated using their share of MICs in each customer category, the profile of consumption in each customer category and the total annual consumption of each customer category.

DCs - Price

The RAs determine the price of the DCs each year. Using a validated Plexos model, and by populating it with fuel/CO2 scenarios, the RAs develop a regression pricing formula for each of the DC products by quarter. This formula is used to price the DCs when suppliers subscribe to the quantity for which they are eligible during the annual DC subscription process. The advantage of this formula is that is it is simple and can be used by all suppliers to calculate the price of the DCs.

Full details of the DC process and products for 2010/'11 are available on the AIP website[18].

3.7.3 NDCs and PSO-related CfDs

In addition to the DCs, generators can offer forward Non-Directed Contracts for Difference (NDCs) in the SEM which suppliers are free to bid for. The RAs have no role in setting the price or volume of these forward contracts. There are two parties who offer NDCs to the all participants in the market, ESB PG and NIEE PPB. While both ESB PG and NIEE PPB determine the products to offer, their reserve prices and the volume, they face different risks.

NIEE PPB have a number of generator unit agreements (GUAs) with different power stations in Northern Ireland, they then act as an intermediary for these power stations in the SEM. The difference between the costs under the GUAs and the revenues received through the SEM Pool, is passed on to the Public Service Obligation (PSO) in Northern Ireland. As part of the regulation of NIEE PPB, it is incentivised to minimize the PSO charge to customers in Northern Ireland. NIEE PPB therefore offer NDCs to market participants as part of their efforts to minimize the Northern Ireland PSO. While any difference payments that arise from the CfD are minimized by fuel hedges taken out by NIEE PPB at the time these CfDs were offered, it is the Northern Ireland PSO that faces ultimate benefit or cost of hedging.

ESB PG, on the other hand, does not face this form of regulation. They base the NDC CfDs they offer to the market on their forecast generation over the period taking into account the amount of DCs imposed on them by the RAs. Any difference payments, paid or received, that arise from these CfDs affect their profits. ESB PG can mitigate the risks involved by purchasing fuel hedges.

ESB PG also offer CfDs associated with the PSO levy[19] in Ireland, which is similar to NIEE PPB's NDCs. The difference is that ESB pass through all the costs that are associated with the PSO and does not including any hedging, such as fuel hedging - therefore any difference payments paid or received are incorporated into the PSO levy, to which the end Irish customer is exposed. These CfDs are offered for auction by ESB PG but the reserve price for these contracts is set by the CER. There are about 600 MW of Irish PSO related CfDs offered to the market and this relates to output from various peat plants - Lough Ree, West Offaly, Edenderry - and from Tynagh and Aughinish Alumina.

As referred to in section 2, one of the issues on which we are seeking feedback is whether PSO-related CfDs should continue, taking account of the interests of the end customer.

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[18] Please see http://www.allislandproject.org/en/market_decision_documents.aspx?article=94e789fa-a86c-42a3-944a-919766a1850b
[19] Please see http://www.allislandproject.org/en/market_decision_documents.aspx?article=1c5adbe9-6dbb-4d50-a480-2ebdd44f8ded

3.7.4 Liquidity & Contracts

DCs, as well as NDCs and PSO related CfDs, also have the benefit of providing forward liquidity to the SEM by helping suppliers, especially those which are not vertically integrated, to manage the risk associated with the inherent volatility in the SEM's SMP. In other words, they provide generators and suppliers with protection against volatile price movements in the SEM pool, thereby encouraging their entry and expansion in the market. Liquidity of these forward contracts is considered especially important for potential new or expanding suppliers with a limited generation arm because, in order to target particular groups of end-customers for supply, they may need the certainty in the price of generation which forward contracts can bring (and which the SEM pool does not). Peaking and mid-merit contracts can also be especially important for suppliers with a limited generation wing given that their generation will typically not cover all their customers' demand at times of higher demand.

3.8 Ring-fencing & EPO

During the development and establishment of the SEM, the RAs jointly considered appropriate ring-fencing conditions between affiliated generating and supply businesses within the ESB and Viridian groups in the SEM, as part of a market power mitigation strategy. The main purpose of these arrangements is to ensure that, via licences, the businesses of ESB and Viridian operate independently of each other. They feature separate management, separate accounts, as well as a prohibition of anti-competitive behaviour, cross-subsidies (either to or from their affiliate businesses) and contracts with affiliates if they are not on an arm's length basis on normal commercial terms. This applies to both the generation and supply arms of the ESB and Viridian groups.

Ring-fencing was specifically referred to in the market power mitigation decision paper AIP/SEM/31/06. The RAs consulted on appropriate ring-fencing arrangements for incumbent Suppliers in August 2005 (AIP/SEM/74/05) and then briefly again as part of a broader consultation paper in February 2007 (AIP/SEM/07/16) which was then followed by a decision in June 2007 (AIP/SEM/304/07).

An important part of the licence requirement on ESB PG and for NIEE PPB is the requirement to contract on an arm's length basis and on normal commercial terms only, i.e. it can't offer special terms to favour its affiliates. In the absence of this, ESB PG and NIEE PPB could refuse to sell forward contracts to independent suppliers on reasonable terms - they could sell to their affiliates below the price to non-affiliates for the same contract, to the detriment of rival suppliers. As a result of this licence clause, there is no incentive for ESB PG or NIEE PPB to offer their affiliates cheap contracts, because the same contracts would need be offered to non-affiliates, meaning no advantage in the supply market while there would be reduced margins for the incumbent generators.

A key regulatory control, included in the supply licences for ESB CS and NIE ES, relates to the EPO. This is in the context of a fully regulated retail market where energy costs are recovered through regulated tariffs. AIP/SEM/304/07 decided to continue this control on ESB and NIE in order to facilitate competition in generation and supply, to protect the interests of final customers and to provide a clear, transparent and non-discriminatory mechanism for the determination of PESs - ESB CS and NIE ES - tariffs. The EPO criteria require ESB CS and NIE ES to purchase forward contracts in a manner that is fair, transparent and non discriminatory while at the same time not overpaying for their contracts. Both suppliers are required to produce a Hedging Policy Statement including procurement principles. By approving these statements the RAs aimed to ensure that ESCB CS and NIE ES operate to a clear set of guidelines when deciding whether or not a particular hedge is viewed as being compliant with the EPO.

The main purpose of the EPO is to encourage the regulated PES suppliers to purchase electricity and associated contracts efficiently, to ensure an economic price and good value for consumers, in the absence of competitive drivers. This is because, otherwise, to the extent that these suppliers pay too much for their contracts, due to market power in the supply (or retail market), their customers will pay too much for their electricity and competition is distorted. Under this obligation, both PES suppliers have to demonstrate that they have achieved “good value” for customers. In demonstrating compliance with the EPO an incumbent supplier, say ESB CS, cannot simply enter into a sales arrangement with, say, ESB PG, for the sale of its output at a price that is more expensive than that offered by other generators in the market, something which could happen (in the absence of an EPO) in a supply market segment which is not sufficiently competitive, where customers would have no choice to switch supplier. Such conduct would allow ESB PG to gain excess profits, and force other suppliers who wish to purchase these contracts to pay above the competitive level and undermine new entry in supply, particularly for suppliers without associated generation assets. So the EPO provides a supplemental constraint on incumbent suppliers in an uncompetitive market, which means that such suppliers cannot use their market power in supply to distort the contract market with their affiliate generators and therefore distort competition in the market more generally.

4. State of the Nation Review - SEM Operation to Date

This section provides information on the operation of the market since the inception of the SEM, including levels of market power in the spot and forward contract markets as well as forward contract liquidity.

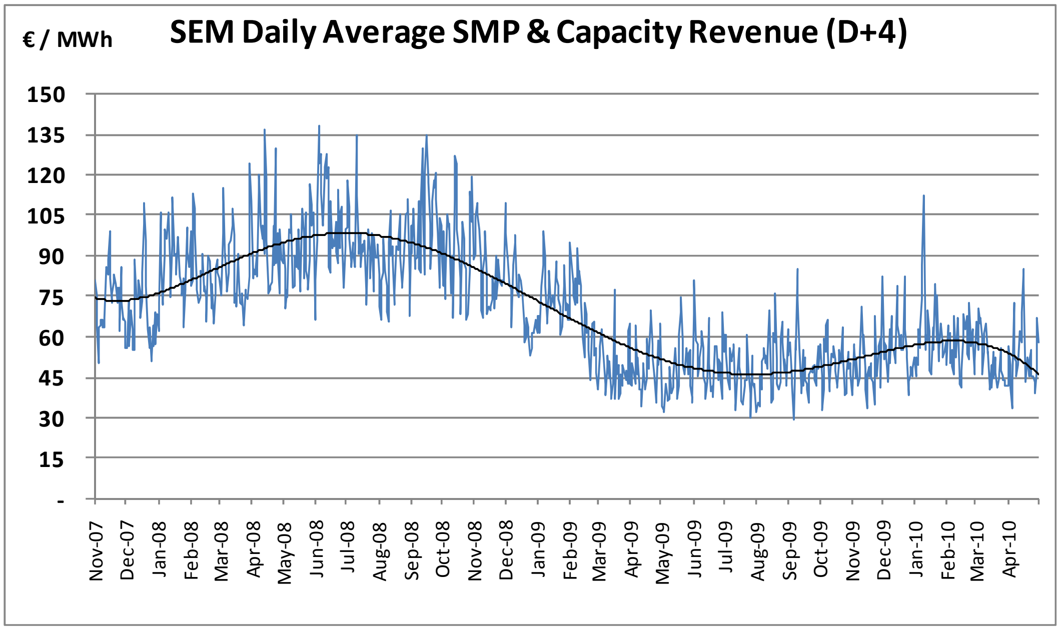
4.1 Review of the Gross Mandatory Pool (Spot)

The primary reference price in the SEM is the System Marginal Price (SMP), which is the price that each generator receives and each supplier pays for every Megawatt Hour (MWh) they are scheduled for. The figures below show the movements in daily average SMP (average of 48 half hourly SMPs) from the beginning of the SEM on 1st November 2007. The SMP has ranged from €3.29/MWh to €696.85/MWh, over the first 30 months of the market and averaged approximately €60/MWh. There is significant volatility in the SMP, particularity when examining each half hourly price, due to the variety of factors that impact on the SMP such as:

- ***Fuel prices*** – this is typically the largest component of generators bids;
- ***Generator efficiency*** – this is the efficiency at which a generator station converts its fuel to electricity and affects the bids they submit to the SEM;
- ***Generator availability*** – from both the more predictable price makers and the less predictable price takers;
- ***Generator starts*** – starting a generator in the market can result in significant increases in the overall SMP, through Uplift, depending on the costs involved and the amount of generation; and,
- ***Demand*** – this normally follows a standard profile and load over the day, while varying across the seasons. But demand can be subject to significant changes in the short term due to influences such as changes in temperature, and in longer term due to changes in the economic climate etc.

Despite this volatility, it is evident that over wider timeframes, such as weeks and months, overall trends in the SMP can be seen, normally following the trends in the underlined generating station fuel prices.

Figure 4



When examining the components of the SMP, Shadow Price (covering fuel costs) and Uplift (covering start-up and no-load costs), as well as the average capacity payments revenue that generators receive, it is clear that the shadow price is the largest component. The following figures also show that uplift and capacity revenue are a lot more stable, than the shadow price which is determined mainly by fuel markets, in particular the gas market.

Figure 5

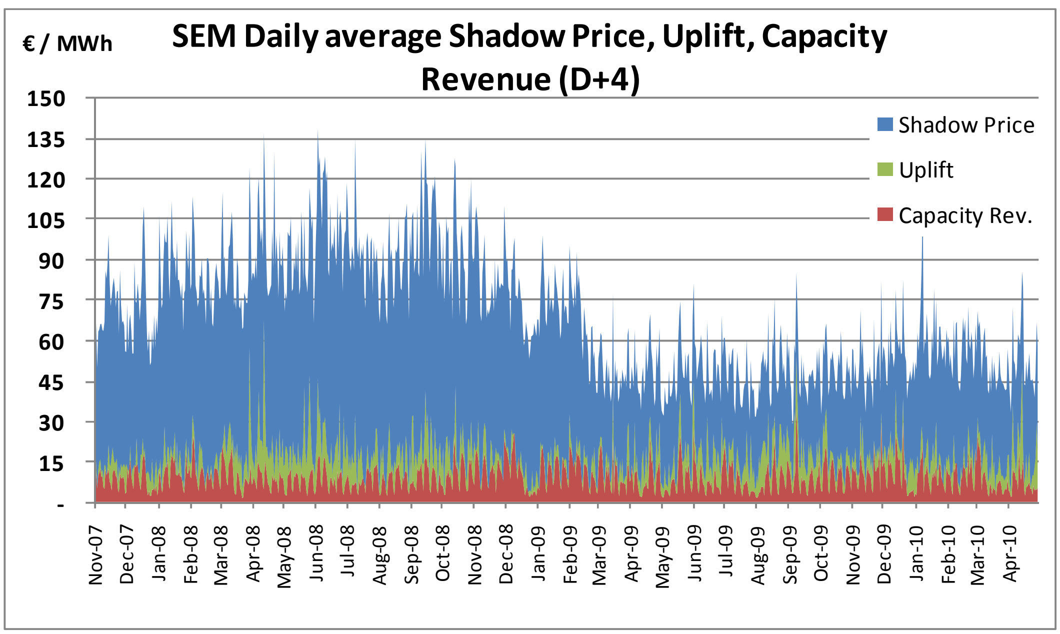
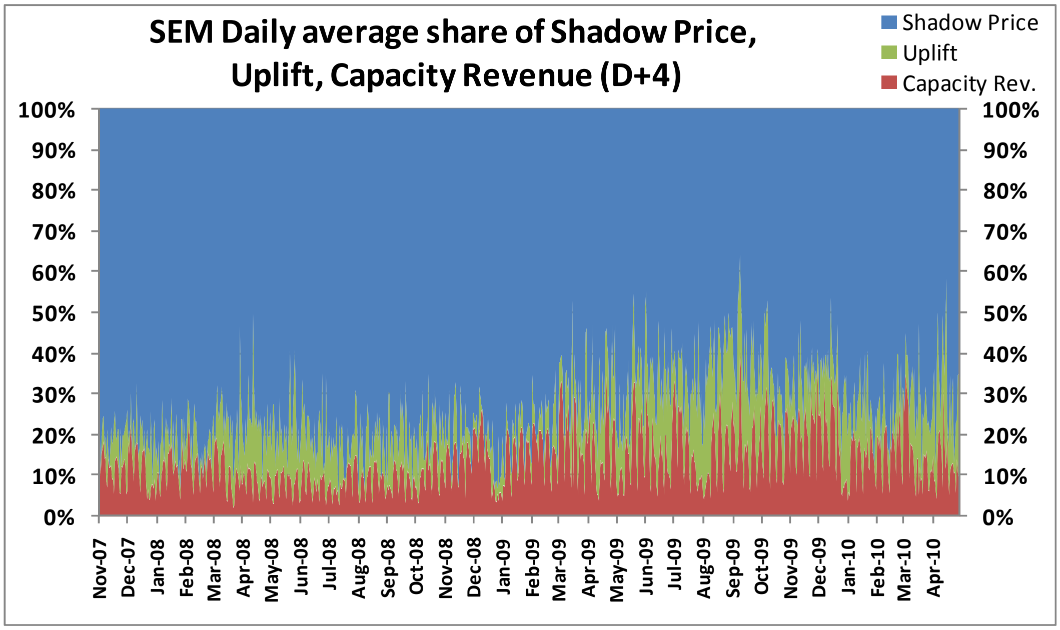


Figure 6



The figures below show the annual changes in shadow price, uplift and capacity revenues in the SEM. This shows dramatic fall in shadow prices and the combined increased share of uplift and capacity revenue from 20% to 30% of the total price from 2008 to 2009.

Figure 7

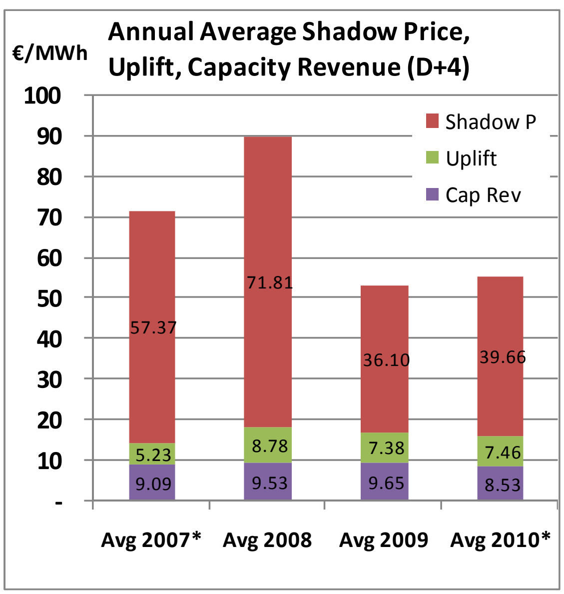
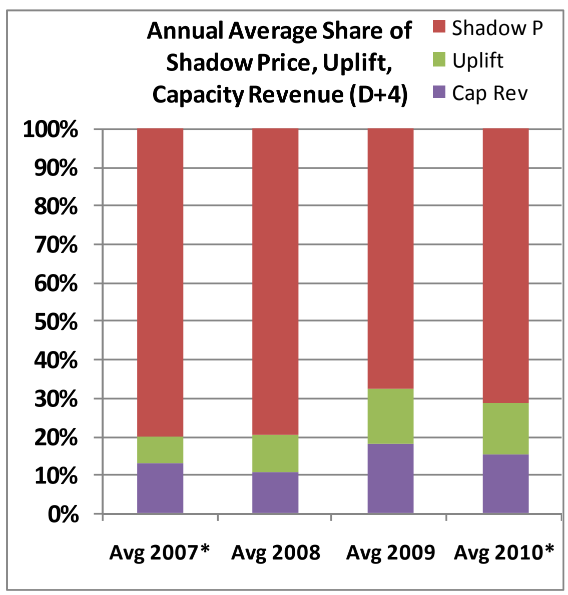


Figure 8



* 2007 ranges from November and December and 2010 ranges from January to April.

4.2 SMP Drivers - Regression Analysis

The following section examines the results of some preliminary regression of the SMP carried out using Ordinary Least Sqaures (OLS) method. When attempting to understand the underlined determinants to the SMP, the data needs to be analyzed at two levels:

1. By the Half Hour – the SMP is determined in each half hour by factors that also change by the half hour such as, generator availability, demand.
2. By the Trading day – generator bids only are only submitted once per trading day and therefore there is no change to the underlined fuel costs or station efficiencies during the half hour.

The following table shows the results of regression of SMPs using half hourly data, using the first 30 months of market data. The four independent variables that were found to be significant in determining the SMP were: 1) interconnector flows (MW), 2) Capacity margin (MW), 3) gas price (c/therm) and 4) carbon prices (€/tonne). Overall this regression explained just under half of the SMP, with an adjusted R Squared of 0.471166.

Regression of Half-hourly SMPs

Table 1

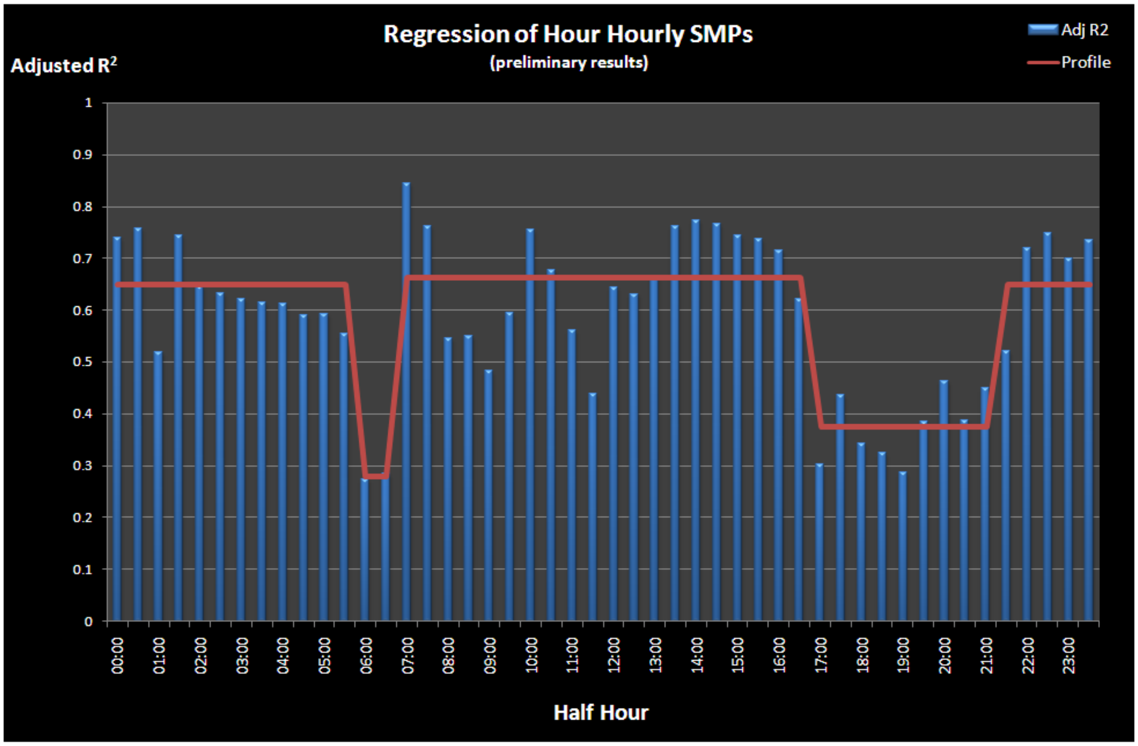
SUMMARY OUTPUT								
Regression Statistics								
Multiple R	0.68645							
R Square	0.471214							
Adjusted R Square	0.471166							
Standard Error	27.03224							
Observations	43758							
ANOVA								
	df	***SS***	***MS***	***F***	***Significance F***			
Regression	4	28491157.63	7122789.409	9747.336959	0			
Residual	43753	31972158.79	730.7420928					
Total	43757	60463316.42						
	Coefficients	***Standard Error***	***t Stat***	***P-value***	***Lower 95%***	***Upper 95%***	***Lower 95.0%***	***Upper 95.0%***
Intercept	108.6438	0.990195531	109.7195365	0	106.7029935	110.5845959	106.7029935	110.5845959
INTERCON (CSV)	-0.004	0.001039473	-3.85228357	0.000117188	-0.006041728	-0.001966958	-0.006041728	-0.001966958
Margin	-0.02224	0.000168225	-132.2071653	0	-0.022570253	-0.021910805	-0.022570253	-0.021910805
Gas (€ c)	0.239788	0.008752865	27.39536685	7.5683E-164	0.222632164	0.256943712	0.222632164	0.256943712
Carbon €	0.703368	0.022116359	31.80304368	1.8798E-219	0.660019068	0.746715999	0.660019068	0.746715999

The following graph shows the results of 48 separate regressions, SMP in each half hour, with a number of independent variables listed below:

- Interconnector flows (MW)
- SEM Wind (MW)
- MSQ[20] (MW)
- Availability Margin (MW)
- Gas (c/therm)
- Carbon (€/Tonne)
- Distillate (€/Tonne)
- Fuel Oil (€/Tonne)

[20] MSQ – Market Schedule Quantity

Figure 9



The above results show that for significant portions of the day some or all of the above variables can explain on average 65% of the SMP. Two periods of exception are the start of the trading day, 6am, and the peak hours, 5pm to 9pm, where only an average of 30% and 40%, respectively, can be explained with the above variables.

Regression of Daily SMPs

The regression below shows that daily average SMPs can be predicted with an adjusted R squared of 0.8884. This shows that the daily average SMPs can be predicted with much greater accuracy than the half hourly SMP. At the daily level fuels become the greatest explanatory factors, as 4 out of the 6 independent variables are fuel or fuel-related (carbon, gas, distillate and a coal-gas ratio[21]).

Table 2

SUMMARY OUTPUT								
Regression Statistics								
Multiple R	0.942934368							
R Square	0.889125223							
Adjusted R Square	**0.8884**							
Standard Error	6.962723075							
Observations	912							
ANOVA								
	df	*SS*	*MS*	*F*	*Significance F*			
Regression	6	351833.342	58638.89033	1209.560228	0			
Residual	905	43873.95892	48.47951262					
Total	911	395707.3009						
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	30.32855533	4.664863193	6.5014887	0.00000	21.17334762	39.48376305	21.17334762	39.48376305
Carbon (€/Tonne)	0.692419647	0.04614797	15.004336	0.00000	0.601850163	0.78298913	0.601850163	0.78298913

[21] Coal-Gas ratio is the cost/MWh of coal divided by gas the cost/MWh using standard station efficiencies.

Margin (MW)	-0.009216032	0.000477097	-19.31690035	0.00000	-0.010152377	-0.008279687	-0.010152377	-0.008279687
Gas (€c/therm)	0.513684891	0.030341531	16.9300915	0.00000	0.454136946	0.573232836	0.454136946	0.573232836
Peak demand (MW)	0.001687436	0.000448325	3.763864661	0.00018	0.000807558	0.002567314	0.000807558	0.002567314
Distillate (€/Tonne)	0.01384417	0.003299866	4.19537367	0.00003	0.007367891	0.020320449	0.007367891	0.020320449
Coal - Gas Ratio	6.875802069	2.230744438	3.082290356	0.00212	2.497768276	11.25383586	2.497768276	11.25383586

4.3 International Comparisons

The following figures compare prices in the SEM with other electricity markets in Europe. It can be seen that prices in the SEM have followed the same trends as those of equivalent markets in Europe. It is also clear that wholesale prices in the SEM are generally above others markets, with the exception of Italy (and Great Britain in the summer of 2008). When attempting to understand the difference between the level of prices in the SEM and other European markets the following factors should be considered:

- ***Generation fuel mix*** – different types of power stations and more significantly the fuel they use has a major impact on the cost of electricity. For example countries with significant levels of hydro and/or nuclear power stations will result in lower average wholesale prices via-via those with more fossil fuel power stations.

- ***Economies of Scale*** – larger markets make it more viable for larger power stations to invest, which can typically have higher efficiencies. There is also the added benefit of having a greater amount/flexibility of power stations to call upon when meeting increases in demand, therefore reducing the risk of price spikes.

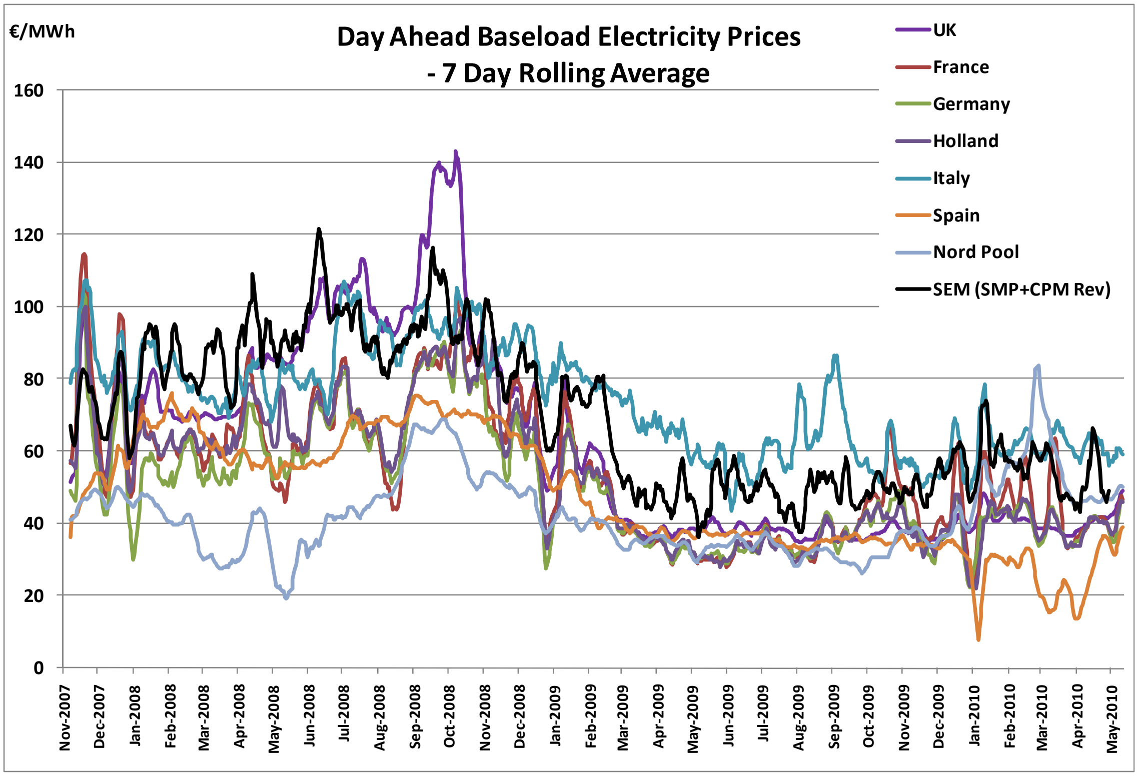
- ***Interconnection*** – countries with high levels of interconnection can benefit from neighbours with lower generation costs. There can also be a reduction in peak prices when interconnected countries have system peaks at different times. Electricity markets that become coupled (prices in both markets merge) have the benefits of economies of scale, identified above.

- ***Capacity Payments*** – countries with explicit capacity payments will have higher capacity component in their wholesale prices than those countries who have an implicit capacity component in years of excess capacity and lower prices in years of capacity shortages.

The SEM is a market dominated by fossil fuels, predominately gas, while many continental markets such as in France have nuclear; Nord Pool is dominated by hydro power. The SEM is also one of the smallest electricity markets in Europe with approximately 35 TWhs of generation a year compared to France with 570TWhs and Nord Pool with 365TWh. The Moyle interconnector links the SEM to BETTA and this amounts to import capacity of just over 4% the total SEM generation capacity. France has approximately 8%[22] import capacity over total installed generation. In addition the SEM is one of the few electricity markets in Europe that has explicit capacity payments and therefore, at certain times, would have higher average prices compared to those markets that implicitly include capacity in their wholesale prices and have sufficient or excess capacity. In the same vein the SEM would be expected to have a lower capacity component in its prices than those markets that implicitly include capacity in their wholesale prices, when they are experiencing capacity shortages.

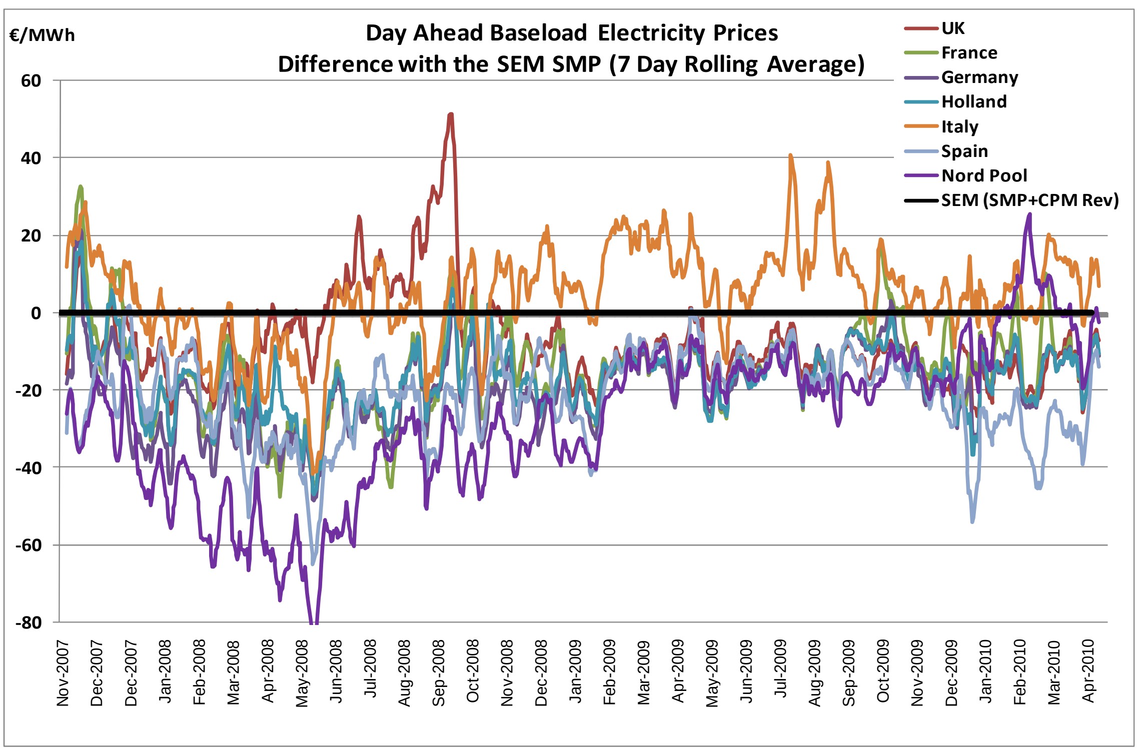
[22] Regional Reporting on electricity interconnections management and use in 2008 (March 2010). http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_INITIATIVES/ERI/Central-West/Report%20on%20electricity%20interconnection%20-%20CWE%20region%20-%20200.pdf

Figure 10



Source: Bloomberg, RAs

Figure 11



Source: Bloomberg, RAs

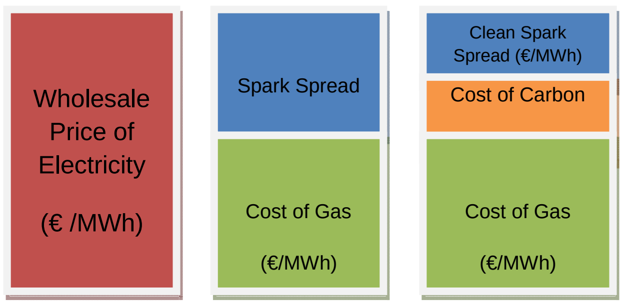
4.4 Spark Spreads

The Spark Spread is measured as the wholesale price of electricity minus the price of natural gas, taking into account the fuel efficiency of natural gas in producing electricity. It is also known as a dirty spark spread.

The Clean Spark Spread is calculated by adjusting for the cost of carbon credits such as European Union Allowance (EUA). The clean spark spread is essentially the theoretical gross income of a gas-fired power plant from selling a unit of electricity (measured in MWh), having bought the fuel and carbon credits required to produce this unit of electricity. All other costs (operation and maintenance, capital and other financial costs) must be covered from the spark spread.

The figure below provides an illustration of dirty spark spreads and clean spark spreads.

Figure 12



Spark spreads are essentially a proxy for a gas station's gross profits, which are impacted by the price of electricity and the price of gas. When spark spread comparisons are made across different countries, the efficiency of the gas station is assumed to be same in all locations and therefore differences in spreads are explained through the price of electricity or the price of gas, or both.

The following figures compare the spark spreads and clean spark spreads in both the SEM and the British Electricity Trading Transmission Arrangements (BETTA). The difference between the two markets is explained by the differences in wholesale electricity, as the price of gas in both markets are practically the same. The factors influencing the difference in wholesale prices between the two markets include those identified in the previous section, i.e. generation fuel mix, economies of scale and explicit capacity payments. These market differences contribute to the differences in spark spreads across the two markets.

Figure 13

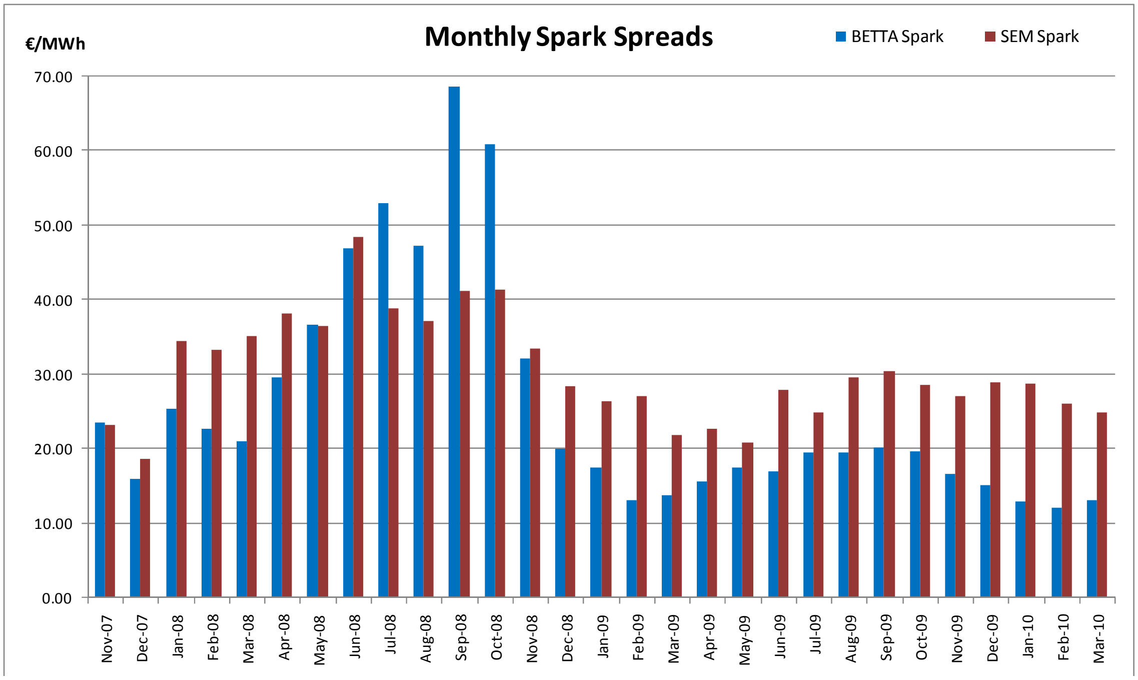
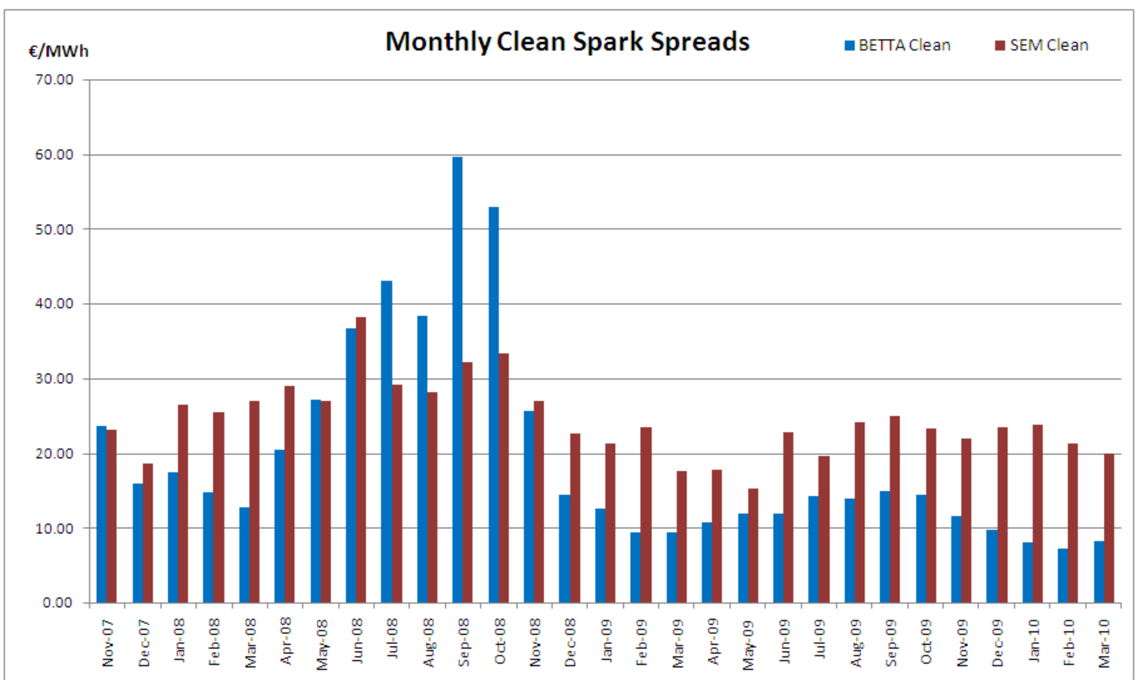


Figure 14



4.5 Generator Spot Market Share

As discussed in section 3, the RAs have market power mitigation measures in place in the SEM to prevent generators with market power abusing that power. A company's generation market share in the SEM can be determined by a number of factors:

- *Installed capacity* – higher installed capacity increases a company's maximum potential generation.
- *Station availability* – higher availability means more potential generation.
- *Station efficiency* – higher station efficiency means more competitive market bids and a greater opportunity to be scheduled in the market.
- *Relative price of station fuels* – the cheaper a station's fuel is, the more competitive its bids will be relative to stations running on other fuels.
- *Transmission Loss Adjusted Factors (TLAFs)* – higher TLAFs increase a stations competitiveness and feeds into reductions in their market bids relative to lower TLAFs.

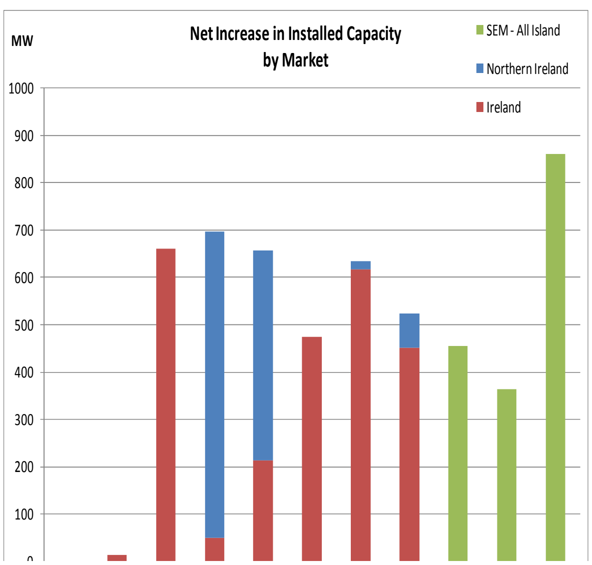
Since the beginning of the SEM, the SEM's installed generation capacity has increased, including new baseload CCGTs and new wind farms as illustrated below. As also shown in the following section, overall generator availability has increased. Generally, station efficiencies decline over time, with the exception of station refurbishments and therefore the age of a company's power stations will affect how competitive they are. The main fuels that compete in the SEM are gas and coal, and the relative price of one to the other will impact on the generation of both types of stations in the market. To date, each station within the SEM is allocated an individual set of TLAFs and those with TLAFs greater than 1.0 will incorporate a reduction on the costs of generation they bid into the market and therefore gain a competitive advantage over equivalent stations with TLAFs below 1.0. TLAFs have been revised on an annual basis and therefore these changes will feed into a company's market share - please note that the TLAFs regime is currently under review by the RAs (see www.allislandproject.org).

Installed Capacity

Over the past decade the installed capacity across the island of Ireland has increased by over 90%. The increase in electricity demand over the period has driven the need for this increased capacity across the island. In the beginning of the decade, due to concerns over new entry in Ireland, a capacity auction was held for new capacity and this was supported by Public Service Obligation (PSO). The second half of the decade has seen new investment without the support of the PSO with the exception of some renewable generation.

The figure opposite shows the net increase in installed generation capacity across the island over the past decade. These figures also account for the station retirements over the period.

Figure 15



The figures below show the installed capacity by company and by fuel type for the past decade. While the installed capacity of the incumbents has either stayed static or fallen, the increase in new capacity has come from independent generators, including ring-fenced entities connected to the incumbents.

There is also a clear trend in the types of generation entering the market, mainly gas fuel stations and wind generation.

Figure 16

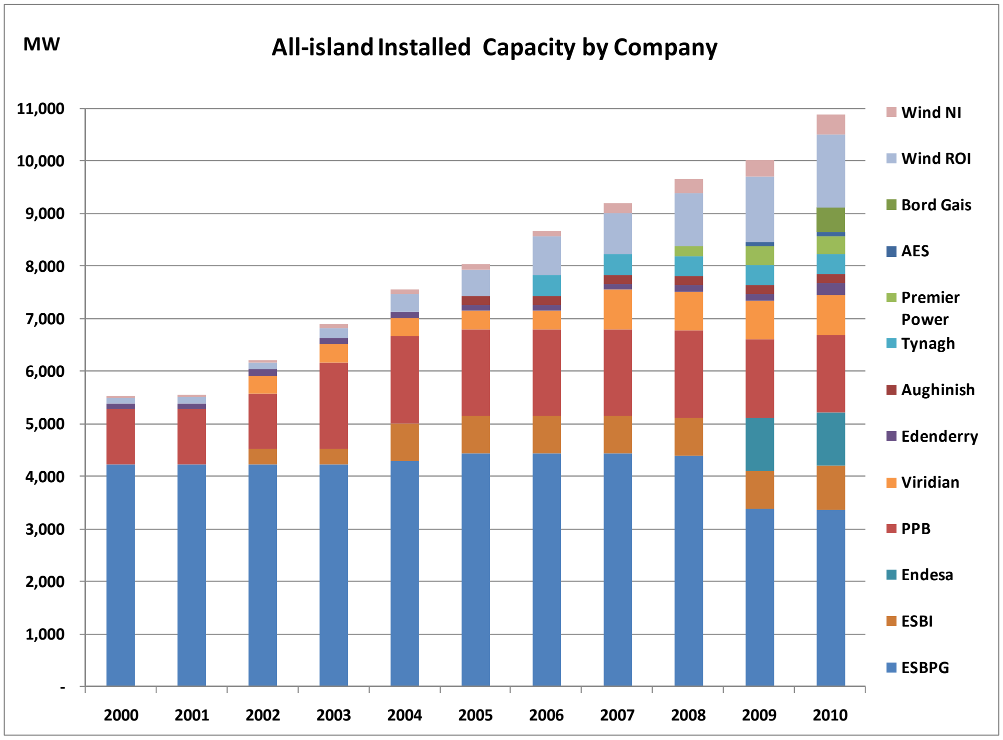
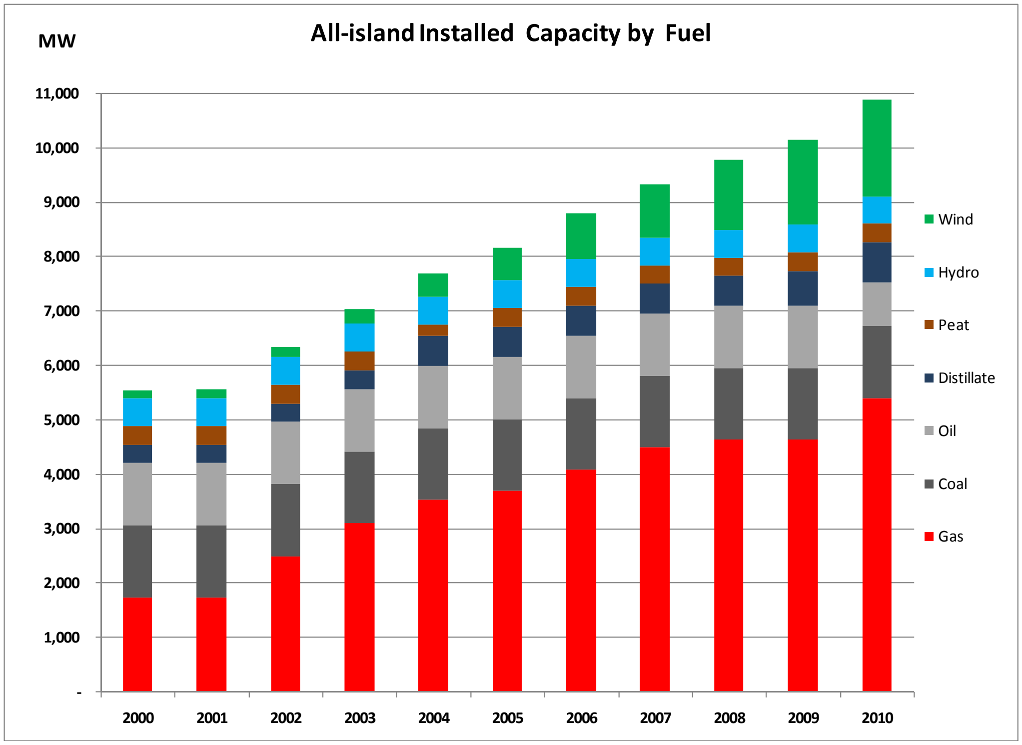


Figure 17



Available Generation

An electricity market's ability to incentive generators to make capacity available to provide electricity is an important element to a competitive market. The SEM has two features which create this incentive, marginal pricing for energy and a capacity payments mechanism. The following figures show the trends in total system availability for each year, by quarter. These figures show yearly increases across in each quarter; with the exception of Q4 2008. Increases in installed capacity would be the main driver of the increases in total availability.

Figure 18

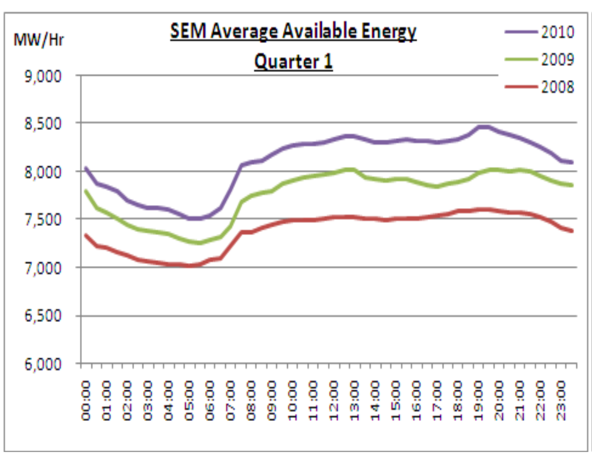


Figure 19

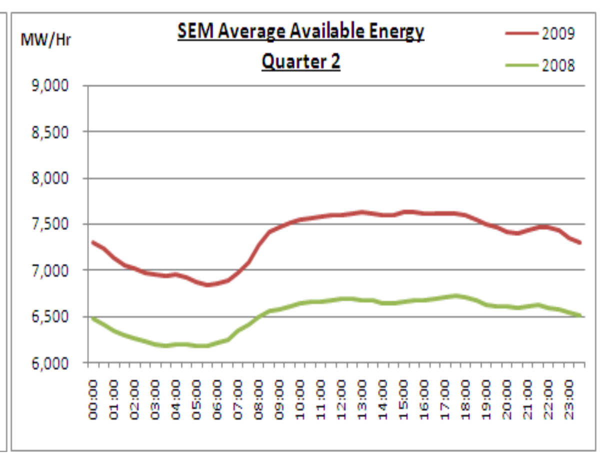


Figure 20

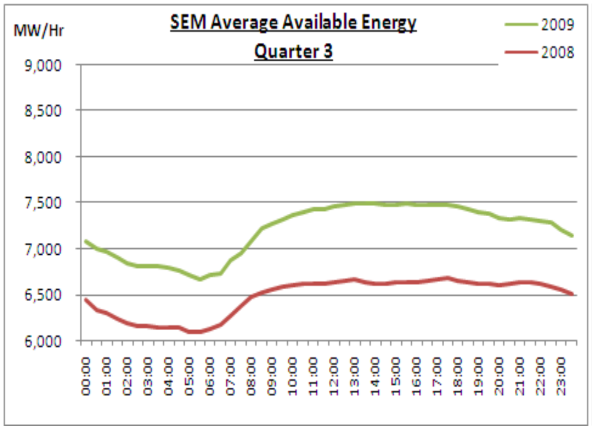
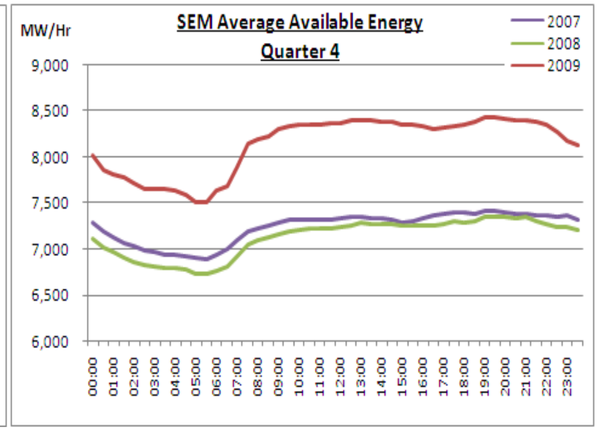


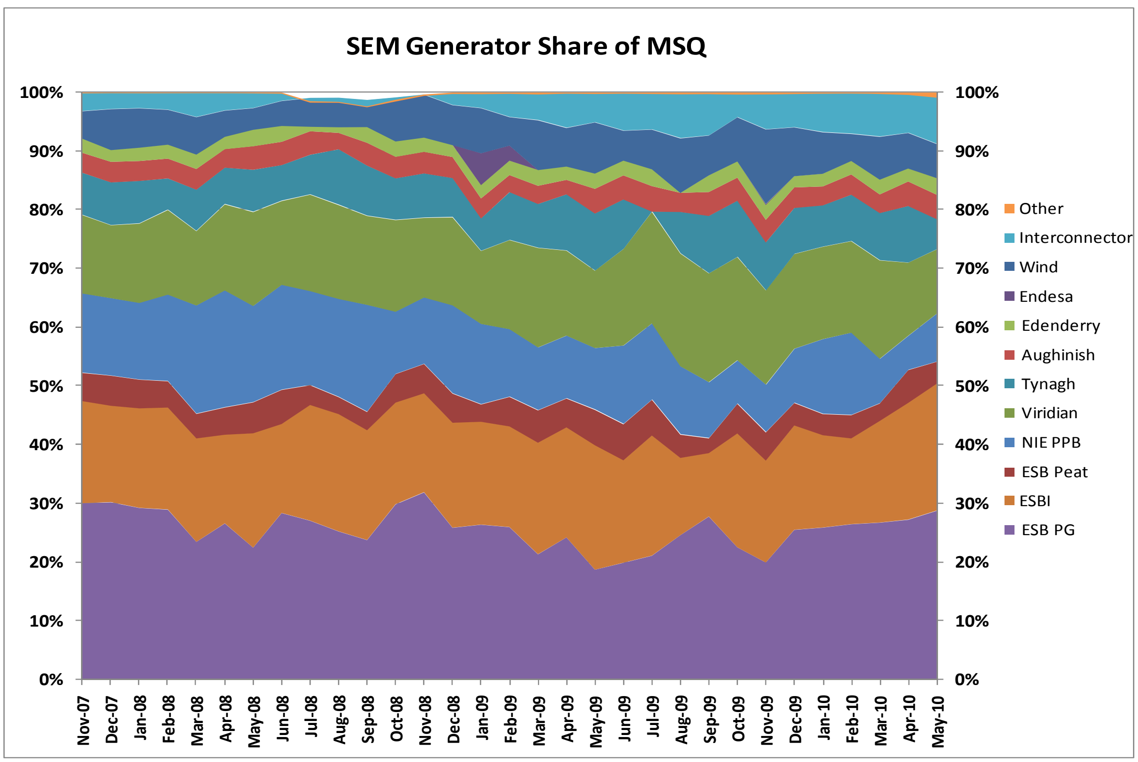
Figure 21



Generation Output

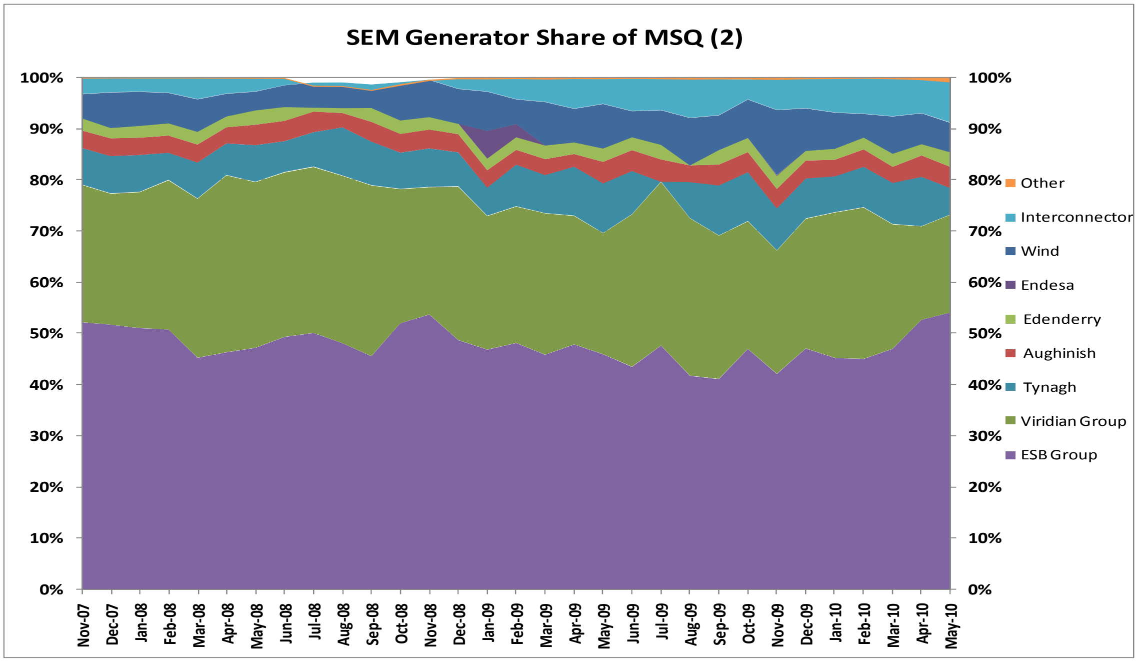
The following graphs show generation market shares by company in the SEM using their market scheduled quantity or MSQ, including ring-fenced entities, from the beginning of the market to May of this year.

Figure 22



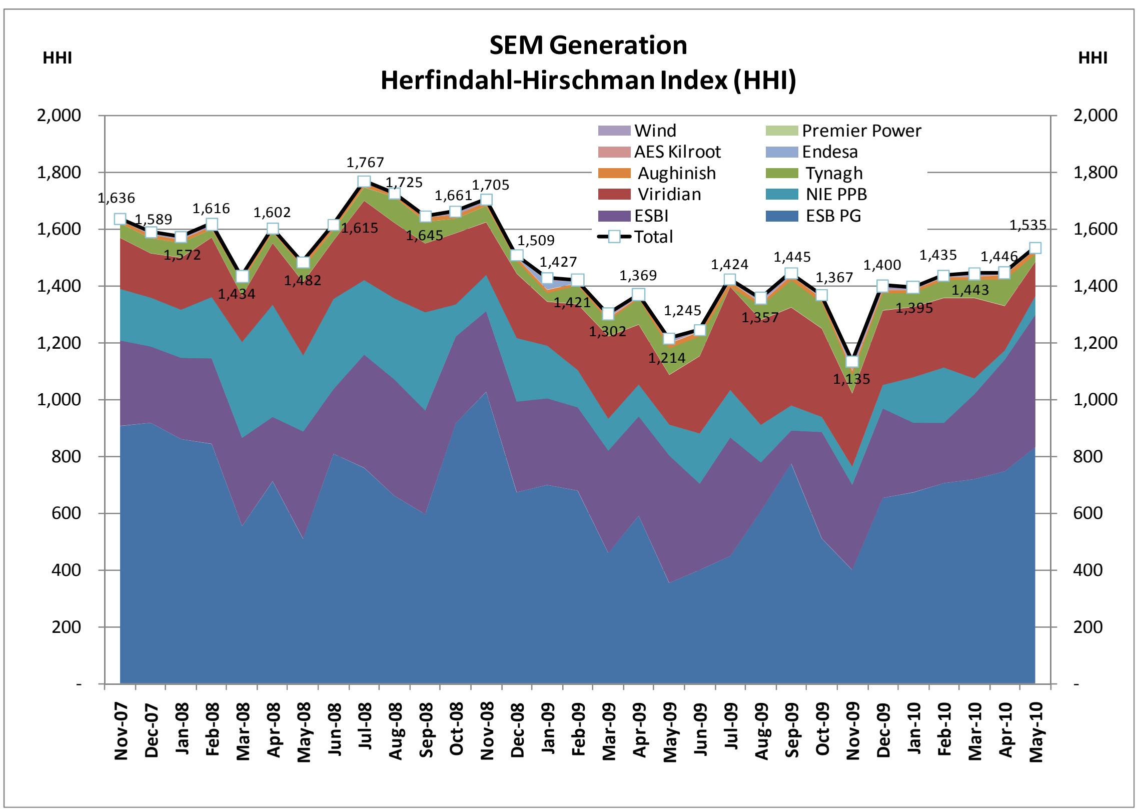
The figure below shows the generation market shares with the incumbent generators combined with their ring-fenced affiliates.

Figure 23



The following figure shows the monthly movement in the HHI from the start of the SEM through to May 2010. This follows the methodology used in calculating the HHI for the DCs on an annual basis, using pool data and excluding the contracted volumes (see section 3 for information on the policy around HHI and DCs).

Figure 24



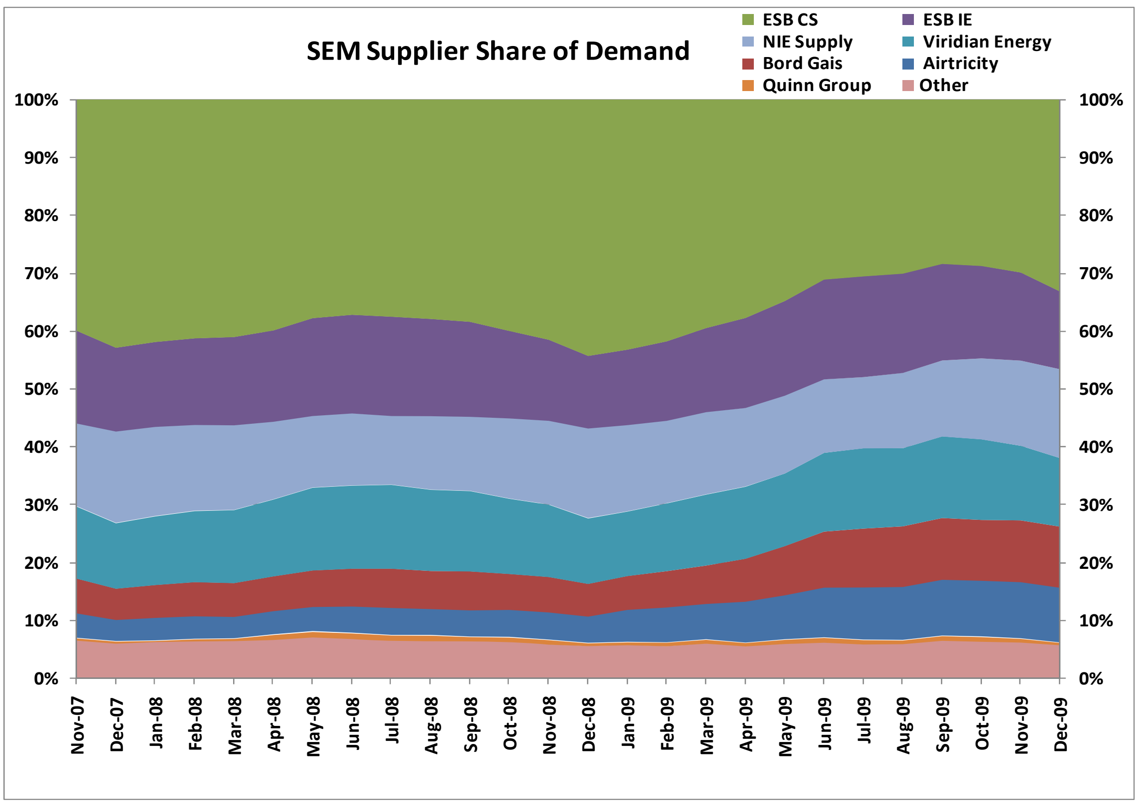
4.6 Supplier Spot Market Share

Suppliers within the SEM's gross mandatory pool have limited opportunity to influence the price of electricity, through demand side bidding, and hence exert limited market power in the spot market. A supplier's market share is as a result of the actual consumption of its customers and this is influenced by the type and number of customers that it has at any point in time. In the CfD market, suppliers have a much more central role, as they compete through bids for volumes that generators offer to the market.

It is worth noting that the retail market in Ireland and Northern Ireland are regulated separately by the CER and the Utility Regulator respectively. While a number of the independent and incumbent's affiliate companies operate in the retail markets of both jurisdictions, the incumbent public electricity suppliers only operate within their original market.

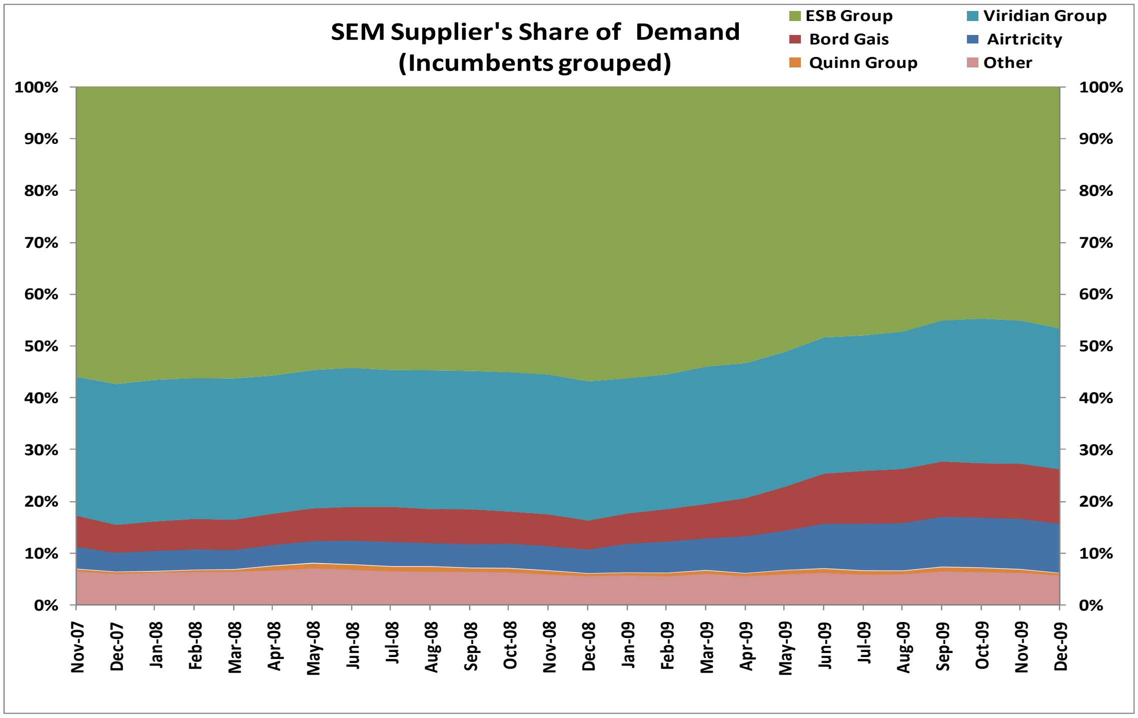
The following graph shows the market shares of each supply company from the start of the market up to the end of 2009. Sustained churn in the Irish retail market has seen ESB's combined market share (PES & ESBIE) continue to decline at a significant pace.

Figure 25



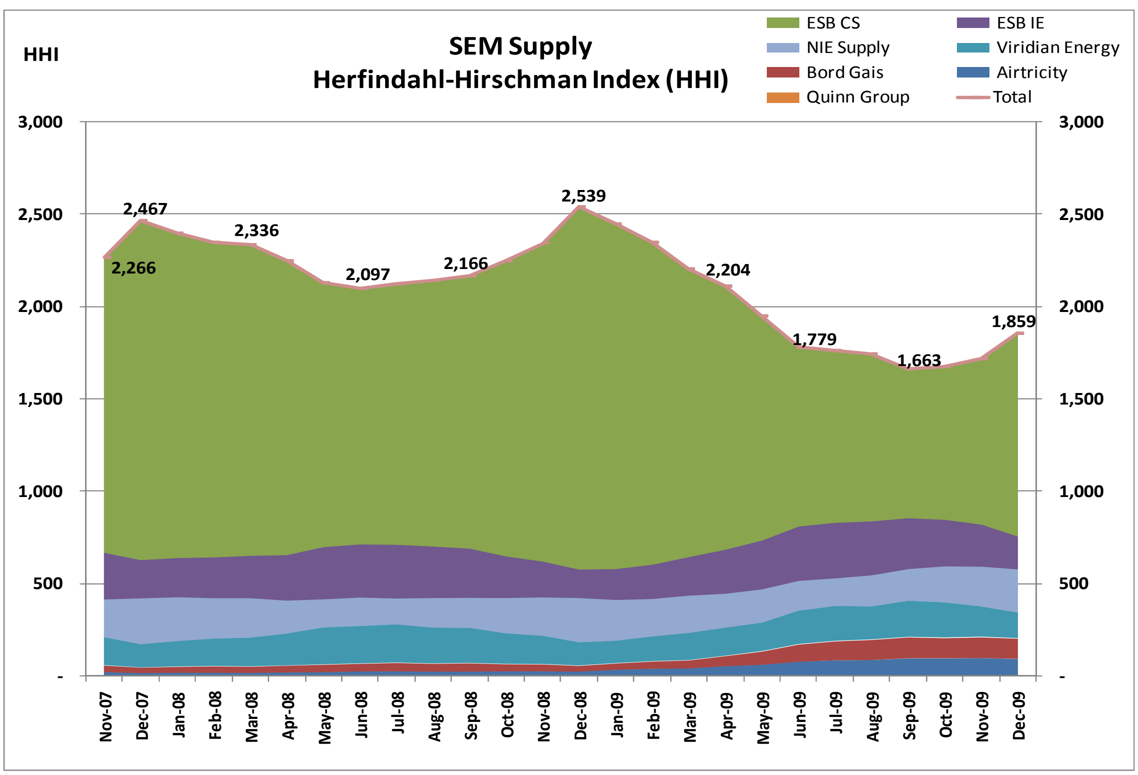
The following graph combines the incumbent supplier's market shares with those of their affiliate supply companies.

Figure 26



The market HHI for supply companies in the SEM, gives an indication of the all-island concentration, but as noted previously, the retail markets operate in two separate jurisdictions in the island of Ireland.

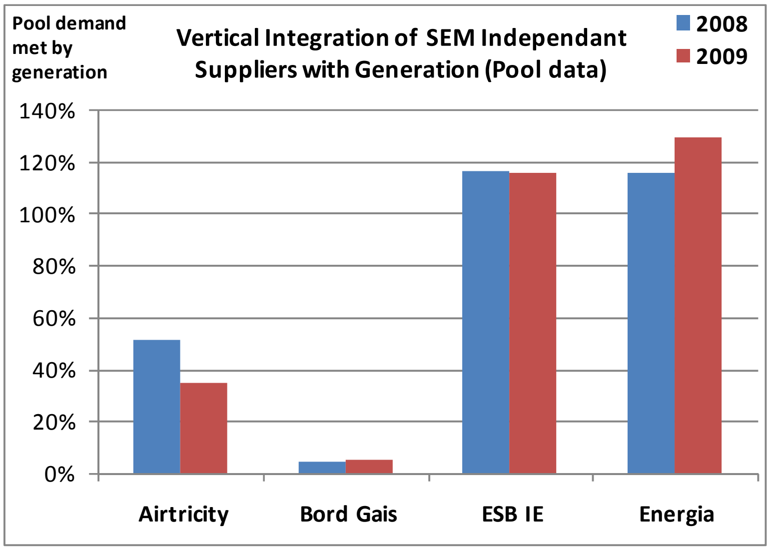
Figure 27



4.7 Vertical integration within the SEM Pool

The figure below shows the vertical integration of the largest independent suppliers in the SEM and the amount of their customer demand met by the generation of their affiliates in the SEM, thereby indicating the potential supply and demand for hedging; together they accounted for 39% and 45% of SEM demand in 2008 and in 2009 respectively. When the two incumbent suppliers, ESB CS and NIE ES, are added to these four independent suppliers, they account for 93% of demand in the SEM.

Figure 28



The figures below show the residual demand of the incumbent suppliers and generators, as well as their affiliate generation and supply companies. It would appear that the incumbent companies have a residual demand to be met, over and above their associated generation (an exception is the summer of 2008 for NIE). In contrast the affiliate supply companies of the incumbents generally have surplus generation to their demand requirements. It should be noted that gross generation and demand has been used in the following figures and does not take into account the half hourly miss-matching of generation and demand.

Figure 29

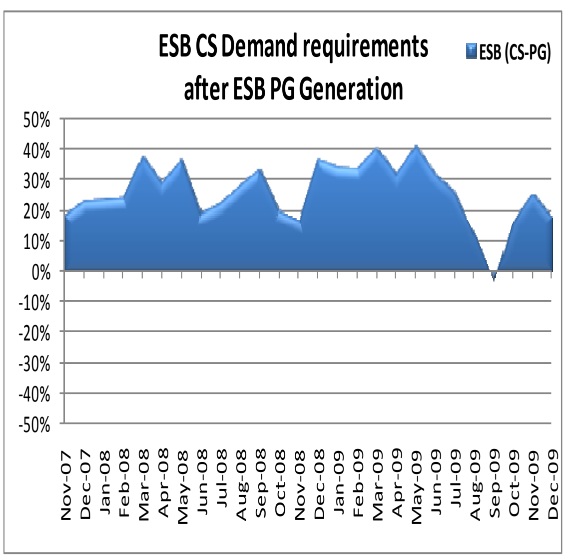


Figure 30

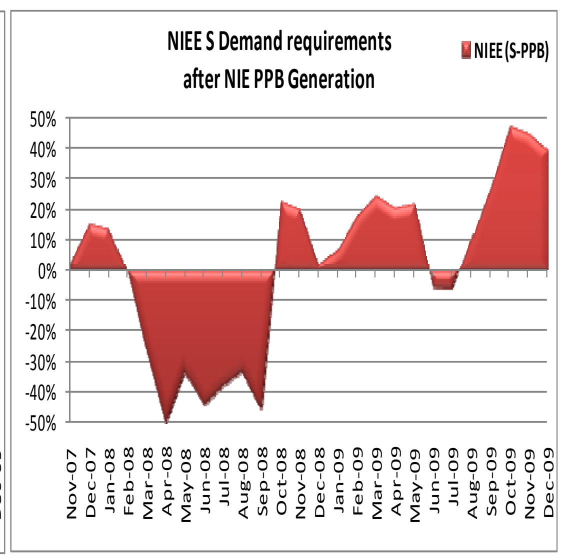


Figure 31

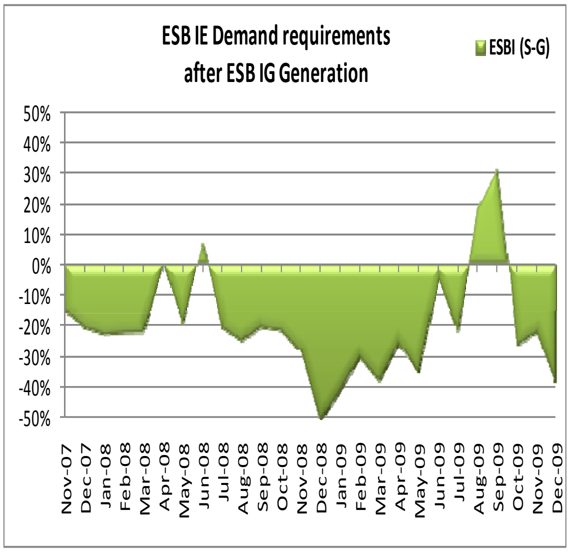
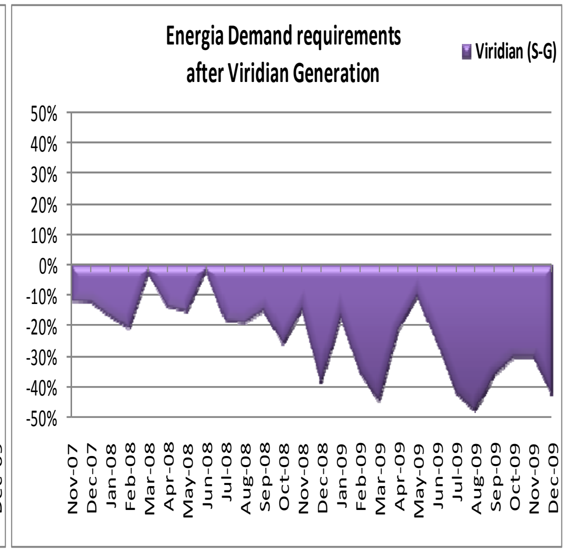
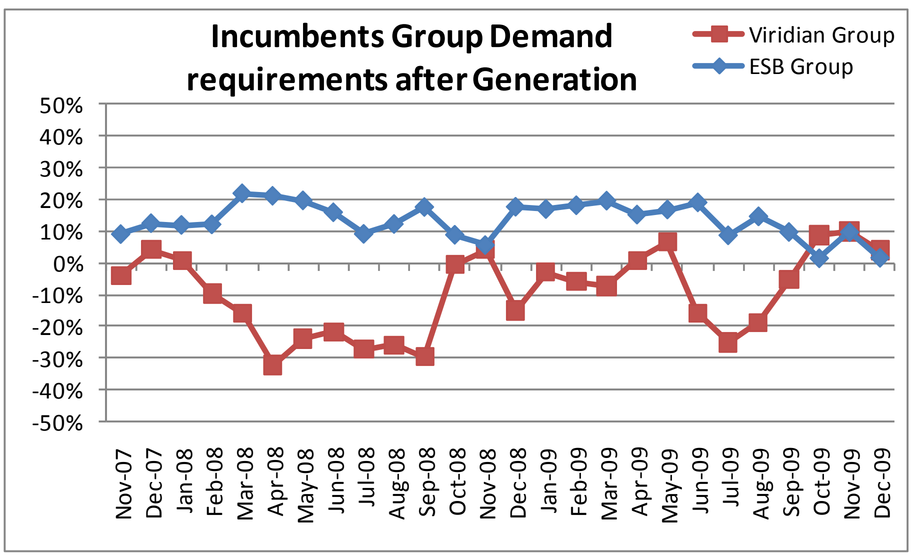


Figure 32



This next figure establishes the incumbents' net group position, and generally shows that, over the period in question, the ESB group had a net residual demand (i.e. was short in generation) and the Viridian group with a surplus generation (i.e. was long in generation).

Figure 33



4.8 Review of the Forwards Market (CfDs)

Prior to each retail tariff year the incumbent generators have offered CfDs to suppliers in the SEM. As discussed in detail in section 3, to date there have been three distinct CfDs offered to suppliers in the SEM:

1. *Directed Contracts (DCs)* – imposed on the incumbent generators by the RAs as part of the market power mitigation strategy.

2. *Non-Directed Contracts (NDCs)* –contracts that the incumbent generators offer to the market based on commercial decision making.
3. *PSO-related Contracts for Difference* –contracts that ESB PG offers to the market, who in turn pass on any difference payments receive or paid to the PSO in Ireland.

CfDs offer generators and suppliers who are not vertically integrated the opportunity to hedge their pool price risk for a period in the future. Ring-fencing arrangements for the incumbent generators and suppliers mean they seek CfDs in order to hedge their pool revenues or costs. The majority of the independent generators and suppliers are vertically integrated and therefore can source the bulk of their hedging requirements internally. Despite this independent suppliers also often require hedges with external generators to cover the parts of their forecast demand that their own generation fails to meet. To date no independent generator has auctioned CfDs for all suppliers.

The following list describes the type of CfDs on offer in the SEM:

- Baseload - 24 hours, 00:00 to 24:00.
- Mid Merit - 07:00 to 23:00 on Business days and 80% of the contract quantity on Non-Business days.
- Mid-Merit 2 - 07:00 to 19:00 on Business days or Weekdays.
- Peak - 17:00 to 21:00, available from October to March.

The following figures show the total volume of CfDs[23] offered to the market for each retail tariff year of the SEM. These figures show that the volume of CfDs offered to the market peaked for the 2008-9 tariff year and have declined in the subsequent two years. This decline started with a fall in NDC volumes and in the Baseload products in 2009-10 in accordance with their declining market share. In 2010-11 the fall was added to by a reduction in PSO related CFD and DC volumes. These declines applied similarly to the total CfDs offered by ESB PG and NIEE PPB. However there has been a rise in mid-merit and peaking volumes, which is often required by suppliers which are not fully vertically integrated (again see section 3).

Figure 34

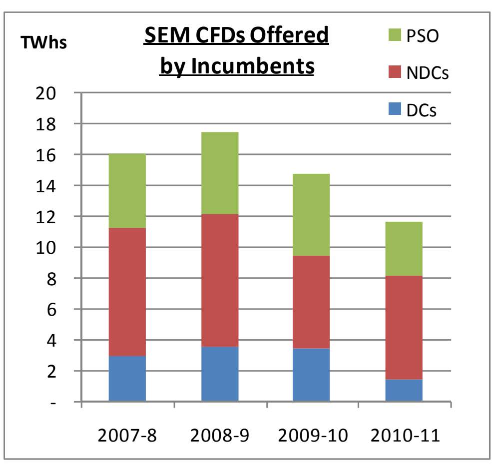
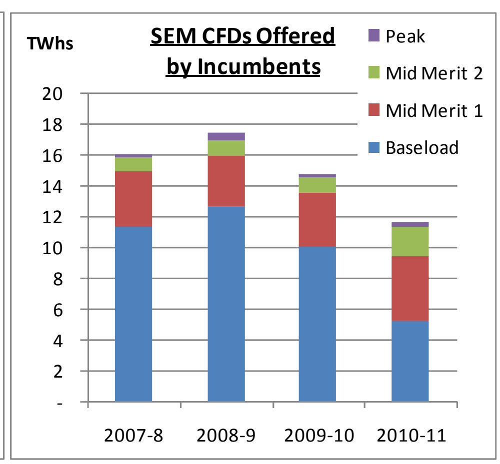


Figure 35



[23] All figures that label data as PSO refers to PSO related CfDs.

Figure 36

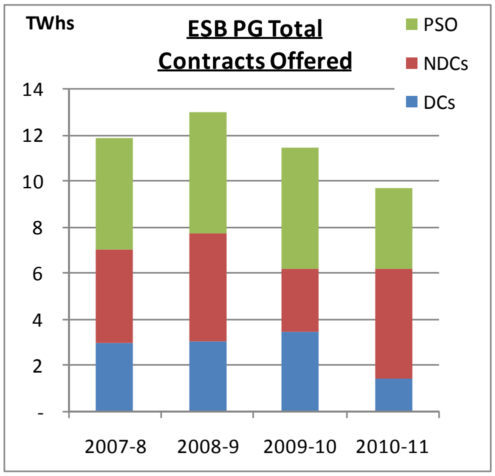


Figure 37

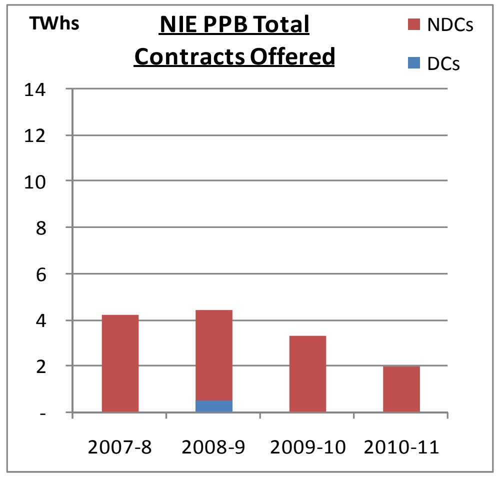
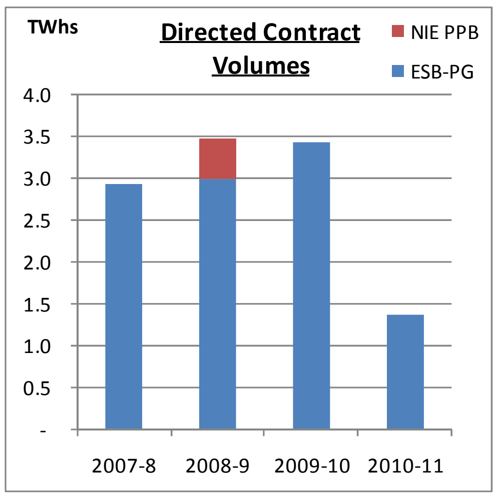


Figure 38



4.9 Timing and Variety of Contracts

The RAs determine the timing of the DC process and the PSO related contracts, while the incumbent generators determine the timing of the NDCs (see section 3).

The following figures show that the total volume of trades hasn't changed much over the first 3 years. These are dominated by the number of trades during DC process. Overall we can see that the size of contracts per trade has fallen. This is mainly in the occurred in the PSO related contracts.

Figure 39

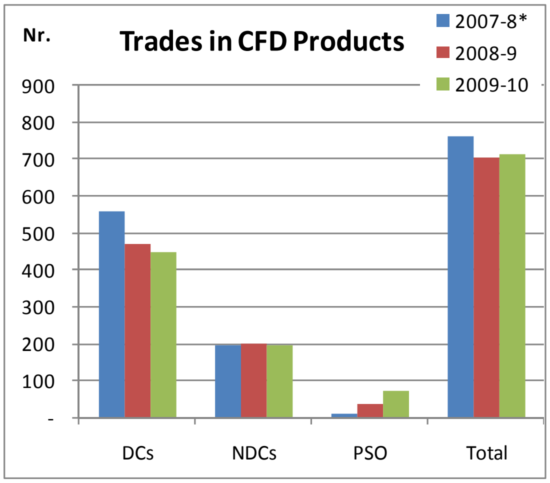


Figure 40

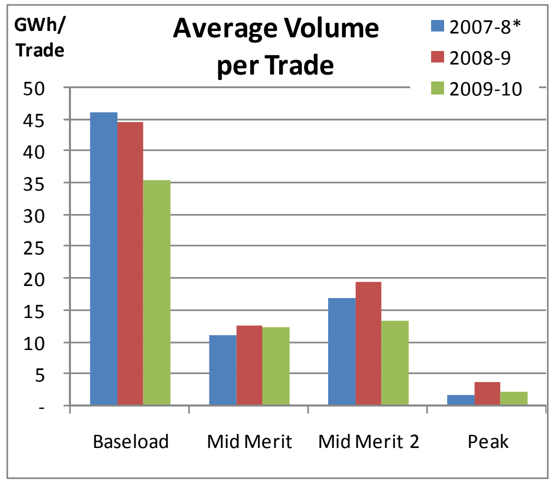
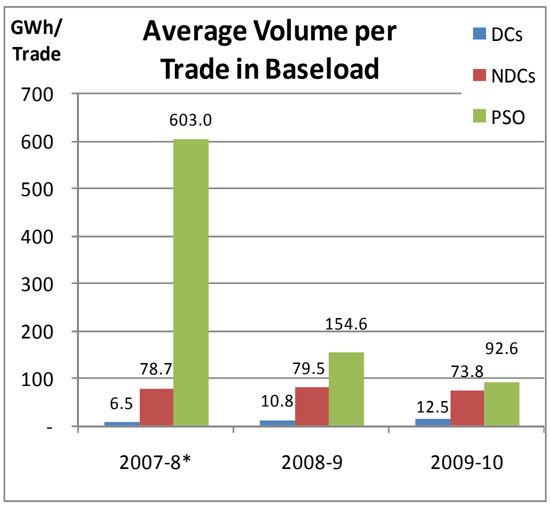


Figure 41 Figure 42



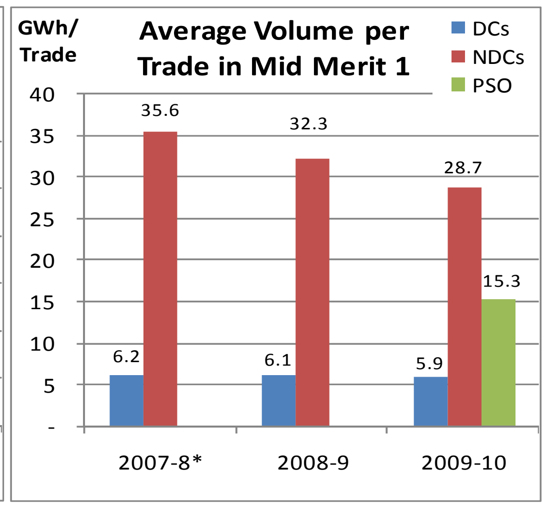


Figure 43

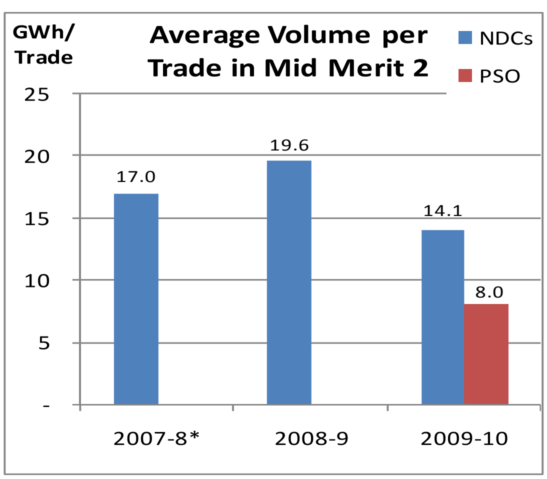
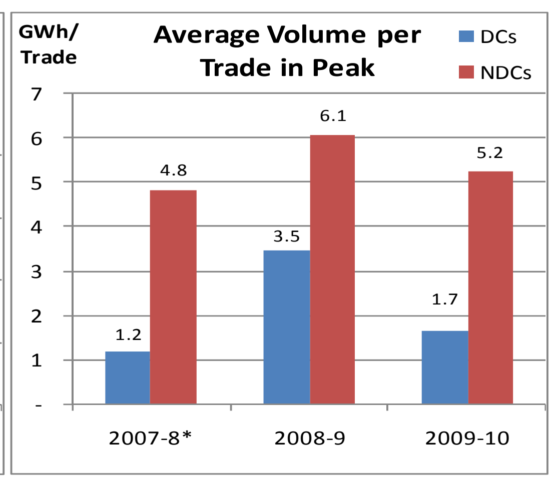


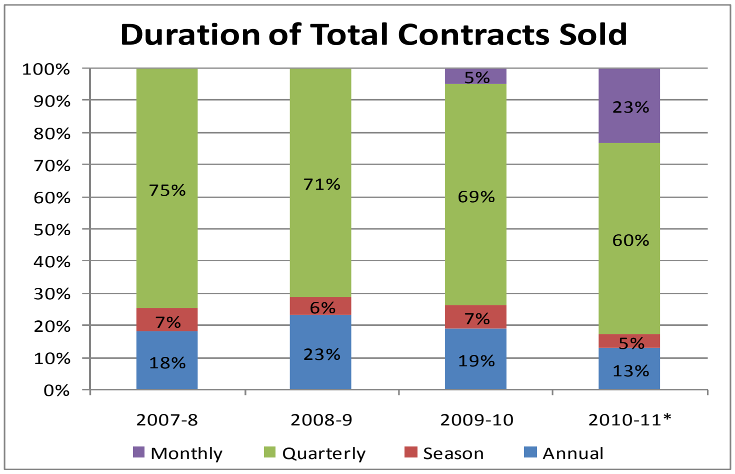
Figure 44



* 2007-8 NDC trades were pro-rata from 2008-9

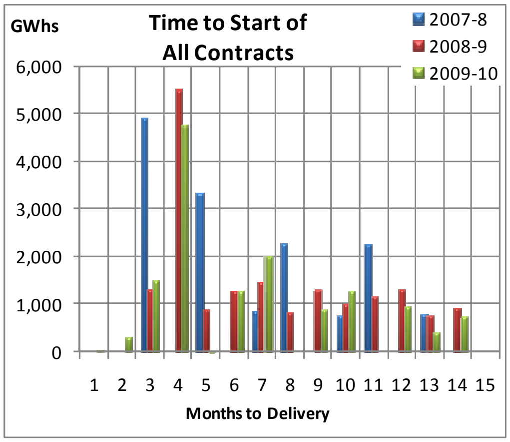
The majority of products sold in blocks of 3 months, quarterly products, while seasonal and annual products were also sold. It can be seen in the figure below that the share of shorter term products, monthly products, has been increasing from 5% for 2009-10 to 23% in 2010-11.

Figure 45



The length of time from the contract sale to the start of its delivery has not changed much over the first three years, the majority falling between 3 and 5 months. The introduction of shorter term products has widened the range particularly for the 2009-10 retail tariff year.

Figure 46



The time from contract sale to the delivery of contract volume has widened from 3-15 months to 1-16 months. The figures below show that over 50% of all contract volumes are purchased 8 months or more before the delivery period.

Figure 47

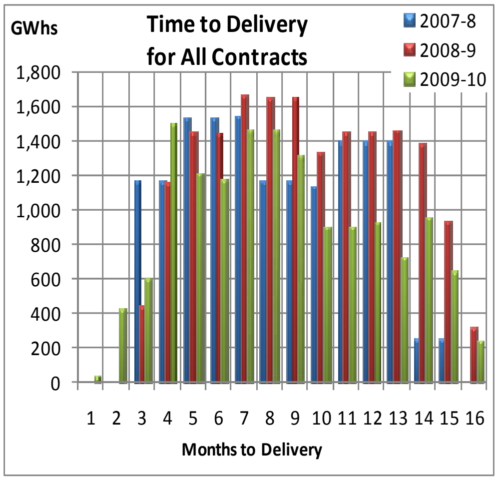
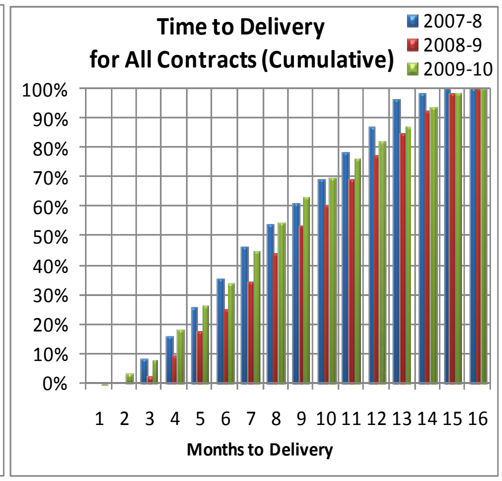


Figure 48



4.10 Generator and Supplier Contract Shares

Figure 49 below shows the increased share of ESB PG in the total contracts offered to the market (in a market where the absolute volume has been falling). Figures 50 to 54 compare the share of contracts purchased by the incumbent suppliers (ESB CS and NIE ES) and independent suppliers, from the incumbent generators. The incumbent suppliers purchase the vast majority of these contracts and this is the case for all contract types, with the exception of Mid Merit 2, where independent suppliers purchased over 50% for 2008-9 and over 30% for 2009-10.

Figure 49

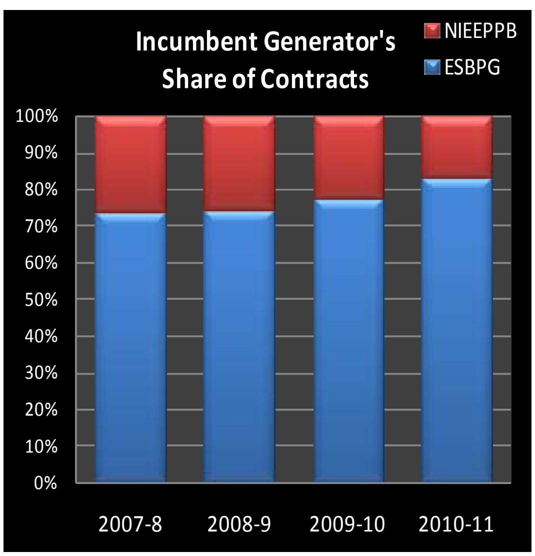


Figure 50

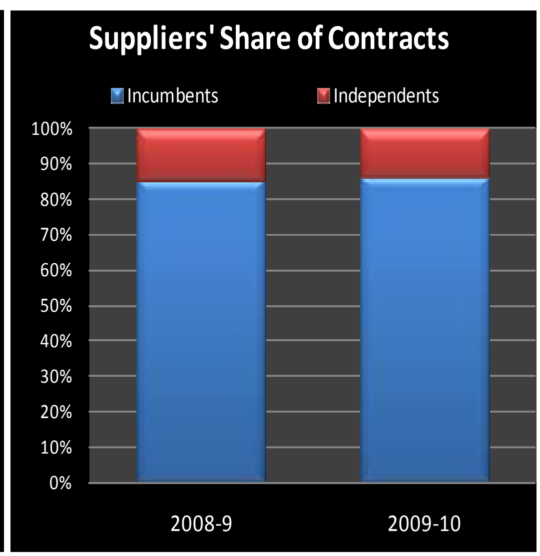


Figure 51

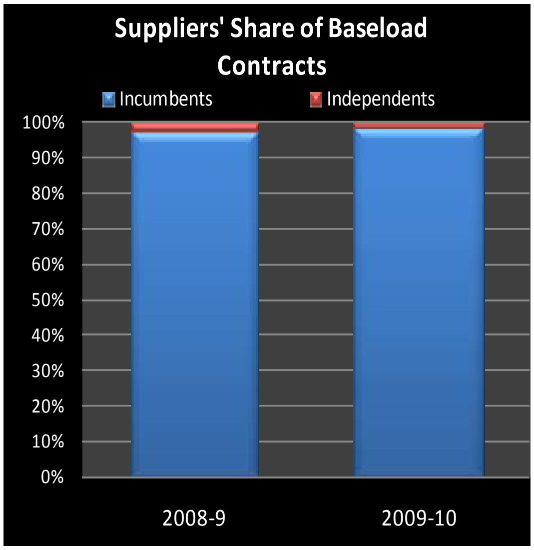


Figure 52

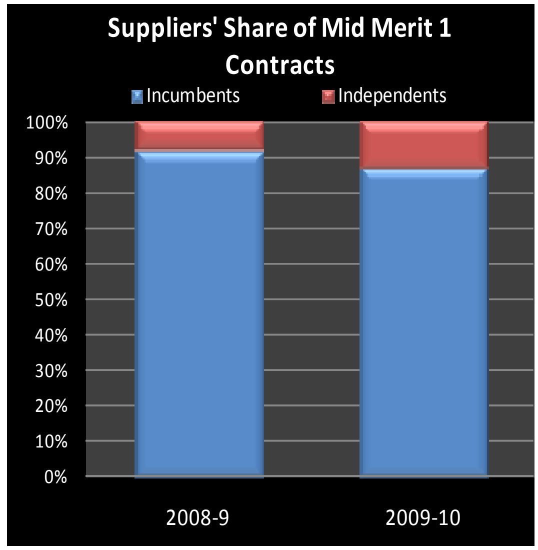


Figure 53

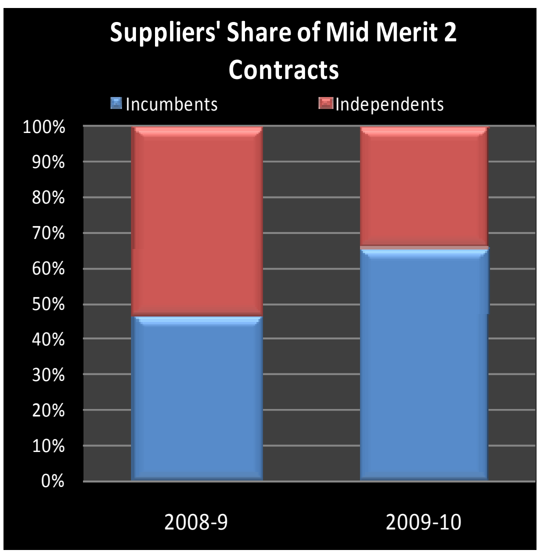
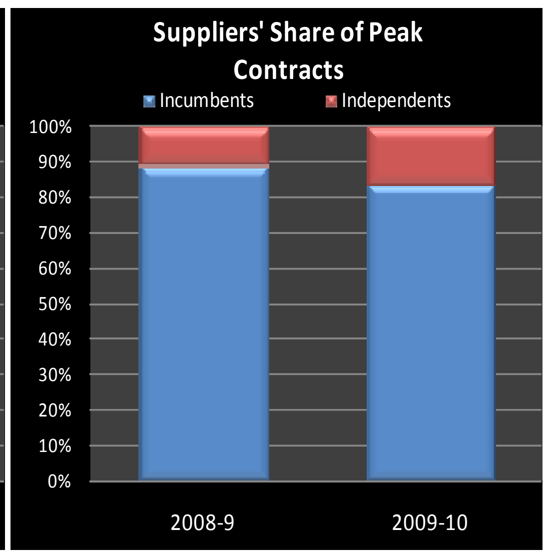


Figure 54



4.11 Trends in CFD premiums

These figures show the average premium for Baseload that suppliers have paid for NDC and PSO related CFDs over and above the reserve prices and also the DC prices in auctions. These figures show that winter products generally received a higher premiums and that the 2008 auctions saw a jump in premiums from the previous and subsequent years largely influenced by the rising prices in the fuel markets during the auctions.

Figure 55

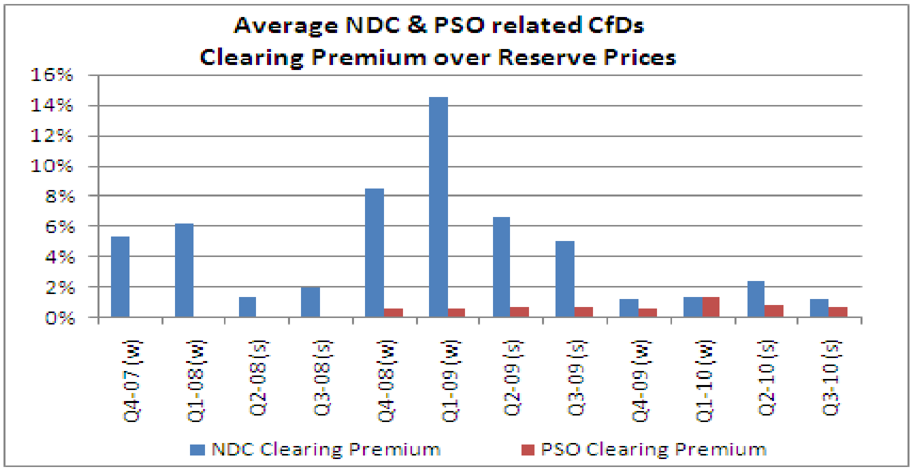
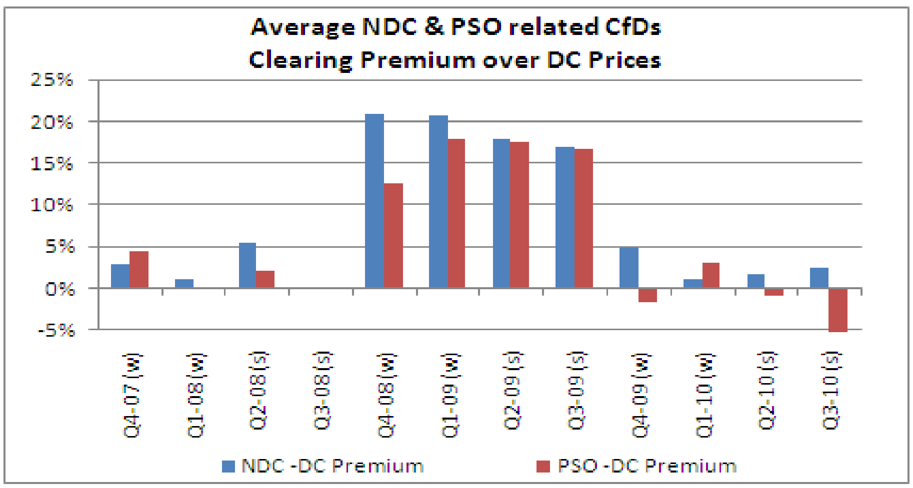


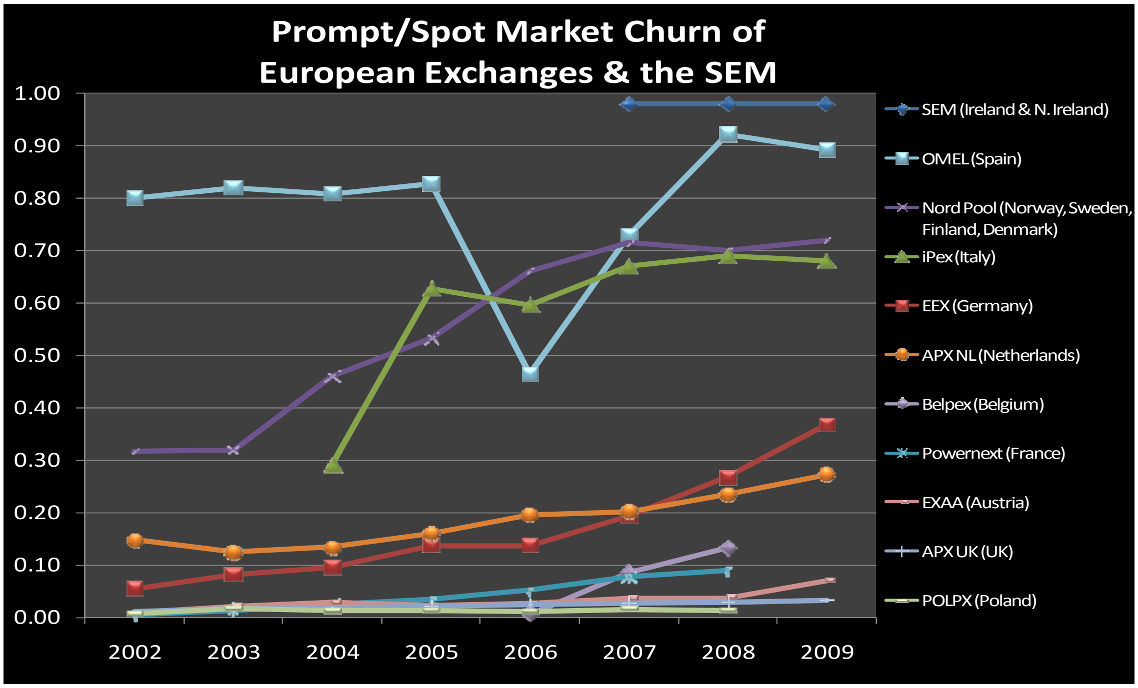
Figure 56



4.12 Comparison with other European Markets

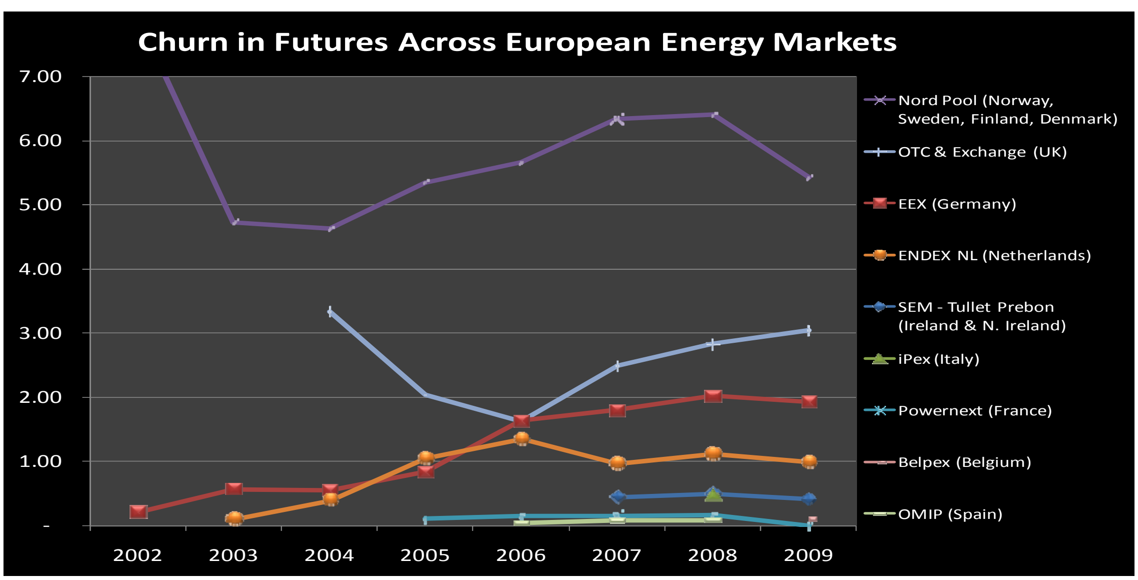
The figure below compares the Churn (volume of contracts divided by the market generation requirement) in the prompt (short term) and spot markets across Europe. Due to the mandatory obligation on generators and suppliers on the island of Ireland to participate in the SEM, it has one of the most liquid prompt/spot markets in Europe.

Figure 57



When comparing the Churn in the futures market across Europe and wide range of liquidity can be seen. Some of the large energy markets have churn ranging from 2 to 6 (EEX, OTC in the UK and NordPool), while exchanges in some of the other large markets (iPEX, Powernext and OMIP) have churn well below 1. The SEM is in between some of the smaller European Energy markets of Belpex and ENDEX. Tullet Prebon launched a power auction platform[24] for the Irish market in the beginning of 2009, where all the incumbents' NDCs and PSO related CfDs were offered. Prior to this, auctions were arranged via a fax based system, arranged by the incumbent generators.

Figure 58



[24] http://www.tullettprebon.com/irelandpowerauction/index.aspx

4.13 Interrelationships between the Spot and Forward Market

The incumbent generators offer CfDs based on forecast generation for the period in question, and will generally attempt to avoid being over hedged. The NDCs offered by the incumbents are typically determined after the RAs decide on the DC volumes. The following figures compare the contracted volumes against the actual MSQs for both ESB PG and NIEE PPB. This shows despite the incumbents desire not be over hedged, they had CfD volumes exceeding their market schelued quantities (MSQs) for a number of months in 2009. This was largely as a result of the relative increase in coal to gas prices, which meant coal stations like ESB PG's Moneypoint and NIEE PPB's Kilroot powers stations were not being scheduled in the market.

Figure 59

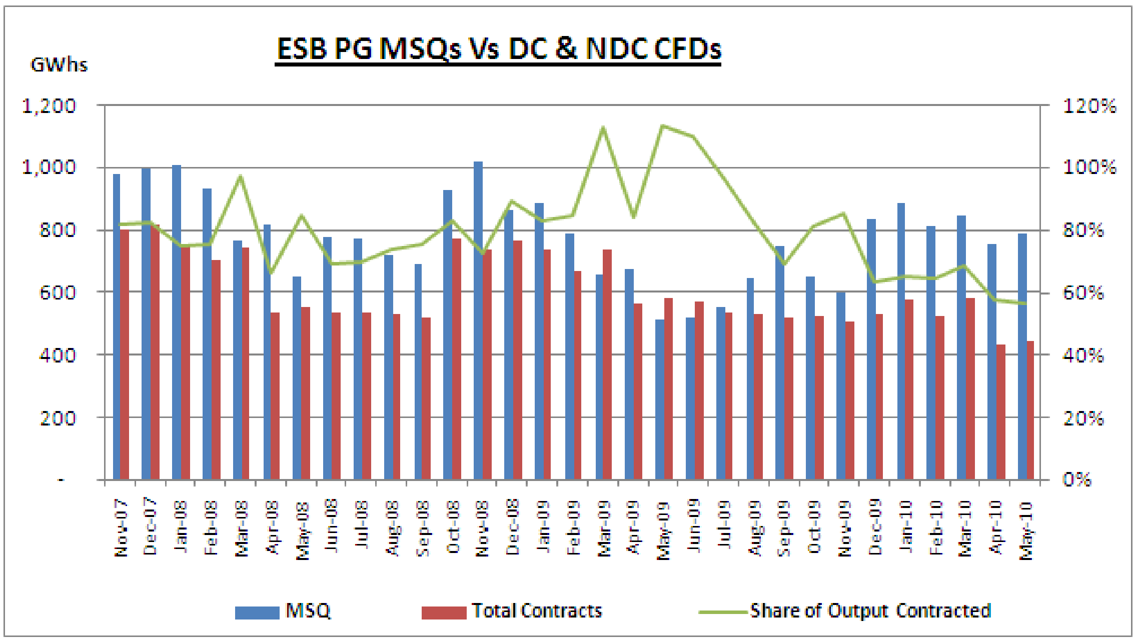


Figure 60

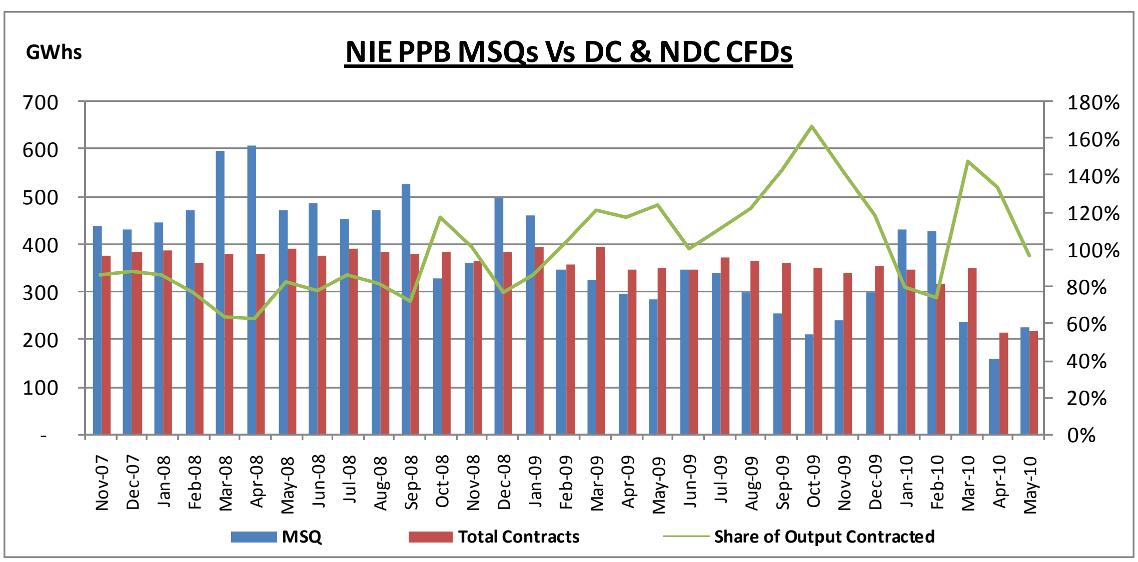


Figure 61

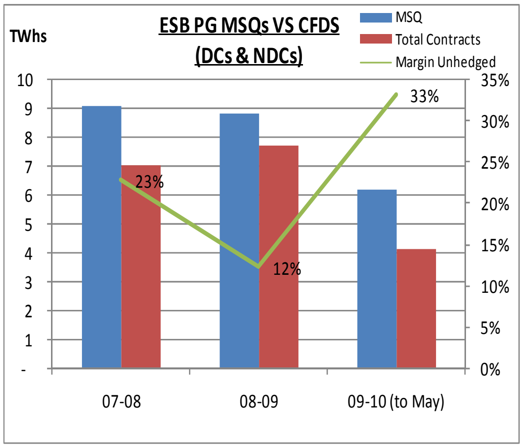
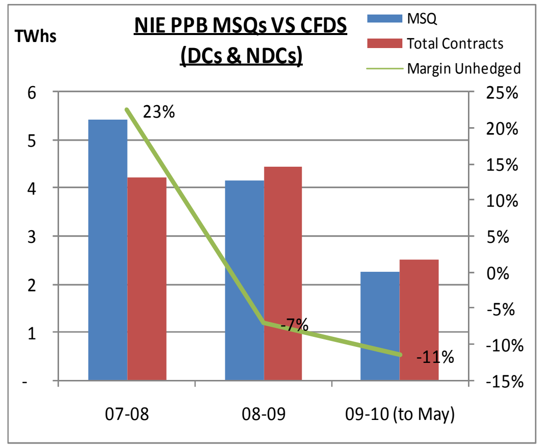


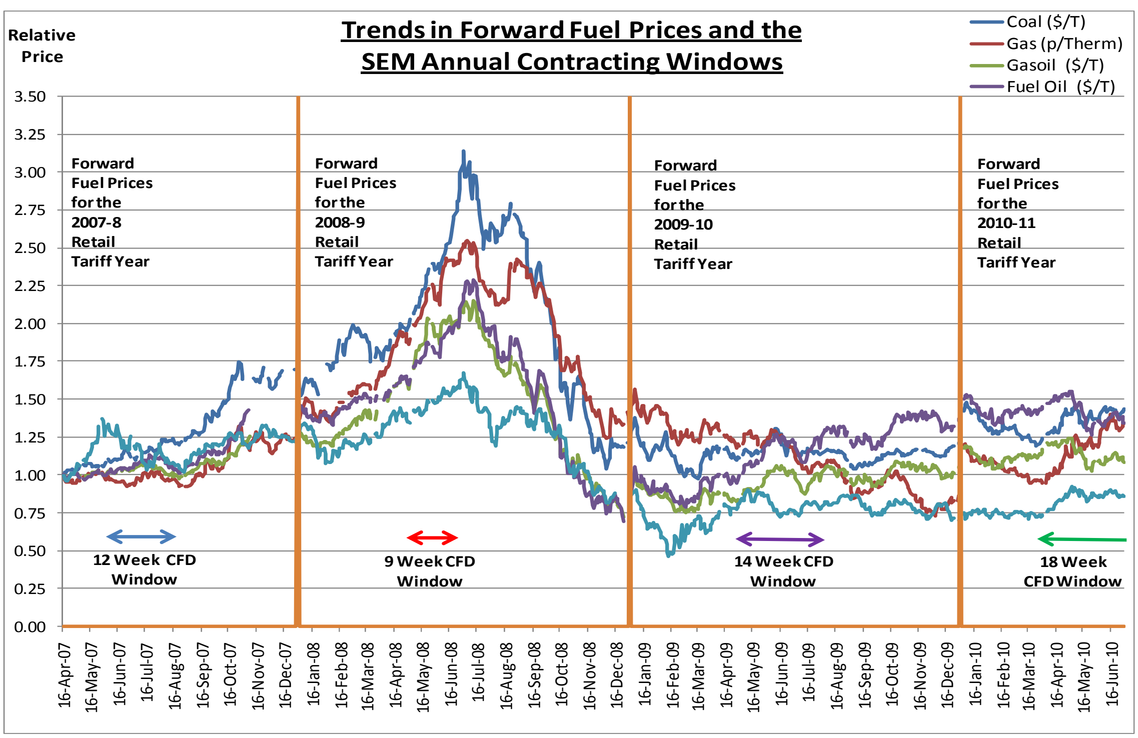
Figure 62



4.14 Strike prices Versus Out-turn prices

The majority of SEM contracting that has taken place during relatively short windows ranging from 9 to 18 weeks held about 6 months before the beginning of the relevant retail tariff year. As can be seen in the figure below, in some years the forward fuel prices rose significantly after the contracting window completed (2007-8), and in others it fell significantly (2008-9). The 2009-10 contracting window saw the commencement of short term contracting, offered by ESB PG at the end of 2009 and during 2010. The PSO related CfDs have also been offered as short term products during 2010.

Figure 63



The figure across shows the trends in CfD prices for the first three retail tariff years and these prices largely reflect the movement in the fossil fuel prices depicted in the figure above. A supplier who hedges with CfDs that are struck up to 6 months before the beginning of the retail tariff year commences, can be at a competitive disadvantage if fuels prices fall during the retail tariff year, relative to other suppliers who hedge on a shorter term basis.

The graphs in the figures on the next page show the trends in Difference payments for the DCs over the first three retail tariff years. The first tariff year shows difference payments going from the ESB PG to suppliers but this reversed in the subsequent two tariff years.

Figure 64

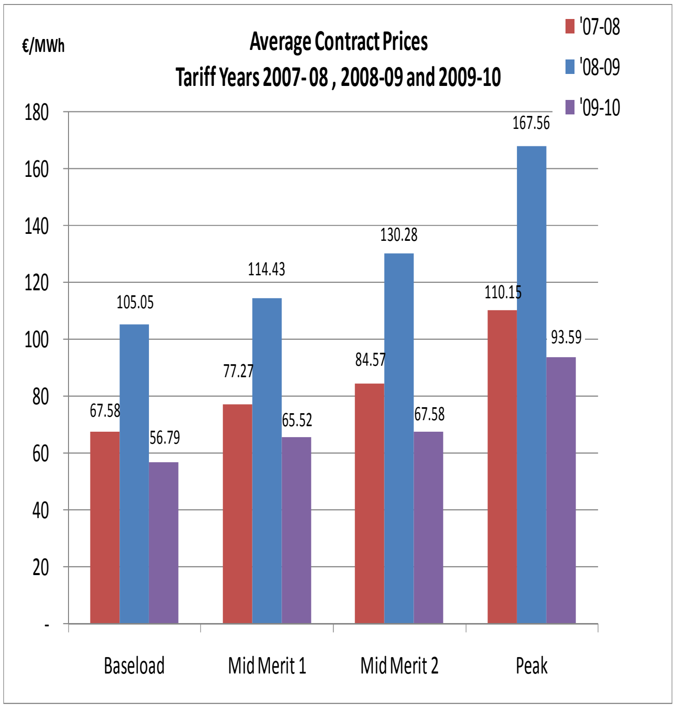


Figure 65

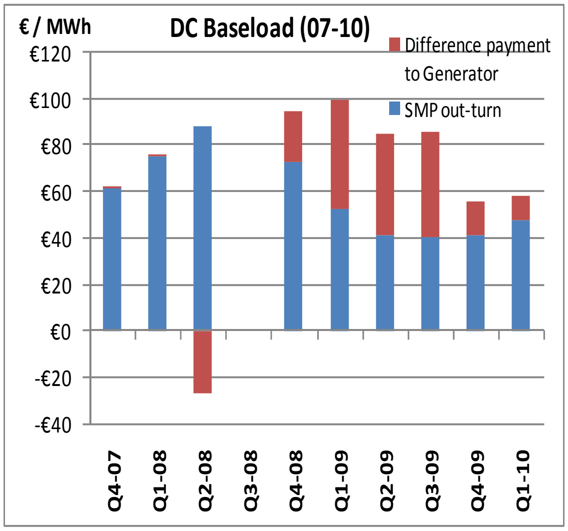


Figure 66

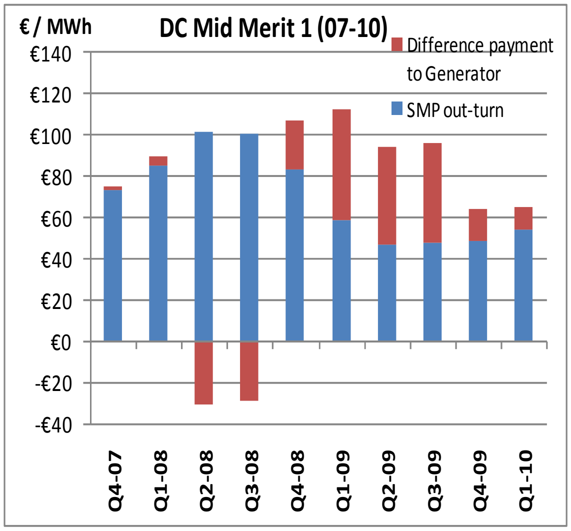
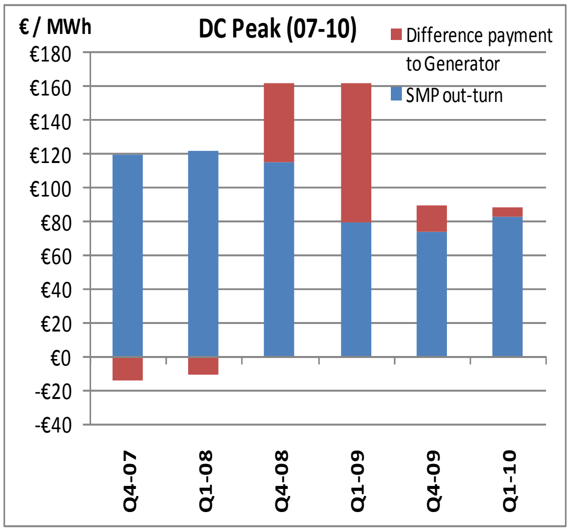


Figure 67



4.15 Relative Contracting of Incumbent Generator and Suppliers

These figures show the total contracts offered and purchased by the incumbent generators and suppliers for two tariff years. The incumbent suppliers generally purchase their hedges from both incumbent generators and these figures show whether they could self supply their associate company i.e. that ESB PG (including DC, NDC & PSO related CfDs) can provide all the contracts that ESB CS purchased in the relevant year. We can see that ESB CS could source all its contracts from ESB PG with the exception of Mid Merit 2, but this could be sourced from either the unsold Baseload or the Mid Merit 1 offered to independent generators. NIE ES would appear be able to source sufficient Mid Merit 1 and 2 from NIE PPB but would have more difficulty acquiring sufficient Baseload and Peak products.

Figure 68

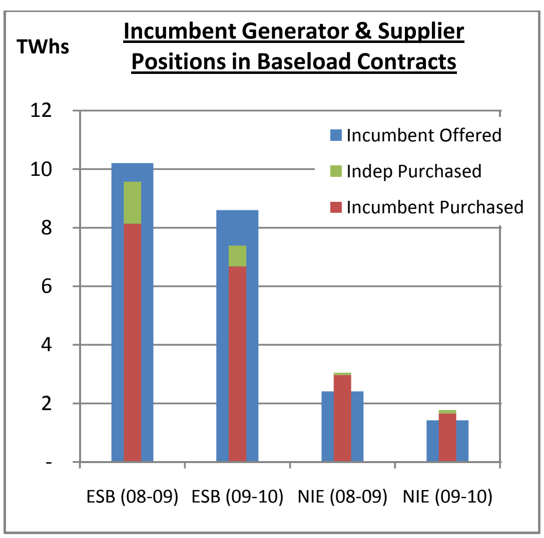


Figure 69

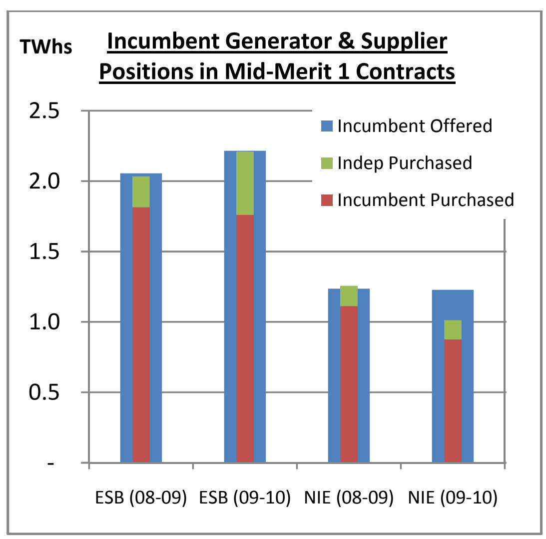


Figure 70

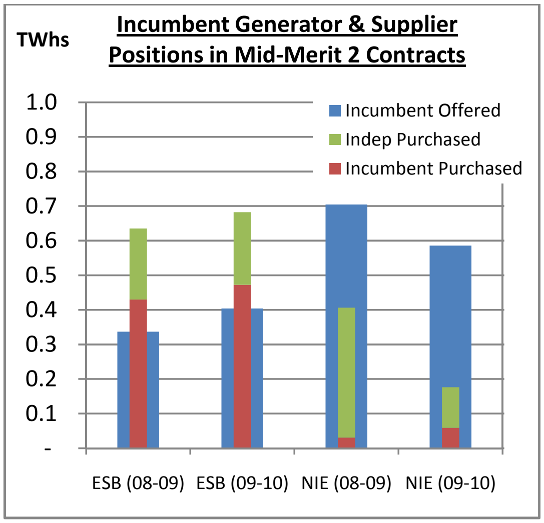
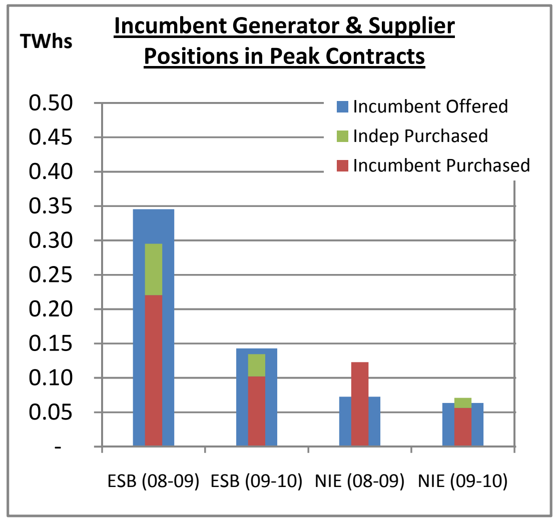


Figure 71



4.16 Incumbent Ring-fencing arrangements and EPO Compliance

The RAs monitor compliance with ring-fencing and the economic purchase obligation separately.

CER receives annual licence compliance reports from each of the licenced generation and supply businesses of ESB. These reports include the businesses' confirmation that they have been compliant with all the ring-fencing conditions. ESB CS is the only supply company that has an EPO and their compliance is audited annually by auditors appointed by the CER.

Licence ring-fencing conditions on both NIE PPB and NIE Energy include a requirement for separate businesses and separate accounts, and a prohibition on cross subsidies. Compliance with these conditions is monitored by NIAUR. NIE Energy has a similar EPO obligation to ESB CS, which is monitored for compliance by NIAUR.

Appendix 1 – Summary of Referenced SEM papers

- AIP-SEM-74-05, **'Market Power and Market Structures Paper', RA Decision paper,** http://www.allislandproject.org/en/market-power-consultation.aspx?article=4197db9b-a5b1-4567-b39c-e80523077bd1
- AIP-SEM-02-06, **'Market Power Mitigation in the SEM', RA Decision,** http://www.allislandproject.org/en/market-power-consultation.aspx?article=42e2f5ce-b5e7-455f-933f-1ad2393bd4e0
- AIP-SEM-31-06, **'Market Power Mitigation in the SEM - Decision Paper', RA Decision,** http://www.allislandproject.org/en/market-power-consultation.aspx?article=42e2f5ce-b5e7-455f-933f-1ad2393bd4e0
- AIP-SEM-07-16, **A Strategy for the Regulation of ESB and NIE in the Single Electricity Market: A Consultation Paper',** http://www.allislandproject.org/en/generation.aspx?article=13cbd060-b1a5-4357-8afa-b4ad557fd4ce
- AIP-SEM-07-304, **'SEM Regulation Decision', RA Decision,** http://www.allislandproject.org/en/generation.aspx?article=4ad994c7-e273-485d-a30f-c658a34e90f7
- SEM-10-022, **'Directed Contracts 2010/2011 Quantification and Pricing: A Decision Paper',** http://www.allislandproject.org/en/market_decision_documents.aspx?article=94e789fa-a86c-42a3-944a-919766a1850b&mode=author

Appendix 2 – Generators Gas Transmission charges

Of the gas transportation charges that impact on electricity generation within the SEM, transmission charges are the most relevant as the vast bulk of generators operating in the SEM are Transmission connected.

Republic of Ireland

Since 2003 Ireland has operated an entry/exit system. Under this approach each separate entry and exit system has a tariff. The separate entry points that currently exist are:

- Inch – the entry point for the Kinsale and Seven Heads gas fields (and associated storage); and
- IC 1 and 2 – the single entry point for the gas shipped from GB.

In the near term the Bellanaboy entry point is expected to become operational, this is the entry point for the Corrib gas field.

A single exit point relating to the onshore system exists whereby the same tariff is charged no matter where the gas is taken off the system.

In relation to charges for transporting through the transmission network, in 2007 the CER carried out a comprehensive review of the price control regime for BGN transmission system for five years from 2007/08 to 2011/12. The price control sets out the revenues which BGN will be allowed to recover over the period (see the CER Decision Paper CER/07/110).

A revenue control formula is used to calculate the maximum allowed revenues for BGN's transmission business for a given year of the control period. These allowed revenues are set against a revised forecast of peak day and throughput demand values to produce annual transmission capacity and commodity tariffs. The CER recently publish a proposed decision on the BGN transmission tariffs for 2010-11 (see CER/10/111).

In 2007 BGN developed a tariff methodology which sets the prices for short term (monthly and daily) capacity products at entry and exit as a percentage of annual tariffs. The CER decided upon the pricing of these short term transmission capacity tariffs as required under European Regulation EC1775/2005 (see CER/07/115).

Northern Ireland

Currently transmission tariffs in Northern Ireland are postalised. Any transmission user pays the same per unit charge as any other transmission user, no matter where gas is taken off the transmission system and this charge includes both the entry (the transportation of the gas to the onshore system) and exit (transportation of the gas through the onshore system) costs. This is in part a reflection of the fact that all users are supplied via the Scotland to Northern Ireland Pipeline (SNIP) and consequently have the same marginal source of gas. It also, however, reflects the legislative position where the 2003 Energy (Northern Ireland) Order requires the Utility Regulator to base tariffs on a postalised system.

The forecast transmission tariffs are calculated as follows:

Transmission capacity tariff is calculated by multiplying the total Postalised allowed costs by the capacity proportion (75%) and dividing the result by the total booked capacity. Similarly, the transmission commodity tariff is calculated by multiplying the total Postalised allowed costs by the commodity proportion (25%) and dividing the result by the total forecast volumes.

Both PTL and BGE(NI) offer firm and interruptible services under their codes. However, these are not offered down to a minimum period of one day. Northern Ireland has piloted an inventory product but this is not yet available. To date there has been no harmonisation of these products with the Republic of Ireland. The Common Arrangements for Gas (CAG) project will harmonise the products available in Northern Ireland and the Republic of Ireland in compliance with relevant European Gas regulation requirements. It is proposed that under CAG, Shippers will book Entry and Exit Capacity products separately according to the rules in the CAG code.

BGE (UK) is price controlled. NIAUR carried out a five year price control in 2007 for the period 07/08 to 11/12. The price control sets out the revenues which BGE (UK) will be allowed to recover over the period.

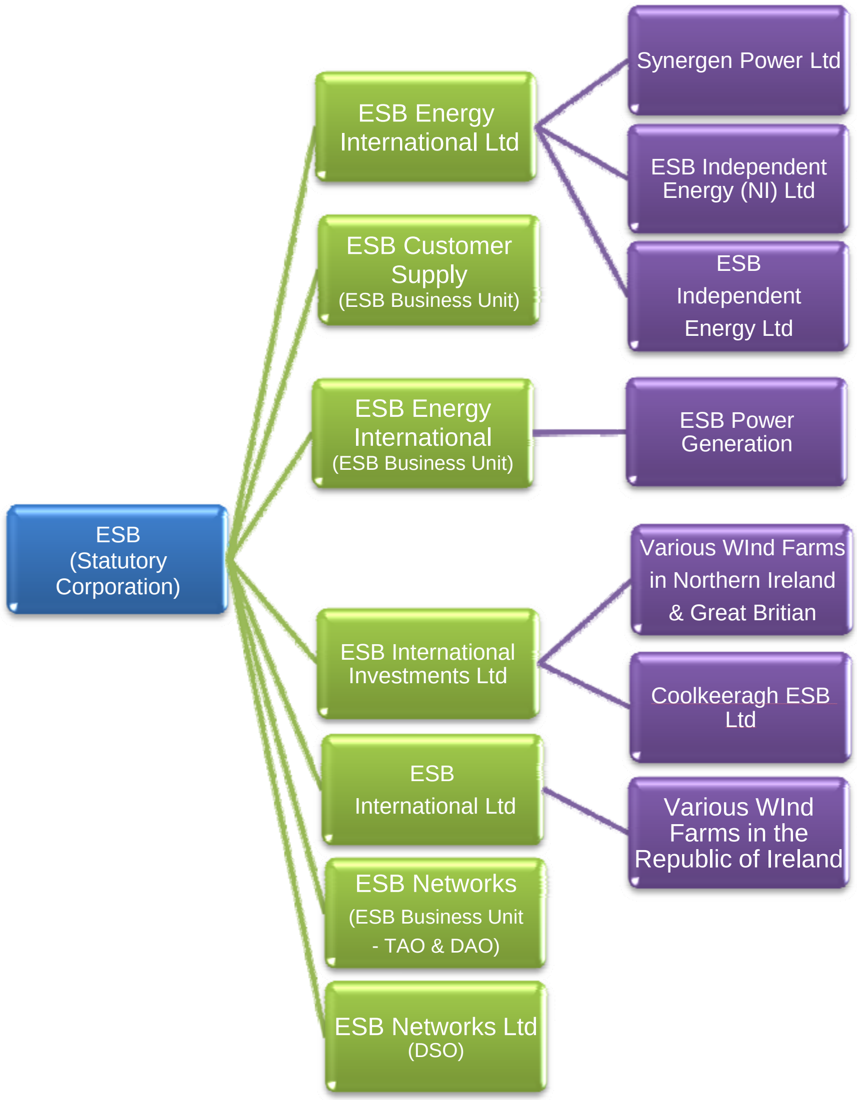
PTL and BGTL's financing are based upon a mutualised model which results in lower financing costs. In order to achieve the benefits of mutualisation, the normal regulatory control over any allowed operational expenditure accrued by both PTL and BGTL has been removed. This entails transferring certain risks to consumers which are normally retained by the shareholders. The resulting transfer of risk has been limited through corporate governance licence conditions contained within the conveyance licences held by both PTL and BGTL. One of these is a condition that allows the Utility Regulator to review the level of operating expenditure forecast to be incurred by PTL and BGTL in the form of a shadow price control.

All Island – Common Arrangements for Gas

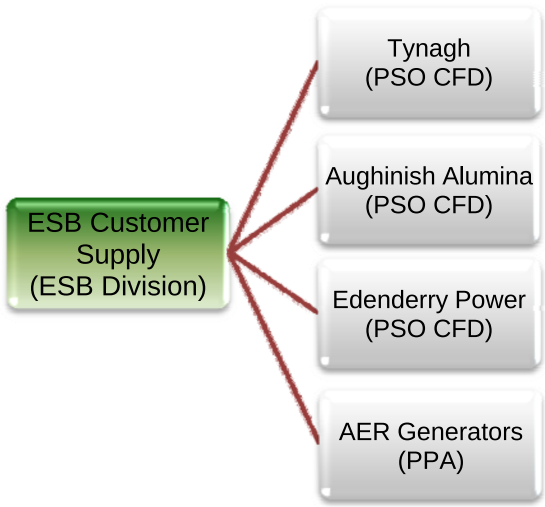
On 14 Feburary 2008 the CER and NIAUR signed a Memorandum of Understanding in relation to Common Arrangements for Gas (CAG). The aim of CAG is to establish All-Island common arrangements for gas whereby all stakeholders can buy, sell, transport, operate, develop and plan the gas market north and south of the border effectively on an all-island basis. It is expected that CAG will harmonise arrangements for gas at transmission level over the next number of years.

Appendix 3 – Regulatory Structure of Incumbent Electricity Companies

1. Electricity Supply Board (ESB)

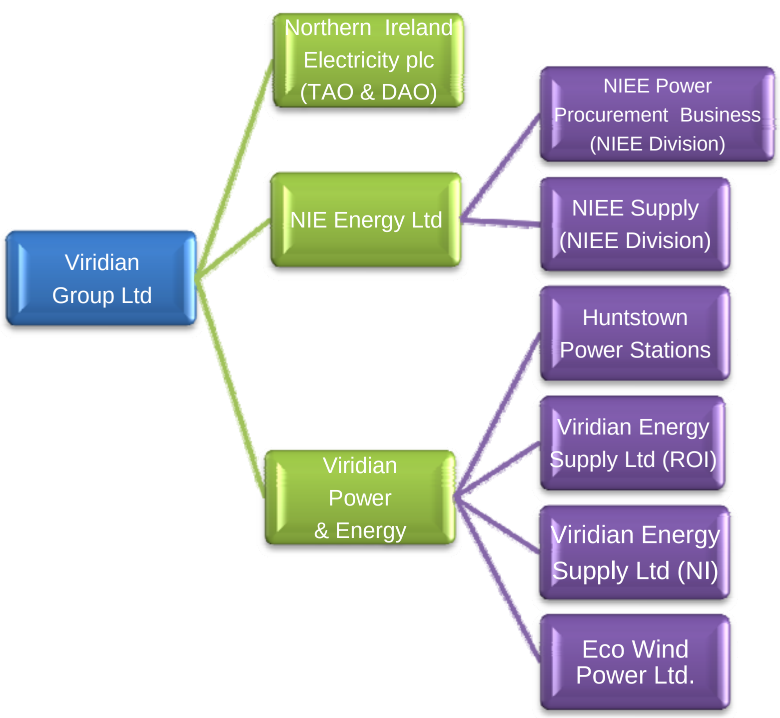


2. ESB Customer Supply PSO contracts

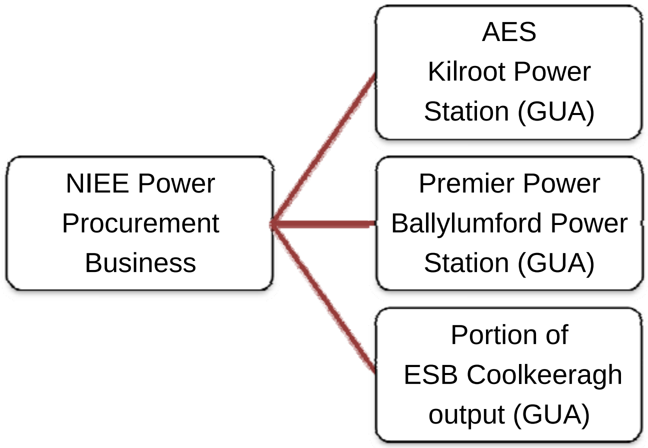


ESB PG includes two Peat stations, Lough Ree and West Offaly, which are included in Ireland's PSO.

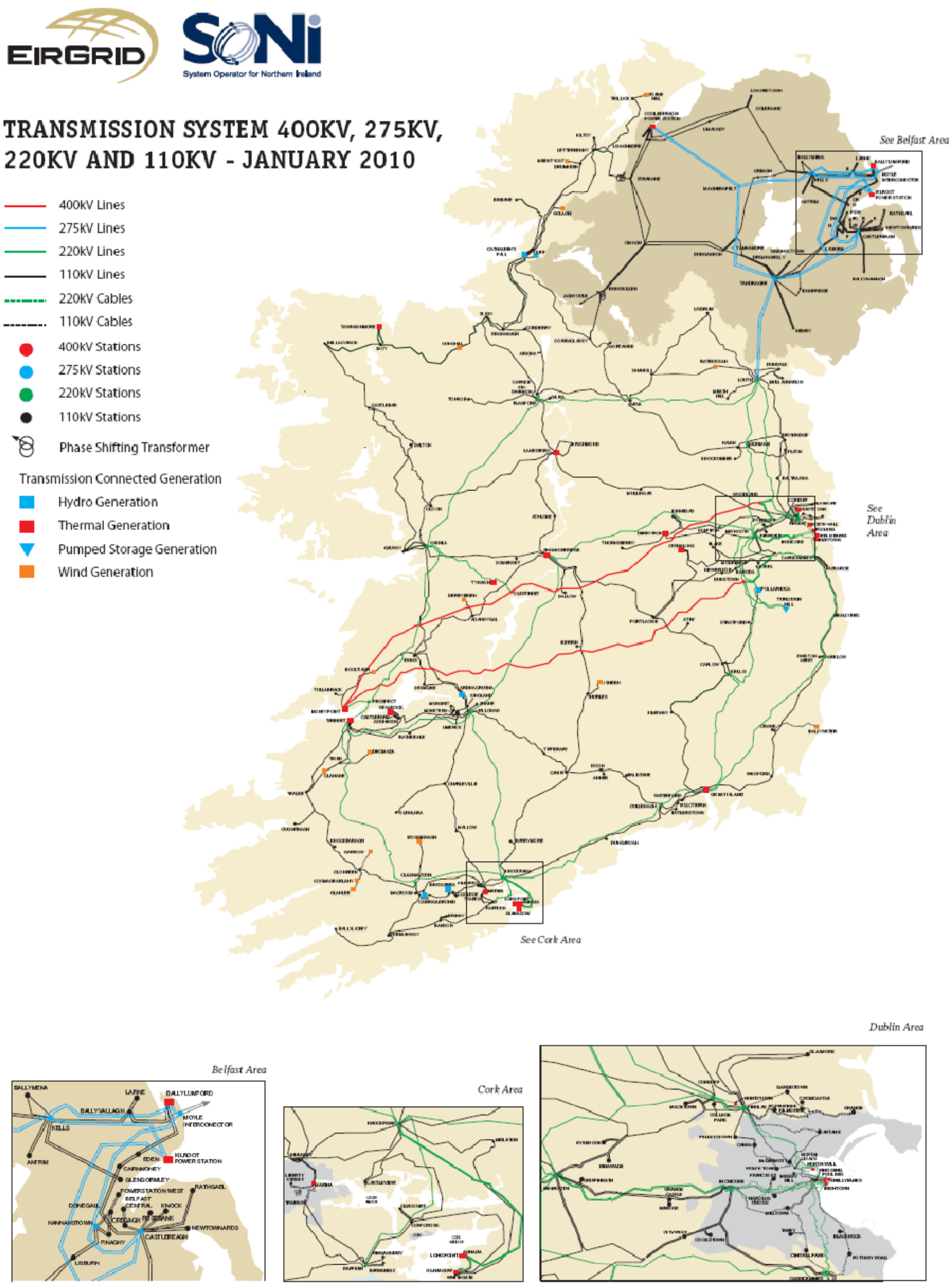
3. Viridian Group



4. NIEE PPB PSO contracts



Appendix 4 – All Island Transmission System



Source: EirGrid, http://www.eirgrid.com/media/All-Island%20Transmission%20Map%20(January%202010).pdf

Appendix 5 – Future Conventional Generation Locations

Source: EirGrid, '*Grid 25' Published October 2008,* www.eir**grid**.com/media/**Grid**%2025.pdf