Single Electricity Market

Market Monitoring Unit

Public Report 2009

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SEM/09/039

EXECUTIVE SUMMARY

The Market Monitoring Unit (MMU) has prepared this paper as a public report on the Single Electricity Market (SEM), its outcomes and key developments following market Go-Live on 1 November 2007 through to 31 December 2008.

Bidding Principles (Chapter 2)

These 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 Short-Run Marginal Cost (SRMC) in to the market, and are designed to help mitigate the potential abuse of market power by Generators. It is a key task of the MMU to monitor the bids of the Generators on an ongoing basis to check for compliance with the principles.

Because the principles are not explicit numerical rules, there is a degree of judgement required in interpreting them and in monitoring / administering them. The SEM Committee has, over the course of the study period, issued a number of Directions and Clarifications to the market in relation to some of the factors that are subject to such, including the cost of carbon emissions, gas transportation capacity and transmission loss adjustments. The largest body of work carried out involved the consideration of costs associated with repeated plant shut-down, and this led to a comprehensive Decision paper issued by the Committee in June 2008 (SEM-08-069).

Generator Bidding and Availability (Chapter 3)

Generally under the Bidding Principles, it is expected that Generator bids should track movements in underlying wholesale fuel prices (though there are other costs that can contribute to SRMC that are not related to fuel price). The section illustrates how the bids for the Generator Units have evolved over the study period, while also examining the fuel price trends.

The fuel prices tended to rise in the early part of 2008, reaching a peak in the middle of the year, before declining steadily in the second half of the year. The 'merit order' (the order of plants from least expensive to most expensive on a particular day) of Generators has shown a tendency to change shape over the study period as a reflection of the relative changes of the price of the varying fuels (coal, gas, oil etc) and the price of carbon emissions.

Generator Schedules and Dispatch (Chapter 4)

The introduction of the SEM coincided with the commissioning of a new CCGT unit (Huntstown Phase II) and the combined effect created an increased tendency for large units on the island to be shut down during overnight periods by the System Operators. This contributed in part to the launch of the MMU inquiry into participant bidding behaviour and the subsequent decision issued by the SEM Committee in June 2008.

The SEM operates on an 'unconstrained' basis and is settled *ex-post*. This leads to a difference between the market schedule and the real-time dispatch because the System Operators must dispatch the Generator Units in real time under additional constraints not considered by the market engine, including the need to maintain reserve and respect transmission line ratings. The report examines the Generator dispatch patterns pre and post-SEM and also looks at the key differences between the market schedule and the real-time dispatch over the study period.

The report also looks at the degree of availability of Generator Units, defined as the proportion of energy the units were available to generate compared to the total volume possible in the absence of any outages. The volume-weighted average Availability Factor of conventional Generator Units over the study period was around 82%.

The report also examines the contribution of SEM-registered Wind Units to serving electricity demand over the study period. The contribution averaged at 246MW over the course of the study period, with approximately 40% more Wind capacity registered in the SEM at the end of the study (950MW) compared to the start (680MW).

Demand, Capacity Margin and Market Prices (Chapter 5)

The report explores trends in demand for electricity in the SEM over the study period. In the winter months, the daily demand profiles tended to show a strong spike in demand around the early evening period (17:30 to 18:00), while during the summer months the profiles exhibited a flatter shape, with the daily peaks occurring around 12:00. The average market demand over the study period was 4201MW with a peak of 6553MW occurring on 18 December 2007.

The Capacity Margin is defined as the difference between the available Generation capacity and the system demand. The Capacity Margin varied throughout the study period, with the lowest ('tightest') margin periods occurring in June and October of 2008 when several large plants were on planned outage.

The clearing price in the SEM (called the System Marginal Price - SMP) is calculated on a half-hourly basis and is measured in Euros per Megawatt-hour (€/MWh). The average SMP over the study period was €78.02/MWh, with a peak of €696.85/MWh occurring on 15 October 2008. The SMP has exhibited the following tendencies:

- The highest SMP points during the day tended to coincide with the highest demand periods during the day.

- SMP has tended to rise and fall across the study period in broad alignment with rises and falls in the key underlying fuels (most notably gas) and the carbon price.

- SMP has tended to rise and fall inversely with the Capacity Margin over the study period. In other words, as the surplus capacity above what is required to serve the demand tightened, the SMP tended to rise (and vice-versa).

- The daily price profile and broad trends in SMP over the study period have shown a tendency to follow the broad trends in balancing prices published by Elexon for the British Electricity Trading and Transmission Arrangements (BETTA).

These observations are encouraging because the SMP can be linked with some confidence to variables that the MMU would expect to be strongly influential and/or correlated, given the market design and Bidding Principles.

<u>Discrete Events</u> (Chapter 6)

The Market Scheduling and Pricing software has on rare occasions produced outcomes that do not appear immediately intuitive for particular days. A few of the most marked events are explored in the report.

<u>Flows, Interconnection and Great Britain</u> (Chapter 7)

The report explores the pattern of SMP against the patterns observed in the balancing market in Great Britain. There is a broad alignment between the patterns on a daily-profile basis and over the long-term trend.

The flows in and out of the SEM over the Moyle Interconnector, as well as the flows over the north-south tie-line on the island are also explored. Overall, there has been a net import of energy over the Moyle Interconnector into the SEM over the study period, with imports outweighing exports by around 5-to-1. There has been a net flow of energy from north-to-south within SEM, with southbound flows outweighing northbound flows by around 5-to-2.

<u>Pivotal Supplier Analysis</u> (Chapter 8)

As part of the monitoring function, the MMU regularly examines market days in which the Capacity Margin may have tightened in order to assess the degree to which market power could be effectively exercised via with-holding of generation capacity. This analysis regularly features Pivotal Supplier Analyses, and some examples of these are explored for the days of tightest margin over the study period.

<u>Generator Revenues</u> (Chapter 9)

The report summarises the revenues, implied infra-marginal rents and capacity payments made to Generator Units, and illustrates how different technologies and different plants have seen varying degrees of revenue from the SEM over the study period. It is important to note in examining these trends that the businesses all have different capital intensities and capital / operational expenditure ratios. This paper does not examine costs and revenues incurred by participants outside of the SEM.

<u>Monitor's Assessment</u> (Chapter 10)

The report concludes by drawing some of the key analyses together and offers a broad assessment of the health of the SEM in the context of the material presented in the main body.

It is the view of the MMU that the SEM has produced outcomes in the study period that broadly align with expectation, given the suite of regulatory decisions and emergent trends in the input variables (demand, availability, wind, fuel prices and so on). The MMU is generally encouraged by the mapping of daily price profiles to those of the BETTA, as well as the recognisably inverse pattern of system margin against SMP, which is commensurate with expectation given the structure of the standing Bidding Principles. The strong correlation between fuel prices and SMP is also encouraging when considered in the context of the Bidding Principles.

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GLOSSARY OF TERMS AND ACRONYMS

AD1	Aghada Unit 1
AT1	Aghada CT Unit 1 [also 2 and 4]
B10	Ballylumford Unit 10
B31	Ballylumford Unit 31 CCGT [also 32]
BCOP	Bidding Code of Practice (see References)
BETTA	British Energy Trading and Transmission Arrangements
BOC4	Ballylumford Unit 4 [also 5 and 6]
C30	Coolkeeragh CCGT
Capacity Margin	Measure of surplus generation capacity in a Trading Period. Sum of all EA minus the Demand
CCGT	Combined-Cycle Gas Turbine
CGT8	Coolkeeragh GT 8
COD	Commercial Offer Data
CPM	Capacity Payment Mechanism
DB1	Dublin Bay CCGT
Demand	Demand for Electricity in the SEM. Usually used in reference to specific instances (e.g. peak), measured in MegaWatts (MW)
DQ	Dispatch Quantity
EA	Eligible Availability
ED1	Edenderry
ESB PG	ESB Power Generation
ESBI	ESB International
FGD	Flue Gas Desulphurisation
GI1	Great Island Unit 1 [also 2, 3]
HN2	Huntstown Phase II
HNC	Huntstown I
I/C	Interconnector
Infra-Marginal Rent	The Revenue a Generator Unit receives from the SMP, minus the costs implied by the Unit's relevant Commercial Offer Data
KCA1	Kilroot Coal Unit 1 [also 2]
KGT1	Kilroot GT 1 [also 2]
Load	See Demand. Typically used to refer to summed Demand or the trend of Demand over a period or timeslice.
LOLE	Loss of Load Expectation, measured in hours.

LR4	Lough Ree
MMU	Market Monitoring Unit of the SEM. A joint regulatory body between CER and NIAUR that monitors the behaviour of the SEM and its participants
MP1	Moneypoint Unit 1 [also 2 and 3]
MRT	Marina
MSP Software	Market Scheduling and Pricing Software
MSQ	Market Schedule Quantity
NI	Northern Ireland
NIE PPB	NIE Energy Power Procurement Business
No-Load Cost	The invariant-with-output running cost, defined in the T&SC under Section 4.17 (see References)
NW5	Northwall Unit 5
NWC	Northwall CCGT
OCGT	Open-Cycle Gas Turbine
PBC	Poolbeg CCGT
PSI	Pivotal Supplier Index
RoI	Republic of Ireland
RP1	Rhode Peaking Unit 1 [also 2]
RST	Residual Supplier Threshold
SEM	Single Electricity Market
SEMC	SEM Committee. A joint regulatory body between CER and NIAUR that administers the operation and development of the SEM.
SEMO	Single Electricity Market Operator
Shadow Price	The marginal cost of serving the demand in a Trading Period, given a set of fixed Unit Commitment decisions (Section N18 of T&SC)
SK3	Sealrock [also 4]
SMP	System Marginal Price
SRMC	Short-Run Marginal Cost
T&SC	Trading and Settlement Code
TB1	Tarbert Unit 1 [also 2, 3, 4]
TLAF	Transmission Loss Adjustment Factor
TOD	Technical Offer Data
TP1	Tawnaghmore Unit 1 [also 3]
Trading Period	The SEM operates of a half-hourly trading period basis, scheduling and pricing over a 60-period horizon from 06:00 to 12:00 the following day.
TYC	Tynagh CCGT

Uplift	A component of the SMP included to ensure that Generators at least recover their submitted costs over each Trading Day (Section N64 of T&SC)
WO4	West Offaly

1. INTRODUCTION

The Market Monitoring Unit (MMU) was established prior to commencement of the Single Electricity Market (SEM) as part of the Regulatory Authorities' (NIAUR and CER) joint approach to effective market power mitigation.

The MMU monitors the inputs, outputs and operation of the SEM and its associated mechanisms to ensure the ongoing health of the market and to check for adherence by the market participants to the standing rules.

Part of the MMU's role is to generate public reports, and this document is intended to constitute the MMU's public assessment of the performance of the SEM for the period 1 November 2007 to 31 December 2008. This exactly covers the two Trading Years 2007 and 2008.

The paper is aimed at providing a factual assessment of the SEM and is designed to be as readable as possible for those not necessarily familiar with the detail of the market design and operation. None-the-less there is some assumed prior knowledge relating to the function of the market systems and the format of Generator technical and commercial offers[1].

The paper also draws together a number of key concepts and developments that have emerged in the regulation of the SEM following Go-Live, including the outcomes relating to the formal Bidding Inquiry conducted early in 2008 and the consequent Decision Paper published by the SEM Committee on June 12 (SEM-08-069).

The report features a large amount of data presentation and discussion, making necessary reference to previous decisions of the SEM Committee, but does not delve into future SEM policy matters.

2. BIDDING PRINCIPLES

Generator Units in the SEM are bound by the Bidding Principles, which form a key building block of the RAs' strategy for mitigation of the potential abuse of market power.

Central to the principles of bidding behaviour for Generator participants in the SEM is the Bidding Code of Practice (BCOP)[2] and the associated Licence Conditions in each jurisdiction, which establish a requirement for Generators to bid their Short-Run Marginal Costs (SRMC) into the market.

The definition of SRMC as it applies to the complex bidding framework of the SEM is a topic of key activity and interest for the MMU, and has occupied much of the MMU's efforts following the commencement of the SEM in November 2007 right through to the end of the study period.

It is worth summarising the evolution of the BCOP and the key decisions that have been made by the SEM Committee in relation to its proper interpretation during the study period, because the market input and output data that is presented and analysed in the remainder of the report are explained partly by these decisions.

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[1] Useful background documentation can be found on the AIP website (www.allislandproject.org), including the Trading and Settlement Code Helicopter Guide (AIP-SEM-07-507) and/or the High Level Design Decision Paper (AIP-SEM-42-05)

[2] http://www.allislandproject.org/en/market-power-decision.aspx?article=7fdc1ef8-3e0e-4267-9b82-0a2c65b1056f

2.1. Bidding Code of Practice

The BCOP is published as an Annex to the Response and Decision paper SEM-07-430. Important excerpts include:

> 6. When calculating the Short Run Marginal Cost of a generation set or unit in respect of a Trading Day, constituent cost-items are to be valued at their Opportunity Cost, and so that a reasoned explanation of the calculation of that Opportunity Cost is capable of being given to the Authority or the Commission (as appropriate) on request.
>
> 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.

It is the expectation of the MMU that, by default, the BCOP stands for itself, and that interpretations of the text therein rests upon the Generator participants in formulation of the offer data (Commercial Offer Data - COD - and Technical Offer Data -TOD) that is submitted to the Market Operator (SEMO). The BCOP forms the core set of principles from which this data is to be constructed by participants.

Notwithstanding this, there have been several issues explored by the MMU relating to specific cost items upon which Decisions / Directions / Clarifications have been issued by the SEM Committee, both before and following the commencement of the SEM[3]. These are explored in the following sub-sections.

2.2. Gas Transportation Capacity

The qualification of gas transportation capacity costs as 'short-run' allowable costs in the sense of the BCOP was explored by the Regulatory Authorities (NIAUR and CER) under consultation prior to Go-Live, and a decision was published as part of the Response and Decision Paper (SEM-07-430).

> Without the ability to buy or sell gas transportation capacity for a trading day, as is the case currently in Ireland, payments for capacity on gas transportation networks are best understood as (semi) fixed costs. This means that, to meet licence conditions applying both in Northern Ireland and the Republic of Ireland, such costs should not be reflected in price bids submitted to the Market Operator.

For the avoidance of doubt, at the time of this writing the SEM Committee is not of the view that sufficient liquidity exists in the emergent trading arrangements for short-term gas transportation capacity for these

[3] Statements issued prior to the commencement of SEM were made jointly by the Regulatory Authorities (NIAUR and CER) rather than by the SEM Committee, as the Committee was only empowered following the commencement of SEM.

costs to yet be considered avoidable in the sense of the BCOP, and that as a consequence such costs remain best understood as fixed.

The SEM Committee is vigilant to the emerging demand for, and participation in, short-term gas transportation capacity trading and will, if and as appropriate, issue a clarification to the market, should the need arise, to revisit the decision made prior to Go-Live regarding these costs.

2.3. Carbon

The reflection of the opportunity cost of carbon emissions was explored under consultation with a subsequent decision paper published in March 2008 (SEM-08-32). The SEM Committee decided that carbon costs should be treated as per the opportunity cost of emitting carbon under the typical interpretation of the clauses in the BCOP (cost of emissions should be referenced to accessible liquid markets etc).

2.4. Repeated Starts

The MMU received complaints in November 2007 from some participants relating to certain bidding behaviour by competing parties following commencement of the SEM. A subsequent inquiry was launched by the MMU, and a final Decision was issued by the SEM Committee on June 12 2008 (SEM-08-069).

The Decision discusses, among other matters, the treatment of the costs associated with repeated shut-down and start-up of a Generator Unit. Broadly, the additional costs that are incurred above those normally associated with nominal plant dispatch, such as the cost of surplus outage hours caused by repeated start-up and shut-down, are addressed. The primary finding is that these costs, where they can be shown to exist, should be built into the commercial Start-Up Cost that is submitted as part of COD rather than in No-Load or incremental P/Q pairs.

The SEM Committee recently published a clarification to the June 12 Paper (SEM-09-014), dealing with the specific issue of association of submitted Start-Up Costs with the short-term commitment status of the plant. The clarification stipulates that the short-term commitment status of the generator units should not be referenced in the formulation of COD.

2.5. Contractual References

Contractual positions should not be reflected in offer data, but some specific cases have been exempted by the SEM Committee.

The Decision paper SEM-08-069 discussed Synergen’s specific contractual arrangements and made a distinct finding in that case. A second specific case was later considered relating to Ballylumford with a subsequent Decision (letter) issued (SEM-08-091).

2.6. Transmission Loss Adjustment Factors

In December 2008 the SEM Committee published a General Direction stipulating how Transmission Loss Adjustment Factors (TLAFs) should be referenced in the construction of COD (SEM-08-179).

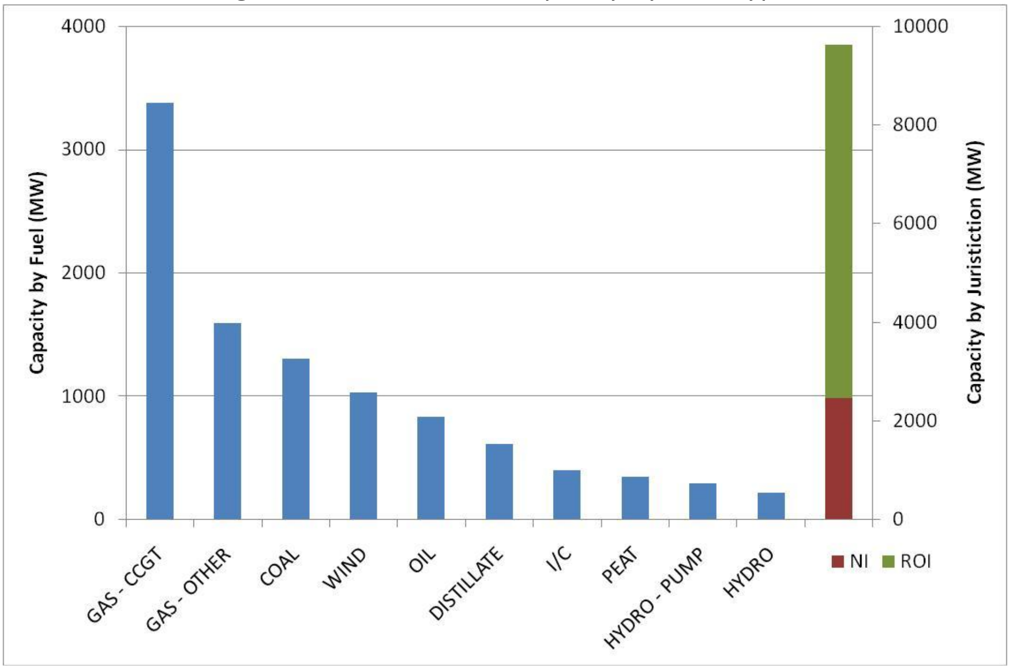
In summary, the Committee found that transmission losses were avoidable in the sense of the BCOP, and that given the specific treatment of TLAFs by the central market systems under the Trading and Settlement Code (T&SC), TLAFs should be factored into the development of incremental prices, but not into Start-Up and No-Load Costs until such time as the T&SC can be examined under a potential modification.

3. Generator Bidding and Availability

3.1. SEM Plant Mix

The Generator Units that participate in the SEM are broken down by fuel type in the figure below:

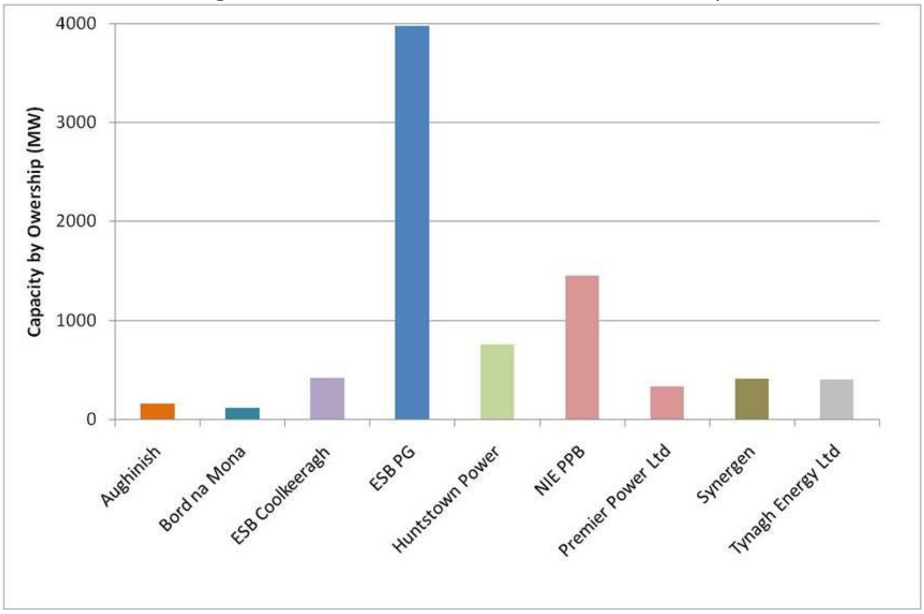
Figure 3.1: Generation Capacity by Fuel Type



Most of the generation capacity is gas-fired, with around 3,400MW of CCGT plant and 1,600MW of other gas-fired plant including OCGT. A tabulated data sheet is provided in Appendix B that details the size, fuel type and ownership of each unit, as used to formulate the Plexos model for Directed Contracts during 2008.

The ownership of conventional plant in the SEM is broken down in the figure below:

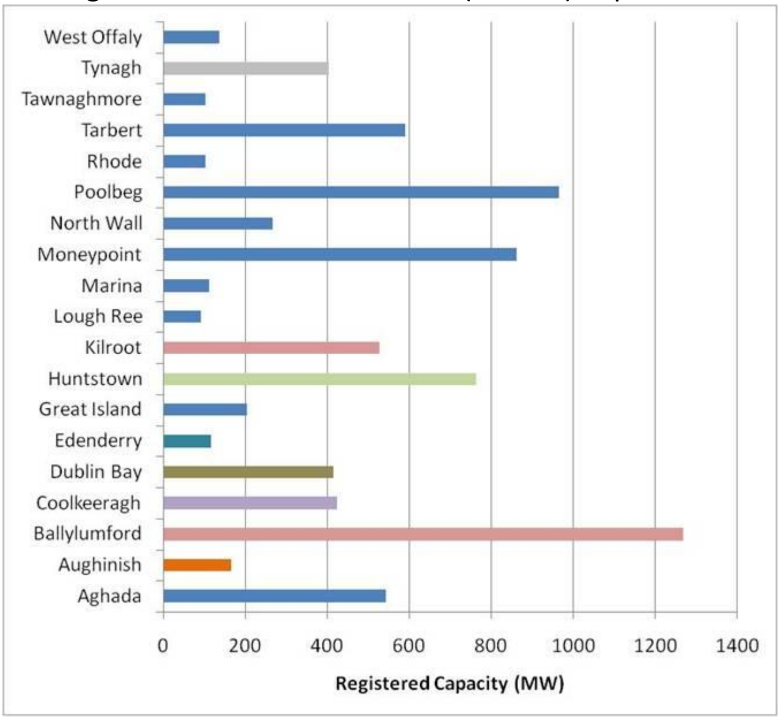
Figure 3.2: Conventional Plant Ownership



Note that in this paper, the portfolio of Endesa plants, recently acquired from ESB PG, is allotted to the ESB PG portfolio because these plant were owned by ESB PG during the study period. In addition, 'PPL' in the figures refer to all Premier Power Limited plant not under intermediary contract with PPB (i.e. no plant is double-counted).

The conventional stations are split out by capacity in the figure below:

Figure 3.3: Conventional Plant (Station) Capacities



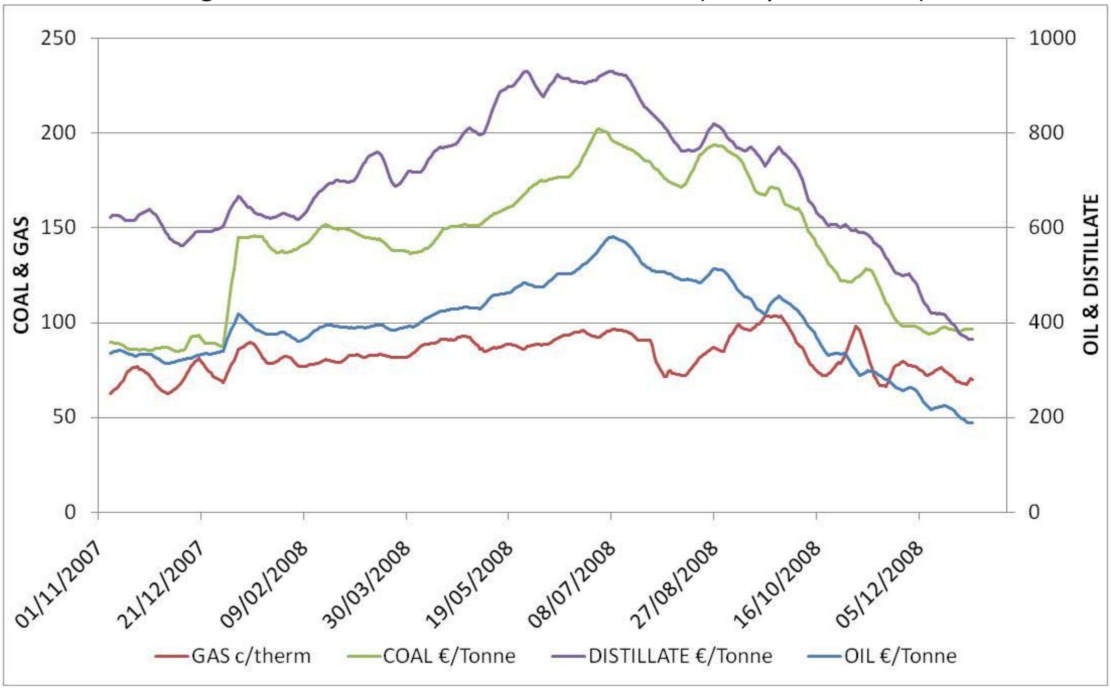
3.2. Fuel and Carbon Price Trends

This section explores the trend of fuel price movements over the course of the study period. These trends are important to consider because the System Marginal Price (SMP) is driven largely by fuel price inputs reflected in Generators' Commercial Offer Data (COD).

The figure below depicts the movement of gas, coal, distillate and oil prices over the study period. All the variables have been indexed to account for the cost of carbon emissions that accompany the employment of the fuels for electricity generation. This provides a better reflection of the effective relative movements of the fuels because the avoidable cost of carbon emissions are bid in to the market by Generator participants (as described in the previous section). While each fuel has a different carbon intensity, the carbon price itself is also a moving variable over the course of the study period, and this has a combined and distinct effect on the relative movements.

The daily data has been smoothed under a 7-day moving average to draw out the trend. Moving averages are used throughout the document to illustrate trend.

Figure 3.4: Carbon-Indexed Fuel Trends (7-day smoothed)



3.2.1. Gas

The gas price exhibited a significant degree of variability from the commencement of SEM on November 1 2007 through to January 2008 before settling at around €0.80 / therm (carbon indexed). A steadily increasing trend emerges from February through to Mid-August, by which time the price had reached around €0.95 / therm (carbon indexed). A sharp drop occurred in Mid-August, followed by a quick recovery as the price surged to over €1.00 / therm (carbon indexed) in early October. From this point the price exhibited significant variability though November before again settling at around €0.70 / therm (carbon indexed).

Of all the four fuels noted here, movement in the price of gas is the most significant for the SEM because of the high penetration of gas-fired generation (discussed earlier) and the frequent tendency for gas-fired plants to ‘set’ the System Marginal Price. The relevance of gas prices to the SMP is explored in more depth later.

3.2.2. Coal

The coal price has exhibited similar trend to the gas price over the study period as the figure indicates, though the descent between July to December 2008 is more extreme, with the coal price dropping to around half its former price over the final 6 months compared to the reduction in the gas price (around one quarter). Of note in the trend is the jump that occurred on January 1st 2008. This was driven by the introduction of the European Commission Emissions Trading Scheme (Phase II), which saw the price of carbon emissions take a step change from close to zero to around €22 / tonne CO2. The higher carbon intensity of coal over the other fuels is the reason why the step change is more prevalent in the trace for coal in the figure than for the other fuels, though smaller corresponding steps can still be seen in the other three traces.

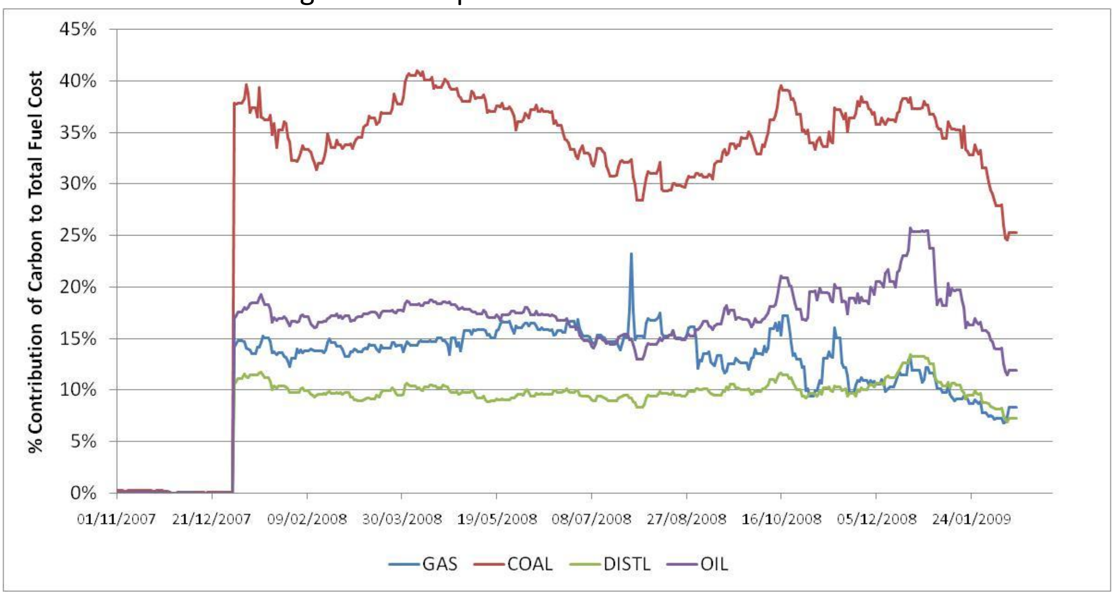
3.2.3. Oil and Distillate

The oil and distillate prices have behaved in a similar fashion to each other over the study period, generally mapping to the gas and coal price. Their movements over the long term have been somewhat more extreme than the gas price, as both ended the 2008 Trading Year at less than half the values seen around the July 2008 peak.

3.2.4. Carbon

Following January 1st 2008, the price of carbon moved generally between €19 and €29 / tonne up until September, after which the price began to decline. The last two months of the study period saw an average price of just €15 / tonne. The evolving impact the carbon price had on the indexed fuel prices is shown below:

Figure 3.5: Impact of Carbon on Fuel Prices



The step change at January 1st is immediately evident. The figure shows that carbon price has accounted for the overall fuel price of coal by as much as 40% but this has not been a consistent trend, with the contribution having fallen sharply away at the end of the period as the carbon price began to decline.

Variable movements in the carbon price also map to a varying contribution to the overall (indexed) price of the other three fuels as indicated in the figure.

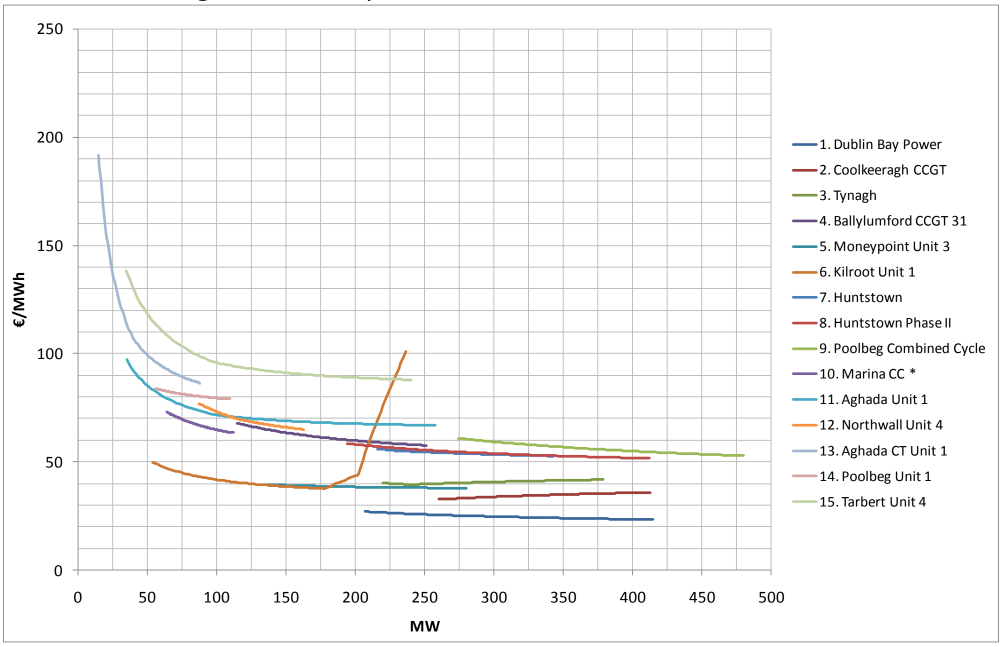
3.3. Generator Cost Curves

The indexed fuel prices combine with Generator technical characteristics (most notably unit heat rates) and with other variable cost elements to drive Generator Commercial Offers that are submitted to the Market Operator on a daily basis. This section examines the evolving 'cost curves' of the generation fleet during the study period. There are some movements and notable aspects of the graphs that relate to changing behaviour in response to SEM Committee decisions. Where appropriate, the MMU has refrained from offering detailed commentary on the underlying drivers in the interest of maintaining commercial confidentiality.

3.3.1. Generator Curves - Group Snapshots

The graphs below show a series of snapshots taken of the combined No-Load and incremental Price offers submitted by a selection of plants in the SEM. In the graphs, the average cost per MWh is plotted on the y-axis with the level of MW output on the x-axis. The curves generally descend from higher per-unit costs at low levels of output to more efficient per-unit costs at higher levels, though this is not strictly the case across the board. The figure below is a snapshot of the 31st of December, 2007:

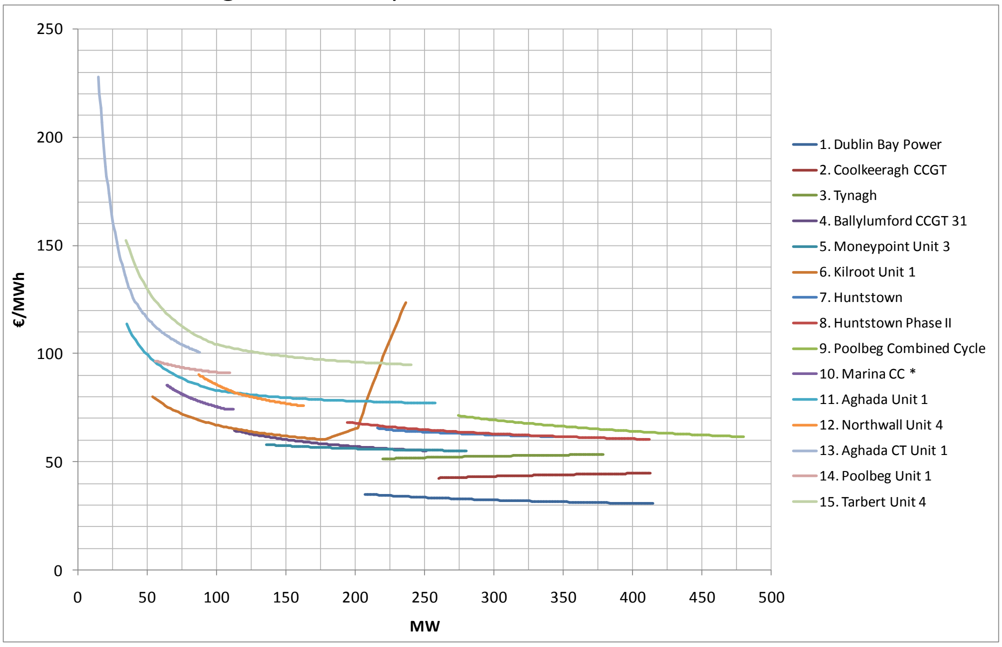
Figure 3.6: Snapshot of COD - 31st December 2007



Notable points on this graph include the sharp rise in Kilroot 1's curve in reflection of the oil-firing capacity that is available between 203MW to 238MW. Dublin Bay has the lowest per-unit costs though it is recognised that this is in the context of the decision made during 2008 in SEM-08-069 in which Synergen were permitted to bid their contractual gas price as opposed to the spot price of gas, which was significantly higher on this day (the strategy was employed by Synergen both before and after issuance of the Decision).

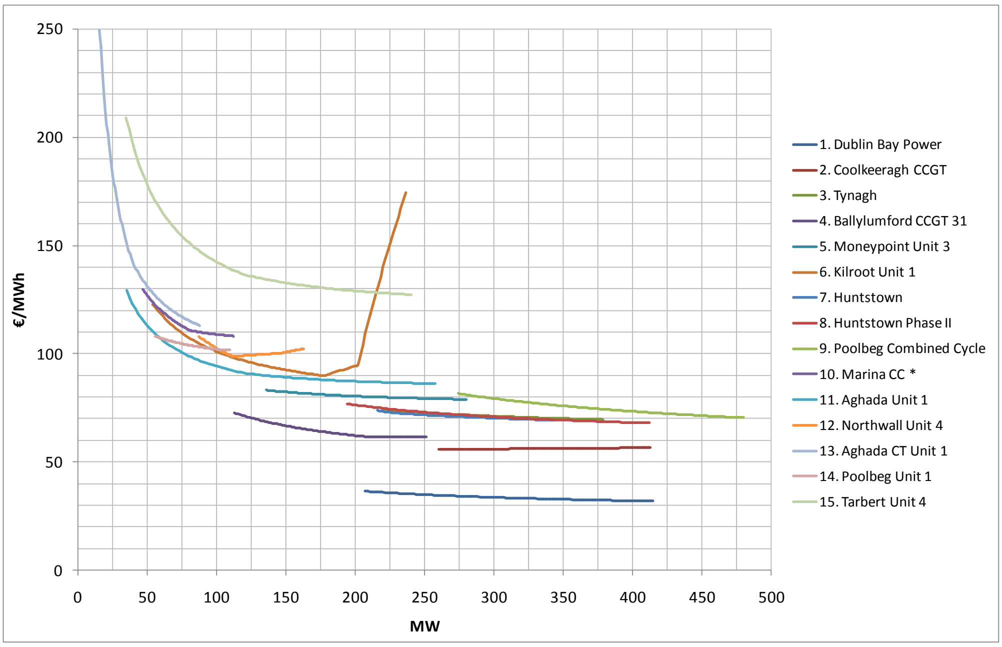
The coal-fired Moneypoint and Kilroot units have amongst the lowest cost curves on this day though this was largely due to the low carbon price, which changed dramatically from January 1st 2008 with the introduction of the EU ETS Phase II. The most expensive fuel types lie at the top of the table, with the distillate and oil-fired plants occupying the top of the picture, in keeping with general expectation.

Figure 3.7: Snapshot of COD - 31st March 2008



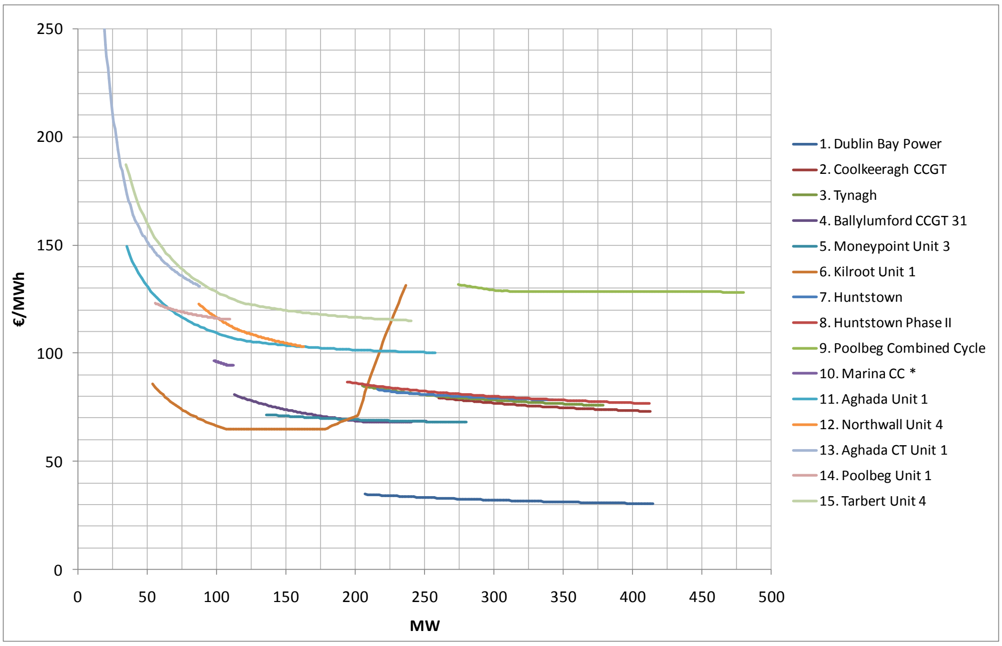
This figure tells a similar story to the first, though there is noticeable movement of the relative costs of the coal-fired plant toward the rest of the generation pack. This was due largely to the increased carbon cost on the day relative to that of the first figure; this is foreshadowed by the step change in the carbon contribution in Figure 3.5 in the previous section moving into January 2008.

Figure 3.8: Snapshot of COD - 30th June 2008



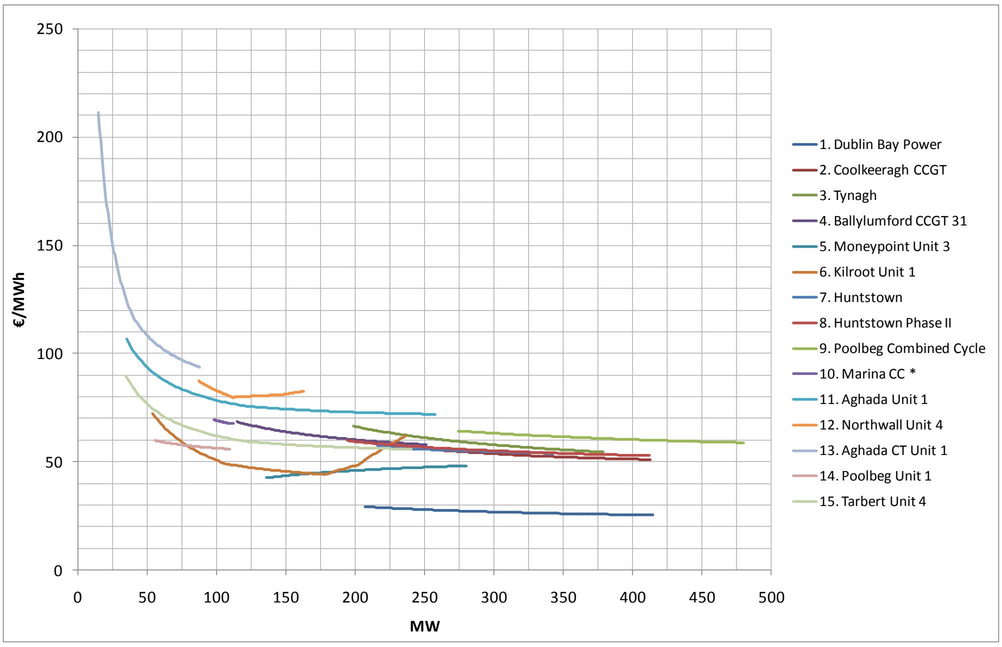
By June 30th 2008 the oil price had increased relative to the other fuel types as indicated in Figure 3.4 in the previous section and this is reflected in the increased separation between Tarbert and the rest of the generation pack in the figure above.

Figure 3.9: Snapshot of COD - 30th September 2008



Fuel price movements are responsible for most of the changes seen relative to the previous figure. The Poolbeg CCGT was at the time under a partial outage (steam unit) requiring it to run in OCGT mode, thus pushing its cost curve markedly higher than what is usually observed.

Figure 3.10: Snapshot of COD - 31st December 2008



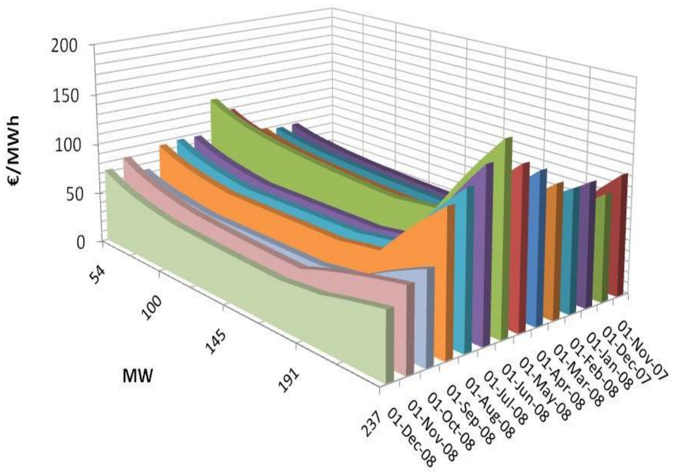
By the end of the year coal prices had dropped significantly relative to the other fuel types as highlighted in the previous section, and this is reflected in the low-cost rankings of Kilroot and Moneypoint.

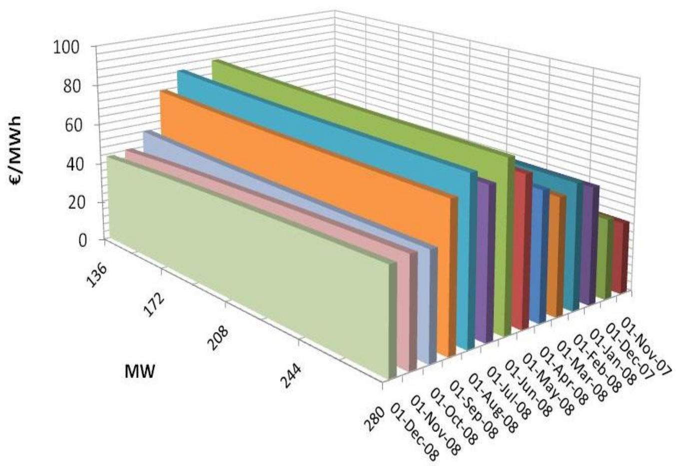
3.3.2. Generator Curves – Plant Timeslices

This section illustrates the changing trend of individual Generator commercial offers over the study period. The graphs show stacked snapshots for the first day of each calendar month. When drawing comparisons it is important to note that these are individual days rather than smoothed averages as depicted in the Fuel Price Section of the report.

Figure 3.11: Snapshot of COD – Kilroot 2

Figure 3.12: Snapshot of COD – Moneypoint 3

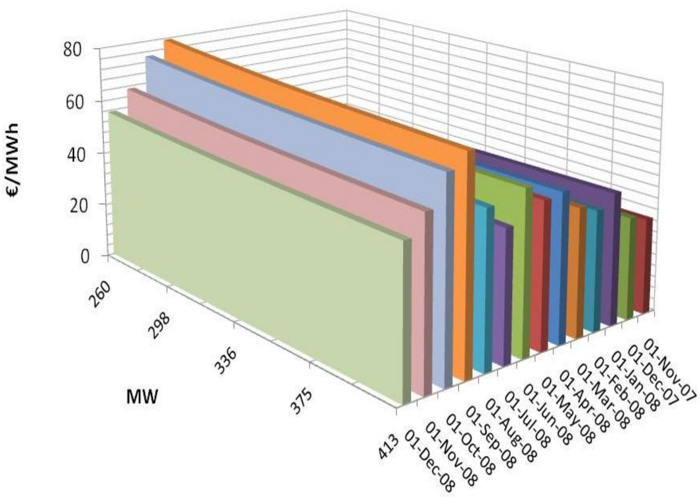




The pattern of rising coal prices to July followed by a steady decline to lower values is mapped reasonably well by the evolutions of the curves for these two coal-fired plants. Kilroot 2's oil-range also maps to the oil trend. There was some widening of the oil operation range in the latter part of the study period and this can be seen in the November 1st 2008 time-slice.

Figure 3.13: Snapshot of COD – Coolkeeragh CCGT

Figure 3.14: Snapshot of COD – Huntstown 2



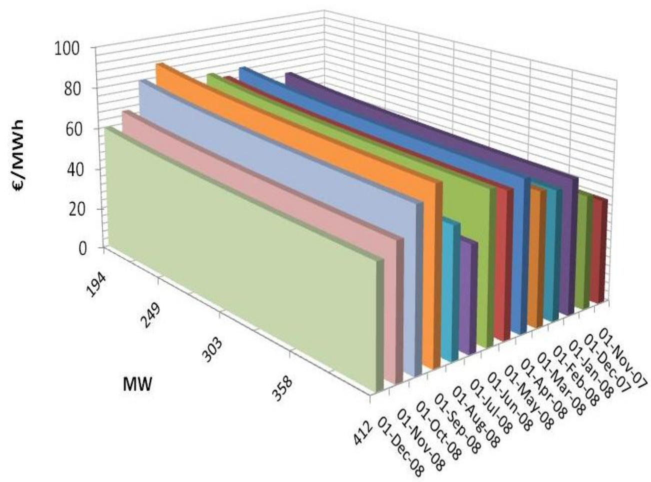
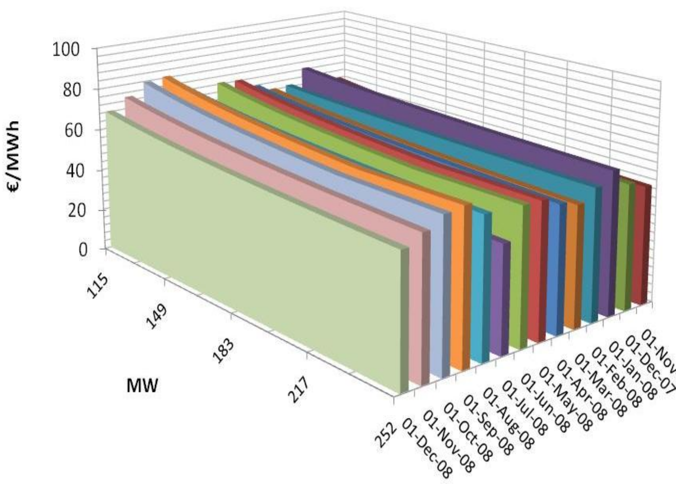
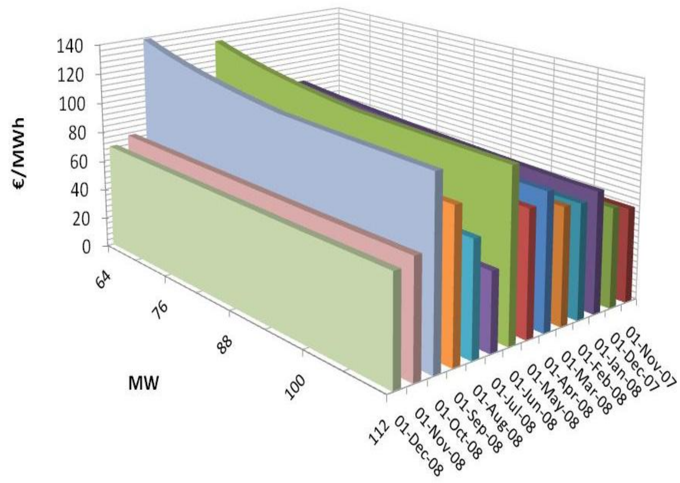


Figure 3.15: Snapshot of COD – Ballylumford 31

Figure 3.16: Snapshot of COD – Marina

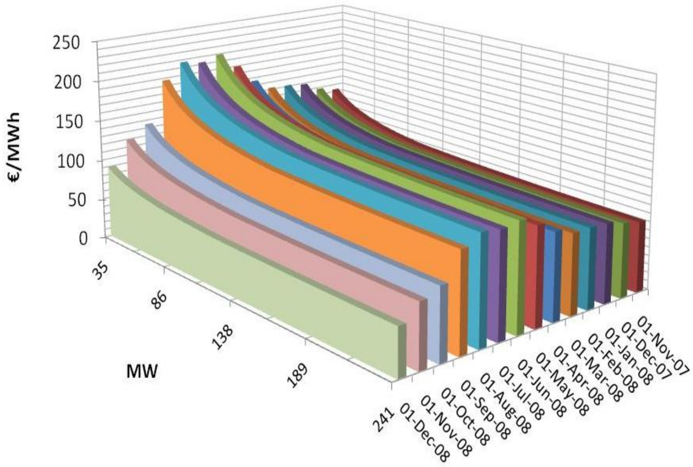


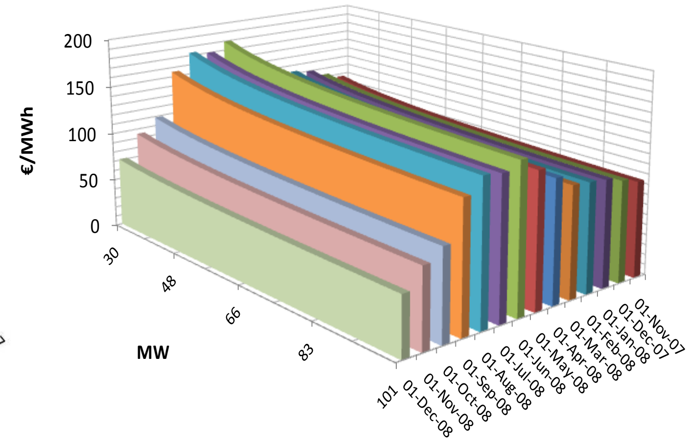


Several factors drive the evolution of the gas-fired cost curves depicted above, including outage impacts and SEM Committee Decisions.

Figure 3.17: Snapshot of COD – Tarbert 4

Figure 3.18: Snapshot of COD – Great Island 3

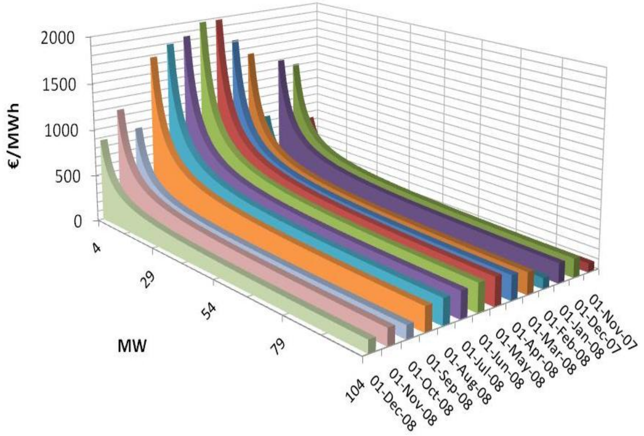


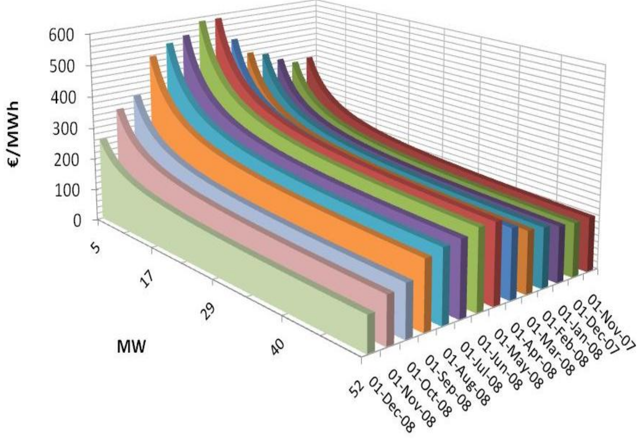


The oil plants exhibit a general mapping to the oil price trend.

Figure 3.19: Snapshot of COD – Northwall 5

Figure 3.20: Snapshot of COD – Rhode 1





The distillate plant also show a mapping to the fuel price trend. The Northwall 5 figure exhibits comparable cost curve characteristics to other distillate plant, though the graph is plotted back to very low output and at these levels the per-unit cost climbs, driving the y-axis higher than as seen in the figure for Rhode 1.

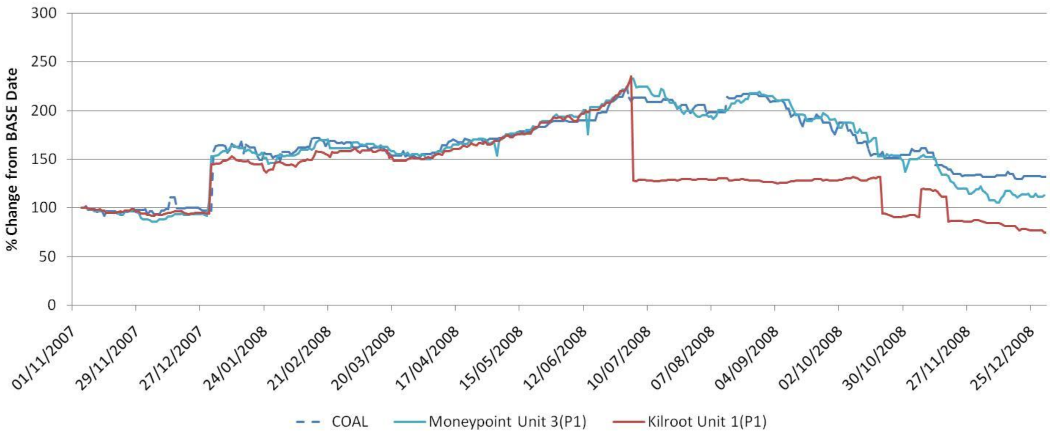
3.4. Commercial Offer Evolutions

The figures in this section show the relative evolution of Commercial Offer Data over the study period for selected units.

3.4.1. First Price

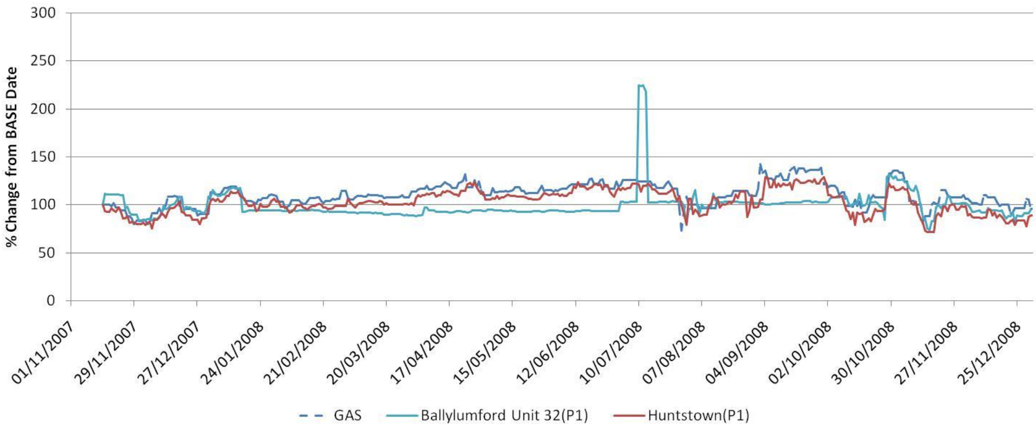
Generators submit up to ten incremental price offers, though typically large plants will only offer two or three. This section examines the evolution of the First Price value for selected plant over the course of the study period.

Figure 3.21: Coal-fired Plant First Price



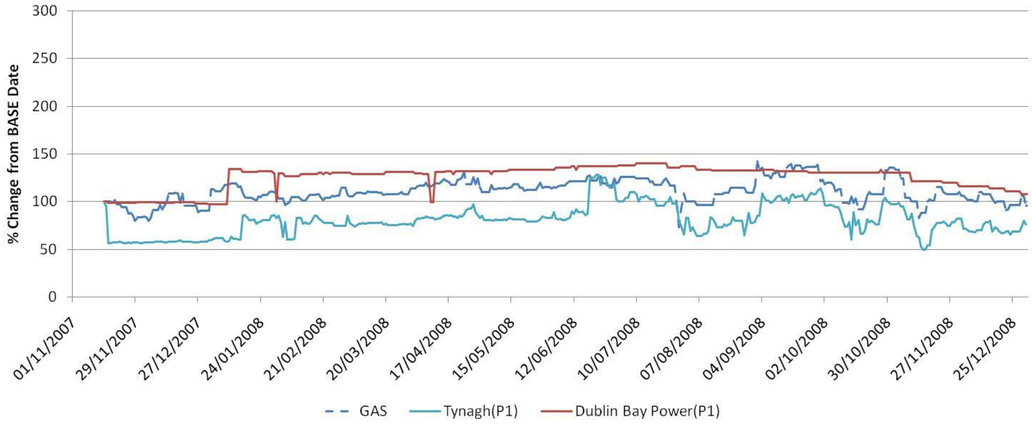
The First Price of the coal stations closely tracks the carbon-indexed coal price up to mid-July, at which point the Kilroot First Price drops to a relatively flat value substantially below the coal price. The Moneypoint First Price takes a departure below the coal price in late November. While not shown, this was accompanied by a departure above the coal price in Moneypoint's Second Price. Both First and Second Prices returned to the previous trend shortly after the end of the study period in this report.

Figure 3.22: Gas-fired Plant First Price



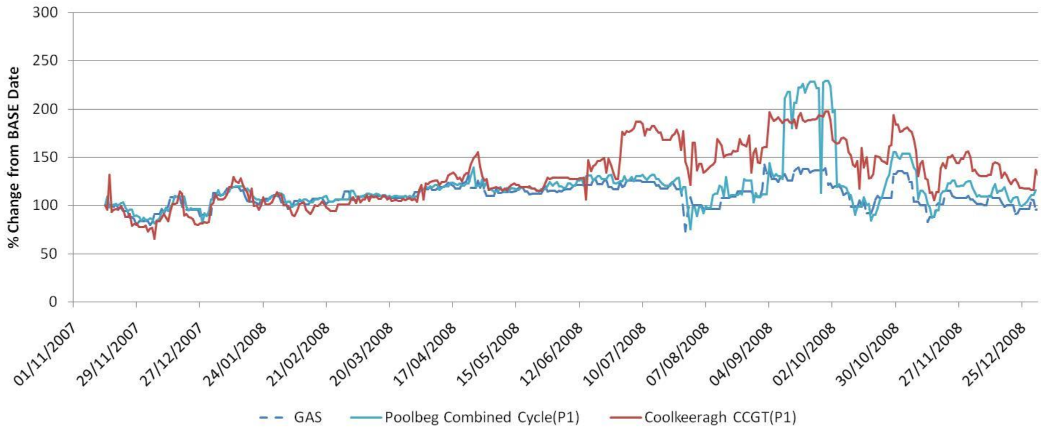
The Huntstown First Price closely follows the gas price trend. Ballylumford's evolving First Price is driven mainly by the SEM Committee Decision taken during 2008 relating to PPB's gas supply contract.

Figure 3.23: Gas-fired Plant First Price (2)



After an initial step following commencement of the SEM, Tynagh's First Price has tracked the relative gas price movement reasonably closely. Dublin Bay's First Price has not and this is specifically related to the SEM Committee Decision taken during 2008 following the Bidding Inquiry.

Figure 3.24: Gas-fired Plant First Price (3)

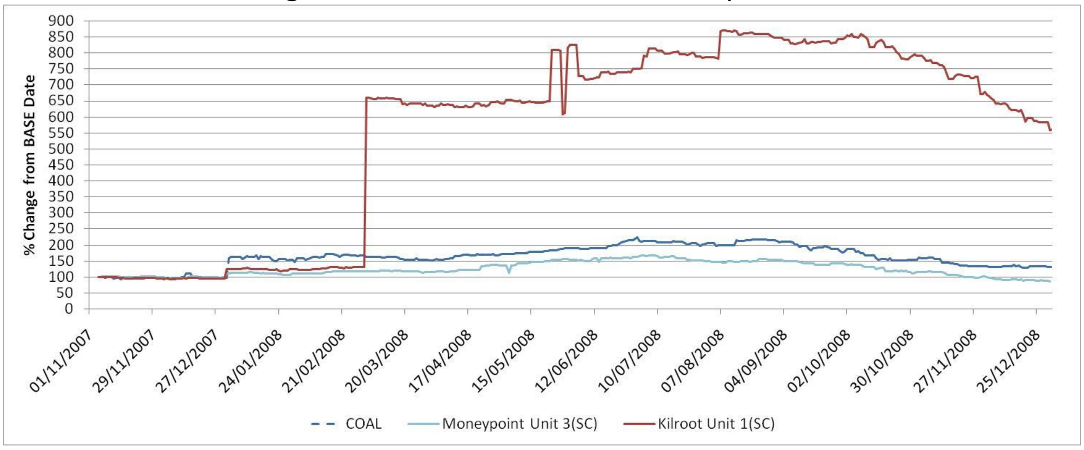


Poolbeg CCGT and Coolkeeragh's First Price have closely tracked the trend in gas price over the study period. A step change appears in Coolkeeragh's First Price in July, this is connected to the SEM Committee Decision regarding inclusion of costs relating to repeated starts. The Poolbeg First Price makes a temporary departure in September, this was caused by partial plant outage which changed the running cost characteristics.

3.4.2. Start-Up Costs

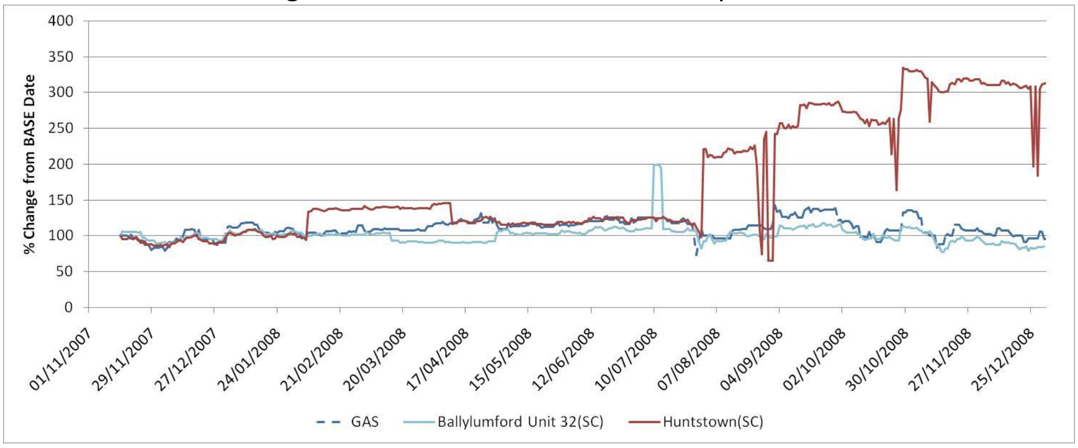
Generators bid a Start-Up Cost as part of their daily Commercial Offer Data. This section examines the evolutions of these submitted costs for selected units.

Figure 3.25: Coal-fired Plant Start-Up Costs



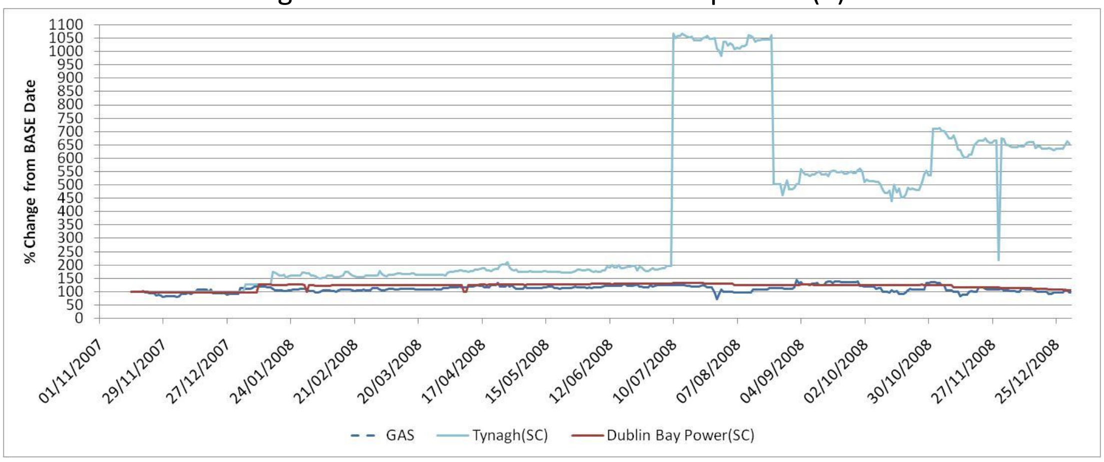
While both coal plants exhibit a broad mapping to the rising / falling coal price over the period, Kilroot's price took a significant step change in late February.

Figure 3.26: Gas-fired Plant Start-Up Costs



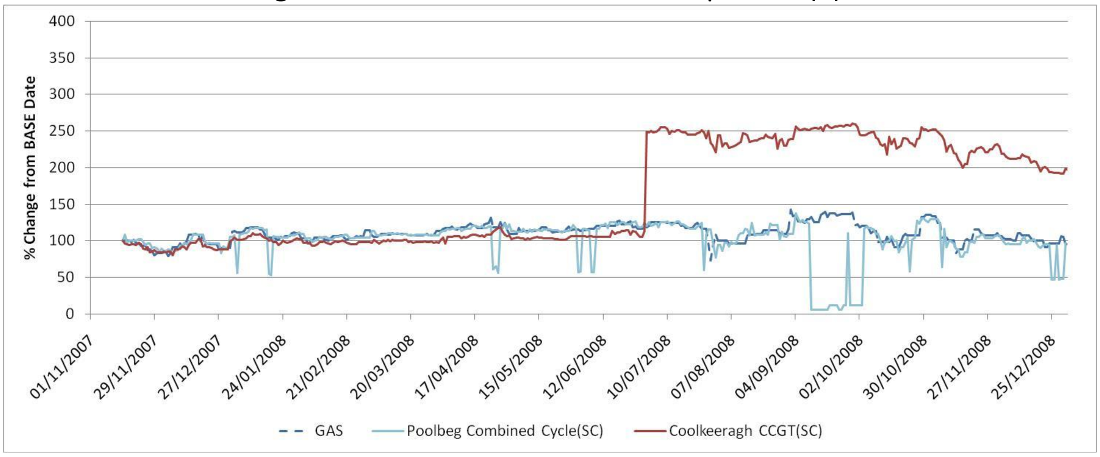
Ballylumford 32's Start-Up Cost follows a similar pattern to the First Price shown earlier. Huntstown's Start-Up Costs undergo a step change in early August following the outcome of the Bidding Inquiry and SEM Committee decision, exhibiting a degree of stepping variability from that point to the end of the study period.

Figure 3.27: Gas-fired Plant Start-Up Costs (2)



Tynagh's Start-Up cost was increased six-fold following the SEM Committee's Decision following the Bidding Inquiry, before halving in early September. A further upward step occurred in October, with a single short-term shock observed at the end of November.

Figure 3.28: Gas-fired Plant Start-Up Costs (3)

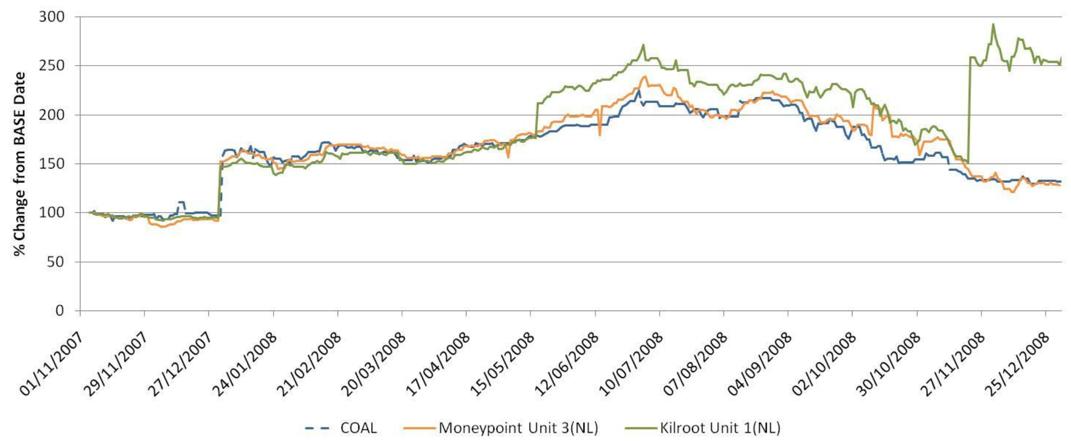


Coolkeeragh's Start-Up Costs took a departure below the gas-price trend at the end of 2007, and made a step change upward in July 2008 following the SEM Committee's Decision. Poolbeg's submitted Start-Up Costs have closely tracked the gas price while making several short-term departures in response to various partial outage events. The specific partial outage event described earlier is evident in the Start-Up Costs in September, reflected as a 90 to 95% short-term reduction.

3.4.3. No-Load Costs

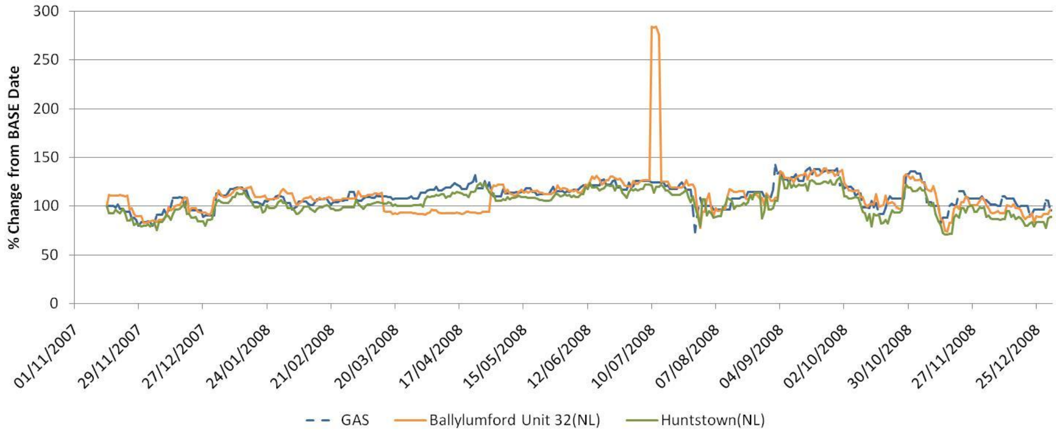
Generators bid a No-Load Cost (€/hr) as part of their daily Commercial Offer Data. The value is defined as that component of running cost incurred for each hour of plant running that does not vary with the level of output of the plant. This section examines the evolutions of these submitted costs for selected units.

Figure 3.29: Coal-fired Plant No-Load Costs



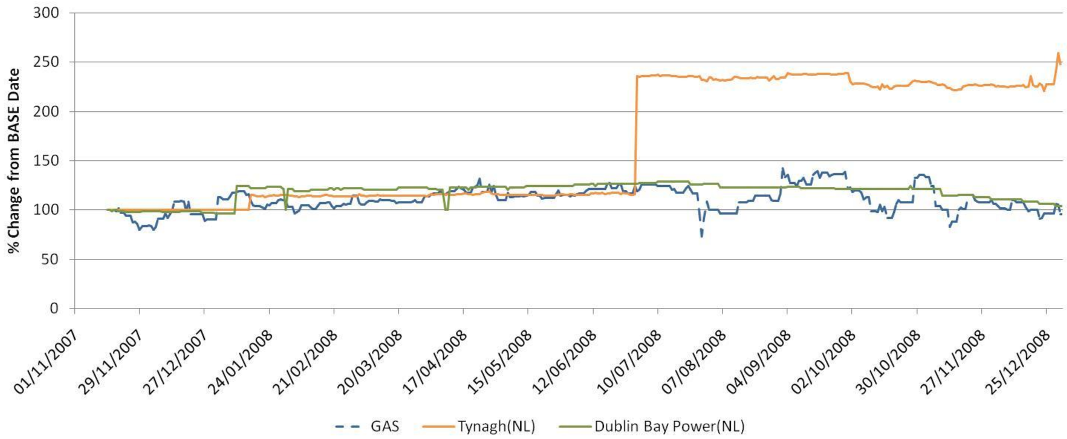
Kilroot's No-Load Cost step-increased in mid-May with a larger step change upward in late November. Moneypoint's No-Load has closely tracked the coal price trend with some departure during October.

Figure 3.30: Gas-fired Plant No-Load Costs



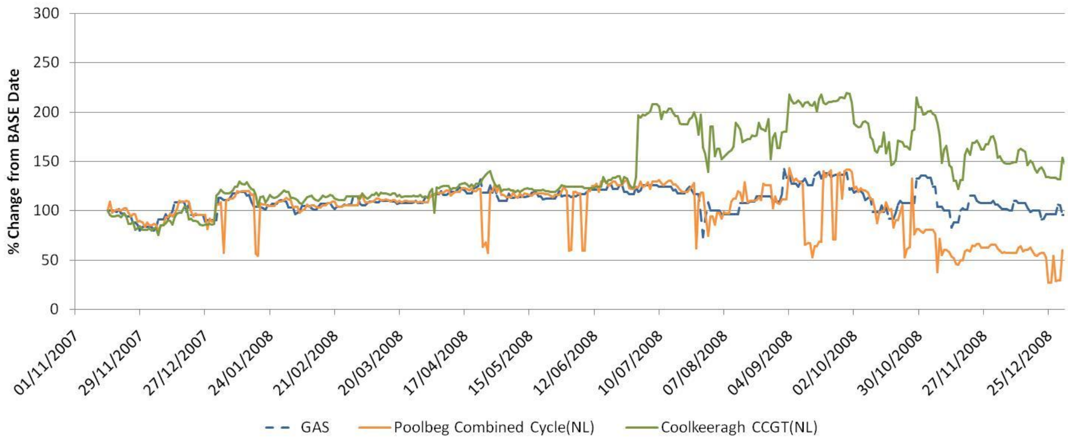
Huntstown's No-Load Cost has closely tracked the gas price movement since SEM start. The pattern for Ballylumford 32 follows a similar path as the data for First Price and Start-Up.

Figure 3.31: Gas-fired Plant No-Load Costs (2)



Tynagh's No-Load Cost has not tracked movements in the gas price to the extent of some of the other gas-fired plant. A step change occurred in July as illustrated. The Dublin Bay No-Load Cost did not track gas-price movements either, this is commensurate with the other COD points for Dublin Bay.

Figure 3.32: Gas-fired Plant No-Load Costs (3)



This figure shows a similar trend for Coolkeeragh and Poolbeg to that shown in the corresponding figures above for First Price and Start-Up Cost. Poolbeg's No-Load Cost reduced by half in November 2008 and remained in that state, continuing to track the gas price through to the end of the study period.

4. Generation Schedules and Dispatch

This section explores the patterns of Generator Unit Schedules and Dispatch for the study period. The term 'schedule' refers herein to the Ex-Post Initial Market Schedule Quantities relevant in any period or group of periods. The term 'dispatch' refers to the actual dispatch instructions issued to the Generator Unit by the System Operators.

4.1. Dispatch Patterns

The introduction of the SEM ushered in a change to the way that Generator Units were dispatched relative to what happened pre-SEM. This change has led to, among other outcomes, an increase in the frequency of plant cycling and shut-downs, which in turn led to a Bidding Inquiry by the MMU and a subsequent set of Decisions issued by the SEM Committee regarding the treatment of the costs associated with such plant behaviour.

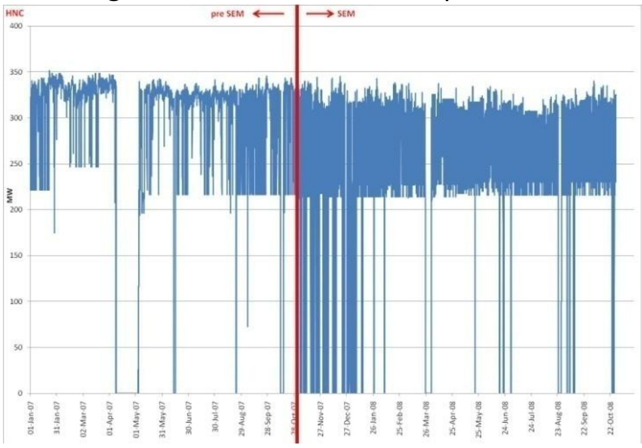
It is worth examining the extent to which the introduction of the SEM impacted the dispatch of large Generator Units. In the figures below, half-hourly dispatch quantities are shown for selected units for a period both before and after the commencement of the SEM, which is indicated by a large red vertical boundary.

A rough index of cycling intensity is calculated as the mean running time observed between each plant start-up (abbreviated as MTBS – mean running time between starts). This is calculated for each plant both before and after SEM-start in order to gain a perspective of the impact of the introduction of the SEM on cycling intensity. Though the graphs conclude around the end of October 2008, the mean times are calculated for the entire study period.

It should be noted that the dispatch patterns reflect forced and planned outage events. Also, the introduction of SEM coincided with the commissioning of the Huntstown Phase II CCGT (HN2), and this certainly increased the level of two-shifting intensity for the CCGT's collectively. The degree to which the introduction of the HN2 plant impacted the cycling intensity over and above the impact of the introduction of the SEM is not explored in this paper.

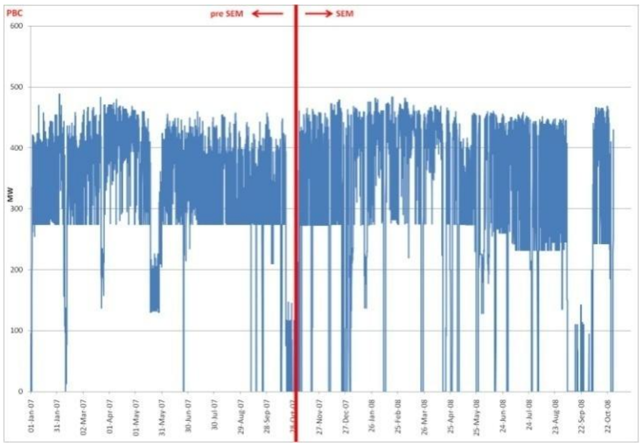
The MTBS shown for some Units is approximate as the pre-SEM data set was not completely available.

Figure 4.1: Huntstown 1 Dispatch Pattern



MTBS pre-SEM: **34 days** MTBS SEM: **7 days**

Figure 4.2: Poolbeg CCGT Dispatch Pattern

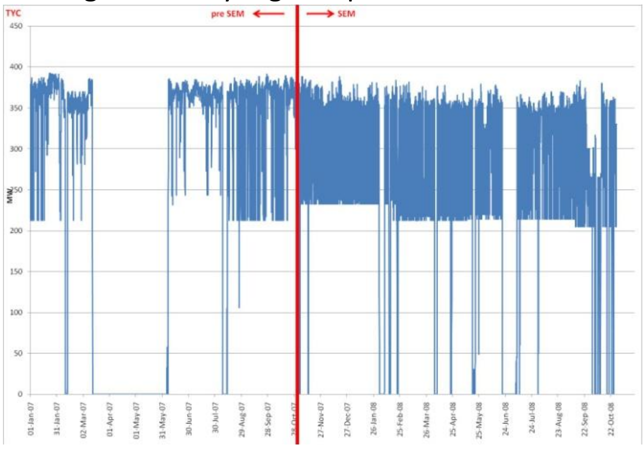


MTBS pre-SEM: **18 days** MTBS SEM: **11 days**

Huntstown 1 saw frequent and repeated shut-down dispatch following the introduction of the SEM compared to that observed previously up until February 2008.

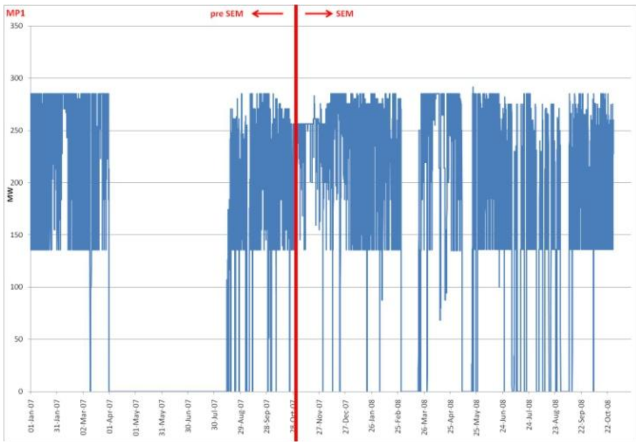
The Poolbeg CCGT has also seen an increased tendency to be shut down following the SEM start, with the mean running time between starts reducing to 11 days from 18. The pattern has been reasonably consistent following SEM start (the partial outage in November notwithstanding), and this is commensurate with the consistency of the COD submitted for Poolbeg over the course of the study period.

Figure 4.3: Tynagh Dispatch Pattern



MTBS pre-SEM: **19 days** MTBS SEM: **13 days**

Figure 4.4: Moneypoint 1 Dispatch Pattern

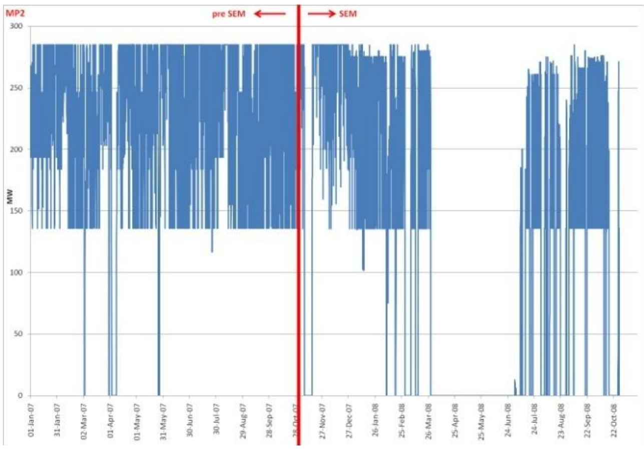


MTBS pre-SEM: **9 days** MTBS SEM: **12 days**

Tynagh's dispatch pattern has also become more cyclic, with the mean time between starts coming down from 19 to 13 days following SEM-start. A period of particularly heavy cycling dispatch occurred in September / October 2008.

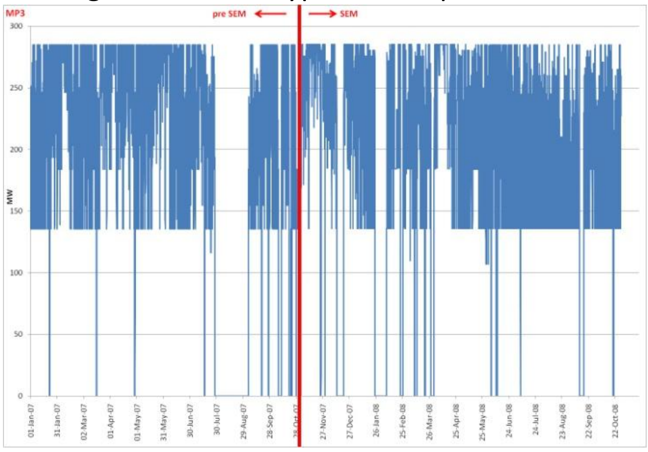
The figure for Moneypoint 1 is dominated by the large gap in the running profile pre-SEM due to the major planned outage which took place at the time. Nonetheless, the data does suggest that, following SEM-start, the unit has been dispatched to cycle less frequently than in the few months prior to the commencement of SEM.

Figure 4.5: Moneypoint 2 Dispatch Pattern



MTBS pre-SEM: **59 days** MTBS SEM: **8 days**

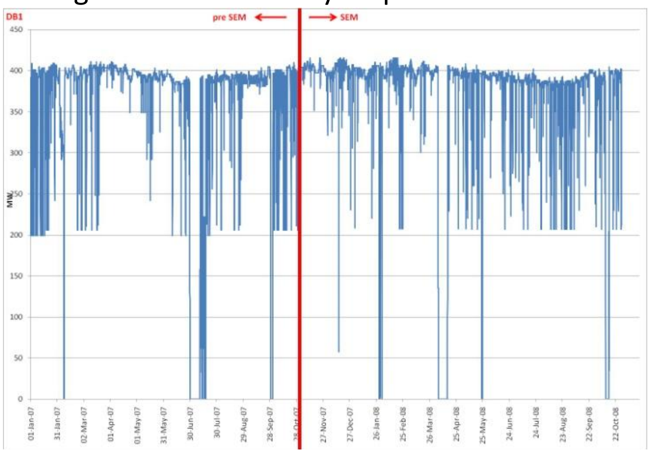
Figure 4.6: Moneypoint 3 Dispatch Pattern



MTBS pre-SEM: **20 days** MTBS SEM: **21 days**

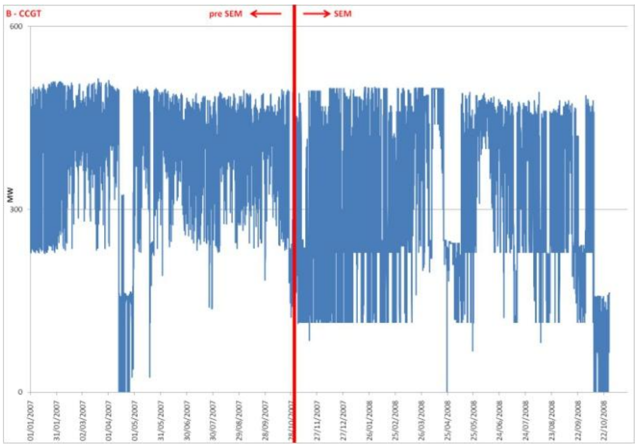
The other two Moneypoint units exhibit contrasting behaviour, suggesting that the large planned outages for Units 1 (pre-SEM) and 2 (post-SEM) are clouding the conclusions somewhat. The Moneypoint 3 record indicates little change relative to pre-SEM, and the highly variable movement of the units inside the 'merit order' (driven by the coal price movement relative to the other fuels as described earlier) further confounds the findings. It is however clear that, overall, the trio of units has collectively been cycled more heavily following the introduction of SEM.

Figure 4.7: Dublin Bay Dispatch Pattern



MTBS pre-SEM: **36 days** MTBS SEM: **51 days**

Figure 4.8: Bally CCGT (2+1) Dispatch Pattern



MTBS pre-SEM: **25 days** MTBS SEM: **12 days**

The Dublin Bay shut-down history is quite sparse, with the mean times driven by just a handful of shut-downs pre and post-SEM. Generally it is likely that the introduction of SEM (and the subsequent suite of SEM Committee Decisions) have had the effect of making the low tendency for Dublin Bay to be shut down somewhat unchanged relative to pre-SEM periods.

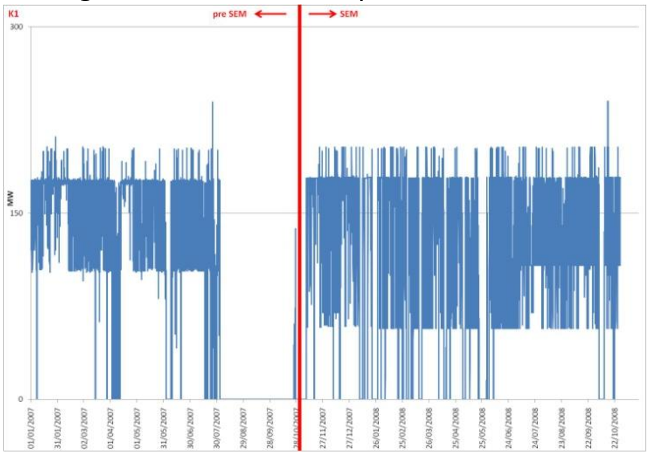
The Ballylumford CCGT is shown as a group (Unit 31+ Unit 32 post-SEM) and exhibits the most interesting behaviour. The mean times are not adequate indices in this case, as several factors are at play:

- The U32 was regularly 'Constrained On' (discussed in next section) while U31 has been very frequently dispatched to shut down repeatedly on a daily cycle.

- The units are treated in the data as a single set for the pre-SEM period.

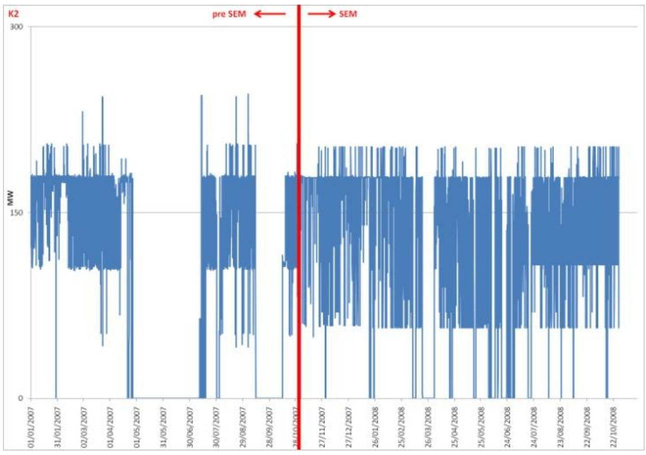
It is clear that the dispatch of the two units and the CCGT set as a whole was impacted by the introduction of the SEM. Following the SEM start and up to the end of October, the entire set was never completely shut down bar a single occasion.

Figure 4.9: Kilroot 1 Dispatch Pattern



MTBS pre-SEM: **6 days** MTBS SEM: **11 days**

Figure 4.10: Kilroot 2 Dispatch Pattern

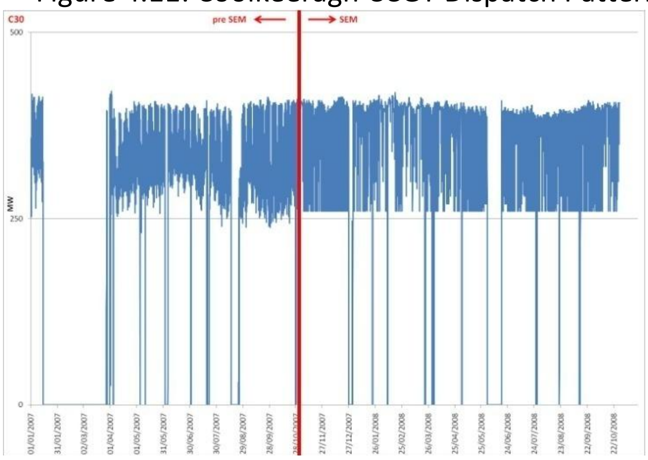


MTBS pre-SEM: **15 days** MTBS SEM: **14 days**

The Kilroot units underwent long-term planned outages in the period pre-SEM as reflected in the figures, which makes it difficult to draw concrete conclusions about the impact of the SEM's introduction. It can be observed that the plants have been dispatched to 'load follow' (reduce output to minimum generation during off-peak demand periods) post-SEM more-so than pre-SEM, when the tendency was for both units to usually be retained above 108MW when available.

The tendency to dispatch the units above their maximum rating on coal (203MW sent-out using the overburn facility) was much more prevalent pre-SEM, with several periods in which Unit 2 was called to switch to oil and run at maximum output (240MW sent-out).

Figure 4.11: Coolkeeragh CCGT Dispatch Pattern



MTBS pre-SEM: **15 days** MTBS SEM: **20 days**

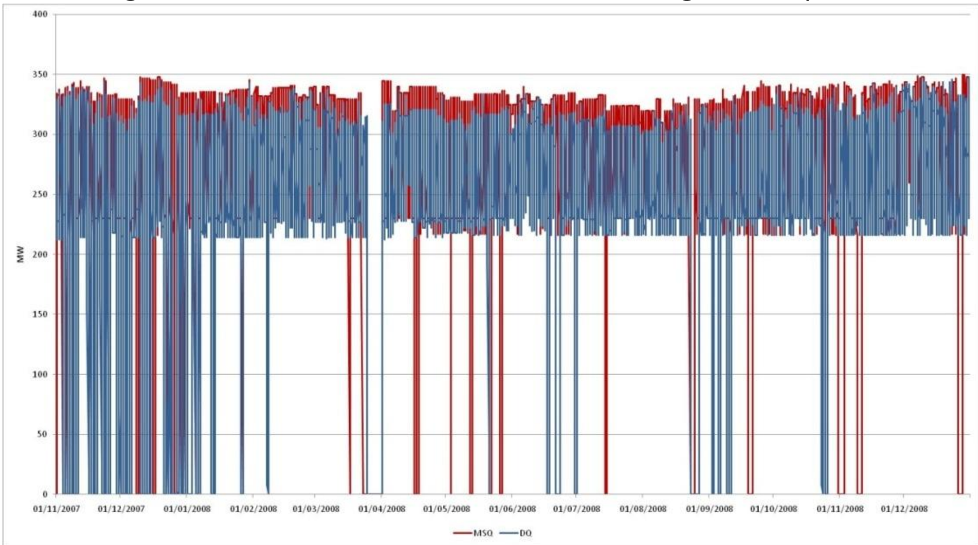
The introduction of the SEM has resulted in a slightly reduced tendency for the Coolkeeragh CCGT to be dispatched to shut down, with 15 running-days between starts pre-SEM increasing to 20 running-days between starts post-SEM.

4.2. Dispatch Patterns against Market Schedules

In the context of these dispatch patterns, it is important to examine how these compare to the market schedules which drive the SMP and in conjunction with Constraint Payments dictate Generator revenues and Supplier charges.

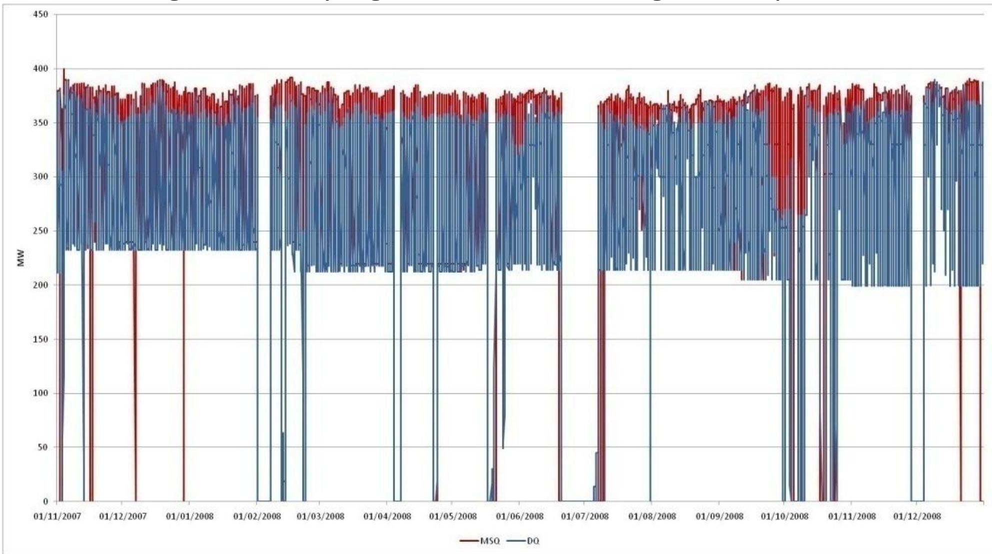
The figures below show the Dispatch Quantities (DQs) of selected units against the Market Schedule Quantities (MSQs). The DQs in blue are the same data plotted on the 'post-SEM' section of the figures in this previous section.

Figure 4.12: Huntstown 1 Market Schedule against Dispatch



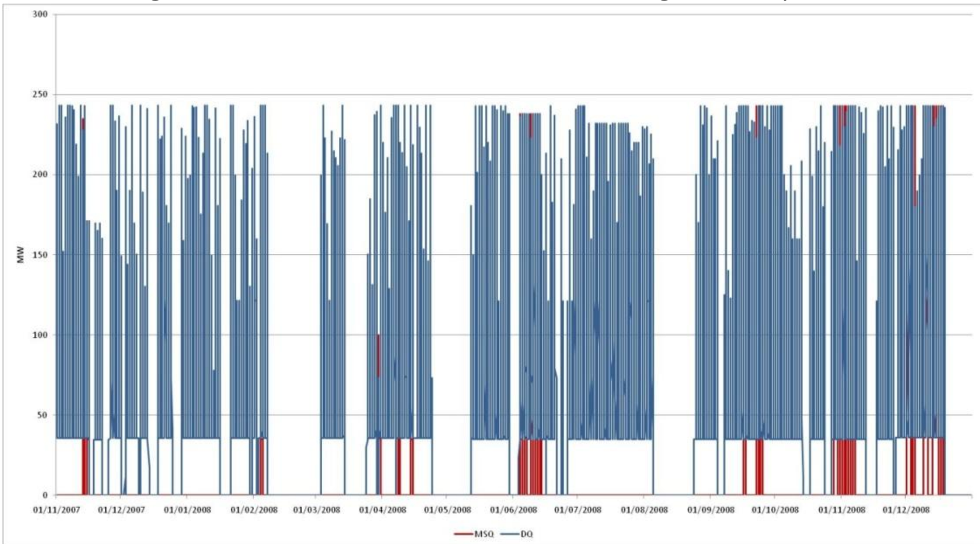
The most striking thing about the figure for Huntstown is the consistent tendency for the DQ to be reduced below the MSQ at typical periods in which the generator is available to run at its maximum rating and is dispatched. The System Operators have advised that this particular constraint (a 'constrained-down' dispatch) is driven by the need to maintain primary reserve for secure system operation. The unit has also seen several 'constrained-on' instructions in which the MSQ is reduced to zero but the unit is kept running in the system dispatch.

Figure 4.13: Tynagh Market Schedule against Dispatch



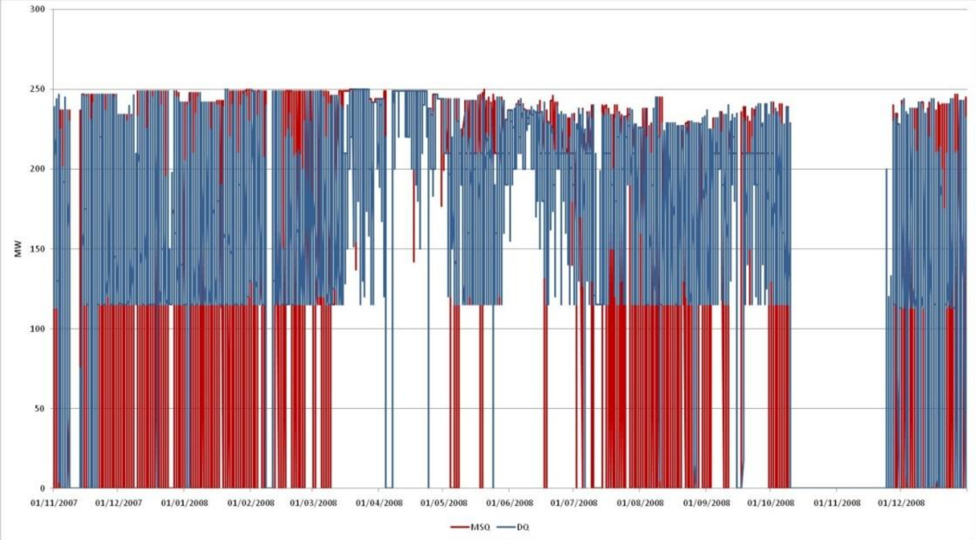
The pattern for Tynagh is largely explained by the need to maintain reserve as per Huntstown 1. The anomaly present in October was caused by a transmission line outage north of Tynagh's export point, necessitating a 'backing off' of the unit's maximum export.

Figure 4.14: Tarbert 4 Market Schedule against Dispatch



Tarbert 4 has been consistently dispatched during the study period while not appearing very often in the market schedule. As the oil price began to rapidly decline toward the end of the study period, Tarbert 3 and 4 have both become more regularly included in the market schedule. The station is required to be run for system support reasons.

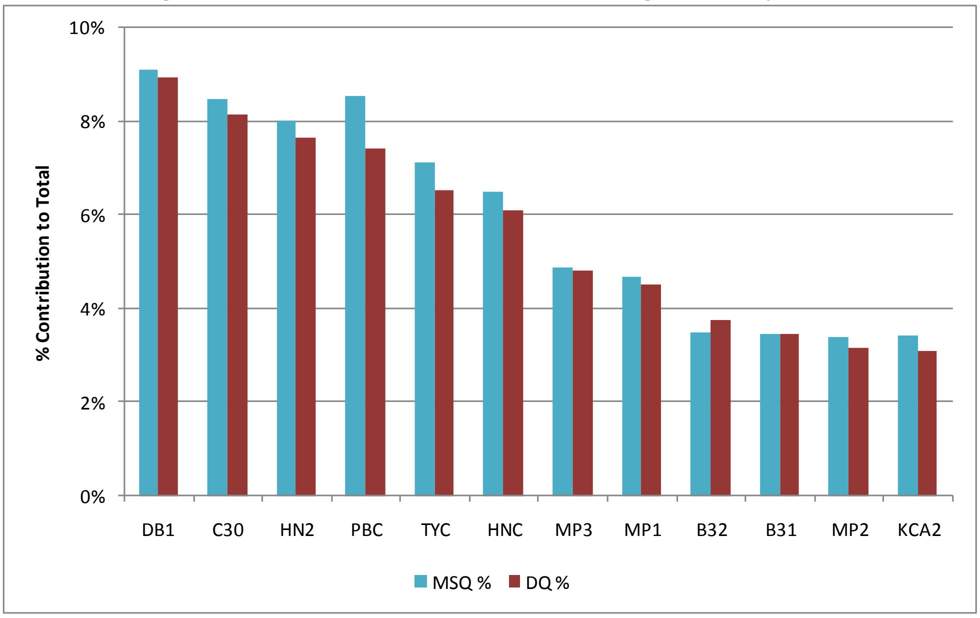
Figure 4.15: Ballylumford U32 Market Schedule against Dispatch



U32 has been consistently 'constrained on' following the commencement of the SEM, though this has generally ceased to be the case since December 2008 following the extended outage period in November.

The figure below shows the contribution of the large generation plants to serving of the demand under dispatch and under the market schedule:

Figure 4.16: Overall Market Schedule against Dispatch



The figure shows a general tendency for large nominally baseload / mid-merit plant to be retained at levels of export slightly below their maximum export capacity level. These trends are generally driven by reserve constraints but several types of other constraints, such as line thermal ratings, voltage support and transient fault stability requirements combine in real time to produce the constrained dispatch.

The table below shows the sum of constraint costs broken down by month over the study period:

Table 4.1: Constraint Costs by Month

2007	**€13,702,976**
Nov	€5,422,640
Dec	€8,280,336
2008	**€128,354,543**
Jan	€9,409,482
Feb	€11,425,816
Mar	€9,998,026
Apr	€9,040,212
May	€12,962,779
Jun	€11,632,607
Jul	€15,745,682
Aug	€13,344,460
Sep	€14,934,196
Oct	€3,632,689
Nov	€9,090,996
Dec	€7,137,598
Total	**€142,057,519**

4.3. Generator Utilisation, Capacity and Availability

This section explores the available generating capacity offered by Generator Units in the SEM and the degree to which this capacity has been utilised in the market schedule and system dispatch.

Three indices are here defined:

Availability Factor = Available Volume / Potential Gross Volume

Capacity Factor = Scheduled Volume / Potential Gross Volume

Utilisation = Scheduled Volume / Available Volume

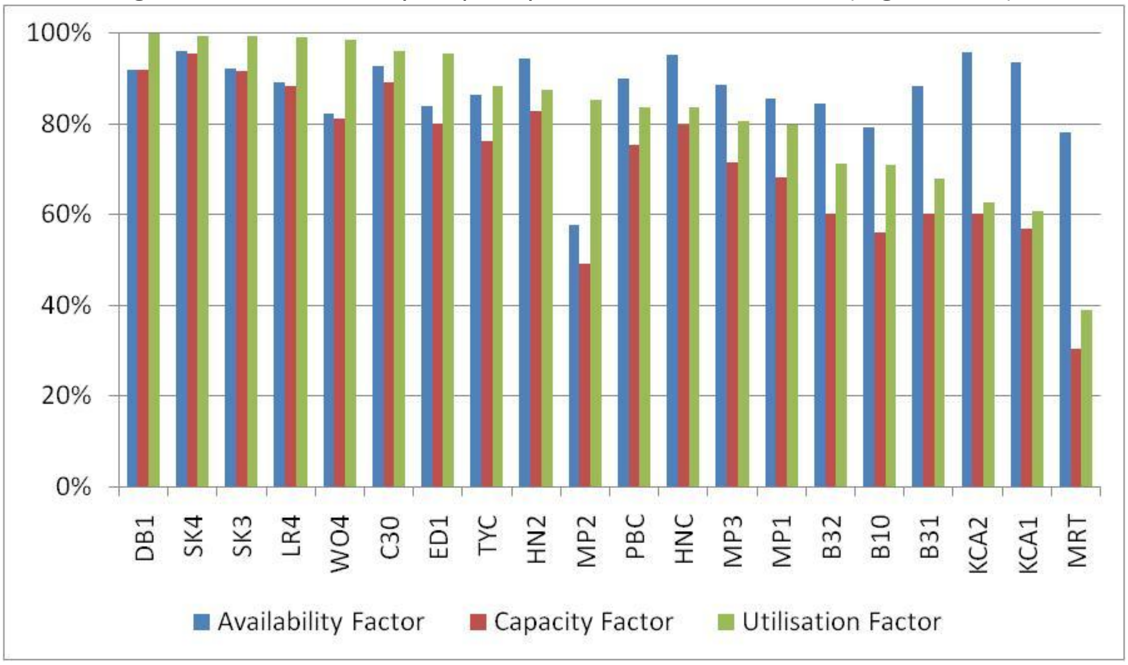
The term ‘Volume’ is used to describe the product of MW and Hours and all three Factors are in units of MWh/MWh.

‘Potential Gross Volume’ refers to the maximum possible quantity of energy that could have been generated if no outages or derating events had occurred.

Note the Utilisation Factor can be read as the ratio between the other two factors (Capacity : Availability).

The Factors are shown for the units with higher utilisation (baseload / mid-merit) in the figure below:

Figure 4.17: Availability, Capacity and Utilisation Factors (highest UFs)



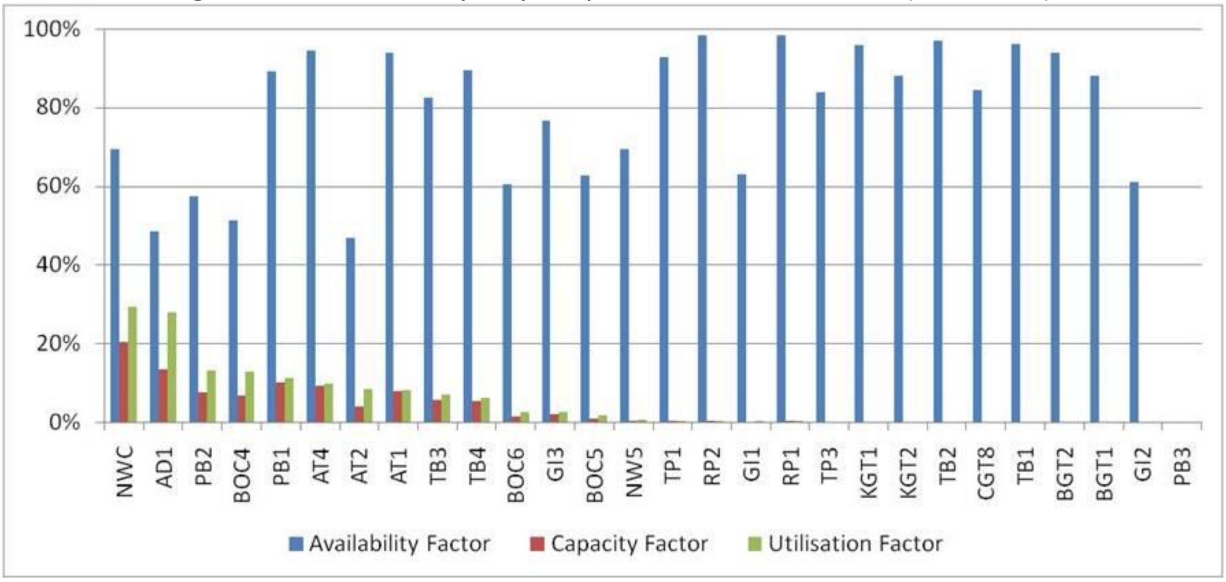
The figure shows significant variability in the Availability Factors across the Generator units. The units that have turned in the highest Availability Factors include the Kilroot (KCA), Huntstown (HNC, HN2) and Sealrock (SK) units with strong performances also from Dublin Bay (DB1) and Coolkeeragh CCGT (C30). The Moneypoint 2 (MP2) Factors reflect an extended planned outage undertaken post-SEM-start to facilitate significant plant upgrade.

The Capacity Factors vary widely across the units, with the Dublin Bay, Coolkeeragh and Sealrock units seeing the highest relative scheduled volumes. Notably low Capacity Factors appear for the Kilroot and Ballylumford CCGT units (B31, B32). The low Kilroot Capacity Factor is due in part to the sparse (in volume terms) scheduling of the oil-firing capacity between 203 and 238MW.

The Utilisation Factor is a combination of the two Factors previous and indicates the degree to which available volumes were scheduled in the market. Very high Utilisation Factors have emerged for Dublin Bay, Coolkeeragh, Sealrock and the fleet of peat-fired units (LR4, WO4, ED1). Tynagh, Huntstown and Poolbeg CCGT (PB4) have seen Utilisation Factors of between 80 and 90%. By comparison the Ballylumford and Kilroot units have seen market utilisation factors of between 60 and 70%.

The Factors are shown for the units with lower utilisation (mid-merit / peaking plant) in the figure below:

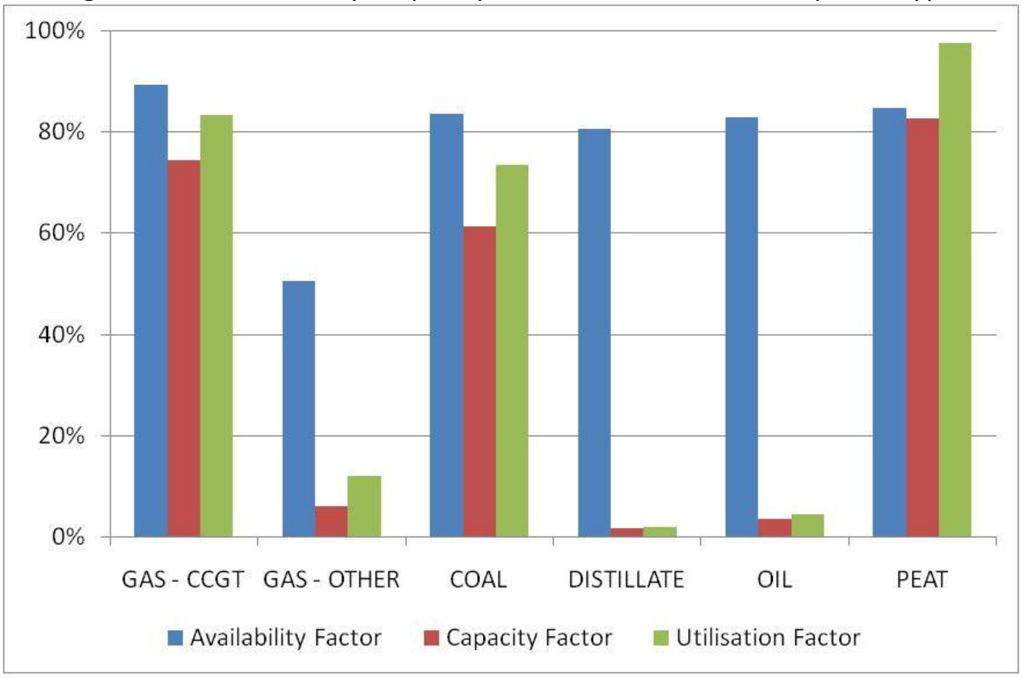
Figure 4.18: Availability, Capacity and Utilisation Factors (lower UFs)



Amongst the peaking plant there is again a wide spread in the Availability Factors, with Rhode 1 and 2 (RP) and Tarbert (TB) 1 and 2 turning in very high values. The larger capacity units in the figure have turned in substantially lower values than seen generally for the higher utilisation units in the previous figure or for the smaller peaking plants. Poolbeg 2, Ballylumford 4, 5 and 6[4], Northwall (NW) and Great Island (GI) all have seen Availability Factors between 50 and 65%.

The figure below groups the three factors under conventional fuel-type. The data is capacity-weighted so that larger units contribute more heavily to the averaged data than smaller units:

Figure 4.19: Availability, Capacity and Utilisation Factors by Fuel Type



Distillate and oil-fired plant immediately stand out as having seen substantially lower Capacity and Availability Factors than the other fuel types and this is commensurate with expectation given the

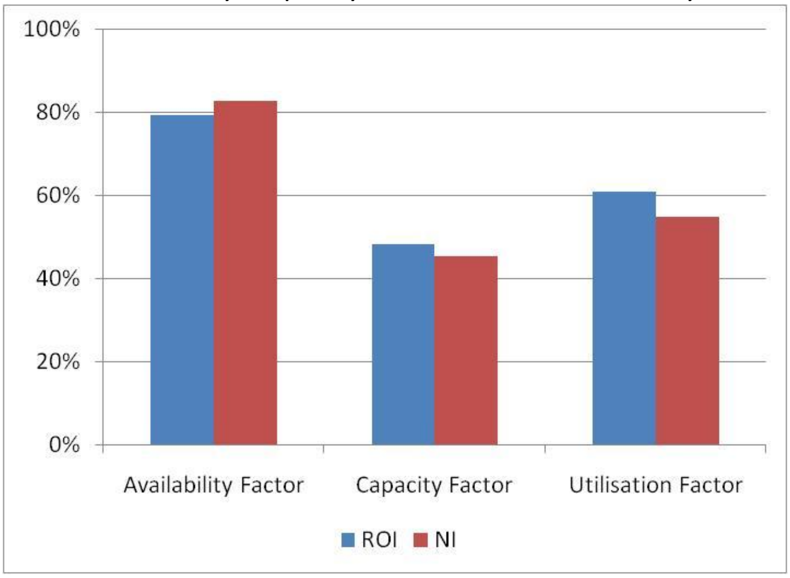
[4] Note Ballylumford 4, 5 and 6 are a special case as the station can only export from two out of three of the units at one time due to network limitations; this impacts on the visible availability of the units.

tendency for these plant to sit in the peaking region of the merit order. The peat-fired plant exhibit the highest Capacity and Utilisation Factors, with CCGT gas and coal next highest in the order of these Factors. Gas (other) includes mainly peaking OCGT gas units so it is not surprising to see the Capacity and Utilisation Factors for these plant at low levels.

Of significant note is the consistency in the Availability Factors across the fuel types, all converging between 80 and 88% with the notable exception of the Gas (other) category which produced collectively an outturn Availability Factor of around 50%. This is explained partly by the inclusion of the Poolbeg 3 unit, which offered no available capacity during the study period but at 240MW accounts for around 15% of the installed capacity under the Gas (other) category.

The Factors are aggregated further (again by capacity-weighting) into Jurisdiction in the figure below:

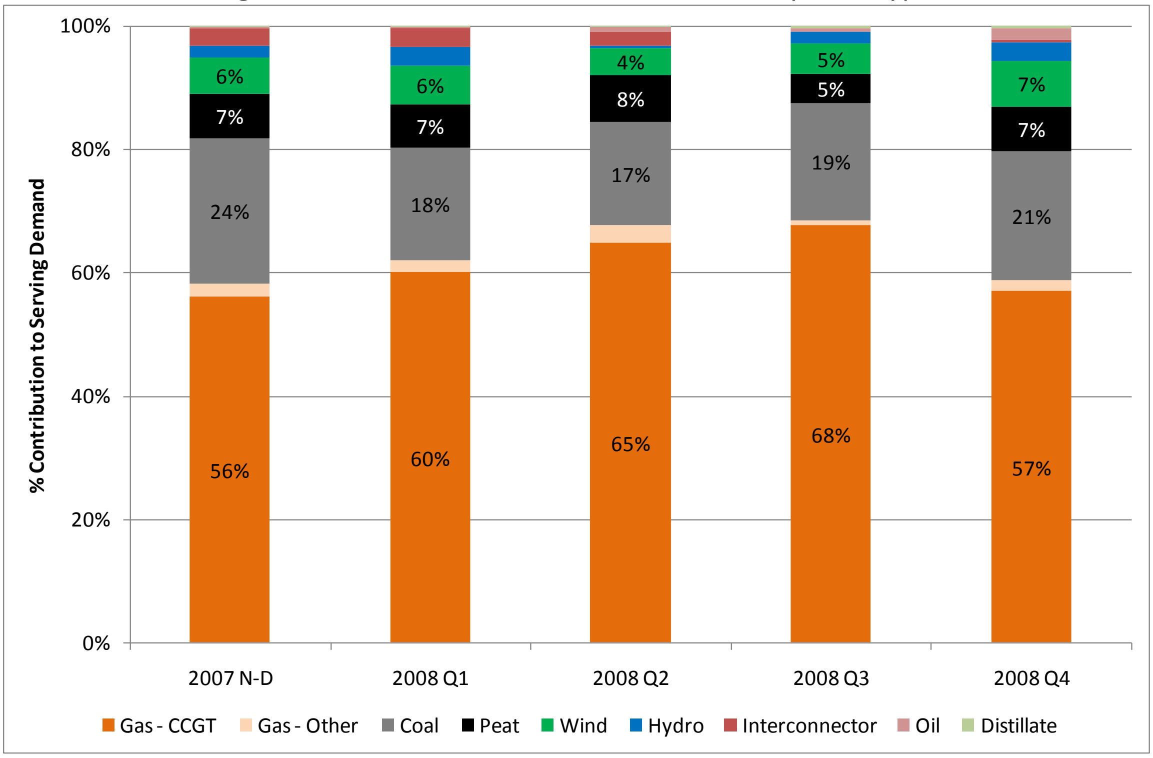
Figure 4.20: Availability, Capacity and Utilisation Factors by Jurisdiction



The relatively low Availability Factors of the smaller plant in both NI and RoI tend to counter the generally higher Factors of the larger plants to leave the overall average Availability Factor at 79 and 83% for RoI and NI, respectively. Again, the Poolbeg 3 unit is included in the aggregation for RoI and this tends to have a downward effect on the overall Availability Factor; exclusion of Poolbeg 3 would lift the Factor to around 82%, comparable with the Factor for NI. The relative Utilisation Factors indicate that RoI units have overall been scheduled to generate higher relative volumes when available compared to the NI units.

The figure below draws the Capacity Factor data together with volumetric contributions from other fuel types, including Wind, Hydro and the Interconnector:

Figure 4.21: Stacked Market Contributions by Fuel Type



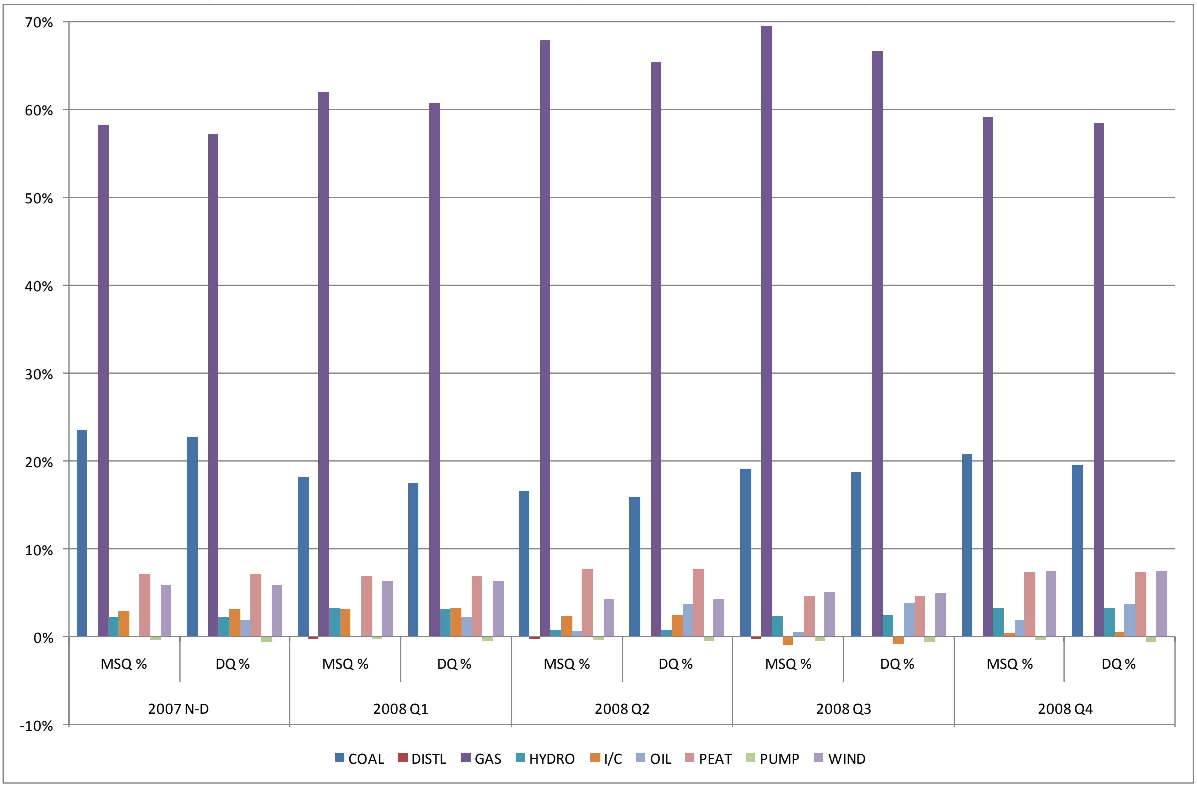
The figure illustrates a heavy contribution across the study period from CCGT gas-fired plant which reaches a peak penetration in the third quarter of 2008. Coal-fired plant served the next largest portion of the load and a significant contribution of between 4 and 7% was made by wind generation. Peat-fired plant also contribute a significant proportion of between 5 and 8%, commensurate with the high Capacity Factors observed for those plant.

The step change in the price of carbon (discussed earlier as having occurred on January 1 2008) can be seen in this figure as the coal-fired contribution sees a marked decrease in the first quarter of 2008 relative to the contribution in November / December 2007.

Contributions from interconnector imports declined over the study period from 2% down to zero (net export) by the third and fourth quarters of 2008. Behaviour of the Moyle Interconnector resource is explored in more depth in Section 7.2.

The figure below repeats the data depicted in the above figure, but adds the volumetric contributions to the system dispatch and splits out the columns for comparison:

Figure 4.22: Split Market and System Contributions by Fuel Type

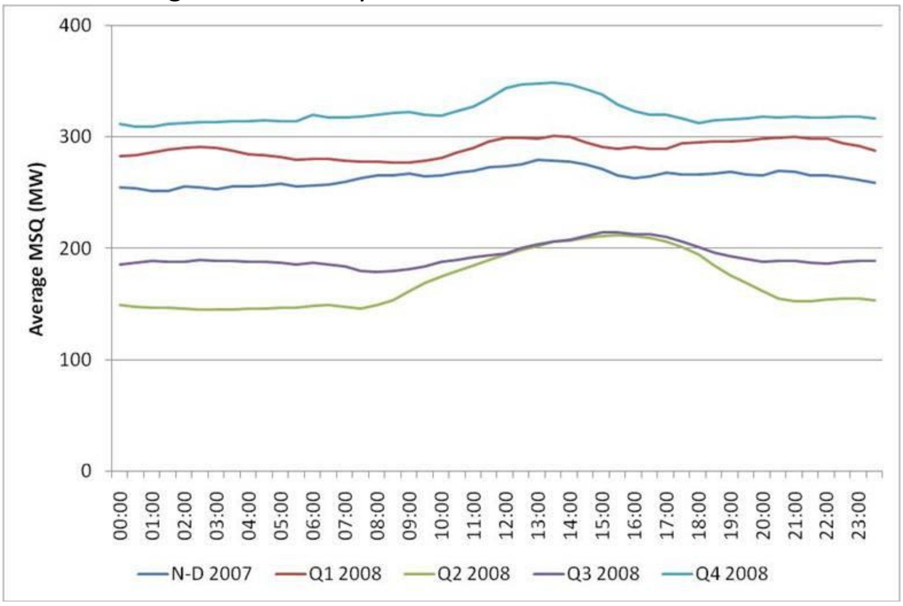


The figure above draws together some of the key messages described earlier relating to the differences between the system dispatch and the market schedule and also shows the evolving contributions of each fuel type across the study period.

4.4. Wind Output

This section examines the profiles of wind output during the study period. The figure below shows the daily average wind output split across the five 'quarters':

Figure 4.23: Daily Wind Profile across Quarters



The figure shows that the output of the collective wind generation in the SEM does not markedly vary over the course of the day, on average, although there is a tendency for increased output in the early through to late afternoon. This trend was particularly prevalent in the second Quarter of 2008. The figure also shows that the highest average wind output occurred in the fourth Quarter of 2008, with the first Quarter of 2008 seeing the second highest output. This result suggests a tendency for more wind output to occur in the winter months than the summer months.

In considering the relative outputs of the Nov – Dec 2007 period, the first and fourth Quarters of 2008, it is important to consider the high growth in the Registered Capacity of wind units in the SEM during the study period. Registered Capacity on the 1st of November 2007 was around 680MW and this grew to 950MW by the 31st of December 2008 which constitutes an increase of nearly 40%.

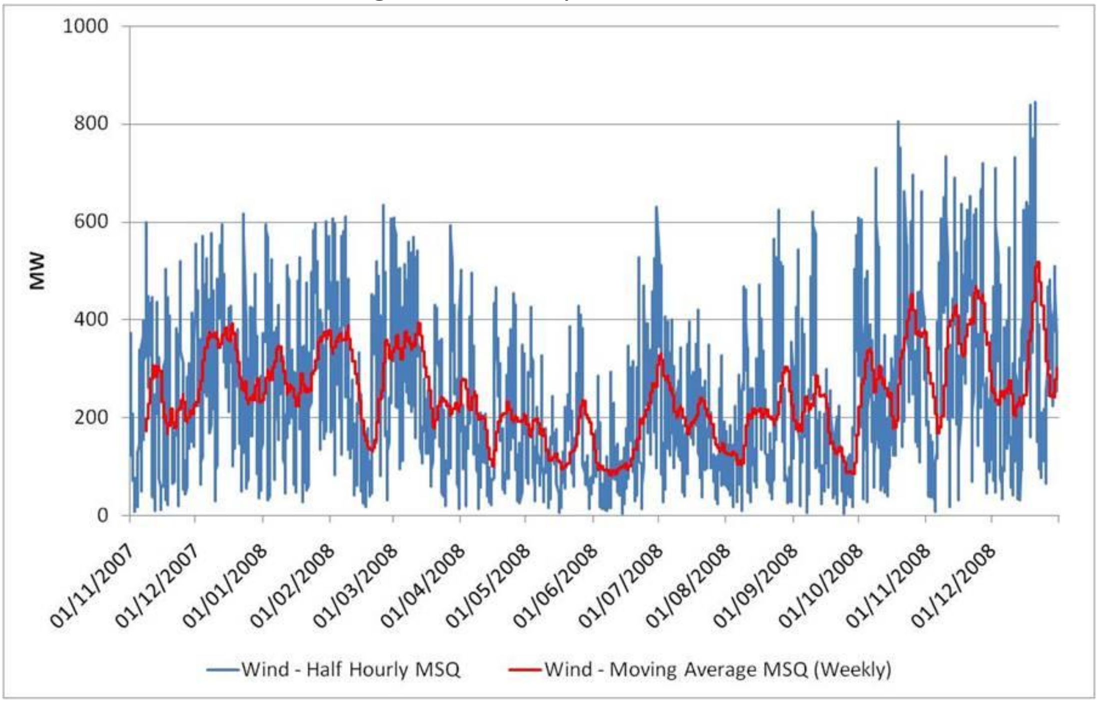
The monthly breakdown of contributions from Wind Generation are shown in the table below:

Table 4.2: Monthly Wind Outcomes

		Wind MSQ (MW)		
Year	Month	Average	Min	Max
2007	11	212	4	591
	12	304	20	607
2008	1	309	28	595
	2	273	19	623
	3	277	11	607
	4	188	11	500
	5	143	7	429
	6	165	2	619
	7	187	14	510
	8	190	3	614
	9	188	4	610
	10	317	16	795
	11	329	8	725
	12	309	21	837
OVERALL		242	3	837

The variability of the Wind Output over the course of the study is shown in the figure below, with half-hourly data shown in blue and a 7-day smoothed version of the data overlaid in red:

Figure 4.24: Daily Wind Profile



The movement of the red curve further illustrates the tendency for the Wind output to increase in the winter period relative to the summer period. The figure also depicts the degree of short term variability in the wind output.

5. DEMAND, CAPACITY MARGIN AND MARKET PRICES

5.1. Market Outcomes - Annual Trends

5.1.1. Market Demand

Load duration curves for the study period are plotted below. The study period is split into the four Calendar quarters of 2008 with Nov-Dec 2007 shown as an additional line on its own. This theme is used in several other graphs and figures in the paper. The load is calculated from the sum of Market Scheduled Quantities (MSQ).

Figure 5.1: Load Duration Curves

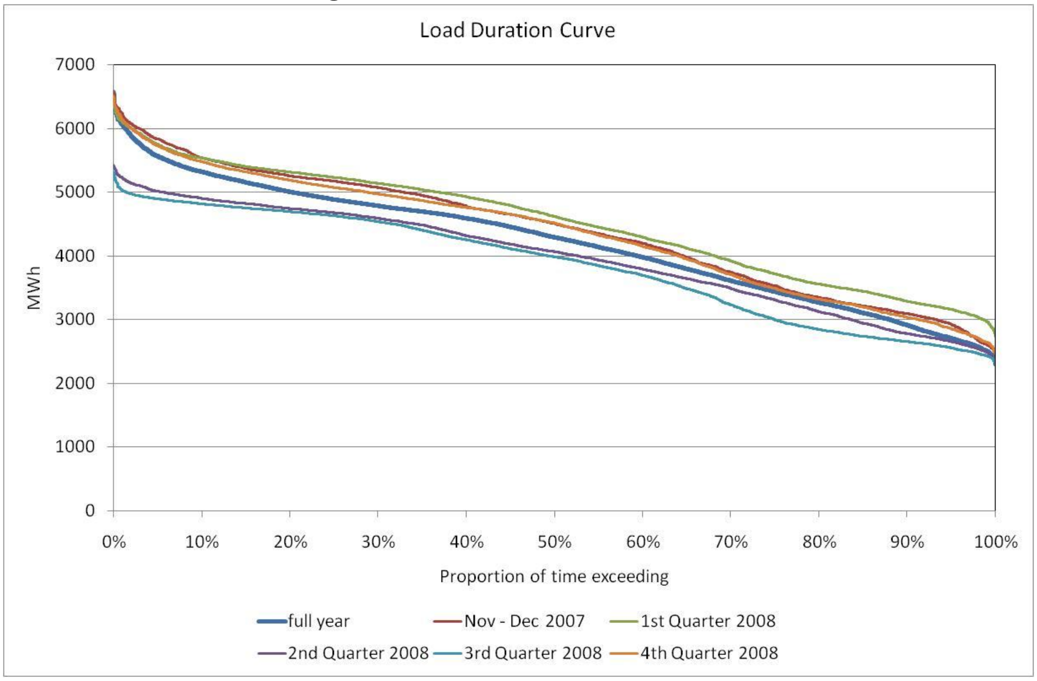
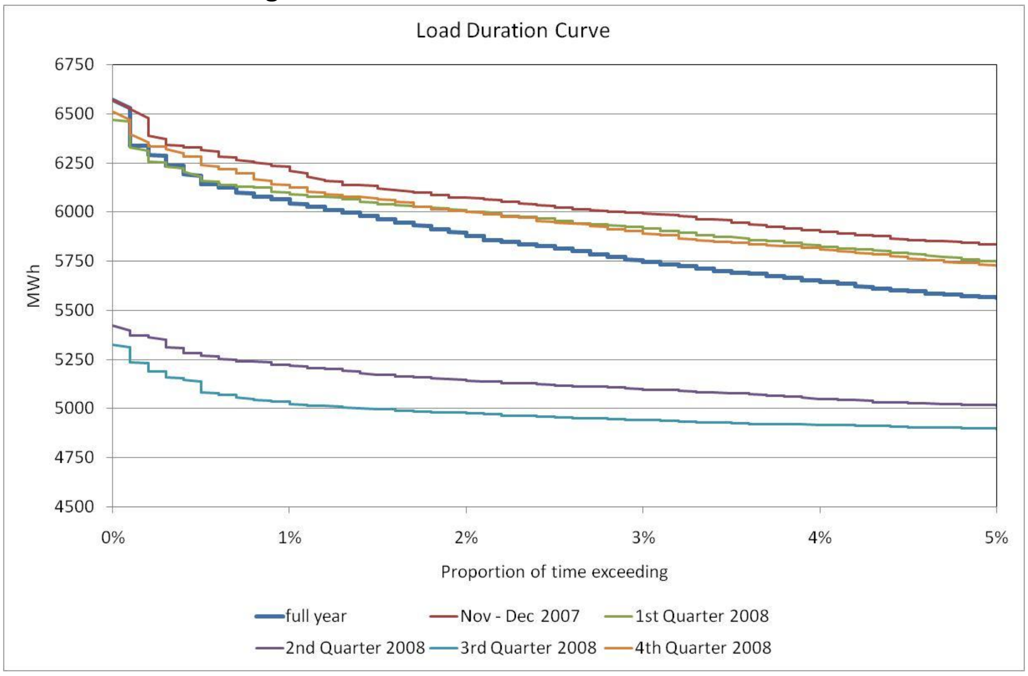


Figure 5.2: Zoomed Load Duration Curves



The location of the demand curves is markedly higher in Quarters 1 and 4 (winter) than in Quarters 2 and 3 (summer), though the shape remains reasonably consistent. The highest demand periods occurred during the initial two months of SEM in November and December 2007.

5.1.2. Market Price

The table below shows a summary of the System Marginal Price statistics for the study period:

Table 5.1: SMP Statistics

SMP Summary (€/MWh)	2007 N-D	Q1 2008	Q2 2008	Q3 2008	Q4 2008
Average SMP (Time Weighted)	62.34	74.95	88.40	86.51	72.65
Average SMP (Demand Weighted)	67.21	78.81	92.49	91.67	77.07
Standard Deviation (All)	45.70	41.68	34.92	31.07	37.34
Standard Deviation (Daily Average)	10.37	10.40	14.15	12.56	12.72
Standard Deviation (Intraday Average)	32.62	23.85	20.82	22.01	24.26
Minimum	29.31	30.19	27.45	30.23	3.29
Maximum	524.65	468.32	525.70	551.46	696.85
1st Quartile	43.33	54.96	62.62	63.46	52.45
3rd Quartile	67.25	80.98	108.34	106.34	83.67

From Table 5.1 it can be seen that average prices were at their highest during Quarter 2 and 3 of 2008, when fuel prices were also at their highest. Averages prices were at their lowest during the first two months of the market (2007 N-D), significantly influenced by the low cost of carbon in this period. For each period the demand-weighted average SMP was about 6% higher than the time-weighted average. This is because the majority of higher prices occurred during periods of high demand and the majority of lower prices occurred during periods of low demand, hence the per-megawatt cost of electricity is higher than the simple (time–weighted) average of prices over the period.

The Standard Deviation (Daily Averages) is the standard deviation of the time-weighted daily average price in each period. This shows that the daily average prices were most volatile during Quarter 2 of 2008. Commercial Offers are submitted to the market on a daily basis, hence the volatility of the daily averages is largely driven by changes in underlying fuel and carbon costs. The Standard Deviation (Intraday Averages) is the standard deviation of the average half hourly prices for each trading period over the trading day – this is a measure of the intraday volatility. This shows the opposite trend, where on average the intraday prices were at their most volatile during 2007 and at their least volatile during Quarters 2 2008, when the intraday SMP price profile was 'flatter'.

Minimum prices for each period have remained steady, apart from Quarter 4 of 2008 when the minimum SMP dropped to €3.29/MWh. This occurred overnight when the demand was low, and the MSP software scheduled all thermal price making generators at their minimum generation, while hydro units set the shadow price during this period with an incremental offer price of zero (€3.29/MWh of Uplift was added). Again the maximum prices have been fairly consistent, and have for the most part been set by Kilroot's oil-firing generation range (explored further below). The maximum price in Quarter 4 2008 however was created by Uplift associated with 'carrying forward' the Start-up Costs of one of the Tarbert units, which has a minimum on-time of 24 hours. These events are discussed in more detail in the Section on Discrete Events (Section 6) in this report.

Price (SMP) Duration curves for the study period are plotted below.

Figure 5.3: Price Duration Curves

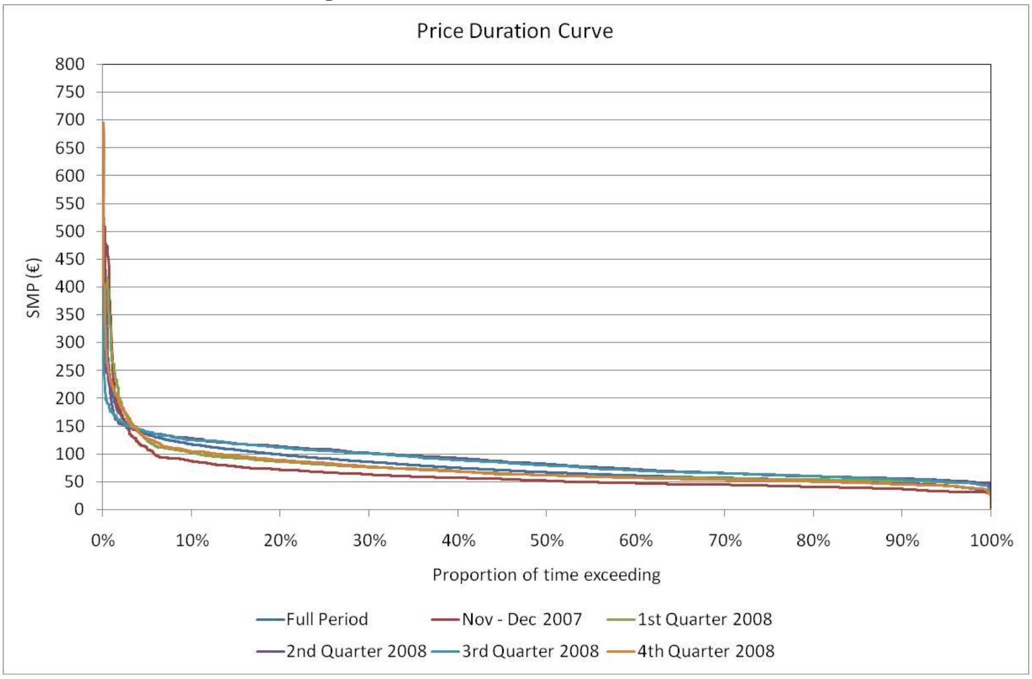
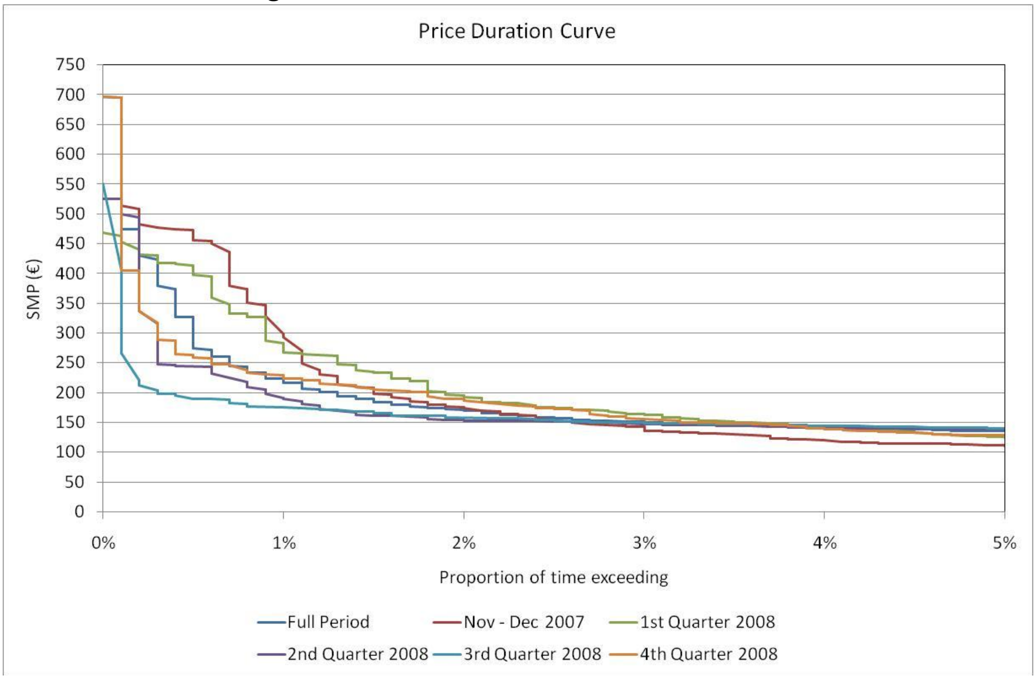


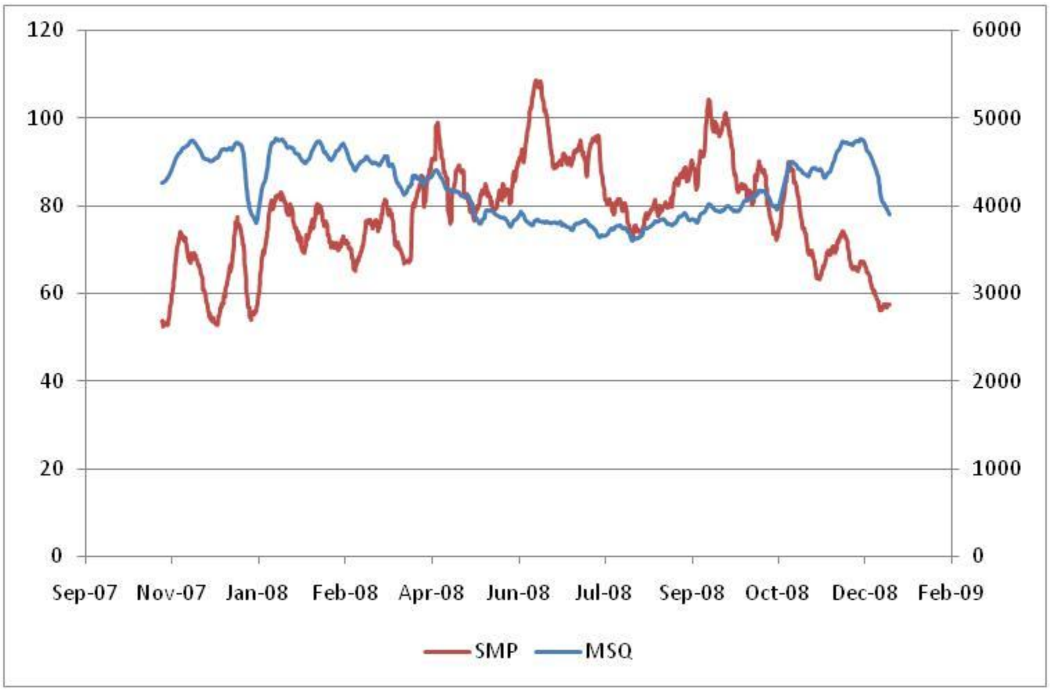
Figure 5.4: Zoomed Price Duration Curves



The price duration curves demonstrate a shift from more volatile ('spiky') behaviour in the summer (Red and Orange lines) to more levelled behaviour over the off-summer quarters (Green, Blue and Purple lines). For example, at the 50% threshold, the prices in Q2 and Q3 of 2008 were 50% higher than at the same threshold in Nov-Dec 2007, while the Nov-Dec 2007 prices exhibit a stronger peak at the 0-1% threshold (much higher prices during the peak period). There are many factors that contributed to this behaviour, including the normal shift in seasonal daily load profile explored earlier, and the significant changes in fuel prices that have been observed over the study period.

The graph below shows the SMP and MSQ profiles, smoothed using a 7-day moving simple average.

Figure 5.5: SMP against summed MSQ



The figure shows an increase in SMP during the middle of 2008 against a reduction in demand. While the reduction in demand is expected given the known seasonal trends, the corresponding increase in SMP is not (necessarily), as price and demand would normally be expected to increase and decrease together. This suggests that there are other variables such as fuel prices and available capacity at play.

The SMP is calculated in each period as the sum of the Shadow Price (SP) and Uplift. The table below shows the 'Top 20' SMP outcomes in the study period with the contributions of each of Shadow Price and Uplift:

Table 5.2 : Top 20 SMP outcomes

Top 20 Peak Prices				
Date	*Period*	*SMP €/MWh*	*Shadow €/MWh*	*Uplift €/MWh*
15/10/2008	06:30:00	696.85	51.36	645.49
15/10/2008	06:00:00	694.72	49.22	645.50
21/08/2008	11:30:00	551.46	551.46	0.00
13/06/2008	11:00:00	525.70	517.96	7.74
19/05/2008	17:00:00	525.44	525.44	0.00
24/11/2007	17:00:00	524.65	524.65	0.00
24/11/2007	17:30:00	524.65	524.65	0.00
03/12/2007	17:30:00	513.45	513.45	0.00
26/11/2007	17:30:00	507.67	507.67	0.00
06/05/2008	21:30:00	499.68	499.68	0.00
23/04/2008	08:00:00	494.56	494.56	0.00
23/04/2008	08:30:00	494.56	494.56	0.00
23/04/2008	09:00:00	494.56	494.56	0.00
23/04/2008	09:30:00	494.56	494.56	0.00
20/12/2007	17:00:00	482.74	482.74	0.00
05/12/2007	17:00:00	482.27	482.27	0.00
19/12/2007	17:30:00	477.22	477.22	0.00
19/12/2007	18:00:00	477.22	477.22	0.00
10/12/2007	17:00:00	474.96	474.96	0.00

10/12/2007	17:30:00	474.96	474.96	0.00

Generally the periods in the above table coincide with scheduling of Kilroot's oil-fired capacity during periods in which the oil price was high. Particular prevalence of this can be seen in the first two months of the SEM. The top two events however do not relate to this but to a discrete event in which the Tarbert units were scheduled for the first two periods of the Trading Day on the 15 October 2008. This is explored in Section 6.

The top two prices are comprised mainly of Uplift. The Top 20 incidences of Uplift are explored below:

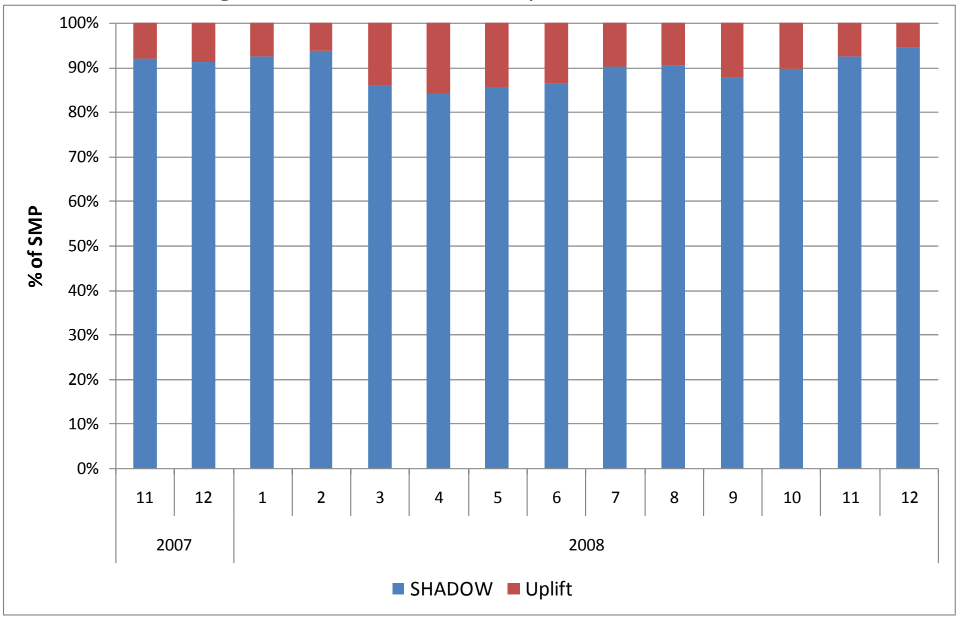
Table 5.3 : Top 20 Uplift outcomes

Top 20 Incidences of Uplift					
Date	*Period*	*Periods*	*SMP €/MWh*	*Shadow €/MWh*	*Uplift €/MWh*
15/10/2008	06:00:00	1	694.72	49.22	645.50
15/10/2008	06:30:00	1	696.85	51.36	645.49
07/06/2008	06:30:00	2	350.28	73.52	276.76
20/11/2007	17:30:00	1	347.37	127.99	219.38
31/03/2008	02:00:00	8	261.72	55.47	206.25
08/06/2008	12:30:00	1	315.71	120.29	195.42
14/04/2008	01:00:00	14	246.05	60.23	185.82
05/02/2008	17:30:00	1	324.82	141.15	183.67
19/02/2008	18:00:00	1	327.34	148.66	178.68
06/12/2007	17:30:00	1	270.65	92.04	178.61
07/01/2008	17:30:00	1	287.03	108.79	178.24
11/03/2008	19:00:00	1	271.7	95.33	176.37
05/03/2008	19:00:00	1	266.06	92.33	173.73
27/05/2008	17:30:00	1	245.66	82.77	162.89
12/01/2008	17:30:00	1	243.82	82.28	161.54
22/03/2008	19:00:00	1	235.43	76.52	158.91
18/12/2007	17:30:00	1	333.78	177.05	156.73
03/09/2008	20:30:00	1	361.35	205.57	155.78
08/10/2008	19:00:00	1	317.75	167.92	149.83
08/03/2008	19:00:00	1	228.55	79.04	149.51

While the same event on the 15 October 2008 occupies the top two slots, the spread of high Uplift events is quite broad across the study period, suggesting that high incidences of Uplift can occur under a varying array of market scenarios.

The proportional contribution of Shadow Price and Uplift to the SMP is broken down across the study period in the figure below:

Figure 5.6: Shadow and Uplift Share of SMP



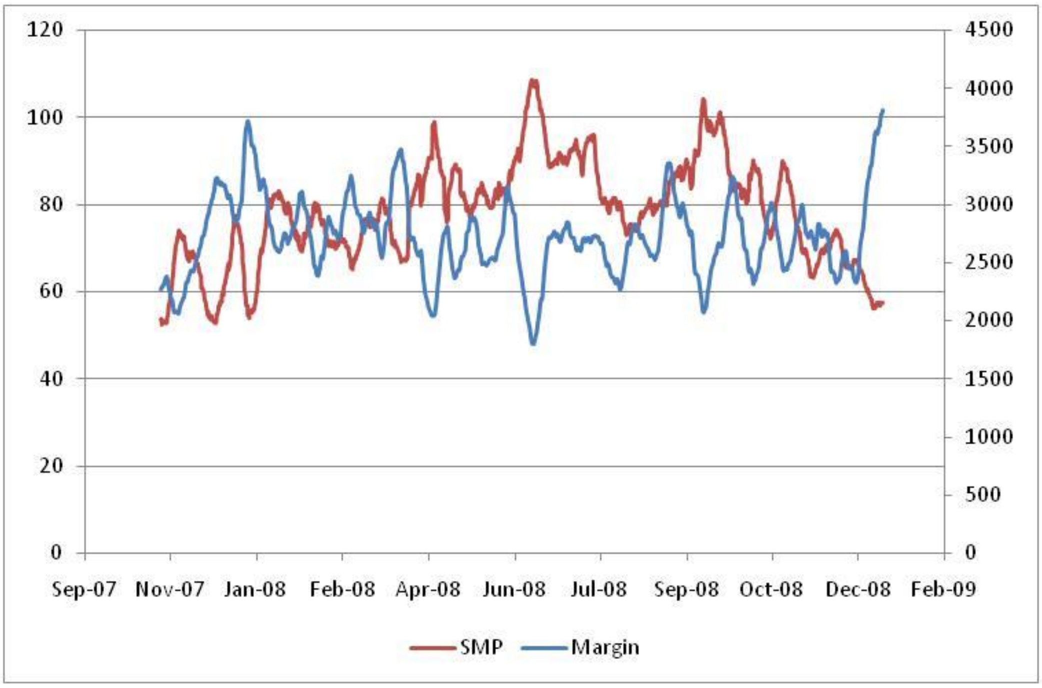
Uplift makes an average 11% contribution to the SMP overall over the study period. The trend of monthly contribution varied between 5% and 15% though there is not much of a clear seasonal pattern. The months in which Uplift made the highest contribution include March through June 2008, with notably low contributions in February and December 2008.

5.1.3. Capacity Margin

The Capacity Margin (Margin) is defined (for the purpose of this report) as the sum of half-hourly Eligible Availability minus the system Demand. This variable is a key indicator of market conditions and is frequently used as an input for analysis by the MMU.

The comparison between Demand and SMP is augmented in the figure below, replacing Demand with Capacity Margin, again using a 7-day moving average so that emergent trends can more easily be seen.

Figure 5.7: SMP against Capacity Margin



The graph shows a striking inverse relation between Capacity Margin and SMP, with repeated and consistent spiking / anti-spiking as the curves mirror each others' behaviour. The correlation co-efficient over the half-hourly data points is -0.59, strongly supporting the clear trend visible in the graph.

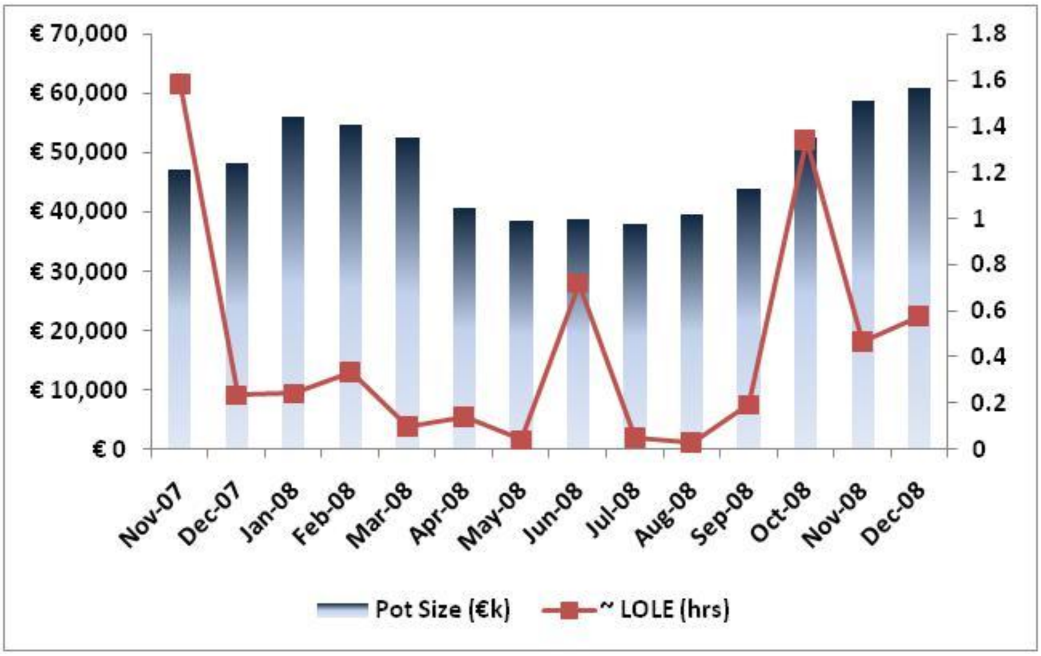
This suggests that the SMP will tend to reasonably and consistently increase as the level of Margin decreases, and is commensurate with expectation under a system of marginal pricing such as the SEM.

This graph largely explains the apparent lack of correlation between SMP and Demand as depicted earlier; chiefly because the low demand period in summer coincided with a low level of available capacity as several plant were offline for scheduled maintenance, driving the smoothed Margin trace to its lowest point in the study period in June 2008.

The Margin calculations were converted to summed Loss of Load Expectations[5] (expected number of hours of lost load) for each month and plotted against the Capacity Payments Mechanism monthly pots in the figure below:

[5] The LOLE estimates are approximate and based on original RA templates used to formulate Appendix M of the T&SC, ranked against outturn Margin as defined above.

Figure 5.8: LOLE and Capacity Payment Pots



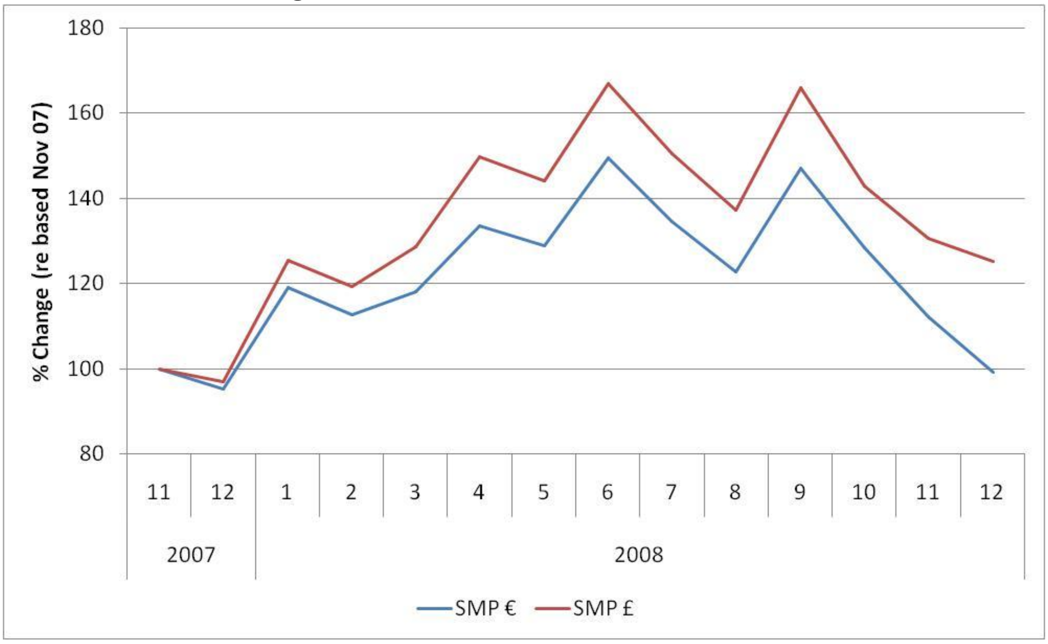
This figure shows the degree of correspondence between monthly Capacity Payments, made to Generators for the provision of available generation capacity, and the ex-post expectations of hours of lost load in each month. While there is a broad correlation in the two data sets with the LOLE rising over the winter months and falling in summer, the LOLE estimates for November 2007, June 2008 and October 2008 strongly buck this trend of correlation.

It is interesting to note the LOLE curve does not map directly to the smoothed 7-day trace of Margin in the previous graph, though some consistency can be seen in the low smoothed margin point in June reflected in the LOLE for June. The reason for this relates to the fact that the LOLE is driven much more heavily by the most extreme margin events than the smoothed margin curve is. The minimum margin in October was 534MW but this was only a very short-term event. As a result the LOLE for October is very high despite the average margin appearing to be no more or less tight than the other months in the previous figure.

5.1.4. Currency Movements

The British Pound has seen a significant decline in value relative to the Euro following the commencement of the SEM and this has impacted on the evolving generation merit order over the study period. The monthly average SMP is plotted in the figure below in both Euro and Great British Pounds (GBP). The evolving relative gap between the two traces is simply the historical exchange rate curve:

Figure 5.9: SMP Under Both Currencies

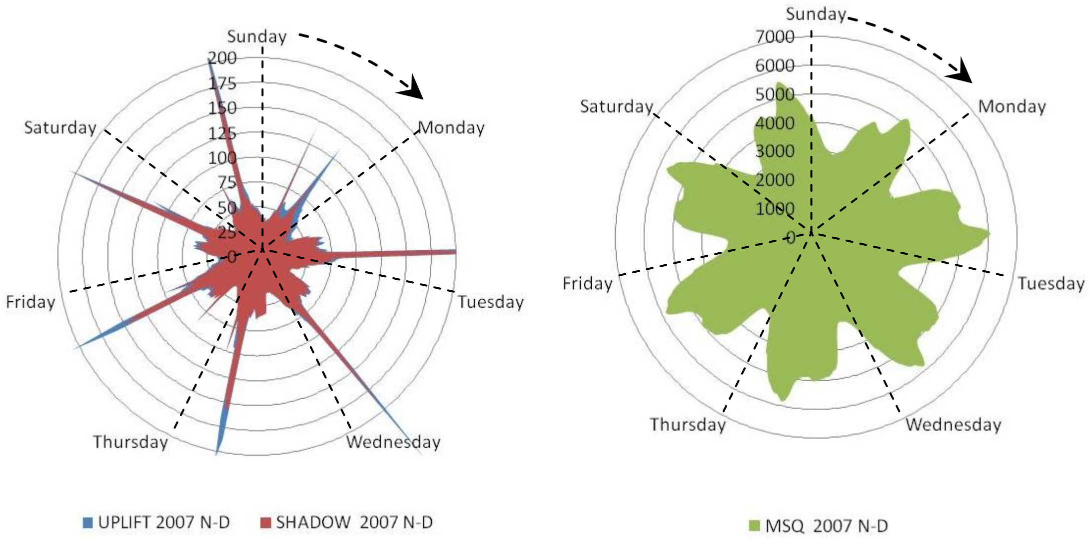


Commensurate with the 7-day smoothed traces shown earlier, the SMP rises to its highest monthly average values in June and September 2008. When the SMP is measured in GBP, the degree of volatility across the study period is amplified compared to the SMP measured in Euro. Particular highlights on this curve include the widening of the gap in December 2007, followed by further 'step' effects in January, April and December 2008.

5.2. Market Outcomes – Weekly Trends

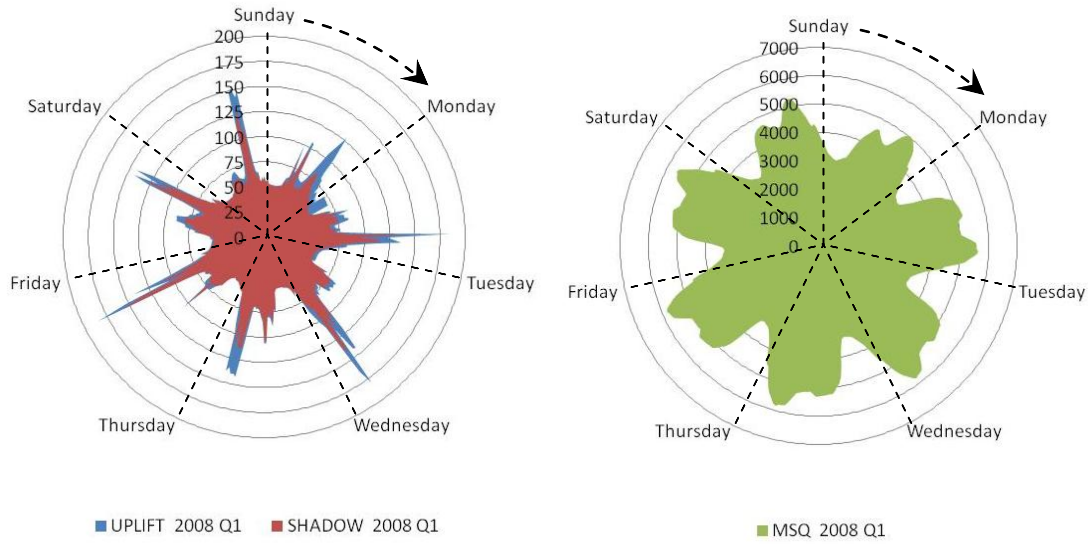
The Price and Demand outcomes are re-presented in this section. The outcomes are split into weekly figures in in order to illustrate how the outcomes vary with day-of week, across the '5 Quarters' employed earlier. The data is displayed on a graphical wheel, which allows the cyclical nature of the weekly outcomes to be more easily shown. The SMP wheels are stacked with Shadow Price in red and with Uplift added on top in blue. Each half-hourly point is computed as the arithmetic mean of the half-hourly spot data points within the quarter:

Figure 5.10: Weekly Shadow, Uplift and MSQ – Nov / Dec 2007



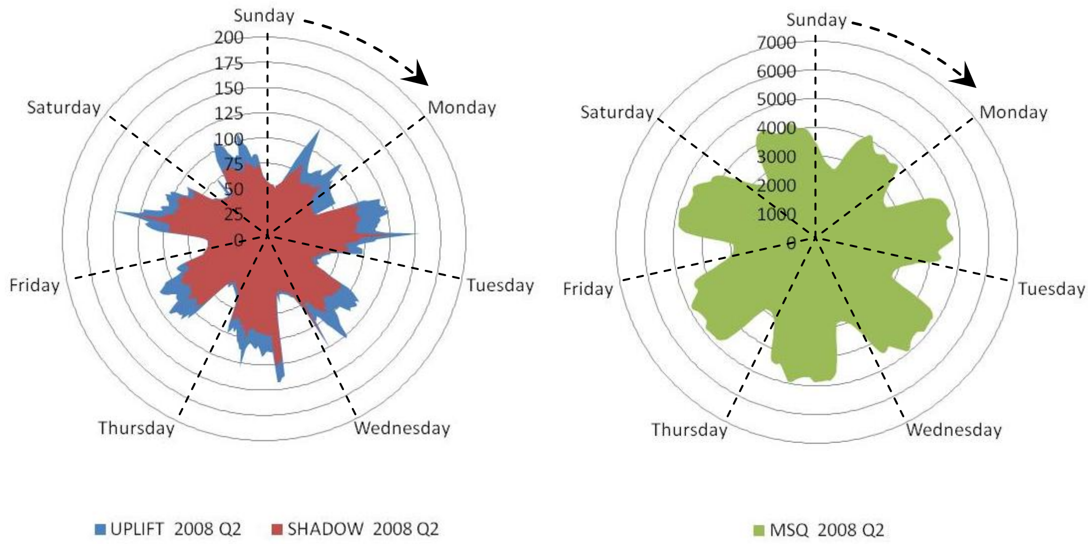
The SMP profile in November – December 2007 demonstrated a strongly spiking behaviour, as the MSP software repeatedly scheduled Kilroot's oil facility to run at peak demand periods during the day, and this tended to set a high Shadow Price at these periods (17:30 and 18:00) as discussed earlier. Sundays were an exception to this trend, and this is easily explained by the relatively low demand profile on Sundays as shown in the MSQ wheel.

Figure 5.11: Weekly Shadow, Uplift and MSQ – Q1 2008



The first quarter of 2008 saw a continuing tendency for the highest prices and peaks in demand to occur in the evening periods, however the severity of these peaks (i.e. their height above the mean) was not as highly pronounced as for November – December 2007. This can be seen in the shorter, fatter spiking behaviour in the SMP and the flatter daily demand profiles.

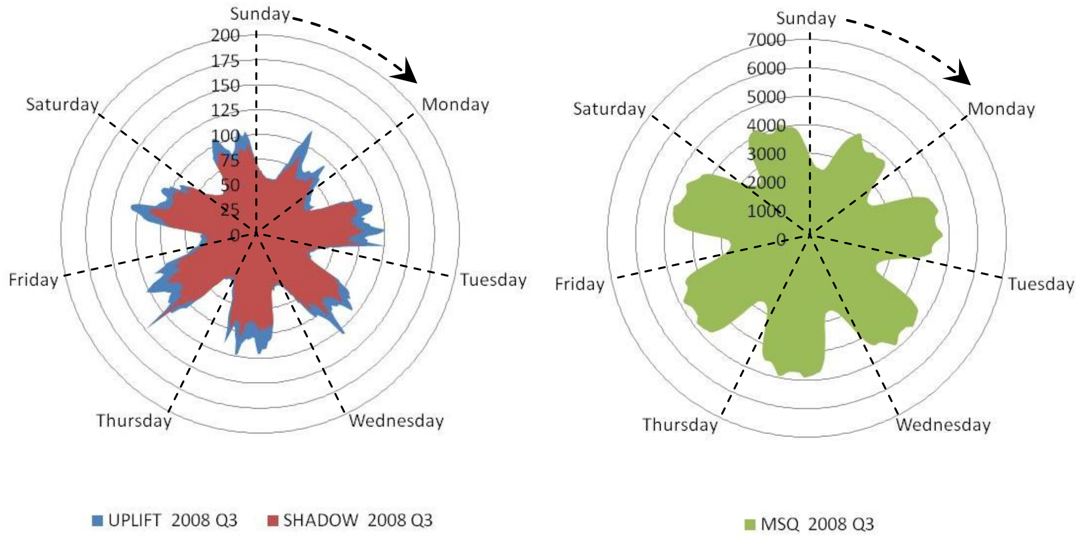
Figure 5.12: Weekly Shadow, Uplift and MSQ – Q2 2008



By the second quarter of 2008 the daily demand profile had changed from strong peaking in the evenings to peaking around midday and a much flatter overall daily profile. This profile is mapped to the Shadow and the SMP in the corresponding wheel. Though the level of 'spikiness' in Price is reduced compared to the previous wheels, there is visually more area inside the Price plot for the Quarter 2 wheel and this backs up the assertion that average SMP was generally at its highest points during the summer months of 2008.

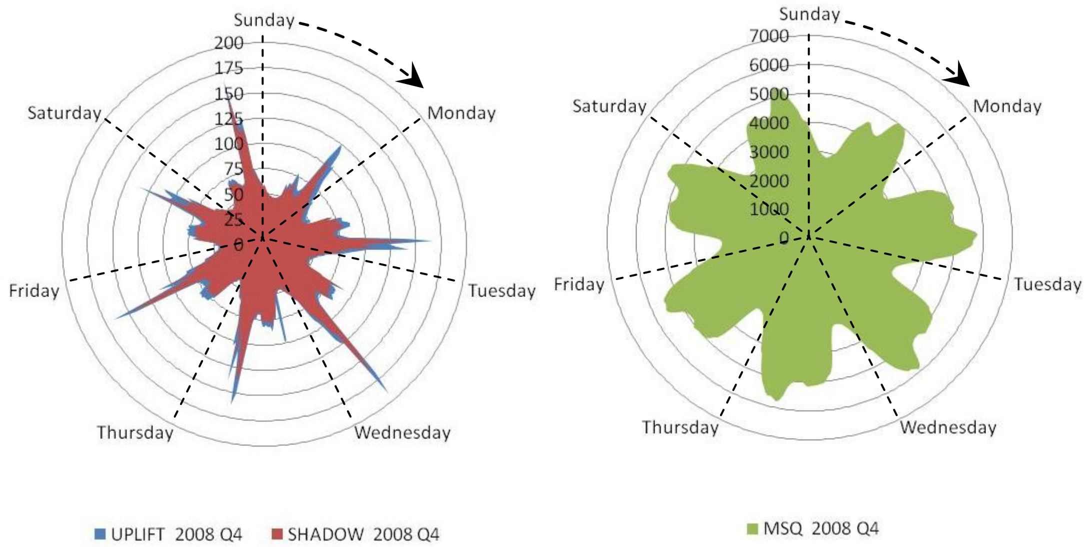
There is a ‘plateau’ of averaged Uplift in the early hours of Monday caused by two discrete events during the second quarter in which the Uplift rose to high levels in the overnight period.

Figure 5.13: Weekly Shadow, Uplift and MSQ – Q3 2008



The Quarter 3 data wheels show very strong similarity to the Quarter 2 wheels. This suggests that the strong similarity seen previously in the duration curves for these two quarters extends as far as the weekly half-hourly profiles. Whether this is a trend for SMP that can be expected in future years is unclear because the price has been shown to vary heavily as a function of fuel prices and Capacity Margin.

Figure 5.14: Weekly Shadow, Uplift and MSQ – Q4 2008



The fourth quarter of 2008 saw a return to evening peaks in the demand profile and corresponding peaks emerge in the Shadow Price and SMP. The figure shows a strong resemblance in shape to that of the first quarter.

5.3. Market Outcomes – Daily Trend

The graphs below zoom in on the daily load, shadow and uplift profiles, again split into the relevant quarters. The 7 days of the week are averaged together in these figures but the distinction between half-hours of the day is more immediately apparent. Also added to these figures are the first and third quartiles of the SMP. Note that the SMP figures are still shown in mean terms rather than median as might be expected in conjunction with the quartiles; this is for simplicity as the curves also illustrate the half-hourly relative contributions of Shadow and Uplift to the SMP, and the medians of these two components do not sum to a meaningful result.

The figure below (left) shows the daily profile over the entire study period. The rest of the figures shows the daily profiles for each of the 'five' quarters:

Figure 5.15: SMP and MSQ for 01/11/07 to 31/12/08

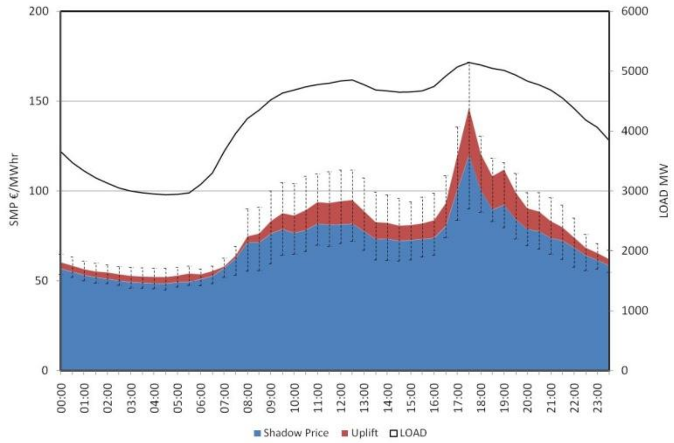


Figure 5.16: SMP and MSQ for Nov / Dec 07

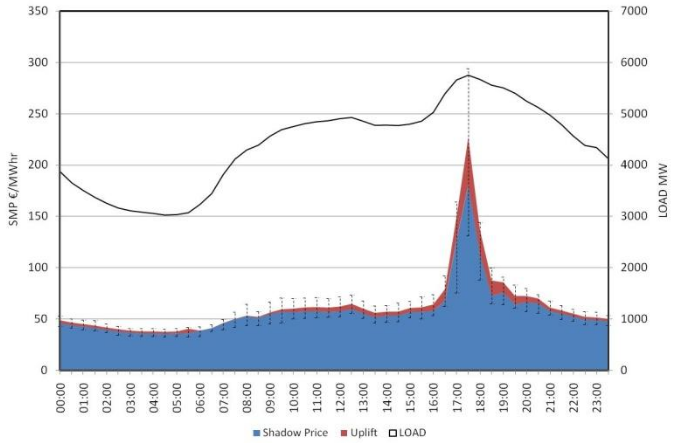


Figure 5.17: SMP and MSQ for Q1 2008

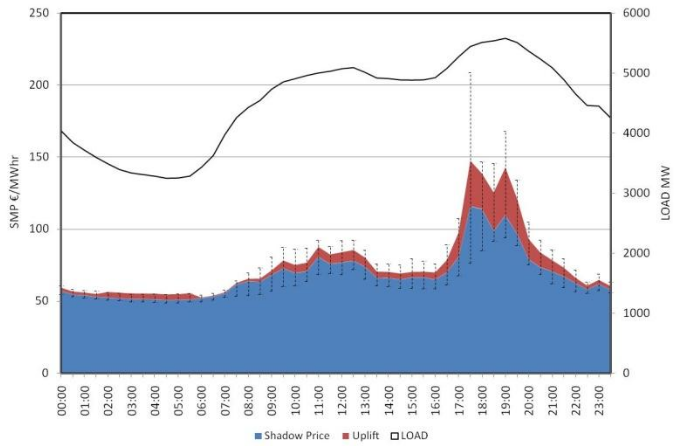


Figure 5.18: SMP and MSQ for Q2 2008

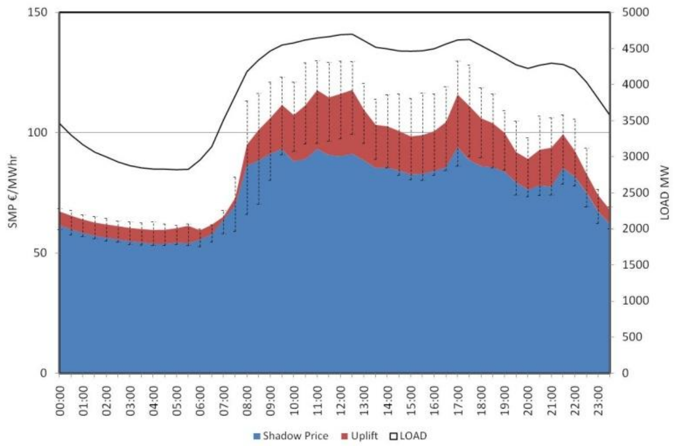


Figure 5.19: SMP and MSQ for Q3 2008

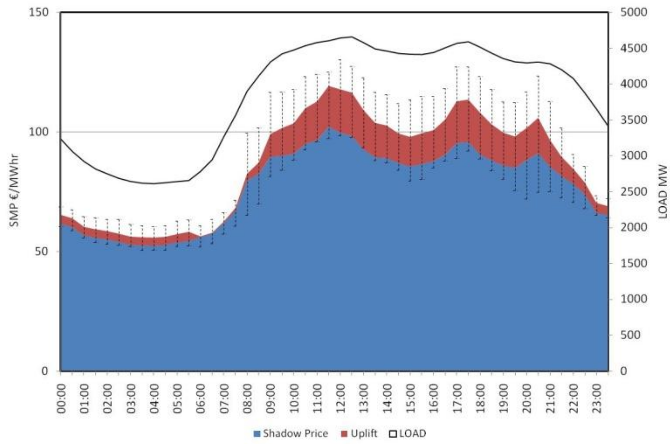
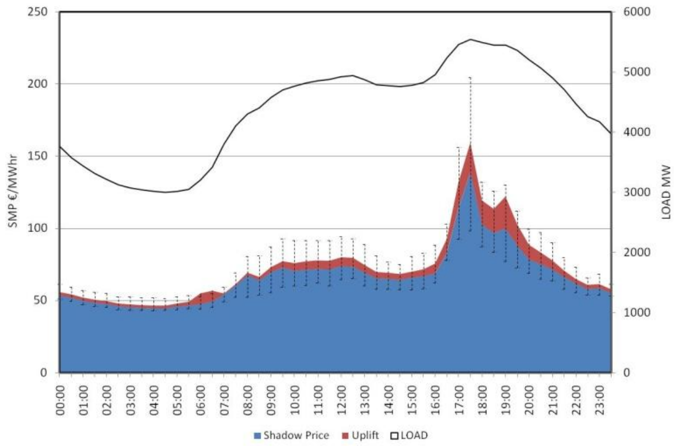


Figure 5.20: SMP and MSQ for Q4 2008

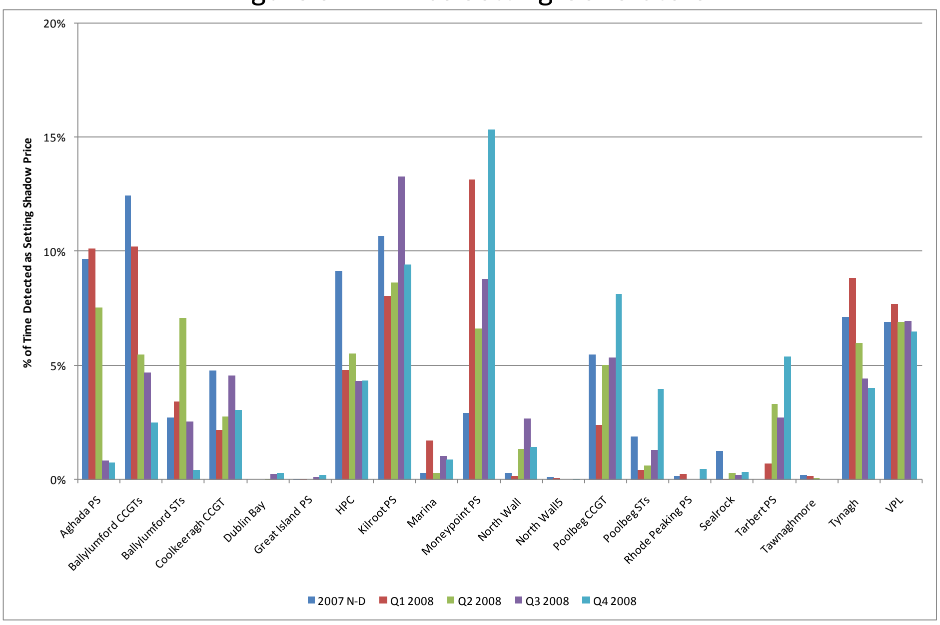


5.4. Price-setting

The concept of 'price-setting plant' is often a focus of market analyses and forecasting. The MMU has found that the SEM Shadow Price can often be traced back to a specific bid made by a specific Generator Unit, but it is important to state that this is not always the case. Indeed the marginal cost of serving the market demand can be driven by any of the constraint equations present in the formulation of the Market Scheduling problem in the MSP algorithm, including inter-temporal effects such as unit ramp-rates.

The percentage of periods in which selected Generator Units were detected by the MMU as setting the Shadow Price are shown in the figure below:

Figure 5.21: Price Setting Generators

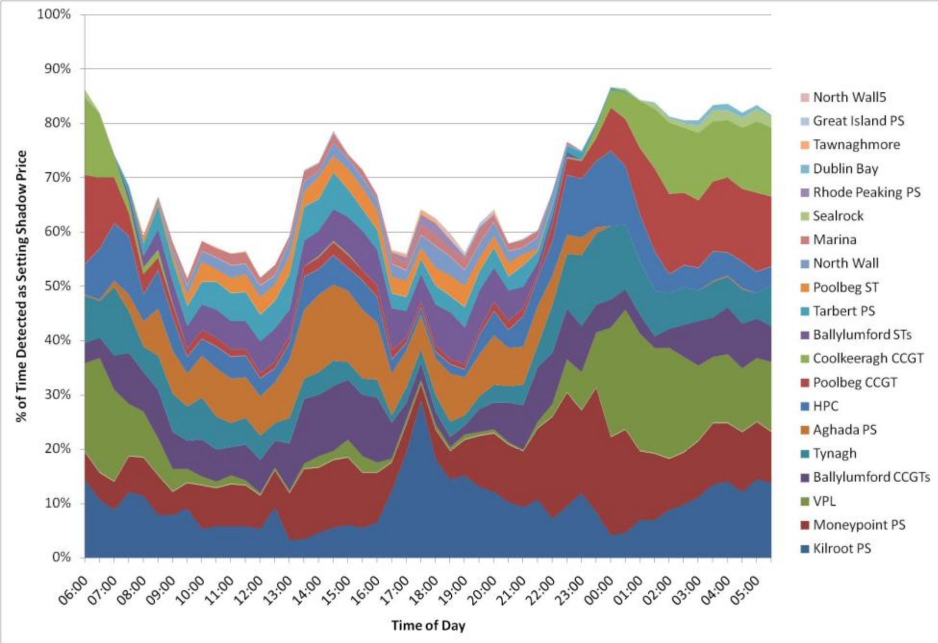


The figure illustrates a number of very interesting trends. The Ballylumford CCGT's have seen a sharp decline in the proportion of time acting as price-setting units over the study period, from 12.5% at the commencement of SEM down to 2.5% by the fourth quarter of 2008. Viridian's Huntstown 2 (VPL in the figure) meanwhile shows a consistent trend to act as price-setter across the study period at around 7%.

The Poolbeg CCGT and Moneypoint station both exhibit a degree of variability across the study period, each seeing a peak in price-setting in the fourth quarter. The Moneypoint station emerges as having acted as price-setter in over 15% of Trading Periods during the fourth quarter.

The price-setting detections are volumetrically grouped into the half-hours of the Trading Day in the figure below. The figure shows the propensity for the different Generator Units to set the price across the day:

Figure 5.22: Price Setting Generators by Time of Day



This figure also reveals much. The Kilroot oil-fired capacity has already been discussed as being prevalent during the winter peak periods and this is reflected well in the figure, as the Kilroot station was detected as having set the Shadow Price for close to 30% of all the 17:30 Trading Periods in the study. This is significant when considering the absence of a peak at 17:30 during summer, suggesting the Kilroot oil facility acted as price-setter for a very high proportion of the time during the winter months.

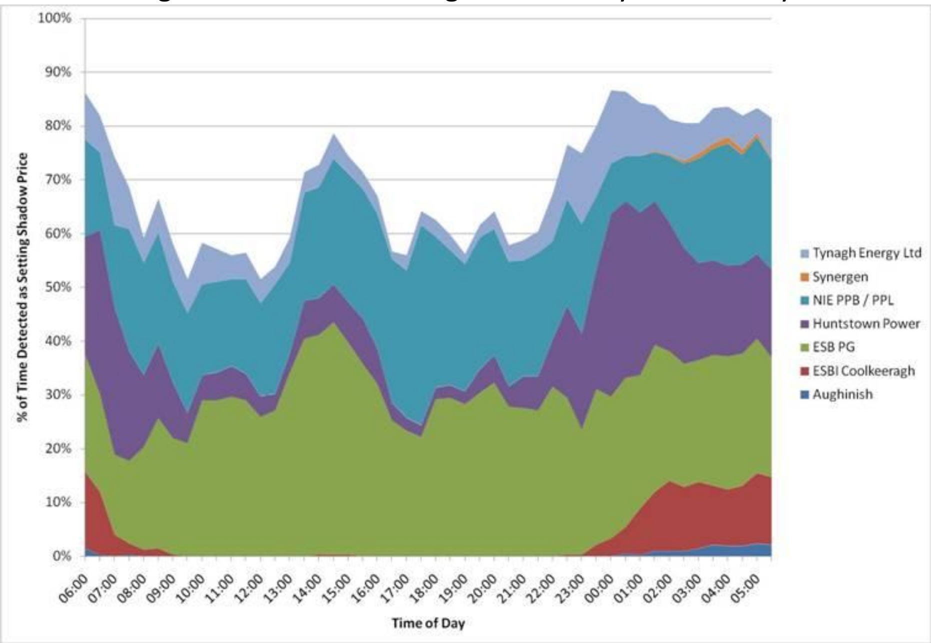
Morning and late-evening periods are shared reasonably smoothly across the selected plant, with the Aghada station making a notable contribution.

Off-peak overnight periods are dominated by the large CCGT and coal-fired plants as these are typically ramped back to lower levels of output at these times and the mid-merit / peaking units are shut down.

The profile of the top line (upon which Northwall 5 is stacked) shows the total percentage of time that the MMU has been confidently able to detect which plant 'set' the Shadow Price. During overnight periods, up to 85% of periods qualified as 'detected', while the proportion during the day is around 60 to 65%. This is because the tendency for the Shadow Price to be driven by more complex constraint interactions increases during the day.

For illustration the data is plotted again in the figure below, aggregated into portfolios:

Figure 5.23: Price Setting Portfolios by Time of Day

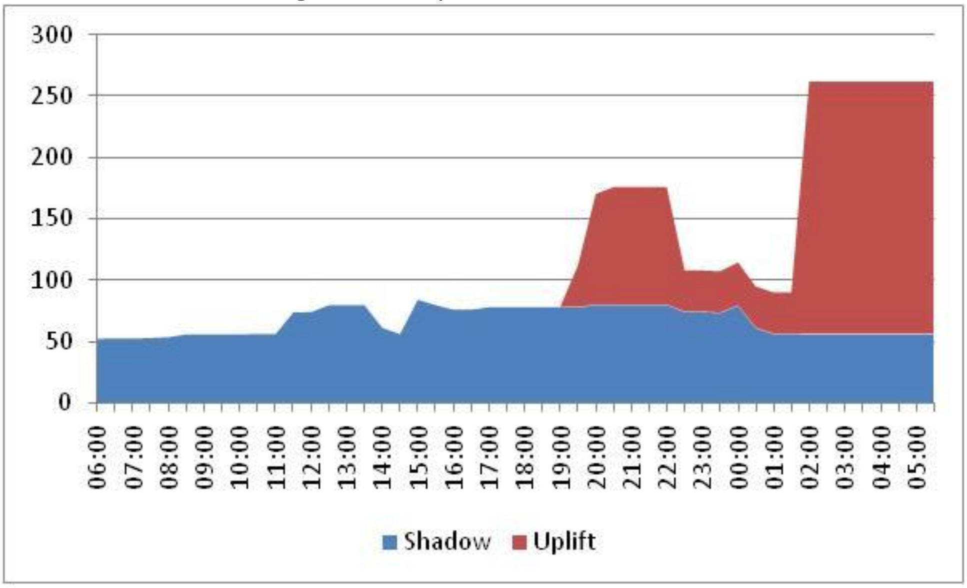


6. Discrete Events

6.1. 30/03/2008 - Uplift

The following figure depicts an unusual Uplift outcome on the 30th March 2008:

Figure 6.1: Uplift on 30/03/2008

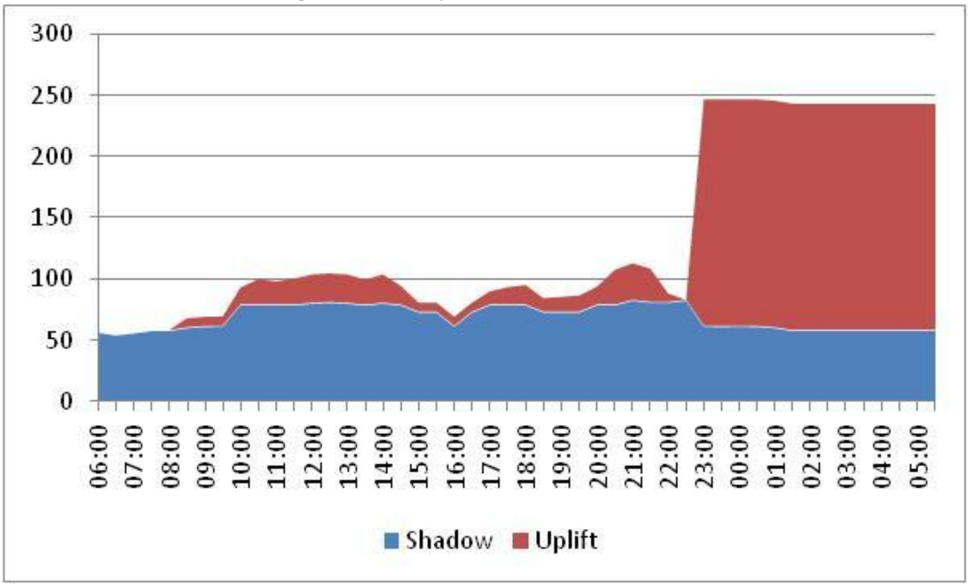


During the early morning period of 31st March 2008 (Trade Date 30th), the SMP plateaued at €262/MWh when demand on the system was relatively low. Approximately 1,000 MW of baseload / near baseload plant was on a scheduled outage. At 15:00 on the 30th March, Coolkeeragh CCGT suffered a forced outage. The plant was not able to resume operations fully until 19:00 on Tuesday 1 April. At approximately 01:30 on the 31st, Kilroot 1 redeclared availability to zero due to technical reasons. The SMP of €262/MWh from 02:00-06:00 is a result of Uplift for Tarbert 3 which was started in the schedule and had to recover a large proportion of Start-up Costs in that Trading Day.

6.2. 13/04/2008 – Uplift

The following figure depicts an unusual Uplift outcome on the 13th April 2008:

Figure 6.2: Uplift on 13/04/2008



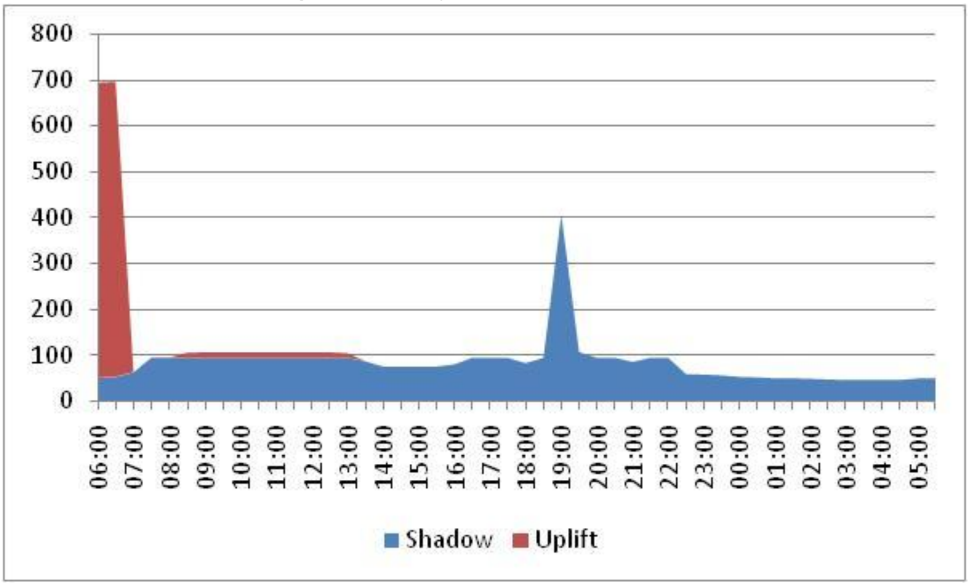
A similar system scenario developed on the 13th April. Both this event and the 30th March event occurred on a Sunday, going in to Monday. Again the Tarbert 3 unit was called to start very late in the Trading Day (23:30) and the Uplift algorithm is programmed to ensure that the cost of the start is spread over the operation zone in the optimisation horizon. Because this horizon ends at 12:00pm the following day (and indeed the Tarbert 3 unit was scheduled out to this point due to its minimum up-time of 24 hours), a large amount of money needed to be assigned to Uplift in the Trading Periods in which the unit was running on the Day. This creates the 'plateau' effect seen on both days.

The incident on the 13th April resulted in the highest daily average SMP in the entire study period of €132.3/MWh.

6.3. 15/10/2008 - Uplift

The following figure depicts an unusual Uplift outcome on the 15th October 2008:

Figure 6.3: Uplift on 15/10/2008



This day followed the lowest Margin event in the study period, which occurred on the 14th October. The 14th is explored as a case study in the Section on Pivotal Supplier Analyses (Section 8).

The 06:00 – 06:30 spike of over €690/MWh is the highest SMP set in the entire study period and was derived from the following sequence of scheduling events:

- The MSP software scheduled Tarbert 3 to run from 07:00 on the 14th to cover a sharp drop in available capacity later in the day.

- The Tarbert unit has a minimum up-time of 24 hours, and so the unit was scheduled to continue running to the end of the look-ahead period (12pm on the 15th).

- Tarbert 3's Start-Up Cost recovery requirement was spread between the Trading Day (14th) and 6-hour look-ahead period, as dictated by the market rules for the Uplift calculation.

- On the 15th of October, the initial conditions were such that the Tarbert unit was committed from the start of the Day at 06:00 am, this had been set according to the results from the 14th.

- The Margin condition on the 15th was markedly superior to the 14th and the Tarbert unit(s) fell out of merit in the Unit Commitment for the 15th by 07:00.

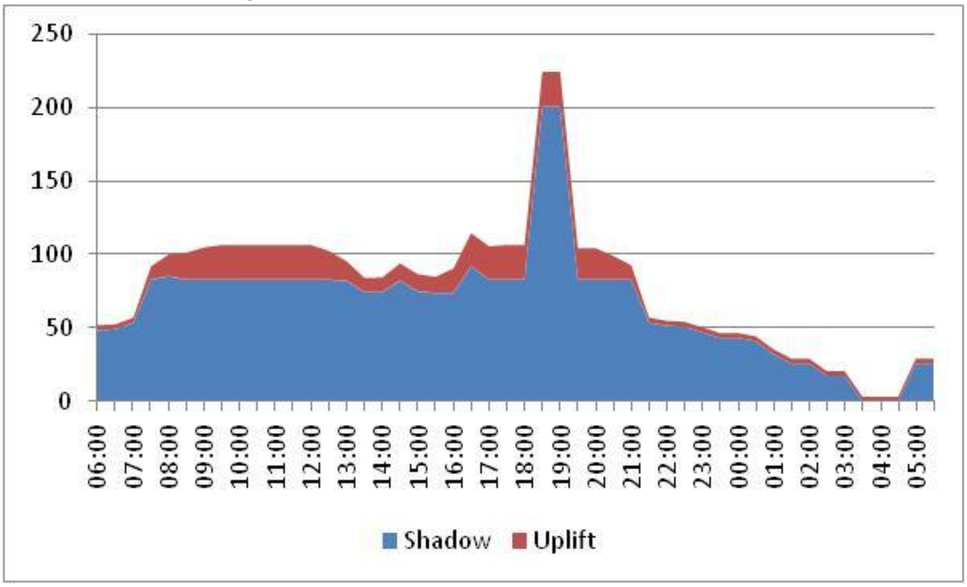
- The un-recouped Start-Up Costs for the scheduling of the unit(s) on the previous day now had to be allotted to the first two periods (06:00 and 06:30) instead of being spread over the six hour period to 12:00pm as had been foreseen by the scheduler when it formulated the Unit Commitment for the look-ahead period on the 14th.

- This resulted in a squashing of these un-recouped costs and a subsequent spike in the Uplift and SMP at 06:00 and 06:30.

6.4. 22/10/2008 – Zero Shadow Price

The following figure depicts a zero Shadow Price outcome on the 22nd of October 2008:

Figure 6.4: Shadow Price on 22/10/2008



On this day, there was a high amount of wind generation overnight, such that the conventional units that were left on the schedule were all ramped back to their minimum stable generation levels. The market rules dictate that when in this condition, the generators cannot 'set' the Shadow Price. The Shadow Price instead was set during these periods by hydro plant with a short-run marginal cost of €0.

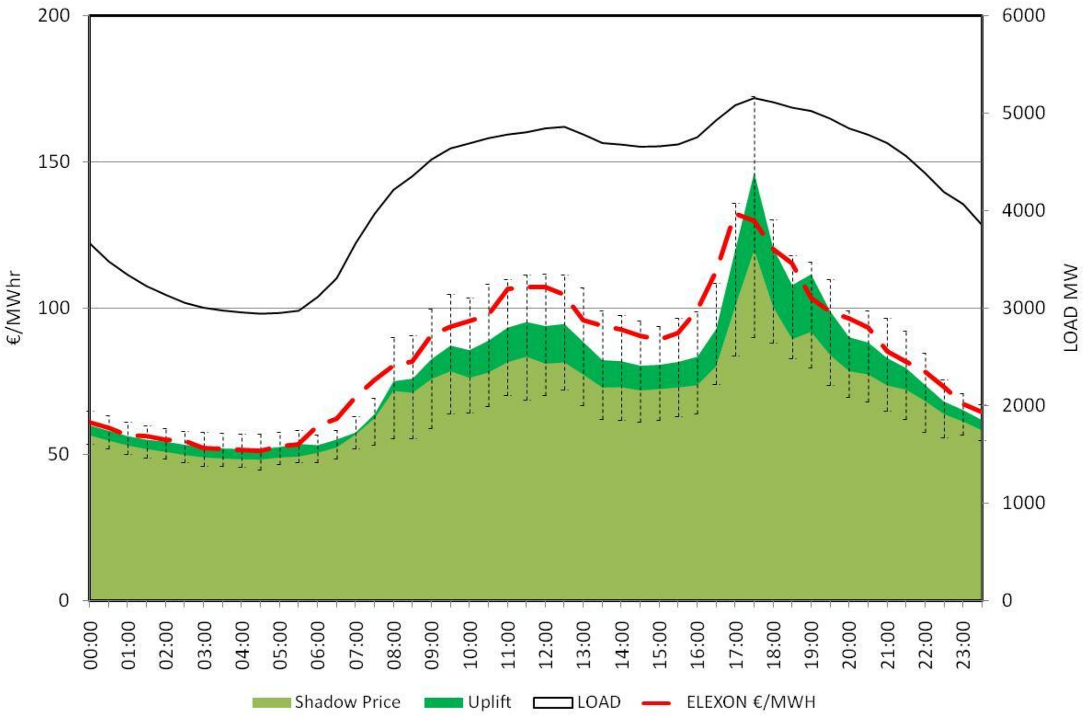
7. Flows, Interconnection and Great Britain

7.1. Markets Comparison

This section examines the behaviour of the SEM (SMP) against balancing prices in the British Energy Trading and Transmission Arrangements (BETTA), issued by Elexon.

The SEM is connected to BETTA via the Moyle Interconnector and as such, the relationship between the two price profiles (analysed at the half-hourly level in this report for both markets) is seen as an informative body of data. The figure below shows the mean SMP, averaged across the Trading Day over the study period, with the first and third quartiles again plotted. Overlaid on the figure is the profile of daily average prices in BETTA.

Figure 7.1: SMP against Elexon Prices – Daily Profile



This report has examined the changing load shape and corresponding changes in SMP daily shapes that emerge as the seasons change, so one must be mindful of the fact that these seasonal trends are 'averaged out' in the figure. The winter peak period dominates the averaged data, and a clear smaller, flatter peak can be seen around midday. BETTA's price profile appears flatter than the SMP, with a higher average morning peak and lower evening peak.

There are several factors to bear in mind in making comparisons between the traces. Notably, the SEM includes an explicit Capacity Payment Mechanism which (in the study period) adds approximately €15 for each MWh consumed, as well as Dispatch Balancing Costs to consider which may add around a further €3. Countering this effect are any surplus costs accorded to consumers in Great Britain relative to SEM that may not be reflected in the Elexon prices (which are balancing prices for the bilateral wholesale market) used to generate the comparison.

To explore the seasonal shifts in the market traces, the figure above is re-plotted on separate figures focusing on each quarter individually:

Figure 7.2: SMP against Elexon Prices – Nov / Dec 2007

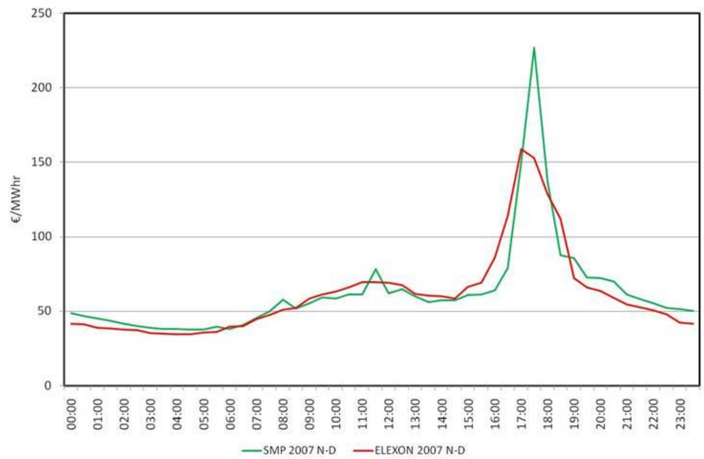


Figure 7.3: SMP against Elexon Prices – Q1 2008

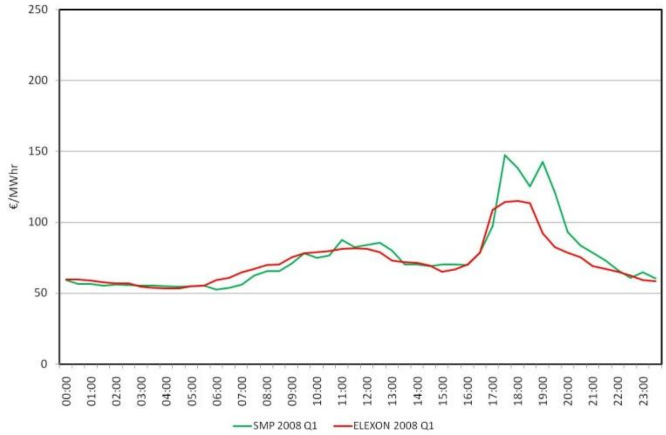


Figure 7.4: SMP against Elexon Prices – Q2 2008

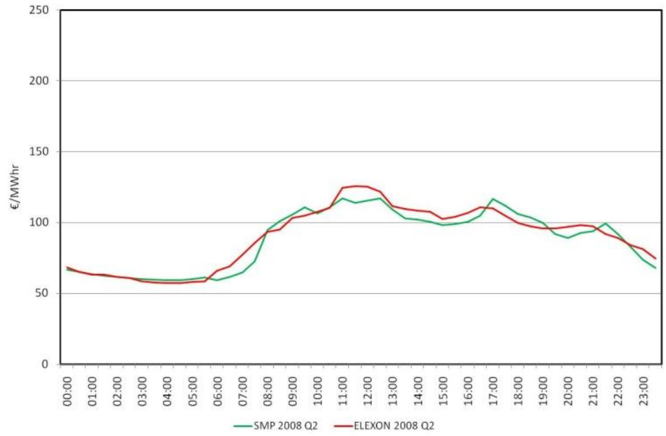


Figure 7.5: SMP against Elexon Prices – Q3 2008

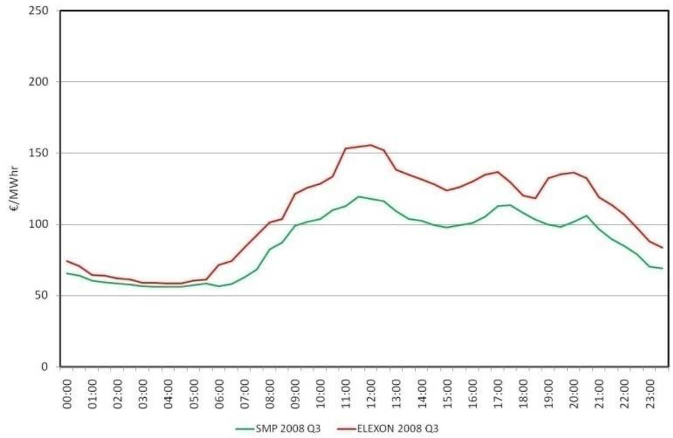
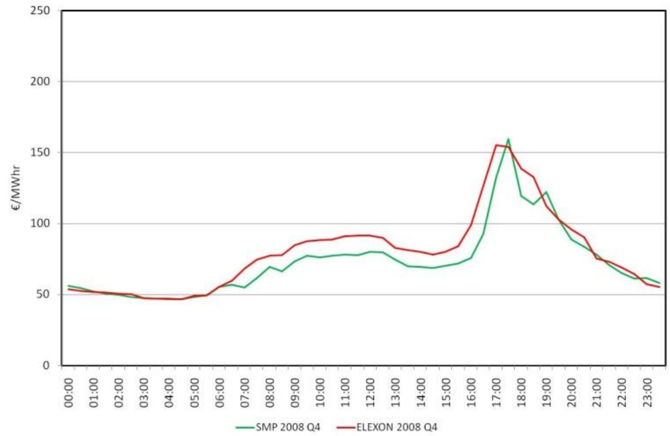
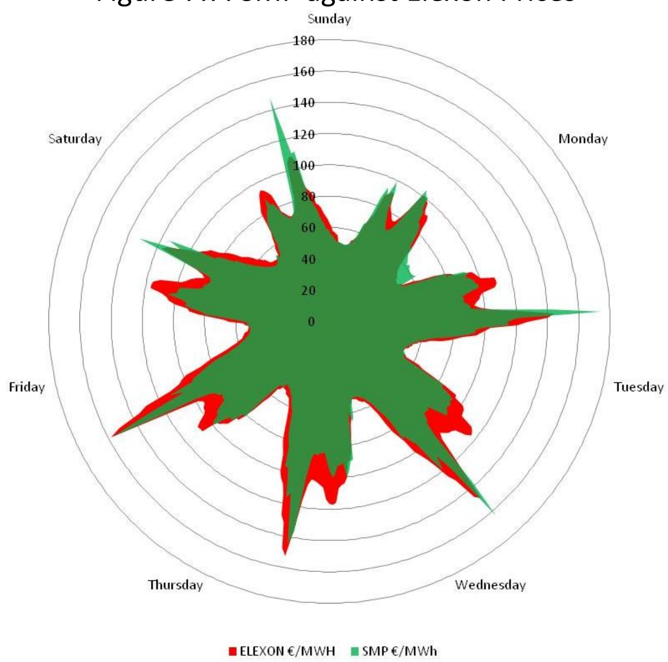


Figure 7.6: SMP against Elexon Prices – Q4 2008



The figure below shows the same data on a weekly wheel:

Figure 7.7: SMP against Elexon Prices

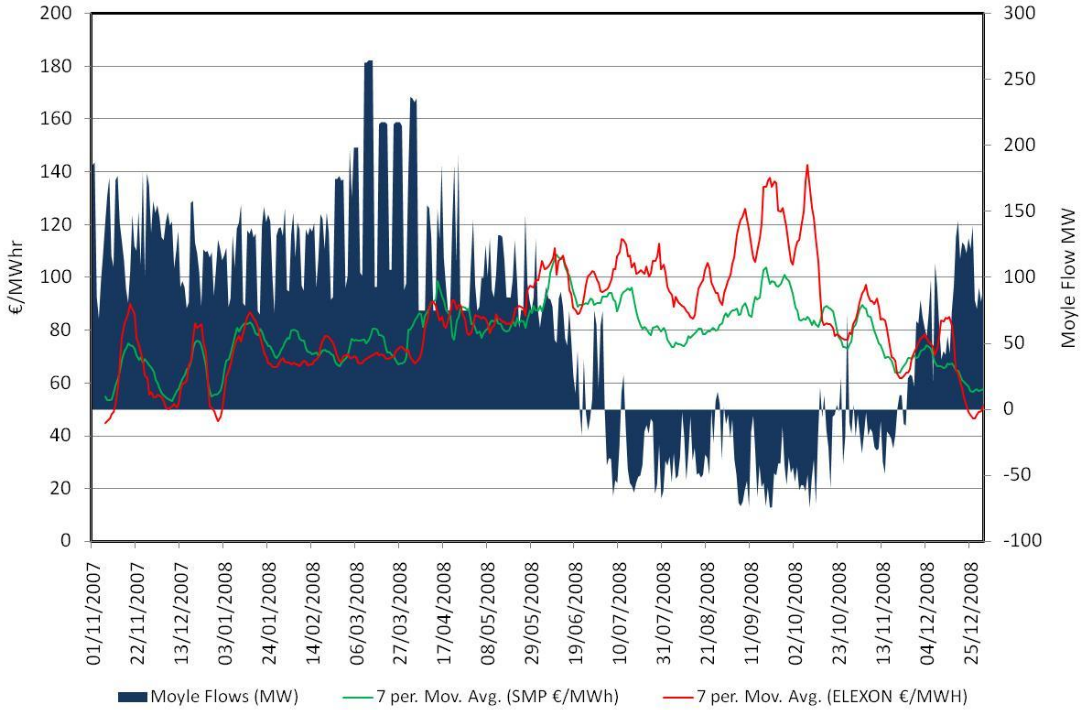


The uniformity of the areas of 'red excess' suggest a consistency in the pattern of separation between the two markets. The highest load days (Tuesday through Thursday) exhibit the most striking consistency in this trend. The discrete Uplift events discussed earlier are evident at the boundary between Sunday and Monday in the SEM profile.

7.2. The Moyle Interconnector

The utilisation of the Moyle Interconnector is shown in the figure below, with smoothed average BETTA and SMP overlaid. The Interconnector data points are the spot-average daily flows (not smoothed).

Figure 7.8: SMP, Elexon Prices (7-day smoothing) and Moyle Flows



There is a striking inversion of average daily Moyle flows from June through to late November relative to the first half of the study period. This maps to the separation in prices between the two markets during this period. While the prices tracked each other reasonably consistently in the first half of the study period, the average flows on the Moyle Interconnector were consistently toward the SEM. This is explained to a degree by the surplus revenues above the SMP available to Generator units that bid on the Interconnector compared to surpluses above BETTA (most notably the Capacity Payment revenue).

The utilisation in each month is broken down in the table below:

Table 7.1: Moyle Flows

		Flow (MW)			Gross Energy (GWh)	
Year	Month	Average	Max	Min	GB->SEM	SEM->GB
2007	Nov	134	259	0	95	0
	Dec	122	219	-30	91	0
2008	Jan	120	219	0	89	0
	Feb	132	259	65	92	0
	Mar	181	407	69	134	0
	Apr	126	338	75	91	0
	May	101	318	0	75	0

	Jun	49	224	-45	37	2
	Jul	-28	189	-80	8	29
	Aug	-30	176	-75	7	29
	Sep	-48	167	-75	5	39
	Oct	-26	125	-75	8	28
	Nov	-7	165	-80	13	18
	Dec	87	265	-80	67	2
	Overall:	**65**	**407**	**-80**	**812**	**148**

Of note are the final gross energy results for the study period showing a flow of 835GWh from BETTA-to-SEM and 148GWh SEM-to-BETTA.

The maximum import (into SEM) capacity of the interconnector (circa 400MW) is not reached during the first half of the study period except in March. The maximum export (into BETTA) capacity (circa 80MW) is reached toward the end of the study suggesting that further arbitrage may have been possible in this period of price separation in the absence of the export constraint.

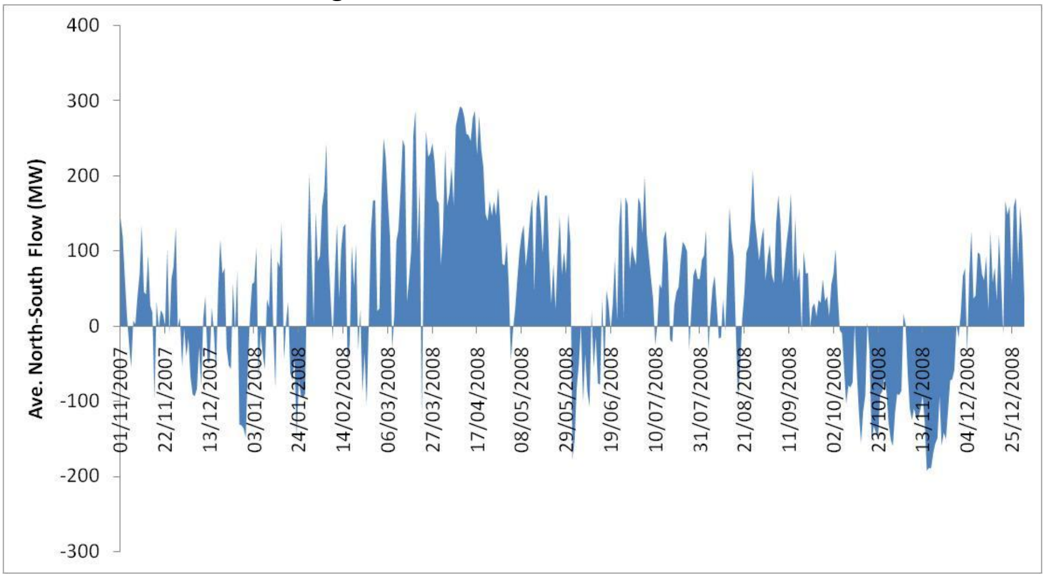
The issues surrounding interconnector usage in the SEM is the subject of further investigations by the Regulatory Authorities and it is expected that a related paper will be published shortly.

7.3. North-South (NI – RoI) Flows

The System Operators have provided 'north-to-south' flow data for the study period. These flows are actual quantities rather than any type of implied market quantities (recall the MSP algorithm does not consider transmission flows or constraints).

The daily average north-to-south flows are shown in the figure below. Positive values indicate an average daily flow from NI to RoI:

Figure 7.9: North-to-South Flows



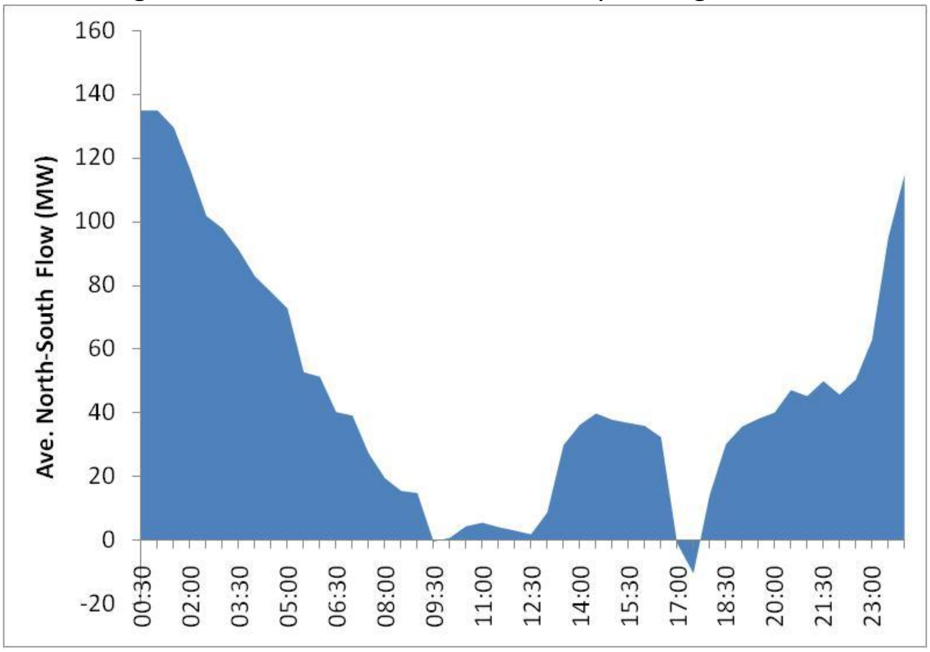
The first three months of the SEM saw energy flowing in both directions at low levels, with reasonably frequent 'flip-flopping' suggesting the distribution of in-merit capacity relative to the jurisdictional loads was reasonably homogenous north and south, bearing in mind the contribution from imports over the Moyle Interconnector that occurred at the time.

From March to May 2008 this pattern changed and there emerged a propensity for energy to typically flow from north to south. This trend continued to an extent through to October 2008 with the notable exception of early June when the Coolkeeragh CCGT was on planned outage.

In October the trend sharply reversed, with the heaviest south-to-north energy flows occurring through to the end of November 2008. This aligns with an increased tendency for the Moyle Interconnector to flow from SEM to GB during this period as explored earlier, though the two behaviours are far from perfectly co-incident. December 2008 saw a return to the north-to-south flow trend, mirroring the return to Moyle's import trend in that month.

The figure below shows the daily average profile of flows north-to-south:

Figure 7.10: North-South Flows – Daily Average Profile



The overall tendency for energy to flow north-to-south illustrated in the previous figure is highlighted in this figure. The figure shows a strong tendency for the highest 'polarisation' between the jurisdictions to occur during the overnight periods.

Interestingly, there is small net south-to-north average flow at the 17:30 period.

The gross north-to-south flow quantities over the study period are broken down in the table below:

Table 7.2: North-South Flows

		Flow (MW)			Gross Energy (GWh)	
Year	Month	Average	Max	Min	N->S	S->N
2007	Nov	33	354	-334	45	21
	Dec	-29	325	-278	26	48
2008	Jan	5	347	-272	37	33
	Feb	71	377	-282	68	18
	Mar	146	364	-333	115	7
	Apr	206	423	-2	148	0
	May	97	323	-172	78	6
	Jun	4	309	-295	38	35
	Jul	72	337	-242	63	10
	Aug	64	359	-238	61	14

	Sep	74	361	-204	59	6
	Oct	-70	245	-298	13	65
	Nov	-105	317	-396	9	84
	Dec	83	324	-247	75	14
Overall:		**46**	**423**	**-396**	**835**	**361**

Of note are the final gross energy results for the study period showing a flow of 835GWh from north-to-south and 361GWh south-to-north.

This compares to Moyle's gross flow outcomes of 812 and 148GWh import / export respectively. This is a very interesting outcome as it suggests that, in net terms across the study period, quantities that flowed north-to-south are largely balanced (or 'answered') by flows from GB into the SEM. This is not true on a quarterly basis much less a day-by-day basis, and indeed there are periods during the year such as September 2008 in which the net flows 'out of NI' were positive down both connections. But the result is informative nonetheless, as the NI jurisdiction appears in energy terms over the study period to have acted largely as a conduit along which power generated in GB was in a notional sense transferred to the Republic.

Against the backdrop of this point, the data does not make it clear whether the mismatch between the south-to-north quantity of 361GWh and the Moyle export value of 148GWh is indicative of a potential 'bottleneck' in the form of the 80MW constraint, though this is a topic of continuing interest.

8. Pivotal Supplier Analysis

The MMU regularly reviews the market data in search of potential days upon which the Capacity Margin (as defined previous) may have dropped to levels low enough to trigger environs for potential abuse of market power via partial physical withholding by Generation firms.

The first 'tier' of this analysis involves the computation of a Pivotal Supplier Index[6] for Generation Firm G in Trading Period t is defined as follows:

$$\mathbf{PSI_G} = \begin{cases} \mathbf{1} \ \ \mathbf{where} \ \left[\left(\sum_{\mathbf{AllG,t}} \mathbf{EA}\right) - \mathbf{EA_{G,t}}\right] \Big/ \mathbf{Demand_t} < \mathbf{RST} \\ \\ \mathbf{0} \ \ \mathbf{where} \ \left[\left(\sum_{\mathbf{AllG,t}} \mathbf{EA}\right) - \mathbf{EA_{G,t}}\right] \Big/ \mathbf{Demand_t} \geq \mathbf{RST} \end{cases}$$

Where $EA_{G,t}$ is the Eligible Availability of Firm G in period t, $Demand_t$ is the system demand (taken from the sum of all Generator MSQs), and RST is the Residual Supplier Threshold:

[6] The literature refers to these types of calculations sometimes as Residual Supplier depending on how the thresholds are defined. To clarify, the variable and parameter names / labels in this paper are not defined necessarily in any other reference.

RST = 1.0
Under this setting the PSI for Generation Firm G will trigger (become 1) whenever the demand could not have been met without the availability contribution made by Firm G.

RST = 1.1
Under this setting the PSI for Generation Firm G will trigger (become 1) whenever the summed availability of all remaining competing Generation Firms other than G does not exceed the demand by at least 10%.

The PSIs feed into a second tier of analysis under which it can be examined whether or not periods in which the PSIs have triggered coincide with unit outage events[7]; and where this is identified, further modelling analysis (for example using Plexos to test counter-factuals) can be explored.

Generally it is expected[8] that opportunities for gains via physical withholding can be found under situations where the RST is at a level above 1.0, in regions where the system approaches a critical margin event in the absence of some portion of availability from any particular competitor.

For the illustrative purpose of this report, the MMU has compiled some selected days during 2008 in which the capacity margin dropped to its lowest levels and computed the PSI under various RST settings for the large price-setting Generation Firms.

8.1. Summary Figures

Summary results for the study period are shown in the figure below:

Table 8.1: Summary PSI Results

RSI Threshold	1		1.05		1.1	
No of Participants	Periods	% of Total	Periods	% of Total	Periods	% of Total
0	6999	34.2%	5991	29.3%	5030	24.6%
1	12972	63.3%	13213	64.5%	12860	62.8%
2	496	2.4%	1162	5.7%	2239	10.9%
3	15	0.1%	103	0.5%	249	1.2%
4+	0	0.0%	13	0.1%	104	0.5%
Participant						
Aughinish	0	0.0%	0	0.0%	25	0.1%
Bord na Mona	0	0.0%	0	0.0%	15	0.1%
Coolkeeragh	0	0.0%	13	0.1%	104	0.5%
Energia	19	0.1%	116	0.6%	354	1.7%
ESBPG	13483	65.8%	14491	70.7%	15452	75.4%
Moyle	0	0.0%	2	0.0%	17	0.1%
PPB	507	2.5%	1276	6.2%	2591	12.7%
PPL	0	0.0%	0	0.0%	20	0.1%

[7] The co-incidence of unit outages and PSI triggers is not evidence of withholding in and of itself as the two events are naturally heavily correlated.
[8] Research on this topic is ongoing

Synergen	0	0.0%	8	0.0%	83	0.4%
Tynagh	0	0.0%	9	0.0%	78	0.4%

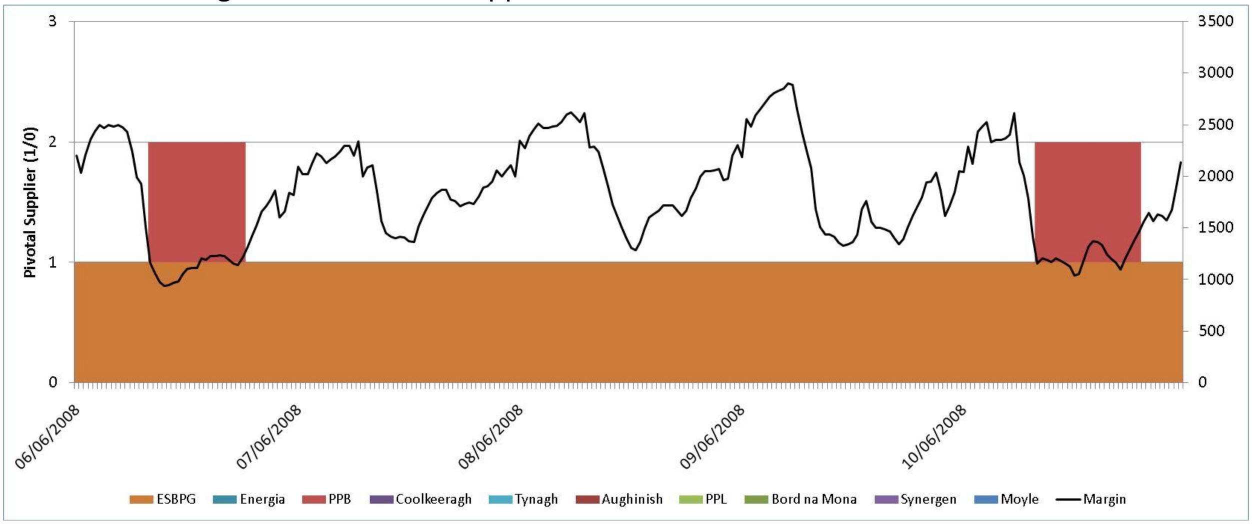
The top half of the table shows the breakdown of periods in which zero, one or more firms were co-incidentally flagged as pivotal. As the RST is increased, this naturally leads to an increased occurrence of triggering of the PSI's.

The second half of the table shows the breakdown of periods in which each generation firm was flagged as pivotal. ESB PowerGen flag as pivotal in 65.8% of periods under an RST of 1.0, with smaller flagging levels for PPB. A degree of flagging also appears for Energia as the RST is increased.

8.2. Early June, 2008

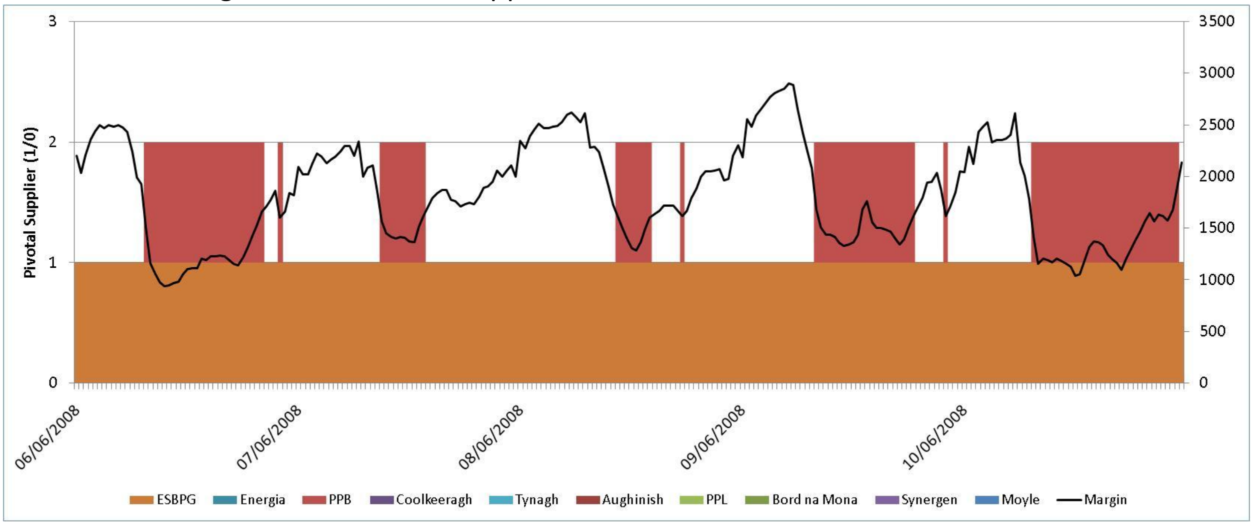
June 2008 saw a relatively high Loss of Load Expectation (see Figure 5.8) emerge as large plant were taken offline for planned annual maintenance. The minimum margin event in June of 939MW occurred on the 6th at a time when the system demand was 4761MW.

Figure 8.1: Residual Supplier Outcomes June 2008 – Threshold 1.0



In the figure above, ESB PG is triggered as a Pivotal Supplier for the entire week in question, while the NIE Power Procurement Business (PPB) is triggered on the 6th at the minimum margin event and again on the 10th, during periods in which the margin slips below around 1200MW.

Figure 8.2: Residual Supplier Outcomes June 2008 – Threshold 1.1



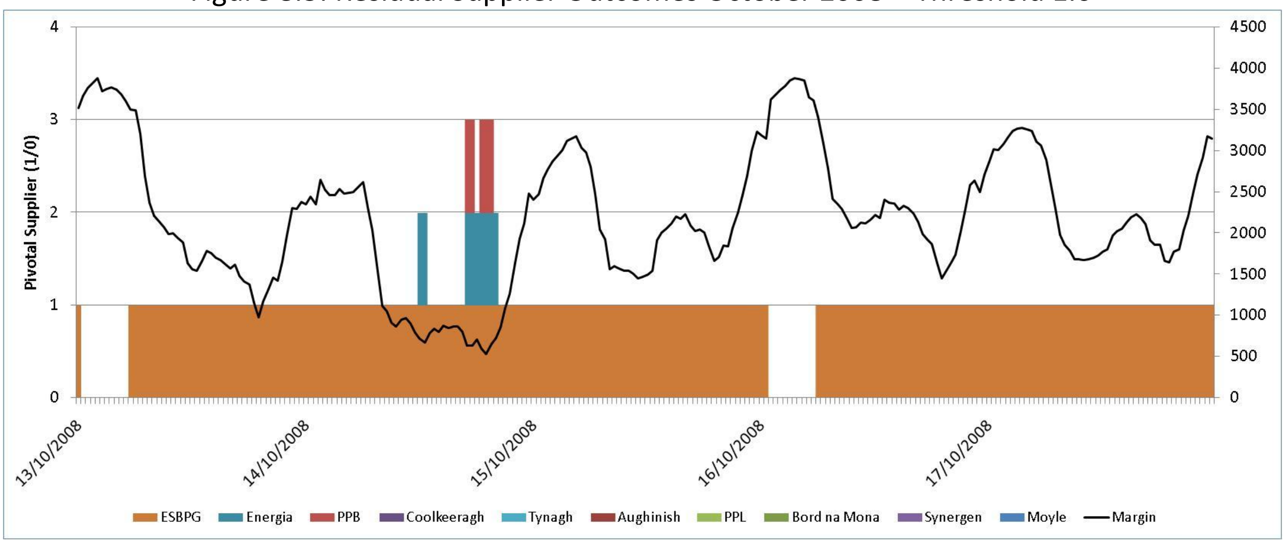
In the figure above, the RST is increased to 1.1. The impact of this is to more easily trigger the PSI's because the residual plant must meet a 10% mark-up on the system demand instead of simply meeting the demand (as per RST of 1.0), and this is obviously more difficult in the absence of availability from any particular Generation Firm.

For the week in June, this results in PPB becoming Pivotal every day of the week, with extension of relevant periods on the tightest days (6th and 10th). Interestingly no other Firms are triggered.

8.3. Mid October, 2008

October was a month of tight margin and volatile SMP, with the highest ever recorded SMP occuring on the 15th (this is a Discrete Event explored in Section 6). The minimum margin event in October of 535MW occurred on the 14th at a time when the system demand was 5914MW.

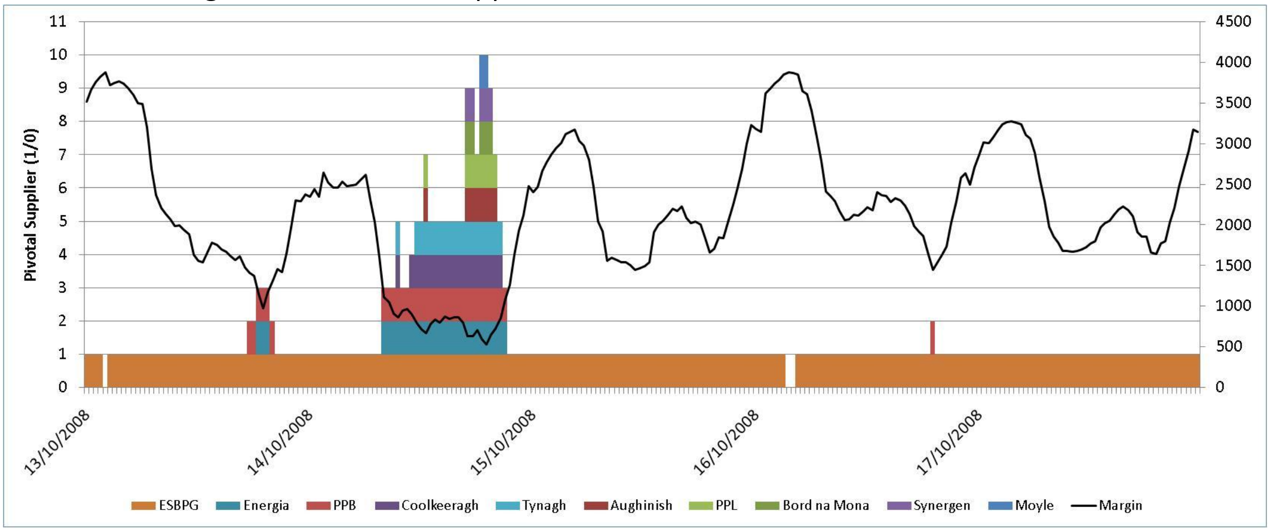
Figure 8.3: Residual Supplier Outcomes October 2008 – Threshold 1.0



The availability offered by ESB PG, Energia and PPB all trigger on this day as being Pivotal to meeting system demand. The reason that Energia trigger early in the day while PPB do not is that several PPB plant were unavailable, such that Energia's summed eligible availability was the higher. As such Energia's PSI trigger is more easily activated for the availability they offered on the day.

An interesting result is ESB PG's absence on the Pivotal Supplier row in the overnight periods of the 13th and 16th as the sharp drop in demand during these periods relative to the day drives a relatively high overnight system Capacity Margin.

Figure 8.4: Residual Supplier Outcomes October 2008 – Threshold 1.1



Under an RST of 1.1 all the Generation Firms become Pivotal at the low margin event. This is to be expected because the margin (535MW) is lower than [1.1 x Peak Demand (5914MW)], so the PSI of all Firms regardless of their size will trigger if the peak demand coincides with the margin.

Of more interest are the periods around the event, in which some of the smaller Firms flicker in and out of 'Pivotal' status. Tynagh and Coolkeeragh trigger for the bulk of the day on the 14th while Aughinish and PPL make notable appearances before and after the low margin event.

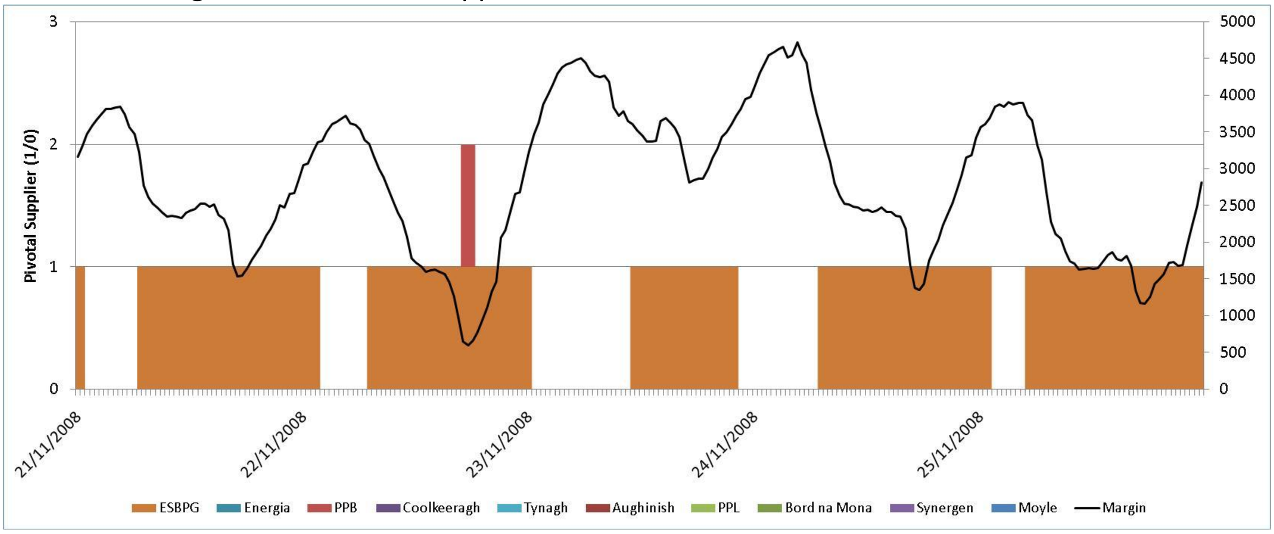
Synergen's Dublin Bay plant was under partial outage on the 14th, explaining its relatively low amount of PSI triggering at the low margin event.

The PPB and Energia rows predictably expand to become Pivotal for the entire daytime period on the 14th. The PPB outages were restricted mainly to the 14th and this can be seen during the peak periods on the 13th and 16th as the PPB PSI is more easily triggered than Energia; indicating a larger capacity contribution from PPB at these times.

8.4. Late November, 2008

The minimum margin event in November of 605MW occurred on the 22nd at a time when the system demand was 5600MW.

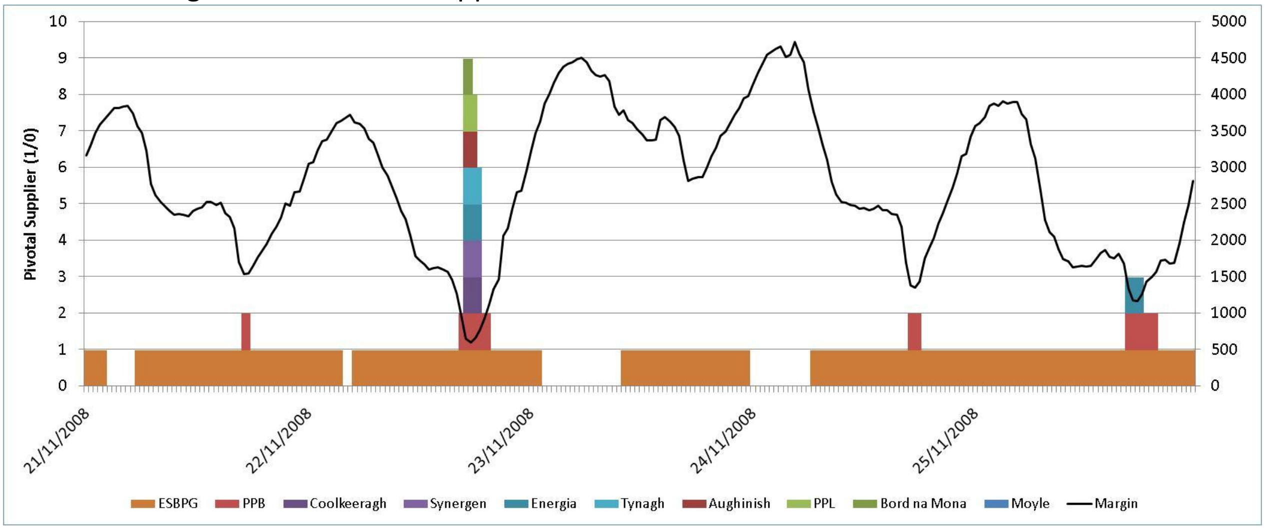
Figure 8.5: Residual Supplier Outcomes November 2008 – Threshold 1.0



ESB PG and PPB trigger as being Pivotal to meeting the demand at the low margin event on the 22nd.

Of note is the highly variable Margin plot which rises quickly out of tight periods to ample amounts in the overnight periods as the demand for electricity begins to follow a more 'peaky' winter shape in November compared to the two cases examined previous. This effect has the impact of ESB PG losing its status as Pivotal overnight.

Figure 8.6: Residual Supplier Outcomes November 2008 – Threshold 1.1

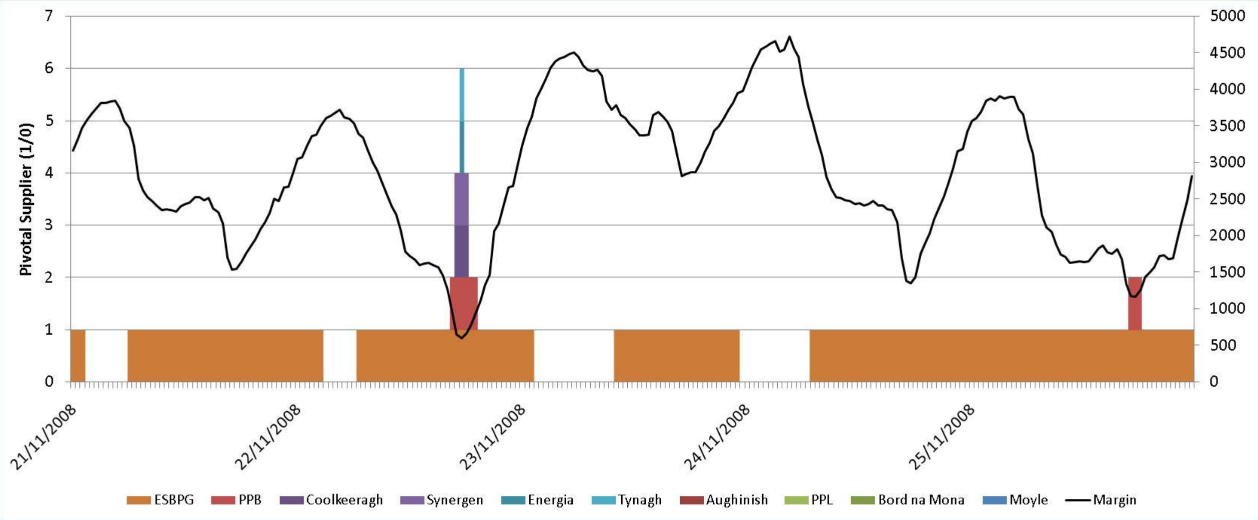


All the Firms bar Moyle trigger under the RST of 1.1 at the low margin event. PPB also has an increased presence in the neighbouring days relative to the previous figure.

The PSI for Energia triggers at the peak on the 25th but does not appear more or less Pivotal than the smaller firms on the 22nd. This is because one of the Huntstown units was unavailable on the 22nd but was back by 9pm on the day, so the portfolio of Energia's available plant was comparable to the smaller firms.

To tease out the low margin event an RST of 1.05 was considered:

Figure 8.7: Residual Supplier Outcomes November 2008 – Threshold 1.05



Applying a smaller RST has the predictable effect of shrinking the PSI trigger zones for each unit. At the low margin event only PPB, Coolkeeragh and Synergen trigger for more than one period, while Energia and Tynagh trigger only during the actual period of lowest margin.

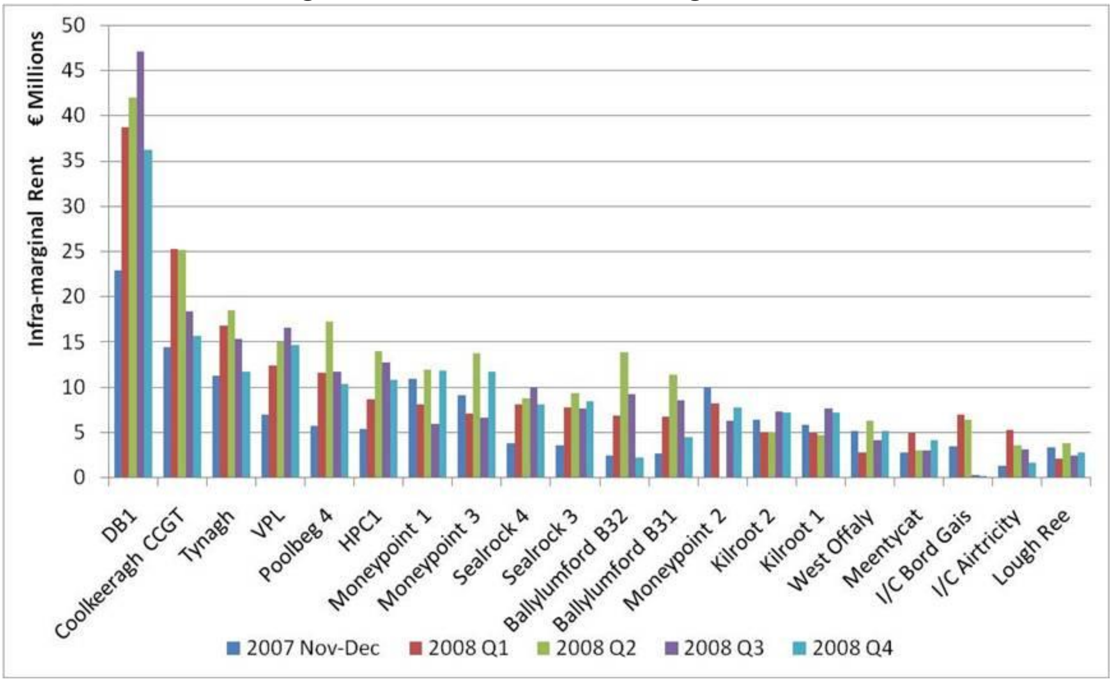
9. GENERATOR REVENUES, RENTS AND CAPACITY PAYMENTS

In this section, infra-marginal rents and capacity payment revenues to Generator units are explored. The data shown here is computed from publicly available market data and is not necessarily a representation of the accounts or financial positions of participants in the market.

For a Generator unit, the term 'infra-marginal rent' refers here to the difference between the SMP and the prices that are offered for each scheduled quantity (including start-up and no load costs) , multipled by the volume of scheduled generation.

The figure below shows the evolution of infra-marginal rents for selected units over the study period:

Figure 9.1: Generator Infra-marginal Rents

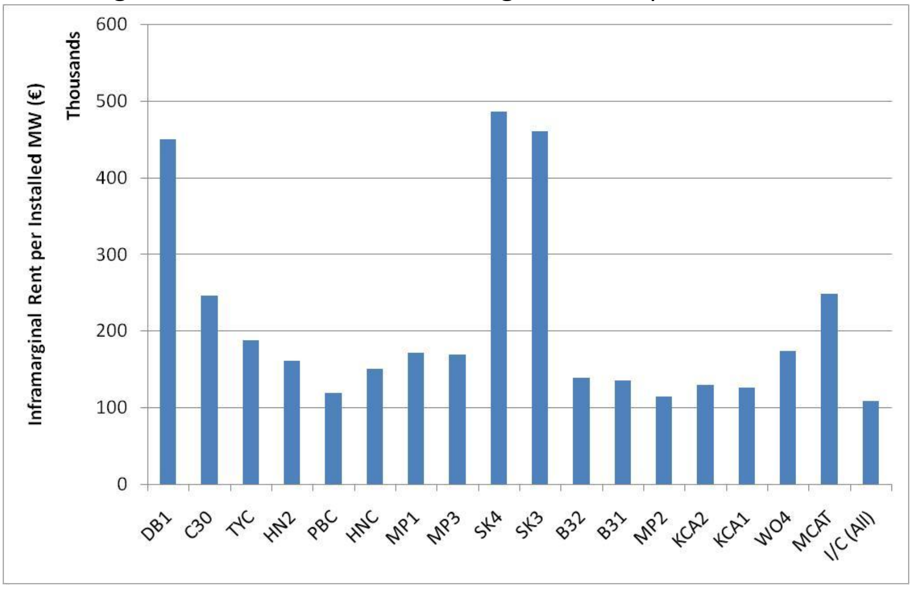


The coal and CCGT plants all turn in a similar trend over the study period, as the high SMP in the summer month's maps through to higher rents during the Quarters 2 and 3 of 2008 for these plant. Interestingly, the wind farm at Meentycat (72.4 MW installed) earns sufficient rents for a like-for-like comparison on the graph with the rents of the larger conventional stations such as Kilroot.

The I/C data in the figure represents rents earned via trading over the Moyle Interconnector by the market participants.

The data is aggregated across the study period and normalised for plant installed capacity in the figure below:

Figure 9.2: Generator Infra-marginal Rents per-unit MW

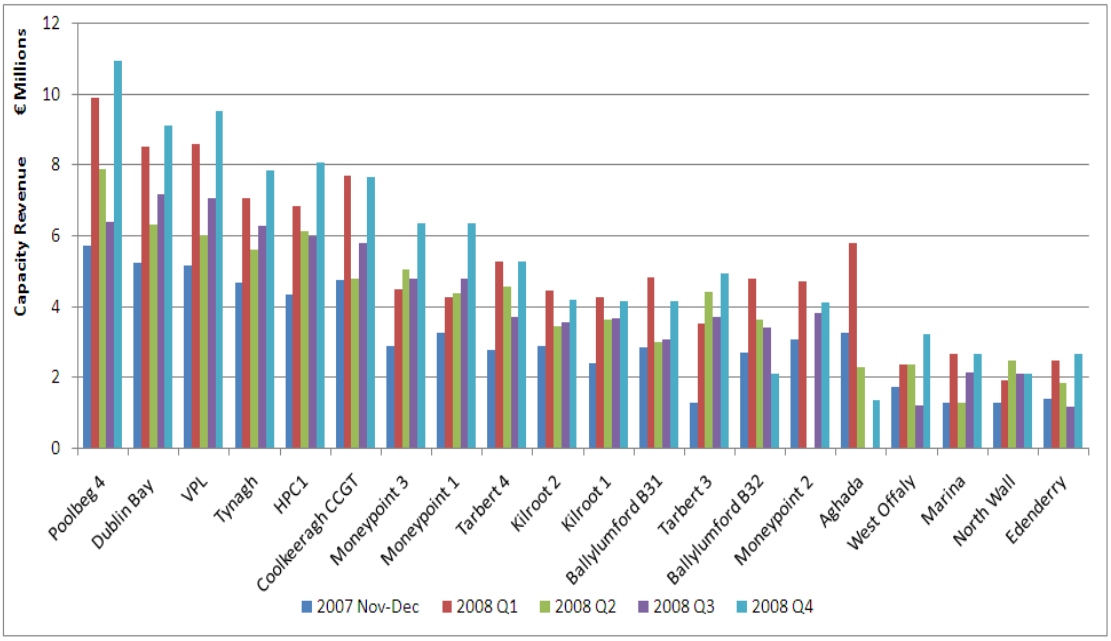


The Dublin Bay and Sealrock stations appear as the highest per-unit earners of inframarginal rent[9]. The Meentycat windfarm (illustratively representative of other wind units) is shown on the figure to also earn high inframarginal rent in comparison to other plant.

The Capacity Payment revenue is now explored using the same graphical format:

[9] Recall Dublin Bay commercial cost curve relative to other CCGTs as discussed in Section 3

Figure 9.3: Generator Capacity Revenue

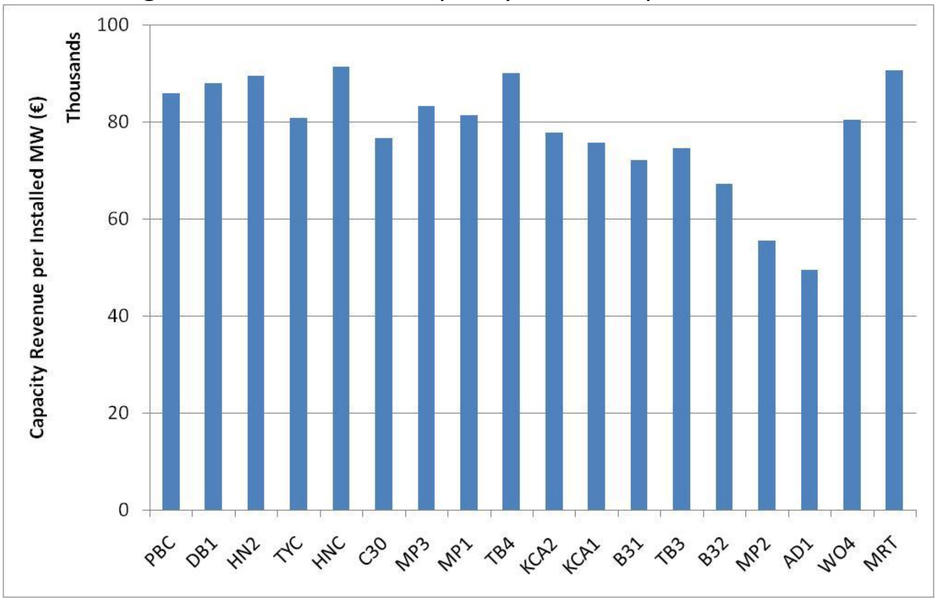


The trends in this figure largely map to the relative amounts of available generation capacity offered by each unit as explored in previous sections. The largest earners are unsurprisingly the units with the largest installed capacity. The tendency for the Q1 and Q4 earnings to be consistently higher than the Q2 and Q3 earnings is to be expected as the monthly capacity pots in Q1 and Q4 are intentionally set relatively higher by the Regulatory Authorities.

Plant outage behaviour drives most of the departures from the trend (Moneypoint 2 for example).

The per-unit Capacity Payment earnings are shown below:

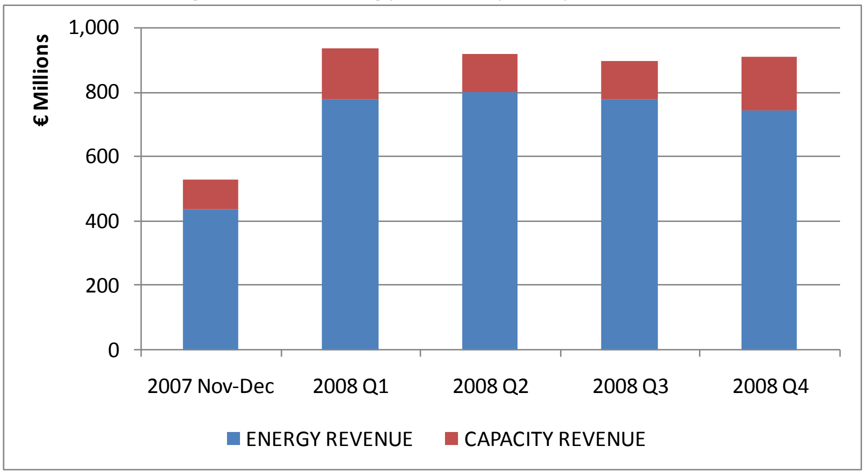
Figure 9.4: Generator Capacity Revenue per-unit MW



The figure shows a tendency for the plant with higher Availability Factors (identified earlier) to generally enjoy a higher relative earning from the Capacity Payment Mechanism, in line with expectation.

The total combined revenue to Generation Firms from the energy pool (SMP x MSQ) and the CPM is shown in the figure below:

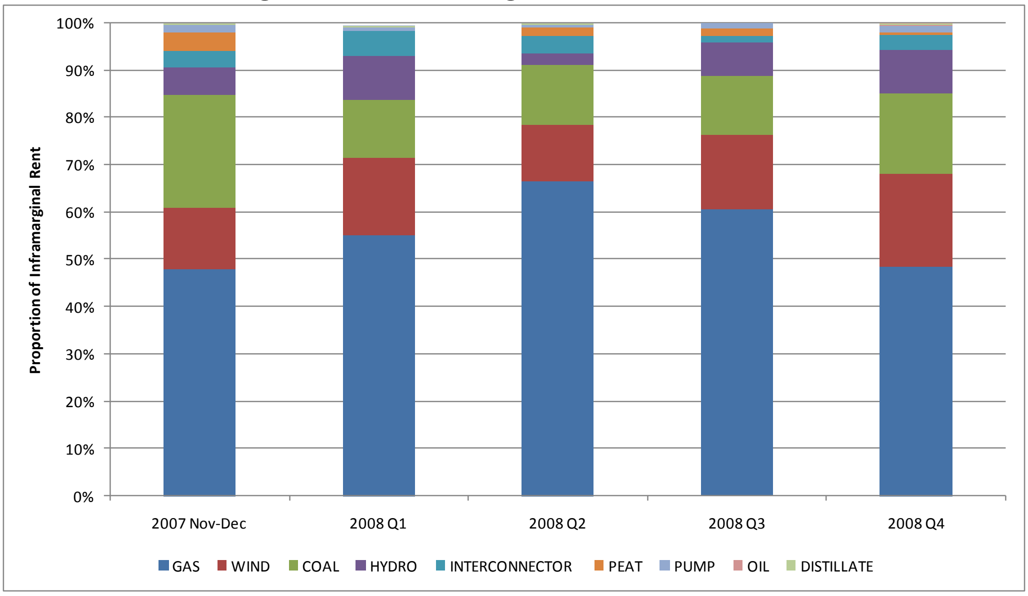
Figure 9.5: Energy and Capacity Revenue



The lower values for November – December 2007 are explained partly by the lower size of the Capacity Payment pots in those months and the lower SMP, but is mainly attributable to the fact that the other four columns comprise three months rather than two.

The share of infra-marginal rents by fuel-type is split out across the study period in the figure below:

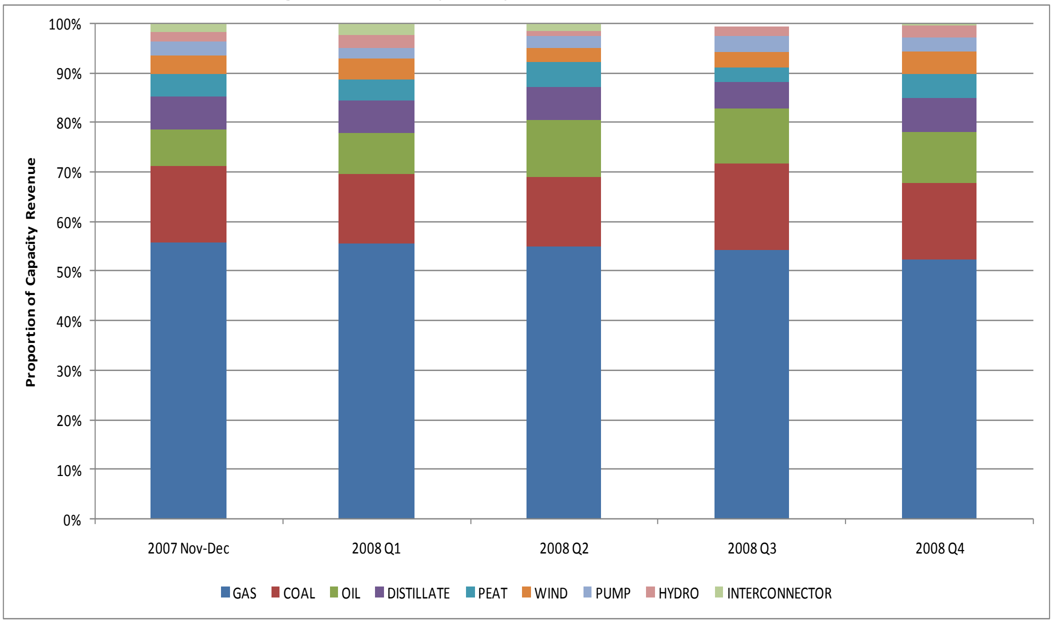
Figure 9.6: Infra-marginal Rent Breakdown



This figure maps reasonably neatly to Figure 4.21, in keeping with expectation as Generators that are scheduled more frequently see higher shares of the total infra-marginal rents.

The breakdown for Capacity Payment revenue is shown below:

Figure 9.7: Capacity Revenue Breakdown



The trend of Figure 4.21 is not repeated here, rather the distributions remain reasonably consistent. This is because the distribution of the CPM monies does not relate (materially) to movements in fuel price that drive the shares of inframarginal rent, but instead to the evolving mix of available generation of the study period.

10. Monitor's Assessment

The trends in the data presented in the report are drawn together in this final section and some broad commentary on the performance of the market is offered.

10.1. Correlations and Regressions

Correlations between the SMP and several key half-hourly variables are shown in the table below:

Table 10.1: SMP and Correlations

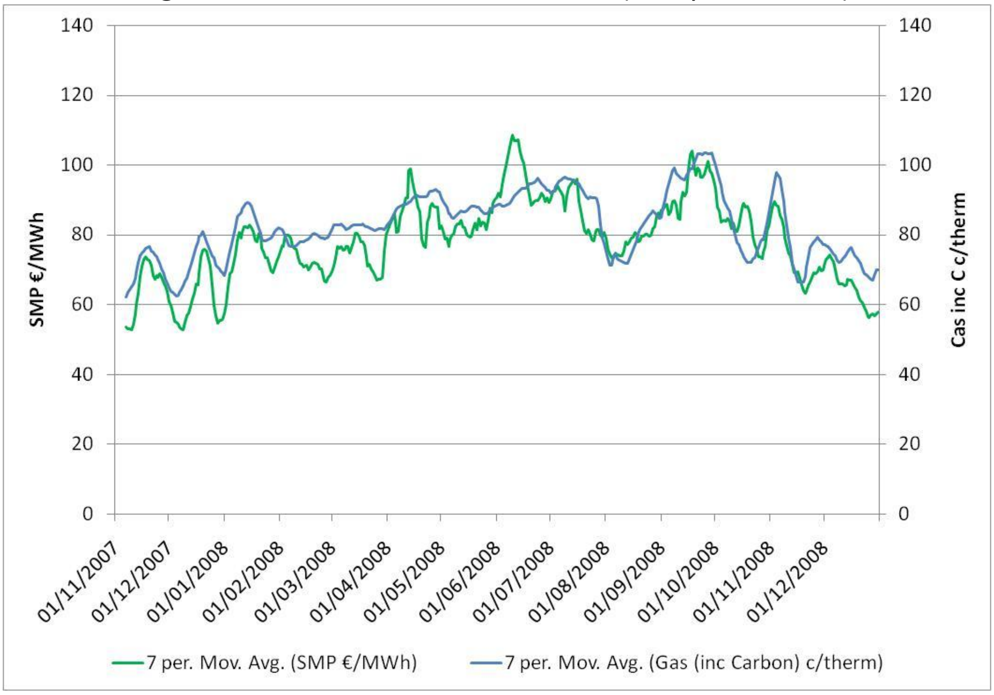
	SMP	MSQ	EA	WIND	MARGIN	MOYLE
Average	78.01	4201	6925	247	2723	65
Max	696.85	6553	8392	844	5035	407
Min	3.29	2275	4878	4.3	535	-80
Correlation With SMP	1.00	0.47	-0.07	-0.15	-0.59	-0.09

In the table all variables are measured in MW bar the SMP (€/MWh) and correlation co-efficients. The results show a stronger correlation between Margin and SMP than MSQ and SMP. This is in keeping with expectation given the data presented earlier. The correlation between Wind penetration and SMP is negative in keeping with expectation.

The fuel prices are not shown in the table above because this data is 'daily' instead of half-hourly. But it is clear that, following the previous Sections, that SMP is partly driven by the gas price, so it is worth illustrating the correspondence between what appear to be the three most interesting variables; SMP, gas price and Margin.

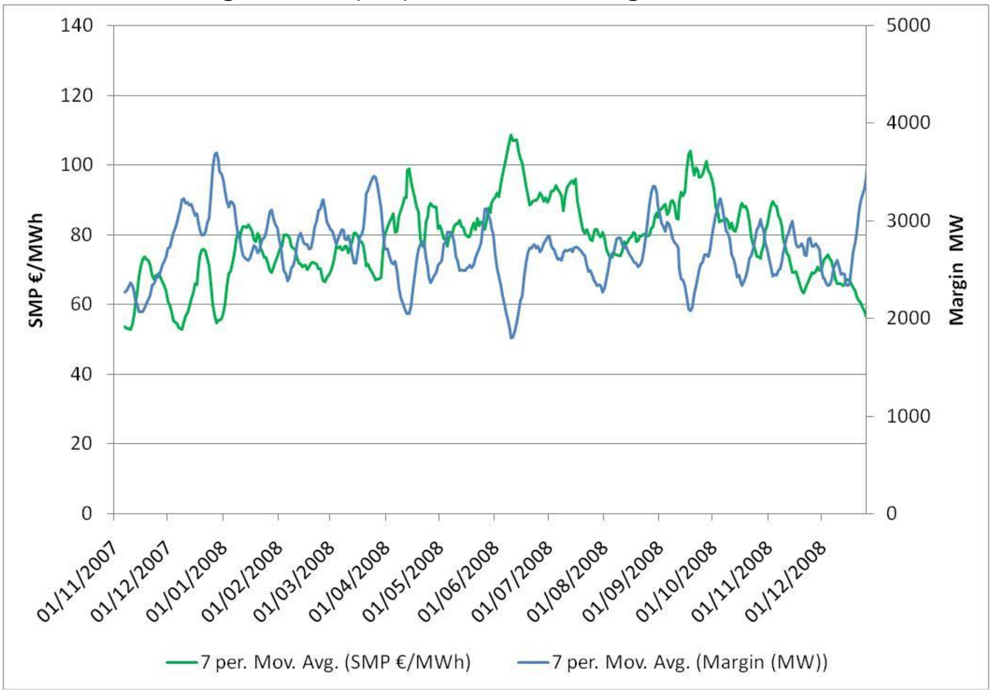
To explore the relationships between SMP and these key variables a bit further, the daily smoothed profiles of SMP and gas price were plotted:

Figure 10.1: Relations - Gas and SMP (7-day smoothed)



Recall the earlier figure in Section 5, illustrating the inverse relation between Margin and SMP:

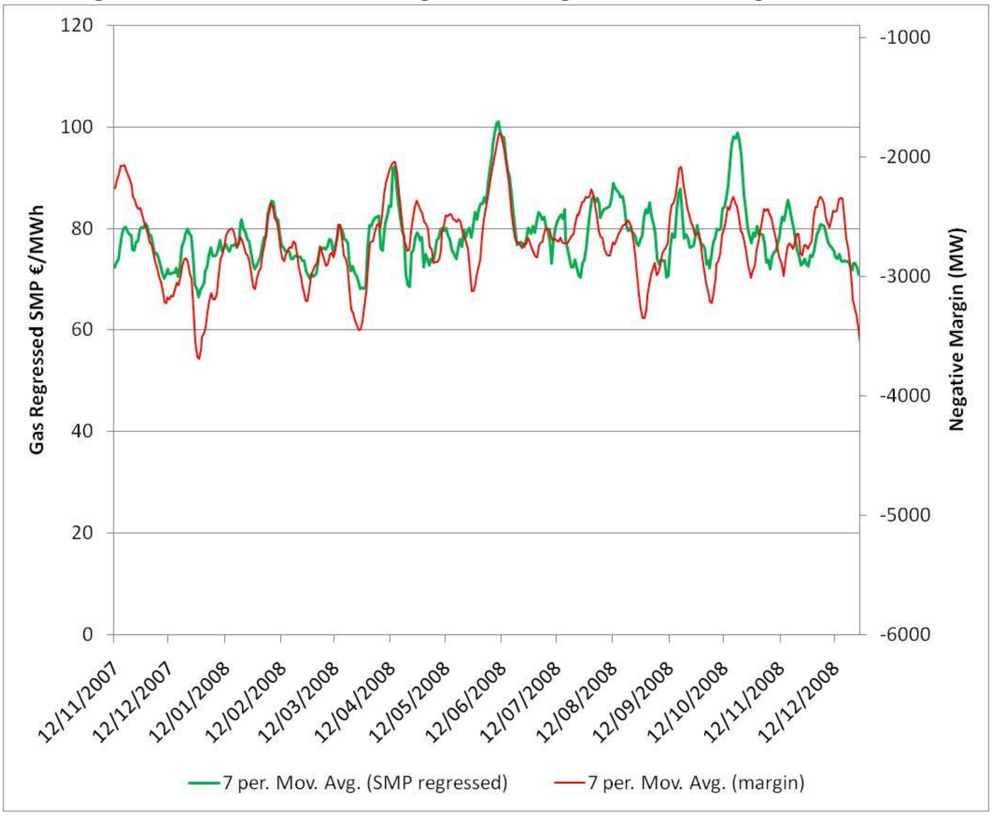
Figure 10.2 (5.7): Relations - Margin and SMP



A simple regression was applied to the carbon-indexed gas price and the SMP, and the results were used to normalise the SMP for the influence of gas price[10]. This normalised SMP was plotted against the Margin, which is shown inverted in the graph below:

[10] Regression #1 : SMP (€/MWh) = [1.000 x CI_Gas_Price (c/therm)] – 4.475

Figure 10.3: Relations – Negative Margin and Gas-Regressed SMP

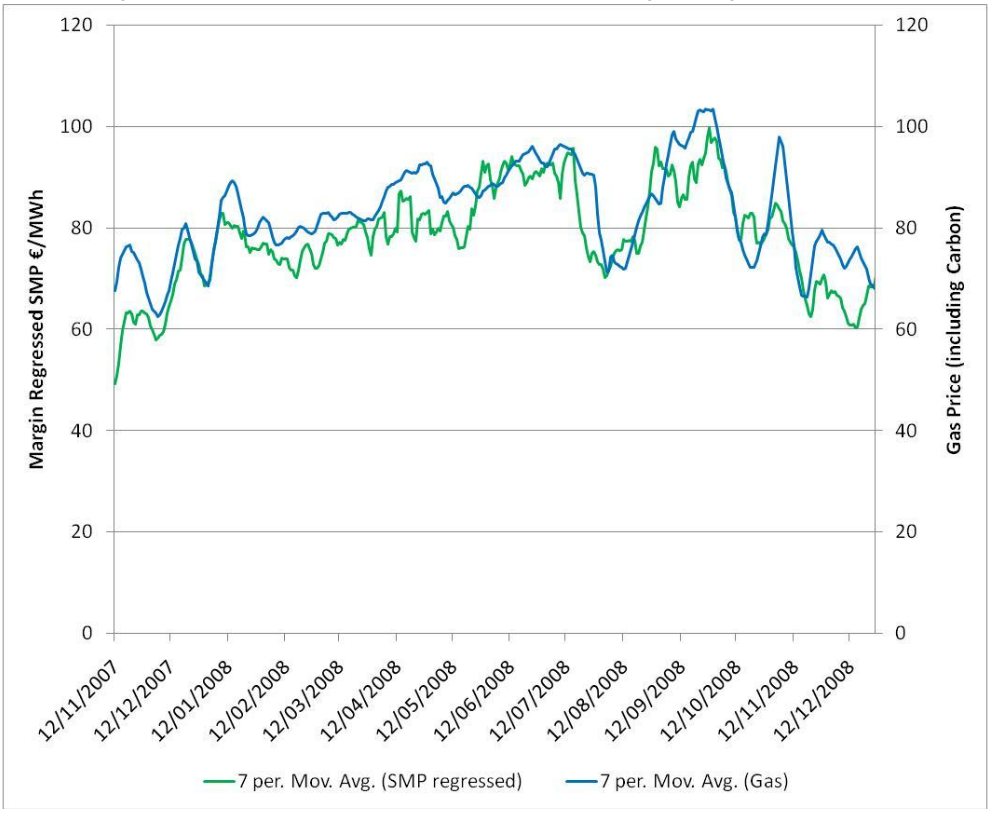


The figure speaks to the tendency for the SMP to broadly align with the (inverse) Margin pattern over the study period.

The reverse treatment was then applied to the variables, with Margin regressed against the SMP[11]. The SMP trace was then normalised for the effect of Margin and plotted alongside the carbon-indexed gas price:

[11] Regression #2 : SMP (€/MWh) = [-0.017 x Margin (MW)] + 124.4

Figure 10.4: Relations – Gas Price and Margin-Regressed SMP



Again the SMP shows a clear trend to broadly map to the trend present in the carbon-indexed gas price.

10.2. Closing Remarks

It is the view of the MMU that the SEM has produced outcomes in the study period that broadly align with expectation, given the suite of regulatory decisions and emergent trends in the input variables (demand, availability, wind, fuel prices and so on). The MMU is generally encouraged by the mapping of daily price profiles to those of the British Electricity Trading and Transmission Arrangements (BETTA), as well as the recognisably inverse pattern of system margin against SMP, which is commensurate with expectation for a short-term market in electricity and consistent with trends in healthy markets.

The Market Operator and System Operators have provided key input during the study period, including the timely provision of market and systems data necessary for the MMU to function. The MMU looks forward to continued strong relations with the Operators to ensure effective oversight of the market behaviour.

Much work has been done regarding the BCOP and its various interpretations, and it is envisaged that this will continue to occupy a significant quantity of research time in the year ahead. At the time of this writing, the MMU is conducting an academic review into the costs associated with repeated plant cycling with the assistance of external consultants. It is hoped the results of this work will be available sometime during Quarter 2 of 2009.

11. APPENDIX A – USEFUL REFERENCES

The SEM Trading and Settlement Code	http://www.sem-o.com/MarketRules/
The SEM Trading and Settlement Code Helicopter Guide	www.**allislandproject**.org/GetAttachment.aspx?id=9a7d9fb5-c6d8-43b9-bd63-fb1dba921e8a
The Bidding Code of Practice	http://www.allislandproject.org/en/market-power-decision.aspx?article=7fdc1ef8-3e0e-4267-9b82-0a2c65b1056f
SEM Committee Decisions, Directions and Clarifications	http://www.allislandproject.org/en/sem-executive-overview.aspx?page=1

12. APPENDIX B – PLEXOS UNIT DATA

This data was made publicly available during the 2008 Plexos Validation Exercise:

PLEXOS Unit ID	Unit Name	Participant (2008)	Start Fuel 1	Start Fuel 2	Fuel for Generation and No Load	Min Stable Capacity	Max capacity
K1 Coal 220	Kilroot Unit 1 FGD	NIE PPB	Oil		Coal	54.0	236.6
K2 Coal 220	Kilroot Unit 2 FGD	NIE PPB	Oil		Coal	54.0	236.6
KGT1	Kilroot GT1	NIE PPB	Distillate		Distillate	5.4	29.0
KGT2	Kilroot GT2	NIE PPB	Distillate		Distillate	5.4	29.0
SK3	Sealrock 3 (Aughinish CHP)	Aughinish	Gas		Gas	40.0	83.0
SK4	Sealrock 4 (Aughinish CHP)	Aughinish	Gas		Gas	40.0	83.0
ED1	Edenderry	Bord na Mona	Oil		Peat	41.0	117.6
CGT8	Coolkeeragh GT8	NIE PPB	Distillate		Distillate	8.0	58.0
CPS CCGT	Coolkeeragh CCGT	ESB International	Gas		Gas	260.0	413.0
AA1	Ardnacrusha Unit 1	ESB PowerGen	Hydro		Hydro	11.9	21.0
AA2	Ardnacrusha Unit 2	ESB PowerGen	Hydro		Hydro	11.9	22.0
AA3	Ardnacrusha Unit 3	ESB PowerGen	Hydro		Hydro	11.9	19.0
AA4	Ardnacrusha Unit 4	ESB PowerGen	Hydro		Hydro	11.9	24.0
AD1	Aghada Unit 1	ESB PowerGen	Gas		Gas	35.0	258.0
AP5	Aghada Peaking Unit	ESB PowerGen	Distillate		Distillate	5.0	52.0
AT1	Aghada CT Unit 1	ESB PowerGen	Distillate		Distillate	15.0	88.0
AT2	Aghada CT Unit 2	ESB PowerGen	Gas		Gas	15.0	90.0
AT4	Aghada CT Unit 4	ESB PowerGen	Gas		Gas	15.0	90.0
ER1	Erne Unit 1	ESB PowerGen	Hydro		Hydro	4.0	10.0
ER2	Erne Unit 2	ESB PowerGen	Hydro		Hydro	4.0	10.0
ER3	Erne Unit 3	ESB PowerGen	Hydro		Hydro	5.0	22.5
ER4	Erne Unit 4	ESB PowerGen	Hydro		Hydro	5.0	22.5
GI1	Great Island Unit 1	ESB PowerGen	Oil	Distillate	Oil	25.0	54.0
GI2	Great Island Unit 2	ESB PowerGen	Oil	Distillate	Oil	25.0	49.0
GI3	Great Island Unit 3	ESB PowerGen	Oil	Distillate	Oil	30.0	101.0
LE1	Lee Unit 1	ESB PowerGen	Hydro		Hydro	3.0	15.0
LE2	Lee Unit 2	ESB PowerGen	Hydro		Hydro	1.0	4.0

LE3	**Lee Unit 3**	**ESB PowerGen**	Hydro		Hydro	3.0	8.0
LI1	**Liffey Unit 1**	**ESB PowerGen**	Hydro		Hydro	3.0	15.0
LI2	**Liffey Unit 2**	**ESB PowerGen**	Hydro		Hydro	3.0	15.0
LI4	**Liffey Unit 4**	**ESB PowerGen**	Hydro		Hydro	0.5	4.0
LI5	**Liffey Unit 5**	**ESB PowerGen**	Hydro		Hydro	0.2	4.0
LR4	**Lough Rea**	**ESB PowerGen**	Peat		Peat	73.0	91.0
MP1	**Moneypoint Unit 1 FGD SCR**	**ESB PowerGen**	Coal	Oil	Coal	136.0	280.0
MP2	**Moneypoint Unit 2 FGD SCR**	**ESB PowerGen**	Coal	Oil	Coal	136.0	280.0
MP3	**Moneypoint Unit 3 FGD SCR**	**ESB PowerGen**	Coal	Oil	Coal	136.0	280.0
MRC	**Marina CC**	**ESB PowerGen**	Gas		Gas	98.0	112.0
MRC No ST	**Marina No ST**	**ESB PowerGen**	Gas		Gas	71.0	85.0
NW4	**Northwall Unit 4**	**ESB PowerGen**	Gas		Gas	87.3	163.0
NW5	**Northwall Unit 5**	**ESB PowerGen**	Distillate		Distillate	4.0	104.0
PB1	**Poolbeg Unit 1**	**ESB PowerGen**	Gas		Gas	56.0	109.5
PB2	**Poolbeg Unit 2**	**ESB PowerGen**	Gas		Oil	36.0	109.5
PB3	**Poolbeg Unit 3**	**ESB PowerGen**	Gas		Gas/Oil	57.0	242.0
PBC	**Poolbeg Combined Cycle**	**ESB PowerGen**	Gas		Gas	274.5	480.0
RH1	**Rhode Unit 1**	**ESB PowerGen**	Distillate		Distillate	5.0	52.0
RH2	**Rhode Unit 2**	**ESB PowerGen**	Distillate		Distillate	5.0	52.0
TB1	**Tarbert Unit 1**	**ESB PowerGen**	Oil	Distillate	Oil	18.0	54.0
TB2	**Tarbert Unit 2**	**ESB PowerGen**	Oil	Distillate	Oil	18.0	54.0
TB3	**Tarbert Unit 3**	**ESB PowerGen**	Oil	Distillate	Oil	34.8	240.7
TB4	**Tarbert Unit 4**	**ESB PowerGen**	Oil	Distillate	Oil	34.9	240.7
TH1	**Turlough Hill Unit 1**	**ESB PowerGen**	Pumped Storage		Pumped Storage	5.0	73.0
TH2	**Turlough Hill Unit 2**	**ESB PowerGen**	Pumped Storage		Pumped Storage	5.0	73.0
TH3	**Turlough Hill Unit 3**	**ESB PowerGen**	Pumped Storage		Pumped Storage	5.0	73.0
TH4	**Turlough Hill Unit 4**	**ESB PowerGen**	Pumped Storage		Pumped Storage	5.0	73.0
TP1	**Asahi Peaking Unit**	**ESB PowerGen**	Distillate		Distillate	5.0	52.0
WO4	**West Offaly Power**	**ESB PowerGen**	Peat		Peat	106.2	137.0
B10	**Ballylumford Unit 10**	**NIE PPB**	Gas		Gas	63.0	102.0
B31	**Ballylumford CCGT 31**	**NIE PPB**	Gas		Gas	115.0	251.6
B32	**Ballylumford Unit 32**	**NIE PPB**	Gas		Gas	115.0	251.6
B4	**Ballylumford Unit 4**	**NIE PPB**	Gas		Gas	54.0	170.0
B5	**Ballylumford Unit 5**	**Premier Power Limited**	Gas		Gas	54.0	170.0
B6	**Ballylumford Unit 6**	**Premier Power Limited**	Gas		Gas	54.0	170.0
BGT1	**Ballylumford GT1**	**NIE PPB**	Distillate		Distillate	8.0	58.0
BGT2	**Ballylumford GT2**	**NIE PPB**	Distillate		Distillate	8.0	58.0
DB1	**Dublin Bay Power**	**Synergen**	Gas		Gas	207.0	415.0
TY	**Tynagh**	**Tynagh Energy**	Gas		Gas	220.0	379.0
HN2	**Huntstown Phase II**	**Viridian / Energia**	Gas		Gas	194.0	412.0
HNC	**Huntstown**	**Viridian / Energia**	Gas		Gas	216.0	343.0