Validation of Market Simulation Software in SEM to end 2012

An Information Paper

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1 Introduction & Overview

1.1 Aim of Project & Paper

The Regulatory Authorities (RAs), consisting of the Commission for Energy Regulation (CER) and the Utility Regulator (UR), have recently validated a PLEXOS model for use in simulating system marginal prices (SMPs) and other market outcomes in the all-island Single Electricity Market (SEM). The SEM is a gross mandatory pool market and the Market Operator, SEMO[1], uses bespoke software to schedule and price the market every day.

The work in validating PLEXOS was carried out by the Market Modelling Group (MMG) in the CER, and this was audited by the Market Monitoring Unit (MMU) in the Utility Regulator. From late 2010 through to June 2011 the RAs' MMG undertook the following, as explained in this paper:

- Calibrated a backcast PLEXOS model against actual half hourly ex post SEM data on system marginal prices, shadow prices, uplift and market schedule quantities. This is explained in section 2 of this paper.
- Validated the PLEXOS forecast model input data, for Q4 2011 and the whole of the calendar year 2012. This is explained in section 3 of this paper.

As a result the PLEXOS model is now validated for the period from 1st October 2011 to end 2012. Section 4 of this paper presents the conclusions and our recommendations on the approach for running the validated PLEXOS SEM model (the forecast model) for Q4 2011 and 2012, which is published on the All-island Project website[2], excluding confidential data.

The RAs already gave a presentation on the validated PLEXOS model to interested parties at a public workshop held in the CER office on 13th June, and the RA slides provided at the workshop have been published[2]. This Information Paper now goes into more technical detail on the slides provided at the public workshop.
The validated PLEXOS model is used by the RAs in modelling market outcomes for the forthcoming contract year, i.e. from October 2011 to end September 2012. It has already been used primarily in the modelling of Directed Contracts (DCs) for the next contract year. Background information on PLEXOS and DCs is included in the paper at the following link:

http://www.allislandproject.org/GetAttachment.aspx?id=e83a335f-8366-416c-a6fe-96a0d54b1721

1.2 Applications for Model

The most immediate use of the model is to support the RAs' market power mitigation strategy, particularly the imposition of DCs on the incumbent market participants, ESB Power Generation and NIE Power Procurement Business as applicable. In putting in place DCs, the RAs require a validation of their market simulation model, PLEXOS, to be carried out first. This validated model is then used to determine the quantity and pricing (SMP) of the DCs made available for the contract year from 1st October. The DC subscription windows for the 1st October 2011 to 31st September 2012 contract year were held in June and July this year and the DC strike prices were published in an SEM Contracting Information Paper on 3rd August 2011[2].

[1] SEMO is a joint venture between EirGrid plc and SONI Limited

[2] http://www.allislandproject.org/en/market_decision_documents.aspx?article=151a9561-cef9-47f2-9f48-21f6c62cef34

In addition, the RAs will use the validated PLEXOS model to support other areas of work such as:

- Assessing future end tariffs;
- Forecasting the SMP for the PSO Levy;
- Market Monitoring; and,
- Modelling to inform RA policy on the SEM.

2 Calibration of Backcast Model

The aim of the backcast calibration exercise is to replicate reasonably closely, within a PLEXOS model, the actual ex-post SMPs, interconnection flows and market schedule quantities (MSQs) observed in the SEM. The PLEXOS modelling configuration that provides the best replication of the ex-post data across the calibration horizon is then used to inform any recommendations for the validated forecast model (see section 3).

2.1 Data

The technical and commercial characteristics of each predictable price maker generator (PPMG) in the SEM are defined by submitted technical and commercial offer data – Technical Offer Data (TOD) and Commercial Offer Data (COD) respectively. For offer price-quantity pairs, no load costs, start costs and start cost times, actual availabilities, min up times, min down times and minimum stable generation, the exact data submitted to the Market Operator was used in the backcast PLEXOS model. The ramp rates were provided in processed form and entered into the PLEXOS model as single ramp up and ramp down rates.

Some of this data was provided by the RAs' Market Monitoring Unit (MMU) and some was taken directly from the SEMO website, before being converted into the appropriate PLEXOS input format.

Some of the data is in half hourly granularity, and some is in daily granularity, as detailed in Table 1 below.

Table 1

Half Hourly Data	Daily Data
Load	Price-Quantity Pairs
Availability	No Load Cost
Minimum Stable Level	Start Costs
	Start Times
	Minimum On/Off Times
	Ramp Rates Up/Down

The Peat, Aughinish, Hydro and Wind generators were modelled differently to the other generators in the SEM, in a similar manner to last year's validation exercise. Sections 2.2.5 and 2.2.6 explain how Peat, Aughinish and Hydro are modelled. The Wind generators were aggregated into a single unit, and the actual aggregate wind output was modelled directly as fixed load on a single wind generator in the PLEXOS model.

2.2 Changes from the Previous Validation Exercise

This section outlines the changes made to PLEXOS modelling approaches for this calibration exercise compared to last year's. Generally the same approach was applied to last year unless indicated here.

2.2.1 PLEXOS 6

Last year the RA's consultants Redpoint validated PLEXOS 5 and this version was used until this year's validation exercise by the RAs. For this validation process, we moved to the latest version of the software, PLEXOS 6. The decision to move from PLEXOS 5 to 6 was based on the fact that:

- PLEXOS 6 has performance advantages over PLEXOS 5; such as the option to save solution files as XML files
- The development focus of Energy Exemplar, the PLEXOS vendor, will be on PLEXOS 6 going forward

Some changes have been made to the interface in PLEXOS 6, but these are small and should not pose problems for users.

In the last validation exercise, the model was calibrated over a longer period (from February 2008 to September 2009) than for this exercise. This year, market data covering the period 1st January 2010 to end December 2010 has been processed and entered into PLEXOS. While the period over which the model is calibrated is shorter than last year, more detailed data has been provided to PLEXOS (e.g. daily Ramp Rates and 3 state Start Costs) and extra features have been added (e.g. "dump energy", see below), which should give more accuracy when calibrating PLEXOS to actual market outcomes in SEM.

2.2.2 3 State Start Costs

The SEM market engine accepts 3 start costs – hot, warm and cold, from generators as part of their COD. In previous years only 1 start cost was inputted to PLEXOS for each generator (the warm start cost) as tests using all 3 showed that results and run times were unacceptable. However this year, due to improvements to the PLEXOS Rounded Relaxation algorithm, tests showed that PLEXOS can now handle 3 start costs. It was decided therefore to move to 3 start costs as this is exactly what is provided to the market engine.

2.2.3 Dump Energy

Dump Energy has now been added to PLEXOS 6. This allows for the possibility of negative prices if generation exceeds demand and energy must be dumped. In the validated model the Price Floor is set to -100 €/MWh to match that used in the market.

2.2.4 Xpress-MP Solver

Last year the RAs recommended that the Validated PLEXOS model be used in conjunction with the MOSEK solver, while this year we recommend that the validated model be used in conjunction with the Xpress-MP solver (see section 2.6.2 later).

2.2.5 Peat and Aughinish

The Peat generators and Aughinish CHP are currently registered as "predictable price taker" generation (PPTG) units. Such units are scheduled in the SEM on the basis of submitted nomination profiles rather than offer prices. In order to replicate this treatment in the calibration exercise we have used the maximum availability as submitted to the Market Operator, and excluded Commercial Offer Data for these units to ensure they are dispatched fully when available, and that they do not impact the calculation of uplift. The SEM uplift algorithm applies a cost recovery constraint to “price maker” generator units (excluding pumped storage). However, the formulation of the cost recovery constraint in PLEXOS considers all generators, and does not distinguish between price makers and price takers. Any plant with non-zero incremental, no load or start costs may therefore impact the cost recovery constraint in the PLEXOS uplift algorithm. Price takers should therefore be modelled in PLEXOS without incremental, no load or start costs to avoid influencing uplift. In last year’s validation only the Peat units were treated as PPTG units.

2.2.6 Hydro

In previous years’ backcast calibrations historic half-hourly market schedule quantities were used to create daily energy limits for each of the four hydro schemes across the backcast horizon. However, since the market engine (especially when using its Lagrangian Relaxation solver) does not always fully schedule the hydro units up to their energy limits, it was thought better this year to use the actual “daily limits” that the market engine was given (a combination of ‘Hydro Energy Limits’ and the units’ actual metered generation).

2.2.7 Turlough Hill Pumped Storage

In previous years’ backcast calibrations the Target Reservoir Levels for the Turlough Hill pumped storage units were not included. This year however they were included as a ‘RHS Day’ constraint on the HEAD storage. Also included on the HEAD storage is a “natural inflow’”. This “natural inflow” fixes inconsistencies in the historical storage levels due to the rescheduling of individual days in the market. These inconsistencies occur when the rescheduled storage level at 05:30 is different, as the storage level at the start of the next day (06:00) remains unchanged at the previous value.

2.2.8 Units under test

In previous years’ backcast calibrations allowance was not made for “units under test”. When units are under test they submit nomination profiles rather than offer prices and receive the SMP. This year it was decided to fix the load of any units under test as there was considerable testing over the course of 2010, especially for the new CCGTs at Aghada and Whitegate.

2.3 The Moyle Interconnector

The Moyle interconnector (Moyle) links Northern Ireland to Scotland, meaning that the Great Britain (GB) market can influence the SEM. Flows on Moyle should be largely driven by arbitrage of the relative prices in the two markets, so when prices are higher in SEM than GB there tends to be imports (of cheaper GB electricity) to SEM while when prices are lower in SEM than GB there tends to be exports (of cheaper SEM electricity) from SEM.

Simply fixing the Moyle flows in the backcast PLEXOS model to the actual flows does not contribute to calibrating the model for use in the forward period, as we do not know what future flows will look like. Last year's PLEXOS validation exercise also showed that fixing Moyle flows resulted in SMP in PLEXOS which was higher on average than historic prices. This is because fixing the flow significantly decreases overall flexibility and also removes the ability of Moyle to set the price in PLEXOS. Hence, the aim of our modelling of Moyle in this project is to come up with a method which:

1. Accurately replicates flows for the backcast calibration period and the impact those flows have on SMP, so that the model is properly calibrated for use in the forward period; and,
2. Predict flows for the forward model which move as would be expected with different fuel/carbon prices across the SEM and GB.

2.3.1 Great Britain market representation

The regression model of Great Britain (GB) gas (and carbon) to electricity prices was developed using the same methodology as applied in last year's validation process. A single gas fired generator is used to represent the GB market. This single generator has 12 different heat rates and variable operating costs, created as described below.

The GB Market Index Price (MIP)[3] was chosen as a representation of the half hourly GB electricity price. 12 separate regressions were then carried out for data from 2010 for GB electricity prices against daily combined gas and carbon prices - one for each of the six traded Electricity Forward Agreement (EFA)[4] block time periods, for both summer and winter. The resulting regression coefficients and constants were then used as the GB generator's heat rates and variable operating costs respectively.

This captures the correlation between the gas generation cost (including carbon) and the GB electricity price, which has traditionally been strong given that gas generation has predominantly been the marginal plant on the GB system.

For example: the graph in Figure 1 below shows the GB price predicted by the regression formula, for the Winter 3am to 7am EFA block, compared to the actual GB MIP price for this EFA block over 2010. It can be seen that the half hourly volatility is removed but that the general price movement is followed closely.

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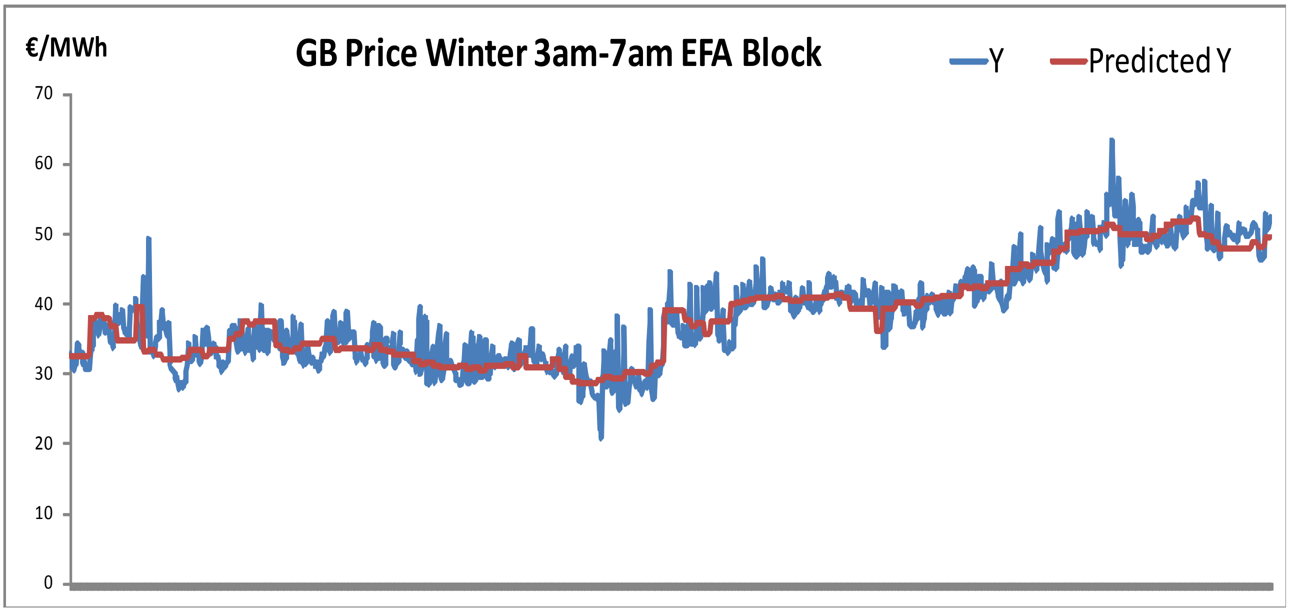
[3] Market Index Prices are calculated from a weighted average of short term trades (out to 20 hours ahead of delivery) and reflect the short term wholesale price

[4] GB electricity can be traded over-the-counter in four hour blocks known as EFA blocks. The six blocks that make up a trading day begin at 23:00 and follow at four hour intervals.

Figure 1 Predicted and Actual GB price



2.3.2 Interconnector Wheeling charges

There are a number of reasons why Moyle flows may not be determined purely on price differential (arbitrage) between GB and SEM. Firstly, the capacity across Moyle is allocated through annual and monthly auctions, with no liquid secondary market for capacity. This restricts the number of market players with access to capacity in the short term. Secondly, gate closure is earlier in SEM than in the BETTA market. Thirdly, participants don't know the exact price in the SEM until four days after the fact. These factors potentially lead to sub-optimal use of the interconnector.

A wheeling charge is a cost applied to flow along an interconnector within PLEXOS. A wheeling charge will create a requirement for an equivalent price differential to exist between two connected markets before flow becomes economic. Last year's validation exercise used a wheeling charge, to represent this price differential requirement, of +13.2 €/MWh and a wheeling charge back of -0.4 €/MWh, both flat across the year. This year the RAs analysed the MIP prices in BETTA and the average Interconnector user bids over 2010 and based the wheeling charges on the difference. This produced 12 different values of wheeling charges, one for each EFA block time period for both summer and winter. Please note that, as explained above, these charges are not the actual charges in place to use the interconnector.

2.4 Kilroot Coal

2.4.1 The Issue

For the initial backcast period, January-October 2010, PLEXOS, using Rounded Relaxation (RR), schedules the Kilroot Coal units much more than the market. The Kilroot Coal units' COD has a very high No Load cost component. This is due to the fact that at low outputs they must burn oil, and this cost must be recovered through the "No Load" component of their bids. The over-scheduling of these units by PLEXOS as compared to the market drives higher uplift and hence SMP, due to these high 'No Load' costs. This issue is explained below.

2.4.2 Comparison with Moneypoint bid structure

Table 2 below contains the average bid structure, over the inital backcast period, of Kilroot Coal unit 2 and Moneypoint unit 3. The Kilroot Coal unit has a large No Load cost. This means that the marginal price component of its bid (ignoring the last PQ pair) can be considerably lower than that of the Moneypoint unit even though its total cost per MWh (up to an output of 175MW) is higher.

Table 2

K2 Coal	NO LOAD	QUANTITY	PRICE	TOTAL COST (/MWh)
1	3945	108	14.43	50.95
2	0	175	38.44	46.17
3	0	236	355.08	126.33
MP3	NO LOAD	QUANTITY	PRICE	TOTAL COST (/MWh)
1	727	195	41.66	45.38
2	0	278	42.06	44.39

The PLEXOS RR algorithm seems to have trouble with units with a very high No Load cost and low marginal price components, i.e. it appears to put greater weight on the marginal price components and not enough weight on the No load cost when the No Load cost is very high. Hence the Kilroot Coal units were over-scheduled in PLEXOS and this drove higher uplift and thus SMP compared to the market. This is shown in section 2.5.

When the commitment of the Kilroot Coal units was fixed to what it was in the market, the backcast price results were much closer to the market outcomes, as discussed in section 2.5 below. This is confirmation that the over-scheduling of the Kilroot Coal units was the main driver behind the higher price.

2.4.3 Change to Kilroot Coal bidding structure

The Kilroot Coal GUA contracts with NIE PPB ended on 1st November 2010. AES carried out a technical review of the units and this lead to a change in the structure of the bids given to the market, which took effect on 1st November 2010. This new bidding structure included a higher Minimum Stable Level and a reduced No Load cost.

It was decided to extend the backcast period by an extra two months - November and December 2010. This was in order to examine if this new bidding structure solved the Kilroot Coal over-scheduling issue in PLEXOS (compared to the market), given that the new Kilroot bids featured lower No Load costs for this period, and high no-load costs appeared to be the primary cause for over-scheduling of PLEXOS. The results are detailed in the next section.

2.5 Backcast Results

This section presents the results of the backcast modelling exercise from January to end December 2010. It describes the base case results obtained by running PLEXOS in Rounded Relaxation mode with our recommended model settings and taking on board the issues discussed in section 2.2 to 2.4 above. Sensitivities are then discussed in the next section.

Due to the Kilroot Coal issue, outlined in Section 2.4, and its effect on the results, the results are laid out in three separate sections as follows:

- January to October 2010 - Kilroot Coal commitment free:
    - where PLEXOS is free to commit the Kilroot Coal units as it sees fit (i..e as with all other generators in PLEXOS);
- January to October 2010 - Kilroot Coal commitment fixed:
    - where the commitment of the Kilroot Coal units is fixed to that seen in the market Note that only the commitment - on or off - is fixed, not the generation level; and,
- November to December 2010
    - where the Kilroot Coal units are using their new bidding structure, as discussed in Section 2.4.3.

2.5.1 January to October 2010 – Kilroot Coal commitment free

Prices

With Kilroot commitment free, the average SMP from PLEXOS is 4.16% higher than the historic SEM outturn price. The reason is likely to be related to over-scheduling of Kilroot as explained in the previous section. The graphs below show the intraday shape of SMP, Shadow Price and Uplift over the 10 months.

Figure 2

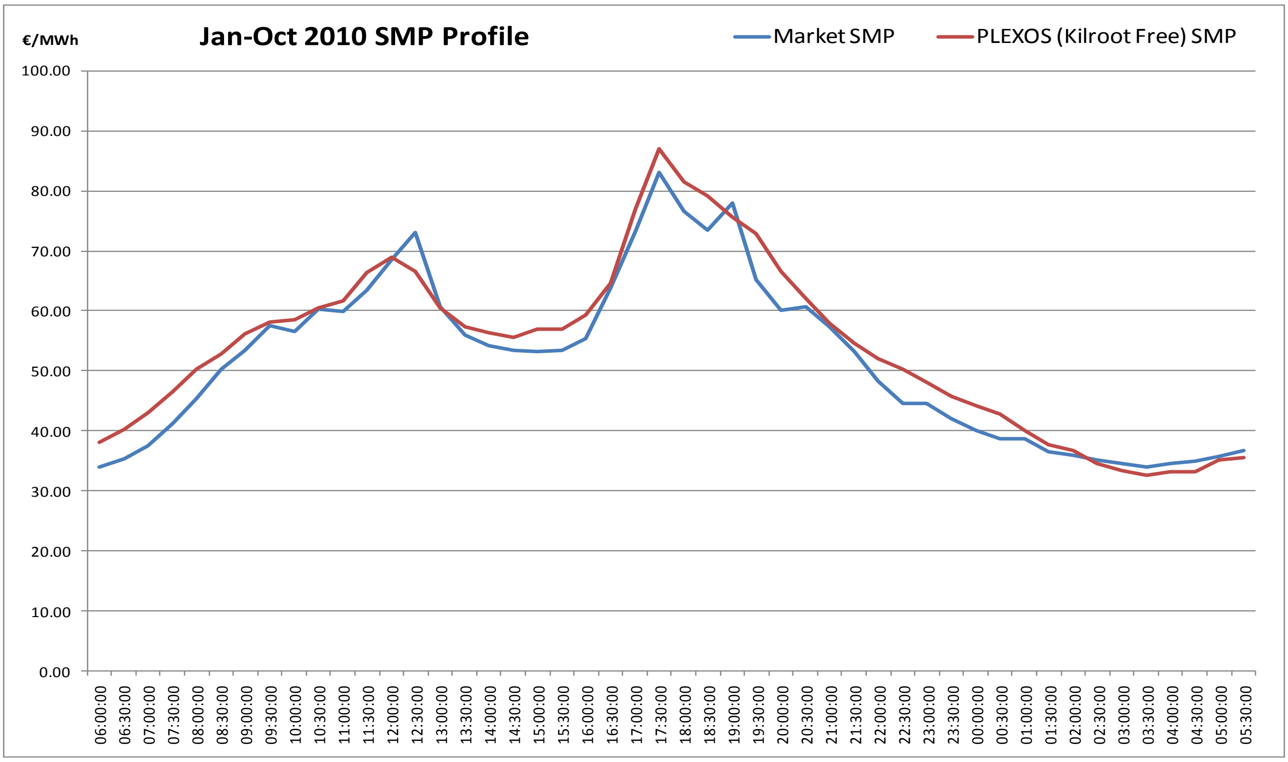


Figure 3

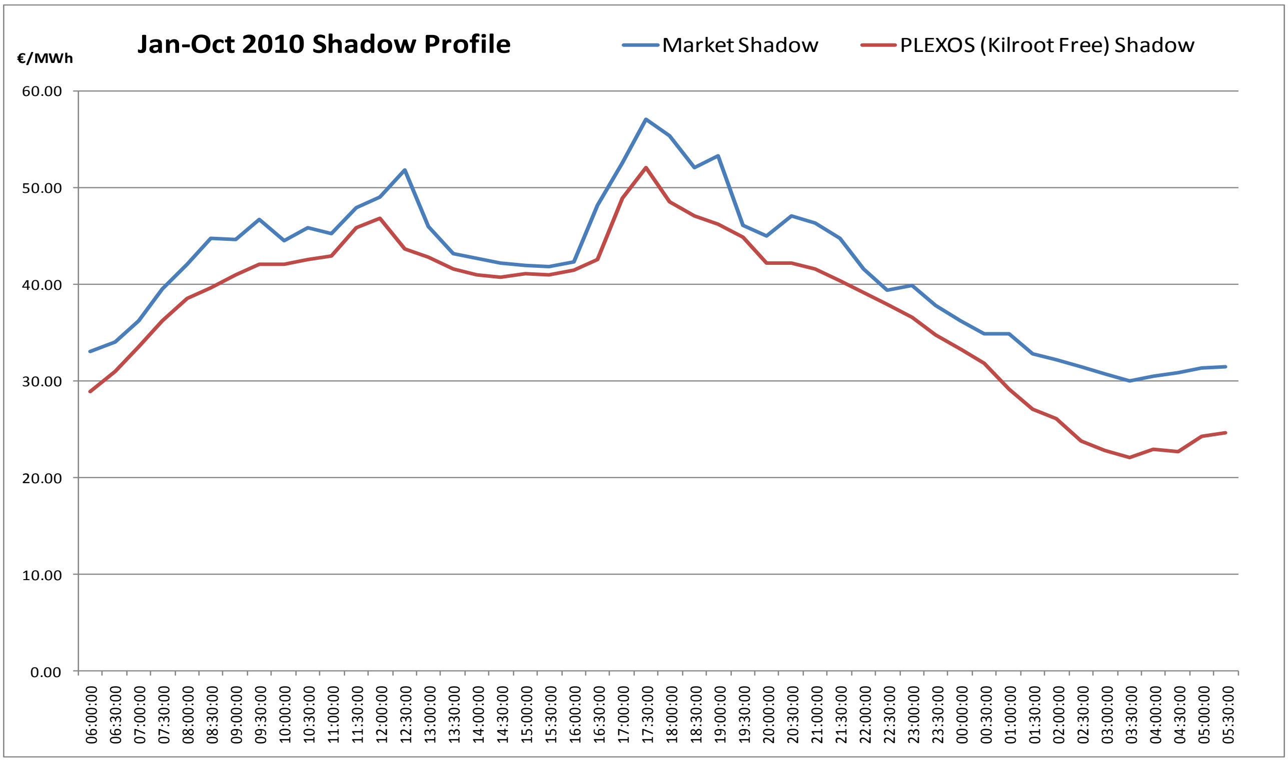


Figure 4

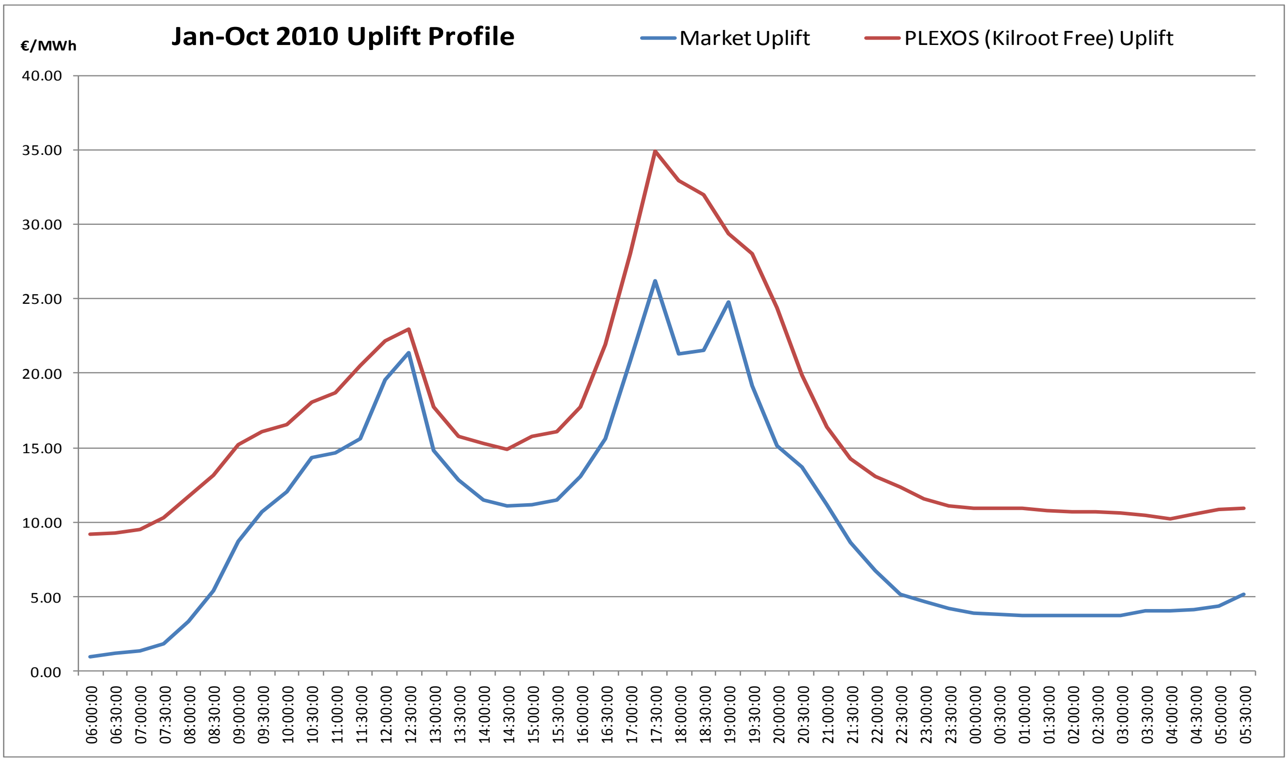
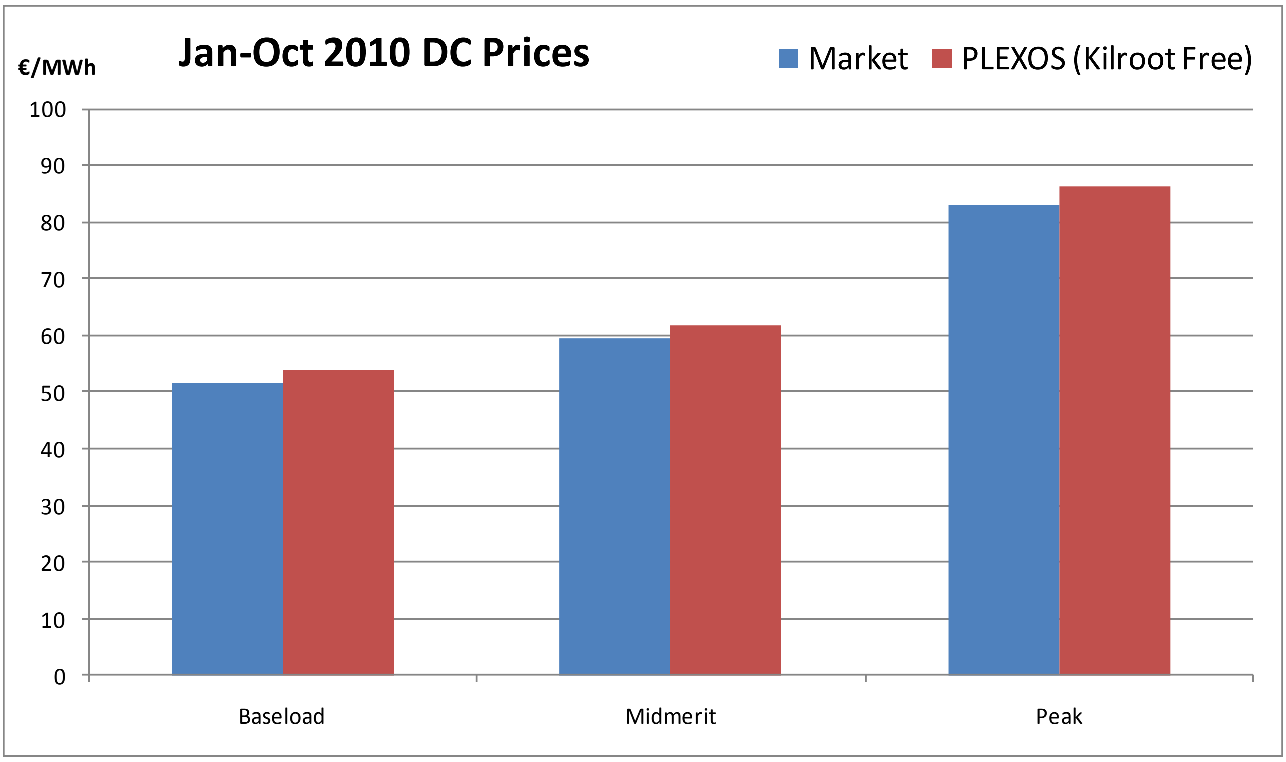


Figure 5 below shows the average levels of SMP across the settlement periods of the three Directed Contract products (Baseload, Midmerit and Peak) over the 10 months. The average Midmerit price from PLEXOS is 4.2% higher than the market outturn and the average Peak price from PLEXOS is 4% higher. As referred to earlier, the baseload SMP (i.e. in all settlement periods) is 4.16% higher in PLEXOS than in the market.

Figure 5



Generation

Figure 6 and Figure 7 below compare generation in PLEXOS and historic MSQs in the market for the 10 months by both fuel type and station. It is clear that PLEXOS very significantly over-scheduled the Kilroot Coal units compared to the market.

Figure 6

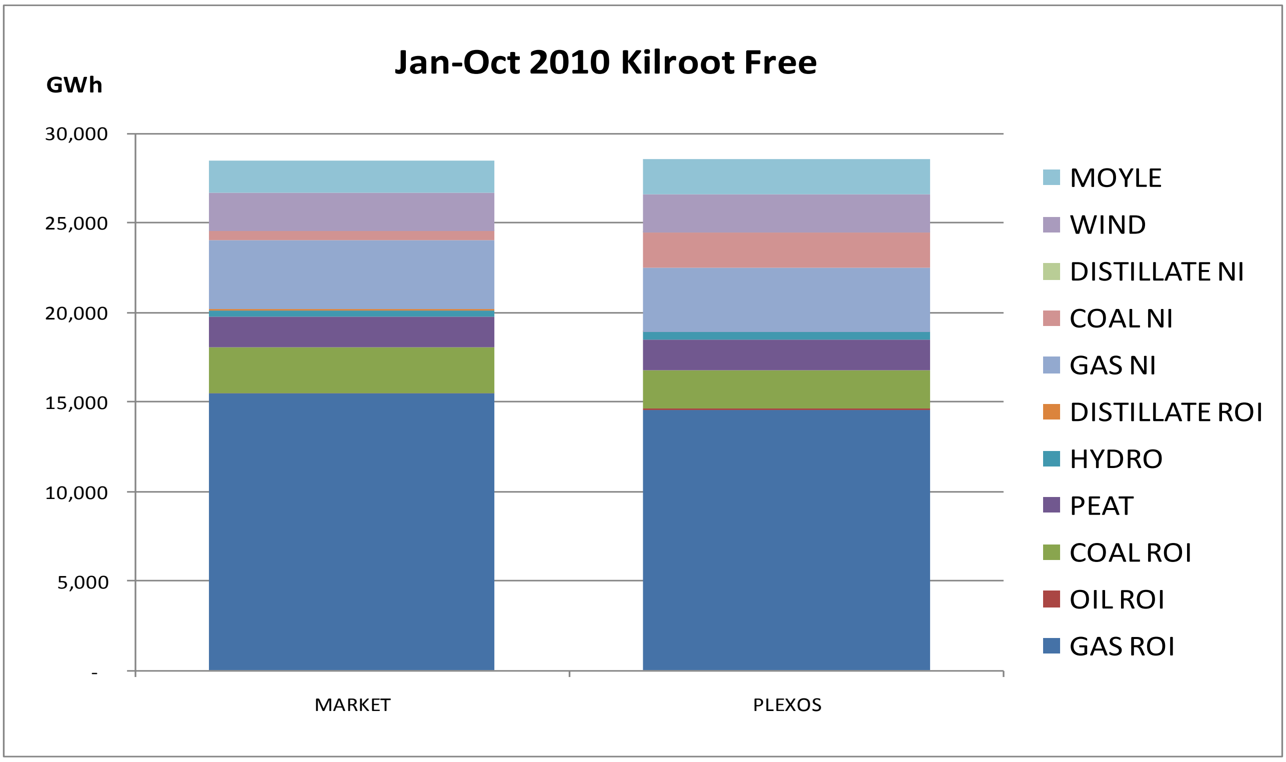
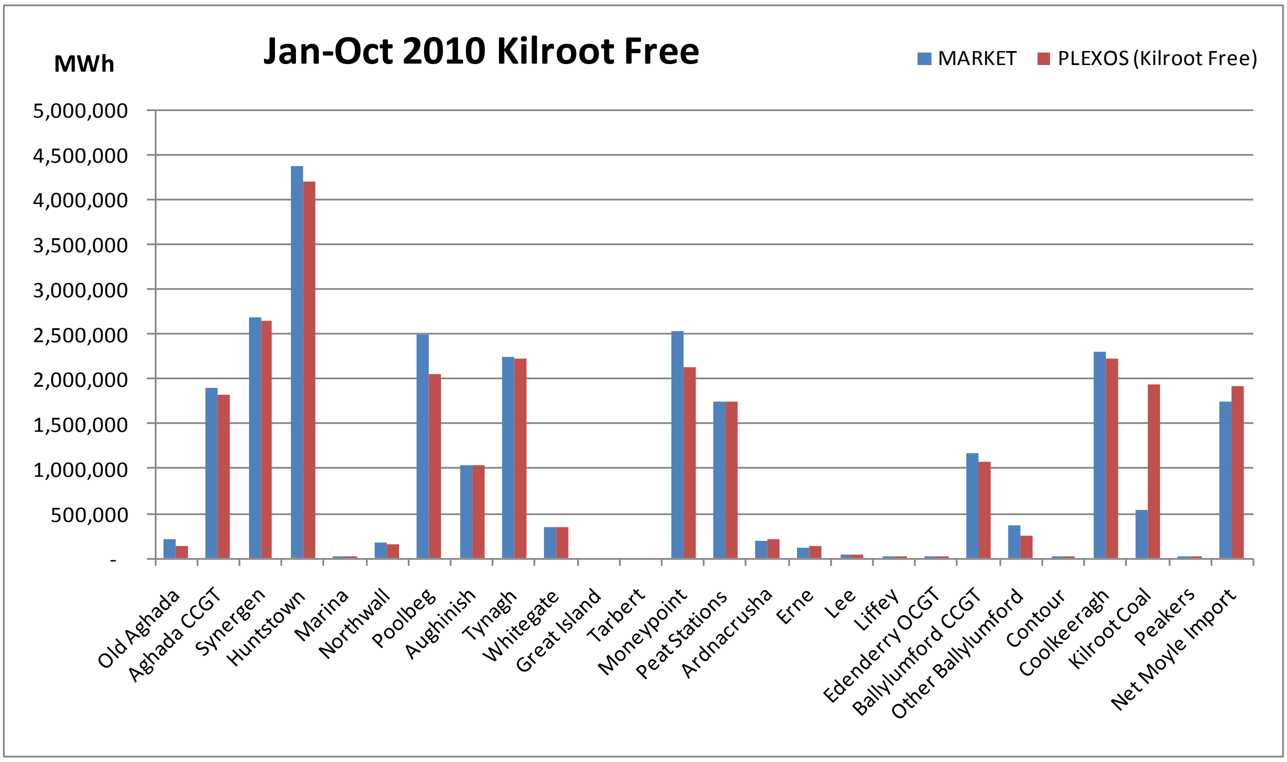


Figure 7



Interconnection

Figure 8 shows the monthly Moyle flows and Figure 9 shows the intraday shape of flows over the 10 months. The PLEXOS interconnector flows here are derived as explained in section 2.3. Note that a negative number indicates net flow from GB to SEM.

Figure 8

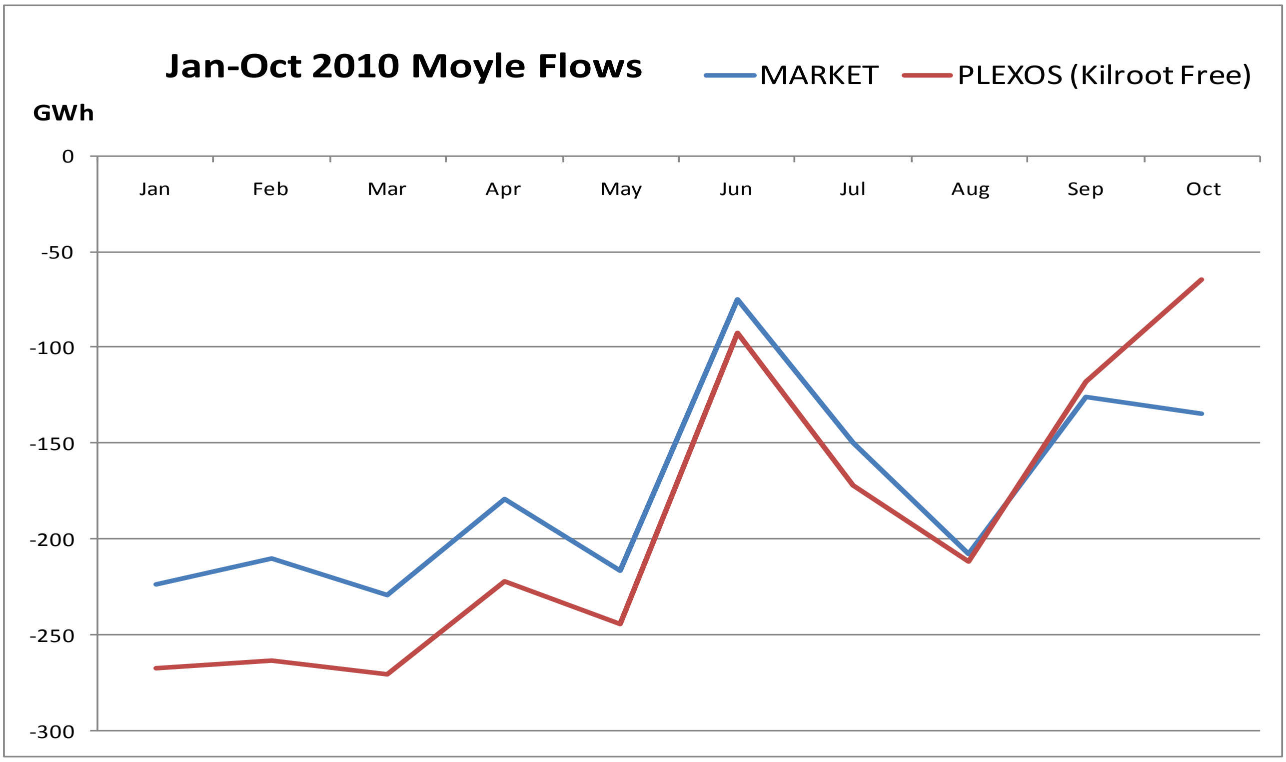
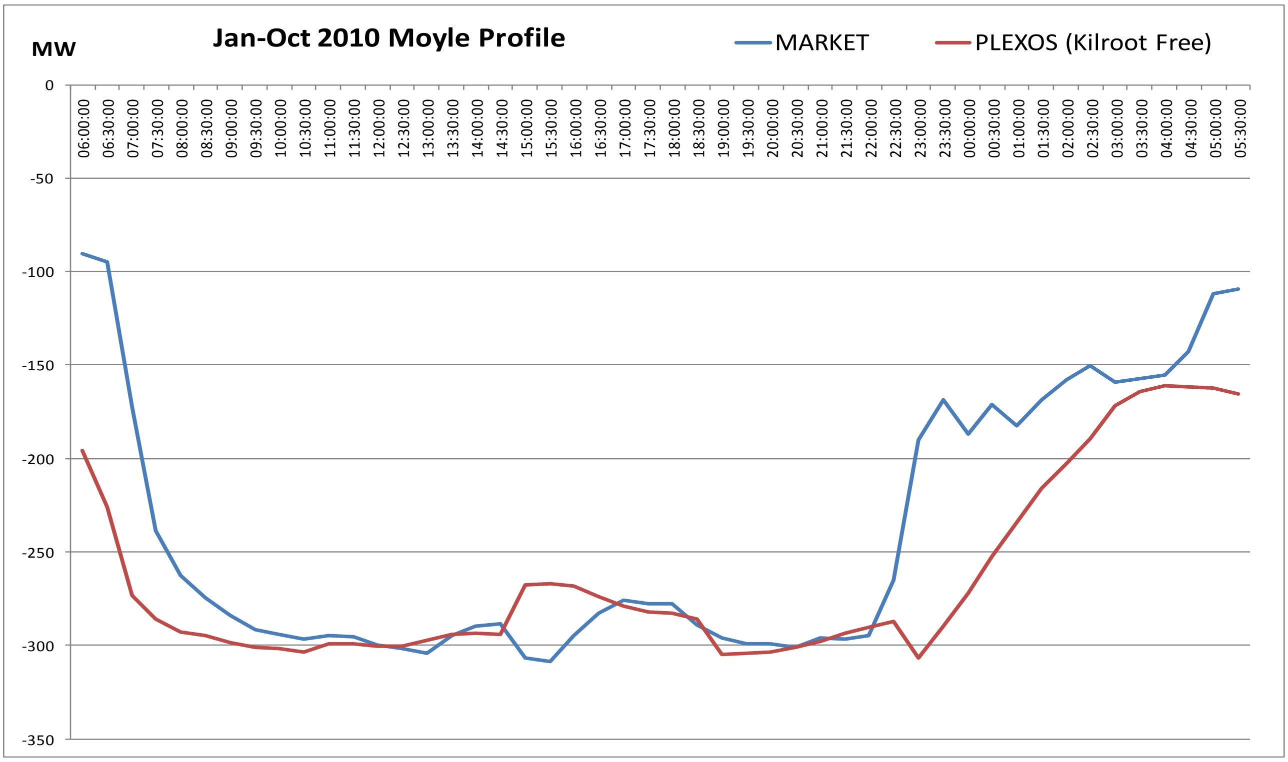


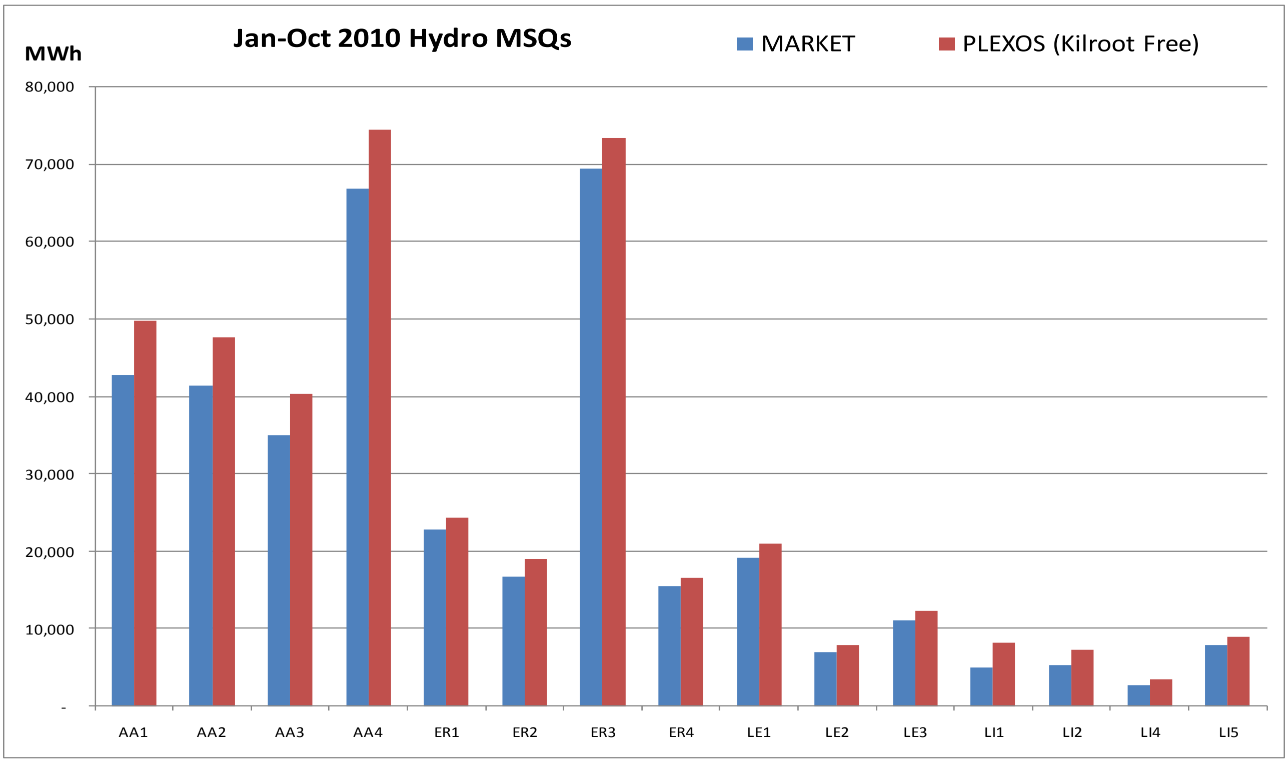
Figure 9



Hydro

Figure 10 shows the generation in PLEXOS and the historic MSQ in the market of the individual Hydro units over the 10 months. When given the actual hydro 'daily limits', as explained in section 2.2.6, PLEXOS schedules the hydro units more than the market does using Lagrangian Relaxation (by approx. 12%).

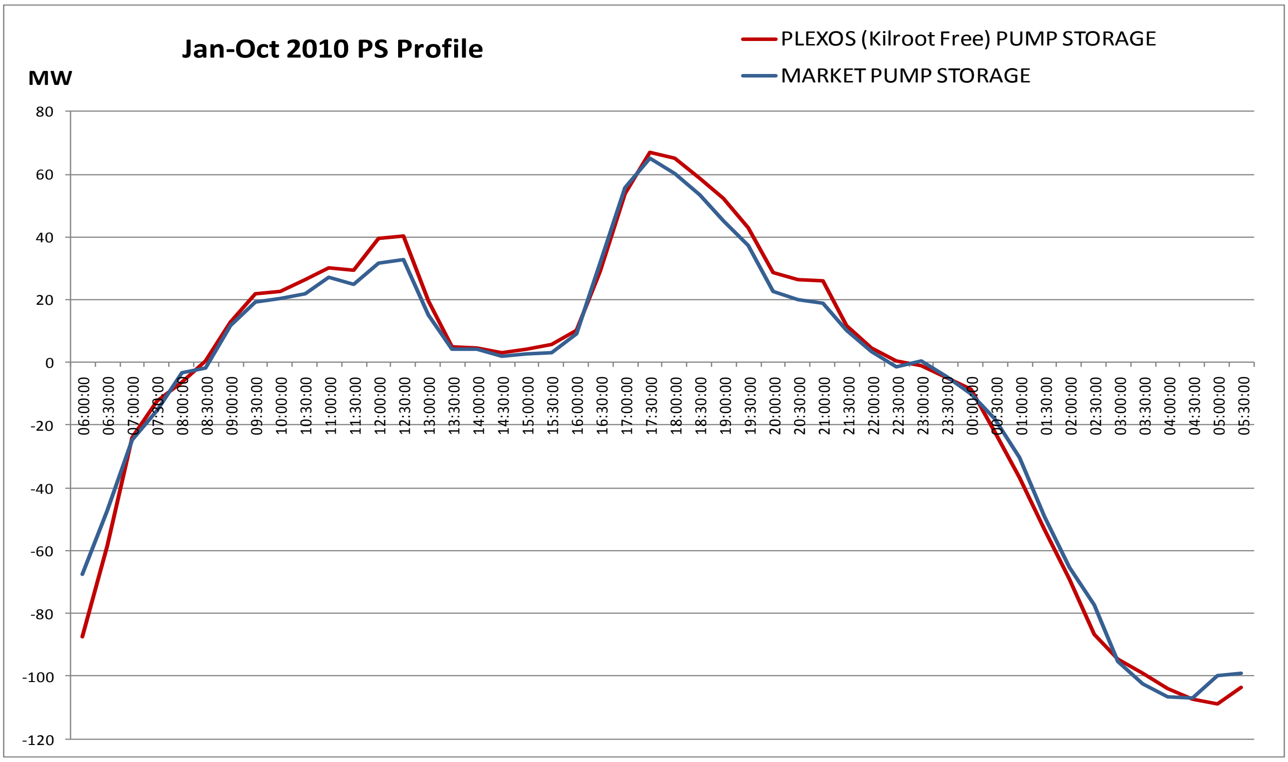
Figure 10



Pumped storage

We have allowed PLEXOS to optimise the pumped storage units, having given it extra data compared to previous validations (as explained in section 2.2.7). Figure 11 shows the intraday shape of the Pumped Storage generation/pumping (up to early July when the station went on outage) in both PLEXOS and the market. The profiles are very closely matched.

Figure 11



2.5.2 January to October 2010 – Kilroot Coal commitment fixed

Prices

With Kilroot commitment fixed, the average SMP from PLEXOS is 1.2% lower than the historic SEM outturn price. This is much closer to the market outturn than the results from the Kilroot commitment free scenario (above), and indicates that it was the over-commitment of the Kilroot units that was driving the higher SMP. The graphs below show the intraday shape of SMP, Shadow Price and Uplift over the 10 months.

Figure 12

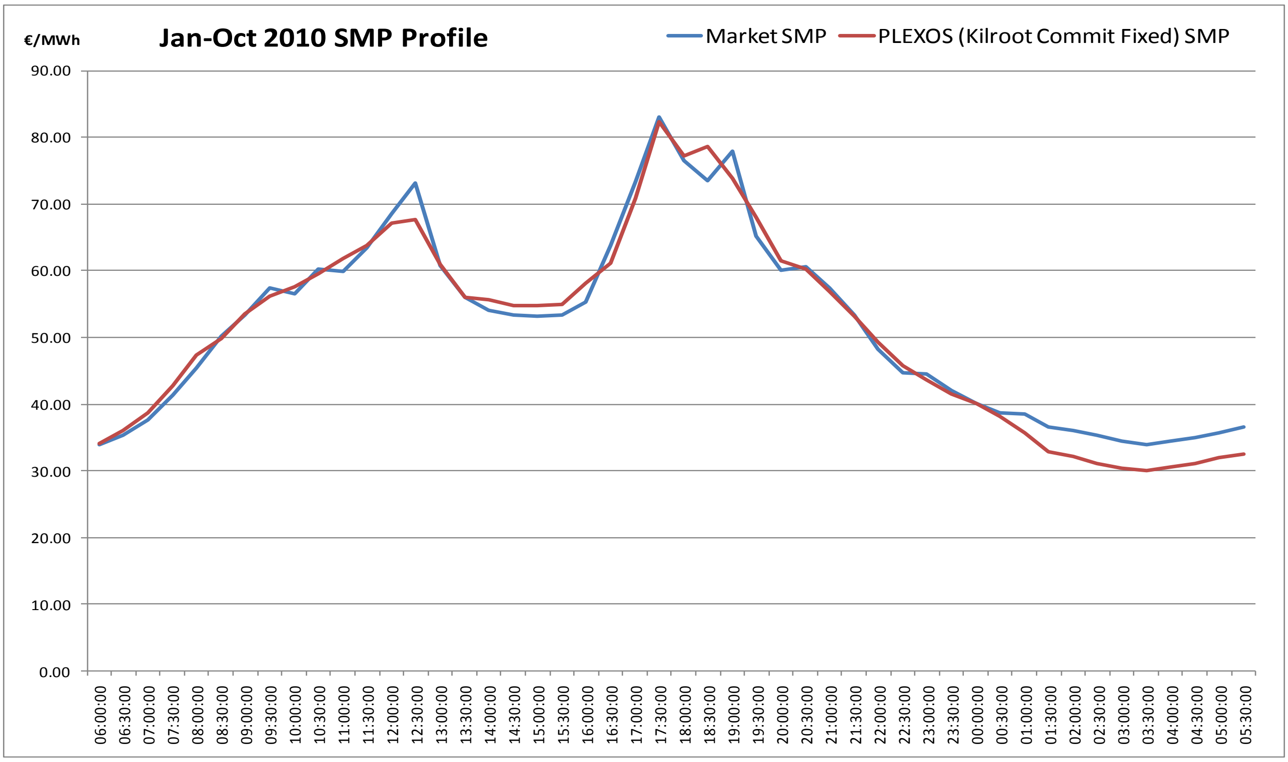


Figure 13

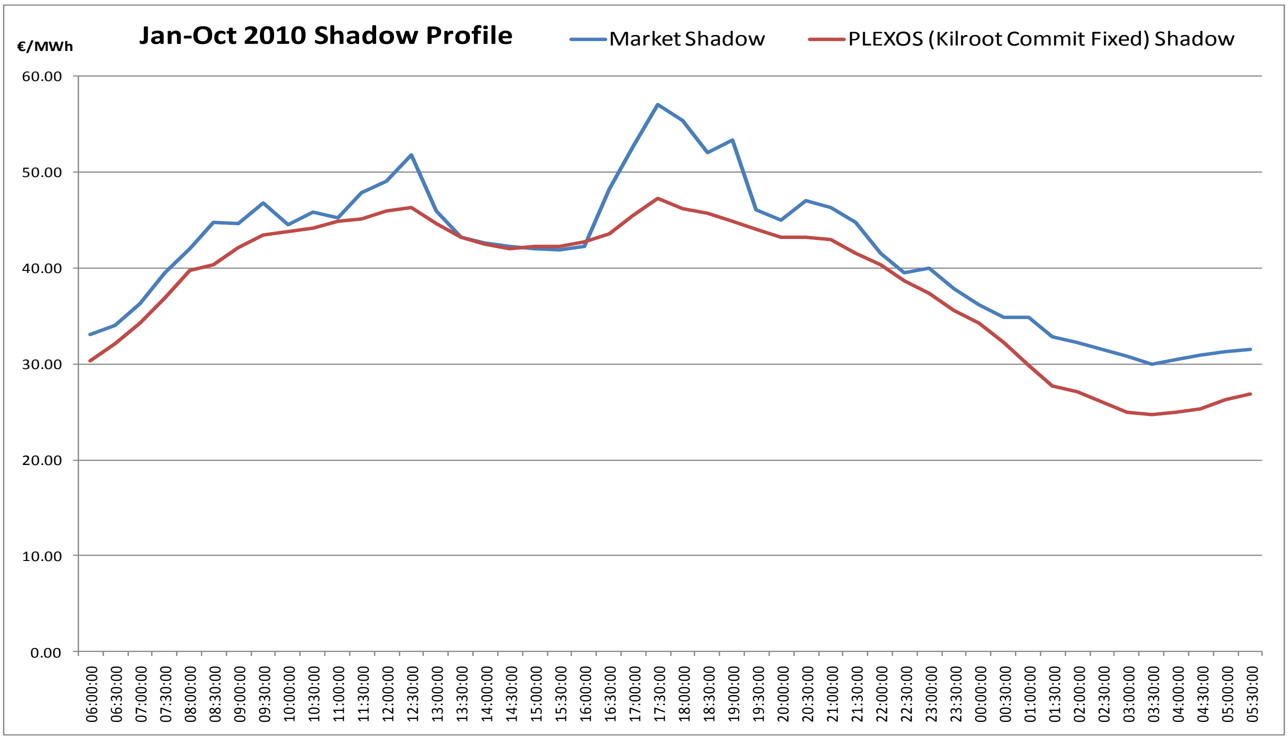


Figure 14

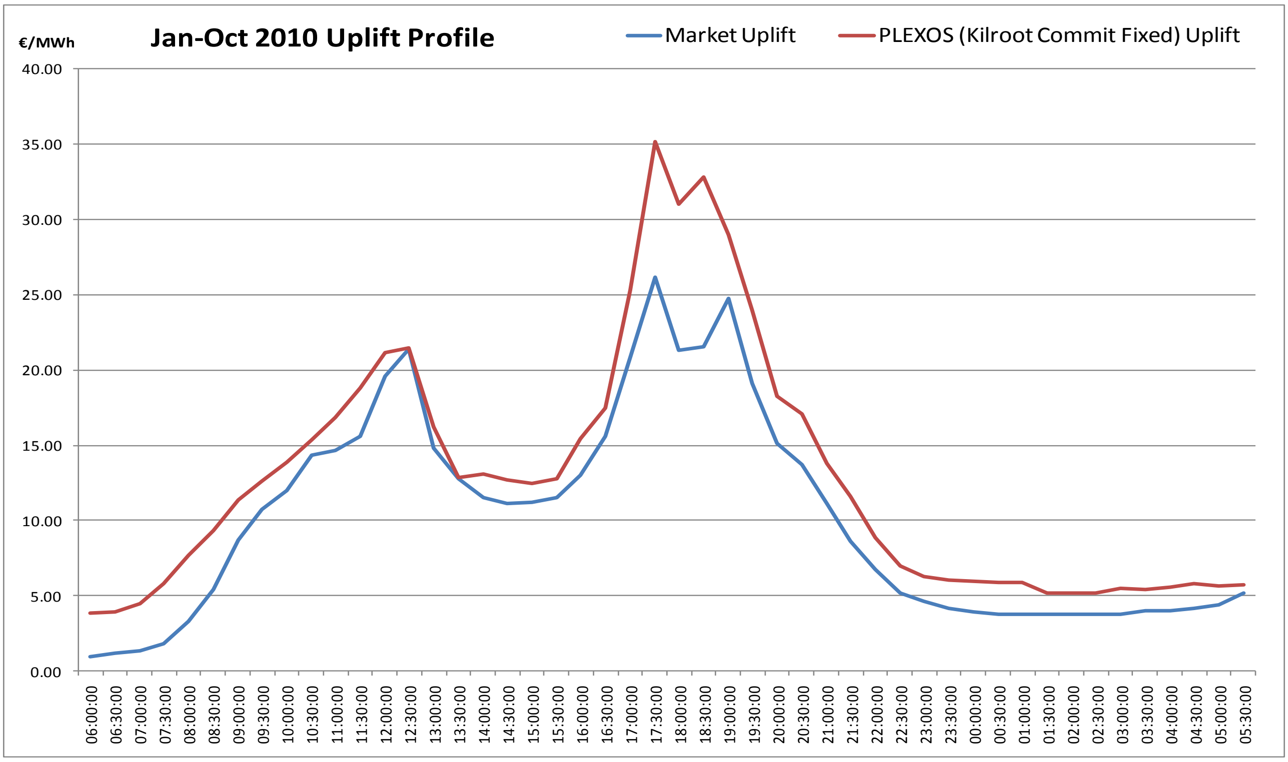
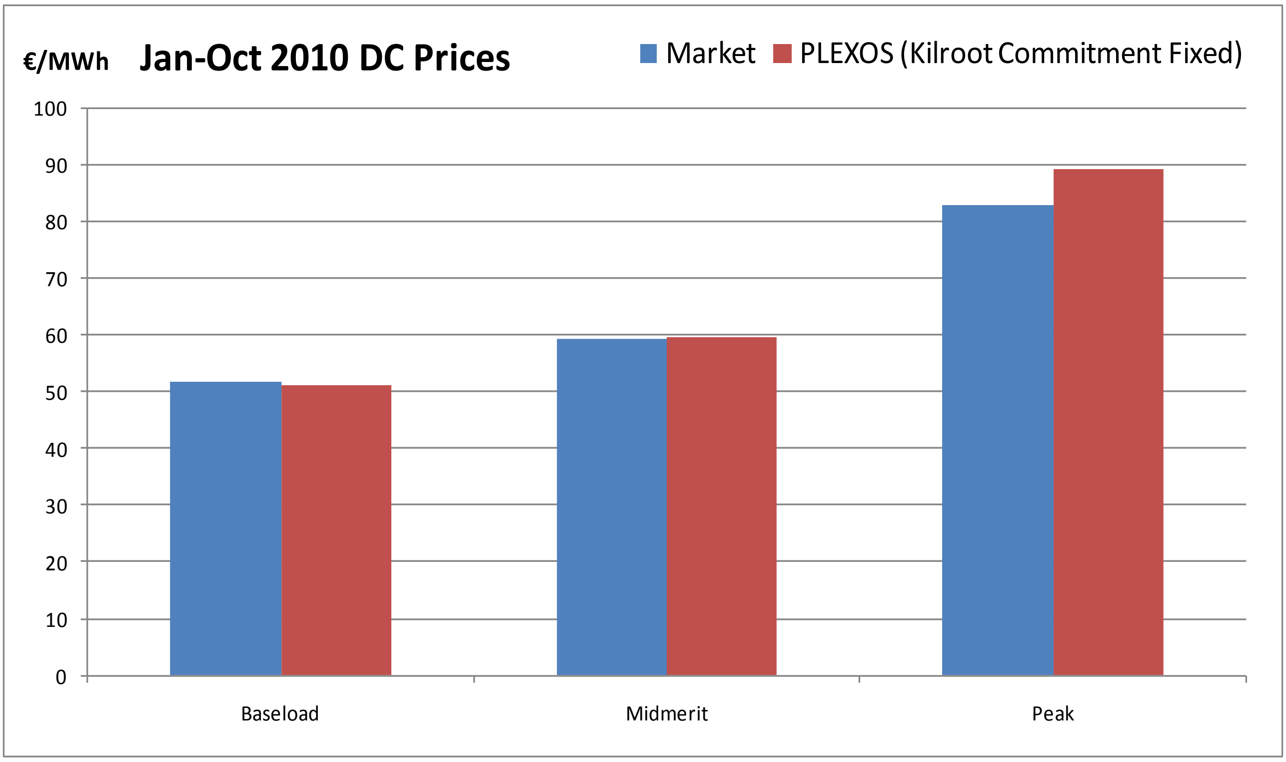


Figure 15 below shows the average levels of SMP across the settlement periods of the three Directed Contract products (Baseload, Midmerit and Peak) over the 10 months. The average Midmerit price from PLEXOS is 0.46% higher than the market outturn and the average Peak price from PLEXOS is 7.7% higher.

Figure 15



Generation

The graphs below compare generation in PLEXOS and historic MSQs in the market by both fuel type and station. Note of course that in this case the commitment of the Kilroot Coal units is fixed to what it was in the market. This leads to the other stations having MSQs closer to their actual market levels.

Figure 16

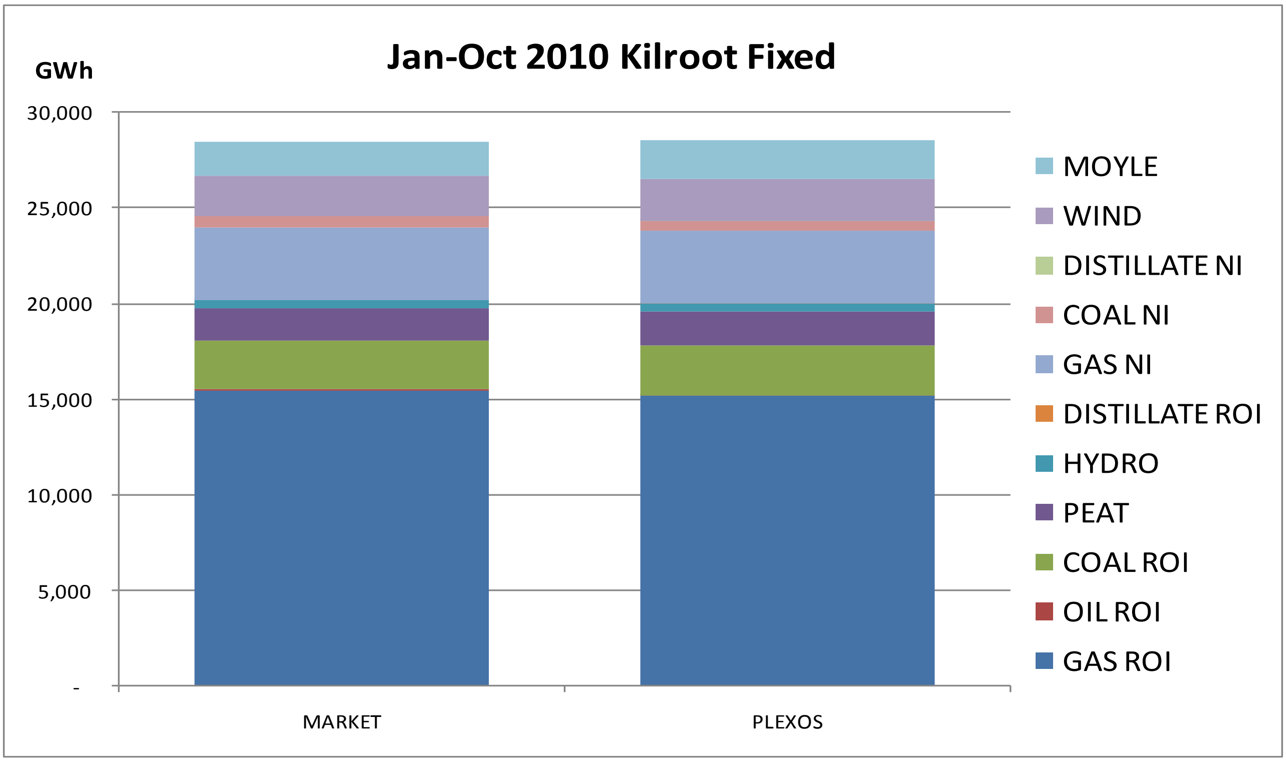
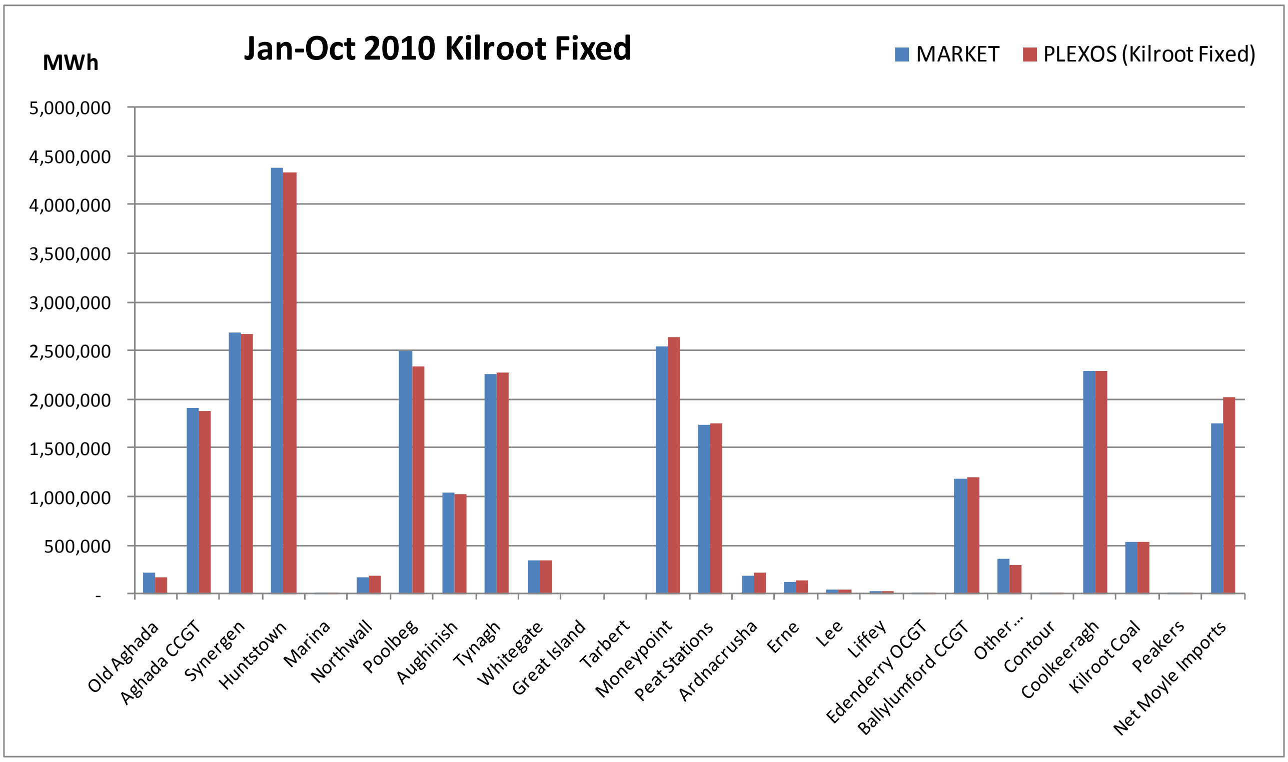


Figure 17



Interconnection

Figure 18 shows the monthly Moyle flows and Figure 19 shows the intraday shape of flows over the 10 months (see section 2.3 for information on interconnector flows). Note that a negative number indicates net flow from GB to SEM.

Figure 18

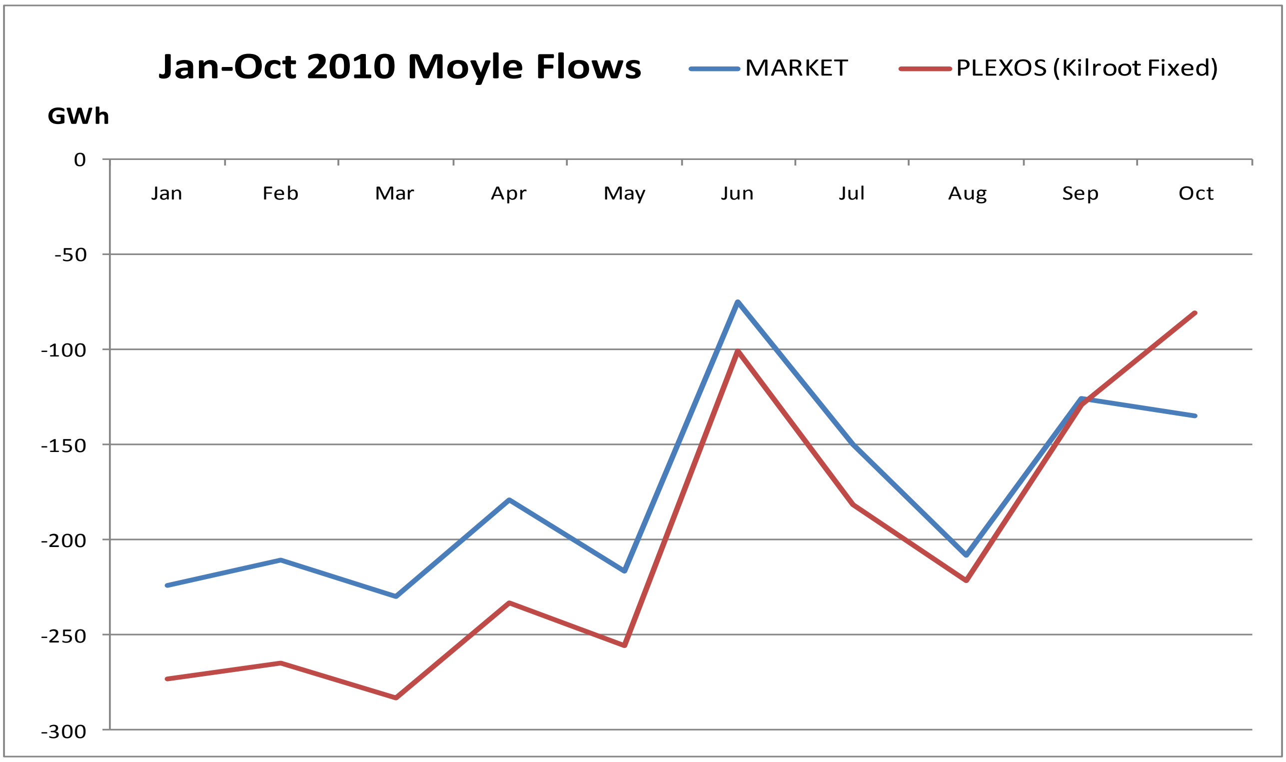
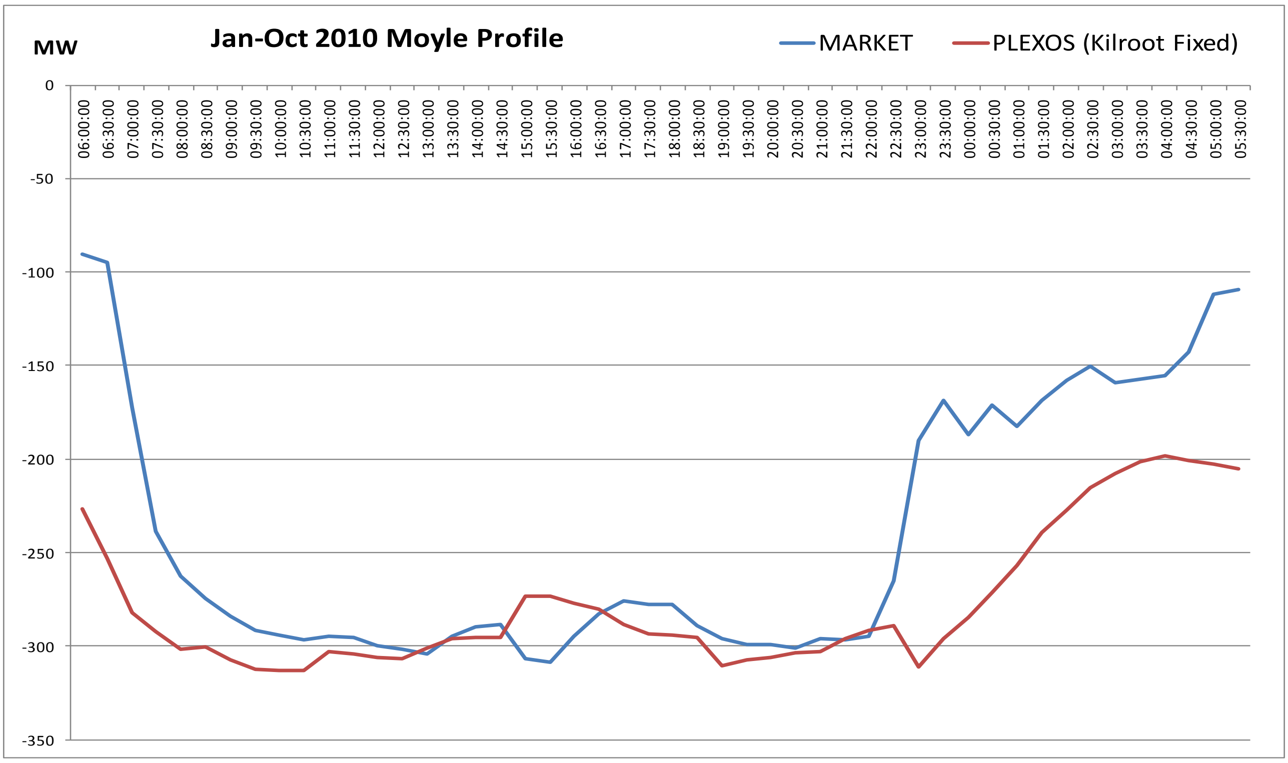


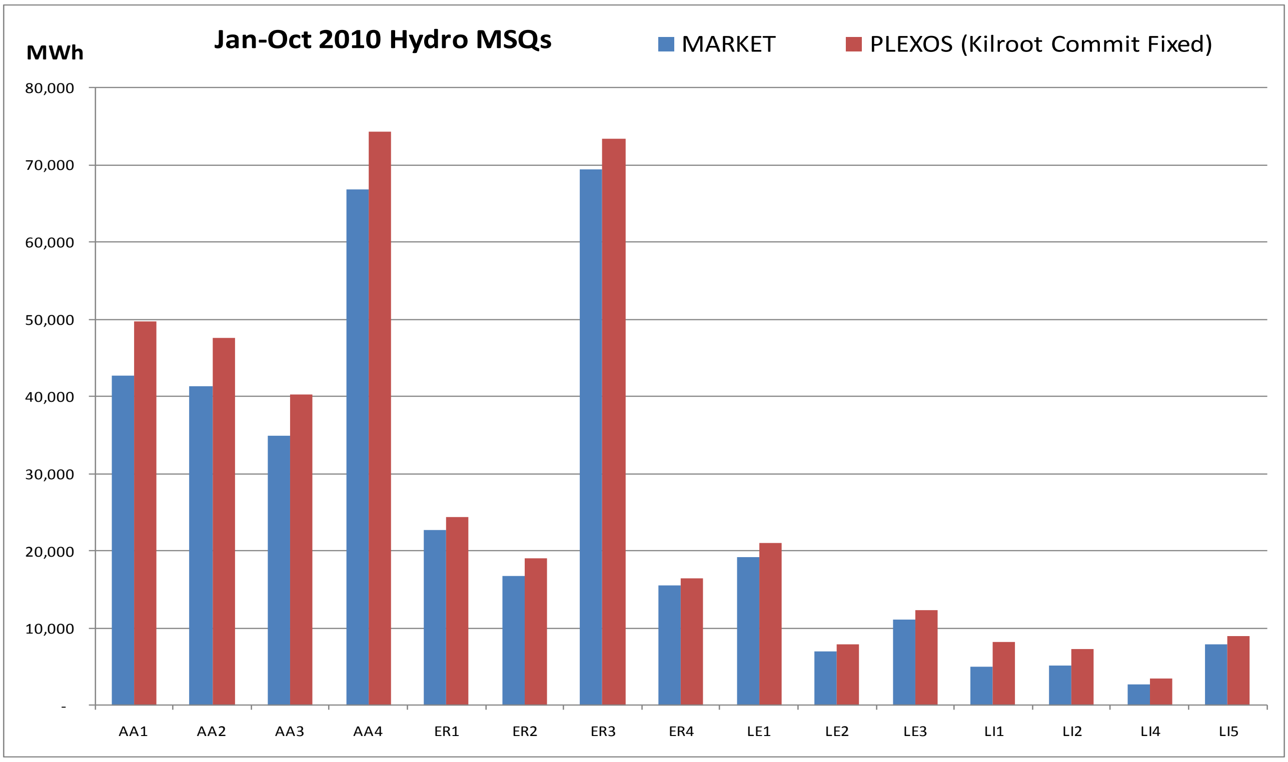
Figure 19



Hydro

Figure 20 shows the generation in PLEXOS and the historic MSQ in the market of the individual Hydro units over the 10 months. When given the actual hydro “daily limits”, as explained in section 2.2.6, PLEXOS schedules the hydro units more than the market does using Lagrangian Relaxation (by approx. 12%).

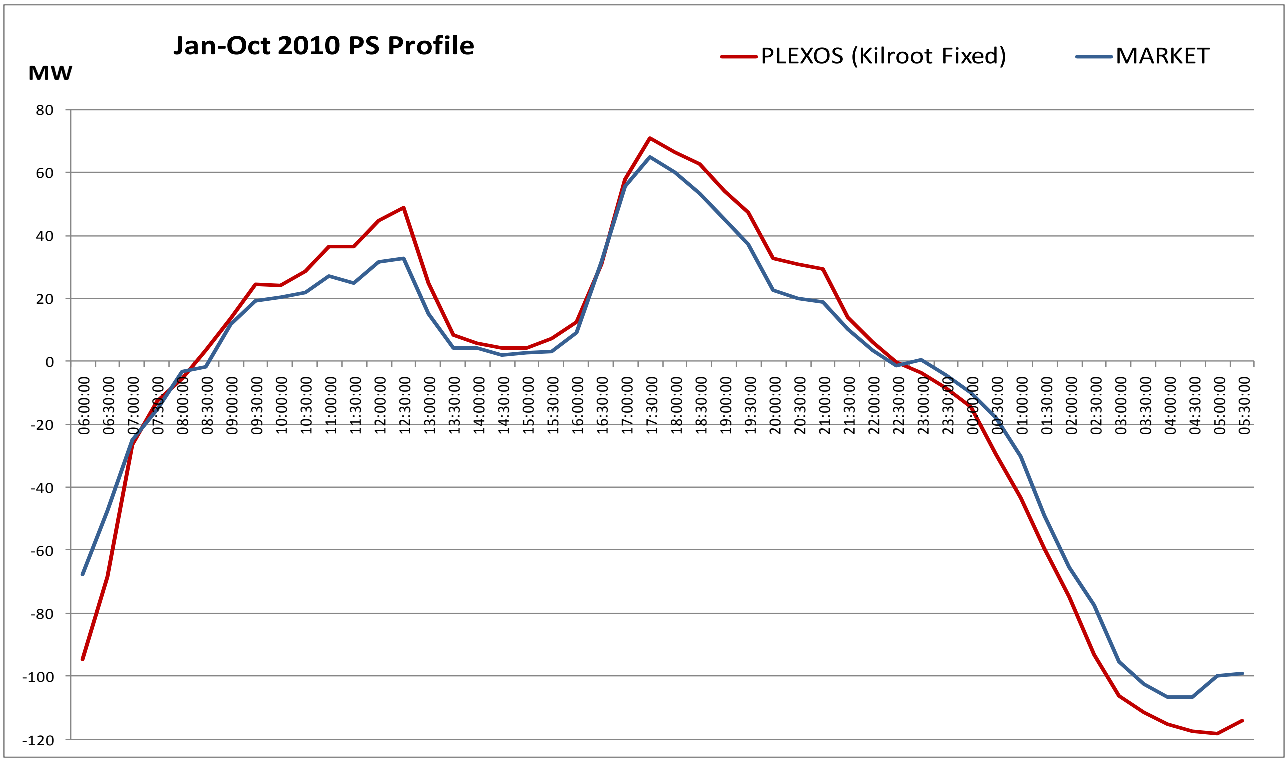
Figure 20



Pumped storage

We have allowed PLEXOS to optimise the pumped storage units, having given it extra data compared to previous validations (as explained in section 2.2.7). Figure 21 shows the intraday shape of the Pumped Storage generation/pumping (up to early July when the station went on outage) in both PLEXOS and the market. The profiles are very closely matched.

Figure 21



2.5.3 November to December 2010

Prices

For November and December 2010, with Kilroot using its new bidding structure, the average SMP from PLEXOS is less than 0.2% lower than the historic SEM outturn price. This is very close and gives confidence that with the Kilroot Coal units using this bidding structure going forward, PLEXOS accurately models the SMP. The graphs below show the intraday shape of SMP, Shadow Price and Uplift over the 2 months.

Figure 22

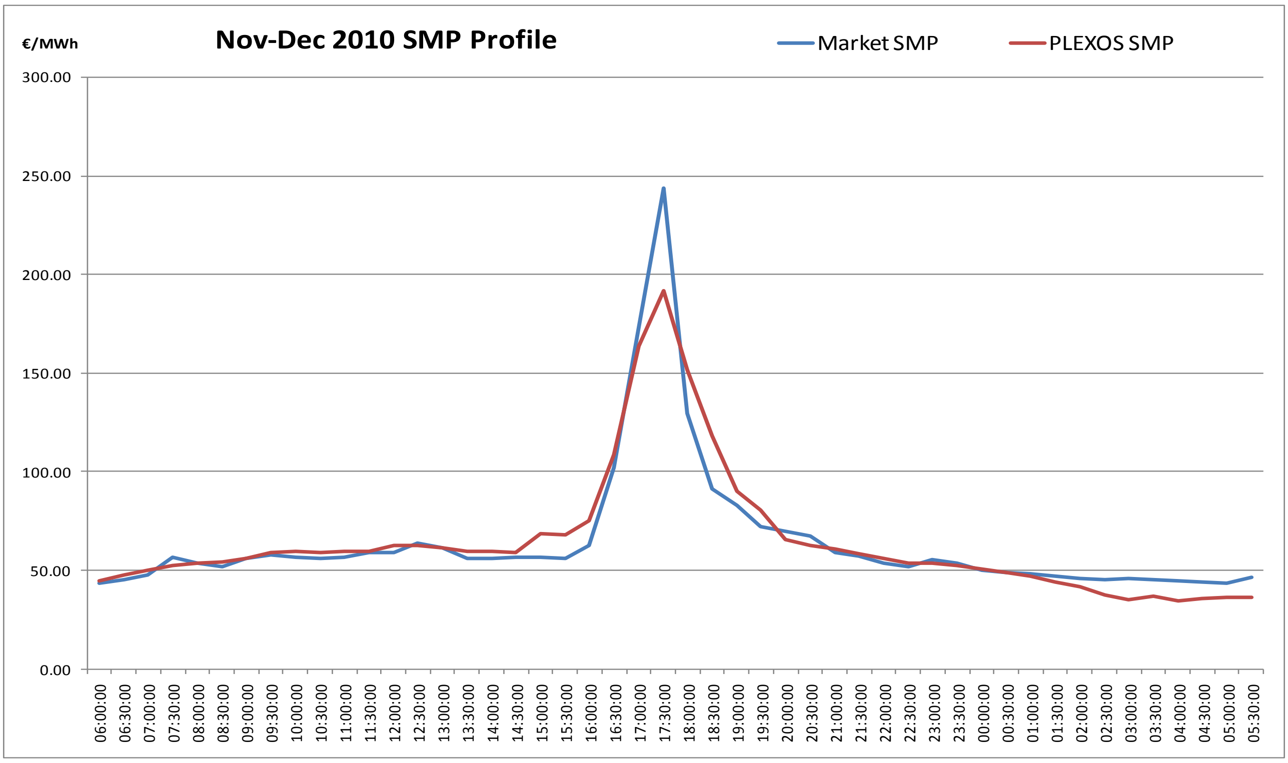


Figure 23

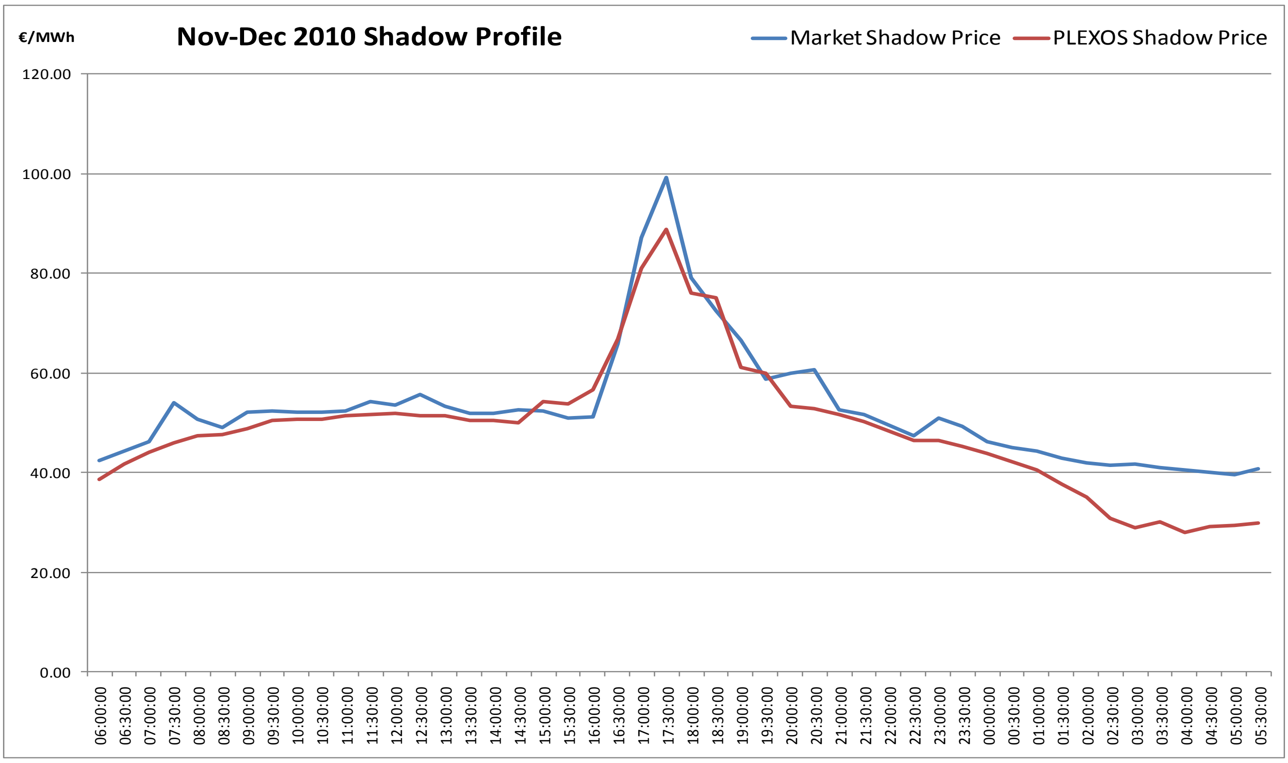


Figure 24

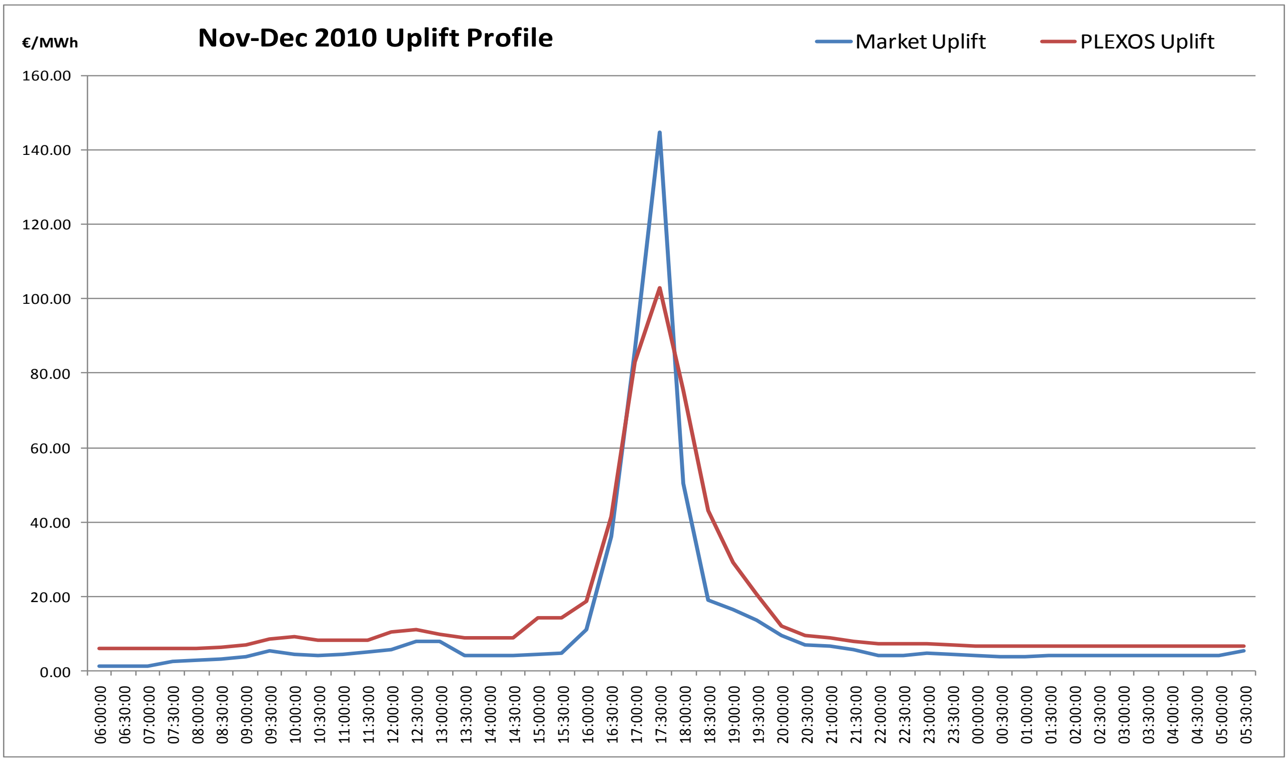
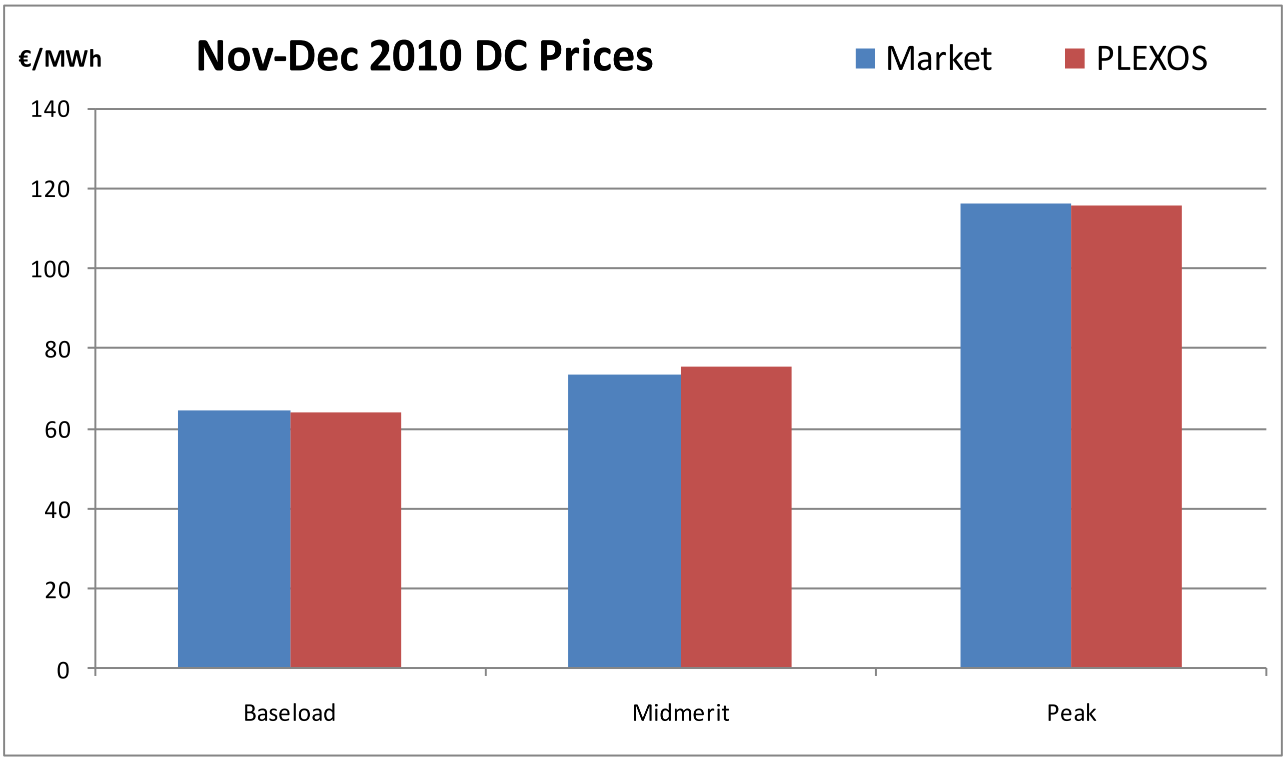


Figure 25 shows the average levels of SMP across the settlement periods of the three Directed Contract products (Baseload, Midmerit and Peak) over the 2 months. The average Midmerit price from PLEXOS is 3% higher than the market outturn and the average Peak price from PLEXOS is 0.7% lower.

Figure 25



Generation

Figure 26 and Figure 27 compare generation in PLEXOS and historic MSQs in the market for the two months by fuel type and station respectively. It shows that generally the PLEXOS and the market results mirror each other closely.

Figure 26

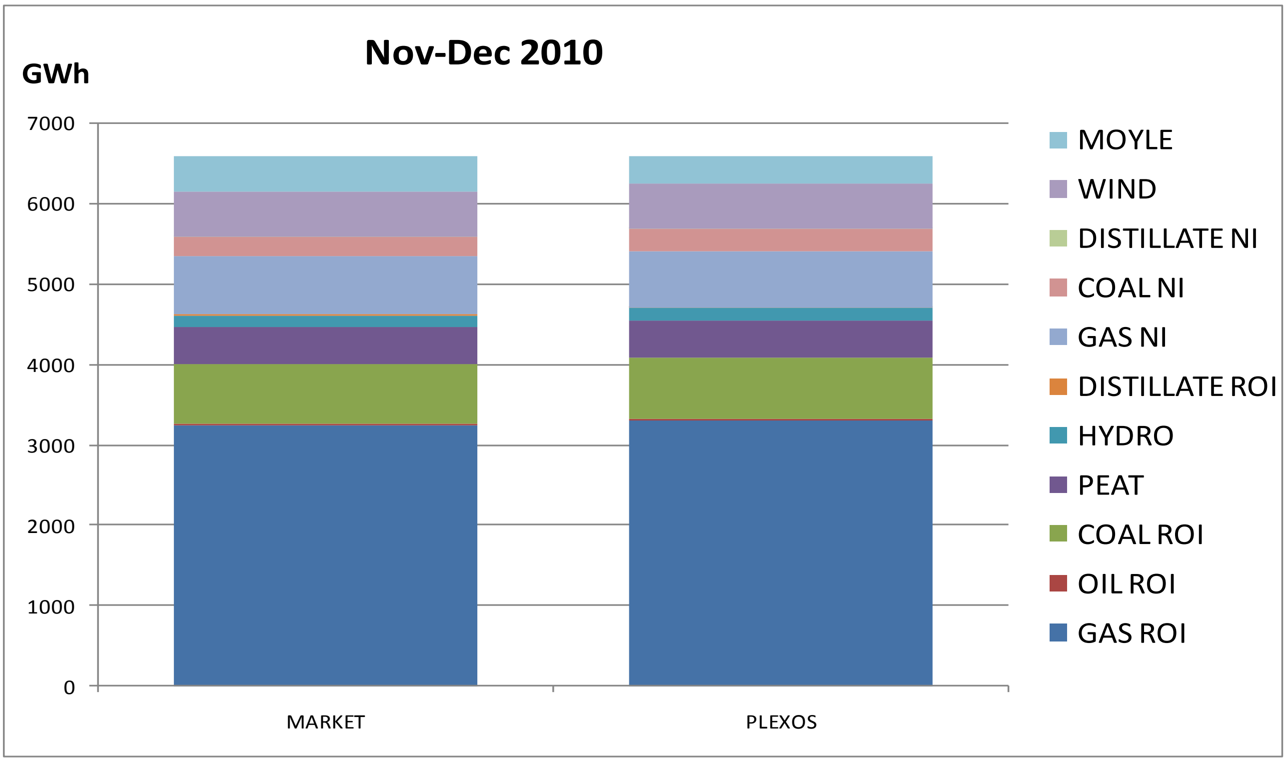
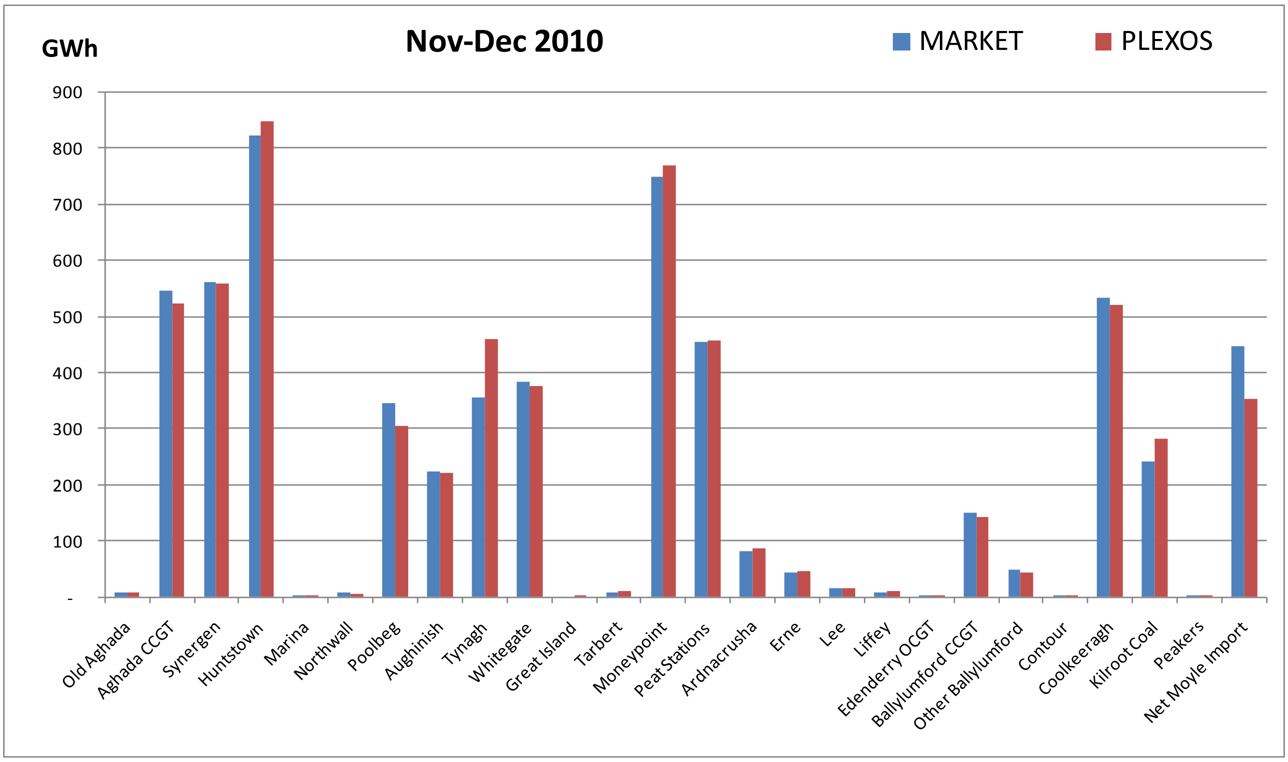


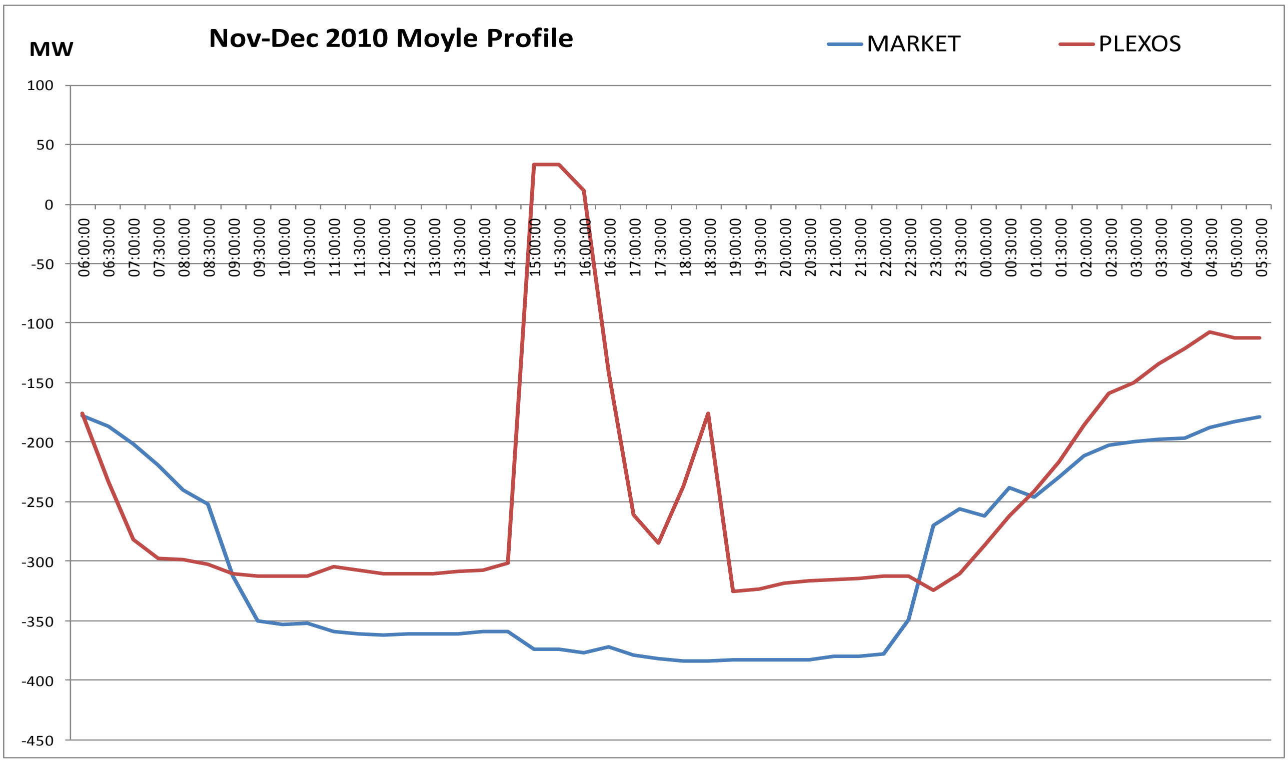
Figure 27



Interconnection

Figure 28 shows the intraday shape of Moyle flows over the 2 months (see section 2.3 for information on interconnector flows). Note that a negative number indicates net flow across a month from GB to SEM.

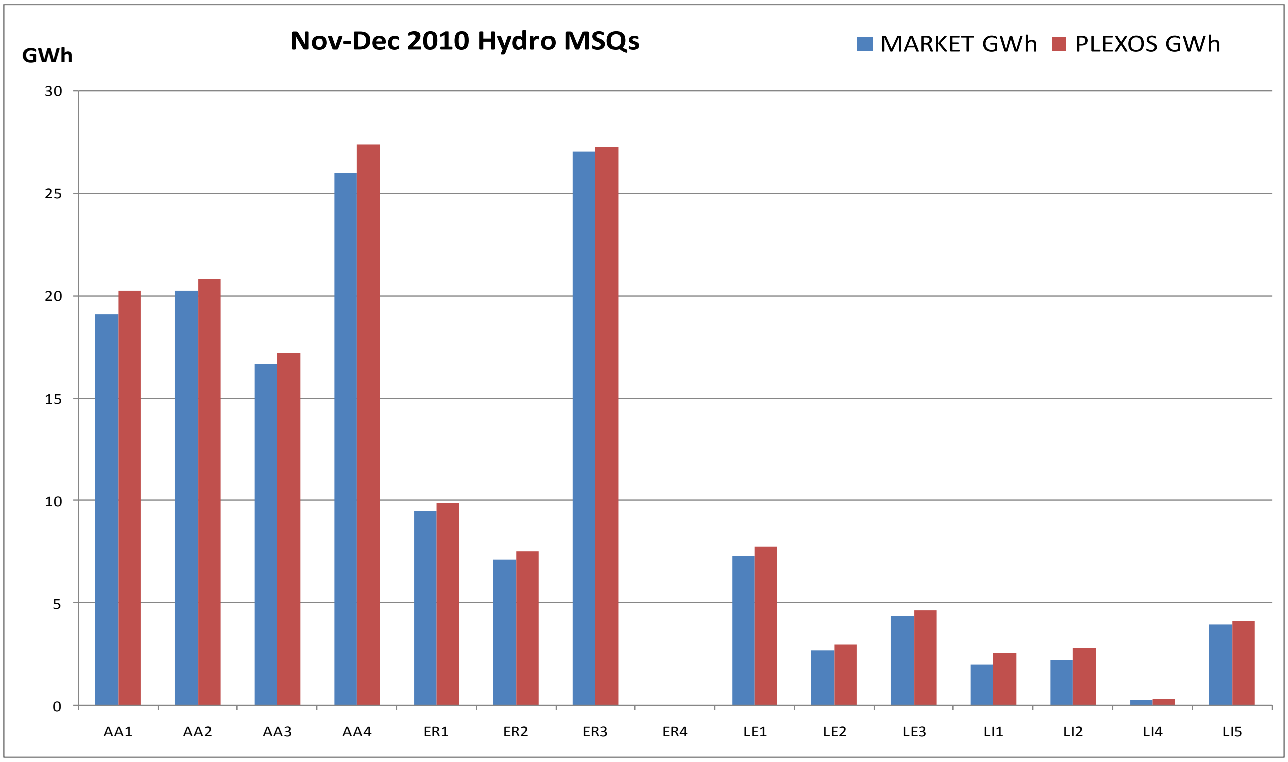
Figure 28



Hydro

Figure 29 shows the generation in PLEXOS and the historic MSQ in the market of the individual Hydro units over the 2 months. When given the actual hydro 'daily limits', as explained in section 2.2.6, PLEXOS schedules the hydro units more than the market using Lagrangian Relaxation (by approx. 5% in these 2 months).

Figure 29



2.6 Sensitivities

2.6.1 Mixed Integer Programming (MIP) vs Rounded Relaxation (RR)

PLEXOS has two methods to solve integer problems – Mixed Integer Programming (MIP) and Rounded Relaxation (RR). MIP is an optimisation process that will return the globally optimal solution if given enough time, whereas RR uses a heuristic to short cut this process. The objective of the model validation process is not to find a theoretically optimal solution but to match as closely as possible, in a reasonable time, the Market Scheduling and Pricing (MSP) software used by SEMO. The MSP software actually uses Lagrangian Relaxation to solve integer problems. This is a different approach again to both the MIP and RR methods in PLEXOS. SEMO do have the capability to rerun the MSP software using MIP, and have done so in the past.

All the results presented in the main results section are runs using RR.

Previous model validation exercises have used RR in PLEXOS 4 and 5. The MIP mode has previously been regarded as too impractical for extended SEM modelling due to its long run times.

As a sensitivity analysis, tests were done with PLEXOS this year using MIP and the Xpress-MP solver. With 'Max Time' set to 300 seconds and 'Relative Gap' set to 0.025%, the run times were approximately 18 hours for January to October 2010 and approximately 5 hours for November to December 2010. These run times are quicker than previous years but remain impractical for modelling a full year. Interestingly, MIP did not suffer the same issue with the Kilroot Coal units as RR did. In fact, MIP actually scheduled the Kilroot Coal units less than they were scheduled in the market.

In terms of SMP, the backcast results using MIP were approximately 2.5% higher than market outturns for January to October 2010 (with free commitment of the Kilroot Coal units) and approximately 2.4% higher than market outturns for November to December 2010. So PLEXOS using MIP does not over-schedule units with high No Load costs and low marginal price components, but does appear to give an SMP that is approximately 2.4% to 2.5% higher than the market, which uses Lagrangian Relaxation.

It is worth noting here that the market operator, SEMO, published a study last year on the use of Lagrangian Relaxation and MIP in the SEM[5]. In this study SEMO solved 170 cases using both Lagrangian Relaxation and MIP and it was found that there was "a tendency towards an increased overall System Marginal Price in the outcomes of the MIP study cases".

2.6.2 Xpress MP versus MOSEK: choice of solver

PLEXOS 6 allows the use of a range of different third party solvers. All the results presented in the main results section are from runs using the Xpress-MP solver (using RR).

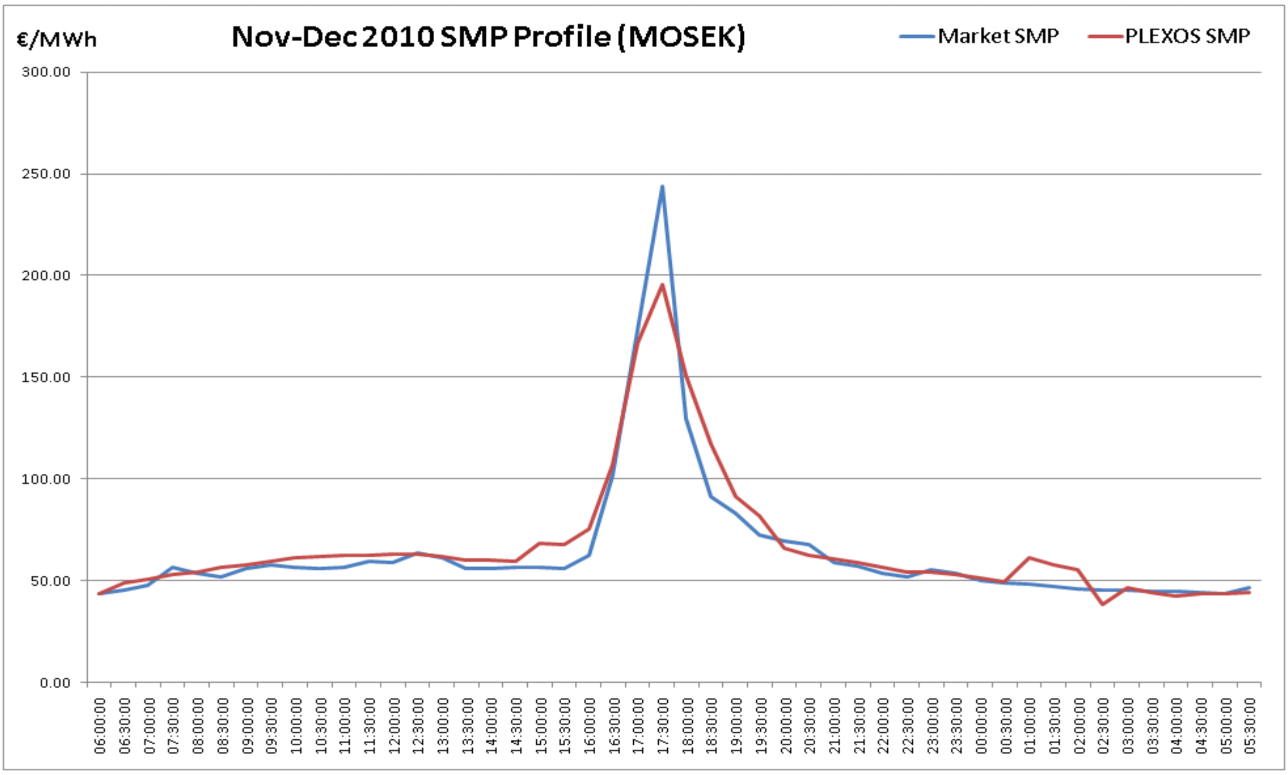
Last year the recommended solver was MOSEK. This year however our tests showed that Xpress-MP gave the better results in the backcast. Xpress-MP also has faster run times. Therefore Xpress-MP is the recommended solver this year.

In terms of SMP, the backcast results using MOSEK and RR were approximately 4.45% higher than market outturns for January to October 2010 (with free commitment of the Kilroot Coal units) and approximately 3.9% higher than market outturns for November to December 2010.

[5] 'Solver Choice in the SEM: A Comparative Study of Lagrangian Relaxation vs. Mixed Integer Programming', available at: http://www.sem-o.com/Publications/General/Solver%20Choice%20in%20the%20SEM%20-%20A%20Comparative%20Study%20of%20Lagrangian%20Relaxation%20vs.%20Mixed%20Integer%20Programming.pdf

Figure 30 below shows the intraday shape of SMP over the months using MOSEK and RR compared to market outturns.

Figure 30



The backcast run times using MOSEK and RR were approximately 18 minutes for January to October 2010 and approximately 4.5 minutes for November to December 2010.

The backcast run times using Xpress-MP and RR were approximately 13 minutes for January to October 2010 and approximately 3 minutes for November to December 2010.

2.6.3 Rounded Relaxation Threshold Setting

The Rounded Relaxation (RR) rounding up threshold is a parameter which controls the commitment of units. A higher value tends to reduce the number of units committed, while a lower value tends to increase the number of units committed. In previous versions of PLEXOS the parameter had a range of 0-10 but it now has a range of 0-1, in steps of 0.01 (i.e. it now has one hundred steps rather than 10 as before. Tests were done on a number of values for the RR threshold. A setting of 0.25 gave results closest to market outcomes and so this value is recommended.

2.7 Other PLEXOS Settings

2.7.1 Uplift Settings

The Uplift MSL filter prevents PLEXOS from setting uplift units that are at Minimum Stable Level (MSL) over the entire course of a contiguous period of operation. This means that if PLEXOS schedules a unit to run at its MSL only, then the uplift algorithm will not include the costs of that unit when calculating uplift. The Uplift Ramping filter does the same for units that are "ramping". Tests were done with these filters off and the results were found to be further from the actual market outcomes. So all results presented in this report are from runs where these filters were set to be on, and it is recommended to keep these filters on.

The Uplift Cost Basis must be set to "bid based" for the backcast. This ensures that the uplift computation in PLEXOS is based on submitted offer data. It must be set to "cost based" for the forecast model. This ensures that the uplift computation is based on heat rates, start fuel offtakes and delivered fuel prices.

2.7.2 3 State Start Costs

In previous years it was recommended that only warm start costs be used. However this year, due to improvements to the PLEXOS Rounded Relaxation algorithm, tests showed that PLEXOS can now handle 3 start costs. It was decided therefore to move to 3 start costs as this is exactly what is provided to the market engine.

3 Validation of the Forecast model

3.1 Forecast model

In order to model SMP and other market outcomes for the last quarter of 2011 and the whole of 2012, a validated forecast PLEXOS model is required, based on various assumptions for this period and using the calibrated backcast model configuration (discussed in section 2). Whereas the calibrated backcast model uses detailed historic data, the forecast model is necessarily based on more general assumptions and up-to-date information provided by market participants. The differences in detail and type of data available lead to specific differences in the model set up, described in Table 3.

Table 3 PLEXOS backcast and forecast model set up

Item	Backcast model	Forecast model
Demand	Uses Actual	Uses forecast assumptions
Max capacity	Uses Actual Availability	Uses submitted max capacity
Availability	Uses Actual Availability	Uses planned outage schedules and forced outage rates
Commercial Offer Data:		
Offer/quantity pairs	Historic market data used directly	Calculated from Incremental heat rates/load points, delivered fuel prices, VOM charges and TLAFs
No load costs	Historic market data used directly	Calculated from no load heat rates, delivered fuel prices, VOM charges and TLAFs
Start costs	Historic market data used directly	Calculated from offtake at start, €/start VOM and TLAFs
Pumped Storage	Optimised by PLEXOS	Optimised by PLEXOS
Hydro	Optimised within day based on actual daily output	Optimised within day based on assumed daily output
Wind	Generation at actual output	Availability based on typical half-hourly output profile
Predictable Price Takers	No Commercial Offer data used	No heat rates, start costs etc used
Interconnectors	Representative GB price series based on historic spot gas and carbon prices	Representative GB price series, using calibrated parameters from the backcast exercise

3.1.1 Data and assumptions required

The types of data and assumptions required and the providers of this data are shown in Table 4.

Table 4 Data and assumptions required

Data/Assumption	Provider/Source
Generator data: • Heat rates • Technical parameters • Forced outage rates • Start fuel offtake • Start and VOM costs	Generation companies
New entrants and retirements	System Operators and generation companies
Planned outage schedules	System Operators
Embedded generation	System Operators
Half hourly demand assumptions	System Operators
Wind capacity and half hourly wind profiles	System Operators
Daily Hydro Availability limits	System Operators
Pumped Storage limits	Published historic market data
Transmission Loss Adjustment Factors	Published values for 2011
Interconnector capacity and scheduled outages	System Operators
Delivered fuel prices [Adjustments from index to delivered]	Public sources where available, and contact with generation companies where required/appropriate

The following sections describe the validation process in more detail.

3.2 Generator Data

3.2.1 Validation process

On 17th December 2010 the RAs commenced the forecast validation process by sending each generation company the previous year's validated data for their units. The RAs asked the generation companies to review the data and provide updates where required with explanations. The RAs then proceeded to validate the updated generator data received through the following stages:

- The first stage was to analyse the changes and iterate with generators on their explanations of these changes.
- The second parallel process was to compare data received to historic market data where possible. The RAs calculated the "theoretical" Commercial Offer Data that would have been submitted on the basis of incremental heat rates, no load heat rates, and starts costs, together with historic fuel and carbon prices. By comparing these "theoretical" offer structures to actual market submissions, we were able to identify anomalies in the submitted data. We also compared submitted parameters between groups of similar SEM units.

In a number of cases we found certain parameters that appeared to be anomalous or inconsistent in some way. Through further contact with the generators we were in all cases able to resolve these situations in conjunction with the generators.

3.2.2 Key validation results

In Table 5 we have indicated some of the types of changes that have been made for certain parameters since the last validation exercise, the reasons for them, and examples of affected units. The changes made were agreed with generators.

Table 5 Generator data changes

Property	Materiality of changes	Example of reason for change	Units affected
Start Fuel	High – significant changes	Change of bidding structure based on technical review	Kilroot Coal Units 1&2
Max Capacity and MSL	Minor to Medium changes,	Generally based on change in latest knowledge, e.g. unit upgrade, technical review, unit has come into operation since last validation or about to come into operation	Kilroot 1,2, GT3 &4; Moneypoint units 1-3; Tynagh CCGT; Aghada CCGT, unit 1 & CT1; Dublin Bay CCGT; Huntstown CCGT; Coolkeeragh CCGT; Tynagh CCGT; Whitegate CCGT; Northwall unit 5; Cushaling unit 3 &5; Great Island unit 3; Marina; Rhode unit 1& 2; Tawnaghmore units 1 & 2; Ardnacrusha unit 1-4; Liffey unit 4; Lough Rea; West Offaly Power; Contour Global units 1-2.

Ramp rates	Mostly Minor changes to few medium	Technical review, Consistency with market submissions	Aghada CCGT & unit 1; Coolkeeragh CCGT; Kilroot 1&2, Moneypoint units 1-3; Poolbeg CCGT; Tynagh CCGT; Great Island units 1-3; Tarbert units 3-4; , Lee unit 2-3; Lough Rea; West offaly Power; Contour Global units 1-2
Min Up/Down	Minor changes, low materiality	Technical review, Consistency with market submissions	Aghada CCGT Kilroot 1&2, Marina; Contour Global units 1-2
Heat Rates: Capacity points	Low, generally minor updates	Technical review	Aghada CCGT Coolkeeragh CCGT Dublin Bay CCGT Kilroot 1&2, Moneypoint 1 – 3 Poolbeg CCGT Tynagh CCGT Whitegate CCGT North wall 5 Cushaling units 3 & 5 Aghada 1, AT 1 - 4 Great Island –3 Marina, Rhode 1 - 2 Tarbert 1 – 4 Tawnghmore unit 1 & 3, Lough Rea, West Offaly Power; Contour Global units 1-2
Heat Rates: No load and incremental	Low to significant, generally minor updates	Technical review (Conversion to LHV basis)	Aghada CCGT, Coolkeeragh CCGT, Moneypoint 1 – 3, Poolbeg CCGT, Tynagh CCGT , Whitegate CCGT, Balylumford Units 4-6, North wall 5, Marina, Aghada 1, AT 1 – 4, Lough Rea, West Offaly Power
Forced outages/ mean time to repair	Minor to medium revisions	Latest data based on technical review	Aghada CCGT Coolkeeragh CCGT Dublin Bay CCGT Moneypoint 1 – 3 Poolbeg CCGT Balylumford Units 31-32, GT1-2, Balylumford Units 4-6, North wall 5 Marina, Ardnacrusha unit 1-4 Aghada 1, AT 1–4, Erne unit 1-4 Lee unit 1-3 Liffey unit 1-5 Thurlough Hill units 1-4 Edenderry Lough Rea,

			West Offaly Sealrock unit 3-4
Start energy	Medium to Significant	Latest data based on technical review	Kilroot 1&2, Tynagh CCGT, Whitegate CCGT Ballylumford units 31 & 32
Boundary times	3 warm starts are used for the first time in a number of years.	Technical review, and a number boundary times were previously submitted cumulatively (hot to cold) instead of incrementally (warm to cold)	Aghada CCGT Dublin Bay CCGT Moneypoint 1 – 3 Poolbeg CCGT Tynagh CCGT, Whitegate CCGT, North wall 5 Marina, Ardnacrusha unit 1-4 Aghada 1, AT 1–4, Erne unit 1-4 Lee unit 1-3 Liffey unit 1-5 Thurlough Hill units 1-4 Lough Rea,
Start costs	Confidential data	Updated for consistency with Commercial Offer Data	Confidential data
VOM	Confidential data	Updated for consistency with Commercial Offer Data	Confidential data
Markups	Confidential data	Updated for consistency with Commercial Offer Data	Confidential data

3.2.3 New entrants and retirements

Generators anticipated to enter and exit the market during the forecast period are indicated below. We asked new participants to provide the same set of unit parameters for these new units as we requested for existing units. Generally the submitted data for these units is necessarily based on expected unit characteristics rather than actual operation experience. Wind generation is detailed in section 3.2.6.

Table 6 New generation units

Unit name	Fuel	Assumed Commissioning date	Capacity (MW)
Contour Global Unit 3	Gas	Sept-10	3
Meath Waste-to-Energy	Waste	Sep-11	17

3.2.4 Confidential data

As in previous years, a number of participants marked certain data items as confidential. These were start costs (in €/start) and Variable O&M costs and mark-ups (in €/hr and €/MWh).

3.2.5 Market data & assumptions

Demand

Annual and peak electricity demand assumptions in ROI and NI were provided by the System Operators, based on SONI's and EirGrid's median demand forecast from the All-Island Generation Adequacy Report 2011-2020[6][7]. Average SEM demand is assumed to increase by 0.2% from 2010 levels in 2011, and then increase by 1.7% in 2012. The assumptions are shown below.

Table 7 Annual and peak demand assumptions

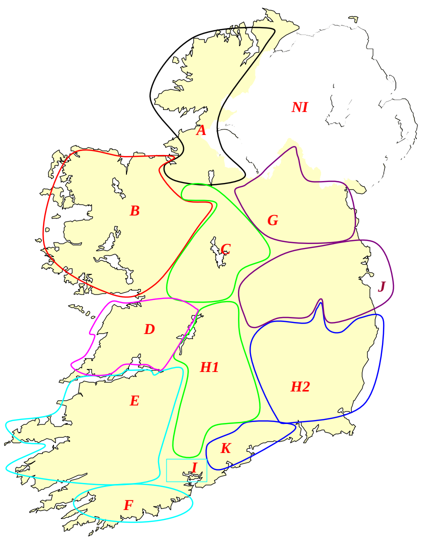
Year	Annual demand (GWh)			Peak demand (MW)		
	ROI	NI	SEM	ROI	NI	SEM
2011	27,345	9,029	36,316	4,722	1,688	6,380
2012	27,897	9,103	37,000	4,810	1,707	6,486

The demand is mapped to half hours based on the historic half hourly load shape in ROI and NI from 2007. The load shapes for the subsequent years were not deemed suitable as the shape was heavily skewed compared to typical demand profiles, due to the impact of the economic crisis reducing demand.

3.2.6 Wind

Wind is modelled in aggregated form, split into the 12 regions shown in Figure 31. Each region has an associated half hourly profile which represents the wind availability in that region in each half hour, as a percentage of total installed capacity in that region.

Figure 31 Wind regions[8]



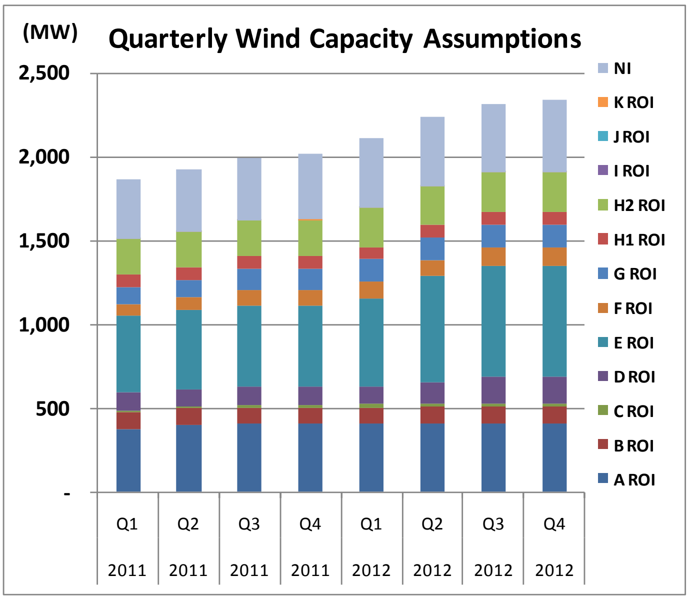
The installed capacity assumptions for each region change quarterly based on agreed connection dates (Figure 32). These figures include both Transmission- and Distribution-connected (Embedded) wind.

[6] Note that Eirgrid's GAR annual demand assumptions are based on a 52-week year. Therefore PLEXOS modelled values are slightly higher than the GAR published values.

[7] http://www.eirgrid.com/media/GCS%202011-2020%20as%20published%2022%20Dec.pdf

[8] [Picture provided by Eirgrid]

Figure 32 Quarterly wind capacity assumptions



3.2.7 Embedded generation

The ROI demand assumptions include demand met by embedded generation and so an estimate of output from embedded generation must be included in the model. This estimate excludes embedded wind, which is included in the wind capacity assumptions. For ROI, the embedded generation follows an hourly profile which is different for weekdays and weekends. The output varies in the range from approximately 89 to 123 MW in 2011 and from 93 to 129 MW in 2012.

The NI demand profile is net of generation from embedded/Small Scale Generation, and therefore an embedded generation profile is not required.

3.2.8 Transmission Loss Adjustment Factors (TLAFs)

The latest available TLAFs, those for 2011, have been used for the validated period in question. This model now applies TLAFs to both No-load and Start up costs in addition to the incremental costs of generators. This follows a recent change to the market rules and systems that now require this to be incorporated into generators bids. There is an XML file, PLEXOS_Param.xml, included with the forecast model which allows for TLAFs to be applied to all three properties.

3.2.9 Outages

SEMO provided a planned outage schedule for large thermal generation units for 2011 and 2012. Forced (unscheduled) outages in the model are based on the forced outage rates submitted by generators.

3.2.10 Hydro availability

Hydro availability is modelled with a daily energy limit, applied across the units that comprise each of the four hydro schemes. This energy limit varies by month, and we validated that the monthly shape reflects historic monthly output. The forecast PLEXOS model optimises the dispatch of hydro units subject to this constraint.

3.2.11 Interconnector capacity and scheduled outages

Moyle

Based on the data provided by the System Operators, the RAs set the capacity of Moyle to import to SEM as 450 MW in the winter and 410 MW in the summer (April –October inclusive), and 80

MW[9] all year for export to GB. Planned outage assumptions were provided by the System Operators and checked against the data published on the Mutual Energy website.

East-West

This interconnector is set to due to commence commercial operation in September 2012, connecting Ireland to Great Britain (Wales). Based on data provided by the System Operators, the RAs set its capacity to import to and export from the SEM as 500 MW to GB.

3.2.12 Delivered fuel prices

The forecast model requires delivered fuel cost assumptions. These are built up outside the PLEXOS model based on:

- fuel price indices
- carbon price index
- currency conversions
- carbon emission rates for each fuel, and
- other adders, e.g. for transport costs or excise tax

The RAs have changed a number of the fuel and carbon price indices from previous years as used in this year's Directed Contracts pricing formula. These sources include:

Table 8

Fuel	Source
Gas	ICE
Coal	Argus
Fuel oil	Reuters
Gasoil	Reuters
Carbon	ICE

The 2011-12 Directed Contracts subscription rules[10] provide the detailed references for each of the fuels. These index values must be converted to delivered fuel prices for PLEXOS. A spreadsheet showing an example of these conversions was published alongside the forecast model.

The transport and excise adders are based on publically available data where possible, or on confidential data where this is more appropriate. Only the aggregate adders for each fuel will be published alongside this report.

3.2.13 Priority dispatch and non-firm capacity

The general approach in SEM PLEXOS modelling to date has been to model wind at zero price on the assumption that it will always run when available, due to its "priority dispatch" status.

As last year, we note that the installed wind capacity in SEM is increasing and is beginning to have the potential to create situations where wind output could be close to the level of demand (e.g. in overnight periods). In the market schedule, very little thermal generation is required in these periods; however in the preceding and following shoulder and peak time periods the requirement for conventional thermal generation may be much higher. Due to the start costs of thermal units, the PLEXOS model solution might reduce wind generation rather than turning off a thermal unit and restarting it later, in order to minimise costs.

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[9] The export capacity of Moyle has subsequently been increased to just under 300MW for 2011.

[10] http://www.allislandproject.org/en/market_decision_documents.aspx?article=c9e3a4bc-f41e-463d-b247-408ea8bd136b

However in the validated forecast model, we found this to be of limited impact – wind generates at over 99.5% of the available energy.

4 Conclusion

The backcast modelling provided the validation of the PEXOS software against market outcomes in the SEM, with differences in SMP of

- less than 1.2% over January to February 2010 with Kilroot Coal commitment fixed; and,
- less than 0.2% over November to December 2010.

The MSQs between PLEXOS and SEM for these periods/approaches were also generally similar. Hence the backcast PLEXOS model has been appropriately calibrated for use in the forecast period. The RAs are also confident that the dataset used in building the forecast model provides a reasonable and consistent representation of the market for Q4 2011 and 2012.

The following section summarises the key changes in the 2011-12 validated model from the previous year's model.

4.1 Main Model Approaches/Changes

4.1.1 PLEXOS Software

The RAs have validated the 2011-12 SEM model using the PLEXOS software version 6.201 R22 and the Xpress MP solver.

4.1.2 Unit Commitment

The RAs have selected to use Rounded Relaxation, as in previous years, as the form of unit commitment. The validated setting is 0.25.

4.1.3 Treatment of Interconnectors

The RAs have chosen to model the interconnector flows, through the use of a representative Great Britain generator and demand, similar to last year's model. This includes the use of wheeling charges to capture the differences between Great Britain prices and the bidding behaviour of Interconnector users. The addition of the new interconnector between Ireland and Wales, the East West interconnector, is included from September 2012.

4.1.4 Start States

This validated model, using the above mentioned version of PLEXOS, utilises all 3 start states. This is a change to the last number of validations, where only a single warm start was used.

4.1.5 TLAFs

In this model TLAFs will be applied to generator start and no-load costs, in line with recent changes to the market rules.

4.1.6 Price Takers

Aughinish Alumina has been included with the existing Price takers in the model, without the use of heat rates, VOM or start up costs.

4.1.7 Confidential data

As with previous years, Variable Operation and Maintenance (VOM) costs are considered to be confidential by a number of generators and are excluded from the published model. We recommend that users of the model incorporate their own estimates as they see appropriate.