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Market Simulation Data & Model Validation

Final Report

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Executive Summary

The Regulatory Authorities require a model to simulate the operation of the SEM for use in the pricing and quantification of directed contracts, to support the calculation of annual capacity payments, to support the review of tariffs, to support market monitoring, and for other purposes. The PLEXOS model was selected by the Regulatory Authorities as the choice of simulation software, and the use of the PLEXOS model – including settings, data and other assumptions – was validated by the Regulatory Authorities for use in the initial 11 months of SEM operation, prior to the SEM market opening in 2007.[1]

The Regulatory Authorities commissioned NERA Economic Consulting (NERA) to validate the use of the PLEXOS model to simulate electricity prices (System Marginal Prices or SMPs) in the SEM for the period October 1 2008 to December 31 2009.

The assignment comprises three tasks:

1) Validation of PLEXOS input data for the period October 1 2008 to December 31 2009;

2) Calibration of PLEXOS results against actual SEM market outcomes for the period November 1 2007 (the opening date of the SEM) through February 2008; and

3) Provision of recommendations regarding how PLEXOS might best be run to model the SEM for the period October 1 2008 to December 31 2009 in light of the outcomes of tasks 1 and 2.

A summary of our conclusions follows.

Regarding the validation of PLEXOS input data for the period October 1 2008 to December 31 2009: in light of the calibration exercise that has been completed and the fact that the input data have been verified and that fuel prices will be updated to reflect the current forward market conditions, NERA is confident in the use of the forecast database, which consists of generator data, system data, and fuel data, to produce realistic forecasts of the SEM.

Regarding the calibration of PLEXOS results against actual SEM market outcomes for the period 1 November 2007 to 29 February 2008: NERA found that with the settings NERA recommends, PLEXOS produced reasonable and unbiased SMP results for the backcast period. NERA has identified that PLEXOS produces higher uplift and lower shadow prices than what was observed in the first four months of the market, but these two effects offset each other. There is sufficient consistency in SMP in PLEXOS backcasts to have confidence in the results of PLEXOS forecasts based on these settings.

Our key recommendations for running PLEXOS to model the SEM for the period October 1 2008 to December 31 2009 in light of the outcomes of the above validation and calibration tasks are:

§ Start states: use warm starts only;

[1] Refer to All Island Project, Market Simulation Model Validation, G06-1647 Doc 3 Rev 1.2, 24 April 2007 and All Island Project Market Simulation Model Validation, Data Validation Report, G06-1647 Doc 2 Rev 1.1, 24 April 2007

- Dispatch Algorithm: Rounded relaxation with rounding threshold set to 5;
- Moyle flexibility: Let PLEXOS optimize Moyle based on a representative model of the Great Britain market;
- Uplift Filters: Continue to use MSL and ramp-rate uplift filters; and
- PLEXOS Model: use of PLEXOS upgrade 4909 R01 or above.

1. Validation of PLEXOS Input Data

NERA developed a validated PLEXOS input database for the last quarter of 2008 and the whole of the calendar year 2009. The validated database includes:

- Generator technical data by unit, including heat rates and technical constraints;
- Generator VOM cost data;
- Generator forced outage rates and planned outage schedules;
- Generator loss factors;
- Pumped storage reservoir limits;
- System load;
- Half hourly load and wind output forecast assumptions;
- Embedded generation forecasts;
- Forecasted monthly hydro generation;
- Variable cost input forecasts, including fuel and carbon costs at the station gate, using published fuel prices and transportation indices;
- Load, technical, and variable-cost data on the GB market to model flows across the Moyle Interconnector; and
- Anticipated unit retirements and capacity reductions – no new thermal capacity was forecast to come online during planning horizon (new wind capacity forecasts are reflected).

NERA engaged in three simultaneous processes to acquire the above information:

1. Contact with generation companies;
2. Contact with the Market Operator; and
3. Contact with ESBPG and NIE PPB for fuel transportation adders.

Each of these processes are discussed below.

1.1. Contact with Generators

NERA sent an initial email to each generation company on 8-Feb-2008 to:

- Describe to the generators NERA's role in the validation process;
- Request any and all updates to the KEMA-validated database from last year, including updates that have not yet taken affect but will by the end of 2009;
- Ask for explanations of differences between:
  - New submissions to NERA and last year's submissions to KEMA; and
  - New submissions to NERA and actual submissions to market.

NERA received updates from some generation companies, while other generation companies stated that their data from the KEMA model was still accurate. NERA focused its validation on the following items that feed into PLEXOS:

- Min Stable Capacity;
- Max capacity;
- No Load Heat Requirement;
- Heat rate curve;
- Forced Outage Rate;
- Mean Time to Repair;
- Ramp Rate Up;
- Ramp Rate Down;
- Min Up Time;
- Min Down Time;
- Start up Energy (Hot, Warm, and Cold);
- Boundary times between start states; and
- VOMs (Both euros/start and euros/MWh).

Prior to finalizing the dataset, NERA sent a draft final dataset to all generation companies with their units data. This was not an opportunity for resubmission, but for typo correction.

1.1.1. Validation of Generator Technical Data: Min Stable Gen, Max Capacity, Ramp Rates, and Min Times Up and Down

The technical characteristics submitted by the generators were compared both against KEMA's validated dataset and against actual technical data offered to the market. NERA identified instances where the submitted data were different from either KEMA's validated database or the generators' technical offers. NERA queried the generators on such differences, and asked for explanations. NERA made clear that its intention was to use technical offers to the market unless there was a satisfactory reason not to.

In general, differences between the generators' submissions to NERA and the generators' technical offer data were resolved with the generators agreeing to the use of their technical offer data.

In other cases, a satisfactory explanation was provided to use the generator submissions instead. For example, if there was an error in max capacity and the technical offer data had the max capacity inclusive of internal use, as opposed to max sent-out capacity, the latter of which is appropriate for PLEXOS.

In some cases with ramp rates, a few units' technical offer ramp rates varied depending on where in the ramping process the unit was. NERA only modelled one ramp rate. NERA chose a consensus ramp rate based on generator submissions to NERA and market offer data.

In line with KEMA's treatment last year, NERA did not include dwell times in determining its consensus ramp rate.

If an insufficient explanation for differences between market offer data and submissions to NERA was provided, then NERA utilized the technical offer data.

Summer capacity ratings for CCGTs were set by derating winter capacity by 3%. CCGTs summer-winter ratings were set with PLEXOS's generator rating property.

Note that run-up rates were not modelled in the forecast, allowing generators to block load at min stable level, as was the case in KEMA's validated model last year.

1.1.2. Validation of Heatrate Curves

NERA required monotonically increasing heat rate curves with no more than four incremental heat rate slopes, as was the case last year. A no-load heat rate was also utilized. Heat rates were expressed on a Low Heating Value (LHV) basis, as was the case last year. In general heat rate curves were similar if not identical to the curves in KEMA's validated dataset. All heat rate changes were within a reasonable range. NERA asked the generators with the largest heat rate changes to explain those changes. In general the changes were the result of a new technical study that evaluated the unit's heat rate. In some circumstances, heat rates were adjusted this year to be in line with the LHV requirement, where they erroneously were not LHV last year.

1.1.3. Start Energy and Start VOMs

Most units did not update their start energy from the values in KEMA's model, though a few did.

Updates to VOMs were generally not provided in the first round of contact from generators, with some exceptions. NERA reviewed the start VOM data and identified units that unexpectedly had start VOMs of zero in KEMA's validated data. NERA queried the owners of those units directly, and they provided their start VOMs.

In PLEXOS, a unit's start costs are the sum of:

a) the euros/start VOMs (Start Cost property in PLEXOS) and

b) start energy (in GJ, the Offtake at Start property) times the units start fuel cost (in euros/GJ).

In the market, a generator's offer start costs implicitly include both their fuel and VOM costs. NERA compared each unit's commercial start cost offers against their start fuel and VOM data submitted to NERA. NERA looked at February, the most recent whole month of available data at the time of the analysis. NERA compared average market offers with average start costs constructed from each unit's VOMs and start fuel costs based on contemporaneous fuel prices. NERA performed the comparison for hot, warm, and cold starts. Where the start costs submitted to the market differed significantly from constructed start costs, NERA queried the owner of the generator in question and asked them to confirm their start cost based on energy requirements and their VOMs. The generators in some cases updated their start costs, in some cases updated their VOMs, and in some cases updated both.

Several units' commercial offer start costs did not match their constructed start costs based VOMs and fuel requirements because the KEMA validated database included "proxy" VOMs for these units based on other units' VOMs. Most of the units in this situation provided their VOM values upon request.

With some units the reason commercial start cost offers did not line up was because those units start on multiple fuels, whereas the default from the KEMA model was to start units on only one fuel. NERA switched to multi-fuel starts for the units in question, which caused their constructed start costs based on fuel costs and VOMs to line up with their commercial offer start costs.

The second check that NERA performed was to calculate the VOMs implicit in generator commercial offers by backing out the start fuel costs from the generators' commercial offers. NERA specifically identified units which appeared to ***not*** bid start VOMs into the market (units with implied start VOMs less than or equal to zero). NERA queried the owners of these units to a) confirm their start fuel requirements were correct and b) if they were correct, to confirm that a zero VOM was correct.

Where generators did not supply updated VOM data, NERA kept their VOM data from the previous year's database, unless it had reason to believe that the previous year's data was incorrect, in which case NERA utilized implied VOMs from commercial offer data.

1.1.4. Boundary Times between Start States

Several generators updated their boundary times after technical reviews of their units performance, or updated them so they were inline with grid code.

1.1.5. Forced Outage Rate and Mean Time to Repair

When generators submitted updated FOR that differed from their validated KEMA values, NERA asked the generators for explanation as to why the changes occurred and reviewed the reasonableness of the changes and of the explanations. For units in ROI, we compared FORs against the recommended outage rates in a study done jointly by EirGrid and consultants to EirGrid for the GAR (Generation Adequacy Report). We generally accepted the generator submissions, as they were in line with – and often more conservative than – the recommendations of the EirGrid study. In general NI units did not update their FORs.

1.1.6. VOMs/MWh

A few units updated their VOMs/MWh from the prior year, and a few units who did not have VOMs in last year's validated model submitted VOMs/MWh for the first time.

1.1.7. Kilroot

Kilroot Coal units have a coal overburn and oil overburn mode, which allow for additional MW above the MW level possible in their "regular" coal burn mode. Last year KEMA kept Kilroot an all coal unit. KEMA modelled the overburn regions by adjusting Kilroot's heat rates so that, at coal prices, Kilroot's costs in the overburn regions would reflect its overburn costs and not its regular coal burn costs. This year NERA continues to model Kilroot as an all coal unit. NERA, however, has kept Kilroot's actual heat rate curve. NERA captures

Kilroot's overburn modes through a VOM that kicks in at the MW levels where Kilroot's coal and oil overburn regions begin. In PLEXOS this is modelled through the Generator "Markup" property.[2]

The Kilroot GTs also have an overburn MW zone which is also modelled through a markup.

The markup property values validated by NERA are not included in the public version of the PLEXOS database because of the confidential nature of those values.

1.1.8. Unit Fuels for Generation and Start-up

Three stations – Moneypoint, Great Island, and Tarbert – submitted their start fuel requirements for two different fuels that they use at startup. NERA accepted these blended-fuel starts. NERA modelled this phenomenon in PLEXOS through creating a hypothetical "blended" fuel for each station.[3] For example, Great Island starts on 61% Oil and 39% Distillate. NERA created a fuel in PLEXOS off of which Great Island would start. That fuel had prices that were a 61%-39% blend of Oil and Distillate prices.

NERA updated the fuel generators burn when generating for a few units. NERA modeled Poolbeg 1 as gas and Poolbeg 2 as Oil, whereas KEMA modelled both as dual fuel. Of the three Aghada CTs, NERA modeled two as gas and one as distillate, whereas KEMA modelled two as distillate and one as gas.

1.2. Contact with the Market Operator

The Market Operator was contacted via an initial email asking for updated information on:

- Half-hourly demand;
- Wind profiles and capacities;
- Outage schedules;
- Monthly hydro generation forecasts;
- Retirements, new units, derates, and expansions;
- Embedded generation profile;
- Generator loss factors; and
- Pumped storage reservoir limits.

Data on each were received. Descriptions follow.

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[2] NERA established late in the assignment that the Kilroot overburn model method was not functioning fully correctly in *cost mode* and we understand that PLEXOS releases 4909 R01 and above have corrected this issue. NERA's work utilised the previous release but subsequent comparisons indicate this issue does not appear to have a material impact on SMP estimation

[3] Tarbert required two blended fuels, as units 1 & 2 had a different blend from units 3&4.

1.2.1. Half-hourly Demand

NERA received forecasts for 2008 through 2009 for NI and ROI, which were combined into one SEM forecast. The forecast in KEMA's model also contained a 2008 forecast. Over that common year, demand was 0.85% lower in the new forecast than in last year's. Between 2008 and 2009 total energy is expected to rise 2.8%, according to the forecasts received.

1.2.2. Wind Profiles and Capacities

As with KEMA's model, ROI was divided into three wind regions (A, B, and C), and NI was its own wind region. NERA received a quarterly capacity forecast for wind for each region. The profiles received were the same as the profiles used in last year's model. NI did not have its own profile, but instead is aligned with ROI profile A, as was the case in last year's validated model.

1.2.3. Outage Schedules

The Market Operator provided an updated outage schedule for each unit in the SEM as well as for Moyle. That schedule was checked for reasonableness against the schedule used in last year's validated model. Where outages data were missing or unclear – or where there were unexpected and large changes from last year's schedule – the Market Operator was queried to confirm or provide more up-to-date information. Any updates were incorporated. A more updated outage schedule became available several weeks into NERA's validation process. This new schedule was reviewed for reasonableness against the previously submitted schedule. This new schedule was accepted by NERA.

Complete Moyle outages were modelled with the line "units out" property. Partial Moyle outages were modelled with the Max Rating and Min Rating properties.

1.2.4. Monthly Hydro Generation Forecasts

The same forecasts from last year's model were submitted by the Market Operator and accepted by NERA in this year's model.

1.2.5. Retirements, New Units, Derates, and Expansions

The Market Operator provided information on unit retirements and derates, which were accepted. There were no new units (except for wind) and no expansions planned during the modelling horizon.

1.2.6. Embedded Generation Profile

The Market Operator provided a typical embedded generation profile (hourly MW for weekdays and weekends). The Market Operator was queried whether this profile should be grown in 2009 to reflect new embedded generation. The Market Operator confirmed that it was appropriate to grow embedded generation based on planned embedded capacity additions as presented in the GAR.

1.2.7. Generator Loss Factors

The Market Operator provided updated monthly day/night loss factors for each unit.

1.2.8. Pumped Storage Reservoir Limits

NERA accepted the upper reservoir limits that the Market Operator provided – the limit was unchanged from KEMA's validated model from last year. NERA modelled the lower reservoir as unlimited capacity, which is how it was modelled in KEMA's validated model as well.

1.3. Contact with ESBPG and NIE PPB for Fuel Transportation Adders

The method of modelling fuel costs in PLEXOS is unchanged from last year's model. The fuel prices inputted into PLEXOS represent all-in prices, inclusive of transportation to plant and any relevant excise charges, taxes, or port duties. Carbon costs are represented as a fuel tax in PLEXOS. The total fuel costs faced by units in PLEXOS is the sum of the fuel price and fuel tax.

NERA contacted PG and PPB to update the fuel transportation costs. Distillate transportation increased the most this year vs. last year, due to the high cost of inland transport.

NERA accepted PG and PPB's transportation adders.[4]

Prices for Great Britain are also needed for Moyle modeling. NERA applied the NI transportation adders to GB as well.[5]

The various price components are converted to all-in (commodity + transport) prices/GJ for entry into PLEXOS. Carbon prices are converted into euros/GJ fuel "taxes" for PLEXOS based on fuel emissions and oxidization factors.

The recommended fuel indexes are:

§ Coal: Argus API2 (CIF, ARA);

§ Gasoil: Platts Gasoil .1% (CIF, NWE);

§ Nat Gas: Heren ICE NBP futures; and

§ LSFO: Platts 1% LSFO (FOB, NWE).

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[4] One exception was with LSFO in NI. The LSFO index price recommended in the model is a FOB price, whereas NI transportation adder was based off of a CIF price. Therefore, NI price did not take account of the premium of CIF over FOB. For this reason the ROI LSFO adder was used in NI as well.

[5] One exception was for natural gas transportation adders, which are lower in GB. NERA accepted the transportation adders verified by KEMA last year for GB for gas.

1.4. Confidentiality of Data

Last year, all data except for VOM costs and outage schedules were published. The published KEMA database is available on the AIP website. This year, NERA asked each generator to specify which data items were confidential. Initially, several generators marked all of their submitted data confidential. Other generators only marked their VOM data as confidential. Still other generators were willing to publish all data items, so long as every generator agreed to publish the same items. The Regulatory Authorities and NERA asked for clarification on confidentiality in several emails and phone calls to generators. The Regulatory Authorities have published data except for VOMs and outage schedules.[6]

[6] One generator has asked its data to be confidential. For this generator, the published database includes only public data: data offered into the market or data from KEMA's published database from last year.

2. Calibration of PLEXOS

In this task NERA has calibrated PLEXOS against actual half hourly ex post data consisting of shadow prices, uplift, SMPs, as well as Market Schedule Quantities (MSQs), from the Market Operator for the period from 1st November 2007 to 29 February 2008;

The basic methodology used in this calibration was as follows:

- Technical and commercial offer data by unit were collected from the Market Operator for the period from 1st November 2007 to 29 February 2008;
- Half hourly ex post load data and autonomous/price taker generator outputs were collected for the period from 1st November 2007 to 29 February 2008;
- These data were used as inputs into PLEXOS runs; and
- Shadow prices, uplift and SMPs from the PLEXOS runs were compared against actual ex post prices from the Market Operator to determine how well PLEXOS models market prices, given similar or identical inputs.

NERA utilised an iterative approach to first determine the degree of calibration between PLEXOS outputs and actual market results, and then sequentially:

- Identified reasons for differences;
- Modified input assumptions or parameter settings so as to reduce or eliminate those differences;
- Reran PLEXOS; and
- Recalibrated results.

At each iteration NERA identified the reasons for differences by first identifying the major outlier(s). These outliers were sometimes evident as price gaps between the PLEXOS outputs and the market results, and sometimes they were evident as significant quantity (MSQ) differences. The iterative process ended when the PLEXOS outputs were deemed to be acceptably-well calibrated with the actual market results.

The following is description of the main steps taken and the results obtained.

2.1. Preparation of the Back-cast Database

The main purpose of calibrating the back-cast is to validate and/or improve the quality of the forecasts from PLEXOS. Accordingly, the back-cast database was prepared under the guiding principles that:

1. for those data items that are entered directly into the forward-looking PLEXOS forecasts, actual data as used by the Market Operator EPUS software should be used in the PLEXOS back-cast; and

2. for those items that are predicted by PLEXOS as part of the solution process in the forecast, for example hydro and Moyle schedules, the same predictive process should be

applied in the back-cast (as opposed to simply entering the actual schedules) since calibrating/ validating PLEXOS's performance in predicting these factors is a key reason for performing the back-cast.

For example, actual system load was used in the back-cast because forecast system load is entered directly into the forecast as an input. Likewise, actual generation commercial offer data was used in the back-cast because commercial offer data is directly entered into the forecast. The same applies to actual wind production since future wind production is directly entered to the forecast and to technical generator offer data including outages.[7]

In the case of commercial offer data there is the extra consideration that actual data is presented in the form of simple price-quantity pairs, start-cost offers, and no-load offers, whereas forecast entry data is entered in the form of a cost function consisting of, among other things, heat rates, forecast fuel prices, fuel required per start-up fuel required for no-load running, and in some cases VOMs per MWh and/or VOMs/start. Nevertheless, the PLEXOS solution process minimises cost regardless of the functional form of the cost function and the equivalence of this solution process is sufficient to ensure that lessons learned in the back-cast are applicable to the forecast. NERA's comparisons of commercial offer data against calculated offers based on submitted generator data is described in section 2; however, it was not the purpose of this assignment to pre-empt the role of the Market Monitoring Unit. To the extent that forecast offer data (including VOMs, heat rates, etc.) has been accepted for use in the PLEXOS forecast model, and that data might or might not be fully consistent with commercial offer data as submitted to the market, either past or present, the use of that data for forecasting in no way implies that the data has been approved as meeting the requirements of the MMU and the applicable generator license conditions. The MMU process is entirely independent.

The remainder of this Section 2.1 describes each major data item used in the back-cast in turn.

2.1.1. Load

Half-hourly load was updated using observed actual load, provided by the System Operator. This actual load was defined as the sum of actual observed generation (excluding the load of pumped storage units) plus net Moyle imports adjusted for losses. This actual load was then input into PLEXOS for each hour, and PLEXOS determined the quantity of pumped storage load to add as part of the pumped storage optimisation process.

2.1.2. Commercial Offer Data

The following commercial offer data was provided by the Market operator and entered directly into PLEXOS for the back-cast:

- Price-quantity pairs;

[7] This is true for planned outages, which are entered directly into both the forecast and backcast. Forced outages, however, are necessarily modelled stochastically in forecasts; yet forced outages are entered directly in the backcast. This is necessary to isolate the effects of modelling decisions – such as Moyle and Hydro modelling – on the calibration of PLEXOS results with market data. If stochastic outages were used in the backcast, then it would not be clear whether the level of calibration achieved was due to modelling choices and/or to different forced outages in the backcast vs. the actual market.

- No-load offers; and
- Start offers – separate for hot, warm, and cold.

The market offer data contained price-quantity pairs expressed on a cumulative MW basis. Therefore it was necessary to utilise the Market Offer Quantity Format features of PLEXOS to accept cumulative offers. It was determined that PLEXOS, in cumulative offer mode, requires that the first quantity point be zero MW. This means that there must be one more quantity entered into PLEXOS than price. NERA adjusted the market offer data accordingly. It was also determined that PLEXOS input formats expect a generating unit to have a consistent number of price/ quantity offer pairs across a planning horizon whereas the SEM allows for the number of price/ quantity offer pairs to change on a daily basis. It was therefore necessary to generate dummy offer pairs with zero incremental MW in each half-hour period for which a unit had fewer offer pairs than in the half-hour period for which its raw data had the maximum number of offer pairs.

When entering offers directly, the PLEXOS model property Uplift Cost Basis needs to be set to Bid based.

When PLEXOS is used in offer mode, heat rates and fuel costs are still required – PLEXOS needs to have some sense of actual costs even when it optimizes the system based on directly-entered generator offers. However, note that fuel offtake at start should be set to zero when actual start offers are entered. This is because with start costs, PLEXOS *always* calculates start costs as the sum of euros/start costs and fuel offtake start costs. If the euros/start encompass the units entire commercial start cost offer (inclusive of implied fuel costs), then fuel offtake must be set to zero to avoid double counting. In constrast, with no-load costs/offers and marginal costs/offers, PLEXOS will default to commercial offers and ignore the costs associated with heat rates and VOMs – that is, with no-load and incremental costs there is not the same potential double counting issue.

2.1.3. Technical Offer Data

The following technical data was provided by the Market Operator and entered directly into PLEXOS for the back-cast:

- Max capacity (with a small adjustment, see below);
- Min Stable Level;
- Ramp rates up and down;
- Min times up and down; and
- Half-hourly availability (with a small adjustment, see below).

The half-hourly availability data we received occasionally included availabilities outside of the “normal” generation range of min stable level and max capacity. PLEXOS does not allow for availabilities below MSL[8] or for generation above max capacity, and so the following adjustments were made:

- Max capacity was set to the max of the technical maximum capacity and the maximum availability throughout the backcast period. In this way technical maximum capacity was not binding—instead actual half-hourly availability set the half-hourly upper bound on generation in the backcast runs;[9] and
- When actual historic availability was below min stable level, availability was set to zero.

Actual half hourly availability was set via the generator rating property.

To be consistent with the forecast model, run-up rates were not modelled in the backcast, allowing generators to block load at min stable level, as was the case in KEMA's validated model last year.

2.1.4. Outages

For the back-cast, availability was not modelled with stochastic forced outages or planned outages. Rather, actual half-hourly availability of each generating unit was input directly from the offer data.

2.1.5. Wind

Actual half-hourly wind production data was provided by the System Operator and input into PLEXOS.

2.1.6. Hydro

Actual half-hourly hydro production data was provided by the System Operator. To enable PLEXOS to schedule hydro production, this data was then aggregated across individual generating units at each hydro station, and was aggregated by month. It was the responsibility then of PLEXOS to schedule these hydro production amounts within each month at each station, taking account of the individual unit capabilities.

2.1.7. Pumped Storage

Pumped storage efficiency factors and other technical parameters were left unchanged from the 2007 process. For the purpose of the back-cast PLEXOS was asked to optimally schedule pumping load and generation from pumped storage.

2.1.8. Peat

Peat has a minimum annual load factor target which must be achieved. For the purpose of this back-cast the load factor target was converted to an equivalent basis for the four months under consideration. This allows PLEXOS to schedule the production of peat so as to meet

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8 At least not when units are otherwise allowed to block-load at MSL, as is the case in both NERA's forecast and backast models, and as was the case in KEMA's validated model.

9 For example, extreme cold conditions may allow a CCGT to achieve output above its normal maximum capacity.

the minimum production requirements in a consistent manner to how peat is treated in the forecast. The peat max capacity factor for the backast period for entry into PLEXOS was calculated for each unit as:(actual total generation Nov-Feb) / ([Hours in Nov-Feb] * Unit Capacity).

2.1.9. Moyle/ Great Britain

Moyle flows were modelled using the 2007 approach of modelling a separate Great Britain region within PLEXOS, connected to the SEM by a constrained Moyle interface. Actual Great Britain load was updated using PowerVision data from Platts. The merit order of representative Great Britain generating units was updated from the 2007 data using National Grid's Seven Year Statement (SYS) report.

2.1.10. Actual Market Outcomes

A database was assembled of actual unit output in each half-hour trading period from 1 November 2007 to 29 February 2008, including Moyle flows, and assumed Moyle losses. The actual Shadow Price, Uplift and SMP in each half-hour were included. An identically-formatted parallel database was then prepared for the PLEXOS output from each of the analyses that follow, so that detailed comparative evaluations could be performed.

2.2. Back-cast Results Obtained

Using the back-cast database and after following an iterative process of modelling improvement, NERA concludes that for the purposes of SMP forecasting and of developing Directed Contract prices in particular, the model is reasonable when the settings and modelling methodologies described in this report are applied.

The charts and table that follow illustrate the main results that were obtained from the back-cast process, using these recommended settings and modelling methodologies. The subsections that follow the charts and table describe the iterative process that was followed and the details of these settings and modelling methodologies.

Figure 2.1 shows average SMP by time of day, averaged over the period November 2007 to February 2008 inclusive, comparing actual SMP to SMP from the back-cast incorporating the recommended settings and methodologies. It shows that the back-cast produces a daily pattern for the back-cast SMP that is largely consistent with that observed in the actual market. It is noticeable that there is a regular and dramatic price spike around period 36 each day (5:30pm) and this sometimes flows onto periods 35 and 37.

Figure 2.2, Figure 2.3, Figure 2.4, and Figure 2.5 illustrate this daily pattern for each of the months of November 2007, December 2007, January 2008 and February 2008 respectively. Of these, December 2007 is the noticeable outlier – with PLEXOS off-peak prices generally higher than observed, while PLEXOS peak prices are lower than observed. This is caused primarily by a redistribution of a proportion of uplift from peak hours to off-peak hours in this month. Uplift was investigated in detail as we describe below. The other noticeable deviation between actual and PLEXOS SMPs was for the mid-day "sub-peak" in January 2008, which was more pronounced in this month than in the others. Overall the pattern of reconciliation is good.

Figure 2.1
SMP Comparison: November 2007 - February 2008

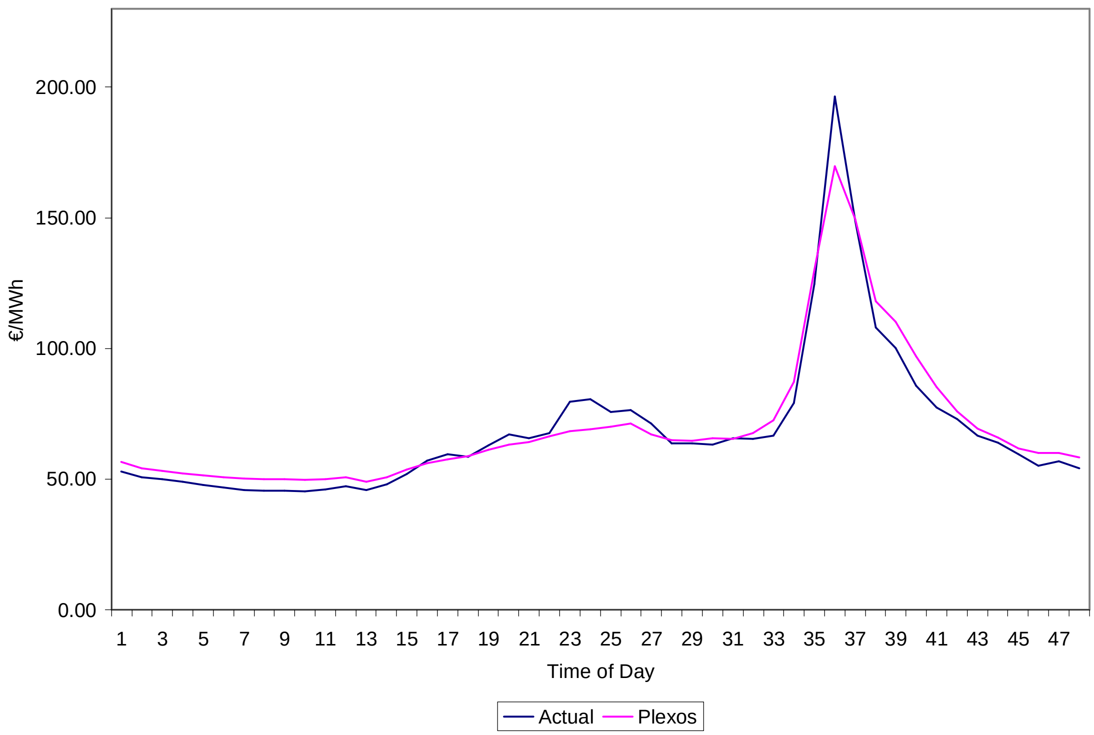


Figure 2.2: SMP Comparison: November 2007

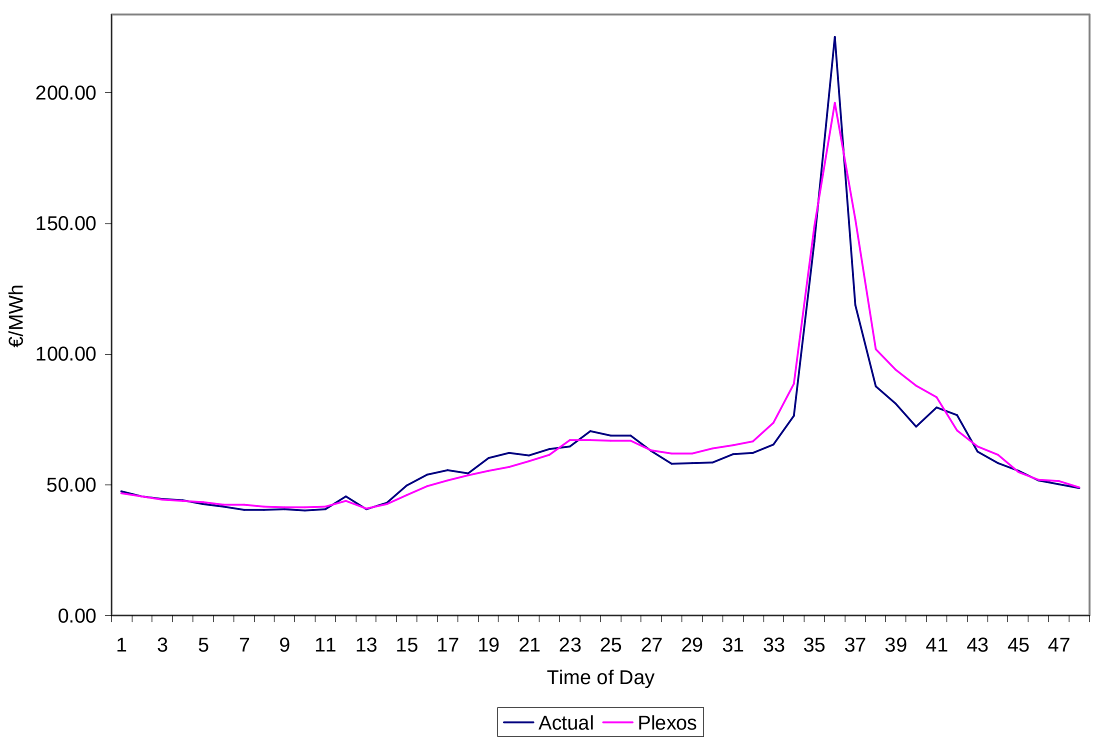


Figure 2.3: SMP Comparison: December 2007

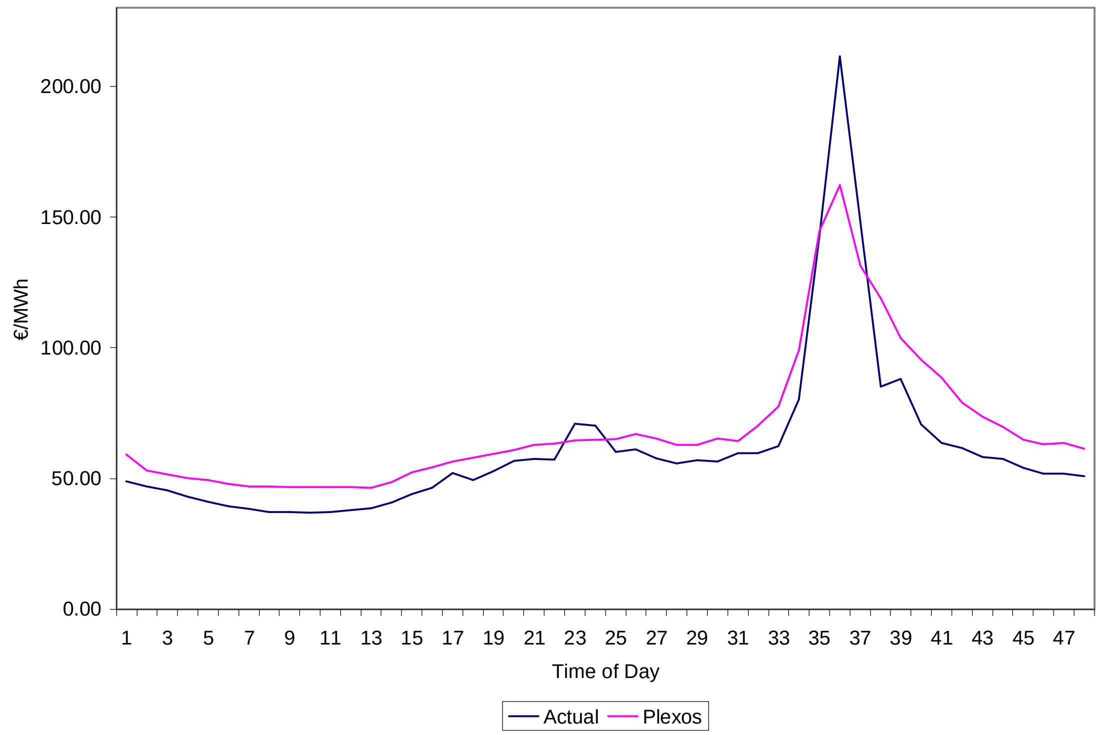


Figure 2.4: SMP Comparison: January 2008

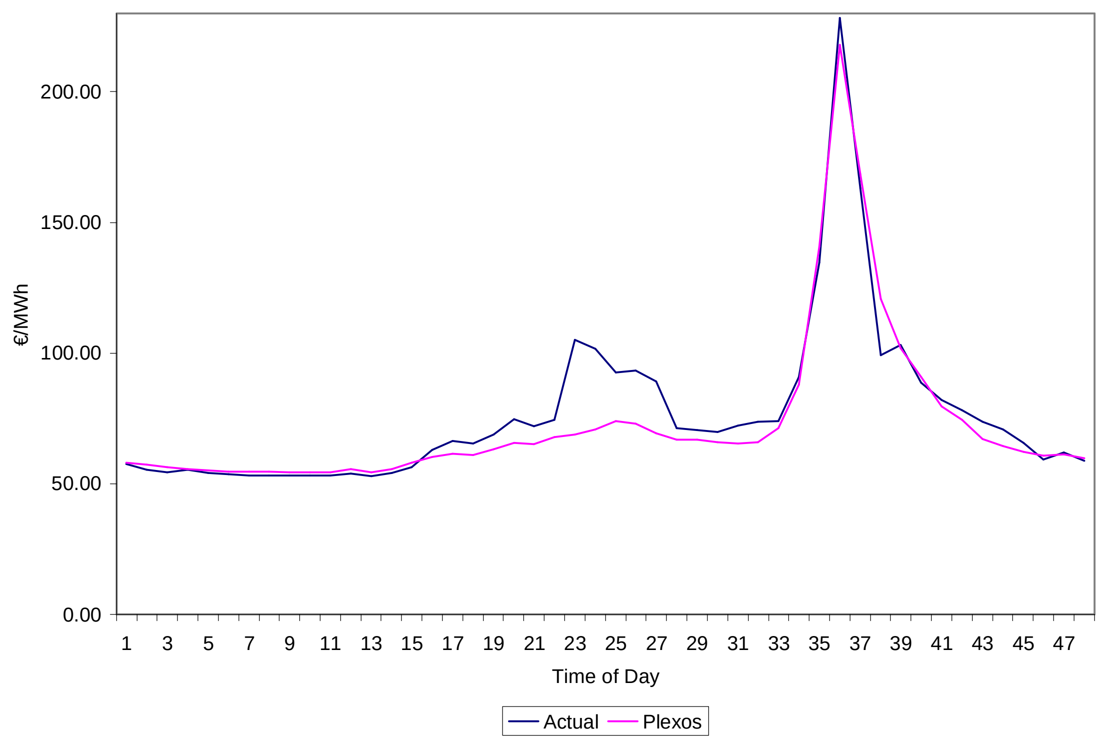
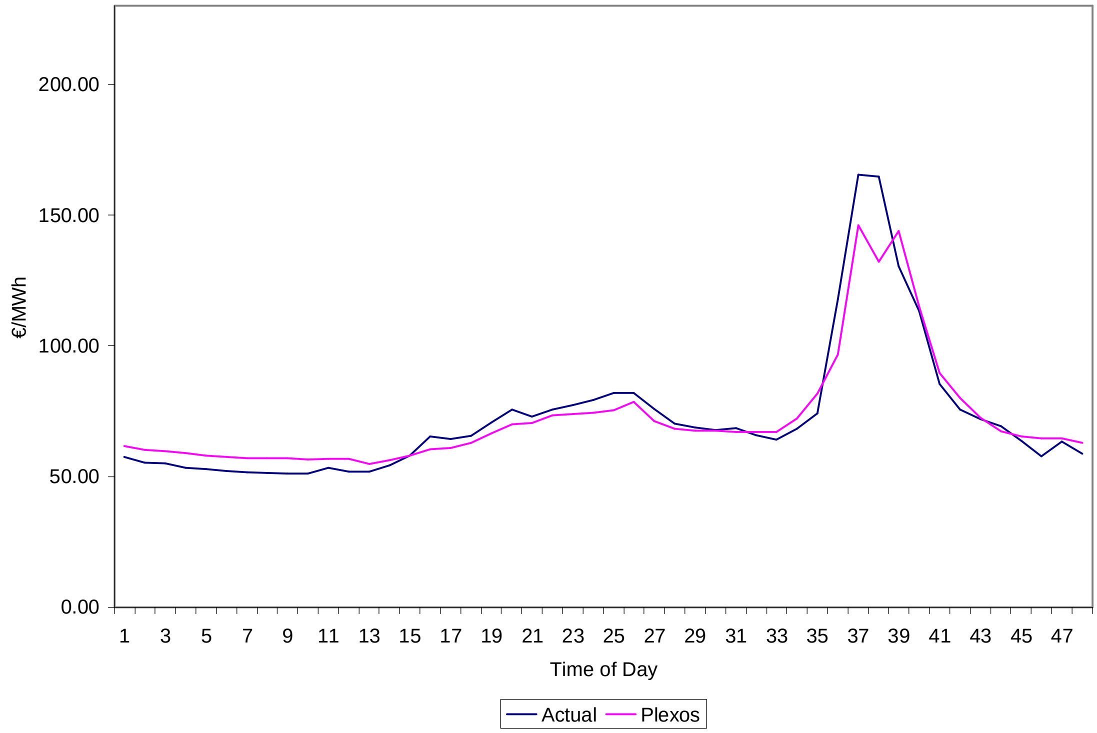


Figure 2.5: SMP Comparison: February 2008



Appendix D contains a chronological half-hourly comparison for each week within the four months concerned.

While the calibration of SMP is a reasonably good fit, the calibration of the components of SMP (shadow price plus uplift) is a much poorer fit. Figure 2.6 and Figure 2.7 illustrate the shadow price component of SMP (as compared to SMP itself) for each of the actual market results and the PLEXOS back-cast, respectively. In the actual market results, the shadow price is a much higher proportion of SMP and uplift is correspondingly much lower.

PLEXOS appears to have a tendency to over-commit units, which depresses the shadow price but increases the uplift by a similar amount. Table 2-1 shows that on average across the four months, PLEXOS SMP was about €1.37/MWh higher than the actual SMP (about 2% different) but uplift was €9.78/MWh higher (€15.06 vs. €5.28) while the shadow price €8.40/MWh lower (€54.68 vs. €63.08). This relationship existed through all the tests and scenarios that NERA ran, and was a central focus of NERA's investigations.

Table 2-1 summarises numerical results for each of the charts just described.

Figure 2.6: SMP & Shadow Price Comparison: Nov 2007 - Feb 2008 (Actual)

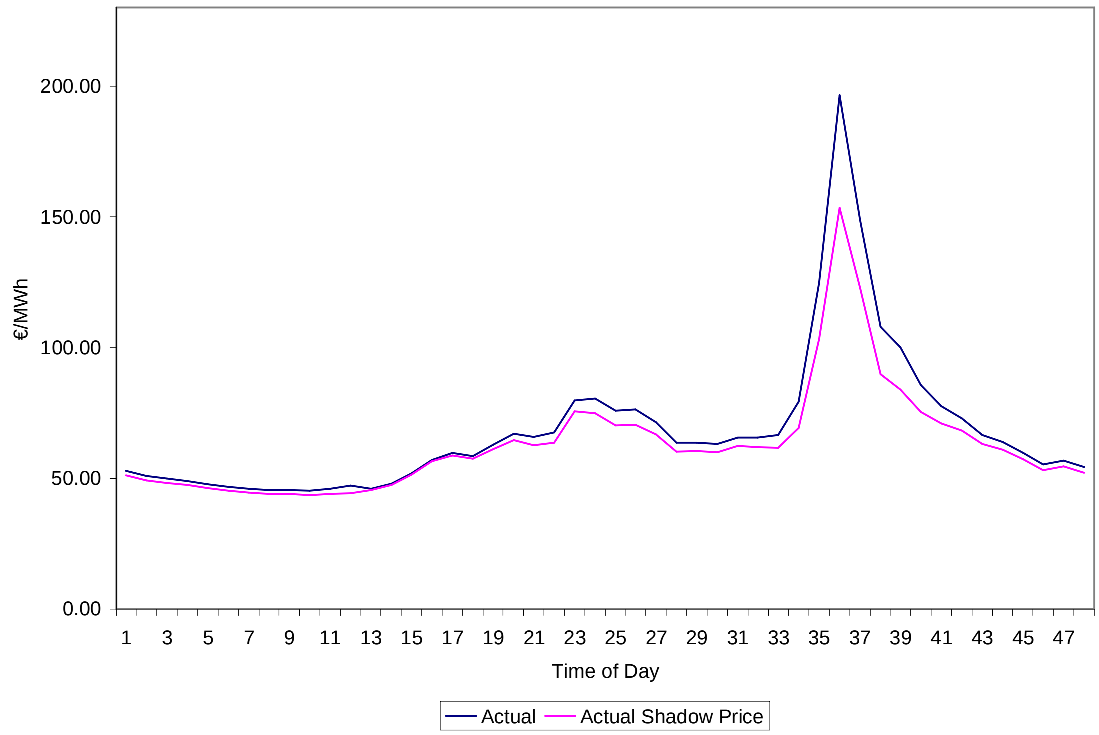


Figure 2.7: SMP & Shadow Price Comparison: Nov 2007 - Feb 2008 (PLEXOS)

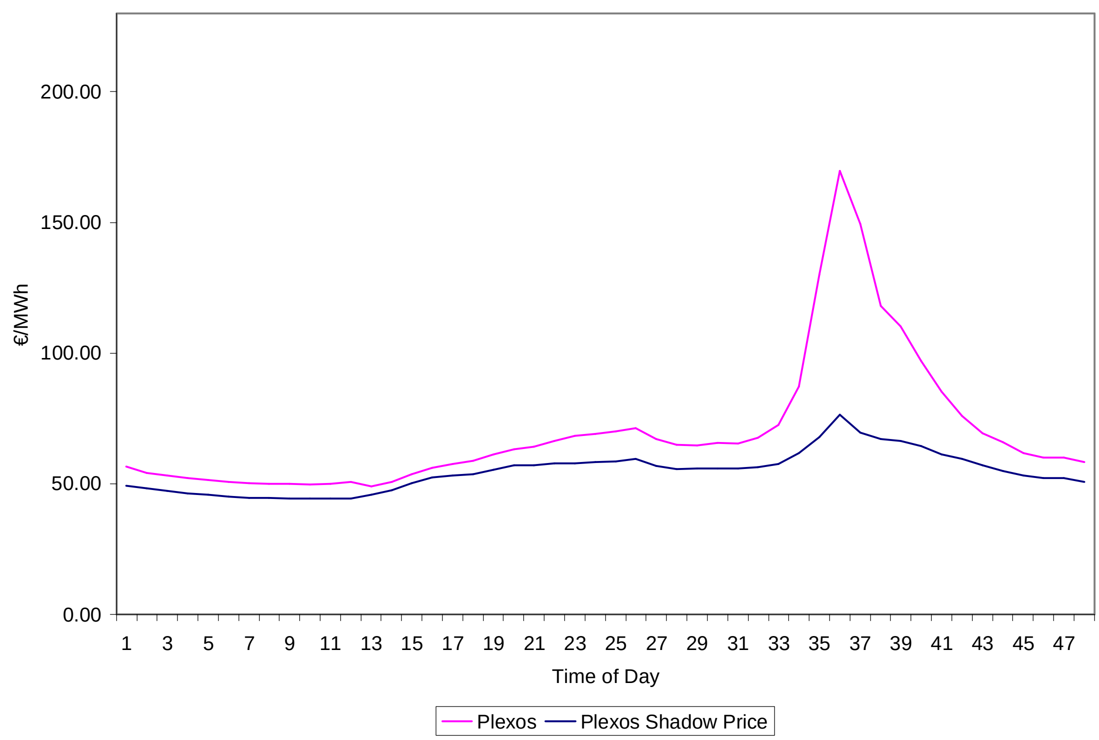


Table 2-1: SMP, Shadow Price and Uplift Comparison

Base prices Nov-Feb

	Sh. Price	Uplift	SMP
Actual	€ 63.08	€ 5.28	€ 68.36
PLEXOS	€ 54.68	€ 15.06	€ 69.74
Variance	(€ 8.40)	€ 9.78	€ 1.37

Mid prices Nov-Feb

	Sh. Price	Uplift	SMP
Actual	€ 71.74	€ 7.33	€ 79.07
PLEXOS	€ 58.98	€ 20.21	€ 79.19
Variance	(€ 12.77)	€ 12.88	€ 0.12

Peak prices Nov-Feb

	Sh. Price	Uplift	SMP
Actual	€ 99.86	€ 20.57	€ 120.42
PLEXOS	€ 67.66	€ 55.40	€ 123.05
Variance	(€ 32.20)	€ 34.83	€ 2.63

Base prices Nov

	Sh. Price	Uplift	SMP
Actual	€ 58.50	€ 5.21	€ 63.72
PLEXOS	€ 49.46	€ 15.70	€ 65.16
Variance	(€ 9.04)	€ 10.48	€ 1.44

Mid prices Nov

	Sh. Price	Uplift	SMP
Actual	€ 67.30	€ 6.96	€ 74.26
PLEXOS	€ 54.38	€ 21.94	€ 76.33
Variance	(€ 12.92)	€ 14.99	€ 2.07

Peak prices Nov

	Sh. Price	Uplift	SMP
Actual	€ 95.13	€ 19.22	€ 114.35
PLEXOS	€ 62.53	€ 61.38	€ 123.91
Variance	(€ 32.59)	€ 42.16	€ 9.57

Base prices Dec

	Sh. Price	Uplift	SMP
Actual	€ 55.85	€ 5.24	€ 61.09
PLEXOS	€ 47.46	€ 21.38	€ 68.84
Variance	(€ 8.39)	€ 16.14	€ 7.75

Mid prices Dec

	Sh. Price	Uplift	SMP
Actual	€ 64.47	€ 7.03	€ 71.50
PLEXOS	€ 51.89	€ 26.81	€ 78.70
Variance	(€ 12.58)	€ 19.78	€ 7.20

Peak prices Dec

	Sh. Price	Uplift	SMP
Actual	€ 99.44	€ 18.59	€ 118.02
PLEXOS	€ 58.88	€ 63.32	€ 122.20
Variance	(€ 40.56)	€ 44.73	€ 4.18

Base prices Jan

	Sh. Price	Uplift	SMP
Actual	€ 70.52	€ 5.96	€ 76.48
PLEXOS	€ 62.04	€ 10.76	€ 72.80
Variance	(€ 8.48)	€ 4.80	(€ 3.68)

Mid prices Jan

	Sh. Price	Uplift	SMP
Actual	€ 79.70	€ 8.57	€ 88.27
PLEXOS	€ 66.24	€ 15.68	€ 81.93
Variance	(€ 13.46)	€ 7.12	(€ 6.34)

Peak prices Jan

	Sh. Price	Uplift	SMP
Actual	€ 104.18	€ 25.53	€ 129.70
PLEXOS	€ 79.53	€ 53.12	€ 132.65
Variance	(€ 24.65)	€ 27.60	€ 2.95

Base prices Feb

	Sh. Price	Uplift	SMP
Actual	€ 67.51	€ 4.65	€ 72.16
PLEXOS	€ 59.82	€ 12.19	€ 72.01
Variance	(€ 7.69)	€ 7.54	(€ 0.15)

Mid prices Feb

	Sh. Price	Uplift	SMP
Actual	€ 75.57	€ 6.66	€ 82.23
PLEXOS	€ 63.52	€ 16.12	€ 79.65
Variance	(€ 12.05)	€ 9.46	(€ 2.59)

Peak prices Feb

	Sh. Price	Uplift	SMP
Actual	€ 100.44	€ 18.67	€ 119.10
PLEXOS	€ 69.53	€ 42.94	€ 112.47
Variance	(€ 30.90)	€ 24.27	(€ 6.63)

Note: Peak and mid-merit definitions reflect the definitions used for directed contracts in the first year of the SEM.

2.3. Iterative Process

This section describes the iterative process used in the production of the solution just illustrated.

2.3.1. Initial Results Using 2007 Settings

The initial run of the back-cast model used the settings from the 2007 PLEXOS process. Results contained high average uplift (well over €20/MWh) and a relatively poor calibration overall to observed prices and MSQ levels. Analysis of detailed results showed substantial over-committing of units relative to the actual market outcomes, which is consistent with a low shadow price and a high uplift. It was established that the extent of the variance warranted investigation.

2.3.2. Analysis of MSL Filters

Analysis of detailed half-hourly level results from the initial results indicated there were some instances in which uplift was caused by cost recovery for units that only ever ran at MSL during a commitment cycle. The Min Stable Level (MSL) and ramping uplift filters[10] available in the PLEXOS SEM Uplift module were checked in a sequence of runs to evaluate their individual and combined impact. The setting of both these filters to the "on" position was consistent with the 2007 process. With the MSL filter on, in particular, it should not have been the case that uplift could be caused by cost recovery for units that only ever ran at MSL during a commitment cycle.

Energy Exemplar, the author of PLEXOS, investigated the example conditions produced and responded with a revised version of the software, and with that update such instances were no longer observed. It appears the impact of the issue was minimal, since the improvement in the calibration was small, being of the order of €0.10 / MWh on average.

The effect of having the MSL filter on or off is significant, however. With the MSL filter off, uplift increases, as expected, causing uplift to diverge even further from historic actual uplift values. Because of rounded relaxations tendency to overcommit and hence have units running at MSL, it is recommended that the uplift filter be kept on.

2.3.3. Analysis of Start States

Investigation of PLEXOS unit commitment decisions showed instances where it appeared that too many units had been started for a commitment cycle. For example, two identical units in particular were sometimes committed to run at their first "elbow point" (the quantity corresponding their first price/quantity pair) which was at just less than 50% of full capacity. They ran at this elbow point for only two or three periods. The result was considerable uplift. By visual inspection it was possible to conclude that running one of the units at double the level of output would have been lower cost overall, and would have created a lower level of price uplift (since whatever remaining start up and no load cost not recovered from running in the commitment cycle would be recovered from twice as many MWhs).

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[10] I.e. the "Detect Active Min Stable Level Constraints" option and the "Detect Active Ramping Constraints" option.

Running PLEXOS using the rounded heuristic appeared to consistently "over-commit" units in a range of tests that were performed.

In looking at the causes for the high levels of uplift resulting from over-commitment it was observed that the rounded relaxation method created particularly high uplift solutions when it started units unnecessarily from a cold-start case.

NERA therefore investigated the impact of assuming all starts are warm starts, and found this made a significant improvement to the calibration. Essentially, PLEXOS would still have a tendency to over-commit when presented with only warm starts, but the impact on uplift and SMP was much less severe. With final NERA backcast assumptions, including warm starts, average PLEXOS SMPs were close on average to actual market SMPs (PLEXOS average SMPs were about 2% higher than actual SMPs with warm stats). The calibration is far worse with three-state starts (PLEXOS average SMPs were about 14% higher than actual SMPs). Over-commitment by the rounded relation method had particularly adverse impacts when a cold start was involved, and simplification to warm-starts only appears to greatly reduce the amount by which uplift is over-stated (uplift reduces by approximately 6.50 euros/MWh[11]). Switching to warm starts only also greatly reduces the problem size, and hence the run-time; almost a 90% reduction in run time was observed.

2.3.4. Analysis of Rounded Relaxation Settings

After simplifying the unit commitment decision to assume all starts had the cost of a warm start, relatively high levels of uplift nevertheless remained. NERA therefore performed a more direct test to attempt to correct the over-commitment issue. PLEXOS users can set PLEXOS's threshold for committing units in the rounded relaxation mode, as explained in more detail in the next paragraph. The relevant model property is "Production Rounding Up Threshold". While that is the formal property name, it is more likely that a PLEXOS user will interact with the property through the interactive tabbed model properties window[12]. In that window, on the Unit Comitment tab, there is a section for "Integer Optimality". When "Rounded Relaxation (Nearest Integer)" is selected, it is possible to set the rounding threshold, with a slider that goes from 0 to 10 – the slider is entitled "Rounding Up Threshold".[13] For the purposes of this report, NERA will refer to this slider as the "rounded relaxation slider", or simply the "slider". This rounded relaxation slider was modified from its default position and various alternative positions were tested.

The rounded relaxation slider has interacting effects. However, simplistically, one of those effects is to impact on the tendency for the rounded relaxation algorithm to decide to run a unit at MSL rather than not run it at all. The first pass of the rounded relaxation algorithm is a linear one, and it is possible for units to initially be scheduled at output levels between zero and their MSL. Modifying the slider influences the tendency of PLEXOS to round up (to

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11 In should be noted that PLEXOS settings have interacting effects, and the level of the euro/MWh impact on SMPs from changing one setting may vary depending on how other PLEXOS options are set.

12 This is reached, among other ways, by right-clicking on a model and selecting properties.

13 The Slider goes from 0 to 10. However, this slider is translated into the PLEXOS model property "Production Rounding Up Threshold". That property goes from 0 to 1 – so, 8 on the slider means 0.8 for the "Production Rounding Up Threshold" property.

MSL) vs. rounding down (to zero). The higher the slider, the less likely it should be to round up, and therefore the amount of over-commitment should be reduced.

NERA investigated various rounded relaxation slider positions, and in particular setting it equal to 8 and then to 10. It was observed that in the back-cast over-commitment indeed decreased, shadow prices increased, and uplift decreased, at the higher slider settings.

However, the back-cast performed a unit commitment with the knowledge of actual half-hourly unit availability – since actual technical and commercial offer data was input. To investigate how alternative rounded relaxation positions would perform on the forecast, indicative forecast runs were performed through the end of the third quarter of 2009 for rounded relaxation slider positions of 5, 8, and 10.

At the position of 5, virtually no unserved energy was predicted in this forecast. At the position of 8, considerable unserved energy was observed. Even more was observed at a position of 10. It was therefore concluded that while increasing the value of the slider improves the calibration of the back-cast, it does not improve the quality of forecast results – which is the purpose of performing the back-cast in the first place.

It appears that increasing the value of the slider decreases instances of over-commitment, however in some instances having a high slider value decreases commitment levels too much - and in a situation where forced outage is stochastic, high levels of unserved energy appear, an unrealistic result. No better position for the slider was determined than the default position of 5.

2.3.5. Analysis of Starting Conditions

It was noted in the tests performed that 1 November 2007 (and only this day) had considerable unserved energy in the PLEXOS results and that its unit commitment schedule was suffering from being the first day of the SEM. This only seemed to occur, or at least was more pronounced, after the rounded relaxation settings were adjusted upwards. For simplicity, all evaluations, including the rounded relaxation slider evaluations, were conducted from November 2, 2007 onwards, so as to avoid bias from November 1's results.[14]

2.3.6. Analysis of Identical Units

It was observed that stations with exactly identical characteristics and prices might sometimes be causing difficulties within the PLEXOS solver. NERA therefore experimented by creating tie-breakers on station costs (a very small adder to the unit cost of one) for stations that are bid as identical, and this resulted in a small improvement in the over-commitment and uplift measure. Measured in uplift, it resulted in an average reduction of about €0.05 /MWh. While NERA did not include tie breaking in its validated dataset due to the relatively small impact on uplift, PLEXOS users may choose to add infinitesimal tie-breakers to identical units.

[14] In general it is recommended to ignore the first day in forecast runs as well. However, when extracting average results, it should be noted that the longer the period over-which one is averaging, the lower the impact of this "first day effect".

2.3.7. Analysis of Mixed Integer Programming

Mixed Integer Programming (MIP) should in theory be capable of producing optimal results, given the data available, without the over-commitment issue. MIP runs were not expected to be part of the recommended solution of the calibration process however, since MIP run times are very high. Nevertheless, to determine how much of the residual calibration difference was caused by the rounded relaxation heuristic, vs. how much was determined by other factors, MIP runs were attempted.

The results were not satisfactory. The MIP runs did not solve to optimality within an acceptable timeframe. Using termination criteria to stop runs when the solution was "close" did result in feasible solutions, however the price calibration was poorer than from the rounded relaxation method.

Energy Exemplar advise that considerable advances are currently being made in new MIP solver logic by the third-party solver engine developers. MIP runs should therefore be re-evaluated as soon as the 2009 model validation process.

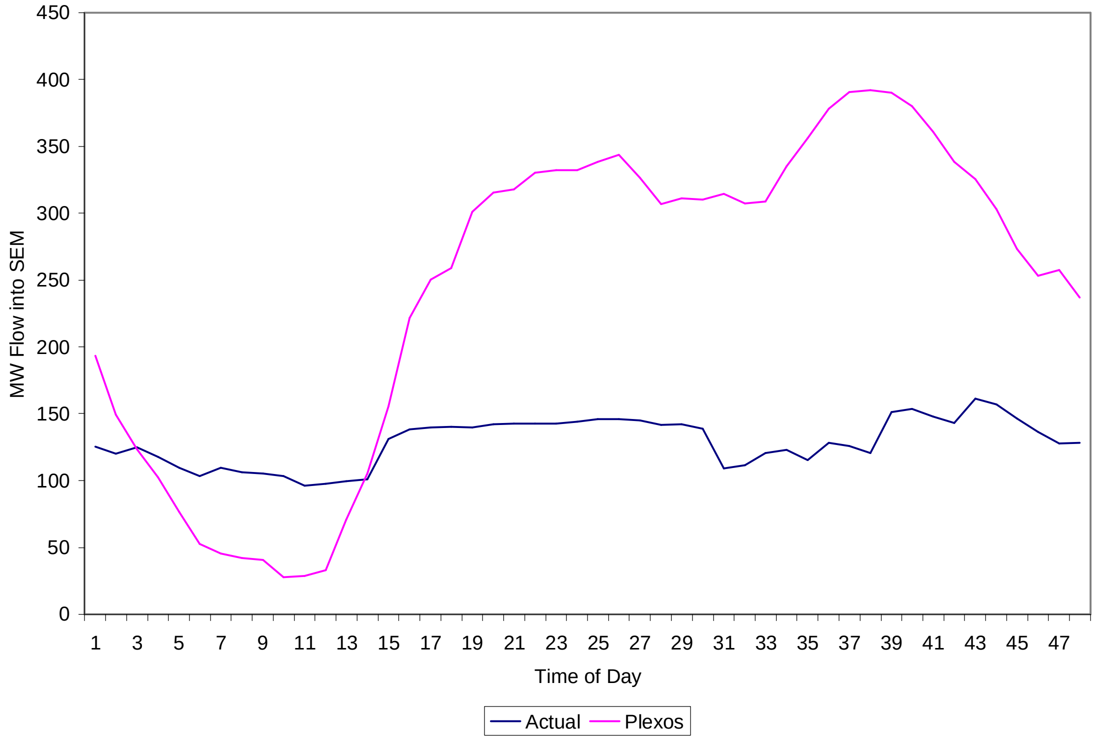
2.3.8. Analysis of Alternative Peaker Min Stable Levels

NERA still observed some instances of over-commitment and multiple peaking units being sent to their elbow point (whereas inspection of the individual circumstances would sometimes show that one unit at higher output would have been feasible and lower cost than two units at their first elbow level). NERA alternatively tested fully block loading peaker units, and then adjusting their MSLs to their elbow point. Neither resulted in significant improvements, or in improvements that justified over-riding the units' technical data, and so this experiment was dropped.

2.3.9. Analysis of Moyle

NERA analysed the typical pattern of predicted flow on Moyle across a day, and this is illustrated in Figure 2.8. (Note this figure represents average Moyle flow into the SEM by time of day and is averaged over the four months November 2007 to February 2008 inclusive).

Figure 2.8: Moyle Comparison: November 2007 - February 2008



It was determined that the pattern of Moyle inflows from PLEXOS is much more responsive to changing market conditions than the pattern of inflows observed in the actual market. A fundamental reason for that may be that PLEXOS schedules Moyle effectively in real-time, by jointly dispatching the SEM and BETTA markets. By way of contrast, actual Moyle flows are scheduled day-ahead and can't be so responsive to short-term market movements.

NERA attempted therefore to reduce the responsiveness of Moyle without biasing the decision as to the average level of flow. To achieve this, a ramp rate constraint was placed on Moyle, with the help of Energy Exemplar who created special conditions to allow this.

The results did not present an improvement however. Without the flexibility afforded by Moyle, the over-commitment and uplift issue significantly worsened. The same was true in experimental cases where Moyle flows were frozen at actual levels.

While we suspect that some aspect of the Great Britain market arrangements prevents Moyle imports form responding to prices on the island of Ireland and that PLEXOS does not model that aspect, this does not appear to have a material impact on SMP estimation.

2.3.10. Analysis of Hydro and Pumped Storage Schedules

NERA analysed hydro schedules and these were deemed to be acceptable. The following figures illustrate average hydro production (actual vs. PLEXOS backcast) by time of day for November 2007 to February 2008 in total, and for each month independently. Figure 3-14 illustrates the November 2007 to February 2008 pattern for pumped storage. PLEXOS performed adequately well at replicating the daily production shape, which changed significantly due to the seasonal nature of hydro production, over and within each of the four months concerned. The PLEXOS pumped storage production pattern followed the appropriate actual daily pattern of production, although PLXEOS did tend to operate the Pumped Storage at lower levels than those observed.

Figure 2.9: Hydro Comparison: November 2007 - February 2008

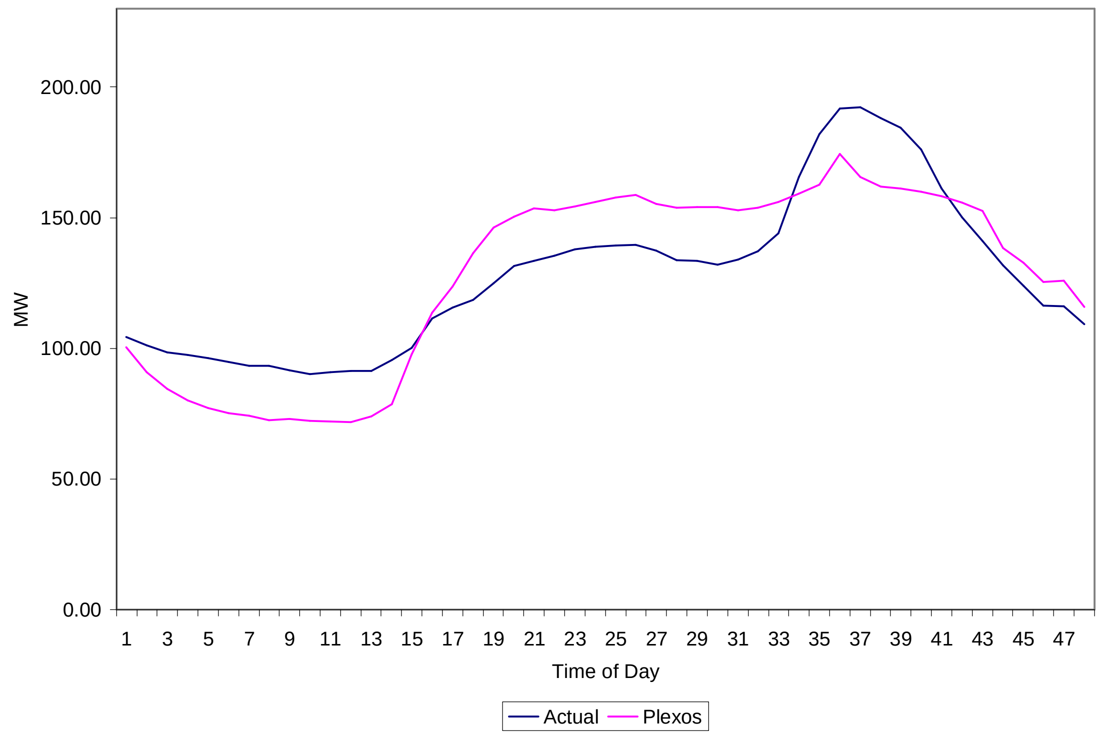


Figure 2.10: Hydro Comparison: November 2007

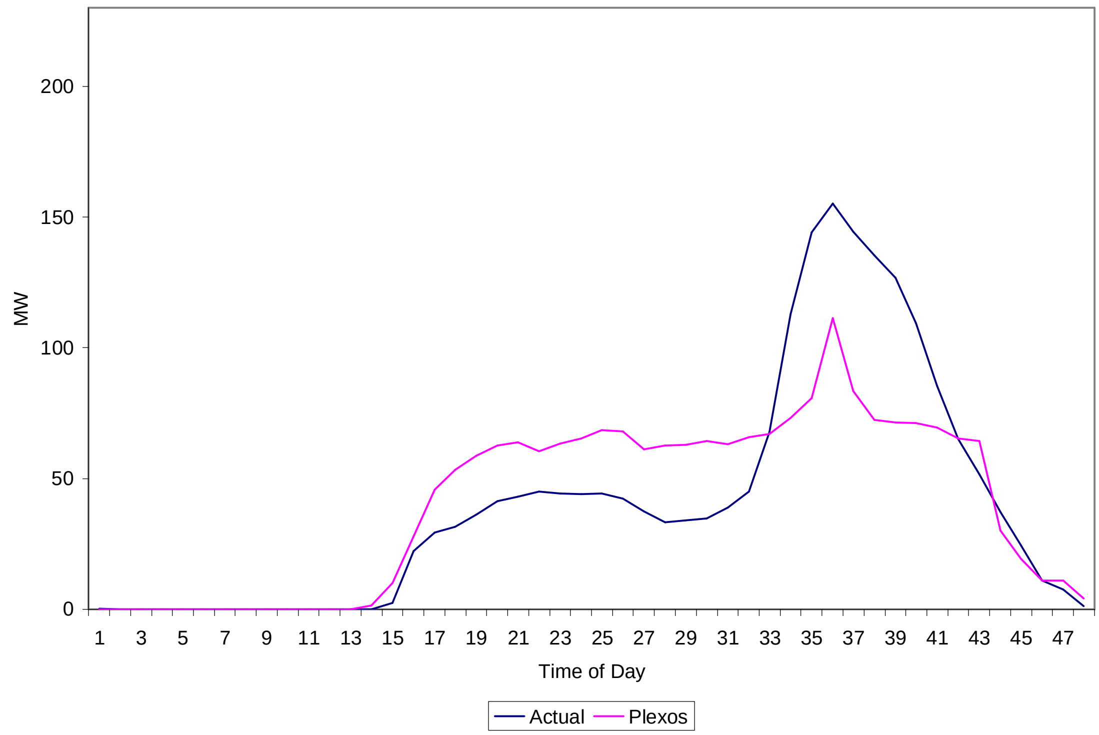


Figure 2.11: Hydro Comparison: December 2007

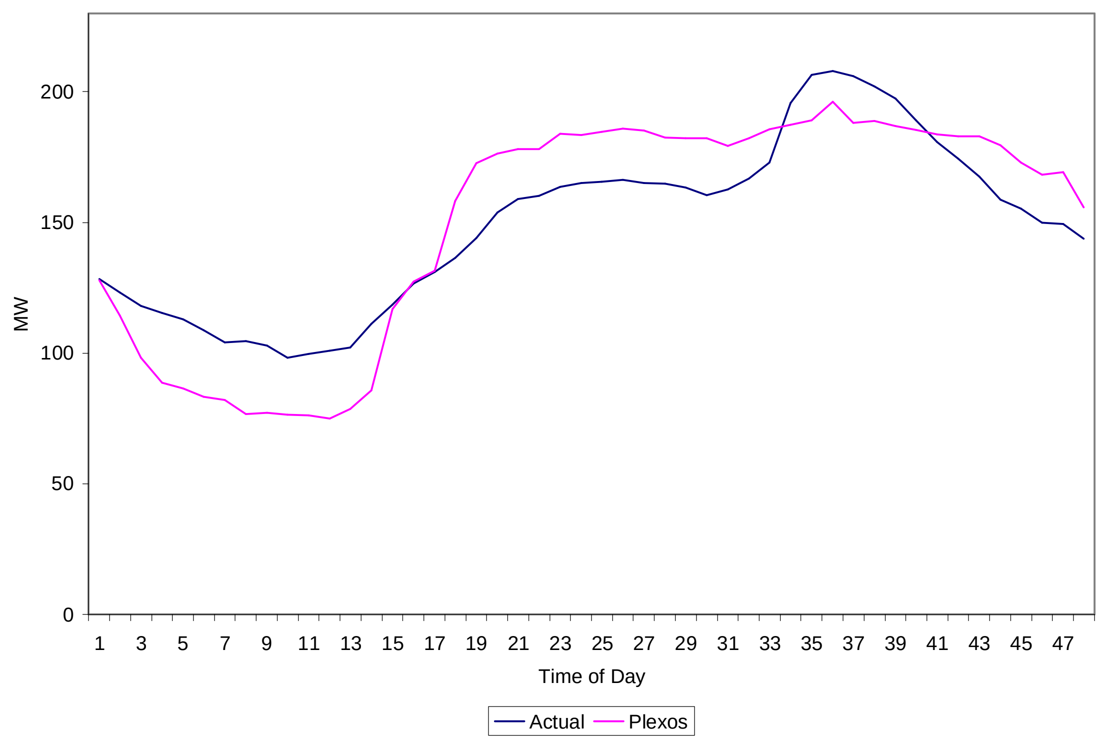


Figure 2.12: Hydro Comparison: January 2008

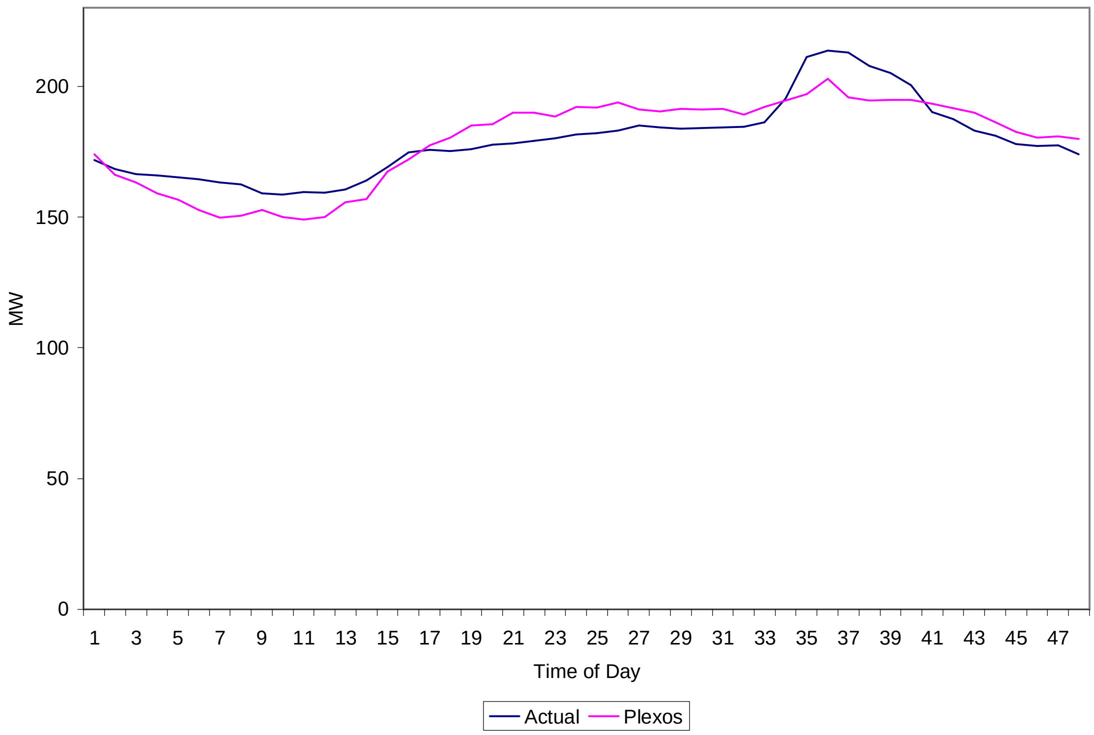


Figure 2.13: Hydro Comparison: February 2008

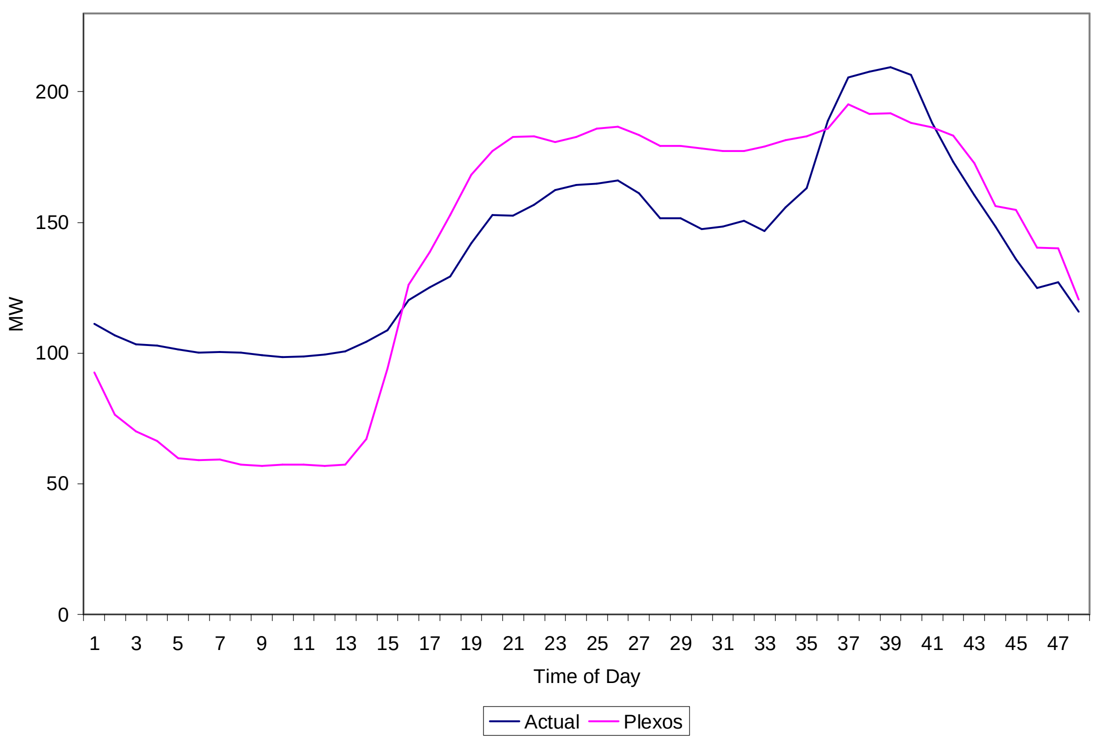
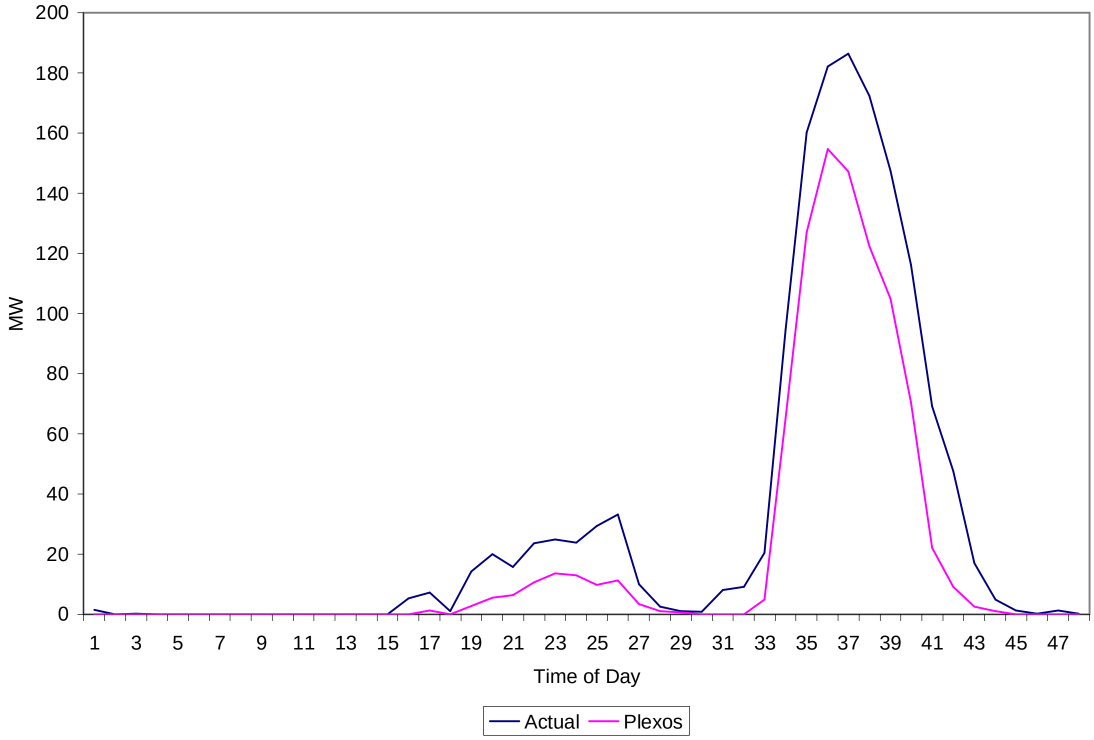


Figure 2.14: Pumped Storage Comparison: November 2007 - February 2008



3. Recommendations

In this section we summarise recommendations on how PLEXOS should best be run to model the SEM in the light of our findings above, and given the need of the Regulatory Authorities to run PLEXOS on the basis of a wide variety of fuel price assumptions.

Warm starts

NERA recommends that only warm starts be modelled, instead of cold, warm and hot. To be specific, when forecasting, for each unit, only one fuel offtake at start GJ value and one euro/start[15] start cost value are recommended to be entered into PLEXOS – the one being the warm state values. This simplifies the PLEXOS database: only one "band" is needed for start costs, and start times are not needed at all.[16] In offer-based backcast runs, it is only the one euro/start start cost value that is needed, as fuel offtake at start should not be not modelled in offer-based mode.

Dispatch algorithm

NERA recommends the rounded relaxation dispatch algorithm, set at the rounded relaxation slider position of 5.

Use of PLEXOS 4909 R01 or above:

NERA recommends that SEM PLEXOS users upgrade to PLEXOS 4909 R01 or above, so as to benefit from the small improvement made to the uplift algorithm by Energy Exemplar.

Use of Uplift Filters:

NERA recommends continued use of the MSL and Ramp rate uplift filters.

MIP

NERA recommends that MIP be re-evaluated in 2009.

These recommendations were discussed and presented in a workshop in Dublin on April 15 2008 at the CER's premises with the Regulatory Authorities, market participants, System Operators, and the Market Operator.

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15 In the forecast mode, the euro/start costs are VOM costs, and these may be zero for some units.

16 Start times is the PLEXOS property that sets the cooling times between start states.

Appendix A. Generator Data Set from 2007 Validation Process

					Heat Rate Curve																						Boundary times	
Unit ID	Unit Name	Min Stable Capacity	Max capacity	Fuel	No Load Heat Requirement (GJ/hr)	Capacity Point [MW exported]					Incremental Heat Rate Slope [GJ/MWhr]				Forced Outage Rate,%	Mean Time to Repair, hrs	Ramp Rate Up, MW/min	Ramp Rate Down, MW/min	Min Up Time (hrs)	Min Down Time (hrs)	Start up Energy (GJ) Cold	Start up Energy (GJ) Warm	Start up Energy (GJ) Hot	Hot to Warm, hrs	Warm to Cold, hrs
						1	2	3	4	5	1 to 2	2 to 3	3 to 4	4 to 5											
AD1	Aghada Unit 1	35.0	258.0	Gas	187.53	35	74	112	180	258	7.877	8.122	8.654	8.740	5.0%	50	4.2	4.2	4.00	3.50	4302	2185	1273	5	72
AT1	Aghada CT Unit 1	15.0	88.0	Distillate	279.86	15	40	88	0	0	7.683	9.533	0.000	0.000	5.0%	50	5.0	5.0	0.00	0.75	63	63	63	1	2
AT2	Aghada CT Unit 2	15.0	88.0	Distillate	279.86	15	40	88	0	0	7.683	9.533	0.000	0.000	5.0%	50	5.0	5.0	0.00	0.75	63	63	63	1	2
AT4	Aghada CT Unit 4	15.0	90.0	Gas	279.86	15	40	90	0	0	7.683	9.533	0.000	0.000	5.0%	50	5.0	5.0	0.00	0.75	63	63	63	1	2
AP5	Aghada Peaking Unit	5.0	52.0	Distillate	86.62	5	52	0	0	0	9.050	0.000	0.000	0.000	5.0%	50	5.0	5.0	0.00	0.08	20	20	20	0.5	1
AA1	Ardnacrusha Unit 1	12.0	21.0	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	6.0	6.0	0.00	0.25				1	2
AA2	Ardnacrusha Unit 2	12.0	22.0	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	6.0	6.0	0.00	0.25				1	2
AA3	Ardnacrusha Unit 3	12.0	19.0	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	6.0	6.0	0.00	0.25				1	2
AA4	Ardnacrusha Unit 4	12.0	24.0	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	6.0	6.0	0.00	0.25				1	2
DBP	Dublin Bay Power	207.0	415.0	Gas/Distillate	479.34	207	415				5.162				2.3%	31	11.0	11.0	4.00	1.00	6930	2340		1	72
ED1	Edenderry	41.0	117.6	Peat	497.60	41	88	98	118		3.933	8.950	8.950		8.0%	72	1.8	1.8	4.00	0.33	2010	1084	436	2.75	8
ER1	Erne Unit 1	4.0	10.0	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	5.0	5.0	0.00	0.17	0	0	0	1	2
ER2	Erne Unit 2	4.0	10.0	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	5.0	5.0	0.00	0.17	0	0	0	1	2
ER3	Erne Unit 3	5.0	22.5	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	10.0	10.0	0.00	0.17	0	0	0	1	2
ER4	Erne Unit 4	5.0	22.5	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	10.0	10.0	0.00	0.17	0	0	0	1	2
GI1	Great Island Unit 1	25.0	54.0	Oil	49.57	25	45	54	0	0	11.249	12.062	0.000	0.000	19.0%	50	1.0	1.0	4.00	2.00	562	449	218	12	48
GI2	Great Island Unit 2	25.0	54.0	Oil	49.57	25	45	54	0	0	11.249	12.062	0.000	0.000	19.0%	50	1.0	1.0	4.00	2.00	562	449	218	12	48
GI3	Great Island Unit 3	30.0	108.0	Oil	102.04	30	98	108	0	0	9.769	9.922	0.000	0.000	21.0%	50	1.1	1.1	4.00	4.00	743	600	293	12	48
LE1	Lee Unit 1	3.0	15.0	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	0.8	0.8	0.00	0.17				1	2
LE2	Lee Unit 2	1.0	4.0	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	2.4	2.4	0.00	0.17				1	2
LE3	Lee Unit 3	3.0	8.0	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	1.5	1.5	0.00	0.17				1	2
LI1	Liffey Unit 1	3.0	15.0	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	5.0	5.0	0.00	0.20				1	2
LI2	Liffey Unit 2	3.0	15.0	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	5.0	5.0	0.00	0.20				1	2
LI4	Liffey Unit 4	0.4	4.0	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	2.0	2.0	0.25	0.13				1	2
LI5	Liffey Unit 5	0.2	4.0	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	0.0	0.0	0.00	0.12				1	2
LR4	Lough Rea	40.0	90.0	Peat	89.55	40	90	0	0	0	9.086	0.000	0.000	0.000	6.0%	50	2.0	2.0	5.00	1.00	562	449	218	8	60
HNC	Huntstown	220.0	343.0	Gas/Distillate	423.00	220	343				5.573				5.0%	55	6.0	6.0	4.00	4.00	9545	4947	1732	8	72
HN2	Huntstown Phase II	250.0	401.0	Gas/Distillate	494.00	250	401				5.335				5.0%	55	10.0	10.0	4.00	4.00	7000	2500	1200	4	72
MRT	Marina CC *	98.0	112.3	Gas	249.80	98	108	112	0	0	6.516	8.883	0.000	0.000	7.0%	50	1.7	1.7	4.00	1.00	50	50	50	10	40
MP1	Moneypoint Unit 1	136.0	285.0	Coal	148.34	136	200	285	0	0	9.313	9.406	0.000	0.000	4.0%	50	4.3	4.3	8.00	5.00	14620	6920	4360	8	72
MP2	Moneypoint Unit 2	136.0	285.0	Coal	148.34	136	200	285	0	0	9.313	9.406	0.000	0.000	4.0%	50	4.3	4.3	8.00	5.00	14620	6920	4360	8	72
MP3	Moneypoint Unit 3	136.0	285.0	Coal	148.34	136	200	285	0	0	9.313	9.406	0.000	0.000	4.0%	50	4.3	4.3	8.00	5.00	14620	6920	4360	8	72
MP1	Moneypoint Unit 1 FGD SCR	136.0	282.5	Coal	148.34	136	200	283	0	0	9.350	9.600	0.000	0.000	4.0%	50	4.3	4.3	8.00	5.00	14620	6920	4360	8	72
MP2	Moneypoint Unit 2 FGD SCR	136.0	282.5	Coal	148.34	136	200	283	0	0	9.350	9.600	0.000	0.000	4.0%	50	4.3	4.3	8.00	5.00	14620	6920	4360	8	72
MP3	Moneypoint Unit 3 FGD SCR	136.0	282.5	Coal	148.34	136	200	283	0	0	9.350	9.600	0.000	0.000	4.0%	50	4.3	4.3	8.00	5.00	14620	6920	4360	8	72

Note: Excludes data in KEMA's validated dataset but not used by KEMA in PLEXOS (namely, run-up rates, synchronization times, and reserves).

Unit ID	Unit Name	Min Stable Capacity	Max capacity	Fuel	Heat Rate Curve: No Load Heat Requirement (GJ/hr)	Capacity Point [MW exported] 1	2	3	4	5	Incremental Heat Rate Slope [GJ/MWhr] 1 to 2	2 to 3	3 to 4	4 to 5	Forced Outage Rate,%	Mean Time to Repair, hrs	Ramp Rate Up, MW/min	Ramp Rate Down, MW/min	Min Up Time (hrs)	Min Down Time (hrs)	Start up Energy (GJ) Cold	Start up Energy (GJ) Warm	Start up Energy (GJ) Hot	Boundary times: Hot to Warm, hrs	Warm to Cold, hrs
NW4	Northwall Unit 4	99.0	163.0	Gas	351.77	99	115	162	163	0	6.074	6.848	8.883	0.000	7.0%	50	2.6	2.6	4.00	0.75	80	80	80	7	48
NW5	Northwall Unit 5	5.0	109.0	Distillate	309.39	5	109	0	0	0	9.715	0.000	0.000	0.000	5.0%	50	8.0	8.0	0.00	0.50	50	50	50	1	2
PB1	Poolbeg Unit 1	56.0	109.5	Gas/Oil	80.18	56	106	110	0	0	9.508	10.228	0.000	0.000	14.0%	50	2.0	2.0	3.00	2.00	1025	625	353	15	120
PB2	Poolbeg Unit 2	56.0	109.5	Gas/Oil	80.18	56	106	110	0	0	9.508	10.228	0.000	0.000	14.0%	50	2.0	2.0	3.00	2.00	1025	625	353	15	120
PB3	Poolbeg Unit 3	57.0	242.0	Gas/Oil	245.86	57	242	0	0	0	8.447	0.000	0.000	0.000	100.0%	50	3.0	3.0	4.25	3.50	4302	2185	1273	15	120
PBC	Poolbeg Combined Cycle	280.0	480.0	Gas	704.52	280	480	0	0	0	5.410	0.000	0.000	0.000	5.0%	50	10.0	10.0	4.00	2.00	3000	2500	2000	15	120
TB1	Tarbert Unit 1	25.0	54.0	Oil	46.05	25	46	54	0	0	11.240	11.712	0.000	0.000	12.0%	50	1.9	1.9	4.00	2.00	562	449	218	12	48
TB2	Tarbert Unit 2	25.0	54.0	Oil	46.05	25	46	54	0	0	11.240	11.712	0.000	0.000	12.0%	50	1.9	1.9	4.00	2.00	562	449	218	12	48
TB3	Tarbert Unit 3	35.0	240.7	Oil	256.89	35	80	115	180	241	7.814	8.226	8.776	8.864	15.0%	50	2.5	2.5	5.00	3.50	3180	1934	1072	14	120
TB4	Tarbert Unit 4	35.0	240.7	Oil	256.89	35	80	115	180	241	7.814	8.226	8.776	8.864	15.0%	50	2.5	2.5	5.00	3.50	3180	1934	1072	14	120
RH1	Rhode Unit 1	5.0	52.0	Distillate	85.01	5	52	0	0	0	9.000	0.000	0.000	0.000	5.0%	50	5.0	5.0	0.00	0.08	20	20	20	0.5	1
RH2	Rhode Unit 2	5.0	52.0	Distillate	85.01	5	52	0	0	0	9.000	0.000	0.000	0.000	5.0%	50	5.0	5.0	0.00	0.08	20	20	20	0.5	1
TP1	Asahi Peaking Unit	5.0	52.0	Distillate	85.01	5	52	0	0	0	9.000	0.000	0.000	0.000	5.0%	50	5.0	5.0	0.00	0.08	20	20	20	0.5	1
SK3	Sealrock 3 (Aughinish CHP)	40.0	83.0	Gas	100.00	40	48	60	72	83	5.000	5.000	5.000	5.000	3.0%	33	6.0	6.0	4.00	4.00	1200	1000	800	8	24
SK4	Sealrock 4 (Aughinish CHP)	40.0	83.0	Gas	100.00	40	48	60	72	83	5.000	5.000	5.000	5.000	3.0%	33	6.0	6.0	4.00	4.00	1200	1000	800	8.00	24
TE	Tynagh	224.0	373.0	Gas/Distillate	564.00	224	373				5.060				3.6%	55	10.0	8.0	4.00	3.50	2811	1633	1144	8	40
TH1	Turlough Hill Unit 1	5.0	73.0	Hydro											2.5%	60	210.0	210.0	0.00	0.00				1	12
TH2	Turlough Hill Unit 2	5.0	73.0	Hydro											2.5%	60	210.0	210.0	0.00	0.00				1	12
TH3	Turlough Hill Unit 3	5.0	73.0	Hydro											2.5%	60	210.0	210.0	0.00	0.00				1	12
TH4	Turlough Hill Unit 4	5.0	73.0	Hydro											2.5%	60	210.0	210.0	0.00	0.00				1	12
WO4	West Offaly Power	52.5	135.7	Peat	124.59	53	136	0	0	0	8.954	0.000	0.000	0.000	6.0%	50	2.0	2.0	5.00	1.00	750	600	450	12	60
B4	Ballylumford Unit 4	56.0	170.0	Gas	161.34	56	170				9.459				2.2%	72	5.0	10.0	4.00	7.00	1912	1374	762	10	36
B6	Ballylumford Unit 6	56.0	170.0	Gas	161.34	56	170				9.459				2.2%	72	5.0	10.0	4.00	7.00	1912	1374	762	10	36
B31	Ballylumford CCGT 31	116.0	240.0	Gas	446.22	116	240				5.184				3.0%	72	11.0	11.0	4.00	2.00	5800	1900	1000	8	48
B32	Ballylumford Unit 32	116.0	240.0	Gas	446.22	116	240				5.184				3.0%	72	11.0	11.0	4.00	2.00	5800	1900	1000	8	48
B10	Ballylumford Unit 10	63.0	103.0	Gas	88.34	63	103				6.003				3.0%	72	4.0	4.0	6.00	4.00	1800	750	500	8	48
BGT1	Ballylumford GT1	8.0	58.0	Distillate	162.00	8	58				9.945				1.4%	72	10.0	10.0	1.00	1.00	14	14	14	n/a = OCGT	
BGT2	Ballylumford GT2	8.0	58.0	Distillate	162.00	8	58				9.945				1.4%	72	10.0	10.0	1.00	1.00	14	14	14	n/a = OCGT	
CPS CCGT	Coolkeeragh CCGT	260.0	404.0	Gas/DIstillate	495.80	260	404				5.454				3.0%	72	11.0	11.0	6.00	3.50	5220	3024	1080	8	36
CGT8	Coolkeeragh GT8	8.0	53.0	Distillate	176.94	8	53				10.860				1.1%	72	10.0	10.0	1.00	1.00	16	16	16	n/a = OCGT	
K1	Kilroot Unit 1	64.1	238.2	Coal/Oil	293.14	64	179	202	238		8.155	44.130	61.050		2.7%	72	3.5	6.5	1.00	5.00	2267	1683	991	10	55
K2	Kilroot Unit 2	64.1	238.2	Coal/Oil	293.14	64	179	202	238		8.155	44.130	61.050		2.7%	72	3.5	6.5	1.00	5.00	2267	1683	991	10	55
KGT1	Kilroot GT1	5.0	29.0	Distillate	102.50	5	24	29			10.990	10.990	221.990		0.8%	72	10.0	10.0	1.00	1.00	8			n/a = OCGT	
KGT2	Kilroot GT2	5.0	29.0	Distillate	102.50	5	24	29			10.990	10.990	221.990		0.8%	72	10.0	10.0	1.00	1.00	8			n/a = OCGT	

Note: Excludes data in KEMA's validated dataset but not used by KEMA in PLEXOS (namely, run-up rates, synchronization times, and reserves).

Appendix B. Revised Gen Data: Oct 1 2008 – Dec 31 2009

PLEXOS Unit ID	Unit Name	Change Date for New Unit Characteristics	Start Fuel 1	Percent	Start Fuel 2	Percent	Fuel for Generation and No Load	Min Stable Capacity	Max capacity	Summer Rating--Where Different
K1 Coal 220	Kilroot Unit 1 FGD	5/1/2008	Oil	100%			Coal	54.0	236.6	
K2 Coal 220	Kilroot Unit 2 FGD	5/1/2008	Oil	100%			Coal	54.0	236.6	
KGT1	Kilroot GT1		Distillate	100%			Distillate	5.4	29.0	
KGT2	Kilroot GT2		Distillate	100%			Distillate	5.4	29.0	
SK3	Sealrock 3 (Aughinish CHP)		Gas	100%			Gas	40.0	83.0	
SK4	Sealrock 4 (Aughinish CHP)		Gas	100%			Gas	40.0	83.0	
ED1	Edenderry		Oil	100%			Peat	41.0	117.6	
CGT8	Coolkeeragh GT8		Distillate	100%			Distillate	8.0	58.0	
CPS CCGT	Coolkeeragh CCGT		Gas	100%			Gas	260.0	413.0	400.6
AA1	Ardnacrusha Unit 1			100%				11.9	21.0	
AA2	Ardnacrusha Unit 2			100%				11.9	22.0	
AA3	Ardnacrusha Unit 3			100%				11.9	19.0	
AA4	Ardnacrusha Unit 4			100%				11.9	24.0	
AD1	Aghada Unit 1		Gas	100%			Gas	35.0	258.0	
AP5	Aghada Peaking Unit		Distillate	100%			Distillate	5.0	52.0	
AT1	Aghada CT Unit 1		Distillate	100%			Distillate	15.0	88.0	
AT2	Aghada CT Unit 2		Gas	100%			Gas	15.0	90.0	
AT4	Aghada CT Unit 4		Gas	100%			Gas	15.0	90.0	
ER1	Erne Unit 1			100%				4.0	10.0	
ER2	Erne Unit 2			100%				4.0	10.0	
ER3	Erne Unit 3			100%				5.0	22.5	
ER4	Erne Unit 4			100%				5.0	22.5	
GI1	Great Island Unit 1		Oil	61%	Distillate	39%	Oil	25.0	54.0	
GI2	Great Island Unit 2		Oil	61%	Distillate	39%	Oil	25.0	49.0	
GI3	Great Island Unit 3		Oil	61%	Distillate	39%	Oil	30.0	101.0	
LE1	Lee Unit 1			100%				3.0	15.0	
LE2	Lee Unit 2			100%				1.0	4.0	
LE3	Lee Unit 3			100%				3.0	8.0	
LI1	Liffey Unit 1			100%				3.0	15.0	
LI2	Liffey Unit 2			100%				3.0	15.0	
LI4	Liffey Unit 4			100%				0.5	4.0	
LI5	Liffey Unit 5			100%				0.2	4.0	
LR4	Lough Rea		Peat	100%			Peat	73.0	91.0	
MP1	Moneypoint Unit 1 FGD SCR	4/1/2008	Coal	68%	Oil	32%	Coal	136.0	280.0	
MP2	Moneypoint Unit 2 FGD SCR	7/15/2008	Coal	68%	Oil	32%	Coal	136.0	280.0	
MP3	Moneypoint Unit 3 FGD SCR	4/1/2008	Coal	68%	Oil	32%	Coal	136.0	280.0	
MRC	Marina CC		Gas	100%			Gas	98.0	112.0	108.6
MRC No ST	Marina No ST		Gas	100%			Gas	71.0	85.0	82.5
NW4	Northwall Unit 4		Gas	100%			Gas	87.3	163.0	158.1
NW5	Northwall Unit 5		Distillate	100%			Distillate	4.0	104.0	
PB1	Poolbeg Unit 1		Gas	100%			Gas	56.0	109.5	
PB2	Poolbeg Unit 2		Gas	100%			Oil	36.0	109.5	
PB3	Poolbeg Unit 3		Gas	100%			Gas/Oil	57.0	242.0	
PBC	Poolbeg Combined Cycle		Gas	100%			Gas	274.5	480.0	465.6
RH1	Rhode Unit 1		Distillate	100%			Distillate	5.0	52.0	
RH2	Rhode Unit 2		Distillate	100%			Distillate	5.0	52.0	
TB1	Tarbert Unit 1		Oil	61%	Distillate	39%	Oil	18.0	54.0	
TB2	Tarbert Unit 2		Oil	61%	Distillate	39%	Oil	18.0	54.0	
TB3	Tarbert Unit 3		Oil	70%	Distillate	30%	Oil	34.8	240.7	
TB4	Tarbert Unit 4		Oil	70%	Distillate	30%	Oil	34.9	240.7	
TH1	Turlough Hill Unit 1			100%				5.0	73.0	
TH2	Turlough Hill Unit 2			100%				5.0	73.0	
TH3	Turlough Hill Unit 3			100%				5.0	73.0	
TH4	Turlough Hill Unit 4			100%				5.0	73.0	
TP1	Asahi Peaking Unit		Distillate	100%			Distillate	5.0	52.0	
WO4	West Offaly Power		Peat	100%			Peat	106.2	137.0	
B10	Ballylumford Unit 10		Gas	100%			Gas	63.0	102.0	98.9
B31	Ballylumford CCGT 31		Gas	100%			Gas	115.0	251.6	244.1
B32	Ballylumford Unit 32		Gas	100%			Gas	115.0	251.6	244.1
B4	Ballylumford Unit 4		Gas	100%			Gas	54.0	170.0	
B6	Ballylumford Unit 6		Gas	100%			Gas	54.0	170.0	
BGT1	Ballylumford GT1		Distillate	100%			Distillate	8.0	58.0	
BGT2	Ballylumford GT2		Distillate	100%			Distillate	8.0	58.0	
DB1	Dublin Bay Power		Gas	100%			Gas	207.0	415.0	402.6
TY	Tynagh		Gas	100%			Gas	220.0	379.0	367.6
HN2	Huntstown Phase II		Gas	100%			Gas	194.0	412.0	399.6
HNC	Huntstown		Gas	100%			Gas	216.0	343.0	332.7

		Heat Rate Curve														
PLEXOS Unit ID	Unit Name	No Load Heat Requirement (GJ/hr)	Capacity Point [MW exported]					Incremental Heat Rate Slope [GJ/MWhr]				Forced Outage Rate,%	Mean Time to Repair, hrs	Ramp Rate Up, MW/min	Ramp Rate Down, MW/min
			1	2	3	4	5	1 to 2	2 to 3	3 to 4	4 to 5				
K1 Coal 220	Kilroot Unit 1 FGD	272.45	54	177	200	237	0	8.68	8.68	9.45	0.00	3.2%	72	6.0	6.0
K2 Coal 220	Kilroot Unit 2 FGD	272.45	54	177	200	237	0	8.68	8.68	9.45	0.00	3.2%	72	6.0	6.0
KGT1	Kilroot GT1	97.38	5	24	29	0	0	10.44	10.44	0.00	0.00	0.8%	72	6.0	6.0
KGT2	Kilroot GT2	97.38	5	24	29	0	0	10.44	10.44	0.00	0.00	0.8%	72	6.0	6.0
SK3	Sealrock 3 (Aughinish CHP)	100.00	40	83	0	0	0	5.00	0.00	0.00	0.00	3.0%	33	6.0	6.0
SK4	Sealrock 4 (Aughinish CHP)	100.00	40	83	0	0	0	5.00	0.00	0.00	0.00	3.0%	33	6.0	6.0
ED1	Edenderry	497.60	41	88	118	0	0	3.93	8.95	0.00	0.00	4.0%	72	1.8	1.8
CGT8	Coolkeeragh GT8	171.00	8	58	0	0	0	10.50	0.00	0.00	0.00	1.1%	72	10.0	10.0
CPS CCGT	Coolkeeragh CCGT	495.80	260	413	0	0	0	5.45	0.00	0.00	0.00	3.0%	72	8.0	18.5
AA1	Ardnacrusha Unit 1	...	...	...	...	...	...	...	...	...	...	2.4%	60	6.0	6.0
AA2	Ardnacrusha Unit 2	...	...	...	...	...	...	...	...	...	...	2.4%	60	6.0	6.0
AA3	Ardnacrusha Unit 3	...	...	...	...	...	...	...	...	...	...	2.4%	60	6.0	6.0
AA4	Ardnacrusha Unit 4	...	...	...	...	...	...	...	...	...	...	2.3%	60	6.0	6.0
AD1	Aghada Unit 1	189.41	35	120	190	258	0	8.09	8.75	8.83	0.00	6.6%	50	3.4	3.7
AP5	Aghada Peaking Unit	86.62	5	52	0	0	0	9.05	0.00	0.00	0.00	5.0%	50	5.0	10.0
AT1	Aghada CT Unit 1	279.85	15	40	88	0	0	7.68	9.53	0.00	0.00	4.0%	50	5.0	5.0
AT2	Aghada CT Unit 2	279.85	15	40	90	0	0	7.68	9.53	0.00	0.00	5.0%	50	5.0	5.0
AT4	Aghada CT Unit 4	280.32	15	40	90	0	0	7.69	9.55	0.00	0.00	4.9%	50	5.0	5.0
ER1	Erne Unit 1	...	...	...	...	...	...	...	...	...	...	2.4%	60	5.0	10.0
ER2	Erne Unit 2	...	...	...	...	...	...	...	...	...	...	2.3%	60	5.0	10.0
ER3	Erne Unit 3	...	...	...	...	...	...	...	...	...	...	0.6%	60	10.0	22.5
ER4	Erne Unit 4	...	...	...	...	...	...	...	...	...	...	2.4%	60	10.0	22.5
GI1	Great Island Unit 1	51.07	25	45	54	0	0	11.59	12.43	0.00	0.00	40.0%	50	1.0	1.0
GI2	Great Island Unit 2	51.07	25	45	49	0	0	11.59	12.43	0.00	0.00	40.0%	50	1.0	1.0
GI3	Great Island Unit 3	102.65	30	98	101	0	0	9.83	9.98	0.00	0.00	40.0%	50	0.8	1.5
LE1	Lee Unit 1	...	...	...	...	...	...	...	...	...	...	2.4%	60	2.4	15.0
LE2	Lee Unit 2	...	...	...	...	...	...	...	...	...	...	2.4%	60	1.5	4.0
LE3	Lee Unit 3	...	...	...	...	...	...	...	...	...	...	2.4%	60	0.6	8.0
LI1	Liffey Unit 1	...	...	...	...	...	...	...	...	...	...	2.4%	60	5.0	10.0
LI2	Liffey Unit 2	...	...	...	...	...	...	...	...	...	...	2.4%	60	5.0	10.0
LI4	Liffey Unit 4	...	...	...	...	...	...	...	...	...	...	2.5%	60	2.0	2.0
LI5	Liffey Unit 5	...	...	...	...	...	...	...	...	...	...	2.4%	60	0.0	2.0
LR4	Lough Rea	84.44	73	91	0	0	0	8.57	0.00	0.00	0.00	6.5%	50	0.8	0.8
MP1	Moneypoint Unit 1 FGD SCR	148.75	136	200	280	0	0	9.42	9.52	0.00	0.00	5.8%	50	3.1	5.0
MP2	Moneypoint Unit 2 FGD SCR	148.75	136	200	280	0	0	9.42	9.52	0.00	0.00	6.3%	50	3.1	5.0
MP3	Moneypoint Unit 3 FGD SCR	148.75	136	200	280	0	0	9.42	9.52	0.00	0.00	5.4%	50	3.1	5.0
MRC	Marina CC	234.51	98	108	112	0	0	6.88	8.75	0.00	0.00	8.2%	50	5.0	5.0
MRC No ST	Marina No ST	234.51	71	81	85	0	0	6.88	8.75	0.00	0.00	8.2%	50	5.0	5.0
NW4	Northwall Unit 4	370.75	87	115	162	163	0	6.40	7.22	8.68	0.00	16.0%	50	3.8	12.0
NW5	Northwall Unit 5	310.63	4	104	0	0	0	9.75	0.00	0.00	0.00	5.0%	50	8.0	8.0
PB1	Poolbeg Unit 1	81.93	56	106	110	0	0	9.35	10.08	0.00	0.00	12.7%	50	1.0	1.0
PB2	Poolbeg Unit 2	81.93	36	106	110	0	0	9.35	10.08	0.00	0.00	13.3%	50	1.0	1.0
PB3	Poolbeg Unit 3	287.71	57	120	190	242	0	8.81	11.77	11.85	0.00	Out 100%	50	2.3	2.6
PBC	Poolbeg Combined Cycle	713.20	275	480	0	0	0	5.48	0.00	0.00	0.00	7.6%	50	16.5	16.5
RH1	Rhode Unit 1	85.01	5	52	0	0	0	9.00	0.00	0.00	0.00	5.0%	50	5.0	10.0
RH2	Rhode Unit 2	85.01	5	52	0	0	0	9.00	0.00	0.00	0.00	5.0%	50	5.0	10.0
TB1	Tarbert Unit 1	44.40	18	46	54	0	0	10.81	11.26	0.00	0.00	13.2%	50	1.0	1.0
TB2	Tarbert Unit 2	44.40	18	46	54	0	0	10.81	11.26	0.00	0.00	13.2%	50	1.0	1.0
TB3	Tarbert Unit 3	256.11	35	120	190	241	0	7.95	8.76	8.84	0.00	14.0%	50	2.0	2.2
TB4	Tarbert Unit 4	256.11	35	120	190	241	0	7.95	8.76	8.84	0.00	14.0%	50	2.0	2.2
TH1	Turlough Hill Unit 1	0.00	0	0	0	0	0	0.00	0.00	0.00	0.00	4.9%	60	210.0	270.0
TH2	Turlough Hill Unit 2	0.00	0	0	0	0	0	0.00	0.00	0.00	0.00	4.7%	60	210.0	270.0
TH3	Turlough Hill Unit 3	0.00	0	0	0	0	0	0.00	0.00	0.00	0.00	11.7%	60	210.0	270.0
TH4	Turlough Hill Unit 4	0.00	0	0	0	0	0	0.00	0.00	0.00	0.00	11.7%	60	210.0	270.0
TP1	Asahi Peaking Unit	85.01	5	52	0	0	0	9.00	0.00	0.00	0.00	5.0%	50	5.0	10.0
WO4	West Offaly Power	114.71	106	137	0	0	0	8.24	0.00	0.00	0.00	5.1%	50	1.0	1.0
B10	Ballylumford Unit 10	88.34	63	102	0	0	0	6.00	0.00	0.00	0.00	3.0%	72	4.0	4.0
B31	Ballylumford CCGT 31	280.80	115	252	0	0	0	5.18	0.00	0.00	0.00	3.0%	72	11.0	11.0
B32	Ballylumford Unit 32	280.80	115	252	0	0	0	5.18	0.00	0.00	0.00	3.0%	72	11.0	11.0
B4	Ballylumford Unit 4	161.34	54	170	0	0	0	9.46	0.00	0.00	0.00	2.2%	72	5.0	10.0
B6	Ballylumford Unit 6	161.34	54	170	0	0	0	9.46	0.00	0.00	0.00	2.2%	72	5.0	10.0
BGT1	Ballylumford GT1	162.00	8	58	0	0	0	10.50	0.00	0.00	0.00	1.4%	72	10.0	18.0
BGT2	Ballylumford GT2	162.00	8	58	0	0	0	10.50	0.00	0.00	0.00	1.4%	72	10.0	18.0
DB1	Dublin Bay Power	479.34	207	415	0	0	0	5.16	0.00	0.00	0.00	2.3%	31	10.0	9.0
TY	Tynagh	564.00	220	379	0	0	0	5.06	0.00	0.00	0.00	3.6%	55	24.0	25.0
HN2	Huntstown Phase II	603.60	194	195	230	412	0	4.24	5.62	5.74	0.00	5.0%	55	20.0	20.0
HNC	Huntstown	541.20	216	217	230	250	343	4.55	5.19	5.99	6.01	5.0%	55	7.0	7.0

							Boundary times	
PLEXOS Unit ID	Unit Name	Min Up Time (hrs)	Min Down Time (hrs)	Start up Energy (GJ) Cold	Start up Energy (GJ) Warm	Start up Energy (GJ) Hot	Hot to Warm, hrs	Warm to Cold, hrs
K1 Coal 220	Kilroot Unit 1 FGD	0.00	0.02	2152	1580	941	10	55
K2 Coal 220	Kilroot Unit 2 FGD	0.00	0.02	2152	1580	941	10	55
KGT1	Kilroot GT1	0.02	0.25	8	8	8	n/a = OCGT	0
KGT2	Kilroot GT2	0.02	0.25	8	8	8	n/a = OCGT	0
SK3	Sealrock 3 (Aughinish CHP)	4.00	4.00	1200	1000	800	8	24
SK4	Sealrock 4 (Aughinish CHP)	4.00	4.00	1200	1000	800	8	24
ED1	Edenderry	4.00	0.50	2010	1084	436	4	48
CGT8	Coolkeeragh GT8	0.02	0.25	8	8	8	n/a = OCGT	0
CPS CCGT	Coolkeeragh CCGT	4.00	1.50	5220	3024	1080	8	36
AA1	Ardnacrusha Unit 1	0.00	0.25	0	0	0	12	60
AA2	Ardnacrusha Unit 2	0.00	0.25	0	0	0	12	60
AA3	Ardnacrusha Unit 3	0.00	0.25	0	0	0	12	60
AA4	Ardnacrusha Unit 4	0.00	0.25	0	0	0	12	60
AD1	Aghada Unit 1	4.00	3.50	4302	2185	1273	5	72
AP5	Aghada Peaking Unit	0.00	0.75	20	20	20	12	60
AT1	Aghada CT Unit 1	0.00	0.75	63	63	63	12	60
AT2	Aghada CT Unit 2	0.00	0.75	63	63	63	12	60
AT4	Aghada CT Unit 4	0.00	0.75	63	63	63	12	60
ER1	Erne Unit 1	0.00	0.17	0	0	0	12	60
ER2	Erne Unit 2	0.00	0.17	0	0	0	12	60
ER3	Erne Unit 3	0.00	0.17	0	0	0	12	60
ER4	Erne Unit 4	0.00	0.17	0	0	0	12	60
GI1	Great Island Unit 1	4.00	2.00	562	449	218	12	48
GI2	Great Island Unit 2	4.00	2.00	562	449	218	12	48
GI3	Great Island Unit 3	4.00	4.00	743	600	293	12	60
LE1	Lee Unit 1	0.00	0.17	0	0	0	12	60
LE2	Lee Unit 2	0.00	0.17	0	0	0	12	60
LE3	Lee Unit 3	0.00	0.17	0	0	0	12	60
LI1	Liffey Unit 1	0.00	0.20	0	0	0	12	60
LI2	Liffey Unit 2	0.00	0.20	0	0	0	12	60
LI4	Liffey Unit 4	0.25	0.13	0	0	0	12	60
LI5	Liffey Unit 5	0.00	0.12	0	0	0	12	60
LR4	Lough Rea	5.00	4.00	500	400	300	8	60
MP1	Moneypoint Unit 1 FGD SCR	6.00	5.00	14620	6920	4360	12	72
MP2	Moneypoint Unit 2 FGD SCR	6.00	5.00	14620	6920	4360	12	72
MP3	Moneypoint Unit 3 FGD SCR	6.00	5.00	14620	6920	4360	12	72
MRC	Marina CC	4.00	1.00	50	50	50	12	40
MRC No ST	Marina No ST	4.00	1.00	50	50	50	12	40
NW4	Northwall Unit 4	4.00	0.75	80	80	80	12	60
NW5	Northwall Unit 5	0.00	0.50	50	50	50	8	48
PB1	Poolbeg Unit 1	4.00	4.00	1025	625	353	15	60
PB2	Poolbeg Unit 2	4.00	4.00	1025	625	353	15	60
PB3	Poolbeg Unit 3	5.50	3.50	4302	2185	1273	15	120
PBC	Poolbeg Combined Cycle	4.00	4.00	11685	11685	11685	8	120
RH1	Rhode Unit 1	0.00	0.75	20	20	20	12	60
RH2	Rhode Unit 2	0.00	0.75	20	20	20	12	60
TB1	Tarbert Unit 1	3.00	2.00	562	449	218	12	60
TB2	Tarbert Unit 2	3.00	2.00	562	449	218	12	60
TB3	Tarbert Unit 3	24.00	4.00	3180	1934	1072	14	120
TB4	Tarbert Unit 4	24.00	4.00	3180	1934	1072	14	120
TH1	Turlough Hill Unit 1	0.00	0.00	0	0	0	12	60
TH2	Turlough Hill Unit 2	0.00	0.00	0	0	0	12	60
TH3	Turlough Hill Unit 3	0.00	0.00	0	0	0	12	60
TH4	Turlough Hill Unit 4	0.00	0.00	0	0	0	12	60
TP1	Asahi Peaking Unit	0.00	0.75	20	20	20	12	60
WO4	West Offaly Power	5.00	1.00	750	600	450	12	60
B10	Ballylumford Unit 10	0.02	0.25	405	225	135	8	48
B31	Ballylumford CCGT 31	0.02	0.25	1611	666	567	8	48
B32	Ballylumford Unit 32	0.02	0.25	1611	666	567	8	48
B4	Ballylumford Unit 4	0.02	0.02	1912	1374	762	10	36
B6	Ballylumford Unit 6	0.02	0.02	1912	1374	762	10	36
BGT1	Ballylumford GT1	0.02	0.25	8	8	8	n/a = OCGT	0
BGT2	Ballylumford GT2	0.02	0.25	8	8	8	n/a = OCGT	0
DB1	Dublin Bay Power	4.00	0.00	7700	2604	2600	1	72
TY	Tynagh	4.00	0.00	4115	2954	1900	8	40
HN2	Huntstown Phase II	4.00	4.00	644	531	318	12	72
HNC	Huntstown	4.00	4.00	4772	2803	835	12	72

Appendix C. Fuel Price Assumptions

Fuel Prices		Fuel Prices - Index Price			Fuel Prices - RoI Transport, Excise and Duties					Fuel Prices - NI Transport, Excise and Duties		
Fuel	**Quarter/Year**	**Import Price**	**Units**	**Description**	**Transport RoI**	**Units**	**Excise Duty**	**Units**	**Description**	**Transport NI**	**Units**	**Description**
Coal	Q4 07	120	$/tonne	Argus API2 (CIF, ARA)	1.60	$/tonne			Port Duties plus Delivery from Rotterdam to Moneypoint - ESBPG	15.80	$/tonne	Transhipment and Port Duties -- NIE PPB
Coal	Q1 08	120	$/tonne	Argus API2 (CIF, ARA)	1.60	$/tonne			Port Duties plus Delivery from Rotterdam to Moneypoint - ESBPG	17.68	$/tonne	Transhipment and Port Duties -- NIE PPB
Coal	Q2 08	120	$/tonne	Argus API2 (CIF, ARA)	1.60	$/tonne			Port Duties plus Delivery from Rotterdam to Moneypoint - ESBPG	17.68	$/tonne	Transhipment and Port Duties -- NIE PPB
Coal	Q3 08	120	$/tonne	Argus API2 (CIF, ARA)	1.60	$/tonne			Port Duties plus Delivery from Rotterdam to Moneypoint - ESBPG	17.68	$/tonne	Transhipment and Port Duties -- NIE PPB
Coal	Q4 08	120	$/tonne	Argus API2 (CIF, ARA)	1.60	$/tonne			Port Duties plus Delivery from Rotterdam to Moneypoint - ESBPG	17.68	$/tonne	Transhipment and Port Duties -- NIE PPB
Coal	Q1 09	120	$/tonne	Argus API2 (CIF, ARA)	1.60	$/tonne			Port Duties plus Delivery from Rotterdam to Moneypoint - ESBPG	17.68	$/tonne	Transhipment and Port Duties -- NIE PPB
Coal	Q2 09	120	$/tonne	Argus API2 (CIF, ARA)	1.60	$/tonne			Port Duties plus Delivery from Rotterdam to Moneypoint - ESBPG	17.68	$/tonne	Transhipment and Port Duties -- NIE PPB
Coal	Q3 09	120	$/tonne	Argus API2 (CIF, ARA)	1.60	$/tonne			Port Duties plus Delivery from Rotterdam to Moneypoint - ESBPG	17.68	$/tonne	Transhipment and Port Duties -- NIE PPB
Coal	Q4 09	120	$/tonne	Argus API2 (CIF, ARA)	1.60	$/tonne			Port Duties plus Delivery from Rotterdam to Moneypoint - ESBPG	17.68	$/tonne	Transhipment and Port Duties -- NIE PPB
Gasoil	Q4 07	1000.00	$/tonne	Platts Gasoil .2% (CIF, NWE)	23.33	€/tonne	56.07	€/tonne	Inland Transport Charge and Margin and Excise -- ESBPG	16.30	€/tonne	Delivery to site (premium on platts) -- NIE PPB
Gasoil	Q1 08	1000.00	$/tonne	Platts Gasoil .1% (CIF, NWE)	23.33	€/tonne	56.07	€/tonne	Inland Transport Charge and Margin and Excise -- ESBPG	16.30	€/tonne	Delivery to site (premium on platts) -- NIE PPB
Gasoil	Q2 08	1000.00	$/tonne	Platts Gasoil .1% (CIF, NWE)	23.33	€/tonne	56.07	€/tonne	Inland Transport Charge and Margin and Excise -- ESBPG	16.30	€/tonne	Delivery to site (premium on platts) -- NIE PPB
Gasoil	Q3 08	1000.00	$/tonne	Platts Gasoil .1% (CIF, NWE)	23.33	€/tonne	56.07	€/tonne	Inland Transport Charge and Margin and Excise -- ESBPG	16.30	€/tonne	Delivery to site (premium on platts) -- NIE PPB
Gasoil	Q4 08	1000.00	$/tonne	Platts Gasoil .1% (CIF, NWE)	23.33	€/tonne	56.07	€/tonne	Inland Transport Charge and Margin and Excise -- ESBPG	16.30	€/tonne	Delivery to site (premium on platts) -- NIE PPB
Gasoil	Q1 09	1000.00	$/tonne	Platts Gasoil .1% (CIF, NWE)	23.33	€/tonne	56.07	€/tonne	Inland Transport Charge and Margin and Excise -- ESBPG	16.30	€/tonne	Delivery to site (premium on platts) -- NIE PPB
Gasoil	Q2 09	1000.00	$/tonne	Platts Gasoil .1% (CIF, NWE)	23.33	€/tonne	56.07	€/tonne	Inland Transport Charge and Margin and Excise -- ESBPG	16.30	€/tonne	Delivery to site (premium on platts) -- NIE PPB
Gasoil	Q3 09	1000.00	$/tonne	Platts Gasoil .1% (CIF, NWE)	23.33	€/tonne	56.07	€/tonne	Inland Transport Charge and Margin and Excise -- ESBPG	16.30	€/tonne	Delivery to site (premium on platts) -- NIE PPB
Gasoil	Q4 09	1000.00	$/tonne	Platts Gasoil .1% (CIF, NWE)	23.33	€/tonne	56.07	€/tonne	Inland Transport Charge and Margin and Excise -- ESBPG	16.30	€/tonne	Delivery to site (premium on platts) -- NIE PPB
Gas	Q4 07	60.00	p/th HHV	Heren ICE NBP futures	0.22	€/GJ			RoI Commodity Element of Transport and UK Transport -- ESBPG	0.22	€/GJ	NI Commodity Element of Tx and UK Tx -- NIE PPB
Gas	Q1 08	60.00	p/th HHV	Heren ICE NBP futures	0.22	€/GJ			RoI Commodity Element of Transport and UK Transport -- ESBPG	0.22	€/GJ	NI Commodity Element of Tx and UK Tx -- NIE PPB
Gas	Q2 08	60.00	p/th HHV	Heren ICE NBP futures	0.22	€/GJ			RoI Commodity Element of Transport and UK Transport -- ESBPG	0.22	€/GJ	NI Commodity Element of Tx and UK Tx -- NIE PPB
Gas	Q3 08	60.00	p/th HHV	Heren ICE NBP futures	0.22	€/GJ			RoI Commodity Element of Transport and UK Transport -- ESBPG	0.22	€/GJ	NI Commodity Element of Tx and UK Tx -- NIE PPB
Gas	Q4 08	60.00	p/th HHV	Heren ICE NBP futures	0.22	€/GJ			RoI Commodity Element of Transport and UK Transport -- ESBPG	0.22	€/GJ	NI Commodity Element of Tx and UK Tx -- NIE PPB
Gas	Q1 09	60.00	p/th HHV	Heren ICE NBP futures	0.22	€/GJ			RoI Commodity Element of Transport and UK Transport -- ESBPG	0.22	€/GJ	NI Commodity Element of Tx and UK Tx -- NIE PPB
Gas	Q2 09	60.00	p/th HHV	Heren ICE NBP futures	0.22	€/GJ			RoI Commodity Element of Transport and UK Transport -- ESBPG	0.22	€/GJ	NI Commodity Element of Tx and UK Tx -- NIE PPB
Gas	Q3 09	60.00	p/th HHV	Heren ICE NBP futures	0.22	€/GJ			RoI Commodity Element of Transport and UK Transport -- ESBPG	0.22	€/GJ	NI Commodity Element of Tx and UK Tx -- NIE PPB
Gas	Q4 09	60.00	p/th HHV	Heren ICE NBP futures	0.22	€/GJ			RoI Commodity Element of Transport and UK Transport -- ESBPG	0.22	€/GJ	NI Commodity Element of Tx and UK Tx -- NIE PPB
LSFO	Q4 07	500.00	$/tonne	Platts 1% LSFO (FOB, NWE)	15.00	$/tonne	14.77	€/tonne	CIF/FOB Differential; Transport from Rotterdam, Excise and Port Charges - ESBPG	15.00	$/tonne	CIF/FOB Differential; Transkport from Rotternam, Excise and Port Charges -- ROI Value
LSFO	Q1 08	500.00	$/tonne	Platts 1% LSFO (FOB, NWE)	15.00	$/tonne	14.77	€/tonne	CIF/FOB Differential; Transport from Rotterdam, Excise and Port Charges - ESBPG	15.00	$/tonne	CIF/FOB Differential; Transkport from Rotternam, Excise and Port Charges -- ROI Value
LSFO	Q2 08	500.00	$/tonne	Platts 1% LSFO (FOB, NWE)	15.00	$/tonne	14.77	€/tonne	CIF/FOB Differential; Transport from Rotterdam, Excise and Port Charges - ESBPG	15.00	$/tonne	CIF/FOB Differential; Transkport from Rotternam, Excise and Port Charges -- ROI Value
LSFO	Q3 08	500.00	$/tonne	Platts 1% LSFO (FOB, NWE)	15.00	$/tonne	14.77	€/tonne	CIF/FOB Differential; Transport from Rotterdam, Excise and Port Charges - ESBPG	15.00	$/tonne	CIF/FOB Differential; Transkport from Rotternam, Excise and Port Charges -- ROI Value
LSFO	Q4 08	500.00	$/tonne	Platts 1% LSFO (FOB, NWE)	15.00	$/tonne	14.77	€/tonne	CIF/FOB Differential; Transport from Rotterdam, Excise and Port Charges - ESBPG	15.00	$/tonne	CIF/FOB Differential; Transkport from Rotternam, Excise and Port Charges -- ROI Value
LSFO	Q1 09	500.00	$/tonne	Platts 1% LSFO (FOB, NWE)	15.00	$/tonne	14.77	€/tonne	CIF/FOB Differential; Transport from Rotterdam, Excise and Port Charges - ESBPG	15.00	$/tonne	CIF/FOB Differential; Transkport from Rotternam, Excise and Port Charges -- ROI Value
LSFO	Q2 09	500.00	$/tonne	Platts 1% LSFO (FOB, NWE)	15.00	$/tonne	14.77	€/tonne	CIF/FOB Differential; Transport from Rotterdam, Excise and Port Charges - ESBPG	15.00	$/tonne	CIF/FOB Differential; Transkport from Rotternam, Excise and Port Charges -- ROI Value
LSFO	Q3 09	500.00	$/tonne	Platts 1% LSFO (FOB, NWE)	15.00	$/tonne	14.77	€/tonne	CIF/FOB Differential; Transport from Rotterdam, Excise and Port Charges - ESBPG	15.00	$/tonne	CIF/FOB Differential; Transkport from Rotternam, Excise and Port Charges -- ROI Value
LSFO	Q4 09	500.00	$/tonne	Platts 1% LSFO (FOB, NWE)	15.00	$/tonne	14.77	€/tonne	CIF/FOB Differential; Transport from Rotterdam, Excise and Port Charges - ESBPG	15.00	$/tonne	CIF/FOB Differential; Transkport from Rotternam, Excise and Port Charges -- ROI Value

Note: Index fuel prices are indicative

Fuel Prices		Fuel Prices - GB Transport, Excise and Duties			Calorific Value Net		Delivered Price		
Fuel	**Quarter/Year**	**Transport GB**	**Units**	**Description**	**Calorific Value Net**	**Units**	**RoI Price (€/GJ)**	**NI Price (€/GJ)**	**GB Price (€/GJ)**
Coal	Q4 07	15.80	$/tonne	Transhipment and Port Duties -- NI Value	25.11	GJ/tonne	3.23	3.61	3.61
Coal	Q1 08	17.68	$/tonne	Transhipment and Port Duties -- NI Value	25.11	GJ/tonne	3.23	3.66	3.66
Coal	Q2 08	17.68	$/tonne	Transhipment and Port Duties -- NI Value	25.11	GJ/tonne	3.23	3.66	3.66
Coal	Q3 08	17.68	$/tonne	Transhipment and Port Duties -- NI Value	25.11	GJ/tonne	3.23	3.66	3.66
Coal	Q4 08	17.68	$/tonne	Transhipment and Port Duties -- NI Value	25.11	GJ/tonne	3.23	3.66	3.66
Coal	Q1 09	17.68	$/tonne	Transhipment and Port Duties -- NI Value	25.11	GJ/tonne	3.23	3.66	3.66
Coal	Q2 09	17.68	$/tonne	Transhipment and Port Duties -- NI Value	25.11	GJ/tonne	3.23	3.66	3.66
Coal	Q3 09	17.68	$/tonne	Transhipment and Port Duties -- NI Value	25.11	GJ/tonne	3.23	3.66	3.66
Coal	Q4 09	17.68	$/tonne	Transhipment and Port Duties -- NI Value	25.11	GJ/tonne	3.23	3.66	3.66
Gasoil	Q4 07	16.30	€/tonne	Delivery to site (premium on platts) -- NI Value	42.75	GJ/tonne	17.45	15.98	15.98
Gasoil	Q1 08	16.30	€/tonne	Delivery to site (premium on platts) -- NI Value	42.75	GJ/tonne	17.45	15.98	15.98
Gasoil	Q2 08	16.30	€/tonne	Delivery to site (premium on platts) -- NI Value	42.75	GJ/tonne	17.45	15.98	15.98
Gasoil	Q3 08	16.30	€/tonne	Delivery to site (premium on platts) -- NI Value	42.75	GJ/tonne	17.45	15.98	15.98
Gasoil	Q4 08	16.30	€/tonne	Delivery to site (premium on platts) -- NI Value	42.75	GJ/tonne	17.45	15.98	15.98
Gasoil	Q1 09	16.30	€/tonne	Delivery to site (premium on platts) -- NI Value	42.75	GJ/tonne	17.45	15.98	15.98
Gasoil	Q2 09	16.30	€/tonne	Delivery to site (premium on platts) -- NI Value	42.75	GJ/tonne	17.45	15.98	15.98
Gasoil	Q3 09	16.30	€/tonne	Delivery to site (premium on platts) -- NI Value	42.75	GJ/tonne	17.45	15.98	15.98
Gasoil	Q4 09	16.30	€/tonne	Delivery to site (premium on platts) -- NI Value	42.75	GJ/tonne	17.45	15.98	15.98
Gas	Q4 07	0.04	€/GJ	GB Commodity Element of Tx -- KEMA GB Value	0.03	GJ/m3	8.14	8.15	7.97
Gas	Q1 08	0.04	€/GJ	GB Commodity Element of Tx -- KEMA GB Value	0.03	GJ/m3	8.14	8.15	7.97
Gas	Q2 08	0.04	€/GJ	GB Commodity Element of Tx -- KEMA GB Value	0.03	GJ/m3	8.14	8.15	7.97
Gas	Q3 08	0.04	€/GJ	GB Commodity Element of Tx -- KEMA GB Value	0.03	GJ/m3	8.14	8.15	7.97
Gas	Q4 08	0.04	€/GJ	GB Commodity Element of Tx -- KEMA GB Value	0.03	GJ/m3	8.14	8.15	7.97
Gas	Q1 09	0.04	€/GJ	GB Commodity Element of Tx -- KEMA GB Value	0.03	GJ/m3	8.14	8.15	7.97
Gas	Q2 09	0.04	€/GJ	GB Commodity Element of Tx -- KEMA GB Value	0.03	GJ/m3	8.14	8.15	7.97
Gas	Q3 09	0.04	€/GJ	GB Commodity Element of Tx -- KEMA GB Value	0.03	GJ/m3	8.14	8.15	7.97
Gas	Q4 09	0.04	€/GJ	GB Commodity Element of Tx -- KEMA GB Value	0.03	GJ/m3	8.14	8.15	7.97
LSFO	Q4 07	15.00	$/tonne	CIF/FOB Differential; Transkport from Rotternam, Excise and Port Charges -- ROI Value	40.47	GJ/tonne	8.85	8.48	8.48
LSFO	Q1 08	15.00	$/tonne	CIF/FOB Differential; Transkport from Rotternam, Excise and Port Charges -- ROI Value	40.47	GJ/tonne	8.85	8.48	8.48
LSFO	Q2 08	15.00	$/tonne	CIF/FOB Differential; Transkport from Rotternam, Excise and Port Charges -- ROI Value	40.47	GJ/tonne	8.85	8.48	8.48
LSFO	Q3 08	15.00	$/tonne	CIF/FOB Differential; Transkport from Rotternam, Excise and Port Charges -- ROI Value	40.47	GJ/tonne	8.85	8.48	8.48
LSFO	Q4 08	15.00	$/tonne	CIF/FOB Differential; Transkport from Rotternam, Excise and Port Charges -- ROI Value	40.47	GJ/tonne	8.85	8.48	8.48
LSFO	Q1 09	15.00	$/tonne	CIF/FOB Differential; Transkport from Rotternam, Excise and Port Charges -- ROI Value	40.47	GJ/tonne	8.85	8.48	8.48
LSFO	Q2 09	15.00	$/tonne	CIF/FOB Differential; Transkport from Rotternam, Excise and Port Charges -- ROI Value	40.47	GJ/tonne	8.85	8.48	8.48
LSFO	Q3 09	15.00	$/tonne	CIF/FOB Differential; Transkport from Rotternam, Excise and Port Charges -- ROI Value	40.47	GJ/tonne	8.85	8.48	8.48
LSFO	Q4 09	15.00	$/tonne	CIF/FOB Differential; Transkport from Rotternam, Excise and Port Charges -- ROI Value	40.47	GJ/tonne	8.85	8.48	8.48
Peat							0	—	—

Conversion	
0.367	th to m3

Cost of Carbon 2007							
Fuel	**Carbon Price**		**Emissions Factor**		**Oxidation Factor**	**Bid Pass Through**	**Cost of Carbon €/GJ**
Coal	0	€/tonne	0.0946	tCO2/GJ	99.0%	100.0%	0.00
Distillate	0	€/tonne	0.0741	tCO2/GJ	99.5%	100.0%	0.00
Gas	0	€/tonne	0.0561	tCO2/GJ	99.5%	100.0%	0.00
HFO	0	€/tonne	0.0774	tCO2/GJ	99.5%	100.0%	0.00
Peat	0	€/tonne	0.106	tCO2/GJ	99.0%	100.0%	0.00

Cost of Carbon 2008							
Fuel	**Carbon Price**		**Emissions Factor**		**Oxidation Factor**	**Bid Pass Through**	**Cost of Carbon €/GJ**
Coal	23	€/tonne	0.0946	tCO2/GJ	99.0%	100.0%	2.15
Distillate	23	€/tonne	0.0741	tCO2/GJ	99.5%	100.0%	1.70
Gas	23	€/tonne	0.0561	tCO2/GJ	99.5%	100.0%	1.28
HFO	23	€/tonne	0.0774	tCO2/GJ	99.5%	100.0%	1.77
Peat	23	€/tonne	0.106	tCO2/GJ	99.0%	100.0%	0.00

Cost of Carbon 2009							
Fuel	**Carbon Price**		**Emissions Factor**		**Oxidation Factor**	**Bid Pass Through**	**Cost of Carbon €/GJ**
Coal	25	€/tonne	0.0946	tCO2/GJ	99.0%	100.0%	2.34
Distillate	25	€/tonne	0.0741	tCO2/GJ	99.5%	100.0%	1.84
Gas	25	€/tonne	0.0561	tCO2/GJ	99.5%	100.0%	1.40
HFO	25	€/tonne	0.0774	tCO2/GJ	99.5%	100.0%	1.93
Peat	25	€/tonne	0.106	tCO2/GJ	99.0%	100.0%	0.00

Appendix D. Weekly SMP Comparisons

Figure D.1: SMP Comparison: Week 1

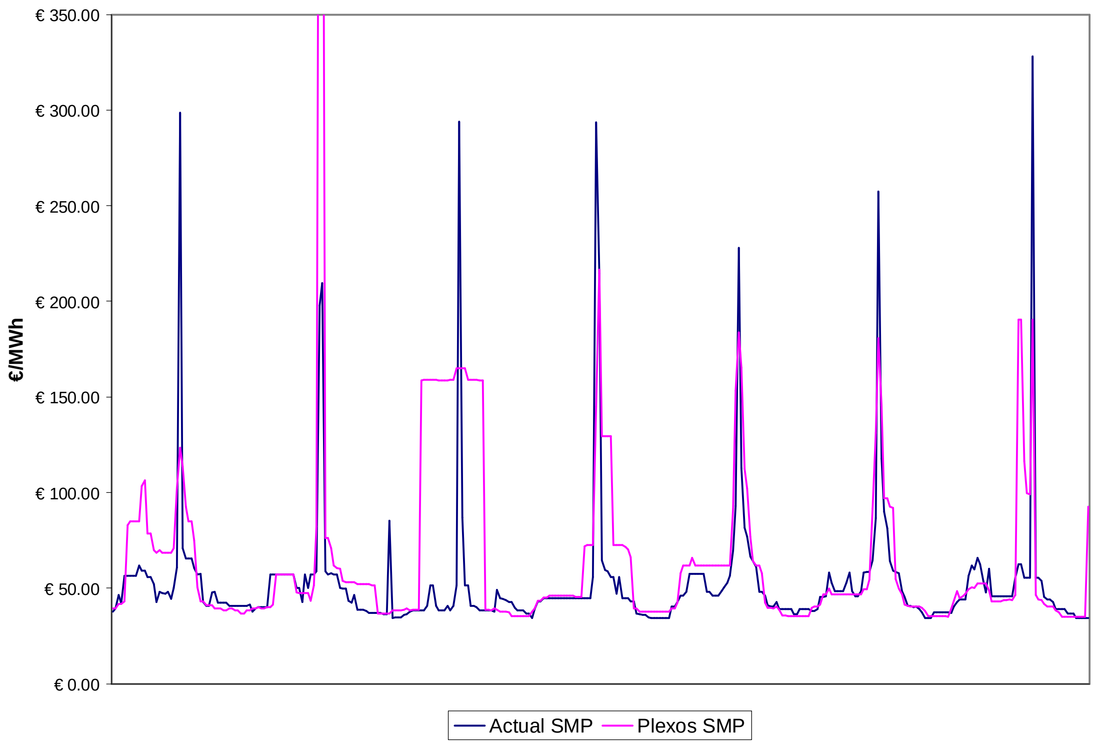


Figure D.2: SMP Comparison: Week 2

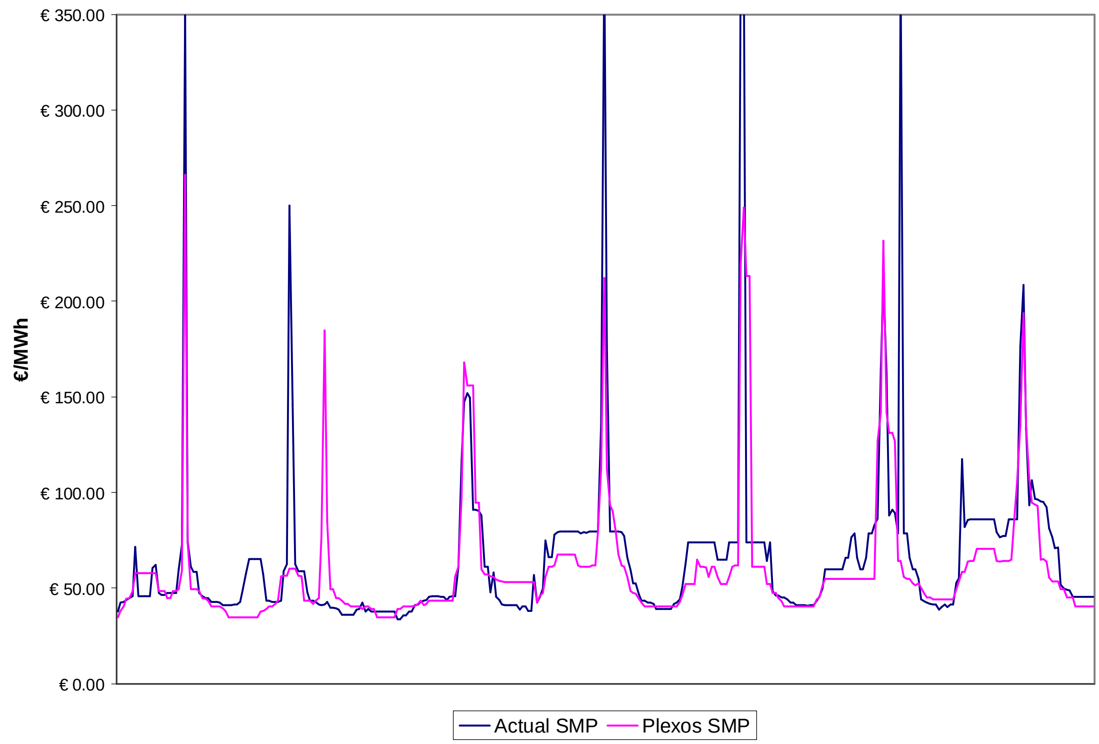


Figure D.3: SMP Comparison: Week 3

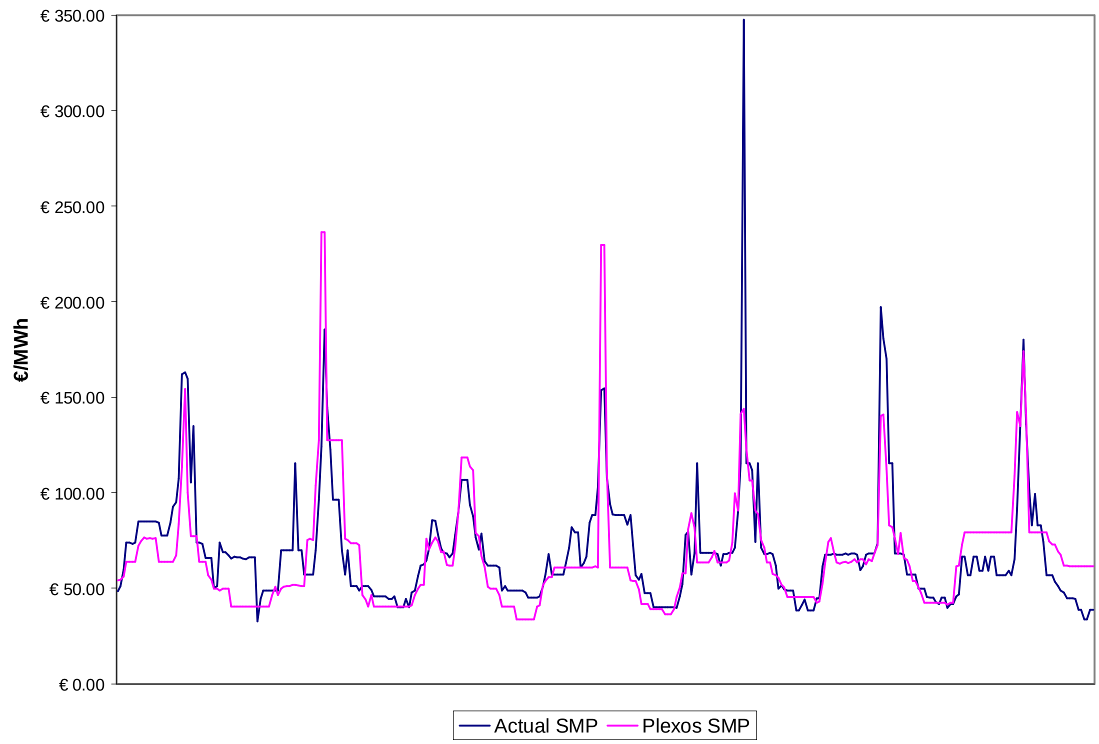


Figure D.4: SMP Comparison: Week 4

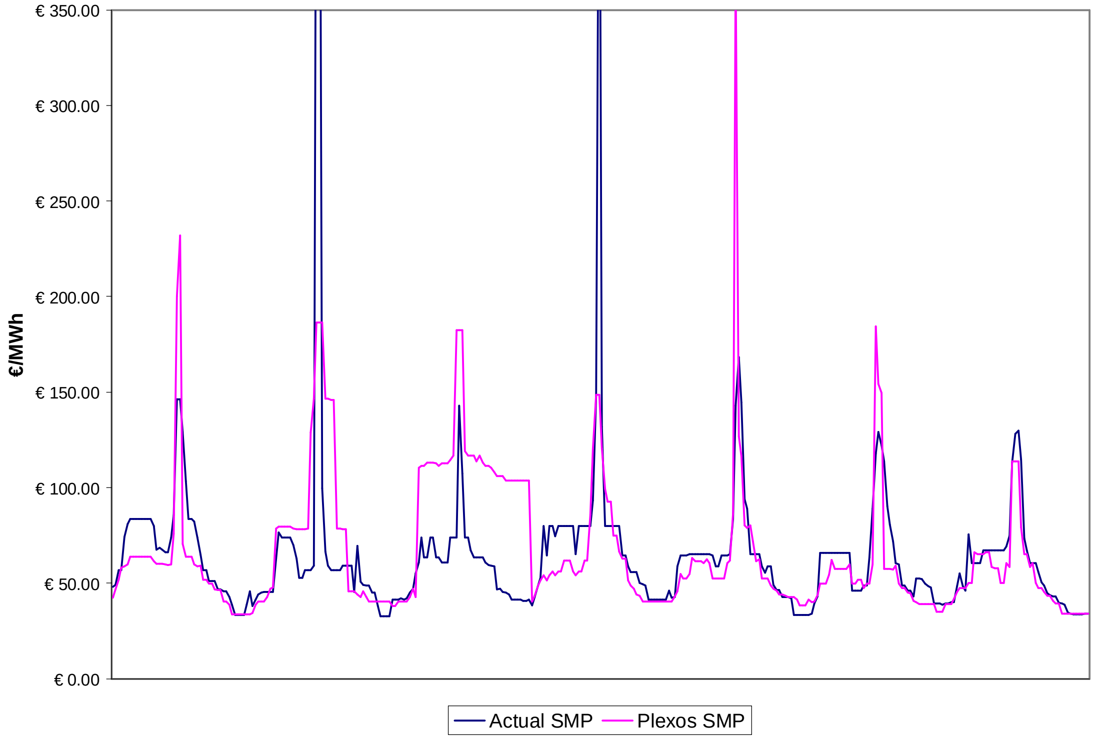


Figure D.5: SMP Comparison: Week 5

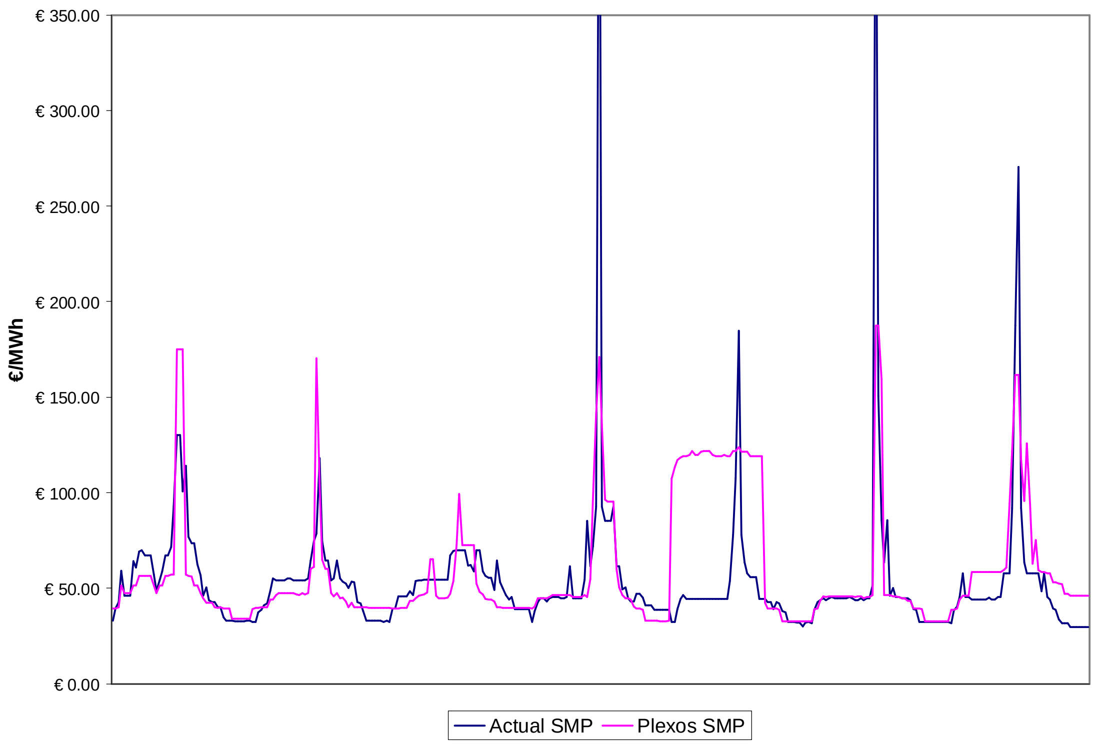


Figure D.6: SMP Comparison: Week 6

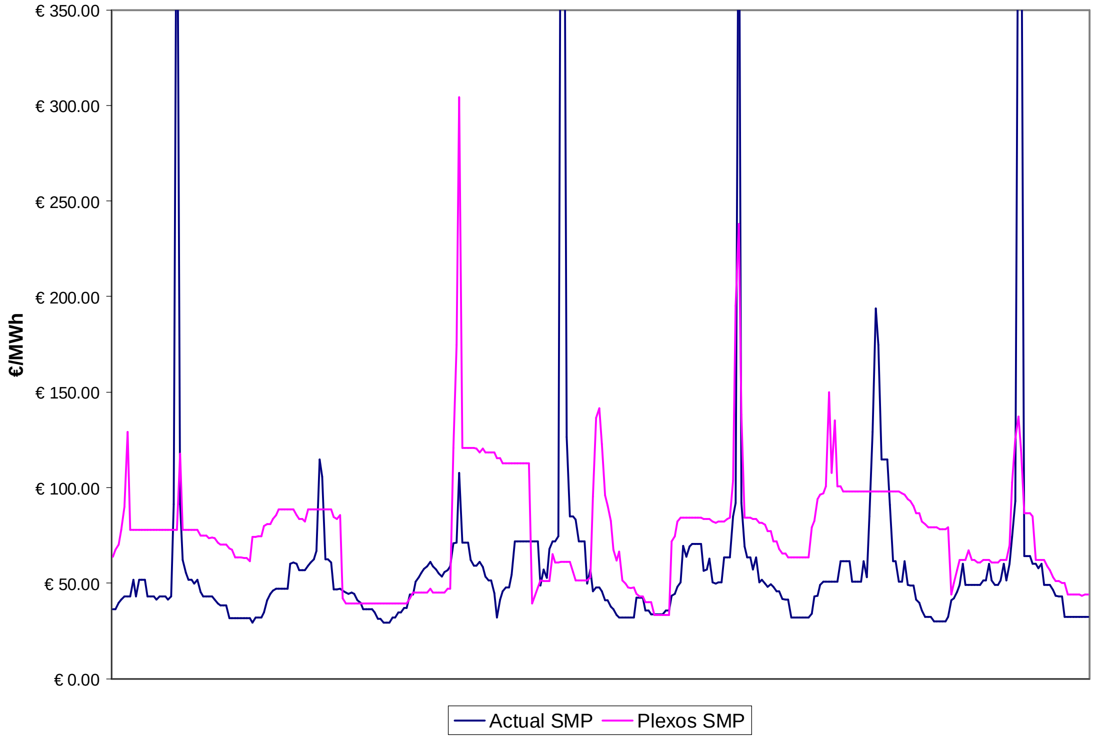


Figure D.7: SMP Comparison: Week 7

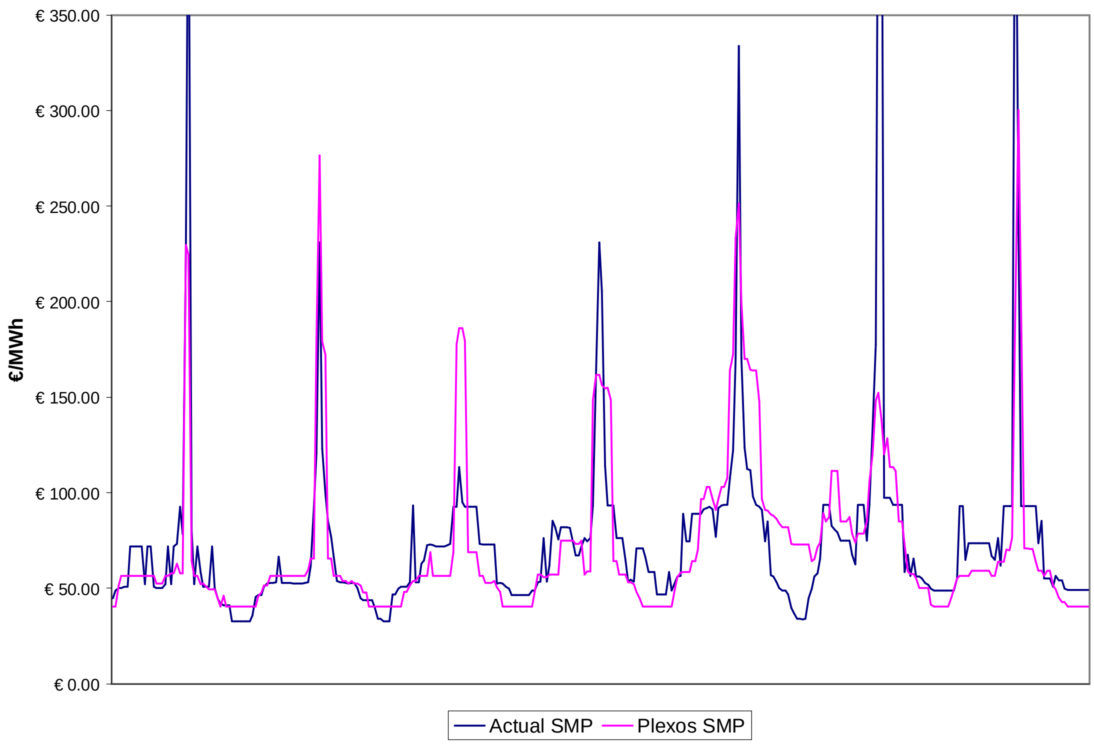


Figure D.8: SMP Comparison: Week 8

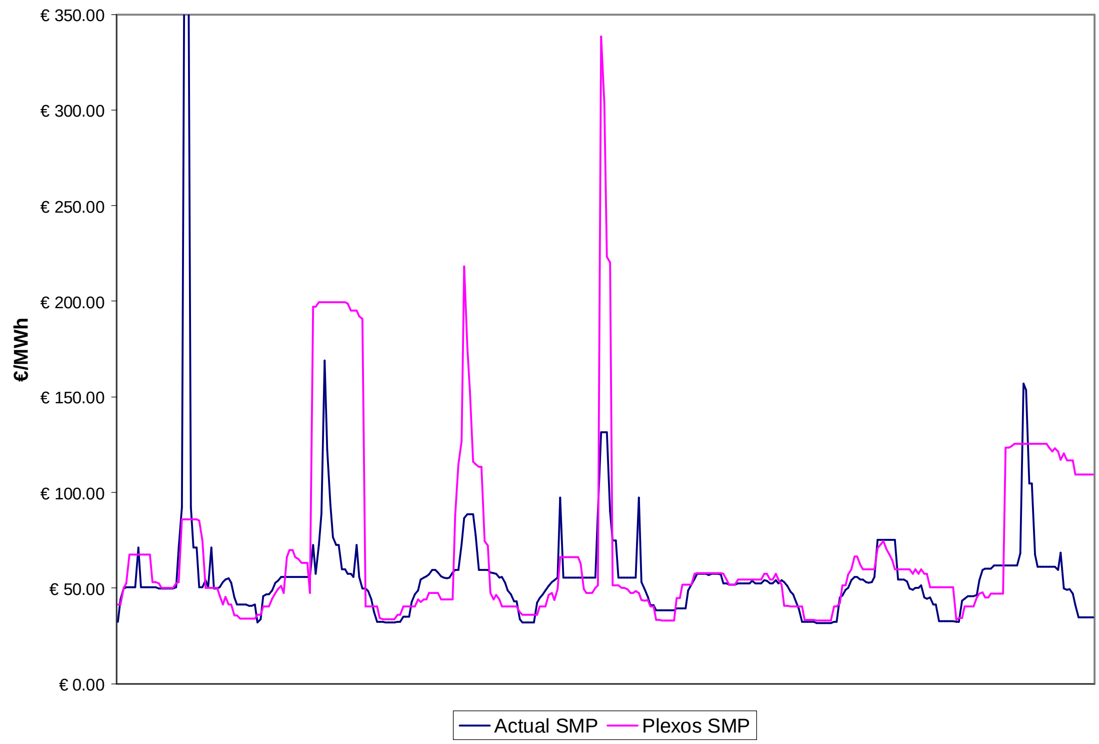


Figure D.9: SMP Comparison: Week 9

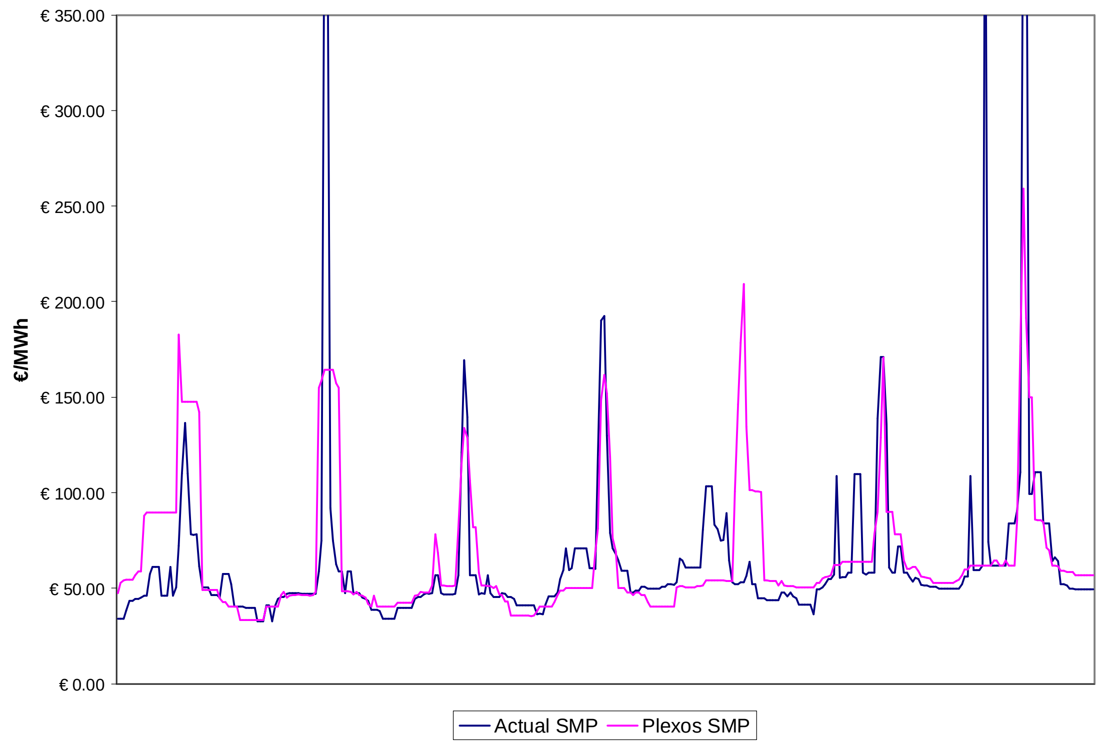


Figure D.10: SMP Comparison: Week 10

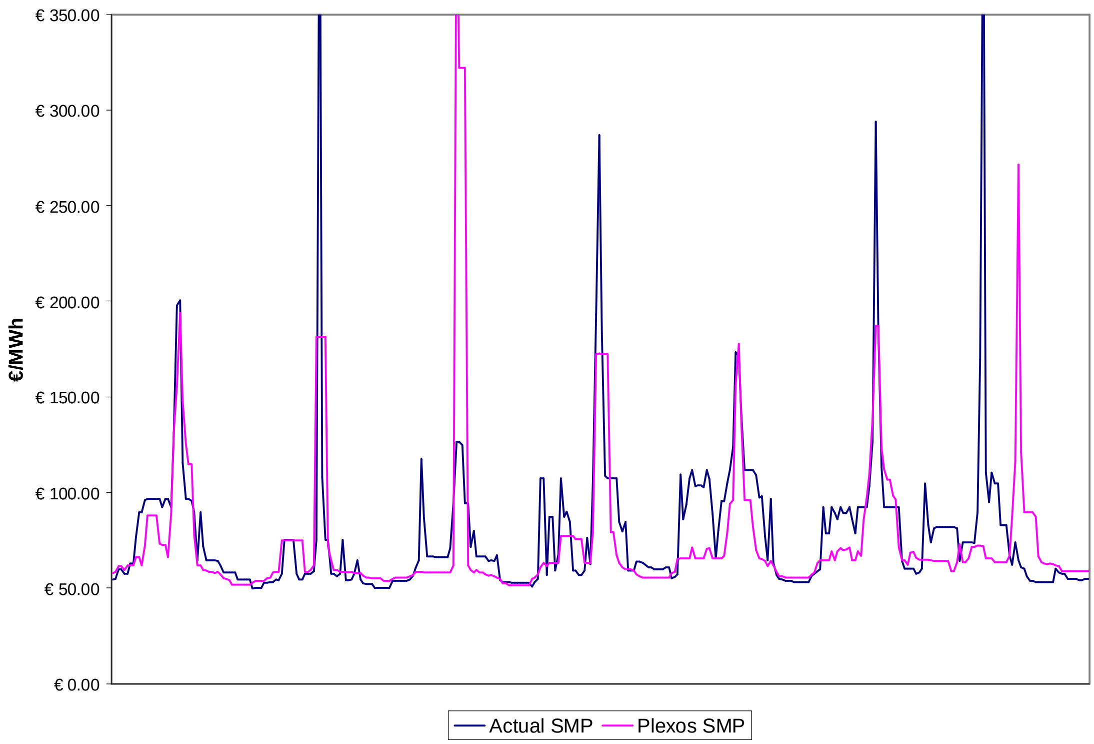


Figure D.11: SMP Comparison: Week 11

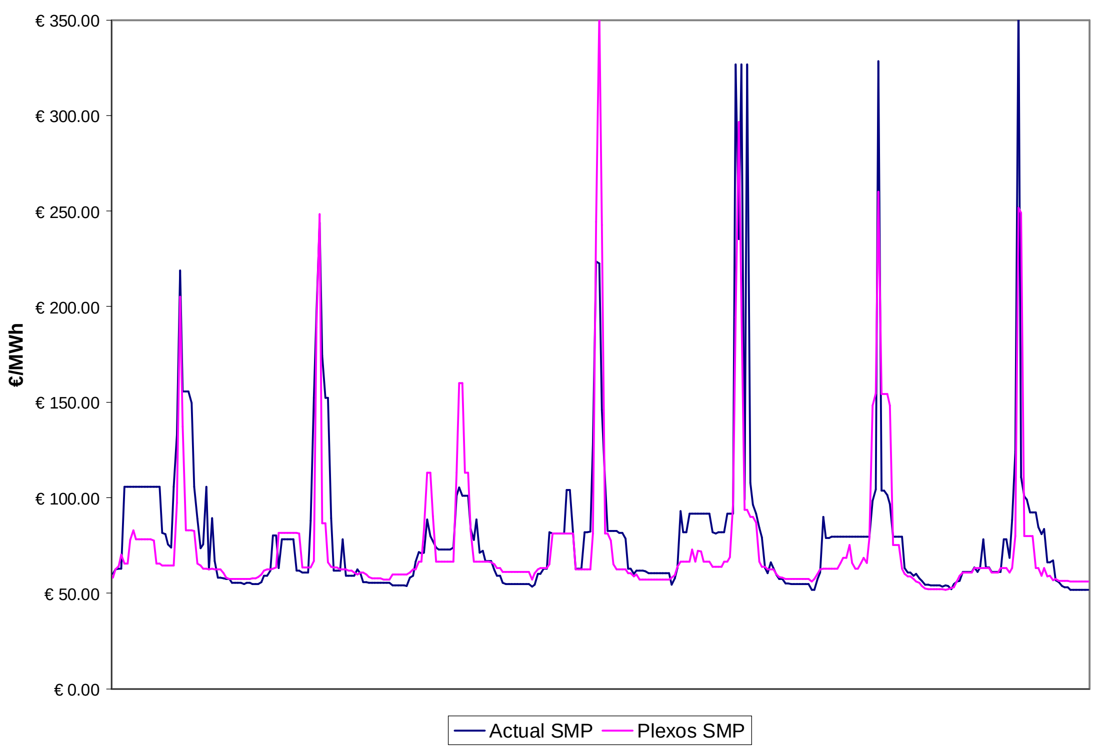


Figure D.12: SMP Comparison: Week 12

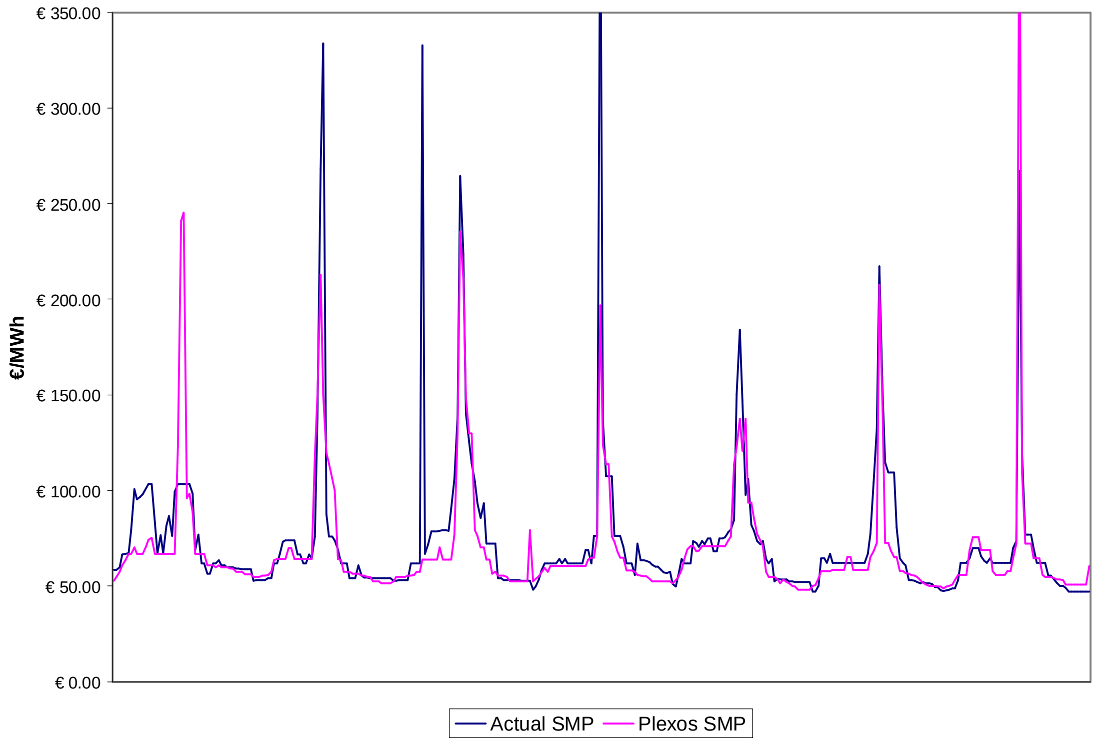


Figure D.13: SMP Comparison: Week 13

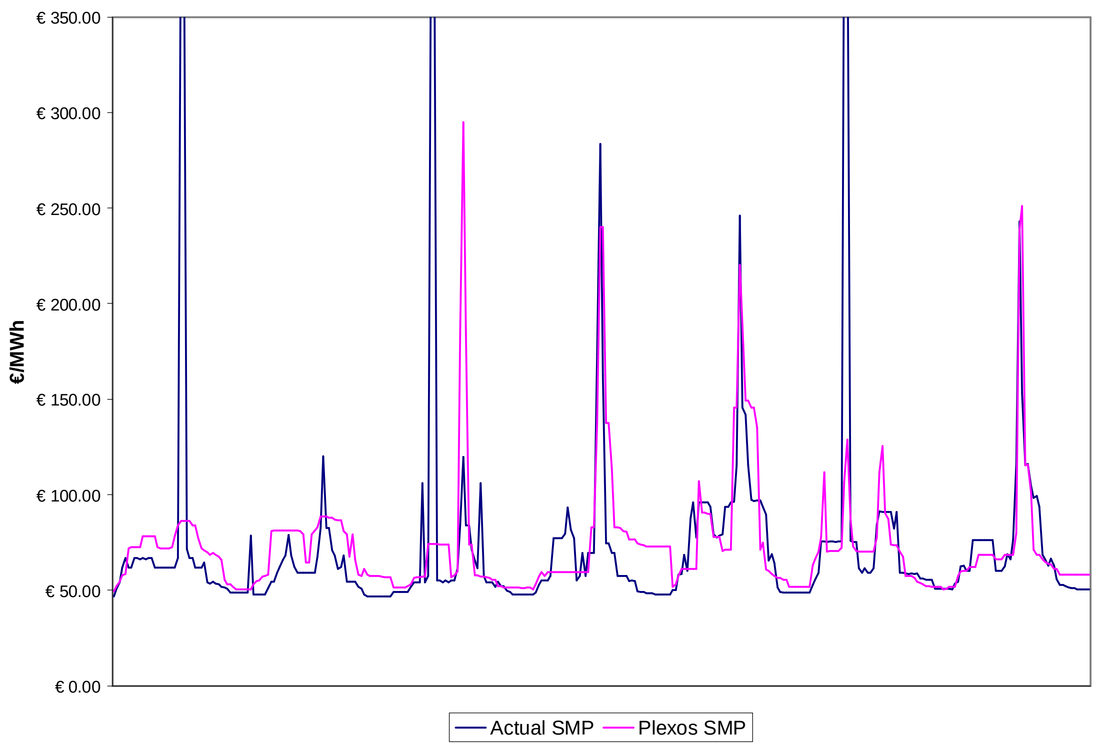


Figure D.14: SMP Comparison: Week 14

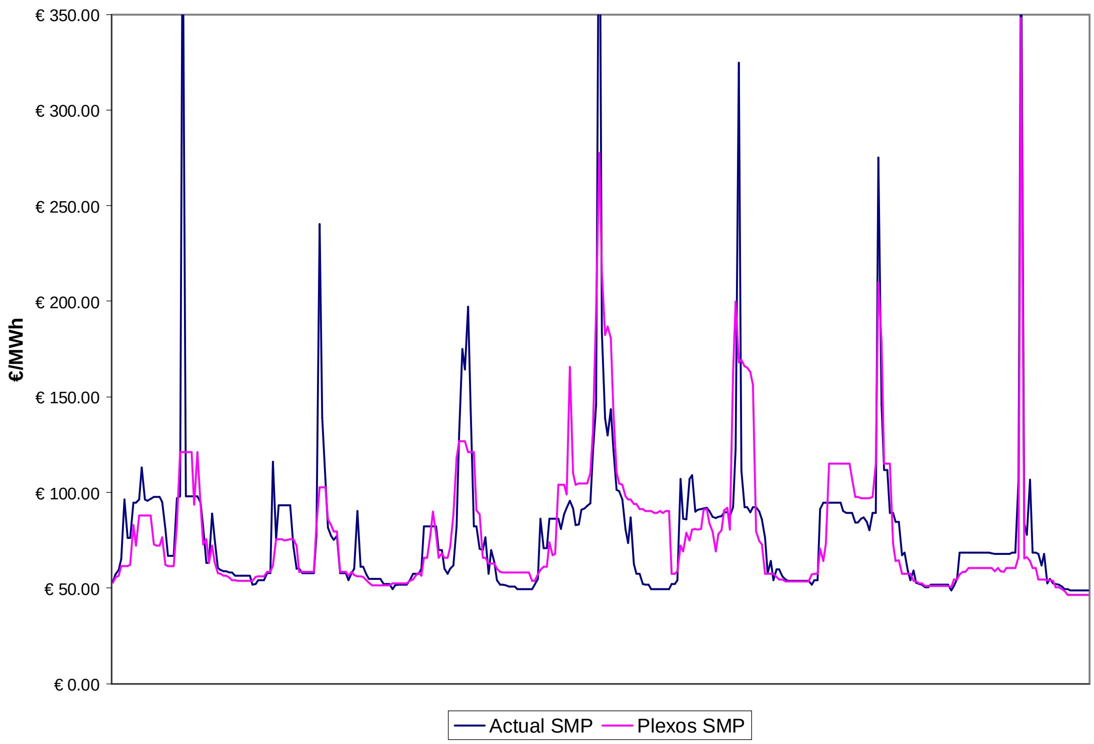


Figure D.15: SMP Comparison: Week 15

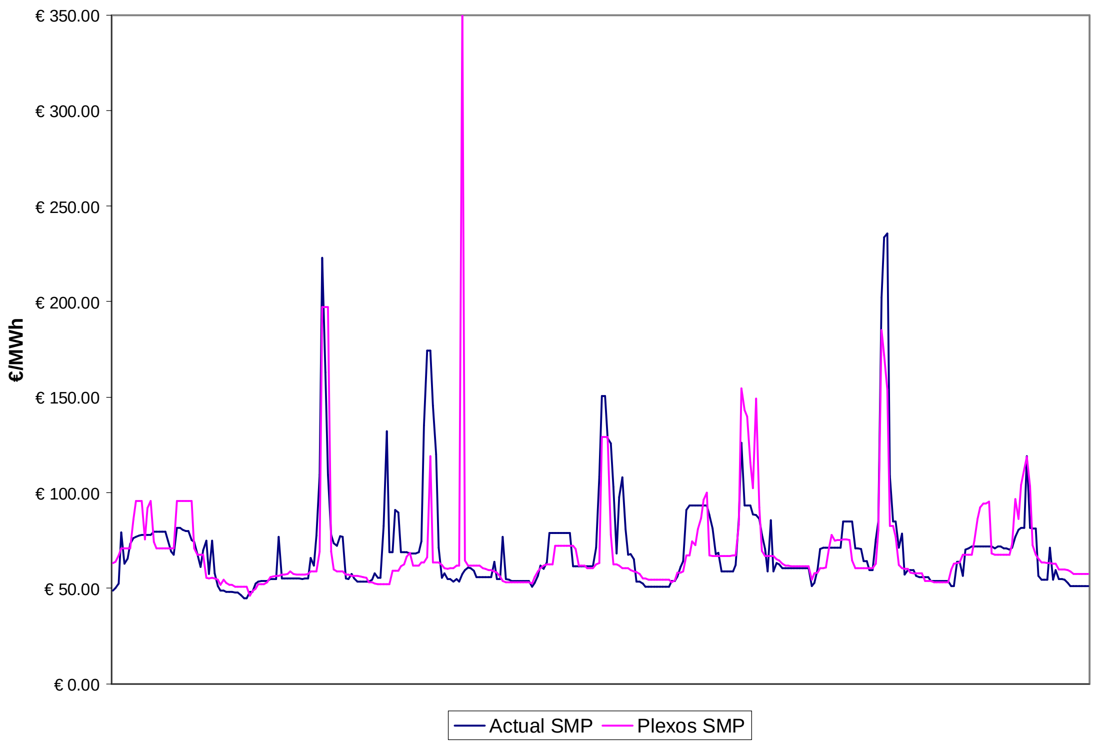
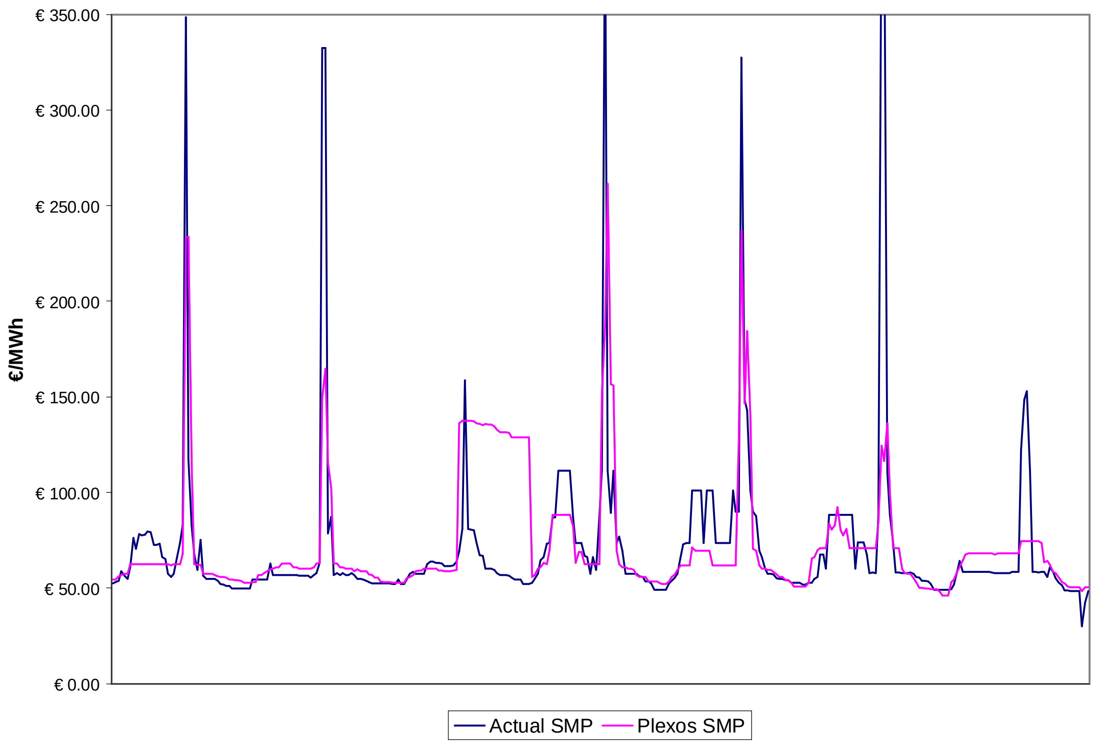
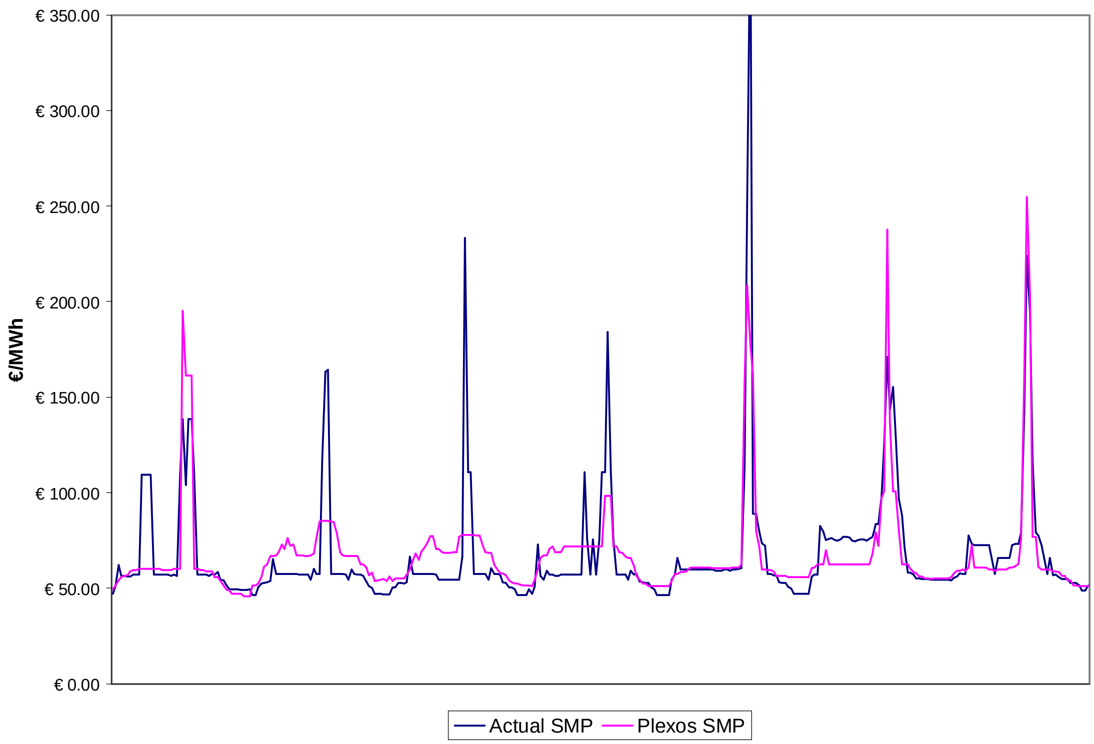


Figure D.16: SMP Comparison: Week 16



FigureD.17: SMP Comparison: Week 17



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