KEMA Limited

All Island Project

Market Simulation Model Validation

Data Validation Report

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Revision History

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1.0	13/4/07	Updated for comments	DL	MW	LP
1.1	24/4/07	Final Version	MW	MW	MW

Executive Summary

The Regulatory Authorities intend to use the PLEXOS model to undertake market simulations which can provide them with estimates to be used in such areas as the pricing of directed contracts, part of the calculation of annual capacity payments, the review of tariffs, possibly in the regulation of incumbents and by the market monitoring unit.

The purpose of this assignment is to provide the RAs with a validated model that is ready to accurately predict electricity prices. A key part of this project is validation of the input data and modeling assumptions. For the purposes of this Data Validation Report, this exercise has been broken down into two parts, namely validation of the generator technical data and validation of other input data and modeling assumptions.

Validation of generator technical data

The major part of the data validation process has been focused on the data that generators have submitted on the technical performance of their stations. This generator data was originally submitted and published in 2005, but was not formally validated at this point. KEMA recognised that the data may have changed and requested a re-submission of the data before commencing the validation process. This validation included assessing appropriateness of all submitted parameters, identification of inconsistencies between power stations and understanding the justification for changing technical data. The validation process also involved extensive industry consultation through bilateral discussions and industry workshops.

Major issues that arose with the data were as follows:

- Thermal Efficiency – The range of calculated Thermal Efficiency of plants was in a wider range than KEMA expected, particularly for CCGTs. This was resolved partly by ensuring all generators were submitting on a Lower Heating Value basis and also by re-submission of some No Load Energy and/or Heat Rates.

- Definition of Short Run Marginal Cost (SRMC) – Generators questioned whether they could include additional elements that they perceived as a SRMC in the technical parameters. It was noted that the RAs had decided to apply SRMC bidding principles rather than detailed bidding rules and that participants would need to decide whether to include other ‘potential’ SRMC factors in their technical parameters. However, generators were asked to be explicit about this to KEMA in order that validation of the technical parameters could still occur. Only one generator took the approach of including additional costs in a technical parameter.

- Contractual Parameters – It was felt that some parameters were contractually based rather than based on true technical performance. Generators were requested to re-submit all data on a technical rather than commercial basis.

- Consistency of Data – One concern for KEMA was that participants may have held different interpretations of some of the data items. KEMA provided some clarifications at the workshop and in subsequent e-mails that gave confidence of a consistent interpretation of technical parameters by market participants.

- Start Up Energy – This was an issue due to the range of values submitted, particularly for CCGTs. After a series of bilateral discussions, clarifications as to the definition and the use of an alternative proxy, this parameter was judged to be in the credible range for all participants.

- Forced Outage Rates – One large generator wished to change many of the Forced Outage Rates. Some of these were clearly justified by historical experience, but others required additional evidence. This was not available in the time period and so recent historical figures were used as the basis for setting updated Forced Outage Rates for these stations.

KEMA believes the validated generator data set now represents a credible set of technical performance data that is:

  – within accepted degrees of freedom;

  – based on submission by generators and expert scrutiny but not detailed technical audits;

  – consistent with indicated varying operational intentions of market participants; and

  – consistent with international benchmarks against comparable plants and technology.

Validation of other input data and modeling assumptions

Alongside the analysis of the generator technical data has been a validation of the other input data and modeling assumptions. This focused on a number of areas:

- Modeling of potential constraints – There were a number of 'constraints' where there was debate on whether they should be included in the unconstrained schedule. KEMA confirmed the following decisions:

  - Moyle Interconnector limits of 400 MW entry and 80 MW exit into and from Ireland (as measured at the Scottish coast) were firm GB transmission access related constraints and not an Irish network constraint. This limitation would therefore be included in the unconstrained schedule.

- No minimum upper reservoir reserve constraint should be applied to the pumped storage plant as the reserve is an Ancillary Service requirement.

- Peat stations are to be treated as must run in the unconstrained schedule.

- Forecasting assumptions – Transparency of demand forecasts was important to many participants. The All Island demand is the sum of those forecasts produced by EirGrid and SONI and are at the generation level. Energy supplied from embedded wind and CHP generation is included in the total demand.

  It was noted that wind forecasts would be generated using three regional availability figures rather than the single availability set used in the LOOP 2 runs. These had been produced by EirGrid and would be made publicly available. Wind Capacity figures have been provided from EirGrid and Northern Ireland Electricity.

- Fuel and related costs – The key concern with fuel and carbon costs is that they need to be derived from recognised transparent (i.e. public) sources. For consistency the set of price indices planned to be used by the RAs for Directed Contracts is recommended. GB Power prices need to be based on the same fuel prices, but the price bid into the All Island Market needs to be adjusted for the expected returns from capacity and uplift. For testing purposes, KEMA used the low set of EirGrid data produced by Pöyry, since due to recent gas price movement this was felt to be the most appropriate self consistent data set.

  EirGrid had provided transport costs, excise duties and exchange rates and KEMA have validated these parameters. KEMA had some concern on the Northern Ireland gas transport prices, where the capacity/commodity split is not appropriate and KEMA have therefore provided alternative figures for 2008. Our recommended approach on exchange rates is that an up-to-date set of historical data from a recognised source (e.g. European Central Bank) should be used to predict forward when PLEXOS model runs are produced.

- Short Run Marginal Cost (SRMC) – A number of generators raised issues over what costs should be included in the data set (or adjustment to fuel prices) to reflect their short run marginal cost. It was agreed that the variable operations and maintenance costs would be a new addition and that an adjustment would be made for Transmission Loss Adjustment Factors (TLAFs). One outstanding decision is whether gas capacity charges should be included as a SRMC. The RAs are currently assessing this point and if required can make a simple adjustment within PLEXOS to include this in the fuel price.

- Generator maintenance schedules – These are considered commercially sensitive by some generators and given similarity with indicated 2008 maintenance plans provided by some generators, it was recommended that the LOOP 2 figures were rolled forward to 2008.

Purpose and advised usage of the Data Validation Exercise addressed in this Report

It is important to note that the purpose of KEMA's data validation work was to provide a deterministic set of input data and modeling assumptions which represent a reasonable start point for annual modeling by the RAs under their LOOP 3 and Directed Contracts initiatives. In other words it provides a representation of average typical input data over the year 2008 and associated forward views (e.g. for wind output and demand) as at this point in time.

A key focus has been ensuring that generator technical data reflects typical average operating characteristics over the duration of a year under normal operating circumstances. However, as highlighted earlier, mapping actual performance to the required data format under the Trading & Settlement Code Version 1.2 (T&SC v1.2) requires a degree of interpretation and judgement by the market participants. KEMA has to allow this degree of freedom within reasonable bounds and different parties will take different views reflecting their risk appetite (e.g. short term flexible operations versus long term wear and tear) and anticipated running regime.

Furthermore, it must be recognised that there are input data and assumptions which are essentially stochastic (e.g. wind) and/or variable in nature within year (e.g. to reflect short term operating conditions) and/or will change to reflect revised forward views at the time of model run (e.g. fuel prices). Thus for modeling exercises which examine substantially shorter timeframes and/or high granularity of outputs and/or model outputs which are highly susceptible to changes in input data and assumptions it is crucial that the input data and assumptions are examined under broad scenarios, focused parameter sensitivities and/or stochastic model runs of PLEXOS as appropriate.

Consequently, use of the validated input data and assumptions in the validated PLEXOS model DOES NOT represent a forecast of SEM prices for 2008.

1. Introduction

1.1 Background

The Commission for Energy Regulation and the Northern Ireland Authority for Energy Regulation (the RAs) are currently developing a single all-island electricity market (the SEM) which is scheduled to come into operation on November 1st 2007. To facilitate their regulatory role under the SEM, the RAs will need to use a market simulation model to provide them with reasonably accurate estimates of the future market price.

The RAs and the System Operators currently use PLEXOS, which is Windows based market simulation software, to model the SEM. The RAs intend to use the PLEXOS model to undertake market simulations which can provide them with estimates to be used in such areas as the pricing of directed contracts, as part of the calculation of annual capacity payments, the review of tariffs, possibly in the regulation of incumbents and by the market monitoring unit.

The purpose of this assignment is to provide the RAs with a validated model that is ready to accurately predict electricity prices. As part of this assignment KEMA will produce a number of reports. This report will summarise our findings from the data validation and present our recommendations as to the data that should be used as an input to the model on an on-going basis.

1.2 Structure of this Report

This data validation report is structured as follow:

- Section 2 provides an overview of KEMA's approach including a list of the key activities necessary to validate the data;
- Section 3 describes the actions that KEMA have taken to validate the generator's technical data and the key issues within this process; and
- Section 4 describes the process for validation the modeling assumptions and other input data.

In addition there are a number of Appendices:

- Appendix A is the original generator data from 2005
- Appendix B is the revised generator data submitted before the Initial Findings Workshop on the 2 March
- Appendix C is the final generator data set

- Appendix D is the list of issues that arose on each of the generator technical parameters and how these have been resolved.

- Appendix E is a summary of how demand data has been calculated in the two jurisdictions of the Republic of Ireland (ROI) and Northern Ireland (NI).

2. Overview of KEMA's approach

2.1 Approach and key activities

The accuracy of any model is reliant on the quality of the input data and it is therefore important that a process is in place to verify the quality of this data. The primary focus of this activity was generator data, although KEMA have also investigated the reasonableness of forecast information such as demand and wind factor data with the System Operators in Republic of Ireland (EirGrid) and Northern Ireland (SONI). The key steps in this process were as follows:

1) Initial collation and review of existing data, identification of sources of the data and data issues/themes to be explored;

2) Generators requested to review and update their existing submitted generator data explaining any changes and why they believe the original or revised data is currently valid. This was done using an initial Data Questionnaire;

3) Opportunity for all market participants to comment on input data. This ran consecutively with generators reviewing their own data and included bilateral meetings between KEMA and market participants upon their request;

4) KEMA reviewed data against historical performance, comparable peer generators in Ireland and our international database on generator performance;

5) KEMA hosted an Initial Findings Workshop to discuss with market participants our early views on model input data and highlight key observations, emergent issues, areas for clarification and issues for exploration/further dialogue;

6) A review and resubmission of data by participants in the light of clarifications and KEMA's Initial Findings Workshop. This provided an opportunity for participants to provide a view on outstanding and newly emerged emerging issues via a 2nd Data Questionnaire;

7) Further bilateral discussion and feedback on modeling assumptions between KEMA and participants as well as discussion with the RAs and EirGrid on key policy related issues;

8) Bilateral resolution of inconsistencies in data with market participants and where necessary KEMA determination; and

9) Provision of final conclusions in report to RAs and in a Final Conclusions Workshop for participants.

2.2 KEMA's project timetable

An outline of the key steps in this process and the associated timetable is shown in the table below along with an explanation of the benefit KEMA believed the project would derive from each step.

Timeframe	Activity	Benefit
w/c 8 January	Inception meeting with CER/NIAER to clarify scope and date for participants workshop	Chance to confirm deliverable
w/c 15/22 January	Workshop on the Project Process and receiving feedback (written and oral) from market participants	Allows participants to gain familiarity with the project process and to provide feedback as to their concerns on the current mode;
w/c 29 Jan	Issue questionnaire on data and modeling assumption	Give participants chance to explains their data
w/c 5-12 Feb	Hold bilateral meetings with market participants	Ensures market participants views are fully aired and understood
w/c 19 Feb	Review of data submissions from market participants - (due 16 Feb)	Validation of all updated data submissions
w/c 26 Feb	Initial Findings Workshop	Allows presentation of the initial findings to market participants and to get their 'buy in' to any issues identified and changes needed
w/c 26 Feb & 5 Mar	Bilateral Meetings as required	Chance to discuss with market participants any changes needed to the data
w/c 12 Mar	Receive feedback on initial findings and assess	Time to consider any feedback not already covered in the bilateral meetings
w/c 19 Mar	Issue Final Process, Data and Model Validation Reports to RAs	Allows forewarning for RAs, some scope for minor refinement and agreement of public versions

w/c 26 Mar	Final Conclusions workshop and presentation of final results	Opportunity to share and explain our findings to the industry

In practice this timetable for the Fixed Project delivery has been largely followed as outlined above. The three main differences which arose were:

a. A number of the bilateral meetings in both of the 1st and 2nd rounds were slipped into the weeks following those initially identified due to diary issues and delays in receipt of data from participants and thus delays in KEMA's initial and secondary assessments. This led to scheduling of w/c 19 Feb for 1st round meetings and w/c 19 March for 2nd round meetings).

b. it was agreed to release Draft Final versions of the Reports to enable feedback from the RAs and thus iteration for provision of final Reports. The timing of provision of the Draft Final Reports was agreed to be w/c 26 March.

c. it was agreed to hold the presentation of final results in w/c 26 March but subsequently to have provision of Final Reports in w/c 9 April reflecting necessary changes following RAs review and to address any major feedback issues from the Final Conclusions Workshop.

3. Validation of Generator Technical Data

3.1 Approach to validation of generator data

The review of a generator's technical data required a number of steps:

- Identification of inconsistencies with similar power stations operating in the All Island market and comparable international generation plant;
- Checking common understanding of technical data being submitted and the development of consistent definitions to be applied in submitting parameter values;
- Investigating areas of concern raised to KEMA on specific data parameter values by other market participants;
- Assessment of the appropriateness of the parameters for each generator bearing in mind technology, age, method of operation and SEM SRMC bidding principles; and
- Checking justification for any changes in data sets from previous submissions.

Our approach was partly based on generators voluntarily re-submitting data due to clarification or better understanding and partly on independent review of the generator's technical data using KEMA in-house market generation technical experts, and associated international knowledge of plant performance. This involved making use of comparable technical and market data KEMA has obtained internationally e.g. comparable Heat Rates for various turbine technologies.

3.2 Technical data validated

The following sets of technical data listed below were included in this review for each generator.

- Min Stable Capacity
- Max Capacity
- Fuel
- Heat Rates Curves
    - No Load Heat Requirements (GJ/hr)
    - Capacity Point (MW exported)
    - Incremental Heat Rate Slope (GJ/MWhr)

- Forced Outage Rate
- Mean Time to Repair (Hours)
- Run up Rate (MW/min)
- Ramp Rate Up and Down (MW/min)
- Min Up Time (mins and hours)
- Min Down Time (mins and hours)
- Reserve (MW)
    - Primary
    - Secondary
    - Tertiary 1
    - Tertiary 2
- Start Up Energy (GJ)
    - Cold
    - Warm
    - Hot
- Synchronisation Times (hrs)
    - From Hot
    - From Warm
    - From Cold
- Boundary Times
    - Hot to Warm (hrs)
    - Warm to Cold (hrs)

A set of data for all generators based on a formal 2005 submission already existed. However, this 2005 data set had not been fully validated and some of this data had changed since the 2005 submission to reflect updated understanding after dialogue between EirGrid and some market participants. The starting point of the investigation was therefore to re-send this information to all generators and request that they re-submit with updated information or confirm this data was still current.

3.3 Resubmission of technical data

KEMA issued its initial Data Questionnaire to market participants on 2 February including, for generators, the latest version of technical data (Appendix A).

A slightly different form of Data Questionnaire was sent to Generators and Suppliers essentially reflecting the fact that it was mainly Generators who had direct data input to provide. However, both Data Questionnaires sought views from the recipients on all aspects of the modeling assumptions and model input data used in PLEXOS for the SEM.

KEMA received a resubmitted set of technical data for generators between 16 February and the 1 March. All but one participant changed some of their data since the submission in 2005. Key changes were as follows:

Parameter	**Changes**
Min Stable Capacity	Increases, Huntstown 1 - 21.2 MW, Huntstown 2 - 39 MW, Tynagh 18 MW, Moneypoint – All units 21 MW Aghada CT Units 5 MW increase to 15 MW
Max Export Capacity	Increase in Dublin Bay Power 19 MW Reduction in Huntstown 1 – 8 MW, Huntstown 2 – 11 MW
No Load Heat Requirement	Huntstown 1 increase by 77%, Huntstown 2 increase by 34% Poolbeg Unit 3 decrease by 10%
Capacity Point	Driven by changes in Min Stable Capacity and Max Capacity
Incremental Heat Rate Slope	Aghada CT> 4% increase in Heat Rate for incremental 1 and 2

Forced Outage Rate	Great Island increased from 9% all units to 19 -21% Poolbeg Unit 3 increased from 12% to 22% Tarbert increases from 6-12% to 15-19%
Ramp Rate up and Down	Tynagh decreased 19 to 10 MW up and 19 to 8 MW down Huntstown 2 decrease from 10 MW to 5 MW Up
Min Up Time	Lough Rea/ West Offley decrease from 12 to 5 hours Tarbert 1 and 2 decrease from 20 hours to 4 hours
Min Down Time	3 hour increase for Huntstown 2 Aughinish 2 now set at 4 hours not previously given
Reserve	Northwall 5 has decreased on Tertiary 3 from 72 to 20MW Poolbeg 1 and 2 had 20 MW increase
Start Up Energy	Huntstown 1 increased from 650 GJ to 20,000 GJ from cold Huntstown 2 increased from 3,000 GJ to 20,000 GJ from cold
Synchronisation Times	Poolbeg Unit 3 increased from 12 hours to 30 hours from cold Huntstown 2 increased from 0.5 hours to 12 hours from cold.
Boundary Times	Significant increases from warm to cold for Dublin Bay Power 8 – 72 hours and Huntstown 2 from 12 – 72 hours

Some of these changes particularly on Start Up Energy and Forced Outage Rates needed further explanations which was addressed at the both the bilateral meetings and the Initial Findings Workshop. In addition, it was felt some existing and unchanged technical data such as re-confirmed Min Up Time and Min Down Time were inappropriately reflecting either (i) contractual performance parameters or (ii) desired running regimes and not true technical performance.

3.4 Bilateral discussions with market participants

KEMA held a number of bilateral discussions with participants in both Dublin and Belfast to discuss concerns on their own and other generator data. At this stage the revised full set of data had not been circulated so participant could only comments on other generators original data submissions. The key concerns broke down into four categories:

- Thermal Efficiency
- CCGT Issues
- SRMC
- Minimum Up Time and Minimum Down Time

Thermal Efficiency

A number of participants raised concerns about the Heat Rate and the Thermal Efficiency proposed for CCGTs. KEMA agreed that they would be investigating this as part of their analysis. A suggestion was made that some participants had calculated their Heat Rates on Lower Heating Value (LHV) and some on a Higher Heating Values (HHV) and this could explain a significant part of the difference. It was suggested that clear guidelines should be produced to enable participants to check they have produced their Heat Rates based on the same principles.

A more general point was that the average Thermal Efficiency of some of the power stations was different from that anticipated for similar stations of this type. There were some specific examples provided where similar technologies had a significant difference in the Thermal Efficiency that could be calculated for the plant or had been declared by the manufacturers in the past.

CCGT Issues

One participant highlighted a concern that CCGT plants do not have a heat function that is accurate when bid using a monotonically increasing rule for bidding. Ideally, the participant would have liked further investigation on developments in centralised unit commitment algorithms to assess whether the monotonically increasing rule is necessary. Assuming it was required, the participant was keen that the RAs should set out clear guidelines on how a Heat Rate curve for a CCGT should be calculated.

KEMA advised that it recognised that CCGT performance did not map to monotonically increasing curve required by the T&SC v1.2 and noted that most CCGTs chose to adopt a single Heat Rate Incremental. KEMA further advised that there were accepted degree of freedom in how CCGTs chose to set this HR (and associate No Load Energy) and KEMA would accept participants doing so based on an expectation of the type of running and typical output levels of the plant (e.g. full or part load).

An additional issue was that CCGT plants suffer degradation over time and that maximum capacity would reduce. KEMA noted that as they were only validating for a year they would expect participants to provide a figure that was correct for the start of 2008. A related concern is the seasonal impact on CCGT performance from temperature changes. It was felt that this could be as much as 5-10MW for a typical CCGT plant. This was most marked in the summer where the ambient temperature change was most significant.

Minimum Up Time and Down Time

Some of the Minimum Up Time and Minimum Down Time figures seemed overly long. One suggestion raised by a participant was that the length of these parameters may be designed to prevent more than 2 start ups per day, which was a contractual limit for some of these stations. This highlighted a more general issue of how to deal with contractual parameters against technical parameters. KEMA offered to discuss this with the RAs.

Short Run Marginal Cost

A number of generators raised issues over where costs such as maintenance or lost capacity should be captured in some of the generator variables. KEMA noted this concern and agreed to provide further guidance at the Initial Findings Workshop.

3.5 Discussions at the Initial Findings Workshop

At the Initial Findings Workshop, KEMA went through the revised submissions they had received from generators. Some substantial changes had been received for a couple of generators, but for most participants the changes were relatively minor.

There were three main areas for discussion on generators' technical data. These related not just to the revised data, but also to the original data sets that generators had submitted in 2005.

These areas were:

- Consistency of data
- Contractual vs. technical issues
- The definition of SRMC

Consistency of data

One significant concern that KEMA had from reviewing the set of participants' data was the consistency of submissions. KEMA were worried that participants may have interpreted some parameters in different ways and it was important that all participants had produced technical data on the same basis. The key areas where this was a concern were Start Up Energy, No Load Energy and calculation of Heat Rates. As an example the level of Start Up Energy for CCGTs is shown below:

Unit Name	Max capacity	Start up Energy (GJ) Cold	Start up Energy (GJ) Warm	Start up Energy (GJ) Hot
Dublin Bay Power	415	7700	2600	
Huntstown	335	20000	10000	5000
Huntstown Phase II	391	20000	10000	5000
Marina CC *	112.29	50	50	50
Northwall Unit 4	163	80	80	80
Poolbeg Combined Cycle	480	2000	2000	2000
Tynagh	404	2811	1633	1144
Ballylumford CCGT 31	240	50	50	50
Ballylumford Unit 32	240	50	50	50
Coolkeeragh CCGT	404	50	50	50

Figure 1 Start Up Energy for CCGTs

KEMA suggested that participants may want to reconsider their Start Up Energy figures.

A suggestion for the range of Heat Rates was that different participants may have used HHV rather than LHV for the calculation of Heat Rate at the stations. In discussion at the Workshop, it was agreed that all participants should produce data based on LHV. Participants would be asked to confirm this in the subsequent data submissions. This needed to apply to Heat Rate slope, No Load Heat Requirement and Start Up Energy.

Technical versus contractual parameters

One concern that participants had was that some of the parameters submitted were commercial parameters reflecting legacy contracts rather than the technical performance of the plant. An example of this is Min Up Time and Min Down Time which it was felt had been set so as to avoid two starts per day. This can be seen in the range of Min Down Times and Min Up Times for gas fired (non CCGT plants).

Unit Name	Min Up Time (mins)	Min Up Time (hrs)	Min Down Time (mins)	Min Down Time (hrs)
Aghada Unit 1	240	4	210	3.5
Aghada CT Unit 4	0	0	45	0.75
Poolbeg Unit 1	180.00	3.00	120.00	2.00
Poolbeg Unit 2	180.00	3.00	120.00	2.00
Poolbeg Unit 3	255.00	4.25	210.00	3.50
Ballylumford Unit 4	240.00	4.00	420.00	7.00
Ballylumford Unit 6	240.00	4.00	420.00	7.00

Figure 2 Minimum Up and Minimum Down Times for Gas Fired Stations

The Regulatory Authorities provided guidance that parameters should be provided on technical performance rather than legacy contractual levels.

Short Run Marginal Cost

A number of participants had questioned whether they should inflate certain parameters to account for elements of short run marginal cost not included in other parameters. Further detail of the issue on what may be considered a SRMC is provided in Section 4 of this Report. However, KEMA requested that if participants included any additional elements of SRMC within their technical parameters that they explain these confidentially with KEMA, in order that KEMA could still validate the technical data.

At the meeting KEMA noted that they would be requesting a resubmission of generator data at the start of the following wee and at the same time would be doing their own investigation of the reasonableness of some of the data based on international experience.

3.6 Re-submission of data

KEMA e-mailed all participants on the 5 March to request a re-submission of data in line with the agree criteria at the workshop. In particular participants were asked to respond on five questions. These five questions and the responses received are detailed below.

1) Can you confirm that Heat Rate calculations have been made on lower heating values rather than higher heating values?

A number of participants had been using HHV values previously. The change to LHV Heat Rates have therefore resulted in a narrowing of Thermal Efficiency rates for types of station.

It was discovered that a number of generators had only adjusted the Heat Rate so the No Load and Start Up Energy also needed adjustment. This conversion was done as a simple conversion by multiplying these variables by 0.9 where participants still had values as HHV. **All changes were discussed with market participants.**

This change and subsequent discussions have had large impact on the consistency of Thermal Efficiency particularly for CCGTS. The table below shows the Thermal Efficiency as at the 5th March. Whilst Marina and Northwall were 1st generation CCGT technology built in the 1980s and could be treated differently, a lot more consistency was expected from the other CCGT generators.

Unit ID	Unit Name	Max capacity	No Load Heat Requirement (GJ/hr)	Heat Rate MSG	Heat Rate Full Output
DBP	Dublin Bay Power	415	532.6	49.74%	57.87%
HNC	Huntstown	335	574	44.67%	48.52%
HN2	Huntstown Phase II	391	670	44.74%	51.33%
MRT	Marina CC *	112.29	249.8	35.58%	40.76%
NW4	Northwall Unit 4	163	351.77	37.39%	42.48%
PBC	Poolbeg Combined Cycle	480	704.52	45.42%	52.34%
TE	Tynagh	404	467.06	48.75%	56.09%
B31	Ballylumford CCGT 31	240	495.8	35.88%	46.00%
B32	Ballylumford Unit 32	240	495.8	35.88%	46.00%
B10	Ballylumford Unit 10	103	98.15	43.75%	47.23%
CPS CCGT	Coolkeeragh CCGT	401.5	495.8	48.91%	53.99%

Figure 3 Thermal Efficiency for CCGTs after initial re-submission

The final revised figures (after further discussions with some generators) included changes in No Load Heat Rates for a number of generator and conversion by Ballylumford to LHV from HHV. This brought the set of modern CCGTS into a might tighter space as would be anticipated.

Unit ID	Unit Name	Max capacity	No Load Heat Requireme nt (GJ/hr)	Heat Rate MSG	Heat Rate Full Output
DBP	Dublin Bay Power	415	479.34	48.15%	56.99%
HNC	Huntstown	343	423	48.03%	52.89%
HN2	Huntstown Phase II	401	494	49.24%	54.82%
MRT	Marina CC *	112.29	249.8	35.58%	40.76%
NW4	Northwall Unit 4	163	351.77	37.39%	42.48%
PBC	Poolbeg Combined Cycle	480	704.52	45.42%	52.34%
TE	Tynagh	373	564	47.51%	54.78%
B31	Ballylumford CCGT 31	240	446.22	39.86%	51.11%
B32	Ballylumford Unit 32	240	446.22	39.86%	51.11%
B10	Ballylumford Unit 10	103	88.335	48.61%	52.47%
CPS CCGT	Coolkeeragh CCGT	401.5	495.8	48.91%	53.99%

Figure 4 Revised Thermal Efficiency for CCGTs

2) Can you provide a figure in €/start and/or €/MWh for Variable Operations and Maintenance costs?

Most stations have provided a figure, which will remain confidential. Where stations were not able to provide data then KEMA have recommended that data from a similar station is included. KEMA queried some anomalous figures and these have now been revised.

3) Can you confirm that figures provided are based on technical parameters and reflects true operational capability rather than contractual parameters?

All data is now technical rather than contractual. KEMA challenged some data items where these were still inconsistent with our international experience and comparable Irish stations.

4) Can you confirm whether any additional costs elements are included in any of the technical parameters? If there are additional costs included can you confirm what these are and how they have been derived (the breakdown will be kept confidential)?

Only one market participant has chosen this approach. They have included additional short run marginal costs in their incremental Heat Rates for the higher capacities. They have had a number of discussions with KEMA and provided a clear explanation as to why the Heat Rate has been calculated at the current level, which KEMA will share with the RAs. This does not pre-empt what the market monitors will determine is an acceptable short run cost when the market is operating.

5) Can you inform us of any emissions limits we should be aware of in relation to your stations?

Edenderry Power has a SOx emissions limit of 600 mg/m3. On occasion due to the variable sulphur content in the fuel it is necessary to reduce load to meet SOx emissions. The station estimates that this would lead to an additional 1% in capacity reduction on an annual basis

Subsequent additional question

An additional question, which was sent subsequently to all participants was a request to confirm that all data was Grid Code compliant. This was in response to concerns that not all generator's data was Grid Code compliant. KEMA got a mixed response to this question with some generators confirming derogations, but others remaining silent on this issue. The RAs suggested that for the purpose of this exercise then this issue should be noted, but it was not the intention of this validation project to check all data items against the Grid Code, nor enforce Grid Code compliance within the generator data or a related requirement for a derogation i.e. the objective is that the data reflects actual technical operating performance as allowed by the System Operators regardless of Grid Code status. Any related Grid Code issues are for the System Operators, and Regulatory Authorities to address.

At the same time as the resubmission of data an internal investigation was undertaken to confirm the reasonableness of certain figures based on our international experience. This investigation helped focus our efforts on the remaining data that needed further explanation.

3.7 Participant issues raised and resolved

In response to the request for updated responses there were a number of questions relating to the consistency of data and understanding what the interpretation should be used for a number of the parameters. The main data items where clarification was provided were

- No Load Energy – The energy (GJ/hr) required to maintain the generator at 0MW

- Start Up Energy for a CCGT – This is the energy required to get a power station into a position of being synchronised at 0MW i.e. No Load. In particular for a CCGT it includes getting both the GT and the ST going to the state of synchronisation.

- Run Up Rate – The increase in exported output in one minute applying to entire 1-hour interval. This covers the output level from 0MW to Minimum Stable Capacity. Participants need to assume the plant has already synchronised.

One issue that arose with CCGTs related to the generation that is produced before the ST synchronises which was a particular issue for multi-shaft CCGTs. It was decided that as this impact was small for most generators this would need to be ignored.

One question that arose from a number of CCGT operators was whether the summer or winter capacity of the plant should be used for CCGTs. KEMA confirmed that the Max Capacity on an average winter day should be used. After discussion with KEMA's generation experts it was decided that within the modelling there would be a reduction of 3% in the summer capacity. It was also clarified that KEMA were looking for parameters that reflect normal operation rather than emergency or exceptional operation.

There were a number of smaller clarifications that required resolution including:

- Submission of non-monotonically increasing Heat Rates;
- Ensuring Max Capacity equals the final capacity points;
- Matching Min Stable Capacity with the first Capacity point;
- Introduction of different Start Up Energy rates for different states (particularly for CCGTs); and
- Modification of some Ramping Rates which seemed too low.

These issues were all resolved after bilateral discussions with participants.

Aughinish had previously indicated a desire to be treated in the same way as other generators and not as a must run plant. KEMA therefore worked with Aughinish to ensure their figures took account of the value of the heat they were produced and therefore fairly reflected their overall combined heat and power production efficiency.

3.8 Second round bilateral meetings

KEMA held a final set of meetings in Belfast and Dublin on the 20th and 21st March to try and resolve the outstanding queries and to provide clarification to participants. These meetings were with Viridian, ESB International, Synergen and ESB.

Key concerns discussed were as follows:

- Thermal Efficiency – KEMA were concerned that the Thermal Efficiency of the Huntstown plants were lower than would be expected for modern CCGTs. The fact that they were air cooled rather that water cooled would contribute to a slightly lower efficiency, but the levels suggested seemed unduly cautious. The No Load Heat Rate has subsequently been adjusted for both plants bringing them into the range KEMA would anticipate for modern CCGTs.
- Start Up Energy – This was a concern for Huntstown 1 and 2 that the level seemed high for CCGTs. This was despite a reduction from the level initially submitted in the first round of re-submission. After checking with generation experts and discussions with Huntstown it

was decided that this was just within the range of credibility for an existing CCGT and was how Viridian currently operate the plant. There was still a concern on why Huntstown 2, which was a different design to Huntstown 1, should be expected to have the identical high usage.

KEMA also requested that ESB examine their Start Up Energy for Moneypoint which still seemed high, although this has not changed from previous submissions. ESB have re-confirmed their Start Up Energy for Moneypoint. As with Huntstown 1, KEMA believes this is within the range of credible levels of Start Up Energy and recommend no further actions on this parameter.

- Forced Outage Rates – ESB had increased a number of their Forced Outage Rates. One participant had explicitly raised concerns on this and KEMA also felt that not all the changes reflected their international experience. At the meeting ESB agreed to send KEMA their historic Forced Outage Rates to allow investigation of whether these changes were justified in the light of historic performance.

- Proxies for Data – KEMA were concerned that in the absence of some data on Ramping Rates, Start Up Energy and Synchronisation Times for Huntstown 2 it had been decided to simply use the figures for Huntstown 1. This linking seemed inappropriate as Huntstown 1 was a different design to the uncommissioned Huntstown 2.

- Modelling of Poolbeg CCGT - Poolbeg is included in the model as a single unit for historical reasons. The plant is very similar to Ballylumford CCGT so it seems an anomaly that they are treated differently in the model and some discussion is going on currently as to whether they should be more appropriately included as a single unit. This will depend how they are dispatched by the System Operators (the RAs have advised that historically EirGrid dispatched Poolbeg as a single entity to simplify market operation and settlement) and there will be other considerations that will be factored into the decision on whether the plant is a single or two units. The timescale for this decision were outside the scope of this project, but this should be noted as a possible change in the future i.e. Poolbeg may be more appropriately represented as two units in the same manner as Ballylumford.

Discussions with ESB International and Synergen focused more on understanding of the definition of various parameters particularly around Start Up and ramping. As a result Synergen resubmitted a new Run Up Rate and small revision to the Forced Outage Rate. ESB International made a number of small data revisions the most important of which were reduction of Ramping Rates to reflect performance over the entire Ramping Rate from min load to full load, modification of Min Up Times and Min Down Times and converting Start Up Energy to Lower Heating Values.

A full summary of the issues that have arisen on each parameter through out this exercise and how these have been resolved is contained in Appendix D to this document.

3.9 Resolution of outstanding queries

There were three significant issues that still needed to be resolved after the meetings on the 20th and 21st March.

KEMA still had some concerns on the technical parameters for both Huntstown stations. The issue with Huntstown 1 related to the Start Up of the plant and the level at which the GT would be synchronising before the ST would synchronise. Due to additional information from Viridian this was found to be a more substantial issue than initially envisaged. A number of options were considered including modelling the GT and ST separately. However, after discussions with both Viridian and internal modelling experts it was decided that ignoring the energy produced at GT synchronisation would be the most appropriate way of modelling.

KEMA decided that in the absence of available data for Huntstown 2 on Start Up Energy, Ramping Rates and Synchronisation times that Huntstown 1 was not the best proxy. Huntstown 1 is a multi shaft generator whereas Huntstown 2 is single shaft generator design and is also more modern and would be expected to operate at base load. KEMA are therefore recommending the use of data from Dublin Bay Power as a guide for these parameters listed above.

ESB provided KEMA with their Forced Outages Rates from 2004-2006 late on the 27th March. KEMA performed a quick review of this data and are now recommending the following actions in respect of the proposed changes to the data.

Unit	**Original Rate**	**Revised Rate**	**Recommendation**
Great Island 1 &2	9%	19%	Increase appropriate given historic figures
Great Island 3	9%	21%	Increase appropriate given historic figures
Tarbert 1&2	12%	19%	This is not justified by the historic figures. Reverted back to 12%.
Tarbert 3&4	6%	15%	Increase appropriate given historic figures
Poolbeg 1&2	10%	14%	Increase appropriate given historic figures
Poolbeg 3	12%	22%	Questions exist on whether this Forced Outage Rate is too low. This Forced Outage rate should be set to

			100% for 2008 as this plant is not expected to operate.
Moneypoint	5%	7%	This is not justified given the historic data. KEMA's recommendation is a reduction in the rate to 4%
Poolbeg CCGT	5%	7%	No reason from the historic data for an increase from 5% to 7%. Rate set at 5%
Aghada	5%	7%	No reason from the historic data for an increase from 5% to 7%. Rate set at 5%
Marina	5%	7%	This is a reasonable average, but varies across years. Accept new figure.
Northwall (CCGT)	5%	7%	The 7% figure was achieved in one of the years. Accept figure as challenging but feasible estimate.

3.10 Final Conclusions Workshop

KEMA presented an update on the changes and resolutions since the Initial Findings Workshop on Friday 30th March. The presentation covered the following points:

- SRMC update
- Consistency of submission
- Technical versus commercial parameters
- Other clarifications
- Changes to Forced Outage Rates
- What is unconstrained

Concerns were raised on the treatment of Peat Plants in the unconstrained schedule noting that this was KEMA's interpretation of advice from RAs.

It was noted at this stage the data was not finalised as Forced Outage Rates were still being discussed with ESB and there was the potential for comments at the meeting which required adjustment to the data set.

3.11 Final Data Set

The final data set for all generators was baselined on Monday 2 April as ESB were not able to produce any additional evidence on Forced Outage Rates in the tight timescales. ESB agreed they would raise any subsequent issues on Forced Outage Rates directly with the RAs.

A number of generators (Coolkeeragh and Huntstown 2 in particular) indicated that they had provided their best figures based on their current understanding of the plant’s performance. One of these plants was coming back from a prolonged outage and the other was commissioning late in 2007. Clearly these figures may changes in the light of operational performance and KEMA accepts that it is appropriate for this to happen as revised operational performance limits and/or operational experience provides justification to do so, but in both cases for this exercise KEMA needed to use best current proxies.

KEMA accepts that on a day to day basis generators can change technical parameters to reflect short term operational issues (e.g. fuel switching or steam turbine failure) and/or performance (e.g. summer ratings for CCGTs). As advised by the RAs, KEMA notes this should be done within a consistent interpretation over time of SRMC bidding principles by each market participant across its generation portfolio and different market participants are able to take differing interpretations/judgements of what costs to include in their bids under the SRMC bidding principles, subject to scrutiny by the RAs monitoring unit. Nonetheless KEMA believes that the final data sets represent a reasonable view of generation technical data figures for the purposes of annual modelling assuming average normal operating performance and represents a suitable starting point for conducting future exercise such as Directed Contracts assessment and LOOP 3 modelling.

A full set of data (minus Variable Operations and Maintenance data which is confidential) is attached as Appendix C.

4. Other Input Data and Modeling Assumptions

4.1 Modeling Assumptions Validated

The following modeling assumptions and data items have been validated as part of this data validation exercise:

- Modeling of potential constraints:
    - Treatment of Moyle Interconnector
    - Treatment of pumped storage
    - Emissions constraints
    - Peat stations
- Forecasting assumptions
    - Demand forecasting and the treatment of demand
    - Treatment of wind and wind forecasting
- Fuel and related costs

    Fuel price forecasts (Oil, Gas, Coal and Peat)

    Carbon prices

    GB wholesale electricity (BETTA) prices

- Short Run Marginal Cost
- Generator maintenance schedules

4.2 Discussions with EirGrid

KEMA held a meeting with EirGrid on the 1 February to discuss the modeling assumptions and input data.

The meeting aimed to confirm the method of calculation for LOOP 2 and consider the input data and modeling assumptions for LOOP 3. Key items discussed as part of this meeting with EirGrid were as follows:

Modeling of potential constraints

EirGrid noted that the Moyle Interconnector will be treated like any other generator in LOOP 3 with hourly prices submitted and the generator running dependent on where it is in the merit order. The interconnector will be assumed to be either 100% importing or exporting, unless it is the marginal plant in that period. It has 400 MW for transfer from GB to Ireland, but a lower figure of 80MW for transfers the other way. There is 50MW capacity that is kept as reserve.

There are a number of different ways that pumped storage can be captured in PLEXOS and these were discussed. The reserve is generally held across the units and currently the power station operates with the aim of having reservoirs full at 8AM in time for the morning pick up. KEMA requested a copy of Turlough Hill's import/export figures for 2006 in order to get a better understanding of how it is operating and consider the best way to capture this in PLEXOS. This data was not provided to KEMA, but it is believed that the operating regime could change, so this data was not deemed to be vital for the purposes of KEMA's data validation exercise.

Forecasting assumptions

The method of wind forecasting is changing between LOOP 2 and LOOP 3. EirGrid have now produced a new data set for wind series time data that breaks the Republic of Ireland down into 3 regions. This was expected to be more accurate than the previous data set, but is only based on wind series data for one year. The intention is that this data set will be used for LOOP 3. Wind generator capacity data has been derived from the Seven Year Statement (SONI) and Transmission Forecast Statement (EirGrid) for LOOP 2 and this approach was expected to continue

Demand forecasting is undertaken by EirGrid and SONI with methodologies published in the Generation Adequacy Report and Seven Year Statement. EirGrid subsequently provided details of this methodology.

Fuel and related costs

Pöyry were commissioned to produce a report looking at future fuel price in September/October 2006. On the basis of this report EirGrid produced a spreadsheet of prices for all fuels, carbon prices and exchange rates. This was provided to KEMA and subsequently it was confirmed that this could be made public. Within this report the fuel prices were all single annual charges, with the exception of gas prices which were monthly charges,

For consistency these fuel prices had also been used to derive GB power prices.

EirGrid recognised that in the LOOP 2 model the transport cost for coal and excise duty had not been fully included in the price for ROI, but this would be updated for LOOP 3. The application of excise duties was also an area of difference between Northern Ireland and the ROI and these costs are explicitly detailed in the EirGrid spreadsheet and can be treated as an addition to the fuel price.

One difference between the jurisdictions was on gas transport charges. In Northern Ireland there is a 50/50 split between commodity and capacity charges to recover the allowable revenue. In the Republic of Ireland this is split 90% for capacity and 10% for commodity. This means that the marginal transport cost for a southern gas fired generator (the commodity part) is significantly less than for a Northern Ireland generator. (This issue subsequently became a debate about whether SRMC includes capacity as well as commodity).

Short Run Marginal Costs

It was confirmed that in previous runs the only variables which make up SRMC were fuel costs (including transport and excise) and carbon costs. There was no allowance for variable operations and maintenance (VOM) costs and Transmission Loss Adjustment Factors were also not part of this calculation. KEMA noted they were considering these figures for future runs.

Generator outages

The RAs have previously had difficulty obtaining maintenance schedules as generators view these as commercially sensitive data. The RAs therefore used SKM to produce some sample schedules for the different generators for LOOP 2. KEMA noted that they would ask participants for this data, but would need to consider what to use in the absence of any response.

4.3 Discussion with market participants - Dublin

Discussions with market participants in Dublin regarding modeling assumptions covered the following points:

Modeling of potential constraints

Participants questioned exactly how the Moyle Interconnnector was set up within PLEXOS and what constraints would exist on the system. In particular there was discussion on why the unconstrained schedule should only allow export of 80 MW when import of 400MW was possible. Participants noted that if this was a system constraint rather than a technical constraint then it should be excluded from the unconstrained schedule.

Similar in nature to the Moyle Interconnector 'constraint' discussion was the handling of pumped storage 'constraint' on the amount of water that needs to remain in the upper reservoir. This is currently set at 0.3GWh for system security reasons. It was argued that this is a system constraint and should not be included in the unconstrained schedule.

Relating back to LOOP 2 it was noted that the current treatment of pumped storage led to results that were counter intuitive in terms of the running regime. In particular unusual events such as pumping during mid-afternoon were seen. However, there was an acceptance that if this was optimal in terms of pricing then it should not be ignored as the optimal solution.

Forecasting Assumptions

Participants were generally happy with the method of calculations with the two System Operators forecasting demand and adding theses figures together. There were concerns that this process should be more transparent. There was particular concern about the difficulty in getting hold of demand figures for Northern Ireland in order that market participants can validate these figures. KEMA noted they would be performing this validation and providing an explanation as to how the demand figures had been derived.

Participants generally felt comfortable about the proposed move to three regional wind availability figures with the use of SONI and EirGrid figures for national capacity.

Fuel and Related Costs

It was requested that fuel and carbon prices should be derived from a credible published source so that all participants would have confidence in the data. Suggestions included Heren, Argus or Morgan Stanley for the different fuel prices and Point Carbon for the Carbon price.

Short Run Marginal Cost

A key element that was felt to be missing from Short Run Marginal Cost was the variable costs of Operations and Maintenance (VOM).

It was noted that the ratio of gas transport commodity and capacity charges elements will change in Northern Ireland from 2008 with increasing capacity and decreasing commodity weightings with gas transport charges. This will affect the variable gas transport cost and if SRMC is judged to only include the commodity price, therefore the SRMC bids for CCGTs in Northern Ireland.

Generator Maintenance Schedules

These were seen by market participants as being commercially sensitive. However, some participants indicated that they were prepared to give indicative schedule which could be used within the models. This should allow a reasonable approximation as used in the LOOP 2 data.

4.4 Discussions with Market Participants - Belfast

Discussions with market participants in Belfast regarding modeling assumptions covered the following points

Modeling of Potential Constraints

A participant highlighted contractual difficulties with the purchase of short term power through the Moyle Interconnector, if this power had not been selected in the initial schedules. As market prices continually move then this could result in very high prices being charged if the System Operator went back at a later point and asks for additional energy. KEMA pointed out that it should be possible for inter-System Operator arrangements to facilitate supply of short term energy at a reasonable cost and that this was out with the scope of the validation exercise.

Issues were discussed on the treatment of pumped storage including how to treat 'constraints' such as the need for the System Operator to have some reserve. One particular concern was how decisions were made on when to pump and in particular whether this decision was based on the Shadow price only or the shadow price and uplift. Periods with the lowest Shadow Price may not be the cheapest periods overall if there is high uplift.

A concern was also raised that there were emissions limit on NOx and SOx that may constrain how a plant can operate. KEMA subsequently contacted generators to confirm any limitations.

Peat plants have a legal requirement to be allowed to operate a certain number of hours per year. However, it is unclear whether this requirement is in the T&SC v1.2 and these are must-run plant in the EPUS schedule, or whether the System Operators should dispatch them but the EPUS schedule should treat them as any other plant.

Forecasting Assumptions

A key discussion was on whether demand side participation would be included in the model and if so how it would be priced. At the meeting KEMA noted that they were currently exploring this issue and would provide further information at the Initial Findings Workshop. There was also a need to confirm whether the current Demand Side Management (DSM) programmes were included in the demand figures and how the forecast dealt with embedded generation.

One question raised on the Northern Ireland demand profiles was how Economy 7 was included in the forecasts. This was estimated at around 100 MW. The assumption with this demand was that it would be anticipated to fall in the same hours as previous years. It was also noted that wholesale and TNUoS charge led to a reduction of about 100 MW in the peak winter periods from 16:00 to 19:00. It was anticipated that this reduction would remain as many customers were now used to operating around these peaks and therefore the forecast would apply going forwards.

Fuel and Related Costs

KEMA confirmed that the full cost of carbon allowances would be included in SRMC calculations as it was an avoidable cost. Again it was stressed that both carbon prices and fuel prices should come from a transparent source. One suggested source was to use the same data set as currently used for pricing spill in the Republic of Ireland.

It was noted that duty rates were different between the two jurisdictions. In the UK (i.e. Northern Ireland) there was no duty on oil consumed for generation. The EirGrid spreadsheet clearly separates out excise duties per jurisdictions and transport rates which KEMA would validate.

Short Run Marginal Cost

Gaining a detailed understanding of what should be in and out of the SRMC modeling was a key concern for many of the participants. A number of items were discussed:

- Transmission Loss Adjustment Factors – It was noted that these would be included in the SRMC of the power station and the PLEXOS model would reflect this.

- VOM – It was agreed that this cost should be within SRMC. It was suggested that some clarity may need to be given to participants to help them calculate this. There was a concern that some participants may already be including this cost within other parameters which makes them appears overly high. One participant raised a concern about how this matches the legacy contracts that exist, where it was felt that VOM was treated as a fixed cost that was paid separately.

- Potential loss of capacity payments by a constrained plant was an issue raised by one participant. This event is likely to occur if some of the plants have constraints that mean they can only operate for a maximum number of hours per year. This could be an emissions limit or could be an operational constraint on the plant. If a participant found their hours were used up in the summer they may miss out on expected higher capacity payments in the winter period. The participant questioned whether the expected value of this lost capacity payment could be included in the SRMC.

- Cost of credit lines and broker fees. Some discussion on whether credit lines were really a variable cost or a fixed cost, as a credit line was normally put in place for a period of time. The participant that raised the issue offered to investigate. Whilst broker fees were accepted as a variable cost, KEMA felt that these were of a low materiality and could be ignored in this modeling.

- Some discussion was held on whether the model would reflect the higher SRMC on the days when plants were testing their back up fuel. This is likely to be fairly infrequent and could only be 1-2 days per annum.

- Gas transport charges are split into a commodity and a capacity element. Whilst the commodity element is clearly variable there has been some discussion on whether the capacity element should also be seen as a variable cost. This may depend on the degree to which capacity can be traded in the short term reflecting an opportunity cost in using the capacity. The difference in the capacity/commodity split between the two jurisdictions will make this an important decision.

- How to include the cost of operating a duel fuel plant at maximum capacity on a more expensive fuel, particularly where this switch will cost money to undertake. In the particular instance discussed the plant could keep running on the cheaper fuel prior to the switch of fuels. It is not possible to include the costs of this fuel switch in start up costs as the plant would already be running. The participant's expectation is that all these additional costs would need to be placed in the Heat Rate of the last incremental based on a forecast of how many MWs would be required and for how long.

One participant raised a number of questions about the need for probabilistic premiums in SRMC to recover the additional costs when unusual events occurred. Examples given were:

- Whether a premium on fuel prices was needed for changes from indicative to actual dispatch. This was felt to be a concern if the participant had purchased gas based on the indicative schedule and then had to sell it back at a lower prices. It is possible that the participant may purchase gas and sell it back at a higher price. This is a potential cost that participants may want to include in their SRMC based on an additional cost and the probability of it occurring, although it may be hard to quantify.

- Whether a premium is needed reflecting the cost and probability that the plant may have to switch fuels and start using a more expensive alternative to keep running.

- Whether a premium should be charged for the risk that a plant may need to run with a higher Heat Rate than planned. A specific example was if a CCGT had to run as an OCGT possibly due to a forced outage on the steam turbine.

- Whether a premium should be charged for the extra maintenance cost of running plant beyond normal operational limits. The example was for GTs where the final incremental was only recommended for a small number of hours per annum (e.g.50). After running for these hours increased maintenance would be required. What SRMC could be factored into this last incremental. As well as 1/50th of the maintenance costs should the lost opportunity cost for having to take time out to perform this maintenance also be included.

Generator Maintenance Schedules

The meetings had some discussion on outage schedules and the degree to which they could be made public domain. It was thought the RAs may be publishing them month ahead next year which would reduce the sensitivity on the publication of best estimates now for 2008.

A concern was raised about how KEMA was dealing with plant commissioning and decommissioning. It was noted that as KEMA's data validation only lasted for a year this was not an issue.

4.5 Discussions at the Initial Findings Workshop

The Initial Findings Workshop covered the following points.

Modeling of Potential Constraints

KEMA outlined their latest thinking that the Moyle Interconnector limit of 400 MW to Ireland and 80 MW to GB was a technical limit that was appropriate to be part of the unconstrained schedule. There was some discussion on whether these limits could be changed if SONI were to make available more capacity (it was believed that 450 MW was available) or if the GB Transmission Entry Capacity was increased in Scotland. This second option was not considered likely due to the long queue for transmission capacity in Scotland at the moment.

In relation to appropriate treatment of pumped storage plant, there was some discussion on whether the limit on the upper reservoir, which was needed for black start, should be included in the unconstrained schedule.

KEMA noted that there were a number of plants that may potentially be restricted in their operating hours by Emissions Constraints. KEMA requested that participants confirm if their plants have any emissions limit as part of their next data submission exercise. (Subsequently only Edenderry Power indicated a small constraint that could reduce annual output by 1%.)

Forecasting Assumptions

KEMA outlined their view of what is included within system demand. KEMA noted they were still in discussion with the System Operators to confirm the approach and check for consistency of approach with variables such as losses, small scale generation and DSM programmes. KEMA also presented the intended approach of using 3 regional wind series availabilities rather than the single availability used in the LOOP 2 calculations.

Fuel and Related Costs

Some discussion was held on the most appropriate fuel indices to be used with the modeling. It was suggested that the Directed Contracts Workshop had recommended a number of fuel and carbon indices and it would be sensible if the model validation project was consistent with these.

Any changes in the fuel price indices would require a new set of data for GB prices to be produced for the model. There were a number of options as to how this could be derived including regression of current modeling by Pöyry, new modeling, or use of other forward curves. There were some questions as to whether the half hourly delineation of data that was currently provided by Pöyry was really required. It was thought that it could be needed for the peak periods when energy could flow in different directions during periods within an EFA block time period. There was also a discussion on whether prices should be adjusted for the expectation of capacity and uplift prices that make up the full value that a UK generator would receive.

On transport prices, KEMA noted that coal prices for Moneypoint could be based on API2 figures as the plant has direct port access. Kilroot had additional costs of getting coal to the station which were estimated at £7 per tonne. Transport costs for gas were published as forecasts by BordGais

Short Run Marginal Cost

The meeting had a lengthy discussion of what should be included in SRMC. It was noted that the RAs have specified overarching SRMC bidding principles rather than detailed SRMC rules. The RAs have advised:

- Expect consistency of approach across each company portfolio and over time
- Consistency not necessarily required across participants

Participants were advised they needed to decide what items to include and how to cost these within their bids. However, KEMA requested that if participants decide to include other SRMC costs in technical parameters then they inform KEMA (on a bilateral and confidential basis) so as to help with KEMA's validation of generator data.

KEMA outlined two costs which they thought it was clear that they should be included in the SRMC.

- Variable Operations and Maintenance (VOM) Costs – These weren't included in LOOP 2 results, but it was felt that this is a SRMC and should be included. KEMA stated that they would be writing to all participants on the 5th March to request their VOM estimates. This could be split into €/MWh or €/start.

- Transmission Loss Adjustment Factors – KEMA would adjust the data to include Transmission Loss Adjustment Factors in the prices. KEMA noted that some assessment was needed as to handle day/night factors. It was also questioned whether No Load Energy and Start Up Energy costs should be adjusted by Transmission Loss Adjustment Factors and KEMA offered to assess this.

One area that caused some concern was the treatment of fuel transport costs for gas and whether both capacity and commodity elements should be included in the SRMC. KEMA had assumed that it was only the commodity elements. However, the RAs had recently decided that fuel transport costs should not be included in the charges to be recovered from the SEM Capacity charges. Participants suggested that the capacity element of the gas transport charges would therefore need to be recovered within the SRMC based bids. KEMA agreed to contact the RAs to discuss this charge.

Finally KEMA ran through a list of issues that had been raised as potential SRMC items including:

- Loss of capacity payments from a constrained plant;
- Cost of credit lines and broker fees;
- Higher SRMC for testing days of back up fuel; and
- Costs of switching from main to back up fuel to increase max capacity

In addition, a number of probabilistic premiums had been suggested:

- Fuel prices cost for changes from indicative schedule;
- Cost and probability that a plant may have to switch fuels;
- If a plant had to run in a state with a higher Heat Rate (OCGT vs CCGT); and
- Likely extra maintenance when running beyond normal operational limits

As stated earlier KEMA indicated that each participant needed to determine for themselves whether to include these anywhere within their technical data, to reflect their view of appropriate risk based costs allowable under the umbrella of SRMC bidding principles outlined by the RAs.

4.6 Final Conclusions Workshop

KEMA provided updates on the input data and modeling assumptions at the Final Conclusions Workshop on the 30th March. At this stage a couple of the data items still needed to be validated and this was done subsequent to the meeting.

One key area of concern was the need to be precise about the derivation of demand. KEMA have discussed this with both System Operators and have included a separate Appendix E, detailed how demand has been calculated.

The final conclusions reached on all the input data and the modeling assumptions that were discussed at the Final Conclusions Workshop are outlined below

4.7 Final conclusions on other input data and modeling assumptions

Modeling of potential constraints

On the Moyle Interconnector the key question had been why there was only 80 MW export capacity from Northern Ireland to Ireland, but 400 MW in the other direction and whether this was a network constraint that should be excluded. KEMA confirmed that this 80MW export on Scottish beach represent contractual firm access i.e. the maximum access granted to Moyle for connection to the GB system and was not a network constraint in the "home" market of SEM. Furthermore above 80MW Moyle has NO rights to constraint payments in GB and indeed would be penalised for exceeding this limit. The Moyle Interconnector modeling will therefore continue to be treated as having 400 MW entry and 80 MW exit in the unconstrained schedule. Interconnector losses should be 1.9% in either direction. This factor was taken from the Invitation to Tender for Capacity for April –October 2007 and has been reviewed in the light of expected trading across the Moyle Interconnector in 2007-08. Moyle capacity values apply at the connection point of the Auchencrosh converter station to the Scottish transmission system.

Regarding treatment of pumped storage, the RAs indicated that Section 5 of the T&SC v1.2 set out the treatment of pumped storage plant, but that from their perspective there was no requirement under the T&SC v1.2 to reserve any level of water for Black Start. Nevertheless their view was that Ancillary Services lay outside the market and agreed with KEMA’s suggestion of removing any Ancillary Service constraints to retain water from the unconstrained schedule.

For Peat stations “priority run” obligations, KEMA indicated that the RAs advised that the general principle is that only ROI customers alone should pay for/subsidise costs incurred due to social/energy policies imposed within ROI and equally the same would apply for NI. Consequently, given the market rules under the T&SC v1.2, KEMA believes that to ensure that Peat stations run as required by legislation they need to be treated as “must run” in the unconstrained schedule (i.e. to force this within the constrained schedule would lead to associated costs being borne by all island customers).

Forecasting assumptions

EirGrid have agreed that their wind series data that divides the ROI into three sectors can be released as Public Domain data. This should improve the accuracy beyond the one time series for the whole Island previously used. It is suggested that Northern Ireland utilise the most northerly region as many of the wind sites will be positioned quite close to the border. To introduce additional time series would be problematic if the same time period was not used for their creation.

KEMA have checked the wind capacity data for ROI against the Generation Adequacy Report. This gave the totals shown below from EirGrid.

	Capacity for RoI (MW)*	Year
Region A	452.61	2007
Region B	458.81	2007
Region C	121.689	2007
Total	1033.109	2007
Region A	492.01	2008
Region B	506.81	2008
Region C	141.139	2008
Total	1139.959	2008

**All values from GAR 2007-2013*

The capacity figures for Northern Ireland are for approximately 392 MW of installed capacity in 2008, which is NIE's expectation of the average installed wind capacity for 2008. This should all be added to Region A, the most northerly region for which the region availability series have been developed.

A key area that KEMA were asked to clarify is how the demand data has been produced in the two jurisdictions. A note covering this is contained in Appendix E to this proposal, however, key points to note are

- Demand includes all losses;
- Demand Side Management schemes including Economy 7 are assumed to continue;
- Demand supplied from embedded generation has not been netted of demand; and
- No direct demand side participation is assumed to occur. This may need to change over time as the market evolves. However, at this point it is not possible to estimate the number of MW that may participate or the price at which this participation may take place.

Fuel and related costs

At the Initial Findings Workshop on the 2nd March it was suggested that the fuel prices used should be consistent with those planned for the Directed Contracts.

The RAs have indicated that these are currently being finalised but are likely to be as follows.

- Gas - ICE Futures for gas as published in the ESGN Heren Report.
- Coal - Forward prices from the Argus Daily Coal International
- LSFO and Gasoil (0.2%) - Platts – Forward Oil Curve Europe
- Carbon Prices - These will be sourced from the London Energy Broker Association

KEMA support the use of these transparent data sources for use in LOOP3 and the Directed Contracts. It will be important to specify a date at which prices will be taken from these reports and exactly how they will be specified e.g. latest carbon price or average of last 'x' days. Ideally the price data should be sourced as close as practical to the timing of the actual modelling run to minimise the risk of market movements.

Due to confidentiality issues with these data sources KEMA cannot utilise or release a data source from the intended sources from directed contracts. KEMA have therefore been doing their testing on fuel prices produced by Pöyry for EirGrid in September/October of 2006. EirGrid have agreed that these can be released into the public domain. Since September 2006 gas prices have moved considerably so KEMA have utilised the Low Scenario as part of its analysis and believe it to be a reasonable internally consistent data set for use for fuel and related GB prices.

Assuming confidentiality issues can be overcome it would be helpful for the RAs to commission an updated spreadsheet to contain all the data in one place at the time of the LOOP3 runs or Directed Contracts. This would ensure that all participants had free access to the data.

One of the advantages of using the EirGrid spreadsheet for fuel prices is that it contains GB wholesale electricity prices that are consistent with the fuel prices. However, determination of the prices that a generator is likely to bid into the Ireland market is more complex than just requiring GB Prices.

It is assumed that a rational generator bidding into the Pool from GB would include a bid that was net of uplift and expected capacity payments. This would reflect the full expected returns from being dispatched in the All Island market. In order to construct a bid in this format the following information is required.

i) A prediction of wholesale electricity (BETTA) prices in the GB market. This data set should be produced and made available once the fuel prices for the Directed Contracts or LOOP3 modeling has been determined.

ii) A prediction of the costs of purchasing interconnector capacity

iii) A prediction of Capacity payments. This will require some modeling to be performed splitting the monthly capacity pot into indicative hourly values that would be paid in the All Island market

A calculation should then be made of i) +ii) - iii) to give capacity return adjusted BETTA prices

iv) A prediction of Uplift in the Irish market - In order to do this the PLEXOS model should be run iteratively with the capacity adjusted BETTA prices with adjustments being made for expected Uplift.

` The final BETTA price set used in modeling should be i) +ii) -iii) - iv)

The EirGrid spreadsheet does provide some exchange rates from Pöyry. These do not seem that close to current exchange rates and whilst these can be used for trial runs for consistency with Moyle Interconnector prices, it is suggested that revised exchange rates are used for more formal runs. Due to the difficulty of forecasting future exchange rates it is recommended that these are taken from recent history of well known sources with a clear decision on which exchange rates to use. The Bank of England and European Central Bank should be the most appropriate. It is suggested that average exchange rates for the last month would be appropriate.

Excise prices are provided in the EirGrid spreadsheet. These only affect a couple of fuels which are fuel oil and distillate and only in ROI. The rates used in the calculations have been checked against the 2007 budget financial resolutions and are then adjusted by density factors to turn the excise charge into a €/tonne charge.

The EirGrid spreadsheet includes gas transport prices from Pöyry that can be used as an adder to the fuel prices. These prices are built up using NBP costs and the costs for the relative jurisdiction. They are commodity only which may need to change depending on the RAs view on whether capacity charges should be included in SRMC. KEMA have validated using BordGais prices for ROI and Premier Transmission price for NI.

The gas transport calculation for ROI can be validated against current gas prices with a small expectation of a price reduction in ROI transmission tariffs for 2008. However, the EirGrid calculations for Northern Ireland seemed to already assume that the change in capacity-commodity split (to 75% capacity rather than current 50%) had been introduced. This is not due to come into force in the Northern Ireland tariff until 1 October 2008. It is therefore suggested that the prices used are based on gas tariffs that apply until September 2008. This will lead to a sizeable increase in these figures as more of the charge is commodity until this point. KEMA have produced an example providing alternative figures for gas transport commodity charges for 2008.

The EirGrid table also contains transport costs for all fuels. For coal the port costs in both NI and ROI are estimated $3.32/tonne. Trans-shipment applies to Northern Ireland only and is estimated at $11.54 per tonne, based on other UK stations of similar size. Fuel Oil is priced for delivery at the port and all plants are at the port. Distillate has an inland transport cost of €10.11/tonne which was based on charges by trucks to various plants.

Short Run Marginal Cost

KEMA are recommending that Variable Operations and Maintenance (VOM) costs and Transmission Loss Adjustment Factors are including in calculations of SRMC. The VOM costs have been collected from generators and in the absence of actual figures KEMA have calculated a proxy based on a similar power station.

It is suggested that monthly values of time weighted TLAFs are used. The 2008 TLAFs are not currently available, but should be available in time for the Directed Contracts and LOOP 3 data. These TLAFs will be included by specifying the relevant loss factor for each generator unit in PLEXOS. This loss factor adjusts the generators' incremental costs as considered in the PLEXOS dispatch optimization, but does not adjust no load and start costs since these are not output dependent. By specifying TLAFs directly in the model, PLEXOS automatically incorporates loss-adjusted incremental costs in the schedule and loss-adjusted revenues in the Uplift cost recovery condition.

The RAs are still considering this treatment of the gas transport tariff and whether capacity should count as a SRMC. It therefore seems inappropriate for KEMA to provide a view at this stage. It is anticipated that the RAs will provide a formal view in the context of modeling work for LOOP 3 and for setting of Directed Contracts. Depending on the decision made it will be a simple task to adjust the gas transport prices in the model to include the capacity element for North and South should this be deemed the correct interpretation. An estimated load factor would need to be determined for each power station (or type of power station) in order to include Capacity within the SRMC.

As stated at the Initial Findings Workshop all other elements of SRMC could be included by participants in technical data, but they needed to clearly explain what had been done. Only one participant chose this route as explained further in Section 3.

Generator maintenance schedules

Maintenance schedules have been provided for some but not all participants. To avoid any confidentiality issues it is recommended that the outage schedule for 2007 is used to derive schedules for 2008.

Appendix A: Generator Data Set from 2005

This Appendix contains the original generator data set provided for the LOOP 2 data runs.

Appendix A: Generator Data Set from 2005

Unit ID	Unit Name	Min Stable Capacity	Max capacity	Fuel	Heat Rate Curve: No Load Heat Requirement (GJ/hr)	Capacity Point [MW exported]					Incremental Heat Rate Slope [GJ/MWhr]				Forced Outage Rate,%	Mean Time to Repair, hrs
						1	2	3	4	5	1 to 2	2 to 3	3 to 4	4 to 5		
AD1	Aghada Unit 1	35	258	Gas	187.17	35	100	180	258		7.86	8.64	8.72		5.0%	50
AT1	Aghada CT Unit 1	10	88	Distillate	267.53	10	40	88			7.35	9.11			3.5%	50
AT2	Aghada CT Unit 2	10	88	Distillate	267.53	10	40	88			7.35	9.11			3.5%	50
AT4	Aghada CT Unit 4	10	90	Gas	268.73	10	40	90			7.38	9.15			3.5%	50
AP5	Aghada Peaking Unit	5	52	Distillate	86.62	5	52				9.05				6.65%	50
AA1	Ardnacrusha Unit 1	11.9	21	Hydro	...	...	...	...	...	...	...	...	...		1.0%	60
AA2	Ardnacrusha Unit 2	11.9	22	Hydro	...	...	...	...	...	...	...	...	...	...	1.0%	60
AA3	Ardnacrusha Unit 3	11.9	19	Hydro	...	...	...	...	...	...	...	...	...	...	1.0%	60
AA4	Ardnacrusha Unit 4	11.9	24	Hydro	...	...	...	...	...	...	...	...	...	...	1.0%	60
DBP	Dublin Bay Power	200	396	Gas	532.6	200	279.2	370.9	411.2		4.665	5.525	5.954		2.0%	31
ED1	Edenderry	40	117.6	Peat	497.6	40	88.2	98.3	117.6		3.933	8.95	8.839		5.0%	72
ER1	Erne Unit 1	4	10	Hydro	...	...	...	...	...	...	...	...	...	...	1.0%	60
ER2	Erne Unit 2	4	10	Hydro	...	...	...	...	...	...	...	...	...	...	1.0%	60
ER3	Erne Unit 3	5	22.5	Hydro	...	...	...	...	...	...	...	...	...	...	1.0%	60
ER4	Erne Unit 4	5	22.5	Hydro	...	...	...	...	...	...	...	...	...	...	1.0%	60
GI1	Great Island Unit 1	25	54	Oil	51.26	25	47.1	54			11.11	11.92			9.0%	50
GI2	Great Island Unit 2	25	54	Oil	51.26	25	47.1	54			11.11	11.92			9.0%	50
GI3	Great Island Unit 3	30	108	Oil	105.38	30	102	108			9.69	9.84			9.0%	50
LE1	Lee Unit 1	3	15	Hydro	...	...	...	...	...	...	...	...	...	...	1.0%	60
LE2	Lee Unit 2	1	4	Hydro	...	...	...	...	...	...	...	...	...	...	1.0%	60
LE3	Lee Unit 3	3	8	Hydro	...	...	...	...	...	...	...	...	...	...	1.0%	60
LI1	Liffey Unit 1	3	15	Hydro	...	...	...	...	...	...	...	...	...	...	1.0%	60
LI2	Liffey Unit 2	3	15	Hydro	...	...	...	...	...	...	...	...	...	...	1.0%	60
LI4	Liffey Unit 4	0.4	4	Hydro	...	...	...	...	...	...	...	...	...	...	1.0%	60
LI5	Liffey Unit 5	0.2	4	Hydro	...	...	...	...	...	...	...	...	...	...	1.0%	60
LR4	Lough Rea	40	91	Peat	89.55	40	91				9.09				5.0%	50
HNC	Huntstown	222.8	342.7	Gas	324.3	222.8	342.7				5.706				3	24
MRT	Marina CC *	77	112.29	Gas	251.24	63.5	77	108	112.3		6.22	7.03	7.03	8.93	5.0%	50
MP1	Moneypoint Unit 1	115	285	Coal	147.79	115	200	285			9.28	9.37			5.0%	50
MP2	Moneypoint Unit 2	115	285	Coal	147.79	115	200	285			9.28	9.37			5.0%	50
MP3	Moneypoint Unit 3	115	285	Coal	147.79	115	200	285			9.28	9.37			5.0%	50
MP1	Moneypoint Unit 1 FGD SCR	115	282.5	Coal	147.79	115	200	280			9.34	9.51			5.0%	50
MP2	Moneypoint Unit 2 FGD SCR	115	282.5	Coal	147.79	115	200	280			9.34	9.51			5.0%	50
MP3	Moneypoint Unit 3 FGD SCR	115	282.5	Coal	147.79	115	200	280			9.34	9.51			5.0%	50
NW4	Northwall Unit 4	112	163	Gas	347.11	112	115.2	161.8	163		5.99	6.76	8.13		5.0%	50
NW5	Northwall Unit 5	5	108	Distillate	317.19	5	108				9.96				3.5%	50
PB1	Poolbeg Unit 1	55	109.5	oil	83.81	55	109.5				9.35				10.0%	50
PB2	Poolbeg Unit 2	55	109.5	oil	88.2	55	109.5				9.46				10.0%	50
PB3	Poolbeg Unit 3	56	242	oil	274.29	56	121	180	242		8.33	9.48	9.58		12.0%	50
PBC	Poolbeg Combined Cycle	280	480	Gas	716.49	280	480				5.5				5.0%	50
TB1	Tarbert Unit 1	25	54	Oil	50.14	25	48.7	54			11.42	11.91			12.0%	50
TB2	Tarbert Unit 2	25	54	Oil	50.14	25	48.7	54			11.42	11.91			12.0%	50
TB3	Tarbert Unit 3	35	240.7	Oil	258.07	35	100	180	240.7		7.85	8.82	8.9		6.0%	50
TB4	Tarbert Unit 4	35	240.7	Oil	258.07	35	100	180	240.7		7.85	8.82	8.9		6.0%	50
RH1	Rhode Unit 1	5	52	Distillate	85.01	5	52				9				6.65%	50
RH2	Rhode Unit 2	5	52	Distillate	85.01	5	52				9				6.65%	50
TP1	Asahi Peaking Unit	5	52	Distillate	85.01	5	52				9				6.65%	50
SK1	Aughinish (Sealrock)	135	150	Gas	506	60	90	120	135	150	4.060	4.094	5.349	5.349	3.0%	33
TE	Tynagh	202	404	Gas	467.06	202	404				5.262				3.6%	40
TH1	Turlough Hill Unit 1	5	73	Hydro	...	...	...	...	...	...	...	...	...	...	1.0%	60
TH2	Turlough Hill Unit 2	5	73	Hydro	...	...	...	...	...	...	...	...	...	...	1.0%	60
TH3	Turlough Hill Unit 3	5	73	Hydro	...	...	...	...	...	...	...	...	...	...	1.0%	60
TH4	Turlough Hill Unit 4	5	73	Hydro	...	...	...	...	...	...	...	...	...	...	1.0%	60
WO4	West Offaly Power	46	137	Peat	124.49	46	137				8.95				5.0%	50
B4	Ballylumford Unit 4	56	170	Gas	179.27	56	170	-			10.51	-			2.19	72
B6	Ballylumford Unit 6	56	170	Gas	179.27	56	170	-			10.51	-			2.19	72
B31	Ballylumford CCGT 31	116	240	Gas	495.8	116	240	-			5.76	-			3.01	72
B32	Ballylumford Unit 32	116	240	Gas	495.8	116	240	-			5.76	-			3.01	72
B10	Ballylumford Unit 10	63	103	Gas	98.15	63	103	-			6.67	-			3.01	72
BGT1	Ballylumford GT1	8	53	Distillate	180	8	58	-			11.05	-			1.37	72
BGT2	Ballylumford GT2	8	53	Distillate	180	8	58	-			11.05	-			1.37	72
CPS CCGT	Coolkeeragh CCGT	260	404	Gas	495.8	260	400	-			5.454	-			3.01	72
CGT8	Coolkeeragh GT8	8	53	Distillate	176.94	8	58	-			10.86	-			1.10	72
K1	Kilroot Unit 1	64	201	Coal	213	64	201	-			8.63	-			2.74	72
K2	Kilroot Unit 2	64	201	Coal	213	64	201	-			8.63	-			2.74	72
KGT1	Kilroot GT1	5	29	Distillate	101.25	5	29	-			10.86	-			0.82	72
KGT2	Kilroot GT2	5	29	Distillate	101.25	5	29	-			10.86	-			0.82	72

Unit ID	Run Up Rate, MW/min	Ramp Rate Up, MW/min	Ramp Rate Down, MW/min	Min UpTime (mins)	Min Up Time (hrs)	Min Down Time (mins)	Min Down Time (hrs)	Reserve (MW): Primary	Secondary	Tertiary 1	Tertiary 2	Start up Energy (GJ) Cold	Start up Energy (GJ) Warm	Start up Energy (GJ) Hot	Synchronisation times: From hot, hrs	From Warm, hrs	From cold, hrs	Boundary times: Hot to Warm, hrs	Warm to Cold, hrs
AD1	4.224	4.224	4.224	300.00	5.00	210.00	3.50	23	20	20	20	4302	2185	1273	3.5	7	12	9	100
AT1	5	5	5	0.00	0.00	45.00	0.75	20	20	20	20	63	63	63	0.33	0.33	2	1	2
AT2	5	5	5	0.00	0.00	45.00	0.75	20	20	20	20	63	63	63	0.33	0.33	2	1	2
AT4	5	5	5	0.00	0.00	45.00	0.75	20	20	20	20	63	63	63	0.33	0.33	2	1	2
AP5	5	5	5	60.00	1.00	40.00	0.67	0	0	0	0	50	50	50	0.08	0.08	0.08	1	2
AA1	6	6	6	0.00	0.00	15.00	0.25	4	12	0	21				0.25	0.25	0.25	1	2
AA2	6	6	6	0.00	0.00	15.00	0.25	4	12	0	22				0.25	0.25	0.25	1	2
AA3	6	6	6	0.00	0.00	15.00	0.25	4	12	0	19				0.25	0.25	0.25	1	2
AA4	6	6	6	0.00	0.00	15.00	0.25	4	15	1	23				0.25	0.25	0.25	1	2
DBP	11	11	11	240.00	4.00	60.00	1.00	13	37	42	42	7700	2600		2	3.5	5	1	8
ED1	1.5	0.5	0.5	240.00	4.00	20.00	0.33	5.9	5.9	9.4	9.4	2010	1084	436	1.25	4.00	12.00	2.75	8
ER1	5	5	5	0.00	0.00	10.00	0.17	0	2	6	6				0.1	0.1	0.1	1	2
ER2	5	5	5	0.00	0.00	10.00	0.17	0	2	6	6				0.1	0.1	0.1	1	2
ER3	10	10	10	0.00	0.00	10.00	0.17	1	14	6	6				0.1	0.1	0.1	1	2
ER4	10	10	10	0.00	0.00	10.00	0.17	1	14	6	6				0.1	0.1	0.1	1	2
GI1	1	1	1	180.00	3.00	120.00	2.00	3	3	3	3	562	449	217.5	2	3	12	12	48
GI2	1	1	1	180.00	3.00	120.00	2.00	3	3	3	3	562	449	217.5	2	3	12	12	48
GI3	1.1	1.1	1.1	180.00	3.00	120.00	2.00	15	20	20	20	743	600	293	2	3	11	12	48
LE1	0.8	0.8	0.8	0.00	0.00	10.00	0.17	0	5	10	10				0.08	0.33	0.33	1	2
LE2	2.4	2.4	2.4	0.00	0.00	10.00	0.17	0	2	3	3				0.08	0.33	0.33	1	2
LE3	1.5	1.5	1.5	0.00	0.00	10.00	0.17	0	3	7	7				0.08	0.33	0.33	1	2
LI1	5	5	5	0.00	0.00	12.00	0.20	1	3	7	7				0.12	0.12	0.12	1	2
LI2	5	5	5	0.00	0.00	12.00	0.20	1	3	7	7				0.12	0.12	0.12	1	2
LI4	2	2	2	15.00	0.25	8.00	0.13	0	0	0	0				0.08	0.08	0.08	1	2
LI5	0.03	0.03	0.03	0.00	0.00	7.00	0.12	1	1	1	1				0.08	0.08	0.08	1	2
LR4	2	2	2	720.00	12.00	120.00	2.00	4	12	0	0	320	320	320	3.5	7	12	12	48
HNC	5	5	10	480.00	8.00	240.00	4.00	17	18	25	25	650	500	250	2	6	12	8	72
MRT	1.66	1.66	1.66	120.00	2.00	60.00	1.00	29	33	35	35	50	50	50	0.5	0.5	0.5	10	30
MP1	4.26	4.26	4.26	480.00	8.00	300.00	5.00	20	45	45	45	14620	6920	4360	5	10	15	8	72
MP2	4.26	4.26	4.26	480.00	8.00	300.00	5.00	20	45	45	45	14620	6920	4360	5	10	15	8	72
MP3	4.26	4.26	4.26	480.00	8.00	300.00	5.00	20	45	45	45	14620	6920	4360	5	10	15	8	72
MP1	4.26	4.26	4.26	480.00	8.00	300.00	5.00	20	45	45	45	14620	6920	4360	5	10	15	8	72
MP2	4.26	4.26	4.26	480.00	8.00	300.00	5.00	20	45	45	45	14620	6920	4360	5	10	15	8	72
MP3	4.26	4.26	4.26	480.00	8.00	300.00	5.00	20	45	45	45	14620	6920	4360	5	10	15	8	72
NW4	2.6	2.6	2.6	120.00	2.00	45.00	0.75	15	40	52	52	80	80	80	0.5	0.5	0.5	10	48
NW5	8	8	8	0.00	0.00	30.00	0.50	32	52	72	72	50	50	50	0.33	0.33	0.33	1	2
PB1	2	2	2	180.00	3.00	120.00	2.00	14	28	8	8	1025	625	353	2	8	10	15	120
PB2	2	2	2	180.00	3.00	120.00	2.00	9	20	8	8	1025	625	353	2	8	10	15	120
PB3	2.98	2.98	2.98	255.00	4.25	210.00	3.50	23	20	20	20	4302	2185	1273	3.5	7	12	15	120
PBC	10	10	10	30.00	0.50	30.00	0.50	60	112	150	150	100	100	100	0.33	0.33	1	15	120
TB1	1.85	1.85	1.85	1200.00	20.00	120.00	2.00	3	3	3	3	562	449	217.5	2	3	12	12	48
TB2	1.85	1.85	1.85	1200.00	20.00	120.00	2.00	3	3	3	3	562	449	217.5	2	3	12	12	48
TB3	1.25	1.25	1.25	300.00	5.00	210.00	3.50	15	19	25	25	3180	1934	1072	3.5	7	12	12	120
TB4	1.25	1.25	1.25	300.00	5.00	210.00	3.50	15	19	25	25	3180	1934	1072	3.5	7	12	12	120
RH1	5	5	5	60.00	1.00	40.00	0.67					50	50	50	0.08	0.08	0.08	1	2
RH2	5	5	5	60.00	1.00	40.00	0.67					50	50	50	0.08	0.08	0.08	1	2
TP1	5	5	5	60.00	1.00	40.00	0.67	0	0	0	0	50	50	50	0.08	0.08	0.08	1	2
SK1	5.8	5.8	5.8	0.00	0.00	0.00	0.00								0.4	0.4	0.4	1 to 4	40
TE	19	19	19	240.00	4.00	210.00	3.50	20	20	32	40	2810.5896	1633.1669	1143.6837	1.5	3.2	4		
TH1	210	210	210	0.00	0.00	0.00	0.00	15	30	33	33				0.1	0.1	0.1	1	12
TH2	210	210	210	0.00	0.00	0.00	0.00	15	30	33	33				0.1	0.1	0.1	1	12
TH3	210	210	210	0.00	0.00	0.00	0.00	15	30	33	33				0.1	0.1	0.1	1	12
TH4	210	210	210	0.00	0.00	0.00	0.00	15	30	33	33				0.1	0.1	0.1	1	12
WO4	2	2	2	720.00	12.00	120.00	2.00	7	15	20	20	500	500	500	3.5	7	12	12	48
B4	1.5	5	10	240.00	4.00	420.00	7.00	35				2124	1527	847	3	5	12	10	36
B6	1.5	5	10	240.00	4.00	420.00	7.00	35				2124	1527	847	3	5	12	10	36
B31	0.46	11	11	600.00	10.00	480.00	8.00	37.1				50	50	50	1.13	1.83	8	8	48
B32	0.46	11	11	600.00	10.00	480.00	8.00	37.1				50	50	50	1.13	1.83	8	8	48
B10	0.23	4	4	600.00	10.00	480.00	8.00	8				50	50	50	0.25	0.25	1.33	8	48
BGT1	6	10	10	60.00	1.00	60.00	1.00	14.5				16	16	16	0.1	0.1	0.1	n/a = OCGT	
BGT2	6	10	10	60.00	1.00	60.00	1.00	14.5				16	16	16	0.1	0.1	0.1	n/a = OCGT	
CPS CCGT	4	22	12	60.00	1.00	480.00	8.00	40							1.16	1.83	8		
CGT8	10	10	10	60.00	1.00	60.00	1.00	15.5				16			1			n/a = OCGT	
K1	0.9	6	6	60.00	1.00	480.00	8.00	30				2247	1645	973	1	2.2	9	10	65
K2	0.9	6	6	60.00	1.00	480.00	8.00	30				2247	1645	973	1	2.2	9	10	65
KGT1	5	10	10	60.00	1.00	60.00	1.00	7.25				8					0.13	n/a = OCGT	
KGT2	5	10	10	60.00	1.00	60.00	1.00	7.25				8					0.13	n/a = OCGT	

Appendix B: Initial Generator Data Revisions

This contains the updated data sets received back from generators prior to the Initial Findings Workshop.

Appendix B: Initial Generator Data Revisions

Unit ID	Unit Name	Min Stable Capacity	Max capacity	Fuel	Heat Rate Curve									
					No Load Heat Requirement (GJ/hr)	Capacity Point [MW exported]					Incremental Heat Rate Slope [GJ/MWhr]			
						1	2	3	4	5	1 to 2	2 to 3	3 to 4	4 to 5
AD1	Aghada Unit 1	35	258	Gas	187.53	35	74	112	180	258	7.877	8.122	8.654	8.74
AT1	Aghada CT Unit 1	15	88	Distillate	279.86	15	40	88	0	0	7.683	9.533	0	0
AT2	Aghada CT Unit 2	15	88	Distillate	279.86	15	40	88	0	0	7.683	9.533	0	0
AT4	Aghada CT Unit 4	15	90	Gas	279.86	15	40	90	0	0	7.683	9.533	0	0
AP5	Aghada Peaking Unit	5	52	Distillate	86.62	5	52	0	0	0	9.05	0	0	0
AA1	Ardnacrusha Unit 1	12	21	Hydro	...	...	...	...	...	...	...	...	...	...
AA2	Ardnacrusha Unit 2	12	22	Hydro	...	...	...	...	...	...	...	...	...	...
AA3	Ardnacrusha Unit 3	12	19	Hydro	...	...	...	...	...	...	...	...	...	...
AA4	Ardnacrusha Unit 4	12	24	Hydro	...	...	...	...	...	...	...	...	...	...
DBP	Dublin Bay Power	207	415	Gas	532.6	207	279.2	370.9	411.2		4.665	5.525	5.954	
ED1	Edenderry	40	117.6	Peat	497.6	40	88.2	98.3	117.6		3.933	8.95	8.839	
ER1	Erne Unit 1	4	10	Hydro	...	...	...	...	...	...	...	...	...	...
ER2	Erne Unit 2	4	10	Hydro	...	...	...	...	...	...	...	...	...	...
ER3	Erne Unit 3	5	22.5	Hydro	...	...	...	...	...	...	...	...	...	...
ER4	Erne Unit 4	5	22.5	Hydro	...	...	...	...	...	...	...	...	...	...
GI1	Great Island Unit 1	25	54	Oil	49.57	25	45	54	0	0	11.249	12.062	0	0
GI2	Great Island Unit 2	25	54	Oil	49.57	25	45	54	0	0	11.249	12.062	0	0
GI3	Great Island Unit 3	30	108	Oil	102.04	30	98	108	0	0	9.769	9.922	0	0
LE1	Lee Unit 1	3	15	Hydro	...	...	...	...	...	...	...	...	...	...
LE2	Lee Unit 2	1	4	Hydro	...	...	...	...	...	...	...	...	...	...
LE3	Lee Unit 3	3	8	Hydro	...	...	...	...	...	...	...	...	...	...
LI1	Liffey Unit 1	3	15	Hydro	...	...	...	...	...	...	...	...	...	...
LI2	Liffey Unit 2	3	15	Hydro	...	...	...	...	...	...	...	...	...	...
LI4	Liffey Unit 4	0.4	4	Hydro	...	...	...	...	...	...	...	...	...	...
LI5	Liffey Unit 5	0.2	4	Hydro	...	...	...	...	...	...	...	...	...	...
LR4	Lough Rea	40	90	Peat	89.55	40	90	0	0	0	9.086	0	0	0
HNC	Huntstown	244	335	Gas/Distillate	574	244	335				5.706			
HN2	Huntstown Phase II	244	391	Gas/Distillate	670	244	391				5.3			
MRT	Marina CC *	98	112.29	Gas	249.8	63.5	63.5	108	112.29	0	6.185	6.989	8.883	0
MP1	Moneypoint Unit 1	136	285	Coal	148.34	136	200	285	0	0	9.313	9.406	0	0
MP2	Moneypoint Unit 2	136	285	Coal	148.34	136	200	285	0	0	9.313	9.406	0	0
MP3	Moneypoint Unit 3	136	285	Coal	148.34	136	200	285	0	0	9.313	9.406	0	0
MP1	Moneypoint Unit 1 FGD SCR	136	282.5	Coal	148.34	136	200	282.5	0	0	9.35	9.6	0	0
MP2	Moneypoint Unit 2 FGD SCR	136	282.5	Coal	148.34	136	200	282.5	0	0	9.35	9.6	0	0
MP3	Moneypoint Unit 3 FGD SCR	136	282.5	Coal	148.34	136	200	282.5	0	0	9.35	9.6	0	0
NW4	Northwall Unit 4	99	163	Gas	351.77	99	115.2	161.8	163	0	6.074	6.848	8.883	0
NW5	Northwall Unit 5	5	109	Distillate	309.39	5	108.5	0	0	0	9.715	0	0	0
PB1	Poolbeg Unit 1	56	109.5	Gas/Oil	80.18	56	106	109.5	0	0	9.508	10.228	0	0
PB2	Poolbeg Unit 2	56	109.5	Gas/Oil	80.18	56	106	109.5	0	0	9.508	10.228	0	0
PB3	Poolbeg Unit 3	57	242	Gas/Oil	245.86	57	242	0	0	0	8.447	0	0	0
PBC	Poolbeg Combined Cycle	280	480	Gas	704.52	280	480	0	0	0	5.41	0	0	0
TB1	Tarbert Unit 1	25	54	Oil	46.05	25	46	54	0	0	11.24	11.712	0	0
TB2	Tarbert Unit 2	25	54	Oil	46.05	25	46	54	0	0	11.24	11.712	0	0
TB3	Tarbert Unit 3	35	240.7	Oil	256.89	35	80	115	180	243	7.814	8.226	8.776	8.864
TB4	Tarbert Unit 4	35	240.7	Oil	256.89	35	80	115	180	244	7.814	8.226	8.776	8.864
RH1	Rhode Unit 1	5	52	Distillate	85.01	5	52	0	0	0	9	0	0	0
RH2	Rhode Unit 2	5	52	Distillate	85.01	5	52	0	0	0	9	0	0	0
TP1	Asahi Peaking Unit	5	52	Distillate	85.01	5	52	0	0	0	9	0	0	0
SK3	Sealrock 3 (Aughinish CHP)	40	83	Gas	1112	40	48	60	72	80	5	7.3	7.4	8.9
SK4	Sealrock 4 (Aughinish CHP)	40	83	Gas	1112	40	48	60	72	80	5	7.3	7.4	8.9
TE	Tynagh	220	404	Gas	467.06	220	404				5.262			
TH1	Turlough Hill Unit 1	5	73	Hydro										
TH2	Turlough Hill Unit 2	5	73	Hydro										
TH3	Turlough Hill Unit 3	5	73	Hydro										
TH4	Turlough Hill Unit 4	5	73	Hydro										
WO4	West Offaly Power	52.5	135.65	Peat	124.59	52.5	137	0	0	0	8.954	0	0	0
B4	Ballylumford Unit 4	56	170	Gas	179.27	56	170	-			10.51	-		
B6	Ballylumford Unit 6	56	170	Gas	179.27	56	170	-			10.51	-		
B31	Ballylumford CCGT 31	116	240	Gas	495.8	116	240	-			5.76	-		
B32	Ballylumford Unit 32	116	240	Gas	495.8	116	240	-			5.76	-		
B10	Ballylumford Unit 10	63	103	Gas	98.15	63	103	-			6.67	-		
BGT1	Ballylumford GT1	8	53	Distillate	180	8	58	-			11.05	-		
BGT2	Ballylumford GT2	8	53	Distillate	180	8	58	-			11.05	-		
CPS CCGT	Coolkeeragh CCGT	260	401.5	Gas	495.8	260	400	-			5.454	-		
CGT8	Coolkeeragh GT8	8	53	Distillate	176.94	8	58	-			10.86	-		
K1	Kilroot Unit 1	64	201	Coal	213	64	201	-			8.63	-		
K2	Kilroot Unit 2	64	201	Coal	213	64	201	-			8.63	-		
KGT1	Kilroot GT1	5	29	Distillate	101.25	5	29	-			10.86	-		
KGT2	Kilroot GT2	5	29	Distillate	101.25	5	29	-			10.86	-		

Unit ID	Forced Outage Rate,%	Mean Time to Repair, hrs	Run Up Rate, MW/min	Ramp Rate Up, MW/min	Ramp Rate Down, MW/min	Min UpTime (mins)	Min Up Time (hrs)	Min Down Time (mins)	Min Down Time (hrs)	Reserve (MW)				Start up Energy (GJ) Cold	Start up Energy (GJ) Warm	Start up Energy (GJ) Hot	Synchronisation times			Boundary times	
										Primary	Secondary	Tertiary 1	Tertiary 2				From hot, hrs	From Warm, hrs	From cold, hrs	Hot to Warm, hrs	Warm to Cold, hrs
AD1	7.0%	50	4.224	4.224	4.224	240	4	210	3.5	22	22	22	22	4302	2185	1273	3	7	18	5	72
AT1	5.0%	50	5	5	5	0	0	45	0.75	20	20	20	20	63	63	63	0.33	0.33	2	1	2
AT2	5.0%	50	5	5	5	0	0	45	0.75	20	20	20	20	63	63	63	0.33	0.33	2	1	2
AT4	5.0%	50	5	5	5	0	0	45	0.75	20	20	20	20	63	63	63	0.33	0.33	2	1	2
AP5	5.0%	50	5	5	5	0	0	4.99999998	0.08333333	0	0	0	0	20	20	20	0.08	0.08	0.08	0.5	1
AA1	2.5%	60	6	6	6	0	0	15.00	0.25	4	8	12	12				0.25	0.25	0.25	1	2
AA2	2.5%	60	6	6	6	0	0	15.00	0.25	4	8	12	12				0.25	0.25	0.25	1	2
AA3	2.5%	60	6	6	6	0	0	15.00	0.25	4	12	12	12				0.25	0.25	0.25	1	2
AA4	2.5%	60	6	6	6	0	0	15.00	0.25	4	15	15	15				0.25	0.25	0.25	1	2
DBP	2.0%	31	11	11	11	240.00	4.00	60.00	1.00	13	37	42	42	7700	2600		2	3.5	5	1	72
ED1	8.0%	72	1.5	0.5	0.5	240.00	4.00	20.00	0.33	5.9	5.9	9.4	9.4	2010	1084	436	1.25	4.00	12.00	2.75	8
ER1	2.5%	60	5	5	5	0	0	10	0.16666667	0	2	6	6	0	0	0	0.1	0.1	0.1	1	2
ER2	2.5%	60	5	5	5	0	0	10	0.16666667	0	2	6	6	0	0	0	0.1	0.1	0.1	1	2
ER3	2.5%	60	10	10	10	0	0	10	0.16666667	1	14	14	14	0	0	0	0.1	0.1	0.1	1	2
ER4	2.5%	60	10	10	10	0	0	10	0.16666667	1	14	14	14	0	0	0	0.1	0.1	0.1	1	2
GI1	19.0%	50	1	1	1	240	4	120	2	3	6	9	9	562	449	218	2	3	12	12	48
GI2	19.0%	50	1	1	1	240	4	120	2	3	6	9	9	562	449	218	2	3	12	12	48
GI3	21.0%	50	1.1	1.1	1.1	240	4	240	4	15	20	20	20	743	600	293	2	3	11	12	48
LE1	2.5%	60	0.8	0.8	0.8	0	0	10	0.16666667	0	5	10	10				0.08	0.33	0.33	1	2
LE2	2.5%	60	2.4	2.4	2.4	0	0	10	0.16666667	0	2	3	3				0.08	0.33	0.33	1	2
LE3	2.5%	60	1.5	1.5	1.5	0	0	10	0.16666667	0	3	7	7				0.08	0.33	0.33	1	2
LI1	2.5%	60	5	5	5	0	0	12	0.2	1	3	7	7				0.12	0.12	0.12	1	2
LI2	2.5%	60	5	5	5	0	0	12	0.2	1	3	7	7				0.12	0.12	0.12	1	2
LI4	2.5%	60	2	2	2	15	0.25	8	0.13333333	0	0	0	0				0.08	0.08	0.08	1	2
LI5	2.5%	60	0.03	0.03	0.03	0	0	7	0.11666667	0	1	1	1				0.08	0.08	0.08	1	2
LR4	6.0%	50	2	2	2	300	5	60	1	5	5	5	5	562	449	218	6	12	18	8	60
HNC	5.00%	55	5	5	10	360.00	6.00	240.00	4.00	17	18	25	25	20000	10000	5000	2	6	12	8	72
HN2	5.00%	55	5	5	10	360.00	6.00	240.00	4.00	20	20	30	30	20000	10000	5000	2	6	12	8	72
MRT	7.0%	50	1.66	1.66	1.66	240.00	4.00	60.00	1.00	29	33	35	35	50	50	50	0.5	0.5	5	10	40
MP1	6.5%	50	4.26	4.26	4.26	480.00	8.00	300.00	5.00	19	44	44	44	14620	6920	4360	5	10	15	8	72
MP2	6.5%	50	4.26	4.26	4.26	480.00	8.00	300.00	5.00	19	44	44	44	14620	6920	4360	5	10	15	8	72
MP3	6.5%	50	4.26	4.26	4.26	480.00	8.00	300.00	5.00	19	44	44	44	14620	6920	4360	5	10	15	8	72
MP1	7.0%	50	4.26	4.26	4.26	480.00	8.00	300.00	5.00	19	44	44	44	14620	6920	4360	5	10	15	8	72
MP2	7.0%	50	4.26	4.26	4.26	480.00	8.00	300.00	5.00	19	44	44	44	14620	6920	4360	5	10	15	8	72
MP3	7.0%	50	4.26	4.26	4.26	480.00	8.00	300.00	5.00	19	44	44	44	14620	6920	4360	5	10	15	8	72
NW4	7.0%	50	2.6	2.6	2.6	240.00	4.00	45.00	0.75	15	40	53	53	80	80	80	0.5	0.5	5	7	48
NW5	5.0%	50	8	8	8	0.00	0.00	30.00	0.50	20	20	20	20	50	50	50	0.33	0.33	0.33	1	2
PB1	14.0%	50	2	2	2	180.00	3.00	120.00	2.00	14	28	28	28	1025	625	353	2	8	10	15	120
PB2	14.0%	50	2	2	2	180.00	3.00	120.00	2.00	14	28	28	28	1025	625	353	2	8	10	15	120
PB3	22.0%	50	2.98	2.98	2.98	255.00	4.25	210.00	3.50	9	20	20	20	4302	2185	1273	3.5	7	30	15	120
PBC	7.0%	50	10	10	10	240.00	4.00	120.00	2.00	60	112	150	150	2000	2000	2000	0.33	0.33	1	15	120
TB1	19.0%	50	1.85	1.85	1.85	240.00	4.00	120.00	2.00	3	6	9	9	562	449	218	2	3	12	12	48
TB2	19.0%	50	1.85	1.85	1.85	240.00	4.00	120.00	2.00	3	6	9	9	562	449	218	2	3	12	12	48
TB3	15.0%	50	1.25	1.25	1.25	300.00	5.00	210.00	3.50	15	19	25	25	3180	1934	1072	3	7	18	14	120
TB4	15.0%	50	1.25	1.25	1.25	300.00	5.00	210.00	3.50	15	19	25	25	3180	1934	1072	3	7	18	14	120
RH1	5.0%	50	5	5	5	0.00	0.00	5.00	0.08	0	0	0	0	20	20	20	0.08	0.08	0.08	0.5	1
RH2	5.0%	50	5	5	5	0.00	0.00	5.00	0.08	0	0	0	0	20	20	20	0.08	0.08	0.08	0.5	1
TP1	5.0%	50	5	5	5	0	0	4.99999998	0.08333333	0	0	0	0	20	20	20	0.08	0.08	0.08	0.5	1
SK3	3.0%	33	6	6	6	240	4	240	4	3.7	3.7	9	30				0.21	0.21	0.21	8	24
SK4	3.0%	33	6	6	6	240	4	240	4	3.7	3.7	9	30				0.21	0.21	0.21	8.00	24
TE	3.6%	40	10	10	8	480.00	8.00	210.00	3.50	19	19	31	38	2810.5896	1633.1669	1143.6837	2	4	8	1 to 8	8 to 48
TH1	2.5%	60	210	210	210	0.00	0.00	0.00	0.00	15	30	33	33				0.1	0.1	0.1	1	12
TH2	2.5%	60	210	210	210	0.00	0.00	0.00	0.00	15	30	33	33				0.1	0.1	0.1	1	12
TH3	2.5%	60	210	210	210	0.00	0.00	0.00	0.00	15	30	33	33				0.1	0.1	0.1	1	12
TH4	2.5%	60	210	210	210	0.00	0.00	0.00	0.00	15	30	33	33				0.1	0.1	0.1	1	12
WO4	6.0%	50	2	2	2	300.00	5.00	60.00	1.00	7	7	14	14	750	600	450	6	12	18	12	60
B4	2.19	72	1.5	5	10	240.00	4.00	420.00	7.00	35				2124	1527	847	3	5	12	10	36
B6	2.19	72	1.5	5	10	240.00	4.00	420.00	7.00	35				2124	1527	847	3	5	12	10	36
B31	3.01	72	0.46	11	11	600.00	10.00	480.00	8.00	37.1				50	50	50	1.13	1.83	8	8	48
B32	3.01	72	0.46	11	11	600.00	10.00	480.00	8.00	37.1				50	50	50	1.13	1.83	8	8	48
B10	3.01	72	0.23	4	4	600.00	10.00	480.00	8.00	8				50	50	50	0.25	0.25	1.33	8	48
BGT1	1.37	72	6	10	10	60.00	1.00	60.00	1.00	14.5				16	16	16	0.1	0.1	0.1	n/a = OCGT	
BGT2	1.37	72	6	10	10	60.00	1.00	60.00	1.00	14.5				16	16	16	0.1	0.1	0.1	n/a = OCGT	
CPS CCGT	3.01	72	4.5	18.5	18.5	60.00	1.00	480.00	8.00	40				50	50	50	1.16	1.83	8	8	36
CGT8	1.10	72	10	10	10	60.00	1.00	60.00	1.00	15.5				16			1			n/a = OCGT	
K1	2.74	72	0.9	6	6	60.00	1.00	480.00	8.00	30				2247	1645	973	1	2.2	9	10	65
K2	2.74	72	0.9	6	6	60.00	1.00	480.00	8.00	30				2247	1645	973	1	2.2	9	10	65
KGT1	0.82	72	5	10	10	60.00	1.00	60.00	1.00	7.25				8					0.13	n/a = OCGT	
KGT2	0.82	72	5	10	10	60.00	1.00	60.00	1.00	7.25				8					0.13	n/a = OCGT	

Appendix C: Final Generator Data Set

This contains the final data set reflecting revisions after the workshop and in final bilateral discussions.

Appendix C: Final Generator Data Set

					Heat Rate Curve																			Reserve (MW)							Synchronisation times			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	Run Up Rate, MW/min	Ramp Rate Up, MW/min	Ramp Rate Down, MW/min	Min UpTime (mins)	Min Up Time (hrs)	Min Down Time (mins)	Min Down Time (hrs)	Primary	Secondary	Tertiary 1	Tertiary 2	Start up Energy (GJ) Cold	Start up Energy (GJ) Warm	Start up Energy (GJ) Hot	From hot, hrs	From Warm, hrs	From cold, hrs	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	4.2	240	4.00	210	3.50	22	22	22	22	4302	2185	1273	3.00	7.00	18.00	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	5.0	0	0.00	45	0.75	20	20	20	20	63	63	63	0.33	0.33	2.00	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	5.0	0	0.00	45	0.75	20	20	20	20	63	63	63	0.33	0.33	2.00	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	5.0	0	0.00	45	0.75	20	20	20	20	63	63	63	0.33	0.33	2.00	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	5.0	0	0.00	5	0.08	0	0	0	0	20	20	20	0.08	0.08	0.08	0.5	1
AA1	Ardnacrusha Unit 1	12.0	21.0	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	6.0	6.0	6.0	0	0.00	15	0.25	4	8	12	12				0.25	0.25	0.25	1	2
AA2	Ardnacrusha Unit 2	12.0	22.0	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	6.0	6.0	6.0	0	0.00	15	0.25	4	8	12	12				0.25	0.25	0.25	1	2
AA3	Ardnacrusha Unit 3	12.0	19.0	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	6.0	6.0	6.0	0	0.00	15	0.25	4	12	12	12				0.25	0.25	0.25	1	2
AA4	Ardnacrusha Unit 4	12.0	24.0	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	6.0	6.0	6.0	0	0.00	15	0.25	4	15	15	15				0.25	0.25	0.25	1	2
DBP	Dublin Bay Power	207.0	415.0	Gas/Distillate	479.34	207	415				5.162				2.3%	31	3.0	11.0	11.0	240	4.00	60	1.00	13	37	42	42	6930	2340		2.00	3.50	5.00	1	72
ED1	Edenderry	41.0	117.6	Peat	497.60	41	88	98	118		3.933	8.950	8.950		8.0%	72	2.0	1.8	1.8	240	4.00	20	0.33	5.9	5.9	9.4	9.4	2010	1084	436	1.25	4.00	12.00	2.75	8
ER1	Erne Unit 1	4.0	10.0	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	5.0	5.0	5.0	0	0.00	10	0.17	0	2	6	6	0	0	0	0.10	0.10	0.10	1	2
ER2	Erne Unit 2	4.0	10.0	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	5.0	5.0	5.0	0	0.00	10	0.17	0	2	6	6	0	0	0	0.10	0.10	0.10	1	2
ER3	Erne Unit 3	5.0	22.5	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	10.0	10.0	10.0	0	0.00	10	0.17	1	14	14	14	0	0	0	0.10	0.10	0.10	1	2
ER4	Erne Unit 4	5.0	22.5	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	10.0	10.0	10.0	0	0.00	10	0.17	1	14	14	14	0	0	0	0.10	0.10	0.10	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	1.0	240	4.00	120	2.00	3	6	9	9	562	449	218	2.00	3.00	12.00	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	1.0	240	4.00	120	2.00	3	6	9	9	562	449	218	2.00	3.00	12.00	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	1.1	240	4.00	240	4.00	15	20	20	20	743	600	293	2.00	3.00	11.00	12	48
LE1	Lee Unit 1	3.0	15.0	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	0.8	0.8	0.8	0	0.00	10	0.17	0	5	10	10				0.08	0.33	0.33	1	2
LE2	Lee Unit 2	1.0	4.0	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	2.4	2.4	2.4	0	0.00	10	0.17	0	2	3	3				0.08	0.33	0.33	1	2
LE3	Lee Unit 3	3.0	8.0	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	1.5	1.5	1.5	0	0.00	10	0.17	0	3	7	7				0.08	0.33	0.33	1	2
LI1	Liffey Unit 1	3.0	15.0	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	5.0	5.0	5.0	0	0.00	12	0.20	1	3	7	7				0.12	0.12	0.12	1	2
LI2	Liffey Unit 2	3.0	15.0	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	5.0	5.0	5.0	0	0.00	12	0.20	1	3	7	7				0.12	0.12	0.12	1	2
LI4	Liffey Unit 4	0.4	4.0	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	2.0	2.0	2.0	15	0.25	8	0.13	0	0	0	0				0.08	0.08	0.08	1	2
LI5	Liffey Unit 5	0.2	4.0	Hydro	...	...	...	...	...	...	...	...	...	...	2.5%	60	0.0	0.0	0.0	0	0.00	7	0.12	0	1	1	1				0.08	0.08	0.08	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	2.0	300	5.00	60	1.00	5	5	5	5	562	449	218	6.00	12.00	18.00	8	60
HNC	Huntstown	220.0	343.0	Gas/Distillate	423.00	220	343				5.573				5.0%	55	6.0	6.0	6.0	240	4.00	240	4.00	17	18	25	25	9545	4947	1732	2.00	6.00	12.00	8	72
HN2	Huntstown Phase II	250.0	401.0	Gas/Distillate	494.00	250	401				5.335				5.0%	55	3.0	10.0	10.0	240	4.00	240	4.00	20	20	30	30	7000	2500	1200	2.00	4.00	6.00	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	1.7	240	4.00	60	1.00	29	33	35	35	50	50	50	0.50	0.50	5.00	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	4.3	480	8.00	300	5.00	19	44	44	44	14620	6920	4360	5.00	10.00	15.00	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	4.3	480	8.00	300	5.00	19	44	44	44	14620	6920	4360	5.00	10.00	15.00	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	4.3	480	8.00	300	5.00	19	44	44	44	14620	6920	4360	5.00	10.00	15.00	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	4.3	480	8.00	300	5.00	19	44	44	44	14620	6920	4360	5.00	10.00	15.00	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	4.3	480	8.00	300	5.00	19	44	44	44	14620	6920	4360	5.00	10.00	15.00	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	4.3	480	8.00	300	5.00	19	44	44	44	14620	6920	4360	5.00	10.00	15.00	8	72
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	2.6	240	4.00	45	0.75	15	40	53	53	80	80	80	0.50	0.50	5.00	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	8.0	0	0.00	30	0.50	20	20	20	20	50	50	50	0.33	0.33	0.33	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	2.0	180	3.00	120	2.00	14	28	28	28	1025	625	353	2.00	8.00	10.00	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	2.0	180	3.00	120	2.00	14	28	28	28	1025	625	353	2.00	8.00	10.00	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	3.0	255	4.25	210	3.50	9	20	20	20	4302	2185	1273	3.50	7.00	30.00	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	10.0	240	4.00	120	2.00	60	112	150	150	3000	2500	2000	4.00	5.00	6.00	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	1.9	240	4.00	120	2.00	3	6	9	9	562	449	218	2.00	3.00	12.00	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	1.9	240	4.00	120	2.00	3	6	9	9	562	449	218	2.00	3.00	12.00	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	2.5	300	5.00	210	3.50	15	19	25	25	3180	1934	1072	3.00	7.00	18.00	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	2.5	300	5.00	210	3.50	15	19	25	25	3180	1934	1072	3.00	7.00	18.00	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	5.0	0	0.00	5	0.08	0	0	0	0	20	20	20	0.08	0.08	0.08	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	5.0	0	0.00	5	0.08	0	0	0	0	20	20	20	0.08	0.08	0.08	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	5.0	0	0.00	5	0.08	0	0	0	0	20	20	20	0.08	0.08	0.08	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	6.0	240	4.00	240	4.00	3.7	3.7	9	30	1200	1000	800	0.21	0.21	0.21	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	6.0	240	4.00	240	4.00	3.7	3.7	9	30	1200	1000	800	0.21	0.21	0.21	8.00	24
TE	Tynagh	224.0	373.0	Gas/Distillate	564.00	224	373				5.060				3.6%	55	10.0	10.0	8.0	240	4.00	210	3.50	19	19	31	38	2811	1633	1144	2.00	4.00	8.00	8	40
TH1	Turlough Hill Unit 1	5.0	73.0	Hydro											2.5%	60	210.0	210.0	210.0	0	0.00	0	0.00	15	30	33	33				0.10	0.10	0.10	1	12
TH2	Turlough Hill Unit 2	5.0	73.0	Hydro											2.5%	60	210.0	210.0	210.0	0	0.00	0	0.00	15	30	33	33				0.10	0.10	0.10	1	12
TH3	Turlough Hill Unit 3	5.0	73.0	Hydro											2.5%	60	210.0	210.0	210.0	0	0.00	0	0.00	15	30	33	33				0.10	0.10	0.10	1	12
TH4	Turlough Hill Unit 4	5.0	73.0	Hydro											2.5%	60	210.0	210.0	210.0	0	0.00	0	0.00	15	30	33	33				0.10	0.10	0.10	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	2.0	300	5.00	60	1.00	7	7	14	14	750	600	450	6.00	12.00	18.00	12	60
B4	Ballylumford Unit 4	56.0	170.0	Gas	161.34	56	170				9.459				2.2%	72	1.5	5.0	10.0	240	4.00	420	7.00	35				1912	1374	762	3.00	5.00	12.00	10	36
B6	Ballylumford Unit 6	56.0	170.0	Gas	161.34	56	170				9.459				2.2%	72	1.5	5.0	10.0	240	4.00	420	7.00	35				1912	1374	762	3.00	5.00	12.00	10	36
B31	Ballylumford CCGT 31	116.0	240.0	Gas	446.22	116	240				5.184				3.0%	72	4.4	11.0	11.0	240	4.00	120	2.00	37.1				5800	1900	1000	1.13	1.83	8.00	8	48
B32	Ballylumford Unit 32	116.0	240.0	Gas	446.22	116	240				5.184				3.0%	72	4.4	11.0	11.0	240	4.00	120	2.00	37.1				5800	1900	1000	1.13	1.83	8.00	8	48
B10	Ballylumford Unit 10	63.0	103.0	Gas	88.34	63	103				6.003				3.0%	72	1.5	4.0	4.0	360	6.00	240	4.00	8				1800	750	500	0.25	0.25	1.33	8	48
BGT1	Ballylumford GT1	8.0	58.0	Distillate	162.00	8	58				9.945				1.4%	72	6.0	10.0	10.0	60	1.00	60	1.00	14.5				14	14	14	0.10	0.10	0.10	n/a = OCGT	
BGT2	Ballylumford GT2	8.0	58.0	Distillate	162.00	8	58				9.945				1.4%	72	6.0	10.0	10.0	60	1.00	60	1.00	14.5				14	14	14	0.10	0.10	0.10	n/a = OCGT	
CPS CCGT	Coolkeeragh CCGT	260.0	404.0	Gas/DIstillate	495.80	260	404				5.454				3.0%	72	4.5	11.0	11.0	360	6.00	210	3.50	40				5220	3024	1080	1.16	1.83	8.00	8	36
CGT8	Coolkeeragh GT8	8.0	53.0	Distillate	176.94	8	53				10.860				1.1%	72	10.0	10.0	10.0	60	1.00	60	1.00	15.5				16	16	16	1.00			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	0.8	3.5	6.5	60	1.00	300	5.00	25				2267	1683	991	4.00	6.00	12.00	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	0.8	3.5	6.5	60	1.00	300	5.00	25				2267	1683	991	4.00	6.00	12.00	10	55
KGT1	Kilroot GT1	5.0	29.0	Distillate	102.50	5	24	29			10.990	10.990	221.990		0.8%	72	5.0	10.0	10.0	60	1.00	60	1.00	7.25				8					0.13	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	5.0	10.0	10.0	60	1.00	60	1.00	7.25				8					0.13	n/a = OCGT	

Appendix D: Issues with Generator Data

Parameter	Issues	Resolution
Min Stable Capacity	Some generators had break points that did not line up with Min Stable Capacity	All generators first break point is now in line with Min Stable Capacity
Min Stable Capacity	Some generators had very high Min Stable Capacity that may not be applicable with Grid Code	Issue noted. Some generators have derogation. Needs to be dealt with between generators and Grid companies
Max Capacity	Some generators had Max Capacity that did not equal their final Capacity Point	All generators now changed to match final capacity with break point.
Max Capacity	Unclear whether CCGT should submit maximum in the winter or summer	Generators should submit the maximum on an average winter day. Within the PLEXOS modelling this figure should be reduced by 3% in the summer.
Fuel	A number of generators only indicated one fuel on which their plant could operate. Many were capable of operating on two fuels.	Plants now indicate where they are capable of dual fuel operation.
Heat Rate – No Load and Heat Rate Slope	A combination of these variables gave an unlikely level of Thermal Efficiency.	This was resolved in a number of ways for different participants i) Participants all submitted data in LHV format ii) Revised Heat Rate slope and No Load parameters submitted for a number of generators iii) Confirmation and evidence provided as to why certain Thermal Efficiencies were higher/lower than initially anticipated
Capacity Points	Multiple Capacity Points below Min Stable Capacity	This was one particular station and the data has now been re-submitted
Heat Rate Slope	None monotonically increasing Heat Rates – Particularly an issue for CCGTs who do not have a monotonically increasing Heat Rate	All stations have now submitted rates that are monotonically increasing. Most CCGTs have chosen to overcome this issue with a single Heat Rate reflecting their likely generation
Forced Outage Rate	A number of generators had increased their Forced Outage Rates from that proposed in November 2005	Where historical evidence backed up the change in Forced Outage Rate this was used. In the absence of historical evidence then proposed changes were not accepted
Mean Time to Repair	Some increases in Mean Time to Repair	Discussions with generators suggested these were all reasonable
Run Up Rates	Some of the Run Up Rates seemed too low	There were a number of issues causing these low run up rates i) Some CCGTs were including the

		time taken to synchronise the ST, which consequently gave a very slow RUR. This was excluded once it was clarified as the RUR after synchronisation ii) One non commissioned unit had overly pessimistic run up rates and it was decided to use an alternative proxy that was similar iii) Some units may have been using contractual values rather than technical values. Plants have resubmitted technical values
Ramp Rate Up	Concern that figures were too low	There were a number of issues causing these low run up rates i) Some units may have been using contractual values rather than technical values. Plants have resubmitted technical values ii) Some units have cautious methods of operation that mean they don't wish to ramp their plants quickly as they believe it causes damage. This is an acceptable method of operation for existing plants iii) One non commissioned unit had overly pessimistic run up rates and it was decided to use an alternative proxy that was similar iv) One operator agreed to increase the ramp rates used for some of its oil plant
Ramp Rate Up/Ramp Rate Down	Concern that figures were too high	One operator had put in the maximum rate that the plant could operate at during only part of the ramping range. It was agreed that they would resubmit to reflect what it could do over the range from min stable capacity to max capacity.
Start Up Energy	High Level of Start Up Energy proposed after the first re-submission of generator data	There were concerns that some participants Start Up Energy costs were too high. This issue was addressed in the following ways i) Reductions in the level of Start Up Energy proposed by generators requiring the most significant amounts ii) Some generators noted that they had based their estimate on HHV rather than LHV values which reduced their requirements.

		iii) Bilateral meetings for those generators with the highest levels of Start Up Energy to explain how those figures had been derived iv) Decision to use a similar generator as a proxy for a non commissioned plant rather than simply a station owned by the same operator.
Start Up Energy	Range of Start Up Energy was wide within a particular technology group. This was particularly apparent with CCGTs.	Generators have been able to easily compare this parameter with that provided by other similar Irish Generators. Particularly on CCGTs there has been a tightening of the range caused by a number of factors i) Use of LHV rather than HHV for all generators Start Up Energy ii) CCGTs all using a consistent definition of Start Up Energy being that required for the steam turbine to synchronise. This resulted in a significant increase for some CCGTs. iii) Reductions by some generators of high start up costs
Start Up Energy	No Start Up Energy for some generators in hot States	It was explained that the plant would not start from hot as the minimum down time would prevent this from being possible.
Start Up Energy	No differentiation between hot, warm and cold states	Generators have adjusted some of their numbers to reflect the varying amounts of energy that will be required to start from different states
Synchronisation Times	Some synchronisation times seemed overly long	Discussions with participants demonstrated why some of the synchronisation times were longer than initially anticipated.
Boundary Times	Some confusion over whether the times were additive or not	Confirmation that time from hot to cold is the sum of hot to warm plus warm to cold.

Appendix E: Derivation of Demand Data

A key area that KEMA were asked to clarify is how the demand data has been produced in the two jurisdictions. This note summarises the approach taken in the two jurisdictions before the number are combined

Republic of Ireland

The demand files provided are on the basis of Total Electricity Requirement. TER represents the amount of energy which is exported from all generation sources (this includes an allowance for on-site consumption by auto-producers (e.g. CHP)). It includes an estimate of losses in both the Distribution and Transmission network. This factor is currently estimated to be 9.3%.

The demand forecasts have been produced using the EirGrid energy forecast model. This is a linear model that divides electricity demand into two sectors requiring different economic inputs to judge growth. These are

- Non domestic electricity sales which are related to GDP
- Domestic electricity sales which are related to growth in Personal Consumption of Goods and Services (PCGS)

High, Medium and Low Demand scenarios are calculated for both electricity sales growth and TER growth based on GDP growth or PCGS growth. These forecasts are taken from the Economic and Social Research Institute (ESRI) which has expertise in modelling the Irish economy.

The loads are specified for each half hour for a full year. These loads have been projected from a base year from 2 Jan 05 to 31 Dec05. The 2008 series is then calculated in half hour periods starting from Sunday 30 Dec 07 to 27 Dec 08. The estimates are adjusted for the desired energy and peak input for the different scenarios. These are as listed in the table below.

	Total Electricity Requirement	Peak Exported (MW)
Low	29,544	5,186
Median	30,230	5,310
High	30,409	5,343

The Median and High forecasts are relatively close, which reflects the economic forecasts.

Peak demand and Demand Side Management (DSM) programmes

The peak demand is based on a historical relationship between annual electricity consumption and the winter peak. This peak is erratic and subject to influences temperate, changing customer habits and Demand Side Management programmes. In recent years these DSM schemes have reduced peak load by about 120 MW. These schemes are included in the demand forecast as they are expected to be sustained. If at some point in the future they were removed them clearly demand would rise.

Embedded generation

Demand that is supplied from embedded generation has not been netted off demand. This embedded generation will be included in the generation calculations. Demand is therefore higher than it would be if the embedded generation was subtracted.

The available embedded generation is estimated as follows in the Generation Adequacy Report 2007-2013

Year End	2007	2008	2009	2010	2011	2012	2013
Industrial Generation	9	9	9	9	9	9	9
Combined Heat and Power	113	115	117	119	121	123	125
Small Scale Hydro	20	21	22	23	24	25	26
Biomass	32	34	36	38	40	42	44
Wind Powered Generation	943	1193	1443	1693	1943	2193	2443
Total Partially/Non-Dispatchable Plant	1117	1372	1627	1882	2137	2392	2647

Figure 5 Summary of non-fully dispatchable capacity

It is suggested that the small scale generation is modelled as regional fixed generation in PLEXOS and then netted of total demand.

Northern Ireland demand

The Northern Ireland demand includes all centrally despatched generation measured at the generation level so will include all network losses.

The demand set for 2008 was created from base year data for 2005. The 2005 data was extrapolated to create the 2008 data using SONI energy forecasts and peak demand forecasts. The growth rate in demand is calculated based on statistical regression analysis. The energy forecast growth was 1.6% with a 1.7% growth expected in peak demand.

Embedded generation

In addition to demand at a generation level the embedded wind generation and CHP need to be added back in.

Wind generation is considerable and is included in the demand profile for 2008. There will be approximately 392 MW of installed capacity in 2008 which is NIE's expectation of the average Installed wind capacity for 2008.

There is small scale CHP generation that wheels power across the network. This is around 0.3% of peak demand and is estimated at around 5MW.

There is approximately 130 MW of generation installed at customer sites and much of this is small diesel generation. There is a DSM programme that operates to reduce demand at peak tariff times. It is assumed that this is running and suppressing the demand profile. This generation is not added back into the profile.

Demand Side Management (DSM)

There are programmes run by SONI for a number of years to encourage large customers to reduce load. It is believed these lead to a reduction of about 120 MW. These are now part of the demand shape and are expected to continue, partly as customers have got used to reducing demand in the peak period.

Economy 7 does exist in Northern Ireland and will be built into the load shape reflecting when demand for electricity is used for heating. It will continue, but is already a relatively small and reducing factor.