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Analysis of the Marginal Emission Factor (MEF)

This report has been prepared by Lane Clark & Peacock LLP ("LCP") and EnAppSys for the Department of Energy and Climate Change ("DECC"). It sets out the results of analysis undertaken to determine historical marginal emission factors and to compare these values to those generated by the Dynamic Dispatch Model ("DDM").

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Executive Summary

The Department for Energy and Climate Change (DECC) currently utilises the Dynamic Dispatch Model (DDM) developed by Lane Clark & Peacock (LCP) to assist in their policy analysis and in producing their published projections. An output of interest to a number of stakeholders is the Marginal Emissions Factor (MEF) which can be used to determine the cost of carbon within the wholesale power price.

Previously, for the years 2010-2011, the model output has matched closely to analysis based on outturn data. However, there are concerns that the modelled values have diverged from actual outturn data over the last two years. On behalf of DECC LCP and EnAppSys have completed this investigation to understand the reason for any differences between the historical data and DDM modelled values.

The first phase of the investigation involved calculating what we believe the historical marginal emissions factor has been for the four years from 2010 to 2013 based on outturn market data. For the purpose of this analysis we have examined three potential methodologies to determine the historical MEF, corresponding to different definitions of which plant is marginal in any given settlement period.

Each of these definitions had limitations and produced different results for the historical MEF value, highlighting that in practice it is difficult to find a reliable measure. However, we concluded that the best methodology was through looking at balancing mechanism bids. In comparing to these results the analysis confirmed more significant differences in 2012 and 2013 as expected. Our research into the differences identified two key areas: the assumption on limited running hours for LCPD plant and the operation of some gas plants running out of merit overnight. After adjusting the DDM model for these factors the models results were considerably closer to the historical values.

However, by their nature these factors may represent historical artefacts and the case for projecting these assumptions into the future would need to be carefully examined. We do however provide some possible model updates that could be implemented if it was deemed necessary but we do not think these are crucial for future use of the DDM.

1. Overview of the approach taken

The analysis was completed in two phases:

1. **Calculating historical MEF -** The first phase involved calculating what we believe the historical marginal emissions factor has been for the four years from 2010 to 2013 based on market data using three methods described below.
2. **DDM analysis -** With this information in hand we then proceeded to run the DDM model for those years and identify any discrepancies, the reasons for them, and test potential assumptions or modelling updates that could be made to address these discrepancies.

2. Calculating historical Marginal Emission Factors (MEF)

2.1. Background

All grid connected power stations in GB notify their dispatch profile to National Grid on a half hourly basis. These notifications include their output and availability and can be revised up to a period of 1 hour prior to each half hour period (a Settlement Period), this period is termed '*gate closure*'. After '*gate closure*' the System Operator, National Grid, balances supply and demand by varying power stations and large demand units output in the Balancing Mechanism. The notifications and balancing actions are published by Elexon in settlement files, on their website www.BMReports.com. EnAppSys collates and stores this data and makes it available to market participants via a web service and database available at www.netareports.com.

Using the notification data for all major GB power stations for the period 1st Jan 2010 to 31st December 2013 at half hour resolution the actual dispatch of power stations pre and post gate closure was extracted and analysed using the methodologies below to determine the marginal station in each half hour based upon the three definitions of 'Marginal Plant'. The different definitions of Marginal Plant explored in the analysis were;

- the power generating unit dispatched in each settlement period with the highest SRMC (Short Run Marginal Cost). This is essentially the concept of marginal used by the DDM,
- the power generating unit whose output in the relevant settlement period followed system demand,
- the power generating unit which post gate closure in each settlement period paid the highest amount on a £/MWH basis to purchase power off the system and hence reduce its output or had the highest accepted cost to increase generation.

The following sections give detail of the methodologies used to determine the 'Marginal Plant' for each of these definitions and the calculation used to determine the Marginal Emissions Factors.

2.2. Methodologies

2.2.1. SRMC Methodology

To determine the marginal power generating unit in each half hour period the notified generation level of all GB Balancing Mechanism Units (BMU's) pre-gate closure was extracted from the EnAppSys database. The notified output pre- gate closure (termed FPN, Final Physical Notification message **BMRS.BM.*.FPN**) was selected as this reflects the dispatch of the BMU's in the market by their owners/operators to meet their bilateral contractual obligations. The assumption would be that the choice to dispatch or not was made on a commercial basis.

Utilising UK commodity closing price data obtained from UK energy brokers and the efficiency, fuel type and carbon emissions factors of each BMU a lookup table was produced at day resolution for the 4 year period of the short run marginal cost of each BMU. The SRMC on a £/MWh basis was then determined for each of the applicable BMU's generating in each Settlement Period and the highest price unit in each period determined to be the marginal plant in that period.

The methodology used to calculate the SRMC's is as set out below;

Fuel Cost: The commodity prices used were the day ahead gas closing gas prices, and monthly closing coal prices, biomass was assumed to be at 2x coal prices.[1] These prices were then applied to station efficiencies used by EnAppSys in other similar analysis which are based upon published gas usage versus actual generation for gas stations, published data on stations in literature and company accounts and technology brochures for the generating units. All efficiencies had some adjustment for typical real world performance. Section 3.2.1 includes a comparison between EnAppSys station efficiencies and those used in the DDM.

Carbon Cost: The commodity price used was closing EU ETS Spot price with UK Carbon Price Floor adjustment applied where applicable. DECC Emissions factors based on te CO2e emitted/ unit of fuel where used along with the fuel efficiency factors above.

Free Carbon: The final analysis assumed that free carbon permits awarded to stations via the UK Phase II and III EU ETS National Allocation Plan was

[1] Biomass is not yet a fully mainstream commodity market so 'curve' data is not readily available. The biomass price was used for the co-firing calculations i.e. ~3 to 8% of fuel cost for a coal fired power station. Biomass published price was calculated to be 2x coal at current prices and therefore biomass curve was linked to the coal commodity curve (biomass pellets =~4.4p/KWh coal 2.2p/Kwh). See the E4tech paper for DECC dated January, 2010 and available at http://www.rhincentive.co.uk/library/regulation/100201Biomass_prices.pdf

factored into the SRMC. Analysis was carried out with and without free carbon but it did not significantly affect the determined marginal plant.

ROC and LEC Discount: ROC and LEC discounts where applied to co-firing and CHP power stations. The level of co-firing was determined based upon published carbon/ ROC returns and company accounts. Increased fuel costs for co-firing stations were also factored in.

Wind Farms & Nuclear: were excluded from the analysis as they were assumed to never be marginal plant due to their fuel costs being zero/ negligible.

Variable Opex: Costs were assumed based upon typical variable opex costs by technology and fuel type.

Fixed Opex: No allowance was made for fixed opex/ capex recovery.

Use of Grid Charges: It was assumed that all stations incur the same BSUoS and imbalance costs and hence these were not included in the SRMC calculation. TNUoS was also not included as it is a fee based on the size of the connection and is not varied by the magnitude of output and so does not contribute to the marginal cost on a HH basis.

CHP: Credit for gas/ fuel usage in heat/ steam generation was applied to Combined Heat and Power stations effectively discounting the cost of fuel at these stations on the basis that part of the fuel bill was reimbursed through their heat sales/ usage. The effect of this was to assume the stations had a thermal efficiency of the order of 70 to 75%.

Grid Support Units: During the period analysed certain BMU's were providing grid frequency response services to National Gird and hence were required to run. These stations were excluded from the analysis during these periods on the basis their dispatch was mandated and not based upon SRMC.

2.2.2. Load Following Methodology

To determine the marginal power generating unit in each half hour period based upon the degree of load following, the notified generation level of all BMU's pre-gate closure (**BMRS.BM.*.FPN)** and the system published GB 'Indicated Demand Outturn' (**BMRS.SYSTEM.INDO)** was extracted from the EnAppSys database. The INDO figure represents GB demand excluding interconnector flows, power station demand and pumped storage demand and was used to represent GB power consumption. It is formally defined as follows:

"The Initial National Demand Out-Turn is the average megawatt value of demand for a Settlement Period INCLUDING transmission losses but EXCLUDING station transformer load, pumped storage demand and interconnector demand. The INDO is made available by the System Operator within 15 minutes after a Settlement Period, based on their operational metering. This figure is derived by the System Operator for submission to the BMRS but is not formally defined in the Grid Code."

Using the notified output pre-gate closure excludes largely the effect of unplanned outages. To remove a number of minor generators any and all generation below 1MWh was excluded from the analysis.

Once a table of FPN for operationally metered power stations in the GB market was obtained, an analysis against the assumed GB consumption (system demand) figures was carried out to identify those stations whose output has varied from the previous settlement period (SP) in the same direction of variation as INDO.

The initial analysis identified that many stations met this criteria i.e. were load following based on this definition and a single 'Marginal' station could not be defined by looking at changes from only one settlement period to the next. The analysis was then extended to use an algorithm that looked up to 3 SP's behind and 3 SP's forward to produce a diminishing list of load following power stations. Once this filtered list comprised of only one BMU this was determined to be the load following marginal plant.

An illustrative example of this process for a single half hour period is included on the following page.

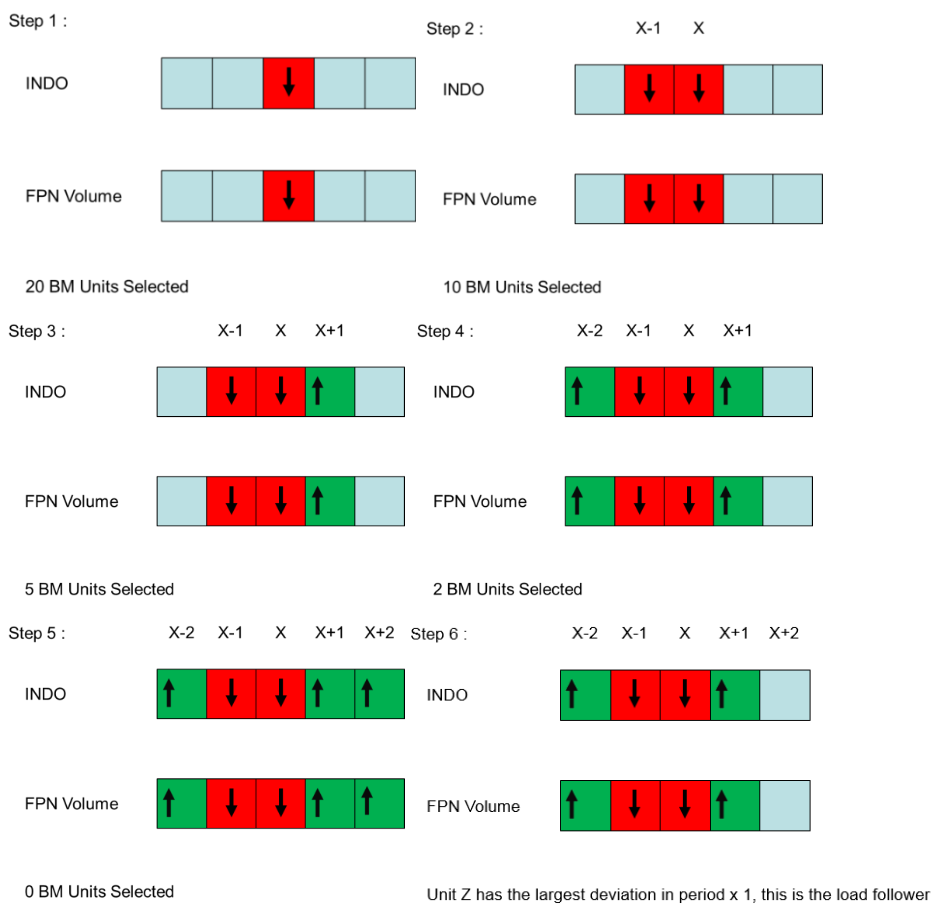
Load Following Methodology Illustrative Example

The following figure shows how this algorithm operated for a single period. In the first step the algorithm identifies that demand (INDO) is falling in the period of interest (labelled X in the diagram). It then identifies all eligible units which are reducing their load (FPN Volume) in this period as possible candidates for the load following marginal unit. In this example 20 units are identified. It then begins to look at adjoining periods.

In the second step the algorithm identifies that demand was also falling in the previous period and finds that 10 of the original 20 units were adjusting their load in the same direction as demand in this period as well. The algorithm repeats this analysis up to three periods before and three periods after the original period (X) to try to determine a single load following unit, shown here as steps four through five.

Where the filtering was left with more than one station at one iterative stage and zero at the next stage (e.g. between steps four and five in the illustration) the marginal station was selected as the one having the greater delta change in the direction of System Demand change (e.g. step six).

2.2.2.1. Figure - Iterative Load Following Algorithm Illustration



2.2.3. Balancing Mechanism Activity Methodology

Unlike the previous two methodologies which utilise pre-gate closure notifications this methodology utilises balancing actions post gate closure. Within the gate closure period it is National Grid's responsibility to balance supply and demand in the GB system to ensure grid frequency stays within a required margin and supply interruptions do not occur.

All notifying BMU's are required to declare the prices in each Settlement Period they will accept to increase generation (offers) and the amount they will pay to the system to decrease generation (bids). The grid then accepts these bids and offers to vary the output of BMU's to balance supply and demand. There are two main types of balancing actions, 'system' where balancing is required due to constraints on the physical transmission system or 'energy' where the balancing is required to match supply with demand. Overall the UK market tends to be long (i.e. BMU's notifying an excess of generation to meet demand) so the majority of grid accepted 'energy' actions are bids. In the four year period of the analysis, 97% of the half hours had accepted energy bids.

The definition of marginal plant used in this methodology assumes that the BMU with the highest accepted bid price (i.e. a station that has encouraged National Grid to reduce its generation by offering a high price to buy excess generation in the system) is the marginal BMU in that period. Where the system was short (i.e. demand > generation) we utilise the highest accepted offer price i.e. the most expensive BMU to increase generation).

The analysis utilises an algorithm which accesses the Indicated System Price stack (ISP) data for each settlement period (message **BMRS.SYSTEM.ISPSTACK**). The ISP stack is a list of all balancing actions in a period that go into the calculation of system prices.

An example of ISP stack data is included in the following table.

2.2.3.1. BMRS.SYSTEM.ISPSTACK data for 25th Jan, 2010, Period 4

Settlement Period	Bid/Offer Indicator	Sequence Number	Component Identifier	Acceptance Number	Bid Offer Pair Number	CADL Flag	System / Energy Flag	Repriced Indicator	Stack Item Original Price	Stack Item Volume	DMAT Adjusted Volume	Arbitrage Adjusted Volume	NIV Adjusted Volume	PAR Adjusted Volume	Stack Item Final Price	Transmission Loss Multiplier	TLM Adjusted Volume	TLM Adjusted Cost
4	Bid	1	1	N/A	N/A	No	System	No	52.99	-40.6230	-40.6230	0.0000	0.0000000	0.0000000	52.99	1.00000	0.0000000	0.000000
		2	T_SHBA-1	67249	-1	No	Energy	No	28.50	-27.4417	-27.4417	-27.4417	0.0000000	0.0000000	28.50	1.00000	0.0000000	0.000000
		3	T_SHBA-1	67250	-1	No	Energy	No	28.50	-21.9167	-21.9167	-21.9167	0.0000000	0.0000000	28.50	1.00000	0.0000000	0.000000
		4	T_DRAXX-1	95755	-1	No	Energy	No	26.47	-0.2083	0.0000	0.0000	0.0000000	0.0000000	26.47	1.00000	0.0000000	0.000000
		5	T_LOAN-2	26115	-1	No	Energy	No	25.00	-0.0012	0.0000	0.0000	0.0000000	0.0000000	25.00	1.00000	0.0000000	0.000000
	Offer	1	T_COTPS-2	28195	1	No	Energy	No	36.95	1.0417	1.0417	0.0000	0.0000000	0.0000000	36.95	1.00000	0.0000000	0.000000
		2	T_COTPS-2	28198	1	No	Energy	No	36.95	1.0417	1.0417	0.0000	0.0000000	0.0000000	36.95	1.00000	0.0000000	0.000000
		3	T_COTPS-3	43009	1	No	Energy	No	36.95	1.1667	1.1667	0.0000	0.0000000	0.0000000	36.95	1.00000	0.0000000	0.000000
		4	T_COTPS-3	43008	1	No	Energy	No	36.95	2.6667	2.6667	0.0000	0.0000000	0.0000000	36.95	1.00000	0.0000000	0.000000
		5	T_COTPS-3	43006	1	No	Energy	No	36.95	30.7500	30.7500	0.0000	0.0000000	0.0000000	36.95	1.00000	0.0000000	0.000000
		6	T_DRAXX-3	90942	1	No	Energy	No	37.00	1.1667	1.1667	0.9638	0.9638122	0.9638122	37.00	0.99218	0.9562752	35.382180
		7	T_DRAXX-2	88806	1	No	Energy	No	37.00	0.7031	0.0000	0.0000	0.0000000	0.0000000	37.00	1.00000	0.0000000	0.000000
		8	T_DRAXX-3	90941	1	No	Energy	No	37.00	1.5833	1.5833	1.3080	1.3079659	1.3079659	37.00	0.99218	1.2977376	48.016290
		9	T_COTPS-4	43856	1	No	Energy	No	37.00	0.5000	0.5000	0.4131	0.4130506	0.4130506	37.00	0.99218	0.4098205	15.163359
		10	T_COTPS-4	43855	1	No	Energy	No	37.00	19.5000	19.5000	16.1090	16.1089700	16.1089700	37.00	0.99218	15.9829990	591.371000
		11	T_EGGPS-2	58358	2	Yes	Energy	No	37.00	0.1607	0.0000	0.0000	0.0000000	0.0000000	37.00	1.00000	0.0000000	0.000000
		12	T_EGGPS-2	58358	1	Yes	Energy	No	37.00	0.7143	0.0000	0.0000	0.0000000	0.0000000	37.00	1.00000	0.0000000	0.000000
		13	T_DEEP-1	43021	1	No	Energy	No	45.00	1.7361	1.7361	1.7361	1.7361000	1.7361000	45.00	0.99218	1.7225237	77.513565
		14	T_DEEP-1	43022	1	No	Energy	No	45.00	0.1042	0.1042	0.1042	0.1042000	0.1042000	45.00	0.99218	0.1033852	4.652332
		15	T_SPLN-1	56937	1	No	Energy	No	50.95	1.0583	1.0583	1.0583	1.0583000	1.0583000	50.95	0.99218	1.0500242	53.498726
		16	T_COSO-1	66014	1	No	Energy	No	52.95	1.4500	1.4500	1.4500	1.4500000	1.4500000	52.95	0.99218	1.4386610	76.177100
		17	T_LOAN-2	26115	1	No	Energy	No	54.00	0.0276	0.0000	0.0000	0.0000000	0.0000000	54.00	1.00000	0.0000000	0.000000
		18	T_RYHPS-1	69295	1	No	Energy	No	54.00	2.3333	2.3333	2.3333	2.3333000	2.3333000	54.00	0.99218	2.3150537	125.012890
		19	T_LOAN-3	16355	1	No	Energy	No	55.00	35.6250	35.6250	35.6250	21.0544030	21.0544030	55.00	0.99218	20.8897600	1148.936800
		20	T_LOAN-3	16354	1	No	Energy	No	55.00	25.0000	25.0000	25.0000	14.7750210	14.7750210	55.00	0.99218	14.6594800	806.271360
		21	T_LOAN-3	16356	1	No	Energy	No	55.00	0.0417	0.0417	0.0417	0.0246447	0.0246447	55.00	0.99218	0.0244520	1.344861
		22	T_LOAN-3	16352	1	No	Energy	No	55.00	1.5000	1.5000	1.5000	0.8865013	0.8865013	55.00	0.99218	0.8795688	48.376280
		23	T_LOAN-3	16353	1	No	Energy	No	55.00	36.0000	36.0000	36.0000	21.2760300	21.2760300	55.00	0.99218	21.1096520	1161.030800
		24	T_COCK-4	13301	1	No	Energy	No	58.00	9.1591	9.1591	9.1591	0.0000000	0.0000000	58.00	1.00000	0.0000000	0.000000
		25	T_COCK-4	13300	1	No	Energy	No	58.00	0.0492	0.0492	0.0492	0.0000000	0.0000000	58.00	1.00000	0.0000000	0.000000
		26	T_COCK-3	13163	1	No	Energy	No	58.00	0.2557	0.0000	0.0000	0.0000000	0.0000000	58.00	1.00000	0.0000000	0.000000
		27	T_COCK-3	13162	1	No	Energy	No	58.00	0.1875	0.0000	0.0000	0.0000000	0.0000000	58.00	1.00000	0.0000000	0.000000
		28	E_DERW-1	55325	1	No	Energy	No	75.00	0.3833	0.0000	0.0000	0.0000000	0.0000000	75.00	1.00000	0.0000000	0.000000

The algorithm works by;

a) Ordering balancing actions by price high to low based on the “Stack Item Original Price” column above.

b) Excluding non-BMU balancing actions (i.e. SO-SO trades across the interconnectors, SO market trades, Other non-BM SO actions etc). These can be identified as they have an integer value and are not tagged by a BM Unit ID.

c) Excluding undo balancing actions (i.e. actions to unwind previously accepted balancing actions). These can be identified by a bid offer pair number opposite to the Bid Offer Indicator, i.e. a negative bid offer pair number when the Bid Offer Indicator is Offer and a positive bid offer pair number when the Bid Offer Indicator is Bid.

d) Excluding SYSTEM actions (i.e. actions to manage grid constraints). See the system / energy flag column.

e) Excluding acceptances at lower than 1 MWh. Such small volumes would tend to be the start or end of a ramp for a much larger acceptance in an adjacent period and not be related to the period in question.

After the ordering and exclusion the BMU with the highest bid or if no bids the highest offer is determined to be the Marginal BMU. More detail on the calculation of imbalance prices and the components of the ISP Stack message and how it applies to the derivation of system prices can be found on the Elexon website[2].

2.3. Calculation of Carbon Emissions Factor

After the Marginal BMU was determined using the methodologies above the Carbon Emissions factor for each Settlement Period was calculated using the EnAppSys station efficiencies for the applicable BMU used in the SRMC calculation and the DECC fuel carbon emissions factors.

The Carbon emissions factors for a specific period were then calculated by averaging all the applicable carbon emission factors in that period without any volume weighting.

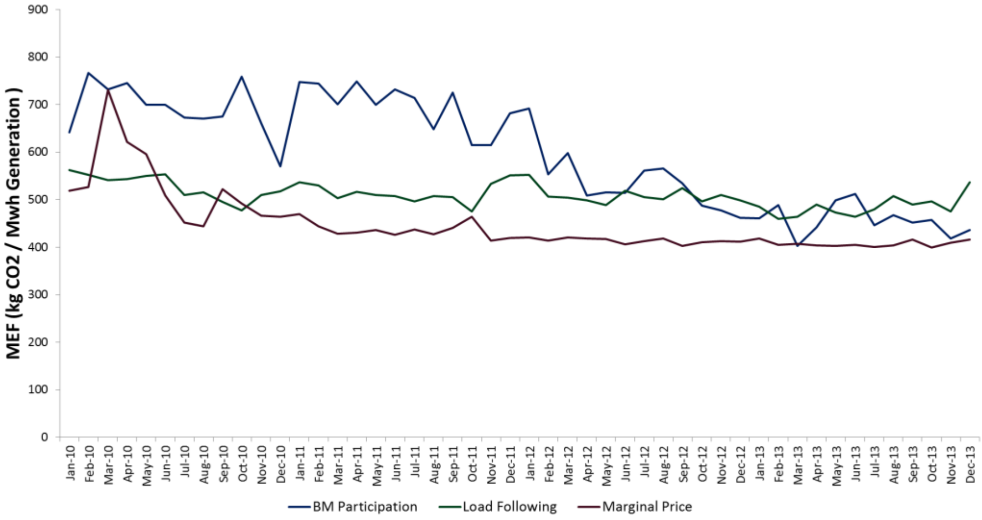
2.4. Results

The following charts show the monthly and seasonal average carbon emissions factors calculated in accordance with the methodologies set out above.

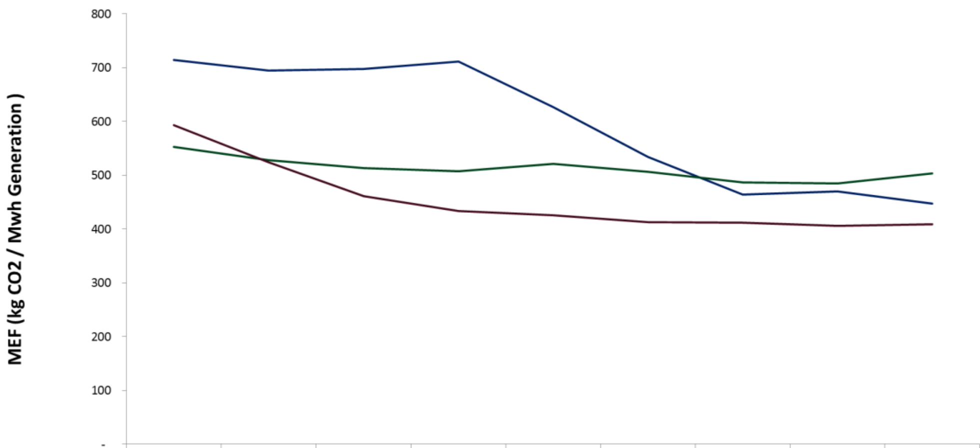
Charts showing MEF distribution on an annual basis by the period of the day are also included in the next chapter. A value of around 800 suggests that coal is the marginal plant for the majority of the time and a value of around 400 corresponds to gas.

[2] http://www.elexon.co.uk/reference/credit-pricing/imbalance-pricing/

2.4.1.1. Monthly Calculated Marginal Emission Factors



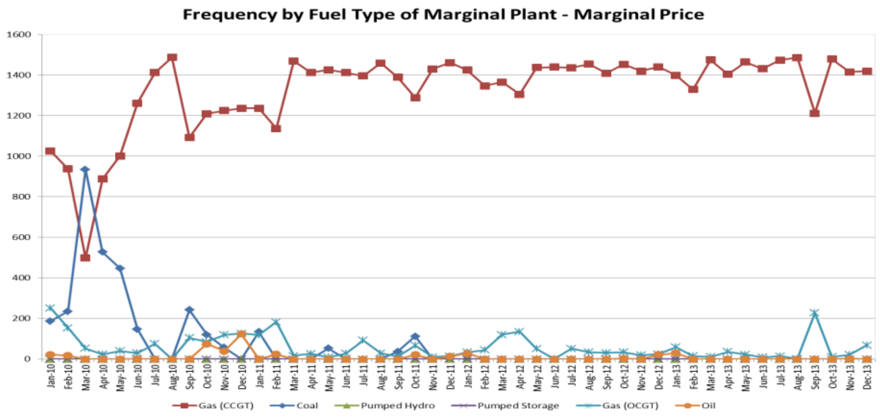
2.4.1.2. Seasonal Calculated Marginal Emission Factors



	W-09	S-10	W-10	S-11	W-11	S-12	W-12	S-13	W-13
BM Participation	714	694	697	711	626	534	463	470	447
Load Following	552	528	513	507	521	506	486	484	503
Marginal Price	592	524	461	433	425	413	411	405	408

To look in more detail at what is behind this data, a set of statistical analysis was carried out of the frequency (in number of SP's) of each fuel type which contributed to the average marginal emissions factor. The following charts show for each methodology the results of this analysis.

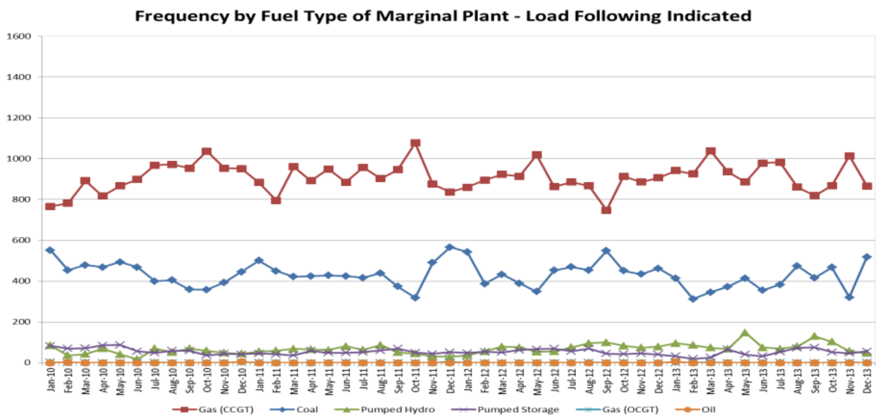
2.4.1.3. SRMC Method – Fuel Type Marginal Plant Frequency (no. of SP's)



The above chart shows that other than in early 2010 the SRMC methodology concludes that gas fired power stations were predominantly the marginal plant. This does highlight problems with this methodology as detailed analysis indicates that there are certain gas fired power stations that run overnight in preference to coal fired power station output despite them running at a loss and therefore not actually setting the wholesale price.

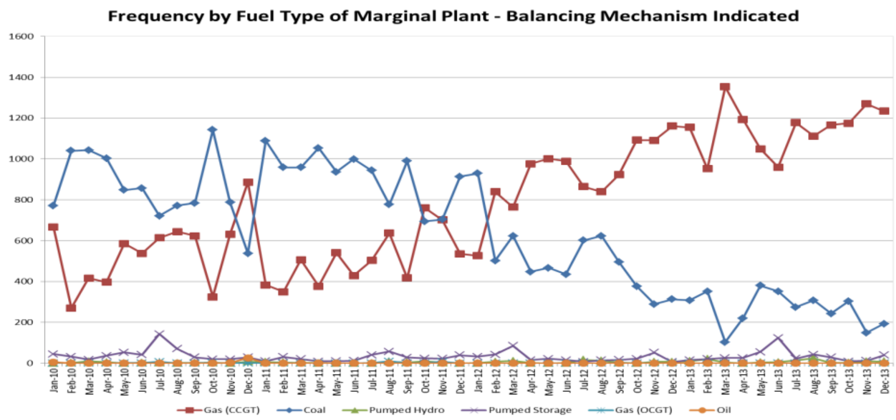
In an effort to explore this and the consequences for the DDM model a more detailed review of gas fired power station running profiles was carried out. The summary of the analysis can be seen in Appendix 0.

2.4.1.4. Chart 2.6.4 Load Following Method – Fuel Type Marginal Plant Frequency (no. of SP's)



The above chart shows that that the load following methodology produces average carbon emission factors that reflect coal being marginal 1/3 of the time with little variation over the overall analysis period. This reflects that both coal and gas stations (and occasionally non-pumped storage hydro at zero carbon) load follow, with coal predominantly load following overnight and gas during the day. Despite an overall switch in the economics of coal generation versus gas in the period the split is consistent with no correlation with varying spark spread/ dark spread values. This suggests that this measure of marginal plant does not correspond to what would normally be considered marginal in an economic sense.

2.4.1.5. BM Method – Fuel Type Marginal Plant Frequency (no. of SP's)



The above chart using the BM methodology indicates a clear correlation between the determined marginal plant and the economics of gas and coal fired power station in the period. In early 2011 coal prices were stagnant while gas prices were rising making coal economically superior. From mid-2011 coal prices and carbon price begun declining and gas prices continued to increase, widening the gap between the fuels.

However, the overnight effect of coal being the marginal plant despite gas generation operating in the period is still apparent.

2.5. Conclusions

The three methodologies we have investigated are all based on different, but intuitively sensible, definitions of the marginal plant. However, each method has limitations and the fact that the results differ so significantly shows the difficultly in defining the marginal plant.

Based on the comparison between the three methodologies it was concluded that the balancing mechanism participation definition of Marginal BMU's was the most sensible measure for comparison purposes.

The load following methodology does not adequately display the trend we would expect. The significant number of plants that switch on and off in each period are doing so due to the regime they operate and, therefore are temporarily running out of line with their economic position in the merit order. Because of this they do not directly correspond to the plant that would be defined as marginal for price setting.

The marginal price methodology is heavily influenced by plant running out of merit, which means they cannot be price setting, and there is no clear way to control for this. Whilst we applied additional factors to account for grid services contracts and CHP there continues to be plant that appear to be running out of merit without a discernible economic based pattern.

The balancing mechanism participation predominantly reflects the cost of adjusting the output of plant that are already operational and therefore removes the complication of on/off decisions from the economics and it is therefore reasonable to assume that these are the plant setting the wholesale price. There are, however, still limitations of this method as balancing mechanism decisions are influenced by flexibility issues that could distort results.

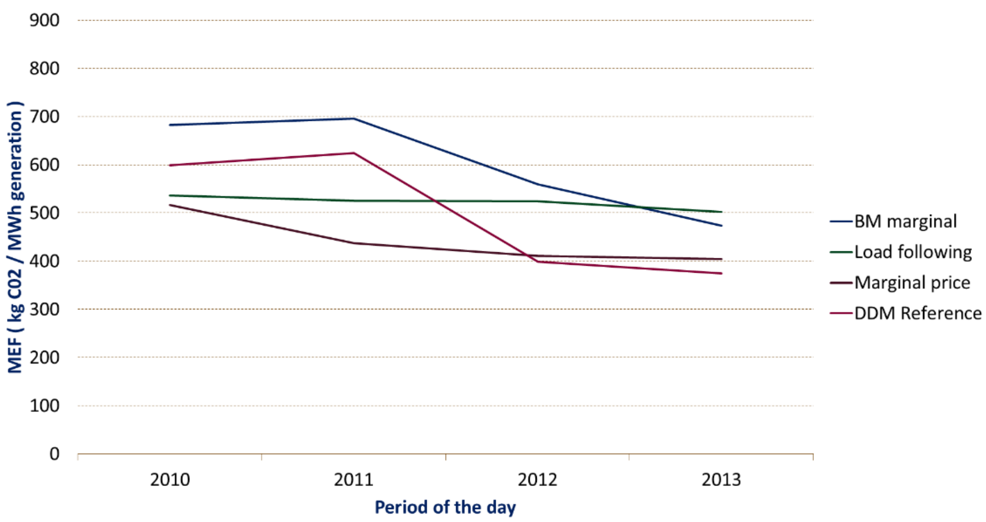
3. Dynamic Dispatch Model (DDM) Analysis

In this section we outline the analysis undertaken to compare the historical MEF figures calculated with those produced by DECC's DDM model.

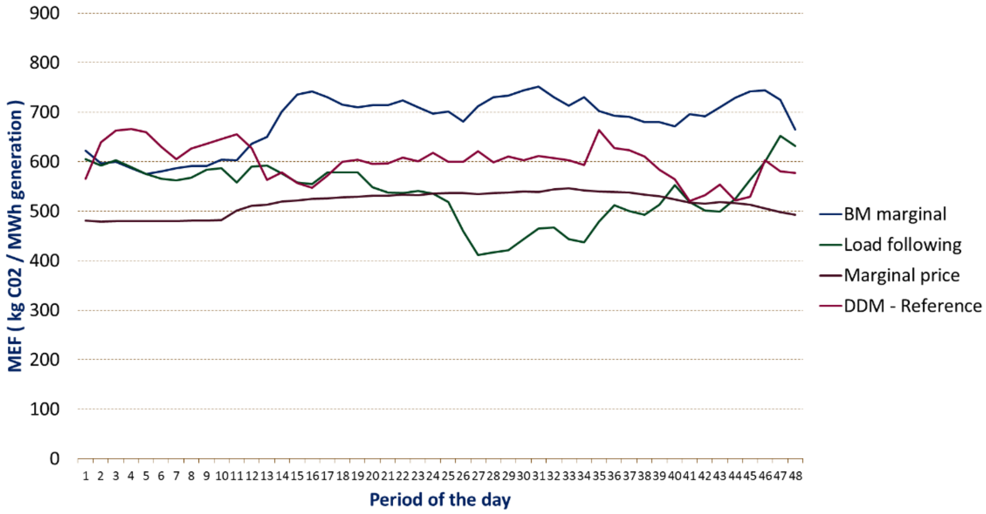
3.1. Comparison of the DDM calculated MEF with historical figures

Running the DDM with DECC's standard assumptions as of December 2013 we are able to generate MEF values for each period of the year. For this initial DDM run no changes were made to attempt to reproduce historical MEFs. These same inputs were reported by DECC to reproduce other historic outcomes, such as wholesale price, with a reasonable degree of accuracy. Here we report and compare these figures summarised as both annual averages and as time of day averages for each year individually.

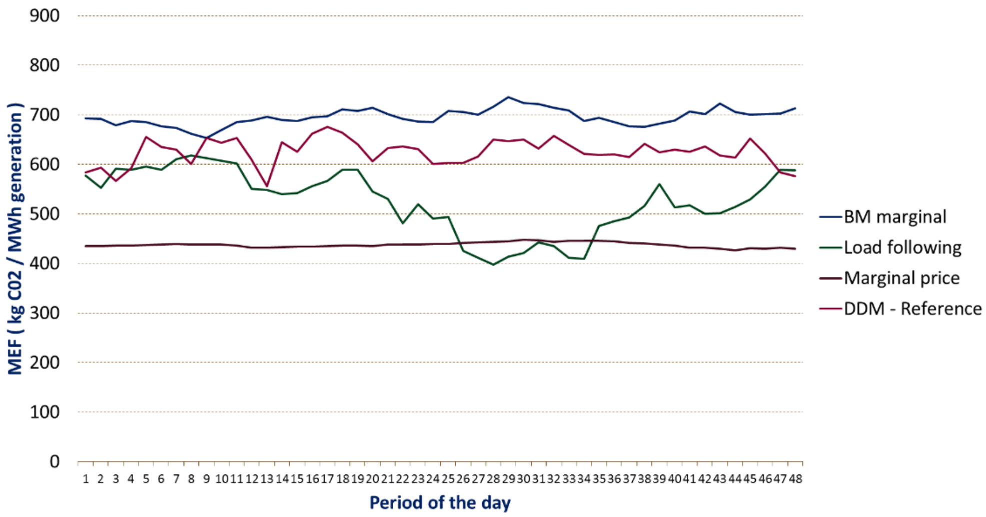
3.1.1.1. Annual MEF



3.1.1.2. MEF by period of day 2010

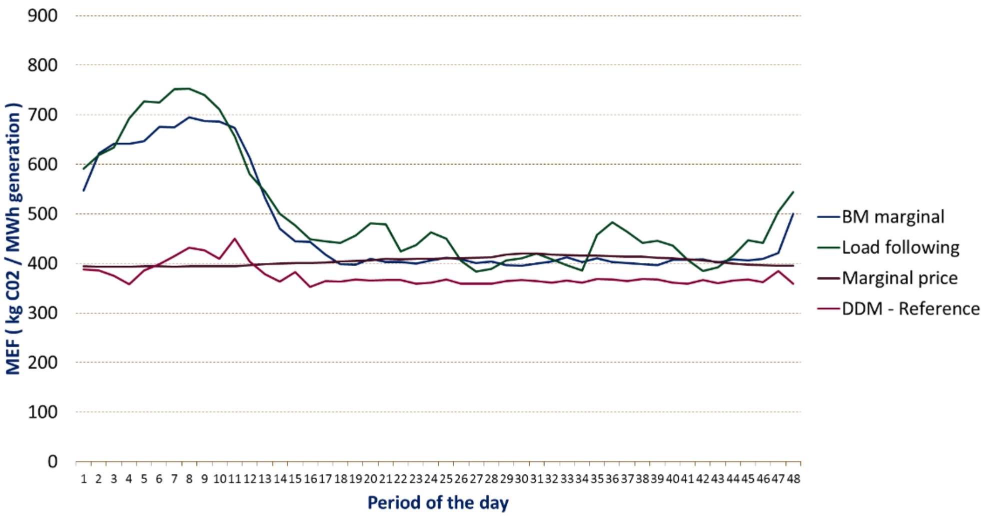


3.1.1.3. MEF by period of day 2011



3.1.1.4. MEF by period of day 2012

3.1.1.5. Emission factor by period of day 2013



The results demonstrate that the MEF values produced by the DDM match within a reasonable margin of error for the years 2010 and 2011. The values for these years, both as an annual average and by period of the day, lie within the three historical figures used and are relatively close to the preferred balancing mechanism marginal methodology.

In the later years of 2012 and 2013 the DDM values fall below the three historical estimates and are around 20% lower than the values given by the balancing mechanism methodology. When we examine the MEF by period of day we can see a clear trend in the historical results in the early morning periods where the marginal emission factor is relatively high. This trend we can see is not adequately reflected in the DDM which remains relatively flat throughout the day.

The results suggest that in reality coal units were marginal overnight and setting the marginal emission factor, however, the DDM is finding gas to be marginal for the majority of the time even overnight.

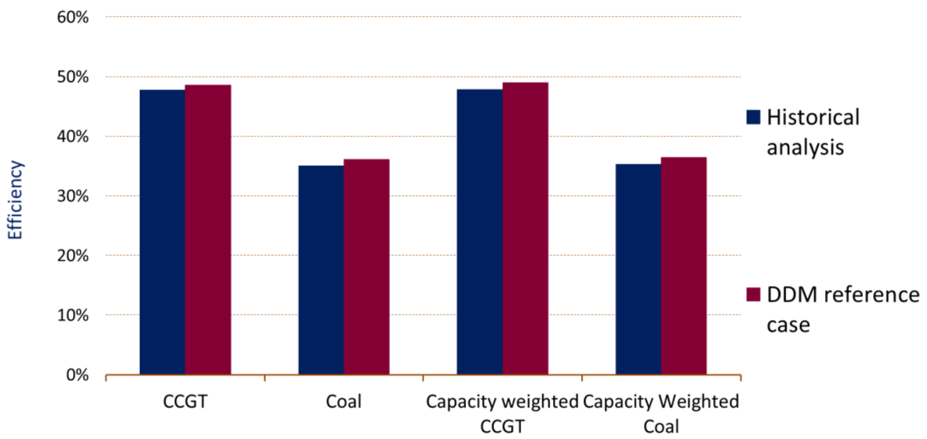
3.2. Comparison of assumptions between DDM and EnAppSys methodologies

A number of differences exist between the assumptions used in the DDM and those identified from historical analysis; in this section we examine each of these assumptions in turn.

3.2.1. Efficiencies of CCGT and Coal units

The efficiency of units is an important component of MEF calculation for two reasons. For the marginal price historical analysis and for the DDM model the efficiency value will be part of determining which unit is marginal at any given point in time. Once the marginal unit is determined the efficiency will also determine the amount of fuel required to produce an extra MW of electricity and, therefore, the amount of carbon emitted.

3.2.1.1. Average efficiency by plant type

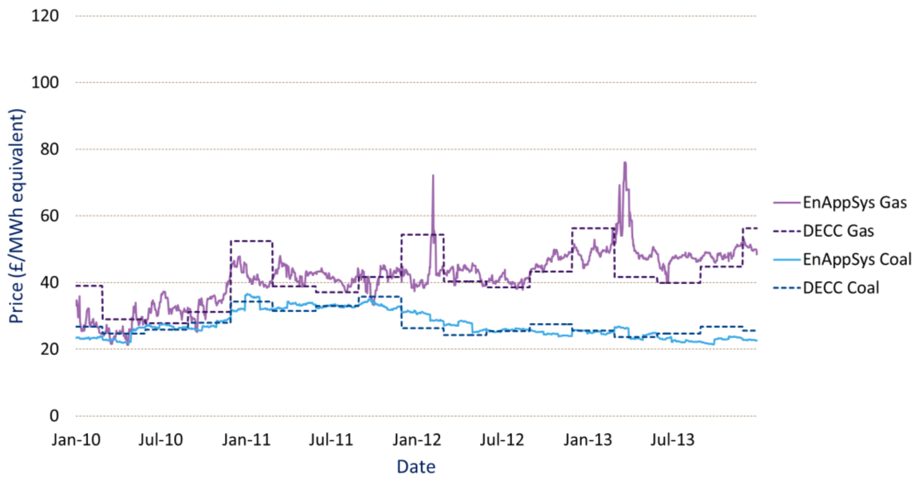


The comparison demonstrates that on average the efficiency assumed by the DDM is higher than that used in the historical analysis. The differences are likely to be caused by lower efficiency of plant when the effects of start-up and ramping are taken into account. This difference will result in MEF calculations approximately 1-3% lower by the DDM. This difference, however, cannot explain the overnight differences in MEF between the DDM and the historical analysis as the size of the difference is relatively similar for both gas and coal and therefore cannot be materially affecting their positions in the merit order.

3.2.2. Fuel prices

Differences in fuel prices between those assumed in the DDM and the actual historical values could potentially explain differences in the calculated MEF. If the difference to actual values were such that the DDM was incorrectly determining the merit order, particularly the relative merit of coal and gas units, this would systematically bias the MEF. We have provided a comparison of fuel prices for gas and coal below, these values have been converted to a £/MWh value using average plant type efficiency to make comparison between the two fuels easier. Fuel prices used within the DDM apply a quarterly distribution to annual estimates. The quarterly distribution, estimated from historic data, is the same for all projection years in the DDM.

3.2.2.1. Fuel price contribution to SRMC



The chart shows that while there are material differences between the assumed gas price and that seen historically in the years of interest, 2012 and 2013, there exists such a gap between coal and gas prices that it is unlikely that the relative merit of these two fuels would be changed.

3.2.3. LCPD Closure dates and operating regimes

The analysis undertaken by EnAppSys identified that a number of the coal units that opted out of the LCPD scheme in fact closed sooner than is assumed in the DDM. The table below shows a summary of the differences.

3.2.3.1. LCPD Coal closure dates

Unit	DDM Closure Date	Actual	Running hours limit
Cockenzie	January 2014	March 2013	14%
Didcot A	January 2014	March 2013	14%
Ferrybridge (1 & 2)	January 2015	March 2014	36%
Kingsnorth	January 2013	Dec 2012	30%

3.2.3.2. LCPD Conversions

Unit	DDM Conversion	DDM Closure Date	Actual Conversion	Actual Closure	Running hours limit
Ironbridge	January 2012	June 2016	Early 2013		12%
Tilbury	January 2012	January 2014	Late 2011	March 2013	47-49%

The differences in closure dates will also correspond to differences in operating regimes. The longer a unit intends to stay open the more it must spread out its allocated operating hours. The annual load factors assumed by the DDM are included in the table above. The earlier closure dates would likely results in less constrained operation in the near term, increasing the likelihood that these coal plants would operate overnight.

3.2.4. Must run gas units

The DDM does not assume that there are any must run gas units but the historical analysis suggests that there are gas plants running overnight at a loss. The volume of this generation can change significantly over time but appears to have been around 2GW over the period of interest. Further detail on this can be found in Appendix 1.

3.3. Simulation of the updated assumptions and reconciliation of results

Having identified differences between the assumptions used in the DDM and the historical analysis we can then look at the materiality of these upon the DDM calculation of MEF values and look to reconcile these results.

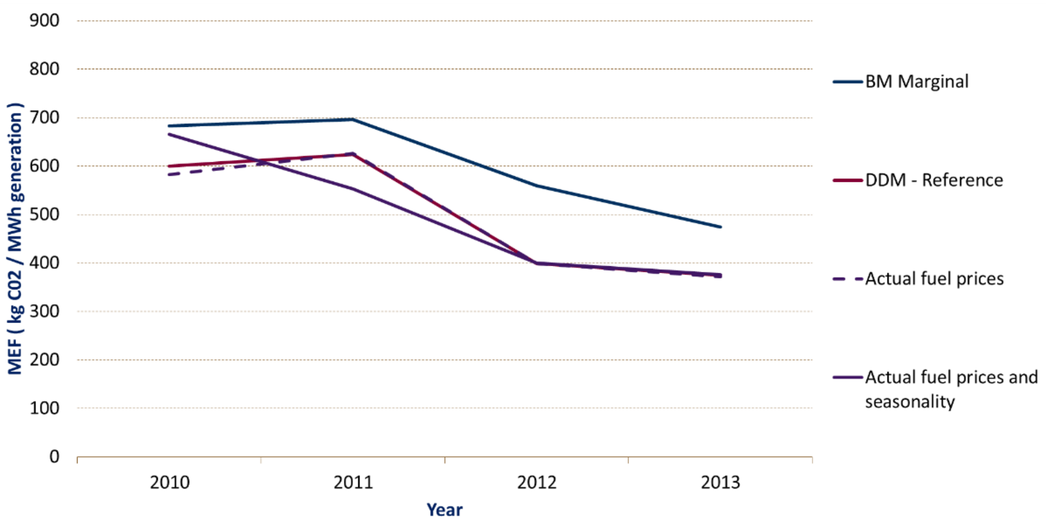
For the purpose of this analysis the BM participation historical definition of marginal unit has been used as the most fit for purpose.

3.3.1. Fuel prices

As identified in the comparison of assumptions the actual values for fuel prices in 2012 and 2013 show a large difference between the cost of coal and gas when converted to SRMC equivalent, as is the case with the DDM model.

Simulation with actual fuel prices results in negligible changes to the calculated MEF values for 2012 and 2013. As seen below the 2010 and 2011 values are sensitive to changes in the seasonality applied, this reflects the fact that coal and gas were relatively closer in the merit order in these years.

3.3.1.1. Annual MEF



3.3.2. LCPD Closure dates and operating regimes

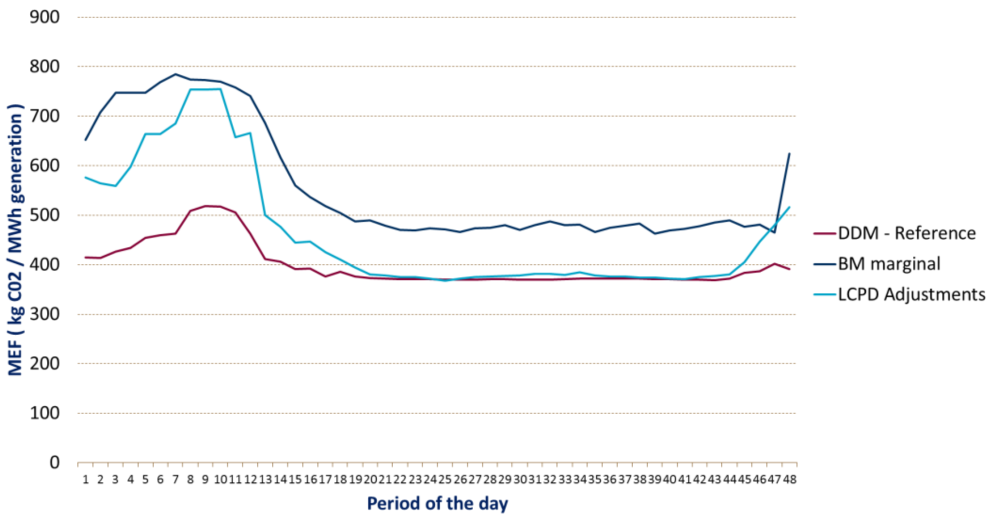
The result of updating the closure dates of the opted out LCPD units and relaxing their running regimes are included below.

On an annual basis we can see the change has moved the simulated MEF values closer to the BM marginal methodology. This change is especially significant in 2012, suggesting that this year is particularly sensitive to changes in assumptions.

When we look closer at 2012 by period of day we see that the DDM is now simulating a profile significantly closer to that of the BM marginal methodology with an overnight spike in MEF as coal units become marginal over this period.

3.3.2.1. Annual MEF

3.3.2.2. MEF by period of day 2012



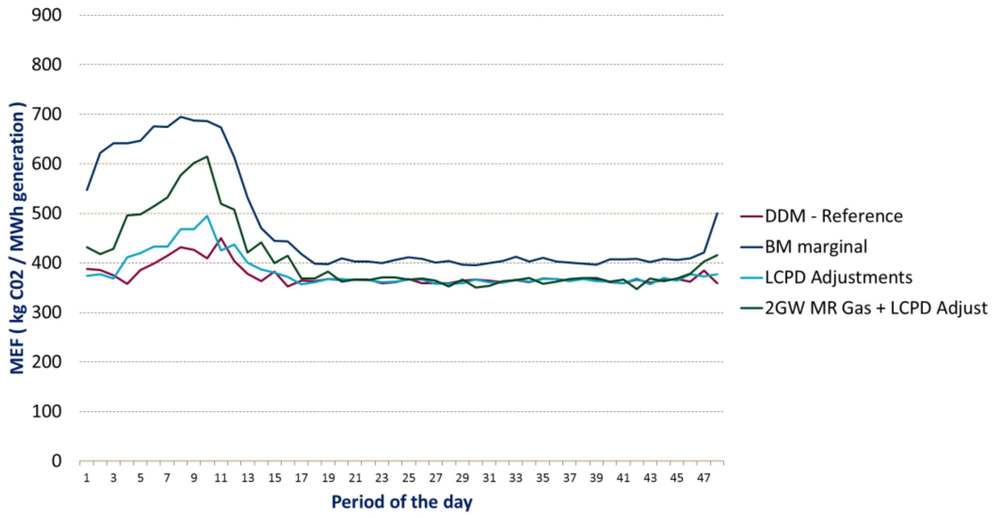
The profile by period of day is not significantly changed in 2010 or 2011 and shows a similar, although smaller, overnight increase in the 2013 simulation (see Appendix 2).

3.3.3. Must run gas units

One of the significant findings of the historical analysis is that a number of gas units are running overnight, even when theoretically out of merit. To test the effect of this change we have additionally lowered the SRMC of around 2GW of CCGT to ensure overnight operation. The results are shown in the following charts.

3.3.3.1. Annual MEF

3.3.3.2. MEF by period of day 2013

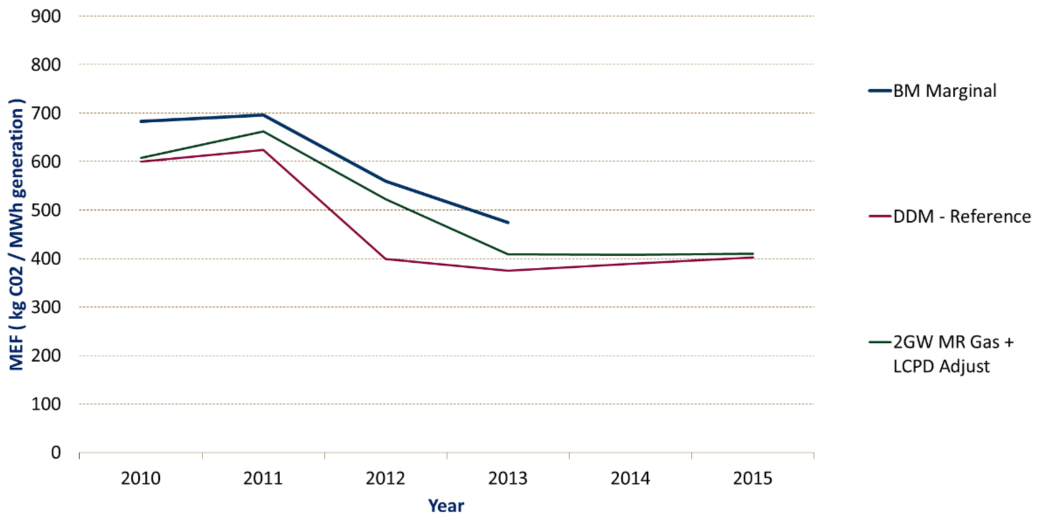


The charts indicate that the combination of these two adjustments result in significantly closer annual MEF values in 2011, 2012 and 2013. Further when we examine the profiles by period of day we can see that the adjustments are resulting in significantly closer MEF profiles with the desired overnight marginal coal pattern.

3.4. Implications for forecasting simulations

The analysis above shows that the relatively minor adjustments to assumptions result in significant changes to the values for historical years. An interesting question is what implication these changes would have for the values simulated for future years. Below we include the results of extending the simulation to 2015.

3.4.1.1. Annual MEF



The chart above shows that the adjusted assumptions do not imply significant changes in results for the forecasted future years 2014 and 2015. This is mainly as issues with LCPD plant assumptions only effect historical values while the impact of having 2GW of CCGT as must run has a decreasing impact in the future as there is less coal plant to push to the margin.

4. Potential updates to the DDM

Through this project there have been two areas where the real world has shown significant differences to the model results.

1. **The running regimes of plant covered by LCPD** – The effect on LCPD plant is largely based on the precise data for individual units that have made decisions on closure dates and running profiles which are different to those assumed within the DDM. It is worth noting that the DDM dataset has not been required to be accurate historically as all model outputs are forward looking.

   If the model is to be used to examine historical values we would recommend that these assumptions, along with other data, are regularly updated to reflect market outturn.

2. **The operation of CCGTs** – The decision of CCGT's to run when they are loss making is not captured by the DDM as decisions are made on a half-hour by half-hour basis depending on the economics of the time. The potential real-life reasons for this could include:
   - Cost, time and reliability of starting up in the morning meaning that plant are willing to sustain losses overnight to increase day time income.
   - Provision of auxiliary services to National Grid
   - Portfolio effects

For the first of these issues one potential development of the DDM would be to consider the cost of ramping and start-up times within the dispatch algorithm. This would be a significant model development for the DDM due to the need to maintain the current model runtime and usability. For example a possible solution would be to optimise across time periods which would make the model orders of magnitude slower than it can currently run. Also we do not believe that this development would explain the extent of the behaviour we have seen for these gas plant.

With all of these potential causes it is easy to implement model updates that would replicate historical behaviour, for example by allowing the SRMC of plant to be adjusted overnight to reflect their desire to not turn off. However, the difficulty is that in the future it is likely that these effects will change and potentially invalidate any adjustments made to the modelling. Because of this we would only recommend making updates in areas where there is a clear economic driver for the behaviour. It should also be noted that including 2GW of must run gas plant has minimal impact on the modelling of future MEFs in 2014 and 2015.

We understand that DECC is separately looking to better understand what is driving the dispatch decisions for some of these plant and once this is better understood it may be appropriate to implement updates to either model assumptions or methodology.

5. Conclusions

Before drawing any outright conclusions it must be stressed the degree to which in practice it is difficult to find a reliable measure for marginal emission factor and therefore the carbon contribution to the wholesale price. In this analysis we examined three methodologies each of which had its limitations but represented a defendable definition of which plant was marginal.

The analysis uncovered a number of differences between the modelling assumptions in the DDM and the real world historical operation of the electricity system. These differences contributed to create systematic differences in MEF over the historical period, particularly 2012 - 2013. In particular the following assumptions were found to be material:

- **the operation of opted out LCPD coal units –** some units having decided to use up their hours prior to the introduction of the CPS, and
- **the operation of CCGT units** – for a number of reasons different CCGT units have been running out of merit including operational, locational and commercial reasons.

After controlling for these two factors in the DDM modelling we see simulated MEF values significantly closer to our preferred historical definition of MEF.

By their nature these two factors may represent historical artefacts and the case for projecting these assumptions into the future would need to be carefully examined. It should be noted that controlling for these factors only materially affected the historical years in the DDM modelling, further weakening the case for any significant changes to the methodology used for projecting forward.

We would however recommend that the MEF is monitored on a regular basis to identify if there are any significant changes or divergence away from the modelled results.

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3 June 2014

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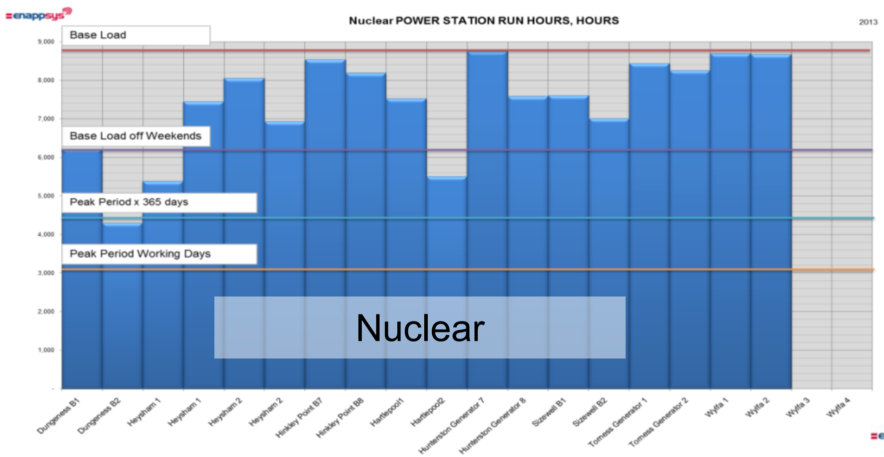
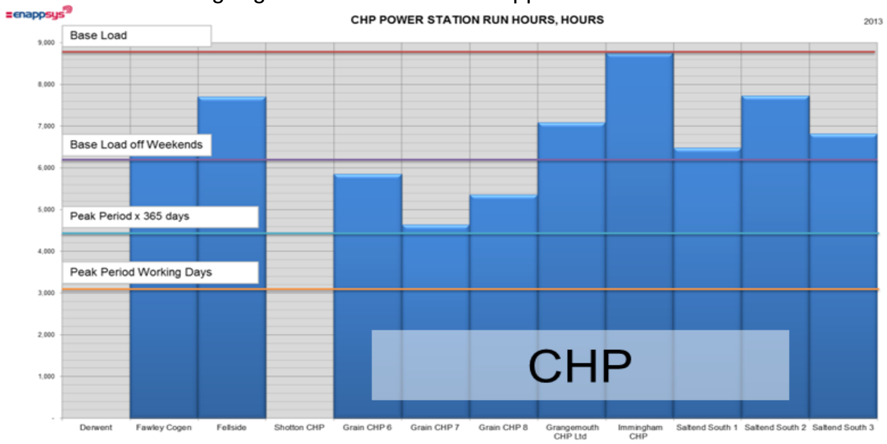
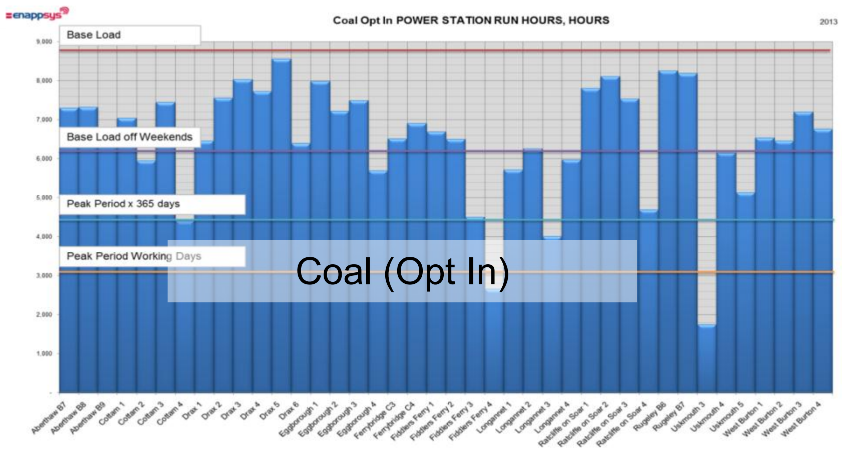
We accept no liability to any third party to whom our work has been provided (with or without our consent), unless the third party has asked us to confirm our liability to them, and we have done so in writing.

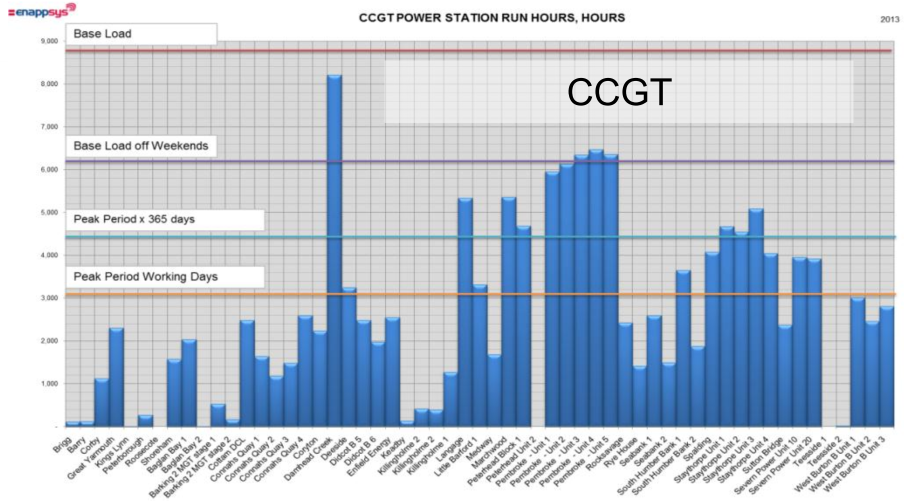
1. APPENDIX 1: Out Of Merit generation overnight analysis

The following charts show running hours analysis by fuel type with a running hour being defined as each period where output is >0MW. It is a useful analysis to perform to get an indication of the running profiles of fuel types over a long period. When lines representing maximum theoretical running hours for different running regimes are plotted against running hours it allows running regimes of stations to be approximated.



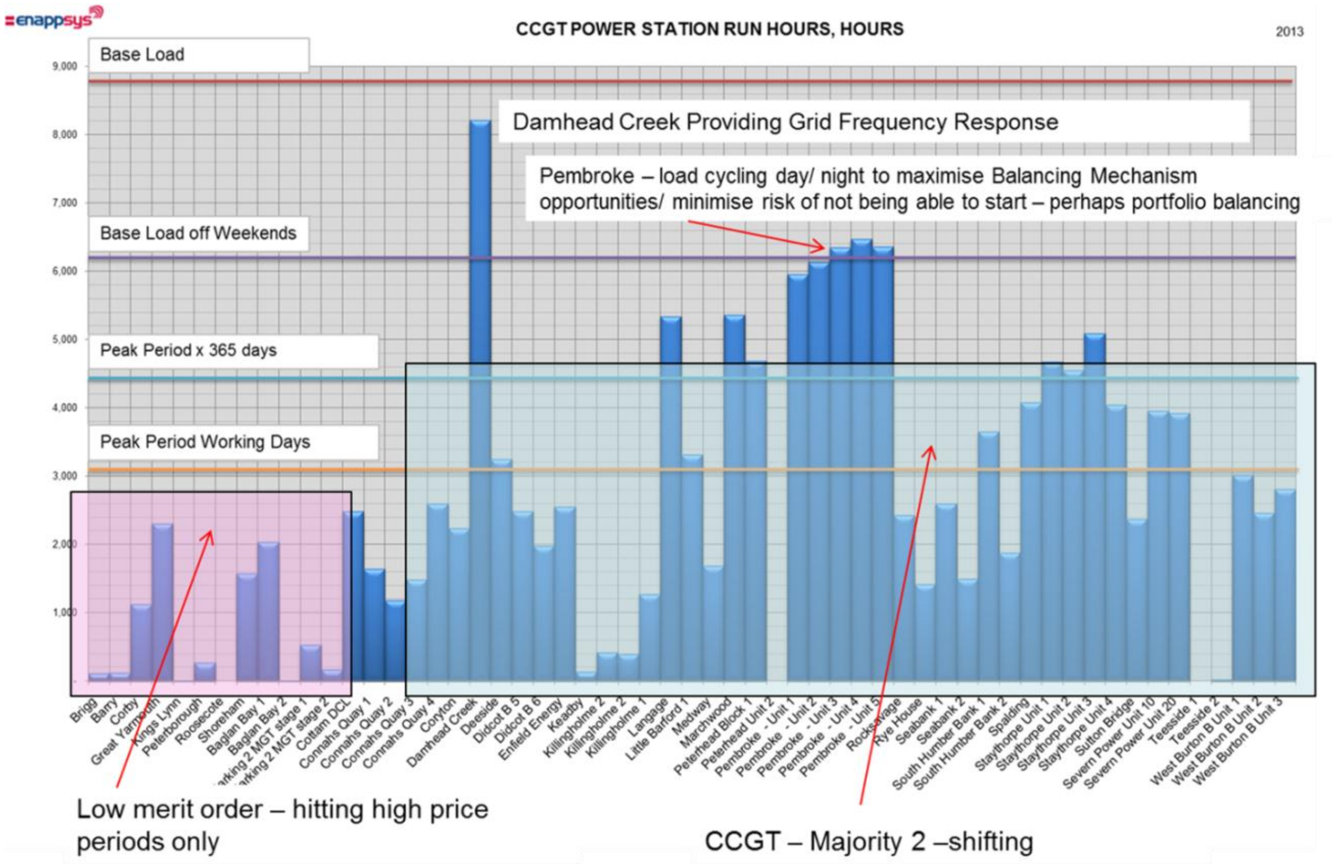






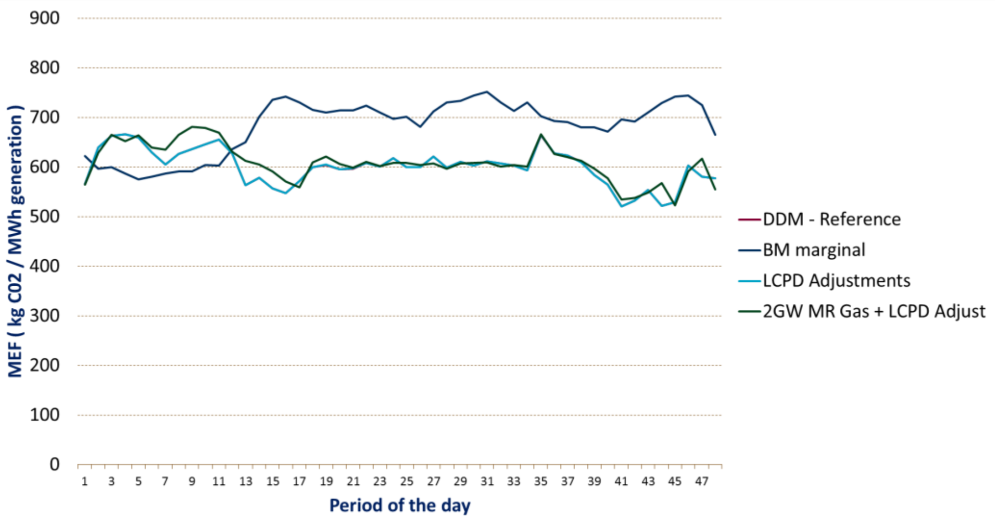
APPENDIX 1: Out Of Merit generation overnight Analysis (cont)

These charts show that whilst Nuclear and CHP operate as would be expected i.e. predominantly between baseload and weekday baseload, certain CCGT stations are operating on weekday baseload regimes despite economics suggesting they run overnight at a loss. With CCGT stations operating overnight the spot market price is driven down effectively causing coal fired stations to reduce load despite their superior economics of generation in the period analysed. Looking at the CCGT chart in more detail it can be seen that Pembroke is one of these stations and on close analysis is operating a load cycling regime with min load overnight and max load within day.



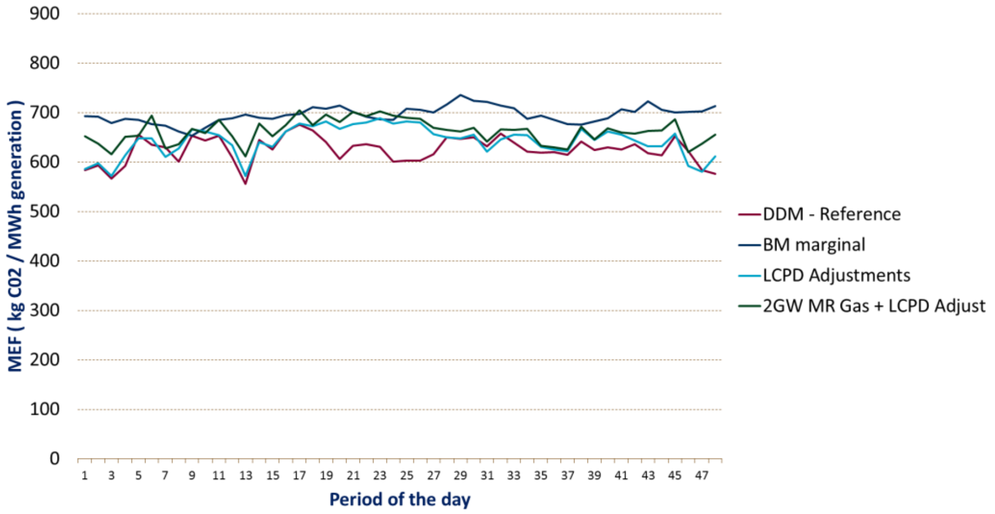
2. APPENDIX 2: Period of day DDM outputs

2.1.1.1. MEF by period of day 2010

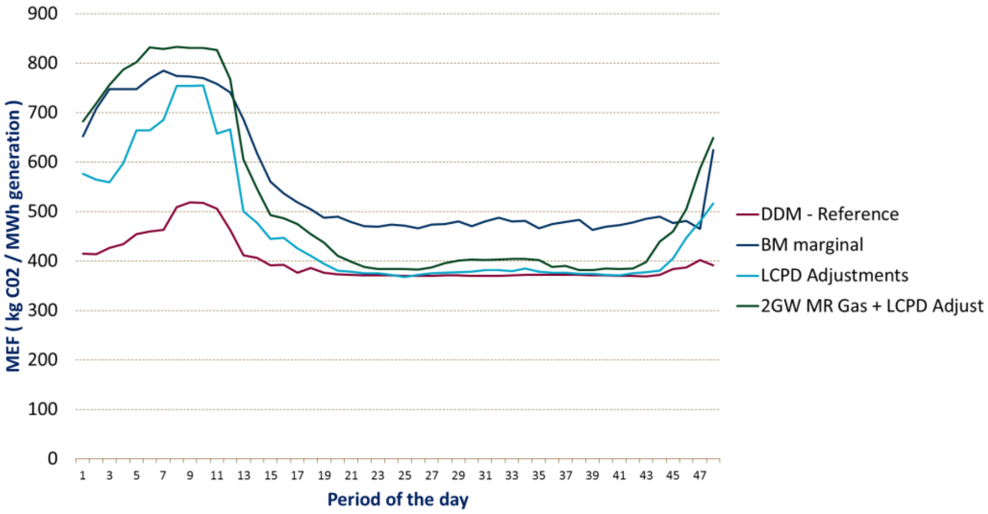


Note: the LCPD Adjustments case and the DDM Reference have identical values in 2010.

2.1.1.2. MEF by period of day 2011



2.1.1.3. MEF by period of day 2012



2.1.1.4. MEF by period of day 2013