ADDENDUM TO GB ECM-18 REPORT TO THE AUTHORITY

GB ECM-18
Locational BSUoS Charging Methodology

26 November 2009

Contents

1. Executive Summary

This report is an addendum to the GB ECM-18 report that was originally submitted to Ofgem on 22nd May 2009. Along with this addendum we have resubmitted the original report with no changes. This addendum should be read along side the original report.

This addendum report presents the further analysis that was requested by Ofgem on the impact of introducing Locational BSUoS as proposed under GB ECM-18. This analysis has been performed against a range of scenarios and assumptions, the results support the conclusion in the main report.

Analysis

We have performed analysis based on the costs of system operation between April 2008 and March 2009 combined with constructed merit orders. The merit orders were based on various input cost and efficiency assumptions. The locational BSUoS charge was calculated and applied to assess the impact of the proposal on the merit order and therefore on the wholesale price and level of constraints.

This process was highly resource intensive, and so to investigate the greatest possible range of sensitivities we have also performed analysis based on a probabilistic model. This uses probabilistic generation availabilities and a discrete demand function to model a year of operation. Linear optimisations were used to model the function of the wholesale energy market and the Balancing Mechanism for each time period, and calculate the associated costs. This allowed the impact of locational BSUoS to be assessed against a much wider range of scenarios.

Conclusions

Locational BSUoS signals the cost of constraints to generators behind non-compliant transmission system boundaries, allowing them to be factored into the despatch decisions made by those generators.

Based on the range of merit orders constructed as part of this analysis, the application of locational BSUoS would encourage marginal thermal plant on the exporting side of a non-compliant derogated transmission system boundary not to run during forecast constrained periods and thus be replaced by marginal thermal generators on the importing side of the non-compliant derogated boundary in the unconstrained merit order. This results in reduced constraint costs socialised under the BSUoS residual component, and also a reduced cost associated with the non-compliant derogated boundary constraint itself.

The effectiveness of locational BSUoS at reducing constraint costs is reliant mainly upon:

(a) The ability of generators to forecast the timing and level of Locational BSUoS charges;

(b) The likelihood that generators will reflect these charges into their price in the wholesale market.

As described in the conclusions report, National Grid is committed to providing as much information as possible to allow generators to forecast the timing and level of locational BSUoS charges.

The likelihood that generators will reflect these charges into their despatch decisions will be dependent upon a number of factors including the liquidity in the short-term energy market, dynamics of plant across a portfolio and the ability of users to exercise market power. The ability of users to exercise market power has been explored by reference to their financial incentives.

Our analysis of historic bids shows a high market concentration behind the Cheviot boundary, and identifies differences between the bid prices offered on each side of this boundary.

Our scenario analysis shows that where a generator behind a non-compliant derogated transmission boundary is able to exercise market power in the pricing of bids in the Balancing Mechanism with socialised BSUoS, it would still be able to do this following the application of Locational BSUoS, although either with reduced profits or by reducing bid price significantly to maintain profits.

We have also analysed the impact of locational BSUoS on the theoretical wholesale energy price. Our analysis shows a minimal change in the wholesale price. In most cases, the application of locational BSUoS causes a slight reduction in the wholesale energy price due to the reduction in socialised costs faced by marginal generators on the importing side of the non-compliant derogated transmission boundary.

Overall, this further analysis confirms the conclusions described in the GB ECM-18 report, that the introduction of locational BSUoS would better meet the relevant charging objectives.

2. Implementation

We consider that the implementation process originally proposed in GB ECM-18 to be equally applicable based on resubmission of the proposals and this addendum. We are currently assuming a Regulatory Impact Assessment leading to an implementation date in April 2010.

3. Background

On 17th February 2009, Ofgem wrote to National Grid requesting that it conduct an urgent review of the commercial and charging arrangements for access to the GB Transmission System, and to explore alternative arrangements to manage the cost of constraints to ensure that costs are recovered on an equitable basis from customers, suppliers and generators.

Given the increasing costs of resolving transmission constraints within the part of the network which is not reinforced to the required standard, and given the decision by Ofgem to extend the principle of over-selling capacity for an interim period, National Grid proposed the introduction of a locational Balancing Services Use of System (BSUoS) charge associated with transmission connected generation which is located behind a non-compliant derogated transmission boundary.

Following consultation with the industry, a conclusions report for GB ECM-18: Locational BSUoS was sent to the Authority on 22nd May 2009. On 17th June 2009, National Grid received a letter from Ofgem which indicated their intention to conduct an impact assessment. The letter also noted that in the course of preparing the impact assessment, Ofgem realised that further analysis would be required and that it was unlikely that National Grid would be able to complete the analysis in the time window set out in National Grid's transmission licence. Ofgem therefore asked National Grid to withdraw the conclusions report prior to 19th June 2009.

The Ofgem letter set out the further analysis required. This focused on three main areas:

1. An assessment of the effect of GB ECM-18 on generators in different locations and using different types of fuel, including an assessment of the impact on the wholesale price assuming no significant changes in the output and typical bid/offer prices by generators under current market conditions.

2. An analysis of the likelihood of changes in the output and bid/offer prices by generators in response to the proposal, together with the resulting impact on costs and volume of constraints and the wholesale price, assuming that no generators have any significant market power and that bid/offer prices are broadly cost-reflective. This analysis should look at the likely impact of the proposed charges on stations running costs and their position in the merit order.

3. Repeat of 2 above, but assuming that generators do have market power. This analysis should look at concentration ratios in relevant zones and consider the

historic bids/offers by different types of plant relative to average bid prices in other zones observed for plant with similar operating characteristics.

The analysis for 1 and 2 should also include sensitivity analysis around potential changes in the market conditions such as changes in coal/gas prices and in the relative position of coal/gas fired plant in the merit order.

National Grid subsequently formally withdrew GB ECM-18 report on 17th June 2009. All of the aforementioned reports and correspondence are available on National Grid's industry website[1].

4. Description of the analysis performed

In this section we describe the analysis we have performed.

National Grid has carried out analysis of the impact of Locational BSUoS using observed historical data and also using a probabilistic model. For both of these models we have carried out a number of sensitivities. In addition on the probabilistic model we have also carried out analysis with bid prices adjusted under a market dominance scenario.

We have also provided information on the concentration of market share and distribution of bid prices offered in the Balancing Mechanism on both sides of the non-compliant derogated boundary as requested by Ofgem.

4.1 2008/09 data

This involves analysing the costs of operation of the system between April 2008 and March 2009 and combining this with a constructed merit order.

Firstly, a merit order was constructed using various input costs for each settlement period analysed. Locational BSUoS was then calculated for each period as described in the GB ECM-18 proposal. These were then combined to model the generation that would meet demand with and without locational BSUoS.

Merit orders were constructed for settlement periods 5, 11, 19, 24, 35 and 43 on every day during the study period. Coal and Gas fuel input prices were taken from Bloomberg, week-ahead coal prices and on-the-day gas spot prices. Each derived a single value per day for Coal and Gas. Carbon prices were also sourced from Bloomberg, again at a single value per day. Efficiencies for power stations were assigned based mainly on the fuel type and the age of the unit, however, where additional information was available it was utilised. Production costs per unit could then be calculated for Coal and Gas fired units using Equation 1 and Equation 2 below.

$$\text{Coal Price}_{ij} = \frac{\pounds perTonCoal_d}{6.97 * Efficiency_{ij}} + (\pounds perTonneCarbon_d * 0.94)$$

[1] http://www.nationalgrid.com/uk/Electricity/Charges/modifications/uscmc/

Equation 1: Coal Price

$$\text{Gas Price}_{ij} = \left(10 * \frac{PencePerThermGas_{d}}{29.3071 * Efficiency_{ij}}\right) + \left(£perTonneCarbon_{d} * 0.41\right)$$

Where i is BMU, j is settlement period and d is day

Equation 2: Gas Price

Base load plant (Wind, Hydro, CHP and Nuclear) were assigned their metered output in the period and set to run. Other marginal units were assigned their declared MEL for the period. Interconnectors were assigned a price representative of the sterling equivalent of the French base load price for the day. Pump Storage stations were assigned a high price if contracted for reserve to prevent them from being brought on in merit. The remaining Pump Storage was assigned the higher of the coal or gas price based on central efficiencies.

Having constructed the merit order as described above, a demand figure was constructed for each of the settlement periods by summating metered values from Elexon corrected for any BM actions that had been taken by the System Operator. This is shown in Equation 3.

$$Demand_{j} = \sum_{i}^{j-x} least\left(0, Active\_MWh_{ij} + QBO\_MWh_{ij}\right)$$

Where i = BMU, j = settlement period

Equation 3: Demand

The formulation of the data to which this equation was applied excluded any interconnector flows.

To this value was added the market length for the settlement period in question. This enabled the “error” in the market’s contracting to also be included and so reflect the actual position that the market took in that period.

Locational BSUoS was added to units behind the non-compliant derogated boundary and the forecast reduction in BSUoS was subtracted from all units. The merit order and demand were then compared to establish the marginal price with and without Locational BSUoS.

4.2 Probabilistic model

The process based on actual data from 2008/09 described above is highly resource intensive, and would not be practicable for the number of sensitivities required to analyse questions of behavioural change or market power.

In order to analyse these questions, the constraint costing model that was developed to analyse the models of access reform considered by the Transmission Access Review (TAR) was modified. This mainly involved calculation and inclusion of locational BSUoS on a period by period basis. The assumptions used in the merit order were also updated and the merit order model adjusted to take account of fixed and variable cost separately. These changes allowed the level of Locational BSUoS and impact on the unconstrained schedule to be optimised.

4.2.1 The model

The basic model uses a static merit order, probabilistic generation availability and a discrete demand function. Generation is split into fuel type categories, each with a separate probabilistic function reflecting a generic plant type. The model has 16 zones representing the major generation and demand areas.

For each study, the model completes two optimisations. The first optimisation establishes an unconstrained merit order by setting generation equal to demand whilst seeking to minimise the relevant costs. This optimisation seeks to replicate an efficient energy market.

The results from the first optimisation are then superimposed on a simple model of the transmission network and a second optimisation honours all boundary constraints by taking bids and offers whilst seeking to minimise balancing costs. This optimisation seeks to replicate an efficient Balancing Mechanism, and gives the cost of constraints.

Specifically to support this analysis some further work has been carried out on the merit order assumptions and identifying individual company revenue flows. The unconstrained merit order is based on:

(i) marginal costs (fuel, carbon, avoidable Opex and Locational BSUoS if applicable); or
(ii) marginal costs (as above) and fixed costs (Capex and unavoidable Opex).

In this analysis we have focused on one boundary, the Cheviot or B6 boundary. All other boundaries in the model have been set to high limits to prevent them from being active. A more detailed description of the model is attached as Annex 1 .

4.2.2 The merit order

The input generator costs were based on the published costs in 'Dynamics of GB Electricity Generation Investment', 18/5/2007, a study by Energy Strategies / Redpoint[2]. These are different to the assumptions made under the 08/09 data analysis, we consider that both are equally valid for this type of analysis and together present a reasonable range of possible outcomes.

The unconstrained schedule uses the basic merit order and the constraint optimisation uses the prices from the merit order adjusted to represent bids and offers in the Balancing Mechanism.

Marginal costs

The marginal cost is the sum of fuel cost, carbon cost and other variable operating costs. The fuel cost includes a slight overlay to create an overall north to south power flow on the electricity transmission network, which is in the order of the locational differential in gas transportation charges.

Fixed costs

The fixed costs are based on the financing of capital costs with an approximate 10% rate of return (e.g. £440/kW capital cost was expressed as £44,000/MW per annum) and fixed annual operating costs (e.g. business rates, etc.).

[2] http://www.berr.gov.uk/files/file38972.pdf

Transmission Network Use of System (TNUoS) charges, including the locational differential, were also included in the fixed costs.

The recovery of fixed costs is incorporated into the merit order by using the load factor (i.e. if a units load factor halves, its fixed cost contribution in each period will be doubled, however if the unit does not run at all there is no revenue recovery).

The TNUoS costs in particular have a significant influence on merit order position of low load factor plant. In order to desensitise the model to large swings due to low load factor plant the model collars fixed cost to that based on a five percent load factor. This 'dampening' could be regarded as reflecting income from other sources such as Balancing Services.

The analysis was performed using marginal costs only and also using marginal & fixed costs. As well as the absolute price, the order of plant in the merit order for marginal and marginal & fixed costs will be different due to the different in locational elements included within each. This is discussed in more detail in 4.2.3 below.

Bid and Offer prices

The Balancing Mechanism bid and offer prices are based on the unconstrained merit order with a 0.8 and 1.2 multiplier applied to bids and offers respectively to reflect the less favourable prices that are observed post gate closure.

4.2.3 Impact of locational costs on merit order

The modelling was performed with both marginal and fixed & marginal costs. These different studies result in very different results. Figure 1 below highlights the effect of load factor in determining the merit order when using fixed costs. It also shows the difference between the fixed & marginal cost and marginal cost as load factor changes.

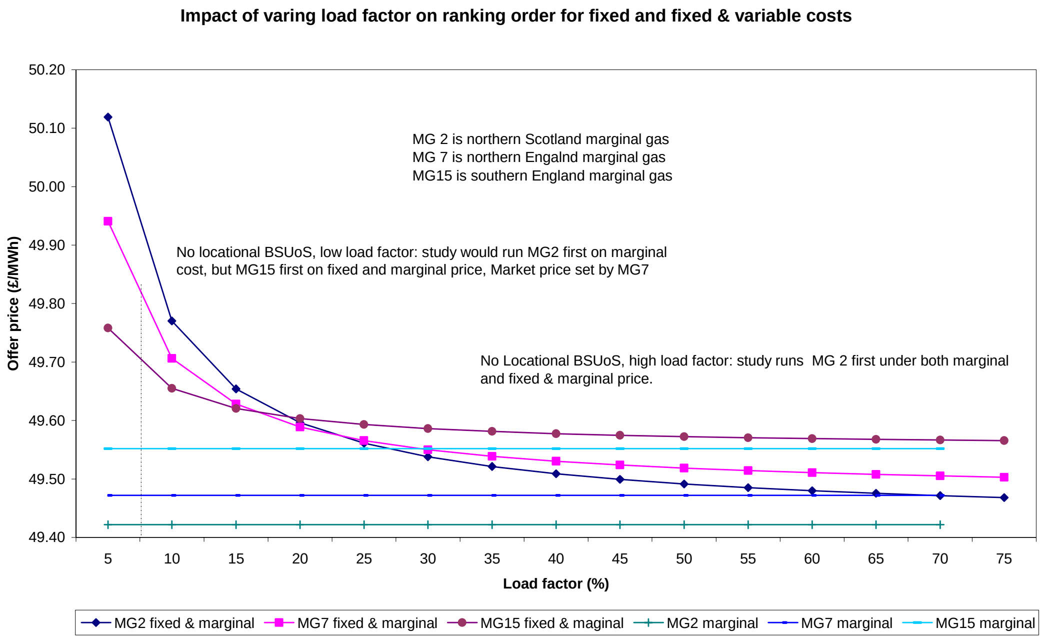


Figure 1 Comparison of marginal and fixed & marginal costs with increasing load factor

Figure 1 demonstrates that at very low load factors, the influence of locational fixed costs dominate in the fixed & marginal merit order (the southern-most marginal gas plant is the highest in the merit order[3] of the marginal plant). At higher load factors the locational fuel cost differential is more dominant (the northern-most marginal gas plant is the highest in the merit order). This shows that above 25% load factors the merit order for marginal and fixed & marginal is the same (although the absolute price is not).

In short-term timescales, fixed costs may be considered as sunk costs by generators and therefore would not have such a significant influence on operational despatch. If this is the case, then marginal costs better portrays unit operating patterns, whereas fixed cost recovery becomes more important at a strategic portfolio level (i.e. future investment and closure decisions).

The fixed cost used do not include other locational differentials such as rates, land costs and labour, including these is likely to reduce the strong north to south differential as these cost are generally more expensive in the south. The influence of fixed cost recovery on Balancing Mechanism prices is a much wider issue encompassing the interaction between the provision of capacity and the efficiency of imbalance prices, which themselves could encourage or discourage investment.

4.2.4 Impact of locational BSUoS charges on merit order

The addition of Locational BSUoS alters the marginal cost and so changes the order in which plant meets demand, and also the volume and order of Balancing Mechanism actions taken by the System Operator. Figure 2 below contrasts the situation with and without the application of Locational BSUoS charges on the merit order of some marginal gas units.

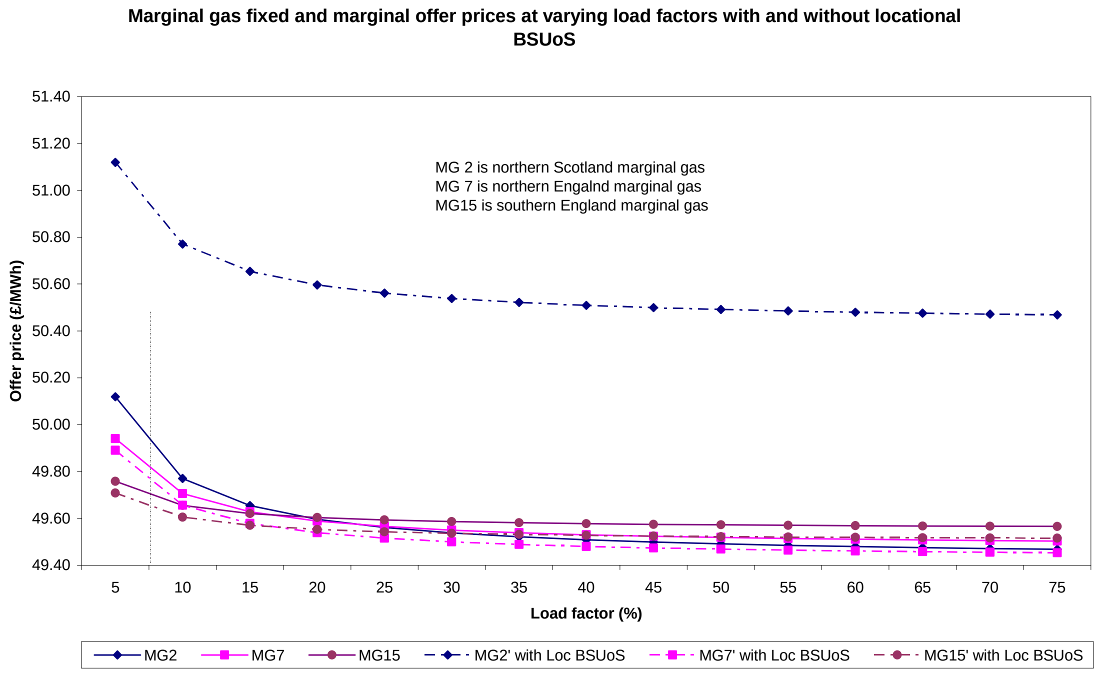


Figure 2 Merit Order with and without Locational BSUoS

[3] Terminology -'highest in the merit order' is the most likely plant to be despatched

In the period shown in Figure 2 the application of locational BSUoS increases costs by approximately £1/MWh in the constrained export area and reduces the cost in the constrained import area by approximately £0.05/MWh. This has the effect of changing the merit order so that plant in the unconstrained area (without the increase) is more likely to run under the unconstrained study (energy market), thus reducing the level of constraints.

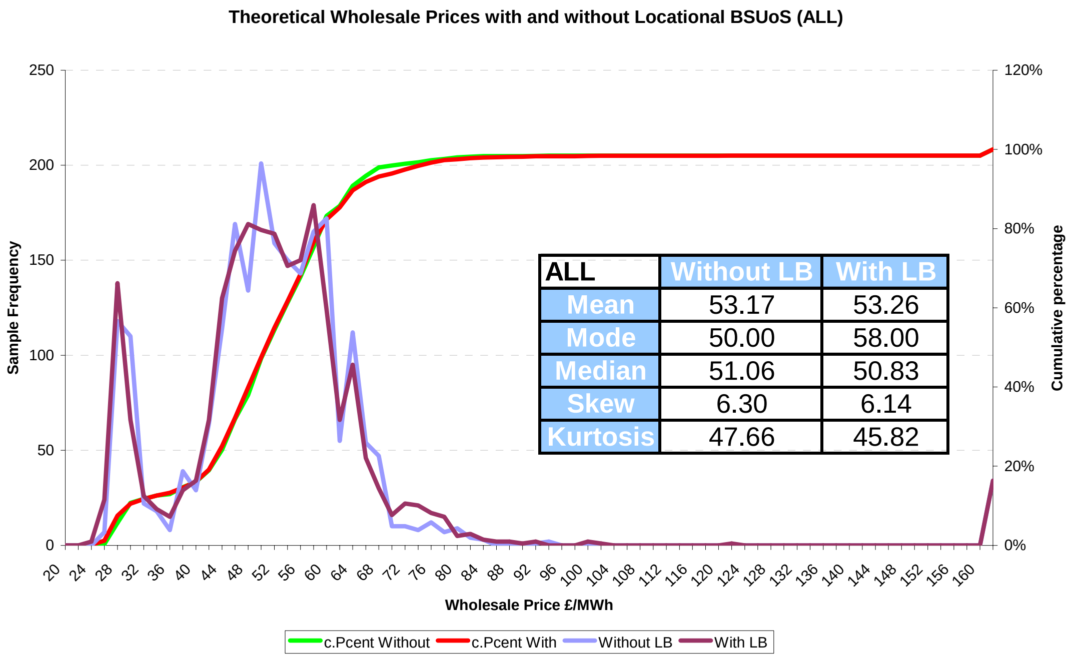
The application of Locational BSUoS to a marginal cost merit order gives approximately the same result as that shown in Figure 2 at the higher load factors, where the influence of the fixed element is minimal.

5. Description of the results

5.1 Analysis on 2008/09 data

5.1.1 Annual results

Inclusion of Locational BSUoS charges in the merit order did elicit changes in generation output between zones and in some instances did result in a difference in the marginal value of wholesale energy. However, these changes were infrequent so did not significantly impact on the mean or median value of margin price in any of the settlement periods studied (table in Figure 3).



ALL	Without LB	With LB
Mean	53.17	53.26
Mode	50.00	58.00
Median	51.06	50.83
Skew	6.30	6.14
Kurtosis	47.66	45.82

Figure 3 Distribution of prices, all periods, with and without Locational BSUoS

The mode value increases although this is mainly due to a reduction in the previous peak rather than an increase in the new peak.

Figure 4 shows the most frequent outcome of adding a Locational BSUoS charge to the theoretical production price is to make no change to the marginal price.

The second most frequent is for a small reduction due to the reduction in BSUoS applied across all units.

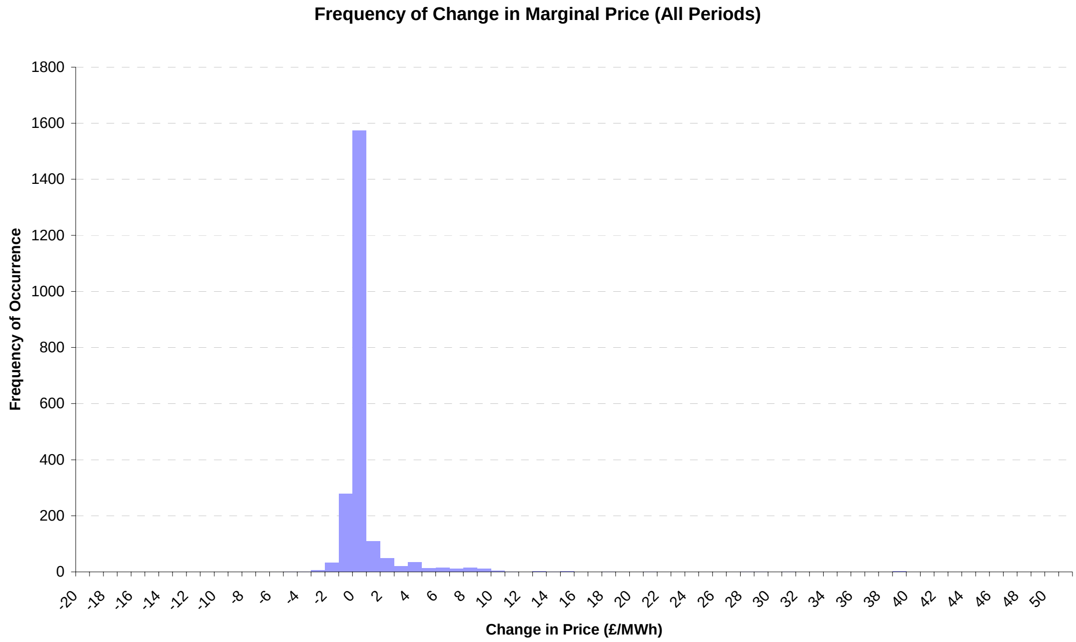


Figure 4 Frequency of Change in Wholesale Power Price with Locational BSUoS, All Periods

Table 1 shows that number of days that the same units were running in any of the settlement periods modelled. This shows that the most affected station falls out of merit on up to 89 days.

Days Running	No LB	With LB	Change
U1	361	326	-35
U2	74	66	-8
U3	156	81	-75
U4	231	170	-61
U5	102	69	-33
U6	254	165	-89
U7	171	146	-25
U8	156	131	-25
U9	176	150	-26
U10	169	143	-26

Table 1 Number of days running

5.1.2 Results by Period

The summary of results in Table 2 below show the statistics applicable to each of the settlement periods studied. The same pattern observed across all the data is repeated i.e. the mean and median values are not hugely altered. Again the mode value does vary with a relatively small number of changes in samples moving this around.

P5	Without LB	With LB
Mean	48.06	48.00
Mode	50.00	48.00/50.00#
Median	49.39	49.27
Skew	-0.73	-0.75
Kurtosis	-0.04	0.04

P11	Without LB	With LB
Mean	46.24	46.16
Mode	54.00	54.00
Median	47.78	47.54
Skew	-0.51	-0.54
Kurtosis	-0.50	-0.46

P19	Without LB	With LB
Mean	51.50	51.45
Mode	50.00/60.00#	58.00
Median	51.50	51.32
Skew	5.40	5.02
Kurtosis	68.92	62.08

P24	Without LB	With LB
Mean	51.83	52.48
Mode	60.00	48.00
Median	51.62	51.55
Skew	5.27	4.29
Kurtosis	66.20	46.80

P35	Without LB	With LB
Mean	70.94	71.44
Mode	60.00	>160 (52)*
Median	55.21	55.14
Skew	2.88	2.84
Kurtosis	7.37	7.23

P43	Without LB	With LB
Mean	50.45	50.01
Mode	58.00	48.00/58.00#
Median	51.55	51.14
Skew	-0.52	-0.49
Kurtosis	-0.03	0.13

* would be £52/MWh if high-cost 'bin' excluded
# both values equally common

Table 2 Summary of results from 2008-09 merit order

The mode value[4] for period 35, moves from £60/MWh without Locational BSUoS to greater than £160/MWh with locational BSUoS. These are periods when the plant margin is small and expensive generation has set the marginal price. The actual number of occurrences greater than £160/MWh has not changed with the introduction of Locational BSUoS, remaining at 32, shown as a line in Figure 5. However, in the rest of the data peaks have been reduced in number so greater than £160/MWh comes to the fore, shown on Figure 5. Excluding the greater than £160/MWh band that is unchanged the mode would drop to from £60/MWh to £52/MWh.

[4] Mode is the value which has the greatest number of observations

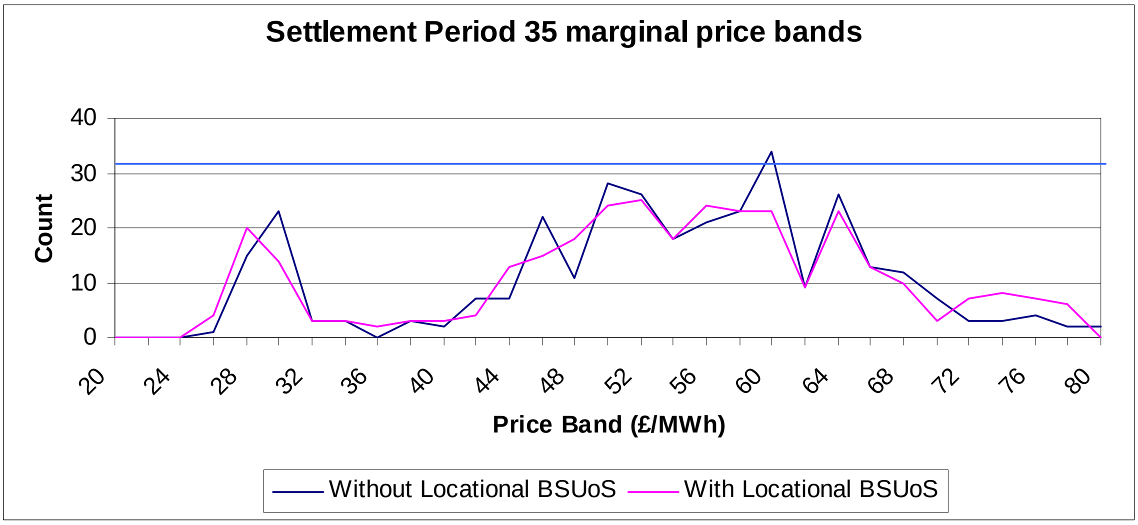


Figure 5 Settlement period 35 mode value

The frequency charts similar to that provided in Figure 4 for these results are provided in Annex 2.

5.1.3 Zonal Generation Patterns

In addition to recording the price of the units, the volume of their capacity that was needed to meet demand was also recorded. From this data Figure 6 below was produced showing the reduction in generation in zones N and P (North Scotland and South Scotland respectively) and the increases elsewhere to replace this generation, particularly in Zone B (East Midlands). The geographical coverage of the BRM zones is provided in Annex 3.

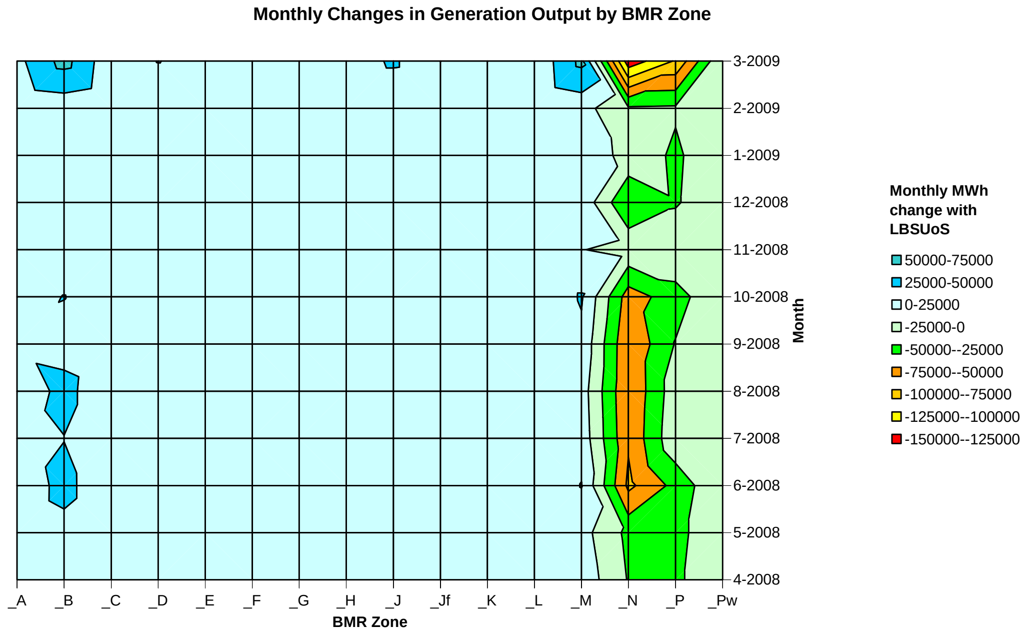


Figure 6 Monthly Change in Zonal Output with Locational BSUoS

5.1.4 Impact of change of fuel price

For this investigation, the same merit order derivation, locational BSUoS charge and gas prices were used. However, the coal price was multiplied by a factor of 3 so as to change the position of coal units within the merit order and look for differences that this may create. The changes to the statistical distribution are shown in Table 3.

ALL	Without LB	With LB
Mean	103.43	103.33
Mode	78.00	78.00
Median	98.65	98.30
Skew	1.28	1.28
Kurtosis	4.55	4.50

Table 3 Prices with Coal x3 fuel price

The threefold increase in coal prices clearly makes a difference to the overall wholesale price, as would be expected, and shows that coal is now driving the marginal price. Under this circumstance there is again little change in any of the values when the locational BSUoS charge from actual 2008/9 data is applied. This is shown in Figure 7 below.

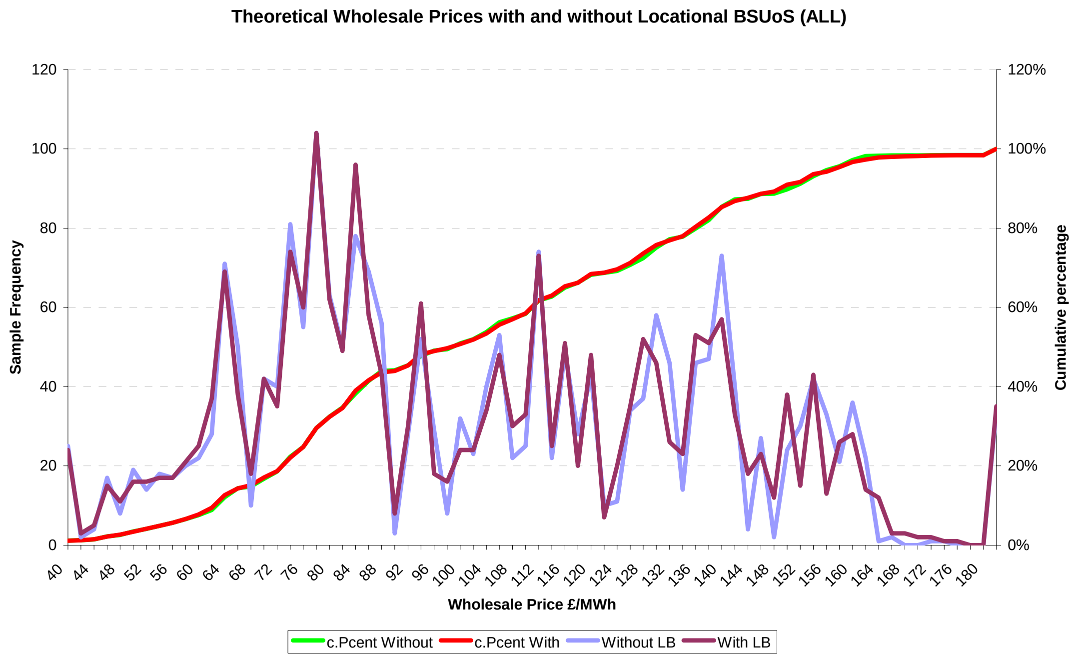


Figure 7 Distribution of prices with coal expensive study

Figure 8 below shows the frequency of changes, in most case it was within the 0 to £1/MWh range.

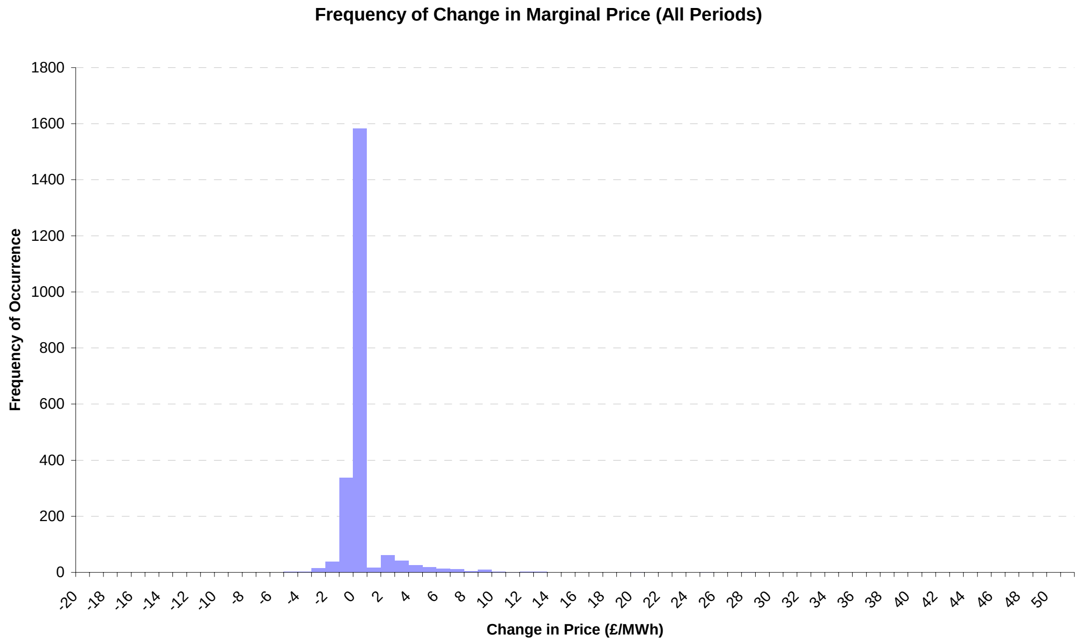


Figure 8 Change in Marginal Price with Locational BSUoS and Coal price x3

5.1.5 Zonal changes in output

Figure 9 below shows the variation in output with the same level of locational BSUoS charge as applied previously. Again, units behind the constrained boundary reduce output with this being picked up in south of the constrained boundary.

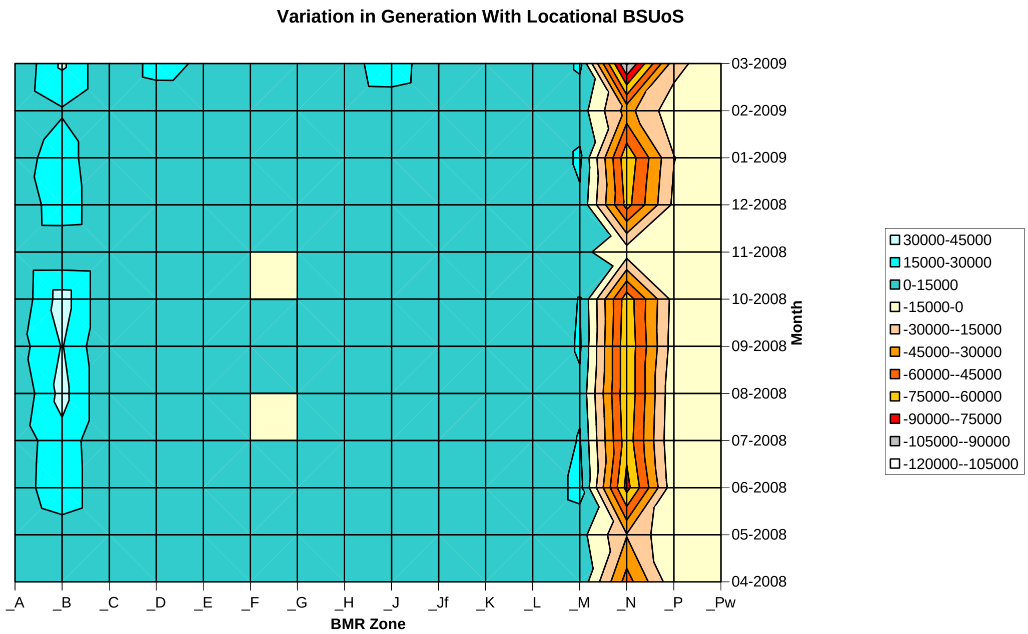


Figure 9 Monthly Change in Zonal Output with Locational BSUoS with Coal price x3

Table 4 below shows that in the Coal x3 study the overall days of constraint is virtually unchanged (403 compared to 417). However, the number of days that gas units (represented by U1 and U2) are running is virtually unchanged although for Coal (U3 to U10) there is less running with Locational BSUoS.

	No LB	LB	Change
U1	361	361	0
U2	363	361	-2
U3	147	51	-96
U4	222	128	-94
U5	98	52	-46
U6	249	123	-126
U7	64	52	-12
U8	57	44	-13
U9	76	61	-15
U10	59	46	-13

Table 4 Number of Days running

5.1.6 Alternative Merit Order

In addition to the basic age and fuel theoretical merit order an alternative was also investigated that sourced previous running information. This alternative merit order was constructed from the following:

- Load factors achieved for all units were calculated for the period January 2006 through to the end of March 2009;
- Nuclear, Wind, Hydro and CHP were treated the same as in the theoretical merit order (i.e. assumed to be 'must run' technologies);
- Units classified as CCGT or Large, Medium or Small coal were separated and for each category:
    - The unit with the highest load factor was given a maximum efficiency for that type;
    - The unit with the lowest load factor was given a minimum efficiency for that type;
    - Units in between were then given an efficiency dependent on their position between these two values using a linear trend, rounded to the nearest whole number.
- Maximum/Minimum efficiencies were as set out in the Table 5 below:

	Max	Min
CCGT	55%	48%
Large Coal	40%	33%
Medium Coal	38%	35%
Small Coal	33%	34%

Table 5 Max & Min Efficiencies

These derived efficiencies were then fed in to the same process as used for the earlier analysis. This alternative approach introduces a differential between the efficiencies of the units and so introduces more variation in unit prices.

The effect of using the derived efficiencies in the analysis is much as with the earlier investigations using age and fuel related efficiencies, the results of the comparison are provided in Table 6. The mean and median values are relatively unchanged with a plus 11 pence and a minus 5 pence change respectively. Overall this suggests that the marginal wholesale price is similar with and without locational BSUoS with the newly derived efficiencies.

ALL	Without LB	With LB
Mean	51.62	51.83
Mode	96.00	96.00
Median	49.44	49.39
Skew	6.39	6.24
Kurtosis	48.48	46.85

Table 6 Prices with Derived Efficiency

This is further shown in Figure 10 with a £0/MWh change in marginal wholesale price being easily the most common effect of adding Locational BSUoS. However, unlike in the earlier analysis the next most common outcome has been a £1/MWh increase rather than a decrease.

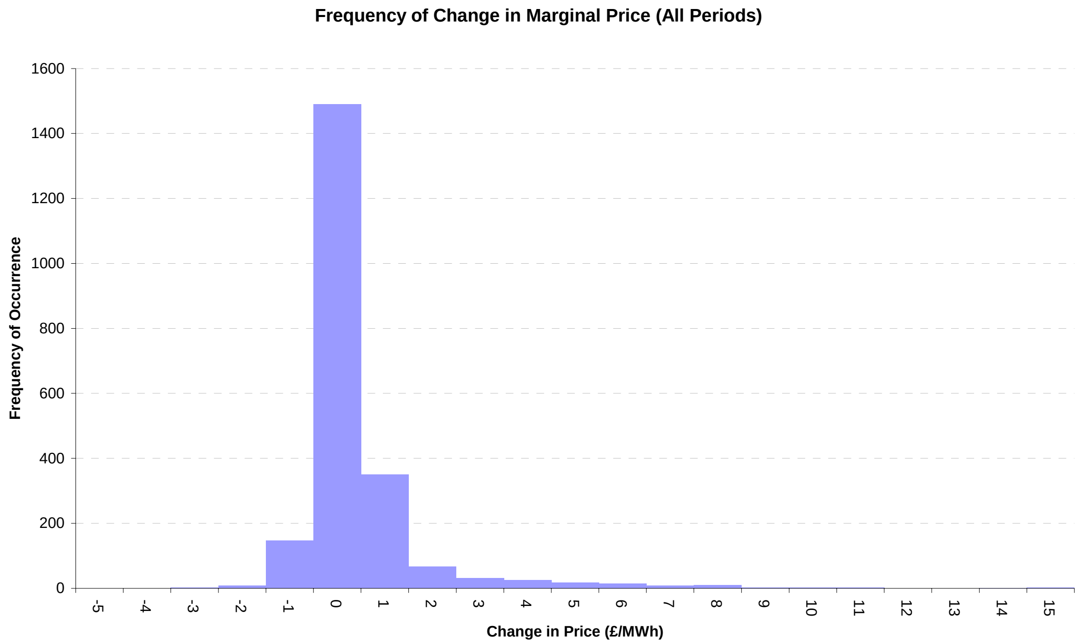


Figure 10 Number of Changes in Marginal Wholesale Price

The detailed results by period are provided in Annex 4

5.2 Results from the probabilistic model

In this section we describe the results of the probabilistic model. Figure 11 below describes how addition of Locational BSUoS changes the production curves and therefore the wholesale price and the constraint cost.

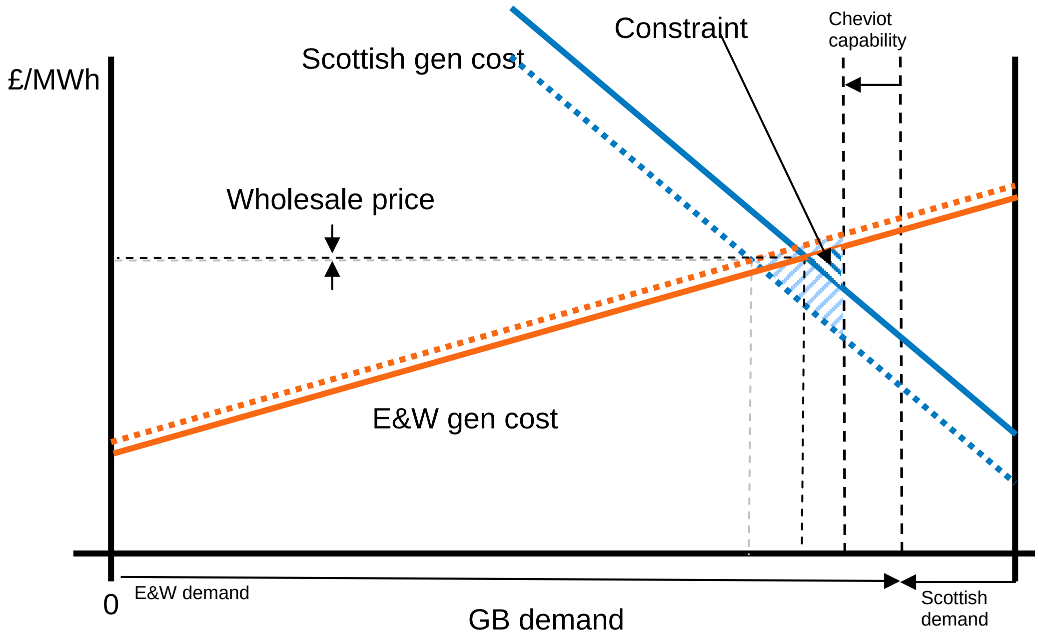


Figure 11 Marginal production slopes with and without Locational BSUoS

Figure 11 demonstrates the operation of Locational BSUoS across GB market in a particular half-hour. The marginal cost of generation in England and Wales is shown (orange line) increasing from left to right with the level of generation output. The dotted line shows the marginal cost without the application of locational BSUoS, and the solid line shows the marginal cost with the application of Locational BSUoS. As the cost of the Cheviot constraint is no longer being dealt with through existing BSUoS then the marginal costs in England and Wales effectively reduce.

The marginal cost of generation in Scotland is also shown (blue line), but this is shown increasing from right to left with the level of generation output. Again, the dotted line shows the marginal cost without the application of Locational BSUoS, and the solid line shows the marginal cost with the application of Locational BSUoS. This shows an increase in the marginal cost as a result of including Locational BSUoS.

Where the dotted lines meet in diagram is where we would expect the unconstrained market to clear, the position declared in Physical Notifications to the System Operator. The System Operator would then need to adjust the unconstrained market solution to take account of system capability, taking bids and offers until the production slopes meet the capability of the system (Cheviot / SYS B6 boundary). Figure 11 clearly shows that the inclusion of Locational BSUoS causes the pre gate market to clear at a position (further to the right) which results in a reduced constraint cost.

The impact on the marginal price is a function of the two marginal cost slopes. In some studies, where the marginal cost slope in England and Wales is steep (e.g. changing from marginal gas to marginal coal) the effect on the wholesale price in a period would be large. However, in our modelling the size of Locational BSUoS more often causes within fuel type switches. As the within fuel type differentials are relatively small (a nearly flat slope) the impact on the wholesale price in minimal. In some cases the net effect on the wholesale price will be negative as a result of the non compliant derogated boundary costs being removed from residual BSUoS.

The adjustment applied to post gate closure prices, 0.8 for bids and 1.2 for offers, is applied in all studies although is not shown on the figures for ease of interpretation.

5.2.1 Outputs from the model

The constraint cost is the sum of all the costs in the Balancing Mechanism i.e. net cost of bids and offers taken to resolve constraints.

The total market cost is the marginal unit cost from the unconstrained schedule multiplied by demand plus the constraint cost calculated on a half hourly basis and then aggregated over a year. This is not stated as the forecast of wholesale price since most trading is assumed to be bilateral forward trades, but it does provide a useful comparison between studies as to the cost drivers.

5.2.2 Results of studies

This section discusses the detailed results of the model.

In the studies with Locational BSUoS there are generally two minimum solutions. For example in study 4.1 the outcome is a low constraint cost, when this in converted into a Locational BSUoS signals it is relatively small, therefore in the next run, 4.2, the impact of locational BSUoS is much less and so constraint cost rises again. Further iterations then cycle between these two states.

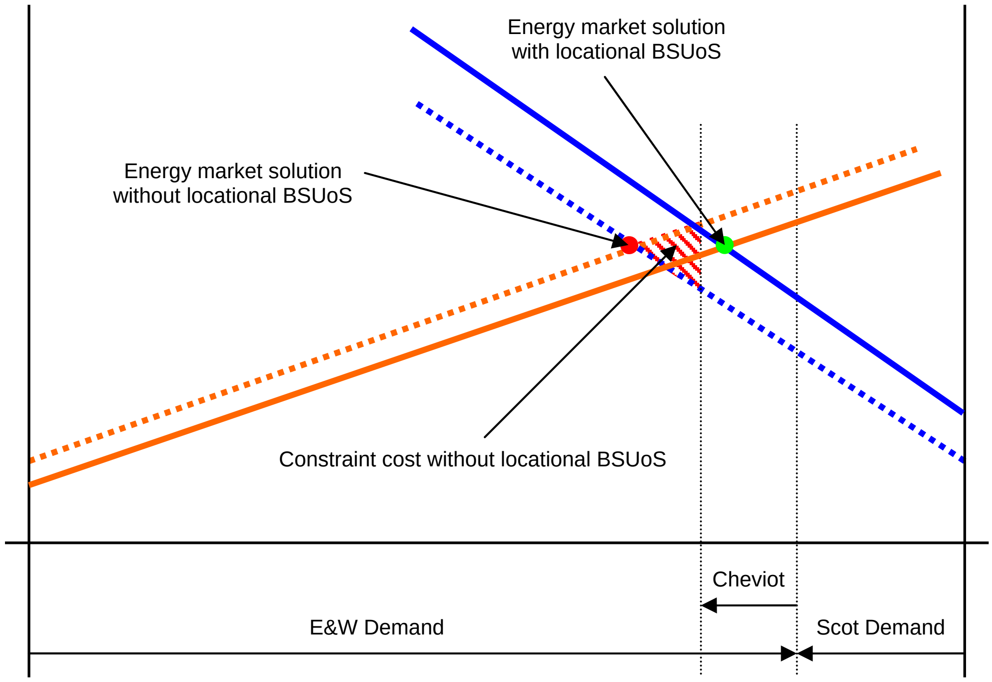


Figure 12 Cycling between iterations

Figure 12 above illustrates why the analysis leads some studies to cycle between two different solutions, instead of converging on one efficient solution.

The marginal generation cost curves without locational BSUoS are shown as dotted lines, and with locational BSUoS as solid lines.

In the example shown in Figure 12, without the application of locational BSUoS charges, the energy market clears at a point (red dot) at which there is a greater output from Scottish generation than can be accommodated by the transmission system, causing a constraint cost (red shaded area).

When the locational BSUoS price is calculated to cover the cost of this constraint and applied to the marginal generation cost curves, the energy market clears at a point (green dot) at which output from generation in Scotland can be accommodated by the current Cheviot boundary, meaning that there is no constraint cost.

The next iteration would naturally then involve recalculating locational BSUoS, but without a constraint cost, this takes us back to the original solution.

This highlights the importance of users' forecasts of constraint costs to the effectiveness of a locational BSUoS charge. If users forecast a low constraint cost, then they will anticipate a small locational BSUoS charge and may declare their plant available behind non-compliant derogated transmission boundaries and cause a larger constraint cost.

Under the non-locational BSUoS study only that proportion of marginal plant behind the non-compliant derogated boundary required to solve the constraint would be constrained by the System Operator. In the model generation is grouped into plant types by zone with each group having a single price, however in practice there is a much finer granularity of prices (individual BMU level and each can have tiered pricing). Within the Balancing Mechanism we see a variation in prices across stations, reflecting ‘duty’ cycles which may be technically or commercially driven. The greater granularity in practice will allow generators to better optimise and react to forecast signals than within the model.

The ability of Generation to manage their position effectively to maximise use of the system in the Locational BSUoS study is linked to the firmness and transparency of information between both generation and transmission i.e. transmission prediction of constraint volume is dependant on generation output submissions. Other sources of uncertainty are demand predictions, although these have a very small error, and faults, and these have a very low probability. Greater transparency of information could also have a negative impact if parties were to exercise market power. Whist Locational BSUoS could reduce the opportunity for market power, being an average signal it does not remove it. This is discussed further under the 60% bid study (section 5.2.7) and section 5.3.

Table 6 summarises the results of the analysis.

Study	**Case**	**Constraint cost £m/yr**	**Total Market cost £m/yr**
Unconstrained merit based on marginal cost and Balancing Mechanism prices based on fixed & marginal costs			
1	No LocBSUoS / 2200	297	17,296 – marginal 37,976- fixed & marginal
Unconstrained merit order and Balancing Mechanism prices based on marginal costs			
2	No LocBSUoS / 2200	58	17,057
3	No LocBSUoS / 3200	7	17,006
4.1	LocBSUoS / 2200	22	17,014
4.2	LocBSUoS / 2200	45	17,041
Unconstrained merit order and Balancing Mechanism prices based on fixed & marginal costs			
5	No LocBSUoS / 2200	173	36,384
6	No LocBSUoS / 3200	22	36,977
7.1	LocBSUoS / 2200	22	37,871
7.2	LocBSUoS / 2200	24	36,890
Closure of marginal plant in Scotland with the unconstrained merit order and Balancing Mechanism prices based on marginal costs			
8	No LocBSUoS / 2200	23	17,194
9	No LocBSUoS / 3200	2	17,173
10.1	LocBSUoS / 2200	7	17,174
10.2	LocBSUoS / 2200	17	17,187
Bid prices at 60% level with the unconstrained merit order and Balancing Mechanism prices based on marginal costs			
11	No LocBSUoS / 2200	98	17,097
12	No LocBSUoS / 3200	12	17,011
13.1	LocBSUoS / 2200	28	17,024
13.2	LocBSUoS / 2200	75	17,072
Coal and gas price switch with the unconstrained merit order and Balancing Mechanism prices based on marginal costs (Coal*0.9 & Gas*1.2)			
14	No LocBSUoS / 2200	120	18,324
15	No LocBSUoS / 3200	31	18,234

16.1	LocBSUoS / 2200	28	18,246
16.2	LocBSUoS / 2200	109	18,324

Table 6 Summary of probabilistic analysis

5.2.3 Unconstrained merit order based on marginal cost and Balancing Mechanism prices based on fixed and marginal costs (Study 1)

This is provided as a base case study. In this study the market (unconstrained solution) has been ranked on marginal cost, but the Balancing Mechanism uses offer prices that include the fixed cost element. This leads to the merit order being slightly different between the unconstrained market and Balancing Mechanism, due to the effects discussed earlier. Whilst this only affects lower merit plant, this is also the plant that is more likely to be used in the Balancing Mechanism. In studies where the inclusion of locational BSUoS removes the constraint this effect also causes the replacement plant in England and Wales to change from the north of England (cheaper based on marginal cost) to the south of England (cheaper on fixed & marginal cost) where the differential in fixed cost of TNUoS outweighs the differential in fuel transport costs.

The use of the fixed & marginal prices in the Balancing Mechanism also leads to constraints being larger than under the marginal study. The inclusion of a multiplier post gate closure on bids and offers also creates a similar effect, but this is not shown. Figure 13 demonstrates the impact of including fixed prices in the Balancing Mechanism. Essentially this creates a disjoint in the production curve. Once the market has settled at a wholesale price, any adjustments carried out by the System Operator in the Balancing Mechanism are prices on a different production curve. In practice the temporal distortion in price would not be as explicit.

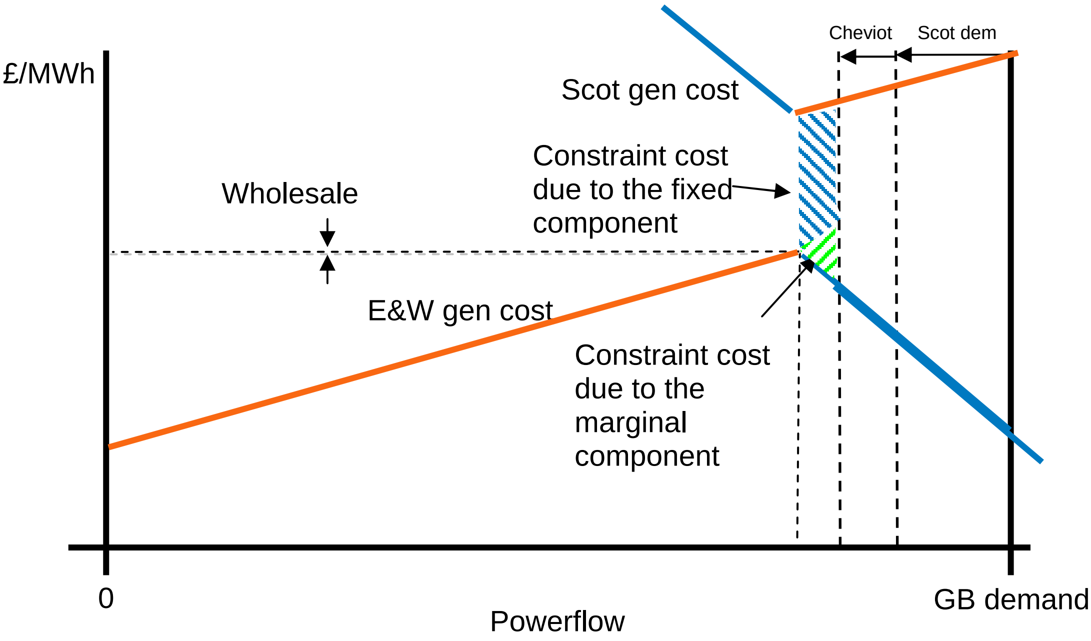


Figure 13 Impact on including fixed prices in the Balancing Mechanism[5]

Figure 13 shows that including the fixed cost in the Balancing Mechanism increases the constraint cost. This is borne out by the analysis where the cost difference between studies 1 and 2 is nearly £250m. In practice including fixed cost in the Balancing Mechanism more closely matches the constraint costs that are currently observed on the transmission system. We have carried out the analysis on both marginal cost and fixed cost, but only supplied some of the fixed cost studies to demonstrate consistency. In general the effect of Location BSUoS is the same between these two studies, albeit the magnitude changes.

We believe the marginal study more clearly demonstrates the behaviour of the market despatch, but does not better demonstrate the cost observed in the Balancing Mechanism and so the cost to resolve constraints. Therefore the constraint cost provided under the marginal study should not be considered as a forecast, but that the comparison of the 'with' and the 'without' locational BSUoS studies indicate the direction and strength of change. The difference in constraint costs between study 1 and study 2 provides a range of outcomes, varying based on the assumption of percentage of fixed cost recovery in the Balancing Mechanism. Parties may only reflect fixed costs when they can, for example, fixed costs may appear in the Balancing Mechanism when wind is in short supply, and this may dampen the cost of wind driven constraints.

The two values of total market cost supplied under Study 1 represent the marginal cost and the marginal & fixed cost studies. This provides a significant range, however under the market bilateral trading arrangements we are not able to state what the market cost is (this is equally true under a Pool with Contracts for Difference). We would expect the total cost to lie within this range, but both have been provided to highlight the extreme positions.

[5] This only displays the inclusion of fixed prices and not the post gate step change in prices, also including this would make offers and bids more expensive to the System Operator.

In most studies (except 5 to 7.2, which is discussed below) the wholesale cost reduces. As we have previously mentioned we believe that operation of plant will be influenced more by its marginal cost, although fixed cost are important in longer term decisions. Studies 5 to 7.2 assume that all plant receives the price of the marginal generator in the unconstrained market (its fixed and marginal cost). With each party seeking to manage their future commercial positions by selling energy forward, we believe that this is an overly simplistic view.

Therefore we mainly base our view of the effectiveness and impact of locational BSUoS on the marginal and not the marginal & fixed studies. However we recognise the importance of fixed assets cost recovery in the investment environment. Providing there are correct signals within the market we would expect parties to forecast the potential charges and react accordingly to mitigate these. Indeed it is only when the correct signals exist that market participants are able to react and minimise costs.

5.2.4 Unconstrained merit order and Balancing Mechanism prices based on marginal costs (Studies 2 - 4.2)

In these studies we have only used marginal prices. Study 2 indicates a constraint cost of £58m without locational BSUoS. As noted earlier this entirely based on variable costs (fuel, carbon and variable Opex costs) with a slight adjustment for the cost of actions taken post gate closure, therefore it is only the effect rather than the absolute value that can be drawn from these studies. The compliant situation here has been calculated to be £7m and therefore Locational BSUoS is targeting £51m.

We have modelled Locational BSUoS as being passed back as an annual average charge and as a charge calculated period by period. In the average we took the cost over the year and calculated a unit cost based on the total MWh generated. This has a similar overall effect of adjusting the merit order and thus reducing the constraints. However, this approach results in periods during which the locational BSUoS charge is adjusting the merit order when there is no constraint, causing the transmission system to be under-utilised and causing plant to operate at less optimal load factors overall (based on the merit order assumptions and economic despatch). Applying the locational BSUoS target on a period by period basis maximises efficient running of plant on both sides of the boundary by ensuring the signal only applies when the system is constrained. As described earlier, transparency of information is critical in ensuring the signal can be acted upon effectively. The discussion on “cycling” (5.2.2 above) demonstrated the importance of users’ ability to forecast the level and timing of constraints and therefore the locational BSUoS charge. As previously discussed, National Grid would endeavour to supply as much ex ante information as practicable and efficient to do so to allow users to predict when constrained periods are likely to occur.

As described in the conclusions report, the forecast process will operate as follows:

- In March of each year for the following financial year we will publish a forecast of the weekly demand peak and the likely generation peak behind the DNTB. We will also publish our best estimate of the boundary capability which will include our latest forecast of planned outages at that time. This information will be updated quarterly and again at two weeks ahead.

- In periods closer to real time we will be able to provide a greater level of data granularity. Sunday to Thursday for the following working day we will publish the forecast of peak demand and generation as well as boundary capability. We will publish the boundary capability at this lead time as well as the incremental capability that we have managed to create due to the arming of any inter-trip. As well as the values at the peak of the day we aim to provide snap shots of forecast demand, generation and boundary capability at other periods of the day to reflect significant variation in constraints across the day.

- Each Friday we will provide the same granularity as determined above for the following Saturday and Sunday.

In the locational BSUoS studies, the result cycles between £22m and £45m compared to a without locational BSUoS level of £58. This cycling effect was discussed earlier and we would expect the market to settle somewhere within this range.

4.1 - £22m study
Figure 14 below shows the change in costs between study 2, £58m without Locational BSUoS, and 4.1 £22m, the lower range with Locational BSUoS.

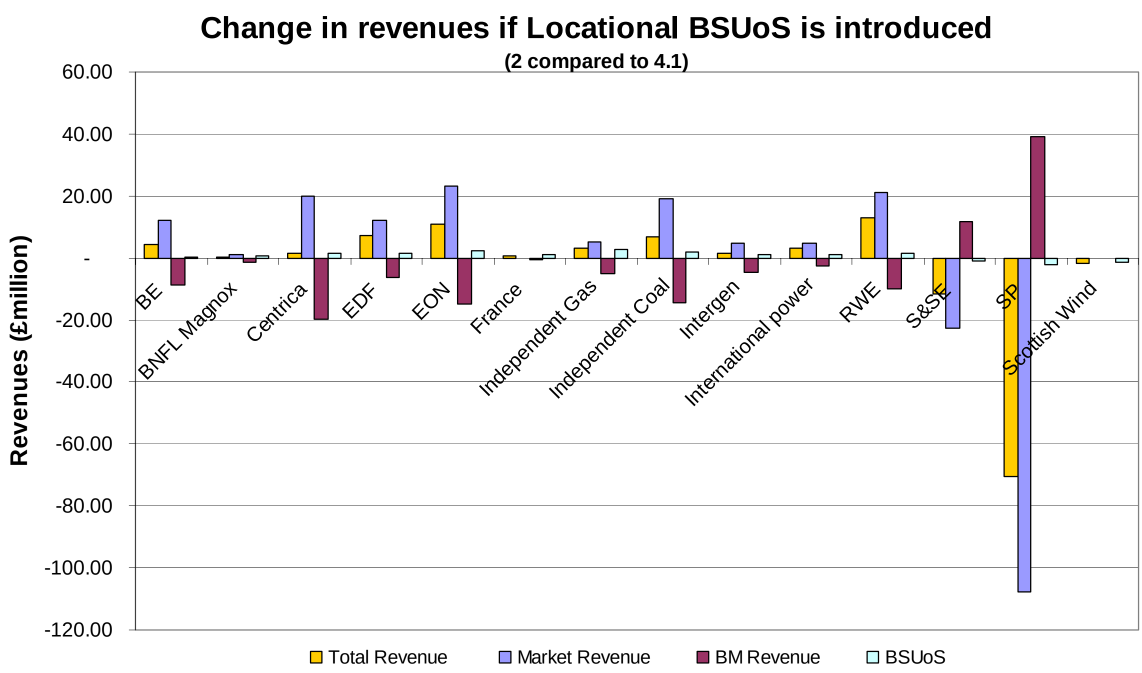


Figure 14 Merit order on marginal price comparing with and without Locational BSUoS – low study

Figure 14 demonstrates that the key affected parties are those with marginal plant in Scotland where their pre-gate unconstrained running is reduced due to the inclusion of Locational BSUoS. The net effect of reduced market income and reduced bid payment overall results in reduced revenues.

In contrast to Study 4.2 BE have a net gain in revenue. This is due to a combination of the portfolio effect of their marginal plant on the unconstrained side of the boundary and a net gain in total BSUoS i.e. the GB saving in BSUoS (removing £51M) outweighs the targeting of Locational BSUoS behind the constraint boundary.

In the base case, BE plant in Scotland face 20% of the GB Generation BSUoS contribution (£5.8m); however under 4.1 they face 20% of the residual BSUoS (£0.7m) and 35% of the target BSUoS (£5.25m) – a net increase in BSUoS cost of approximately zero (positive in Figure 14 due to the portfolio effect of E&W plant).

Other units in England and Wales see a net change in revenue that is positive as they no longer contribute to the £51m constraint. Their revenue previously under the Balancing Mechanism is replaced with revenue received from unconstrained running. Due to the lumpiness of our merit order this 'benefit' is slightly magnified. Similarly, the disbenefit to Scottish parties is also overstated as we would expect them to tailor their output so as to maximise output, but not cause a constraint and therefore incur locational BSUoS.

4.2 - 45m study

The study displayed in Figure 15 show a smaller drop in constraints, although as discussed, along with 4.1 is an outlying solution.

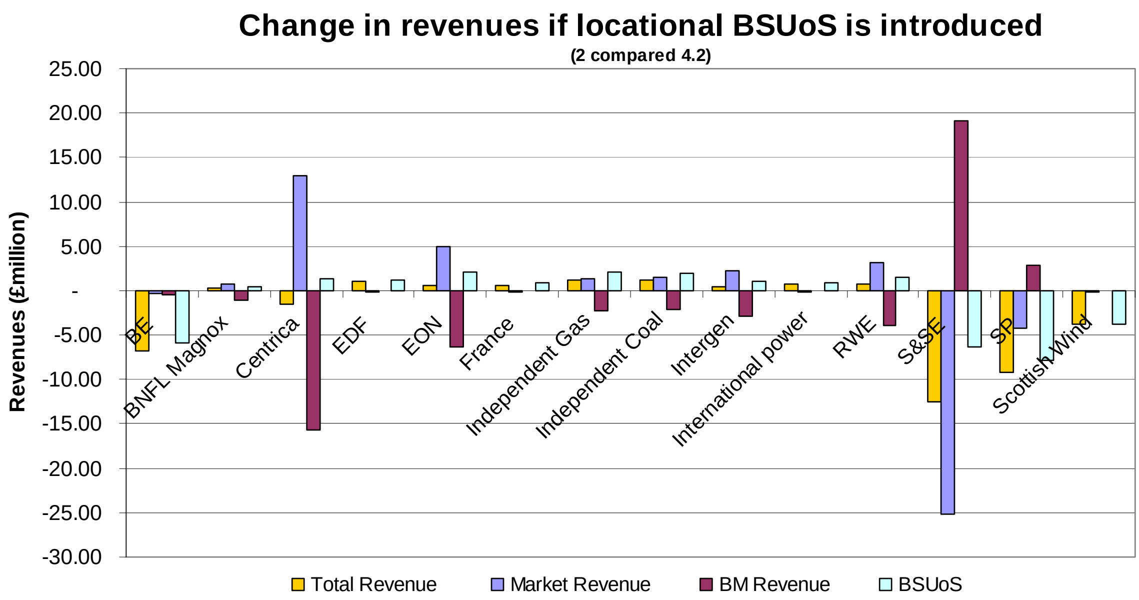


Figure 15 Merit order on marginal price comparing with and without Locational BSUoS – high study

This again shows that flexible plant in Scotland receives less running in the unconstrained study. As the targeted locational BSUoS is low, based on a £22m constraint, the impact of Locational BSUoS is much less than 4.1. Therefore the reduction in constrained running in Scotland is much less.

In this particular study the net effect on BE is negative as it picks up a larger proportion of the Locational BSUoS than it saves in BSUoS and it receives no increase in unconstrained running in England and Wales.

This study also shows that the net effect on Centrica is very slightly negative. This is as a result of the slight difference in income from generating in the unconstrained merit order to that of being constrained ‘on’ in the Balancing Mechanism (Balancing Mechanism offers have been assumed to be 1.2 times unconstrained merit order price). Assuming the step change in prices post gate closure is cost reflective, this actual loss in revenue will be balanced by a reduction in costs. It should also be noted that under study 4.1, the much larger reduction in BSUoS nets this effect out.

The analysis assumes that there is no market power, and the assumptions we have made about the merit order means that we would expect marginal thermal generation behind the non-compliant transmission boundary to react to the change in short-term costs by reducing output. Provided that this occurs, the output will be nearer to study 4.1 above, where the constraint cost is avoided. If this does not occur then revenue flows are likely to be nearer to study 4.2 above, where constraints remain high, but the costs are spread across generation behind the non-compliant boundary rather than GB.

There are a number of reasons why plant may not respond to this signals, the primary ones being the ability of users to exercise market power in the pricing of bids in the Balancing Mechanism, a lack of liquidity in the short-term market, dynamics of plant across a portfolio and the transparency and quality of information exchange between generation and transmission. The primary area we have investigated further in this analysis is the market power issue.

5.2.5 Unconstrained merit order and Balancing Mechanism prices based on fixed and marginal costs

This study is based on marginal and fixed costs and is included for completeness. We have discussed the issues surrounding fixed costs and therefore believe this to be overly pessimistic and not representative of real time despatch behaviour. The total market cost is also overly pessimistic being set by the full fixed and marginal cost of the marginal generating unit.

However, even at these ranges the effect of Locational BSUoS is still to reduce constraints from £173m to £22/24m. The impact of load factor on fixed cost recovery in these studies causes a “positive feedback” effect which minimises the difference between the two solutions. This occurs because as a unit has less running it is required to recover its costs over fewer running hours, increasing its unit cost and making it even less likely to run.

The negative effect on the wholesale price associated with the introduction of locational BSUoS is caused by changes to the means by which peaking generators recover their fixed costs. Without locational BSUoS, these generators are not in merit in the wholesale market and recover their fixed costs in offers accepted in the Balancing Mechanism. With locational BSUoS, generators in Scotland fall out of merit and are replaced by these peaking units, and in these periods they are assumed to recover their fixed costs in the wholesale market, effectively setting the wholesale price at a high value.

As mentioned above, each party is seeking to manage their future commercial positions by selling energy forward and therefore modelling based on the recovery of the fixed costs of the marginal generator in the wholesale market may be an overly simplistic view.

Our studies show that even a small change in the constraint cost produces a significant swing in total wholesale cost. Even with damping the minimum load factor to 5% in the price setting, a change from 10% to 5% load factor increases the unit cost by 73%. When this is reflected through to the wholesale cost calculation the impact is very large. The financing of individual Power Stations is extremely subjective, particularly those towards the end of their life. It is worth noting that these older units are also more likely to be the marginal units.

In the modelling we have used the capital costs expressed in the Redpoint study, although this may not be appropriate depending on the generator's financing arrangements.

5.2.6 Closure of marginal plant in Scotland with the unconstrained merit order and Balancing Mechanism prices based on marginal costs (Studies 8-10.2)

In this study a marginal coal unit in the South of Scotland was closed. As expected this dramatically reduces the base level of constraint, significantly reducing the level of locational BSUoS. In order to allow comparison between scenarios, we have not altered the non-compliant level of transmission. Recalculation of the compliant level would reduce the capacity to around 2600MW (for this study in isolation) using the deterministic criteria. The effect of this would be to increase the compliant level of constraints and so greatly reduce the cost of locational BSUoS completely.

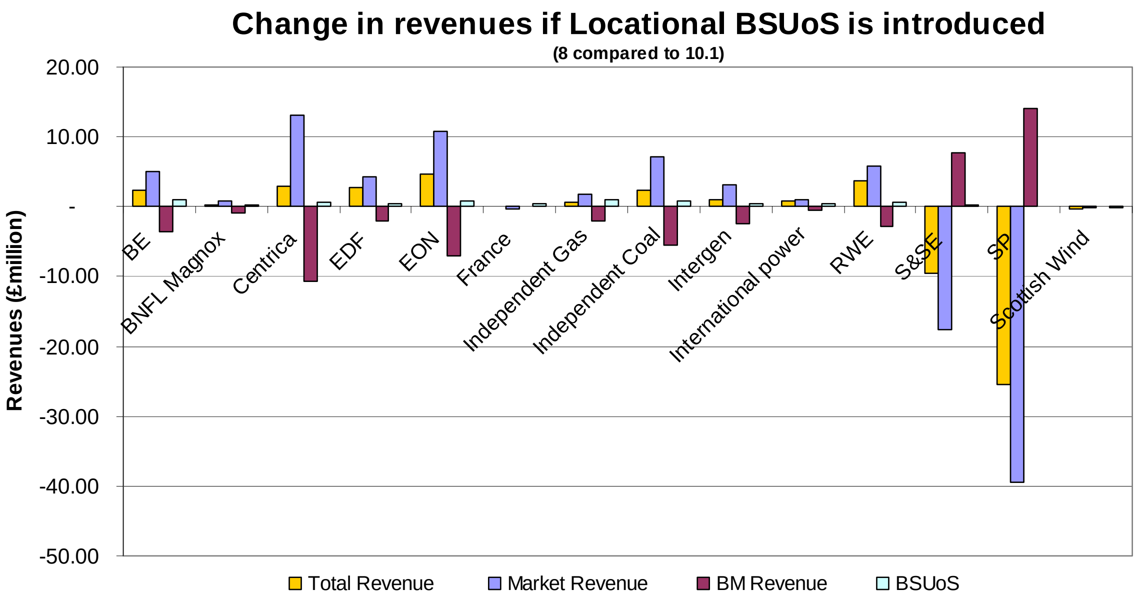


Figure 16 Closure of plant behind the non-compliant boundary

The removal of any plant on the system that was previously in merit would be expected to increase the cost of the marginal unit in some periods. Compared to Study 2 we do see slight increase in wholesale cost in the study. We consider this to be associated with a reduction in the level of generation capacity in the market in the short-term and would expect it to occur irrespective of the location of the plant leaving the system. This capacity would be replaced by new generation capacity in the medium term, and indeed with significant levels of new plant commissioning we would expect older plant to retire. When the new plant is of a different type, particularly intermittent, which has a lower capacity credit, we would not expect a one for one exchange, although a ‘one for one’ exchange of thermal plant could be expected to reduce the wholesale cost as newer plant is likely to be more efficient.

Whether new plant connecting behind a constrained boundary causes an increase of constraints will depend on its ‘duty’. If the new plant is replacement for intermittent then it will share capacity and so is unlikely to cause constraints. If the plant is to run base load, and therefore independent of the intermittent plant, then it is much more likely to cause constraints and so require transmission reinforcement. With only one annual capacity product and limited options for users to elect to share transmission access, the transmission companies are required to assume duty in order to invest efficiently.

The effect within this study is shown on Figure 16. Overall introduction of locational BSUoS reduces the cost of constraints. Marginal generation behind the constraints is pushed out of merit and so has far less unconstrained running, leading to the reduced constraints. This is consistent with the previous studies. Generator other than those with marginal units behind the non-compliant boundary see increased unconstrained running and a slight reduction in BSUoS (due to the removal of socialised constraint costs). The exception is wind in Scotland which sees a very small increase in costs, due to the additional cost of Locational BSUoS and a slight reduction in the unconstrained market revenue (the volume running is unchanged).

We note the concerns expressed with regard to security of supply. In this study there remains plant still in merit and available in Scotland, indeed sufficient volume to cause an export constraint and non compliance. Any local issue such as voltage consideration could be dealt with though a combination of managing closure notice and local reinforcement, such as reactive compensation.

Under the current CUSC arrangements plant can exit the system with a minimum of five days notice which is clearly inconsistent with the time needed to reinforce the transmission network. Where plant was expected to exit the system and this would cause a security problem in advance of reinforcement the System Operator may need to consider the use of Balancing Services to contract for plant to maintain security in the short term.

5.2.7 Bid prices at 60% level with the unconstrained merit order and Balancing Mechanism prices based on marginal costs (Studies 11-13.2)

In this study we have tested the effect with bids set to 60% (as per Table 9) of the marginal cost in the non compliant area. This increases the without Locational BSUoS case from a £58m to a £98m constraint cost. In this study the unconstrained solution is the same as for study 2. This is confirmed as the wholesale cost (without constraints), which is set by the marginal unconstrained unit is the same in both studies at £16,999m.

As with the other studies the locational BSUoS studies change between two states, £28m and £75m, indicating a reduction in constraint cost of between £70m and £28m. Figure 17 below provides the change in revenue flows between the 60% base case without locational BSUoS and the study with locational BSUoS and a total constraint cost of £28m.

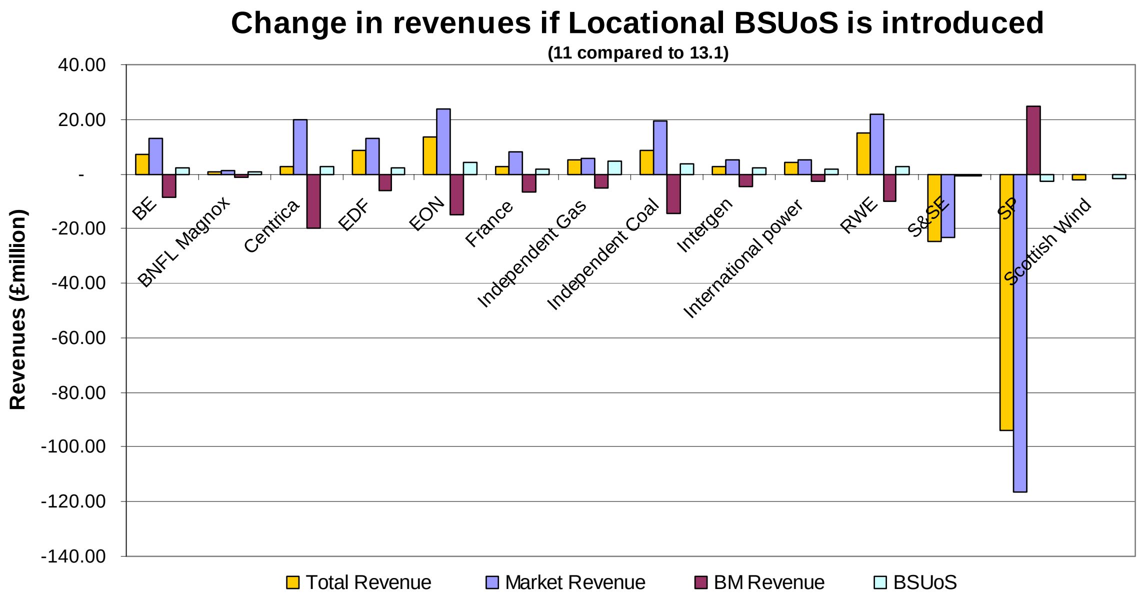


Figure 17 Merit Order on marginal price with bids in noncompliant area at 60% level comparing with and without Locational BSUoS – low study

The revenue flows follow the same pattern as with 4.1 and 4.2. When the constraint cost forecast high, Locational BSUoS has a big effect on behaviour. The difference in cost is as a result of the decrease in bid revenue.

This shows that, providing users react, locational BSUoS is more effective at reducing constraint costs if the bid prices behind the non-compliant transmission system boundary are lower. This is because the reduced bid price increases the size of the locational BSUoS charge, making it even more significant when compared with differences in the merit order, and therefore causing a greater change in generator despatch decisions.

Not shown here, but similar to the 4.1/4.2 studies, British Energy's revenue changes from positive to negative if marginal generation behind the non-constrained boundary does not react to Locational BSUoS.

The proposed Locational BSUoS modification is based on cost recovery so if an individual party chose to exercise locational market power it would only lessen the benefit rather than remove it.

5.2.8 Size of bid price change to recover lost revenue

Here we have investigated the revenue flow that results with no change in behaviour. Also, if a party were to seek to recover lost revenue, by how much they would need to adjust bid price.

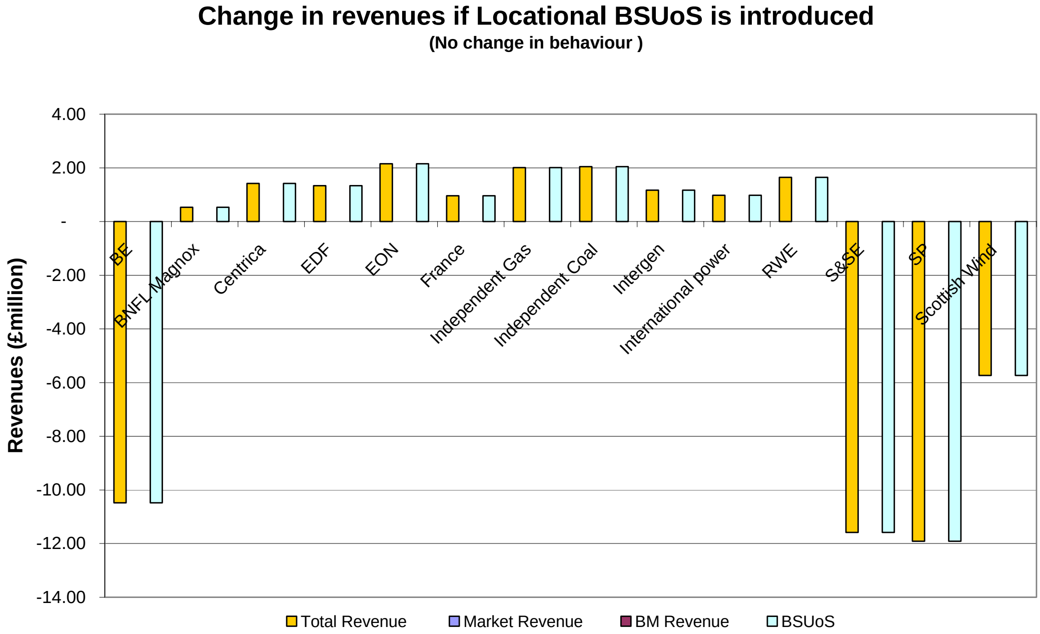


Figure 18 Locational BSUoS introduced based on based on study 2 (marginal) with no change in behaviour

Figure 18 shows the change in revenue flows if there is no reaction to the introduction of Locational BSUoS by generation i.e. plant running is the same in both the constrained and unconstrained solutions. Parties behind the non-compliant derogated boundary see an overall net reduction in revenue. At a system level the original £58m constraints in study 2 would have been split 50:50 with demand (£29m each). However Locational BSUoS adjusts this creating an overall saving of £25.5m for demand. In this case Scottish wind is 1930MW, at a 35% load factor this would give an annual output of approximately 5.9TWhs. With a total Scottish output of 47TWh, Scottish Wind sees an increase on net BSUoS payments of approximately £5.6m.

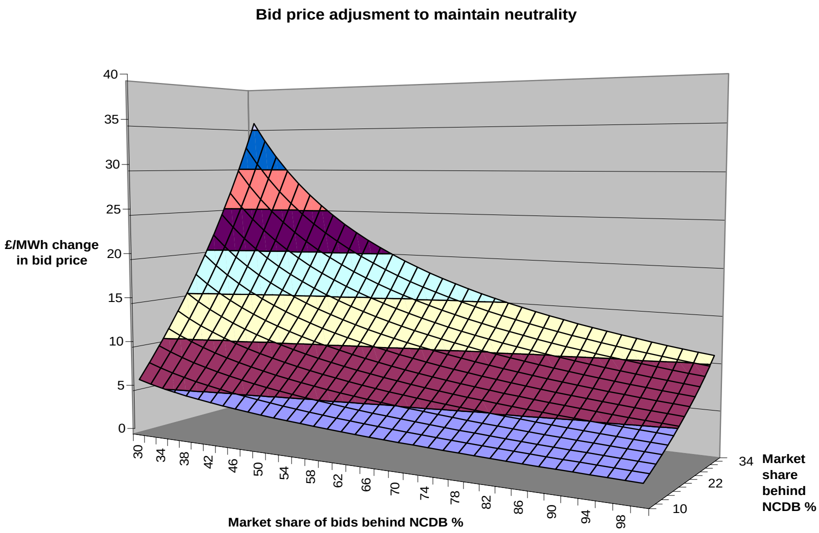


Figure 19 Size of adjustment in bid price to maintain revenue neutrality avoid a reduction

Figure 19 above shows the size of change that an individual generator would need to make to maintain neutrality to locational BSUoS for the example of a 200MW constraint with 8.4GW of generation in Scotland. This represents the increase in cost across all the user's plant in behind the NCDB recovered from its plant that has bids accepted[6].

This shows that as bid market share reduces the generator has to recover more per unit of bid accepted (reduce bid price). Similarly, as market share increases (subject to Locational BSUoS) the generator is exposed to greater locational BSUoS and so needs to increase the size of bid change.

In this particular example a generator with 30% exposure to Locational BSUoS (market share) and 50% of the bid volume would need to reduce bid price by approximately £9/MWh. Thefore such a behaviour is likely to be notiacable reklative to similar plant.

5.2.9 Coal and gas price switch with the unconstrained ranking order and Balancing Mechanism prices based on marginal costs (Studies 14-16.2)

In this further sensitivity study we have tested the switch over of Coal and Gas fuel prices. The Coal input price was multiplied by 0.9 and the gas price was multiplied by 1.2. These multipliers were chosen to cause a switch without causing an interaction with other plant types in the merit order.

In this study the switch in fuel price increases the basic fuel price causing an increase in the wholesale energy price. If we chose multipliers that represented a reduction, we would equally expect a reduction. The impact of locational BSUoS is consistent with the other marginal studies, with a reduction in wholesale price of between £0 and £78m.

[6] In this example we have assume a demand behind the NCDB of 6GW, boundary capacity of 2GW, a NCDB volume of 300MW and a cost of resolving of £65/MWh. The example also included an assumes reduction in BSUoS for generation on the complaint part of the system based on a 5% total market share.

In terms of constraint costs, introducing Locational BSUoS results in a reduction in constraint costs of between £11m and £89m. Consistent with the other studies, there is the effect in the model of high locational BSUoS (strongest signal) causing the greatest change in constraints.

The base level of constraints increases because a switch in coal and gas plant in the merit order leads to a much greater level of unconstrained running behind the non-compliant boundary i.e. there is more coal than gas. When Locational BSUoS is introduced in this study the overall impact on the unconstrained merit order is very significant because the level of non-compliant constraints is very high in the base case. The overall effect is roughly proportional to the increase in the constraint costs i.e. it doubles.

Figure 20 below display the revenue changes with and without locational BSUoS for the £28m constraint study.

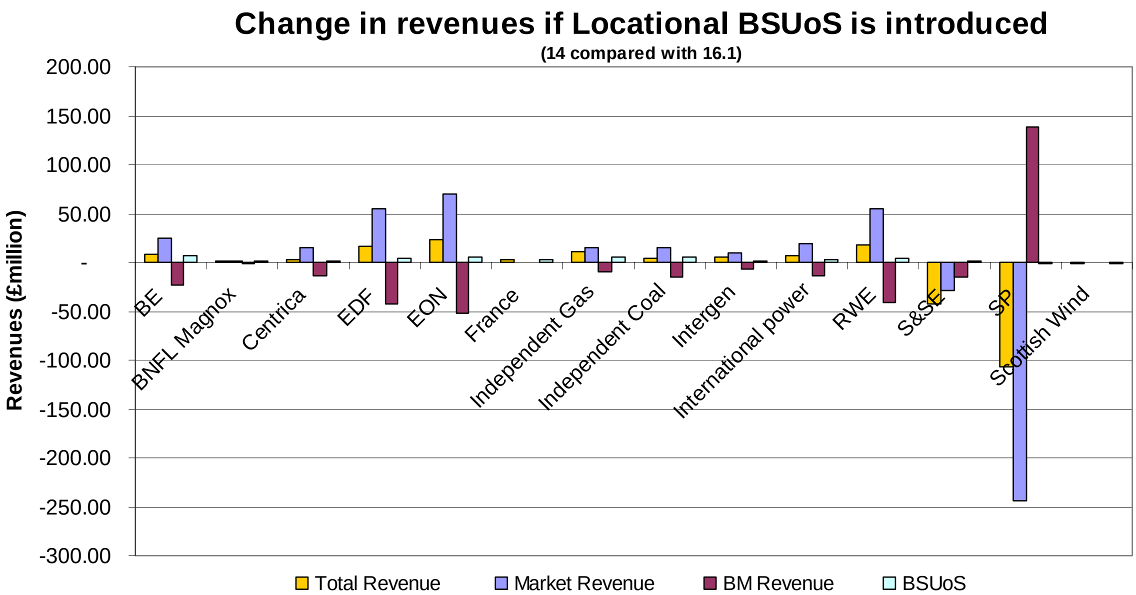


Figure 20 Ranking on marginal price with Coal and gas switched over in the merit order comparing with and without Locational BSUoS – low study

Figure 20 above shows the revenue changes with and without locational BSUoS for the £28m constraint study. As with the 60% study, we have only shown the low study, the impact of the high study is consistent with the 4.1.and 4.2 comparison i.e. if marginal units do not respond to the signal then BE and Scottish wind (inflexible plant) see a proportional decrease in revenue.

5.3 Market Share

In this section we have provided the market share information and presented historic bids prices by location as requested by Ofgem.

5.3.1 Market Share

Based on 2008/09 market metered data the Herfindahl-Hirschman Index, HHI, expressed as a percentage for GB as a whole is 9.47%. Our understanding is that a level below 10% is reasonable, in terms of indicating the potential competitiveness of a market. Table 7 below shows the HHI based on metered position since 2005.

	2005-06	2006-07	2007-08	2008-09
HHI as a percentage	10.3%	9.88%	9.94%	9.47%

Table 7 HHI index for GB based on metered output

By contrast the position for Scotland using the same data[7] is 32.88% for 2008/09, which we understand is considered as a high concentration, indicating that competition could be frustrated. These figures are based on metered output. Table 8 shows the figures from 2005 for Scotland.

	2005-06	2006-07	2007-08	2008-09
HHI as a percentage	35.57%	33.02%	32.76%	32.88%

Table 8 HHI index for Scotland based on metered output

If we considered the market for bids, as generally only two parties have flexible plant, HHI would tend to be a higher value (i.e. for two parties the sum of squares will be at least 50%).

5.3.2 Historic bids

We have also examined the historic bid volumes offered and available to the System Operator. The analysis was performed by looking at generators with a positive FPN and submitting bid volume data into the balancing mechanism. The data is that submitted to the Balancing Mechanism 1st April 2008 to 31st May 2009. The bid volumes were adjusted to ensure that they were within the plants' operating range i.e. bounded by the volume available between the MEL / FPN and SEL[8].

The figures below show, the relative levels of bid volumes available in Scotland and England & Wales, banded by the offered price. Note that a positive bid price reflects a reduction in the cost of BSUoS and would be taken in preference to those with more costly lower prices.

Figure 21 shows that in England & Wales 45% of the bid volumes available are priced positively with 1.4% priced at between £0/MWh and -£100/MWh; 44% of the bids offered were priced more expensive than -£10k/MWh. In comparison,

[7] HHI is the sum of squares commonly used to shown concentration in a market, we have expressed it here as a % the is also commonly shown as a number e.g. 10% shown as 1000. Note these calculations are based on metered output that has not been corrected by bid offer data. Where a party has been taken off through the Balancing Mechanism it will not show in these figures.

[8] MEL, Maximum Export Limit; FPN, Final Physical Notification; SEL, Stable Export Limit. The SO can despatch plant below SEL although it has to take the full remaining volume i.e. take the unit off. We have also performed the analysis without a collar at SEL, the results are approximately the same.

28% of the bid volume available in Scotland was positively priced; 8% was priced between £0/MWh and -£100/MWh; 62% being offered at priced more expensive than -£10,000/MWh.

Looking at the £0 to £100 band in
Table 10 shows that Scottish bids are approximately 60% of those in England and Wales. The reverse is true £0/MWh to -£100/MWh, although the bid volume in England and Wales is greatly reduced.

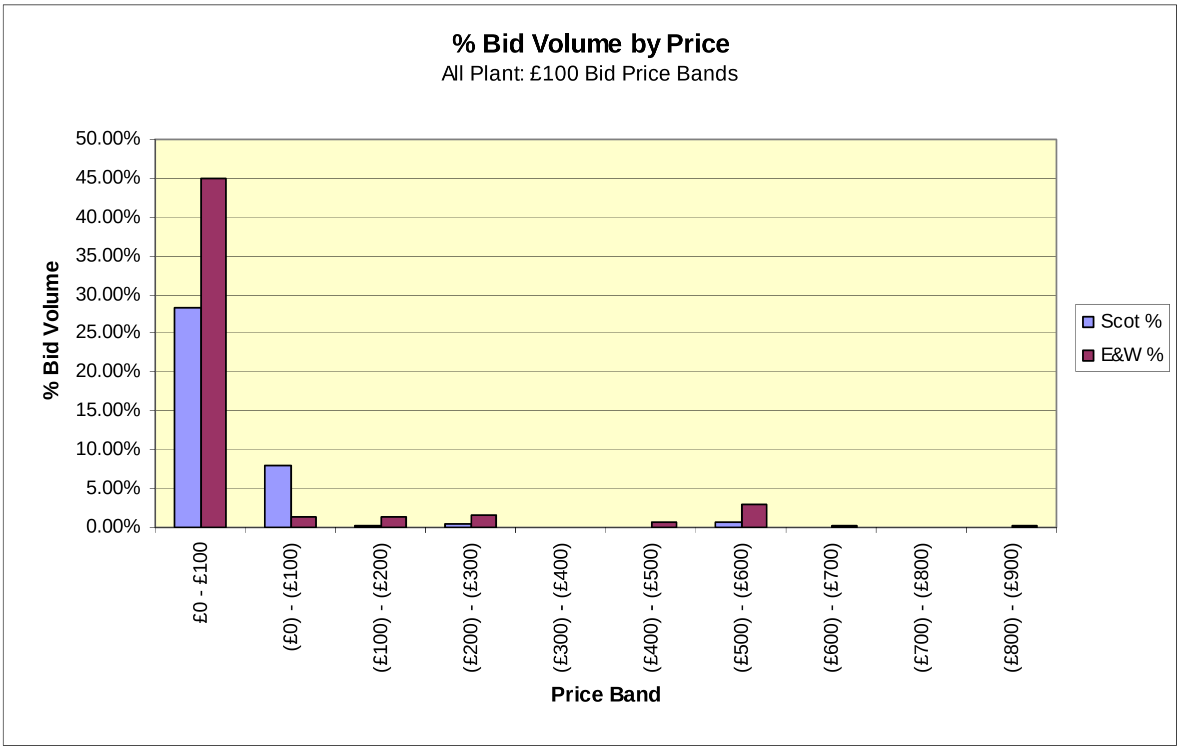


Figure 21 Bid spread

Table 9 below shows the results displayed in
Figure 21

Price	Scot Avg BP	E&W Avg BP	Scot %	E&W %
>=£100			0.00%	0.00%
£0 - £100	£20.25	£33.40	28.39%	45.01%
(£0) - (£100)	-£38.62	-£37.23	8.07%	1.44%
(£100) - (£200)	-£110.55	-£111.36	0.12%	1.44%
(£200) - (£300)	-£247.95	-£230.84	0.39%	1.59%
(£300) - (£400)	-£300.00	-£330.67	0.01%	0.11%
(£400) - (£500)		-£442.63	0.00%	0.60%
(£500) - (£600)	-£554.04	-£503.81	0.78%	2.97%
(£600) - (£700)	-£666.00	-£600.25	0.03%	0.20%
(£700) - (£800)	-£748.83	-£750.00	0.10%	0.03%
(£800) - (£900)		-£800.11	0.00%	0.26%
<=(£1000)			62.10%	46.36%

Table 9 Bid spread wide range

Further analysis of the critical volumes within the range +£100/MWh and -£100/MWh shows that 76% of England and Wales plant is offered in a range above £20, whereas in Scotland this figure is only 15%. These results are shown in
Figure 22 and
Table 10 below. At this granularity the differential in average price within the bands appear to be much less much less, however the volume offered at the more positive prices is much less in Scotland (i.e. at a granularity of the bands reduces to £1 the volume within the bands becomes more critical).

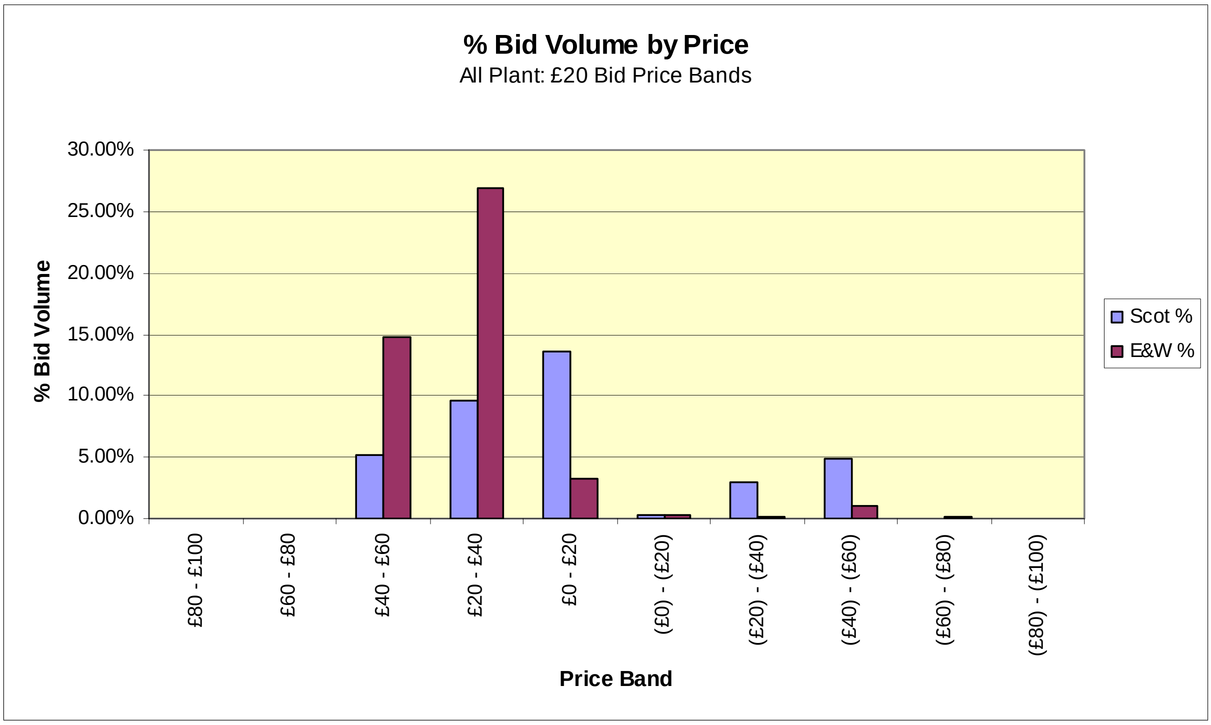


Figure 22 Bid spread close range

Price	Scot Avg BP	E&W Avg BP	Scot %	E&W %
>=£100			0.00%	0.00%
£80 - £100	£87.00	£85.64	0.00%	0.00%
£60 - £80	£63.35	£61.82	0.04%	0.05%
£40 - £60	£44.93	£45.53	5.19%	14.81%
£20 - £40	£27.63	£30.14	9.64%	26.85%
£0 - £20	£6.71	£8.93	13.52%	3.30%
(£0) - (£20)	-£10.11	-£9.69	0.23%	0.26%
(£20) - (£40)	-£20.14	-£27.45	2.99%	0.12%
(£40) - (£60)	-£40.03	-£49.93	4.81%	0.97%
(£60) - (£80)	-£60.00	-£64.41	0.03%	0.09%
(£80) - (£100)	-£99.00	-£95.25	0.00%	0.01%
<=(£100)			63.54%	53.55%

Table 10 Bid spread close range

The same analysis was performed purely on Coal & Gas plant, and therefore excluding potentially inflexible plant, such as Nuclear and wind, which could have the potential to skew results due to the relative volumes in each area. The results are shown below in

Figure 23 and
Table 11. This shows that even with the relatively inflexible plant excluded the comparison shows a similar profile.

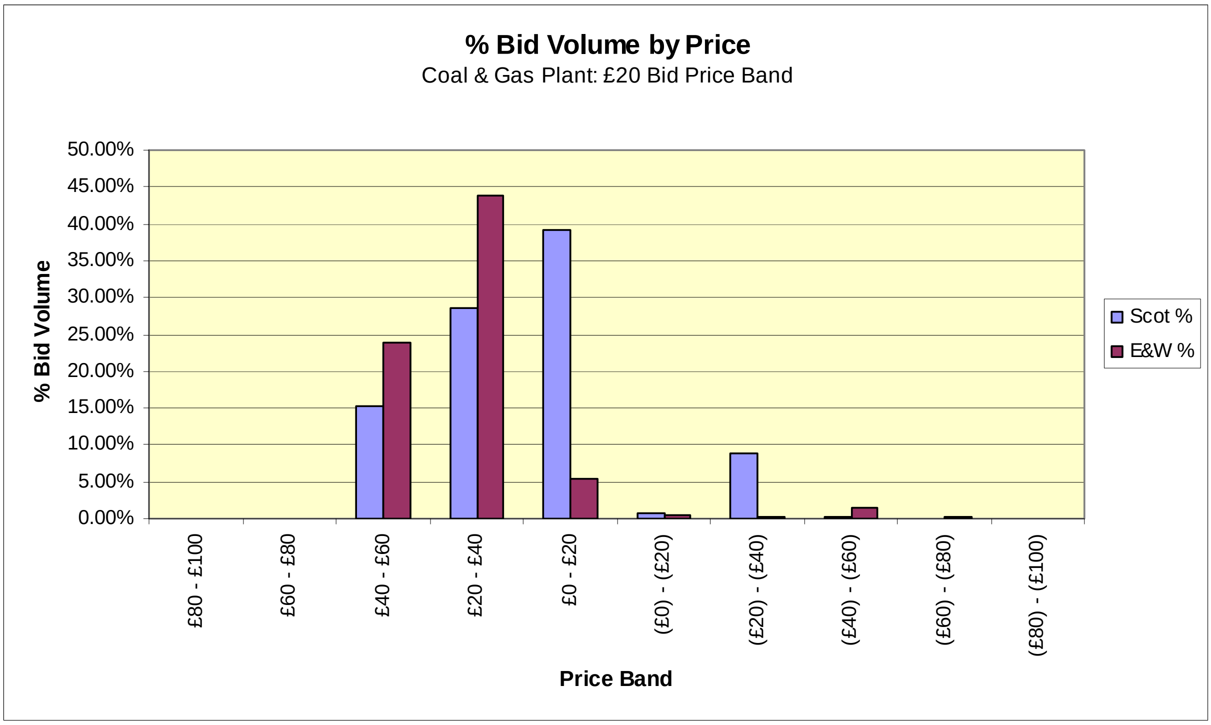


Figure 23 Bid spread for Coal and Gas

Price	Scot Avg BP	E&W Avg BP	Scot %	E&W %
>=£100			0.00%	0.00%
£80 - £100		£85.00	0.00%	0.00%
£60 - £80	£63.63	£61.65	0.11%	0.03%
£40 - £60	£44.81	£45.51	15.35%	23.81%
£20 - £40	£27.65	£30.13	28.61%	43.86%
£0 - £20	£7.16	£8.93	39.15%	5.38%
(£0) - (£20)	-£10.12	-£9.68	0.69%	0.42%
(£20) - (£40)	-£20.08	-£27.50	8.89%	0.19%
(£40) - (£60)	-£49.81	-£49.93	0.16%	1.58%
(£60) - (£80)		-£64.41	0.00%	0.14%
(£80) - (£100)	-£99.00	-£95.25	0.00%	0.01%
<=(£100)			7.03%	24.57%

Table 11 Bid spread for coal and gas

6. Conclusions

Locational BSUoS signals the cost of constraints to generators behind non-compliant transmission system boundaries, allowing them to be factored into the despatch decisions made by those generators.

Based on the range of merit orders constructed as part of this analysis, including those derived from historical running data and published prices and those constructed based on theoretical costs, the application of locational BSUoS would cause marginal thermal plant on the exporting side of non-compliant transmission system boundaries to drop out of merit and be replaced by marginal thermal generators on the importing side during constrained periods. This is based on our assumptions described in this report. If the actual difference between the marginal price of plant in Scotland and the wholesale energy price is greater than the forecast of Locational BSUoS there would be of course be no change in PN position.

The scenarios considered in both the analysis of actual data for 2008/09 and, in particular, the probabilistic analysis has demonstrated that the effectiveness of locational BSUoS at reducing constraint costs is reliant mainly upon:

(a) Generator's ability to forecast the timing and level of locational BSUoS charges;
(b) The likelihood that generators will reflect these charges into their price in the wholesale market.

If we assume that generators are able to predict the timing and level of locational BSUoS charges, and factor the recovery of these charges into their price in the wholesale market, then the application of locational BSUoS leads to a reduction in the level of constraint costs when compared to fully socialised BSUoS. This result was consistent across all scenarios, including a marginal cost and fixed plus marginal cost merit order, the closure of a marginal thermal plant in Scotland, bids reduced to 60% on the exporting side of the non-compliant transmission system boundary, and for a merit order based on a switch in the price of coal and gas.

As described in the conclusions report, National Grid is committed to providing as much information as possible to allow generators to forecast the timing and level of locational BSUoS charges.

The likelihood that generators will reflect these charges into their price in the wholesale market will be dependent upon a number of factors including the potential lack of liquidity in the short-term market, dynamics of plant across a portfolio and the ability of users to exercise market power. The ability of users to exercise market power has been explored by reference to their financial incentives.

Our analysis of historic bids shows a high market concentration behind the Cheviot boundary, and identifies differences between the bid prices offered on each side of the boundary. Our scenario analysis shows that generators behind a non-compliant transmission boundary that are able to exercise market power in the pricing of bids in the Balancing Mechanism with socialised BSUoS will still be able to do this following the application of locational BSUoS.

Locational BSUoS would either reduce the profits associated with exercising market power or require users with market power to reduce bid prices in the Balancing Mechanism even further to maintain profits, with the reduction in bid required being related to market share behind the non-compliant transmission boundary and the share of the constraint. To maintain full recovery would require bid prices to change by a level that should be noticeable with respect to similar plant.

We have also analysed the impact of locational BSUoS on the theoretical wholesale energy price. Our analysis, based both on historic data and probabilistic analysis, shows a minimal change in the wholesale price. In most cases, the application of locational BSUoS causes a slight reduction in the wholesale energy price due to the reduction in socialised costs faced by marginal generators on the importing side of the non-compliant transmission boundary, however, these results are heavily sensitive to the assumptions we have made about the merit order.

For the cases which show an increase in the wholesale price, we have concluded that these increases are caused by capacity issues in the market, with the recovery of the fixed costs of peaking plant moving from the Balancing Mechanism to the wholesale market. With each party seeking to manage their future commercial positions by selling energy forward, we believe that this scenario, which involves the recovery of the marginal generator’s fixed costs in the wholesale market may represent an overly simplistic view.

Our analysis shows that a more cost reflective BSUoS methodology is likely lead to changes in the basic ranking order. If these changes are realised in the despatch merit order directly associated constraint cost will be minimised. If changes are not passed through to the despatched merit order or the signal is not sufficient to have an impact on the ranking order, the proposed change still better meets the objective of charges that reflect the costs incurred in providing a service.

This analysis confirms that conclusions described in the GB ECM-18 report, that the introduction of locational BSUoS would better meet the relevant charging objectives.

Annex 1 - Background to the probabilistic model developed by National Grid

This note describes the process that the spreadsheet model uses to calculate constraint costs together with the associated key assumptions in further detail.

Generation Studies

The actual generation background for 2008/09 has been used in all studies.

Demand

In order to model a year of operation, 500 simulations have been used.

Annual demand has been assumed to be 343TWh, with a peak of 60GW (including losses) in all studies. The full demand/duration curve for the year has been modelled as a number of representative blocks across the following seasons:

- Winter high (18 blocks);
- Winter low (13 blocks);
- Summer high (13 blocks); and
- Summer low (7 blocks).

The demand level in each of the 500 simulations has been sampled from a discrete distribution which is based on the demand blocks and their associated duration (or probability).

Generation availability

All generators have been grouped into categories shown in the table below, and generation availability in each of the 500 simulations has been sampled based on the typical distributions shown for each category.

Generation category	Distribution	Min	Most likely	Max	Mean		Standard Deviation
					High demand	Low demand	
Other renewables	Binomial				85%		
Base gas	Binomial				85%		
Marginal gas	Binomial				85%		
Base coal	Binomial				75%		
Marginal coal	Binomial				75%		
France					100%		
Nuclear	Binomial				70%		
Peakers (mainly oil & OCGT)	Binomial				85%		
Water	Normal				60%	5%	4%
Pumped storage	Binomial				90%	15%	
Wind	Triangular	5%	20%	80%	35%		

In order to model the effect of weather systems on adjacent windfarms, a 60% correlation has been assumed for the output from windfarms in adjacent transmission system areas (or zones).

Generation "merit order"

In order to model the theoretical efficient energy market outcome for each of the 500 simulations, a static generation merit order has been constructed based on the generation categories listed above.

This merit order is described further in section 4.2.2.

It should be noted that the constraint cost results are highly sensitive to merit order assumptions.

Unconstrained schedule

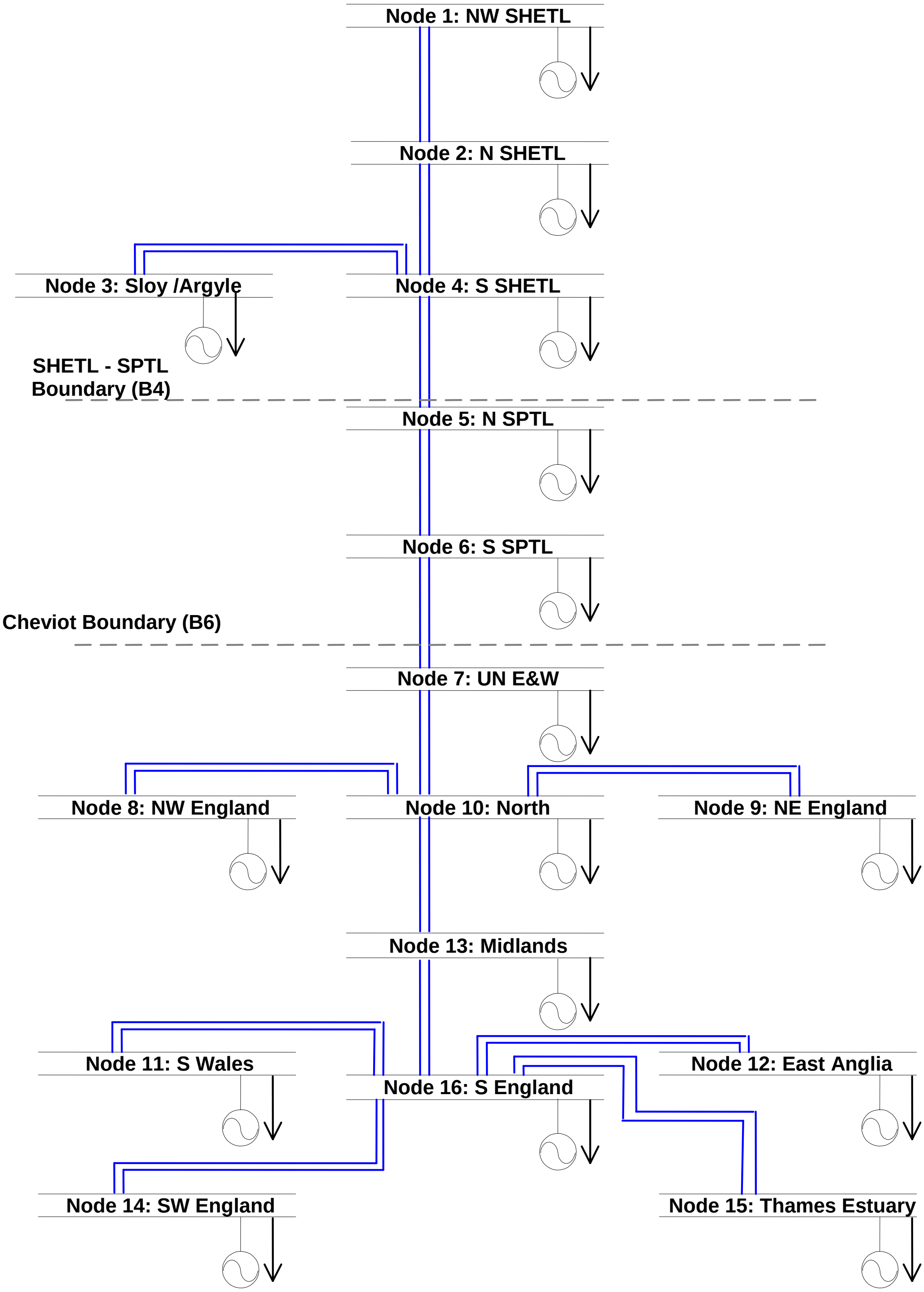
For each of the 500 simulations, an optimisation is performed to calculate the unconstrained generation schedule (the theoretical efficient energy market outcome). The optimisation seeks to minimise fuel cost subject to the condition that total generation = total demand.

This is purely an energy balance schedule and takes no account of the capability of the transmission system. It should be noted that the final results have been found to be very sensitive to merit order assumptions.

Transmission network

The network model used in this analysis is a highly simplified 16 node representation of the GB Transmission System (shown in the diagram below).

16 node representation of the GB Transmission System



The capability of the transmission system is represented by the boundary capabilities (in MW) between nodes (e.g from none 1 “NW SHETL” to node 2 “N SHETL”).

For the purposes of this analysis, the boundary between node 6 and node 7 (the Cheviot boundary) has been set to either the actual or SQSS compliant level with all other boundaries set to very high capabilities such that the only constraints considered are those on the Cheviot boundary.

	Actual	**SQSS compliant**
Cheviot boundary	2200MW	3300MW

Transmission outages

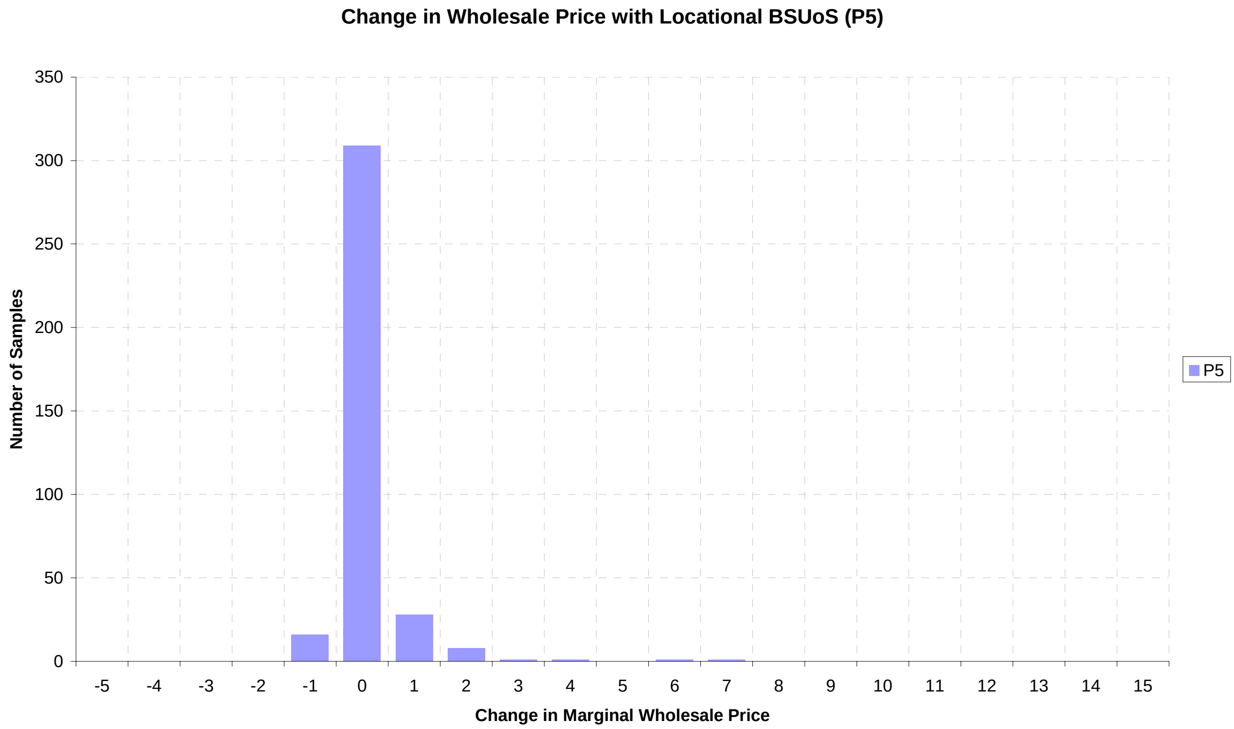
The capabilities shown on the table above represent the normal winter intact boundary capabilities. In order to model the effects of transmission system outages, 12 weeks of outage at a capability of 1760MW (80%) has been assumed for the Cheviot boundary. The value of 80% was originally chosen as generic across all boundaries and so understates the impact on a single boundary.

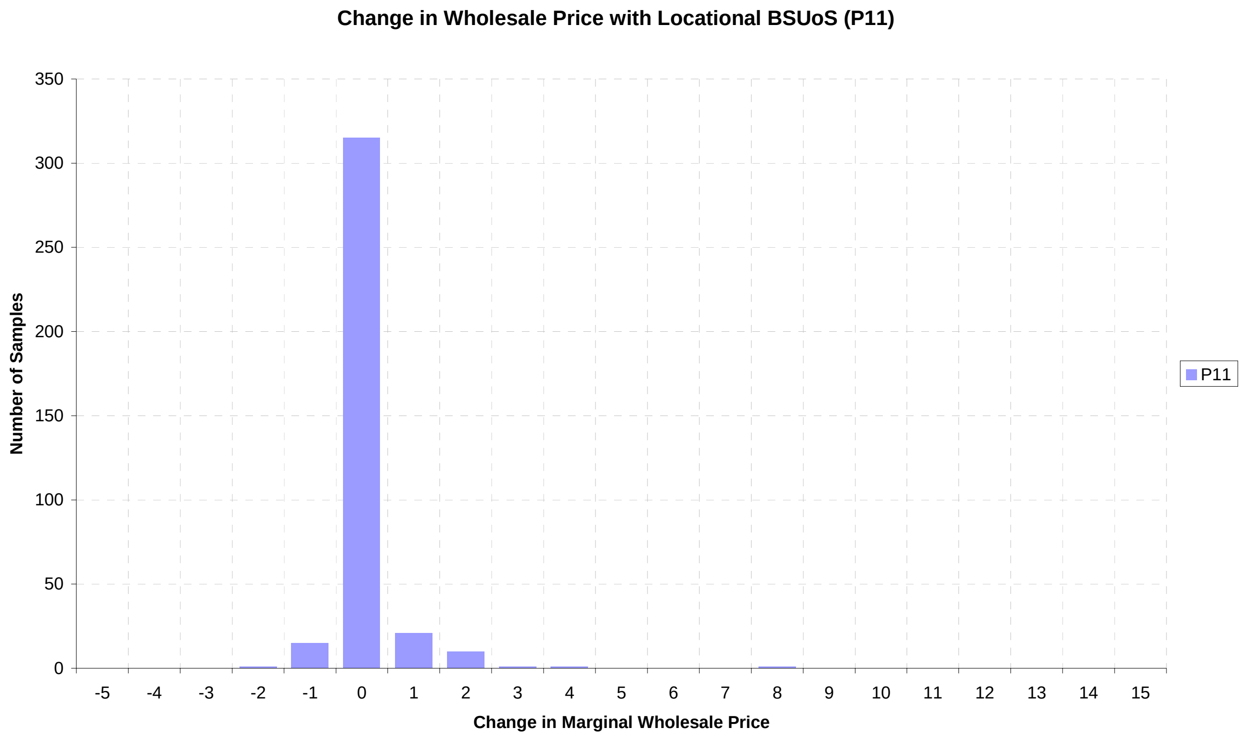
Constrained schedule

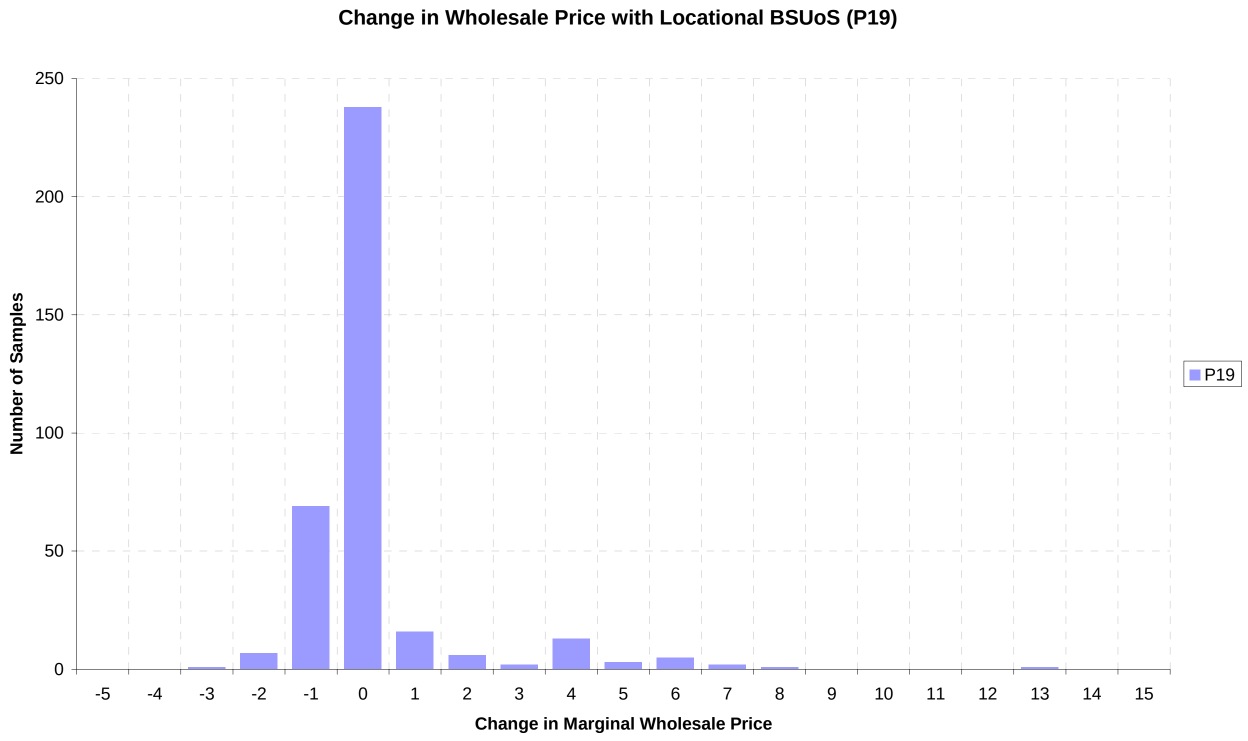
The unconstrained generation schedule described above is then superimposed on the model of the transmission system with the relevant transmission system boundary capabilities.

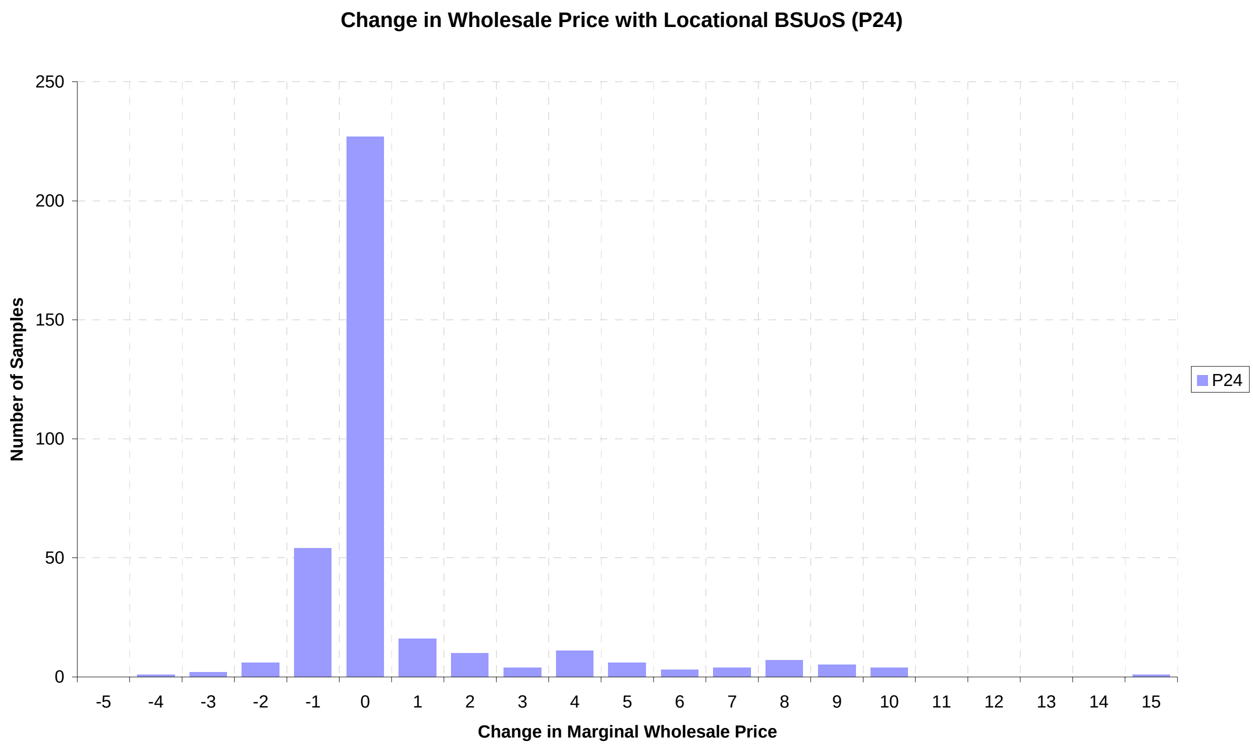
A further optimisation is then performed to calculate constraint costs. The optimisation seeks to minimise balancing costs (sum of bid/offer receipts/costs) subject to the transmission system limits on circuit flows.

Annex 2 - Charts for Results by period

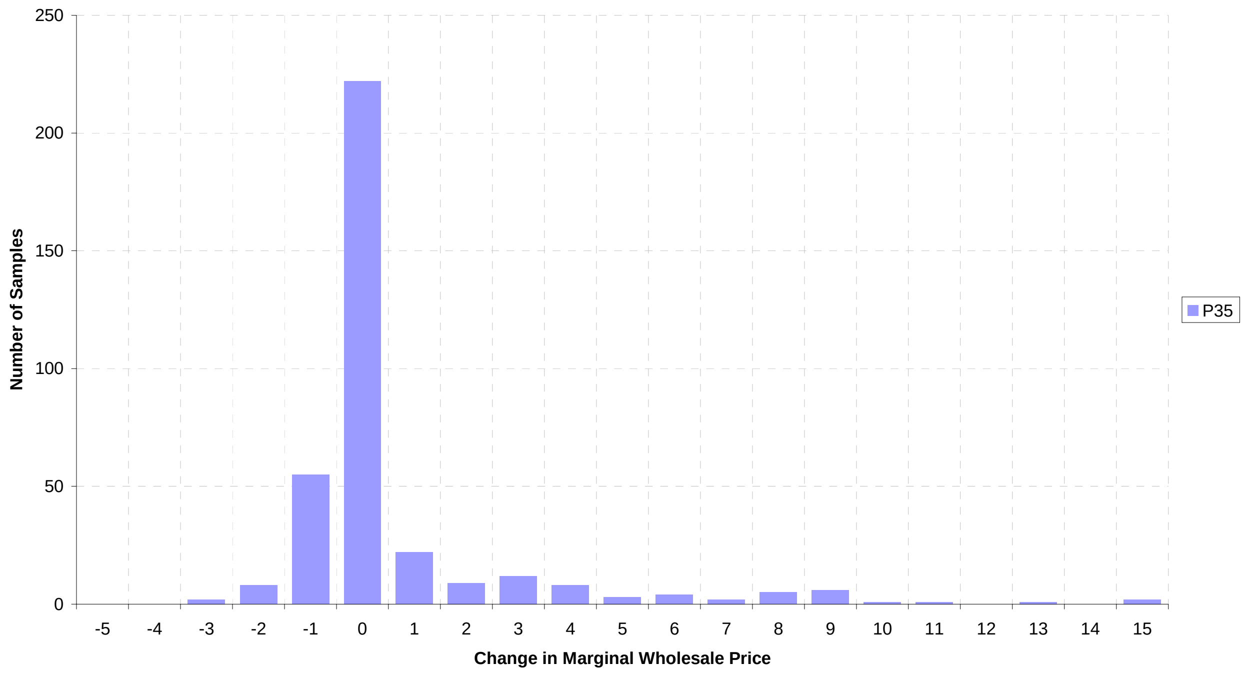




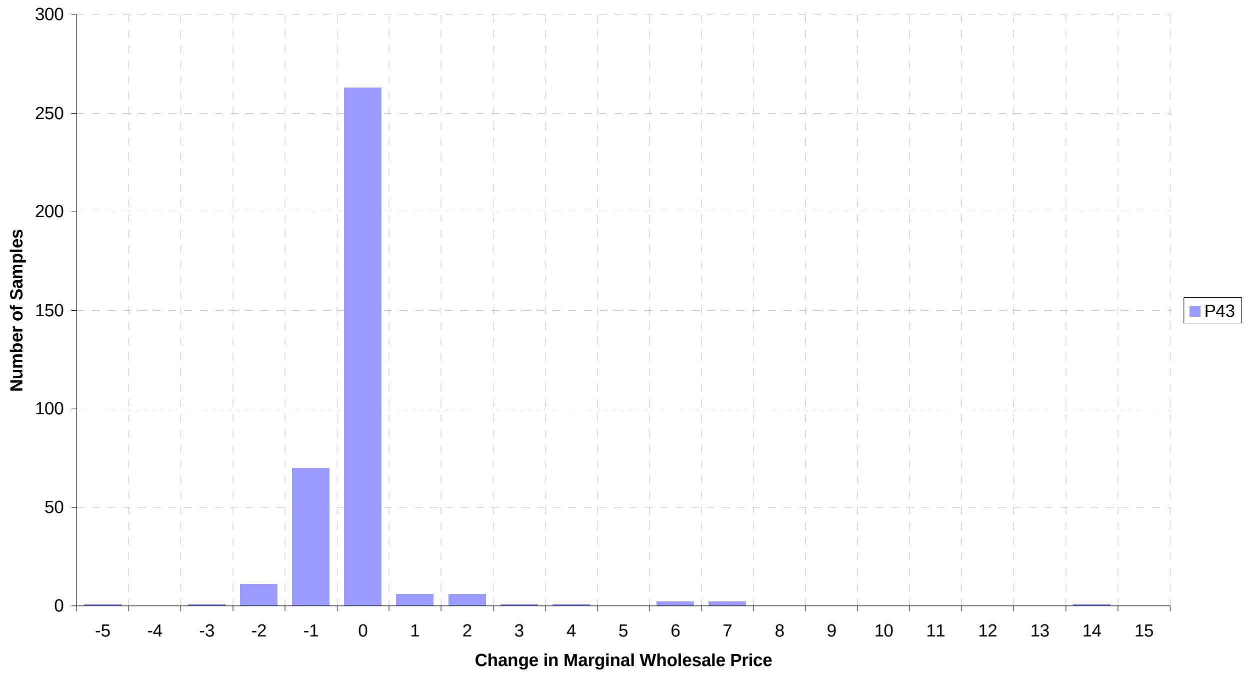

Change in Wholesale Price with Locational BSUoS (P19)
Number of Samples
250
200
150
100
50
0
-5
-4
-3
-2
-1
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
Change in Marginal Wholesale Price
P19


Change in Wholesale Price with Locational BSUoS (P24)
Number of Samples
250
200
150
100
50
0
-5
-4
-3
-2
-1
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
Change in Marginal Wholesale Price
P24

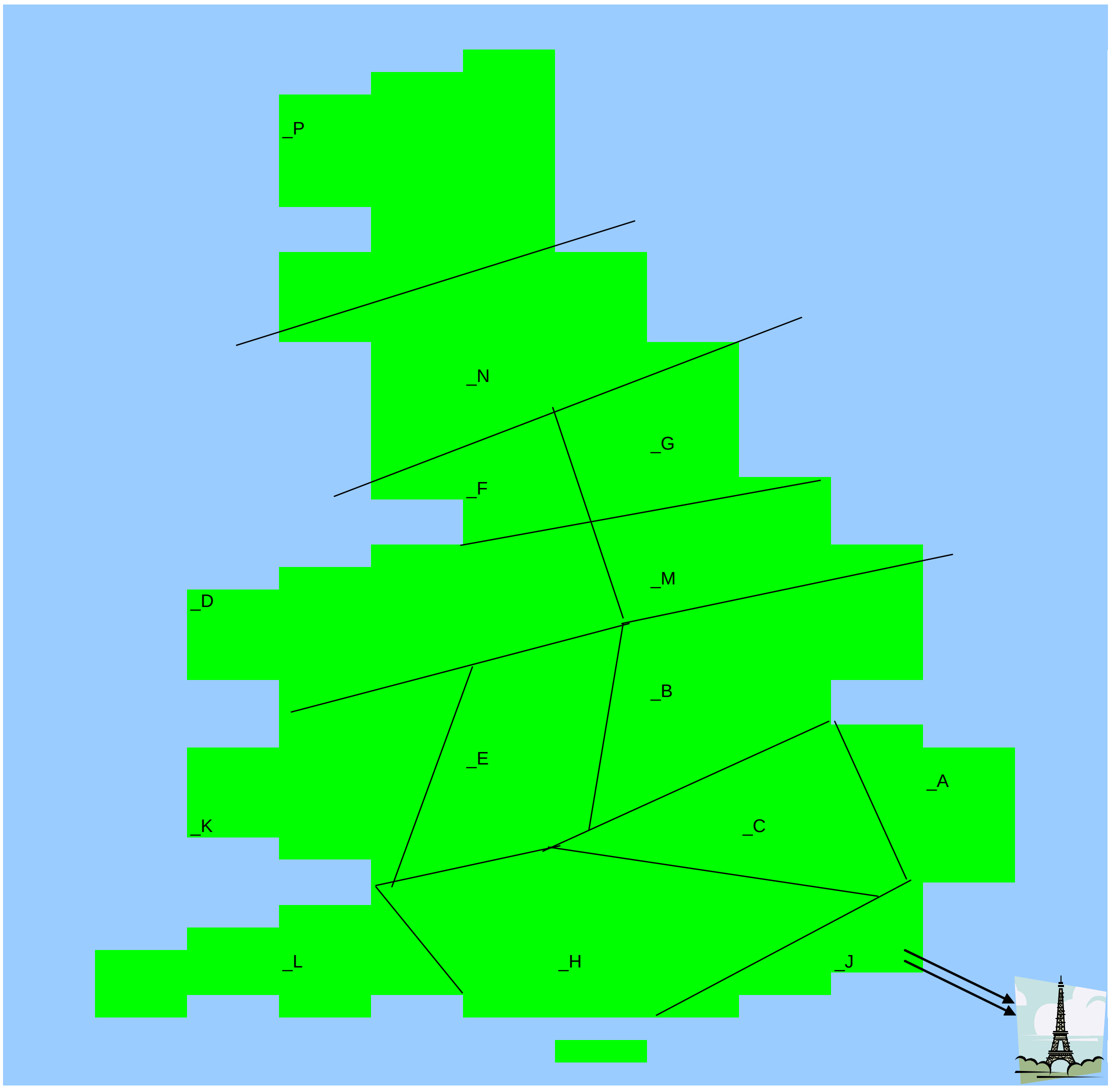
Change in Wholesale Price with Locational BSUoS (P35)



Change in Wholesale Price with Locational BSUoS (P43)



Annex 3 - BRM zones for 08/09 analysis



Annex 4- Results by Period for alternative merit order

Breaking the results down in to the separate settlement periods studied shows that off-peak (P5, 11, 43) Locational BSUoS results in a small decrease in the mean marginal price, however across the peak, when demand is higher and therefore there is less spare capacity, the opposite happens.

P5	Without LB	With LB
Mean	45.91	45.79
Mode	53.00	53.00
Median	47.18	47.12
Skew	-0.68	-0.72
Kurtosis	-0.11	-0.05

P11	Without LB	With LB
Mean	44.73	44.65
Mode	27.00	26.00
Median	46.01	45.81
Skew	-0.51	-0.55
Kurtosis	-0.45	-0.41

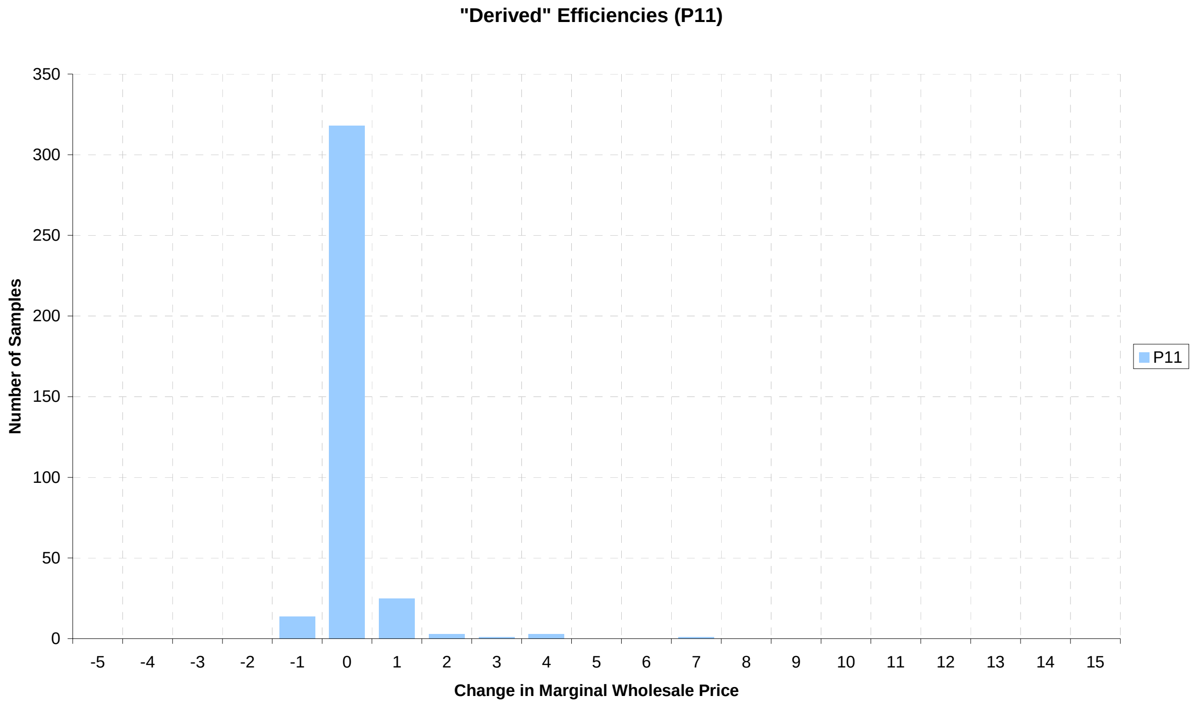
P19	Without LB	With LB
Mean	50.04	50.30
Mode	43.00	43.00
Median	50.35	50.40
Skew	5.69	5.20
Kurtosis	73.80	64.88

P24	Without LB	With LB
Mean	50.64	51.34
Mode	47.00	43.00
Median	50.55	50.75
Skew	5.43	4.56
Kurtosis	69.06	52.73

P35	Without LB	With LB
Mean	69.84	70.38
Mode	59.00	58.00
Median	53.45	54.10
Skew	2.89	2.86
Kurtosis	7.40	7.31

P43	Without LB	With LB
Mean	48.59	48.53
Mode	45.00	53.00
Median	49.62	49.84
Skew	-0.47	-0.45
Kurtosis	0.01	0.01

The charts show that the most common outcome of applying Locational BSUoS to the derived efficiency merit order is for there to be no change in wholesale price. However, there are a number of occasions where marginal wholesale price did increase. Although this increase is predominantly of the order of £1/MWh there are a relatively small number of samples where the price increased by more than £3/MWh.


"Derived" Efficiencies (P11)
Number of Samples
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50
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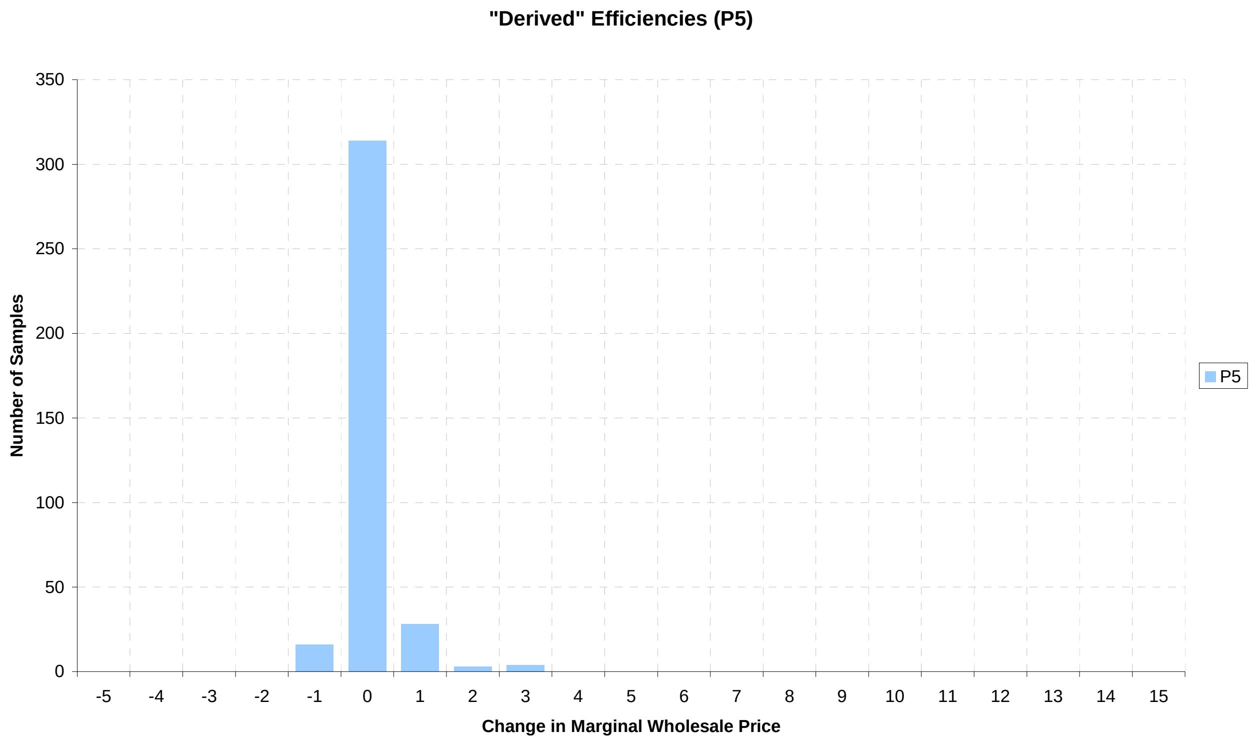
Change in Marginal Wholesale Price
P11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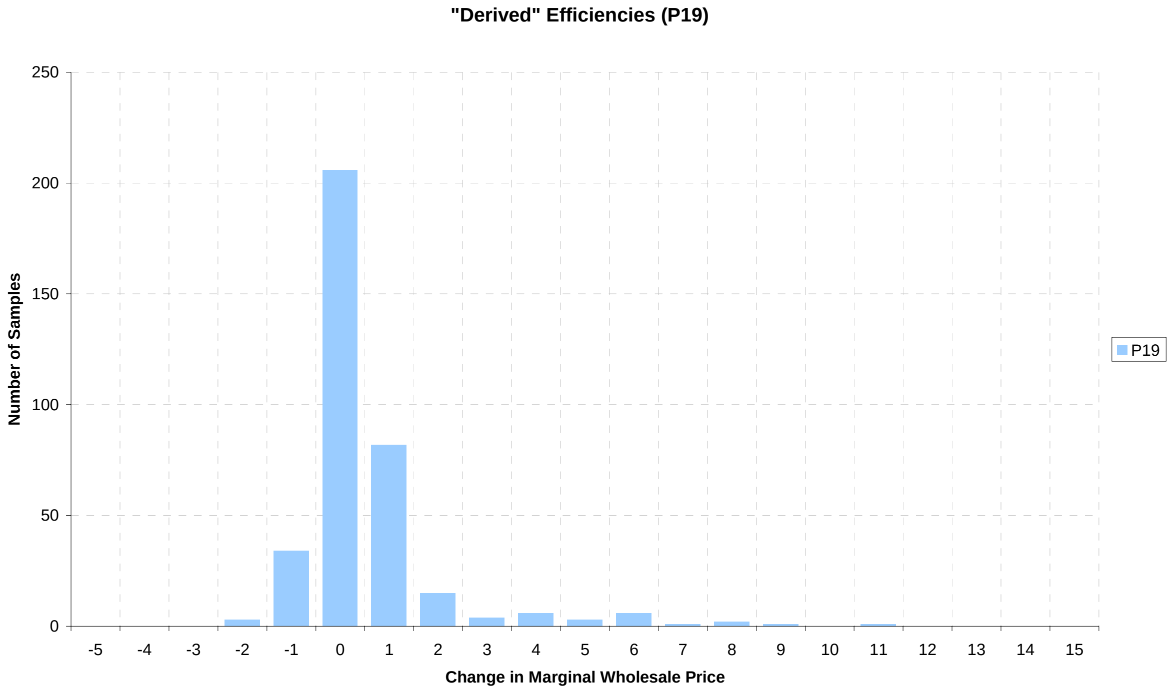
Change in Marginal Wholesale Price
P5


"Derived" Efficiencies (P19)
Number of Samples
250
200
150
100
50
0
-5
-4
-3
-2
-1
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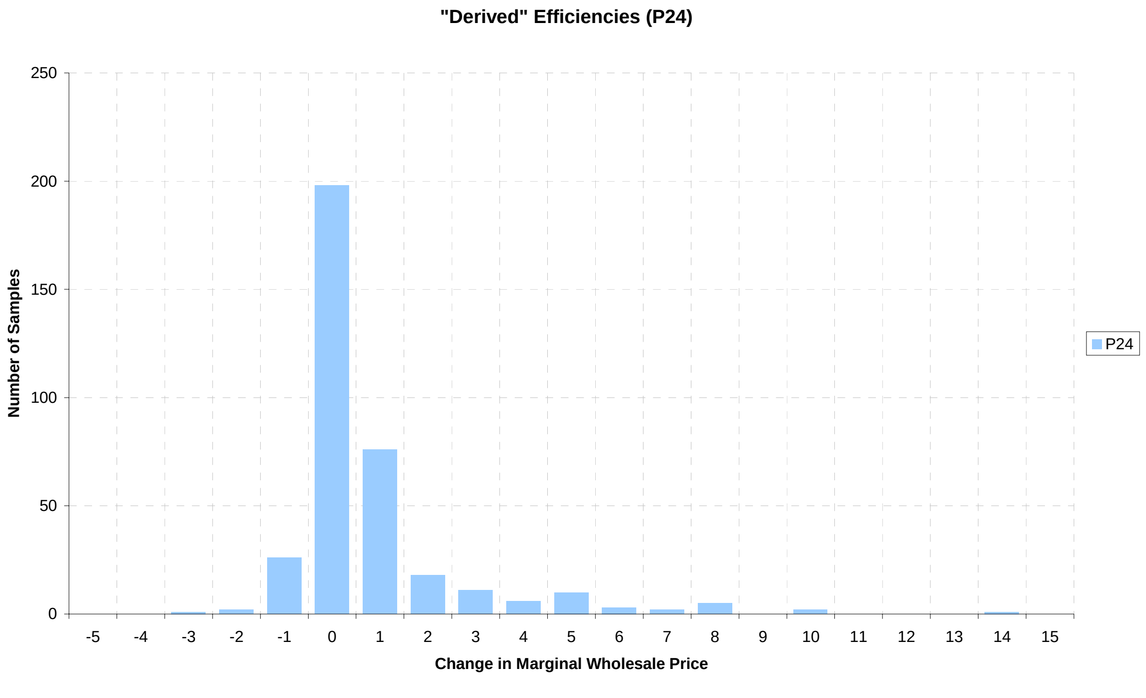
11
12
13
14
15
Change in Marginal Wholesale Price
P19


"Derived" Efficiencies (P24)
Number of Samples
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50
0
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-4
-3
-2
-1
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9
10
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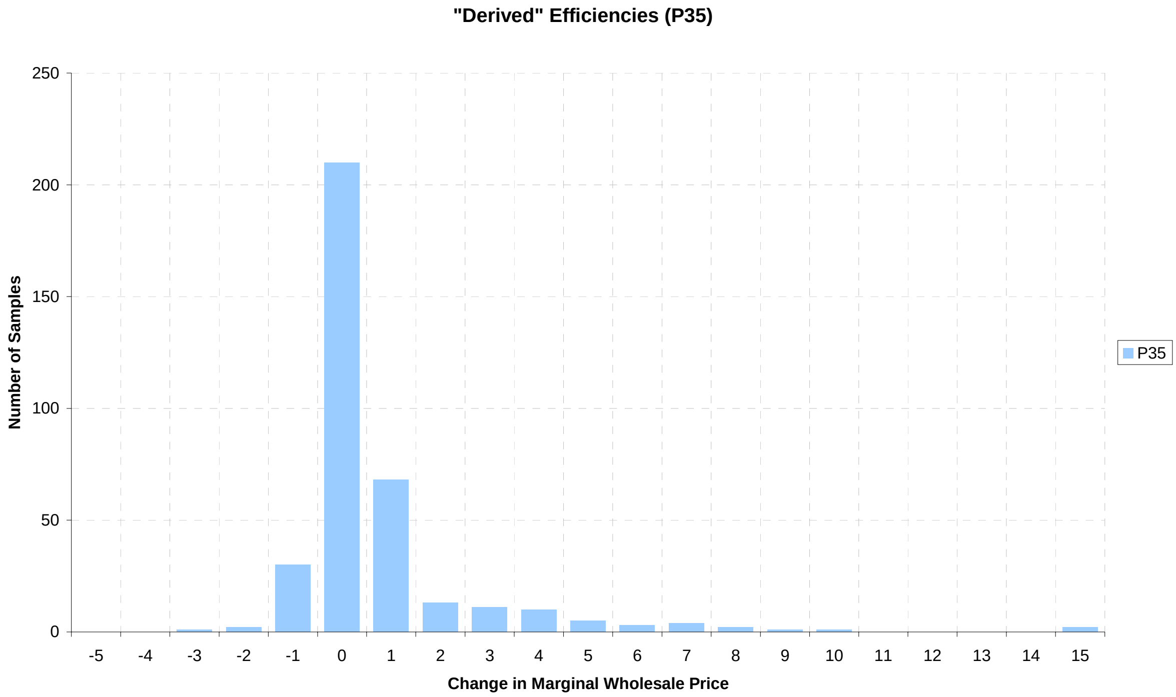
12
13
14
15
Change in Marginal Wholesale Price
P24


"Derived" Efficiencies (P35)
Number of Samples
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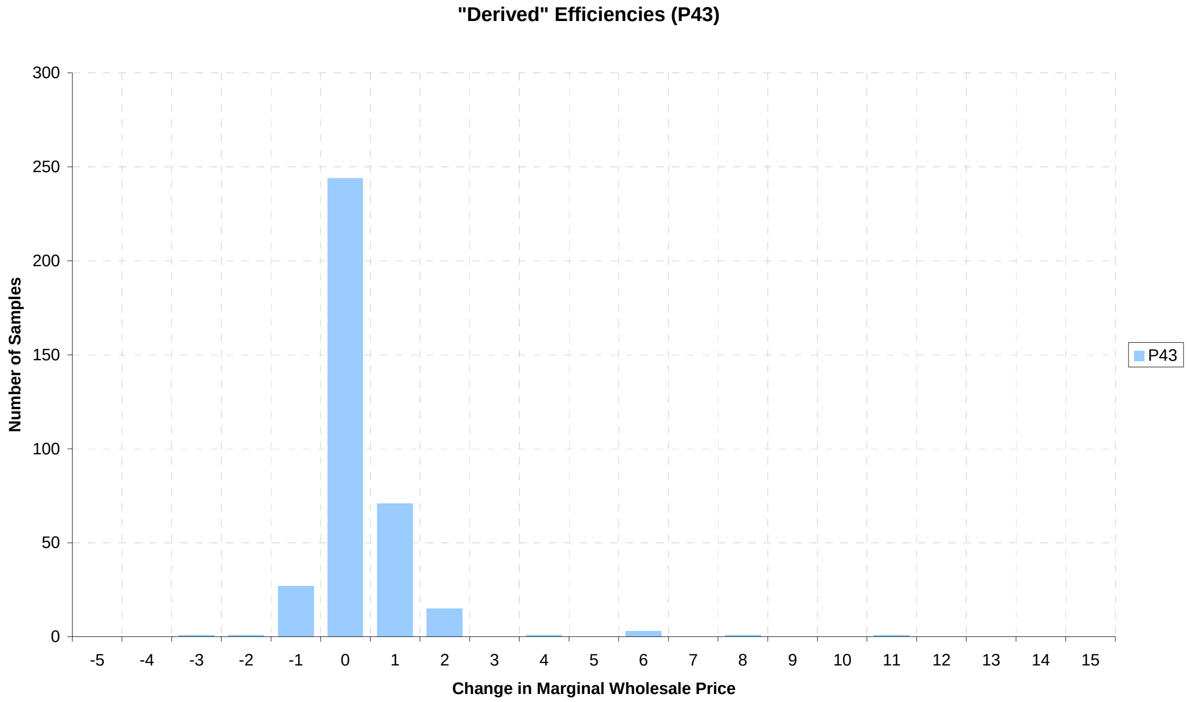
200
150
100
50
0
-5 -4 -3 -2 -1 0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15
Change in Marginal Wholesale Price
P35


"Derived" Efficiencies (P43)
Number of Samples
300
250
200
150
100
50
0
-5 -4 -3 -2 -1 0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15
Change in Marginal Wholesale Price
P43