University College Dublin

THE PRICE AND DISPATCH IMPACT OF A CENTRALISED WHOLESALE ELECTRICITY MARKET IN IRELAND

A report to CER

April 2003

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1. INTRODUCTION AND SUMMARY

Background

1.1 The Commission for Energy Regulation (CER) is undertaking a review of the electricity trading arrangements in Ireland. The review will result in a set of electricity trading arrangements which will apply to a fully opened electricity market, once the present transitional arrangements have expired in 2005. The high level principles of the future market are to be decided shortly.

1.2 The Commission has already indicated its preference for a centralised trading market, in which all physical power[1] is traded through a 'gross pool'. Half-hourly market prices may be determined for the market as a whole (known as uniform pricing), or for different points on the system (known as locational pricing). Alternatively, there may be a mix of uniform prices for suppliers (and their customers) with locational prices for generators. Differences arise between prices at different locations because of transmission constraints and energy losses on the electricity grid. In the case of a single uniform price, the impact of transmission constraints is ignored in pricing[2] and losses are assumed to be spread evenly across the system.

1.3 Another feature of the preferred market design is that there is no separate, explicit mechanism for rewarding the provision of available generating capacity[3] to the system. The preferred design is therefore for an 'energy-only' market, in which generators only receive revenue from the pool when they actually operate; there is no additional payment for making capacity available which might not necessarily run. It is anticipated that, in this energy-only market, prices will rise to reflect the value of available capacity at times when there is a potential shortage – i.e. when demand is high and/or there are a number of plant outages. In this way it is anticipated that generators will earn sufficient net revenue to keep plant open and/or to bring forward new plant (depending on the needs of the system at the time).

1.4 We have been commissioned by CER to analyse how such a market would operate, given the structure of the Irish electricity sector. The most significant feature of this structure is the dominance of ESB Power Generation (ESB PG). For example, in our central view of the position in the year 2006, we project that ESB PG will retain a 67% share of the generation market. It is important to note that our analysis takes this market dominance as a given.

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1 Possibly bar some de minimis exceptions.

2 At least ahead of real-time.

3 Or of demand reduction.

1.5 The work which we have undertaken to fulfil CER's commission is best described as an independent research study. We do not dwell upon the principles of electricity market design; rather we present the outputs from quantitative analyses so as to assist interested parties to make their own judgments about the new trading arrangements.

1.6 We have focused our analysis on the year 2006, for two reasons:

- it will be early in the life of the new fully opened market, which will be introduced in 2005; and
- ESB National Grid (ESB NG) is currently undertaking works aimed at enhancing the network. One outcome of these improvements is that the present level of voltage constraints on the network may be relieved; these works are expected to have been completed by 2006.

Market scenarios

1.7 As a first step in our analysis we have developed eight alternative scenarios for the behaviour of ESB PG in the market, in the first instance assuming uniform pricing throughout. The scenarios are defined as combinations of:

- the general level of price which emerges, expressed as a time-weighted average (TWA) of all the half-hourly prices over 2006;
- the extent to which ESB PG's bids into the market might generally be higher than the energy bids which would be expected in an atomistic market[4]; and
- the degree to which ESB PG might raise its bids further at times of high demand, to reflect the price pattern which might be expected from an energy-only market (without an explicit mechanism for rewarding available capacity).

1.8 The combinations which define our eight market scenarios are displayed in Table 1 below.

[4] Which, for each generating unit, would generally be at its SRMC (short-run marginal cost) of generation at most times of the day and year.

Table 1 – Market scenarios

TWA price (€/MWh)	General % by which ESB PG bids exceed SRMC bids[5]	% of half-hours over which VoC is spread
45	0	20%
45	0	10%
45	0	5%
45	25%	20%
45	25%	10%
45	25%	5%
51	43%	10%
55	60%	10%

1.9 The TWA prices have been selected as follows:

- €45/MWh is the Best New Entrant (BNE) price[6] which underpins the present transitional regime for top-up power. It also corresponds to our own view of the base-load price which would be required by a generic new-entrant CCGT (combined-cycle gas turbine) in 2006. A TWA price of €45/MWh would therefore be consistent with a competitive market in equilibrium with new entry by CCGTs;
- a TWA of €51/MWh corresponds to the revenue which is effectively allowed to ESB PG at present, through the wholesale component in the price control on supply to the franchise market; and
- the €55/MWh has been chosen so that, together with the €45/MWh, it brackets the current €51/MWh.

1.10 In each scenario, the relevant TWA is achieved by applying a combination of two factors to the bids which would be expected in an atomistic (every generation station atomised to create a highly competitive environment) market. The first factor is a percentage by which ESB PG's bids are higher than the corresponding SRMC energy bids for its plants. Such a bid factor leads to prices which vary smoothly over the year.

5 Strictly speaking, this is the percentage ESB PG bids exceed their SRMC less start costs.

6 When calculated from the ILEX central view for gas prices in the year 2006.

1.11 The second factor is a value of capacity (VoC), which is spread over the half-hours of highest demand in the year. The VoC reflects the addition to price which might be anticipated, in an atomistic energy-only market, in order to reward the provision of available generating capacity. Depending on the scenario, the absolute value of the VoC is either:

- at the level which would be required to just incentivise new entry by a peaking plant[7] (in the €51/MWh and €55/MWh scenarios, in each of which the bid above SRMC is a residual calculated so as to achieve the required TWA price); or
- at a level which, when combined with the pre-selected percentage bid above SRMC, gives the required TWA price (in each of the €45/MWh scenarios).

1.12 The VoC is distributed across the half-hours in the year according to the following rules:

- it only applies in the Y% of half-hours with the highest demand; Y is 5%, 10% or 20%, depending on scenario; and
- in each of those half-hours, its value is proportional to the extent to which the demand in that particular half-hour exceeds the lowest demand over all the Y% of half-hours.

1.13 This process simulates a type of bidding behaviour by ESB PG (who currently own all the mid-merit and peaking plant and therefore would be expected to own the marginal price setting plant on most occasions), which would lead to 'peaky' prices, concentrated at times of high demand. We consider that the price pattern which results from a Y of 10% most closely reflects what might be anticipated from an atomistic energy-only market.

Overview of analysis

1.14 We have separately addressed a market with uniform pricing and one with locational pricing. Our analysis of uniform pricing focuses on:

- the pattern of half-hourly prices over the year, for each of our eight scenarios;
- the implications of these prices (together with the corresponding dispatch patterns) for generators;
- the impacts of the price patterns on differing classes of customer; and
- the effect on ESB PG of putting contracts[8] in place to cover the majority (80%) of its output; the half-hourly strike prices and volumes in these contracts are taken from our €45/MWh TWA scenario with no bid above SRMC and a Y of 10%.

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7 Assumed to be an OCGT (open-cycle gas turbine).

8 Known as 'vesting contracts', in the form of Contracts for Differences (CfDs).

1.15 For our analysis of locational pricing we have concentrated on one of our eight scenarios (that with a TWA of €51/MWh), to investigate:

- the degree of variation in prices between locations, at different times throughout the year;
- the differing impacts upon locational prices of building a new 400MW CCGT either in the south-west of the country or in the Dublin area; and
- the extent to which locational prices might be disturbed due to plant outages at power stations sited at particularly sensitive locations in the transmission system.

1.16 We describe our analysis in this report, which is organised as follows:

- Section 2: the development and definition of our market scenarios, in detail;
- Section 3: our modelling methodology, covering electricity demand (including locational demand), generator bidding, our 'LMP Model' for the calculation of locational prices, and the data and assumptions used to model the ESB NG network. Over all these aspects we identify a central view of what the position may be in 2006;
- Section 4: the findings from our analyses of pricing and dispatch under uniform pricing; and
- Section 5: the outcomes from our analyses of locational pricing.

Detailed technical descriptions and data are presented in Annexes to this document, and in a separate Appendix.

1.17 In the sub-sections below we present the key findings from our work.

Prices and dispatch with uniform pricing

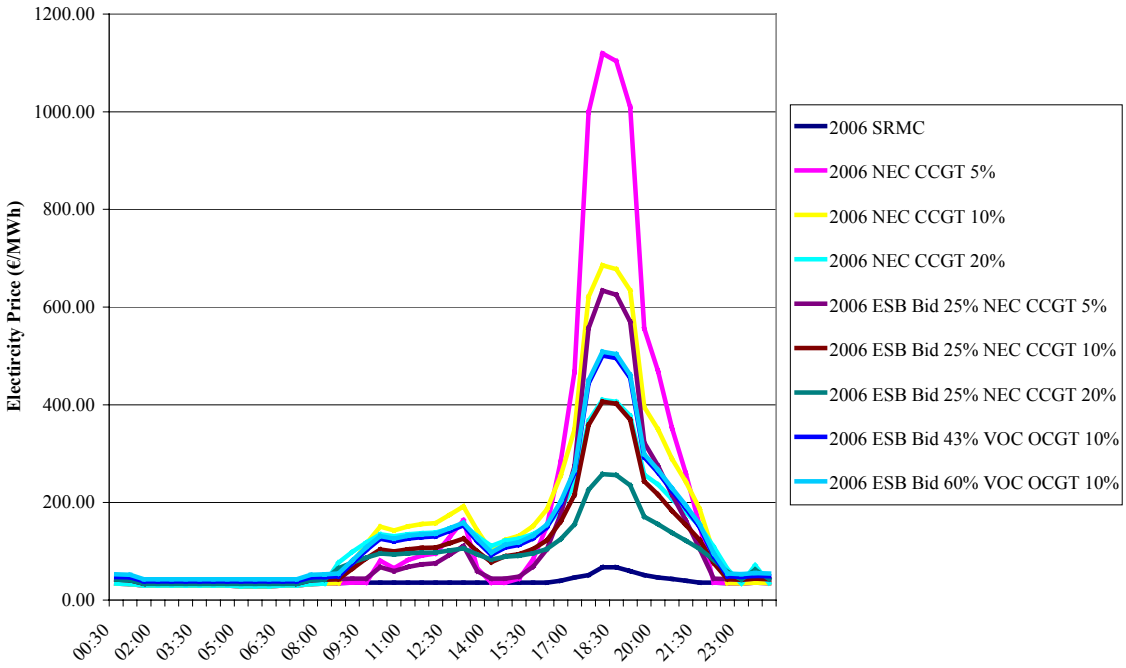
1.18 We have run the non-locational model for eight scenarios presented above. As a comparison we have also presented a case with no value of capacity or bidding above SRMC– labelled the SRMC case[9].

Electricity price projections

1.19 The electricity price profiles under all scenarios for the peak day are shown in Figure 1. This clearly shows that the peakiest prices will occur in the scenario with no uniform bidding up over the year and with the VoC spread over only the 5% of highest demand half-hours. The range in prices between the eight scenarios is over €1000/MWh at peak.

[9] Note: SRMC-only bidding is not a sustainable outcome in the long run, as fixed costs would not be covered. The SRMC case is provided only as a base case.

Figure 1 – Peak day prices



Source: ILEX analysis.

1.20 The price duration curves (PDCs) under the six NEC CCGT (€45/MWh) cases are shown in Figure 2 and Figure 3.

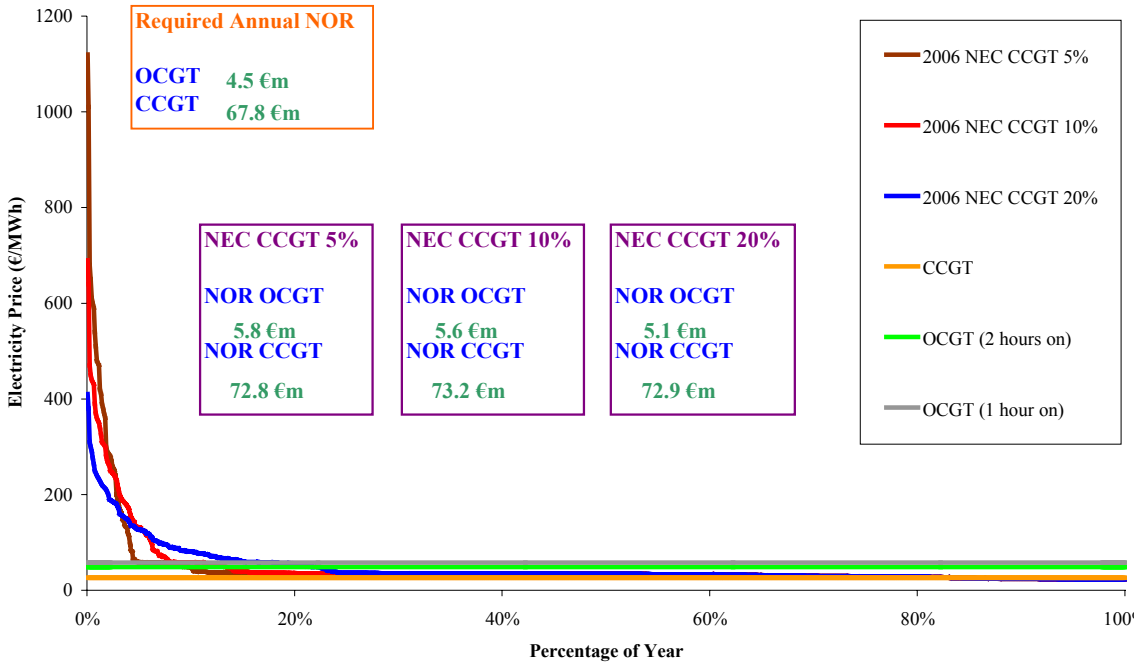
1.21 On each chart we have also included the short-run marginal costs (SRMC) for a CCGT[10] and an OCGT. For the OCGT we have shown the SRMC for an OCGT operating for one hour and for an OCGT operating for two hours.

1.22 The area under each PDC above the short-run marginal cost for a CCGT or OCGT is equivalent to the net revenue this plant would receive to cover all their fixed and capital costs. On each chart we show the net revenue a CCGT and an OCGT[11] would receive under each scenario (for plant sized at 400MW and 50MW respectively), and compare this with the net revenue required by that plant each year to be economically viable.

10 We have used the ILEX CCGT new entrant assumptions. If we were to use the CER BNE the marginal costs would be higher but the required net revenues to cover fixed and capital costs would be lower.

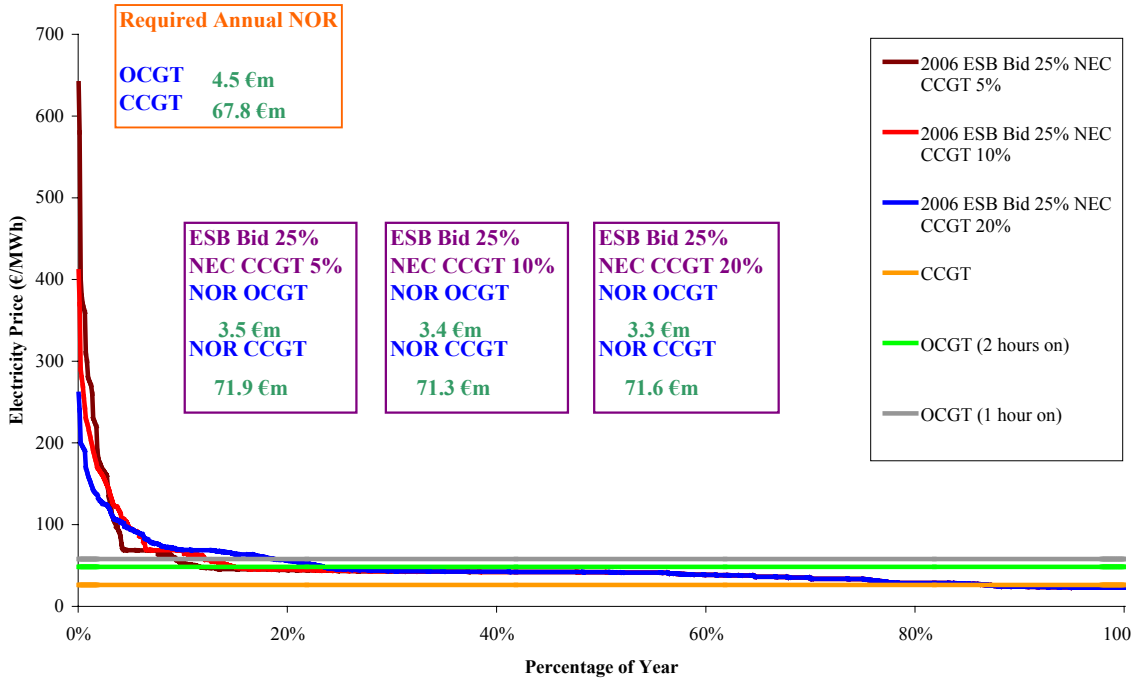
11 Assuming that the plant incurs one start per hour of operation.

Figure 2 – PDC for NEC CCGT 0% ESB PG bidding cases



Source: ILEX analysis.

Figure 3 – PDC for NEC CCGT 25% ESB PG Bidding cases



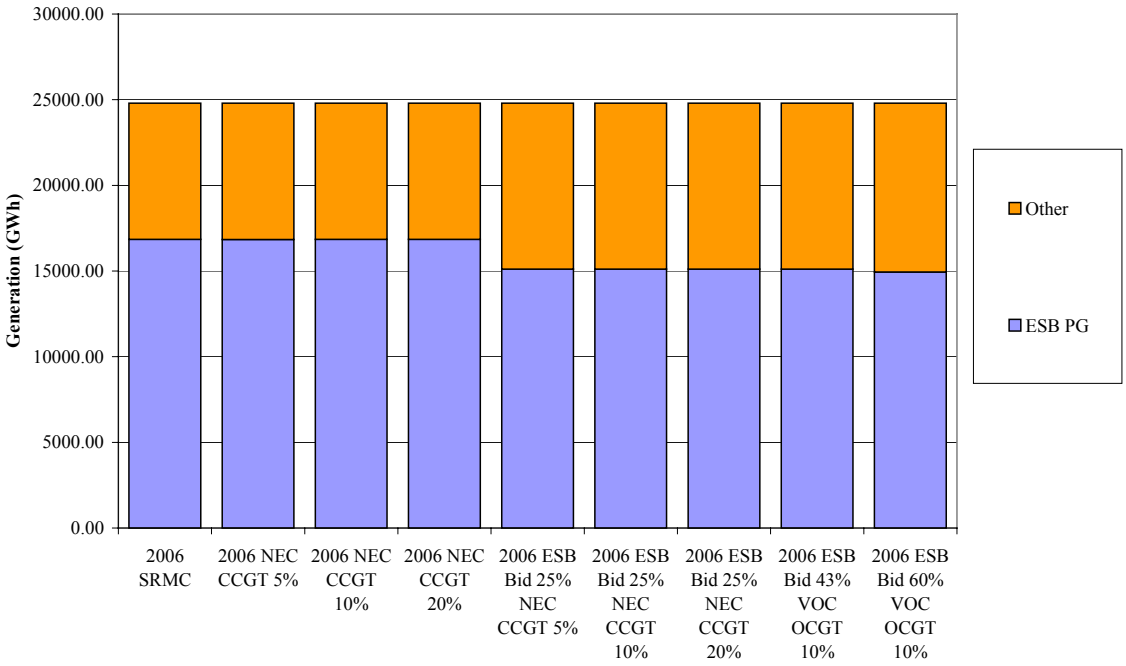
Source: ILEX analysis.

1.23 The charts show that should the price setting plant (ESB PG) use bid prices uniformly above SRMC such that prices are flatter across the year, then this would disadvantage an OCGT new entrant. For example, in the case where ESB PG bids above SRMC by 25% and the residual value of capacity is less than that required by a new entrant OCGT, an OCGT peaker is not viable (Figure 3). However if ESB PG does not bid above SRMC prices uniformly across the year, which results in very high prices at peak, then OCGT new entry is incentivised (as in Figure 2).

Generation

1.24 The annual generation under all nine cases is shown in Figure 4. The generation is the same under all cases except where ESB PG bids above SRMC, and as a consequence loses volume to its competitors. However, it is interesting to note that once ESB PG has bid above SRMC by 25%, it no longer loses volume to any significant extent.

Figure 4 – Annual generation

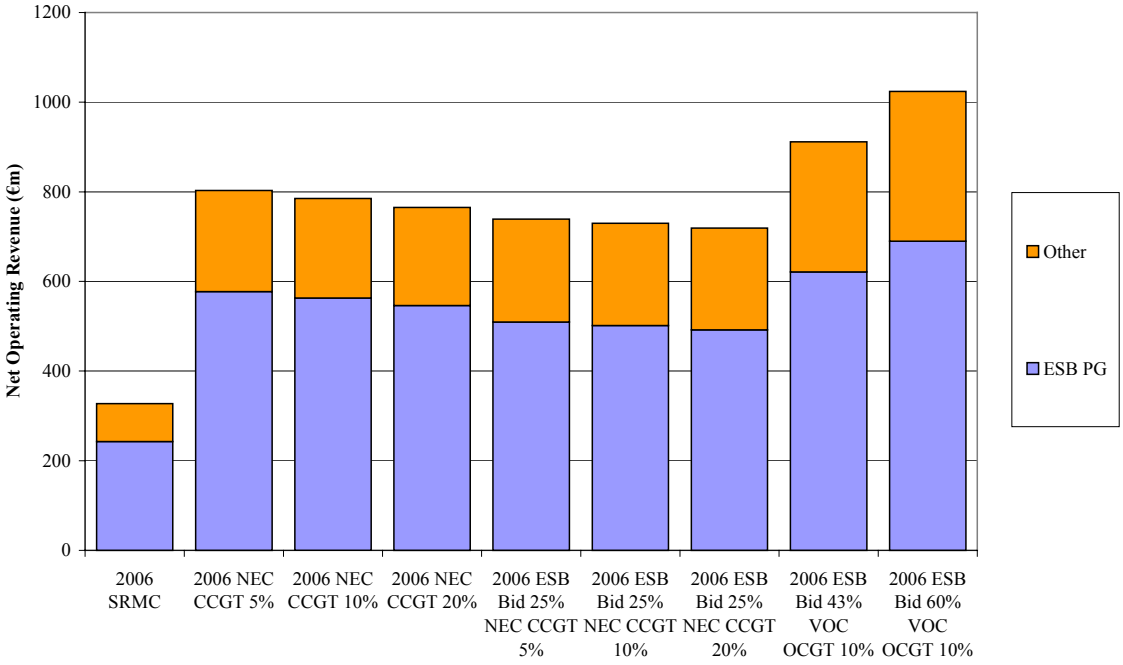


Source: ILEX analysis.

Net operating revenues

1.25 In Figure 5 we present the net operating revenue[12], under all scenarios.

Figure 5 – Annual net operating revenue



Source: ILEX analysis.

1.26 Figure 5 clearly shows that ESB PG would lose net revenue if it bid above SRMC by 25% as opposed to not covering some element of other cost and not bidding above SRMC. ESB PG then increases revenue when bidding up at 43% and 60%; this is partly due to the higher annual TWA electricity prices in these scenarios. The fact that ESB PG will not lose volume when bidding at 43% as compared to 25% means that ESB PG will not lose revenue should it bid at higher than 43%. This is confirmed by the 60% bid-up case. This is an illustration of the level of ESB PG's market dominance.

Central Trader contracts

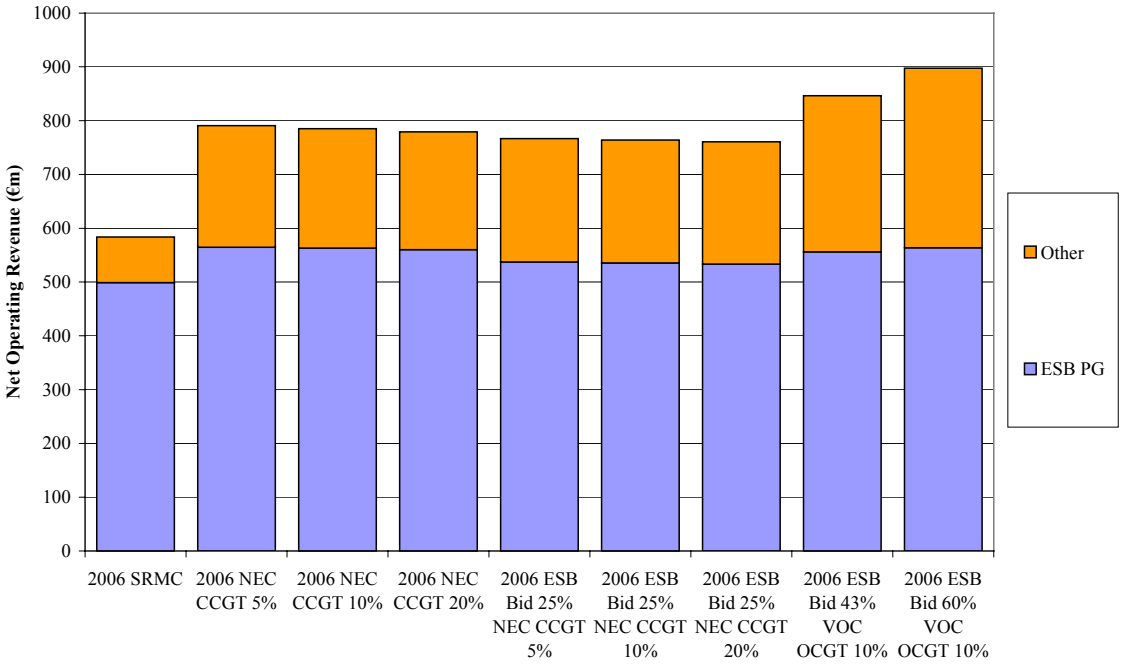
1.27 It has been proposed that 'vesting contracts' or 'central trader contracts' could be put in place to dilute ESB PG's incentive to use its market power. ESB PG would have contracts, in the form of Contracts for Differences (CfDs), in place for the majority of its output at a competitive strike price.

12 Gross revenue net of fuel costs, variable other works costs and start costs – with a limit on two starts per day for each unit.

1.28 We have modelled the impact on ESB PG's net operating revenues under central trader contracts, as discussed in paragraph 1.14.

1.29 The net operating revenues for all generators under these CfDs are shown in Figure 6.

Figure 6 – Annual net operating revenue under central trader contracts



Source: ILEX analysis.

1.30 As can be seen by comparing Figure 6 with Figure 5, the Central Trader contracts have the desired effect in holding net revenues near to the NEC CCGT 10% case, even when ESB PG bids above SRMC outside of the highest 10% of demand. These results will be very reliant on the volume of the contracts – the lower the volume then the less impact on ESB PG.

1.31 It should be noted that here we have not assumed that ESB PG's bidding behaviour is affected by the contracts. We have simply taken that behaviour as a given, as defined by each of our scenarios. Should the contracts have the desired effect of incentivising bidding at their strike prices, then **all** scenarios will tend even closer to the 'NEC CCGT 10%' case.

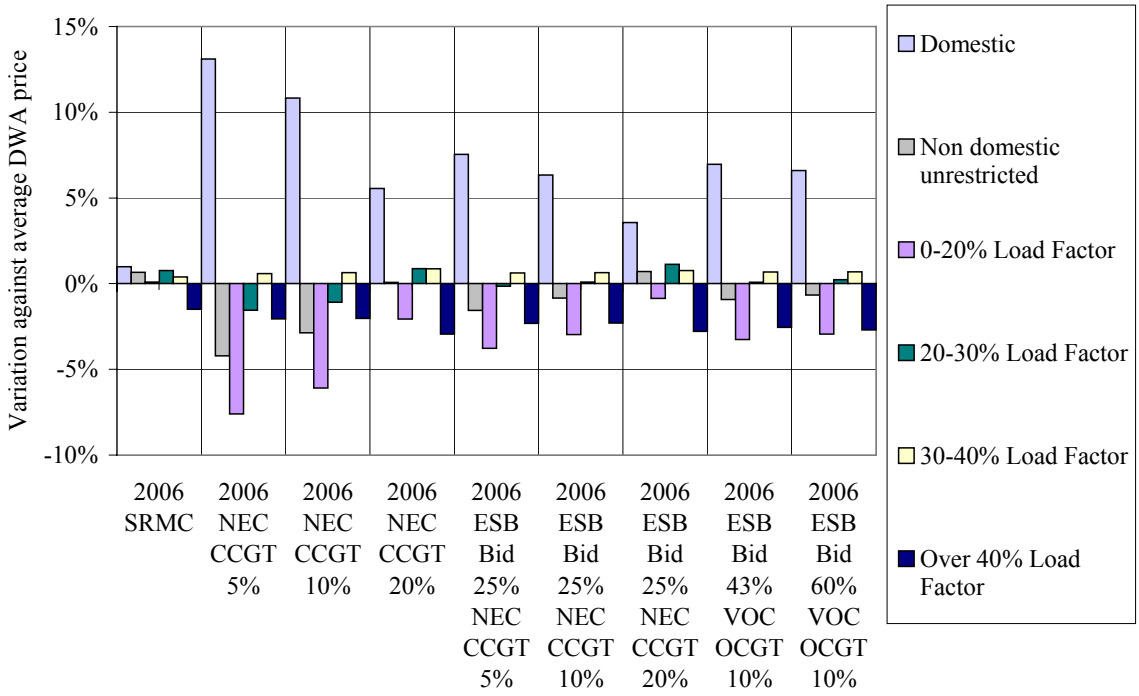
Customer demand profiles

1.32 We have taken customer load profiles published on the CER website to illustrate the impact different price scenarios could have on different groups of customers.

1.33 In order to calculate a demand-weighted average (DWA) price for each customer class, we used the price arrays calculated for each scenario and weighted them by the demand profiles for each customer class. We have then compared the DWA price for each class against the average DWA price over all customer classes for that scenario[13].

1.34 The variation by customer type across scenarios is shown in Figure 7 below. It should be noted that these results are illustrations of wholesale electricity prices, rather than final delivered prices to customers.

Figure 7 – Impact of different price scenarios on demand-weighted average prices



Source: ILEX analysis.

1.35 For example, it can be seen in the NEC CCGT 5% case that Domestic customers face higher DWA prices than the average over all customers, whereas the Non-domestic customers face lower prices.

1.36 The reason for this is that the price profile is highly correlated to the demand profile for domestic customers and hence the peak half-hourly prices correspond to the peak in domestic demand. Non-domestic demand does not follow the price profile to the same extent and therefore the DWA price is lower than the average. It can also be seen from Figure 34 that the DWA prices increases as load factor

13 We have used a simple, unweighted, arithmetic average across the seven customer DWA values.

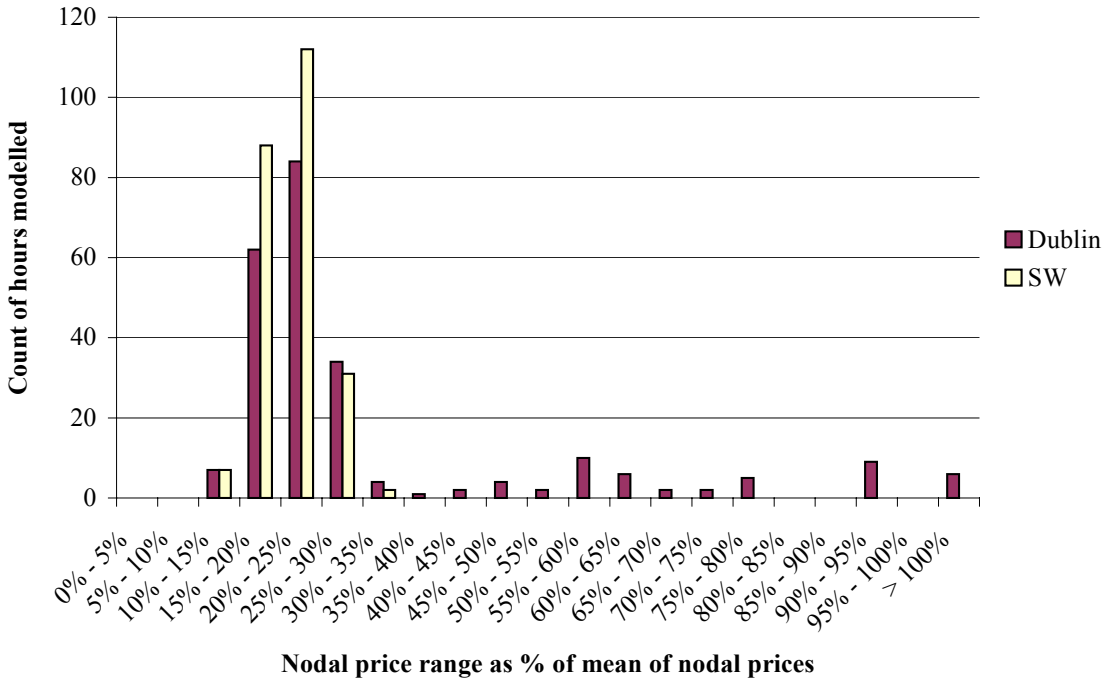
increases for non-domestic customers. This is due to the fact that the 0-20% load factor profile does not relate to the 0-20% highest half-hour prices, whereas the 40% load factor profile covers a far higher proportion of the high-priced periods

1.37 Comparison across the scenarios shows that the peakier the wholesale prices, the greater the difference in DWA price across categories. For instance, comparison of the three 2006 NEC CCGT cases shows that, as the number of periods over which high prices are spread increases, the extent of variation around the average price is reduced.

Locational prices

1.38 Under normal circumstances, the spread of locational marginal prices (LMPs) is relatively modest, with the vast majority lying between 15% and 30% of the mean LMP. This is shown in Figure 8, which illustrates the range of LMPs for each of the 240 hours tested, with a new CCGT built in either Dublin or the southwest.

Figure 8 – Frequency distribution of nodal price range

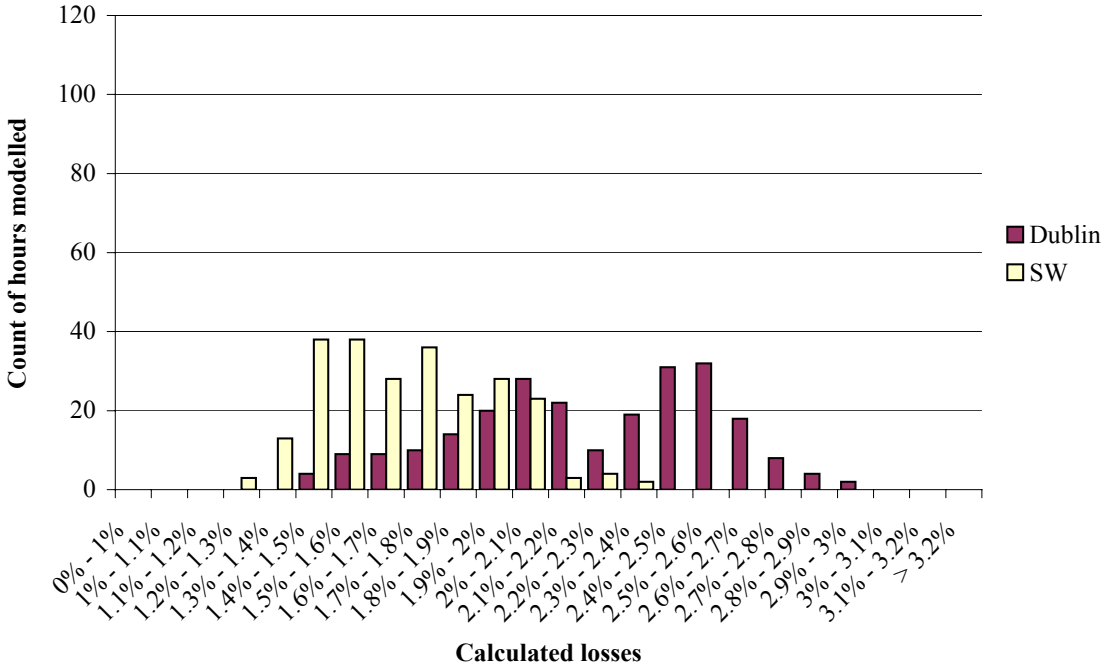


Included – 61 nodes with generation or demand response, counted over 240 modelled hours, with a new CCGT in Dublin or the southwest, assuming annual average price level in line with ESB PG's current price control

1.39 There are, however, circumstances in which much higher spreads, even greater than 100% of the mean price, are possible. The very highest spreads are associated with the siting of a new CCGT at Dublin rather than in the southwest. These outliers are clearly visible in Figure 8.

1.40 Total losses on the network would be higher if a new CCGT were to locate in Dublin rather than in the southwest. This is shown in Figure 9, which shows a frequency distribution of transmission losses under the main cases tested.

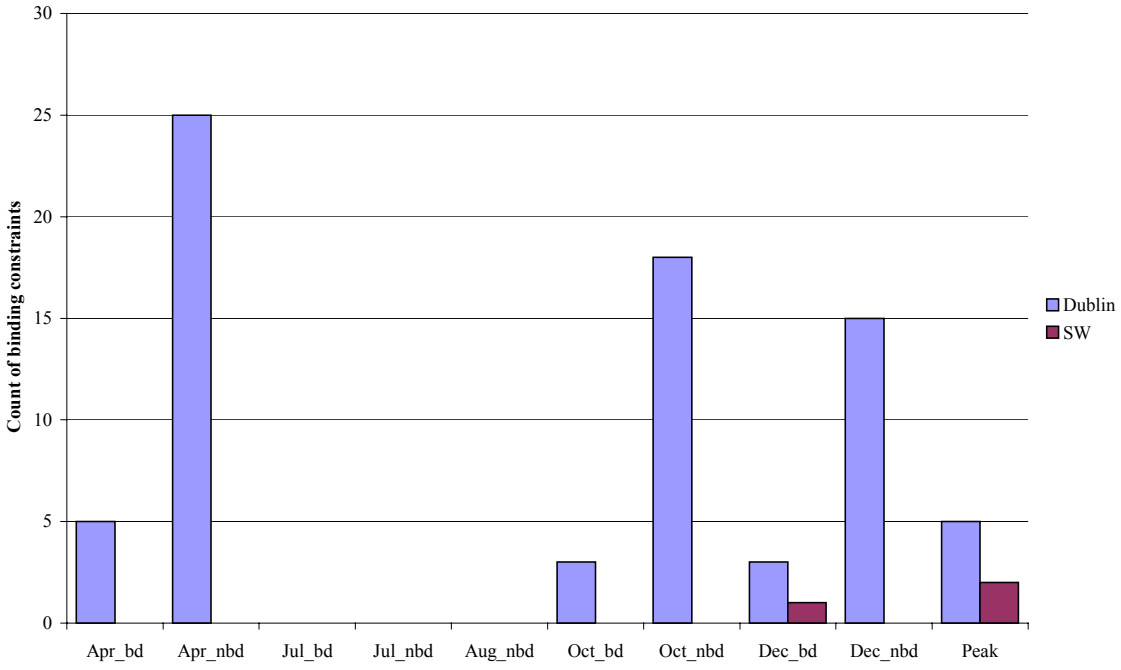
Figure 9 – Frequency count of transmission losses



Included – losses as a percentage of generation, counted over 240 modelled hours, with a new CCGT in Dublin or the southwest, assuming annual average price level in line with ESB PG's current price control

1.41 The number of binding transmission constraints on the network would be also greater if a new CCGT were located in Dublin rather than in the southwest. This is illustrated in Figure 10, which shows a frequency distribution of the binding constraints by the representative days modelled. The instances of binding transmission constraints are discussed in greater detail from paragraph 5.20.

Figure 10 – Binding transmission constraints by sample day



Included – all binding surrogate transmission constraints, counted across the 240 hours modelled, with a new CCGT located in Dublin or the southwest

Nodal pricing at key hours

1.42 Within the modelling, we consider in some detail the winter peak hour, summer peak hour and summer night valley periods. In addition, we consider a shoulder period in which Moneypoint 3 is dispatched down and the range of prices increases.

1.43 With the new CCGT located in the southwest, the range of nodal prices increases with the level of total generation, whereas with the new CCGT located in Dublin this is broadly true except for a number of outliers that occur in shoulder periods. Table 2 shows the range of nodal price in these four key hours, in both absolute and relative terms.

Table 2 – Nodal price range for key hours

Case	Dublin			SW		
	Max €/MWh	Min €/MWh	Range %	Max €/MWh	Min €/MWh	Range %
Winter peak hour	591	439	32%	614	457	32%
Summer peak hour	92	73	24%	92	73	25%
Summer night valley hour	25	22	16%	25	22	15%
Shoulder hour[14]	72	21	104%	46	38	19%

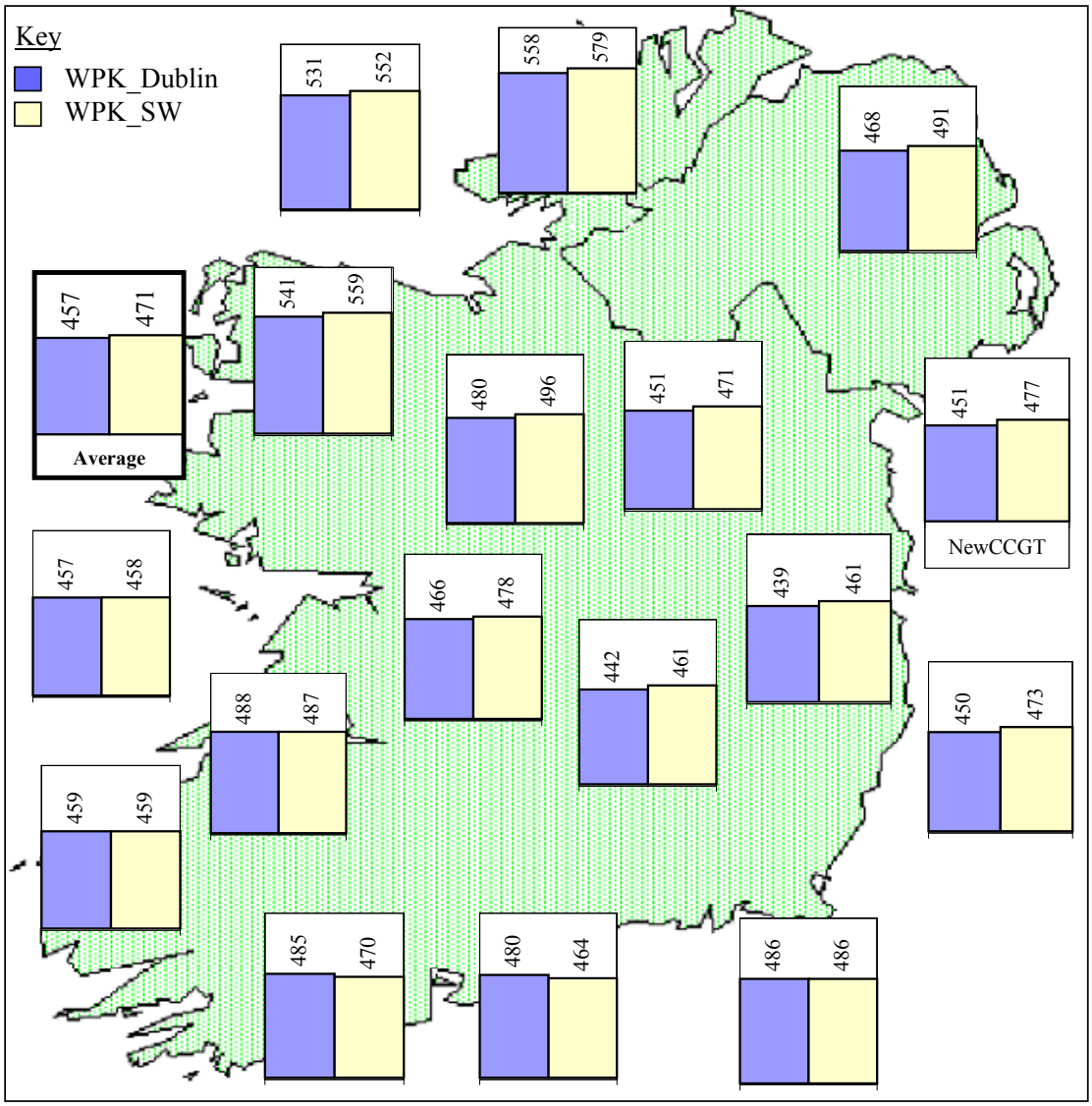
Included – 61 nodes with generation or demand response, for four key hours, with a new CCGT in Dublin or the southwest, assuming annual average price level in line with ESB PG's current price control. 'Range' refers to the absolute range in prices (maximum – minimum) as a percentage of the mean price across the 61 nodes.

Winter peak hour

1.44 The spread of generator LMPs at system peak is projected to be 32%, irrespective of the location of a new CCGT. The level of LMPs is generally lowest around Dublin and highest in the northern area.

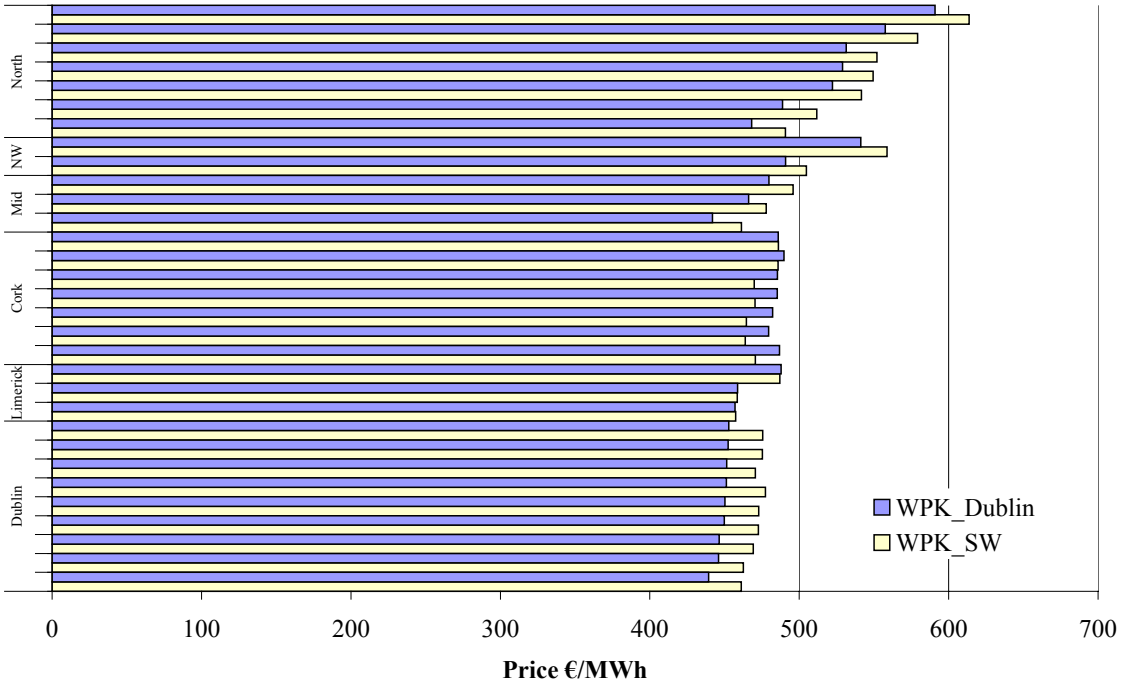
[14] For example, we model this occurrence at 22:00 on an April non-business day. While the outcome is a real phenomenon, the exact timing may be a consequence of our model assumptions.

Figure 11 – System peak price patterns (€/MWh)



Included – prices at 17 selected nodes, at system peak (18:00 on peak winter day), with new CCGT in Dublin or the southwest, assuming annual average price level in line with ESB PG's current price control

Figure 12 – Nodal prices at winter peak hour

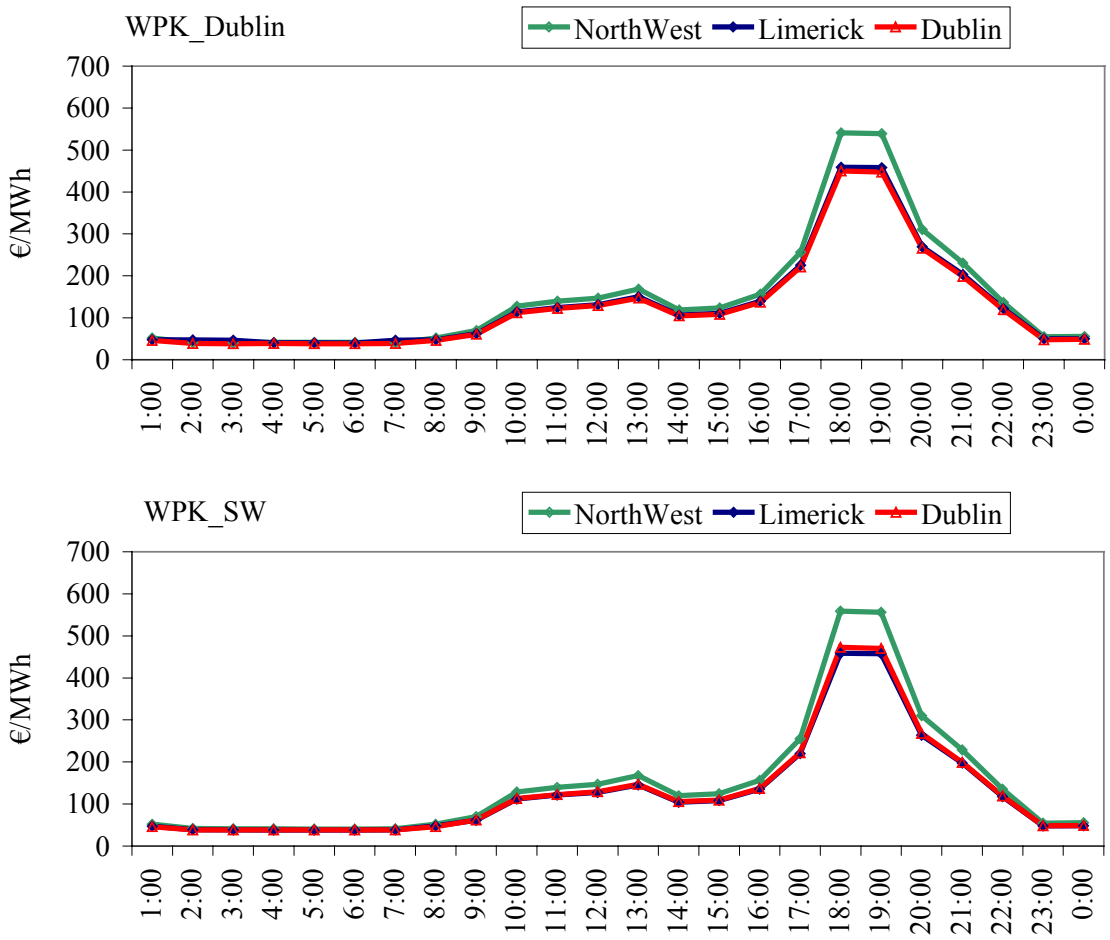


Included – prices at 31 selected nodes, at system peak (18:00 on peak winter day), with new CCGT in Dublin or the southwest, assuming annual average price level in line with ESB PG's current price control

1.45 Figure 11 and Figure 12 show the variation in nodal prices at different points on the network for the peak hour, assuming new entry in either Dublin or the southwest.

1.46 Figure 13 illustrates prices in the Dublin, Limerick and northwest areas, over the 24 hours of the winter peak day. The price variation follows the profile of demand, with the greatest variance over the evening peak period. The impact of locating the new CCGT in Dublin or the southwest is not high.

Figure 13 – Pricing across the winter peak day at three points

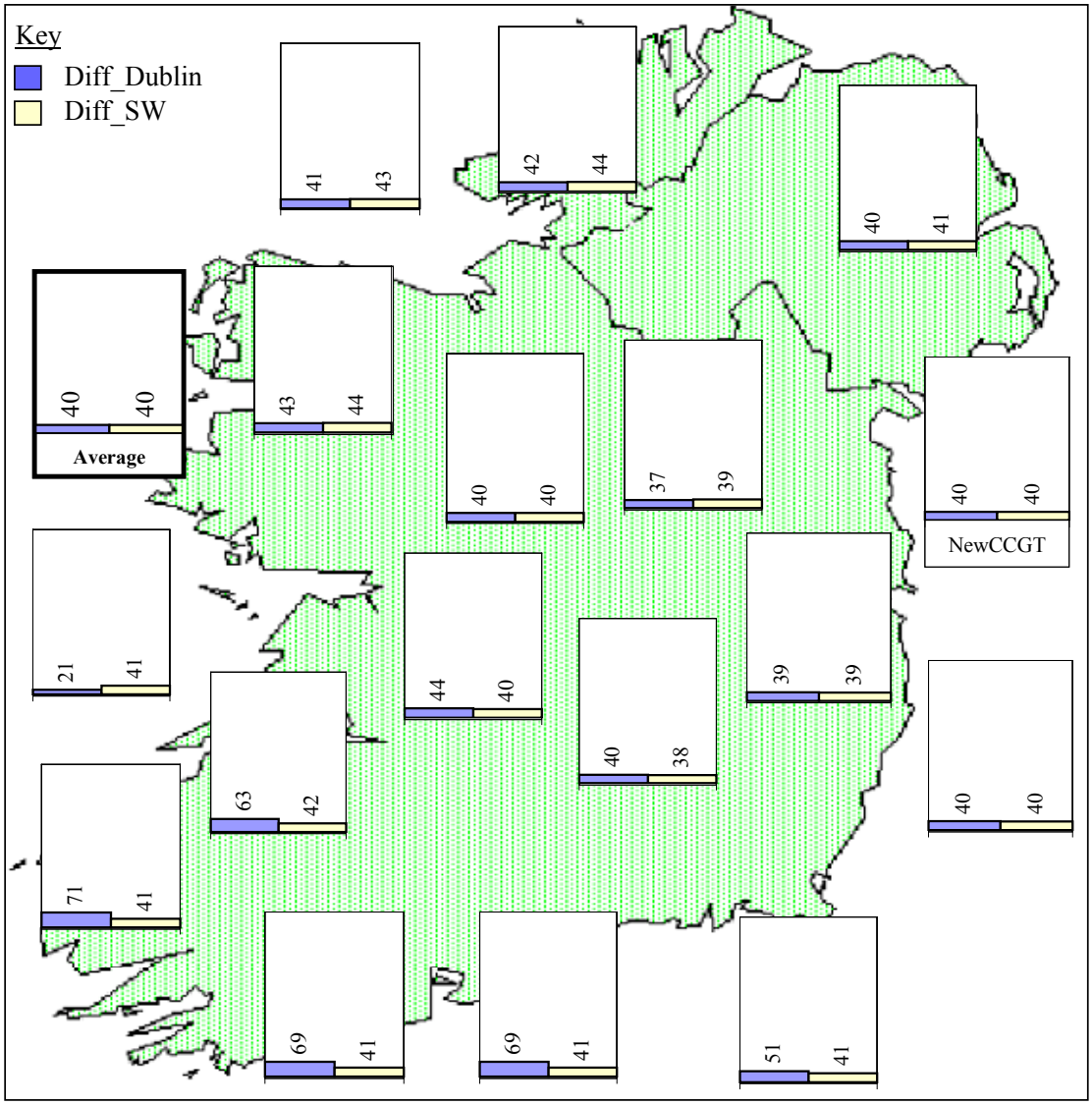


Included – prices at three representative nodes across the 24 hours of the winter peak day

Shoulder hour

1.47 Shoulder hours reveal some of the particular circumstances that can give rise to larger spreads than normal. For example, LMPs at 22:00 hours on an April non-business day[15] range from €21/MWh to €72/MWh – a spread of 104% of the mean price. Figure 14 and Figure 15 show nodal prices across the country for a shoulder hour, with new entry in either Dublin or the southwest.

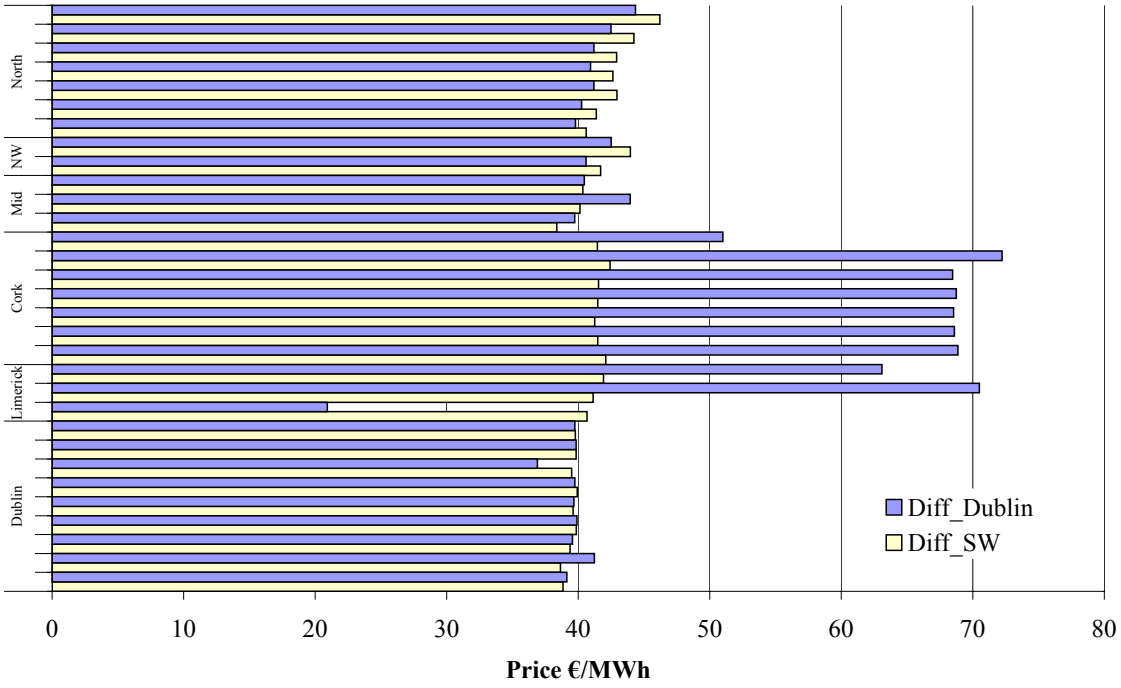
Figure 14 – Shoulder hour period price patterns (€/MWh)



15 The analysis is intended to consider a range of circumstances in a series of snapshots. The precise times at which these larger spreads in prices occur in the model may not be significant, although transmission constraints may well occur in shoulder periods in which transfers of power from one region to another are high.

Included – prices at 17 selected nodes, at a shoulder period (22:00 on an April non-business day), with new CCGT in Dublin or the southwest, assuming annual average price level in line with ESB PG's current price control

Figure 15 – Nodal prices at a shoulder period (April non-business day)



Included – prices at 31 selected nodes, at a shoulder period (22:00 on an April non-business day), with new CCGT in Dublin or the southwest, assuming annual average price level in line with ESB PG's current price control

1.48 The effect of maintenance and outages on price patterns can be marked. We have assessed this, and found that system states with plants removed for scheduled maintenance and/or forced outages display LMP patterns which are broadly encompassed by the cases discussed above.

2. SCENARIO DEVELOPMENT

2.1 We distinguish between two types of model run:

- scenarios – alternative futures, created as a basis for testing different policies; and
- sensitivity tests – model runs designed to assess the sensitivity of results to particular assumptions.

2.2 The locational and non-locational analyses are designed to address different questions, and the scenario definitions differ in each case.

2.3 In particular, the non-locational analysis is designed to assess the implications of an energy-only market, bidding behaviour and policies to address market dominance. For this, it is important to review the profile of prices across the year, with a focus on peak times. Scenarios were defined with this in mind.

2.4 The locational analysis is designed to consider the implications of an LMP market. Here, the emphasis is on creating a series of snapshots to assess the stability of the locational price patterns.

Scenario definitions

Non-locational analysis – scenarios

2.5 The non-locational analysis assesses the profile of prices across the year and at peak times, by varying three key input assumptions:

- level of the market value of capacity (which may alternatively be formulated to represent bidding strategies and/or market power);
- distribution of the market value of capacity across the year (which may be formulated to represent bidding strategies and/or market power); and
- the extent to which ESB PG might also bid generally above the SRMC of its units in a more uniform manner than exclusively around higher demand periods.

2.6 We also cover more extreme prices at system peaks, in order to assess the remuneration to owners of peaking plant at these times. These may be considered as sensitivity tests.

2.7 The base year for the modelling, from which data inputs are defined, is 2002. The 2002 demand figures are collapsed into 25 sample days[16] – a business day and a

[16] This is not to be confused with the ten historical days of nodal demand provided by ESB NG, refer paragraph 2.16.

non-business day for each month, plus a peak day representing the ten peak-demand days of the year – each with half-hourly data.

2.8 The non-locational modelling is done for each of the half-hours in these 25 sample days, and the results for each day are then combined to form annual averages and distributions across the year.

2.9 The future year considered is 2006, a year for which ESB NG has provided detailed data on the network configuration for use in the locational analysis.

2.10 The non-locational cases are conducted using the LMP model with the demand and generation allocated to a single node. This allows the effects of start costs to be considered in the dispatch patterns – this is discussed in more detail from paragraph 3.23 below.

Non-locational analysis – central trader

2.11 One particular aspect of the non-locational analysis relates to the role of the central trader.

2.12 We have been advised to model the central trader as holding offtake contracts with ESB PG, each taking the form of a financial swap contract (or CfD). This is done separately for each plant, based on a percentage of its expected profile of output across the year in a competitive market. We applied contracts of 80% of the output of each of the ESB PG plants in each half-hour, based on an initial model run assuming competitive outcomes and no transmission constraints.

2.13 We assign a value to these contracts based on the non-locational market prices arising from the same assumed competitive outcomes.

Locational analysis – scenarios

2.14 The locational analysis is intended to show the pattern of prices in different locations, and the robustness of these patterns to different assumptions. Therefore, the emphasis is on testing alternative plausible cases, as a series of snapshots. A second aim is to understand the effect of collating the nodal prices into zonal or national averages, for generation and demand separately.

2.15 The principle scenario variable in the locational analysis is the location of new entrant generation. For 2006 we have two alternative assumptions, a 400MW CCGT at either Knockraha (in the southwest) or Maynooth (Dublin area). These points were selected in consultation with ESB NG as points that did not require additional deep reinforcement, in order that the network model would not be changed.

2.16 In the locational model we also test cases relating to 2006, with generation bids selected from the non-locational scenarios. The LMP network model uses a linear

program algorithm. The model with the entire network in place takes far longer to solve than under the non-locational cases.

2.17 For the locational analysis, the LMP model requires a breakdown of the pattern of demand across each node on the network. We have been provided with detailed demand data across the different nodes on the network for ten selected days in 2002, with hourly variation.

2.18 We also have demand data associated with three future year (2006) network states provided by ESB NG planning, which cover the winter peak, summer night valley and summer peak hours. For this case, other nodal demand breakdowns can be arrived at by interpolating total system demand between its values at each of the three snapshot times (see paragraph 3.8). This approach has been used in the main model runs.

Model outputs

2.19 The model delivers, for each period modelled, detailed dispatch patterns, locational market prices, generation costs and revenues. These may be combined into aggregate figures, such as the annual impact on a particular generator or class of consumer, and the total cost of meeting demand.

2.20 The model outputs are summarised as follows – results are compared across scenario and policy cases as appropriate:

Non-locational analysis – model outputs (annualised)

- price duration curves (overall and with a focus on the peak periods)
- generation costs and revenues by company and by plant type;
- overall payoffs to ESB PG, given the central trader contracts; and
- wholesale price component for different customers.

Locational analysis – model outputs (snapshots)

- nodal prices by location;
- transmission losses;
- constraints;
- costs of meeting generation; and
- generator revenues.

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3. METHODOLOGY

Overview of methodology

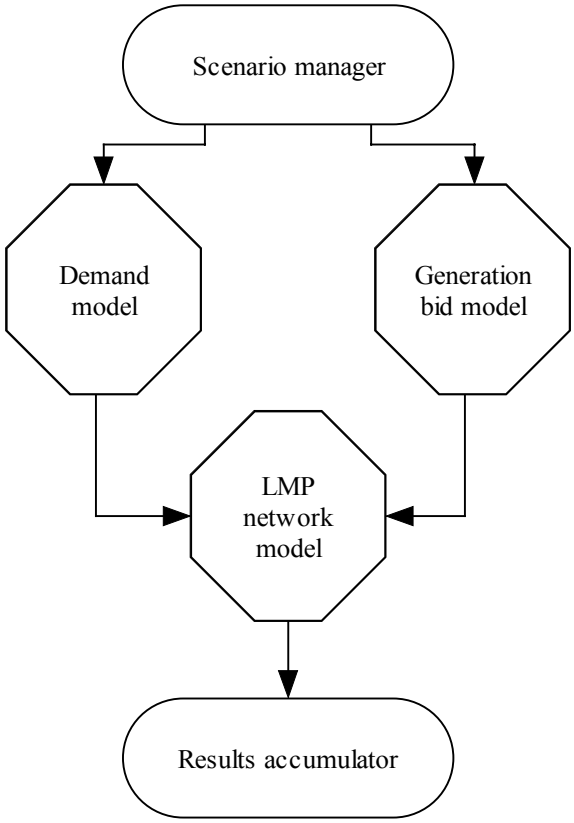
3.1 This section sets out the methodology and key assumptions for the CER market design modelling work. There are two parts to the analysis:

- *non-locational*, in which we explore aspects of an energy-only market and of market dominance; and
- *locational*, in which we explore the locational price signals emerging from an LMP market.

3.2 Scenarios are defined as alternative futures, covering combinations of future year assumptions. We also conduct some sensitivity testing to assess the robustness of the results to the input assumptions.

3.3 The model structure is shown in Figure 16 below.

Figure 16 – Model structure



Demand modelling

3.4 Electricity demand data is used in the demand model, the generation bid model, the LMP model and the results accumulator. In each of these the definition is slightly different due to the needs of the model. For the LMP model, demand is allocated to individual nodes on the network. The main features of demand used in the different models are outlined below:

Pre-processing

- ESB NG provided base year demand data, in terms of half-hourly figures for each day in 2002 net of house load; and
- the base year demand is collapsed, using an averaging process, to half-hourly system load profiles for 25 sample days.

Demand growth model

- sample day half-hourly demand figures for the base year are scaled, using annual and peak demand growth figures, to create future year demand patterns by sample day and half-hour;
- demand met by distributed and non-centrally dispatched generation is excluded from the future year data – this provides input to the generation bid model, and to the LMP model for the non-locational analysis; and
- a nodal breakdown is created, based on either hourly data for ten days in 2002 or on 3 snapshot future network states provided by ESB NG planning (see from paragraph 3.6), for input to the LMP model within the locational analysis.

Generation bid model

- the future year demand data forms the basis for indicative generation patterns, which are estimated to derive start costs and reserve provision;
- a limited amount of demand response is estimated, located at various nodes, and is bid into the LMP model; and
- additional demand related to pumped storage are added to the base demand profiles.

LMP network model – non-locational analysis

- future year demand, by sample day and half hour, is allocated to a single node; and
- the demand includes an estimate of transmission losses.

LMP network model – locational analysis

- future year demand is required for each node on the network;

- demand is adjusted to exclude transmission losses, assumed to be 2.9% of demand (since losses are estimated separately within the LMP model); and
- generation (and demand response) is dispatched to meet nodal demand.

Results accumulator

- the cost of meeting demand is estimated:
  - at different locations (within the locational analysis); and
  - across the year for different classes of consumer (in the non-locational analysis).

3.5 The definitions of demand are summarised as follows:

Table 3 – Definitions of demand data

Aspect of data	Raw 2002 half-hourly totals	Demand growth	Generation bid model	LMP network
Year	2002	2002 -> 2006	2006	2006
Dimension	365 day 48 half-hour	Peak total Annual total	25 sample day 48 half-hour	10 days 24 hours (locational analysis) 25 sample day 48 half-hour (non-locational analysis)
Demand from embedded generation	Included	Apply growth, then exclude	Excluded	Excluded
House load	Excluded	Excluded	Excluded	Excluded
Interconnector export	Excluded (assumed zero)	Excluded	Excluded (modelled)	Included
Pumping demand	Included	Excluded	Excluded (modelled)	Included
Demand from hydro generation	Included	Excluded	Excluded (modelled)	Included
Non-market demand response	Included (i.e. deducted)	Included (i.e. deducted)	Included (i.e. deducted)	Included (i.e. deducted)
Market demand response (e.g. Powersave)	Excluded (i.e. added back in)	Excluded	Excluded (modelled)	Included (modelled)
Transmission losses	Included	Included	Included	Included for non-locational analysis Excluded for locational analysis (modelled)

Aspect of data	Raw 2002 half-hourly totals	Demand growth	Generation bid model	LMP network
Reserve	Excluded	Excluded	Included (modelled) to calculate start costs and reserve	Excluded (modelled through part-loading plant)

Locational demand data

3.6 We have been given two sources of locational demand data:

- *planning data* – load within the network for 2006, provided by ESB NG planning, covering three snapshot network states (winter peak, summer peak and summer night valley hours); and
- *historic data* – hourly nodal demand figures for 2002 for ten selected days, extracted from operational databases (SCADA) by ESB NG operations.

3.7 For both of these, we have devised a way of creating future-year nodal demand patterns within the model, for the hours tested.

3.8 For the planning data, nodal patterns of demand are generated by interpolating total system demand for the cases to be analysed between total system demand at the three snapshots provided (winter peak, summer peak and summer night valley hours), and weighting the absolute MW demand at each node accordingly[17].

3.9 For the historic data, the demand patterns have been applied to the future-year demand level, and also made to fit the assumed physical state of the network in that year.

3.10 There are differences between the nodal demand patterns given by the two datasets, which have made it difficult to do a complete detailed comparison:

- the future-year network includes a number of additional nodes that are not yet built;
- the future-year network used in the LMP model includes some of the 38kV network, with load allocated at the lowest level possible, whereas the historic demand data are allocated to the 110kV buses;
- in some cases the future-year network includes assumptions about known additional load, for example industrial parks; and

[17] For any cases with system demand above the hypothetical winter peak demand in the planning network, the model uses the winter peak demand distribution, but scales demand at each node to match the total system demand. The same approach is used for cases where system demand lies below summer night valley system demand.

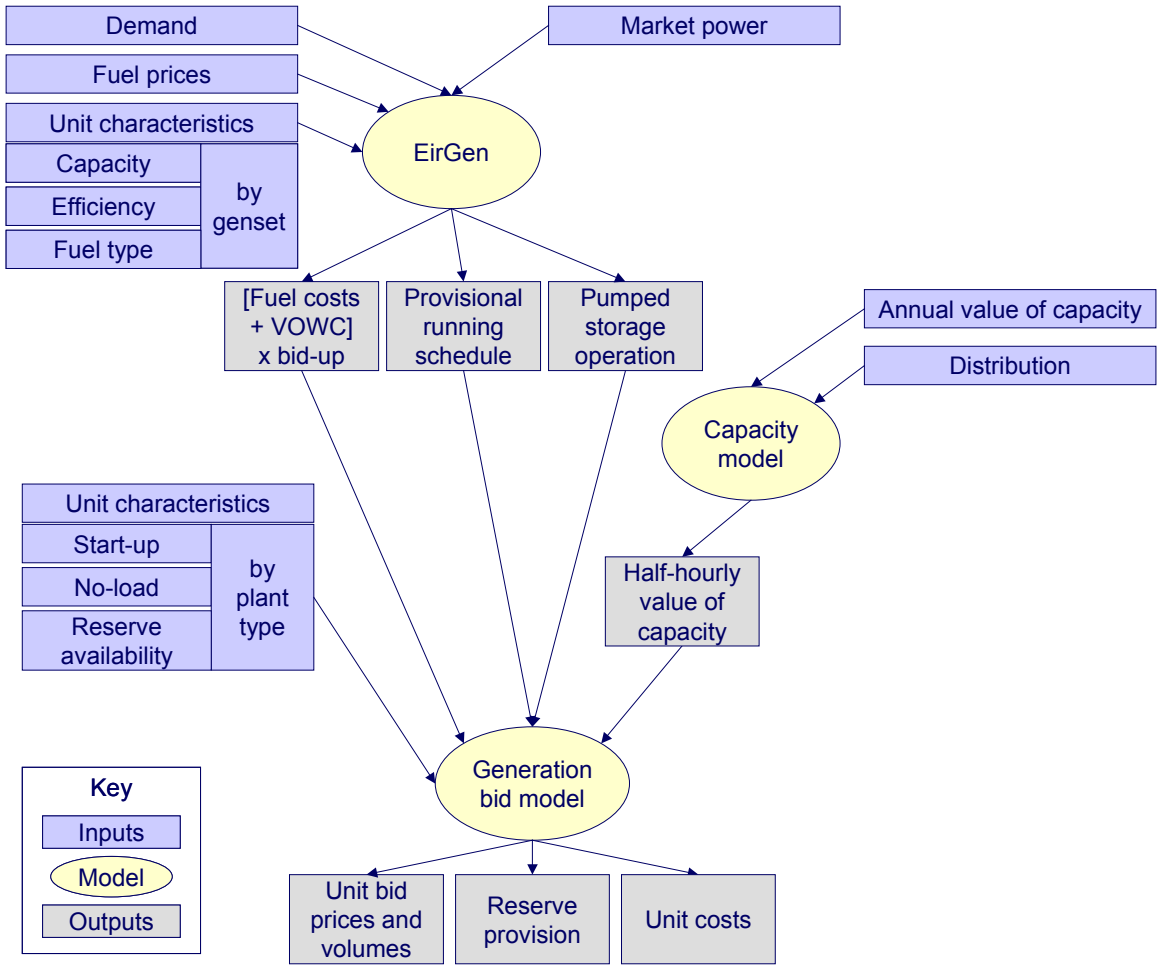
- the historic data have a number of days where the demand at particular buses was zero due to maintenance.

3.11 Despite these inherent differences, we have normalised the demand projections from the historic data so that they encompass the demand for the three planning states in 2006 – winter peak, summer peak and summer night valley hours.

Generation bid model

3.12 The generation bid model takes our input assumptions, specified below, to derive bid prices and quantities for each unit. Our approach to determining the prices and volumes is illustrated in Figure 17 below.

Figure 17 – Generation bid model operation



3.13 We first use our dispatch model of the Irish electricity market, *EirGen*, to incorporate our assumptions regarding available capacity, unit characteristics, demand and fuel costs for each sample day. We also include any bids above

SRMC and/or exercise of market power by bidding-up units' costs at this stage. Based on this information, *EirGen* calculates a merit order and provisional running schedule. We use these to calculate the fuel and VOWC (variable other-works costs) components of generators' bids, and to estimate the number of hours over which to spread units' start-up costs. *EirGen* also calculates a pumping and generation schedule for the pumped storage plant.

3.14 The capacity model combines our assumptions regarding the absolute value of capacity and the number of periods over which it is spread, to create a half-hourly distribution of the value of capacity across the year.

3.15 The final input into the generator bid model is our assumption regarding the costs of start-up and no load. The generation bid model then calculates bid quantities and prices for each unit for each half hour, based on the components illustrated in Figure 18 below. The model also records the fuel and VOWC of each unit.

Figure 18 – Components of generator half-hourly bid price

3.16 Our input assumptions and methodology are explained in more detail below.

Plant modelled

3.17 The model contains details of all transmission-connected plant. This includes all those units that are centrally dispatched, plus a number of large wind farms, two of which are assumed to have been commissioned by 2006.

Plant retirals

3.18 We assume that the only plant retirals are of peat plant, as specified in the generation adequacy report.

New entry

3.19 We assume that the two new peat plant, Lough Ree Power and West Offaly Power, are fully operational by 2006.

3.20 We have assumed two cases for gas-fired new entry, based on two hypothetical new 400MW CCGTs. Each case is assumed to include one such CCGT, either located inside Dublin (Maynooth) or in the southwest of the country (Knockraha). These points were chosen as additional deep reinforcement of the transmission network was not required for connection. These plant are assumed to have the technical characteristics of the CER's best new entrant (BNE).

Plant capacities and efficiencies

3.21 We have used data provided by market respondents for units' maximum available export capacity and full load efficiency. We have also used the CER's efficiency assumptions regarding a BNE for recent CCGTs. We assume that plant bid in at their maximum export capacity, adjusted by an availability factor (discussed in paragraph 3.34 below). The fuel cost component of the bid is therefore calculated based on the full load efficiency of the plant.

3.22 No data were made available for the two new peat plant. We have assumed that they have the capacities stated in the generation adequacy report, and the efficiency is consistent with that of a best new entrant peat plant.

Start-up costs

3.23 To estimate the costs of start to include in each unit's bid, we use an average maintenance cost by plant type, plus an energy requirement which varies with the size of plant. For simplicity, we assume that all starts are warm.

3.24 In order to incorporate the costs of a start into generators' bids, we use the ILEX model *EirGen* to produce a merit order for each sample day. For those plant that *EirGen* calculates to be in-merit during the day, we spread the costs of a start over its scheduled running hours, with a minimum of one hour. For out of merit plant, we assume that a start-up cost is spread over one hour. The start costs are based on a pattern of operation derived without considering transmission constraints, and considering only incremental operating costs – this is an approximation to avoid the need to iterate between the model elements.

3.25 If this first-order dispatch estimate were adopted, we would find that peaking plants with high marginal costs but low start-up costs would rarely be scheduled – instead, the simplistic model might assume that larger units with lower incremental costs (but higher start costs) would run at peak times.

3.26 However, this is addressed with the use of the LMP model to calculate dispatch patterns, in both the non-locational and the locational analysis. The start costs of different types of unit are included in their bid prices and, within the LMP model, dispatch patterns are then recalculated allowing for start costs.

No-load costs

3.27 The model calculates generation bid prices on the assumption that units are not part-loaded. Therefore, no-load costs are not used within the generation bid model.

Ramp rates and plant dynamics

3.28 Ramp rates and plant dynamics such as minimum stable generation are not considered within the models. These will not have a significant impact on our results.

Reserve

3.29 The generation bid model is required to deal with reserve (defined as the requirement to part-load plant) for two reasons:

- for start-up costs – the model estimates generation bid prices including start costs, and allows for generation units being called beyond those required for energy volumes alone; and
- to provide to the LMP network model a list of the plants which will be part-loaded, and the amount by which each will be part-loaded to provide reserve.

3.30 Part-loading to provide reserve is initially estimated in the generation bid model, on the grounds that reserve will be provided from the higher-priced units in operation at any time (subject to physical capability).

3.31 In order to model this, we have obtained an understanding of the reserve policy, including:

- the volume of part-loaded plant required at different times to provide reserve;
- the capabilities of different plants to provide reserve; and
- the number of sets typically used for reserve at different times (and the associated volumes).

3.32 The preliminary merit order produced by the generator bid model is used to assess which plants would be providing reserve, and the volume of deload necessary for each plant to provide the required amount of reserve.

Availability

3.33 We have used information provided by respondents to calculate an average availability by plant type for each sample day. This availability includes an estimate of both scheduled and forced outage rates and is used to reduce the declared export capacity. This approach provides a good representation of outages for the non-locational analysis where we are interested in the spread of prices across the year.

3.34 For the locational analysis, we have assessed sensitivities under which some units are considered unavailable for a given sample day, to test the effect on locational prices. Under these scenarios we have combined assumptions regarding:

- scheduled outage – plant are assumed unavailable in the *EirGen* merit order calculation (i.e. their outage is known ahead of time), and they therefore submit a zero offer volume to the LMP model;

- forced outage – these plant are assume to be fully available in the *EirGen* merit order calculation (i.e. their outage is not known ahead of time), but unavailable for dispatch in the LMP model; and
- remaining plant – all other plant are assumed to have an availability of 100% for the given sample day.

Fuel prices

3.35 We have confirmed our assumptions regarding the fuel used at each unit with the CER. We have used ILEX central fuel price projections to calculate the cost of energy delivered to the power station for each type of fuel.

Interconnection

3.36 The generator bid model includes power available for import into the Republic. We do not consider power for export in this analysis.

3.37 We have used historic data provided by ESB NG, and also from the Eirgrid website, to derive an annual average figure for actual power transfer across the interconnector. For simplicity, we assume a flat, baseload import from North to South of 35MW. This was deemed reasonable as there may be a capacity shortage in Northern Ireland in 2006. This assumption is significantly less than the stated available transfer capacity of the interconnector, the remainder of which we understand is reserved for system support.

3.38 The LMP model includes the interconnector as a single line and the generation bid model reflects this.

Pumped storage

3.39 We use *EirGen* to calculate the energy market operation of the four units at Turlough Hill based on the initial run used to calculate start-up costs. Once *EirGen* has calculated the merit order for a sample day, pumped storage can then 'decide' to generate or pump in any half-hour, based on the price differentials within the day.

3.40 We have assumed that only three units are available for operation at any one time, following discussion with ESB NG. The model also assumes a pumping:generation ratio which we have based on historical information provided by ESB NG. Based on these inputs, the pumped storage plant is scheduled to pump at times of low price and generate during peak periods.

3.41 *EirGen* takes into account the impact on prices caused by the pumped storage operation, so that if the plant's operation would affect the price differential to the extent that the plant's decisions would change, the generation profile is adjusted accordingly.

3.42 We have used historic data for generation and pumping (as provided by ESB NG) to ensure that the modelled levels of pumped storage operation are in line with actual levels. The charts below compare the modelled operation for a winter and summer sample day with the actual figures. As might be expected, the projections do not follow the actual behaviour exactly, but in our view represent a good approximation. The historic figures include operation of the pumped storage to provide ancillary services, while the ILEX projection represent energy market operation only. The historic figures reflect average profiles across a series of days, whereas the ILEX figures relate to a single profile.

Figure 19 – Pumped storage operation – actual operation against ILEX projection – winter business day

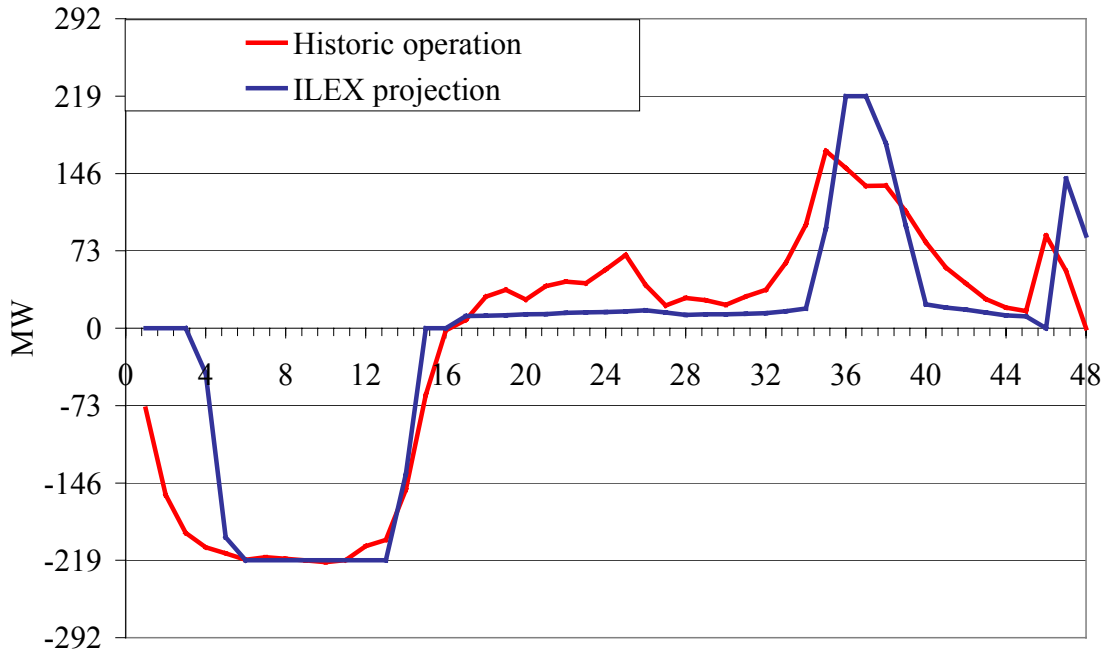
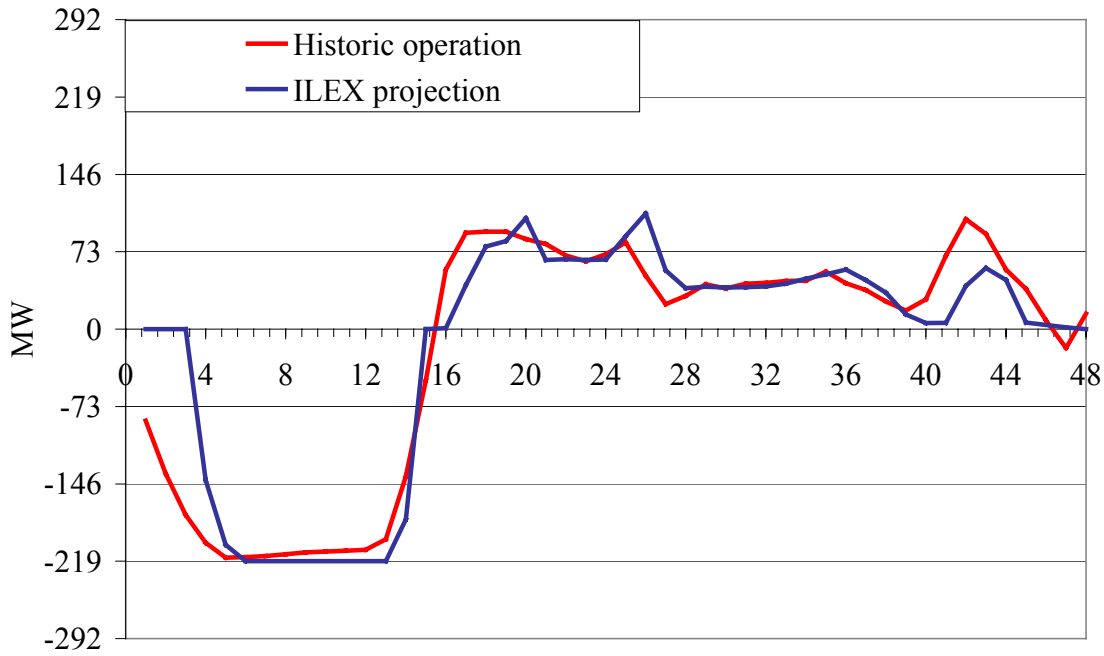


Figure 20 – Pumped storage operation – actual operation against ILEX projection – summer business day



Demand response

3.43 The model considers the impact of price-responsive demand. It is possible that, at times, the existence of such demand may affect prices and could mitigate market power.

3.44 We have been provided with data on the Powersave volumes and prices. For a few days in 2002, up to 60MWh of load was shed at prices of €635/MWh at peak hours, and up to 100MWh was shed at €254/MWh at off-peak times.

3.45 We assume that these volumes are actively bid into the market as demand response. We have allocated the price-responsive demand to locations on the network, with CER's assistance.

Value of capacity

3.46 A central tenet of the non-locational modelling is that there is no single solution to the level of above-SRMC prices that will be found at peak times, given ESB PG's dominant position. We address the issue by testing a range of cases (including an assumed competitive outcome) and evaluating the impact on the position of ESB PG and others, with and without a Central Trader in place.

Value of capacity in a competitive market

3.47 Electricity markets require an excess of generation capacity over peak demand in order to provide a reliable supply of energy. In an energy-only market, it is essential that prices exceed SRMC levels at times, to permit owners of capacity (in particular peaking capacity that may rarely operate) to recover their fixed costs of operation.

3.48 A competitive electricity market will deliver prices above the levels of short-run marginal cost at times when there is an expectation of a tight capacity margin or in the extreme insufficient generation to meet demand. At times of extreme shortage, prices may be set by demand response, initially voluntary load-shedding in response to price, and in extremis involuntary load shedding with prices perhaps set at an administered value of lost load (VOLL).

3.49 It is possible to estimate a competitive value of capacity in a number of ways. Ultimately, the long term average level of electricity prices in a competitive market should be sufficient to cover the cost of new generation capacity – for illustration, in our existing central price projections for the longer term we estimate this to deliver a value of capacity of around €74/kW, or €8.5/MWh over the year as a whole (in 2002 prices).

3.50 ESB NG has a planning standard of eight hours of loss-of-load expectation in each year. Using updated figures taken from the CER paper on capacity payments[18], we consider a marginal peaking unit with annuitised costs of €49,700 (2003 figures). Assuming that the marginal peaking unit earns above its own SRMC for just these 8 hours (and with plant availability of 91.8%), then it would require a price of €6,767/MWh (2003 figures) in each of these hours to recover its annualised costs, including costs of finance.

3.51 If this price were earned by the capacity operating at peak demand of 4795MW (our initial modelled figure for 2006) for eight hours[19], compared with an assumed short-run marginal fuel cost of €63/MWh, the total cost payable above SRMC of the marginal plant would be around €257million pa, or around €9.28/MWh (2003 prices) across projected annual demand in 2006 of 27.7TWh.

3.52 In the medium term we would not expect average prices to fall below the level required to keep existing plants in operation (the net annual avoidable cost). For 2006 in Ireland, our existing price projections assume a value of capacity of €4.2/MWh (2002 prices). This corresponds to the ILEX estimate of the net avoidable cost of keeping existing capacity on the system.

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18 Reference CERESB0064; CER, 10 November 2000.

19 In reality, a planning loss-of-load expectation of eight hours is very unlikely to lead to actual loss of load of eight hours.

3.53 The value of capacity in any year is dependent on the precise margin of generation capacity, and could be outside the range implied by new entrant costs and net avoidable costs.

3.54 Within our modelling, we assume a high level of market entry, with 400MW of new capacity by 2006. This would deliver a large system margin in that year and, for a competitive market, would be consistent with a low value of capacity.

Distribution of the value of capacity under competitive conditions

3.55 Under fully competitive conditions, the value of capacity in an energy-only market would be distributed across the periods of tightest plant margin.

3.56 This distribution would vary depending on the point in time at which prices are set in the market. For example, prices in a day-ahead market will factor in some uncertainty on the level of demand and plant availability for the following day, whereas a real-time market will be conducted under far greater certainty.

3.57 In order to emulate competitive outcomes, we adopt a pragmatic approach in which the total value of capacity is spread across the periods of highest demand. Our experience of other energy-only markets suggests that the value of capacity should be spread over something like the 10% of periods with the highest demand, with the value of capacity in each of the chosen half hours related to the extent to which demand in the half hour exceeds the lowest demand over the 10%.

3.58 The approach to distributing the value of capacity is described below. For the year modelled (2006), we take the profile of demand (on a 25 sample day-type by half-hourly basis). We identify the Y% (say 5% or 10%) of half-hours with the highest demand, and record the threshold value of half-hourly demand (X) for inclusion in this category.

3.59 The total value of capacity K (expressed in €/MW p.a.) will be spread across the qualifying half-hours, pro-rata with the difference between the actual level of demand in the hour D_h and the threshold level of demand X:

- if $D_h > X$:

$$k_h = \frac{(D_h - X)}{\Sigma_h (D_h - X)} * K$$

- if $D_h <= X$

$$k_h = 0$$

3.60 We have reviewed this approach against experience in other markets, including the energy-only Dutch market and the capacity element of the old England and Wales Pool price. We found that either the 5% or 10% figure, when combined with our Dutch SRMC price projection for 2001, gave rise to a similar price duration curve to the Dutch APX spot prices for 2000-2001. We also reviewed

the capacity price duration curve against the values observed in the England and Wales Pool, and found either the 5% or 10% value to be a reasonable fit.

3.61 As our competitive benchmark, we spread the total value of capacity across the 10% of half-hours with highest demand. In other tests we consider more and less peaky profiles.

Bidding strategies

3.62 A simple analysis of the capacity of different generators against the range of demand levels suggests that ESB PG would be able to raise market prices profitably at virtually all times (subject only to regulatory constraints and/or the proposed vesting contracts in the form of CfDs).

3.63 The dominant position of ESB PG means that competitive market outcomes are may not be delivered in the near term. We therefore consider alternative cases of bidding by ESB PG (the assumption is regarding ESB PG as they currently own all the price setting mid merit and peaking plant). This may take a variety of forms:

- bidding at short run marginal cost levels (as a comparator – it is unrealistic as it is unsustainable in the long run);
- bidding at a level above marginal cost levels, sufficient to recover total costs of operation (or regulatory allowed revenues);
- bidding at levels consistent with a competitive market value of capacity; and
- a potential market power scenario.

3.64 We have tested cases which just ESB PG plant bids at above SRMC at different times.

3.65 We also consider alternative ways in which the above-SRMC element of prices could be distributed across the season/day/peak:

- an increase in prices across a wide set of hours;
- an increase in prices over a very narrow set of hours (this may encourage entry of peaking generation);
- an emulation of competitive outcomes, in which prices are increased mainly at peak times; and
- a combination of these.

LMP model

3.66 The LMP model takes as input the generation price and quantity offers from *EirGen*, the nodal pattern of demand and a specification of the network. The

model also considers reserve holdings, taking as input the part-loading of individual units.

3.67 The model estimates transmission losses, with limited iteration within the model. This is a DC approximation, which generally should underestimate total losses because MVar losses are not included. The resulting LMPs consistently reflect both transmission constraints and marginal transmission losses.

Model details

3.68 The developed LMP model belongs to a class of DC Optimal Power Flow (OPF) solvers. It minimises the total generation costs while satisfying the DC network power flow equations, surrogate network constraints and limits on outputs of generators. The model also optimises the tap position of phase shifters (our network has just one of these represented, in the Dublin area).

3.69 The DC power flow model neglects the reactive power component of the flows, assumes that the voltage magnitude at all busbars is 1 p.u., line reactance is significantly larger than line resistance and that the sine of the voltage phase angle difference between two ends is equal to the phase angle difference (i.e. that the angle is small).

3.70 The DC model estimates losses and is formulated as a piecewise linear optimisation problem. The piecewise representation of line losses uses six segments to represent the quadratic relationship between power flow and power loss on each individual line. The end points of the linear segments are positioned on the quadratic function.

3.71 The LMP model includes optimisation of the tap position of phase shifters. The phase shifter functionality models control of the power flows on the system as an economic option, to mitigate violation of constraints. The specific use of the phase shifter in this model is used to preserve flow between buses 1742 and 17431 (in the Dublin area) to be always below 180MW.

3.72 The developed DC model has been tested extensively to verify its adequacy and accuracy. Two types of tests were carried out. One set of tests is based on comparisons between AC and DC load flows. In the full AC load flow model the voltage magnitudes of all busbars were set and maintained at 1 p.u. (by ensuring that sufficient reactive support was available). The results of this study are directly comparable with the DC model.

3.73 Furthermore, these tests were performed on a number of test systems (standard IEEE models) including an ESB NG network model. The tests confirm that the developed DC network model operated correctly.

3.74 The accuracy of the DC approximation is acceptable. The maximum difference in network flows between the AC and DC models is in the order of only 3.2%.

3.75 The evaluation of optimal generation dispatch and the corresponding flows and losses is carried out by solving the corresponding linear programming problem (LP) in an iterative manner. In most cases the solution is found after three iterations.

3.76 In the absence of the constraints the LMPs will reflect the cost of marginal losses. Due to the piecewise linear approximation of losses, these LMPs will be generally slightly smaller than the true LMPs.

3.77 A number of studies were performed by UMIST using a full non-linear AC OPF[20] to establish that the DC based LMPs are reasonably accurate. (The accuracy could be enhanced by increasing the number of linear segments, at the expense of an increase in size of the LP, and consequently computer processing time.)

Use of the LMP model in the analysis

3.78 For the non-locational work, the LMP model is run for each of the sample days for each future scenario – within each day it solves each half hour independently.

3.79 For the locational analysis we have performed model runs for 240 hours (24 hours for 10 sample days). These have been done separately assuming a new entrant CCGT in Dublin and in the southwest. We then focused on a few key network states for further analysis, starting with the three network snapshots provided by ESB NG. For each case tested, the LMP model calculates prices at each node, generation dispatch and revenue at each set (plus demand response and interconnector import/export), and nodal demand.

Network data assumptions

3.80 Both the locational and non-locational analysis use the same models and tools. For the locational work, the differences relate to the model inputs:

- the transmission network is defined in the LMP model[21];
- demand (which in the locational analysis includes an estimate for transmission losses[22]) is reduced by these losses, as the LMP model estimates these losses and dispatches generation sufficient to meet load plus losses;
- demand is allocated across the nodes on the network; and

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20 Pudjianto, D., Ahmed, S. and Strbac,G., "Allocation of VARs support using LP and NLP based optimal power flows", IEE Proceeding Generation Transmission and Distribution, no. 4, vol. 149, July 2002, pp. 377 - 383.

21 Within the non-locational analysis, generation and demand are collapsed to a single bus on the network.

22 We use a figure of 2.9%, quoted by ESB NG as the average figure.

- the modelling is conducted on an hourly basis for up to 10 representative days, and there is no aggregation to a year as a whole.

Network description

3.81 We have been provided with three future year full AC network models by ESB NG planning:

- 2006 Summer night valley hour (the lowest demand of the year);
- 2006 Summer peak hour (peak summer demand); and
- 2006 Winter peak hour (the highest demand of the year).

3.82 These planning networks were adapted to form three equivalent DC network models suitable for LMP calculations. The adaptations consisted of the removal of any redundant network (transformers, buses etc.), house load and parts of the low voltage network, and the aggregation of load at some buses. Additions were made to the planning network to reflect new CCGTs. Some existing CCGTs were modelled as single units connected to the transmission network via one transformer.

3.83 From the resulting DC network models an equivalent winter peak full AC network model was formed, and passed on to ESB NG for calibration against the original ESB NG winter peak planning model. Winter peak planning loads and generator levels were used in this study. The results of this calibration test indicate that there are some very minor differences in the load flow calculations between the two models, particularly for MVar flows in the Dublin area. These MVar differences were not unexpected, and do not impact on the results of our work which are based on MW flows. Comparison between these AC model results and the equivalent DC model indicated that MW flows were again similar.

3.84 For the non-locational analysis, generation and demand are collapsed to a single bus on the network[23].

N-1 security constraints

3.85 The network specifications cover the full Irish network of 348 nodes, and in addition to limits on individual lines it includes three types of algebraic surrogate constraint to represent the major n-1 contingency constraints and voltage constraints:

- constraints on individual lines;

[23] This means that transmission losses are not calculated within the LMP model in the non-locational analysis. Demand inputs were adjusted to represent transmission losses of 2.9% of total generation.

- limits on flows across transfer boundaries; and
- export and import limits for predefined 'zones'.

3.86 ESB NG derived these surrogate constraints for an intact network. It should be noted that these surrogate constraints would not necessarily capture the n-1 security constraints when the network has elements out for maintenance.

3.87 As summer limits are more binding because of lower line ratings in the summer, calibration of these surrogate constraints initially concentrated on a summer peak case. The summer peak DC network model was converted to an equivalent full AC network model. The pattern of generation and load was chosen from one of the market simulation cases. This network was deemed to be n-1 secure and feasible by ESB NG. Comparison between this full AC network model and the DC model again showed very little difference (< 1MW) in the MW flows, with the exception of a few lines around the phase shifting transformer in Dublin.

4. PRICES AND DISPATCH IN AN ENERGY-ONLY MARKET

4.1 In this section we present the results of our analysis of a uniform pricing market under a number of scenarios for ESB PG's behaviour. ESB PG currently owns all mid merit and peaking plant which would be expected to be on the margin most of the time and therefore setting the price.

Scenarios

4.2 We have run the non-locational model for a number of scenarios of ESB PG behaviour for 2006. Under this analysis the electricity pricing is assumed to be uniform over the network.

4.3 We model 25 sample days in the year. We have ensured that our demand projections are consistent with the demand in the three future year networks used by ESB NG planning.

4.4 We have analysed eight alternative scenarios for the behaviour of ESB PG in the market. The scenarios are defined as combinations of:

- the general level of price which emerges, expressed as a time-weighted average (TWA) of all the half-hourly prices over 2006;
- the extent to which ESB PG's bids into the market might generally be higher than the energy bids which would be expected in an atomistic market[24]; and
- the degree to which ESB PG might raise its bids further at times of high demand, to reflect the price pattern which might be expected from an energy-only market (without an explicit mechanism for rewarding available capacity) – we call this the value of capacity (VoC).

4.5 The TWA prices have been selected as follows:

- €45/MWh is the Best New Entrant (BNE) price[25] which underpins the present transitional regime for top-up power. It also corresponds to our own view of the base-load price which would be required by a generic new-entrant CCGT (combined-cycle gas turbine) in 2006. A TWA price of €45/MWh would therefore be consistent with a competitive market in equilibrium with new entry by CCGTs.
- A TWA of €51/MWh corresponds to the revenue which is effectively allowed to ESB PG at present, through the wholesale component in the price control on supply to the franchise market.

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24 Which, for each generating unit, would generally be at its SRMC (short-run marginal cost) of generation at most times of the day and year.

25 When calculated from our central view for gas prices in the year 2006.

- The €55/MWh has been chosen so that, together with the €45/MWh, it brackets the current €51/MWh.

4.6 In each scenario, the relevant TWA is achieved by applying a combination of two factors to the bids which would be expected in an atomistic (every generation station atomised to create a highly competitive environment) market. The first factor is a percentage by which ESB PG's bids are higher than the corresponding SRMC energy bids for its plants. Such a bid factor leads to prices which vary smoothly over the year.

4.7 The second factor is a value of capacity (VoC), which is spread over the half-hours of highest demand in the year. The VoC reflects the addition to price which might be anticipated, in an atomistic energy-only market, in order to reward the provision of available generating capacity. Depending on the scenario, the absolute value of the VoC is either:

- at the level which would be required to just incentivise new entry by a peaking plant[26] (in the €51/MWh and €55/MWh scenarios, in each of which the bid above SRMC is a residual calculated so as to achieve the required TWA price); or
- at a level which, when combined with the pre-selected percentage bid above SRMC, gives the required TWA price (in each of the €45/MWh scenarios).

4.8 The VoC is distributed across the half-hours in the year according to the following rules:

- it only applies in the Y% of half-hours with the highest demand; Y is 5% or 10% or 20%, depending on scenario; and
- in each of those half-hours, its value is proportional to the extent to which the demand in that particular half-hour exceeds the lowest demand over all the Y% of half-hours.

4.9 This process simulates a type of bidding behaviour by ESB PG which would lead to 'peaky' prices, concentrated at times of high demand. We consider that the price pattern which results from a Y of 10% most closely reflects what might be anticipated from an atomistic energy-only market.

4.10 As a comparison we have a case with no value of capacity or bidding above SRMC – labelled the SRMC case.[27] The resulting set of cases is shown in Table 4.

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26 Assumed to be an OCGT (open-cycle gas turbine).

27 Note: SRMC-only bidding is not a sustainable outcome in the long run, as fixed costs would not be covered. The SRMC case is provided only as a base case.

Table 4 – Cases modelled for the non-locational analysis

Case Identifier	Target Electricity Prices	ESB PG Bidding over SRMC	Annual TWA Value of Capacity	Half-hour spreading
2006 SRMC	SRMC level	0%	0	-
2006 NEC CCGT 5%	NEC[28] CCGT (TWA €45/MWh)	0%	€12.8/MWh	5%
2006 NEC CCGT 10%	NEC CCGT (TWA €45/MWh)	0%	€12.8/MWh	10%
2006 NEC CCGT 20%	NEC CCGT (TWA €45/MWh)	0%	€12.8/MWh	20%
2006 ESB PG Bid 25% NEC CCGT 5%	NEC CCGT (TWA €45/MWh)	25%	€6.7/MWh	5%
2006 ESB PG Bid 25% NEC CCGT 10%	NEC CCGT (TWA €45/MWh)	25%	€6.7/MWh	10%
2006 ESB PG Bid 25% NEC CCGT 20%	NEC CCGT (TWA €45/MWh)	25%	€6.7/MWh	20%
2006 ESB PG bid 43% VOC OCGT 10%	ESB PG Allowed Revenues (TWA €51/MWh)	43%	€8.4/MWh	10%
2006 ESB PG bid 60% VOC OCGT 10%	Above ESB PG Allowed Revenues (TWA €55/MWh)	60%	€8.4/MWh	10%

Annual TWA electricity prices

4.11 In Figure 21 below, we present a comparison of the time-weighted average (TWA) prices for 2006 under all nine cases.

4.12 It can be seen that the annual TWA prices are above the targets specified in Table 4. This is due to rounding errors in the LMP model, which in certain half-hours result in the dispatch of a plant which had not been dispatched in the generation

[28] Net Effective Cost of a new entrant CCGT – which is consistent with the Best New Entrant price discussed earlier.

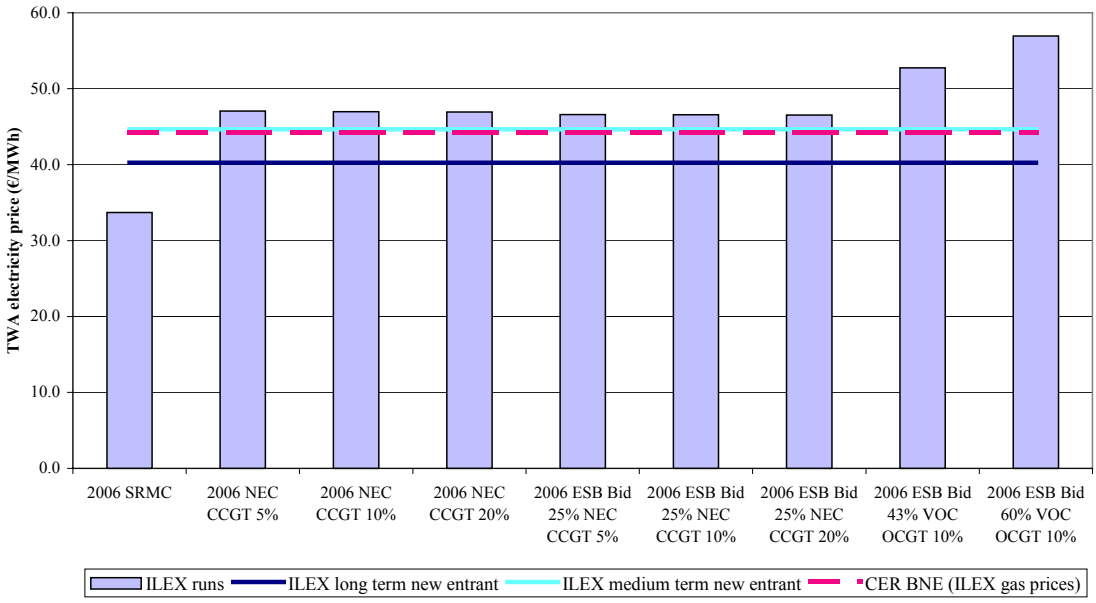
bid model. The offer price for these additional plant includes a component for start costs, which is spread over one hour's operation. However in the LMP model the plant can be dispatched for several hours, and consequently prices are artificially high in these hours leading to the slightly higher annual TWA prices. It should be noted that this modelling discrepancy in no way invalidates the results presented in this section.

4.13 These annual price projections are compared against the prices required by a CCGT new entrant running at base-load to cover its all-in costs. We have considered three scenarios for new entry:

- costs based on the ILEX medium-term new entrant;
- costs based on the ILEX long-term new entrant; and
- costs based on the CER best new entrant (BNE).

4.14 We summarise these new entry assumptions in Annex B.

Figure 21 – TWA price projections under all cases



Source: ILEX analysis.

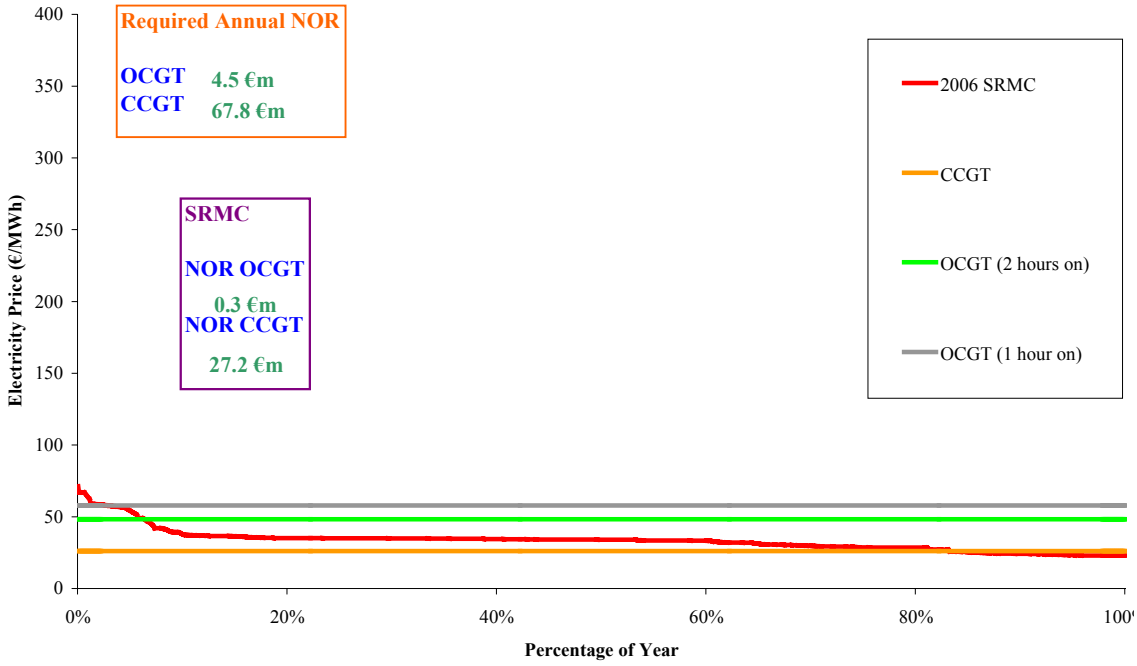
Annual price duration curves

4.15 The difference in prices at times of peak and off-peak between the nine cases can be illustrated by comparing the price duration curves (PDCs) as shown in Figure 22 to Figure 25. These curves show the percentage of year that the electricity price is above a certain value.

4.16 On each chart we have also included the short-run marginal costs for a CCGT[29] and an OCGT. For the OCGT we have shown the SRMC for an OCGT operating for one hour and for an OCGT operating for two hours.

4.17 The area under each PDC above the SRMC cost for a CCGT or OCGT is equivalent to the net revenue this plant would receive to cover all their fixed and capital costs. On each chart we show the net revenue a CCGT and an OCGT[30] would receive under each scenario, (for plant sized at 400MW and 50MW respectively) and compare this with the net revenue required by that plant each year to be economically viable[31].

Figure 22 – PDC for SRMC case



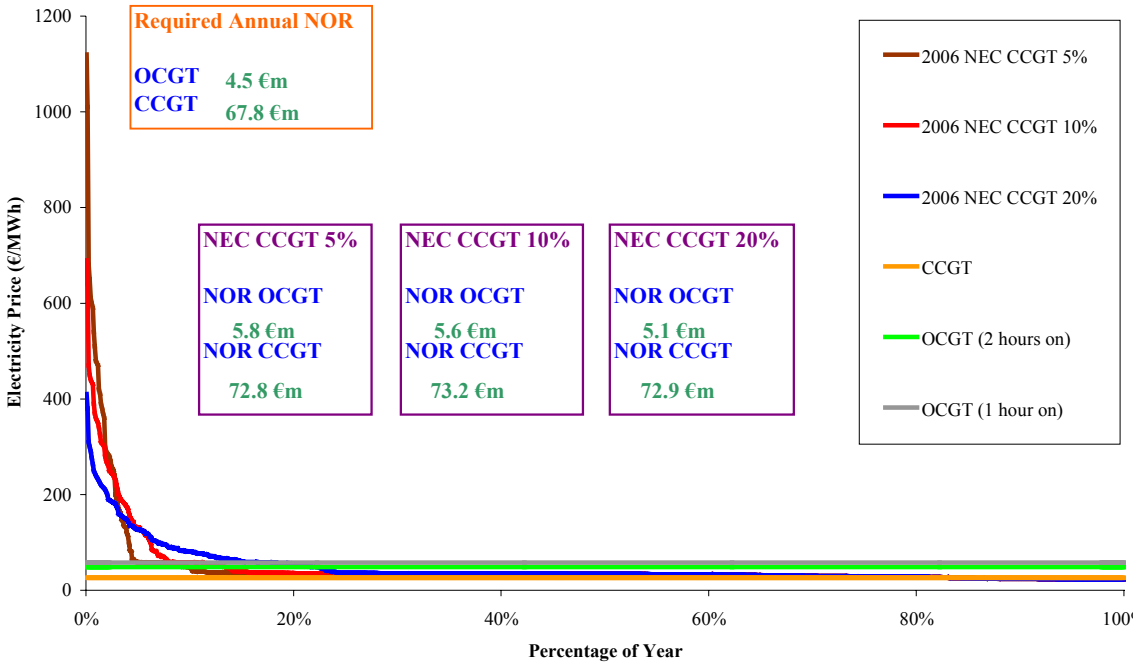
Source: ILEX analysis.

29 We have used the ILEX CCGT new entrant assumptions. If we were to use the CER BNE the marginal costs would be higher but the required net revenues to cover fixed and capital costs would be lower.

30 Assuming that the plant incurs one start per hour of operation.

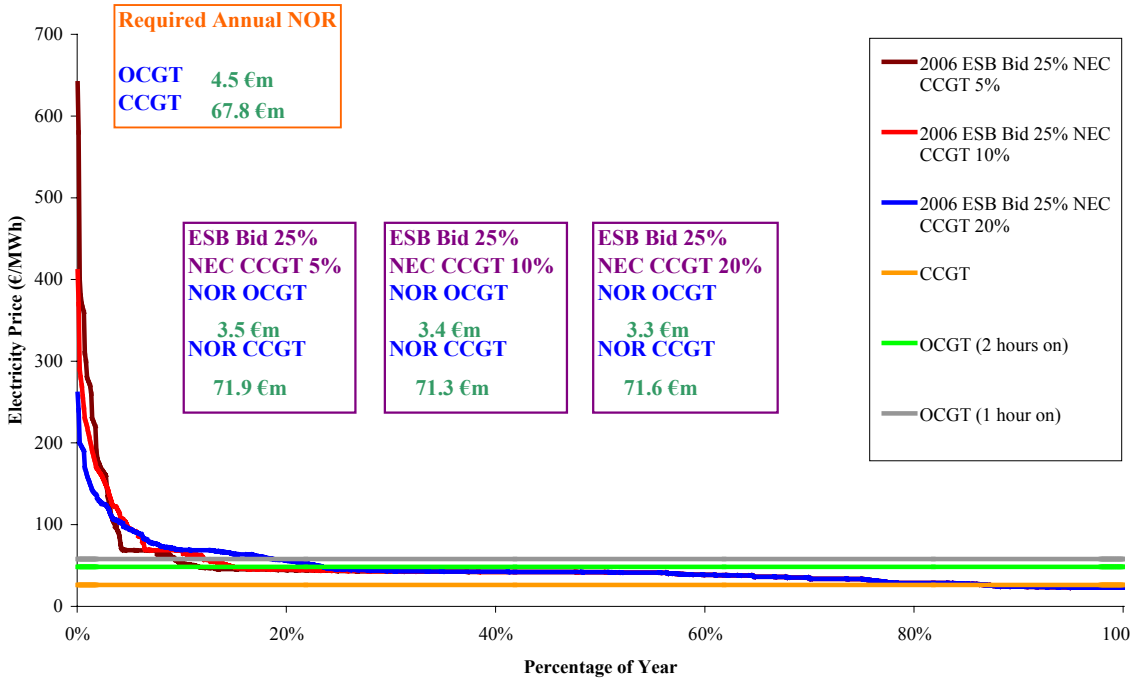
31 The assumptions behind the new entrant costs are contained in Annex B.

Figure 23 – PDC for NEC CCGT 0% ESB PG bidding cases



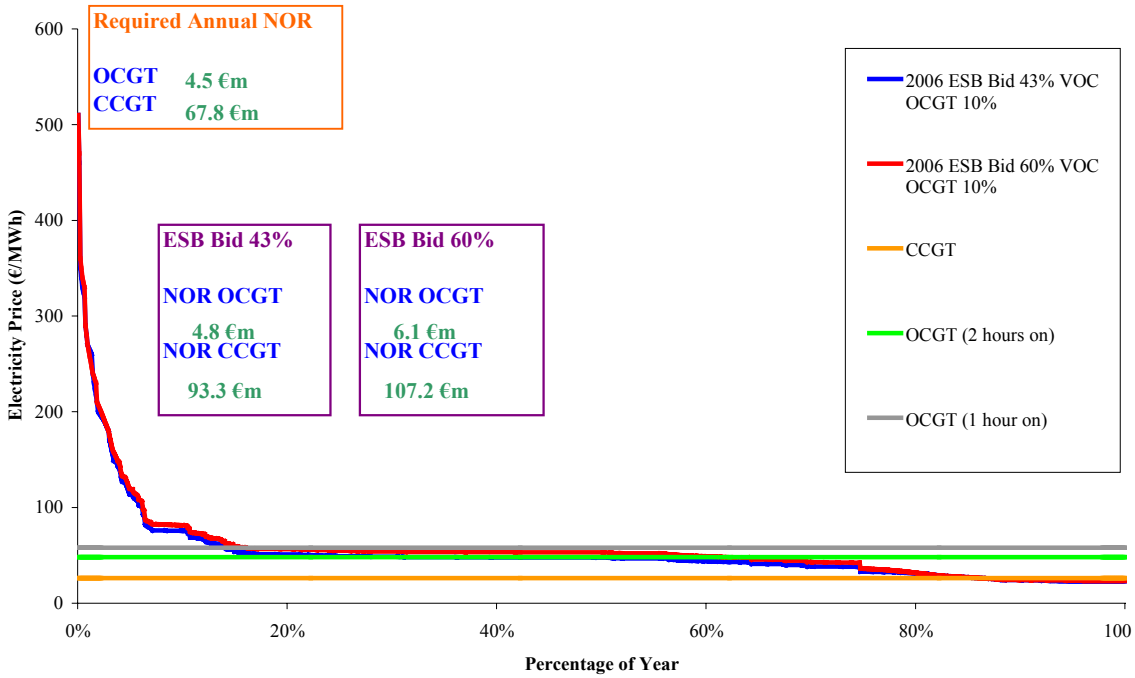
Source: ILEX analysis.

Figure 24 – PDC for NEC CCGT 25% ESB PG Bidding cases



Source: ILEX analysis.

Figure 25 – PDC for ESB PG Bidding 43% and above cases



Source: ILEX analysis.

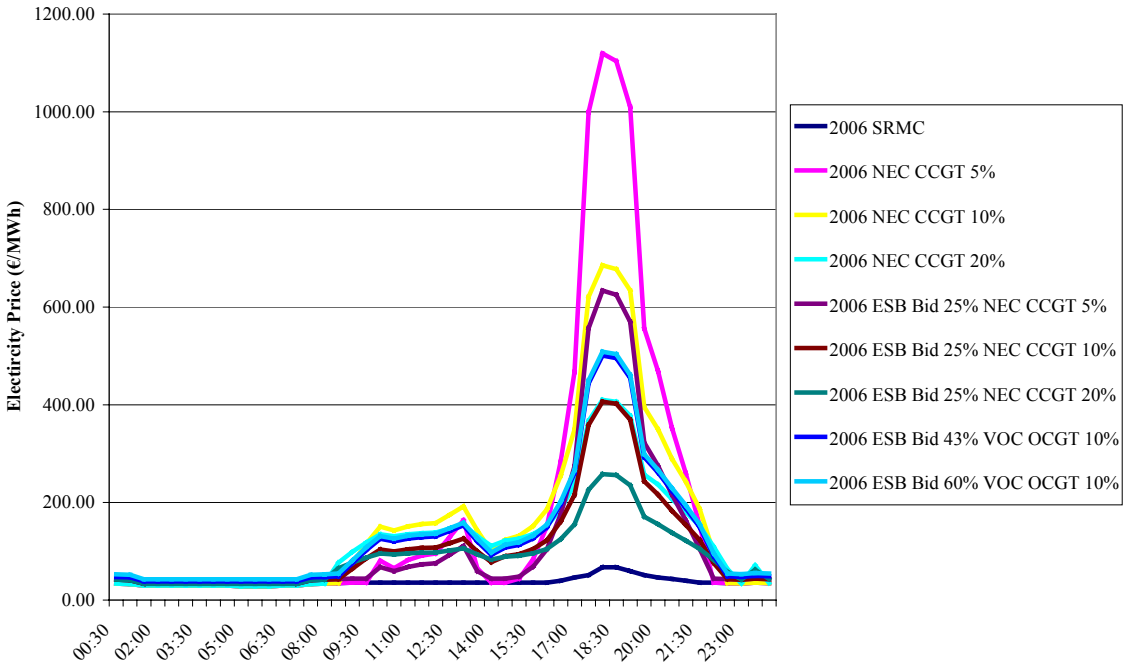
4.18 Under an SRMC-only case, new entry would not be viable – as expected. CCGT new entry is viable in all cases, which is expected since the chosen annual TWA prices are above the new entry cost for CCGTs.

4.19 The charts show that should price setting plant bid prices above SRMC such that prices are flatter across the year, then this would disadvantage an OCGT new entrant. For example, in the case where ESB PG plant bids above SRMC by 25% and the residual value of capacity is less than that required by a new entrant OCGT, an OCGT peaker is not viable (see Figure 24). However if ESB PG does not bid prices above SRMC uniformly across the year, which results in very high prices at peak, then OCGT new entry is incentivised (as in Figure 23).

4.20 In the scenarios in which ESB PG bids above SRMC at 43% and 60%, we have assumed that the residual value of capacity would be in line with that required to cover the fixed and capital costs of an OCGT peaker – and hence OCGTs are viable in both scenarios.

4.21 As a further comparison, in Figure 26 we show the half-hourly prices for the peak day under all cases. This clearly shows that the range in prices is over €1000/MWh at peak (excluding the SRMC case).

Figure 26 – Peak day prices

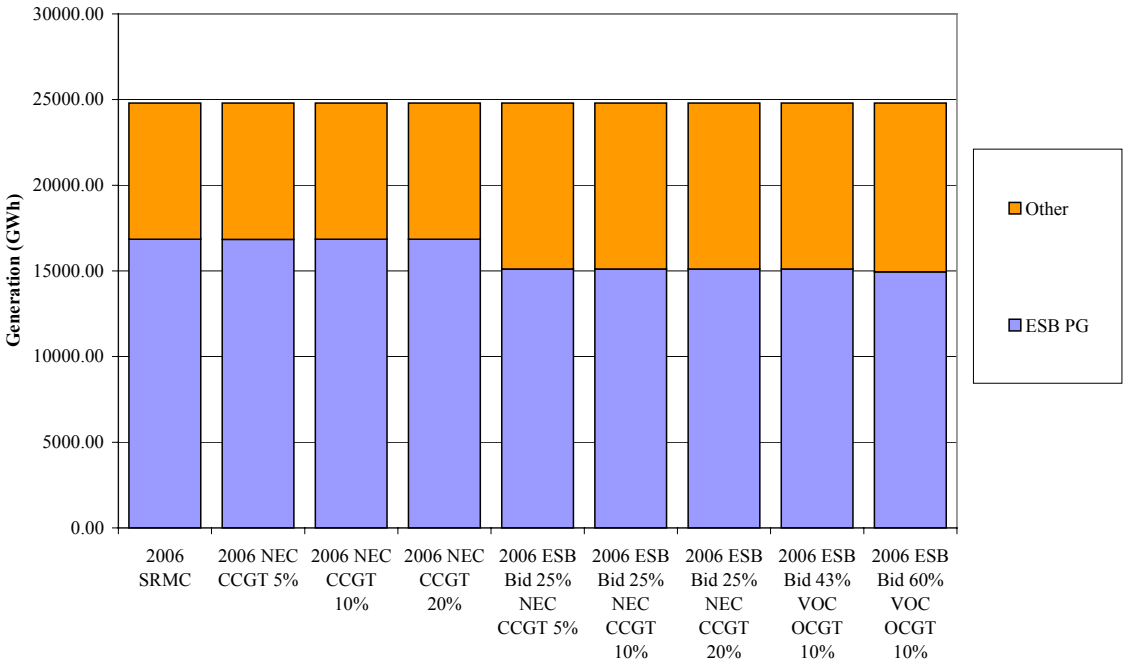


Source: ILEX analysis.

Annual generation

4.22 The annual generation under all nine cases is shown in Figure 27. The generation will be the same under all cases except where ESB PG bids up above SRMC in addition to peak periods, and as a consequence loses volume to its competitors.

Figure 27 – Annual generation[32]



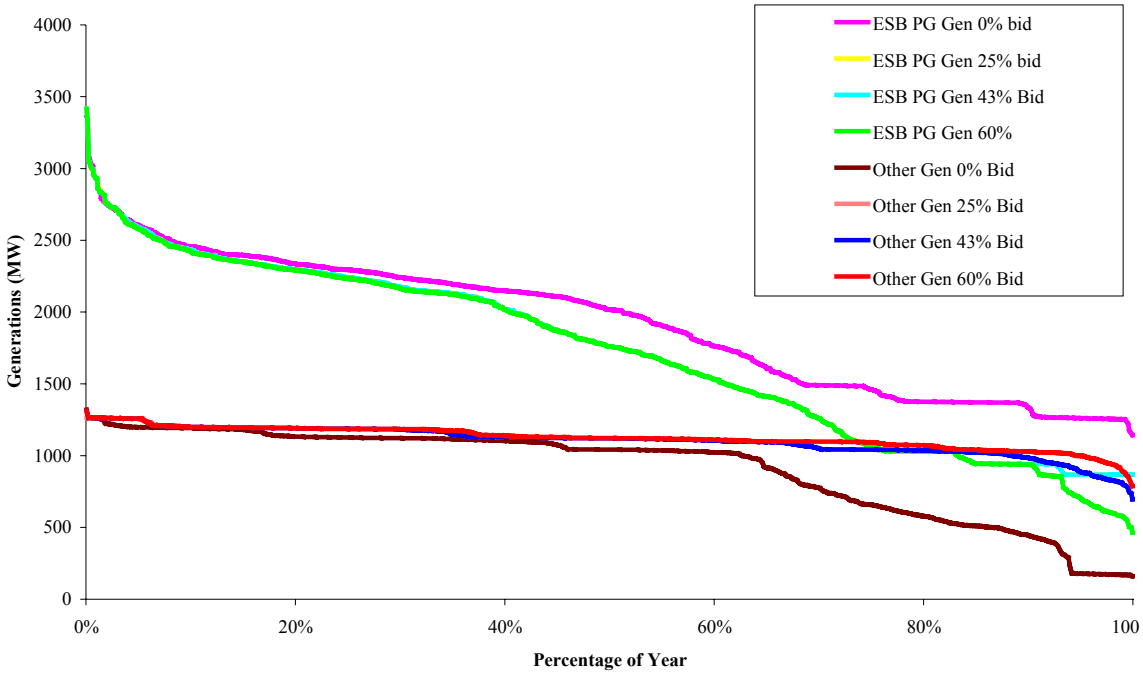
Source: ILEX analysis.

4.23 It is interesting to note that once ESB PG has bid above SRMC by 25% it no longer loses volume to any significant extent. This is a clear indication of the market dominance enjoyed by ESB PG. ESB PG's market share by generation under the scenarios where ESB PG does not bid above SRMC except during peak periods, as would be expected in an energy only market, is 67%.

4.24 In Figure 28 we show the generation curve for ESB PG, and all other non-ESB plant, under each of the ESB PG bidding cases. The curves show the percentage of the year that generation is above a certain level. It can be seen that ESB PG losses significant volume when bidding up to 25% higher, but from then even if ESB PG bids up to 60% higher it only loses volume in the extreme off-peak periods.

32 ESB PG does not include the ESB/Statoil plant.

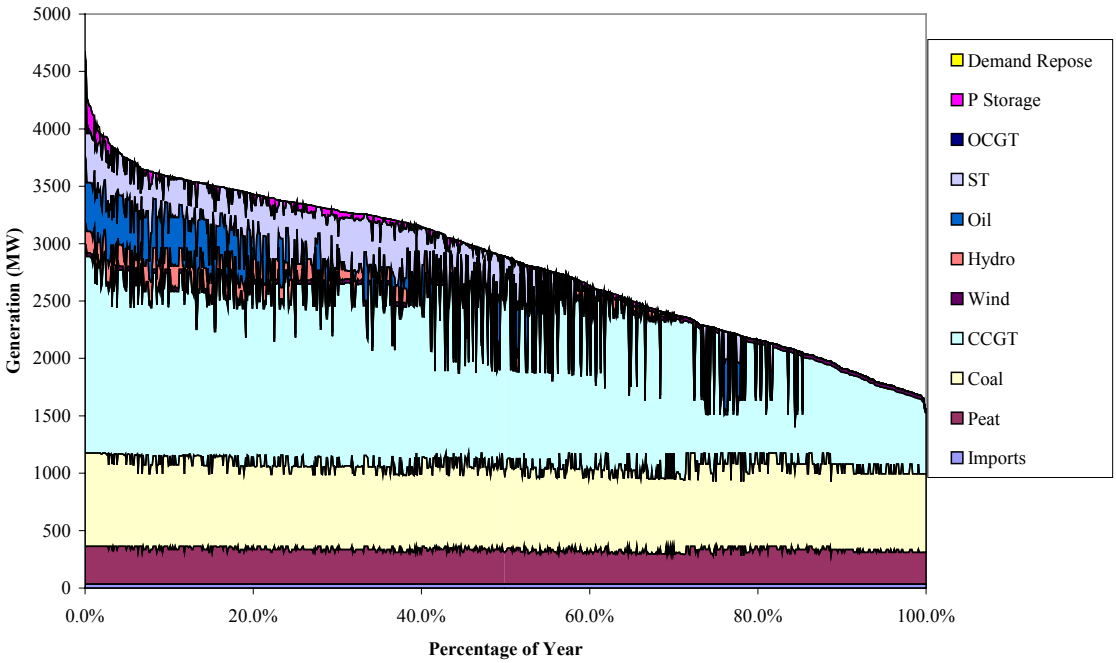
Figure 28 – ESB PG Generation Curve



Source: ILEX analysis.

4.25 In Figure 29 we present a generation PDC chart for the 0% ESB PG case where we show the generation by type. As can be seen the peat and coal plant are base-loaded all year while CCGTs are providing some mid-merit operation.

Figure 29 – Annual generation by type



Source: ILEX analysis.

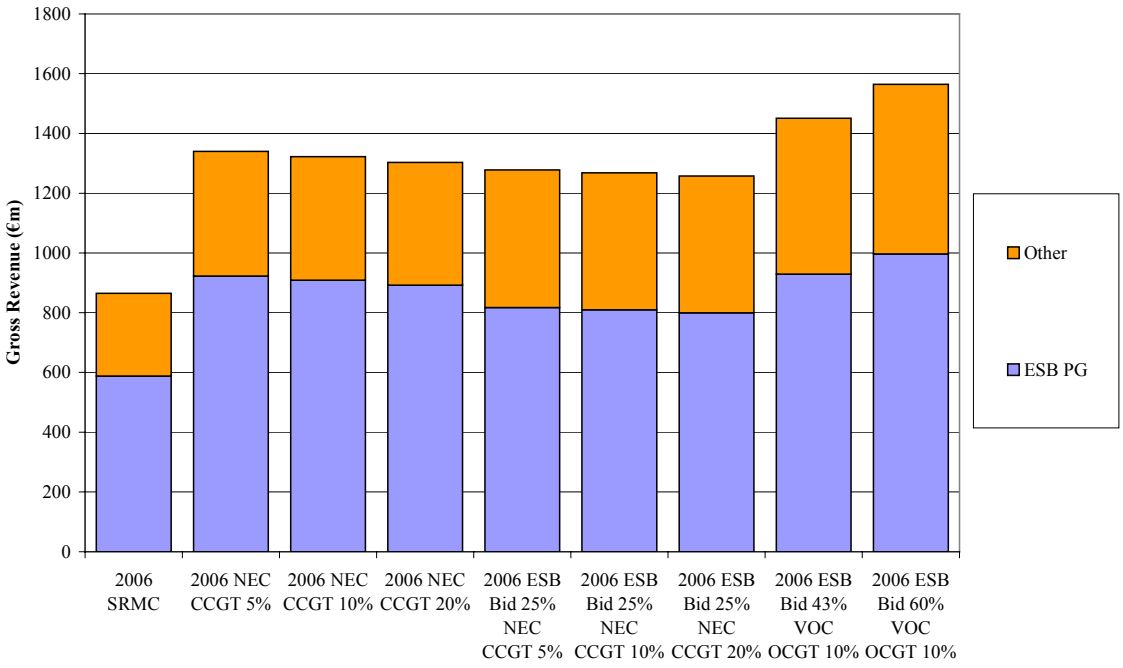
4.26 The 'spikiness' in Figure 29 is due to the different availability patterns for plant types over the year. For example the low CCGT generation patterns between the 40% and 60% mark will be due to the summer maintenance assumptions at this time.

Annual revenue

4.27 In Figure 30 and Figure 31 we present the gross revenue and net operating revenue,[33] respectively.

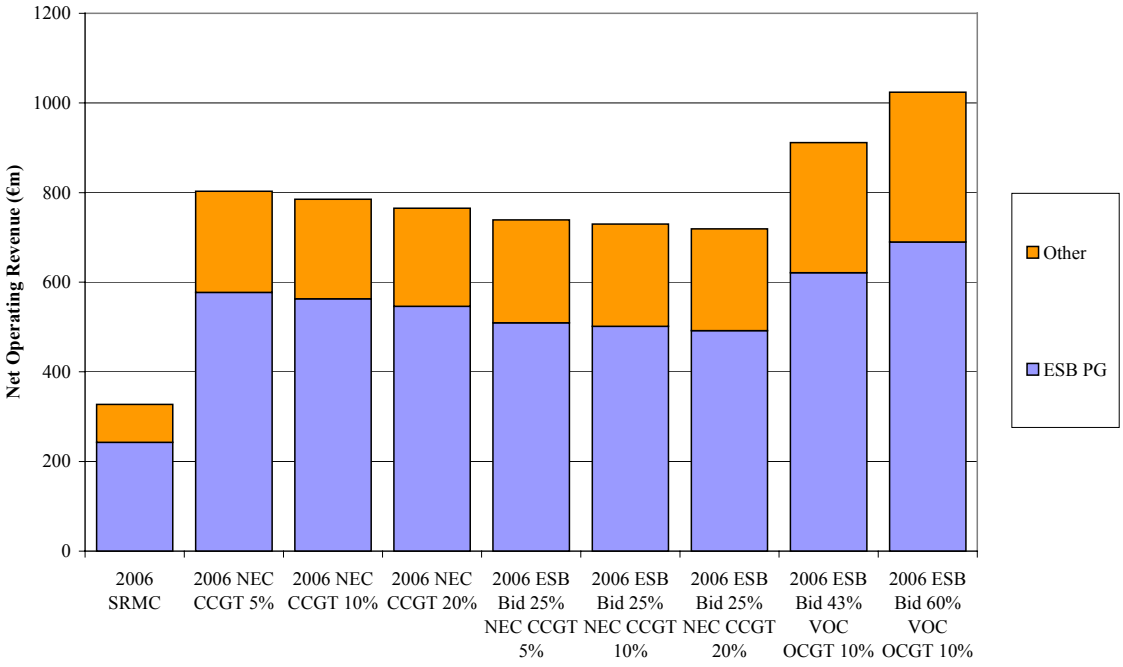
[33] Gross revenue net of fuel costs, variable other works costs and start costs – with a limit on two starts per day for each unit.

Figure 30 – Annual gross revenue



Source: ILEX analysis.

Figure 31 – Annual net operating revenue



Source: ILEX analysis.

4.28 Figure 31 clearly shows that ESB PG would lose net revenue if it bid above SRMC prices by 25% as opposed to not bidding up. ESB PG then increases revenue when bidding up at 43% and 60%; this is partly due to the higher annual TWA electricity prices in these scenarios. The fact that ESB PG will not lose volume when bidding at 43% as compared to 25% means that ESB PG will not lose revenue should it bid at higher than 43%. This is confirmed by the 60% bid-up case. Again this is an illustration of the level of ESB PG's market dominance.

Central Trader contracts

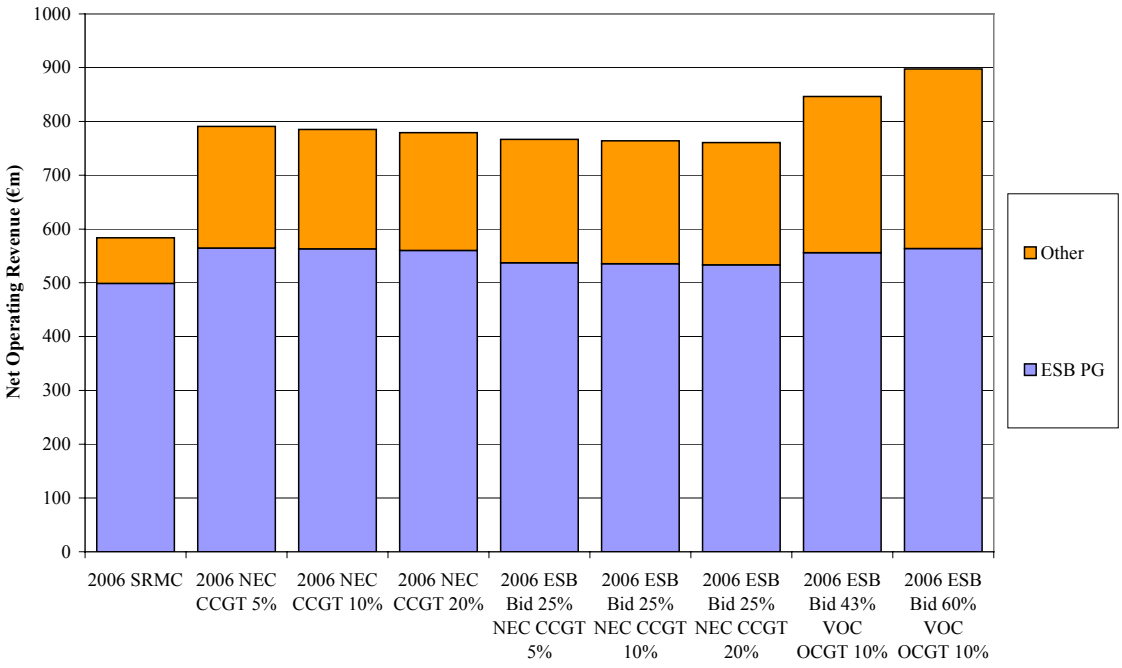
4.29 It has been proposed that 'vesting contracts' or 'central trader contracts' could be put in place to dilute ESB PG's incentive to use its market power. ESB PG would have contracts, in the form of Contracts for Differences (CfDs), in place for the majority of its output at a 'competitive' strike price.

4.30 We have modelled the impact on ESB PG's net operating revenues under central trader contracts with the following strike price and volume:

- with half-hourly volumes for each unit set at 80% of the volume from the NEC CCGT 10% case with no bidding up; and
- with half-hourly prices for each unit set at the prices from the NEC CCGT 10% case with no bidding up.

4.31 The net operating revenues for all generators under these CfDs are shown in Figure 32.

Figure 32 – Annual net operating revenue under central trader contracts



Source: ILEX analysis.

4.32 As can be seen by comparing Figure 32 with Figure 31, the Central Trader contracts have the desired effect in holding net revenues near to the NEC CCGT 10% case, even when ESB PG bids above SRMC at peak and at periods other than peak. These results will be very reliant on the volume of the contracts – the lower the volume then the less impact on ESB PG.

4.33 It should be noted that here we have not assumed that ESB PG's bidding behaviour is affected by the contracts. We have simply taken that behaviour as a given, as defined by each of our scenarios. Should the contracts have the desired effect of incentivising bidding at their strike prices, then **all** scenarios will tend even closer to the 'NEC CCGT 10%' case.

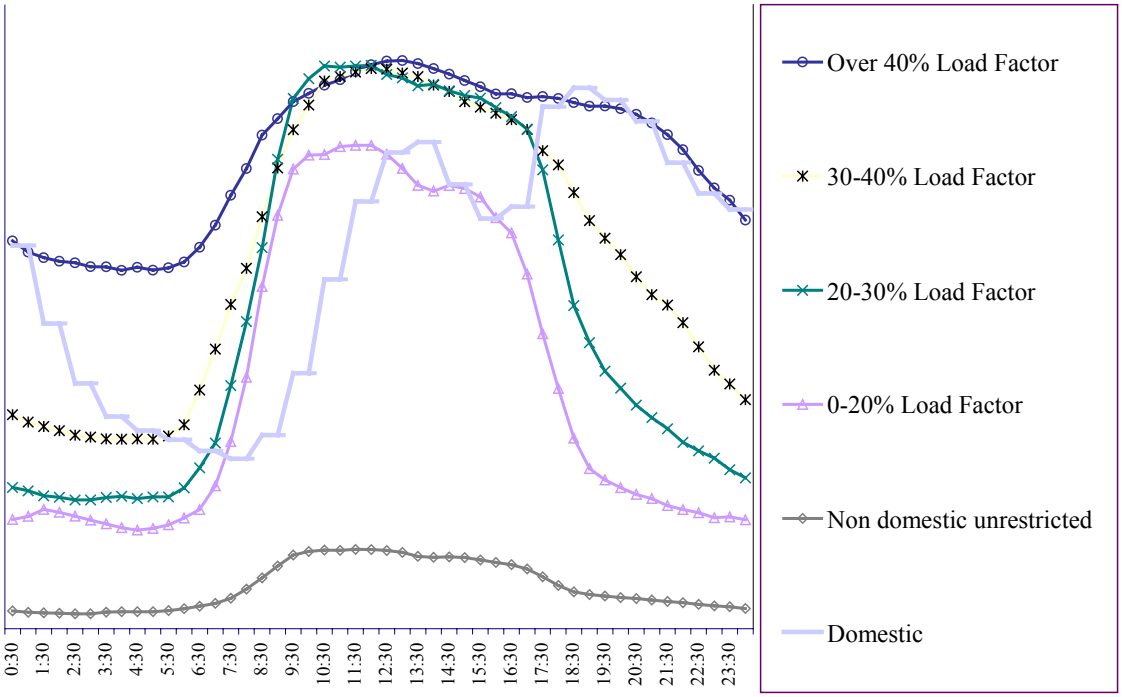
Customer demand profiles

4.34 Finally, we present the impact of these non-location results on the prices customer would pay given their load profiles.

Demand-weighted average prices

4.35 We have taken customer load profiles published on the CER website to illustrate the impact different price scenarios could have on different groups of customers. A sample winter business day profile shape for each customer category is shown in Figure 33 below.

Figure 33 – Sample customer demand profiles

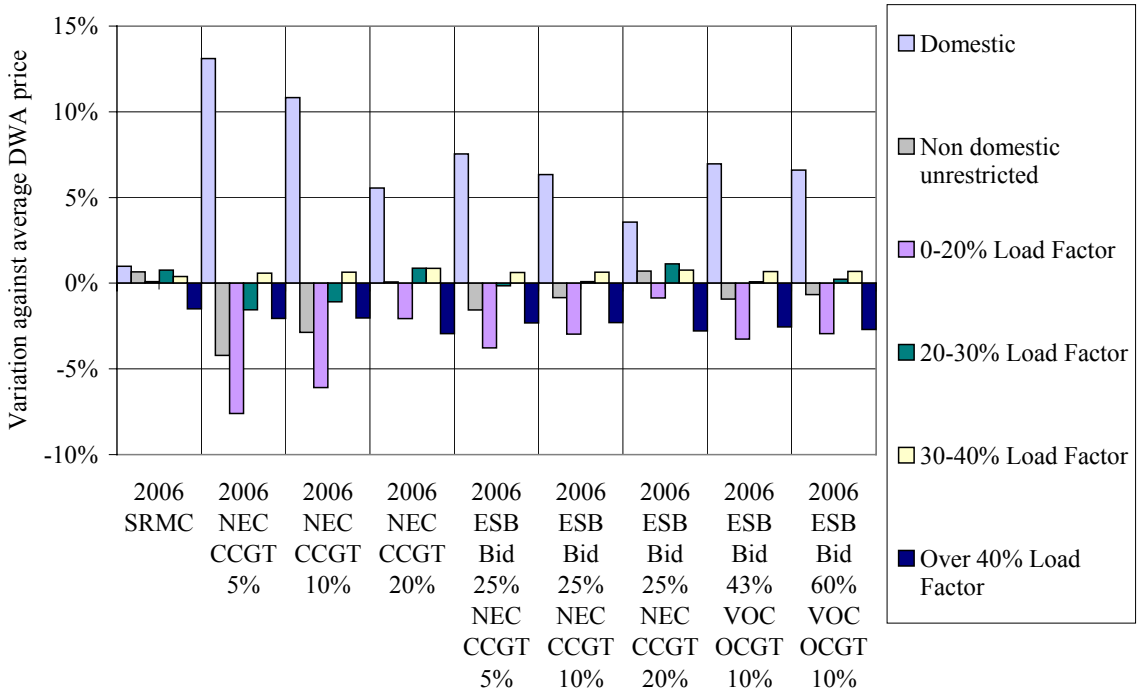


Source: CER Website.

4.36 In order to calculate a demand-weighted average (DWA) price for each customer class, we used the price arrays we calculated for each scenario and weighted them by the various demand profiles. We have then compared the DWA price for each class against the average DWA price for that scenario[34]. The variation by customer type across scenarios is shown in Figure 34 below. It should be noted that these results are illustrations of wholesale electricity prices, rather than final delivered prices to customers.

[34] We have used a simple, unweighted, arithmetic average across the seven customer DWA values.

Figure 34 – Impact of different price scenarios on demand-weighted average prices



Source: ILEX analysis.

4.37 For example, it can be seen in the NEC CCGT 5% case that Domestic customers face higher DWA prices than the average over all customers, whereas the Non-domestic customers face lower prices.

4.38 The reason for this is that the price profile is highly correlated to the demand profile for domestic customers and hence the peak half-hourly prices correspond to the peak in domestic demand. Non-domestic demand does not follow the price profile to the same extent and therefore the DWA price is lower than the average. It can also be seen from Figure 34 that the DWA prices increases as load factor increases for non-domestic customers. This is due to the fact that the 0-20% load factor profile does not relate to the 0-20% highest half-hour prices, whereas the 40% load factor profile covers a far higher proportion of the high-priced periods

4.39 Comparison across the scenarios shows that the peakier the wholesale prices, the greater the difference in DWA price across categories. For instance, comparison of the three 2006 NEC CCGT cases shows that, as the number of periods over which high prices are spread increases, the extent of variation around the average price is reduced.

5. LOCATIONAL MARGINAL PRICES

Introduction

5.1 This section describes the results of the locational modelling, focusing on the range and stability of the locational marginal prices. We look at price ranges across the nodes, and consider some specific cases in more detail. As with the non-locational work, all price values are expressed at 2002 levels.

5.2 The LMP model creates prices for each of the 348 nodes on the network. Within this report we illustrate the variation in prices across the country using a set of representative nodes. These nodes represent key points with generation capacity, and some other strategic points on the network – the prices at points that are not represented will be close to those that are depicted.

5.3 We have conducted a variety of locational model runs, with two main tests spanning 240 separate supply-demand states (24 hours in each of 10 representative days). These two main tests assume a new 400MW CCGT in either Dublin (Maynooth) or alternatively in the southwest (Knockraha). In addition we have run some sensitivity tests relating to plant maintenance.

5.4 Each of the locational model runs has been based on the scenario under which market prices are at around the levels implied by ESB PG's current price control. We achieve this through ESB PG bidding at 43% above its per-MWh marginal costs (excluding start costs) at all times, and even higher for the 10% of half-hours of highest demand in the year. This is discussed in paragraph 4.6 above.

5.5 Throughout the locational analysis we assume that the bidding behaviour is the same as in the non-locational analysis. We have not considered the impact of local market power.

5.6 The locational model runs are to be considered as snapshots, and have not been aggregated to represent a year as a whole. We have not attempted to weight the importance of individual hours in reporting results. Similarly, in reporting prices we have not considered the relative importance of different nodes – where we report aggregate figures, they are simple averages across the 240 hours modelled[35].

5.7 The precise time at which each price pattern may occur may not, in some circumstances, be accurately represented by the model. Constraints arise from interactions between dispatch and plant availability and the state of the network. Some constraints may occur when there are plant outages, or when parts of the network are being maintained, and the timing of these constraints is only approximated in this analysis.

5.8 We model plant availability by deloading each unit by a pre-determined value to account for seasonal plant maintenance and expected forced outage rates. It is possible that this could understate the incidence of constraints at certain times, as we effectively model slightly reduced generation capacity at each location against a complete network. To mitigate this we have modelled a large number of system states designed to consider a range of possible outcomes. We have also considered some specific sensitivity tests to look at different patterns of plant availability in order to capture the predominant patterns in nodal prices.

5.9 Some of the model results are expressed as price ranges across the chosen nodes. We present first the results for the ten sample days, covering 240 separate demand states. We then show more detailed information on the nodal prices in four key hours, including the three ESB NG planning network states (winter peak, summer peak and summer night valley hours), plus a case where price differentials across the nodes are high.

Range of nodal prices

Ten sample days

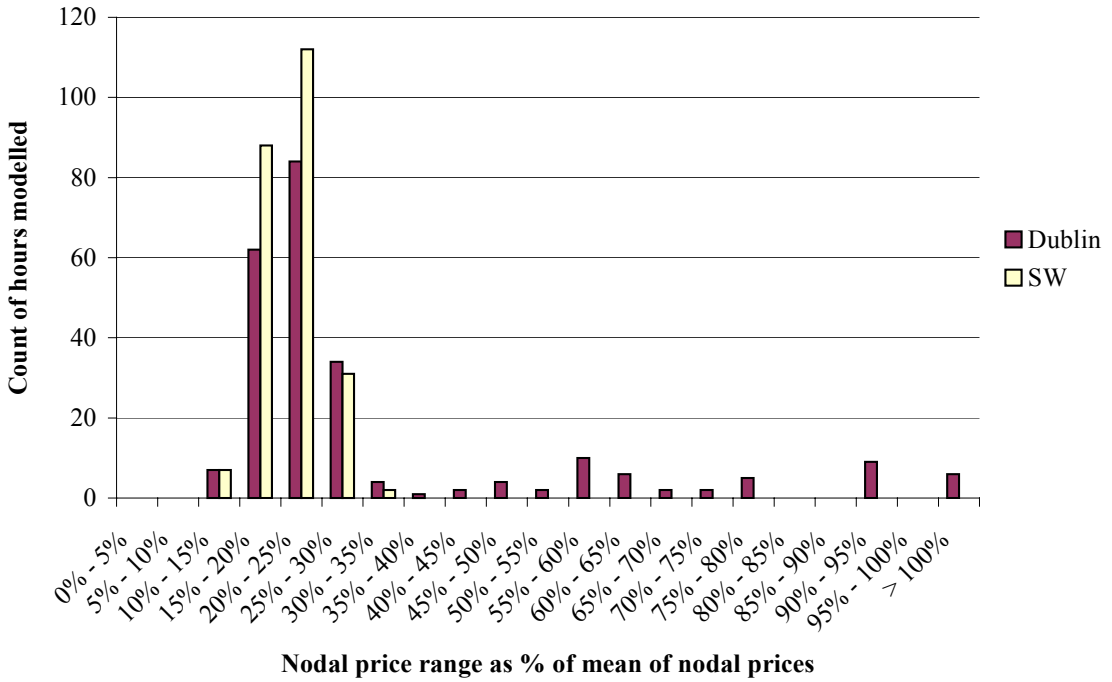
5.10 For this analysis we consider the range of nodal prices in the two main tests (Dublin or southwest location for the new CCGT), as a frequency count across the 240 hours modelled. The range of prices is measured across 61 nodes that are modelled with generation or demand response, and is expressed as a percentage as follows:

Range = (maximum nodal price – minimum nodal price) / (mean of nodal prices)

[35] For example, we believe that using a generation volume-weighted average price measure could be misleading, as the nodal prices are correlated with generation volumes.

5.11 Figure 35 plots a frequency count of these nodal price range percentages, counting the number of hours modelled (out of 240 in each test).

Figure 35 – Frequency distribution of nodal price range

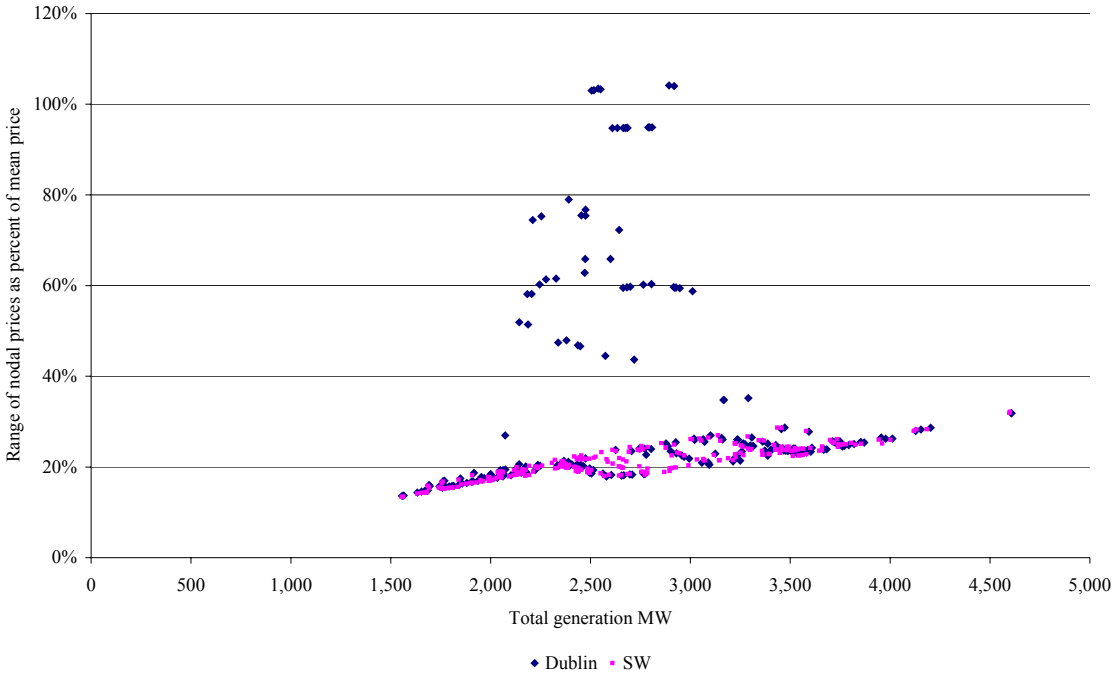


Included – 61 nodes with generation or demand response, counted over 240 modelled hours, with a new CCGT in Dublin or the southwest, assuming annual average price level in line with ESB PG's current price control

5.12 With the new CCGT at either location, in the majority of hours the range of nodal prices (maximum price - minimum price) is below 25% of the mean nodal price. However, with the CCGT located in Dublin, there is a small number of hours with a larger price range. Closer investigation reveals that, at these times, Moneypoint unit 3 (which is connected to the local 220kV network) is dispatched down. This is addressed in greater detail from paragraph 5.39 below.

5.13 Figure 36 plots the price range against the total generation in MW. With the CCGT in the southwest, the relationship is well behaved, with a near-linear fit between the price range and the level of generation. With the CCGT in Dublin, the relationship is similar but with a number of outliers with a higher range in prices. As noted in the previous paragraph, these outliers relate to the instances when Moneypoint 3 is dispatched down due to a transmission constraint.

Figure 36 – Nodal price range (percentage of mean) against total hourly generation



Included – 61 nodes with generation or demand response, counted over 240 modelled hours, with a new CCGT in Dublin or the southwest, assuming annual average price level in line with ESB PG's current price control

Four key hours

5.14 As well as looking in detail at the winter peak, summer peak and summer night valley periods, we consider an hour in which Moneypoint 3 is dispatched down and the range of prices increases. Table 5 shows the price range in these key hours; each of these hours is considered in more detail from paragraph 5.23.

Table 5 – Nodal price range for key hours

Case	Dublin			SW		
	Max €/MWh	Min €/MWh	Range %	Max €/MWh	Min €/MWh	Range %
Winter peak hour	591	439	32%	614	457	32%
Summer peak hour	92	73	24%	92	73	25%
Summer night valley hour	25	22	16%	25	22	15%
Shoulder hour[36]	72	21	104%	46	38	19%

Included – 61 nodes with generation or demand response, for four key hours, with a new CCGT in Dublin or the southwest, assuming annual average price level in line with ESB PG's current price control. 'Range' refers to the absolute range in prices (maximum – minimum) as a percentage of the mean price across the 61 nodes.

5.15 The Table shows the range of prices in these hours in both absolute and relative terms. Both Figure 36 and Table 5 illustrate similar points – for the southwest test, the range of nodal prices increases with the level of total generation, whereas for the Dublin test this is broadly true except for a number of outliers.

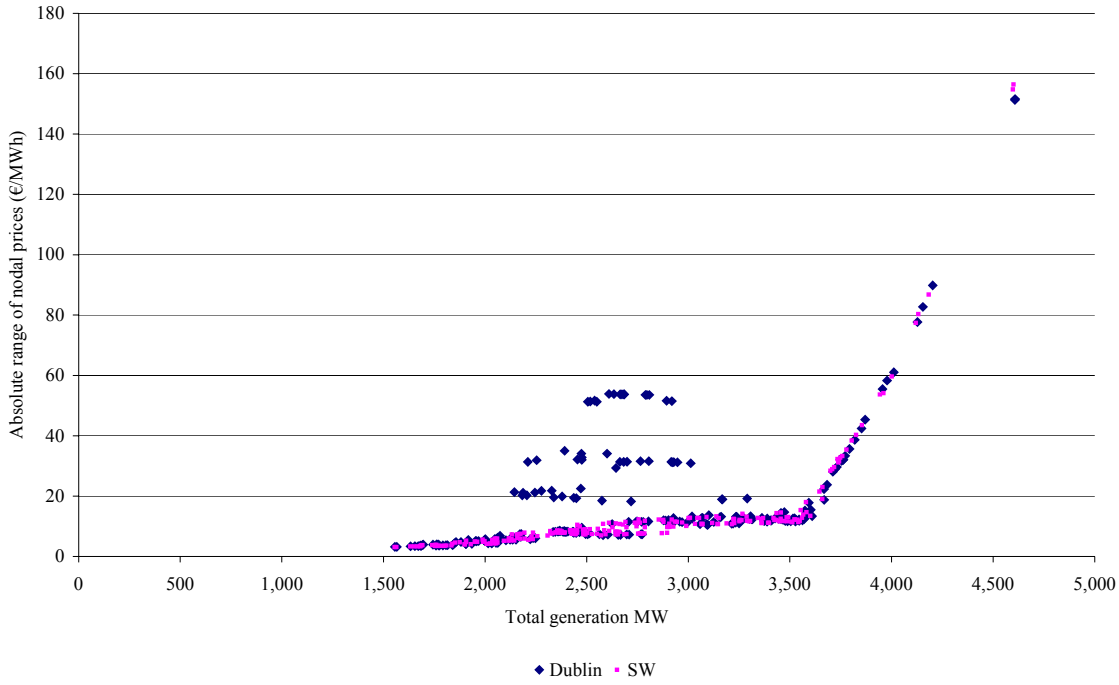
5.16 These outliers are clustered around the 'shoulder' months, in which we model a lower level of plant maintenance than in the summer, but in which the lower (summer) network ratings are assumed. One of these outliers is considered from paragraph 5.39.

Ten sample days – absolute price range

5.17 Figure 37 plots the absolute range of nodal prices against the total level of generation in each hour. Excepting the outliers in the Dublin test, this pattern is clear and similar across both tests with a step change in the relationship at generation levels above 3500MW. This is in line with the price profile.

[36] For example, we model this occurrence at 22:00 on an April non-business day. While the outcome is a real phenomenon, the exact timing may be a consequence of our model assumptions.

Figure 37 – Nodal price range (absolute) against total hourly generation



Included – 61 nodes with generation or demand response, counted over 240 modelled hours, with a new CCGT in Dublin or the southwest, assuming annual average price level in line with ESB PG's current price control

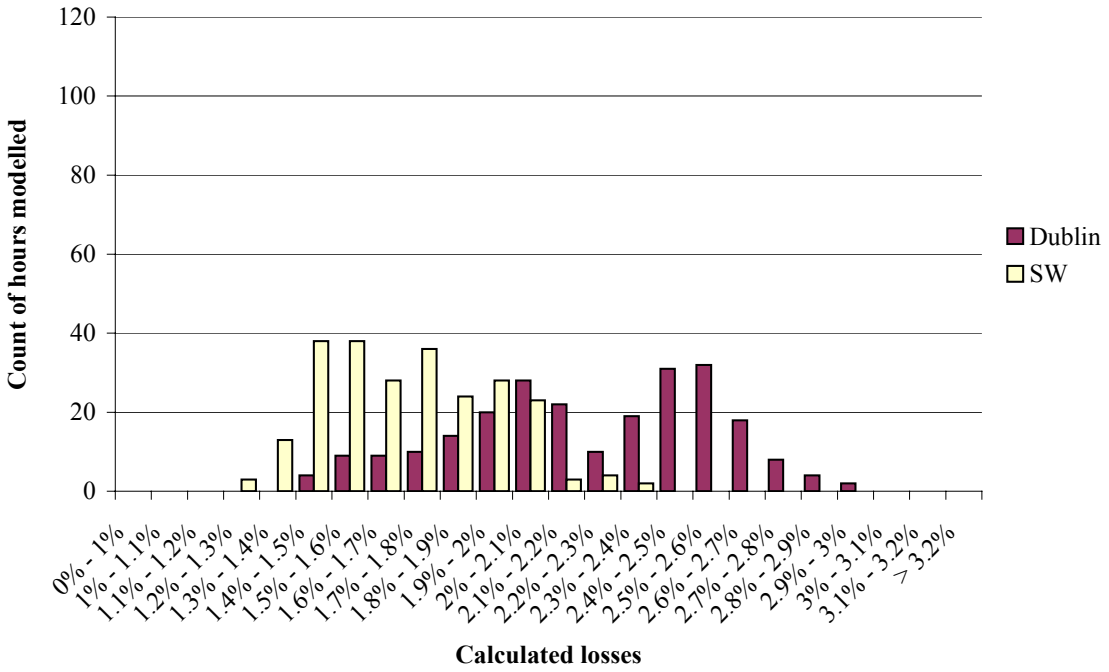
Transmission losses

5.18 The level of transmission losses is dependent on the location of the new CCGT, given the typical pattern of power flow. Overall, across the 240 hours modelled[37], there is typically a net outflow of power from the Dublin area, and a net import in other areas. At periods of higher demand the import to the southwest is reduced as mid-merit units there, such as Marina, Aghada 3 and Tarbert 1 are scheduled. With the new CCGT located in the southwest, the Cork area becomes broadly balanced across the 240 hours tested, and the overall export from Dublin reduces.

5.19 As expected, locating the new CCGT in the southwest reduces the average level of losses. Figure 38 shows a frequency count of the transmission losses estimated in the DC load flow, for each of the 240 hours modelled. The values are calculated as the aggregate volume lost as a percentage of total generation in the hour.

[37] These estimates are based on the 240 hours modelled, but have not been aggregated to a year as a whole. The pattern is different in different hours, depending on which units are scheduled.

Figure 38 – Frequency count of transmission losses



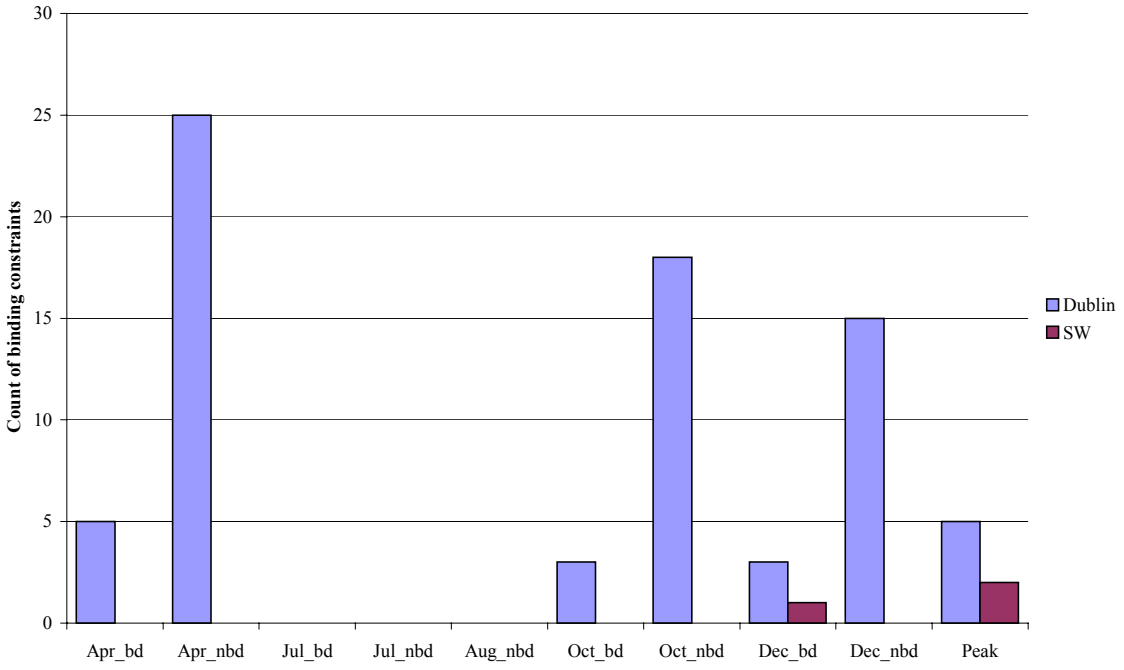
Included – losses as a percentage of generation, counted over 240 modelled hours, with a new CCGT in Dublin or the southwest, assuming annual average price level in line with ESB PG's current price control

Transmission constraints

5.20 The nodal price patterns are a result of a combination of transmission losses and transmission constraints. As expected, we have found that when using the surrogate limits to represent the n-1 security constraints, the individual line constraints are not binding.

5.21 Figure 39 shows the frequency of transmission constraints, by sample day modelled, for the two cases. It shows that constraints are far more frequent with the new CCGT located in Dublin, with most constraints occurring in the shoulder months. With the new CCGT in the southwest, constraints are only reached at winter peaks, as is borne out by time-of-day analysis.

Figure 39 – Binding transmission constraints by sample day



Included – all binding surrogate transmission constraints, counted across the 240 hours modelled, with a new CCGT located in Dublin or the southwest

5.22 As noted in paragraph 5.16, we model the constraints as falling predominantly around the shoulder months, in which we assume summer (lower) network ratings but winter (higher) plant availability.

Detailed assessment of key hours

5.23 We consider four hours in more detail:

- winter peak hour;
- summer peak hour;
- summer night valley hour; and
- high price ranges – April non-business day hour starting 22:00.[38]

5.24 The prices at key nodes are shown in two ways – firstly as a series of bar charts for 17 representative points on the network placed on a map of Ireland, and secondly as a bar chart showing prices at 31 different locations. We repeat results

[38] The timing is considered to be illustrative, and the scenario could and would occur at other times, for example in shoulder periods when transfers of power between areas may be high.

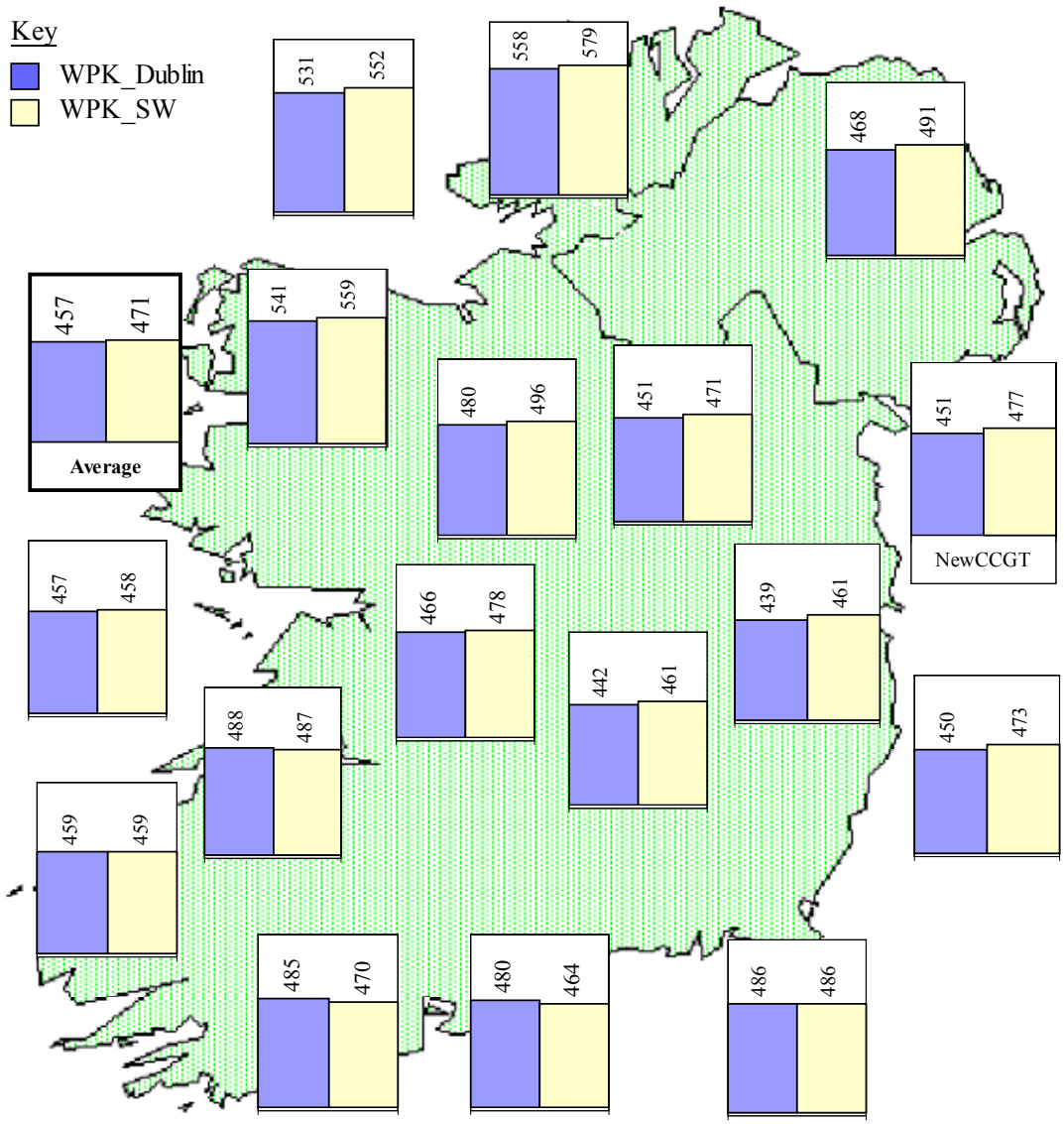
for the two main cases, with the new CCGT located alternatively in Dublin or in the southwest.

Winter peak hour

5.25 Figure 40 considers the pattern of prices at system peak hour with the new CCGT in the two alternative locations. The average price is also shown in the top-left, calculated as a generation-weighted average price (total generator revenue divided by total generation)[39]. The range of prices at the generator nodes is around 32% of the mean nodal price (a maximum difference in prices of around €150/MWh), whether the new CCGT is in Dublin or the southwest.

[39] For reference, in the non-locational analysis (before consideration of transmission constraints) the market-clearing price at system peak is around €500/MWh The prices in the locational and non-locational analysis are not exactly comparable since, in deriving the load for the non-locational analysis from generation (export) totals, we deduct an average value for losses (2.9%). The losses estimated within the LMP model in any hour may not match that figure.

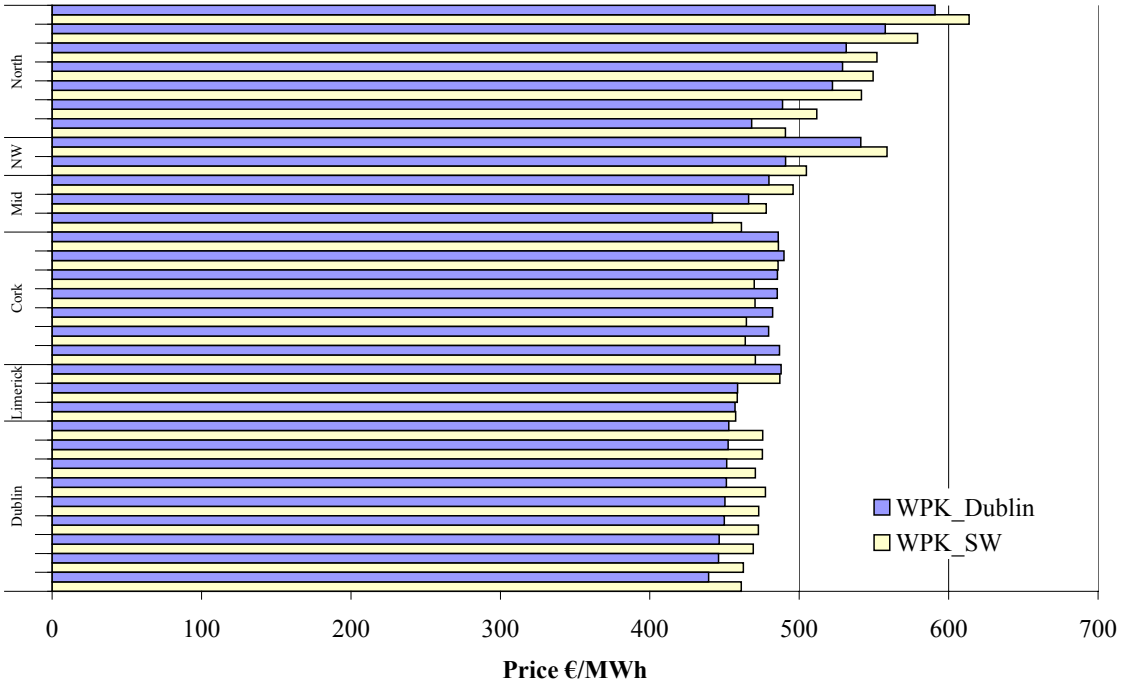
Figure 40 – System peak price patterns (€/MWh)



Included – prices at 17 selected nodes, at system peak (18:00 on peak winter day), with new CCGT in Dublin or the southwest, assuming annual average price level in line with ESB PG's current price control

5.26 Figure 41 shows the prices at 31 selected points on the network in the winter peak hour, in the cases with the new CCGT at Dublin and in the southwest.

Figure 41 – Nodal prices at winter peak hour



Included – prices at 31 selected nodes, at system peak (18:00 on peak winter day), with new CCGT in Dublin or the southwest, assuming annual average price level in line with ESB PG's current price control

5.27 Figure 40 and Figure 41 show that the highest prices at winter peak are in the northern area, and the lowest prices are around Dublin. With the exception of a must-run constraint raising the price slightly, we have established that the price differentials in the Dublin case are entirely due to transmission losses.

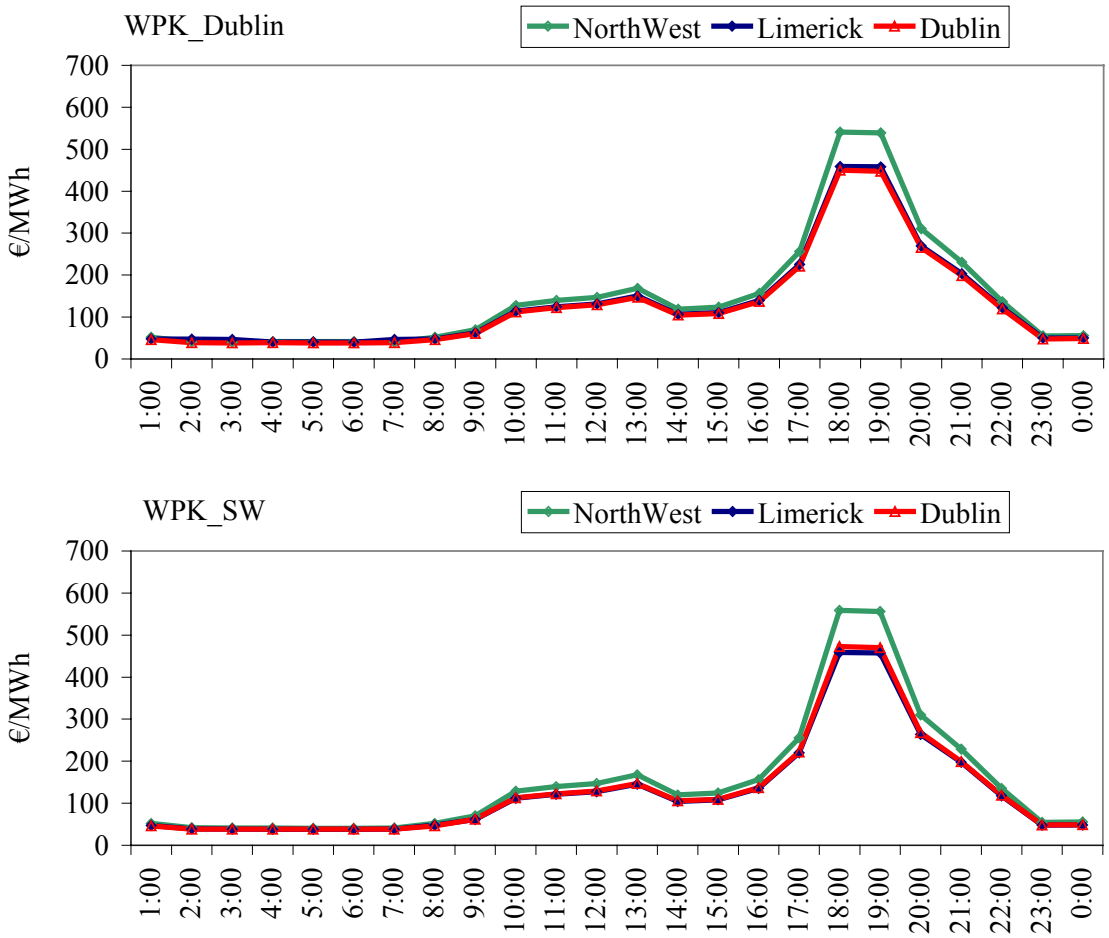
5.28 As expected, the location of the new CCGT influences the price patterns. By locating the CCGT in the southwest, peak prices in the Cork area would be lower than in the Dublin case (by around 3%), in the Limerick area there would be little impact, but prices in other areas including the Dublin area would be 3-6% higher.

5.29 By locating the new CCGT in the southwest, we estimate that total losses in the peak hour would be lower (2.3% instead of 2.5%, using the DC approximation). Assuming a very simple treatment of start costs (equally spread across all 24 hours), with the new unit located in the southwest, the total costs of generation would be fractionally (<0.5%) lower, and overall generator revenue (and average prices to consumers) would be around 3% higher compared with the Dublin case.

5.30 One possible explanation for the coupling of reduced costs with increased prices is that the particular loss factor which applies to the unit which is marginal (over the vast majority of the network, which is generally unconstrained in this hour) is increased.

5.31 Figure 42 illustrates prices in the Dublin, Limerick and northwest areas, over the 24 hours of the winter peak day. The price variation follows the profile of demand, with the greatest variance over the evening peak period. The impact of locating the new CCGT in Dublin or the southwest is not high.

Figure 42 – Pricing across the winter peak day at three points

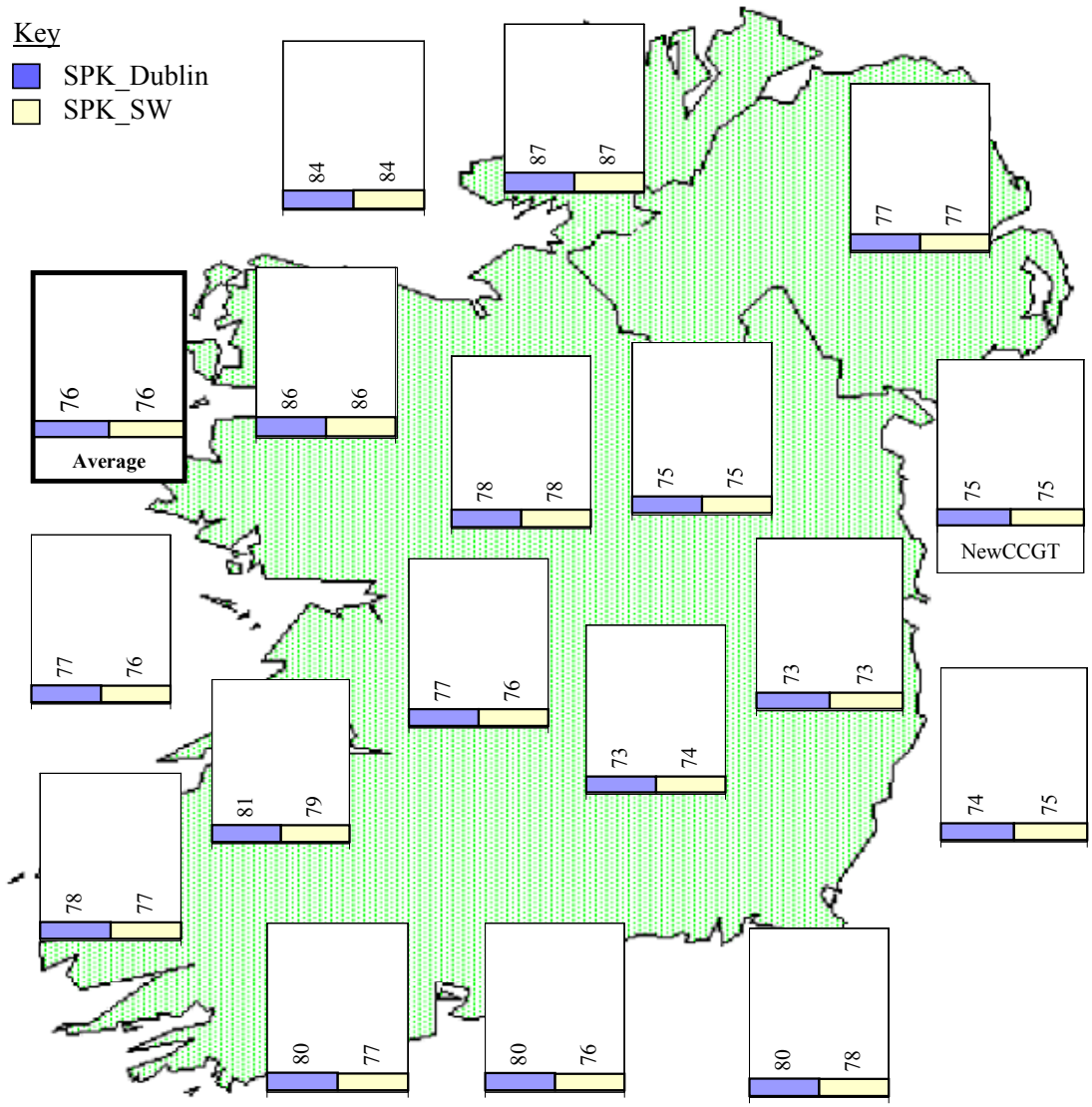


Included – prices at three representative nodes across the 24 hours of the winter peak day

Summer peak hour

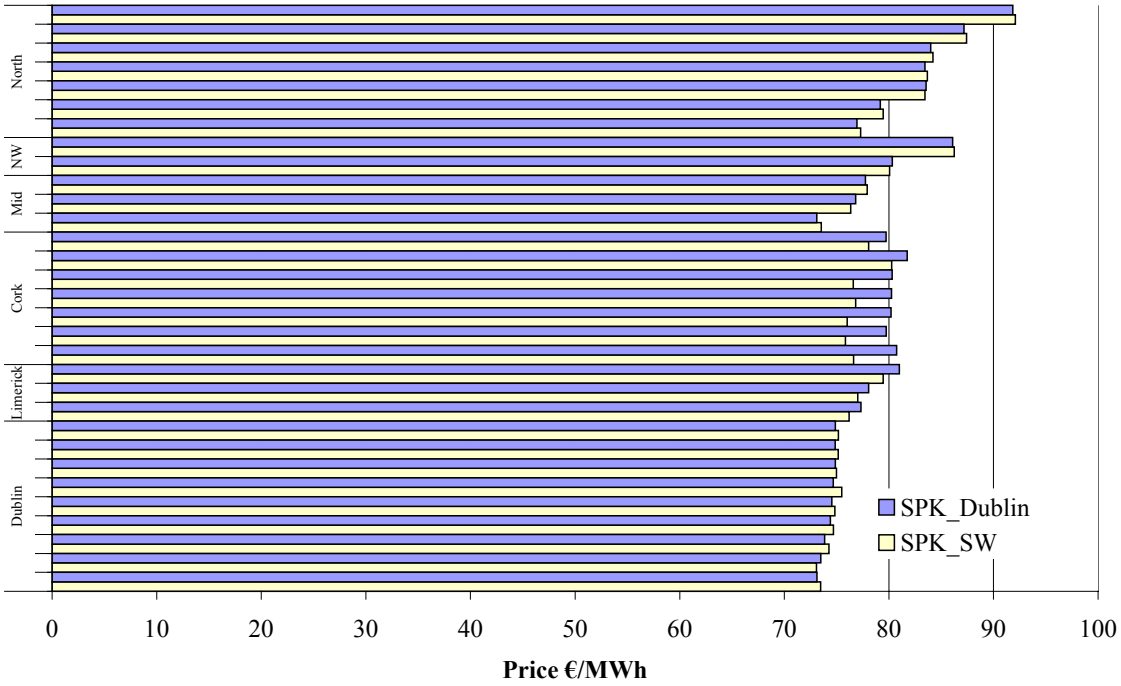
5.32 Figure 43 and Figure 44 show the prices at different locations in the summer peak hour. The range of prices is around 25% of the mean nodal price (a range of around €19/MWh), irrespective of where the new CCGT is located.

Figure 43 – Summer peak price patterns (€/MWh)



Included – prices at 17 selected nodes, at summer peak (13:00 on peak summer day), with new CCGT in Dublin or the southwest, assuming annual average price level in line with ESB PG's current price control

Figure 44 – Nodal prices at summer peak hour

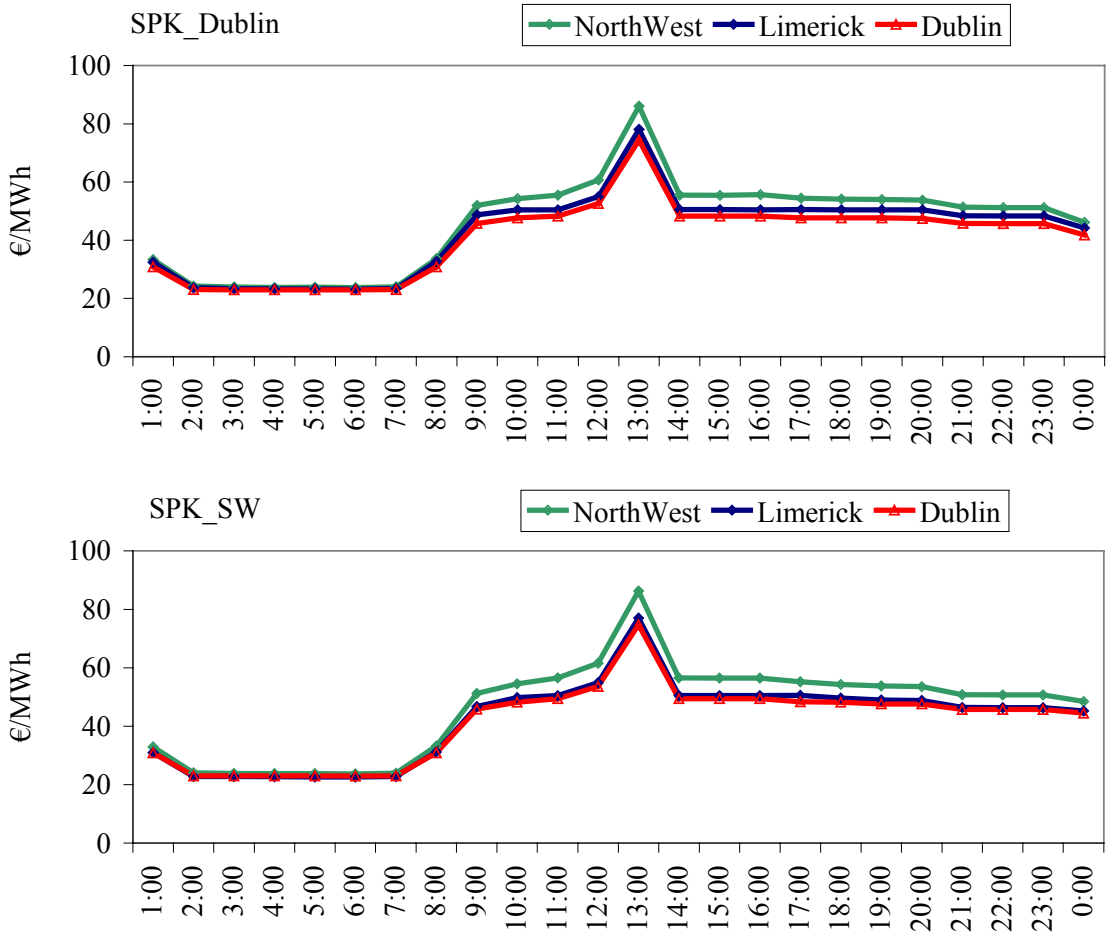


Included – prices at 31 selected nodes, at summer peak (13:00 on peak summer day), with new CCGT in Dublin or the southwest, assuming annual average price level in line with ESB PG's current price control

5.33 In the summer peak hour, locating the new CCGT in the southwest would reduce prices in the Cork area by around 5%, and would have only a small impact on the price patterns elsewhere. If located in the southwest, losses would be marginally lower (1.9% instead of 2.1%), and both generator costs and revenue very slightly lower (around 0.5%).

5.34 Figure 45 shows the prices in the Dublin, Limerick and northwest areas, over the 24 hours of the summer peak day. The price variation is highest at lunchtime, coincident with peak demand. With the new CCGT in the southwest, the prices in the Limerick area are closer to those in Dublin.

Figure 45 – Pricing across the summer peak day at three points



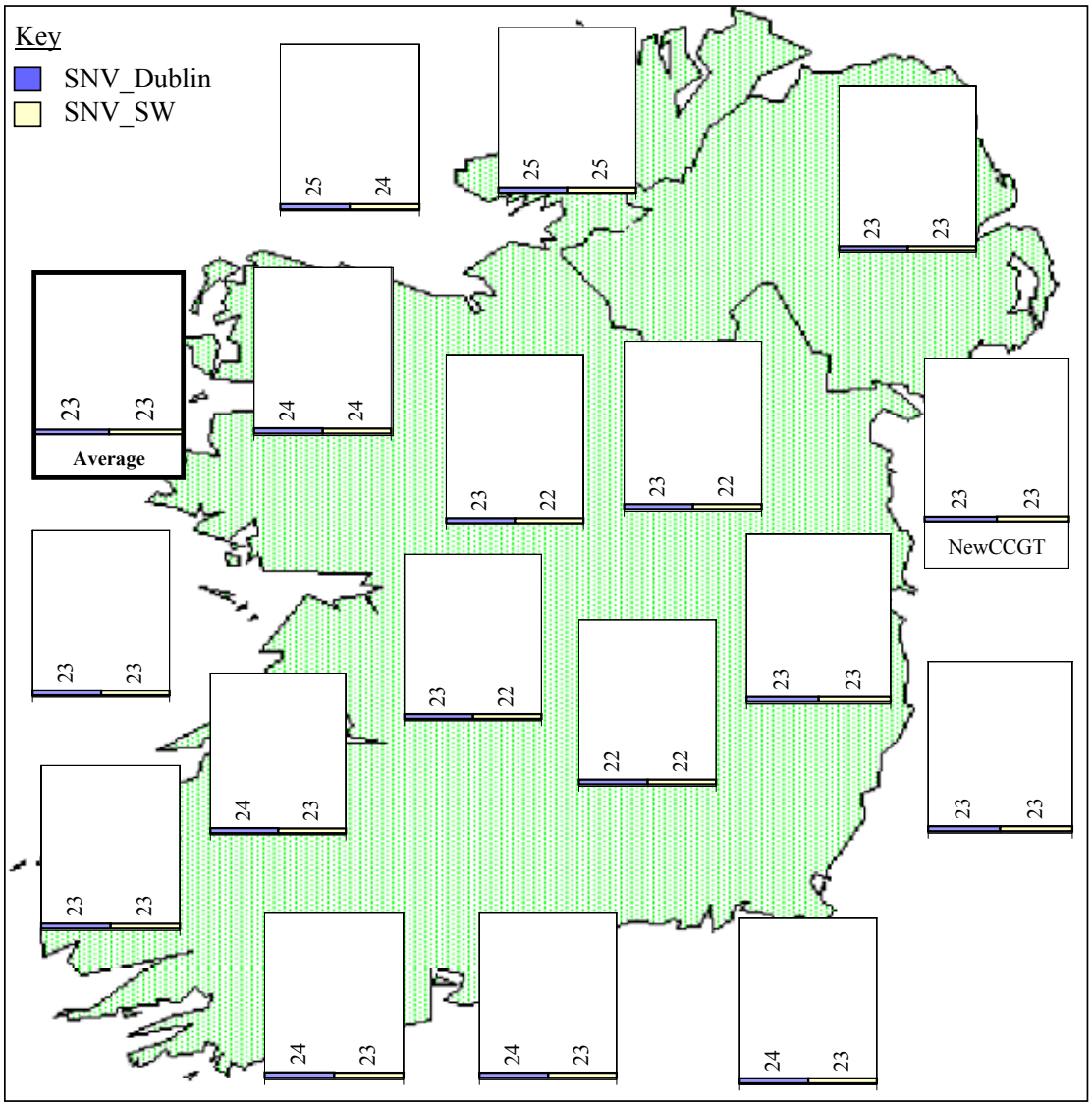
Included – prices at three representative nodes across the 24 hours of the summer peak day

Summer night valley

5.35 At summer night valley, the point of lowest demand in the year, the overall range of nodal prices is relatively low – around 15% of the mean nodal price (a range of around €4/MWh) in both the Dublin and southwest test.

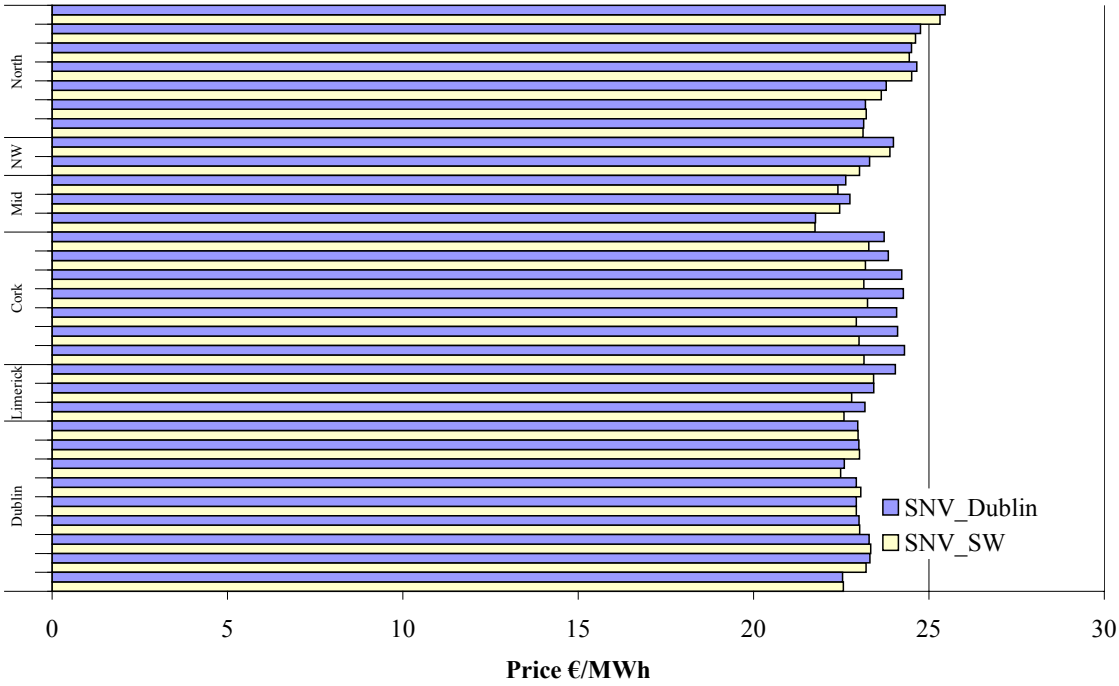
5.36 Figure 46 and Figure 47 illustrate the nodal price patterns at summer night valley. In most cases the prices are unaffected, but the southwest test reduces prices in Limerick and Cork by 3-5%.

Figure 46 – Summer night valley price patterns (€/MWh)



Included – prices at 17 selected nodes, at summer night valley (05:00 on summer non-business day), with new CCGT in Dublin or the southwest, assuming annual average price level in line with ESB PG's current price control

Figure 47 – Nodal prices at summer night valley

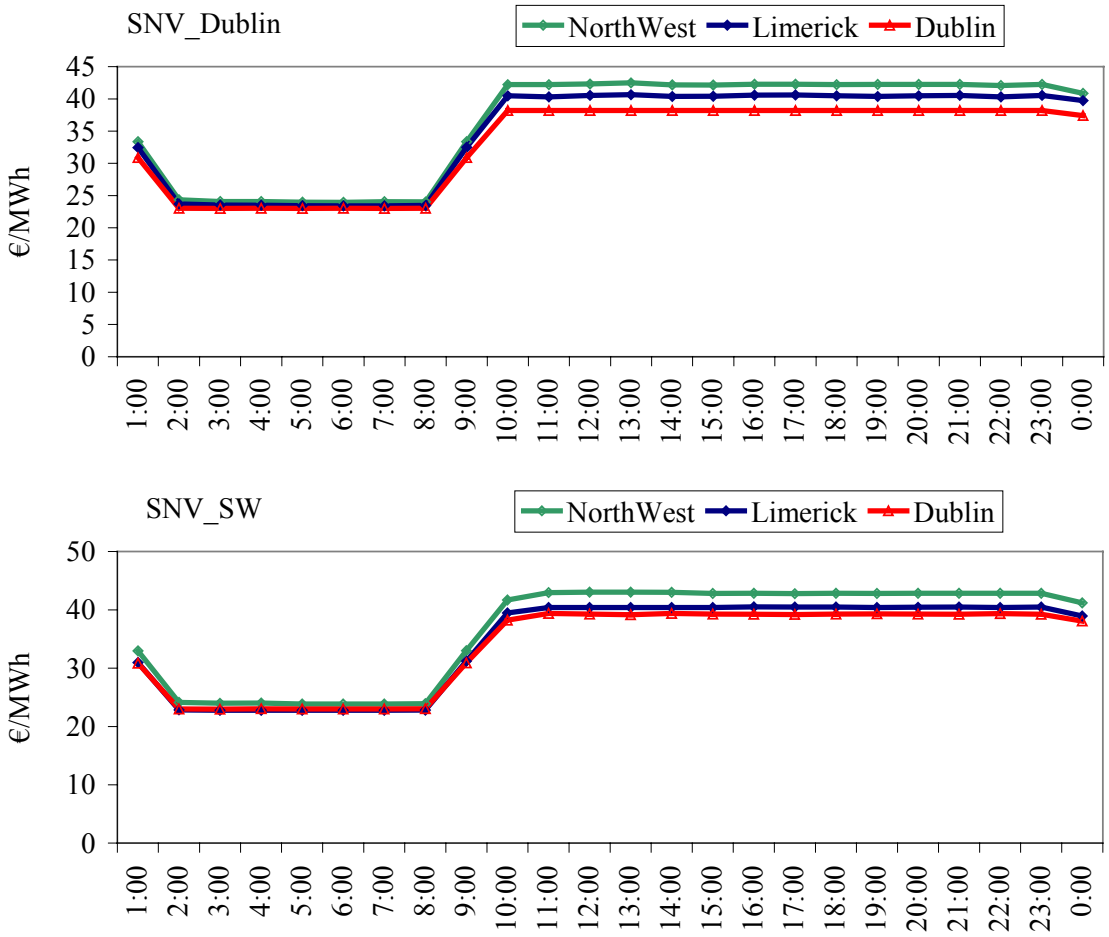


Included – prices at 31 selected nodes, at summer night valley (05:00 on summer non-business day), with new CCGT in Dublin or the southwest, assuming annual average price level in line with ESB PG's current price control

5.37 Overall, locating the new CCGT in the southwest (compared with Dublin) results in lower losses at summer night valley (1.3% instead of 1.6%), and has minimal impact on total generation cost and total revenue.

5.38 Figure 48 shows the prices in Dublin, Limerick and the northwest, over the 24 hours of a summer non-business day. The price variation is generally low. With the new CCGT in the southwest, Limerick prices are closer to those in Dublin.

Figure 48 – Pricing across the summer night valley day at three points



Included – prices at three representative nodes across the 24 hours of a summer non-business day

April non-business night – Moneypoint 3 dispatched down marginally

5.39 We have identified a number of outliers in which the range of nodal prices rises, in the test with the new CCGT in Dublin[40]. We have investigated all hours where the price range at the 61 key nodes exceeds 50% of the mean nodal prices.

5.40 At all these times, the output of Moneypoint unit 3 (MP3, which is connected to the local 220kV network) is dispatched down due to constraints binding. This reduces the local price at that and nearby nodes to the marginal price of MP3. We have assumed, in line with all the locational analysis, that bid behaviour is not

40 As noted in paragraph 5.16, we model the constraints as falling predominantly in the shoulder months, in which we assume summer (lower) network ratings but winter (higher) plant availability. The timing of maintenance and outages will influence the times at which such constraints occur.

changed – in reality there may be opportunities here to exercise some locational market power.

5.41 In most cases when this occurs, the reduced output from MP3 is met outside its area by increased output from the marginal part-loaded generator. This reduces prices at the MP3 and immediately surrounding nodes, but leaves prices elsewhere unchanged. This is because it becomes the marginal generator in its area for the period.

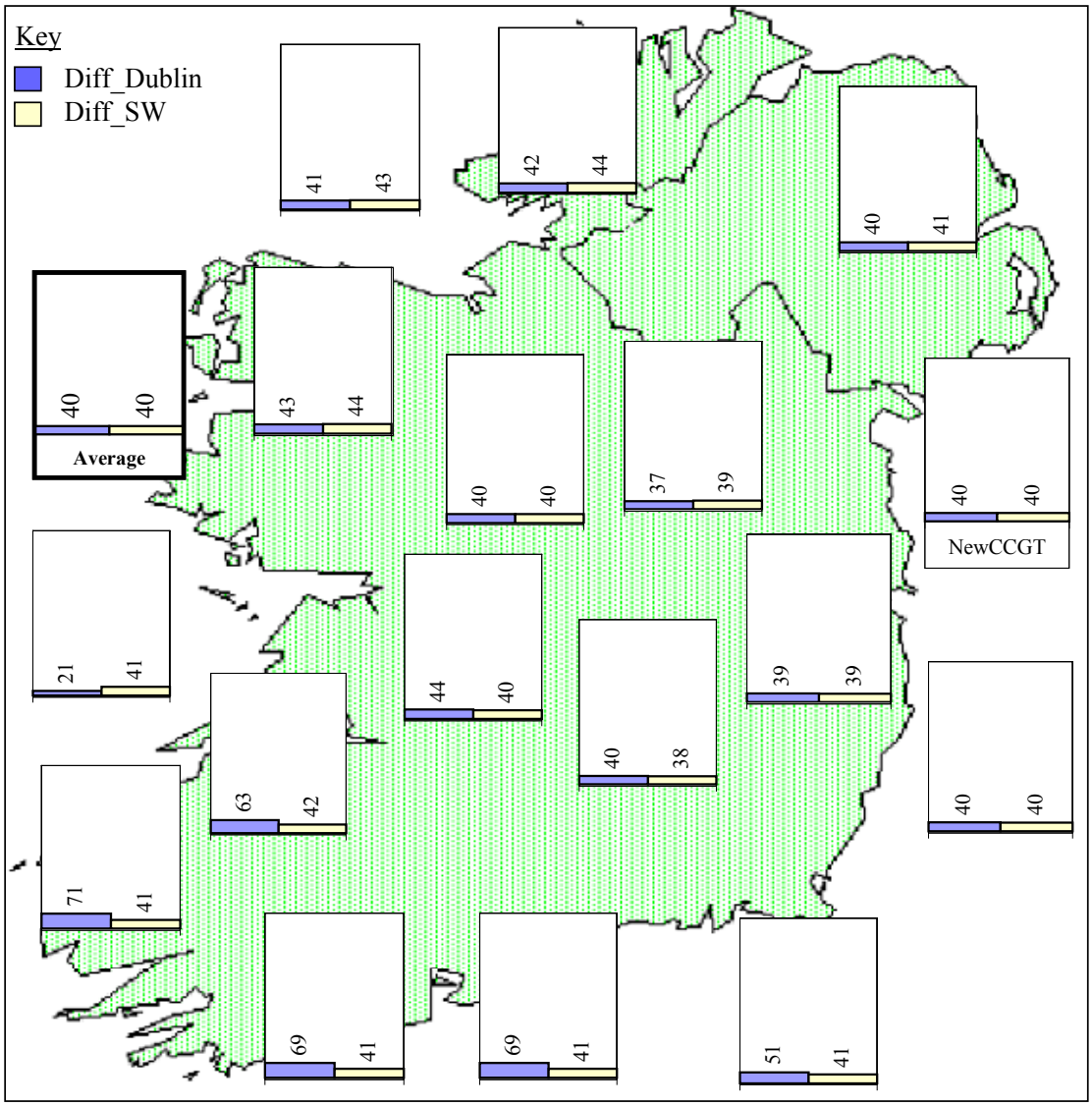
5.42 However, there are a few cases modelled in which the reduced output from MP3 cannot be met by the marginal part-loaded unit due to further transmission constraints, and an additional unit is dispatched on. This raises prices at all other areas. We consider an extreme example, hour 22:00 on the April non-business day. Other cases give a smaller price range.

5.43 For this hour, two separate constraints are binding which restrict import into the southwest area.

5.44 The nodal prices range between €20.92 and €72.42. In this case, unit MP3 is dispatched down, the existing marginal unit elsewhere is dispatched up and also another unit is called to start. There are now three separate marginal plants, each governing prices in its own local area, with the area boundaries dictated by the transmission constraints.

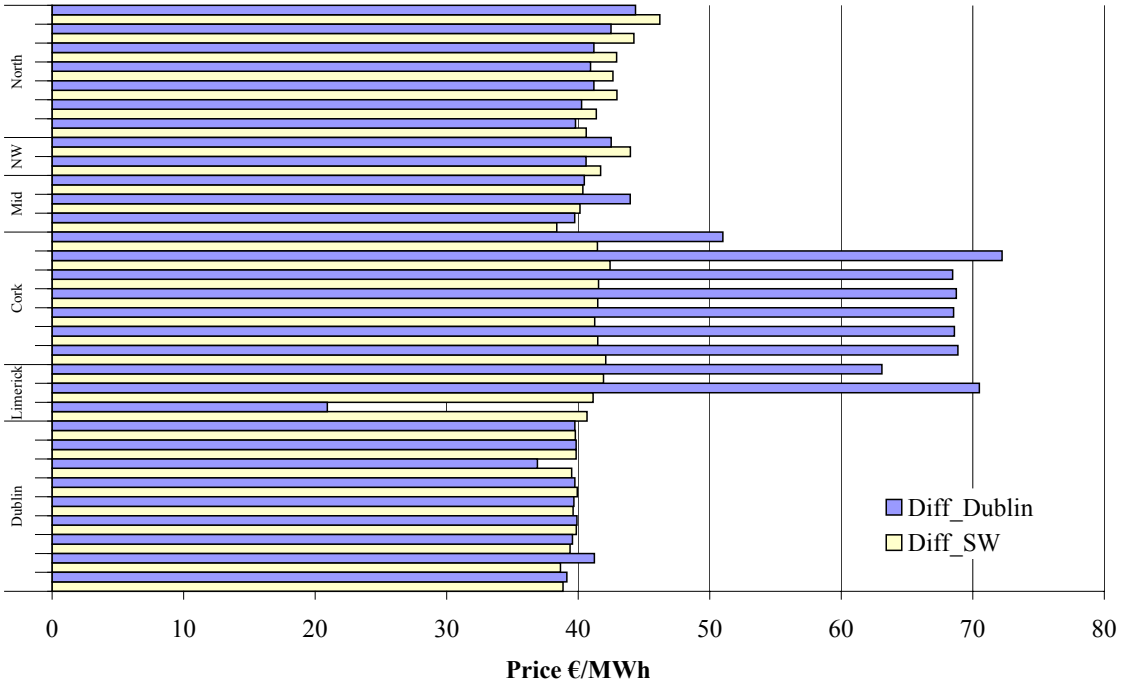
5.45 Figure 49 and Figure 50 show how prices vary around the country in this hour, comparing the new CCGT in Dublin (which gives the large price differentials) and in the southwest (which leaves prices similar around the country).

Figure 49 – Shoulder hour period price patterns (€/MWh)



Included – prices at 17 selected nodes, at a shoulder period (22:00 on an April non-business day), with new CCGT in Dublin or the southwest, assuming annual average price level in line with ESB PG's current price control

Figure 50 – Nodal prices at a shoulder period (April non-business day)



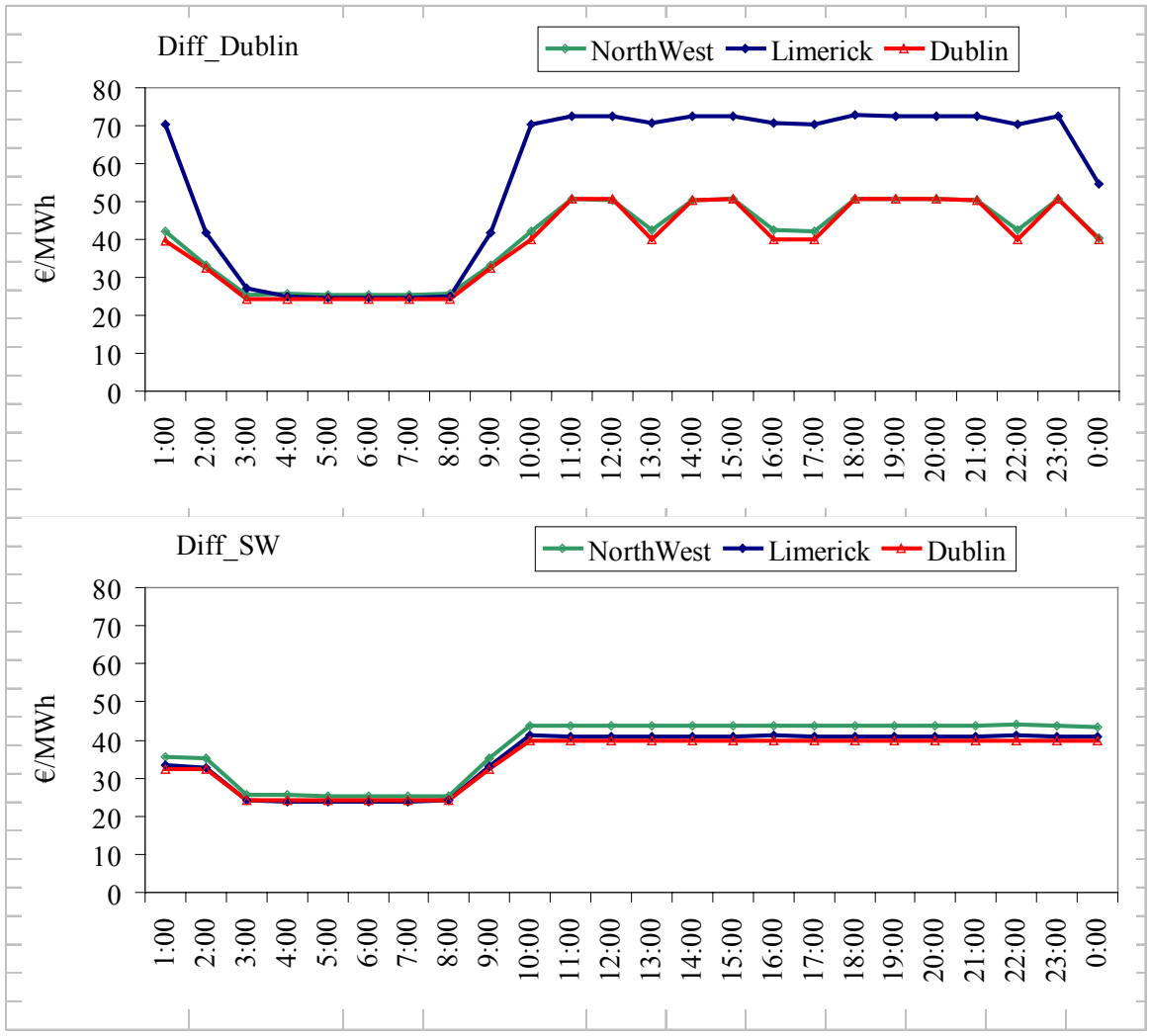
Included – prices at 31 selected nodes, at a shoulder period (22:00 on an April non-business day), with new CCGT in Dublin or the southwest, assuming annual average price level in line with ESB PG's current price control

5.46 The impact of the constraint in the Dublin test is clear – prices in the southwest are sharply increased, prices at Moneypoint 3 are reduced, and elsewhere in the country there is little change. Losses are materially higher (from 1.7% to 2.4%) and the cost of meeting demand is around 3% higher than in the southwest test.

5.47 It should be noted that in our modelling we calculate the bid prices for each plant based on a level of generation which ignores network effects. These bid prices include the start cost spread over the projected hours of operation, but with a minimum of one hours operation for those plant that we project will not generate. However, as in the example above, should a plant be despatched in the LMP model for significantly more hours than we originally projected, for reasons such as constraints on the network, the resulting prices may be too high since they include the recovery of start costs over fewer hours than necessary. This issue could be addressed by iterating the model so that we determine the bid prices for each plant based on the output from the previous iteration. This could continue until the input assumptions are consistent with the output.

5.48 Figure 51 illustrates prices in the Dublin, Limerick and northwest areas, over the 24 hours of the April non-business day. It clearly shows the impact of the transmission constraint raising prices in the Limerick area over a large part of the day, when the new CCGT is located in Dublin.

Figure 51 – Pricing across the April non-business day at three points



Included – prices at three representative nodes across the 24 hours of the April non-business day

Maintenance and outage sensitivity tests

5.49 We have considered a number of sensitivity tests relating to different patterns of plant outage[41], in the winter peak and summer peak hours.

Winter peak outage sensitivity tests

5.50 The winter peak sensitivity cases are intended to show the results of some plausible scenarios. In these cases, the starting assumption is that there is no planned maintenance, but that some plant has a forced outage at alternative locations. The cases are as follows:

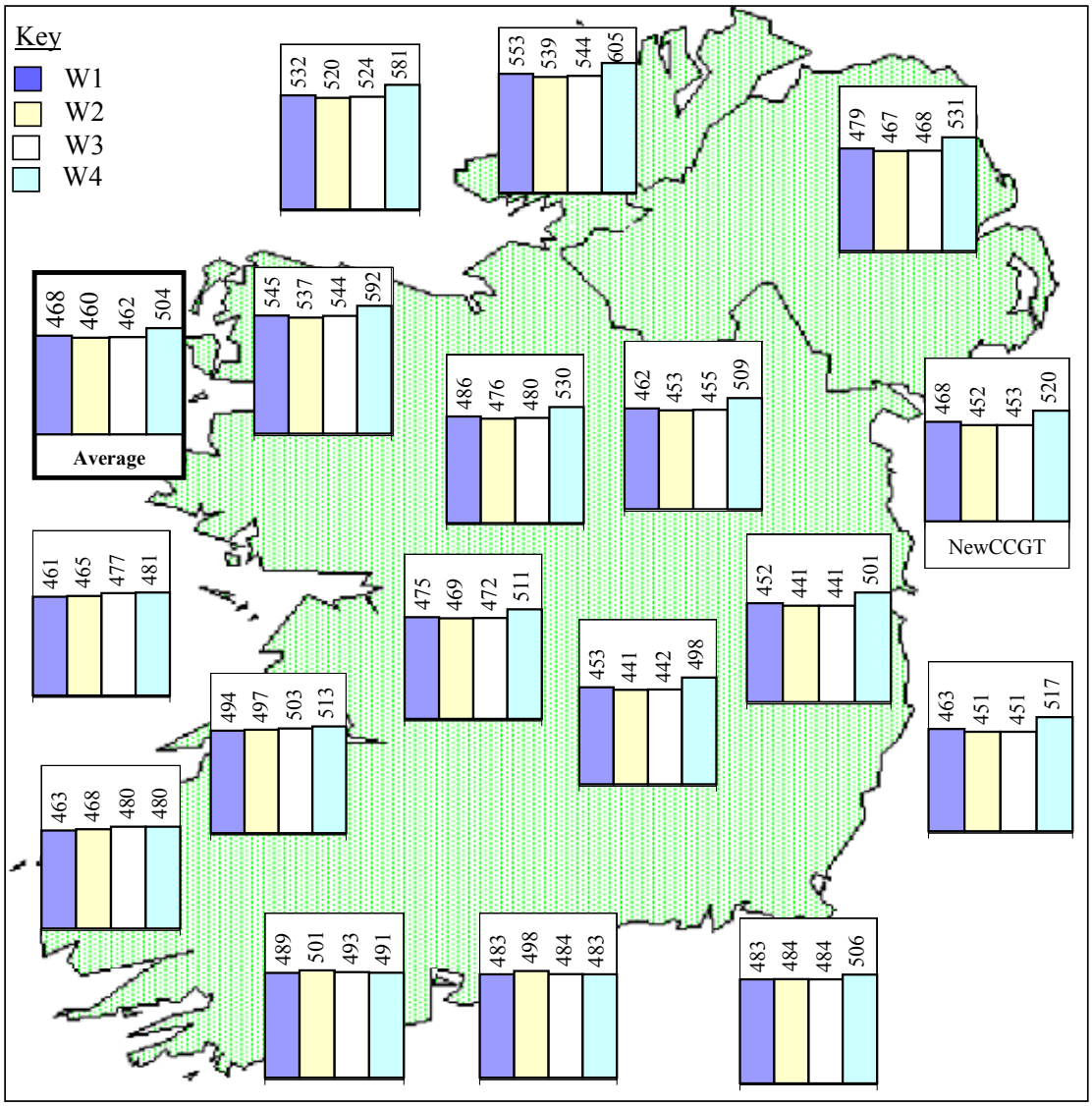
41 We have not considered network outages.

- W1 no new entry, all units fully available **– case for comparison**;
- W2 new entry in Dublin, 600MW forced outage in southwest (mainly in Cork area) **– aim is to increase the net import to the southwest**;
- W3 new entry in Dublin, 600MW forced outage in southwest (mainly in Tarbert) **– aim is to increase the net import to the southwest**; and
- W4 new entry in southwest, 600MW outages in Dublin **– aim is to reduce the net import to the southwest**.

5.51 Figure 52 and Figure 53 show the pattern of prices across the country in the four winter outage cases. The highlights are as follows – in each case, the comparator is the state with no outages or new entry (case W1):

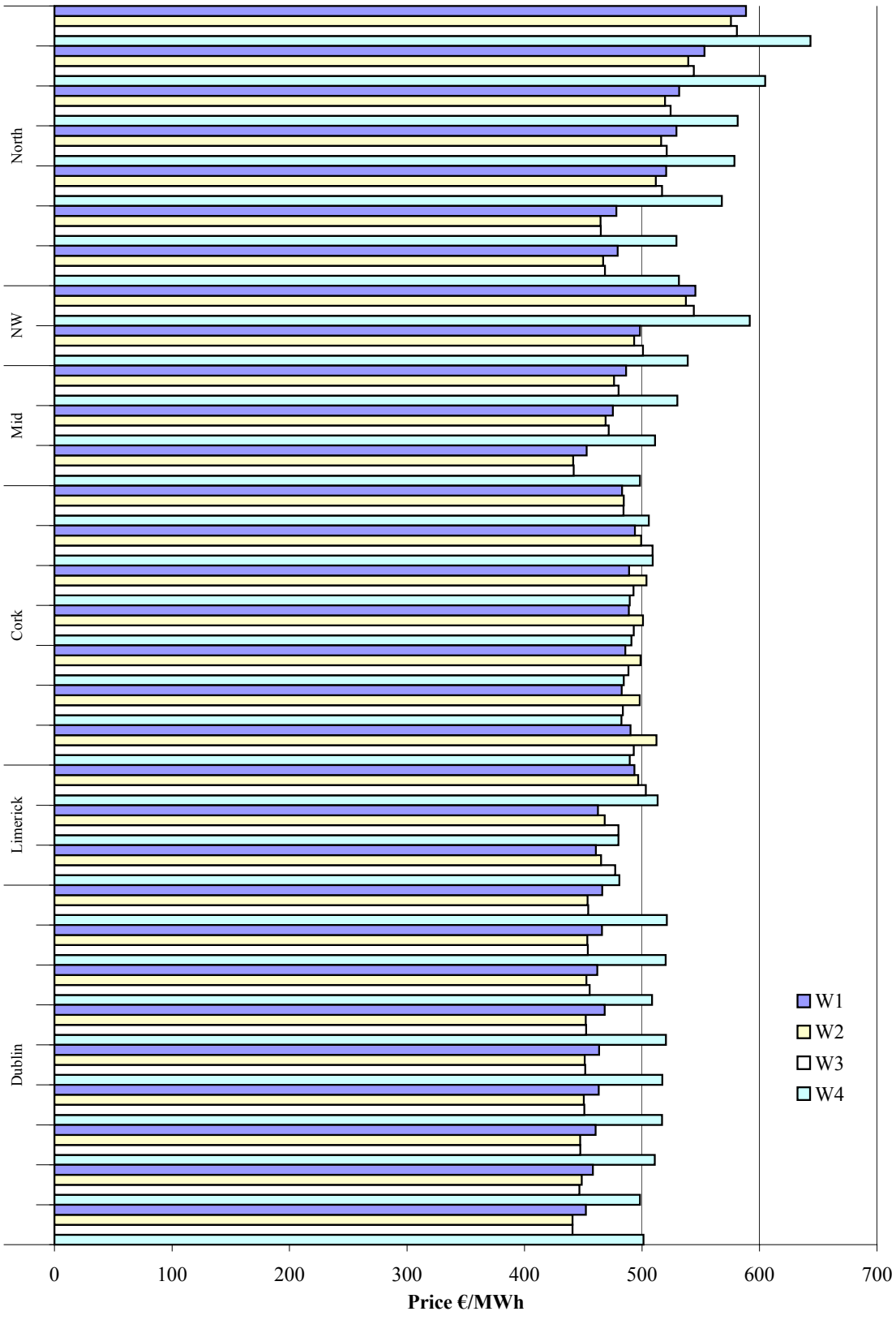
- the resultant price patterns remain relatively stable, with nodal price ranges across the 61 generator nodes of around 30% (of the mean price at these nodes) in all of the four maintenance tests;
- the results of cases W2 and W3 (taking out low and high-priced generation in the southwest) are similar to each other – the impact is that prices in the southwest are higher (by up to 5%) and prices in the remainder of the country including Dublin are lower (by up to 3%); and
- the impact of case W4 (taking out generation in Dublin) on prices is more dramatic – prices in Dublin, the north and west are around 10% higher, whereas prices in the Cork and the southwest area remain broadly unchanged.

Figure 52 – Winter peak outage sensitivity case – LMPs



Included – prices at 17 selected nodes, at the winter peak period – four plant maintenance sensitivity tests, assuming annual average price level in line with ESB PG's current price control

Figure 53 – Winter peak outage sensitivity tests – LMP values



Included – prices at 31 selected nodes, at the winter peak period – four plant maintenance sensitivity tests, assuming annual average price level in line with ESB PG's current price control

Summer peak maintenance and outage cases

5.52 The summer peak maintenance cases allow for scheduled maintenance as well as forced outages. These are modelled differently – for scheduled outages, the estimation of reserve provision and of the inclusion of start costs in generator bid prices takes into account the plants known to be unavailable, whereas for forced outages, the units are simply marked as being unavailable within the LMP dispatch calculation.

5.53 The summer peak maintenance scenarios may be summarised as follows:

- S1 no new entry, all units fully available **– case for comparison**;
- S2 new entry in Dublin, 300MW planned outage in Dublin, 600 outages in southwest (mainly in Cork area) **– aim is to increase the net import to the southwest**;
- S3 new entry in Dublin, 300MW planned outage in Dublin, 600MW outages in southwest (mainly in Tarbert) **– aim is to increase the net import to the southwest**; and
- S4 new entry in southwest, 300MW planned outage at Moneypoint 2 (Dublin), 600MW forced outage in Dublin **– aim is to reduce the net import to the southwest**.

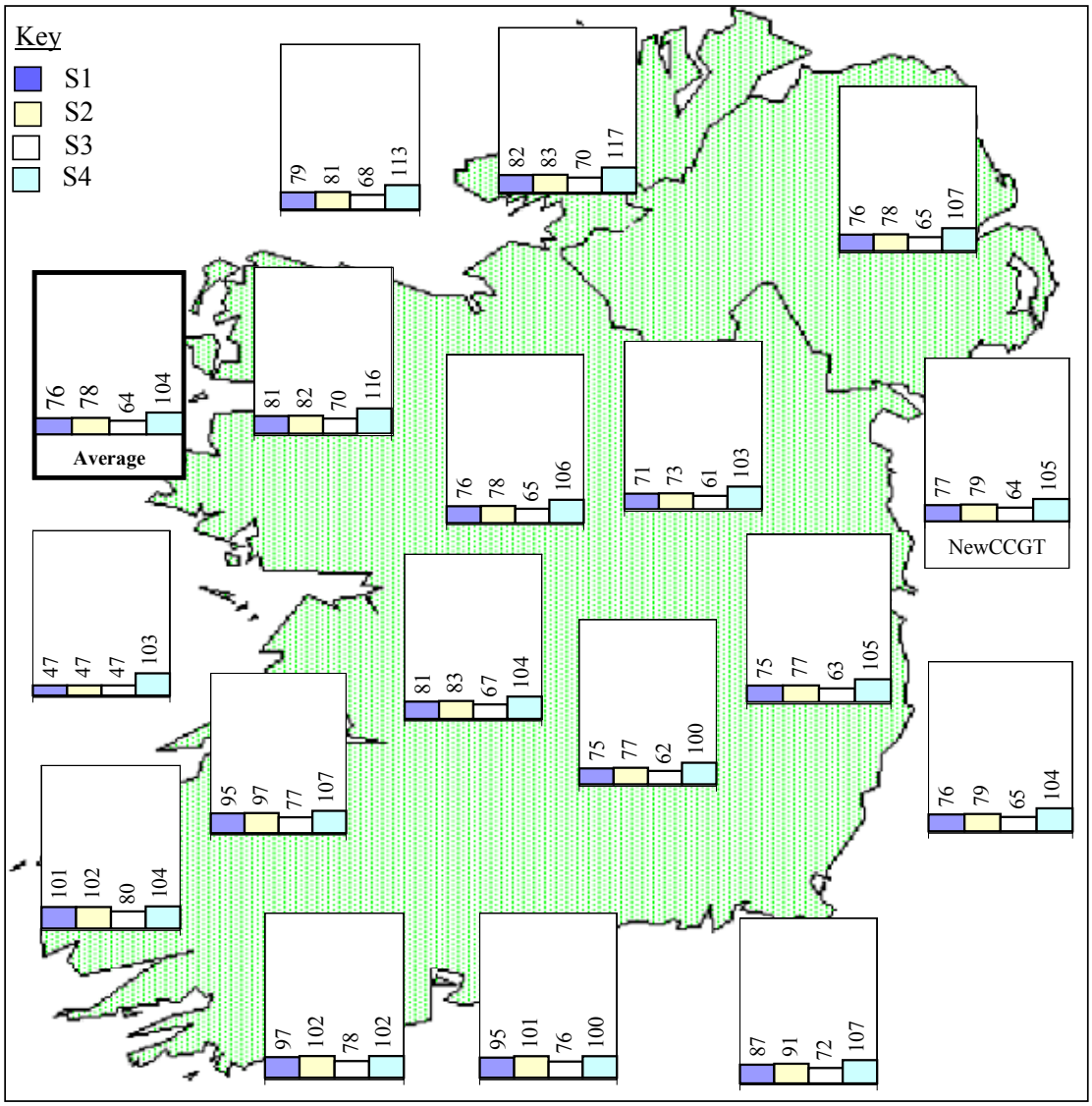
5.54 The results of these scenarios are depicted in Figure 54 and Figure 55. The headline findings are as follows:

- in cases S1, S2 and S3, the range of prices is high (50-70% of the nodal mean price); and
- in case S4 (reduced availability in Dublin and new generation in the southwest), the prices at virtually all nodes are materially higher than in the case S1, and in particular MP3 is no longer dispatched down.

5.55 In cases S1, S2 and S3 we find that Moneypoint unit 3 is dispatched down, in a similar way to the April non-business night hour detailed from paragraph 5.39 above. This causes a low price in and around the MP3 node (around €47/MWh, compared with around €77/MWh in the previous summer peak cases in which all units are partly de-rated to allow for maintenance and forced outages)[42].

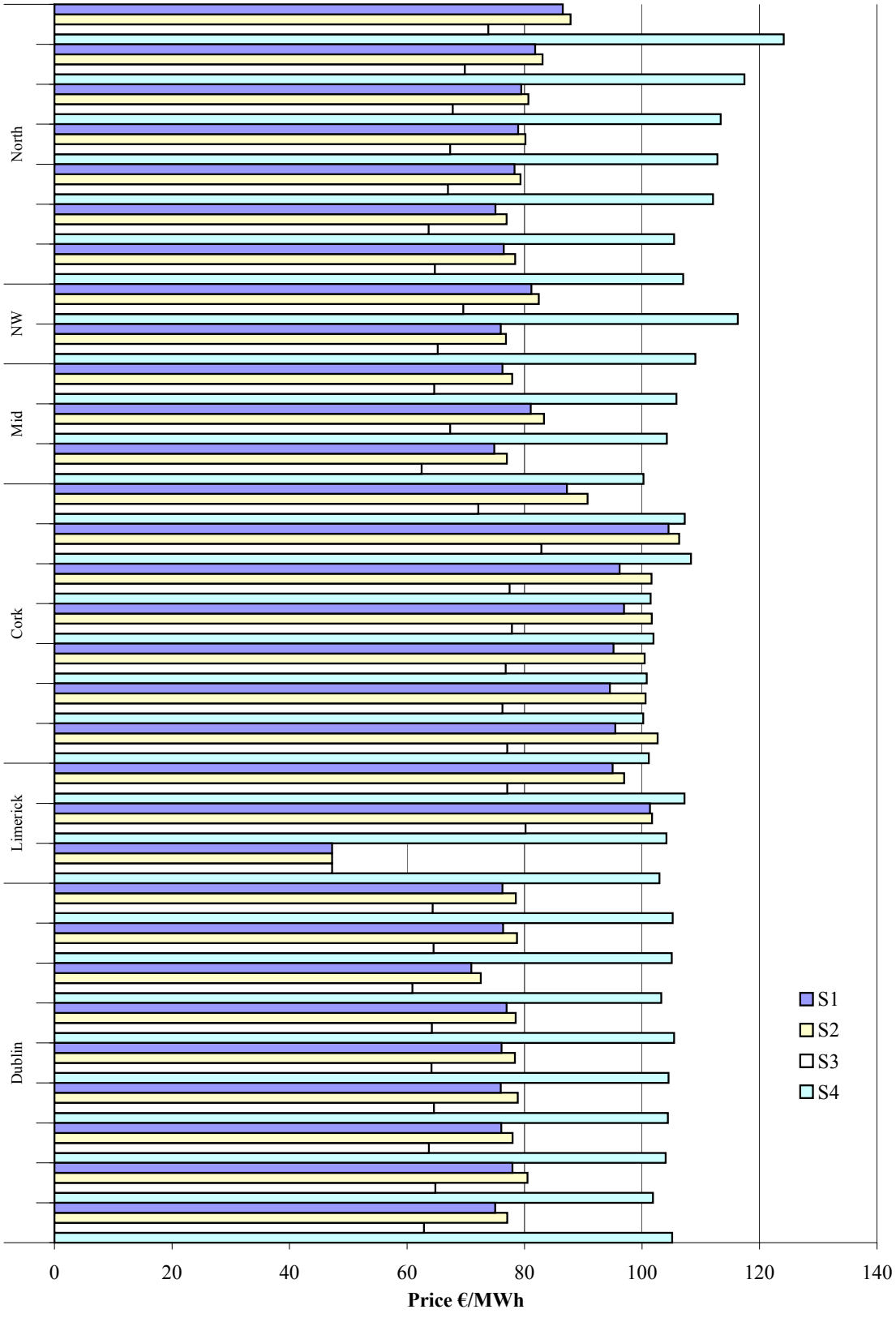
[42] As noted from paragraph 5.7, the effect of this treatment of maintenance may be to understate the importance of transmission constraints at certain times. However, by testing a large range of cases and a series of sensitivity tests on plant outages we have covered the impact of key constraints. We have not tested the impact of network maintenance.

Figure 54 – Summer peak maintenance and outage sensitivity tests – LMP values



Included – prices at 17 selected nodes, at the summer peak period – four plant maintenance sensitivity tests, assuming annual average price level in line with ESB PG's current price control

Figure 55 – Summer peak maintenance and outage sensitivity tests – LMP values



Included – prices at 31 selected nodes, at the summer peak period – four plant maintenance sensitivity tests, assuming annual average price level in line with ESB PG's current price control

5.56 We conclude from these sensitivity tests on plant maintenance that the main cases modelled already encompass the results found in these new tests.

5.57 We have performed a large number of model runs during the course of our work, as various assumptions have changed and the treatment of different aspects of our model has evolved. The pattern of results and the main findings have remained virtually unchanged. This indicates that the resulting price patterns are robust to changes in the inputs and assumptions.

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ANNEX A– ABBREVIATIONS

Abbreviation	Description
AC	Alternating current – an electrical current that reverses direction at regular intervals
bd	Business day – categorisation used for ILEX modelling including all weekdays except statutory holidays
BNE	Best new entrant – the plant cost assumptions used by the CER for the calculation of TopUp and Spill prices
CCGT	Combined cycle gas turbine – where the gas turbine exhaust heat is fed through a boiler and steam cycle to improve efficiency.
CER	Commission for Energy Regulation (formerly the Commission for Electricity Regulation) – the regulator in the Republic of Ireland
CfD	Contract for differences – a financial swap contract
DC	Direct current – an electricity current that flows in only one direction
DWA	Demand-weighted average – weighted by the profile of demand
EirGen	The ILEX generation bid model
ESB	Electricity Supply Board – the incumbent electricity utility in the Republic of Ireland, now separated into the following business units: ESB (Generation), ESB Transmission, ESB National Grid (ESB NG), ESB Distribution, ESB Public Electricity Supplier (ESB PES) and ESB Independent Energy (ESBIE)
LDC	Load duration curve – showing the proportion of time for which a given level of demand or load is exceeded
LMP	Locational marginal pricing
MP3	Moneypoint unit 3 – one of the three sets at the coal-fired power station
NAC	Net avoidable cost – the price needed to retain existing plant on the system
nbd	Non-business day – categorisation used for ILEX modelling including Saturdays, Sundays and statutory holidays

Abbreviation	Description
NEC	Net effective cost - the capital, fixed and fuel costs of a new entrant plant
NOR	Net operating revenue – in this report, gross revenues less operating costs
OCGT	Open cycle gas turbine – where the gas turbine drives an alternator making no use of exhaust heat (also GT)
OPF	Optimal power flow – class of solver used for ILEX analysis
PDC	Price duration curve –showing the proportion of time for which a given price is exceeded
PSDB	Power station database – list of generation sets in EirGen
S1-S4	The four summer peak sensitivity cases considered in the locational analysis
SCADA	Supervisory control and data acquisition - ESB NG operational database
SMP	System marginal price – the bid price of the last power station unit required to meet the system demand plus start-up and no-load costs
SNV	Summer night valley – one of the days considered for the locational analysis
SPK	Summer peak – one of the days considered for the locational analysis
SRMC	Short-run marginal cost – the cost of producing the next unit of output
SW	Southwest – the locational modelling considers the location of new entry generation in two locations, Maynooth in Dublin and Knockraha in the southwest
TWA	Time-weighted average – the average price (usually across a year)
VoC	Value of capacity – any reward, over and above the wholesale market price, for making generation capacity available
VOLL	Value of lost load – the price that customers would be prepared to pay to avoid loss of electricity supply
VOWC	Variable operating works cost – the non-fuel costs that vary with output, e.g. consumables and maintenance

Abbreviation	Description
	output - e.g. consumables and maintenance
W1-W4	The four winter peak sensitivity cases considered in the locational analysis
WPK	Winter peak – one of the days considered for the locational analysis

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ANNEX B – NEW ENTRANT COSTS

B.1 The assumptions we have used regarding the costs of a new entrant in Ireland are presented below.

Short- to medium-term CCGT

B.2 ILEX continually reviews UK CCGT projects to validate assumptions for current and advanced new entrant prices. ILEX is in a strong position to do this since it has been engaged by the lending banks or the developers on nearly all of the recent UK CCGT projects. This analysis has led to the development of the ILEX projections of new-entrant price in the medium and longer term.

B.3 The ILEX projection of price in €/MWh for a medium-term new-entrant can be stated using the following formula :

$$p = 19.7 + 0.68g$$

where g is the gas price in €c/therm and p represents generating costs at a 90% load factor.

B.4 This forms the basis to our new entrant price for the period 2001 to 2009. Where further improvements are made in efficiency after 2001 these are likely to be associated with higher risk or higher turnkey costs. We therefore use this current new entrant calculation throughout the 2001 to 2009 period.

B.5 Since a majority of our original information on the costs of a new entrant CCGT is in US$, and we assume that costs will continue to be quoted in dollars in the future, the original formula is calculated in US$ and then converted into Euros.

New OCGT entrant costs

B.6 Open-cycle gas turbines (OCGTs) are less efficient, but cheaper than CCGTs. As such they can be useful as peaking or mid-merit plants. Present figures for the latest technology are an efficiency of 34.5% (HHV) combined with a capital cost of €425/kW (excluding funds used during construction), fixed other works costs of €19.3/kW p.a. and variable non-fuel costs of 0.084€c/kWh (all 2002 money).

B.7 If, in the limit, such a plant were not to operate at all, it would set a value of capacity of €90/kW p.a. (in 2002 money). If that were the case, the value of capacity on the system would be expected to average out at that level.

B.8 We consider, however, that the value of peaking capacity will be somewhat less than this, because:

- plant in a purely peaking role will tend to be of relatively low capital cost, even at the expense of reduced efficiency;
- peaking plant can be conveniently located within the distribution network where they may gain economic benefit by being sited close to electricity demand which reduces their effective cost to the larger system (although the extent to which there will be such an 'embedded benefit' in Ireland remains unclear); and
- there may be a growth in demand-side management as a means of coping with periods of peak demand on the system and this will tend to weaken the value of peaking generation capacity towards the cost of the cheapest projects.

B.9 Therefore, we consider that a lower figure of €74kW p.a. would be appropriate for the value of peaking capacity in the longer term (but in 2002 money-values). This €74/kW p.a. "cap", which is equivalent to 0.85€c/kWh on a TWA basis, is used as a guide to the value of capacity in our projections.

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Quality Control Check Sheet

THE PRICE AND DISPATCH IMPACT OF A CENTRALISED WHOLESALE ELECTRICITY MARKET IN IRELAND

Report Unique Serial No: 2003/042

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