ROI INTERFACE STUDY

Modelling Appendix of
Final Report for
the IME Group

Prepared by NERA

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1. INTRODUCTION

This appendix to our Final Report for the IME Group summarises the results of our LMP modelling for Part A ("NI remains separate from MAE") and Part B of our study ("MAE Integration").

PART I: SUMMARY OF PART A MODELLING RESULTS

2. PART A BASE CASE RESULTS

2.1. Definition of the Base Cases

In Part A of the study, we considered NI and the ROI as separate markets, with an LMP spot market in the ROI only.

We have used 2006-07 and 2009-10 as base years for our modelling. Our assumptions for 2009-10 differ from those we are using for 2006-07 in the following respects: load is higher in 2009-10, and the capacity of the ESB network in the Dublin-Louth corridor is increased. For each base year, we have modelled four load periods as follows:

- Winter peak day, peak half hour;
- Winter peak day, minimum half hour;
- Summer minimum day, peak half hour; and
- Summer minimum day, minimum half hour.

Our key assumptions are as follows:

- ***interconnector ratings*** – we have used the current net transfer capacities (NTC) of the Moyle and Tandragee-Louth interconnectors for the purpose of our modelling.
- ***new generation in ROI*** – following completion of the CER's tender for new generating capacity, we have assumed that two new efficient CCGT plants at Auginish and Tynagh Mines increase ROI capacity by 130 MW and 400 MW respectively.
- ***generator offer strategies*** – we assume that all generators (traders) offer into the ROI LMP market at their fuel costs (i.e. we assume that all generators adopt a strategy of "marginal cost bidding"). Our assumptions about fuel prices and GB electricity spot market prices (used to determine the offer price of imports across the Moyle) are shown in Tables 2.1 and 2.2.[1]
- ***wind and hydro generation*** – we have assumed that all wind generators have zero output in our base cases (a "calm or still day" scenario). We have assumed that all storage and run-of-river hydro generation in the ROI has zero output in the summer, and is constrained-on in winter. (The pumped storage in the ROI is assumed to be used as primary operating reserves only.)

[1] The assumptions used here are taken from a recent NERA study of the GB market in the context of ongoing arbitration between a number of large GB market participants.

2.2. Base Case Results

Our key results for the 2006-07 and 2009-10 base years are summarised in Table 2.3 and Table 2.4 respectively. These tables contain the following data:

- ***LMPs*** – we show LMPs for the Tandragee and Louth ends of the Tandragee-Louth interconnector. We also show the demand price in the ROI ("ROI Demand") calculated as the weighted average of LMPs at withdrawal nodes, with the volume of withdrawals used as weights.
- ***Tandragee price setting units*** – where possible, we list the names of the generating units whose offer prices determine the LMP at the Tandragee end of the Tandragee-Louth interconnector. This information is useful for identifying the extent to which any generator is likely to be able to use its market power to influence border prices.
- ***N-S IC flows*** – we show the total net flow from NI to the ROI across the Tandragee-Louth interconnector.
- ***Congestion in ROI and across the N-S IC*** – we show the incidence of congestion within the ROI system ("In ROI") and across the Tandragee–Louth interconnector ("On N-S IC"). Where there is congestion within the ROI system, LMPs in the ROI diverge, as is illustrated by the charts presented below. Where there is congestion across the Tandragee–Louth interconnector, the LMPs at either end of the interconnector diverge.
- ***Key points*** – we highlight some of the key features of the results in each case concerning the pattern of variation of LMPs and the market power of ESB.

In Figures 2.1 to 2.8, we also show charts illustrating the variation in LMPs across injection nodes. The list of plant on the X-axis of the charts is ordered from left to right as follows: Tandragee-Louth interconnector (north-east), Dublin area (east), Wexford area (south-east), Cork area (south-west), Limerick area (west), Shannonbridge area (west-central), and the north-west. They therefore follow a clockwise loop[2] from the north-east of the ROI through to the north-west.

Only in the "winter-maximum" runs in 2006-07 and 2009-10 and the "summer-maximum" run in 2009-10 do we find significant congestion within the ROI transmission system, with wide variation in LMPs across the system. In all other runs, we find negligible congestion within the ROI system, evidenced by almost uniform LMPs. In the runs where we find congestion in the ROI system, the LMPs at the two new generators at Auginish and Tynagh Mines are well below the average, reflecting local constraints in the transmission system that prevent these efficient new generators from producing at maximum output. These

[2] The new Auginish power plant will be located in the Limerick area, whereas the Tynagh Mines plant will be in the Galway area.

examples demonstrate that the benefits of efficient locational signals depend as much on decisions about regulated transmission investment as they do on the LMP pricing scheme itself.

In all but summer maximum demand conditions in 2006-07, we find that the 275 kV N-S interconnector is congested from S to N, and hence that LMPs are higher at the northern end of the interconnector than at the southern end. However, only in winter maximum demand conditions is there a material difference in LMPs on either side of the border. In summer maximum demand conditions in 2006-07, we find an uncongested flow from N to S of about 117 MW, and correspondingly no price differential across the N-S interconnector.

We see a similar pattern in 2009-10, except that a lack of sufficient transmission and generation capacity in the ROI results in a reversal of the flow on the N-S interconnector in winter maximum demand conditions, and a congested N to S flow in summer maximum demand conditions.

Table 2.1
Fuel Prices (ex. transport & duty)

2004 prices	**HFO**	**Distillate**	**Coal**	**Gas**			**UK Electricity**	
				Annual Average	**Summer day**	**Winter day**	**Summer**	**Winter**
Price "location"	Platts £/tonne	Platts £/tonne	ARA £/tonne	UK NBP p/therm	UK NBP p/therm	UK NBP p/therm	£/MWh	£/MWh
2006/07	87.14	139.09	19.48	20.3	15.85	24.77	27.90	40.56
2009/10	87.14	139.09	19.48	20.3	15.85	24.77	28.27	40.43

Table 2.2
Fuel Transport Costs and Duties

	Units	Value
Republic of Ireland		
Transport costs		
Gas	p/therm	5.38
HFO	£/t	1.85
Gasoil	£/t	23.47
Coal	£/t	1.24
Fuel duties		
HFO	£/t	8.75
Gasoil	£/t	34.42
Northern Ireland		
Transport costs		
Gas	p/therm	4.22
HFO	£/t	1.85
Gasoil	£/t	23.47
Coal	£/t	8.24
Fuel duties		
HFO	£/t	38.01
Gasoil	£/t	50.54

Table 2.3
Summary of Key Results for 2006-07

Case	LMPs, £/MWh Tand-ragee	Louth	ROI Demand	Tandragee Price Setting Units	N to S IC flows, MW	Congestion? In ROI	On N-S IC	Key points
Winter Max (6,311 MW)	40.6	32.6	38.9	Moyle IC	-1	Yes	Yes	Border LMP at Tandragee node above the ROI demand price. Most LMPs in Dublin area and elsewhere below average. LMPs at Ardnacrushna Hydro and Lanesboro-Lough Ree Power quite high. Small negative flows across the Tandragee – Louth interconnector.
Winter Min (3,786 MW)	19.9	18.5	18.5	Ballylumford CCGT	-1	Yes	Yes	Border LMP at Tandragee node slightly above ROI demand price. Uniform LMPs elsewhere, except at MoneyPoint 1 and Tynagh Mines. Small negative flows across the Tandragee – Louth interconnector.
Summer Max (4,857 MW)	19.0	19.0	19.0	Poolbeg	141	Yes	No	Uniform LMPs, except at MoneyPoint 1 and Tynagh Mines.
Summer Min (2,021 MW)	12.1	11.4	11.4	Coolkeeragh CCGT	0	Yes	Yes	Uniform LMPs almost everywhere. Insignificant flows across the Tandragee – Louth interconnector.

Notes: figure shown in brackets under the case name are for all-island demand.

Table 2.4
Summary of Key Results for 2009-10

Case	LMPs, £/MWh			Tandragee Price Setting Units	N to S IC flows, MW	Congestion?		Key points
	Tand-ragee	Louth	ROI Demand			In ROI	On N-S IC	
Winter Max (6,859 MW)	85.2	709.6	1,385	Ballylumford GT	330	Yes	Yes	Border LMP at Tandragee node and most LMPs elsewhere below the average ROI demand price. LMP at Shannonbridge-West Offaly Power quite low. LMP at Lanesboro-Lough Ree Power very high.
Winter Min (4,115 MW)	19.9	18.5	18.5	Ballylumford CCGT	-1	Yes	Yes	Border LMP at Tandragee node slightly above ROI demand price. Uniform LMPs elsewhere, except at Money Point 1 and Tynagh Mines. Small negative flows across the Tandragee – Louth interconnector.
Summer Max (5,286 MW)	21.0	21.1	33.9	Ballylumford steam units	330	Yes	Yes	Border LMP at Tandragee node and most LMPs elsewhere below the average ROI demand price. LMPs at Cliff-Erne and Cathaleen's Fall-Erne Hydro quite high.
Summer Min (2,363 MW)	12.1	11.4	11.4	Coolkeeragh CCGT	-1	Yes	Yes	Border LMP at Tandragee node slightly above ROI demand price. Uniform LMPs almost elsewhere. Small negative flows across the Tandragee – Louth interconnector.

Notes: figure shown in brackets under the case name are for all-island demand.

Figure 2.1
Avg Demand Price, Ouput and LMP – Winter Max 2006-07

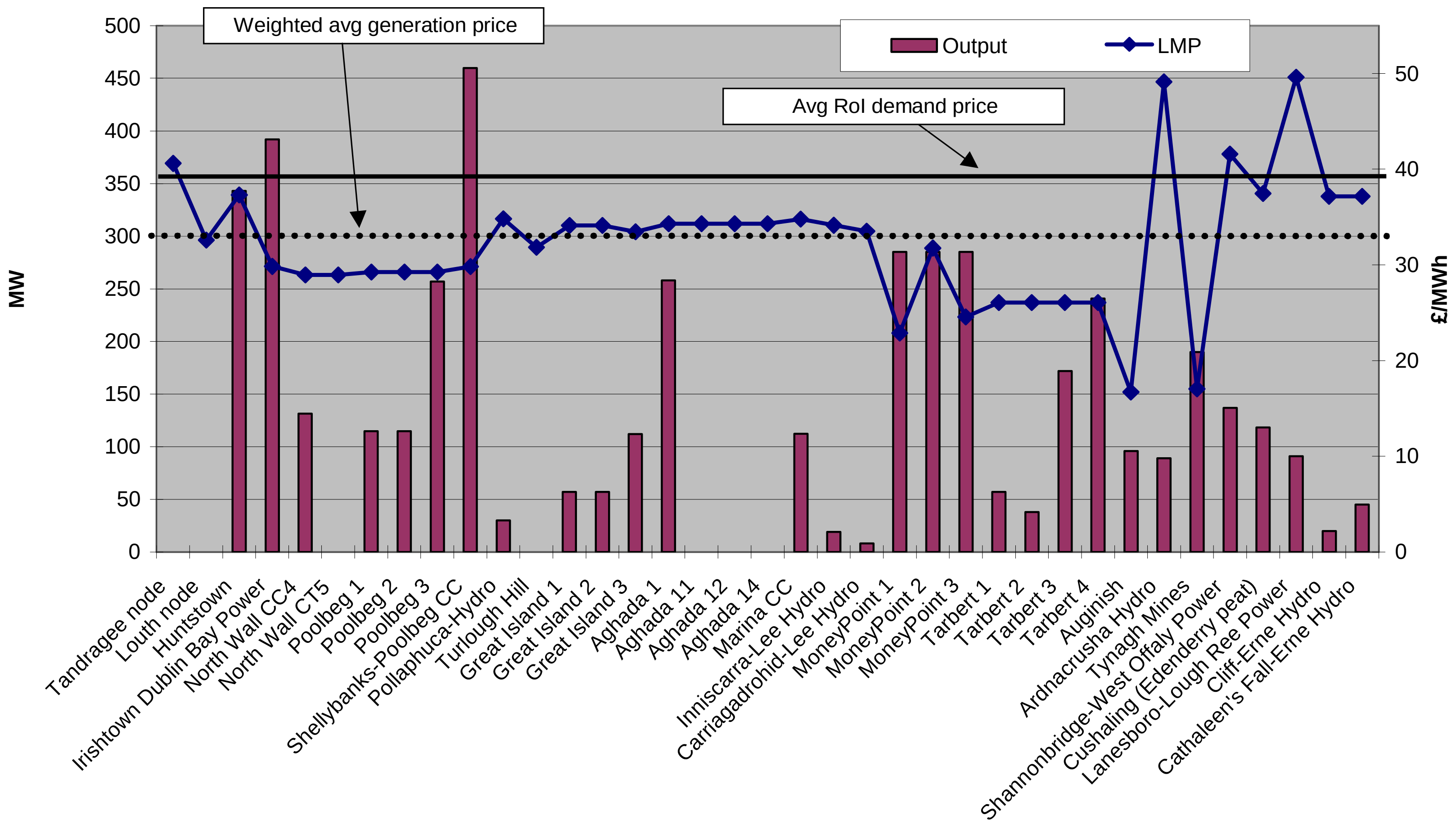


Figure 2.2
Avg Demand Price, Ouput and LMP – Winter Min 2006-07

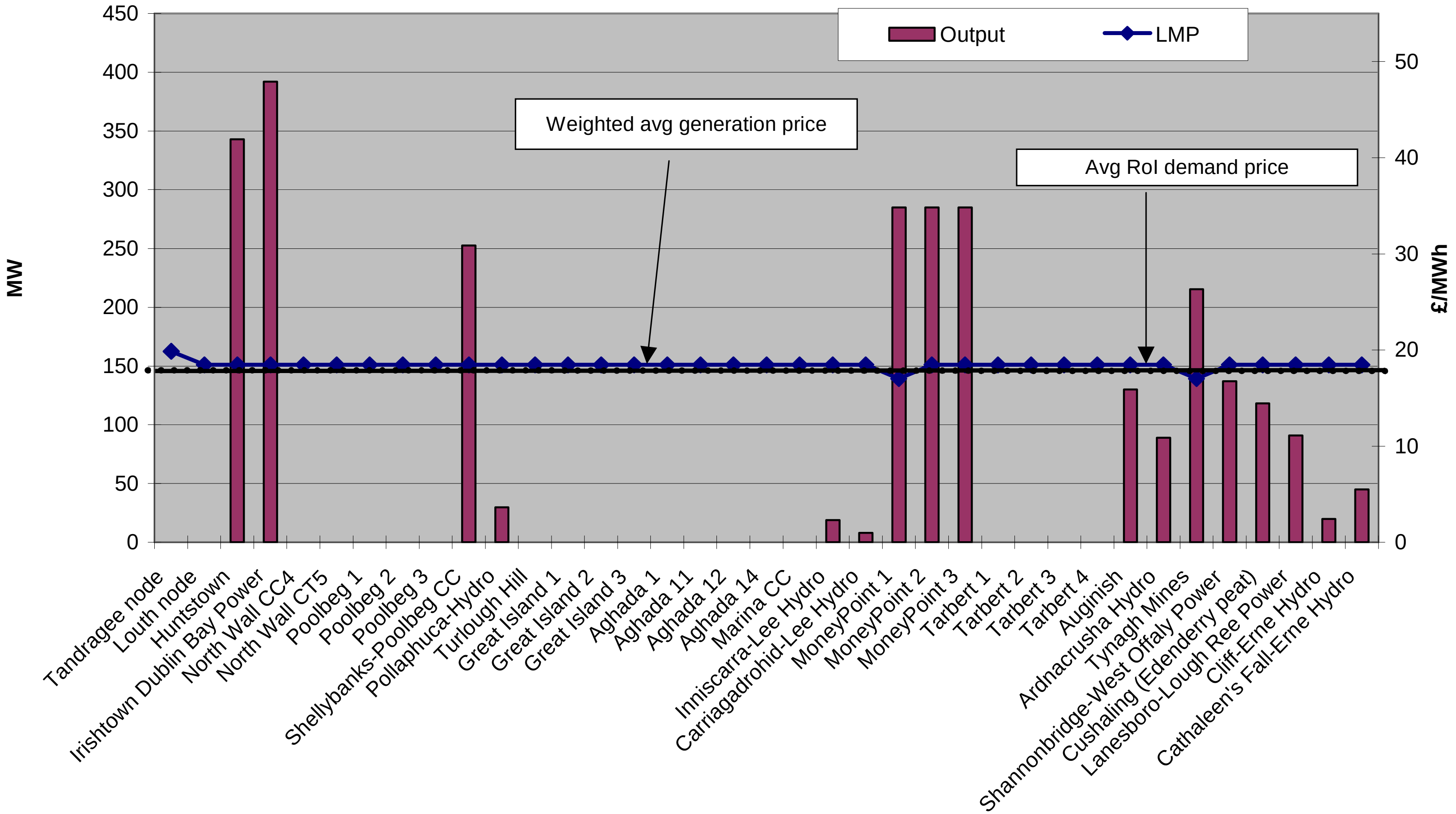


Figure 2.3
Avg Demand Price, Ouput and LMP – Summer Max 2006-07

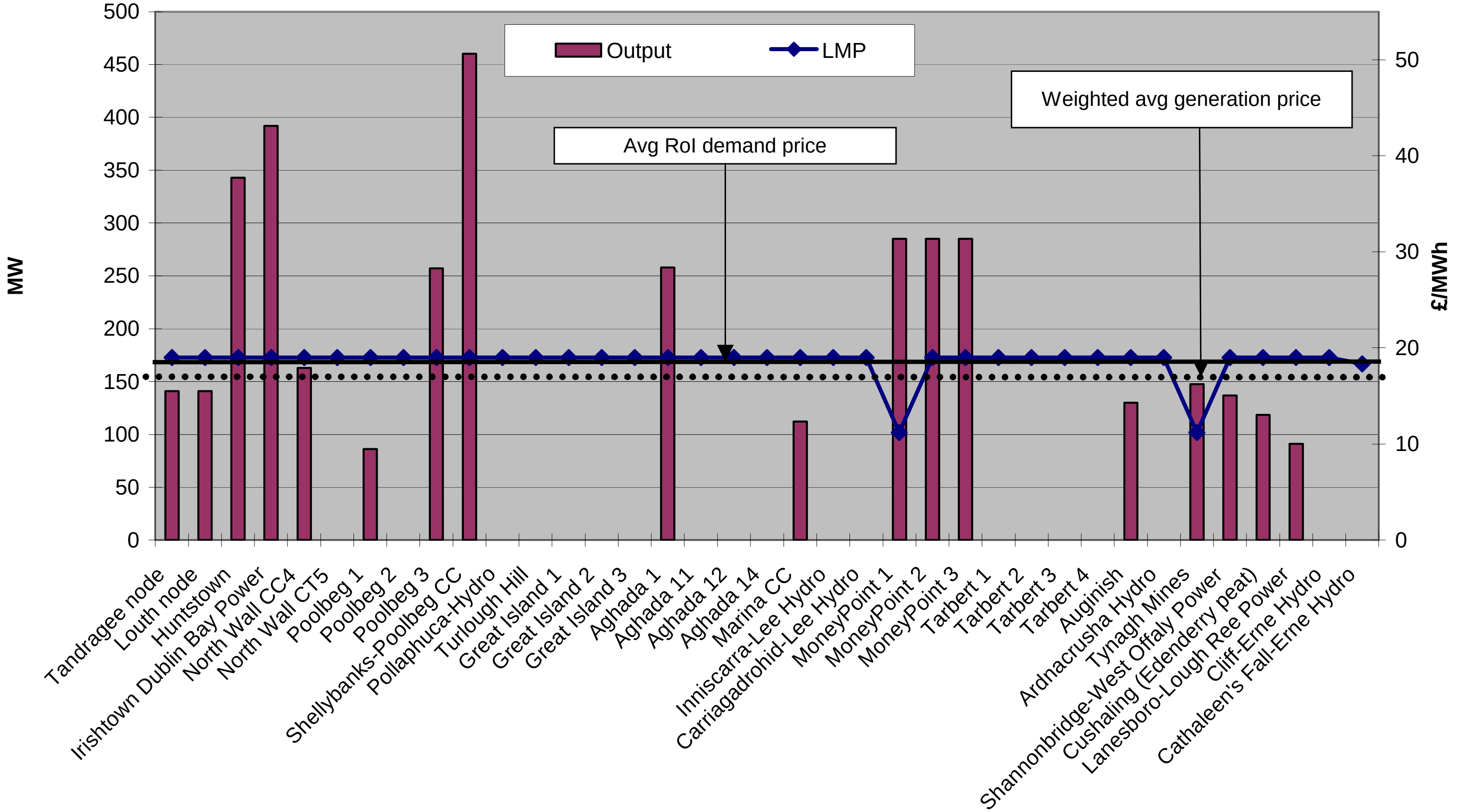


Figure 2.4
Avg Demand Price, Ouput and LMP – Summer Min 2006-07

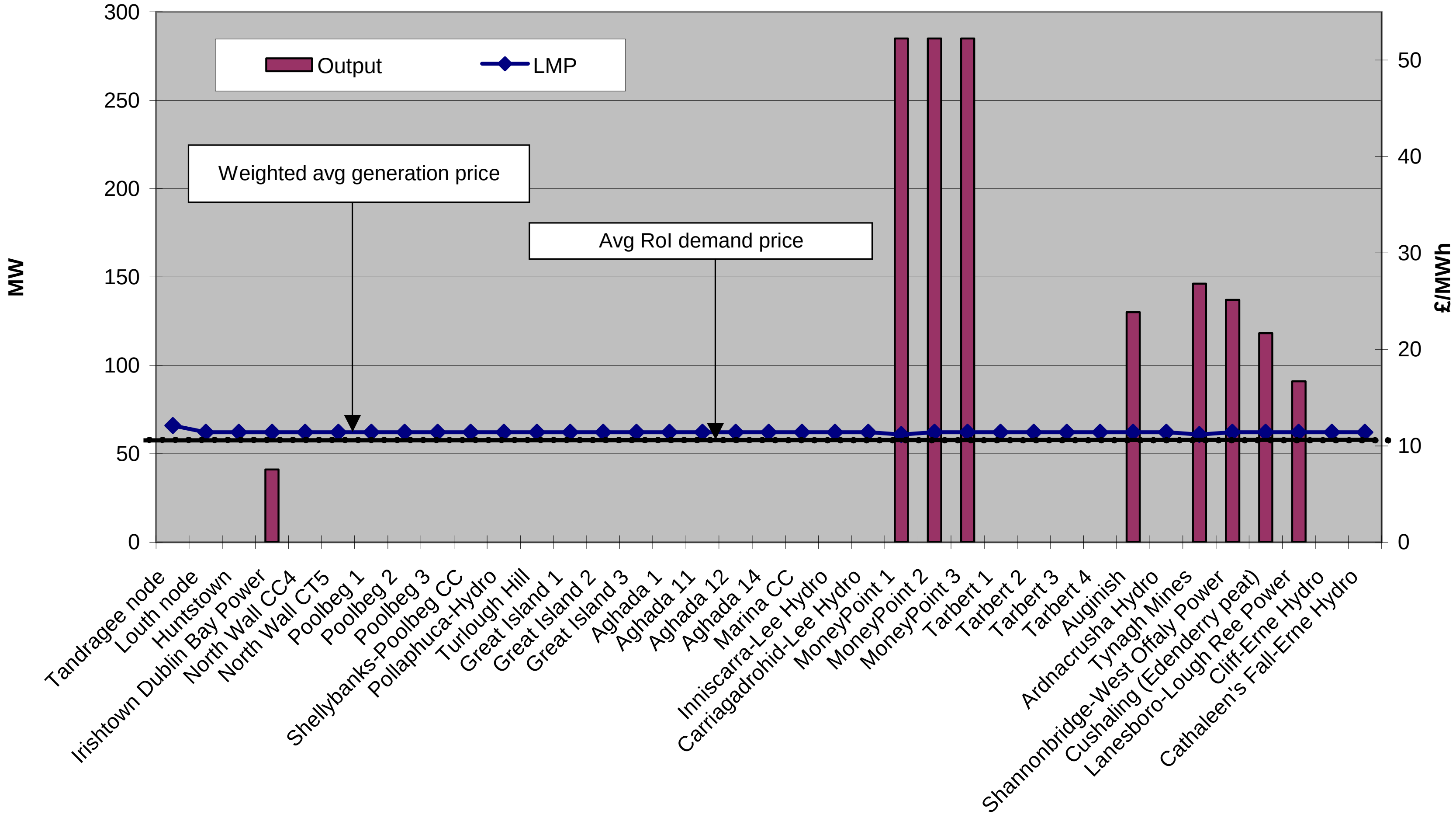


Figure 2.5
Avg Demand Price, Ouput and LMP – Winter Max 2009-10

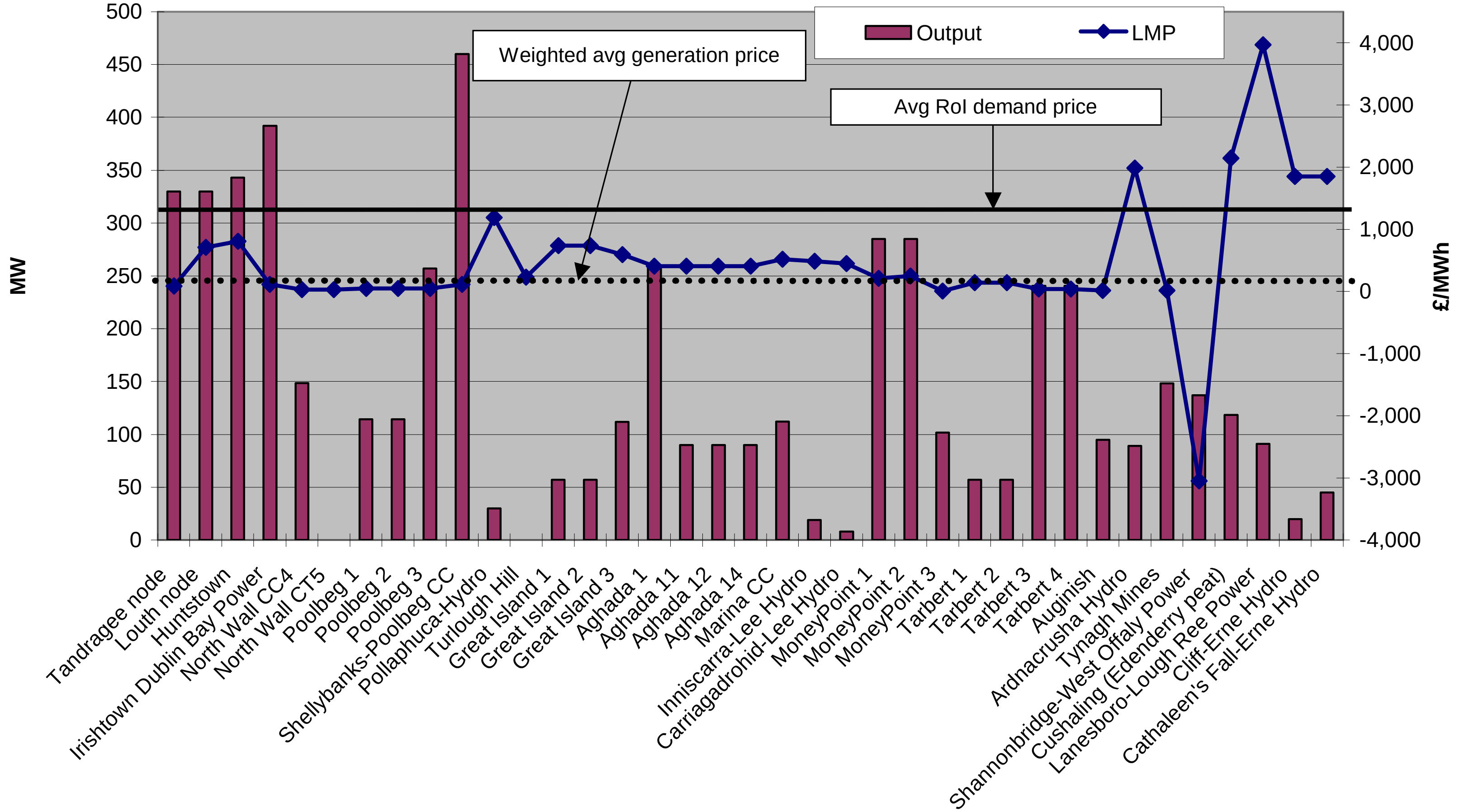


Figure 2.6
Avg Demand Price, Ouput and LMP – Winter Min 2009-10

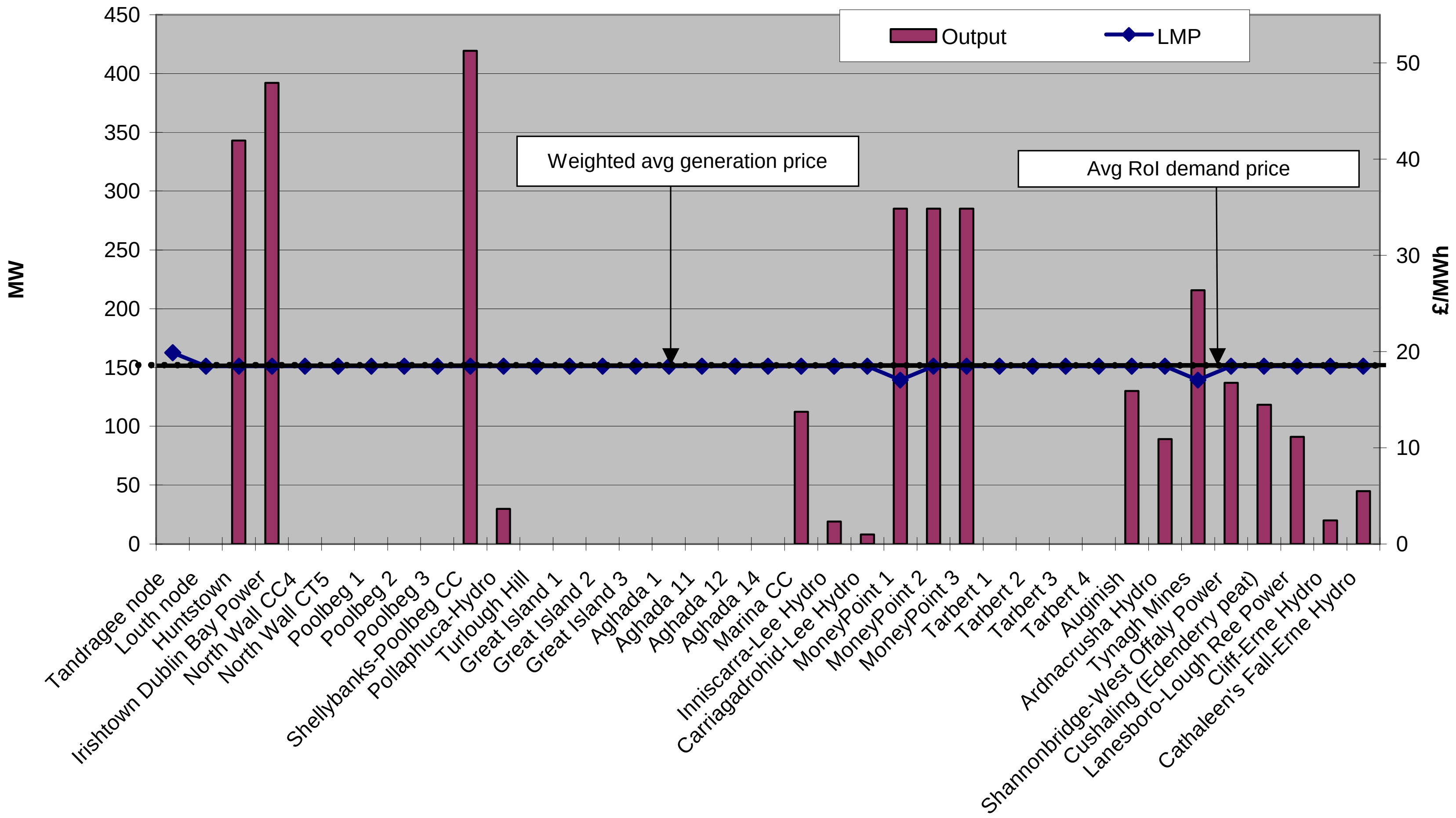


Figure 2.7
Avg Demand Price, Ouput and LMP – Summer Max 2009-10

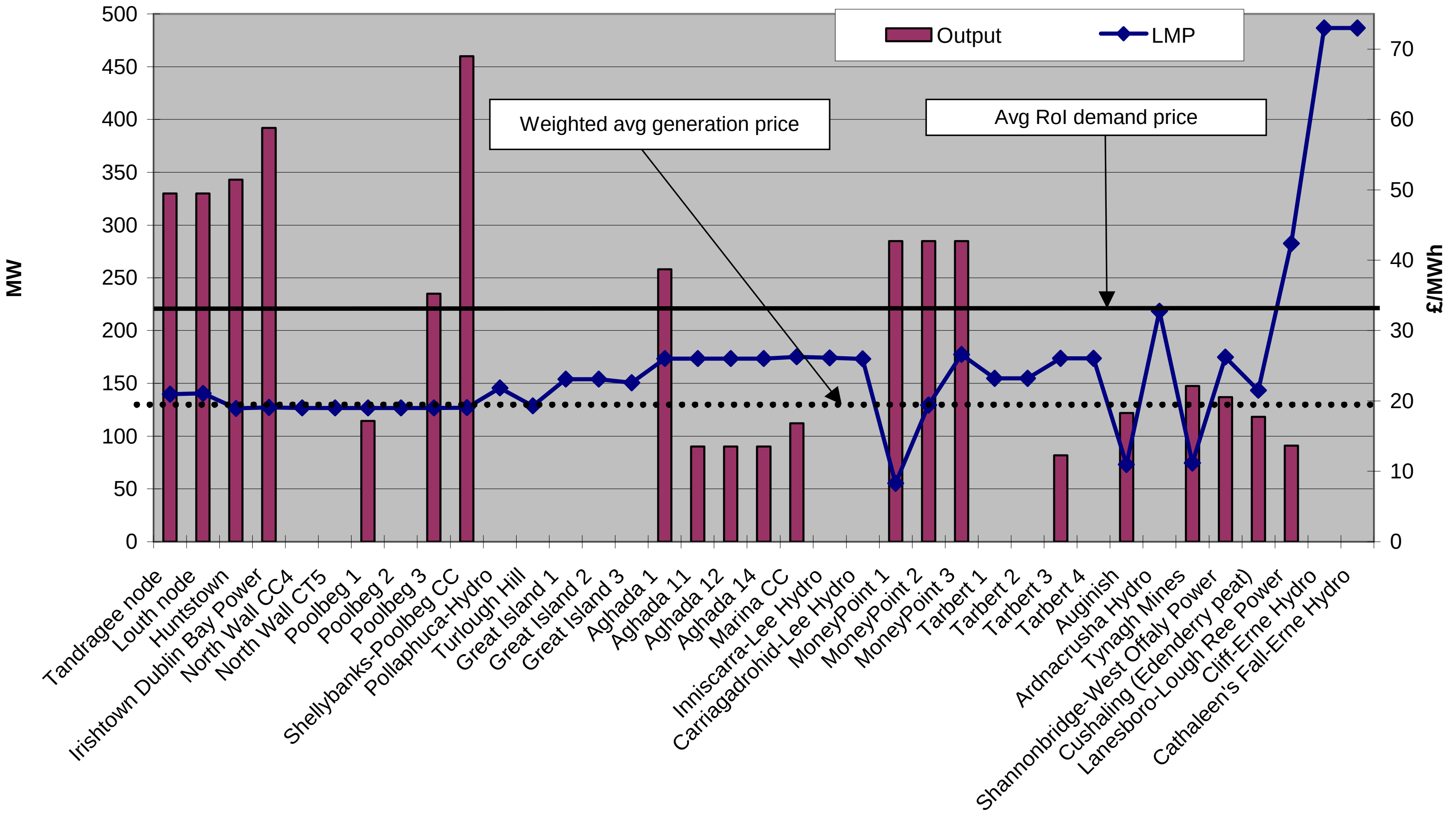
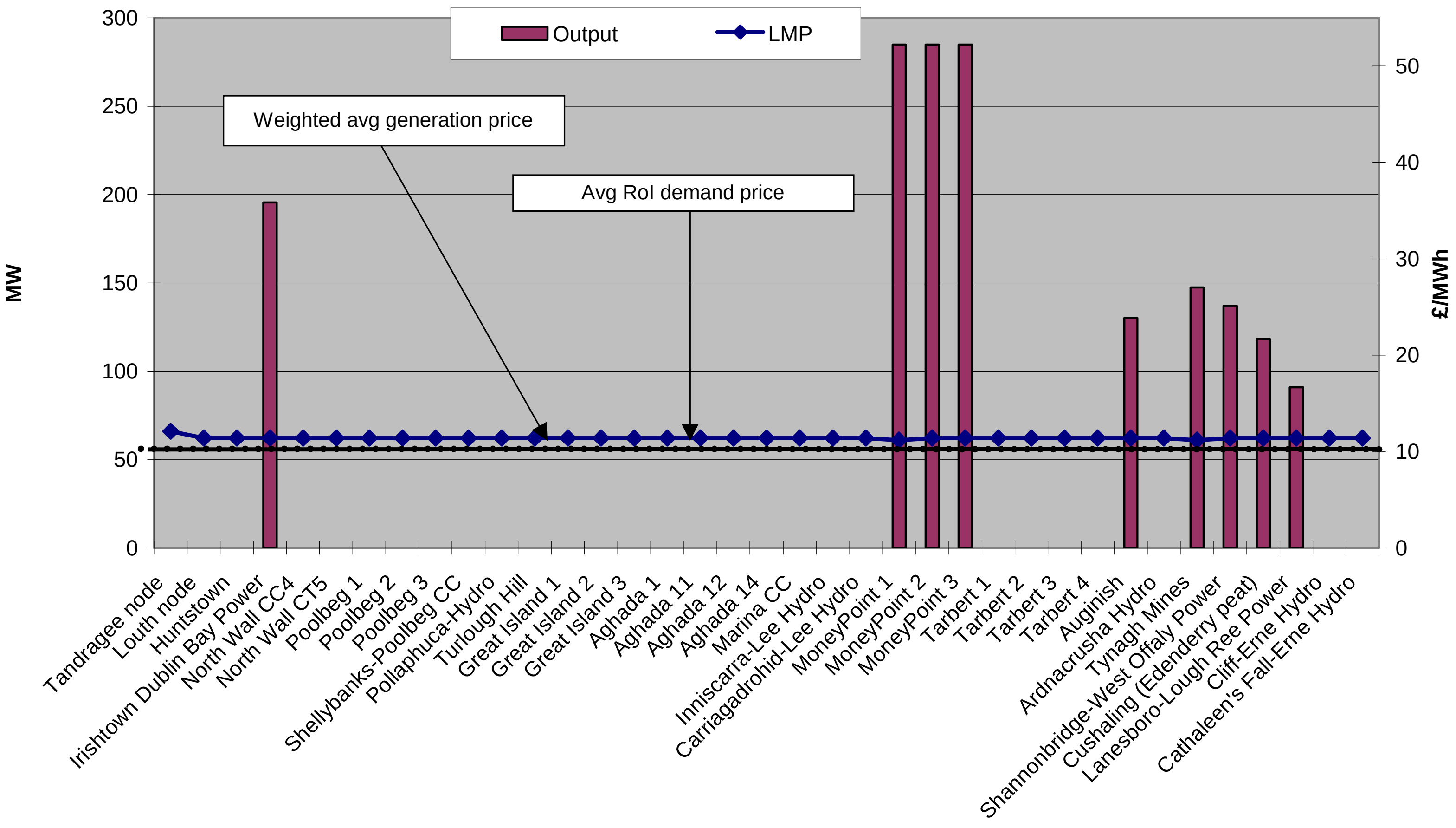


Figure 2.8
Avg Demand Price, Ouput and LMP – Summer Min 2009-10



3. PART A VARIANTS

To test the sensitivity of our results, we have looked at two variants to our base cases. In the first variant, we analyse the effects of wind generation. In the second, analyse the effects of EU Emissions Trading Scheme in a "carbon trading" variant.

3.1. "Wind-On" Variant

In this variant, we assume that all wind generation capacity in NI and ROI that currently has a signed connection agreement produces at 70% of its rated capacity. We have run this variant in summer maximum demand conditions. Since there is more wind generation capacity in the ROI than NI, we expected to find a lower N to S flow across the N-S interconnector in this variant than we saw in the base case, or even a revesal of the direction of flow. In fact, we find that output from wind generation in the ROI causes congestion in the ROI system, which was absent in the base case, and results in increased flows from N to S. While the flow from N to S is still uncongested, output from wind generation also has the effect of lowering the LMP of the NI node. Indeed, the LMP of the NI node is below the average ROI demand price in this variant.

We have not run this scenario in other demand conditions, but the variant we have looked at shows that certain aspects of our results (e.g., the differentials between NI and ROI LMPs) are indeed sensitive to the pattern of output from wind generation.

3.2. "Carbon Trading" Variant

We consider the effect of a carbon trading variant in 2006-07 winter and summer peak demand conditions.[3]

We find that the only effect of carbon trading in summer peak demand conditions is to raise the average level of LMPs across the island. The level of flow from N to S across the N-S interconnector remains the same as in the base case. And there is again no congestion in the ROI system (except from two local "blips" at Moneypoint and Tynagh Mines).

In winter peak demand conditions, on the other hand, we find some significant changes relative to the base case. In the carbon trading variant, we find that there is an uncongested flow of about 59 MW across the N-S interconnector, and that the average ROI demand price is significantly above the LMP at the NI node. Whereas in the base case, the N-S interconnector was congested from S to N and the ROI demand price was below the LMP at the NI node.

[3] We assume a carbon price equal to 13 euros/tCO_2.

While we have not run this variant in mimimum demand conditions, the above results illustrate that certain aspects of our results are indeed sensitive to the introduction of carbon trading.

Table 3.1
Summary of Key Results for the 2006-07 Wind On Variant

Case	LMPs, £/MWh			Tandragee Price Setting Units	N-S IC flows, MW	Congestion?		Key points
	Tandragee	Louth	ROI Demand			In ROI	On N-S IC	
Summer Max (4,857 MW)	18.1	18.1	18.9	Not clear	219	Yes	No	Border LMPs below the average ROI demand price. LMPs in the Cork and Limerick areas above average. LMPs in the Dublin area about average.

Notes: figure shown in brackets under the case name are for all-island demand.

Figure 3.1
Average Demand Price, Output and LMP – Summer Max 2006-07 – Wind On Variant

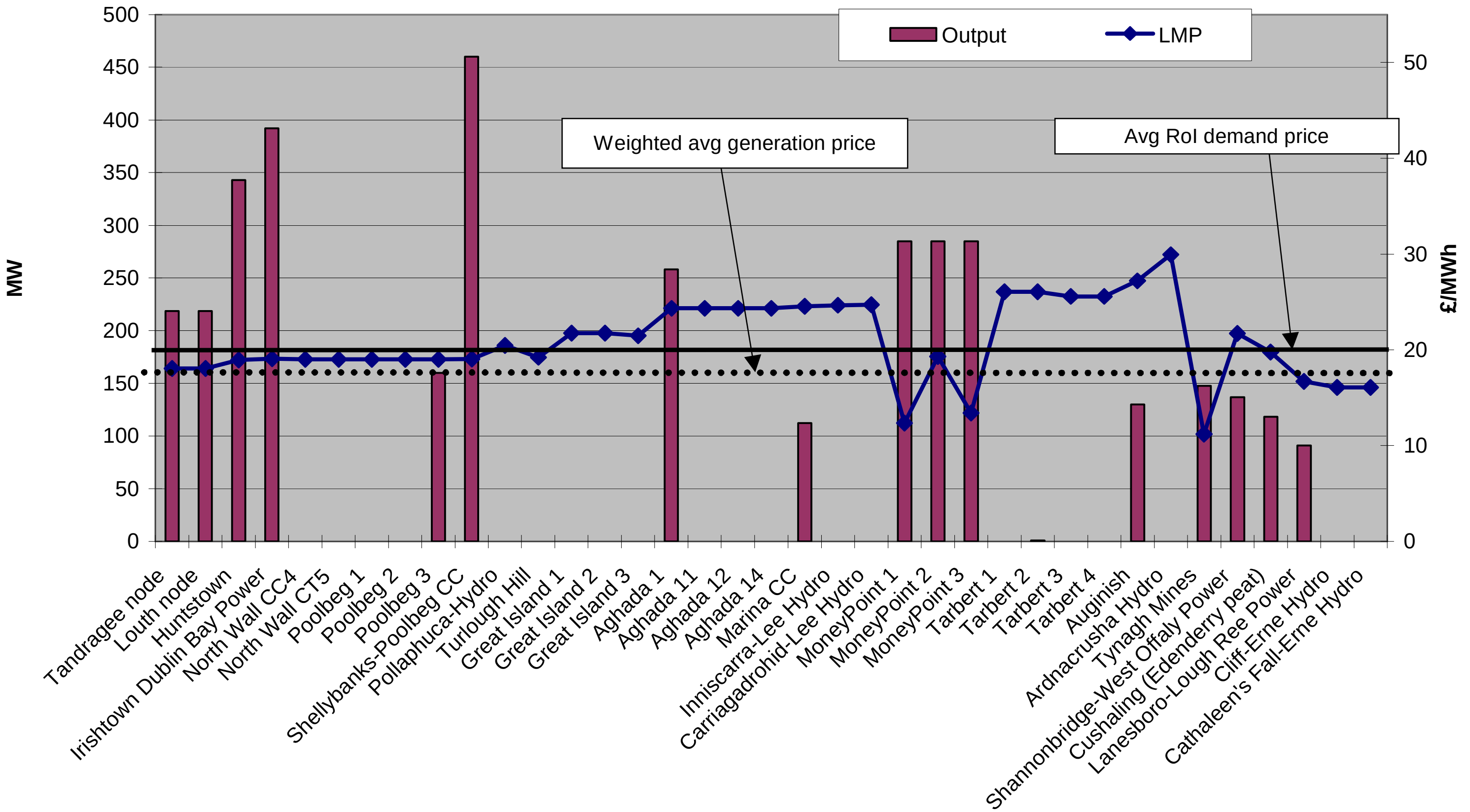


Table 3.2
Summary of Key Results for the 2006-07 Carbon Trading Variant

Case	LMPs, £/MWh			Tandragee Price Setting Units	N-S IC flows, MW	Congestion?		Key points
	Tandragee	Louth	ROI Demand			In ROI	On N-S IC	
Winter Max (6,311 MW)	41.4	41.4	49.6	Moyle IC	59	Yes	No	Border LMPs below ROI demand price. LMPs at Auginish and Tynagh Mines particularly low. Most LMPs in the Dublin area and elsewhere below average.
Summer Max (4,857 MW)	24.0	24.0	24.0	Aghada 1 North Wall CC4	141	Yes	No	Low LMPs at MoneyPoint 1 and Tynagh Mines. Uniform LMPs elsewhere.

Notes: figure shown in brackets under the case name are for all-island demand.

Figure 3.2
Average Demand Price, Output and LMP – Winter Max 2006-07 – Carbon Trading Variant

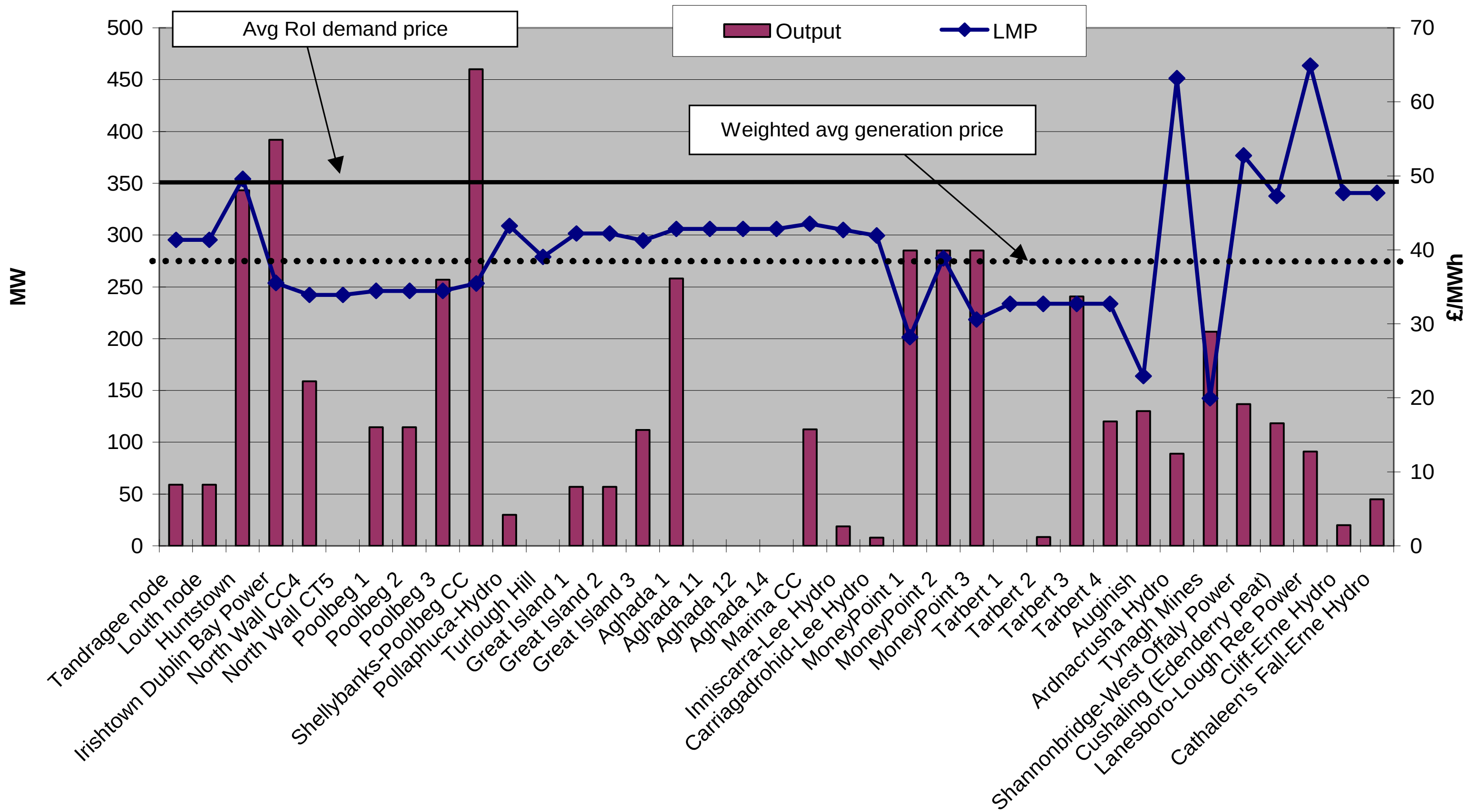
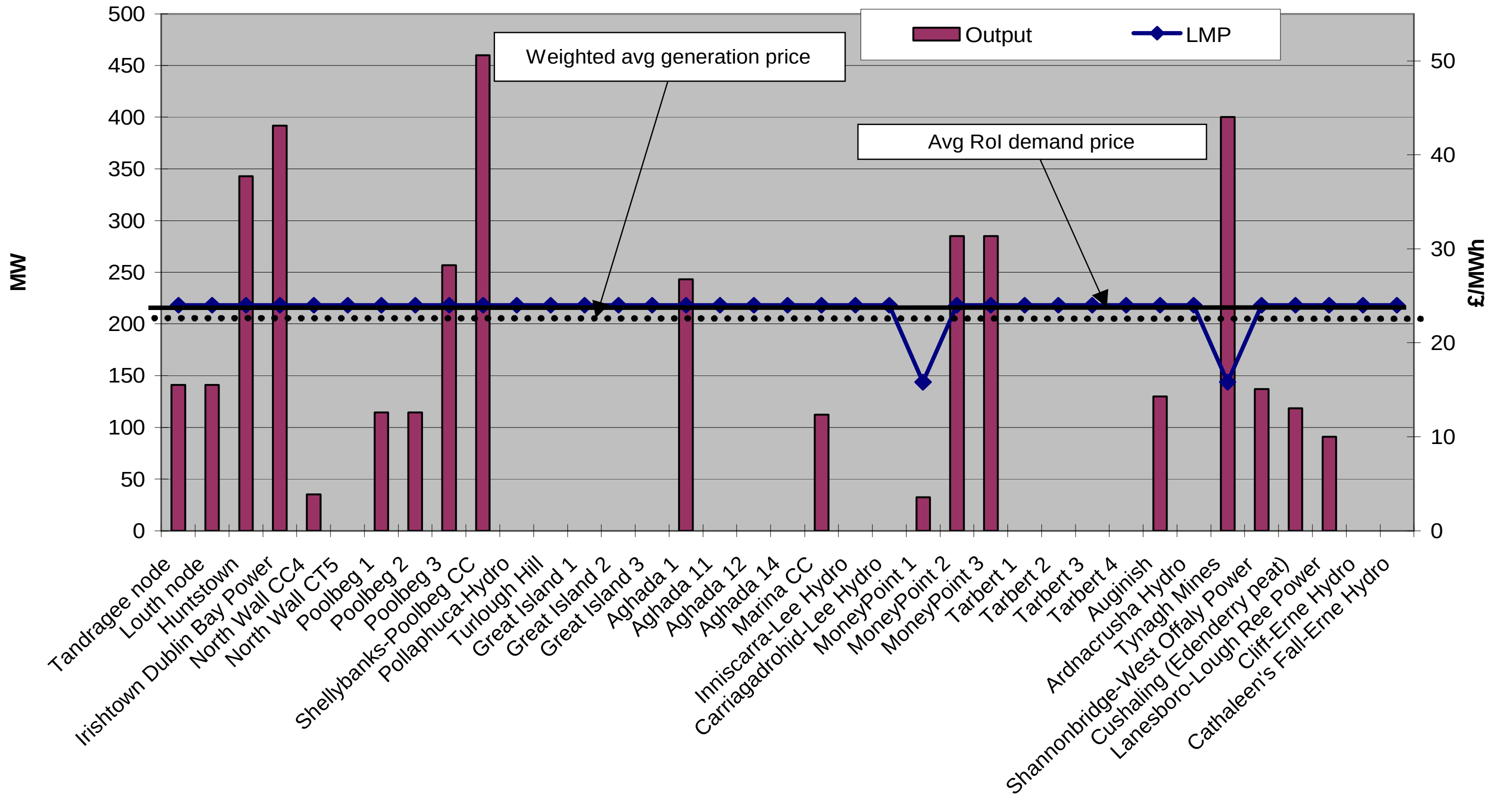


Figure 3.3
Average Demand Price, Output and LMP – Summer Max 2006-07 – Carbon Trading Variant



PART II: SUMMARY OF PART B MODELLING RESULTS

4. PART B BASE CASE RESULTS

4.1. Definition of the Base Cases

In Part B of the study we considered the Republic of Ireland and Northern Ireland as forming part of a single, integrated LMP spot market (i.e. an "MAE Integration" scenario). Apart from this change, we have maintained the same base case assumptions as we used in Part A.

4.2. Base Case Results

Table 4.1 summarises our Part B base case results for a sub-sample of the demand periods we considered in Part A. This sub-sample covers winter and summer peak and minimum demand conditions. In none of these runs did we find any evidence of congestion within the NI network, whether in 2006-07 or 2009-10.[4] This means that our Part B results for this sub-sample of demand periods are essentially the same as those we obtained in Part A, except that in Part B we explicitly calculate and report separate (but uniform) LMPs for each node in the NI network. On the basis of this sub-sample of results, we concluded that it was not worthwhile to run a complete set of base case runs for Part B.

Figures 4.1 to 4.5 show charts illustrating how LMPs vary across injection nodes, including nodes in Northern Ireland, in our sub-sample of demand periods. By comparing these charts with the equivalent Part A charts, the reader can easily see that the pattern of LMPs and outputs is the same in both cases.

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[4] In 2009-10 winter peak conditions there are two demand nodes with very high prices resulting from constraint violation penalties. These nodes are 33 kV transformers. SONI have advised us that this type of asset is routinely replaced or upgraded as necessary as part of SONI's ordinary network maintenace programme. Since this sort of

Table 4.1
Summary of Results of Part B Base Cases

Case	Av. NI generation price, £/MWh	Demand price, £/MWh NI	Demand price, £/MWh All-island	Imports over Moyle	Exports to ROI
2006-07: Winter Max	40.6	40.6	39.4	Volume: 172 MW Cost: £ 40.6 / MWh	-
2006-07: Summer Max	19.0	19.0	19.0	-	Volume: 117 MW Value: £ 19.0 / MWh
2006-07: Summer Min	12.1	12.1	11.6	-	-
2009-10: Winter Max	85.2	998	1,277	Volume: 400 MW Cost: £85.2 / MWh	Volume: 330 MW Value: £ 709.6 / MWh
2009-10: Summer Max	21.1	21.1	30.7	-	Volume: 324 MW Value: £ 21.1 / MWh

Figure 4.1
Average Demand Price, Output and LMP – Summer Min 2006-07

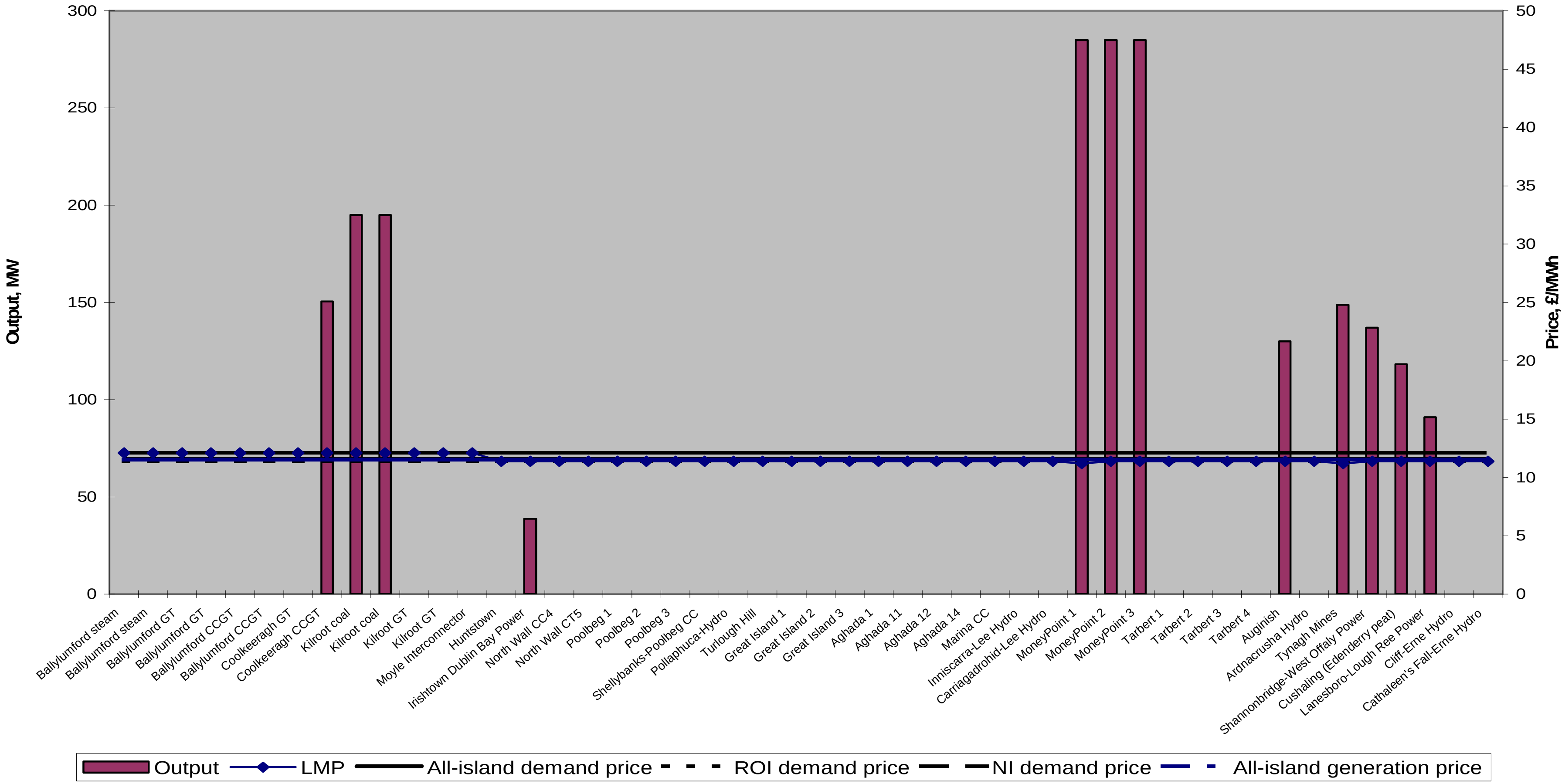


Figure 4.2
Average Demand Price, Output and LMP – Summer Max 2006-07

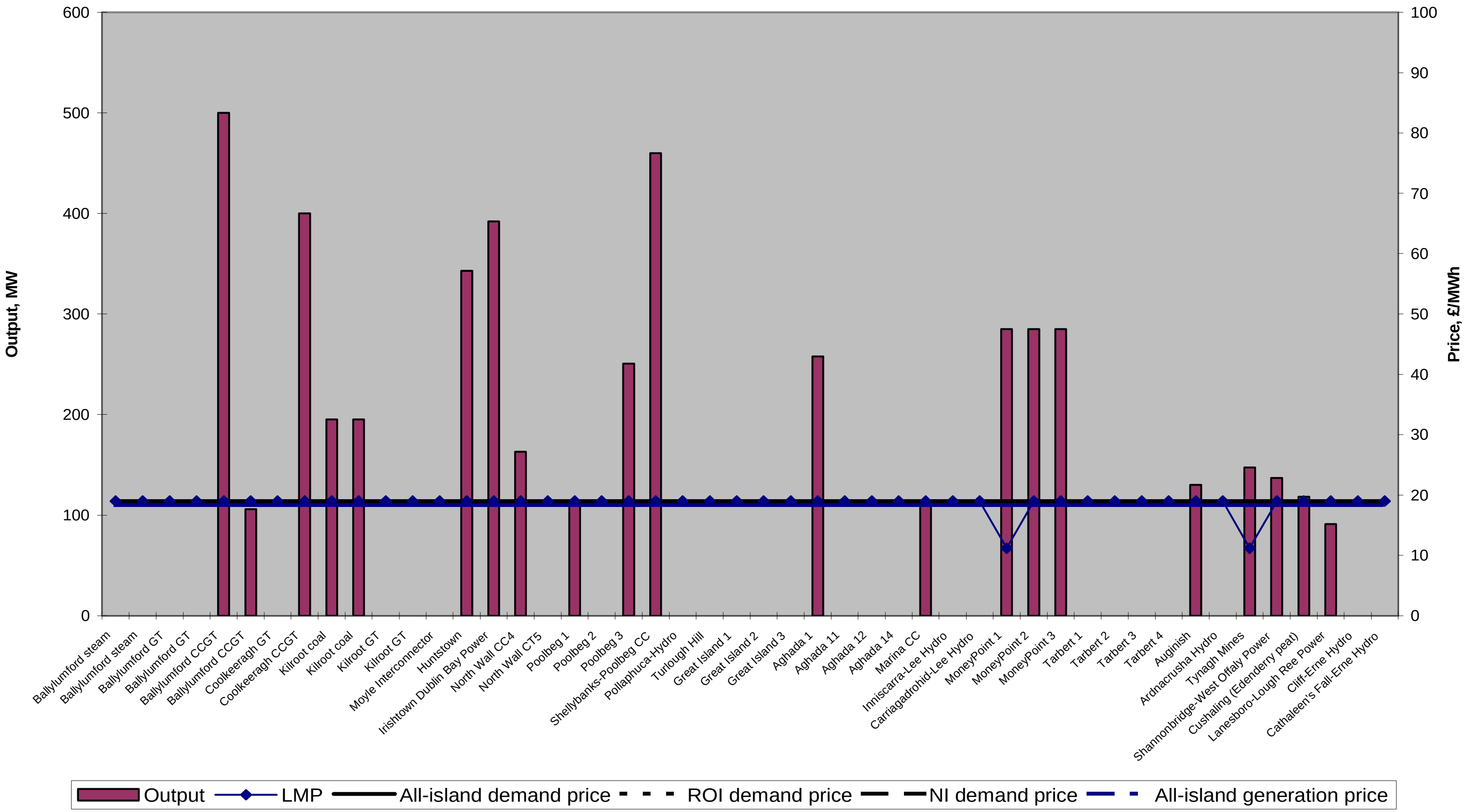


Figure 4.3
Average Demand Price, Output and LMP – Winter Max 2006-07

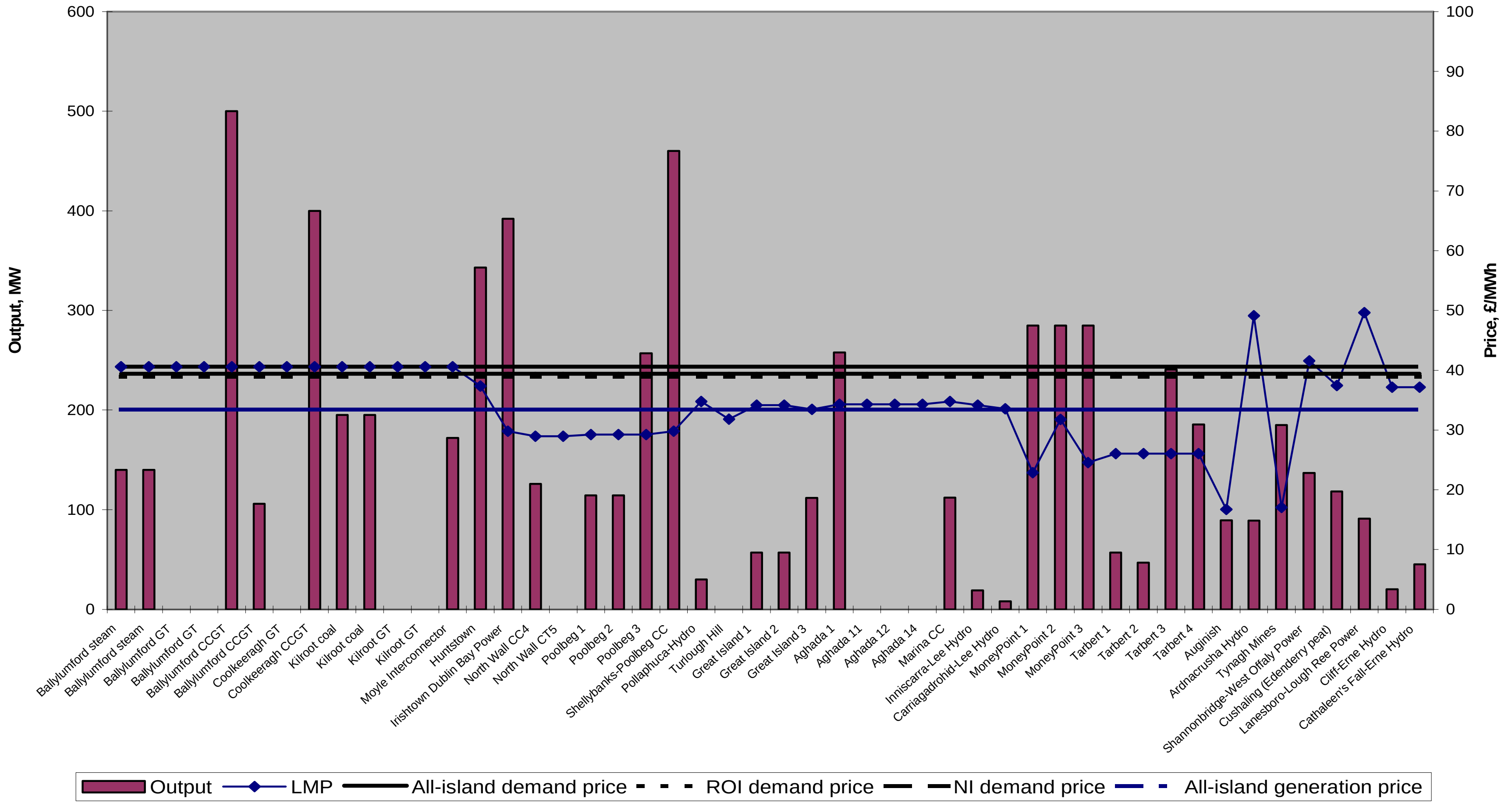


Figure 4.4
Average Demand Price, Output and LMP – Summer Max 2009-10

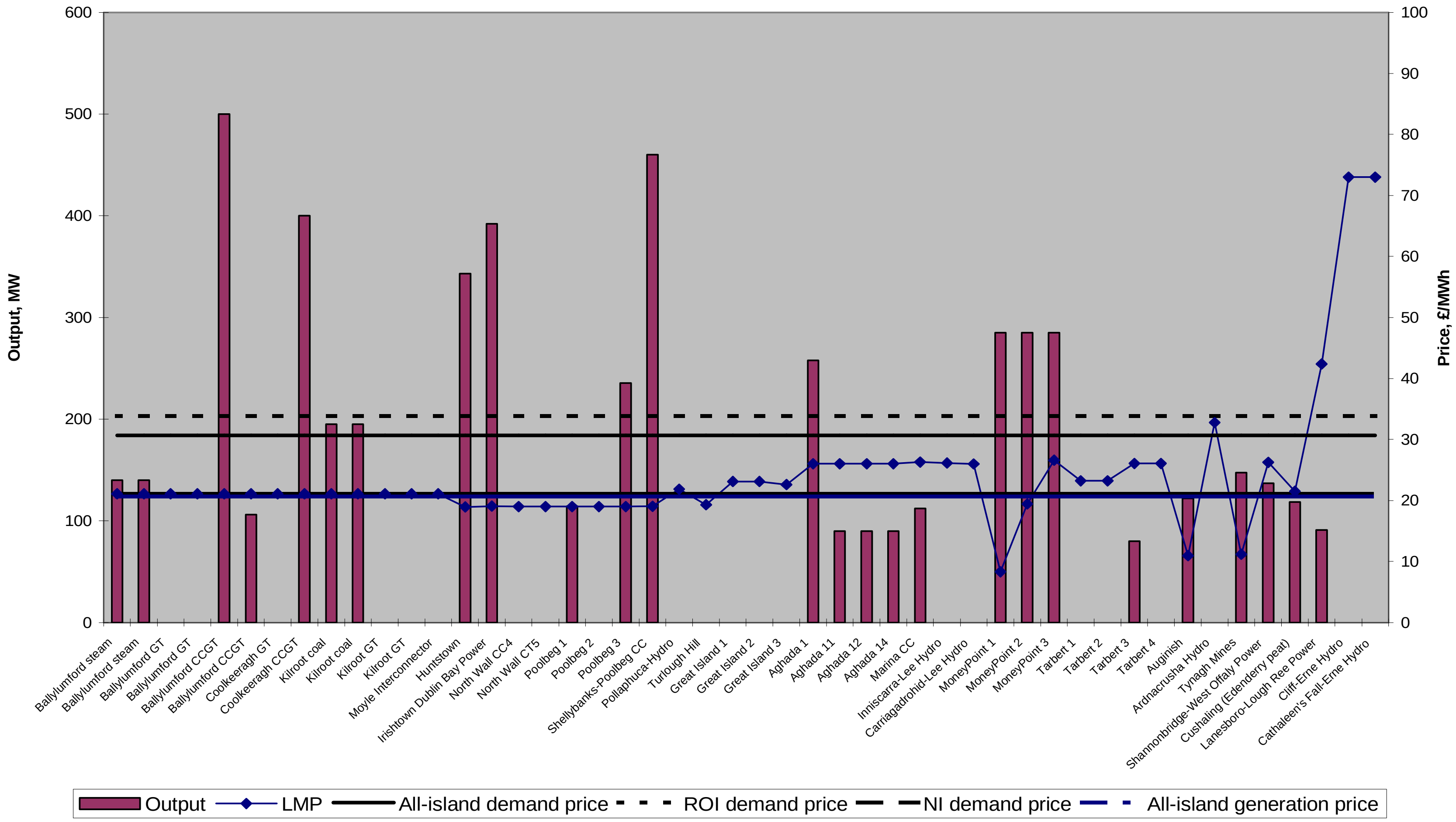
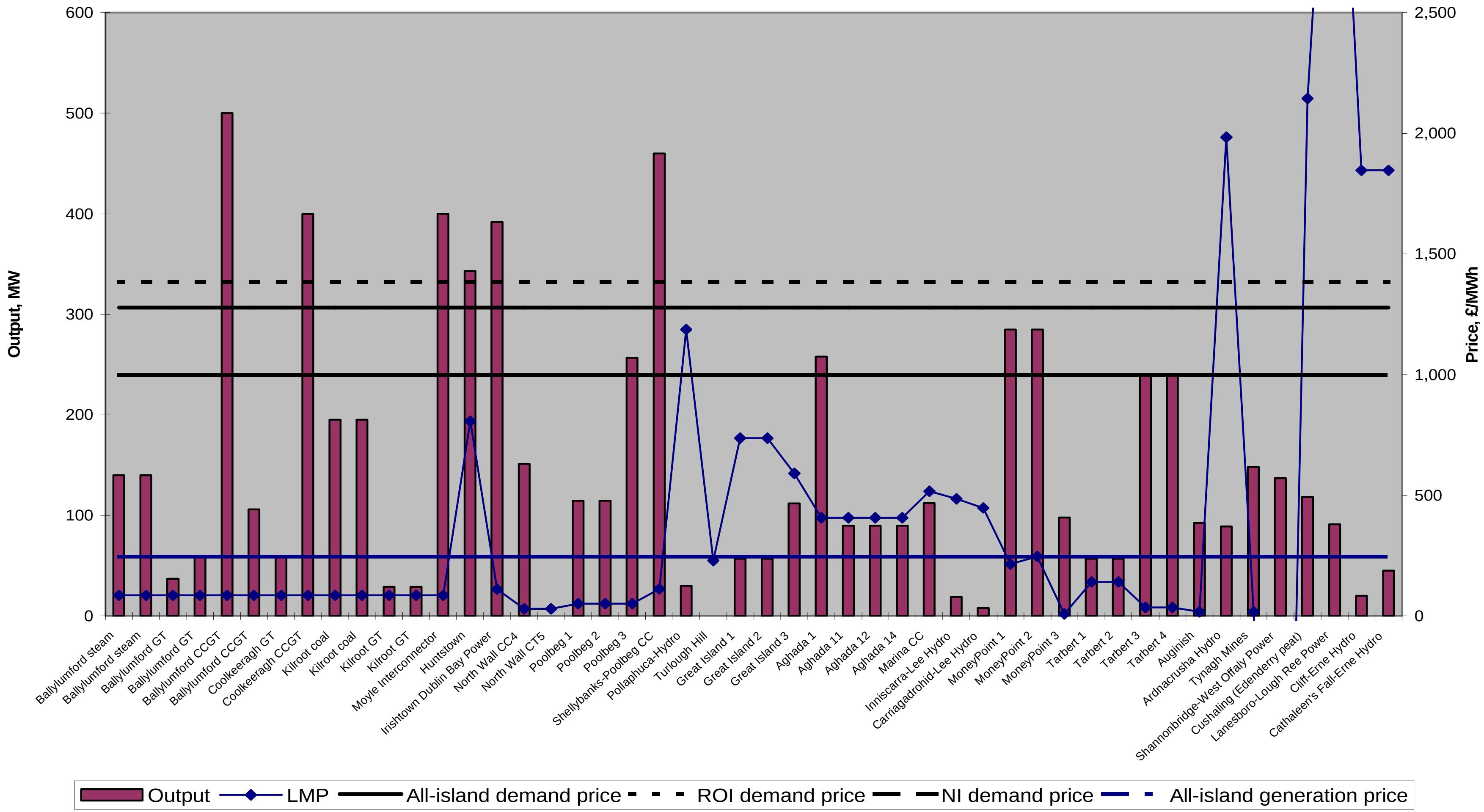


Figure 4.5
Average Demand Price, Output and LMP – Winter Max 2009-10



5. PART B VARIANTS

To help us appraise the costs and benefits of MAE Integration for NI, we have modelled the following Part B variants:

- Increase the NTC of the 275 kV Tandragee-Louth interconnector to 500MW in both directions;
- Small but Significant Non-transitory Increase in Price (SSNIP) test for generators located in Northern Ireland;
- SSNIP test for generators controlled by ESB; and
- Setting the net transfer capacity of the two 110kV interconnectors to 100 MW in both directions.

Table 5.1 summarises the results of these variants.

5.1. NTC of 275 kV N-S Interconnector Set to 500 MW

When we run this variant for winter peak 2006-07 conditions, we find that it leads to significant flows from S to N across the 275 kV interconnector, and lower LMPs in NI that we found in the base case.

5.2. SSNIP Test for Generators Located in NI

In this variant, we assume that all generators located in NI raise their offer prices by 10% with respect to the base case. The purpose of running this variant is to test whether NI is a separate market. If a 10% increase in offer prices is profitable for NI generators, we can conclude that NI is a separate market.

In our 2006-07 base cases, we find that the N-S interconnector is congested from S to N in all demand conditions, apart from the summer maximum demand period when there is an uncongested flow from N to S of about 117 MW. In most demand conditions, therefore, ROI generators cannot act as an effective competitive constraint on NI generators. The S to N transmission constraints prevent an increase in imports from ROI in response to in increase in offer prices by NI generators. Further, in each of these cases the Moyle import price is greater than 10% above the most expensive NI generator that is dispatched in the base case. Therefore, neither can imports from Moyle effectively constrain NI generators from profitably raising their offer prices by 10%. If we combine these findings with the fact that the demand for electricity highly price inelastic, we can immediately conclude that a SNNIP will be profitable for NI generators, and hence that in most demand conditions NI is a separate market.

The results of this variant for the summer peak demand period are shown in Figure 5.3. A comparison of this chart with the equivalent chart for the base case shows that a 10% increase in NI offer prices has no impact on the ressults. This is confirmed by Table 5.2, which shows that NI generators' profits do not change as a result of a 10% increase in offer prices. This suggests that NI is not a separate market in summer peak demand conditions.

5.3. SSNIP Test for Generators Controlled by ESB

In this variant, we assume that all generators controlled by ESB raise their offer prices by 10% with respect to the base case. The purpose of running this variant is to test whether ESB has market power. If a 10% increase in offer prices is profitable for ESB, we can conclude that ESB has market power.

As is shown by the results in Figure 5.4 and Figure 5.5, and Table 5.3 and Table 5.4, our modelling confirms that ESB has market power in winter and summer peak demand conditions in 2006-07.

5.4. Setting NTC of 110kV Interconnectors to 100 MW

This variant is intended to give an indication of the sensitivity of our base case results to our assumption that the 110 kV interconnectors are not used for trading. We have run this variant for 2006-07 winter and summer peak demand conditions. The results are illustrated in Figure 5.6 and Figure 5.7.

When we opened the 110kV interconnectors for trading in winter peak demand conditions, we found that the model could not find a feasible solution. This was caused by interactions between the 110 kV interconnectors and the main 275 kV interconnector. In our base case, we found that the 275 kV interconnector was congested S to N in 2006-07 winter peak conditions, but the flow from S to N was zero because of our assumption of a zero NTC S to N. The zero NTC constraint from S to N in the base case reflects the "system separation" constraints adopted by ESB NG. It does not make sense to assume that the S to N NTC of the 110 kV interconnectors is positive (i.e., that ESB NG's "system separation" constraint has been slackened), without also assuming that the NTC of the 275 kV interconnector is positive. In winter peak demand conditions, therefore, we have analysed a variant in which the N to S NTC of the 110 kV interconnectors is increased to 100 MW, in combination with an increase in the N to S NTC of the 275 kV interconnector to 330 MW (reflecting the current S to N NTC).

As we expected, it turns out that neither of these constraints is binding in the solution. We find that there is a flow from S to N of about 158 MW in this variant, i.e. a similar level to that we saw in the "500 MW NTC" variant described above. We also find a similar impact on LMPs.

In summer peak demand conditions, on the other hand, we find no change from our base case results, other than that 11 MW of the N to S flow goes across the 110 kV interconnectors rather than the 275 kV interconnector.

Table 5.1
Summary of Results of Part B Variants

Variant	Effect on N-S flow	Effect on LMPs: NI	Effect on LMPs: ROI	Effect on demand price	Effect on injections in NI
Winter Max 2006-07: 500 MW capacity on 275 kV interconnector	275 kV: - 170 MW 110 kV: 0 MW Total: - 170 MW	Uniform decrease (-7.1 %).	Unchanged in Dublin, mostly higher in NW.	NI only price: - 7.1 % All-island price: + 9.3%	Moyle I/C from 172 to 0 MW.
Summer Max 2006-07: SSNIP test for NI generators	275 kV: 0 MW 110 kV: 0 MW Total: 0 MW	Unchanged.	Unchanged.	Unchanged.	Unchanged.
Summer Max 2006-07: SSNIP test for ESB generators	275 kV: + 214 MW 110 kV: 0 MW Total: + 214 MW	Uniform increase (10.5 %).	Uniform increase (10.5%).	NI only price: + 10.5 % All-island price: +10.5%	Ballylumford steam from 0 to 217 MW.
Winter Max 2006-07: SSNIP test for ESB generators	275 kV: 0 MW 110 kV: 0 MW Total: 0 MW	Unchanged.	Slightly higher in Wexford and NW	NI only price: no change All-island price: + 11.6%	Unchanged.
Summer Max 2006-07: 100 MW capacity on 110 kV interconnectors	275 kV: - 10.8 MW 110 kV: 10.8 MW Total: 0 MW	Unchanged.	Unchanged.	Unchanged	No significant changes
Winter Max 2006-07: 100 MW capacity on 110 kV interconnectors	275 kV: - 130 MW 110 kV: - 37.8 MW Total: - 168 MW	Uniform decrease (-5.2%).	Slightly higher in Wexford, Cork and NW	NI only price: - 4.92 % All-island price: + 9.9 %	Moyle I/C from 172 to 0 MW.

Figure 5.1
Average Demand Price, Output and LMP – Winter Max 2006-07 500 MW interconnector

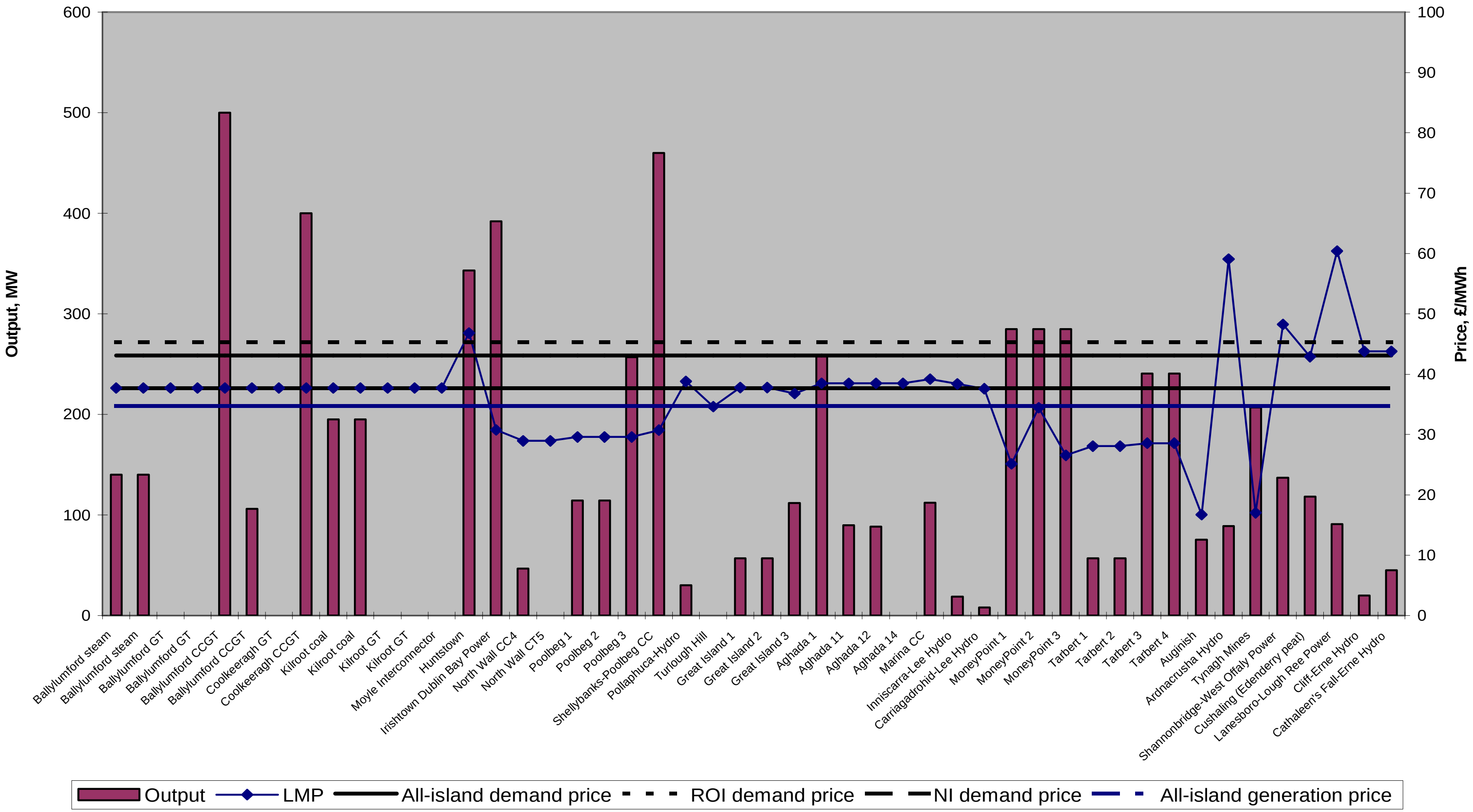


Figure 5.2
Average Demand Price, Output and LMP – Winter Max 2009-10 500 MW interconnector

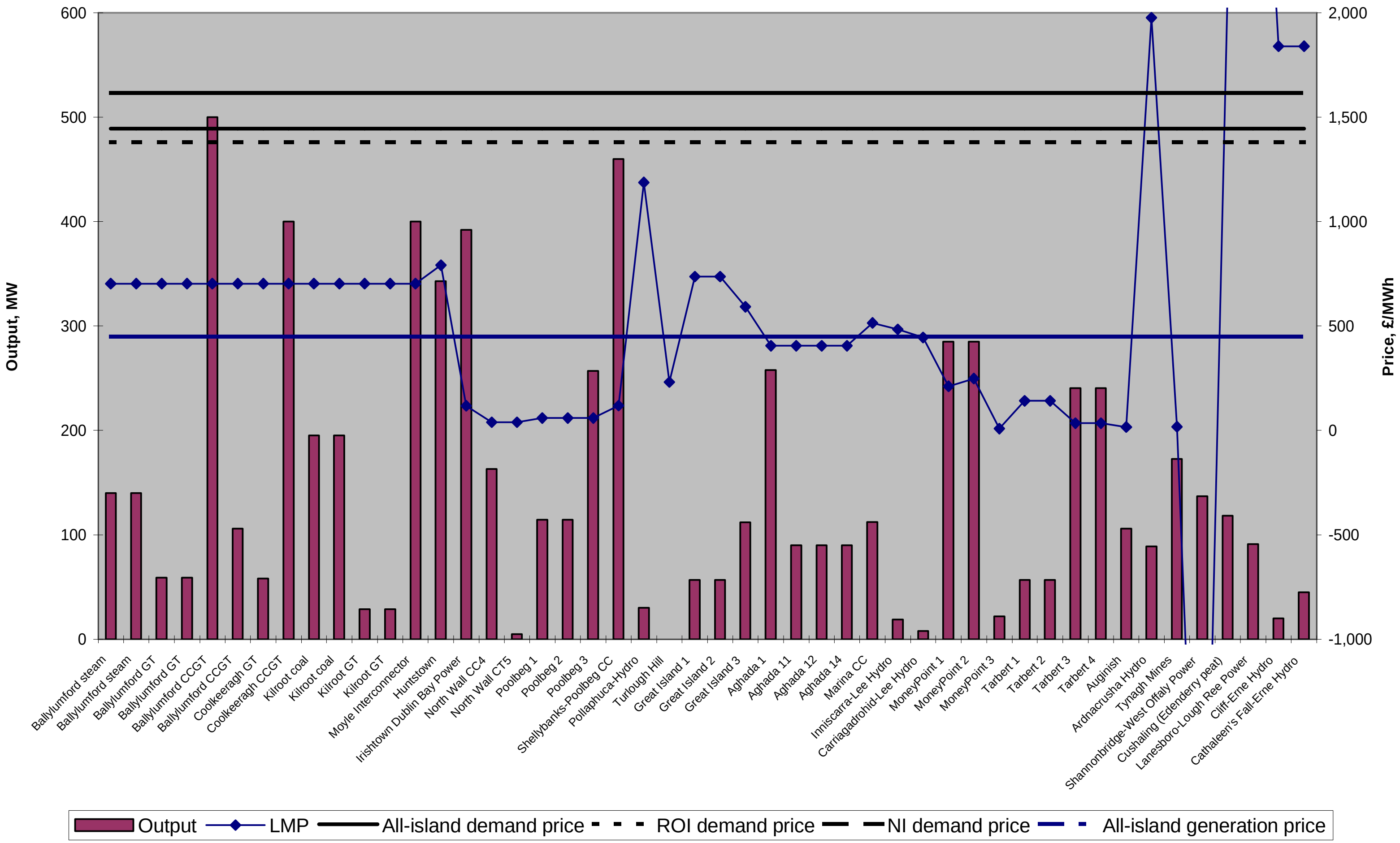


Figure 5.3

Average Demand Price, Output and LMP – Summer Max 2006-07 SSNIP test for Northern Ireland generators

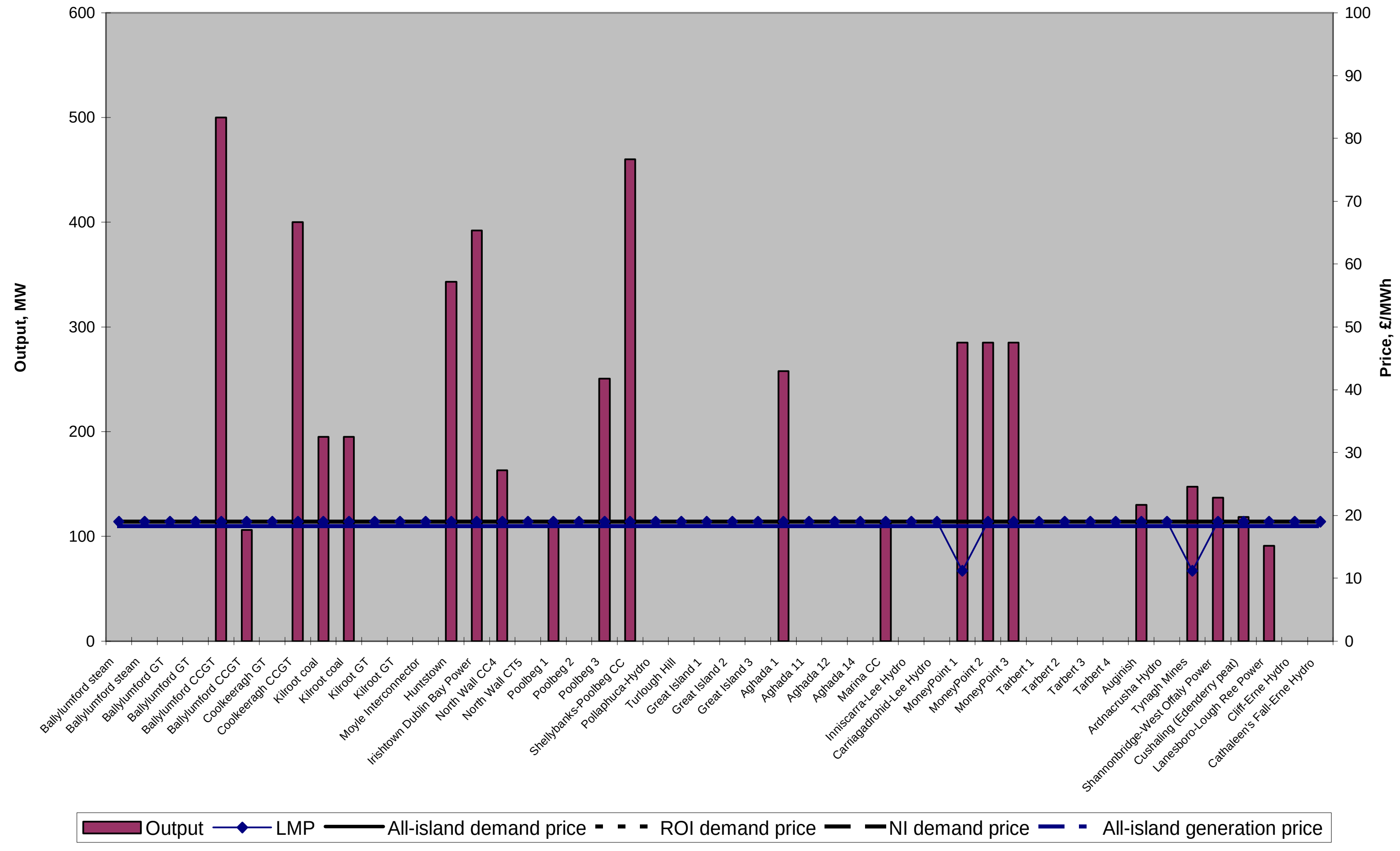


Figure 5.4
Average Demand Price, Output and LMP – Summer Max 2006-07 SSNIP test for ESB generators

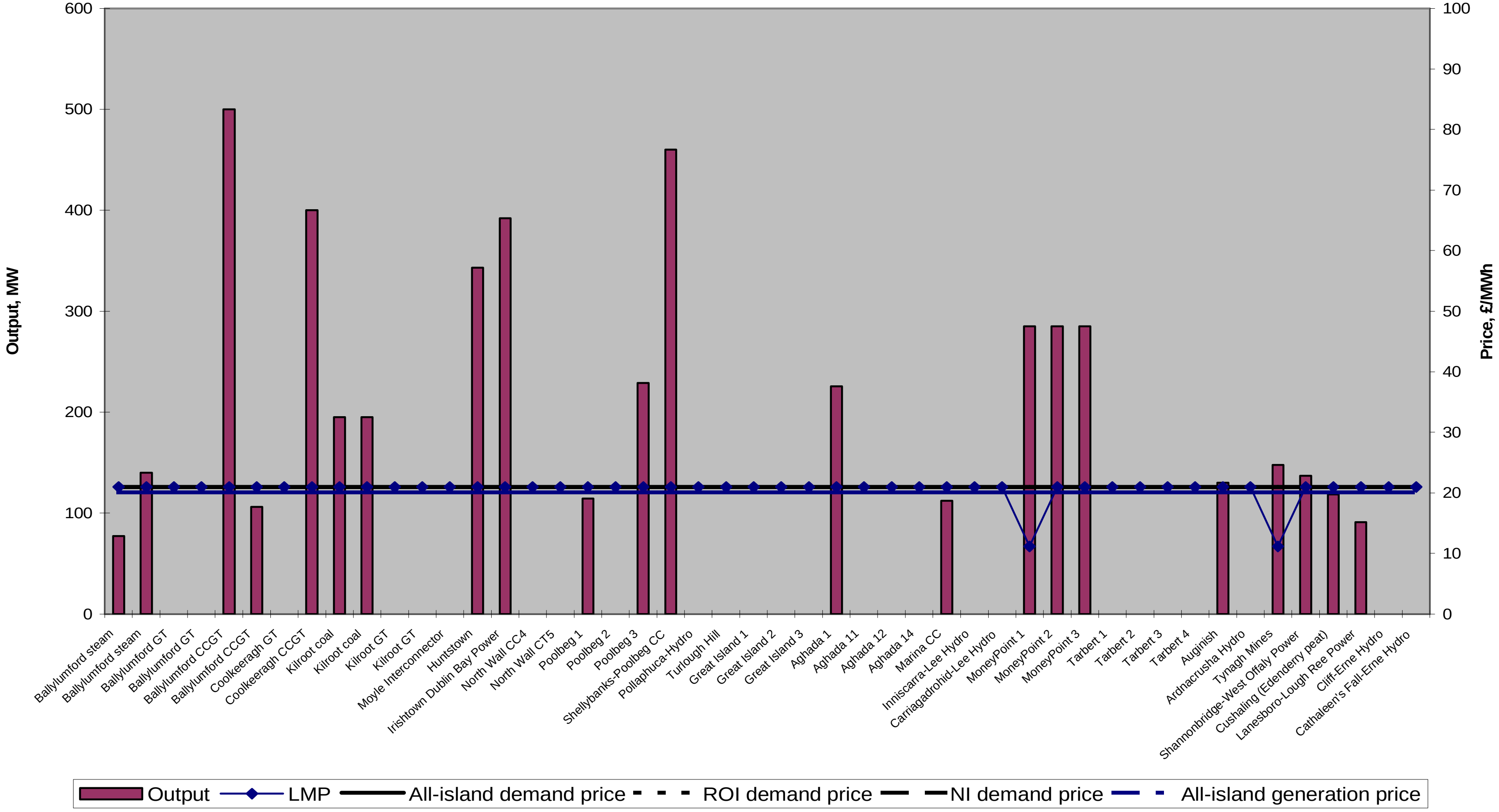


Figure 5.5
Average Demand Price, Output and LMP – Winter Max 2006-07 SSNIP test for ESB generators

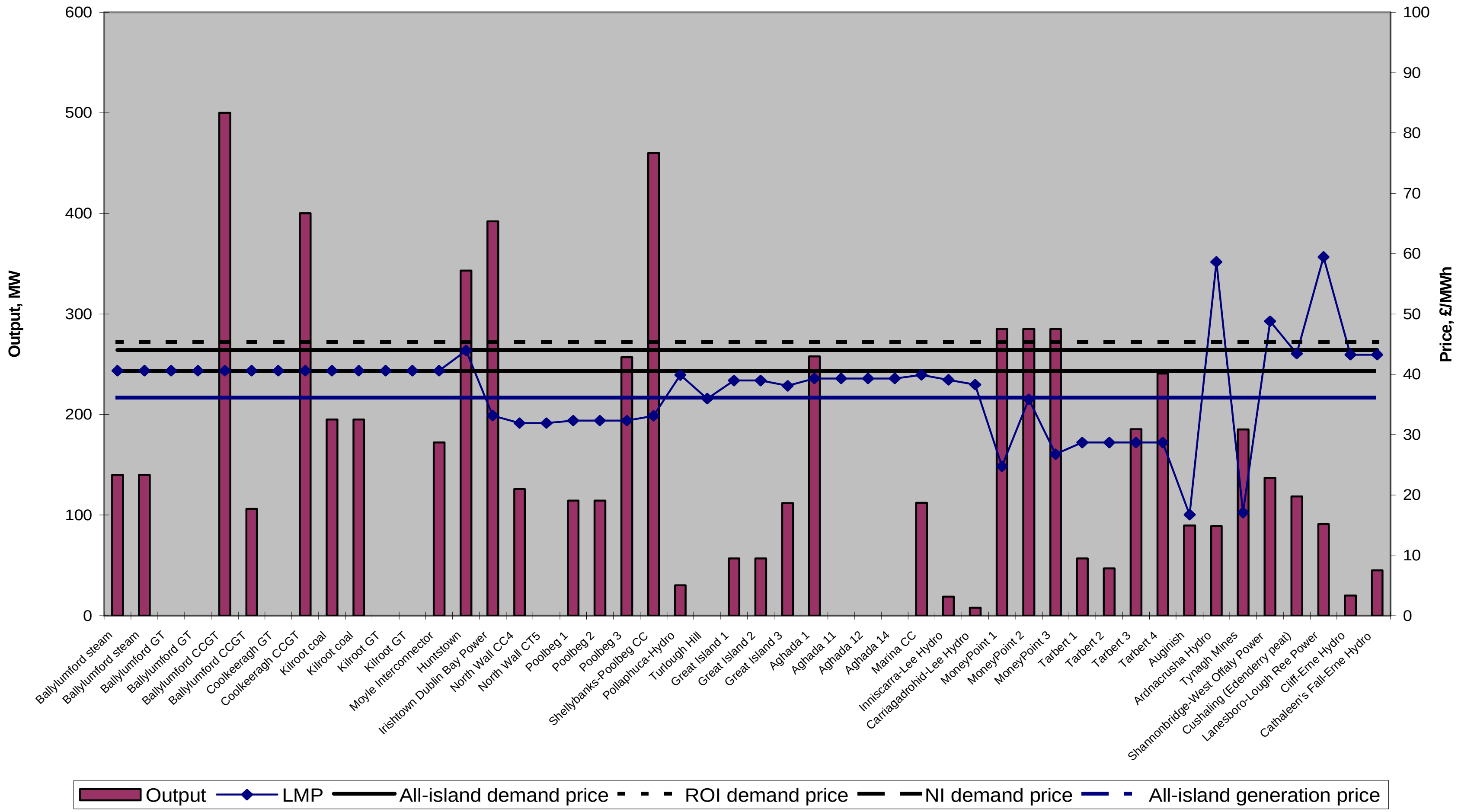


Figure 5.6
Average Demand Price, Output and LMP – Summer Max 2006-07 100 MW interconnectors

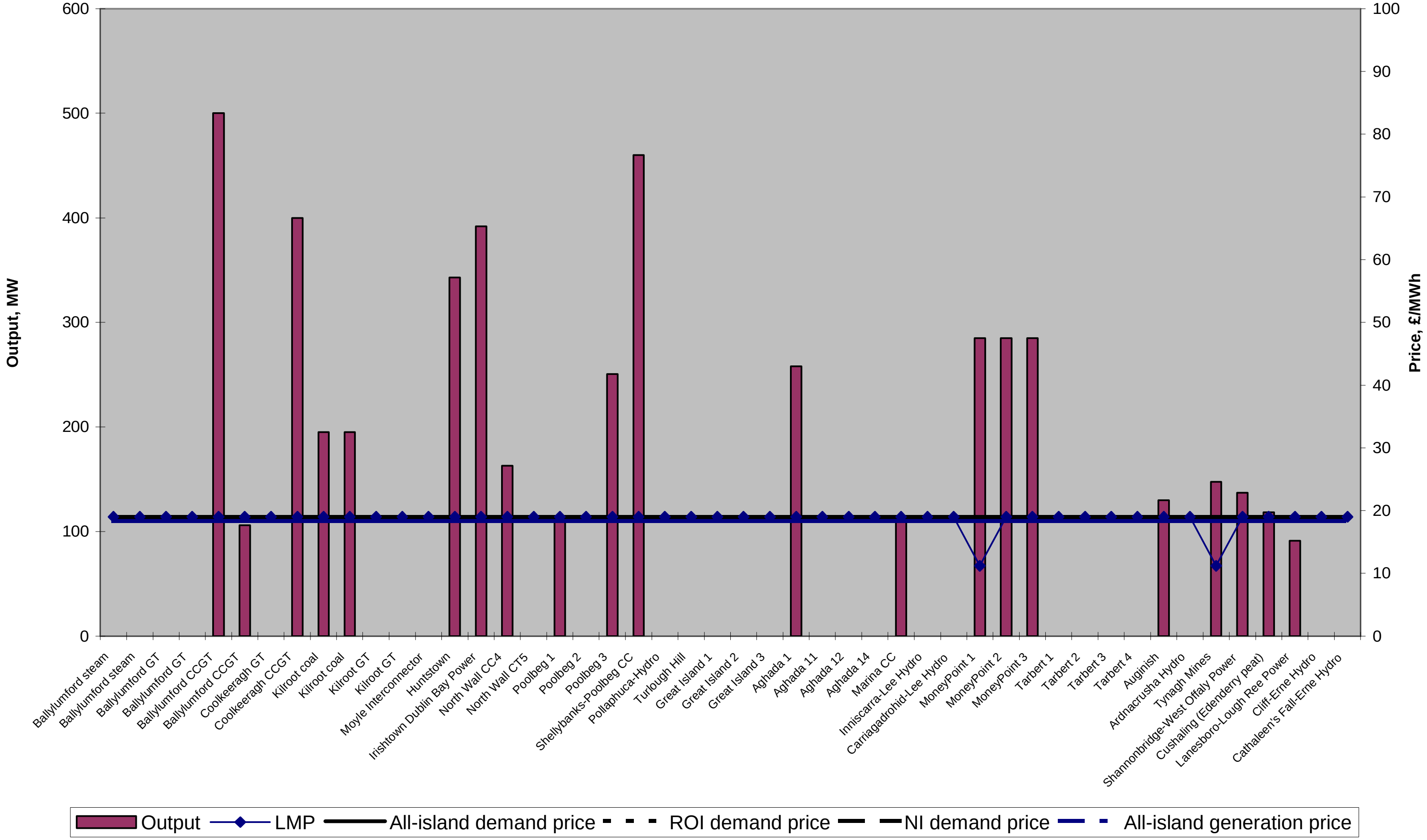


Figure 5.7
Average Demand Price, Output and LMP – Winter Max 2006-07 100 MW interconnectors

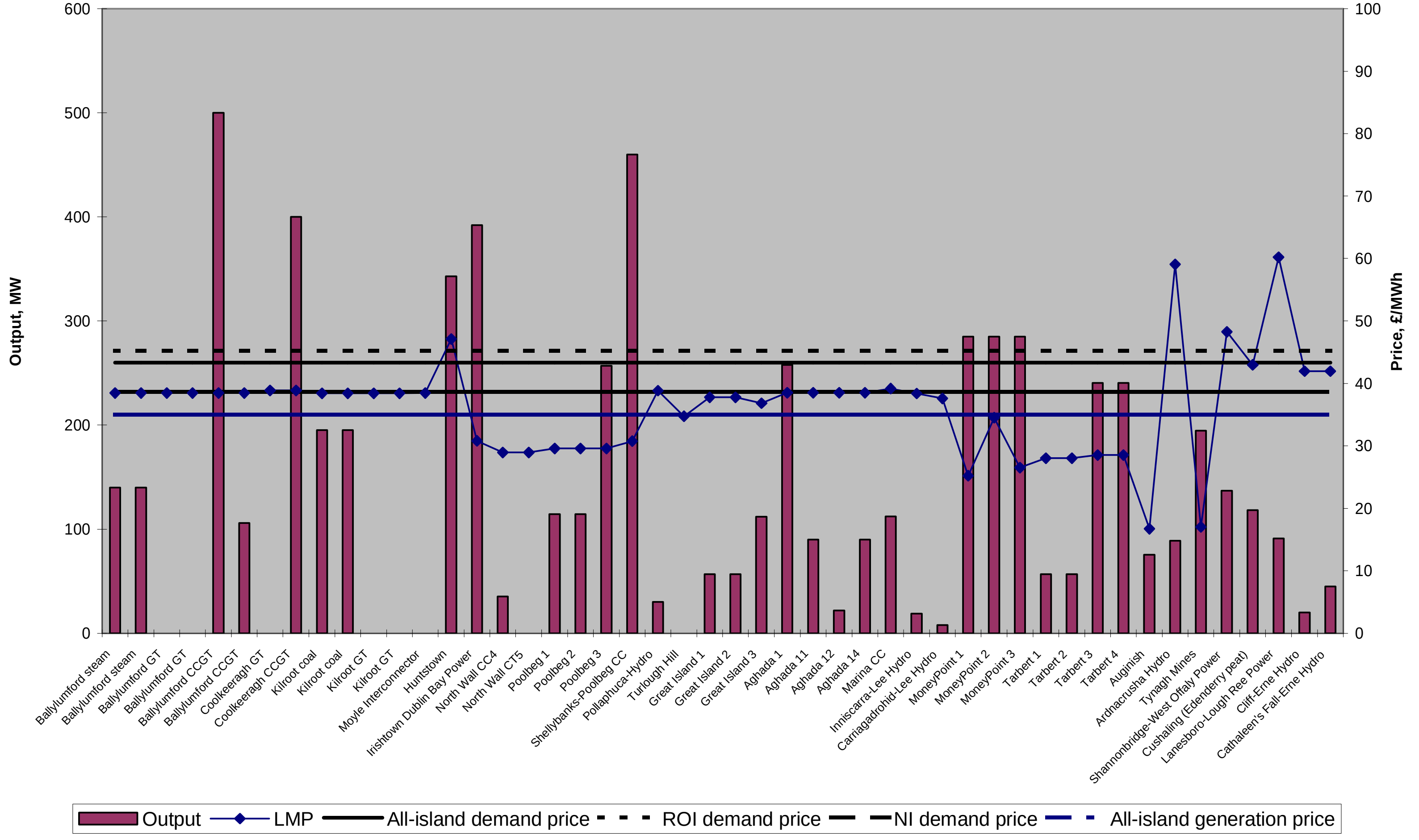


Table 5.2
Results of the "Small but Significant Non-transitory Increase in Price" test for NI generators

		10% mark-up					Marginal cost bidding				
Generator	Fuel cost £/MWh	LMP £/MWh	Output MW	Hourly fuel cost £	Hourly energy revenue £	Hourly gross profit £	LMP £/MWh	Output MW	Hourly fuel cost £	Hourly energy revenue £	Hourly gross profit £
Ballylumford steam	21.0	19.0	0	0	0	0	19.0	0	0	0	0
Ballylumford steam	21.0	19.0	0	0	0	0	19.0	0	0	0	0
Ballylumford GT	85.2	19.0	0	0	0	0	19.0	0	0	0	0
Ballylumford GT	85.2	19.0	0	0	0	0	19.0	0	0	0	0
Ballylumford CCGT	13.4	19.0	500	6,690	9,506	2,816	19.0	500	6,690	9,506	2,816
Ballylumford CCGT	13.4	19.0	106	1,418	2,015	597	19.0	106	1,418	2,015	597
Coolkeeragh GT	85.2	19.0	0	0	0	0	19.0	0	0	0	0
Coolkeeragh CCGT	12.1	19.0	400	4,838	7,605	2,767	19.0	400	4,838	7,605	2,767
Kilroot coal	11.3	19.0	195	2,202	3,707	1,506	19.0	195	2,202	3,707	1,506
Kilroot coal	11.3	19.0	195	2,202	3,707	1,506	19.0	195	2,202	3,707	1,506
Kilroot GT	85.2	19.0	0	0	0	0	19.0	0	0	0	0
Kilroot GT	85.2	19.0	0	0	0	0	19.0	0	0	0	0

(1) Total profits at marginal cost bidding: 9,192 £
(2) Total profits after raising prices by 10%: 9,192 £
(3) = (2) - (1) Difference: 0 £

Table 5.3
Results of the "Small but Significant Non-transitory Increase in Price" test for ESB generators – Summer Max 2006-07 run

Generator	Fuel cost £/MWh	10% mark-up LMP £/MWh	10% mark-up Output MW	10% mark-up Hourly fuel cost £	10% mark-up Hourly energy revenue £	10% mark-up Hourly gross profit £	Marginal cost bidding LMP £/MWh	Marginal cost bidding Output MW	Marginal cost bidding Hourly fuel cost £	Marginal cost bidding Hourly energy revenue £	Marginal cost bidding Hourly gross profit £
Coolkeeragh CCGT	12.1	21.0	400	4,838	8,385	3,547	19.0	400	4,838	7,605	2,767
Huntstown	11.4	21.0	343	3,905	7,191	3,286	19.0	343	3,905	6,521	2,616
Irishtown Dublin Bay Power	11.4	21.0	392	4,463	8,218	3,755	19.0	392	4,463	7,453	2,990
North Wall CC4	19.0	21.0	0	0	0	0	19.0	163	3,099	3,099	0
North Wall CT5	25.3	21.0	0	0	0	0	19.0	0	0	0	0
Poolbeg 1	19.0	21.0	115	2,177	2,400	223	19.0	115	2,177	2,177	0
Poolbeg 2	19.0	21.0	0	0	0	0	19.0	0	0	0	0
Poolbeg 3	19.0	21.0	229	4,351	4,798	447	19.0	251	4,766	4,766	0
Shellybanks-Poolbeg CC	12.1	21.0	460	5,576	9,643	4,068	19.0	460	5,576	8,746	3,170
Great Island 1	26.9	21.0	0	0	0	0	19.0	0	0	0	0
Great Island 2	26.9	21.0	0	0	0	0	19.0	0	0	0	0
Great Island 3	26.9	21.0	0	0	0	0	19.0	0	0	0	0
Aghada 1	19.0	21.0	225	4,287	4,727	440	19.0	258	4,905	4,905	0
Aghada 11	25.3	21.0	0	0	0	0	19.0	0	0	0	0
Aghada 12	25.3	21.0	0	0	0	0	19.0	0	0	0	0
Aghada 14	25.3	21.0	0	0	0	0	19.0	0	0	0	0
Marina CC	12.1	21.0	112	1,361	2,354	993	19.0	112	1,361	2,135	774
MoneyPoint 1	8.2	11.2	285	2,324	3,179	856	11.2	285	2,324	3,189	865
MoneyPoint 2	8.2	21.0	285	2,324	5,975	3,651	19.0	285	2,324	5,418	3,095
MoneyPoint 3	8.2	21.0	285	2,324	5,975	3,651	19.0	285	2,324	5,418	3,095
Tarbert 1	26.1	21.0	0	0	0	0	19.0	0	0	0	0
Tarbert 2	26.1	21.0	0	0	0	0	19.0	0	0	0	0
Tarbert 3	26.1	21.0	0	0	0	0	19.0	0	0	0	0
Tarbert 4	26.1	21.0	0	0	0	0	19.0	0	0	0	0
Auginish	11.0	21.0	130	1,427	2,725	1,298	19.0	130	1,427	2,472	1,045
Tynagh Mines	11.2	11.2	148	1,653	1,648	-5	11.2	148	1,650	1,650	0

(1) Total profits at marginal cost bidding:	**20,417**	**£**
(2) Total profits after raising prices by 10%:	**26,211**	**£**
(3) = (2) - (1) Difference:	**5,794**	**£**

Table 5.4

Results of the "Small but Significant Non-transitory Increase in Price" test for ESB generators – Winter Max 2006-07 run

		10% mark-up					Marginal cost bidding				
Generator	**Fuel cost £/MWh**	**LMP £/MWh**	**Output MW**	**Hourly fuel cost £**	**Hourly energy revenue £**	**Hourly gross profit £**	**LMP £/MWh**	**Output MW**	**Hourly fuel cost £**	**Hourly energy revenue £**	**Hourly gross profit £**
Coolkeeragh CCGT	17.9	40.6	400	7,179	16,241	9,062	40.6	400	7,179	16,241	9,062
Huntstown	17.3	43.9	343	5,945	15,068	9,123	37.3	343	5,945	12,800	6,854
Irishtown Dublin Bay Power	17.3	33.2	392	6,795	12,998	6,203	29.8	392	6,795	11,696	4,901
North Wall CC4	28.9	31.9	126	3,643	4,014	371	28.9	126	3,643	3,643	0
North Wall CT5	38.5	31.9	0	0	0	0	28.9	0	0	0	0
Poolbeg 1	28.9	32.3	115	3,315	3,702	387	29.3	115	3,315	3,350	35
Poolbeg 2	28.9	32.3	115	3,315	3,702	387	29.3	115	3,315	3,350	35
Poolbeg 3	28.9	32.3	257	7,440	8,309	869	29.3	257	7,440	7,519	80
Shellybanks-Poolbeg CC	18.5	33.1	460	8,489	15,233	6,744	29.8	460	8,489	13,710	5,221
Great Island 1	26.9	39.0	57	1,534	2,221	687	34.1	57	1,534	1,945	411
Great Island 2	26.9	39.0	57	1,534	2,221	687	34.1	57	1,534	1,945	411
Great Island 3	26.9	38.1	112	3,014	4,266	1,251	33.5	112	3,014	3,748	733
Aghada 1	28.9	39.3	258	7,469	10,139	2,671	34.3	258	7,469	8,853	1,384
Aghada 11	38.5	39.3	0	0	0	0	34.3	0	0	0	0
Aghada 12	38.5	39.3	0	0	0	0	34.3	0	0	0	0
Aghada 14	38.5	39.3	0	0	0	0	34.3	0	0	0	0
Marina CC	18.5	39.9	112	2,072	4,483	2,410	34.8	112	2,072	3,906	1,834
MoneyPoint 1	8.2	24.7	285	2,324	7,045	4,722	22.9	285	2,324	6,519	4,196
MoneyPoint 2	8.2	35.9	285	2,324	10,222	7,899	31.8	285	2,324	9,055	6,731
MoneyPoint 3	8.2	26.7	285	2,324	7,619	5,295	24.6	285	2,324	6,998	4,674
Tarbert 1	26.1	28.7	57	1,485	1,635	150	26.1	57	1,485	1,485	0
Tarbert 2	26.1	28.7	47	1,221	1,344	123	26.1	47	1,221	1,221	0
Tarbert 3	26.1	28.7	185	4,832	5,319	488	26.1	241	6,272	6,272	0
Tarbert 4	26.1	28.7	241	6,272	6,905	633	26.1	185	4,832	4,832	0
Auginish	16.7	16.7	90	1,496	1,498	2	16.7	90	1,496	1,496	0
Tynagh Mines	17.0	17.1	185	3,154	3,159	5	17.0	185	3,154	3,154	0

(1) Total profits at marginal cost bidding:	**46,563**	**£**
(2) Total profits after raising prices by 10%:	**60,169**	**£**
(3) = (2) - (1) Difference:	**13,606**	**£**