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Generation Adequacy in an Island Electricity System

by

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1. Introduction[1]

Electricity systems are unusual because of the fact that electricity cannot be stored. This means that supply must exactly equal demand second by second throughout the day. Generation capacity takes time to build and is very expensive and demand is quite insensitive to price signals. The result is a system where either there is sufficient spare generation capacity to meet all possible levels of demand or else, periodically, the lights will go off for some consumers.

For other services, such as retailing or transport, temporary shortages may not have serious economic and social consequences, but in the case of electricity the effects may be very serious, for example affecting emergency health services. While there is a high cost for consumers when electricity supply is uncertain, generally they cannot or do not reflect this cost in price signals. If there were a market mechanism, where consumers could pay an insurance premium to ensure emergency supply, the market could be allowed to determine the optimal level of capacity. However, such a market generally does not exist.[2]

Thus policy makers in the Commission for Energy Regulation (CER) and in the Department of Communications Marine and Natural Resources (DCMNR) in the Republic, and in the Northern Ireland Authority for Energy Regulation (NIAER) and the Department of Enterprise Trade and Industry (DETI) in the North, must take the possibility of such unexpected failures very seriously and protect the economy and society generally from the serious consequences of such failures. This involves ensuring that the electricity generation capacity available throughout the year is always sufficient to cover not only expected demand, but also enough to cover unexpected failures in generators or unexpected surges in demand, guaranteeing a reliable electricity supply to all consumers. Because spare capacity is very expensive to provide, it is important that the level of unused capacity is no more than is needed to ensure a specified level of reliability. Otherwise consumers could find themselves paying an unnecessarily high price for electricity, effectively buying a more expensive "insurance policy" than they really need.

All electricity systems face uncertainty as to their capacity to continuously meet fluctuating levels of demand. This uncertainty can arise from a number of different factors. For example, the growth in demand may over time outpace supply. Also, even if existing capacity may be adequate to meet expected demand, unexpected failures by individual generating units could leave supply suddenly lower than demand, giving rise to blackouts.

The issue of the adequacy of generation capacity to meet expected future demand levels, where both future supply and future demand are treated as being "certain", is

[1] The author would like to thank the staff of Eirgrid and Northern Ireland Electricity for their advice and helpful criticism in preparing this paper. The author alone is responsible for the analysis and conclusions presented here.

[2] An exception is the case where consumers install emergency generators. However, such generators are themselves not fully reliable and for many consumers installation of such capacity is not a feasible option.

considered elsewhere (Eirgrid, 2004b and Bergin, *et al.*, 2003). Instead this paper concentrates on how unexpected breakdowns in individual generation units can affect the reliability of supply and on how much additional capacity is needed to cover for such unexpected equipment failures. This paper assesses how much generation capacity is needed to provide a specified level of reliability in an uncertain world. Specifically, it considers how different levels of interconnection between the two electricity systems on this island would affect the reliability of the supply north and south of the border.

Using a special model, this paper looks at the extent of the generation capacity which would have been needed in 2003[3] to meet a given reliability standard for the Republic of Ireland electricity system treated in isolation, for the Northern Ireland system treated in isolation, and how the picture would be changed if there were a fully integrated all-island system. It also looks at how additional or reduced capacity would have affected the probability of a loss of load (where demand exceeds supply and some consumers suffer blackouts), giving an indication of how the system might perform in later years. This paper does not attempt to breakdown the benefits of different levels of interconnection for the consumers in the two electricity systems.

The difference between the cost of meeting a given adequacy standard on the basis of the two systems remaining isolated and the cost for an integrated island-wide system is a measure of one of the potential benefits of moving towards an all-island electricity system. Such a benefit, from savings in reserve or "spare" capacity, would be additional to any benefits that might arise from trading in an all-island market, achieving a more efficient dispatch of existing generation stations. Further possible gains could also be expected from the enhanced level of competition possible in a larger market. These additional potential benefits are not considered in this paper.

The creation of a fully integrated all-island system, where reserves of generation capacity could be shared independently of where they were located, would require significant additional investment in transmission capacity. The costs of such investment would have to be offset against the potential benefits, discussed below, to arrive at an informed costs-benefit analysis of creating an all-island electricity system.

Today there is already one interconnector linking the two systems North and South. However, this interconnector has strictly limited capacity, partly due to congestion in the system south of the border. Even with no such congestion, reliance on a single interconnector to provide security would be unsafe for both parts of the island because all transmission lines are subject to possible failure, for example through the effects of strikes by lightning. However, even in its present limited form, the North-South interconnector has significant value in enhancing the security of the two systems, North and South of the border. This paper models the benefits of a fully integrated system compared to the current system with limited interconnection, and also compared to a system with no interconnector.

[3] This exercise could be repeated for forecast demand and supply levels for later years. The results of using forecast data for later years could affect the magnitude and the distribution of benefits from integration. As indicated later, the electricity systems in both jurisdictions are continually developing. To reflect this two slightly different configurations are tried for Northern Ireland generation capacity. The results for 2003 are intended for illustrative purposes only.

The data used in the model are summarised in Section 2. Section 3 describes the model and Section 4 describes the results obtained concerning the generation capacity needed to meet specified levels of security of supply. Section 5 provides conclusions. Further technical details are given in appendices

2. Data

The model uses historical data for hourly demand for each of the 365 days of 2003 for the Republic of Ireland and for Northern Ireland. It is run for each hour of the year to check on the probability that generators might be unexpectedly out of action and that, as a result, demand would have exceeded supply in that hour, resulting in unmet demand.

Each generation unit, North and South, is separately identified in the model (as opposed to aggregating the generation units by station). This allows for the fact that, while one generation unit in a station, like Moneypoint, could suffer unexpected failure, the other units in the plant could often still run independently. The generation capacity of each of the stations is identified in the model, and the model determines the aggregate capacity likely to be available on each system (North and South) for each hour of the year.

The generation capacity assumed to be available from each unit is specified in Appendix 3. This configuration roughly approximates the situation in 2003. However, with the system changing all of the time it can not be considered an exact representation of the generation capacity on the island on any individual day. As described in Section 4 we tested the sensitivity of the results to a small change in the configuration where there was an additional generation unit in Northern and where, as a result, the North had an additional 243 MW of capacity available.

For each generation unit an assumption is made about the expected availability over the year. This is specified in terms of the percentage of the year for which the unit will be available. The time when it is not available is required to undertake scheduled maintenance. The maintenance on each unit is assumed to take place over a continuous period and is specified in terms of the days when the plant is out of operation. (The number of days when the generator is specified as off for maintenance is chosen to give the planned percentage annual availability specified in Appendix 3). The maintenance schedules for all plant are designed to leave a fairly similar margin between peak capacity and planned availability over the course of the year. This means that the bulk of the maintenance is scheduled between late March and October.

While a “sensible” maintenance schedule has been specified, it would, of course, be possible to search for the “optimal” schedule simultaneously with the modelling of unexpected outages, where “optimal” was defined as that schedule which would minimise the likelihood of a shortage of power. However, adding such a dimension to the model would greatly complicate the solution process and it is not considered further here in this note.

In the case of the hydro stations, it is assumed that they are available throughout the year to cover peak demand. The number of hours for which they are assumed to be available is calculated to give roughly the average availability for the year that has been observed in the past[4]. The hours when each plant is generating are pre-specified in the model and no allowance is made for maintenance. As with all other stations the hydro stations are subject to the possibility of unexpected failure.

For the wind generators (210 MW in the Republic, 20 MW in the North) and the other renewables a simplifying assumption is made that they are unavailable on a random basis throughout the year, with the probability of their being unavailable being an input into the model. For example, *ex post* electricity from the wind generators is assumed to be available on 37% of the days of the year. It is assumed that all wind generators are together either fully available or totally unavailable on individual days. This is obviously an extreme assumption, but any more sophisticated treatment would have little appreciable effect on the results.

In addition to the proportion of the year for which each generation unit is expected to be unavailable due to planned maintenance, each unit is assigned a probability of forced or unexpected outage. These probabilities are shown in Appendix 3. These probabilities are assumed to be independent, and no account is taken of the possibility of other parts of the system failing, in particular no account is taken of potential transmission problems, other than potential problems with the North-South interconnector(s) and the Moyle interconnector to Scotland.[5] This assumption of "independence" of failure probabilities may not be fully realistic as there could, for example, be a fault in the connection to the grid at Moneypoint, which could put all three generation sets offline simultaneously. Other possible non-grid causes of failure of more than one generating set on a single site could include local fuel supply difficulties, problems with cooling water etc.. However, this assumption of independence provides a reasonable basis for simplifying the analysis.

The forced outages are all assumed to begin at midnight and to last for a full day (with the exception of the hydro stations, which are in any event assumed to run for only part of the day). Once again this simplification is used to make the model more tractable. As discussed in Appendix 1, identical results could be expected if the forced outage were assumed to occur at random on an hourly basis throughout the year.

The average expected availability for a plant over the year is then defined as:

$$(1-P_1)\ (1-P_2)$$

where P_1 is the percentage of the year that a station will be unavailable because of planned maintenance and where P_2 is the probability of unexpected failure.

3. The Model

This paper describes the model that has been developed of the electricity system that takes account of the fact that all generation stations are subject to a non-zero probability of unexpected breakdown, as is the link(s) between the systems in the

[4] Because of the use of hourly data rather than data by the minute, there is some small "rounding" error.

[5] For each interconnector a probability of forced outage over the course of the year of 1% is assumed.

Republic and in Northern Ireland. It models how the probability of unexpected failure in one or more generation units could result in overall capacity falling short of demand, leading to forced reductions in supply to some customers. The model also takes account of planned maintenance. The model makes the simplifying assumption that the maintenance schedule is planned well in advance and that it cannot be varied in the event of unexpected breakdowns.

The model takes each generation set each day and first checks whether it is down for planned maintenance (see Appendix 2 for the annotated code for the model).[6] Then, using a random number generator, the model checks to see whether the station is available on all other days in the year (when not undergoing planned maintenance) or whether it is subject to an unexpected outage. The probability of an unexpected outage is specified separately for each plant. Over the course of a large number of simulations the model will produce an average availability of each plant (excluding planned maintenance) as defined above. However, there may be significant deviations from this average from day to day and from simulation to simulation. These deviations reflect the uncertainty defined by the probabilities of unexpected outage.

The model sums the availability of generation capacity in MW for the Republic, for the North, and for the island as a whole for each hour in each day in each simulation. There is a small variation within the day in the availability because of the predetermined timing of the generation from the hydro plant.[7] For each day of 2003 the model compares the availability by hour for each system (North, South, and the island as a whole) to the hourly demand for that day and determines how many hours, if any, demand would have exceeded supply. It also estimates the number of GWh (gigawatt hours) that would be lost as a result of forced outages, causing supply to be inadequate. The number of hours of shortage (loss of load) and the total amount of unmet demand (in GWh) is calculated for the year as a whole.

Table 1: Options on North-South Interconnection

Option	Transfer Capacity		Forced Outage of Interconnector
	North-South	South-North	
1	0	0	Not relevant
2	300	100	Possible
3	300	300	Possible
4	600	100	Possible
5	600	400	Possible
6	Infinite	Infinite	Not possible

This process is subject to a monte carlo simulation, with the model being run 1,000 times for the same year with different random draws of plant availability for each period in each simulation. The average annual number of hours of loss of load across all the 1,000 simulations is then assumed to represent the probability of loss of load.[8]

[6] The planned maintenance is implemented in the model through a matrix with unity for each day when a station is available and zero for when it is undergoing planned maintenance. This matrix is the YrCons sheet in the spreadsheet Modelin.XLS, available from the author.

[7] See the DayConsH sheet in the Modelin.XLS spreadsheet.

[8] There is very little difference when the model is run for only 1,000 rather than 10,000 iterations.

A commonly used measure of reliability is the Loss of Load Expectation (LOLE), the expected number of hours in the year in which demand would exceed supply. The standard currently applied in the Republic is a LOLE of 8 hours in the year.

The model checks a number of variants (Table 1) on the extent of the interconnection of the two electricity systems on the island, from one extreme where there is assumed to be no connection between the two systems North and South to the other extreme where the island system is fully integrated with no possibility of a failure of interconnection. The model also allows for differing maximum transfer capacities from North to South and from South to North. In each case the capacities are used for illustrative purposes. They do not represent the exact engineering possibilities of the current system and the characterisation of future systems is, of necessity, stylised. Finally, the model also allows for differing assumptions on the extent to which the interconnector(s) is (are) subject to possible unexpected failure.

Option 1 considers the case where the two systems are completely independent, as they were from the early 1970s until the restoration of the interconnector in the late 1990s.[9] The second option considers a stylised version of the current situation where there is a limited transfer capability from the North to the South of 300MW and from the South to the North of only 100MW.[10] (The difference in transfer capabilities arises because of excess generation capacity in Dublin combined with transmission constraints in the Louth area.) According to Eirgrid, 2004c, "both internal reinforcement and a new 275kV interconnector would be required to increase interconnector transfer capability beyond existing limits."[11] Eirgrid, 2004c, also states that "studies show that exports to Northern Ireland are also limited by a lack of transmission capacity between Dublin and Drogheda" – the Louth area. The third stylised scenario is characterised as a relaxation in transmission constraints in the Republic sufficient to allow a symmetric transfer capability of 300MW. The fourth option looks at the case where a new interconnector is built, without addressing the transmission constraints in the Louth area, increasing the North-South capacity with no change in the South-North capacity. The fifth option is the same as option 4, with the exception that it also includes the strengthening of the grid in the Louth area, allowing much greater exports from the South to the North.[12] The final option considers the case where there is unlimited certain transfer capability in both directions.

It should be noted that a loss of load expectation (LOLE) of 8 hours or around 0.09% of the year (the threshold used here) for the island as a whole is a tighter standard than a similar LOLE for either of the jurisdictions taken on their own. This is because a

[9] The interconnector was put out of action by terrorist action in the early 1970s and was only restored after the Good Friday agreement.

[10] Detailed engineering studies would be required before precise quantification of the transfer capacities of the different options could be made available.

[11] There may also be a need for some strengthening of the grid within Northern Ireland to allow a major increase in trade in electricity.

[12] An additional option was tried where the interconnectors were treated as certain – not subject to forced outage. However, this made almost no difference to the results where two interconnectors were involved.

given LOLE for the island will result in a smaller percentage of customers suffering a loss of load than would be the case for either of the two systems taken on their own. As described later, this is reflected in the estimated unmet demand under the different scenarios.

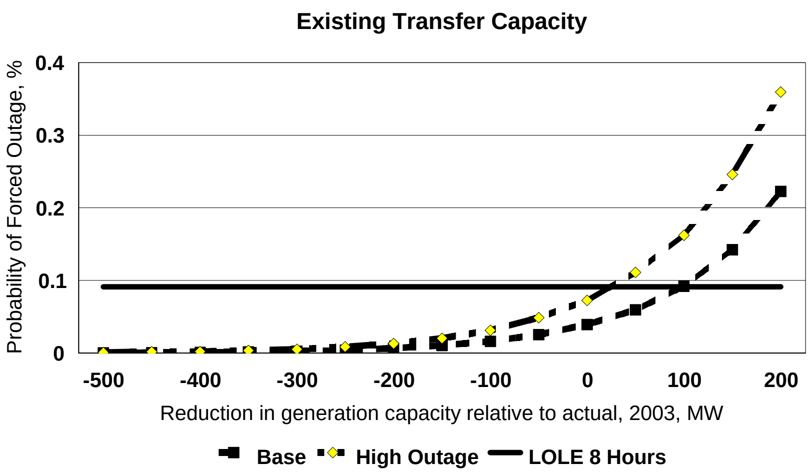
In order to test the sensitivity of the results and to help in estimating the additional generation needed to meet the specified LOLE standard, the model also simulates the likely LOLE with additional or reduced generation capacity (or demand) compared to the baseline simulation of the capacity available in 2003. The model simulates the effects of up to 700MW more capacity and up to 800 MW less capacity than in 2003 in increments (decrements) of 50MW. It is possible to interpolate the results for intervening configurations. In each case these changes in capacity (demand) are treated as certain – a zero probability of planned or unplanned outage for the change in capacity.[13]

4. Results

Availability

When the model was simulated with both the planned availability assumptions and the forced outage probabilities shown in Appendix 3, it produced an average availability for the Republic of Ireland of 75.1% and an average availability for Northern Ireland of 89.7%. The average for the island electricity system was 79.0%. These average availability figures take account of the expected low availability of hydro and wind in the Republic, together with the low availability of the small amount of wind currently installed in the North.

Figure 1: Republic of Ireland Generation Requirements with Higher Forced Outage



On the basis of the existing interconnector, the model was run for the electricity system in the Republic, assuming that the average availability of generating stations in the Republic was reduced by around 0.8 percentage points (from 75.1% to 74.3%).

[13] An alternative way of viewing the results where capacity is assumed to vary is to consider the variation as a change in (certain) demand of the same amount, but opposite sign.

This was implemented by assuming a higher level of forced outage across all stations in the Republic. The model results showed the risk of forced outage at different capacity levels.

As shown in Figure 1, on the basis of the existing interconnector, the security standard of a Loss of Load Expectation (LOLE) of 8 hours could still have been met with a saving in capacity of around 100 MW compared to the actual capacity in 2003 (see also Table 2). However, with a reduction in average availability of around 0.8 percentage points, to hold the LOLE at the 8 hour standard would have only permitted a saving in generation capacity of around 25 MW – a reduction in savings of 75MW at a capital cost of around €50 million compared to the base[14]. Eirgrid, 2004b, has a very similar estimate of the cost of high levels of unexpected outage – 100 MW for a 1 percentage point reduction in average availability.[15] This illustrates the high cost resulting from the current low levels of availability in the Republic.

Interconnection Options

The results of simulating the model with different assumptions on interconnection between Northern Ireland and the Republic are shown in Table 2 for the Republic of Ireland. The Table shows the probability of a forced outage occurring in the Republic over the course of last year. Appendix 5 gives details of the related unmet demand that such outages would have given rise to. The numbers in bold are for the cases where the Loss of Load Expectation (LOLE) exceeds the equivalent of 8 hours (a probability of 0.09%), the current *de facto* standard for security of supply in the Republic.

Table 2: Republic of Ireland, Probability of Loss of Load, 2003, %

Bold worse than 0.09%

		Interconnection Capacity to RoI					
Simulation Number		1	2	3	4	5	6
Possible unexpected breakdown			Uncertain	Uncertain	Uncertain	Uncertain	Certain
	MW	0	300	300	600	600	Unlimited
more generation / less load	300	0.03	0.00	0.00	0.00	0.00	0.00
	200	0.08	0.01	0.01	0.00	0.00	0.00
	100	**0.17**	0.02	0.01	0.00	0.00	0.00
With Current Generation Capacity		**0.35**	0.04	0.04	0.01	0.01	0.01
Less generation / more load	-100	**0.70**	0.09	0.09	0.03	0.03	0.03
	-200	**1.32**	**0.22**	**0.22**	**0.12**	**0.12**	**0.12**
	-300	**2.35**	**0.55**	**0.55**	**0.45**	**0.45**	**0.45**
	-400	**3.98**	**1.47**	**1.47**	**1.40**	**1.40**	**1.40**
	-500	**6.39**	**3.67**	**3.67**	**3.63**	**3.62**	**3.63**

In simulation 1, with the available capacity in 2003, if there had been no interconnection between the North and the South there would have been a probability of loss of load of 0.35%, equivalent to a LOLE of 31 hours for the year, very much greater than the 8 hours standard (equivalent to a probability of 0.09%). The Table

[14] As explained later, the cost of generation capacity is taken from CER, 2004.

[15] Transmission System Operator, 2003, *Generation Adequacy Report 2004-2010*, p.78.

shows that approximately an additional 200MW of capacity would have been needed in the Republic in 2003 to ensure system adequacy in the absence of an interconnector to Northern Ireland, restoring the probability of loss of load to less than 0.09%.[16]

Simulation 2 approximates the current level of interconnection between the North and the South. As shown in simulation 2, given the possibility of transfer of 300MW through the existing interconnector from the North whenever the Northern system was in surplus in 2003, the probability of a loss of load was reduced to 0.04%, well within the threshold of a LOLE of 8 hours.[17] In fact the LOLE standard (probability of loss of load of 0.09%) could have been met with 100MW less capacity than was actually in place in 2003. Thus, at the benchmark standard of a LOLE of 8 hours, the interconnector could have saved the Republic 300MW of installed capacity compared to the case if the two electricity systems were completely independent.

For the Republic simulation 3 is identical to simulation 2, only involving different transfer capacities from south to north. In simulation 4, it is assumed that there are two interconnectors, allowing a gross transfer from North to South of 600MW. As can be seen from the Table 2, the probability of a forced outage is marginally reduced in this simulation compared to the current level of interconnection. As shown later in Table 4, in this simulation the Republic could have saved approximately a further 75MW of capacity compared to the situation with the current level of interconnection. The doubling of the interconnector would be worth much less to the Republic than is the availability of the existing interconnector. This illustrates the diminishing marginal returns to investment in transmission.

Table 3: Northern Ireland, Probability of Loss of Load, 2003, %

Bold worse than 0.09%

		Interconnection Capacity to North					
Simulation Number		1	2	3	4	5	6
Possible unexpected breakdown			Uncertain	Uncertain	Uncertain	Uncertain	Certain
	MW	0	100	300	100	400	Unlimited
	300	0.00	0.00	0.00	0.00	0.00	0.00
More generation / less load	200	0.00	0.00	0.00	0.00	0.00	0.00
	100	0.02	0.00	0.00	0.00	0.00	0.00
With Current Generation Capacity		0.05	0.02	0.00	0.02	0.00	0.00
	-100	**0.15**	0.05	0.01	0.05	0.01	0.01
less generation / more load	-200	**0.40**	**0.16**	0.05	**0.16**	0.03	0.03
	-300	**0.89**	**0.45**	**0.15**	**0.45**	**0.12**	**0.11**

Simulation 5 is identical to simulation 4 for the Republic. A further simulation (not shown) was carried out assuming that there was no possibility of unplanned failures

[16] Using interpolated data, a more precise quantification is shown later in Table 4.

[17] This allows for the possibility of a forced outage of the interconnector with a probability of 1%, as specified in Appendix 3.

on the two interconnectors. This produced identical results to simulations 4 and 5, where there is a 1% probability of forced outage for each of the two interconnectors.

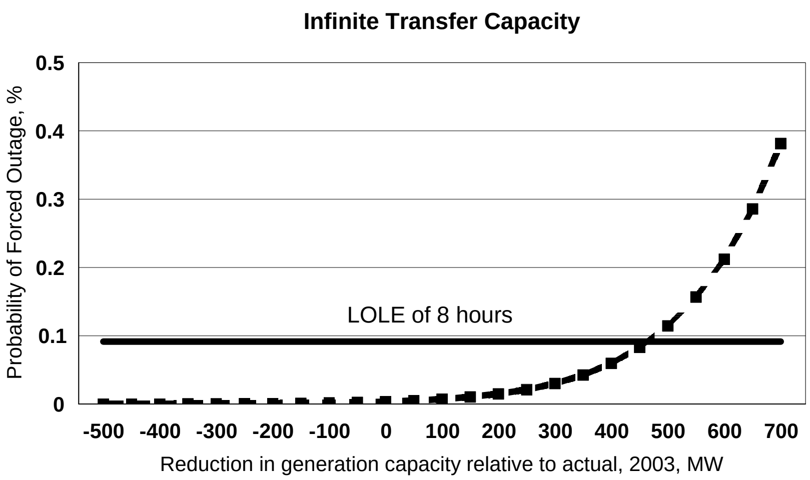
The sixth simulation assumed an infinite potential to transfer power from North to South. This simulation produced identical results to the case of simulations 4 and 5 (where the two interconnectors have a combined capacity of 600MW and still have some independent probability of forced outage for each interconnector). This suggests that there would be no additional security benefits for the Republic from further investment, over and above that needed to install a second interconnector.

The results of simulating the model for Northern Ireland are shown in Table 3. In simulation 1, with the available generation capacity in Northern Ireland in 2003, if there had been no interconnection between the North and the South, there would have been a probability of loss of load of 0.05%, less than the 0.09% corresponding to the 8 hours LOLE threshold. The LOLE standard could have been met with 50MW less of capacity. In simulation 2, with the existing limited interconnection capacity of 100MW from South to North, the probability of forced outage would have been even lower at 0.02%.

With a strengthening of the transmission in the Louth areas of the Republic to allow a transfer capacity from South to North of 300MW the probability of forced outage in the North would have fallen even further, as shown in simulation 3. As shown in Table 3, this would have allowed a further saving in capacity in the North of around 100MW compared to the current level of interconnection.

For the North simulation 4 is the same as simulation 2. For simulation 5 the transfer capacity from South to North would be enhanced by a further 100MW (to 400MW) compared to simulation 3. In this case the probability of a loss of load would be even lower, allowing a further small saving in capacity. As shown in Simulation 6, moving to an infinite transfer capacity would produce an imperceptible reduction in the risk of forced outage for consumers in Northern Ireland.

Figure 2: All-Island System: Probability of Outage by Generation Capacity



Examination of the detailed results for lower capacity and higher probabilities of forced outage (not shown here) indicates that the likelihood of forced outage increases more rapidly for Northern Ireland than for the Republic, the greater the shortage of capacity. For example, if the study was repeated but with 250 to 300 MW less generation located in Northern Ireland, the increase in the probability of loss of load for Northern Ireland would be greater than would be the case under similar circumstances in the Republic. This reflects the fact that unit sizes are larger relative to the overall size of the system in Northern Ireland, so that a forced outage of a similar magnitude, in terms of MW of capacity, can have a bigger percentage effect on availability in the North than in the Republic. However, moving from the Republic's system to an all island system would not have much effect as the number of units and their average size relative to the system in the Republic is already quite small.

Figure 2 shows the probability of a loss of load plotted against different levels of installed generation capacity.[18] These results are for an all island system with infinite transfer capacity. This shows that the LOLE of 8 hours (a probability of around 0.09%) could have been achieved with a saving in generation capacity of around 350 MW.

Table 4 summarises the results for the different options on interconnection shown in Tables 2 and 3. For each option, based on assumed demand and generation capacity in place in 2003, it shows the probability of forced outage and the related Loss of Load Expectation. It also shows the number of GWh of unmet demand that could be expected to arise as a result of this level of forced outage. The figures are shown separately for the North and the Republic. At the current level of interconnection, as characterised in this paper, both systems would have met the LOLE standard of 8 hours.

The second half of Table 4 shows the savings in generation capacity that could be made under the different interconnection scenarios, while still preserving a LOLE of 8 hours. It also shows the value of these savings on the basis of the CER's costings for the capital cost of a "Best New Entrant" Combined Cycle Gas Turbine (CCGT) station in 2005 (CER, 2004). The CER paper puts the capital cost at €0.66 million per MW of installed generation capacity.

In the second half of Table 4 the savings are expressed as a change compared to the current level of interconnection. Thus if there were no interconnection between the Republic and the North an additional 290 MW of plant would have been required in the Republic (compared to the optimal stock under the current situation) to ensure the same security standard as was possible in 2003. To provide such additional plant would have cost around €191 million. For the North the absence of the current interconnector would have required an additional 90 MW of generation capacity (compared to the optimal stock under the current situation) at a capital cost of around €59 million.

[18] Here the reduction in capacity is assumed to be a certain (not subject to unexpected breakdown) reduction of the specified amount in the generation capacity available. Alternatively it could represent an increase in demand of the same amount.

Table 4: Summary Results for Different Interconnector Options

	Probability of Loss of Load and Related Unmet Demand						
Interconnection Options		None	Existing	Existing	Additional	Additional	Infinite
Internal constraints addressed		None	None	In Republic	In North	All	All
Transfer Capacity:[19]							
Power to Northern Ireland	MW	0	100	300	100	400	Infinite
Power to Republic of Ireland	MW	0	300	300	600	600	Infinite
Northern Ireland LOLE	Hours	4.3	1.5	0.2	1.5	0.1	0.1
	% outage	0.05	0.02	0.00	0.02	0.00	0.00
	GWh	0.4	0.1	0.0	0.1	0.0	0.0
Republic LOLE	Hours	30.8	3.4	3.4	0.6	0.6	0.6
	% outage	0.35	0.04	0.04	0.01	0.01	0.01
	GWh	4.0	0.4	0.4	0.1	0.1	0.1
	Approximate capacity benefit compared to existing network						
Saving in MW of Capacity							
Northern Ireland	MW	-90	0	110	0	125	135
Republic of Ireland	MW	-290	0	0	75	75	75
Capacity Saving, value € M							
Northern Ireland	€ M	-59	0	73	0	83	89
Republic of Ireland	€ M	-191	0	0	50	49	50
All Island	€ M	-251	0	73	50	132	139

[19] The transfer capacities used here are for illustrative purposes only. Further engineering studies would be needed to come up with more precise quantification of the nature of the existing constraints and how they would be changed by new infrastructure.

For the island as a whole, applying the LOLE security standard separately to the North and the South, the current interconnector, as characterised in this paper, saves around 380 MW of plant (simulation 1 in Table 4 compared to simulation 2). This is almost equal to the combined North-South and South-North transfer capacity on the existing interconnector. The value of this saving in avoided capital investment is around €250 million for the island as a whole.

The third simulation considers the case where the transmission is strengthened in the Louth region of the Republic so that the export capacity to the North from the Republic would be equal to the current assumed transfer capacity in the other direction of 300 MW. As shown in Table 4, this would allow a saving in generation capacity in the North relative to the current situation of 110MW of generation capacity, valued at around €73 million. Obviously there would be no impact on the generation capacity required in the Republic.

The fourth simulation examines the effects of a second North-South interconnector without any strengthening in the transmission in the Louth region of the Republic.[20] In this case, for the same level of security, the saving in generation capacity in the Republic would be 75MW, valued at €50 million. This is somewhat smaller than the saving which would arise from the strengthening of the transmission within the Republic, simulation 3.

The fifth simulation looks at the effects of a second North-South interconnector combined with a strengthening of the transmission in the Republic. For the same level of security as under the current level of interconnection, this would allow a combined saving on the island of 200 MW of generation capacity, valued at €132 million.

The sixth simulation looks at the effects of having unlimited (certain) transmission capacity between the North and the South. The results in Table 4 indicate that the additional benefits from this option would be small compared to simulation 5 - a second interconnector combined with the strengthening of the transmission capacity in the Louth area of the Republic.

Security Standard

So far we have considered the capacity required in each jurisdiction to meet a LOLE security standard of 8 hours a year, roughly equivalent to a forced outage rate of 0.09%. On the basis of the current level of interconnection (using the stylised quantification of transfer capacities described earlier), Table 5 shows the LOLE and the related measure of unmet demand in GWh at different levels of generation capacity.[21] (To simplify presentation this Table only shows results for a limited range of options on generation capacity.) It shows in bold those cases that would have approximated the security standard of 8 hours LOLE. For example, Table 5 shows that for the Republic of Ireland the LOLE standard of 8 hours could have been met last year with 100 MW less capacity. This would have resulted in an expected unmet demand of around 0.98 GWh.

[20] This might also require some strengthening of the transmission in Northern Ireland.

[21] Appendix 5 gives details of the unmet demand under the range of simulations discussed in this paper.

For Northern Ireland the LOLE standard could have been met with a capacity saving of around 150 MW. This would have translated into an expected level of unmet demand of 0.73 GWh. Thus if the LOLE standard of 8 hours were applied separately to the two jurisdictions, with the current level of interconnection the expected level of unmet demand on the island of Ireland would have been the sum of the unmet demand for the two systems taken separately – 0.98 GWh plus 0.73 GWh making a total of 1.71 GWH.

Table 5 also shows that for the island of Ireland, treated as an integrated electricity system with infinite transfer capacity, the LOLE standard could have been met with a saving of 350 MW of generating capacity.[22] At this level of capacity the 8 hours LOLE would have resulted in an expected level of unmet demand of 1.12 GWh. This level of unmet demand would have been much less than the level of unmet demand where the LOLE standard was applied to the two jurisdictions separately. This shows that the LOLE standard applied on an island-wide basis is a more rigorous standard than where it is applied to the North and the Republic separately; it would result in less disappointed customers on the island.

Table 5: Effects on Security of Different Capacity Levels with Current Interconnector

Generation Capacity Interconnection Transfer Capacity North–South and South–North		Republic of Ireland Existing: 300/100	Northern Ireland Existing: 300/100	Island of Ireland Infinite
Current	LOLE	3.4	1.5	0.6
	Probability %	0.04	0.02	0.01
	GWh Unmet	0.4	0.11	0.07
Less Generation or More Load				
-100 MW	LOLE	**8.1**	4.6	1.3
	Probability %	**0.09**	0.05	0.02
	GWh Unmet	**0.98**	0.4	0.16
-150 MW	LOLE	12.3	**7.9**	2.0
	Probability %	0.14	**0.09**	0.02
	GWh Unmet	1.56	**0.73**	0.25
-200 MW	LOLE	19.5	14.3	2.9
	Probability %	0.22	0.16	0.03
	GWh Unmet	2.53	1.3	0.37
-350 MW	LOLE	78.8	59.6	**8.8**
	Probability %	0.9	0.68	**0.1**
	GWh Unmet	11.77	6.51	**1.12**

Thus an LOLE standard is not invariant across jurisdictions and this raises the question as to what is the appropriate metric to use in considering the effects on the security of supply on the island of different strategies on interconnection.

[22] With an integrated island system a separate application of the LOLE criterion to each jurisdiction would mean that if the island system were short of power all the cuts would be applied in the jurisdiction where the shortage occurred. An island wide application would involve a possible sharing of the shortage on some predetermined basis, independent of the jurisdiction in which it actually arose.

Sensitivity

A number of additional tests were carried out to examine the sensitivity of the results to changes in generation capacity. These tests considered the effects on generation capacity needed to meet the specified LOLE standard from three options: more generating capacity in Northern Ireland; more wind generation; and the effects of a large nuclear station.

In the first test we considered the case where there was an additional generating unit in Northern Ireland of 180 MW compared to the situation shown in Appendix 3 and where another unit was specified with a capacity of 180 MW rather than a capacity of 117 MW. This would have resulted in an addition to the generating capacity for Northern Ireland of 243 MW. Obviously, for a given LOLE in a fully integrated island electricity system the inclusion of an additional 243 MW of generating capacity in Northern Ireland would allow a reduction in generating capacity in the Republic of a similar amount. However, it would change the distribution of the benefits from enhanced interconnection.

Table 6: Savings in Generation Capacity, MW, with different interconnection options

	Saving from Interconnection Options					
	Republic of Ireland			Northern Ireland		
Generation Capacity	Benchmark	Higher Northern	Difference	Benchmark	Higher Northern	Difference
Interconnection Options						
No interconnection	-290	-292	-2	-90	-81	9
Existing Network and Interconnection	0	0	0	0	0	0
Reinforcement within Republic	0	-8	-8	110	80	-30
Additional Interconnection and reinforcement in North	75	149	74	0	2	2
Additional Interconnection and reinforcement within North and South	75	152	77	125	94	-31
Infinite transfer capacity	75	157	82	135	95	-40

In this simulation it is assumed that the LOLE is held constant at its 2003 level in the face of changes in interconnection. Table 6 shows the value of the different interconnection options under the two scenarios for generation capacity in Northern Ireland, in each case holding the LOLE constant. With the higher generation capacity in Northern Ireland the value of reinforcing the transmission in the Republic in the Louth area is substantially reduced. Also the value for Northern Ireland of a second interconnector to transfer power from the Republic to the North is reduced. This is because the increased generation capacity in Northern Ireland would have made the North more secure, reducing the value of the enhanced access to spare generation capacity in the Republic.

Similarly, the additional generation capacity in Northern Ireland would increase the potential spare capacity available for export to the Republic. In turn, this means that the value of any expansion in the transfer capacity from the North to the Republic would also be enhanced. Overall, with an increased imbalance in the distribution of generating capacity on the island (relative to demand), the benefits from enhanced interconnection will be greater than in the benchmark scenario.

This scenario highlights the fact that the distribution of the benefits from enhanced interconnection will be very sensitive to the relative levels of surplus generating capacity in the North and in the Republic. These balances can change quite rapidly from year to year with growing demand and changes in the mix of generation capacity available. However, in the long run, as systems adjust to their optimal levels, the long-term benefits for the island as a whole from enhanced interconnection should be reasonably predictable.

A simulation was carried out to examine how the system would be affected by a major increase in wind capacity – in this case an increase in wind of 1000MW. This simulation suggested that, because of its intermittent nature, the additional wind would not add to system security. This replicates the results in Garrad Hassan (2002) and Eirgrid, 2004a. However, the results could be different if a more realistic assumption were used, allowing for a wider dispersion of wind availability across time. In the current case all of the wind capacity is assumed to be either available or unavailable for a day. In practise there will be some days when some of the wind is available and other parts of the wind system are not.

The final simulation considered a situation where the output from the Poolbeg and Dublin Bay power plants was replaced by a single 1000 MW nuclear plant, leaving total generation capacity unchanged in the Republic.[23] This assumption reflects the importance of economies of scale in nuclear plants – they come in much larger unit sizes than do other types of generating capacity. This would mean that instead of the 1000 MW of generation capacity being spread over four independent units, subject to independent probabilities of forced outage, all the capacity would be concentrated in one unit. If that unit was forced to halt production it would immediately take 1000 MW from the system. With four independent plants it would be exceptionally unlikely for all four of them to close simultaneously in the same way. Thus a single nuclear plant would seriously reduce the level of system security.

The model simulations suggest that the maintenance of the 8 hours LOLE with such a nuclear plant on the system, and with current interconnection to Northern Ireland, would require an additional 330 MW of capacity. In a fully integrated island system it would still require an additional 270 MW of generation capacity to maintain system security unchanged. This need for additional generation capacity to back up the system would significantly increase the cost of any nuclear option. These calculations take no account of the greatly increased demand for spinning reserve that such a large plant would require to cover for unexpected events. What these simulations suggest is that even if there were no wider environmental or political concerns about building a nuclear plant, the economics of such an option would, in any event, be unattractive. The isolated nature and the small size of the Irish electricity system is likely to make this option unattractive on economic grounds alone for some time to come.

[23] The output from the Marina plant was also reduced to ensure no change in generation capacity.

5. Summary and Conclusions

This paper develops a methodology to quantify some of the benefits from enhanced electricity interconnection on this island. The benefits considered are the increased reliability for electricity consumers on the island arising from enhanced interconnection. This model is applied to data for 2003 to provide a preliminary quantification of the benefits under a range of different options on interconnection.

The data used in the model are provided for illustrative purposes only. To use the model to measure the effects of enhanced interconnection on system security in the future it will be necessary to calibrate the data correctly to the situation in the future year when such additional transfer capacity would be likely to become available. As currently configured, the model takes no account of the possible introduction of an East-West interconnector. Such a modification to the network could significantly affect these results.

While the model shows the benefits separately for consumers in the North and the Republic, this breakdown will not be robust in the case of changes in the supply demand balance over the coming years. This is highlighted by the sensitivity tests described in Section 4. However, the results in terms of the aggregate benefits for consumers on the island can provide an appropriate benchmark against which to judge the advantages of different options on interconnection.

The results indicate that electricity consumers on the island are receiving a very significant benefit from the operation of the, albeit constrained, existing interconnector between the North and the South. These benefits, in terms of reduced investment in generation capacity, are worth about €251 million. They arise as a result of the increased security provided by a more integrated island electricity system. This is likely to be substantially more than the replacement costs of the current interconnector.

The model results also suggest that the construction of a second interconnector combined with reinforcement of the transmission system in the Louth region of the Republic would result in further potential savings in capacity worth around €132 million. The strengthening of the transmission in the Louth region is likely to bring marginally greater benefits, in terms of increased security, than will the construction of a second interconnector. These savings of €132 million, on their own, would be likely to account for a significant part of the cost of a second interconnector and of the strengthening of the transmission in the Republic. On top of these savings there would be benefits in terms of a more efficient despatch of generating capacity on the island, enhanced competition, and further dynamic benefits as the system evolved in the future to accommodate the second interconnector.

Finally, these results illustrate the fact that the LOLE standard produces different levels of expected unmet electricity demand depending on whether it is applied to both the electricity systems treated separately or to an island-wide system.

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Appendix 1: Outage Probability Problem

This appendix considers whether modelling forced outage on a day by day basis or on an hourly basis will have the same result when the model is run with a large enough number of simulations.

NOTE: The hour in which the demand for electricity is greatest each day is regarded as the "peak hour".

1. There are 8760 hours in a year. If you pick one hour from all the hours in a year, what is the probability that it is a peak hour?

Answer: If there is one peak hour each day, there are 365 peak hours in a year.

365/8760 = 365/(365*24) = 1/24

2. If the 8760 hours in a year are split into 365 groups of 24 consecutive hours (e.g. days). Choosing only one group, what is the probability of still picking a peak hour?

Answer: Since the groups contain 24 CONSECUTIVE hours, there will always be one peak hour in each group. Therefore, on a group level, there is a probability of one that the chosen group will contain a peak hour (365/365). However, within each group the 24 consecutive hours can be arranged consecutively in 24 different ways. This is a permutation of the derivative from 365 to 365 x 24.

365/365… 365/(365*24) = 1/24

CONCLUSION:

Whether the forced outage probabilities are applied on an hourly or daily basis is of no consequence, especially after consideration for the number of iterations, 10,000, in the monte carlo simulation.

Appendix 2: Annotated Code

This code was written to run for the Gauss econometrics package. However, with the exception of the functions used, the code could easily be converted to run under a range of other languages.

```
new;cls;
ts=hsec;
datestr (0) "          " timestr(0);
format /rd 6,6;

library pgraph;
graphset;

Iter=1000; // The number of monte carlo simulations
Trans =SpreadsheetReadM("ModelIn.xls", "b71:d72", 1); //Read in details of interconnectors
NSTrans1 = Trans[1,1]; //N-S transfer capacity on interconnector 1.
SNTrans1 = (Trans[1,1]-200)*(Trans[1,1]>0); //S-N transfer capacity on interconnector 1.
NSTrans2 = Trans[2,1]; //N-S transfer capacity on interconnector 2.
SNTrans2 = Trans[2,1]; //S-N transfer capacity on interconnector 2.

Capacity = SpreadsheetReadM("ModelIn.xls", "b2:b70", 1); // The capacity of each generating unit
CapAll = Capacity[1:69];

Oper1 = SpreadsheetReadM("ModelIn.xls", "b2:br366", 2);
Oper = Oper1';          // Oper1 transposed. this is one when the station is available and zero when it is undergoing
                        //planned maintenance
OperAll = Oper[1:69,1:365];

DayCons1 = SpreadsheetReadM("ModelIn.xls", "c2:ax70", 3); //This is one for the hours available in day, otherwise 0
DayCons = DayCons1'; //Transpose it

Fout = SpreadsheetReadM("ModelIn.xls", "i2:i70", 1);   //Forced Outage percentages//
FoutAll = Fout[1:69];
// Foutall=Foutall.*0+1; This option is used if there is a zero probability of forced outage

FD = SpreadsheetReadM("InterconnectP.xls", "e2:g17521", 3);//Read in demand on a 15 minute basis
FD1 = FD[.,1]; FD2 = FD[.,2]; FD3 = FD[.,3]; // Split it into final demand for North, South and the Island
FDRoI = sumc((reshape(fd1,24*365,2))')/2; //Turn the data into hourly data
FDNI = sumc((reshape(fd2,24*365,2))')/2; //Turn the data into hourly data
FDAll = sumc((reshape(fd3,24*365,2))')/2; //Turn the data into hourly data

LolRoI = matinit(10000, 31, 0); //Initialise the matrix with the value of zero, dimensions, 1000, 30
LolNI = matinit(10000, 31, 0);
LolAll = matinit(10000, 31, 0);
LostMWRoI = matinit(10000, 31, 0);
LostMWNI = matinit(10000, 31, 0);
LostMWAll = matinit(10000, 31, 0);

// Statavail cumulates the capacity available over all iterations for each station for each hour
// This is used to calculate average availability over all iterations
StatAvail = matinit(8760,69,0);
// Var is a matrix of additions or reductions in capacity to test sensitivity of LOLE to varying capacity
Var=matinit(31, 1, 0);
for i(1, 31, 1);
Var[i] = i * 50 - 750;
endfor;


//This repeats the exercise for the specified number of iterations
for i(1, Iter, 1);

// Fileall  is the capacity available from each station for every hour of the day
FileAll = matinit(69, 8760, 0);

for j(1, 69, 1);
   for k(1, 365, 1);
// Capinop is the capacity available for the day for the relevant plant. For hydro stations they are only
// available for some hours in the day. Rndyu is the random number generator
   CapinOp = (rndu(1,1) < Foutall[j]) * capacity[j] * OperAll[j,k];
      for n(1, 24, 1);
```

```
        m = (k-1)*24+n;
        fileAll[j,m] = CapinOp*DayCons[n,j];
        StatAvail[m,j] = StatAvail[m,j]+FileAll[j,m];
        endfor;
    endfor;
endfor;
// Avilroi etc. give the total availability in each jurisdiction for each hour in the year
    availroi=sumc(fileall[1:52,.])';
    availni=sumc(fileall[53:69,.])';
    availall=sumc(fileall)';
    for m(1,31,1);

// Check and see whether interconnector(s) is forced out
    Ic1Op = (rndu(1,1) < Trans[1,2]*(1-Trans[1,3]));
    Ic2Op = (rndu(1,1) < Trans[2,2]*(1-Trans[2,3]));
    NSTrans = Ic1Op*NSTrans1+Ic2Op*NSTrans2;
    SNTrans = Ic1Op*SNTrans1+Ic2Op*SNTrans2;
// capacity available for transfer - either a positive number or 0
        SpareCNI= ((AvailNI-Var[M])'-FDNI).*(((AvailNI-Var[M])'-FDNI).>0); //Spare capacity in NI
        SpareCRoI= ((AvailRoI-Var[M])'-FDRoI).*(((AvailRoI-Var[M])'-FDRoI).>0); //Spare capacity in RoI
        SpareNI = (SpareCNI .> NSTrans)*NSTrans + (SpareCNI .<= NSTrans).* SpareCNI; //Spare in NI that can be transferred
        SpareRoI = (SpareCRoI .> SNTrans)*SNTrans + (SpareCRoI .<= SNTrans).* SpareCRoI; //Spare in RoI that can be
transferred
        LolRoI[i,m]=sumc((FDRoI .> (availRoI-Var[m]+SpareNI')')*100/(365*24));
        LolNI[i,m]=sumc((FDNI .> (availNI-Var[m]+SpareRoI')')*100/(365*24));
        LolAll[i,m]=sumc((FDAll .> (availAll-Var[m])')*100/(365*24));
        LostMWRoI[i,m]=sumc((FDRoI .> (availRoI-Var[m]+SpareNI')').*(FDRoI - (availRoI-Var[m]+SpareNI')'));
        LostMWNI[i,m]=sumc((FDNI .> (availNI-Var[m]+SpareRoI')').*(FDNI - (availNI-Var[m]+SpareRoI')'));
        LostMWAll[i,m]=sumc((FDAll .> (availAll-Var[m])').*(FDAll - (availAll-Var[m])'));
    endfor;
endfor;
// this shows the average loss of load in percentage for variations in capacity (by 50MW); base capacity is row 5.
LoLRoIS=sumc((LoLRoI[1:Iter,1:31]))./Iter;
LoLNIS=sumc((LoLNI[1:Iter,1:31]))./Iter;
LoLAllS=sumc((LoLAll[1:Iter,1:31]))./Iter;

LostMWRoIS=sumc((LostMWRoI[1:Iter,1:31]))./Iter;
LostMWNIS=sumc((LostMWNI[1:Iter,1:31]))./Iter;
LostMWAllS=sumc((LostMWAll[1:Iter,1:31]))./Iter;


StatAvail1 = Statavail./Iter;

matrixtowrite1=var ~ LolRoIS ~ LolNIS ~ LolAllS ~ LostMWRoIS ~ LostMWNIS ~ LostMWAllS;
matrixtowrite2=iter ~ iter ~ iter ~ iter ~ iter ~ iter ~ iter;
matrixtowrite = matrixtowrite2 | Matrixtowrite1;
SpreadsheetWrite(Iter,"ModelOutput.xls","b2:b2",1);
SpreadsheetWrite(NSTrans1,"ModelOutput.xls","b39:b39",1);
SpreadsheetWrite(SNTrans1,"ModelOutput.xls","b40:b40",1);
SpreadsheetWrite(NSTrans2,"ModelOutput.xls","c39:c39",1);
SpreadsheetWrite(SNTrans2,"ModelOutput.xls","c40:c40",1);
SpreadsheetWrite(MatrixtoWrite,"ModelOutput.xls","b6:h37",1);

spreadsheetWrite(StatAvail,"ModelOutput.xls","b2:br8761",2);

runtime = hsec-ts;print "Runtime = " runtime/100 " seconds";
```

Appendix 3: Input Data

This is the first sheet of the input matrix ModelIn.XLS

Unit	Capacity MW	Planned Availability	Probability of Forced Outage
Moneypoint	285	0.909	0.072
Moneypoint	285	0.909	0.072
Moneypoint	285	0.909	0.072
GreatIsland	57	0.873	0.092
GreatIsland	57	0.873	0.092
GreatIsland	112	0.873	0.092
Tarbert	57	0.873	0.086
Tarbert	57	0.873	0.086
Tarbert	241	0.873	0.086
Tarbert	241	0.873	0.086
Aghada	258	0.873	0.039
Aghada CT	90	0.873	0.026
Aghada CT	90	0.873	0.026
Aghada CT	90	0.873	0.026
Marina	112	0.873	0.038
NorthWall CC	109	0.873	0.080
NorthWall CT	163	0.873	0.051
PoolbegSteam	115	0.873	0.068
PoolbegSteam	114	0.873	0.068
PoolbegSteam	257	0.873	0.092
PoolbegCCGT	230	0.873	0.020
PoolbegCCGT	230	0.873	0.020
Ardnacrusha	89	1.000	0.010
Clady	4	1.000	0.010
Erne	65	1.000	0.010
Lee	27	1.000	0.010
Liffey	34	1.000	0.010
TurloughHill	73	1.000	0.020
TurloughHill	73	1.000	0.020
TurloughHill	73	1.000	0.020
TurloughHill	73	1.000	0.020
Bellacorick	37	0.873	0.150
Edenderry	118	0.910	0.081
West Offaly	0	0.910	0.081
Lough Ree	0	0.910	0.081
Lanesboro	85	0.873	0.150
Shannonbridge	125	0.873	0.150
Dublin Bay	196	0.910	0.080
Dublin Bay	196	0.910	0.080
Viridian	171.5	0.910	0.038
Viridian	171.5	0.910	0.038
Tynagh	0	0.910	0.050
Tynagh	0	0.910	0.050
Aughinish	0	0.910	0.050
Aughinish	0	0.910	0.050
Peak- Aghada	0	0.910	0.040
Peak- Killala	0	0.910	0.040
Peak - Rhode	51	0.910	0.040
CHP	137	1.000	0.200

Wind	210	1.000	0.630
Renewable - Hydro	16	1.000	0.400
Renewable - LFG	19	1.000	0.150
Ballylumford CC20	250	0.900	0.040
Ballylumford CC20	250	0.900	0.040
Ballylumford CC10	100	0.900	0.040
Ballylumford CC10	117	0.900	0.031
Ballylumford GT	58	0.900	0.010
Ballylumford GT	58	0.900	0.010
Kilroot ST	195	0.900	0.012
Kilroot ST	195	0.900	0.012
Kilroot GT	29	0.900	0.009
Kilroot GT	29	0.900	0.009
Coolkeragh ST	57	0.900	0.012
Coolkeragh GT	57	0.900	0.012
Coolkeragh CCGT	0	0.910	0.038
Coolkeragh CCGT	0	0.910	0.038
Northern CHP	100	1.000	0.200
Northern Wind	20	1.000	0.630
Interconnector	500	1.000	0.010
N-S Interconnector 1	300	1.000	0.010
N-S Interconnector 2	300	1.000	0.010

Appendix 4: List of Spreadsheets used

The data are available from the author.

InterconnectP: Sheet 3 shows demand in the Republic and in the North for every 15 minute period of 2003

Modelin.XLS: Sheet Data lists the stations and the percentage planned availability and assumed probability of forced outage. Sheet YrCons specifies the pattern of planned maintenance on a daily basis. Sheet DayConsH specifies which hours in the day stations are on or off. This only affects the hydro stations.

ModelOutput.XLS: This gives the results shown above as Tables 2 and 3 in Sheet "Aggregate". Sheet 2 shows the availability by station for each day of the year summed over all simulations. At the bottom it checks that the realised availability of each station equals the expected availability. Summaries of the results in terms of probabilities of forced outage, LOLE and unmet demand are given in subsequent sheets.

Appendix 5: Estimated Unmet Demand, GWh

Republic of Ireland

Interconnection Capacity to RoI

Expected Loss of Load, GWh		None	Existing	Existing	Potential	Potential	Potential
			Uncertain	Uncertain	Uncertain	Uncertain	Certain
		0	300	300	600	600	Unlimited
	300	0.32	0.02	0.02	0.00	0.00	0.00
more generation / less load	200	0.79	0.06	0.05	0.00	0.00	0.00
	100	1.82	0.16	0.14	0.01	0.01	0.01
With Current Generation Capacity		4.01	0.40	0.38	0.07	0.07	0.07
	-100	8.47	0.98	0.95	0.32	0.32	0.32
	-200	17.06	2.53	2.49	1.40	1.40	1.42
less generation / more load	-300	32.77	6.85	6.79	5.60	5.60	5.61
	-400	60.05	20.32	20.32	19.37	19.37	19.39
	-500	104.87	57.52	57.34	56.77	56.77	56.79

Northern Ireland

Interconnection Capacity to NI

Expected Loss of Load, GWh		None	Existing	Existing	Existing	Potential	Potential
			Uncertain	Uncertain	Uncertain	Uncertain	Certain
		0	100	300	100	400	Unlimited
	300	0.00	0.00	0.00	0.00	0.00	0.00
more generation / less load	200	0.02	0.01	0.00	0.01	0.00	0.00
	100	0.10	0.03	0.00	0.03	0.00	0.00
With Current Generation Capacity		0.37	0.11	0.02	0.11	0.01	0.01
	-100	1.15	0.40	0.08	0.40	0.06	0.05
less generation / more load	-200	3.44	1.30	0.37	1.30	0.28	0.24
	-300	8.77	3.94	1.39	3.94	1.14	1.05

All Ireland

Interconnection Capacity

Expected Loss of Load, GWh		None	Existing	Existing	Potential	Potential	Potential
			Uncertain	Uncertain	Uncertain	Uncertain	Certain
	600	0.00	0.00	0.00	0.00	0.00	0.00
more generation / less load	400	0.00	0.00	0.00	0.00	0.00	0.00
	200	0.01	0.01	0.01	0.01	0.01	0.01
With Current Generation Capacity		0.07	0.07	0.07	0.07	0.07	0.07
	-200	0.37	0.37	0.37	0.35	0.35	0.37
less generation / more load	-400	1.68	1.67	1.68	1.64	1.64	1.66
	-600	6.72	6.69	6.70	6.63	6.63	6.67
	-800	23.40	23.33	23.33	23.27	23.27	23.31