Appendix 1

Swell Directionality

1. Introduction

To give an indication of swell directionality at different parts of the coast eight points reasonably offshore and, where possible, close to an existing M buoy were selected as master points. The locations are as follows:

Table A1.1

Directional Reference Points

Master Point	Latitude	Longitude	Nearest Buoy
"Galway"	53.5°N	11.0°N	M1
"Donegal"	55.0°N	9.75°N	M4
"Shannon"	52.5°N	11.0°N	-
"Kerry"	51.25°N	10.75°N	M3
"Malin Head"	55.5°N	7.0°N	-
"Dublin (Irish Sea) "	53.5°N	5.25°N	M2
"Cork"	51.5°N	8.0°N	FSI
"St. Georges Channel"	52.0°N	5.5°N	M5

2. Analysis of Directionality

The hourly, monthly and seasonal frequencies of occurrence (WAM) within 30° sectors were tabulated between September 2001 and November 2004 inclusive and may be summarised for the overall period as follows:

Table A1.2

Summarised Directionality % Occurrence/Sector

Sector °	030	060	090	120	150	180	210	240	270	300	330	360
Galway						1	7	22	36	20	9	5
Donegal							2	22	43	19	10	6
Shannon						2	6	20	36	25	9	3
Kerry						2	6	17	36	25	9	2
Malin Head								1	17	64	16	2
Dublin	4	2	2	2	4	20	34	8	4	4	6	11
Cork				1	3	7	23	56	7			
St. Georges Channel						1	17	58	9	4	4	3

The rounded figures in the above table show that the West coast sites "Donegal, Galway, Shannon, Kerry" are predominantly (36% of time) subject to westerly swell falling into Sector 270^o. On either side of this swell approaching from sectors 240^o and 300^o are broadly similar with about 20% of occurrences. Thus the West Coast is dominated by swell approaching from sectors 240^o-300^o with 270^o predominating. There is little difference in directionality between annual and winter values, although in the North West winter occurrences rise above the mean somewhat. At the south west corner of the country it may be noted that the directionality for "Shannon" and "Kerry" is very similar.

On the north coast ("Malin") sector 300^o predominates markedly at 64% (Winter 72%) with the adjacent 270^o and 300^o sectors contributing 16-17% each.

On the south coast the sites at "Cork" and "St. George" are dominated by the 240^o sector (56-58%) with 210^o as the main secondary sector (17-28%). The 270^o sector makes a relatively small contribution at 7-9%. Compared with the west coast the sheltered configuration of the south coast is evident. The dominance of the 240^o sector increases by a few percentage points in winter.

Finally the Irish Sea location, "Dublin", shows an input from all points of the compass with Sector 210^o predominating (34%) followed by sectors 180^o (20%) and 360^o (11%). This shows a near north-south swell influence there which is quite different from that demonstrated on other coasts but is in line with fetch and movement of tidal streams. Its directionality varies little in winter.

3. Conclusion

The bulk of the annual incident wave energy arriving on the Irish coast approaches the Atlantic coast from the sectors 240^o – 300^o with 270^o predominating. At the northern end of the coast 300^o tends to emerge as dominant direction.

Appendix 2

Calibration of Predicted Waves against Buoy Measurements

1. Introduction

The predicted seasonal wave power trends at selected grid points are compared with those that have been measured over the past few years by the Marine Institute via its Irish Marine Weather Buoy Network maintained in association with Met. Eireann and the UK Met. Office. The raw data was kindly been made available by the Institute's Ocean Science Services unit and has been converted to power and energy levels as part of the present study for comparison purposes.

The basic purpose of these buoys is to enhance safety at sea and their general features are tabulated below.

Table A2.1

Buoy	Date Deployed	Sig. Wave height Hs	Wave Period T_z
M1 M2 M3 M4 M5 FSI	November 2000 May 2001 July 2002 April 2003 Autumn 2004 Available from Jan. 2003	Accuracy 40mm Hs = 4 times RMS value of water level above average level for 17.5 min record period each hour.	Measured from the number of times a wave passes through mean water level in an upward direction over the preceding 17.5 min. period.

2. Review of Record Quality

Inspection of the results from the Marine Institute buoys shows a fair number of null readings where either Tz or Hs or both have failed to register and a small number of aberrations where one variable has recorded a large value that is well out of scale with its neighbours, leading to a corresponding overstatement of power level for that hour. Such values were deleted.

The percentage of valid returns was noted as a means of indicating the incidence of null readings at particular periods. In some cases a whole month of data was missing. One other area noted was where a string of exactly the same power values occurred over several hours. This excited some attention but was attributed to the relatively low resolution of the readings, particularly in non stormy conditions where the same Tz and Hs were repeated for several hours in a row. Where these were not significantly different from the varying values occurring before and after the set of constant values, they were retained as being reasonably representative of the prevailing conditions.

The monthly buoy data recovery levels are shown in percentage terms on Table A2.3 below. These were calculated on an hourly basis and the hour by hour values were compared later with the WAM hindcast values for the corresponding hours to provide the tabulated coefficients of correlation and determination (r and r^2 respectively). (Table A2-4)

Ideally about ten years of records are desirable for energy related studies but as it is necessary to work with the more limited data currently available it is to be expected that these coefficients should improve with time when more measured data becomes available.

Examination of Table A2.3 shows that while generally the rate of return of data from the buoys has been good, in only one instance was 100% recovery achieved in any month. The absence of buoy data for particular periods means that the corresponding wave forecast data cannot be used for correlation purposes as it is necessary to compare forecast and measured data for identical hours only. There is a broad indication that the incidence of null readings from the buoys increases with time after installation. This and the fact that it is difficult to service buoys during winter conditions suggests that they should, if possible, be serviced in mid Autumn so as to enhance their ability to remain functional during the Winter/early Spring period when it is most important to acquire high quality data.

Buoy measurement of Tz is rounded to the nearest second and this is a relatively crude measure when utilising the result for power calculation.

3. Selection of Sample Months for Comparison

Having reviewed the hourly data return levels for the buoys since installation it was decided that, as none of the buoys had continuous records over the four year period for which DMI-WAM predictions were available, the following selection criteria should apply to the buoy data:

(1) Selected months should represent Spring, Summer, Autumn and Winter seasons where possible.

(2) Selected months should be those for which there is maximum availability of records.

Thus the same months were not necessarily selected each year. The overriding consideration was utilisation of months for which near complete actual buoy records were available. Thus particular months showing large numbers of null returns or other defective readings were avoided. The sampling arrangement is shown on Table A2-4.

Thus 48 months out of the set available were chosen for comparison. Table A2-4 also shows the values of r and r^2 between the hourly forecast and measured power flux values. Given the numbers of hourly values in the samples the application of the ‘t’ test confirms the very strong positive correlation between the hindcast values and those derived from adjacent buoys. It will be noted that the buoy records are intermittent where gaps in data recovery occur whereas the WAM records are near continuous. The correlation computation applies only to those sections of record where both are present.

It should be noted that to maximise clarity, the vertical scales in the figures vary depending on the range of power flux encountered in each case (e.g. the wave regime at buoy M1 is much more active than at buoy M2 and so merits a higher range). The time histories are colour coded to show power flux levels derived from buoys (navy blue), unmodified DMI-WAM forecast (red), modified DMI-WAM forecast (green). This last is labelled (Power *) on the diagrams and represents a scaled down compromise level as discussed below.

4. Review of Data

In reviewing the data as plotted in monthly power flux time series, regression lines and distribution curves it is evident that either the buoys underestimate the power levels reached during storms or the DMI Model tends to over-predict somewhat. As the power level is proportional to H_s^2Tz it is possible that the round off of Tz to the nearest second in the buoys or relatively small errors in Hs contribute to the differences. On the other hand bearing in mind the scale over which the WAM model is operated to yield these outputs and the many variables that contribute to its predictions it would not be surprising if there were some effects that contribute to small mismatching under particular circumstances. The visual level of correlation found is not dissimilar to the comparison between WAM results and buoy data shown in Ref. (21) (Fig. 8.7)

In general there is a tendency for the forecast power values to be larger than those deduced from buoy records in respect of buoys M1, M2 (partly), M4, M5, FSI. This is particularly the case during stormy conditions at all seasons.

M3 shows much better correlation and in some cases buoy measurements exceed forecast power values. The intermittency of buoy readings (particularly FSI) does not help in other cases.

The question arises as to whether, on the basis of these discrepancies, the basic forecast Hs, Tz, values should be scaled down somewhat to achieve a closer relationship with the buoy values, possibly reflecting the shallowing waters as the coast is approached.

The most important buoy is M1 located at a pivotal Atlantic location off Galway at (53.122^{o}N, 11.2^{o}W). The nearest adjacent forecast model grid point is 7km distant at (53^{o}N, 11.25^{o}W). The bathymetry between the points shows virtually no change in the depth of 125m (Admiralty Chart 1125).

Considering Figs. A2-1.1 to A2.1-21 it is evident that the forecast storm events generally coincide in time with the events recorded by the buoy. In general the forecast Tz, Hs and power flux levels during storms exceed those recorded by the buoy.

Whether this is primarily due to over-estimation in the forecast or understated buoy readings is unclear at this point. It can be noted that the Tz measurement at the buoy is relatively coarse (1 sec. round off) and would contribute to differences in computed power level. It has been noted (13) elsewhere that small (Waverider) buoys have been found to underrecord storm conditions due variously to (1) the buoy being dragged through or around peak waves (2) interference with buoy aerial and transmissions during extreme conditions. It is assumed that the larger ODAS buoys have better resistance to these effects but the incidence of null readings is rather high.

Comparison of energy output predicted by buoy and forecast for particular months, showed that there could be significant forecast overstatements of energy figures derived from WAM compared with those derived from buoy measurement. From the distribution curves for Hs, Tz during the month it was evident that differences with forecasts occurred in both Hs and Tz and that these contributed non linearly to the differences at power flux level. Five of the six buoys reflected these differences.

It was felt that with measurements being made at these several buoys during all seasons over the three years for which data is available which showed lower values than forecast, there was a case to be made for some reduction in forecast values and that an adjustment should be made to Hs and Tz from WAM that would bring forecasts more into line with actual field measurements. This would impact on both the theoretical and technical resources. The theoretical power and energy resource would be conservatively reduced in response to the changes in Hs and Tz which would be also reflected in the occurrence scatter diagrams from which the technical resource is derived. The technical resource would be to some extent shielded from the effect of this change which would have most impact during storms when the power matrices of the commercial converters show that they move into a 'survival' rather than a 'power generation' mode of operation. Clearly optimisation of such adjustments would merit a special study in its own right which was outside the scope of the present work and for which a sufficient duration of comparative data is not yet available. Consequently, based on the factors found necessary to bring the separate Hs and Tz buoy and WAM exceedence curves into coincidence at each buoy location, the following smoothed reductions in WAM values were utlised over those areas of the WAM grid for which the respective buoys might reasonably be considered as being representative:

(1) **Tz Values**

1.1 Gradual reduction of Tz by 0-13% 0-15%, 0-14%, 0-30% in regions represented by buoys M1, M3, M4, FSI respectively

1.2 No reduction of Tz in region represented by M2.

(2) **Hs Values**

2.1 Gradual reduction of Hs by 0-17% in region represented by M4.

2.2 Gradual reduction of Hs by 0-5% in region represented by FSI.

2.3 Gradual reduction of Hs by 0-2% in region represented by M1.

2.4 No reduction of Hs in regions represented by M1, M2, M3.

The adjustments can be modified in future if further results show that this is necessary. The values plotted in the contoured maps reflect this reduction. The original unreduced values have also been retained in the database. The method used was as follows:

Table A2-2

Deviations of Hs, Tz Reduction Factors based on Annual 'best fit plots for WAM values adjacent to particular buoys

	2002 m	**Inverse $^1/_m$**	**2003 m**	**Inverse $^1/_m$**	**2004 m**	**Inverse $^1/_m$**	**Mean**	**Peak Factor**
M1 Hs Tz	1.89% 1.1704	.8406 .8544	.9276 1.1248	1.0780 0.8890	.9603 1.154	1.0413 .8665	.9866 .8699	(-1%) (-13%)
M3 Hs Tz	0.9768 1.2036	1.0237 0.8308	0.9343 1.1439	1.0703 0.8742	0.9644 1.905	1.0369 .8399	1.0436 .8483	(+ 4%) (- 16%)
FS1 Hs Tz	- -	- -	1.0481 1.4134	0.9541 0.7075	1.1012 1.444	.9081 .6925	.9311 .7	(-7%) (-30%)
M4 Hs Tz	- -	- -	1.1427 1.1313	0.8751 .8792	1.2548 1.1937	.7969 .8377	.836 .858	(-16%) (-14%)
M2 Hs Tz	1.0006 .9409	.9994 1.0628	.9393 .9968	1.0646 1.0032	1.0126 1.0653	.9875 .9387	1.017 1.001	1 1

When Hs and Tz output from WAM is plotted against corresponding values from the buoys the 'best fit' lines should pass through the origin, and ideally the slopes of these lines should be 1, showing perfect correlation between buoy and WAM values. The extent to which this does not occur is a measure of the mean over or under statement of the measured value at the buoy by WAM (if the buoy's readings are accepted as being the factual measurements).

Thus the increase of the slopes of the best fit lines can be used as multipliers to restore the slopes to unity and as a measure of the level of over reading occurring at least in the vicinity of particular buoys. It is assumed that the discrepancy between buoy and WAM figures reduces with distance from the buoy particularly in a seaward direction and that eventually the discrepancy will vanish in deep water well offshore.

A range of multipliers is therefore developed for both HS and TZ having the above (**$^1/_m$**) (where m is the slope of the 'best fit' line) values in the vicinity of the respective buoys and diminishing with distance until they 'feather out' to unity i.e. the WAM values are then taken at face value without modification. The 'Peak Factor' of Table A2-2 is the difference between the WAM value at the grid point closest to the buoy location and the buoy value, measured as a percentage of WAM value

5. Conclusions

5.1 Given the nature of the wave buoy records obtained to date and a comparison of 48 monthly sets of hourly records with corresponding DMI-WAM forecast values, it is concluded that the high level of correlation that exists between the buoy and forecast values for all four seasons at six locations around the Irish coast justifies in principle the use of the WAM data in estimating the theoretical wave power resource.

5.2 To minimise the divergence noted, particularly during storms, between forecast and measured values of Hs, Tz and consequently power flux, it is appropriate to scale down the forecast figures somewhat to bring them into closer agreement with the measured values recorded at the six buoys around the coast. It is considered unlikely that all of these buoys, well spaced around the coast, suffer from a common mode of failure that would lead to consistent consistent underrecording of data given that at least one correlates well with an independent seventh buoy (waverider) located closer to the coast.

5.3 It is most desirable that the joint wave measurement programme operated by the Marine Institute should continue. While this programme primarily exists for the purposes of supporting safety at sea, it is worth reiterating its value in providing a baseline for monitoring the wave power resource. **With each year that passes these accumulated records become more valuable as convergence with the desired 10-year duration approaches.** (It is understood that the location of Buoy M4 has been transferred to a new location 50km westward because of unexpectedly low values obtained at its present site). The quality of the records arising from this programme needs to be upgraded particularly in terms of Tz, if possible, for use in power studies.

5.4 Future refinement of the model will be possible in the light of continued buoy measurements as more information based on a longer period of measurements becomes available.

Table A2.3

Monthly Buoy Data Recovery Levels (%)

Buoy	M1	M2	M3	M4	M5	FS1	
Jan. 01	-	-	-	-	-	-	
Feb.	-	-	-	-	-	-	
Mar.	91.53	-	-	-	-	-	
Apr.	90.56	-	-	-	-	-	
May	99.19	90.46	-	-	-	-	
July	97.85	98.79	-	-	-	-	
Aug.	95.02	95.56	-	-	-	-	
Sept.	98.89	98.75	-	-	-	-	
Oct.	98.12	99.46	-	-	-	-	
Nov.	97.78	91.8	-	-	-	-	
Dec.	97.98	98.52	-	-	-	-	
Jan. 02	96.64	98.25	-	-	-	-	
Feb.	92.7	96.43	-	-	-	-	
Mar.	95.02	98.92	-	-	-	-	
Apr.	87.64	99.72	-	-	-	-	
May	96.1	94.22	-	-	-	-	
June	93.6	94.03	-	-	-	-	
July	72.3	94.89	-	-	-	-	
Aug.	99.06	100	-	-	-	-	
Sept.	98.89	99.03	-	-	-	-	
Oct.	97.85	97.85	-	-	-	-	
Nov.	93.75	93.19	-	-	-	-	
Dec.	94.89	96.23	-	-	-	-	
Jan. 03	-	95.03	97.04	-	-	-	
Feb.	-	90.63	93	-	-	89.6	
Mar.	80.24	86.83	93.41	-	-	89.38	
Apr.	93.19	99.3	97.36	47.9	-	91.8	
May	95.56	98.79	96.5	97.3	-	90.3	
June	90.83	98.75	88.06	98.05	-	88.47	
July	91.26	98.92	98.12	97.85	-	72.71	
Aug.	93.41	96.24	95.03	93.15	-	72.82	

Sept.	96.8	97.5	96.81	95.5	-	89.72	
Oct.	88.97	88.57	85.48	85.08	-	92.39	
Nov.	94.16	93.19	92.78	91.5	-	83.61	
Dec.	96.37	94.22	87.5	95.8	-	88.57	
Jan. 04	89.52	82.26	90.32	54.57	-	90.72	
Feb.	98.96	91.52	73.13	-	-	81.89	
Mar.	95.69	93.55	75.54	-	-	90.19	
Apr.	80.97	73.61	65.83	-	-	89.03	
May	96.5	82.66	82.0	-	-	89.78	
June	96.1	89.16	77.92	77.08	-	88.05	
July	98.52	62.63	89.38	82.25	-	89.38	
Aug.	24.7	-	96.9	92.34	-	82.12	
Sept.	90.42	90.87	98.47	89.86	-	90.42	
Oct.	87.23	94.35	97.45	88.44	-	85.75	
Nov.	83.3	83.3	96.94	87.92	92.69	90.42	
Dec.	-	-	-	-		-	

Max. No. of records per month	31 day month: 744 30 day month: 720	29 day month: 696 28 day month: 672	(leap year)	

Table A2-4

Coefficients of Correlation (r) and Determination (r^2) between

Hourly Forecast and Measured Power Flux Levels at 48 Sample Points

Buoy	M1		M2		M3		M4		M5		FSI
						2001					
Sept.	$r = 0.883$ $r^2 = 0.7797$	Sept.	$r = 0.8621$ $r^2 = 0.7782$	-	-	-	-	-	-	-	-
						2002					
Jan.	$r = 0.9104$ $r^2 = 0.8209$	Jan.	$r = 0.9182$ $r^2 = 0.843$	-	-	-	-	-	-	-	-
-	-	Mar.	$r = 0.8029$ $r^2 = 0.6448$	-	-	-	-	-	-	-	-
June	$r = 0.9326$ $r^2 = 0.8697$	June	$r = 0.8357$ $r^2 = 0.6984$	-	-	-	-	-	-	-	-
Sept.	$r = 0.8805$ $r^2 = 0.7752$	Sept.	$r = 0.8506$ $r^2 = 0.7236$	-	-	-	-	-	-	-	-
Dec.	$r = 0.9728$ $r^2 = 0.9463$	-	-	Oct.	$R = 0.9612$ $R^2 = 0.8538$	-	-	-	-	-	-

Buoy	M1		M2		M3		M4		M5		FSI
						2003					
-	-	Jan.	r = 0.9055 r^2 = 0.8201	Jan.	r = 0.9252 r^2 = 0.8561	-	-	-	-	Feb.	r = 0.8807 r^2 = 0.7758
-	-	Apl.	r = 0.8581 r^2 = 0.7364	Apl.	r = 0.7911 r^2 = 0.6259	-	-	-	-	-	-
May	r = 0.9192 r^2 = 0.8449	June	r = 0.8954 r^2 = 0.8018	July	r = 0.743 r^2 = 0.5521	June	r = 0.8843 r^2 = 0.7821	-	-	June	r = 0.8977 r^2 = 0.8059
Sept.	r = 0.8876 r^2 = 0.878	Sept.	r = 0.8938 r^2 = 0.7989	Sept.	r = 0.7218 r^2 = 0.521	Sept.	r = 0.8236 r^2 = 0.6784	-	-	Sept.	r = 0.9273 r^2 = 0.86
						2004					
Jan.	r = 0.9006 r^2 = 0.8111	-	-	Jan.	r = 0.893 r^2 = 0.7975	-	-	-	-	Jan.	r = 0.9169 r^2 = 0.8408
-	-	Mar.	r = 0.9454 r^2 = 0.8938	Mar.	r = 0.9539 r^2 = 0.9101	-	-	-	-	Apl.	r = 0.9003 r^2 = 0.8105
May	r = 0.9614 r^2 = 0.9243	June	r = 0.9183 r^2 = 0.8434	July	r = 0.974 r^2 = 0.8969	July	r = 0.9536 r^2 = 0.9093	-	-	June	r = 0.9204 r^2 = 0.8472
Sept.	r = 0.9229 r^2 = 0.8519	Sept.	r = 0.9248 r^2 = 0.8553	Sept.	r = 0.9427 r^2 = 0.8888	-	-	-	-	Sept.	r = 0.9551 r^2 = 0.9124
Nov.	r = 0.8657 r^2 = 0.7494	Nov.	r = 0.8768 r^2 = 0.7689	Nov.	r = 0.8685 r^2 = 0.7543	Nov.	r = 0.8626 r^2 = 0.7442	Nov.	r = 0.8955 r^2 = 0.802	Nov.	r = 0.8185 r^2 = 0.6701

The figures listed below arise from the calibration process. In these figures the power flux estimated from measurement of Hs and Tz at the nearest buoy is shown navy blue, that from the unadjusted DHI-WAM Forecast is shown red, while that from the adjusted DHI-WAM forecast figures is shown green. The term forecast is used as these were wave forecasts at the time that they were made.

Table A2.5

Monthly Power Flow Time History and Correlation – Buoy M1

Buoy M1 (53.123°N, 11.2°W) Adjacent Grid Point (53°N, 11.25°W)

Fig.	A2-1.1	Power Flux @ M1 – Sept. 2001
	A2-1.2	Correlation @ M1 – Sept. 2001
	A2-1.3	Power Flux @ M1 – Jan. 2002
	A2-1.4	Correlation @ M1 – Jan. 2002
	A2-1.5	Power Flux @ M1 – June 2002
	A2-1.6	Correlation @ M1 – June 2002
	A2-1.7	Power Flux @ M1 – Sept. 2002
	A2-1.8	Correlation @ M1 – Sept. 2002
	A2-1.9	Power Flux @ M1 – Dec. 2002
	A2-1.10	Correlation @ M1 – Dec. 2002
	A2-1.11	Power Flux @ M1 – May 2003
	A2-1.12	Correlation @ M1 – May 2003
	A2-1.13	Power Flux @ M1 – Sept. 2003
	A2-1.14	Correlation @ M1 – Sept. 2003
	A2-1.15	Power Flux @ M1 – Jan. 2004
	A2-1.16	Correlation @ M1 – Jan. 2004
	A2-1.17	Power Flux @ M1 – May 2004
	A2-1.18	Correlation @ M1 – May 2004
	A2-1.19	Power Flux @ M1 – Sept. 2004
	A2-1.20	Correlation @ M1 – Sept. 2004
	A2-1.21	Power Flux @ M1 – Nov. 2004
	A2-1.22	Correlation @ M1 – Nov. 2004

Table A2.6

Monthly Power Flux Time History and Correlation – Buoy M2

Buoy M2 (53.468^{o}N, 5.417^{o}W) Adjacent Grid Point (53.5^{o}N, 5.5^{o}W)

Fig.	A2-2.1	Power Flux @ M2 – Sept. 2001
	A2-2.2	Correlation @ M2 – Sept. 2001
	A2-2.3	Power Flux @ M2 – Jan. 2002
	A2-2.4	Correlation @ M2 – Jan. 2002
	A2-2.5	Power Flux @ M2 – March 2002
	A2-2.6	Correlation @ M2 – March 2002
	A2-2.7	Power Flux @ M2 – June 2002
	A2-2.8	Correlation @ M2 – June 2002
	A2-2.9	Power Flux @ M2 – Sept. 2002
	A2-2.10	Correlation @ M2 – Sept. 2002
	A2-2.11	Power Flux @ M2 – Jan. 2003
	A2-2.12	Correlation @ M2 – Jan. 2003
	A2-2.13	Power Flux @ M2 – April 2003
	A2-2.14	Correlation @ M2 – April 2003
	A2-2.15	Power Flux @ M2 – June 2003
	A2-2.16	Correlation @ M2 – June 2003
	A2-2.17	Power Flux @ M2 – Sept. 2003
	A2-2.18	Correlation @ M2 – Sept. 2003
	A2-2.19	Power Flux @ M2 – Dec. 2003
	A2-2.20	Correlation @ M2 – Dec. 2003
	A2-2.21	Power Flux @ M2 – March 2004
	A2-2.22	Correlation @ M2 – March 2004
	A2-2.23	Power Flux @ M2 – June 2004
	A2-2.24	Correlation @ M2 – June 2004
	A2-2.25	Power Flux @ M2 – Sept. 2004
	A2-2.26	Correlation @ M2 – Sept. 2004
	A2-2.27	Power Flux @ M2 – Nov. 2004
	A2-2.28	Correlation @ M2 – Nov. 2004

Table A2.7

Monthly Power Flux Time History and Correlation – Buoy M3

Buoy M3 (51.217^{o}N, 10.55^{o}W) Adjacent Grid Point (51.25^{o}N, 10.5^{o}W)

Fig.	A2-3.1	Power Flux @ M3 – Oct. 2003
	A2-3.2	Correlation @ M3 – Oct. 2002
	A2-3.3	Power Flux @ M3 – Jan. 2003
	A2-3.4	Correlation @ M3 – Jan. 2003
	A2-3.5	Power Flux @ M3 – Apr. 2003
	A2-3.6	Correlation @ M3 – Apr. 2003
	A2-3.7	Power Flux @ M3 – July 2003
	A2-3.8	Correlation @ M3 – July 2003
	A2-3.9	Power Flux @ M3 – Sept. 2003
	A2-3.10	Correlation @ M3 – Sept. 2003
	A2-3.11	Power Flux @ M3 – Jan. 2004
	A2-3.12	Correlation @ M3 – Jan. 2004
	A2-3.13	Power Flux @ M3 – March 2004
	A2-3.14	Correlation @ M3 – March 2004
	A2-3.15	Power Flux @ M3 – July 2004
	A2-3.16	Correlation @ M3 – July 2004
	A2-3.17	Power Flux @ M3 – Sept. 2004
	A2-3.18	Correlation @ M3 – Sept. 2004
	A2-3.19	Power Flux @ M3 – Nov. 2004
	A2-3.20	Correlation @ M3 – Nov. 2004

Table A2.8

Monthly Power Flux Time History and Correlation – Buoy M4

Buoy M4 (54.67^{o}N, 9.067^{o}W) Adjacent Grid Point (54.75^{o}N, 9^{o}W)

Fig.	A2-4.1	Power Flux @ M4 – June 2003
	A2-4.2	Correlation @ M4 – June 2003
	A2-4.3	Power Flux @ M4 – Sept. 2003
	A2-4.4	Correlation @ M4 – Sept. 2003
	A2-4.5	Power Flux @ M4 – Dec. 2003
	A2-4.6	Correlation @ M4 – Dec. 2003

A2-4.7 Power Flux @ M4 – July 2004

A2-4.8 Correlation @ M4 – July 2004

A2-4.9 Power Flux @ M4 – Nov. 2004

A2-4.10 Correlation @ M4 – Nov. 2004

Table A2.9

Monthly Power Flux Time History and Correlation – Buoy M5

Buoy M5 (51.67°N, 6.713°W) Adjacent Grid Point (51.75°N, 6.75°W)

Fig. A2-5.1 Power Flux @ M5 – Nov. 2004

A2-5.2 Correlation @ M5 – Nov. 2004

Table A2.10

Monthly Power Flux Time History and Correlation – Buoy FS1

Buoy FSI (51.37°N, 7.945°W) Adjacent Grid Point (51.25°N, 8°W)

Fig. A2-6.1 Power Flux @ FSI – Feb. 2003

A2-6.2 Correlation @ FSI – Feb. 2003

A2-6.3 Power Flux @ FSI – June 2003

A2-6.4 Correlation @ FSI – June 2003

A2-6.5 Power Flux @ FSI – Sept. 2003

A2-6.6 Correlation @ FSI – Sept. 2003

A2-6.7 Power Flux @ FSI – Jan. 2004

A2-6.8 Correlation @ FSI – Jan. 2004

A2-6.9 Power Flux @ FSI – April 2004

A2-6.10 Correlation @ FSI – April 2004

A2-6.11 Power Flux @ FSI – June 2004

A2-6.12 Correlation @ FSI – June 2004

A2-6.13 Power Flux @ FSI – Sept. 2004

A2-6.14 Correlation @ FSI – Sept. 2004

A2-6.15 Power Flux @ FSI – Nov. 2004

A2-6.16 Correlation @ FSI – Nov. 2004

Table A2.11

Annual Buoy Versus WAM Correlation Curves

Fig. A2-7.1 Correlation @ M1-2002-Tz

Fig. A2.7-2 Correlation @ M1-2002-Hs

Fig. A2.7-3 Correlation @ M1-2002-Power Flux

Fig. A2-7.4 Correlation @ M1-2003-Tz

Fig. A2.7-5 Correlation @ M1-2003-Hs

Fig. A2.7-6 Correlation @ M1-2003-Power Flux

Fig. A2-7.7 Correlation @ M1-2004-Tz

Fig. A2.7-8 Correlation @ M1-2004-Hs

Fig. A2.7-9 Correlation @ M1-2004–Power Flux

Fig. A2-7.10 Correlation @ M3-2002-Tz

Fig. A2.7-11 Correlation @ M3-2002-Hs

Fig. A2.7-12 Correlation @ M3-2002-Power Flux

Fig. A2-7.13 Correlation @ M3-2003-Tz

Fig. A2.7-14 Correlation @ M3-2003-Hs

Fig. A2.7-15 Correlation @ M3-2003-Power Flux

Fig. A2.7-16 Correlation @ M3-2004-Tz

Fig. A2.7-17 Correlation @ M3-2004-Hz

Fig. A2.7-18 Correlation @ M3-2004-Power Flux

Fig. A2.7-19 Correlation @ FS1-2003-Tz

Fig. A2.7-20 Correlation @ FS1-2003-Hs

Fig. A2.7-21 Correlation @ FS1-2003-Power Flux

Fig. A2.7-22 Correlation @ FS1-2004-Tz

Fig. A2.7-23 Correlation @ FS1-2004-Hs

Fig. A2.7-24 Correlation @ FS1-2004-Power Flux

Fig. A2.7-25 Correlation @ M2-2002-Tz

Fig. A2.7-26 Correlation @ M2-2002-Hs

Fig. A2.7-27 Correlation @ M2-2002-Power Flux

Fig. A2.7-28 Correlation @ M2-2003-Tz

Fig. A2.7-29 Correlation @ M2-2003-Hs

Fig. A2.7-30 Correlation @ M2-2003-Power Flux

Fig. A2.7-31 Correlation @ M2-2004-Tz

Fig. A2.7-32 Correlation @ M2-2004-Hs

Fig. A2.7-33 Correlation @ M2-2004-Power Flux

Fig. A2.7-34 Correlation @ M4-2003-Tz

Fig. A2.7-35 Correlation @ M4-2003-Hs

Fig. A2.7-36 Correlation @ M4-2003-Power Flux

Fig. A2.7-37 Correlation @ M4-2004-Tz

Fig. A2.7-38 Correlation @ M4-2004-Hs

Fig. A2.7-29 Correlation @ M4-2004-Power Flux

Appendix 3

Wave Energy Resource Ranking Framework

1. Introduction

The selection and application of a recommended renewable resource ranking framework has been developed in Ref. (2) and adopted by Sustainable Energy Ireland. It forms an easily understood generalised terminology with wide application across energy markets, of which wave energy forms apart. This can be summarised in the ranked resource hierarchy shown in Fig. 2 (Main Report) with definitions as below.

2. Unified Terminology

2.1 Theoretical Total Resource

The gross energy content of the particular form of renewable energy that occurs within a given space over a time thereby having the potential to displace fossil energy. (Relatively invariant over long term, annual, seasonal variation occurs).

The term “Theoretical” is used in preference to “Total” or “Gross” to suggest that this unconstrained resource is only academically available. A distinction has to be made between a naturally occurring resource and one that is a by-product of some other process.

2.2 Constrained Resources

2.2.1 Technical Resource (Subset of Theoretical Resource)

Theoretical resource as above, constrained by the efficiency of the currently available technology to respectively extract renewable energy from the resource or inject it to an electricity or heat using system over a given time thereby displacing fossil energy. (Slowly variable over time as technology improves).

2.2.2 Practicable Resource (Subset of Technical Resource)

Technical resource as above, constrained by practical physical or other incompatibilities e.g. where resource capture or injection systems simply cannot meaningfully be located due to physical interference or other practical reason e.g. crops do not grow on roads, floating wave converters cannot operate on mud flats etc. (slowly variable over time).

For strategic planning purposes the “Practicable” resource and those below it are of most interest. This permits issues of accessibility and commercial viability to be considered.

2.2.3 Accessible Resource (Subset of Practicable Resource)

Practicable Resource as above but constrained by manmade, institutional/regulatory deletions that limit energy extraction e.g. environmental, health and safety, energy policy, planning zonation, by-product management criteria etc. In general all of the accessible resource may not be commercially viable because of the high cost of development. (variable over time depending on other pressures and constraints).

For the purposes of this study it is proposed to utilise these definitions extending to the accessible resource to ensure harmony of terminology among decision makers and interested parties in the wider Irish energy field.

This will also permit later assessment of the viable managed and open market resources depending on such pricing structures as may be available from time to time for ocean energy, in particular wave energy.

At the next level it is recognised that two levels of commercial viability can occur. In the managed or supported energy market it is recognised that certain projects can be made viable as an instrument of public policy having regard to wider economic benefits for the community as a whole. Thus supported market viability can exist. The price range will lie between that for best new entrant and an upper limit set at a public policy limit that will achieve the immediate public objective.

The second level of viability, which is a subset of the above, is the free or open unsupported market viability where the project is inherently viable without support. (See Fig. 2). In the electricity market it can be considered as the resource whose generation technologies allow the unit price of power production to fall below that of the Best New Entrant as published by the Commission for Energy Regulation.

(The managed market is by definition a distorted one. It arises primarily because of the commercial inability of a particular renewable source to contribute a politically desirable proportion of its accessible resource under the open market conditions prevailing at the particular time. It therefore needs intervention or "market management" to create the conditions under which it can contribute. This may arise for a number of reasons e.g. the resource may be inherently diffuse, difficult or expensive to develop, the currently available conversion processes may be relatively inefficient etc. Thus the boundary between the open market (which is rarely completely open) and the managed market is not necessarily a rigid one over time. It is quite possible for a resource that was once viable on the open market to encounter difficulties in supply, rising costs (e.g. environmental costs) or other circumstances that would force movement into the managed market if it is to remain viable. This might be necessary if there was a considerable capital investment or employment tied up in existing generating plant or infrastructure associated with the particular resource or if it was considered to be strategically necessary for a particular period of time).

The public policy limit price has to be set having regard to the resource cost curves for the particular technology and the sustainability of paying above the Best New Entrant Price to achieve a public objective of supporting a particular resource on a particular scale for a particular period. It has the objective of bringing that resource into the portfolio at an ultimately lower unit price when a developmental phase has been completed. It may also have the objective of tapping a resource because it is available even if the price has to be higher than BNE indefinitely.

3. Conclusion

The resource definitions proposed above can be used for both electricity and heat markets in the context of this and associated reports where resource ranking frameworks for renewable energy resources are required.

Appendix 4

Estimation of Power Level along 20m Bathymetric Contour

1. Introduction

The objective is to create a series of points along the 20m bathymetric line adjoining the coast where mean power levels may be estimated. Taken with the power levels at the offshore grid points these will permit contouring of the theoretical power resource distribution across the gap between the 20m depth and the offshore grid points. This is necessary because in the most extreme cases e.g. off North Mayo and West Cork there is otherwise a gap exceeding 20km between the 20m depth and the nearest offshore grid point due to the mismatch between the orthogonal latitude/longitude grid and the coastal orientation. The method is that of Ref. (20) (EM1110-2-1100 (Part II) Page 11-3-13) which has been arranged for spread sheet analysis.

2. General Methodology

2.1 Inshore Points

The points numbered 1-134 are established around the coast where lines of latitude and longitude intersect the 20m depth contour, thus their coordinates of latitude and longitude are easily determined.

Each point is assessed against twelve 30^{o} segments of the compass within which it is assumed ocean swell may approach. Directions from which the approach would be significantly obstructed by sheltering land forms, shallows etc. are subsequently ignored. The relevant swell approach directions are from 360, 030, 060, 090, 120, 150, 180, 210, 240, 270, 300, 330 deg., several of which will be feasible for any one point. These data are fixed for the respective points throughout the analysis.

2.2.1 Offshore Grid Points

The relevant 113 offshore reference points are those grid points that are adjacent to the above points and for which significant offshore wave height (Hso) period (Tz), depth (do) and swell direction in addition to their latitude and longitude are available as input. It is assumed that these source points feed the wave regime in towards their corresponding inshore points on the 20m line. Auxiliary points are provided where the nearest offshore grid points might be unsuitable or unrepresentative.

Thus there is an association between each inshore point and one or at most two offshore grid points for each swell directional vector. Where the swell leaving a grid point travels directly to the inshore point along one of the swell directional vectors listed above only that offshore reference point will be involved (e.g. where swell travels eastwards along 270^o line to arrive at an inshore point facing westward).

Where the vector passes between two offshore reference points en route to the inshore receptor point, the weighted means of the Hso, and Tz values from these offshore grid points are used. (In the analysis it is assumed that there is little or no change in Tz as the waves approach the shoreline so that separate Tzo and Tzi values do not arise). The inputs in each case are

- Significant Wave Height Hso at offshore grid point
- Zero crossing period Tz at offshore grid point (and at 20m contour)
- Swell Direction at or between offshore grid points, defined by resultant vectors given as Whole Circle Bearing (WCB) at grid point
- Depth do at one relevant offshore grid point.

2.3 Seabed Contours

The seabed contours run broadly parallel to the coast but deviate locally in numerous areas. It is assumed that a fixed set of receptor angles can be measured between the normal to these contours and the respective travel vectors leading to each inshore point. θo is the initial angle between swell crests and contours or more specifically between normals to swell crests S (resultant vectors above) and normal to contour at offshore grid point also given as WCB. θo = (WCB vector – WCB normal to contour). These are utilised in estimating the power losses due to refraction. Power losses are assumed to occur due to the influence of both shoaling and refraction on significant wave height as the waves approach the 20m contour. The shoaling and refraction coefficients Ks and Kr can be combined as a single coefficient to reduce offshore significant wave height (Hso) to inshore significant wave height (Hsi) and are a function of Tz and reception angle θo. Knowing Hsi and Tz, power flux can be calculated.

2.4 Directionality

Given that the swell may approach from different directions over time, the distribution of approaching swell over the set of feasible directional vectors listed above must also be considered. It may be that over a given season or other time period very little swell coincides with most of these vectors and little energy arrives at the inshore receptor point. (In an initial calculation the monthly distributions of directionality were computed for eight key reference grid points around the coast and it was assumed that identical directionalities could be applied to sub sets of grid points each associated with one of these key points. This was found to be insufficiently sensitive to deal with the variation in directionality that could occur simultaneously even at adjacent grid points.) Clearly the ability to compute the individual directionalities along the perimeter of relevant offshore grid points would improve estimation of the incidence of swell at the corresponding inshore points and this approach was adopted.

The method used for estimating loss of head between the offshore grid points and the inshore reference points on the 20m contour is of necessity an approximation based on the approach used for computing the coefficients of refraction and shoaling as per the Coast Protection Manual. This permits the reception angles between seabed contours and the fixed sector centrelines to be determined once for each reference point around the coast (Appendix 7). There are no positive or negative directions associated with these angles, it is only the magnitude of the angle that matters.

However the method assumes that the offshore swell directionality will fall into one of the sectors for which the reception angle has been predetermined. This is not always the case as the distribution of directionality at the inshore grid points can be sufficiently erratic to give simultaneous values from adjoining grid points that fall in different sectors. This can cause difficulties where the method attempts to make calculations based on a directionality that is outside its appropriate sector e.g. if direction 090 occurs at a grid point within sector (180 ± 15) it is not recognised as contributing to the wave flux in that sector and reports a zero value for Hsi there. This can lead to an understatement of the number of occurrences of Hsi and a (small) reduction in the reported mean power and energy levels reported at the 20m contour and leads to a somewhat conservative result.

Flow Chart Detailing Management

Of Directionality at Offshore Grid Points

1. Check and correct values to ensure consistent whole circle bearing angle between directions at offshore grid points A and B (Dir. A, Dir. B respectively)

2. When Z = | Dir. A – Dir. B | is small, check and correct to ensure consistent scaled directionality at source point between Points A, B relative to the north line (360^o).

3. When Z > 30, check and correct where, for rapid storm swings or other reason, Z exceeds sector size and precludes use of specific sector to identify multipliers Mult A, Mult B to estimate S. Replace S = with mean of six values at A and B to obtain single mean value and corresponding sector.

4. Check and correct for case where Z, even if small, straddles two sector edges, again precluding use of specific multipliers to estimate S. Again next step is to estimate S = mean of six values at relevant grid points to obtain single representative mean value.

5. Where using S = mean of six values as in steps 3, 4 above, check whether S as obtained falls into an illogical non matching sector and returns a value of Hsi = 0. If so, correct by transferring to the sector indicated by the value of Dir. A (or mean of Dir. A and Dir. B) provided that this sector adjoins the original sector that gave rise to Hsi = 0. Recalculate Hsi using reception angle etc. appropriate to new sector. This reduces incidence of unrepresentative zero values for Hsi.

2.5 Energy and Power

The energy produced (in kWh) for each time period hour, day, month, season, year is summed and output. This can be divided by the number of hours in that period to yield the average theoretical power flux for the period. This will be used in conjunction with the values calculated for each point on the overall offshore grid to allow G.I.S. contours to be drawn.

2.6 Definition of Variables

do	=	Depth at Offshore Point
Tz	=	Wave Period at Offshore (and inshore) point
Lo	=	Wave length at offshore point
g	=	Acceleration of gravity
Lo	=	$gT^2_z/2\Pi$
do/Lo	=	Depth/wave length ratio [determines formulae for later use]
Li	=	Wave length at inshore point
L^1i	=	A first approximation to Li
di	=	Depth of Inshore point (= 20m)
Ci	=	Inshore Wave celerity
Co	=	Offshore Wave celerity
Cgi	=	Inshore Group velocity
Cgo	=	Offshore Group velocity = 0.78Tz
θo	=	Reception Angle Offshore
θ1	=	Reception angle inshore
Ks	=	Shoaling Coefficient
	=	$(Cgo/Cgi)^{0.5}$
	=	$(0.78Tz/Cgi)^{0.5}$
Kr	=	Refraction Coefficient = $[(1-\mathrm{Sin}^2\theta o)/(1-\mathrm{Sin}^2\theta i)]^{0.25}$
	=	

$$\left[\left(1-\mathrm{Sin}^2 q_o\right)/1-\left(\frac{\mathrm{Ci\,Sin}qo}{\mathrm{Co}}\right)^2\right]^{0.25} = \left[\left(1-\mathrm{Sin}^2 q_o\right)/1-\left(\frac{\mathrm{LiSin}qo}{1.561\mathrm{T}_z^2}\right)^2\right]$$

thus eliminating Sin θi.

Hso = Significant Wave Height Offshore

Hsi = Significant Wave Height Inshore

Hsi = Hso Kr Ks

Power Flux Inshore = 0.55 H^2si Tz

Additional variables used in spreadsheet

A = General identifier for an initial offshore WAM grid point

B = General identifier for a second offshore WAM grid point

P = General identifier for a point on 20m bathymetric contour

(A and B are used as sources of wave conditions at P)

Mult A = Weighting Multiplier in deriving Hs calc. T_z calc. from HsA, TzA

Mult B = Weighting Multiplier in deriving Hs calc. Tz calc. from HsB, TzB

Dir. A = Swell direction X reported at point A (from WAM)

Dir. B = Swell direction Y reported at point B (from WAM)

Z = Angular difference between Dir. A and Dir. B

S = Averaged directionality of swell at source point between A and B from which it is deemed to travel toward P. (The reception angle θo is the angular difference between S and the measured normal to the sea bed contour where S occurs).

S^1 = Version of S = Mean of Dir. A + Dir. B (see 2.7.3.5)

HsA = Significant wave height at Point A (from WAM)

HsB = Significant wave height at Point B (from WAM)

Hs calc = Significant wave height derived from HsA, HsB for source point between A and B

TzA = Mean zero crossing wave period at point A (from WAM)

TzB = Mean zero crossing wave period at point B (from WAM)

Tz calc. = Mean zero crossing period derived from TzA, TzB for source point between A and B

(Note that all angles are whole circle bearings 0-360^o)

2.7 Detailed Steps

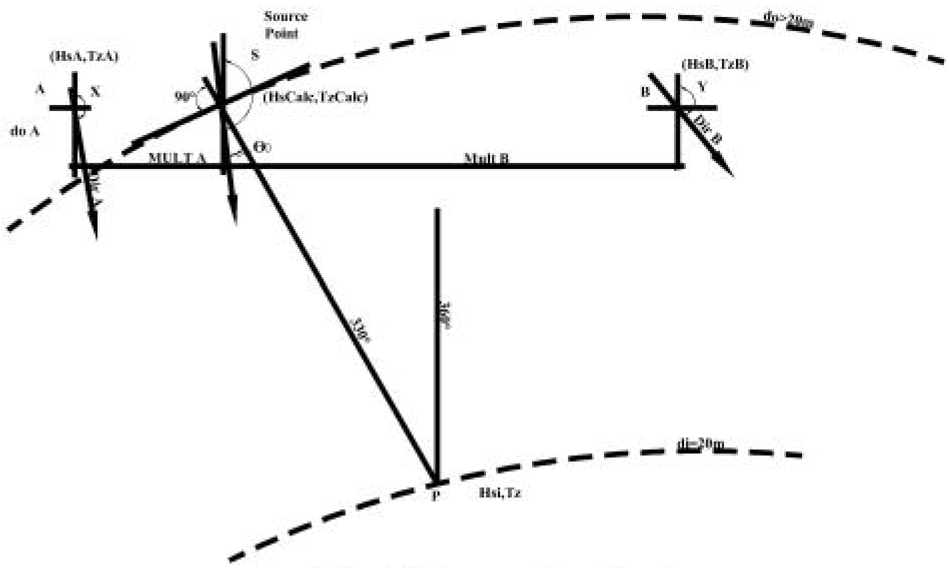
2.7.1 Define database of 113 No. relevant offshore grid points that form the origin of the waves approaching the 20m contour in terms of:

Point No., Latitude, Longitude, depth [Fixed], Hso, Tz, Directionality [Variable] for each point.

2.7.2 Define database of 134 No. inshore points on 20m depth contour identifying:

Point No., Latitude, Longitude, depth = 20m, Feasible approach directions (1 to 12), corresponding reception angles, Offshore source points, Weighting factors for Hso and Tz at source points. [Fixed], Computed Hsi, Tz, Power Flux, Energy, Mean Power for Period (Variable).

2.7.3 Averaging differing directionalities between adjacent grid points to produce a composite swell bearing Angle S.



Schematic Diagram of Transition Zone
Fig. A4.1

2.7.3.1 Consider a reference point P on the 20m depth contour as shown in the schematic diagram. The following assumptions are made:

- The wave climate at P is influenced by the swell and wave conditions pertaining between the offshore grid points A and B.
- For a given hour when the swell has a mean direction that falls within a particular sector centred on P (say that whose centre line is shown at 330°) then waves between A and B will approach P along this sector centre line.
- Conditions at the source point where this sector centre line intersects the line joining A and B can be represented by weighed means of conditions prevailing at A and B.

- These means are in terms of Hs and Tz at the source point computed as

  Hs calc = a_1 Hsa + b_1 Hsb

  Tz calc = a_1 Tza + b_1 Tzb

- In terms of directionality the case is somewhat more complex and is discussed below.

2.7.3.2 The location of the source point between A and B is given in terms of Hs and Tz by the weighting factors Mult A, Mult B (Cols. 20, 21) as shown in the diagram these are the distances between the source point and points B and A respectively. (Mult A is the multiplier that reflects the influence of the Hz, Ts values at Point A relative to those at Point B. The closer the source point is to point A, the larger is the value of Mult A and the smaller is that of Mult B. These terms can also be used to apportion the angular difference Z between A and B but are applied in a reverse way to that used above for apportioning Hs and Tz.

Normally there is a little difference in the simultaneous swell directions reported for adjacent grid points. The difference is found by subtraction and simple linear apportioning between the grid points, dependent on where the source point is located.

In the spreadsheet X and Y are tabulated as Dir A and Dir B respectively and, assuming Y < X, for directionality at source point we get:

$$S = \text{Dir B} + \left| \text{Dir A} - \text{Dir B} \right| \text{Mult A}$$

this may be generalised as "If X > Y, S = Y + Z Mult A; If Y > X, S = X + Z Mult B"

A difficulty arises where the directionalities lie on either side of the North bearing where the apparent difference may be excessively large and the following steps become necessary in developing the S values of column 24.

"Let X and Y be the simultaneous directionalities at grid points A and B (Cols. 13 and 17).

Their difference Z = $|(X\text{-}Y)|$

Test if Z > 180?

If not, insert Z in Col. 19

If yes, insert Z = (360-Z) in Col. 19".

A second issue that can arise is the need to check S to ensure that it lies on the correct side of 360^o.

Given: Difference between directionalities X, Y at A, B = Z (Col. 19)

1. Test: If X > Y?
2. If not, go to 10

3. If yes, then Mean Swell Angle S = Y + (Z) Mult A
4. Test: Is 270 < X < 360?
5. If not, go to 10
6. If yes, test: is S > 360?
7. If not, continue
8. Insert S in Col. 24
9. If yes, replace S by (S – 360) in Col. 24
10. Mean Swell Angle S = X + (Z) Mult B
11. Test: Is 270 < Y < 360?
12. If not, go to 16
13. If yes, test: is S > 360?
14. If not, Insert S in Col. 24
15. If yes, continue
16. Replace S by (S – 360) in Col. 24.
17. End.

2.7.3.2 A third issue that can arise during non storm conditions is that directionality at A or B may be strongly influenced by local conditions such that Dir A or Dir B may be simultaneously more than 30^o apart (i.e. $Z > 30^o$). Since the sectors in the diagram subtend angles of 30^o only it is no longer possible to obtain a single pair of values for Mult A and Mult B as these fall simultaneously into different sectors. It is necessary to obtain a single short term mean value for S that will fall within one sector.

The approach adopted was to take S as being equal to the mean of six values viz. the directionalities at A and B for the preceeding hour, the present hour and the following hour (this is available since one is dealing with past records not real time) summed and divided by 6.

This results in S falling within a particular sector (of Col. 1 in the spreadsheet) and the values of Mult A (and Mult B if present) for this sector are utilised as later described. The value of S obtained via this approximation is inserted in the spreadsheet (Co. 22) instead of the method detailed in 2.7.3.2 above.

Example: If $Z \geq 30^o$

$S = ((Dir A + Dir B) @ t\text{-}1, + (Dir A + Dir B) @ t + (Dir A + Dir B) @ t + 1)) \div 6$

Consider the case of Point 127 on 7-11-2001:

Time	11.00	12.00	13.00
Dir A^o	284	250	308
Dir B^o	304	286	306
Diff Z^o	20	36	2

(At 12.00, Z > 30)

$S = (284 + 304 + 250 + 286 + 308 + 306) \div 6 = 289.6^o$ which implies sector 300^o (300 ± 15) which would have encompassed four of the six directional values.

Again even where $Z < 30^o$ but points A and B occur in two different sectors it is necessary to combine their directional values to determine which sector should be chosen for application of Mult A and Mult B. This is done in the same way by averaging the A and B values over three hourly records. The sector chosen must still of course be a valid one i.e. not sheltered by landmass or islands.

2.7.3.4 During storm conditions Dir A and Dir B display rapid swings and may simultaneously be quite different. Again in this case the movement is damped down by averaging via the three hour moving average at both A and B to give a mean S as described in 2.7.3.3.

Depending on the value of S, the relevant approach sector and bearing of its centre line can be identified.

2.7.3.5 A problem arises where the directionality occurring at a grid point within a sector is actually appropriate to a different sector. Where S has been determined by the averaging process it is almost inevitable that some of the values on which it is based will be appropriate to sectors other than that indicated by the final mean value of S. Frequently S has a borderline value between two sectors which is a consequence of the necessarily arbitrary framework chosen. Normally the resulting mismatch would lead to rejection of the first sector/grid point combination as being non viable and no output for estimation of Hscalc, Tzcalc would derive from there.

If, however, there is no other valid sector/grid point combination for the given hours it could result in the unrealistic return of zero values for Hsi at these times. This would distort the overall statistics of mean Hsi and consequently of mean power flux and energy.

To counter this the following is arranged where S has been derived by averaging over six values:

(1) Test: does available input result in Hsi = 0?

(2) If not, go to (7)

(3) If yes, test:

Do both Dir. A and Dir. B (if present) used in estimating Hs calc, lie within sector containing ‘S’?

(4) If not, replace that sector by sector containing Dir. A (or mean of Dir. A + Dir. B if latter is present).

(5) Test: Is new sector = (Old Sector $\pm 30^o$)

(6) If not: go to (9)

(7) If yes: Continue

(8) Recalculate Hs calc, Tz calc and S’ = (Mean of Dir. A + Dir. B) using new reception angle and other factors from new sector to give new Hsi > 0.

(9) Continue.

2.7.3.6 The offshore swell reception angle θ^o is the difference between the normal to the sea bed contour at the source point and the direction of swell travel (S) there. This is predetermined by measurement for all valid sector centre lines as tabulated in column (7) and as the swell is deemed to travel along the centre line of the active sector it is then known for the swell. It can be inserted in the appropriate equations below to determine KrKs, depending on offshore depth.

Once KrKs has been determined Hsi at the inshore reference points can be estimated from (KrKs Hs calc).

Tz calc is assumed to apply at the inshore reference point as well as at the source point, thus the power flux at the inshore point can be readily estimated from the formula 0.55 Hs^2i Tz calc kW/m.

2.7.3.7 The frequency of occurrence of swell bearing angles are grouped into the respective valid 30^o sectors appropriate to the particular inshore point on the 20m contour. Each is deemed to have an offshore reception angle θo equal to the reception angle tabulated (in Col. 7) between the sector centre line and the contour direction identified as being applicable for that reference point and direction.

The swell bearing angle S is allocated to the appropriate sector via its size and a ‘1’ is recorded in Col. 25 for this sector.

2.7.4 Depth Category

The water depth do at the Offshore grid point is checked for category by computation of do/Lo where Lo is the offshore wave length (usually Lo = $gTz^2/2\Pi$). The category determines the appropriate formulae to be used, as shown in Table A4.1 below.

Category: do/Lo > 0.04 1. (Shallow Conditions)	do/Lo = 0.04 – 0.5 2. (Transitional Conditions)	do/Lo > 0.5 4. (Deep Conditions)
4.1 Wave Celerity $Ci = Li/T_z = \sqrt{gdi}$	$Ci = Li/T_z = \dfrac{gT_z}{2\Pi} \tanh\left(\dfrac{2\Pi di}{Li}\right)$	$Co = Lo/T_z = \dfrac{gT_z}{2\Pi}$ $= 1.56Tz$
4.2 Inshore Wave Length $Li = T_z\sqrt{gdi} = CT_z$	$Li = \dfrac{gT_z^2}{2\Pi} \tanh\left(\dfrac{2\Pi di}{Li}\right)$	$Lo = \dfrac{gT_z^2}{2\Pi} = Co\,T_z$
4.3 Group Velocity $Cgi = C = \sqrt{gdi}$	$Cgi = nC =$ $0.5\left[1 + (4\Pi di/Li)/(\mathrm{Sinh}(4\Pi\, di/Li)\right]C$	$Cgo = 0.5Co = \dfrac{gT_z}{4\Pi}$

Appropriate Formulae for Input to Estimation of KrKs

Table A4.1

From above: Deepwater Wave Length Lo = $1.561T^2_z$ =

Inshore Wave Length:

$$Li = \frac{gT_z^2}{2\Pi}\tanh\left(\frac{2\Pi di}{Li}\right) \approx \frac{gT_z^2}{2\Pi}\sqrt{\mathrm{Tanh}\left(\frac{4\Pi^2 di}{T_z^2 g}\right)}$$

Use second expression for L^1_i for first approximation to Li and resubstitute for Li

2.7.5 Compute (Kr Ks) using steps below

2.7.5.1 Shoaling Coefficient

$Ks = (Cgo/Cgi)^{0.5}$

Cgo = Offshore group velocity = 0.5 Co = (0.5) (1.561T_z)

= 0.78 T_z

Cgi = Inshore group velocity = nC

$$= (0.5)\,[1 + (4\Pi di/Li)/\mathrm{Sinh}\,(4\Pi di/Li)]\,\left[\frac{gT_z}{2\Pi}\tanh(2\Pi di/Li)\right]$$

$Ks = (0.78\ Tz/Cgi)^{0.5}$ = $\boxed{}$

2.7.5.2 Refraction Coefficient:

$$Kr = \frac{[(1 - \mathrm{Sin}^2\theta o)]^{0.25}}{[(1 - \mathrm{Sin}^2\theta i)]^{0.25}} \qquad \text{where } \mathrm{Sin}\ \theta i = \frac{Ci\ \mathrm{Sin}\ \theta o}{Co} = \frac{(Li/Tz)\ \mathrm{Sin}\ \theta o}{1.561Tz}$$

substituting for $\mathrm{Sin}^2\ \theta i$

$$\frac{[Li\ \mathrm{Sin}\ \theta o]^2}{[1.561\ T^2z]^2} = \mathrm{Sin}^2\ \theta i \qquad Kr = \boxed{}$$

$Hsi = Hso\ (Kr)\ (Ks)$ = $\boxed{}$

2.7.6 Compute Hsi and hence inshore power flux

Inshore Power Flux = $0.55Hsi^2\ Tz$

2.7.7 Sum these energy values to give theoretical energy for period selected.

2.7.8 Output: Mean theoretical power at reference point, summed energy at reference point by hour, day, week, month, year as selected.

Note:
Suffix o, i denote offshore, inshore respectively; $T = T_z$ throughout.

3. Explanation of Inshore Power Computation Spreadsheet

The above steps may be conveniently arranged via the attached spreadsheet which is explained in detail below. The individual columns are numbered 1-32 from the left.

Column 1

Identifier for receptor points 1-134 on 20m contour. (Points P)

Column 2, 3

Latitude and Longitude (Northing and Westing) of each identified receptor point, West longitudes are prefixed (-) to denote that they lie (-East) i.e. West of Greenwich.

Column 4

di = inshore depth of interest = constant 20m

Column 5

Sectors 0-330 = List of twelve @ 30 degree sectors centered on the receptor point giving augular compass directions along which wave flux <u>could</u> approach receptor points.

Column 6

Approach feasbility of a given sector at particular site is affirmed by a "1" or is otherwise rejected. The only valid sectors are those where the receptor is open to the sea without hindrance of islands, shallows, headlands or landmass.

Column 7

The reception angle (in degrees) is that made by the line of the incoming sector centre line (being normal to the swell in that sector) with the normal to the sea bed contours, which are plotted as 20m, 50m, 100m depth contours. The reception angles are estimated and tabulated as constants for each receptor point. (The angle (θo) is utilised in the calculations for Kr the refraction coefficient). The simple method breaks down when the angle exceeds about 80^o (i.e. incoming swell is becoming almost parallel with seabed contours) so this is used as an upper limit.

Column 8, 9

Give the latitude and longitude of an offshore grid point A whose Hs and Tz (given in cols. 11, 12) will be used either alone or in conjunction with a second grid point B (lat and long in Cols. 14, 15) to estimate the value of Hsi (Col. 26) at the receptor point of interest.

Column 10

Gives the offshore depth do A (m) at the representative offshore point A to allow determination of the ratio do/Lo and hence calculation category (2.7 above) to be followed in estimating KrKs, the refraction and shoaling coefficients, (col. 25).

Columns 11, 12, 13

Contain Hs, Tz and swell direction Dir. A reported for point A.

Column 14, 15, 16, 17

Contain the latitude, longitude and Hs and Tz at the second offshore grid point B, if more than one offshore point is necessary to provide an indication of Hs and Tz at the inshore receptor point.

Column 18

Contains swell direction Dir. B reported for point B.

Column 19

Contains difference between swell directions Dir. A and Dir. B at A and B respectively.

Column 20

Where a single grid point A is sufficient due to proximity or direction, column 20 contains the multiplier “1” by which Hs A and Tz A (Cols. 11, 12) are multiplied to yield cols. 22, 23 Hs (calculated) and Tz (calculated) which are simply Hs A and Tz B, the offshore significant wave height and period used as the starting point for calculating Hsi (inshore).

Column 21, 22, 23

If the inshore Hsi is to be derived from both offshore points A and B then Mult A and Mult B (20, 21) contain a pair of factors (totalling unity) that allow the weighted means of Hs A and Hs B, Tz A and Tz B respectively to be obtained when they are multiplied and added e.g.

(Col. 11 x Col. 20 + Col. 16 x Col. 21) = Col. 22, Hs calc.

(Col. 12 x Col. 20 + Col. 17 x Col. 21) = Col. 23, Tz calc.

Multiplying Col. 22 by Col. 26 yields Col. 27 (Hsi) while Col. 23 is kept unchanged.

Column 23

Actual or weighted mean of Tz at offshore grid points. (Tz calc)

Column 24

Actual or weighted mean of swell bearing angle (S) at offshore grid source points.

Column 25

Identification of active sector for this hour for counting and calculation of KrKs.

Column 26

Shoaling and refraction coefficients Ks Kr calculated as per formulae provided. (2.7 above)

Column 27

Hsi or inshore significant wave height (at 20m depth) which is product of cols. 22 and 26 i.e. (Kr Ks) (Hs. Calc.)

Column 28

Power Flux kW/m = 0.55 Hsi^2 Tz Calc. This is the theoretical hydrodynamic power flux kW/m derived from each of the valid sectors of Cols. 5 and 6 at the receptor point for that hour.

Column 29

The figures of Col. 28 are summed in blocks of 24 to give daily theoretical energy subtotal (kWh) at inshore point.

Column 30

The figures in Col. 29 are summed in blocks of seven to give weekly theoretical energy subtotals (kWh) at inshore point.

Column 31

The figures of Col. 29 are summed in calendar blocks to give monthly theoretical energy subtotals (kWh) at inshore point.

Column 32

The figures of Col. 31 are summed to give annual theoretical energy totals at inshore point ÷ 1000 (MWh).

The output from this process is a set of power/energy values at 134 inshore points that form an inner edge along the 20m contour to allow plotting of the power/energy distribution across the offshore grid points for the same period.

Note:
The above spreadsheet layout has been given as a general approach. Where the databases containing the original wave records utilise particular macro software developed in Visual Basic for EXCEL or ACCESS or other language it is convenient to use the same for the above spread sheet. In other cases particular software may be used for application of the internal tests and calculations specified in 2.7.3 – 2.7.8 above.

Appendix 5

Evaluation of Reception Angles between Incoming Swell and Normals to Offshore Contours

A5.1 Introduction

The following explanation and tables refer to evaluation of the reception angles between the incoming swell and the normals to bed contours between the wave source points and respective 30^o sectors centred on the 134 reference points selected on the 20m bathymetric contour around the Irish Coast. These angles are used as input in estimating the loss of significant wave height that occurs between the offshore source point and the 20m contour. Power levels along this contour form inshore boundary values to the offshore power and energy distributions.

A5.2 Conventions Used

A5.2.1 Seabed Contours

The direction along the seabed contours (or 'strike' of the bed in geological terms) which are assumed to be basically parallel, have been estimated for a set of sector lines radiating from each of 134 sites on the 20m bathymetric line around the coast. The bearing of the tangent to the 50m contour has been measured as being representative of conditions near the inner edge of the offshore grid points that can be considered as the source of swell arriving inshore. A typical contour might have a whole circle orientation of 090-270^o i.e. east-west. This may be referred to as having a bearing of 090^o or 270^o. For brevity only one bearing is typically used but the other is always implied.

A5.2.2 Normals to Contours

These are lines projecting in the seaward direction at 90^o to the above contours and may assume any bearing angle depending on the contortions of the bed contours. On the different coasts this will usually have the following ranges:

Table A5.1

Typically Directionality of Normals to Seabed Contours

Coast	Bearing Range
North	270-090
South	090-270
East	0-180
West	180-360

A5.2.3 The Reception Angle

This is the angle made between the direction of incoming swell(s) and the normal defined above. Although the incoming swell can assume a wide variety of directions and can change enroute from its offshore source point, it is assumed that the frequency of occurrence can be ascribed to one of the 30^o sectors that face seaward. All incoming swells for a given period the direction of whose source lies within a particular sector are in principle, grouped and assigned to that sector.

Thus conceptually for each site calculations need only be made for a number of preset reception angles which depend on the site approach geometry and contour configuration. In reality a number of correction factors require to be incorporated.

The following table A5.2 shows the 12 sectors spaced as columns 0^o – 330^o, with the directionality of the contour, its normal and reception angle where intersected by the sector line, tabulated as rows for each numbered reference point. The difference between the Sector Bearing and the Bearing of the Normal to the contour gives the Reception Angle.

Table A5.2

Swell Reception Angles at 50m Bathymetric Depth — Sheet 1 of 9

Ref. Point	Sector Bearing	0	30	60	90	120	150	180	210	240	270	300	330
1	Contour Normal Recep. Ang.	60 330 30	60 330 60							180 270 30	230 320 50	230 320 20	230 320 10
2	Contour Normal Recep. Ang.									190 280 40	150 240 30		
3	Contour Normal Recep. Ang.								150 240 30	150 240 0	170 260 10		
4	Contour Normal Recep. Ang.							140 230 50	150 240 30	150 240 0			
5	Contour Normal Recep. Ang.								140 230 20	140 230 10			
6	Contour Normal Recep. Ang.								140 230 20	140 230 10			
7	Contour Normal Recep. Ang.										240 330 60	150 240 60	
8	Contour Normal Recep. Ang.					120 210 80	120 210 60	125 215 35	120 210 0	100 270 30			
9	Contour Normal Recep. Ang.						060 150 0	060 150 30	125 215 05	130 220 20			
10	Contour Normal Recep. Ang.								60 150 30	60 150 60	130 220 20		
11	Contour Normal Recep. Ang.									120 210 30	210 330 60		
12	Contour Normal Recep. Ang.					50 160 40	90 180 30	120 210 30	120 210 0	120 210 30			
13	Contour Normal Recep. Ang.						90 180 30	100 190 10	120 210 0	120 210 30			
14	Contour Normal Recep. Ang.				80 170 90	50 140 20	50 140 10	90 180 0	120 210 0	150 240 0	90 180 90		
15	Contour Normal Recep. Ang.					90 180 60	50 140 10	50 140 40	90 180 30	120 210 30			

Ref. Point	Sector Bearing	0	30	60	90	120	150	180	210	240	270	300	330
16	Contour Normal Recep. Ang.						110 200 50	40 140 40	90 180 30	120 210 30			
17	Contour Normal Recep. Ang.				70 160 70	70 160 40	80 170 20	80 170 10	70 160 50				
18	Contour Normal Recep. Ang.					70 160 40	70 160 10	110 180 0	50 140 70	120 210 30			
19	Contour Normal Recep. Ang.				60 150 60	70 160 40	70 160 10	110 200 20	50 140 70				
20	Contour Normal Recep. Ang.					70 160 40	70 160 10	70 160 20	110 200 10	70 160 80			
21	Contour Normal Recep. Ang.					70 160 40	70 160 10	70 160 20	70 160 50				
22	Contour Normal Recep. Ang.				70 160 80	70 160 40	70 160 10	70 160 20					
23	Contour Normal Recep. Ang.				60 150 60	60 150 30	70 140 10	70 140 40					
24	Contour Normal Recep. Ang.				60 150 60	70 160 40	70 160 10	70 160 20	70 160 50				
25	Contour Normal Recep. Ang.				60 150 60	65 155 35	70 160 10	70 160 20	70 160 50				
26	Contour Normal Recep. Ang.				60 150 40	60 150 30	65 155 5	70 160 20	70 160 50				
27	Contour Normal Recep. Ang.				60 150 60	60 150 30	60 150 0	60 150 30	70 160 5				
28	Contour Normal Recep. Ang.				60 150 60	60 150 30	60 150 0	60 150 30	60 150 50				
29	Contour Normal Recep. Ang.				60 150 60	60 150 30	60 150 0	60 150 30	60 150 60				
30	Contour Normal Recep. Ang.				60 150 60	60 150 30	60 150 0	60 150 30	60 150 60				
31	Contour Normal Recep. Ang.			60 150 90	60 150 60	60 150 30	60 150 0	60 150 30	60 150 60				

Ref. Point	Sector Bearing	0	30	60	90	120	150	180	210	240	270	300	330
32	Contour Normal Recep. Ang.				60 150 60	75 165 45	70 160 10	60 150 30					
33	Contour Normal Recep. Ang.				80 170 80	80 170 50	60 150 0	60 150 30					
34	Contour Normal Recep. Ang.					90 180 60	90 180 30	65 155 25	60 150 60				
35	Contour Normal Recep. Ang.					90 180 60	85 175 25	80 170 10	70 160 50				
36	Contour Normal Recep. Ang.					90 180 60	90 180 30	85 175 5	80 170 40				
37	Contour Normal Recep. Ang.					90 180 60	90 180 30	90 180 0	90 180 30	80 170 70			
38	Contour Normal Recep. Ang.					40 130 10	90 180 30	90 180 0	90 180 30	80 170 70			
39	Contour Normal Recep. Ang.						40 130 20	90 180 0	90 180 30	80 170 70			
40	Contour Normal Recep. Ang.				40 130 40	40 130 10	40 130 20	90 180 0	90 180 30	90 180 60			
41	Contour Normal Recep. Ang.				40 130 40	40 130 10	40 130 20	90 180 0	90 180 30				
42	Contour Normal Recep. Ang.						40 130 20	40 130 50	90 180 30				
43	Contour Normal Recep. Ang.				40 130 40	90 180 60	40 130 20	40 130 50	40 130 80	90 180 60			
44	Contour Normal Recep. Ang.		15 105 75	20 110 50	20 110 20	35 125 5	35 125 25	40 130 50	40 130 80				
45	Contour Normal Recep. Ang.		15 105 75	20 110 50	20 110 20	20 110 10	30 120 30	30 120 60					
46	Contour Normal Recep. Ang.		15 105 75	15 105 45	15 105 15	20 110 10	20 110 40	25 115 65					
47	Contour Normal Recep. Ang.			30 120 60	30 120 30	15 105 15	15 105 45	0 90 80					

Ref. Point	Sector Bearing	0	30	60	90	120	150	180	210	240	270	300	330
48	Contour Normal Recep. Ang.		30 120 80	30 120 60	30 120 30	30 120 0	30 120 30	30 120 60					
49	Contour Normal Recep. Ang.			0 90 30	30 120 30	35 120 0	30 120 30	30 120 60					
50	Contour Normal Recep. Ang.			160 90 10	180 90 0	180 90 30	30 120 30	30 120 60					
51	Contour Normal Recep. Ang.	180 90 80	140 70 40	160 70 10	160 70 20	160 70 50							
52	Contour Normal Recep. Ang.	170 80 80	170 80 50	170 80 20	170 80 10								
53	Contour Normal Recep. Ang.	170 80 80	170 80 50	170 80 20	170 80 10	150 60 60	180 90 90						
54	Contour Normal Recep. Ang.		180 90 60	170 80 20	170 80 10	170 80 40	150 60 90						
55	Contour Normal Recep. Ang.		175 85 85	180 90 60	180 90 30	170 80 10	150 60 60						
56	Contour Normal Recep. Ang.		15 105 65	15 105 45	0 90 0	15 105 15	350 80 70						
57	Contour Normal Recep. Ang.			30 120 60	15 105 15	10 100 20	10 100 50						
58	Contour Normal Recep. Ang.			45 135 75	30 120 30	15 105 15	10 100 50	30 120 60					
59	Contour Normal Recep. Ang.				30 120 30	30 120 0	30 120 30	20 120 60					
60	Contour Normal Recep. Ang.			45 135 75	40 130 40	30 120 0							
61	Contour Normal Recep. Ang.					45 135 15	45 135 15	45 135 45					
62	Contour Normal Recep. Ang.			50 140 80	- - -	- - -	45 135 15	45 135 45	45 135 75				
63	Contour Normal Recep. Ang.			45 135 75	40 130 40	30 120 0	40 130 20	45 135 45					

Ref. Point	Sector Bearing	0	30	60	90	120	150	180	210	240	270	300	330
64	Contour Normal Recep. Ang.		170 80 50	170 80 20	30 120 30	30 120 0	30 120 30	30 120 60	60 150 60				
65	Contour Normal Recep. Ang.	150 60 60	170 80 50	170 80 20	170 80 10	170 80 40	170 80 70						
66	Contour Normal Recep. Ang.	150 60 60	170 80 50	170 80 20	20 110 20	30 120 0							
67	Contour Normal Recep. Ang.	130 40 40	150 60 30	150 60 0	150 60 30	150 60 60							
68	Contour Normal Recep. Ang.	120 30 30	120 30 0	150 60 0	130 40 50								
69	Contour Normal Recep. Ang.	150 60 60	120 30 0	120 30 30	150 60 30								
70	Contour Normal Recep. Ang.	145 55 55	145 55 25	150 60 0	150 60 30								
71	Contour Normal Recep. Ang.	150 60 60	150 60 0	145 55 5	0 90 0								
72	Contour Normal Recep. Ang.	150 60 60	150 60 30	150 60 0	150 60 30	150 60 50							
73	Contour Normal Recep. Ang.	150 60 60	150 60 30	150 60 0	150 60 30	150 60 60							
74	Contour Normal Recep. Ang.	150 60 60	150 60 30	150 60 0	150 60 30	150 60 60							
75	Contour Normal Recep. Ang.	120 30 30	120 30 0	150 60 0	150 60 30							270 360 60	
76	Contour Normal Recep. Ang.			120 30 30									240 330 0
77	Contour Normal Recep. Ang.	90 0 0	90 0 30									240 330 30	240 330 0
78	Contour Normal Recep. Ang.	90 0 0	90 0 30	90 0 60								240 330 30	240 330 0
79	Contour Normal Recep. Ang.	90 0 0	90 0 30	120 30 30									

Sheet 6 of 9

Ref. Point	Sector Bearing	0	30	60	90	120	150	180	210	240	270	300	330
80	Contour Normal Recep. Ang.	110 20 20	90 0 30	90 0 60									240 330 0
81	Contour Normal Recep. Ang.	120 30 30	120 30 0	150 60 0								210 300 0	300 30 60
82	Contour Normal Recep. Ang.	90 0 0	120 30 0	150 60 0	120 30 60								300 30 60
83	Contour Normal Recep. Ang.	120 30 30	120 30 0	180 90 30	150 60 60								240 330 0
84	Contour Normal Recep. Ang.	90 0 0	120 30 0	120 30 30	0 90 0								240 330 0
85	Contour Normal Recep. Ang.	60 30 30	60 30 0	120 30 30							240 330 60	240 330 30	240 330 0
86	Contour Normal Recep. Ang.	60 30 30	60 30 0								240 330 60	240 330 30	240 330 0
87	Contour Normal Recep. Ang.	240 330 30	240 330 60								240 330 60	240 330 30	240 330 0
88	Contour Normal Recep. Ang.	60 30 30	60 30 0	60 30 30							270 360 30	240 330 30	240 330 0
89	Contour Normal Recep. Ang.	090 0 0	060 30 60								270 360 90	270 360 60	270 360 30
90	Contour Normal Recep. Ang.	090 0 0	120 30 0	60 30 90							270 360 90	270 360 60	270 360 30
91	Contour Normal Recep. Ang.	090 0 0	90 0 30	60 30 90									270 360 30
92	Contour Normal Recep. Ang.		90 0 30								210 300 30	210 300 0	210 300 30
93	Contour Normal Recep. Ang.	030 60 60								210 300 060	210 300 30	210 300 0	210 300 30
94	Contour Normal Recep. Ang.	030 60 60										210 300 0	210 300 30
95	Contour Normal Recep. Ang.									210 300 60	210 300 30	210 300 0	210 300 30

Ref. Point	Sector Bearing	0	30	60	90	120	150	180	210	240	270	300	330
96	Contour Normal Recep. Ang.									180 270 30	180 270 0	210 300 0	
97	Contour Normal Recep. Ang.										240 330 60	240 330 30	210 300 30
98	Contour Normal Recep. Ang.	60 30 30								225 315 75	225 315 45	225 315 15	225 315 15
99	Contour Normal Recep. Ang.									120 210 30	120 210 60		
100	Contour Normal Recep. Ang.									120 210 30			
101	Contour Normal Recep. Ang.										240 330 60	180 270 30	
102	Contour Normal Recep. Ang.										180 270 0	240 330 30	
103	Contour Normal Recep. Ang.										270 360 90	210 300 0	240 330 0
104	Contour Normal Recep. Ang.											210 300 0	240 330 0
105	Contour Normal Recep. Ang.	90 0 0	30 120 090									210 300 0	270 360 030
106	Contour Normal Recep. Ang.	090 0 0	120 030 0									210 300 0	210 300 030
107	Contour Normal Recep. Ang.	040 50 50	120 30 0										270 360 030
108	Contour Normal Recep. Ang.	90 0 0	90 0 30	90 0 60								270 360 60	270 360 30
109	Contour Normal Recep. Ang.	90 0 0	90 0 30	90 0 60								270 360 60	270 360 30
110	Contour Normal Recep. Ang.	90 0 0	90 0 30	90 0 60								270 360 60	270 360 30
111	Contour Normal Recep. Ang.	90 0 0	90 0 30	90 0 60								270 360 60	270 360 30

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Ref. Point	Sector Bearing	0	30	60	90	120	150	180	210	240	270	300	330
112	Contour Normal Recep. Ang.	90 0 0	90 0 30	90 0 60								210 300 0	210 300 30
113	Contour Normal Recep. Ang.	60 30 30										210 300 0	240 330 0
114	Contour Normal Recep. Ang.	90 0 0	90 0 30	60 30 80							210 300 30	210 300 0	210 300 30
115	Contour Normal Recep. Ang.	30 60 60	30 60 30							210 300 60	210 300 30	210 300 0	210 300 30
116	Contour Normal Recep. Ang.	30 60 60								210 300 60	210 300 30	210 300 0	210 300 30
117	Contour Normal Recep. Ang.	30 60 60							120 210 0	180 270 30	180 270 0	210 300 0	210 300 30
118	Contour Normal Recep. Ang.									180 270 30	180 270 0	180 270 30	210 300 30
119	Contour Normal Recep. Ang.									180 270 30	180 270 0	120 210 80	
120	Contour Normal Recep. Ang.										180 270 0	180 270 30	
121	Contour Normal Recep. Ang.	0 90 80									180 270 0	330 240 60	330 240 80
122	Contour Normal Recep. Ang.								150 240 30	180 270 30	180 270 0	180 270 30	
123	Contour Normal Recep. Ang.						150 240 80	150 240 60	150 240 30	150 240 0	180 270 0	180 270 30	
124	Contour Normal Recep. Ang.								150 240 30	150 240 0	120 210 60		
125	Contour Normal Recep. Ang.							120 210 30	150 240 30	150 240 0	120 210 60	120 210 80	
126	Contour Normal Recep. Ang.									190 280 40	210 300 30	210 300 0	
127	Contour Normal Recep. Ang.									180 270 30	180 270 0	180 270 30	

Ref. Point	Sector Bearing	0	30	60	90	120	150	180	210	240	270	300	330
128	Contour Normal Recep. Ang.										210 300 30	210 300 0	210 300 30
129	Contour Normal Recep. Ang.									240 330 80	240 330 60	240 330 30	240 330 0
130	Contour Normal Recep. Ang.									180 270 30	210 300 60	210 300 30	
131	Contour Normal Recep. Ang.										180 270 30	240 330 60	210 300 30
132	Contour Normal Recep. Ang.	60 30 30									180 270 0	240 330 30	240 330 0
133	Contour Normal Recep. Ang.	60 30 30	60 30 0							240 330 80	240 330 60	240 330 30	240 330 0
134	Contour Normal Recep. Ang.	60 30 30	60 30 0							240 330 80	240 330 60	240 330 30	240 330 0

Appendix 6
Nearshore Ocean Wave Conversion Technology

A6.1 Introduction

This section is limited to devices for which prototypes have been built and tested, or have undergone sufficient laboratory scale tests for there to be sufficient data available to draw conclusions about their likely power output and costs. Many hundreds of device concepts have been proposed but very few have reached the stage of prototype deployment.

Much has been written regarding the expected performance of as yet unbuilt device concepts but until a converter has been tested, at the very least at model scale in the laboratory, published claims regarding its power output must be treated with caution. The following named converter devices are, among others, known to be under development at present.

A6.2 Offshore Oscillating Water Columns (OWCs)

A6.2.1 Introduction

Several offshore OWC device concepts have been put forward, usually consisting of a buoy containing an oscillating water column within it. The combination of higher wave power available further from the shore and the lack of civil engineering involved means that they have a better chance of eventually being able to generate commercially competitive electricity. However, these same factors also mean that survivability is more of an issue, because of the more energetic wave climate, and that cabling to carry the generated power ashore is likely to be more expensive. These devices are currently in an earlier stage of development than are shoreline OWCs. Offshore navigation buoys are routinely powered by OWCs, but these are small, generate only enough power for a light and are used in an application where the cost of power is not an issue.

A6.2.2 Reverse Duct Buoy

An original Japanese concept utilising an oscillating water column has been further developed by a consortium led by a Cork based company Ocean Energy Ltd. It is understood that tank testing to refine the design with a view to development of a pilot project is ongoing.

A6.2.3 Plymouth MOWC

A team at Plymouth University developed a multiple OWC buoy originally called the “Sperboy” under an EU funded programme. It consisted of a set of tubes of different lengths resembling a set of organ pipes that extend to different depths beneath the surface. The rationale behind this was that each tube would have a different resonant frequency enabling the device to extract energy over a wider range of frequencies than would a single OWC. Tests at sea were conducted but the device came away from its moorings twice, the second time leading to irrecoverable damage. Insufficient data were obtained to confidently estimate the power output of the device. The development of this device is currently being taken forward by a Plymouth University spin off company Orecon which hopes to deploy an array of devices off the South West of England. No economic analysis has been published. (Ref. 22)

A6.3 Overtopping devices

A6.3.1 Floating wave power vessel

This device is being promoted by Sea Power International AB of Sweden. A sea test appears to have been conducted but cost and output data do not appear to have been published.

A6.3.2 Wave Dragon

The Wave Dragon is an offshore wave energy converter of the overtopping type. It consists of two wave reflectors focusing the waves towards a ramp, a reservoir for collecting the overtopping water and a number of special low head hydro turbines for converting the pressure head into power. In the period from 1998 to 2001 extensive testing on a scale 1:50 model was carried out. During 2003, testing has started on a prototype of the Wave Dragon in Nissum Bredning, Denmark (wave climate in scale 1:4.5 of the North Sea). The prototype has been grid connected in June 2003 as the world's first offshore wave energy converter. During the coming 2 years an extensive measuring program will establish the background for optimal design of the structure and regulation of the power take off system. Planning for full-scale deployment of a 7 MW unit within the next 2-3 years is in progress. (Ref. 23)

Power output data are in the process of being collected and a projected power output table was provided during the course of this project.

Other Converters

A6.4.1 IPS buoy

The IPS buoy was developed by Inter Project Service AB of Sweden. Instead of using the motion of the water column to drive an air turbine, it drives a piston which in turn drives a generator. The device has been tested in the sea and the developers claim that their device is capable of generating electricity at a price as low as 3.5 €c/kWh. No published test results appear to be available to confirm this. The device does not appear to be undergoing further development and a successor device concept, the AquaBuoy, a combination of the IPS buoy and the hosepump, is now being promoted by AquaEnergy Group Ltd of Washington State USA. More information can be found in Ref. (24).

A6.4.2 Sloping IPS Buoy

A team at Edinburgh University has developed what it calls a "sloped IPS buoy". This is still very much at the research stage and no sea trials have been conducted. More information can be found at Ref. (25).

A6.5.2 Pelamis

The Pelamis is a floating near/off shore device composed of cylinders linked by hinged joints with the whole device spanning successive wave crests. The wave-induced motion of the joints is resisted by hydraulic rams that pump high-pressure oil through hydraulic motors. The device is developed by Ocean Power Delivery Ltd of Edinburgh. It is intended to be moored in 50-60m of water typically 5-10km from the shore. Several devices can be connected together and linked to shore through a seabed cable. The device has undergone a series of model and prototype tests at increasing scale culminating in a 750kw full-scale prototype that has recently finished construction and has been deployed to the Orkney test centre. This prototype is 120m long and 3.5 m in diameter and contains three Power Conversion Modules each rated at 250MW. Each module contains a complete electro-hydraulic power generation system.

Previous to this a $^{1}/_{7}$ scale prototype has been tested and power output and cost estimates have been published based on this. The Pelamis currently appears to be the most developed wave energy device. A report has been published giving a detailed analysis of the performance and economics.

Three converters are under construction for installation in Portugal in 2006 with an option on a further 30 machines.

A6.6 Danish point absorber

The Danish Point Absorber is a floating buoy reacting against the seabed. The buoy is connected to the seabed by a polyester rope. The buoy moves up and down relative to the seabed activating an onboard hydraulic pump. Survival tests were completed in a tank at the Danish Maritime Institute June 1998. Energy production tests completed June 1999. Open sea testing at scale 1:10 was completed January 2000. (Ref. 27)

A6.7 Archimedes wave swing

The Archimedes Wave Swing (AWS) is a submerged piston and cylinder that moves in response to changes in pressure caused by waves at the surface. A prototype device is in the process of being tested off the coast of Portugal. More details can be found in Ref. (28). Results from the tests are not yet available.

A6.8 Wavebob

This converter is being developed by Wavebob Ltd., a Wicklow based company and has been undergoing mathematical analysis and tank testing. Details are commercially confidential at present but it is understood that the project has received funding from a number of industrial and other agencies and that work continues on a specific programme. A projected power output bivariate distribution table was provided during the present project.

A6.9 McCabe Wave Pump

This device is being developed by Hydam Technology Ltd of Killarney, Co Kerry, and is similar in principle to the Pelamis but instead of cylindrical sections it consists of two pontoons connected by hinged joints to a central platform fitted with a submerged damping plate. The pontoons move only in one plane whereas in the Pelamis they move with two degrees of freedom. Tests have been conducted by HMRC in the mouth of the Shannon. Results have not yet been published. The developers are promoting the device mainly for supplying potable water (obtained via reverse osmosis) for isolated island communities, which suggests they do not currently expect it to be able to deliver competitively priced electricity in a developed country

A6.10 Conclusions : Near Shore Wave

(1) Much interest will centre on the performance of at least three wave power converters currently undergoing prototype tests in Orkney, Portugal and United States. A similar number of credible converters are under advanced pre prototype development.

(2) The principal challenge will centre on whether the best of these systems can consistently produce electricity at a rate competitive with offshore wind.

(3) As has been shown elsewhere in this report there is every indication that the Irish wave energy resource is very substantial and that ongoing measurements will confirm this in the longer term. The power levels attainable at selected locations provide extremely favourable regimes for converter trials.

(4) The area is still one of Research, Development and Demonstration but emphasis is now on commercial demonstration.

Appendix 7
Constraints Arising from Other Uses of Sea Areas

A7.1 Introduction

As part of this work a preliminary assessment was made of potential constraints that could possibly arise from other uses of the relevant sea areas.

The absence of a Strategic Environmental Assessment (SEA) carried out under Ref. (2) would appear at first sight to undermine the ability of the Department of Communications, Marine and Natural Resources to issue a Foreshore Licence for significant wave farm development within the 12 mile limit. However an informal view expressed by Department staff is that the Environmental Assessment Process likely to be carried out prior to award of permission for any significant wave farm development would meet the SEA obligations. Legislation is not yet in place to operate a licencing regime for the Irish Economic Zone of the Continental Shelf. Until these issues have been dealt with, wave power development on a large scale would appear to be precluded there. It is however reasonable to argue that prototype or small scale deployment on a temporary basis can be considered as a necessary part of information gathering that would inform a Strategic Environmental Assessment via the collection of representative measurements and other potential input data.

The production of a draft environmental impact statement or similar document is quite outside the scope of this report but the issue of interfacing with others arises in connection with identification of constraints that define the accessible resource. Early identification of other uses of those sea areas likely to be of interest from a wave power perspective should go some way in reducing the potential for later misunderstanding and consequential difficulties.

Liaison with the following bodies has resulted in production of Fig. A8.1 which incorporates key constraints.

- Dept. of Communications, Marine & Natural Resources (Dublin)
- Dept. of Agriculture & Rural Development (Belfast)
- Commissioners of Irish Lights
- Bord Iaschaigh Mara
- The Heritage Service
- Kingfisher Information Services

- Irish Maritime Development Office
- Irish Naval Service

A7.2.1 Fisheries

Fishing data was provided by the two Government Departments listed above and by Bord Iaschaigh Mara. It falls under three headings (1) Navigation channels for fishing boats on passage, (2) Fishing grounds and (3) Fish Farms.

Fishing boats on passage are assumed to have the same requirements as apply to the coastal shipping trade of the mercantile marine. Thus notional navigation channels providing access to key ports have been incorporated as well as anchorages for small craft (and yachts) where indicated on Admiralty and other charts.

Fishing grounds vary with species, season and vessel size. Numerous wreck locations have been incorporated and defined fishing areas are shown as notified. No specific nursery areas where it might be desired to strengthen stocks by excluding active fishing in the future have been notified. Lobster, crab and salmon netting are inshore fishing activities that can extend several km off the coast and require individual attention. The general assumption is made that duly licenced and marked wave farms can in the future coexist with the fishing industry bearing in mind the standards of vessels, equipment and training now being required in the industry.

Based on the information received, fish farms and similar developments (shell fish beds) are located in sheltered bays and shallows generally inside the 20m bathymetric contour. As stated in Table 7.1 a reduction of 50% is made in length of power flux contours where they pass through fishing areas shown on Figs. 27.28.

A7.2.2 Marks and Lights

The Commissioners of Irish Lights is the statutory body with responsibility for the installation operation and maintenance of marine lights, buoys and beacons around the coast of Ireland apart from inshore areas where these services are provided by local harbour authorities or other local authorities. An operating buffer area has been incorporated around all deepwater lighthouse installations and buoys in consultation with the Commissioners staff.

A7.2.4 Heritage Areas

Designated heritage areas include certain stretches of coastline, and adjacent waters, together with near shore rocks and islands. Because of their proximity to the coast few of these are likely to be impacted by wave

power conversion developments, apart from the possible routing of submarine or underground cables to transmit power ashore. Wreck locations however are considered to be of archaeological significance as well as potential fishing sites and are marked for deletion.

A7.2.5 Sea Bed Cables

Sea bed cable and pipeline routes have been incorporated courtesy of Kingfisher Information Services and a 1km corridor width has been preserved along these routes. Transatlantic cables are routed well to the north and south of Ireland while the bulk of the shorter cables transit the low wave power Irish sea area. The corridor width is deducted from the length of each power flux or energy contour crossing the cable or pipeline in estimating the accessible level. (Table 7.1)

A7.2.6 Coastal Shipping

As noted under fishing, indicative navigation channels have been provided into commercial ports and estuaries. It is understood that providing floating converters are properly licenced, marked and show prescribed obstruction lights and are kept out of harbour approaches, commercial shipping requirements will, in general terms, be met.

At particular locations separation corridors as charted have, with some extensions for manoeuvring purposes, been incorporated along the south west, south east and north east coasts. Further offshore the Law of the Sea relating to freedom of Navigation would appear to preclude the construction of a continuous cordon of wave power generators where this would interfere with navigation. An approach corridor 5km wide is provided at main ports and is extended offshore to interact power flux and energy contours. A corresponding deduction is made when estimating accessible level for each contour (Table 7.1)

A7.2.7 Mineral Exploration and Development

The two headings that have been of most significance to date are oil/gas and sand/gravel resources. Prime locations are functions of seabed tertiary and quaternary geology and much geophysical and related mapping data is now available to the Irish Geological Survey. The Kinsale gas deposit is now being depleted while that off Mayo is entering development. Exploitable sand and gravel deposits are mostly associated with the Irish Sea and south coast banks which are not areas of high wave power. These banks form an important offshore wind power resource. Clearly where these location-specific resources exist they should have priority for development where this is economically advantageous. In some cases while exploration designations exist, it is clear that development in the short or medium term is rather unlikely. In any event there is little loss to the overall wave power resource by excluding these areas from consideration.

A7.2.8 Offshore Wind Resource

By definition the offshore wind resource is mostly located in shallow coastal areas within the 20m contour and on offshore banks where this depth is also applicable as an operating limit. To date only a small fraction of the resource has been developed and it may be that some existing exploration licences will be allowed to lapse. The relevant shallow water areas are deleted.

The concept of floating offshore wind farm development has also been under consideration. While in theory this, if successful, could open up areas for exploitation the Atlantic coast practical considerations would suggest that development in quiescent areas close to key electrical consumption areas e.g. South East, East and North East coasts would be more likely.

A7.2.9 Tidal Current Power

The tidal current power resource has been investigated in other reports (29). The most promising conversion technology now under development seeks to combine low capital cost with maximum output by locating cable stayed submerged converters in strong currents. The most significant areas of strong tidal currents around the Irish coast do not coincide with strong wave resources, being located off Northern Ireland (North Channel), Arklow Banks and Shannon Estuary. No specific reduction has been made for areas that might be earmarked for tidal current development in the future.

A7.2.10 Security Considerations

Fulfilment of legal requirements, recognition of the need to avoid hindering service training operations, anti smuggling and fishery patrols, search and rescue operations, the maintenance and functioning of marks, lights and beacons (A8.2.3) means that each installation will be subject to specific licence requirements. For this reason no additional reductions in resource have been made under this heading.

A7.2.11 International Boundaries

All of the areas concerned lie within EU waters and are subject to the International Law of the Sea (UN). For fishery management and protection purposes and for licencing of offshore economic development administrative boundaries have been agreed between Britain and Republic of Ireland. There is however some uncertainty in respect of Northern Ireland for fishery protection. Devolved government in Scotland has led to revision in areas of responsibility between Scotland and Northern Ireland

for fishery protection. It is outside the scope of this report to address these or associated issues other than to note the existence and extent of charted submarine exercise areas within the area for which the wave power resource has been mapped.

A7.2.12 The Electricity Network

The onshore electricity network in the coastal areas is shown on the accompanying maps. A single all Ireland electricity market is in the process of being established and the scope, terms and conditions for access to the network are as established from time to time by the Regulators (North and South). At present the most significant user of the network for intermittent energy supply is the onshore wind power industry (with a small amount of offshore wind and small hydropower). As supply from the wind resource increases the demands for balancing services provided by the conventional plant mix also increase together with pressures to improve quality of supply from these intermittent sources. This has led to both revision upwards of connection standards and reduction in available spare capacity in the onshore network. Rolling forward plans for network improvement are published in the annual Generation Adequacy Report produced by Eirgrid in the South and Seven Year Statement produced by System Operator Northern Ireland (SONI). These statements should be consulted for information on the locations of spare line capacity likely to exist at a given planning horizon. Usually this is confined to the 110kV level or above which may not be of immediate relevance to initial wave power developments. On cost grounds alone these are more likely to be focussed at voltages in the 10kV-20kV-33kV-38kV range for pilot and preliminary projects. The cost of connection to any of the lines mapped and their ability to absorb power can only be quantified by direct liaison with the network companies concerned.

The subject is discussed again in Appendix 8.

At the strategic level the 400kV lines from Moneypoint Co. Clare provide potential for significant future power transfer at high voltage from the Atlantic coast to the rest of the country. The cost of this however would be likely to place it outside the range where it could be furnished by wave power alone.

Appendix 8

Commercial Criteria

A8.1 Introduction

Commercial development of the wavepower resource is dependent on finding a market niche for part of the accessible resource in the managed market stratum as the technology is not currently commercially viable in the open market.

In this it is similar to other renewable resources in their development stage and in particular to offshore wind power. A detailed review of the commercial status of different renewable resources in Ireland has already been carried out incorporating application of a purposely developed levelised cost model. (Ref. 2).

The model has wide application and has been used below at client request to assess conceptual commercial aspects of the accessible resource developed in preceding sections of this report. It was decided to base the analysis on a nominal 160MW of wave power capacity utilising Pelamis as the reference converter. Developers of Pelamis were not in a position to advise a budget price for this capacity at present due to commercial sensitivity. The estimate used has been prorated from public domain data previously supplied to Electric Power Research Institute in the United States Ref. (30).

A8.2 Levelised Cost Analysis

Power Plants are most frequently compared on the basis of their Levelised Electricity Costs (LEC), which relate the capital cost of the plant, its annual operating and maintenance costs and fuel prices to the annual production of electricity and account for the time value of money. LEC analysis is a useful first stage screening device that provides a means for comparing and ranking the most economically efficient technology in terms of energy output. (This is also known as economic analysis).

A8.3 Resource Cost Curves

Resource cost curves provide a means of comparing costs of different projects both within a specific technology and between technologies. The primary value of resource cost curves is in comparing different generating options with each other given similar economic assumptions and evaluation methodologies. They are designed to provide the user with maximum flexibility to compare various options under different conditions. They can be used to determine which technologies can make the greatest energy contribution bearing in mind the availability of the resource and economics of the technology. Production of detailed curves which would involve assessment of incremental costs of wave power with increasing distance from coast, increasing reinforcement of network etc. is outside the scope of this project but it is possible to provide some indicative data.

A8.4 Selection of Rate of Return

Some issues in financial analysis and investment appraisal are subject to debate. The main source of debate in the appraisal of investment decisions based upon discounted cash flows is in the selection of the required rate of return, in particular, the treatment of risk. Risk arises because the future is uncertain so there is a risk that the outcome of an investment decision will not be as expected. Risk therefore manifests itself as variability in returns.

If the outcome of a project is certain, so that it has no risk, there is no problem in deciding what the Required Rate of Return (RRR) should be. It would simply be the interest rate on zero risk investments such as index linked Government Bonds.

If the outcome of an investment is uncertain, investors will need to be offered the prospect of a higher rate of return to compensate for taking on the risk involved. Therefore the RRR on a project should be equal to the risk free rate plus a premium for risk.

Since cost of funds is the rate that must be earned to satisfy investors (both equity providers and lenders), it is up to the capital markets where investors trade to provide an estimate of the cost of funds.

Typically a power project will have two types of risk

Market risk – which will depend upon factors such as the extent to which electricity demand varies with general economic conditions. (Under Irish law, renewables must be preferentially dispatched so that the volume risk is small).

Specific risk – which encompasses a whole range of uncertainties such as delays in bringing a plant on stream, cost escalation, technical performance etc

It is only the projects market risk (measured by its Beta B) that is considered when the RRR is being set. This is because investors can eliminate most specific risk through diversifying their investment portfolio.

The cost of equity is given by

Cost of Equity = Interest Rate + Beta X expected market risk premium.

To calculate a project's cost of capital therefore the risk free interest rate, the project Beta and the market risk premium are required.

Index linked Government Bonds provide an estimate of the minimum acceptable return on a marketable risk free investment. This would be the minimum RRR on a project with no risk.

Since individual projects are not traded on the stock market, it is not possible to measure their Beta values directly. Published figures provide the Beta value of a typical risk project for a sector or company. Published risk measures can be used to determine the risk for a project that is typical of its industry.

It is necessary to use a long period of data, since over short periods of time equity returns are uncertain.

The required rate of return on a renewable project will be given by its Weighted Average Cost of Capital (WACC)

RRR = (Return on Equity) X (Proportion of equity) + (Interest Rate on Debt) X (Proportion of debt)

The return on equity required will be dependent not only on the risk of the project but who finances the project. Venture capital funding typically will require a return of 20% on equity. Banks will typically require a return less than that of Venture Capitalists.

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Table A8.1

CER Calculation for the Weighted Average Cost of Capital %

		Description	Value %	Calculation
Cost of Debt	(A)	Nominal risk free rate	4.63	
	(B)	Debt risk premium	1.50	
	(C)	Inflation	2.2	B + ((1 + A)/(1 + C)-1
	(D)	Real cost of debt (rd)	3.88	
Cost of Equity	(E)	Nominal risk free rate	4.63	
	(F)	Inflation	2.2	(1 + A)/(1 + B)-1
	(G)	Real risk free rate	2.38	
	(H)	Equity risk premium	5.5	
	(I)	Expected market rate of return	7.88	G + H
	(J)	Equity beta	1.83	
	(K)	Post-tax cost of equity	12.44	G + H - J
	(L)	Tax Rate	12.5	
	(M)	Pre-tax cost of equity (rc)	14.22	K/(1 - L)
WACC	(N)	Gearing (g)	70	
	(O)	WACC = g x rd + (1 – g) x rc	7.0	

For the purposes of evaluating different projects on a consistent basis ESBI has selected the values for the various variables as used by the CER in its evaluation of the Best New Entrant (nominal 400 MW CCGT).

The Best New Entrant price for 2006 was published by the CER in August 2005, Ref. (30). The weighted average cost of capital (WACC) and the components of the BNE price as calculated by the CER is shown in Table A8.2. There have been some changes in the methodology used by CER compared with earlier years.

Table A8.2

BNE Price Component Summary

Item	**Units**	**BNE 2006**
1. WACC	%	7.0
2. Exported Capacity	MW	383
3. Plant cost inc. IDC	EuroM	253.9
4. Transmission connection	EuroM	2.28
5. Gas Connection	EuroM	4.77
6. Total Capital	EuroM	260.85
7. Capital specific	Euro/kW	681
8. Life	Years	15
9. Cap. Specific /year	Euro/kW.year	( )
10. Fixed O&M, Rates, etc.	EuroM/yr	18.7
11. Fixed O&M specific	Euro/kW.yr	( )
12. Var. O&M	Euro/MWh	0.05
13. Mature FOR	%	4.00
14. Average SOD	weeks p.a.	2.29
15. Availability	%	91.6
16. Utilisation factor	%	99.00
17. Capacity factor	%	90.68
18. Unit output	GWh p.a.	3046
19. Fuel price	Ecents/therm (GCV)	69.15
20. GCV/NCV Factor	1.10	(-)
21. Energy price	Euro/GJ (NCV)	(-)
22. Efficiency	% (NCV basis)	54.1%
Unit Cost		
23. Capacity	Ecents/kWh	1.55
24. Fixed O&M, Rates, etc.	Ecents/kWh	Incl.
25. Var. O&M	Ecents/kWh	0.22
26. Energy	Ecents/kWh	4.84
Total	**Ecents/kWh**	6.61

A8.5 Discount Rate

The Discount rates used to estimate the present value of projects are based on the Weighted Average Cost of Capital (WACC) using the same assumptions as the CER in evaluating the BNE.

A8.6 Cost Structure of Renewable Energy Technologies

The economics of renewable-energy technologies are rather different from those of conventional fossil power systems:

1- The capital cost of the equipment is relatively high, especially for larger plants.

2- The running costs are generally low

3- The output of the system depends the resources available (differs with location).

4- The output of the system depends on the load pattern.

5- The reliability is high.

A8.7 Model Analysis

A8.7.1 Introduction

An EXCEL model (Ref. 2) has been developed for analysis of renewable energy sources as described earlier. The model produces a levelised cost analysis and the typical financial analysis a potential investor would carry out as part of any decision to invest in a renewable energy project. An additional module in the model provides resource cost curves for three of the technologies wind, landfill gas and solar thermal power.

The model allows the user to select choices in relation to Project Construction, Financing, Economic options, Project Revenues and Technical Options as listed in Table 8.3 below. For comparison purposes the assumptions have been aligned with those used by the CER in determining the Unit Price of the Best New Entrant (BNE) to the generation market in Ireland based on a 400 MW CCGT.

A8.7.2 Selected Assumptions in the Model Analysis

The following assumptions apply

- Capital expenditure during the construction period is based on the current construction rates related to each type of plant.
- Interest charged during the construction period is 6.1 %. This is phase one of the financing where the project is financed 100% by debt during the construction period.
- The project is refinanced in the first year of operation using an interest rate equal to the rates used for debt by the CER in its calculation of the Weighted Average Cost of Capital (WACC) for the BNE.

- Each project is evaluated based on a 70/30 debt equity ratio.
- The term of the loan in Phase 2 is set at 15 years
- It is assumed that all assets (Plant & Equipment) are depreciated over 8 years
- A 2.2% inflation rate is used in the analysis
- The Equity Beta used in the calculation of the WACC by CER is 1.83 and is applied resulting in a Real WACC of 7.0% before Tax.
- For comparison purposes a rate of 10 Cents/kWh has been allowed for ocean energy in the developmental stage. Each of the project revenues are adjusted for inflation in the model analysis.
- It is assumed at this stage that there are no grants receivable for the projects and that emission credits are not used.
- The financial analysis is based on a period of 20 years (covering pre construction planning etc.).
- The option of accelerating income during the early years of the project and balancing this against income in later years (allowed under AER) has not been used.

Table A8.3

Options Available to the Model User

	Options
Project Construction	• Scheduling of Capital Expenditure During Construction Periods
Project Financing	• Interest Rate During Construction • Any combination of Debt and Equity for Project Financing • Term of Loan 5,10, or 15 years • Alternative Depreciation periods for Assets 1 through 15 years
Economic Options	• Any Inflation Rate from 0 upwards • Risk free rate for debt • Debt Risk Premium • Equity Risk free rate • Equity Risk Premium • Equity Beta
Project Revenues	• Any Unit Revenue (Cents/kWh) by project • Default Unit Revenues based on AER 6 Price Cap • Volume of Emission Credits per MWh Generated • Value of Emission Credits (Euro/Credit) • Annual Grants (000 Euros) • Period in years for which Grant is applicable • Acceleration of payments (AER6)
Technical Options	• Capacity Factor • Operating Life

In the absence of specified values, default values are available (Ref. 2)

A8.7.3 Model Inputs

The construction periods for each of the different technologies are as follows.

Table A8.4

Construction Schedules by Technology

	Year						
Technology	-6	-5	-4	-3	-3	-1	0
BNE 400MW				30%	30%	30%	10
Ocean Wave				5%	47%	48%	0

Each of projects capital and operating costs used for the Financial and Economic Analysis are listed below in Table A8.5 and ranked in terms of Unit Operating Costs costs. The capital cost of each technology includes interest accrued during construction phases of each project.

Table A8.5

Unit Capital and Operating Costs

Project Costs (excl. IDC)	**Capital Costs Euro/kW**	**Unit Operating Costs Cents/kWh**
BNE 400MW	681	5.6
Ocean Energy Wave 157MW	1518	3.11

The project revenues are as shown Table A8.6 below. For comparison purposes the rate of 10 Cents/kWh for Wave Energy is used. This results in an inflation to 11.7c/kWh (average) and 13.56c/kWh (peak) value at the end of the 15 year period. Each of the project revenues are adjusted for inflation in the Financial Analysis.

Table A8.6

Project Revenues

Technology	Cents/kWh
BNE 400MW	6.1
Ocean Energy Wave 157 MW	10

A8.7.4 Basis for Costs Used in Table 8.7

(1) Introduction

Because wave converters are at an early stage of commercial development there is little reliable cost data publicly available. However in the case of 'Pelamis', three units are being fabricated (2005) for installation in Portugal (2006) with options for supply of a further 30 units under negotiation.

In addition detailed estimates were evaluated by EPRI (Ref. 31) for the cost of 213 units derated to 500kW to match the rather low power environment (20kW/m) about 28km off the Californian coast adjacent to San Francisco. For the purposes of this report consideration was given to a wave farm of 209 units (rated at 750kW) under an average wave flux of 40kmW/m at approximately the same distance offshore having a combined capacity of 157MW and an implied capacity factor of 0.32 (Fig. 5 suggests the possibility).

(2) Cost Built Up for Table 8.7

In converting the U.S. costs for use in the Irish model the following conventions have been used relative to Table 7 of Ref. (31).

(1) USD to Euro conversion at 1€ = $1.23 as of mid 2004.

(2) All costs increased by 5% to allow for Irish increases to mid 2005.

(3) Items 2.2, 2.3, 2.4, 2.5 of Table A8.7 are new.

(4) Item 3.1 ("Plant") incorporates "Power Conversion Modules".

(5) Item 3.2 ("Civil Works") incorporates "Mooring Spread" and "Concrete Structural Sections".

(6) Item 3.3 ("Engineering Installation") incorporates "Installation".

(7) Item 3.4 ("Contingency") is new.

(8) Item 3.5 ("Electrical Interconnection") incorporates "onshore Transmission and Grid Interconnection" and "Subsea Cables".

(9) Item 3.6 ("Owner Engineering, Project Mgt., Commissioning") incorporates "Construction Management and Commissioning".

(10) Item 3.7 ("Initial O&M Mobilisation") is new.

(11) Item 3.8 ("Support Facilities, Spares") incorporates "Facilities" and a preliminary inventory of spares, partly included in Table 7 as "Yearly Parts".

(12) Item 3.9 ("O&M Contingencies") is new.

(13) Item 4 ("Interest during Construction") replaces "Construction Financing Cost".

(14) Item 5.1 ("Salaries, Owner Maintenance, Admin.") incorporates "Yearly Labor".

(15) Item 5.2 ("Insurance") incorporates "Yearly Insurance".

(16) Item 5.3 ("Rates and Charges") is new.

(17) Item 5.4 ("Spares") replaces "Yearly Parts".

(18) Item 5.5 ("Transmission User Charge") is new.

(19) Item 5.6 ("Transmission User Maintenance Charge") is new.

Reference (31) budgets for a complete removal and refit of the units on dry land at Year 10 together with biannual quay side inspection. It may be observed that the original "Pelamis" units are rolled steel tubing which requires internal sand ballast and periodic repainting. It is envisaged that the units discussed here will be mostly made from reinforced concrete requiring less, if any, ballast. It is also more likely that the refitting process would be spread over several summer seasons than carried out on all units simultaneously.

It is also likely that the economics of a dedicated shoreline dock may prove attractive during refitting operations with consequential saving in cost.

Thus the costs of this element are kept separate to those in the general analysis. The local figure corresponding to that in Ref. 31 (including parts and 5% increase for Irish conditions) budgets at €24.2m. Creation of a sinking fund (at 6% rate of interest) to provide for this amount after 10 years requires an annual input of:

€(0.07587) (24.2) = €1.836M

On annual generation of: (0.32) (157000) (8760) = 440 102 400kWh which equates to 0.417 €cents/kWh or an approximate 0.524€c/kWh increase in selling price. This is added to the 10c/kWh revenue allowed in 8.7.2 above to give a final revenue figure of 10.5€c/kWh.

Table A8.7
Commercial Analysis – Ocean Energy Wave – 1

1.	Technical Assumptions		
1.1	Capacity	MW	157
1.2	Project Life	Yr.	20
1.3	Annual Capacity Factor	%	32.l0
1.4	Average Annual Electricity Production (15 Op. years)	MWh	440,102
2.	Capital Costs	€000	€000/MW
2.1	Site Procurement	-	-
2.2	Pre Financial Closure Costs	1,000	6.37
2.3	Environmental Closure Costs	300	1.91
2.4	Engineering	500	3.18
2.5	Financial and Legal Costs	500	3.18
3.	Post Financial Closure Costs		
	EPC Contract		
3.1	Plant	113,453	722.63
3.2	Civil Works	65,756	418.83
3.3	Engineering Installation	9,749	62.10
3.4	Contingency	10,000	63.69
3.5	Electrical Interconnection	14,340	91.34
3.6	Owner Engineering, Project Mgt., Commissioning	10,190	64.90
3.7	Initial O&M Mobilisation	250	1.59
3.8	Support Facilities, Spares	10,244	65.25
3.9	O&M Contingencies	2,000	12.74
		238,282	1,517.72
4.	Interest during Construction	15,365	
	Total Investment Costs:	253,647	1,616
5.	Annual Operating Costs:		
5.1	Salaries & Owner Maintenance & Admin Costs	2,206	0.5
5.2	Insurance	4,475	1.02
5.3	Rates & Charges	1,330	0.3
5.4	Spares	3,670	.83
5.5	TUOS Charge	1,700	0.39
5.6	TUOS Maintenance Charge	287	0.07
	Annual O&M Costs	13,668	3.11

Table A8.8

Commercial Analysis – Ocean Energy Wave – II

1.	Economic Assumptions		
1.1	Inflation Rate	%	2.2
1.2	Levelised cost 20 years	Cents/kWh	8.18
1.3	Emission Credits	Number	0.0
1.4	Value of Emission Credits	€/credit	0.0
1.5	Annual Grant	€000	-
1.6	Period Payable	Years	-
2.	Project Financing		
2.1	Interest during construction	6%	
2.2	Project financing by debt	70%	
2.3	Term of Loan	15	
2.4	Inflation	2.2%	
2.5	Cost of Debt (Real)	4%	
2.6	Cost of Equity (Real)	( )	
2.7	Real Risk Free Rate	2%	
2.8	Equity Risk Premium	6%	
2.9	Expected Market Rate of Return (Real)	8%	
2.10	Equity Beta	1.83%	
2.11	Tax Rate	13%	
2.12	Post Tax cost of equity	12%	
2.13	WACC (Real Pretax)	7%	
2.14	WACC (Real Post Tax)	6%	
3.	Financial Results		
3.1	Average Annual Cash Flow	€000	15,702
3.2	Average Nett Profit	€000	11,653
3.3	Average Unit revenue used	€c/kWh	11.70
3.4	Interest during construction	€000	-15,365
4.	Project Analysis (Pre Tax)		
4.1	Project NPV (Real)	€000	18,018
4.2	Project NPV (Nominal)	€000	21,534
4.3	Project IRR (Nominal)	%	10.4%
4.4	Project IRR (Real)	%	8.4%

5.	Equity Analysis		
5.1	Equity NPV (Nominal)	€000	36,206
5.2	Equity NPV (Real)	€000	25,235
5.3	Equity IRR (Nominal)	%	17%
5.4	Equity IRR (Real)	%	15%
6.	Accounts Analysis	%	7%
6.1	Profitability Index Project (Pretax)	%	7%
6.2	Profitability Index Equity (Post tax)	%	50%
6.3	Debt Service Coverage		1.96

A8.8 Model Results

A8.8.1 Introduction

In reviewing the following results it should be noted that the various wave conversion technologies are not uniformly developed. In addition the economic analysis and financial analysis are affected by the selected scales of each project.

A8.8.2 Levelised Cost Analysis

Levelised cost analysis based on the varying operating lives of each technology are provided below in Table A8.9. Both the project cash outflows and plant outputs (kWh) are discounted at the Weighted Average Cost of Capital (WACC) as calculated by the CER for the BNE at 7% real. The CERs WACC is based on a 70/30 debt equity ratio.

The levelised cost approach identifies the most economically efficient technology in terms of minimising the cost of electricity generation. The power sector is scale sensitive so that for any technology the levelised cost of each technology will fall as capacity rises.

Table A8.9 below shows the project lives used in the levelised cost analysis of each project.

Table A8.9

Levelised Cost and Project Lives

	Cents/kWh	Project Life
BNE 400 MW	6.48	15
Ocean Energy Wave 157 MW	8.18	20

A8.8.3 Financial Analysis

A financial analysis has been run in the model for each renewable project producing cash flow and profit and loss account for each project. The purpose of the analysis is to determine whether the price cap provides sufficient incentives for potential investors in renewable projects and to identify the breakeven unit revenues required under the selected assumptions for the project discounted at the WACC.

The financial analysis is presented in terms of project results, equity results, profitability and breakeven analysis. The financial results presented below are based on the assumptions of

- 2% inflation applying to costs and revenues
- Loan period of 10 years
- 70% debt financing
- Depreciation period 15 years

A8.8.4 Project Results

The project results are shown in Table A8.10 below. The project analysis is not concerned with project finance and therefore it is assumed that the project is 100% equity financed. Those projects that have a negative Net Present Value are not generating sufficient funds over a 15 year period to recover the initial investment discounted at a WACC of 8.88%.

As shown in Table A8.10 below under the cost and operating assumptions ocean energy is clearly financially viable under the unit revenues applied in Table A8.8 above.

The projects InternaI Rate of Return is closely related to the NPV. The IRR is the discount rate which will set the NPV of projects cash flow equal to 0. If the IRR is less than the WACC of 7.0% real and 9.18% Nominal, then the project is not generating sufficient funds using the stated price caps for the its cash flows to breakeven.

Table A8.10

Project Results

	Project NPV (Nominal)	Project NPV (Real)	Project IRR (Nominal)	Project IRR (Real)
	000	000	%	%
BNE 400 MW	15,100	18,600	10	8.0
Ocean Energy Wave 157 MW	18,066	21,534	10.4	8.4

A8.5 Equity Analysis

Under the operating and financial assumptions in Tables A8.4, 5 above including a debt equity ratio of 70/30, the equity analysis of each project is presented below in Table A8.11. The returns to equity are based on the annual free cash flow available for dividends i.e the annual cash balances after paying for operating costs, debt servicing and taxation. The equity analysis reflects the project analysis above where those projects that have a non negative or near non negative NPV result also have a positive equity NPV.

Table A8.11

Equity Analysis

	Equity NPV (Nominal)	Equity NPV (Real)	Equity IRR (Nominal)	Equity IRR (Real)
	000 €	000 €	%	%
BNE 400 MW	27,400	11,100	13%	11
Ocean Energy Wave 157MW	38,206	25,235	17	15

A8.6 Breakeven Analysis

The unit revenues required for each project to recover initial investments at a WACC of 9% are shown in Table A8.12 below. The breakeven selling price for the analysis provided below is that unit revenue required in each project so the NPV of the project cash flow discounted at the WACC is 0. The break even analysis carried out on each project has been developed under the identical assumptions in the financial analysis.

The breakeven analysis identifies the gap between the price cap and the unit revenue required (cents/kWh) to a achieve a non negative NPV under the CER's discount rates.

The results show that even the high capital cost and low capacity factor of the wave project as considered do not completely militate against financial viability using the WACC for the BNE as the discount rate. However it should be noted that wave projects will have different risk than that of the BNE and therefore should have a different discount rate. The higher the risk the higher should be the discount rate and therefore the higher the unit revenue required to achieve a non negative NPV.

Table A8.12

Breakeven Analysis (Cents/kWh)

	Price Cap	Project Breakeven Price	Variance
BNE 400 MW	6.61	6.55	0.06
Ocean Energy Wave 157 MW 15 yr	10	9.5	0.5

A8.9 Prospects for Commercial Development to 2020

In 2004 ESBI-Bacon Ref. (2) having considered the then available information, projected a case for development of 200MW of installed wave power capacity to deliver 2.37 TWh of electrical energy at a price of around 10c/kWh (operating at a capacity factor of 35%).

It was suggested that this would have a present value of €170million in 2007 if discounted at a public sector real discount rate of 2.5%. Since then the unit price calculated for the Best New Entrant combined cycle gas turbine has risen to 6.1c/kWh for 2006 (a 27% increase in two years, primarily due to fuel price fluctuation). Undoubtedly energy related increases due to fuel, environmental, legislative and other drivers will work through to push up the capital costs of both conventional and wave power plant. This preliminary Wave Power atlas, which was also called for in Ref. (2) has shown that the above price estimate and capacity factor are just about achievable with present day technology under the scenarios envisaged for 2020.

Major competitors for wave power are onshore and offshore wind power development. There are still large untapped resources of onshore wind available for development although somewhat perversely these sectors of society that called for wind power development in the first instance are frequently to be found among the objectors to specific developments or to the necessary consequential strengthening of the electrical network in particular parts of the country. While offshore windpower development has been successfully demonstrated at Arklow there has been a slow-down in bringing other projects to commercial operation compared with projections of a few years ago. Undoubtedly some of the deceleration arises from the unexpected costs of pioneering in a difficult environment and some of these will transfer to wave power development when full scale offshore installations begin to appear.

Issues such as interfacing with the fishing industry, already under severe pressure due to declining stocks, will be thrown into sharper relief than with offshore wind where the sandbanks involved were of relatively limited fishery interest.

There are still areas of research that require resolution such as optional spacing of wave power that converters (a rather conservative approach has been taken in this Report)

Nevertheless the coupled forces of the need for predictable and low cost energy to meet sustained growth, rising fossil fuel costs, carbon emission management strictures and technological development present an opportunity for wave power that, in the context of the accessible Irish resource is equalled in few other economies at present.

Fig. 28 shows that 14.25 MWe/km of Pelamis converters located 25km off West Mayo or South West Kerry would attain an average annual capacity factor of 30.5% along cordons of 60km and 100km length, giving installed capacities of 855 MW and 1425 MW respectively (Total 2280 MW).

A8.10 Development of Indicative Resource/Cost Curves to 2020

The development of definitive resource/cost curves is as stated earlier outside the scope of this report as it would require in depth load flow studies and a detailed knowledge of planned network developments and more definitive information on converter system cost trends over the period in question. Nevertheless it is possible to provide some indicative estimates of costs implied by connecting a portion of this resource to the network by a target date of 2020 bearing in mind the following constraints:

- The overall quantities of energy identified as being accessible off the coasts of Mayo and Kerry are too large to be integrated into the Irish network without in-depth load flow, and fault condition studies which could indicate the need for deep reinforcement or network reconfiguration.
- There is an 'entry barrier' for wave power in that if initial developments are small scale, the unit capital cost of the installation will be high even though it may be able to utilise existing medium voltage lines near the coast. Without proven pilot installation however, raising finance for installations where economy of scale will come into play may prove impossible.
- Where transmission over relatively long lengths to the load centres becomes necessary the higher the voltage that can be used to minimise line losses the better. The coastal areas concerned are extremely exposed and it is desirable to consider such sheltered bays

as may be available for bringing cables ashore. On land the overhead power lines will be subject to severe wind loads and may also suffer from poor foundation conditions. Thus there is little likelihood that the necessary lines will be particularly cheap to construct.

- Windfarm development in these areas has led to some upgrading of existing lines and proposals for additional developments, the largest of which is a multi megawatt installation in the vicinity of Bellacorick, Co. Mayo. Technically this would appear to justify a 220kV connection but it is understood that the project will take up the existing 110kV links when the existing peat fired station is phased out, utilising heavier conductors.
- In the following cases links for the Mayo Wave Field are considered between the coast and Bellacorrick and onwards to Sligo or Flagford at 38kV and 110kV. For the Kerry Field links are considered between Smerwick and/or Doulus Bay and Tralee, also at 38kV and 110kV levels. The limited capacity of the 38kV line over these lengths will be evident. Standard costings for these types of link are derived from Ref. (32). A 10% reduction in carrying capacity of the 300 ACSR type conductor is made although power flow during high ambient temperature Summer conditions is likely to be minimal, with the lines being heavily loaded in the cooler parts of the year. Line life is 40 years and discount rate 6%.
- The necessary calculations are tabulated on Table A8.13 where the respective columns are as follows:

Column	Contents
1	Route from coast
2	Length of Route (km)
3	Line voltage kV
4	Line capacity MVA, dictated by voltage, length, size
5	No.of Pelamis converters to provide line capacity
6	Implied length of cordon of converters off coast (km)
7	Annual energy output MWh
8	Line cost/km
9	Cost of line €
10	Cost of Switchyard/trafo Station €
11	Total cost of Line and Station
12	Annual Transmission cost (€c/kWh)
13	Annual Wave converter systm cost (€c/kWh)

14	Resource cost (€c/kWh) for development as sized in Col. (4) above.

- The resource costs are extracted from the table (Col. 14) and plotted in order of increasing costs as shown in Figs. A8.1 and A8.2 for the 110kV and 38kV cases respectively.

The routes labelled for both 38kV and 110kV on the figures are as follows:

A	Kinfinalta (Blacksod Bay) – Bellacorick	(29km)
B	Smerwick Harbour – Tralee	(60km)
C	Kinfinalta – Bellacorick – Sligo or Flagford	(119km)
D	Annagh Bay (Belmullet) – Bellacorick	(38km)
E	Doulus Bay – Tralee	(80km)
F	Annagh Bay – Bellacorick – Sligo or Flagford	(128km)

- The annualised cost of a 157 MW sized installation has been developed at length in this Appendix. Similarly a 20MW case was considered at draft report stage, based on publicly quoted figures for the initial 2.25 MW Pelamis Pilot installation off Portugal, giving a figure of circa €c18/kWh. Plant costs for installations between 12.5 MW and 358 MW (Cols 4, 14) were derived using log – log straight line interpolation/extrapolation from the unit costs of the 20MW and 157MW installations.
- It is useful to keep the plant cost and transmission cost/kWh separate. It is assumed that the transmission lines are built at cost and still carry TUOS charges etc.
- The line cost varies from about 2-10% of the project capital cost over the range of projects considered. In all cases it is assumed that the converter installation is sized such that the line capacity is fully utilised as under utilisation of a particular line would normally mean additional costs had to be borne per kWh of resource. This analysis does not ignore the cases where spare capacity may exist in existing lines close to the shoreline where a very short connection may be possible. This was an option in the San Francisco case considered by EPRI in Ref. (31) and the cost of such a short line is included in Item 3.5 of Table A8.7 (which also includes the Subsea cables as noted in A8.7.4) (Item 3.5 would be mostly absorbed by the sea bed cable element. It made little provision for the onshore power lines as the San Francisco site was well served by an existing near shore grid i.e. Pacifica where the cost of a 100kV connection was estimated at $4m). It is however, outside the scope of this report to determine the extent to which such locations may exist on the Irish

coast. In many cases such pockets of spare capacity as may exist may be taken up by wind from or other developments.

- The stepped curves highlight the relative merit of 110kV (or higher) transmission levels for bulk movement of energy. It would in fact be quite unrealistic to consider 38kV for transfer on some of the long routes chosen but this in turn highlights the difficulty facing wave power at prime locations on the west coast. The most attractive options are connection of projects of some scale into Bellacorick from which existing 110kV lines feed out on different routes. Tralee has three routes feeding out but all lines in the vicinity of Tarbert are understood to be fully committed while Tarbert remains on load.
- The question of scale is critical. It is unrealistic to expect investors to embrace wave power until it is well proven. Hence the critical need for special arrangements to get demonstration scale plants operational and connected to the network.

A8,11 Conclusions

(1) The figures given here are indicative only and are prorated from published information from Ref. (31, 32). They are not endorsed by OPD as the cost of production machines is still subject to commercial negotiation.

(2) The capital cost of early production wave converters will be relatively high especially for larger plants but the running costs are generally low.

(3) Levelised cost analysis provides the best evaluation of the most efficient technologies (Tables A8.2 and A8.14)

Table A8.14

Levelised Cost Analysis

	Cents/kWh	Project Life
BNE 400 MW	6.61	15
Ocean Energy Wave 157MW	8.18	20

(4) No allowance is made for carbon credits. The generation cost of carbon for BNE is €0.0017/kWh. (0.17 cents/kWh).

(5) It is important to note that the weighed average cost of capital (WACC) of 7% used as the discount rate was derived by CER for a 400MW CCGT project on a scale and level of risk that might be appropriate to development by a utility or large player and (from a financiers point of view) reflecting the expectation of an appropriate income stream.

This would not necessarily hold true for a wave power project developer where the level of risk would be considered higher and where financiers therefore would demand a higher WACC. Thus a higher discount rate might be considered appropriate when estimating the levelised cost for development of the this resource.

(6) The above analysis suggests that a conceptual “Pelamis” based wave farm of 157MW capacity (extending over a length of 10km broadside on to the predominant wave direction) could supply energy to the Irish network from selected locations about 30km off parts of the Mayo or Kerry coasts at a price of approximately 10.5 cents/kWh.

(7) Indicative resource – cost curves prepared for prime locations indicate the importance of economy of scale and the limits imposed by transmission distances and voltage levels.

(8) These show that installed capacities of 360-460 MW with associated 110kV lines would be required in the Mayo field to bring the projected cost/kWh down to 8-8.5 cents. Corresponding figures for Kerry are installations in the range 170-230MW to obtain costs of 9.6 – 10.6 cents/kWh.

(9) If the same lines were confined to 38kV, the cost/kWh would typically be double that of the 110kV case due to the throttling effect of the 38kV link on the permissible installed capacity.

Table A8.13
Computation for Projected Resource Cost Curve

Resources Route	Length Km	Line Type kV	Line Capacity MVA	No. of Mach	Cordon Length kM	Annual Output MWh	Line Rate €000/km	Trans Line Cost€	Trans Station Cost €	Total Trans. Cost €	Annual Trans. Cost c/kWh	Plant Cost c/ kWh	Resource Cost €c/kWh
Mayo													
Annagh-Bellacorick	38	38	40	53	2.81	112,128	95	3,610k	1,800k	5,410k	0.32	15.5c	15.82
"	38	110	358	477	25.1	1,003,546	180	6,840k	2,800k	9,640k	0.064	8.5	8.564
Kinfinalta-Bellacorick	29	38	54	72	3.8	151,373	95	2,755k	1,800k	4,555k	0.2	14.0	14.2
"	29	110	469	625	32.9	1,314,701	180	5,220k	2,800k	8,020k	0.04	8.0	8.04
Annagh-Sligo/Flagfd	128	38	12.5	17	0.88	35,040	95	12,160k	1,800k	13,960 k	2.6	22.0	24.6
"	128	110	106	141	7.44	297,139	180	23,040k	2,800k	25,840 k	0.57	11.5	12.07
Kinfinalta-Sligo/Flagfd	119	38	13.5	18	0.95	37,843	95	11,365k	1,800k	13,165 k	2.31	22	24.31
Kinfinalta-Sligo/Flagfd	119	110	114	152	8.0	319,566	180	21,420k	2,800k	24,220 k	0.5	11.5	12.0
Kerry													
Smerwick-Tralee	60	38	27	36	1.68	75,686	95K	5,700k	1,800k	7,500k	0.657	17	17.66
"	60	110	227	303	15.9	636,326	180K	10,800k	2,800k	13,600 k	0.142	9.5	9.64
Doulus-Tralee	80	38	20	27	1.4	56,064	95K	7,600k	1,800k	9,400k	1.11	18.5	19.61
"	80	110	170	227	11.9	476,544	180K	14,400k	2,800k	17,200 k	0.23	10.4	10.63
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)

Appendix 9

Wave Power Atlas

The marine wind resource is mapped in Ref. (1) utilising a series of coastal area blocks or zones. Essentially these have been replicated in this atlas with a view to identifying both the near shore mean marine wave resource levels and the onshore infrastructure for convenience of users.

The zones differ slightly from those used in the wind atlas to accommodate greater sea areas and an additional block (without coastline) has been included off Donegal. The arrangement facilitates commonality with the waters off Northern Ireland should this prove necessary in the future. The variables mapped are mean annual theoretical wave power flux (kW/m) combined with constraints used in estimating the Accessible Resource and the respective zones are as follows:

Zone	**County Coasts**
A	Louth-Dublin
B	Dublin-Wexford
C	Wexford
D	Waterford-Cork
E	Cork-Kerry
F	Kerry
G	Kerry-Clare
H	Galway-Mayo (inshore
I	Galway-Mayo (Offshore)
J	Mayo
K	Mayo-Donegal (inshore)
L	Donegal
M	Donegal-Derry
N	(Antrim)
O	(Down)
P	Mayo-Donegal (Offshore)

Appendix 10

Abridged Brief

1. Requirements

As part of the process of assessing the national ocean energy resource, a strategic study of Ireland's wave energy resource was commissioned by the Marine Institute in 1999. In the light of the evolution of wave energy technology from fixed shoreline structures to second generation floating devices and of recent new sources of wave data, it is now proposed to update this study.

2. Scope of Work

The Institute invited proposals for a limited study to:

- Carry out an assessment of the total, feasible and practical offshore wave energy resource
- The "offshore" resource is defined as that which is accessible to the latest generation of floating wave energy devices.

  The study should assess the following:

  - Wave energy levels impacting on the offshore environment in areas suitable for deployment of floating wave energy conversion devices using computer models of wave climate validated with actual recorded data where possible.
  - Estimated annual average wave energy levels should be converted to electrical output using relevant availability data and expected efficiency of suitable wave energy conversion devices.
  - Assess this data in terms of total, feasible and practical energy generation taking into account infrastructural, legal, planning and other constraints as appropriate.

3. Presentation of Results

A graphical/textual presentation of data acquired as well as an accessible GIS tool for presentation of data is desirable.