System Level Design, Performance and Costs – Massachusetts State Offshore Wave Power Plant

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1. Introduction and Summary

This document describes the results of the system level design, performance and cost study for both a feasibility demonstration pilot plant and a commercial size offshore wave power plant installed off the coast of Massachusetts. For purposes of this point design study, the Ocean Power Delivery (OPD) Pelamis wave energy conversion (WEC) device and an area for deployment off the coast at Cape Cod was selected. The study was carried out using the methodology and standards established in the Design Methodology Report (Reference 1), the Power Production Performance Methodology Report (Reference 2) and the Cost Estimate and Economics Assessment Methodology Report (Reference 3).

A pilot scale wave power demonstration plant using a single Pelamis Wave Energy Conversion device was evaluated. The yearly electrical energy produced and delivered to the grid interconnection is estimated to be 964 MWh at the selected deployment site and would cost $5.5 million to build (build ($4.9 million after the Massachusetts installation tax deduction and Federal 10% tax credit). This cost only reflects the capital needed to purchase a single Pelamis unit, the construction costs to build it and the grid interconnection cost. Therefore, it represents the installed capital cost needed to evaluate and test a single Pelamis WEC system, but does not include the following elements:

- Detailed Design, Permitting and Construction Financing
- O&M Costs
- Test and Evaluation Cost

A commercial scale wave power plant was also evaluated to establish a base case from which cost comparisons to other renewable energy systems can be made. The yearly electrical energy produced and delivered to bus bar is estimated to be 1,453 MWh/year for each Pelamis WEC device. In order to meet the target output of 300,000 MWh/year a total of 206 Pelamis WEC devices are required. This is the equivalent output of a commercial 100MW wind farm with a 40% capacity factor. The elements of cost and economics (with cost in 2004$) are:

- Total Plant Investment = $273 million
- Annual O&M Cost = $12.4 million; 10-year Refit Cost = $26.5 million
- Levelized Cost of Electricity (COE)[1] = 13.4 cents/kWh (nominal rate) - 11.1 cents/kWh (real rate)
- Internal Rate of Return (IRR) = 7.6% with Renewable Energy Certificates (RECs) and based on industrial electricity sell price

In order to compare offshore wave power economics to shore based wind, which reached a installed capacity base of about 40,000 MW in 2004, industry standard learning curves were

[1] For the first 103 MW plant assuming a regulated utility generator owner, 20 year plant life and other assumptions documented in Reference 3

applied. The results indicate that, even with worst-case assumptions, the economics of wave power compares favorable to wind power at all equal cumulative production levels.

Offshore wave energy electricity generation is a new and emerging technology. The first time electricity was provided to the electrical grid from an offshore wave power plant occurred in early August, 2004 by the full scale preproduction OPD Pelamis prototype in the UK. Many important questions about the application of offshore wave energy to electricity generation remain to be answered, such as:

- There is not a single wave power technology. It is unclear at present what type of technology will yield optimal economics. It is also unclear at present at which size these technologies will yield optimal economics.
- Given a device type and rating, what capacity factor is optimal for a given site?
- Will the installed cost of wave energy conversion devices realize their potential of being much less expensive per COE than solar or wind?
- Will the performance, reliability and cost projections be realized in practice once wave energy devices are deployed and tested?

E2I EPRI Global makes the following specific recommendations to the Oregon State Electricity Stakeholders relative to the Douglas County pilot demonstration plant:

1. Encourage the ongoing R&D at universities such as University of Massachusetts, MIT and Woods Hole Oceanographic Institute
2. Coordinate efforts to attract a pilot feasibility demonstration wave energy system project to the Massachusetts coast
3. Now that the project definition study is complete and a compelling case has been made for investing in wave energy in Massachusetts, proceed to the next phase of the Project

   If this recommendation cannot be implemented at this time (due to lack of funding or other reason), E2I EPRI Global recommends that the momentum built up in Phase 1 be sustained in order to bridge the gap until Phase II can start by funding what we will call Phase 1.5 with the following tasks:

   a. Tracking potential funding sources
   b. Tracking wave energy test and evaluation projects overseas (primarily in the UK, Portugal and Australia) and in Hawaii
   c. Tracking status and efforts of the permitting process for new wave projects
   d. Track and assess new wave energy devices
   e. Establish a working group for the establishment of a permanent wave energy testing facility in the U.S.

4. Build collaboration with other states with common goals in offshore wave energy.

In order to stimulate the growth of ocean energy technology in the United States and to address and answer the techno-economic challenges, we recommend the following take place:

- Federal and state recognition of ocean energy as a renewable resource and that expansion of an ocean energy industry in the U.S. is a vital national priority
- Creation of an ocean energy program within the Department of Energy's Energy Efficiency and Renewable Energy division
- DOE works with the government of Canada, Australia, the UK and on nations on an integrated bi-lateral ocean energy strategy.
- The process for licensing, leasing, and permitting renewable energy facilities in U.S. waters must be streamlined
- Provision of production tax credits, renewable energy credits, and other incentives to spur private investment in Ocean Energy technologies and projects.
- Provision of adequate federal funding for ocean energy R&D and demonstration projects.
- Ensuring that the public receives a fair return from the use of ocean energy resources and that development rights are allocated through an open, transparent process that takes into account state, local, and public concerns.

2. Site Selection

Cape Cod was selected as an area for locating an offshore wave power plant. The land fall of the power cable would occur at Le Count Hollow Beach. Fabrication and assembly would occur at one of the larger ports off the coast of Massachusetts or Maine. Operation and Maintenance can be carried out in Wellfleet, which is in close proximity to the deployment site. No easement to land a power cable has been identified, although it is likely that easements such as sewer outfalls exist in this area. The pilot plant can be connected to the grid close to shore, by simply tapping into a local distribution line. For a commercial size plant, grid interconnection can occur at the Wellfleet substation. Upgrades on 5km of transmission line will likely be required to interconnect the wave farm to the nearby 115kV transmission line. Figure 1 shows the high voltage power line route across Cape Cod.

Figure 1: Cape Cod Power Transmission Infrastructure

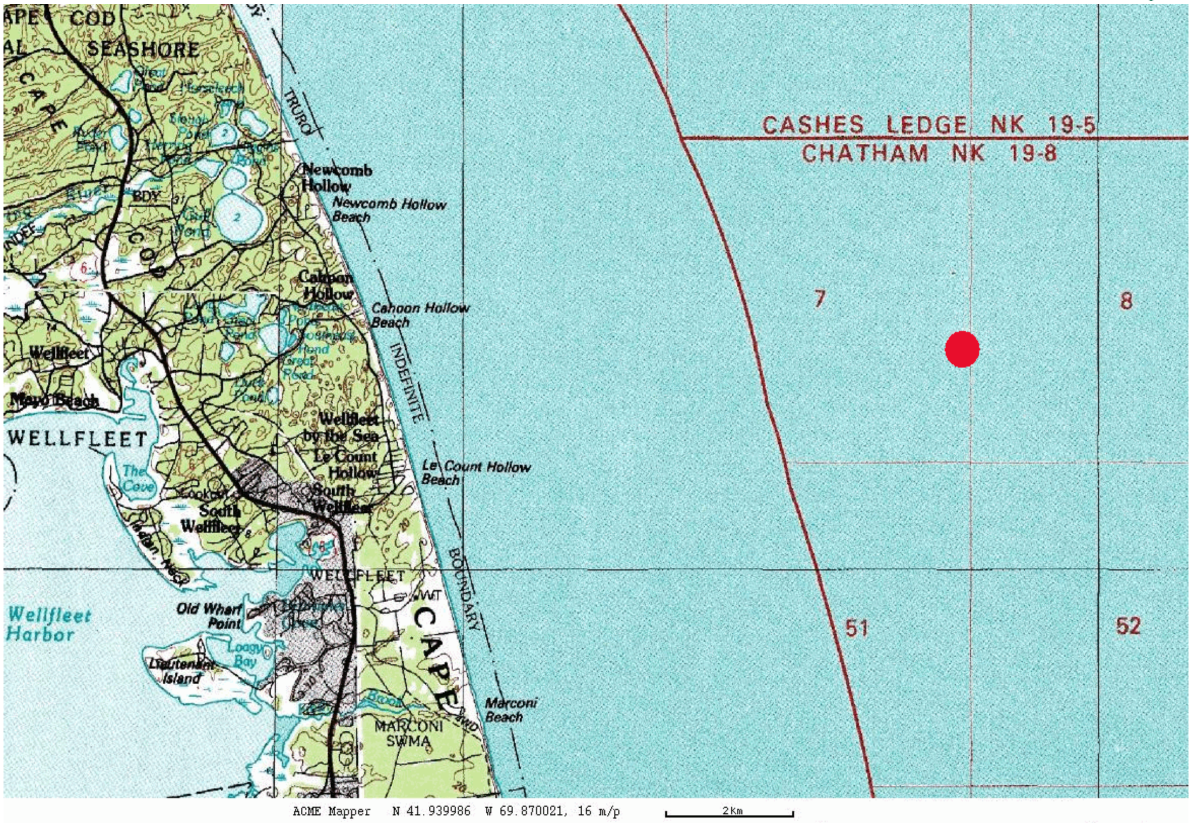


Figure 2: Wave Farm Deployment Site

The dot in Figure 2 shows the deployment site. It is located 9.1km from the beach at a water depth of 50m-60m. Figure 3 shows the local electrical interconnection points.

Figure 3 is a zoomed in map of Figure 2 to show the location of the cable landing and grid interconnection. The dot indicted as #1 is the cable shore crossing site and dot #2 shows the location of the Wellfleet substation.

Ocean floor sediments along the proposed cable route and at the deployment site consist mostly of sand, which allows the sub-sea cable to be buried appropriately and provides adequate soft sediments to use the Pelamis standard mooring configuration. Detailed bathymetry and geotechnical assessments will need to be carried out in a detailed design and engineering phase. Special attention will need to be paid to identify potential obstacles such as large rock formations in the cable route and at the deployment location. This is accomplished by using a combination of side scan radar, sub-bottom profiler, local dives and sediment sampling.

Figure 3: Cable Landing and Grid Interconnection

The deployment features the following relevant parameters:

Water Depth at Deployment Site:	50-60 m
Distance from shore to 12kV line:	500 m
Subsea Cable Length:	9.1 km
Total Cable Length Required:	9.6 km
Distance to Shore:	9.1 km
Overland Transmission Substation-Cable landing Site:	5 km
Ocean Floor Sediments:	Sand
Transit Distance to Wellfleet for O&M:	72 km

3. Wave Energy Resource Data

In order to characterize the wave resource at the proposed site, the NDBC 44018 wave measurement buoy was chosen to obtain wave data from. Only a single year of measurement data was available from this measurement station. Below are some key results of the reference measurement station and characterization of the wave climate. The measurement buoy is in close proximity to the proposed deployment site. As a result, the measurements are representative of the wave climate that the wave power units will experience. Figure 4 shows the average monthly wave energy power flux (in kW/m) Scatter tables for the wave energy resource were created for each month and used to estimate the power production of Pelamis as described in Section 6.

Measurement buoy:	NDBC 44018
Station Name:	SE Cape Cod
Water depth:	74 m
Coordinates:	41° 15’30’’ N 69° 17’40’’ W
Data availability:	1 year (2003)
Maximum Significant Wave Height (Hs):	7.6m
Maximum Significant Wave Period (Tp):	11.43 s
Average Wave Power Density (kW/m):	13.8kW/m

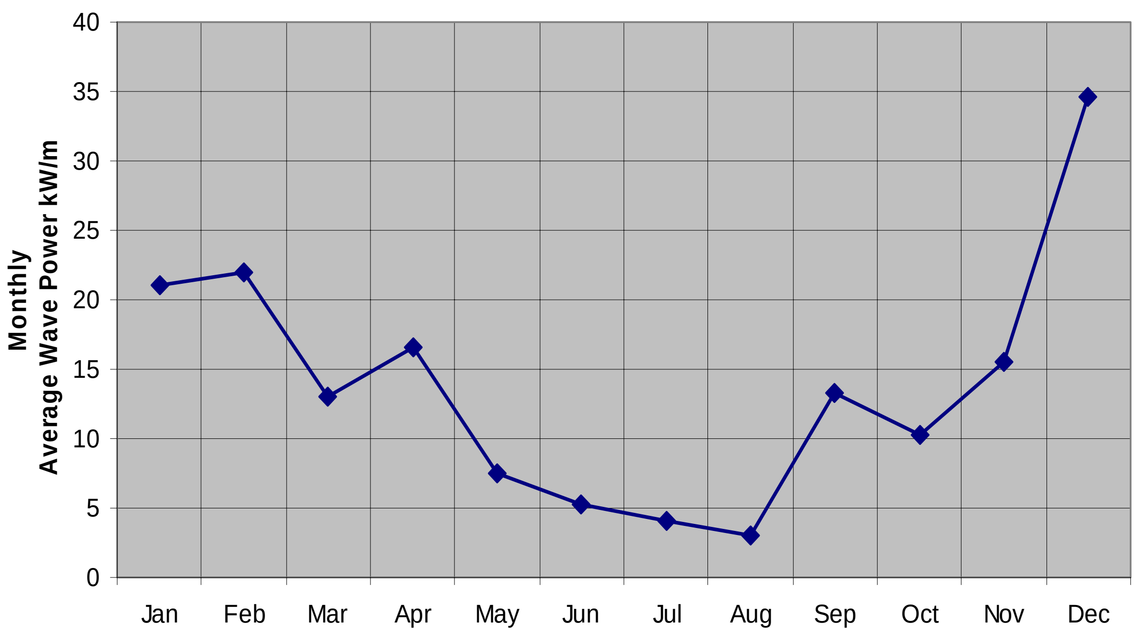


Figure 4: Monthly Average Wave Power Flux (kW/m)

4. The Technologies

The WEC device chosen for the Massachusetts point design is the Pelamis from Ocean Power Delivery (OPD). The device consists of a total of 4 cylindrical steel sections, which are connected together by 3 hydraulic power conversion modules (PCM). Total length of the device is 120m and the device diameter is 4.6m. Figure 5 shows the device being tested off the Scottish coast. Individual units are arranged in wave farms to meet specific energy demands in a particular site as illustrated in Figure 6.

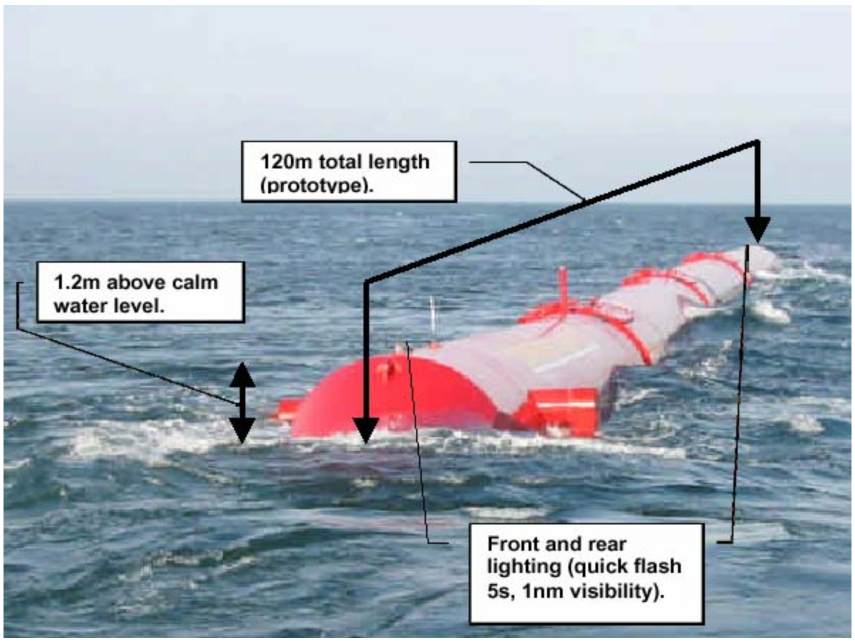


Figure 5: Pelamis pre-production prototype undergoing sea-trials

Figure 6: A typical Pelamis wave farm

The following sections provide a high level overview of the different subsystems that are device specific. Subsystems covered include the power conversion modules (PCM), the structural steel sections and the mooring system. The summary table below shows the key specifications of the Pelamis.

Table 1: Pelamis Device Specifications

Structure	
Overall Length	123 m
Diameter	4.6m
Displacement	700 tons
Nose	5m long conical drooped
Power Take Off	3 independent PCM's
Total Steel Weight	380 tons
Power Conversion Module (PCM)	
Power Take Off	4 x hydraulic rams (2 heave, 2 sway)
Ram Speed	0 – 0.1 m/s
Power Smoothing Storage	High pressure Accumulators
Working Pressure	100 – 350 bars
Power Conversion	2 x variable displacement motors
Generators per PCM and Speed	2 x 125kW and 1,500 rpm
Power	
Generator Type /Rated Power	Asynchronous /750kW
System Voltage	3-phase, 415/690VAC 50/60Hz
Transformer	950kVA step up to required voltage
Site Mooring	
Water depth	> 50m
Current Speed	< 1 knot
Mooring Type	Compliant slack moored

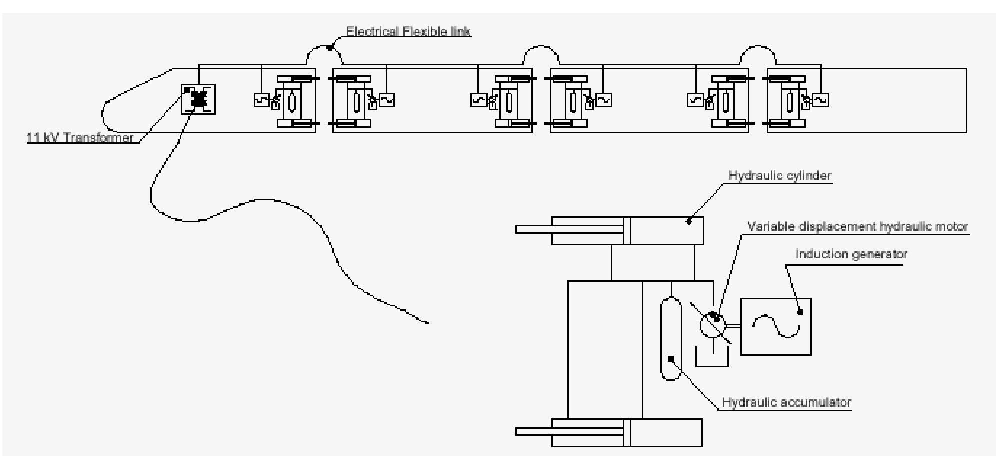


Figure 7: Pelamis Power Conversion Train

The Power Conversion Module (PCM)

As illustrated in Figure 7, a total of 3 power conversion modules (PCM's) connect the 4 individual steel tubes forming a Pelamis device. Each PCM contains a heave and sway joint. The modular power-pack is housed in a second fully sealed compartment behind the ram bay so that in the event of seal failure only the hydraulic rams are immersed. Access to all system components is via a hatch in the top of the power conversion module. Maximum individual component weight is less than 3 tons to allow replacement using light lifting equipment.

The wave-induced motion of each joint is resisted by sets of hydraulic rams configured as pumps. These pump oil into smoothing accumulators which then drain at a constant rate through a hydraulic motor coupled to an electrical generator. The accumulators are sized to allow continuous, smooth output across wave groups. An oil-to-water heat exchanger is included to dump excess power in large seas and provide the necessary thermal load in the event of loss of the grid. Overall power conversion efficiency ranges from around 70% at low power levels to over 80% at full capacity. Each of the three generator sets are linked by a common 690V, 3 phase 'bus' running the length of the device. A single transformer is used to step-up the voltage to an appropriate level for transmission to shore. High Voltage power is fed to the sea bed by a single flexible umbilical cable, then to shore via a conventional sub-sea cable.

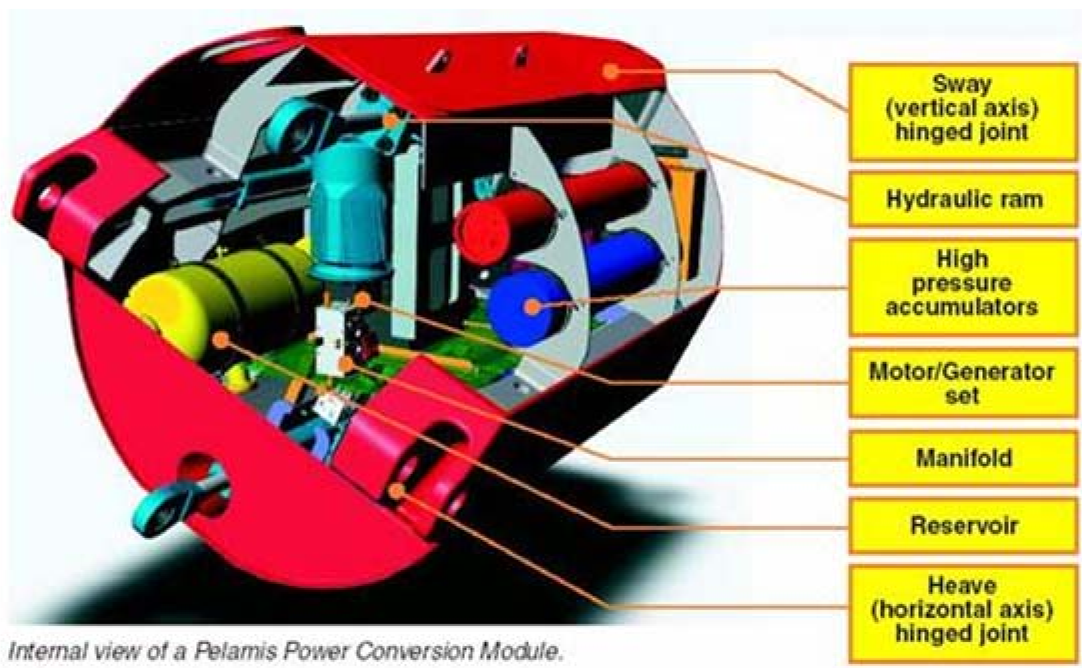


Figure 8: Internal View of the Pelamis PCM

Tubular Steel Sections

There are a total of 4 tubular steel sections, which are the main structural elements of the device. Each steel section is 25m long and weighs roughly 70tons. The main tube sections are manufactured in segments using steel plates that are rolled into shape as shown in Figure 9. Once formed, individual sections are welded together to form a segment. This manufacturing process is extensively in the wind industry to manufacture wind turbine towers. The process can be automated and lends itself well to cost reduction.

Cast end caps on the steel tubes incorporate hinges, which then interconnect to the Power Conversion Modules. In order to properly ballast the device, sand is added.

Alternative construction materials were evaluated under a contract by the Department of Trade and Industry. Materials analyzed and compared to each other were steel, pre-tensioned concrete and GRP (filament wound composite). Out of the 3 options, concrete emerged as the preferred option (Reference 5).

Figure 9: Manufacturing Steel Tubular Sections

Mooring System

The mooring arrangement of Pelamis needs to be designed specifically for the site conditions. Similar to a wind turbine foundation, which needs to be type approved, the Pelamis mooring system needs to be designed by OPD and adapted to specific site conditions. Survival conditions, maximum current velocity, water depth, seafloor soil densities and other factors will need to be considered in a detailed design phase.

For the purpose of this project, the reference mooring system used for Ocean Power Delivery prototype testing was used to establish a costing base case as shown in Figure 10.

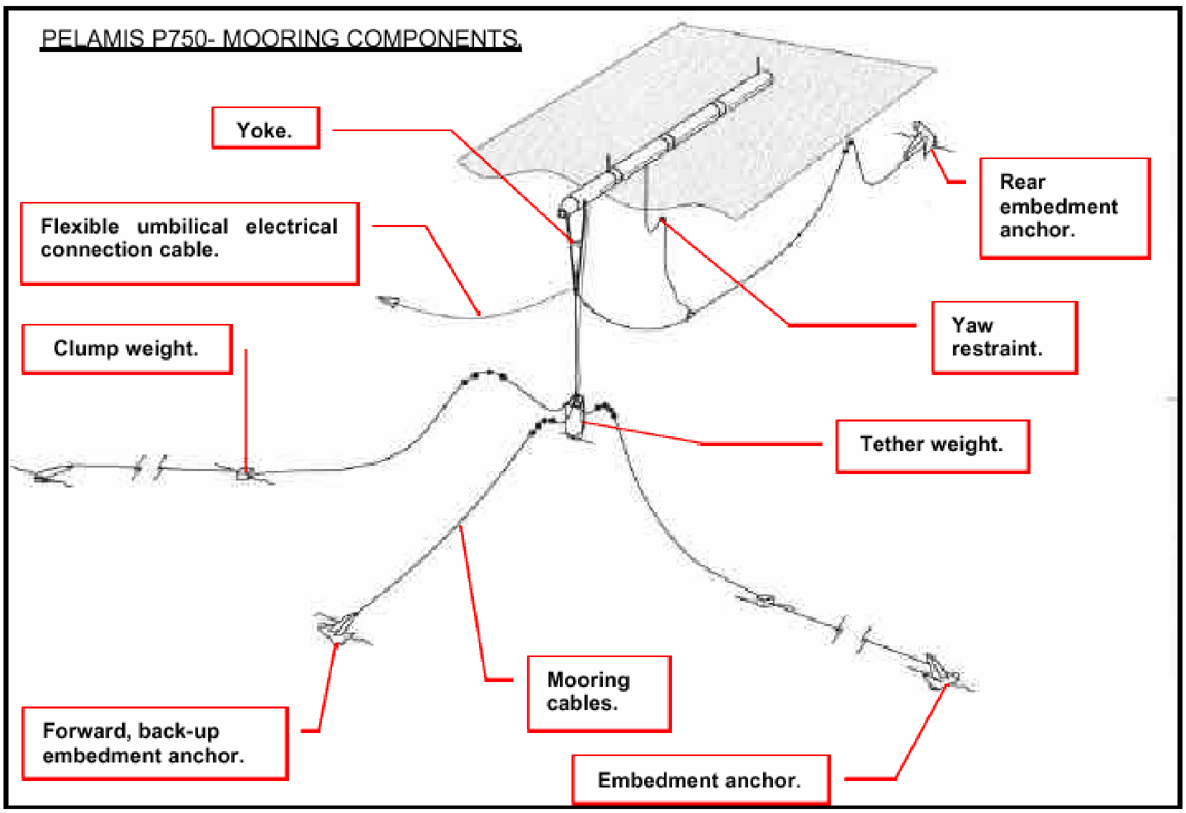


Figure 10: Mooring Arrangement of Pelamis

As shown in Figure 10, the Pelamis mooring system is a catenary type mooring using a combination of steel wire, chain, dead weights and embedment anchors. The following four pictures of Figure 10 show some of the individual mooring elements in an assembly yard to provide the reader with an understanding of the size of these individual components.


Embedment anchor.


Clump weight.


Mooring cable.

Figure 11: Mooring Illustrations

Electrical Interconnection & Communication

Each Pelamis device houses a step-up transformer to increase the voltage from generator voltage to a suitable wave farm interconnection voltage. The choice of the voltage level is driven by the grid interconnection requirements and the wave farm electrical interconnection design. A flexible riser cable is connecting the Pelamis to a junction box, sitting on the ocean floor. If multiple devices are connected together, they are daisy-chained by a jumper cable which runs from one device to the next. Only at certain strong-points the electrical cable is then brought to the ocean floor. This approach reduces the number of riser cables required and makes the cabling more accessible for maintenance from the surface. Riser and jumper cables undergo a large number of cyclic loadings and it is likely that they will need to be replaced after 10 years of operation.

The cables used are 3-phase cables with a fiber core. This fiber core is used to establish reliable communication between the devices and a shore-based supervisory system. Remote diagnostic and device management features are important from an O&M stand-point as it allows to pin-point specific issues or failures on each Pelamis unit, reducing the physical intervention requirements on the device and optimizing operational activities. Operational activities offshore are expensive and minimizing such intervention is a critical component of any operational strategy in this harsh environment. A wireless link is used as a back-up in case primary communication fails.

Subsea Cabling

Umbilical cables to connect offshore wave farms (or wind farms) to shore are being used in the offshore oil & gas industry and for the inter-connection of different locations or entire islands. In order to make them suitable for in-ocean use, they are equipped with water-tight insulation and additional armor, which protects the cables from the harsh ocean environment and the high stress levels experienced during the cable laying operation. Submersible power cables are vulnerable to damage and need to be buried into soft sediments on the ocean floor. While traditionally, sub-sea cables have been oil-insulated, recent offshore wind projects in Europe, showed that the environmental risks prohibit the use of such cables in the sensitive coastal environment. XLPE insulations have proven to be an excellent alternative, having no such potential hazards associated with its operation. Figure 12 shows the cross-sections of armored XLPE insulated submersible cables.

Figure 12: Armored submarine cables

For this project, 3 phase cables with double armor and a fiber core are being used. The fiber core allows data transmission between the Pelamis units and an operator station on shore. In order to protect the cable properly from damage such as an anchor of a fishing boat, the cable is buried into soft sediments along a predetermined route. If there are ocean floor portions with a hard bottom, the cable will have to be protected by sections of protective steel pipe, which is secured by rock bolts.

An important part of bringing power back to shore is the cable landing. Existing easements should be used, such as the easement associated with the existing effluent pipe at the International Paper facility. If they do not exist, directional drilling is the method with the least impact on the environment. Directional drilling is a well established method to land such cables from the shoreline into the ocean and has been used quite extensively to land fiber optic cables on shore.

Onshore Cabling and Grid Interconnection

Traditional overland transmission is used to transmit power from the shoreline to a suitable grid interconnection point. Grid interconnection requirements are driven by local utility requirements. At the very least, breaker circuits need to be installed to protect the grid infrastructure from system faults.

Procurement and Manufacturing

For the single-module Pelamis pilot plant, it was assumed that the 3 Power Conversion Modules are procured from Ocean Power Delivery (OPD) and is shipped from the UK to Massachusetts and that the structural steel sections are built locally in an appropriate shipyard. A number of shipyards exist along the Maine and Massachusetts coastline, capable of manufacturing the large steel sections. Figure 13 shows the Pelamis prototype under construction in Scotland. The picture on the left shows a hydraulic ram being mounted in one of the Power Conversion Modules. The picture on the right shows the large tubular steel sections of the Pelamis being completed.

Figure 13: Manufacturing the Pelamis

Mooring components such as wire, chain and the various anchor components will be purchased from local manufacturers and assembled in a local staging site before deployment. Sub-sea cables, circuit breakers etc. will also be purchased from US based manufacturers.

At the commercial scale envisioned, it will make economic sense to establish local manufacturing facilities for the Power Conversion Modules (PCM's). A number of capable manufacturing facilities exist in Massachusetts, which would be able to build and test these modules. This will allow for a large amount of US content in the devices and bring benefits to the local economy.

Wellfleet is used as the location to carry out annual overhauls and 10-year refits, which will be required to replace major subsystems.

Installation Activities

Installation and operational offshore activities require special equipment such as anchor handler vessels, barges and heavy uplift cranes. In order to understand the offshore installation and removal activities and their impacts on cost, detailed process outlines were created to be able to estimate associated resource requirements. Results were verified with Ocean Power Delivery who deployed a prototype device this year, offshore operators and Sea Engineering Hawaii who managed the installation of Ocean Power Technologies Power Buoy in Hawaii. The major installation activities for both pilot demonstration plant and commercial wave farm are:

1. Pulling Power Cables through existing Effluent Line and grid interconnection
2. Installation of sub-sea cables
3. Installation of Mooring System
4. Commissioning and Deployment of Pelamis

Offshore handling requirements were established based on technical specifications supplied by Ocean Power Delivery. Figure 14 below shows the anchor handler vessel used for the installation of the prototype in the UK. It is a standard vessel used in the UK offshore Oil & Gas industry.

For the commercial plant, it proved to be cost effective to include a AHATS class vessel in the project cost and hire dedicated staff to carry out operational activities. Figure 15 shows the prototype Pelamis being towed to its first deployment site off the coast of Scotland.

Figure 14: AHATS class vessel used for prototype installation in UK

Operational stand-by time was included in form of a weather allowance. Weather allowances depend on many factors such as vessel capabilities, and deployment and recovery processes.

Comparable numbers from the North Sea offshore oil & gas industry were adapted to local conditions, based on feedback from local offshore operators.

Figure 15: Towing the Pelamis P-750

Operational Activities

Pelamis was designed with a minimum amount of physical intervention in mind. Sophisticated remote monitoring capabilities allow the operator to monitor the device and, in case of a failure, isolate the fault to determine the exact problem and if required schedule physical intervention. In addition, the device features many levels of redundancies which will reduce the need to immediately respond to a failure.

The devices maintenance strategy is to completely detach the device from its moorings, tow the unit into a nearby harbor and carry out any repair activities along a dock-side. Initially it is envisioned, that the device is removed every year for maintenance activities. As the technology becomes more mature, these regular maintenance activities will become more infrequent. For the commercial reference plant, we assumed that removal for scheduled maintenance occurs every 2 years.

Every 10 years, the device will be recovered for a complete overhaul and refit. For that purpose, it will need to be de-ballasted and completely recovered to land. It is likely that only some touch-up painting will be required and the exchange of some of the power take off elements, such as hydraulic rams will take place at that point. The device will also need to be inspected at that time by the American Bureau of Shipping (ABS) or a related agency.

5. System Design – Pilot Plant

The outline below (Figure 16) shows the electrical setup of the demonstration pilot plant. A single Pelamis WEC device is floating on the surface and moored in a water depth of 50m – 60m. An umbilical riser cable is connecting the Pelamis to a junction box on the ocean floor. From this junction box, a double armored 3 phase cable is laid on the ocean floor, buried into the soft sediments on the ocean floor. The cable landing site will be at the Le Count Hollow Beach. It is assumed, that a suitable 12kV distribution line is in close proximity to the cable landing site. There is sufficient development in the area that it is highly probable such a distribution line is available in close proximity.

The cable is landed on shore using directional drilling. Directional drilling is well established to land cables to shore and is viewed as the method, which has the least impact on the environment. Detailed assessment of the local electrical infrastructure will be required in subsequent project phases.

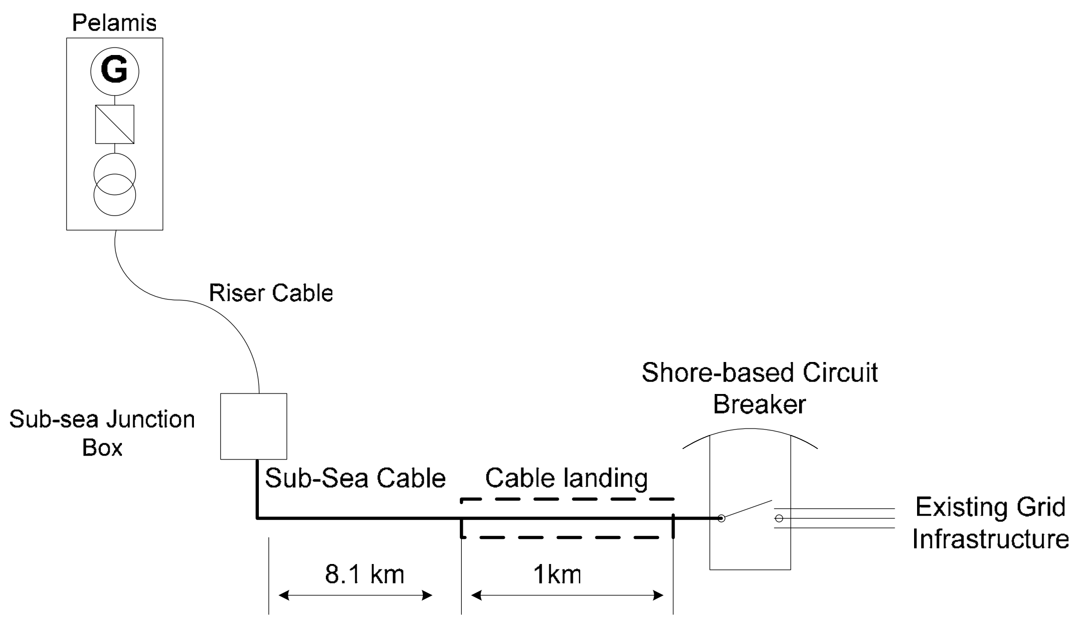


Figure 16: Electrical Interconnection of a single unit Pelamis Pilot Plant

6. System Design - Commercial Scale Wave Power Plant

While the conceptual design of the pilot plant focused on finding existing easements, allowing the installation of a small demonstration system in a cost effective manner, the commercial scale wave farm design focused on establishing a solid costing base case, and assessing manufacturing and true operational costs for a large plant. The commercial scale cost numbers were used to compare energy costs to commercial wind farms to come to a conclusion on the cost competitiveness of wave power in this particular location.

The following subsections outline the electrical system setup, the physical layout and the operational and maintenance requirements of such a deployment. In order to meet the target output of 300,000 MWh/year, a total of 206 Pelamis units are required.

Electrical Interconnection and Physical Layout

As shown in Figure 17, the commercial system uses a total of 4 clusters, each one containing 51 Pelamis units, connected to sub-sea cables. Each cluster consists of 3 rows with 17 devices per row. The 4 sub-sea cables are connecting the 4 clusters to shore as shown in Figure 17. The electrical interconnection of the devices is accomplished with flexible jumper cables, connecting the units in mid-water. The introduction of 4 independent sub-sea cables and the interconnection on the surface will provide some redundancy in the wave farm arrangement.

The 4 clusters are each 2.58 km long and 1.8 km wide, covering an ocean stretch of roughly 10 km. The 4 arrays and their safety area occupy roughly 18 square kilometers. Further device stacking of up to 4 rows might be possible reducing the array length, but is not considered in this design, as subsequent rows of devices will likely see a diminished wave energy resource and therefore yield a lower output. Such effects and their impacts on performance are not well understood at present. It is not clear at present what the best interconnection voltage for this site would be. 26kV was assumed to be the system voltage.

Based on the above setup the following key site parameters emerged:

Array Length	10 km
Array Width	1.8 km
Device Spacing	150m
Number of Rows	3
System Voltage	26kV
Sub-sea cable specs	26kV / 40MVA / 3-phase with fiber optic core

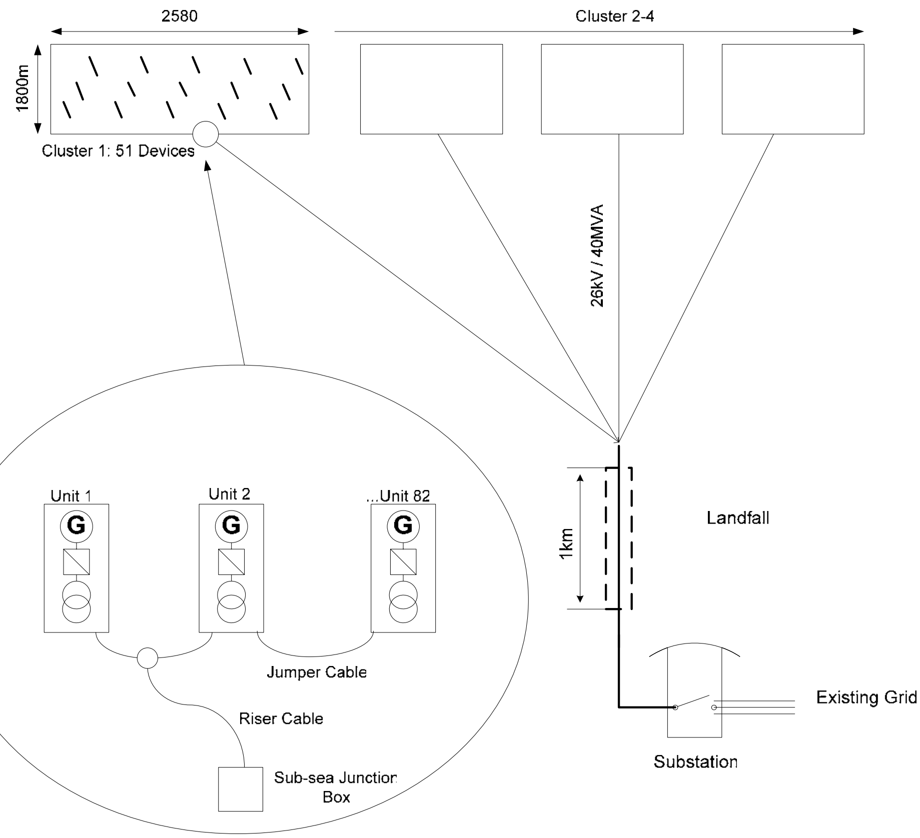


Figure 17: Overall System Layout and Electrical Connections

Operational and Maintenance Requirements

General operational activities are outlined in a previous section. It made economic sense for this wave farm to include an AHATS class vessel in the capital cost of the project. Based on the workload, the vessel will be at 100% capacity during the installation phase of the project and then its usage will drop to less then 50% to operate the wave farm.

This type of vessel has sufficient deck space to accommodate the heavy mooring pieces and a large enough crane to handle the moorings. In addition the vessel has dynamic positioning capabilities and is equipped for a 24-hour operation. Based on the work loads involved with O&M and 10-year refit operation a total full-time crew of 20 is required. This includes onshore personnel to carry out annual maintenance activities and 10-year refits.

O&M activities can be carried out at a suitable pier side in Wellfleet, with the device remaining in the water. For the 10-year refit, the device will need to be recovered to land. Budget allowances were given to accommodate infrastructure modifications to streamline operational tasks.

7. Device Performance

The device performance was assessed based on data supplied by the manufacturer and the wave climate (outlined in previous section). The following summarizes the projected device performance as described in Section 2 off the coast of Cape Cod.

Transmission line losses for the sub-sea cable from the offshore farm to the grid interconnection point at the substation were ignored as they are not significant at the design voltage levels used and can only be estimated in a detailed design phase.

Scatter or joint probability diagrams for the wave energy resource were created for each month and used for power production calculations. Figure 18 shows the average power (kW) delivered to the grid by a single Pelamis WEC Device sited as described in Section 2.

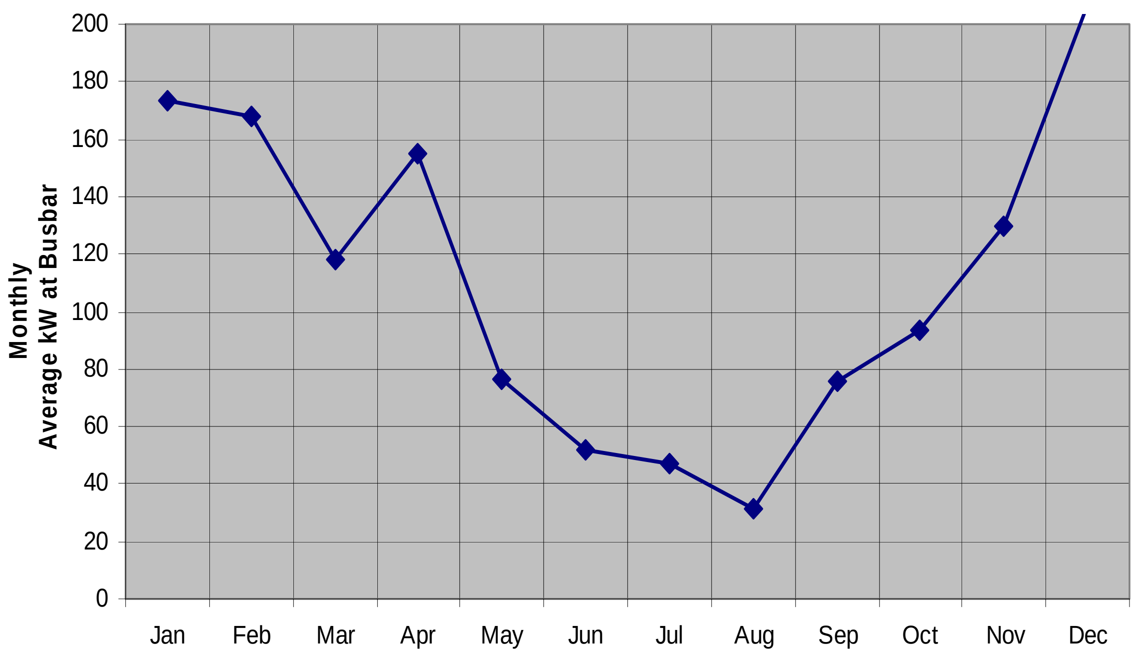


Figure 18: Monthly average power delivered to bus bar – Pilot Plant

A scatter diagram of the annual and monthly wave energy available at the deployment site was developed using long-term statistics from the Cape Cod NDBC 44018 wave measurement buoy. The scatter diagram for the annual energy is shown in Table 2.

Table 2: Massachusetts Site Annual occurrence of hours per sea-state

		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total annual hours
Hs and Tp bin boundaries			Tp (sec)																	
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	
9.75	10.25	**10**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	**9.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	**9**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	**8.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	**8**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	**7.5**	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	2
6.75	7.25	**7**	0	0	0	0	0	0	0	1	6	2	0	0	0	0	0	0	0	9
6.25	6.75	**6.5**	0	0	0	0	0	0	0	8	2	4	0	0	0	0	0	0	0	14
5.75	6.25	**6**	0	0	0	0	0	0	2	10	4	0	5	0	0	0	0	0	0	21
5.25	5.75	**5.5**	0	0	0	0	1	0	7	6	15	9	3	0	0	0	0	0	0	41
4.75	5.25	**5**	0	0	0	0	1	4	9	6	18	4	6	0	0	0	0	0	0	48
4.25	4.75	**4.5**	0	0	0	0	9	14	11	8	25	6	3	1	0	0	0	0	0	77
3.75	4.25	**4**	0	0	0	3	23	31	24	27	34	5	0	2	0	0	0	0	0	149
3.25	3.75	**3.5**	0	0	0	11	45	74	35	30	41	11	6	7	0	0	0	0	0	260
2.75	3.25	**3**	0	0	0	45	80	132	52	52	54	17	6	8	5	3	0	0	0	454
2.25	2.75	**2.5**	0	0	16	142	127	190	96	101	72	17	22	16	4	1	0	0	0	804
1.75	2.25	**2**	0	1	91	270	205	227	133	102	119	34	19	23	9	2	1	0	0	1,236
1.25	1.75	**1.5**	0	35	181	298	338	359	152	135	137	40	36	22	4	1	0	0	0	1,738
0.75	1.25	**1**	19	163	266	442	507	616	275	188	115	20	7	8	2	0	0	0	0	2,628
0.25	0.75	**0.5**	31	65	116	179	240	295	107	73	38	2	0	8	9	1	0	0	0	1,164
0	0.25	**0.125**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		8,766	*50*	*264*	*670*	*1,390*	*1,576*	*1,942*	*903*	*747*	*682*	*171*	*113*	*95*	*33*	*8*	*1*	*0*	*0*	**8,645**

Table 3: Pelamis Wave Energy Conversion Absorption Performance (kW)

Hs (m) \ Tp (s)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20
10	750	750	750	750	750	750	750	750	750	750	750	750	711	750	750	738	734
9.5	750	750	750	750	750	750	750	750	750	750	750	750	691	750	710	694	662
9	750	750	750	750	750	750	750	750	750	750	750	750	670	746	668	650	592
8.5	750	750	750	750	750	750	750	750	750	750	750	750	650	699	626	606	551
8	750	750	750	750	750	750	750	750	750	750	750	750	630	653	584	562	509
7.5	750	750	750	750	750	750	750	750	750	750	750	748	610	607	542	518	467
7	750	750	750	750	750	750	750	750	750	750	750	692	566	560	500	474	425
6.5	750	750	750	750	750	750	750	750	750	750	723	592	617	513	458	430	384
6	597	630	663	684	750	750	750	750	750	750	616	633	525	476	396	386	329
5.5	428	497	566	612	750	750	750	750	750	635	642	532	482	400	399	341	322
5	259	364	469	539	750	750	750	750	644	641	531	482	399	394	330	308	274
4.5	94	233	371	467	735	744	738	634	626	520	473	390	382	319	299	250	208
4	105	216	326	394	632	616	583	585	494	454	374	361	339	283	236	197	153
3.5	0	86	211	326	484	577	568	502	421	394	330	312	260	216	196	164	140
3	0	91	180	246	402	424	417	369	343	331	275	229	208	173	144	120	93
2.5	0	7	93	171	279	342	351	320	274	230	210	174	145	120	100	84	65
2	0	0	66	109	199	219	225	205	195	162	135	112	93	77	64	54	41
1.5	0	0	26	62	112	141	143	129	110	91	76	63	52	43	36	30	23
1	0	0	11	27	50	62	64	57	49	41	34	28	23	0	0	0	0
0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

The total energy in each sea state was calculated by multiplying each cell of the Pelamis performance scatter diagram (Table 3) with each corresponding cell in the hours of reoccurrence scatter diagram (Table 2). By summing up the two tables, the annual output (MWh/year) per Pelamis WEC device was derived. Pilot plant performance numbers are summarized in Table 4.

Table 4: Pilot Plant Pelamis Performance

Device Rated Capacity	750kW
Annual Energy Absorbed	1268 MWh/year
Device Availability	85%
Power Conversion Efficiency	80%
Annual Generation at bus bar	964 MWh/year
Average Power Output at bus bar	98 kW

The commercial plant performance was assessed using the pilot plants performance data as its basis. In addition certain performance improvements were considered. Based on well established wave theory, the Pelamis device is only absorbing a small fraction of its theoretical limit. An increase in performance by a factor of 2-3 is possible without significant changes to the device geometry. Although there are significant improvements possible, for the purpose of this study, only performance improvements were considered which could be achieved in the near future, without any additional research. Therefore, this 2-3x improvement is not considered in this study. The potential performance improvement is based on theoretical analysis of advanced strategies to actively tune the devices resonance period to the prevailing wave conditions. Readers interested in the tuning and control strategy topic are referred to "Ocean Waves and oscillating Systems" by Johannes Falnes, ISBM 0 521 78211 2 Hardback. The following shows the changes incorporated in the commercial Pelamis performance numbers:

- Changing the mooring configuration will yield a performance improvement of 37%. Design changes to achieve this performance increase are OPD commercially sensitive at this time. OPD states that this mooring configuration has been evaluated in wave tank tests and theoretical studies and is well quantified.

- The current Power Conversion Modules use standard off the shelf components. Customizing some of these components could increase the power conversion efficiency by more then 10%. The technologies to improve the conversion efficiency exist and are therefore included in the performance for the commercial plant.

- The rated capacity was changed to 500kW, because the 750kW design is overrated for the Massachusetts wave climate. The 500kW power conversion module is also reflected in the cost assessment of the power plant.

Table 5 summarizes the performance values for a commercial Pelamis module incorporating improvements as outlined above.

Table 5: Commercial Plant Pelamis Performance

Device Rated Capacity	500kW
Annual Energy Absorbed	1,738 MWh/year
Device Availability	95%
Power Conversion Efficiency	88%
Annual Generation at bus bar	1,453 MWh/year
Average Electrical Power at bus bar	166 kW
# Pelamis required to meet target 300,000 MWh/yr	206

8. Cost Assessment – Pilot Plant

The cost assessment for the pilot was carried out using a rigorous assessment of each cost center. Installation activities were outlined in detail and hourly breakdowns of offshore operational activity created to properly understand the processes and associated cost implications. Wherever possible, manufacturing estimates were obtained from local manufacturers. An uncertainty range was associated to each costing element and a Monte Carlo Simulation was run to determine the uncertainty of capital cost. Operational costs were not assessed in detail for the Pilot plant. This is a task that is scheduled for subsequent project phases. Cost centers were validated by Ocean Power Delivery, based on their production experience of their first full scale prototype machine, which was deployed in 2004.

Based on the above assumptions the following results in constant year 2004$ are presented:

Table 6: Cost Summary Table rounded to the nearest $1000

Cost Element	Pilot Plant	Basis
Onshore Transmission & Grid Interconnection	$694,000	(1)
Subsea Cables	$1,013,000	(2)
Pelamis Power Conversion Modules	$1,565,000	(3)
Pelamis Manufactured Steel Sections	$851,000	(4)
Pelamis Mooring	$243,000	(5)
Installation	$633,000	(6)
Construction Mgmt and Commissioning (10% of cost)	$500,000	(7)
Total Before Fed Inv Tax Credit and State Installation Tax Deduction	**$5,498,000**	
Federal 10% tax Credit	545,000	
State Installation Tax Deduction (9.5% tax rate)	60,000	
Total After Installation Tax Deduction	**$4,893,000**	

1) Cost includes a breaker circuit and double armored power cable being laid through existing easement in place. Cable cost is based on quotes from Olex cables.

2) Subsea cable cost is based on quotes from Olex cables. It includes a sub-sea, pressure compensated junction box, to connect the riser cable. This cost component could be reduced by $500,000 if direct drilling at land fall could be avoided by use of an existing easement

3) Based on estimate by Ocean Power Delivery. Shipping cost is included from Edinburgh (UK) to Reedsport Massachusetts based on quote by Menlo International.

4) Cost for 4 manufactured steel sections was estimated by using $2,850/per ton of manufactured steel. Each steel section of this unit weighs roughly 70 tons

(excluding ballast). This is consistent with OPD experience with manufacturing their pre-production machine and input from local manufacturers. It includes cast elements and protective coatings. Range of cost from different sources was $2,500/ton - $3,500/ton.

5) Based on OPD's experience with their pre-production prototype. Cross checks were performed using local construction management feedback.

6) Installation costs were estimated by a rigorous assessment of vessel handling requirements, breakdown of installation tasks, quotes from local operators for vessel cost, fuel and crew, and allowance for weather downtime.

7) Based on E2I EPRI Project Team experience managing like custom construction projects and commissioning to owner acceptance.

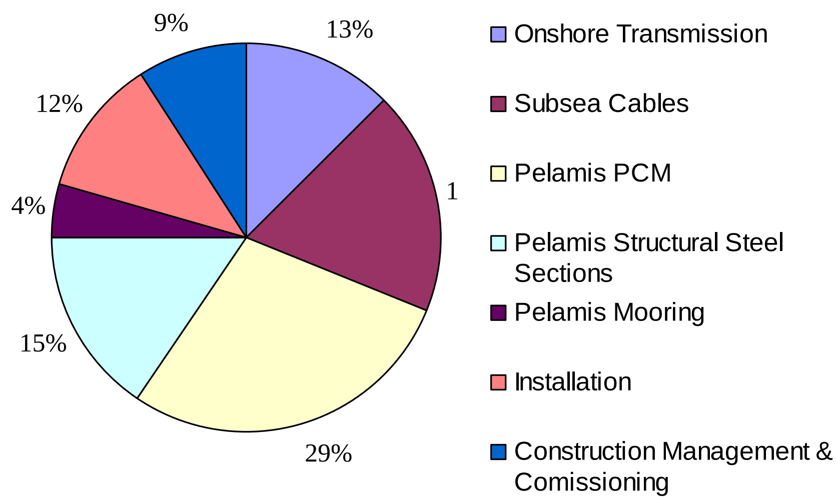


Figure 19: Pie Chart of cost centers for single unit installation

Cost uncertainties were estimated for each cost component and a Monte Carlo simulation was used to determine the likely capital uncertainty of the project. Figure 20 below shows the cost as a function of cost certainty as an S-curve. A steep slope indicates a small amount of uncertainty, while a flat slope indicates a large amount of uncertainty. It shows that the cost accuracy is within -20% to +22%. This bottom-up approach to uncertainty estimation compares to an initially estimated accuracy of -25% to +30% for a pilot scale plant based on a preliminary cost estimate rating (from the top-down EPRI model described in Ref 3).

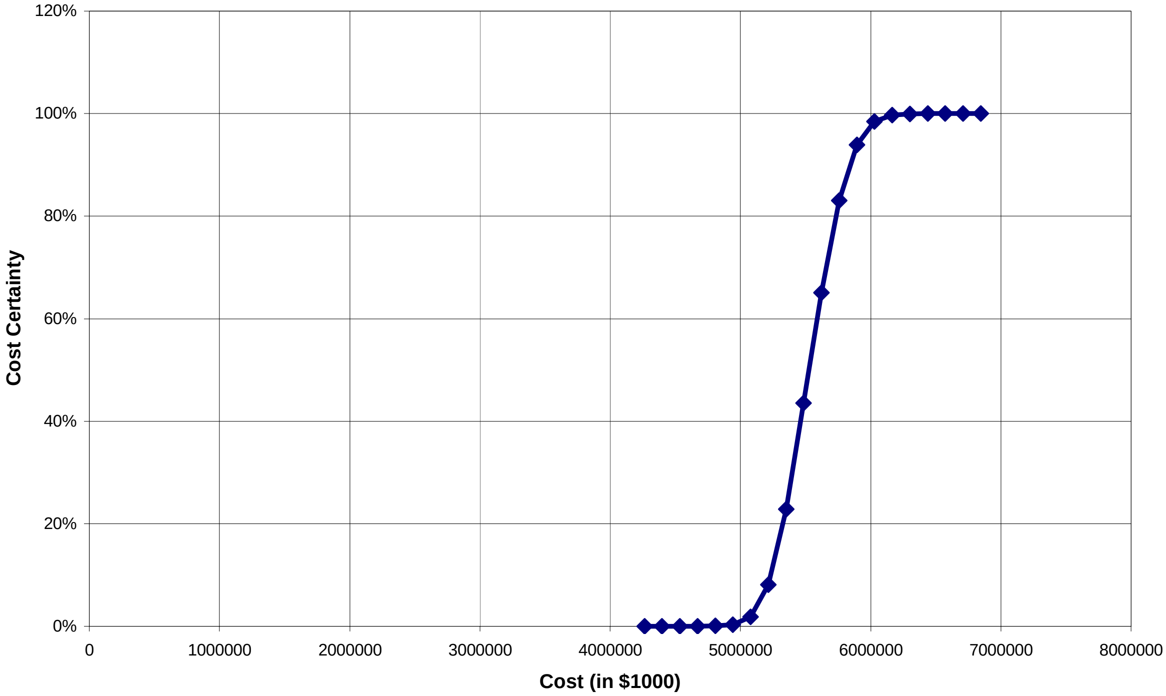


Figure 20: Capital cost uncertainty

9. Cost Assessment – Commercial Scale Plant

The cost assessment for the commercial wave power plant followed a rigorous assessment of each cost center. Instead of simply applying learning curves, a point design for the commercial plant using 206 devices was outlined and its cost estimated. For cost centers, which lend themselves well to cost reduction, outlines were created of how such cost reduction will be achieved. Installation activities were outline in detail and hourly breakdowns of offshore operational activity created to properly understand their impacts on cost and resources. Cost centers were validated by Ocean Power Delivery, based on their production experience of their first full scale prototype machine, which was deployed in 2004. Operational tasks and outlines were validated by local operators.

Table 7: Installed Cost Breakdown for Commercial Scale Plant

Cost Element	**206-Pelamis Device System**		**Basis**
Constant Dollar Year	2004	in %	
Installed Cost			
Onshore Transmission & Grid Interconnection	$6,000,000	2.4%	
Subsea Cables	$4,886,000	2.0%	
206 x Mooring Spread	$24,090,000	9.7%	(1)
206 x Power Conversion Modules	$128,536,000	51.5%	(2)
206 x Concrete Structural Sections	$50,429,000	20.2%	(3)
Facilities	$12,000,000	4.8%	(4)
Installation	$12,170,000	4.9%	(5)
Construction Mgmt and Commissioning (5% of cost)	$11,297,000	4.5%	(6)
Total Plant Cost	**$249,408,000**	**100%**	
Construction Financing Cost	$23,700,000		
Total Plant Investment	**$273,108,000**		
Yearly O&M			
Labor	$2,516,000	21.0%	(7)
Parts (2%)	$4,920,000	39.5%	(8)
Insurance (2%)	$4,920,000	39.5%	(9)
Total	**$12,355,000**	**100%**	
10-year Refit			
Operation	$10,570,000	41.0%	(7)
Parts	$15,962,000	59.0%	(7)
Total	**$26,531,000**	**100%**	

(1) The mooring spread is an assembly of standard elements and equipment. A moderate cost reduction of 30% was assumed (as compared to the prototype). This cost reduction can easily be achieved by purchasing in larger quantities.

(2) Three (3) Power Conversion Modules (PCM) are required for a single Pelamis unit. Cost of a hydro-electric power take off will be significantly lower then initial production units. The performance assessment for our reference site also shows that the PCMs are overrated and reducing the rated power to 500kW per device would yield a relatively small decrease in annual output. This is mainly attributed to the fact that the Massachusetts site has lower energy levels then UK sites for which the device was originally developed. Reference 6 shows that the cost for the three (3) PCM 500kW prototype unit in production volume is $289,00 for the power conversion train alone and another $234,000 for the manufactured steel enclosure, hinges and assembly for a total Pelamis unit cost (3 PCMs) of $523,000.

(3) The summary table in Reference 5 shows a production cost of $51,000 per tube or $204,000 per device excluding the end caps on the tubes. Including the end caps, the cost for the 4 concrete sections is $245,000 per Pelamis device. Concrete is widely used in the offshore industry and is considered the most reliable option among construction materials. However, it is important to understand that a design using concrete tubes will require design efforts up-front, to properly test the long-term fatigue characteristics of a particular design.

(4) Includes an AHATS class vessel, which is equipped to operate 24 hours per day and some provisions for dock modifications and heavy lift equipment.

(5) Installation cost was estimated by a rigorous assessment of vessel handling requirements, breakdown of installation tasks, quotes from local operators for vessel cost, fuel and crew and allowance for weather downtime.

(6) Construction management and commissioning cost was estimated at 5% of the plant cost based on discussions with experienced construction management organizations.

(7) The most cost effective approach to operate the wave power plant included an AHATS class vessel capable to operate effectively 24-hours per day. Based on a rigorous assessment of the tasks involved in operating the wave farm, it was concluded, that the vessel would be at less then 50% capacity. Shore-based and offshore operations and maintenance tasks were estimated and the results showed that a crew of 18 persons is required to operate a 180 Pelamis wave farm. In other words, it will require 0.1 full-time crew per device is required. Reduction in personnel is possible with appropriate redesign of the units to make them easier to handle and improve their reliability. A major refit is required every 10-years for a commercial plant. In other words, assuming a 20-year life, one refit is required. Elements such as hydraulic rams are replaced during that period. In addition, some of the hull is repainted. Unlike the bi-annual maintenance activities, which can be carried out on a pier side, the 10-year refit requires de-ballasting the device and recovering it onto land. It will also need to be inspected at that point by ABS or a related agency.

(8) It is unclear at present what the failure rate of components and sub-systems are. Operational experience will be required with this specific technology to draw any conclusions. An allowance of 2% of Capital cost was included for a commercial project.

(9) 2% is a typical insurance rate for offshore projects using mature technology.

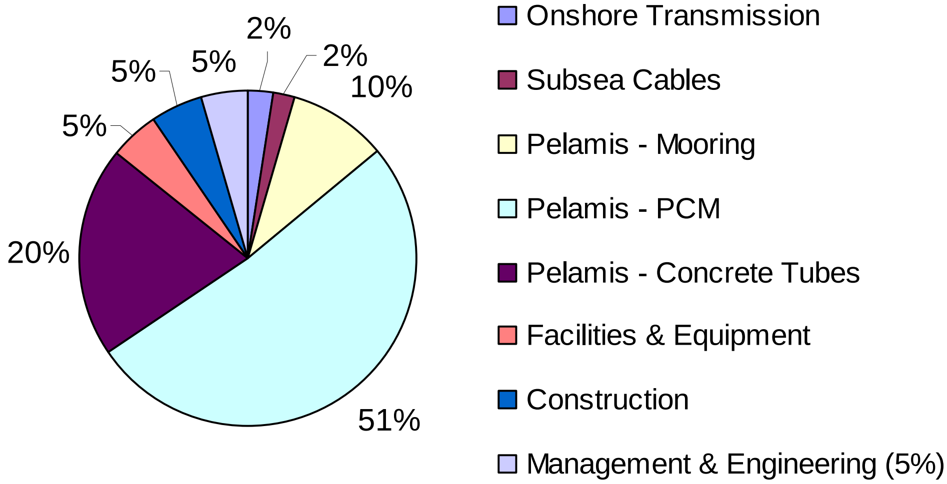


Figure 21: Installed Cost Breakdown for commercial scale plant

Cost uncertainties were estimated for each cost component and a Monte Carlo simulation was run to determine the likely capital uncertainty of the project. Figure 22 below shows the cost as a function of cost certainty as an S-curve. A steep slope indicates little uncertainty, while a flat slope indicates a large amount of uncertainty. The uncertainty for a large-scale project is bigger at this stage because it is unclear at present how well cost reductions could be achieved. These cost uncertainties were estimated for each cost center analyzed.

It shows that the cost accuracy is -24% to + 34%. This bottoms-up approach to uncertainty estimation compares to an initially estimated accuracy of -25% to +30% (from the top-down EPRI model described in Reference 2). The reason, why the projections to a commercial plant have a higher uncertainty, then for a single unit demonstration plant is because certain cost centers include cost reduction measures, which have a higher uncertainty.

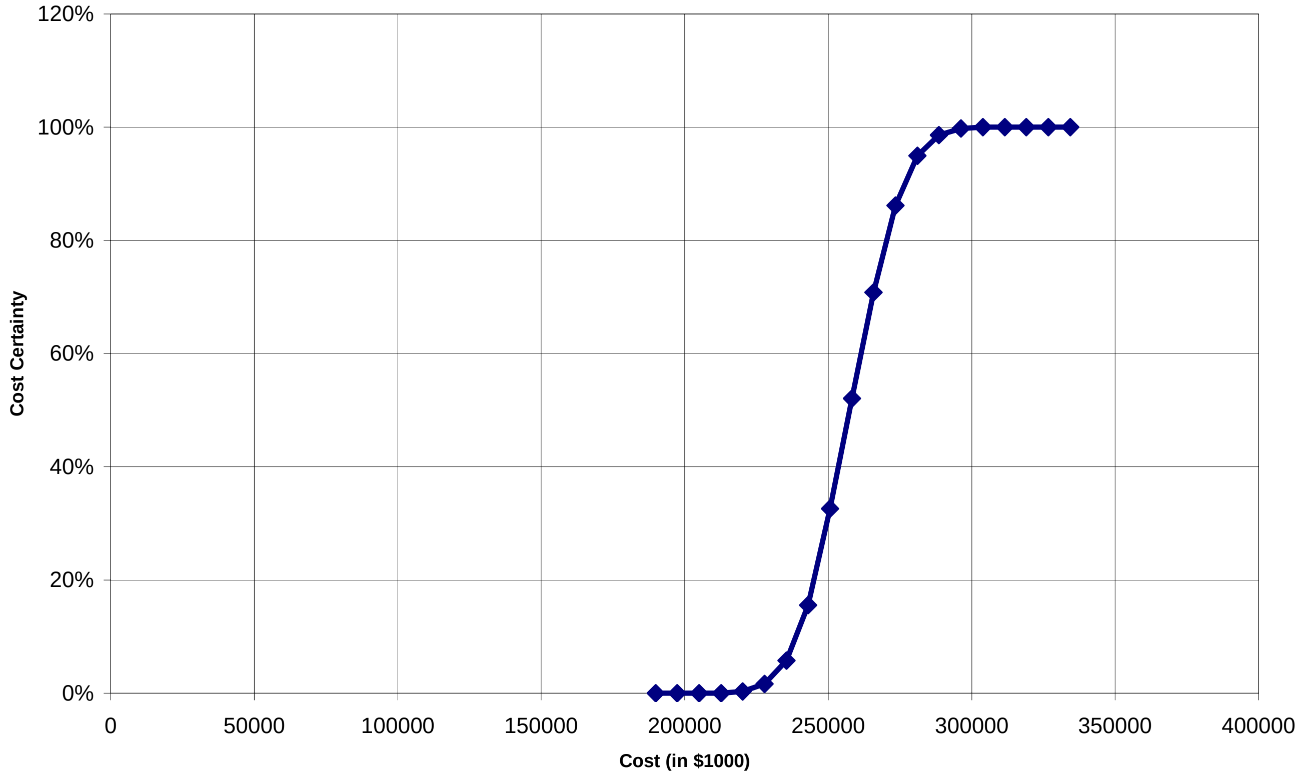


Figure 22: Installed Cost uncertainty S-curve

10. Cost of Electricity/Internal Rate of Return Assessment – Commercial Scale Plant

The Utility Generators (UG) cost of electricity (COE) and the Non-Utility Generator (NUG) internal rate of return (IRR) was assessed based on previously developed methodologies described in reference 3. In order to calculate the COE and IRR, underlying assumptions such as applicable tax rates, tax incentives, depreciation schedules and electricity price forecasts were identified based on the states applicable regulatory environment. Spreadsheet solutions were created for both UG and NUGs and the results are outlined in this section.

Table 8: UG and NUG Assumptions for the State of Massachusetts

	UG	NUG
Year Constant Dollar	2004	2004
Number of Devices	206	206
Annual Electrical Plant Output	300,000 MWh/yr	300,000 MWh/yr
Book Life	20 years	20 years
Taxation		
Federal Tax Rate	35%	35%
State Tax Rate (Massachusetts)	9.5%	9.5%
Composite Tax Rate	41.2%	41.2%
Financing		
Common Equity Financing Share	37.5%	30%
Preferred Equity Financing Share	10%	
Debt Financing Share	52.5%	70%
Nominal Common Equity Financing Rate	13%	17% (IRR hurdle rate)
Nominal Preferred Equity Financing Rate	10.5%	
Nominal Debt Financing Rate	7.5%	8%
Real Debt Financing Rate	4.5%	5%
Real Construction Financing Rate	4.5%	5%
Constant $ Discount Rate before Tax	7.52%	10.7%
Constant $ Discount Rate after Tax	6.47%	8.39%
Inflation rate	3%	3%
Renewable Credits & Incentives		
Federal Investment Tax Credit	10% of TPI	10% of TPI
Federal Production Tax Credit	1.8 cents/kWh (first 10 years)	1.8 cents/kWh (first 10 years)
State Investment Tax Credit	Installation Cost is Tax Deductible	Installation Cost is Tax Deductible

Renewable Energy Certificates (RECs)/		Through the MA RPS program, renewable energy generators receive revenue from selling RECs. Long-term projections for RECs are 2.5 cents/kWh.
Depreciation	MACR Accelerated	MACR Accelerated
Industrial Electricity Price (2002$) and	N/A	6.5 cents/kWh
Industrial Electricity Price Forecast (2002$)	N/A	8% decline from 2002 to 2008, stable through 2011 and then a constant escalation rate of 0.3%

The capital, O&M and 10-Year Refit cost and their uncertainty was previously estimated in section 8. Table 9 shows the translation of those numbers into a levelized cost of electricity (COE), using the methodology described in Reference 3.

Table 9 Major Cost elements and their Impacts on Cost of Electricity for Utility Generators (2004 constant year $) - Without RECs

Cost Element	Low	Best	High
Total Plant Investment	$202,103,000	$273,108,000	$355,818,000
Annual O&M Cost	$9,993,000	$12,356,000	$18,738,000
10-year Refit Cost (1 time cost)	$17,920,000	$26,532,000	$35,921,000
Fixed Charge rate (Nominal)	9.2	9.8	10.1
Cost of Electricity (c/kWh) (Nominal)	**10.0**	**13.4**	**19.1**
Fixed Charge rate (Real)	6.9	7.2	7.7
Cost of Electricity (c/kWh) (Real)	**8.4**	**11.1**	**16.0**

O&M costs have a significant effect on COE. It is a cost center with potential for significant improvements and is also the cost center with the most uncertainty at present because there is little experience with operating such wave farms which could be used to validate any of the numbers. Currently standard offshore oil & gas industry practices and rates were applied to derive appropriate operational costs. The offshore oil & gas industry is well known for it's high operational overhead and steep cost profiles. In order to reduce this cost center, the industry needs to learn by doing operating small wave farms. Cost reductions can be expected by improving the reliability of the deployed devices as well as improving the operational strategies.

In terms of definition, the Internal Rate of Return (IRR) is the discount rate that sets the present value of the net cash flows over the life of the plant to the equity investment at the commercial operating date. The net present value represents the present value of profit or returns using the time value of money. This calculation results from discounting the net cash flows at the 'discount rate."

Table 10 shows the translation of capital, O&M and 10-Year Refit cost and their uncertainty into an IRR using the methodology described in Reference 3.

Table 10: Major Cost elements and their impacts on Cost of Electricity for Non Utility Generators (2008 initial operation – 20 year life – current year $ = With and Without the REC)

Cost Element	Lowest Estimate	Best Estimate	High Estimate
Total Plant Investment (2004)	$209,027,000	$274,702,000	$365,977,000
Annual O&M Cost (2004$)	$9,993,000	$12,356,000	$18,738,000
10-year Refit Cost (2004$)	$17,920,000	$26,532,000	$35,921,000
With REC			
Internal Rate of Return	32.90%	7.6%	No IRR
Without REC			
Internal Rate of Return	No IRR	No IRR	No IRR

Table 10 shows that the first commercial plant owned by a NUG does have a positive internal rate of return with RECs but does not without RECs. Figure 23 and 25 shows the cumulative cash in current year dollars for the 20 year life of the project with and without RECs, respectively. Figure 24 and 26 shows the net cash flow in current year dollars for the life of the project with and without RECs, respectively. The economics analysis worksheets for these first UG and NUG commercial offshore wave power plant, both with and without RECs, are contained in Appendix B, C and D respectively

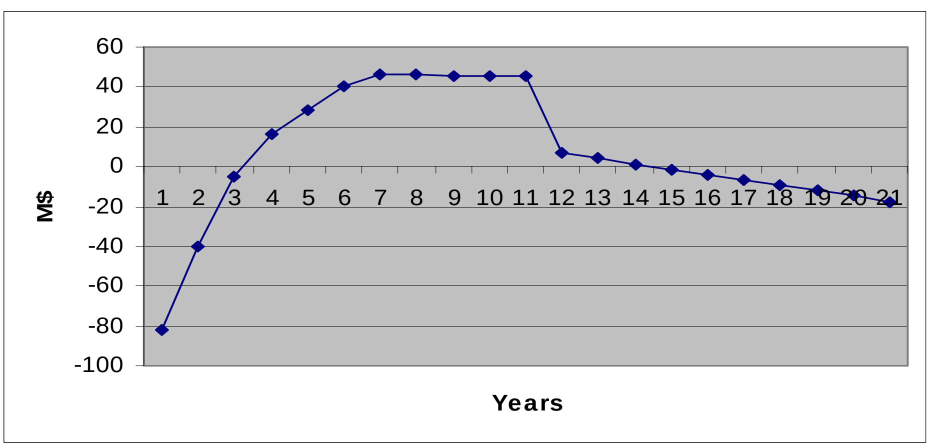


Figure 23: Cumulative Cash Flow Over 20 Year Project Life

Figure 24: Net and Cumulative Cash Flow Over 20 Year Project Life – With REC

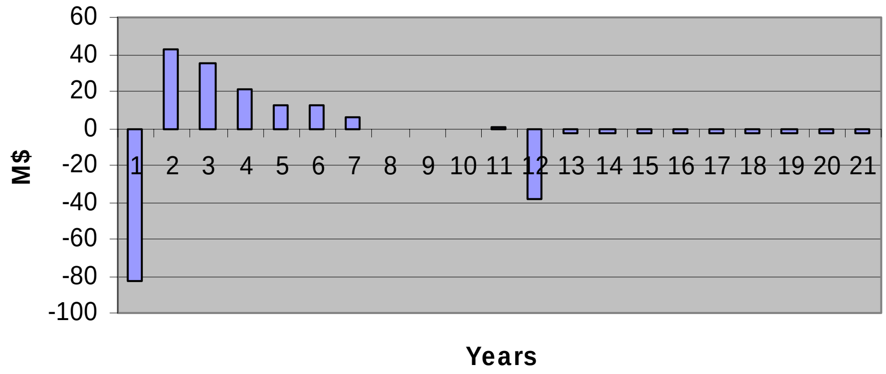


Figure 25: Cumulative Cash Flow Over 20 Year Project Life

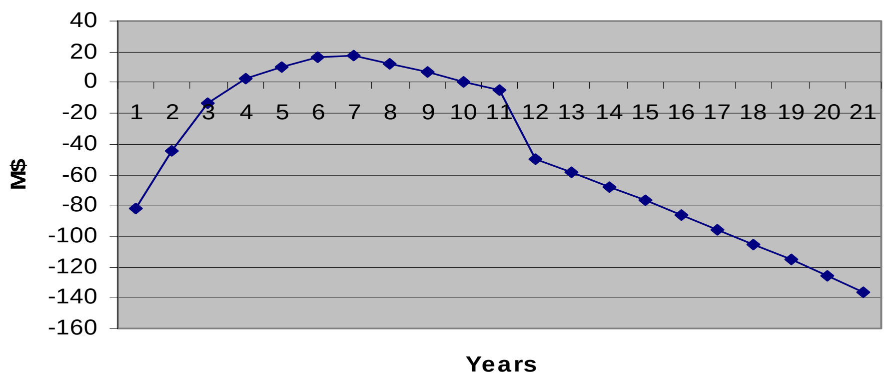
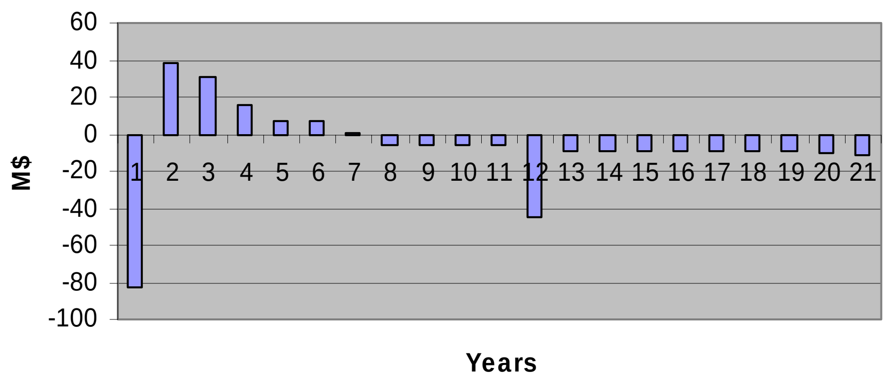


Figure 26: Net and Cumulative Cash Flow Over 20 Year Project Life – Without REC



11. Learning Curves

Operating in competitive markets makes enterprises do better. This fact is at the core of the learning curve phenomenon. Learning through production experience reduces prices for energy technologies and these reductions influence the dynamic competition among technologies. In addition, learning curves are used by Government policymakers to design measures to stimulate the production of new technologies to where they become commercially competitive.

In order to make available environmentally effective technologies (or technologies that have characteristics that are deemed to be of societal benefit), which are price competitive, governments support these technologies through funding of RD&D and through price subsidies or other forms of deployment policy. Crucial questions concern how much support a technology needs to become competitive and how much of this support has to come from government budgets. Learning curves make it possible to answer such questions because they provide a simple, quantitative relationship between price and the cumulative production or use of a technology. There is overwhelming empirical support for such a price-experience relationship forms all fields of industrial activity, including the production of equipment that transfers or uses energy.

As explained in reference 3, cost reduction goes hand-in-hand with cumulative production experience and follows logarithmic relations such that for each doubling of the cumulative production volume, there is a corresponding percentage drop in cost. An 82% learning curve is the curve to use for wave technology based on experience in the wind, photovoltaic and offshore oil and gas platform industry.

How a learning curve is used to show the deployment investment necessary to make a technology, such as wave energy, competitive with an existing technology, such as wind energy is illustrated in Figure 27. It does not, however, forecast when the technologies will break-even. The time of break-even depends on the deployment rates, which the decision-maker can influence through policy.

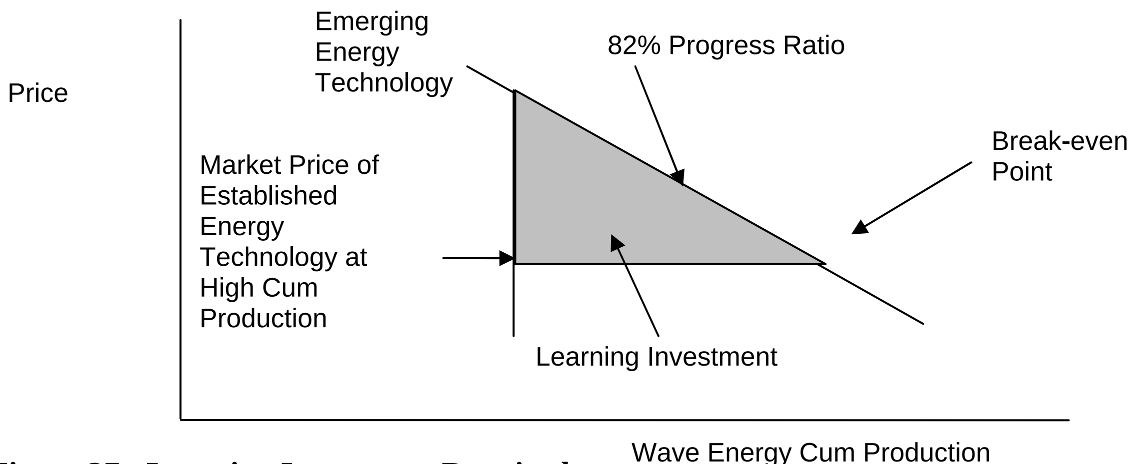


Figure 27: Learning Investment Required

12. Comparison with Commercial Scale Wind Power Plant

The cost (in 2004$) of a 750 kW pilot offshore wave energy power plant is described in Section 7 using the production experience gained by OPD from the build of the first prototype machine. The cost of a 103 MW commercial scale offshore wave energy power plant is described in Section 8 and was estimated as an extension of the costs of the pilot plant with cost reductions estimated for each major component individually, i.e., an overall learning curve was not used.

In this section, we apply learning cost reductions discussed in the previous section to wave power systems using the cost of the 103 MW commercial plant as the entry point to the learning curve process. The purpose is to enable the comparison of the cost of an offshore commercial scale wave farm versus the cost of an equivalent wind farm assuming the same level of production experience for both technologies.

For wind power plants and as reported by the National Wind Coordinating Council (NWCC), the installed capital cost has decreased from more than $2,500/kW in the early eighties to the 1997 range of $900/kW to $1,200/kW in 1997$[2]. The actual cost for a given installation depends on the size of the installation, the difficulty of construction, and the sophistication of the equipment and supporting infrastructure. "Total installed cumulative production volume topped 39,000 MW in 2003 and was about 10,000 MW in 1997"[3]. Based on the above numbers, the wind industry shows a progress ratio of 82%.

It turns out that the comparison of installed cost per unit of maximum or rated power as a function of cumulative installed capacity is not a meaningful comparison because of the effect of overrated or derated energy conversion devices. The 206 device Pelamis 1st commercial plant system has a rating of 103 MW, however, it could be overrated or derated by the manufacturer without much of a change in the annual energy production.

In order to make a meaningful comparison between wind and wave, a levelized comparison using COE numbers is required. In order to predict the cost of electricity for wave, a forecast of O&M cost is required. The following facts were considered in coming up with a conclusion:

- Offshore systems are more difficult to access then onshore systems and it is likely that it will always be more expensive to operate them then onshore systems
- Reliability will be similar to modern wind turbines Today (assuming the same cumulative production volume)
- Improvement in O&M costs can be made by paying greater attention to operational aspects in the design of the device

[2] "Wind Energy Costs" NWCC Wind Energy Series, Jan 1997, No 11
[3] "Wind Energy Industry Grows at Steady Pace, Adds Over 8,000 MW in 2003" American Wind Energy Association

Based on numerous discussions, we believe a reasonable assumption for mature wave power technology O&M cost is 50% higher then shore based wind at a cumulative installed capacity of 40,000 MW. Using the O&M cost quoted by WCC of 1.29 cents/kWh, wave would have 1.9 cents/kWh at the equivalent cumulative installed capacity. Based on this assumption, COE costing curves are presented as a function of installed capacity and compared to wind. Optimistic and pessimistic scenarios are presented based on the uncertainty in opening Total Plant Investment and O&M costs of the commercial plant outlined in earlier sections of this report.

The NWCC (footnote 3) also provides data on O&M costs (in 1997$) as follows:

Management, Insurance, Land use and Property Taxes	0.39 cents/kWh
Unscheduled Maintenance	0.68 cents/kWh
Preventative Maintenance	0.18 cents/kWh
Major Overhaul	0.04 cents/kWh
Total	**1.29 cents/kWh**

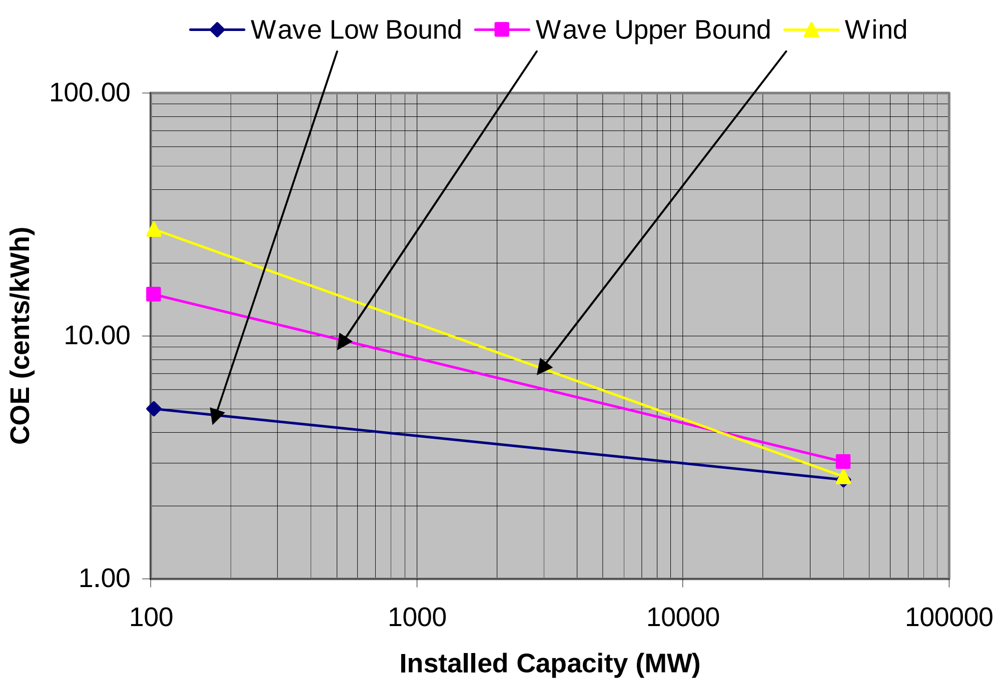


Figure 28: Levelized Wave Energy COE comparison to Wind - Without REC

The results in Figure 28 show that wave energy economics are favorable to wind energy economics at equivalent cumulative production level of less than 15,000 for the high wave cost estimate and to 40,000 MW for the low wave cost estimate. The reason that the slopes of the wave curves are different from the 82% learning curve slope of the wind curve is the lower learning slope of the wave energy O&M costs. The O&M component of COE for wave energy presents a challenge to the wave energy industry to drive down O&M costs to offer even more economic favorability for cumulative production volumes in excess of 40,000 MW..

The techno-economic assessment forecast made by the Project Team is that wave energy will become commercially competitive with the current 40,000 MW installed land-based wind technology at a cumulative production volume of about 40,000 MW. The size of a wave machine will be an order of magnitude smaller that an equivalent rated power wind machine and therefore is forecast to be less costly. The O&M costs for a remotely located offshore wave machine in a somewhat hostile environment will be higher than for a land based wind machine. The results of this study show that the lower cost machine only outweighs the additional O&M cost on a cost of electricity basis until a cumulative production volume of about 40,000 MW.

In addition to economics, there are other compelling arguments for investing in offshore wave energy. The first is that, with proper siting, converting ocean wave energy to electricity is believed to be one of the most environmentally benign ways of electricity generation. Second, offshore wave energy offers a way to avoid the 'Not In My Backyard' (NIMBY) issues that plague many energy infrastructure projects, from nuclear, coal and wind generation to transmission and distribution facilities. Because these devices have a very low profile and are located at a distance from the shore, they are generally not visible. Third, because wave energy is less intermittent that other renewable technologies such as solar and wind, it offers the possibility of being dispatchable and earning a capacity payment (this needs to be explored – see recommendations in Section 14)

The key characteristic of wave energy that promises to enable it to be one of the lowest cost renewable technologies is its high power density. Solar and wind power systems use a very diffuse solar and wind energy source. Processes in the ocean tend to concentrate the solar and wind energy into ocean waves making it easier and cheaper to harvest.

Lastly, since a diversity of energy sources is the bedrock of a robust electricity system, to overlook wave energy is inconsistent with our national needs and goals. Wave energy is an energy source that is too important to overlook.

13. Conclusions

Pilot Offshore Wave Power Plant

The upper arm of Cape Cod, Massachusetts is potentially a good location an offshore wave power plant. There are plenty of manufacturing facilities in Massachusetts, which could be used to build, assemble and deploy the wave power plant. Easements to land the power cable have not been identified, although they very likely exist. If such an easement can be identified, this would lower the cost for a pilot plant by about $500,000 and eliminate many cumbersome permitting issues.

The next steps forward towards implementing a wave energy pilot plant in Cape Cod Massachusetts are 1) Identify a local easement to land the power cable to shore, 2) to assess local public support and local infrastructure interest (marine engineering companies and fabricators), 3) to analyze site-specific environmental effects and 4) to develop a detailed implementation plan for a Phase II (Detailed Design, Environmental Impact Statement, Permitting , Construction Financing and Detailed Implementation Planning for Construction, and Operational Test and Evaluation)

Commercial Scale Offshore Wave Power Plants

The Cape Cod Massachusetts commercial scale power plant design, performance and cost results show that an offshore wave power plant, if learning investments are made to achieve the same degree of learning as today's wind technology, will provide favorable economics compared to wind technology in terms of both COE for a UG and in terms of IRR for a NUG.

As a new and emerging technology, offshore wave power has essentially no production experience and therefore its costs, uncertainties and risks are relatively high compared to existing commercially available technologies such as wind power with a cumulative production experience of about 40,000 MW installed. Private energy investors most probably will not select offshore wave technology when developing new generation because the cost, uncertainties and risk are too high at this point in time.

Government subsidy learning investments in wave energy technology, both RD&D and deployment are needed to ride down the experience curve to bring prices down to the break even point with wind energy technology. The market will then be transformed and offshore wave energy technology will be able to compete in the market place without further government subsidy (or at a subsidy equal to the wind energy subsidy). The learning effect irreversibly binds tomorrow's options to today's actions. Successful market implementation sets up a positive price-growth cycle; market growth provides learning and reduces price, which makes the product more attractive, supporting further growth which further reduces price. Conversely, a technology, which cannot enter the market because it is too expensive will be denied the learning necessary to overcome the cost barrier and therefore the technology will be locked-out from the market.

The learning-curve phenomenon presents the Government policy-maker with both risks and benefits. The risks involve the lock-out of potentially low-cost and environmentally benign technologies. The benefits lie in the creation of new technology options by exploiting the learning effect. However, there is also the risk that expected benefits will not materialize. Learning opportunities in the market and learning investments are both scarce resources. Policy decisions to support market learning for a technology must therefore be based on assessments of the future markets for the technology and its value to the energy system

In a market where price reflects all present and future externalities, we expect the integrated action of the actors to produce an efficient balance of the technology options. The risk of climate change and the social and health costs of some electricity generation options, however, pose an externality, which might be very substantial and costly to internalize through price alone. Intervening in the market to support a climate-friendly technology that may otherwise risk lock-out is a legitimate way for the Government policy-maker to manage the externality.

We conclude that offshore wave technology requires a Federal Government learning investment subsidy in order for it to be able to compete with available electricity generation technologies. All electricity generation technologies commercially available today have received Federal Government subsidies in the past. Subsidy of beneficial societal energy options has traditionally not been handled by State Governments. Wave energy technology will not be the first electricity generation technology to reach the commercial market place without Federal Government subsidy. Governments in Europe and the Government of Australia are subsidizing off shore wave energy. Should the U.S. Government drive the cumulative volume up and the price down by funding offshore wave energy technology RD&D and providing deployment subsidies?

Techno-Economic Challenges

Offshore wave energy electricity generation is a new and emerging technology application. The first time electricity was provided to the electrical grid from an offshore wave power plant occurred in early August 2004 by the full scale preproduction OPD Pelamis prototype in the UK. Many important questions about the application of offshore wave energy to electricity generation remain to be answered. Some of the key issues which remain to be addressed are:

- There is not a single wave power technology. Rather we are talking about a wide range of wave power technologies and power conversion machines which are currently under development. It is unclear at present what type of technology will yield optimal economics.

- It is also unclear at present at which size these technologies will yield optimal economics. Wave Power devices are typically tuned to prevailing wave conditions. As such optimization is largely driven by the wave climate at the deployment site. Very few existing designs have been optimized for the US wave climate. Wind turbines for example have grown in size from less then 100kW per unit to over 3MW in order to drive down cost.

- Given a certain device type and rating, what capacity factor is optimal for a given site? Ocean waves have a vast range of power levels and optimal power ratings can be only determined using sophisticated techno-economic optimization procedures.

- Will the low intermittency (relative to solar and wind) and the better predictability of wave energy (relative to solar and wind) earn capacity payments for its ability to be dispatched for electricity generation?

- Will the installed cost of wave energy conversion devices realize their potential of being much less expensive per COE than solar or wind (because a wave machine is converting a much more concentrated form of energy than a solar or wind machine and is therefore smaller in size)?

- Will the O&M cost of wave energy conversion devices be as high as predicted in this study and remain much higher than the O&M cost of solar or wind (because of the more remote and harsher environment in which it operates and must be maintained)?

- Will the performance, reliability and cost projections be realized in practice once wave energy devices are deployed and tested?

14. Recommendations

Pilot Offshore Wave Power Plant

E2I EPRI makes the following specific recommendations to the Massachusetts State Electricity Stakeholders:

1. Encourage the ongoing R&D at universities such as University of Massachusetts , MIT and Woods Hole Oceanographic Institute to include technology cost reduction, improvement in efficiency and reliability, identification of sites, interconnection with the utility grid and study of impacts of the technology on marine life and the shoreline

2. Coordinate efforts to attract a pilot feasibility demonstration wave energy system project to the Massachusetts coast

3. Now that the Cape Cod Massachusetts pilot demonstration plant project definition study is complete, proceed to the next steps of assessing local public support, local infrastructure interest (marine engineering companies and fabricators), analyzing site-specific environmental effects and developing a detailed implantation plan for a Phase II (Detailed Design, Environmental Impact Statement, Permitting, Construction Financing and Preliminary Implementation Planning for Construction, and Operational Test and Evaluation)

   If this recommendation cannot be implemented at this time (due to lack of funding or other reason), E2I EPRI Global recommends that the momentum built up in Phase 1 be sustained in order to bridge the gap until Phase II can start by funding what we will call Phase 1.5 with the following tasks

   a. Tracking potential funding sources
   b. Tracking wave energy test and evaluation projects overseas (primarily in the UK, Portugal and Australia) and in Hawaii
   c. Tracking status and efforts of the permitting process for new wave projects
   d. Track and assess new wave energy devices
   e. Establish a working group for the establishment of a permanent wave energy testing facility in the U.S.
   f. Develop Communications Plan and Messaging Kit for State Champions

4. Build collaboration with other states with interest and common goals in offshore wave energy.

Commercial Scale Offshore Wave Power Plants

E2I EPRI makes the following specific recommendations to the Massachusetts State Electricity Stakeholders relative to a Cape Cod Massachusetts commercial scale offshore wave power plant

1. Understand the implications of Government subsidy of wave energy technology, the use of learning curves to assist in subsidy decision-making and the potential for lock-out of the technology if the Government decides to withhold subsidy from this technology.

If after gaining this understanding, you advocate Government subsidy of offshore wave energy technology:

1. Encourage Department of Energy leaders to initiate an ocean energy RD&D program. Specifically, we recommend that the Federal government develop a wave energy technology roadmap and RD&D plan to fill the known technology gaps and then plan a RD&D program with levels of funding and timeframes.

2. Encourage DOE leaders to participate in the development of offshore wave energy technology (standards, national offshore wave test center, etc).

Technology Application

In order to stimulate the growth of ocean energy technology in the United States and to address and answer the techno-economic challenges listed in Section 13, we recommend the following take place:

- Federal recognition of ocean energy as a renewable resource, and public recognition by Congress that expansion of an ocean energy industry in the U.S. is a vital national priority.

- Creation of an ocean energy program within the Department of Energy's Energy Efficiency and Renewable Energy division.

- DOE works with the government of Canada on an integrated bi-lateral ocean energy strategy.

- The process for licensing, leasing, and permitting renewable energy facilities in U.S. waters must be streamlined

- Provision of production tax credits, renewable energy credits, and other incentives to spur private investment in Ocean Energy technologies and projects.
- Provision of adequate federal funding for ocean energy R&D and demonstration projects.
- Ensuring that the public receives a fair return from the use of ocean energy resources and that development rights are allocated through an open, transparent process that takes into account state, local, and public concerns.

15. References

1. E2I EPRI WP US 005 "Methodology for Conceptual Level Design of Offshore Wave Power Plants" Mirko Previsic and Roger Bedard, June 9, 2004

2. E2I EPRI WP US 001 "Guidelines for Preliminary Estimation of Power Production by Offshore Wave Energy Conversion Devices" George Hagerman and Roger Bedard, December 22, 2003

3. E2I EPRI WP US 003 "Economic Assessment Methodology for Offshore Wave Energy Power Plants" Rev 2. Mirko Previsic and Roger Bedard, August 16, 2004

4. E2I EPRI WP US 004 "E2I EPRI Assessment Offshore Wave Energy Devices" Rev 1, Mirko Previsic, Roger Bedard and George Hagerman, June 16, 2004

5. "Pelamis WEC – Main Body Structural Design and Material Selection", Department of Trade and Industry (DTI)

6. "Pelamis WEC – Conclusion of Primary R&D", Department of Trade and Industry (DTI)

Appendix A – Monthly Wave Energy Resource Scatter Diagrams

Table A-1: Scatter diagram January

		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries											Tp (sec)									
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	3	1	0	0	0	0	0	0	0	0	4
5.75	6.25	6	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	1
5.25	5.75	5.5	0	0	0	0	0	0	3	1	1	0	0	0	0	0	0	0	0	5
4.75	5.25	5	0	0	0	0	0	0	5	2	2	0	0	0	0	0	0	0	0	9
4.25	4.75	4.5	0	0	0	0	1	4	4	3	6	0	0	0	0	0	0	0	0	18
3.75	4.25	4	0	0	0	1	5	11	5	4	4	1	0	0	0	0	0	0	0	31
3.25	3.75	3.5	0	0	0	4	16	14	2	4	6	0	0	0	0	0	0	0	0	47
2.75	3.25	3	0	0	0	14	23	32	4	10	6	1	0	0	0	0	0	0	0	91
2.25	2.75	2.5	0	0	2	39	22	16	11	3	5	0	0	0	0	0	0	0	0	98
1.75	2.25	2	0	0	30	54	28	20	12	12	16	0	0	0	0	0	0	0	0	174
1.25	1.75	1.5	0	6	25	33	24	15	8	6	11	0	0	0	0	0	0	0	0	130
0.75	1.25	1	4	11	17	30	16	22	20	7	4	0	0	0	0	0	0	0	0	133
0.25	0.75	0.5	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	2
0	0.25	0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		744	5	17	75	176	137	136	75	57	64	2	0	0	0	0	0	0	0	744

Table A-2: Scatter Diagram February

		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries											Tp (sec)									
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	2
5.75	6.25	6	0	0	0	0	0	0	1	5	1	0	0	0	0	0	0	0	0	7
5.25	5.75	5.5	0	0	0	0	1	0	1	3	3	0	0	0	0	0	0	0	0	8
4.75	5.25	5	0	0	0	0	0	1	1	1	3	1	4	0	0	0	0	0	0	11
4.25	4.75	4.5	0	0	0	0	0	1	1	0	2	0	0	1	0	0	0	0	0	5
3.75	4.25	4	0	0	0	0	0	5	3	2	4	0	0	0	0	0	0	0	0	14
3.25	3.75	3.5	0	0	0	3	9	15	6	5	12	2	0	0	0	0	0	0	0	53
2.75	3.25	3	0	0	0	15	18	20	1	3	4	4	2	0	0	0	0	0	0	68
2.25	2.75	2.5	0	0	4	28	25	33	2	8	13	1	1	0	0	0	0	0	0	116
1.75	2.25	2	0	0	16	52	31	15	9	9	8	3	2	0	0	0	0	0	0	146
1.25	1.75	1.5	0	5	15	25	29	4	3	8	17	0	0	0	0	0	0	0	0	107
0.75	1.25	1	2	16	11	13	16	15	15	10	3	0	0	0	0	0	0	0	0	102
0.25	0.75	0.5	3	4	2	5	1	6	5	4	3	0	0	0	0	0	0	0	0	33
0	0.25	0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		672	5	25	49	141	131	116	49	61	74	11	9	1	0	0	0	0	0	672

Table A-3: Scatter Diagram March

		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries											Tp (sec)									
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.75	6.25	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.25	5.75	5.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.75	5.25	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.25	4.75	4.5	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	2
3.75	4.25	4	0	0	0	0	3	2	2	0	5	2	0	0	0	0	0	0	0	14
3.25	3.75	3.5	0	0	0	1	3	16	2	2	5	4	0	0	0	0	0	0	0	33
2.75	3.25	3	0	0	0	1	6	16	11	7	2	4	0	0	0	0	0	0	0	47
2.25	2.75	2.5	0	0	1	13	10	24	21	16	10	0	0	0	0	0	0	0	0	95
1.75	2.25	2	0	0	11	39	17	30	13	14	22	2	0	0	0	0	0	0	0	148
1.25	1.75	1.5	0	10	32	22	17	26	4	7	9	1	0	0	0	0	0	0	0	128
0.75	1.25	1	4	28	27	27	32	22	7	7	1	0	1	0	0	0	0	0	0	156
0.25	0.75	0.5	3	10	17	8	21	34	12	4	1	0	0	0	0	0	0	0	0	110
0	0.25	0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		733	7	48	88	111	110	171	72	57	55	13	1	0	0	0	0	0	0	733

Table A-4: Scatter Diagram April

		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries											Tp (sec)									
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.75	6.25	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.25	5.75	5.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.75	5.25	5	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	1
4.25	4.75	4.5	0	0	0	0	0	2	1	0	0	0	0	0	0	0	0	0	0	3
3.75	4.25	4	0	0	0	0	1	2	3	4	2	1	0	0	0	0	0	0	0	13
3.25	3.75	3.5	0	0	0	1	4	10	8	5	3	1	2	0	0	0	0	0	0	34
2.75	3.25	3	0	0	0	2	10	17	15	12	3	3	0	0	0	0	0	0	0	63
2.25	2.75	2.5	0	0	0	8	12	19	35	43	20	3	1	0	0	0	0	0	0	143
1.75	2.25	2	0	0	2	24	27	22	18	21	24	1	0	0	0	0	0	0	0	141
1.25	1.75	1.5	0	3	23	28	21	26	17	24	17	0	0	0	0	0	0	0	0	161
0.75	1.25	1	0	3	15	14	15	35	32	26	7	0	0	0	0	0	0	0	0	149
0.25	0.75	0.5	0	0	0	0	1	8	2	1	1	0	0	0	0	0	0	0	0	13
0	0.25	0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		720	0	6	40	78	92	143	133	138	78	9	3	0	0	0	0	0	0	720

Table A-5: Scatter Diagram May

		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries											Tp (sec)									
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.75	6.25	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.25	5.75	5.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.75	5.25	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.25	4.75	4.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3.75	4.25	4	0	0	0	0	0	2	2	1	2	0	0	0	0	0	0	0	0	7
3.25	3.75	3.5	0	0	0	0	0	3	0	0	3	1	0	0	0	0	0	0	0	7
2.75	3.25	3	0	0	0	0	2	3	3	1	2	0	0	0	0	0	0	0	0	12
2.25	2.75	2.5	0	0	0	3	6	14	3	5	4	0	0	0	0	0	0	0	0	36
1.75	2.25	2	0	0	4	12	11	34	11	2	3	0	0	0	0	0	0	0	0	76
1.25	1.75	1.5	0	1	14	28	29	74	25	26	9	2	0	0	0	0	0	0	0	209
0.75	1.25	1	0	22	26	32	57	88	43	16	7	1	0	0	0	0	0	0	0	292
0.25	0.75	0.5	1	1	4	9	18	53	16	3	0	0	0	0	0	0	0	0	0	105
0	0.25	0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		744	1	24	48	84	123	270	103	55	32	4	0	0	0	0	0	0	0	744

Table A-6: Scatter Diagram June

		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries											Tp (sec)									
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.75	6.25	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.25	5.75	5.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.75	5.25	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.25	4.75	4.5	0	0	0	0	0	1	0	0	1	0	0	0	0	0	0	0	0	2
3.75	4.25	4	0	0	0	0	1	0	1	0	3	1	0	0	0	0	0	0	0	6
3.25	3.75	3.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2.75	3.25	3	0	0	0	0	2	1	1	5	4	0	0	0	0	0	0	0	0	13
2.25	2.75	2.5	0	0	0	2	0	2	0	1	0	0	0	0	0	0	0	0	0	5
1.75	2.25	2	0	0	0	1	5	6	5	0	2	0	0	0	0	0	0	0	0	19
1.25	1.75	1.5	0	0	9	16	45	46	26	9	8	0	0	0	0	0	0	0	0	159
0.75	1.25	1	1	12	13	28	54	121	57	21	7	0	0	0	0	0	0	0	0	314
0.25	0.75	0.5	0	9	11	41	59	67	13	2	0	0	0	0	0	0	0	0	0	202
0	0.25	0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		720	1	21	33	88	166	244	103	38	25	1	0	0	0	0	0	0	0	720

Table A-7: Scatter Diagram July

		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries			Tp (sec)																	
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.75	6.25	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.25	5.75	5.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.75	5.25	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.25	4.75	4.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3.75	4.25	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3.25	3.75	3.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2.75	3.25	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2.25	2.75	2.5	0	0	0	0	0	6	0	0	0	0	0	0	0	0	0	0	0	6
1.75	2.25	2	0	0	0	2	13	31	14	1	0	0	0	0	0	0	0	0	0	61
1.25	1.75	1.5	0	0	0	27	42	34	9	0	0	0	0	0	0	0	0	0	0	112
0.75	1.25	1	0	6	12	84	142	125	15	5	2	0	0	0	0	0	0	0	0	392
0.25	0.75	0.5	0	2	3	21	64	61	10	8	3	0	0	0	0	0	0	0	0	172
0	0.25	0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		744	0	8	15	134	262	258	48	14	5	0	0	0	0	0	0	0	0	744

Table A-8: Scatter Diagram August

		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries			Tp (sec)																	
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.75	6.25	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.25	5.75	5.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.75	5.25	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.25	4.75	4.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3.75	4.25	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3.25	3.75	3.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2.75	3.25	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2.25	2.75	2.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1.75	2.25	2	0	0	0	3	10	7	1	0	0	0	0	0	0	0	0	0	0	21
1.25	1.75	1.5	0	1	3	29	46	52	1	0	0	0	0	0	0	0	0	0	0	132
0.75	1.25	1	1	6	45	113	85	58	0	9	8	0	0	0	0	0	0	0	0	325
0.25	0.75	0.5	4	11	48	68	61	54	13	0	6	0	0	0	0	0	0	0	0	265
0	0.25	0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		744	5	18	96	213	202	171	15	9	14	0	0	0	0	0	0	0	0	744

Table A-9: Scatter Diagram September

		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries			Tp (sec)																	
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.75	6.25	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.25	5.75	5.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.75	5.25	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.25	4.75	4.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3.75	4.25	4	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	2
3.25	3.75	3.5	0	0	0	0	0	0	0	0	0	1	4	7	0	0	0	0	0	12
2.75	3.25	3	0	0	0	0	0	0	0	1	8	3	4	8	5	3	0	0	0	32
2.25	2.75	2.5	0	0	0	0	0	1	1	0	7	11	20	16	4	1	0	0	0	62
1.75	2.25	2	0	0	1	5	6	7	5	8	16	18	11	23	9	2	1	0	0	114
1.25	1.75	1.5	0	2	12	18	23	25	9	6	35	21	22	13	2	1	0	0	0	192
0.75	1.25	1	0	14	28	15	17	43	32	25	18	15	2	1	2	0	0	0	0	214
0.25	0.75	0.5	2	4	3	1	7	10	15	19	11	1	0	8	9	1	0	0	0	92
0	0.25	0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		720	2	20	45	40	54	86	63	60	96	71	64	79	31	8	1	0	0	720

Table A-10: Scatter Diagram October

		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries			Tp (sec)																	
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.75	6.25	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.25	5.75	5.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.75	5.25	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.25	4.75	4.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3.75	4.25	4	0	0	0	0	0	1	2	4	2	0	0	0	0	0	0	0	0	9
3.25	3.75	3.5	0	0	0	0	0	2	2	4	1	0	0	0	0	0	0	0	0	9
2.75	3.25	3	0	0	0	0	0	11	5	7	5	0	0	0	0	0	0	0	0	28
2.25	2.75	2.5	0	0	4	5	9	27	12	14	0	0	0	0	0	0	0	0	0	72
1.75	2.25	2	0	1	10	30	25	16	16	20	7	4	5	0	0	0	0	0	0	136
1.25	1.75	1.5	0	2	27	24	16	28	11	12	12	11	13	9	2	0	0	0	0	169
0.75	1.25	1	6	15	44	38	28	36	31	19	26	3	4	6	0	0	0	0	0	257
0.25	0.75	0.5	0	4	3	5	7	1	7	23	12	0	0	0	0	0	0	0	0	63
0	0.25	0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		744	6	22	88	102	86	124	87	104	66	18	22	15	2	0	0	0	0	744

Table A-11: Scatter Diagram November

		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries			Tp (sec)																	
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.75	6.25	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.25	5.75	5.5	0	0	0	0	0	0	0	1	1	1	1	0	0	0	0	0	0	4
4.75	5.25	5	0	0	0	0	1	1	0	0	4	1	0	0	0	0	0	0	0	7
4.25	4.75	4.5	0	0	0	0	7	0	1	1	5	2	0	0	0	0	0	0	0	16
3.75	4.25	4	0	0	0	2	13	2	2	5	6	0	0	0	0	0	0	0	0	30
3.25	3.75	3.5	0	0	0	2	7	6	5	3	2	0	0	0	0	0	0	0	0	25
2.75	3.25	3	0	0	0	6	8	15	4	1	7	1	0	0	0	0	0	0	0	42
2.25	2.75	2.5	0	0	1	15	28	17	1	6	9	2	0	0	0	0	0	0	0	79
1.75	2.25	2	0	0	6	13	13	12	7	8	14	6	1	0	0	0	0	0	0	80
1.25	1.75	1.5	0	3	6	17	24	8	25	26	7	5	1	0	0	0	0	0	0	122
0.75	1.25	1	1	17	19	28	35	38	20	28	20	0	0	0	0	0	0	0	0	206
0.25	0.75	0.5	16	18	21	17	2	4	15	9	0	1	0	0	0	0	0	0	0	103
0	0.25	0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		714	17	38	53	100	138	103	80	88	75	19	3	0	0	0	0	0	0	714

Table A-12: Scatter Diagram December

		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries			Tp (sec)																	
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	2
6.75	7.25	7	0	0	0	0	0	0	0	1	6	2	0	0	0	0	0	0	0	9
6.25	6.75	6.5	0	0	0	0	0	0	0	3	1	4	0	0	0	0	0	0	0	8
5.75	6.25	6	0	0	0	0	0	0	1	4	3	0	5	0	0	0	0	0	0	13
5.25	5.75	5.5	0	0	0	0	0	0	3	1	10	8	2	0	0	0	0	0	0	24
4.75	5.25	5	0	0	0	0	0	2	2	3	9	2	2	0	0	0	0	0	0	20
4.25	4.75	4.5	0	0	0	0	0	5	4	4	11	4	3	0	0	0	0	0	0	32
3.75	4.25	4	0	0	0	0	0	6	4	7	6	0	0	0	0	0	0	0	0	23
3.25	3.75	3.5	0	0	0	0	6	8	10	7	9	2	0	0	0	0	0	0	0	43
2.75	3.25	3	0	0	0	7	11	17	8	5	13	1	0	0	0	0	0	0	0	63
2.25	2.75	2.5	0	0	4	31	15	33	10	5	4	0	0	0	0	0	0	0	0	102
1.75	2.25	2	0	0	11	39	20	30	23	7	7	0	0	0	0	0	0	0	0	137
1.25	1.75	1.5	0	2	16	33	23	25	15	12	12	0	0	0	0	0	0	0	0	139
0.75	1.25	1	0	14	11	23	13	18	5	16	12	1	0	1	0	0	0	0	0	116
0.25	0.75	0.5	1	2	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0	11
0	0.25	0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		744	1	18	47	136	90	145	87	76	107	24	12	1	0	0	0	0	0	744

Appendix B- Commercial Plant Cost Economics Worksheet – Regulated Utility

INSTRUCTIONS

Indicates Input Cell (either input or use default values)

Indicates a Calculated Cell (do not input any values)

Sheet 1. TPC/TPI (Total Plant Cost/Total Plant Investment)

a) Enter Component Unit Cost and No. of Units per System
b) Worksheet sums component costs to get TPC
c) Adds the value of the construction loan payments to get TPI

Sheet 2. AO&M (Annual operation and Maintenance Cost)

a) Enter Labor Hrs and Cost by O&M Type)
b) Enter Parts and Supplies Cost by O&M Type)
c) Worksheet Calculates Total Annual O&M Cost

Sheet 3. O&R (Overhaul and Replacement Cost)

a) Enter Year of Cost and O&R Cost per Item
b) Worksheets calculates the present value of the O&R costs

Sheet 4. Assumptions (Financial)

a) Enter project and financial assumptions or leave default values

Sheet 5. NPV (Net Present Value)

A Gross Book Value = TPI
B Annual Book Depreciation = Gross Book Value/Book Life
C Cumulative Depreciation
D MACRS 5 Year Depreciation Tax Schedule Assumption
E Deferred Taxes = (Gross Book Value X MACRS Rate - Annual Book Depreciation) X Debt Financing Rate
F Net Book Value = Previous Year Net Book Value - Annual Book Depreciation - Deferred Tax for that Year

Sheet 6. CRR (Capital Revenue Requirements)

A Net Book Value for Column F of NPV Worksheet
B Common Equity = Net Book X Common Equity Financing Share X Common Equity Financing Rate
C Preferred Equity = Net Book X Preferred Equity Financing Share X Preferred Equity Financing Rate
D Debt = Net Book X Debt Financing Share X Debt Financing Rate
E Annual Book Depreciation = Gross Book Value/Book Life
F Income Taxes = (Return on Common Equity + Return of Preferred Equity - Book Depreciation + Deferred Taxes) X (Comp Tax Rate/(1-Comp Tax Rate))
G Property Taxes and Insurance Expense =
H Calculates Investment and Production Tax Credit Revenues
I Capital Revenue Req'ts = Sum of Columns B through G

Sheet 7. FCR (Fixed Charge Rate)

A Nominal Rates Capital Revenue Req'ts from Columnn H of Previous Worksheet
B Nominal Rate Present Worth Factor = 1 / (1 + After Tax Discount Rate)
C Nominal Rate Product of Columns A and B = A * B
D Real Rates Capital Revenue Req'ts from Columnn H of Previous Worksheet
E Real Rates Present Worth Factor = 1 / (1 + After Tax Discount Rate - Inflation Rate)
F Real Rates Product of Columns A and B = A * B

Sheet 8. Calculates COE (Cost of Electricity)

COE = ((TPI * FCR) + AO&M + LO&R) / AEP

In other words…The Cost of Electricity =

The Sum of the Levelized Plant Investment + Annual O&M Cost + Levelized Overhaul and Replacement Cost Divided by the Annual Electric Energy Consumption

TOTAL PLANT COST (TPC) - 2004$

TPC Component	Unit	Unit Cost	Total Cost (2004$)	
Procurement				
Onshore Trans & Grid I/C	1	$6,000,000	$6,000,000	
Subsea Cables	1	$4,886,000	$4,886,000	
Mooring	206	$116,941	$24,089,846	
Power Conversion Modules (set of 3) at $	206	$623,961	$128,535,966	
Concrete Structure Sections	206	$244,800	$50,428,800	
Facilities	1	$12,000,000	$12,000,000	
Installation	1	$12,170,000	$12,170,000	
Construction Management	1	$11,297,000	$11,297,000	
TOTAL			$249,407,612	

TOTAL PLANT INVESTMENT (TPI) - 2004 $

End of Year	Total Cash Expended TPC (2004$)	Before Tax Construction Loan Cost at Debt Financing Rate	2004 Value of Construction Loan Payments	TOTAL PLANT INVESTMENT 2004$
2006	$124,703,806	$9,352,785	$8,444,953	$133,148,759
2007	$124,703,806	$18,705,571	$15,250,479	$139,954,285
Total	$249,407,612	$28,058,356	$23,695,432	$273,103,044

ANNUAL OPERATING AND MAINTENANCE COST (AO&M) - 2004$

Costs	Yrly Cost	Amount	
LABOR	$2,516,000	$2,516,000	
PARTS AND SUPPLIES (2%)	$4,920,000	$4,920,000	
INSURANCE (2%)	$4,920,000	$4,920,000	
Total		$12,356,000	

OVERHAUL AND REPLACEMENT COST (OAR) - 2004$

O&R Costs	Year of Cost	Cost in 2004$	
10 Year Retrofit			
Operation	10	$10,570,000	
Parts	10	$15,962,000	
Total		$26,532,000	

FINANCIAL ASSUMPTIONS

(default assumptions in pink background - without line numbers are calculated values)

1	Rated Plant Capacity ©	103	MW
2	Annual Electric Energy Production (AEP)	300,000	MWeh/yr
	Therefore, Capacity Factor	33.23	%
3	Year Constant Dollars	2004	Year
4	Federal Tax Rate	35	%
5	State	Mass	
6	State Tax Rate	9.5	%
	Composite Tax Rate (t)	0.41175	
	t/(1-t)	0.7000	
7	Book Life	20	Years
8	Construction Financing Rate	7.5	
9	Common Equity Financing Share	52	%
10	Preferred Equity Financing Share	13	%
11	Debt Financing Share	35	%
12	Common Equity Financing Rate	13	%
13	Preferred Equity Financing Rate	10.5	%
14	Debt Financing Rate	7.5	%
	Nominal Discount Rate Before-Tax	10.75	%
	Nominal Discount Rate After-Tax	9.67	%
15	Inflation Rate = 3%	3	%
	Real Discount Rate Before-Tax	7.52	%
	Real Discount Rate After-Tax	6.47	%
16	Federal Investment Tax Credit	10	% 1st year only
17	Federal Production Tax Credit	0.018	$/kWh for 1st 10 years
18	State Investment Tax Credit	0	% of TPI up to $2.5M
19	State Investment Tax CreditLimit		Credit-1st year only> $10M plant
20	Renewable Energy Certificate	0.025	$/kWh
21	State Tax Depreciation	$12,170,000	Installation Cost

NET PRESENT VALUE (NPV) - 2004 $

TPI = $273,103,044

Year End	Gross Book Value	Book Depreciation Annual	Book Depreciation Accumulated	Renewable Resource MACRS Tax Depreciation Schedule	Deferred Taxes	Net Book Value
	A	B	C	D	E	F
2007	**273,103,044**					**273,103,044**
2008	273,103,044	13,655,152	13,655,152	0.2000	16,867,527	242,580,365
2009	273,103,044	13,655,152	27,310,304	0.3200	30,361,548	198,563,665
2010	273,103,044	13,655,152	40,965,457	0.1920	15,967,925	168,940,587
2011	273,103,044	13,655,152	54,620,609	0.1152	7,331,752	147,953,684
2012	273,103,044	13,655,152	68,275,761	0.1152	7,331,752	126,966,780
2013	273,103,044	13,655,152	81,930,913	0.0576	854,621	112,457,006
2014	273,103,044	13,655,152	95,586,066	0.0000	-5,622,509	104,424,363
2015	273,103,044	13,655,152	109,241,218	0.0000	-5,622,509	96,391,720
2016	273,103,044	13,655,152	122,896,370	0.0000	-5,622,509	88,359,076
2017	273,103,044	13,655,152	136,551,522	0.0000	-5,622,509	80,326,433
2018	273,103,044	13,655,152	150,206,674	0.0000	-5,622,509	72,293,790
2019	273,103,044	13,655,152	163,861,827	0.0000	-5,622,509	64,261,146
2020	273,103,044	13,655,152	177,516,979	0.0000	-5,622,509	56,228,503
2021	273,103,044	13,655,152	191,172,131	0.0000	-5,622,509	48,195,860
2022	273,103,044	13,655,152	204,827,283	0.0000	-5,622,509	40,163,216
2023	273,103,044	13,655,152	218,482,436	0.0000	-5,622,509	32,130,573
2024	273,103,044	13,655,152	232,137,588	0.0000	-5,622,509	24,097,930
2025	273,103,044	13,655,152	245,792,740	0.0000	-5,622,509	16,065,287
2026	273,103,044	13,655,152	259,447,892	0.0000	-5,622,509	8,032,643
2027	273,103,044	13,655,152	273,103,044	0.0000	-5,622,509	0

CAPITAL REVENUE REQUIREMENTS

TPI = $273,103,044

End of Year	Net Book	Returns to Equity Common	Returns to Equity Pref	Interest on Debt	Book Dep	Income Tax on Equity Return	ITC and PTC	Capital Revenue Req'ts
	A	B	C	D	E	F	H	I
2008	242,580,365	16,398,433	3,311,222	6,367,735	13,655,152	12,626,846	47,710,304	4,649,083
2009	198,563,665	13,422,904	2,710,394	5,212,296	13,655,152	28,896,030	20,400,000	43,496,777
2010	168,940,587	11,420,384	2,306,039	4,434,690	13,655,152	17,680,687	20,400,000	29,096,952
2011	147,953,684	10,001,669	2,019,568	3,883,784	13,655,152	10,827,786	20,400,000	19,987,959
2012	126,966,780	8,582,954	1,733,097	3,332,878	13,655,152	10,019,839	20,400,000	16,923,920
2013	112,457,006	7,602,094	1,535,038	2,951,996	13,655,152	4,927,531	20,400,000	10,271,811
2014	104,424,363	7,059,087	1,425,393	2,741,140	13,655,152	84,577	20,400,000	4,565,348
2015	96,391,720	6,516,080	1,315,747	2,530,283	13,655,152	-224,661	20,400,000	3,392,601
2016	88,359,076	5,973,074	1,206,101	2,319,426	13,655,152	-533,899	20,400,000	2,219,854
2017	80,326,433	5,430,067	1,096,456	2,108,569	13,655,152	-843,137	20,400,000	1,047,106
2018	72,293,790	4,887,060	986,810	1,897,712	13,655,152	-1,152,375	7,500,000	12,774,359
2019	64,261,146	4,344,053	877,165	1,686,855	13,655,152	-1,461,613	7,500,000	11,601,612
2020	56,228,503	3,801,047	767,519	1,475,998	13,655,152	-1,770,851	7,500,000	10,428,865
2021	48,195,860	3,258,040	657,873	1,265,141	13,655,152	-2,080,089	7,500,000	9,256,118
2022	40,163,216	2,715,033	548,228	1,054,284	13,655,152	-2,389,327	7,500,000	8,083,371
2023	32,130,573	2,172,027	438,582	843,428	13,655,152	-2,698,565	7,500,000	6,910,624
2024	24,097,930	1,629,020	328,937	632,571	13,655,152	-3,007,803	7,500,000	5,737,876
2025	16,065,287	1,086,013	219,291	421,714	13,655,152	-3,317,041	7,500,000	4,565,129
2026	8,032,643	543,007	109,646	210,857	13,655,152	-3,626,279	7,500,000	3,392,382
2027	0	0	0	0	13,655,152	-3,935,517	7,500,000	2,219,635
Sum of Annual Capital Revenue Requirements								210,621,381

FIXED CHARGE RATE (FCR) - NOMINAL AND REAL LEVELIZED

TPI = $273,103,044

End of Year	Capital Revenue Req'ts Nominal A	Present Worth Factor Nominal B	Product of Columns A and B C	Capital Revenue Req'ts Real D	Present Worth Factor Real E	Product of Columns D and E F
2008	4,649,083	0.9118	4,239,189	4,254,570	0.9392	3,995,843
2009	43,496,777	0.8314	36,164,967	38,646,323	0.8821	34,088,950
2010	29,096,952	0.7581	22,059,415	25,099,287	0.8284	20,793,114
2011	19,987,959	0.6913	13,817,531	16,739,601	0.7781	13,024,348
2012	16,923,920	0.6303	10,667,888	13,760,696	0.7307	10,055,508
2013	10,271,811	0.5748	5,903,914	8,108,662	0.6863	5,565,005
2014	4,565,348	0.5241	2,392,668	3,498,959	0.6446	2,255,319
2015	3,392,601	0.4779	1,621,275	2,524,414	0.6054	1,528,207
2016	2,219,854	0.4358	967,306	1,603,669	0.5686	911,779
2017	1,047,106	0.3973	416,050	734,419	0.5340	392,167
2018	12,774,359	0.3623	4,628,173	8,698,717	0.5015	4,362,497
2019	11,601,612	0.3304	3,832,695	7,670,032	0.4710	3,612,683
2020	10,428,865	0.3012	3,141,510	6,693,892	0.4424	2,961,175
2021	9,256,118	0.2747	2,542,411	5,768,107	0.4155	2,396,467
2022	8,083,371	0.2505	2,024,533	4,890,572	0.3902	1,908,317
2023	6,910,624	0.2284	1,578,211	4,059,263	0.3665	1,487,616
2024	5,737,876	0.2082	1,194,853	3,272,231	0.3442	1,126,264
2025	4,565,129	0.1899	866,826	2,527,601	0.3233	817,067
2026	3,392,382	0.1731	587,353	1,823,573	0.3036	553,637
2027	2,219,635	0.1579	350,422	1,158,411	0.2851	330,306
	210,621,381		118,997,193	161,532,997		112,166,267

	Nominal $		Real $
1. The present value is at the beginning of 2006 and results from the sum of the products of the annual present value factors times the annual requirements	118,997,193		112,166,267
2. Escalation Rate	3%		3%
3. After Tax Discount Rate = i	9.67%		6.47%
4. Capital recovery factor value = $i(1+i)^n/(1+i)^n-1$ where book life = n and discount rate = i	0.114818371		0.090575595
5. The levelized annual charges (end of year) = Present Value (Item 1) * Capital Recovery Factor (Item 4)	13,663,064		10,159,526
6. Booked Cost	273,103,044		273,103,044
7. The levelized annual fixed charge rate (levelized annual charges divided by the booked cost)	**0.0500**		**0.0372**

LEVELIZED COST OF ELECTRICITY CALCULATION - UTILITY GENERATOR

COE = ((TPI * FCR) + AO&M + LO&R) / AEP

In other words…

The Cost of Electricity =

The Sum of the Levelized Plant Investment + Annual O&M Cost + Levelized Overhaul and Replacement Cost

Divided by the Annual Electric Energy Consumption

NOMINAL RATES

	Value	Units	From
TPI	$273,103,044	$	From TPI
FCR	5.00%	%	From FCR
AO&M	$12,356,000	$	From AO&M
LO&R = O&R/Life	$1,326,600	$	From LO&R
AEP =	300,000	MWeh/yr	From Assumptions
COE - TPI X FCR	4.55	cents/kWh	
COE - AO&M	4.12	cents/kWh	
COE - LO&R	0.44	cents/kWh	
COE	$0.0912	$/kWh	Calculated
COE	**9.12**	cents/kWh	Calculated

REAL RATES

	Value	Units	From
TPI	$273,103,044	$	From TPI
FCR	3.72%	%	From FCR
AO&M	$12,356,000	$	From AO&M
LO&R = O&R/Life	$1,326,600	$	From LO&R
AEP =	300,000	MWeh/yr	From Assumptions
COE - TPI X FCR	3.39	cents/kWh	
COE - AO&M	4.12	cents/kWh	
COE - LO&R	0.44	cents/kWh	
COE	$0.0795	$/kWh	Calculated
COE	**7.95**	cents/kWh	Calculated

Appendix C - Commercial Plant Cost Economics Worksheet – NUG – With REC

INSTRUCTIONS

Fill in first four worksheets (or use default values) - the last two worksheets are automatically calculated. Refer to E2I EPRI Economic Methodology Report 004 Rev 2

Indicates Input Cell (either input or use default values)

Indicates a Calculated Cell (do not input any values)

Sheet 1. Total Plant Cost/Total Plant Investment (TPC/TPI) - 2004$

1. Enter Component Unit Cost and No. of Units per System
2. Worksheet sums component costs to get TPC
3. Worksheet adds the value of the construction loan payments to get TPI

Sheet 2. AO&M (Annual Operation and Maintenance Cost) - 2004$

1. Enter Labor Hrs and Cost by O&M Type)
2. Enter Parts and Supplies Cost by O&M Type)
3. Worksheet Calculates Total Annual O&M Cost

Sheet 3. O&R (Overhaul and Replacement Cost) - 2004$

1. Enter Year of Cost and O&R Cost per Item
2. Worksheet calculates inflation to the year of the cost of the O&R

Sheet 4. Assumptions (Project, Financial and Others)

1. Enter project, financial and other assumptions or leave default values

Sheet 5. Income Statement - Assuming no capacity factor income - Current $

1. 2008 Energy payments(2002-2008) = AEP X 2002 wholesale price X 92% (to adjust price from 2002 to 2008 (an 8% decline) X Inflation from 2002 to 2008
   2009-2011 Energy payments = 2008 Energy Payment X Inflation
   2012-2027 Energy payments = 2011 Energy Price X 0.3% Price escalation X Inflation
2. Calculates State Investment and Producient tax credit
3. Calculates Federal Investment and Production Tax Credit
4. Scheduled O&M from TPC worksheet with inflation
5. Scheduled O&R from TPC worksheet with inflation
8. Earnings before EBITDA = total revenues less total operating costs
9. Tax Depreciation = Assumed MACRS rate X TPI
10. Interest paid = Annual interest given assumed debt interest rate and life of loan
11. Taxable earnings = Tax Depreciation + Interest Paid
12. State Tax = Taxable Earnings x state tax rate
13. Federal Tax = (Taxable earnings - State Tax) X Federal tax rate
14. Total Tax Obligation = Total State + Federal Tax

Sheet 6. Cash Flow Statement - Current $

1. EBITDA
2. Taxes Paid
3. Cash Flow From Operations = EBITDA - Taxes Paid
4. Debt Service = Principal + Interest paid on the debt loan
5. Net Cash Flow after Tax
   Year of Start of Ops minus 1 = Equity amount
   Year of Start of Ops = Cash flow from ops - debt service
   Year of Start of Ops Plus 1 to N = Cash flow from ops - debt service
6. Cum Net Cash Flow After Taxes = previous year net cash flow + current year net cash flow
7. Cum IRR on net cash Flow After Taxes = discount rate that sets the present worth of the net cash flows over the book life equal to the equity investment at the commercial operations

TOTAL PLANT COST (TPC) - 2004$

TPC Component	Unit	Unit Cost	Total Cost (2004$)	Notes and Assumptions
Procurement				
Onshore Trans & Grid I/C	1	$6,000,000	$6,000,000	
Subsea Cables	1	$4,886,000	$4,886,000	
Mooring	206	$116,941	$24,089,846	
Power Conversion Modules (set of 3)	206	$623,961	$128,535,966	
Concrete Structure Sections	206	$244,800	$50,428,800	
Facilities	1	$12,000,000	$12,000,000	
Installation	1	$12,170,000	$12,170,000	
Construction Management	1	$11,297,000	$11,297,000	
TOTAL			$249,407,612	

TOTAL PLANT INVESTMENT (TPI) - 2004 $

End of Year	Total Cash Expended TPC ($2004)	Before Tax Construction Loan Cost at Debt Financing Rate	2004 Value of Construction Loan Payments	TOTAL PLANT INVESTMENT (TPC + Loan Value) ($2004)
2006	$124,703,806	$9,976,304	$9,012,019	$133,715,825
2007	$124,703,806	$19,952,609	$16,281,876	$140,985,682
Total	$249,407,612	$29,928,913	$25,293,895	$274,701,507

ANNUAL OPERATING AND MAINTENANCE COST (AO&M) - 2004$

Costs	Yrly Cost	Amount	
LABOR	$2,516,000	$2,516,000	
PARTS AND SUPPLIES (2%)	$4,920,000	$4,920,000	
INSURANCE (2%)	$4,920,000	$4,920,000	
Total		$12,356,000	

OVERHAUL AND REPLACEMENT COST (OAR) - 2004$

O&R Costs	Year of Cost	Cost in 2004$	
10 Year Retrofit			
Operation	10	$10,570,000	
Parts	10	$15,962,000	
Total		$26,532,000	

FINANCIAL ASSUMPTIONS

(default assumptions in pink background - without line numbers are calculated values)

1	Rated Plant Capacity ©	90	MW
2	Annual Electric Energy Production (AEP)	300,000	MWeh/yr
	Therefore, Capacity Factor	38.03	%
3	Year Constant Dollars	2004	Year
4	Federal Tax Rate	35	%
5	State	Mass	
6	State Tax Rate	9.5	%
	Composite Tax Rate (t)	0.41175	%
	t/(1-t)	0.7000	
7	Book Life	20	Years
8	Construction Financing Rate	8	
9	Common Equity Financing Share	30	%
10	Preferred Equity Financing Share	0	%
11	Debt Financing Share	70	%
12	Common Equity Financing Rate	17	%
13	Preferred Equity Financing Rate	0	%
14	Debt Financing Rate	8	%
	Current $ Discount Rate Before-Tax	10.7	%
	Current $ Discount Rate After-Tax	8.39	%
15	Inflation rate	3	%
16	Federal Investment Tax Credit	10	% 1st year only
17	Federal Production Tax Credit	0.018	$/kWh for 1st 10 yrs
18	State Investment Tax Credit	0	% 1st year only
			% of TPI up to $2.5M
19	Renewable Energy Certificate	0.025	$/kWh
20	Wholesale electricity price - 2002$	0.065	$/kWh
21	Decline in wholesale elec. price from 2002 to 2008	8	%
22	Yearly Unscheduled O&M	5	% of Sch O&M cost
23	MACRS Year 1	0.2000	
24	MACRS Year 2	0.3200	
25	MACRS Year 3	0.1920	
26	MACRS Year 4	0.1152	
27	MACRS Year 5	0.1152	
28	MACRS Year 6	0.0576	
29	State Tax Deduction	$12,170,000	Installtion Cost

INCOME STATEMENT ($) **CURRENT DOLLARS**

Description/Year	2008	2009	2010	2011	2012	2013	2014	2015
REVENUES								
Energy Payments	21,421,298	22,063,937	22,725,855	23,407,631	24,182,189	24,982,378	25,809,045	26,663,066
Renewable Energy Certificates	7,500,000	7,725,000	7,956,750	8,195,453	8,441,316	8,694,556	8,955,392	9,224,054
Federal ITC and PTC	32,870,151	5,400,000	5,400,000	5,400,000	5,400,000	5,400,000	5,400,000	5,400,000
TOTAL REVENUES	61,791,449	35,188,937	36,082,605	37,003,083	38,023,505	39,076,934	40,164,437	41,287,120
AVG $/KWH	0.206	0.117	0.120	0.123	0.127	0.130	0.134	0.138
OPERATING COSTS								
Scheduled and Unscheduled O&M	13,906,787	14,323,990	14,753,710	15,196,321	15,652,211	16,121,777	16,605,431	17,103,594
Scheduled O&R	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0
TOTAL	13,906,787	14,323,990	14,753,710	15,196,321	15,652,211	16,121,777	16,605,431	17,103,594
EBITDA	47,884,662	20,864,947	21,328,895	21,806,762	22,371,294	22,955,156	23,559,006	24,183,527
Tax Depreciation	54,940,301	87,904,482	52,742,689	31,645,614	31,645,614	15,822,807	0	0
Interest Paid	15,383,284	15,047,126	14,684,074	14,291,979	13,868,515	13,411,175	12,917,248	12,383,806
State Installation Cost Tax Deduction	12,170,000							
TAXABLE EARNINGS	-34,608,924	-82,086,661	-46,097,868	-24,130,830	-23,142,835	-6,278,826	10,641,759	11,799,721
State Tax	-3,287,848	-7,798,233	-4,379,297	-2,292,429	-2,198,569	-596,488	1,010,967	1,120,973
Federal Tax	-10,962,377	-26,000,950	-14,601,500	-7,643,440	-7,330,493	-1,988,818	3,370,777	3,737,561
TOTAL TAX OBLIGATIONS	-14,250,224	-33,799,183	-18,980,797	-9,935,869	-9,529,062	-2,585,307	4,381,744	4,858,535

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
27,545,347	28,456,823	29,398,459	30,371,254	31,376,239	32,414,478	33,487,074	34,595,161	35,739,915	36,922,548	36,922,548	38,144,316
9,500,776	9,785,799	10,079,373	10,381,754	10,693,207	11,014,003	11,344,423	11,684,756	12,035,298	12,396,357	12,768,248	13,151,295
5,400,000	5,400,000										
42,446,123	43,642,622	39,477,832	40,753,008	42,069,445	43,428,481	44,831,496	46,279,916	47,775,213	49,318,906	49,690,796	51,295,611
0.141	0.145	0.132	0.136	0.140	0.145	0.149	0.154	0.159	0.164	0.166	0.171
17,616,702	18,145,203	18,689,559	19,250,245	19,827,753	20,422,585	21,035,263	21,666,321	22,316,310	22,985,800	23,675,374	24,385,635
0	0	60,703,297	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
17,616,702	18,145,203	79,392,856	19,250,245	19,827,753	20,422,585	21,035,263	21,666,321	22,316,310	22,985,800	23,675,374	24,385,635
24,829,421	25,497,419	-39,915,024	21,502,763	22,241,693	23,005,896	23,796,234	24,613,596	25,458,903	26,333,106	26,015,423	26,909,976
0	0	0	0	0	0	0	0	0	0	0	0
11,807,689	11,185,483	10,513,500	9,787,758	9,003,957	8,157,453	7,243,227	6,255,864	5,189,512	4,037,851	2,794,058	1,450,761
13,021,732	14,311,936	-50,428,524	11,715,004	13,237,735	14,848,443	16,553,006	18,357,732	20,269,391	22,295,255	23,221,365	25,459,215
1,237,065	1,359,634	-4,790,710	1,112,925	1,257,585	1,410,602	1,572,536	1,743,985	1,925,592	2,118,049	2,206,030	2,418,625
4,124,634	4,533,306	-15,973,235	3,710,728	4,193,053	4,703,244	5,243,165	5,814,812	6,420,330	7,062,022	7,355,367	8,064,206
5,361,698	5,892,940	-20,763,945	4,823,653	5,450,637	6,113,847	6,815,700	7,558,796	8,345,922	9,180,071	9,561,397	10,482,832

CASH FLOW STATEMENT

Description/Year	2006	2007	2008	2009	2010	2011
EBITDA			47,884,662	20,864,947	21,328,895	21,806,762
Taxes Paid			-14,250,224	-33,799,183	-18,980,797	-9,935,869
CASH FLOW FROM OPS			62,134,886	54,664,129	40,309,692	31,742,631
Debt Service			-19,585,269	-19,585,269	-19,585,269	-19,585,269
NET CASH FLOW AFTER TAX		-82,410,452	42,549,618	35,078,861	20,724,424	12,157,363
CUM NET CASH FLOW		-82,410,452	-39,860,834	-4,781,974	15,942,450	28,099,813
IRR ON NET CASH FLOW AFTER TAX						

2012	2013	2014	2015	2016	2017	2018	2019
22,371,294	22,955,156	23,559,006	24,183,527	24,829,421	25,497,419	-39,915,024	21,502,763
-9,529,062	-2,585,307	4,381,744	4,858,535	5,361,698	5,892,940	-20,763,945	4,823,653
31,900,357	25,540,463	19,177,262	19,324,992	19,467,723	19,604,479	-19,151,079	16,679,110
-19,585,269	-19,585,269	-19,585,269	-19,585,269	-19,585,269	-19,585,269	-19,585,269	-19,585,269
12,315,088	5,955,194	-408,006	-260,277	-117,546	19,211	-38,736,348	-2,906,159
40,414,901	46,370,095	45,962,088	45,701,811	45,584,266	45,603,476	6,867,128	3,960,969

2020	2021	2022	2023	2024	2025	2026	2027
22,241,693	23,005,896	23,796,234	24,613,596	25,458,903	26,333,106	26,015,423	26,909,976
5,450,637	6,113,847	6,815,700	7,558,796	8,345,922	9,180,071	9,561,397	10,482,832
16,791,055	16,892,049	16,980,533	17,054,800	17,112,981	17,153,035	16,454,026	16,427,144
-19,585,269	-19,585,269	-19,585,269	-19,585,269	-19,585,269	-19,585,269	-19,585,269	-19,585,269
-2,794,214	-2,693,219	-2,604,735	-2,530,469	-2,472,288	-2,432,234	-3,131,243	-3,158,125
1,166,755	-1,526,464	-4,131,199	-6,661,668	-9,133,956	-11,566,190	-14,697,433	-17,855,558
							7.6%

Appendix D - Commercial Plant Cost Economics Worksheet – NUG – W/O REC

INSTRUCTIONS

Fill in first four worksheets (or use default values) - the last two worksheets are automatically calculated. Refer to E2I EPRI Economic Methodology Report 004 Rev 2

Indicates Input Cell (either input or use default values)

Indicates a Calculated Cell (do not input any values)

Sheet 1. Total Plant Cost/Total Plant Investment (TPC/TPI) - 2004$

1 Enter Component Unit Cost and No. of Units per System
2 Worksheet sums component costs to get TPC
3 Worksheet adds the value of the construction loan payments to get TPI

Sheet 2. AO&M (Annual Operation and Maintenance Cost) - 2004$

1 Enter Labor Hrs and Cost by O&M Type)
2 Enter Parts and Supplies Cost by O&M Type)
3 Worksheet Calculates Total Annual O&M Cost

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1 Enter Year of Cost and O&R Cost per Item
2 Worksheet calculates inflation to the year of the cost of the O&R

Sheet 4. Assumptions (Project, Financial and Others)

1 Enter project, financial and other assumptions or leave default values

Sheet 5. Income Statement - Assuming no capacity factor income - Current $

1 2008 Energy payments(2002-2008) = AEP X 2002 wholesale price X 92% (to adjust price from 2002 to 2008 (an 8% decline) X Inflation from 2002 to 2008
2009-2011 Energy payments = 2008 Energy Payment X Inflation
2012-2027 Energy payments = 2011 Energy Price X 0.3% Price escalation X Inflation
2 Calculates State Investment and Producint tax credit
3 Calculates Federal Investment and Production Tax Credit
4 Scheduled O&M from TPC worksheet with inflation
5 Scheduled O&R from TPC worksheet with inflation
8 Earnings before EBITDA = total revenues less total operating costs
9 Tax Depreciation = Assumed MACRS rate X TPI
10 Interest paid = Annual interest given assumed debt interest rate and life of loan
11 Taxable earnings = Tax Depreciation + Interest Paid
12 State Tax = Taxable Earnings x state tax rate
13 Federal Tax = (Taxable earnings - State Tax) X Federal tax rate
14 Total Tax Obligation = Total State + Federal Tax

Sheet 6. Cash Flow Statement - Current $

1 EBITDA
2 Taxes Paid
3 Cash Flow From Operations = EBITDA - Taxes Paid
4 Debt Service = Principal + Interest paid on the debt loan
5 Net Cash Flow after Tax
Year of Start of Ops minus 1 = Equity amount
Year of Start of Ops = Cash flow from ops - debt service
Year of Start of Ops Plus 1 to N = Cash flow from ops - debt service
6 Cum Net Cash Flow After Taxes = previous year net cash flow + current year net cash flow
7 Cum IRR on net cash Flow After Taxes = discount rate that sets the present worth of the net cash flows over the book life equal to the equity investment at the commercial operations

TOTAL PLANT COST (TPC) - 2004$

TPC Component	Unit	Unit Cost	Total Cost (2004$)	Notes and Assumptions
Procurement				
Onshore Trans & Grid I/C	1	$6,000,000	$6,000,000	
Subsea Cables	1	$4,886,000	$4,886,000	
Mooring	206	$116,941	$24,089,846	
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Concrete Structure Sections	206	$244,800	$50,428,800	
Facilities	1	$12,000,000	$12,000,000	
Installation	1	$12,170,000	$12,170,000	
Construction Management	1	$11,297,000	$11,297,000	
TOTAL			$249,407,612	

TOTAL PLANT INVESTMENT (TPI) - 2004 $

End of Year	Total Cash Expended TPC ($2004)	Before Tax Construction Loan Cost at Debt Financing Rate	2004 Value of Construction Loan Payments	TOTAL PLANT INVESTMENT (TPC + Loan Value) ($2004)
2006	$124,703,806	$9,976,304	$9,012,019	$133,715,825
2007	$124,703,806	$19,952,609	$16,281,876	$140,985,682
Total	$249,407,612	$29,928,913	$25,293,895	$274,701,507

ANNUAL OPERATING AND MAINTENANCE COST (AO&M) - 2004$

Costs	Yrly Cost	Amount	
LABOR	$2,516,000	$2,516,000	
PARTS AND SUPPLIES (2%)	$4,920,000	$4,920,000	
INSURANCE (2%)	$4,920,000	$4,920,000	
Total		$12,356,000	

OVERHAUL AND REPLACEMENT COST (OAR) - 2004$

O&R Costs	Year of Cost	Cost in 2004$	
10 Year Retrofit			
Operation	10	$10,570,000	
Parts	10	$15,962,000	
Total		$26,532,000	

FINANCIAL ASSUMPTIONS

(default assumptions in pink background - without line numbers are calculated values)

1	Rated Plant Capacity ©	90	MW
2	Annual Electric Energy Production (AEP)	300,000	MWeh/yr
	Therefore, Capacity Factor	38.03	%
3	Year Constant Dollars	2004	Year
4	Federal Tax Rate	35	%
5	State	Mass	
6	State Tax Rate	9.5	%
	Composite Tax Rate (t)	0.41175	%
	t/(1-t)	0.7000	
7	Book Life	20	Years
8	Construction Financing Rate	8	
9	Common Equity Financing Share	30	%
10	Preferred Equity Financing Share	0	%
11	Debt Financing Share	70	%
12	Common Equity Financing Rate	17	%
13	Preferred Equity Financing Rate	0	%
14	Debt Financing Rate	8	%
	Current $ Discount Rate Before-Tax	10.7	%
	Current $ Discount Rate After-Tax	8.39	%
15	Inflation rate	3	%
16	Federal Investment Tax Credit	10	% 1st year only
17	Federal Production Tax Credit	0.018	$/kWh for 1st 10 yrs
18	State Investment Tax Credit	0	% 1st year only
			% of TPI up to $2.5M
19	Renewable Energy Certificate	0.000	$/kWh
20	Wholesale electricity price - 2002$	0.065	$/kWh
21	Decline in wholesale elec. price from 2002 to 2008	8	%
22	Yearly Unscheduled O&M	5	% of Sch O&M cost
23	MACRS Year 1	0.2000	
24	MACRS Year 2	0.3200	
25	MACRS Year 3	0.1920	
26	MACRS Year 4	0.1152	
27	MACRS Year 5	0.1152	
28	MACRS Year 6	0.0576	
29	State Tax Deduction	$12,170,000	Installtion Cost

INCOME STATEMENT ($) **CURRENT DOLLARS**

Description/Year	2008	2009	2010	2011	2012	2013	2014	2015
REVENUES								
Energy Payments	21,421,298	22,063,937	22,725,855	23,407,631	24,182,189	24,982,378	25,809,045	26,663,066
Renewable Energy Certificates	0	0	0	0	0	0	0	0
Federal ITC and PTC	32,870,151	5,400,000	5,400,000	5,400,000	5,400,000	5,400,000	5,400,000	5,400,000
TOTAL REVENUES	54,291,449	27,463,937	28,125,855	28,807,631	29,582,189	30,382,378	31,209,045	32,063,066
AVG $/KWH	0.181	0.092	0.094	0.096	0.099	0.101	0.104	0.107
OPERATING COSTS								
Scheduled and Unscheduled O&M	13,906,787	14,323,990	14,753,710	15,196,321	15,652,211	16,121,777	16,605,431	17,103,594
Scheduled O&R	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0
TOTAL	13,906,787	14,323,990	14,753,710	15,196,321	15,652,211	16,121,777	16,605,431	17,103,594
EBITDA	40,384,662	13,139,947	13,372,145	13,611,309	13,929,978	14,260,601	14,603,614	14,959,473
Tax Depreciation	54,940,301	87,904,482	52,742,689	31,645,614	31,645,614	15,822,807	0	0
Interest PaId	15,383,284	15,047,126	14,684,074	14,291,979	13,868,515	13,411,175	12,917,248	12,383,806
State Installation Cost Tax Deduction	12,170,000							
TAXABLE EARNINGS	-42,108,924	-89,811,661	-54,054,618	-32,326,283	-31,584,151	-14,973,381	1,686,366	2,575,667
State Tax	-4,000,348	-8,532,108	-5,135,189	-3,070,997	-3,000,494	-1,422,471	160,205	244,688
Federal Tax	-13,338,002	-28,447,844	-17,121,800	-10,239,350	-10,004,280	-4,742,819	534,157	815,842
TOTAL TAX OBLIGATIONS	-17,338,349	-36,979,951	-22,256,989	-13,310,347	-13,004,774	-6,165,290	694,361	1,060,531

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
27,545,347	28,456,823	29,398,459	30,371,254	31,376,239	32,414,478	33,487,074	34,595,161	35,739,915	36,922,548	36,922,548	38,144,316
0	0	0	0	0	0	0	0	0	0	0	0
5,400,000	5,400,000										
32,945,347	33,856,823	29,398,459	30,371,254	31,376,239	32,414,478	33,487,074	34,595,161	35,739,915	36,922,548	36,922,548	38,144,316
0.110	0.113	0.098	0.101	0.105	0.108	0.112	0.115	0.119	0.123	0.123	0.127
17,616,702	18,145,203	18,689,559	19,250,245	19,827,753	20,422,585	21,035,263	21,666,321	22,316,310	22,985,800	23,675,374	24,385,635
0	0	60,703,297	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
17,616,702	18,145,203	79,392,856	19,250,245	19,827,753	20,422,585	21,035,263	21,666,321	22,316,310	22,985,800	23,675,374	24,385,635
15,328,646	15,711,620	-49,994,397	11,121,009	11,548,486	11,991,893	12,451,811	12,928,840	13,423,604	13,936,749	13,247,175	13,758,681
0	0	0	0	0	0	0	0	0	0	0	0
11,807,689	11,185,483	10,513,500	9,787,758	9,003,957	8,157,453	7,243,227	6,255,864	5,189,512	4,037,851	2,794,058	1,450,761
3,520,957	4,526,137	-60,507,897	1,333,250	2,544,529	3,834,441	5,208,583	6,672,976	8,234,093	9,898,898	10,453,117	12,307,920
334,491	429,983	-5,748,250	126,659	241,730	364,272	494,815	633,933	782,239	940,395	993,046	1,169,252
1,115,263	1,433,654	-19,165,876	422,307	805,979	1,214,559	1,649,819	2,113,665	2,608,149	3,135,476	3,311,025	3,898,534
1,449,754	1,863,637	-24,914,126	548,966	1,047,710	1,578,831	2,144,634	2,747,598	3,390,388	4,075,871	4,304,071	5,067,786

CASH FLOW STATEMENT

Description/Year	2006	2007	2008	2009	2010	2011
EBITDA			40,384,662	13,139,947	13,372,145	13,611,309
Taxes Paid			-17,338,349	-36,979,951	-22,256,989	-13,310,347
CASH FLOW FROM OPS			57,723,011	50,119,898	35,629,134	26,921,656
Debt Service			-19,585,269	-19,585,269	-19,585,269	-19,585,269
NET CASH FLOW AFTER TAX		-82,410,452	38,137,743	30,534,629	16,043,866	7,336,388
CUM NET CASH FLOW		-82,410,452	-44,272,709	-13,738,080	2,305,786	9,642,173
IRR ON NET CASH FLOW AFTER TAX						

Description/Year	2012	2013	2014	2015	2016	2017	2018	2019
EBITDA	13,929,978	14,260,601	14,603,614	14,959,473	15,328,646	15,711,620	-49,994,397	11,121,009
Taxes Paid	-13,004,774	-6,165,290	694,361	1,060,531	1,449,754	1,863,637	-24,914,126	548,966
CASH FLOW FROM OPS	26,934,752	20,425,890	13,909,253	13,898,942	13,878,892	13,847,983	-25,080,270	10,572,043
Debt Service	-19,585,269	-19,585,269	-19,585,269	-19,585,269	-19,585,269	-19,585,269	-19,585,269	-19,585,269
NET CASH FLOW AFTER TAX	7,349,484	840,622	-5,676,016	-5,686,327	-5,706,377	-5,737,286	-44,665,539	-9,013,226
CUM NET CASH FLOW	16,991,657	17,832,279	12,156,263	6,469,936	763,559	-4,973,726	-49,639,266	-58,652,491

Description/Year	2020	2021	2022	2023	2024	2025	2026	2027
EBITDA	11,548,486	11,991,893	12,451,811	12,928,840	13,423,604	13,936,749	13,247,175	13,758,681
Taxes Paid	1,047,710	1,578,831	2,144,634	2,747,598	3,390,388	4,075,871	4,304,071	5,067,786
CASH FLOW FROM OPS	10,500,776	10,413,062	10,307,176	10,181,242	10,033,217	9,860,878	8,943,104	8,690,895
Debt Service	-19,585,269	-19,585,269	-19,585,269	-19,585,269	-19,585,269	-19,585,269	-19,585,269	-19,585,269
NET CASH FLOW AFTER TAX	-9,084,492	-9,172,206	-9,278,092	-9,404,027	-9,552,052	-9,724,391	-10,642,165	-10,894,374
CUM NET CASH FLOW	-67,736,984	-76,909,190	-86,187,282	-95,591,309	-105,143,361	-114,867,752	-125,509,917	-136,404,291
IRR ON NET CASH FLOW AFTER TAX								#NUM!