System Level Design, Performance, Cost and Economic Assessment – Minas Passage Nova Scotia Tidal In-Stream Power Plant

Report:	EPRI – TP - 006 - NS
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1. Introduction and Summary

The Minas Passage, which connects the Minas Basin to the Bay of Fundy, contains to some of the most energetic currents in North America and the World. In average 1,013MW of power is embodied in the tidal stream, of which about 152MW could be extracted without any negative impact on the environment.

This document describes the results of a system level design, performance and cost study for both a demonstration pilot plant at Cape Blomidon transect and an economics assessment of a commercial size in-stream tidal power plant installed at the Cape Sharp transect in the Minas Passage. The primary purpose of this design study is to identify and quantify the risks and benefits of using TISEC technology at the Minas Passage site. As such it addresses the technology, energy production, cost of a pilot and commercial power plant system and the cost of electricity of a commercial scale plant.

The study was carried out using the methodology and standards established in the Design Methodology Report [5], the Power Production Performance Methodology Report [2] and the Cost Estimate and Economics Assessment Methodology Report [2].

For purposes of this design study, the Nova Scotia stakeholders and EPRI decided to work with two TISEC device developers: Lunar Energy and Marine Current Turbines (MCT). Lunar Energy's RTT 2000 is a fully submersed ducted water turbine with the power conversion system (containing rotors and power generation equipment) inserted in a slot in the duct as a cassette. This allows the critical components to be recovered for operation and maintenance without having to remove the whole structure. MCT's SeaGen consists of two horizontal-axis rotors and power trains (gearbox, generator) attached to a supporting monopile by a cross-arm. The monopile is surface piercing and includes an integrated lifting mechanism to pull the rotors and power trains out of the water for maintenance access. MCT also offered information on their conceptual fully submersed design, which consists of 6 rotors mounted on a single structure, which can be raised to the surface for maintenance using an integrated lifting mechanism. It is unlikely, however, that MCT's 2nd

generation device would be ready for commercial pilot plant demonstration for at least 2 years as proof of high reliability is a prerequisite.

The purpose of working with two TISEC device developers was to provide a redundant check of design points and to increase the confidence level of the assessment work. There is no intent to compare the two device developers nor their technology. At this nascent stage of TISEC development, a pursuit towards the development and demonstration of as many good ideas as possible is warranted.

Only MCTs surface piercing SeaGen offered sufficiently solid engineering specifications at this time (January through March 2006) to perform an independent cost assessment. SeaGen was therefore used to establish cost estimates. Given the similar scale and technology used on MCT's fully submersed technology, MCT believes that the cost and performance will be similar to the surface piercing SeaGen. EPRI believes that it is unlikely that MCTs second generation technology would be ready for commercial pilot demonstration within the next couple of years. However EPRI believes that surface piercing SeaGen devices may be installed at the Cape Sharp Transect in the Minas Passage along the channels shoals in suitable water depths if ice engineering issues can be resolved. Designing for ice in the Minas passage might add substantial cost to a commercial project. A preliminary study of forces and related cost showed that as a direct result of having to design for ice impact at the site, the dockside capital cost would increase by as much as 78% and the cost of electricity by about 50% (see appendix). While these cost increases are not dominant in a pilot system, a commercial plants economics would suffer as a direct consequence of having to design for ice. It is therefore likely that non surface piercing structures will become the preferred choice at this site.

A pilot consisting of a single SeaGen unit would cost $5.8M to build and would produce an estimated 4,157 MWh per year. This cost reflects only the capital needed to purchase a SeaGen unit, install it on site, and connect it to the grid. Therefore, it represents the installed capital cost, but does not include detailed design, permitting and construction financing, yearly O&M or test and evaluation costs.

A commercial scale tidal power plant at the same location was also evaluated to establish a base case from which economic comparisons to other renewable and non renewable energy systems could be made. The potential to harness energy at the site is limited to about 15% to assure that the system produces no significant or noticeable ecological or environmental effects. The yearly electrical energy produced and delivered to bus bar is estimated to be 1,138,647 MWh/year for an array consisting of 250 dual-rotor MCT turbines. These turbines have a combined installed capacity of 288 MW, and on average extract 152 MW of kinetic power from the tidal stream, which is roughly 15% of the total kinetic energy at the site. The elements of cost and economics (in 2005 US$) for MCT's SeaGen are:

- Utility Generator (UG) Total Plant Investment = $486 million
- Annual O&M Cost = $18 million
- UG Levelized Cost of Electricity (COE) = 3.9 (Real) – 4.6 (Nominal) cents/kWh with renewable financial incentives equal to that the government provides for renewable wind energy technology
- Municipal Generator (MG) Levelized Cost of Electricity (COE) = 3.9 (Real) – 4.6 (Nominal) cents/kWh with renewable financial incentives equal to that the government provides for renewable wind energy technology
- Nun Utility Generator (Independent Power Producer) Internal Rate of Return of net cash-flows after tax is 31%.

It is encouraging that a commercial plant at the Minas Passage site can potentially have a cost of electricity that is about the Nova Scotia avoided cost level (avoided cost based on a proxy of wholesale price is believed to be 5.6 cents/kWh (US cents). The resource is significant in size, but because the resource is so large, required upgrades to the electric grid may constrain its usage. In order to tap into it, further work needs to be carried out to better quantify and qualify the resource, address consenting issues and continue to work with device developers and help them apply their technology to the site and it's unique requirements. The next immediate step is to work towards the implementation of a pilot demonstration system. A pilot system is an important intermediary step before proceeding to a commercial installation and is used to:

- Proof technology reliability and performance at the site and reduce commercial risks
- Measure and quantify environmental impacts
- Focus the consenting process for a commercial installation

Before proceeding with the installation of a pilot plant, remaining uncertainties need to be addressed. Some of these uncertainties include:

- Tidal velocity distribution at the site
- Seabed geology required for detailed foundation design
- Ownership issues
- Consenting issues
- Political and public education issues

In order to promote development of TISEC, EPRI recommends that stakeholders build collaboration within Nova Scotia and with other State/Federal Government agencies by forming a provincial electricity stakeholder group and joining a TISEC Working Group to be formed by EPRI. Additionally, EPRI encourages the stakeholders to support related R&D activities at a state and federal level and at universities in the region. This would include:

- Implement a national tidal energy program
- Operate a national in stream tidal energy test facility
- Promote development of industry standards
- Continue Canadian membership in the IEA Ocean Energy Program
- Clarify and streamline federal, provincial and local permitting processes
- Study provisions for tax incentives and subsidies needed to incentivize potential investors and owners to bring this technology to the marketplace
- Ensure that the public receives a fair return from the use of tidal energy resources
- Ensure that development rights in provincial waters are allocated through a fair and transparent process that takes into account provincial, local, and public concerns.

2. Site Selection

The Nova Scotia electricity stakeholders selected the Minas Passage for an assessment of in stream tidal power. Site selection is determined by the following primary consideration:

- Good tidal energy resource
- Good electrical interconnection
- Nearby harbor support infrastructure

Of the seven North America seven sites analyzed by EPRI in this study, the Minas Passage is the largest tidal in stream energy resource and is five times larger than the second largest. Fabrication, assembly and installation could be performed out of either Halifax/Dartmouth, NS or Saint John, NB. Operation and maintenance could be performed out of Parrsboro. Grid interconnection could be at a substation in Parrsboro. Figure 1 shows a Google Earth depiction of the region.

Figure 1: Location of Minas Passage, Nova Scotia

The Minas Passage shown in a closer view in Figure 2 is a 4,500 meter wide passage (at its narrowest constriction), which connects the Minas Basin and Cobequid Bay to the Bay of Fundy and the Atlantic Ocean. The tidal difference between the Minas Basin and Cobquid Bay and the Bay of Fundy and open ocean forces the water through this channel, creating high current velocities suitable for locating TISEC devices. Two transects were looked at in view of deploying TISEC devices. Figure 3 shows the 4,500m wide Cape Sharp transect and the 6,900m wide Cape Blomidon Transect. While Cape Sharp has the higher energy potential because of higher current velocities at the site, it was deemed to be too remote to be interconnected with the electric power grid for a pilot demonstration system. As a result, Cape Blomidon was selected as the prototype deployment site.

Figure 2: Minas Passage Intermediate View

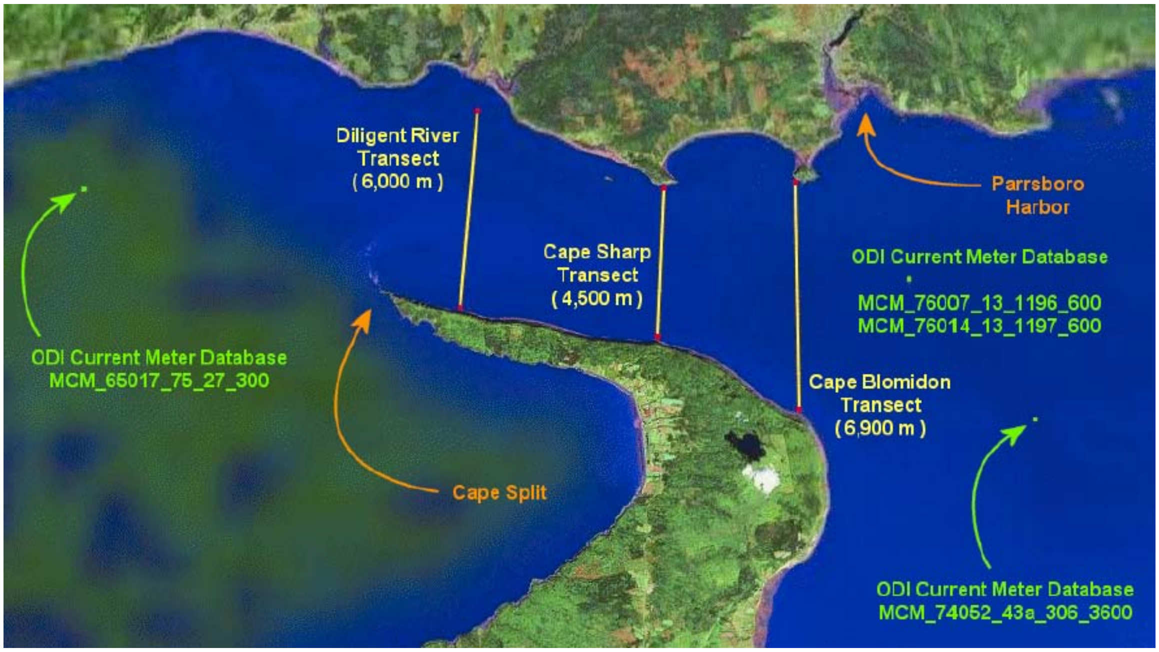


Figure 3 - Minas Passage Local View

Tidal Energy Resource Cape Blomidon Transect

Tidal velocities at a tidal instream deployment location are of high importance as the power in a stream increases to the cube power of its velocity. As a result, even small velocity differences can have a major impact on the actual performance of a TISEC device. EPRI used a methodology to extrapolate actual tidal current data which is described in Reference 1 (001 report). The velocity distribution at the Minas Passage was extrapolated from short term Canadian Hydrographic Service (CHS) measurement data using the Canada Department of Fisheries WebTide model. The following shows tidal energy statistics and resource graphs for the Cape Blomidon Transect. The Cape Blomidon Transect was assessed because of the proximity to existing grid infrastructure.

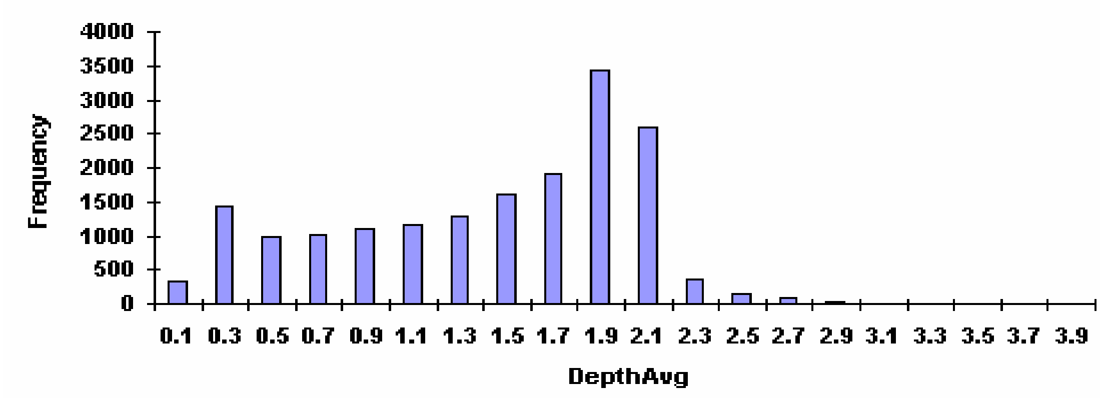


Figure 4 - Depth averaged velocity distribution at the Cape Blomidon demonstration plant site. Velocity shown is in m/s.

Table 1 – Depth averaged velocity and energy distribution at the Cape Blomidon Transect

Velocity (m/sec)	Power Density (kW/m^2)	Number of Cases	Percentage of Cases	Number of Hours	Energy Density (kWh/m^2)
0.1	0.0	319	1.8%	160	0.1
0.3	0.0	1431	8.2%	716	9.9
0.5	0.1	997	5.7%	499	31.9
0.7	0.2	1004	5.7%	502	88.2
0.9	0.4	1093	6.2%	547	204.2
1.1	0.7	1173	6.7%	587	400.1
1.3	1.1	1298	7.4%	649	730.7
1.5	1.7	1602	9.1%	801	1,385.5
1.7	2.5	1915	10.9%	958	2,410.9
1.9	3.5	3420	19.5%	1710	6,011.1
2.1	4.7	2600	14.8%	1300	6,170.1
2.3	6.2	369	2.1%	185	1,150.5
2.5	8.0	163	0.9%	82	652.6
2.7	10.1	80	0.5%	40	403.5
2.9	12.5	43	0.2%	22	268.7
3.1	15.3	11	0.1%	6	84.0
3.3	18.4	2	0.0%	1	18.4
3.5	22.0	0	0.0%	0	0.0
3.7	26.0	0	0.0%	0	0.0
3.9	30.4	0	0.0%	0	0.0
4.1	35.3	0	0.0%	0	0.0
4.3	40.7	0	0.0%	0	0.0
4.5	46.7	0	0.0%	0	0.0
4.7	53.2	0	0.0%	0	0.0
4.9	60.3	0	0.0%	0	0.0
		17520	**1**	**8760**	**20,020.5**

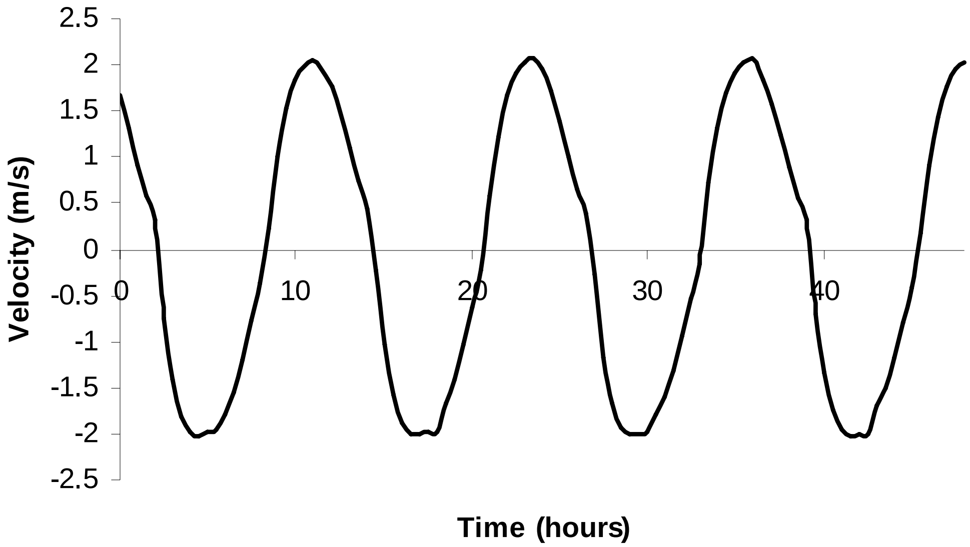


Figure 5 - Depth average velocity profile at the Cape Blomidon Transect

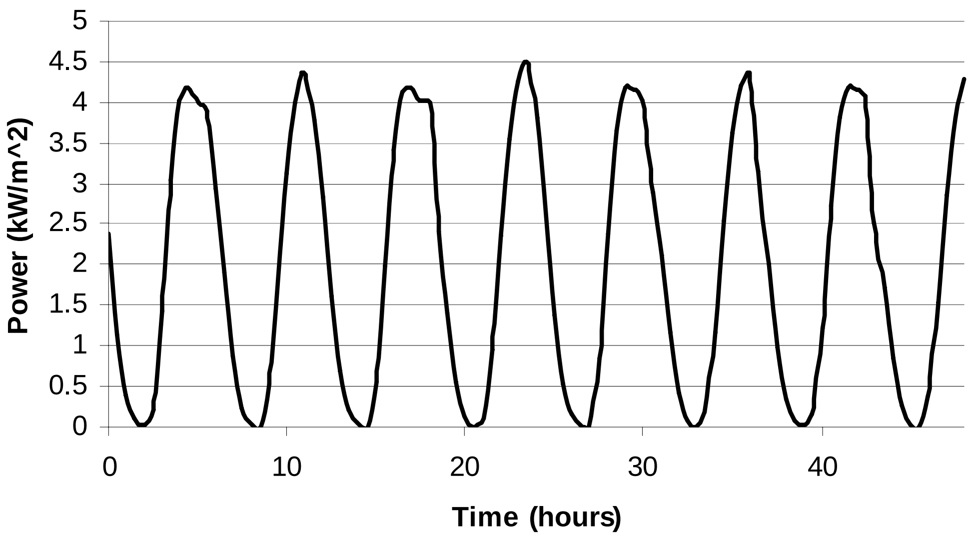


Figure 6 - Depth averaged power density over 48-hour period at Cape Blomidon Transect

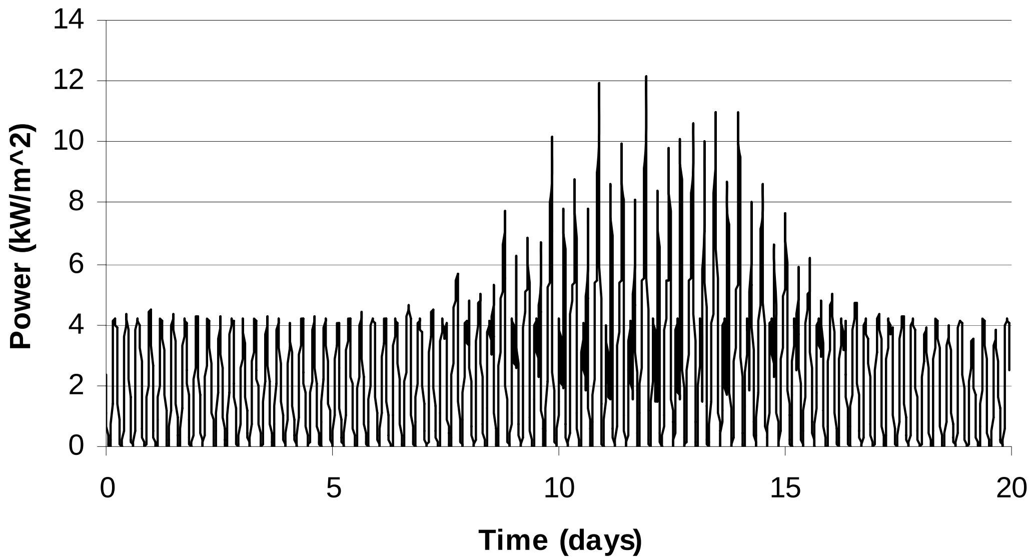


Figure 7 - Depth averaged power density at Cape Blomidon Transect over a full lunar cycle

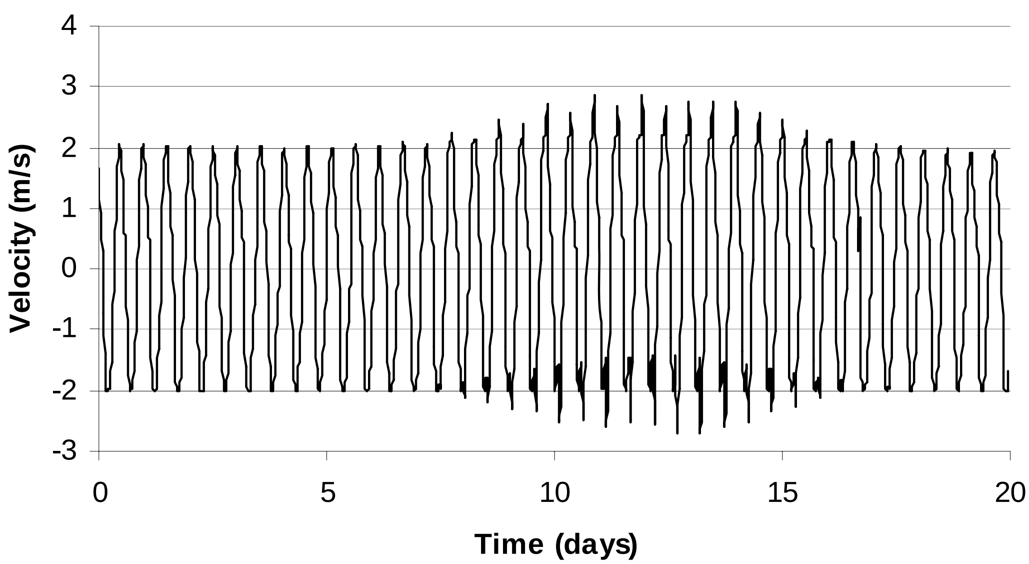


Figure 8 - Depth averaged velocity at Cape Blomidon over a full lunar cycle

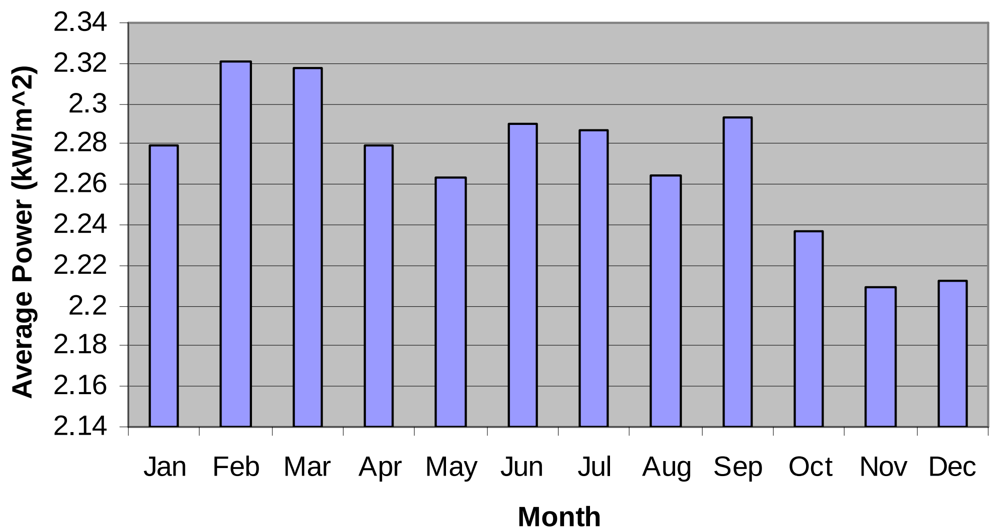


Figure 9 - Monthly average power density at Cape Blomidon Transect

Tidal Energy Resource Cape Sharp Transect

The Cape sharp transect is the highest energy transect within the Minas Passage and is therefore well suited to deploy a commercial sized TISEC array. The following resource graphs characterize the resource at that transect.

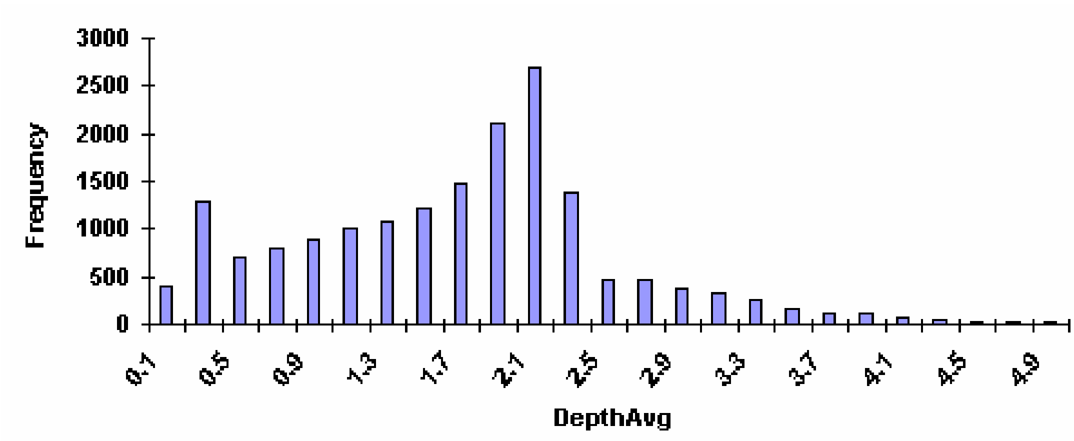


Figure 10 - Depth averaged velocity distribution at the Cape Sharp commercial site. Velocity shown is in m/s

Table 2 - Depth averaged velocity and energy distribution at the Cape Sharp Transect

Velocity (m/sec)	Power Density (kW/m^2)	Number of Cases	Percentag e of Cases	Number of Hours	Energy Density (kWh/m^2)
0.1	0.0	398	2.3%	199.0	0
0.3	0.0	1290	7.4%	645.0	9
0.5	0.1	703	4.0%	351.5	23
0.7	0.2	800	4.6%	400.0	70
0.9	0.4	879	5.0%	439.5	164
1.1	0.7	1014	5.8%	507.0	346
1.3	1.1	1070	6.1%	535.0	602
1.5	1.7	1225	7.0%	612.5	1,059
1.7	2.5	1468	8.4%	734.0	1,848
1.9	3.5	2108	12.0%	1054.0	3,705
2.1	4.7	2695	15.4%	1347.5	6,396
2.3	6.2	1390	7.9%	695.0	4,334
2.5	8.0	472	2.7%	236.0	1,890
2.7	10.1	459	2.6%	229.5	2,315
2.9	12.5	374	2.1%	187.0	2,337
3.1	15.3	320	1.8%	160.0	2,443
3.3	18.4	259	1.5%	129.5	2,385
3.5	22.0	172	1.0%	86.0	1,890
3.7	26.0	123	0.7%	61.5	1,597
3.9	30.4	110	0.6%	55.0	1,672

4.1	35.3	70	0.4%	35.0	1,236
4.3	40.7	48	0.3%	24.0	978
4.5	46.7	31	0.2%	15.5	724
4.7	53.2	22	0.1%	11.0	585
4.9	60.3	20	0.1%	10.0	603
		17520	**1**	**8760**	**39,211**

The following shows velocity and power as a function of time. What is apparent by looking at the following figures is the presence of a secondary velocity peak. It is important to understand that this peak occurred because of the methodology used to fit the tidal current data to the actual site. In reality these curves will likely have the shape of a sinusoid. It also illustrates the uncertainty still present in the actual tidal current predictions and the importance of detailed modeling and measurement of the resource at the deployment site.

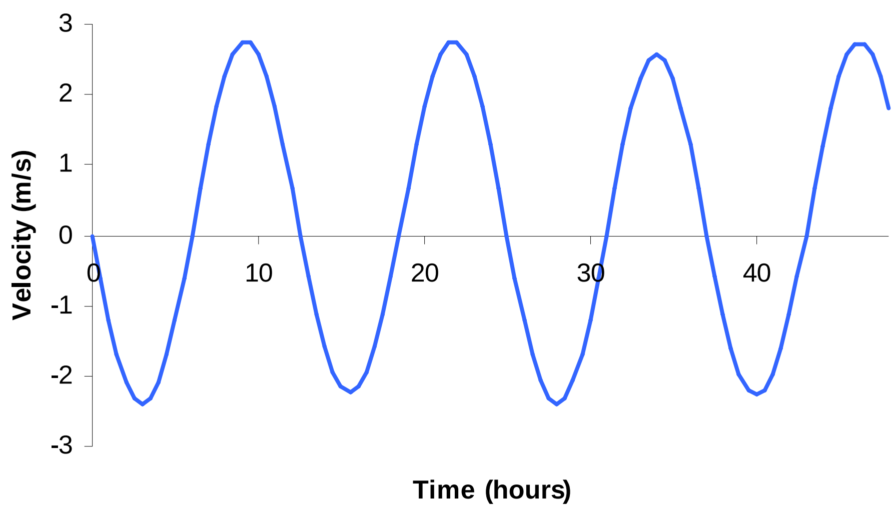


Figure 11 - Depth averaged velocity profile at Cape Sharp

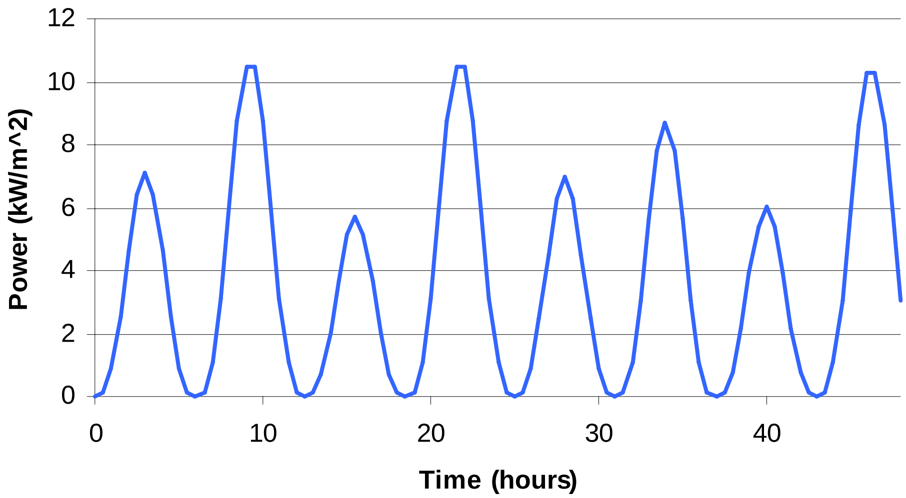


Figure 12 - Depth averaged power density variation at Cape Sharp over 48 hours

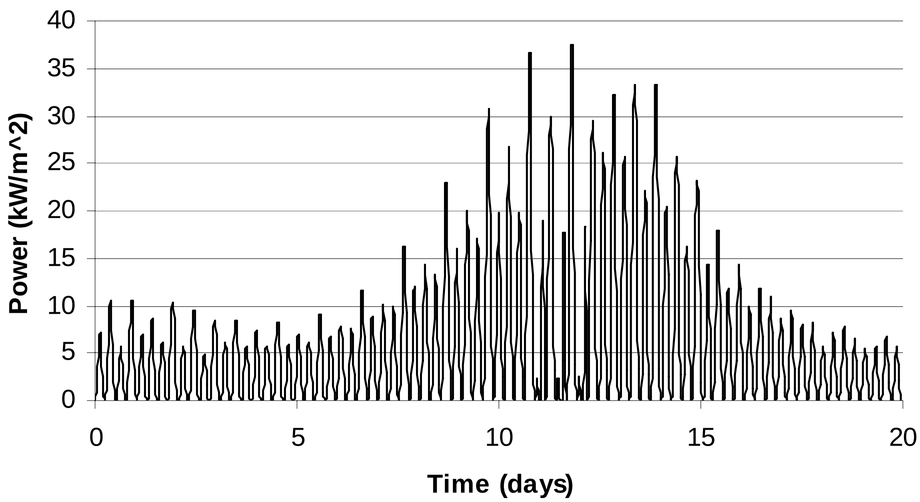


Figure 13 - Depth average power density at Cape Sharp

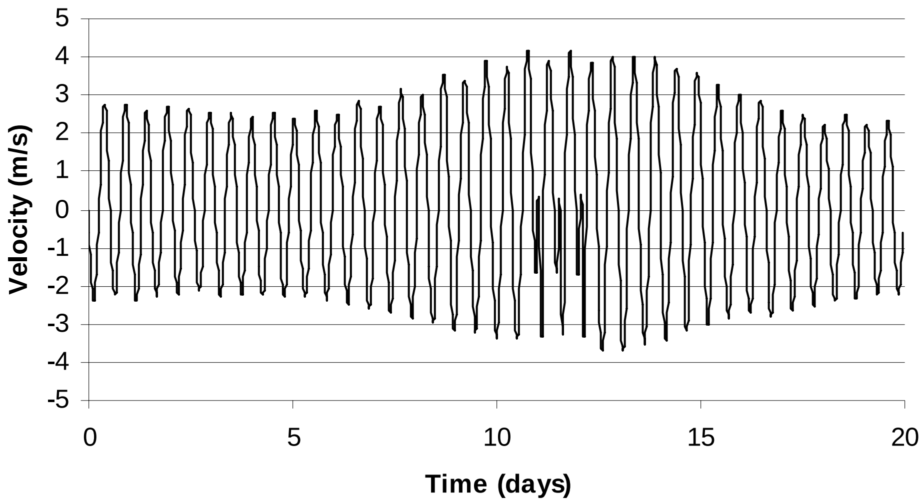


Figure 14 - Depth average velocity over full lunar cycle

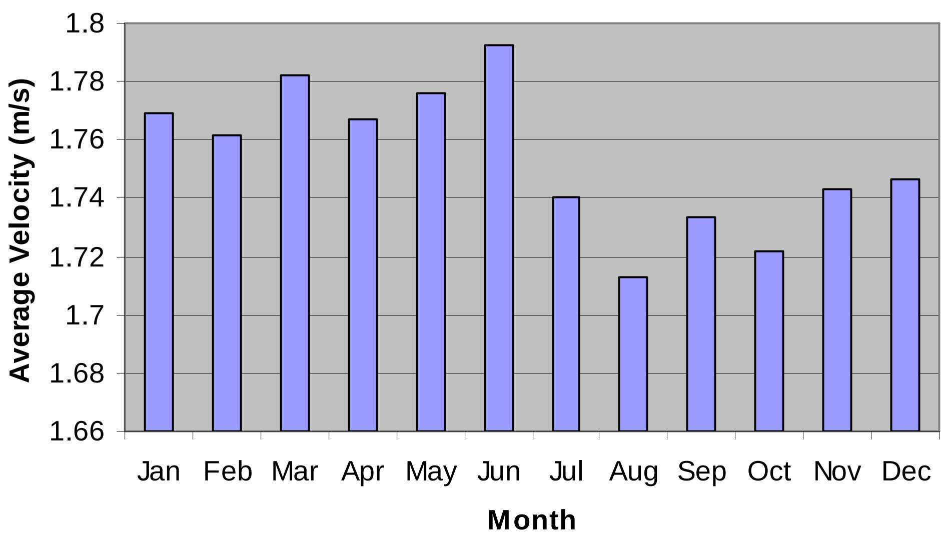


Figure 15 - Monthly average velocities

Bathimetry

The bathymetry (the ocean equivalent to land topography) is an important determinant in the siting of tidal turbines. In shallow water, there may be insufficient surface and seabed clearance for the turbine rotor. This drives site selection towards deeper water sites. Figure 16 shows a section of a nautical chart for the Minas Passage. Depths are in fathoms, with additional feet as subscript (1 fathom = 6 ft = 1.8 m).

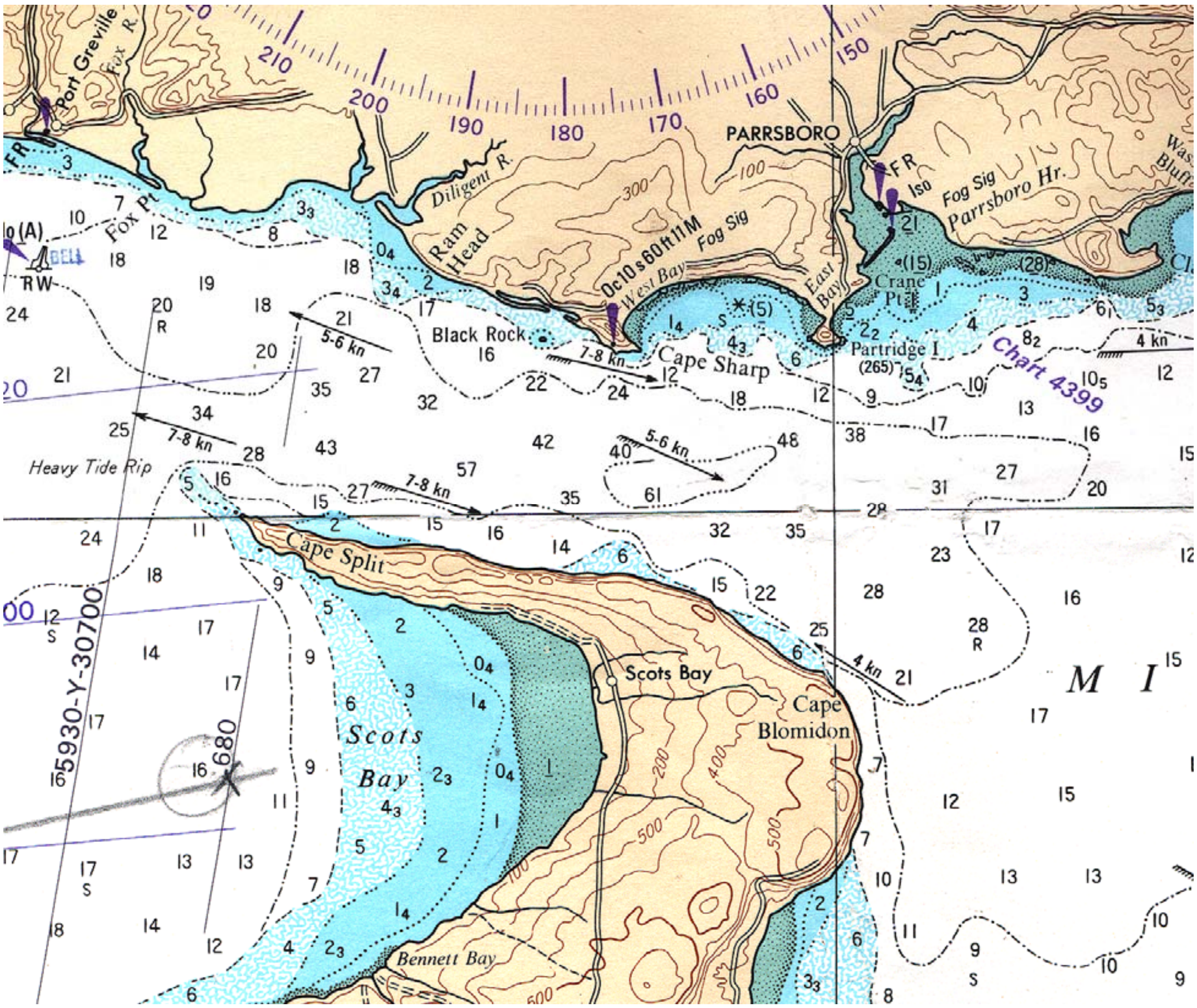


Figure 16 - Minas Passage nautical chart

Also shown in Figure 16 are current speeds around the Cape Sharp Transect area. It is interesting to note that high current speeds can be found over a relatively long channel section from the Cape Sharp transect to Cape Split. This provides a relatively large area suitable for the deployment of TISEC devices.

Based on the above nautical chart, cross-sections were generated for the Cape Sharp and the Cape Blomidon Transect to illustrate the depth-variation over the cross-section. The following 2 charts show the channel cross sections.

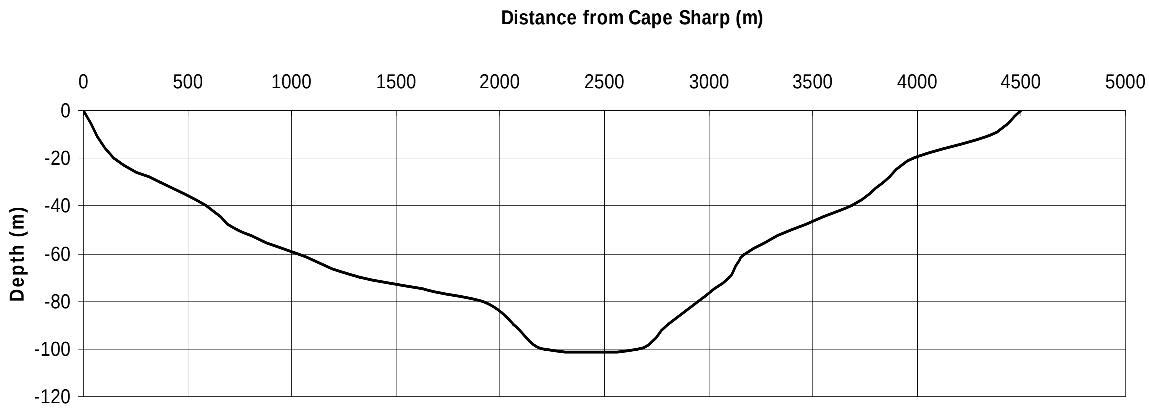


Figure 17 - Cape Sharp channel cross section

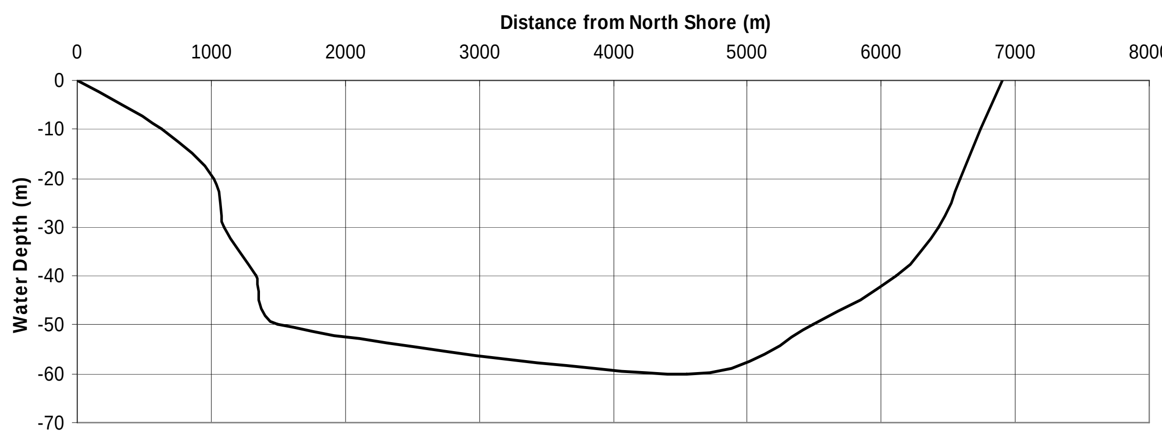


Figure 18 - Cape Blomidon channel cross section

A critical issue that needed to be addressed was if 15% of the resource could really be extracted based on the available channel width and length for deployment of devices at commercial site (Cape Sharp). A cursory review indicated that the area suitable for the deployment of TISEC devices could accommodate enough MCT size turbines to extract an average of 981MW in deep waters (>40m) and in shallow water using surface piercing technology such as MCT's SeaGen an average of 122MW could be extracted. Therefore, there are plenty of deployment locations in areas where high velocities occur to meet the environmentally acceptable limit of 152MW (15%).

Grid Interconnection options

Because of lower grid interconnection cost for a pilot demonstration project, Nova Scotia electricity stakeholders chose a pilot site at Cape Blomindon. The commercial site, where the tidal energy is the greatest, is at Cape Sharp. However this commercial site will require the addition of a dedicated overland electric transmission corridor to the existing Parsborro substation. The following map shows a local site overview.

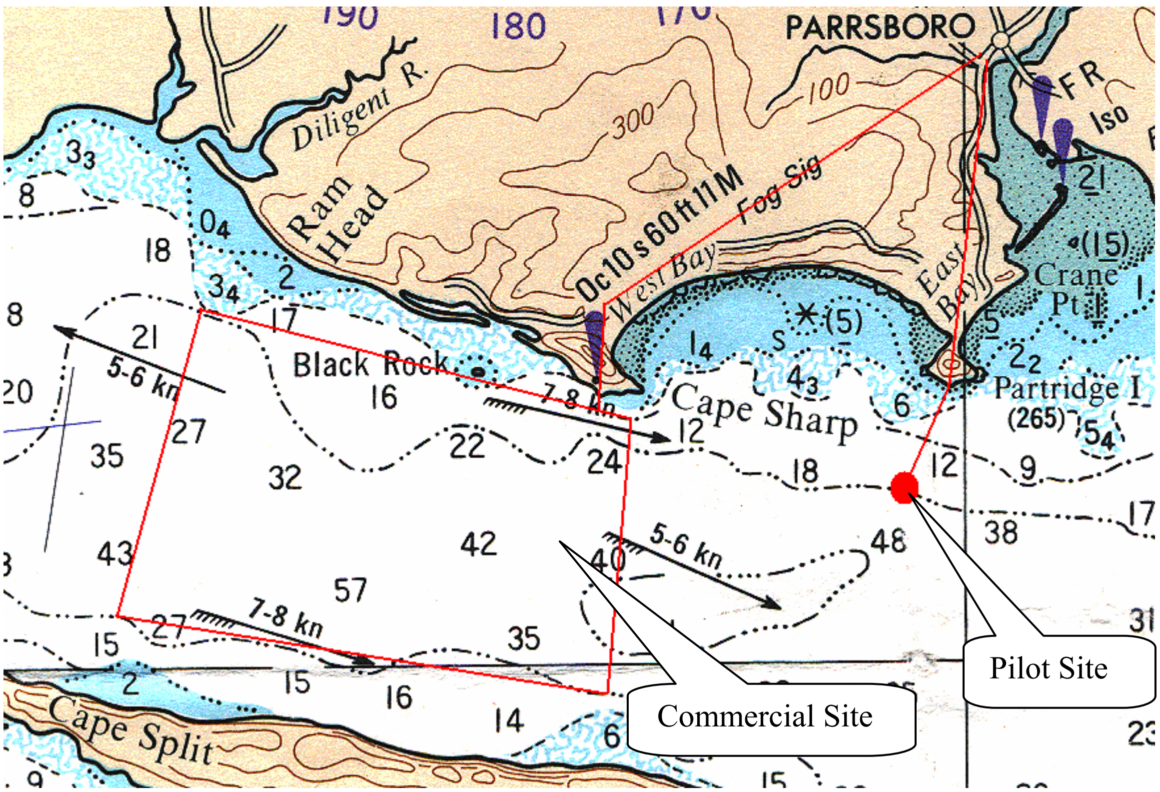


Figure 19 - Local Site overview showing pilot and commercial deployment sites

For the pilot plant, the electric distribution system needs to be upgraded to provide and interconnection point at the South Point of Partridge island. The interconnection would be limited to a demonstration plant with a capacity of less then 2MW. The cost for connection to a nearby pole is estimated at CAD (Canadian dollar) 475,000 and would provide a 12.5kV distribution-level grid interconnection point on the south of Partridge Island. Another CAD 60,000 needs to be included for provision of interconnect facilities (which typically consist of a couple poles, recloser and primary metering), leading to a total cost CAD535,000. At an exchange rate of 0.88, this is a US dollar equivalent of $470,800.

For the commercial plant at Cape Sharp, a new overland transmission corridor would need to be built to Parrsboro substation, from where the power could be exported. Because of the significant generation potential at the Cape Sharp site (up to 350MW), the following provides a summary of limitations and order of magnitude cost estimates.

- The use of a 69kV interconnection to the site (requires new 12.5km long transmission corridor) and use of the existing transmission infrastructure into Parrsboro would limit the commercial plant capacity to roughly 50MW. The order of magnitude cost estimate for this first 50MW is CAD 3.5million and would include only cost dedicated to the facility. No recoverable network upgrades are required at this level.
- Increasing the transmission capacity to 138kV would increase transmission capacity to about 150MW, would involve reconfiguration of the substation at Maccan and the conversion of Parrsboro substation to accommodate the higher voltage level. Thermal line ratings will limit the electric power export to 120MW in summer and 150MW in winter. For the purpose of this study, it was assumed that the limit would be 120MW. The total cost directly applied to the TISEC plant at the site is CAD 5.8 million dollars. An additional CAD 1.2 million would be incurred in network upgrades, which would be recovered by the utility over the plants life.
- An initial look at the proposed 350 MW (required capacity to extract 15% of the tidal resource at the Cape Sharp transect) tidal project in the area of the Cape Sharp Transect confirmed that such a project would have a significant impact on the reliability and operation of the Nova Scotia and potentially the Maritimes power system. The proposed site sits in an area that would impact the Nova Scotia - New Brunswick interconnection and therefore a joint study by NSPI and NBSO would be required. The import-export capability of this interconnection would be preserved, and if required, enhanced by the transmission reinforcement required for the TISEC Installation. The "Order of Magnitude of Probable Cost" is CAD 200 million which would consist of 345KV Transmission, substations and reactor/capacitor

banks required to maintain conformance with Transmission standards. It should also be noted that the future state of system development can have a large influence on this value in the open access development configuration. Out of the CAD 200 million, only 5% or CAD 10million would be required for building a 375kV transmission corridor to Parrsboro, with the remaining CAD 190million being network upgrade cost, which would be recovered by the utility over the project life. For the purpose of estimating cost of electricity only the first CAD 10 million are being considered. This is a US dollar equivalent of $8.8 million (using an exchange rate of 0.88).

A full System Impact Study would be required to proceed with assessment of the installations impact to the power system. Transmission access is provided on a first-come, first-served basis, up to the Available Transfer Capability of the transmission path of interest, under Open Access development mechanisms.

NSPI, as do all transmission operators in North America, design and operate the power systems to criteria and standards established by the North American Electric Reliability Council (NERC) and its affiliated regional council Northeast Power Coordinating Council (NPCC). As the System Study is completed, it would be published on the NSPI public Open Access Same-time Information System (OASIS) and the project would be reviewed by NPCC.

A full System Impact Study would address the following issues at a minimum:

1. Develop a valid computer model of the TISEC generation and prime-mover equipment and controls.
2. Review the expected operational characteristics: controllability, ability to schedule, etc. of the technology
3. Review potential power quality issues (flicker, harmonics, resonance) if non-conventional technology is proposed.

4. Develop alternative interconnection options

5. Evaluate the steady-state and transient performance of the interconnected power system for all NPCC standard and extreme contingencies (load flow and stability studies)

6. Evaluate the impact of multiple units comprising 350 MW installation on NS reserve requirements.

7. Evaluate the ability to maintain equipment with a minimum of disruption to production, while still meeting NPCC criteria.

8. Potential for plant to provide ancillary services (tie line control, frequency control, reserve) particularly with high penetration of wind energy conversion systems in NS.

9. Recommend least-cost configuration meeting system reliability requirements.

Generator interconnection and procedures for requesting transmission access (firm or non-firm) for both NSPI and NBSO can be found at oasis.nspower.ca and http://www.nbso.ca/www.nbso.ca. A full System Impact Study and Facilities study would cost in the order of CAD 150,000 and take 12 months to complete.

For the purpose of this design study, cost components required to build-out the capabilities of the substation or upgrade the transmission capacity of the electric grid were excluded. Under US FERC regulations (and EPRI assumes that the Canadian regulations are similar), such cost is covered by 'wires' charges and is not considered to be a part of the levelized busbar plant cost of electricity (COE). However it is clear that exceeding 120MW in capacity would present major hurdles as cost increases for generation capacity above this level are likely substantial.

Nearby Port facilities

A wide variety of shipyards and offshore marine contractors exists is the Halifax-Dartmouth area, well suited for fabrication and assembly of TISEC devices.

For shore side support services (inspection, maintenance, and repair of operating devices), the nearest city with an extensive maritime infrastructure is Saint John, New Brunswick, but this port is located approximately 130 km southwest of Minas Passage. A service vessel traveling at a cruising speed of 6 – 7 m/s would require a transit time of 4-1/2 hours if going with the current, or 5-1/2 hours if going against the current. At a tow speed of 3 – 3.5 m/s the trip would take 9 to 11 hours, depending on timing relative to the tide.

Parrsboro, Nova Scotia, has a well-maintained wharf and is located just inside the Minas Passage. A service vessel traveling to Cape Split at a cruising speed of 6 7 m/s would require a transit time of less than an hour if going with the current, or 1-1/2 hours if going against the current. At a tow speed 3 – 3.5 m/s the trip would take 1 to 3 hours, depending on timing relative to the tide.

Compared to coming from Saint John, a vessel's response time from Parrsboro would be 5 to 6 hours faster for investigating a problem or delivering a service crew to the project site, and would be 8 to 9 hours faster if towing a device. This saves fuel and greatly reduces down time for a device outage incident. It also minimizes exposure to waiting-on-weather delays, compared to a trip that covers half the length of the Bay of Fundy. Moreover, compared to Saint John, the local weather at Parrsboro is virtually identical to that in Minas Passage, greatly reducing the risk of unexpected wave or wind conditions found by the service vessel when it arrives on site.

The Parrsboro Harbour Commission has been briefed on this study and is keen to provide local support for tidal in-stream projects in the upper Bay of Fundy. Moreover, they have significant funding from the Atlantic Canada Opportunity Agency to improve their harbour facilities, as well as a work building with a gantry crane support structure next to the government wharf.

Seabed Composition

Sedimentation at a tidal energy deployment site is an important consideration for foundation design and has an impact on the type of foundation used, installation methods and scour protection methods (if required).

Seismic reflection and sidescan sonar surveys have been undertaken in Minas Passage to support bedrock mapping and the earlier tidal power assessment in the 1960s and 1970s.

Minas Passage is underlain mostly by Triassic sedimentary bedrock, but a long, linear volcanic deposit occurs parallel to the passage just south of the north shore and is mapped as the Triassic McKay Head Basalt. As shown in Figure 20, almost the entire seafloor of Minas Passage is exposed bedrock, with gravel deposits close to shore on either side.

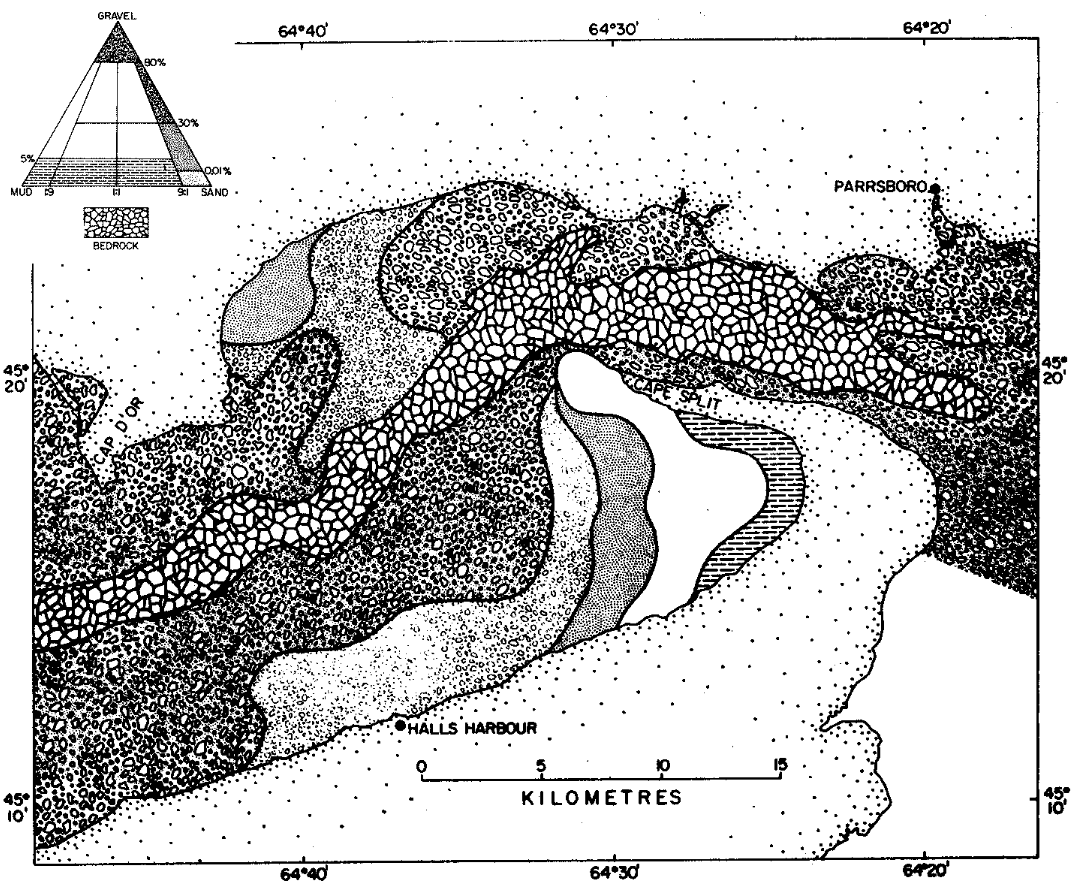


Figure 20 – Seabed Sedimentation in the Minas Passage

Navigational Clearances

The maximum draft required for deep draft vessels passing though the Minas passage is 15m below lowest astronomical tide (LAT). The channel is wide and allows for sufficient space in the middle even if some surface piercing TISEC devices are located along the 30m water depth contour line. As a matter of fact, the piles could effectively be used as navigational aid for passing ship traffic.

Interference with ice

Anecdotal reference has it that in the winter of 1958, it was possible to walk across the Minas passage over the ice. Further, a report[2] funded by the National Research Council (NRC) of Canada comes to the conclusion that TISEC devices deployed in the Minas passage would need to be engineered to tolerate at least 30% cover of sea ice 15cm thick in floes of at least 100m in length. In very severe winters, TISEC devices may be subjected to periods of 70% cover of 15-30 cm rapidly moving or packed sea ice. Although high velocity sites such as the Cape Sharp transect at which a commercial TISEC plant would be installed is mostly wiped clean of ice because of the high currents, the issue of pieces of ice that float in the water and potentially collide with the surface piercing structures remains. While it is possible to build monopile structures to withstand the ice-impacts at the site, the structural cost will significantly increase as a result of the increased steel thickness and make completely submersible technology the technology of choice. A preliminary assessment (see appendix) revealed that the cost of electricity could increase by as much as 50% as the direct consequence of having to design for ice-impact in heavy currents.

Other Site Considerations

The energy world is changing. Nova Scotia Power recognizes that they must find new ways to meet challenges. Right now, approximately 12-15 % of the electricity consumed (approximately 20 % of capacity) by Nova Scotia is currently generated from renewables. Nova Scotia Power wants to increase that amount by developing more renewable energy

[2] Richard Sanders and Emile Baddour, Document Ice in the bay of Fundy Canada, March 2006

options. Already, Nova Scotia Power has the only tidal power plant in the western hemisphere, located at Annapolis Royal. They have a strong wind resource and are a leader in wind energy development in Canada. One big driver of change is their customers who have expressed a strong desire for more energy from renewable sources. The provincial government is also looking at ways to increase energy from these sources. Nova Scotia Power and the Province of Nova Scotia have co-sponsored this EPRI research to better understand the potential for tidal energy development in the Bay of Fundy.

The Cape Split area has recently been declared a Nova Scotia provincial park. Projects to mine the seabed of the Cape Split Sand Wave Field for marine aggregates were first embraced by the provincial and federal governments, but later cancelled by the provincial government.

Tourism and eco-tourism are a growing industry in the region. Although visual impact could be a concern for a device such as the monopile-based Marine Current Turbines, several individuals commented that they would be no more objectionable than an offshore lighthouse, and may have merit as supplemental aids to navigation. Another common remark is that when viewed from cliff heights, the surface expression of these devices would appear almost insignificant against the immense scale of the Minas Passage and its bordering coastlines.

Relevant Site Data

For the purpose of establishing point designs for both a demonstration and commercial system, the following data points are relevant.

Site (Cape Sharp)	
Channel Width	4,500 m
Average deployment depth (from LAT)	65 m
Deepest Point	100 m
Tidal Range	m
Seabed Type	Bedrock
Site (Cape Blomidon)	
Channel Width	6,900 m
Deployment Depth (from LAT)	30 m
Deepest Point	60 m
Tidal Range	m
Seabed Type	Bedrock some gravel
Tidal Energy Statistics (Cape Sharp)	
Depth Averaged Power Density	4.5 kW/m^2
Average Power Available	1,013 MW
Average Power Extractable (15%)	152 MW
# Homes equivalent (1.3 kW/home)	117,000
Peak Velocity at Site (surface)	5.3 m/s
Tidal Energy Statistics (Cape Blomidon)	
Depth Averaged Power Density	2.3 kW/m^2
Average Power Available	793 MW
Average Power Extractable (15%)	119 MW
# Homes equivalent (1.3 kW/home)	90,000
Peak Velocity at Site (surface)	3.5 m/s
Grid Interconnection Demo	
Subsea Cable Length	3,500 m
Cable Landing	Directional Drilling
Overland Interconnection Upgrade cost	$475,000
Infrastructure Upgrade Cost	None assumed
Grid Interconnection Commercial	
Cable Landing	Directional Drilling required
Overland Interconnection cost	Contingency of $10million included. Cost may be substantially higher (see grid interconnection section)
Infrastructure Cost	None considered

3. Lunar Energy Device

Device Description

The Lunar Energy technology, known as the Rotech Tidal Turbine (RTT) and illustrated in Figure 21, is a horizontal axis turbine located in a symmetrical duct. Unique features of the RTT are the use of a fixed duct, a patent pending blade design and the use of a hydraulic speed increaser. The full-scale prototype is designed to produce 1 MW of electricity while the initial commercial unit, the RTT 2000, is designed to produce 2 MW from a 7.2 knot (surface current) tidal stream. While no detailed cost analysis was carried out for this device, EPRI used the geometry of the RTT2000 to establish parameters for this project to address critical engineering issues. Ballast and structural reinforcements were scaled to meet load conditions at the site based on the maximum tidal current speed. Where required scour protection and other measures were assessed which are likely to impact the design at a particular site. The gravity foundation is provided by a concrete base, which can be provided with additional ballast to meet the required stability in high currents. The duct consists of steel plates which are supported by a steel tubular frame.

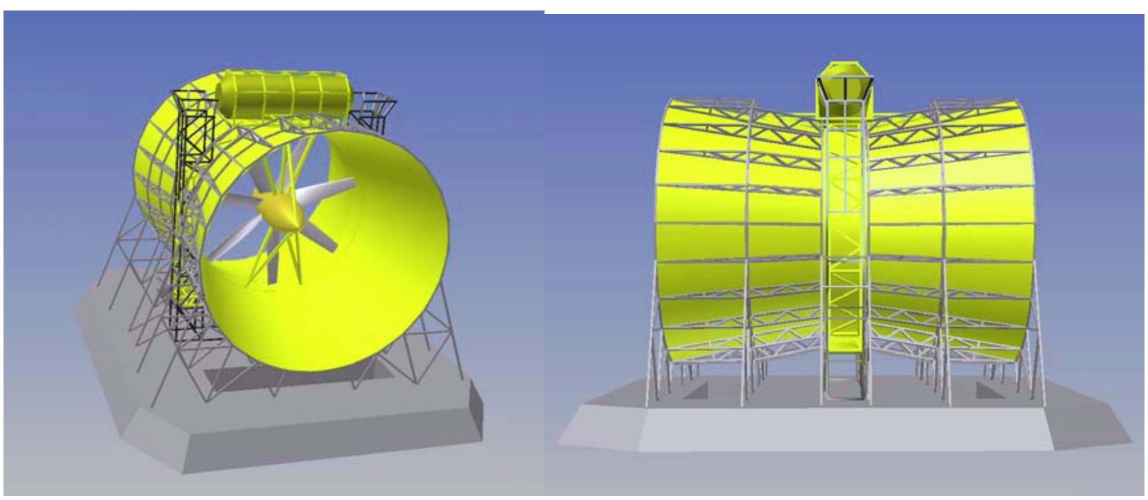


Figure 21 - Lunar Energy Mark I Prototype design

A cassette with the complete power take off, including rotor, hydraulic power conversion, electrical generation and grid synchronization is inserted as a module into the duct. This arrangement allows for relatively simple removal and replacement of the power conversion system and simplifies O&M procedures.

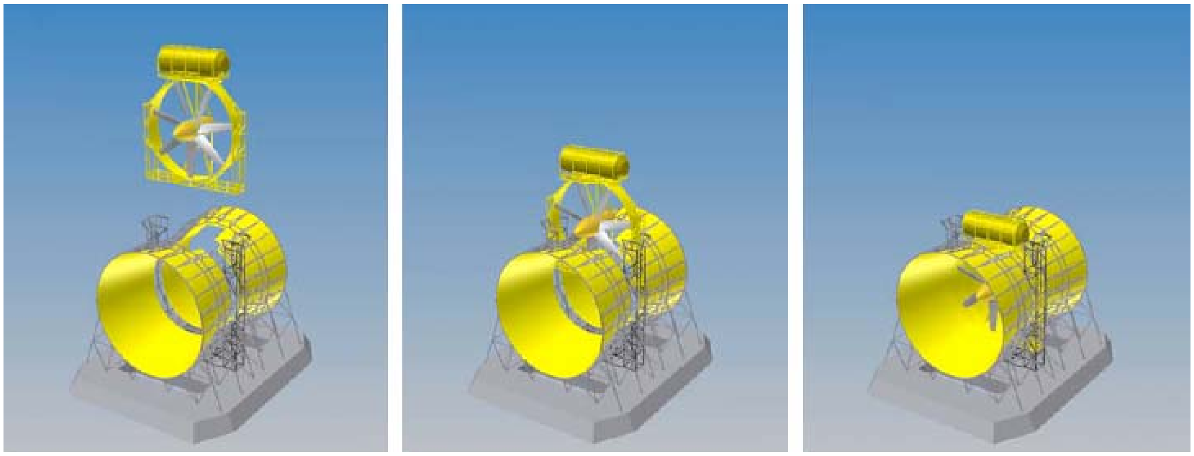


Figure 22 - Insertion and removal of cassette

Based on the site design velocity (maximum occurring velocity) the basic design's weight breakdown was scaled to ensure structural integrity and device stability. The following table contains the key properties for this site-design.

Table 3 - RTT2000 Mark II Specifications optimized for Cape Sharp Site conditions

Generic Device Specs	
Power Conversion	Hydraulic
Electrical Output	Synchronized with Grid
Foundation	Gravity Base
Average Deployment Depth	70m
Dimensions	
Duct Inlet Diameter	21m
Duct Length	27m
Duct Clearance to Seafloor	10m
Duct Inlet Area	346m^2
Hub Height above Seafloor	20.5m
Weight Breakdown	
Structural Steel	1,118 tons
Ballast	1,339 tons
Total installed dry-weight	2,457 tons
Power	
Cut-in speed	0.7 m/s
Rated speed	2.92 m/s
Rated Power	1,621kW
Capacity Factor	23%
Availability	95%
Transmission losses	2%
Net annual generation at bus bar at site	3,297MWh

Device Performance

Given a velocity distribution for a site, the calculation of extracted and electrical power is discussed in [1]. Site surface velocity distributions have been adjusted to hub height velocity assuming a 1/10th power law.

The overall efficiency of the Lunar Energy RTT2000 is the product of rotor efficiency, gearbox efficiency and generator efficiency. The following chart shows the efficiency of the various elements as a function of rated speed as provided by Lunar Energy. In order to get to obtain the relative efficiency of the device, the numbers below should be multiplied by the Betz limit which is 0.593.

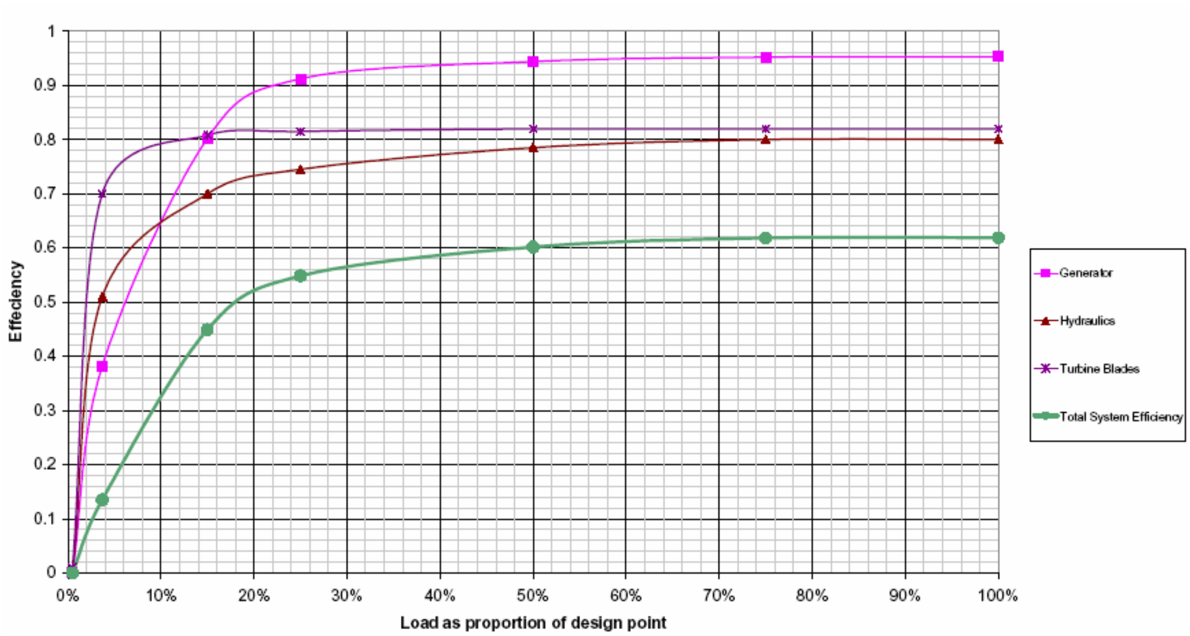


Figure 23 - Efficiency curves of Power Conversion System

Based on this efficiency chain and the exposed duct inlet area the device performance in a given site can be obtained. The following table shows the energy calculations at the Golden Gate site. The following definitions may help the reader understand:

- Flow velocities are depth adjusted using a 1/10 power law and represent the bin midpoint of the fluid speed at hub-height of the TISEC device.
- % Cases represents the percentage of time the flow at the site is at the flow velocity
- % Load represents the electrical output as a percentage of rated output of the device
- Power flux shows the incident power per square meter at the referenced velocity

- Flow power is the power passing through the cross sectional area of the device
- Extracted Power shows the amount of absorbed power

Average values can be found in the last column of the table.

Table 4 – Device Performance at deployment site (depth adjusted)

Fluid Speed m/s	% of Cases	% Load	Pfluid kW/m^2	Pfluid kW	Rotor Eff %	PCS Eff. %	Pelectric kW
0.09	1.94%	0.0%	0.00	0	33%	0%	0
0.27	6.62%	0.1%	0.01	3	33%	1%	0
0.44	3.98%	0.3%	0.04	15	34%	2%	0
0.62	3.95%	1.0%	0.12	42	35%	5%	0
0.80	4.53%	2.0%	0.26	89	38%	10%	3
0.97	4.91%	3.7%	0.47	163	41%	18%	12
1.15	5.21%	6.1%	0.78	270	44%	29%	34
1.33	5.86%	9.4%	1.20	414	46%	41%	79
1.50	6.60%	13.7%	1.74	603	47%	53%	152
1.68	7.79%	19.1%	2.43	842	48%	62%	251
1.86	11.14%	25.8%	3.28	1136	48%	68%	374
2.03	12.80%	33.9%	4.31	1493	48%	72%	515
2.21	9.93%	43.5%	5.53	1917	48%	73%	677
2.39	2.60%	54.8%	6.97	2415	48%	74%	865
2.56	2.51%	67.9%	8.64	2992	48%	75%	1083
2.74	2.00%	82.9%	10.55	3655	48%	76%	1336
2.92	1.84%	100.0%	12.73	4409	48%	76%	1622
3.10	1.58%	100.0%	15.19	5260	48%	76%	1621
3.27	1.12%	100.0%	17.94	6214	48%	76%	1621
3.45	0.82%	100.0%	21.01	7278	48%	76%	1621
3.63	0.61%	100.0%	24.41	8456	48%	76%	1621
3.80	0.58%	100.0%	28.16	9754	48%	76%	1621
3.98	0.37%	100.0%	32.28	11180	48%	76%	1621
4.16	0.26%	100.0%	36.78	12738	48%	76%	1621
4.51	0.00%	100.0%	46.99	16274	48%	76%	1621
4.69	0.00%						
Avg.			3.91	1353			404

Comparison of flow power to electric power generated is shown in Figure 24. Note particularly the cut-in speed (below which no power is generated) and rated speed (above which the power generated is constant).

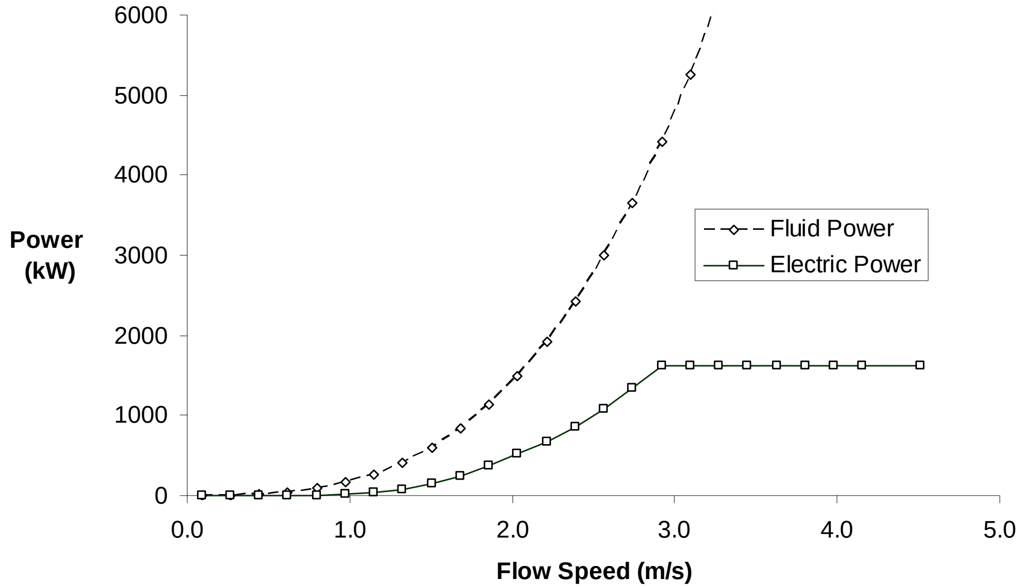


Figure 24 – Comparison of water current speed and electrical power output

The electrical output of the turbine compared to the fluid power crossing the swept area of the rotor is given in Figure 25, for a representative day. The effect of truncating turbine output at rated conditions is obvious.

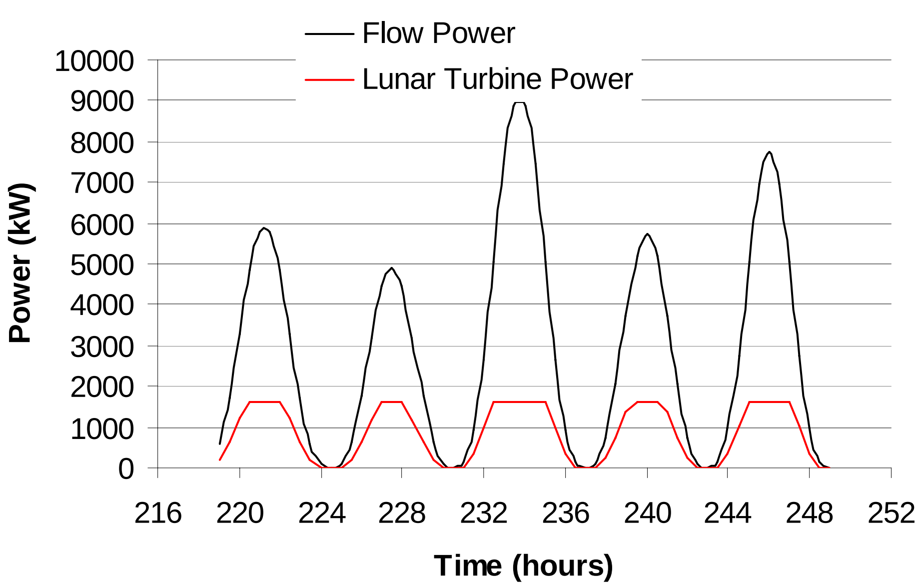


Figure 25 – Variation of flow power and electrical power output at the site

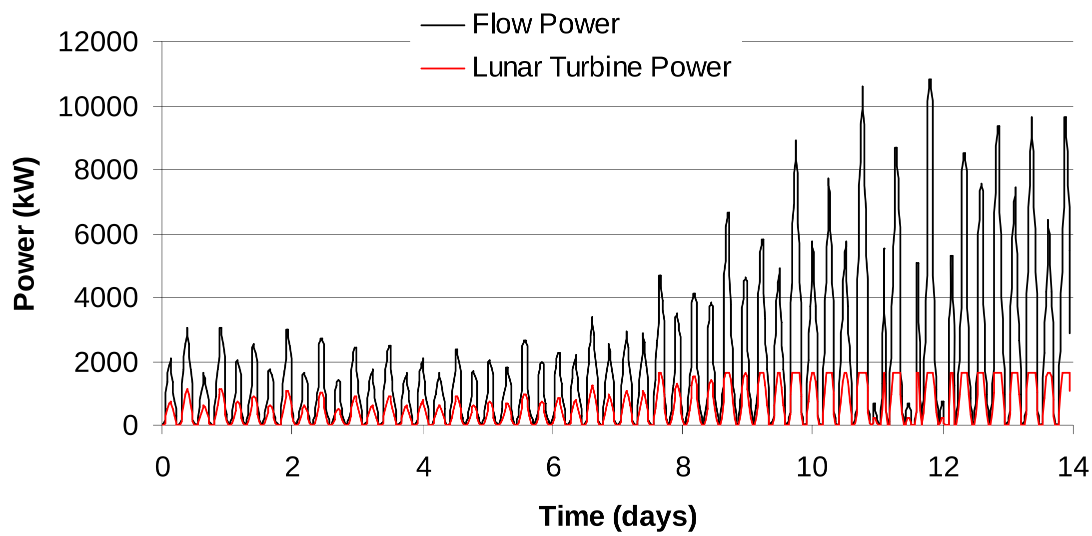


Figure 26 - Flow power vs. electrical power output at the site

Lunar Device Evolution

Current design efforts carried out by Lunar Energy is focused on value engineering. Whereas the prototype development is in its final design phase, the commercial units are expected to benefit from several potential areas of improvements, including:

1. Device Streamlining: Improving the overall design envelope to yield less drag, will reduce the stresses on the structure and result in savings on structural elements, foundation cost and weight.

2. Use of different materials: Replacing steel with concrete and composites could significantly reduce overall capital cost of the device.

3. Improving power train reliability: Improving the reliability of the power conversion system will result in less maintenance and could prove to provide significant savings. In particular replacing existing hydraulic elements with a direct induction generator could cut the number of interventions required over the devices design life by more then 50%.

4. Improving power train efficiency: The currently used hydraulic power conversion system shows an efficiency of about 76% at rated capacity. This is low as compared to other power train alternatives having efficiencies of up to 95%.

It is important to understand that none of the above measures would require novel technology and most of the measures could be implemented by means of simple value-engineering. Discussions with Lunar Energy showed that many of these improvements are already under consideration.

In March 2006, Lunar Energy provided EPRI with information on their redesigned prototype the RTT 2000 Mark II. The systems overall structural design was simplified by replacing the concrete base with 3 'steel-can' legs. These steel pipes can be filled with ballast to provide stability against sliding in heavy currents. The duct-steelwork was also streamlined by making the duct a load-carrying element and eliminating the structural frame. While the overall redesign increased the steel-weight slightly, it reduced manufacturing complexities and associated cost.

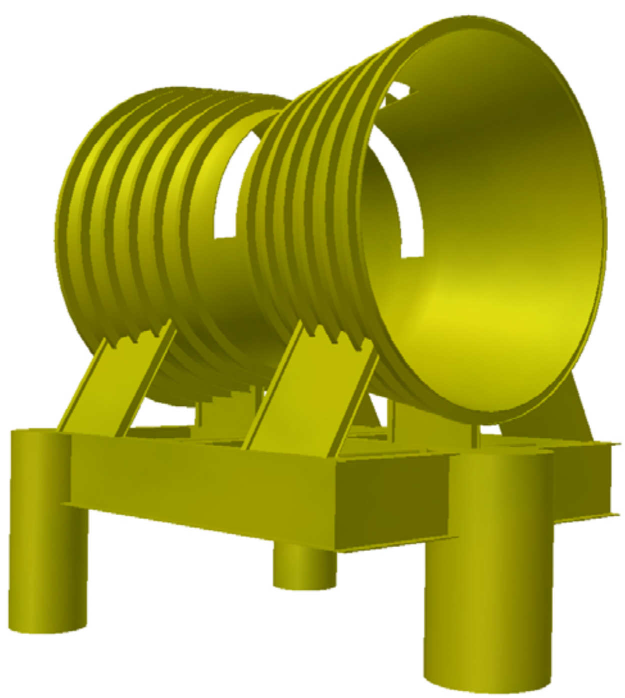


Figure 27 - RTT 2000 Mark II structural design

Installation of Lunar Module

The largest crane barges on the US west coast have capacities of up to 600 tons. With over 2000 tons, Lunar Energy's RTT2000 total system weight is well beyond of what any available crane-barge could handle and one of the big questions that needed to be answered was how this system was to be deployed, recovered and maintained. As a result, a detailed outline was developed of how the deployment and recovery of the device could be accomplished at reasonable cost. For the purpose of this outline we assumed that the device is deployed in two pieces, the concrete base and the duct. The text below outlines the deployment procedure.

The concrete base is constructed on a casting barge in calm, protected waters. The casting barge is then outfitted with four vertical pontoons (3m long), which are attached to each corner of the barge deck to provide stability during barge submersion. After the base is complete, the barge is ballasted until the deck is about 1.5m below the water level. This will allow the completed base shell to float free with a draft of about 1.2m. Once the base is floated off the barge it is sunk to the bottom in a water depth of at least 8m. Riser pipes are used to control the decent. A transport barge is floated over the base and preinstalled strand jacks are used to lift the base from the seabed until it is directly underneath the barge. The base is then filled with ballast and made ready for deployment. Finally, the barge is towed to it's deployment location and the same strand jacks are used to lower the base to it's prepared seabed.

Both the duct as well as the cassette unit are guided into final position using pre-installed guide wires extending vertically from the base structure to beams extending out in front of a derrick barge. The derrick barge places the duct onto a frame attached to the front of the barge. The duct is then attached to the guide wires and the guide wires are tensioned. Finally the duct is lowered onto the base using strand-jacks and guide wires. After set down, a ROV will disconnect strand jacks and guide wires from the base and duct.

The same procedure can be used to deploy and recover the cassette. The only difference is that the cassette weighs less and as a result a smaller (and less costly) derrick barge can be used.

Scour protection (if required) can be provided by either using concrete infill below the base or by placing articulated concrete mats onto the seabed. Both of these approaches have been successfully used in a number of North American projects.

Most installation and maintenance activities can be carried out from a derrick barge. These barges are in operation all over North and Central America and are used for a large variety of construction projects. Figure 28 shows Manson Construction's 600 ton derrick barge WOTAN doing construction work on an offshore drilling rig. Two tug boats are used for positioning the derrick barge and set moorings if required.

Figure 28 - Manson Construction 600 ton Derrick Barge WOTAN operating offshore

In heavy currents these barges use a mooring spread that allows them to keep on station and accurately reposition themselves continuously using hydraulic winches controlled by the operator.

A second piece of equipment that becomes really important for subsea installations is the remote operated vehicle (ROV). These systems increasingly replace divers and are used to monitor the subsea operation, visual inspections and carrying out various manipulation tasks such as connecting and disconnecting of guide wires, unplugging electrical cables etc. Technological advances have made these submersibles increasingly capable, in many instances eliminating the need to send down divers. This in turn reduces cost while increasing safety. A typical dual manipulator arm ROV making an underwater electrical connection is shown in Figure 21.

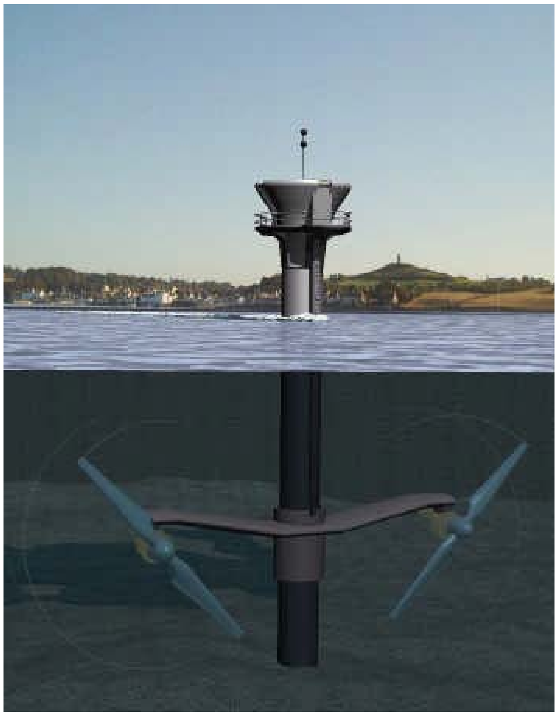
Figure 29 – Remotely Operated Vehicle (ROV) – (courtesy of Schilling Robotics - www.ssaalliance.com)

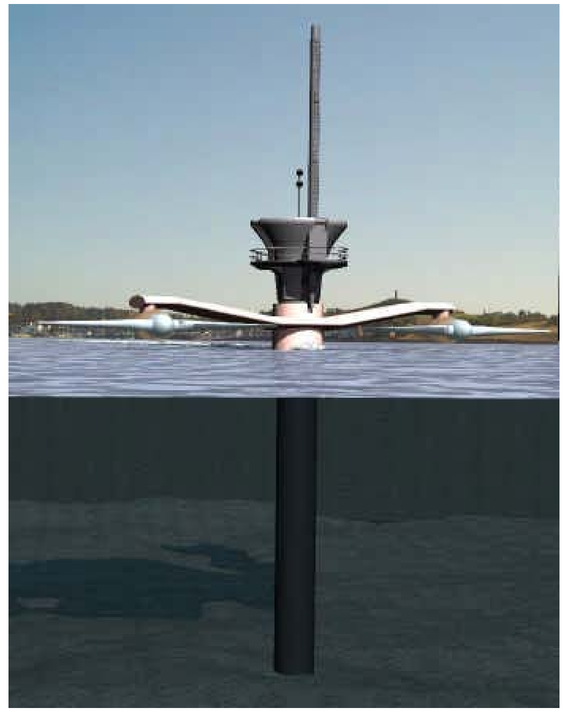
Operational Activities Lunar Energy

The O&M philosophy of Lunar Energy's RTT 2000 is to provide a reliable design that would require a minimal amount of intervention over its lifetime. In order to accomplish this Lunar Energy decided early on to use highly reliable and proven components even if that meant lower power conversion efficiency and performance as a result. All of the power conversion equipment of the RTT 2000 is mounted on a cassette, which can be removed from the duct and brought into a port to carry out operation and maintenance activities. The fact that the device is completely submersed makes its operation very dependent on attaining claimed reliability as each repair requires the recovery of the duct which requires specialized equipment. Lunar Energy has addressed this issue by optimizing its operation and maintenance strategy for minimal intervention. It is expected that the cassette is swapped out every 4 years and undergoes a complete overhaul after which it is ready to operate for another 4 years. The critical components prone to failure in the power conversion system are the hydraulic power conversion system. Given the high cost for maintenance intervention, reliability of the system becomes a critical attribute of the system, which will need to be proven on a prototype system. The L90 life of a component specifies after how much time 10% of components will fail (i.e. 90% of the components are still in good order therefore the term L90). The most critical hydraulic component of the RTT2000 has a L90 life of 5 years (meaning that after 5 years 90% of all devices are still operating without any issues). Given a typical Weibull failure distribution it was deemed that a 4-year service interval as proposed by the company is a sensitive approach.

4. Marine Current Turbines

The Marine Current Turbine (MCT) SeaGen free flow water power conversion device has twin open axial flow rotors (propeller type) mounted on "wings" either side of a monopile support structure which is installed in the seabed. Rotors have full span pitch control and drive induction generators at variable speed through three stage gearboxes. Gearboxes and generators are submersible devices the casings of which are exposed directly to the passing sea water for efficient cooling. A patented and important feature of the technology is that the entire wing together with the rotors can be raised up the pile above the water surface for maintenance. Blade pitch is rotated 180° at slack water to accommodate bi-directional tides without requiring a separate yaw control mechanism. This device is illustrated in Figure 30.



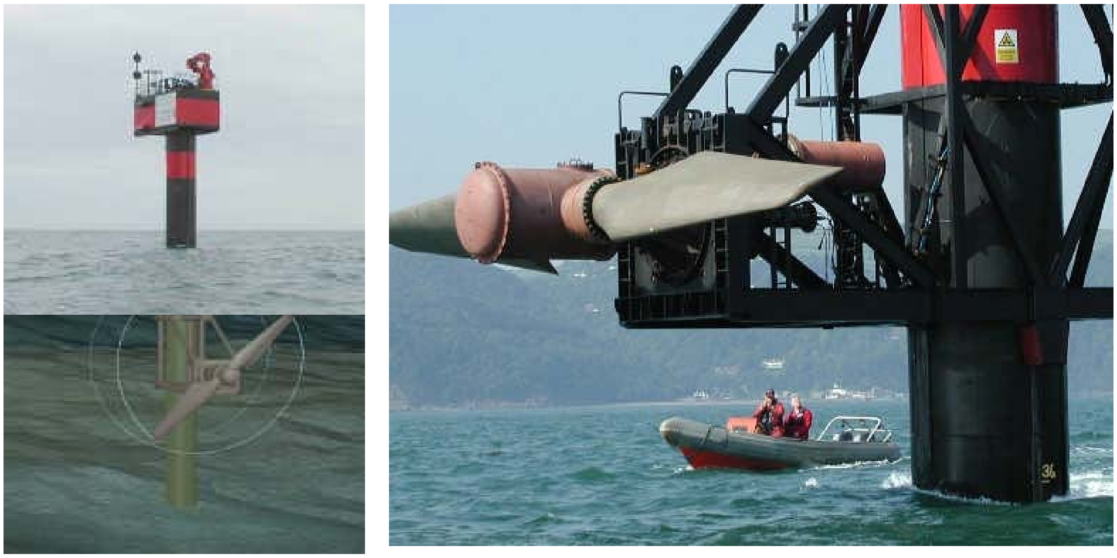


Operation Maintenance

Figure 30 – MCT SeaGen (courtesy of MCT)

(In printed from,' the pictures are upside down courtesy of Microsoft or our MS Word skills)

A 1.2 MW prototype SeaGen is presently being built and is scheduled for UK deployment in the fall of 2006. SeaGen is intended as a commercial prototype (not proof of concept) – and incorporates important learnings from SeaFlow, a 300kW single rotor test rig (Figure 31), which has been in operation for about 3 years. SeaFlow tested many of the features of SeaGen and has informed the design process by providing large amounts of data. The photo shows the rotor raised out of the water for maintenance – the submersible gearbox and generator are clearly visible. The rotor diameter is 11m and the pile diameter is 2.1m.



Operation Maintenance

Figure 31 – MCT SeaFlow Test Unit (courtesy of MCT)
(In printed from,' the pictures are upside down courtesy of Microsoft or our MS Word skills)

Device Performance

Given a velocity distribution for a site, the calculation of extracted and electrical power is discussed in [1]. Site surface velocity distributions have been adjusted to hub height velocity assuming a 1/10th power law.

The overall efficiency of the MCT SeaGen is the product of:

- Rotor: constant efficiency = 45%
- Gearbox: efficiency at rated power = 96%
- Generator: maximum efficiency = 98%

The efficiency of the gearbox and generator is expressed as a function of the load on the turbine (% load). Balance of system efficiency (BOS) is assumed to follow the same form as for a conventional wind turbine drive train – which can be approximated by the following function:

$$\eta_{BOS} = 0.8337e^{0.1467(\%\,\text{Load})} - 0.7426e^{-33.89(\%\,\text{Load})}$$

The performance of a single turbine deployed at the site is shown in

Table 5. Average values can be found in the last row of the table.

Table 5 – MCT Device Performance at Cape sharp (depth adjusted)

Fluid Speed m/s	% of Cases	% Load	Pfluid kW/m^2	Pfluid kW	Pextracted kW	PCS %	Pelectric kW
0.09	1.94%	0.0%	0.00	0	0	9.28%	0
0.26	6.62%	0.2%	0.01	5	0	13.51%	0
0.44	3.98%	0.8%	0.04	22	0	27.41%	0
0.61	3.95%	2.3%	0.12	60	0	49.31%	0
0.79	4.53%	4.8%	0.25	127	57	69.55%	40
0.96	4.91%	8.8%	0.46	232	104	80.74%	84
1.14	5.21%	14.6%	0.75	383	172	84.64%	146
1.31	5.86%	22.4%	1.16	588	265	86.12%	228
1.49	6.60%	32.6%	1.68	856	385	87.45%	337
1.66	7.79%	45.5%	2.35	1195	538	89.13%	479
1.84	11.14%	61.5%	3.17	1614	726	91.24%	663
2.01	12.80%	80.7%	4.17	2120	954	93.85%	895
2.19	9.93%	100.0%	5.35	2723	1182	94.08%	1112
2.36	2.60%	100.0%	6.74	3430	1182	94.08%	1112
2.54	2.51%	100.0%	8.35	4250	1182	94.08%	1112
2.71	2.00%	100.0%	10.20	5191	1182	94.08%	1112
2.89	1.84%	100.0%	12.30	6262	1182	94.08%	1112
3.06	1.58%	100.0%	14.68	7471	1182	94.08%	1112
3.24	1.12%	100.0%	17.34	8827	1182	94.08%	1112
3.41	0.82%	100.0%	20.31	10337	1182	94.08%	1112
3.59	0.61%	100.0%	23.60	12010	1182	94.08%	1112
3.76	0.58%	100.0%	27.22	13855	1182	94.08%	1112
3.94	0.37%	100.0%	31.20	15879	1182	94.08%	1112
4.11	0.26%	100.0%	35.55	18092	1182	94.08%	1112
4.28	0.46%	100.0%	40.28	20501	1182	94.08%	1112
4.46	0.46%	100.0%	45.42	23116	1182	94.08%	1112
4.63	0.46%	100.0%	50.98	25943	1182	94.08%	1112
Avg.			3.96	2016	594	94.08%	549

comparison of flow power to electric power generated is shown in Figure 32. Note particularly the cut-in speed (below which no power is generated) and rated speed (above which the power generated is constant).

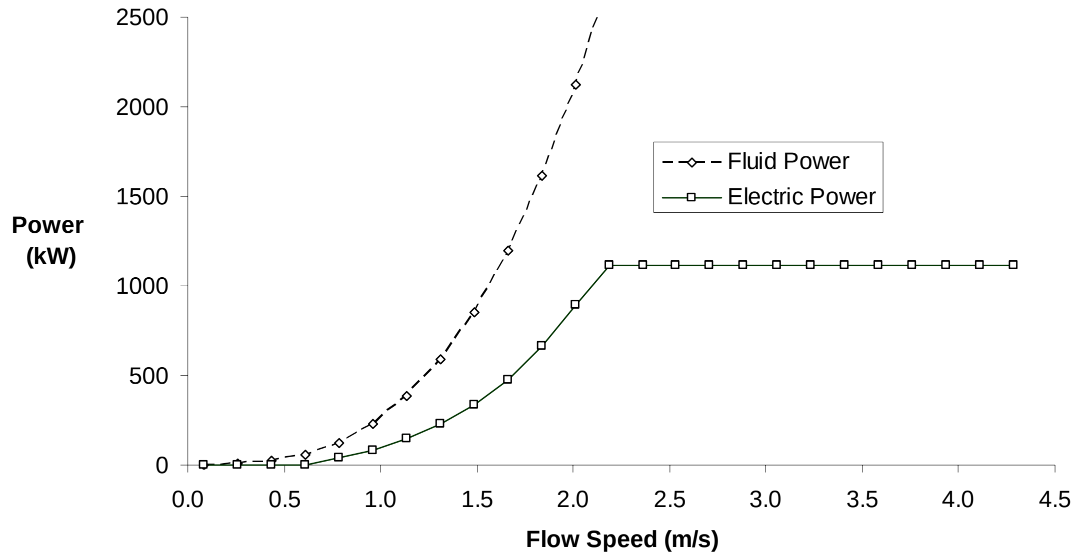


Figure 32 – Comparison of water current speed and electrical power output

The electrical output of the turbine compared to the fluid power crossing the swept area of the rotor is given in Figure 33, for a representative day. The effect of truncating turbine output at rated conditions is obvious.

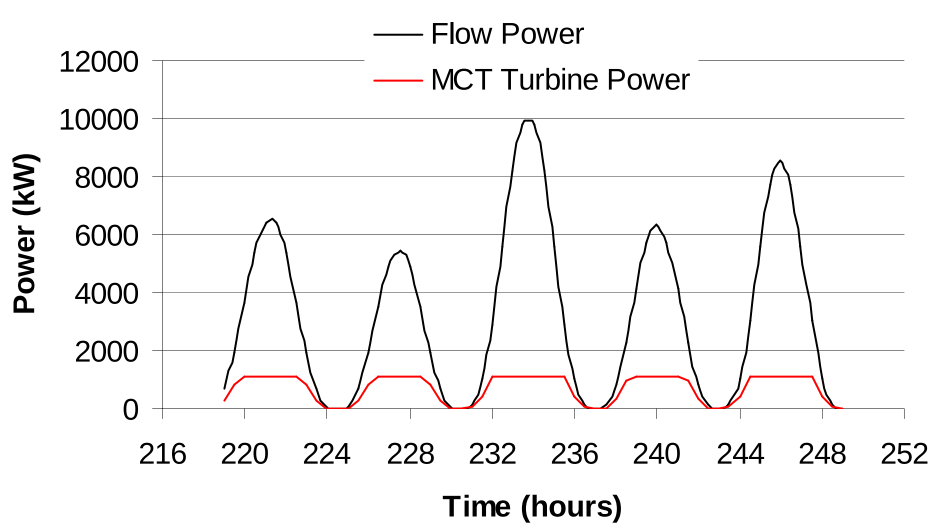


Figure 33 – Variation of flow power and electrical power output at the site

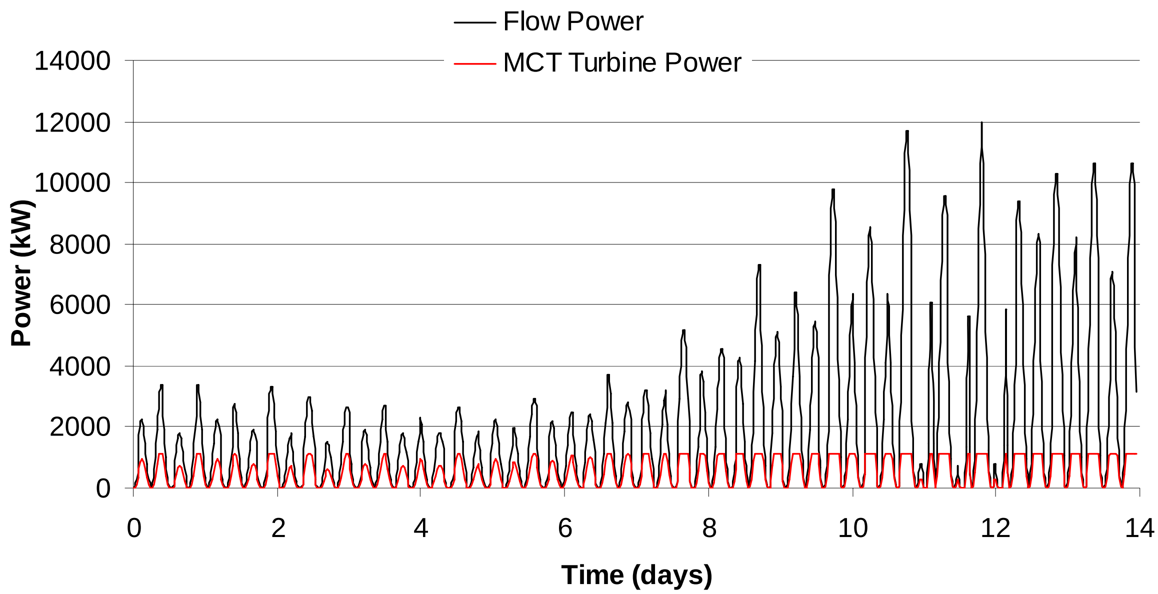


Figure 34 - Device power vs. flow power in cross sectional area of device

Device Specification

While in principle SeaGen is scalable and adaptable to different site conditions in various ways, EPRI used the 18m dual rotor version and optimized the system to local site conditions to estimate device cost parameters. The following provides specifications which are later used to estimate device cost. Since MCT's second generation completely submersed concept is not yet designed for manufacturing, EPRI was not able to do an independent cost analysis or it. Therefore the costing model represents an installation depth of 30m (which is representative of MCTs SeaGen technology). Based on discussions with MCT it is reasonable to expect that subsequent generation devices will have similar capital cost.

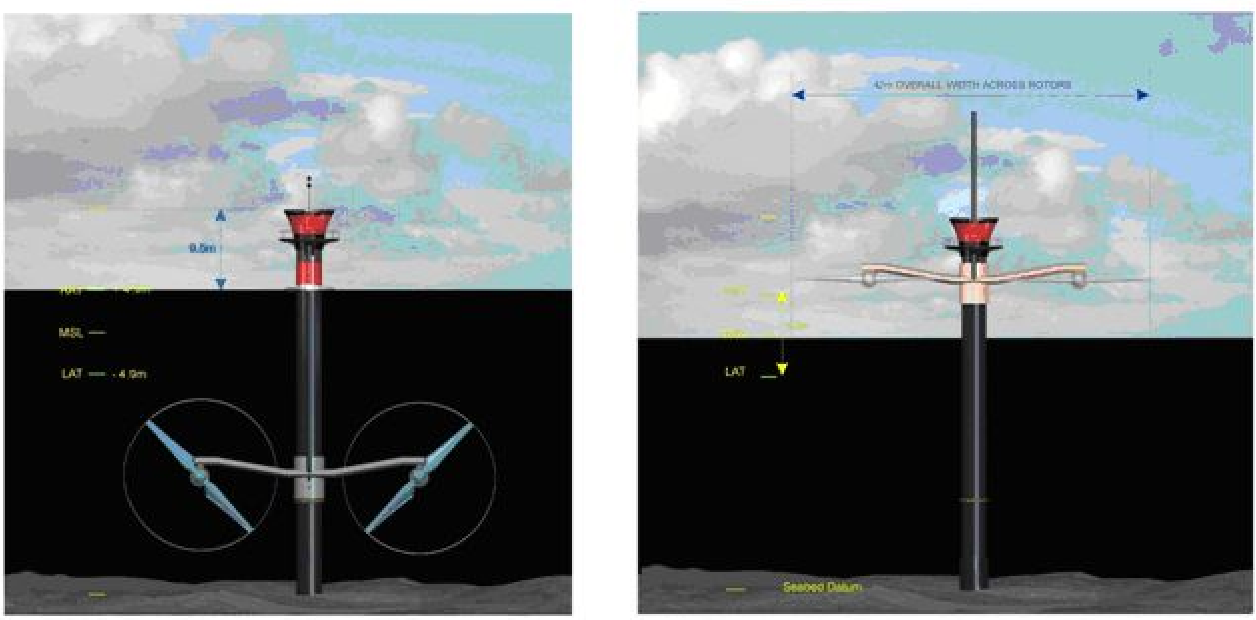
Table 6 – SeaGen Device Specification optimized for the Cape Sharp site

Generic Device Specs	
Speed Increaser	Planetary gear box
Electrical Output	Synchronized to grid
Foundation	Monopile drilled and grouted into bedrock
Average Deployment Water Depth	65 m
Reference Dimensions	
Pile Length	68m
Pile Diameter	3.5m
Rotor Diameter	18m

# Rotors per SeaGen	2
Rotor Tip to Tip spacing	46m
Hub Height above Seafloor	17m
Weight Breakdown	
Monopile	357 tons
Cross Arm	104 tons
Total steel weight	461 tons
Performance	
Cut-in speed	0.7 m/s
Rated speed (optimized to site)	2.16 m/s
Rated Electric Power	1,112 kW
Capacity Factor	46%
Availability	95%
Transmission efficiency	98%
Net annual generation at bus bar	4,480 MWh

MCT Device Evolution

MCTs first commercial unit, the SeaGen has been designed for a target water depth of less then 50m using a surface piercing monopile, which will allow low cost access to the devices critical components such as the rotor, power conversion system, gearbox etc. This configuration is shown in Figure 35.



Operation Maintenance

Figure 35 – MCT SeaGen (courtesy of MCT)

This configuration is not necessarily suitable for all sites for two reasons. First, deployment in deep water would be difficult and expensive. Second, surface piercing turbines are incompatible in some channels due to interference with shipping traffic. Since a number of sites prospective sites in North American are located in deeper water or in shipping channels, MCT has revealed a conceptual design for a deep-water, non-surface piercing turbine. It is based on MCTs existing turbine technology with an arrangement to raise the whole system to the surface where it can be accessed easily for operation and maintenance purposes. A preliminary review suggests that capital and operational costs are likely going to be in a similar range then for the SeaGen unit for which detailed cost models were built to evaluate the technology's economics in selected sites in North America.

Since a number of prospective sites in North American are located in deeper water or in shipping channels, MCT is considering a number of conceptual designs for deep-water, non-surface piercing installations. These next-generation devices would use the same power train as the SeaGen, but attached to a different support structure. Figure 36 shows a conceptual illustration of such a design.

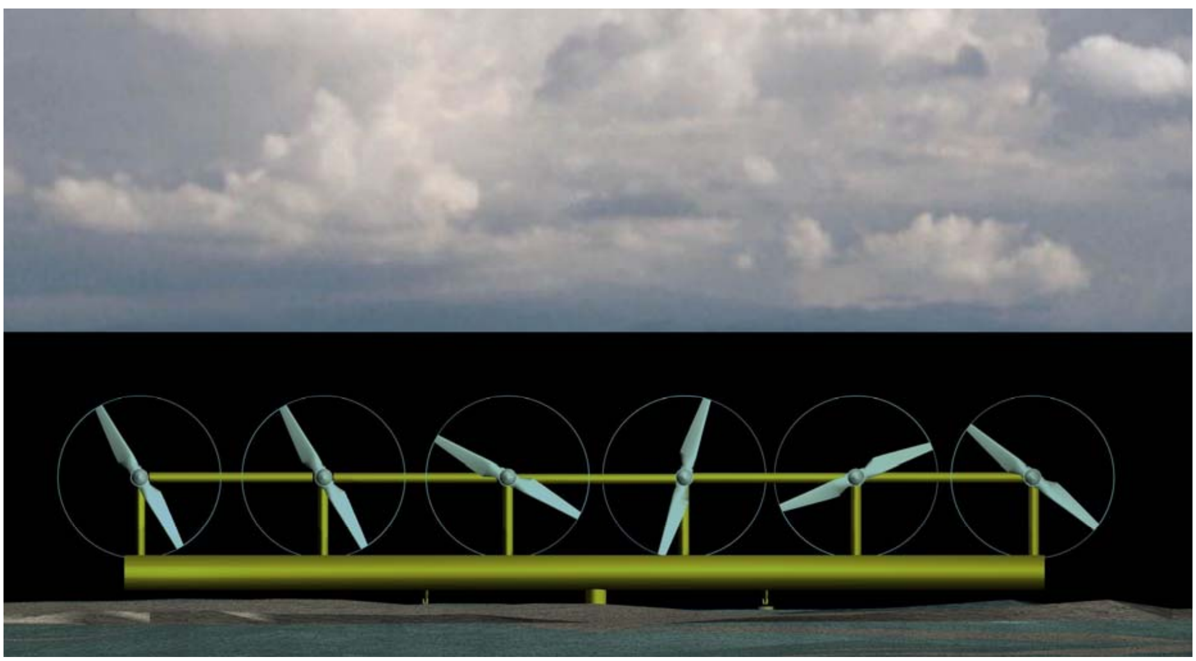


Figure 36 - MCT next generation conceptual illustration

A lifting mechanism (type to be determined) to surface the array for maintenance and repair without the use of specialized craft remains an integral part of MCT's design philosophy and would be present in any next-generation design. MCT is also investigating the use of gravity foundations instead of monopiles for certain sites.

MCT anticipates that maintenance of a completely submerged turbine will be more complicated than for a surface piercing structure. As a result, deployment of completely submerged turbines is contingent upon proving the reliability of the SeaGen power train.

Monopile Foundations

The MCT SeaGen is secured to the seabed using monopile foundation. Figure 37 shows a representative simulation of seabed/pile interaction. Near the surface the seabed yields due to stresses on the pile, but deforms elastically below a certain depth.

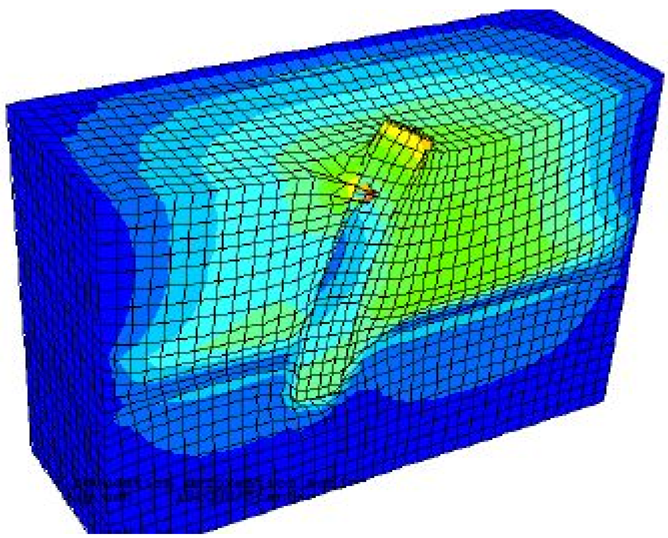


Figure 37 - Simulation of pile-soil interaction subject to lateral load (Source: Danish Geotechnical Institute)

Simulations such as the one shown above require detailed knowledge of the local soil conditions. Because this study did not perform any detailed geophysical assessment, three different types of soil conditions were chosen to model the pile thickness based on a simplified mechanical model:

- Bedrock
- Bedrock with 10m of sediment overburden
- Soft sediments

The design criterion was to limit maximum stresses to 120N/mm^2 and account for corrosion over the pile life. For the Cape Sharp commercial plant, the seabed is modeled as bedrock and for the Cape Blomidon pilot site as bedrock with 10m sediment overburden.

Figure 38 shows the range of pile weights as a function of design velocity (the maximum occurring fluid velocity at the site). These curves were then directly used to estimate capital costs of the piles depending on local site conditions. While the model is well suited for a first order estimate, it is important to understand that the detailed design phase may show deviation from EPRI's base model.

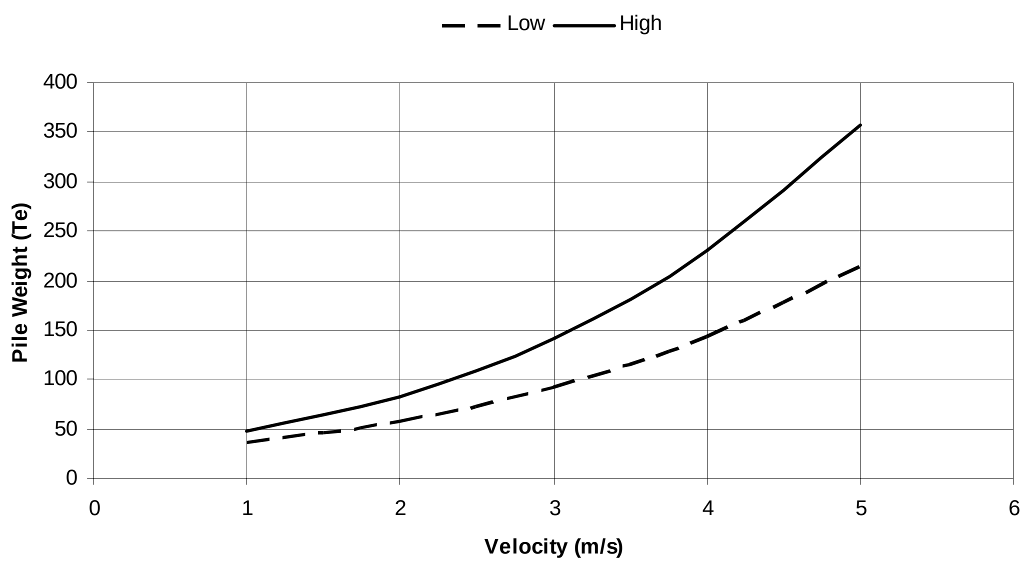


Figure 38 - Pile Weight as a function of design velocity for different sediment types

Pile Installation

MCT proposes to install their large diameter monopiles (3.5m - 4m outer diameter) using a jack-up barge. This is consistent with other European offshore wind projects that have used such barges to deploy offshore wind turbine foundations. While a few operators were found on the east-coast that use jack-up barges, most of them are used in the Gulf of Mexico and no suitable jack-up barge was found on the US west coast. Given the expense of mobilizing marine construction equipment from the Gulf of Mexico, EPRI decided to investigate lower-cost alternatives. The following outline shows the installation of a pile in bedrock from a jack-up barge.

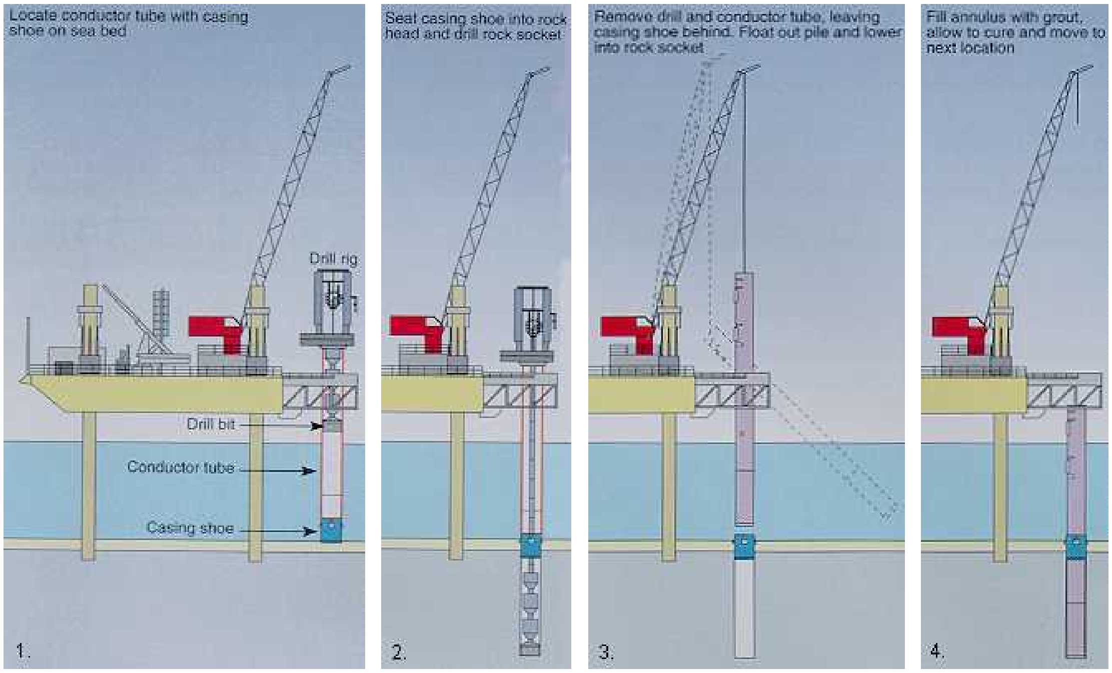


Figure 39 – Pile Installed in Bedrock (Seacore)

While jack-up barges are not commonly available in US waters, there are a significant number of crane barges available from which the installation of theses piles could be carried out. These derrick barges operate on the US west and east coast and are extensively used for construction projects in heavy currents such as rivers. Typical construction projects include the construction of bridges, cofferdams and pile installations. Crane capacities vary with some of the largest derrick barges being able to lift up to 600 tons. To carry out the installation of these relatively large 3.5m diameter piles, it was determined that a crane capacity of about 400 tons or more would be adequate to handle the piles, drilling bits and other installation equipment. Figure 27 shows Manson Construction's 600 ton derrick barge WOTAN doing construction work on an offshore drilling rig. Two tug boats are used for positioning the derrick barge and set moorings if required.

Figure 40 - 600 ton Derrick Barge WOTAN operating offshore (Manson Construction)

In heavy currents these barges use a mooring spread that allows them to keep on station and accurately reposition themselves continuously using hydraulic winches controlled by the operator.

Working from a barge, rather then from a jack-up platform does not set hard limits on the water depth in which piles can be installed. Some preliminary studies suggest that type of pile required for the MCT SeaGen device could be installed in water depths of as much as 90m. However such a configuration may not be cost effective due to high cost. In the offshore industry, piles are oftentimes used as mooring points for offshore structures. Installation of driven piles in water depths of more then 300m is not uncommon. It is, however, clear that pile installation in deeper waters becomes more costly and presents a limiting factor to their viability. Several options exist for installing piles, but it is important to stress that few marine construction companies in the US have experience with the installation of large piles in high current waters. Potential construction methods include:

- Driving piles using a hydraulic hammer

- Combination of water jetting and vibratory hammer
- Drill and socket a sleeve, then grout pile in place

Each of these methods has advantages and disadvantages. A drilled pile installation would involve drilling into the consolidated sediments and stabilizing the walls of the drill hole with a metal sleeve (follower). Once the hole has been drilled to a suitable depth, the pile is inserted and grouted into place. This method of installation is preferred by MCT to limit excessive pile fatigue during the installation process and drilling is required in most locations because of bedrock that would need to be penetrated.

Operational and Maintenance Activities

The guiding philosophy behind the MCT design is to provide low cost access to critical turbine systems. Since an integrated lifting mechanism on the pile (or level arm for the next generation design) can lift the rotor and all subsystems out of the water, general maintenance activities do not require specialized ships or personnel (e.g. divers). The overall design philosophy appears to be that the risks associated with long-term underwater operation are best offset by simplifying scheduled and unscheduled maintenance tasks. The only activity that could require use of divers or ROVs would be repairs to the lifting mechanism or inspection of the monopile, none of which are likely to be required over the project life.

Annual inspection and maintenance activities are carried out using a small crew of 2-3 technicians on the device itself. Tasks involved in this annual maintenance cycle include activities such as; replacement of gearbox oil, applying bearing grease and changing oil filters. In addition, all electrical equipment can be checked during this inspection cycle and repairs carried out if required. Access to the main structure can be carried out safely using a small craft such as a RIB (Rigid Inflatable Boat) in most sea conditions.

Figure 41: Typical Rigid Inflatable Boat (RIB)

For repairs on larger subsystems such as the gearbox, the individual components can be hoisted out with a crane or winch and placed onto a motorized barge. The barge can then convey the systems ashore for overhaul, repair or replacement. For the purpose of estimating the likely O&M cost, the mean time to failure was estimated for each component to determine the resulting annual operational and replacement cost. Based on wind-turbine data, the most critical component is the gearbox which shows an average mean time to failure of 10.8 years.

For the next generation design for a completely submerged turbine (assumed for commercial plant) major intervention could require the use of a crane barge to dismount the power train from the support structure. Since the lifting mechanism would also be subsurface, a failsafe retrieval method (e.g. retrieval hook) would be required in the case of a failure of the lifting mechanism. MCT does not anticipate the added complexity of full submergence to greatly increase maintenance costs, because deployment of a fully submerged device is contingent on proving that the chosen power train requires limited maintenance intervention.

5. Electrical Interconnection

Each TISEC device houses a step-up transformer to increase the voltage from generator voltage to a suitable array interconnection voltage. The choice of the voltage level of this energy collector system is driven by the grid interconnection requirements and the array electrical interconnection design but is typically between 12kV and 40kV. For the pilot scale, 12kV systems are anticipated – depending on local interconnection voltages. This will allow the device interconnection on the distribution level. For commercial scale arrays, voltage levels of 33kV are used. This allows the interconnection of an array with a rated capacity of up to about 40MW on a single cable.

A 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 unit, reducing the physical intervention requirements on the device and optimizing operational activities. Operational activities offshore are expensive and minimizing such interventions is a critical component of any operational strategy in this harsh environment.

The Surface piercing MCT SeaGen device has all it's electrical components located inside the monopile, where it is well protected and easily accessible for operation and maintenance activities. In other words, sub sea connectors or junction boxes are not required to interconnect the device to the electrical grid.

The completely submersed Lunar Energy Device houses all the generation equipment and step-up transformer in cylindrical watertight container mounted on the cassette, which needs to be recovered to the surface for servicing. Interconnection is envisioned to be accomplished using a pressure compensated junction box that allows a single device to be connected to a device cluster. The cassette can be interconnected by either using sub sea wet-mate cable connectors or using a flexible cable that is attached to the cassette so that it can be connected and disconnected on the surface.

Subsea Cabling

Umbilical cables to connect turbines to shore are being used in the offshore oil & gas industry and for the inter-connection of different locations or entire islands. With other words, it is well established technology with a long track-record. In order to make these cables 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 42 shows the cross-sections of armored XLPE insulated submersible cables.

Figure 42 – 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 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. There are different technologies available to bury the cable along the cable route. All of them require the creation of a trench in which the cable can be laid. In order to protect the cable, this channel is then back-filled with rocks. Various trenching technologies exist such as the use of a plough in soft sediments, use of a subsea rock-saw in rock (if going through hard-rock) or the use of water jets. All of these cable laying operations can be carried out from a derrick barge that is properly outfitted for the particular job. The choice of technology best suited for getting the job done depends largely on the outcome of detailed geophysical assessments along the cable route. For this study, the EPRI team assessed both the use of a trenching rock saw as well as a plough.

An important part of bringing power back to shore is the cable landing. Existing easements should be used wherever possible to drive down costs and avoid permitting issues. 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. Given some of the deployment location proximity to shore, detailed engineering might even reveal that directional drilling directly to the deployment site is possible. This would reduce environmental construction impacts at the site, while reducing overall cost.

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. VAR compensation voltage step-up and other measures might be introduced based on particular local requirements.

6. System Design – Pilot Plant

The purpose of a pilot plant is first, and foremost, to demonstrate the viability of a particular technology. Pilot plants are, in general, not expected to produce cost competitive electricity and often incorporate instrumentation absent from a commercial device.

For the pilot TISEC plant, the following should be successfully demonstrated prior to installation of a commercial array:

- Turbine output meets predictions for site
- Installation according to design plan with no significant problems
- Turbine operates reliably, without excessive maintenance intervention
- No significant environmental impacts for both installation as well as operational aspects.

For the pilot plant at the Blomidon transect, the following issues deserve particular attention and should be an integral part of the pilot testing plan:

- Large marine mammal and fish interaction with turbine. This will require instrumentation for fish monitoring.
- Bio-accumulation on turbine and support structure over course of demonstration.

The following illustration shows how a single TISEC device is connected to the electric grid.

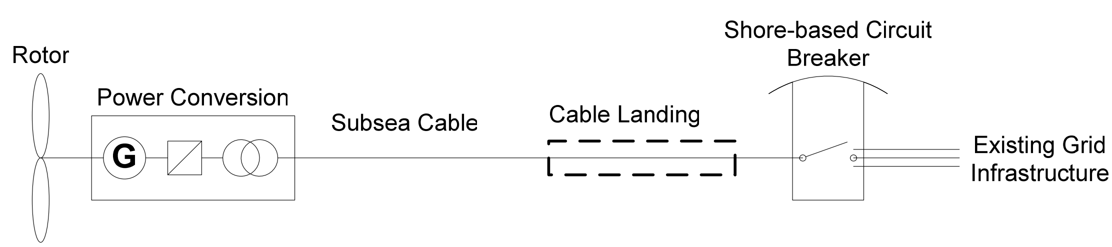


Figure 43 - Conceptual Electrical Design for a single TISEC Unit

Pilot power collection and grid interconnection details are summarized in Table 7 – Pilot Grid Interconnection. The cost for overland interconnection is for routing the power take-off cable from the beach to distribution line. Infrastructure upgrade costs are expected to be minor since power is being fed into an existing distribution line.

Table 7 – Pilot Grid Interconnection

Grid Interconnection Demo	
Grid Interconnection Point	12.5 kV distribution line on south side of Patridge Island
Subsea Cable Length	1500m
Subsea Trench Length	1500m
Sediment type along cable route	Gravel/Rock
Cable Landing	Directional Drilling
Overland Interconnection Cost	Estimated at $470,800
Infrastructure Upgrade Cost	None

The deployment location for a single unit is described in the site selection section and turbine performance is outlined in the performance section.

7. System Design - Commercial TISEC Power Plant

The purpose of a commercial tidal plant is to generate cost competitive electricity for the grid without causing unacceptable environmental impacts. The single largest impact on the cost of electricity for a TISEC farm is the current velocity profile. The reason is that structural loads (and corresponding structural cost) increase to the second power of velocity, while the power generated increase to the 3rd power of the velocity. In a channel the fluid velocity will increase in narrow passages. So the channel transect with the lowest cross-sectional area will generally prove to be the most economic one.

Other factors considered in the design of this commercial tidal power plant are:

- Install turbines only in waters sufficiently deep to meet shipping clearance requirements or alongside the passage to not interfere with shipping traffic.
- Turbines are not to extract more then 15% of the total estimated resource
- Locate the plant in close proximity to a grid interconnection point to reduce costs

For purposes of establishing a conceptual design point, we assumed that either MCT's surface piercing SeaGen unit, MCT's next generation multi-rotor machine or Lunar Energy's RTT2000 would be installed at the site. Out of these 3 machines, only MCT's SeaGen is surface piercing and could be installed alongside the channel. The other 2 designs are completely submersed and do not directly interfere with shipping activities when in operation. Only installation and O&M activities will interfere directly with surface based activities. It is reasonable that such activities can be coordinated so as not to conflict with other uses of the sea space. For design and cost estimate purposes we assumed that the commercial MCT design use the same rotor diameter and clearance requirements as the surface piercing SeaGen device.

Electrical Interconnection

In order to interconnect a large number of turbines to the electric grid, a power collection network needs to be set up. In order to maximize availability and stay within reasonable limits on the amount of electrical power fed back to shore per single cable devices are arranged in clusters. Each cluster connects back to shore using a single cable. This allows a cluster of devices to be isolated if required.

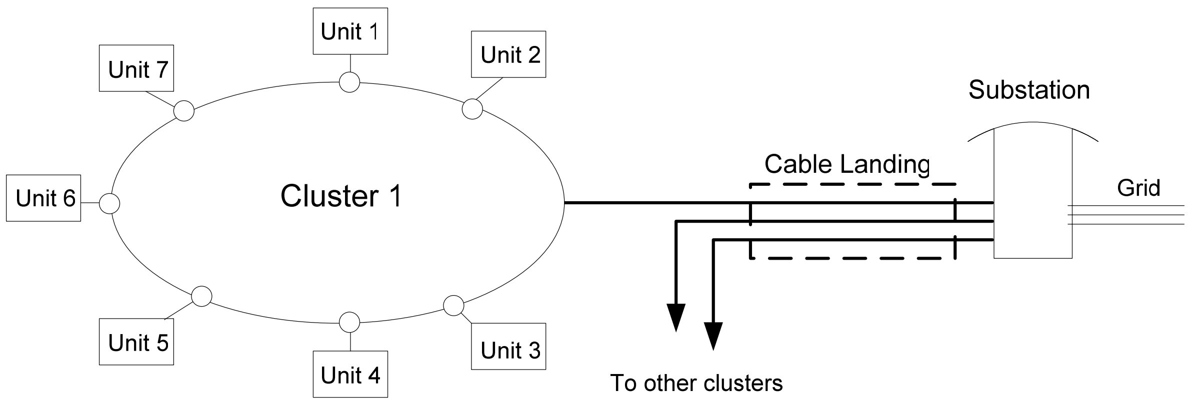


Figure 44 - Electrical Power Collection and Grid Interconnection for commercial plant

Physical Layout

In order to extract 15% of the resource at the site, a significant portion of the cross-sectional area needs to be intersected. With existing prototype device rotor diameters and non stackable structures, this can only be achieved by arranging the turbines in rows across the channel width in areas with sufficient depth. In addition, it might require the rows of turbines to be installed at different depths behind each other with sufficient spacing in order to avoid the wake of the previous row of turbines to affect subsequent rows. The rectangular area in Figure 45 shows the length and width of interest for turbine deployment where we will likely encounter high current velocities. Detailed modeling of the resource could reveal hot-spots and provide more information as to where such turbines should be located. However in absence of such models, the outline shown below shows reasonable boundaries within which devices could be deployed. It is clear from the picture that the area is rather large, which is a positive factor from a commercial point of view. Also the relatively long area (about 5,600m) allows surface piercing turbines to be sited alongside the channel in water depths of 30-40m.

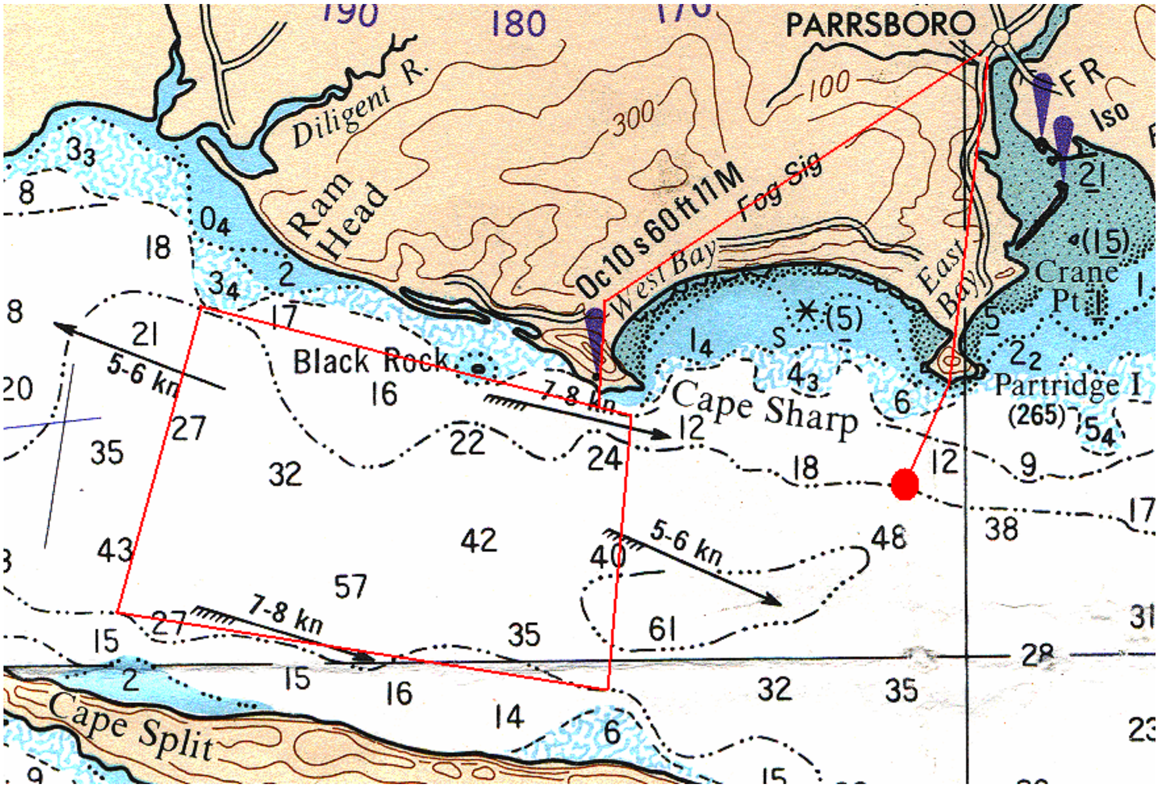


Figure 45 – Cape Sharp Deployment Site. Water depth shown in fathom (1 fathom = 1.8m)

Figure 46 shows the cross sectional profile at Cape Sharp. Indicated in yellow are potential deployment locations for surface piercing units. The blue section shows the maximum ships draft below which completely submersed devices could be located.

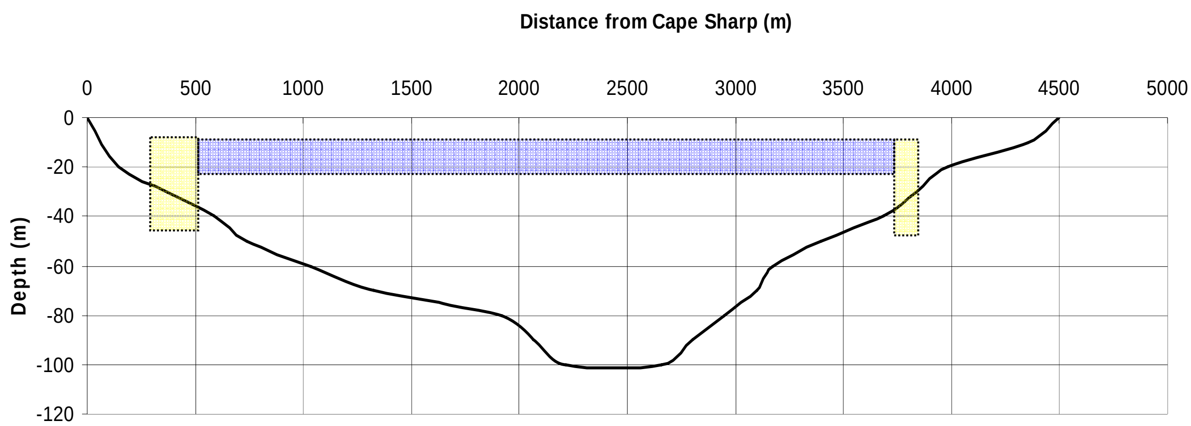


Figure 46 - Channel Cross section at Cape Sharp

The following illustrations show the spacing assumptions for Lunar Energy's RTT2000 and MCT's SeaGen.

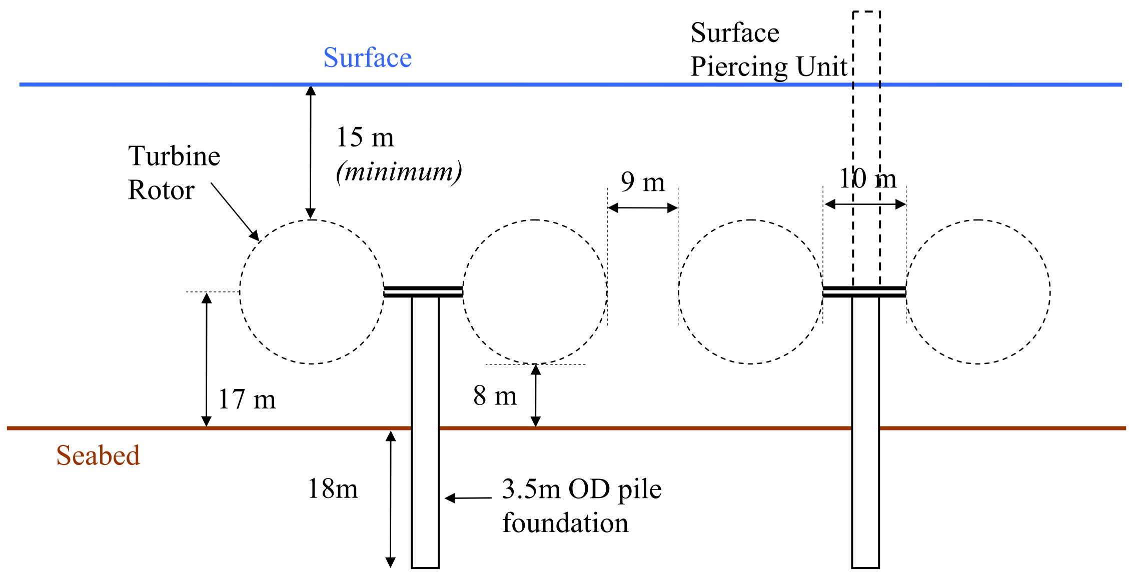


Figure 47 – MCT SeaGen Turbine Spacing Assumptions

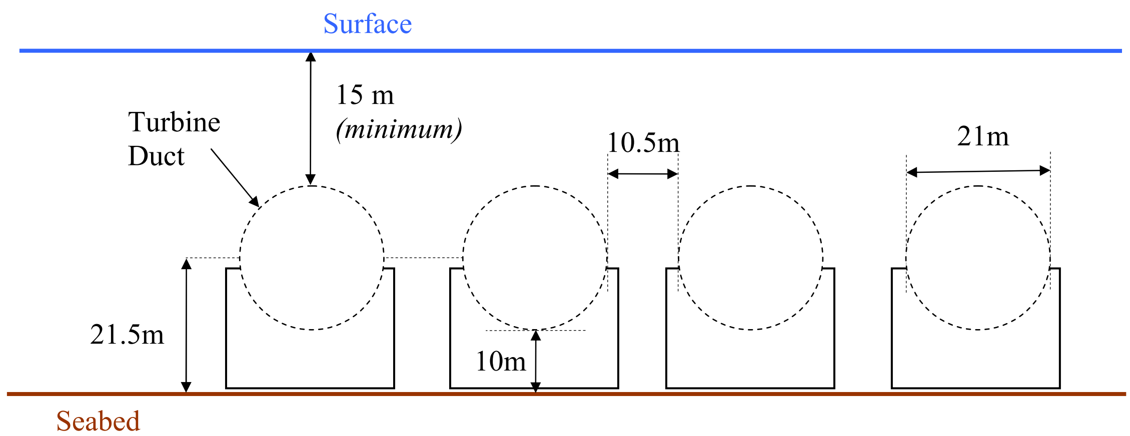


Figure 48 - Lunar RTT 2000 Spacing Assumptions

Based on this cross sectional area and considerations for technology requirements for water depths, the useable channel width that accommodates sufficient water depth is 3,500m. The section length within which high fluid velocities are available is about 5,600m (See Figure 45). Based on this data the following table summarizes the critical assumptions leading to the likely number of turbines that could be deployed at the site.

Table 8 - Physical Layout Assumptions

	MCT Second Generation	MCT SeaGen Surface Piercing	Lunar RTT2000
Turbine Diameter	2 x 18m	2 x 18m	21m
Device Width	46m	46m	21m
Device Spacing	9m	9m	10.5m
Channel width per device	55m	55m	31.5m
Downstream Spacing	185m	185m	235m
Useful Channel Length	5,600m	5600m	5,600m
Useful Channel Width	3,100m	400m	3,100m
# of Turbines per Row	63	7	98
# of Rows	30	30	23
Total # of Turbines deployable	1890	210	2254
Average Power Extracted per Turbine	584kW	584kW	572kW
15% Extraction Limit	152MW	152MW	152MW
Technology Specific Extraction Limit	1103MW	122MW	1289 MW

The above table shows that the extraction is limited by the 15% significant impact fator to preclude any noticeable ecological effects. Interestingly up to 122 MW could be extracted using surface piercing MCT technology. The above table also shows that all technologies can provide similar extraction limits and therefore have similar extraction densities. The critical assumption taken is that the spacing between two rows of turbines needs to be 10x the device inlet cross-section. This spacing is required so the second row of turbines is placed outside of the wake of the first row. New research by the Carbon Trust however indicates that the spacing requirement could be as low as 3-4 times the turbine diameter. To meet the extraction limit of 152MW, a total of 250 SeaGen's or 265 Lunar RTT2000 would need to be deployed in the channel.

8. Cost Assessment – Demonstration Plant

The cost assessment of the pilot demonstration plant was carried out by taking manufacturer specifications for their devices, assessing principal loads on the structure and scaling the devices to the design velocity at the deployment site. The MCT cost model was developed by EPRI, MCT provided data and support to calibrate the model, which was an important step to come up with a meaningful model. Installation and operational costs were evaluated by creating detailed cost build-ups for these aspects taking into considerations equipment availability and North American rates. A high-level capital cost breakdown relevant to the deployment site is shown in the table below.

Table 9 - Capital Cost breakdown of MCT Pilot plant

	$/kW	$/Turbine	in %
Power Conversion System	$1,428	$1,587,000	27.3%
Structural Steel Elements	$532	$591,000	10.2%
Subsea Cable Cost	$65	$72,000	1.2%
Turbine Installation	$1,297	$1,442,000	24.8%
Subsea Cable Installation	$1,482	$1,647,000	28.3%
Onshore Electric Grid Interconection	$425	$471,000	8.2%
Total Installed Cost	$5,234	$5,810,000	100.0%

A single unit will cost significantly more then subsequent units installed at the site. This is apparent by an increase in capital and installation cost. Installation costs are dominated by mobilization charges and the fact that the first unit will always be more expensive then subsequent ones. Capital costs are higher as well for similar reasons. The assessment of operational and maintenance cost was not part of the scope of this study. It is important to understand that subsea cable installation cost could be potentially reduced by up to $1 million by careful siting of the prototype and use of directional drilling instead of trenching.

It is also important to understand that the purpose of the pilot plant is not to provide low cost electricity, but to reduce risks associated with a full-blown commercial scheme. Risks include technological risks such as device performance, operation & maintenance requirements and validation of structural integrity as well as environmental risks associated with the interaction between the natural habitat and the TISEC device.

9. Cost Assessment – Commercial Plant

Costs for the commercial plant are, as for most renewable energy generating technologies, heavily weighted towards up-front capital. In order to determine the major cost centers of the commercial plant, detailed cost build-ups were created in order to assess them properly in the context of the given site conditions. There are a few major influences impacting the relative economic cost at a particular site which are discussed below:

Design Current Speed: The design current speed is the maximum velocity of the water expected to occur at the site. Structural loads (and related structural cost) on a structure increase to the second power of the fluid velocity. Given the velocity distribution at the site, the design velocity can be well above the velocity at which it is economically useful to extract power. In other words, the design velocity can have a major influence on the cost of the structural elements. During normal operating conditions, the loads on the structure will peak near the rated turbine velocity and decrease thereafter as the turbine blades are pitched to maintain constant power output, decreasing the thrust coefficient on the rotor blades. For conservatism, the design velocity is set to the site peak, rather than device rating, in order to simulate the loads experienced during runaway operation in the event of pitch control failure.

Velocity Distribution: The velocity distribution at the site is outlined in chapter 2 of this report. It shows the tidal current velocities at which there is a useful number of reoccurrence to pay for the capital cost which is needed to tap into this velocity bin. Rather then trying to make assumptions on where the appropriate rated velocity of the TISEC device should be, an iterative approach was chosen to determine which rated speed of the machine will yield the lowest cost of electricity at the particular site. This in turn resulted in different machine capacity factors as rated speed of the machine was adjusted for lowest cost of electricity.

Seabed Composition: The seabed composition at the site has a major impact on the foundation design of the TISEC device. For a monopile foundation the seabed composition determines the installation procedure (i.e. drilling and grouting or pile driving). The soil-type will also impact the cost of the monopile. Typically soft soils yield higher monopile cost then rock foundations. For a bottom standing device there is a cost impact on the installation for seabed preparation, scour protection and assuring device stability in weak soils.

Number of installed units: The number of TISEC devices deployed has a major influence on the resulting cost of energy. In general a larger number of units will result in lower cost of electricity. There are several reasons for this which are outlined below:

- Infrastructure cost required to interconnect the devices to the electric grid can be shared and therefore their cost per unit of electricity produced is lower.

- Installation cost per turbine is lower because mobilization cost can be shared between multiple devices. It is also apparent that the installation of the first unit is more expensive then subsequent units as the installation contractor is able to increase their operational efficiency.

- Capital cost per turbine is lower because manufacturing of multiple devices will result in reduction of cost. The cost of manufactured steel as an example is very labor intensive. The cost of hot rolled steel plates as of July 2005 was $650 per ton. The final product can however cost as much as $4500 per manufactured ton of steel. With other words there is significant potential to reduce capital cost by introducing more efficient manufacturing processes and engineering a structure in such a way that it can be manufactured cost effectively. The capital cost for all other equipment and parts is very similar.

Device Reliability and O&M procedures: The device component reliability directly impacts the operation and maintenance cost of a device. It is important to understand that it is not only the component that needs to be replaced, but that the actual operation required to recover the component can dominate the cost. Additional cost of the failure is incurred by the downtime of the device and its inability to generate revenues by producing electricity. In order to determine these operational costs, the failure rate on a per component basis was estimated. Then operational procedures were outlined to replace these components and carry out routine maintenance such as changing the oil. The access arrangement plays a critical role in determining what kind of maintenance strategy is pursued and the resulting total operation cost.

Insurance cost: The insurance cost can vary greatly depending on what the project risks are. While this is an area of uncertainty, especially considering the novelty of the technologies used and the likely lack of specific standards, it was assumed that a commercial farm will incur insurance costs similar to mature an offshore project which is typically at about 1.5% of installed cost.

The following table shows a cost breakdown of a commercial TISEC farm at the deployment site. It was assumed that a total of 250 turbines are installed at the site each one with a rated capacity of 1,153 kW and a capacity factor of 45%, producing an annual output of 4555MWh each.

Table 10 – MCT commercial plant capital cost breakdown

	$/kW	$/Turbine	$/Farm	in %	Ref
Power Conversion System	$519	$598,067	$149,517,000	30.8%	1
Structural Elements	$788	$908,273	$227,068,000	46.8%	2
Subsea Cable Cost	$15	$16,765	$4,191,000	0.9%	3
Turbine Installation	$210	$242,083	$60,521,000	12.5%	4
Subsea Cable Installation	$121	$139,119	$34,780,000	7.2%	5
Onshore Electric Grid Interconection	$31	$35,200	$8,800,000	1.8%	6
Total Installed Cost	**$1,683**	**$1,939,506**	**$484,877,000**	**100%**	
O&M Cost	$37	$42,941	$10,735,000	60%	7
Annual Insurance Cost	$25	$29,165	$7,273,000	40%	8
Total annual O&M cost	**$62**	**$72,034**	**$18,009,000**	**100%**	

1. Power conversion system cost includes all elements required to go from fluid power to electrical power suitable to interconnect to the TISEC farm electrical collector system. As such it includes rotor blades, speed increaser, generator, grid synchronization and step-up transformer. The cost is based on a drive-train cost study by NREL [12] with necessary adjustments made such as marinization,

gearing-ratio, rotational speed and turbine blade length. Manufacturing cost progress ratio's were used to scale to different production volumes.

2. Structural steel elements include all elements required to hold the turbine in place. In the case of MCT, it includes the monopile and the cross arm. For the Lunar turbine it includes all the structural members, the duct as well as ballast. In order to determine the amount of steel required, the manufacturer's data was scaled based on the estimated loads on the structure. Only principal loads based on the fluid velocity were considered and it was assumed that they are the driving factor. While this approach is well suited for a conceptual study, it needs to be stressed that other loading conditions such as wave loads or resonance conditions can potentially dominate and will need to be taken into consideration in a detailed design phase.

3. Sub sea cable cost includes the cable cost to collect the electricity from the turbines and bring the electricity to shore at a suitable location.

4. Turbine installation cost includes all cost components to install the turbines. Detailed models were developed to outline the deployment procedures using heavy offshore equipment such as crane barges, tugs, supply vessels drilling equipment, mobilization charges and crew cost. Discussions with experienced contractors and offshore engineers were used to solidify costs.

5. Subsea cable installation cost includes, trenching, cable laying and trench back-fill using a derrick barge. It also includes cable landing costs. If existing easements such as pipes or existing pier or bridge structures are in place, the cable can be landed on shore using these easements. If not, it was assumed that directional drilling is used to bring the cable to shore.

6. Onshore electrical grid interconnection includes all cost components required to bring the power to the selected substation. Cost components required to build-out the capabilities of the substation or upgrade the transmission capacity of the electric grid were excluded. Under U.S. FERC regulations, such cost is covered by 'wires'

charges and is not considered to be a part of the levelized busbar plant cost of electricity (COE) and we assume that Candian regulations are similar..

10. Cost of Electricity Assessments

To evaluate the economics of tidal in-stream power plants, three standard economic assessment methodologies have been used:

a. Utility Generator (UG),
b. Municipal Generator (MG)
c. Non-Utility Generator (NUG) or Independent Power Producer (IPP).

Taxable regulated utilities (independently owned utilities) are permitted to set electricity rates (i.e., collect revenue) that will cover operating costs and provide an opportunity to earn a reasonable rate of return on the property devoted to the business. This return must enable the UG to maintain its financial credit as well as to attract whatever capital may be required in the future for replacement, expansion and technological innovation and must be comparable to that earned by other businesses with corresponding risk.

Non taxable municipal utilities also set electricity rates that will cover operating costs, however, utility projects are financed by issuing tax-exempt bonds, enabling local governments to access some of the lowest interest rates available

Because the risks associated with private ownership are generally considered to be greater than utility ownership, the return on equity must be potentially higher in order to justify the investment. However, it is important to understand that there is no single right method to model an independently owned and operated NUG or IPP renewable power plant. Considerations such as an organization's access to capital, project risks, and power purchase and contract terms determine project risks and therefore the cost of money.

This regulated UG and MG methodologies are based on a levelized cost approach using real (or constant) dollars with 2005 as the reference year and a 20-year book life. The purpose of this standard methodology is to provide a consistent, verifiable and replicable basis for computing the cost of electricity (COE) of a tidal energy generation project (i.e., a project to engineer, permit, procure, construct, operate and maintain a tidal energy power plant).

The NUG methodology is based on a cash flow analysis and projections of market electricity prices. This allows a NUG to estimate how quickly an initial investment is recovered and how returns change over time.

The results of this economic evaluation will help government policy makers determine the public benefit of investing public funds into building the experience base of tidal energy to transform the market to the point where private investment will take over and sustain the market. Such technology support is typically done through funding R&D and through incentives for the deployment of targeted renewable technologies.

If the economics of the notional commercial scale tidal in-stream power plant is favorable with respect to alternative renewable generation options, a case can be made for pursuing the development of tidal flow energy conversion technology. If, however, even with the most optimistic assumptions, the economics of a commercial size tidal flow power plant is not favorable and cannot economically compete with the alternatives, a case can be made for not pursuing tidal flow energy conversion technology development.

The methodology is described in detail in Reference [2]. The yearly electrical energy produced and delivered to bus bar is estimated to be 1, 138,750 MWh/year for an array consisting of 250 dual-rotor MCT turbines. These turbines have a combined installed capacity of 188 MW, and on average extract 130 MW of kinetic power from the tidal stream, which is 15% of the total kinetic energy at the site. The elements of cost and economics (in 2005 US$) for MCT's SeaGen are:

- Utility Generator (UG) Total Plant Investment = $486 million
- Annual O&M Cost = $18 million
- UG Levelized Cost of Electricity (COE) = 3.9 (Real) – 4.6 (Nominal) cents/kWh with renewable financial incentives equal to that the government provides for renewable wind energy technology

- Municipal Generator (MG) Levelized Cost of Electricity (COE) = 3.8 (Real) – 4.6 (Nominal) cents/kWh with renewable financial incentives equal to that the government provides for renewable wind energy technology
- Nun Utility Generator (Independent Power Producer) Internal Rate of Return of net cash-flows after tax is 31%.

It is encouraging that a commercial plant at the Minas Passage site can potentially have a cost of electricity that is about the Nova Scotia avoided cost level (avoided cost based on a proxy of wholesale price is believed to be 5.6 cents/kWh (US cents). The detailed worksheets including financial assumptions used to calculate COE and IRR are contained in the Appendix.

TISEC technology is very similar to wind technology and has benefited from the learning curve of wind technology, both on shore and off shore. Therefore, the entry point for a TISEC plant is much less than that of wind technology back in the late 1970s and early 1980s (i.e., over 20 cents/kWh). Additional cost reductions will certainly be realized through value engineering and economies of scale.

Economic assessments of a commercial scale tidal power plant and other renewable and non renewable energy systems were made.

The current comparative costs of several different central power generation technologies are given in Table 11 - COE for Alternative Energy Technologies: 2010 for 2010. Capital costs are given in $/kW. They have wide ranges that depend on the size of the plant and other conditions such as environmental controls for coal and quality of the resource for geothermal. We are using generally accepted average numbers and ranges from EPRI sources.

Table 11 - COE for Alternative Energy Technologies: 2010

	Capacity Factor (%)	Capital Cost[1] ($/kW)	COE (cents/kWh)	CO2 (lbs per MWh)
Tidal In Stream	45	2,000	3.9-4.6	None
Wind (Class 3-6)	30-42	1,150	4.7-6.5	None
Solar Thermal Trough	33	3,300	18	None
Coal PC USC (2)	80	1,275	4.2	1760
NGCC[3] @ $7/MM BTU)	80	480	6.4	860
IGCC[2] with CO2 capture	80	1,850	6.1	344[4]
Nuclear Evolutionary (ABWR)	85-90	1,660	4.7-5.0	None

Notes:

1 Costs in 2005$;
2. 600 MW capacity; Pittsburgh#8 coal
3. Based on GE 7F machine or equivalent by other vendors
4. Based on 85% removal

The fuel cost for coal and natural gas (NG) is the price of fuel (in $ per Mbtu), times the heat rate (BTUs needed to generate a kWh of electricity – 10,000 for PC Coal, 9,000 for IGCC, 12,000 for Gas CT and 7,000 for NG CC), divided by 10,000.

Table 13 - Assumptions forming the Basis for COE for Alternative Energy Technologies

	Book Life/ Tax life)	Fed Tax Rate	State Prov-ince Tax Rate	Dep Sch	% Equity UG/ NUG/ Public	Equity Disc't Rate (Real) UG/NUG	% Debt UG/ NUG/ Public	Debt Disc't Rate (Real) UG/NUG/ Public	Inflation Rate
Tidal	20/20	22	NS 16%	CA Acc Dep	65/ 30 0	13/ 17/ 5	35/ 70/10 0	7.5/ 8/ 5	3
Wind	30/ 20	35	6.5	MAC RS	45/ 30/ 0	11.5/ 13/ N/A	55/ 70/ 100	6/5 8/ 4.5	2
Coal(2) PC First of a Kind USC	30/ 20	35	6.5	MAC RS	45/ 30/ 0	11.5/ 13/ N/A	55/ 70/ 100	6/5 8/ 4.5	2
NGCC(3) Advanced (@ $7/MM Btu)	30/ 20	35	6.5	MAC RS	45/ 30/ 00	11.5/ 13/ N/A	55/ 70/ 100	6/5 8/ 4.5	2
Nuclear First of a kind (Gen IV)	30/ 20	35	6.5	MAC RS	45/ 30/ 0	11.5/ 13/ N/A	55/ 70/ 100	6/5 8/ 4.5	2

11. Sensitivity Studies

The results reported thus far are for a single design case. Certain key parameters can have a significant impact on the cost of energy from a TISEC array. Among these are:

- Array size – economies of scale with larger arrays
- Plant system Availability – deployment of maturing technology
- Current velocities at site
- Financial assumptions – financing rates, renewable energy production credits

Cost of energy numbers presented are real costs for a UG generator with assumptions discussed in Chapter 9. All costs are in 2005 USD.

Array Size

This sensitivity has already been implicitly shown in the unit capital cost differences for pilot turbine versus commercial scale array. Figure 49 shows the sensitivity of cost of energy (COE) to the number of turbines installed.

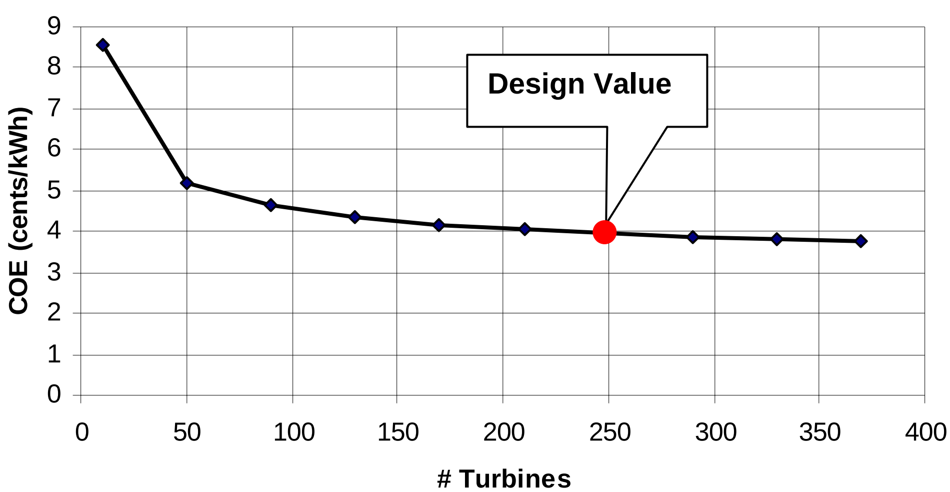


Figure 49 – Sensitivity of COE to number of turbines installed

Due to economies of scale (mobilization costs, increased manufacturing efficiency), the capital and operating costs for the array decrease with the number of installed turbines. The sensitivity of the different elements of capital cost to the number of turbines installed is given in Figure 50.

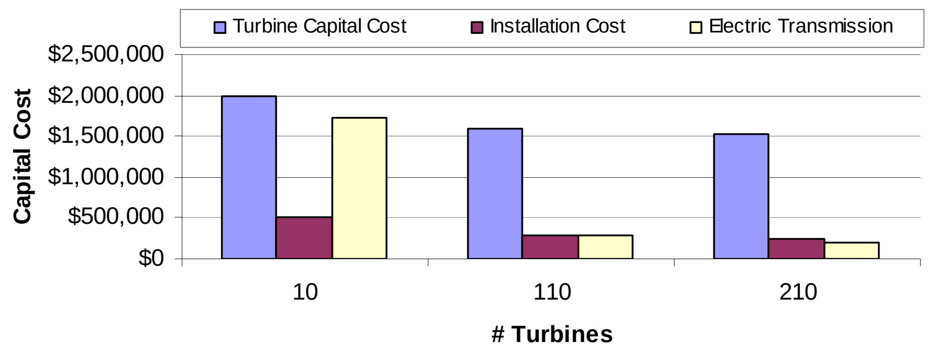


Figure 50 – Sensitivity of capital cost elements to number of installed turbines

Economies of scale due to decreasing capital cost occur in equipment, installation, and electrical interconnection. Installation and electrical transmission costs are near identical. Cost of energy decreases are not driven exclusively by scale in one particular area. Note that equipment costs dominate in all cases. Annual O&M costs also decrease due to economies of scale (e.g. maintenance mobilization costs spread out over more turbines). The sensitivity of annual O&M costs to number of installed turbines is given in Figure 51.

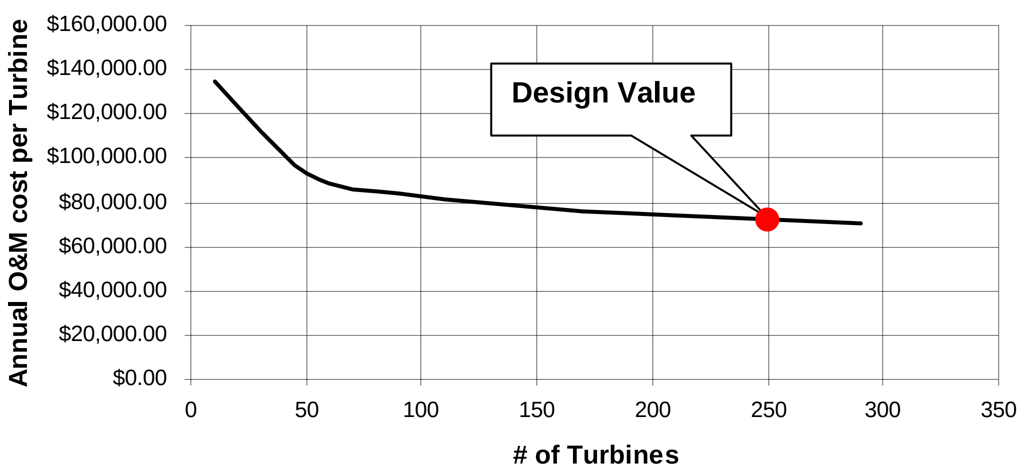


Figure 51 – Sensitivity of annual O&M cost to number of installed turbines

Power Plant System Availability

Given that tidal in-stream energy is an emerging industry and limited testing has been done to validate component reliability, the impact of the plant system availability on cost of energy is key. If the availability is lower than anticipated, array output will be lower, but costs will be the same. This is shown in Figure 52, where all parameters aside from availability are held constant for the commercial array design.

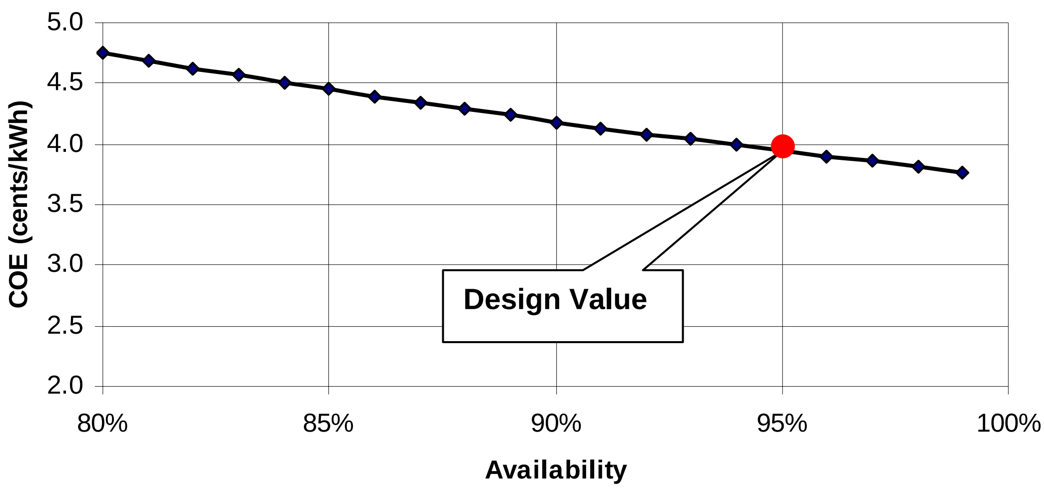


Figure 52 – Sensitivity of COE to array availability

If system availability is as low at 80%, the cost of energy with increase by a bit more than 1.5 cents/kWh (20% increase) compared to the assumed availability of 95%. This is a substantial increase and highlights the need of developers to verify expected component lifetimes and service schedules.

Current Velocity

One of the greatest unknowns in the array design is current velocity over the region of array deployment. The sensitivity of cost of energy to average current and power flux is shown in Figure 53 and Figure 54, where most other parameters are held constant for the commercial array design. Current velocity is modified by multiplying each velocity ‘bin’ by a constant value (e.g. 0.7). As a result, the shape of the velocity histogram is unchanged, only the mean value. As the velocity changes, the rated speed of the turbine is allowed to vary to maintain the lowest possible cost of energy. Note that average current velocity and power flux are not independent variables, the design point average current velocity corresponds to the design point average power flux.

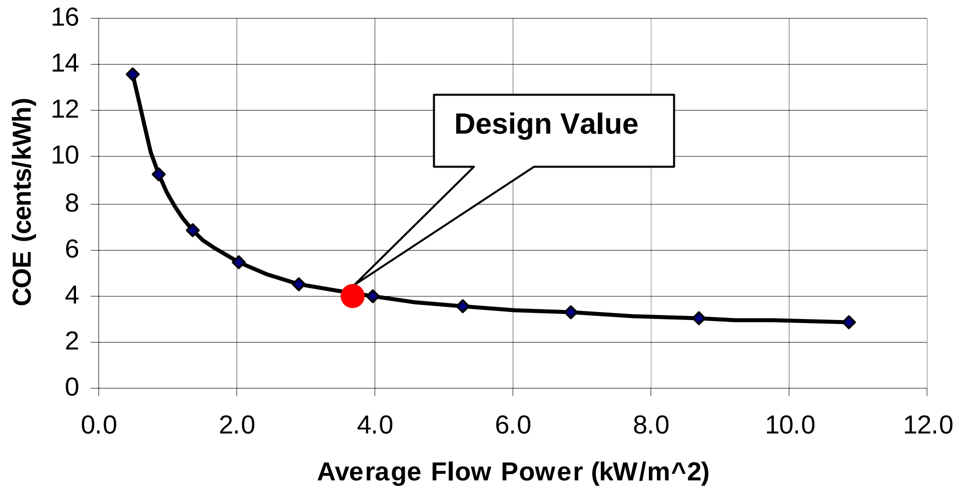


Figure 53 – Sensitivity of COE to average flow power in kW/m^2

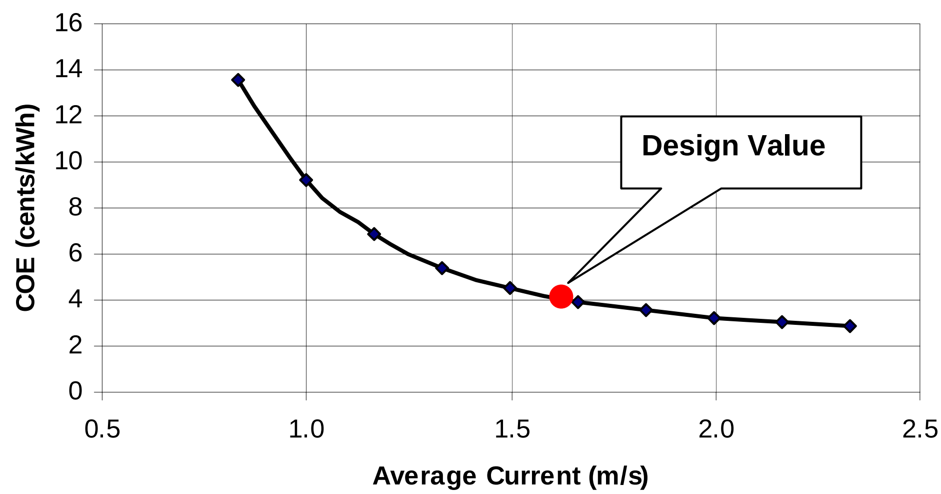


Figure 54 – Sensitivity of COE to average current speed (m/s)

Clearly, the average velocity at the site has a significant effect on cost of energy, particularly if average current speeds are lower than expected. Note that these results are dependent on the shape of the velocity distribution histogram and therefore, we can not broadly draw conclusions about the cost of energy at other sites from this analysis (though one would expect the general direction of the results to be comparable for all west coast sites).

Design Velocity

As discussed in Chapter 3, the design velocity for the turbine has been chosen to approximate "runaway" conditions – a pitch control failure in the maximum current existing at the site. However, since the most significant design load is the thrust on the rotors – which is maximized near rated conditions – this represents a potential system overdesign. If manufacturers are able to achieve sufficient operating experiences with their turbines to ensure that turbines will never operate in a "runaway" mode, then the design velocity could be set much closer to the rated velocity. Similar functionality is used in large wind-turbines to reduce loading conditions. Figure 55 shows the effect on the real cost of energy by lowering the design speed.

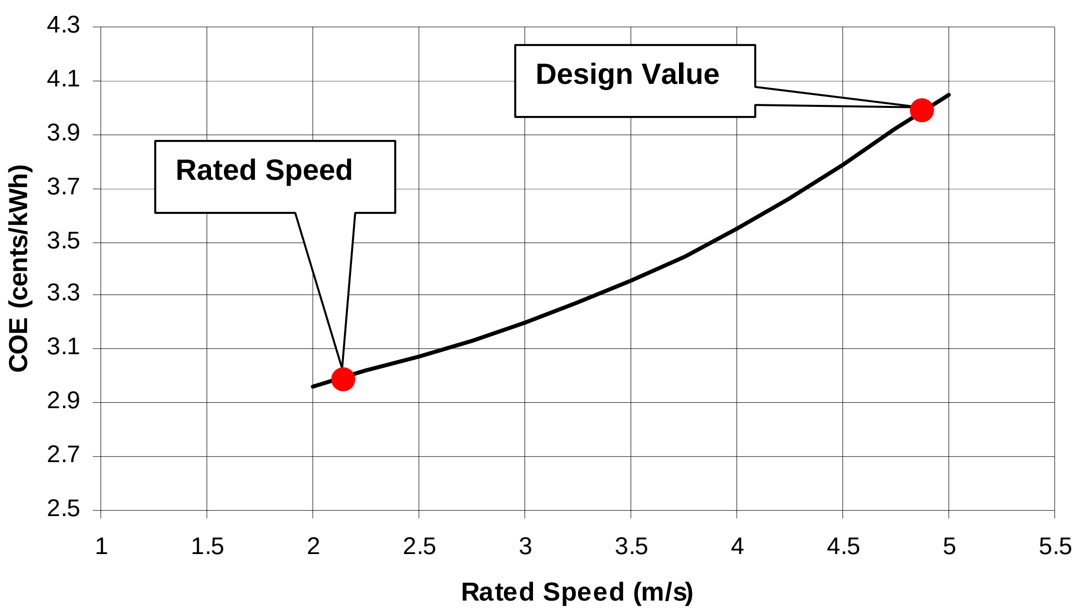


Figure 55 – Sensitivity of COE to design speed

Financial Assumptions

The effect of varying the cost of capital to finance the project is shown in the following figure. The fixed charge rate represents a single indicator of the cost of capital and is used here (see Reference 2 for a detailed explanation). It includes effects of interest rates, return of capital, taxation and production tax credits.

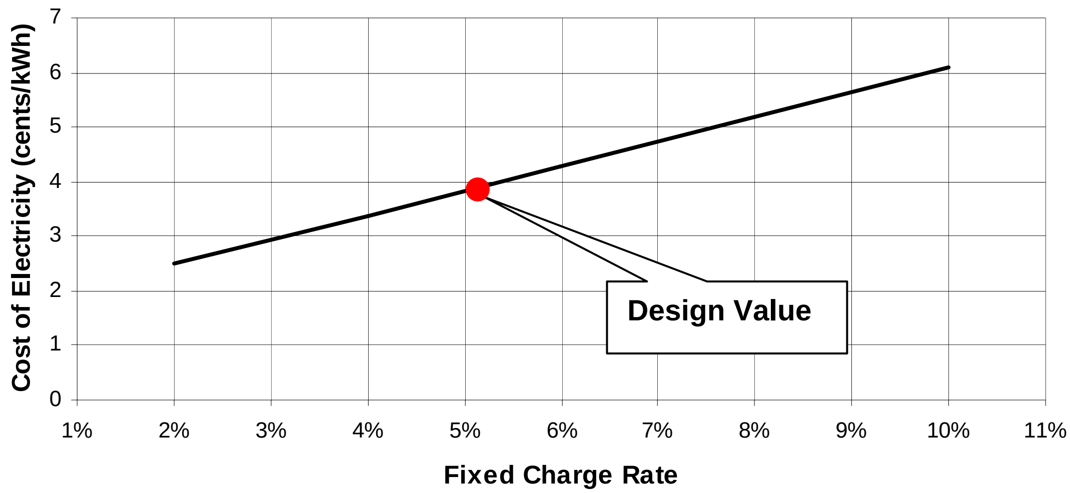


Figure 56 – Sensitivity of COE to Fixed Charge Rate

If a project is deemed ineligible for renewable production credits, or funds for such credits are not fully budgeted, COE increases substantially. Figure 57 shows the sensitivity of COE to production credits, with credits varied from 0% (no credits) to more credits than are currently assumed in the financial analysis, 100% being the design value used in our financing assumptions.

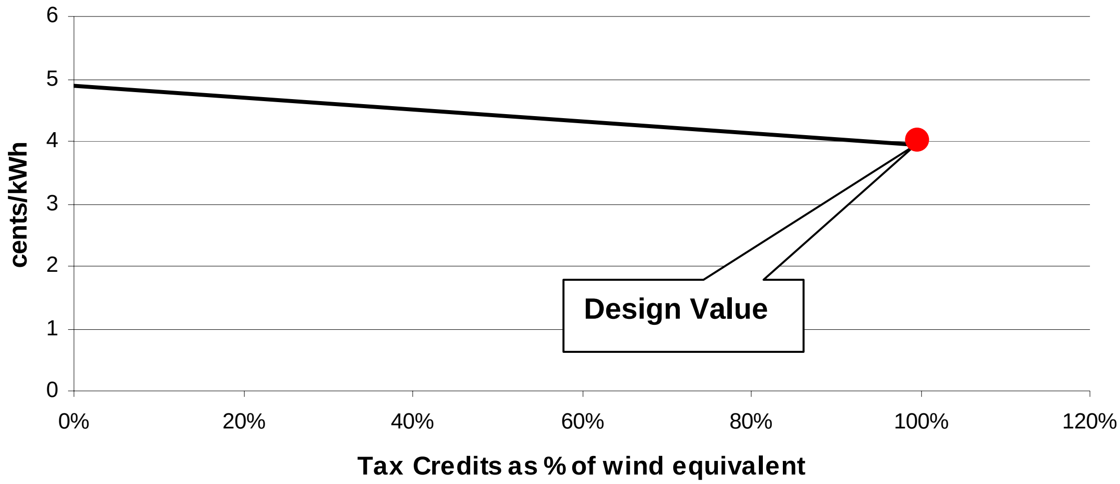


Figure 57 – Sensitivity of COE to renewable incentives

12. Conclusions

Pilot In-Stream Tidal Power Plant

For the single turbine pilot installation, the south side of Partridge island offers good potential sites. While the predicted resource is not as strong as at Cape Sharp, interconnection is easily achieved, reducing the cost for a single unit or small number of units pilot demonstration plant. A surface piercing SeaGen could be easily sited about 1.5 km south of Patridge Island in a suitable water depth of 30m. A pilot system is an important intermediary step before proceeding to a commercial installation and should use similar technology and units that are of similar scale as the full-scale devices. The purpose of the pilot is to demonstrate the potential for a commercial array, verify low environmental impact, and generally build towards regulatory acceptance of an array of similar devices. It is important to understand that many design requirements are unique to the site and the manufacturers will need to take local site conditions into consideration when adapting their technology to meet these requirements. If a surface piercing SeaGen unit is deployed, ice-issues and their impact on cost will need to be addressed

Commercial In-Stream Tidal Power Plant

Cape Sharp is a strong candidate site for the installation of a commercial tidal in-stream power plant. Among the sites investigated in this collaborative study, it shows the largest energy potential by a factor of 5 over the second largest energy site. Additionally, the predicted cost of energy from harnessing this resource is low compared to other local generation alternatives. Multiple turbine clusters could be installed at the transect. Grid interconnection could be accomplished at the Parsborro substation and the plant could provide electricity to export into the Nova Scotia and New Brunswick grid infrastructure. Given technology evaluated in this study, the resource extraction is only limited by environmental considerations, which was an extraction of 15% of the total kinetic energy at the site. For safety reasons, it may be necessary to set up a recreation (e.g. diving) exclusion zone within this area.

Significant uncertainties in respect to the resource prediction are still present and will need to be addressed in subsequent design phases.

As a new and emerging technology, in-stream tidal 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 (as of the end of 2004). Technological uncertainties also represent risks in that it is unclear at present which technology is best suited for the site and most manufacturers involved in TISEC are small companies that may or may not be around a few years from now. As such it is important that the resource is being developed as a strategic asset without locking into a single technology path or committing to a single company.

Techno-economic Challenges

The cost for the first tidal plant leverages the learnings gained from wind energy. Rather than seeing a sharp reduction in unit cost in early production, a substantial decrease might require another 40,000 MW of installed capacity (double the end of 2004 wind production volume). Device manufacturers are pursuing value engineering and novel approaches to array-scale installations. The economic analysis presented in this report is based on first-generation device economics. The assumption contingent in this analysis is that while next-generation devices will enable turbine deployment at a wider range of sites (e.g. deep water) and with greater versatility (e.g. integrated lift without surface piercing pile) the cost of installing and operating next-generation turbines will be similar to first-generation devices. O&M costs are particularly uncertain since no tidal current turbine has been in service for extended periods of time. Assumptions regarding intervention frequencies, refit costs, and component lifetimes will not be completely borne out for at least a decade.

Sensitivities show that the cost of energy is highly dependent on the currents (and power flux) at the deployment site. Furthermore, sensitivity analysis indicates the manufacturers are best served by designing turbines which experience their design loads close to rated device speed.

Sensitivities also show that the cost of energy is sensitive to the number of turbines installed, since for larger arrays fixed mobilization costs are spread over a greater number of turbines. Therefore, a phased installation of the array (e.g. 10 turbines/year for 6 years) would substantially increase the cost of energy for the entire project. A regulatory approach that requires a long-term phased installation plan to study the impact of turbine deployment should be discouraged if the project will not be compensated for the increased cost.

General Conclusions

In-stream tidal current energy shows significant promise for Nova Scotia and represents a way to make sustainable use of a local renewable resource without the visual distractions that delay so many other energy projects. The installation of a TISEC array in the Minas passage would provide valuable benefits to the local economy and further reduce its dependence on environmentally problematic fossil energy resources.

In-stream tidal energy electricity generation is a new and emerging technology. Many important questions about the application of in stream tidal energy to electricity generation remain to be answered, such as:

- There is not a single in-stream power technology. There is a wide range of in stream tidal power technologies and power conversion machines which are currently under development. It is unclear at present what type of technology will yield optimal economics. Not all devices are equally suitable for deployment in all depths and currents.
- It is also unclear at present at which size these technologies will yield optimal economics. Tidal power devices are typically optimized to prevailing conditions at the deployment site. Wind turbines for example have grown in size from less then 100kW per unit to over 3MW in order to drive down cost.
- Will the predictability of in stream energy earn capacity payments for its ability to be dispatched for electricity generation?
- How soon will developers be ready to offer large-scale, fully submerged, deep water devices?

- Will the installed cost of in-stream tidal energy conversion devices realize their potential of being much less expensive than solar or wind (because a tidal machine is converting a much more concentrated form of energy than a solar or wind machine)?
- Will the O&M cost of in-stream tidal 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 in stream tidal energy devices are deployed and tested?

And in particular for the Minas Passage:

- Detailed velocity measurements and 3 dimensional flow simulations will be necessary prior to the deployment of even a pilot plant. Will the actual power flux experienced at the site meet the predictions made in this study? Sensitivity analysis clearly shows that the power flux has a substantial impact on the cost of electricity.
- Are assumptions related to turbine spacing (both laterally and downstream) reasonable? Could the array be packed even closer together (further reducing its footprint) without degrading individual turbine performance?
- Is extracting 15% of the kinetic energy resource a reasonable target? Could more of the resource be extracted without degrading the marine environment? If so, the cost of energy for the project could be further reduced by increasing the size of the array.
- Resolve ice-design issues. Are there better ways to dealing with ice if surface piercing structures are used? What are the economic trade-offs?

In-stream tidal energy is a potentially important energy source and should be evaluated for adding to Nova Scotia's energy supply portfolio. A balanced and diversified portfolio of energy supply options is the foundation of a reliable and robust electric grid. TISEC offers an opportunity for Nova Scotia to expand its supply portfolio with a resource that is:

- Local – providing long-term energy security and keeping development dollars in the region

- Sustainable and green-house gas emission free
- Cost competitive compared to other options for expanding and balancing the region's supply portfolio

Recommendations

EPRI makes the following recommendations to the Nova Scotia Electricity stakeholders:

General

Build collaboration with other provinces and the Federal Government with common goals. In order to accelerate the growth and development of an ocean energy industry in the United States and to address and answer the many techno-economic challenges, a technology roadmap is needed which can most effectively be accomplished through leadership at the national level. The development of ocean energy technology and the deployment of this clean renewable energy technology would be greatly accelerated if the Federal Government was financially committed to supporting the development.

Join a working group to be established by EPRI for existing and potential owners, buyers and developers of tidal in stream energy including the development of a permanent in stream tidal energy testing facility in the U.S. For this group EPRI will track and regularly report on:

- Potential funding sources
- In-stream tidal energy test and evaluation projects overseas (primarily in the UK) and in the U.S (Verdant RITE project, etc)
- Status and efforts of the permitting process for new in stream tidal projects
- Newly announced in-stream tidal energy devices

Encourage R&D at universities

Encourage Provincial and Federal government support of RD&D

- Implement a national tidal energy program

- Promote development of industry standards
- Continue Canadian membership in the IEA Ocean Energy Program
- Clarify and streamline federal permitting processes
- Study provisions for tax incentives and subsidies
- Ensure that the public receives a fair return from the use of ocean tidal energy resources
- Ensure that development rights in provincial waters are allocated through a fair and transparent process that takes into account provincial, local, and public concerns

Pilot Demonstration

In order to proceed with a pilot plant in the Minas Passage, remaining technology, consenting and environmental issues will need to be resolved. This includes:

- Detailed velocity profiling survey and 3-dimensional flow simulations. Computational fluid dynamic (CFD) modeling of tidal flows could help focus this work on the most promising areas, as well as identifying turbulent eddies which could degrade turbine performance.
- High resolution bottom bathymetry survey
- Geotechnical seabed survey
- Detailed design using above data
- Resolving ice-design issues
- Environmental impact assessments
- Public outreach
- Implementation planning for Phase III – Construction
- Financing/incentive requirements study four Phase III and IV (Operation)

13. References

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14. Appendix

Irrelevance of Flow Decay Concerns

A concern established by some other researchers, particularly Bahaj and Myers [11] is that the power available in a tidal stream is reduced for each subsequent transect of turbines. Their results point to a substantial reduction in flow power, and degraded array performance, for arrays with more than a few transects.

This analysis is, however, in error as it violates mass conservation for tidal channels by assuming that the cross-sectional area of the channel is constant along the entire array. If the velocity of the flow is decreasing over each transect, then the area of the channel would have to increase to maintain conservation of mass.

However, the fuller picture is considerably more counter-intuitive. The total power in a tidal stream is the summation of the kinetic energy due to its velocity and the potential energy due to its height. For representative tidal channels, if the height of the water was to increase to satisfy mass conservation, the potential energy of the stream would also increase. In fact, this increase in potential energy would actually exceed the decrease of kinetic energy due to the presence of turbines and the total power in the channel would increase after each transect. Since this rationale violates conservation of energy it is also, clearly, incorrect. In order to satisfy both conservation of mass and energy, after each transect the height of the water decreases and velocity *increases*. The net effect is a decrease in channel power, but from a kinetic energy standpoint, the presence of upstream turbines actually should improve the performance of those downstream. This effect is described in detail for an ideal channel in Bryden and Couch.

However, without detailed information about cross-channel flow both upstream and downstream of the proposed turbine array it is not possible to model the potential performance enhancement. As a result, any such transect-to-transect enhancement is omitted from the model. However, it would appear that concerns related to flow degradation have little scientific basis.

Hub-height Velocity Approximation

In order to simplify calculations, it has been assumed that the power flux over the swept area of the turbine may be approximated by the power flux at the hub height. Assuming the velocity profile in the channel varies with a 1/10th power law, the average power flux over the area of the turbine is given by the following integral:

$$\overline{P} = \frac{\int_0^{2\pi}\int_0^{R} \frac{1}{2}\rho u_o^3 \left(\frac{r\sin\theta + z_{hub}}{z_o}\right)^{3/10} r dr d\theta}{\int_0^{2\pi}\int_0^{R} r dr d\theta}$$

where P is the average power flux, R is the radius of the turbine, u_o is the surface current velocity, z_o is the depth of the water, and z_{hub} is the hub height.

This integral is not readily evaluated by analytical methods, but may be approached numerically. This is done by approximating the rotor as a series of rectangles with height Δz and width Δx. The power flux for the rectangles is calculated, and an area-weighted average taken to find the average power flux over the rotor. A representation of this method is shown in Figure 58.

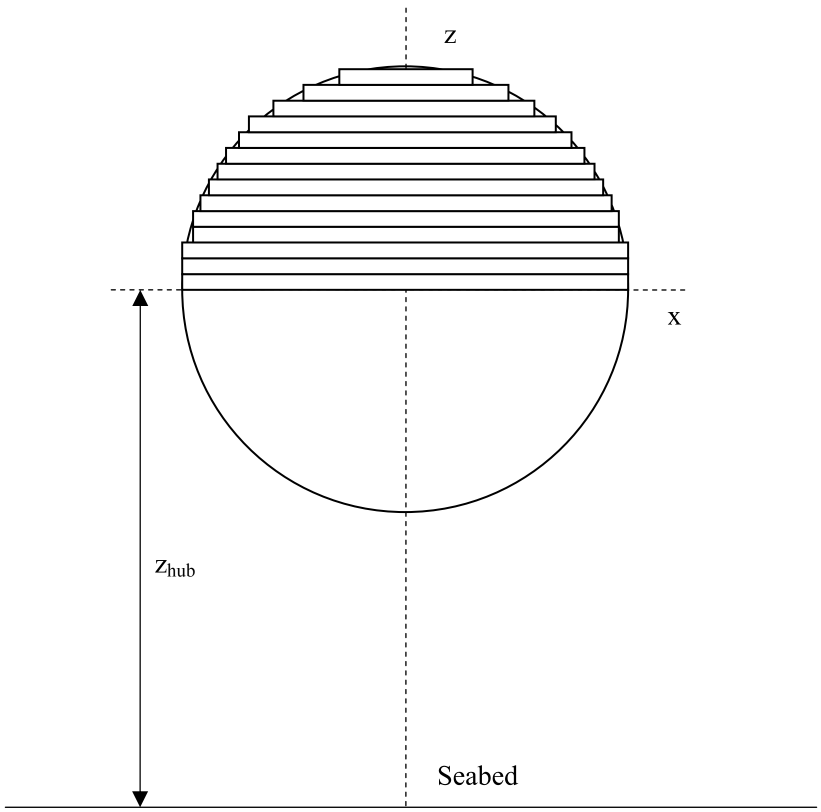

Figure 58 – Representative Numerical Integration

The result of this calculation is independent of water depth and velocity, but is dependent on hub height above the seabed. The variance from midpoint power flux (defined as $\Delta P/P_{hub\ height}$) is tabulated in Table 12.

Table 12 – Approximation Variance as Function of Hub Height

Hub Height (m)	Variance
10	-2.7%
15	-1.0%
20	-0.6%
30	-0.3%

A hub height of 17m (as assumed for the purposes of this feasibility study) introduces an error of -0.8% — that is, the actual power extracted by a turbine when approximating the power flux as the midpoint power flux is approximately 1% less than would be extracted by a turbine operating in water with a 1/10th power velocity profile. For the purposes of a feasibility study, this approximation is reasonable.

Pile Ice Loading

One of the issues that came up during the design phase was that the Minas passage is getting quite a bit of ice in the winter time. For surface piercing structures such as MCT's SeaGen this would pose a problem as large chunks of ice would collide with the surface piercing piece of the monopile and damage the structure. So the critical question that needed to be answered was; what is the additional load on the pile and can the pile be designed for these additional loads or do surface-piercing structures need to be avoided in the Minas Passage. Anecdotal reference has it that in the winter of 1958, it was possible to walk across the Minas passage over the ice. Further, a report[3] funded by the National Research Council (NRC) of Canada comes to the conclusion that TISEC devices deployed in the Minas passage would need to be engineered to tolerate at least 30% cover of sea ice 15cm thick in floes of at least 100m in length. In very severe winters, TISEC devices may be subjected to periods of 70% cover of 15-30 cm rapidly moving or packed sea ice. Although high velocity sites such as the Cape Sharp transect at which a commercial TISEC plant would be installed is mostly wiped clean because of the high currents, the issue of pieces of ice that float in the water and potentially collide with the surface piercing structures remains.

The United States Army Corp of Engineers (USACE) Ice Engineering design manual[4] lays out standard methods to compute ice loadings on structures in waterways. Three likely loads have been assessed, with the maximum load used for the purposes of design calculations.

1. Brittle fracture of ice sheet against structure
2. Fracture of ice floe against structure
3. Ice floe impact on structure

For the Minas Passage site, only the last two loads are likely to be encountered in practice, since full coverage of Minas Passage by sheet ice is rare.

[3] Richard Sanders and Emile Baddour, Document Ice in the bay of Fundi Canada, March 2006
[4] http://www.usace.army.mil/inet/usace-docs/eng-manuals/em1110-2-1612/entire.pdf

In the case of brittle fracture of an ice sheet against the pile structure, the force applied is given by:

$$F = \left(\frac{5h}{D+1}\right)^{1/2} p_e D h$$

where D is the pile diameter, h is the ice thickness, and p_e is the effective pressure during failure (1.5 – 2.0 MPa).

In the case of fracture of an ice floe against the pile structure, the force applied is given by:

$$F = 3.3 h k_{1c} \lambda^{1/2}$$

where h is the ice thickness, λ is the floe length, and k is the fracture toughness (50-250 kPa $m^{0.5}$).

For Minas Passage, we assume:

- Ice thickness of 30 cm
- Floe length of 100 m
- Pile diameter of 3.5 m (ice collars on pile can substantially increase diameter)
- Effective pressure of 2.0 MPa (conservative)
- Fracture toughness of 250 kPa $m^{0.5}$ (conservative)

The first two ice loadings are independent of floe velocity and would be most appropriate when structures will interact only with wind driven ice in weak currents. However, due to the high currents experienced in Minas Passage, impact of rapidly moving ice floes is probable.

When an ice floe impacts on a pile (assumed to bring the floe to a stop) is given by momentum conservation:

$$\frac{Mv^2}{2} = p_e V$$

where M is the mass of the floe, v is the floe velocity, V is the volume of the floe crushed by impact, and pe is the effective pressure applied by the impact. This relation can be solved for effective pressure and the force applied given by:

$$F = p_e A$$

where A is the crush area – defined for this study as the crush volume divided by the length of the floe.

For Minas Passage, we assume:

- Ice thickness of 30 cm
- Floe length of 100 m
- Floe width of 100 m
- Density of floe equal to density of seawater – assuming sedimentation balances lower density of ice compared to liquid water
- Crush volume of 10% of the ice floe

Forces applied to the pile for all three types of ice impact are listed in the table below. Forces due to current driven ice impact are highest, but unfortunately also have the highest degree of uncertainty due to estimation of such quantities as crush volume etc.

Table 13 - Ice Loading Forces for Minas Passage

Loading Mode	**Probability**	**Loading (MN)**
Sheet fracture	Low	1.48
Floe fracture	High	2.5
Floe impact	High	3.8

Applied to a pile with a length of 30m, the resulting pile moment of the floe impact scenario is 114MN-m, which needs to be added to the load on the structure. As a result the pile weight increase was calculated to provide an estimate of the potential cost increase of the pile. As a result of the increase in the piles stress-level, the pile weight increases by a factor of 2.4 over the baseline design. This would result in a dockside capital cost increase of 78% over the base design and increase COE by almost 50%. It is important to understand that this cost increase is based on a back-of the envelope type calculation and further study of the subject might reveal better options or alternative designs. If no significant improvements can be found to reduce ice-induced structural loads, it is likely that sub-surface technology will proof to be the favorable alternative. For the purpose of a pilot unit, the impact on cost however is marginal as steel cost does not dominate the cost picture.

Utility Generator Cost of Electricity Worksheet

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
	d)	Enter Annual O&M Type including annualized overhaul and refit cost
	c)	Worksheet Calculates insurance cost and Total Annual O&M Cost
Sheet 2.	**Assumptions (Financial)**	
	a)	Enter project and financial assumptions or leave default values
Sheet 3.	**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 4.	**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 -
		Interest on Debt + 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 5.	**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 6.	**Calculates COE (Cost of Electricity)**	
		COE = ((TPI * FCR) + AO&M) / AEP
		In other words…The Cost of Electricity =
		The Sum of the Levelized Plant Investment + Annual O&M Cost including Levelized
		Overhaul and Replacement Cost Divided by the Annual Electric Energy Consumption

TOTAL PLANT COST (TPC) - 2005$

TPC Component	Unit	Unit Cost	Total Cost (2005$)
Procurement			
Power Conversion System	250	$598,067	$149,516,750
Structural Elements	250	$908,272	$227,068,000
Subsea Cables	Lot	$1,575,000	$1,575,000
Turbine Installation	250	$242,083	$60,520,750
Subsea Cable Installation	Lot	$36,728,000	$36,728,000
Onshore Grid Interconnection	Lot	$10,000,000	$10,000,000
TOTAL			$485,408,500

TOTAL PLANT INVESTMENT (TPI) - 2005 $

End of Year	Total Cash Expended TPC (2005$)	Before Tax Construction Loan Cost at Debt Financing Rate	2005 Value of Construction Loan Payments	TOTAL PLANT INVESTMENT 2005$
2007	$242,704,250	$18,202,819	$14,840,590	$257,544,840
2008	$242,704,250	$18,202,819	$13,400,082	$256,104,332
Total	$485,408,500	$36,405,638	$28,240,672	$513,649,172

ANNUAL OPERATING AND MAINTENANCE COST (AO&M) - 2005$

Costs	Yrly Cost	Amount
Labor and Parts	$10,735,000	$10,735,000
Insurance (1.5% of TPC)	$7,281,128	$7,281,128
Total		$18,016,128

	FINANCIAL ASSUMPTIONS		
	(default assumptions in pink background - without line numbers are calculated values)		
1	Rated Plant Capacity ©	288	MW
2	Annual Electric Energy Production (AEP)	1,138,750	MWeh/yr
	Therefore, Capacity Factor	45.1	%
3	Year Constant Dollars	2005	Year
4	Federal Tax Rate	22	%
5	Province	Nova Scotia	
6	Provincial Tax Rate	16	%
	Composite Tax Rate (t)	0.3448	
	t/(1-t)	0.5263	
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	9.84	%
15	Inflation Rate = 3%	3	%
	Real Discount Rate Before-Tax	7.52	%
	Real Discount Rate After-Tax	6.65	%
16	Federal Investment Tax Credit (1)	0	
17	Federal Production Tax Credit (2)	0.0088	
18	Provincial Investment Tax Credit < $1.76M	35	% of TPI
19	Provincial Investment Tax Credit > $1.762M	20	
20	Provincial Investment Tax Credit Limit	None	
21	Renewable Energy Certificate (3)	0	$/kWh

Notes

1 % 1st year only - cannot take Fed ITC and PTC

2 $/kWh for 1st 10 years with escalation (assumed 3% per yr)

3 $/kWh for entire plant life with escalation (assumed 3% per yr)

NET PRESENT VALUE (NPV) - 2005 $

TPI = $513,649,172

Year End	Gross Book Value	Book Depreciation Annual	Book Depreciation Accumulated	Renewable Resource Tax Depreciation Schedule	Deferred Taxes	Net Book Value
	A	B	C	D	E	F
2008	**513,649,172**					**513,649,172**
2009	513,649,172	25,682,459	25,682,459	0.3000	44,276,559	443,690,155
2010	513,649,172	25,682,459	51,364,917	0.2100	28,336,998	389,670,698
2011	513,649,172	25,682,459	77,047,376	0.1470	17,179,305	346,808,935
2012	513,649,172	25,682,459	102,729,834	0.0940	7,792,674	313,333,802
2013	513,649,172	25,682,459	128,412,293	0.0660	2,833,700	284,817,644
2014	513,649,172	25,682,459	154,094,752	0.0460	-708,425	259,843,610
2015	513,649,172	25,682,459	179,777,210	0.0350	-2,656,594	236,817,745
2016	513,649,172	25,682,459	205,459,669	0.0220	-4,958,975	216,094,261
2017	513,649,172	25,682,459	231,142,127	0.0100	-7,084,249	197,496,052
2018	513,649,172	25,682,459	256,824,586	0.0000	-8,855,312	180,668,905
2019	513,649,172	25,682,459	282,507,044	0.0000	-8,855,312	163,841,758
2020	513,649,172	25,682,459	308,189,503	0.0000	-8,855,312	147,014,611
2021	513,649,172	25,682,459	333,871,962	0.0000	-8,855,312	130,187,464
2022	513,649,172	25,682,459	359,554,420	0.0000	-8,855,312	113,360,318
2023	513,649,172	25,682,459	385,236,879	0.0000	-8,855,312	96,533,171
2024	513,649,172	25,682,459	410,919,337	0.0000	-8,855,312	79,706,024
2025	513,649,172	25,682,459	436,601,796	0.0000	-8,855,312	62,878,877
2036	513,649,172	25,682,459	462,284,255	0.0000	-8,855,312	46,051,730
2027	513,649,172	25,682,459	487,966,713	0.0000	-8,855,312	29,224,583
2028	513,649,172	25,682,459	513,649,172	0.0000	-8,855,312	12,397,436

CAPITAL REVENUE REQUIREMENTS 2005$

TPI : $513,649,172

End of Year	Net Book	Returns to Equity Common	Returns to Equity Pref	Interest on Debt	Book Dep	Income Tax on Equity Return	Prov ITC & Fed PTC and REC	Capital Revenue Req'ts
	A	B	C	D	E	F	H	I
2009	443,690,155	29,993,454	6,056,371	11,646,867	25,682,459	36,142,701	113,014,834	-3,492,983
2010	389,670,698	26,341,739	5,319,005	10,228,856	25,682,459	26,190,952	10,021,000	83,742,011
2011	346,808,935	23,444,284	4,733,942	9,103,735	25,682,459	19,078,616	10,021,000	72,022,035
2012	313,333,802	21,181,365	4,277,006	8,225,012	25,682,459	13,169,988	10,021,000	62,514,831
2013	284,817,644	19,253,673	3,887,761	7,476,463	25,682,459	9,734,953	10,021,000	56,014,309
2014	259,843,610	17,565,428	3,546,865	6,820,895	25,682,459	7,148,061	10,021,000	50,742,707
2015	236,817,745	16,008,880	3,232,562	6,216,466	25,682,459	5,456,377	10,021,000	46,575,743
2016	216,094,261	14,607,972	2,949,687	5,672,474	25,682,459	3,644,928	10,021,000	42,536,520
2017	197,496,052	13,350,733	2,695,821	5,184,271	25,682,459	1,988,196	10,021,000	38,880,480
2018	180,668,905	12,213,218	2,466,131	4,742,559	25,682,459	569,129	10,021,000	35,652,495
2019	163,841,758	11,075,703	2,236,440	4,300,846	25,682,459	82,087	0	43,377,535
2020	147,014,611	9,938,188	2,006,749	3,859,134	25,682,459	-404,955	0	41,081,574
2021	130,187,464	8,800,673	1,777,059	3,417,421	25,682,459	-891,997	0	38,785,614
2022	113,360,318	7,663,157	1,547,368	2,975,708	25,682,459	-1,379,039	0	36,489,654
2023	96,533,171	6,525,642	1,317,678	2,533,996	25,682,459	-1,866,081	0	34,193,693
2024	79,706,024	5,388,127	1,087,987	2,092,283	25,682,459	-2,353,123	0	31,897,733
2025	62,878,877	4,250,612	858,297	1,650,571	25,682,459	-2,840,166	0	29,601,772
2026	46,051,730	3,113,097	628,606	1,208,858	25,682,459	-3,327,208	0	27,305,812
2027	29,224,583	1,975,582	398,916	767,145	25,682,459	-3,814,250	0	25,009,851
2028	12,397,436	838,067	169,225	325,433	25,682,459	-4,301,292	0	22,713,891
Sum of Annual Capital Revenue Requirements								815,645,277

FIXED CHARGE RATE (FCR) - NOMINAL AND REAL LEVELIZED - 2005$						
TPI =	$513,649,172					
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
2009	-3,492,983	0.6869	-2,399,258	-3,103,471	0.7731	-2,399,258
2010	83,742,011	0.6253	52,365,336	72,236,594	0.7249	52,365,336
2011	72,022,035	0.5693	41,000,202	60,317,320	0.6797	41,000,202
2012	62,514,831	0.5183	32,398,416	50,830,278	0.6374	32,398,416
2013	56,014,309	0.4718	26,427,726	44,218,213	0.5977	26,427,726
2014	50,742,707	0.4295	21,794,884	38,890,060	0.5604	21,794,884
2015	46,575,743	0.3910	18,212,133	34,656,727	0.5255	18,212,133
2016	42,536,520	0.3560	15,141,994	30,729,287	0.4928	15,141,994
2017	38,880,480	0.3241	12,600,067	27,269,986	0.4620	12,600,067
2018	35,652,495	0.2950	10,518,438	24,277,614	0.4333	10,518,438
2019	43,377,535	0.2686	11,650,547	28,677,661	0.4063	11,650,547
2020	41,081,574	0.2445	10,044,969	26,368,699	0.3809	10,044,969
2021	38,785,614	0.2226	8,633,608	24,169,912	0.3572	8,633,608
2022	36,489,654	0.2026	7,394,545	22,076,841	0.3349	7,394,545
2023	34,193,693	0.1845	6,308,235	20,085,191	0.3141	6,308,235
2024	31,897,733	0.1680	5,357,248	18,190,831	0.2945	5,357,248
2025	29,601,772	0.1529	4,526,054	16,389,784	0.2762	4,526,054
2026	27,305,812	0.1392	3,800,819	14,678,219	0.2589	3,800,819
2027	25,009,851	0.1267	3,169,227	13,052,454	0.2428	3,169,227
2028	22,713,891	0.1154	2,620,317	11,508,941	0.2277	2,620,317
	815,645,277		291,565,508	575,521,143		291,565,508

	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	291,565,508		291,565,508
2. Escalation Rate	3%		3%
3. After Tax Discount Rate = i	9.84%		6.65%
4. Capital recovery factor value = i(1+i)"/(1+i)"-1 where book life = n and discount rate = i	0.1162186		0.091808285
5. The levelized annual charges (end of year) = Present Value (Item 1) * Capital Recovery Factor (Item 4)	33,885,336		26,768,129
6. Booked Cost	513,649,172		513,649,172
7. The levelized annual fixed charge rate (levelized annual charges divided by the booked cost)	**0.0660**		**0.0521**

LEVELIZED COST OF ELECTRICITY CALCULATION - UTILITY GENERATOR - 2005$			
COE = ((TPI * FCR) + AO&M) / AEP			
In other words…			
The Cost of Electricity =			
The Sum of the Levelized Plant Investment + Annual O&M Cost including Levelized Overhaul and Replacement C			
Divided by the Annual Electric Energy Consumption			
NOMINAL RATES			
	Value	**Units**	**From**
TPI	$513,649,172	$	From TPI
FCR	6.60%	%	From FCR
AO&M	$18,016,128	$	From AO&M
AEP =	1,138,750	MWeh/yr	From Assumptions
COE - TPI X FCR	2.98	cents/kWh	
COE - AO&M	1.58	cents/kWh	
COE	$0.0456	$/kWh	Calculated
COE	**4.56**	cents/kWh	Calculated
REAL RATES			
TPI	$513,649,172	$	From TPI
FCR	5.21%	%	From FCR
AO&M	$18,016,128	$	From AO&M
AEP =	1,138,750	MWeh/yr	From Assumptions
COE - TPI X FCR	2.35	cents/kWh	
COE - AO&M	1.58	cents/kWh	
COE	$0.0393	$/kWh	Calculated
COE	**3.93**	cents/kWh	Calculated

Non Utility Generator Internal Rate of Return Worksheet

INSTRUCTIONS		
Fill in first four worksheets (or use default values) - the last two worksheets are automatically calculated. Refer to EPRI Economic Methodology Report 002		
		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) - 2005$**	
	1	Enter Component Unit Cost and No. of Units per System
	2	Worksheet sums component costs to get TPC
	3	Worksheet adds the value of the construction loan payments to get TPI
Sheet 2.	**AO&M (Annual Operation and Maintenance Cost) - 2005$**	
	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) - 2005$**	
	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 1st Year Energy payments = AEP X 2005 wholesale price X 97.18% (to adjust price
		from 2005 to 2008 (an 2.82% decline) X Inflation from 2005 to 2008
		2009-2011 Energy payments = AEP X Previous Year Elec Price X Annual Price
		de-escalation of -1.42% X Inflation
		2012-2025 Energy payments = AEP X Previous Year Elec Price X 0.72% Price
		escalation X Inflation
	2	Calculates State Investment and Prodution 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) - 2005$

TPC Component	Unit	Unit Cost	Total Cost (2005$)	Notes and Assumptions
Procurement				
Power Conversion System	250	$598,067	$149,516,750	
Structural Elements	250	$908,272	$227,068,000	
Subsea Cables	Lot	$1,575,000	$1,575,000	
Turbine Installation	250	$242,083	$60,520,750	
Subsea Cable Installation	Lot	$36,728,000	$36,728,000	
Onshore Grid Interconnection	Lot	$10,000,000	$10,000,000	
TOTAL			$485,408,500	

TOTAL PLANT INVESTMENT (TPI) - 2005 $

End of Year	Total Cash Expended TPC ($2005)	Before Tax Construction Loan Cost at Debt Financing Rate	2005 Value of Construction Loan Payments	TOTAL PLANT INVESTMENT (TPC + Loan Value) ($2005)
2006	$242,704,250	$21,843,383	$17,824,799	$260,529,049
2007	$242,704,250	$21,843,383	$16,101,896	$258,806,146
Total	$485,408,500	$43,686,765	$33,926,696	$519,335,196

ANNUAL OPERATING AND MAINTENANCE COST (AO&M) - 2005$

Costs	Yrly Cost	Amount	
Labor and Parts	$10,735,000	$10,735,000	
Insurance (1.5% of TPC)	$7,281,128	$7,281,128	
Total		$18,016,128	

	FINANCIAL ASSUMPTIONS		
	(default assumptions in pink background - without line numbers are calculated values)		
1	Rated Plant Capacity ©	288	MW
2	Annual Electric Energy Production (AEP)	1,138,750	MWeh/yr
	Therefore, Capacity Factor	45.11	%
3	Year Constant Dollars	2005	Year
4	Federal Tax Rate	22	%
5	Province	Nova Scotia	
6	Province Tax Rate	16	%
	Composite Tax Rate (t)	0.3448	%
	t/(1-t)	0.5263	
7	Book Life	20	Years
8	Construction Financing Rate	9	
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	8.77	%
15	Inflation rate	3	%
16	Federal Investment Tax Credit	0	Assumed take PTC
17	Federal Production Tax Credit inc 3% escalation	0.0088	$/kWh for 1st 10 yrs
18	Provincial Investment Tax Credit < $1.76M	35	% of TPI
19	Provincial Investment Tax Credit > $1.762M	20	% of TPI
20	Wholesale electricity price - 2005$	$0.056	$/kWh
21	Decline in wholesale elec. price from 2005 to 2008	4.20	%
22	Annual decline in wholesale price, 2009 - 2011	1.42	%
23	Annual increase in wholesale price, 2012 - 2025	0.72	%
24	Yearly Unscheduled O&M	5	% of Sch O&M cost
25	Acc Tax Depreciation Year 1	0.3000	
26	Acc Tax Depreciation Year 2	0.2100	
27	Acc Tax Depreciation Year 3	0.1470	
28	Acc Tax Depreciation Year 4	0.0940	
29	Acc Tax Depreciation Year 5	0.0660	
30	Acc Tax Depreciation Year 6	0.0460	
31	REC Rate	0.0000	$/kWh for Project Life

Electricity Price Forecast Area

The electricity price forecast from the EIA (Doc 002, Reference 8):

"Average U.S. electricity prices, in real 2003 dollars, are expected to decline by 11% from 7.4 cents/kWh in 2003 to 6.6 cents in 2011, then rise to 7.3 cents/kWh in 2025."

	2003	7.4	7.4		
	2004		7.29		
Base	2005		7.19		
	2006		7.09		
	2007		6.99		
	2008		6.89	-4.20%	Decline (2005 - 2008)
	2009		6.79		
	2010		6.7		
	2011	6.6	6.6	-1.42%	Annual Decline (2009 - 2011)
	2012		6.65		
	2013		6.7		
	2014		6.74		
	2015		6.79		
	2016		6.84		
	2017		6.89		
	2018		6.94		
	2019		6.99		
	2020		7.04		
	2021		7.09		
	2022		7.14		
	2023		7.2		
	2024		7.25		
	2025	7.3	7.3	0.72%	Annual Increase (2012 - 2025)

INCOME STATEMENT ($)		CURRENT DOLLARS							
Description/Year	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
REVENUES									
Energy Payments	66,756,748	67,783,099	68,825,231	69,883,384	72,500,035	75,214,662	78,030,933	80,952,654	83,983,773
REC income	0	0	0	0	0	0	0	0	0
Province ITC	104,131,039								
Federal ITC	0								
Fedaral PTC	10,021,000	10,321,630	10,631,279	10,950,217	11,278,724	11,617,085	11,965,598	12,324,566	12,694,303
TOTAL REVENUES	170,887,787	67,783,099	68,825,231	69,883,384	72,500,035	75,214,662	78,030,933	80,952,654	83,983,773
AVG $/KWH	0.150	0.060	0.060	0.061	0.064	0.066	0.069	0.071	0.074
OPERATING COSTS									
Scheduled and Unscheduled O&M	18,016,128	18,556,611	19,113,310	19,686,709	20,277,310	20,885,630	21,512,198	22,157,564	22,822,291
Other	0	0	0	0	0	0	0	0	0
TOTAL	18,016,128	18,556,611	19,113,310	19,686,709	20,277,310	20,885,630	21,512,198	22,157,564	22,822,291
EBITDA	152,871,660	49,226,488	49,711,921	50,196,675	52,222,725	54,329,033	56,518,735	58,795,089	61,161,482
Tax Depreciation	155,800,559	109,060,391	76,342,274	48,817,508	34,276,123	0	0	0	0
Interest Paid	29,082,771	28,447,248	27,760,884	27,019,610	26,219,034	25,354,412	24,420,621	23,412,126	22,322,952
TAXABLE EARNINGS	-32,011,670	-88,281,151	-54,391,236	-25,640,443	-8,272,432	28,974,620	32,098,114	35,382,963	38,838,530
State Tax	-5,121,867	-14,124,984	-8,702,598	-4,102,471	-1,323,589	4,635,939	5,135,698	5,661,274	6,214,165
Federal Tax	-5,915,757	-16,314,357	-10,051,500	-4,738,354	-1,528,745	5,354,510	5,931,731	6,538,772	7,177,360
TOTAL TAX OBLIGATIONS	-11,037,624	-30,439,341	-18,754,098	-8,840,825	-2,852,335	9,990,449	11,067,430	12,200,046	13,391,525

2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
87,128,386	90,390,744	93,775,255	97,286,492	100,929,201	104,708,304	108,628,909	112,696,313	116,916,013	121,293,712	125,835,326
0	0	0	0	0	0	0	0	0	0	0
13,075,132										
87,128,386	90,390,744	93,775,255	97,286,492	100,929,201	104,708,304	108,628,909	112,696,313	116,916,013	121,293,712	125,835,326
0.077	0.079	0.082	0.085	0.089	0.092	0.095	0.099	0.103	0.107	0.111
23,506,960	24,212,169	24,938,534	25,686,690	26,457,291	27,251,009	28,068,540	28,910,596	29,777,914	30,671,251	31,591,389
0	0	0	0	0	0	0	0	0	0	0
23,506,960	24,212,169	24,938,534	25,686,690	26,457,291	27,251,009	28,068,540	28,910,596	29,777,914	30,671,251	31,591,389
63,621,426	66,178,575	68,836,721	71,599,802	74,471,910	77,457,295	80,560,369	83,785,717	87,138,099	90,622,461	94,243,938
0	0	0	0	0	0	0	0	0	0	0
21,146,643	19,876,230	18,504,184	17,022,375	15,422,020	13,693,637	11,826,984	9,810,998	7,633,734	5,282,288	2,742,726
42,474,783	46,302,345	50,332,537	54,577,427	59,049,890	63,763,657	68,733,385	73,974,719	79,504,366	85,340,173	91,501,211
6,795,965	7,408,375	8,053,206	8,732,388	9,447,982	10,202,185	10,997,342	11,835,955	12,720,699	13,654,428	14,640,194
7,849,340	8,556,673	9,301,453	10,085,909	10,912,420	11,783,524	12,701,930	13,670,528	14,692,407	15,770,864	16,909,424
14,645,305	15,965,049	17,354,659	18,818,297	20,360,402	21,985,709	23,699,271	25,506,483	27,413,105	29,425,292	31,549,618

CASH FLOW STATEMENT							
Description/Year	2007	2008	2009	2010	2011	2012	2013
EBITDA			152,871,660	49,226,488	49,711,921	50,196,675	52,222,725
Taxes Paid			-11,037,624	-30,439,341	-18,754,098	-8,840,825	-2,852,335
CASH FLOW FROM OPS			163,909,283	79,665,829	68,466,019	59,037,500	55,075,060
Debt Service			-37,026,806	-37,026,806	-37,026,806	-37,026,806	-37,026,806
NET CASH FLOW AFTER TAX		-155,800,559	126,882,478	42,639,023	31,439,214	22,010,694	18,048,254
CUM NET CASH FLOW		-155,800,559	-28,918,081	13,720,942	45,160,156	67,170,850	85,219,104

2014	2015	2016	2017	2018	2019	2020	2021
54,329,033	56,518,735	58,795,089	61,161,482	63,621,426	66,178,575	68,836,721	71,599,802
9,990,449	11,067,430	12,200,046	13,391,525	14,645,305	15,965,049	17,354,659	18,818,297
44,338,584	45,451,305	46,595,044	47,769,956	48,976,121	50,213,527	51,482,062	52,781,505
-37,026,806	-37,026,806	-37,026,806	-37,026,806	-37,026,806	-37,026,806	-37,026,806	-37,026,806
7,311,778	8,424,499	9,568,238	10,743,151	11,949,316	13,186,721	14,455,257	15,754,699
92,530,881	100,955,381	110,523,619	121,266,769	133,216,085	146,402,806	160,858,062	176,612,762

2022	2023	2024	2025	2026	2027	2028
74,471,910	77,457,295	80,560,369	83,785,717	87,138,099	90,622,461	94,243,938
20,360,402	21,985,709	23,699,271	25,506,483	27,413,105	29,425,292	31,549,618
54,111,508	55,471,586	56,861,098	58,279,234	59,724,994	61,197,169	62,694,320
-37,026,806	-37,026,806	-37,026,806	-37,026,806	-37,026,806	-37,026,806	-37,026,806
17,084,702	18,444,780	19,834,292	21,252,428	22,698,188	24,170,364	25,667,514
193,697,464	212,142,244	231,976,536	253,228,964	275,927,153	300,097,516	325,765,030
			IRR ON NET CASH FLOW AFTER TAX			31.4%

Municipal Generator Cost of Electricity Worksheet

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
	a)	Enter Labor Hrs and and Parts Cost by O&M inc overhaul and refit
	c)	Worksheet Calculates Insurance and 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 - Interest on Debt + 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 including Levelized Overhaul and Replacement Cost Divided by the Annual Electric Energy Consumption

TOTAL PLANT COST (TPC) - 2005$

TPC Component	Unit	Unit Cost	Total Cost (2004$)	
Procurement				
Power Conversion System	250	$598,067	$149,516,750	
Structural Elements	250	$908,272	$227,068,000	
Subsea Cables	Lot	$1,575,000	$1,575,000	
Turbine Installation	250	$242,083	$60,520,750	
Subsea Cable Installation	Lot	$36,728,000	$36,728,000	
Onshore Grid Interconnection	Lot	$10,000,000	$10,000,000	
TOTAL			$485,408,500	

TOTAL PLANT INVESTMENT (TPI) - 2005 $

End of Year	Total Cash Expended TPC (2005$)	Before Tax Construction Loan Cost at Debt Financing Rate	2005 Value of Construction Loan Payments	TOTAL PLANT INVESTMENT 2005$
2007	$242,704,250	$12,135,213	$11,006,995	$253,711,245
2008	$242,704,250	$12,135,213	$10,482,853	$253,187,103
Total	$485,408,500	$24,270,425	$21,489,848	$506,898,348

ANNUAL OPERATING AND MAINTENANCE COST (AO&M) - 2005$

Costs	Yrly Cost	Amount	
Labor and Parts	$10,735,000	$10,735,000	
Insurance (1.5% of TPC)	$7,281,128	$7,281,128	
Total		$18,016,128	

	FINANCIAL ASSUMPTIONS		
	(default assumptions in pink background - without line numbers are calculated values)		
1	Rated Plant Capacity ©	288	MW
2	Annual Electric Energy Production (AEP)	1,138,750	MWeh/yr
	Therefore, Capacity Factor	45.1	%
3	Year Constant Dollars	2005	Year
4	Federal Tax Rate	0	%
5	Province	Nova Scotia	
6	Province Tax Rate	0	%
	Composite Tax Rate (t)	0	
	t/(1-t)	0.0000	
7	Book Life	20	Years
8	Construction Financing Rate	5	
9	Common Equity Financing Share	0	%
10	Preferred Equity Financing Share	0	%
11	Debt Financing Share	100	%
12	Common Equity Financing Rate	0	%
13	Preferred Equity Financing Rate	0	%
14	Debt Financing Rate	5	%
	Nominal Discount Rate Before-Tax	5.00	%
	Nominal Discount Rate After-Tax	5.00	%
15	Inflation Rate = 3%	3	%
	Real Discount Rate Before-Tax	1.94	%
	Real Discount Rate After-Tax	1.94	%
16	Federal Investment Tax Credit	0	
17	Federal REPI or CREB (1)	0	$/kWh
18	Province Investment Tax Credit	0	% of TPI
19	Province Investment Production Tax Credit	0	
20	Renewable Energy Certificate (2)	0	$/kWh
21	Provincial	0	Installation Cos

Notes
1 $/kWh for 1st 10 years with escalation (assumed 3% per yr)
2 $/kWh for entire plant life with escalation (assumed 3% per yr)

NET PRESENT VALUE (NPV) - 2005 $

TPI = $506,898,348

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
2008	**506,898,348**					**506,898,348**
2009	506,898,348	25,344,917	25,344,917	0	0	481,553,431
2010	506,898,348	25,344,917	50,689,835	0	0	456,208,513
2011	506,898,348	25,344,917	76,034,752	0	0	430,863,596
2012	506,898,348	25,344,917	101,379,670	0	0	405,518,679
2013	506,898,348	25,344,917	126,724,587	0	0	380,173,761
2014	506,898,348	25,344,917	152,069,504	0	0	354,828,844
2015	506,898,348	25,344,917	177,414,422	0	0	329,483,926
2016	506,898,348	25,344,917	202,759,339	0	0	304,139,009
2017	506,898,348	25,344,917	228,104,257	0	0	278,794,092
2018	506,898,348	25,344,917	253,449,174	0	0	253,449,174
2019	506,898,348	25,344,917	278,794,092	0	0	228,104,257
2020	506,898,348	25,344,917	304,139,009	0	0	202,759,339
2021	506,898,348	25,344,917	329,483,926	0	0	177,414,422
2022	506,898,348	25,344,917	354,828,844	0	0	152,069,504
2023	506,898,348	25,344,917	380,173,761	0	0	126,724,587
2024	506,898,348	25,344,917	405,518,679	0	0	101,379,670
2025	506,898,348	25,344,917	430,863,596	0	0	76,034,752
2036	506,898,348	25,344,917	456,208,513	0	0	50,689,835
2027	506,898,348	25,344,917	481,553,431	0	0	25,344,917
2028	506,898,348	25,344,917	506,898,348	0	0	0

CAPITAL REVENUE REQUIREMENTS - 2005$

TPI : $506,898,348

End of Year	Net Book	Returns to Equity Common	Returns to Equity Pref	Interest on Debt	Book Dep	Income Tax on Equity Return	REPI	Capital Revenue Req'ts
	A	B	C	D	E	F	H	I
2009	481,553,431	0	0	24,077,672	25,344,917	0	0	49,422,589
2010	456,208,513	0	0	22,810,426	25,344,917	0	0	48,155,343
2011	430,863,596	0	0	21,543,180	25,344,917	0	0	46,888,097
2012	405,518,679	0	0	20,275,934	25,344,917	0	0	45,620,851
2013	380,173,761	0	0	19,008,688	25,344,917	0	0	44,353,605
2014	354,828,844	0	0	17,741,442	25,344,917	0	0	43,086,360
2015	329,483,926	0	0	16,474,196	25,344,917	0	0	41,819,114
2016	304,139,009	0	0	15,206,950	25,344,917	0	0	40,551,868
2017	278,794,092	0	0	13,939,705	25,344,917	0	0	39,284,622
2018	253,449,174	0	0	12,672,459	25,344,917	0	0	38,017,376
2019	228,104,257	0	0	11,405,213	25,344,917	0	0	36,750,130
2020	202,759,339	0	0	10,137,967	25,344,917	0	0	35,482,884
2021	177,414,422	0	0	8,870,721	25,344,917	0	0	34,215,639
2022	152,069,504	0	0	7,603,475	25,344,917	0	0	32,948,393
2023	126,724,587	0	0	6,336,229	25,344,917	0	0	31,681,147
2024	101,379,670	0	0	5,068,983	25,344,917	0	0	30,413,901
2025	76,034,752	0	0	3,801,738	25,344,917	0	0	29,146,655
2026	50,689,835	0	0	2,534,492	25,344,917	0	0	27,879,409
2027	25,344,917	0	0	1,267,246	25,344,917	0	0	26,612,163
2028	0	0	0	0	25,344,917	0	0	25,344,917
Sum of Annual Capital Revenue Requirements								747,675,064

FIXED CHARGE RATE (FCR) - NOMINAL AND REAL LEVELIZED - 2005$

TPI = $506,898,348

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
2009	49,422,589	0.8227	40,660,086	43,911,330	0.9260	40,660,086
2010	48,155,343	0.7835	37,730,971	41,539,222	0.9083	37,730,971
2011	46,888,097	0.7462	34,988,620	39,268,043	0.8910	34,988,620
2012	45,620,851	0.7107	32,421,887	37,093,927	0.8740	32,421,887
2013	44,353,605	0.6768	30,020,266	35,013,146	0.8574	30,020,266
2014	43,086,360	0.6446	27,773,852	33,022,107	0.8411	27,773,852
2015	41,819,114	0.6139	25,673,308	31,117,348	0.8250	25,673,308
2016	40,551,868	0.5847	23,709,837	29,295,532	0.8093	23,709,837
2017	39,284,622	0.5568	21,875,147	27,553,443	0.7939	21,875,147
2018	38,017,376	0.5303	20,161,426	25,887,983	0.7788	20,161,426
2019	36,750,130	0.5051	18,561,313	24,296,165	0.7640	18,561,313
2020	35,482,884	0.4810	17,067,874	22,775,113	0.7494	17,067,874
2021	34,215,639	0.4581	15,674,578	21,322,055	0.7351	15,674,578
2022	32,948,393	0.4363	14,375,275	19,934,319	0.7211	14,375,275
2023	31,681,147	0.4155	13,164,171	18,609,335	0.7074	13,164,171
2024	30,413,901	0.3957	12,035,813	17,344,623	0.6939	12,035,813
2025	29,146,655	0.3769	10,985,068	16,137,796	0.6807	10,985,068
2026	27,879,409	0.3589	10,007,101	14,986,556	0.6677	10,007,101
2027	26,612,163	0.3418	9,097,365	13,888,688	0.6550	9,097,365
2028	25,344,917	0.3256	8,251,578	12,842,061	0.6425	8,251,578
	747,675,064		424,235,537	525,838,794		424,235,537

	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	424,235,537		424,235,537
2. Escalation Rate	3%		3%
3. Discount Rate = i	5.00%		1.94%
4. Capital recovery factor value = $i(1+i)^n/(1+i)^n-1$ where book life = n and discount rate = i	0.08024259		0.060813464
5. The levelized annual charges (end of year) = Present Value (Item 1) * Capital Recovery Factor (Item 4)	34,041,757		25,799,232
6. Booked Cost	506,898,348		506,898,348
7. The levelized annual fixed charge rate (levelized annual charges divided by the booked cost)	**0.0672**		**0.0509**

LEVELIZED COST OF ELECTRICITY CALCULATION - MUNICIPAL GENERATOR - 2005$

COE = ((TPI * FCR) + AO&M) / 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	$506,898,348	$	From TPI
FCR	6.72%	%	From FCR
AO&M	$18,016,128	$	From AO&M
AEP =	1,138,750	MWeh/yr	From Assumptions
COE - TPI X FCR	2.99	cents/kWh	
COE - AO&M	1.58	cents/kWh	
COE	$0.0457	$/kWh	Calculated
COE	**4.57**	cents/kWh	Calculated

REAL RATES

	Value	Units	From
TPI	$506,898,348	$	From TPI
FCR	5.09%	%	From FCR
AO&M	$18,016,128	$	From AO&M
AEP =	1,138,750	MWeh/yr	From Assumptions
COE - TPI X FCR	2.27	cents/kWh	
COE - AO&M	1.58	cents/kWh	
COE	$0.0385	$/kWh	Calculated
COE	**3.85**	cents/kWh	Calculated