# System Level Design, Performance, Cost and Economic Assessment – Knik Arm Alaska Tidal In-Stream Power Plant

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Author: Brian Polagye and Mirko Previsic
Contributors: Roger Bedard
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**Organization(s) that prepared this document**

**Electricity Innovation Institute**

**Global Energy Partners LLC**

**Virginia Polytechnic Institute and State University**

**Mirko Previsic Consulting**

**Brian Polagye[1] Consulting**

[1] PhD Student, Department of Mechanical Engineering, University of Washington

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# 1. Introduction and Summary

This document describes the results of a system level design, performance and cost study for both a feasibility demonstration pilot plant and a commercial size offshore in-stream tidal power plant installed in Knik Arm. For purposes of this design study, both the Marine Current Turbine (MCT) and Lunar Energy tidal in-stream energy conversion (TISEC) devices were considered for deployment at Cairn Point. The study was carried out using the methodology and standards established in the Design Methodology Report [1], the Power Production Performance Methodology Report [4] and the Cost Estimate and Economics Assessment Methodology Report [2].

At Cairn Point, current velocities and water depths are suitable for the deployment of either a Lunar Energy RTT 2000 or fully submerged next-generation MCT turbine. The site resource is such that, on average, 17 MW of energy could be extracted from the flow without environmental impact. The site is in close to proximity to a major urban load center (Anchorage) and has access to electrical infrastructure through nearby Elmendorf AFB. However, a number of site specific issues complicate turbine deployment. These are the seasonal ice pack, ongoing shifts in the seabed, a high level of sedimentation in the water, and concern over impacts to marine mammals (particularly the Beluga whale). Due to ice considerations, the turbine support structure should not be surface piercing.

Lunar Energy's RTT 2000 is a fully submersed ducted 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 fully submerged design concept (separate from the SeaGen device being deployed in Strangford Lough) uses a free-flow horizontal axis turbine anchored to the seabed by a monopile foundation. While MCT has established baseline costs for the SeaGen unit, the fully submerged design is conceptual at this stage. As a result, costing and design work for this study assume the SeaGen turbine could be used as an adequate cost model to broadly consider tidal energy feasibility.

On this basis, a single pilot turbine would cost \$4.8M to build and produced an estimated 1940 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 required to evaluate and test a SeaGen TISEC system, 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. These turbines will, on average, extract 17MW of kinetic power from the tidal stream – 15% of the total kinetic energy in the flow at Cairn Point. The amount of energy produced depends on the type of turbine chosen, as Lunar and MCT have chosen different power train configurations. In order to extract 15% of the kinetic resource, turbines will be arranged at the site in rows, or transects. For an array of MCT turbines, the elements of cost and economics (in 2005\$) are:

- Total Plant Investment = \$110 million (excludes \$3.25 million transmission upgrade to be paid back to project with interest)
- Annual O&M Cost = \$4.0 million
- Utility Generator (UG) Levelized Cost of Electricity (COE)[2] = 9.2 (Real) – 10.8 (Nominal) cents/kWh with renewable energy incentives equal to those that the government provides for renewable wind energy technology
- Non Utility Generator (NUG) Levelized Cost of Electricity (IRR) = N/A
- Municipal Generator (MG) Levelized Cost of Electricity (COE) = 7.1 (Real) – 8.4 (Nominal) cents/kWh with renewable energy incentives equal to those that the government provides for renewable wind energy technology

Knik Arm has the potential of being a good location for siting an in-stream tidal power plant. Strong currents occur four times each day in a passage with sufficient cross-sectional area to embody over 100 MW of kinetic energy on average. The east side of Cairn Point has significant electrical infrastructure. Knik Arm is in close proximity to the Port of

Anchorage – a major port facility which could serve as a base of operations for both installation and maintenance.

A pilot demonstration tidal plant at Cairn Point is recommended to help address the following issues:

- Reliability and availability
- Most cost effective type of technology and optimum size for individual turbines
- Uncertainty in project costs, particularly installation and O&M costs
- Dispatcher ability to make use of a predictable, though varying resource
- Regulatory willingness to permit TISEC installations
- Political and public acceptance

In-stream tidal energy is a potential important energy source and should be evaluated for adding to Anchorage'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 Anchorage 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

Except for a few large tidal energy resource sites, such as Minas Passage, TISEC is in the grey zone between central and distributed power applications. Typical distributed generation (DG) motivations are:

- Delay transmission and distribution (T&D) infrastructure upgrade
- Provide voltage stability
- Displace diesel fuel in off-grid applications

[2] For the 45.7 MW 20 year plant life, 10 years of PTC at 0.18 cents/kWh for a taxable entity, a REPI credit at 0.015 cents/kWh for a non taxable MG, and other assumptions documented in [2].

- Provide guaranteed power

In order to promote development of TISEC, EPRI recommends that stakeholders build collaboration within Alaska and with other State/Federal Government agencies by forming a state electricity stakeholder group and joining TISEC Working Group to be formed by EPRI. Additional, 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:

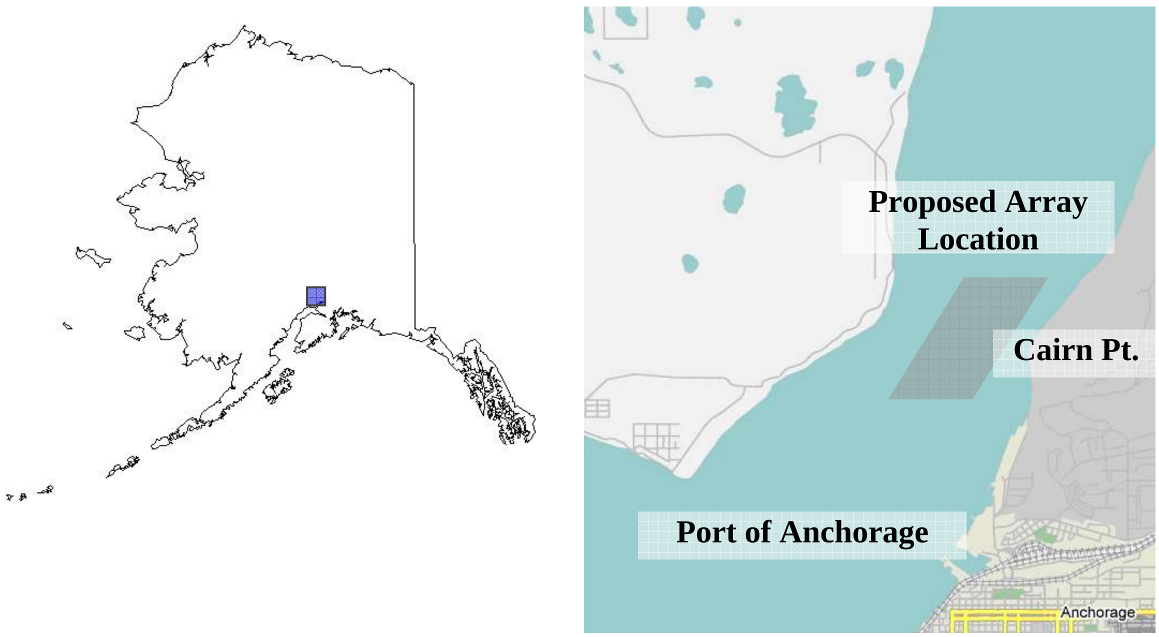
- Implement a national ocean tidal energy program at DOE
- Operate a national offshore ocean tidal energy test facility
- Promote development of industry standards
- Continue membership in the IEA Ocean Energy Program
- Clarify and streamline federal permitting processes
- Study provisions for tax incentives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

Since neither the Lunar RTT 2000 nor a fully submerged MCT device is at a point where deployment in the challenging waters of Cairn Point would be possible, it is recommended that Alaska stakeholders undertake the following activities.

- Quantify the total TISEC resource in-state by means of a statewide site survey
- ADCP velocity measurements at Cairn Point to improve the understanding of flow velocities
- Commission a study of sub-surface ice behavior
- Commission a study on future trends in seabed bathymetry
- Conduct a site-specific regulatory and environmental assessment

## 2. Site Selection

The Alaska stakeholders selected Knik Arm for an assessment of in-stream tidal power. Fabrication, assembly, and operation and maintenance would be performed out of the Port of Anchorage. Grid interconnection would be on the eastern side of Knik Arm, and would interface with Elmendorf AFB's electric grid for transmission to Anchorage Municipal Light and Power. Figure 1 shows an aerial schematic of Knik Arm.




Outline Map Aerial Schematic

Figure 1 – Knik Arm [5]

Knik Arm is located in upper Cook Inlet, approximately two miles north of the city of Anchorage. While much of the Knik Arm to the north and south of Cairn Point is quite shallow (less than 15m deep), water depths off of Cairn Point exceed 50m. Due to Cook Inlet's substantial tidal range and the constriction at the point, the twice-daily tidal exchange generates high velocities.

Site selection is determined by the following considerations:

- Strong tidal energy resource
- Low-cost interconnection
- Close proximity to major port

The Cairn Point site satisfies all these criteria. Tidal currents at Cairn Point are among the strongest reported in upper Cook Inlet – 1.1 m/s average speed. This translates to a depth averaged power flux of 1.6 kW/m$^2$ using the methodology described in [1]. The channel at Cairn Point has a substantial average cross-section (73,200 m$^2$), yielding an average flow power of 116 MW. Elmendorf AFB has high voltage electrical transmission lines (35 kV) relatively close to shore than could be overbuilt to 115kV to accommodate a commercial plant. Cairn Point is in close proximity to the Port of Anchorage, a major port facility. In short – the site satisfies all the primary criteria for siting a TISEC plant.

In addition to issues driving the general siting decision, other factors are important to take into account in the design process:

- Bathymetry: relatively flat seafloor preferred
- Seabed composition: bearing capacity and type will determine foundation design
- Navigational clearance: turbines may need to share waterway with shipping traffic
- Site specific issues: ice, turbine interaction with marine life, etc.

These issues, as well as those discussed above are considered in more detail in the following sections. Site parameters are summarized in Table 1.

Table 1 - Relevant Site Design Parameters

| **Site** | |
|---|---|
| Channel Width | 2,540 m |
| Average Depth (from MLLW) | 29 m |
| Deepest Point | 59 m |
| Maximum Tidal Range | 12 m |
| Seabed Type | Dense, silty sand |
| **Tidal Energy Statistics** | |
| Depth Averaged Power Density | 1.6 kW/m$^2$ |
| Average Power Available | 116 MW |
| Average Power Extractable (15%) | 17.4 MW |
| # Homes equivalent (1.3 kW/home) | 12,000 |
| Peak Surface Velocity at Site | 3.9 m/s |
| **Interconnection** | |
| Pilot Plant | Connection to Elmendorf distribution line at 12kV |
| Commercial Plant | Connection to new 115kV substation at 33kV |
| **Nearest Port** | Port of Anchorage (3.2 km) |

## 2.1. Tidal Energy Resource

When siting a commercial TISEC system, the primary consideration is the magnitude of the resource. This is a function of the strength of the currents and cross-sectional area of the channel.

Since power varies with the cube of velocity, even small variations in velocity have a big impact on power. The power flux – or power per unit area – of a tidal current is given by $P = \frac{1}{2}\rho U^3$, where $P$ is the power flux (kW/m$^2$), $\rho$ is the density of seawater (1024 kg/m$^3$), and $U$ is the current velocity (m/s).

The methodology for calculating currents (m/s) and power flux (kW/m$^2$) in Knik Arm is described in [1]. Based on NOAA tidal current stations (2005 predictions), the power flux at Cairn Point is the strongest in Knik Arm. This is not to say that stronger currents might not exist elsewhere in the channel – only that identification of these currents will require additional measurements and modeling. For example, ADCP profiles for the design of the Knik Arm Bridge indicate currents may be faster at the proposed bridge transect [6]. However, depths at the bridge site are such that installation of even small diameter turbines would be problematic.

The approximate locations of the tidal current stations are shown in Figure 2 and the strength of the currents at each station is given in Table 2. For the tabulated NOAA station data, the power flux to the northeast of Cairn Point is highest.

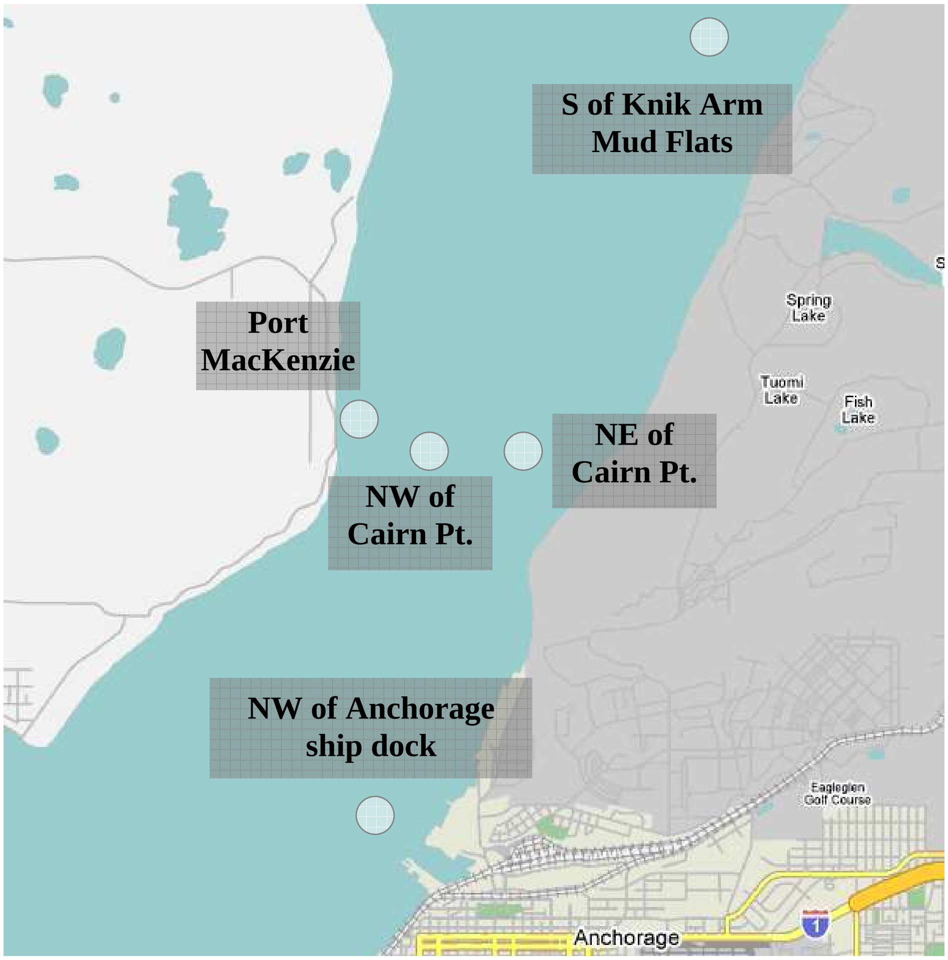



Figure 2 – Knik Arm NOAA Current Stations [5,7]

Table 2 – Knik Arm NOAA Current Stations Predicted Velocity and Power Flux

| Station | Depth Averaged Velocity (m/s) | Depth Averaged Power Flux (kW/m$^2$) |
|---|---|---|
| NE of Cairn Pt. | 1.1 | 1.8 |
| NW of Cairn Pt. | 1.1 | 1.4 |
| Port MacKenzie | 1.0 | 1.1 |
| NW of Anchorage ship dock | 1.2 | 1.8 |
| S of Knik Arm Mud Flats | 0.9 | 0.8 |

For the purposes of estimating the available channel resource, power flux prediction for the weaker NW station were averaged with the stronger station to the NE of Cairn Point. Therefore, the estimated power flux for the purpose of resource assessment is 1.6 kW/m$^2$ (average of 1.8 and 1.4 kW/m$^2$). However, since the deep water channel suitable for current deployment intersects the station NE of Cairn Point, those current predictions were used to predict device performance. As a result, the average power flux at hub height for the deployed turbines is greater than the average power flux for the entire channel. While the Anchorage ship dock also shows a high power flux, shallow depth and deep draft shipping clearances restrict turbine deployment at this site. It is possible that a much smaller array could be incorporated into the structure of a proposed new dock to provide dockside power.

Variations in surface currents over a representative tidal cycle are shown in Figure 3. At Cairn Point, the ebb tide is slightly stronger than the flood due to river flows further up Knik Arm (NE of Cairn Pt. average maximum flood = 2.0 m/s, average maximum ebb = 2.1 m/s). NOAA lists ebb and flood tides for the station NE of Cairn at an angle of $167^{o}$ [7]. This is a substantial departure from bi-directional tides of $180^{o}$ and has important implications for turbine design, since turbines will experience off-axis flows of at least $6.5^{o}$.

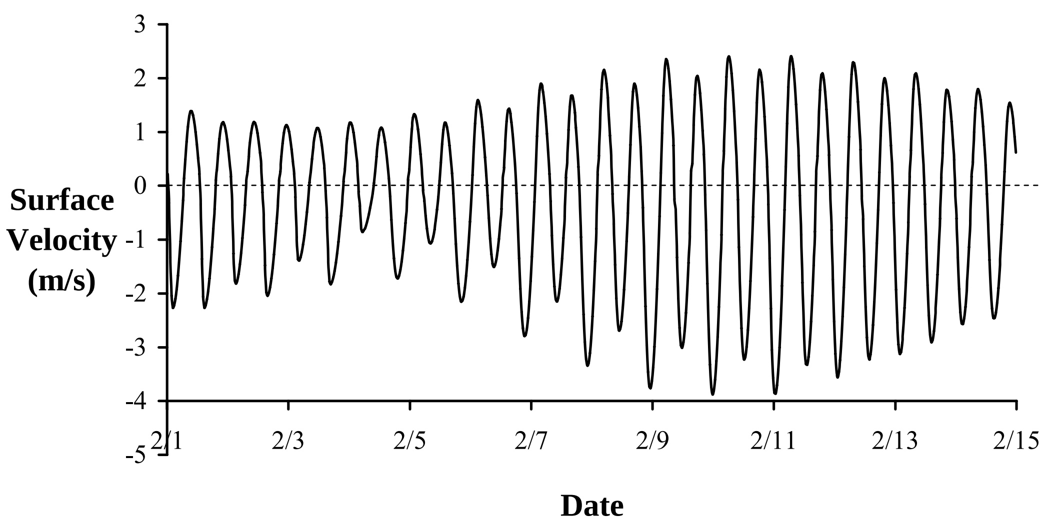



Figure 3 – Tidal Cycle Velocity Variation NE of Cairn Pt. (Feb 1st-14th, 2005)

These data are most conveniently represented by a histogram of velocities and frequencies. A histogram for the tidal currents NE of Cairn Pt. is given in Figure 4.

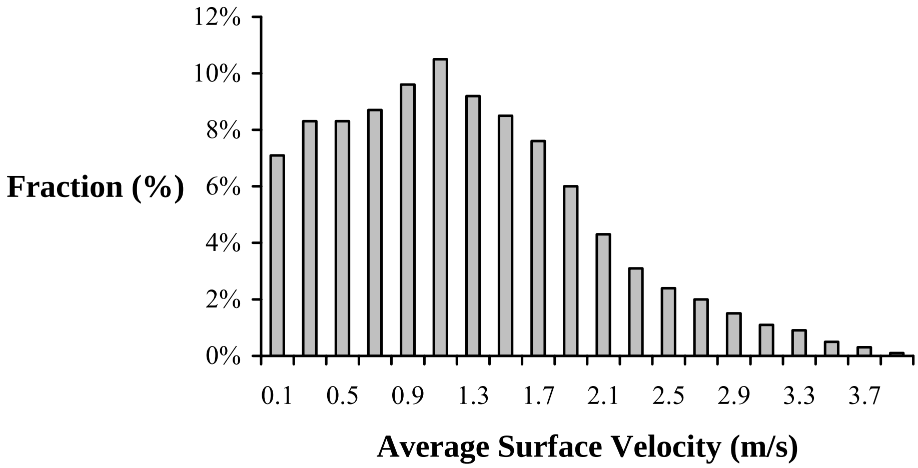



Figure 4 –Tidal Current Histogram NE of Cairn Pt.

Second only to power flux in the viability of a tidal energy site is the channel mass flow rate – a function of the velocity and cross-sectional area. Total power is equal to power flux (kW/$m^2$) multiplied by channel cross-section ($m^2$). As a result, tiny channels with high power flux are of little use for commercial tidal power generation since the overall tidal resource is quite small.

At Cairn Point, Knik Arm is approximately 2540m wide. Depth considerations limit deployment of full-size turbines to a deep-water channel trending from SW to NE. Figure 5 shows a depth profile for Knik Arm in the vicinity of Cairn Point. The figure is as the narrows at Cairn Point would appear to an observer standing on the seabed looking north. Depths are referenced to MLLW. The depth across Cairn Pt. changes quite rapidly and irregularly, and the potential area for turbine deployment is confined to a relatively narrow deep-water zone. This may complicate turbine deployment since steep slopes are not compatible with gravity foundations and pile installation can destabilize steep slopes [18]. Note, however, that the vertical scale is exaggerated. Only the steepest aspects of the east and west bank should present significant obstacles to turbine installation.

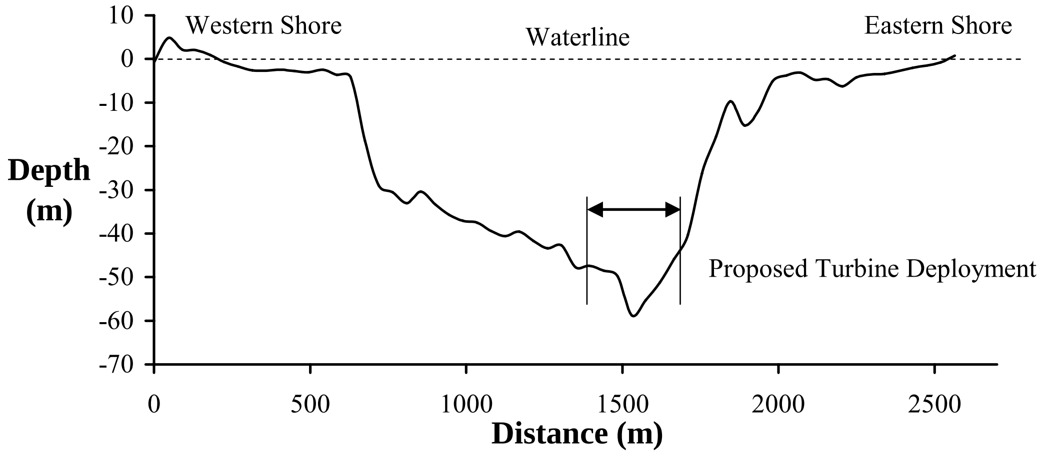



Figure 5 – Depth Profile of Knik Arm in vicinity of Cairn Pt.

Due to the tidal range in Cook Inlet, the cross-sectional area of Knik Arm varies with time. In the region of interest for turbine deployment, the average cross-sectional area is approximately 73,200 $m^2$.

Taken in combination with the power flux discussed in the previous section, channel power for Cairn Point is quite substantial – more than 100 MW on average. Again, this is based on an average of the power embodied by the current stations NW and NE of Cairn Point. Results are summarized in Table 3. In order to avoid any major ecological impact from the operation of this array, no more than 15% of the average channel power may be extracted [1].

Table 3 – Channel and Extractable Power at Cairn Point

| | **Depth Averaged Power Flux ($kW/m^2$)** | **Cross-sectional Area ($m^2$)** | **Channel Power (MW)** | **Extractable Power (MW)** |
|---|---|---|---|---|
| Annual Average | 1.6 | 73,200 | 116 | 17 |
| Maximum | 44.1 | 86,900 | 1398 | 210 |
| Minimum | - | 57,300 | - | - |

Note that average and maximum cross-section and power flux are not exactly coincident in time, so that average and maximum channel power is not a straight multiplication of power flux and area. This may be partially a phase error stemming from the use of the tidal range station for Anchorage in conjunction with tidal current data north of Cairn Point.

Figure 7 shows predicted channel power variations for a single day (February 10th, 2005).

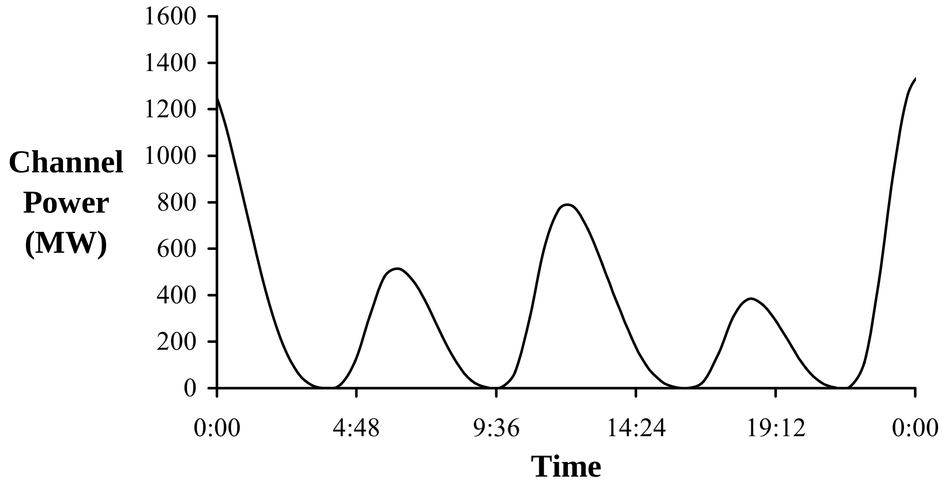



Figure 6 – Daily Channel Power Variation at Cairn Pt. (February 10th, 2005)

Figure 7 shows channel power for a 14-day tidal cycle. The variations in channel power due to the tidal cycle are apparent.

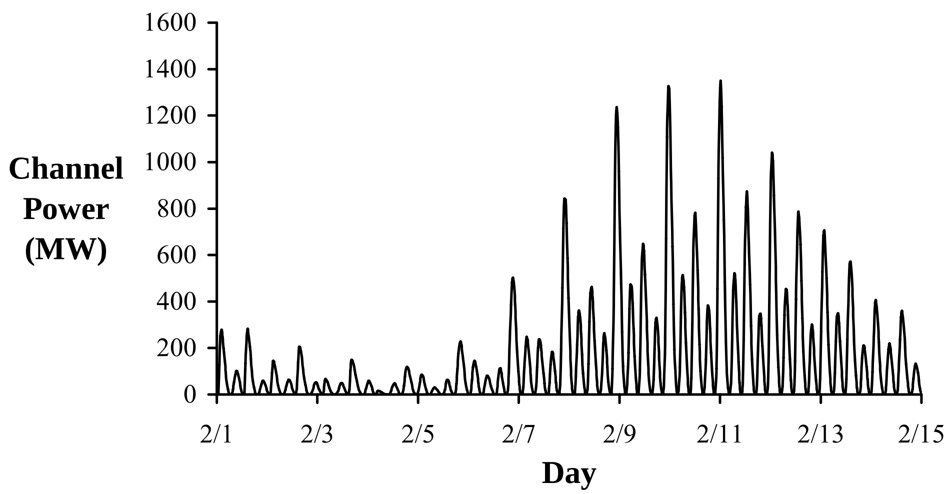



Figure 7 – Tidal Cycle Channel Power Variation at Cairn Pt. (February 1st-14th, 2005)

Figure 8 shows monthly average channel power over an entire year. The average channel power varies from month to month, with a maximum variation of 15%.

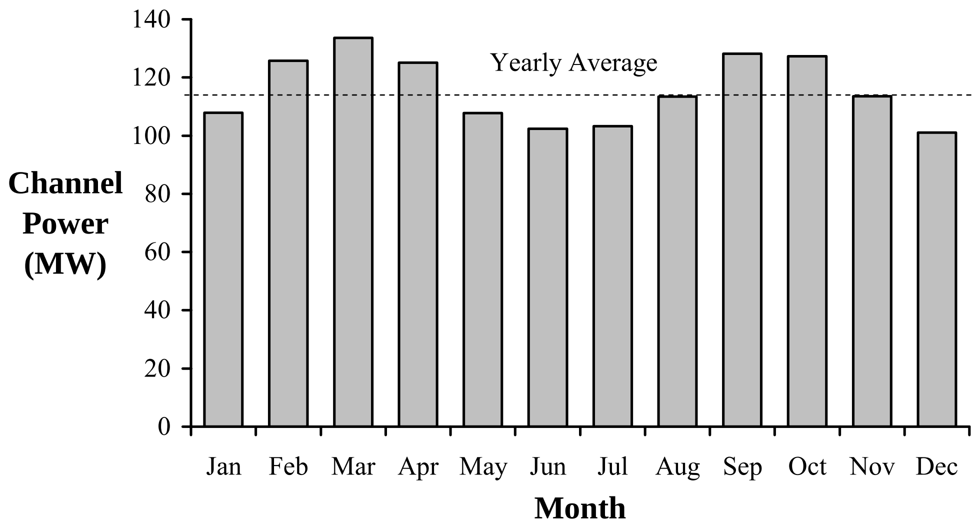



Figure 8 – Monthly Average Channel Power at Cairn Pt. (2005)

## 2.2. Grid Interconnection Options

The power that could be produced from a tidal stream is of little value if large capital outlays would be required to connect it to the electric grid. This barrier has delayed the development of wind power at some sites in the US, since the cost of the transmission lines to bring the power to market may be on the same order as the cost to construct the wind farm. Fortunately, this is not the case at Cairn Point.

Until recently Elmendorf AFB maintained its own power grid, separate from Anchorage Municipal Light and Power. Expertise should remain on-base to help coordinate interconnection of both the pilot and commercial TISEC plants. The maximum line voltage available for backhaul to Anchorage is currently 35kV, which would greatly limit the maximum power output of the array. It has been proposed that this line could be overbuilt to 115kV, allowing a maximum power of 120MW from an array [9]. While the cost to overbuild the line is not exorbitant, expansion of power transmission lines has historically been a hard sell to nearby landowners.

If the proposed Knik Arm Bridge is constructed, utilities would be routed along the bridge access road and across the bridge [11]. This could provide an alternative tie-in point for the power take-off, but this is not assumed for this feasibility study.

## 2.3. Nearby Port Facilities

If a turbine is far from a major port, both installation and maintenance costs may be prohibitive due to long mobilization times. Cairn Point is located about two miles from the Port of Anchorage. Port MacKenzie, while even closer to the proposed site, consists of little more than a dock and would currently be unsuitable for anything beyond light maintenance activities. Significant expansion to Port MacKenzie has been proposed, which could allow it to serve as a base for installation and major maintenance activities.

Figure 9 – Aerial Photograph of Port of Anchorage [5]

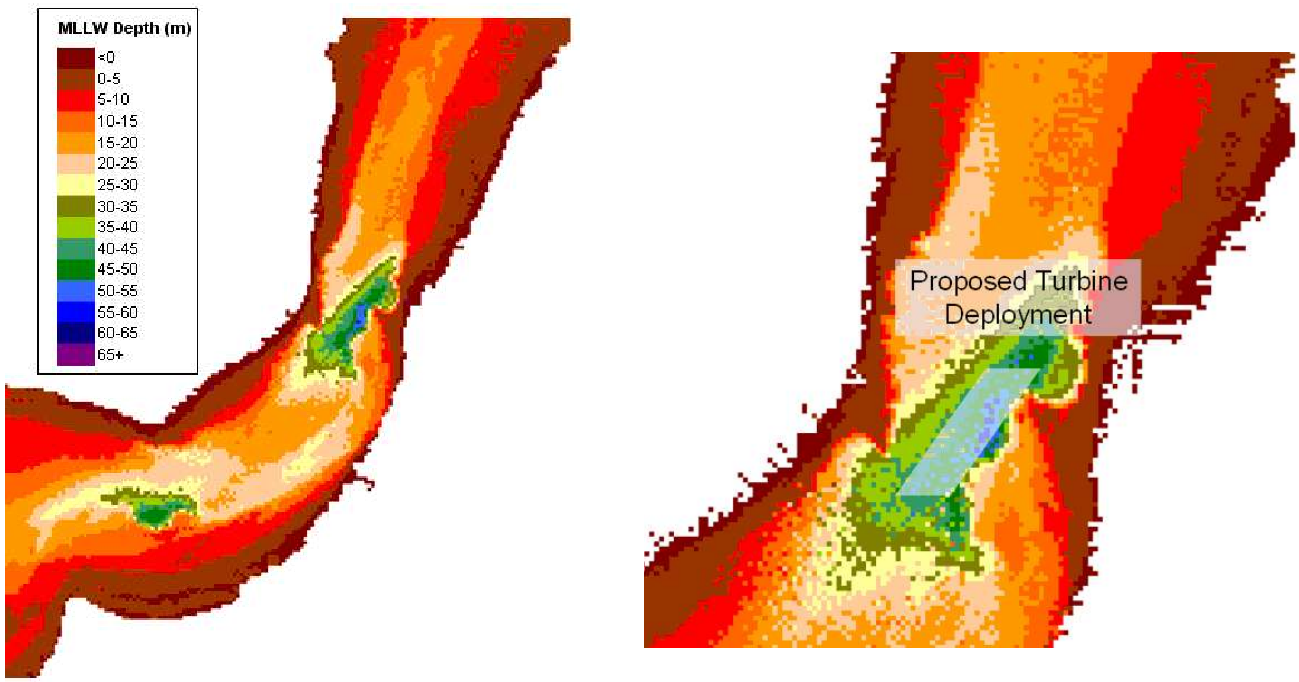
## 2.4. Bathymetry

Bathymetry[3] is an important determinant in the siting of turbines. In shallow water there may be insufficient surface and seabed clearance to install a turbine. This drives site selection towards deeper water sites. However, installation and maintenance costs increase

[3] Bathymetry is the oceanographic equivalent of topography.

with water depth. These two competing influences result in a range of depths where it is most practical to deploy a turbine.

Bathymetric data for Knik Arm was obtained from NOAA hydrographic surveys [10]. These data are presented in Figure 10 – all depths are mean lower low water (MLLW). The shaded box showing the detailed bathymetry in the region of Cairn Point indicates the probable site for turbine deployment.




Knik Arm Cairn Pt. Detail

Figure 10 – Knik Arm Bathymetry (10m data)

Bathymetric data confirms that the Cairn Pt. region has a channel of sufficient depth to support the installation of multiple rows of large diameter TISEC devices. It is worth noting that much of the rest of Knik Arm is unsuitably shallow for the deployment of any TISEC device. The only other deep water site is west of the Port of Anchorage and is in a major shipping lane. Substantial regions of water 15-25m deep exist, but, ice considerations (discussed further on) place significant limits on the deployment of even small diameter turbines in these waters.

Both sediment transport and geologic adjustments from the 1964 Good Friday earthquake continue to alter the bathymetry at the proposed turbine site. As part of the design work for the proposed Knik Arm Bridge, existing hydrographic surveys were analyzed to understand how Knik Arm has changed over the past sixty years [12]. One analysis transect, shown in Figure 11, runs the length of the deep water channel suitable for turbine deployment. Channel depth along the transect for each historical survey is given in Figure 12.

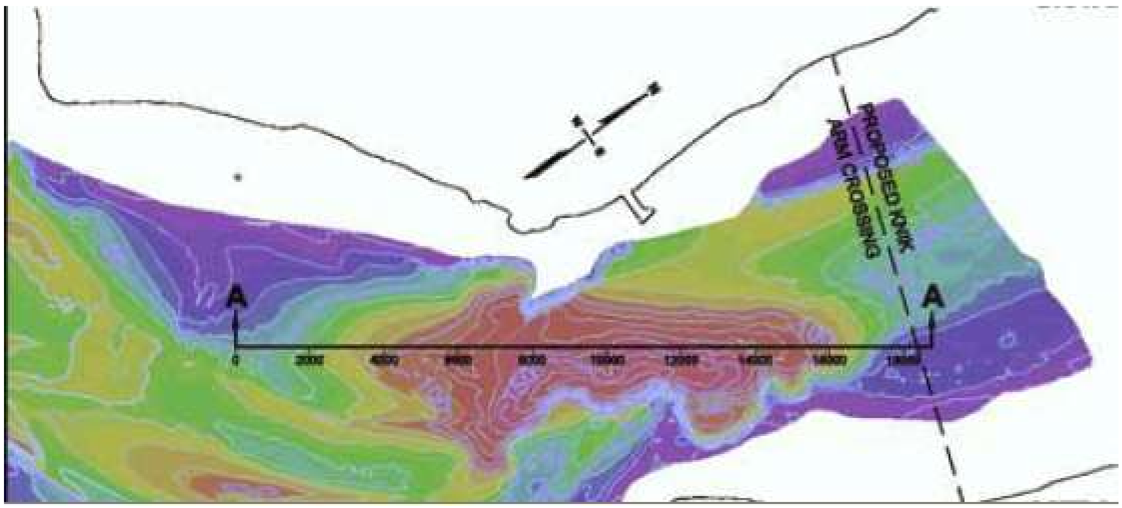



Figure 11 – Historical Survey Transect

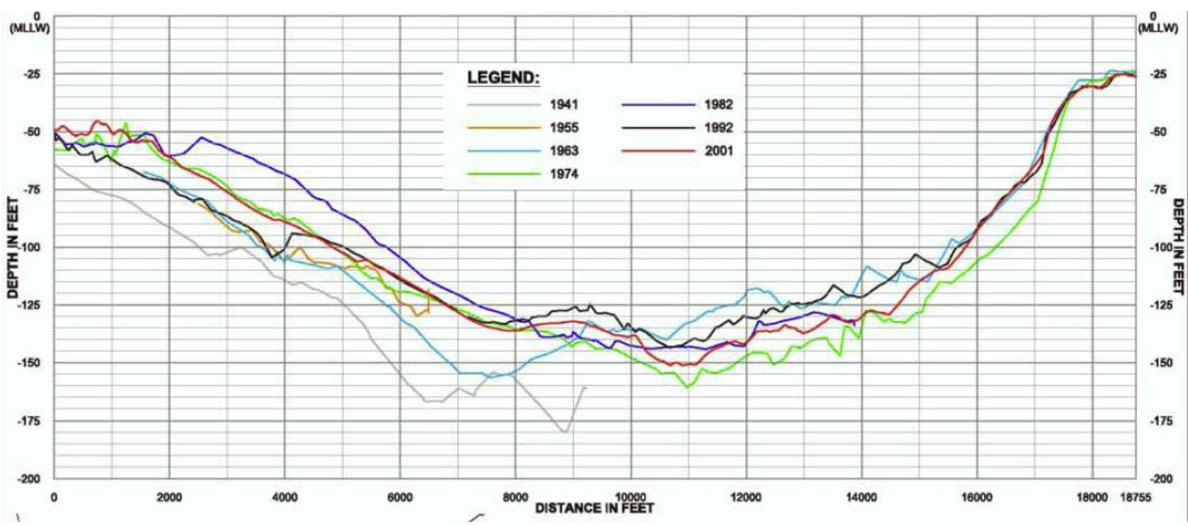



Figure 12 – Results of Historical Bathymetric Surveys

From the results of this study, it is clear that while the overall bathymetry at the site has been consistent since the quake, there are substantial local variations. For example, between the 1992 survey (black line) and 2001 survey (red line) the seabed surface dropped more than 3m in some places. An extrapolation of trends in seabed bathymetry is beyond the scope of this survey, but will be an important factor in the design of turbine foundations.

### 2.5. Seabed Composition

Geotechnical surveys for the proposed Knik Arm Bridge and general geotechnical surveys of Knik Arm characterize the seabed geology as 100' feet of dense, silty sand overlying hard, gravelly clay [13, 15]. There may also be a surface layer of a few feet of loose surface sand and sediments. Cobbles and boulders may be present on the seabed, especially near the eastern shore due to erosion of bordering bluffs. While the thin layer of loose surface sands may liquefy in the event of an earthquake, this is not expected to be an issue for the denser sand that would form the basis for the foundation support [15].

### 2.6. Navigational Clearance

Cairn Point does not currently accommodate very much marine traffic with the largest vessels restricted to shallow draft barges heading up Knik Arm. However, there has been a push to expand the capabilities of Port MacKenzie (northwest of Cairn Pt.) which could lead to increased use by deep draft vessels (including cruise ships). Since there is relatively little development on the west side of Knik Arm, expansion of the port is contingent on the approval of funds to construct the Knik Arm Bridge in the relatively shallow waters north of Cairn Point. The bridge transect is more than a mile north of the proposed turbine deployment area and its construction should not directly impact the siting or operation of a turbine array. However, in the case that deep draft vessels were to make use of Port MacKenzie, a navigational clearance of 15m from LAT (Lowest Astronomical Tide) would probably be required [16]. For the purposes of this report, 4m navigational clearance associated with shallow draft barges and small surface craft is assumed. However, this assumption is superseded by ice clearance requirements.

### 2.7. Other Site Specific Considerations

A number of site specific issues further influence the design of pilot and commercial arrays. Points and headlands introduce recirculating eddies into tidal streams. The shallow water off the eastern and western shores of Cairn Point induce significant eddies at ebb and flood tide. The size and strength of these eddies must be assessed prior to the deployment of a commercial array since the flood and ebb eddies on the eastern side of the channel potentially overlap with the deep water region suitable for turbine deployment. A representative image of expected eddy location is given in Figure 13. Note that the extent of the strong eddy region is unknown and would require further study to quantify.

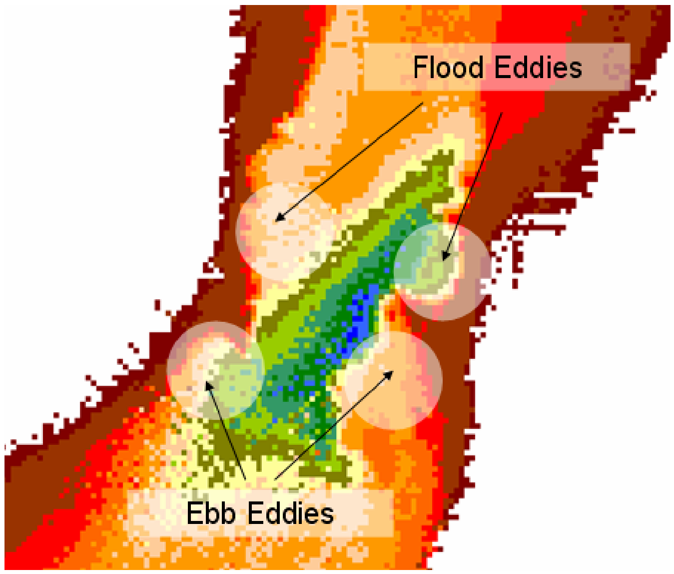



Figure 13 – Expected Location of Large-scale Eddies

Turbines should not be installed in eddies as the flow velocity will be much lower than in the undisturbed flow. Furthermore, extreme turbulence is likely to accelerate blade fatigue and reducing operating lifetime.

The proposed turbine deployment area is located between several other use areas associated with shipping and the operational of a circular antenna array at the AFB. Both Port of Anchorage and Port MacKenzie operating zone falls quite close to the proposed site, as does the shipping lane for Port MacKenzie. Existing use zones are shown superimposed on the bathymetric plot in Figure 14. A cursory inspection reveals that the deep water channel suitable for turbine deployment may be on the margins of these areas and installation of an array would not impact existing activities.

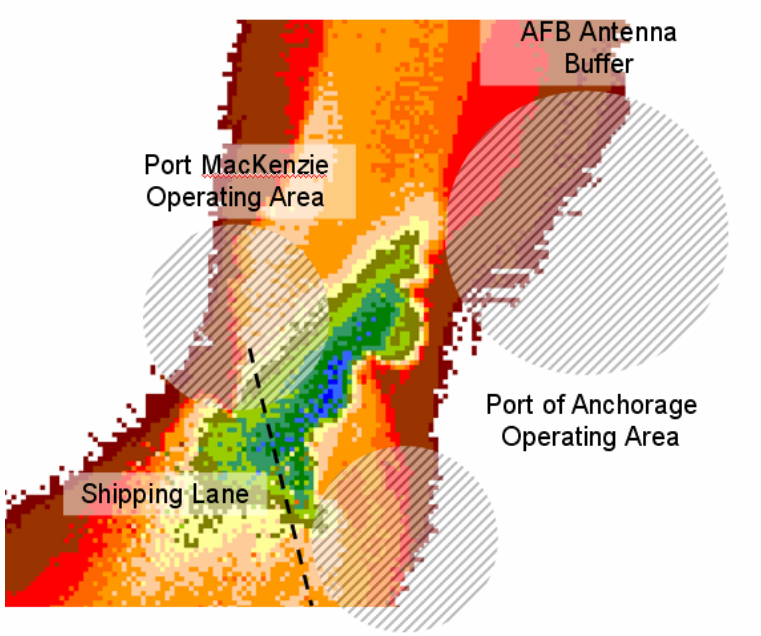



Figure 14 – Existing use zones in the vicinity of proposed TISEC array

Knik Arm is home to a number of protected species – including the endangered Beluga whale [11] and multiple species of salmon. Given the continuously declining numbers of Belugas in Knik Arm, it will be absolutely imperative to ensure that a pilot or commercial array of tidal turbines would not directly or indirectly impact their habitat. From discussions pertaining to the construction of the Knik Arm Bridge, the habitat of greatest concern is the shallow areas to either side of the deep water channel. Since the turbines can not be sited in these areas due to ice clearance restrictions, deployment may have less impact on Belugas than bridge construction. This issue must be addressed in-depth prior to construction of a pilot or commercial plant. Any study on turbine interaction should seek to leverage the extensive body of work generated from the design phase of the proposed Knik Arm Bridge. Beluga activity in Knik Arm is lowest from winter to mid-May which may indicate a construction window for turbine installation which would not be disruptive to Beluga.

Suspended sediment concentration is very high (10 g/L [13]) in the water in Knik Arm – most of which is thought to originate from Susitna River [11] in northern Knik Arm. For the purposes of turbine deployment, this is problematic for two reasons. First, the turbidity of the water will make visual inspection of the turbine by divers nearly impossible and potentially complicate installation activities. Second, the velocity reduction across the turbine and wake around the support structure will probably result in some sediment deposition. Since ebb tides are stronger than flood, this could, over time, result in a build-up in sediments to one side of the turbine and supports. The high level of sedimentation does, however, offer two benefits. First, the high turbidity of the water limits photoactive growth in Knik Arm, which should reduce bio-accumulation rates for turbines and support structures. Second, since the level of suspended sediment is so high, construction methods which disturb sediments may be more permissible in Knik Arm than at other sites considered as part of the EPRI study.

Guidelines for typical ice cover in Knik Arm [14] are:

- *Dec 1-15*: 70% coverage by new ice (10-30cm thick)
- *Dec 16-31*: 70% coverage by new ice (10-30cm thick)
- *Jan 1-15*: 70% coverage by first year ice (>30cm thick)
- *Jan 16-31*: 70% coverage by first year ice (>30cm thick)
- *Feb 1-15*: 70% coverage by first year ice (>30cm thick)
- *Feb 16-28*: 70% coverage by first year ice (>30cm thick)
- *March 1-15*: 60% coverage by first year ice (>30cm thick)
- *March 16-31*: 30% coverage by new ice (10-30cm thick)

This ice cover consists of several types of ice, including pack, beach, and frazil [13,14]. Of these, pack, beach, and frazil pose the greatest concern to turbine operation and deployment.

- *Pack Ice*: forms by direct freezing of seawater and floats on surface. Large irregular masses of pack ice may be found in the waters of Knik Arm. The thickness of this ice is well understood and not likely to exceed 2-3m.
- *Frazil Ice:* low density mass of weakly bonded ice crystals typically formed in turbulent waters. Slush-like consistency. Turbine blades sweeping through regions of frazil ice would experience uneven, cyclic loads. The maximum depth to which frazil ice is present is not well documented.
- *Beach Ice:* massive blocks of ice and sediment formed by successive formation and consolidation action on the shallower upper shores of Knik Arm. Beach ice has

been reported to be up to 12m thick [14] and may be entrained along with pack ice. Since beach ice is difficult to distinguish from pack ice on the surface, it has been assumed that its freeboard elevation is near waterline and that 12m overhead clearance will be necessary for turbines installed at Cairn Point. Blocks of beach ice have significant mass and strength and are known to pose a shipping hazard. During spring break-up, direct impact by beach ice being carried along with a high current flow has the potential to damage or destroy turbine blades and any surface piercing support structure.

Ice considerations drive two design constraints. First, the turbine must be fully submerged, with no surface piercing structure. Second, access to the turbine site for installation and maintenance will probably not be possible from November until the ice breaks up in March.

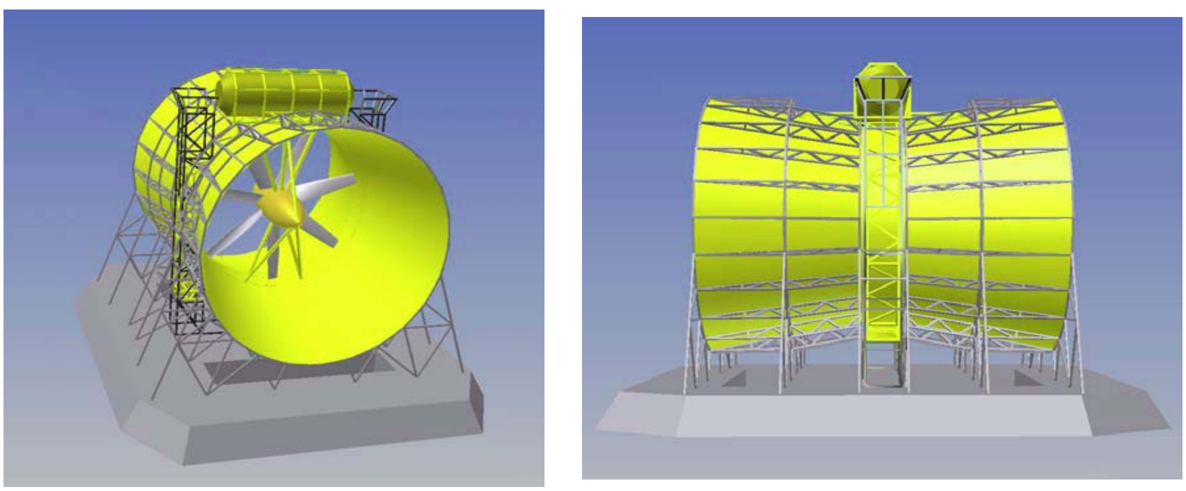
Knik Arm is an active seismic zone and ground response and support structure resonance must be part of any detailed design. The strongest recorded North American earthquake on record occurred on Good Friday in 1964, centered between Anchorage and Valdez in Prince William Sound. The duration of the earthquake – several minutes (which varies significantly from California earthquakes with durations typically of less than a minute [11]) resulted in widespread damage to the Anchorage area and significantly altered several estuary features. Provided the seabed at Cairn Point is comparable to denser silty sands encountered at the proposed Knik Arm Bridge transect, soil liquefaction should not occur during a major seismic event [15]. However, during detailed design, any pile foundations should be designed to avoid resonant behavior during a major earthquake.

There is potentially unexploded ordnance (UXO) at Cairn Point due to an old military artillery range (Susitna Gunnery). Ordnance was fired from the Port MacKenzie side to the Anchorage side, placing Cairn Point within the firing fan. As a result, there is a possibility (though low) of unexploded ordnance on the seabed at the turbine deployment site. While this could present a construction issue, methods developed for dealing with the problem further north at the proposed site of the Knik Arm Bridge should be applicable at Cairn Point [11].

# 3. Lunar Energy

## 3.1. Device Description

The Lunar Energy TISEC device, known as the Rotech Tidal Turbine (RTT) (Figure 15), 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 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 tidal stream. While no detailed cost analysis was carried out for this device, EPRI used the geometry of the RTT 2000 to establish parameters for this project to address critical engineering issues. Ballast and structural reinforcements were scaled to meet local load conditions. Since the sandy seabed at Cairn Point is particularly susceptible to scour, scour protection will be required and is expected to materially impact the cost of electricity. Figure 15 shows an illustration of the prototype turbine. The gravity foundation is 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 tubular steel frame.



3-D View Side View

Figure 15 - 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. As shown in Figure 16, this arrangement allows for relatively simple removal and replacement of the power conversion system and simplifies O&M procedures.

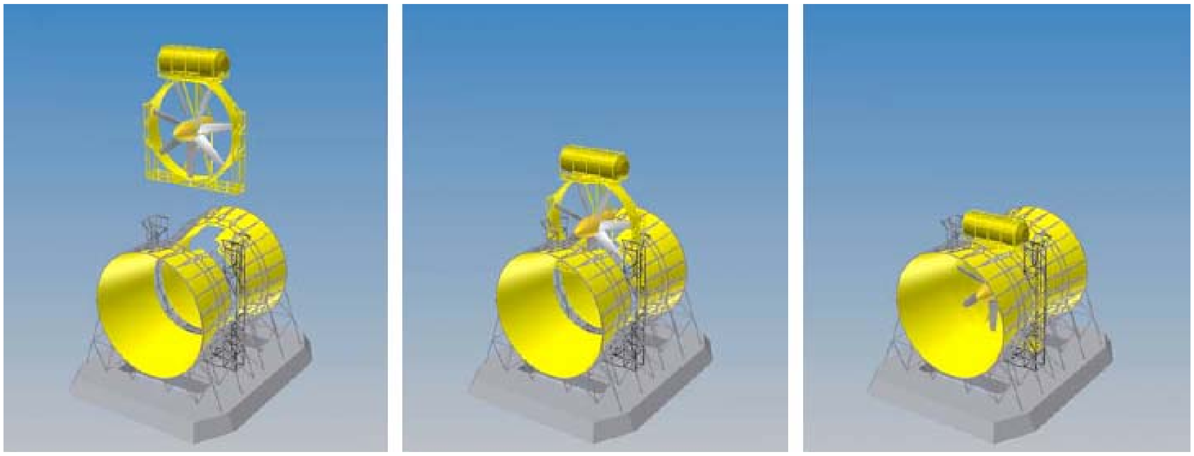


Figure 16 - Insertion and removal of cassette

Based on the site design velocity (maximum occurring velocity) the basic design weight breakdown was scaled to ensure structural integrity and device stability. Table 4 contains the key properties for this site-design.

Table 4 – RTT 2000 Specifications optimized for Cairn Point site

| | |
|---|---|
| **Generic Device Specs** | |
| Power Conversion | Hydraulic |
| Electrical Output | Synchronized with Grid |
| Foundation | Gravity Base |
| **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 | 780 tons |
| Ballast | 934 tons |
| Total installed dry-weight | 1,714 tons |
| **Power** | |
| Cut-in speed | 1.0 m/s |
| Rated speed | 2.55 m/s |
| Rated Power | 1,082kW |
| Capacity Factor | 15% |
| Availability | 95% |
| Transmission losses | 2% |
| Net annual generation at bus bar at site | 1,439 MWh |

### 3.2. 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 1/10$^{th}$ power law.

The overall efficiency of the Lunar Energy RTT 2000 is the product of rotor efficiency, gearbox efficiency and generator efficiency. Figure 17 shows the efficiency of the various elements as a function of rated speed as provided by Lunar Energy. The overall device efficiency is given by:

$$\eta_{Device} = \eta_{Turbine}\eta_{Hydraulics}\eta_{Generator}$$

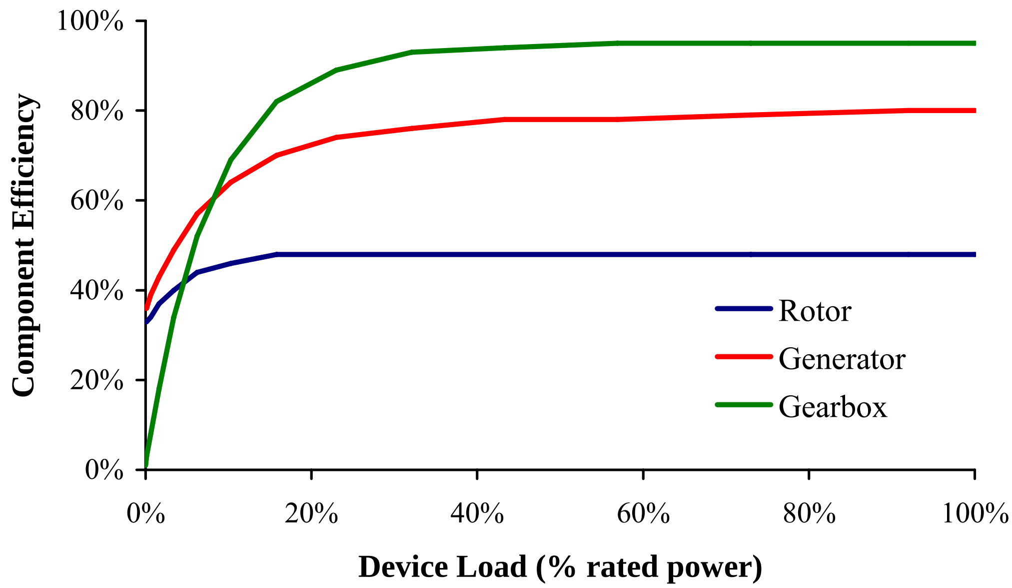



Figure 17 - Efficiency curves of Power Conversion System

Based on this efficiency chain and the exposed duct inlet area the device performance in a given site can be obtained. For a commercial array, the mean installation depth for an RTT 2000 would be 48 m. Table 5 shows the energy calculations at the Cairn Point site. The following definitions are used:

- *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 power extracted by the device
- *PTO Efficiency* shows the efficiency of the power take-off (generator, hydraulics)

Annual average values for velocity and power generated are given in the last row of the table.

Figure 18 – Device Performance at Cairn Point

| Flow Velocity (m/s) | % Cases | % Load | Power Flux (kW/m$^2$) | Flow Power (kW) | Extracted Power (kW) | PTO Efficiency | Electric Power (kW) |
|---|---|---|---|---|---|---|---|
| 0.09 | 7.07% | 0.0% | 0.00 | 0 | 0 | 0% | 0 |
| 0.28 | 8.28% | 0.1% | 0.01 | 4 | 0 | 1% | 0 |
| 0.46 | 8.28% | 0.6% | 0.05 | 17 | 0 | 3% | 0 |
| 0.64 | 8.74% | 1.6% | 0.14 | 47 | 0 | 8% | 0 |
| 0.83 | 9.58% | 3.4% | 0.29 | 100 | 0 | 17% | 0 |
| 1.01 | 10.54% | 6.2% | 0.53 | 183 | 0 | 29% | 0 |
| 1.19 | 9.17% | 10.3% | 0.87 | 302 | 140 | 44% | 62 |
| 1.38 | 8.51% | 15.8% | 1.34 | 464 | 221 | 57% | 127 |
| 1.56 | 7.64% | 23.0% | 1.95 | 676 | 325 | 66% | 216 |
| 1.75 | 6.01% | 32.1% | 2.72 | 943 | 455 | 71% | 323 |
| 1.93 | 4.27% | 43.3% | 3.68 | 1274 | 615 | 73% | 450 |
| 2.11 | 3.09% | 56.9% | 4.83 | 1673 | 809 | 74% | 600 |
| 2.30 | 2.42% | 73.0% | 6.20 | 2149 | 1039 | 75% | 780 |
| 2.48 | 1.98% | 92.0% | 7.82 | 2707 | 1310 | 76% | 996 |
| 2.66 | 1.53% | 100.0% | 9.68 | 3354 | 1424 | 76% | 1082 |
| 2.85 | 1.11% | 100.0% | 11.83 | 4097 | 1424 | 76% | 1082 |
| 3.03 | 0.87% | 100.0% | 14.27 | 4942 | 1424 | 76% | 1082 |
| 3.22 | 0.46% | 100.0% | 17.02 | 5896 | 1424 | 76% | 1082 |
| 3.40 | 0.30% | 100.0% | 20.11 | 6966 | 1424 | 76% | 1082 |
| 3.58 | 0.11% | 100.0% | 23.55 | 8158 | 1424 | 76% | 1082 |
| **Average** 1.14 | | | 1.79 | 620 | 249 | | 176 |

Comparison of flow power to electric power generated is shown in Figure 19. Note particularly the cut-in speed (below which no power is generated) and rated speed (above which the power generated is constant).

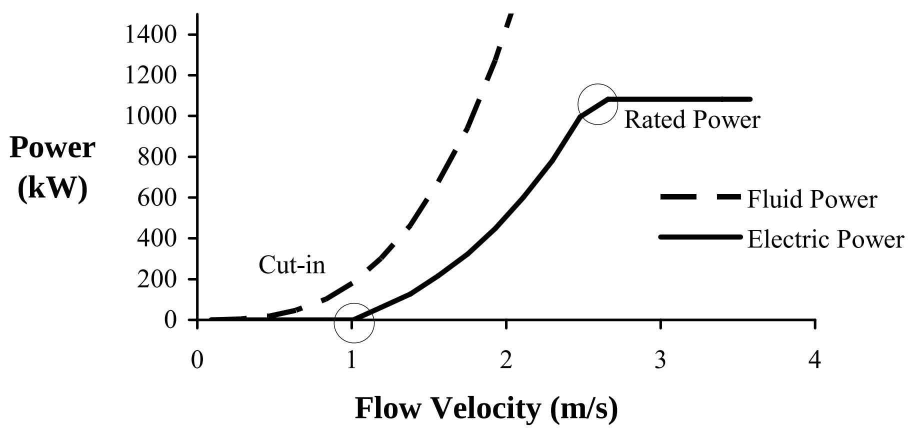



Figure 19 – Comparison of Flow and Electric Power at Cairn Pt.

The electrical output of the turbine compared to the fluid power crossing the swept area of the rotor is given in Figure 20, for a representative day. The effect of truncating turbine output at rated conditions is obvious.

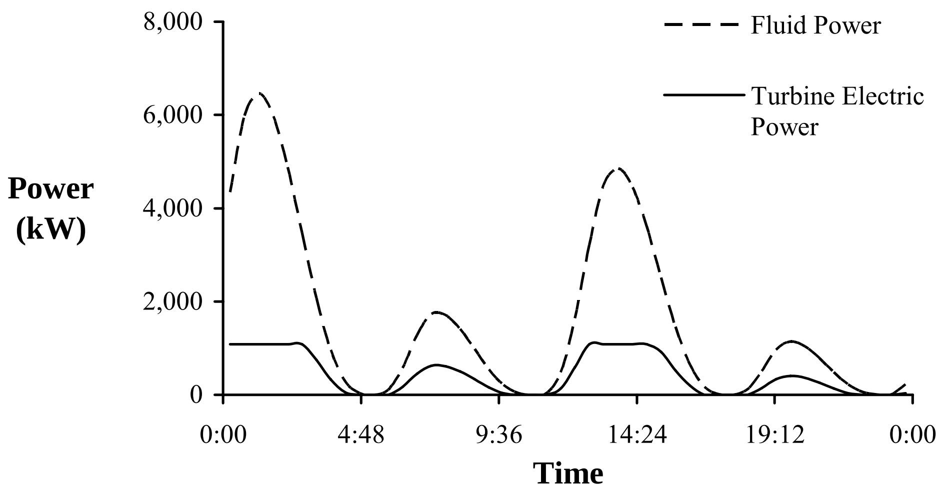



Figure 20 – Daily Variation of Flow and Electric Power at Cairn Pt. (February $12^{th}$, 2005)

## 3.3. Lunar Energy Device Evolution

Lunar Energy's current design effort is focused on value engineering. Whereas the prototype design is in its final phase, the commercial units are expected to benefit from several potential areas of cost reduction, 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%, resulting in significant cost savings.

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.

Lunar Energy also provided EPRI with information on their redesigned prototype (Mark II) of the RTT 2000. 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 (e.g. low-cost aggregate) 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. A representative picture of this design is shown in Figure 21.

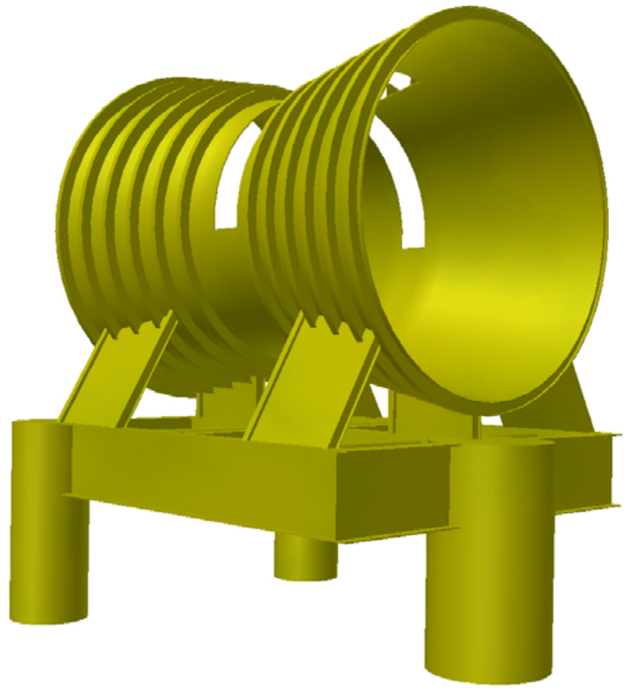


Figure 21 - RTT 2000 Mark II Structural Design

### 3.4. Installation of Lunar Energy Module

The largest crane barges on the US west coast have capacities of up to 600 tons. At more than 2000 tons, Lunar Energy's RTT 2000 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 it was assumed that the device is deployed in two pieces, the concrete base and the duct. Deployment procedure is outlined below.

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 its deployment location and the same strand jacks are used to lower the base to the prepared seabed.

Both the duct and 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 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. Given the sandy nature of the seabed in Knik Arm, scour protection will probably be necessary to ensure the long-term integrity of an installed device.

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 22 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 22 - 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 important for subsea installations is the remote operated vehicle (ROV). These systems have increasingly replaced 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. Pictures of an ROV in operation are shown in Figure 23.

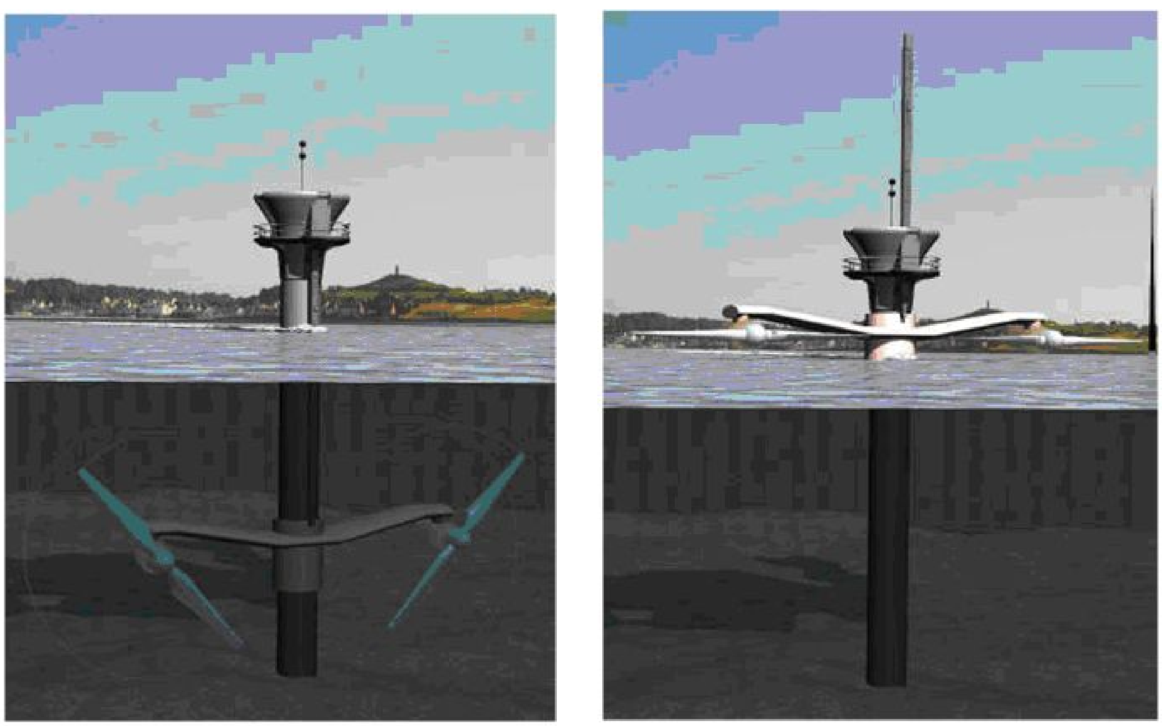
Figure 23 – Two-arm ROV (courtesy of Schilling Robotics www.ssalliance.com)

### 3.5. 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 four years and undergoes a complete overhaul after which it is ready to operate for another four 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 RTT 2000 has a L90 life of five years (meaning that after five years 90% of all devices are still operating without any issues). Given a typical Weibull failure distribution it was deemed that a four-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, with casings directly exposed 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$^{o}$ at slack water to accommodate bi-directional tides without a separate yaw control mechanism. This device is illustrated in Figure 24.



Operation Maintenance

Figure 24 – MCT SeaGen (courtesy of MCT)

## 4.1. Device Performance

Given a velocity distribution for a site, the calculation of extracted and electrical power is discussed in [4]. Site surface velocity distributions have been adjusted to hub height velocity assuming a 1/10th power law, consistent with turbulent flow.

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

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

The efficiency of the gearbox and generator (together termed balance of system efficiency) is a function of the load on the turbine (% load). Power take off (PTO) efficiency is assumed to follow the same form as for a conventional wind turbine drive train – which is approximated by

$$\eta_{PTO} = 0.8337e^{0.1467(\%\,\mathrm{Load})} - 0.7426e^{-33.89(\%\,\mathrm{Load})} \quad [17]$$

This function is capped at 94% - the product of maximum gearbox and generator efficiency.

Performance of the turbine over a range of flow velocities is given in Table 5. The turbine is assumed to be installed at a depth of 55m (MLLW reference), consistent with the design of the commercial plant discussed in Chapter 7. The following definitions are used:

- *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 power extracted by the device
- *PTO Efficiency* shows the efficiency of the power take-off (generator, hydraulics)

Annual average values for velocity and power generated are given in the last row of the table.

Table 5 – Device Performance at Cairn Point

| Flow Velocity (m/s) | % Cases | % Load | Power Flux ($kW/m^2$) | Flow Power (kW) | Extracted Power (kW) | PTO Efficiency | Electric Power (kW) |
|---|---|---|---|---|---|---|---|
| 0.09 | 7.07% | 0.0% | 0.00 | 0 | 0 | 9.38% | 0 |
| 0.27 | 8.28% | 0.3% | 0.01 | 5 | 0 | 16.13% | 0 |
| 0.45 | 8.28% | 1.3% | 0.05 | 24 | 0 | 36.54% | 0 |
| 0.63 | 8.74% | 3.7% | 0.13 | 66 | 0 | 62.66% | 0 |
| 0.82 | 9.58% | 7.9% | 0.28 | 141 | 64 | 79.18% | 50 |
| 1.00 | 10.54% | 14.4% | 0.51 | 258 | 116 | 84.58% | 98 |
| 1.18 | 9.17% | 23.7% | 0.84 | 425 | 191 | 86.30% | 165 |
| 1.36 | 8.51% | 36.4% | 1.28 | 654 | 294 | 87.95% | 259 |
| 1.54 | 7.64% | 53.1% | 1.87 | 951 | 428 | 90.12% | 386 |
| 1.72 | 6.01% | 74.1% | 2.61 | 1328 | 598 | 92.94% | 555 |
| 1.90 | 4.27% | 100.0% | 3.52 | 1793 | 807 | 94.08% | 759 |
| 2.08 | 3.09% | 100.0% | 4.63 | 2356 | 807 | 94.08% | 759 |
| 2.26 | 2.42% | 100.0% | 5.95 | 3026 | 807 | 94.08% | 759 |
| 2.45 | 1.98% | 100.0% | 7.49 | 3811 | 807 | 94.08% | 759 |
| 2.63 | 1.53% | 100.0% | 9.28 | 4723 | 807 | 94.08% | 759 |
| 2.81 | 1.11% | 100.0% | 11.33 | 5769 | 807 | 94.08% | 759 |
| 2.99 | 0.87% | 100.0% | 13.67 | 6959 | 807 | 94.08% | 759 |
| 3.17 | 0.46% | 100.0% | 16.31 | 8302 | 807 | 94.08% | 759 |
| 3.35 | 0.30% | 100.0% | 19.27 | 9808 | 807 | 94.08% | 759 |
| 3.53 | 0.11% | 100.0% | 22.57 | 11487 | 807 | 94.08% | 759 |
| **Average** 1.13 | | | 1.72 | 873 | 260 | | 238 |

A comparison of flow power to electric power generated is shown in Figure 25. Note particularly the cut-in speed (below which no power is generated) and rated speed (above which the power generated is constant).

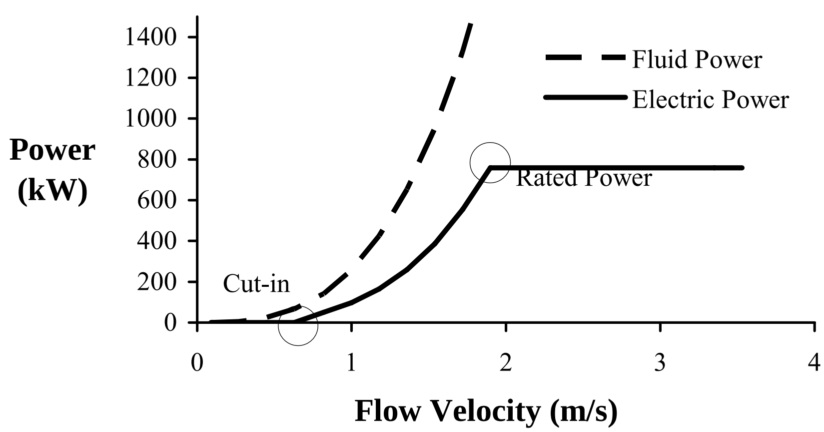



Figure 25 – Comparison of Flow and Electric Power at Cairn Point

The electrical output of the turbine compared to the fluid power crossing the swept area of the rotor is given in Figure 26, for a representative day. The effect of truncating turbine output at rated conditions is obvious.

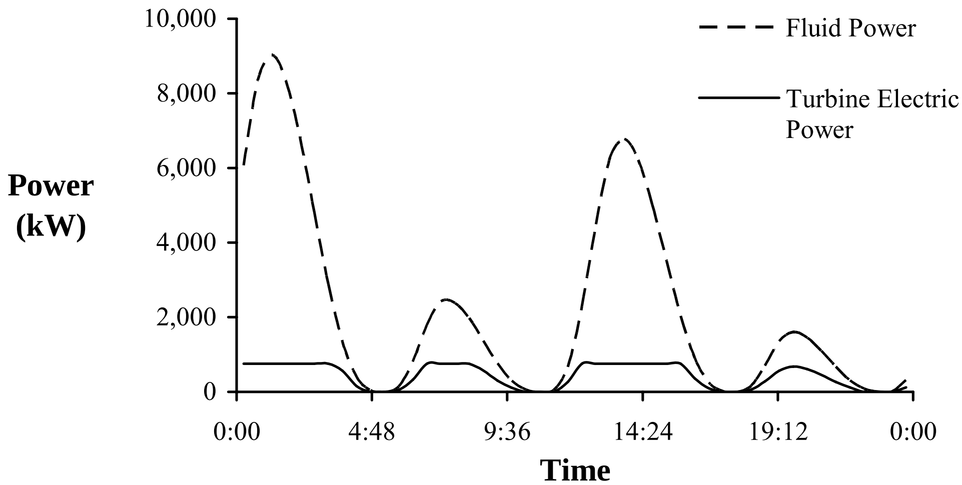



Figure 26 – Daily Variation of Flow and Electric Power at Cairn Pt. (February 12th, 2005)

### 4.2. 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. Please note the water depth of 30m, which is not representative of the commercial plant. However, since the submerged MCT design is purely conceptual, 30m installation for the SeaGen was chosen as a baseline cost. The assumption is that fully submerged, deeper water devices would have similar capital costs.

Table 6 – SeaGen Device Specification for Target Site

| | |
|---|---|
| **Generic Device Specs** | |
| Speed Increaser | Planetary gear box |
| Electrical Output | Synchronized to grid |
| Foundation | Monopile drilled or driven into consolidated sediment |
| Water Depth | 30m |
| **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 | 220 t |
| Cross Arm | 78 t |
| Total steel weight | 298 t |
| **Performance** | |
| Cut-in speed | 0.7 m/s |
| Rated speed (optimized to site) | 1.90 m/s |
| Rated Electric Power | 759 kW |
| Capacity Factor | 29% |
| Availability | 95% |
| Transmission losses | 2% |
| Net annual generation at bus bar | 1941 MWh |

The optimized rated speed for the site is slightly lower than MCT would typical rate a SeaGen.

## 4.3. MCT Device Evolution

MCT has been experimenting with a 300kW single rotor test rig, SeaFlow (Figure 27), near Lynmouth since 2003. 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. 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 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. Within the next year, SeaFlow should be decommissioned [19].

Operation

Maintenance

Figure 27 – MCT SeaFlow Test Unit (courtesy of MCT)

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 the one shown in Figure 24. This is the device configuration (with an 18m diameter rotor) that has been adopted for the pilot plant.

This configuration is not necessarily suitable for all sites for two reasons. First, deployment in deep water would be difficult and expensive. At a minimum there is significantly more uncertainty in installation costs. Second, surface piercing turbines may incompatible with tidal channels with shipping traffic. Depending on the authorities involved, installation of surface piercing turbines may be limited to the periphery of shipping channels or disallowed entirely.

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 28 shows a conceptual illustration of such a design.

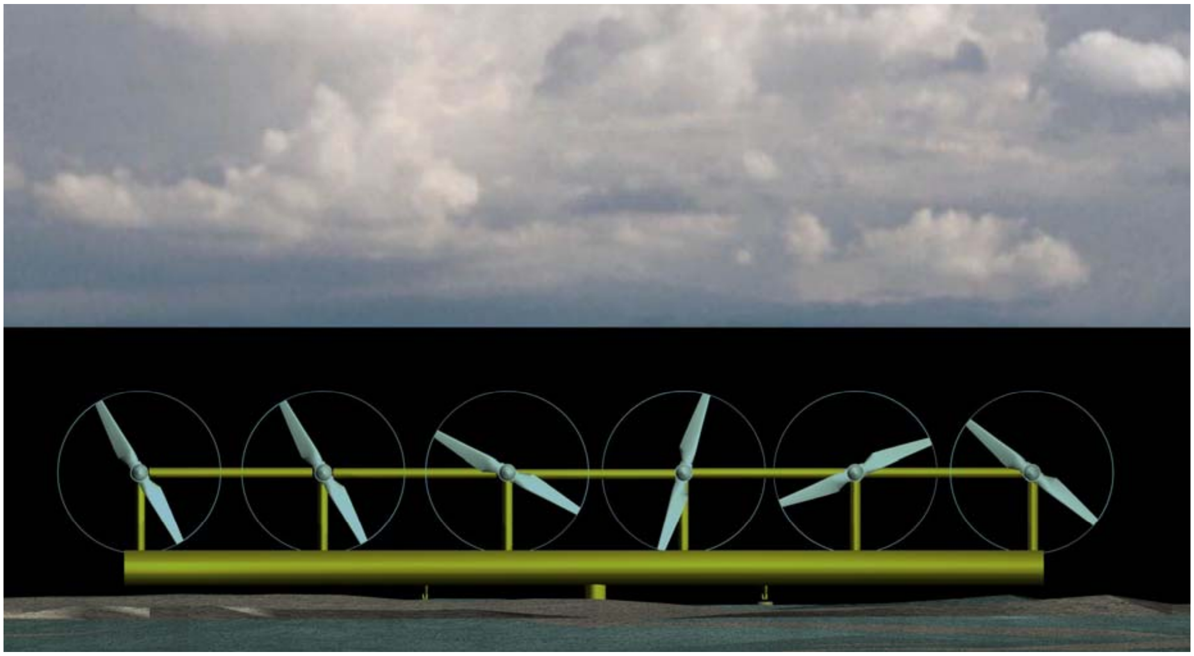


Figure 28 - Conceptual MCT deep water configuration (courtesy of MCT)

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.

## 4.4. Monopile Foundations

The MCT SeaGen is secured to the seabed using monopile foundation. Figure 29 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 [23].

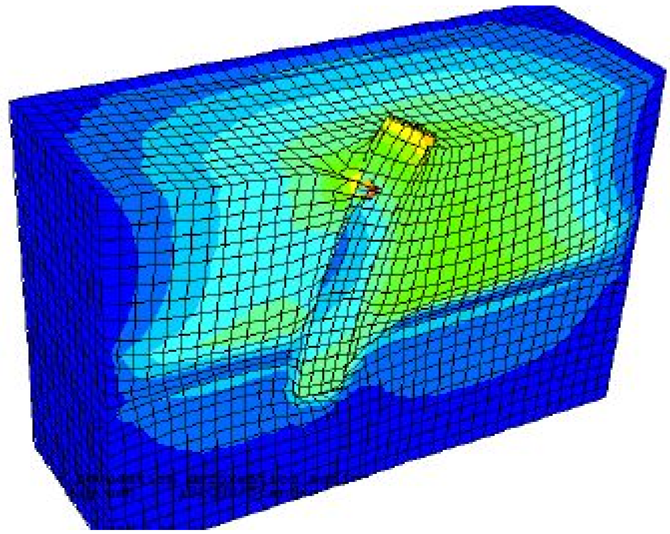


Figure 29 - Simulation of pile-soil interaction subject to lateral load [22]

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 Cairn Point, the heavily consolidated sand seabed is modeled as bedrock with 10m of sediment overburden.

Figure 14 shows the pile weight as a function of design velocity (the maximum occurring fluid velocity at the site) and soil conditions. 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 significant deviation from EPRI's base model.

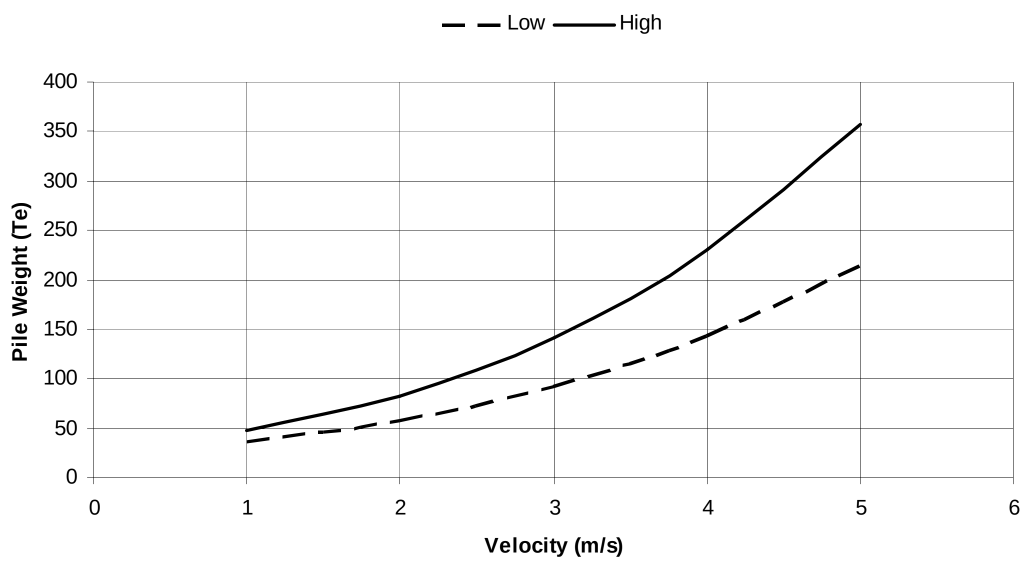



Figure 30 - Pile Weight as a function of design velocity for different sediment types

## 4.5. 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 jack-up barges to deploy offshore wind turbine foundations. Jack-up barges operate as follows [18]:

- Barge is towed into position with jack-up legs (4-8) raised
- During period of slack water, legs are lowered to seabed and forces on each leg are equalized. Mats built into the bottom of the legs reduce scour potential. If legs are lowered in high currents they may be damaged.
- Barge jacked up out of water. Platform is now stable and does not require additional mooring to maintain position in high currents.
- At the completion of the project, this process is reversed. Water jetting may be required to free the legs from certain types of seabeds (e.g. consolidated clay).

The following outline (Figure 31) shows the installation of a pile in bedrock from a jack-up barge.

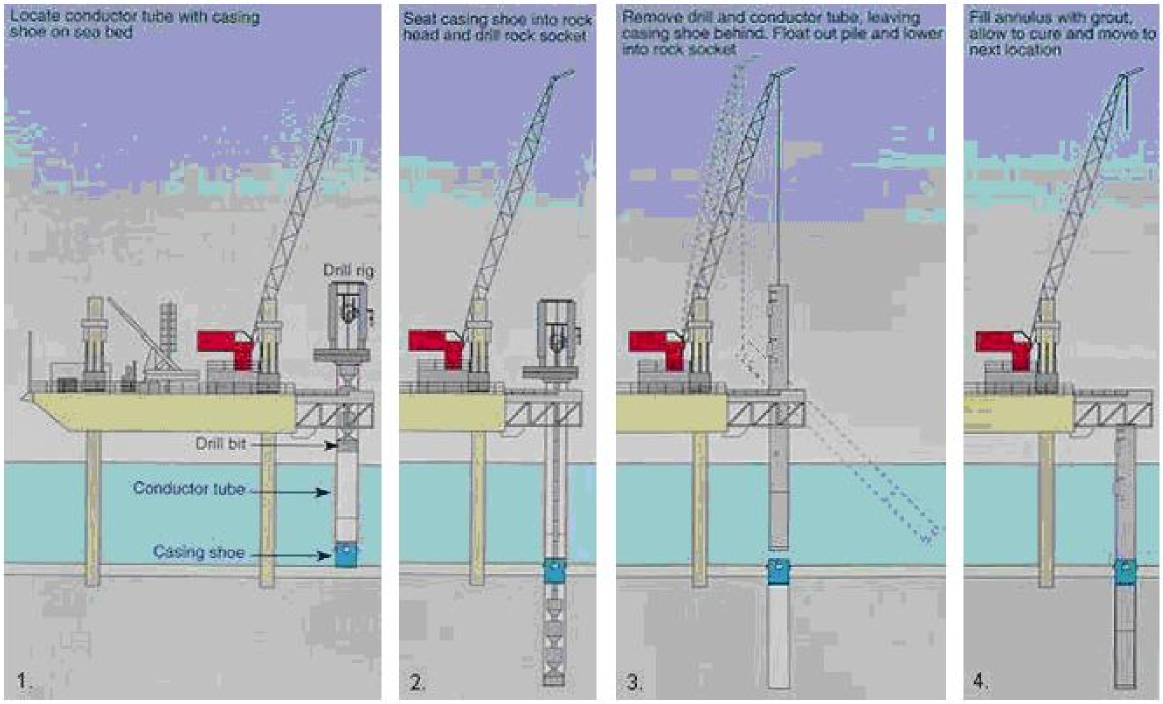



Figure 31 – Pile Installed in Bedrock (courtesy of Seacore Ltd.)

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 barges were found on the US west coast for the San Francisco, Washington and Alaska sites. In addition to the expense of mobilizing equipment from the Gulf of Mexico, jack-up barges are six times more likely to suffer serious damage or loss during relocation or transit than while in operation on site. As a result, EPRI decided to investigate alternatives.

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 large diameter 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 from about 30 tons all the way 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 vibratory hammers. Figure 32 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 32 - Manson Construction 600 ton Derrick Barge WOTAN operating offshore (courtesy of 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. This is in contrast to the fixed anchoring function of a jack-up barge leg.

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 (in a jack-up the length of the legs sets the limit on installation depth). 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 (e.g. a long follower between pile and hammer might be needed in deep water).

While monopile foundations are used extensively in US waterways for the construction of bridges and piers, installation of piles at Cairn Point would be under relatively challenging conditions. Several options exist for installing piles in hardpan, but it is important to stress that west coast marine construction companies have limited experience with such methods in deep, 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.

The force required to drive a large diameter pile into consolidated sand using a hydraulic hammer is quite high, and could involve mobilization of a suitably powerful hammer (>1,000,000 ft-lbs/blow) from Europe [20]. Driving a pile with this much force could induce significant fatigue and compromise structural integrity [19]. One potential installation procedure might consist of driving the pile to refusal[4], cleaning out the inside of the pile can, and driving again until a suitable depth has been reached. It may also be necessary to break up the sand around the pile perimeter using water jets if exterior skin friction leads to refusal [18, 20].

Since consolidated sand readily breaks up under water jetting, a combination of water jetting and vibratory hammering could be lower cost option to hammering alone since a suitable hammer could be mobilized at lower cost. Installation procedure would consist of water jetting to break up sediments, driving the pile, additional jetting, etc. Once the pile reaches specified depth, the hammer would act on the pile for a number of additional strikes, helping to reconsolidate the disrupted sediments [18]. Environmental regulations typically restrict the use of water jetting since it results in significant sediment disruption [20], but this may be less of a concern at Cairn Point given the high level of sedimentation natural occurring in the water.

A drilled pile installation would involve drilling into the consolidated sediments and stabilizing the walls of the drill hole with a metal sleeve. 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 [19] and equipment for drilling could be mobilized from Europe. For the purposes of this feasibility study, it is assumed that pile installation would be by drilling. A detailed design which incorporates the findings of a site-specific geotechnical survey will be required to determine the most feasible option.

### 4.6. Operational and Maintenance Activities

The guiding philosophy behind the MCT design is to provide low cost access to critical turbine systems. MCT feels this is especially important since the majority of unplanned interventions during the SeaFlow demonstration involved minor problems or false alarms [19]. Since then integrated lifting mechanism on the pile can lift the rotor and all subsystems out of the water, general maintenance activities do not require specialized ships or personnel (e.g. divers). Furthermore, for major repairs or scheduled refits, a barge can be positioned under the power train for relatively simple dismounting.

The overall design philosophy appears to be that the risks associated with long-term underwater operation are best offset by minimizing the cost of scheduled and unscheduled maintenance tasks. The only activities that could require use of divers or ROVs would be repairs to the lifting mechanism or inspection of the outer surface 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. Since Knik Arm experiences little wave action, maintenance intervention should be feasible year-round.

[4] Refusal is defined as 1000 blows/meter penetration or 800 blows for 0.3meter penetration.

Figure 33 - 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 which is a relatively low cost vessel. The barge can then convey the systems ashore for overhaul, repair or replacement. For the purpose of modeling O&M costs, 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 [19].

Barges for major maintenance activities could be mobilized from the Port of Anchorage or, if facilities are expanded, Port MacKenzie.

## 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. While there is little incremental cost in increasing turbine output voltage from 12 to 40kV (different step-up transformer required), above 40kV the cost of circuit breakers, interconnection, overvoltage protection, etc. increase dramatically. As a result, it is not feasible to step-up turbine generator voltage to transmission line voltage levels (115 kV) at the turbine. However, once commercial array cables have been brought ashore, they may be readily stepped up to transmission line voltages.

A generalized array interconnection scheme is shown in Figure 34. Power generated by a cluster, or transect, or turbines is aggregated and landed onshore where it feeds into the grid.

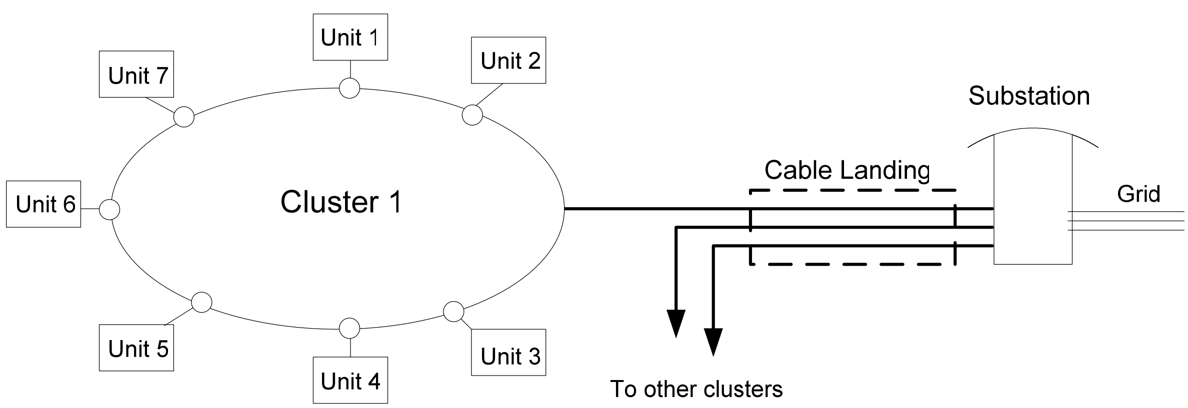



Figure 34 – Generalized interconnection for turbine array

A fiber optic 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.

For the surface piercing MCT SeaGen device (pilot plant), most electrical components are located inside the top of the monopole, where they are well protected and easily accessible for operation and maintenance activities. No sub sea connectors or junction boxes are required to interconnect the device to the electrical grid. A fully submersed MCT device (commercial plant) would not require a junction box either, but would require a J-tube to guide the subsea cable up to the power train.

### 5.1. 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. In order to make them suitable for in-ocean use, they are equipped with water-tight insulation and additional armor, which protects the cables from the harsh ocean environment and the high stress levels experienced during the cable laying operation. Submersible power cables are vulnerable to damage and need to be buried into soft sediments on the seabed or otherwise protected. 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 35 shows the cross-sections of armored XLPE insulated submersible cables.

Figure 35 – 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 must either be trenched into the seabed or shielded. In general, a trench is carved in the seabed, the cable is laid down, and 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 in consolidated sediments. 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.

## 5.2. 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, circuit breakers need to be installed to protect the grid infrastructure from system faults. VAR compensation and other measures might be introduced based on particular requirements. The peak power output of the plant will determine the appropriate grid interconnection voltage.

## 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 Cairn Point, 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 – particularly Beluga whales and salmon. This will require instrumentation for fish monitoring.
- Maximum experienced ice depth, particularly from frazil and beach ice.
- Inspection and maintenance activities not complicated by high degree of sedimentation.

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

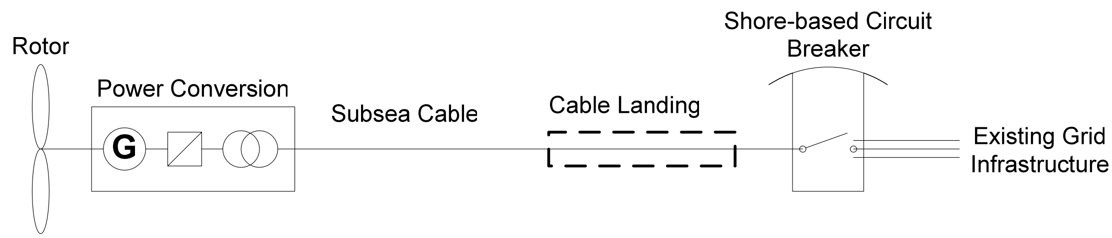



Figure 36 –Grid Interconnection for Single Device

Deployment of a pilot turbine at Cairn Point in the immediate term is complicated by site-specific conditions: ice conditions rule out surface piercing turbines, high levels of sedimentation rule out devices requiring significant diver intervention, and concern over Beluga whale impact may necessitate screening the rotor of any installed device. Both the Lunar Energy RTT 2000 and next-generation MCT turbine appear to be viable candidates for commercial scale deployment, but neither design is currently ready for pilot deployment in such a challenging environment. As such, tidal energy development at Cairn Point must await the successful demonstration of either a Lunar Energy or fully submerged MCT device in a more standard ocean environment. Once the device has been technically demonstrated elsewhere, a pilot test at Cairn Point would be able to focus on site specific issues: ice, sedimentation, and marine mammal impacts.

While the MCT SeaGen will share characteristics with the fully submerged next-generation technology (e.g. power train, pile foundation), a SeaGen probably can not be deployed at Cairn Point due to ice considerations. A monopile could probably be sufficiently reinforced (e.g. concrete reinforcement in inter-tidal zone, increased steel thickness) to shear pack ice, a direct impact from beach ice at peak current during the spring break-up could be catastrophic and would, in all likelihood, necessitate the installation of a highly site specific and over-designed foundation. The use of a conical deflector to reduce lateral loads from ice impact (a common ice load reducer for off-shore wind) would be challenging given the great tidal range at Cairn Point. In order to achieve the optimal pitch angle in a tidal channel with a 10m+ maximum range, the top of the conical deflect would extend multiple pile diameters from the actual pile. Since significant engineering effort would be required to install a surface-piercing pilot turbine, and most of it focused on aspects of design irrelevant for a fully submerged device, installation of a surface-piercing pilot in Cairn Point can not be recommended.

Taken that both devices are equally close to market, pilot designs for each turbine are addressed below.

Pilot power collection and grid interconnection details (summarized in Table 7) are identical for either turbine deployment. Power take-off cables would be trenched across the shallow tide plane on the eastern side of the channel and routed up the bluffs to interconnect with the electric grid on Elmendorf AFB. The cost for overland interconnection is for routing the power take-off cable from the bluffs to the interconnection point on Elmendorf. Additionally an infrastructure upgrade, consisting of a "substation" with a fusing circuit breaker, would be required at the interconnection point on Elmendorf AFB. Offshore interconnection costs are described further in Chapter 9.

Table 7 – Pilot Grid Interconnection

| | |
|---|---|
| **Offshore Cable** | |
| Cable Length | 950 m |
| Trench Length | 950 m |
| Sediment type along cable route | Loose to dense sand and clay |
| Offshore Interconnection Cost | $0.8M |
| **Onshore Cable** | |
| Cable Landing | On beach, trenched up to bluffs |
| Cable Length | TBD |
| Onshore Interconnection Cost | $0.6M |
| Infrastructure Upgrade Cost | $0.1M |

The deployment location for either a single fully submerged MCT or Lunar turbine is shown in Figure 37. The deployment location is chosen primarily to keep the turbine away from turbulent eddies forming off the headland. Note that the brown area on the right side of the deployment map is not dry ground, but rather shallow water and tide flats.

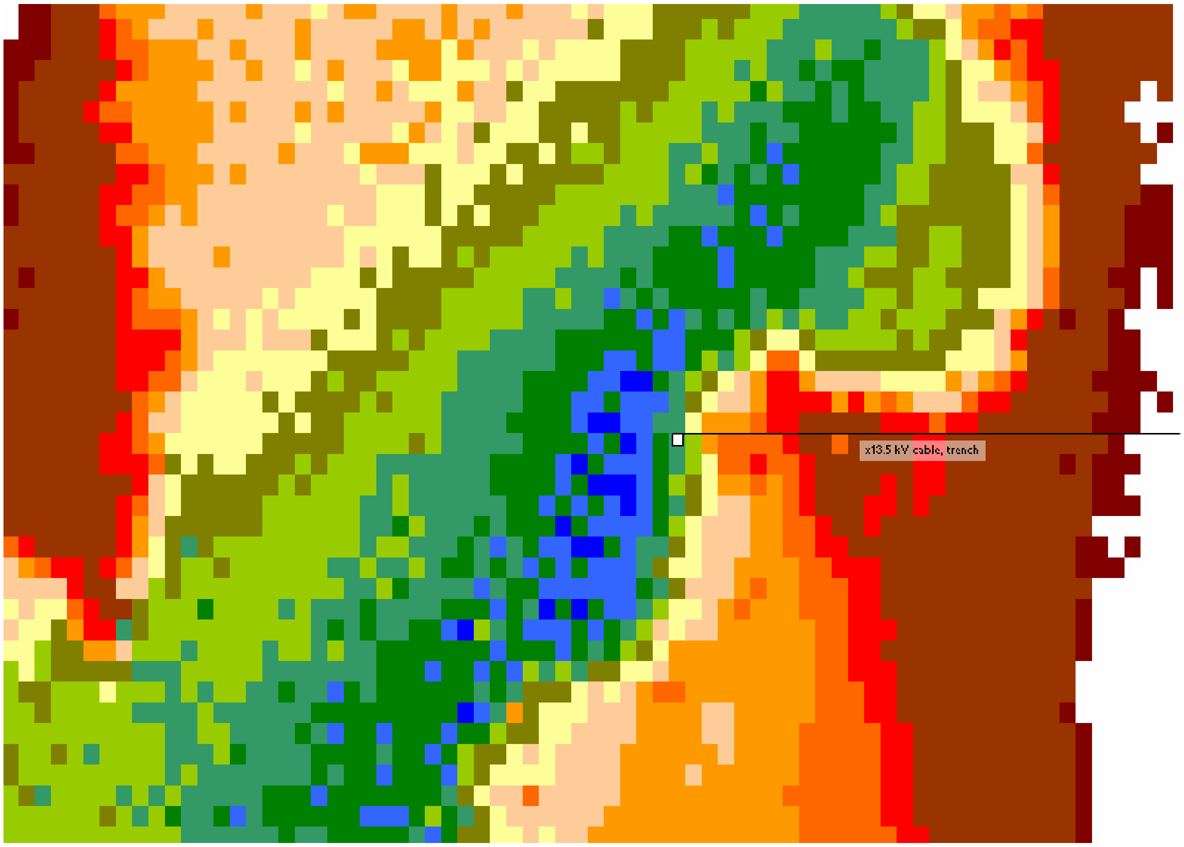



Figure 37 – Cairn Point Pilot Plant Layout

Assuming resource estimates are accurate for Cairn Point, the projected power output from the pilot turbine will be as discussed in Chapters 3 and 4.

## 7. System Design - Commercial Plant

The purpose of a commercial tidal plant is to generate cost competitive electricity for the grid. By installing a large number of turbines, economies of scale will decrease unit costs. The design of a commercial tidal array is driven by the following principles:

- Install turbines only in waters sufficiently deep to meet clearance requirements
- Install sufficient turbines to extract 15% of estimated resource
- Design turbine interconnection for redundancy to maximize array availability

For a commercial plant, both next-generation fully submerged MCT turbines and Lunar Energy turbines could be deployed in Knik Arm at Cairn Point. For design and cost estimate purposes it was assumed that the commercial MCT design uses the same rotor diameter and clearance requirements as the surface piercing SeaGen device.

The seasonal ice pack and Beluga whale activity may both place limits on the construction window for the site. Since Beluga activity is lowest from December to mid-May, construction would be least problematic from the standpoint of habitat impact during this time. However, since ice does not break up until mid-March, this would have the effect of limiting construction to a three month window (March to May). Given the relatively large number of turbines required for either commercial array, these restrictions could extend installation to several seasons. A detailed design phase would be required to fully quantify the operational window for construction activities.

### 7.1. Marine Current Turbines (MCT)

The principles discussed above lead to the array design shown in Figure 38. The array consists of sixty six (66) dual rotor, eighteen (18) meter diameter turbines arranged in seven (7) transects as designated by white rectangles (approximately to scale). The turbines will be fully submerged during operation. Turbine units are designated by white squares. Electrical infrastructure is shown in red. The design is described in more detail in the following sections.

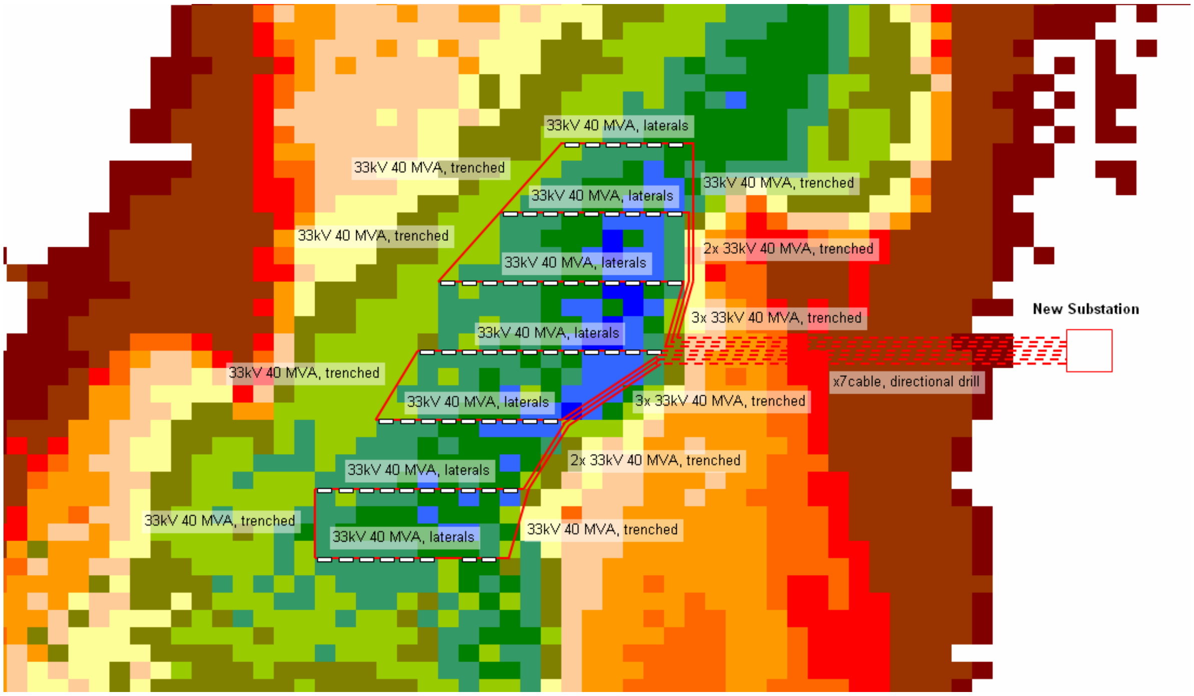



Figure 38 – Cairn Point Commercial Array Layout (MCT Array)

## Array Layout

The commercial array is assumed to consist of dual-rotor MCT turbines which will not be surface piercing. A conceptual design of a fully submerged MCT device is briefly discussed in Chapter 4. While straight-line transects are used here, it is worth remembering that with detailed site velocity data, arrays might be laid out along curves of constant power flux [19].

The layout of the turbine array is governed by the following spacing rules:

- 8m clearance between rotor tip and seabed to prevent cyclic blade stresses due to operation in the boundary layer.
- 12m clearance between rotor tip and surface to prevent catastrophic beach ice impact. This clearance should also place the turbine swept area below layers of frazil ice. A detailed study of ice depth in Knik Arm is needed to verify these assumptions.
- 9m clearance between each turbine to prevent lateral interaction between rotors [25].
- 180m (10 turbine diameters) downstream spacing between array transects to allow turbulent dissipation of rotor wake [27].

Note that these spacing rules have been developed based on analogues to wind-turbine array layouts, and require additional modeling and testing to verify.

Since the next-generation, fully submerged turbine is conceptual at this stage, the following assumptions have been made in for design and costing purposes:

- Fully submerged in operation
- Integrated lifting mechanism to bring turbine to surface for maintenance and inspection without use of specialty craft
- Monopile foundation
- Two rotors per supporting foundation (dual-rotor turbine)
- Equipment and installation costs for next-generation MCT turbines in-line with equipment and installation costs for SeaGen type device

Since both the lifting mechanism and support structure for a fully submerged turbine are entirely conceptual, this represents a significant uncertainty in the site assessment. A representative cross-section of a channel showing important clearances and dimensions for an MCT array is shown in Figure 39.

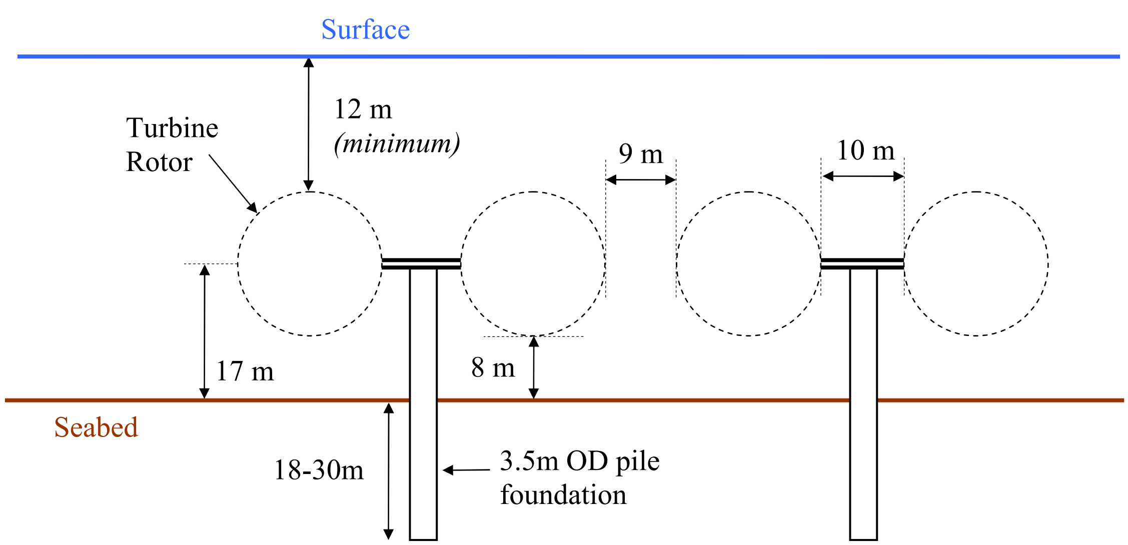



Figure 39 – Turbine Size and Spacing (MCT Array)

Array planning is an iterative process. First an array layout is chosen with a specified number of turbines. From this, the average turbine depth may be calculated and used to predict the power output of the array. Using the cost model discussed in Chapter 9, a rated speed is chosen to give the lowest cost of energy (COE). The power extracted by the array is then checked to determine that no more than 15% of the kinetic energy has been removed from the flow. If too much/not enough energy has been removed from the flow turbines are removed/added to the array layout and the process continues until a lowest COE array that extracts 15% of the kinetic energy from the flow has been designed. The number of turbines may be further reduced to limit the peak electric output to 120 MW, a general feed-in limit at 115kV.

The Cairn Point array consists of 66 dual-rotor turbines, arranged in seven transects of six to twelve turbines. These will, on average, extract 17 MW of power – 15% of the average channel power. The mean depth of water for installation is 46m. Installation depths range from 40 – 56m (MLLW reference) as shown in Figure 40.

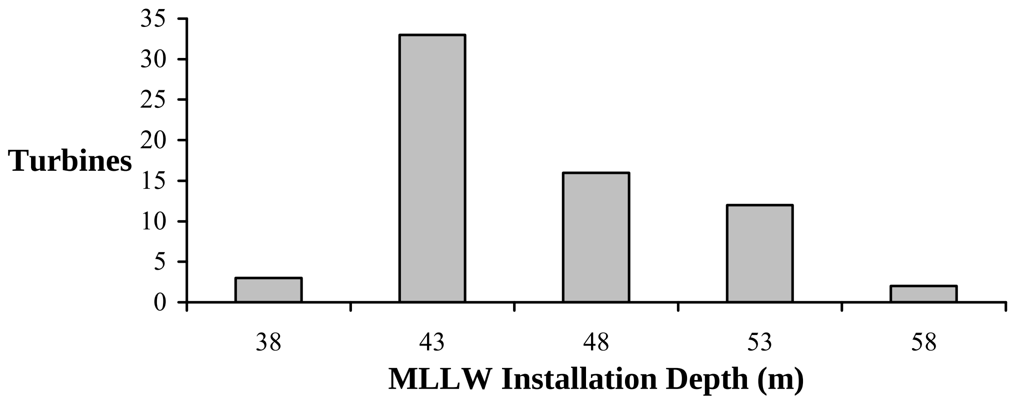



Figure 40 – Pile Installation Depth Distribution (MCT Array)

At this depth, monopile installation from a derrick barge should be feasible.

<u>Electrical Interconnection</u>

As discussed in Chapter 4, the rated electrical output for the dual-rotor devices is 759 kW. The rated power load in MW of each transect is given in Table 8. The transects are as shown in Figure 38 and are numbered sequentially from north to south.

Table 8 – Cairn Point Transect MVA Ratings (MCT Array)

| **Transect** | **Turbines** | **Transect Rating (MW)** |
|---|---|---|
| 1 | 6 | 4.6 |
| 2 | 9 | 6.8 |
| 3 | 12 | 9.1 |
| 4 | 12 | 9.1 |
| 5 | 9 | 6.8 |
| 6 | 10 | 7.6 |
| 7 | 8 | 6.1 |

By using 33kV subsea cable (thermally rated to accommodate up to 40MW), a ring redundancy can be accomplished by connecting pairs of transects. Seven cables are required to bring the power on shore – one for each transect. Since all seven take-off cables can be laid in a single routing, the incremental cost of shore redundancy is relatively low and has little impact on the cost of energy.

Due to the variable nature of the mud flats on the eastern shore and the high bluffs at shoreline, directional drilling from above the bluffs to the array location is the preferred method of cable installation and would require directional drilling for nearly 1000m. Burying the main cluster of take-off cables deep enough to prevent exposure over the lifetime of the array is probably not practical. The seabed out at the array site should be less prone to bulk sediment transport, and lateral and longitudinal cables could be secured by plowing them into the seabed. The directionally drilled cables will come ashore on the bluffs above Cairn Point. From here, onshore cables would bring power back to a new near-shore substation on Elmendorf AFB. Here, voltage would be stepped up to 115kV for backhaul to Anchorage Municipal Light and Power.

For the purposes of the commercial array design it is assumed that a new substation will have to be constructed at an estimated cost of $1.5 to $2M. Additionally, overbuilding the existing 33kV line back to Anchorage has been estimated to cost $3.25M. The $3.25M for the transmission line upgrade, while borne by the project, would be paid back to the project as a future wires charge and do not impact the cost of energy On-shore infrastructure (e.g.

cable landing, breakers) is estimated to cost $500,000. Details of the commercial interconnection plan are given in Table 9. Costs are described further in Chapter 9.

Table 9 – Cairn Point Commercial Array Grid Interconnection (MCT Array)

| | |
|---|---|
| **Offshore Cable** | |
| Cable Length | 10,560 m |
| Trench Length | 2665 m |
| Directional Drilling Length | 950 m |
| Sediment type along cable route | Loose to dense sand and clay |
| Offshore Interconnection Cost | $12.3M |
| **Onshore Cable** | |
| Cable Landing | On bluffs |
| Onshore Interconnection Cost | $0.5M |
| Infrastructure Upgrade Cost | $2.0M |

Array Performance

Array performance calculations are based on the following assumptions:

- Predicted surface velocity at site is valid for the entire region of deployment (see Appendix)
- Flow velocity does not appreciably decay between first row and last row of turbines (see Appendix)
- Average power flux over turbine is approximately the power flux at hub height (see Appendix)
- The mean depth for the site is representative of the depth for all turbines

Using this assumption, the output of the array may be found by multiplying the output of a single, representative turbine by the total number of turbines in the array. Array performance is summarized in Table 10.

Table 10 – Cairn Point Array Performance (MCT Array)

| | |
|---|---|
| **Array Performance** | |
| Number of turbines | 66 |
| Number of transects | 7 |
| Availability | 95% |
| Transmission Efficiency to Shore | 98% |
| Capacity Factor | 29% |
| Average Extracted Power | 17 MW (17 MW extraction limit) |
| Average Electric Power | 14.6 MW |
| Maximum Electric Power | 50.1 MW |
| Annual Electricity Generation | 128,099 MWh |

The array power output over a single day, 14-day tidal cycle, and for each month is given in Figure 41, Figure 42, and Figure 44. The truncating effect of the rated power of each turbine is evident in both the daily and tidal cycle plots. Note, transmission losses and availability are not taken into account in the daily or tidal cycle plots, but are accounted for in the monthly averages. Averages are for the period shown on the plots – note that the average power generated for the reference day is higher than the average for the entire year. The annual variation is perhaps most easily shown by the daily average array electrical output (Figure 43) over a year.

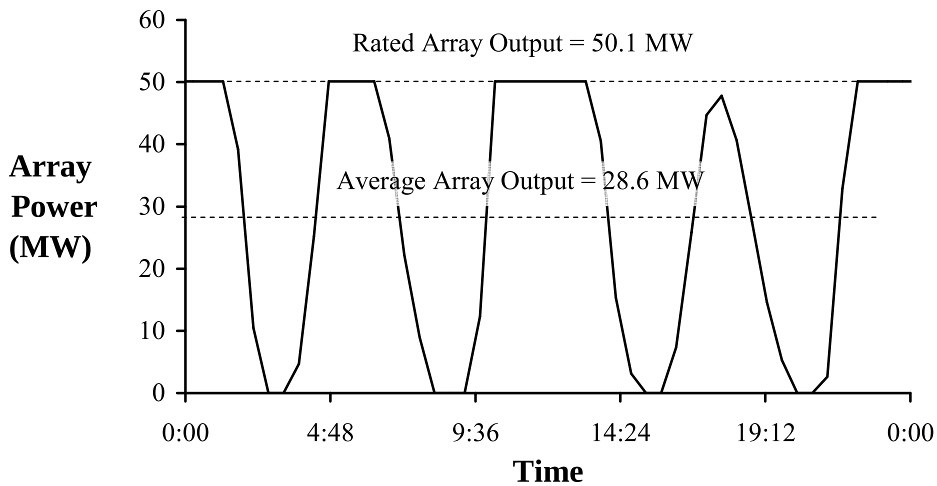



Figure 41 – Daily Array Power Output (February 9th, 2005) (MCT Array)

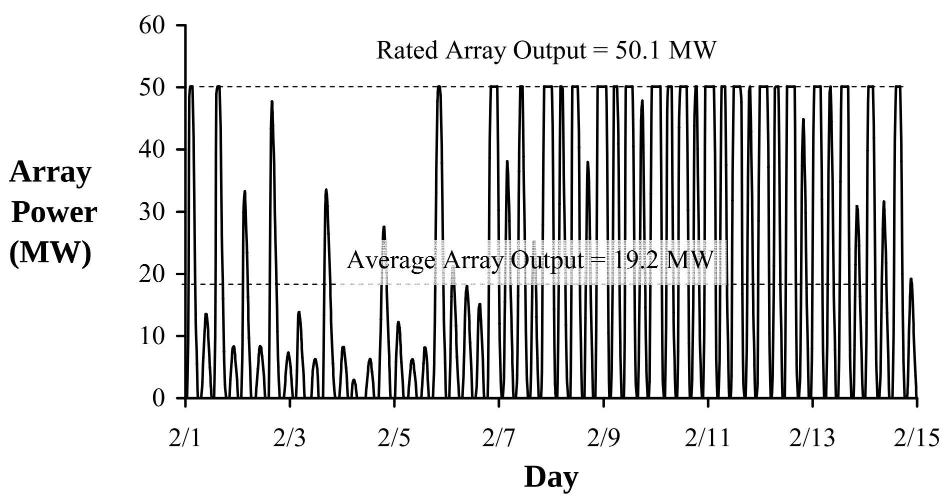



Figure 42 – Tidal Cycle Array Power Output (February 1st-14th, 2005) (MCT Array)

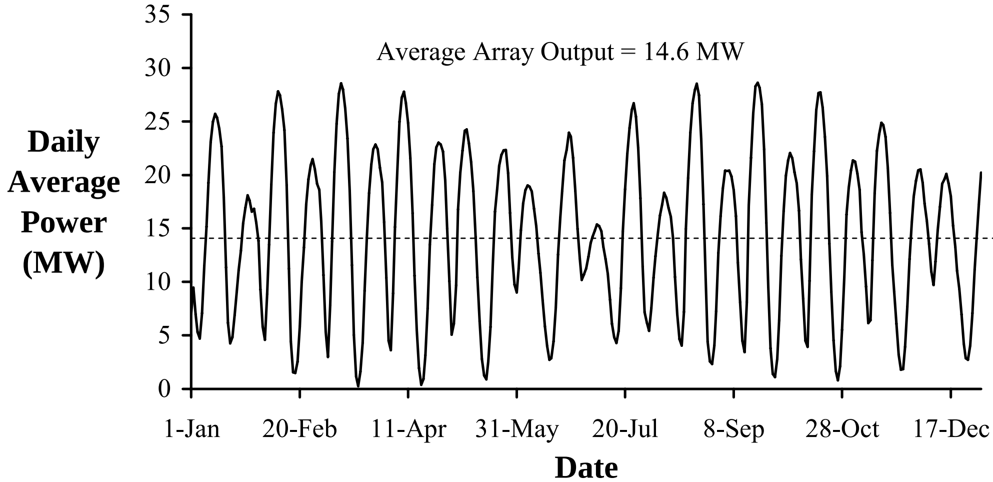



Figure 43 – Daily Average Array Power (2005) (MCT Array)

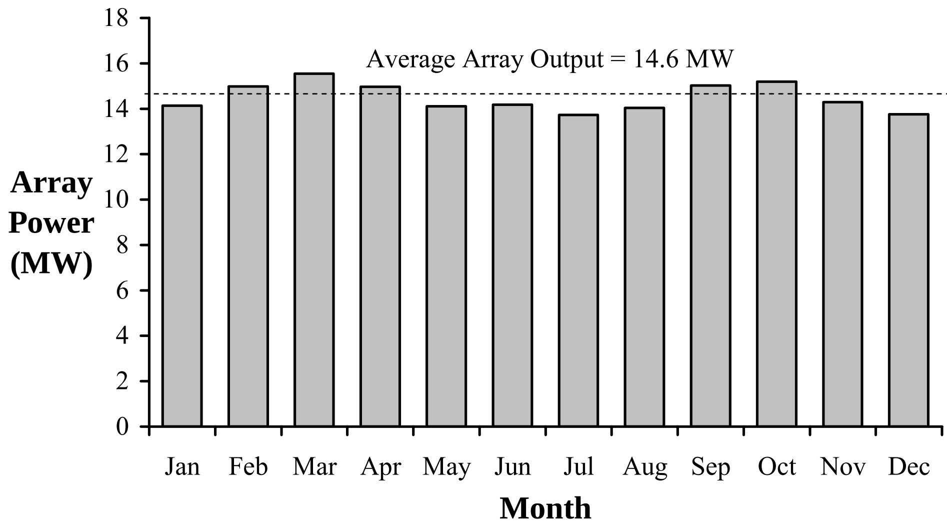



Figure 44 – Monthly Average Array Power Output (2005) (MCT Array)

The array power output, while relatively uniform on a monthly or annual basis, shows significant daily and hourly variation due to the tidal cycle. Since generation does not always coincide with peak demand, the utilities will need to determine how best to integrate the power generated from a commercial tidal array with their existing generation portfolios.

Site Specific Issues

*Directionality of Tides:* As previously discussed, tides on the east side of Cairn Point are not fully bi-directional and turbines will experience off-axis flow. This is expected to reduce the output of an unducted horizontal axis turbine lacking yaw control. However, little information is available to quantify this performance decrease and it is not included in this feasible study.

*Seasonal Ice Pack:* Since the commercial plant is fully submerged, with surface clearances consistent with the greatest reported beach ice thickness, ice impact is not expected to be an issue. Maintenance schedules should be arranged around the seasonal ice pack. *Ice clearances are uncertain should be the subject of detailed study prior to turbine deployment.* This overhead clearance should be sufficient to allow passage of shipping traffic in the event of an expansion at Port MacKenzie.

*Marine Mammals:* Special measures may, however, be required to eliminate any detrimental effect on Beluga whales or their habitat. This may include, but not be limited to, protective screens around the turbine rotors and acoustic shrouding of the gearbox. Since the MCT gearbox is currently designed to be cooled by currents, acoustic shrouding may necessitate the incorporation of additional heat transfer surfaces to maintain gearbox cooling rates. Juvenile Beluga whales are about 4-5 feet long and less than 2 feet in girth [24]. Protective screens with 1 foot gaps should be sufficient to protect Belugas from the rotor blade (if regulators require this measure) without greatly degrading turbine performance by restricting flow. Due to the opacity of waters in Knik Arm, biological accumulation on a screen may not be nearly as problematic as at other sites. Since MCT has not considered screening their rotors (and to date has had no reason to believe this would be necessary), screening and acoustic shrouding will require additional site-specific engineering.

*Seabed Movement:* The continuing changes in channel depth discussed in Chapter 2 pose a concern for an MCT design. If long-term trends can be identified, turbines could either be sited in areas not prone to significant change, or pile foundations could be designed for future expected conditions (e.g. another 3m increase in channel depth).

*Turbulent Eddies:* The length of the northernmost transects have been truncated so that turbines should not be installed within the turbulent eddy region. Eddies to the south of Cairn Point and on the west side of the channel are not expected to degrade turbine operation.

### 7.2. Lunar Energy

The principles discussed at the start of the chapter lead to the array design shown in Figure 38. The array consists of sixty nine (69) ducted, twenty-one (21) meter diameter turbines arranged in seven (6) transects as designated by white rectangles (approximately to scale). The turbines will be fully submerged during operation. Turbine units are designated by white squares. Electrical infrastructure is shown in red. The design is described in more detail in the following sections.

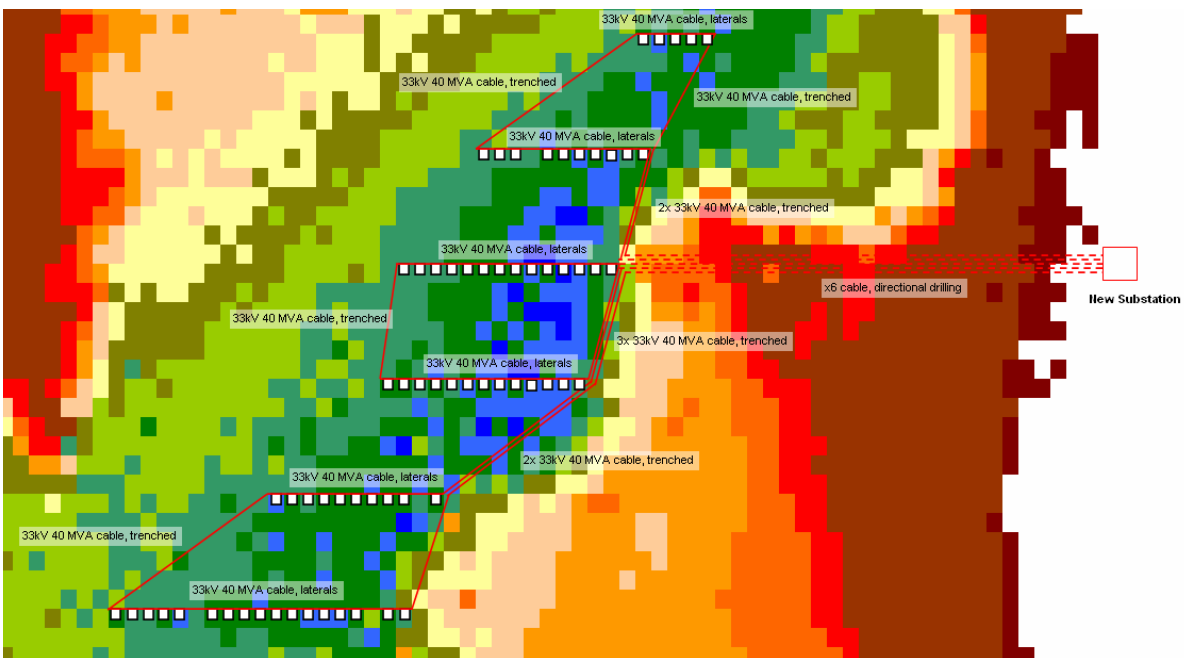



Figure 45 – Cairn Point Commercial Array Layout (Lunar Array)

#### Array Layout

The layout of the turbine array is governed by the following spacing rules:

- 10m clearance between base of inlet duct and seabed to prevent cyclic blade stresses due to operation in the boundary layer.
- 12m clearance between rotor tip and surface to prevent catastrophic beach ice impact. This clearance should also place the turbine swept area below layers of

frazil ice. A detailed study of ice depth in Knik Arm is needed to verify these assumptions.

- 10.5m (one half rotor diameter) clearance between each turbine to prevent lateral interaction between rotors [25].
- 210m (10 turbine diameters) downstream spacing between array transects to allow turbulent dissipation of rotor wake [27].

Note that these spacing rules have been developed based on analogues to wind-turbine array layouts, and require additional modeling and testing to verify.

A representative cross-section of a channel showing important clearances and dimensions for a Lunar Energy turbine array is shown in Figure 39.

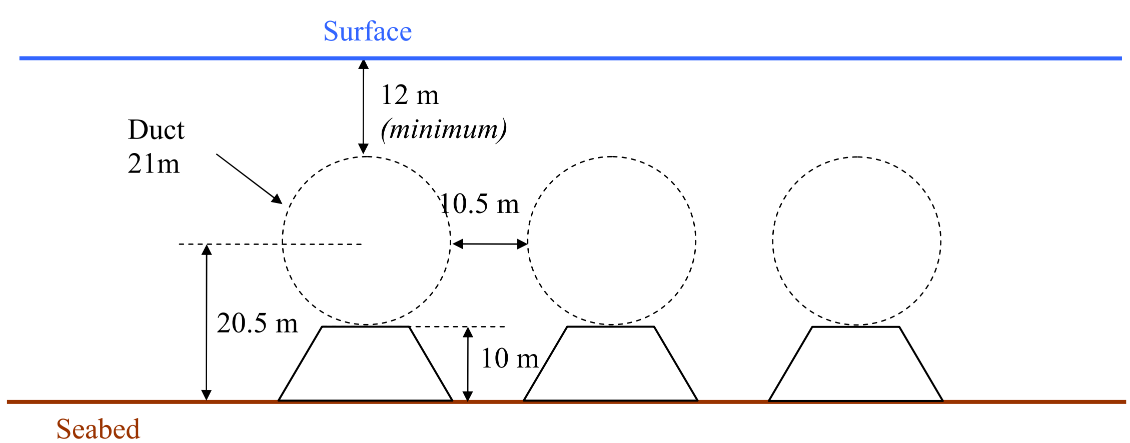



Figure 46 – Turbine Size and Spacing (Lunar Array)

Array planning is an iterative process. First an array layout is chosen with a specified number of turbines. From this, the average turbine depth may be calculated and used to predict the power output of the array. Since no cost model could be created for the Lunar Energy turbine, rated speed was chosen using best estimate of turbine performance. The power extracted by the array is then checked to determine that no more than 15% of the kinetic energy has been removed from the flow. If too much/not enough energy has been removed from the flow turbines are removed/added to the array layout and the process continues until an array that extracts 15% of the kinetic energy from the flow has been designed. The number of turbines may be further reduced to limit the peak electric output to 120 MW, a general feed-in limit at 115kV.

The Cairn Point array consists of 69 ducted turbines, arranged in six transects of five to seventeen turbines. These will, on average, extract 17 MW of power – 15% of the average channel power. The mean depth of water for installation is 48m. Installation depths range from 43 – 60m (MLLW reference) as shown in Figure 40.

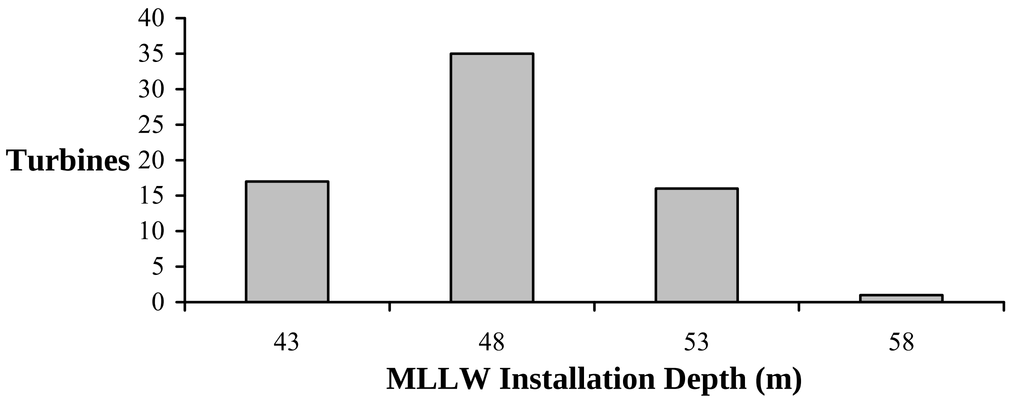



Figure 47 – Installation Depth Distribution (Lunar Array)

Electrical Interconnection

As discussed in Chapter 3, the rated electrical output for the Lunar turbine is 1082 kW. The rated power load in MW of each transect is given in Table 8. The transects are as shown in Figure 38 and are numbered sequentially from north to south.

Table 11 – Cairn Point Transect MVA Ratings (Lunar Array)

| **Transect** | **Turbines** | **Transect Rating (MW)** |
|---|---|---|
| 1 | 5 | 5.4 |
| 2 | 10 | 10.8 |
| 3 | 14 | 15.1 |
| 4 | 13 | 14.1 |
| 5 | 10 | 10.8 |
| 6 | 17 | 18.4 |

By using 33kV subsea cable (thermally rated to accommodate up to 40MW), a ring redundancy can be accomplished by connecting pairs of transects. Six cables are required to bring the power on shore – one for each transect. Since all six take-off cables can be laid in a single routing, the incremental cost of shore redundancy is relatively low and has little impact on the cost of energy.

Due to the variable nature of the mud flats on the eastern shore and the high bluffs at shoreline, directional drilling from above the bluffs to the array location is the preferred method of cable installation and would require directional drilling for nearly 1000m. Burying the main cluster of take-off cables deep enough to prevent exposure over the lifetime of the array is probably not practical. The seabed out at the array site should be less prone to bulk sediment transport, and lateral and longitudinal cables could be secured by plowing them into the seabed. The directionally drilled cables will come ashore on the bluffs above Cairn Point. From here, onshore cables would bring power back to a new near-shore substation on Elmendorf AFB. Here, voltage would be stepped up to 115kV for backhaul to Anchorage Municipal Light and Power.

For the purposes of the commercial array design it is assumed that a new substation will have to be constructed at an estimated cost of $1.5 to $2M. Additionally, overbuilding the existing 33kV line back to Anchorage has been estimated to cost $3.25M. The $3.25M for the transmission line upgrade, while borne by the project, would be paid back to the project as a future wires charge and do not impact the cost of energy On-shore infrastructure (e.g. cable landing, breakers) is estimated to cost $500,000. Details of the commercial interconnection plan are given in Table 12. Costs are described further in Chapter 9.

Table 12 – Cairn Point Commercial Array Grid Interconnection (Lunar Array)

| | |
|---|---|
| **Offshore Cable** | |
| Cable Length | 9597 m |
| Trench Length | 2761 m |
| Directional Drilling Length | 950 m |
| Sediment type along cable route | Loose to dense sand and clay |
| Offshore Interconnection Cost | $12.3M |
| **Onshore Cable** | |
| Cable Landing | On bluffs |
| Onshore Infrastructure Cost | $0.2M |
| Infrastructure Upgrade Cost | $2.0M |

Array Performance

Array performance calculations are based on the following assumptions:

- Predicted surface velocity at site is valid for the entire region of deployment (see Appendix)
- Flow velocity does not appreciably decay between first row and last row of turbines (see Appendix)
- Average power flux over turbine is approximately the power flux at hub height (see Appendix)
- The mean depth for the site is representative of the depth for all turbines

Using this assumption, the output of the array may be found by multiplying the output of a single, representative turbine by the total number of turbines in the array. Array performance is summarized in Table 10.

Table 13 – Cairn Point Array Performance (Lunar Array)

| **Array Performance** | |
|---|---|
| Number of turbines | 69 |
| Number of transects | 6 |
| Availability | 95% |
| Transmission Efficiency to Shore | 98% |
| Capacity Factor | 15% |
| Average Extracted Power | 17 MW (17 MW extraction limit) |
| Average Electric Power | 11 MW |
| Maximum Electric Power | 75 MW |
| Annual Electricity Generation | 99,273 MWh |

The array power output over a single day, 14-day tidal cycle, and for each month is given in Figure 41, Figure 42, and Figure 44. The truncating effect of the rated power of each turbine is evident in both the daily and tidal cycle plots. Note, transmission losses and availability are not taken into account in the daily or tidal cycle plots, but are accounted for in the monthly averages. Averages are for the period shown on the plots – note that the average power generated for the reference day is higher than the average for the entire year. The annual variation is perhaps most easily shown by the daily average array electrical output (Figure 50) over a year.

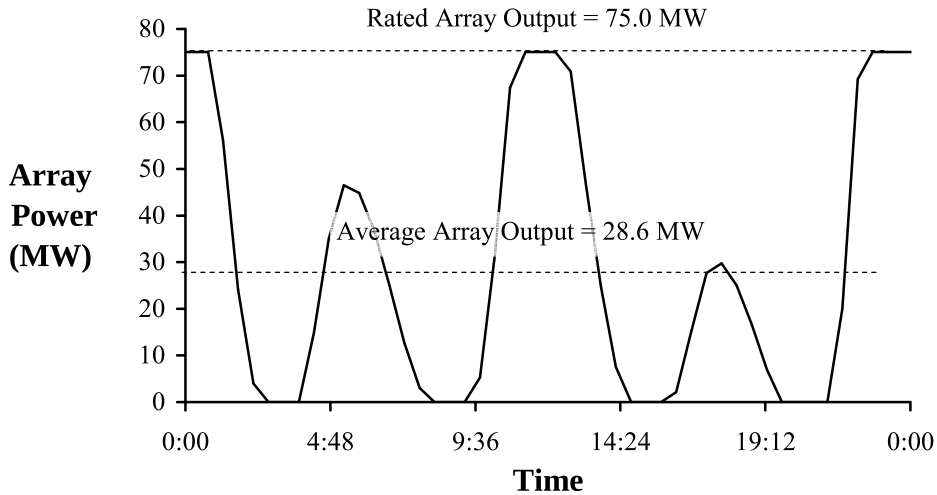



Figure 48 – Daily Array Power Output (February 9th, 2005) (Lunar Array)

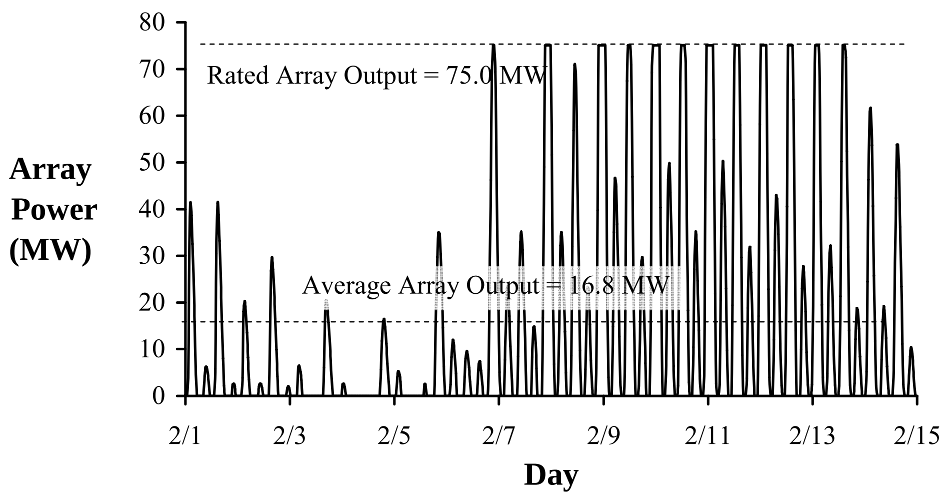



Figure 49 – Tidal Cycle Array Power Output (February 1st-14th, 2005) (Lunar Array)

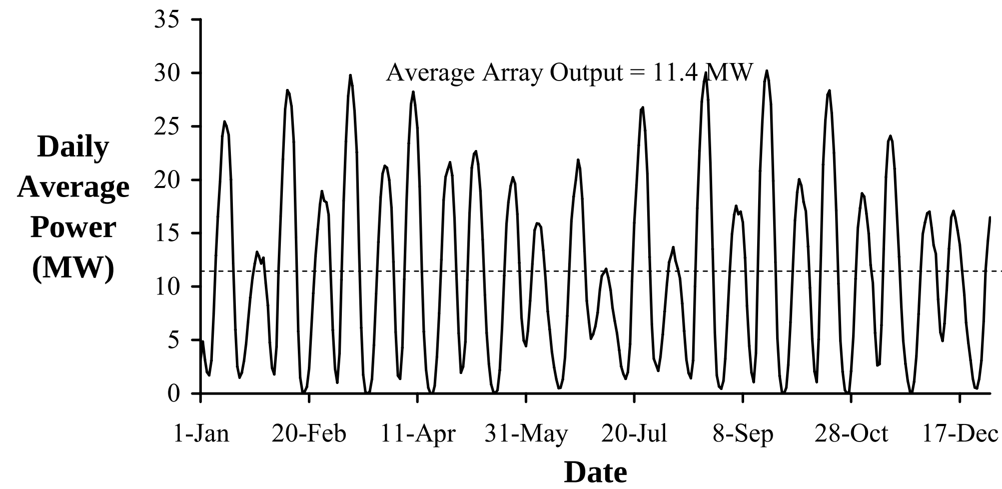



Figure 50 – Daily Average Array Power (2005) (Lunar Array)

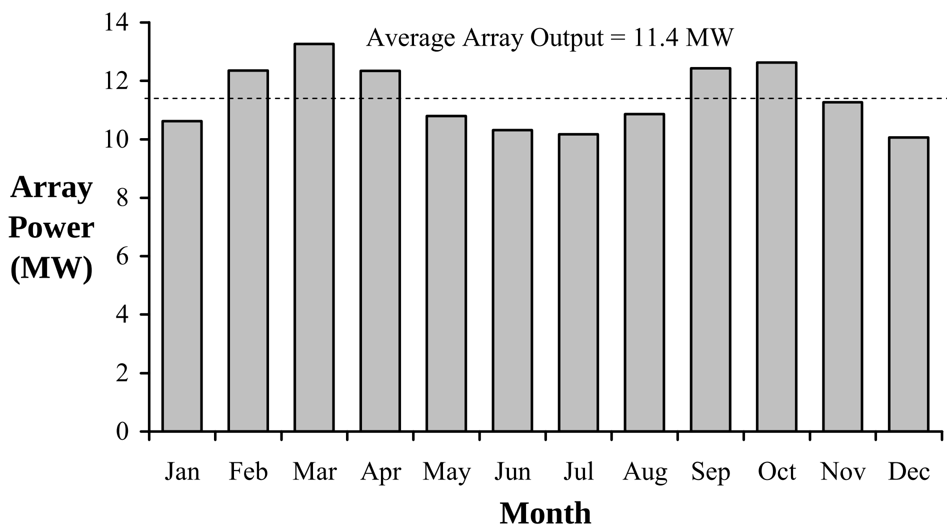



Figure 51 – Monthly Average Array Power Output (2005) (Lunar Array)

The array power output, while relatively uniform on a monthly or annual basis, shows significant daily and hourly variation due to the tidal cycle. Since generation does not always coincide with peak demand, the utilities will need to determine how best to integrate the power generated from a commercial tidal array with their existing generation portfolios.

Site Specific Issues

*Directionality of Tides:* As discussed in Chapter 2, tides on the east side of Cairn Point are not fully bi-directional and turbines will experience off-axis flow. Due to the ducted design of the Lunar Energy turbine, this will have the effect of enhancing flow and power output. However, since it has not been established that bi-directionality is uniform over the channel, this benefit is not included in the base case of this feasible study.

*Seasonal Ice Pack:* Since the commercial plant is fully submerged, with surface clearances consistent with the greatest reported beach ice thickness, ice impact is not expected to be an issue. Maintenance schedules should be arranged around the seasonal ice pack. *Ice clearances are uncertain should be the subject of detailed study prior to turbine deployment.* This overhead clearance should be sufficient to allow passage for shipping traffic in the event of an expansion at Port MacKenzie.

*Marine Mammals:* Special measures may, however, be required to eliminate any detrimental effect on Beluga whales or their habitat. This may include, but not be limited to, protective screens around the turbine rotors and acoustic shrouding of the hydraulic generator. Juvenile Beluga whales are about 4-5 feet long and less than 2 feet in girth [24]. Protective screens with 1 foot gaps should be sufficient to protect Belugas from the rotor blade (if regulators require this measure) without greatly degrading turbine performance by restricting flow. Due to the opacity of waters in Knik Arm, biological accumulation on a screen may not be nearly as problematic as at other sites.

*Seabed Movement:* The continuing changes in channel depth discussed in Chapter 2 pose a concern for an Lunar Energy design. If long-term trends can be identified, turbines should be sited in areas not prone to bulk sediment transport that could either undermine or cover a gravity foundation. It is possible that the Mark II turbine could be designed with supporting legs of sufficient length to allow for expected future seabed movement.

*Sediment Loading:* As velocity decreases across the turbine, some sediment will drop out of the flow and deposit in the turbine duct. While the reversing of the tides will partially compensate, since ebb and flood are not perfectly balanced, this bias may result in accumulation of sediments to one side of the rotor. Sedimentation issues must be explored further prior to turbine development as clearing sediment build-up would be a non-standard O&M intervention outside of Lunar Energy's standard maintenance philosophy.

*Turbulent Eddies:* The length of the northernmost transects have been truncated so that turbines should not be installed within the turbulent eddy region. Eddies to the south of Cairn Point and on the west side of the channel are not expected to degrade turbine operation.

## 8. Cost Assessment – Pilot Plant

The cost assessment of the 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. While all costing models were developed internally, MCT provided data and support to calibrate the models, which was an important step to come up with meaningful models. 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. Note that the costs in this table do not include any specialty instrumentation or measurement equipment that may be deployed over the course of the pilot to satisfy regulatory requirements for a commercial array.

Table 14 – Pilot Plant Cost Breakdown (MCT)

| | $/kW | $/Turbine | % |
|---|---|---|---|
| Power Conversion System | $1,428 | $1,083,886 | 22.5% |
| Structural Steel Elements | $839 | $636,784 | 13.2% |
| Subsea Cable Cost | $60 | $45,600 | 0.9% |
| Turbine Installation | $1,899 | $1,442,000 | 29.9% |
| Subsea Cable Installation | $1,198 | $909,605 | 18.9% |
| Onshore Electric Grid Interconnection | $922 | $700,000 | 14.5% |
| Total Installed Cost | $6,346 | $4,817,875 | 100% |

A single unit will cost significantly more then subsequent units installed at the site. Installation costs are dominated by mobilization charges. Additional, the first unit equipment costs will always be higher then subsequent ones due to learning scale. The assessment of operational and maintenance cost for the pilot was not part of the scope of this study.

It is, however, important to understand that the purpose of the pilot plant is not to provide low cost electricity, but to reduce risks associated with a commercial array. Risks include technological uncertainty in device performance, operation and maintenance requirements, validation of structural integrity, and environmental impact associated with the interaction of the natural habitat with 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. The major influences on cost for a particular site 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 with the square 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. As the rated velocity of the device increases, so do power train costs. Since the velocity distribution tails off at higher velocities, the capital cost for equipment to extract incrementally more flow power at high velocities may not be "paid back" by the additional power generated. Rather than make assumptions as to appropriate rated velocities of TISEC devices, an iterative approach was chosen to determine the rated speed of the machine which yields the lowest cost of electricity at the particular site.

*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.

*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 due to economies of scale. 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 to 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. MCT is seeking to mitigate this problem by working with DNV (Det Norske Veritas), the ship classification society, to use existing marine standards in its design wherever possible [19].

The following table shows a cost breakdown of a commercial TISEC array at the deployment site.

Table 15 - Commercial Plant Cost Breakdown (MCT)

| | **$/kW** | **$/Turbine** | **$/Array** | **%** | |
|---|---|---|---|---|---|
| Power Conversion System | $657 | $498,512 | $32,901,815 | 30.0% | 1 |
| Structural Elements | $817 | $620,469 | $40,950,960 | 37.3% | 2 |
| Subsea Cable Cost | $32 | $24,059 | $1,587,920 | 1.4% | 3 |
| Turbine Installation | $422 | $320,216 | $21,134,248 | 19.3% | 4 |
| Subsea Cable Installation | $213 | $161,696 | $10,671,914 | 9.7% | 5 |
| Onshore Electric Grid Interconnection | $50 | $37,879 | $2,500,000 | 2.3% | 6 |
| Total Installed Cost | $2,190 | $1,662,831 | $109,746,858 | 100% | |
| O&M Cost | $49 | $36,885 | $2,434,440 | 59.7% | 7 |
| Annual Insurance Cost | $33 | $24,942 | $1,646,203 | 40.3% | 8 |
| Total annual O&M cost | $81 | $61,828 | $4,080,643 | 100.0% | |

1. Power conversion system cost includes all elements required to go from fluid power to electrical power suitable to interconnect to the TISEC array 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 [17] with necessary adjustments made such as marinization, gearing-ratio, rotational speed and turbine blade length. Progress ratios were used to account for cost changes at different production volumes.

2. Structural steel elements include all elements required to hold the turbine in place. In the case of MCT, this is the monopile and cross arm. 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 must be stressed that other loading conditions such as wave loads, resonance conditions, pile driving forces, or seismic activity can potentially dominate and will need to be taken into consideration in a detailed design phase.

3. Subsea 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 next substation. Cost components required to build-out the capabilities of the substation or upgrade the transmission capacity of the electric grid are excluded from cost of energy calculations as these are born by the project but paid back as a wires charge over its life.

# 10. Cost of Electricity Assessments

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

1. Utility Generator (UG),
2. Municipal Generator (MG)
3. 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 both real (constant) and nominal (current) dollars with 2005 as the reference year and a 20-year book life. The purpose of these standard methodologies 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 by the commercial TISEC plant described in sections 6 and 8 is estimated to be 128,100 MWh/year for an array consisting of sixty-six dual-rotor turbines. These turbines will, on average, extract 17MW of kinetic power from the tidal stream – 15% of the total kinetic energy in the flow at Cairn Point. Turbines will be arranged in five rows of twelve to thirteen devices. The elements of cost and economics (in 2005$) are:

- Total Plant Investment = $110 million (excludes $3.25 million transmission upgrade to be paid back to project with interest)
- Annual O&M Cost = $4.1 million

- Utility Generator (UG) Levelized Cost of Electricity (COE)[5] = 9.2 (Real) – 10.8 (Nominal) cents/kWh with renewable energy incentives equal to those that the government provides for renewable wind energy technology
- Non Utility Generator (NUG) Levelized Cost of Electricity (IRR) = N/A
- Municipal Generator (MG) Levelized Cost of Electricity (COE) = 7.1 (Real) – 8.4 (Nominal) cents/kWh with renewable energy incentives equal to those that the government provides for renewable wind energy technology

The detailed worksheets including financial assumptions used to calculate these COEs and IRR are contained in Appendices 14.4 through 14.6

The COE for a Municipal Generator such as Anchorage Municipal Power and Light is in the range of other renewable and non renewable energy supply options. A commercial project in Alaska will not provide an internal rate of return (IRR) for a Non-Utility Generator as the avoided cost (average industrial wholesale rate is used as a proxy for avoided cost) is not high enough for tidal in-stream energy to compete.

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.

Except for the Minas Passage in Nova Scotia which clearly has the size to be considered central power, all other sites studied in the U.S. and Canada fall in between the definition of distributed generation (DG) and central power generation.

We use the term distributed generation (DG) or distributed resources (DR) to describe an electric generation plant located in close proximity to the load that it is supplying and is

[5] For 45.7 MW, 20 year plant life, 10 years of PTC at 0.18 cents/kWh for a taxable entity, a REPI credit at 0.015 cents/kWh for a non taxable MG, and other assumptions documented in [2].

either connected to the electric grid at distribution level voltages or connected directly to the load. Examples of DG/DR (DR when some form of storage is included) are rooftop photovoltaic systems, natural gas micro turbines and small wind turbines. Large wind projects and traditional fossil and nuclear plants are examples of central generation where the electricity delivers power into the grid at transmission voltage levels.

DG types of systems traditionally find applications in niche markets because of unique market drivers such as:

- Delay or defer an upgrade to T&D infrastructure that would otherwise have been necessary to bring power generated away from a load center to that load center
- Voltage stability support
- Displace diesel fuel in off grid applications
- Satisfy local citizens desires to have control of their own power source

A realistic comparison to equitably evaluate the cost of deferring T&D expenses with the cost of installing DG/DR is complex and requires considering depreciation and tax benefits, property tax and insurance for both options, maintenance and fuel costs of operating the DG/DR and employing discounted cash flow methods. This comparison must be made on a case-by-case basis.

EPRI, in collaboration with DOER, NJBPU and CEC, and funded by NASEO, is studying political and financial mechanisms for win-win DG/DR solutions for both the distribution utility and the end user.

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 12 below 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 [26].

Table 16 - COE for Alternative Energy Technologies: 2010 for a Utility Generator

| | **Capacity Factor (%)** | **Capital Cost[1] ($/kW)** | **COE (cents/kWh)** | **CO2 (lbs per MWh)** |
|---|---|---|---|---|
| Tidal In Stream | 29-33 | 2,000 | 6-9 | 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[3] 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 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 In-Stream** | 20/20 | 35 | WA/0- | MAC RS | | | | | 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 | ACR S | 45/ 30/ 0 | 11.5/ 13/ N/A | 55/ 70/ 100 | 6/5 8/ 4.5 | 2 |
| **IGCC(2) GE Quench W/O CO2 capture** | 30/ 20 | 35 | 6.5 | ACR S | 45/ 30/ 00 | 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 | ACR S | 45/ 30/ 00 | 11.5/ 13/ N/A | 55/ 70/ 100 | 6/5 8/ 4.5 | 2 |
| **NGCC(3) Advanced @ $5/MM Btu)** | 30/ 20 | 35 | 6.5 | ACR S | 45/ 30/ 0 | 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 | ACR S | 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
- 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 utility generator (UG) with assumptions discussed in Chapter 10. All costs are in 2005 USD. The base case for the commercial plant is 9.2 cents/kWh. Sensitivity plots are given only for the Marine Current Turbine (MCT) array as no mature costing data could be developed for Lunar Energy turbines.

## 11.1. Array Size

This sensitivity has already been implicitly shown in the unit capital cost differences for pilot turbine versus commercial scale array. Figure 52 shows the sensitivity of cost of energy (COE) to the number of turbines installed[6].

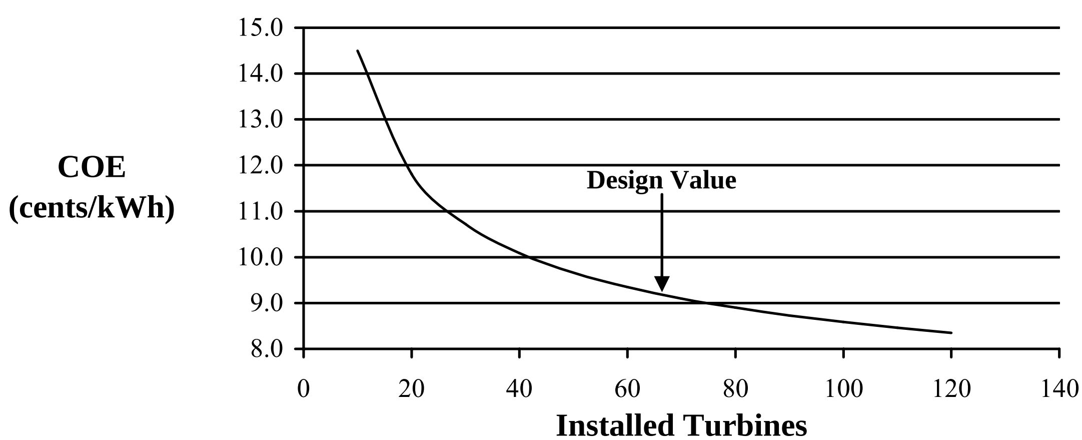



Figure 52 – Sensitivity of COE to number of turbines installed

[6] Real COE for utility generator. Assumes seven transect deployment of all turbines for purposes of calculating required subsea cable lengths.

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 53.

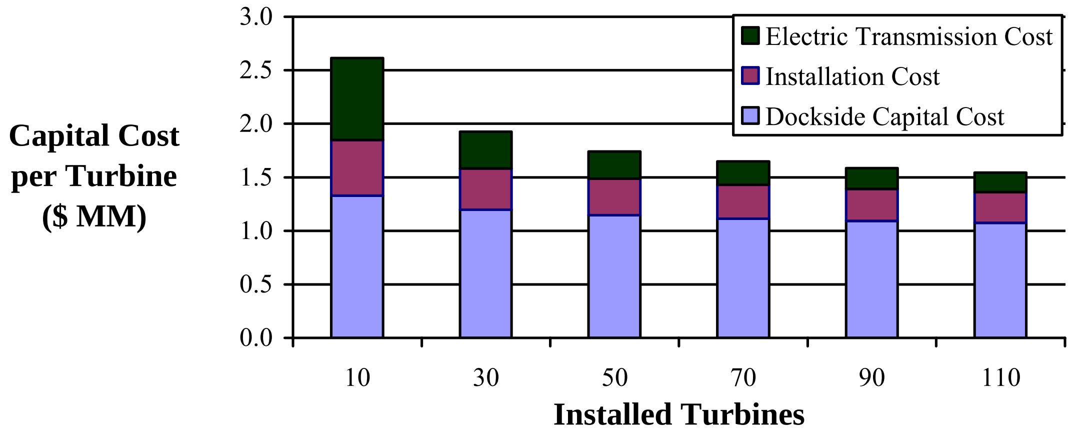



Figure 53 – Sensitivity of Capital Cost elements to number of installed turbines

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 – even for small arrays. 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 54.

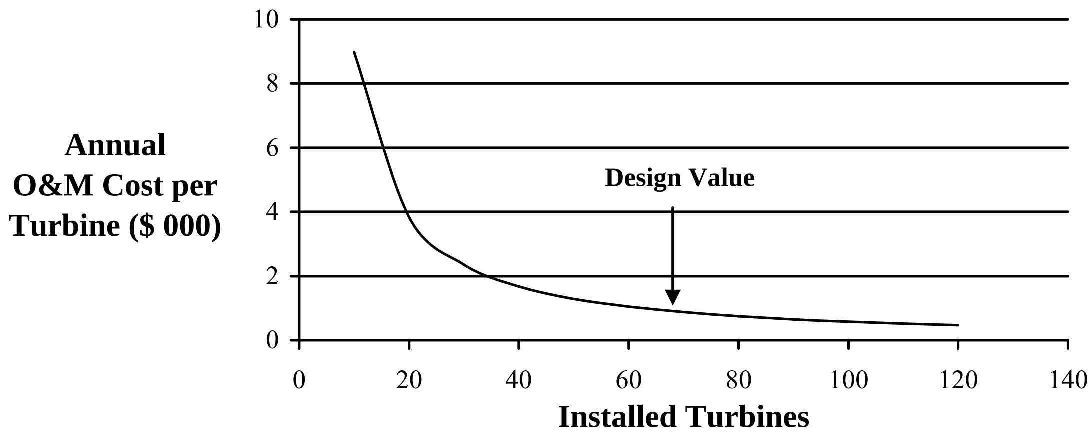



Figure 54 – Sensitivity of annual O&M cost to number of installed turbines

### 11.2. Array Availability

Given that tidal in-stream energy is an emerging industry and limited testing has been done to validate component reliability, the impact of array 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 55, where all parameters aside from availability are held constant for the commercial array design.

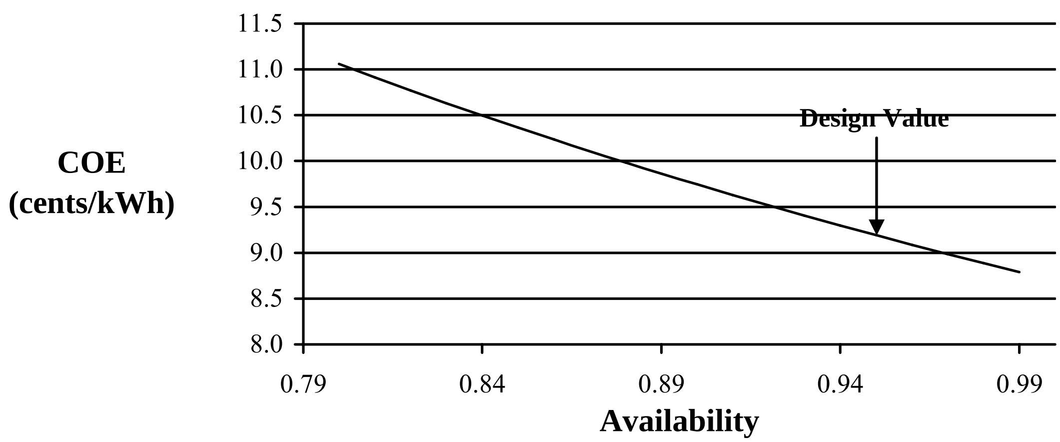



Figure 55 – Sensitivity of COE to array availability

If array availability is as low as 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.

## 11.3. 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 56 and Figure 57, 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 statistical description of the velocity distribution is the same for all cases, only the mean value changes. As the maximum site velocity is varied, 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.

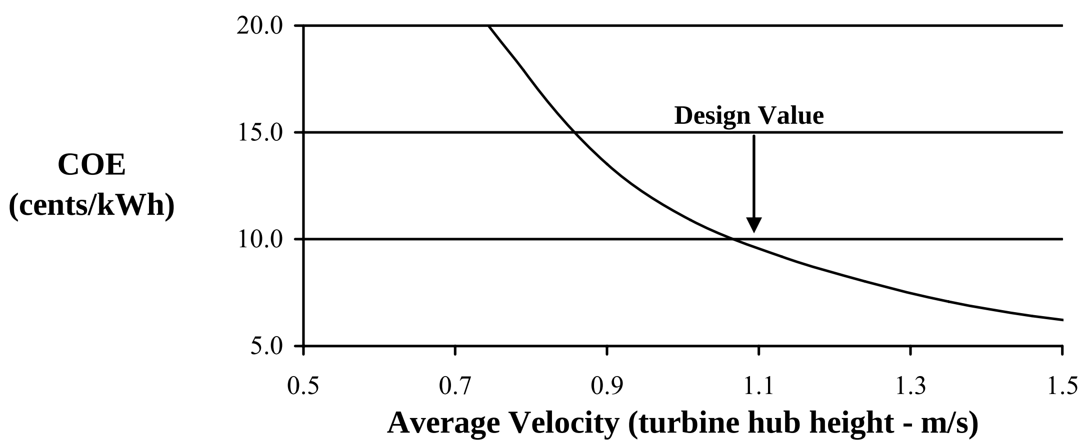



Figure 56 – Sensitivity of COE to average velocity

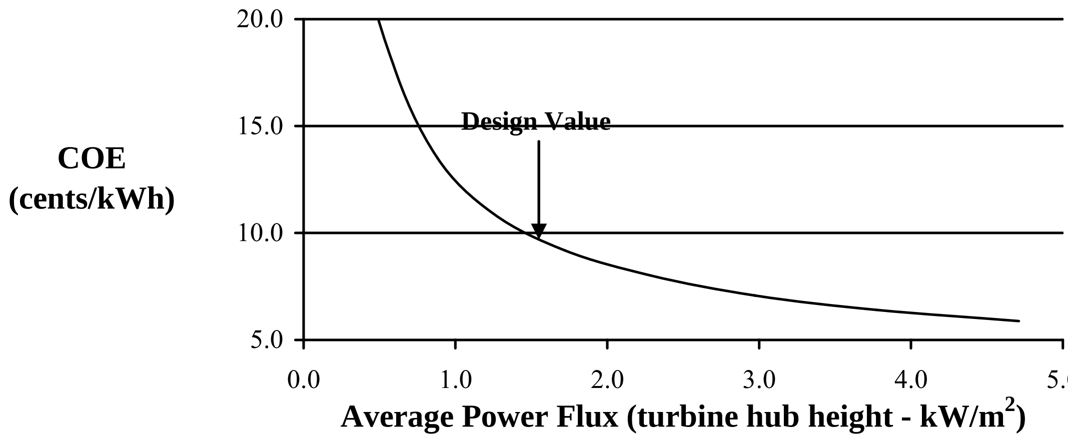



Figure 57 – Sensitivity of COE to average power flux

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 this result is 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.

### 11.4. Design Velocity

During normal operation, peak loads on the support structure occur around rated current velocity. For current velocities in excess of rated, power extracted by the rotors is reduced by the pitching mechanism. Rotor thrust contributes to the majority of design stress (pile drag accounting for the remainder). As the rotor pitch changes above rated current velocity, the thrust coefficient on the rotors decreases. If the rotor pitch mechanism is functioning correctly, the support structure would experience similar stresses from rated velocity up to maximum site velocity. However, as discussed in Chapter 4, 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. If manufacturers are able to achieve sufficient operating experiences with their turbines to ensure that turbines will never operate in a “runaway” mode (e.g. incorporation of failsafe braking mechanism), 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 58 shows the effect on the real cost of energy by bringing design and rated speed to parity.

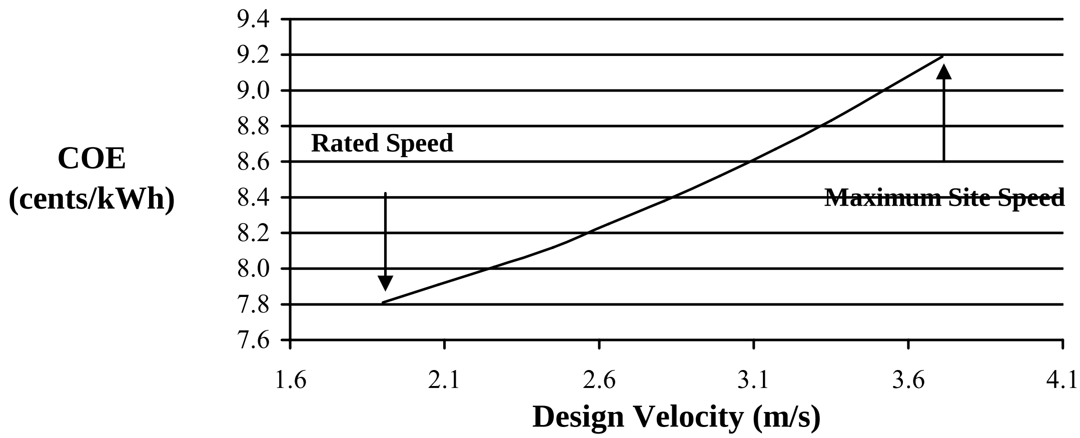



Figure 58 – Sensitivity of COE to design speed

### 11.5. Financial Assumptions

The effect of varying the fixed charge rate is shown in Figure 59. Fixed charge rate is varied by 30% from baseline value for the sensitivity.

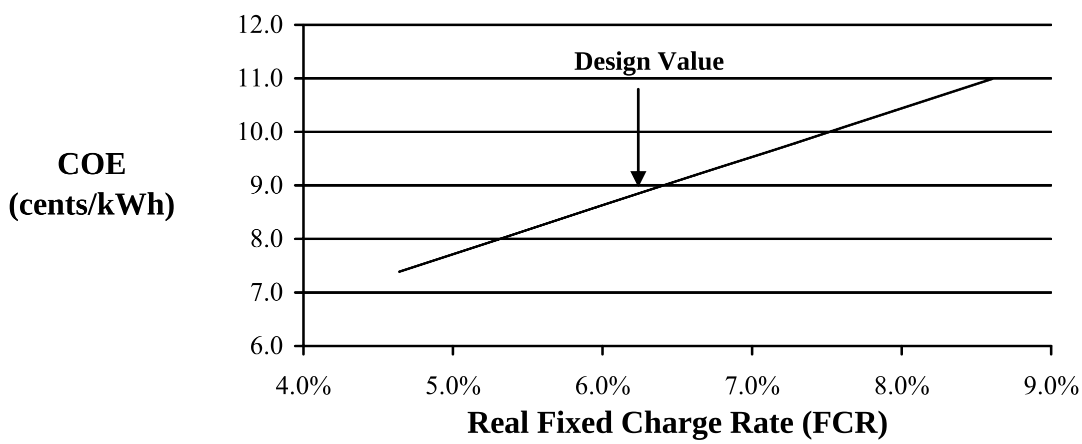



Figure 59 – Sensitivity of COE to debt financing rate

A sensitive assumption is the application of renewable energy production credits to the project. If a project is deemed ineligible for renewable production credits, or funds for such credits are not fully budgeted, COE increases substantially. Figure 60 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.

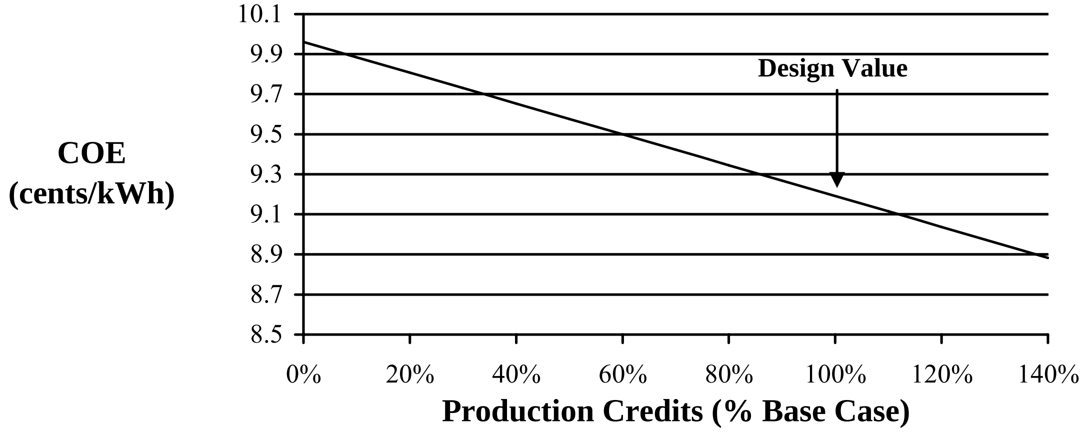



Figure 60 – Sensitivity of COE to production credits

# 12. Conclusions

## 12.1. Pilot In-Stream Tidal Power Plant

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 such an array. Due to ice concerns, a pilot plant can not be surface piercing. Additionally, high sedimentation levels, expected future shifts in seabed geometry, and concern over endangered marine mammals complicate deployment plans. However, the in-stream tidal resource at Cairn Point is quite good and should be pursued in due course. It is recommended that a pilot await the successful deployment of fully submerged Lunar or MCT turbines elsewhere in the world. The technology gap to be covered by both Lunar Energy and MCT in order to get to the point where a full-scale, fully-submersed TISEC pilot could be deployed is relatively small and it is reasonable to expect that such a deployment could occur within 3 years given a firm local commitment to move forward with this project.

## 12.2. Commercial In-Stream Tidal Power Plant

In the longer term, Cairn Point is a good candidate site for the installation of a commercial tidal in-stream plant. The predicted resource is sufficient to generate a meaningful level of electric power (>10MW on average) and interconnection at 115kV could be accomplished. Fully submerged turbines should be able to mitigate ice issues and the high opacity of the water column may allow screening of turbine rotors to protect marine mammals. The cost elements for a commercial plant in 2005$ are:

- Total Plant Investment = $110 million (excludes $3.25 million transmission upgrade to be paid back to project with interest)
- Annual O&M Cost = $4.1 million

- Utility Generator (UG) Levelized Cost of Electricity (COE)[7] = 9.2 (Real) – 10.8 (Nominal) cents/kWh with renewable energy incentives equal to those that the government provides for renewable wind energy technology
- Non Utility Generator (NUG) Levelized Cost of Electricity (IRR) = N/A
- Municipal Generator (MG) Levelized Cost of Electricity (COE) = 7.1 (Real) – 8.4 (Nominal) cents/kWh with renewable energy incentives equal to those that the government provides for renewable wind energy technology

The commercial scale power plant design, performance and cost results show that an in-stream tidal power plant may provide favorable economics in terms of COE for both a MG and UG in comparison to other locally available renewable energy production options.

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. Private energy investors most probably will not select in-stream tidal technology when developing new generation because the cost, uncertainties and risk are too high at this point in time.

## 12.3. 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.

[7] For 45.7 MW, 20 year plant life, 10 years of PTC at 0.18 cents/kWh for a taxable entity, a REPI credit at 0.015 cents/kWh for a non taxable MG, and other assumptions documented in [2].

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. This highlights the need for detailed site velocity measurements. 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. Given the relatively short construction window at Cairn Point, a phased deployment may be unavoidable.

### 12.4. General Conclusions

In-stream tidal current energy shows significant promise for Knik Arm 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 at Cairn Point would provide valuable benefits to the local economy and reduce Anchorage's 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 tuned 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 per COE 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 Knik Arm:

- Detailed velocity measurements will be necessary around Cairn Point 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 if the power flux is much lower than expected, the cost of energy will increase substantially.
- How far out into the channel do the eddies from the headlands on either side of Cairn Point extend at ebb and flood tide? How close to Cairn Point can turbines be sited without performance being degraded by eddies?
- 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.
- What regulatory concerns need to be addressed prior to the granting of a permit for a commercial plant, and how can the pilot plant best address them? What additional regulatory concerns would need to be addressed for the commercial plant since aspects of the device will change from pilot to commercial?
- How much ice clearance is required to deploy turbines at Cairn Point? A detailed study of frazil and beach ice depths will be necessary prior to the deployment of a pilot or commercial plant. If clearances of greater than 12m are required, the potential for deployment will be significantly restricted. If shallower clearances are possible, fewer transects could be deployed at lower cost.
- What future trends can be expected for seabed depth around Cairn Point? What risks are associated with a 20-year operating lifetime?

In-stream tidal energy is a potential important energy source and should be evaluated for adding to Anchorage'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 Anchorage 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

Except for a few large tidal energy resource sites, such as Minas Passage, TISEC is in the grey zone between central and distributed power applications. Typical distributed generation (DG) motivations are:

- Delay transmission and distribution (T&D) infrastructure upgrade
- Provide voltage stability

- Displace diesel fuel in off-grid applications
- Provide guaranteed power

## 12.5. Recommendations

EPRI makes the following recommendations to the State of Alaska Electricity stakeholders:

*General*

Build collaboration within Alaska and with other states 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 need 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.

Encourage R&D at universities - potentially in partnership with pilot plant device developer.

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

*Pilot Demonstration and Commercial Plant*

Cairn Point is the only site in Knik Arm suitable for the deployment of full-scale TISEC devices due to depth considerations. Despite a reasonably high resource, the site suffers from a number of particular challenges (ice, sedimentation, endangered species) which complicate deployment of a pilot or commercial plant. Unlike other states and provinces involved in this project, the Alaskan coastline contains multiple inlet features that are the hallmark of high current sites. It is recommended that Alaska undertake a full site survey to better understand the indigenous resource. Other sites in Cook Inlet, or further south around Juneau, may prove to have a strong a resource as predicted for Cairn Point.

If it is decided to pursue development at Cairn Point, there are three key next steps.

1. *Current velocities at Cairn Point need to be verified using ADCP*. Since the bathymetry of Cairn Point varies substantially over the length of the proposed turbine deployment, detailed ADCP measurements will be required. Measurements at Cairn Point as part of the Knik Arm Bridge survey projects may be of some use – but data only exists for a single transect.
2. *A study should be undertaken to consider depth issues associated with beach and frazil ice in Knik Arm*. Ice considerations are the ultimate arbiter of turbine deployment sites in Knik Arm.
3. Given the recurring environmental theme in much of the work associated with the Knik Arm Bridge (Beluga whales), an *environmental and permitting study* will be necessary for a turbine deployment at Cairn Point. While the bridge efforts may be leveraged in this area, the use of rotors to extract kinetic energy from the tidal flows will probably represent an additional area of concern for environmental regulators.
4. Since turbine foundation design will require an understanding of trends in seabed depth at Cairn Point, additional work is required to quantify and predict seabed movement.

In addition, EPRI recommends that Alaskan stakeholders conduct a full site survey to quantify the statewide in-stream resource. There may be substantial opportunities in the south east portion of the state in and around Juneau.

References

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# 13. Appendix

## 13.1. Validity of Cairn Point Velocity Predictions for Commercial Array

Given the irregular bathymetry of the seabed at Cairn Point, the extension of NOAA reference predictions to the entire proposed area of turbine deployment is a clear source of uncertainty in this study. However, without extensive ADCP measurements at Cairn Point, this uncertainty can not be satisfactorily resolved. As a result, NOAA predictions have been used as a "best guess" for current velocities on site.

## 13.2. Irrelevance of Flow Decay Concerns

A concern established by some other researchers, particularly Bahaj and Myers [27] 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 [28].

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.

### 13.3. Hub-height Velocity Approximation

In order to simply 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 $\Delta z$ and width $\Delta x$. 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 61.

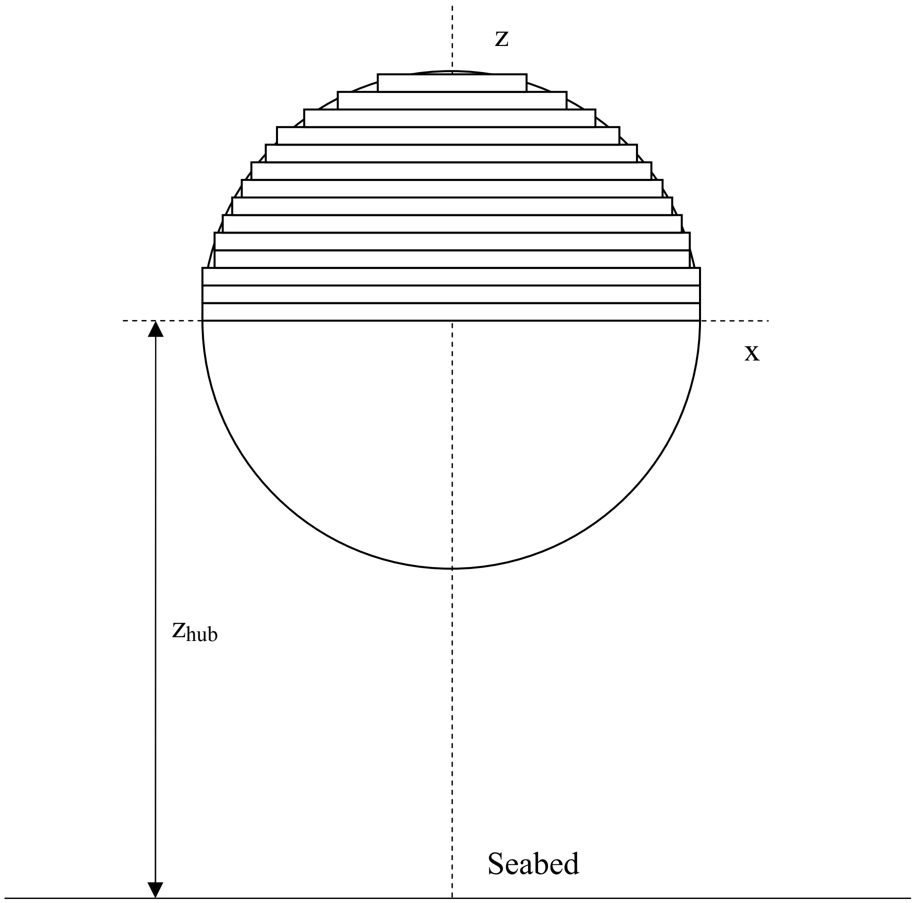


Figure 61 – Representative Numerical Integration

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 17.

Table 17 – 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 1/10$^{th}$ power velocity profile. For the purposes of a feasibility study, this approximation is reasonable.

## 13.4. 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 | 0 | $0 | $0 | |
| Structural Elements | 0 | $0 | $0 | |
| Subsea Cables | 0 | $0 | $0 | |
| Turbine Installation | 0 | $0 | $0 | |
| Subsea Cable Installation | 0 | $0 | $0 | |
| Onshore Grid Interconnection | 0 | $109,746,858 | $109,746,858 | |
| | | | | |
| TOTAL | | | $109,746,858 | |

**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 | $54,873,429 | $4,115,507 | $3,355,335 | $58,228,764 |
| 2008 | $54,873,429 | $4,115,507 | $3,029,648 | $57,903,077 |
| Total | $109,746,858 | $8,231,014 | $6,384,983 | $116,131,841 |

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

| Costs | Yrly Cost | Amount | |
|---|---|---|---|
| Labor and Parts | $2,434,438 | $2,434,438 | |
| Insurance (1.5% of TPC) | $1,646,203 | $1,646,203 | |
| | | | |
| Total | | $4,080,641 | |

**FINANCIAL ASSUMPTIONS**

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

| | | | |
|---|---|---|---|
| | Rated Plant Capacity © | 50.1 | MW |
| | Annual Electric Energy Production (AEP) | 128,099 | MWeh/yr |
| | Therefore, Capacity Factor | 29.2 | % |
| 1 | Year Constant Dollars | 2005 | Year |
| 2 | Construction Start | 2007 | Year |
| 3 | Construction Period | 2 | Year |
| | Federal Tax Rate | 35 | % |
| 5 | State | Alaska | |
| 6 | Generator | Utility Generator | |
| | State Tax Rate | 9.41 | % |
| | Composite Tax Rate (t) | 0.41117 | |
| | t/(1-t) | 0.69827 | |
| 7 | Book Life | 20 | Years |
| | Construction Financing Rate | 7.5 | % |
| | Common Equity Financing Share | 52 | % |
| | Preferred Equity Financing Share | 13 | % |
| | Debt Financing Share | 35 | % |
| | Common Equity Financing Rate | 13.0 | % |
| | Preferred Equity Financing Rate | 10.5 | % |
| | Debt Financing Rate | 7.5 | % |
| | Nominal Discount Rate Before-Tax | 10.75 | % |
| | Nominal Discount Rate After-Tax | 9.67 | % |
| 8 | Inflation Rate = 3% | 3 | % |
| | Real Discount Rate Before-Tax | 7.52 | % |
| | Real Discount Rate After-Tax | 6.48 | % |
| | Federal Investment Tax Credit (1) | 0 | |
| | Federal Production Tax Credit (2) | 0.018 | |
| | Federal REPI (3) | 0.000 | |
| | State Investment Tax Credit | 0 | $ |
| | State Investment Tax Credit Limit | None | |
| | Renewable Energy Certificate (4) | 0.000 | $/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 1st 10 years with escalation (assumed 3% per yr)
4. $/kWh for entire plant life with escalation (assumed 3% per yr)

**NET PRESENT VALUE (NPV) - 2005 $**

**TPI =** $116,131,841

| 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** | **116,131,841** | | | | | **116,131,841** |
| 2009 | 116,131,841 | 5,806,592 | 5,806,592 | 0.2000 | 7,162,402 | 103,162,847 |
| 2010 | 116,131,841 | 5,806,592 | 11,613,184 | 0.3200 | 12,892,324 | 84,463,931 |
| 2011 | 116,131,841 | 5,806,592 | 17,419,776 | 0.1920 | 6,780,407 | 71,876,931 |
| 2012 | 116,131,841 | 5,806,592 | 23,226,368 | 0.1152 | 3,113,258 | 62,957,082 |
| 2013 | 116,131,841 | 5,806,592 | 29,032,960 | 0.1152 | 3,113,258 | 54,037,232 |
| 2014 | 116,131,841 | 5,806,592 | 34,839,552 | 0.0576 | 362,895 | 47,867,745 |
| 2015 | 116,131,841 | 5,806,592 | 40,646,144 | 0.0000 | -2,387,467 | 44,448,620 |
| 2016 | 116,131,841 | 5,806,592 | 46,452,737 | 0.0000 | -2,387,467 | 41,029,496 |
| 2017 | 116,131,841 | 5,806,592 | 52,259,329 | 0.0000 | -2,387,467 | 37,610,371 |
| 2018 | 116,131,841 | 5,806,592 | 58,065,921 | 0.0000 | -2,387,467 | 34,191,246 |
| 2019 | 116,131,841 | 5,806,592 | 63,872,513 | 0.0000 | -2,387,467 | 30,772,122 |
| 2020 | 116,131,841 | 5,806,592 | 69,679,105 | 0.0000 | -2,387,467 | 27,352,997 |
| 2021 | 116,131,841 | 5,806,592 | 75,485,697 | 0.0000 | -2,387,467 | 23,933,872 |
| 2022 | 116,131,841 | 5,806,592 | 81,292,289 | 0.0000 | -2,387,467 | 20,514,748 |
| 2023 | 116,131,841 | 5,806,592 | 87,098,881 | 0.0000 | -2,387,467 | 17,095,623 |
| 2024 | 116,131,841 | 5,806,592 | 92,905,473 | 0.0000 | -2,387,467 | 13,676,499 |
| 2025 | 116,131,841 | 5,806,592 | 98,712,065 | 0.0000 | -2,387,467 | 10,257,374 |
| 2026 | 116,131,841 | 5,806,592 | 104,518,657 | 0.0000 | -2,387,467 | 6,838,249 |
| 2027 | 116,131,841 | 5,806,592 | 110,325,249 | 0.0000 | -2,387,467 | 3,419,125 |
| 2028 | 116,131,841 | 5,806,592 | 116,131,841 | 0.0000 | -2,387,467 | 0 |

## CAPITAL REVENUE REQUIREMENTS 2005$

**TPI =** $116,131,841

| End of Year | Net Book | Returns to Equity Common | Returns to Equity Pref | Interest on Debt | Book Dep | Income Tax on Equity Return | Fed PTC and REC | Capital Revenue Req'ts |
|---|---|---|---|---|---|---|---|---|
| | A | B | C | D | E | F | H | I |
| 2009 | 103,162,847 | 6,973,808 | 1,408,173 | 2,708,025 | 5,806,592 | 8,963,227 | 2,305,782 | 23,554,043 |
| 2010 | 84,463,931 | 5,709,762 | 1,152,933 | 2,217,178 | 5,806,592 | 12,246,123 | 2,305,782 | 24,826,806 |
| 2011 | 71,876,931 | 4,858,881 | 981,120 | 1,886,769 | 5,806,592 | 7,494,963 | 2,305,782 | 18,722,543 |
| 2012 | 62,957,082 | 4,255,899 | 859,364 | 1,652,623 | 5,806,592 | 4,591,743 | 2,305,782 | 14,860,439 |
| 2013 | 54,037,232 | 3,652,917 | 737,608 | 1,418,477 | 5,806,592 | 4,249,178 | 2,305,782 | 13,558,990 |
| 2014 | 47,867,745 | 3,235,860 | 653,395 | 1,256,528 | 5,806,592 | 2,091,748 | 2,305,782 | 10,738,341 |
| 2015 | 44,448,620 | 3,004,727 | 606,724 | 1,166,776 | 5,806,592 | 39,946 | 2,305,782 | 8,318,982 |
| 2016 | 41,029,496 | 2,773,594 | 560,053 | 1,077,024 | 5,806,592 | -91,365 | 2,305,782 | 7,820,116 |
| 2017 | 37,610,371 | 2,542,461 | 513,382 | 987,272 | 5,806,592 | -222,676 | 2,305,782 | 7,321,249 |
| 2018 | 34,191,246 | 2,311,328 | 466,711 | 897,520 | 5,806,592 | -353,986 | 2,305,782 | 6,822,383 |
| 2019 | 30,772,122 | 2,080,195 | 420,039 | 807,768 | 5,806,592 | -485,297 | 0 | 8,629,298 |
| 2020 | 27,352,997 | 1,849,063 | 373,368 | 718,016 | 5,806,592 | -616,608 | 0 | 8,130,431 |
| 2021 | 23,933,872 | 1,617,930 | 326,697 | 628,264 | 5,806,592 | -747,919 | 0 | 7,631,565 |
| 2022 | 20,514,748 | 1,386,797 | 280,026 | 538,512 | 5,806,592 | -879,229 | 0 | 7,132,698 |
| 2023 | 17,095,623 | 1,155,664 | 233,355 | 448,760 | 5,806,592 | -1,010,540 | 0 | 6,633,832 |
| 2024 | 13,676,499 | 924,531 | 186,684 | 359,008 | 5,806,592 | -1,141,851 | 0 | 6,134,965 |
| 2025 | 10,257,374 | 693,398 | 140,013 | 269,256 | 5,806,592 | -1,273,161 | 0 | 5,636,098 |
| 2026 | 6,838,249 | 462,266 | 93,342 | 179,504 | 5,806,592 | -1,404,472 | 0 | 5,137,232 |
| 2027 | 3,419,125 | 231,133 | 46,671 | 89,752 | 5,806,592 | -1,535,783 | 0 | 4,638,365 |
| 2028 | 0 | 0 | 0 | 0 | 5,806,592 | -1,667,094 | 0 | 4,139,498 |
| **Sum of Annual Capital Revenue Requirements** | | | | | | | | 200,387,874 |

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

TPI = $116,131,841

| 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 | 23,554,043 | 0.6913 | 16,281,827 | 20,927,462 | 0.7780 | 16,281,827 |
| 2010 | 24,826,806 | 0.6303 | 15,648,328 | 21,415,821 | 0.7307 | 15,648,328 |
| 2011 | 18,722,543 | 0.5747 | 10,760,225 | 15,679,835 | 0.6862 | 10,760,225 |
| 2012 | 14,860,439 | 0.5240 | 7,787,491 | 12,082,897 | 0.6445 | 7,787,491 |
| 2013 | 13,558,990 | 0.4778 | 6,478,921 | 10,703,592 | 0.6053 | 6,478,921 |
| 2014 | 10,738,341 | 0.4357 | 4,678,665 | 8,230,044 | 0.5685 | 4,678,665 |
| 2015 | 8,318,982 | 0.3973 | 3,304,946 | 6,190,104 | 0.5339 | 3,304,946 |
| 2016 | 7,820,116 | 0.3622 | 2,832,806 | 5,649,418 | 0.5014 | 2,832,806 |
| 2017 | 7,321,249 | 0.3303 | 2,418,233 | 5,134,977 | 0.4709 | 2,418,233 |
| 2018 | 6,822,383 | 0.3012 | 2,054,748 | 4,645,711 | 0.4423 | 2,054,748 |
| 2019 | 8,629,298 | 0.2746 | 2,369,776 | 5,704,983 | 0.4154 | 2,369,776 |
| 2020 | 8,130,431 | 0.2504 | 2,035,892 | 5,218,615 | 0.3901 | 2,035,892 |
| 2021 | 7,631,565 | 0.2283 | 1,742,466 | 4,755,739 | 0.3664 | 1,742,466 |
| 2022 | 7,132,698 | 0.2082 | 1,484,957 | 4,315,400 | 0.3441 | 1,484,957 |
| 2023 | 6,633,832 | 0.1898 | 1,259,314 | 3,896,677 | 0.3232 | 1,259,314 |
| 2024 | 6,134,965 | 0.1731 | 1,061,918 | 3,498,685 | 0.3035 | 1,061,918 |
| 2025 | 5,636,098 | 0.1578 | 889,543 | 3,120,571 | 0.2851 | 889,543 |
| 2026 | 5,137,232 | 0.1439 | 739,311 | 2,761,515 | 0.2677 | 739,311 |
| 2027 | 4,638,365 | 0.1312 | 608,656 | 2,420,728 | 0.2514 | 608,656 |
| 2028 | 4,139,498 | 0.1197 | 495,295 | 2,097,450 | 0.2361 | 495,295 |
| | 200,387,874 | | 84,933,317 | 148,450,222 | | 84,933,317 |

| | 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** | 84,933,317 | | 84,933,317 |
| **2. Escalation Rate** | 3% | | 3% |
| **3. After Tax Discount Rate = i** | 9.67% | | 6.48% |
| **4. Capital recovery factor value = i(1+i)ⁿ/(1+i)ⁿ-1 where book life = n and discount rate = i** | 0.114830578 | | 0.090586334 |
| **5. The levelized annual charges (end of year) = Present Value (Item 1) * Capital Recovery Factor (Item 4)** | 9,752,942 | | 7,693,798 |
| **6. Booked Cost** | 116,131,841 | | 116,131,841 |
| **7. The levelized annual fixed charge rate (levelized annual charges divided by the booked cost)** | **0.0840** | | **0.0663** |

**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 Cost
Divided by the Annual Electric Energy Consumption

**NOMINAL RATES**

| | Value | Units | From |
|---|---|---|---|
| **TPI** | $116,131,841 | $ | From TPI |
| **FCR** | 8.40% | % | From FCR |
| **AO&M** | $4,080,641 | $ | From AO&M |
| **AEP =** | 128,099 | MWeh/yr | From Assumptions |
| **COE - TPI X FCR** | 7.61 | cents/kWh | |
| **COE - AO&M** | 3.19 | cents/kWh | |
| **COE** | $0.1080 | $/kWh | Calculated |
| **COE** | **10.80** | cents/kWh | Calculated |

**REAL RATES**

| | Value | Units | From |
|---|---|---|---|
| **TPI** | $116,131,841 | $ | From TPI |
| **FCR** | 6.63% | % | From FCR |
| **AO&M** | $4,080,641 | $ | From AO&M |
| **AEP =** | 128,099 | MWeh/yr | From Assumptions |
| **COE - TPI X FCR** | 6.01 | cents/kWh | |
| **COE - AO&M** | 3.19 | cents/kWh | |
| **COE** | $0.0919 | $/kWh | Calculated |
| **COE** | **9.19** | cents/kWh | Calculated |

## 13.5. 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 | 0 | $0 | $0 | |
| Structural Elements | 0 | $0 | $0 | |
| Subsea Cables | 0 | $0 | $0 | |
| Turbine Installation | 0 | $0 | $0 | |
| Subsea Cable Installation | 0 | $0 | $0 | |
| Onshore Grid Interconnection | 0 | $0 | $0 | |
| | | | | |
| TOTAL | | | $109,746,835 | |

**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 | $54,873,418 | $4,938,608 | $4,030,039 | $58,903,457 |
| 2007 | $54,873,418 | $4,938,608 | $3,640,505 | $58,513,923 |
| Total | $109,746,835 | $9,877,215 | $7,670,544 | $117,417,380 |

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

| Costs | Yrly Cost | Amount | |
|---|---|---|---|
| Labor and Parts | $2,434,438 | $2,434,438 | |
| Insurance (1.5% of TPC) | $1,646,203 | $1,646,203 | |
| | | | |
| Total | | $4,080,641 | |

**FINANCIAL ASSUMPTIONS**

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

| | | | |
|---|---|---|---|
| 1 | Rated Plant Capacity © | 50.1 | MW |
| 2 | Annual Electric Energy Production (AEP) | 128,099 | MWeh/yr |
| | Therefore, Capacity Factor | 29.17 | % |
| 3 | Year Constant Dollars | 2005 | Year |
| 4 | Federal Tax Rate | 35 | % |
| 5 | State | Alaska | |
| 6 | State Tax Rate | 9.41 | % |
| | Composite Tax Rate (t) | 0.411165 | % |
| | t/(1-t) | 0.6983 | |
| 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 | 8.40 | % |
| 15 | Inflation rate | 3 | % |
| 16 | Federal Investment Tax Credit | 0 | Assumed take PTC |
| 17 | Federal Production Tax Credit inc 3% escalation | 0.018 | $/kWh for 1st 10 yrs |
| 18 | State Investment Tax Credit | 0 | % |
| 19 | State Production Tax Credit | | |
| 20 | Wholesale electricity price - 2005$ | 0.086 | $/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 | NA | % of Sch O&M cost |
| 25 | MACRS Year 1 | 0.2000 | |
| 26 | MACRS Year 2 | 0.3200 | |
| 27 | MACRS Year 3 | 0.1920 | |
| 28 | MACRS Year 4 | 0.1152 | |
| 29 | MACRS Year 5 | 0.1152 | |
| 30 | MACRS Year 6 | 0.0576 | |
| 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 | 11,572,716 | 11,750,641 | 11,931,301 | 12,114,739 | 12,568,352 | 13,038,950 | 13,527,169 | 14,033,668 | 14,559,133 |
| REC income | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| State ITC | 21,135 | | | | | | | | |
| Federal ITC | 0 | | | | | | | | |
| Fedaral PTC | 2,305,782 | 2,374,955 | 2,446,204 | 2,519,590 | 2,595,178 | 2,673,033 | 2,753,224 | 2,835,821 | 2,920,896 |
| TOTAL REVENUES | 11,593,851 | 11,750,641 | 11,931,301 | 12,114,739 | 12,568,352 | 13,038,950 | 13,527,169 | 14,033,668 | 14,559,133 |
| AVG $/KWH | 0.091 | 0.092 | 0.093 | 0.095 | 0.098 | 0.102 | 0.106 | 0.110 | 0.114 |
| OPERATING COSTS | | | | | | | | | |
| Scheduled and Unscheduled O&M | 4,080,641 | 4,203,060 | 4,329,152 | 4,459,026 | 4,592,797 | 4,730,581 | 4,872,498 | 5,018,673 | 5,169,233 |
| Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 4,080,641 | 4,203,060 | 4,329,152 | 4,459,026 | 4,592,797 | 4,730,581 | 4,872,498 | 5,018,673 | 5,169,233 |
| EBITDA | 7,513,210 | 7,547,581 | 7,602,149 | 7,655,712 | 7,975,555 | 8,308,369 | 8,654,671 | 9,014,995 | 9,389,899 |
| Tax Depreciation | 23,483,476 | 37,573,562 | 22,544,137 | 13,526,482 | 13,526,482 | 0 | 0 | 0 | 0 |
| Interest Paid | 6,575,373 | 6,431,687 | 6,276,505 | 6,108,910 | 5,927,906 | 5,732,422 | 5,521,300 | 5,293,288 | 5,047,034 |
| TAXABLE EARNINGS | -22,545,639 | -36,457,668 | -21,218,493 | -11,979,679 | -11,478,833 | 2,575,947 | 3,133,371 | 3,721,708 | 4,342,865 |
| State Tax | -2,121,545 | -3,430,667 | -1,996,660 | -1,127,288 | -1,080,158 | 242,397 | 294,850 | 350,213 | 408,664 |
| Federal Tax | -7,148,433 | -11,559,450 | -6,727,642 | -3,798,337 | -3,639,536 | 816,743 | 993,482 | 1,180,023 | 1,376,970 |
| TOTAL TAX OBLIGATIONS | -9,269,978 | -14,990,117 | -8,724,302 | -4,925,625 | -4,719,694 | 1,059,139 | 1,288,333 | 1,530,236 | 1,785,634 |

**CURRENT DOLLARS**

| 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|---|
| 15,104,272 | 15,669,823 | 16,256,550 | 16,865,245 | 17,496,733 | 18,151,865 | 18,831,527 | 19,536,638 | 20,268,150 | 21,027,053 | 21,814,371 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3,008,523 | | | | | | | | | | |
| 15,104,272 | 15,669,823 | 16,256,550 | 16,865,245 | 17,496,733 | 18,151,865 | 18,831,527 | 19,536,638 | 20,268,150 | 21,027,053 | 21,814,371 |
| 0.118 | 0.122 | 0.127 | 0.132 | 0.137 | 0.142 | 0.147 | 0.153 | 0.158 | 0.164 | 0.170 |
| 5,324,310 | 5,484,040 | 5,648,561 | 5,818,018 | 5,992,558 | 6,172,335 | 6,357,505 | 6,548,230 | 6,744,677 | 6,947,017 | 7,155,428 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5,324,310 | 5,484,040 | 5,648,561 | 5,818,018 | 5,992,558 | 6,172,335 | 6,357,505 | 6,548,230 | 6,744,677 | 6,947,017 | 7,155,428 |
| 9,779,961 | 10,185,783 | 10,607,989 | 11,047,228 | 11,504,174 | 11,979,530 | 12,474,022 | 12,988,408 | 13,523,473 | 14,080,036 | 14,658,943 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4,781,081 | 4,493,851 | 4,183,643 | 3,848,618 | 3,486,791 | 3,096,018 | 2,673,983 | 2,218,185 | 1,725,924 | 1,194,281 | 620,108 |
| 4,998,881 | 5,691,932 | 6,424,346 | 7,198,610 | 8,017,383 | 8,883,512 | 9,800,039 | 10,770,222 | 11,797,549 | 12,885,754 | 14,038,836 |
| 470,395 | 535,611 | 604,531 | 677,389 | 754,436 | 835,938 | 922,184 | 1,013,478 | 1,110,149 | 1,212,549 | 1,321,054 |
| 1,584,970 | 1,804,712 | 2,036,935 | 2,282,427 | 2,542,032 | 2,816,651 | 3,107,249 | 3,414,861 | 3,740,590 | 4,085,622 | 4,451,223 |
| 2,055,365 | 2,340,323 | 2,641,466 | 2,959,816 | 3,296,467 | 3,652,589 | 4,029,433 | 4,428,338 | 4,850,739 | 5,298,171 | 5,772,278 |

**CASH FLOW STATEMENT**

| Description/Year | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|---|---|
| EBITDA | | | 7,513,210 | 7,547,581 | 7,602,149 | 7,655,712 | 7,975,555 | 8,308,369 |
| Taxes Paid | | | -9,269,978 | -14,990,117 | -8,724,302 | -4,925,625 | -4,719,694 | 1,059,139 |
| CASH FLOW FROM OPS | | | 16,783,188 | 22,537,698 | 16,326,451 | 12,581,337 | 12,695,250 | 7,249,230 |
| Debt Service | | | -8,371,454 | -8,371,454 | -8,371,454 | -8,371,454 | -8,371,454 | -8,371,454 |
| NET CASH FLOW AFTER TAX | | -35,225,214 | 8,411,734 | 14,166,244 | 7,954,997 | 4,209,884 | 4,323,796 | -1,122,223 |
| CUM NET CASH FLOW | | -35,225,214 | -26,813,480 | -12,647,235 | -4,692,238 | -482,354 | 3,841,441 | 2,719,218 |

**IRR ON NET CASH FLOW AFTER TAX**

## CASH FLOW STATEMENT

| 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|
| 8,654,671 | 9,014,995 | 9,389,899 | 9,779,961 | 10,185,783 | 10,607,989 | 11,047,228 |
| 1,288,333 | 1,530,236 | 1,785,634 | 2,055,365 | 2,340,323 | 2,641,466 | 2,959,816 |
| 7,366,338 | 7,484,759 | 7,604,265 | 7,724,597 | 7,845,460 | 7,966,522 | 8,087,411 |
| -8,371,454 | -8,371,454 | -8,371,454 | -8,371,454 | -8,371,454 | -8,371,454 | -8,371,454 |
| -1,005,115 | -886,694 | -767,189 | -646,857 | -525,994 | -404,931 | -284,042 |
| 1,714,103 | 827,408 | 60,220 | -586,637 | -1,112,631 | -1,517,562 | -1,801,605 |

| 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|
| 11,504,174 | 11,979,530 | 12,474,022 | 12,988,408 | 13,523,473 | 14,080,036 | 14,658,943 |
| 3,296,467 | 3,652,589 | 4,029,433 | 4,428,338 | 4,850,739 | 5,298,171 | 5,772,278 |
| 8,207,707 | 8,326,941 | 8,444,589 | 8,560,069 | 8,672,734 | 8,781,864 | 8,886,665 |
| -8,371,454 | -8,371,454 | -8,371,454 | -8,371,454 | -8,371,454 | -8,371,454 | -8,371,454 |
| -163,747 | -44,513 | 73,135 | 188,616 | 301,280 | 410,411 | 515,212 |
| -1,965,352 | -2,009,865 | -1,936,730 | -1,748,114 | -1,446,834 | -1,036,423 | -521,211 |

**IRR ON NET CASH FLOW AFTER TAX** -0.7%

## 13.6. 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 (2005$) | |
|---|---|---|---|---|
| Procurement | | | | |
| Power Conversion System | 0 | $0 | $0 | |
| Structural Elements | 0 | $0 | $0 | |
| Subsea Cables | 0 | $0 | $0 | |
| Turbine Installation | 0 | $0 | $0 | |
| Subsea Cable Installation | 0 | $0 | $0 | |
| Onshore Grid Interconnection | 0 | $109,746,858 | $109,746,858 | |
| | | | | |
| TOTAL | | | $109,746,858 | |

**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 | $54,873,429 | $2,743,671 | $2,488,591 | $57,362,020 |
| 2008 | $54,873,429 | $2,743,671 | $2,370,087 | $57,243,516 |
| Total | $109,746,858 | $5,487,343 | $4,858,677 | $114,605,536 |

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

| Costs | Yrly Cost | Amount | |
|---|---|---|---|
| Labor and Parts | $2,434,438 | $2,434,438 | |
| Insurance (1.5% of TPC) | $1,646,203 | $1,646,203 | |
| | | | |
| Total | | $4,080,641 | |

**FINANCIAL ASSUMPTIONS**

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

| | | | |
|---|---|---|---|
| | Rated Plant Capacity © | 50.1 | MW |
| | Annual Electric Energy Production (AEP) | 128,099 | MWeh/yr |
| | Therefore, Capacity Factor | 29.2 | % |
| 1 | Year Constant Dollars | 2005 | Year |
| 2 | Construction Start | 2007 | Year |
| 3 | Construction Period | 2 | Year |
| | Federal Tax Rate | - | % |
| 5 | State | Alaska | |
| 6 | Generator | Municipal Generator | |
| | State Tax Rate | - | % |
| | Composite Tax Rate (t) | 0.00000 | |
| | t/(1-t) | 0.00000 | |
| 7 | Book Life | 20 | Years |
| | Construction Financing Rate | 5.0 | % |
| | Common Equity Financing Share | - | % |
| | Preferred Equity Financing Share | - | % |
| | Debt Financing Share | 100 | % |
| | Common Equity Financing Rate | - | % |
| | Preferred Equity Financing Rate | - | % |
| | Debt Financing Rate | 5.0 | % |
| | Nominal Discount Rate Before-Tax | 5 | % |
| | Nominal Discount Rate After-Tax | 5.00 | % |
| 8 | Inflation Rate = 3% | 3 | % |
| | Real Discount Rate Before-Tax | 1.94 | % |
| | Real Discount Rate After-Tax | 1.94 | % |
| | Federal Investment Tax Credit (1) | 0 | |
| | Federal Production Tax Credit (2) | 0.000 | |
| | Federal REPI (3) | 0.015 | |
| | State Investment Tax Credit | 0 | $ |
| | State Investment Tax Credit Limit | None | |
| | Renewable Energy Certificate (4) | 0.000 | $/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 1st 10 years with escalation (assumed 3% per yr)

4 $/kWh for entire plant life with escalation (assumed 3% per yr)

**NET PRESENT VALUE (NPV) - 2005 $**

**TPI =** $114,605,536

| 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** | **114,605,536** | | | | | **114,605,536** |
| 2009 | 114,605,536 | 5,730,277 | 5,730,277 | 0.2000 | 0 | 108,875,259 |
| 2010 | 114,605,536 | 5,730,277 | 11,460,554 | 0.3200 | 0 | 103,144,982 |
| 2011 | 114,605,536 | 5,730,277 | 17,190,830 | 0.1920 | 0 | 97,414,705 |
| 2012 | 114,605,536 | 5,730,277 | 22,921,107 | 0.1152 | 0 | 91,684,429 |
| 2013 | 114,605,536 | 5,730,277 | 28,651,384 | 0.1152 | 0 | 85,954,152 |
| 2014 | 114,605,536 | 5,730,277 | 34,381,661 | 0.0576 | 0 | 80,223,875 |
| 2015 | 114,605,536 | 5,730,277 | 40,111,938 | 0.0000 | 0 | 74,493,598 |
| 2016 | 114,605,536 | 5,730,277 | 45,842,214 | 0.0000 | 0 | 68,763,322 |
| 2017 | 114,605,536 | 5,730,277 | 51,572,491 | 0.0000 | 0 | 63,033,045 |
| 2018 | 114,605,536 | 5,730,277 | 57,302,768 | 0.0000 | 0 | 57,302,768 |
| 2019 | 114,605,536 | 5,730,277 | 63,033,045 | 0.0000 | 0 | 51,572,491 |
| 2020 | 114,605,536 | 5,730,277 | 68,763,322 | 0.0000 | 0 | 45,842,214 |
| 2021 | 114,605,536 | 5,730,277 | 74,493,598 | 0.0000 | 0 | 40,111,938 |
| 2022 | 114,605,536 | 5,730,277 | 80,223,875 | 0.0000 | 0 | 34,381,661 |
| 2023 | 114,605,536 | 5,730,277 | 85,954,152 | 0.0000 | 0 | 28,651,384 |
| 2024 | 114,605,536 | 5,730,277 | 91,684,429 | 0.0000 | 0 | 22,921,107 |
| 2025 | 114,605,536 | 5,730,277 | 97,414,705 | 0.0000 | 0 | 17,190,830 |
| 2026 | 114,605,536 | 5,730,277 | 103,144,982 | 0.0000 | 0 | 11,460,554 |
| 2027 | 114,605,536 | 5,730,277 | 108,875,259 | 0.0000 | 0 | 5,730,277 |
| 2028 | 114,605,536 | 5,730,277 | 114,605,536 | 0.0000 | 0 | 0 |

## CAPITAL REVENUE REQUIREMENTS 2005$

**TPI =** $114,605,536

| End of Year | Net Book | Returns to Equity Common | Returns to Equity Pref | Interest on Debt | Book Dep | Income Tax on Equity Return | Fed PTC and REC | Capital Revenue Req'ts |
|---|---|---|---|---|---|---|---|---|
| | A | B | C | D | E | F | H | I |
| 2009 | 108,875,259 | 0 | 0 | 5,443,763 | 5,730,277 | 0 | 1,921,485 | 9,252,555 |
| 2010 | 103,144,982 | 0 | 0 | 5,157,249 | 5,730,277 | 0 | 1,921,485 | 8,966,041 |
| 2011 | 97,414,705 | 0 | 0 | 4,870,735 | 5,730,277 | 0 | 1,921,485 | 8,679,527 |
| 2012 | 91,684,429 | 0 | 0 | 4,584,221 | 5,730,277 | 0 | 1,921,485 | 8,393,013 |
| 2013 | 85,954,152 | 0 | 0 | 4,297,708 | 5,730,277 | 0 | 1,921,485 | 8,106,499 |
| 2014 | 80,223,875 | 0 | 0 | 4,011,194 | 5,730,277 | 0 | 1,921,485 | 7,819,986 |
| 2015 | 74,493,598 | 0 | 0 | 3,724,680 | 5,730,277 | 0 | 1,921,485 | 7,533,472 |
| 2016 | 68,763,322 | 0 | 0 | 3,438,166 | 5,730,277 | 0 | 1,921,485 | 7,246,958 |
| 2017 | 63,033,045 | 0 | 0 | 3,151,652 | 5,730,277 | 0 | 1,921,485 | 6,960,444 |
| 2018 | 57,302,768 | 0 | 0 | 2,865,138 | 5,730,277 | 0 | 1,921,485 | 6,673,930 |
| 2019 | 51,572,491 | 0 | 0 | 2,578,625 | 5,730,277 | 0 | 0 | 8,308,901 |
| 2020 | 45,842,214 | 0 | 0 | 2,292,111 | 5,730,277 | 0 | 0 | 8,022,388 |
| 2021 | 40,111,938 | 0 | 0 | 2,005,597 | 5,730,277 | 0 | 0 | 7,735,874 |
| 2022 | 34,381,661 | 0 | 0 | 1,719,083 | 5,730,277 | 0 | 0 | 7,449,360 |
| 2023 | 28,651,384 | 0 | 0 | 1,432,569 | 5,730,277 | 0 | 0 | 7,162,846 |
| 2024 | 22,921,107 | 0 | 0 | 1,146,055 | 5,730,277 | 0 | 0 | 6,876,332 |
| 2025 | 17,190,830 | 0 | 0 | 859,542 | 5,730,277 | 0 | 0 | 6,589,818 |
| 2026 | 11,460,554 | 0 | 0 | 573,028 | 5,730,277 | 0 | 0 | 6,303,304 |
| 2027 | 5,730,277 | 0 | 0 | 286,514 | 5,730,277 | 0 | 0 | 6,016,791 |
| 2028 | 0 | 0 | 0 | 0 | 5,730,277 | 0 | 0 | 5,730,277 |
| **Sum of Annual Capital Revenue Requirements** | | | | | | | | 149,828,315 |

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

TPI = $114,605,536

| 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 | 9,252,555 | 0.8227 | 7,612,100 | 8,220,775 | 0.9260 | 7,612,100 |
| 2010 | 8,966,041 | 0.7835 | 7,025,128 | 7,734,186 | 0.9083 | 7,025,128 |
| 2011 | 8,679,527 | 0.7462 | 6,476,797 | 7,268,967 | 0.8910 | 6,476,797 |
| 2012 | 8,393,013 | 0.7107 | 5,964,758 | 6,824,288 | 0.8740 | 5,964,758 |
| 2013 | 8,106,499 | 0.6768 | 5,486,798 | 6,399,345 | 0.8574 | 5,486,798 |
| 2014 | 7,819,986 | 0.6446 | 5,040,832 | 5,993,368 | 0.8411 | 5,040,832 |
| 2015 | 7,533,472 | 0.6139 | 4,624,898 | 5,605,610 | 0.8250 | 4,624,898 |
| 2016 | 7,246,958 | 0.5847 | 4,237,146 | 5,235,357 | 0.8093 | 4,237,146 |
| 2017 | 6,960,444 | 0.5568 | 3,875,836 | 4,881,915 | 0.7939 | 3,875,836 |
| 2018 | 6,673,930 | 0.5303 | 3,539,328 | 4,544,622 | 0.7788 | 3,539,328 |
| 2019 | 8,308,901 | 0.5051 | 4,196,560 | 5,493,163 | 0.7640 | 4,196,560 |
| 2020 | 8,022,388 | 0.4810 | 3,858,906 | 5,149,265 | 0.7494 | 3,858,906 |
| 2021 | 7,735,874 | 0.4581 | 3,543,893 | 4,820,741 | 0.7351 | 3,543,893 |
| 2022 | 7,449,360 | 0.4363 | 3,250,131 | 4,506,985 | 0.7211 | 3,250,131 |
| 2023 | 7,162,846 | 0.4155 | 2,976,310 | 4,207,417 | 0.7074 | 2,976,310 |
| 2024 | 6,876,332 | 0.3957 | 2,721,198 | 3,921,476 | 0.6939 | 2,721,198 |
| 2025 | 6,589,818 | 0.3769 | 2,483,633 | 3,648,623 | 0.6807 | 2,483,633 |
| 2026 | 6,303,304 | 0.3589 | 2,262,523 | 3,388,337 | 0.6677 | 2,262,523 |
| 2027 | 6,016,791 | 0.3418 | 2,056,839 | 3,140,118 | 0.6550 | 2,056,839 |
| 2028 | 5,730,277 | 0.3256 | 1,865,614 | 2,903,484 | 0.6425 | 1,865,614 |
| | 149,828,315 | | 83,099,227 | 103,888,041 | | 83,099,227 |

| | 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** | 83,099,227 | | 83,099,227 |
| **2. Escalation Rate** | 3% | | 3% |
| **3. After Tax 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** | 0.080242587 | | 0.060813464 |
| **5. The levelized annual charges (end of year) = Present Value (Item 1) * Capital Recovery Factor (Item 4)** | 6,668,097 | | 5,053,552 |
| **6. Booked Cost** | 114,605,536 | | 114,605,536 |
| **7. The levelized annual fixed charge rate (levelized annual charges divided by the booked cost)** | **0.0582** | | **0.0441** |

**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 including Levelized Overhaul and Replacement Cost
Divided by the Annual Electric Energy Consumption

**NOMINAL RATES**

| | Value | Units | From |
|---|---|---|---|
| **TPI** | $114,605,536 | $ | From TPI |
| **FCR** | 5.82% | % | From FCR |
| **AO&M** | $4,080,641 | $ | From AO&M |
| **AEP =** | 128,099 | MWeh/yr | From Assumptions |
| **COE - TPI X FCR** | 5.21 | cents/kWh | |
| **COE - AO&M** | 3.19 | cents/kWh | |
| **COE** | $0.0839 | $/kWh | Calculated |
| **COE** | **8.39** | cents/kWh | Calculated |

**REAL RATES**

| | Value | Units | From |
|---|---|---|---|
| **TPI** | $114,605,536 | $ | From TPI |
| **FCR** | 4.41% | % | From FCR |
| **AO&M** | $4,080,641 | $ | From AO&M |
| **AEP =** | 128,099 | MWeh/yr | From Assumptions |
| **COE - TPI X FCR** | 3.95 | cents/kWh | |
| **COE - AO&M** | 3.19 | cents/kWh | |
| **COE** | $0.0713 | $/kWh | Calculated |
| **COE** | **7.13** | cents/kWh | Calculated |