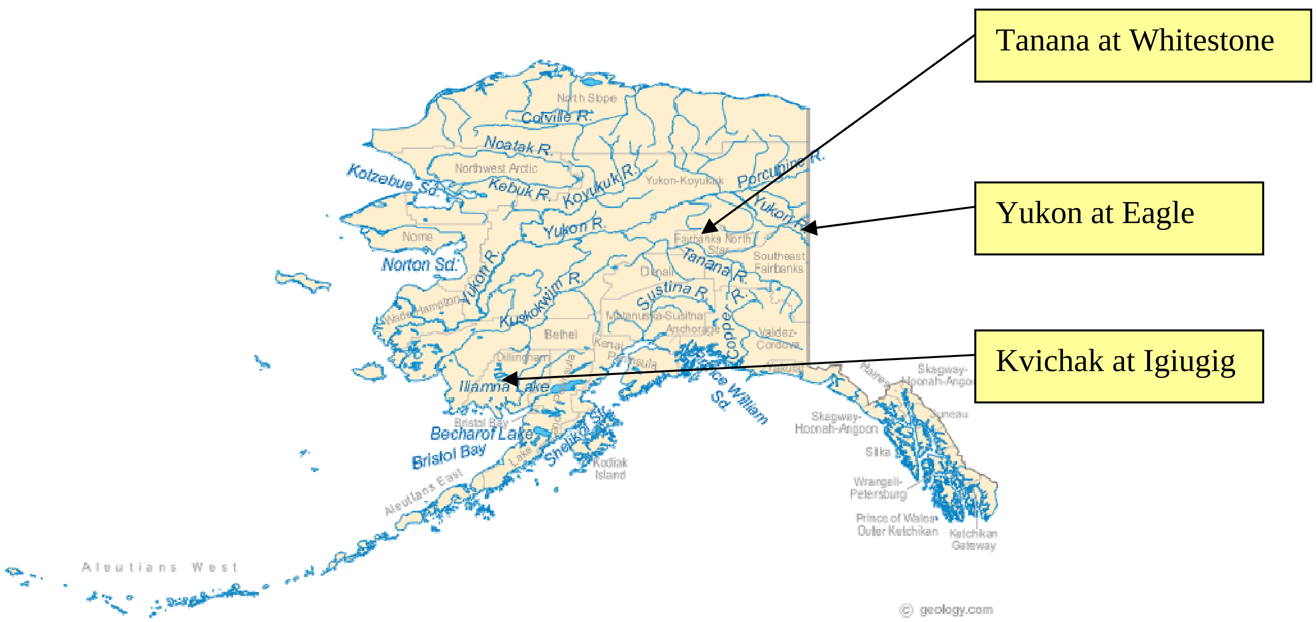
System Level Design, Performance, Cost and Economic Assessment – Alaska River In-Stream Power Plants



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1. Introduction and Summary

The Electric Power Research Institute (EPRI), under the sponsorship of the Alaska Energy Authority (AEA), Anchorage Municipal and Light, Chugach Electric and the Village of Iguigig, conducted a study to investigate the feasibility of a technology known as River In-Stream Energy Conversion (RISEC) for Alaska river applications. RISEC technology converts the kinetic energy of water in free-flowing rivers into electricity by placing water turbines (similar to wind turbines) directly into the flowing water.

A total of six (6) river sites were selected for site assessment; the results are contained in Reference 1. After careful review, three sites were selected for conceptual level feasibility studies, the results of which are described in this report. The three sites were:

- Tanana River at Whitestone
- Yukon River at Eagle
- Kvichak River at Igiugig

This report describes the results of a system-level design, performance, cost and economic study of RISEC power plant installed at the three Alaska river sites of interest. Eagle and Igiugig are villages with isolated grid infrastructures, while Whitestone, near Big Delta, is located near a 26kV transmission line that would allow for a potentially larger-scale build-out.

Currently, RISEC devices are at a very early stage of development. In order to carry out performance, cost and economic assessments, EPRI established a baseline device design consisting of open rotor horizontal axis turbines mounted on a pontoon structure. Based on that baseline design, a parametric performance, cost and economic model was established to adapt the technology to the site conditions encountered at various sites of interest.

Cost estimates were cross-checked with data supplied by Verdant Power from their 5m diameter rotor design. While this proved a useful point of comparison, it is important to understand that Verdant Power’s machine is significantly larger in scale then the conceptual designs outlined in this report. As such, data could not directly be applied to this application, but was useful as a validation point for some of the model's underlying assumptions.

The economic model used the simple payback period (SPP) as an indicator of the economic value of the potential project. SPP refers to the period of time required for the return on an investment to "repay" the sum of the original investment. For example, a $1000 investment which returned $500 per year would have a two-year payback period. It intuitively measures how long something takes to "pay for itself"; shorter payback periods are obviously preferable to longer payback periods (all else being equal). Payback period is widely used due to its ease of use.

The SPP for a RISEC power plant is the number of years it takes for the accumulated value of the revenues from the sale of electricity to equal the capital cost and the yearly operating and maintenance cost of the plant.

Iguigig and Eagle were treated as remote villages, and the RISEC plants were sized to meet a significant portion of the daily load (40kW for Iguigig and 70kW for Eagle). Whitestone was treated as a grid connected with a 26kV line that could likely be used to export more then 5MW. However, to be conservative, this study used a plant rated at 500kW. Any excess electricity produced is assumed to be absorbed by electrical resistive loads such as heating.

The value of electricity revenues is the avoided cost. For a rural Alaskan utility running on diesel, the avoided cost is essentially the fuel cost. With fuel costs of $8/gallon delivered and efficiencies of 13kWh/gallon, the avoided cost is typically 65 cents/kWh. The O&M cost of a diesel genset is 2-5 cents/kwh, but it was conservatively assumed that there would be no O&M savings.

The following assumptions about escalation of costs were made:

Escalation of non fuel cost = 3% per year

Escalation of fuel costs = 8% per year

The results of this study showed that:

- As EPRI has found in previous ocean wave and tidal feasibility studies, economic viability of the deployment site is directly linked to the power density at the site.
- Rotor size for a horizontal axis turbine is limited by the water depth at the deployment sites. This limits the technology's ability to scale a single horizontal axis rotor to higher power outputs.
- Power density peaks in Alaskan rivers occur during summer periods. This mismatch between resource availability and demand limits grid penetration. However some of this could be shifted by using electricity for alternative purposes such as heating.
- The commercial scale economics is limited in the isolated villages. Small deployment scales will yield higher comparable cost. This is not only true for RISEC technology, but is true for many other generation technologies as well.
- Small changes in the local velocities will create significant changes in power density since power density is a function of the velocity cubed. Detailed assessment of the local flow variations becomes a very important aspect of siting a RISEC device.
- Operational issues with this technology remains to be addressed with in-river tests. In particular, interference with ice, debris and wildlife need to be studied and, where required, mitigation measures incorporated into the RISEC device design.
- The SPP for remote village isolated-grid Iguigig is 3 to 4 years, for remote village isolated-grid Eagle 4 to 5 years, and for the remote village but grid-connected Whitestone case 8 to 9 years.

RISEC is an evolving technology field with different manufacturers pursuing different device concepts. Appendix B contains a list of developers active worldwide. It is included to provide the reader with an understanding of the range of technologies under development.

2. Site Selection

Site Overviews

In the spring of 2008, EPRI completed a site characterization study, in which a total of six sites in Alaska were assessed {Reference 1}. After reviewing the data for those six sites, three sites were selected for conceptual feasibility design studies. The three selected sites are: (1) Tanana River at Whitestone, (2) Yukon River at Eagle and (3) the Kvichack River at Igiugig. The following illustration shows the location of the selected three sites in yellow. The Igiugig and Eagle sites are connected to small isolated village grids, while the Whitestone site is located near a 26kV transmission line.

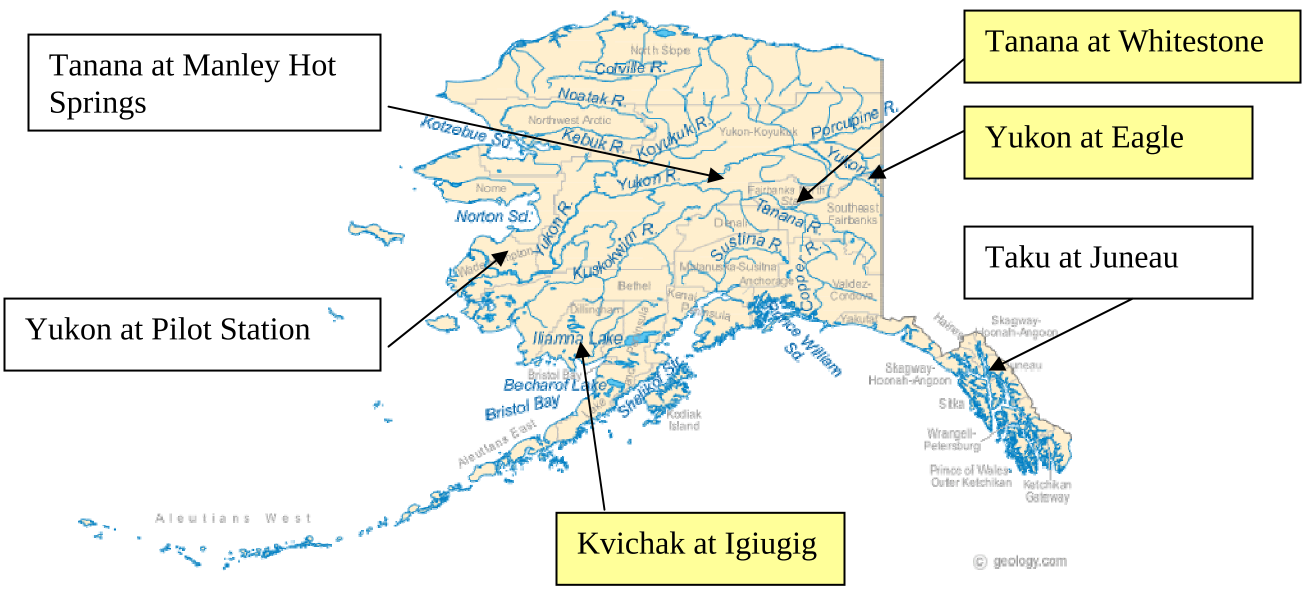


Figure 1: Site Location Overviews

The following sections summarize critical site condition data at the three sites of interest. The following figure shows the cross-sectional transects at the USGS measurement stations of the three sites.

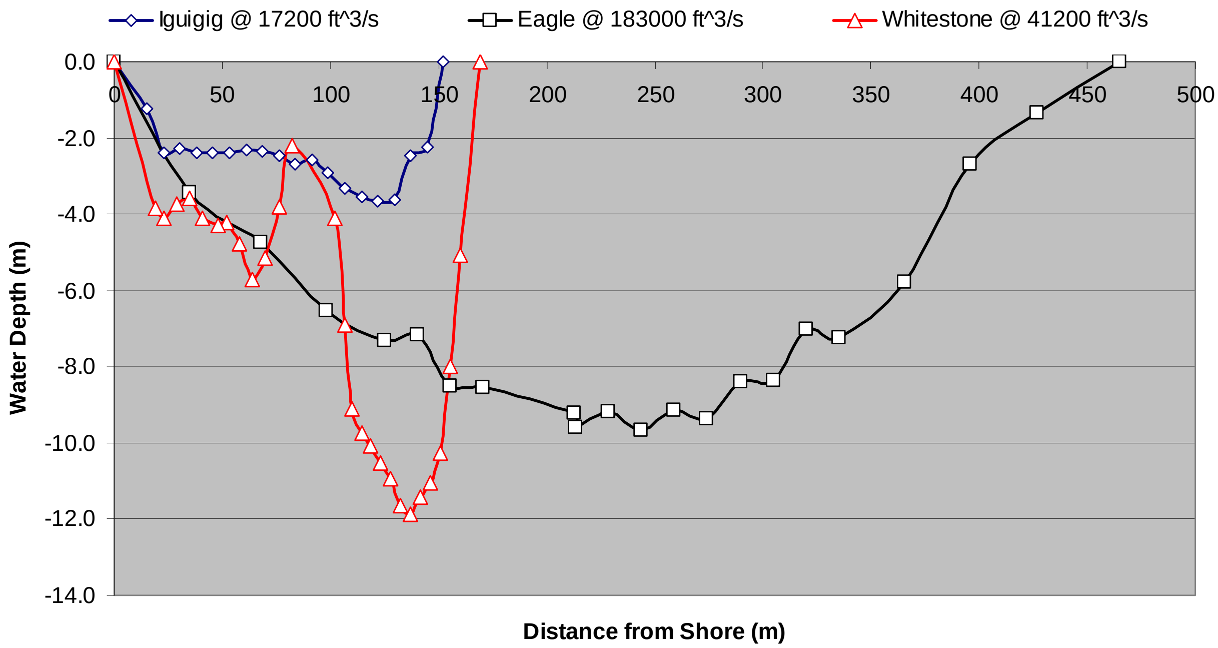


Figure 2: Cross sectional profiles of three sites during annual average river discharge rates

The following two figures represent the monthly average velocities and the monthly average cross sectional power densities. The figures show that the Iguigig site has much less summer/winter variability than the other two sites. This is a direct result of the storage provided by Lake Iliamna upstream of the Iguigig site. The higher river discharge rates during summer and associated higher velocities are a direct result of snow melt-off.

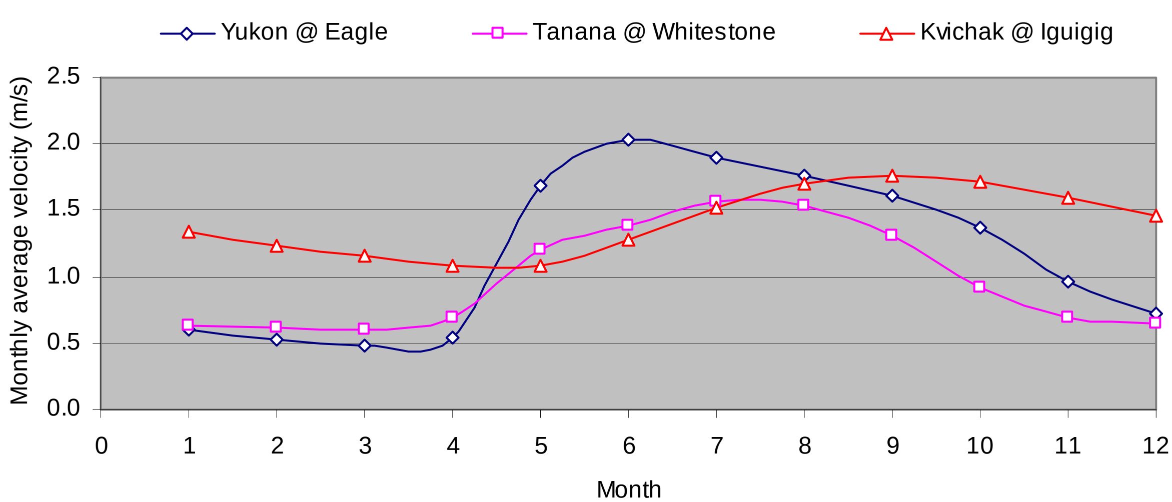


Figure 3: Average monthly river velocities at the three sites

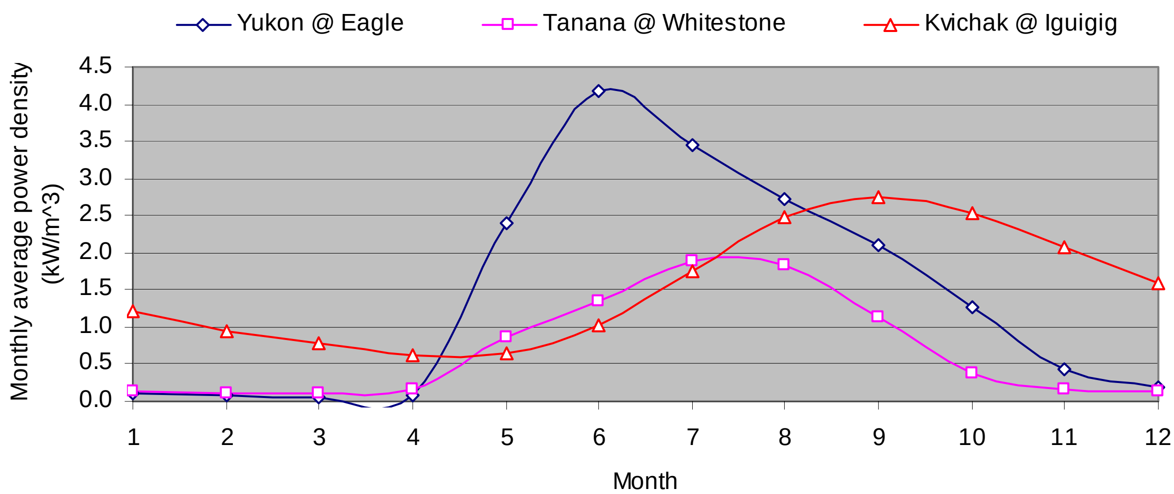


Figure 4: Average monthly power densities at the sites of interest

Alaskan discharge rates are fairly constant over the short term, however inter-annual variability can be significant. The hydrokinetic power density of a free-flowing stream relates to the cube of fluid velocity. The figure above shows the seasonal variability of power densities at the site. It shows that the power densities for all three sites are much higher during summer than winter. Hydrokinetic power density at a river site relates directly to rotor power output and forms therefore a critical part of the technology's economics.

All three sites are located near small Alaskan villages. Grid interconnection could be accomplished using a short underwater umbilical cable to shore from the unit deployment location. Because micro-siting studies have not been completed, it was assumed that all three deployment locations will require about 75m of underwater electrical cabling back to shore from their deployment locations and are interconnected on shore by a distribution line.

2.1. Electrical Interconnection

All deployment sites are within a few hundred yards of a suitable distribution line that could be used to connect the generation scheme. In a very generic sense, facilities with a total nameplate capacity of less then 1MW will require the following: a dedicated transformer, revenue metering, a disconnect device, a circuit interrupting device and a multifunction relay. In addition a RISEC deployment in rural Alaska will likely require real time satellite-based SCADA monitoring that includes voltage/frequency/power output, fault alarms, and webcams. It is expected that most deployments in Alaska will be less then 1MW in capacity. All devices are connected to the same cable that connects the array back on land. The following illustration shows the general arrangement of these devices in clusters.

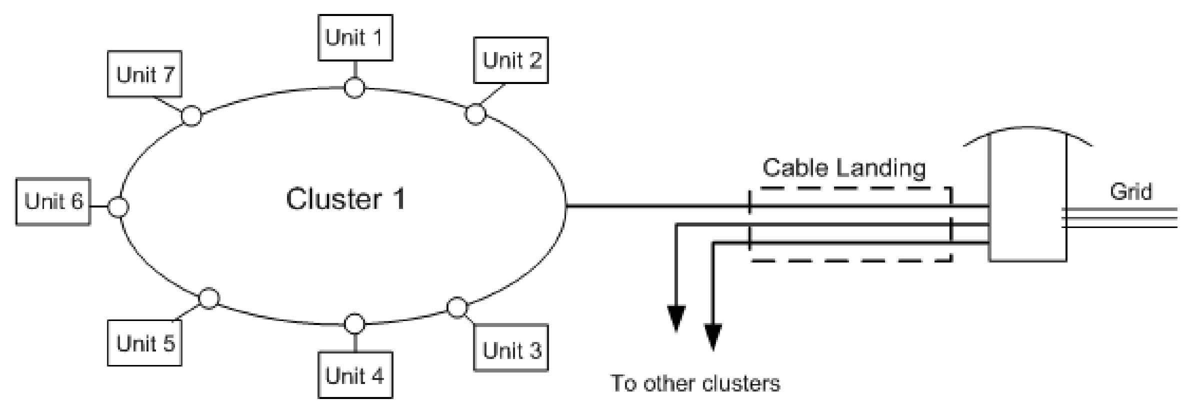


Figure 5: Generic electrical interconnection diagram

One of the key engineering issues to be addressed is connecting the RISEC devices, located in the river with the electrical grid on-shore. While the overland transmission is relatively simple and can be done by extending the existing grid network to the deployment site, the difficulty is with extending that transmission into the river. There are two different options that could be considered: 1) directional drilling and 2) ballasting the cable to the river-bed. These options are briefly discussed below.

Directional drilling is by far the most reliable option. Using this technique, a conduit will be buried sufficiently deep to fully protect the cable even during ice-breakup. Directional drilling is a well-established method, but will also be relatively expensive. Initial budgetary estimates by an Alaskan contractor came in between $150 to $300 per foot of directional drilling for a 4-inch diameter steel conduit. For more remote areas that do not have road access, cost will likely increase for mobilization charges because the equipment would need to be flown in.

A secondary option is simply to put the cable into a trench down to the water and then lay the cable onto the river-bed by ballasting the cables. The key issue with this option is the cable exposure during spring breakup, where ice-blocks scour the river-bed. As such, the cable would need to be removed while the units are retrieved during spring breakup. The cable could be ballasted using concrete blocks or concrete mats during deployment, which will likely require diver support. In order to achieve lower cost deployments, diver intervention needs to be avoided where possible. This would call for a cable design that integrates ballasting options such as clump-weights or interlocking steel pipe pieces that could be clamped to the cable at regular spacing to provide sufficient ballast and keep the cable in place. Ideally, such a cable could be deployed and recovered from a small working boat. It would require the cable to be sufficiently reinforced and flexible to handle the additional stress-levels and fatigue from the annually reoccurring deployment and recovery procedures. For the purpose of this conceptual design study, it was assumed that such a cable and deployment/recovery procedure can be designed and a fixed cost of $40,000 included in the cost buildup. The high cost of directional drilling would likely render this technique uneconomic for most of the smaller-scale deployments.

For places where ice-breakup and seabed scouring is not an issue, the cable could be placed in a 3" schedule 40 or schedule 80 pipe and laid on the river bed. The weight and structural integrity of this type of pipe would provide the cable with additional armor and keep it in place by its own weight. This type of piping is transported to the site in 20' or 40' length and welded together onsite.

2.2. Load Matching and Energy Storage

Electricity is an energy source that does not allow for easy energy storage. Demand and supply need to be closely matched to ensure voltage stability in the grid network. In remote grids, this is typically accomplished by running the generator in a load-following mode, meaning that the diesel generator automatically adjusts it's power output automatically as the electrical load on the network changes. In order to maximize the economic benefits of a RISEC plant, one needs to be able to always sell the electricity into the grid. Because RISEC plant power output is expected to be highest during summer months when loads on the grid network is lowest there is a need to limit the rated plant capacity to the summer low in electricity loads. Further, loads vary throughout the day. Typically more electricity is used during daytime then during nighttime. In order to accommodate these short-term fluctuations, some energy storage may be required and/or excess energy could be dissipated for heating purposes, displacing further heating fuel. Because little data was available on hourly load fluctuations, this study does not account for energy storage requirement. AEA has measured hourly data in Iguigig and also have typical daily and seasonal load variation models that can be used to create hourly data from monthly or annual data. These grid integration issue would need to be studied further as this technology is implemented in remote villages. The following shows some load data for Iguigig as an example of the potential short-term load variability.

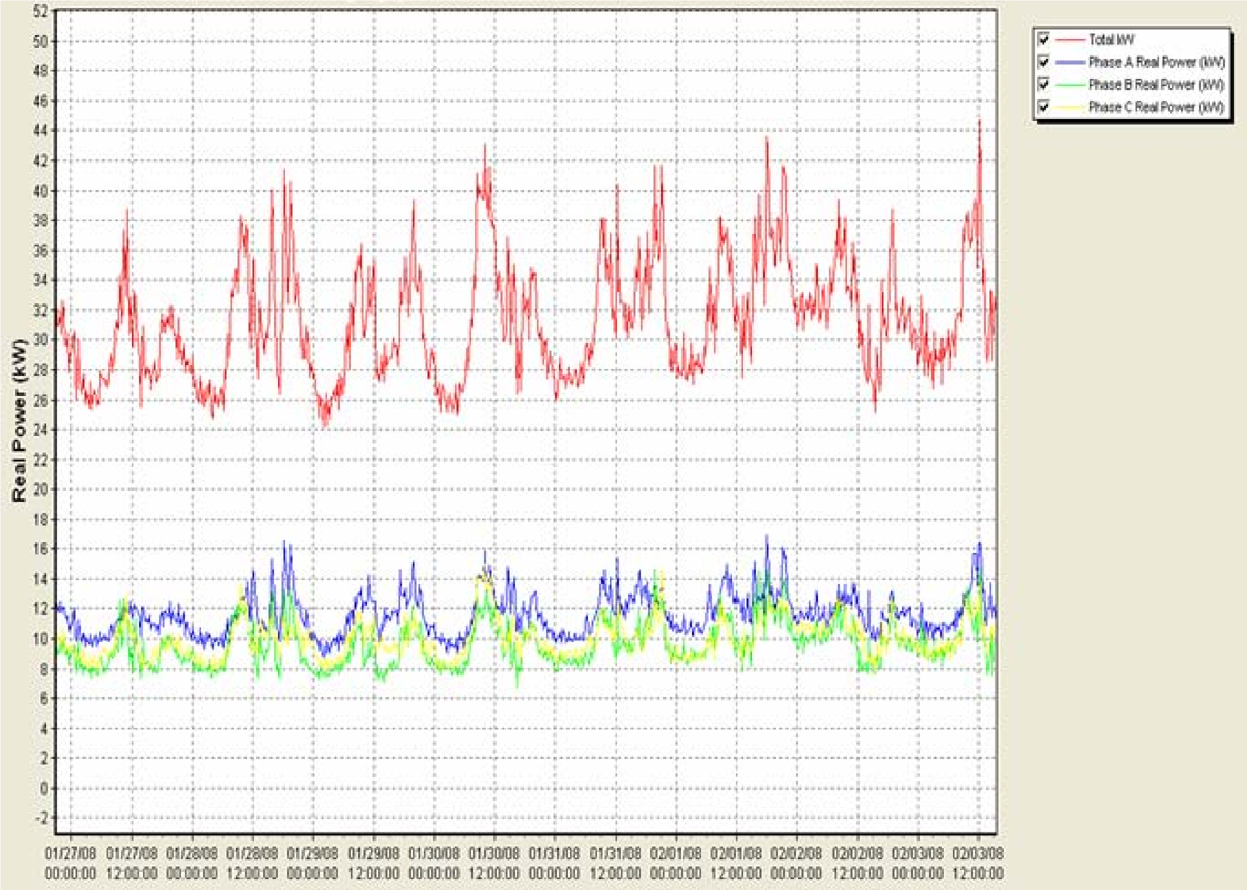


Figure 6: Iguigig Generator Load Data

3. RISEC Design

The purpose of this design study was to establish a conceptual RISEC device suitable for deployment at the selected sites. A horizontal axis machine was chosen because it allowed for the reuse of empirical data for rotor performance from the wind industry, and because Verdant Power, which cooperated in this study, provided access to performance and cost data for their 5m-diameter horizontal axis machine. Turbine diameter is limited in all locations by the water depth. The resulting small turbine diameters for this application did not lend themselves well to a variable pitch rotor. A fixed pitch rotor was chosen because of the resulting lower machine complexity. Vertical axis machines were not evaluated as part of this study, but cost and site-design issues are not likely to be very different from a horizontal axis machine.

A RISEC machine consists of multiple horizontal axis rotors that are immersed into the stream, connected to a power conversion system that generates electricity suitable for direct connection to the electrical grid. These power-modules are mounted onto a structure suitable for the installation location. During the study, different design options were investigated and parametrically modeled to determine and quantify principal advantages and disadvantages. Mounting multiple rotors on a single support structure was a primary strategy to reduce cost and improve the economic attractiveness of such a design. The following sections provide an overview of the various elements investigated.

3.1. Support Structure for Natural Rivers

For deployment in natural rivers, a floating platform was designed, consisting of two floating pontoons from which rotors are suspended into the water column. The following illustrations show the pontoon-boat with four rotors with a diameter of 1 meter suspended below the structure. Pontoon boats have been extensively used as leisure crafts and can be manufactured using existing capabilities at relatively low cost. The structure is designed to be constructed from marine grade aluminum and can be shipped in standard containers to the site, where the units are bolted together and deployed. The structure is scaleable and could accommodate more rotors or larger rotors, depending on how wide the structure is built. A water-tight box on the deck accommodates frequency converters and other electrical protection equipment required for grid interconnection. The mooring system consists of a combination of conventional steel cables and chains. An embedment anchor provides the necessary holding strength. The following illustrations show 3-D renderings of the device. In order to provide directional stability, the rotors are counter-rotating (the two inner rotors rotate in the opposite direction of the two outer rotors) to offset their torque, and the rotors are mounted toward the back of the pontoon. The rotor size can be adjusted to accommodate the water depth at the site. If rotor size is increased, the corresponding pontoon width will be increased as well. The basic structure can accommodate rotor sizes from 1m to 4m in diameter.

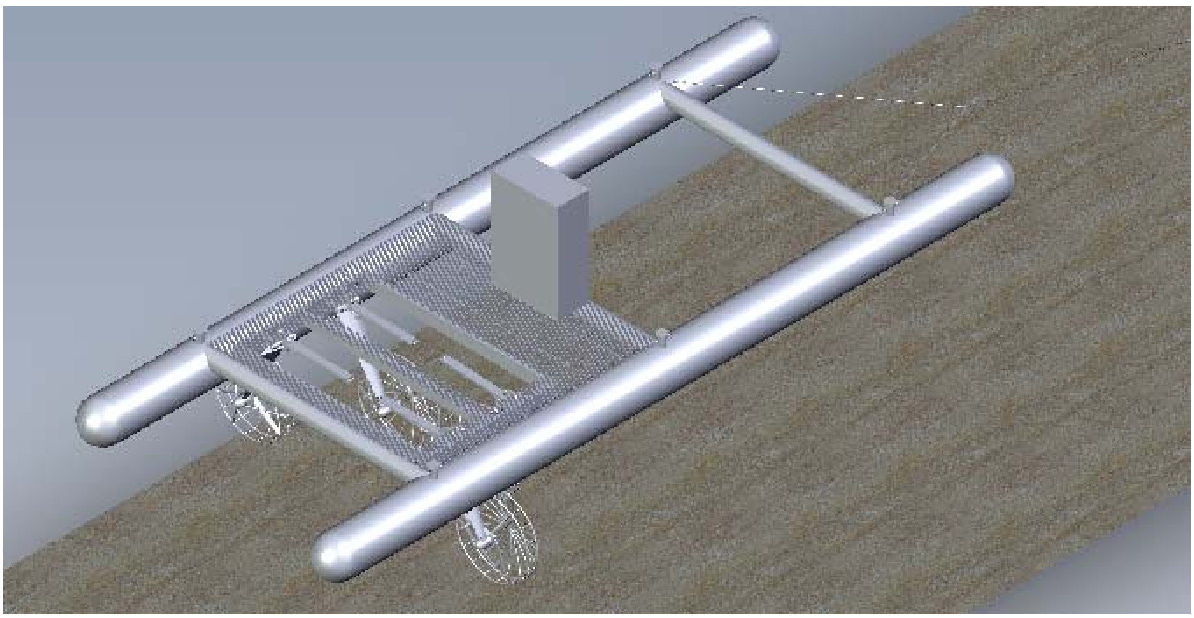


Figure 7: Pontoon Structure with lowered rotors

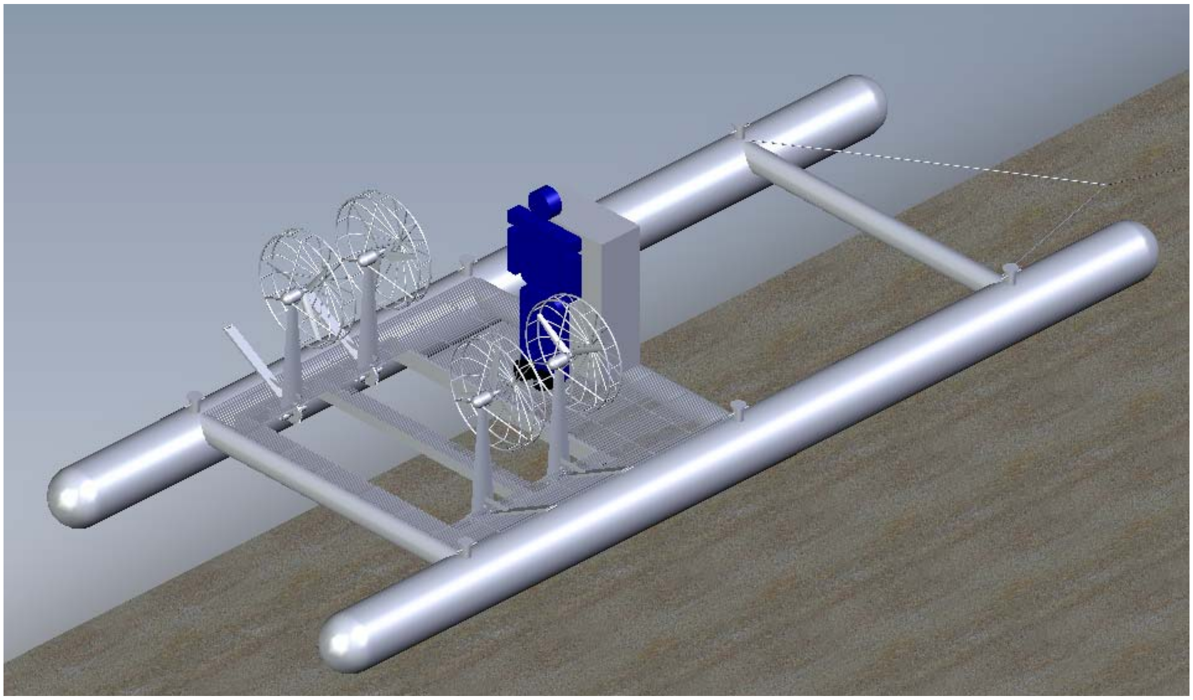


Figure 8: Pontoon structure with raised rotors. Human figure on pontoon is 6ft tall.

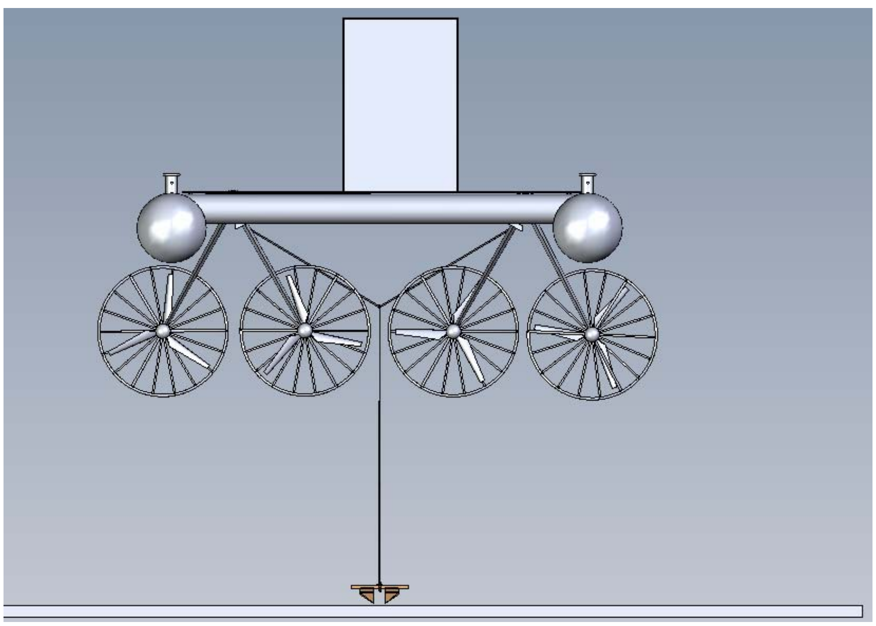


Figure 9: Pontoon Structure (front view)

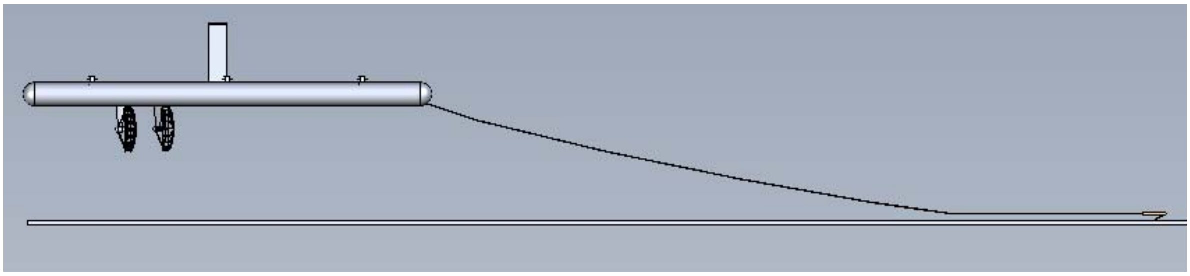


Figure 10: Pontoon structure mooring arrangement

To access the individual rotors for maintenance such as cleaning of the screen, they can be raised onto the deck. The rotors are connected by a strut to pin-type bearing that allows the rotors mounted at the end of the strut be rotated out of the water. In order for this to be accomplished without the rotors interfering with one another, they are offset in longitudinal directions, creating two bays through which they can be raised and lowered. A simple lever allows this operation to be completed easily for smaller rotors. If the same mechanism is applied for larger rotors, a winch could be used to raise and lower the individual rotors.

The following provides a summary of the specifications for this pontoon-structure. It is important to realize that depending on the rotor size, the width and the weight of the structure will change. The initial base-design and the above illustrations are based on a rotor diameter of 1m. The pontoon will, however, provide sufficient stability and buoyancy for rotors up to 4m in diameter.

Table 1: Pontoon Specification

Pontoon Length	10m
Pontoon Diameter	0.6m
Pontoon Width	4m – 16m
Rotor Diameter	1-4m
Number of rotors	4
Total Rotor Swept Area	$3.1m^2 – 50m^2$
Material	Marine grade aluminum
Total Assembly Weight	1800kg (depends on rotor size)

3.2. Complete Device Submersion

In order to be able to operate below the ice in winter, a completely submersible design alternative was evaluated. Complete submersion of the device will also allow the device to avoid most of the debris, present near the water surface. The device consists of a very similar pontoon structure that can be ballasted with water in order to completely submerse. As shown in the figure below, the pontoon structure is very similar, with the only differences being that 1) the rotors are fixed above the bottom two pontoons, 2) a third pontoon was added to provide stability during submersion, and 3) a hose assembly (shown in red) allows for ballasting and de-ballasting of the structure by allowing the adding and removal of water from the pontoons.

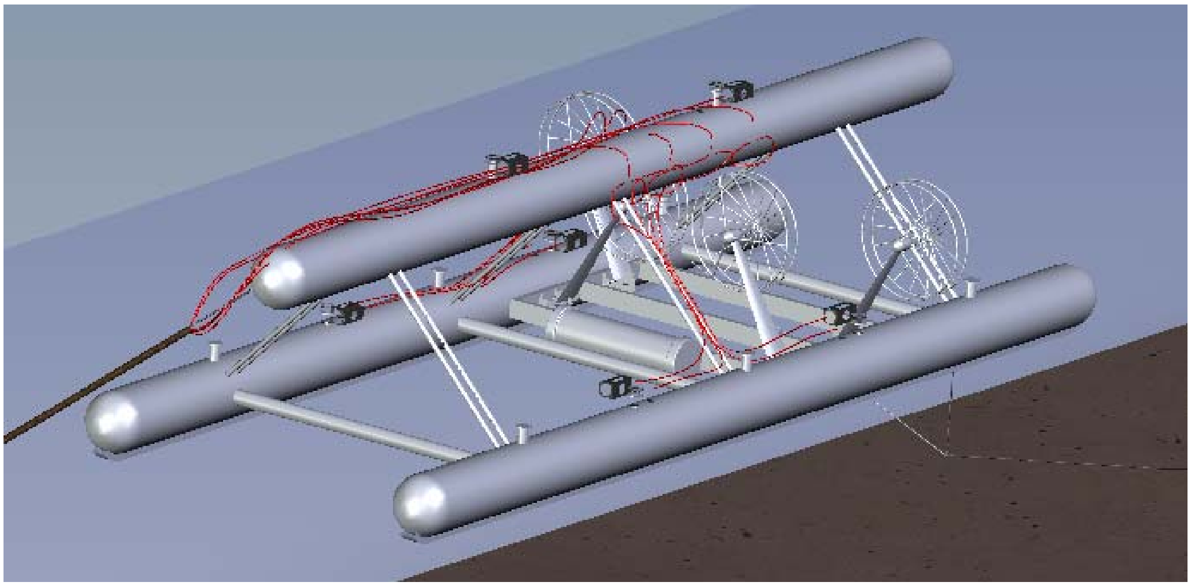


Figure 11: Completely submersible pontoon structure

The following figures illustrate the ballasting/de-ballasting process of the structure. First, the device is towed out to the deployment site and connected to its front-end mooring using an embedment anchor or other means to secure it to the riverbed. Once the device is in place, the boat is attached to the back and the device's hose assembly is placed on deck. The hose assembly enables the adding of water selectively to the three pontoons to allow for controlled submersion of the device.

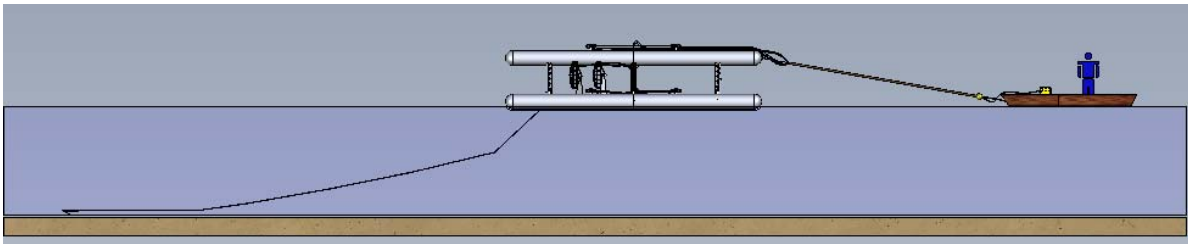


Figure 12: Floating Device before deployment

Next the bottom pontoons are selectively ballasted, leading to slow submersion of the device. The top-tank still provides buoyancy, ensuring that the device remains upright during submersion.

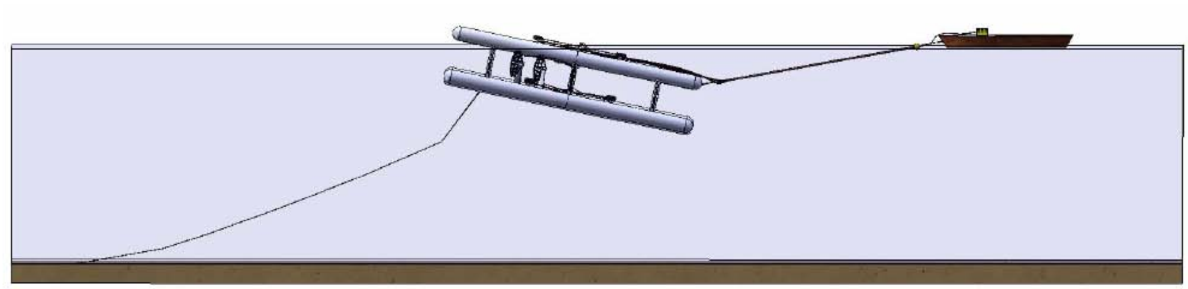


Figure 13: Device during submersion process

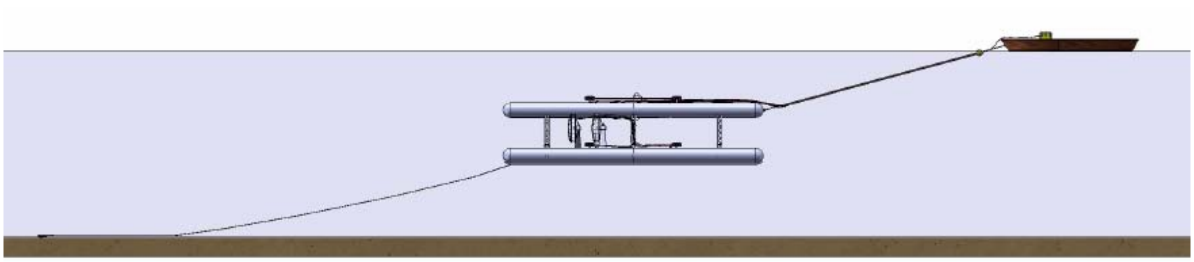


Figure 14: Device during controlled ballasting

Once the device sits on the river-bed, the top-side pontoon is ballasted as well to ensure that the device sits firmly on the river-bed. The hose assembly is either disconnected or stored submersed on the device itself.

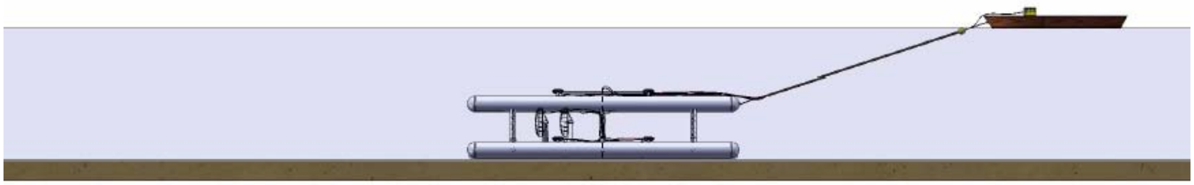


Figure 15: Device completely submersed

The recovery process will work in a very similar way. First the hose assembly is recovered to selectively pump air into the submersed pontoons (starting with the top-pontoon to provide stability).

3.3. Device Performance Calculations

To calculate turbine performance, two procedures were used: one for variable speed and one for fixed speed operation. Using the frequency distribution of velocities at the site, the power density can be calculated using the following equation:

$P/A=0.5 \times Rho \times V^3$

Where P/A is measured in watts per square meters, where P is the power in watts, A is the swept area in m^2, Rho is the water density ($1000 kg/m^3$) and V is the velocity measured in meters per second. Once the power density is known, it can be multiplied by the rotor swept area to obtain the total power acting on the rotor disk.

The remaining efficiency factors are applied to get from fluid power to electrical power. For a rotor operating at variable speed, the rotor's conversion efficiency is effectively constant. However, for a rotor operating at fixed speed, the efficiency changes as a function of tip-speed ratio, meaning at each velocity, the rotor will perform at a different efficiency. In order to optimize rotor performance, an iterative routine was used to determine optimal rotor speed.

3.4. Rotor Performance

The efficiency of a rotor (operating at a fixed blade pitch angle) in a free-flowing stream can be expressed as a function of its tip-speed ratio. The tip-speed ratio is the ratio between the velocity of the rotor's tip and the free-stream water velocity. If the fluid speed increases, the rotor speed has to increase as well to keep the rotor performing optimally. The following illustration shows a power coefficient for a small fixed pitch wind-turbine rotor. The performance of a water turbine should be similar.

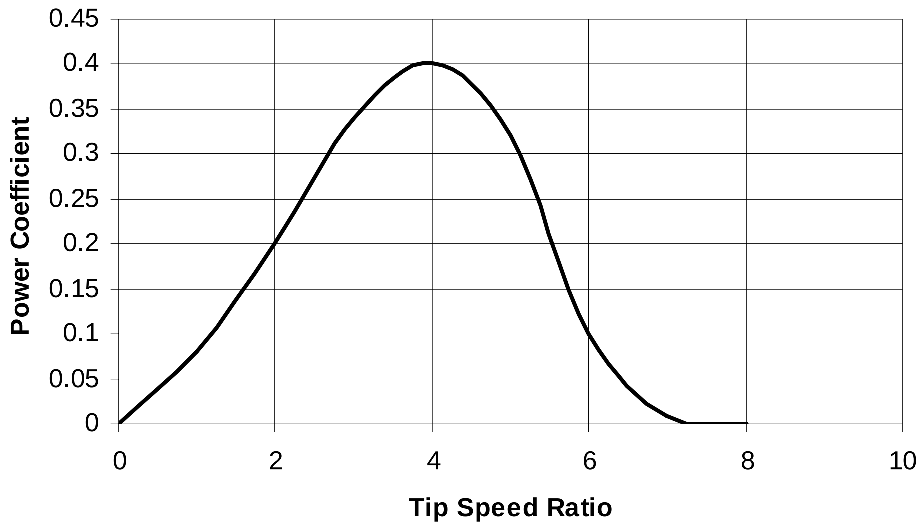


Figure 16 - Power Coefficient as a function of Tip-Speed Ratio (CP)

It is important to understand that this tip-speed ratio of the turbine can be influenced by blade design and number of blades employed. For the purpose of this design, a three-bladed rotor was chosen with a tip-speed ratio of four and a power coefficient of 40%. While this power coefficient is significantly below the 59% Betz limit (the theoretical upper limit to conversion efficiency from open rotor systems), this was viewed as a representative efficiency for smaller machines. For smaller machines, turbulent losses induced by its blade-tips tend to be higher than losses for larger diameter rotors, leading to lower overall power conversion efficiencies.

The rotational speed must be adjusted to yield the optimal tip-speed ratio. This adjustment requires that the generator is able to operate at variable speed. The variable speed operation can be attained by using a frequency converter, which converts the variable frequency input of the generator to a fixed synchronized frequency and voltage suitable for interconnection with the electric grid.

The tip speed of an underwater turbine is limited by cavitation. Cavitation is caused by water vaporizing due to pressure reduction on the back of the propeller blades. This distortion of the flow pattern can significantly reduce power output and erode the rotating propeller blades. While this critical cavitation speed is a function of many factors, including blade profile, water depth and turbulence, for the purpose of this study a limit on the rotor's tip-speed of 8m/s was assumed to keep the rotor in a safe operating range.

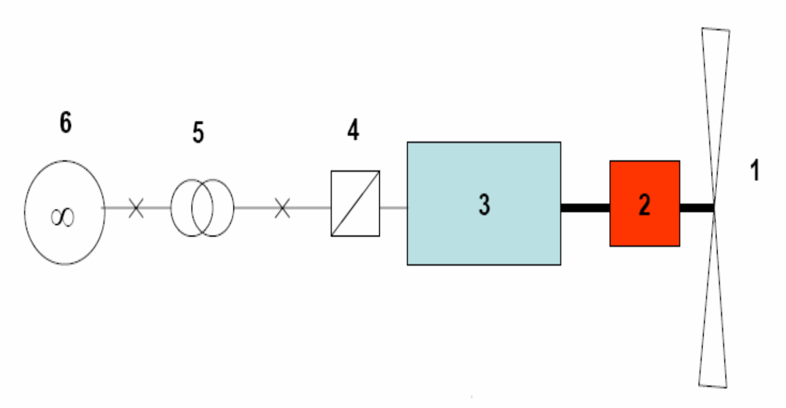
Additional losses occur in the conversion of primary mechanical energy into electricity. The following list offers typical efficiencies of a wind-turbine power train consisting of a gearbox, generator, frequency converter and step-up transformer.

Rotor Efficiency	40%
Gearbox	95%
Generator	95%
Frequency Converter	98%
Step-up transformer	98%
Power-train combined efficiency	34%

The resulting overall efficiency (water to wire) at the rotor's efficiency peak is 34.4% (40% power coefficient times 86% power train combined efficiency). A more detailed discussion on performance of horizontal axis rotors can be found in references 8, 9, 10 and 11.

3.5. Powertrain

The power-train of the system is very similar to a wind-turbine and consists of the following elements as outlined in the figure below:



Legend
1. Rotor
2. Gearbox
3. PM Generator
4. Frequency Converter
5. Step-up Transformer
6. Electrical Grid

Figure 17: Drive-train schematic

A basic strategy in the development of this conceptual design was the ability to re-use components from small wind turbines and thereby minimize risky and costly custom developments. However, there are a few fundamental differences between a wind turbine and a RISEC device:

1. RISEC rotors turn slower than equivalently rated wind machines because the rotor's tip-speed is limited by cavitation.
2. Because of the slower rotation, blade-root stresses are higher at equivalent machine size. At the same time, the rotor diameter is smaller because of the higher power-density in water than in air.
3. RISEC devices operate below the water, requiring additional component protection such as encasing the generator and other components in water-tight enclosures.
4. There is a good chance that debris suspended in mid-water can damage the open rotors. While there is limited experience with such issues, it is likely that some sort of a screen will be required to protect the rotating blades from such damage. Such screens will likely require frequent cleaning. Also, flow interference of the screen on the rotor would need to be evaluated.

The following paragraphs provide outlines of the device's key elements, including the water-tight housing, the rotor and the protective screen. The following is a sketch of the power-train module in three different sizes. Dimensions shown are in millimeters.

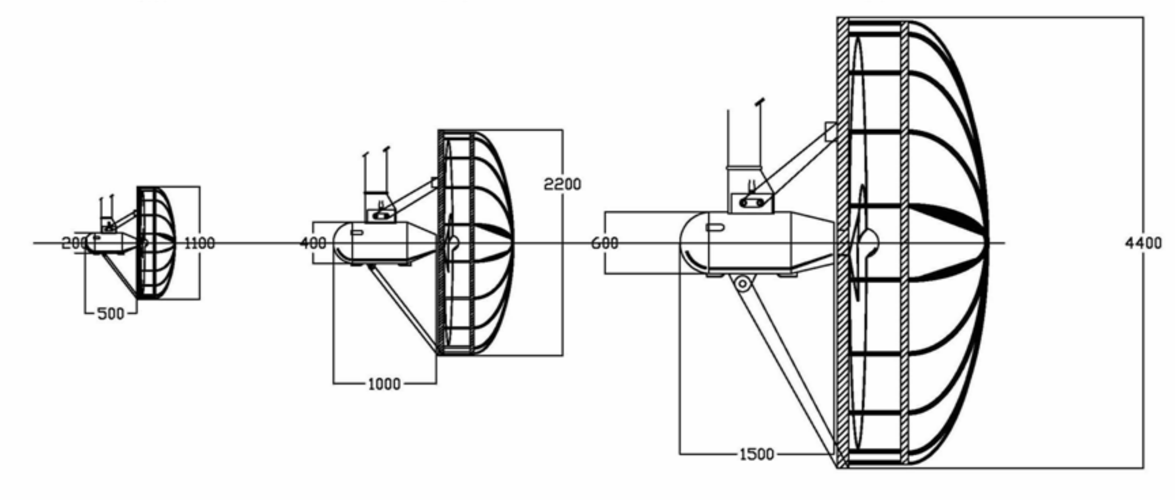


Figure 18: Power-train module at 3 different diameters

The generator housing provides an air-tight enclosure to protect the electric generator and gearbox from water intrusion. It also transfers the principal loads from the generator to the strut that connects the rotor assembly to the support structure.

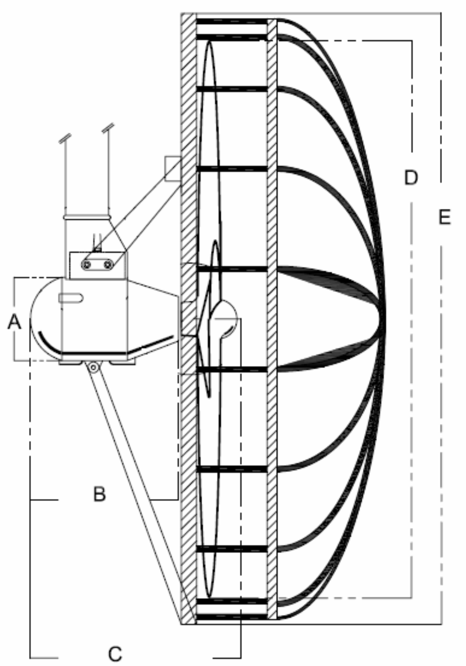


Figure 19: Power-train Design

While the dimensions of the rotor and screen are a function of the rotor diameter, the generator housing is largely a function of power rating. The following table provides the generator housing dimensions at various rated capacities (Dimension A and B in above sketch).

Table 2: Powertrain housing specifications

Rated Capacity	Housing diameter (A)	Housing length (B)	Weight
0.5kW	200mm	500mm	13.6 kg
2 kW	400mm	1000mm	18.1 kg
5 kW	600mm	1500mm	25 kg

A protective screen is required for sites that have a high amount of debris suspended in the water column. The protective screen is built from a ½ inch round stainless steel bar to withstand the impact of debris pieces. The screen is mounted onto the generator housing. A front-view and a side-view of the screen are shown below.

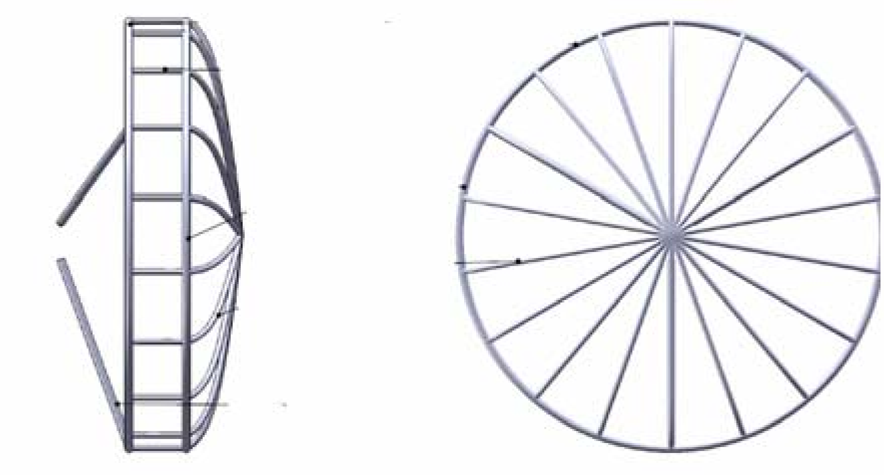


Figure 20: Protective screen

AP&T has designed a similar pontoon-type device with a trash rack mounted on its front end which may be a more robust alternative to the design described herein. The rotor may also need a fish screen as shown in the illustration below. Detailed design requirements for these elements are unknown at present because there is no operational experience yet available.

Figure 21: Example of fish screen

3.6. Investigation of Design Alternatives

Power-train topology alternatives to the base case described above were investigated in respect to their cost-reduction potential and impact on lowering O&M cost. The following sections provide a brief review of these options. The costs evaluated in this report refer to the baseline design, not any of the alternative topologies outlined.

Removal of the speed-increaser gearbox and use of a low-rpm direct-drive generator: Material cost of permanent magnet generators scales directly to the peak torque it generates given a particular generator topology. Power is the product of torque and rotational speed (rpm). Because rotor rpm is limited by the rotor's tip-speed, smaller rotors can operate at higher rpm and therefore make direct drive permanent magnet topologies more attractive from a cost point of view. Some generic cost studies on gearboxes also revealed that they tend to be more costly at smaller sizes, making them an unattractive alternative at lower power ratings. Gearboxes also tend to be somewhat unreliable. Eliminating the need for a gearbox has the potential to significantly improve the overall system's reliability.

Use of a fluid-filled PM generator design, allowing the elimination of seals that otherwise would be required with a water-tight enclosure:

Various PM direct drive machines have been built as “wet” designs for applications such as ship-propulsion and submersible design. Instead of an air-gap between the stator and the rotor of the machine, the gap is simply filled with fluid. This option could reduce the cost of the enclosure significantly and provide for a potentially more reliable overall design.

Operating the unit at fixed speed, thereby eliminating the need for a frequency converter: This proves to be a useful design alternative for sites that have very consistent fluid velocities; as a result, variable speed operation would only minimally increase energy production. The elimination of a frequency converter can reduce the overall system cost significantly.

Placing the frequency converter on-shore:

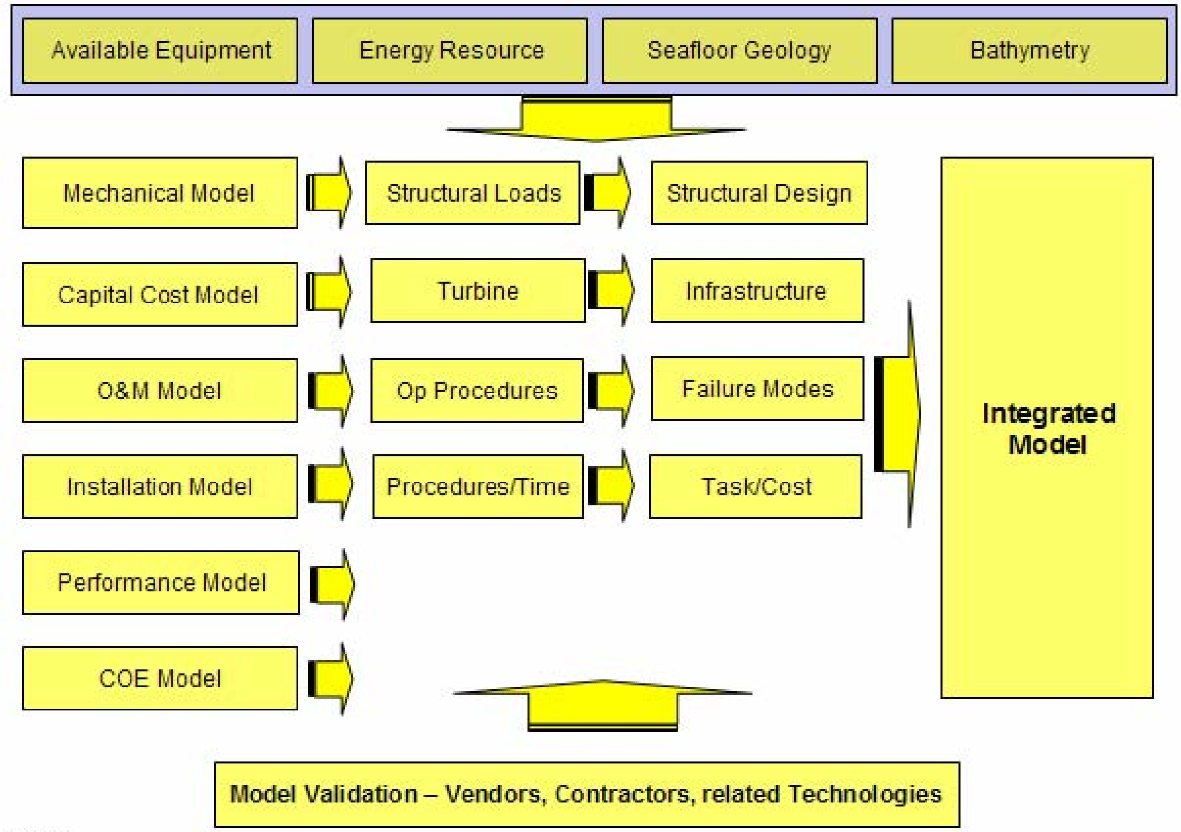
The rotor speed at which maximum efficiency is achieved is a direct function of the water velocity. Multiple units deployed in the same area are going to be subjected to very similar flow conditions (although there may be minor variations in flow locally). Thus, the optimal rotational speed and resulting AC frequency coming from the different generators is the same for all the rotors. This makes it possible to connect all the machines to the same cable and locate the frequency converter onshore. This option would reduce the complexity of the equipment located on the pontoon barge and provide the ability to place the frequency converter onshore into a protected environment without compromising efficiency.

Reduction of structural loads by use of furling mechanism:

Furling is used by small wind turbines to reduce the loads on the turbine. A wind-turbine or RISEC rotor is typically perpendicular to the fluid flow. A furling mechanism typically consists of a spring or weight-controlled mechanism that allows rotor to rotate out of that perpendicular direction, and therefore reduces the frontal area intersecting the fluid flow. The result is reduced power absorption, but also reduced loads on the rotor, which is favorable in conditions where it does not make economic sense to extract the additional power. This type of mechanism does not add much cost, but could reduce peak structural design loads significantly and therefore reduce cost.

3.7. *Integrated Modeling*

Integrated modeling is an approach that allows a rapid evaluation of different generation options and design alternatives. The basic concept is that changing one design aspect will have a ripple effect in terms of both cost and design to other components within the overall system. The following displays the elements of such an integrated model.



For the purpose of this study the conceptual designs served as the foundation to establish cost estimates of the technology, which were then used in an established integrated modeling framework.

3.8. *Uncertainties in cost predictions*

For emerging renewable energy technologies such as RISEC, the only pathway to estimate project costs (and underlying economics) for a plant is by modeling technology-related parameters. Costs can then be estimated based on historical quotes and projects in related technology fields and projects. This approach introduces a significant amount of uncertainties, especially with technologies that have not yet been tested at full scale. Manufacturers typically underestimate cost in the early stages of development, and as the technology's maturity moves towards commercial maturity, such cost-projections increase. The actual build and operational cost of a pilot device or a pilot RISEC-farm will then reveal a complete cost picture and provide a solid starting point for further cost-studies. Once a technology reaches commercial maturity, volume production will begin driving down cost.

The following figure shows the typical cost projection as a function of design maturity.

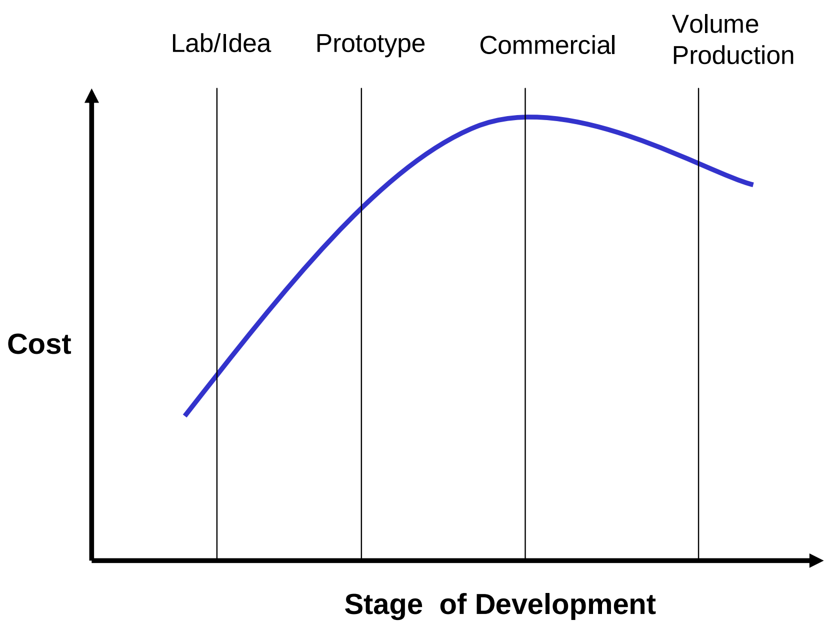


Figure 22: Cost projection as a function of Development Status

Based on experience of estimating energy project cost, EPRI has developed a cost estimate rating table which assesses the likely range of uncertainty based on the technology's design maturity and the amount of detail included in the cost estimate.

Table 3 - EPRI cost estimate rating table

Cost Estimate Rating	A Mature	B Commercial	C Demonstration	D Pilot	E Conceptual (Idea or Lab)
A. Actual	0	-	-	-	-
B. Detailed	-5 to +5	-10 to +10	-15 to +20	-	-
C. Preliminary	-10 to +10	-15 to +15	-20 to +20	-25 to +30	-30 to +50
D. Simplified	-15 to +15	-20 to _20	-25 to +30	-30 to +30	-30 to +80
E. Goal	-	-30 to +70	-30 to +80	-30 to +100	-30 to +200

Using this table, the accuracy of the cost estimates for this project during the Feasibility Study is expected to be:

- Initial capital cost – pilot stage of development and simplified cost estimate = -30 to +30% accurate based on the existence of prototypes and the simplified cost estimate level of detail for this project.
- Replacement and overhaul capital cost and O&M – conceptual stage of development and simplified cost estimate = -30 to +80% accurate based on the lack of existing experience with periodic replacement, overhaul and O&M.

The estimates will have a relatively high degree of uncertainty, particularly in the periodic replacement, overhaul and O&M area.

In addition to technology-related cost uncertainties, the cost for raw materials such as steel and copper has increased significantly, and many relevant industries such as underwater cable manufacturers have limited additional capacity to meet global infrastructure expansions. As a direct result, end product costs are artificially inflated. A comparison of manufacturer quotes for subsea cables between 2004 and 2007 revealed a cost increase of over 200% for a similar cable. Other industries are affected by this trend as well. Wind energy costs reached an all-time low in the year 2000 when the costs sank to about $1100 per installed kW. Since then, cost has steadily increased and is now (2007) at over $1800 per installed kW. As a result of the above factors, significant uncertainties in the prediction of cost remain, and any cost and/or economic projections of these emerging technologies should be viewed with these factors in mind.

4. Site Design

Extracting power from a river will have a feedback effect on the water flow in the river. The following sections address turbine placement and the impact of energy extraction on the free-flowing stream. Given the relatively low level of extraction, the feedback effects are likely to be marginal for the sites of interest.

4.1. Turbine arrangement

Turbines are arranged in rows within the stream in the areas where the highest velocities are present. The purpose of this study is not to determine the exact location where these turbines are to be located, but to determine generic spacing assumptions and placement. Turbines will create a cone-shaped wake behind themselves. For wind turbines, this wake typically extends about 10 rotor diameter, which determines the rows' minimal downstream spacing. Wake effects for water turbines are expected to be very similar. For a 2m rotor, this indicates a minimal row-to-row spacing of 20m, within which distance the flow will recover to uniform flow conditions. Rivers at the sites of interest show the highest velocities during summer months. However, energy consumption in these villages is lowest during summer and highest in winter. For two of the three sites under investigation (Igiugig and Eagle), the targeted generation capacity is therefore set to summer levels. The difference in energy required at the site can be met using the existing diesel generators. In Eagle, the required summer generation capacity is about 70kW and in Igiugig about 40kW.

Because Whitestone is connected to the electric grid network, the upper grid interconnection limits are higher. The 26kV line would likely allow for more than 10MW of power to be connected to the grid. This would require a significant number of units to be deployed at the site. It appears impractical at this point in time to evaluate such a large deployment scheme. Instead, a nearer-term target of 30 units was used as a commercial design point. This design point was chosen because of the following reasons:

1. Grid interconnection and other infrastructure cost components no longer play a dominant role in the cost of the RISEC farm.

2. Tooling cost can be shared across a sufficient production volume to reduce cost to a commercial level. Increasing volume will yield only insignificant improvements in commercial scale economics.

3. Energy extraction from the stream does not significantly reduce available kinetic energy and therefore can be largely neglected in economic calculations. The next section will describe the impacts of this in more detail.

As such, the commercial design near Whitestone does not represent the extractable upper limit of this site, but is rather a design point representative of the cost profile of a commercial plant at the site.

5. Results for Igiugig on the Kvichak River

The community of Igiugig is located at the head of the Kvichak River as it drains out of Lake Iliamna. Igiugig is a small village (population 56) located in southwestern Alaska, on the south bank of the mouth of the Kvichak River and Lake Iliamna. The village is 48 miles southwest of Iliamna, Alaska, and 56 miles northeast of King Salmon, Alaska. The Village's population consists mainly of Yupik Eskimos, Aleuts, and Athabascan Indians. The map below shows the likely deployment location (red rectangle). Grid interconnection opportunities exist near the shoreline for such a plant. The site is ice-free through the winter. However, during spring breakup turbines would need to be removed to protect them from ice-chunks that come from Lake Iliamna.

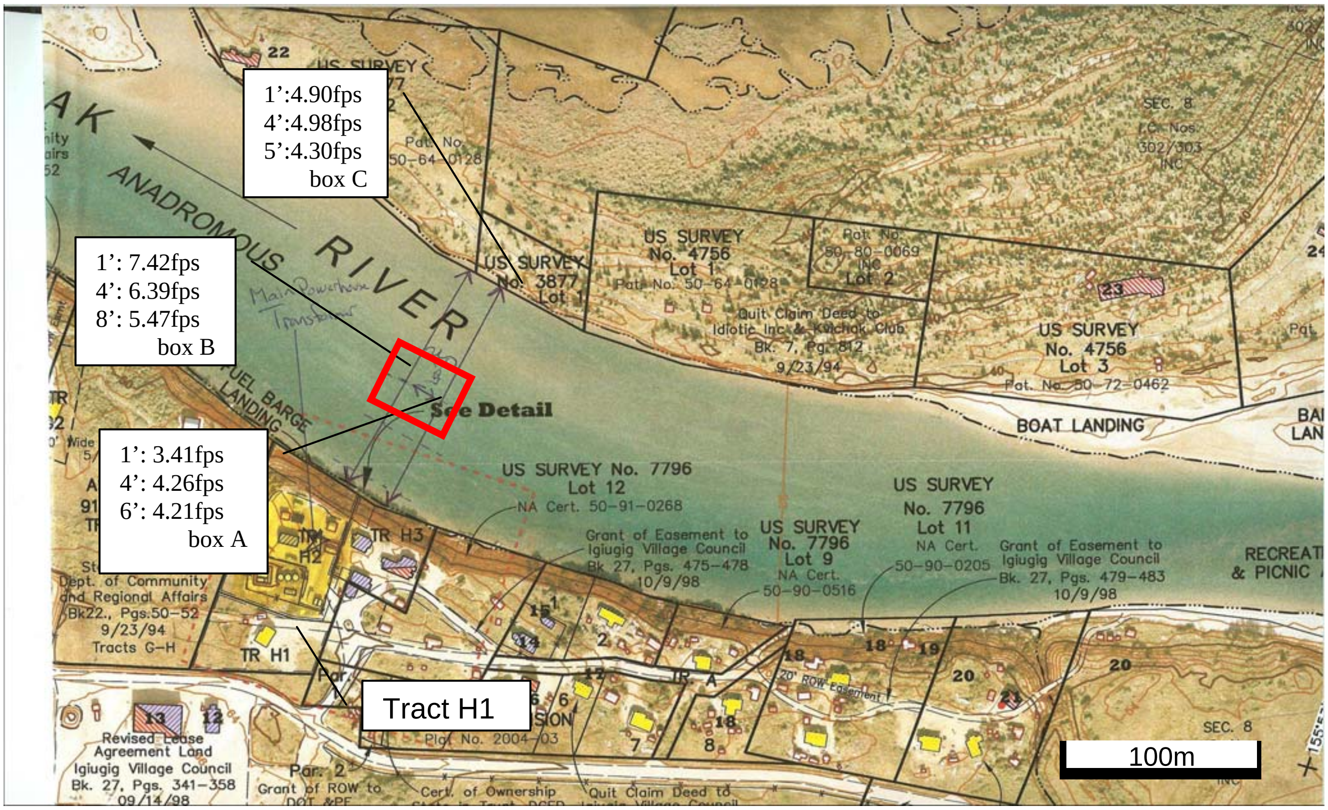


Figure 23: Community Profile Map and Water velocity readings at proposed site: June 20th 2007

The village of Iguigig has three generators ranging from 60 to 100kW that work independently per load, as necessary to energize the community’s 7200-volt three-phase distribution system installed in two phases, 1998 and 2002.

Tract H1 (see Figure 22) contains the community powerhouse/bulk fuel facility and illustrates the optimal location of the powerhouse to the river/hydro source for generation and distribution (all within 200’ of the rivers edge). Historical load patterns range from 40kW to 95kW with the coldest months of December, January and February requiring the greatest peak load demands. However some of the peak-loads come from running the diesel generators at capacity to clean them out. Diesel generators running below their rated capacity for extended periods of time tend to During that period the loads are dumped over load banks.

Currently Igiugig has 56 year-round residents with a summer population of 75, and provides goods and services to six area tourism lodges and their respective clientele and workforce of 90 additional persons per week.

As with most of the Alaskan villages, the village's electrical demand is lowest during summer and highest during winter. The Kvichak River, on the other hand, shows the highest discharge rates and related power-densities during summer months. For this site, a RISEC plant feeding power into the isolated grid at Iguigig is rated at 40kW.

The following illustrations show the river cross-sectional profile and the depth averaged velocity. It shows that the river is relatively shallow and velocities are highest in the middle of the channel. Another factor to be considered is that velocity tends to be highest near the surface and decrease with depth.

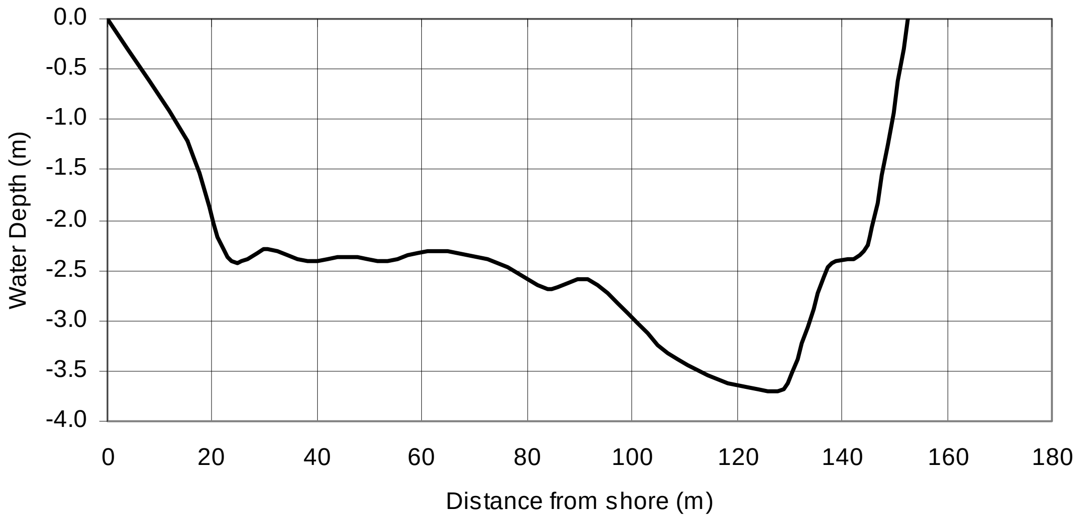


Figure 24: River cross-sectional profile at annual average discharge rate

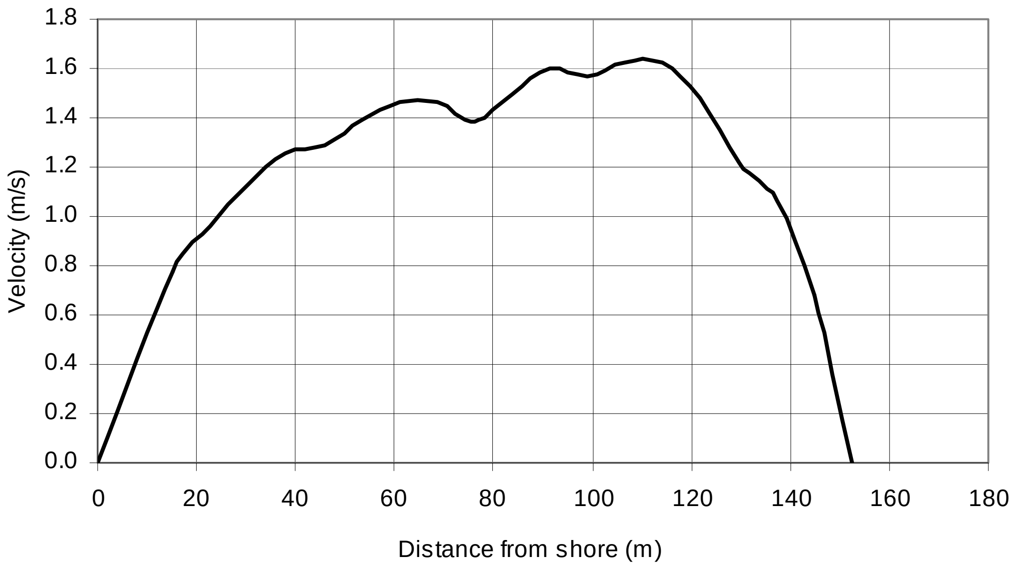


Figure 25: Depth-Averaged Velocity Distribution across river at annual average discharge rate

The water depth at the site of interest will likely limit the rotor size to 1.5m. Given this limitation, a total of three machines with 4 x 1.5m diameter rotors are needed to reach the electrical capacity of 40kW during summer peak flows. The following table summarizes the specifications for the commercial plant to be deployed at the site of interest.

Table 4: Technical Parameters

Machine Parameters	
# Rotors per RISEC device	4
Rotor Diameter	1.5m
Rotor Cross-Sectional Area	$1.8m^2$
RISEC device Width	7.5m
# Rows of machines	1
Array Parameters	
# RISEC machines	3
Array Width	50m
Array Length (incl. Moorings)	50m
Total Rotor Cross-Sectional Area	$21.2m^2$

Velocity distributions for each month of the year were generated based on USGS velocity calibration data and historical discharge rates, against which device performance data could be mapped. The following shows the velocity distribution at the site, which was used to calculate machine performance.

Table 5: Monthly Frequency Distributions at the deployment site

(m/s)	January	February	March	April	May	June	July	August	September	October	November	December
0.10	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
0.30	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
0.50	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
0.70	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
0.90	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1.10	0.00%	44.83%	100.00%	100.00%	100.00%	33.33%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1.30	100.00%	55.17%	0.00%	0.00%	0.00%	66.67%	16.13%	0.00%	0.00%	0.00%	0.00%	32.26%
1.50	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	83.87%	3.23%	0.00%	0.00%	63.33%	67.74%
1.70	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	96.77%	100.00%	100.00%	36.67%	0.00%
1.90	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Monthly average power production values for the commercial plant consisting of three RISEC devices were calculated; the results are presented in the graph below, showing the summer/winter variability of the resource at the site.

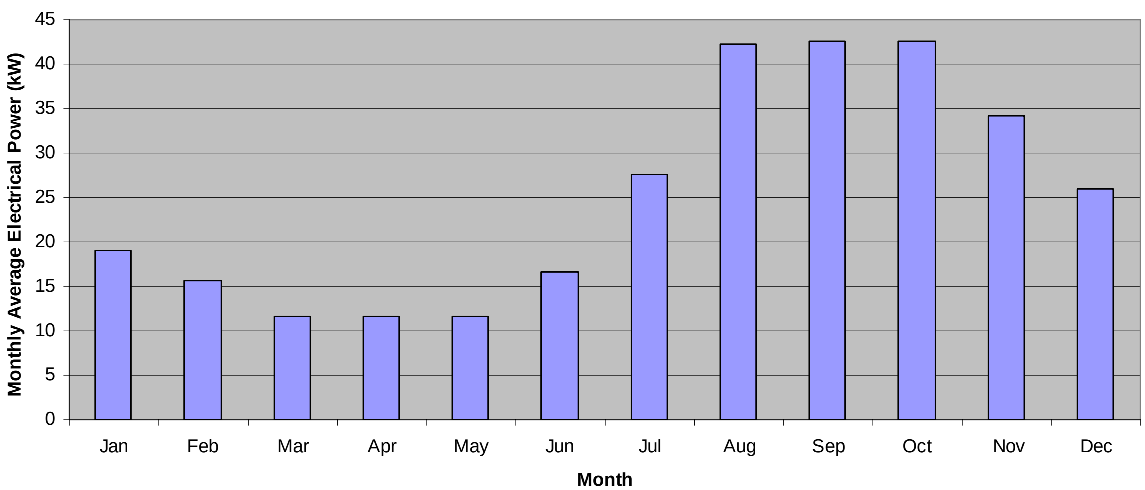


Figure 26: Monthly Average Power Output of 40kW rated RISEC farm (load limiting month is August)

An alternative to this first scenario of rating the plant to summer conditions would be to rate the RISEC plant so that it is able to deliver a constant base-load of 40kW over the entire year. This is possible at this particular site because the variation of flows is not quite as high as some of the other river sites of interest. The RISEC machines are de-rated by shedding excess power during summer months. To accomplish that, it would take a total of 9 RISEC machines. The following graph shows the monthly average output of such an array. The capacity factor of this array is 98%.

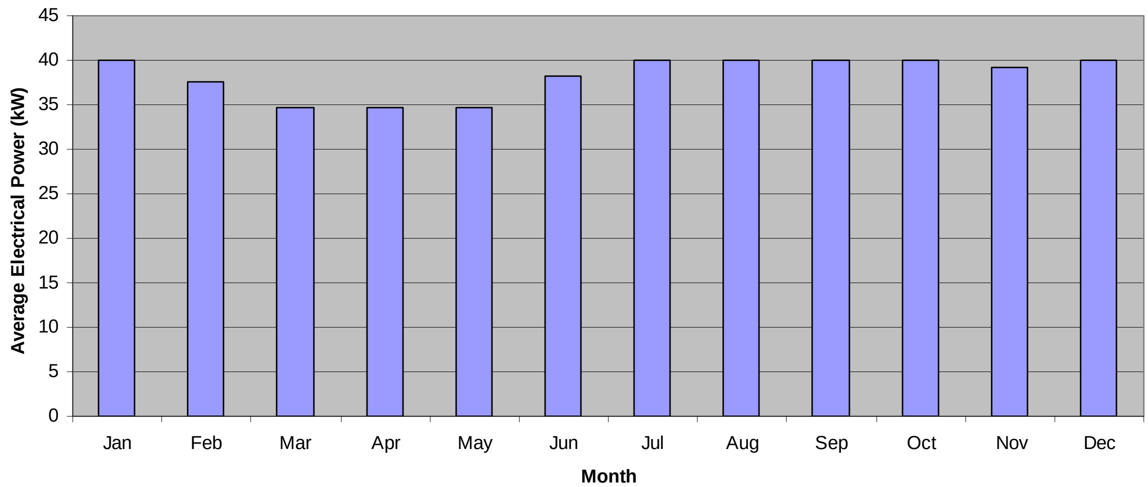


Figure 27: Monthly Average Electrical Power Output for 9-unit RISEC plant rated at 40kW.

5.1. Pilot Plant Cost

The primary purpose of a pilot plant is to gain technical, environmental and commercial confidence in a technology. For the purpose of doing so, a single pontoon unit with two counter-rotating 1.5m diameter rotors is proposed. This same unit will be able to accommodate a total of four rotors, but in order to reduce the cost for the pilot the unit is equipped with only two rotors. The following shows the cost and performance numbers for this single machine.

Table 6: Pilot Plant cost and performance (2007 $)

Capital Cost				
Cost Center	**Machine Cost**	**Farm Cost**	**Cost per kW**	**Cost (in %)**
Structural Elements	$12,910	$12,910	$1,855	6.9%
Powertrain Mounting	$9,870	$9,870	$1,418	5.3%
Powertrain	$9,990	$9,990	$1,436	5.3%
Assembly	$3,430	$3,430	$493	1.8%
Manufacturers Margin	$5,250	$5,250	$754	2.8%
Transport to Site	$3,000	$3,000	$431	1.6%
Onsite Assembly	$2,000	$2,000	$287	1.1%
Device Deployment	$500	$500	$72	0.3%
Underwater Cabling	$40,000	$40,000	$5,749	21.4%
Grid Interconnection	$100,000	$100,000	$14,371	53.5%
Installed Cost	**$186,940**	**$186,940**	**$26,866**	100.0%

Performance				
Energy Extraction (variable rpm)	**Per Rotor**	**Per Machine**	**Per Field**	
Average Extracted Power	2.2	4.5	4	kW
Average Electric Power	2.0	3.9	4	kW
Rated Electric Power	3.4	6.9	7	kW
Machine Capacity Factor	65%	65%	65%	
Availability	90%	90%	90%	
Transmission Efficiency	98%	98%	98%	
Annual Output	17.3	34.5	35	MWh

5.2. Commercial Plant Performance and Cost

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 and assess them properly in the context of the given site conditions, detailed cost build-ups were created. There are a few major influences impacting the relative economic cost at a particular site, as 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) increase to the second power of the fluid velocity. Given the velocity distribution at the site, the design velocity can be well above the velocity at which it is economically useful to extract power. In other words, the design velocity can have a major influence on the cost of the structural elements. For conservatism, the design velocity is set to 120% of the peak velocity measured at the site.

Velocity Distribution: The velocity distribution at the deployment site is illustrated in earlier chapters in this report. They detail the river current velocities at which there is a useful number of reoccurrence to pay for the capital cost which is needed to tap into this velocity bin. The velocity distribution is then used to calculate the annual energy output of the machine at the installation site. Rather than make assumptions as to where the appropriate rated velocity of the RISEC device should be, an iterative approach was chosen to determine which rated speed of the machine will yield the lowest cost of electricity at the particular site.

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

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

- 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 than 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, for example, is very labor-intensive. The cost of hot rolled steel plates as of July 2005 was $650 per ton. The final product, however, can cost as much as $4500 per manufactured ton of steel. In other words, there is significant potential to reduce capital cost by introducing more efficient manufacturing processes. The capital cost for all other equipment and parts is very similar.

Device Reliability and O&M procedures: The device component reliability directly impacts the operation and maintenance cost of a device. It is important to understand that not only does the component need to be replaced, but the actual operation required to recover the component needs to be included as well. Additional cost of the failure is incurred by the downtime of the device and its inability to generate revenues by producing electricity. 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 the project risks. This is especially true with un-tested technologies such as RISEC. No insurance cost was included for the purpose of this study.

Permitting, detailed design and environmental monitoring cost: These cost components are difficult to estimate and are not included in this study. They could be substantial, especially for the first deployments.

The following two tables present a cost breakdown of a commercial RISEC farm at the two deployment sites.

Table 7: Cost and performance of a 3-unit array at Igiugig site (cost in 2007 dollars)

Capital Cost					
Cost Center	Machine Cost	Farm Cost	Cost per kW	Cost (in %)	
Structural Elements	$12,220	$36,670	$890	11.9%	
Powertrain Mounting	$14,460	$43,370	$1,053	14.1%	
Powertrain	$17,110	$51,330	$1,246	16.7%	
Assembly	$3,020	$9,050	$220	2.9%	
Manufacturers Margin	$4,630	$13,880	$337	4.5%	
Transport to Site	$2,000	$6,000	$146	1.9%	
Onsite Assembly	$2,000	$6,000	$146	1.9%	
Device Deployment	$500	$1,500	$36	0.5%	
Underwater Cabling	$13,330	$40,000	$971	13.0%	
Grid Interconnection	$33,330	$100,000	$2,428	32.5%	
Installed Cost	**$102,600**	**$307,810**	**$7,474**	100.0%	
Annual O&M Cost					
Replacement parts	$860	$2,570	$86	21.1%	
Cleaning Screen	$1,200	$3,600	$120	29.6%	
Labor	$2,000	$6,000	$200	49.3%	
Total Annual Cost	**$4,060**	**$12,170**	**$405**	**100%**	
Performance					
Energy Extraction (variable rpm)		**Per Rotor**	**Per Machine**	**Per Field**	
Average Extracted Power		2.2	8.9	27	kW
Average Electric Power		2.0	7.9	24	kW
Rated Electric Power		3.4	13.7	41	kW
Machine Capacity Factor		65%	65%	65%	
Availability		90%	90%	90%	
Transmission Efficiency		98%	98%	98%	
Annual Output		17.3	69.1	207	MWh

A second potentially attractive option, which would provide the village with baseload power over the whole year, is shown in the following table. In order to accomplish this, excess power is shed during periods of high flows.

Table 8: Iguigig plant configured to provide a constant output over the whole year (base-load)

Capital Cost						
Cost Center		**Machine Cost**	**Farm Cost**	**Cost per kW**	**Cost (in %)**	
Structural Elements		$11,370	$90,940	$2,153	19.1%	
Powertrain Mounting		$12,210	$97,710	$2,313	20.5%	
Powertrain		$7,780	$62,270	$1,474	13.1%	
Assembly		$2,450	$19,640	$465	4.1%	
Manufacturers Margin		$3,760	$30,110	$713	6.3%	
Transport to Site		$2,000	$16,000	$379	3.4%	
Onsite Assembly		$2,000	$16,000	$379	3.4%	
Device Deployment		$500	$4,000	$95	0.8%	
Underwater Cabling		$5,000	$40,000	$947	8.4%	
Grid Interconnection		$12,500	$100,000	$2,367	21.0%	
Installed Cost		**$59,580**	**$476,670**	**$11,283**	100.0%	
Annual O&M Cost						
Replacement parts		$390	$3,110	$39	10.8%	
Cleaning Screen		$1,200	$9,600	$120	33.4%	
Labor		$2,000	$16,000	$200	55.7%	
Total Annual Cost		**$3,590**	**$28,710**	**$359**	**100%**	
Performance						
Energy Extraction (variable rpm)			**Per Rotor**	**Per Machi**	**Per Field**	
	Average Extracted Power		1.3	5.3	42	kW
	Average Electric Power		1.2	4.6	37	kW
	Rated Electric Power		1.3	5.3	42	kW
	Machine Capacity Factor		100%	100%	100%	
	Availability		90%	90%	90%	
	Transmission Efficiency		98%	98%	98%	
	Annual Output		10.2	40.7	326	MWh

5.3. *Feedback Effects on Flow*

A 1-D model was used to investigate the feedback effects of extracting energy from the river. The velocity reduction as a result of extracting energy from the river in Iguigig proved to be so small that it will likely not be measurable. The following two tables show the inputs to the model. Extraction effects were modeled for a typical average flow condition at the deployment site. Background information on the 1D modeling approach is offered in appendix A.

Table 9: Turbine Parameters

Rotors/machine	4
Machines/row	3
Rows	1
Total rotors	12
Diameter	1.5m
Extraction efficiency	40%

Table 10: Site Parameters

Velocity	1.39m/s
Depth	2.4m
Width	152m
Length	800m
Elevation Change	0.6m
Manning roughness	0.035

It is assumed that the extraction will not alter the river flow rate. The case described extracts 23 kW from the flow and increases the river depth by 6mm. Given natural flow variability for the site, this change is probably not measurable. The respective changes to flow velocity and power density are also negligible.

Along-channel velocity and depth profiles for the site are shown in Figure 28 and Figure 29. It should be noted that the gradients across rows of turbines will probably not be as sharp as those portrayed here using a 1-D assumption, but the profile will be generally saw-toothed. For all cases tested, velocity increases across each transect and depth decreases, indicating an exchange of kinetic and potential energy in the system. Note, however, that the variations are quite small relative to their mean values.

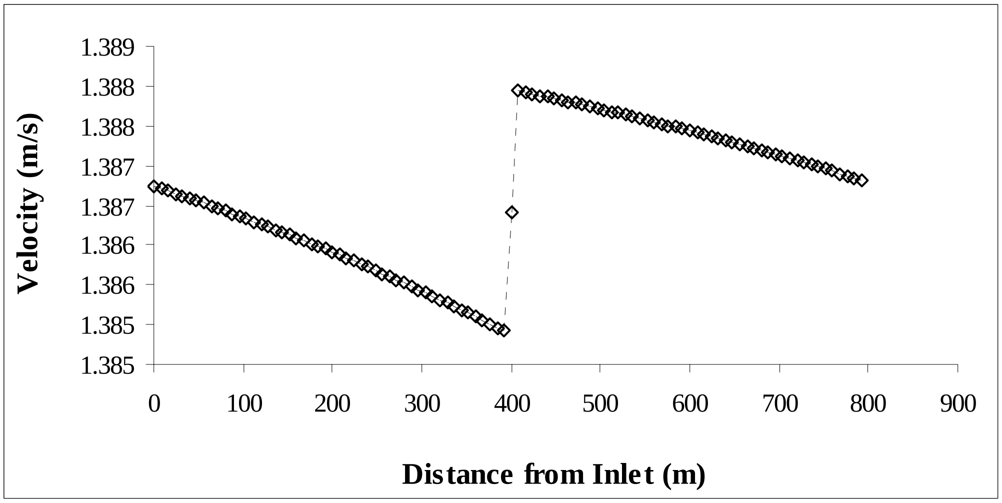


Figure 28 – Iguigig at Kvichak: velocity profile, 12 rotors – 23 kW extraction

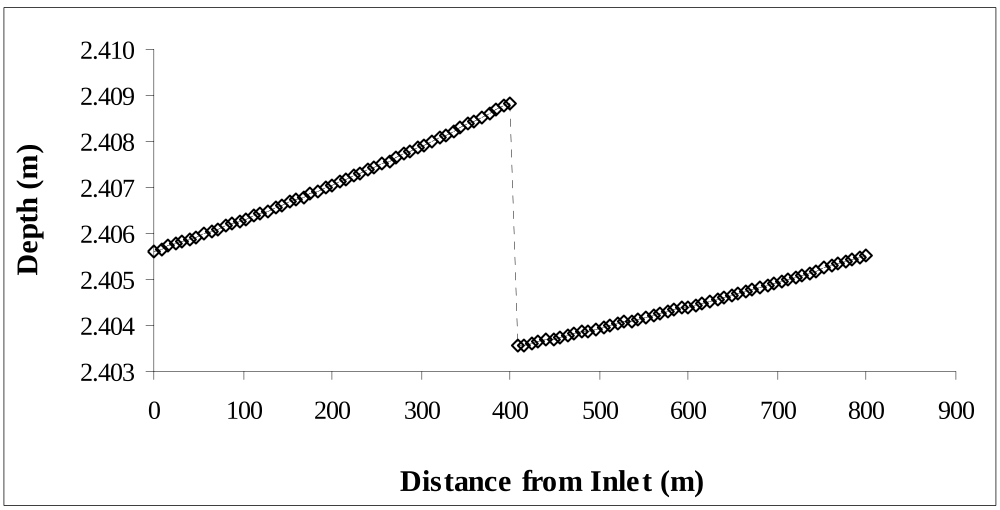


Figure 29 – Iguigig at Kvichak: depth profile, 12 rotors – 23 kW extraction

5.4. Economic Analysis

A Simple Payback Period (SPP) refers to the period of time required for the return on an investment to "repay" the sum of the original investment. For example, a $1000 investment which returned $500 per year would have a two-year payback period. It intuitively measures how long something takes to "pay for itself"; shorter payback periods are obviously preferable to longer payback periods. The results of the SPP calculation for Iguigig show a 3-4 year payback period. The calculation assumes installation in 2009 and beginning of operation Jan 1, 2010. The installation year is counted as part of the payback period. The breakdown of the analysis is shown in the table below.

Table 11: SPP calculation for baseline scenario

Parameter	Unit	Value
Capital Cost	2007 $	307,810
O&M Cost	2007 $	12,170
Annual Energy Production	MWh/year	207
Avoided Cost Level	2008$/kWh	0.65
Yearly Escalation of non Fuel Costs		0.03
Yearly Escalation of Diesel Fuel Costs		0.08

	Annual Cost	Cumulative Cost	Annual Revenue	Cumulative Revenue
2009	$326,556	$326,556	$0	$0
2010	$13,298	$339,854	$169,494	$169,494
2011	$13,697	$353,552	$183,054	$352,548
2012	$14,108	$367,660	$197,698	$550,246
2013	$14,532	$382,192	$213,514	$763,760
2014	$14,968	$397,159	$230,595	$994,355
2015	$15,417	$412,576	$249,043	$1,243,398
2016	$15,879	$428,455	$268,966	$1,512,364
2017	$16,355	$444,810	$290,483	$1,802,847
2018	$16,846	$461,656	$313,722	$2,116,569
2019	$17,352	$479,008	$338,820	$2,455,389
2020	$17,872	$496,880	$365,925	$2,821,314

To illustrate the above table further, Figure 30 shows the cumulative cost and the cumulative revenue as a function of time. The simple payback period is defined by the point where the cumulative revenues equal or exceed the cumulative cost. and where 2009 is counted as the first year. the payback period is 3 to 4 years.

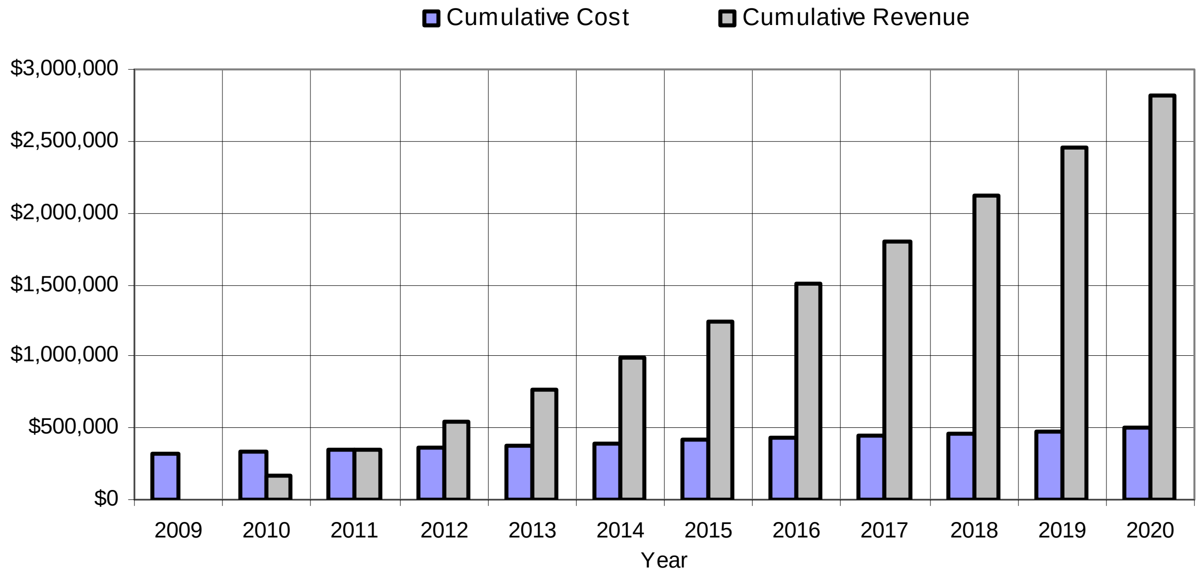


Figure 30: Cumulative cost vs. cumulative revenue

A secondary scenario was investigated to provide baseload power to the village. The payback period for that scenario is also 3 to 4 years. The following table shows the SPP analysis of that scenario and Figure 31 shows the cumularive costs and revenues over time..

Table 12: Baseload Scenario for Iguigig Village

Parameter	Unit	Value
Capital Cost	2007 $	476,670
O&M Cost	2007 $	28,710
Annual Energy Production	MWh/year	326
Avoided Cost Level	2008$/kWh	0.65
Yearly Escalation of non Fuel Costs		0.03
Yearly Escalation of Diesel Fuel Costs		0.08

	Annual Cost	Cumulative Cost	Annual Revenue	Cumulative Revenue
2009	$505,699	$505,699	$0	$0
2010	$31,372	$537,071	$266,933	$266,933
2011	$32,313	$569,385	$288,288	$555,221
2012	$33,283	$602,668	$311,351	$866,571
2013	$34,281	$636,949	$336,259	$1,202,830
2014	$35,310	$672,258	$363,159	$1,565,989
2015	$36,369	$708,627	$392,212	$1,958,201
2016	$37,460	$746,087	$423,589	$2,381,790
2017	$38,584	$784,671	$457,476	$2,839,267
2018	$39,741	$824,413	$494,074	$3,333,341
2019	$40,934	$865,346	$533,600	$3,866,941
2020	$42,162	$907,508	$576,288	$4,443,229

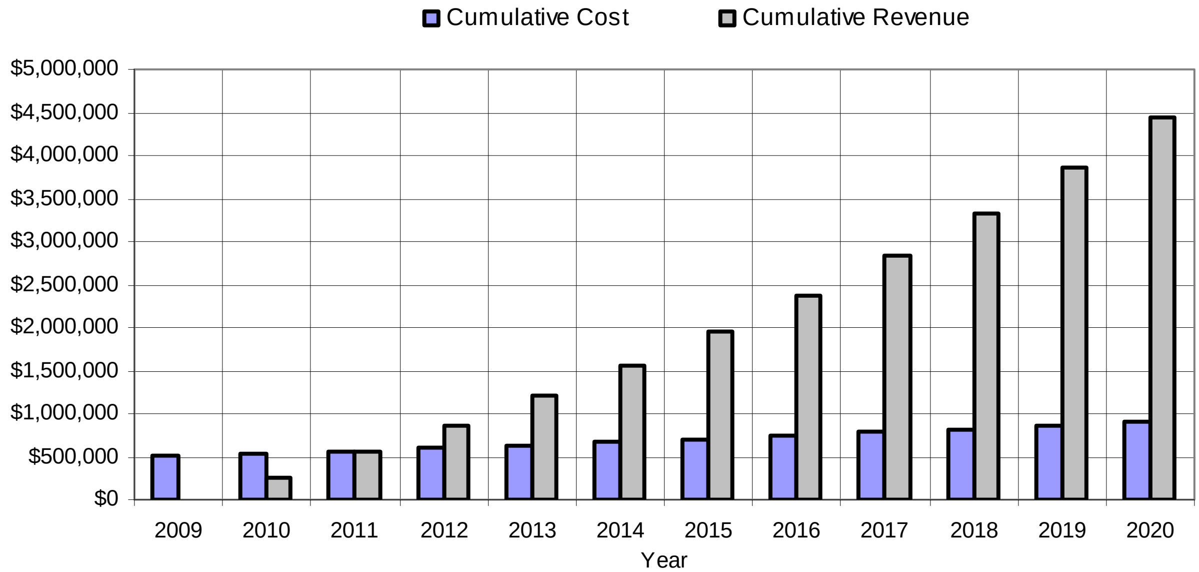


Figure 31: Cumulative cost vs. cumulative revenue

6. Results for Eagle on the Yukon River

Eagle is located on the west bank of the Yukon River, on the north terminus of the Taylor Highway and about 6 miles west of the Alaska-Canada border. Eagle Village, at about 850 feet above sea level, is located approximately 3 miles upriver from the City of Eagle. Alaska Power and Telephone (AP&T) is actively investigating RISEC technology and has done a significant amount of groundwork for that site. This data was not available at the time of writing this report and was therefore not included. The velocity data in this report was calibrated using USGS data, which was not taken directly at the project location. Background on AP&T's work can be found in their FERC Draft Pilot license application, which can be downloaded from their website at www.aptalaska.com.

The Yukon River is located in the interior region of Alaska. The Tanana and Chena River flow into the Yukon. The river starts in the Yukon, Canada, and flows through Alaska, emptying into the Bering Sea. The Yukon is one of the largest rivers in North America. The river is very remote with only a few dozen sizeable communities along its entire length. The river was a highway for prospectors during gold rush days (1890s) and continues to be an important river highway. Due to glacial run-off, the waters of the Yukon are silty during most of the year.

Eagle has a state-owned airstrip with commercial flights from Fairbanks, which provides access to this remote community all year long. In summer the small community is also accessible by river boat and via the Taylor Highway.

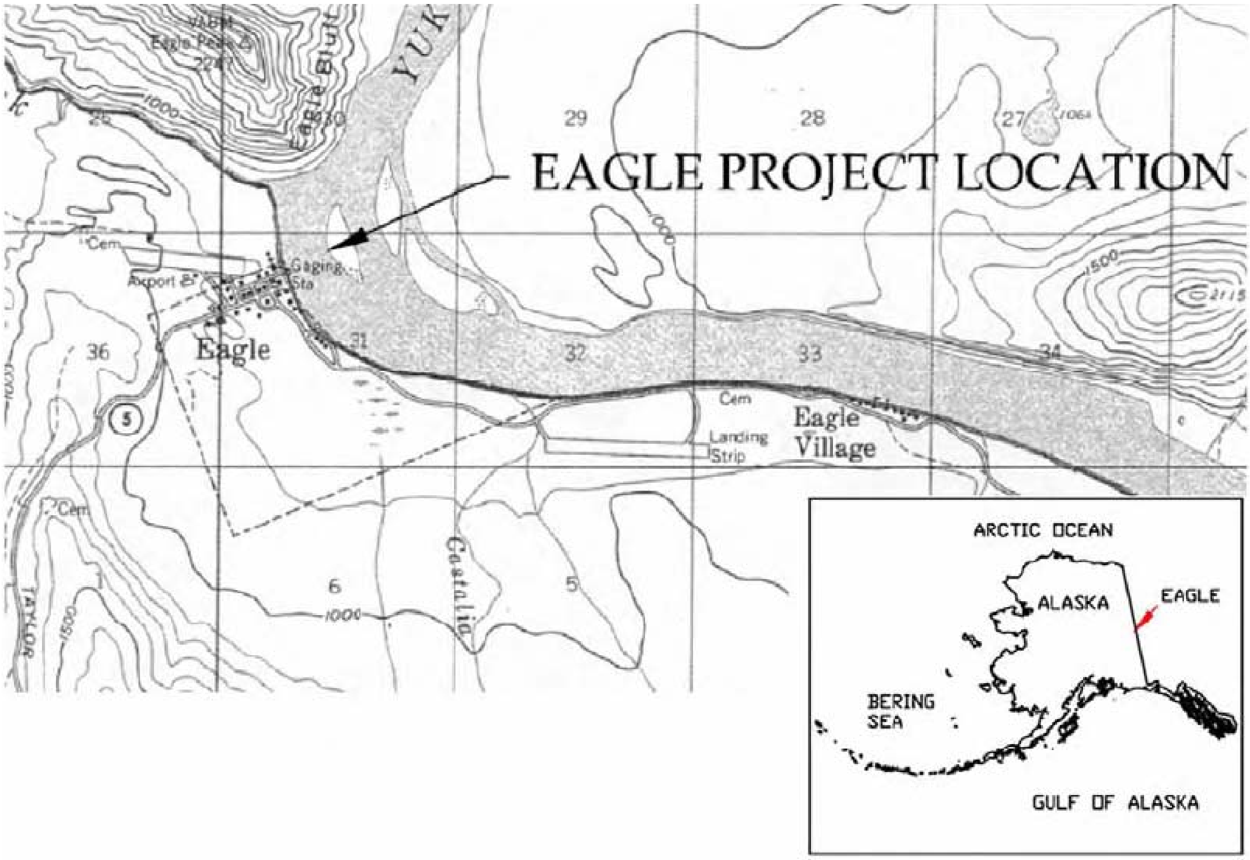


Figure 32: View onto village and Deer Island

AP&T serves about 190 customers in the two communities (Eagle Village and City of Eagle), providing electricity and communication services. The isolated grid has average loads of 70kW in summer and 150kW in winter. Diesel generators are used to generate electricity and annually consume 57,000 gallons of fuel.

As with all of the Alaskan villages, the village's electrical demand is lowest during summer and highest during winter. The Tanana River, on the other hand, shows the highest discharge rates and related power-densities during summer months. This means that a RISEC plant feeding power into the isolated grid at Eagle will need to be rated at the summer capacity low, which is about 70kW.

The river normally begins to freeze in October, freezing to solid ice with a thickness of 4-8 feet. There is also a frazil ice-layer below the solid ice. Ice breakup normally occurs in April and clears by May. This breakup is potentially destructive, with large pieces of ice scouring the river bottom and edges.

The following two illustrations show the river's cross-sectional profile and the velocity distribution across the river. They show that the river is fairly deep with the highest velocities about 150m from shore. The depth would potentially allow for devices being located below the ice in winter. However, the low discharge rates during winter and the fact that velocities are concentrated near the river surface combine to make operation impractical during the winter. Devices will be deployed at the end of the ice-breakup in early May and recovered before freeze-over in early October, giving about 5 months of operational time each year.

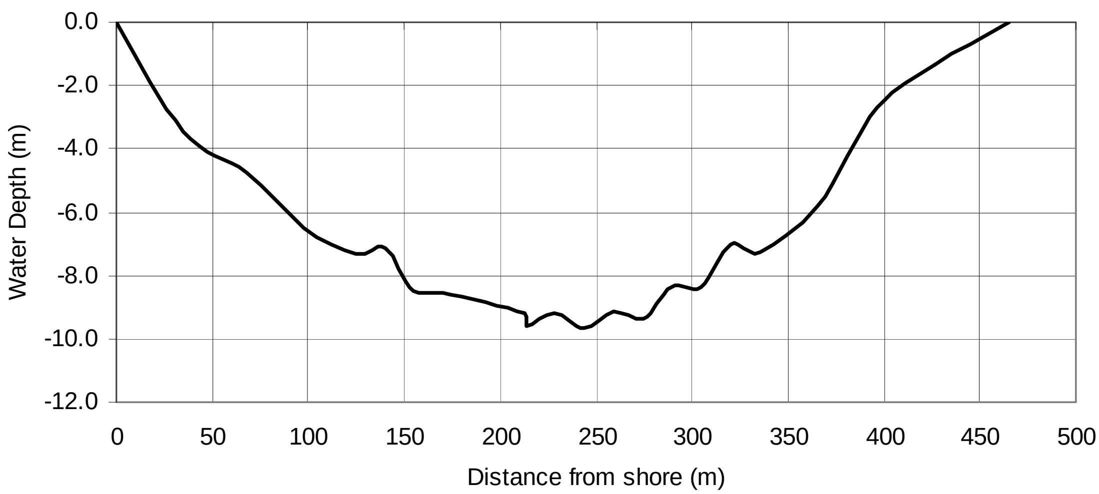


Figure 33: Cross sectional profile at USGS calibration site at annual average discharge rate

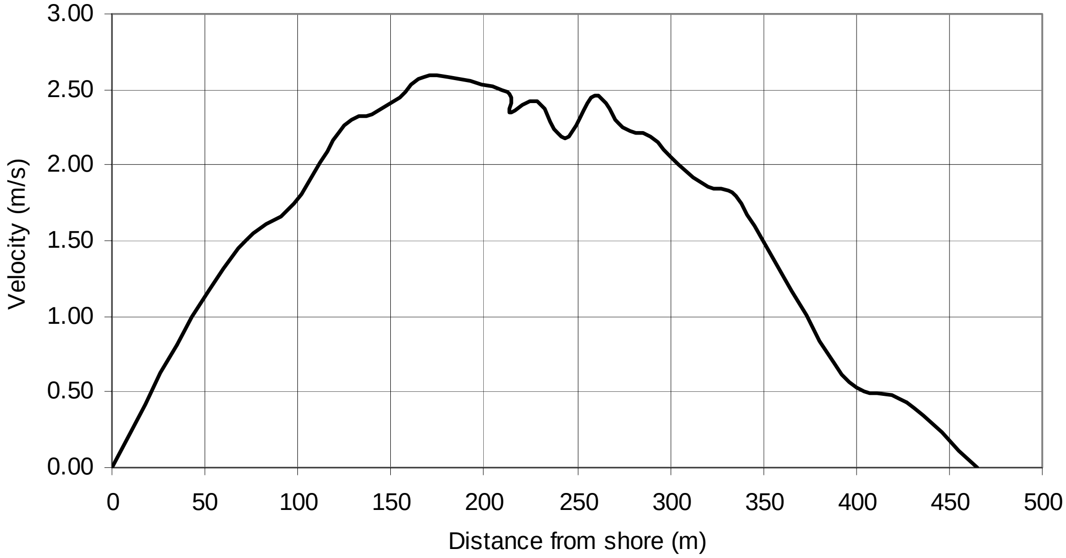


Figure 34: Cross sectional variation in depth-averaged velocity at USGS calibration site at annual average discharge rate

The following aerial view shows the likely project location (shown in red). Grid interconnection options are plentiful near the shoreline, by either tapping into a distribution line or building a line extension directly from the shoreline to the substation.

Figure 35: Likely site location (shown in red)

Micro-siting activities may reveal better power densities a few hundred yards up or down the river and the project deployment location could be adjusted accordingly. Based on the above site-constraints, the following table shows the specifications for a commercial-sized machine that would produce about 60kW at rated capacity.

Table 13: Technical Parameters

Machine Parameters	
# Rotors per RISEC device	4
Rotor Diameter	2m
Rotor Cross-Sectional Area	3.1 m^2
RISEC device Width	10 m
# Rows of machines	1
Array Parameters	
# RISEC machines	1
Array Width	10m
Array Length (incl. Moorings)	50m
Total Rotor Cross-Sectional Area	12.5m^2

Monthly velocity frequency distributions for the site of interest were derived based on historical USGS discharge rates and calibration parameters. The following table shows the monthly frequency distributions of velocities for that site. It is important to remember that these velocities are applicable for the particular measurement transect the USGS has chosen to calibrate the discharge rates of the river. Velocities and associated power densities can vary depending on the exact project location.

Table 14: Monthly frequency distributions for cross-section average velocities at the site

(m/s)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0.1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
0.3	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
0.5	77.42%	100.00%	100.00%	83.33%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
0.7	22.58%	0.00%	0.00%	16.67%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	50.00%	100.00%
0.9	0.00%	0.00%	0.00%	0.00%	9.68%	0.00%	0.00%	0.00%	0.00%	6.45%	50.00%	0.00%
1.1	0.00%	0.00%	0.00%	0.00%	9.68%	0.00%	0.00%	0.00%	0.00%	45.16%	0.00%	0.00%
1.3	0.00%	0.00%	0.00%	0.00%	19.35%	0.00%	0.00%	0.00%	3.33%	48.39%	0.00%	0.00%
1.5	0.00%	0.00%	0.00%	0.00%	9.68%	0.00%	0.00%	0.00%	96.67%	0.00%	0.00%	0.00%
1.7	0.00%	0.00%	0.00%	0.00%	16.13%	0.00%	0.00%	80.65%	0.00%	0.00%	0.00%	0.00%
1.9	0.00%	0.00%	0.00%	0.00%	19.35%	0.00%	70.97%	19.35%	0.00%	0.00%	0.00%	0.00%
2.1	0.00%	0.00%	0.00%	0.00%	16.13%	40.00%	29.03%	0.00%	0.00%	0.00%	0.00%	0.00%
2.3	0.00%	0.00%	0.00%	0.00%	0.00%	60.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2.5	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2.7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2.9	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Velocities vary throughout the profile of any particular cross-section. The comparison of data from different rivers showed that in natural rivers, the peak velocity in a particular cross-section is about 30% higher than the average velocity. In order to attain proper velocity distributions for a likely deployment site, channel-average velocity was multiplied by a factor of 1.3.

Based on these velocity distributions, the commercial machine's monthly average power production was calculated. The following graph shows the machine output over a typical year.

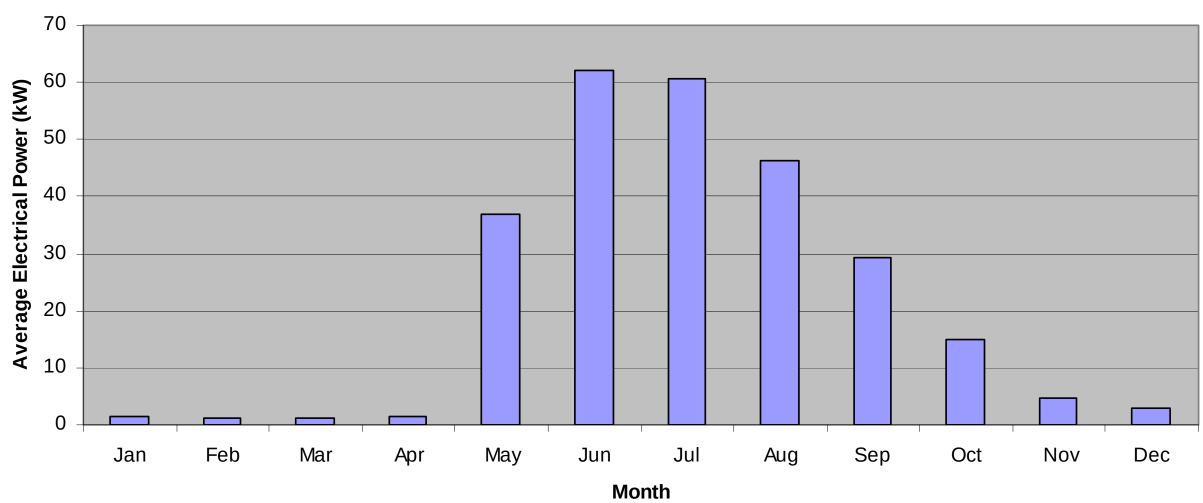


Figure 36: Monthly average power production

The above figure shows that power production during the winter months under the ice do not add a lot of value to the system. Initial trade-off analysis suggests that not only are the winter months in this location highly un-productive, the complete submersion of the device would also bring the device near the river-bed, where velocities are lowest. This would further reduce overall power production and affect the economic viability negatively. Therefore it was decided that the devices would be deployed after the ice breakup in May and removed in early October before the ice freezes over, providing about 5 months of continued operation.

6.1. Pilot Plant Cost

The primary purpose of a pilot plant is to gain technical, environmental and commercial confidence in a technology. For the purpose of doing so, a single pontoon unit with 2 counter-rotating 2m diameter rotors is proposed. This same unit will be able to accommodate a total of 4 rotors, but in order to reduce the cost for the pilot the unit is equipped with only two rotors. The following shows the cost and performance numbers for this single machine.

Table 15: Cost and Performance of Pilot Unit at Eagle (2007 $)

Cost Center	Machine Cost	Farm Cost	Cost per kW	Cost (in %)
Structural Elements	$13,700	$13,700	$447	6.0%
Powertrain Mounting	$13,340	$13,340	$435	5.9%
Powertrain	$39,070	$39,070	$1,275	17.2%
Assembly	$5,990	$5,990	$196	2.6%
Manufacturers Margin	$9,180	$9,180	$300	4.0%
Transport to Site	$3,000	$3,000	$98	1.3%
Onsite Assembly	$2,000	$2,000	$65	0.9%
Device Deployment	$500	$500	$16	0.2%
Underwater Cabling	$40,000	$40,000	$1,306	17.6%
Grid Interconnection	$100,000	$100,000	$3,264	44.1%
Installed Cost	**$226,770**	**$226,770**	**$7,402**	100.0%

Energy Extraction (variable rpm)	Per Rotor	Per Machine	Per Field	
Average Extracted Power	8.8	17.5	18	kW
Average Electric Power	3.2	6.4	6	kW
Rated Electric Power	15.3	30.6	31	kW
Machine Capacity Factor	57%	57%	57%	
Availability	38%	38%	38%	
Transmission Efficiency	98%	98%	98%	
Annual Output	28.2	56.4	56	MWh

6.2. Commercial Plant Performance and Cost

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 and assess them properly in the context of the given site conditions, detailed cost build-ups were created. There are a few major influences impacting the relative economic cost at a particular site, as 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) increase to the second power of the fluid velocity. Given the velocity distribution at the site, the design velocity can be well above the velocity at which it is economically useful to extract power. In other words, the design velocity can have a major influence on the cost of the structural elements. For conservatism, the design velocity is set to 120% of the peak velocity measured at the site.

Velocity Distribution: The velocity distribution at the deployment site is illustrated in earlier chapters in this report. They detail the river current velocities at which there is a useful number of reoccurrence to pay for the capital cost which is needed to tap into this velocity bin. The velocity distribution is then used to calculate the annual energy output of the machine at the installation site. Rather than make assumptions as to where the appropriate rated velocity of the RISEC device should be, an iterative approach was chosen to determine which rated speed of the machine will yield the lowest cost of electricity at the particular site.

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

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

- 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 than 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, for example, is very labor-intensive. The cost of hot rolled steel plates as of July 2005 was $650 per ton. The final product, however, can cost as much as $4500 per manufactured ton of steel. In other words, there is significant potential to reduce capital cost by introducing more efficient manufacturing processes. The capital cost for all other equipment and parts is very similar.

Device Reliability and O&M procedures: The device component reliability directly impacts the operation and maintenance cost of a device. It is important to understand that not only does the component need to be replaced, but the actual operation required to recover the component needs to be included as well. Additional cost of the failure is incurred by the downtime of the device and its inability to generate revenues by producing electricity. 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 the project risks. This is especially true with untested technologies such as RISEC. No insurance cost was included for the purpose of this study.

Storage Cost: The device is in operation during only 5 months in the summer. No storage cost was added to account for winter storage of these machines.

Permitting, detailed design and environmental monitoring cost: These cost components are difficult to estimate and are not included in this study. They could be substantial, especially for the first deployments.

The following table presents a cost breakdown of a commercial RISEC farm rated at 47kW at the Eagle deployment site.

Table 16: Cost and performance of a single at Eagle site (cost in 2007 dollars)

Capital Cost					
Cost Center	Machine Cost	Farm Cost	Cost per kW	Cost (in %)	
Structural Elements	$14,840	$14,840	$318	5.5%	
Powertrain Mounting	$26,430	$26,430	$567	9.8%	
Powertrain	$67,520	$67,520	$1,448	25.1%	
Assembly	$5,750	$5,750	$123	2.1%	
Manufacturers Margin	$8,810	$8,810	$189	3.3%	
Transport to Site	$3,000	$3,000	$64	1.1%	
Onsite Assembly	$2,000	$2,000	$43	0.7%	
Device Deployment	$500	$500	$11	0.2%	
Underwater Cabling	$40,000	$40,000	$858	14.9%	
Grid Interconnection	$100,000	$100,000	$2,144	37.2%	
Installed Cost	**$268,850**	**$268,850**	**$5,765**	100.0%	
Annual O&M Cost					
Replacement parts	$3,380	$3,380	$52	51.4%	
Cleaning Screen	$1,200	$1,200	$19	18.2%	
Labor	$2,000	$2,000	$31	30.4%	
Total Annual Cost	**$6,580**	**$6,580**	**$102**	**100%**	
Performance					
Energy Extraction (variable rpm)		**Per Rotor**	**Per Machine**	**Per Field**	
Average Extracted Power		8.3	33.1	33	kW
Average Electric Power		3.0	12.2	12	kW
Rated Electric Power		11.7	46.6	47	kW
Machine Capacity Factor		71%	71%	71%	
Availability		38%	38%	38%	
Transmission Efficiency		98%	98%	98%	
Annual Output		26.7	106.7	107	MWh

6.3. *Feedback Effects on Flow*

A 1-D model was used to investigate the feedback effects of extracting energy from the river. The velocity reduction as a result of extracting energy from the river in Eagle proved to be so small that it will likely not be measurable. The following two tables show the inputs to the model. Extraction effects were modeled for a typical average flow condition at the deployment site. Background information on the 1D modeling approach is shown in appendix A.

Table 17: Turbine Parameters

Rotors/machine	4
Machines/row	2
Rows	1
Total rotors	8
Diameter	2.0m
Extraction efficiency	40%

Table 18: Site Parameters

Velocity	1.15m/s
Depth	6.8m
Width	464m
Length	1000m
Elevation Change	0.13m
Manning roughness	0.035

It is assumed that the extraction will not alter the river flow rate. The case described extracts 17 kW from the flow and increases the river depth by 8mm. Given natural flow variability for the site, this change is probably not measurable. The attendant changes to flow velocity and power density are also negligible.

Along-channel velocity and depth profiles for the site are shown in Figure 37 and Figure 38. It should be noted that the gradients across rows of turbines will probably not be as sharp as those portrayed here under a 1D assumption with discontinuous extraction, but the profile will be generally saw-toothed. For all cases tested, velocity increases across each transect and depth decreases, indicating an exchange of kinetic and potential energy in the system. Note, however, that the variations are quite small relative to their mean values.

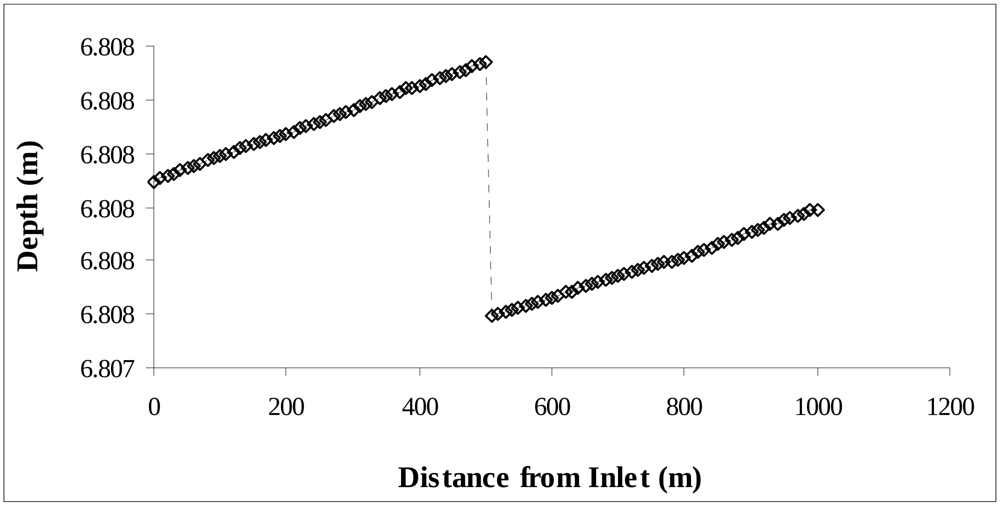


Figure 37 – Eagle at Yukon: depth profile, 8 rotors –17 kW extraction

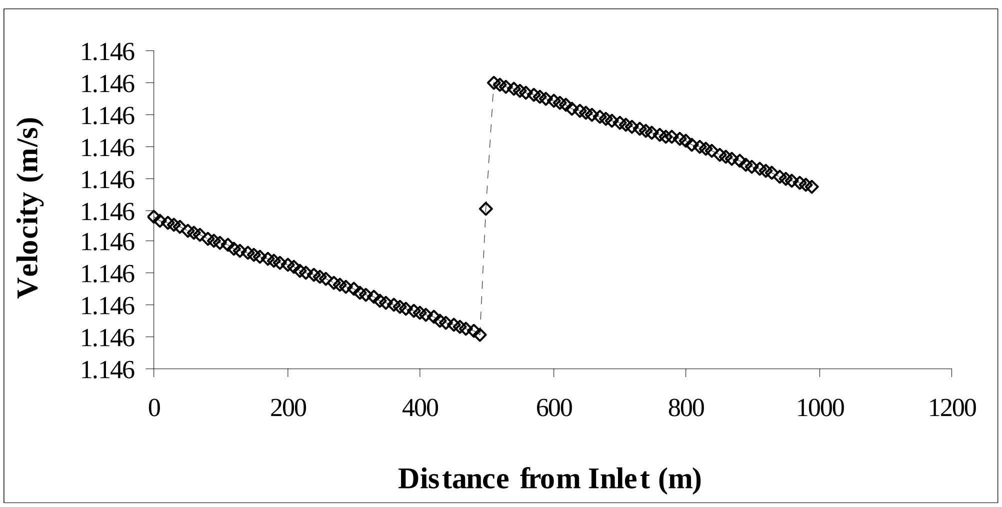


Figure 38 – Eagle at Yukon: velocity profile, 8 rotors –17 kW extraction

6.4. Economic Analysis

A Simple Payback Period (SPP) refers to the period of time required for the return on an investment to "repay" the sum of the original investment. For example, a $1000 investment which returned $500 per year would have a two-year payback period. It intuitively measures how long something takes to "pay for itself"; shorter payback periods are obviously preferable to longer payback periods. The calculation assumes installation in 2009 and beginning of operation Jan 1, 2010. The installation year (2009) is counted as part of the payback period. The breakdown of the analysis is shown in the table below. The results of the SPP calculation for Eagle show a 4-5 year payback period.

Table 19: SPP Calculation for Eagle site

Parameter	Unit	Value
Capital Cost	2007 $	268,850
O&M Cost	2007 $	6,580
Annual Energy Production	MWh/year	107
Avoided Cost Level	2008$/kWh	0.65
Yearly Escalation of non Fuel Costs		0.03
Yearly Escalation of Diesel Fuel Costs		0.08

	Annual Cost	Cumulative Cost	Annual Revenue	Cumulative Revenue
2009	$285,223	$285,223	$0	$0
2010	$7,190	$292,413	$87,613	$87,613
2011	$7,406	$299,819	$94,622	$182,235
2012	$7,628	$307,447	$102,192	$284,427
2013	$7,857	$315,304	$110,367	$394,794
2014	$8,093	$323,396	$119,196	$513,990
2015	$8,335	$331,732	$128,732	$642,723
2016	$8,585	$340,317	$139,031	$781,753
2017	$8,843	$349,160	$150,153	$931,907
2018	$9,108	$358,268	$162,165	$1,094,072
2019	$9,382	$367,650	$175,139	$1,269,211
2020	$9,663	$377,313	$189,150	$1,458,361

To illustrate the above table further, Figure 39 shows the cumulative cost and the cumulative revenue as a function of time. The simple payback period is defined by the point where the cumulative revenues equal or exceed the cumulative cost.

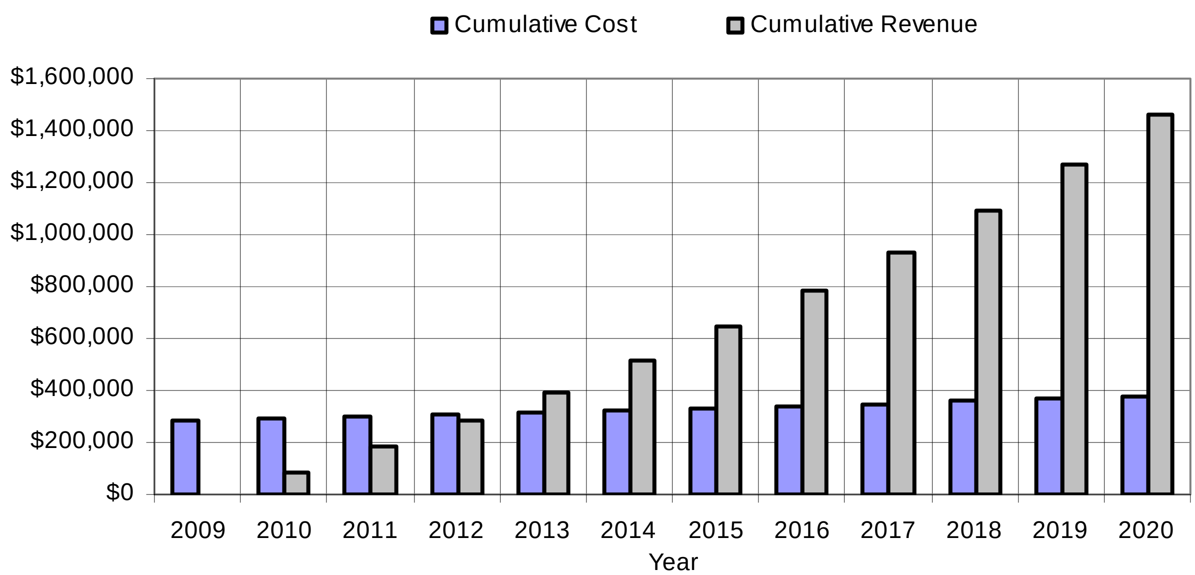


Figure 39: Cumulative cost vs. cumulative revenue

7. Results for Whitestone on the Tanana River

The Whitestone community is located northwest of Delta Junction on the western side of the Delta River near the town of Big Delta. The community has over 200 residents and is represented by the Whitestone Community Association (WCA) in its work with State agencies and other organizations. The Department Commerce and Community Development certified the Whitestone Community Association as an unincorporated community for purposes of revenue sharing for FY04.

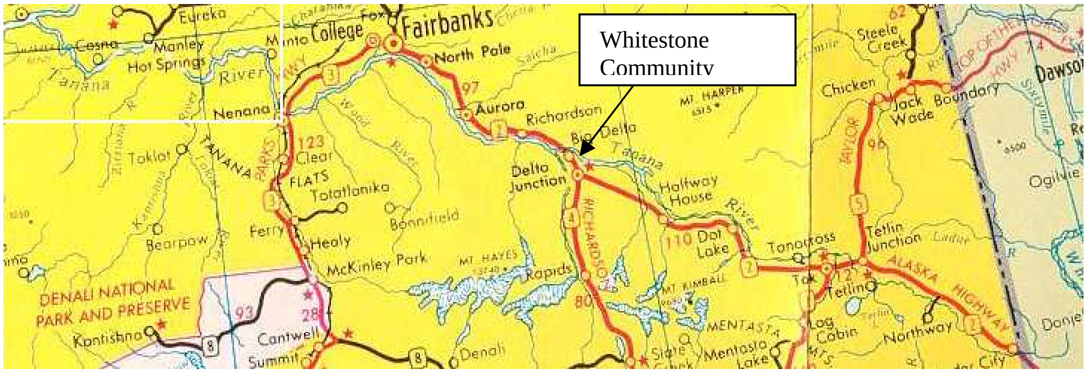


Figure 40: Whitestone Community on the Tanana River

Figure 41: Site Overview

There are two main grid interconnection options. The first option is interconnecting directly to the isolated grid of the Whitestone community; the second is to connect to the Golden Valley Electric Association (GVEA) grid. The isolated grid at the Whitestone community has a generator capacity of 390kW. A RISEC farm could be connected to the grid at 480V and 12.47kV. The remote portion of the GVEA Intertie, operating at 12.47kV, will likely provide for more substantial feed-in capacity, and could be connected at Mile 275 Richardson Highway. The following table shows the average and peak loads on the Whitestone isolated grid.

Table 20: Whitestone Community Monthly Load Patterns

Month	Average Load(kW)	Peak Load (kW)
January	115	160
February	120	160
March	120	150
April	120	150
May	110	130
June	90	120
July	90	120
August	90	120
September	110	130
October	115	130
November	115	140
December	120	150

For the purpose of this design study, it was assumed that a RISEC plant is connected to the GVEA grid. As such, the local village-load does not provide a hard limit to size generation capacity against. It is likely that more than 5MW of RISEC power could be connected to the utility grid near Whitestone. For the purpose of this design study, it was assumed that a total of 30 units (with 4 X 2m diameter rotors each) will be deployed at the site to form the commercial base-case. The following figure shows the monthly average power production of that plant.

Table 21: Technical Parameters

Machine Parameters	
# Rotors per RISEC device	4
Rotor Diameter	2m
Rotor Cross-Sectional Area	3.1m^2
RISEC device Width	10m
# Rows of machines	10

Array Parameters	
# RISEC machines	30
Array Width	50m
Array Length (incl. Moorings)	500m
Total Rotor Cross-Sectional Area	$377m^2$

The following two illustrations show the river's cross-sectional profile and the velocity distribution across the river. They show that the river is fairly deep, with the high velocities at less then 50m from shore. According to local sources, portions of the river stay ice-free for the whole year. This would allow for year-round operation of RISEC devices at the site.

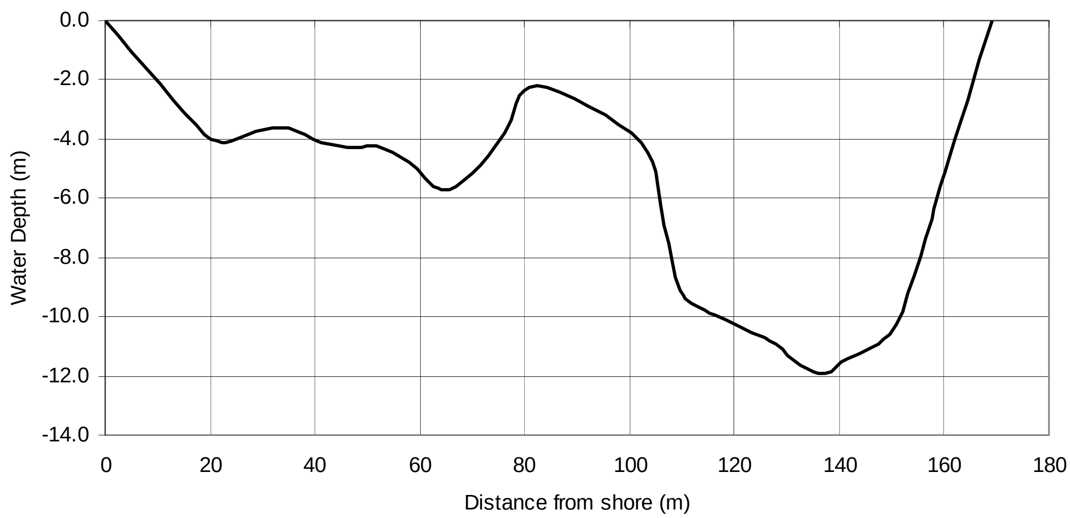


Figure 42: River cross-sectional profile at Whitestone at annual average discharge rate

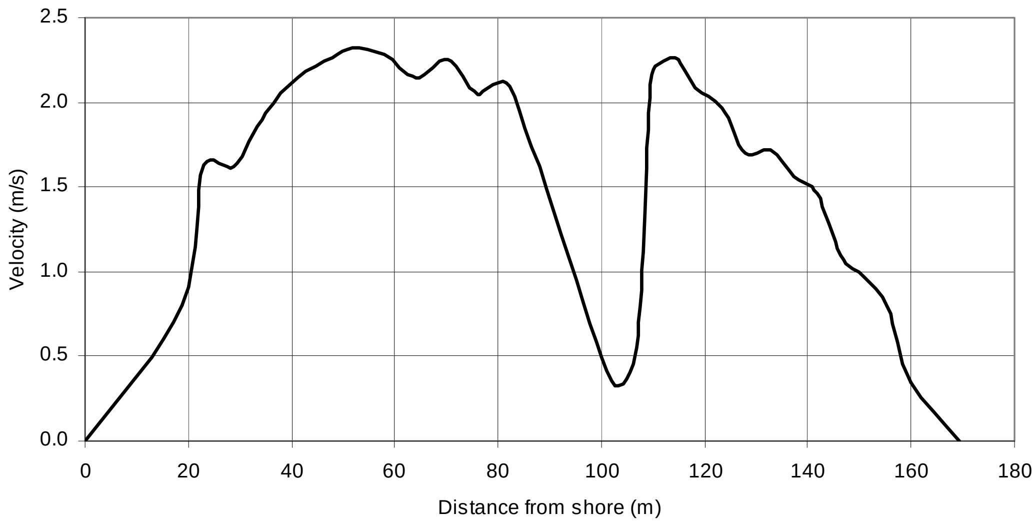


Figure 43: Depth-averaged cross-sectional velocity distribution at site near Whitestone at annual average discharge rate

Based on historical USGS discharge rates and calibration parameters, monthly velocity frequency distributions for the site of interest were derived. The following table shows the monthly frequency distributions of velocities for that site. It is important to remember that these velocities are applicable for the particular measurement transect the USGS has chosen to calibrate the discharge rates of the river. Velocities and associated power densities can vary depending on the exact project location.

Table 22: Monthly frequency distribution of velocities at site near Whitestone

(m/s)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0.1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
0.3	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
0.5	0.00%	37.93%	54.84%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
0.7	100.00%	62.07%	45.16%	100.00%	3.23%	0.00%	0.00%	0.00%	0.00%	48.39%	100.00%	100.00%
0.9	0.00%	0.00%	0.00%	0.00%	22.58%	0.00%	0.00%	0.00%	0.00%	51.61%	0.00%	0.00%
1.1	0.00%	0.00%	0.00%	0.00%	38.71%	0.00%	0.00%	0.00%	36.67%	0.00%	0.00%	0.00%
1.3	0.00%	0.00%	0.00%	0.00%	35.48%	66.67%	0.00%	0.00%	63.33%	0.00%	0.00%	0.00%
1.5	0.00%	0.00%	0.00%	0.00%	0.00%	33.33%	41.94%	54.84%	0.00%	0.00%	0.00%	0.00%
1.7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	58.06%	45.16%	0.00%	0.00%	0.00%	0.00%
1.8	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Velocities vary throughout the profile of any particular cross-section. The comparison of data from different rivers showed that in natural rivers, the peak velocity in a particular cross-section is about 30% higher than the average velocity. In order to attain proper velocity distributions for a likely deployment site, they were multiplied by a factor of 1.3.

Based on these velocity distributions, the commercial machine's monthly average power production was calculated. The following graph shows the machine output over a typical year.

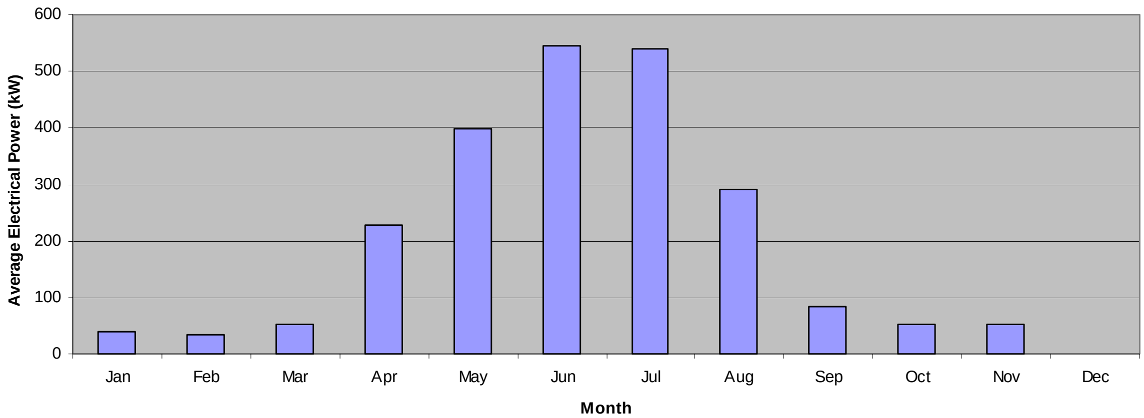


Figure 44: Monthly average electrical power production from commercial RISEC plant near Whitestone

The above graph shows that electrical production levels in winter are quite low, because the discharge rates of this river are quite low during the winter months.

7.1. Pilot Plant Cost

The primary purpose of a pilot plant is to gain technical, environmental and commercial confidence in a technology. For the purpose of doing so, a single pontoon unit with two counter-rotating 1.5m diameter rotors is proposed. This same unit will be able to accommodate a total of four rotors, but in order to reduce the cost for the pilot the unit is equipped with only two rotors. The following shows the cost and performance numbers for this single machine.

Table 23: Pilot Plant Performance and Cost at Whitestone (2007 $)

Capital Cost					
Cost Center	**Machine Cost**	**Farm Cost**	**Cost per kW**	**Cost (in %)**	
Structural Elements	$13,180	$13,180	$1,065	6.6%	
Powertrain Mounting	$12,350	$12,350	$998	6.2%	
Powertrain	$18,750	$18,750	$1,516	9.3%	
Assembly	$4,310	$4,310	$348	2.1%	
Manufacturers Margin	$6,610	$6,610	$534	3.3%	
Transport to Site	$3,000	$3,000	$243	1.5%	
Onsite Assembly	$2,000	$2,000	$162	1.0%	
Device Deployment	$500	$500	$40	0.2%	
Underwater Cabling	$40,000	$40,000	$3,234	19.9%	
Grid Interconnection	$100,000	$100,000	$8,084	49.8%	
Installed Cost	**$200,690**	**$200,690**	**$16,223**	100.0%	

Performance				
Energy Extraction (variable rpm)	**Per Rotor**	**Per Machine**	**Per Field**	
Average Extracted Power	1.9	3.9	4	kW
Average Electric Power	1.7	3.4	3	kW
Rated Electric Power	6.2	12.4	12	kW
Machine Capacity Factor	31%	31%	31%	
Availability	90%	90%	90%	
Transmission Efficiency	98%	98%	98%	
Annual Output	14.9	29.8	30	MWh

7.2. Commercial Plant Performance and Cost

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 and assess them properly in the context of the given site conditions, detailed cost build-ups were created. There are a few major influences impacting the relative economic cost at a particular site, as 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) increase to the second power of the fluid velocity. Given the velocity distribution at the site, the design velocity can be well above the velocity at which it is economically useful to extract power. In other words, the design velocity can have a major influence on the cost of the structural elements. For conservatism, the design velocity is set to 120% of the peak velocity measured at the site.

Velocity Distribution: The velocity distribution at the deployment site is illustrated in earlier chapters in this report. They detail the river current velocities at which there is a useful number of reoccurrence to pay for the capital cost which is needed to tap into this velocity bin. The velocity distribution is then used to calculate the annual energy output of the machine at the installation site. Rather than make assumptions as to where the appropriate rated velocity of the RISEC device should be, an iterative approach was chosen to determine which rated speed of the machine will yield the lowest cost of electricity at the particular site.

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

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

- 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 than 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, for example, is very labor-intensive. The cost of hot rolled steel plates as of July 2005 was $650 per ton. The final product, however, can cost as much as $4500 per manufactured ton of steel. In other words, there is significant potential to reduce capital cost by introducing more efficient manufacturing processes. The capital cost for all other equipment and parts is very similar.

Device Reliability and O&M procedures: The device component reliability directly impacts the operation and maintenance cost of a device. It is important to understand that not only does the component need to be replaced, but the actual operation required to recover the component needs to be included as well. Additional cost of the failure is incurred by the downtime of the device and its inability to generate revenues by producing electricity. 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 the project risks. This is especially true with untested technologies such as RISEC. No insurance cost was included for the purpose of this study.

Permitting, detailed design and environmental monitoring cost: These cost components are difficult to estimate and are not included in this study. They could be substantial, especially for the first deployments.

The following two tables present a cost breakdown of a commercial RISEC farm at the two deployment sites.

Table 24: Cost and performance of a 30-unit array at Whitestone site (cost in 2007 dollars)

Capital Cost					
Cost Center	Machine Cost	Farm Cost	Cost per kW	Cost (in %)	
Structural Elements	$10,600	$317,910	$536	17.5%	
Powertrain Mounting	$11,770	$353,160	$596	19.4%	
Powertrain	$21,930	$657,980	$1,110	36.1%	
Assembly	$2,850	$85,600	$144	4.7%	
Manufacturers Margin	$4,380	$131,260	$221	7.2%	
Transport to Site	$2,000	$60,000	$101	3.3%	
Onsite Assembly	$2,000	$60,000	$101	3.3%	
Device Deployment	$500	$15,000	$25	0.8%	
Underwater Cabling	$1,330	$40,000	$67	2.2%	
Grid Interconnection	$3,330	$100,000	$169	5.5%	
Installed Cost	**$60,700**	**$1,820,910**	**$3,071**	100.0%	
Annual O&M Cost					
Replacement parts	$1,100	$32,900	$46	25.5%	
Cleaning Screen	$1,200	$36,000	$51	27.9%	
Labor	$2,000	$60,000	$85	46.5%	
Total Annual Cost	**$4,300**	**$128,900**	**$182**	**100%**	
Performance					
Energy Extraction (variable rpm)		**Per Rotor**	**Per Machine**	**Per Field**	
Average Extracted Power		1.4	5.7	172	kW
Average Electric Power		1.3	5.0	151	kW
Rated Electric Power		4.9	19.8	593	kW
Machine Capacity Factor		29%	29%	29%	
Availability		90%	90%	90%	
Transmission Efficiency		98%	98%	98%	
Annual Output		11.0	44.2	1325	MWh

Whitestone is planning to connect to the GVEA grid, however it is presently not grid connected. A second scenario was created by assuming the electricity grid at Whitestone is not grid-connected. Therefore a capacity limit was superimposed onto this scenario. The following table shows the results.

Table 25: Isolated grid scenario for Whitestone village

Capital Cost						
	Cost Center	**Machine Cost**	**Farm Cost**	**Cost per kW**	**Cost (in %)**	
	Structural Elements	$12,440	$49,750	$629	12.0%	
	Powertrain Mounting	$17,050	$68,200	$863	16.4%	
	Powertrain	$25,920	$103,690	$1,311	25.0%	
	Assembly	$3,480	$13,910	$176	3.4%	
	Manufacturers Margin	$5,330	$21,330	$270	5.1%	
	Transport to Site	$2,000	$8,000	$101	1.9%	
	Onsite Assembly	$2,000	$8,000	$101	1.9%	
	Device Deployment	$500	$2,000	$25	0.5%	
	Underwater Cabling	$10,000	$40,000	$506	9.6%	
	Grid Interconnection	$25,000	$100,000	$1,265	24.1%	
	Installed Cost	**$103,720**	**$414,880**	**$5,247**	100.0%	
Annual O&M Cost						
	Replacement parts	$1,300	$5,180	$49	28.8%	
	Cleaning Screen	$1,200	$4,800	$45	26.7%	
	Labor	$2,000	$8,000	$75	44.5%	
	Total Annual Cost	**$4,500**	**$17,980**	**$169**	**100%**	
Performance						
	Energy Extraction (variable rpm)		**Per Rotor**	**Per Mach**	**Per Field**	
	Average Extracted Power		1.8	7.0	28	kW
	Average Electric Power		1.5	6.2	25	kW
	Rated Electric Power		4.9	19.8	79	kW
	Machine Capacity Factor		36%	36%	36%	
	Availability		90%	90%	90%	
	Transmission Efficiency		98%	98%	98%	
	Annual Output		13.6	54.3	217	MWh

7.3. Feedback Effects on Flow

A 1D model was used to investigate the feedback effects of extracting energy from the river. The velocity reduction as a result of extracting energy from the river in Whitestone proved to be significant enough to require incorporation of feedback effects into the device performance model. The following two tables show the inputs to the model. Extraction effects were modeled for a typical average flow condition at the deployment site. Background information on the 1D modeling approach is offered in appendix A.

Table 26: Turbine Parameters

Rotors/machine	4
Machines/row	3
Rows	10
Total rotors	120
Diameter	2.0m
Extraction efficiency	40%

Table 27: Site Parameters

Velocity	0.979m/s
Depth	6.7m
Width	169m
Length	500m
Elevation Change	0.051m
Manning roughness	0.035

It is assumed that the extraction will not alter the river flow rate. The case described extracts 123 kW from the flow and increases the river depth by over 50cm. This is a meaningful change and is accompanied by a substantial drop in kinetic power density (~20%) at the site. This may have economic implications for site build-out.

Along-channel velocity and depth profiles for the site are shown in Figure 45 and Figure 46. It should be noted that the gradients across rows of turbines will probably not be as sharp as those portrayed here under a 1D assumption with discontinuous extraction, but the profile will be generally saw-toothed. For all cases tested, velocity increases across each transect and depth decreases, indicating an exchange of kinetic and potential energy in the system. Note, however, that the variations are quite small relative to their mean values.

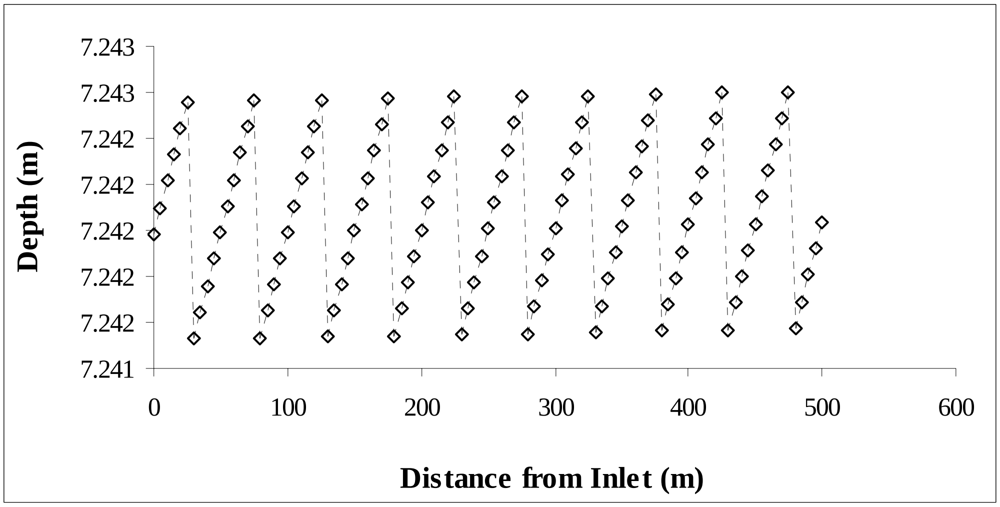


Figure 45 – Whitestone at Tanana: depth profile, 120 rotors –123 kW extraction

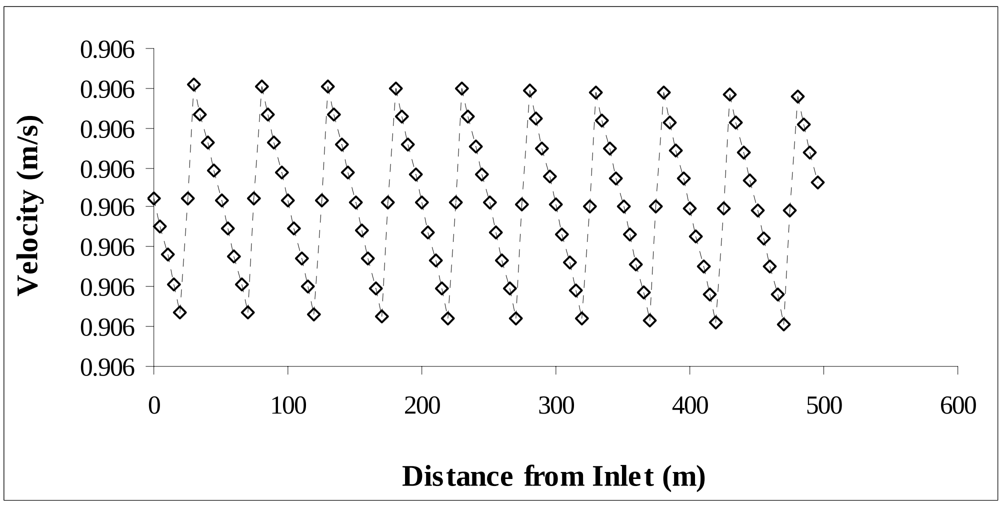


Figure 46 – Whitestone at Tanana: velocity profile, 120 rotors –123 kW extraction

Since this level of extraction does meaningfully alter the inlet depth of the river and the flow regime (velocity and power density), it is worth considering the effects for different levels of extraction. The increased inlet depth corresponds to a reduced inlet velocity with the volume flow rate held constant (Figure 47).

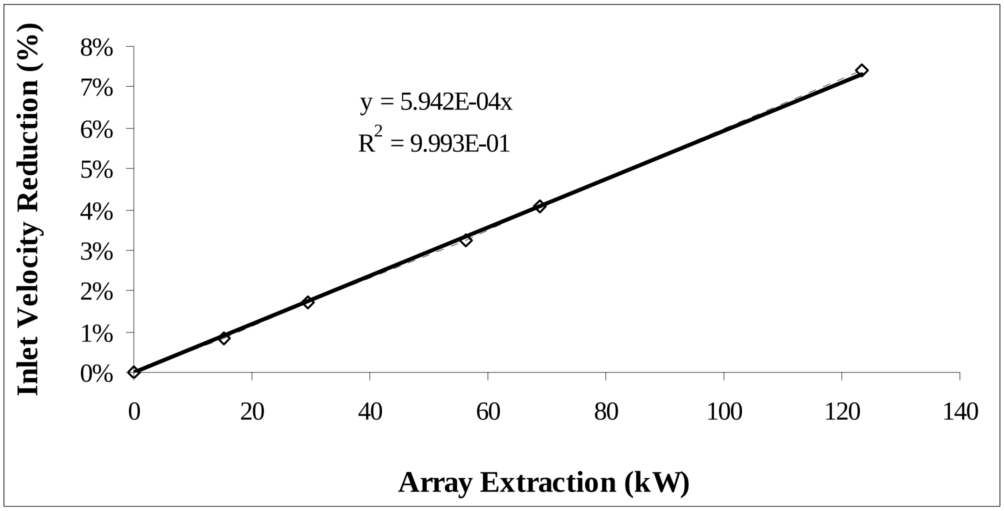


Figure 47 – Channel velocity reduction (cross-sectional average) as a function of extraction

Since power density is proportional to the cube of velocity, its reduction is more pronounced. (Figure 48).

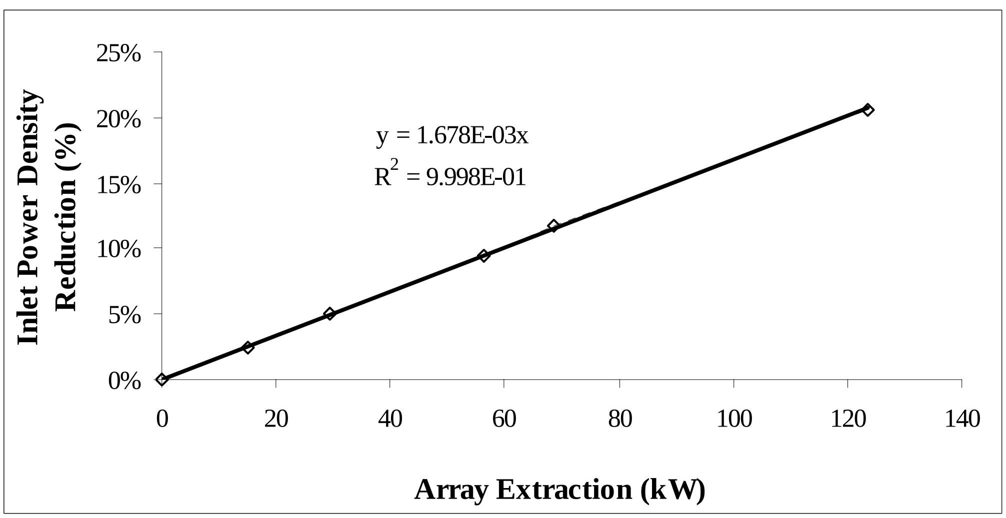


Figure 48 – Channel power density reduction (cross-sectional average) as a function of extraction

Finally, the reduced power density decreases the output per rotor in a nearly linear manner as extraction increases (Figure 49).

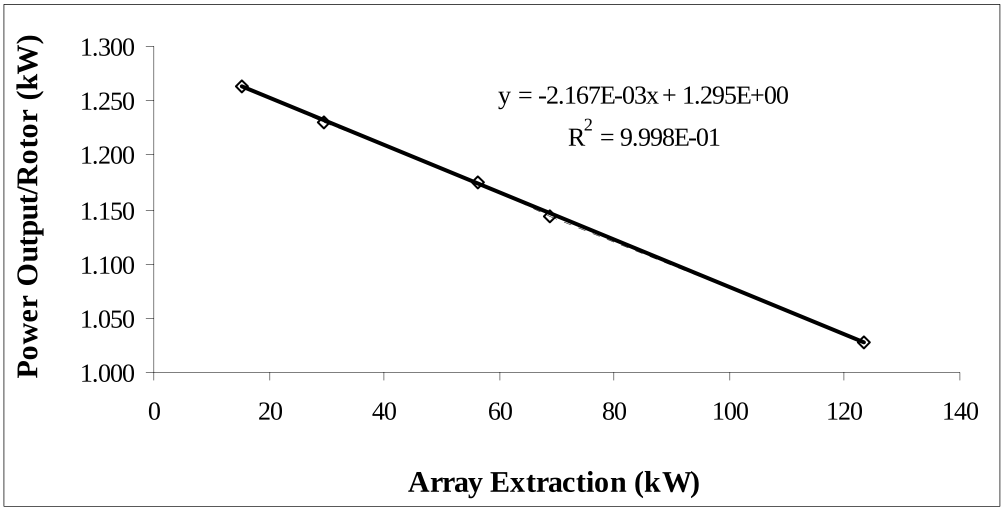


Figure 49 – Power output per rotor as a function of extraction

For the cases considered, flow quantities and power output decline in a nearly linear manner. If additional rows of turbines were added to flow, the decline would intensify (becoming quadratic in nature), eventually reaching a point at which additional turbines would generate less power.

7.4. Economic Analysis

A Simple Payback Period (SPP) refers to the period of time required for the return on an investment to "repay" the sum of the original investment. For example, a $1000 investment which returned $500 per year would have a two-year payback period. It intuitively measures how long something takes to "pay for itself"; shorter payback periods are obviously preferable to longer payback periods. The calculation assumes installation in 2009 and beginning of operation Jan 1, 2010. The installation year (2009) is counted as part of the payback period. The breakdown of the analysis is shown in the table below. The results of the SPP calculation for Whitestone show a 8-9 year payback period.

Table 28: SPP Calculation for Whitestone

Parameter	Unit	Value
Capital Cost	2007 $	1,820,910
O&M Cost	2007 $	128,900
Annual Energy Production	MWh/year	1,325
Avoided Cost Level	2008$/kWh	0.18
Yearly Escalation of non Fuel Costs		0.03
Yearly Escalation of Diesel Fuel Costs		0.08

	Annual Cost	Cumulative Cost	Annual Revenue	Cumulative Revenue
2009	$1,931,803	$1,931,803	$0	$0
2010	$140,853	$2,072,656	$300,441	$300,441
2011	$145,078	$2,217,734	$324,477	$624,918
2012	$149,430	$2,367,164	$350,435	$975,353
2013	$153,913	$2,521,078	$378,470	$1,353,822
2014	$158,531	$2,679,609	$408,747	$1,762,569
2015	$163,287	$2,842,895	$441,447	$2,204,016
2016	$168,185	$3,011,080	$476,763	$2,680,779
2017	$173,231	$3,184,311	$514,904	$3,195,682
2018	$178,428	$3,362,739	$556,096	$3,751,778
2019	$183,781	$3,546,520	$600,584	$4,352,362
2020	$189,294	$3,735,814	$648,630	$5,000,992

To illustrate the above table further, Figure 50shows the cumulative cost and the cumulative revenue as a function of time. The simple payback period is defined by the point where the cumulative revenues equal or exceed the cumulative cost.

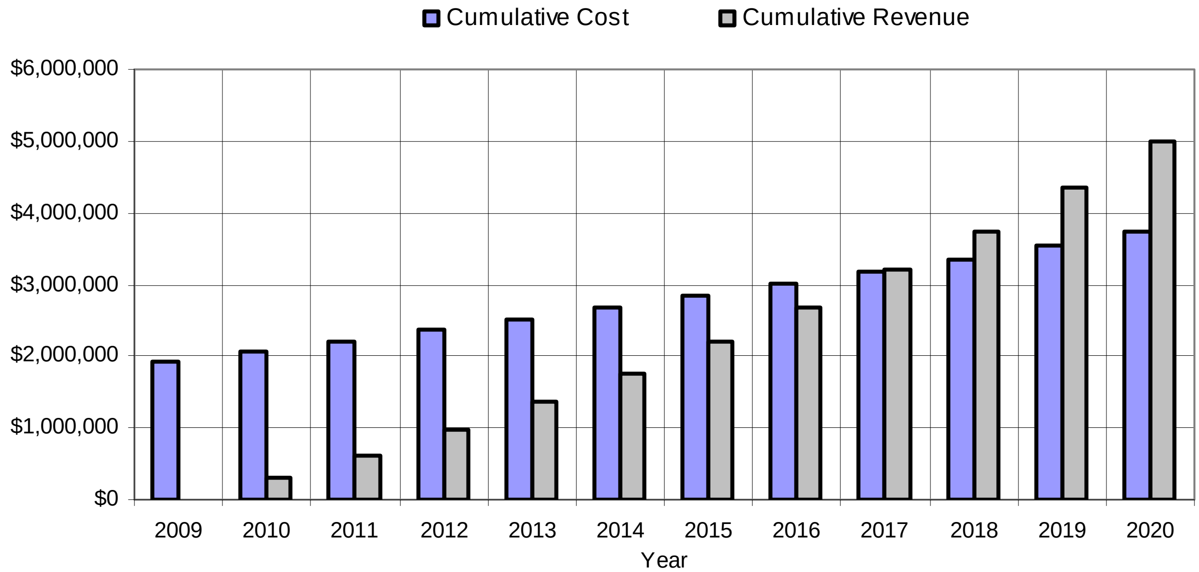


Figure 50: Cumulative cost vs. cumulative revenue

The secondary scenario for a smaller plant at Whitestone that is only connected to the local isolated grid showed a payback period of 3-4 years. The following table shows SPP calculations for that scenario.

Table 29: SPP Calculation for Whitestone Baseload Scenario

Parameter	Unit	Value
Capital Cost	2007 $	414,880
O&M Cost	2007 $	17,980
Annual Energy Production	MWh/year	217
Avoided Cost Level	2008$/kWh	0.65
Yearly Escalation of non Fuel Costs		0.03
Yearly Escalation of Diesel Fuel Costs		0.08

	Annual Cost	Cumulative Cost	Annual Revenue	Cumulative Revenue
2009	$440,146	$440,146	$0	$0
2010	$19,647	$459,793	$177,682	$177,682
2011	$20,237	$480,030	$191,897	$369,579
2012	$20,844	$500,874	$207,249	$576,828
2013	$21,469	$522,343	$223,829	$800,657
2014	$22,113	$544,456	$241,735	$1,042,392
2015	$22,777	$567,233	$261,074	$1,303,465
2016	$23,460	$590,692	$281,960	$1,585,425
2017	$24,164	$614,856	$304,516	$1,889,941
2018	$24,889	$639,745	$328,878	$2,218,819
2019	$25,635	$665,380	$355,188	$2,574,007
2020	$26,404	$691,784	$383,603	$2,957,610

To illustrate the above table further, Figure 51 shows the cumulative cost and the cumulative revenue as a function of time. The simple payback period is defined by the point where the cumulative revenues equal or exceed the cumulative cost.

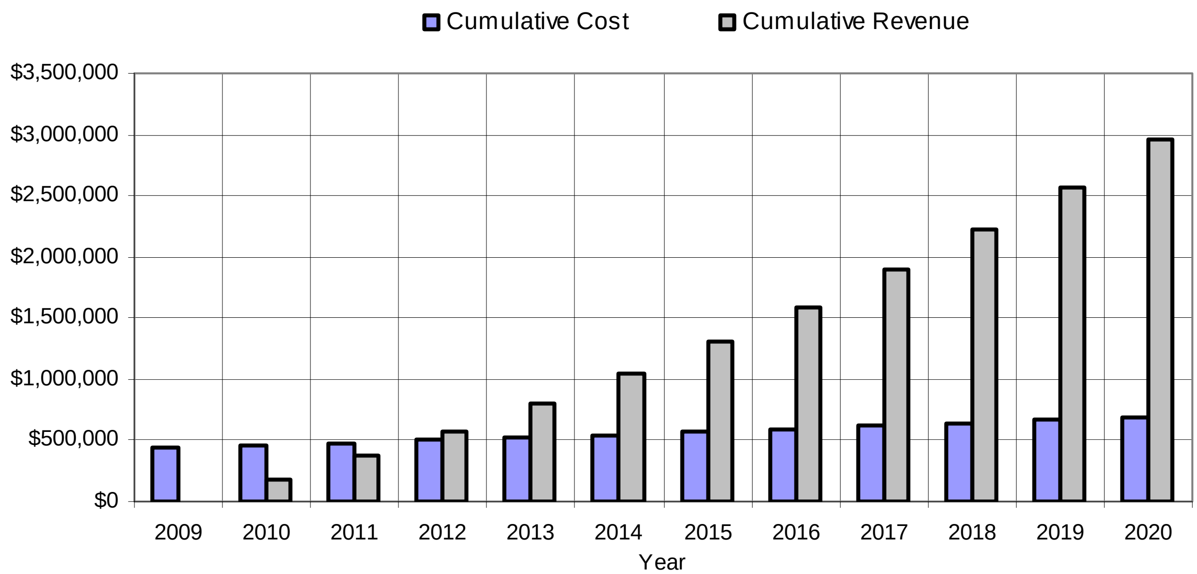


Figure 51: Cumulative cost vs. cumulative revenue

8. Conclusions

Conceptual RISEC design studies for three different sites in Alaska were carried out. The three sites have very different site conditions affecting their viability. The conceptual site designs were largely based on data that was collected in a previous site assessment study-phase. Results of that study-phase are detailed in Reference 1. RISEC devices under development remain at an immature stage of commercial development. In order to be able to carry out performance, cost and economic assessments, EPRI established a baseline device design consisting of four rotors mounted on a single pontoon structure. Based on that baseline design, a parametric cost and performance model was established to be able to adapt the technology to the site conditions encountered at the various sites of interest.

Iguigig Village located on the Kvichak River is a small community, where a RISEC plant could be used to complement existing diesel-based generation. A RISEC plant at that site could be continuously operated because the river at Iguigig remains ice-free throughout the year. During ice breakup (about two weeks), the system would have to be removed to avoid damage. The Kvichak River discharges water from the Llama Lake, which smoothes the summer/winter variability of discharge rates. As a result, power densities do not drop off as much in winter time as they do in other locations. The generation capacity of a commercial RISEC plant would be limited to a summer usage low of 40kW.

The village of Eagle is a small community on the Yukon River, near the Canadian border. While accessible by road during summer months, the village is not connected to an electrical grid and generates its electricity using a diesel generator. The river at that location freezes over completely during winter months. While the river is relatively deep and would potentially allow for under-ice operation during winter months, the flow velocities during that time is so small that it does not seem to make economic sense to generate power during these months. As a result it was decided to plan for removal of the floating RISEC units before freeze-over and redeployment after ice breakup in spring. This results in a period of five months during which the plant would be operational.

Whitestone Village located on the Tanana River is a small community located near the Big Delta junction. The Richardson Hwy crosses the Tanana River just about one mile upstream from Whitestone. An electrical transmission line (GVEA grid) runs alongside the highway which could be used to export power from a potential RISEC generation site. While Whitestone is presently not grid-connected, there are well-advanced plans to integrate the community into the GVEA grid. While potentially more then 5MW of capacity could be exported from that location, the baseline study focused on a deployment of a 500kW, 30 RISEC device plant. This allowed evaluation of the impacts of commercial scale deployments.

The following table provides an overview of the high level results for the three sites. It is important to understand that cost numbers shown in this report are reflecting installed machine cost only. Additional cost incurred for permitting and environmental monitoring may result in significant increases in cost for the first few installations.

Table 30: Site Summary

	Iguigig	**Eagle**	**Whitestone**
Site Parameters			
Ice freeze-over	No	Yes	No
Annual Average Power Density	1.48 kW/m^2	1.5 kW/m^2	0.67 kW/m^2
Mid-channel Average Power density	3.24 kW/m^2	3.2 kW/m^2	1.48 kW/m^2
Average Total Kinetic Power	719 kW	4,601 kW	762 kW
Summer/Winter Power Density Variability	1:4	1:20	1:10
Site Distance from Shore	60 m	150 m	50 m
Grid Feed-In Limit	40 kW	70 kW	> 5 MW
RISEC plant parameters			
# of RISEC Devices	3	2	30
# Rotors per Machine	4	4	4
Rotor Diameter	1.5 m	2 m	2 m
Plant Rated Capacity	42 kW	61 kW	593 kW
Plant Annual Output	220 MWh/yr	113 MWh/yr	1325 MWh/yr
Capacity Factor	65 %	57 %	29%
Availability	90%	38%[1]	90%
Cost and Economic Parameters			
Installed Cost	$308,000	$269,000	$1,821,000
Installed Cost per kW	$7,500/kW	$5,800/kW	$3,100/kW
Assumed Avoided Cost (selling price)	0.65 $/kWh	0.65 $/kWh	0.18 $/kWh
Simple Payback Period	3-4 Years	4-5 Years	8-9 Years

[1] Availability for Eagle site is low because plant only operates during 5months of the year.

River discharge rates and related hydrokinetic power densities are highest during summer months when electrical loads in these villages is lowest. As a result the plant rated capacity was sized to the daily average summer low to make sure that the electrical demand can absorb all the power generated by these RISEC units. Hourly patterns (day/night) were however neglected and it may require some additional battery storage to accommodate these hourly load fluctuations.

Additional scenarios were evaluated for the Whitestone and the Iguigig sites. The additional scenario for Whitestone assumed that the plant would not be connected to the GVEA grid, but instead is connected to an isolated Whitestone grid. This smaller capacity plant has a shorter payback period then the larger grid-connected counterpart because present generation costs are higher. However, it would not allow for the same scale of adoption because of the limited grid feed-in capacity at the site. The second scenario for Iguigig aimed at providing base-load capabilities for the site. This scenario showed an almost equal payback period.

Extracting power from a river has feedback effects on the flow within the river: fluid velocities will slow down as a direct result of extracting power from the river and water levels increase. A one-dimensional model was developed to simulate the effects of extracting power from the river. The low level of extraction in Iguigig and Eagle will not affect flows in these rivers in any measurable way. For the larger scale plant at Whitestone, a power-density reduction of about 7% was modeled during typical flow conditions. It is unlikely that this reduction will have any significant environmental impact.

A parametric model was developed to evaluate the sensitivity of various cost and simple payback period (SPP) parameters to the critical input parameter including rotor diameter, site power density, number of rotors per machine and other parameters to determine what creates the attributes for a good RISEC site. Because RISEC is an emerging technology with almost no operational experience, evaluating what makes a good river site is one of the most important aspects of a technical study such as this one. The following parameters have the most significant impact on the cost of electricity from an in-stream device:

- The higher the power density at the site, the more attractive the economics

- Less variability in flow and power density at the site will result in higher capacity factors and better economics.

- Larger rotor sizes will yield better economics, requiring deeper water. Rotor sizes of 6ft or more should be targeted. Vertical axis rotors could potentially prove advantageous in shallow river sites but were not investigated as part of this study.

Significant uncertainties remain to be addressed in respect to actual operation of plants in the three sites. The following are critical considerations to be addressed if any of the above villages is to move forward with developing a site.

1. Velocities and power densities were established using USGS data. The USGS data was not measured at the most likely deployment site and carries therefore a significant amount of uncertainty, as velocities can change significantly within short distances in a particular river reach. Before moving forward with a plant, a detailed bathymetric and velocity profiling survey should be carried out at potential deployment locations.

2. Interaction of the machine with debris is an issue that is not well-understood at present. There is little data on what type and how much debris is passing down the river at the sites of interest. More importantly, cellulosic debris (such as logs) tend to float near the surface and it is unclear to what extent such debris may also float in mid-water. Initial operational experience will be needed to design potential mitigation measures.

3. The machine and rotor interaction with fish is not well-understood and will require acoustic monitoring of fish movement around the turbines to evaluate the impacts of the machine operation on the fish population.

4. This feasibility study assessed the cost of installed RISEC systems. However, with no actual installations on which to base cost and performance data, cost uncertainties remain significant, especially in respect to O&M activities.

While many issues in respect to commercial deployment of RISEC devices remain to be addressed, the results of this study indicate that this technology could be used to offset some of the diesel generation in remote villages and could be attractive from an economic point of view.

9. References

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10. Appendix A - River Extraction Model

In order to determine the effects of extraction for a particular site using a 1D model, the following parameters must be known:

- Cross-sectional average velocity (*U*)
- Channel width (*b*)
- Channel depth (*H*)
- Channel length (*L*)
- Elevation change along channel length (*Δz*)
- Manning roughness coefficient (*n*)

These parameters are related via the Manning equation:

$$U = \frac{R_h^{2/3}}{n}\left(\frac{\Delta z}{L}\right)^{1/2} \qquad (1)$$

where R_h is the hydraulic radius – the ratio of the cross-sectional area to wetted perimeter.

For the sites of interest in this study, only the velocity and channel geometry (width, depth, length) parameters are known. However, using generally accepted Manning roughness coefficients for natural channels (e.g. n=0.035), the elevation change for the channel may be calculated through algebraic rearrangement of the Manning equation.

In order to model kinetic power extraction from a river, a number of simplifying assumptions are made with respect to geometry and the underlying physics. It is assumed that the river channel is a rectangular prism of constant width and downward slope (Figure 1). In a case without power extraction, the accelerating effect of the downward slope (elevation distance from inlet to outlet) is exactly counter-balanced by friction between the moving water and riverbed. As a result, the river depth and velocity do not vary along its length.

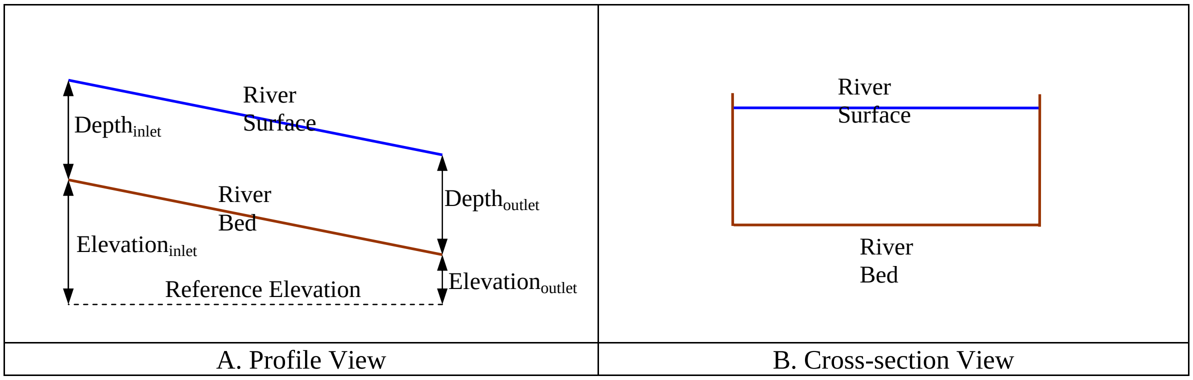


Figure 1 - River Geometry

The flow is modeled in one dimension. That is, the flow is predominantly in the upstream and downstream direction, with no variation in the cross-channel direction or depth. This simplification significantly simplifies the physics involved.

Since the flow is at steady-state, the discretized form of the governing equations may be solved by a marching technique. That is, for a given depth and velocity at an upstream position, it is possible for the calculations to proceed downstream in discrete intervals. The discretized model is shown in Figure 2, where the river has been broken into eight segments.

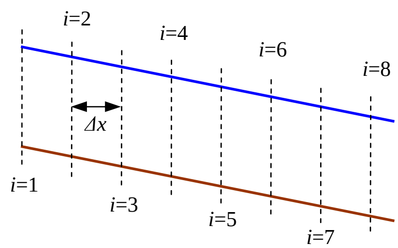


Figure 2 – Discretized River Geometry

Consider two points on the river (i=1 and i=2) separated by some distance (Δx). Between those two points, mass and energy must be conserved. Since the density of the water is constant and the system is assumed to be at a steady state, conservation of mass can be represented as conservation of the flow rate (Q – m^3/s) from station 1 to station 2.

$$Q_1 = Q_2 = Q \tag{2}$$

In order for energy to be conserved, the difference in kinetic and potential energy (total energy) between stations 1 and 2 must match energy dissipated or added to the system between those two stations.

$$\frac{1}{2g}\left(\frac{Q}{h_2 b}\right)^2 + \left(h_2 + z_2\right) - \frac{1}{2g}\left(\frac{Q}{h_1 b}\right)^2 - \left(h_1 + z_1\right) = \text{Additions - Losses} \quad (3)$$

- g: acceleration due to gravity (9.81 m/s^2)
- h: water depth (m)
- z: elevation relative to reference datum (m)

For the river model, there are no additions of energy, and losses are due either to friction between the flow and riverbed or extraction of kinetic energy. Losses due to friction are modeled using another form of the manning equation:

$$\text{loss}_{\text{friction}} = \frac{n^2}{R_h^{4/3}}\left(\frac{Q}{hb}\right)^2 \Delta x \quad (4)$$

Losses due to energy extraction are modeled as removing a fraction of the upstream kinetic energy:

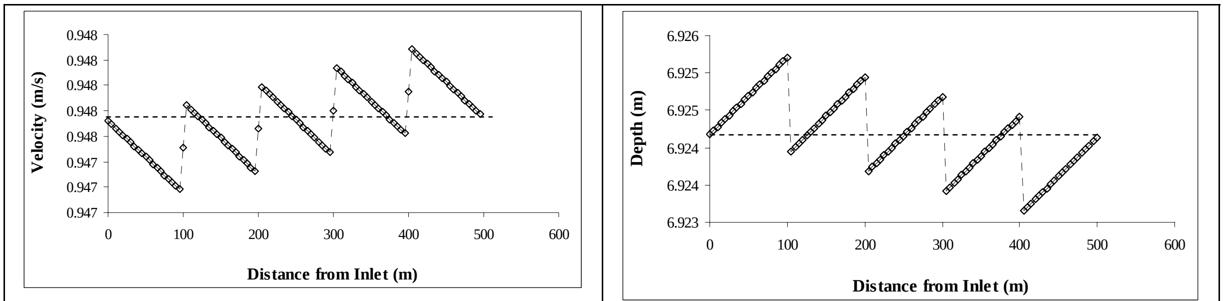
$$\text{loss}_{\text{extraction}} = \frac{1}{2\text{g}} k \left(\frac{Q}{h_1 b}\right)^2 \quad (5)$$

- k: extraction coefficient – product of the rotor efficiency and blockage ratio
- *blockage ratio*: ratio of swept area of a row of turbines to the cross-sectional area of a channel

It is assumed that turbines are distributed in transects (rows) spanning the channel. Transects are evenly spaced along the channel. Since the channel center velocity tends to be greater than the cross-sectional average velocity, an adjustment is made to the area of each turbine. The area is increased such that the intercepted power under cross-sectional average flow conditions is equal to the intercepted power for channel center velocity. This is a coarse approximation to account for the actual location of turbines in the channel in determining the effect on the flow.

If the upstream depth, flow rate and elevation are known, and the downstream elevation is also known, then equation (2) can be solved for downstream depth and the processes repeated for the next segment of the discretized river. This method does not resolve the turbine wake or any three-dimensional flow effects associated with turbine operation.

For the cases considered in this report, it is assumed that extraction will not change the volume of water in the river channel, but rather increase the water depth at the inlet and reduce the cross-sectional average velocity. Since this case is still at steady-state, the depths and velocities at the channel inlet and outlet remain equal, though there is some variation over the rows of turbines as shown in Figure 3.



A. Channel Velocity	B. Channel Depth

Figure 3 – Sample Output

11. Appendix B – RISEC Technologies under Development

Today, a number of entrepreneurial companies are leading the commercialization of in-stream river energy conversion technologies. The table below presents known RISEC developers as of July 31, 2008.

Table 21 River In Stream Energy Conversion Device Developers

Device Developer(1) Website	Device Name(2)	Type(3)	Development Status(4)
AeroHydro Research and Technology www.ahrta.com	Unknown	Oscillatory	Laboratory
Free Flow Power www.freeflowpower.com	FFP Turbine Generator	Horizontal Axis	Experimental
Free Flow 69 www.hi-spec.uk.co/page10.htm	Osprey	Vertical Axis	Experimental
Lucid Energy www.licidenergy.com	Gorlov Helical Turbine (GHT)	Vertical Axis	Technology Demonstration
Hydro Green Energy www.hgenergy.com	Krouse Turbine	Horizontal Axis	Experimental
New Energy Corporation www.newenergycorp.ca	EnCurrent Turbine	Vertical Axis	Commercial Demonstration
Ocean Renewable Power Corp www.oceanrenewablepower.com	OCGen	Crossflow Axis	Technology Demonstration
UEK www.uekus.com	Underwater Electric Kite	Horizontal Axis	Commercial Demonstration
Verdant Power www.verdantpower.com	Free Flow Turbine	Horizontal Axis	Commercial Demonstration
Vortex Hydro www.vortexhhydro.com	VIVACI	Vertical Axis	Laboratory

(1) This list excludes individual inventors with conceptual level technology.
(2) Name given to the device.
(3) The principle of operation.
- HA – Horizontal Axis Open Rotor
- HA – Ducted Horizontal Axis
- VA – Vertical Axis
- Oscillatory

(4) The following definition of development status was used:
- Laboratory testing stage
- Experimental – Subscale at sea testing
- Technology Demonstration – Large size engineering prototype at sea testing whose purpose is to test for function and performance
- Commercial Demonstration – Large size manufacturing prototype at sea testing whose purpose is to test for commercial viability
- Early Commercial – Offering many units of large size for purposes of generating and selling the electricity produced

Aero Hydro Research and Technology Associates

Aero Hydro Research and Technology Associates (AHRTA) is developing a type of hydropower generator that uses oscillating wings to convert the flow energy of rivers and tidal streams into electrical energy. AHRTA's concept manipulates an airfoil to oscillate in both plunge (pure translation) and pitch (rotation about some axis on the airfoil chord line) to extract energy from the air or water flow. The phase angle between the pitch and plunge oscillations must be close to 90 degrees. AHRTA has constructed an experimental model which enforces the plunge and pitch oscillation with the proper phasing between the two motions, as shown in Figure 70. The model has two wings arranged in a tandem configuration so that the two wings also operate with a 90-degree phasing. Thus far, the model system has operated satisfactorily. AHRTA is now in the process of developing a new model with a simpler mechanism to enforce the phasing between the pitch and plunge motion.

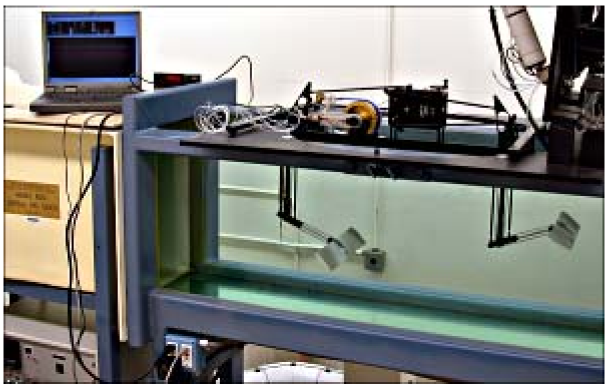


Figure 70
AHRTA Oscillating Turbine Experimental Configuration

Free Flow Power

Free Flow Power (FFP) is developing a RISEC turbine system that uses a rim-mounted, permanent magnet, direct-drive generator with front and rear diffusers and one moving part (the rotor) to maximize efficiency. The generator uses a start-up bearing and a combination of magnetic levitation and hydrodynamic bearings. At a flow of nine feet per second, the turbine can produce 20kW of power.

Magnetic arrays, using rare earth Neodymium magnets, provide high field strength for greater efficiency and lower harmonic content. This arrangement facilitates easier grid synchronization than traditional bi-polar magnet arrays. Meanwhile, the generator's rotor is designed to operate over a wider range of flow speeds (from two meters per second to five meters per second). Figures 10-15 illustrate both the cross section and component parts that comprise the FFP turbine generator, as well as an experimental rotor.

FFP is designing a prototype turbine in collaboration with Springfield, N.J.-based Sigma Design Co., Malta, N.Y.-based Advanced Energy Conversion, and Norwich, Vt.-based Turbo Solutions Engineering. Looking ahead, the company plans to place six to 12 turbines in arrays on pilings, 25 feet off the bottom of a river and at least 40 feet below the surface to stay clear of ships and boats.

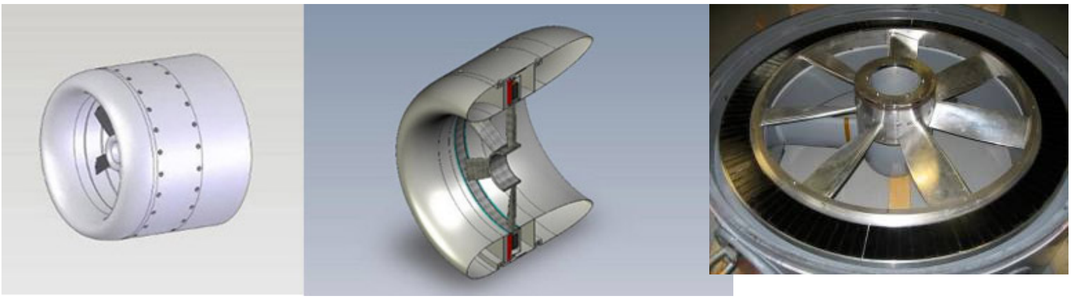


Figure 71
FFP Turbine Generator

FFP expects to manufacture two versions of the Free Flow Turbine Generator:

- a two-meter version expected to generate 10kW in flows of 2 meters per second
- a one-meter version expected to generate 10kW in flows of 3 meters per second

Free Flow 69

Free Flow 69, founded in 2005, is researching a tidal power concept called "the sea engine," invented in 1988 but never developed. It has developed a vertical axis turbine, called the Osprey. Although the design of the turbine is still confidential, the key advantages of the turbine include 1) its suitability for both river and tidal streams, 2) efficiency in variable heights of flow, 3) relatively simple design and manufacture, and 5) easy maintenance (most of the complex components are above water level).

Figure 72 shows the Osprey Prototype Turbine test rig, a 30-foot aluminum catamaran manufactured by Able Engineering. Initial pilot trials are now being conducted.

Figure 72 Free Flow 60 Osprey Turbine in Experimental Test Configuration

Hydro Green

Houston, TX-based Hydro Green Energy, LLC, has developed and patented a hydrokinetic turbine array (HTA) system. The company intends to operate as an Independent Power Producer (IPP), selling the power generated from its HTAs via long-term, wholesale power purchase agreements (PPAs). Figure 73 illustrates a 2x2 hydrokinetic Hydropower Turbine Array configuration. Figure 74 is an underwater view of the patented hydrokinetic in-stream river current device array configuration.

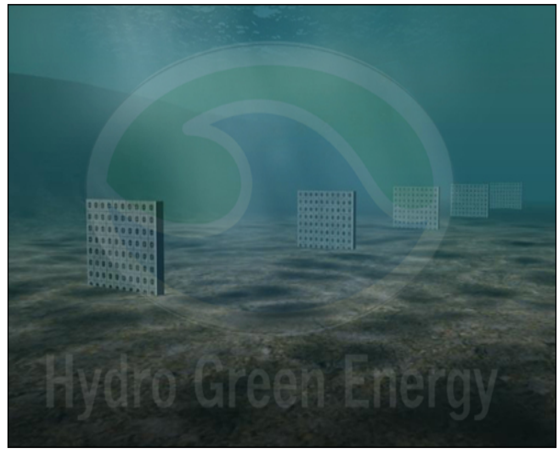


Figure 73
Hydro Green Turbines

Figure 74
Hydro Green Turbine Array Configuration

Lucid Energy Technologies

Formed in March of 2007, Lucid Energy Technologies is a joint venture between GCK Technology, Inc., and Vigor Clean Tech, Inc. The company is focusing on designing and commercializing complete hydrokinetic electricity generation systems based on the Gorlov Helical Turbine (GHT). Figures 75 and 76, respectively, show a Lucid Energy turbine prototype and an array configuration.

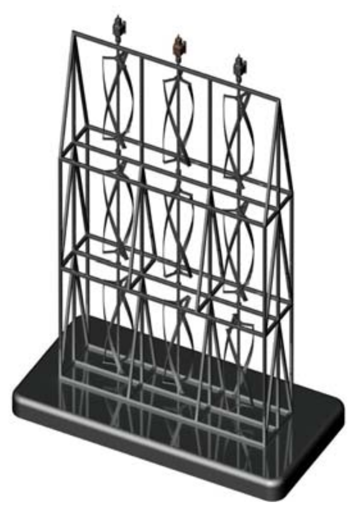


Figure 75
Lucid Energy Turbine

Figure 76
Lucid Energy Array Configuration

New Energy Corp.

New Energy Corporation is a Canada-based RISEC manufacturer of its proprietary EnCurrent Turbines. The technology is based on the Darrieus wind turbine, also called an eggbeater or whisk turbine due to its shape. The EnCurrent Turbine is a cross-flow turbine, meaning that the direction of rotation is perpendicular to direction of water flow. When the turbine rotor is placed within a water current, the hydrofoils generate a lift vector in the forward orientation which can be captured at the shaft as a positive rotation. The hydrofoils experience their maximum forward torque at the top and bottom of their rotation, when the water moving past them is tangential. The turbine rotates in the same direction regardless of the direction of the water current and captures between 35% and 40% of the energy in moving water. It rotates at a very low speed, between 2 and 2.5 times the speed of the water in which it is submerged.

One of the unique properties of the Darrieus Turbine design is that it is able to capture the energy from the water irrespective of the direction of the current. This property enables the EnCurrent Turbine to harness the energy contained in both flood and ebb tides. A permanent magnet generator is mounted on the turbine shaft to convert the torque generated by the rotor into electricity. The output from the permanent magnet generator is a variable voltage AC signal which is rectified to DC and fed into an inverter. The inverter takes the DC signal as input and provides an AC output. Different inverters can be used to provide the appropriate power for the regulatory requirements of any given area in the world.

New Energy currently manufactures 5kW, 10kW and 25kW models of the EnCurrent Power Generation System; it is working to have 125kW and 250kW models available by Q4 of 2008. New Energy also provides a set of ancillary products that support the installation of the EnCurrent Power Generation System. A mount on a double hull pontoon boat is shown in

Figure 77
New Energy EnCurrent Turbine

Figure 78
Illustration of a pontoon mount

Ocean Renewable Power Corp.

Ocean Renewable Power Company, LLC (ORPC), founded in 2004, has developed a proprietary RISEC turbine named the ocean current generation (OCGen) Turbine Generating Unit (TGU). The TGU turbine rotates in one direction only, regardless of current flow direction. Two cross flow turbines drive a permanent magnet generator on a single shaft. TGUs are "stacked" (horizontally or vertically) and incorporated into OCGen modules that contain the ballast/buoyancy tanks and power electronics/control system (See Figure 79).

Assembled OCGen modules are deployed in arrays comprised of tens to hundreds of modules and held into position underwater using deep sea mooring systems. A power and control cable connects each OCGen module to an underwater transmission line that interconnects with an on-shore substation. Generating capacity of up to 250kW is achievable in a six-knot current (varies with current speed).

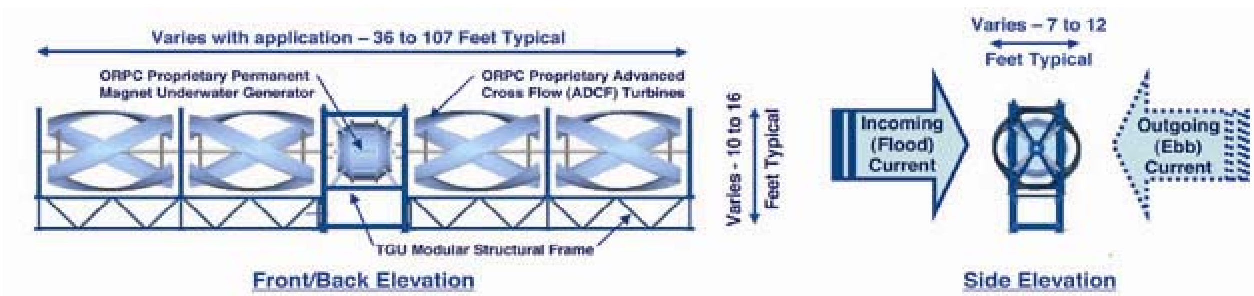


Figure 79
Ocean Renewable power Corp OCGen™ Module

In mid-May 2007, ORPC commenced an OCGen TGU demonstration project in tidal currents in Western Passage (Passamaquoddy Bay) near Eastport, Maine. The demo, completed in early 2008, successfully proved the basic design and technical feasibility of the TGU. Data was also collected for use in the subsequent TGU commercial designs.

The final and most critical test during the demonstration project was a seven-day continuous deployment conducted while a barge with the TGU fully deployed was attached to stationary moorings near Dog Island (Western Passage) (see Figure 80). The achieved results met or exceeded expectations for all but two related performance parameters: ADCF Turbine Efficiency and TGU Average and Peak Output.

Figure 80
Testing of the Ocean Renewable power Corp OCGen™ Module in the Western Passage

UEK Corp.

UEK Corporation, founded in 1981, has developed the Underwater Electric Kite (UEK), a twin horizontal axis turbine which features a unique, very high solidity (85%-95%) turbine design and an augmenter ring (augments or increases the internal velocity of the water flow) in order to create a system with high efficiency. Figure 81 shows a twin unit that tested for 36 days in May 2000 in the flume of the DeQew Hydroelectric Power Plant, owned and operated by Ontario Hydro. Figure 82 illustrates a unit tested in the Chesapeake Bay. UEK is targeting project opportunities at potential sites that can support underwater parks of twelve units or more.

Figure 81
Twin UEK Turbine Installed at Ontario Hydro

Figure 82:
17’ Single UEK tested in the Chesapeake Bay

Verdant Power

New York, NY-based Verdant Power, founded in 2000, has built, tested and deployed four working marine energy system prototypes. Dubbed the Free Flow, the system is comprised of arrays of three-blade horizontal-axis turbines that resemble and operate similarly to present-day wind turbines (see Figures 83 and 84). The turbine rotor is spun slowly and steadily (~32 rpm) by the natural currents of tides and rivers. This motion drives a speed increaser, which in turn drives a grid-connected generator, both of which are encased in a waterproof streamlined nacelle mounted on a streamlined pylon.

Figure 83
Verdant Power Free Flow Turbine

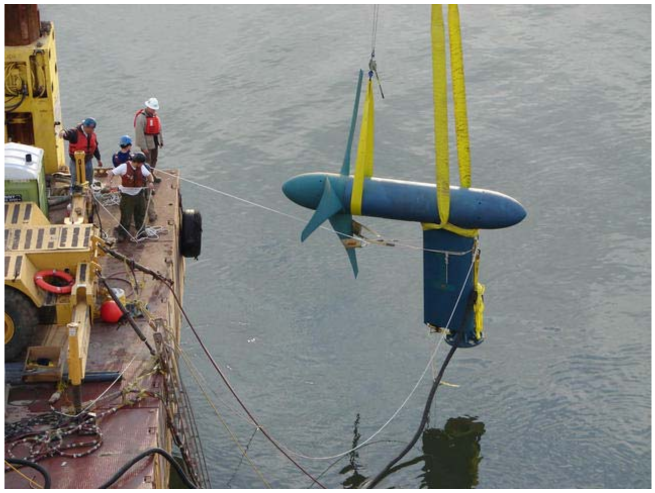


Figure 84
Verdant Power Turbine being lowered into the East River prior to mounting with a monopile

Free Flow turbines can operate in both tidal and river settings. Turbines deployed in tidal settings are assembled with internal yaw bearings, which allow the turbines to pivot with the changing tide and capture energy for the majority of the day. Turbines deployed in rivers are fixed and generate power on the continuous flow of the river throughout the day, providing nearly 24-hour power. Depending on the site, various types of devices can be used to anchor the turbines underwater.

Vortex Hydro

Founded in 2004, Vortex Hydro Energy LLC (VHE) is a Michigan-based company that has developed a technology nicknamed VIVACE (Vortex Induced Vibrations Aquatic Clean Energy). VIVACE uses vortex induced vibrations to extract energy from ocean, river, tidal and other water currents. For decades, engineers have been trying to prevent Vortex Induced Vibrations (VIV) from damaging offshore equipment and structures. VIVACE works by maximizing and exploiting VIV rather than spoiling and preventing it.

As depicted in Figure 85, VIV results from vortices forming and shedding on the downstream side of a bluff body in a current. Vortex shedding alternates from one side to the other, thereby creating a vibration or oscillation. The VIV phenomenon is non-linear, which means it can produce useful energy at high efficiency over a wide range of current speeds.

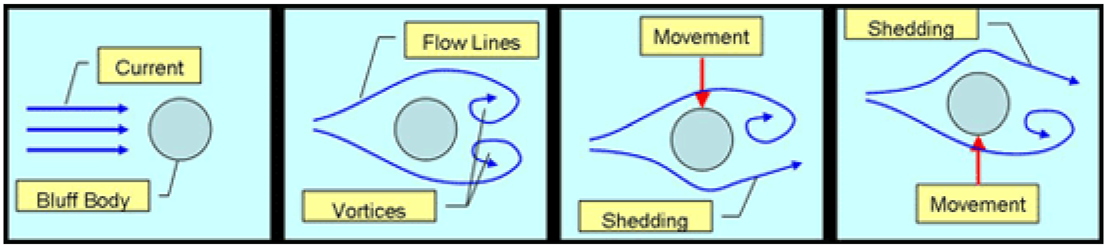


Figure 85
Vortex Induced Vibrations Oscillates Objects in Fluid Currents

VIVACE devices can be positioned beneath the surface, thereby avoiding interference with other river uses, such as fishing, shipping and tourism. In addition, VIVACE utilizes vortex formation and shedding, the same mechanism fish use to propel themselves through the water, to allow for greater compatibility with marine life.

A VIVACE prototype is currently operating in the Marine Hydrodynamics Laboratory at the University of Michigan. Testing is being funded by the U.S. DOE and the Office of Naval Research.