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7 FINANCIAL EVALUATION AND COST OF ENERGY

7 - FINANCIAL EVALUATION AND COST OF ENERGY

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WHAT DOES THIS MODULE COVER?

Project developers, lenders, and equity investors will require some level of assurance that a tidal energy project is likely to be profitable over time. This section identifies the capital and operating costs and methods of evaluating the financial viability of the capital investment in in-stream tidal energy and the estimated cost of energy.

This module outlines the following financial considerations of developing a tidal energy resource:

- The capital, operating, and maintenance costs of a tidal energy project;
- The industry-appropriate methods to evaluate the financial viability of the tidal energy project;
- Methods for estimating the levelized cost (cost per MWh) of energy.

This module is for anyone interested in the costs of tidal energy and how such investments are evaluated.

7.0 - INTRODUCTION:CAPITAL INVESTMENT EVALUATION

Tidal energy devices are relatively immature technology. The investment horizons are long and the upfront investment is proportionately high. Much is still unknown about tidal in-stream energy conversion, but a modest amount of relevant knowledge can be garnered from the experiences with offshore wind energy and wave energy.

Eventually, electricity generated from tidal energy conversion (TEC) devices will need to be competitive with other renewable sources. Costs in the technology development and pre-commercialization stages are high. Engineers and scientists are working to lower the costs of the technology so TEC can be financially sustainable, which is critical for attracting the financing to proceed through the stages of commercialization.

In this section, the revenues, capital expenditures, and ongoing costs of tidal in-stream energy conversion will be described as they are understood today. Key cost drivers are also identified and the cost reductions expected as experience is gained and competition in the supply chain develops are noted. An example of the investment evaluation for a 1 MW test turbine is provided in Table 7-1 at the end of this module.

FOUNDATIONAL CONCEPT: CAPITAL INVESTMENT EVALUATION

A comprehensive account of costs to be estimated in the capital investment evaluation is included in the EquiMar Protocols. For more detailed information, refer to Chapter III.A of "Protocols for the Equitable Assessment of Marine Energy Converters," at http://www.see.ed.ac.uk/~shs/Wave%20Energy/Equimar%20protocols.pdf.

7.0.1 - CAPITAL EXPENDITURE (CAPEX)

The capital expenditures (capital costs) for tidal energy development begin long before construction starts. There are six major elements to capital cost: the project itself, the manufacture/supply of turbine(s), its foundation, electrical components, onshore facilities and monitoring equipment, installation and commissioning costs, and decommissioning (Renewable UK, 2011). Each of these elements will be described below.

FOUNDATIONAL CONCEPT: CAPITAL COST

Capital cost, for Canadian tax purposes, includes all the costs associated with getting the equipment built, shipped, installed, and commissioned. It includes such expenditures as legal fees, permitting costs, shipping charges, interest on construction loans, and sales tax. The total capital cost is used in the calculation of investment tax credits and is amortized (expensed for tax purposes) over the economic life of the asset.

7.0.1.1 - PROJECT COSTS

Project costs include those incurred during technology development, resource assessment, acquisition of permits, project management, and other administrative activities. Development costs are expenditures to design the technology, build the prototype and conduct trials. Resource assessment includes mapping, current measurements and modelling.

The permitting process includes the environmental assessment, wildlife surveys, engineering studies, planning and legal activities (Renewable UK, 2011), First Nations consultation and a Mi'kmaq Ecological Knowledge Study (MEKS). The permitting process can take a year or longer, and must be completed before construction can begin. The time it takes to go from application to approval is dependent on the complexity of dealing with multiple planning bodies. For more information, refer to Module 4: Regulatory Regime for Tidal Energy.

Project management includes administrative activities and professional services such as accounting, legal advice, and insurance (Entec, 2006). It also includes assurances of schedule, quality and cost.

7.0.1.2 - TEC DEVICE (TURBINE)

The cost of the TEC device includes the manufacture or purchase of the device itself and the electrical components (electrical systems that connect the device to the array cables) (Carbon Trust, 2005; Renewable UK, 2011). Included in this are the costs of materials, components and labour in manufacture, fabrication, and the assembly of the turbine components. The costs of transporting the components to a construction port may either be included in the construction cost or in the installation costs. Installation costs are also a capital cost and will be discussed below.

The turbine itself consists of steel and composite materials and requires fabrication. To convert the relatively slow moving water to usable electrical energy, blades, control systems, electrical generators, and in some designs, hydraulic systems, and a gearbox are needed. The cost will be greatly dependent on the resource where the turbine will be located. Considerations include water depth, mean water speed, rated power of the turbine, and rotor diameter. The location will also dictate the electrical cable length and the size and design of the foundation (Renewable UK, 2011), as will be discussed later.

FOUNDATIONAL CONCEPT: RATED POWER & CAPACITY FACTOR

The "rated power" or "nameplate power" of the device is how much power it can generate when running at its full capacity. When operating, it usually generates less. "Capacity factor" is the device's average energy output as a percent of its rated power (Entec, 2006, p.12):

$$\text{Capacity factor (\%)} = \frac{\text{mean power output over a period of time (in MWh)}}{\text{rated power output over a period of time (in MWh)}}$$

Once the economical size of device is decided upon, the electrical and mechanical costs (size of generator needed, etc.) can be determined (Entec, 2006).

7.0.1.3 - FOUNDATION AND MOORINGS

The structure needed to fix the turbine in place depends on its design and location: water depth and speed, ground conditions, and the tidal range (the amount by which the water depth changes). It needs to be designed for the maximum load the turbine will encounter so it can stay in place in the roughest conditions (Entec, 2006).

The device may be held in place using a concrete gravity base, with a monopole, or supported from the surface. See Module 3: Tidal Power Extraction Devices for descriptions. The foundation and the cost of its manufacture vary greatly with the design of the TEC device.

7.0.1.4 - ELECTRICAL CABLES AND SWITCHGEAR

The electrical connections are not as new a technology as the TEC devices themselves, owing to the experience of offshore wind farms. They consist of cables required to interconnect individual devices to a common interconnection point in the tidal channel (EPRI, 2006), cables linking to shore, and onshore electrical systems, including onshore cables and a substation at the point of connection to the transmission system (Renewable UK, 2011), and power quality equipment (inverters, filters). Costs will be dependent upon distance to shore, ground conditions along any cable route (Entec, 2006), and voltage levels.

Whether the costs of the electrical connections are borne by the developer or by the transmission network owner depends on the jurisdiction. Costs will either be capital costs to the developer and associated maintenance costs as part of operating expenses, or be in the form of fees paid to the network owner.

IN NOVA SCOTIA: GRID INTERCONNECTION COSTS.

In Nova Scotia, grid interconnection costs for projects >100kW are borne by the developer. The work is done by Nova Scotia Power Inc. and the cost charged to the developer. The work includes the following:

1. Two studies
    a. Preliminary review
    b. System impact and facilities study
2. Generator tie-in line extension
3. Distribution/transmission system upgrades, if needed (Includes upgrade of one-phase distribution service, increasing conductor size, system voltage conversion, equipment relocations) (InnovaCorp Playbook, 2011, pp. 7-8).

7.0.1.5 - TIDAL FARM

To be commercially viable, an array of multiple TEC devices may be needed to obtain sufficient economies of scale. In the case of arrays, there will be additional capital costs (though less per unit) associated with civil engineering infrastructure. The costs will be based on the number of devices installed, their configuration within a farm, and inter-device spacing (EquiMar III.A, 2011). As well, in the case of tidal arrays, there may be one or more "redundant" devices, essentially excess capacity at the ready, so the downtime for routine repair and maintenance of individual units does not reduce the farm yield.

7.0.1.6 - ONSHORE FACILITIES AND EQUIPMENT

Onshore, there will be need for office and warehouse space. It is likely space can be rented in existing buildings, such as in a nearby industrial park. If leased, rental fees will be part of operating expenses; if built, the cost of construction will be a capital cost. Deployment, retrieval, and maintenance facilities may already exist at a nearby port for other maritime industries.

7.0.1.7 - INSTALLATION/DEPLOYMENT

Installation includes the transportation of the components to a construction port, onshore preparation, and setting the equipment in place and commissioning (Renewable UK, 2011). The method of installation depends on device design. Some devices may be towed to the site by tugs and anchored with an anchor handler. Others must be carried by a heavy lift vessel or barge or may require an expensive jack-up barge to install them (Entec, 2006). Costs of these can be estimated using vessel charter rates. Timing and availability of some equipment will affect these costs. Sea conditions and the tidal range also affect the choice and cost of vessel. The distance from port will have a bearing on the duration of the vessel charters.

In general, installation costs will be influenced by the water depth, tidal stream, tidal range, and distance from port (Entec, 2006). Installation costs will generally increase as the turbines are located further offshore due to transporting time, size and specialty of equipment required to do the work, and weather-related delays.

7.0.1.8 - PERIODIC OVERHAULS AND REFITS

The turbines and their moving parts (gears, bearings, seals), as well as the mooring cables and parts, will need to be overhauled during the TEC device's economic life. When, and how often, will depend on their design and the environment they operate in. For instance, overhauls may be scheduled in 5-year intervals. Unlike routine and emergency maintenance, overhauls and refits may be considered capital costs and be amortized over the life of the refit.

7.0.1.9 - DECOMMISSIONING

The costs of decommissioning include removing the device and cable from the water, and restoring the site to its original state. The cost of decommissioning may be defrayed through the reuse, recycle, or sale of the components and materials. The decommissioning expenditure is at the end of the device's economic life, which may be 20 years or more, so in present value terms, it is a comparatively small portion of total CAPEX. It is, however, harder to predict these costs since they occur well into the future.

BEST PRACTICE: COVERING DECOMMISSIONING COSTS

Decommissioning may be paid for through an upfront decommissioning bond or annual payments into an endowment fund over the life of the project (EquiMar Work Package 7.2.1, 2009).

7.0.1.10 - TAX CREDITS AND ACCELERATED AMORTIZATION

The costs of capital investments are defrayed by tax savings on the amortization (CCA tax shield) and investment tax credits (ITC). Expenditures in Canadian renewable energy are subject to accelerated amortization, allowing companies to claim larger amounts of amortization against taxable income in early years. This will be of limited value to a small company if it has insufficient income in the early years to take advantage of the tax deductible expense, but large companies can benefit immediately. More information on tax incentives is provided in Module 10: Financing, Government Supports and Managing Risk.

7.0.2 - OPERATING COSTS

One of the key advantages of tidal energy is the absence of primary fuel costs. The energy is renewable and provided by the moving water, in contrast to fossil fuels. However, the operating costs are significant and ongoing for the economic life of the turbine. The operating expenses of the tidal energy project are for monitoring and for routine and emergency maintenance activities.

7.0.2.1 - MONITORING

Monitoring occurs both remotely, onshore and on-site, where the turbines are installed. The devices can be equipped with monitoring equipment that can self-test device connection and stability. This data is sent via data cables and accessed online (Li, Lence, & Calisal, 2011). For some devices, monitoring of vibration and seal checks, if applicable to the technology being used, are done on-site (Li et al., 2011). The impact of the turbine on the local environment must be continually monitored.

The costs of monitoring include electrical power, data management, and salaries of skilled employees. There would also be costs of tools and devices, and if on-site checks apply, transportation costs.

7.0.2.2 - ROUTINE MAINTENANCE

The cost of preventative, routine maintenance depends on many variables, including the number of times it is scheduled, the number of turbines, labour hours per turbine, engineer and technician salaries, distance from shore, transportation costs (vessel charter costs), the need for special vessels, their travelling speed, the cost of electrical and mechanical tools, cleaning and protective equipment, and diagnostic equipment (Li et al., 2011; Renewable UK, 2011). Costs also include those necessary to protect the health and safety of workers.

The time turbines are shut down for routine maintenance results in lost revenue. As much work as possible is done during periods of slack tide; however, slack tide is a brief window of opportunity. Maintenance costs (and availability) will also depend on the maintenance scheme used, such as whether service is completed on-site or if the device is returned to shore for maintenance (EquiMar Work Package, 2009).

7.0.2.3 - EMERGENCY MAINTENANCE

If a breakdown has occurred or one is eminent, unscheduled maintenance or repair work must be undertaken. The costs of emergency maintenance include cost of replacement materials, plus many of the costs noted in routine maintenance (transportation, labour, etc.). Repair is difficult and expensive when it has to be conducted on-site (Li et al., 2011). With some device designs, on-site repair is impossible; the device must be taken to shore. The amount of downtime while crews access and repair the turbine also affects the output of the turbine, hence affecting the revenues generated from it.

Estimating emergency maintenance costs is difficult for new technology. Reliability is estimated during the design stage, based on tank tests and sea trials. As the technology matures, the frequency of failure and time to repair will be reduced and be more predictable (EquiMar Work Package 7, 2009, p. 3-3).

Key cost drivers of emergency maintenance include failure rates, severity of the failure, replacement cost of the broken components, turbine downtime, equipment needed (special vessels, cranes), skilled labour costs, accessibility of the materials needed for the repair, and accessibility of the turbine (Li et al., 2011). While there is an absence of warranties on these new technologies, these costs will often be borne by the project developer.

Weather and sea states add a level of uncertainty and variability to operating and maintenance (O&M) costs (Li et al., 2011). The threshold wind and water speeds for work to be done on site and of sufficient duration to complete the work need to be determined. A time series analysis of the tidal site will give information regarding the typical frequency and duration of suitable working conditions (EquiMar Protocol III.A, 2011).

7.0.2.4 - OTHER OPERATING COSTS

Other operating costs may include rental (or related ownership costs) of space for the control center, warehousing costs of components, port berthing fees, insurance, legal and accounting fees, bank charges, amortization, audit fees, seabed lease fees charged by the crown (Renewable UK, 2011), and transmission network charges, if applicable (UK ERC, 2010).

An example of an investment evaluation of a 1 MW turbine is in Table 7-1, located at the end of this module. An evaluation of a small-scale turbine (0.5 MW), done by Synapse Consulting for the Nova Scotia Utility and Review Board, can be found at http://www.nsuarb.ca/NSUARB_Exhibits_JOOMLA/get_document.php?doc=B-1&no=2422.

TOOLBOX: RETSCREEN

RETScreen is developed and distributed by Natural Resources Canada. It is an "Excel-based clean energy project analysis software tool that helps decision makers quickly and inexpensively determine the technical and financial viability of potential renewable energy, energy efficiency and cogeneration projects." RETScreen can be downloaded, free of charge, from www.retscreen.net .

7.0.3 - COST DRIVERS AND UNCERTAINTIES

Capital, operating and maintenance costs are difficult to estimate for TEC since there is little experience worldwide with installed devices. With time, as devices are deployed, learning will be gained and a supply chain established, so these costs will diminish.

7.0.3.1 - HIGH COSTS IN THE BEGINNING

In the early days of the industry, capital and operating costs will be high. Being "one-offs," causes of high costs in prototypes and initial farms include the following (Carbon Trust, 2005):

- In the absence of a supply of materials and parts to build the technology, developers need to use "off the shelf" components for some designs or "built from scratch" for others.
- There are few or no economies of scale in the manufacture of the technology and bases.
- There is limited experience with installation, operation, and maintenance of the plants. Contractors' perceptions of risk will be factored into the price of the service. Sometimes, very specific and expensive deployment vessels are needed.
- Hold-ups can occur in the nascent supply chain.

The supply chain may include the provision of seagoing vessels, gear boxes, blades, bearings, generators, cables for inter-array and connection to shore, transformers, foundations, field instruments, control systems, and power quality equipment. As for infrastructure, there needs to be port availability of sufficient size and capability. Installation vessels may include heavy-lift vessels and special vessels for cable laying. Dedicated equipment is non-existent in Canada and this will likely be the case until there is sufficient promise in tidal energy to warrant the investment by supply chain companies. Refer to Module 9: Opportunities and Strategies for Businesses.

IN NOVA SCOTIA: SUPPLY CHAIN

Presently, in Nova Scotia, the nascent tidal energy industry is without its own supply chain. Developers require the services of supply chain companies that are now focused on other industries, such as offshore oil and gas, shipbuilding, manufacturing, and wind energy. The tidal energy industry is not a strategic priority for these companies, so it must compete with the much larger, more lucrative customers. While the tidal energy industry needs to grow sufficiently to incent the supply chain companies to make the needed investments, it has difficulty achieving such growth without these very supply chain companies. Likewise, the needed skilled workers work in competing industries such as offshore oil and gas.

Delays, both in terms of absolute costs and revenue foregone, significantly affect the project's viability. These also serve as a deterrent in the supply chain since lengthy delays can undermine confidence in the potential of the tidal energy industry (UK ERC, 2010, p.xii).

7.0.3.2 - LOWERING OF COSTS

Over time, however, as the technologies and processes improve with experience, costs will decline. As well, economies of scale will arise as the size of units and scale of deployment increase. Operating and maintenance procedures will become more efficient through learning and incremental changes.

Competition in the supply chain will affect costs. While the industry is small, there will be insufficient suppliers of services, materials, and components. Inefficiencies and bottlenecks in the supply chain or infrastructure may occur, driving up costs. However, as the industry gains momentum, companies serving other sectors will expand to serve the marine renewable energy industry and new companies will enter, resulting in greater supply, economies of scale, and competition, all of which should reduce prices.

DISCUSSION: LOWERING COSTS – THE US EXPERIENCE WITH ONSHORE WIND

"Considering plausible assumptions for not only capital cost and capacity factor, but also O&M, financing & availability, the LCOE for 2012-2013 [onshore wind] projects is estimated to be as much as ~24% and ~39% lower than the previous low in 2002-2003 in 8 m/s and 6 m/s (at 50 m) resource areas, respectively (with the PTC/MACRS); when only considering capital cost and capacity factor, the reduction is ~5% and ~26%" (Weiser et al., 2012, p.116).

Other key cost uncertainties are commodity prices and foreign exchange rates. Over time, project cost uncertainties due to foreign exchange rates will be lessened as more work is sourced locally. Also, planning and consenting processes will become more streamlined, reducing costs related to delays (UK ERC, 2010).

7.0.4 - ENERGY PRODUCTION AND REVENUES

The revenues from tidal energy depend on the output of the turbine(s), availability (up-time), energy losses in the electrical cable to shore, and the price paid for electricity. Energy yield depends on a number of factors:

- energy available in the resource (tidal current velocity),
- design of the mechanical components that extract the energy from the resource,
- the power takeoff system that converts mechanical energy to electricity (power output),
- the extent to which the device's capacity for extraction/conversion is matched to the available energy resource,
- the efficiency of the system's energy conversion, and
- the device's availability (Carbon Trust, 2005; Entec, 2006).

FOUNDATIONAL CONCEPT: ENERGY YIELD

Energy yield is the amount of energy generated by a turbine during a period of time, measured in MWh.

Availability, or the amount of time the device is operational, will affect energy production and revenues. Availability is generally summarized in a single percentage, such as 90% availability. Failure rates and service time will affect availability. Failure rates can be estimated only through modeling until devices have been in the water and observations made. Time to repair depends on the particular failure, availability of parts and expertise, and whether the repair can be made remotely or not. Also, there may be "knock-on effects of faults" that subsequently require repair. With many components, all with different failure rates, predicting reliability is very difficult (Entec, 2006).

Annual energy production is estimated from:

- device characteristics for a range of sea conditions;
- number of times each sea condition occurs in an average year, combined with performance characteristics to estimate gross energy output;
- likely losses while transmitting energy to shore; and
- sea conditions, system complexity, and repair procedures (Entec, 2006, p.8).

Foundational Concept: Average Annual Energy Production and Long Term Capacity Factor

$$\textit{Annual average energy production} = \frac{\textit{Total amount of electricity expected over the service life}}{\textit{Length of service life}}$$

$$\textit{Long term capacity factor} = \frac{\textit{Average annual energy production}}{(\textit{Rated capacity} \times \textit{number of hours in a year})}$$

The newer the technology, the more difficult it is to estimate the energy to be produced. At the earliest stage, device performance and its ability to convert the theoretically available resource into usable energy will be based upon data generated through small-scale tank testing, then scale and full-scale prototype devices in sea trials, and then deployment in multi-device arrays (EquiMar Work Package D7.2.1, 2009).

The price paid for electricity is another variable. The price paid for electricity over the life of the project can be highly variable and difficult to predict. This makes government support in the form of a feed-in tariff highly beneficial for developers and investors since it reduces the uncertainty of the project's cash flows.

IN NOVA SCOTIA: FEED-IN TARIFFS AND RATE OF RETURN

In Nova Scotia, community feed-in tariffs have been set. The rate is intended to reflect the costs of energy plus a return of 15% to investors of small scale (≤ 0.5 MW) developmental, community-invested tidal energy projects. For larger developmental projects (>0.5 MW), feed-in tariffs are pending.

Lower rates will be set later for demonstration projects beginning in 2014 or later that will reflect the learning gained and the development of the technologies. Once projects are ready for commercial licences, they will be expected to produce electricity at a cost competitive with other renewable sources.

7.1 - CALCULATING THE LEVELIZED COST OF ENERGY

In the energy industry, the levelized cost of energy (LCOE), or more simply stated, the cost of energy, is the metric used to evaluate a project's financial feasibility. The cost of energy is calculated using present value calculations. Typically, all the costs are forecasted and present valued, using the net present value method, but not the revenues (See Appendix 7-1: Net Present Value and Internal Rate of Return and Weighted Average Cost of Capital).

One method of estimating the cost of electricity is to calculate the present value of all costs (capital costs, operations, and maintenance) and then calculate the annuity (annual amount) that would yield the same present value. This is called the equivalent annual cost.

To calculate the levelized cost of electricity using this method, the equivalent annual cost (EAC) is divided by the expected average annual output in MWh.

$$LCOE = \frac{\textbf{Equivalent annual cost}}{\textbf{Estimated annual energy output in MWh}}$$

Where:

$$EAC = \frac{PV\ (Capital\ Costs - ITCs - CCA\ Tax\ Shield + \Delta Net\ Working\ Capital + Annual\ after\text{-}tax\ \ O\&M\ Costs)}{\left[\frac{1 - \frac{1}{(1+WACC)^n}}{WACC}\right]}$$

$$\textbf{Estimated Annual Energy output (in MWh)} = \textbf{Rated Power} \times \textbf{Capacity Factor} \times 8760\ \textbf{hours per year}$$

Present valuing the project costs is done by discounting at the project developer's cost of capital (WACC), a weighted average of the after-tax cost of debt and the required return by equity investors. The resulting amount is an estimated cost per MWh. Converted to cost per kWh (divide by 1000), it can be compared to the price the market will bear for electricity or the feed-in tariff, if available. If the price paid for electricity will be greater than the estimated cost per kWh, the project is considered financially acceptable to investors. If not, the differential is the amount the government needs to make up in order to encourage development.

Referring to the cost estimates in Table 7-1, the estimated cost of energy for the "Median" scenario is as follows:

$$LCOE_{Median} = \frac{(\$1{,}904{,}628)}{(1MW \times 0.4 \times 8760)} = \$683/MWh$$

This translates into a median estimated cost, assuming a 40% capacity factor, of $0.683 per kWh. Note: This is the estimate of a one-off test turbine, so it is comparatively expensive.

Discussion: Calculation of LCOE by Utilities

Utilities commonly calculate LCOE using a slightly different approach, in which lifetime costs are present valued and then divided by the present value of the estimated lifetime output of energy.

$$\text{LCOE} = \frac{\textit{PV (Capital Costs - ITCs - CCA Tax Shield + ΔNet Working Capital + Annual after-tax O\&M Costs)}}{\textit{PV Energy produced over life of project in MWh}}$$

The denominator is the present value of the expected lifetime energy to be generated. If the MWh generated are expected to be level over the years, the two methods presented in this module will yield the same result.

7.2 - COST OF CAPITAL

The discount rate used in the above calculations can dramatically affect the Net Present Value (NPV) and the levelized cost of energy, so estimating it needs careful consideration. The discount rate used should be the weighted average of the estimated costs of financing. In some cost of energy calculations, a proxy is used that is a ballpark estimate of investors' required rates of return reflecting their perception of the riskiness of the project (i.e. 8% for debt, 15% for equity, debt/equity ratio of 50/50). This is proxy only; a better discount rate to use is the weighted average cost of capital (WACC). Refer to Appendix 7-1 for how to calculate the WACC.

The rates required by lenders and investors will be influenced by the proponent's ability to raise capital and perceived ability to manage the project. A utility or other large organization will be able to raise capital based on its general creditworthiness and project management experience at lower rates than a newer, small technology developer. The cost of capital will also reflect the technology and other risks. Investors will insist on a higher premium for higher risk.

Capital is raised by the developer in a combination of debt and equity; the rates of return required by lenders and equity investors will differ, so the combination of debt and equity used to finance the project will affect the overall cost. Debt is less expensive than equity because lenders' exposure to risk is less and interest expense is tax deductible.

Different financing arrangements will dramatically change the cost of financing, hence the discount rate, and by extension, the present value of the cash flows and estimated viability of the project.

Photo Credit: Leigh Melanson

Table 7 1: Example of a 1MW Turbine CAPEX, OPEX, LCOE (testing stage)

Source: Fundy Energy Research Network (Engineering Challenges Subcommittee), Feb. 2012.

		LOW	HIGH	MEDIAN	% of CAPEX	Notes
A.	Preliminary Engineering					
	Site Selection	$ 50,000	$ 250,000	$ 150,000	1%	Use public info
	Resource Assessment	400,000	1,000,000	700,000	5%	Macro then micro siting
	Environmental Permitting	300,000	2,000,000	1,150,000	8%	Adaptive management principles
	Device Selection	50,000	100,000	75,000	1%	
	Land Control	0	2,000,000	1,000,000	7%	Subsea leasing not yet understood
	Total Preliminary Engineering	$ 800,000	$ 5,350,000	$ 3,075,000	21%	
B.	Procurement					
	IP		$ 1,500,000	$ 1,500,000	10%	
	Detailed Engineering	800,000	1,200,000	1,000,000	7%	Much higher than typical mature project
	Turbine/Generator	400,000	1,000,000	700,000	5%	
	Gravity Base	500,000	1,000,000	750,000	5%	
	Instrumentation/Data Management	200,000	600,000	400,000	3%	Includes on board processing
	Cabling-Power/Communication	1,000,000	3,000,000	2,000,000	13%	Single unit to shore - less if array
	On shore	800,000	2,000,000	1,400,000	9%	Modest buildings, grid connection
	Power Conversion/Power Quality	200,000	600,000	400,000	3%	DC to shore or AC clean up
	Total Procurement	$ 3,900,000	$ 9,400,000	$ 6,650,000	45%	
C.	Construction					
	Deployment	$ 800,000	$ 2,000,000	$ 1,400,000	9%	Still risky - one tidal cycle
	Subsea Cable	1,000,000	3,000,000	2,000,000	13%	Many unknowns in an energetic resource
	On Shore Electrical	500,000	2,000,000	1,250,000	8%	Function of grid connection
	Total Construction	$ 2,300,000	$ 7,000,000	$ 4,650,000	31%	
D.	Overhauls					
	Overhauls (every 4 years, 25 year life)	$ 3,257,494	$ 6,514,988	$ 4,886,241	33%	Concept is to remove, replace, overhaul. See table below.
E.	Decommissioning					
	Retrieve equipment, restore site	$ 60,338	$ 166,264	$ 113,301	1%	Real $, present valued at 12%
F.	CCA Tax Shield (present valued @12%)	$ (2,362,522)	$ (6,510,036)	$ (4,436,279)		
	Present Value Net Capital Expenditure	**$ 7,955,310**	**$ 21,921,216**	**$ 14,938,263**	100%	Does not account for investment tax credits
G.	Annual Operation, Maintenance					
	Environmental Monitoring/Reporting	$ 300,000	$ 1,000,000	$ 650,000		
	Lease/Insurance/Compensation	$ 200,000	$ 600,000	$ 400,000		
	General	$ 200,000		$ 200,000		Small staff
	Annual Operation, Maintenance(before tax)	**$ 700,000**	**$ 1,600,000**	**$ 1,250,000**		
	PV Operation, Maintenance (after tax)	**$ 3,843,138**	**$ 3,843,138**	**$ 5,490,197**		
	Equivalent Annual Cost (CAPEX & OPEX)	**$ 1,504,302**	**$ 3,284,954**	**$ 1,904,628**		
	Levelized Cost of Energy $/MWh					
	Capacity factor 40%					
	Annual MWh generated	3,504	3,504	$ 3,504		
	Cost of Energy $/MWh	**$ 429**	**$ 937**	**$ 683**		Equivalent annual cost/estimated annual energy output Equivalent Annual Cost/(1 MW X 8760 hrs X c.f)
	Capacity factor 60%					
	Annual MWh generated	5,256	5,256	$ 5,256		
	Cost of Energy $/MWh	**$ 286**	**$ 625**	**$ 456**		

X. Other assumptions, input variables

					LOW	HIGH	MEAN
Life			Overhauls (4 year freq.)				
TISEC	20 to 30 yrs		Cost per overhaul (real dollars)		2,000,000	4,000,000	3,000,000
Subsea Cable	25 to 40 yrs		PV @ 12%	Year			
On shore	40 to 70 yrs			4	1,271,036	2,542,072	1,906,554
Capacity Factor	35 to 65%	Fixed blades vs. pitching		8	807,766	1,615,533	1,211,650
Cost of capital (nominal):	15%			12	513,350	1,026,700	770,025
Cost of capital (real)	12%			16	326,243	652,487	489,365
CCA rate, declining balance	50%			20	207,334	414,667	311,000
Corporate tax rate	30%	(Approx. combined federal & provincial)		24	131,764	263,528	197,646
Assumed economic life for calcuations	25				3,257,494	6,514,988	4,886,241

*Capacity factor is energy produced in a time period divided by the energy produced if operated at nameplate (rated power) times 100%.

Appendix 7-1: Net Present Value, Internal Rate of Return, and Weighted Average Cost of Capital

NET PRESENT VALUE AND INTERNAL RATE OF RETURN

The typical approach for evaluating capital investments is to calculate either the Net Present Value (NPV) or the Internal Rate of Return (IRR). To calculate the NPV, all revenues and costs are estimated for the life of the project. These are all present valued to time zero (the start date of the project), discounted by the company's cost of capital or required rate of return. The present value of the expected capital costs and operating expenses are subtracted from the present value of expected revenues. If the NPV > 0, the project is expected to be profitable, based on forecasted numbers and probabilities, over and above the financing costs.

$$\textit{Net Present Value} = \sum_{i=0}^{n} \frac{CF_i}{(1+WACC)^i}$$

The internal rate of return is related to the NPV. Rather than discounting the cash flows at the weighted average cost of capital (WACC) to solve for the NPV, the NPV is assumed to be $0 (the breakeven scenario). The discount rate that equates the present value of inflows with outflows, so that the NPV will be $0, is the internal rate of return. If the IRR>WACC, the project is expected to be profitable, again based on forecasted numbers.

$$\$0 = \sum_{i=0}^{n} \frac{CF_i}{(1+IRR)^i}$$

WEIGHTED AVERAGE COST OF CAPITAL

A company's cost of capital is a function of the returns required by lenders and equity investors, the tax deductibility of interest expense, and the proportions of debt and equity in the capital structure.

$$WACC = w_d r_d (1-t) + w_e r_e$$

Where: w_d is the proportion of the company's capital structure that comes from debt financing and w_e is the proportion from equity, r_d is the interest on the debt, r_e is the required rate of return by equity investors. The company's tax rate is represented by t.

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