TEN MILE RIVER HYDROPOWER FEASIBILITY STUDY

FINAL

Prepared for:

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Executive Summary

The Essex Partnership was retained by the City of East Providence (City) to evaluate the feasibility of hydropower development at its three existing dams on the Ten Mile River in Rhode Island (Turner Reservoir, Hunt's Mill and Omega Pond). Results of the study indicate that redevelopment of the historic Hunt's Mill Dam-Powerhouse hydropower alignment (Alternative E) using new equipment would be the most attractive alternative. Restoring hydropower at Hunt's Mill would also be consistent with the City's long-term plans for the site as a "green technology" education and learning center.

Development of hydropower at the Turner Reservoir Dam may be viable pending resolution of the spillway adequacy issue. Development at the Omega Pond site does not appear economic due to very low head conditions.

Depending upon minimum flow requirements, redevelopment of the Hunts Mill site could produce between 500 and 1,200 megawatt hours (MWH) of energy per year on average at an estimated cost ranging from $3.3 million to $4.0 million. Assuming a "middle of the road" solution to the minimum flow issue, the project would yield a 5% cash-on-cash internal rate of return (IRR). Financing the project with low cost, long-term debt increases the IRR to 6% and produces over $350,000 of net present value benefits (NPV) over a 20-year study period. Additional agency consultations and analyses that balance equipment selection with refined environmental and civil requirements would be needed to firm-up these findings.

Development of the Turner Reservoir Dam is overshadowed by potential dam safety issues. Available information suggests the spillway capacity of the dam may be inadequate. Additional study would be required to resolve this issue. Remedial measures, if required, could easily exceed the benefits of hydro development. Absent the spillway issue, developing the hydro potential of the Turner Reservoir Dam would yield IRR's ranging from -1% to 8% over the 20-year study period.

Based on preliminary visual inspections, all three dams appear to be in good overall condition. With the exception of the spillway capacity issue at Turner Reservoir Dam, there are no apparent issues that would technically preclude hydropower development. With proper care and maintenance, the dams can reasonably be expected to continue to perform as intended for many years.

Electrical interconnection at each of the sites would require less than one mile of upgraded (3-phase, 15-kv) service. At 15 kv, the projects are not likely to overload the circuit or require additional system upgrades.

Introduction

The City of East Providence (City) owns and maintains three existing dams on the Ten Mile River in Rhode Island; Turner Reservoir Dam, Hunt's Mill Dam and Omega Pond Dam. With funding assistance from the Rhode Island Economic Development Commission (RIEDC) and the American Recovery and Reinvestment Act (ARRA) the City commissioned a study to evaluate the technical and economic feasibility of developing hydropower at its existing three dams. The feasibility study (FS) included the following:

1. Preliminary Dam Inspections;
2. Hydrology and Hydraulic Analysis;
3. Preliminary Project Configurations;
4. Environmental Resources and Regulatory Analysis;
5. Energy Modeling and Generation Potential;
6. Cost Estimates; and
7. Economic Analysis.

Six alternative project configurations were evaluated reflecting various development scenarios involving the three dam sites. All six alternatives explored power generation to be used exclusively for municipal facilities. For alternatives that entailed diverting water from the river to a location further downstream (to capture additional head), three different instream flow scenarios were modeled to evaluate the range of regulatory requirements that could be imposed. Three options were also evaluated specific to the Hunt's Mill site to reflect potential scenarios for reusing the existing powerhouse and generating equipment.

Screening-level energy models and discounted cash flow analyses were developed for each alternative and instream flow scenario to identify the most economically attractive development options. A levered cash flow analysis was also performed on the most attractive options to determine the impact of low cost, long-term financing on economic performance. The economic findings and financial modeling presented in this report are preliminary and will likely change based on additional site specific information and more detailed analyses.

Study Sites

Turner Reservoir, Hunt's Mill, and Omega Pond dams are all located in the lower reach of the Ten Mile River in East Providence, Rhode Island (Figure 1). The Ten Mile River watershed drains an area of approximately 52 square miles, including parts of Rhode Island and Massachusetts, before discharging to the Seekonk River.

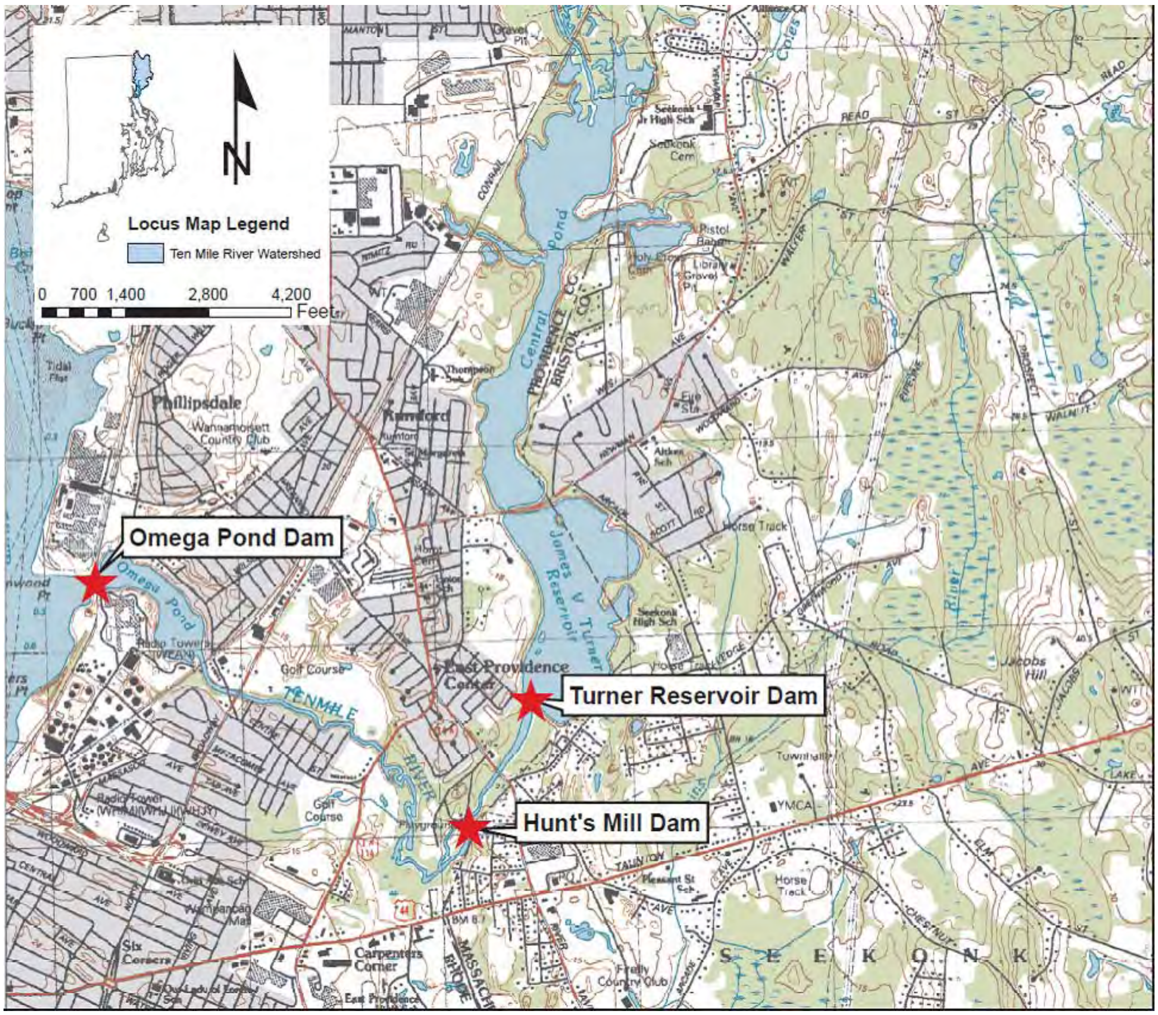


Figure 1: Project Locus Map. Study sites are marked with red stars.

The City is currently working with several project partners to install fish passage at each of the dams. The hydropower feasibility study includes consideration of the operational requirements for fish passage, both upstream and downstream, as part of the analysis of hydropower potential.

Turner Reservoir Dam

The James V. Turner Reservoir Dam is the most upstream dam of the sites studied. The dam is classified by the State as an intermediate size structure with high hazard potential. Built in 1934, the 550 foot-long dam consists of two sections of earthen embankments and a 200 foot long concrete overflow spillway. A 25 foot-long concrete low level outlet abuts the right end of the spillway. The structure contains two 54-inch diameter conduits and an abandoned 66-inch diameter penstock intake. The penstock is reportedly buried under ground and runs approximately 2,400 feet along the right river bank toward the Hunt's Mill Dam downstream. The penstock was historically used for water supply however records on file at the Rhode Island Department of Environmental Management (RIDEM) indicate that this use was abandoned in 1970 due to water quality concerns.

The drainage area at the dam is 48 square miles. The impoundment has a maximum reservoir storage and surface area of 3,100 acre-feet and 390 acres, respectively. Current use of the impoundment is primarily for recreation. Efforts to restore upstream fish passage on the river will expand its use to provide spawning and rearing habitat for anadromous fishes (river herring and shad). The dam and entire reservoir shoreline are owned by the City.

Hunt's Mill Dam

The Hunt's Mill Dam is located on the Ten Mile River approximately 2,300 feet downstream of the Turner Reservoir Dam (Figure 1). The 175 foot-long dam consists of an overflow spillway at an abandoned headrace entrance. The appurtenant facilities, all abandoned, include a penstock, headrace, pumphouse, and a tailrace. The dam with impoundment storage of 140 acre-feet and surface area of 0.4 acres is classified by the State as a small size structure with low hazard potential. The dam was used for hydropower generation and public water supply from the 1930s to 1970.

A denil fish ladder is currently being installed at the right (west) side of the dam. The former intake, headrace, concrete conduit and stilling well have been removed to accommodate the fish ladder. Prior to installation of the fish ladder the headrace downstream of the entrance closure wall had a short, open flume transitioning into an underground steel penstock which leads to the pumphouse. The pumphouse contains a 144 kW vertical Francis hydro-generating unit, presently retired. The historic hydro station discharged to a now abandoned 900-foot long tailrace channel which created a 1,200 foot-long river bypass reach.

Omega Pond Dam

The Omega Pond Dam is located at the confluence of the Ten Mile and Seekonk Rivers. The 200 foot-long, 18 foot-high dam consists of an overflow spillway and abutment walls. The 112 foot-long, 15 foot-high spillway is a concrete gravity structure with downstream stone facing. The dam impoundment has a storage capacity of 280 acre-feet and a surface area of 33 acres. The impoundment is used for recreation and water supply by several adjacent industries.

Downstream of Omega Dam the Ten Mile River discharges into the Seekonk River which is a tidal estuary. Consequently, tailwater levels are tidally influenced. The dam is classified by the State as a small size structure with low hazard potential. The existing structure was built in 1918 downstream of an original timbercrib dam erected in 1883. Similar to the Turner and Hunt's Mill Dams, the Omega Pond Dam is scheduled for installation of a denil fish ladder at the right (north) side of the dam utilizing a portion of the existing spillway.

Preliminary Dam Inspection

The Essex Partnership, with assistance from MBP Consulting (MBP), conducted visual inspections of the study dams in October 2010. Results of these inspections indicate that the dams are no longer being used for their originally intended uses. There are some signs of deterioration; however, with routine maintenance typical for water retaining structures, these dams could be expected to exist well into the future. There were no observed conditions that would preclude hydropower development. A complete copy of the Preliminary Inspection report is provided as Appendix A.

Suggested measures related to operation, maintenance and repair of the dams include removal of brush and trees from water retaining structures, and re-pointing of joints and voids in masonry components. Additional recommendations include repair of deteriorated spillways and retaining walls and in some cases, restoration of inoperable low-level outlets.

If developed for hydropower, jurisdiction for dam safety would transfer from RIDEM to the Federal Energy Regulatory Commission (FERC). FERC typically has more stringent safety criteria than State dam safety offices. Consideration of potential exposure of this jurisdictional transfer is important in evaluating overall project feasibility.

The Hunt’s Mill and Omega Pond dams, are classified by RIDEM as low hazard structures, and thus would be strong candidates for an exemption from the requirements outlined in the Federal Power Act (FPA) Part 12 (concerning dam safety – administered by FERC). The Turner Reservoir Dam, with an existing RIDEM high hazard classification, would likely be subject to compliance with Part 12 if it were to be developed for hydropower.

Phase I (US Army Corps 1978) and Phase II (New England Engineering 1982) dam inspection reports of the Turner Reservoir Dam indicate that the existing spillway appears undersized (i.e., not able to adequately pass extreme flood flows). The Phase II analysis of the spillway’s hydraulic capacity (New England Engineering 1982) included several potential structural measures to address this concern. Phase II cost estimates to implement these measures ranged from $700,000 to $3.5mm (escalated 2.5%/yr. from 1982- 2010 dollars), depending on the alternative.

A more current and detailed analysis would be needed to determine the likely nature and cost of remedial measures needed, if any, to meet FERC Part 12 safety criteria. Before expending significant funds on hydropower development activities, it would be prudent to perform additional, site-specific hydrologic and stability analyses for the Turner Reservoir Dam. A preliminary estimate of $180,000 for additional engineering studies has been included in the cost estimates for alternatives involving the Turner Reservoir Dam. These studies and analyses could be done in conjunction with licensing efforts.

Hydrologic Analysis

The first step in evaluating a site's hydro potential is to collect sufficient data to characterize the magnitude and variability of river flows. In the United States this is typically accomplished using average daily flow data recorded by a USGS gauge on the river being studied. If the river is ungaged or the period of record is too short (typically 30 years or more of record are required) then one or more surrogate gauges may be used.

The existing gauge on the Ten Mile River (USGS 01109403 TEN MILE R., PAWTUCKET AVE. AT E. PROVIDENCE, RI) was established in 1986. Because this gage represents a limited, 24 year period of record, additional data were obtained from the Woonasquatucket River (USGS 01114500 WOONASQUATUCKET R. AT CENTERDALE, RI) which has a 69 year period of record. Data from both gages were pro-rated to reflect the same hypothetical 50 square mile drainage area and compared to determine if the data from the Ten Mile River were representative of longer-term regional trends. The two data sets compare well (see Figure 2), suggesting that the Ten Mile River gage data set is representative of long-term hydrologic conditions. For purposes of this feasibility study flow data from the USGS gauge on the Ten Mile River were used.

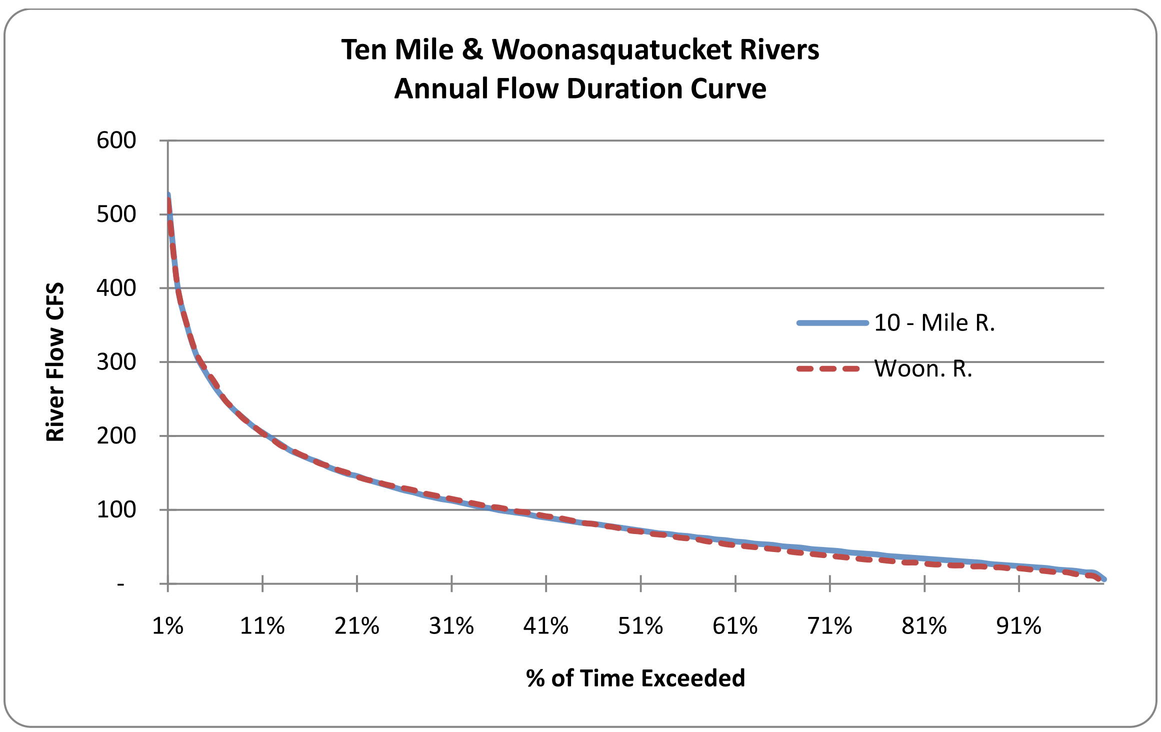


Figure 2: Annual flow exceedance curves (Ten Mile & Woonasquatucket Rivers).

Referring to Figure 2, above, some initial approximations can be made regarding the hydraulic capacity (or turbine size) for hydropower development. Although the graph is a simple plot of river flows (Y-axis) verses % of time the flow is exceeded (X-axis) it provides a good overall picture of the relationship between the magnitude of river flows and their variability over an average flow year.

For example, the 25% exceedance flow is approximately 132 cfs. This means that the river will have a flow of 132 cfs or higher 2,190 hours in an average year (25% of 8,760 hours/year). Installing a hydro turbine(s) with this hydraulic capacity would utilize river flows up 132 cfs. Flows in excess of 132 cfs would be spilled over the dam – without generating any power. Increasing the hydraulic capacity to 500 cfs would allow the turbine to utilize river flows that occur 99% of the time. The remaining one percent of the time (87.6 hours/yr.) the river would exceed 500 cfs and the additional flows would be spilled.

Installing a larger turbine, however, may not necessarily optimize the hydro potential of the site. Depending upon the type of turbine used, the minimum operating point ranges from 10% to 20% of the hydraulic capacity (maximum operating point). Francis turbines, such as the existing unit at Hunt's Mill, typically have a minimum operating point around 20% of hydraulic capacity. For the 500 cfs turbine mentioned above, this means the minimum operating point would be approximately 100 cfs. Referring to Figure 2 above, all of the river flows below 100 cfs would not be utilized for energy production.

Other factors to consider when configuring a project and selecting an installed capacity are seasonal operating restrictions to provide adequate protection of environmental resource (i.e., fish passage, water quality and instream flow concerns). As described in the Environmental Inventory section, Rhode Island has a standard instream flow requirement to protect instream resources. On an average monthly basis the minimum stream flow requirement at the three study sites would be approximately 70 cfs. If the project configuration involved a bypass reach – the first 70 cfs of river flows would have to be released at the dam – and would not be available for generation. Referring once again to Figure 2, this would have the effect of moving the X-axis up 70 cfs, which would make the flow duration curve much steeper. To address these factors in our energy calculations, monthly flow exceedence relationships were developed. Using these data the energy model was run on a monthly basis to capture the seasonal variations in environmental flow requirements (fish passage and instream flows).

Project Configurations & Site Hydraulics

Six different physical project configurations were evaluated for the feasibility study. Each configuration represents a different combination of turbine intake and tailrace to depict a unique head characteristic.

Figure 3 presents a simple line diagram of the study area and the physical project configuration alternatives evaluated. The gross hydraulic head developed under each of these configurations is tabulated in the table on the following page.

In general, more head will provide more power. However, alternatives that entail water diversions and penstocks (i.e. Alternatives B, C, and E shown in Figure 3) would involve environmental and economic trade-offs that need to be considered as part of the evaluation. Additional detail on the configurations and specific trade-offs is provided in subsequent sections of this report.

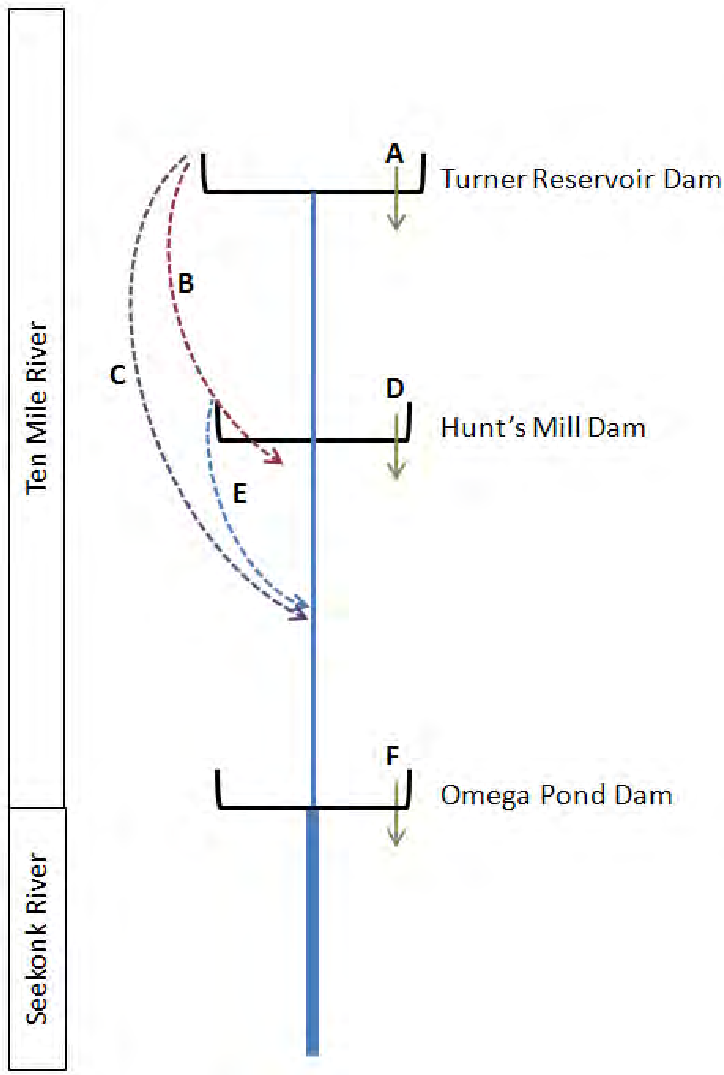


Figure 3: Schematic of configurations evaluated.

In order to determine the hydraulic head at each site, field measurements were taken of water surface elevations upstream and downstream of each dam were taken during the preliminary dam inspections. The field measurements were taken using an assumed local datum at each dam to determine hydraulic head. This survey approach however, using a local datum at each dam, is not applicable for determining head between adjacent dams.

To address this data gap, we reviewed Corps fish passage plans and reports, the 1980 Hydro Feasibility Study (Maguire), and the FEMA FIS flood profiles to obtain elevations along the river between Turners and Hunt's Mill. Ultimately the FIS profiles were used to estimate available head due to various inconsistencies in some of the reported elevation data (i.e., the Corps reported tailwater elevations at Turner below headwater elevations at Hunt's Mill). The estimated tailwater elevations result in calculated hydraulic head values which closely agree with previous assessments of hydraulic head between the two sites (Maguire 1980), as well as the cumulative head generated between alternatives A and E. Gross hydraulic head values for each of the project configurations evaluated as part of this FS are tabulated below.

Alt.	Description of Project Configuration	Gross Head
A	Turner Reservoir Dam • Intake & discharge at spillway; no bypass[1] reach	14.5
B	Turner - Hunt's Mill Dam • Intake at Turner Res. with discharge at toe of Hunt's Mill spillway • Develops head between two sites • Creates 2,300 ft. long bypass reach	22
C	Turner - Hunt's Mill Powerhouse • Intake at Turner Res. with discharge through historic Hunt's Mill tailrace • Develops the maximum head between two sites • Creates 3,500 ft. long bypass	38
D	Hunt's Mill Dam • Intake & discharge at spillway; no bypass reach	8.5
E	Hunt's Mill Dam – Hunt's Mill Powerhouse • Intake at spillway, discharge through historic tailrace • Redevelops historic head • Creates 1,200 foot long bypass reach • Restores/upgrades existing historic turbine and tailrace	23.5
F	Omega Pond Dam • Intake & discharge at spillway; no bypass reach • Actual head fluctuates through tidal action	8

A simple linear relationship was used to develop corresponding headwater and tailwater elevations for flows on the Ten Mile ranging from 0 to 1,000 CFS. Since tailwater elevation tends to rise faster than the headwater elevation we made the conservative assumption that gross head (headwater elevation – tailwater elevation) decreased by 1.5-feet over this range of river flows.

[1] A bypass reach is used to describe a section of a river that is subjected to diversion of all or part of the natural flows to accommodate other uses. Since reductions in the flows in the bypass reach can be detrimental to the riparian ecosystem health detailed studies are typically required the impacts and develop mitigation measures.

Hunt's Mill Options

In addition to configuration D, tabulated above, we explored three additional options for redeveloping the Hunts Mill site:

1. *Hunt's Mill New* - install all new modern equipment, either in the existing powerhouse or in a new powerhouse adjacent to the existing powerhouse building;
2. *Hunt's Mill Repowered* - upgrade the existing unit with modern equipment (see detailed description below);
3. *Hunt's Mill Restored* – restore the existing turbine and generator to their original, as-new operating condition.

Options #1 and 2 above were modeled for water withdrawn from Hunt's Mill Dam (Alternative E - historic hydropower alignment) and for water withdrawn from Turner Reservoir (Alternative C alignment). Option #3 listed above was modeled only for water withdrawn from the Hunt's Mill Dam because published reports indicate that the existing equipment was designed for 23.5-ft. of hydraulic head. It is difficult to predict how or if the original unit would operate under the significantly larger head (38-ft.) that would be associated with withdrawals from Turner Reservoir.

Existing Unit

The existing Hunt's Mill unit is a 1924 vertical Francis turbine manufactured by the James Leffel Company. The turbine is installed in a vertical cylindrical steel pressure case and discharges into a vertical steel draft cone. Relevant photographs from our October 13, 2010 site visit are presented on the following pages. In general, the equipment is inoperable and would require a significant amount of work to return to reliable operation. The runner (waterwheel, or rotating part of the turbine) and draft cone were not accessible during our site visit. A more detailed inspection would be required to better ascertain the condition of the equipment and develop a firm scope of work for restoration.

Although hydro equipment manufactured during the 1920's tended to be robust, performance typically falls way short of current technology. Modern designs typically offer a broader operating range, substantially higher efficiencies and increased output. Given the age and apparent amount of work that would be required to restore the existing Leffel unit, installation of a new, modern designed turbine (Repowering) is likely to provide the most beneficial reuse of existing infrastructure.

Hunt's Mill Repowering

Repowering typically involves selecting an existing turbine design that best fits the setting and existing water passages at the site. For purposes of developing performance parameters and preparing cost estimates, we assumed the following scope of work for repowering:

1. Remove the existing turbine (wicket gate assembly and runner);
2. Repair and paint the steel pressure case and draft cone;
3. Rework the turbine/generator shaft, machine the couplings and line bore and install fitted new coupling bolts;
4. Install a new Wicket gate assembly (stay vanes, headcover and wicket gates);
5. Install a new, modern design runner;
6. Replace the existing governor with a new, solid state gate actuator;
7. Rewind the existing generator;
8. Install new electrical controls and switchgear.

Hunt's Mill Restoration

We also developed preliminary cost estimates for restoring the unit to its original, as-new operating condition. While this would not be an optimal alternative from an energy production perspective, it represents an historic preservation case if that were to become the primary objective of the project. As mentioned above, a more thorough inspection would be required to ascertain the scope of work required to refurbish the unit. For purposes of this FS we assumed the following work would be required:

1. Remove the existing turbine (wicket gate assembly and runner);
2. Repair and paint the steel pressure case and draft cone;
3. Rework the turbine/generator shaft, machine the couplings and line bore and install fitted new coupling bolts;
4. Rework the wicket gate assembly and install new stay vanes, headcover and wicket gates identical to the existing equipment;
5. Obtain the original runner design from Leffel or make a pattern of the existing runner blades and fabricate a new runner identical to the existing;
6. Rewind the existing generator;
7. Replace the existing governor with a new, solid state gate actuator. Restoring the existing governor may be cost prohibitive but it could be cleaned and left in place for educational and display purposes.
8. Install new electrical controls and switchgear. For personnel safety and protection of the equipment we do not recommend restoring the original controls and switchgear. However, the existing electrical gear could be cleaned and left in place for educational and display purposes.

Figure 4. Existing Hunt's Mill Generator and Governor

Figure 5. Steel penstock and Vertical Pressure Case

Figure 6. Headcover, Stay Vanes and Wicket Gate Assembly

Environmental Resources & Regulatory Analysis

Hydropower projects are typically licensed and permitted in a manner conditioned to avoid, minimize, and reduce adverse environmental impacts. To that end many modern hydropower developments are configured to allow for eventual certification by the Low Impact Hydropower Institute (LIHI). LIHI certification evaluates candidate projects against ten criteria reflecting sensitive environmental resources. In many states LIHI certification is a requirement to participate in Renewable Energy Certificate (REC) markets and therefore provides an economic incentive. Typical issues include, but are not limited to; stream flows, water quality, fish passage and protection, cultural and historic resources, recreation, and consistency with watershed management goals. Additional detail on the LIHI certification program is available at http://www.lowimpacthydro.org.

In recognition of the LIHI criteria, this study includes project configurations designed to avoid and minimize adverse impacts to sensitive resources. Examples of these provisions include; utilization of existing dams and impoundments, flow allowances for fish passage, turbine discharges sited to eliminate bypass channels or provisions for instream flows, and turbine selection to address biological and architectural considerations. The scope of this FS also includes evaluation of several project configurations (B, C, and E) that may not be considered strong candidates for LIHI certification due to significant bypass reaches. In these cases, operational adjustments were made to anticipate regulatory conditions on project operations for protection of environmental resources. Additional protection, mitigation and enhancement (PM&E) measures would likely be identified and incorporated on a site specific basis during regulatory processing.

The following sections provide additional detail on the environmental resources present in the study area as well as a discussion of the regulatory requirements and relative level of risk and complexity associated with each configuration evaluated.

Environmental Inventory

Several sources of information were reviewed to gain a better understanding of existing environmental resources in the study area. These sources included, but were not limited to; RIDEM fisheries data, water quality monitoring data, fish passage plans and permitting materials, and Rhode Island and Massachusetts Geographic Information Systems. The figure below was compiled using publically available GIS-based data from RI and MA; it illustrates the location of regulated and/or sensitive resources in relation to the study sites. More detailed resource mapping is provided in Appendix D.

Based on observations made during site visits, GIS-based natural resource mapping, preliminary discussions with regulators and experience with similar projects, there are several environmental resource areas that would need to be addressed during the development of hydropower at the site. A copy of the meeting notes from initial discussions with regulators is provided in Appendix D. The following sections provide additional detail on these resources, potential implications for project development, and possible resolution and/or mitigation strategies.

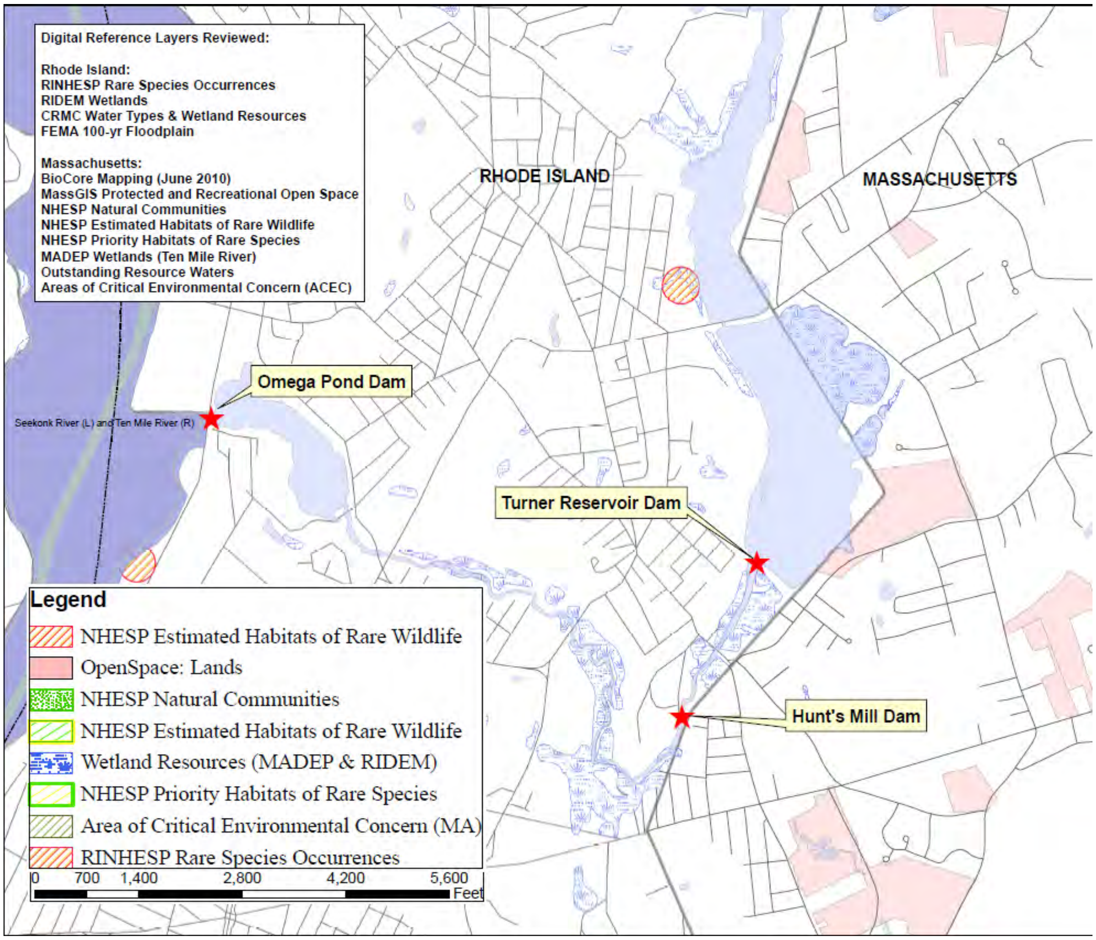


Figure 7: Environmental Resources Inventory Map of the Study Area. More detailed mapping is provided in Appendix D.

Aquatic Resources

Diverting portions of river flows for hydropower generation can potentially have adverse impacts on the aquatic environment. Any variation in river flows and water surface elevations associated with project operations would need to be evaluated to determine the extent and severity of any environmental impacts.

There are several standard approaches for protecting aquatic resources. Operation of the project in a "run-of-river" mode (i.e., inflows equal outflows) without storage or ponding is generally considered the least disruptive operational mode and is a requirement for LIHI certification.

Rhode Island has developed a standard approach for protecting instream resources from proposed diversions and withdrawals known as the Rhode Island Modified Base Flow Methodology (RI ABF) (Richardson 2005). This method prescribes minimum flow requirements to approximate natural flow conditions and is intended to provide stream flows adequate to protect aquatic resources. The standards are based on the size of the drainage area at the location of the proposed impact and vary by season (monthly intervals). Alternatives B, C, and E would discharge flows used for generation downstream of the intake points (creating a bypass reach) these alternatives would likely be subject to an instream flow requirement. Alternatives A, D, and F would discharge at the base of the spillway (and would not bypass the river). We have assumed that they would not be subject to an instream flow requirement (aside from provisions to maintain fishway operations).

In today's regulatory climate, almost any project with a bypass reach will be subject to an instream flow requirement to protect aquatic resources. These requirements reduce the volume of water available to the turbine thereby reducing generation potential (see Energy Modeling). Site specific studies can be used to propose modified instream flow requirements as an alternative to accepting the standard, desk-top instream flow settings. Based on our experiences the trade-off in upfront study costs and back end generation gains is often justified (see Energy Modeling).

Fisheries

The Ten Mile River in the study area is classified as a Class B warm water fishery by the RIDEM. According to RIDEM and Corps fish survey data the following species occur in the river and impoundments within the study area (Appendix D).

Warm Water Fish Assemblage of the Ten Mile River	
Yellow perch	Pumpkin seed
Redfin pickerel	Yellow bullhead
Largemouth bass	Golden shiner
Bluegill	American eel
White perch	Black crappie
White sucker	White catfish

Standard conditions for the licensing and permitting of hydropower projects typically include provisions for providing safe passage for migratory and resident fishes occurring in the vicinity of a project. There are currently efforts underway at each dam to install upstream fish passage for migratory populations of blueback herring (*Alosa aestivalis*), alewife (*Alosa pseudoharengus*) and American shad (*Alosa sapidissima*) as well as American eel (*Anguilla rostrata*). Additional information on the Ten Mile River fish passage restoration program can be found on the Corps' project website http://www.nae.usace.army.mil/projects/ri/tenmile/10mile.htm).

Downstream passage for most fish species will be accomplished via notches in the project spillways (outmigrant notch). Downstream passage/protection for adult eels usually focuses on conditions near the project intake and can include restrictions to intake approach velocities, bar rack angles or spacing, and reduced operation during migration periods to avoid impacts associated with impingement on the racks and injury and mortality due to turbine passage.

From a hydropower perspective, development at dams with existing provisions for fish passage presents a double edged sword. As a positive, a potential project does not have to bear the capital expense of designing and installing passage facilities. The drawback is that the fish passage facilities may not have been designed to be compatible with hydropower and can constrain design options.

Regardless of the design focus, a hydropower project with fish passage requirements needs to consider operational practices that facilitate passage. These provisions include; providing adequate flows to the ladder and outmigrant notch to ensure proper functionality (fish ladder flows) as well as provisions for flows near the fish ladder entrance to ensure that migrating fish can locate and use the facility (attraction flows). These flow requirements are seasonal, corresponding to key biological requirements (bioperiods), and result in a reduction in flows available for generation.

Provisions for eel and fish passage/protection have been included as part of the energy modeling and economic analysis conducted for this study.

Water Quality

The Turner Reservoir is on Rhode Island's list of impaired waters due to lead, copper, phosphorous, coliform bacteria and dissolved oxygen levels. Assessments of water quality in the study area completed by the Corps indicate that water quality is generally acceptable to support aquatic life. The RIDEM is currently in the process of developing a Total Maximum Daily Load (TMDL) model for the river focused primarily on metals and nutrient pollution. A water quality monitoring program has been in place on the river since 2007 to support development of the TMDL. Preliminary review of water quality data provided by RIDEM support the assessment that the Turner Reservoir and Omega Pond experience seasonal dissolved oxygen impairments. RIDEM summaries of the water quality monitoring program for 2007 and 2009 are provided in Appendix D.

As water flows over a dam's spillway it is aerated. Routing flows through a hydroelectric turbine resulting in less flow over the spillway can reduce aeration and impact dissolved oxygen levels in the water, particularly if dissolved oxygen levels are already low. Provisions for instream flows (discussed above) can help to minimize and/or mitigate for such impacts.

It is common for regulators to request a commitment from project operators to have no impact on baseline (pre-project) water quality conditions. Since water quality is already a concern in the study area, it is very likely that potential water quality impacts will be raised as an issue during licensing and permitting efforts. We have included provisions for environmental studies (including water quality modeling) in our cost estimates to address such issues. Possible resolution strategies can include: provisions for instream flows (over the dam) to maintain water quality, real-time water quality monitoring and operational adjustments, and/or provisions for aeration of flows through the turbine. The history of water quality issues at the Turner Reservoir is expected to require additional analysis and consultations.

Wetlands / Floodplains

Wetland resources in the vicinity of the project are generally confined to the river channel and associated floodplains (RIDEM and wetland data available through RIGIS). Turner Reservoir and Omega Pond have wetland complexes consisting of emergent, scrub-shrub and forested wetland types which occur along the impoundment shorelines. Operating the project in a run-of-river mode will avoid impacts to upstream wetlands associated with water level fluctuations in the headpond. Alternatives which include installation of a penstock from the Turner to Hunt's Mill sites would likely include some impacts to wetlands along the penstock alignment as well as floodplain wetlands located between Turner Reservoir and Hunt's Mill (see Appendix D). Alternatives that would restore the historic Hunt's Mill tailrace would include some excavation of vegetated wetland resources that have become established in the tailrace channel following project retirement.

The hydraulic capacity of the Turner Reservoir spillway is currently limited. Development which further reduces this capacity would be expected to trigger some concerns and possibly require mitigation of lost flood conveyance or storage functions.

Costs and provisions for wetland and flood impact assessments as well as an allowance for some mitigation measures that may be required for development activities have been included in the cost estimates and economic analyses where appropriate.

Rare, Threatened & Endangered Species

The Rhode Island Natural Heritage and Endangered Species Program (NHESP) recognize a small area on the northwest shore of the Turner Reservoir impoundment as a known occurrence for a rare species (Appendix D). Considering the location of the occurrence in relation to the potential project and the nature of run-of-river hydropower projects, it is unlikely that normal project operations would impact this resource. Depending on specific ecological requirements of the rare species, it is possible that avoidance and mitigation measures associated with potential impacts from construction related activities may be required.

Cultural / Historic Resources

Considering the industrial history of the Ten Mile River watershed and the project sites there may be potential impacts to cultural and/or historic resources from project development. Coordination with the State Historic Preservation Office (SHPO) and Native American tribal nations is a requirement during project licensing and permitting proceedings. Depending on the identification and determination of resource significance there is potential for both direct and

indirect impacts from project related activities. Mitigation options are varied and depend on the specific situation and resource. Potential outcomes can include archival documentation of significant resources and/or interpretive signage and displays.

Recreational Resources

FERC licensing/exemption may require making accommodations for recreational use of project lands. Provisions for public access can be negotiated with local and state agencies charged with providing recreational facilities in the area. Previous and on-going efforts by the City to enhance recreational opportunities may be used to (at least partially) address this issue. We have included provisions in the economic analysis for additional assessments and consultations in relation to recreational resources during project licensing and permitting.

Regulatory Analysis

Taking environmental impacts into account during the preliminary planning stages of hydropower development can help to avoid a contentious regulatory proceeding. Since a portion of the Turner Reservoir is in, or abuts the State of Massachusetts we assume that some coordination and approvals with regulators in that State would be required to develop hydropower at that site. The following regulatory approvals are anticipated for hydropower development on the Ten Mile River:

- Federal:
  - Federal Energy Regulatory Commission (FERC)
    - Federal Power Act (FPA) Part 1 - license or exemption from licensing
  - Corps Dredge and Fill Permit – Clean Water Act Section 404
  - Coastal Zone Management Act – Consistency Review (Omega Pond only)
- State of Rhode Island:
  - Wetlands Permit – insignificant alteration or permit to alter
  - Water Quality Certificate (WQC) – Clean Water Act Section 401
  - Historic Preservation – Section 106
- State of Massachusetts (Turner Reservoir Only):
  - Wetlands Protection Act – Order of Conditions
  - Natural Heritage and Endangered Species Program – Review

Typically hydropower projects take 3-5 years to license and permit. A significant portion of this time is dictated by statutory requirements for both public and agency review and comment of the proposed project associated with FERC processing. Low impact design and operating protocols as well as early outreach and coordination with regulators and other stakeholders can reduce the time and complexity of the process. Projects with more contentious resource concerns can take longer than 5 years and require significant time and capital to complete.

Since each of the projects is currently owned by the City, we would recommend pursuing an exemption from FERC licensing. This provision allows entities with all the ownership rights to develop operate and maintain small hydropower projects to obtain approval in perpetuity (does not require re-licensing). In order to obtain an exemption, a project must meet three key eligibility criteria; the applicant must own all the real property interest to develop and operate the project, the applicant must be installing new capacity, and the total installed capacity must be 5MW or less.

On paper there is an outside chance that redevelopment of the Hunt's Mill site could be relieved of some of the FERC processing burden due to its historic use for hydropower if it is found to be outside of FERC's jurisdiction. According to FERC guidelines (unless a project has a valid pre-1920 federal permit), non-federal hydroelectric projects are jurisdictional if:

1. The project is located on navigable waters of the United States.
2. The project occupies public lands or reservations of the United States.
3. The project utilizes surplus water or waterpower from a federal dam.
4. The project is located on a body of water over which Congress has Commerce Clause jurisdiction, project construction occurred on or after August 26, 1935, and the project affects the interests of interstate or foreign commerce.

Because the Ten Mile is a navigable river and generation from Hunt's Mill would feed into the existing interstate transmission system it is unlikely that the project would be found non-jurisdictional (fails tests #1 and #4). However a request for a jurisdictional determination is fairly simple and straight forward with no penalties related to the decision. As a practical matter however, even with a non-jurisdictional ruling the environmental review would involve the same resource agencies and the process would be similar to an exemption application.

Each of the project configurations evaluated in this FS has a unique combination of regulatory risk and complexity depending on the specific development requirements and nexus with sensitive resources. The following table summarizes the key drivers of relative regulatory risks and complexity associated with each of the evaluated configurations.

For the purpose of this analysis, "risk" is a qualitative measure of the likelihood of receiving a FERC license/exemption with favorable conditions. A "low" risk reflects a relatively high probability of receiving a license or exemption as designed. A "medium" risk implies that there is a greater than 50% chance of having to do extra studies and receiving a license/exemption with conditions that adversely affect project economics. A "high" risk implies the likelihood of having to do additional environmental studies and potentially receiving onerous license conditions or costly remediation requirements (i.e., Turner Reservoir Dam and FERC safety criteria).

Complexity here relates to the regulatory process and the degree of difficulty (typically measured in time and money) associated with obtaining the license/exemption. Similar to "risk", a "low" complexity implies a relatively straightforward regulatory process. A "medium" complexity implies that there will likely be extra consultations required and possibly more time and costs than a simple project. A "high" complexity implies that the process will likely involve numerous stakeholders and be protracted.

ID	Summary of Key Regulatory Drivers	Risk	Complexity
A	**Turner Reservoir Dam** • No bypass reach • Significant water quality (D.O.) issues • Dam safety (FERC)	**High**	**Medium**
B	**Turner – Hunt's Mill Dam** • Creates 2,300 ft. long bypass reach and associated instream flow concerns • Turner Res. Fish ladder attraction flow issues • Dam safety (FERC) • Significant water quality (D.O.) issues • Wetland impacts from penstock construction and modified bypass reach flows	**High**	**High**
C	**Turner - Hunt's Mill Powerhouse** • Creates 3,500 ft. long bypass and associated instream flow concerns • Turner Res & Hunt's Mill fish ladders attraction flow issues • Dam safety (FERC) • Significant water quality (D.O.) issues • Wetland impacts from penstock construction and modified bypass reach flows	**High**	**High**
D	**Hunt's Mill Dam** • No bypass reach • Potential water quality (D.O.) concerns	**Low**	**Low**
E	**Hunt's Mill Dam – Hunt's Mill Powerhouse** • Creates 1,200 foot long bypass reach and associated instream flow concerns • Hunt's Mill fish ladder attraction flow issues • Potential water quality (D.O.) concerns • Wetland impacts from tailrace restoration	**Medium**	**Medium**
F	**Omega Pond Dam** • No bypass reach • Potential water quality (D.O.) concerns	**Low**	**Low**

Preliminary Energy Modeling & Generation Potential

The following section briefly describes the energy model developed for estimating generation potential and how the model was used to begin the process of optimizing the development of the various configurations outlined above.

Energy Modeling

A monthly flow duration model was developed to estimate installed capacity and energy production for the various alternatives at each site. Major components of the model include: hydrology (river flows); site hydraulic characteristics (head); equipment performance; and potential license mandated operating conditions to protect environmental resources.

Hydrology data were developed as described in the Hydrologic Analysis section. Other physical site characteristics including information on the hydraulic head at each site are described in the Project Configurations & Site Hydraulics section.

For equipment performance characteristics, the proprietary turbine design software "TRBNPRO" was used to develop equipment configurations, sizes and performance characteristics. Typically axial flow (propeller) turbines are best suited for the range of heads at the three sites (6-ft. to 36-ft). Given the wide range of flows on the Ten Mile, a double regulated axial flow turbine (Kaplan) will provide much higher efficiency than a fixed-blade turbine over the entire operating range Therefore, for all cases involving new equipment, we assumed double regulated axial flow turbines would be used.

For the Hunt's Mill site (Alternatives C and E) we modeled two special cases using the existing vertical Francis turbine arrangement. As previously described, one scenario involves designing and installing a new runner to increase efficiency and output. The other scenario replicates the existing turbine design. Based on our experience refurbishing hydro units we developed preliminary work scopes which included installing a new Francis turbine assembly (runner, headcover and wickets gates) in the existing water passages (cylindrical pressure case and conical draft tube). Using TRBNPRO we developed a modern design Francis runner to fit the following parameters of the existing Hunt's Mill configuration:

Speed	225 RPM
Runner Diameter	Approximately 1 meter
Runner Setting	13-ft above tailwater
Gross Head	23.5 feet

Typical efficiency curves for Kaplan and (modern design) Francis units are shown in the graph below. For all alternatives modeled we assumed an overall generator efficiency of 95% for the conversion of mechanical power to electrical power.

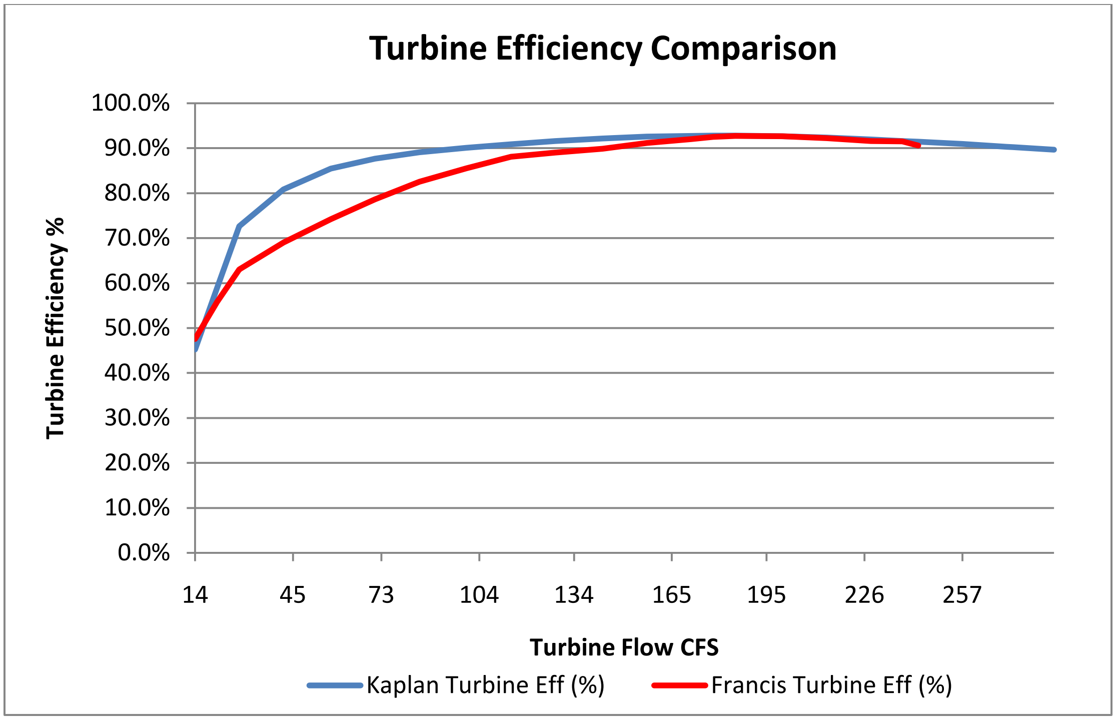


Figure 8. Francis and Double Regulated Kaplan Efficiency Curves

Various license conditions typically associated with hydro projects affect operation of the project and hence, energy production. Specific license conditions for the Ten Mile River would likely include seasonally adjusted minimum flows to maintain aquatic habitat conditions in the bypass reach, minimum flows over the dam for aeration and dissolved oxygen, fishery flows for upstream passage (attraction water and fish ladder flows) and fishery flows for downstream passage. Based on the results of our preliminary regulatory review we developed a range of anticipated license conditions for the three sites and incorporated them into the energy model. In most cases this resulted in a reduction in the amount of flow available for energy production (see Energy Estimates section).

Using the above information we calculated the gross energy production on a monthly basis and then totaled the results to develop annual estimates for each alternative. Gross generation was reduced by 5% for planned and unplanned outages and by an additional 1% for station service consumption to develop estimates of net energy production.

Determining Installed Capacity

Results from the energy model were used to make a preliminary determination of the optimal installed hydraulic capacity at each site. Curves were developed for each site that plot annual energy production in megawatt hours (MWH) as a function of installed hydraulic capacity (flow to the turbine in cubic feet per second [cfs]), as shown below for Alternative A.

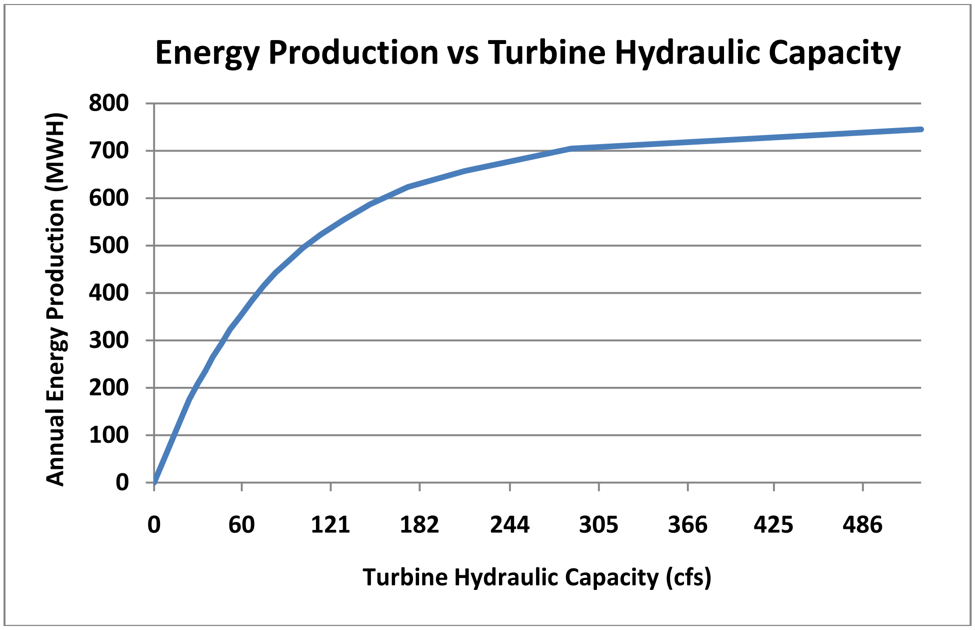


Figure 9. Annual energy production as a function of turbine hydraulic capacity for Alternative A

These curves were used in conjunction with other model outputs, particularly the calculated capacity factor[2] for each installed capacity. Smaller turbines (designed to operate in the lower range of the flow exceedance curve – see Figure2) would run frequently, but would generate a relatively small amount of energy leaving a significant portion of the site's energy potential undeveloped.

Referring to Figure 9, incrementally increasing the turbine size from 'zero' provides a "one for one" gain in energy production along the steep part of the curve. Absent any limiting license conditions, the costs associated with installing larger equipment are offset by the additional energy production and associated revenues. For hydraulic capacities greater than 60 cfs the curve begins to flatten out; indicating that incremental increases in equipment size (to capture the additional hydraulic capacity) result in smaller incremental gains in energy production. Beyond

[2]Capacity Factor is the amount of energy a unit or plant actually produces over a specific time period divided by the amount of energy the unit would have produced if it operated 100% of the time. For example a 1MW project (1,000 kW) producing 4,380 MWH of energy a year would have an annual Capacity Factor of 50% (4,380 MWH/(1 MW x 8,760 hours)). Capacity Factor is frequently used in the power industry as a measure of a plant (or individual unit's) utilization. For the 50% Capacity Factor example above, the plant would be used 50% of the year and 'sit' idle 50% of the time.

305 cfs the curve is nearly horizontal. Increasing the installed capacity from 305 cfs to 486 cfs (62%) produces only a 50 MWH increase (7%) in energy production.

For conventional hydroelectric projects in the Northeast United States the optimal installed capacity is usually in the transition area between the steep and flat portions of the curve. Our experience with hydroelectric projects in the Northeast also suggests that a Capacity Factor in the range of 40% appears to be the limiting value for successful development (in other words, installing capacity that sits idle 60% or more of the time typically is not economic). Applying these two criteria to Alternative A suggests an installed capacity in the range of 115 cfs would be optimal for Turner.

Energy Estimates

Using the approach described above, installed capacities were selected, and preliminary energy production estimates generated for each project configuration. For configurations that involve bypass reaches (i.e. Alternatives B, C, and E), three different installed capacities were selected reflecting three different potential instream flow requirements. Annual energy production estimates for each site configuration are shown in the table below.

Table 1, Preliminary Annual Energy Production Estimates

			Annual Energy Potential (MWH)		
Site		**Head (FT)**	**RI ABF Instream Flows**	**1/2 RI ABF Instream Flows**	**No Instream Flows**
Turner					
	A	14.5	720	same	same
	B	22.0	460	630	1,050
	C	38.0	830	1,140	1,890
Hunt's					
	D	8.5	400	same	same
	E	23.5	520	720	1,180
Omega					
	F	8.0	380	same	same

Energy production estimates range from 380 to 1,890 MWH depending on the site and the instream flow scenario. Estimates for Alternatives A, D, and F are the same for each Instream Flow scenario because these alternatives involve releasing water directly below the dam and therefore will not require instream flow releases. It is possible that the regulatory agencies may require some flow be released over the spillway (not run through the turbine) to maintain dissolved oxygen levels in the river, or for aesthetic purposes.

For those alternatives with bypass reaches (B, C, and E) assumptions regarding instream flows have a significant impact on energy production (see table above). This impact is shown graphically in Figure 10 below, which illustrates the difference in power production potential with and without the RI ABF.

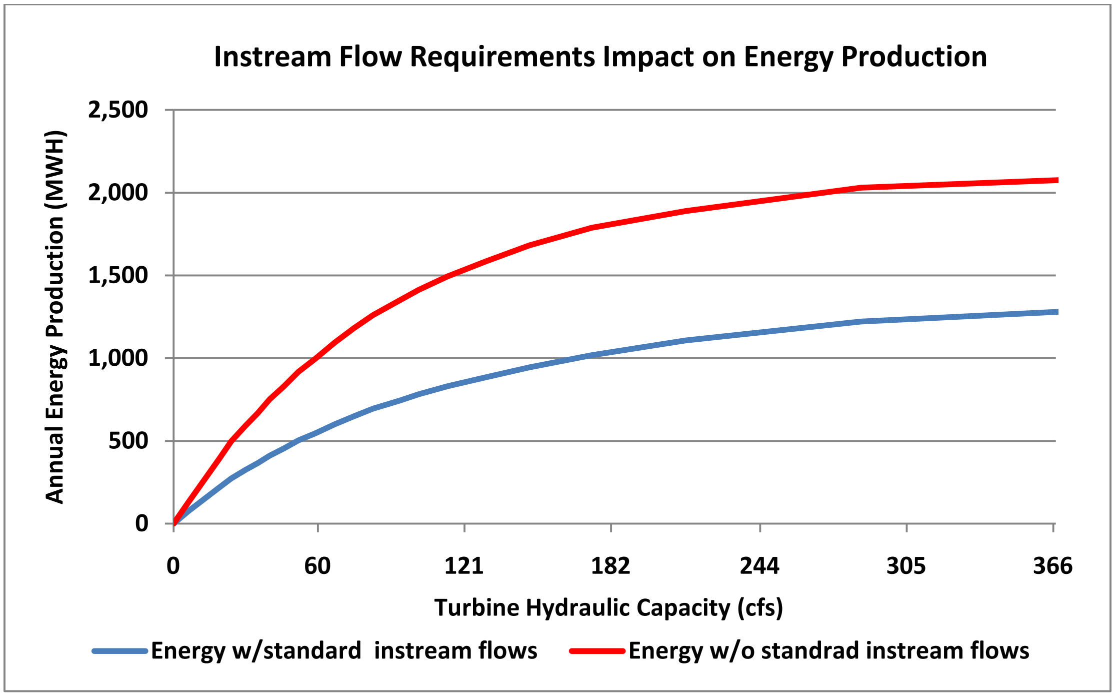


Figure 10: Comparison of installed capacity and annual energy production (using Alternative C as an example).

While it is not realistic to assume a development with no instream flow requirement, the analysis provides a basis for comparison and illustrates the potential up-side that could be achieved by conducting site-specific studies to establish a site-based compliance standard. The analysis also underscores the value of working with the State to develop site-specific instream flows that very likely would be less than the standard desk-top approach.

The existing RI ABF is extremely conservative and in some cases reflects a requirement of more water in the river than currently occurs under natural, unregulated conditions. The energy estimates shown in Table 1 with the assumption of "half instream flows" reflect a "middle of the road" approximation of what may be possible if site-specific studies were conducted to determine a resource specific instream flow requirement.

Equipment Selection

For each alternative we evaluated new turbine equipment as well as options for repowering or restoring the existing turbine and generator equipment at Hunt's Mill (as described below).

Double Regulated Bulb Turbines

For those alternatives that would involve installation of a new powerhouse located at an existing dam (Alternatives A, B, D, and F), we assumed horizontal, double regulated Kaplan turbines in a bulb configuration (commonly referred to as Bulb Turbines).

Benefits of this equipment option include; potential for eliminating a bypass reach and associated turbine flow restrictions, high energy conversion efficiency (~92%) and the ability to operate efficiently over a broader range of flow conditions. Drawbacks associated with these units compared to simpler equipment such as Siphon turbines include higher equipment costs and typically more civil construction requirements. Based on our recent experience with similar low head projects in Rhode Island, Bulb turbines tend to be more economic than other simpler options. The additional energy production achieved by the more efficient bulb turbines helps offset other fixed development costs such as licensing. A typical cross section of a bulb unit installation is shown below.

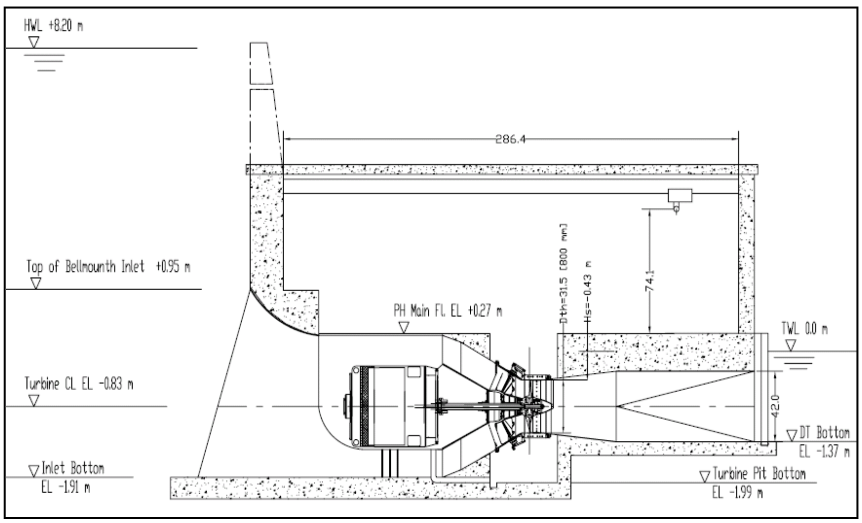


Figure 11. Schematic of a typical bulb turbine installation.

Depending on the site, and assumed instream flow scenario (which affects the assumed hydraulic design capacity); we selected different turbine runner diameters to optimize the utilization of the units given the site characteristics and available flow for generation.

Vertical Kaplan and Francis Turbines – Hunt's Mill

Three equipment alternatives were considered for the Hunts Mill site:

1. New double regulated vertical Kaplan turbine;
2. Repowered Francis turbine, and;
3. Restored Francis turbine.

New development assumes installation of a new, state-of-the-art double regulated vertical Kaplan turbine and associated generator set. This is the same basic technology as the bulb turbine. The major differences being the turbine axis is vertical and the generator is located outside and above the water passages. The new Kaplan unit represents the greatest energy production at the site because of the efficiency benefits associated with technology modern design, double-regulated turbine. The repowered Francis alternative costs less than the new Kaplan alternative and produces almost as much energy. A typical cross section of a vertical Francis unit installation is shown below.

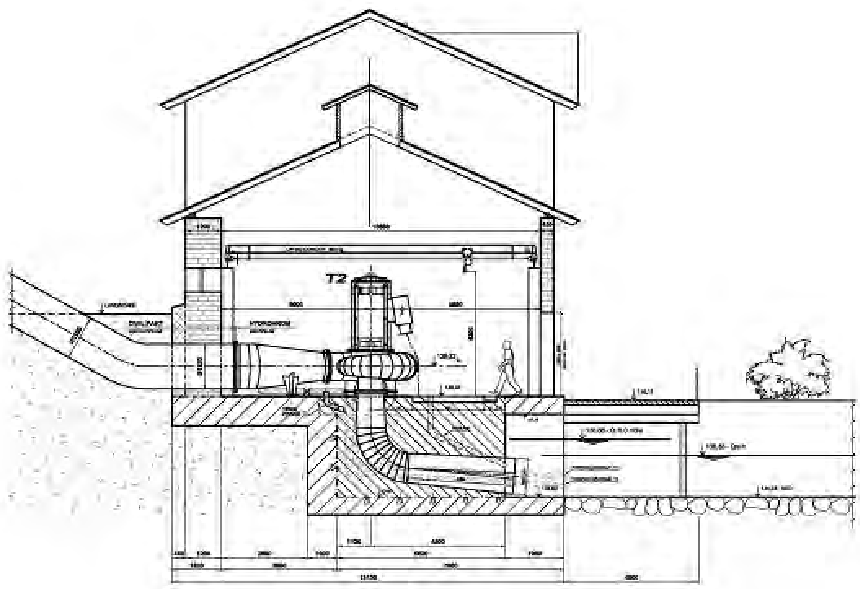


Figure 12. Schematic of a typical Francis turbine installation.

The Repowered case assumes that the existing turbine would be replaced with a modern Francis runner as described in more detail in the Hunt's Refurbishment section of this report. Under this alternative, the energy production potential of the site would be higher than the existing nameplate due to the efficiency benefits of the modern design runner.

Under the Restored case, we assumed that the existing unit at Hunt's Mill would be restored to its original, 'as-new' operating condition. Under this alternative the installed capacity would be approximately the same as the unit's existing generator nameplate rating (approximately 150 kw) and the unit would produce approximately 450 MWH per year of energy. To verify the accuracy of our energy model, we calibrated the model input to reflect a headloss condition and equipment efficiency reflective of the existing configuration and equipment (3-ft maximum headloss and a peak efficiency of 80%) and calculated the installed kW capacity. Our modeled estimates were very close to the nameplate rating on the existing generator (147 vs. 144 kW). This tended to confirm the calibration of our preliminary energy model. We did not run a Restored case for Alternative C (water delivered from Turner Reservoir to Hunt's Mill) because published reports indicate that the existing equipment was designed for 23.5-ft. of hydraulic head. It is difficult to predict how or if the original unit would operate under a significantly larger head (38-ft.).

Electrical Interconnection

All of the hydro development options studied will require interconnection to the National Grid distribution system (the grid). Based on our preliminary electrical analysis each generating unit will require a 3-phase 15 kv class distribution line. The connection to National Grid will require a sectionalizing switch at the point of interconnection, three single phase pole mounted step-down transformers, and a 15 kv fused disconnecting switch. Each generator will also require its own set of service switchgear including a main disconnecting switch, generator breaker and branch circuit breakers.

Existing service at the Turner and Hunt's Mills sites is currently single phase (220v/110v). Interconnection of hydroelectric generators would require approximately .33 and .52 miles (respectively), of upgraded (3-phase, 15-kv) service. Interconnection at the Omega Pond site could be accomplished through the installation of approximately two new utility poles to a nearby (0.05 miles) 3-phase service associated with a Narragansett Bay Commission (NBC) sewage pumping station.

At 15 kv, the projects would add approximately 8 amps to the existing distribution lines and are not likely to overload the circuit or require additional upgrades. Conceptual alignments for the interconnections are included in the Preliminary Project Configurations provided in Appendix C.

Tabulated below are preliminary costs estimates to complete the interconnections at each site. These estimates are included in the economic analysis provided in subsequent sections.

Item / Description	*Turner Res.*	*Hunt's Mill*	*Omega Pond*
13.8 kv Overhead Distribution Line	$33,000	$52,000	$5,000
13.8 kv Sectionalizers	$10,000	$10,000	$10,000
13.8 kv Pole-Mounted Transformers	$30,000	$30,000	$30,000
13.8 kv Fused Disconnecting Switch	$10,000	$10,000	$10,000
Service Switchgear	$20,000	$20,000	$20,000
TOTAL	**$103,000**	**$122,000**	**$75,000**

Cost Estimates

Estimates for each of the alternatives were developed to reflect initial investment requirements. The cost estimates include the following specific items; civil/construction, dam repairs, licensing and permitting, equipment and controls, electrical interconnection, routine operations & maintenance and maintenance overhauls. The cost estimates also include provisions for Owner's administrative costs, legal review and counsel, as well as engineering design. A 20% contingency was added to all cost estimates cover unknowns and reflects our confidence level in the numbers at this phase of the analysis.

The table below summarizes the total estimated capital costs for each alternative evaluated. Ranges are provided for alternatives involving flow diversions (Alternatives B, C, and E) that reflect different environmental flow requirements and associated equipment sizing. Note that smaller environmental restrictions equate to more water available for generation and thus larger installed turbines which are more expensive, but produce more energy. Alternatives with diversions also require penstocks, which can add significantly to the cost of development. All numbers below are rounded to the nearest tenth for capacity and the nearest $100,000 for cost for the purposes of comparing between alternatives.

Alternative	Installed Capacity (kW)	Installed Cost ($1,000's)
A	210	3,600
B	160 - 290	4,600 - 5,700
C	290 - 530	5,000 – 6,100
D	100	3,400
E	180 - 340	3,300 – 4,000
F	100	3,300

The civil structural costs for each alternative were derived from our recent experience at similar projects. Powerhouse civil costs for each specific alternative were calculated based on the equipment and water passage size requirements. All of the alternatives considered include an allowance for an automated trashrake at the project intake.

Cost estimates for dam repairs were developed based on the results of the preliminary dam inspection. These estimates reflect costs to bring the dams up to current standards as well as any engineering studies or investigations necessary to determine remediation requirements. Provisions for on-going dam maintenance were not included as they were considered to be required whether the hydro projects are pursued or not. Costs estimates for potential dam safety remediation were not included in the economic analysis because the likelihood and exact nature of the remedial measures that may be required by FERC, if any, will depend on the findings of more detailed analysis.

Requirements for water passages (penstock sizes) to deliver water to the turbines were determined by establishing an acceptable design head loss. Since head loss is a function of velocity squared, increasing the size of water passages results in lower headlosses. For this study we sized penstock diameters based on an acceptable maximum water passage velocity of 8 feet per second (fps). Prices for the various penstock sizes were derived from vendor quotes received within the last two years for similar projects.

Equipment cost estimates are based on our experience at similar recently completed projects. Allowances were made for auxiliary electrical and auxiliary mechanical equipment. Cost for turbine/generator packages were developed using vendors quotes received within the past two years. The quotes were adjusted to fit alternative specific equipment size and configuration.

Itemized cost estimates for interconnection were developed for each site. The estimates take into account the length of the interconnecting power line, recent equipment quotes from vendors and our recent experience interconnecting projects with National Grid.

Regulatory processing cost estimates include FERC licensing as well as other non-FERC permits (i.e., Water Quality Certificate, Wetlands, etc.). Alternatives with higher complexity and/or risk were adjusted to reflect efforts to address resource concerns such as instream flows, water quality concerns, or wetland impacts. A summary of regulatory costs by alternative is tabulated below.

Alts.	**Key Regulatory Drivers**	**Consultations (yrs.)**	**Studies (yrs.)**	**Regulatory Costs ($1,000's)**
A, D, F	• No bypass reach; • No stream flow concerns, and; • No wetland concerns.	2	0.5	$288
B, E	• Creation of bypass reach; • Wetland impacts, and; • Assumes acceptance of State instream flow standard.	2	2	$400
C	• Longest bypass reach; • Highest wetland impacts, and; • Assumes acceptance of State instream flow standard.	3	2	$450
B, E	• Creation of bypass reach; • Wetland impacts, • Assumes completion of site specific studies to modify instream flow standard.	3	2.5	$488
C	• Longest bypass reach; • More Wetland Impacts, and; • Assumes completion of site specific studies to modify instream flow standard.	3	3	$525

For alternatives that do not entail bypass reaches and penstocks (A, D, and F), we assumed minimal studies and 2 years of agency/stakeholder consultations for a total licensing and permitting cost of $288,000. For alternatives that involve bypass reaches and wetland impacts, we assumed greater study and consultation costs resulting in a total estimated licensing and permitting cost of $400,000 to $488,000, depending on whether the standard RI ABF is accepted or site-specific instream flow studies are assumed. For Alternative C, that involves a longer bypass reach and penstock, including greater potential wetland impacts, we assumed further increases in study and consultation costs resulting in a total estimated licensing and permitting cost of $450,000 to $525,000 for the standard RI ABF and site-specific instream flow cases respectively.

All cost estimates were developed based on the assumption that sites would be developed individually. Pursuing multiple sites as part of a portfolio development would likely result in economy of scale benefits.

Detailed cost estimates for each alternative are provided in Appendix E, including details on the powerhouse, water passage and equipment cost estimate calculations.

Economic Analysis

A discounted cash flow analysis was used to evaluate the economic performance of the projects over a 20 year study period. A residual value was added to the last year of the study to incorporate the long-term, intrinsic value of the project. The model reflects a cash-on-cash, pre- tax position. As a result, the predicted performance tends to be conservative. A leveraged analysis was also performed to illustrate the effect of financing the project. Key assumptions used in the models are listed below. Detailed descriptions of the preliminary cost estimates, expected revenues, and modeled development scenarios are provided in Appendix E.

#	Input	Model Assumption
1	O&M	1.5¢/KWH
2	Property Taxes	$0 Assumes exemption due to municipal development
3	Major maintenance[3]	$50k in years 5 & 15, $125k in years 10 & 20
4	Renewable Energy Rate[4]	$125/MWH
5	Renewable Energy Certificates	$25/MWH
6	State Grants	5 % of Initial Investment
7	Federal Incentives	15% of Initial Investment
8	Interest Rate (leveraged proformas only)	2% Assumes low cost financing is available to the City
9	Residual Value	Net cash flow last year of study divided by the growth rate
10	Initial Investment Contingency	20% of total development costs
11	Discount Rate	5%
12	Escalation Rate	2.5%/ yr. Applies to all recurring revenues and costs (O&M, insurance, energy rate, etc.)
13	Study Period	20 years

Full proformas were prepared for each alternative (Appendix E). The proformas include cost estimates for development (construction, equipment, licensing & permitting, etc.), estimates of energy production and associated revenues, and operations and maintenance costs. Based on discussions with resource agency staff and our experience with other hydropower developments, we identified environmental concerns and developed operational scenarios to reflect likely requirements for environmental protection, mitigation and enhancement measures (PM&E).

[3] Major maintenance costs were levelized over the 20 year study period.
[4] This energy rate represents the potential value of energy under a "net-meter" type arrangement. Current Rhode Island law does not allow for net-metering of hydropower projects. Efforts are underway to modify the renewable energy contracting laws in the State. The rate used in our analysis assumes the availability of net-metering or other comparable contracting mechanism for monatizing the value of distributed renewable energy generation.

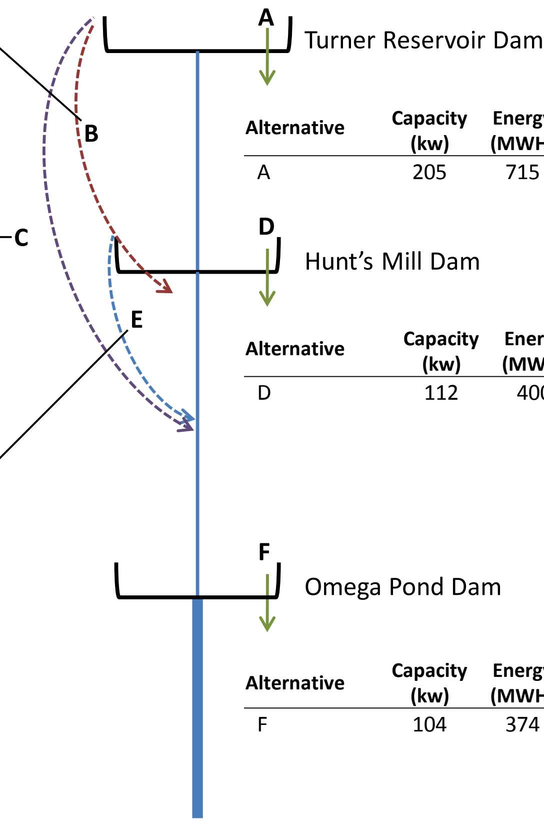
From a purely economic perspective, the preliminary results suggest that alternatives with a positive Net Present Value (NPV) produce benefits for the City. Alternatives with a positive IRR and a negative NPV may also produce benefits – but at a lower rate than the City's target discount rate. Alternatives with both negative IRR's and NPV's were screened from further analysis. Cash-on cash, pre-tax proforma results for each of the site configurations are summarized in the tables below.

ECONOMIC SUMMARIES BY ALTERNATIVE

Alternative	Capacity (kw)	Energy (MWH)	IRR (%)	NPV ($1,000's)
B (w/ Q min)	156	456	<0	-2,568
B (1/2 Q Min)	176	626	1	-1,874
B (no Q min.	288	1,050	5	-291

Alternative	Capacity (kw)	Energy (MWH)	IRR (%)	NPV ($1,000's)
C (w. Q Min)	288	831	3	-842
C (Francis)	282	743	3	-865
C (1/2 Q Min)	326	1,137	6	561
C (No Q Min)	534	1,889	9	3,919

Alternative	Capacity (kw)	Energy (MWH)	IRR (%)	NPV ($1,000's)
E (w. Q Min)	184	524	2	-1,047
E (Francis)	178	464	1	-1,145
E (Restored Francis)	110	335	<0	-1,729
E (1/2 Q Min)	209	717	5	-170
E (No Q Min)	341	1,184	8	1,927
E (Francis, No Q Min)	271	815	6	593



Alternative	Capacity (kw)	Energy (MWH)	IRR (%)	NPV ($1,000's)
A	205	715	4%	-215

Alternative	Capacity (kw)	Energy (MWH)	IRR (%)	NPV ($1,000's)
D	112	400	<0	-1,758

Alternative	Capacity (kw)	Energy (MWH)	IRR (%)	NPV ($1,000's)
F	104	374	<0	-1,823

** Q Min refers to the Standard RI Instream Flow requirement. Model sensitivities that assume modified Q Min requirements are noted using this shorthand.*

Alternatives B, C, and E, would entail bypass reaches, and were evaluated for multiple instream flow scenarios. Alternatives A, D, and F would be designed to capture a larger portion of river flows (but less head) with only minor deductions for fish passage requirements. These alternatives would release water directly below the dams and likely would not require significant instream flows.

In addition to the all equity proforma analyses, we also performed a levered analysis of each alternative. Assumptions for the levered cases were essentially the same as the cash proformas with the addition of 2% debt over a 35-year period to reflect low cost financing mechanisms available to the City (i.e, EDC loan or bonding with a 35 year term). The model 'back calculated the equity required to achieve an average debt coverage ratio (DCR) of 2.0 (cash on hand is equal to 2x the annual debt service obligation). Results of the most economically attractive alternatives are summarized below. Additional sensitivity results are provided in Appendix E.

Debt Levered After-Tax Economic Summary (Alternatives C & E assume ½ RI ABF)

No	Alternative	Project IRR (%)	Cumulative NPV ($1,000s)	Discounted Payback Period (yrs.)
A	Turner Reservoir Dam	6	319	19
C	Turner – Hunt's Mill Powerhouse (1/2 RI ABF)	8	1,528	19
E	Hunt's Mill Dam – Hunt's Mill Powerhouse (1/2 RI ABF)	6	367	19

Alternative A entails constructing a turbine at the Turner Reservoir Dam to develop approximately 14-feet of head. This configuration reduces environmental impacts – allowing the project to capture a large percentage of river flows. On an all-equity basis, this alternative yields a 4% IRR. Financing the project with long-term debt increases the IRR to 6% and produces over $300,000 of NPV benefits.

Alternative C involves diverting water from Turner Reservoir to the historic Hunt's Mill powerhouse to develop the greatest amount of head (38 feet). Under the RI Modified Base Flow scenario the configuration is not economic because instream flow requirements significantly reduce the amount of flow available to the turbine for generation. Under the "half min flow" scenario however, the alternative becomes more attractive (due to the availability of more flow for generation) yielding an all equity IRR of 6%. Leveraging this alternative increases the IRR to 8% and produces over $1.5 million of NPV benefits. Under the "no min flow" scenario, the value of Alternative C increases even further providing an all equity IRR of 9% and approximately $3.9 million of NPV benefits. This indicates the significant upside potential of conducting site-specific studies and agency consultations to refine instream flow requirements.

Development of Alternatives A and C must be weighed against the regulatory risk associated the spillway adequacy issue at the Turner Reservoir Dam. The cost of remedial measures could easily exceed the benefits from hydro development. These risks would have to be better understood before proceeding with hydro development at Turner Reservoir.

Alternative E, would utilize the historic hydropower alignment diverts water from the Hunt's Mill Dam to the old Hunt's Mill powerhouse. Under the "half min flow" scenario, an all equity project would yield a 5% IRR. Financing the project increases the IRR to 6% and produces over $350,000 of NPV benefits. The "no min flow" scenario would yield an 8% IRR and nearly $2 million of NPV benefits for an all-equity project. As with Alternative C, there is significant upside potential if the instream flow requirements can be reduced through agency consultations and site specific study.

Development at Omega Pond Dam (Alternative F) does not appear economic, largely because of low average head (8 feet).

Of the options evaluated for the Hunt's Mill powerhouse site, redeveloping the existing powerhouse with a new, modern designed Francis turbine appears to hold the most promise. A significant upside to this configuration is the potential reuse of existing civil features and infrastructure. A more detailed optimization analysis of this alternative would refine and balance generating equipment options with potential instream flow requirements.

Summary of Findings

Key findings from the feasibility study are summarized below. Findings regarding economic viability reflect an all-equity analysis with no consideration of possible tax treatments or financial leveraging. This approach tends to be conservative. Where there was uncertainty, we also tended to make conservative assumptions to help avoid surprises.

Dam Conditions and Suitability for Hydro Development

- The existing dams appear to be in good overall condition. With proper care and maintenance customary to the hydro industry, all three dams can reasonably be expected to last a long time (i.e., equal to or greater than life of the hydro project).
- Published reports indicate that the hydraulic capacity of the Turner Reservoir Dam spillway may be inadequate. This issue represents an area of significant uncertainty relative to hydropower licensing.

Electrical Interconnections

- Interconnection of hydroelectric generators at each of the sites would require less than one mile of upgraded (3-phase, 15-kv) service.
- At 15 kv, the projects would add approximately 8 amps to the existing distribution lines and are not likely to overload the circuit or require any significant upgrades.

Development Integral with Dam (Alternatives A, D, and F)

- Development of configurations involving less than 10-ft of head does not appear economic given the river's flow characteristics. Only Turner Reservoir Dam exhibits enough head to produce sufficient generation to offset threshold development costs, as shown in the table below.

Dam	Alt.	Head	IRR
Turner Reservoir Dam	A	14.5-ft	4%
Hunt's Mill Dam	D	8.5	<0
Omega Pond Dam	F	8.0	<0

- Additional analyses that look more specifically at load proximity and refined equipment selection for the Omega Pond Dam could affect these preliminary results and may be warranted.

Development Involving River Bypasses (Alternatives B, C, and E)

- None of the alternatives involving a river bypass reach are attractive with full RI ABF requirements.
- With half of the RI ABF, two Alternatives, C & E appear potentially attractive.
- With no minimum flow, Alternatives C & E become very attractive. These results suggest that conducting site specific instream flow and water quality studies would be warranted to establish a minimum flow less than the RI ABF standard. Preliminary discussions with regulators indicate that alternative instream flow regimes could be negotiated based on site specific analysis.

- Alternative C (Turner to Hunt's Mill powerhouse) appears slightly more attractive than Alternative E (historic Hunt's mill alignment), but has over twice the bypass reach and wetland impact as well as significant risk associated with the Turner Reservoir spillway adequacy.
- A reasonable strategy would be to proceed with Alternative E as the preferred least risk option while the spillway adequacy issue at Turner Reservoir is investigated.

Re-Development of Hunt's Mill

- Repowering the existing hydropower unit at Hunt's Mill with a modern design Francis runner appears slightly more attractive than constructing a new powerhouse with a new Kaplan unit. This approach takes advantage of existing infrastructure, avoids the cost of powerhouse construction, and reflects lower overall equipment cost.
- Restoring hydropower at Hunt's Mill is consistent with the City's long-term plans for the site as a "green technology" education and learning center.
- A logical next step would be to conduct an optimization analysis to further refine and balance equipment options with respect to reuse of existing infrastructure and instream flow requirements.

Next Steps (Phase II)

- Confirm redevelopment of the Hunt's Mill (Alternative E) as the preferred option.
- Evaluate the spillway adequacy issue at the Turner Reservoir Dam. If the issue cannot be resolved with further study and costly remedial measures would be required, hydro development may not be feasible.
- Explore options for pre-development funding assistance with the Rhode Island Economic Development Corporation, the Rhode Island Foundation, and others.
- Prepare and file a preliminary permit application with FERC to secure priority status for the Hunt's Mill and Turner Reservoir sites. This would be relatively short money to preserve the City's options and avoid potentially costly legal proceedings in the event of competing applications.
- In parallel, file a request for a formal determination of FERC has jurisdiction at the formerly powered Hunt's Mill site.
- Investigate the remaining waterpower infrastructure associated with Alternative E to support redevelopment.
- Initiate formal consultations with regulatory agencies and other stakeholders to identify/confirm natural and cultural resource concerns. Work collaboratively to identify, develop and implement appropriate strategies to address these concerns.
- Optimize Alternative E (i.e., configuration and equipment) to make the best use of existing infrastructure. Optimization analysis would help to control development costs, maximize energy production and provide adequate protection of environmental resources.
- Refine cost estimates, energy model and economic analysis based on the results of the optimization study.

APPENDIX A

Preliminary Dam Inspection Report

Hydropower Feasibility Study
City of East Providence, Rhode Island

PRELIMINARY INSPECTION OF TURNER, HUNT'S MILL, & OMEGA DAMS

DRAFT

The Essex Partnership LLC
Newport, Rhode Island

November 2010

MBP Consulting
planning & engineering

Hydropower Feasibility Study
City of East Providence, Rhode Island

Preliminary Inspection
of
Turner, Hunt's Mill, and Omega
Dams

Prepared for:

The Essex Partnership LLC
Newport, Rhode Island

Prepared by:

MBP Consulting
Portland, Maine

DRAFT

November 2010

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1.0 SUMMARY

A preliminary inspection of Turner Reservoir, Hunt's Mill, and Omega Pond dams, all located on the Ten Mile River, Rhode Island, was performed on October 13, 2010. The purpose of the inspection was to evaluate their condition in relation to potential hydropower development and public safety. The inspection was conducted by MBP Consulting (MBP), Portland, Maine acting as a subcontractor to The Essex Partnership LLC (Essex), Newport, Rhode Island. The inspected dams are small to intermediate size, run-of-river structures. Two dams, Hunt's Mill and Omega Pond, are classified by the State of Rhode Island (State) as low hazard potential facilities[1] and Turner Dam is rated as high hazard potential structure[2].

Visual inspection of the dams was performed with the spillways in an overflow condition, except the Turner Dam which was in non-overflow condition. Flow over the spillways limited the assessment of the Hunt's Mill and Omega Pond facilities. The preliminary results indicate that all inspected dams are structurally sound and in fair condition. There were no apparent conditions that would preclude them from hydropower development. No adverse conditions were observed that require immediate remedial actions.

The Turner Reservoir Dam is classified by the State as a high hazard potential structure and would therefore be subject to compliance with Part 12 of the Federal Power Act (Dam safety) if it was to be redeveloped for hydropower under a Federal Energy Regulatory Commission (FERC) license. More detailed analyses and studies would have to be performed to determine if additional remedial measures would be required to meet FERC safety criteria. The Hunt's Mill and Omega Pond Dams are classified as low hazard structures by the State.

Based on the inspection findings, major recommendations related to public safety include restoration of the manholes to monitor condition of the drainage system of the left embankment of the Turner Reservoir Dam and repair of the leaking headrace entrance closure wall and deteriorated upstream wall of the Hunt's Mill Dam.

Typical recommendations related to operation and maintenance of the inspected dams include; brush and tree removal, repair of deteriorated concrete surfaces, and repointing of stone masonry structures.

It is also recommended that the Hunt's Mill and Omega Pond Dams be inspected during a low flow period to observe the exposed water retaining structures for signs of deterioration, seepage, undermining, and structural distress. This inspection should be supplemented by an underwater and/or bathymetric survey of the submerged areas of dams, as required. Installation of fish passage facilities is currently underway of planned for each dam. This work will require dewatering portions of the project areas and presents an opportunity for more detailed inspection. and survey prior to and during construction work. Following the above-water and underwater inspection findings, additional remedial measures should be developed, as necessary.

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[1] Failure of dams with low hazard potential classification can result in no probable loss of human life and low economic and /or environmental losses (Reference 1).

[2] Failure of dams with high hazard potential classification can probably result in loss of human life (Reference 1).

This report includes an opinion of probable cost for recommended remedial measures (Section 7) and comparison of dam safety regulations adopted by the Rhode Island Department of Environmental Management (RIDEM) and FERC (Section 8).

2.0 INTRODUCTION

A visual inspection of Turner Reservoir, Hunt's Mill, and Omega Pond dams, all located on the Ten Mile River, a tributary of the Seekonk River, in the City of East Providence, Providence County, Rhode Island was conducted by MBP on October 13, 2010. The purpose of the inspection was to identify existing or potential deficiencies in water retaining structures which could adversely impact their operation, integrity, and public safety and/or complicate the development of hydropower. The inspection was performed as a part of a hydropower feasibility study undertaken by Essex and the City of East Providence (City), RI, the owner and operator of the dams.

As part of this assessment MBP also reviewed available documentation on each dam, including previous dam inspection reports, photographic records, engineering assessments and drawings, and fish passage restoration plans. Interviews with the representatives from the City were conducted to gain additional information on each site and understand current operations and maintenance practices.

3.0 DAM DESCRIPTIONS

3.1 Turner Reservoir Dam

The James V. Turner Reservoir Dam (State No. 407, National No. RI01002), is the most upstream dam of the inspected projects. The 1,550 foot-long dam consists of a left[3] embankment, spillway, low level outlet, and right (west) dike (References 2, 4-10). The dam supports an impoundment with a maximum reservoir storage and surface area of 3,100 acre-feet and 390 acres, respectively. Historically the impoundment was used for public water supply. According to State records use of the reservoir as a water supply source was abandoned circa 1970 due to water quality concerns. The impoundment is currently served to provide recreational opportunities. Efforts to restore upstream fish passage on the river will expand its use to provide spawning and rearing habitat for anadromous fishes (river herring and shad). The dam is classified by the State as an intermediate size structure with high hazard potential.

The left earthen embankment spans the original river streambed, and is 525 feet long, 22 feet above the original streambed grade and 15 feet wide at the top. Upstream and downstream slopes are 3H:1V (horizontal to vertical) and 4H:1V, respectively. The top of the embankment is at el, 51.0[4]. The upstream slope is armored with 3 foot-thick riprap and the top and downstream slope are grassed. Embankment seepage control is provided by a corewall and drainage blanket installed in 1984. According to engineering drawings there is a concrete corewall with the top el. 48± is 3 feet below the top of the embankment and contains a steel sheet pile cutoff at the base extending to underlying bedrock. A 6-inch diameter perforated drain runs along the concrete corewall footing and discharges through an outlet in the downstream end of the left concrete retaining wall. A manhole on the top of the embankment provides access to the drain pipe. A 300 foot-long, 1 foot-thick gravel drainage blanket is located at the toe of the embankment and extends from the left abutment toward the spillway. The blanket contains two 6-inch diameter seepage collection pipes with the outlets in stone gabion walls at the toe of the blanket. There is a 16-inch diameter storm drain within the embankment discharging in the middle of the left retaining wall. Manholes at the toe of the embankment provide access to the blanket and stormwater drains.

The concrete overflow spillway is 200 feet long with a rounded crest at elevation 46.0 and a maximum freeboard of 5 feet. The toe of the spillway is protected with a 30-35 foot-wide concrete stilling basin and a 50 foot-wide stone apron located immediately downstream of the stilling basin. The left concrete retaining wall between the spillway and left embankment extends about 100 feet downstream. The spillway is likely founded on sedimentary type bedrock.

The 25 foot-long concrete low level outlet abuts the right end of the spillway. The structure contains two 54-inch diameter conduits and a 66-inch diameter penstock intake. The invert of the conduits and intake are at el. 29.5 and el. 32.25, respectively. The penstock is buried into the

[3] The terms "left" and "right" refer to an orientation looking in the downstream direction.
[4] All elevations in the report taken from the previous inspection reports, unless otherwise noted, are in feet and refer to the National Geodetic Vertical Datum (NGVD).

ground and runs approximately 2,400 feet along the right river bank toward the Hunt's Mill Dam downstream. In the past, the penstock was used for water supply and was abandoned in 1970. A brick gatehouse on the top of the outlet structure contains three manual operators to adjust the position of slide gates for the conduits and penstock. The right concrete retaining wall, curved in plan, extends about 100 feet downstream from the outlet structure.

The right earthen dike is 750 feet long, 6 feet high, and 15 feet wide at the top which is at el. 51.0. The 3H:1V upstream slope of the dike is covered with riprap. The dike top and 2H:1V downstream slope are grass protected.

The reservoir banks also include a west berm and east earthen dikes 1 and 2 to contain the impoundment during high water. The east dikes are 2 feet high, 15 feet wide at the top, and 550 feet long (dike 1) and 350 feet long (dike 2). These features were not observed as part of the inspection.

The dam drainage area is 48 square miles. For a high hazard structure the project spillway design flood (SDF) is equal to one half of the probable maximum flood (½PMF). Phase II analysis (Citation__) calculated the ½ PMF outflow to be 16,828 cubic feet per second (cfs) resulting in overtopping of the earthen dam structures by 1.2 feet under current condition and by 1.65 feet with the proposed fishway (References 6, 10). The combined hydraulic capacity of the existing spillway and outlet works is 9,316 cfs or 55 percent of the ½ PMF. The existing spillway capacity with both outlet gates closed or inoperable is 8,750 cfs or 52 percent of the ½ PMF. Installation of the fishway will reduce the spillway and low level outlet capacity to 9,022 cfs or 54 percent of the ½ PMF.

The dam was built in 1934 and repaired in 1984-1990. The rehabilitation activities included installation of a drainage blanket at the toe of the left embankment (1984), resurfacing of the spillway, outlet works, and retaining walls (1989), placement of stone riprap on the upstream slope of the right dike and stone gabions at the toe of the right retaining wall to control scour (1990). Construction of a denil fish ladder on the left side of the spillway, designed by the US Army Corps of Engineers (USACE), is scheduled for the fall of 2010.

The dam was previously inspected by the USACE in 1981, New England Engineering in 1982, RIDEM in 1989, 1999, 2001, 2004 and 2007, City in 2004, and Pare Corporation in 2007. The most recent inspection reports (2007) found the dam to be in good to fair condition.

3.2 Hunt's Mill Dam

The Hunt's Mill Dam (State No. 405, National No. RI02601), is located on the Ten Mile River approximately2,600 feet downstream of the Turner Reservoir Dam. The 175 foot-long dam consists of an overflow spillway and a closure wall at an abandoned headrace entrance. The appurtenant facilities, all abandoned, include a penstock, headrace, pumphouse, and a 100 foot-long tailrace (References 2, 11-14). There is also a pond retaining wall upstream of the intake closure wall at the City's park area. The dam with impoundment storage of 140 acre-feet and surface area of 0.4 acres is classified by the State as a small size structure with low hazard potential. The dam was used for hydropower generation and public water supply from the 1930s to 1970. The Hunt's Mill Dam is currently used for recreation.

The curved stone masonry spillway is 125 feet long, 10 feet high and is founded on bedrock. A 36" diameter concrete conduit penetrates the spillway near the right end, continues a short distance downstream and terminates in a rounded concrete stilling well. The headrace entrance was sealed with a steel sheet pile and concrete wall. The headrace downstream of the entrance closure wall has a short, open flume transitioning into an underground steel penstock which leads to the pumphouse. The pumphouse contains a 144 kW vertical Francis hydro-generating unit, presently retired. The 100 foot-long tailrace re-joins the river downstream of the pumphouse.

According to the National Inventory of Dams (NID) inventory, the dam was built in 1928 (Reference 11), however, hydropower generation is reported to have existed at the site since 1893 (Reference 14). There are no construction or inspection records of the dam. There is a photographic record of the dam taken by the City during the March 31, 2010 flood. The photos indicate that the dam was completely submerged during the flood with the pond level at the top of the upstream retaining wall. Fish passage designed by the USACE, New England District is currently being installed at the right side of the dam will remove the concrete conduit and stilling well and utilize the abandoned headrace.

3.3 Omega Pond Dam

The Omega Pond Dam (State No. 406, National No. RI01001), is located at the confluence of the Ten Mile and Seekonk Rivers. The 200 foot-long, 18 foot-high dam consists of an overflow spillway and abutment walls. The dam impoundment has storage of 280 acre-feet and surface area of 33 acres and is used for recreation and supply water by several adjacent industries. The dam is classified by the State as a small size structure with low hazard potential.

The 112 foot-long, 15 foot-high spillway is a concrete gravity structure with downstream stone facing. The stone facing was built of nine stair-stepped granite courses, each 20 inches high (Reference 16). The spillway crest and base are at el. 9.90 and el. -5.4±, respectively (Reference 17). The spillway crest is 4 feet wide and inclined upward in the downstream direction. The 15 foot-wide spillway base is supported with four rows of wooden piles installed across the streambed. Foundation seepage control is provided with two rows of 6 inch-thick, 24 foot-deep wooden splined pile sheeting located at the heel and toe of the structure. The spillway toe is protected with a 70± foot-wide concrete apron with wooden planking on the top and supported with wooden foundation piles.

Massive, stone-mortared walls with the top at el. 14.8 feet (NGVD) or 4.9 feet above the spillway crest form both spillway abutments. The abutment walls support a steel truss railroad bridge located immediately downstream of the dam. The original drawings (Reference 16) indicate that the abutments contain concrete core walls, similar in construction to the spillway, extending 42 feet into earthen railroad embankments.

The existing dam was built in 1918 downstream of an original timbercrib dam erected in 1883. There are no construction or inspection records of the previous dam. Similar to the Turner and

Hunt's Mill Dams, the Omega Pond Dam is scheduled for installation of a fishway to restore anadromous fish runs in the river. The fish passage designed by the USACE, New England District will be installed at the right side of the dam utilizing a portion of the existing spillway. The fishway drawings contain the project elevations surveyed by the USACE in 2009 and include plans of the existing and original dams.

4.0 INSPECTION

Prior to site visits, available data including the RIDEM and NID records, aerial maps, historic photographs, previous inspection reports, studies for proposed hydropower developments and fishway installation at the dams, and other pertinent information were reviewed.

The inspection briefly started with Hunt's Mill Dam, proceeded to the Turner Dam, then Omega Dam, and ended at the Hunt's Mill Dam. The inspection included visual observation of the dams from both abutments for signs of misalignment, movement, settlement, sinkholes, cracking, leakage or seepage, excessive deterioration, erosion, scouring, and vegetation growth. Pond water level control equipment, such as gates, were observed for serviceability and access. A digital photo record was made at each dam site to document findings and for later reference (Appendix A).

Where available, observations were compared with the findings from previous inspections. The inspection was performed by Myron Petrovsky, P.E. of MBP assisted by Fred Szufnarowski, P.E. and Jon Petrillo of Essex. Senior Planner for the City, Mr. Patrick Hanner was present at the beginning of the inspection.

The inspection was conducted on October 13, 2010. The weather was clear with ambient temperature in the mid-60s° F. The following are inspection findings for each dam arranged in upstream to downstream order.

4.1 Turner Reservoir Dam

During the time of the inspection, the reservoir was lowering with the one outlet gate half-open and the other outlet gate closed in preparation for construction of a fish passage at left end of the spillway. The reservoir level at the beginning of the inspection was 2.3 feet below the spillway crest. The tailwater level was measured 2.7 feet below the top of the downstream section of the left retaining wall.

Left Embankment. The inspection was conducted with silt fences installed along the top and toe of the embankment for scheduled construction of a fish passage at the spillway this fall. The embankment top will serve as an access route to the construction area.

The upstream slope of the embankment covered with dumped, 3 to 4-foot size blasted stone riprap was in stable condition (Photo 5). The slope showed no signs of sloughing or excessive erosion. The riprap at some areas of the slope was displaced exposing bedding, more notably at the spillway area. Some woody vegetation was growing through open spaces in riprap. The top and downstream slope covered with manicured grass, were solid with no areas of significant erosion, cracking, wetness, seepage, or animal activities observed. The drainage blanket installed at the toe of the embankment was firm, with no soft spots noted. The drainage blanket discharged through two, 6-inch diameter seepage collection pipe outlets stone gabion walls at the toe (Photo 6). The gabion walls appeared stable with the pipe outlets discharging no flow. The area downstream of the drainage blanket was covered with a large body of stagnant water which is reported to be the location of the original stream. The toe of the embankment and a portion of the drainage blanket were overgrown with trees and woody brush not allowing a thorough inspection (Photos 2, 5, 6). The vegetation's root systems may penetrate the blanket and reduce its hydraulic efficiency.

The foundation drain collecting seepage at the base of the concrete corewall appeared to be functioning with moderate discharge observed exiting the semi-submerged pipe outlet in the left retaining wall. The seepage flow was clear, with no signs of soil migration. Some small pieces of bacterial greenish sludge were coming out of the pipe. The manholes installed on the top of the embankment and drainage blanket to the monitor condition of the underground collection drains were not accessible for observation.

Spillway. The spillway with the exposed crest and downstream face appeared to be true to the original alignment (Photos 1, 2). No signs of movement, sagging, or deterioration of the structure, which was rehabilitated in 1989, were observed. The downstream face was dry including vertical expansion joints separating the spillway monoliths. The spillway toe was submerged and the stilling basin and riprap revetment were not visible through the water. No pressure boils indicating excessive seepage at the base were observed at the toe area. A pile of stone was accumulated in the stilling basin floor near the left retaining wall at a distance of approximately 20 feet from the spillway (Photos 2, 3). This stone accumulation, not noted in the previous inspection reports, could be the result of riprap displacement during the record flood of March 31, 2010. The spillway approach and discharge channels were clear from debris. The approach channel at the area near the left training wall appeared to be partially silted with the top of sediment measured 5-7 feet below the spillway crest.

Retaining Walls. Both the left and right concrete retaining walls, resurfaced in 1989, appeared stable and solid (Photos 1-3). The left wall showed some signs of deterioration with two areas of minor spalling on the top (Photo 3). The channel face of the wall contained a near horizontal crack, approximately 4 feet above tailwater, covered with efflorescence (Photo 2). The crack and vertical construction joints, observed from the right bank of the discharge channel, were dry. The area at the downstream end of the wall was densely vegetated impeding the inspection (Photo 2). The right retaining wall contained a few small areas on the top with deteriorated concrete at vertical construction joints and a sub-horizontal crack with efflorescence at the downstream end (Photo 1). The wall appeared to be sound. The top of stone gabion walls installed over the spillway channel floor in 1990 to control scour from low level outlet discharges at the retaining wall base were visible. The assessment of the gabion walls as an erosion protection measure was difficult due to submergence.

Low Level Outlets. The outlet works, repaired in 1989, were observed from the left embankment and right dike and appeared sound, stable, and operable (Photo 1). No significant cracking, deterioration, or signs of movement were found. A random cracking observed on the upstream face of the structure appeared superficial. The juncture of the outlet with the right dike was tight, with no signs of depression or erosion at the interface between two structures. The outlet conduits, which were half-exposed on the downstream side, appeared sound. The brick gatehouse walls and floor observed from the outside and inside were intact and free of structural cracks. The manual gate operators were reportedly in serviceable condition (Photo 4). Although not a structural concern, the plywood flooring of the gatehouse appeared to be nearing the end of its useful life and if left in its current state may pose a safety hazard.

Right Dike. The right earthen dike extending between the outlet works and right dam abutment was stable and in sound condition (Photos 1, 7). The shallow structure was covered with manicured grass on the top and downstream slope and heavy riprap on the upstream slope. The dike was true to the design alignment and showed no signs of sinkholes, cracking, wetness, or active seepage. The slope riprap refilled in 1989 was stable with some missing or displaced stones at the area near the outlet structure. Woody brush was growing in gaps between some riprap stones. The toe of the dike was sparsely vegetated with large trees and a manicured grass understory.

4.2 Hunt's Mill Dam

Spillway. During the time of the inspection, the pond level estimated at an existing staff gage was 3.9 feet below the top of the upstream retaining wall. The spillway was discharging a few inches of flow impeding a thorough inspection of the structure and other project facilities. The curved stone masonry spillway appeared to be true to the original alignment (Photos 8, 9). No visible signs of movement or deterioration of the structure were observed through moving water. The pattern of the flow over the spillway crest was relatively uniform indicating that the crest was intact and contained no large gaps created by missing stone blocks. The spillway approach channel was generally unobstructed to the flow. The left abutment overgrown with dense vegetation (Photo 8) was inaccessible for evaluation. The toe of the spillway in immediate proximity was covered with discharging flow. Approximately 30-50 feet downstream of the spillway, the streambed exposed highly irregular rock outcrops with a massive rock island rising to nearly the level of the spillway crest and then dropping about 10-15 feet to the streambed. This rock island may reduce the spillway capacity by early submergence during high water.

Conduit and Chamber. The right side of the spillway contained a 36" diameter steel conduit penetrating through the structure (Photo 9), then connected to a reinforced concrete pipe (Photo 10) leading to a concrete chamber (Photo 11). The steel conduit was rusty and corrosion pitted but appeared sound. This conduit has reportedly been removed after the inspection as part of the fish passage construction project. A section of the concrete pipe attached to the steel penstock was severely deteriorated exposing steel reinforcing. The 12 inch-thick concrete chamber, about 8-10 feet in diameter, was deteriorated with friable, laminated concrete observed on the upper part of the structure. The conduit outlet at the chamber floor was moderately leaking. The riverside chamber wall contained a 2 foot-deep waste weir with wooden planks for releasing excess water (Photo 11). The conduit between the spillway and the chamber was supported with concrete pedestals which were not accessible for the inspection.

Headrace. The abandoned headrace consisted of an open flume and underground steel penstock leading to the pumphouse. The entrance to the headrace from the pond was plugged with PZ-steel sheet piles and sealed with a concrete wall on the downstream side. The composite closure wall appeared stable and in fair condition. The steel piling was well interlocked, with no apparent gaps and signs of movement or buckling (Photos 12, 13). The concrete wall was generally free of major cracks and deterioration, however, the left side of the concrete wall was leaking at the juncture with the riverside headrace wall (Photo 13). The headrace walls of brick and stone masonry construction covered with concrete showed signs of deterioration resulting in spalling and missing concrete cover in some areas (Photo 14). The floor of the headrace was vegetated with brush and covered with debris impeding the inspection (Photo 13). The underground section of the headrace (penstock) was inaccessible and not inspected. The mortared-stone pumphouse containing an original turbine-generation unit was in excellent condition.

Pond Retaining Wall. The wall on the right side of the pond extends upstream from the headrace entrance encompassing a portion of the pond adjacent to the City park (Photo 15). The wall of mortared rubble was covered with concrete. The concrete cover on about two thirds of the wall length was deteriorated to a depth of 2 inches exposing steel reinforcing on the top (Photos 15, 16). The end of the wall, overgrown with dense vegetation, was disintegrated exposing original masonry.

4.3 Omega Pond Dam

Spillway. During the time of the inspection, the spillway was discharging a 1-2 inch-deep flow impeding a thorough visual inspection (Photos 17, 19). The maximum spillway freeboard measured at the right retaining wall was 5 feet conforming to the original drawings. The spillway alignment between the abutment walls was straight and true to the design intent. The cascading flow pattern was smooth and uniform suggesting no presence of areas with significant erosion or damage on the crest and downstream face (Photo 17). The discharge channel containing a concrete apron covered with timber planking was inundated with shallow water. The apron flow surface was relatively even, with no major disturbances which could be the result of deep scour.

Abutment Walls. The spillway abutment walls supporting the downstream steel truss railroad bridge appeared stable and plumb (Photos 17, 19, 21). No signs of wall instability or seepage were observed. The cut stone blocks forming the walls were intact and in place, except the right wall where a stone block was likely missing at the bottom of the steps (Photo 21). The top of the left wall covered with concrete experienced surficial erosion (Photo 18). Both walls contained a number of open masonry joints with missing mortar (Photos 17, 21). Concrete corewalls at each abutment as indicated on the project drawings, were not observed. However, the areas with assumed corewall location were heavily vegetated obstructing the inspection (Photos 17, 19). The earthen railway embankments forming the dam abutments were stable and watertight.

5.0 CONCLUSIONS AND DISCUSSIONS

Based on review of project information and field observations made during the October 13, 2010 site visits, the inspected Turner, Hunt's Mill, and Omega dams appear to be structurally sound, safe, operational, and well suited for hydropower development. There are no major structural, maintenance or operational deficiencies in the dam projects requiring immediate remedial actions. The dams appeared true to the original alignment as shown in the project drawings and were in reasonable condition. All dams were able to withstand the record, March 31, 2010 flood without noticeable change in condition.

The toe of the spillways was not inspected for scour, erosion, undermining, and seepage due to submergence. During construction of fish passage facilities, the City may take advantage of a rare opportunity to inspect, survey, and evaluate the condition of the coffer-dammed and dewatered portions of the dams which are usually submerged.

5.1 Turner Reservoir Dam

- The high hazard potential dam observed with the reservoir lowered and no water flowing over the spillway appeared true to the original alignment and stable. The project was in process of preparations for installation of fish passage facilities at the left end of the spillway.

- The exposed spillway, resurfaced in 1989, was in sound condition, with no signs of erosion, cracking, or seepage. Stone piles accumulated at the left area of the spillway stilling basin, not observed in the previous inspections, could be the result of spillway operation during the record March 31, 2010 flood.

- According to the hydrologic studies conducted in 1981 and 1982 (References 5, 6), the existing spillway is undersized and cannot pass the ½ PMF, the project spillway design flood (SDF), resulting in overtopping and failure of the earthern embankment dam by erosion. High hazard dams under the FERC jurisdiction would be required to conduct a hydrologic/hydraulic study to determine the Inflow Design Flood (IDF) involving dam break analysis and incremental inundation assessment of the impacted downstream areas. The resulting IDF may be equal to the PMF or be a fraction of the PMF.

- The concrete retaining walls supporting the left embankment and right dike were rehabilitated in 1989. The walls experienced relatively minor deterioration in the form isolated spalling and random cracking. No seepage through or around the walls was observed. The downstream areas of the walls were heavily vegetated obstructing the inspection.

- The low level outlet concrete substructure and brick superstructure (gatehouse) were in good order, with no significant signs of deterioration (excepting the interior flooring). The outlets, gates, and operators were in serviceable condition. The penstock intake gate located in the gatehouse was closed long ago (circa 1970), abandoned, and its operability is unknown.

- The left embankment (aka an embankment dam) was stable and well maintained. The upstream slope riprap placed in 1990 was displaced at the area near spillway and showed signs of opportunistic vegetative colonization. The downstream face and toe appeared sound with no evidence of seepage. The corewall foundation drain was functioning, discharging a moderate flow. Both drainage blanket pipe outlets appeared to be dry which could be the result of the embankment watertightness or reduction in drainage effectiveness due to internal siltation or/and plugging with vegetation roots. The toe of the embankment was densely covered with trees and brush. The manholes installed to monitor and maintain drainage systems of the embankment were inaccessible for the inspection (overgrown??). The top of the embankment containing the manhole(s) will be used as an access route during construction of the fishway.

- The right dike was stable, well maintained and in sound condition.

- The reservoir perimeter west berm and dikes 1 and 2 were not observed during this inspection.

5.2 Hunt's Mill Dam

- The low hazard potential dam observed with the spillway discharging flow over the crest appeared in good alignment and stable. The left spillway abutment was densely overgrown and not inspected.

- The 3 to 4-foot diameter steel/concrete conduit penetrating through the right end of the spillway and connected to the concrete chamber downstream was significantly deteriorated exposing steel reinforcing in its concrete section. The conduit was not visible on the pond side through a shallow depth of water. The pipe leakage at the chamber outlet was minimal. The chamber concrete was in poor to fair condition.

- The steel sheet pile/concrete wall plugging an entrance to the abandoned headrace from the pond was stable and in fair condition. The wall was moderately leaking at the downstream corner with the left headrace wall. The open headrace flume walls, overlaid with concrete, were deteriorated at several areas and appeared stable. The flume floor was covered with debris and vegetated. The underground penstock was inaccessible. The stone masonry pumphouse containing a retired hydro-generating unit was in excellent condition.

- The upstream concrete/masonry wall located along the right shoreline of the pond and adjacent to the headrace entrance was deteriorated significantly. The wall is not a critical project structure, however, failure of the wall could result in the bank erosion and undermining of the City's park security fence.

- The site is scheduled for installation of a fish passage at the right dam abutment. According to available drawings (Reference 12), the construction will involve removal of the concrete conduit and chamber, and lowering of the headrace entrance closure wall.

- The dam is not equipped with a low level outlet for maintenance or repairs. The City may consider installation of outlet works at the location of the abandoned conduit or headrace closure wall during construction of fish passage.

5.3 Omega Pond Dam

- The low hazard potential dam, observed with a 1 to 2-inch deep flow over the spillway, appeared well aligned and conformed to the original plans.

- Based on the observed flow pattern, the spillway crest, downstream face, and apron had not experienced significant deterioration due to the continuous impact of the flowing water.

- The spillway abutment walls made of granite ashlar stone were intact and stable with some masonry joints open due to missing mortar.

- The earthen railway embankments abutting the dam were stable and watertight. The dam abutments were overgrown with dense vegetation impeding the inspection. The concrete corewalls extending from the dam into the embankments, as indicated on the original drawings, were not found.

- The dam is scheduled for installation of fish passage facilities at the left end of the spillway. The fishway will occupy about 31 feet of the spillway length (Reference 17) which will likely reduce the hydraulic capacity of the spillway.

- The project does not have a low level outlet to draw the pond level down for maintenance and repair of the dam. The City may consider installation of a new outlet works at the dam during construction of the fish passage facility.

6.0 RECOMMENDATIONS

There are no major safety or maintenance/operation concerns with the inspected dams requiring immediate attention or implementation of remedial measures. The following recommendations are proposed to verify the inspection findings, and improve a long-term reliability, operational readiness, and safety of the City's dams. Implementation of the proposed recommendations will also aid the City to comply with the FERC safety regulations if the dam sites are otherwise feasible for development of hydroelectric power.

6.1 Turner Reservoir Dam

1. Conduct, under direction of a professional engineer, a visual inspection and survey of the dewatered dam construction area prior to and during installation of the fish passage. Perform an underwater and/or bathymetric survey of the remaining submerged areas at the toe of the spillway and outlet works during a low flow period. Based on the above-water and underwater inspection findings, develop remedial measures for the dam, as necessary.

2. Repair the areas of the left and right concrete retaining walls with surface concrete deterioration.

3. Repair the inaccessible manholes of the left embankment and evaluate the internal condition of drains and drainage blanket. Protect the manholes from traffic during construction of the fish passage.

4. Monitor water level and flow in the left embankment manholes quarterly coupled with recording the reservoir level to ensure proper function and identify changes in flow rates and/or water clarity.

5. Monitor the seepage flow at the foundation drain outlet in the left retaining wall quarterly for change in condition combined with recording the reservoir level to ensure proper function and identify changes in flow rates and/or water clarity.

6. Replace riprap in the areas of the upstream slope of the left embankment and right dike with displaced or missing riprap.

7. Cut and remove vegetation from the toe of the left embankment and downstream areas of the left and right retaining walls and inspect the cleared areas of the structures. Include vegetation control at the dam into a project maintenance plan.

8. Inspect the west berm and dikes 1 and 2 located in the reservoir perimeter and assess their condition.

6.2 Hunt's Mill Dam

1. Conduct a visual inspection and survey of the dewatered dam construction area prior to and during installation of a proposed fish passage. Perform an underwater and/or bathymetric survey of the remaining submerged areas of the of the spillway during a low flow period. Based on the above-water and underwater inspection findings, develop remedial measures for the dam, as necessary.

2. Repair the leaking area of the closure wall at the headrace entrance.

3. Repair deteriorated concrete on the interior surfaces of the open flume headrace walls.

4. Repair the deteriorated upstream concrete/masonry wall located along the right shoreline of the pond and adjacent to the headrace entrance.

5. Inspect the abandoned underground steel penstock of the headrace and evaluate condition.

6. Cut and remove trees and brush from the left spillway abutment. Inspect the cleared area and evaluate condition.

6.3 Omega Pond Dam

1. Conduct a visual inspection and survey of the dewatered dam construction area prior to and during installation of a proposed fish passage. Perform an underwater and/or bathymetric survey of the remaining submerged areas of the spillway and apron during a low flow period. Based on the above-water and underwater inspection findings, develop remedial measures for the dam, as necessary.

2. Repoint open joints in the masonry work of the right and left abutment retaining walls of the dam.

3. Cut and remove brush and trees from the upstream areas at the left and right abutment retaining walls. Inspect the cleared abutment areas and assess condition.

7.0 OPINION OF CONSTRUCTION COST OF REMEDIAL MEASURES

An opinion of remedial cost for each dam was developed based on the available project data, inspection findings, recommendations, and our experience with similar repair projects. The remedial measures considered include items which are related directly to dam safety. Operation and maintenance (O&M) items, such as brush and tree removal, masonry repointing, grass mowing, riprap replacement, or repair of deteriorated concrete surfaces were considered to be O&M items and were not included in the cost estimate.

7.1 Turner Reservoir Dam

• Inspect by a professional engineer the dewatered areas of the dam prior to and during construction of the fish passage.	$5K-$10K
• Conduct the underwater/bathymetric survey of the submerged areas of the spillway and outlet works.	$5K-$10K
• Repair the inaccessible manholes of the left embankment.	$10K-$15K
Total	$20K-$30K

7.2 Hunt's Mill Dam

• Conduct the underwater/bathymetric survey of the submerged areas of the spillway.	$5K-$10K
• Repair the leaking headrace entrance closure wall.	$5K-$10K
• Repair the deteriorated upstream concrete/masonry wall.	$10K-$20K
Total	$20K-$40K

7.3 Omega Pond Dam

• Conduct the underwater/bathymetric survey of the submerged areas of the spillway and spillway apron.	$5K-$10K
Total	$5K-$10K

8.0 COMPARISON OF RIDEM AND FERC DAM SAFETY REGULATIONS

A brief comparison was made between the RIDEM and FERC dam safety regulations based on RIDEM *Rules and Regulations for Dam Safety* (December 2007) and FERC *Engineering Guidelines for Evaluation of Hydropower Projects* (2003) and *Operating Manual for Inspection of Projects and Supervision of Licenses for Water Power Projects*.

Hazard Classification. Both agencies use high, significant, and low hazard potential classification for dams based on the guidelines developed by the USACE for the National Program for the Inspection of Non-Federal Dams in 1976 and FEMA in 1998. The dam hazard potential rating in the State is established based on dam size (small, intermediate, high) and evaluation of downstream population and major infrastructure at risk.

The FERC approach to dam hazard is based on hydrologic analysis of the watershed and incremental impact of downstream flooding with no-failure and failure of the dam.

Spillway Design Flood (SDF). There are apparently no State regulations for the SDF to be used for different dam hazard ratings. The states usually accept the USACE criteria for selection of the SDF based on a hazard potential classification and dam size. With the existing dam size and hazard rating, the SDF for the Turner Dam is the PMF and is the 50 to 100-year flood for the Hunt's Mill and Omega dams.

FERC requires that the inflow design flood (IDF) for dams with significant or high hazard category (Turner Dam) to be determined. The IDF for the project is defined as the flood when combined with a dam failure will cause no significant incremental impact to downstream areas. The IDF could be equal to the full PMF or a fraction of the PMF. There are no FERC hydrologic/hydraulic requirements for low hazard dams (Hunt's Mill and Omega dams).

Stability Analysis. There are no State regulations for stability of dams.

FERC requires that dams with high and significant hazard potential classification be analyzed for stability. For the Turner Dam, major water retaining structures such as a spillway, outlet works, left embankment, and right dike, should evaluated for stability. No stability analysis would be for required by FERC for Hunt's Mill and Omega dams.

Emergency Action Plan (EAP). The State has apparently no EAP regulations.

FERC requires that EAP's be developed for dams with high and significant hazard potential rating.

Inspection Frequency. The State requires that high hazard dams to be inspected every 2 years and significant and low hazard dams every 5 years.

FERC mandates that dams with high and significant hazard potential be inspected by a FERC approved independent consultant every 5 years and all dams by a FERC engineer annually.

9.0 REFERENCES

General

1. Federal Emergency Management Agency. *Federal Guidelines for Dam Safety: Hazard Potential Classification Systems for Dams.* October 1998.
2. CE Maguire Inc. *Reconnaissance Study. Turner Reservoir Dam and Hunts Mill Pond Dam. Ten-Mile River. Proposed Small-Scale Hydro Development.* August 1980.
3. US Army Corps of Engineers. *Real Estate Plan, Feasibility Phase. Ten Mile River Ecosystem Restoration, East Providence, RI.* June 2004.

Turner Reservoir Dam

4. National Inventory of Dams. *James V. Turner Reservoir Dam. RI.*
5. US Army Corps of Engineers. *James V. Turner Dam. Phase I Inspection Report.* January 1981.
6. New England Engineering Inc. *James V. Turner Dam. Phase II Investigation.* October 1982.
7. Pare Corporation. *James V. Turner Dam. Phase I Inspection Report.* September 21, 2007.
8. RIDEM. *James V. Turner Reservoir Dam Inspection Report.* October 7, 2004 & December 6, 2007.
9. US Army Corps of Engineers. *Fish Passage Facility at Turner Reservoir Dam. Ten Mile River, East Providence, RI.*
10. US Army Corps of Engineers. *Turner Reservoir-Construction of Fish Passage: responses/clarifications to RIDEM.* September 12, 2008.

Hunt's Mill Dam

11. National Inventory of Dams. *Ten Mile Reservation Dam. RI.*
12. US Army Corps of Engineers. *Fish Passage Facility at Hunt's Mill Dam. Ten Mile River, East Providence, RI.*
13. East Providence. *East Providence Comprehensive Plan Update 2010-2015. Historical and Cultural Element.*
14. Durkee, Brown, Viveiros, Werenfels Architects. *Hunt's Mills Pump/Re-Use Study. Sustainable Technology Education Center.* February 2009.

Omega Pond Dam

15. National Inventory of Dams. *Omega Pond Dam. RI.*
16. O. Perry Sarle Engineer. *Omega Pond Dam.* Design Drawings (3), 1918.
17. US Army Corps of Engineers. *Fish Passage Facility at Omega Pond Dam. Ten Mile River, East Providence, RI.*

Appendix A

Inspection Photographs

Photo 1. Turner Reservoir Dam. Spillway, outlet works, right retaining wall, and right dike from left embankment.

Photo 2. Turner Reservoir Dam. Spillway, left retaining wall, and left embankment from right river bank. Note horizontal crack in left retaining wall (red arrow), stone pile in tailwater (blue arrow), and vegetation at left embankment toe.

Photo 3. Turner Reservoir Dam. Left retaining wall. Note areas with concrete deterioration (red arrows) and pile of stone in tailwater (blue arrow).

Photo 4. Turner Reservoir Dam. Low level outlet gatehouse with two floor gate operators.

Photo 5. Turner Reservoir Dam. Left embankment from spillway.

Photo 6. Turner Reservoir Dam. Stone gabion wall with drain pipe outlet (arrow) at toe of left embankment.

Photo 7. Turner Reservoir Dam. Right dike looking toward gatehouse. Note upstream slope area with missing riprap (arrow).

Photo 8. Hunt's Mill Dam. Spillway from right abutment.

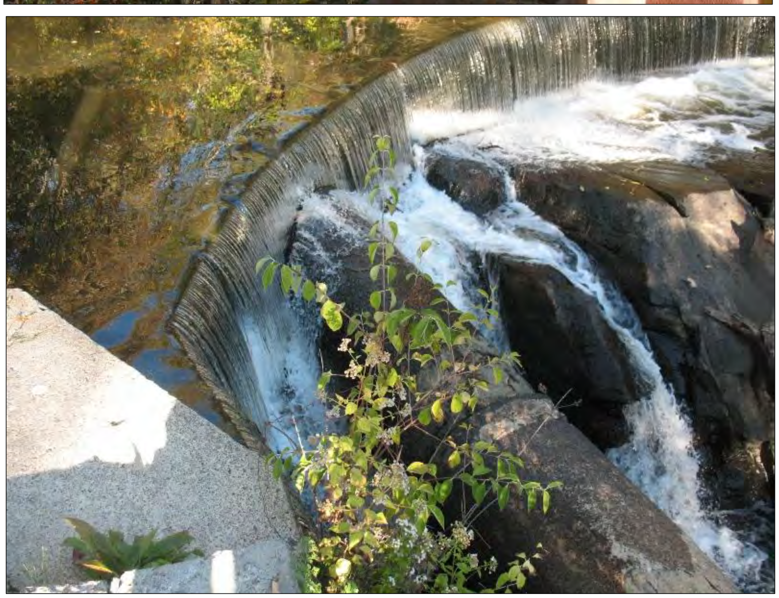


Photo 9. Hunt's Mill Dam. Abandoned power penstock at spillway toe.

Photo 10. Hunt's Mill Dam. Deteriorated concrete section of abandoned penstock (arrow).

Photo 11. Hunt's Mill Dam. Concrete chamber interior with upstream penstock inlet on bottom and waste weir with wooden planks in riverside wall (arrow). Note concrete wall deterioration.

Photo 12. Hunt's Mill Dam. Upstream view of abandoned headrace entrance closure wall (arrow).

Photo 13. Hunt's Mill Dam. Downstream view of abandoned headrace closure wall leaking at left corner (arrow).

Photo 14. Hunt's Mill Dam. Concrete deterioration of riverside headrace open flume wall. Note stone masonry exposed due to missing concrete cover (arrow).

Photo 15. Hunt's Mill Dam. Retaining wall upstream of headrace entrance closure wall.

Photo 16. Hunt's Mill Dam. Deteriorated concrete with exposed reinforcement on top of upstream retaining wall (arrow).

Photo 17. Omega Pond Dam. Spillway and left abutment.

Photo 18. Omega Pond Dam. Deteriorated concrete on top of left masonry abutment.

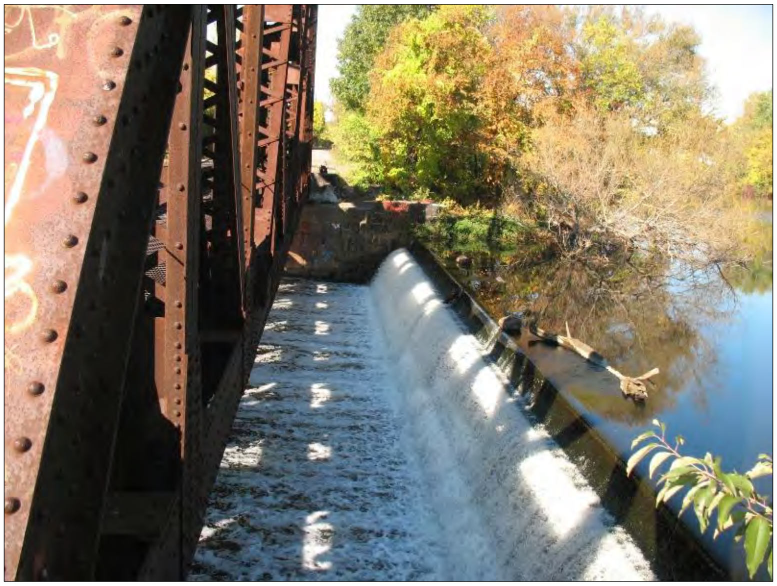


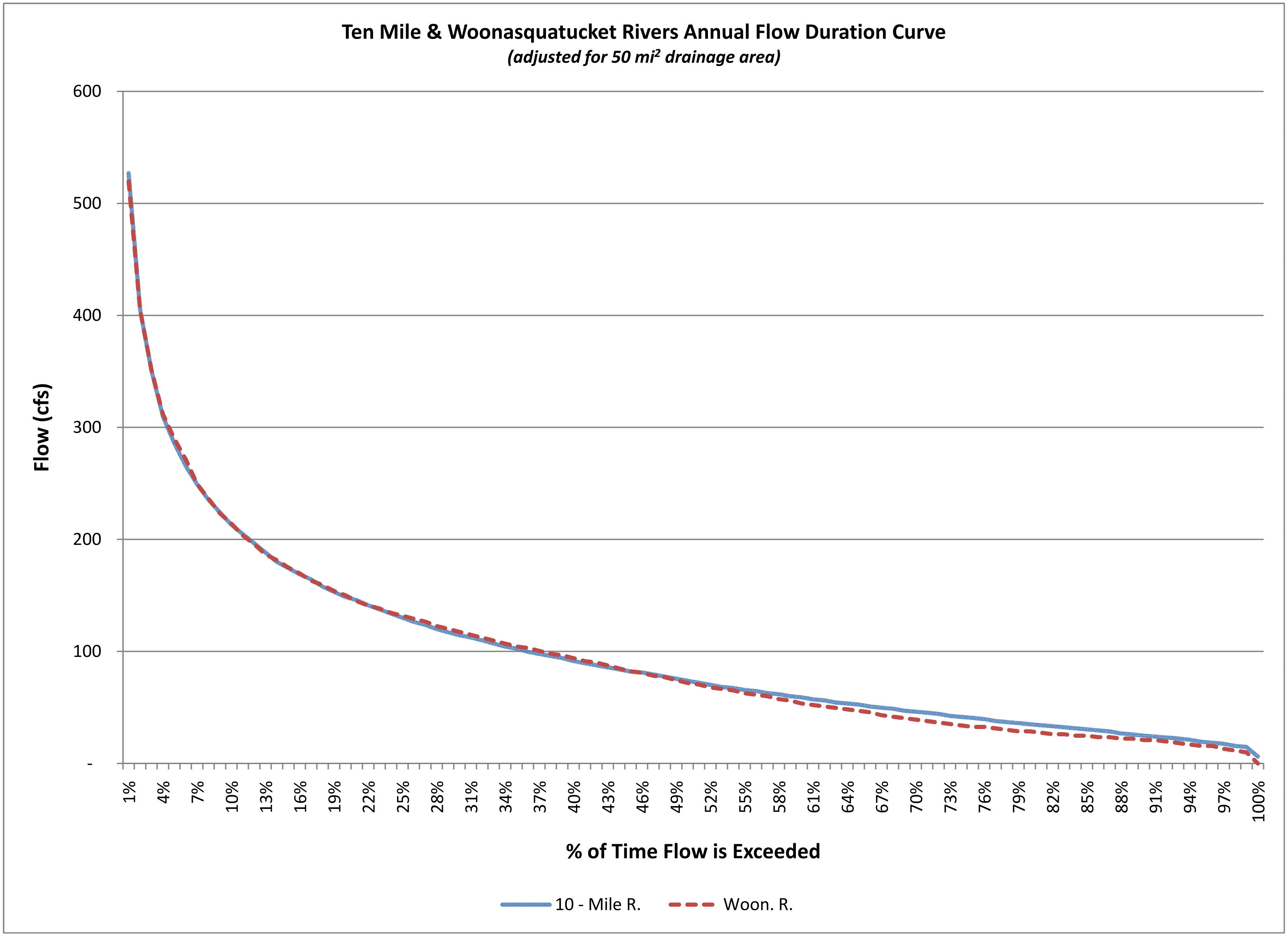
Photo 19. Omega Pond Dam.
Spillway and right abutment.

Photo 20. Omega Pond Dam.
Top of right dam masonry abutment from railway bridge.

Photo 21. Omega Pond Dam.
Right dam abutment from left abutment wall. Note open masonry joints , missing stone step at bottom (arrow) and vegetation.

APPENDIX B

Hydrologic and Hydraulic Data


Ten Mile & Woonasquatucket Rivers Annual Flow Duration Curve
(adjusted for 50 mi² drainage area)
Flow (cfs)
600
500
400
300
200
100
-
1%
4%
7%
10%
13%
16%
19%
22%
25%
28%
31%
34%
37%
40%
43%
46%
49%
52%
55%
58%
61%
64%
67%
70%
73%
76%
79%
82%
85%
88%
91%
94%
97%
100%
% of Time Flow is Exceeded
10 - Mile R.
Woon. R.

ID	Site	BM	BM Notes	HW	TW	Gross Head (rounded)	D.A. (SqMi)	Notes
A	Turners Reservoir Dam	52.6	1,4	47.6	33.1	14.5	48	Pond was drawndown for fishpassage construction (10/13/10), HW assumes pond elev. @ spillway crest.
B	Turner - Hunt's Mill	see notes	1,4	47.6	25.6	22.0	48	Alt. develops head between 2 sites. Creates ~2.3k' bypass reach. Assumes new unit at Hunt's spillway.
C	Turner - Hunt's Mill 2	see notes	3,4	47.6	10.6	38.0	48	Alt. develops head between 2 sites. Creates ~3.5 k' bypass reach. Repowers existing unit and restores 66" penstock and tailrace.
D	Hunt's Mill Dam	38.0	1,4	34.0	25.6	8.5	49	Assumes discharge to upper pool area d/s of spillway to minmize instream flow concerns.
E	Hunt's Mill Dam 2	38.0	1,3,4	34.0	10.6	23.5	49	Assumes: intake at Hunt's Mill spillway, restore existing turbine & tailrace. Creates ~ 1.2k' bypass.
F	Omega Pond Dam	14.8	1,2,4	10.1	1.9	8.0	50	Tailwater is tidally influenced (see notes below). GH range; crest elevation (9.9' NAVD 88) +/- 1/2 tidal range (2.085')= 7.8-12'

BM Note References:

1. Elevation control from ACOE fishway plans (NAVD 88)
2. TW is tidally influenced:

a. Tidal range from NOAA Tidal Observation Station @ Providence (Sta. # 8454000) due to consistency in vertical datum w/ fishpassage plans.
http://tidesandcurrents.noaa.gov/data_menu.shtml?stn=8454000 Providence, RI&type=Historic+Tide+Data

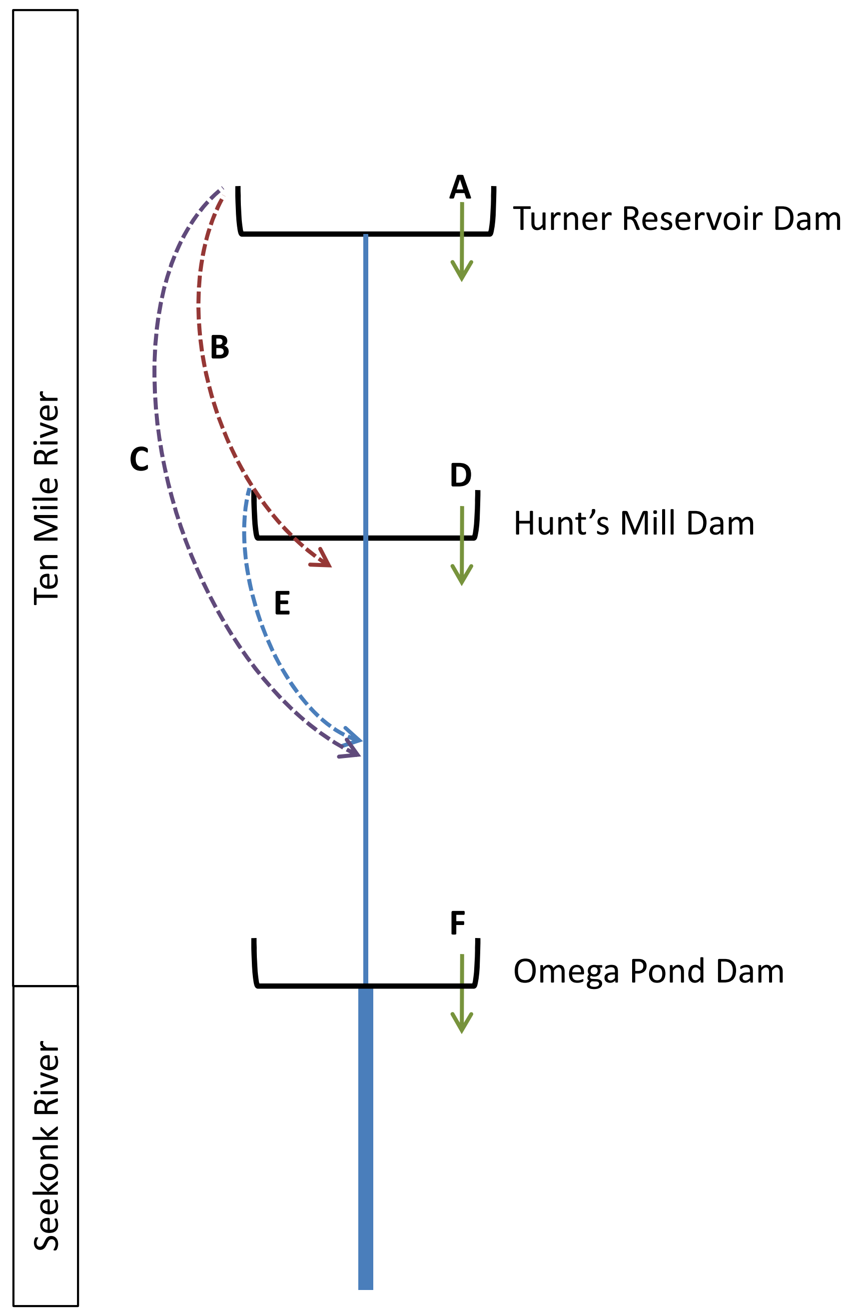
b. Mean tidal range @ station is 4.17'.

c. TW elev. recorded corresponds to -1.77 (NAVD 88) @ 15:00 on 10/13/10

3. Hunt's Mill Tailrace TW elevations derived from FIS floodprofile; expressed in NGVD 29. Approximate NGVD 29 tailrace elevation of 12' converted to NAVD 88. To determine conversion factor - NGVD 29 elevation of Turner Spillway = 49', NAVD 88 elevation of Turner Spillway = 47.6; conversion of NGVD to NAVD by subtracting difference [1.4'] from the NGVD elevation. Calculated tailrace elevation at Hunt's Mill is approximately 10' NAVD 88 (NGVD 29 elevation of 12 - 1.4 = 10.6' NAVD 88).
4. Several inconsistencies in available information were noted during site hydraulic analysis. For example, Corps noted tailwater elevations at Turner Reservoir below headwater elevations at Hunt's Mill located downstream. To compensate for these inconsistencies FEMA FIS floodprofiles were used to estimate the available gross head at options which developed head between Turner and Hunt's Mill. These data were provided in NGVD 29 and were subject to the conversion factor described above to maintain consistent vertical control datums.

APPENDIX C

Preliminary Project Configurations


Ten Mile River
Seekonk River
A
Turner Reservoir Dam
B
C
D
Hunt's Mill Dam
E
F
Omega Pond Dam

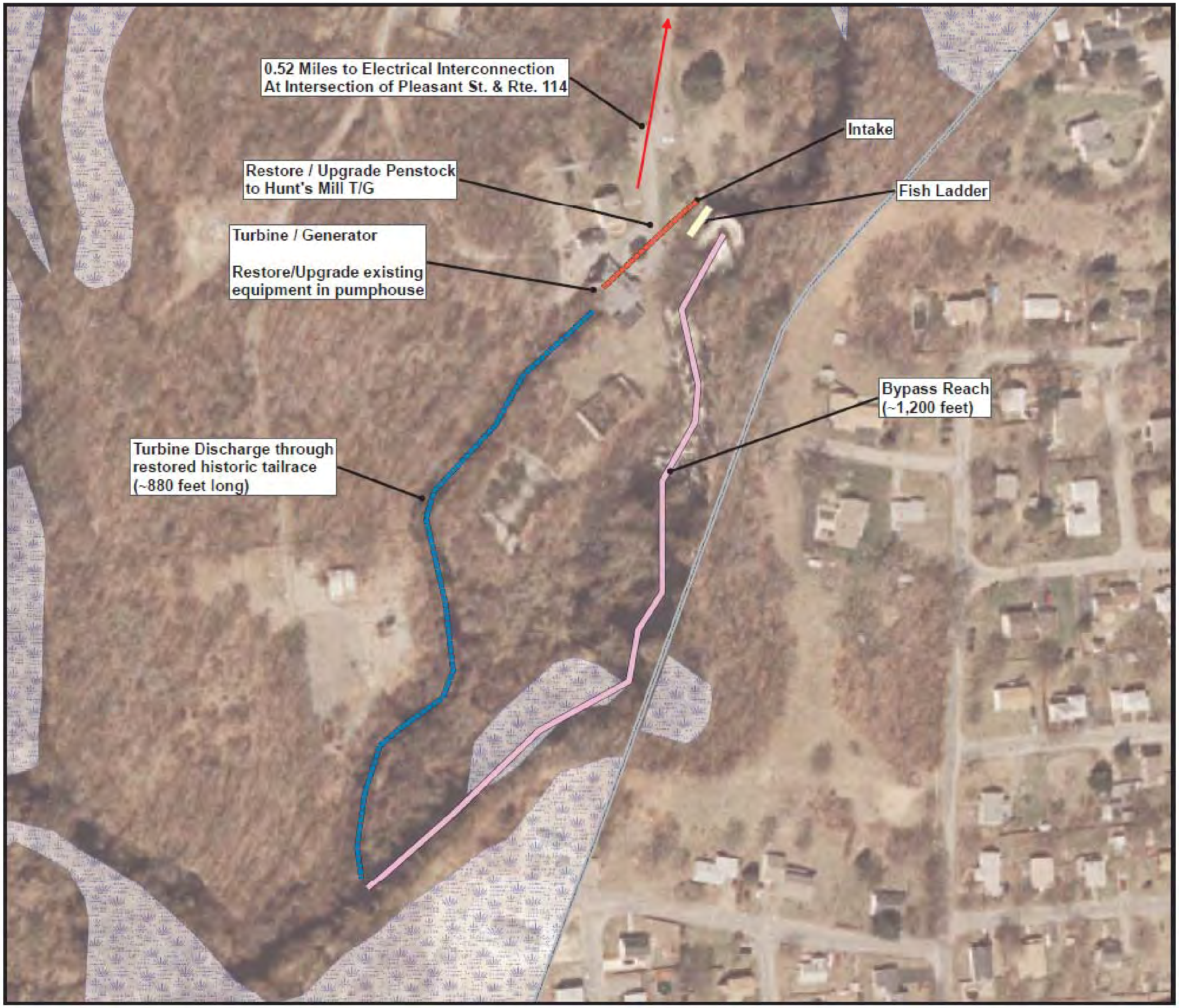
A Turner's Reservoir Dam

B Turner – Hunt's Mill

C Turner – Hunt’s Mill 2

D **Hunt's Mill Dam**

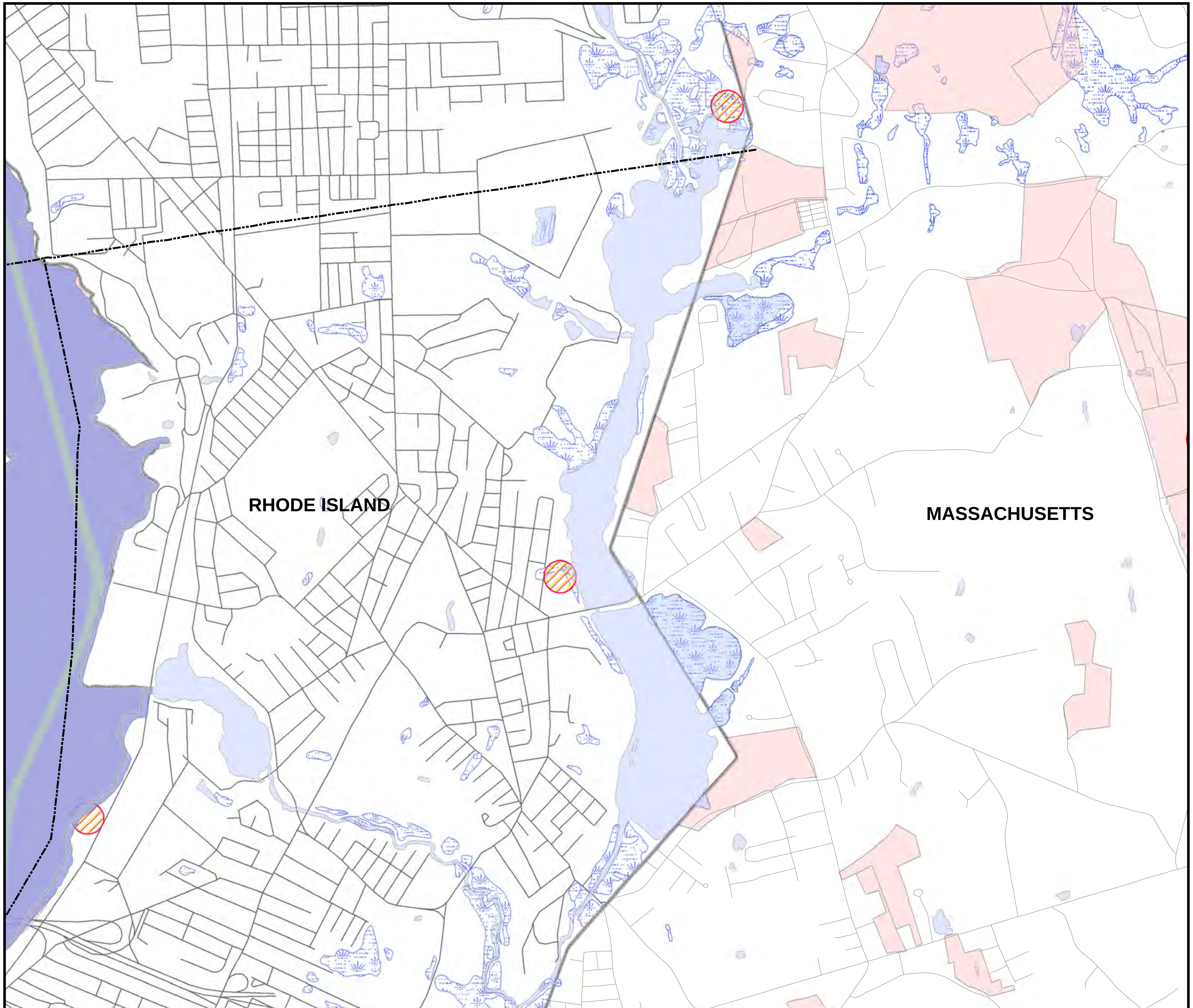
D Hunt's Mill 2

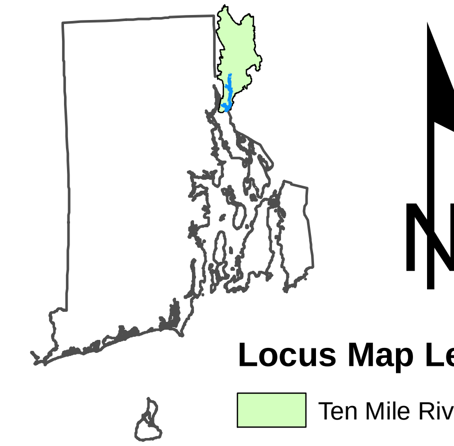


E **Omega Pond Dam**

APPENDIX D

Natural Resource Mapping





Locus Map Legend

- Ten Mile River Watershed

Digital Reference Layers Reviewed:

Rhode Island:
RINHESP Rare Species Occurrences
RIDEM Wetlands
CRMC Water Types & Wetland Resources
FEMA 100-yr Floodplain

Massachusetts:
BioCore Mapping (June 2010)
MassGIS Protected and Recreational Open Space
NHESP Natural Communities
NHESP Estimated Habitats of Rare Wildlife
NHESP Priority Habitats of Rare Species
MADEP Wetlands (Ten Mile River)
Outstanding Resource Waters
Areas of Critical Environmental Concern (ACEC)

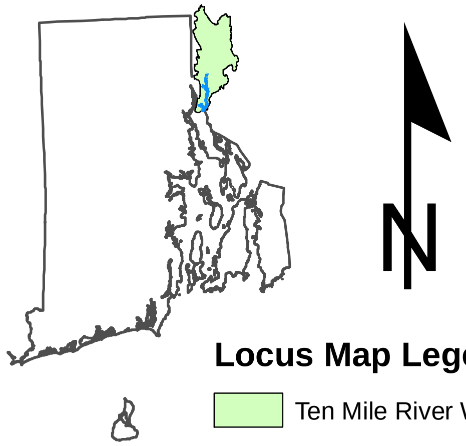
Legend

- NHESP Estimated Habitats of Rare Wildlife
- OpenSpace: Lands
- NHESP Natural Communities
- NHESP Estimated Habitats of Rare Wildlife
- Wetland Resources (MADEP & RIDEM)
- NHESP Priority Habitats of Rare Species
- Area of Critical Environmental Concern (MA)
- RINHESP Rare Species Occurrences

Ten Mile River
Hydropower Feasibility Study

Natural Resources Inventory

0 550 1,100 2,200 3,300 4,400
Feet



Locus Map Legend

Ten Mile River Watershed

Digital Reference Layers Reviewed:

Rhode Island:
RINHESP Rare Species Occurrences
RIDEM Wetlands
CRMC Water Types & Wetland Resources
FEMA 100-yr Floodplain

Massachusetts:
BioCore Mapping (June 2010)
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Outstanding Resource Waters
Areas of Critical Environmental Concern (ACEC)

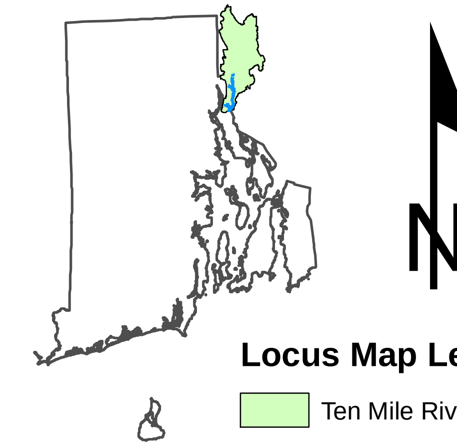
Legend

- NHESP Estimated Habitats of Rare Wildlife
- OpenSpace: Lands
- NHESP Natural Communities
- NHESP Estimated Habitats of Rare Wildlife
- Wetland Resources (MADEP & RIDEM)
- NHESP Priority Habitats of Rare Species
- Area of Critical Environmental Concern (MA)
- RINHESP Rare Species Occurrences

Ten Mile River Hydropower Feasibility Study

Natural Resources Inventory

0 195 390 780 1,170 1,560
Feet



Locus Map Legend

Ten Mile River Watershed

Digital Reference Layers Reviewed:

Rhode Island:
RINHESP Rare Species Occurrences
RIDEM Wetlands
CRMC Water Types & Wetland Resources
FEMA 100-yr Floodplain

Massachusetts:
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NHESP Priority Habitats of Rare Species
MADEP Wetlands (Ten Mile River)
Outstanding Resource Waters
Areas of Critical Environmental Concern (ACEC)

Legend

- NHESP Estimated Habitats of Rare Wildlife
- OpenSpace: Lands
- NHESP Natural Communities
- NHESP Estimated Habitats of Rare Wildlife
- Wetland Resources (MADEP & RIDEM)
- NHESP Priority Habitats of Rare Species
- Area of Critical Environmental Concern (MA)
- RINHESP Rare Species Occurrences

Ten Mile River
Hydropower Feasibility Study

Natural Resources Inventory

0 160 320 640 960 1,280
Feet

RIDEM WATER QUALITY & FISHERIES DATA

TURNER RESERVOIR-OMEGA POND- 2007 CONTINUOUS DISSOLVED OXYGEN MEASUREMENTS

Continuous measurements of dissolved oxygen, temperature, depth, specific conductance, and chlorophyll were collected in Central Pond and the Turner Reservoir from July 30 through Nov 7, 2007. These data were collected using YSI 6-series sondes, deployed at ‘surface’ and ‘depth’ locations in Turner Reservoir and a single ‘surface’ station in Central Pond. Deployments occurred in what was estimated to be the deepest part of each impoundment.

The approximate locations of both sondes are shown in Figure 1. In Turner Reservoir, a ‘surface’ sonde was deployed approximately 0.6-0.9 meters below the surface and a ‘depth’ sonde was deployed approximately 0.9 meters off the bottom. In Central Pond, the single ‘surface’ sonde was located approximately 0.6-0.9 meters below the surface. Total water column depths were approximately 3.5-4.0 meters in the Turner Reservoir and 1.8 meters in Central Pond.

Sondes were secured at fixed vertical depths to nylon marine line which in turn was attached to a 20 lb-anchor. Buoy systems were used to maintain the sondes in a vertical position for the duration of deployment. Sondes were changed every two to three weeks. Independent measurements of the measured parameters were made with an YSI-85 handheld monitor. Chlorophyll samples were collected at the time the sondes were changed and were analyzed by the URI Watershed Watch Laboratory in Kingston, RI.

Figure 1. Approximate Location of 2007 Sonde Deployments.

All data underwent QA-QC by URI GSO staff in 2007. The data collected was found to be of good quality with the exception that sensor/sonde failure produced periods of missing data as listed below:

Central Pond- 9/10/2007-11/07/2007
Turner Reservoir (surface) - 9/10/2007-10/23/2007
Turner Reservoir (depth) – 8/16/2007-10/23/2007

The station results were provided by GSO staff based upon the available data and are as follows using Rhode Island's freshwater warm water fish habitat criteria for dissolved oxygen (Table 1. 8.D: http://www.dem.ri.gov/pubs/regs/regs/water/h20q09.pdf)

Central Pond- **no** violations

Lower Turner Reservoir (surface water station)-
4 violations to the daily average (<60% saturation)
95 violations of the instantaneous values (<5 mg/L) using hourly data

Lower Turner Reservoir (bottom water column station)-
2 violations of the 7 day mean (<6 mg/L for a 7 day period)
8 violations of the daily average (<60% saturation)
217 violations of the instantaneous values (<5 mg/L) using hourly data

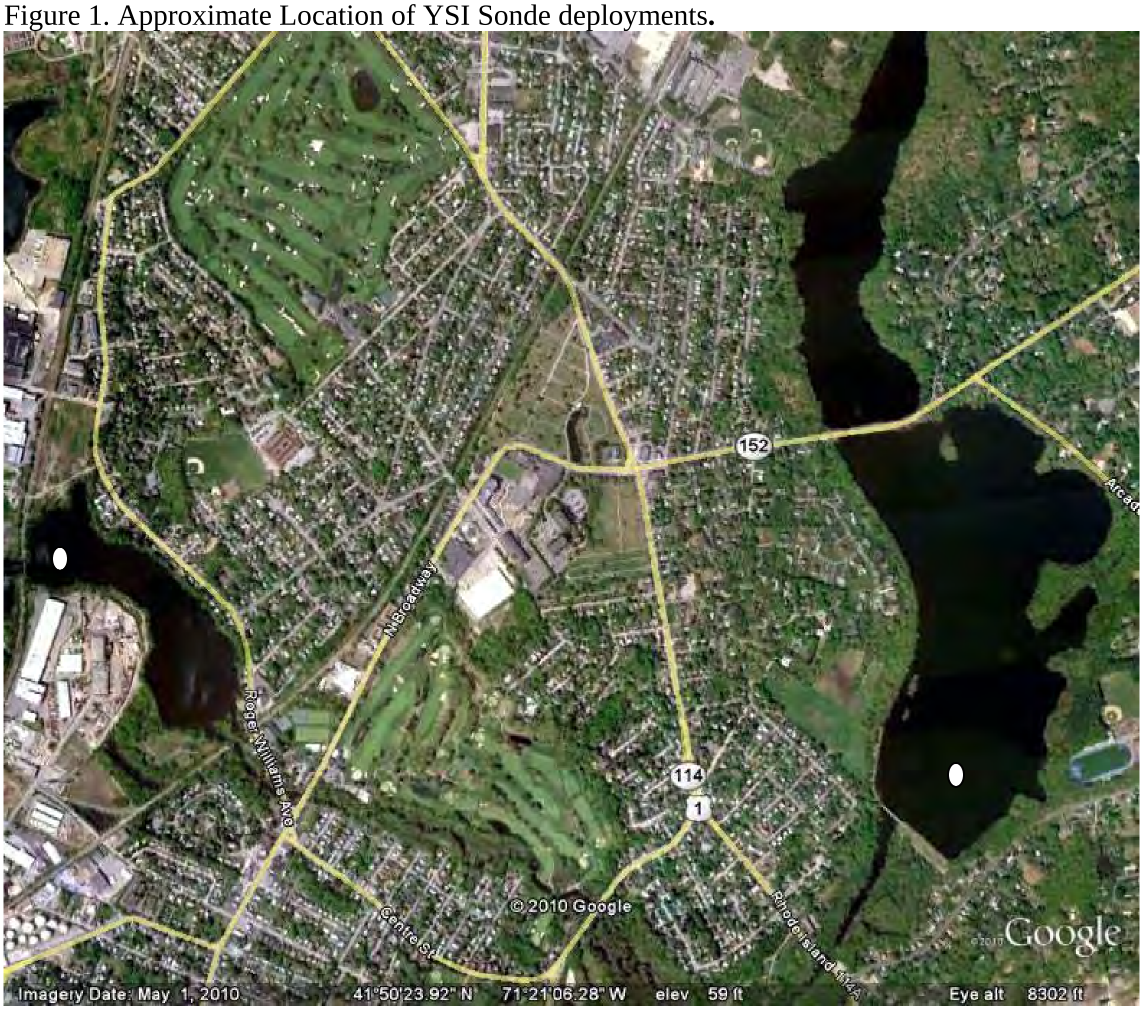
During the monitoring period a widespread cyanobacteria bloom affected both Central Pond and Turner Reservoir. The bloom appeared in early July and lasted until mid-November. Photographs are provided below. The first image is of Central Pond, the second is of Turner Reservoir. Given the conditions during the survey (see below), hypoxic bottom waters and wide diel swings in surface saturation would not be unexpected and are seen in the data.

TURNER RESERVOIR-OMEGA POND- 2009 CONTINUOUS DISSOLVED OXYGEN MEASUREMENTS
Continuous measurements of dissolved oxygen, temperature, depth, specific conductance, and chlorophyll were collected in Turner Reservoir and Omega Pond from June through Sept 2009. These data were collected using YSI 6-series sondes, deployed at ‘surface’ and ‘depth’ locations in the water column in what was estimated to be the deepest part of each impoundment.

The approximate locations of both sondes are shown in Figure 1. At each location, a ‘surface’ sonde was deployed approximately 0.6-0.9 meters below the surface and a ‘depth’ sonde was deployed approximately 0.9 meters off the bottom. Total water column depths were approximately 3.5-4.0 meters in the Turner Reservoir and 3.5 meters in Omega Pond.

Sondes were secured at fixed vertical depths to nylon marine line which in turn was attached to a 20 lb-anchor. Buoy systems were used to maintain the sondes in a vertical position for the duration of deployment. Sondes were changed every two to three weeks. Independent measurements of the measured parameters were made with an YSI-85 handheld monitor. Chlorophyll samples were collected for analysis by the URI Watershed Watch Laboratory in Kingston, RI.

Figure 1. Approximate Location of YSI Sonde deployments**.**



The 2009 data have undergone QA-QC by DEM staff and have been flagged and/or edited where necessary. In general, the data reveal occasional hypoxic conditions at the surface and near anoxic conditions in the bottom waters. The hydrogen sulfide released from sulfur fixing bacteria in the sediments is believed to have affected the bottom sensors' accuracy in measuring dissolved oxygen conditions in the Turner Reservoir with measurements indicating more severe hypoxia/anoxia than possibly exist – thus these data have been flagged and edited from the dataset.

Vertical profiling data obtained with a YSI-85 handheld monitor frequently showed weak to moderate thermal stratification accompanied by near-anoxic conditions in the bottom 0.5 to 1.0 meters of both impoundments. Examination of precipitation and discharge data in conjunction with dissolved oxygen levels obtained from YSI 6-series sondes showed that moderate rainfall events and associated increases in flow flushed out the near-anoxic bottom water in both impoundments and mixed the water column such that dissolved oxygen levels became similar at surface and depth. After these types of events, the impoundments again showed thermal stratification and associated decreases in bottom water dissolved oxygen levels. The continuous dissolved oxygen data obtained in 2007 from the Turner Reservoir show similar near-anoxic conditions in the bottom waters of the Turner Reservoir, adding credibility to the 2009 'near-bottom' datasets.

Rhode Island's freshwater warm water fish habitat criteria for dissolved oxygen are given in Table 1. 8.D of the States' Water Quality Regulations:

http://www.dem.ri.gov/pubs/regs/regs/water/h20q09.pdf)

Both Turner Reservoir and Omega Pond are listed on the State's 2010 303(d) List of Impaired Waters for dissolved oxygen, based on the 2007 and 2009 datasets.

Stream Name/Station No.: Ten Mile River/9.b.19
Station Location Road/Town: Hunts Mill Rd.-Pawtucket Ave./ East Providence
Sample Date: 28 Aug 00
Sampling Duration (s): 5704
Station Length(m)/Width(m): 265/14
Land Use/Percent Canopy: Suburban/25
Temperature (°C) Air/H2O: 23/24.2
DO (mg/l): 8.07 *pH:* 8.29 *Conductivity (uS/cm):* 442
Dominate Substrate Types (%):
bedrock (20), boulder (20), cobble (20), gravel (20)

Species	N	Total Length (mm) Mean (Range)
bluegill	100	134 (84-204)
largemouth bass	85	86 (46-425)
white perch	75	174 (152-189)
American eel	65	295 (139-550)
pumpkinseed	34	105 (75-161)
white catfish	15	163 (63-208)
golden shiner	13	140 (96-203)
yellow bullhead	5	145 (103-165)

Pond Name/Station No.: Turner Reservoir/9.b.20
Station Location: East Providence
Sample Date: 23 Apr 01
Sampling Duration (s): 5088
Land Use: Suburban
Temperature (°C) Air/H2O: 13/16.5
DO (mg/l): 13.23 *pH:* 8.30 *Conductivity (uS/cm):* 355
Dominate Substrate Types (%):
Unknown because of high turbidity.

Species	N	Total Length (mm) Mean (Range)
white perch	206	223 (186-255)
bluegill	98	149 (37-213)
pumpkinseed	94	140 (45-193)
yellow perch	43	166 (94-240)
largemouth bass	28	299 (165-462)
black crappie	4	206 (198-211)
white sucker	3	412 (280-497)
white catfish	2	282 (281-282)
yellow bullhead	1	250
goldfish	*	132

* Collected during supplemental sampling.

Pond Name/Station No.: Central Pond/9.b.21
Station Location: East Providence
Sample Date: 25 Apr 01
Sampling Duration (s): 5817
Land Use: Suburban
Temperature (°C) Air/H2O: 10.5/17.5
DO (mg/l): 11.47 *pH:* 7.54 *Conductivity (uS/cm):* 387
Dominate Substrate Types (%):
Unknown because of high turbidity.

Species	*N*	*Total Length (mm) Mean (Range)*
yellow perch	111	193 (112-271)
white perch	96	224 (105-268)
bluegill	60	160 (83-200)
pumpkinseed	25	151 (94-195)
largemouth bass	17	334 (82-562)
yellow bullhead	2	199 (182-215)
brown bullhead	1	270
golden shiner	1	210
white catfish	1	310

Stream Name/Station No.: Ten Mile River/9.b.37
Station Location Road/Town: Slater Memorial Park/Pawtucket
Sample Date: 31 Jul 01
Sampling Duration (s): 6446
Station Length(m)/Width(m): 465/12.4
Land Use/Percent Canopy: Suburban/10
Temperature (°C) Air/H2O: 22/20.5
DO (mg/l): 8.64 *pH:* 6.81 *Conductivity (uS/cm):* 571
Dominate Substrate Types (%):
sand (40), gravel (30)

Species	*N*	*Total Length (mm) Mean (Range)*
white sucker	39	55 (35-75)
largemouth bass	35	91 (42-375)
yellow perch	35	212 (160-253)
yellow bullhead	29	129 (30-232)
bluegill	22	167 (37-202)
pumpkinseed	6	100 (78-143)
tessellated darter	4	54 (47-60)
white perch	3	189 (160-205)
redfin pickerel	2	133 (125-140)

Pond Name/Station No.: Omega Pond/9.b.43
Station Location: East Providence
Sample Date: 17 May 02
Sampling Duration (s): 4213
Land Use: Urban
Temperature (°C) Air/H2O: --/17
DO (mg/l): 9.56 *pH:* 7.19 *Conductivity (uS/cm):* 310
Dominate Substrate Types (%):
Unknown because of high turbidity.

Species	*N*	*Total Length (mm) Mean (Range)*
bluegill	64	156 (43-205)
pumpkinseed	27	132 (90-200)
white perch	22	154 (96-246)
largemouth bass	18	306 (103-490)
yellow perch	16	185 (100-266)
golden shiner	8	172 (92-212)
black crappie	6	221 (190-254)
alewife	5	272 (255-286)
gizzard shad	4	455 (414-477)
white sucker	2	444 (442-445)
American eel	1	320
white catfish	1	310

Initial Agency Coordination

Meeting Notes

27 Vaughan Ave.
Newport, RI 02840
(401) 619 - 4872

MEETING NOTES

Revised 2/28/11

MEETING DATE: February 15, 2011

SUBJECT: Ten Mile River Hydropower Feasibility Study: Preliminary Agency Coordination Meeting

LOCATION: Hunt's Mill and Turner Reservoir Dams (Part I)
East Providence City Hall (Part II)

PARTICIPANTS:

Name	Organization	Contact Info:
Patrick Hanner	East Providence – Sr. Planner / Project Mgr.	phanner@cityofeastprov.com 401-435-7533
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Jonathan Petrillo	EP	jon@essexpartnerhsip.com 203-623-4637

The meeting was held to discuss preliminary results of a hydropower feasibility study at three dams on the Ten Mile River. Discussion focused on the State's instream flow requirements and other potential resource concerns in the context of hydropower development. A summary of the discussions follows. Copy of background materials provided to participants ahead of the meeting are provided as an attachment.

I. **Site Visits –** Meeting participants conducted brief walking tours of the Hunt's Mill and Turner Reservoir dams. EP provided an overview of the hydropower alternatives considered at each site and the anticipated resource protection concerns. PH provided a summary of on-going fish passage restoration efforts at each site as well as a synopsis of the City's longer-term goals for redevelopment of the Hunt's Mill property as a "green technology" education center. The site historically supported hydropower operations – redevelopment of hydropower would complement the City's future re-use plans and provide a modern context for the historic use. River flows during the site visit were approximately 150 cfs representing the 22 % annual exceedance flow.

II. Discussion – A more detailed review of the preliminary FS results and associated resource concerns was conducted at City Hall. Jeanne Boyle (Director of Planning) joined the group at this point. The following sections provide a brief summary of the items discussed – additional background information was provided to participants ahead of the meeting.

a. *Drivers of Hydropower* – EP discussed the relationship between resource protection requirements and associated operating conditions on hydropower feasibility. EP evaluated several alternative project configurations for the Omega Pond, Hunt's Mill and Turner Reservoir dams. The analysis included provisions for providing anticipated resource protection, mitigation and enhancement (PM&E) measures, such as; RI ABF instream flows, fish passage (ladder, attraction, and downstream passage), wetland mitigation, recreation, etc. Since stream flows provide the "fuel" for hydropower generation reductions in the flow available for generation significantly impact the economics of alternatives that would be subject to instream flow requirements (i.e., include bypass reaches).

b. *RI Aquatic Base Flow Methodology (RIABF)* - AR provided an overview of the State's standard instream flow policy, including the formulation of State standards. The RI ABF is intended to provide a starting point for applicants interested in projects with water diversion components. DEM understands that each situation has a unique set of variables; modifications to the RI ABF to accommodate specific resource rand/or project requirements would be entertained. The burden of proof for an alternative instream flow standard falls on the applicant. Applicants have not historically pursued alternative instream flow criteria. Several potential site specific approaches were identified; IFIM, MesoHABsim, low flow connectivity analysis; additional methods would also be considered. EP has used the Demonstration Flow Assessment (DFA) methodology in the past with good results. This method engages the applicant as well as agency personnel in assessing habitat types under various flow conditions and determining appropriate and protective instream flows. DEM does not appear to have a favored analytical methodology for determining site specific requirements.

c. *Additional concerns* – The group discussed other potential concerns with respect to hydropower redevelopment, these concerns are summarized below:

i. *Water Quality* – All water quality pollutants are subject to the State anti-degradation policy. The 10-Mile R is on the State 303(d) list of impaired waters. Particular concerns for the study reach include; Cu, Pb, and benthic macroinvertebrates[1]. In the past, DEM has allowed applicants to develop monitoring and mitigation protocols to address WQ concerns following demonstration of project operations. Although not included on the State's 303(d) list dissolved oxygen levels would also be of concern. Regulatory thresholds for DO are typically tied to existing (baseline) conditions. A development at Hunt's Mill would likely utilize WQ conditions at the inlet to Omega Pond as the point of project reference.

ii. *Fish Passage* – Considering the on-going efforts to restore fish passage to the 10-Mile any hydropower development would need to consider maintaining the effectiveness of fish passage measures. EP included several assumptions for monthly fish passage (attraction, ladder, downstream passage flow, etc.) as part of the analysis. Additional discussion with fish passage partners and stakeholders to review the assumptions and identify concerns is warranted.

    Subsequent to the meeting we learned that there is a possibility that hydropower development at sites where funding assistance for fish passage restoration was received from federal partners could require a refund of federal grant monies. This potential requirement should be explored with RIDEM (Jay McGinn) and other fish passage stakeholders.

iii. *Wetland Impacts* – Alternatives at the Turner Reservoir and Hunt's Mill sites could include impacts to existing wetland resources. Examples include:
    1. Connectivity of the wetland complex downstream of Turner with the stream channel.
    2. Restoration of the historic tailrace at Hunt's Mill would convert an existing scrub-shrub wetland to open water. Implications of this cover type transition would need to be discussed and evaluated in more detail with the DEM-Wetlands division.

iv. *Regulatory Processing* – High level discussion of potential approaches to streamline State permitting process for small (i.e., micro – nano) hydropower projects. Several other States (i.e., Colorado) have MOU's in place with FERC to achieve this end. In the case of Colorado the State performed an initial screening of sites that could be developed with minimal environmental impacts. Hydropower opportunities in Rhode Island are limited – a potential approach for RI would be to provide preliminary terms and conditions early on. EP offered to facilitate a

[1] This listing indicates that sampling results of the benthos did not correlate to the expected results. The details of the incongruity were not discussed.

discussion between DEM and FERC on overall coordination of hydropower licensing and permitting.

APPENDIX E

Economic Analysis

Energy Modeling Results

Results w/ Instream Flows

ID	Site	D.A. (SqMi)	Gross Head (ft)	Hyd.Cap (cfs)	Installed Capacity (kw)	Net Annual Energy (MWH)	Capacity Factor	Runner Dia Meters	Penstk Dia Ft.	Equipment Configuration
A	Turners Reservoir Dam	48	14.5	213	205	715	40%	1.25	5.82	Horz Tube
B	Turner - Hunt's Mill	48	22	114	156	456	33%	0.90	4.26	Horz Tube
C	Turner - Hunt's Mill 2	48	38	114	288	831	33%	0.90	4.26	Vert Kaplan
C-2	Turner - Hunt's Mill 2 (Repowered Franci	48	38	114	282	743	30%	0.92	4.26	Vert Francis
D	Hunt's Mill Dam	53	8.5	213	112	400	40%	1.25	5.82	Horz Tube
E	Hunt's Mill Dam 2	53	23.5	114	184	524	33%	0.90	4.26	Horz Tube
E-2	Hunt's Mill Dam 2 (Repowered Francis)	53	23.5	114	178	464	30%	0.90	4.26	Vert Francis
E-3	Hunt's Mill Dam 2 (Restored Francis)	53	23.5	84	110	335	35%	0.81	3.66	Vert Francis
F	Omega Pond Dam	56	8	213	104	374	40%	1.25	5.82	Horz Tube

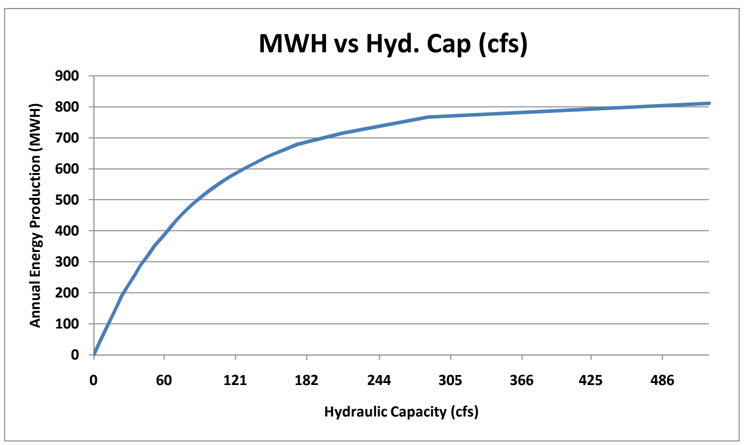
Results w. 1/2 Instream Flows

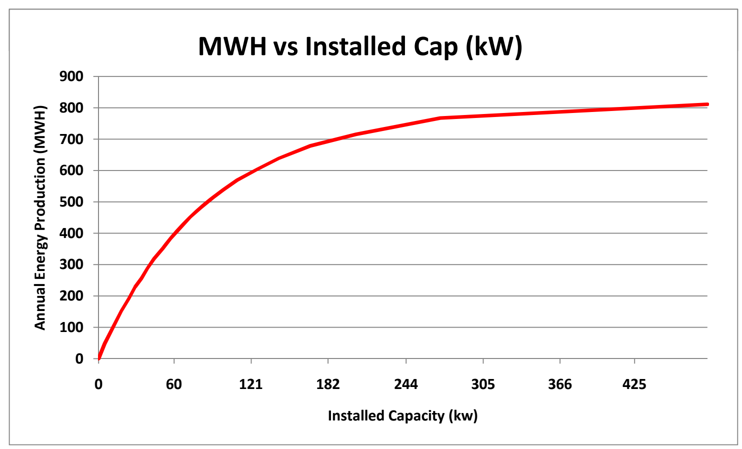
ID	Site	D.A. (SqMi)	Gross Head (ft)	Hyd.Cap (cfs)	Installed Capacity (kw)	Net Annual Energy (MWH)	Capacity Factor	Runner Dia Meters	Penstk Dia Ft.	Equipment Configuration
B	Turner - Hunt's Mill	48	22	130	176	626	41%	0.95	4.55	Horz Tube
C	Turner - Hunt's Mill 2	48	38	130	326	1,137	40%	0.95	4.55	Vert Kaplan
E	Hunt's Mill Dam 2	53	23.5	130	209	717	39%	0.95	4.55	Horz Tube

Results w. No Instream Flows

ID	Site	D.A. (SqMi)	Gross Head (ft)	Hyd.Cap (cfs)	Installed Capacity (kw)	Net Annual Energy (MWH)	Capacity Factor	Runner Dia Meters	Penstk Dia Ft.	Equipment Configuration
B	Turner - Hunt's Mill	48	22	213	288	1,050	42%	1.25	5.82	Horz Tube
C	Turner - Hunt's Mill 2	48	38	213	534	1,889	40%	1.25	5.82	Vert Kaplan
E	Hunt's Mill Dam 2	53	23.5	213	341	1,184	40%	1.25	5.82	Horz Tube
E-2	Hunt's Mill 2 (Repowered Francis)	53	23.5	174	271	815	38%	1.12	5.21	Vert Francis

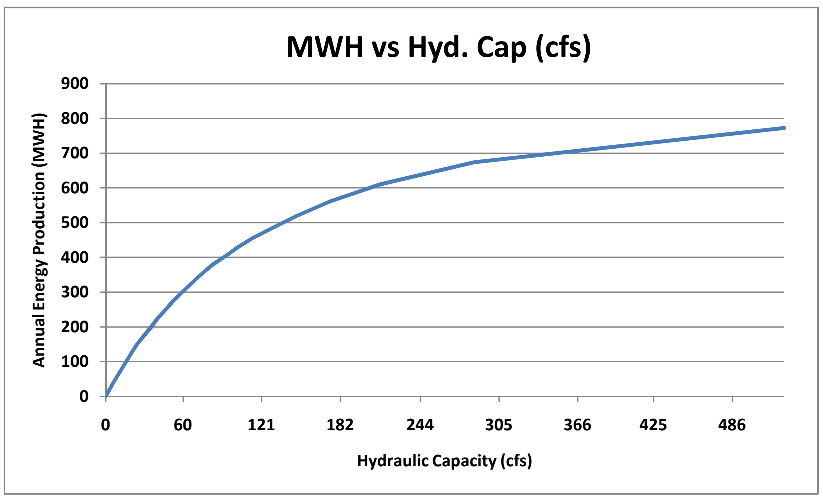
% Exceedance	Max Turbine Flow (CFS)	Net Energy (MWH) Head (FT)											Net Capacity Factor (%)	Alternative A Installed Capacity (kW)	Alternative D Installed Capacity (kW)	Alternative F Installed Capacity (kW)
													Head for Installed capacity (FT)	14.5	8.5	8.0
		5	**6**	**8.0**	**8.5**	**10**	**11**	**12**	**13**	**14**	**14.5**	**16**				
100%	**6**	14	18	25	27	30	34	38	41	45	49	52	93%	**6**	**3**	**3**
95%	**19**	44	55	78	84	95	106	118	129	140	152	163	91%	**19**	**11**	**10**
90%	**25**	55	70	98	105	120	134	148	163	177	191	206	89%	**24**	**14**	**13**
85%	**30**	66	83	117	126	143	160	177	194	211	228	245	87%	**30**	**17**	**15**
80%	**35**	75	94	132	142	161	180	199	218	237	257	276	85%	**34**	**19**	**18**
75%	**41**	84	106	149	160	181	203	224	246	267	289	310	83%	**40**	**22**	**21**
70%	**46**	93	117	165	176	200	224	248	271	295	319	343	81%	**45**	**25**	**23**
65%	**53**	103	129	182	195	221	247	273	300	326	352	378	78%	**51**	**28**	**26**
60%	**59**	112	141	198	212	240	269	297	325	354	382	411	76%	**58**	**32**	**30**
55%	**67**	123	154	217	232	263	294	325	356	387	418	450	73%	**66**	**36**	**34**
50%	**76**	133	167	234	251	284	318	351	385	418	452	485	70%	**74**	**41**	**38**
45%	**84**	143	178	250	268	303	339	375	410	446	482	517	67%	**82**	**45**	**42**
40%	**94**	153	191	267	286	324	362	401	439	477	515	553	64%	**92**	**51**	**47**
35%	**102**	160	200	280	300	340	380	419	459	499	539	579	62%	**99**	**55**	**51**
30%	**114**	170	212	296	317	359	401	443	485	527	569	611	59%	**111**	**61**	**57**
25%	**130**	181	225	314	337	381	426	470	515	559	604	648	55%	**126**	**69**	**65**
20%	**149**	192	239	333	357	404	451	498	545	592	639	686	51%	**143**	**79**	**73**
15%	**174**	204	254	354	379	429	479	529	579	629	679	729	46%	**168**	**92**	**86**
10%	**213**	216	269	374	400	453	505	558	610	663	715	768	40%	**205**	**112**	**104**
5%	**286**	232	288	401	429	485	542	598	654	711	767	823	32%	**271**	**147**	**136**
1%	**527**	243	303	422	452	512	572	632	691	751	811	870	19%	**484**	**254**	**235**

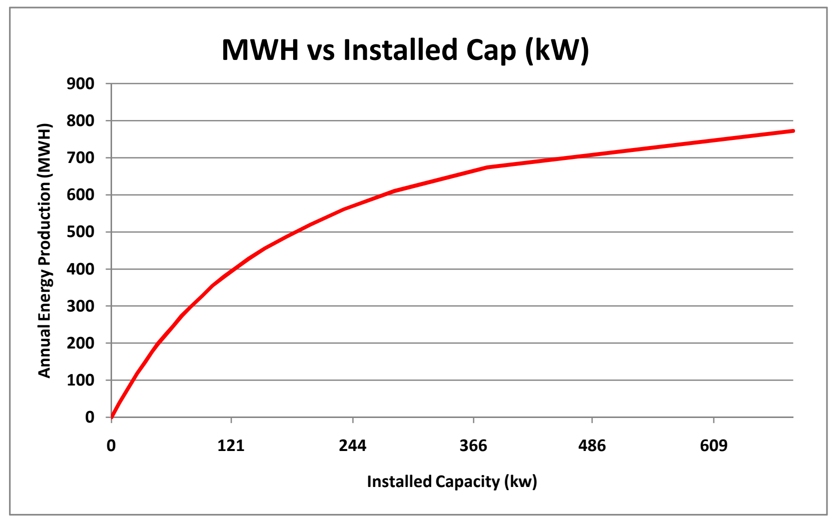




Head for Installed capacity (FT) 22.0

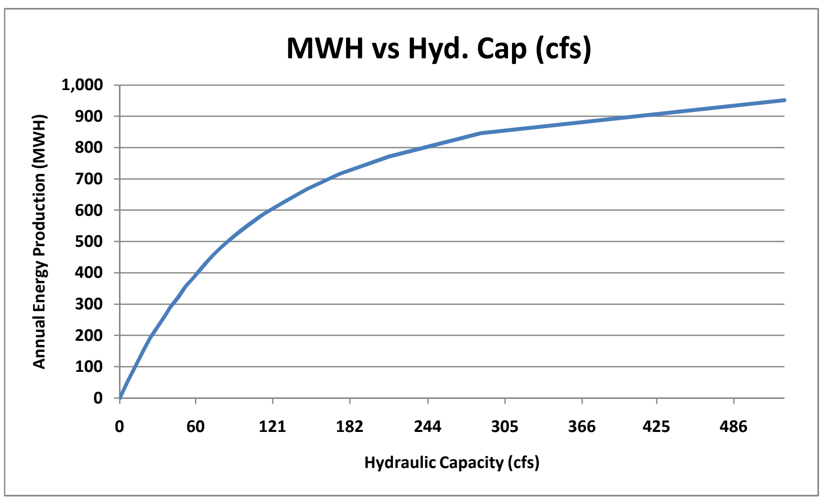
% Exceedance	Max Turbine Flow (CFS)	Net Energy (MWH)											Net Capacity Factor (%)	Installed Capacity (kW)
		Head (FT)												
		22	24	26	28	30	32	34	36.6	38	40	42		
100%	**6**	40	44	48	53	57	61	65	71	74	78	82	55%	8
95%	**19**	118	131	144	156	169	181	194	210	219	231	244	51%	27
90%	**25**	148	164	180	195	211	227	242	263	274	289	305	50%	34
85%	**30**	176	195	213	232	251	269	288	312	325	343	362	48%	42
80%	**35**	198	219	240	261	282	303	324	351	365	386	407	47%	48
75%	**41**	224	247	271	294	318	341	365	395	412	435	459	46%	55
70%	**46**	247	273	299	325	351	377	403	437	455	481	507	45%	63
65%	**53**	274	302	331	360	388	417	446	483	503	532	560	44%	72
60%	**59**	298	329	360	391	422	454	485	525	547	578	609	42%	81
55%	**67**	328	362	396	430	464	498	532	577	601	635	669	40%	93
50%	**76**	355	391	428	465	502	539	576	623	649	686	723	39%	103
45%	**84**	380	419	458	498	537	576	616	667	694	734	773	38%	114
40%	**94**	407	449	491	533	575	617	659	714	743	785	828	36%	128
35%	**102**	428	472	517	561	605	649	693	751	782	826	870	35%	139
30%	**114**	456	503	549	596	643	690	737	798	831	878	925	33%	156
25%	**130**	486	536	586	636	686	735	785	850	885	935	985	31%	176
20%	**149**	520	573	626	679	732	786	839	908	945	998	1,052	29%	201
15%	**174**	561	618	675	733	790	847	905	979	1,019	1,076	1,134	27%	235
10%	**213**	611	673	735	797	859	922	984	1,065	1,108	1,170	1,233	24%	287
5%	**286**	674	743	811	879	947	1,016	1,084	1,173	1,221	1,289	1,357	20%	380
1%	**527**	772	850	928	1,006	1,083	1,161	1,239	1,340	1,394	1,472	1,550	13%	689

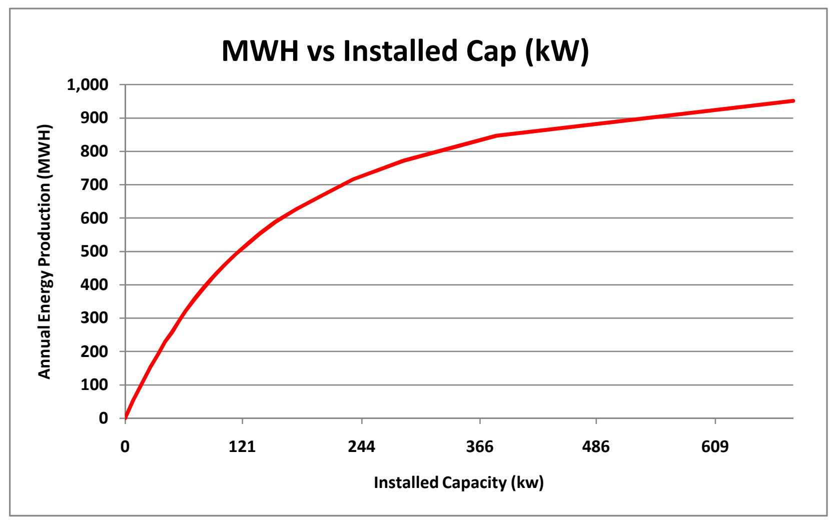




Head for Installed capacity (FT) 22.0

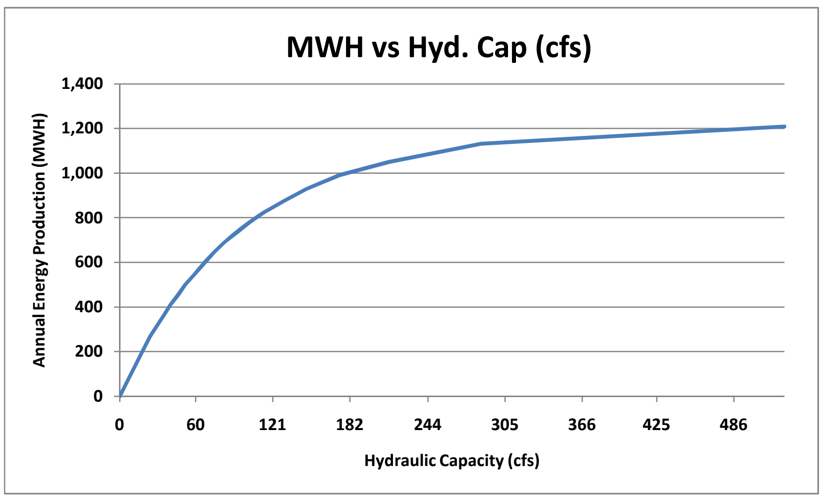
% Exceedance	Max Turbine Flow (CFS)	Net Energy (MWH) Head (FT) 22	24	26	28	30	32	34	36.6	38	40	42	Net Capacity Factor (%)	Installed Capacity (kW)
100%	**6**	52	57	63	68	74	79	85	92	96	101	107	71%	8
95%	**19**	154	170	187	203	219	235	252	273	284	300	317	66%	27
90%	**25**	192	213	233	253	274	294	314	340	355	375	395	64%	34
85%	**30**	229	253	277	301	325	349	373	405	421	445	470	63%	42
80%	**35**	258	285	312	339	366	393	420	456	475	502	529	61%	48
75%	**41**	291	321	352	382	412	443	473	513	534	565	595	60%	55
70%	**46**	321	355	388	422	455	489	523	566	590	623	657	58%	63
65%	**53**	355	392	430	467	504	541	578	626	652	689	726	56%	72
60%	**59**	388	428	469	509	549	590	630	683	711	752	792	55%	81
55%	**67**	426	470	515	559	603	647	692	749	780	825	869	53%	92
50%	**76**	461	509	557	604	652	700	748	810	843	891	939	51%	104
45%	**84**	492	543	594	645	696	747	798	864	899	950	1,001	49%	114
40%	**94**	528	582	637	691	745	800	854	925	963	1,017	1,072	47%	129
35%	**102**	554	611	668	725	782	839	896	970	1,010	1,067	1,124	45%	139
30%	**114**	589	649	709	770	830	890	951	1,029	1,071	1,132	1,192	43%	156
25%	**130**	626	690	754	818	882	946	1,010	1,093	1,137	1,201	1,265	41%	176
20%	**149**	667	734	802	870	938	1,006	1,074	1,162	1,209	1,277	1,345	38%	202
15%	**174**	716	789	861	934	1,006	1,079	1,151	1,246	1,297	1,369	1,442	35%	235
10%	**213**	772	850	928	1,006	1,083	1,161	1,239	1,341	1,395	1,473	1,551	31%	288
5%	**286**	846	932	1,017	1,102	1,187	1,272	1,357	1,468	1,527	1,612	1,697	25%	383
1%	**527**	951	1,046	1,141	1,235	1,330	1,425	1,520	1,643	1,709	1,804	1,899	16%	689

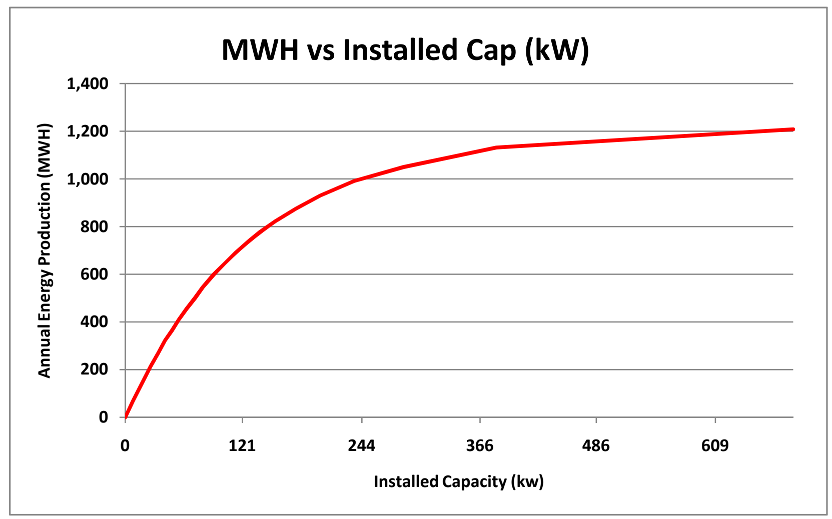




Head for Installed capacity (FT) 22.0

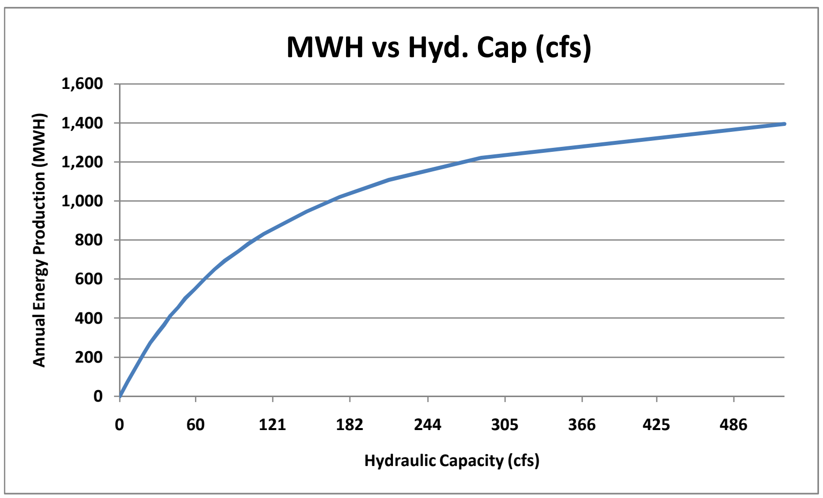
% Exceedance	Max Turbine Flow (CFS)	Net Energy (MWH) Head (FT) 22	24	26	28	30	32	34	36.6	38	40	42	Net Capacity Factor (%)	Installed Capacity (kW)
100%	**6**	68	75	83	90	97	104	112	121	126	133	140	93%	8
95%	**19**	213	236	259	281	304	326	349	378	394	417	439	92%	27
90%	**25**	270	298	326	355	383	412	440	477	497	525	554	90%	34
85%	**30**	322	356	390	424	458	492	526	570	594	627	661	88%	42
80%	**35**	363	401	439	477	516	554	592	641	668	706	744	86%	48
75%	**41**	410	452	495	538	581	624	666	722	752	795	837	84%	56
70%	**46**	453	500	548	595	642	689	737	798	831	878	925	82%	63
65%	**53**	501	553	605	657	709	761	813	881	918	970	1,022	79%	72
60%	**59**	545	602	658	715	771	828	885	958	998	1,054	1,111	77%	81
55%	**67**	598	660	722	784	846	907	969	1,050	1,093	1,155	1,217	74%	92
50%	**76**	647	714	780	847	914	980	1,047	1,134	1,180	1,247	1,314	71%	103
45%	**84**	691	763	834	905	976	1,047	1,118	1,210	1,260	1,331	1,402	69%	115
40%	**94**	741	817	893	969	1,045	1,120	1,196	1,295	1,348	1,424	1,500	66%	128
35%	**102**	777	856	936	1,015	1,095	1,174	1,253	1,357	1,412	1,492	1,571	64%	139
30%	**114**	823	907	991	1,074	1,158	1,242	1,326	1,435	1,494	1,577	1,661	60%	156
25%	**130**	875	964	1,053	1,142	1,231	1,319	1,408	1,524	1,586	1,675	1,763	56%	177
20%	**149**	930	1,024	1,118	1,212	1,306	1,399	1,493	1,615	1,681	1,775	1,869	53%	202
15%	**174**	991	1,091	1,191	1,290	1,390	1,489	1,589	1,718	1,788	1,888	1,987	48%	236
10%	**213**	1,050	1,155	1,260	1,364	1,469	1,574	1,679	1,816	1,889	1,994	2,099	42%	288
5%	**286**	1,131	1,244	1,356	1,469	1,581	1,694	1,806	1,952	2,031	2,143	2,256	34%	383
1%	**527**	1,209	1,328	1,448	1,567	1,686	1,806	1,925	2,080	2,164	2,283	2,402	20%	689

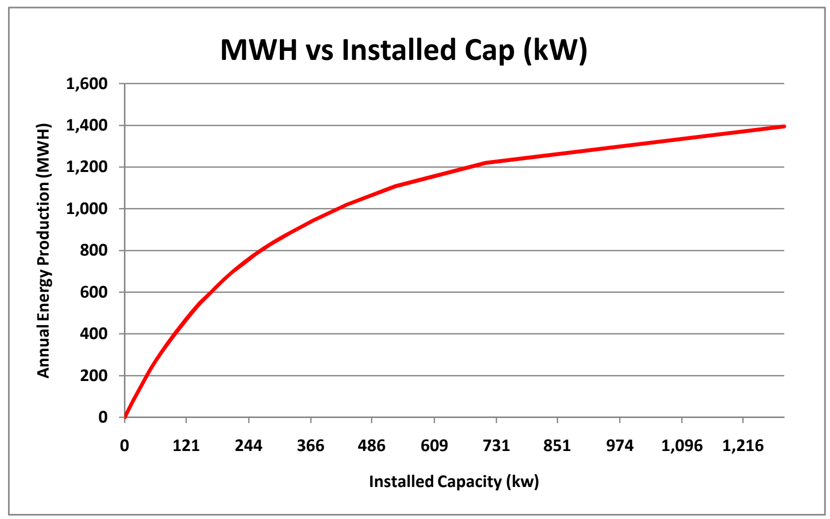




Head for Installed capacity (FT) 38.0

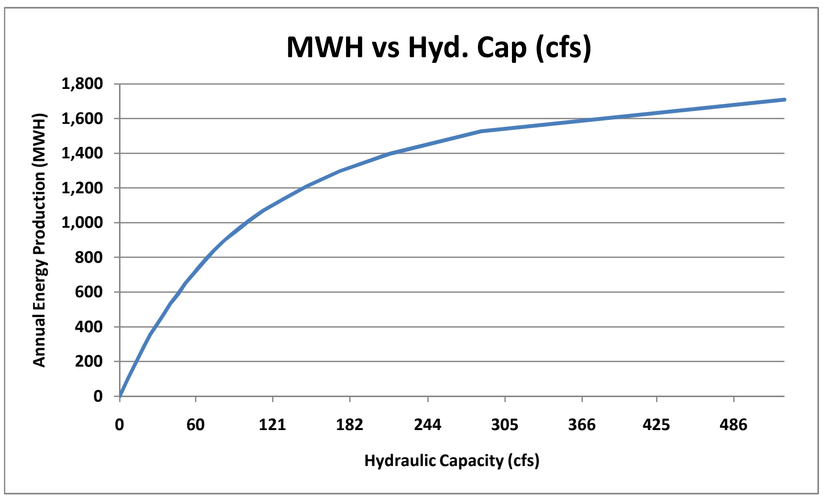
% Exceedance	Max Turbine Flow (CFS)	Net Energy (MWH)											Net Capacity Factor (%)	Installed Capacity (kW)
		Head (FT)												
		22	24	26	28	30	32	34	36.6	38	40	42		
100%	**6**	40	44	48	53	57	61	65	71	74	78	82	55%	15
95%	**19**	118	131	144	156	169	181	194	210	219	231	244	51%	49
90%	**25**	148	164	180	195	211	227	242	263	274	289	305	50%	63
85%	**30**	176	195	213	232	251	269	288	312	325	343	362	48%	77
80%	**35**	198	219	240	261	282	303	324	351	365	386	407	47%	88
75%	**41**	224	247	271	294	318	341	365	395	412	435	459	46%	102
70%	**46**	247	273	299	325	351	377	403	437	455	481	507	44%	117
65%	**53**	274	302	331	360	388	417	446	483	503	532	560	43%	132
60%	**59**	298	329	360	391	422	454	485	525	547	578	609	42%	149
55%	**67**	328	362	396	430	464	498	532	577	601	635	669	40%	171
50%	**76**	355	391	428	465	502	539	576	623	649	686	723	39%	190
45%	**84**	380	419	458	498	537	576	616	667	694	734	773	38%	211
40%	**94**	407	449	491	533	575	617	659	714	743	785	828	36%	237
35%	**102**	428	472	517	561	605	649	693	751	782	826	870	35%	257
30%	**114**	456	503	549	596	643	690	737	798	831	878	925	33%	288
25%	**130**	486	536	586	636	686	735	785	850	885	935	985	31%	326
20%	**149**	520	573	626	679	732	786	839	908	945	998	1,052	29%	373
15%	**174**	561	618	675	733	790	847	905	979	1,019	1,076	1,134	27%	437
10%	**213**	611	673	735	797	859	922	984	1,065	1,108	1,170	1,233	24%	533
5%	**286**	674	743	811	879	947	1,016	1,084	1,173	1,221	1,289	1,357	20%	710
1%	**527**	772	850	928	1,006	1,083	1,161	1,239	1,340	1,394	1,472	1,550	12%	1,297

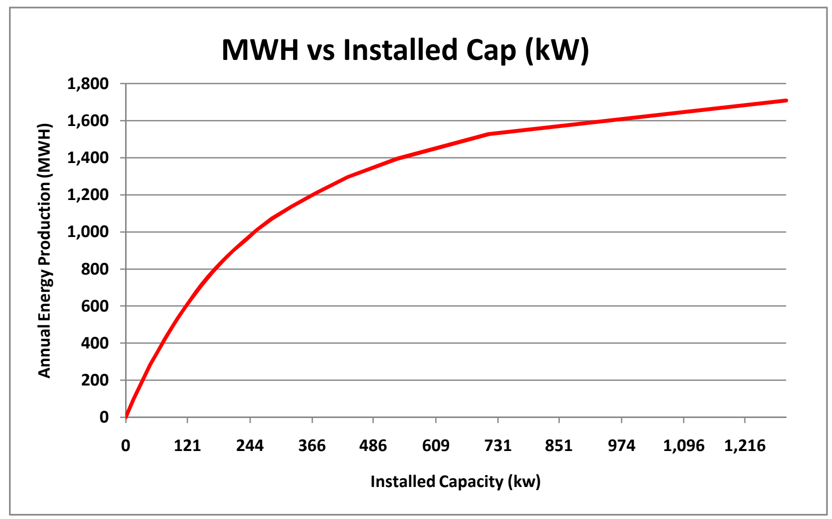




Head for Installed capacity (FT) 38.0

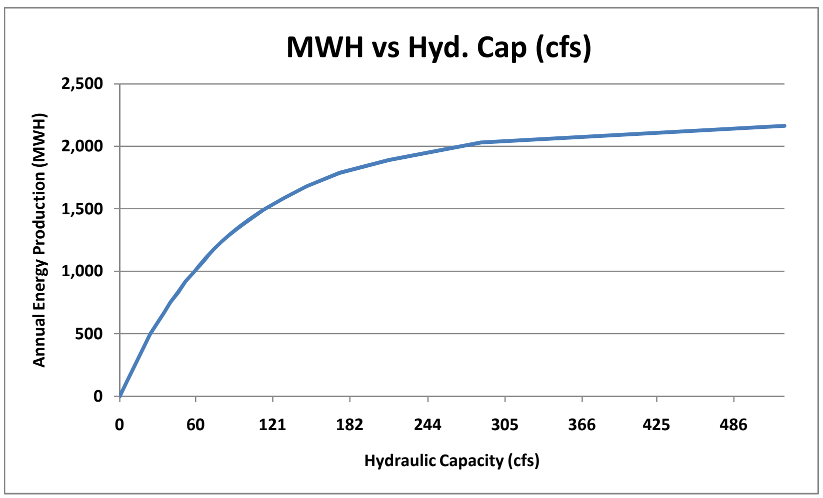
% Exceedance	Max Turbine Flow (CFS)	Net Energy (MWH) Head (FT)											Net Capacity Factor (%)	Installed Capacity (kW)
		22	24	26	28	30	32	34	36.6	38	40	42		
100%	**6**	52	57	63	68	74	79	85	92	96	101	107	71%	15
95%	**19**	154	170	187	203	219	235	252	273	284	300	317	66%	49
90%	**25**	192	213	233	253	274	294	314	340	355	375	395	64%	63
85%	**30**	229	253	277	301	325	349	373	405	421	445	470	63%	77
80%	**35**	258	285	312	339	366	393	420	456	475	502	529	61%	89
75%	**41**	291	321	352	382	412	443	473	513	534	565	595	60%	102
70%	**46**	321	355	388	422	455	489	523	566	590	623	657	58%	116
65%	**53**	355	392	430	467	504	541	578	626	652	689	726	56%	132
60%	**59**	388	428	469	509	549	590	630	683	711	752	792	55%	149
55%	**67**	426	470	515	559	603	647	692	749	780	825	869	52%	170
50%	**76**	461	509	557	604	652	700	748	810	843	891	939	50%	192
45%	**84**	492	543	594	645	696	747	798	864	899	950	1,001	49%	211
40%	**94**	528	582	637	691	745	800	854	925	963	1,017	1,072	46%	238
35%	**102**	554	611	668	725	782	839	896	970	1,010	1,067	1,124	45%	257
30%	**114**	589	649	709	770	830	890	951	1,029	1,071	1,132	1,192	43%	288
25%	**130**	626	690	754	818	882	946	1,010	1,093	1,137	1,201	1,265	40%	326
20%	**149**	667	734	802	870	938	1,006	1,074	1,162	1,209	1,277	1,345	37%	375
15%	**174**	716	789	861	934	1,006	1,079	1,151	1,246	1,297	1,369	1,442	34%	437
10%	**213**	772	850	928	1,006	1,083	1,161	1,239	1,341	1,395	1,473	1,551	30%	534
5%	**286**	846	932	1,017	1,102	1,187	1,272	1,357	1,468	1,527	1,612	1,697	24%	713
1%	**527**	951	1,046	1,141	1,235	1,330	1,425	1,520	1,643	1,709	1,804	1,899	15%	1,297

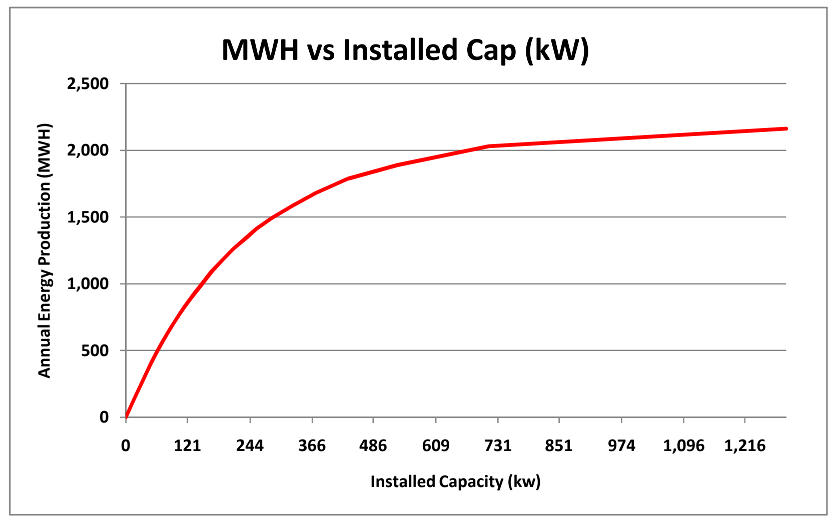




Head for Installed capacity (FT) 38.0

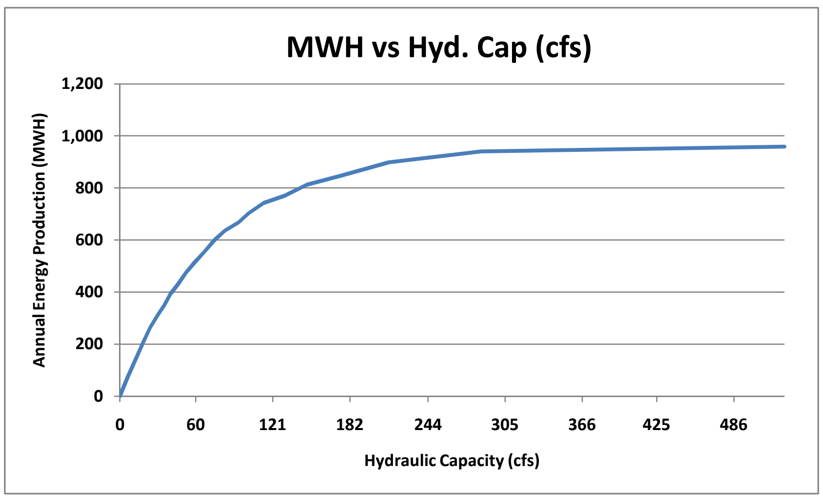
% Exceedance	Max Turbine Flow (CFS)	Net Energy (MWH) Head (FT) 22	24	26	28	30	32	34	36.6	38	40	42	Net Capacity Factor (%)	Installed Capacity (kW)
100%	**6**	68	75	83	90	97	104	112	121	126	133	140	94%	15
95%	**19**	213	236	259	281	304	326	349	378	394	417	439	92%	49
90%	**25**	270	298	326	355	383	412	440	477	497	525	554	90%	63
85%	**30**	322	356	390	424	458	492	526	570	594	627	661	88%	77
80%	**35**	363	401	439	477	516	554	592	641	668	706	744	86%	89
75%	**41**	410	452	495	538	581	624	666	722	752	795	837	84%	102
70%	**46**	453	500	548	595	642	689	737	798	831	878	925	82%	116
65%	**53**	501	553	605	657	709	761	813	881	918	970	1,022	79%	133
60%	**59**	545	602	658	715	771	828	885	958	998	1,054	1,111	76%	149
55%	**67**	598	660	722	784	846	907	969	1,050	1,093	1,155	1,217	74%	170
50%	**76**	647	714	780	847	914	980	1,047	1,134	1,180	1,247	1,314	71%	191
45%	**84**	691	763	834	905	976	1,047	1,118	1,210	1,260	1,331	1,402	68%	212
40%	**94**	741	817	893	969	1,045	1,120	1,196	1,295	1,348	1,424	1,500	65%	237
35%	**102**	777	856	936	1,015	1,095	1,174	1,253	1,357	1,412	1,492	1,571	63%	257
30%	**114**	823	907	991	1,074	1,158	1,242	1,326	1,435	1,494	1,577	1,661	59%	288
25%	**130**	875	964	1,053	1,142	1,231	1,319	1,408	1,524	1,586	1,675	1,763	55%	327
20%	**149**	930	1,024	1,118	1,212	1,306	1,399	1,493	1,615	1,681	1,775	1,869	51%	373
15%	**174**	991	1,091	1,191	1,290	1,390	1,489	1,589	1,718	1,788	1,888	1,987	47%	438
10%	**213**	1,050	1,155	1,260	1,364	1,469	1,574	1,679	1,816	1,889	1,994	2,099	40%	534
5%	**286**	1,131	1,244	1,356	1,469	1,581	1,694	1,806	1,952	2,031	2,143	2,256	33%	713
1%	**527**	1,209	1,328	1,448	1,567	1,686	1,806	1,925	2,080	2,164	2,283	2,402	19%	1,297

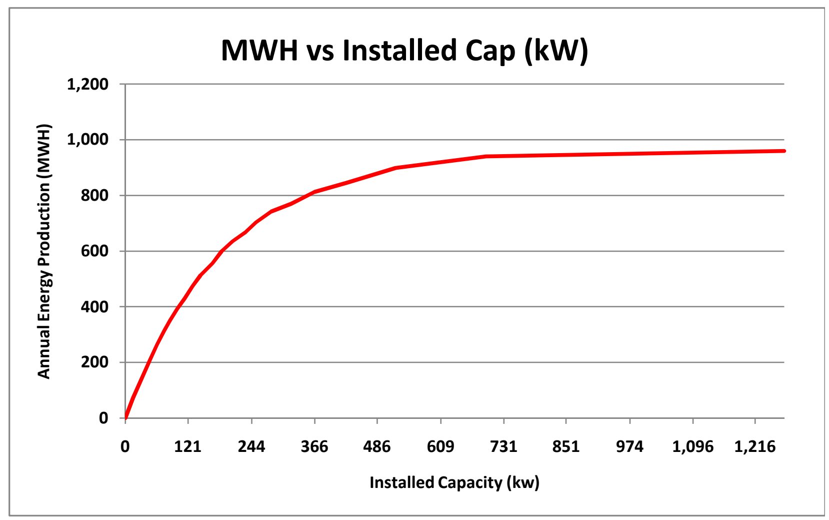




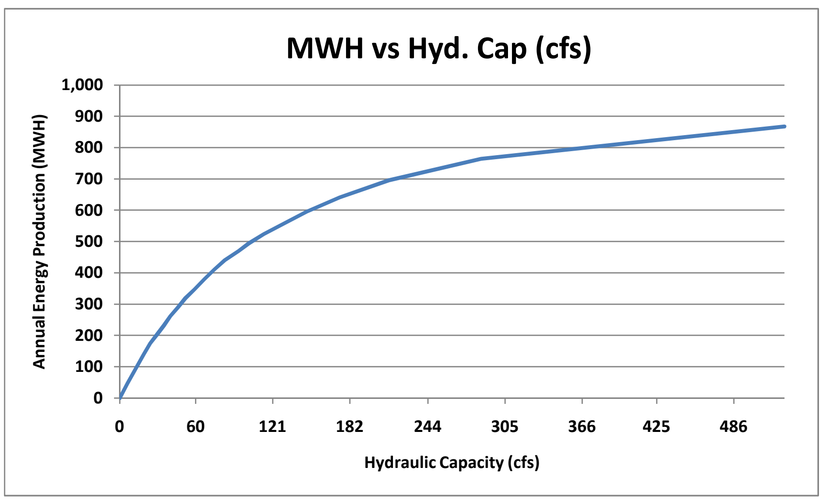
Head for Installed capacity (FT) 38.0

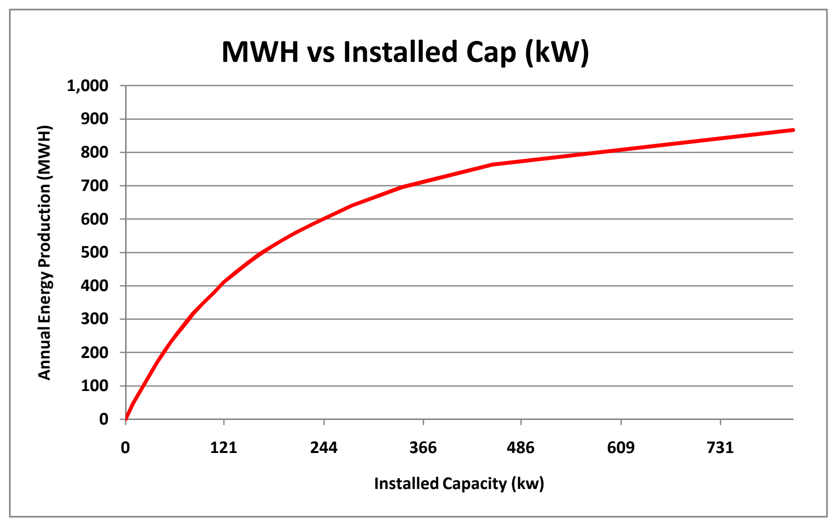
% Exceedance	Max Turbine Flow (CFS)	Net Energy (MWH) Head (FT) 22	24	26.2	28	30	32	34	36.6	38	40	42	Net Capacity Factor (%)	Installed Capacity (kW)
100%	**6**	38	42	47	51	55	59	64	69	72	76	81	55%	15
95%	**19**	111	124	137	149	161	173	186	202	211	223	236	50%	48
90%	**25**	139	155	172	186	202	217	233	253	264	279	295	49%	62
85%	**30**	165	184	204	220	239	257	276	300	312	331	349	47%	75
80%	**35**	185	206	229	247	268	288	309	336	350	371	391	46%	87
75%	**41**	208	231	257	277	300	324	347	377	393	416	439	45%	100
70%	**46**	228	253	281	304	329	354	380	412	430	455	481	43%	115
65%	**53**	251	279	310	335	363	390	418	454	474	502	529	42%	130
60%	**59**	273	303	336	363	393	423	453	492	513	543	573	40%	146
55%	**67**	296	328	364	393	426	459	491	533	556	589	621	38%	168
50%	**76**	320	355	393	425	460	495	530	576	600	635	670	37%	187
45%	**84**	339	376	417	450	487	524	561	609	635	672	709	35%	207
40%	**94**	356	395	438	473	512	551	590	640	667	706	745	33%	232
35%	**102**	376	417	462	498	539	580	621	674	703	744	785	32%	253
30%	**114**	398	441	488	527	570	613	656	712	743	786	829	30%	282
25%	**130**	412	457	506	546	591	636	681	739	770	815	860	27%	320
20%	**149**	435	483	534	577	624	671	718	779	812	859	907	25%	366
15%	**174**	453	502	556	601	650	699	748	812	846	895	944	23%	428
10%	**213**	482	534	591	638	690	742	794	862	899	951	1,003	20%	522
5%	**286**	505	559	619	668	723	777	831	902	940	995	1,049	15%	697
1%	**527**	515	570	631	682	737	793	848	920	959	1,015	1,070	9%	1,272





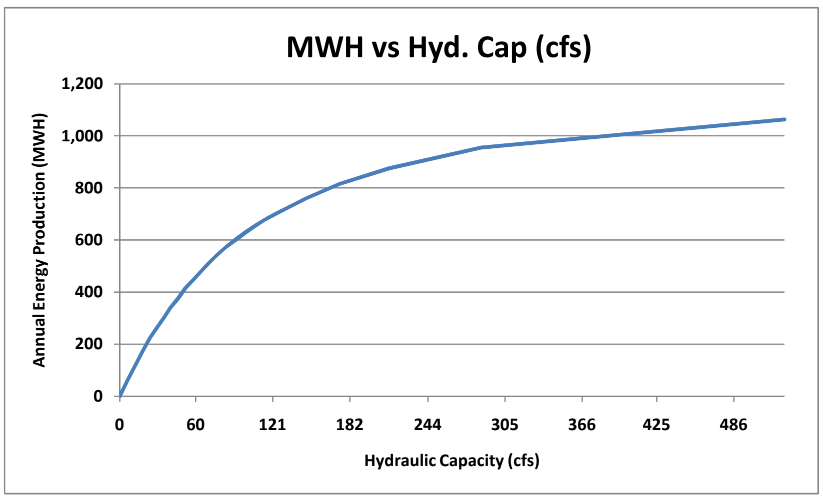
													Head for Installed capacity (FT)	23.5
% Exceedance	**Max Turbine Flow (CFS)**	**Net Energy (MWH)**											**Net Capacity Factor (%)**	**Installed Capacity (kW)**
		Head (FT)												
		22	**23.5**	**26.0**	**28**	**30**	**32**	**34**	**36**	**38**	**40**	**42**		
100%	**6**	44	47	52	57	61	65	69	74	78	82	86	55%	10
95%	**19**	130	139	155	168	180	193	205	218	230	243	255	51%	31
90%	**25**	163	174	194	210	225	241	257	272	288	304	319	49%	40
85%	**30**	193	207	230	249	267	286	304	323	341	360	379	48%	49
80%	**35**	217	233	259	280	300	321	342	363	384	405	426	47%	57
75%	**41**	244	262	291	315	338	362	385	409	432	456	479	46%	66
70%	**46**	269	289	321	347	373	399	425	451	477	503	529	44%	75
65%	**53**	298	319	355	384	412	441	470	498	527	556	584	43%	85
60%	**59**	324	347	386	417	448	479	510	542	573	604	635	42%	95
55%	**67**	355	381	423	458	492	526	560	594	628	662	696	40%	109
50%	**76**	383	411	457	494	531	568	604	641	678	715	752	39%	122
45%	**84**	410	439	488	528	567	607	646	685	725	764	803	37%	135
40%	**94**	438	470	522	565	607	649	691	733	775	817	859	35%	151
35%	**102**	461	494	549	593	637	682	726	770	814	859	903	34%	165
30%	**114**	489	524	583	630	677	724	770	817	864	911	958	33%	184
25%	**130**	520	558	620	670	720	770	820	870	919	969	1,019	31%	209
20%	**149**	555	595	661	715	768	821	874	927	981	1,034	1,087	29%	238
15%	**174**	598	640	712	769	827	884	941	998	1,056	1,113	1,170	26%	279
10%	**213**	649	695	773	835	898	960	1,022	1,084	1,146	1,209	1,271	23%	340
5%	**286**	713	764	849	917	986	1,054	1,122	1,191	1,259	1,327	1,396	19%	451
1%	**527**	809	867	965	1,042	1,120	1,198	1,276	1,353	1,431	1,509	1,587	12%	821

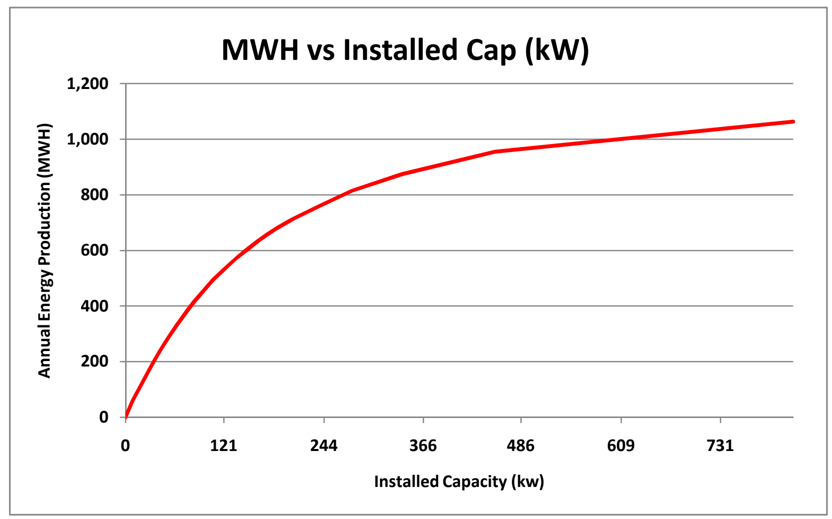




Head for Installed capacity (FT) 23.5

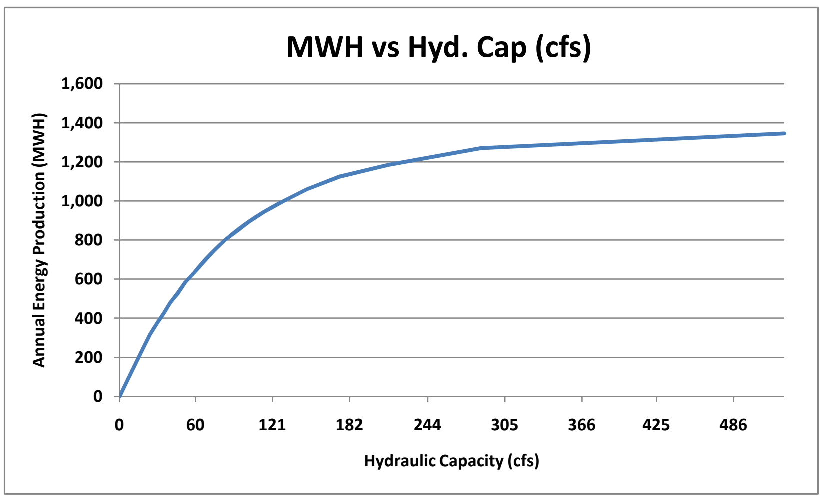
% Exceedance	Max Turbine Flow (CFS)	Net Energy (MWH) Head (FT) 22	23.5	26.0	28	30	32	34	36	38	40	42	Net Capacity Factor (%)	Installed Capacity (kW)
100%	**6**	57	61	68	73	79	84	90	95	101	106	112	71%	10
95%	**19**	169	181	202	218	234	250	267	283	299	315	332	66%	31
90%	**25**	211	226	251	272	292	312	333	353	373	393	414	64%	41
85%	**30**	250	268	299	323	347	371	395	419	443	467	491	62%	49
80%	**35**	282	302	336	363	390	417	444	471	499	526	553	61%	57
75%	**41**	317	340	378	408	439	469	500	530	561	591	622	59%	66
70%	**46**	350	375	417	451	484	518	551	585	618	652	686	57%	74
65%	**53**	387	414	461	498	535	572	609	646	683	721	758	56%	85
60%	**59**	421	452	502	542	583	623	664	704	745	785	825	54%	95
55%	**67**	462	495	550	595	639	683	727	772	816	860	904	52%	109
50%	**76**	499	534	594	642	690	737	785	833	881	929	976	50%	123
45%	**84**	531	569	633	684	735	786	836	887	938	989	1,040	48%	135
40%	**94**	568	609	677	731	786	840	895	949	1,003	1,058	1,112	46%	152
35%	**102**	595	638	709	766	823	880	937	994	1,051	1,108	1,165	44%	165
30%	**114**	631	676	752	812	872	933	993	1,053	1,114	1,174	1,234	42%	184
25%	**130**	669	717	797	861	925	989	1,053	1,117	1,181	1,245	1,309	39%	209
20%	**149**	710	761	846	914	982	1,050	1,117	1,185	1,253	1,321	1,389	36%	239
15%	**174**	760	815	906	978	1,051	1,123	1,196	1,268	1,341	1,413	1,486	33%	279
10%	**213**	817	875	972	1,050	1,128	1,206	1,284	1,362	1,440	1,518	1,596	29%	341
5%	**286**	892	956	1,062	1,147	1,232	1,317	1,402	1,487	1,573	1,658	1,743	24%	454
1%	**527**	992	1,063	1,182	1,276	1,371	1,466	1,561	1,655	1,750	1,845	1,940	15%	821

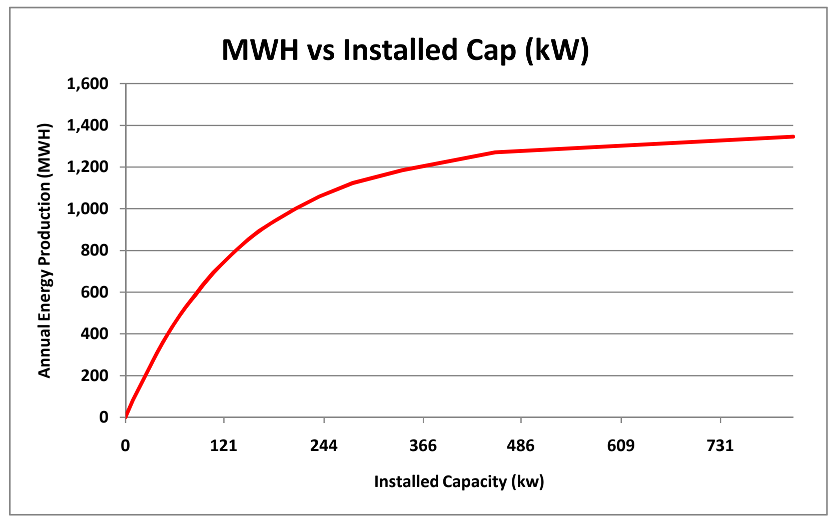




Head for Installed capacity (FT) 23.5

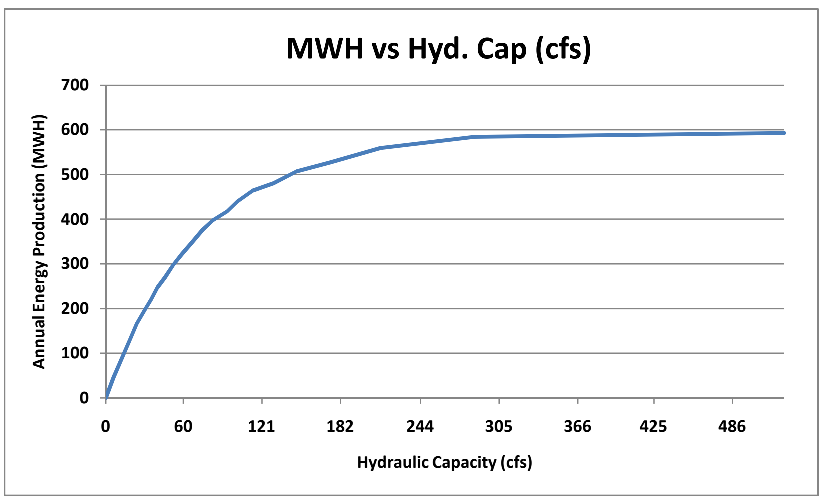
% Exceedance	Max Turbine Flow (CFS)	Net Energy (MWH) Head (FT) 22	23.5	26.0	28	30	32	34	36	38	40	42	Net Capacity Factor (%)	Installed Capacity (kW)
100%	**6**	75	81	90	97	104	111	119	126	133	140	148	93%	10
95%	**19**	235	252	280	303	325	348	370	393	416	438	461	92%	31
90%	**25**	296	317	353	381	410	438	467	495	524	552	580	90%	40
85%	**30**	353	379	421	455	489	523	557	591	624	658	692	88%	49
80%	**35**	397	426	473	511	549	587	626	664	702	740	778	86%	57
75%	**41**	447	479	532	575	618	661	704	746	789	832	875	83%	66
70%	**46**	493	529	588	635	682	730	777	824	871	918	966	81%	75
65%	**53**	544	583	649	701	753	805	857	909	961	1,013	1,065	78%	85
60%	**59**	591	634	704	761	818	874	931	987	1,044	1,100	1,157	76%	96
55%	**67**	647	694	771	833	895	956	1,018	1,080	1,142	1,204	1,266	73%	109
50%	**76**	698	749	832	899	965	1,032	1,099	1,165	1,232	1,299	1,365	70%	122
45%	**84**	745	798	887	958	1,029	1,101	1,172	1,243	1,314	1,385	1,456	67%	136
40%	**94**	796	853	948	1,024	1,100	1,176	1,252	1,328	1,404	1,480	1,555	64%	152
35%	**102**	833	893	992	1,072	1,151	1,230	1,310	1,389	1,469	1,548	1,627	62%	165
30%	**114**	880	943	1,048	1,132	1,216	1,300	1,383	1,467	1,551	1,635	1,719	58%	184
25%	**130**	933	1,000	1,111	1,200	1,289	1,378	1,466	1,555	1,644	1,733	1,822	55%	209
20%	**149**	988	1,058	1,176	1,270	1,364	1,458	1,551	1,645	1,739	1,833	1,927	51%	238
15%	**174**	1,049	1,124	1,248	1,348	1,448	1,547	1,647	1,746	1,846	1,946	2,045	46%	280
10%	**213**	1,106	1,184	1,316	1,420	1,525	1,630	1,735	1,840	1,945	2,050	2,155	40%	341
5%	**286**	1,186	1,270	1,411	1,523	1,635	1,748	1,860	1,973	2,085	2,198	2,310	32%	454
1%	**527**	1,256	1,346	1,495	1,614	1,733	1,853	1,972	2,091	2,211	2,330	2,449	19%	821

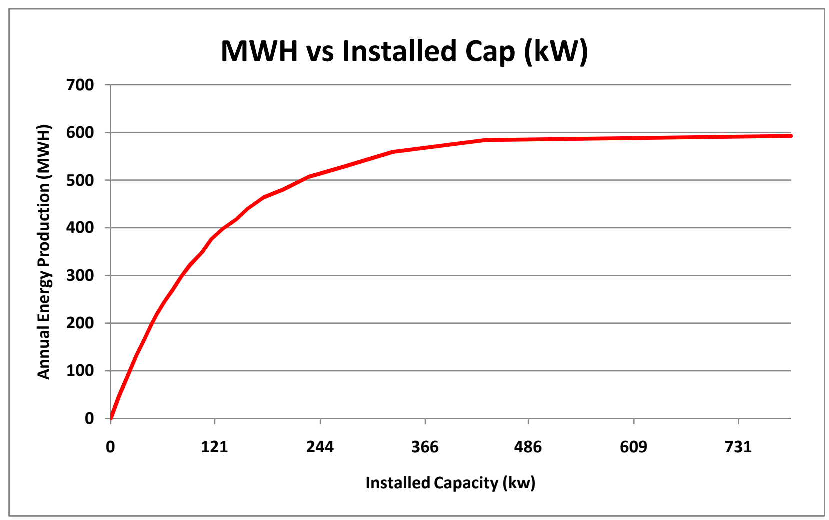




Head for Installed capacity (FT): 23.5

% Exceedance	**Max Turbine Flow (CFS)**	**Net Energy (MWH)**											**Net Capacity Factor (%)**	**Installed Capacity (kW)**
		Head (FT)												
		22	**23.5**	**26.2**	**28**	**30**	**32**	**34**	**36.6**	**38**	**40**	**42**		
100%	**6**	42	45	51	55	59	64	68	73	76	81	85	54%	10
95%	**19**	123	133	149	161	173	185	198	214	223	235	248	50%	30
90%	**25**	154	166	187	201	216	232	247	268	279	294	310	48%	39
85%	**30**	182	196	221	238	256	274	293	317	330	348	366	47%	48
80%	**35**	204	220	248	266	287	307	328	355	369	390	410	46%	55
75%	**41**	229	247	278	299	322	345	368	398	414	437	460	44%	63
70%	**46**	251	270	304	327	352	377	403	435	453	478	504	42%	73
65%	**53**	276	297	335	360	387	415	443	479	499	526	554	41%	82
60%	**59**	299	322	362	389	420	450	480	519	540	570	600	40%	92
55%	**67**	324	349	392	422	454	487	519	562	584	617	650	37%	106
50%	**76**	349	376	423	455	490	525	560	605	630	665	700	36%	118
45%	**84**	370	398	448	481	518	555	592	640	666	703	740	35%	131
40%	**94**	388	418	470	505	544	583	622	672	700	739	778	33%	146
35%	**102**	409	440	495	532	572	613	654	707	736	777	818	31%	159
30%	**114**	432	464	522	561	604	647	690	746	777	820	863	30%	178
25%	**130**	447	481	541	581	626	671	716	774	805	850	895	27%	202
20%	**149**	471	507	570	613	660	707	754	815	848	895	943	25%	230
15%	**174**	490	527	594	638	687	736	785	849	883	932	981	22%	270
10%	**213**	520	560	630	677	729	781	833	901	937	989	1,042	19%	328
5%	**286**	543	584	658	707	761	815	870	941	979	1,033	1,088	15%	436
1%	**527**	551	593	668	718	774	829	885	957	996	1,051	1,107	9%	792

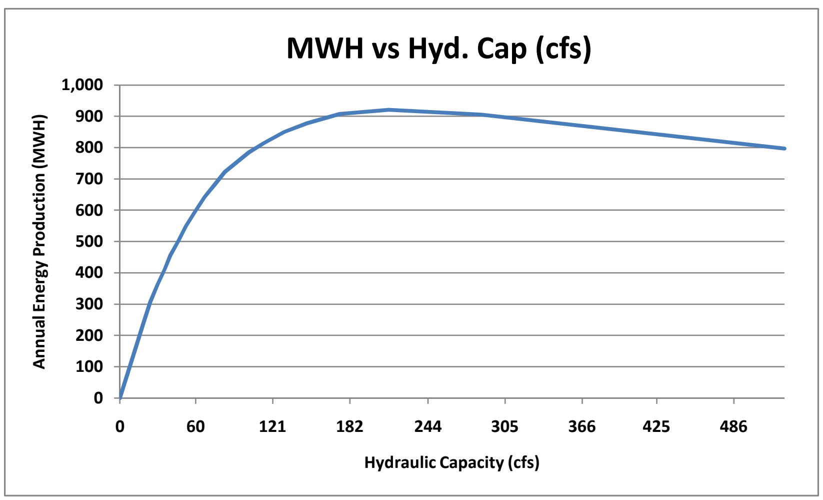


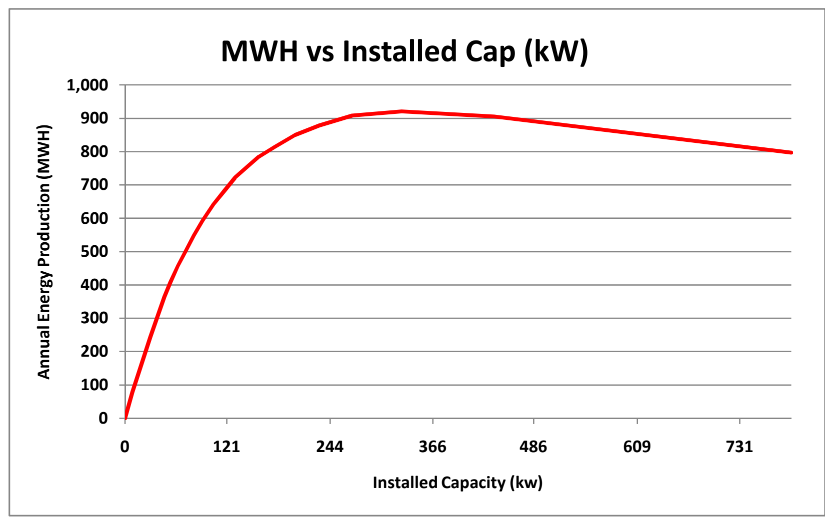


THE ESSEX PARTNERSHIP

Head for Installed capacity (FT): 23.5

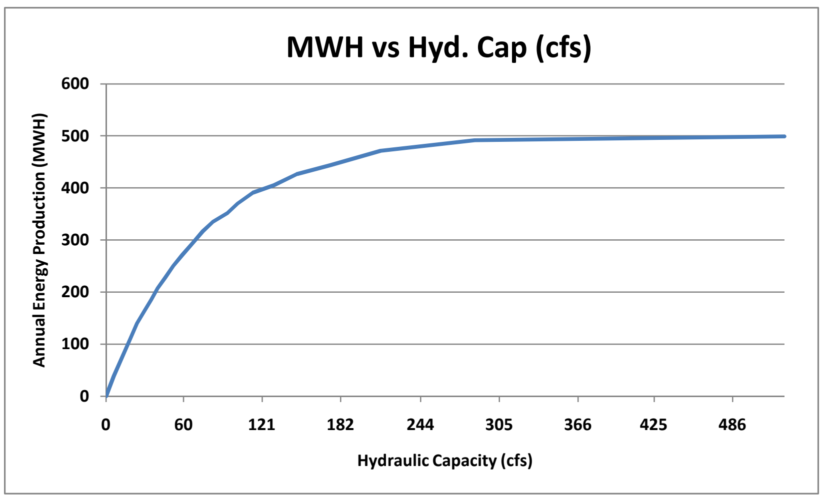
% Exceedance	Max Turbine Flow (CFS)	Net Energy (MWH) Head (FT) 22	23.5	26.2	28	30	32	34	36.6	38	40	42	Net Capacity Factor (%)	Installed Capacity (kW)
100%	**6**	72	78	88	94	102	109	116	126	131	138	146	93%	10
95%	**19**	226	243	274	295	317	340	363	393	409	431	454	91%	30
90%	**25**	285	306	345	371	399	428	456	494	514	542	571	90%	39
85%	**30**	339	365	410	441	475	509	543	587	611	645	679	87%	48
80%	**35**	380	408	459	494	532	570	608	657	684	722	760	85%	55
75%	**41**	424	456	513	552	594	637	679	734	764	806	849	82%	64
70%	**46**	465	500	563	605	651	698	744	805	837	884	930	79%	72
65%	**53**	510	548	617	663	714	765	816	882	917	968	1,019	76%	83
60%	**59**	552	593	667	716	771	826	881	953	991	1,046	1,101	73%	93
55%	**67**	597	642	722	776	835	895	954	1,032	1,073	1,133	1,192	70%	105
50%	**76**	634	682	767	824	887	950	1,013	1,095	1,139	1,203	1,266	66%	118
45%	**84**	672	722	812	872	939	1,006	1,072	1,159	1,206	1,273	1,340	63%	131
40%	**94**	705	758	853	916	986	1,056	1,126	1,217	1,266	1,336	1,406	59%	147
35%	**102**	730	784	882	948	1,020	1,093	1,165	1,259	1,310	1,382	1,455	56%	159
30%	**114**	758	815	916	984	1,059	1,134	1,210	1,307	1,360	1,435	1,510	52%	178
25%	**130**	791	850	955	1,026	1,104	1,183	1,261	1,363	1,418	1,496	1,574	48%	202
20%	**149**	818	878	987	1,060	1,141	1,222	1,303	1,408	1,464	1,545	1,626	43%	232
15%	**174**	845	908	1,021	1,096	1,179	1,263	1,346	1,455	1,513	1,597	1,680	38%	271
10%	**213**	857	920	1,034	1,110	1,195	1,280	1,364	1,474	1,533	1,618	1,702	32%	329
5%	**286**	843	906	1,018	1,093	1,177	1,260	1,343	1,452	1,510	1,594	1,677	24%	439
1%	**527**	742	797	897	964	1,038	1,112	1,186	1,282	1,334	1,408	1,482	11%	792

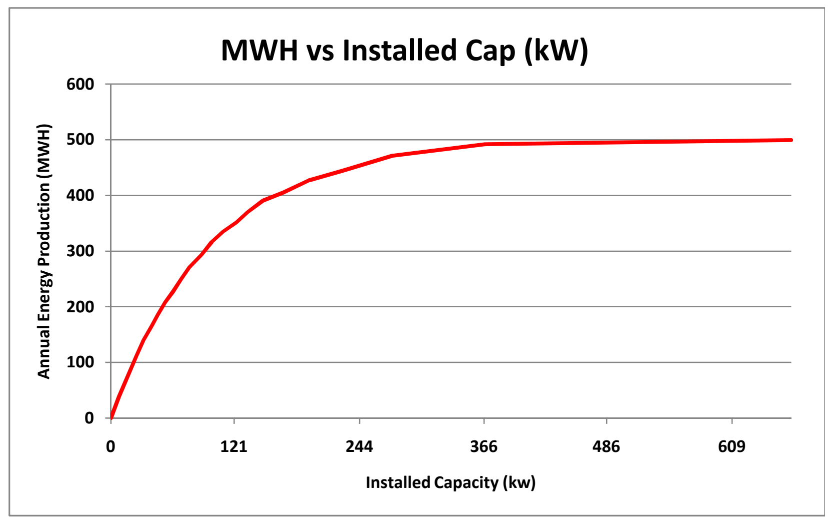




Head for Installed capacity (FT): 23.5

% Exceedance	Max Turbine Flow (CFS)	Net Energy (MWH)											Net Capacity Factor (%)	Installed Capacity (kW)
		Head (FT)												
		22	23.5	26.2	28	30	32	34	36	38	40	42		
100%	**6**	36	38	43	46	50	53	57	61	64	68	71	54%	8
95%	**19**	104	112	126	135	146	156	167	177	188	198	209	50%	26
90%	**25**	130	140	157	169	182	195	208	221	235	248	261	48%	33
85%	**30**	154	165	186	200	216	231	247	262	278	293	308	47%	40
80%	**35**	172	185	209	224	242	259	276	294	311	328	346	46%	46
75%	**41**	193	208	234	251	271	290	310	329	349	368	387	44%	53
70%	**46**	211	227	256	275	296	318	339	360	382	403	424	42%	61
65%	**53**	233	250	282	303	326	350	373	396	420	443	467	41%	69
60%	**59**	252	271	305	328	353	379	404	429	455	480	505	40%	78
55%	**67**	273	293	330	355	383	410	437	465	492	520	547	37%	89
50%	**76**	294	316	356	383	412	442	471	501	530	560	589	36%	99
45%	**84**	311	335	377	405	436	467	499	530	561	592	623	35%	110
40%	**94**	327	352	396	425	458	491	524	556	589	622	655	33%	123
35%	**102**	344	370	417	448	482	517	551	585	620	654	689	31%	134
30%	**114**	363	391	440	472	509	545	581	618	654	690	727	30%	150
25%	**130**	377	405	456	490	527	565	603	640	678	716	753	27%	170
20%	**149**	397	427	480	516	556	595	635	675	714	754	794	25%	194
15%	**174**	413	444	500	537	578	620	661	702	744	785	826	22%	227
10%	**213**	438	471	530	570	614	658	702	745	789	833	877	19%	277
5%	**286**	458	492	554	595	641	687	733	778	824	870	916	15%	367
1%	**527**	464	499	563	605	651	698	745	792	839	885	932	9%	667





THE ESSEX PARTNERSHIP

	1	2	3	4	5
Net Head (FT)	Turbine Discharge (% Q Max)	Turbine Discharge (CFS)	Kaplan Turbine Eff (%)	Francis Turbine Eff (%)	Turbine Output (KW)
14.0	0.050	14	45.2%	5.8%	8
14.0	0.075	21	59.0%	14.2%	15
14.0	0.100	29	72.7%	22.7%	25
14.0	0.150	43	80.9%	35.9%	41
14.0	0.200	57	85.4%	47.6%	58
14.0	0.250	72	87.7%	55.8%	74
14.0	0.300	86	89.1%	63.0%	91
14.0	0.350	100	90.1%	69.0%	107
14.0	0.400	114	90.9%	74.2%	123
14.0	0.450	129	91.6%	78.7%	140
14.0	0.500	143	92.2%	82.5%	156
14.0	0.550	157	92.6%	85.6%	173
14.0	0.600	172	92.7%	88.1%	189
14.0	0.623	178	92.8%	89.0%	196
14.0	0.650	186	92.8%	89.9%	205
14.0	0.700	200	92.6%	91.2%	220
14.0	0.750	215	92.3%	92.0%	235
14.0	0.800	229	91.9%	92.5%	249
14.0	0.833	238	91.6%	92.8%	259
14.0	0.850	243	91.5%	92.6%	264
14.0	0.900	257	90.9%	92.3%	278
14.0	0.950	272	90.3%	91.6%	291
14.0	0.956	274	90.3%	91.5%	293
14.0	1.000	286	89.7%	90.6%	304

Cost Estimates

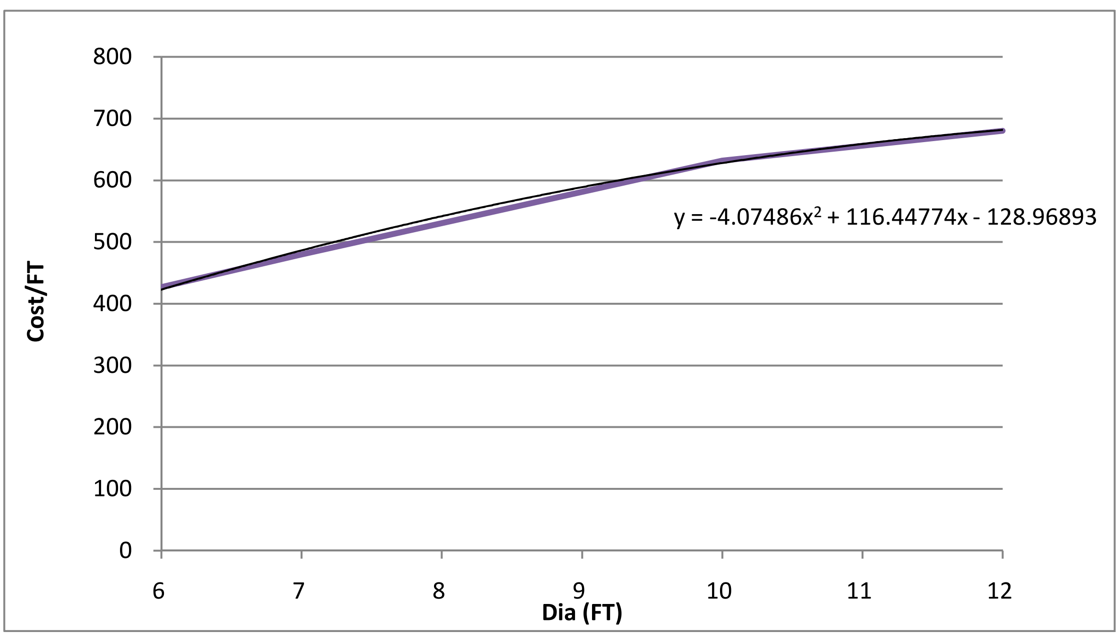
Source	Length (FT)	Diameter (FT)	Cost (FOB)	2010 Cost	Cost/FT
DB Cotton, Apr 2009	300	6	125,000	128,125	427
Val, July 2011	300	7	144,000	144,000	480
DB Cotton, Apr 2009	1,500	8	520,000	533,000	355
DB Cotton, Apr 2009	300	10	185,000	189,625	632
Val, July 2010	300	12	204,000	204,000	680

Values for Formula

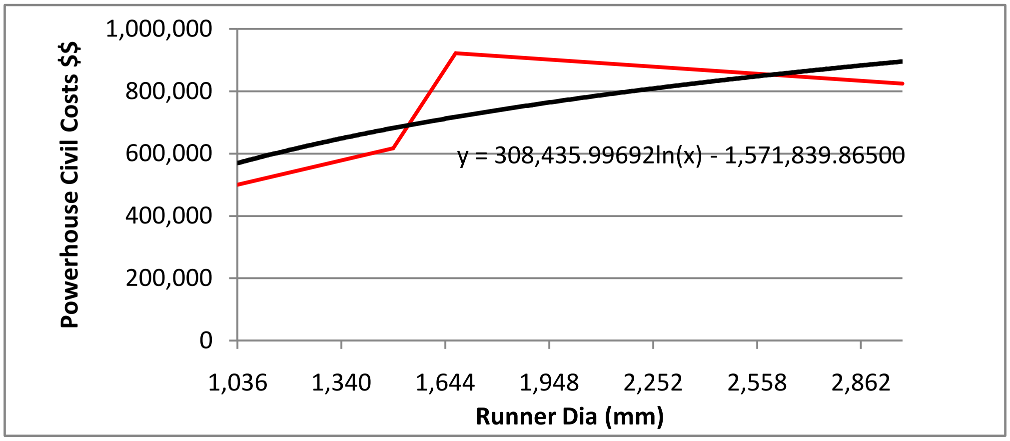
					Cost/FT	Eq
DB Cotton, Apr 2009	300	6	125,000	128,125	427	423
Val, July 2011	300	7	144,000	144,000	480	486
DB Cotton, Apr 2009	300	10	185,000	189,625	632	628
Val, July 2010	300	12	204,000	204,000	680	682

Values for East Providence

Dia (FT)	Material $/FT	Length FT	Material	Transp and Install	Total 2010 Costs
3.7	246	1	246	123	$369
4.3	296	1	296	148	$445
4.7	328	1	328	164	$492
4.6	317	1	317	158	$475
5.8	409	1	409	205	$614
5.2	367	1	367	184	$551
7.0	486	1	486	243	$730
8.0	542	1	542	271	$813



	Runner Diameter (mm)	Powerhouse Civil (items 2c-i)	2010 Civil Cost	Formula
Pawtuxet	1,050	488,279	500,486	573,809
Pawtuxet	1,500	602,419	617,480	683,821
Cargill Falls	1,700	899,967	922,466	722,425
Blackstone R.	3,000	805,200	825,330	897,612



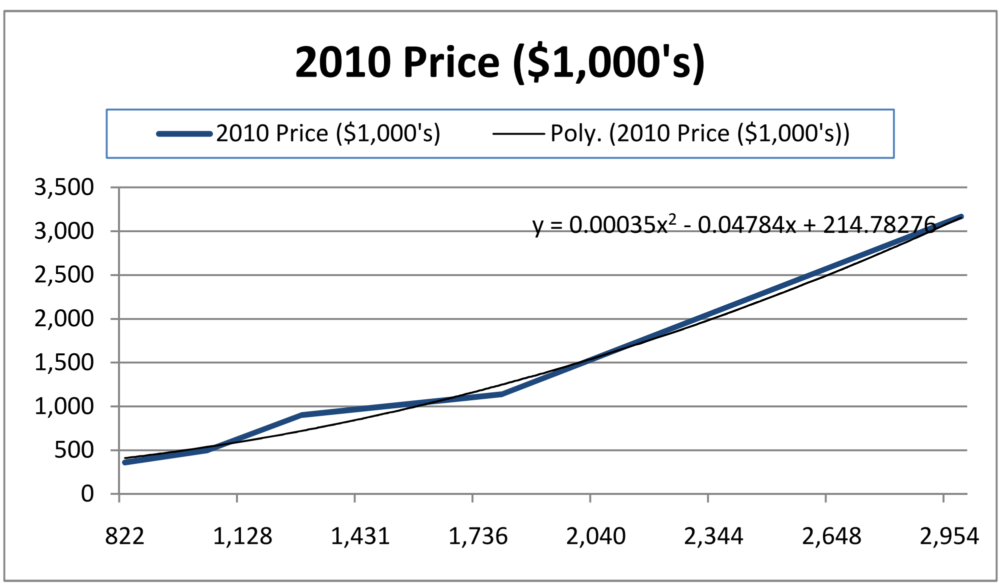
Case	Runner Diameter (mm)	Runner Diameter (FT)	2010 Civil Cost Formula + $50k for intake
B,C, E; w/ Qmin	900	2.95	576,264
C2, E2, E3	920	3.02	583,043
B,C, E; 1/2 Qmin	950	3.12	592,940
A, F; and B,C, E; no Qmin	1,250	4.10	677,586

No	Description	2009	2010		
1	Mavel 0.85M Bulb, Dbl Reg	350			
2	Mavel 1.29M Vert Kapl	450			
3	Mavel 1.05M Bulb, Dbl Reg	490			
4	Mavel 1.8M Vert Kapl	1,125			
5	Mavel 0.85M Vert Kapl	400	650	mm	0.00035185
6	Mavel 1.29 Bulb, Dbl Reg		900	bb	60
7	Mavel 1.8 Bulb, Dbl Reg		1,140	b=	293
				m=	0.471
		Dia	Price	Eq	
	Dbl Reg Bulbs (esc 2009 by 2.5%)	850	359	693	314
		1,050	502	787	448
		1,290	900	900	646
		1,500	999	999	852
		1,800	1,140	1,140	1,200
		3,000	3,167	1,705	3,227
			1,900		
			2,533		

<u>Cost Calculator</u>

Input Diameter Bulb 1,250 702 2010 Price ($1,000's)

Runner Diameter (mm)	Cost	
810	406	405,667
900	455	455,227
920	467	467,010
950	485	485,210
1250	702	701,858



Licensing & Permitting Summary

Alternatives	**Key Regulatory Drivers**	**Consultations (yrs)**	**Studies (yrs)**	**Costs ($1,000's)**
A, D, F	Minimal Env. Impacts (bypass, stream flows & wetlands)	2	0.5	$288
B, E	Bypass, Wetland Impacts, Standard ABF	2	2	$400
C	Longer Bypass, More Wetland Impacts, Standard ABF	3	2	$450
B, E	Bypass, Wetland Impacts, Modified ABF	3	2.5	$488
C	Longer Bypass, More Wetland Impacts, Modified ABF	3	3	$525

ITEM / DESCRIPTION		INTERCONNECTION TO NATIONAL GRID											
		Turner Reservoir (Single Circuit)				Hunt's Mill (Single Circuit)				Omega Pond (Single Circuit)			
		Qty	Units	Unit Price	Total Price	Qty	Units	Unit Price	Total Price	Qty	Units	Unit Price	Total Price
1	13.8 kV Overhead Distribution Line	0.33	mi.	$100,000	$33,000	0.52	mi.	$100,000	$52,000	0.15	mi.	$100,000	$15,000
2	13.8 kv Sectionalizers	1	ea	$10,000	$10,000	1	ea	$10,000	$10,000	1	ea	$10,000	$10,000
3	13.8 kV Pole-Mounted Distribution Transformers	3	ea	$10,000	$30,000	3	ea	$10,000	$30,000	3	ea	$10,000	$30,000
4	3-Phase Fused Disconnecting Switch	1	ea	$10,000	$10,000	1	ea	$10,000	$10,000	1	ea	$10,000	$10,000
5	Service Switchgear - Main disconnecting switch -Branch circuit breakers	1	ea	$20,000	$20,000	1	ea	$20,000	$20,000	1	ea	$20,000	$20,000
	Total				**$103,000**				**$122,000**				**$85,000**

Dam	Repair Costs	General Maintenance Costs	TOTAL ($1,000's)
Omega	10,000	10,000	**20**
Hunt's Mill	40,000	10,000	**50**
Turner Reservoir	210,000	10,000	**220**

Repair estimates from Phase I Inspection Rpt (MBP Consulting, 11/10);
Turner includes $180k for FERC studies
General Maintenance costs are catch-up allowances

THE ESSEX PARTNERSHIP

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
1	**General**					
a	Mob/Demob		1	25,000	25	Allowance
b	Site Prep		1	10,000	10	Allowance
c	Clear & Grub	acre	0.5	8,000	4	Allowance
d	E&S Control	ft.	100	10	1	Allowance
e	Dam Repairs		1	220,000	220	From Phase I Dam Repair Costs (MBP Consulting 2010)
f	Subtotal, General				260	
2	**Powerhouse/Intake**					
a	Coffer dam, Pond				100	Allowance
b	Cofferdam, Tailrace				10	Allowance
c	Powerhouse Civil		1	677,586	678	Includes: intake, powerhouse, tailrace and trashrake
k	Sluice gate		1	20,000	20	
l	Misc. metals		1	5,000	5	Allowance
m	HVAC		1	10,000	10	Allowance
n	Auxilliary Mechanical		1	10,000	10	Allowance
o	Lighting, auxilliary electrical		1	5,000	5	Allowance
p	Other		0		0	
q	Subtotal, Powerhouse				838	
3	**Equipment**					
a	Turbine, generator, & governor		1	701,858	702	Runner 1.25m, estimated costs developed from recent projects
b	Shipping Handling & Installation		1	163,372	163	20% of equipment costs
c	Switchgear		1	20,000	20	Fostiak Engineering (2010)
d	Instrumentation & Controls		1	50,000	50	Allowance, includes license min flow compliance
e	Station Service, MCC		1	20,000	20	Allowance
f	Protection		1	25,000	25	Allowance
g	Subtotal, Equipment				980	
8	**PM&E Measures**					
a	Water Quality		1	20,000	20	Allowance
b	D/S fish passage		0	20,000	0	Assumes installed by others
c	Min flow verification		0	5,000	0	Included in Instrumentation & Controls
d	Wetlands	acre	0.5	60,000	30	Allowance
e	Recreation		1	20,000	20	Allowance
f	Cultural		1	7,500	8	Allowance
g	Subtotal, PM&E				78	
9	**Licensing & Permitting**					
a	Consultations	year	2	50,000	100	Allowance
b	Studies	year	0.5	75,000	38	Allowance
c	Draft FERC Application		1	50,000	50	Allowance
d	Final FERC Application		1	25,000	25	Allowance
e	Legal review		1	25,000	25	Allowance
f	Non-FERC Permits		1	50,000	50	Allowance: WQC, Wetlands, S. 106, S. 404, CZM, etc.
g	Subtotal, Lic. & Permitting				288	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
10	**Land & Land Rights**					
a	Flowage rights		1	5,000	5	Allowance
b	Project works, land in fee		1		0	
c	Interconnection R.O.W.		1	5,000	5	Allowance
d	Legal		1	10,000	10	Allowance
e	Other				0	
f	Subtotal, Land				20	
11	**Interconnection**					
a	Clear & Grub	acre	0.5	8,000	4	Allowance
b	New Line		1	33,000	33	Fostiak Eng. (2010)
c	Metering		1	10,000	10	Allowance
c	Switchyard		1	50,000	50	Includes: sectionalizers, transformers, disconnect switch. From Interconnection Costs (Fostiak Eng. 2010)
d	Consultations		1	20,000	20	Allowance
f	Subtotal, Interconnection				117	
12	**Indirect Costs**					
a	A/E		1	206,385	206	8% of Direct Costs
b	Construction Management		1	25,000	25	Allowance
c	Testing		1	20,000	20	geo-tech, concrete
d	FERC submittals		1	35,000	35	Design Report, Status Reports
e	Owner's Admin & Overhead		1	100,000	100	Allowance
f	Other				0	
g	Subtotal, Indirects				386	
	Totals					
1	General				260	
2	Powerhouse/Intake				838	
3	Equipment				980	
8	PM&E Measures				78	
9	Licensing & Permitting				288	
10	Land & Land Rights				20	
11	Interconnection				117	
	Subtotal, Directs				2,580	
12	Indirect Costs				386	
	Subtotal				2,966	
13	Contingency		$2,966,201	20%	593	
	Grand Total				**3,559**	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
1	**General**					
a	Mob/Demob		1	25,000	25	Allowance
b	Site Prep		1	10,000	10	Allowance
c	Clear & Grub	acre	4	8,000	32	Allowance, includes penstock alignment
d	E&S Control	ft.	2000	10	20	Allowance, includes penstock alignment
e	Dam Repairs		1	270,000	270	From Phase I Dam Repair Costs (MBP Consulting 2010)
f	Subtotal, General				357	
2	**Powerhouse/Intake**					
a	Coffer dam, Pond				100	Allowance
b	Cofferdam, Tailrace				10	Allowance
c	Powerhouse Civil		1	576,264	576	Includes: intake, powerhouse, tailrace and trashrake
k	Penstock	ft.	2000	445	889	4.3' diameter penstock. Includes: materials, shipping & installation
l	Misc. metals		1	5,000	5	Allowance
m	HVAC		1	10,000	10	Allowance
n	Auxilliary Mechanical		1	10,000	10	Allowance
o	Lighting, auxilliary electrical		1	5,000	5	Allowance
p		cy			0	
q	Subtotal, Powerhouse/Intake				1,606	
3	**Equipment**					
a	Turbine, generator, & governor		1	455,227	455	900mm runner, estimated costs developed from recent projects
b	Shipping Handling & Installation		1	114,045	114	20% of equipment costs
c	Switchgear		1	20,000	20	Fostiak Eng. (2010)
d	Instrumentation & Controls		1	50,000	50	Allowance, includes license min flow verification
e	Station Service, MCC		1	20,000	20	Allowance
f	Protection		1	25,000	25	Allowance
g	Subtotal, Equipment				684	
8	**PM&E Measures**					
a	Water Quality		1	40,000	40	Allowance for monitoring
b	D/S fish passage		0	20,000	0	Assumes installed by others
c	Min flow verification		0	5,000	0	Included in Instrumentation & Controls
d	Wetlands	acre	1.5	60,000	90	Allowance for impacts from penstock alignment
e	Recreation		1	20,000	20	Allowance
f	Cultural		1	7,500	8	Allowance
g	Subtotal, PM&E				158	
9	**Licensing & Permitting**					
a	Consultations	year	2	50,000	100	Allowance
b	Studies	year	2	75,000	150	Alowance; assumes acceptance of standard instream flow settings
c	Draft FERC Application		1	50,000	50	Allowance
d	Final FERC Application		1	25,000	25	Allowance
e	Legal review		1	25,000	25	Allowance
f	Non-FERC Permits		1	50,000	50	Allowance: WQC, Wetlands, S. 106, S. 404, CZM, etc.
g	Subtotal, Lic. & Permitting				400	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
10	**Land & Land Rights**					
a	Flowage rights		1	5,000	5	Allowance
b	Project works, land in fee		1	20,000	20	Allowance for penstock alignment
c	Interconnection R.O.W.		1	5,000	5	Allowance
d	Legal		1	10,000	10	Allowance
e	Other				0	
f	Subtotal, Land				40	
11	**Interconnection**					
a	Clear & Grub	acre	1	6,200	6	Allowance
b	New Line		1	52,000	52	Fostiak Eng. (2010)
c	Metering		1	10,000	10	Allowance
c	Switchyard		1	50,000	50	Includes: sectionalizers, transformers, disconnect switch. From Interconnection Costs (Fostiak Eng. 2010)
d	Consultations		1	20,000	20	Allowance
f	Subtotal, Interconnection				138	
12	**Indirect Costs**					
a	A/E		1	270,598	271	8% of Direct Costs
b	Construction Management		1	25,000	25	Allowance
c	Testing		1	20,000	20	geo-tech, concrete
d	FERC submittals		1	35,000	35	Design Report, Status Reports
e	Owner's Admin & Overhead		1	100,000	100	Allowance
f	Other				0	
g	Subtotal, Indirects				451	
	Totals					
1	General				357	
2	Powerhouse/Intake				1,606	
3	Equipment				684	
8	PM&E Measures				158	
9	Licensing & Permitting				400	
10	Land & Land Rights				40	
11	Interconnection				138	
	Subtotal, Directs				3,382	
12	Indirect Costs				451	
	Subtotal				3,833	
13	Contingency		$3,833,070	20%	767	
	Grand Total				**4,600**	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
1	**General**					
a	Mob/Demob		1	25,000	25	Allowance
b	Site Prep		1	10,000	10	Allowance
c	Clear & Grub	acre	4	8,000	32	Allowance, includes penstock alignment
d	E&S Control	ft.	2000	10	20	Allowance, includes penstock alignment
e	Dam Repairs		1	270,000	270	From Phase I Dam Repair Costs (MBP Consulting 2010)
f	Subtotal, General				357	
2	**Powerhouse/Intake**					
a	Coffer dam, Pond				100	Allowance
b	Cofferdam, Tailrace				10	Allowance
c	Powerhouse Civil		1	592,940	593	Includes: intake, powerhouse, tailrace and trashrake
k	Penstock	ft.	2000	475	950	Assumes 4.6' diameter penstock. Includes: materials, shipping & installation
l	Misc. metals		1	5,000	5	Allowance
m	HVAC		1	10,000	10	Allowance
n	Auxilliary Mechanical		1	10,000	10	Allowance
o	Lighting, auxilliary electrical		1	5,000	5	Allowance
p	Other				0	
q	Subtotal, Powerhouse/Intake				1,682	
3	**Equipment**					
a	Turbine, generator, & governor		1	485,210	485	Runner 950mm, Estimated costs developed from recent projects
b	Shipping Handling & Installation		1	120,042	120	20% of equipment costs
c	Switchgear		1	20,000	20	Fostiak Eng. (2010)
d	Instrumentation & Controls		1	50,000	50	Allowance, includes license min flow verification
e	Station Service, MCC		1	20,000	20	Allowance
f	Protection		1	25,000	25	Allowance
g	Subtotal, Equipment				720	
8	**PM&E Measures**					
a	Water Quality		1	40,000	40	Allowance for monitoring
b	D/S fish passage		0	20,000	0	Assumes installed by others
c	Min flow verification		0	5,000	0	Included in Instrumentation & Controls
d	Wetlands	acre	1.5	60,000	90	Allowance for impacts from penstock alignment
e	Recreation		1	20,000	20	Allowance
f	Cultural		1	7,500	8	Allowance
g	Subtotal, PM&E				158	
9	**Licensing & Permitting**					
a	Consultations	year	3	50,000	150	Allowance
b	Studies	year	2.5	75,000	188	Alowance; assumes instream flow studies
c	Draft FERC Application		1	50,000	50	Allowance
d	Final FERC Application		1	25,000	25	Allowance
e	Legal review		1	25,000	25	Allowance
f	Non-FERC Permits		1	50,000	50	Allowance: WQC, Wetlands, S. 106, S. 404, CZM, etc.
g	Subtotal, Lic. & Permitting				488	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
10	**Land & Land Rights**					
a	Flowage rights		1	5,000	5	Allowance
b	Project works, land in fee		1	20,000	20	Allowance for penstock alignment
c	Interconnection R.O.W.		1	5,000	5	Allowance
d	Legal		1	10,000	10	Allowance
e	Other				0	
f	Subtotal, Land				40	
11	**Interconnection**					
a	Clear & Grub	acre	1	6,200	6	Allowance
b	New Line		1	52,000	52	Fostiak Eng. (2010)
c	Metering		1	10,000	10	Allowance
c	Switchyard		1	50,000	50	Includes: sectionalizers, transformers, disconnect switch. From Interconnection Costs (Fostiak Eng. 2010)
d	Consultations		1	20,000	20	Allowance
f	Subtotal, Interconnection				138	
12	**Indirect Costs**					
a	A/E		1	286,633	287	8% of Direct Costs
b	Construction Management		1	25,000	25	Allowance
c	Testing		1	20,000	20	geo-tech, concrete
d	FERC submittals		1	35,000	35	Design Report, Status Reports
e	Owner's Admin & Overhead		1	100,000	100	Allowance
f	Other				0	
g	Subtotal, Indirects				467	
	Totals					
1	General				357	
2	Powerhouse/Intake				1,682	
3	Equipment				720	
8	PM&E Measures				158	
9	Licensing & Permitting				488	
10	Land & Land Rights				40	
11	Interconnection				138	
	Subtotal, Directs				3,583	
12	Indirect Costs				467	
	Subtotal				4,050	
13	Contingency		$4,049,550	20%	810	
	Grand Total				**4,859**	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
1	**General**					
a	Mob/Demob		1	25,000	25	Allowance
b	Site Prep		1	10,000	10	Allowance
c	Clear & Grub	acre	4	8,000	32	Allowance, includes penstock alignment
d	E&S Control	ft.	2000	10	20	Allowance, includes penstock alignment
e	Dam Repairs		1	270,000	270	From Phase I Dam Repair Costs (MBP Consulting 2010)
f	Subtotal, General				357	
2	**Powerhouse/Intake**					
a	Coffer dam, Pond				100	Allowance
b	Cofferdam, Tailrace				10	Allowance
c	Powerhouse Civil		1	677,586	678	Includes: intake, powerhouse, tailrace and trashrake
k	Penstock	ft.	2000	614	1,228	5.8' diameter penstock. Includes: material, transporation and installation
l	Misc. metals		1	5,000	5	Allowance
m	HVAC		1	10,000	10	Allowance
n	Auxilliary Mechanical		1	10,000	10	Allowance
o	Lighting, auxilliary electrical		1	5,000	5	Allowance
p	Other				0	
q	Subtotal, Powerhouse/Intake				2,046	
3	**Equipment**					
a	Turbine, generator, & governor		1	701,858	702	Runner 1.25m, estimated costs developed from recent projects
b	Shipping Handling & Installation		1	163,372	163	20% of equipment costs
c	Switchgear		1	20,000	20	Fostiak Eng. (2010)
d	Instrumentation & Controls		1	50,000	50	Allowance, includes license min flow verification
e	Station Service, MCC		1	20,000	20	Allowance
f	Protection		1	25,000	25	Allowance
g	Subtotal, Equipment				980	
8	**PM&E Measures**					
a	Water Quality		1	40,000	40	Allowance for monitoring
b	D/S fish passage		0	20,000	0	Assumes installed by others
c	Min flow verification		0	5,000	0	Included in Instrumentation & Controls
d	Wetlands	acre	1.5	60,000	90	Allowance for impacts from penstock alignment
e	Recreation		1	20,000	20	Allowance
f	Cultural		1	7,500	8	Allowance
g	Subtotal, PM&E				158	
9	**Licensing & Permitting**					
a	Consultations	year	3	50,000	150	Allowance
b	Studies	year	2.5	75,000	188	Alowance; assumes instream flow studies
c	Draft FERC Application		1	50,000	50	Allowance
d	Final FERC Application		1	25,000	25	Allowance
e	Legal review		1	25,000	25	Allowance
f	Non-FERC Permits		1	50,000	50	Allowance: WQC, Wetlands, S. 106, S. 404, CZM, etc.
g	Subtotal, Lic. & Permitting				488	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
10	**Land & Land Rights**					
a	Flowage rights		1	5,000	5	Allowance
b	Project works, land in fee		1	20,000	20	Allowance for penstock alignment
c	Interconnection R.O.W.		1	5,000	5	Allowance
d	Legal		1	10,000	10	Allowance
e	Other				0	
f	Subtotal, Land				40	
11	**Interconnection**					
a	Clear & Grub	acre	1	6,200	6	Allowance
b	New Line		1	52,000	52	Fostiak Eng. (2010)
c	Metering		1	10,000	10	Allowance
c	Switchyard		1	50,000	50	Includes: sectionalizers, transformers, disconnect switch. From Interconnection Costs (Fostiak Eng. 2010)
d	Consultations		1	20,000	20	Allowance
f	Subtotal, Interconnection				138	
12	**Indirect Costs**					
a	A/E		1	336,485	336	8% of Direct Costs
b	Construction Management		1	25,000	25	Allowance
c	Testing		1	20,000	20	geo-tech, concrete
d	FERC submittals		1	35,000	35	Design Report, Status Reports
e	Owner's Admin & Overhead		1	100,000	100	Allowance
f	Other				0	
g	Subtotal, Indirects				516	
	Totals					
1	General				357	
2	Powerhouse/Intake				2,046	
3	Equipment				980	
8	PM&E Measures				158	
9	Licensing & Permitting				488	
10	Land & Land Rights				40	
11	Interconnection				138	
	Subtotal, Directs				4,206	
12	Indirect Costs				516	
	Subtotal				4,723	
13	Contingency		$4,722,549	20%	945	
	Grand Total				**5,667**	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
1	**General**					
a	Mob/Demob		1	25,000	25	Allowance
b	Site Prep		1	10,000	10	Allowance
c	Clear & Grub	acre	4	8,000	32	Allowance, includes penstock alignment
d	E&S Control	ft.	2000	10	20	Allowance, includes penstock alignment
e	Dam Repairs		1	270,000	270	Phase I Dam Repair Cost (MBP Consulting)
f	Subtotal, General				357	
2	**Powerhouse/Intake**					
a	Coffer dam, Pond				100	Allowance
b	Cofferdam, Tailrace				10	Allowance
c	Powerhouse Civil		1	576,264	576	Includes: intake, powerhouse, tailrace and trashrake
k	Penstock	ft.	2300	445	1,023	4.3' diameter penstock. Includes: materials, shipping & installation
l	Misc. metals		1	5,000	5	Allowance
m	HVAC		1	10,000	10	Allowance
n	Auxilliary Mechanical		1	10,000	10	Allowance
o	Lighting, auxilliary electrical		1	5,000	5	Allowance
p	Other				0	
q	Subtotal, Powerhouse/Intake				1,739	
3	**Equipment**					
a	Turbine, generator, & governor		1	455,227	455	900mm runner, estimated costs developed from recent projects
b	Shipping Handling & Installation		1	114,045	114	20% of equipment costs
c	Switchgear		1	20,000	20	Fostiak Eng. (2010)
d	Instrumentation & Controls		1	50,000	50	Allowance, includes license min flow verification
e	Station Service, MCC		1	20,000	20	Allowance
f	Protection		1	25,000	25	Allowance
g	Subtotal, Equipment				684	
8	**PM&E Measures**					
a	Water Quality		1	40,000	40	Allowance for monitoring
b	D/S fish passage		0	20,000	0	Assumes installed by others
c	Min flow verification		0	5,000	0	Included in Instrumentation & Controls
d	Wetlands	acre	3	60,000	180	Allowance for impacts from penstock and tailrace alignment
e	Recreation		1	20,000	20	Allowance
f	Cultural		1	7,500	8	Allowance
g	Subtotal, PM&E				248	
9	**Licensing & Permitting**					
a	Consultations	year	3	50,000	150	Allowance
b	Studies	year	2	75,000	150	Alowance; assumes acceptance of standard instream flow settings
c	Draft FERC Application		1	50,000	50	Allowance
d	Final FERC Application		1	25,000	25	Allowance
e	Legal review		1	25,000	25	Allowance
f	Non-FERC Permits		1	50,000	50	Allowance: WQC, Wetlands, S. 106, S. 404, CZM, etc.
g	Subtotal, Lic. & Permitting				450	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
10	**Land & Land Rights**					
a	Flowage rights		1	5,000	5	Allowance
b	Project works, land in fee		1	20,000	20	Allowance for penstock alignment
c	Interconnection R.O.W.		1	5,000	5	Allowance
d	Legal		1	10,000	10	Allowance
e	Other				0	
f	Subtotal, Land				40	
11	**Interconnection**					
a	Clear & Grub	acre	1	6,200	6	Allowance
b	New Line		1	52,000	52	Fostiak Eng. (2010)
c	Metering		1	10,000	10	Allowance
c	Switchyard		1	50,000	50	Includes: sectionalizers, transformers, disconnect switch. From Interconnection Costs (Fostiak Eng. 2010)
d	Consultations		1	20,000	20	Allowance
f	Subtotal, Interconnection				138	
12	**Indirect Costs**					
a	A/E		1	292,469	292	8% of Direct Costs
b	Construction Management		1	25,000	25	Allowance
c	Testing		1	20,000	20	geo-tech, concrete
d	FERC submittals		1	35,000	35	Design Report, Status Reports
e	Owner's Admin & Overhead		1	100,000	100	Allowance
f	Other				0	
g	Subtotal, Indirects				472	
	Totals					
1	General				357	
2	Powerhouse/Intake				1,739	
3	Equipment				684	
8	PM&E Measures				248	
9	Licensing & Permitting				450	
10	Land & Land Rights				40	
11	Interconnection				138	
	Subtotal, Directs				3,656	
12	Indirect Costs				472	
	Subtotal				4,128	
13	Contingency		$4,128,326	20%	826	
	Grand Total				**4,954**	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
1	**General**					
a	Mob/Demob		1	25,000	25	Allowance
b	Site Prep		1	10,000	10	Allowance
c	Clear & Grub	acre	4	8,000	32	Allowance, includes penstock alignment
d	E&S Control	ft.	2000	10	20	Allowance, includes penstock alignment
e	Dam Repairs		1	270,000	270	Phase I Dam Repair Cost (MBP Consulting)
f	Subtotal, General				357	
2	**Powerhouse/Intake**					
a	Coffer dam, Pond				100	Allowance
b	Cofferdam, Tailrace				10	Allowance
c	Powerhouse Civil		1	592,940	593	Includes: intake, powerhouse, tailrace and trashrake
k	Penstock	ft.	2300	475	1,092	Assumes 4.6' diameter penstock. Includes: materials, shipping & installation
l	Misc. metals		1	5,000	5	Allowance
m	HVAC		1	10,000	10	Allowance
n	Auxilliary Mechanical		1	10,000	10	Allowance
o	Lighting, auxilliary electrical		1	5,000	5	Allowance
p	Other				0	
q	Subtotal, Powerhouse/Intake				1,825	
3	**Equipment**					
a	Turbine, generator, & governor		1	485,210	485	950mm, Costs developed from recent projects
b	Shipping Handling & Installation		1	120,042	120	20% of equipment costs
c	Switchgear		1	20,000	20	Fostiak Eng. (2010)
d	Instrumentation & Controls		1	50,000	50	Allowance, includes license min flow verification
e	Station Service, MCC		1	20,000	20	Allowance
f	Protection		1	25,000	25	Allowance
g	Subtotal, Equipment				720	
8	**PM&E Measures**					
a	Water Quality		1	40,000	40	Allowance for monitoring
b	D/S fish passage		0	20,000	0	Assumes installed by others
c	Min flow verification		0	5,000	0	Included in Instrumentation & Controls
d	Wetlands	acre	3	60,000	180	Allowance for impacts from penstock and tailrace alignment
e	Recreation		1	20,000	20	Allowance
f	Cultural		1	7,500	8	Allowance
g	Subtotal, PM&E				248	
9	**Licensing & Permitting**					
a	Consultations	year	3	50,000	150	Allowance
b	Studies	year	3	75,000	225	Alowance; assumes instream flow studies
c	Draft FERC Application		1	50,000	50	Allowance
d	Final FERC Application		1	25,000	25	Allowance
e	Legal review		1	25,000	25	Allowance
f	Non-FERC Permits		1	50,000	50	Allowance: WQC, Wetlands, S. 106, S. 404, CZM, etc.
g	Subtotal, Lic. & Permitting				525	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
10	**Land & Land Rights**					
a	Flowage rights		1	5,000	5	Allowance
b	Project works, land in fee		1	20,000	20	Allowance for penstock alignment
c	Interconnection R.O.W.		1	5,000	5	Allowance
d	Legal		1	10,000	10	Allowance
e	Other				0	
f	Subtotal, Land				40	
11	**Interconnection**					
a	Clear & Grub	acre	1	6,200	6	Allowance
b	New Line		1	52,000	52	Fostiak Eng. (2010)
c	Metering		1	10,000	10	Allowance
c	Switchyard		1	50,000	50	Includes: sectionalizers, transformers, disconnect switch. From Interconnection Costs (Fostiak Eng. 2010)
d	Consultations		1	20,000	20	Allowance
f	Subtotal, Interconnection				138	
12	**Indirect Costs**					
a	A/E		1	308,228	308	8% of Direct Costs
b	Construction Management		1	25,000	25	Allowance
c	Testing		1	20,000	20	geo-tech, concrete
d	FERC submittals		1	35,000	35	Design Report, Status Reports
e	Owner's Admin & Overhead		1	100,000	100	Allowance
f	Other				0	
g	Subtotal, Indirects				488	
	Totals					
1	General				357	
2	Powerhouse/Intake				1,825	
3	Equipment				720	
8	PM&E Measures				248	
9	Licensing & Permitting				525	
10	Land & Land Rights				40	
11	Interconnection				138	
	Subtotal, Directs				3,853	
12	Indirect Costs				488	
	Subtotal				4,341	
13	Contingency		$4,341,074	20%	868	
	Grand Total				**5,209**	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
1	**General**					
a	Mob/Demob		1	25,000	25	Allowance
b	Site Prep		1	10,000	10	Allowance
c	Clear & Grub	acre	4	8,000	32	Allowance, includes penstock alignment
d	E&S Control	ft.	2000	10	20	Allowance, includes penstock alignment
e	Dam Repairs		1	270,000	270	Phase I Dam Repair Cost (MBP Consulting)
f	Subtotal, General				357	
2	**Powerhouse/Intake**					
a	Coffer dam, Pond				100	Allowance
b	Cofferdam, Tailrace				10	Allowance
c	Powerhouse Civil		1	677,586	678	Includes: intake, powerhouse, tailrace and trashrake
k	Penstock	ft.	2300	614	1,412	5.8' diameter penstock. Includes: material, transporation and installation
l	Misc. metals		1	5,000	5	Allowance
m	HVAC		1	10,000	10	Allowance
n	Auxilliary Mechanical		1	10,000	10	Allowance
o	Lighting, auxilliary electrical		1	5,000	5	Allowance
p	Other				0	
q	Subtotal, Powerhouse/Intake				2,230	
3	**Equipment**					
a	Turbine, generator, & governor		1	701,858	702	Runner 1.25m, estimated costs developed from recent projects
b	Shipping Handling & Installation		1	163,372	163	20% of equipment costs
c	Switchgear		1	20,000	20	Fostiak Eng. (2010)
d	Instrumentation & Controls		1	50,000	50	Allowance, includes license min flow verification
e	Station Service, MCC		1	20,000	20	Allowance
f	Protection		1	25,000	25	Allowance
g	Subtotal, Equipment				980	
8	**PM&E Measures**					
a	Water Quality		1	40,000	40	Allowance for monitoring
b	D/S fish passage		0	20,000	0	Assumes installed by others
c	Min flow verification		0	5,000	0	Included in Instrumentation & Controls
d	Wetlands	acre	3	60,000	180	Allowance for impacts from penstock and tailrace alignment
e	Recreation		1	20,000	20	Allowance
f	Cultural		1	7,500	8	Allowance
g	Subtotal, PM&E				248	
9	**Licensing & Permitting**					
a	Consultations	year	3	50,000	150	Allowance
b	Studies	year	3	75,000	225	Alowance; assumes instream flow studies
c	Draft FERC Application		1	50,000	50	Allowance
d	Final FERC Application		1	25,000	25	Allowance
e	Legal review		1	25,000	25	Allowance
f	Non-FERC Permits		1	50,000	50	Allowance: WQC, Wetlands, S. 106, S. 404, CZM, etc.
g	Subtotal, Lic. & Permitting				525	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
10	**Land & Land Rights**					
a	Flowage rights		1	5,000	5	Allowance
b	Project works, land in fee		1	20,000	20	Allowance for penstock alignment
c	Interconnection R.O.W.		1	5,000	5	Allowance
d	Legal		1	10,000	10	Allowance
e	Other				0	
f	Subtotal, Land				40	
11	**Interconnection**					
a	Clear & Grub	acre	1	6,200	6	Allowance
b	New Line		1	52,000	52	Fostiak Eng. (2010)
c	Metering		1	10,000	10	Allowance
c	Switchyard		1	50,000	50	Includes: sectionalizers, transformers, disconnect switch. From Interconnection Costs (Fostiak Eng. 2010)
d	Consultations		1	20,000	20	Allowance
f	Subtotal, Interconnection				138	
12	**Indirect Costs**					
a	A/E		1	361,422	361	8% of Direct Costs
b	Construction Management		1	25,000	25	Allowance
c	Testing		1	20,000	20	geo-tech, concrete
d	FERC submittals		1	35,000	35	Design Report, Status Reports
e	Owner's Admin & Overhead		1	100,000	100	Allowance
f	Other				0	
g	Subtotal, Indirects				541	
	Totals					
1	General				357	
2	Powerhouse/Intake				2,230	
3	Equipment				980	
8	PM&E Measures				248	
9	Licensing & Permitting				525	
10	Land & Land Rights				40	
11	Interconnection				138	
	Subtotal, Directs				4,518	
12	Indirect Costs				541	
	Subtotal				5,059	
13	Contingency		$5,059,193	20%	1,012	
	Grand Total				**6,071**	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
1	**General**					
a	Mob/Demob		1	25,000	25	Allowance
b	Site Prep		1	10,000	10	Allowance
c	Clear & Grub	acre	4	8,000	32	Allowance, includes penstock alignment
d	E&S Control	ft.	2000	10	20	Allowance, includes penstock alignment
e	Dam Repairs		1	270,000	270	Phase I Dam Repair Cost (MBP Consulting)
f	Subtotal, General				357	
2	**Powerhouse/Intake**					
a	Coffer dam, Pond				100	Allowance
b	Cofferdam, Tailrace				10	Allowance
c	Powerhouse Civil		1	100,000	100	Includes: intake, trashracks & powerhouse repairs
k	Penstock	ft.	2300	445	1,023	4.3' diameter penstock. Includes: material, shipping & installation
l	Misc. metals		1	5,000	5	Allowance
m	HVAC		1	10,000	10	Allowance
n	Auxilliary Mechanical		1	10,000	10	Allowance
o	Lighting, auxilliary electrical		1	5,000	5	Allowance
p	Trashrake		1	150,000	150	
q	Subtotal, Powerhouse/Intake				1,413	
3	**Equipment**					
a	Turbine, generator, & governor		1	400,000	400	Allowance
b	Shipping Handling & Installation		1	103,000	103	20% of equipment costs
c	Switchgear		1	20,000	20	Fostiak Eng. (2010)
d	Instrumentation & Controls		1	50,000	50	Allowance, includes license min flow verification
e	Station Service, MCC		1	20,000	20	Allowance
f	Protection		1	25,000	25	Allowance
g	Subtotal, Equipment				618	
8	**PM&E Measures**					
a	Water Quality		1	40,000	40	Allowance for monitoring
b	D/S fish passage		0	20,000	0	Assumes installed by others
c	Min flow verification		0	5,000	0	Included in Instrumentation & Controls
d	Wetlands	acre	3	60,000	180	Allowance for impacts from penstock and tailrace alignment
e	Recreation		1	20,000	20	Allowance
f	Cultural		1	7,500	8	Allowance
g	Subtotal, PM&E				248	
9	**Licensing & Permitting**					
a	Consultations	year	3	50,000	150	Allowance
b	Studies	year	2	75,000	150	Alowance; assumes acceptance of standard instream flow settings
c	Draft FERC Application		1	50,000	50	Allowance
d	Final FERC Application		1	25,000	25	Allowance
e	Legal review		1	25,000	25	Allowance
f	Non-FERC Permits		1	50,000	50	Allowance: WQC, Wetlands, S. 106, S. 404, CZM, etc.
g	Subtotal, Lic. & Permitting				450	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
10	**Land & Land Rights**					
a	Flowage rights		1	5,000	5	Allowance
b	Project works, land in fee		1	20,000	20	Allowance for penstock alignment
c	Interconnection R.O.W.		1	5,000	5	Allowance
d	Legal		1	10,000	10	Allowance
e	Other				0	
f	Subtotal, Land				40	
11	**Interconnection**					
a	Clear & Grub	acre	1	6,200	6	Allowance
b	New Line		1	52,000	52	Fostiak Eng. (2010)
c	Metering		1	10,000	10	Allowance
c	Switchyard		1	50,000	50	Includes: sectionalizers, transformers, disconnect switch. From Interconnection Costs (Fostiak Eng. 2010)
d	Consultations		1	20,000	20	Allowance
f	Subtotal, Interconnection				138	
12	**Indirect Costs**					
a	A/E		1	261,066	261	8% of Direct Costs
b	Construction Management		1	25,000	25	Allowance
c	Testing		1	20,000	20	geo-tech, concrete
d	FERC submittals		1	35,000	35	Design Report, Status Reports
e	Owner's Admin & Overhead		1	100,000	100	Allowance
f	Other				0	
g	Subtotal, Indirects				441	
	Totals					
1	General				357	
2	Powerhouse/Intake				1,413	
3	Equipment				618	
8	PM&E Measures				248	
9	Licensing & Permitting				450	
10	Land & Land Rights				40	
11	Interconnection				138	
	Subtotal, Directs				3,263	
12	Indirect Costs				441	
	Subtotal				3,704	
13	Contingency		$3,704,388	20%	741	
	Grand Total				**4,445**	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
1	**General**					
a	Mob/Demob		1	25,000	25	Allowance
b	Site Prep		1	10,000	10	Allowance
c	Clear & Grub	acre	0.5	8,000	4	Allowance
d	E&S Control	ft.	100	10	1	Allowance
e	Dam Repairs		1	50,000	50	Phase I Dam Repair Cost Est. (MBP Consulting 2010)
f	Subtotal, General				90	
2	**Powerhouse/Intake**					
a	Coffer dam, Pond				100	Allowance
b	Cofferdam, Tailrace				10	Allowance
c	Powerhouse Civil		1	677,586	678	Includes: intake, powerhouse, tailrace and trashrake
k	Sluice gate		1	20,000	20	
l	Misc. metals		1	5,000	5	Allowance
m	HVAC		1	10,000	10	Allowance
n	Auxilliary Mechanical		1	10,000	10	Allowance
o	Lighting, auxilliary electrical		1	5,000	5	Allowance
p	Other				0	
q	Subtotal, Powerhouse/Intake				838	
3	**Equipment**					
a	Turbine, generator, & governor		1	701,858	702	Runner 1.25m, estimated costs developed from recent projects
b	Shipping Handling & Installation		1	163,372	163	20% of equipment costs
c	Switchgear		1	20,000	20	Fostiak Eng. (2010)
d	Instrumentation & Controls		1	50,000	50	Allowance, includes license min flow verification
e	Station Service, MCC		1	20,000	20	Allowance
f	Protection		1	25,000	25	Allowance
g	Subtotal, Equipment				980	
8	**PM&E Measures**					
a	Water Quality		1	20,000	20	Allowance
b	D/S fish passage		0	20,000	0	Assumes installed by others
c	Min flow verification		0	5,000	0	Included in Instrumentation & Controls
d	Wetlands	acre	0.5	60,000	30	Allowance
e	Recreation		1	20,000	20	Allowance
f	Cultural		1	7,500	8	Allowance
g	Subtotal, PM&E				78	
9	**Licensing & Permitting**					
a	Consultations	year	2	50,000	100	Allowance
b	Studies	year	0.5	75,000	38	Allowance
c	Draft FERC Application		1	50,000	50	Allowance
d	Final FERC Application		1	25,000	25	Allowance
e	Legal review		1	25,000	25	Allowance
f	Non-FERC Permits		1	50,000	50	Allowance: WQC, Wetlands, S. 106, S. 404, CZM, etc.
g	Subtotal, Lic. & Permitting				288	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
10	**Land & Land Rights**					
a	Flowage rights		1	5,000	5	Allowance
b	Project works, land in fee		1		0	
c	Interconnection R.O.W.		1	5,000	5	Allowance
d	Legal		1	10,000	10	Allowance
e	Other				0	
f	Subtotal, Land				20	
11	**Interconnection**					
a	Clear & Grub	acre	0.5	8,000	4	Allowance
b	New Line		1	52,000	52	Fostiak Eng. (2010)
c	Metering		1	10,000	10	Allowance
c	Switchyard		1	50,000	50	Includes: sectionalizers, transformers, disconnect switch. From Interconnection Costs (Fostiak Eng. 2010)
d	Consultations		1	20,000	20	Allowance
f	Subtotal, Interconnection				136	
12	**Indirect Costs**					
a	A/E		1	194,305	194	8% of Direct Costs
b	Construction Management		1	25,000	25	Allowance
c	Testing		1	20,000	20	geo-tech, concrete
d	FERC submittals		1	35,000	35	Design Report, Status Reports
e	Owner's Admin & Overhead		1	100,000	100	Allowance
f	Other				0	
g	Subtotal, Indirects				374	
	Totals					
1	General				90	
2	Powerhouse/Intake				838	
3	Equipment				980	
8	PM&E Measures				78	
9	Licensing & Permitting				288	
10	Land & Land Rights				20	
11	Interconnection				136	
	Subtotal, Directs				2,429	
12	Indirect Costs				374	
	Subtotal				2,803	
13	Contingency		$2,803,121	20%	561	
	Grand Total				**3,364**	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
1	**General**					
a	Mob/Demob		1	25,000	25	Allowance
b	Site Prep		1	10,000	10	Allowance
c	Clear & Grub	acre	4	6,200	25	Allowance, includes penstock alignment
d	E&S Control	ft.	2000	10	20	Allowance, includes penstock alignment
e	Dam Repairs		1	50,000	50	Phase I Dam Repair Cost (MBP Consulting)
f	Subtotal, General				130	
2	**Powerhouse/Intake**					
a	Coffer dam, Pond				100	Allowance
b	Cofferdam, Tailrace				10	Allowance
c	Powerhouse Civil		1	576,264	576	Includes: intake, powerhouse, tailrace and trashrake
k	Penstock	ft.	300	445	133	4.3' diameter penstock. Includes: materials, shipping & installation
l	Misc. metals		1	5,000	5	Allowance
m	HVAC		1	10,000	10	Allowance
n	Auxilliary Mechanical		1	10,000	10	Allowance
o	Lighting, auxilliary electrical		1	5,000	5	Allowance
p		ea			0	
q	Subtotal, Powerhouse/Intake				850	
3	**Equipment**					
a	Turbine, generator, & governor		1	455,227	455	900 mm runner, Estimated costs developed from recent projects
b	Shipping Handling & Installation		1	114,045	114	20% of equipment costs
c	Switchgear		1	20,000	20	Fostiak Eng. (2010)
d	Instrumentation & Controls		1	50,000	50	Allowance, includes license min flow verification
e	Station Service, MCC		1	20,000	20	Allowance
f	Protection		1	25,000	25	Allowance
g	Subtotal, Equipment				684	
8	**PM&E Measures**					
a	Water Quality		1	40,000	40	Allowance for monitoring
b	D/S fish passage		0	20,000	0	Assumes installed by others
c	Min flow verification		0	5,000	0	Included in Instrumentation & Controls
d	Wetlands	acre	1.5	60,000	90	Allowance for impacts from tailrace
e	Recreation		1	20,000	20	Allowance
f	Cultural		1	7,500	8	Allowance
g	Subtotal, PM&E				158	
9	**Licensing & Permitting**					
a	Consultations	year	2	50,000	100	Allowance
b	Studies	year	2	75,000	150	Alowance; assumes acceptance of standard instream flow settings
c	Draft FERC Application		1	50,000	50	Allowance
d	Final FERC Application		1	25,000	25	Allowance
e	Legal review		1	25,000	25	Allowance
f	Non-FERC Permits		1	50,000	50	Allowance: WQC, Wetlands, S. 106, S. 404, CZM, etc.
g	Subtotal, Lic. & Permitting				400	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
10	**Land & Land Rights**					
a	Flowage rights		1	5,000	5	Allowance
b	Project works, land in fee		1	20,000	20	Allowance for penstock alignment
c	Interconnection R.O.W.		1	5,000	5	Allowance
d	Legal		1	10,000	10	Allowance
e	Other				0	
f	Subtotal, Land				40	
11	**Interconnection**					
a	Clear & Grub	acre	1	6,200	6	Allowance
b	New Line		1	52,000	52	Fostiak Eng. (2010)
c	Metering		1	10,000	10	Allowance
c	Switchyard		1	50,000	50	Fostiak Eng. (2010)
d	Consultations		1	20,000	20	Allowance
f	Subtotal, Interconnection				138	
12	**Indirect Costs**					
a	A/E		1	191,954	192	8% of Direct Costs
b	Construction Management		1	25,000	25	Allowance
c	Testing		1	20,000	20	geo-tech, concrete
d	FERC submittals		1	35,000	35	Design Report, Status Reports
e	Owner's Admin & Overhead		1	100,000	100	Allowance
f	Other				0	
g	Subtotal, Indirects				372	
	Totals					
1	General				130	
2	Powerhouse/Intake				850	
3	Equipment				684	
8	PM&E Measures				158	
9	Licensing & Permitting				400	
10	Land & Land Rights				40	
11	Interconnection				138	
	Subtotal, Directs				2,399	
12	Indirect Costs				372	
	Subtotal				2,771	
13	Contingency		$2,771,375	20%	554	
	Grand Total				**3,326**	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
1	**General**					
a	Mob/Demob		1	25,000	25	Allowance
b	Site Prep		1	10,000	10	Allowance
c	Clear & Grub	acre	4	6,200	25	Allowance, includes penstock alignment
d	E&S Control	ft.	2000	10	20	Allowance, includes penstock alignment
e	Dam Repairs		1	50,000	50	Phase I Dam Repair Cost (MBP Consulting)
f	Subtotal, General				130	
2	**Powerhouse/Intake**					
a	Coffer dam, Pond				100	Allowance
b	Cofferdam, Tailrace				10	Allowance
c	Powerhouse Civil		1	592,940	593	Includes: intake, powerhouse, tailrace and trashrake
k	Penstock	ft.	300	475	142	Assumes 4.6' diameter penstock. Includes: materials, shipping & installation
l	Misc. metals		1	5,000	5	Allowance
m	HVAC		1	10,000	10	Allowance
n	Auxilliary Mechanical		1	10,000	10	Allowance
o	Lighting, auxilliary electrical		1	5,000	5	Allowance
p	Other				0	
q	Subtotal, Powerhouse/Intake				875	
3	**Equipment**					
a	Turbine, generator, & governor		1	485,210	485	950mm runner, estimated costs developed from recent projects
b	Shipping Handling & Installation		1	120,042	120	20% of equipment costs
c	Switchgear		1	20,000	20	Fostiak Eng. (2010)
d	Instrumentation & Controls		1	50,000	50	Allowance, includes license min flow verification
e	Station Service, MCC		1	20,000	20	Allowance
f	Protection		1	25,000	25	Allowance
g	Subtotal, Equipment				720	
8	**PM&E Measures**					
a	Water Quality		1	40,000	40	Allowance for monitoring
b	D/S fish passage		0	20,000	0	Assumes installed by others
c	Min flow verification		0	5,000	0	Included in Instrumentation & Controls
d	Wetlands	acre	1.5	60,000	90	Allowance for impacts from tailrace alignment
e	Recreation		1	20,000	20	Allowance
f	Cultural		1	7,500	8	Allowance
g	Subtotal, PM&E				158	
9	**Licensing & Permitting**					
a	Consultations	year	3	50,000	150	Allowance
b	Studies	year	2.5	75,000	188	Alowance; assumes instream flow studies
c	Draft FERC Application		1	50,000	50	Allowance
d	Final FERC Application		1	25,000	25	Allowance
e	Legal review		1	25,000	25	Allowance
f	Non-FERC Permits		1	50,000	50	Allowance: WQC, Wetlands, S. 106, S. 404, CZM, etc.
g	Subtotal, Lic. & Permitting				488	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
10	**Land & Land Rights**					
a	Flowage rights		1	5,000	5	Allowance
b	Project works, land in fee		1	20,000	20	Allowance for penstock alignment
c	Interconnection R.O.W.		1	5,000	5	Allowance
d	Legal		1	10,000	10	Allowance
e	Other				0	
f	Subtotal, Land				40	
11	**Interconnection**					
a	Clear & Grub	acre	1	6,200	6	Allowance
b	New Line		1	52,000	52	Fostiak Eng. (2010)
c	Metering		1	10,000	10	Allowance
c	Switchyard		1	50,000	50	Fostiak Eng. (2010)
d	Consultations		1	20,000	20	Allowance
f	Subtotal, Interconnection				138	
12	**Indirect Costs**					
a	A/E		1	203,890	204	8% of Direct Costs
b	Construction Management		1	25,000	25	Allowance
c	Testing		1	20,000	20	geo-tech, concrete
d	FERC submittals		1	35,000	35	Design Report, Status Reports
e	Owner's Admin & Overhead		1	100,000	100	Allowance
f	Other				0	
g	Subtotal, Indirects				384	
	Totals					
1	General				130	
2	Powerhouse/Intake				875	
3	Equipment				720	
8	PM&E Measures				158	
9	Licensing & Permitting				488	
10	Land & Land Rights				40	
11	Interconnection				138	
	Subtotal, Directs				2,549	
12	Indirect Costs				384	
	Subtotal				2,933	
13	Contingency		$2,932,510	20%	587	
	Grand Total				**3,519**	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
1	**General**					
a	Mob/Demob		1	25,000	25	Allowance
b	Site Prep		1	10,000	10	Allowance
c	Clear & Grub	acre	4	6,200	25	Allowance, includes penstock alignment
d	E&S Control	ft.	2000	10	20	Allowance, includes penstock alignment
e	Dam Repairs		1	50,000	50	Phase I Dam Repair Cost (MBP Consulting)
f	Subtotal, General				130	
2	**Powerhouse/Intake**					
a	Coffer dam, Pond				100	Allowance
b	Cofferdam, Tailrace				10	Allowance
c	Powerhouse Civil		1	677,586	678	Includes: intake, powerhouse, tailrace and trashrake
k	Penstock	ft.	300	614	184	5.8' diameter penstock. Includes: material, transporation and installation
l	Misc. metals		1	5,000	5	Allowance
m	HVAC		1	10,000	10	Allowance
n	Auxilliary Mechanical		1	10,000	10	Allowance
o	Lighting, auxilliary electrical		1	5,000	5	Allowance
p	Other	ea			0	
q	Subtotal, Powerhouse/Intake				1,002	
3	**Equipment**					
a	Turbine, generator, & governor		1	701,858	702	Runner 1.25m, estimated costs developed from recent projects
b	Shipping Handling & Installation		1	163,372	163	20% of equipment costs
c	Switchgear		1	20,000	20	Fostiak Eng. (2010)
d	Instrumentation & Controls		1	50,000	50	Allowance, includes license min flow verification
e	Station Service, MCC		1	20,000	20	Allowance
f	Protection		1	25,000	25	Allowance
g	Subtotal, Equipment				980	
8	**PM&E Measures**					
a	Water Quality		1	40,000	40	Allowance for monitoring
b	D/S fish passage		0	20,000	0	Assumes installed by others
c	Min flow verification		0	5,000	0	Included in Instrumentation & Controls
d	Wetlands	acre	1.5	60,000	90	Allowance for impacts from tailrace alignment
e	Recreation		1	20,000	20	Allowance
f	Cultural		1	7,500	8	Allowance
g	Subtotal, PM&E				158	
9	**Licensing & Permitting**					
a	Consultations	year	3	50,000	150	Allowance
b	Studies	year	2.5	75,000	188	Alowance; assumes instream flow studies
c	Draft FERC Application		1	50,000	50	Allowance
d	Final FERC Application		1	25,000	25	Allowance
e	Legal review		1	25,000	25	Allowance
f	Non-FERC Permits		1	50,000	50	Allowance: WQC, Wetlands, S. 106, S. 404, CZM, etc.
g	Subtotal, Lic. & Permitting				488	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
10	**Land & Land Rights**					
a	Flowage rights		1	5,000	5	Allowance
b	Project works, land in fee		1	20,000	20	Allowance for penstock alignment
c	Interconnection R.O.W.		1	5,000	5	Allowance
d	Legal		1	10,000	10	Allowance
e	Other				0	
f	Subtotal, Land				40	
11	**Interconnection**					
a	Clear & Grub	acre	1	6,200	6	Allowance
b	New Line		1	52,000	52	Fostiak Eng. (2010)
c	Metering		1	10,000	10	Allowance
c	Switchyard		1	50,000	50	Fostiak Eng. (2010)
d	Consultations		1	20,000	20	Allowance
f	Subtotal, Interconnection				138	
12	**Indirect Costs**					
a	A/E		1	234,802	235	8% of Direct Costs
b	Construction Management		1	25,000	25	Allowance
c	Testing		1	20,000	20	geo-tech, concrete
d	FERC submittals		1	35,000	35	Design Report, Status Reports
e	Owner's Admin & Overhead		1	100,000	100	Allowance
f	Other				0	
g	Subtotal, Indirects				415	
	Totals					
1	General				130	
2	Powerhouse/Intake				1,002	
3	Equipment				980	
8	PM&E Measures				158	
9	Licensing & Permitting				488	
10	Land & Land Rights				40	
11	Interconnection				138	
	Subtotal, Directs				2,935	
12	Indirect Costs				415	
	Subtotal				3,350	
13	Contingency		$3,349,825	20%	670	
	Grand Total				**4,020**	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
1	**General**					
a	Mob/Demob		1	25,000	25	Allowance
b	Site Prep		1	10,000	10	Allowance
c	Clear & Grub	acre	4	6,200	25	Allowance, includes penstock alignment
d	E&S Control	ft.	2000	10	20	Allowance, includes penstock alignment
e	Dam Repairs		1	220,000	220	Phase I Dam Repair Cost (MBP Consulting)
f	Subtotal, General				300	
2	**Powerhouse/Intake**					
a	Coffer dam, Pond				100	Allowance
b	Tailrace (cofferdam and excavation)				25	Allowance
c	Powerhouse Civil		1	100,000	100	Allowance for intake, trashracks and powerhouse repairs
k	Penstock	ft.	300	445	133	Assumes 4.3' diameter penstock. Includes: materials, shipping & installation
l	Misc. metals		1	5,000	5	Allowance
m	HVAC		1	10,000	10	Allowance
n	Auxilliary Mechanical		1	10,000	10	Allowance
o	Lighting, auxilliary electrical		1	5,000	5	Allowance
p	Trash Rake	ea	1	150,000	150	Allowance
q	Subtotal, Powerhouse				538	
3	**Equipment**					
a	Turbine, generator, & governor		1	400,000	400	Allowance
b	Shipping Handling & Installation		1	103,000	103	20% of equipment costs
c	Switchgear		1	20,000	20	Fostiak Eng. (2010)
d	Instrumentation & Controls		1	50,000	50	Allowance
e	Station Service, MCC		1	20,000	20	Allowance
f	Protection		1	25,000	25	Allowance
g	Subtotal, Equipment				618	
8	**PM&E Measures**					
a	Water Quality		1	40,000	40	Allowance for monitoring
b	D/S fish passage		0	20,000	0	Assumes installed by others
c	Min flow verification		1	5,000	5	Allowance
d	Wetlands	acre	1.5	60,000	90	Allowance for impacts from tailrace alignment
e	Recreation		1	25,000	25	Allowance
f	Cultural		1	7,500	8	Allowance
g	Subtotal, PM&E				168	
9	**Licensing & Permitting**					
a	Consultations	year	2	50,000	100	Allowance
b	Studies	year	2	75,000	150	Alowance; assumes acceptance of standard instream flow settings
c	Draft FERC Application		1	50,000	50	Allowance
d	Final FERC Application		1	25,000	25	Allowance
e	Legal review		1	25,000	25	Allowance
f	Non-FERC Permits		1	50,000	50	Allowance: WQC, Wetlands, S. 106, S. 404, CZM, etc.
g	Subtotal, Lic. & Permitting				400	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
10	**Land & Land Rights**					
a	Flowage rights		1	5,000	5	Allowance
b	Project works, land in fee		1	20,000	20	Allowance for penstock alignment
c	Interconnection R.O.W.		1	5,000	5	Allowance
d	Legal		1	10,000	10	Allowance
e	Other				0	
f	Subtotal, Land				40	
11	**Interconnection**					
a	Clear & Grub	acre	1	6,200	6	Allowance
b	New Line		1	52,000	52	Fostiak Eng. (2010)
c	Metering		1	10,000	10	Allowance
c	Switchyard		1	50,000	50	Includes: sectionalizers, transformers, disconnect switch. From Interconnection Costs (Fostiak Eng. 2010)
d	Consultations		1	20,000	20	Allowance
f	Subtotal, Interconnection				138	
12	**Indirect Costs**					
a	A/E		1	176,151	176	8% of Direct Costs
b	Construction Management		1	25,000	25	Allowance
c	Testing		1	20,000	20	geo-tech, concrete
d	FERC submittals		1	35,000	35	Design Report, Status Reports
e	Owner's Admin & Overhead		1	100,000	100	Allowance
f	Other				0	
g	Subtotal, Indirects				356	
	Totals					
1	General				300	
2	Powerhouse/Intake				538	
3	Equipment				618	
8	PM&E Measures				168	
9	Licensing & Permitting				400	
10	Land & Land Rights				40	
11	Interconnection				138	
	Subtotal, Directs				2,202	
12	Indirect Costs				356	
	Subtotal				2,558	
13	Contingency		$2,558,036	20%	512	
	Grand Total				**3,070**	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
1	**General**					
a	Mob/Demob		1	25,000	25	Allowance
b	Site Prep		1	10,000	10	Allowance
c	Clear & Grub	acre	4	6,200	25	Allowance, includes penstock alignment
d	E&S Control	ft.	2000	10	20	Allowance, includes penstock alignment
e	Dam Repairs		1	220,000	220	Phase I Dam Repair Cost (MBP Consulting)
f	Subtotal, General				300	
2	**Powerhouse/Intake**					
a	Coffer dam, Pond				100	Allowance
b	Tailrace (cofferdam and excavation)				25	Allowance
c	Powerhouse Civil		1	100,000	100	Allowance for intake, trashracks and powerhouse repairs
k	Penstock	ft.	300	551	165	Assumes 5.21' diameter penstock. Includes: materials, shipping & installation
l	Misc. metals		1	5,000	5	Allowance
m	HVAC		1	10,000	10	Allowance
n	Auxilliary Mechanical		1	10,000	10	Allowance
o	Lighting, auxilliary electrical		1	5,000	5	Allowance
p	Trash Rake	ea	1	150,000	150	Allowance
q	Subtotal, Powerhouse				570	
3	**Equipment**					
a	Turbine, generator, & governor		1	475,000	475	Allowance for repowering 1.12m diameter Francis runner
b	Shipping Handling & Installation		1	118,000	118	20% of equipment costs
c	Switchgear		1	20,000	20	Fostiak Eng. (2010)
d	Instrumentation & Controls		1	50,000	50	Allowance
e	Station Service, MCC		1	20,000	20	Allowance
f	Protection		1	25,000	25	Allowance
g	Subtotal, Equipment				708	
8	**PM&E Measures**					
a	Water Quality		1	40,000	40	Allowance for monitoring
b	D/S fish passage		0	20,000	0	Assumes installed by others
c	Min flow verification		1	5,000	5	Allowance
d	Wetlands	acre	1.5	60,000	90	Allowance for impacts from tailrace alignment
e	Recreation		1	25,000	25	Allowance
f	Cultural		1	7,500	8	Allowance
g	Subtotal, PM&E				168	
9	**Licensing & Permitting**					
a	Consultations	year	2	50,000	100	Allowance
b	Studies	year	2	75,000	150	Alowance; assumes acceptance of standard instream flow settings
c	Draft FERC Application		1	50,000	50	Allowance
d	Final FERC Application		1	25,000	25	Allowance
e	Legal review		1	25,000	25	Allowance
f	Non-FERC Permits		1	50,000	50	Allowance: WQC, Wetlands, S. 106, S. 404, CZM, etc.
g	Subtotal, Lic. & Permitting				400	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
10	**Land & Land Rights**					
a	Flowage rights		1	5,000	5	Allowance
b	Project works, land in fee		1	20,000	20	Allowance for penstock alignment
c	Interconnection R.O.W.		1	5,000	5	Allowance
d	Legal		1	10,000	10	Allowance
e	Other				0	
f	Subtotal, Land				40	
11	**Interconnection**					
a	Clear & Grub	acre	1	6,200	6	Allowance
b	New Line		1	52,000	52	Fostiak Eng. (2010)
c	Metering		1	10,000	10	Allowance
c	Switchyard		1	50,000	50	Includes: sectionalizers, transformers, disconnect switch. From Interconnection Costs (Fostiak Eng. 2010)
d	Consultations		1	20,000	20	Allowance
f	Subtotal, Interconnection				138	
12	**Indirect Costs**					
a	A/E		1	185,904	186	8% of Direct Costs
b	Construction Management		1	25,000	25	Allowance
c	Testing		1	20,000	20	geo-tech, concrete
d	FERC submittals		1	35,000	35	Design Report, Status Reports
e	Owner's Admin & Overhead		1	100,000	100	Allowance
f	Other				0	
g	Subtotal, Indirects				366	
	Totals					
1	General				300	
2	Powerhouse/Intake				570	
3	Equipment				708	
8	PM&E Measures				168	
9	Licensing & Permitting				400	
10	Land & Land Rights				40	
11	Interconnection				138	
	Subtotal, Directs				2,324	
12	Indirect Costs				366	
	Subtotal				2,690	
13	Contingency		$2,689,704	20%	538	
	Grand Total				**3,228**	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
1	**General**					
a	Mob/Demob		1	25,000	25	Allowance
b	Site Prep		1	10,000	10	Allowance
c	Clear & Grub	acre	4	6,200	25	Allowance, includes penstock alignment
d	E&S Control	ft.	2000	10	20	Allowance, includes penstock alignment
e	Dam Repairs		1	220,000	220	Phase I Dam Repair Cost (MBP Consulting)
f	Subtotal, General				300	
2	**Powerhouse/Intake**					
a	Coffer dam, Pond				100	Allowance
b	Cofferdam, Tailrace				10	Allowance
c	Powerhouse Civil		1	100,000	100	Allowance for intake, trashracks and powerhouse repairs
k	Penstock	ft.	300	369	111	Assumes 3.7' diameter penstock. Includes: materials, shipping & installation
l	Misc. metals		1	5,000	5	Allowance
m	HVAC		1	10,000	10	Allowance
n	Auxilliary Mechanical		1	10,000	10	Allowance
o	Lighting, auxilliary electrical		1	5,000	5	Allowance
p	TrashRake	ea	1	150,000	150	Allowance
q	Subtotal, Powerhouse				501	
3	**Equipment**					
a	Turbine, generator, & governor		1	350,000	350	Estimated costs for restoration of 0.81 m diameter Francis runner
b	Shipping Handling & Installation		1	93,000	93	20% of equipment costs
c	Switchgear		1	20,000	20	Fostiak Eng. (2010)
d	Instrumentation & Controls		1	50,000	50	Allowance
e	Station Service, MCC		1	20,000	20	Allowance
f	Protection		1	25,000	25	Allowance
g	Subtotal, Equipment				558	
8	**PM&E Measures**					
a	Water Quality		1	40,000	40	Allowance for monitoring
b	D/S fish passage		0	20,000	0	Assumes installed by others
c	Min flow verification		1	5,000	5	Allowance
d	Wetlands	acre	1.5	60,000	90	Allowance for impacts from tailrace restoration
e	Recreation		1	20,000	20	Allowance
f	Cultural		1	7,500	8	Allowance
g	Subtotal, PM&E				163	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
9	**Licensing & Permitting**					
a	Consultations	year	2	50,000	100	Allowance
b	Studies	year	2	75,000	150	Alowance; assumes acceptance of standard instream flow settings
c	Draft FERC Application		1	50,000	50	Allowance
d	Final FERC Application		1	25,000	25	Allowance
e	Legal review		1	25,000	25	Allowance
f	Non-FERC Permits		1	50,000	50	Allowance: WQC, Wetlands, S. 106, S. 404, CZM, etc.
g	Subtotal, Lic. & Permitting				400	
10	**Land & Land Rights**					
a	Flowage rights		1	5,000	5	Allowance
b	Project works, land in fee		1	20,000	20	Allowance for penstock alignment
c	Interconnection R.O.W.		1	5,000	5	Allowance
d	Legal		1	10,000	10	Allowance
e	Other				0	
f	Subtotal, Land				40	
11	**Interconnection**					
a	Clear & Grub	acre	1	6,200	6	Allowance
b	New Line		1	52,000	52	Fostiak Eng. (2010)
c	Metering		1	10,000	10	Allowance
c	Switchyard		1	50,000	50	Fostiak Eng. (2010)
d	Consultations		1	20,000	20	Allowance
f	Subtotal, Interconnection				138	
12	**Indirect Costs**					
a	A/E		1	167,940	168	8% of Direct Costs
b	Construction Management		1	25,000	25	Allowance
c	Testing		1	20,000	20	geo-tech, concrete
d	FERC submittals		1	35,000	35	Design Report, Status Reports
e	Owner's Admin & Overhead		1	100,000	100	Allowance
f	Other				0	
g	Subtotal, Indirects				348	
	Totals					
1	General				300	
2	Powerhouse/Intake				501	
3	Equipment				558	
8	PM&E Measures				163	
9	Licensing & Permitting				400	
10	Land & Land Rights				40	
11	Interconnection				138	
	Subtotal, Directs				2,099	
12	Indirect Costs				348	
	Subtotal				2,447	
13	Contingency		$2,447,186	20%	489	
	Grand Total				**2,937**	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
1	**General**					
a	Mob/Demob		1	25,000	25	Allowance
b	Site Prep		1	10,000	10	Allowance
c	Clear & Grub	acre	0.5	8,000	4	Allowance
d	E&S Control	ft.	100	10	1	Allowance
e	Dam Repairs		1	20,000	20	From Phase I Dam Repair Costs (MBP Consulting 2010)
f	Subtotal, General				60	
2	**Powerhouse/Intake**					
a	Coffer dam, Pond				100	Allowance
b	Cofferdam, Tailrace				10	Allowance
c	Powerhouse Civil		1	677,586	678	Includes: intake, powerhouse, tailrace and trashrake
k	Sluice gate		1	20,000	20	
l	Misc. metals		1	5,000	5	Allowance
m	HVAC		1	10,000	10	Allowance
n	Auxilliary Mechanical		1	10,000	10	Allowance
o	Lighting, auxilliary electrical		1	5,000	5	Allowance
p	Other				0	
q	Subtotal, Powerhouse/Intake				838	
3	**Equipment**					
a	Turbine, generator, & governor		1	701,858	702	Runner 1.25m, estimated costs developed from recent projects
b	Shipping Handling & Installation		1	163,372	163	20% of equipment costs
c	Switchgear		1	20,000	20	From Interconnection Costs (Fostiak Eng. 2010)
d	Instrumentation & Controls		1	50,000	50	Allowance, includes license min flow verification
e	Station Service, MCC		1	20,000	20	Allowance
f	Protection		1	25,000	25	Allowance
g	Subtotal, Equipment				980	
8	**PM&E Measures**					
a	Water Quality		1	20,000	20	Allowance
b	D/S fish passage		0	20,000	0	Assumes installed by others
c	Min flow verification		0	5,000	0	Included in Instrumentation & Controls
d	Wetlands	acre	0.5	60,000	30	Allowance
e	Recreation		1	20,000	20	Allowance
f	Cultural		1	7,500	8	Allowance
g	Subtotal, PM&E				78	
9	**Licensing & Permitting**					
a	Consultations	year	2	50,000	100	Allowance
b	Studies	year	0.5	75,000	38	Allowance
c	Draft FERC Application		1	50,000	50	Allowance
d	Final FERC Application		1	25,000	25	Allowance
e	Legal review		1	25,000	25	Allowance
f	Non-FERC Permits		1	50,000	50	Allowance for: WQC, Wetlands, S. 106, S. 404, CZM, etc.
g	Subtotal, Lic. & Permitting				288	

No.	Item	Unit	Qty	Rate	Amount ($1,000's)	Comments
10	**Land & Land Rights**					
a	Flowage rights		1	5,000	5	Allowance
b	Project works, land in fee		1		0	
c	Interconnection R.O.W.		1	5,000	5	Allowance
d	Legal		1	10,000	10	Allowance
e	Other				0	
f	Subtotal, Land				20	
11	**Interconnection**					
a	Clear & Grub	acre	0.5	8,000	4	Allowance
b	New Line		1	15,000	15	From Interconnection Costs (Fostiak Eng. 2010)
c	Metering		1	10,000	10	Allowance
c	Switchyard		1	50,000	50	Includes: sectionalizers, transformers, disconnect switch. From Interconnection Costs (Fostiak Eng. 2010)
d	Consultations		1	20,000	20	Allowance
f	Subtotal, Interconnection				99	
12	**Indirect Costs**					
a	A/E		1	188,945	189	8% of Direct Costs
b	Construction Management		1	25,000	25	Allowance
c	Testing		1	20,000	20	geo-tech, concrete
d	FERC submittals		1	35,000	35	Design Report, Status Reports
e	Owner's Admin & Overhead		1	100,000	100	Allowance
f	Other				0	
g	Subtotal, Indirects				369	
	Totals					
1	General				60	
2	Powerhouse/Intake				838	
3	Equipment				980	
8	PM&E Measures				78	
9	Licensing & Permitting				288	
10	Land & Land Rights				20	
11	Interconnection				99	
	Subtotal, Directs				2,362	
12	Indirect Costs				369	
	Subtotal				2,731	
13	Contingency		$2,730,761	20%	546	
	Grand Total				**3,277**	

Pre-tax, Cash on Cash Economic Summary

ID	Project / Description				
A	Turner Reservoir				
B	Turner - Hunt's Mill				
C	Turner - Hunt's Mill 2	C-2	w/ repowered unit		
D	Hunt's Mill				
E	Hunt's Mill 2	E-2	w/ repowered unit	E-3	w/ restored unit
F	Omega Pond				

All Alts

Escalation Rate	2.5%	Discount Rate	5%		Denotes cells for user input
REC's ($//MWH)	$25	Term (Yrs)	20		

Results With Instream Flows

Alt	Installed Cost ($1,000's)	Installed Capacity (kW)	Installed Costs ($/kw)	Energy (MWH)	RI Grants	Fed Grant	Energy Rate $/MWH	IRR (%)	NPV ($1,000s)
A	3,559	205	17,405	715	5%	15%	$125	4%	(215)
B	4,600	156	29,558	456	5%	15%	$125	-2%	(2,568)
C	4,954	288	17,222	831	5%	15%	$125	3%	(842)
C-2	4,445	282	15,749	743	5%	15%	$125	3%	(865)
D	3,364	112	30,128	400	5%	15%	$125	-1%	(1,758)
E	3,326	184	18,066	524	5%	15%	$125	2%	(1,047)
E-2	3,070	178	17,240	464	5%	15%	$125	1%	(1,145)
E-3	2,937	110	26,688	335	5%	15%	$125		(1,729)
F	3,277	104	31,536	374	5%	15%	$125	-2%	(1,823)

Results with 1/2 Instream Flows

Alt	Installed Cost ($1,000's)	Installed Capacity (kW)	Installed Costs ($/kw)	Energy (MWH)	RI Grants	Fed Grant	Energy Rate $/MWH	IRR	NPV ($1,000s)
B	4,859	176	27,567	626	5%	15%	$125	1%	(1,874)
C	5,209	326	15,959	1,137	5%	15%	$125	6%	561
E	3,519	209	16,866	717	5%	15%	$125	5%	(170)

Results with No Instream Flows

Alt	Installed Cost ($1,000's)	Installed Capacity (kW)	Installed Costs ($/kw)	Energy (MWH)	RI Grants	Fed Grant	Energy Rate $/MWH	IRR	NPV ($1,000s)
B	5,667	288	19,698	1,050	5%	15%	$125	5%	(291)
C	6,071	534	11,376	1,889	5%	15%	$125	9%	3,919
E	4,020	341	11,797	1,184	5%	15%	$125	8%	1,927
E-2	3,228	271	11,926	815	5%	15%	$125	6%	593

Notes:

1 RI (State) Grants: defined % of Direct Costs
2 Fed Grant: Assumes extension of Investment Tax Credit (ITC) & assocaited muni. benefit of partnership with outside tax investor
3 Energy Rate: assumes pricing for distributed renewable energy
4 IRR: Internal Rate of Return
5 NPV (Net Present Value): values given represent NPV at end of study period
6 Estimates based on 20 year study period.
7 REC (Renewable Energy Certificate): additional commodity value for energy derived from qualified renewable sources

Debt Levered Economic Summary

ID	Project / Description				
A	Turner Reservoir				
B	Turner - Hunt's Mill				
C	Turner - Hunt's Mill 2	C-2	w/ repowered unit		
D	Hunt's Mill				
E	Hunt's Mill 2	E-2	w/ repowered unit	E-3	w/ restored unit
F	Omega Pond				

All Alts

Escalation Rate	2.5%	Discount Rate	5%
REC's ($//MWH)	$25	Term (Yrs)	35

Denotes cells for user input

Results With 1/1 RI ABF

Alt	Installed Cost ($1,000's)	Installed Capacity (kW)	Installed Costs ($/kw)	Energy (MWH)	RI Grants	Fed Incentives	Energy Rate $/MWH	% Debt	Interest Rate	Equity ($1,000's)	Min DCR	AVG DCR	IRR (%)	NPV ($1,000s)
A	3,559	205	17,405	715	5%	15%	$125	37%	2.0%	1,782	1.6	2.0	6%	319
B	4,600	156	29,558	456	5%	15%	$125	12%	2.0%	3,230	1.6	2.0	-2%	(2,343)
C	4,954	288	17,222	831	5%	15%	$125	32%	2.0%	2,700	1.6	2.0	5%	(209)
C-2	4,445	282	15,749	743	5%	15%	$125	31%	2.0%	2,468	1.6	2.0	4%	(319)
D	3,364	112	30,128	400	5%	15%	$125	14%	2.0%	2,314	1.6	2.0	-1%	(1,569)
E	3,326	184	18,066	524	5%	15%	$125	25%	2.0%	2,008	1.6	2.0	2%	(720)
E-2	3,070	178	17,240	464	5%	15%	$125	22%	2.0%	1,925	1.6	2.0	2%	(879)
E-3	2,937	110	26,688	335	5%	15%	$125	11%	2.0%	2,098	1.6	2.0		(1,603)
F	3,277	104	31,536	374	5%	15%	$125	12%	2.0%	2,299	1.6	2.0	-2%	(1,661)

Results with 1/2 RI ABF

Alt	Installed Cost ($1,000's)	Installed Capacity (kW)	Installed Costs ($/kw)	Energy (MWH)	RI Grants	Fed Incentives	Energy Rate $/MWH	% Debt	Interest Rate	Equity ($1,000's)	Min DCR	AVG DCR	IRR	NPV ($1,000s)
B	4,859	176	27,567	626	5%	15%	$125	21%	2.0%	3,073	1.6	2.0	1%	(1,466)
C	5,209	326	15,959	1,137	5%	15%	$125	46%	2.0%	2,277	1.6	2.0	8%	1,528
E	3,519	209	16,866	717	5%	15%	$125	38%	2.0%	1,745	1.6	2.0	6%	367

Results with 0/1 RI ABF

Alt	Installed Cost ($1,000's)	Installed Capacity (kW)	Installed Costs ($/kw)	Energy (MWH)	RI Grants	Fed Incentives	Energy Rate $/MWH	% Debt	Interest Rate	Equity ($1,000's)	Min DCR	AVG DCR	IRR	NPV ($1,000s)
B	5,667	288	19,698	1,050	5%	15%	$125	38%	2.0%	2,817	1.6	2.0	6%	569
C	6,071	534	11,376	1,889	5%	15%	$125	73%	2.0%	1,306	1.6	2.0	17%	5,700
E	4,020	341	11,797	1,184	5%	15%	$125	65%	2.0%	1,135	1.6	2.0	13%	2,971
E-2	3,228	271	11,926	815	5%	15%	$125	50%	2.0%	1,316	1.6	2.0	9%	1,244

Notes:

1. RI (State) Grants: defined % of Direct Costs
2. Fed Grant: Assumes extension of Investment Tax Credit (ITC) & assocaited muni. benefit of partnership with outside tax investor
3. Energy Rate: assumes pricing for distributed renewable energy
4. IRR: Internal Rate of Return
5. NPV (Net Present Value): values given represent NPV at end of study period
6. Estimates based on 20 year study period.
7. REC (Renewable Energy Certificate): additional commodity value for energy derived from qualified renewable sources

Proformas

No.	Item/ Study Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	**Costs ($1,000's)**																					
a	Initial Investment	3,559																				
b	O&M		11	11	12	12	12	12	13	13	13	14	14	14	15	15	16	16	16	17	17	18
c	Major Maintenance		23	24	24	25	25	26	27	27	28	29	30	30	31	32	33	33	34	35	36	37
d	Insurance		9	9	10	10	10	10	11	11	11	11	12	12	12	13	13	13	14	14	14	15
e	Payment in lieu of Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f																						
g	Subtotal, Costs	3,559	43	44	45	47	48	49	50	51	53	54	55	57	58	60	61	63	64	66	67	69
2	**Revenues ($1,000's)**																					
a	State Grants	178																				
b	Federal Grants	534																				
c	Energy		92	94	96	99	101	104	106	109	112	114	117	120	123	126	130	133	136	139	143	147
d	Recs		18	19	19	20	20	21	21	22	22	23	23	24	25	25	26	27	27	28	29	29
e	Avoided Distribution																					
f	Capacity/Demand		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g	Residual Value																					4,273
h	Subtotal, Revenues	712	110	113	116	118	121	124	128	131	134	137	141	144	148	152	155	159	163	167	172	4,449
3	**Cashflows ($1,000's)**																					
a	Nominal Dollars	(2,848)	67	68	70	72	74	76	77	79	81	83	86	88	90	92	94	97	99	102	104	4,379
b	NPV	(2,848)	64	62	61	59	58	56	55	54	52	51	50	49	48	47	45	44	43	42	41	1,651
c	Cum NPV	(2,848)	(2,784)	(2,722)	(2,661)	(2,602)	(2,544)	(2,488)	(2,433)	(2,379)	(2,326)	(2,275)	(2,225)	(2,176)	(2,129)	(2,082)	(2,037)	(1,992)	(1,949)	(1,907)	(1,866)	(215)
4	**Levered Cashflow ($1,000's)**																					
a	Investment Cost	2,848																				
b	Equity	1,782																				
c	Net Operating Income		67	68	70	72	74	76	77	79	81	83	86	88	90	92	94	97	99	102	104	4,379
d	Debt Service		(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)
e	Debt Coverage Ratio		1.6	1.6	1.6	1.7	1.7	1.8	1.8	1.9	1.9	2.0	2.0	2.1	2.1	2.2	2.2	2.3	2.3	2.4	2.4	2.4
f	Cash after debt service		24	26	28	29	31	33	35	37	39	41	43	45	47	50	52	54	57	59	62	4,337
g	Interest Payment		(21)	(21)	(20)	(20)	(20)	(19)	(19)	(18)	(18)	(17)	(17)	(16)	(16)	(15)	(14)	(14)	(13)	(13)	(12)	(12)
h	Taxable Income		3	5	7	9	12	14	16	19	21	24	26	29	32	34	37	40	43	46	49	4,325
i	Income tax																					
j	After Tax Cash	(1,782)	24	26	28	29	31	33	35	37	39	41	43	45	47	50	52	54	57	59	62	4,337
k	NPV	(1,782)	23	23	24	24	24	25	25	25	25	25	25	25	25	25	25	25	25	25	24	1,635
l	Cum NPV	(1,782)	(1,759)	(1,736)	(1,712)	(1,688)	(1,664)	(1,639)	(1,614)	(1,589)	(1,564)	(1,539)	(1,514)	(1,489)	(1,464)	(1,439)	(1,414)	(1,389)	(1,364)	(1,340)	(1,316)	319
	Proforma Inputs		Esc. Rate	2.5%		Disc. Rate	5.0%		MWH	715		Max KW	205		State Grants	178		Fed Grants	534			
			Energy Rate	125	$/MWH	Avg. Power		KW	Rec Rate	25	$/MWH	Demand	0	$/KW-mos	O&M	0.015	c/kWh	Prop Tax	0.0%			
	Proforma Results																					
	Pre-Tax, Cash on Cash			PreTax, Cash on Cash IRR			4.5%		Cum NPV	(215)					Discounted Pay Back	20						
	Debt Levered, After-Tax			Debt Levered, After Tax IRR			6.0%		Cum NPV	319					Discounted Pay Back	19						

Assumptions

1 O&M: 1.5¢/KWH escalated at defined rate (see summary sheet)
2 Major maintenance: $50k in years 5 & 15, $125k in years 10 & 20
3 Payment in Lieu of Property taxes: 1.5% of initial investment, escalated
4 Insurance: 0.25% of initial investment, escalated
5 Residual Value: calculated growth rate of year 19 revenues (only if positive cashflows)
6 Average Debt Coverage Ratio (DCR) set to 2.0 for all levered cases.

Denotes cell input linked to Summary Tab
Denotes cell input linked to Individual Cost Tabs
Denotes summary results

No.	Item/ Study Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	**Costs ($1,000's)**																					
a	Initial Investment	4,600																				
b	O&M		7	7	7	8	8	8	8	8	9	9	9	9	9	10	10	10	10	11	11	11
c	Major Maintenance		23	24	24	25	25	26	27	27	28	29	30	30	31	32	33	33	34	35	36	37
d	Insurance		12	12	12	13	13	13	14	14	14	15	15	15	16	16	17	17	17	18	18	19
e	Payment in lieu of Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f																						
g	Subtotal, Costs	4,600	42	43	44	45	46	47	49	50	51	52	54	55	56	58	59	61	62	64	65	67
2	**Revenues ($1,000's)**																					
a	State Grants	230																				
b	Federal Grants	690																				
c	Energy		58	60	61	63	64	66	68	69	71	73	75	77	79	80	82	85	87	89	91	93
d	Recs		12	12	12	13	13	13	14	14	14	15	15	15	16	16	16	17	17	18	18	19
e	Avoided Distribution																					
f	Capacity/Demand		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g	Residual Value																					1,804
h	Subtotal, Revenues	920	70	72	74	75	77	79	81	83	85	87	90	92	94	97	99	101	104	107	109	1,916
3	**Cashflows ($1,000's)**																					
a	Nominal Dollars	(3,680)	28	29	30	30	31	32	33	34	34	35	36	37	38	39	40	41	42	43	44	1,849
b	NPV	(3,680)	27	26	26	25	24	24	23	23	22	22	21	21	20	20	19	19	18	18	17	697
c	Cum NPV	(3,680)	(3,653)	(3,627)	(3,601)	(3,576)	(3,552)	(3,528)	(3,505)	(3,482)	(3,460)	(3,438)	(3,417)	(3,396)	(3,376)	(3,357)	(3,337)	(3,319)	(3,301)	(3,283)	(3,265)	(2,568)
4	**Levered Cashflow ($1,000's)**																					
a	Investment Cost	3,680																				
b	Equity	3,230																				
c	Net Operating Income		28	29	30	30	31	32	33	34	34	35	36	37	38	39	40	41	42	43	44	1,849
d	Debt Service		(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)
e	Debt Coverage Ratio		1.6	1.6	1.6	1.7	1.7	1.8	1.8	1.9	1.9	2.0	2.0	2.1	2.1	2.2	2.2	2.3	2.3	2.4	2.4	2.4
f	Cash after debt service		10	11	12	12	13	14	15	16	16	17	18	19	20	21	22	23	24	25	26	1,831
g	Interest Payment		(9)	(9)	(9)	(8)	(8)	(8)	(8)	(8)	(7)	(7)	(7)	(7)	(7)	(6)	(6)	(6)	(6)	(5)	(5)	(5)
h	Taxable Income		1	2	3	4	5	6	7	8	9	10	11	12	13	15	16	17	18	20	21	1,826
i	Income tax																					
j	After Tax Cash	(3,230)	10	11	12	12	13	14	15	16	16	17	18	19	20	21	22	23	24	25	26	1,831
k	NPV	(3,230)	10	10	10	10	10	10	10	11	11	11	11	11	11	11	11	10	10	10	10	690
l	Cum NPV	(3,230)	(3,220)	(3,210)	(3,200)	(3,190)	(3,180)	(3,170)	(3,159)	(3,149)	(3,138)	(3,127)	(3,117)	(3,106)	(3,096)	(3,085)	(3,075)	(3,064)	(3,054)	(3,043)	(3,033)	(2,343)
	Proforma Inputs		Esc. Rate	2.5%		Disc. Rate	5.0%		MWH	456		Max KW	156		State Grants	230		Fed Grants	690			
			Energy Rate	125	$/MWH	Avg. Power		KW	Rec Rate	25	$/MWH	Demand	0	$/KW-mos	O&M	0.015	c/kWh	Prop Tax	0.0%			
	Proforma Results																					
	Pre-Tax, Cash on Cash			PreTax, Cash on Cash IRR			-2.1%		Cum NPV	(2,568)				Discounted Pay Back		20						
	Debt Levered, After-Tax			Debt Levered, After Tax IRR			-2.1%		Cum NPV	(2,343)				Discounted Pay Back		20						

Assumptions

1 O&M: 1.5¢/KWH escalated at defined rate (see summary sheet)
2 Major maintenance: $50k in years 5 & 15, $125k in years 10 & 20
3 Payment in Lieu of Property taxes: 1.5% of initial investment, escalated
4 Insurance: 0.25% of initial investment, escalated
5 Residual Value: calculated growth rate of year 19 revenues (only if positive cashflows)
6 Average Debt Coverage Ratio (DCR) set to 2.0 for all levered cases.

Denotes cell input linked to Summary Tab
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Denotes summary results

THE ESSEX PARTNERSHIP

No.	Item/ Study Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	**Costs ($1,000's)**																					
a	Initial Investment	5,667																				
b	O&M		16	17	17	17	18	18	19	19	20	20	21	21	22	22	23	23	24	25	25	26
c	Major Maintenance		23	24	24	25	25	26	27	27	28	29	30	30	31	32	33	33	34	35	36	37
d	Insurance		15	15	15	16	16	16	17	17	18	18	19	19	20	20	21	21	22	22	23	23
e	Payment in lieu of Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f																						
g	Subtotal, Costs	5,667	54	55	56	58	59	61	62	64	65	67	69	70	72	74	76	78	80	82	84	86
2	**Revenues ($1,000's)**																					
a	State Grants	283																				
b	Federal Grants	850																				
c	Energy		135	138	141	145	148	152	156	160	164	168	172	176	181	185	190	195	200	205	210	215
d	Recs		27	28	28	29	30	30	31	32	33	34	34	35	36	37	38	39	40	41	42	43
e	Avoided Distribution																					
f	Capacity/Demand		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g	Residual Value																					6,886
h	Subtotal, Revenues	1,133	161	165	170	174	178	183	187	192	197	202	207	212	217	222	228	234	240	246	252	7,144
3	**Cashflows ($1,000's)**																					
a	Nominal Dollars	(4,534)	108	110	113	116	119	122	125	128	131	134	138	141	145	148	152	156	160	164	168	7,058
b	NPV	(4,534)	103	100	98	95	93	91	89	87	85	83	81	79	77	75	73	71	70	68	66	2,660
c	Cum NPV	(4,534)	(4,431)	(4,331)	(4,233)	(4,138)	(4,045)	(3,954)	(3,865)	(3,778)	(3,694)	(3,611)	(3,531)	(3,452)	(3,375)	(3,300)	(3,227)	(3,156)	(3,086)	(3,018)	(2,951)	(291)
4	**Levered Cashflow ($1,000's)**																					
a	Investment Cost	4,534																				
b	Equity	2,817																				
c	Net Operating Income		108	110	113	116	119	122	125	128	131	134	138	141	145	148	152	156	160	164	168	7,058
d	Debt Service		(69)	(69)	(69)	(69)	(69)	(69)	(69)	(69)	(69)	(69)	(69)	(69)	(69)	(69)	(69)	(69)	(69)	(69)	(69)	(69)
e	Debt Coverage Ratio		1.6	1.6	1.6	1.7	1.7	1.8	1.8	1.9	1.9	2.0	2.0	2.1	2.1	2.2	2.2	2.3	2.3	2.4	2.4	2.4
f	Cash after debt service		39	42	44	47	50	53	56	59	63	66	69	73	76	80	83	87	91	95	99	6,989
g	Interest Payment		(34)	(34)	(33)	(32)	(31)	(31)	(30)	(29)	(28)	(28)	(27)	(26)	(25)	(24)	(23)	(22)	(22)	(21)	(20)	(19)
h	Taxable Income		5	8	12	15	19	22	26	30	34	38	42	47	51	56	60	65	70	75	80	6,971
i	Income tax																					
j	After Tax Cash	(2,817)	39	42	44	47	50	53	56	59	63	66	69	73	76	80	83	87	91	95	99	6,989
k	NPV	(2,817)	37	38	38	39	39	40	40	40	40	40	40	40	40	40	40	40	40	40	39	2,634
l	Cum NPV	(2,817)	(2,780)	(2,742)	(2,704)	(2,665)	(2,626)	(2,586)	(2,546)	(2,506)	(2,465)	(2,425)	(2,385)	(2,344)	(2,304)	(2,263)	(2,223)	(2,183)	(2,144)	(2,104)	(2,065)	569
	Proforma Inputs		Esc. Rate	2.5%		Disc. Rate	5.0%		MWH	1,050		Max KW	288		State Grants	283		Fed Grants	850			
			Energy Rate	125	$/MWH	Avg. Power		KW	Rec Rate	25	$/MWH	Demand	0	$/KW-mos	O&M	0.015	c/kWh	Prop Tax	0.0%			
	Proforma Results																					
	Pre-Tax, Cash on Cash			PreTax, Cash on Cash IRR			4.6%		Cum NPV	(291)				Discounted Pay Back		20						
	Debt Levered, After-Tax			Debt Levered, After Tax IRR			6.1%		Cum NPV	569				Discounted Pay Back		19						

Assumptions

1 O&M: 1.5¢/KWH escalated at defined rate (see summary sheet)
2 Major maintenance: $50k in years 5 & 15, $125k in years 10 & 20
3 Payment in Lieu of Property taxes: 1.5% of initial investment, escalated
4 Insurance: 0.25% of initial investment, escalated
5 Residual Value: calculated growth rate of year 19 revenues (only if positive cashflows)
6 Average Debt Coverage Ratio (DCR) set to 2.0 for all levered cases.

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	Denotes summary results

THE ESSEX PARTNERSHIP

No.	Item/ Study Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	**Costs ($1,000's)**																					
a	Initial Investment	4,859																				
b	O&M		10	10	10	10	11	11	11	11	12	12	12	13	13	13	14	14	14	15	15	15
c	Major Maintenance		23	24	24	25	25	26	27	27	28	29	30	30	31	32	33	33	34	35	36	37
d	Insurance		12	13	13	13	14	14	14	15	15	16	16	16	17	17	18	18	18	19	19	20
e	Payment in lieu of Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f																						
g	Subtotal, Costs	4,859	45	46	47	49	50	51	52	54	55	56	58	59	61	62	64	65	67	69	70	72
2	**Revenues ($1,000's)**																					
a	State Grants	243																				
b	Federal Grants	729																				
c	Energy		80	82	84	86	89	91	93	95	98	100	103	105	108	111	113	116	119	122	125	128
d	Recs		16	16	17	17	18	18	19	19	20	20	21	21	22	22	23	23	24	24	25	26
e	Avoided Distribution																					
f	Capacity/Demand		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g	Residual Value																					3,268
h	Subtotal, Revenues	972	96	99	101	104	106	109	112	114	117	120	123	126	129	133	136	139	143	146	150	3,422
3	**Cashflows ($1,000's)**																					
a	Nominal Dollars	(3,888)	51	52	54	55	56	58	59	61	62	64	65	67	69	70	72	74	76	78	80	3,349
b	NPV	(3,888)	49	48	46	45	44	43	42	41	40	39	38	37	36	36	35	34	33	32	32	1,262
c	Cum NPV	(3,888)	(3,839)	(3,791)	(3,745)	(3,700)	(3,656)	(3,612)	(3,570)	(3,529)	(3,489)	(3,450)	(3,412)	(3,374)	(3,338)	(3,302)	(3,268)	(3,234)	(3,201)	(3,168)	(3,137)	(1,874)
4	**Levered Cashflow ($1,000's)**																					
a	Investment Cost	3,888																				
b	Equity	3,073																				
c	Net Operating Income		51	52	54	55	56	58	59	61	62	64	65	67	69	70	72	74	76	78	80	3,349
d	Debt Service		(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)
e	Debt Coverage Ratio		1.6	1.6	1.6	1.7	1.7	1.8	1.8	1.9	1.9	2.0	2.0	2.1	2.1	2.2	2.2	2.3	2.3	2.4	2.4	2.4
f	Cash after debt service		19	20	21	22	24	25	27	28	30	31	33	34	36	38	40	41	43	45	47	3,317
g	Interest Payment		(16)	(16)	(16)	(15)	(15)	(15)	(14)	(14)	(13)	(13)	(13)	(12)	(12)	(12)	(11)	(11)	(10)	(10)	(9)	(9)
h	Taxable Income		2	4	5	7	9	11	12	14	16	18	20	22	24	26	29	31	33	35	38	3,308
i	Income tax																					
j	After Tax Cash	(3,073)	19	20	21	22	24	25	27	28	30	31	33	34	36	38	40	41	43	45	47	3,317
k	NPV	(3,073)	18	18	18	18	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	1,250
l	Cum NPV	(3,073)	(3,055)	(3,037)	(3,019)	(3,001)	(2,982)	(2,963)	(2,944)	(2,925)	(2,906)	(2,887)	(2,868)	(2,849)	(2,829)	(2,810)	(2,791)	(2,772)	(2,753)	(2,735)	(2,716)	(1,466)
	Proforma Inputs		Esc. Rate	2.5%		Disc. Rate	5.0%		MWH	626		Max KW	176		State Grants	243		Fed Grants	729			
			Energy Rate	125	$/MWH	Avg. Power		KW	Rec Rate	25	$/MWH	Demand	0	$/KW-mos	O&M	0.015	c/kWh	Prop Tax	0.0%			
	Proforma Results																					
	Pre-Tax, Cash on Cash			PreTax, Cash on Cash IRR			0.9%		Cum NPV	(1,874)				Discounted Pay Back		20						
	Debt Levered, After-Tax			Debt Levered, After Tax IRR			1.3%		Cum NPV	(1,466)				Discounted Pay Back		20						

Assumptions

1 O&M: 1.5¢/KWH escalated at defined rate (see summary sheet)
2 Major maintenance: $50k in years 5 & 15, $125k in years 10 & 20
3 Payment in Lieu of Property taxes: 1.5% of initial investment, escalated
4 Insurance: 0.25% of initial investment, escalated
5 Residual Value: calculated growth rate of year 19 revenues (only if positive cashflows)
6 Average Debt Coverage Ratio (DCR) set to 2.0 for all levered cases.

Denotes cell input linked to Summary Tab
Denotes cell input linked to Individual Cost Tabs
Denotes summary results

No.	Item/ Study Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	**Costs ($1,000's)**																					
a	Initial Investment	4,954																				
b	O&M		13	13	13	14	14	14	15	15	16	16	16	17	17	18	18	19	19	19	20	20
c	Major Maintenance		23	24	24	25	25	26	27	27	28	29	30	30	31	32	33	33	34	35	36	37
d	Insurance		13	13	13	14	14	14	15	15	15	16	16	17	17	17	18	18	19	19	20	20
e	Payment in lieu of Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f																						
g	Subtotal, Costs	4,954	49	50	51	52	54	55	56	58	59	61	62	64	65	67	69	70	72	74	76	78
2	**Revenues ($1,000's)**																					
a	State Grants	248																				
b	Federal Grants	743																				
c	Energy		106	109	112	115	118	120	123	127	130	133	136	140	143	147	150	154	158	162	166	170
d	Recs		21	22	22	23	24	24	25	25	26	27	27	28	29	29	30	31	32	32	33	34
e	Avoided Distribution																					
f	Capacity/Demand		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g	Residual Value																					5,066
h	Subtotal, Revenues	991	128	131	134	138	141	145	148	152	156	160	164	168	172	176	181	185	190	194	199	5,270
3	**Cashflows ($1,000's)**																					
a	Nominal Dollars	(3,963)	79	81	83	85	87	90	92	94	97	99	101	104	107	109	112	115	118	121	124	5,192
b	NPV	(3,963)	75	74	72	70	69	67	65	64	62	61	59	58	56	55	54	53	51	50	49	1,957
c	Cum NPV	(3,963)	(3,888)	(3,814)	(3,742)	(3,672)	(3,604)	(3,537)	(3,471)	(3,408)	(3,345)	(3,285)	(3,225)	(3,167)	(3,111)	(3,056)	(3,002)	(2,949)	(2,898)	(2,848)	(2,799)	(842)
4	**Levered Cashflow ($1,000's)**																					
a	Investment Cost	3,963																				
b	Equity	2,700																				
c	Net Operating Income		79	81	83	85	87	90	92	94	97	99	101	104	107	109	112	115	118	121	124	5,192
d	Debt Service		(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)
e	Debt Coverage Ratio		1.6	1.6	1.6	1.7	1.7	1.8	1.8	1.9	1.9	2.0	2.0	2.1	2.1	2.2	2.2	2.3	2.3	2.4	2.4	2.4
f	Cash after debt service		29	31	33	35	37	39	41	44	46	48	51	53	56	59	61	64	67	70	73	5,142
g	Interest Payment		(25)	(25)	(24)	(24)	(23)	(23)	(22)	(21)	(21)	(20)	(20)	(19)	(18)	(18)	(17)	(17)	(16)	(15)	(14)	(14)
h	Taxable Income		3	6	8	11	14	16	19	22	25	28	31	34	38	41	44	48	51	55	59	5,128
i	Income tax																					
j	After Tax Cash	(2,700)	29	31	33	35	37	39	41	44	46	48	51	53	56	59	61	64	67	70	73	5,142
k	NPV	(2,700)	27	28	28	29	29	29	29	30	30	30	30	30	30	30	30	29	29	29	29	1,938
l	Cum NPV	(2,700)	(2,673)	(2,645)	(2,617)	(2,588)	(2,559)	(2,530)	(2,501)	(2,471)	(2,442)	(2,412)	(2,382)	(2,352)	(2,323)	(2,293)	(2,264)	(2,234)	(2,205)	(2,176)	(2,147)	(209)
	Proforma Inputs		Esc. Rate	2.5%		Disc. Rate	5.0%		MWH	831		Max KW	288		State Grants	248		Fed Grants	743			
			Energy Rate	125	$/MWH	Avg. Power		KW	Rec Rate	25	$/MWH	Demand	0	$/KW-mos	O&M	0.015	c/kWh	Prop Tax	0.0%			
	Proforma Results																					
	Pre-Tax, Cash on Cash			PreTax, Cash on Cash IRR			3.5%		Cum NPV	(842)				Discounted Pay Back		20						
	Debt Levered, After-Tax			Debt Levered, After Tax IRR			4.5%		Cum NPV	(209)				Discounted Pay Back		20						

Assumptions

1 O&M: 1.5¢/KWH escalated at defined rate (see summary sheet)
2 Major maintenance: $50k in years 5 & 15, $125k in years 10 & 20
3 Payment in Lieu of Property taxes: 1.5% of initial investment, escalated
4 Insurance: 0.25% of initial investment, escalated
5 Residual Value: calculated growth rate of year 19 revenues (only if positive cashflows)
6 Average Debt Coverage Ratio (DCR) set to 2.0 for all levered cases.

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(yellow)	Denotes cell input linked to Individual Cost Tabs
(green)	Denotes summary results

No.	Item/ Study Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	**Costs ($1,000's)**																					
a	Initial Investment	6,071																				
b	O&M		29	30	31	31	32	33	34	35	35	36	37	38	39	40	41	42	43	44	45	46
c	Major Maintenance		23	24	24	25	25	26	27	27	28	29	30	30	31	32	33	33	34	35	36	37
d	Insurance		16	16	16	17	17	18	18	18	19	19	20	20	21	21	22	23	23	24	24	25
e	Payment in lieu of Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f																						
g	Subtotal, Costs	6,071	68	69	71	73	75	77	78	80	82	85	87	89	91	93	96	98	100	103	106	108
2	**Revenues ($1,000's)**																					
a	State Grants	304																				
b	Federal Grants	911																				
c	Energy		242	248	254	261	267	274	281	288	295	302	310	318	325	334	342	351	359	368	377	387
d	Recs		48	50	51	52	53	55	56	58	59	60	62	64	65	67	68	70	72	74	75	77
e	Avoided Distribution																					
f	Capacity/Demand		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g	Residual Value																					14,245
h	Subtotal, Revenues	1,214	290	298	305	313	321	329	337	345	354	363	372	381	391	400	410	421	431	442	453	14,709
3	**Cashflows ($1,000's)**																					
a	Nominal Dollars	(4,857)	223	228	234	240	246	252	258	265	271	278	285	292	300	307	315	323	331	339	347	14,601
b	NPV	(4,857)	212	207	202	197	193	188	184	179	175	171	167	163	159	155	151	148	144	141	137	5,503
c	Cum NPV	(4,857)	(4,645)	(4,438)	(4,235)	(4,038)	(3,845)	(3,657)	(3,474)	(3,294)	(3,120)	(2,949)	(2,782)	(2,619)	(2,460)	(2,305)	(2,154)	(2,006)	(1,862)	(1,721)	(1,583)	3,919
4	**Levered Cashflow ($1,000's)**																					
a	Investment Cost	4,857																				
b	Equity	1,306																				
c	Net Operating Income		223	228	234	240	246	252	258	265	271	278	285	292	300	307	315	323	331	339	347	14,601
d	Debt Service		(142)	(142)	(142)	(142)	(142)	(142)	(142)	(142)	(142)	(142)	(142)	(142)	(142)	(142)	(142)	(142)	(142)	(142)	(142)	(142)
e	Debt Coverage Ratio		1.6	1.6	1.6	1.7	1.7	1.8	1.8	1.9	1.9	2.0	2.0	2.1	2.1	2.2	2.2	2.3	2.3	2.4	2.4	2.4
f	Cash after debt service		81	86	92	98	104	110	116	123	129	136	143	150	158	165	173	181	189	197	205	14,459
g	Interest Payment		(71)	(70)	(68)	(67)	(65)	(64)	(62)	(60)	(59)	(57)	(55)	(54)	(52)	(50)	(48)	(46)	(45)	(43)	(41)	(39)
h	Taxable Income		10	17	24	31	39	46	54	62	71	79	88	97	106	115	124	134	144	154	165	14,420
i	Income tax																					
j	After Tax Cash	(1,306)	81	86	92	98	104	110	116	123	129	136	143	150	158	165	173	181	189	197	205	14,459
k	NPV	(1,306)	77	78	79	81	81	82	83	83	83	84	84	84	84	83	83	83	82	82	81	5,449
l	Cum NPV	(1,306)	(1,229)	(1,151)	(1,071)	(991)	(909)	(827)	(745)	(662)	(578)	(495)	(411)	(327)	(244)	(160)	(77)	5	88	169	251	5,700
	Proforma Inputs		Esc. Rate	2.5%		Disc. Rate	5.0%		MWH	1,889		Max KW	534		State Grants	304		Fed Grants	911			
			Energy Rate	125	$/MWH	Avg. Power		KW	Rec Rate	25	$/MWH	Demand	0	$/KW-mos	O&M	0.015	c/kWh	Prop Tax	0.0%			
	Proforma Results																					
	Pre-Tax, Cash on Cash			PreTax, Cash on Cash IRR			9.2%		Cum NPV	3,919				Discounted Pay Back		19						
	Debt Levered, After-Tax			Debt Levered, After Tax IRR			16.6%		Cum NPV	5,700				Discounted Pay Back		15						

Assumptions

1 O&M: 1.5¢/KWH escalated at defined rate (see summary sheet)
2 Major maintenance: $50k in years 5 & 15, $125k in years 10 & 20
3 Payment in Lieu of Property taxes: 1.5% of initial investment, escalated
4 Insurance: 0.25% of initial investment, escalated
5 Residual Value: calculated growth rate of year 19 revenues (only if positive cashflows)
6 Average Debt Coverage Ratio (DCR) set to 2.0 for all levered cases.

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Denotes cell input linked to Individual Cost Tabs
Denotes summary results

No.	Item/ Study Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	**Costs ($1,000's)**																					
a	Initial Investment	5,209																				
b	O&M		17	18	18	19	19	20	20	21	21	22	22	23	24	24	25	25	26	27	27	28
c	Major Maintenance		23	24	24	25	25	26	27	27	28	29	30	30	31	32	33	33	34	35	36	37
d	Insurance		13	14	14	14	15	15	15	16	16	17	17	18	18	18	19	19	20	20	21	21
e	Payment in lieu of Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f																						
g	Subtotal, Costs	5,209	54	55	57	58	59	61	63	64	66	67	69	71	72	74	76	78	80	82	84	86
2	**Revenues ($1,000's)**																					
a	State Grants	260																				
b	Federal Grants	743																				
c	Energy		146	149	153	157	161	165	169	173	178	182	187	191	196	201	206	211	216	222	227	233
d	Recs		29	30	31	31	32	33	34	35	36	36	37	38	39	40	41	42	43	44	45	47
e	Avoided Distribution																					
f	Capacity/Demand		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g	Residual Value																					7,737
h	Subtotal, Revenues	1,004	175	179	184	188	193	198	203	208	213	218	224	229	235	241	247	253	260	266	273	8,016
3	**Cashflows ($1,000's)**																					
a	Nominal Dollars	(4,206)	121	124	127	130	134	137	140	144	147	151	155	159	163	167	171	175	180	184	189	7,930
b	NPV	(4,206)	115	112	110	107	105	102	100	97	95	93	91	88	86	84	82	80	78	76	75	2,989
c	Cum NPV	(4,206)	(4,091)	(3,978)	(3,868)	(3,761)	(3,656)	(3,554)	(3,455)	(3,357)	(3,262)	(3,169)	(3,079)	(2,990)	(2,904)	(2,820)	(2,738)	(2,657)	(2,579)	(2,503)	(2,428)	561
4	**Levered Cashflow ($1,000's)**																					
a	Investment Cost	4,206																				
b	Equity	2,277																				
c	Net Operating Income		121	124	127	130	134	137	140	144	147	151	155	159	163	167	171	175	180	184	189	7,930
d	Debt Service		(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)
e	Debt Coverage Ratio		1.6	1.6	1.6	1.7	1.7	1.8	1.8	1.9	1.9	2.0	2.0	2.1	2.1	2.2	2.2	2.3	2.3	2.4	2.4	2.4
f	Cash after debt service		44	47	50	53	56	60	63	67	70	74	78	82	86	90	94	98	102	107	112	7,853
g	Interest Payment		(39)	(38)	(37)	(36)	(35)	(35)	(34)	(33)	(32)	(31)	(30)	(29)	(28)	(27)	(26)	(25)	(24)	(23)	(22)	(21)
h	Taxable Income		5	9	13	17	21	25	29	34	38	43	48	52	57	62	68	73	78	84	90	7,832
i	Income tax																					
j	After Tax Cash	(2,277)	44	47	50	53	56	60	63	67	70	74	78	82	86	90	94	98	102	107	112	7,853
k	NPV	(2,277)	42	43	43	44	44	45	45	45	45	45	45	45	45	45	45	45	45	44	44	2,960
l	Cum NPV	(2,277)	(2,235)	(2,193)	(2,150)	(2,106)	(2,062)	(2,017)	(1,972)	(1,927)	(1,882)	(1,837)	(1,791)	(1,746)	(1,700)	(1,655)	(1,610)	(1,565)	(1,520)	(1,476)	(1,432)	1,528
	Proforma Inputs		Esc. Rate	2.5%		Disc. Rate	5.0%		MWH	1,137		Max KW	326		State Grants	260		Fed Grants	743			
			Energy Rate	125	$/MWH	Avg. Power		KW	Rec Rate	25	$/MWH	Demand	0	$/KW-mos	O&M	0.015	c/kWh	Prop Tax	0.0%			
	Proforma Results																					
	Pre-Tax, Cash on Cash			PreTax, Cash on Cash IRR			5.8%		Cum NPV	561					Discounted Pay Back	19						
	Debt Levered, After-Tax			Debt Levered, After Tax IRR			8.1%		Cum NPV	1,528					Discounted Pay Back	19						

Assumptions

1 O&M: 1.5¢/KWH escalated at defined rate (see summary sheet)
2 Major maintenance: $50k in years 5 & 15, $125k in years 10 & 20
3 Payment in Lieu of Property taxes: 1.5% of initial investment, escalated
4 Insurance: 0.25% of initial investment, escalated
5 Residual Value: calculated growth rate of year 19 revenues (only if positive cashflows)
6 Average Debt Coverage Ratio (DCR) set to 2.0 for all levered cases.

Denotes cell input linked to Summary Tab
Denotes cell input linked to Individual Cost Tabs
Denotes summary results

THE ESSEX PARTNERSHIP

No.	Item/ Study Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	**Costs ($1,000's)**																					
a	Initial Investment	4,445																				
b	O&M		11	12	12	12	13	13	13	14	14	14	15	15	15	16	16	17	17	17	18	18
c	Major Maintenance		23	24	24	25	25	26	27	27	28	29	30	30	31	32	33	33	34	35	36	37
d	Insurance		11	12	12	12	13	13	13	14	14	14	15	15	15	16	16	16	17	17	18	18
e	Payment in lieu of Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f																						
g	Subtotal, Costs	4,445	46	47	48	49	51	52	53	55	56	57	59	60	62	63	65	66	68	70	72	73
2	**Revenues ($1,000's)**																					
a	State Grants	222																				
b	Federal Grants	667																				
c	Energy		95	98	100	102	105	108	110	113	116	119	122	125	128	131	134	138	141	145	148	152
d	Recs		19	20	20	20	21	22	22	23	23	24	24	25	26	26	27	28	28	29	30	30
e	Avoided Distribution																					
f	Capacity/Demand		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g	Residual Value																					4,367
h	Subtotal, Revenues	889	114	117	120	123	126	129	132	136	139	143	146	150	154	157	161	165	169	174	178	4,550
3	**Cashflows ($1,000's)**																					
a	Nominal Dollars	(3,556)	68	70	72	74	75	77	79	81	83	85	87	90	92	94	97	99	101	104	107	4,477
b	NPV	(3,556)	65	63	62	61	59	58	56	55	54	52	51	50	49	48	46	45	44	43	42	1,687
c	Cum NPV	(3,556)	(3,491)	(3,428)	(3,366)	(3,305)	(3,246)	(3,188)	(3,132)	(3,077)	(3,024)	(2,971)	(2,920)	(2,870)	(2,821)	(2,774)	(2,728)	(2,682)	(2,638)	(2,595)	(2,553)	(865)
4	**Levered Cashflow ($1,000's)**																					
a	Investment Cost	3,556																				
b	Equity	2,468																				
c	Net Operating Income		68	70	72	74	75	77	79	81	83	85	87	90	92	94	97	99	101	104	107	4,477
d	Debt Service		(44)	(44)	(44)	(44)	(44)	(44)	(44)	(44)	(44)	(44)	(44)	(44)	(44)	(44)	(44)	(44)	(44)	(44)	(44)	(44)
e	Debt Coverage Ratio		1.6	1.6	1.6	1.7	1.7	1.8	1.8	1.9	1.9	2.0	2.0	2.1	2.1	2.2	2.2	2.3	2.3	2.4	2.4	2.4
f	Cash after debt service		25	26	28	30	32	34	36	38	40	42	44	46	48	51	53	55	58	60	63	4,433
g	Interest Payment		(22)	(21)	(21)	(20)	(20)	(20)	(19)	(19)	(18)	(18)	(17)	(16)	(16)	(15)	(15)	(14)	(14)	(13)	(12)	(12)
h	Taxable Income		3	5	7	10	12	14	17	19	22	24	27	30	32	35	38	41	44	47	51	4,421
i	Income tax																					
j	After Tax Cash	(2,468)	25	26	28	30	32	34	36	38	40	42	44	46	48	51	53	55	58	60	63	4,433
k	NPV	(2,468)	24	24	24	25	25	25	25	25	26	26	26	26	26	26	25	25	25	25	25	1,671
l	Cum NPV	(2,468)	(2,444)	(2,420)	(2,396)	(2,371)	(2,346)	(2,321)	(2,295)	(2,270)	(2,244)	(2,219)	(2,193)	(2,167)	(2,142)	(2,116)	(2,091)	(2,065)	(2,040)	(2,015)	(1,990)	(319)
	Proforma Inputs		Esc. Rate	2.5%		Disc. Rate	5.0%		MWH	743		Max KW	282		State Grants	222		Fed Grants	667			
			Energy Rate	125	$/MWH	Avg. Power		KW	Rec Rate	25	$/MWH	Demand	0	$/KW-mos	O&M	0.015	c/kWh	Prop Tax	0.0%			
	Proforma Results																					
	Pre-Tax, Cash on Cash			PreTax, Cash on Cash IRR			3.2%		Cum NPV	(865)				Discounted Pay Back		20						
	Debt Levered, After-Tax			Debt Levered, After Tax IRR			4.2%		Cum NPV	(319)				Discounted Pay Back		20						

Assumptions

1 O&M: 1.5¢/KWH escalated at defined rate (see summary sheet)
2 Major maintenance: $50k in years 5 & 15, $125k in years 10 & 20
3 Payment in Lieu of Property taxes: 1.5% of initial investment, escalated
4 Insurance: 0.25% of initial investment, escalated
5 Residual Value: calculated growth rate of year 19 revenues (only if positive cashflows)
6 Average Debt Coverage Ratio (DCR) set to 2.0 for all levered cases.

Denotes cell input linked to Summary Tab
Denotes cell input linked to Individual Cost Tabs
Denotes summary results

No.	Item/ Study Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	**Costs ($1,000's)**																					
a	Initial Investment	3,364																				
b	O&M		6	6	6	7	7	7	7	7	7	8	8	8	8	8	9	9	9	9	10	10
c	Major Maintenance		23	24	24	25	25	26	27	27	28	29	30	30	31	32	33	33	34	35	36	37
d	Insurance		9	9	9	9	10	10	10	10	11	11	11	11	12	12	12	12	13	13	13	14
e	Payment in lieu of Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f																						
g	Subtotal, Costs	3,364	38	39	40	41	42	43	44	45	46	47	48	50	51	52	53	55	56	58	59	60
2	**Revenues ($1,000's)**																					
a	State Grants	168																				
b	Federal Grants	505																				
c	Energy		51	53	54	55	57	58	59	61	62	64	66	67	69	71	72	74	76	78	80	82
d	Recs		10	11	11	11	11	12	12	12	12	13	13	13	14	14	14	15	15	16	16	16
e	Avoided Distribution																					
f	Capacity/Demand		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g	Residual Value																					1,514
h	Subtotal, Revenues	673	62	63	65	66	68	70	71	73	75	77	79	81	83	85	87	89	91	94	96	1,612
3	**Cashflows ($1,000's)**																					
a	Nominal Dollars	(2,691)	24	24	25	25	26	27	27	28	29	30	30	31	32	33	33	34	35	36	37	1,552
b	NPV	(2,691)	23	22	21	21	20	20	20	19	19	18	18	17	17	16	16	16	15	15	15	585
c	Cum NPV	(2,691)	(2,668)	(2,646)	(2,625)	(2,604)	(2,584)	(2,564)	(2,544)	(2,525)	(2,506)	(2,488)	(2,471)	(2,453)	(2,436)	(2,420)	(2,404)	(2,388)	(2,373)	(2,358)	(2,343)	(1,758)
4	**Levered Cashflow ($1,000's)**																					
a	Investment Cost	2,691																				
b	Equity	2,314																				
c	Net Operating Income		24	24	25	25	26	27	27	28	29	30	30	31	32	33	33	34	35	36	37	1,552
d	Debt Service		(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)
e	Debt Coverage Ratio		1.6	1.6	1.6	1.7	1.7	1.8	1.8	1.9	1.9	2.0	2.0	2.1	2.1	2.2	2.2	2.3	2.3	2.4	2.4	2.4
f	Cash after debt service		9	9	10	10	11	12	12	13	14	14	15	16	17	18	18	19	20	21	22	1,537
g	Interest Payment		(8)	(7)	(7)	(7)	(7)	(7)	(7)	(6)	(6)	(6)	(6)	(6)	(6)	(5)	(5)	(5)	(5)	(5)	(4)	(4)
h	Taxable Income		1	2	3	3	4	5	6	7	7	8	9	10	11	12	13	14	15	16	18	1,532
i	Income tax																					
j	After Tax Cash	(2,314)	9	9	10	10	11	12	12	13	14	14	15	16	17	18	18	19	20	21	22	1,537
k	NPV	(2,314)	8	8	8	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	579
l	Cum NPV	(2,314)	(2,305)	(2,297)	(2,289)	(2,280)	(2,272)	(2,263)	(2,254)	(2,245)	(2,236)	(2,227)	(2,219)	(2,210)	(2,201)	(2,192)	(2,183)	(2,174)	(2,166)	(2,157)	(2,148)	(1,569)
	Proforma Inputs		Esc. Rate	2.5%		Disc. Rate	5.0%		MWH	400		Max KW	112		State Grants	168		Fed Grants	505			
			Energy Rate	125	$/MWH	Avg. Power		KW	Rec Rate	25	$/MWH	Demand	0	$/KW-mos	O&M	0.015	c/kWh	Prop Tax	0.0%			
	Proforma Results																					
	Pre-Tax, Cash on Cash			PreTax, Cash on Cash IRR			-1.3%		Cum NPV	(1,758)				Discounted Pay Back		20						
	Debt Levered, After-Tax			Debt Levered, After Tax IRR			-1.3%		Cum NPV	(1,569)				Discounted Pay Back		20						

Assumptions

1. O&M: 1.5¢/KWH escalated at defined rate (see summary sheet)
2. Major maintenance: $50k in years 5 & 15, $125k in years 10 & 20
3. Payment in Lieu of Property taxes: 1.5% of initial investment, escalated
4. Insurance: 0.25% of initial investment, escalated
5. Residual Value: calculated growth rate of year 19 revenues (only if positive cashflows)
6. Average Debt Coverage Ratio (DCR) set to 2.0 for all levered cases.

(blue)	Denotes cell input linked to Summary Tab
(yellow)	Denotes cell input linked to Individual Cost Tabs
(green)	Denotes summary results

THE ESSEX PARTNERSHIP

No.	Item/ Study Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	**Costs ($1,000's)**																					
a	Initial Investment	3,326																				
b	O&M		8	8	8	9	9	9	9	10	10	10	10	11	11	11	11	12	12	12	13	13
c	Major Maintenance		23	24	24	25	25	26	27	27	28	29	30	30	31	32	33	33	34	35	36	37
d	Insurance		9	9	9	9	9	10	10	10	10	11	11	11	11	12	12	12	13	13	13	14
e	Payment in lieu of Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f																						
g	Subtotal, Costs	3,326	40	41	42	43	44	45	46	47	48	50	51	52	53	55	56	57	59	60	62	63
2	**Revenues ($1,000's)**																					
a	State Grants	166																				
b	Federal Grants	499																				
c	Energy		67	69	71	72	74	76	78	80	82	84	86	88	90	93	95	97	100	102	105	107
d	Recs		13	14	14	14	15	15	16	16	16	17	17	18	18	19	19	19	20	20	21	21
e	Avoided Distribution																					
f	Capacity/Demand		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g	Residual Value																					2,618
h	Subtotal, Revenues	665	81	83	85	87	89	91	93	96	98	101	103	106	108	111	114	117	120	123	126	2,747
3	**Cashflows ($1,000's)**																					
a	Nominal Dollars	(2,661)	41	42	43	44	45	46	47	49	50	51	52	54	55	56	58	59	61	62	64	2,684
b	NPV	(2,661)	39	38	37	36	35	35	34	33	32	31	31	30	29	29	28	27	27	26	25	1,012
c	Cum NPV	(2,661)	(2,622)	(2,583)	(2,546)	(2,510)	(2,475)	(2,440)	(2,406)	(2,373)	(2,341)	(2,310)	(2,279)	(2,249)	(2,220)	(2,191)	(2,164)	(2,136)	(2,110)	(2,084)	(2,059)	(1,047)
4	**Levered Cashflow ($1,000's)**																					
a	Investment Cost	2,661																				
b	Equity	2,008																				
c	Net Operating Income		41	42	43	44	45	46	47	49	50	51	52	54	55	56	58	59	61	62	64	2,684
d	Debt Service		(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)
e	Debt Coverage Ratio		1.6	1.6	1.6	1.7	1.7	1.8	1.8	1.9	1.9	2.0	2.0	2.1	2.1	2.2	2.2	2.3	2.3	2.4	2.4	2.4
f	Cash after debt service		15	16	17	18	19	20	21	23	24	25	26	28	29	30	32	33	35	36	38	2,658
g	Interest Payment		(13)	(13)	(13)	(12)	(12)	(12)	(11)	(11)	(11)	(11)	(10)	(10)	(10)	(9)	(9)	(9)	(8)	(8)	(7)	(7)
h	Taxable Income		2	3	4	6	7	9	10	11	13	15	16	18	19	21	23	25	26	28	30	2,651
i	Income tax																					
j	After Tax Cash	(2,008)	15	16	17	18	19	20	21	23	24	25	26	28	29	30	32	33	35	36	38	2,658
k	NPV	(2,008)	14	14	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	1,002
l	Cum NPV	(2,008)	(1,994)	(1,979)	(1,965)	(1,950)	(1,935)	(1,920)	(1,905)	(1,889)	(1,874)	(1,859)	(1,843)	(1,828)	(1,813)	(1,797)	(1,782)	(1,767)	(1,752)	(1,737)	(1,722)	(720)
	Proforma Inputs		Esc. Rate	2.5%		Disc. Rate	5.0%		MWH	524		Max KW	184		State Grants	166		Fed Grants	499			
			Energy Rate	125	$/MWH	Avg. Power		KW	Rec Rate	25	$/MWH	Demand	0	$/KW-mos	O&M	0.015	c/kWh	Prop Tax	0.0%			
	Proforma Results																					
	Pre-Tax, Cash on Cash			PreTax, Cash on Cash IRR			1.9%		Cum NPV	(1,047)				Discounted Pay Back		20						
	Debt Levered, After-Tax			Debt Levered, After Tax IRR			2.4%		Cum NPV	(720)				Discounted Pay Back		20						

Assumptions
1 O&M: 1.5¢/KWH escalated at defined rate (see summary sheet)
2 Major maintenance: $50k in years 5 & 15, $125k in years 10 & 20
3 Payment in Lieu of Property taxes: 1.5% of initial investment, escalated
4 Insurance: 0.25% of initial investment, escalated
5 Residual Value: calculated growth rate of year 19 revenues (only if positive cashflows)
6 Average Debt Coverage Ratio (DCR) set to 2.0 for all levered cases.

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THE ESSEX PARTNERSHIP

No.	Item/ Study Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	**Costs ($1,000's)**																					
a	Initial Investment	4,020																				
b	O&M		18	19	19	20	20	21	21	22	22	23	23	24	24	25	26	26	27	28	28	29
c	Major Maintenance		23	24	24	25	25	26	27	27	28	29	30	30	31	32	33	33	34	35	36	37
d	Insurance		10	11	11	11	11	12	12	12	13	13	13	14	14	14	15	15	15	16	16	16
e	Payment in lieu of Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f																						
g	Subtotal, Costs	4,020	52	53	54	56	57	58	60	61	63	64	66	68	69	71	73	75	77	78	80	82
2	**Revenues ($1,000's)**																					
a	State Grants	201																				
b	Federal Grants	603																				
c	Energy		152	156	159	163	168	172	176	180	185	190	194	199	204	209	214	220	225	231	237	243
d	Recs		30	31	32	33	34	34	35	36	37	38	39	40	41	42	43	44	45	46	47	49
e	Avoided Distribution																					
f	Capacity/Demand		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g	Residual Value																					8,347
h	Subtotal, Revenues	804	182	187	191	196	201	206	211	216	222	227	233	239	245	251	257	264	270	277	284	8,639
3	**Cashflows ($1,000's)**																					
a	Nominal Dollars	(3,216)	131	134	137	141	144	148	151	155	159	163	167	171	176	180	184	189	194	199	204	8,556
b	NPV	(3,216)	124	121	118	116	113	110	108	105	103	100	98	95	93	91	89	87	85	83	81	3,225
c	Cum NPV	(3,216)	(3,092)	(2,970)	(2,852)	(2,736)	(2,623)	(2,513)	(2,405)	(2,300)	(2,198)	(2,098)	(2,000)	(1,905)	(1,812)	(1,721)	(1,632)	(1,545)	(1,461)	(1,378)	(1,298)	1,927
4	**Levered Cashflow ($1,000's)**																					
a	Investment Cost	3,216																				
b	Equity	1,135																				
c	Net Operating Income		131	134	137	141	144	148	151	155	159	163	167	171	176	180	184	189	194	199	204	8,556
d	Debt Service		(83)	(83)	(83)	(83)	(83)	(83)	(83)	(83)	(83)	(83)	(83)	(83)	(83)	(83)	(83)	(83)	(83)	(83)	(83)	(83)
e	Debt Coverage Ratio		1.6	1.6	1.6	1.7	1.7	1.8	1.8	1.9	1.9	2.0	2.0	2.1	2.1	2.2	2.2	2.3	2.3	2.4	2.4	2.4
f	Cash after debt service		47	51	54	57	61	64	68	72	76	80	84	88	92	97	101	106	111	115	120	8,473
g	Interest Payment		(42)	(41)	(40)	(39)	(38)	(37)	(36)	(35)	(34)	(33)	(33)	(31)	(30)	(29)	(28)	(27)	(26)	(25)	(24)	(23)
h	Taxable Income		6	10	14	18	23	27	32	37	41	46	51	57	62	67	73	79	84	90	97	8,450
i	Income tax																					
j	After Tax Cash	(1,135)	47	51	54	57	61	64	68	72	76	80	84	88	92	97	101	106	111	115	120	8,473
k	NPV	(1,135)	45	46	47	47	48	48	48	49	49	49	49	49	49	49	49	48	48	48	48	3,193
l	Cum NPV	(1,135)	(1,090)	(1,044)	(998)	(950)	(903)	(855)	(806)	(757)	(709)	(660)	(611)	(562)	(513)	(464)	(415)	(367)	(318)	(270)	(223)	2,971
	Proforma Inputs		Esc. Rate	2.5%		Disc. Rate	5.0%		MWH	1,184		Max KW	341		State Grants	201		Fed Grants	603			
			Energy Rate	125	$/MWH	Avg. Power		KW	Rec Rate	25	$/MWH	Demand	0	$/KW-mos	O&M	0.015	c/kWh	Prop Tax	0.0%			
	Proforma Results																					
	Pre-Tax, Cash on Cash			PreTax, Cash on Cash IRR			8.3%		Cum NPV	1,927					Discounted Pay Back	19						
	Debt Levered, After-Tax			Debt Levered, After Tax IRR			13.5%		Cum NPV	2,971					Discounted Pay Back	19						

Assumptions
1 O&M: 1.5¢/KWH escalated at defined rate (see summary sheet)
2 Major maintenance: $50k in years 5 & 15, $125k in years 10 & 20
3 Payment in Lieu of Property taxes: 1.5% of initial investment, escalated
4 Insurance: 0.25% of initial investment, escalated
5 Residual Value: calculated growth rate of year 19 revenues (only if positive cashflows)

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Denotes summary results

THE ESSEX PARTNERSHIP

No.	Item/ Study Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	**Costs ($1,000's)**																					
a	Initial Investment	3,519																				
b	O&M		11	11	12	12	12	12	13	13	13	14	14	14	15	15	16	16	16	17	17	18
c	Major Maintenance		23	24	24	25	25	26	27	27	28	29	30	30	31	32	33	33	34	35	36	37
d	Insurance		9	9	9	10	10	10	10	11	11	11	12	12	12	12	13	13	13	14	14	14
e	Payment in lieu of Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f																						
g	Subtotal, Costs	3,519	43	44	45	46	48	49	50	51	53	54	55	57	58	59	61	62	64	66	67	69
2	**Revenues ($1,000's)**																					
a	State Grants	176																				
b	Federal Grants	528																				
c	Energy		92	94	97	99	101	104	107	109	112	115	118	121	124	127	130	133	136	140	143	147
d	Recs		18	19	19	20	20	21	21	22	22	23	24	24	25	25	26	27	27	28	29	29
e	Avoided Distribution																					
f	Capacity/Demand		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g	Residual Value																					4,294
h	Subtotal, Revenues	704	110	113	116	119	122	125	128	131	134	138	141	145	148	152	156	160	164	168	172	4,470
3	**Cashflows ($1,000's)**																					
a	Nominal Dollars	(2,815)	67	69	71	72	74	76	78	80	82	84	86	88	90	93	95	97	100	102	105	4,401
b	NPV	(2,815)	64	62	61	59	58	57	55	54	53	51	50	49	48	47	46	45	43	42	41	1,659
c	Cum NPV	(2,815)	(2,751)	(2,689)	(2,628)	(2,568)	(2,510)	(2,454)	(2,398)	(2,344)	(2,292)	(2,240)	(2,190)	(2,141)	(2,093)	(2,046)	(2,000)	(1,956)	(1,912)	(1,870)	(1,829)	(170)
4	**Levered Cashflow ($1,000's)**																					
a	Investment Cost	2,815																				
b	Equity	1,745																				
c	Net Operating Income		67	69	71	72	74	76	78	80	82	84	86	88	90	93	95	97	100	102	105	4,401
d	Debt Service		(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)	(43)
e	Debt Coverage Ratio		1.6	1.6	1.6	1.7	1.7	1.8	1.8	1.9	1.9	2.0	2.0	2.1	2.1	2.2	2.2	2.3	2.3	2.4	2.4	2.4
f	Cash after debt service		24	26	28	29	31	33	35	37	39	41	43	45	47	50	52	54	57	59	62	4,358
g	Interest Payment		(21)	(21)	(21)	(20)	(20)	(19)	(19)	(18)	(18)	(17)	(17)	(16)	(16)	(15)	(15)	(14)	(13)	(13)	(12)	(12)
h	Taxable Income		3	5	7	9	12	14	16	19	21	24	26	29	32	35	37	40	43	47	50	4,347
i	Income tax																					
j	After Tax Cash	(1,745)	24	26	28	29	31	33	35	37	39	41	43	45	47	50	52	54	57	59	62	4,358
k	NPV	(1,745)	23	24	24	24	25	25	25	25	25	25	25	25	25	25	25	25	25	25	24	1,643
l	Cum NPV	(1,745)	(1,722)	(1,698)	(1,674)	(1,650)	(1,625)	(1,601)	(1,576)	(1,551)	(1,526)	(1,500)	(1,475)	(1,450)	(1,425)	(1,400)	(1,375)	(1,350)	(1,325)	(1,300)	(1,276)	367
	Proforma Inputs		Esc. Rate	2.5%		Disc. Rate	5.0%		MWH	717		Max KW	209		State Grants	176		Fed Grants	528			
			Energy Rate	125	$/MWH	Avg. Power		KW	Rec Rate	25	$/MWH	Demand	0	$/KW-mos	O&M	0.015	c/kWh	Prop Tax	0.0%			
	Proforma Results																					
	Pre-Tax, Cash on Cash			PreTax, Cash on Cash IRR			4.6%		Cum NPV	(170)				Discounted Pay Back		20						
	Debt Levered, After-Tax			Debt Levered, After Tax IRR			6.1%		Cum NPV	367				Discounted Pay Back		19						

Assumptions

1 O&M: 1.5¢/KWH escalated at defined rate (see summary sheet)
2 Major maintenance: $50k in years 5 & 15, $125k in years 10 & 20
3 Payment in Lieu of Property taxes: 1.5% of initial investment, escalated
4 Insurance: 0.25% of initial investment, escalated
6 Average Debt Coverage Ratio (DCR) set to 2.0 for all levered cases.

Denotes cell input linked to Summary Tab
Denotes summary results

No.	Item/ Study Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	**Costs ($1,000's)**																					
a	Initial Investment	3,070																				
b	O&M		7	7	7	8	8	8	8	8	9	9	9	9	10	10	10	10	11	11	11	11
c	Major Maintenance		23	24	24	25	25	26	27	27	28	29	30	30	31	32	33	33	34	35	36	37
d	Insurance		8	8	8	8	9	9	9	9	10	10	10	10	11	11	11	11	12	12	12	13
e	Payment in lieu of Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f																						
g	Subtotal, Costs	3,070	38	39	40	41	42	43	44	45	46	48	49	50	51	52	54	55	57	58	59	61
2	**Revenues ($1,000's)**																					
a	State Grants	153																				
b	Federal Grants	460																				
c	Energy		59	61	62	64	66	67	69	71	72	74	76	78	80	82	84	86	88	90	93	95
d	Recs		12	12	12	13	13	13	14	14	14	15	15	16	16	16	17	17	18	18	19	19
e	Avoided Distribution																					
f	Capacity/Demand		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g	Residual Value																					2,127
h	Subtotal, Revenues	614	71	73	75	77	79	81	83	85	87	89	91	94	96	98	101	103	106	109	111	2,241
3	**Cashflows ($1,000's)**																					
a	Nominal Dollars	(2,456)	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	51	52	2,181
b	NPV	(2,456)	32	31	30	29	29	28	27	27	26	26	25	24	24	23	23	22	22	21	21	822
c	Cum NPV	(2,456)	(2,424)	(2,393)	(2,363)	(2,333)	(2,305)	(2,277)	(2,249)	(2,222)	(2,196)	(2,171)	(2,146)	(2,122)	(2,098)	(2,075)	(2,052)	(2,030)	(2,008)	(1,987)	(1,967)	(1,145)
4	**Levered Cashflow ($1,000's)**																					
a	Investment Cost	2,456																				
b	Equity	1,925																				
c	Net Operating Income		33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	51	52	2,181
d	Debt Service		(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)
e	Debt Coverage Ratio		1.6	1.6	1.6	1.7	1.7	1.8	1.8	1.9	1.9	2.0	2.0	2.1	2.1	2.2	2.2	2.3	2.3	2.4	2.4	2.4
f	Cash after debt service		12	13	14	15	16	16	17	18	19	20	21	22	24	25	26	27	28	29	31	2,159
g	Interest Payment		(11)	(10)	(10)	(10)	(10)	(10)	(9)	(9)	(9)	(9)	(8)	(8)	(8)	(7)	(7)	(7)	(7)	(6)	(6)	(6)
h	Taxable Income		1	2	4	5	6	7	8	9	11	12	13	14	16	17	19	20	22	23	25	2,154
i	Income tax																					
j	After Tax Cash	(1,925)	12	13	14	15	16	16	17	18	19	20	21	22	24	25	26	27	28	29	31	2,159
k	NPV	(1,925)	11	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	814
l	Cum NPV	(1,925)	(1,914)	(1,902)	(1,890)	(1,878)	(1,866)	(1,854)	(1,842)	(1,829)	(1,817)	(1,804)	(1,792)	(1,779)	(1,767)	(1,754)	(1,742)	(1,730)	(1,717)	(1,705)	(1,693)	(879)
	Proforma Inputs		Esc. Rate	2.5%		Disc. Rate	5.0%		MWH	464		Max KW	178		State Grants	153		Fed Grants	460			
			Energy Rate	125	$/MWH	Avg. Power		KW	Rec Rate	25	$/MWH	Demand	0	$/KW-mos	O&M	0.015	c/kWh	Prop Tax	0.0%			
	Proforma Results																					
	Pre-Tax, Cash on Cash			PreTax, Cash on Cash IRR			1.1%		Cum NPV	(1,145)				Discounted Pay Back		20						
	Debt Levered, After-Tax			Debt Levered, After Tax IRR			1.5%		Cum NPV	(879)				Discounted Pay Back		20						

Assumptions

1 O&M: 1.5¢/KWH escalated at defined rate (see summary sheet)
2 Major maintenance: $50k in years 5 & 15, $125k in years 10 & 20
3 Payment in Lieu of Property taxes: 1.5% of initial investment, escalated
4 Insurance: 0.25% of initial investment, escalated
5 Residual Value: calculated growth rate of year 19 revenues (only if positive cashflows)
6 Average Debt Coverage Ratio (DCR) set to 2.0 for all levered cases.

(blue)	Denotes cell input linked to Summary Tab
(yellow)	Denotes cell input linked to Individual Cost Tabs
(green)	Denotes summary results

No.	Item/ Study Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	**Costs ($1,000's)**																					
a	Initial Investment	3,228																				
b	O&M		13	13	13	13	14	14	15	15	15	16	16	16	17	17	18	18	19	19	20	20
c	Major Maintenance		23	24	24	25	25	26	27	27	28	29	30	30	31	32	33	33	34	35	36	37
d	Insurance		8	8	9	9	9	9	10	10	10	10	11	11	11	11	12	12	12	13	13	13
e	Payment in lieu of Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f																						
g	Subtotal, Costs	3,228	44	45	46	47	48	50	51	52	53	55	56	58	59	60	62	64	65	67	68	70
2	**Revenues ($1,000's)**																					
a	State Grants	153																				
b	Federal Grants	460																				
c	Energy		104	107	110	112	115	118	121	124	127	130	134	137	140	144	147	151	155	159	163	167
d	Recs		21	21	22	22	23	24	24	25	25	26	27	27	28	29	29	30	31	32	33	33
e	Avoided Distribution																					
f	Capacity/Demand		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g	Residual Value																					5,205
h	Subtotal, Revenues	614	125	128	132	135	138	142	145	149	153	156	160	164	168	173	177	181	186	191	195	5,405
3	**Cashflows ($1,000's)**																					
a	Nominal Dollars	(2,614)	81	83	86	88	90	92	94	97	99	102	104	107	109	112	115	118	121	124	127	5,335
b	NPV	(2,614)	78	76	74	72	70	69	67	65	64	62	61	59	58	57	55	54	53	51	50	2,011
c	Cum NPV	(2,614)	(2,536)	(2,461)	(2,387)	(2,315)	(2,244)	(2,175)	(2,108)	(2,043)	(1,979)	(1,917)	(1,856)	(1,796)	(1,738)	(1,681)	(1,626)	(1,572)	(1,519)	(1,468)	(1,418)	593
4	**Levered Cashflow ($1,000's)**																					
a	Investment Cost	2,614																				
b	Equity	1,316																				
c	Net Operating Income		81	83	86	88	90	92	94	97	99	102	104	107	109	112	115	118	121	124	127	5,335
d	Debt Service		(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)
e	Debt Coverage Ratio		1.6	1.6	1.6	1.7	1.7	1.8	1.8	1.9	1.9	2.0	2.0	2.1	2.1	2.2	2.2	2.3	2.3	2.4	2.4	2.4
f	Cash after debt service		29	32	34	36	38	40	42	45	47	50	52	55	58	60	63	66	69	72	75	5,283
g	Interest Payment		(26)	(25)	(25)	(24)	(24)	(23)	(23)	(22)	(22)	(21)	(20)	(20)	(19)	(18)	(18)	(17)	(16)	(16)	(15)	(14)
h	Taxable Income		4	6	9	11	14	17	20	23	26	29	32	35	39	42	45	49	53	56	60	5,269
i	Income tax																					
j	After Tax Cash	(1,316)	29	32	34	36	38	40	42	45	47	50	52	55	58	60	63	66	69	72	75	5,283
k	NPV	(1,316)	28	29	29	29	30	30	30	30	30	31	31	31	31	30	30	30	30	30	30	1,991
l	Cum NPV	(1,316)	(1,288)	(1,259)	(1,230)	(1,201)	(1,171)	(1,141)	(1,111)	(1,081)	(1,050)	(1,020)	(989)	(958)	(928)	(897)	(867)	(837)	(807)	(777)	(747)	1,244

Proforma Inputs

Esc. Rate 2.5% | Disc. Rate 5.0% | MWH 815 | Max KW 271 | State Grants 153 | Fed Grants 460

Energy Rate 125 $/MWH | Avg. Power KW | Rec Rate 25 $/MWH | Demand 0 $/KW-mos | O&M 0.015 c/kWh | Prop Tax 0.0%

Proforma Results

Pre-Tax, Cash on Cash	PreTax, Cash on Cash IRR	6.4%	Cum NPV	593	Discounted Pay Back	19
Debt Levered, After-Tax	Debt Levered, After Tax IRR	9.1%	Cum NPV	1,244	Discounted Pay Back	19

Assumptions

1 O&M: 1.5¢/KWH escalated at defined rate (see summary sheet)
2 Major maintenance: $50k in years 5 & 15, $125k in years 10 & 20
3 Payment in Lieu of Property taxes: 1.5% of initial investment, escalated
4 Insurance: 0.25% of initial investment, escalated
5 Residual Value: calculated growth rate of year 19 revenues (only if positive cashflows)
6 Average Debt Coverage Ratio (DCR) set to 2.0 for all levered cases.

Denotes cell input linked to Summary Tab
Denotes cell input linked to Individual Cost Tabs
Denotes summary results

THE ESSEX PARTNERSHIP

No.	Item/ Study Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	**Costs ($1,000's)**																					
a	Initial Investment	2,937																				
b	O&M		5	5	5	6	6	6	6	6	6	6	7	7	7	7	7	7	8	8	8	8
c	Major Maintenance		23	24	24	25	25	26	27	27	28	29	30	30	31	32	33	33	34	35	36	37
d	Insurance		8	8	8	8	8	9	9	9	9	9	10	10	10	10	11	11	11	11	12	12
e	Payment in lieu of Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f																						
g	Subtotal, Costs	2,937	36	37	38	38	39	40	41	42	44	45	46	47	48	49	50	52	53	54	56	57
2	**Revenues ($1,000's)**																					
a	State Grants	147																				
b	Federal Grants	440																				
c	Energy		43	44	45	46	47	49	50	51	52	54	55	56	58	59	61	62	64	65	67	69
d	Recs		9	9	9	9	9	10	10	10	10	11	11	11	12	12	12	12	13	13	13	14
e	Avoided Distribution																					
f	Capacity/Demand		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g	Residual Value																					1,007
h	Subtotal, Revenues	587	51	53	54	55	57	58	60	61	63	64	66	68	69	71	73	75	76	78	80	1,089
3	**Cashflows ($1,000's)**																					
a	Nominal Dollars	(2,349)	16	16	17	17	17	18	18	19	19	20	20	21	21	22	22	23	23	24	25	1,032
b	NPV	(2,349)	15	15	14	14	14	13	13	13	12	12	12	12	11	11	11	10	10	10	10	389
c	Cum NPV	(2,349)	(2,334)	(2,320)	(2,305)	(2,291)	(2,278)	(2,265)	(2,252)	(2,239)	(2,226)	(2,214)	(2,203)	(2,191)	(2,180)	(2,169)	(2,158)	(2,148)	(2,138)	(2,128)	(2,118)	(1,729)
4	**Levered Cashflow ($1,000's)**																					
a	Investment Cost	2,349																				
b	Equity	2,098																				
c	Net Operating Income		16	16	17	17	17	18	18	19	19	20	20	21	21	22	22	23	23	24	25	1,032
d	Debt Service		(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
e	Debt Coverage Ratio		1.6	1.6	1.6	1.7	1.7	1.8	1.8	1.9	1.9	2.0	2.0	2.1	2.1	2.2	2.2	2.3	2.3	2.4	2.4	2.4
f	Cash after debt service		6	6	7	7	7	8	8	9	9	10	10	11	11	12	12	13	13	14	15	1,022
g	Interest Payment		(5)	(5)	(5)	(5)	(5)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(3)	(3)	(3)	(3)	(3)	(3)
h	Taxable Income		1	1	2	2	3	3	4	4	5	6	6	7	7	8	9	9	10	11	12	1,019
i	Income tax																					
j	After Tax Cash	(2,098)	6	6	7	7	7	8	8	9	9	10	10	11	11	12	12	13	13	14	15	1,022
k	NPV	(2,098)	5	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	385
l	Cum NPV	(2,098)	(2,093)	(2,087)	(2,082)	(2,076)	(2,070)	(2,064)	(2,059)	(2,053)	(2,047)	(2,041)	(2,035)	(2,029)	(2,023)	(2,017)	(2,011)	(2,006)	(2,000)	(1,994)	(1,988)	(1,603)

Proforma Inputs	Esc. Rate	2.5%	Disc. Rate	5.0%	MWH	335		Max KW	110	State Grants	147	Fed Grants	440
	Energy Rate	125	$/MWH	Avg. Power	KW	Rec Rate	25	$/MWH	Demand	0	$/KW-mos	O&M 0.015 c/kWh	Prop Tax 0.0%
Proforma Results													
Pre-Tax, Cash on Cash	PreTax, Cash on Cash IRR	#NUM!	Cum NPV	(1,729)	Discounted Pay Back	20							
Debt Levered, After-Tax	Debt Levered, After Tax IRR	#NUM!	Cum NPV	(1,603)	Discounted Pay Back	20							

Assumptions

1 O&M: 1.5¢/KWH escalated at defined rate (see summary sheet)
2 Major maintenance: $50k in years 5 & 15, $125k in years 10 & 20
3 Payment in Lieu of Property taxes: 1.5% of initial investment, escalated
4 Insurance: 0.25% of initial investment, escalated
5 Residual Value: calculated growth rate of year 19 revenues (only if positive cashflows)
6 Average Debt Coverage Ratio (DCR) set to 2.0 for all levered cases.

Denotes cell input linked to Summary Tab
Denotes cell input linked to Individual Cost Tabs
Denotes summary results

THE ESSEX PARTNERSHIP

No.	Item/ Study Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	**Costs ($1,000's)**																					
a	Initial Investment	3,277																				
b	O&M		6	6	6	6	6	7	7	7	7	7	7	8	8	8	8	8	9	9	9	9
c	Major Maintenance		23	24	24	25	25	26	27	27	28	29	30	30	31	32	33	33	34	35	36	37
d	Insurance		8	9	9	9	9	10	10	10	10	10	11	11	11	12	12	12	12	13	13	13
e	Payment in lieu of Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f																						
g	Subtotal, Costs	3,277	37	38	39	40	41	42	43	44	45	46	48	49	50	51	53	54	55	57	58	59
2	**Revenues ($1,000's)**																					
a	State Grants	164																				
b	Federal Grants	492																				
c	Energy		48	49	50	52	53	54	56	57	58	60	61	63	64	66	68	69	71	73	75	77
d	Recs		10	10	10	10	11	11	11	11	12	12	12	13	13	13	14	14	14	15	15	15
e	Avoided Distribution																					
f	Capacity/Demand																					
g	Residual Value																					1,295
h	Subtotal, Revenues	655	57	59	60	62	63	65	67	68	70	72	74	75	77	79	81	83	85	87	90	1,387
3	**Cashflows ($1,000's)**																					
a	Nominal Dollars	(2,622)	20	21	21	22	22	23	23	24	25	25	26	27	27	28	29	29	30	31	32	1,328
b	NPV	(2,622)	19	19	18	18	18	17	17	16	16	16	15	15	14	14	14	13	13	13	13	500
c	Cum NPV	(2,622)	(2,602)	(2,583)	(2,565)	(2,547)	(2,530)	(2,512)	(2,496)	(2,479)	(2,464)	(2,448)	(2,433)	(2,418)	(2,404)	(2,389)	(2,376)	(2,362)	(2,349)	(2,336)	(2,324)	(1,823)
4	**Levered Cashflow ($1,000's)**																					
a	Investment Cost	2,622																				
b	Equity	2,299																				
c	Net Operating Income		20	21	21	22	22	23	23	24	25	25	26	27	27	28	29	29	30	31	32	1,328
d	Debt Service		(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)
e	Debt Coverage Ratio		1.6	1.6	1.6	1.7	1.7	1.8	1.8	1.9	1.9	2.0	2.0	2.1	2.1	2.2	2.2	2.3	2.3	2.4	2.4	2.4
f	Cash after debt service		7	8	8	9	9	10	11	11	12	12	13	14	14	15	16	16	17	18	19	1,315
g	Interest Payment		(6)	(6)	(6)	(6)	(6)	(6)	(6)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(4)	(4)	(4)	(4)	(4)	(4)
h	Taxable Income		1	2	2	3	4	4	5	6	6	7	8	9	10	10	11	12	13	14	15	1,311
i	Income tax																					
j	After Tax Cash	(2,299)	7	8	8	9	9	10	11	11	12	12	13	14	14	15	16	16	17	18	19	1,315
k	NPV	(2,299)	7	7	7	7	7	7	8	8	8	8	8	8	8	8	8	8	7	7	7	496
l	Cum NPV	(2,299)	(2,292)	(2,284)	(2,277)	(2,270)	(2,263)	(2,255)	(2,248)	(2,240)	(2,232)	(2,225)	(2,217)	(2,210)	(2,202)	(2,194)	(2,187)	(2,179)	(2,172)	(2,164)	(2,157)	(1,661)
	Proforma Inputs		Esc. Rate	2.5%		Disc. Rate	5.0%		MWH	374		Max KW	104		State Grants	164		Fed Grants	492			
			Energy Rate	125	$/MWH	Avg. Power		KW	Rec Rate	25	$/MWH	Demand	0	$/KW-mos	O&M	0.015	c/kWh	Prop Tax	0.0%			
	Proforma Results																					
	Pre-Tax, Cash on Cash			PreTax, Cash on Cash IRR			-2.1%		Cum NPV	(1,823)					Discounted Pay Back	20						
	Debt Levered, After-Tax			Debt Levered, After Tax IRR			-2.1%		Cum NPV	(1,661)					Discounted Pay Back	20						

Assumptions

1 O&M: 1.5¢/KWH escalated at defined rate (see summary sheet)
2 Major maintenance: $50k in years 5 & 15, $125k in years 10 & 20
3 Payment in Lieu of Property taxes: 1.5% of initial investment, escalated
4 Insurance: 0.25% of initial investment, escalated
5 Residual Value: calculated growth rate of year 19 revenues (only if positive cashflows)
6 Average Debt Coverage Ratio (DCR) set to 2.0 for all levered cases.

Denotes cell input linked to Summary Tab
Denotes cell input linked to Individual Cost Tabs
Denotes summary results

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