Hydropower Integrated Design and Economic Assessment Tool for Use in Preliminary Feasibility Assessments – Modeling Framework

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Abstract

Recently, Oak Ridge National Laboratory (ORNL) published a series of initial capital cost equations to support the national-scale economic evaluation for nearly 80 GW of non-powered dam (NPD) and new stream-reach development (NSD) sites across the U.S.. While these equations are capable of providing reasonable 'ballpark' cost estimates, they do not account for design considerations which may greatly impact accuracy. To fill this gap, ORNL has developed the Hydropower Integrated Design and Assessment (HIDEA) tool. This tool combines multiple generation technology options, each with specific project design considerations and performance quantification to holistically demonstrate project feasibility. The model's bottom-up approach supports technology comparison and cost reduction identification, explicitly designed for assessing new and emerging technologies and alternative materials but equally applicable to traditional designs.

This paper documents the model's cost components and describes how design, performance, and economic considerations are modeled. To illustrate how the linked engineering and economic analysis in the model supports the evaluation of site and technology feasibility, this document includes a case study comparing multiple proposed real-world design configurations for a new powerhouse on an existing unpowered Army Corps of Engineers dam. These multiple designs differ significantly in both total capacity and technology choice, and their comparison using the model documented here illustrate the key tradeoffs between performance, cost, and flexibility inherent in hydropower economic analysis.

A partial validation on the model's cost estimating accuracy is performed using information from 17 constructed U.S. projects, showing that modeled initial capital cost estimates are within 50% for 15 projects, within 30% for 10 projects, and within 10% for 6 projects.. Based on this preliminary application, the model is able to reasonably estimate the variability and magnitude of hydropower cost. While not intended to supplant true feasibility studies that include refined engineering, the integrated model provides a robust, design-driven cost and performance tool which may be widely applicable and improves upon more basic methods by more explicitly capturing site-specific design considerations.

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1. Introduction

Recent resource assessments conducted by United States Department of Energy have identified nearly 80 GW of new stream reach development (NSD) sites and non-powered dam (NPDs) hydropower potential across U.S. (Hadjerioua et al., 2012, Kao et al., 2014). While the resource potential for new hydropower is clear, improved cost estimation tools are necessary for evaluating the economic feasibility of these resources. As most hydropower development is highly capital-intensive and burdened by long lead time, such an investment demands a high degree of confidence (Copestake and Young, 2008). The initial capital cost remains a major barrier to development for small, low-head hydropower (Zhang et al, 2014).

This report documents the development of a new modeling tool at Oak Ridge National Laboratory (ORNL)—the Hydropower Integrated Design and Economic Assessment model (alternative referred to as the "HIDEA", "the model" or "the Integrated Model"). The primary function of the model is to support the evaluation of hydropower project economics and the prospective impacts of R&D for the U.S. Department of Energy's Water Power Program. The Integrated Model is first and foremost a research tool, and the design and cost assumptions and case study described in this document are intended to serve as an initial vehicle for feedback from industry stakeholders. The model is very much still a work in progress, but exists in a functional state where industry expertise can help ensure accuracy in the modeled representation of hydropower's key design concerns and performance.

Subsequently, as the model evolves given constructive industry feedback, the site-specific, integrated evaluation approach documented here may be of interest to other hydropower stakeholders. As constructed, all assumptions and equations in the model are intended to be transparently documented, and all software implementations with the exception of Microsoft Excel are built on free and open source software (FOSS) platforms.

The remainder of this Section 1 expands on the motivation and need for a new modeling tool and illustrates the general framework of the model. Section 2 provides a summary level introduction to the design, cost, and economic logic in how hydropower plant components are represented in the model, and Section 3 demonstrates how the model performs in two analyses. The first is an evaluation of alternative design options at an existing dam, and the second is a comparison of modeled plant cost and actual cost for 17 real-world projects. For readers interested in the next layer of detail on model formulation, Appendix A includes a detailed list of all input assumptions, equations, and data sources.

This technical report for Hydrovision International 2016 is intended to be the beginning of a conversation and model refinement process. A more thorough report documenting the function and assumptions underlying the model will be available by the end of 2016 on http://hydropower.ornl.gov.

1.1 Existing Tools for Hydropower Design and Economic Assessment

In 2015, Oak Ridge National Laboratory (ORNL) published a series of initial capital cost equations to support the national-scale economic evaluation for prospective U.S. hydropower resources (O'Connor et al., 2015a and 2015b). While these cost equations do not account for design-specific considerations, they are suitable for national or regional evaluation of hydropower economic competitiveness. However, the cost, design, and performance of – and subsequently the impacts of policy and technology advancement on hydropower projects – are site-specific. For example, hydrology, geology and markets can play a significant role in the optimum design and cost of a hydropower project. To address such challenges, it was determined that a tool which fully integrated key components of design with performance simulation would be necessary to evaluate for technology impacts on the economics of hydropower projects.

Current industry tools such as the Renewable Energy Technology Screen (RETScreen) model (National Resources Canada, 2004), the U.S. Bureau of Reclamation (USBR) hydropower assessment tool (USBR, 2011), and U.S. Army Corps of Engineers (USACE) methodologies are capable of evaluating site-specific design and an economic assessment of a hydropower project (USACE, 2013)[1]. However, these tools offer only limited capabilities and simplified economic and reconnaissance analysis—and relative t to the objective of evaluation the impacts of policy and technology advances—all faced one or more of the following limitations:

- Simplified performance simulation: Existing hydropower assessment tools are based on conventional technology and design, which prevents evaluation of new and emerging hydropower technologies. These tools do not enable evaluation of multiple different turbine technologies within the same project.
- Simplified civil design: All of these tools determine project cost using static parametric cost equations and rule-of-thumb. In reality, new emerging technologies have dynamic cost impacts on powerhouse design and generation efficiency and interact uniquely with other technologies.
- Limited financial analysis capabilities: Existing tools do not provide sufficient flexibility to evaluate government policy impact on project economics.

To address these gap in the existing models, better assess the viability of developing significant untapped resources, and help identify key areas for research, development, and deployment (RD&D),ORNL has developed hydropower integrated design and economic assessment tool to enable technology and policy impact analysis through design and economic evaluation. Some key features of the model are:

- Site-specific design and cost simulation: as in other hydropower costing tools, HIDEA attempts to simulate site-specific design and cost estimation using recent

[1] Zhang et. al. (2013) provides more detail about existing small hydropower assessment software

industry experience for a variety of considerations. The model provides a reconnaissance level (i.e., AACE Class 5[2]) design and cost estimates.

- Explicit operational simulation: The model includes a performance optimization routine to explicitly simulate the dispatch of individual units in a plant.

- The model cost is estimated using dynamic civil design based on user-defined turbine technologies. For example: the model computes powerhouse cost using dynamic three-dimensional powerhouse design based on selected turbine technologies and design parameters.

- Flexibility to accommodate mixed turbine technology application: rather than limiting analysis to powerhouses containing a single turbine technology, the model allows for a mixed technologies, an important design feature which many hydropower facilities have included to meet site-specific needs given variations in het head and flows at a facility.

- Flexibility to accommodate new (e.g., modular) design philosophies[3]: The model provides flexibility to add any new technologies for project evaluation based on technology-specific characteristics.

- Greater financial analysis capabilities: The model allows multiple-run scenarios for evaluating policy impacts (e.g., incentives) on project cost.

1.2 Key Data Sources

While existing tools did not fit the model design criteria perfectly, they, and 100 years of industry expertise, provide a robust foundation for the new model development. The key data sources used to develop HIDEA include:

- USBR and USACE historical design reports and project data (USBR, 1980; USBR, 2011; USACE, 2013; and USACE 1979)

- European Small Hydro design guide (ESHA, 2004)

- RETScreen energy project assessment software documentation (NRC, 2004)

- “HydroHelp” hydropower project assessment software documentation (Hydro Help, 2016)

[2] AACE (2013) class 5 cost estimation accuracy ranges from -50 to +100%

[3] Currently, the HIDEA tool is developed for conventional design approaches, but with flexibility to accommodate new (e.g. modular) design philosophies. The current HIDEA tool allows selecting conventional Francis (horizontal and vertical), Kaplan, and Bulb turbines. The next version of HIDEA tool will allow adding other axial-flow Kaplan implementation (e.g. S-type).

- INL historical cost report (INL, 2003)
- ORNL Baseline Cost Modeling reports and internal databases (O'Connor et al., 2015a and 2015b)

1.3 Modeling Framework

The HIDEA conceptual modeling framework and basic linkage between modeling components is presented in Figure 1. As seen in the Figure, the model requires various input parameters and includes four different modules: design, cost, operations, and economic assessment. The input parameters include site and financial information defined by the user.. The design module performs overall project design based on input parameters using a combination of parametric, heuristic, and engineering-based design approaches. The cost module provides project component cost information using parametric and volumetric costing methods. The operations module provides net energy generation and energy revenue estimates using explicit performance simulation. The economic assessment module integrates the estimates of cost and performance into a discounted cash flow analysis which can be used to evaluate various economic metrics such as Net Present Value (NPV), Internal Rate of Return (IRR) and the Levelized Cost of Energy (LCOE).

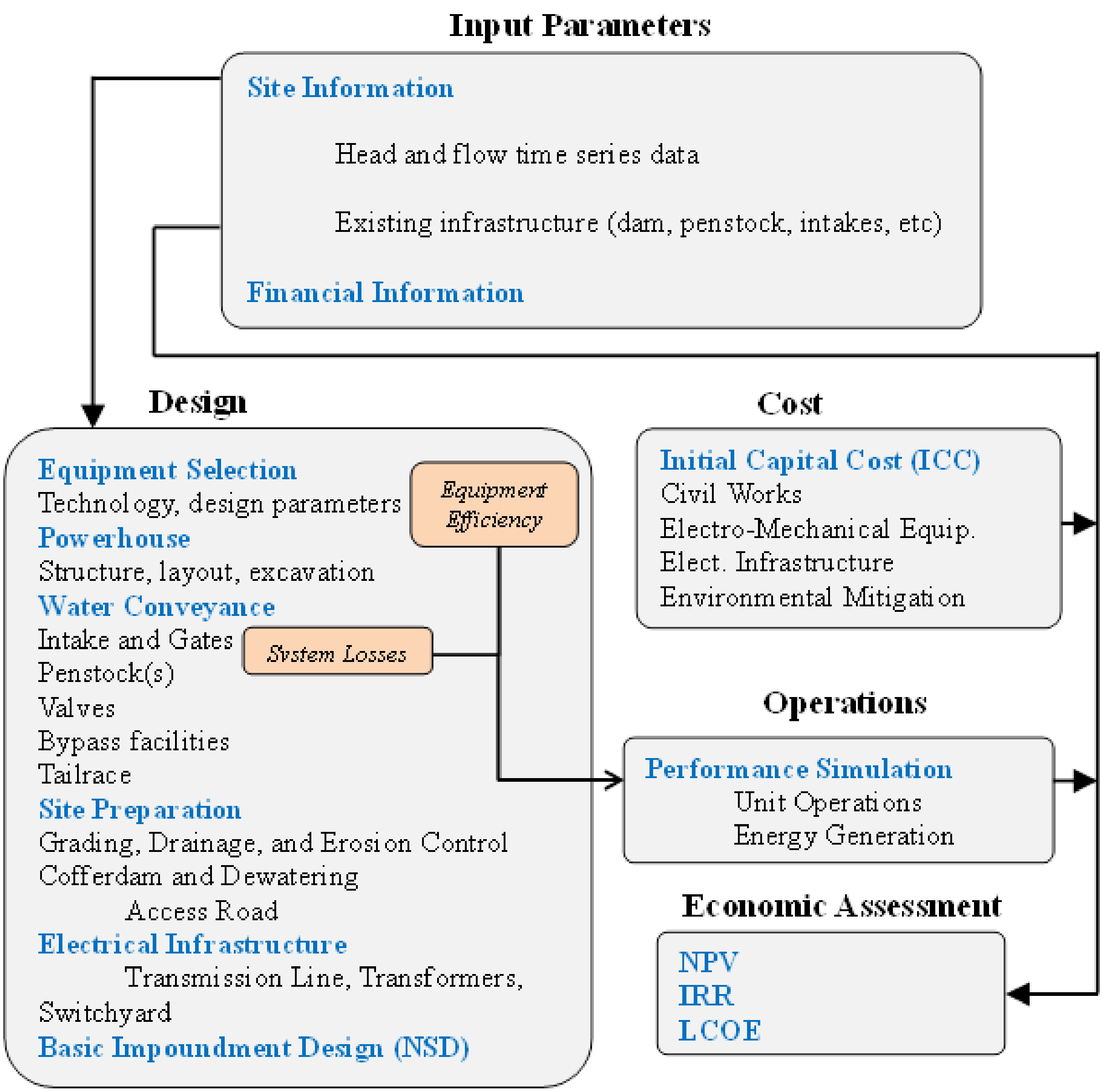

Figure 1. Conceptual Modeling Framework

1.4 Applicability and Assumptions

As an important consideration, the current HIDEA tool is applicable for assessing NPD and NSD sites with potential capacity ranges from 1 MW to 50 MW and hydraulic head up to 100 ft. Application beyond this range should be used with caution, though this application range may be extended in the future.

2. Summary of Model Components

The HIDEA Design Module incorporates component-level design of civil works, electro-mechanical equipment, and electrical infrastructure. The tool uses a combination of parametric, heuristic, and engineering-based design approaches. Other project features which are not explicitly designed within the model include estimation of engineering and construction management requirements and environmental mitigation needs. Instead, these features are assumed to scale with project size, and such cost implications are captured accordingly in the costing process.

Readers which are not concerned with the concepts underlying the modeling of hydropower project component should skip ahead to Section 3 to explore the performance of the model in the costing and economic evaluation of recent constructed or proposed projects.

2.1 Inputs

Concurrent with its intention as a research tool, the model is designed to provide an initial assessment of a hydropower site using minimal site data. Project design, performance, and economic evaluation are based on two sets of inputs—site characteristics and technology selection.

2.1.1 Site Characteristics

The first inputs to the model are basic site attributes which influence the design and operational needs of the project to be modeled. The most important of these is a time series data set detailing the gross net head and average flow at a project across a given time period. Generally, daily average time series are adequate to distinguish variability in head and flow at a site, and the operational simulation component of the model may further average the series from hundreds to thousands of observations down to a computationally faster amount (typically 50-500 bins of head-flow pairs).

Beyond head and flow data, the model provides the option to specify the need for key project features including the number and length of penstocks—or whether those project features already exist, including the dam, intakes, and penstocks. Many recent NPD projects have been constructed on some of the more economically competitive dams, which often already include existing intake structures and high-pressure pipelines. The civil infrastructure savings from these existing structures can be significant.

2.1.2 Turbine Technology Selection

Where the site characterstics define the bounds of how a project is design and operated, the selection of turbine technology and its key characteristics is the input which determines project design and cost, and the performance attributes of the plant relative to the site parameters. The model requires the selection on an individual unit basis of:

1. The turbine technology and configuration. The model currently has representations of Francis (Horizontal and Vertical), Kaplan (Vertical), Bulb (Horizontal), and Propeller units. An additional axial-flow turbine may be added to the model's capabilities in the future (e.g. S-type Kaplan).
2. Design head
3. Design flow

The choice of these three parameters for each desired unit is what drives the design of the plant in combination with the specification of the site characteristics. A unique feature of the model is in allowing for the selection of mixed turbine technologies and characteristics within the same plant. For example, the model enables the combination of Kaplan and Francis turbines in the same project and will notify the user if the selected mixed turbine types are incompatible (e.g., Bulb or turbine with Kaplan/Francis turbines.)

The model has also been designed with flexibility to simplify the process of simulating new technologies. This important feature should prove useful as the tool extends beyond conventional hydropower application to assess the impacts of new technology alternatives.

2.2 Design Outputs

This section details the basic design principles and model application for various features of a hydropower project. Intentionally, this discussion is left at a high level with few equations and figures. The intention is to give the reader a general idea of the considerations which drive design and cost within a project. However, a wealth of accumulated hydropower design and costing knowledge as embodied in small hydropower literature produced over the last 40 years drives the inner workings of the model, and a detailed list of equations which define the operation of the model are provided in Appendix A unless otherwise specified.

2.2.1 Electro-Mechanical Equipment

The electro-mechanical equipment includes supply and installation of the generating equipment and supporting electromechanical infrastructure, including powertrain equipment and ancillary electrical and mechanical equipment. Based on the selected turbine technologies and design conditions, the model computes design characteristics such as minimum flow, maximum flow, minimum head, maximum head, design efficiency, specific speed, and turbine runner diameter based on the selected turbine technologies and input parameters. These then inform the generation of turbine efficiency curves.

Design flow and head can dramatically affect the overall project performance (HPPI and ORNL, 2011). The model generates the turbine efficiency curve for the selected turbine types, which are ultimately used to simulate operations at a unit-level. The tool determines the peak efficiency and shape of the efficiency curve for selected turbine technology using empirically derived efficiency curves (Gordon, 2001). Figure 2 shows efficiency characteristic against hydraulic head for the Francis turbine. As seen in the figure, the efficiency changes significantly among different operating heads and capacities of the turbine. Generally, Gordon's efficiency equations reflect differences in turbine efficiency arising from physical size and age (more specifically the sophistication of design techniques available when the unit was first commissioned).

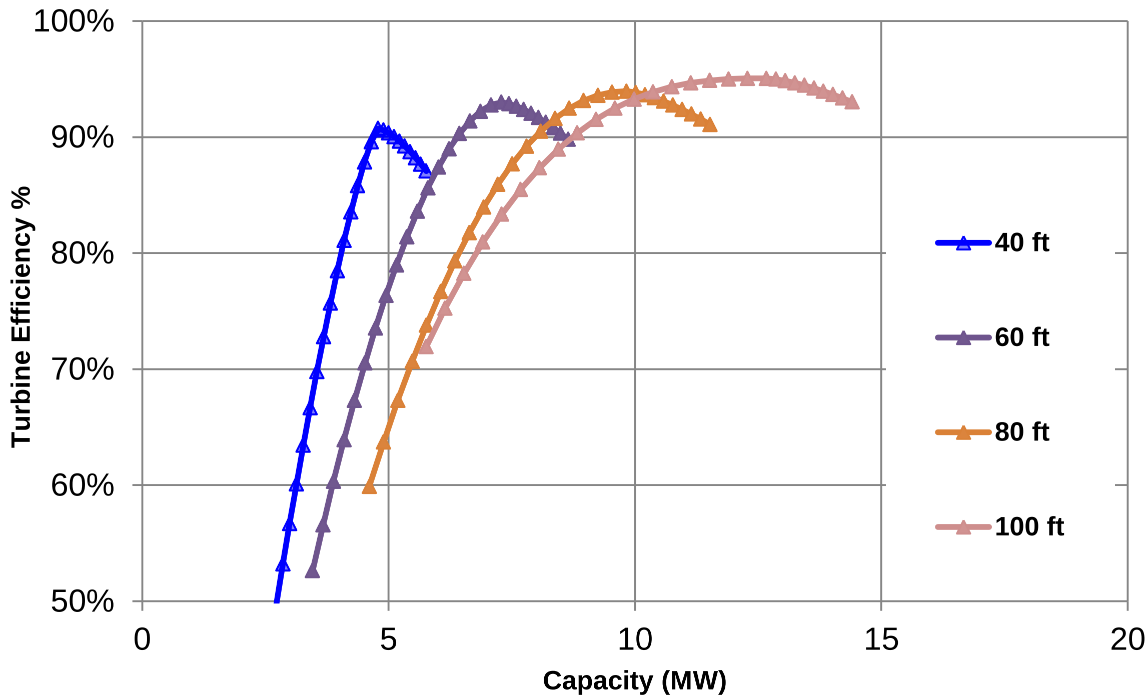

Figure 2. Efficiency characteristics of Francis turbines with varying design parameters

2.2.2 Water Conveyance System

The water conveyance system encompasses both the upstream structures used to transfer water from an upstream dam or a diversion structure to the turbine as well as the downstream structures used to discharge water out of an away from the turbine or powerhouse structure. Various structural arrangements are typically included from the conveyance system inlet (i.e. intake) to the outlet (i.e. tailrace). The water conveyance system in in the model includes the intake(s), intake gate(s), penstock(s), penstock bifurcation, valve(s), bypass facilities, and tailrace. A brief description on the design of each component is provided below.

Intakes

For small hydropower design, the intake is generally constructed at the upstream face of a dam. The intake regulates the flow of water into a penstock and includes the trash rack, which prevents debris from entering the penstock. HIDEA uses design flow to determine the size and number of intakes required. Intake structures may also be specified as being existing infrastructure when building on a non-powered dam.

Intake Gates

The intake gate is placed in the intake, to direct, control, or restrict water into the penstock. The gate size is based on the design flow and maximum intake velocity. HIDEA uses a maximum unit gate area[4] of 2500 ft^2 and 2000 ft^2 for slide and radial gates, respectively, and a maximum intake velocity[5] of 3 ft/s. When the maximum unit gate area is exceeded, the tool designs multiple smaller, equally-sized gates. Siphon-type intakes are not yet represented.

Penstocks

The penstock conveys water from the intake to the turbine. The penstock is most commonly made of steel to accommodate high pressure water; however, other materials such as concrete or HDPE may be used in certain applications. Penstock design is based on design flow and maximum penstock velocity.

The HIDEA model assumes a circular steel penstock and requires a user-defined penstock length. The penstock diameter is determined based on the design flow and a user-defined maximum penstock velocity of 10, 12, or 14 ft/s. The penstock diameter is computed to the nearest ½ foot and is used to determine the cross sectional area of penstock.

Penstock Bifurcation

A penstock bifurcation is the splitting of a single penstock into multiple penstocks and is used when multiple turbines are serviced from a single penstock. HIDEA requires a user-defined penstock bifurcation length .

Valves

Valve or wicket gate is provided to control water flow through the turbine. For such purpose, HIDEA assumes butterfly valve as default, but it allows user to select fixed cone valve. The model assumes one valve[6] for each turbine-generator unit. The valve diameter and area is calculated as similar to penstock.

Bypass Facilities

Small hydropower projects often require a defined water release rate, regardless of power production, to minimize environmental impact. Under such conditions, a provision is made to bypass water around the turbine and often includes a bypass facility upstream of the powerhouse to divert and convey this water.

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[4] The maximum gate area information was from Vortex Hydra, hydraulic gate manufacturer. This can be accessed through http://www.vortexhydradams.com/. The maximum velocity information was from USBR (1980) report.

[5]

[6] For Bulb turbines with no penstock, the model excludes turbine inlet valve.

The bypass facility design is based on a user-defined bypass conduit length and assumes a circular steel penstock to bypass the water. HIDEA requires a user-defined bypass conduit length and assumes no bypass facility if no length is provided. Existing bypass works can be designated as being existing infrastructure when building on a non-powered dam.

Tailrace

The tailrace conveys water discharged from the turbine to a downstream dam, reservoir, canal, or river. USBR (1980) provides powerhouse dimensions, including tailrace, based on different turbine types. These powerhouse dimensions were then used to determine the tailrace length, width, and height. For a multi-unit powerhouse, the tailrace length and height are set to the maximum value computed among the individual units, and the tailrace width is adjusted based on the maximum tailrace depth among units. HIDEA designs the tailrace for each turbine unit, and the length may be manually overridden. The tailrace may be specified as an existing feature of the project—this is particularly useful for many non-powered dams where discharges can be release into an existing tailrace or stilling basin.

2.2.3 Powerhouse Design

Once the turbine characterstics have been generated, the model uses an preliminary engineering-based approaches to design the powerhouse layout, structure, and excavation for both single unit and multiple unit arrangements. USBR (1980) provides powerhouse dimensions for different turbine technologies based on the turbine runner diameter[7] (see example in Figure 3).

[7] The model uses a parametric equation consists of design flow and head to calculate the turbine runner diameter. Please refer Electro-mechanical Equipment section for details

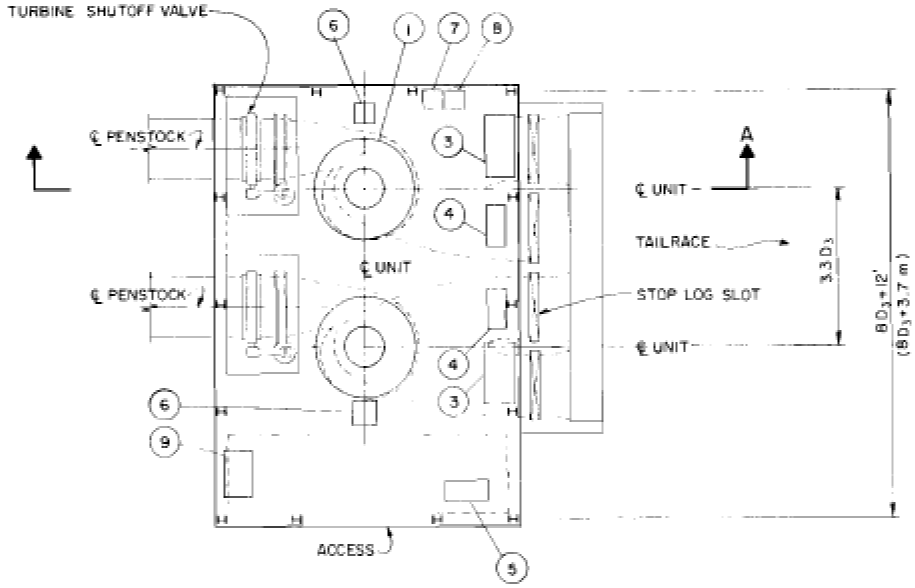

Figure 3. Typical plan of multiple vertical units Francis powerhouse (USBR, 1980)

An additional feature currently under development[8] is a 3-dimensional implementation of the 2D powerhouse layouts using Computer Assisted Design (CAD) software to generate volumetric materials estimates and graphically illustrate a three-dimensional powerhouse based on the specified technologies and unit arrangements. An example is shown below in Figure 4 for a two unit Francis plant. At this time the CAD implementation is purely exploratory.

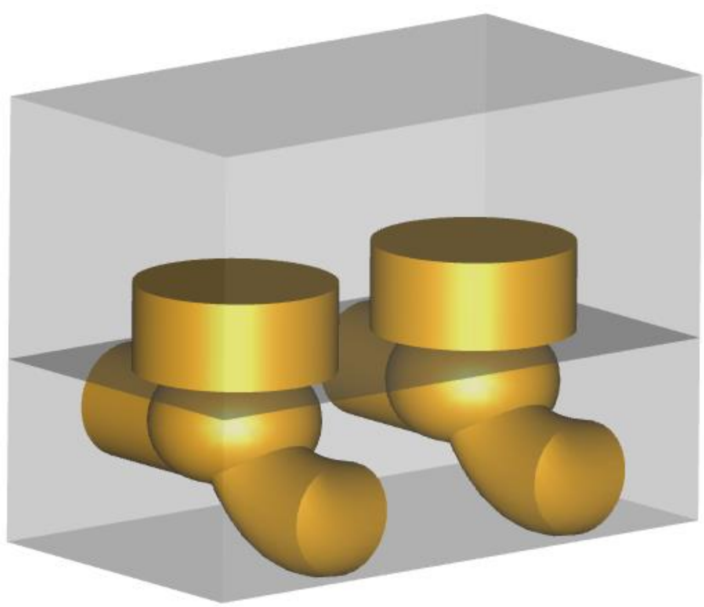

Figure 4. 3-Dimensional layout of two vertical Francis units

[8] The current prototype implementation is done in FreeCAD.

The model computes the powerhouse excavation volume based on the computed powerhouse area and depth of excavation.

2.2.4 Impoundment Structure Design

A dam or diversion structure obstructs flow and increases water elevation behind it, thus creating a potential head. When applicable (e.g., for a new stream reach development project), the model will design a basic impoundment structure. A typical impoundment structure cross section assumed in HIDEA is shown in Figure 5.

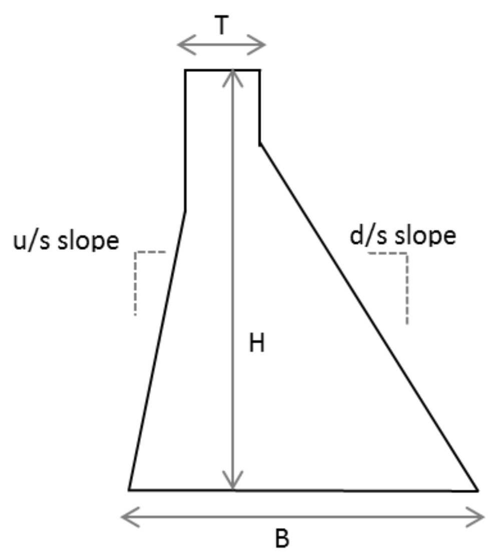

Figure 5. Example cross section of impoundment structure (modified from Kaushik et. al., 2014)

The dam's upstream slope (concrete material = 0.083, earth material = 3) and downstream slope (concrete material = 2, earth material = 2) are based on various literature (Kaushik et al, 2014 and Stone, 2003). To calculate the dam crest width, HIDEA uses an empirical relation between dam crest width and dam height (Stone, 2003)[9].

$$T = 0.2158\,H + 7.33$$

Where, T is the dam crest width in ft, H is the dam height in ft. To model a dam, HIDEA allows a user-defined dam height Or, In lieu of dam height information, may assume dam height equals 130% of the design head.

[9] The regression analysis results using data from Stone (2003).

2.2.5 Site Preparation

Site preparation works includes preliminary activities completed prior to starting construction. It includes: 1) site access road, 2) site development, and 3) coffer dam and dewatering during construction. The site access road is constructed first and provides access to the site for starting construction activities. The site development activities include grading, drainage and erosion control. A coffer dam, a temporary, watertight enclosure, is constructed to enable construction of a dam, powerhouse, and other structures. An additional requirement, dewatering is performed to temporarily drain surface and groundwater for proper foundation works and mobilization.

HIDEA requires a user-defined site access road length. The site development area is determined based on a calculated powerhouse area and user-defined terrain factor. The site development area, meant to represent the area disrupted for construction activities, is equivalent to the calculated powerhouse area multiplied by a user-defined terrain factor. The terrain factor is largely arbitrary and determined based on the user-defined terrain complexity[10] of the proposed project location. The terrain factor for the site development area is 5, 10, or 15 for low, medium, or high terrain complexity. The grading area and drainage area is assumed equivalent to the site development area, while the erosion control area is assumed a smaller portion of the site development area – 10%, 20%, or 50% for low, medium, or high terrain complexity. Similarly, HIDEA assumes the cofferdam area is twice the powerhouse area.

2.2.6 Electrical Infrastructure Design

Electrical infrastructure includes any electrical infrastructure that is used to convert mechanical energy into electrical energy and deliver it to the electricity grid. A user-defined transmission line length and transformer voltage is used.

2.3 Costing

HIDEA uses a bottom-up approach for determining project costs and separates total cost into initial capital cost (ICC) , development cost, and annual operation & maintenance costs. Since many of these cost assumptions are based on historical cost curves or data, proper escalation techniques are needed. The model uses five different historical cost indices to escalate costs to 2015$, including:

1. U.S. Bureau of Reclamation (USBR) Construction Cost Trends (CCT) and USBR Composite Index (USBR, 2016)

2. U.S. Consumer Price Index (CPI) (BLS, 2016)

3. U.S. Army Corps of Engineers (USACE) Civil Works Construction Cost Index System (CWCCIS) (USACE, 2016)

[10] Terrain complexity is based proposed project location. Low terrain refers flat land, plain area or no complex areas, medium terrain includes hill or medium altitude less complex area, high terrain refers mountainous area or higher altitude more complex area

4. Engineering News-Record (ENR) Construction Cost Indices (ENR, 2016)

5. RS Means Historical Cost Indices (RSMeans, 2016)

The initial capital cost (ICC), also referred to as direct construction cost, includes five cost categories: 1) civil works, 2) electromechanical equipment, 3) electrical infrastructure, 4) engineering & construction management, and 5) environmental mitigation. A brief discussion of each cost category is provided below.

One note of caution is that the efforts have been prioritized to the development and validation on major cost drivers that may be directly modified by new technology or design philosophies. Because of this, new empirical relationships have been derived for turbine-generator costs and increased focus placed on a volume based design and cost of the powerhouse—this later topic remains an area of active study and analysis. These two cost centers are those in which major cost tradeoffs are evident in emerging modular unit designs and as such need to have a robust representation that can accommodate the analysis of new technologies.

2.3.1 Site Preparation Cost

The site preparation cost includes the cost to develop the site access road, perform erosion control, drainage, leveling and grading activities, and complete coffer dam & dewatering. Site access road costs are based on parametric cost equation provide in the National Resources Canada (NRC) “RETScreen International: Small Hydro Project Analysis” report (NRC, 2004). RETScreen provides an empirical relationship between site access road length and cost in 2001 CAD. An escalation factor of 1.09 was used to convert costs from 2001 CAD to 2015$[11].

The model’s site development costs are based on USBR (1980)and include the cost of leveling and grading, drainage, and erosion control. The cost curves represent empirical relationships between site development area and cost (Figure 6).

The original estimated cost curve for site development activities was provided in 1978$ and has been escalated to 2015$ using an escalation factor of 3.41 based on the USBR CCT Powerplant Structure Index.

[11] CAD is Canadian Dollars. The escalation factor includes a conversion factor of 0.68 to convert 2001 CAD to 2001$, which is escalated to 2015$ using an escalation factor of 1.61 based on the USBR CCT Powerplant Structure Index.

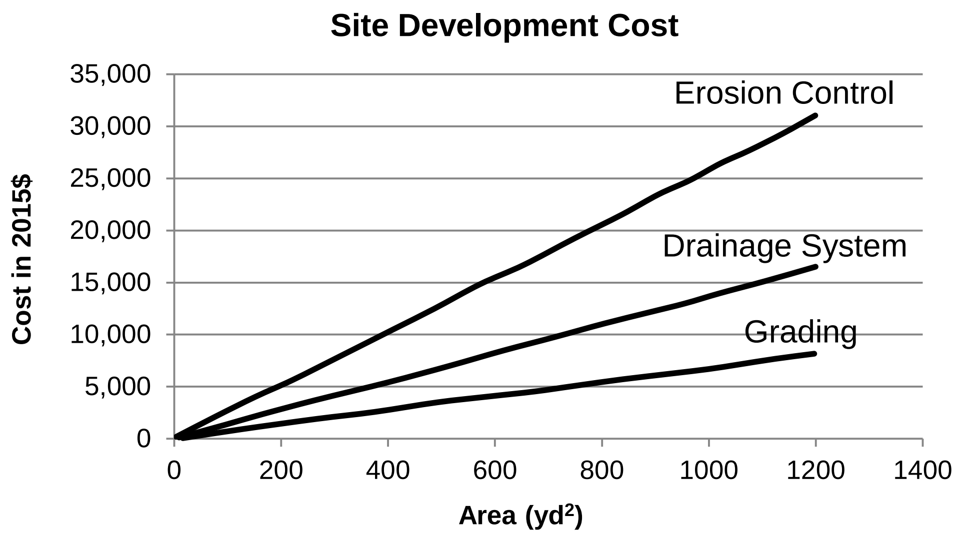

Figure 6 Grading, Drainage and Erosion Control Cost (modified from USBR, 1980)

The coffer dam cost was estimated based on an assumed unit rate for sheet piling area (30 $/ft^2$)[12], and the dewatering cost was estimated based on an assumed unit rate for dewatering area (10 $/ft^2$). These rates are in 2015$.

2.3.2 Impoundment Structure Cost

Impoundment structure cost equations are based on USBR (1980). For concrete dams, an empirical relationship between concrete volume and cost is used to determine the impoundment structure cost.

For earth dams, impoundment structure cost includes the cost of an earth dam structure, spillway, and outlet works. An empirical relationship between earth volume and cost is used to determine the earth dam structure cost. An empirical relationship between head, project capacity, and cost is used to determine the cost of spillway and outlet works.

The original estimated cost curves for impoundment structures are in 1978$ and are escalated to 2015$ using an escalation factor of 3.41 based on the USBR CCT Powerplant Structure Index.

2.3.3 Water Conveyance System Cost

The water conveyance system cost includes the costs of the intake, intake gate, penstock, penstock bifurcation, bypass facilities, valves, and the tailrace. All cost components are based on equations derived from USBR (1980) and escalated to $2015 based on the USBR CCT Powerplant Structure Index.

[12] The sheet piling unit area cost was accessed through http://portofcoosbay.com/appcsy.pdf

Additional considerations for select water conveyance components are briefly described below as necessary:

- **Intakes:** Cost is determined based on design flow.
- **Intake Gates:** Costs for both slide and radial gates are based on gate area.
- **Penstocks:** Cost based on the cross sectional area (calculated from design flow and velocity information) and length. An additional method costing based on a volumetric/materials basis is under development
- **Penstock Bifurcation:** Cost is based on design flow.
- **Valves:** Cost for both butterfly and fixed cone valves are determined based on valve diameter which is in turn calculated from design flow.
- **Bypass Facilities:** Costs include both the bypass facility structure and bypass valve, based on design flow. The cost of any required bypass conduits is based on penstock cost equation.
- **Tailrace:** Tailrace costing includes the costs of excavation and lining, and is similar in approach to the methods used to estimate the cost of excavating the powerhouse. The tailrace excavation cost estimation approach is similar to powerhouse excavation. The tailrace lining cost is 25% of tailrace excavation cost.

2.3.3.1 Powerhouse Cost

The cost of the powerhouse cost is based on USBR (1980) inclusive of the powerhouse structure and excavation. The powerhouse structure cost is parametric is driven by powerhouse area (calculated from runner diameter).

The original estimated cost curve for the powerhouse structure was provided in 1978$ and has been escalated to 2015$ using an escalation factor of 3.41 based on the USBR CCT Powerplant Structure Index.

HIDEA's powerhouse excavation cost is based on USBR (1980) and assumes a soil excavation rate (2$/yd^3) and rock excavation rate (10 $/yd^3), provided in 1978$. These rates have been escalated to 2015$ using an escalation factor of 3.41 based on the USBR CCT Powerplant Structure Index.

2.3.4 Electro-Mechanical Equipment Cost

HIDEA's electro-mechanical equipment cost includes the turbine-generator package and ancillary electrical and mechanical system. HIDEA computes the turbine-generator package cost assuming inclusion of the turbine, runner/distributor assembly, draft tube liner, generator, hydraulic power unit, and switchgear/control/protection system. Based on the selected turbine technology, the turbine-technology (TG) package cost is estimated using an empirical relationship between project capacity, design head and number of turbine unit.

For Francis turbines[13],

$$TG\ Cost\ (2015\ \$) = 3{,}377{,}998\ P^{0.730}H^{-0.236}\ N^{0.708}$$

For Kaplan turbines[14],

$$TG\ Cost\ (2015\$) = 12{,}772{,}452\ P^{0.915}H^{-0.676}\ N^{0.723}$$

For Propeller turbines[15],

$$TG\ Cost\ (2015\$) = 11{,}495{,}207\ P^{0.915}H^{-0.676}\ N^{0.723}$$

For Bulb turbines[16],

$$TG\ Cost\ (2015\$) = 6{,}771{,}669\ P^{0.824}H^{-0.478}\ N^{0.892}$$

Where, P = installed capacity (MW), H = Head (ft), N = No. of Unit.

The above TG costs are for a package of electromechanical equipment, including runner/distributor assembly, draft tube liner, generator, hydraulic power unit, and switchgear/control/protection system. The cost of electromechanical package is referred to as turbine-generator (TG) cost throughout this report. The number of units factor, *N*, is important, as there are key cost savings from using multiple units of the same design by reducing the cost implications of initial design. The regression techniques used to develop these costs will be available in the full model documentation to be released in 2016.

The ancillary electrical and mechanical equipment includes lubrication system, water cooling system, compressed air system, and station maintenance equipment, etc. HIDEA's ancillary electrical system cost is calculated as 14% of the turbine generator cost. The ancillary mechanical system cost is calculated as 12% of the turbine generator cost. Installation of the ancillary electrical and mechanical system is assumed to require an additional 15% cost.

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[13] The Francis turbine cost equation is based on regression analysis using data for 194 projects from North America.

[14] The Kaplan turbine cost equation is based on regression analysis using data for 107 projects from North America.

[15] The Propeller turbine cost is 10% lower than the Kaplan turbine (USBR, 1980)

[16] The Bulb turbine cost equation is based on regression analysis using data for 309 projects from North America.

2.3.5 Electrical Infrastructure Cost

The electrical infrastructure cost includes the transmission line, transformers, switchyard, and substation costs.

Transmission line costs are based on USBR (2011) as a function of length for three different ranges of transmission line voltages (below 69 kV, 69-115 kV, and greater than or equal to 115 kV).

The original estimated cost curve for the transmission line is provided in 2010$ and has been escalated to 2015$ using an escalation factor of 1.11 based on the USBR CCT Powerplant Equipment Index.

Transformer, switchyard, and substation cost equations are based on NRC (2004) and determines cost based on an empirical relationship between project capacity, transmission line voltage, and the number of turbine units. Installation of the transformer, switchyard and substation is assumed to require an additional 15% cost.

The original estimated transformer, switchyard and substation cost curves are provided in 2001 CAD[17] and have been escalated to 2015$ using an escalation factor of 1.05.

2.3.6 Engineering and Construction Management Cost

HIDEA's engineering and construction management (ECM) cost is based on USBR (2011) and includes detailed engineering design, procurement, administration, and project commissioning costs. The ECM cost is calculated as 15% of the cumulative civil works, electro-mechanical equipment, and electrical infrastructure cost.

2.3.7 Environmental Mitigation Cost

Environmental mitigation includes the labor, materials, and equipment necessary to install structures and mitigation technologies to meet environmental mitigation needs. The model incorporates five major mitigation types as defined in INL (2003): 1) fish and wildlife mitigation, 2) recreation mitigation, 3) historical and archeological mitigation, 4) water quality monitoring, and 5) fish passage.

The original estimated environmental mitigation cost curves are provided in 2002$ and have been escalated to 2015$. The fish passage, recreation facilities, and historical & archeological mitigation costs uses an escalation factor of 1.58 based on the USBR CCT Powerplant Structure Index. The fish & wildlife mitigation and water quality monitoring mitigation costs uses an escalation factor of 1.32 based on the CPI Index.

While the costs provided in INL (2003) are useful as a first estimate, there are considerable implementation considerations around their use. O'Connor et al. (2015)

[17] CAD is Canadian Dollars. The escalation factor includes a conversion factor of 0.68 to convert 2001 CAD to 2001$, which is escalated to 2015$ using an escalation factor of 1.61 based on the USBR CCT Powerplant Equipment Index.

documents these in more detail, but improved, site-specific (rather than simple parametric) environmental mitigation and regulatory compliance costs are a “known unknown” in the costing literature, and remain a considerable uncertainty both from a modeling perspective, and in the prediction of real world requirements heading into the permitting process. Recent research is beginning to clarify the latter—see Schramm et al. (2016) and DeRolph et al. (2016)—but the cost of these requirements still remains a key uncertainty.

2.3.8 Development Cost

Project development includes all activities from project inception to commercial operation, and “development cost” in the model is inclusive of both licensing and initial engineering costs.

Licensing cost is based on INL (2003) and is determined based on project capacity and development type (i.e., NPD or NSD) as it is expected that projects on existing water resource infrastructure which do not require a new impoundment (and the resulting environmental impacts) will require less study and public consultation, lowering the overall cost required to move through the permitting and licensing process. The original estimated cost for licensing was provided in 2002$ and has been escalated to 2015$ using an escalation factor of 1.32 based on the CPI Index.

Initial engineering costs are estimated as 2.75% of the civil works cost, based on USACE(1979).

2.3.9 Annual Operations and Maintenance Cost

Annual operations and maintenance (O&M) costs include all operations-related and maintenance-related costs of a hydropower facility. These costs include: Operations Expenses, Water Power Expenses, Hydraulic Expenses, Electric Expenses, Generation Expenses, Rent Expenses, Engineering Expenses, Structures Expenses, Dams Expenses, Plant Expenses, and Miscellaneous Plant Expenses, as defined by FERC Form 1 (FERC, 2015).

Operation & maintenance cost equations in the model are obtained from 2015 ORNL “Hydropower Baseline Cost Modeling Version 2” (O’Connor et. al, 2015b). The original estimated cost for annual O&M was provided in 2014$ and has been escalated to 2015$ using an escalation factor of 1.005 based on the USBR CCT Composite Index.

As documented in the report, these costs may be very conservative, particularly for non-powered dam or conduit applications where the power project owner is not financially liable for the upkeep of the water conveyance infrastructure.

2.3.10 Contingencies

Contingencies are added to the original estimated project cost to cover any unforeseen conditions which may cause project costs to increase and is added to provide a level of conservatism. HIDEA assumes a 20% contingency for civil works and 15% contingency for electro-mechanical equipment, based on USBR (2011).

2.4 Operations

Plant operations are simulated using the individual turbine efficiency curves generated during the characterization of the electromechanical equipment and the head losses calculated during the design of the water conveyance system. The resulting performance curve is linearized intro three segments, for use in the construction of a mixed-integer linear program (MILP) which maximizes plant generation at each head-flow pair in the site resource dataset. An example of a linearized unit performance curve is shown below in Figure 7 for a 3 MW Propeller unit—this is the same performance curve used for Design 2 in the case study discussion in Section 3. The black line represents the linear approximation of efficiency[18], the blue dots are modeled unit efficiencies as calculated from Gordon (2001).

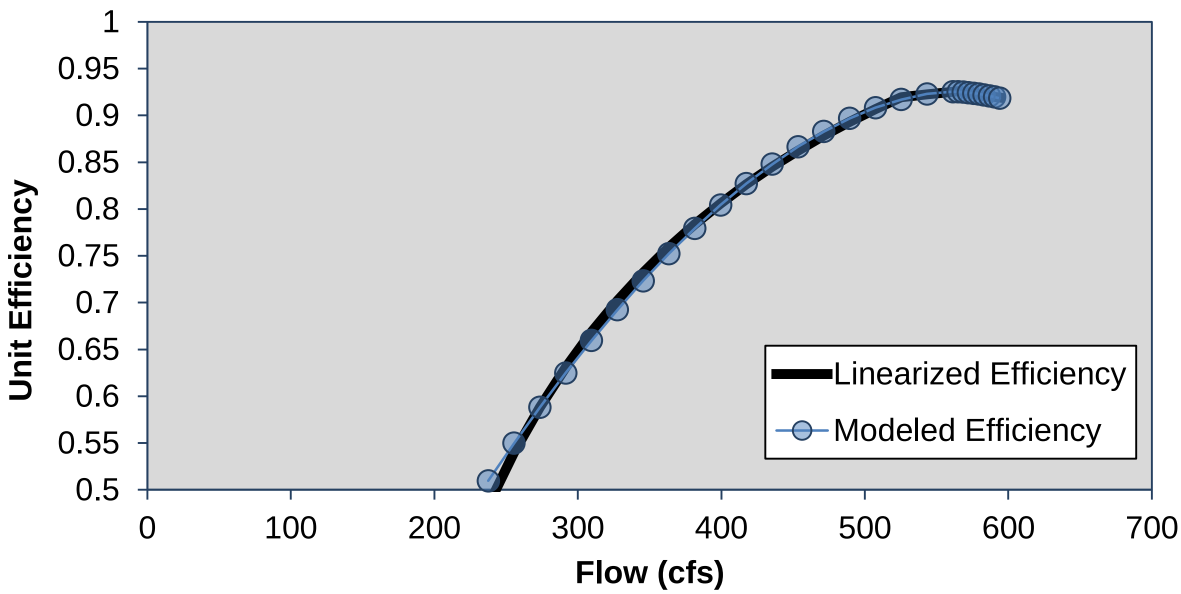

Figure 7. Comparison of modeled and linearized efficiency curves for an example propeller turbine

The linear fit is extremely accurate for Francs and Kaplan (and by extension, Bulb) units. The Propeller curve shown above experiences the largest deviation between the linear approximation and the calculated power and efficiency curves, however, it is still a very close approximation and initial evaluations suggest there is minimal impact on the estimation of project generation.

[18] To be more precise—the *power curve* of each unit is linearized to minimize the squared error at a sampling of 28 point estimates of modeled power output at minimum head, design head, and maximum operating head. Linear interpolation is used to generate a head-specific power curve for each step in the resource data. Subsequently, the efficiency curve shown in Figure 7 is actually back-calculated from the linearized power curve.

At present, performance and revenues are modeled purely on a run-of-river and generation basis. However, future model improvements will accommodate projects with limited intraday storage and the subsequent ability to shift fuel (water) to higher value times of day and/or provide some ancillary services in select cases.

2.5 Economic Assessment

The economic assessment of an energy generation project can be performed using various metrics, including levelized cost of electricity (LCOE), net present value (NPV) and internal rate of return (IRR). LCOE is most often used to evaluate the cost and performance of electricity production and is a useful financial tool to compare alternative energy sources. Furthermore, LCOE can be used as a ranking tool to assess the cost competitiveness of available hydro resources, which can help to guide the policy initiatives at the national scale.

As part of economic analysis, HIDEA calculates a plant-LCOE comprised of individual O&M, Licensing, and ICC LCOE values. LCOE is a value that can be used to quickly assess the basic financial feasibility of a prospective project by representing the cost per unit of energy produced over a project's entire financial life (EIA, 2015). The LCOE requires preliminary calculation of the project's capital recovery factor (CRF), which utilizes the inputs of interest rate and project life, and is used to ascertain the value of initial costs over time. This result is divided by the actual generation of the plant in order to return a simple LCOE value.

$$LCOE\ (\$/MWh)\ = \frac{\text{Cost x CRF} + \text{O\&M}}{Actual\ Generation\ (MWh)}$$

Where:

$$CRF = \frac{Interest\ rate\ (1 + Interest\ rate)^{Project\ life}}{(1 + Interest\ rate)^{Project\ life} - 1}$$

As a very conservative default setting, the model assumes a 5.4% real discount rate and 20 years of project economic life, per the National Renewable Energy Laboratory (NREL) standard scenarios assumptions for hydropower projects (NREL, 2015). In real world development, hydropower is often developed by entities with long time horizons, e.g. municipal utilities, which have access to low-cost financing. However, the values listed above are typical of Independent Power Producers currently pursuing renewable energy generation projects.

The financial assumptions listed here are intentionally made simple for transparency and are used in the case study evaluation documented in Section 3. However, more sophisticated evaluations using the model are possible—and strongly suggested—incorporating federal and state incentives, various tax policy considerations, and more complicated project finance structures.

3. Evaluation of Model Application to Existing and Proposed Projects

The assumptions documented in the prior sections are all important components of how the model functions and ultimately how accurately it represents the economies of scale and cost dynamics of hydropower project evaluation. However, the ultimate test of the model's utility is in its ability to characterize a whole project, capturing the linkages between design decisions, project cost, and financial value. To test the model, this section contains two analyses to illustrate and evaluate model performance relative to real world projects:

The first is an assessment of the costing methods in isolation from the design and performance simulation components in order to assess the overall accuracy of the total plant capital cost estimating features.

The second analysis is a case study exploration of the Army Corps of Engineer's Cave Run Dam. Over the past 10 years, three developers have submitted three different preliminary permit applications—each with noticeably different design assumptions related to power project capacity and technology choice. The model is used to evaluate these three design alternatives to illustrate how it resolves complex tradeoffs between cost, performance, and economic viability.

3.1 Comparison of Modeled versus Actual Capital Costs of Non-Powered Dam Projects

While the development of new hydropower projects in the U.S. has been relatively slow for the last 30 years (Uria-Martinez et al., 2015), there has been a limited but consistent pipeline of projects where power has been added to non-powered dams. Of the dozens of new NPD projects which have reach commercial operation over this timeframe, reliable capital cost data is available from multiple sources for 17 projects (see O'Connor et al. 2015b for more information). These 17 NPDs provide a unique test case for the integrated model as are designed in all shapes and sizes, with design heads ranging from 17 to 310 ft, capacities ranging from 2.6 to 105 MW, and implement a diverse array of turbine technologies in single and multi-unit configurations. Figure 8 provides a comparison of the model-estimated costs with actual, as-built costs; project names and specific site features are anonymized given the non-disclosure and contractual commitments made to secure the cost data, however, general trends are still apparent.

The model-estimated cost is within 50% for 15 projects, within 30% for 10 projects, and within 10% for 6 projects. These errors are still significant from the perspective of economic analysis, however, as discussed previously, they fit well into the error bounds generally considered likely for reconnaissance level hydropower project estimates of -50% to +100%. This is consistent with the outcome seen in Figure 8a where the model generally over-predicts the cost of the least expensive (on a relative, $/kW basis) projects, and under-predicts the costs of the most expensive projects. This is simply a function of the uncertainties in early-stage hydropower development before many cost, regulatory, and geotechnical uncertainties can resolve.

However, some of these uncertainties can be accommodated at the reconnaissance level of project evaluation by accounting for the presence of existing infrastructure, particularly bypass conduits, penstocks/existing pressurized outlet works, and intakes. Model accuracy considerably improved once these unique, site-specific attributes were incorporated into the costing considerations.

Beyond the inherent uncertainty in hydropower cost estimating, Figure 8b and Figure 8c suggest that cost prediction error is not biased towards high level site features such as plant capacity or design head, respectively.

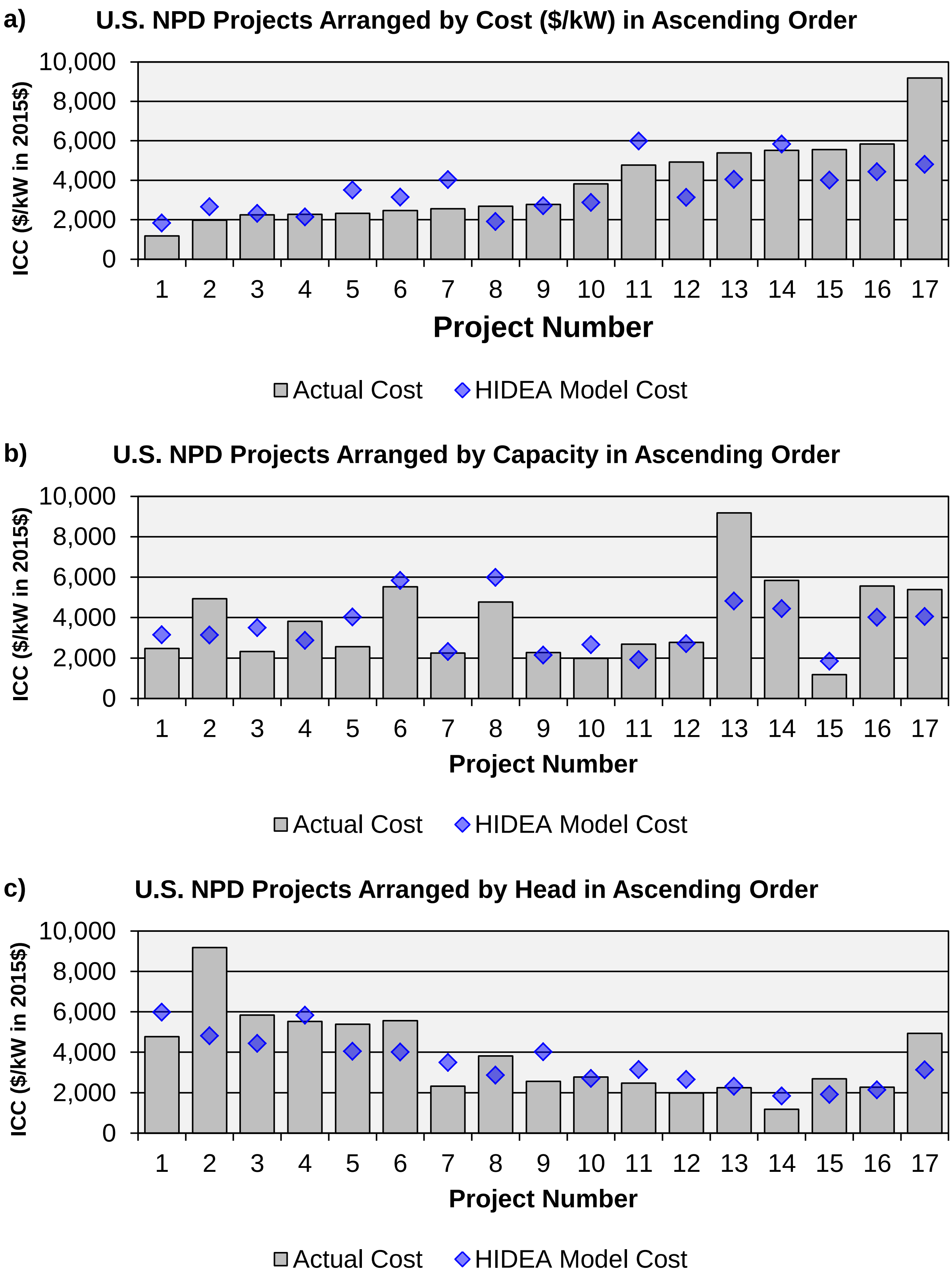

Figure 8. Comparison of HIDEA model-estimated costs with actual costs

Beyond aggregate, whole-plant costs, limited data is available to evaluate the accuracy of the model's cost estimating function at the individual component level. A handful of historical case studies contain some cost estimates from the Department of Energy's (DOE) small hydropower development efforts in the late 1970s and early 1980s (DOE and EPRI, 1985a, 1985b, 1986, 1987). Generally, many components are modeled well, although estimates electromechanical equipment and the a lesser extent powerhouse structures can have the largest uncertainty—the former can be driven by large uncertainties in market conditions and supplier choice, the latter by conscious design decision such as avoiding the use of a concrete superstructure. The cost of impoundment structures is also a major uncertainty which has not be explored as no data is available for validation, at least for projects constructed explicitly for hydropower generation. Necessarily, improvement is still possible and feedback and suggestions on potential data sources to support model refinement is encouraged. Contact information for the authors is available in the Conclusion and in the author biographies.

3.2 Case Study – Cave Run Dam

3.2.1 Introduction to Design Alternatives

The previous section evaluated model accuracy on the costing of NPD projects across a wide range of design characterstics. However, the model is intended to evaluate the combined tradeoffs in cost, design, and performance which complicate hydropower project evaluation relative to more standardized power technologies such as solar and wind. To illustrate this fact and explore the ability of the model to capture these complex differences in project economics, this section details a comparative case study of alternative design options at the Army Corps of Engineers' Cave Run Dam—an existing structure that lacks power generating capabilities.

Cave Run dam is a 2700ft long structure with a maximum height of 148ft primarily used for flood control purposes on the Licking River in Rowan & Bath Counties, Kentucky. In the last 10 years, the project has been the subject of three successive preliminary permit applications in 2007, 2012, and 2015. Developer interest in the site is not surprising as Cave Run has a number of attractive features which potentially lower the cost of adding power relative to other non-powered dam projects; foremost among these are two key attributes: (1) existing intakes and water conveyance structures (which reduce required civil works expenditures) and (2) location proximal to a nearby substation (reducing the need for long, expensive transmission lines and infrastructure).

Despite these relatively promising site attributes, each permit application has featured meaningfully different project design, particularly the number, type, and configuration of the turbine generators:

- **Design 1**: The 2007 application proposed to install two 2.2 MW Kaplan generators for a total project capacity of 4.4 MW. As Kaplan units are highly efficient, this would allow the project to extract maximum power over a wide range of flows at the site up to the 4.4 MW capacity.

- **Design 2**: The 2012 application proposed to install two larger propeller units—each 3 MW—for a total project capacity of 6 MW. Propeller units do not handle flow variation well and subsequently would only operate efficiently in a narrow band around the design flow of the units.

- **Design 3**: The 2015 permit application proposed the most complex site design, featuring 2 propeller and 1 Kaplan unit for a total of 4.95 MW of capacity; individual unit capacities were not specified. Presumably, this more complex design is intended to optimize operations against variations and flow in head at the project.

The preliminary permit applications (as accessed from the Federal Energy Regulatory Commission's "eLibrary" database[19]) for the three designs also described other project features which in some cases could differ, such as the use of existing bypass capabilities and existing high-pressure conduits through the dam as well specific details related to transmission infrastructure. These are described in more detail in Table 1 below.

Table 1 Technical and Site Information for the Proposed Cave Run Dam Designs

Items	**Unit**	**Design 1**	**Design 2**	**Design 3[20]**
FERC Permit No		P-12979	P-14376-000	P-14376-002
Installed Capacity	MW	4.4	6	4.95
Annual Generation	MWh	26000	34164	20000
Turbine Configuration		2 x 2.2 MW Kaplan	2 x 3 MW Propeller	2 Propeller and 1Kaplan (Each 1.65 MW)
Stated Gross Head	ft	70	62-68	62-68
Access Road		Existing	Existing	Existing
Intake/Gate		Existing	Existing	Existing
Penstock Length	ft		70	70
Penstock Diameter	ft	4	12.5	12.5
Bypass		Existing	Existing	Existing
Powerhouse (L, W, H)	ft	60, 40, 30	50, 50, 30	50, 50, 30
Tailrace		New	None	None
Transmission Line	mile	0.25	0.2	0.2
Transmission Voltage	kv		12.7	12.7
Mitigation[21]		Minimal	Minimal	Minimal

[19] To access the FERC e-Library, visit http://www.ferc.gov/docs-filing/elibrary.asp.
[20] Case 3: the project capacity distribution among three units is not listed explicitly in the permit application. Hence the total capacity (4.95 MW) is equally distributed among three units (1.65 MW each).
[21] Mitigation cost significantly varies among mitigation measures (eg. Fish Passsage mitigation cost is x times higher than recreation cost). To minimize the cost uncertainty in the model, mitigation cost is neglected for modeling the case study project.

However, these details—while important in the context of real-world project development—complicate and potentially confound the comparison. To simplify the comparative evaluation of the powerhouse configurations, this case study assumes identical assumptions for transmission interconnection and the use of existing penstocks and intakes as well as for design head (65ft). The resulting unit configurations used in the analysis are described in Table, which also includes the model estimate runner diameter—a key input into the sizing and ultimately the cost of the powerhouse and electro-mechanical equipment.

Table 2 Technology Choice and Characteristics for Proposed Designs

Item	Configuration	Flow (cfs)	Head (ft)	Turbine Runner Diameter (ft)
Design 1	Kaplan 1	434	65	5.7
	Kaplan 2	434	65	5.7
Design 2	Propeller 1	594	65	6.5
	Propeller 2	594	65	6.5
Design 3	Propeller 1	327	65	5.0
	Propeller 2	327	65	5.0
	Kaplan 3	327	65	5.0

3.2.2 Cave Run Dam Site Resource and Design Power Performance

Evaluation of the three design alternatives requires relative assessment of their capital costs versus performance attributes. A necessary input to this process is the simulation of performance again best available site resource (i.e. head and flow) data. Data on the Historical net head and flow data for Cave Run Dam between 1983 to 2011 were obtained from US Army Corps of Engineers based on daily average data collected for the Corps 2014 assessment of power potential on their NPDs (USACE, 2013)[22]. The resulting flow and head-duration curves are illustrated below in Figure 9.

[22] Data file was obtained via personal communication between Patrick O'Connor (ORNL) and Mark Parrish (USACE).

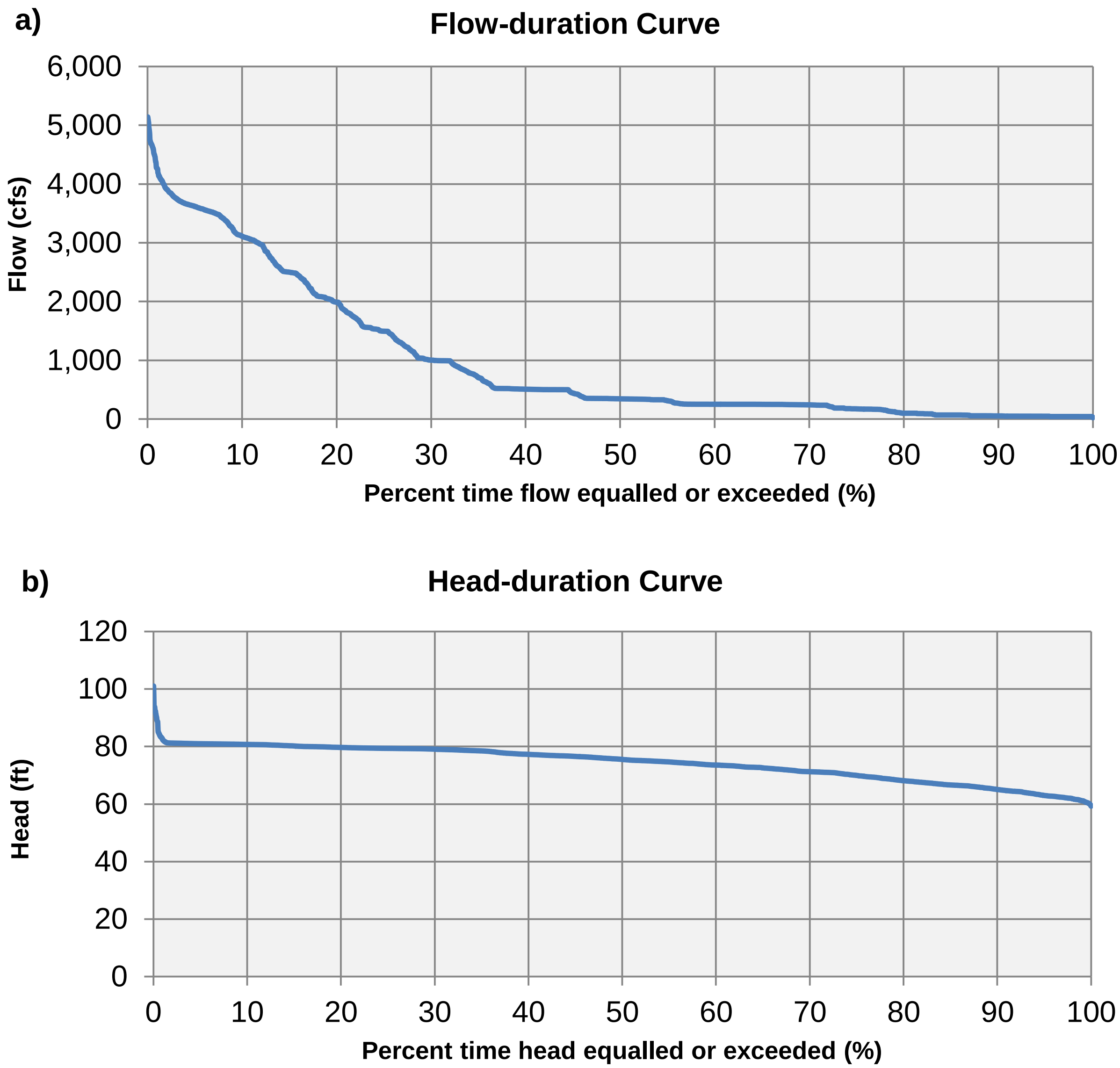

Figure 9. Flow and head duration curve for USACE Cave Run Dam

As a clarification to the choice of a design head 65 feet, the permit applications provide developer estimates of nominal gross head on Cave Run Dam—70 ft for Design 1 and a range of 62 to 68 feet in Designs 2 and 3. To simplify the comparison, the study uses 65 ft design head for all three cases; for reference water conveyance losses from gross head were estimated as being approximately ~1ft at full design flow. For the case study project, design flow is back calculated from the given installed capacity.

To place the choice of plant configuration in the context of the site's available head and flow, the turbine efficiency curves produced by the model are illustrated below in Figure 10. The Kaplan performance curve is for the units from Design 1, the Propeller curve is for the units from Design 2. While the units in Design 3 are slightly smaller (and subsequently marginally less efficient) the two performance curves shown in the figure are largely representative of Design 3's capabilities.

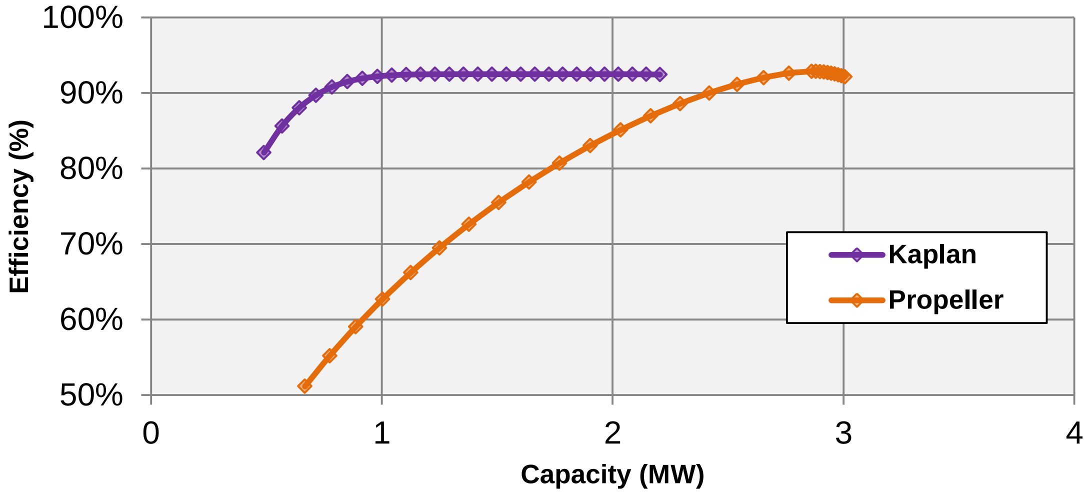

Figure 10. Efficiency curve by turbine type for the Cave Run Dam designs

Figure 11 shows the whole plant efficiency curves for all three designs over a range of flow values. Designs 1 and 3 incorporate 2 and 1 Kaplan units respectively and are able to begin operation at a relatively high efficiency and then maintain that level until design flow values are reached. Design 2 is comprised solely of propeller units, which have a much larger variation in design efficiency over varying flows and a more rapid decline in efficiency past design flow, resulting in large variations in efficiency across the project's operating range.

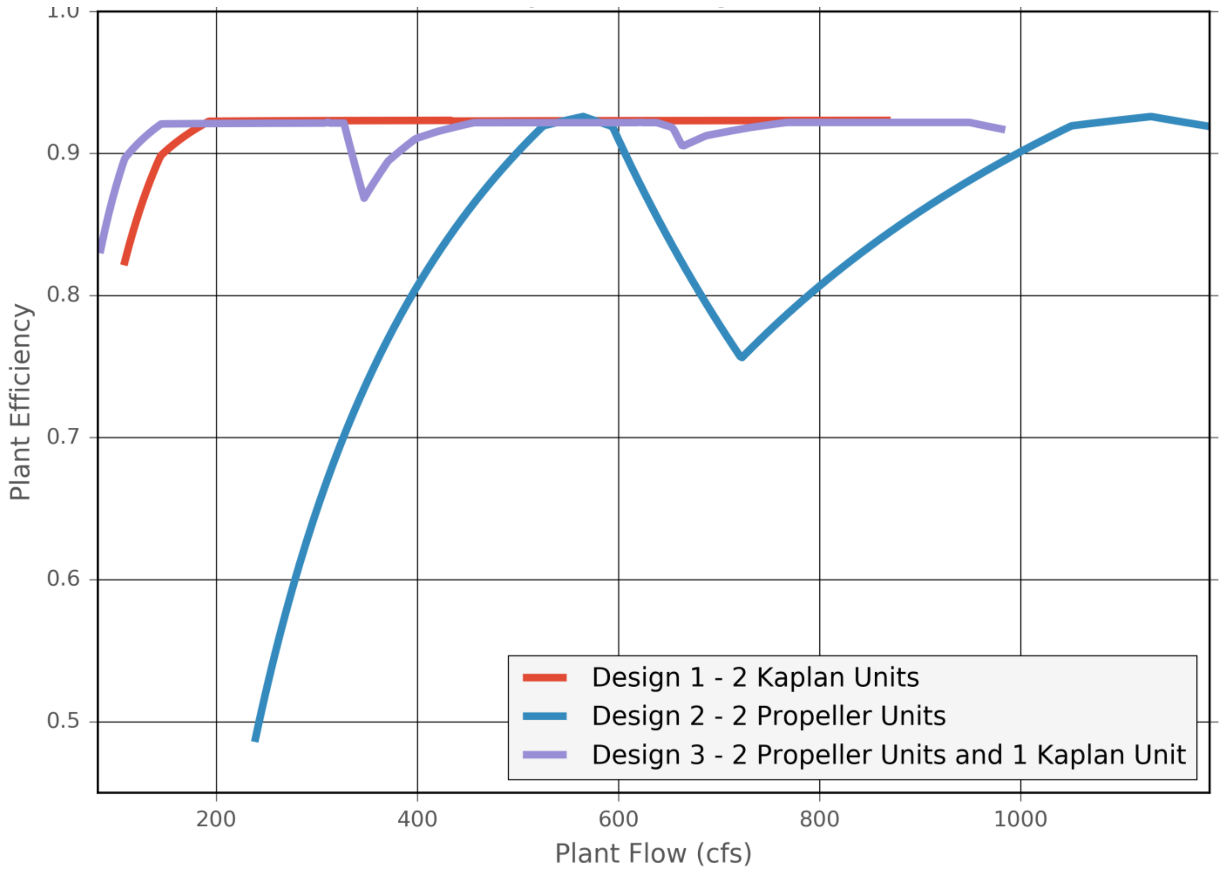

Figure 11. Whole plant efficiency curves for the three proposed Cave Run Dam designs

Based on the individual unit-level efficiency curves, the model simulated optimal plant operations relative to the historical values of flow and head assuming—as in the permit applications—that the projects operate in “run-of-river” configuration, using only the water the Corps chooses to release at the dam. The resulting estimated annual average capacity factor for all three design configurations is shown in Figure 12 alongside the original capacity factor estimates derived from the preliminary permit applications.

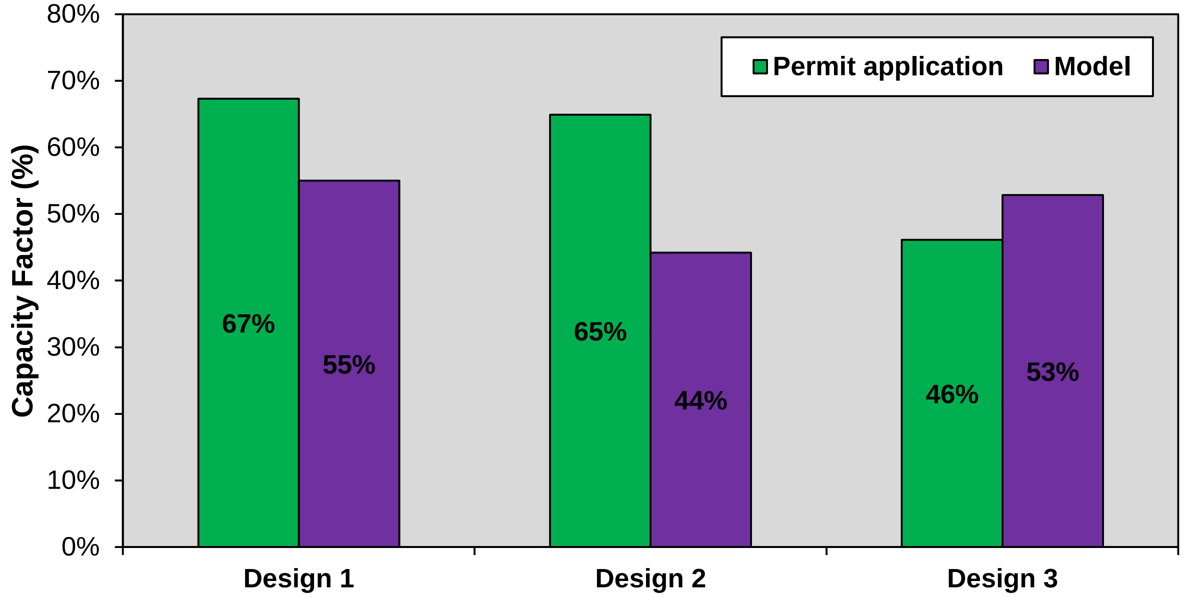

Figure 12. Comparison of Cave Run Dam design capacity factors from FERC preliminary permit applications and model simulation results

Designs 1 and 3 have similar modeled annual average capacity factors despite Design 3 incorporating three units. As expected, Design 2 has a much lower capacity factor given both the more narrow efficiency band of propeller units relative to the Kaplan alternatives and the reality that at 6 MW, this design is sized larger than the two alternatives, reducing the amount of time where the units can operate at full capacity.

Generally, earlier designs (1 and 2) appear to have had overly optimistic estimates for power production relative to the site resource. This is not necessarily an analytical error as detailed data may not yet have been available to the prospective developers.

3.2.3 Project Economics

The simulated performance illustrated in Figure 12 can be combined with the cost information generated by the model to produce an evaluation of the economic competitiveness of each of the design alternatives. Typically, this involves complex evaluations of risk and return (e.g. NPV and IRR), but for illustrative purposes, this case study limits the evaluation to a comparison of LCOE as an approximate economic metric. Real-world energy prices (and the timing of generation relative to these prices) could change comparison outcomes in a more thorough evaluation. Standard discounted cash flow capabilities are built into the model and are undergoing refinement. To illustrate the cost side of the LCOE equation (described above in Section 2.5), Figure 13 shows the resulting installed capital cost (ICC in $/kW) for each of the designs, broken into four major component categories.

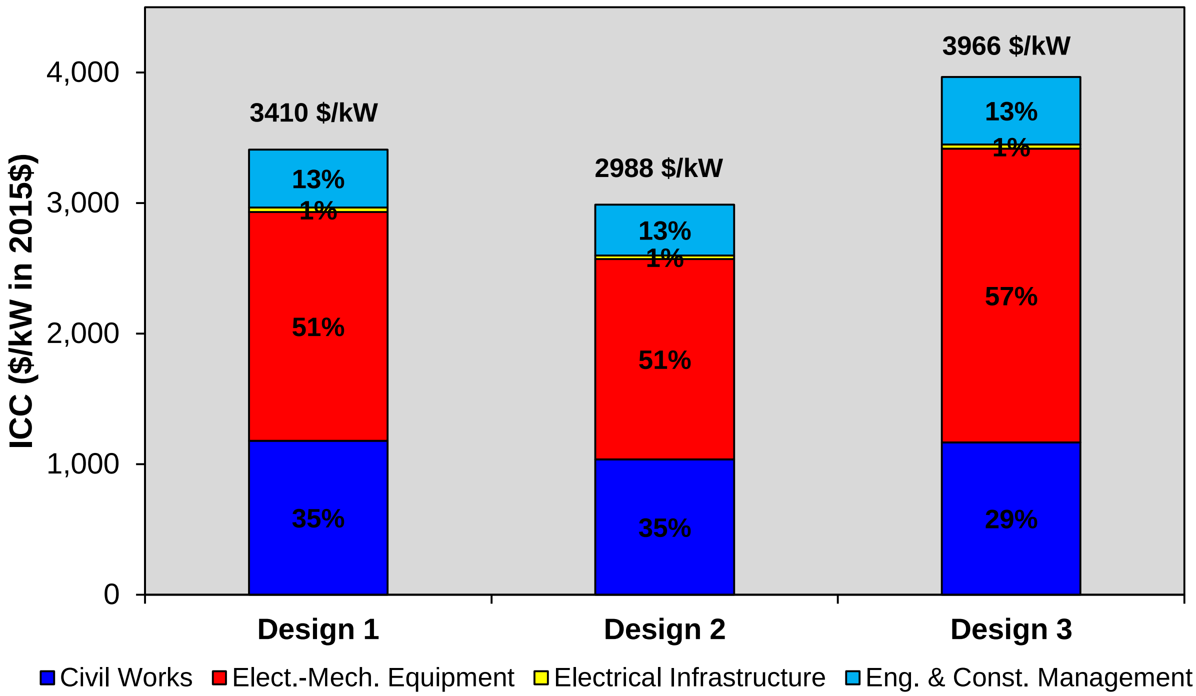

Figure 13. ICC breakdown by project configuration of the Cave Run Dam designs

While ICC varies considerably between the projects configurations and civil works and equipment costs constitute about 80% of the total project cost, with electromechanical costs representing the primary cost driver. The similarity in cost distribution between Designs 1 and 2 is incidental to how cost changes owing to the lesser expense of propeller turbines and cost savings from Design 2 being larger. The Cave Run designs universally benefit from the expected ability to interconnect into a nearby substation. For many small hydropower projects, interconnection can be a major source of cost—oftentimes unexpected if interconnecting utilities demand substation or other infrastructure upgrades.

Design 2 is the least expensive (~$3000/kW) of the three alternatives as it uses the simplest turbine configuration—propeller units are less expensive by virtue of not having adjustable blades—and is the largest of the designs, benefitting from hydropower's economies of scale in project development[23]. Design 1 at $3400/kW is more expensive as it is smaller in capacity than Design 2 by nearly 30% (thus benefits less from economies of scale) and has more expensive generating equipment owing to the choice of Kaplan turbines. Design 3, at approximately $4000/kW is the most expensive option of the 3 given its complex 3-unit configuration. The major difference in cost between Design 3 and the Designs 1 and 2—coupled with the reality that the Design 3 does not

[23] In this case economies of scale refers to the relatively lower cost (as measured on a $/kW basis) of projects with higher capacity. Hydropower also benefits from economies of scale related to project head (that is, higher head projects are relatively less expensive), but this has been controlled for the in comparative study discussed here.

have a higher capacity factor than Design 1—suggests that overall project economies may not be favorable for more complex configurations.

This observation is borne out quantitatively in the comparison of design LCOEs shown in Figure 14, which incorporates the costs of licensing and O&M detailed in section 2 in addition to ICC.

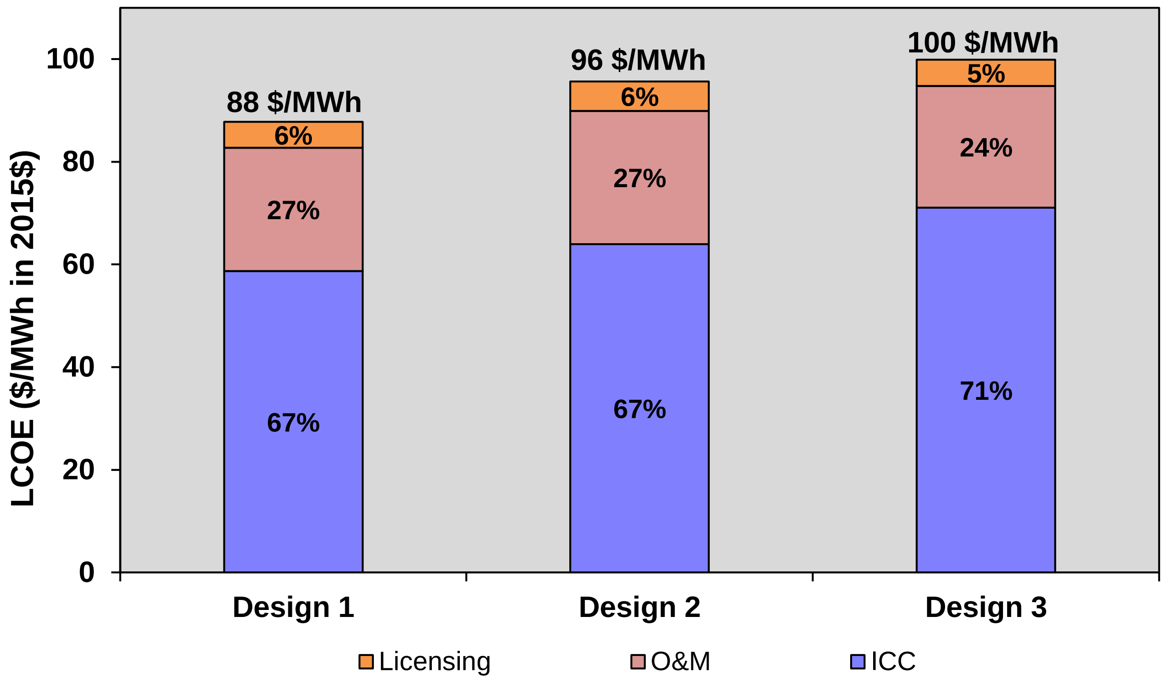

Figure 14. LCOE distribution for the Cave Run Dam designs

As suggested before, Design 3—with a more complex unit configuration (which raises cost) that produces no tangible improvement in generation performance is the least competitive of the three design options. Design 2 embodies an imperfect tradeoff between costs and performance. Both the choice of propeller units and the larger capacity reduce relative capital costs but these cost reductions—although substantial relative to Design 1—are not enough to offset the reduce ability to efficiently utilize the available flow at the site. Ultimately, at least judged by LCOE, Design 1 is the closest of the three proposed configurations to economic optimality. Near-term improvements to the model will allow for the explicit exploration of optimal design through the use of black box optimization techniques, such as single and multi-objective genetic algorithms (SOGA and MOGA), a technique which has shown promise in previous applications to small hydropower but has not yet been coupled with detailed, US-centric cost models.

3.2.4 Case Study Considerations

As documented by this brief case study comparison of the three alternative design options at Cave Run Dam, the model is producing generally intuitive results and illustrates that the at least the model framework is capable of detailing the tradeoffs between design, cost, and performance inherent to hydropower project development. There are a number of areas where this brief exploration could be expanded to improve realism and applicability to real world development including:

- The use of IRR and NPV-based economic metrics using projected energy price data

- More detailed evaluation of site geologic conditions and likely environmental mitigation measures which may change the relative tradeoff between capital expenditures and plant performance

- The Gordon (2001) equations used to model unit efficiencies may be representative of top-tier equipment suppliers, and additional tradeoffs may be possible in the use less-expensive, but potentially less efficient turbines.

- The use of the O&M equations from O'Connor et al. (2015) may also obscure certain *dis*-economies of scale in O&M with respect to number of units. That is, for a given plant at a given capacity, O&M should be higher the more units installed. In practice this would only serve to further erode the economics of Design 3. Propeller units may also have lower O&M cost than Kaplan units owing to the lack of adjustable blades.

- The highly simplified financial considerations documented in Section 2 are overly conservative for many hydropower developers. While this would lower LCOE across the board for the three designs, it would have marginal impact on their relative competitiveness with each other.

- An acknowledgement that the designs submitted in preliminary permit applications are in no way final (or even detailed), and may reflect a lack of data intended to be gathered during the project evaluation process.

There are many of other potential improvements and comment is welcome on elements of the design, cost, and project development process which have been excluded or treated too simply within the model. For a more detailed look at the configurations underlying the high-level economic analysis documented in this section, they are available in Appendix B for the powerhouse, water conveyance system, and site preparation. Appendix B also includes a more detailed breakout of the costs of the three design configurations.

4. Conclusion

The last five years have seen an extended, US DOE supported effort to improve the evaluation of the nation's hydropower resource opportunities through a series of major hydropower resource assessments (Hadjerioua et al., 2012, Kao et al., 2014), a first-of-its-kind Hydropower Market Report (Uría-Martinez et al., 2015), and a series of project-level capital expenditure and operational expenditure parametric cost equation studies (O'Connor et al., 2015a and 2015b), These efforts in conjunction with a review of existing, publically available hydropower project evaluation tools led to the conclusion that expanded modeling capabilities would be necessary to quantify the impact of policy and technology change on the economic competitiveness of small hydropower projects. As such this paper has documented the concept and initial function of the Hydropower Integrated Design and Economic Assessment (HIDEA) tool to better improve site-specific design and cost simulation across the broad U.S. non-powered dam (NPD) and new stream-reach development (NSD) resource.

Using a combination of parametric, heuristic, and engineering-based design approaches as well as parametric and volumetric cost methods, the model follows a bottom-up approach and has been flexibly designed to allow future modifications for new, alternative technology selection. The tool also enables the combination of different generation technology options, each with explicit design and performance simulation, and offers robust financial analysis.

In Section 3, the application of the model has been tested relative to actual project costs from 17 NPD projects and has been used to comparative the economics of three alternative design options for a n Army Corps' NPD. While preliminary testing of HIDEA is encouraging in that it produces results well within the standard uncertainties associated with early-stage hydropower cost estimating, many of the design and cost assumptions will benefit from additional, recent hydropower project experience.

Hydropower design is often highly site-specific, and the finalized construction layout may differ drastically from the preliminary design. Considering its intent as a research tool intended to resolve technology and policy impacts at the reconnaissance level of preliminary design the model produces useful estimates of cost, performance, and economics. However, HIDEA's cost assumptions, while based on historically reliable sources, can be significantly improved using additional recent project experience. Due to a multi-decade gap in widespread hydropower development, relatively few projects are available to validate model outputs against, especially at a component-level. In addition, many advances in technology, materials, manufacturing, and construction have been realized and may not be adequately reflected in some component cost estimates.

The authors encourage comment and discussion by interested stakeholders. If you have any comment, would like to know more about the model, or willing to provide contemporary detailed hydropower project cost data, please contact Dol Raj Chalise (chalised@ornl.gov) or Patrick O'Connor (oconnorpw@ornl.gov).

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Appendix A – Detailed Design and Cost Assumptions

Site Preparation Design

Items	Symbol	Units	Formula	Coefficient	Source/ Comment
Site Access					
Access road length	L_r	mile	Default = 0.5 miles		User input
Site Development					USBR, 1980
Powerhouse Area	A_{ph}	yd^2	$L_{ph}\ B_{ph}$		
Site Development Area	A_s	yd^2	$A_{ph}\ F_t^{\dagger}$	F_t = 5, 10, or 15	
Leveling and Grading Area	A_g	yd^2	A_s		
Drainage Area	A_d	yd^2	A_s		
Erosion Control Area	A_e	yd^2	$A_s\ F_t^{\dagger}$	F_t = 0.1, 0.2, or 0.5	
Coffer Dam & Dewatering					
Coffer Dam Area^{+}	A_{cd}	ft^2	$2\ A_{ph}$		
Coffer Dam Perimeter	P_{cd}	ft	$4\ (A_{cd})^{0.5}$		
Coffer Dam Height†	H_{cd}	ft	$2\ D_{ph}$		
Coffer Dam Sheet Piling Area	A_{cdsp}	ft^2	$P_{cd}\ H_{cd}$		
Coffer Dam Dewatering Area	A_{cdd}	ft^2	A_{cd}		

$F_t^{\dagger}$ Coefficients correspond to a terrain complexity of Low, Medium, or High, respectively.
Coffer Dam Area^{+} equals twice the powerhouse. Coffer Dam Height† is twice the powerhouse excavation depth.

Site Preparation Cost

Items	Unit	Cost (2015$)†	Source/Modified from
Site Access			
Site Access Road	km	$27{,}370\ L_r^{0.9}\ F_t^{\dagger}\ F_c^{\dagger}$ (F_t = 1, 3, or 5)	NRC, 2004
Site Development			
Leveling and Grading	yd^2	$26\ A_g\ F_c^{\dagger}$	USBR, 1980
Drainage	yd^2	$14\ A_d\ F_c^{\dagger}$	USBR, 1980
Erosion Control	yd^2	$7\ A_e\ F_c^{\dagger}$	USBR, 1980
Coffer Dam & Dewatering			
Dewatering	ft^2	$10\ A_{cdd}$	Assumption*
Coffer Dam	ft^2	$30\ A_{cdsp}$	Web1*

† All costs are escalated to 2015$ using USBR CCT Structure Index.
$F_t^{\dagger}$ coefficients correspond to a terrain complexity of low, medium, or high, respectively.
$F_c^{\dagger}$ coefficients correspond to type of a construction new = 1, refurbishment = 0.5, or existing = 0, respectively.
Assumption* Dewatering cost is assumed as 10$/$ft^2$.
Web1* http://portofcoosbay.com/appcsy.pdf

Impoundment Structure Design

Items	Symbol	Units	Formula	Source
Dam Height†	H_d	ft		User input
Dam Length†	L_d	ft		User Input
Dam Width	B_d	ft	$0.2158\ H_d + 7.33$	
Dam Upstream Slope	S_u		Concrete = 0.083, Earth = 3	
Dam Downstream Slope	S_d		2	
Dam c/s Area	A_{dcs}	ft^2	$H_d\ (0.5\ S_u\ H_d + B_d + 0.5\ S_d\ H_d)$	
Dam Volume	V_d	yd^3	$A_{dcs}\ L_d/27$	

Dam Height† is user defined; if it is not given then HIDEA calculates as, H_d = 1.1 Design Head
Dam Length† is user defined; if it is not given then HIDEA calculates as, L_d = 0.7 Design Head

Impoundment Structure Cost

Items	Unit	Cost (2015$)†	Source
Dam Structure	$V_d\ (yd^3)$	Concrete Dam: $648\ V_d\ F_c^{\dagger}$, if $V_d < 10^4$, $256\ V_d\ F_c^{\dagger}$, if $V_d > 210^6$:, $260\ (V_d/10^6)^{-0.193}\ F_c^{\dagger}$, if $10^4 \le V_d \le 210^6$ Earth Dam: $21\ V_d\ F_c^{\dagger}$, if $V_d < 2\ (10^4)$, $7\ V_d\ F_c^{\dagger}$, if $V_d > 10^7$, $13\ (V_d/10^6)^{-0.281}\ F_c^{\dagger}$, if $2\ (10^4) \le V_d \le 10^7$	Modified from (USBR, 1980)
Dam Spillway	P (MW)	$1{,}428{,}238\ P^{0.96}\ F_c^{\dagger}$ (For Earth Dam only)	Modified from (USBR, 1980)
Dam Outlet Works		$898{,}528\ P^{0.44}\ F_c^{\dagger}$ (For Earth Dam only)	Modified from (USBR, 1980)

† Impoundment structure cost is escalated to 2015$ using USBR CCT Structure Index
$F_c^{\dagger}$ Coefficients correspond to type of a construction New = 1, Refurbishment = 0.5, or Existing = 0, respectively. P = Q H η / 11800 (Capacity in MW)

Water Conveyance Design

Items	Symbol	Units	Formula	Source/Comment
Design Flow	Q	cfs		User Input
Design Head	H	ft		User input
Intake Gate				
Intake Gate Type	T_{ig}		Slide, Radial	User Input
Intake Gate Flow	Q_{gi}	cfs	Q	
Intake Maximum Velocity	V_{maxi}	ft/s	3	USBR, 1978
Intake Maximum Gate Area	A_{maxig}	ft^2	Slide = 2500, Radial = 2000	Vortex Hydra, 2015
Intake Gate Area	A_{ig}	ft^2	Q / V_{maxi}	
Intake				
Intake Maximum Flow	Q_{maxi}		$A_{maxig}\ V_{maxi}$	
Number of Intakes	N_i		Q / Q_{maxi}	
Intake Unit Flow	Q_{iu}		Q / N_i	
Penstock*				
Penstock Length	L_p	ft		User Input
Penstock Max Velocity	V_{maxp}	ft/s	10,12,14	User Input
Penstock Flow	Q_p	cfs	Q	
Penstock Unit Diameter	D_{pu}	ft	$[4\ Q_p / \pi\ V_{maxp}]^{0.5}$	
Penstock Unit Area	A_{pu}	ft^2	$\pi\ d_{pu}{}^2/4$	
Penstock Design Capacity	Q_{pu}		$A_{pu}\ V_{maxp}$	
Penstock Bifurcation				
No of Penstock Bifurcation	N_{pb}		for single unit turbine = 0, for multiple unit turbine =1	
Penstock Bifurcation Diameter	D_{pb}	ft	$[4\ Q / \pi\ V_{maxp}]^{0.5}$	
Penstock Bifurcation Area	A_{pb}	ft^2	$\pi\ D_{pb}{}^2/4$	
Valve				
Valve Type	T_v		Butterfly, Fixed Cone	User Input
Valve Diameter	D_{vi}	ft	D_{pu}	
Valve Area	A_{vi}	ft^2	$\pi\ D_v{}^2/4$	
Bypass Facilities				
Bypass Requirement			Yes, No	User Input
Bypass Conduit Length	L_b	ft		User Input
Bypass Max Velocity	V_{maxb}	ft/s	14	Assumption
Bypass Flow	Q_b	cfs	Q	
Bypass Conduit Diameter	D_{bu}	ft	$[4\ Q_b / \pi\ V_{maxb}]^{0.5}$	
Bypass Conduit Unit Area	A_{bu}	ft^2	$\pi\ D_{bu}{}^2/4$	
Tailrace				
Length of Tailrace†	L_t	ft	$(C_1\ D) + C_2$ For Vert. Francis (VF) or Kaplan: C_1 = 5.4, C_2=12 Horiz. Francis (HF): C_1 = 9, C_2 = 0 For Bulb: C_1 = 13, C_2 = 0	USBR, 1980.
Width of Tailrace	B_t	ft	$C_3\ D$ For VF or Kaplan: C_3 = 3.3, For HF: C_3 = 3.8, For Bulb: C_3 = 3	USBR, 1980
Depth of Tailrace	D_t	ft	$C_4\ D$ For VF or Kaplan C_4 = 1.5, For HF C_4 = 1.5, For Bulb C_4 = 1.5	USBR, 1980
Tailrace Volume	V_t	ft^3	$L_t\ B_t\ H_t$	
Total Tailrace Volume	V_{tt}	yd^3	$V_t /27$	

Penstock* material is steel. Penstock Max Velocity* is provided as 10, 12,or 14 ft/s (USBR, 1980)
$D = 13.055\ Q^{0.4287}\ H^{-0.09272}$ (Turbine Runner Diameter in ft). Length of Tailrace† can be replace by user.

Water Conveyance Cost

Items	Unit	Cost (2015\$)†	Source/ Modified from
Intake	cfs	$3.41\ N_i\ (C_1 Q_{iu}^3 + C_2\ Q_{iu}^2 + C_3\ Q_{iu} + C_4)\ F_c^{\dagger}$ For $Q_{iu} \le 1500$ cfs, $C_1 = C_2 = 0$, $C_3 = 1498$, $C_4 = -94{,}019$ For $Q_{iu} > 1500$ cfs, $C_1 = -2E^{-6}$, $C_2 = 4E^{-2}$, $C_3 = 14.8$, $C_4 = 19{,}844$	USBR, 1980
Intake Gate	ft^2	$3.41\ (C_1\ A_{ig} + C_2)\ F_c^{\dagger}$ For Slide Gate: $C_1 = 147$, $C_2 = 384$ For Radial Gate: $C_1 = 249$, $C_2 = -6250$	USBR, 1980
Penstock	ft ft^2 ft/s	$3.41\ L_p\ (C_1\ A_{pu} + C_2)\ F_c^{\dagger}$ for $V_{maxp} = 10$, $C_1 = 7.761$, $C_2 = 43.766$, for $V_{maxp} = 12$,$C_1 = 7.921$, $C_2 = 17.668$, for $V_{maxp} = 14$, $C_1 = 7.885$, $C_2 = 18.288$	USBR, 1980
Penstock Bifurcation	A_{pb} (ft^2) Vmaxp (ft/s)	$3.41\ (C_1\ A_{pb} + C_2)\ F_c^{\dagger}$ For $A_{pb} \le 100$, for $V_{maxp} = 10$, $C_1 = 316$, $C_2 = 220$, for $V_{maxp} = 12$,$C_1 = 354$, $C_2 = -1968$, for $V_{maxp} = 14$, $C_1 = 250$, $C_2 = 684$ For $A_{pb} > 100$, for $V_{maxp} = 10$, $C_1 = 789$, $C_2 = -50{,}718$, for $V_{maxp} = 12$,$C_1 = 822$, $C_2 = 56{,}868$, for $V_{maxp} = 14$, $C_1 = 736$, $C_2 = -41{,}180$	USBR, 1980
Bypass Facility	ft^2	For $A_{bu} \le 40$, $(12.6\ A_{bu}^3 - 1{,}386\ A_{bu}^2 + 63{,}217\ A_{bu} + 131{,}316)\ F_c^{\dagger}$ For $A_{bu} > 40$, $(6{,}047\ A_{bu} + 1{,}039{,}948)\ F_c^{\dagger}$	USBR, 1980
Bypass Conduit	ft	$3.41\ L_b\ (C_1\ A_{bu} + C_2)\ F_c^{\dagger}$ for $V_{maxp} = 10$, $C_1 = 7.761$, $C_2 = 43.766$, for $V_{maxp} = 12$,$C_1 = 7.921$, $C_2 = 17.668$, for $V_{maxp} = 14$, $C_1 = 7.885$, $C_2 = 18.288$	USBR, 1980
Valve	ft^2	$3.41\ (C_1\ A_{vu} + C_2)\ F_c^{\dagger}$ For Butterfly Valve : $C_1 = 1{,}641$, $C_2 = 6587$, Fixed Cone Valve: $C_1 = 1{,}976$, $C_2 = 72{,}375$	USBR, 1980
Tailrace*	yd^3	$(0.625\ C1\ V_{tt} + 0.625\ C2\ V_{tt} + 51{,}150)\ F_c^{\dagger}$ Soil Excavation $C_1 = 7$ \$/yd^3, Rock Excavation $C_2 = 34$ \$/yd^3	USBR, 1980

† All costs are escalated to 2015\$ using USBR CCT Structures Index. Tailrace* construction assumes 50% soil and 50% rock excavation. $F_c^{\dagger}$ Coefficients correspond to type of a construction New = 1, Refurbishment = 0.5, or Existing = 0, respectively.

Powerhouse Structure Design

Items	Vertical Francis/Kaplan/ Propeller	Horizontal Francis	Bulb	Mixed
Length (L_{ph}) Single Unit	$4D+12+t_w$	$4D+12+t_w$	$2.7+6+t_w$	
Length (L_{ph}) Multiple Units	$2\ (4D+6+t_w)$ + $(3.3D+t_w)\ (n-2)$	$2\ (4D+10+t_w)$ + $(2D+7+t_w)\ (n-2)$	$2\ (3D+5+t_w)$ + $(3D+t_w)\ (n-2)$	$(4D+6+t_w) + (3.3D+t_w)\ (n-n_{hf}-1)$ + $(4D+10+t_w) + (2D+7+t_w)\ (n_{hf}-1)$
Width (B_{ph})	$4D_{max}+12+2t_w$	$4D_{max}+9+2t_w$	$5D_{max}+2t_w$ (for P ≤5MW) $3.5D+2t_w$ (for P >5MW)	$4D_{max}+12+2t_w$
Depth of Excavation (D_{ph})	$2.9D_{max}$	$2.4D_{max}$	$2.7D_{max}$	$2.9D_{max}$
Height above ground level (H_{phf})	18	$16+t_f$	$12+t_f$	18
Area of Powerhouse (A_{ph})	$L_{ph}\ B_{ph}$	$L_{ph}\ B_{ph}$	$L_{ph}\ B_{ph}$	$L_{ph}\ B_{ph}$
Excavation Volume of Powerhouse (V_{ph})	$L_{ph}\ B_{ph}\ D_{ph}$	$L_{ph}\ B_{ph}\ D_{ph}$	$L_{ph}\ B_{ph}\ D_{ph}$	$L_{ph}\ B_{ph}\ D_{ph}$

Note: $D = 0.617\ Q^{0.429}\ H^{-0.093}$ (Turbine Runner Diameter in ft), D_{max} = Maximum Runner Diameter in ft, t_w = Powerhouse Wall Thickness & t_f = Powerhouse Floor Thickness are assumed 2 ft
n = Total No of Turbine Unit, n_{hf} = No of Horizontal Francis Turbine
$P = Q\ H\ \eta\ /\ 11800$ (Capacity in MW)

Powerhouse Cost

Items	Unit	Cost (2015\$)†	Source/ Modified from
Powerhouse Excavation*			
Soil Excavation	yd^3	$3.75\ V_{ph}\ F_c^{\dagger}$	USBR, 1980
Rock Excavation	yd^3	$17.5\ V_{ph}\ F_c^{\dagger}$	USBR, 1980
Powerhouse Structure	ft^2	$(675\ A_{ph} + 397{,}504)\ F_c^{\dagger}$	USBR, 1980

† All costs are escalated to 2015$ using USBR CCT Structure Index. Powerhouse Excavation* assumes 50% soil and 50% rock. $F_c^{\dagger}$ Coefficients correspond to type of a construction New = 1, Refurbishment = 0.5, or Existing = 0, respectively

Electro-mechanical Equipment

Items	Symbol	Unit	Formula	Source
Design Flow	Q	cfs		User Input
Design Head	H	ft		User Input
Turbine Runner Diameter	D	ft	$13.055\ Q^{0.429}\ H^{-0.093}$	ORNL1*

ORNL1* regression analysis results using 16 data from Gordon (2001).

Electro-mechanical Equipment Cost

Items	Unit	Cost (2015$)†	Source
Turbine Generator	P (MW) H (ft)	For Francis Turbine: $3{,}377{,}998\ (P^{0.730} + H^{-0.236} + N^{0.708})\ F_c^{\dagger}$, For Kaplan Turbine: $12{,}722{,}452\ (P^{0.915} + H^{-0.676} + N^{0.723})\ F_c^{\dagger}$, For Propeller Turbine: $11{,}495{,}207\ (P^{0.915} + H^{-0.676} + N^{0.723})\ F_c^{\dagger}$, For Bulb Turbine: $6{,}771{,}669\ (P^{0.824} + H^{-0.478} + N^{0.892})\ F_c^{\dagger}$	ORNL2*
Ancillary Plant Electrical Systems			
Ancillary Electrical Cost		14% of Turbine Generator Cost	USBR, 2011 (modified)
Ancillary Electrical Install Cost		15% of Ancillary Electrical Cost	
Ancillary Plant Mechanical Systems			
Ancillary Mechanical Cost		12% of Turbine Generator Cost	USBR, 2011(modified)
Ancillary Mechanical Install Cost		15% of Ancillary Mechanical Cost	

† All costs are escalated to 2015$ using USBR CCT Equipment Index.
ORNL2* Regression analysis results using turbine cost data from North America. $F_c^{\dagger}$ Coefficients correspond to type of a construction New = 1, Refurbishment = 0.5, or Existing = 0, respectively

Electrical Infrastructure Design

Items	Symbol	Units	Formula	Base Year	Source Comment
Transmission Line	L_{tl}	miles			User Input
Transformer Voltage	V_{tl}	kV			User Input

Electrical Infrastructure Cost

Items	Unit	Cost (2015$)†	Source/ modified from
Transmission Line	miles	For V_{tl} < 69 kV, 111,000 L_{tl} F_c† For $V_{tl} \leq$ 115 kV, 222,000 L_{tl} F_c† For V_{tl} > 115 kV, 255,300 L_{tl} F_c†	USBR, 2011
Transformers, Switchyard, and Substation	kV	$[2{,}533\ N^{0.95} + 2{,}026\ (N+1)]\ (P/0.95)^{0.9}\ (V_{tl})^{0.3}\ F_c$†	NRC, 2004
Installation of Transformers, Switchyard, and Substation		15% of Transformer Switchyard Cost	NRC, 2004

† All costs are escalated to 2015$ using USBR CCT Equipment Index.
F_c† Coefficients correspond to type of a construction New = 1, Refurbishment = 0.5, or Existing = 0, respectively

Engineering and Construction Management Cost

Items	Unit	Cost (2015$)	Source
Engineering and Construction Management		15% of (Civil Works Cost + Elec. Mech. Cost + Elec. Infrastructure Cost)	USBR, 2011

Environmental Mitigation Cost

Items	Unit	Cost (2015$)†	Source/ Modified from
Fish Passage	MW	2,054,000 $P^{0.56}$ F_c†	INL, 2003
Fish and Wildlife Mitigation	MW	419,635 $P^{0.96}$ F_c†	INL, 2003
Water Quality Monitoring and Mitigation	MW	264,000 $P^{0.44}$ F_c†	INL, 2003
Recreation Facilities	MW	268,600 $P^{0.97}$ F_c†	INL, 2003
Historical and Archeological Mitigation	MW	134,300 $P^{0.72}$ F_c†	INL, 2003

†Fish Passage, Recreation Facilities and Historical and Archeological Mitigation costs are escalated using USBR CCT Structure Index. Fish & Wildlife Mitigation and Water Quality & Monitoring Costs are escalated using CPI index. F_c† Coefficients correspond to type of a construction New = 1, Refurbishment = 0.5, or Existing = 0.1, respectively. P = Q H η / 11800 (Capacity in MW)

Development Cost

Items	Unit	Cost (2015$)†	Source
Permitting, Licensing, and Site Acquisition	MW	409,200 $P^{0.7}$ (For NPD project) 805,200 $P^{0.7}$ (For NSD Project)	INL, 2003 (modified)
Initial Engineering		2.75% of Civil Works Cost	USACE, 1979

†Development Costs are escalated using CPI index. P = Q H η / 11800 (Capacity in MW)

Annual Operation and Maintenance Cost

Items	Unit	Cost (2015$)†	Source Comment
Annual O&M Cost†			
First Method		226,606 $P^{0.547}$	O'Connor et al., 2015b (modified)
Second Method		2.5% of Capital cost	IRENA, 2015

†Annual O&M cost is escalated to 2015$ using USBR CCT Composite index. † HIDEA tool uses minimum value obtained from the above two methods. P = Q H η / 11800 (Capacity in MW)

Appendix B – Selected Detailed Cave Run Case Study Model Outputs

Powerhouse Design

For the Cave Run Dam case study project, HIDEA includes a selected turbine type and estimated turbine runner diameter as input. Based on these input, the model design the powerhouse layout for homogeneous (case 1 & case 2) as well as mixed turbine technologies (case 3). Such a unique feature of modeling multiple technology options, each with specific project design parameters allows holistic approach of project feasibility. The model-design powerhouse dimension is shown in Table **Error! Reference source not found.**B-1.

Table B-1 Powerhouse size for different project configuration

Project	Powerhouse size from permit document	Model estimated powerhouse
Case 1 (2 Kaplan)	60 x 40 x 30 ft	62 x 39 x 35 ft
Case 2 (2 Propeller)	50 x 50 x 30 ft	68 x 42 x 37ft
Case 3 (2 Prop. & 1 Kaplan)	50 x 50 x 30 ft	73x 37 x 33 ft

To evaluate the case study powerhouse design, the model-estimated, dimension-based powerhouse area is compared with parametric powerhouse area curve from USBR (1980) and the powerhouse area from permit documents as shown in Figure B-1. The results indicate that, the model-estimated powerhouse area lies within 10% of the permit application powerhouse area, although

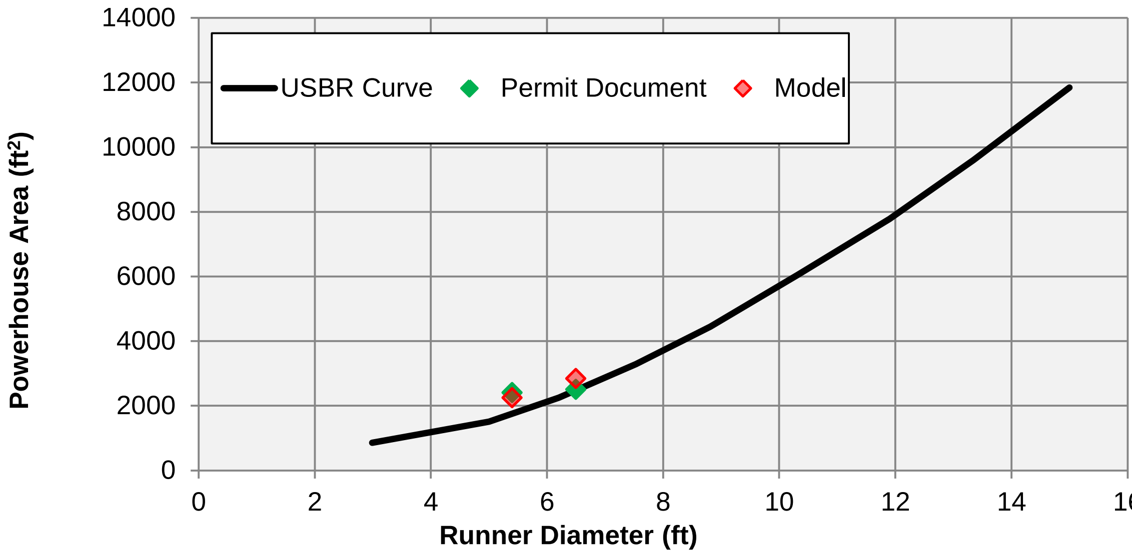

Figure B-1 Comparison of USBR and HIDEA estimated powerhouse area

Water Conveyance System Design

As per the permit document, the Cave Run Dam project has existing intake and bypass facilities. For the case study project, Penstock, Valve, and Tailrace[24] are designed as a part of water conveyance system. Based on design flow and maximum penstock velocity of 10 ft/s as input, the model calculates penstock diameter. The model uses butterfly valve as input, and valve dimeter is assumed equivalent to penstock diameter. HIDEA uses turbine type and runner diameter information to design the tailrace. The model estimated water conveyance design parameters for all three cases are shown in Table B-2.

[24] The permit document shows that new tailrace is required for case 1, but no tailrace required for case 2& case 3. For case 2 & case 3, turbine flow is proposed to discharge directly into the existing stilling basin.

Table B-2 Water conveyance design for different project configuration

Project	Case 1	Case 2	Case 3
Design Flow (cfs)	868	1,188	981
Intake / Gate	Existing	Existing	Existing
Penstock Diameter (ft)	2 x 7.5 ft	2 x 9 ft	3 x 6.5 ft
Valve	Butterfly	Butterfly	Butterfly
Tailrace Dimensions[25] (ft)	2 @ 43 x 19 x 9	None	None

The model-estimated penstock diameter (case 1& 2:7.5 ft) is found higher than the permit document (case 1: 4 ft, case 2: 12.5 ft).

Site Preparation

For the Cave Run Dam case study project, HIDEA includes estimated powerhouse area, medium terrain complexity[26]. Based on powerhouse area and terrain complexity, the model calculates site development area for different activities. The model estimated grading area and drainage area is assumed equivalent to site development area. The model estimated erosion control area is assumed 20% of site development area. Similarly, the model estimated coffer dam area is assumed twice the powerhouse area. Table B-3 provides model estimated area for various site development activities for all three cases.

[25] Tailrace dimension includes draft tube area

[26] Terrain complexity is based proposed project location. Low terrain refers flat land, plain area or no complex areas, medium terrain includes hill or medium altitude less complex area, high terrain refers mountainous area or higher altitude more complex area. For medium terrain complexity, HIDEA uses terrain factor 10 for levelling, grading and drainage activities and terrain factor 0.2 for erosion control activity.

Table B-3 Site preparation for different project configuration

Project	Unit	Case 1	Case 2	Case 3
Grading Area	yd^2	2,632	3,157	2,912
Drainage Area	yd^2	2,632	3,157	2,912
Erosion Control Area	yd^2	527	632	583
Coffer Dam Area	ft^2	4,738	5,684	5,241

Project Cost

Table B-4 HIDEA estimated ICC for the case study Cade Run Dam project

Item	2 x 2.2 MW Kaplan (Case 1) 2015 $/kW	2 x 3 MW Propeller (Case 2) 2015 $/kW	2 Propeller & 1 Kaplan (each 1.65 MW Case 3) 2015 $kW
Civil Works	1,179	1,036	1,167
Site Preparation	356	321	310
Water Conveyances	217	203	204
Powerhouse	607	512	653
Electro-Mechanical Equipment	1,752	1,536	2,248
Powertrain Equipment	1,349	1,182	1,731
Ancillary Plant Electrical Systems	217	190	279
Ancillary Plant Mechanical Systems	186	163	239
Electrical Infrastructure	27	26	33
Switchyard, Substation System	23	22	28
Switchyard, Substation System Installation	3	3	4
Transmission Line (TL)	8	1	1
Engineering and Construction Management	445	390	517
Initial Capital Cost (ICC)	3,410	2,988	3,966

Note: Contingency costs for civil works and electro-mechanical equipment at 20% and 15%,resepectively are included

For the case study Cave Run Dam project, HIDEA's estimated development cost is shown in Table B-5.

Table B-5 HIDEA estimated development cost for case study Cade Run Dam project

Project Configurations	Cost (2015$)	Cost (2015 $/kW)
Case 1 (2 x 2.2 MW Kaplan)	1,296,150	294
Case 2 (2 x 3 MW Propeller)	1,602,960	267
Case 3 (2 Propeller & 1 Kaplan, each 1.65 MW)	1,409,400	285

Similarly, HIDEA's estimated annual O&M cost for the Cave Run Dam case study is shown in Table B-6.

Table B-6 HIDEA estimated annual O&M cost for case study Cade Run Dam project

Project Configurations	Cost (2015$)	Cost (2015 $/kW)
Case 1 (2 x 2.2 MW Kaplan)	509,835	116
Case 2 (2 x 3 MW Propeller)	603,800	101
Case 3 (2 Propeller & 1 Kaplan, each 1.65 MW)	541,178	110

No cost data were available in the permit applications for comparing the model-estimated ICC, development cost or annual O&M cost for the case study Cave Run Dam project.

Author Biographies

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