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How to Model the Value of "Real Options," as Determined by Flexible Design Principles, for Hydropower Facilities in Developing Nations Given the Uncertainties of Climate Change, Energy Demand, and Cos

Adam Richard Swanson
University of Colorado at Boulder, adsw4515@colorado.edu

HOW TO MODEL THE VALUE OF REAL OPTIONS, AS DETERMINED BY FLEXIBLE DESIGN PRINCIPLES, FOR HYDROPOWER IN DEVELOPING NATIONS GIVEN THE UNCERTAINTIES OF CLIMATE CHANGE, ENERGY DEMAND AND COST OVERRUNS

by

ADAM RICHARD SWANSON

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M.A., Tufts University, 2008

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(Dr. Paul Chinowsky)

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(Dr. Kenneth Strzepek)

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The final copy of this thesis has been examined by the signatories, and we find that both the content and the form meet acceptable presentation standards of scholarly work in the above-mentioned discipline.

ABSTRACT

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How to model the value of "real options," as determined by flexible design principles, for hydropower facilities in developing nations given the uncertainties of climate change, energy demand, and cost overruns.

Thesis directed by Professor Paul Chinowsky

Africa, and other developing regions, are moving forward with an electricity program that includes significant amounts of hydropower. While this push to harness river flows to electrify nations holds great promise, there are complex risks that threaten the completion of such projects. Specifically, climate change may disrupt river flows, creating revenue risks for a power source dependent on flow volumes. Demand and cost overrun uncertainties are more familiar, but also pose problems. Flexible design, at the project level, provides a risk-mitigating response that does not require pinpoint accuracy in project forecasting. Rather, it builds flexibility into the design phase of the project life-cycle. To properly value the design possibilities generated by a flexible approach, a real options analysis is needed. Real options can be a powerful decision making tool for developers of large projects. It may also add value to public private partnership contracts, by unlocking hidden value that can be leveraged for both parties in the concession. Using two case studies from Africa, the Batoka Gorge Dam, and the Inga Dam complex, this dissertation details a framework for the valuation of flexible design, how to build a real options model, and illustrates the framework's use in real world projects.

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ABREVIATIONS

AECON	Canadian Construction Firm
AfDB	African Development Bank
BCA	Benefit-Cost Analysis
BGHD	Batoka Gorge Hydropower Dam
BOOT	Build Own Operate Transfer
BTO	Build Transfer Operate
CIDA	Climate Informed Decision Analysis
CMI	Climate Moisture Index
DCF	Discounted Cash Flow
DRC	Democratic Republic of Congo
ECRAI	Enhancing the Climate Resilience of Africa's Infrastructure
ENPV	Expected Net Present Value
GDP	Gross Domestic Product
ICOLD	International Commission On Large Dams
IGSM	Integrated Global Solution Model
IPCC	International Panel on Climate Change
kWh	Kilo-watt hour
MDB	Multilateral Development Banks
MIT	Massachusetts Institute of Technology
MOU	Memorandum of Understanding
MW	Mega Watt
NGO	Non-Governmental Organization
NPV	Net Present Value
NT2	Nam Theun 2
NTPC	Nam Theun Power Company
O&M	Operations and Maintenance
OECD	Organization of Economically Developed Countries
P&T	Precipitation and Temperature
PIDA	Program for Infrastructure in Africa
PPA	Power Purchase Agreement
PPP	Public Private Partnership
PV	Present Value
RDM	Robust Decision Making
RO	Real Options
ROA	Real Options Analysis
SADC	Southern African Development Community
SAPP	Southern African Power Pool
SNEL	Société Nationale d'Electricite (DRC's National Power Company)
SSA	Sub-Saharan Africa
T&D	Transmission and Distribution
USAID	U.S. Agency for International Development
WEAP	Water Evaluation and Planning
ZRA	Zambezi River Authority

CHAPTER I

INTRODUCTION

Large hydropower projects are at the center of a debate weighing the value and costs of renewable energy against the risks of climate change, and other uncertainties such as demand and cost overruns. Some say the risks outweigh the benefits, while others disagree. The African continent has large untapped hydropower resources; the Democratic Republic of the Congo (DRC) alone is estimated to have the potential for 100,000 MW, though it has only developed 2,400 (van Der Wat, 2013). Potential from proposed facilities on the Zambezi River, along the border of Zambia and Zimbabwe, exceeds 14,000 MW (ECA, 2009). Many advocate that Africa should prioritize investments in hydropower resources as the continent seeks to add generation capacity to meet consumer demand, seeing it as a vital contribution to a green energy corridor on the continent. Detractors say these projects are too expensive and risky, and therefore offer little value when compared with alternatives. Considering the many uncertainties that hydropower facilities face, flexible design has emerged as a potent risk-mitigating strategy for resilience at the project level.

This dissertation presents a framework for the valuation of flexible design as a risk resiliency strategy at hydropower plants. This topic is important because we need frameworks that adequately communicate the full value of adaptive designs. We need them for at least two reasons: One, valuations are used as decision making tools to show us answers to central questions of engineering, such as what to build and when to build it. Two, project sponsors, and developers need ways of communicating to funding agencies and financiers the full value of a project. The contribution of this research is, therefore, threefold:

1. <u>To offer a framework for the valuation of flexible design as a project resiliency aspect or strategy</u>. This includes integrating climate with other risks into a valuation/decision-making model, especially one that allocates appropriate value to the incremental resiliency components of the asset. The framework gets to the heart of the question: What, specifically, should we build, and when and how should we build it? I will show that we can make the intuitive value of flexibility explicit. This is also important because banks and funds are asking, not just for the additional costs of adaptive capacity, but also for the value it creates, especially if resiliency leads to different design choices, which I will show that it can.
2. <u>Demonstrate that other valuation techniques may not adequately value flexibility at hydropower plants apart from real options analysis (ROA)</u>. ROA is unique in its ability to value flexible design. Though Benefit Cost analysis, and Robust decision-making have been widely adopted in the literature for climate-related decision making, Richard de Neufville, at MIT, suggests that these approaches reflect a "bunker mentality" (de Neufville and Scholtes, 2011).
3. <u>Accelerate uptake of ROA to inform contractual arrangements</u>. Finally, I hope to accelerate the uptake of the ROA approach to offer insight to contractual agreements. Optionality adds value and that value can be leveraged. There is a paucity of examples of real options applied to PPPs for hydropower development, though applications can be extrapolated from other sectors. The use of these instruments may make some projects more feasible and attractive to private capital. I'll illustrate how this could work, especially how to right-price these incentives. Other tools can also be created including insurance against singular risks, and decision making criteria for additional investment.

To preview some results from the framework, I will show that flexibility at Batoka Gorge Hydropower Dam, augments project value by up to 20% depending on the design, and that it may save developers up to $500 million over the next-best design alternative. I will also show that without a real options analysis, other decision making tools consistently undervalue flexible design. Furthermore, I will illustrate that the additional value, found in a flexibly designed project, can be leveraged to create an additional $3.5 billion in value at the Inga facility, if one pathway is chosen over another. Other ancillary findings are also surfaced from the analysis.

African government leaders are among those who want to move forward with large projects, though one immediate challenge is the cost. In 2012, African Heads of State endorsed the Program for Infrastructure Development in Africa (PIDA) to close Africa's infrastructure gap, including electricity generation. The program calls for an expansion of hydroelectric power generation of more than 54,000 MW. The PIDA framework includes a Priority Action Plan listing the highest priority projects. This, more focused plan, calls for US$ 21.3 billion worth of hydropower investments for nine generation facilities (Cervigni et al. 2015). Since project prices often exceed what governments can afford, they are beginning to look to private investors to partner in the initial capital requirements. Private consortia may also be better at designing and managing large facilities. Public-private partnerships (PPPs) may be an attractive alternative to public utilities in developing these projects. However, private investors enter at a price, which is determined by the risks associated with the project. To attract the funding, risks must be quantified and mitigated. Three risks, that are particularly associated with large hydroelectric projects are climate risk (related to river flows), demand risk (related to infrastructure build out), and cost overrun risk.

Climate change works its way into revenue expectations because precipitation and temperature patterns are expected to change, resulting in changing river flows at dam sites. Therefore, hydropower facilities, and other long-lived assets, will likely face climate impacts that shorter-lived infrastructure may not. Particularly when the breakeven return on investments is far away, climate uncertainties become investor risks. Various tools for quantifying these risks, and offering decision-makers some guidelines for investment strategies, are increasingly used to evaluate policy choices and specific investment decisions considering climate change. The long-lived nature of hydropower facilities, and its reliance on river flow, means that projects are potentially exposed to greater climate variability, and therefore climate-related revenue risk, than some other investments. These risks should be integrated into a broader calculus of uncertainties, which may affect project values. Thus, climate risks have become increasingly scrutinized in the dam design process. Hydropower energy output is subject to changing patterns of river flows, droughts, and floods. Both seasonal fluctuations, and drought cycles can significantly affect generation. When cash flows are tied to firm power delivery, the revenue profile of a project may become inherently risky. Further complicating the revenue side of the equation is the long technical and economic life of large hydro-projects. Any PPP concessionaire will need to account for climate-induced output and cash flow risk over the project life cycle.

Decision-making under climate change is itself a topic that has received attention in recent years, as climate change further increases investment uncertainty. In response, several decision-making tools have emerged, to help planners address climate uncertainties. Current climate models show that the future climate may be very different from the past, but they disagree on whether specific locations will be wetter or drier. For a hydro facility, this means that investors may face a dry future, with lower than expected flows, and a project with the inability to return the initial capital costs to build it. This is the risk of *overbuilding*. On the other hand, there is also the chance of a wet future, in which investors would want to capture larger than expected flows. This is the risk of *underbuilding*. To help manage these uncertainties, flexibility can be built in to some designs, allowing the project to start small and expand if a wetter future is realized.

Demand risk must also be considered. While consumer demand in Africa is high, there is a risk to power producers that necessary transmission corridors to deliver electricity to demand centers may not be available. Generated electricity must be delivered to customers for plant owners to receive revenues. This introduces an additional risk for generation projects in developing countries, as it adds another expensive infrastructure layer to the calculus; and, the largest infrastructure deficits are in Sub-Saharan Africa (SSA). Rates of access to electricity in Africa are around 43%, a very low figure by global standards, meaning that about 621 million people, lack access to electricity (Cook, 2015). Whether measured in terms of generation and distribution capacity, electricity consumption, or security of supply, SSA's power sector delivers a fraction of the service needed or found elsewhere in the developing world. Furthermore, per capita access is gradually falling, because new power infrastructure construction has not kept up with growing populations and electricity demands (Cook, 2015). These facts illustrate the demand risk factor for hydropower investors in Africa: unless the corresponding transmission and distribution (T&D) lines are built, there can be no project revenue. This risk is referred to as demand risk, for the purposes of this analysis. Over-estimating demand in the long-term can lead to investment losses. On the other hand, underestimates could lead to missed opportunities for delivering capacity and to capturing greater returns on investment through economies of scale. Again, design flexibility may provide some value.

Finally, large infrastructure projects have been famously plagued by significant cost overruns. While there are many project and governance dynamics that could lead to overruns, the effect of these is to erode the value of the project under consideration. On one hand, organizations such as the International Commission on Large Dams (ICOLD) urge that hydropower offers a low-cost alternative to generation based on carbon fuel sources. But on the other, detractors say developers consistently under-estimate costs to win the bid for the project, and then must add expensive delays and other costs after contracts are signed, and construction is underway. Overly optimistic assessments can be either intentional or unintentional. Unintentionally, planners systematically focus on estimations of individual projects, without acknowledgement of larger, consistent trends in the industry of significant estimation error. Intentionally, these optimistic estimations are often aggravated by deceptive practices – intentional misrepresentation by project bidders (Ansar et al., 2014). These risks have further dampened the enthusiasm of both public and private sponsors, and must also be considered by investors.

The concept of flexible design has been offered in response to the unknowns surrounding infrastructure investment. Flexible design means incorporating the flexibility to initiate, expand, stop, or contract, a project based on information received later. While most projects are *managed* to respond to new information, flexible design seeks to build flexibility into the *design* of the project from the planning stage. Flexible design allows planners to anticipate certain future decisions and incorporate them into their valuation models. Flexible design is not a new concept; however, it has recently gained momentum in the engineering world as an adaptation strategy for climate change when planning long-lived infrastructure. Perhaps the best advocate for flexible design is Richard de Neufville of MIT who asserts that flexibility can be incorporated into many contexts from corporate investment, to real estate development, to infrastructure design (de

Neufville and Scholtes, 2001). In the case of a hydropower facility, it may mean an initial investment to broaden the foundation of a dam, so the dam height can be increased later; or including the civil works for additional turbines, but delaying the inclusion of expensive turbines until more is known about the effects of climate change on river flows. Perhaps slightly more expensive at the beginning of a project, flexibility can delay higher-cost investments until more is known about existing uncertainties. Flexibility creates options – decisions to be made at a future date. But determining the value of those options, and which option should be chosen over others, requires a more sophisticated analysis than standard tools such as discounted cash flow (DCF) and net present value (NPV). To determine the value of flexible designs, a real options analysis (ROA) is typically used.

Real options (RO), based on the principles of stock options, is the only decision-making method that makes the value of this type of optionality explicit. RO is based on stock options, a form of financial derivative. Stock options *derive* their value from an underlying corporate stock. Options represent the monetary value of the *right to decide* about buying, holding, or selling that stock in the future. An RO also derives its value from an underlying asset, but in this case the underlying asset is a *real project* as opposed to a stock. As in the case of stock options, the RO also represents the value of the right to decide about the underlying project: whether to buy, sell, hold, expand or contract. Option values can be helpful to determine which project to pursue. For example, they can help project designers create the right kind of project flexibility. Option values can also help investors with timing decisions for future investments; and, they can help the drafters of public-private partnership contracts assign the right trigger points and values for contract clauses dealing with actions such as insurance payments or exercise dates. Often, options augment the value of a project designed with flexibility over those which are designed with no flexibility (which are called *static* designs). A real options approach has been widely used in the energy sector, to better understand and measure risk and uncertainty. However, the approach has not been as extensively used in evaluating renewable energy projects, nor does it frequently appear in climate change literature. This undertaking responds to this gap.

As an example of real options, consider a preliminary valuation of the Batoka project with several design possibilities (Table 1). Among them are a 1600, 2400, and 3000 MW design. If climate change leads to increased river flows at the site, a larger facility will be the clear choice based on the largest NPV. However, if river flows are diminished, the initial capital costs associated with the larger options mean that the NPV for the project could be negative. In this case, the smaller design would be investor's choice.

However, two additional alternatives are possible, represented as A' and B' in Table 1. A 1600 MW facility could be built, which includes flexibility to increase the capacity to 2400 MW, or a 2400MW facility could be built with the option to increase to 3000. The price of the flexible facility would be slightly increased over the static design (and thus the present value slightly lower), but the project could then be converted to a larger size for the added investment of the strike price. The *option* to invest in converting the facility has its own value. By using a common option valuation equation, discussed later, the value of the option to convert A' is \$1.9 billion; and to convert B' is \$640 mm. To calculate the value of the facility with flexibility this figure is then added to the original value of the flexible project. The actual value of the 2400 MW facility with flexibility is \$3.59 billion, which exceeds the value of the larger facility. This example illustrates a central theme behind real options analysis: the comprehensive value of a project that includes flexibility is its net present value *plus* the value of the option created by the flexibility:

$$Full\ value\ of\ project = Net\ present\ value + Value\ of\ the\ option \tag{1}$$

Table 1: Design Possibilities at Batoka, Estimated Costs and Expected Present Values

Design	Initial ENPVs	Strike price	**Call value**	ENPV + call
Batoka A	$1,795,000,000	$-	$-	$-
Batoka A'	$1,309,000,000	$390,000,000	$1,952,000,000	$3,261,000,000
Batoka B	$3,287,000,000	$-	$-	$-
Batoka B'	$2,954,000,000	$305,000,000	$640,000,000	$3,593,000,000
Batoka C	$3,499,000,000	$-	$-	$-

Besides real options, there are other methods that have been applied to climate-related decision making. These include benefit-cost analysis (BCA) under uncertainty, and the process of "robust decision making" (RDM). Each has its strengths and weaknesses, and offers answers to related, but sometimes different, questions. All begin in a similar fashion, by developing a broad range of scenarios under which the facility will be built and operate. These parameters are combined in a revenue, and net present value model, that yields its output, in the form of a pdf, of possible project values. The mean of this final pdf is the *expected* net present value (ENPV) of the project. This is the starting point of each decision-making method. After that, the methods diverge. The subsequent processes will be discussed later. In fact, the alternative methods, and some of their pros and cons are explored in the case studies. A comparison of methods is also offered, to assess the strengths of each method to value flexibility in design.

The primary concepts that form the foundation of the dissertation are flexible design and real options. Real options analysis takes a proven financial concept and applies it to engineering design. Specifically, the dissertation will focus on the methodology and rationale for building an Excel-based binomial-lattice model that assess the value of real options for flexibly-designed hydropower.[1] The output of the model is the value of design options for selected hydropower

[1] Other software tools may ultimately allow for an easier and faster processing; however, this "how-to" keeps the model in Excel for better accessibility.

facilities. Values can be used as a decision tool to select the most valuable project design from a suite of available choices, and can be leveraged as various incentives.

The valuation model begins by bringing precipitation and temperature projections into the WEAP model. WEAP takes these inputs and models river flow rates based on baseline data. With the WEAP model, a hydropower facility is built with configurations that reflect real world designs. WEAP then calculates the hydropower output that can be achieved at the site, for many climate scenarios. The full range of possible hydropower outputs is then multiplied by a range of possible electricity prices, for each year of operation. The result of this calculation is a probability distribution of annual revenues. From this range of revenues, a pdf of possible costs (construction and operations and maintenance) is subtracted. The result is a pdf of net revenues, which is discounted to yield a pdf of NPVs, the mean of which is the expected NPV, or ENPV (the process is discussed in greater detail later).

In this way, the model integrates the three risks into one revenue model, and then calculates an expected NPV based on expected revenues. From the expected NPV, option values for different configurations, and option types can be evaluated. The effect of climate risk alone can be isolated in the model, and the other risks can be tested for their impact on the project through a sensitivity analysis. A similar sensitivity analysis can be used to test the impact of other parameters such as discount rate, risk-free rate, etc.

The two case studies afford a slightly different focus for each. The Batoka project will be used to evaluate decision-making methods, and the value of optionality among competing design alternatives. Inga will focus on the application of ROA as a tool for PPP design. Within the Batoka case study, I first employ three decision-making methods - BCA, RDM and ROA - considering climate risk only. This allows a straightforward comparison of results across methods, while isolating the effects of climate risk. I then incorporate additional uncertainties into the analysis, combining the risks of demand, cost overrun and climate, analyzing their combined effect on project value. In this way, the model can deliver objective values for each design configuration, evaluating the costs of flexibility, and the ultimate effects on expected project values. The Batoka case also presents extensive sensitivity analyses around key parameters. The Inga case focuses instead on several possible applications of ROA, especially as they concern the interaction between a public sponsor of the project and a private-sector partner. Not only does the different design of the physical facility of the plant offer a different dimension of analysis, so the attempt to attract private sector financing changes the application of the ROA. Private sector investment will have a unique vantage point in terms of required returns, project management, and investment horizon.

The dissertation is structured as follows: immediately after this introduction, a literature review is given. The literature review highlights the genesis of real options theory, and illustrates many of the additional applications of the valuation methodology. It also places the research in the context of the ongoing discussion on valuation under the unknowns of climate change. Following the literature review, the dissertation proceeds to define and elaborate on several key concepts, namely the risks associated with hydropower in developing nations, flexible design to mitigate risks, and real options as a valuation technique for flexible design. Following the section on key concepts, the inputs required for ROA are discussed in some depth, as is a typology of real options. Then detail of the methodology is presented. This section presents the method for building a real options model for valuing flexible design at a hydropower facility. Finally, two case studies are presented, which illustrate several uses of real options. The first is the Batoka Gorge Hydropower Dam (BGHD), on the Zambezi River between Zambia and Zimbabwe, the second is the Grand Inga on the Congo River in the DRC. The case studies are conceived as hypothetical situations, though they involve actual, pipeline projects; they have been chosen to illustrate the framing, method, and power of the analysis.

After the case studies and the conclusion, several annexes are also provided. The first offers the mathematics behind the binomial lattice that is used for calculating an option's value. The second provides the mathematics behind another commonly used option pricing tool, the Black-Scholes Formula. The third includes the numerical data and specifications for the development of the Batoka Gorge Hydropower Dam. This includes the cost model that was developed, as well as other site-specific parameters used in the case study. And, the fourth gives the numerical data and parameters for developing the Inga Dam case study.

Both public agencies, considering large energy projects, and private investors considering various forms of partnership, are concerned with the various risks. Flexible design is one of several resiliency adaptations for dealing with the uncertainties for which project sponsors must account. To appreciate the value behind such design measures, and to nuance agreements between parties, an ROA can be a very useful tool.

CHAPTER II

LITERATURE REVIEW

The literature review places the current research within its proper context, and illustrates the contribution it will make. This review provides three aspects. First, as a foundation, it reviews relevant, introductory literature from the primary topics of this dissertation: real options (RO), financial options, and flexible design. Second, it highlights the current applications of ROA, especially in the water and energy sectors, showing that there are significant research gaps in applying ROA to climate and other risks at hydropower facilities. Third, it places this research into the context of risk assessment and decision-making tools with special application to the uncertainties of climate change. This final discussion illustrates the need for accessible decision-making tools for project-level investment strategy. The research at hand addresses the gap in published methodology and model creation for project-level valuations at flexibly-designed hydropower facilities, considering climate change and other risk factors.

Primary Topics

Real Options. There is a small body of books detailing the RO methodology, several of which are listed below. The theory takes derivative pricing methods from modern finance, and applies them to project-related finance. Some of the texts apply the principles to specific disciplines, whereas others are applied more broadly. RO researchers agree that current practice for most asset pricing, which follows a single discounted cash flow (DCF) method, is inadequate for incorporating uncertainty into the valuation. The unique value that RO brings is to price assets in a world of uncertainty, and capture the value of optionality in facility operations.

Shockley (2006), Copeland and Antikarov (2003), Amram and Kulatilaka (1999), and Trigeorgis (1996), draw analysis from the world of financial options, and apply it to project-level analysis. Copeland and Antikarov offer a definition: “the right, but not the obligation, to take an action (e.g., deferring, expanding, contracting or abandoning) at a predetermined cost, called exercise price, for a predetermined period – the life of the option.” All authors show that an option valuation can serve to guide corporate investment decisions, and choose between different configurations at the project level. Rooting the practice in the world of engineering, Black, N., Harriet, M., Aktan (2009) present real options for engineering systems. The authors show engineering applications across different disciplines such as industrial and civil engineering, and computer science. Kogut and Kulatilak (2001) expand the definition of real options to include investments toward other corporate investment avenues. They see real options as, “the investment in physical assets, human competence, and organizational capabilities that provide the opportunity to respond to future contingent events.”

Financial Options. The ability to price stock options was a breakthrough in the world of finance. Black, Merton and Scholes won the Nobel Prize in Economics for their work in developing a formula for European call and put option prices. This formula is now widely used in finance and economics. Other kinds of options are priced through different means.

Black and Scholes (1973) showed that an option is a type of financial insurance - the right, but not the obligation, to act in the future, buying or selling an asset. The theory describes the price of an option and what a financial intermediary could manufacture the options for, using different assets available in the market. In other words, the *market value* of a future decision can be replicated using existing and available financial products such as stocks and bonds.

Dixit and Pindyck (1994) identify three important characteristics, common to all investments, but not addressed in the traditional DCF analysis methods: 1) investments are irreversible (at least partially); 2) future payoffs are uncertain, and; 3) timing is not always fixed.

They argue that orthodox theory and traditional analysis has not recognized the implications of these characteristics. But, their options approach, for valuing investments, resolves these anomalies.

Flexible Design. de Neufville and Scholtes (2011) show that flexibility in design maximizes the expected value of a system or project over time. Flexibility enables owners and operators to adapt the system for optimal performance as its requirements and opportunities evolve over its useful life. de Neufville and Scholtes, present a full framework and evaluation process for flexibility (de Neufville & Scholtes, 2011).

Flexible design has been applied to many aspects of long-lived infrastructure. Basupi et al., (2015), evaluates flexibility in water distribution system design. Hu et al., (2015) applies the principles more broadly, and shows that expected NPV improved by an average of 10% when applying flexible design to waste-to-energy projects in Singapore, reducing downside risks, and capitalizing on upside opportunity.

Deng et al., (2013) assess flexibility in design of waste-to-energy to achieve environmental and economic sustainability under uncertainty. They seek to answer questions of when and how to exercise the flexibility in the face of growing uncertainty, especially given long-term life-cycles. The authors propose a multistage stochastic programming model to design an optimal decision rule to guide decision making for expansion. Their experiments show that the expected net present value (ENPV) of the flexible design provides significant improvement over the fixed rigid design in terms of economic lifecycle performance.

Secondary Topics

There is also a developing body of literature applying real options to infrastructure valuation and investment planning. This includes application for public private partnerships (PPP) in terms of contract protection for concessions and concessionaires, insurance clauses, and other applications.

Fernandez et al., (2011) reviews the current methods and applications of real options to both renewable and non-renewable energy projects. One of the author's conclusions is that there is a gap in applications of ROA to renewable sources of energy.

Jeuland and Whittington (2013) develop the approach for planning new water infrastructure investments and their operating strategies, by applying the concept to hydropower along the Blue Nile. They find the value of real options is that it can be used to identify dam configurations that are both robust to poor outcomes and sufficiently flexible to capture high potential upside benefits.

Gersonius et al., (2013) shows that investment decisions for water and flood systems are frequently based on state-of-the-art impact assessments using a *specified* climate change scenario to identify a singular optimal adaptive strategy. He argues that responsible adaptation requires an alternative method that effectively allows for the lack of knowledge about future climate change through an adaptive strategy. Furthermore, the authors show that ROA can facilitate the development of such a strategy to climate change. They show the economic benefits of adaptation by building in flexibility, using ROA, applied for the first time, to urban drainage infrastructure.

Abadie (2014), applies an ROA approach to the valuation of wind energy projects. The author provides a method for valuing an operating wind farm and the finite-lived option to invest in it under different reward/support schemes. Those schemes are: 1) a constant feed-in tariff, 2) a premium on top of the electricity market price, and 3) a transitory subsidy. The model considers up to three sources of uncertainty: the electricity price, the level of wind generation, and the certificate price where appropriate.

Madlener et al., (2012) uses ROA to study the economic feasibility of constructing a coal-fired power plant, using a specific plant in Turkey as a case study. The authors investigate the peculiarities and uncertainties related to large-scale power generation, focusing on the real options value embedded in the project development cycle. They employ a sequential investment model using the binomial tree method. The four decision points within the project development cycle are: 1) initial project development; 2) detailed planning and permitting; 3) first major project payments; and 4) release of final order. Madlener et al. find that ROA can be very useful compared to traditional NPV analysis. High option value compared to the NPV of the project makes clear that the flexibilities of reacting during the project cycle, can have a substantial value. A further advantage of the ROA for a staged investment lies in the fact that it also delivers, besides the option value of the investment, the optimal strategy for exercising the option – if, and when, to invest.

Marques et al., (2014), show that real options can be used when making decisions around the design and operation of water networks under uncertainty. ROA can point to adaptive strategies in the decision process, especially when some decisions can be delayed pending future conditions.

Zhang (2012), uses an ROA to evaluate innovative water technologies to provide decision support for designing water supply systems under uncertainty. The development of these technologies provides flexibility to the water supply system, and is a fundamental and effective means of risk management. ROA offers the right kind of decision support to identify their full value under a general, prescriptive Integrated Water Resources Management framework.

Biljana (2014) shows that PPPs offer numerous benefits to both partners in delivery of infrastructure projects. However, risks must be adequately managed and mitigated. The author's objective is to investigate whether the real option of abandoning the project increases its value. The author's results suggest that project value, including the American abandonment option, is greater than with the European abandonment option, implying that American options offer greater flexibility and may be more valuable for private partners.

Blank et al., (2009) shows that often PPP agreements may include subsidies, guarantees and other forms of support designed to reduce the risk to the private investor. Some real options can be identified in these structures and it is necessary to use the correct methodology to analyze project economic feasibility and risk allocation. As an example of application, a hypothetical toll road concession is modeled and three real options are proposed and analyzed: a minimum traffic guarantee, a maximum traffic ceiling and an implicit option to abandon.

Decision-Making Tool

Besides the applications above, ROA is included in the climate change decision-making literature, as one tool among many. It is not the purpose of this dissertation to fully treat the benefits and drawbacks of the multitude of decision-support tools for climate change adaptation and decision-making around infrastructure, or even around hydropower. It is, however, necessary to firmly position Real Options Analysis within the lexicon of decision-making tools, and highlight its benefits considering other common techniques. In that regard, this section presents the current discussion of decision support tools, which are being especially promoted for climate uncertainty.

Doczi (2013), reviews "so-called tools" for adapting to and managing climate variability within the water sector. He identifies 137 unique tools (many of which overlap), and maintains that these are largely "supply-driven" with little demand found for many of them. Doczi offers input on how and if new tools should be developed, and made more effective.

Hallegatte et al., (2012) strike a more inclusive tone. In "Investment Decision Making Under Deep Uncertainty – Application to Climate Change," the authors survey several decision-making tools available for developers to evaluate climate risks in long-lived infrastructure. These include cost-benefit analysis (CBA), CBA with Real Options (RO), Robust Decision Making (RDM), and Climate Informed Decision Analysis (CIDA). The article concludes that a menu of tools is necessary due to the level of uncertainty and the fact that each tool comes with applications that stretch the capacities of the other tools.

Cervigni et al., (2015), in "Enhancing the Climate Resilience of Africa's Infrastructure," aim to develop a deeper understanding of the impacts of climate change on infrastructure development. Using a consistent methodology and state-of-the-art future climate scenarios, the study evaluates the impacts of climate change on irrigation and hydropower in Africa's primary river basins. It applies those impacts to the electricity sector across the four regional power pools. The study adopts a Robust Decision Making analysis to evaluate among specific projects, and calls for broader adaptation of this method.

Hydropower introduces an additional set of uncertainties for investors to consider. Recently dam construction has come back into favour for investment by the World Bank and other multilaterals. While vigilant design and implementation may overcome some of the environmental and social challenges faced by hydropower, some still criticize these facilities, maintaining that dams are often politically and financially mismanaged, creating unacknowledged risks.

Harrison and Whittington (2003) show that river flows and hydropower production are sensitive to changes in precipitation and temperature. Ansar, et al., (2014) surveyed the post hoc realized costs of hydropower projects and found significant overruns. His study suggests that hydro-project planners tend to take an overly optimistic "inside view" of projects by narrowly focusing on the project under consideration, rather than the broader landscape of difficulties in hydro development. This results in optimistic projections of time, costs, and benefits. He notes that cost overruns occurred in every region of the world, and that nearly half the dams studied suffered a cost overrun such that sunk costs may not be recovered.

Nombre (2014) disputes the findings of the Ansar et al. As president of the International Commission on Large Dams (ICOLD), Nombre states that, “cost recovery has not been a substantial problem for hydropower projects.” (Nombre 2014) He questions the data and assumptions of Ansar’s study. The disagreement highlights the complexity of decision-making surrounding proposals of large projects under uncertainty.

There is an observed lack of research applying real options analysis to value flexible design options, under climate and other uncertainties, for hydropower facilities at the project level. This research is designed to help fill this gap.

CHAPTER III

FOUNDATIONAL CONCEPTS

The theme of this thesis is the use of ROA to identify hidden value in flexibly designed projects. To appreciate the power of a real options model to value flexibility, it is essential to understand three primary concepts: financial options, real options and flexible design. Financial options (one type of financial derivative) provide the conceptual backdrop for pricing real options. Though real options are based on the theory of financial derivatives, they have a project as their underlying asset, rather than a stock. Finally, the concept known as flexible design creates options within the design of projects, so owners and managers can gather information before making expensive decisions. Design flexibilities are the *options* in real options analysis. Three secondary concepts are also important, reflecting the application of the model. The first is hydropower as an important renewable electricity source for Africa, the second is the concept of decision-making under uncertainty, and the third is public-private partnerships (PPP), possibly an important application for real options. These represent important aspects of the context in which I apply the model in the two case studies. This chapter offers an in-depth definition of these three primary and three secondary concepts.

Financial Options

ROA is based on the principles of financial options. This section defines financial options, summarizes the reason for their attractiveness using an illustration, and offers some of the mathematical theory behind them.

A financial *call* option is the right, but not the obligation, to purchase a financial security (a corporate stock), at a predetermined price, at a specific time in the future. The agreed upon price is called the *strike*, or exercise price. If the actual price of the stock is higher than the strike price, the owner of the option will exercise his right, purchase the stock and collect the difference in values (minus a fee) as profit. By contrast, a *put* option gives the owner the right to *sell* a stock at a predetermined price.

Figure 1: Call Option Payout Diagram

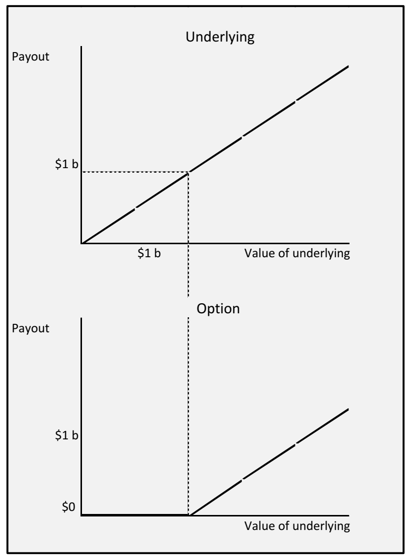


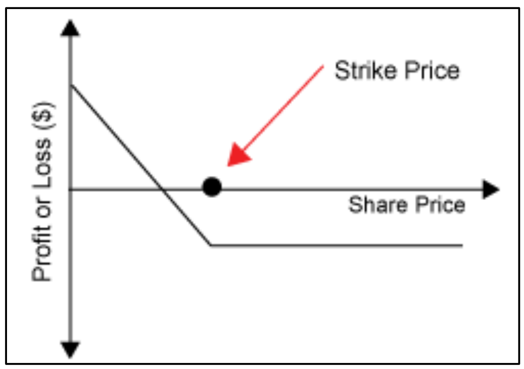
Figure 1 illustrates the value of a call option. As the value of the underlying asset rises (increasing along the x-axis), the value of the option eventually gets to the point of also holding positive value. This point is the strike price. Unless the value of the underlying asset surpasses that of the strike price, the value of the option will be zero.

$$Value\ of\ Call - MAX[Value\ of\ asset - Strike, 0] \quad (2)$$

Call options are attractive instruments for the buyer because they allow the holder a sizeable potential upside (possibility of profit), while minimizing the downside (possibility of loss). Consider this example: an investor purchases an option to buy 1 million Euros with Dollars one year in the future, for an exercise price of $1.25. If the value of the Euro to the Dollar is 1.24 or less, the holder lets his option pass; he has lost only the price of the option. However, if the value is $1.26, he has made a profit of $10,000. If the value is $1.27 he has profited $20,000. By holding the option, the investor has created a large potential upside with a limited downside risk – that of the cost of the option (de Neufville & Scholtes, 2011).

Put options are used when an investor thinks the price of a stock will fall. A *put* allows the investor to *sell* an asset at an exercise price. If the spot price is below the exercise price the investor can purchase the asset at the spot price, and immediately sell it at the exercise price. Using the example above, if the investor purchases a put option at the exercise price of $1.25, she/he will profit if the price falls below that mark, by buying euros (at $1.23, for example), and then immediately selling at $1.25.

Figure 2: Payout Diagram for a Put Option



Source: Investopedia

Merton and Scholes won the 1997 Nobel Prize in economics for their theoretical work (along with the late Fisher Black) in modeling how to price call options of stocks, in 1973. The Black-Scholes model has been widely used in determining the prices of financial options:

$$C = SN(d_1) - N(d_2)Ke^{-rt} \tag{3}$$

Where: *C* is the price of the option; *S* is current stock price; *t* is time until option exercise in years; *K* is the option strike price; *r* is the risk-free interest rate; *N* is the cumulative standard normal distribution (mean = 0; σ = 1); *e* is the exponential term; and

$$d_1 = \frac{ln\left(S/_K\right) + \left(r + \sigma^2/_2\right)t}{\sigma * \sqrt{t}} \; and \; d_2 = d_1 - \sigma * \sqrt{t} \qquad (4)$$

Where: σ = standard deviation of returns; *ln* = natural log

One breakthrough of the Black-Scholes model was that it considered volatility in valuing an option. The Black-Scholes formula demonstrates that the value of the option increases with volatility, which is measured as the standard deviation of returns over the period. In the example, the larger the variance in price of Euros, the more valuable it is to hold the option. The reason is that the upside potential will be higher, while the downside remains fixed at the price of the option.[2] Another breakthrough for Black-Scholes was the inclusion of the probability that the price of the asset will pay off in time *(t)* – the *N(d1)* value; and the probability that the option will be exercised – the *N(d2*) value. In other words, option values have the probabilities of outcomes "baked in."

The Black-Scholes equation will be utilized in the case studies. However, implicit in its simplicity are several assumptions that limit its use for extensive analysis of real options (Copeland & Antikarov, 2003). Because of these limitations, another more robust valuation process will also be used: the construction of a binomial lattice, or tree. This process is discussed in Chapter VI.

Real Options

Real options extend the concepts developed by Black and Scholes from stock options to options on physical projects. Stock options derive their value from an underlying corporate stock; similarly, a real option (RO) also derives its value from an underlying asset. However, the underlying asset is a real project, with cash flows, as opposed to a stock. Real options are herein defined, and their features are mapped to stock call options; additionally, the practical decision-making utility of real options is discussed.

[2] Volatility in option pricing is typically taken from a tracking portfolio, a group of stocks that normally trends with the stock being analyzed.

Copeland and Antikarov (2003) define a real option, “as the right, but not the obligation, to take an action (e.g., deferring, expanding, contracting or abandoning) at a predetermined cost, called an exercise price, for a predetermined period, which is defined as the life of the option.” The holder of the option may choose to spend money (exercise price) now or in the future, in return for an asset (project with associated cash flows) of some value. She will choose to invest, if the project is “in the money” – that is, if the present values of its cash flows are greater than the exercise price. If it is, she will receive a positive net payoff. If it is not, the investor will not exercise her option to invest. In this case, it is said that the option is “out of the money.” She has lost only the price of the option.

A call option on a stock incorporates several concepts. These concepts can be mapped to characteristics of real projects. The value of the underlying stock, reflected in its market price, can be mapped to the present value of a project’s expected cash flows. The exercise price of the option equates to the value of the investment outlay required to convert the project. The time to maturity for a call option relates to the deferral time of the real option on the project. The risk-free rate represents the time value of money. And finally, the historical volatility of stock returns can be represented by the projected volatility of the project’s return. Table 2 summarizes.

Table 2: Real Project Characteristics Mapped to Call Option Concept

Real Project Characteristics	Stock Call Option
Present value of expected cash flows	Stock price
Present value of investment outlays	Exercise price
Length of deferral time	Time to maturity
Time value of money	Risk-free rate
Volatility of project’s return	Standard Deviation of stock returns

Source: (Fernandes et al. 2011)

Real options can be used to gain insight on many decisions available to a manager, and are especially applicable if the project faces high degrees of uncertainty, which is likely to be resolved by the passage of time. The following lists four different types of real options (Copeland & Antikarov, 2003):

- *Option to expand*: if initial investment succeeds
- *Option to wait and learn*: before investing in the first place
- *Option to shrink or abandon*: when market changes create adverse conditions, the decision to abandon the project before all money is spent can minimize losses
- *Option to switch*: investors can alter the product offering mix to adjust to changing market preferences.

Real options analysis is also an excellent decision-making tool. Implicit in each of the option types listed, are flexibility points within a project; an ROA can help project designers create the right kind of project flexibility. For example, real options can help investors make timing decisions for future project-level investments. They can help the drafters of public-private partnership contracts assign the right trigger points for actions such as insurance payments or decision dates. Introducing an option approach to project analysis may have several other positive effects. It may reduce initial investor risk, by giving investors the option to invest in smaller parts of a project. Project sponsors can use these signals to inform investors of the value embedded within their projects. Valuations can also serve as an incentive for developers to perform efficiently knowing that new investment may depend on current performance. However, the primary usefulness of RO is often to help managers make decisions about their capital budgeting, and how and when to investment in new capacity.

Flexible Design

Flexible design means incorporating the flexibility to alter a project based on new information. While most projects are *managed* in such a way to respond to new information, flexible design seeks to build flexibility into the *design* of the project from the planning stage. Flexibility can help to manage risks, and increase the value of projects (de Neufville & Scholtes, 2011). This section describes flexible design, provides an apologetic for its use, offers a few examples, and concludes with a framework for applying the concept at the project level.

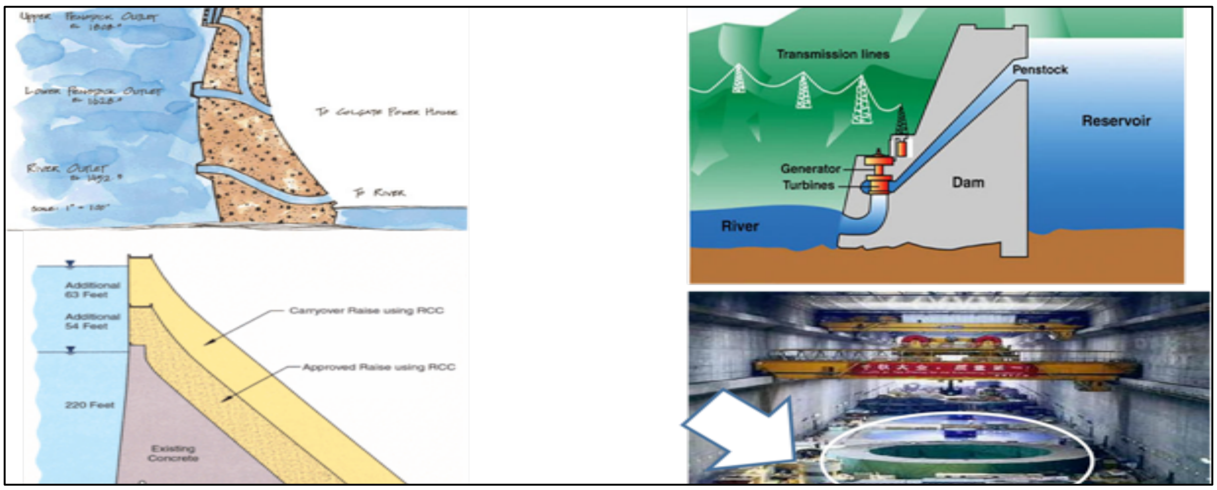
"Flexible design is a fundamental approach to designing systems and long-lived assets, allowing designers to maximize expected value over time. It enables owners and managers to adapt assets for optimal performance as requirements and opportunities evolve during operations," according to de Neufville & Scholtes (2011). In the case of a hydropower facility, it may mean an initial investment to broaden the foundation of a dam, so the dam height can be increased later; or including the civil works for additional turbines, but delaying the inclusion of expensive turbines until more is known about the effects of climate change on river flows. Occasionally more expensive at the beginning of a project, flexibility can delay higher-cost investments until more is known about existing uncertainties. Flexibility creates options – decisions to be made at a future date, when a market has been tested, a technology proven, or river flow rates better established. The decision may be whether to invest additional money to expand operations (creating a call option), or to sell a project at a predetermined price (creating a put), or to further delay the decision (extending the life of the option).

Flexible design has recently been used as a paradigm from which to conceive projects that may be threatened by climate change, including hydropower facilities (Jeuland & Whittington 2013). There are inherent challenges in assessing the value of large-scale hydropower projects. These projects have long build-times, during which much can change in energy markets, policy regimes, and technology. This can introduce uncertainty in energy prices and facility output. Since much of the capital required to get a project fully functional is required well before cash flows are available, these unknowns introduce significant risk. Furthermore, once a project comes on line, it is typically locked in to the operating assumptions made during the initial design stage, leaving no room for modification to take advantage of new opportunities, or to avoid pitfalls (de Neufville & Scholtes, 2011). Despite sophisticated modeling techniques, we cannot know the future. No matter how hard we try to create reliable projections, the forecasts are always wrong, and new information frequently takes us by surprise. Rather than to expect more accurate forecasts, we need to adapt to circumstances as they arise. To achieve the best possible results, we need designs that can be modified to easily take advantage of new opportunities, or to mitigate bad outcomes. Design options that do not account for a range of possibilities that may occur over the full asset lifecycle, run the risk of either leaving value untapped, or of incurring major losses. An uncertain future provides a range of opportunities and risks. We can best deal with these, and maximize value, if we build flexibility into our designs (de Neufville and Scholtes, 2011).

When a project is built with flexibility, it contains an option. The flexibility can be harnessed at a point in the project's development when new information is available. At that time, it may be appropriate to expand, abandon, maintain, or scale-back the project. These decision points are called "flexibility candidates," and represent possible points of divergence from the original plan, or dedicated points of decision established in the original design (de Neufville & Scholtes, 2011).

In Figure 2, four examples of flexible design for a hydropower facility are pictured. In the top two, the location of the penstock and water levels are shown. The opportunity to use a lower penstock increases the amount of available water for hydropower use, as does increasing the level of storage behind the dam wall. In the lower left diagram, capacity for increasing the height of the dam is shown. And in the lower right, the open civil works of a turbine bay is pictured; since turbines are often a very expensive component, it may make financial sense to construct the bay, but wait to buy the turbine, thereby purchasing an option to install the turbine later. Though it is not pictured, pumped storage is another possible flexible design candidate. Of course, these decisions could be made post hoc from a statically designed facility, but the cost of conversion would be significantly higher.

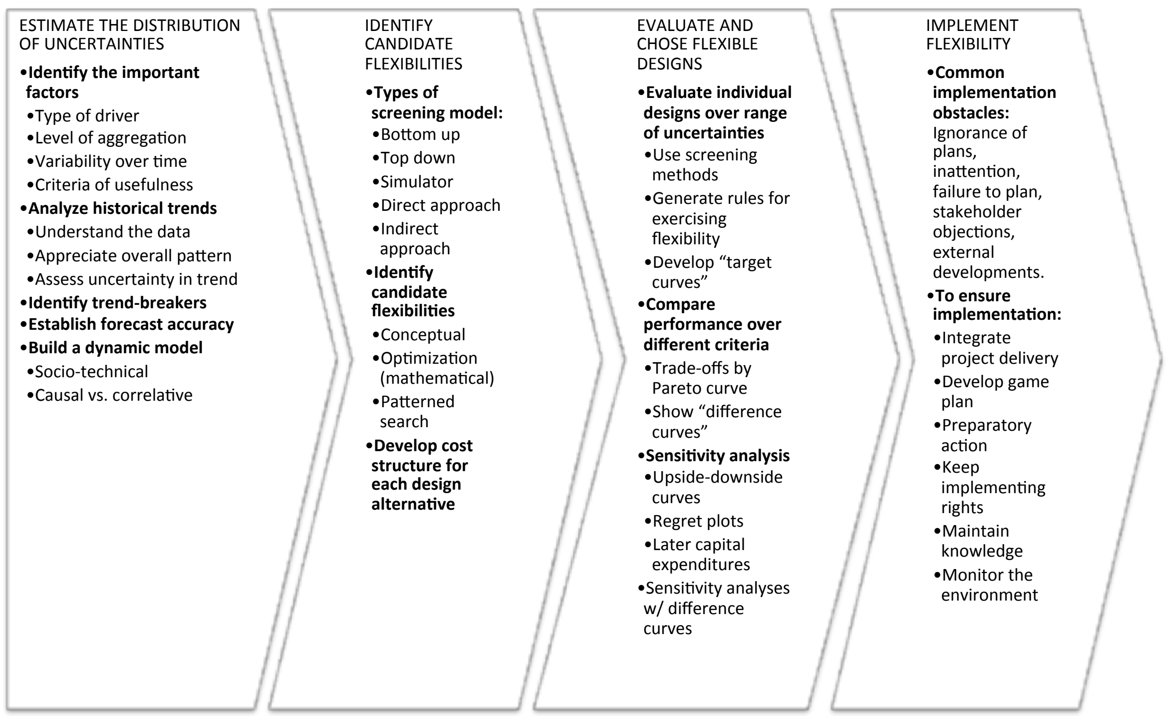
Figure 3: Examples of Possible Flexible Design for Hydropower



Source: Dr. Kenneth Strzepek, MIT

de Neufville and Scholtes (2011) have created a framework for using flexible design at the project level. They describe the flexible design process as having four steps. The first is to estimate the distribution of possible future outcomes. This range is likely to be much larger than designers typically consider. The process involves identifying important decision-making factors, analyzing trends, and creating a model. The second step is to identify candidate flexibilities unique to the project. This includes three steps: 1) the use of a screening model to evaluate various design options, 2) the identification of flexibility points based on the model, and 3) the development of costs structures for each option. Step three is to evaluate and chose among the flexible-design options. This step includes an evaluation of each design over a range of uncertainties, a comparison of performance over different criteria, and a sensitivity analysis. The final step is to implement flexibility. Figure 3 summarizes the process.

Figure 4: Process for Implementing Flexibility



Source: Adapted from de Neufville & Scholtes (2011)

Optionality, embedded in a project, creates additional value because the decision itself has value, which is tied to the additional cash flows available from the optioned project. The option gives access to those cash flows. The value of any hydropower project is based on the potential cash flows from that project, which will accrue to the owners. To make design decisions, these cash flows are discounted and compared with those of other design configurations. The usual manner of assessing the value of a project is to use a discounted cash flow (DCF) approach, and then subtract the capital investment required by the project. That yields a Net Present Value (NPV). If this is a *cumulative-value* project NPV it will reflect the market value of *all* the potential incremental cash flows of the project. Cumulative-value NPVs are held in contrast to *static* NPVs, which are expected valuations without optionality.

Secondary Concepts

Three other concepts also permeate this dissertation, and should be mentioned. The first is the importance of hydropower for Africa's development; the second is decision-making under uncertainty, specifically the uncertainties of climate change; the third is public private partnership. These concepts provide the context within which the model is useful.

Hydropower for Southern Africa. Hydropower, as a renewable energy source, holds great promise in Southern Africa; however, it also presents significant challenges. PIDA is calling for an expansion of generation capacity of over 54,000 MW to help close the continent's electricity gap (United Nations, 2014; Van Der Wat, 2013). Within the PIDA framework, a Priority Action Plan calls for $21.3 billion specifically for hydropower (Cervigni et al., 2015). However, realizing the plan will be challenging for several reasons. For example, hydropower plants have been environmentally disruptive, and therefore face political challenges. In addition, hydro's large up-front costs expose investors to cost overruns and construction delays, both of which place returns at risk (Ansar et al., 2014). And, while demand for electricity has been established (Castellano 2015), the rate at which transmission and distribution lines can be extended to customers remains in question. This translates into demand uncertainty, which can place investors' capital at risk.

Large dams attract controversy because they involve complex decisions in the areas of technical and economic efficiency, equity, and ecological and environmental impact (Biswas and Tortajada, 2001). Amidst the debate on whether large dams are a stepping stone to a more sustainable future, four international organizations signed a World Declaration on Water Storage for Sustainable Development (Kyoto, 2012) to make a case for the importance of water storage and hydropower infrastructure. ICOLD, the International Commission on Irrigation and Drainage, the International Hydropower Association, and the International Water Resources Association all look to an uncertain and resource-constrained future when they advocate for the value of well-designed and well-managed dams. Within the Kyoto agreement, these international bodies urge that water infrastructure can help meet society's challenges in the following key areas:

- Flood management and drought mitigation, in the face of more severe and frequent floods due to climate change
- Irrigation for food production, to expand viable crop growth beyond traditionally arable land
- Energy production, as a renewable, storable, and carbon-free energy source to improve the reliability and sustainability of power sources
- Drinking water and sanitation, expanding access to the 1 in 8 people who lack safe water for drinking and cooking.
- Industrial water supply, offering a needed resource for new industries in developing countries

The groups claim these projected benefits of dams accrue to society when the hydropower projects are well-adapted to local conditions and when these projects are legitimately executed.

However, the post hoc impact of large dams is rarely studied in practice. Ansar et al. surveyed the realized costs of hydropower projects and found them plagued by significant cost overruns (2014). The study suggests that hydro-project planners tend to take an "inside view" of projects, i.e. they focus intently on the issues at stake in the project under consideration, instead of looking to the collective set of experiences and possibilities of a large set of projects. The "inside view" results in overly optimistic projections of time, costs, and benefits of their decisions. Hydropower advocates dispute the findings of the Ansar et al. study, questioning the data, and showing that cost recovery has not been a detrimental issue (Nombre, 2014).

The two groups disagree about outcomes such as actual time to construct, average cost, and the degree of cost overrun. While these are seemingly items of fact, the measurements often depend assumptions and counterfactual benchmarks. This type of disagreement highlights the complexity of decision-making surrounding proposals of large projects under uncertainty. To reconcile the different views, advocates of large dams typically make a strong general case for the *available benefits* of large dams, provided they are well planned and efficiently delivered and operated. By contrast, post hoc studies have often focused on the *actual value capture* of these projects, revealing the issues encountered during planning and delivery that have eroded the idealized value of dams. Chief among these are uncertain and variable environmental linkages, build costs, and realized production values (Ansar et al., 2014).

Decision-Making Under Climate Uncertainty. Decision-making under climate change is itself a topic that has received attention in recent years, as climate change further increases the level of investment uncertainty, and possible risk. In response, several decision-making tools have emerged, to help planners address climate uncertainties. Current climate models show that the future climate will be very different from the past, but they disagree on whether specific locations will be wetter or drier. For a hydropower facility, this means that investors may face a dry future, with lower than expected flows, and a project with the inability to return the initial capital costs to build it. This could lead to an overbuilt facility. On the other hand, there is also the chance of a wet future, in which investors would want to capture larger than expected flows. In this case investor prefer additional capacity. To help manage these uncertainties, a variety of tools have emerged. These include benefit-cost analysis under uncertainty, and the process of "robust decision making." Each method has its strengths and weaknesses, and all offer answers to related, but sometimes different questions. While these topics are essential to this thesis, further discussion is saved for the case studies.

Public Private Partnerships. PPPs are a means of financing public works projects that involve both the public and private sector. The World Bank offers this definition: A long-term contract between a private party and a government entity, for providing a public asset or service, in which the private party bears significant risk and management responsibility, and remuneration is linked to performance (World Bank, 2014). These partnerships can take a variety of forms, but usually proceed with an initial investment from the private sector, followed by a concession period, during which the investing entity receives a return on that investment. Eventually the project in question reverts to public ownership and management.

When private sector funding is needed, there are three primary models:

1. BOOT (Build, Own, Operate, Transfer) – In this case the company owns the project for the duration of the concession. At the end, it is transferred back to the host government, usually free of charge. The concession period is long enough for the concessionaire to recover its initial building costs, and profits from operations.
2. BTO (Build, Transfer, Operate) – In this case a private company is contracted to build and operate the facility, but ownership remains in public hands. The public sector maintains more control over the project, but is also exposed to risks of mismanagement by the private sector.
3. Parastatal – In this case a public project is financed by private debt using a parastatal company as the borrower. The project is then supported by Sovereign Guarantees.

Projects that do not qualify for private funding will need to remain in the public sector. In poorer nations, these will require some form of concessionary financing arrangement, usually from grants and other credits, and on terms that the private sector cannot offer. However, development banks are hopeful that they will be able to partner with private parties for energy asset investment.

The African Development Bank (AfDB) is taking steps to help attract private financial capital to the continent, for energy infrastructure. In 2012, the Bank targeted 10 energy projects financed by the private sector, including combined cycle projects, hydropower projects, waste-to-energy projects, and Africa's largest wind farm located at Lake Turkana. The Bank invested nearly US $400 mm of its resources toward US$ 2 billion worth of energy projects (African Development Bank, 2017). According to the Bank, PPPs have emerged as one of the most attractive ways to foster development. The trend has been fueled by a lack of public investment, growing pressures on government budgets and a general concern about service provision by state agencies. PPPs have taken place mainly in infrastructure, such as power, transport, telecommunications, and water and sanitation.

For more PPPs to emerge in Africa, countries will need to improve their business climates, as serious constraints now exist in many countries. These include inadequate legal and regulatory frameworks, a lack of technical skills to manage contracts and projects, an unfavorable investor perception of country risk, Africa's limited role in global trade and investment, small market size, limited infrastructure and limited financial markets. The African Development Bank is encouraging African countries to create the necessary legal and regulatory framework for PPPs; as well as facilitating networking and sharing of experience among regulatory agencies and other similar organizations (AfDB, 2016).

As an illustration of a large-scale PPP consider the following example of the *Nam Theun 2* hydropower plant in Laos:

The Nam Theun 2 Hydropower (NT2) energy export project in Laos, illustrates a unique blend of the vehicles presented above. According to a World Bank review, "Nam Theun 2 demonstrates that it is possible to privately finance a large and complex project in a small and economically weak country. It also demonstrates how a single project can dramatically improve economic growth, and contribute to poverty reduction and environmental protection (Head, 2006)."

The project is a trans-basin hydropower project consisting of a 48-meter-high dam on the Nam Theun River. The reservoir covered 450 square meters. Power production at the time of conception was estimated at 1,070 megawatts/year. 95% of this power is sold to Thailand, and the remaining 5% to Laos. When the NT2 closed its financing, it boasted several firsts: 1) it was the largest ever foreign investment in the Lao PDR, 2) it was the world's largest private sector cross-border power project financing deal, and 3) it was the largest hydroelectric project ever to use private sector financing (World Bank, 2005).

The financing structure was built as follows:

- *US $500 M came as debt from foreign commercial banks and Development Finance Institutions*
- *US $450 M came as equity*
- *US $500 M came as debt from Thai commercial banks (Asian Development Bank, 2012)*

The capital structure features a debt to equity ratio of 72/28, and the private sector supplied about 85% of the total cost. The project was developed as a BOOT (Build, Own, Operate, Transfer) and cost $1.2 billion. The concessionaire is a locally registered special purpose company, the Nam Theun 2 Power Company (NTPC), of which the Government *of Laos owns 25%. NTPC contracted to finance and develop the project, and then to operate it for 25 years. After that, it will revert to the State free of charge. During the concession period, the Government will receive dividends, royalties and taxes amounting to $80m/year (Head, 2012).*

To make the project bankable, and secure financing, a power purchase agreement (PPA) was established between NTPC and the Electricity Generating Authority of Thailand (EGAT). This was a 25-year agreement for NTPC to supply 5,636 GWh/year to EGAT on a take-or-pay basis. This means that sales were guaranteed. The tariff was predetermined and denominated half in US$ and half in Thai Baht, to avoid exposure to local currency devaluation (Head, 2012).

Funds for the 25% equity portion of NTPC, which is owned by the Government of Laos, amounted to $87 M. This was raised through concessionary loans and grants. However, money was made available to the Lao Holding State Enterprise (the Government holding company) as a loan at commercial rates. This difference in rates created an additional revenue stream for the government (Head, 2012).

International debt totaling $350m has been raised from export credit agencies (ECAs). Multilateral banks insured this debt against political risk by offering guarantees. However, debt coming from Thai commercial banks (about $500 M) is uncovered for political risk. The project showcases the use of the credit enhancement mechanisms now being offered by the MDBs. Guarantees only covered $126 M (excluding export credits), or 10% of the total cost, but they provided sufficient confidence to leverage a much larger sum from international sources. The public sector provided only 15% of the total project *cost, and much of this was concessionary lending for the purchase of the Laos government equity shares (Head, 2012).*

To satisfy transparency requirements, the Head Contractor extended an RFP to five subcontractors, who bid competitively for participation. The winning group holds most of the construction risk. All have fixed-price contracts with some provision for sharing geological risk with the Head Contractor and NTPC. The Thai power authority also shares some of the hydrological risk. The Government of Laos is protected from risk, except through its 25% holding in NTPC (Head, 2012).

The project was originally developed in 1993, but did not close until 2005, reflecting one category of risk. NGO opposition led to a series of additional social and environmental impact studies. By the time these were completed the region was suffering badly from the '97 Asian financial crisis. To mitigate future opposition, the project provided $49 M to cover the cost of a social and environmental management program (Head, 2012).

Real options can offer insight to some of the details appearing in PPP contracts; however, it should be noted that these contracts can be very complex and an ROA will only inform certain aspects of the agreement, especially where optionality is included. Finally, since the subject of PPPs is a very complicated one, this dissertation will not delve far into the topic. The point of introducing the topic here is merely to mention that ROA can be used to develop valuable information to inform PPPs. This concept will be further illustrated, especially in the Inga case.

This section has defined and illustrated the three primary concepts of financial options, real options, and flexible design. It has also discussed the secondary topics of application for these concepts: hydropower in Africa, decision-making under uncertainty, and public private partnerships. The following chapter offers a typology of real options and their usefulness.

CHAPTER IV

TYPOLOGY OF OPTIONS

Financial options, and other derivatives, are used to build a multitude of financial assets which create value. Some of these strategies have their parallel in real options. This thesis primarily uses call options to determine the value of flexibility in design. However, there are other types of options, some of which are illustrated in the case studies. This section provides a typology of the most commonly used options and some sample applications. It begins with the European call option, then discusses European put options, American style options and compound options.

European Call Options

European call options give the holder the right, but not the obligation to *purchase* something in the future at a predetermined price. This translates into allowing the holder of the option to capture benefits from increases in project value, while protecting her from downside risk. The exercise of the option typically involves putting more money into the project, which is reflected in the strike price. Finally, the option is exercised when expectations of positive returns increase.

In addition to what has been discussed in relation to the value of flexibility, there are other applications for European calls. These include the value of waiting, of greenfield development, expansion plans, restarting temporarily closed operations, and other investment strategies.

Consider a small renewable power generating unit in South Africa as an example for a greenfield investment opportunity, and the possibility of waiting to develop. A developer may enter an auction to bid on a site for development. The developer's bid represents the value of the project to them at that time. They are not willing to bid higher, believing that a higher price creates a negative value for the project. However, there are two ways the developer can approach the project. One approach is to see the project as a now-or-never investment opportunity. In this case, she would approach the auction with the perspective that winning the bid means immediate development of the facility. To value this static opportunity, the present value would be calculated, and the cost of investment would be subtracted, including the cost of the winning bid at the auction. This would be the NPV of the static project. By contrast, the developer could approach the auction differently, viewing a successful bid as an *option* to develop the project sometime in the future. In this case, she would see the winning bid as the value of the option, and the initial development investment as the strike price (the investment needed to exercise the option). Holding this view may change the minimum bid for the developer, if the option is perceived to hold value in addition to the actual project. It may also change the timing restrictions for development, likely adding a good deal of flexibility. (Whether the option valuation or static valuation is higher will depend on the project, especially the uncertainty which surrounds it, and the likelihood that uncertainties will be resolved.) If the developer views the project as potentially valuable, based on analysis, the bid itself would be the price of the option to develop.

Call options can also be used to evaluate whether and when to reopen a mothballed operation. This is a special case of an expansion option. The choice is based on the formula: *MAX[remain closed, re-open],* and the calculations presented in Chapter VI work the same as for other call options.

European Put Options

A European put option is an opposite strategy to a call option. Rather than the right to *buy* an asset in the future, a put option gives the holder the right to *sell* in the future, at a guaranteed price (the *strike* price). The decision rule for a put option is then (K is the strike price, V_t is the value of the asset at time t):

$$put\ payout = MAX[K - V_t, 0] \tag{5}$$

In this case, the strike, or sales price, must be *higher* than the value of the asset for the option to be in the money. If it is, the holder of the option will sell the asset for more than it is worth. Put options may involve short-term costs or salvage value.

Put options are often used to create insurance policies against potentially declining asset values, by creating a "value floor." If asset values fall *below* the floor, holders of the option have the right to sell the asset *at* the predetermined value floor (the strike price). The policy will pay when the value of the asset falls below the strike price. The process for valuing the put option is the same as for a call option, with the exception that the payout is reflected in equation 4 above (recall that the payout for a call option is: $MAX[V_t - K, 0]$).

As an example of an application, one can isolate risks in the model, and derive put option values based on single uncertainties. For example, an insurance contract for climate risks could be developed around an asset. To do so would require framing the option to isolate climate risk, and developing a decision rule based on a climate phenomenon, rather than on overall value (which integrates all risks). An example of a put option is given in the Inga case.

Other types of contract clauses also reflect a put option strategy. Short of abandoning the project, a deceleration or narrowing of involvement can be assessed. This would reduce the level of, and exposure to, potential losses. For example, a put option could be used to effectively evaluate the temporary closure of operations in an unfavorable environment.

American Options

American options can be either the call or put variety. While European options are those with a fixed exercise date, American-style options can be exercised at any time, from the creation of the option until the exercise date. However, the longer the time to the final date of exercise, the more valuable the option. So, an important feature of American options is that even if one can exercise early, one will always wait, *unless* the cost of waiting becomes sufficiently high. This can occur if the underlying asset pays a dividend, experiences storage costs, or there is added risk to waiting. This type of cost is called *value leakage*. The following are examples of value leakage for projects (Amram & Kulatilaka, 1999).

Dividends: dividends reduce the value of the underlying when owners distribute a portion of the value of the asset prior to the exercise of the option. When dividends are paid, a *call* option held on the underlying asset becomes less valuable, while a *put* increases in value.

Cost of storage: when a company must pay a predetermined fee for storage, the value of holding product may be compromised. The value of the option is especially affected if the storage fee is disconnected from the price of the product in question. For example, consider an oil storage facility. An oil company realizes cash flows when it sells oil, but it may want to hold the oil in anticipation of higher prices. The problem is that oil prices are volatile, while storage fees are usually not. Fees that are based on volume stored will continue whether prices rise or fall.

Additional risks: additional risks include the risk of competitors entering the market, changes in the regulatory landscape, technological changes in the industry, or commodity price fluctuation. These risk factors all have the characteristic of being "lumpy;" that is, they do not reveal themselves smoothly over time, but rather occur periodically, affecting the value of the asset at points in time. Each of these may cause value leakage.

In cases such as these, American option calculations can be used to determine the value of the options, and especially, the value of *waiting*. If the value of waiting exceeds the value of exercising the option, the option will be held. In this way, real options can be used to develop the optimal *timing* of investment, an important component in any strategic investment plan. This application will also be illustrated in the Inga case.

A final example of an American option is the *abandonment option*. This tells developers when to *stop* investing in a project. The option analysis reveals when a project's value has fallen past a point of no return, and should be abandoned. However, it can also show investors that sometimes, a project that is no longer making money, may still be more valuable alive than dead (Shockley, 2007). The decision rule for an American option is slightly different than it is for its European counterpart, and can be expressed as follows:

$$MAX[Value\ of\ keeping\ option\ alive, value\ of\ exercising].$$

Compound Options

A compound option is an option for which the underlying asset is itself, an option. Compound options in financial markets usually have two strike prices, and two exercise dates. In fact, using real options, compound options can be options on any series of underlying options. Using a compound options approach makes sense if a project has several phases, each of which is contingent on the previous phase. Again, the calculations are similar, except that the underlying asset becomes the *last* option to be exercised. All other options in the compound chain are valued as options, and not as assets. Still, the analysis can become quite complex, as the values of the options are often interdependent (Shockley, 2007).

Compound options can be used in structured financial arrangements, and in contract situations where participation in an early phase grants the option to participate in later development phases. They can also be used in system-wide applications where continual switching between modes of operation is possible (Shockley, 2007). These, more complex valuation problems, are outside the scope of this dissertation, but would be compelling for additional research applied to switching generation sources for on and off-grid delivery in Africa, as well as other applications.

CHAPTER V

INPUTS AND UNCERTAINTIES

Inputs to the model, some of which are dealt with as project uncertainties, reflect the real-world environment in which the project operates. Results generated by the model are only as good as the reliability of the inputs it receives. Furthermore, some results can be highly sensitive to small movements in the values of certain inputs. Calculations for determining the values of inputs is given in Chapter VI; however, this chapter offers a brief discussion on the inputs themselves, as some are the subject of ongoing debate. First, the three sources of uncertainty for hydropower in Africa: climate, costs, and electricity demand are covered; then a discussion on appropriate discount rates ensues.

Climate Change Uncertainty in Africa

Climate change models display a wide range of uncertainty, particularly around the probabilities of which futures we might expect. The uncertainties are more pronounced when making projections for specific geographies.

These uncertainties notwithstanding, the IPCC has projected certain impacts of climate change for Africa. Specifically, existing stresses on water availability in Africa will likely be amplified. This will influence hydropower production as competition among other water users (agriculture, energy, industry and municipal use) increases. Water resources on the continent experience high variability over space and time, and remain a vital factor in the continent's ongoing economic development. The impacts of climate change will be superimposed onto already water-stressed catchments. The effects will be especially felt in those with complex land uses and engineered water systems (Niang, 2014). Currently observed trends over southern Africa show a reduction in late summer precipitation in western parts, toward the Congo during the second half of the 20th century. The drying is associated with an upward trend in tropical Indian Ocean sea surface temperatures. Modest downward trends in rainfall are found in Botswana, Zimbabwe, and western South Africa. Apart from changes in total or mean summer rainfall, some intra-seasonal characteristics may also be seen. These include a delay of the rainy season and possibly its duration, the frequency of dry spells, and rainfall intensity (Niang, 2014).

The effects on hydropower could be several. The possible shortage of water availability, due to competition of resources, is one effect, as is the variability of precipitation. Another is reservoir evaporation due to higher temperatures; as reservoirs require additional water resources to maintain proper working head levels, hydropower output may fall. Droughts followed by intense rainfall, another climate impact, can also negatively affect hydropower production by creating a silt build-up behind the dam wall. The build-up also reduces working head at the dam, creating a need to dredge the reservoir when levels get too high.

Electricity Demand

Electricity demand outstrips supply in Africa; however, it has recently experienced a slow-down. Even while much of the continent remains unreached by central grid services, several factors have combined to slow growth, and future growth rates are uncertain. Significant factors include low cost-recovery rates, leading to a lack of energy infrastructure investment for the entire electricity value chain. Even as new generation becomes available, development of the transmission and distribution (T&D) network to deliver electricity has lagged.

Low collection rates are common and compounded by the high poverty rates in the region. In certain instances, these high poverty rates also impact tariff pricing which is set below the cost of service, and results in utilities being unable to recover the all-in delivered cost of electricity. The result is that insufficient funds are generated leading to inadequately maintained systems and little incentive for future investment. An example of this type of tariff pricing is found in DRC where tariffs are approximately one tenth of those of other African countries (KPMG, 2016).

Sub-Saharan Africa (SSA) has a current installed generation capacity of approximately 70GW. However, at least 25% is unavailable due to poor infrastructure and maintenance. The World Bank estimates that in the short-term an additional 70GW is required, and that investment of as much as US$ 160 billion is needed, each year, to provide electricity access to the entire region by 2030 (KPMG, 2016). The lack of power infrastructure is proving a bottleneck to growth in the region. More than 30 African countries are now experiencing power shortages leading to either expensive short-term outages or blackouts (KPMG, 2016). Even if generation capacity were adequate, without a proper transmission network, electricity cannot effectively be delivered to different regions within a country or to power pools for trading purposes. A lack of transmission infrastructure is common across SSA countries, many of which suffer from aging and under-built transmission networks. T&D line losses add to the problem as the power delivered to end users is only a fraction of what is generated. Poor distribution infrastructure, damaged power lines, and illegal connections further compound the problems. T&D system decline has become increasingly important as there has been a focus on solving the crisis by merely adding additional generation capacity, without consideration as to if and how, the additional power can be delivered. This leads to problems when new generation facilities are connected to the electricity grids which cannot handle the additional capacity (KPMG, 2016).

Because of these complex energy market dynamics, the model relies on historical consumption, and an elasticity relationship between consumption and price, to determine price volatilities for energy. Historical consumption is calculated from a thirteen-year trend of consumption data for all SAPP nations. Even so, these relationships may vary; as a result, I have included two important aspects. One, the elasticity that relates consumption to price is treated as a random variable (μ=0.3, σ=0.295).[3] Two, a sensitivity analysis of the effect of price on both asset and option valuation has been conducted. Full discussion and results are found in the BGHD case.

Cost Overruns

The difficulties that Ansar et al. (2014) surfaces, suggest that planners tend to take an optimistic view of their projects by focusing estimates on the project under consideration, rather than considering other projects' challenges. This results in an under-projection of time, costs, and benefits. Ansar et al. finds overwhelming evidence that cost estimates are systematically biased below actual costs for large hydropower dams, suggesting that in most countries, large dams are too costly and take too long to build to deliver a positive, risk-adjusted return. Ansar et al. observes that three of every four dams suffered a cost overrun, and that actual costs were 96% higher than estimated costs. Costs more than doubled for 2 of 10 dams, and tripled for 1 in 10. Typical anticipated benefit-to-cost ratios have been 1.4, suggesting that net present benefits outweigh net present costs by 40%. However, nearly half the dams Ansar studied suffered a cost overrun by of 1.4 or greater suggesting that sunk costs would not be recovered. Furthermore, there seems to be little learning that takes place within the industry. Cost overruns have followed the same distribution patterns for decades, and continue today, according to Ansar et al.

The authors suggest two reasons for the optimistic estimations. First, experts and laypersons are systematically too optimistic about the time, costs and benefits of a decision. This "planning fallacy" is well documented, according to Ansar et al., and stems from taking an *inside view* of one's own project, rather than an *outside view*, which would look to others of similar

[3] This mean and standard deviation are for use in a Monte Carlo simulation that draws on value at random for each run of the model. The derivation of the mean and standard deviation is based on several elasticity figures published in Bernstein and Griffin (2006).

breadth for costing and budget expectations. Established psychological biases such as overconfidence and an over-reliance on heuristic measures – like rule-of-thumb estimations - consistently reinforce these errors in actual practice. Second, optimistic judgments are often exacerbated by intentional misrepresentation by promoters. The authors quote literature in infrastructure delivery to say there is strong evidence that misplaced political incentives lead to further flawed decision making. Results from the article place the mean cost overrun for Africa at around 40%, and the standard deviation of all projects under study at 360%.

However, the findings of, Ansar et al., should be placed in context. For example, other infrastructure projects also experience overruns, some of far greater magnitude, according to the report. For example, mean cost overruns for nuclear power are 207%, while thermal plants are 6%. Flyvbjerg, a co-author on the Ansar et al. report, has also extensively studied cost overruns for infrastructure, with a focus on highway development. Flyvbjerg's results for cost overruns are somewhat less severe. When dealing with rail and road projects, the author places average overruns at 51% with a standard deviation of 52% for rail, and 9.5% with standard deviation of 44.3% for road construction. This is a significant reduction in volatility from the 360% found by Ansar et al. for hydropower. In place of the very large volatility figure, I have used 125%.[4] This is an attempt to balance the Ansar findings with other, more extensively researched findings of others, albeit considering other forms of infrastructure.

I have chosen a standard deviation that is much lower, based on balancing Ansar's findings with Flyvbjerg's, less severe findings, presented below (Flyvbjerg, 2005). I have also performed sensitivity analyses for this input. As will be shown in the case studies, project values are highly sensitive to the cost overrun, especially to the standard deviation. The values of the options

[4] Flyvbjerg's analyses have been performed over a much longer time horizon than Ansar's, and so are more heavily weighted in my analysis. I gave a weight of 25% to Ansar's standard deviation number and 37.5% to each of Flyvbjerg's figures.

themselves are also sensitive to the standard deviation of cost overruns, though not as significantly so.

Discount Rate

The rate selected for discounting future revenues to present day values will depend on the perspective of the entity doing the analysis. Private financial firms, looking to invest in public infrastructure for profit, will likely choose a higher discount rate than a government seeking the maximum economic benefit. The difference lies in the contrasts between financial and economic analysis, and in what values are being compared. A small difference in rates can lead to a big difference in priorities. For example, Nordhaus' (Nordhaus, 2007) review of Stern (Stern, 2007), claims the very low discount rates used in *The Stern Review on the Economics of Climate Change*, lead to overly radical adjustments. This section discusses 1) the impact of discount rates on project and option values, 2) the philosophical difference between financial and economic analysis, and 3) summarizes Nordhaus' critique of Stern's use of discounting. The differences in opinion and perspective have significant impact on the level of attractiveness for private funders to be involved in public projects. These issues are not solved in this dissertation; it is simply my intention to highlight some of the discussion.

The Impact of Discount Rate Selection. The *value of the option,* on flexible designs under study, is not directly impacted by the discount rate, as that rate does not appear in the option valuation calculations. However, there is an impact on the valuation of the future project, and this figure directly determines the value of the payout function. The chosen discount rate does directly impact the ENPVs of each of the *projects*. In the climate change literature, a very low discount rate is often advocated, sometimes as low as 1% or 0.5%. This practice places the future value of money at nearly equivalent to the present value, resulting in very high NPVs for projects, all else equal. By contrast, private investors will use a higher discount rate, as the rate will reflect possible returns from competing investment opportunities. As an example, JP Morgan suggests a range of 15%-25% for infrastructure projects in non-OECD nations (Kohn, 2007). Finally, when considering development projects, the World Bank uses a formulation based on anticipated economic growth within the country. For much of Africa, growth is expected to be 3% per year in the near-term; and rate calculus yields a discount rate of 6%. For my baseline analysis, I have chosen the World Bank rate of 6% for Africa.[5]

Risk-Free Rates. A related concept is the time-value of money, which acts as the theoretical rate of return on an investment with zero risk. This rate would be required by any investor to place her money in an absolutely, risk-free investment. In practice, however, the risk-free rate does not exist because even the safest investments carry a very small amount of risk. The U.S. bond rate is often used, since this is considered a nearly risk-free asset and is available in world markets (Investopedia, 2017). During the period in which I am building the model, this figure is 1.75%. A risk-free rate is not used in discounting project values, but it is in valuing options; therefore, the rate chosen can have a significant effect on the option values.[6]

Financial vs. Economic Perspective. The discussion of discount rates surfaces the distinction between *financial* and *economic* analyses. The financial appraisal of a project views investment decisions from the perspective of a firm – in the case of a project, the firm would be the project's ownership. It assesses the viability of a project based on the anticipated cash flows to that project, and eventually to the firm. The primary considerations will be whether the anticipated

[5] The World Bank makes use of the famous Ramsey equation to assess a social discount rate (Ramsey 1928). This equation: $r = \rho + \sigma g$; where r is the equilibrium real return on capital, ρ is the time discount rate applied to different generations, α is the population, and g is a constant rate of growth of consumption per generation. Use of the equation for World Bank discounting practices is discussed in Fay and Hallegatte (2016). The equation is discussed in Nordhaus (2007)

[6] Option valuation is based on constricting a *tracking portfolio* to mimic the value of option. The tracking portfolio is developed using a combination of risk-free bonds, and shares of an aggregate market index fund. The conditional mean of the tracking portfolio is set to the expected cash flow of the option payouts. For an excellent discussion see Shockley (2006), Chapter 2.

revenues will be sufficient to cover the expenditures of the project, and return a profit to the firm. Included in the expenditures will be the firm's cost of capital, or the opportunity cost of capital (the anticipated return on other available investments). If cash inflows of revenue exceed the cash outflows of expenditures the firm anticipates the project will be "commercially viable" (Hamburg University, 2010). By contrast, the *economic* analysis of a project comes from a different perspective, and is more comprehensive. In addition to a project-specific due diligence, an economic appraisal considers the external benefits and costs of the project as well as the project's impact on a broad set of stakeholders. When the analysis is accomplished from the perspective of a government, the benefits accrued to society at large, will be contrasted with the society's incurred costs. Economic analyses attempt to answer the question of whether society will be better or worse off after undertaking the investment. Because of the differences in perspective, financial and economic appraisals are different; it will not always be the case that a financially viable project will also be economically viable, nor that an economically viable one will necessarily be financially profitable. However, the two analyses can also be complementary. Some may argue that for a project to be economically viable, it must be financially sustainable; if it is not, there will be no adequate funds to properly operate, maintain and replace assets. On the other hand, many projects that have been deemed economically beneficial, can be supported financially by government subsidies of various kinds, obviating the need for project-specific returns (Hamburg University, 2010).

Discounting and Climate Change. According to Nordhaus, discounting involves two related, but often confused concepts. The first is the idea of a discount rate on goods (including money), the second is a discount concept that involves "the relative weight of the economic welfare of different generations over time;" it is also called the "pure rate of social time preference" or “time-discount rate” for short. The *discount rate on goods* measures the relative price of goods at different points in time, and directly relates to concepts such as real return on capital, real interest rates, opportunity costs of capital, and real returns. For example, real returns measure the yield on investments corrected by the change in overall price level, a concept that is observable in the marketplace through the returns of various assets including bonds and corporate stocks (Nordhaus, 2007). By contrast the *time-discount rate* refers to a change in future welfare, rather than the value of goods or money. Nordhaus writes that a very low time discount rate means that the welfare of “future generations is treated symmetrically with present generations.” Any discounting that takes place will assign a higher value to present generations. Stern contends that it is indefensible to place a higher value on present generations over future ones (Nordhaus, 2007). His position is based on the idea that higher discount rates would lead present generations to ignore investments that pay off only in the long term. However, Nordhaus argues that we must “look carefully at the returns on alternative investments – at the real interest rate – as the benchmark for climatic investments.” The reason is that time-discount rates, as suggested by Stern, are irrelevant for use in actual financial and capital markets. Therefore, they are not useful as countries weigh their self-interest in international bargains about emissions reductions. Instead, nations will look to compare *actual* gains from competing investment concepts, including any international emissions deal making.

To illustrate these differences and the impacts on option and project value, I include two discount rate scenarios in the Batoka case study, to test whether the choice of project changes. Specifically, I create a scenario using a rate of 15%, and another using a rate of 1%. When using the higher rate, I find that the electricity price must increase significantly for the project to be profitable, and that the higher rate does shift the design selection to a smaller, less expensive design, that includes optionality. The reason for this shift is that a high discount rate is “skeptical” of long-range cash flows, and gives a higher weight to cash flows in the short term. Since much of the short-term cash flow is negative, due to construction costs, more expensive projects are less appealing. The opposite is true for the lower rate. The more expensive larger projects, with bigger cash flows well in to the future, are favored under this regime. In addition to the two rate scenarios, a sensitivity analysis is performed to measure the sensitivity of both option values and project values to discount rates and risk free rates. Results are discussed in the BGHD case study.

CHAPTER VI

METHODOLOGY: VALUING FLEXIBLE DESIGN

A ROA for valuing flexibility, involves three broad steps: 1) framing the application, 2) gathering the inputs, and 3) calculating the option (Amram & Kulatilaka, 1999). The first step is to frame the application. The process involves gathering basic information about the project and how it is to be managed, and includes recording the answers questions about how the real options framework is being applied to the problem at hand. The *application frame* should include a list of stakeholders, the mechanism for decision making and a decision rule, sources of uncertainty, flexibility candidates, any leakages in value, and should define the underlying asset. The second step is to gather the inputs. There are relatively few inputs required for a real option analysis. They include the volatility of key uncertainties, the expected NPV of the underlying asset, an appropriate discount rate, and a risk-free rate of return. Some of the inputs can be gathered from markets, but others must be modeled, which is the case of some in this dissertation. The third and final step is to calculate the option. There are several ways to calculate the value of an option. These include using the Black-Scholes equation, a Monte Carlo calculator (which I employ below to measure risk), or some type of lattice model. This dissertation primarily uses a binomial-style lattice model for option valuation, though the Black-Scholes equation is also employed (this is a form of the partial derivative approach to option value calculation, a subject outside the scope of this research).

Step 1: Frame the Application

Every project is a story of sorts; the frame of the real options analysis attempts to identify the most foundational elements of that story. Specifically, all projects feature a group of stakeholders including sponsors, planners, investors/owners, developers, and clients/benefactors. Ideally, the exercise of framing the application would take place with all stakeholders represented in some way. Additionally, all projects involve the development of an asset, with unique properties and characteristics. The asset presumably offers a service, and from that service, revenues will be generated. Revenues are set against costs, the difference of which drives value. This section, framing the application, discusses the basic elements of the project's story: stakeholders, the decision-making structure, project uncertainties, value leakage, and the underlying asset.

The Stakeholders. Stakeholders will often have differing agendas and priorities for the project. The group will include government personnel, private investors, and project managers, among others.

The Decision. The second aspect of the project frame consists of the decision-making structure of the project. This defines the who, what, when, why and how of the decisions regarding the project. It includes, but is not limited to the following questions:

- What is the project, and why is it being developed? The answer is not trivial. For example, a power plant for the purposes of revenue generation will have a different profile than one developed strictly to meet unmet demand. In the first instance the highest electricity price might be sought, whereas in the second, prices may be subsidized. The two instances will differ significantly in their revenue profiles.
- What are the possible decisions regarding investment strategy; especially, what are the flexibility candidates (the points where the project can be altered)?
- Who will be making the decisions?
- When will the decisions be made?
- How will the decision be made?

The last question is likely the most important; it involves the selection of a *decision rule*, a criterion that triggers one choice over another. The decision rule is a statement specifying the criterion (or criteria) that will be used to determine if, and when, the option will be exercised. The decision to exercise the option and enact the flexibility, could be based on cash flows, the market price of an output, the project's value at a point in time (such as the exercise date), or another metric. The decision rules for the case studies in this dissertation, are primarily the project's value. While this does introduce some difficulty, namely that the project must be valued at regular intervals, this is a common approach found in the literature – especially when option pricing is used as a decision-making tool. If, at the decision point, the value of the project has reach a predetermined point, where future value exceeds the cost of further investment, the decision to exercise the option will be made.

Uncertainties. The second part of the *application frame* is to identify the sources of uncertainty. Uncertainties exist all around us; but, when they may negatively affect the efficiency or effectiveness of a project, they become risks. There is a difference between the sources of uncertainty for financial options, and for real options. When working with financial options, uncertainties are accounted for in the market price of the underlying asset (the stock). Working with real options, things are more challenging. Real assets often have several sources of uncertainty, which can be reflected in two categories of risks: market and private.

Market risk is priced into a market price, and can generally be quantified through some observable market trend. Private risk is project specific, and can be more difficult to model. In the case of a hydropower facility in Africa, demand risk is an example of market-priced risk; demand for electricity is embedded into consumption growth, and is observable as new customers purchase power. One can track the consumption growth of electricity in Southern Africa and assume that the risk for power reaching the demand centers, and being paid for, is generally implicit in that consumption. By contrast, neither the cost of the specific project, nor the specific production level at a site is contained in the market price for electricity. These are project-specific risks and fall in to the category of private risk. Since they cannot be observed in the market, these require special modeling.

Value Leakage. The third part of the *application frame* is the identification of potential value leakage. Physical assets can lose value over time, affecting project returns. This is called value leakage. Examples of value leakage are operation and maintenance costs (O&M), convenience yields, storage costs, a competitor's entrance into the market, etc. Any leakage that accrues before the exercise date of the option, must be accounted for in the model. For a hydropower facility, examples could be the erosion of production capacity through poor maintenance, siltation buildup behind a dam wall that lowers the working head, or declining capacity factor. In the case studies below, an operation and maintenance cost is subtracted from revenues. This, plus a tax rate, are the only value leakages that are modeled.

Identify the Underlying Asset. The fourth part of the *application frame* is to identify the underlying asset. The underlying asset is what one receives upon exercising the option. In cases of flexible design, it will be the incremental cash flows of the upgraded design, if the option to expand is taken. In many cases, financial markets, or productive assets that are similar to the one being considered, can be used to model the value of the underlying. For example, the revenues of another large dam on the same river, with similar attributes could be used for a hydropower facility. In this case, the hydropower output has been modeled, using actual design parameters, and projected river flows, even though production has yet to begin. The value of the underlying asset is based on the anticipated performance of the dam.

Step 2: Gather the Inputs

Define the Inputs. The inputs for an RO valuation of flexible design at a hydropower facility are relatively few. Some are available from the NPV calculations for a project. Others must be calculated using processes outlined below. The table shows what inputs are needed, and my process for securing them.

Table 3: Inputs for Option Calculator

Inputs Required for Options Calculator	
Volatility of key uncertainties	Observed in markets or modeled
Volatility of output due to climate change	Modeled in WEAP & from CMI[7]
Volatility of demand	Modeled based on consumption changes
Volatility of cost overruns	Modeled based on literature
Current value of the underlying asset	Calculated from revenue model
Discount rate	Cost of capital, or official World Bank rate
Risk-free rate of return	U.S. government bond

First, key uncertainties for a hydropower facility in a Sub-Saharan African context were defined; these are climate change effects on river flow, electricity demand, and cost overruns. Next, the volatilities for these uncertainties were modeled (the measure for volatility is the standard deviation of the annual log changes of the parameter). In the case of climate change effects on river flow, the WEAP hydrologic model was employed, which was combined with a Monte Carlo simulation for Inga. In the case of electricity demand, the only market-priced risk of the three, actual consumption has been used as a proxy; and, price volatility was derived from consumption growth rates through a Monte Carlo analysis. To determine cost overrun volatility, studies from Ansar et al., (2014) and Flvybjerg (2011) were used. Further details about the parameters are given

[7] CMI is the Climate Moisture Index, a measure of aridity, which closely correlates to river flow and hydropower output, see Cervigni (2015), 72.

in the case studies, and a lengthy discussion of the methodology summarized above is offered below.

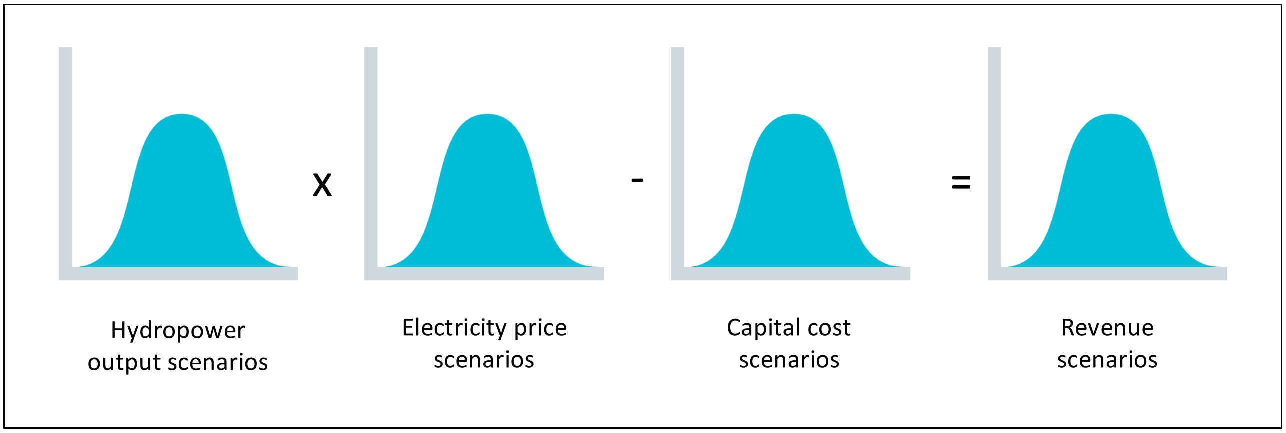
Second, the current value of the underlying asset is required. The underlying asset is always what one receives if the option is exercised. For flexible design alternatives, the underlying asset is the incremental cash flows from the augmented facility, or the next aspect developed in a phased design. The current value of those incremental cash flows is equal to the sum of the cash flows, discounted to present time. Note that this is the Present Value (PV), not the Net Present Value (NPV). The capital cost normally subtracted to determine NPV is the strike price, and will be duly considered in the valuation.

Third, a discount rate must be chosen. The World Bank recommends a social discount rate of 6% for African development projects, in countries where expected growth rates are 3%. According to Trading Economics (2017) this is a reasonable expectation for the economies of Zambia, and Zimbabwe.

Fourth, a risk-free rate must be chosen. The literature for real options calculations, indicates that the yield for U.S. bonds of a similar duration to the project at hand, is chosen (Amram & Kulatilaka, 1999).

As discussed earlier, the uncertainties are expressed as probability distribution functions, meaning that scenarios created to reflect hydropower output are randomly matched with scenarios of electricity growth paths, and cost overrun scenarios. The model is recalculated many times to ensure that the draws are sufficient in number to secure a meaningful expected value.

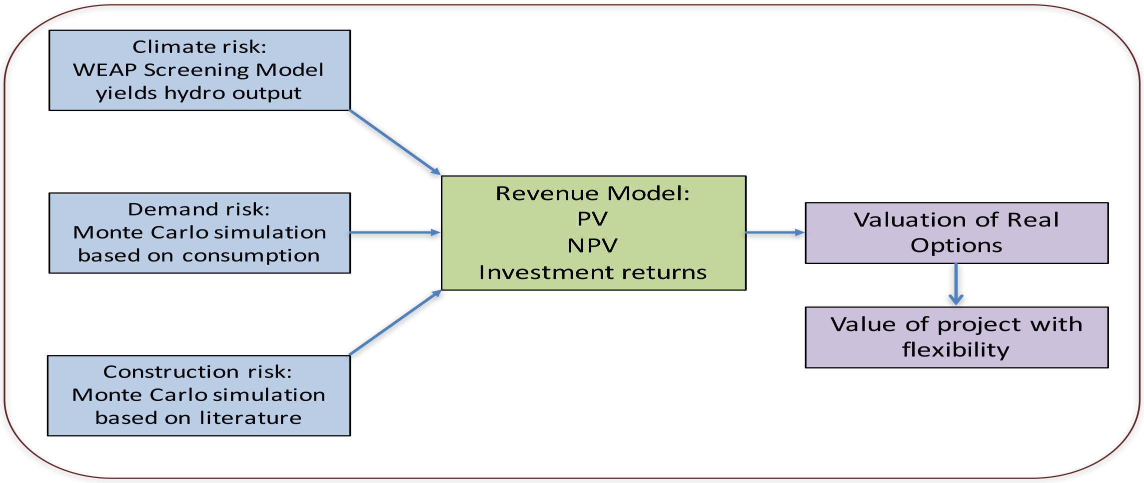
Figure 5: Interaction of PDFs in Model

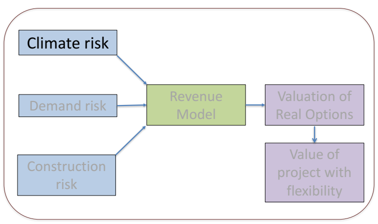


From the revenue scenarios, NPV scenarios are determined, as are return on investment scenarios. These also are expressed as a probability distribution function. The mean value for each, is the expected value. This concludes the definition of inputs required. The next section describes how to model the inputs.

Model the Inputs. This section discusses the quantitative steps taken to determine the volatility and impact of each of the uncertainties. First, it outlines the process used to project hydropower output under climate change. Second, it describes the modeling process for demand uncertainty and anticipated energy prices. Third, it discusses the construction of cost models for the various design candidates to be considered, both static and flexible design candidates. The points of flexibility create the options for future decisions at the site. Once the uncertainties are modeled and integrated, the revenue model and construction of a binomial tree for option valuation can be discussed. Figure 6 is a schematic of the process.

Figure 6: Model Schematic

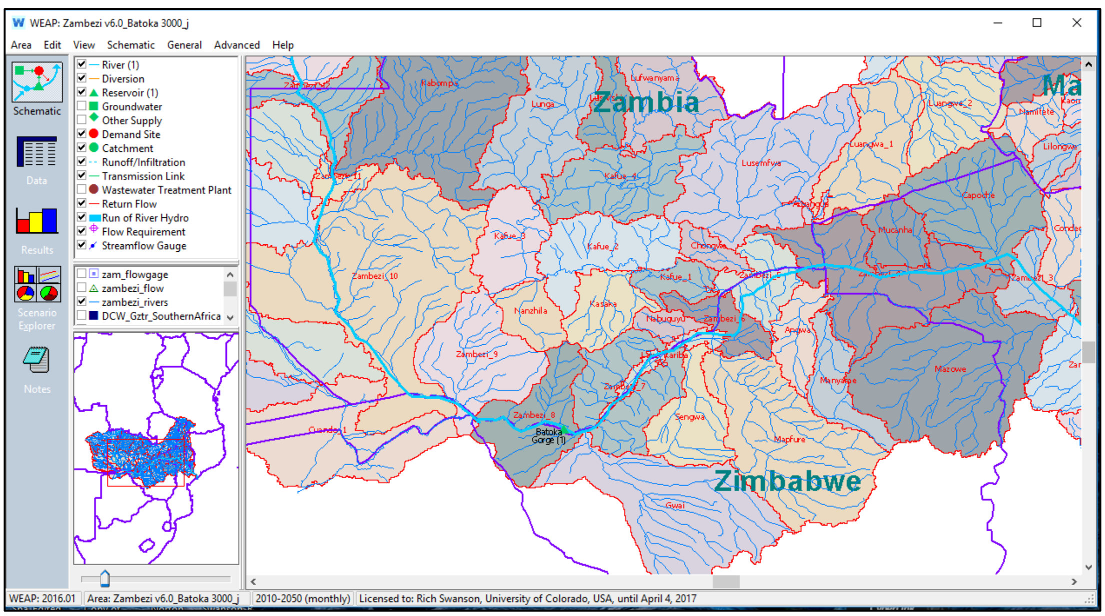




Model Climate Risk. Climate risk is embodied in the variability of river flows, and how flows translate to hydropower. Electricity at hydropower sites is generated by water flowing through a hydraulic turbine. The turbine converts the kinetic energy of flowing water into mechanical energy. In turn, a hydroelectric generator converts the mechanical energy into electricity (USGS, 2016). The flow of water is critical to the electricity that is available to sell into the market. Low flows therefore place revenues at risk, just as higher flows can increase revenues, *if* there is available capacity at the facility. Climate uncertainty becomes a risk for hydropower plant owners if climate change threatens to reduce flows at the site, curtailing revenues. To incorporate this volatility into a cash flow projection and revenue model, a hydrologic model is first used to calculate the electricity output generated from a series of flows at the site.

The WEAP model[8] is used as a hydrological model. WEAP assesses possible hydropower output under all the river flow scenarios. The flow scenarios are generated by possible (future) temperature and precipitation patterns; these are referred to as “climates”. First, a “screening model” is created using the WEAP modeling tool. Data inputs for WEAP include river flow, precipitation, temperature.[9] The specifications for hydropower facilities at the sites under study are also inputs; these include head, turbine capacity, elevation curve, plant factor, and an efficiency coefficient. Industry experts have been interviewed to determine the best flexibility-candidates for the structure.[10] Various dam construction specifications were used, to model the different configurations of the site. A table of the WEAP inputs is available in the Annexes for each case study.

Figure 7: Screenshot of WEAP Interface: Zambezi River, BGHD



[8] The hydrological and water balance model applied for the case study model is the Water Evaluation and Planning system, or WEAP, (www.weap21.org). WEAP is a globally available model developed by the Stockholm Environment Institute (SEI) and improved over the course of over 20 years. There are currently of 10,000 registered users on the WEAP user forum, located in over 170 countries. WEAP integrates climate-driven inputs (temperature and precipitation data) for estimating streamflow. A very simple screening model was used, taking streamflow output from a previous study (World Bank 2015), to generate hydropower outputs for each facility.
[9] WEAP can also consider competing demands, though no other demands were considered in this study; the data used incorporated all upstream withdrawals. Please see Appendixes 3 and 4.
[10] Alan Bates, a hydropower cost-estimator was interviewed multiple times to determine the best flexibility candidates for the Batoka project.

Second, hydropower generation was then computed in the model using the working head on the turbine and constrained by the maximum turbine flow and the plant's operation and efficiency, according to the following equation:

$$HP = 9.806 \times Q \times H \times e \tag{7}$$

Where *HP* = hydropower output; *Q* = flow; *H* = head; *e* = efficiency factor (plant factor, operating efficiency); and *9.806* is the gravity coefficient.

WEAP models for both case studies were developed. The first is the Batoka Gorge Dam on the Zambezi River, along the border of Zimbabwe and Zambia. The second is the Inga Dam on the Congo River in Democratic Republic of Congo (DRC).

At Batoka, three designs were built into the model to represent the construction configurations now being evaluated. These include a 1600 MW, a 2400 MW, and a 3000 MW facility. For each configuration, the model generates multiple vectors of hydropower generation, one for each climate scenario.

The Zambezi is subject to significant variability in flow at Batoka Gorge, yielding a range of hydropower production possibilities. Future precipitation and temperature (P&T) levels have been modeled for Africa, at MIT, using the Integrated Global System Modeling Framework[11] (IGSM). To model the impacts of climate on flows at Batoka, a baseline flow is developed using historical data; then P&T projections are added to the baseline to represent the possible future climates the basin might face. In total, 800 such projected futures have been created, broken in to two policy futures: a *no policy future*, and a *policy future*. This is an important step, as part of the uncertainty around climate change revolves around policy.

[11] The IGSM Framework can be found here: http://globalchange.mit.edu/research/IGSM.

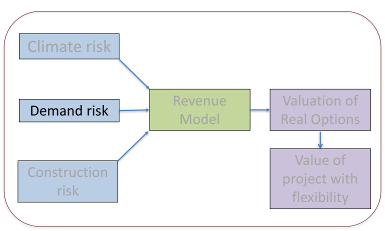
The *no climate policy* future assumes that no significant mitigation strategy is introduced by the end of the century, resulting in a business as usual emissions release, or an "unconstrained emissions" scenario. Under this scenario, 400 possible futures emerge, based on 400 projected P&T patterns. The actual projections are drawn from the IGSM results of Sokolov et al. (2009), who considers a no-policy climate scenario, where human emissions are left unconstrained; one result is higher levels of uncertainty in the impacts.

The *policy future* assumes that a full range of mitigation steps have been taken to curb greenhouse gas emissions over the next 40 years, with the result that carbon emissions growth slows during the century. Correspondingly, the impacts of climate change begin to curtail during the century. P&T projections for a *policy future* are also IGSM results (and include 400 such future patterns), but from a significant climate policy scenario called the "level 2 stabilization," or L2 (Sokolov et al., 2009). This projection anticipates a 660 ppm CO2-equivalent stabilization target at 2100. The result is that climate change impacts taper off over time.

An expected hydropower output is finally calculated for each phase of the build out. Hydropower output is modeled for all 800 climate change scenarios (400 under *no policy*, and 400 under *policy*). This yields a probability distribution function showing the full range of possible hydropower outputs for of Inga's phases. Finally, a probability is given to the *no policy* and *policy* futures. For the purposes of this study, a 50% chance of achieving a carbon-mitigating policy framework was chosen, meaning each broad scenario was equally likely. The result is 400 pathways of expected hydropower production; one for each climate scenario. WEAP output can be displayed in a variety of ways; a unit of kWh was selected for this exercise.

At Inga, the model was designed around the phased construction now proposed for the site. Inga I and II are built, and now Inga III is being considered after a long delay. Inga IV-VII are also long-range possibilities. To develop the model, I focus on the next three phases, called A, B, and C, which are fully described in the case study.

The Congo River basin includes catchments from above and below the equator, and therefore enjoys two rainy seasons each year; therefore, it is not anticipated to be significantly impacted by climate. To endeavor an alternative method for developing pdfs for hydropower output, the data of the ECRAI report for the Congo River basin were used to project hydropower output at Inga. Six climates, spanning from wet to dry, were imported as precipitation and temperature files into WEAP, producing a distribution of hydropower outputs for each of the phases at Inga (Boehlert et al., 2015). The moments from that distribution were used to create a Monte Carlo simulation of 400 possible future output pathways at Inga, beginning with values from AECON (2011). Additional detail for this process is given in the Inga case study.



Model Energy Demand, Uncertainty, and Electricity Prices. The next step is to model energy demand, and its uncertainty, along different pathways of development for Africa. This is accomplished by using a Monte Carlo simulation. Electricity consumption was used as a proxy measurement for demand, as consumption growth rates include the growth rates of delivery system infrastructure such as transmission and distribution. First, actual electricity consumption from the SAPP region is recorded, for a period of 13 years, from 2001 to 2013.[12] From these data annual growth rates for the period were calculated. Using the mean and standard deviation of the growth

[12] The source of the data is the World Bank Data Tables: http://data.worldbank.org/indicator/EG.USE.ELEC.KH.PC. No data were available for Lesotho or Malawi; nor were data available for a longer period.

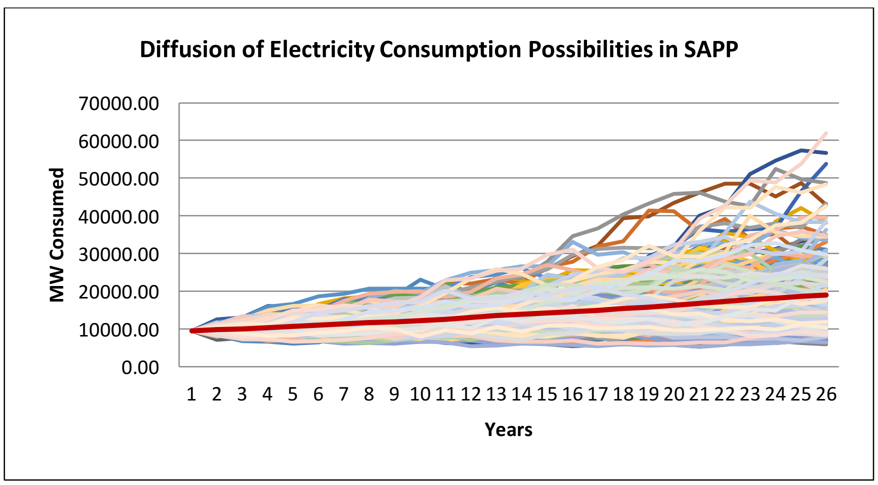
rates, 400 random samples of 25-year growth paths were generated. The growth rates were multiplied by today's average South African Power Pool electricity consumption to produce a distribution of possible consumption over 25 years.

$$C_1 = C_0 * e^{g_t} \tag{8}$$

$$g_t = m * \Delta t + (\sigma * \xi) * \sqrt{\Delta t} \tag{9}$$

Where C_0 and C_t are consumption at time 0 and t respectively, $e = 2.71828\ldots$, g_t is the growth rate at time t; m is the mean of log growth rates, σ is the standard deviation of log growth rates, Δt is the time slice, and ξ is a random coefficient ~N (0,1), generated from the RAND() function in Excel.

Figure 8: Results of Diffusion Modeling for Electricity Consumption in SAPP



**Red is expected value*

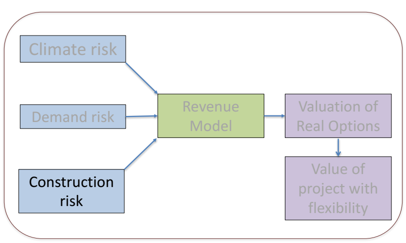
From consumption growth projections, an electricity price projection can be derived based on consumption-price elasticities. Year on year changes in consumption for each pathway are used to calculate an expected change factor for the electricity price, using elasticities from the literature. The starting price for 2016 is an input, which is the average wholesale price for the appropriate market. Several studies have shown that the price elasticity of electricity is small in the short-term.

Bernstein and Griffin place short-term elasticity within a range of 0.17 - 0.25 (Bernstein and Griffin, 2006). The principle of elasticity can be used to calculate changes in price over time, based on the projected consumption pathways.

$$\Delta\%P = \Delta\%C * \varepsilon \tag{10}$$

Where *Δ%P* is the percentage change in price, *Δ%C* is the percentage change in consumption, and ε is the price elasticity of demand for electricity, a constant for this analysis, and based on the literature (Bernstein and Griffin 2006). Please see the table of parameters in the case study sections for the specific values used to develop the cases.

Plugging the SAPP consumption deltas for Δ%C, in to the formula yields a Δ%P value for each year in the model. This, an annual change in electricity price, allows for the calculation of a projected retail electricity price for each year along all 400 pathways, beginning with the starting electricity price (see parameters).



Model Construction Risks and Costs. The cost model builds out the anticipated costs of the project and risks of cost overrun. The costs of each design possibility must be considered independently. For Inga, the cost for each phase is available in the literature (AECON, 2011). At Batoka, the build-out possibilities are based on the candidate flexibilities discussed above, and include number of turbines, penstocks and the size of some civil works. Three design alternatives have been, or are being, considered: a 1600 MW, a 2400 MW, and a 3000 MW facility. To value flexibility in design, the costs of alternatives that include certain civil works built into the original design are modeled, as are the costs to upgrade the original design to a larger facility. The detailed specifications are discussed in the case studies, and the cost worksheets are provided in the Annex.

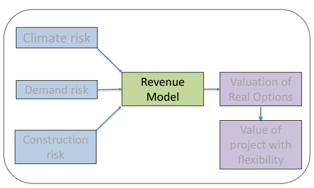
There are no feasibility studies for Batoka Gorge dam available for public review, though there are some indications of certain items such as volume of concrete required for the dam, lengths of penstocks, and number of turbines. In the absence of a feasibility study, I have created a 140-line cost estimation for the baseline 1600 MW design based on data found in the literature (Environmental Resources Management, 2015).[13] These data include feasibility estimates from two other hydropower dams built in Africa: 1) the Karadobi Dam on the Blue Nile, a 1600 MW facility; and, 2) the Mepanda Uncua on the Zambezi, a 1300 MW facility, from which a full cost estimate was obtained (Bates 2016). The costs of these facilities provided guidelines for calculating the information missing from the Batoka project. Figures from these existing assessments, and the known specifications from Batoka, allowed for the development of an estimate, reflecting the 1600 MW version of Batoka. This was considered a baseline. From this baseline costs were added to provide flexible design and to augment the facility. Flexible design costs include increasing the civil works of some aspects, but do not include other more expensive items such as turbines and penstock steel. These investments would be saved for later when the options to expand are exercised. The additional costs to exercise the expansion options are considered the *strike price* for the option. There are many ways to include flexibility into hydropower design. Based on other best-practice in Africa, I have chosen one primary method, that of expanding the power house by adding turbines. Other possibilities could be several penstock levels, to accommodate low flow, or pumps for re-filling the reservoir during non-peak hours.

[13] The estimates have been reviewed by professional cost estimator Alan Bates, former Technical Director at Knight Piesold and Scott Wilson Consultants, June 30, 2016.

The final step in cost estimation is to include the uncertainty of cost overruns. To model this risk factor, a Monte Carlo simulation is performed using cost overrun analysis from the literature. Ansar et al., (2013) indicate construction overruns for hydropower in Africa and a standard deviation.[14] In this case, the volatility is added to the right side of the distribution function, since cost overruns cannot fall below zero (Shockley, 2006). The Monte Carlo formulation is (K = capital cost):

$$K_t = K_0 * e^{(\mu+0.5(\sigma*\xi))} \tag{11}$$

The initial capital costs of building the facility are modeled in this fashion. The costs of operation and maintenance are also assumed to be subject to this variability, and therefore to fluctuate with the fixed costs, at a fixed percentage of capital costs (see parameters).



Model Revenue. The revenue model projects the anticipated revenues for each configuration of the project, arriving at an expected NPV. This step combines the hydropower output with the sales price of electricity, and subtracts the costs, to create a revenue model. To estimate revenues for the Inga project, the 400 pathways of hydropower output are multiplied by the 400-possible retail electricity price outcomes, both generated in the Monte Carlo analyses above. The result is a distribution of 400 possible revenue pathways for each design possibility, which incorporates climate and demand risks. Cash flows are discounted at the discount rate per the previous discussion. Finally, the simulated initial capital costs (also discounted over an

[14] Ansar finds the average cost overrun in Africa is about 37.5% and the standard deviation 360%.

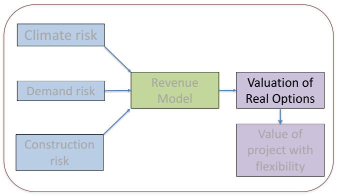
assumed 5-year build time) are subtracted from each pathway to generate 400 present values (PV) and net-present values (NPVs) for each design. This final step incorporates cost-overrun risk.

Outputs from this process are required to calculate the value of optionality. The expected NPV of the project is calculated for 20 years of operation plus a five-year build period. The continually compounded rate of return is calculated based on the expected revenues.

$$r = \frac{1}{t} * \ln\left(\frac{net\ cashflows}{capital\ costs}\right) \tag{12}$$

Reviewing the Inputs. As a review of the inputs, power output at the dam is calculated under a series of water flow projections. The power output is then multiplied by the anticipated market electricity price to calculate gross revenues for the facility per year. If there are other revenue sources, they must be added as well (there are no other revenue sources at the locations under study here). Then, annual operation and maintenance costs, are subtracted during the appropriate years of construction and operation, to yield net revenue per year. The annual net revenues are discounted over the period in question, and fixed capital costs are subtracted to yield a net present value (NPV) of a static design.

Present Value of the Underlying Asset. To get the EPV of the underlying asset, the present value of the incremental cash flows of the augmented design is required. This is the difference between the value of the cash flows already being realized at the facility, and the new, increased cash flows possibly available from a larger design. To calculate this input, the ENPV of the original flexible design, is subtracted from the PV of the augmented design. Note that the incremental cash flows must be discounted all the way back to the present day, but the new investment costs will be subtracted when the value of the option itself is calculate, in a subsequent step. The present value of the underlying asset is the final input required before moving on to the final step of calculating the option.

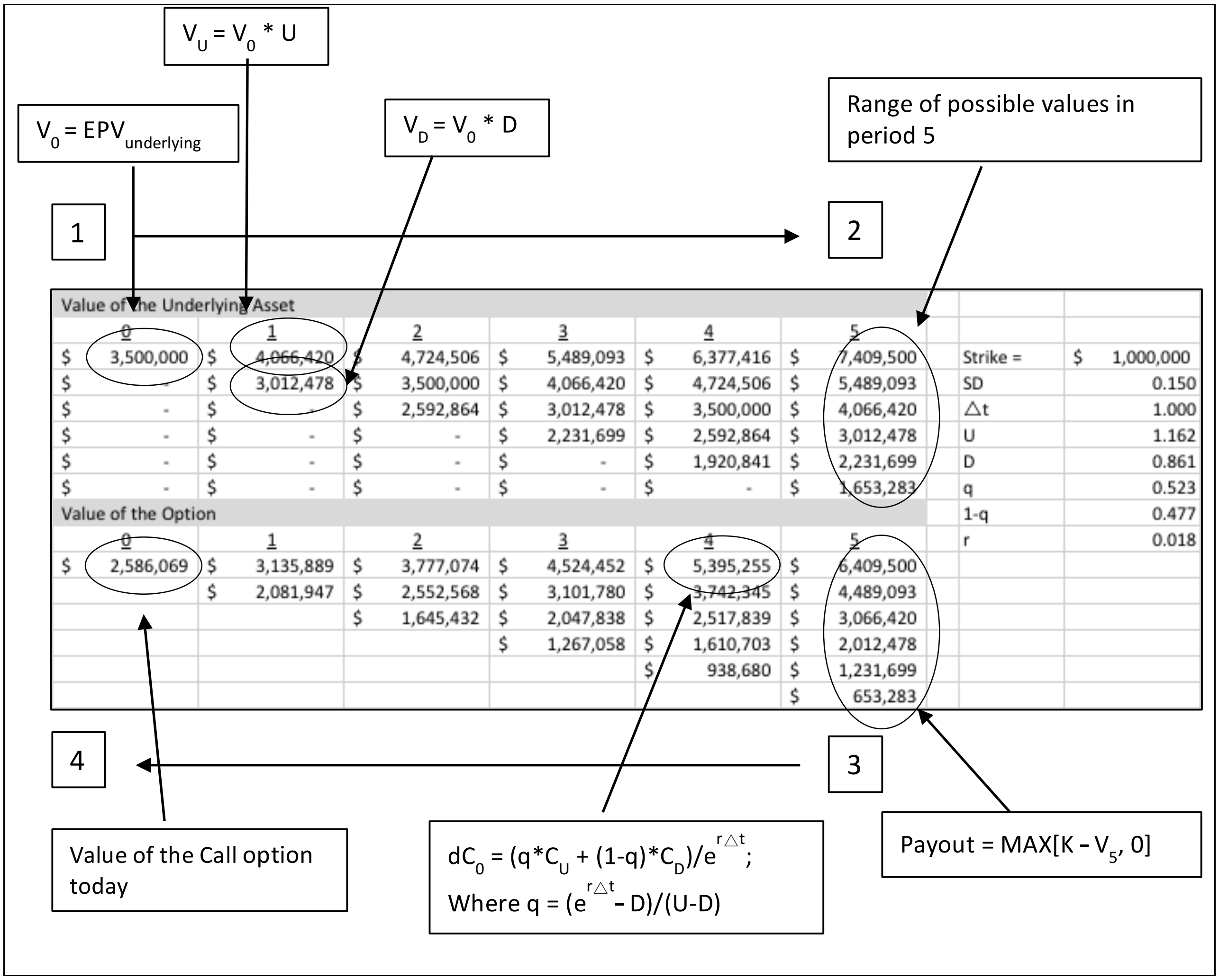


Step 3: Calculate the Option

The "option calculator" is used to determine the value, or price, of the option. This step determines the present values of all the options embedded in each design. These are the values of flexibility-in-design. The value of the option represents the "market value" of the right, but not the obligation, to act in the future. There are several ways to calculate the value of an option; these include the use of partial derivatives, and Monte Carlo processes. However, the most common and accessible approach is through the construction of a binomial lattice, or "tree." This is the method outlined below, and used in this dissertation.

Two interrelated binomial trees are created. The first tree models the value of the underlying asset; this is what one receives when the option is exercised. The second tree models the value of the option, that is based on the value of the underlying asset. One first creates a binomial tree of values to simulate the value of the underlying asset (steps 1 & 2 below), this process begins with the present value of the asset, and moves forward through time. Second, one calculates the payoff of the option, if it is exercised, by moving backward through time (step 3 & 4 below). This step begins at the end of the time-period by determining the payoff of the option during the year when the option can be exercised, and proceeds by discounting backwards through the tree, to arrive at a current value.

Figure 9: Option Calculator Process



Value of the Underlying Asset							
0	1	2	3	4	5		
$ 3,500,000	$ 4,066,420	$ 4,724,506	$ 5,489,093	$ 6,377,416	$ 7,409,500	Strike =	$ 1,000,000
$ -	$ 3,012,478	$ 3,500,000	$ 4,066,420	$ 4,724,506	$ 5,489,093	SD	0.150
$ -	$ -	$ 2,592,864	$ 3,012,478	$ 3,500,000	$ 4,066,420	△t	1.000
$ -	$ -	$ -	$ 2,231,699	$ 2,592,864	$ 3,012,478	U	1.162
$ -	$ -	$ -	$ -	$ 1,920,841	$ 2,231,699	D	0.861
$ -	$ -	$ -	$ -	$ -	$ 1,653,283	q	0.523
Value of the Option						1-q	0.477
0	1	2	3	4	5	r	0.018
$ 2,586,069	$ 3,135,889	$ 3,777,074	$ 4,524,452	$ 5,395,255	$ 6,409,500		
	$ 2,081,947	$ 2,552,568	$ 3,101,780	$ 3,742,345	$ 4,489,093		
		$ 1,645,432	$ 2,047,838	$ 2,517,839	$ 3,066,420		
			$ 1,267,058	$ 1,610,703	$ 2,012,478		
				$ 938,680	$ 1,231,699		
					$ 653,283		

In the diagram, the first value of the underlying asset is $3,500,000, at time $t = 0$. The value of the asset can then move up or down according to the formulation discussed below. The values of the option payouts are given in the lower half of the table, beginning with the end-of-period payout at time $t = 5$. The valuation to present day then moves backward from step 3 to step 4. On the right side of the table, the inputs are given.

- *Strike*: the investment required to exercise the option
- *SD*: the standard deviation of log returns on the underlying asset (calculations shown below)

- *Δt*: the time steps in the period (*Δt = T/number of time steps, where T is the life of the option*)
- *U and D*: the up and down step multiplier, as calculated below
- *q and (1-q):* the risk-neutral probabilities of the up and down steps
- *r*: the risk-free interest rate

Value the Underlying Asset. The first binomial tree begins with the initial value of the underlying asset on which the option is based. This is the *present value* of what one receives if one exercises the option. In the case studies, the initial value of the underlying asset will be the present value of either the next facility at Inga, or the incremental cash flows from an upgraded project at Batoka Gorge. So, step one is to calculate the present value of the additional cash flows available if the option is exercised.

From this initial value, the value of future time periods are modeled through a binomial process. To create the binomial tree, an assumption is made that, during each time-period, the asset can increase or decrease in value. The amount and probability of the up or down step is calculated by the following formulas, where the standard deviation is that of the projected log returns on the existing asset, computed below (for a mathematical justification of these formulas, please see Appendix B):

$$U = e^{\sigma\sqrt{\Delta t}} \tag{13}$$

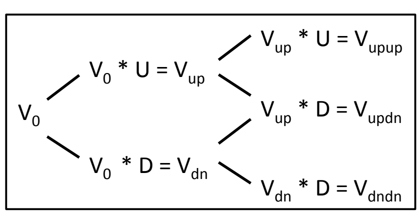
$$D = \frac{1}{U} \tag{14}$$

Each value from the figure above is a possible value of the underlying asset at a state of nature, and is based on the changes in value that are expected from that asset, by integrating the volatility in the log returns to the project (the σ value). From $t = 0$, values either go up or down, depending on relevant economic forces (river flows, electricity demand, cost-overruns, etc.) Then, the process repeats in the following period.

In summary, the steps to build the first binomial tree, the upper portion of Figure 9, are as follows (Shockley, 2007):

1. Calculate the initial expected present value of the underlying asset V_0 (in Figure 6, $V_0 = \$3,500,000$)
2. Calculate the standard deviation of the log returns of the existing asset, σ (this is the volatility).
3. Determine the time-to-exercise for the option T.
4. Choose the time-period for each binomial step, Δt; $\Delta t = T/N$, where N is the number of time steps.[15]
5. Choose an annual risk-free rate of return (a U.S. bond rate is often used)[16].
6. Determine the size of the up and down movements for each step in the tree using formulas 9, and 10 above.
7. Beginning with the present value of the underlying asset, build the tree by multiplying V_0 by an up-step, U, and a down-step D (in the figure above, $V_0 * U = \$4,066,420$). This process is repeated for each time-step in the tree.

Figure 10: Calculating the Steps of the Binomial Tree



[15] In each of the case studies below, Δt is equal to one (1 year).
[16] A risk-free rate is used in option pricing models and reflects the principle of a risk-free opportunity cost of money. Option pricing is based on the creation of securities which mimic others possessing the same risk profile. This is accomplished by combining an index security with a risk-free bond to replicate a future

Determine the Value of the Option. Once the underlying asset is modeled, the option can then be valued. First, the end-of-period payoffs from the option are established. These are the payouts when the option is exercised. Second, the value of the payoff is calculated back to present time.

End-of-period (column 5 in the figure above) payoffs are determined by finding the maximum value between the new project values minus the cost of the new investment, or zero:

$$Payout = MAX[V_0 - K, 0] \tag{15}$$

Where V_0 is the value of the underlying asset at the exercise date, and K is the strike price – the amount of money owners would need to invest to alter the project at the time of decision. If the value of the underlying asset exceeds the strike price, the option will be "in the money," $(V_0 > K)$ and will be exercised. If the strike price exceeds the value of the underlying $(V_0 < K)$, the option will expire "out of the money."

The process for determining the value of a put option are identical, except that the payout expression is reversed. Since the strike price for a put represents a value floor, the holder of the option is watching for an asset value that is *below* that of the strike price, rather than above. So, the payout equation reads as follows:

$$Payout = MAX[K - V_0, 0] \tag{16}$$

Once the payouts for each end-of-period possibility are determined, the value of those payouts for all previous years is determined in backward fashion. This is possible because if we know the value of two derivatives at a future date, and the probabilities associated with those futures, we can calculate the value for today. These are the values of the option in years 0-4 in the figure above. Derivative pricing uses a risk-neutral approach based on the probabilities of up and down movements in the value of the underlying asset (the cash flows from the project). The t_o

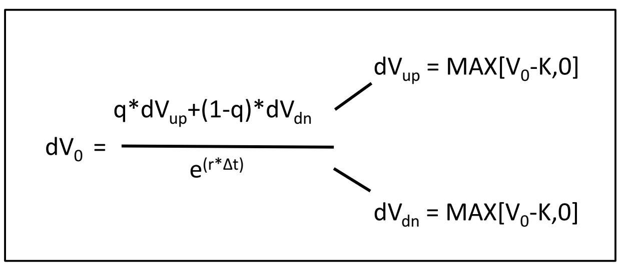
value of a derivative (dV_0) can be calculated from two future values, an up value and a down value, by the following equations:

$$dV_0 = \frac{q * V_{up} + (1 - q) * V_{dn}}{e^{r*\Delta t}} \tag{17}$$

Where dV_0 is the present value of the derivative, q is the risk-neutral probability of an up step, dV_{up} is the value of the derivative after an up step, dV_{dn} is the value of the derivative after a down step, e = 2.71828…, r is the risk-free rate, and Δt is the change in time.

The value of the derivative at each time step is built from the exercise date (year 5 above) back to present time in the following fashion, where each year moving backward is another dV_0 calculation:

Figure 11: Backward Steps (Two Periods) in a Binomial Tree



Source: Copeland and Antikarov 2003

The process results in a table of option values based on the values of the underlying asset. The end-of-period values, from period 5 in Figure 9, are the values of the underlying asset *minus* the strike price. The rest of the values (periods 0-4) are calculated using the equation above.

The value of the option is then *added* to the value of the flexible project to determine the full value of the project with flexibility.

In summary, the steps to calculate the option payouts, the lower half of Figure 9, are as follows (Shockley, 2007):

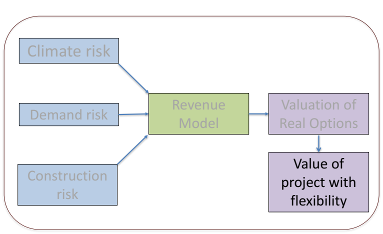
1. Calculate the payoffs of the option for each of the terminal values from the first tree. In column 5 of the lower aspect of Figure 8, the values in each cell have been calculated using equation 11, above.
2. Determine the risk-neutral probability of the up and down steps using equations 12, and 13.
3. Beginning at the end of the tree, calculate the expected present value of the option using the risk-neutral probabilities obtained above. This step has been taken in column 4 of Figure 9.
4. Move backward through the tree to $t = 0$, using the same formula. The final value is the current value of the option.

These backward moving calculations yield the value of a European option. When using an American option the decision is slightly different, though the process is essentially the same. In this case, the decision is not simply whether the value of the asset exceeds the strike price, but rather whether the value of waiting exceeds the value of exercising the option. To calculate an American option, column 4 will use the following payout equation (call):

$$Payout = MAX[value\ of\ exercising, value\ of\ waiting] \tag{18}$$

or:

$$Payout = MAX\left[(V_0 - K), \left(\frac{q * V_{up} + (1-q) * V_{dn}}{e^{r*\Delta t}}\right)\right] \tag{19}$$



The value of the option, within each design, can be added to the value of the static design to obtain the full value of the project with flexibility.

NPV of static design + Value of the option = Full value of the project

CHAPTER VII

CASE STUDY 1: FLEXIBLE DESIGN AT BATOKA DAM

This case study presents a real options analysis for flexible design in the context of an African hydropower project on the Zambezi River called the Batoka Gorge Hydropower Dam (BGHD). The case develops a comparison between real options analysis and two other decision making tools, specifically benefit-cost analysis and robust decision making, for valuing flexibility at the site. In contrast to the case study of the Inga project, which looks at the value of a phased design built over time, Batoka affords the chance to study competing design options at the same site. With a forthcoming feasibility study stimulating new interest in Batoka, specific risks should be identified and addressed. The comparison of three decision-making methods allows for a deeper understanding of the interactions between risks and values of competing configurations.

The Batoka Dam represents an important, international initiative that holds promise for meeting significant electricity demand in Zambia, Zimbabwe, and the larger SAPP. However, as with other similar projects, there are attendant risks with developing Batoka. Various tools for quantifying these risks, and offering decision-makers some guidelines for investment strategies, particularly under climate uncertainty, are increasingly used to evaluate policy choices and specific investment decisions. Given the uncertainties of climate change, and the wide range of decision-making levels, multiple tools may well have a role, depending on the need of the decision maker. This case study reviews three methods of analysis for decision making under uncertainty: Benefit-Cost analysis under uncertainty (BCA), Robust Decision Making (RDM), and Real Options Analysis (ROA). The case study then illustrates each within the BGHD project. The comparison finds that within the context of Batoka, the three analyses point to similar design choices with one important exception: Real Options offers values for flexibilities embedded in the design, whereas the others do not incorporate these valuations. Furthermore, the analysis finds that the value of flexibility, especially when integrating multiple risks into the project, creates value in smaller designs, such that the ENPV exceeds that of inflexible, though larger designs.

This case study begins with a brief overview of the BGHD project. It then provides a frame for the project as described above. After framing the project, the case study progresses to a synopsis of the three methods of analysis: BCA, RDM and ROA. The methodology section that follows offers a brief review as to how the various risks in the analysis have been modeled for this case. Finally, the methodologies are applied to the BGHD, and results are presented.

Within the case study the three methods first consider climate risk only. This allows a straightforward comparison of results across methods, while isolating the effects of climate risk. Then additional uncertainties are incorporated into the analysis, combining the risks of demand, cost overrun, and climate, analyzing their combined effect on project value. Since value is inextricably linked to the actual design of the hydropower facility, several design configurations were adopted to understand how different approaches affect project value in the context of the risks. Also evaluated are the incremental costs to build in flexibility, and their effects on expected project values. The specific results seen in this case study are therefore:

1. Does the framework make the value of flexibility explicit?
2. Is ROA unique in its ability to identify the value of flexibility?
3. What additional insights does the framework identify?

Background for the Batoka Facility

The Zambezi River is the fourth-longest river in Africa (2,574 km), and the largest African river that flows into the Indian Ocean. Its basin has an area of 1,390,000 square kilometers, slightly less than half that of the Nile. There are two primary hydropower sites on the river: The Kariba

Dam, which provides power to Zambia and Zimbabwe, and the Cahora Bassa Dam in Mozambique, which sends its power to Mozambique and South Africa. Both are downstream of the BGHD site (Everett, 2015).

The Zambezi River Basin is subjected to one of the most variable climates of any major river basin in the world, experiencing extreme conditions across the catchment. This section reviews historical and projected temperature and precipitation.

Temperature variation across the Basin across seasons is not high. The coolest temperature is experienced in July and winter temperatures range from 13 °C (higher elevation areas to the south) to 23 °C (lower elevation areas in the delta). Mean daily temperatures in the summer range between 23 °C in the highest elevation areas, to 31 °C for the lower parts of the Zambezi valley. Temperatures are warmest along the border of Zambia and Zimbabwe (Everett, 2015). Average annual rainfall in the Basin is approximately 950 mm/year, although this average is unevenly distributed with the northern and eastern portions of the Basin receiving the highest proportion of rainfall. For example, annual rainfall varies from more than 1600 mm in the northern highland areas to approximately 550 mm in the southern portion of the basin (Everett, 2015).

The Zambezi Basin experiences a dry season from June to August, when average precipitation is less than 0.05 mm/ day; and a wet season from December to February, when average precipitation is more than 5 mm/da. Flooding is problematic, occurring nearly every decade resulting in numerous socio-economic impacts. Between 1997 -2001, the Basin has experienced extreme floods during the rainy seasons of 1999 – 2000, 2005 - 2006 and 2007. Tropical cyclones originating in the Indian Ocean are the main driver behind the flood cycles. Multi-year droughts are also observed in the Basin, with implications for river flows and hydropower production. For example, the effect of the 1991/92 drought on hydropower potential in the Kariba Dam resulted in a regional impact that included a reduction of GDP of US$ 102 million, US$ 36 million reduction in export earnings and the loss of 3 000 jobs (Everett, 2015).

The projected climate builds on these uncertainties. The Zambezi Basin has been classified by the IPCC as possessing the ‘worst’ potential effects of climate change among 11 major African river basins (IPCC, 2014). This classification is largely based on the climate change-induced increased temperature and decreased precipitation in the Basin, discussed below. Overall, temperatures in the Basin are expected to increase because of climate change. Some report a projected warming trend of 0.3 – 0.6 °C per decade until the end of the century, while others project annual temperature increase in the Basin of as great as 2.9 °C (Everett, 2015). Temperature increases will likely have implications for water availability. In addition, climate change is expected to result in prolonged dry periods and enhanced drought conditions. Precipitation, across the Basin, is expected to decline by 10 - 15% by the end of the century. In addition, alterations in seasonal rainfall patterns are projected. These include a delay in the onset of the rainy season, with implications for hydropower generation. Climate change is expected to result in tropical cyclones of increased intensity, with higher peak wind speeds and heavier rainfall (the result of increasing sea surface temperatures), with implications for the flooding regime in the Basin (Everett, 2015). Using P-E as a proxy to determine the water budget of the Bakota Gorge catchment, Everett projects a reduction of approximately 1.7% per decade compared to the baseline (Everett, 2015). If climate change were accelerated, the worst-case scenario would be a reduction in the water budget of approximately 3.5% per decade.

There are several governing bodies that have an interest in the development of the Batoka project. The purpose of the dam is to generate electricity for Zambia and Zimbabwe, with possible export capability to the greater SAPP region. The increased capacity will reduce local reliance on electricity imports. As an additional benefit, the renewable energy source would help to balance the mostly fossil-fired generation mix in the SAPP. This project is in the Zambezi River Basin, which spans the East African Community and Common Market for Eastern and Southern Africa regions. The Zambezi River Authority (ZRA) plays a major role in the implementation of this project; and, the East African Power Pool is also involved in the project development.

The original feasibility study for BGHD, completed in 1993, was for a dam and hydropower facility; the generation capacity was to be 1600 MW. However, today, a new design is being developed with a 2400 MW capacity. An ultimate capacity of 3000 MW has also been discussed. Since no feasibility study is currently publically available, I have begun my financial analysis with the earlier 1600 MW design, adding development options from that baseline.

Indications are that Batoka will be an RCC gravity-arch dam. The facility will include two powerhouses, one each on the Zambian and Zimbabwean side of the river respectively. Recent reports state that both will be above ground, though others have indicated underground construction to preserve the landscape just east of Victoria Falls. The volume of the reservoir will be 1,680,000,000 m^3 with an area measuring 26 km^2. The mean annual flow at that point in the river is approximately 1,080 m^3/second, while the maximum recorded flow was 12,800 m^3/sec (ECA, 2009).

However, there are also flexible design alternatives at BGHD. In addition to the three designs mentioned above, two intermediary configurations are also possible. A 1600 MW facility could be built, with the flexibility to be converted to 2400 MW. In this case, less expensive civil works of the larger facility would be built, while expensive mechanical and electrical works would be saved for the expansion. In similar fashion, a 2400 MW configuration could also be built, with flexibility for conversion to 3000 MW. Results from the analyses should identify the value of this type of optionality. Static designs - those with no flexibility - are often not as valuable as flexible ones. The different values of the options should not only be included in any authentic project valuation; they also provide excellent decision making information about how to maximize project value. The design possibilities at BGHD are summarized as follows in Table 5.

Table 4: Design Possibilities Evaluated in this Dissertation

Five Evaluated Design Possibilities	
Design A	1600 MW facility with no flexibility for climate or demand uncertainty
Design A'	1600 MW facility with option to expand to 2400 MW
Design B	2400 MW facility with no flexibility to expand facility
Design B'	2400 MW facility with option to expand to 3000 MW
Design C	3000 MW facility with no flexibility

Step 1: Frame the Batoka Project

The Stakeholders. The stakeholders in the BGHD project are the various bodies leading the management of the River, the basin, and the development mandates from the government: especially the Zambezi River Authority. ZAMCOM is the Zambezi Watercourse Commission, an agency established by all nations that hold territory in the River Basin. Other stakeholders include the utilities from Zambia and Zimbabwe, and the SAPP[17], which is an international trading platform. Finally, the governments, specifically the Ministries of Energy, who represent the national interests and the people of the respective nations.[18] These various entities have similar, but not identical mandates, and therefore goals. National governments, particularly in Africa, often desire energy security; that is, they would prefer not to rely on imported electricity as this has occasionally been unreliable. They are also concerned with improving supply at home, a politically

[17] The Southern African Power Pool (SAPP) was created with the primary aim to provide reliable and economical electricity supply to the consumers of each of the SAPP member, consistent with the reasonable utilization of natural resources and the effect on the environment. (SAPP, 2017)

[18] This list is partly redundant. The ZRA Secretariat is run by one representative from the Ministries of Energy of each Zambia and Zimbabwe, and a representative from each country's Ministries of Finance.

popular theme. By contrast, the SAPP would like to see more frequent trading as they attempt to smooth demand and supply gaps over the entire SADC Region. The ZRA has been given the mandate to manage the hydropower development along this section of the river, and reports to the Ministries of Energy and Finance in Zambia and Zimbabwe. Absent from this list are any lenders, or equity investors. Private investors will have a priority of securing a financial return on investment. This would affect project analysis, and perhaps project design. For example, the application of a social discount rate to the analysis would likely need to be altered to one that included the cost of capital and additional risk factors for the investor. This may change the price at which energy is sold, and perhaps the way the project is developed and maintained.

The Decision. At this point, the financial arrangements of the BGHD are not clear. Some may call for a public private partnership, while others may say this is too costly. For the purposes of this case study, I will assume that the decisions on development, timing, offtake price, and other project aspects will fall to the ZRA. Furthermore, I assume that the ZRA will charge an electricity price that is in line with existing market prices in Zambia and Zimbabwe. However, I further assume that 20% of the electricity from BGHD will be sold internationally, through the SAPP platform. This will provide additional liquidity to facility managers. The derived electricity price, used in the model, is found below. Therefore, the BGHD is a hydropower dam with the primary purpose of supplying electricity to Zambia and Zimbabwe, and a secondary purpose of selling electricity internationally through the SAPP.

The flexibility candidates are two design configurations that include the civil works to increase capacity at the dam, but do not include the electrical works, namely the turbines, that would be required should valuations warrant expansion. The costs of the upgrades can be seen in the strike prices that appear in the results section (a full cost analysis is available in Appendix B).

An important aspect of the Decision is the Decision Rule. As intimated previously, the decision rule is the value of the facility at the point of exercise. A strike price higher than the value of the facility will mean that no action will be taken, and the option will expire. For the purposes of the case study, the decision will be made at the end of ten years. This is the exercise period of the option.

Uncertainties. The second part of the application frame is to identify uncertainties. These have been well developed in previous chapters, and there is nothing to add here, except to reiterate that the uncertainties considered are the effects of climate change on river flows, electricity demand, and cost overruns.

Value Leakage. The only value leakages considered in this analysis are operations and maintenance (O&M) costs, and a tax on profits that commences five years into the project. The O&M costs are based on the literature, which considers O&M as a fixed percentage of the total initial investment. For both countries in question, the tax rate begins after 5 years of operation, giving the project a tax-free start. The actual percentages for both are found below.

Identify the Underlying Asset. In this case, the underlying asset is the projected performance of the BGHD itself, as modeled through the process outlined in Chapter VI, Methodology.

Step 2: Gather the Inputs

The inputs are found in Table 5 below. The following is a brief defense of each as a parameter of the model. The investment time horizon was chosen as the full-time horizon for the model. Real options analysis normally would take place over 15 years, but a hydropower facility has a long build time (5 years is assumed), which leads to a longer time-frame to recoup investment costs and realize a profit. The discount rate has been established based on the World Bank's social discount rate for African climate-related projects; the rate recognizes the perspective of an economic analysis, rather than a financial one. However, different discount rates are applied in the results section below to test the outcomes for both types of analyses: economic vs. financial. The risk-free rate is reflective of a U.S. government bond of the same duration as the option. The initial electricity price is the average price currently being charged in the Zambian and Zimbabwean market. Electricity price elasticity comes from the literature (Bernstein and Griffin, 2006). The O&M, as a percentage of the initial capital costs for the facility, comes from the International Energy Agency. Average cost overrun for dams in Africa comes from the Ansar, et al. report (Ansar et al. 2014), as does the standard deviation (Ansar's standard deviation is much higher. The amount below has been adjusted downward, and reflects smaller volatility numbers in other reports, especially Flyvbjerg et al., 2011). The corporate tax rate is from the local government's web pages regarding tax rates. The following assumptions were made in the analysis:

Table 5: Assumptions

Inputs	
Investment time horizon (includes 5-year build per phase)	25 years
Discount rate[19]	15%
Risk-free rate	1.75%
Required ROR	15%
Initial elec. price	0.08
Initial electricity price elasticity (a random variable)	0.22
O&M as percentage of capital costs	2.5%
Average cost overrun for dams	0.4
Standard deviation for cost overruns	1.25
Corp Tax rate	15%

[19] JP Morgan's Infrastructure Investing: Key Risks and Benefits, places merchant power generation development and non-OECD country infrastructure in its "higher risk" category, and suggests a range of leveraged IRRs, from 15%-25%. I have generated results for both ends of this spectrum.

Step 3: Calculate the Option

The final step is the calculate the option. This is accomplished below. However, first the other decision-making methods are employed: BCA and RDM.

Decision-Making Under Uncertainty. There are many decision-making tools available to planners for use as evaluation methods under uncertainty. This section briefly summarizes three decision-making tools currently in use for planning under climate change. These were chosen based on the researcher's personal experience in observing the tools used in the field, especially in Africa. They are benefit-cost analysis (BCA), Robust Decision Making (RDM), and real options. Each tool is used in its most simple and basic capacity, which likely under-utilize the tools' full potential.

Benefit Cost Analysis Under Uncertainty. BCA is a well-known tool in project analysis. A standard BCA compares the investment costs of a project to the discounted sum of the net benefits. To make use of the tool in decision making under uncertainty involves the identification of competing projects, along with the sources of uncertainty. Costs and benefits are calculated for each project, and then discounted to determine a net present value. Finally, the "robustness" of the result is evaluated against the identified uncertainties. For example, when using the tool to determine the robustness of a project under climate change, the choice will be the project that retains the highest NPV across all future climate scenarios (Hallegatte et al., 2012).

The standard evaluation for benefit cost analysis follows this equation:

$$NPV = \sum_{t=0}^{T} \frac{1}{(1+r)_t} (Benefits_t - Costs_t) \tag{20}$$

Where *NPV* = Net Present Value, *t* = time interval, *T* = time, and *r* = the discount rate.

When evaluating net benefits and costs *under uncertainty*, the *expected* values, calculated over a range of possible parameters, are used:

$$E[NPV] = E_o\left[\sum_{t=0}^{T}\frac{1}{(1+r)_t}(Benefits_t - Costs_t)\right] \tag{21}$$

Where E = the expected (or average) value, and E_o = the expected value at $t=0$.

One advantage to the BCA is the relative straightforwardness of the process. One weakness for evaluating climate impacts however, is that results can be very sensitive to assigned probabilities of climatic occurrences. Since climate impacts are highly uncertain, the range of outcomes can be large, making comparisons difficult (Hallegatte et al., 2012).[20]

According to Hallegatte et al., BCA is a very useful tool, but especially so under situations of limited uncertainties (2012). In these cases, BCA can be helpful to determine the best investment opportunities. It can also be used to collect stakeholder opinions and to help organize the context and terms for discussion – especially around the parameters of the analysis. However, in areas of deeper uncertainty the process should be a complement to other methods and consultations. As will be shown, the BCA undervalues projects that include optionality.

Robust Decision Making. RDM is also a well-known tool. The goal of RDM is to identify investment plans that perform well over a wide variety of future conditions. In the present context, RDM would consider a suite of infrastructure investments, which perform well under a wide variety of possible climate futures, and which minimize bad investment outcomes, called "regrets." The aim is not necessarily to offer a strict ordering of investment priorities, but rather to provide several potentially "robust" strategies, and to identify important trade-offs between them (Cervigni et al., 2015).[21]

The analysis begins with a "perfect foresight" adaptation plan. This is an optimization process that "optimizes" infrastructure investments for a climate scenario. For example, in a river

[20] Hallegatte, et. al., Investment Decision Making Under Deep Uncertainty – Application to Climate Change, 2012
[21] Civigni, p 50

basin with limited resources spread over competing needs, modelers may seek the economically optimal mix of hydropower, irrigation, municipal and industrial demand. Perfect foresight assumes that planners know the climate they will encounter, and are able to develop the optimal investment mix for that future. In the Batoka Case study below, the perfect foresight assumption is that the smaller 1600 MW facility is designed “optimally” for a relative dry climate, the 2400 MW facility for a medium climate, and the 3000 MW facility for a wet climate. While this is a significant over-simplification of the optimization process, it does allow for a comparison of methods.

The RDM analysis then compares each optimized investment across *all* selected futures (in our case a dry, medium and wet scenario). This is accomplished by calculating the “regrets” for each investment decision. Regrets are defined as the forgone value of each design, if the future turns out to be different than the one for which that configuration was developed. The investment that performs best, with the least regrets, across *all* the different futures is said to be the most “robust” under all scenarios (Cervigni et al., 2015).

In the following table, Configuration A (1600MW) is designed especially for a drier climate, Configuration B (2400) for a medium climate, and Configuration C (3000) for a wet climate. Regrets for each are calculated by subtracting the value of the optimized configuration for a climate, from other configurations and summing the total. This is the forgone value for each design.

Table 6: Mini-Max Regret

Climate	Configuration A	Configuration B	Configuration C
Dry	-	NPV A - NPV B	NPV A – NPV C
Med	NPV B – NPV A	-	NPV B – NPV C
Wet	NPV C – NPV A	NPV C – NPV B	-
Sum	***Sum = Regret for A***	***Sum = Regret for B***	***Sum = Regret for C***

Source: Author’s compilation

According to Hallegatte et al., (2012), RDM is the most valuable in situations where there are multiple and deep uncertainties, and a group of stakeholders with a wide range of opinions about future opportunities. It allows for a full vulnerability analysis at the project level, and for stakeholders to develop alternatives based on existing options. However, it can be costly and time intensive, and the stakeholder process significantly influences the analysis, as it will determine the range of policies that is studied.

Real Options. Project developers often desire to have the flexibility to adapt to conditions, either avoiding losses, or allowing them to capture greater profits if the future climate allows. This type of choice is illustrated directly with a hydropower facility. Under a dry future climate, investors risk over-building today only to realize smaller-than-anticipated cash flows because of lower-than-expected river flows. On the other hand, under a wet future, investors risk under-building today, and leaving hydropower output undeveloped, due to an undersized facility, with no cost-effective way to recapture it.

An ROA assumes that time will increase understanding, thereby decreasing uncertainty. So, decisions about investments are not viewed as “yes” versus “no,” but as “now” versus “later, once we receive more information.” As established, it is the right, but not the obligation, to make an investment decision in the future. The decision points are based around the realization of new information, and the ability to respond to it. The process can be applied to refine the accuracy and precision of economic evaluation, particularly for flexibly designed projects. Furthermore, an ROA offers an explicit valuation of project choices allowing planners to choose between static and flexible designs. However, as Hallegatte et al., point out, the complexity of the analysis, especially over a CBA approach, can be significant, and thus more expensive (2015). Therefore, a real options approach is especially useful when specific valuations are required, and when project flexibility is an advantage.

To accomplish the comparison between methods of analysis, a scenario was established, whereby planners initiate the project in a world without a climate policy (the unconstrained emissions scenario above), but believe that a policy will soon come into place, with 50% certainty. All results are *expected results*, based on 400,000 runs of the model. (The methodology for establishing the other risks and inputs has been established in Chapter V.)

I utilized the three decision making processes to evaluate the five design configuration options. Here are the results from each assessment. However, first, an important caveat: the intent is not to offer specific valuations of the projects, but rather comparative ones. To offer point estimates of actual values would require greater access to site costs, and broad agreement of inputs.

Results

Results for each analysis method are first presented considering climate risks alone. This analysis answers the question: will climate *alone*, so affect the flows at the BGHD, such that one design configuration is more valuable than another? Following these climate screenings, results from combining climate with the additional risks of cost overrun and demand are given under each method. Considering climate risk alone, all three methods point to the same result: Batoka C. However, once multiple risks are incorporated, the ROA reveals that the configuration of a smaller facility with an *option to expand* is more valuable than the larger facility. While it is not my purpose to offer definitive results for decision makers, it is my objective to illustrate that under certain conditions, different methods of analysis will yield different results, and especially that ROA can illuminate the value of optionality embedded in design. Furthermore, the RDM approach changes its rankings when adding the *full value* of the flexible projects, favoring configuration *A'*

+ *Call Option,* when considering all risks. However, unless an ROA is combined with the RDM, the RDM counts the costs of flexibility against the project, but has not accrued its benefits.

Results for Climate Risks Alone

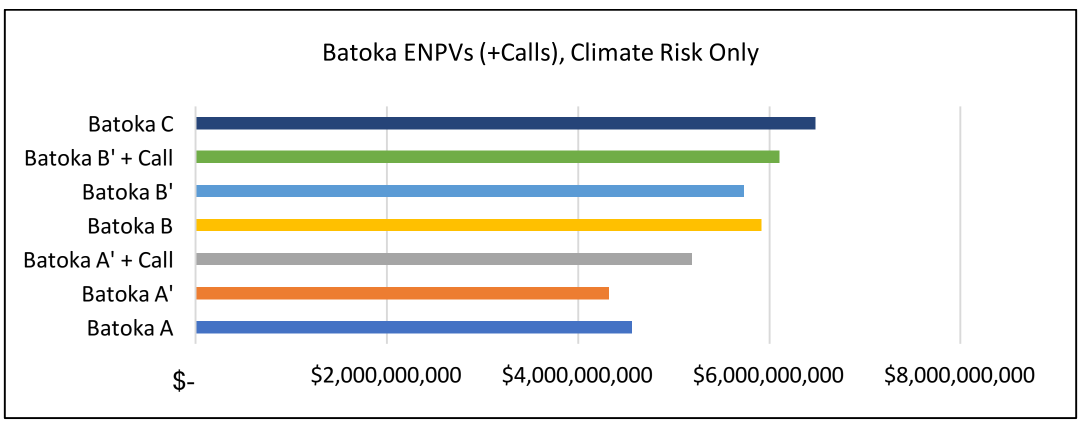
ROA, Climate Risk Alone. The helpful nuance of the real options analysis is that it includes the value of the option to expand. Table 8 presents the values of the five design configurations, considering climate risk alone. As mentioned, configurations A' and B' represent built-in civil works (especially the cost of bins to hold additional turbines in the power house, but not the turbines themselves) that allow for the relatively inexpensive upgrading of the facility to a larger size if increased river flows are realized.

Table 7: Expected NPVs and Call Values Considering Climate Risk Alone

Expected NPVs and Call Values Considering Climate Risk Alone				
Design	Initial NPVs	Strike price	Call value	NPV + call
A	$4,558,951,920		NA	
A'	$4,321,946,021	$389,965,000	$864,102,740	$5,186,048,761
B	$5,916,692,311		NA	
B'	$5,732,306,165	$305,003,000	$371,419,451	$6,103,725,616
C	**$6,482,586,222**		NA	

**The Strike price is the assumed investment needed, in 10 years, to upgrade the facility from the smaller configuration to the larger one.*

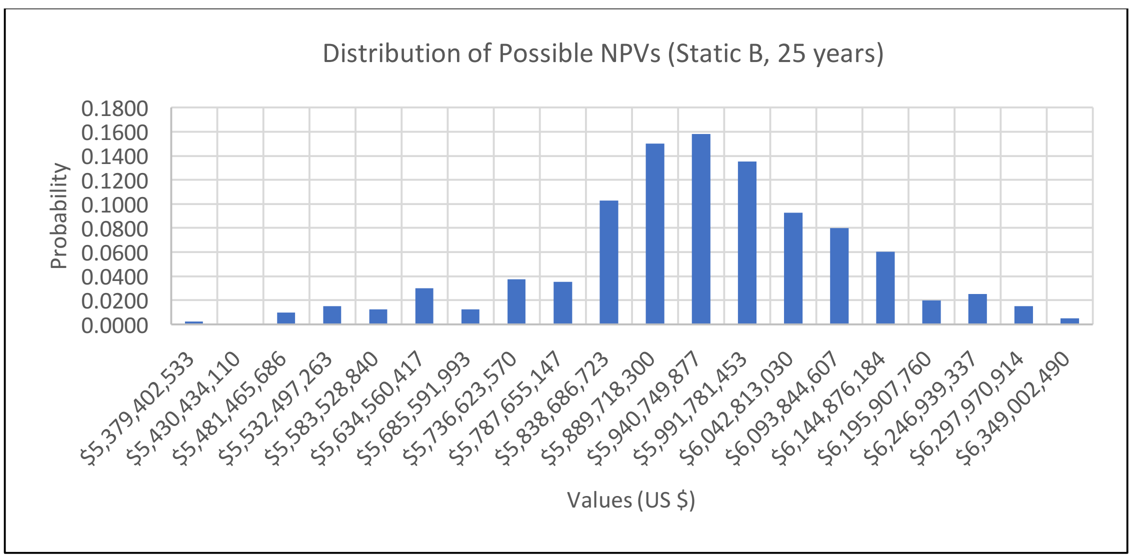
Figure 12: Full ENPVs Showing Climate Risk Only



When seeking to address climate risk alone, the ROA analysis shows that optionality does not necessarily add sufficient value to the project to change the decision from Configuration C to another design option: the *full value* (NPV + call) of either A' or B', the two flexible candidates, is still less than C.

BCA, Climate Risks Alone. The advantage to incorporating uncertainty in the BCA analysis is that single point estimates of the parameters are typically not known. When uncertainty is considered, a range of possible outcomes can be reasonably expected. The following figure shows my calculated range of possible values of a 2400 MW facility at Batoka Gorge, given only climate risk at the site. One observation is that climate alone may not be the most significant risk at Batoka. In fact, no climate futures resulted in a negative NPV for the facility, given the parameters. However, were the values to shift significantly to the left, for example due to lower electricity prices, the distribution may tell a different story, and values may be threatened.

Figure 13: Distribution of Possible NPVs at a 2400 MW Facility, Given Climate Risks



However, as a decision-making method, BCA has not incorporated flexibility in design. The process yields the expected net present value of each of the three static design options at Batoka Gorge. If a flexible option is included, the NPV will be *under-estimated*. The reason is that, in this case, BCA has included the additional costs of flexibility, but not the value of the option on the incremental expansion (see designs A' and B' below). The ENPVs for each design are shown in Table 8.

Table 8: Expected NPVs Considering Climate Risks Only

Expected Benefits and Costs (N=400,000)			
Design	Benefits	Costs	Net
Batoka A	$6,977,030,409	$(2,418,078,488)	$4,558,951,920
Batoka A'	$6,932,130,783	$(2,610,184,762)	$4,321,946,021
Batoka B	$8,850,252,697	$(2,933,560,386)	$5,916,692,311
Batoka B'	$8,815,321,631	$(3,083,015,466)	$5,732,306,165
Batoka C	$9,814,629,189	$(3,332,042,968)	**$6,482,586,222**

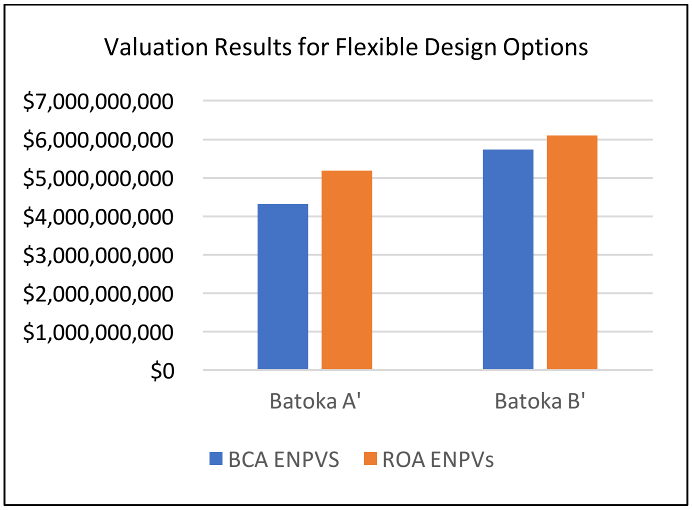
Design C, the 3000 MW facility, has the highest NPV; therefore, the results from this analysis would lead the decision maker to choose configuration C.

The ENPVs of the BCA analysis, are identical to those using the ROA. However, the ROA also shows the value of flexibility. Batoka A' and B' thus have values that are augmented by the value of the option. In Table 9 and Figure 14 below, the expected values of the flexible designs are shown. Only ROA adequately values the flexibility. For Configuration A', BCA undervalues the flexible design by $870 million, or 16% of the full project value; and at B' by $370 million, or 6% of project value.

Table 9: Comparison of the Value Given to Flexibility; BCA vs. ROA

Design	BCA ENPVs	ROA ENPVs	BCA Under Estimates Design Value By:
Batoka A'	$4,321,946,021	$5,186,048,761	16%
Batoka B'	$5,732,306,165	$6,103,725,616	6%

Figure 14: Valuation Results for Flexible Options; Compares BCA and ROA Results

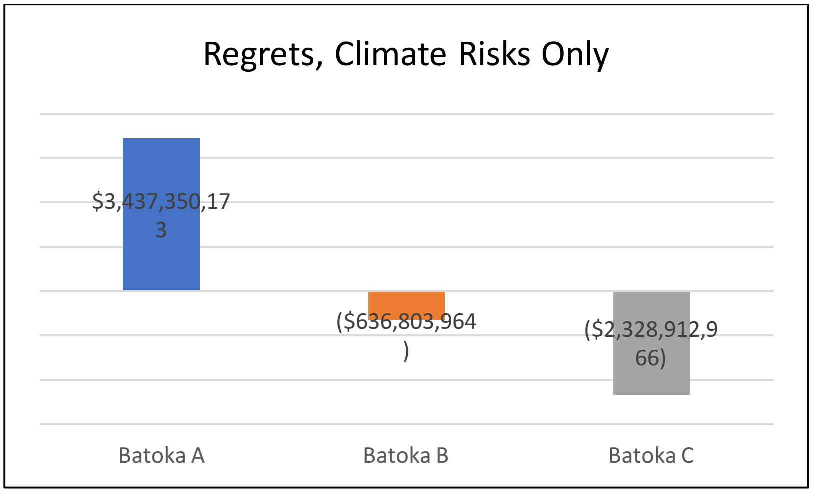


RDM, Climate Risks Alone. Results from the RDM process are also presented for each of the three static configurations at the facility. The least regret method, outlined above, is employed and displayed in the table below. Recall that each design is heuristically matched (or "optimized") for a future: the smaller design A for a dry future, B for a medium, and C for wet. Under a full RDM analysis, a more sophisticated optimization would take place.

Table 10: Results for RDM Analysis at BGHD, Climate Risk Only

Regrets			
	Batoka A	**Batoka B**	**Batoka C**
Dry	NA	$(1,276,953,555)	$(1,761,127,976)
Medium	$1,362,697,606	NA	$(567,784,990)
Wet	$2,074,652,567	$640,149,591	NA
SUM	$3,437,350,173	$(636,803,964)	**$(2,328,912,966)**

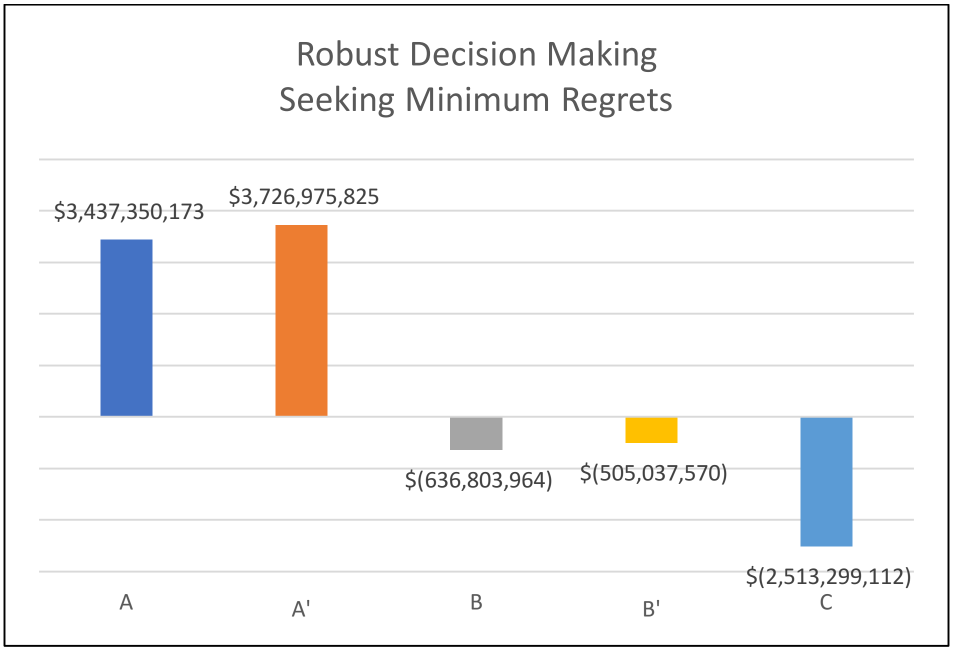
Figure 15: RDM Results - Regrets, Climate Risks Only



The minimum-maximum regret from the table also supports the selection of the Batoka C design. The totals show the maximum regret experienced by each configuration, in each climate future (dry, medium and wet). Design A results in the maximum regret, whereas Design B, shows a lower regret. Design B outperforms A in a dry future, but underperforms Design C in a wet future. By contrast, Design C significantly outperforms both rival designs, even though it was not initially thought to have been optimized for a dry or medium future. In this case, the ranking of the projects is the same as the rankings from the other two analyses. (Please see Table 6 above for a review of the min-max regret calculations.)

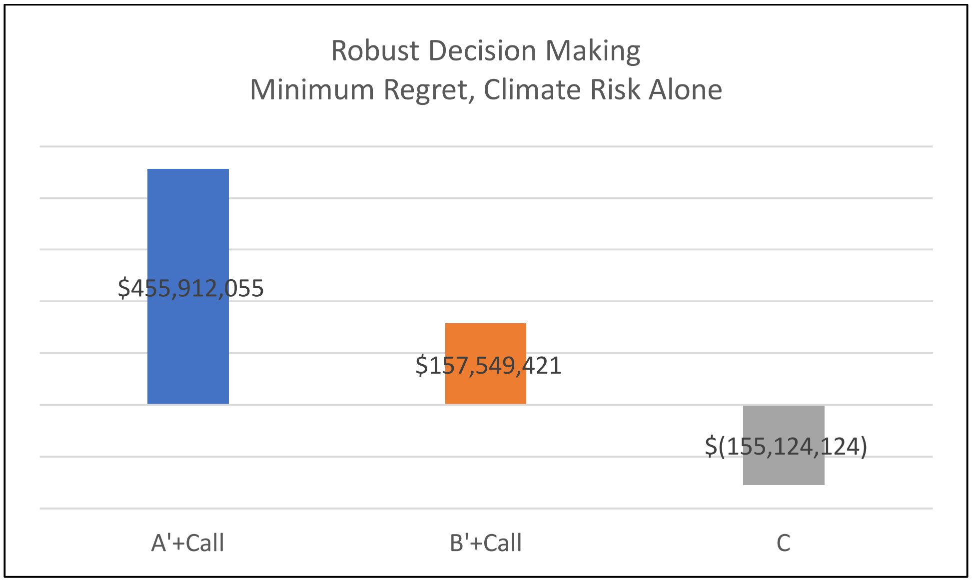
Neither does RDM, in its most rudimentary form, incorporate the value of flexible design. In the graphic below, the designs "optimized" for the three different climate scenarios are as follows: A' for Dry, B' for Medium, and C for Wet. The results for the static values of A and B are included for comparison. RDM has added the additional costs of the flexibility to the projects, but, has not accounted for the value of the flexibility. In this case, RDM has undervalued A' by 7% and B' by 20%.

Figure 16: Robust Decision Making Results, All Configurations (Climate Risks Only)



However, RDM can incorporate flexibility if is combined with an option valuation. In the following graphic, the RDM process was used, but this time, the *full project value* (NPV + Call Option), was used as the perfect foresight investment choice for each of the three climates. In this way, both the costs and the benefits of the flexibly designed projects are accounted for in the RDM process. As Figure 17 shows, for climate risks alone, the tool leads us to the same decision: Batoka C has the minimum-maximum regret when considering climate risks. However, the difference in results is not as stark as what is presented in Figure 16, comparing regrets across all configurations. The reader will notice that the values of the maximum regrets are much closer to one another, and considerably smaller, than when comparing all five design options. This tells us that the different designs perform more similarly across all three climate scenarios, relative to the static A and B designs.

Figure 17: RDM Analysis for All Design Configurations



Results that include the additional uncertainty of energy demand and cost overrun are presented below, beginning with ROA, then BCA, and finally RDM. The reader will notice that the valuation numbers are significantly lower. The primary reason is that the volatility in costs for infrastructure is high, leading to significant expected cost overruns. This drives down the expected value of the project, regardless of the configuration proposed.

Integrating Multiple Risks

ROA, Multiple Risks. When risk exposure increases, so does the value of optionality and of delayed decision-making. The table below shows the results of integrating the risks of demand and cost overrun, with climate risks, into the Real Options Analysis. The risks drive expected costs higher and increase the volatility of demand, while lowering expected values.

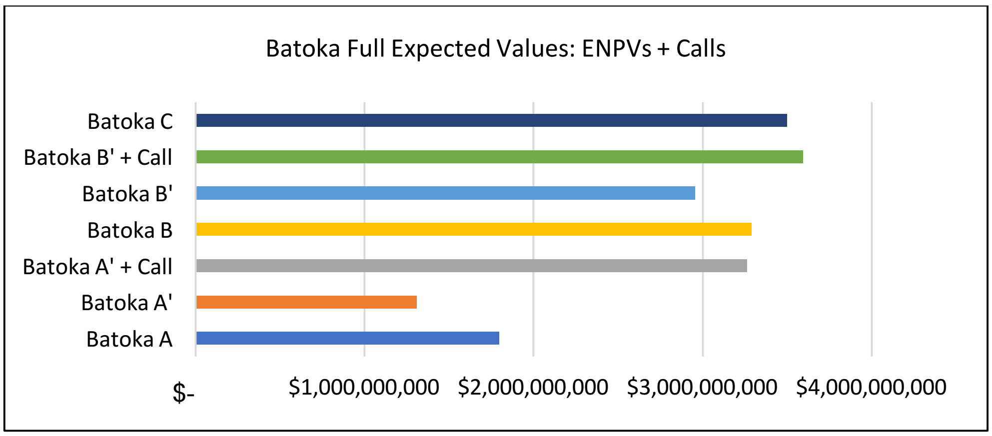
Table 11: ROA Configuration Values Considering Multiple Risks

Expected Rounded Mean Design Values				
Design	Initial ENPVs	Strike price	Call value	NPV + call
Batoka A	$1,795,000,000	$-	$-	$-
Batoka A'	$1,309,000,000	$390,000,000	$1,952,000,000	$3,261,000,000
Batoka B	$3,287,000,000	$-	$-	$-
Batoka B'	$2,954,000,000	$305,000,000	$640,000,000	**$3,593,000,000**

Batoka C	$3,499,000,000	$-	$-	$-

Under this analysis, I find that the most valuable project has now become the medium (2400 MW) facility, *with the option to expand* to 3000 MW (Design B'); when combined with the value of the option, Batoka B' offers the highest value of all the configurations, by $94 million.[22]

Figure 18: Shows Full Expected Values for All Configurations, All Risks, ROA



Considering multiple risks, and under both a constrained emissions future and an unconstrained, the project configuration with the highest value is the B' configuration (2400 MW with the flexibility to expand to 3000) – even though it was undervalued by other techniques. The reason is that the project comes with an option to expand to a larger facility *if* the anticipated policies are realized. From my calculations, the option is worth approximately $640 million.

It is acknowledged that the NPV figures presented above, are close in value. However, it is significant that among closely-clustered values there are differences among methods; those differences warrant attention. The sensitivity analysis below, around several parameters shows that the analysis is especially sensitive to the electricity price and discount rate, but less so to the risk-

22 The difference between the initial NPVs in the ROA table, and the Net Benefits in the BCA table is from rounding during model runs.

free rate. Because of the high volatility, especially of cost overruns, the model was run many times, each time with a high number of iterations (400,000). The results across runs differed in values, but were consistent in result. The B' configuration was consistently valued the highest.

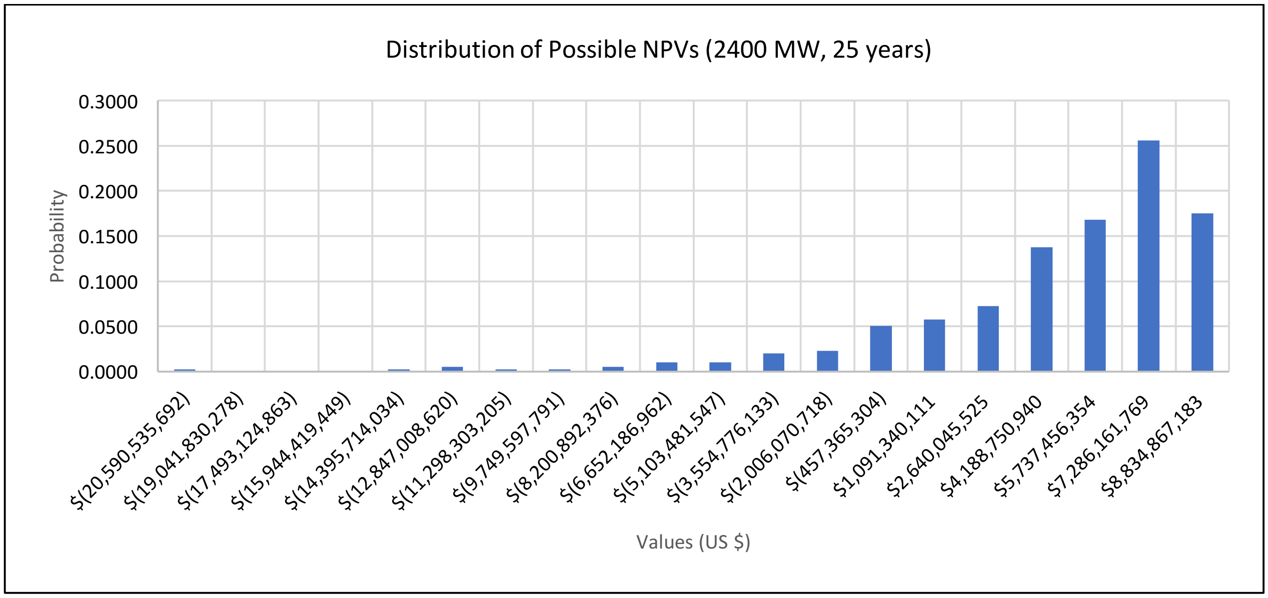
BCA, Multiple Risks. As the additional risks are added to the analysis the BCA model still shows a preference for Configuration C, the largest facility, though the values are more clustered together. This makes sense, especially considering the possibility of large cost overruns. However, there is another result that is important: the BCA analysis has, once again, *undervalued* the flexible configurations - A' and B' - as will be shown. There is another result that can be seen in Table 12 below: if developers build B' and do not exercise their option to expand to a larger facility, they will have saved $500 million (costs of C minus costs of B').

Table 12: BCA w/Uncertainty, Considering 3 Risks

Rounded Expected Benefits and Costs (N=400,000)			
Design	**Benefits**	**Costs**	**Net**
Batoka A	$6,692,000,000	$(4,897,000,000)	$1,795,000,000
Batoka A'	$6,598,000,000	$(5,290,000,000)	$1,309,000,000
Batoka B	$9,225,000,000	$(5,938,000,000)	$3,287,000,000
Batoka B'	$9,192,000,000	$(6,238,000,000)	$2,954,000,000
Batoka C	$10,232,000,000	$(6,733,000,000)	**$3,499,000,000**

Figure 19 shows the distribution of possible values for the static Design C. The expected value is the net from Table 12; however, due to the long tail of possible negative values, results also show a 14% chance of negative NPVs. This illustrates the asymmetry of project values, and is one reason why standard techniques of averaging inputs, with the expectation of receiving an average output, is not always appropriate in large-scale project analysis, an underlying theme of this dissertation. Also, when comparing this pdf of possible values, with the one considering climate risk alone (Figure 13), one can see that climate risk is not the most significant at Batoka.

Figure 19: Distribution of Possible NPVs for Configuration C

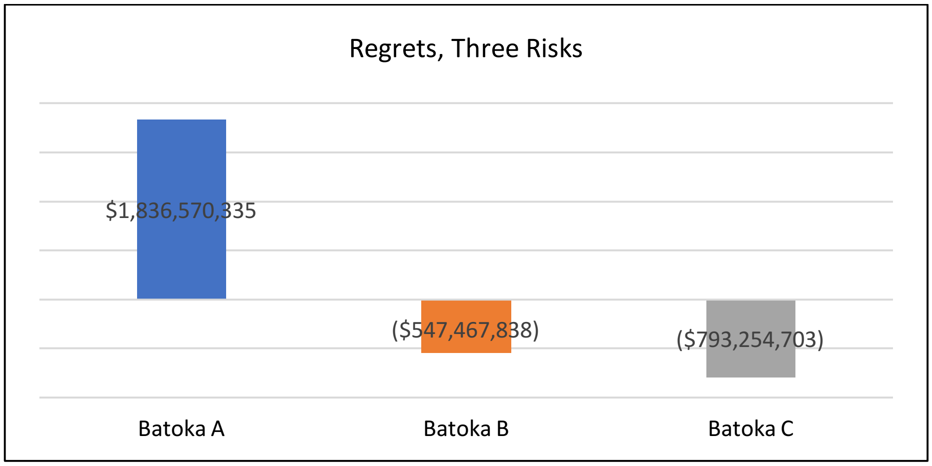


RDM, Multiple Risks. As additional risks are added to the calculations for Robust Decision Making's minimum-max regret, the preference of the project also remains the 3000 MW project, when using values from the static designs.

Table 13: RDM Results 3 Risk Factors

Regrets			
	Batoka A	**Batoka B**	**Batoka C**
Dry	NA	$(711,291,931)	$(694,475,654)
Medium	$798,836,234	NA	$(98,779,049)
Wet	$1,037,734,101	$163,824,094	NA
SUM	$1,836,570,335	$(547,467,838)	**$(793,254,703)**

Figure 20: RDM Results - Regrets, 3 Risks, No Option Values

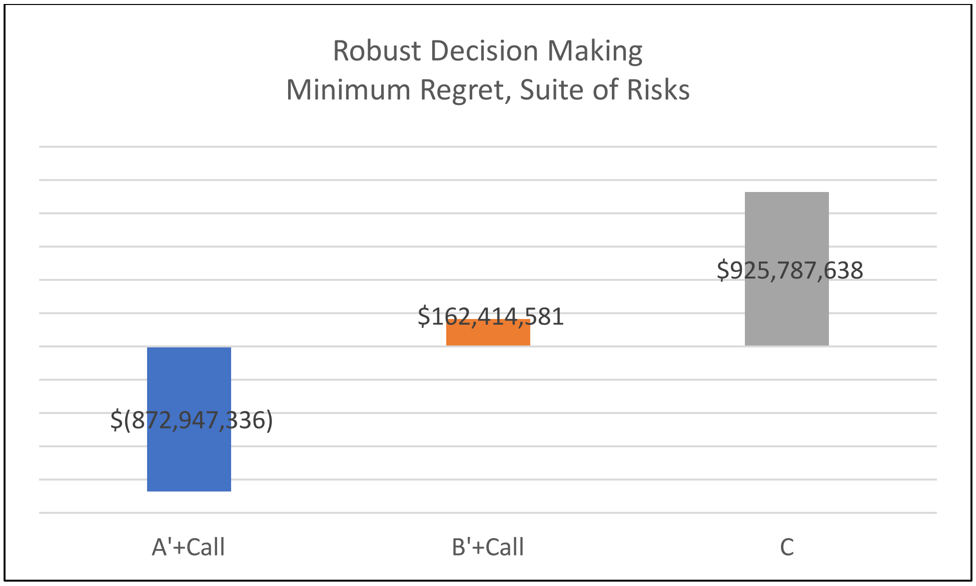


When the RDM models are run with the additional risk factors, plus climate risk, the minimum-maximum regret from the table still supports the selection of the Batoka C design, in agreement with the BCA analysis. The totals show the maximum regret that would be experienced by each configuration in each climate future (dry, medium and wet). In this case, Batoka C (3000 MW) results in the minimum regret, meaning C *outperforms* A and B in the respective dry and medium futures. While Design B outperforms Design A in a dry climate, it underperforms C in a wet future, making the total regret, across all futures, larger than the C design.[23] Finally, since it is the intent of RDM analysis to identify robust designs in general, it should be noted, that Design B also performs robustly across all futures.

However, the results are reversed when using *full project values*. When the *A' + Call Option* is used as the optimized value for a Dry future, and *B' + Option* for a medium climate, (C is kept as optimized for a Wet climate), then *A' + Call* shows the minimum maximum regret. The reason is that the cost overrun risk of both *B' + Call* and C create additional possible regret, that *A' + Call* avoids due to the lower cost, and higher value relative to costs, of the design.

[23] It should be noted that Robust Decision Making could accommodate the values of any project configuration, including an option value added to a design. In that case, an RDM evaluation could incorporate values from flexible design. However, to do the analysis would require an option valuation first.

Figure 21: RDM Minimum Regrets, Considering All Risks, Including Option Values



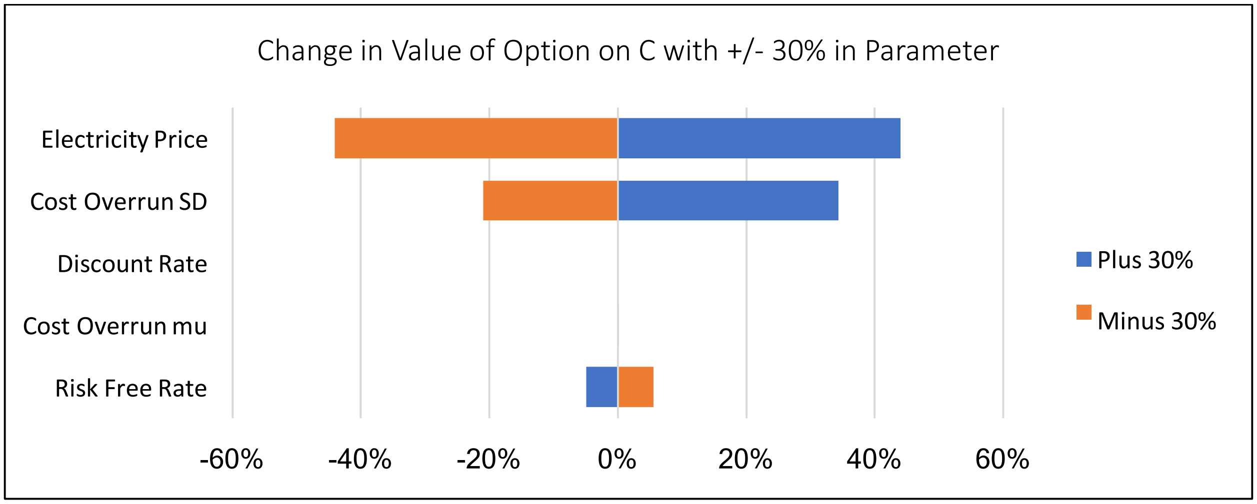
In summary, ROA leads to a full-project valuation, by identifying and making explicit, the value of the flexibility at the site; the value of the flexibility is as much as $870 million depending on the design option, and the value of B' over the next highest valuation is $94 million. By contrast, BCA undervalues the flexibility, by counting the costs against the project, but not including the full benefits. RDM also undervalues flexibility, unless it is combined with an ROA analysis; when this is done, it leads planners to choose the more conservative configuration A', largely to avoid the risk of significant cost overruns for the larger configurations.

Sensitivity Analysis

Two sensitivity analyses were conducted for the most impactful inputs to the model. Both use Design B'; the first measures the change in *value of the option* for the Design, the second the *change in value of Design B'*. The following inputs are changed by +/- 30%: electricity tariff, discount rate, risk-free rate, cost overrun average and cost overrun standard deviation (the average and standard deviation of cost overruns are used in the Monte Carlo simulation to calculate possible cost pathways and therefore affect the expected costs of the project). Figure 22 shows results for the value of the option, while Figure 20 shows results for the value of the complete Design B'.

Sensitivity of Option Values. As can be seen in the tornado diagrams, the impact of the movement of these inputs varies on the value of the option. Blue refers to an increase in the value of the input by 30%; while orange refers to a decrease of the same amount. The largest impact comes from the starting electricity price. A +30% in that input leads to a 44% change in the value of the option. The second largest impact results from changes in the *volatility* of potential cost overruns: a 30% increase in volatility results in a 33.6% increase in the value of the call option. By contrast, a 30% decrease results in a decrease of 21%. The result illustrates the point made earlier regarding option valuation: the more volatile the system, the more valuable the option. After these, the value of the option is also sensitive to the risk-free rate: *increasing* its value by 30% creates a *decrease* of 5.1% change in option value, while *decreasing* the risk-free rate by the same margin results in an *increase* in option value of 5.3%. This is to be expected; as the risk-free rate falls, the value of the option grows because the holder is holding the option against relatively cheap money. The risk-free rate used in the analysis is relatively low, and typically U.S. bond yields are higher. A large increase in the risk-free rate would significantly *decrease* the value of the option.

Figure 22: Change in Value of Option with +/-30% Change in Value of Input



Sensitivity of Project Value. The *value of the individual designs* is more highly sensitive to electricity price, cost overrun standard deviation and mean, as well as discount rate. Again, the blue values represent a *positive* change in the input value of 30% while the orange a *negative* change of the same magnitude. Once again, movement in the electricity price is the most significant. A +30% change in the price of electricity increases the value of the project by nearly 90%, while a decrease tends to decrease the value of the project roughly the same amount. Project values are also sensitive to the cost overrun volatility. A 30% increase in that value decreases project value by 125%. The effect is not symmetrical, however, as a decrease in the same amount only increases project value by 30%. Project values are also sensitive to the discount rate; a lower rate leads to higher values. These sensitivities are to be expected as these inputs are at the heart of project values, and the cost of capital for investment.

Figure 23:Change in Value of Design B' with +/-30% Change in Value of Input

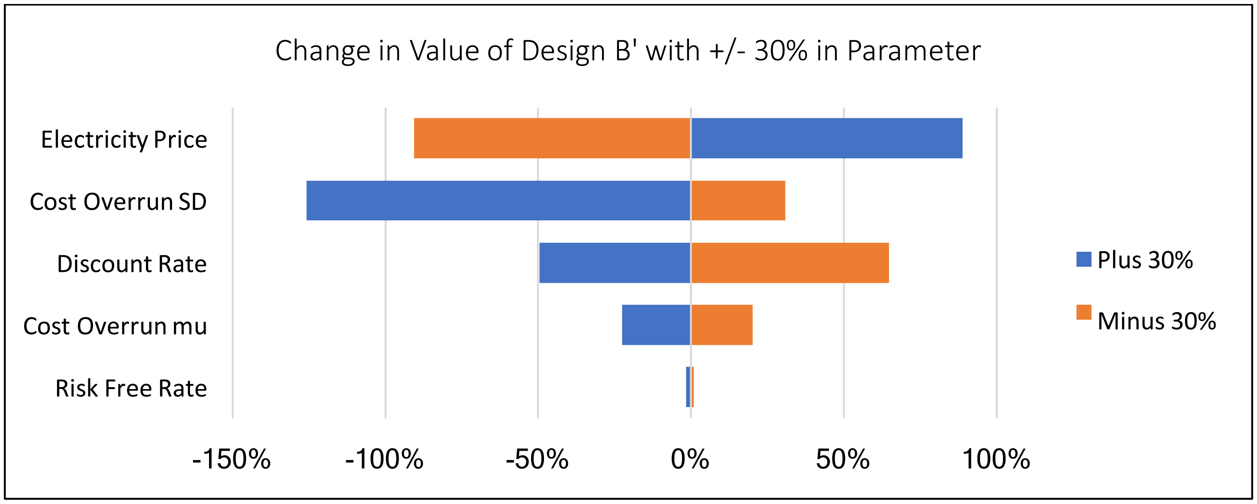


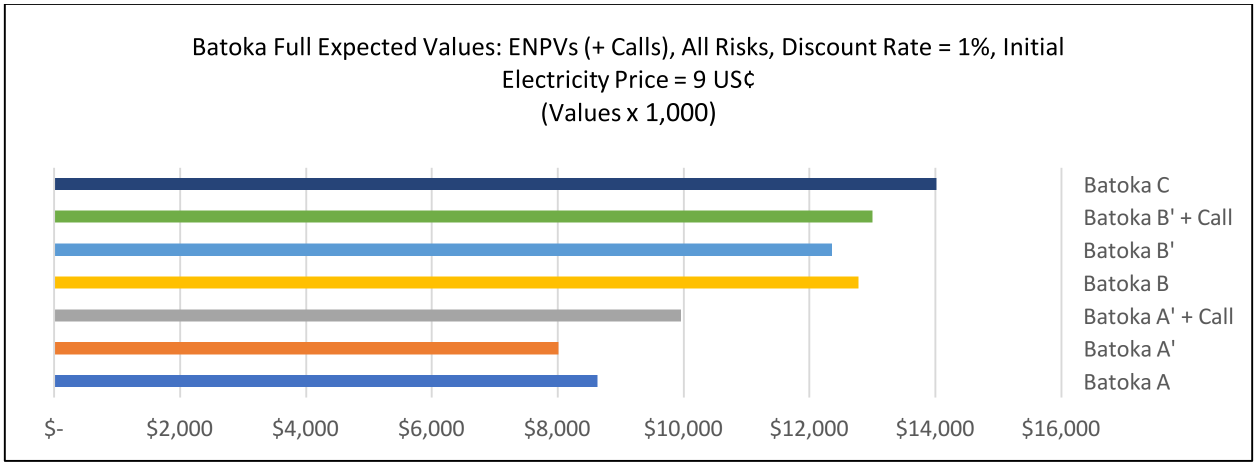
Table 14: Sensitivity of Design B' to Various Model Inputs

Input	Effect of change of input of +30%	Effect of change of input of -30%
Risk Free Rate	1.0%	-1.63%
Cost Overrun mu	20.30%	-22.44%
Discount Rate	64.87%	-49.58%
Cost Overrun SD	30.80%	-125.85%
Electricity Price	-91%	89%

Two Final Scenarios. To more fully appreciate these sensitivities, and to integrate a previous chapter's content related to discount rates, two additional scenarios were run for the Batoka facility. One ran the model using Stern's 1% social discount rate, which places a value on the future as nearly the same as today. The second uses a 15% discount rate; this rate reflects a market rate for infrastructure investments in a non-OECD nation according to JP Morgan (Kohn, 2011). One can easily see the vast difference in project design values, in comparison with previous valuation figures.

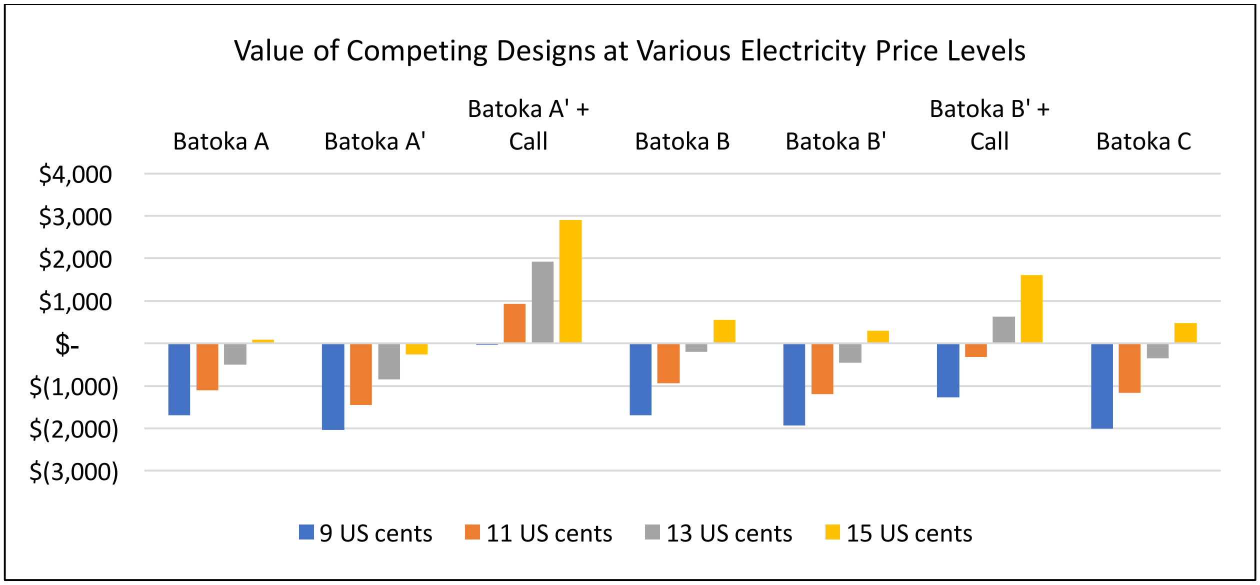
The figure below displays the ENPVs of the various configurations using a 1% discount rate, and the baseline starting electricity price of 9 US cents. Values are much larger, illustrating the relative equity between cash today, and cash in the very distant future. Interestingly, the higher rate also nullifies the value of optionality, even when considering all risks. The reason is that short-term costs, even if overrun, are less of a concern than very long-term project value, even cash flows that accrue well in to the future.

Figure 24: Relative Values of All Analyzed Configurations Using a 1% Discount Rate



When private parties, that require higher rates of return, come to the table, the value of flexibility will increase. To make any version of the project truly viable from a private investment standpoint (using a higher discount rate), the price for electricity would need to climb significantly. Here I used a higher cost of capital and ran the model against increasing electricity tariffs. I began with 9 cents and added in two-cent increments. The smaller facility, with flexibility, displays a positive ENPV at a lower electricity price than any of the other designs. To get the project to move from a negative ENPV to positive would require an electricity price of 10 US cents; even this case yields a positive ENPV for only the Design A' – that is the smallest available design with the option to expand. A price of nearly 15 cents was required for other designs to approach non-concessionary returns. That would mean a doubling of tariffs in Zambia and Zimbabwe – something that is not likely to happen. Projects with lower capital costs, but with flexibility, may well be more attractive to private investment dollars. The reason is the higher discount rate views long-range cash flows as less valuable. Interestingly, the flexibly-designed projects are consistently more highly valued than the static projects when viewed from the perspective of a higher cost of capital. This illustrates the possible difference of priorities between parties in a joint agreement. As private capital is sought for projects, higher costs of capital may mean different project selection criteria, for different parties.

Figure 25: Electricity Price Effect on Project Selection (15% Disc. Rate)



The sensitivity analysis, and especially the interaction of the discount rate and electricity prices, highlights the need for broad stakeholder discussion of parameters as projects such as Batoka are being discussed and designed. Because different parties will bring divergent priorities, it is essential for all parties to understand that the dynamics of initial decisions will have a significant impact on project outcomes.

Conclusion

Results of Comparison Across Methods. Given these designs and data, the findings of the comparisons are several:

- When accounting for climate risk alone, all tools pointed decision makers to the same design: Configuration C.
- BCA and RDM, treat flexibility as a static design, and undervalue it; by contrast ROA assessed an appropriate value. For example, A' is more valuable than A by $870 million, and B' is more valuable than B by $370 million.
- When accounting for all risks, ROA points decision makers to B', which is more valuable than C by $94 million. This choice may also lead to a cost savings of $500 million over configuration C, if the B' facility is build and not expanded.
- The RDM analysis, when combined with ROA points to the smaller and more flexible design as the one with least regrets.
- Climate risk is not the most significant at Batoka, others affect the project more profoundly.
- Private capital, with higher required rates of return, will likely favor a smaller, more flexible design such as A'.

The three methods of decision-making that were illustrated, point to similar decisions when analyzing climate risk alone. However, as uncertainties deepen, and as climate risk interacts with others, a more robust analysis is often necessary. If flexible design is considered, an ROA can place an explicit value on optionality, reducing risk exposure, and increasing investor returns, on average. The framework has also shown that without a real options analysis, RDM and BCA will tend to undervalue flexible designs at these facilities. Finally, the analysis has exposed the potentially conflicting viewpoints of stakeholders. These differences are not immaterial, as they can point to very different conclusions for project optimization.

The example of the Batoka Gorge project, from a perspective of ROA, illustrates the strength of the method as a decision-making strategy, whether considering private capital costs from a financial perspective, or government welfare-related discount rates from an economic analysis. It is fundamentally different from the other methods because it asks and answers different questions, explicitly valuing the nuance of design decisions. Real Options is especially useful when determining various structural options for an investment, that is exposed to high levels of uncertainty. It can guide decisions for a single project such as BGHD, or it can help to establish a policy direction around a series of interconnected projects.

CHAPTER VII

CASE STUDY 2: PHASED DEVELOPMENT AT INGA DAM

While the Batoka case focused on the ROA as contrasted with other methods, the Inga case will focus on applications for the analysis in a transactional setting. The Inga project offers another useful case study, but with different types of design questions than the Batoka project. As a site, Inga offers a greater array off possibilities than Batoka, and backers of the project have suggested a design that allows the facility to be developed in a series of phases. This type of design allows for the testing of the model to value the opportunity to expand by taking large steps, creating a truly mega-project. Also, Inga backers have been forthright about their desire to attract private sector financing, though details are scant. Therefore, the applications within this case study focus on hypothetical aspects of a possible PPP contract. When options are embedded in the PPP concession agreement, they may provide avenues for a public-sector agency to engage with and monitor the concessionaire, as well as create incentives for the concessionaire to flexibly exercise decisions to capture the available value and secure the benefits of the project.

Three applications are highlighted, developed within three hypothetical situations. In the first, project sponsors are seeking a private sector financial partner for a build-operate style PPP. The hypothetical uses a type of contract clause found in extractive industries called a right of first refusal; an ROA is uniquely able to place a value on that type of contract clause. The intent is to offer an additional incentive to the private sector partner through the inclusion of this clause. The second hypothetical suggests an insurance policy against cost overruns. The case uses a put option, to establish the value of such a clause at different levels of coverage. If costs exceed a certain threshold, the sponsors may choose to abandon the project, as cost recovery becomes doubtful. The third hypothetical is one in which a PPP concessionaire wishes to monitor the electricity demand trend for indicators of when to build the next phase. The ROA uses an American-style option to determine appropriate timing for investment, based on demand.

With these issues in mind, the case study illuminates an approach that could help both public and private entities to evaluate possible aspects of a PPP concession approach. I explicitly account for the three different types of uncertainty, commenting on their effect on project value, and evaluating the effects of phasing on expected project valuations. However, unlike the Zambezi River, the Congo is not expected to experience the impacts of climate change in the same magnitude. In fact, according to the World Bank's *Enhancing the Climate Resilience of Africa's Infrastructure (ECRAI)* (Cervigni et al., 2015), Inga will experience very little climate impact. With this perspective in view, the climate analysis has been adapted to make use of the *ECRAI* report, generating climate pdfs in a different way, which is spelled out in detail below. The demand uncertainty has been calculated in the same manner; SAPP regional consumption has been used as a proxy for demand, and price fluctuations have been based on demand elasticities. From a cost perspective, the site has been well studied, and I have drawn on summarized feasibility studies and cost estimates for developing the models; no new cost model was developed. To ground the case study, familiar steps were taken: frame the project, gather the inputs, and calculate the option. First, however, a brief history of the site is warranted.

Background of Inga

The Congo River and First Facilities. The hydropower potential of the Congo River was recognized during colonial times, when rivers were first being harnessed to generate electricity. Belgium first studied the Inga site in the 1920s and 30s, but research was suspended during World War II. In the 1950s the Belgian government began planning a hydropower facility on the site.

Construction delays pushed the start of the project into the 1960s when Inga was interrupted again during the independence movement, and a subsequent coup.

The first hydropower facilities were finally developed in the 1960s and 70s. Inga 1 was completed in 1972 with financing from the government of the Democratic Republic of the Congo. The facility is a six-turbine plant that generates 351 MW, and electrical output is delivered mainly to populated areas in nearby Kinshasa. Inga 2 was the second hydropower project built at the site, completed 10 years after Inga 1. The Inga 2 dam contains eight turbines, and its max capacity is 1,424 MW. Power from this facility is dedicated to mining activity in the south in the Katanga Province near the Zambian border. Ingas 1 & 2 were constructed, and are owned and operated, by the state-owned power utility Société Nationale d'Electricité (SNEL) (PowerTechnology.com 2014) (Showers, 2009).

Inga 3 and Grand Inga have recently been redesigned with a flexible, phased, build-out plan. In 1974, Inga 3 was designed as a large concrete arched dam with approximately 150 meters of head. However, the project was never developed. In 2011, AECON published a conceptual, pre-feasibility study for hydroelectric development of the site and associated transmission interconnections to deliver output (AECON 2011). Rather than the previously designed single-arched dam, the AECON study called for a series of dams and run-of-river projects. The rationale was that smaller, stand-alone projects are easier to phase, finance, build and manage, as opposed to a large monolithic facility. The phased construction plan may also allow the initial phase to begin earlier than expected (HYDRO 2011). AECON's study explored two project pathways, making the case that either would be better than the single structure, though both eventually lead to a large concrete dam. AECON calls the two alternatives "Progressive" and "Accelerated", and recommends the later. Once either of the two alternatives is completed, a series of large run-of-river projects could be added to the site, in four additional phases.

Progressive plan: Phases A', B', and then C': This concept, called *Progressive* envisions an initial dam (Inga A') of 150 meters, with a subsequent spillway constructed alongside the dam, creating an additional run-of-river power site (Inga B'). Later, the dam could be raised to 205 meters; the spillway would be covered and incorporated into the new larger dam (Inga C'). The total output from this series of facilities would be 11432 MW, with a construction cost of US $16.2 billion (AECON, 2011).

Accelerated plan: (Recommended by AECON): Phase A and then C (no Inga B' spillway). The second alternative, called *Accelerated*, envisions a flexible design of the first dam, A, and then an augmentation of the dam to a larger one. In this alternative, Inga A would be built to the initial height of 150 meters, and then Inga C would be developed as an expansion of the original dam. The new dam would be 205 meters high, though it would possess a smaller capacity than the previous alternative. The advantage to this design, is that there is no overbuild for Inga B. The total output from this series of facilities would be 5716 MW, with a construction cost of US $10.4 billion (AECON, 2011).

To accomplish the build out would require river closure, and the flooding of the Bundi Valley (adjacent to the current Inga dams) to create a 22,000-hectare reservoir, stretching 15km up river (Tshombe et al., 2007). An outlet from the reservoir would continue to feed Ingas 1&2. In addition to building the dam wall and Inga C hydropower plant by 2020, the project proposes a power line that would stretch more than 3,000 km, from the powerhouse to South Africa, through Zambia and Namibia (AECON, 2011).

The final four phases (D through G) involve the construction of four headraces, and attendant powerhouses, creating additional spillways from the reservoir. Head pond levels would remain the same, as no new retaining structures would be built. Natural head on this portion of the river is 100 meters. New capacity would be approximately 7,400 MW per headrace. The entire system would utilize 52 generating units, each with a capacity of 750 MW. Completing all phases would bring the total capacity to 42,000 MW, with a mean annual production of 331,663 GWh (AECON, 2011).

Table 15: Head, Max Generating Capacity, and Fixed Costs for Each Phase

Summary of Construction Options			
Phase	**Head (m)**	**Output (MW)**	**Initial Costs ($)**
Inga A' - Progressive	150	3709	$7,313,818,147
Inga B' - Progressive	100	3275	$4,845,293,063
Inga C' - Progressive	205	4448	$4,042,264,685
Cumulative Progressive	205	11432	$16,201,375,895
-----	-----	-----	-----
Inga A - Accelerated	150	3492	$6,347,936,307
Inga C - Accelerated	205	2224	$4,042,264,685
Cumulative Accelerated	205	5716	$10,390,200,992
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Inga D	100	6370	$4,481,050,722
Inga E	100	7080	$4,516,094,866
Inga F	100	7070	$4,765,974,873
Inga G	100	7080	$4,464,844,891
Cumulative Final Phases		27600	$18,227,965,352

Source: AECON 2011

AECON analysis leaves the last four Phases D – G on the table for consideration. According to the report, there could also be an additional Phase H, that would add additional capacity of approximately 7,000 MW. This case study focuses primarily on the first phases of the site: A-C.

Step 1: Frame the Inga Project

Stakeholders. The stakeholders for Inga form a similar group to those for Batoka, with a few exceptions. The national electrical utility in the DRC is SNEL (Société Nationale d'Electricité), which is a government owned entity; this body would oversee the facility from the utility standpoint. The DRC's ministry of energy, and indeed its national government are also stakeholders. The dam is important to government, and the population of DRC for several reasons, some of which may be in conflict. On one hand, the DRC has very low rates of electrification, and would like to use Inga to service domestic need; on the other hand, the financial condition of the nation, and the expense of the facility may mean that a good portion of the power would need to be sold to the highest bidder.

The DRC has one of the lowest rates of electrification in the world. Based on 2013 data, DRC's national electrification access rate was just 9%, with 1% in rural areas and 19% in urban areas. The DRC's installed generation capacity of just under 2,500 MW is 99% hydropower. Most of this generation is concentrated at the current Inga site. Currently, the DRC utilizes just 2% of its estimated 100,000 MW of hydroelectric potential, around 40,000 MW of which is concentrated at Inga. Unfortunately, the government has been unable to meaningfully increase generation capacity in recent years. To address the power constraint on economic growth, the government approved a new Electricity Code in 2014 which authorized the establishment of a regulatory agency and a rural electrification agency, while opening the power sector to private investment. The Electricity Code is now in the process of implementation. (USAID, 2016).

Another stakeholder is the fast-growing mining industry, especially mines in the copper-belt region, which has been the recipient of most available power. The copper sector complains of a current shortfall of 300 MW of power.

The nation of South Africa is also a potential stakeholder. South Africa and the DRC signed a Memorandum of Understanding (MOU) in November 2011 for the development of Grand Inga. Under the legally binding agreement Inga would supply 2,500 MW to South Africa by 2021 (Vidal, 2016). Though transmission development remains a problem, the idea is that Inga would sell power directly to South Africa in a bilateral agreement. This agreement could have a significant impact on the price of electricity supplied by Inga, and therefore its revenue stream, as South Africa's electricity price is significantly higher than most other nations in the SAPP. The DRC government is attempting to fast-track development to fulfil the contract signed with the South African government.

The financial structure should consider national budgets. DRC government revenues for 2013 were U.S. $5.8 billion. Expenses during the same period were U.S. $6.5 billion, leading to a deficit of 3.5% of GDP. GDP in 2015 was U.S. $35.2 billion (World Bank Congo, 2016), and government debt equals U.S. $6.9 billion (Index Mundi, 2014). Unfortunately, the DRC is not a traditionally transparent government when it comes to revealing budgetary information; it received a score of just 39/100 for 2015 on the Open Budget Survey of International Budget Partnership, a non-profit (International Budget Partnership, 2014).[24] Grants and external aid make up a large portion of DRC's revenue stream. According to an OECD report, in 2005 grants made up about one-third of government revenue, or 5.2 per cent of GDP, and in 2006 external aid was 57% of the government's budget ($2.2 billion, or 9.5 per cent of GDP). Tax revenue is partly reliant on mining and oil exports, which can be volatile (OECD, 2008).

The result of tight public budgets, the government has been open about its need to attract private financing to develop the Inga site. This may take the form of a build-operate-transfer, or a

[24] A perfect score is 100; DRC is 23rd from the bottom and up from a score of zero in 2008, and 6 in 2010. http://survey.internationalbudget.org/#rankings.

parastatal. Current thinking for the financial structure for Phase A is to offer private shares in the amount of $2.22 billion to a consortium that would include a private developer and SNEL (the National Electric Company); and to finance the remaining $6.65 billion as debt from a variety of sources including multilateral and bilateral banks, Chinese Policy banks, and commercial banks. This would double the national debt, and create a pre-operational debt to revenue ratio of 2:1. Inga backers have been actively discussing the need for a public private partnership, but the need for private financing changes the project considerably, especially relative to required rates of return.

The Decision. Since there is the possibility for various stakeholders to come to the project with different priorities, significant work would need to go into the contract for collaboration, including the definition of a decision rule. Part of the contractual agreement would be the criteria around decision-making. For the purposes of the case study, I will make some basic assumptions about the working relationships of the various parties, which are reflected in the project parameters below. As for the decision rule, the value of the project will once again be used.

Uncertainties. The same uncertainties will once again be modelled and analyzed.

Value Leakage. In this case, the cost of O&M is the only source of value leakage.

Underlying Asset. The underlying asset – what one receives if they exercise the option - is again modelled based on the anticipated cash flows of the future facility.

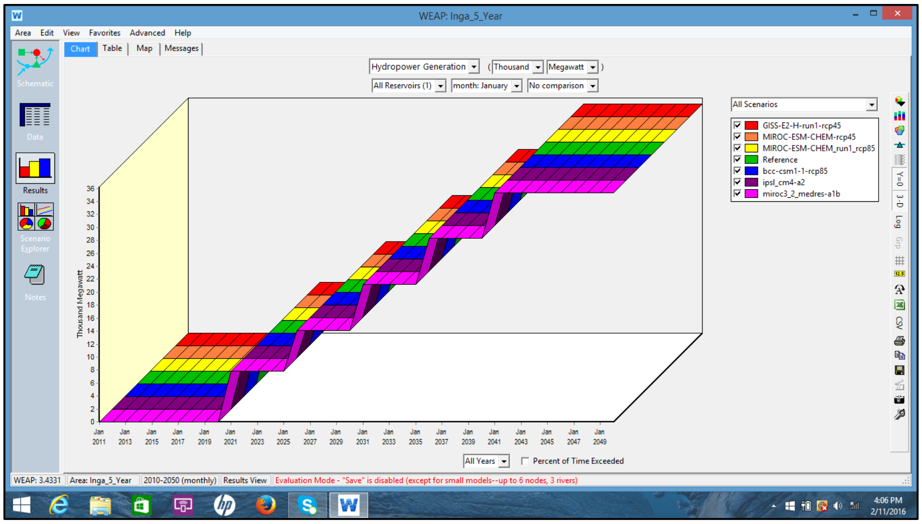
Step 2: Gather the Inputs

Table 16: Inputs for Option Calculator

Inputs Required for Options Calculator	
Volatility of key uncertainties	Observed in markets or modeled
Volatility of output due to climate change	Modeled in WEAP and Monte Carlo
Volatility of demand	Modeled based on consumption changes
Volatility of cost overruns	Modeled based on literature
Current value of the underlying asset	Calculated from revenue model
Discount rate	Cost of capital, or official World Bank rate
Risk-free rate of return	U.S. government bond

Hydropower Output. The Congo River basin includes catchments from above and below the equator, and therefore enjoys two rainy seasons each year. As a result, a WEAP screening tool shows negligible climate impact on hydropower output at Inga. Figure 23 shows the WEAP model's average annual hydropower production under six different climate futures, ranging from wet to dry, stair-stepped to simulate five consecutive build-out plans. This is confirmed in Cervigni et al., "Enhancing the Climate Resilience of Africa's Infrastructure (ECRAI)" report, (2015). To endeavor an alternative method for developing pdfs for hydropower output, data from the ECRAI report for the Congo River basin were used to project hydropower output at Inga. The report used the Climate Moisture Index (CMI) as a proxy for climate impacts on hydropower. The CMI is an aridity measure that combines the effect of rainfall and temperature projections. Index values range from -1 to +1, with values below zero indicating more arid conditions. Values higher than zero indicate that rainfall rates exceed potential evapotranspiration rates. According to the report, CMI is "reasonably well correlated with the hydropower and irrigation impacts expected from each climate projection" (Boehlert et al., 2015). The moments from the distribution of hydropower outputs for the facility were then used to conduct a Monte Carlo simulation of 400 runs. Starting hydropower output values were taken from the AECON feasibility study (Table 15), with a 90% capacity factor assumed.

Figure 26: WEAP Results Graphic Showing Regular Build Intervals



Volatility of Demand and Cost Overruns. The same procedure from the Batoka case, already discussed at length in that case study, and in the Methodology chapter, was used for the Inga case study.

The three uncertainties are then combined into the revenue model, which generates 400 possible revenues for the various phases at the Inga site. The volatility input for the ROA is the standard deviation of the log returns to the project. To accurately compute real option values, the continually compounded rate of return is used. This was calculated, for each of the 400 revenue scenarios, using the following formula and solving for r:

$$\sum_{t=1}^{n} K_t e^{-rt} = \sum_{t=1}^{n} CF_t e^{-rt} \tag{22}$$

Where *K = initial capital costs; r = rate of return; t = years; and CF = net annual cash flows (revenues – operation and maintenance)*. The resulting formula for calculating the rate of return is:

$$r = \frac{ln\left(\frac{K_t}{CF_t}\right)}{-t} \tag{23}$$

Separately, the costs of build-out possibilities must be considered for each facility. The build-out possibilities are based on candidate flexibilities discussed above. AECON envisions the build-out of Inga in discrete self-contained pieces, each of which can function independently. The advantage to this design is its flexibility. At the completion of each phase, developers have the flexibility to stop, to wait, or to keep expanding the project. For this analysis, the cost estimates from the AECON feasibility study are used. These costs represent generation only; no transmission or distribution infrastructure is considered.

Table 17: Fixed Costs Per Phase (AECON)

Phase	Initial Costs ($)
Inga A' - Progressive	$7,313,818,147
Inga B' - Progressive	$4,845,293,063
Inga C' - Progressive	$4,042,264,685
Cumulative Progressive	$16,201,375,895
-----	-----
Inga A - Accelerated	$6,347,936,307
Inga C - Accelerated	$4,042,264,685
Cumulative Accelerated	$10,390,200,992
-----	-----
Inga D	$4,481,050,722
Inga E	$4,516,094,866
Inga F	$4,765,974,873
Inga G	$4,464,844,891
Cumulative Final Phases	$18,227,965,352

Value of Underlying. Similarly, the value of the underlying asset was calculated from the revenue model at Inga. The future value of cash flows from the development of the next phases of the facility, were discounted to present day, using a DCF technique. The strike price of the expansion is the cost of investment to build the next phase of the facility.

Discount Rate. One important difference exists between the previous Batoka case study and this case on Inga. Since sponsors have indicated an interest in attracting private capital in a PPP agreement, a discount rate of 15% has been chosen, based on a JP Morgan report detailing typical internal rates of return for non-OECD infrastructure development (Kohn, 2007). There are some other differences in the chosen parameters, selected to augment the illustration of the model's applicability. These are discussed in each of the *Hypotheticals* below. The assumption I have made for this case study is that a private investor would operate the phases at Inga. Private investment would require a higher internal rate of return (see the parameters below). Though the government's "social discount rate" would apply later in the life of the project, the discounted value would be negligible as the cash flows from the first 25 years (another assumption) would belong to the private consortium.

Table 18: Inga Assumptions

Inputs	
Investment time horizon (includes 5-year build per phase)	25 years
Discount rate[25]	15%
Risk-free rate	1.75%
Required ROR	15%
Initial elec. price[26]	0.12
Electricity price elasticity	0.20
O&M as percentage of capital costs	2.5%
Average cost overrun for dams	0.4
Standard deviation for cost overruns	1.25
Corp Tax rate	15%

[25] JP Morgan places the risk of investment in non-OECD countries as "high;" it has the same assessment for merchant power generation. The range given is 15%-25%. Both extremes have been modeled, and the results are presented. (Kohn 2007)

[26] According to Climate Scope, 2016, the average electricity tariff for DRC is $0.048 per kWh, the lowest amongst members of the South African Power Pool and well below SNEL's costs. The result is a financial losses equivalent to 4% of GDP. The DRC recently approved a general tariff increase that increased tariffs for mining customers to 5.69 US cents per kWh and for residential customers to 8.7 US cents per kWh, which has allowed SNEL to increase its collections to the level of $35-40 million per month. (Climate Scope, 2016). To calculate an electricity price, one option is to use a weighted average electricity price allocating 68% to the South African price of 11.2 U.S. cents/kWh, and 16% to mining and residential each. The resulting weighted average price is US$ 0.0918/kWh. However, given the other parameters in the model, this electricity price does not offer a breakeven on the design. So, I have chosen a higher rate for some of the hypotheticals, for purposes of illustration.

Step 3: Calculate the Option

For the first *hypothetical* – a right of first refusal - the Black-Scholes formula is used to calculate the value of the phased design. The formula calculates the value of the option to build the second, and third facility in the series. The Black-Scholes calculator has already been discussed. For the second hypothetical – a cost overrun insurance policy - the same calculator is applied. However, the calculator is run many times, to generate a picture of the cost for insurance given different levels of coverage. For the third hypothetical – a demand driven trigger – a binomial tree lattice model of a *call option* has been used. The same lattice method has been used. However, in this case, an American option valuation has been developed (recall that an American option allows the holder to exercise anytime between the date of issue and the exercise date),

Results

Hypothetical 1: What is the value of a *right of first refusal* clause? The answer requires the value of the option to expand, modeled as a European call. This initial application takes the real options methodology to identify the value of the option, and then applies it to a hypothetical contract case.

The presumed goal is to leverage the additional value found in the design, to help attract a private investment partner. By explicitly valuing the option to expand the facility, a cash value is created that might be used as an additional incentive. The holder of the option would maintain the right to take an action in the future. They could exercise the option, and develop the next facility; or, they could cash in the option for the value determined by the analysis.

To calculate the value of optionality, I used the Black-Scholes formula, by inserting the present value of Inga C, and its cost into the equation (Table 17). The risk-free rate remained

1.75%. Two important counterfactual assumptions were made, to illustrate the analysis for this hypothetical situation. One, I used an electricity price of US$ 0.12, which is considerably higher than the likely tariff, even after a recently approved general tariff increase. (Electricity tariffs are exceptionally low in the DRC, and at the calculated initial price, the first facility did not recover its costs. So, for the purposes of illustration, I increased the tariff so comparisons could be more easily seen.) Two, I did not include the payment of a tax in this version of the model. Finally, and importantly, the purpose is to evaluate hidden sources of value and changes in value rather than specific valuations. To arrive at more precise NPVs would require greater specificity of inputs, agreed upon by stakeholders.

With these caveats, the static ENPVs calculated for *Accelerated* project A as presented in Table 19, is $415 million. But the cumulative value of the investment opportunity would include the project itself, and the value of the option to move forward with project C at some point in the future. The option adds an additional US$ 2.7 million. While this is not a significant amount, given the size of the project, the values change when considering AECON's *Progressive* menu of options, discussed below. First, however, consider how the addition of the option value may be applied to the PPP agreement.

Table 19: Value of A' Plus Expansion Options on B' and C' (Grand Inga)

Aspect	ENPV A	Option Value for C	Full A-project Value
A	$415,016,091	$2,775,566	$417,791,657

A right of first refusal, or a preferential right, generally refers to the right to choose to purchase an interest or asset owned by another party based on a triggering event. The triggering event may be the passage of time, or some other observed phenomenon (Poitevent and Hewitt, 2000). The term usually refers to the right granted a joint operator, to purchase the interest of another party to the agreement, upon that party's decision to sell. As Poitevent & Hewitt point out, these rights are akin to a call option, and are frequently encountered in the oil and gas industry, as well as in real estate. Applications for other corporate style assets are also frequent. In this case, the proposal is to offer the right, and cash value, to the developer, who would then have the option to either develop the next facility, or sell the option back to the project sponsors for cash. By explicitly adding the value of the option to a Joint Venture contract, along with the right type of legal safeguards, government sponsors may incentivize initial engagement in the project, and keep control of the list of approved developers.[27] An ROA has placed a value of $2.7 million on the preferential right.

Turning attention to AECON's *Progressive* series (A', B', C'), the model shows a more profound impact by including option values. In this case, calculations show a *negative* ENPV for the first phase. However, the options on B' and C' indicate that the comprehensive value is positive; in fact, the option values from the *Progressive* series augment the initial A' project more significantly than the *Accelerated* build-out plan. The B' option value is calculated as a call option on the second in the *Progressive* series of projects, while the option on C' is the call on the third phase. The call option on B' is worth $283 million, while the call option on C' is worth an additional $3.3 billion; this means the full project value, including the value of flexibility from phasing the project is $3.9 billion for project A'. The *Progressive* pathway leads to a significant increase in value over the *Accelerated* pathway in which the full value of the first project is just $417 million. The options are valuable because they represent the opportunity for future cash flows at the next phase of development.

[27] First-right-of-refusal provisions are generally included in operating agreements to serve two purposes. First, the option affords each party the opportunity to increase its ownership position and economic stake in the project, which will likely have increased in value by development and operations. Second, the provision gives the parties some control over the identity of their co-owners by allowing the holders of the preferential right to preempt the participation of an undesirable third party as a co-owner in the unit (Christiansen, 1996)

Table 20: Expected Benefits and Cost for Progressive Build-Out

Aspect	Benefits	Costs	Net
A'	$10,469,345,105	$(10,166,645,554)	$302,699,551
B'	$4,668,209,135	$(4,845,293,063)	$1,135,836,596
C'	$6,741,035,861	$(4,042,264,685)	$5,432,089,183

Table 21: Comprehensive Value for A', Includes Options on B', C'

Option values		
	Option Values	Full A-Project Value
Call on B'	$283,179,777	$585,879,329
Call on C'	$3,347,728,392	$3,933,607,720

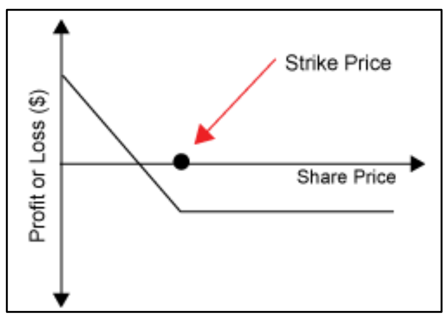
The difference in values comes from a combination of sources. First, the *Progressive* B' costs are lower than those of the next phase of the *Accelerated* pathway; the revenues from the successive projects are also higher. Second, the fact that the *Progressive* pathway allows for two additional phases of development, and that the final stage (site C') is 10 years hence, means that the option values are considerably higher. The option on C' contains 10 years of possible demand increases, and possible flow increases due to a changing climate.

The phased design has augmented the value of the project. Were Inga to have remained a static design, there would be no optionality, and no additional value for subsequent phases. The subsequent phases hold financial value because they represent the possibility of future cash flows. This represents embedded value in the early phases of the project, that could be accessed by the owners of the facility, in the manner described.

Finally, though AECON recommends the *Accelerated* build-out of moving from Inga A directly to Inga C, the analysis indicates that this decision may leave uncaptured value. While initial costs are lower for the *Accelerated* design, the values are significantly higher for the *Progressive* pathway.

Hypothetical 2: An insurance policy for the sponsors against project overruns. In this situation, a case is created in which the sponsors of the project would like insurance against cost overruns due the developer. The controversy surrounding large dams, that has been discussed elsewhere in this dissertation, is aptly illustrated at Inga. If fully developed, Inga would be the largest hydropower plant in the world, and the first two phases have already been plagued by mismanagement, unpaid debt, and cost delays, at Inga I and II. However, in this case study, I present one approach for assessing the available benefits while avoiding the typical pitfalls of the "inside view" of a typical project proposal.

Figure 27: Payout Diagram for a Put Option



Source: Investopedia

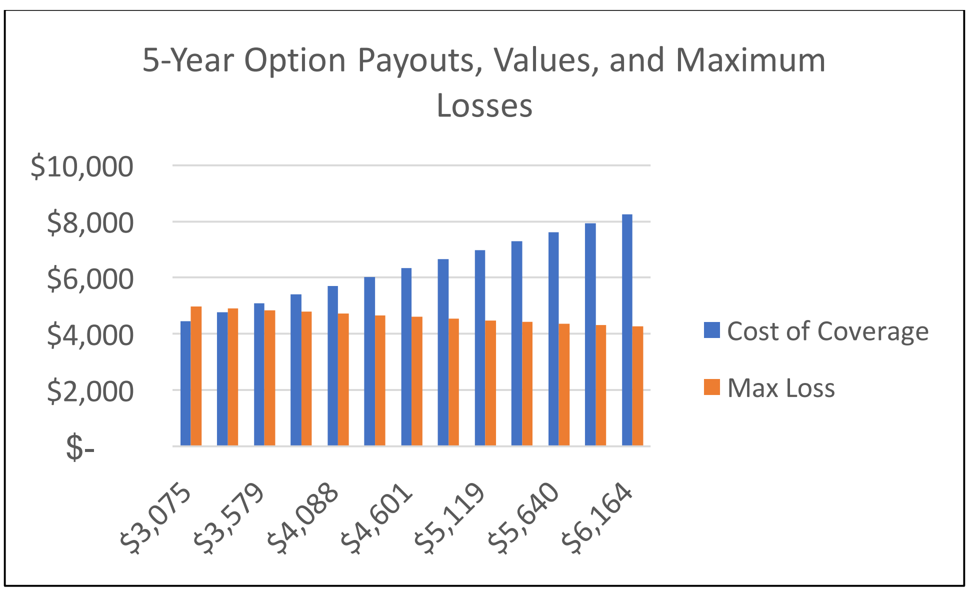
This case once again makes use of the *Accelerated* Inga A, at a projected cost of $6.35 billion[28], and uses the Black-Scholes formula to calculate a 5-year *put* option. The put option creates a value floor; when values fall below the floor, the holder of the option can exercise and "sell" the project for the strike price. The strike price has been set at the project cost of $6.35 billion. The option would give the holder, in this case the project sponsors, the right to a refund in the amount of the originally estimated cost of the project. However, the option valuation begins

[28] Once again, the electricity starting price is $0.12/kWh, set to preserve a positive project value.

with the present value of Inga A, which is $9.86 billion. The net present value is smaller, at $415 million.

Doing the analysis reveals that the value of such an option is $4.60 billion, based on cost overrun risk alone. In a PPP contract, there are many ways to include an insurance contract, but one way would be for the sponsor to pay the developer the value of the option ($4.6 billion) as insurance for cost overruns that could be much higher. This would essentially turn the contract with the developer into a fixed-price contract. The Monte Carlo simulation for cost overruns at the initial Inga A project, indicates an expected cost of $13 million. Incremental payments during the construction phase need to be dealt with as well, another aspect of the contract. The policy serves as an incentive for the developer to maintain the costs of the project, but also gives a significant buffer for overruns. Figure 28 shows various levels of coverage that could be purchased. Higher coverage levels come with higher costs. While the cost of coverage appears high, it is based on the frequency and severity of a broad, global experience of cost overruns.

Figure 28: 5-Year Insurance Option Payouts, Values, Maximum Losses



Continuing with the example above, a put option, purchased for \$4.6 billion (the centermost value in Figure 28), would receive a payout of \$6.3 billion, if the value of the project were to fall below that point. This option would insure that the sponsor would never lose more than \$4.9 billion, the estimated cost of the project; this is set against an *expected* cost of \$13 b.

Project Cost =	\$6.3 b
+ Cost of Option =	+\$4.6 b
- Option Payout =	- \$6.3 b
Maximum Loss =	\$4.6 b

Other values can be substituted for the cost of the option, from the x-axis values in Figure 28, yielding smaller or greater payouts, and therefore, smaller or greater maximum losses, depending on the desire of the option holder. Additionally, other insurance clauses could also be explored. For example, equity owners could calculate and purchase an insurance clause against declining consumption due to a lack of infrastructure development, or to infrastructure decline. The process of creating a put option would be the same as illustrated here.

Hypothetical 3: Develop demand-driven triggers for a decision rule on next phase investment. Under this hypothetical situation, developers are concerned about electricity demand. Having developed the first phase, Inga A, they desire a mechanism that tracks demand, and points to a trigger – a decision rule – that indicates at what point to move forward with the next phase. The option to expand expires after 10 years, and developers have until that time to decide whether they want to exercise the option. This requires the use of an American-style call option (the option can be exercised any time up to the exercise date). The analysis shows that, aside from a cost associated with waiting, the choice will be to wait until the end of the period to exercise the option. This is a typical result from American options.

I have constructed a series of decision trees to determine at what point the holder of an option to develop Inga C (after having built A-*Accelerated*) would decide to build, using realized demand as a decision rule. Assuming price and demand are linked, through the elasticity described earlier, two lattices were created: one of electricity prices, and the other of electricity demand. (I further assume that Inga is the only generation facility fulfilling new demand.) The two lattices are then combined into one revenue lattice. This lattice represents possible revenue pathways over the first ten years of the facility's operation.

The process involves explicitly modeling demand risk, through building a binomial tree of possible demand pathways, and tying that risk to electricity prices. The up-step in each lattice is calculated using the equation 11: $U = e^{\sigma * \sqrt{\Delta t}}$; and the down value uses equation 12: $D = \frac{1}{U}$. The σ figure is from the log consumption changes in the SAPP derived earlier. The binomial tree is found below. For the demand lattice, I have chosen an initial demand value of 2500 MW, the amount specified in the MOU with South Africa. From the initial demand, values can either increase ($V_{up} = V_0 * U$) or decrease ($V_{dn} = V_0 * D$). To build the price lattice, the same method was used. For this hypothetical, however, an initial electricity price of US$ 0.099 was used.[29] Again, prices move either up or down, and the σ figure comes from the log changes in prices, derived from changes in demand.

Figure 29: Binomial Lattices for Demand, Price and Revenue

Demand	2500	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Consume mu	0.0223	2500	2734	2989	3268	3573	3907	4272	4671	5108	5585
Consume s.d.	0.0893		2286	2500	2734	2989	3268	3573	3907	4272	4671
U =	1.0934			2091	2286	2500	2734	2989	3268	3573	3907
D =	0.9146				1912	2091	2286	2500	2734	2989	3268
						1749	1912	2091	2286	2500	2734
							1600	1749	1912	2091	2286
								1463	1600	1749	1912
									1338	1463	1600

[29] Please see foot note 28 for the calculations of this electricity price.

										1224	1338
											1119

Price	0.0662	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Price mu	0.0028	0.07	0.07	0.08	0.09	0.09	0.10	0.11	0.12	0.14	0.15
Price S.D.	0.0301		0.06	0.07	0.07	0.08	0.09	0.09	0.10	0.11	0.12
U =	1.0305			0.06	0.06	0.07	0.07	0.08	0.09	0.09	0.10
D =	0.9704				0.05	0.06	0.06	0.07	0.07	0.08	0.09
						0.05	0.05	0.06	0.06	0.07	0.07
							0.04	0.05	0.05	0.06	0.06
								0.04	0.04	0.05	0.05
									0.04	0.04	0.04
										0.03	0.04
											0.03

Revenue Pathways		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
(X 1,000,000)		$1,449	$1,733	$2,071	$2,476	$2,961	$3,540	$4,232	$5,060	$6,049	$7,232
q =	0.50924		$1,212	$1,449	$1,733	$2,071	$2,476	$2,961	$3,540	$4,232	$5,060
1-q =	0.49076			$1,014	$1,212	$1,449	$1,733	$2,071	$2,476	$2,961	$3,540
U =	1.19557				$848	$1,014	$1,212	$1,449	$1,733	$2,071	$2,476
D =	0.83642					$709	$848	$1,014	$1,212	$1,449	$1,733
							$593	$709	$848	$1,014	$1,212
								$496	$593	$709	$848
									$415	$496	$593
										$347	$415
											$290

To determine the impact of demand on future development, the electricity prices from each state of nature (represented by individual cells) were multiplied against the demand figures from the corresponding state of nature. The result (including a conversion from MW to kWh) is found in Figure 23. This process has yielded a range of 10 possible revenue pathways by year 2026, 10 years after the option is granted. The next step is to build a standard DCF cash flow model that takes each revenue pathway, and considers an NPV of the next phase of the project: Inga C, 10-years hence. To do so, I assumed the following. The cost of operation and maintenance was 2.5% of the estimated cost of Inga C; this value was held constant. The depreciation was a straight-line depreciation. A corporate income tax was assessed, as this hypothetical comes from the perspective of a private investor. Finally, I estimated income as growing from the various pathways by calculating a forward value. The forward value applied was determined based on the revenue pathway, according to the equation:

$$F_t = V_0 * e^{(r-ncy)t} \tag{24}$$

Where F_t = *the forward price at time = t;* V_0 = *present value; r is the risk-free rate* and *ncy* is the net convenience yield.[30] The *ncy* was calculated based on the changes in the Revenue pathways.

Figure 30: Static DCF and NPV at Future C Facility

(X 1,000,000)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Annual costs	$-	$(101)	$(101)	$(101)	$(101)	$(101)	$(101)	$(101)	$(101)	$(101)	$(101)
Operating Income	$1,449	$1,477	$1,506	$1,535	$1,564	$1,595	$1,625	$1,657	$1,689	$1,721	$1,755
Less Depreciation	$-	$(162)	$(162)	$(162)	$(162)	$(162)	$(162)	$(162)	$(162)	$(162)	$(162)
Income before Tax	$-	$1,214	$1,243	$1,272	$1,302	$1,332	$1,363	$1,394	$1,426	$1,459	$1,492
Less: Tax	$-	$(182)	$(186)	$(191)	$(195)	$(200)	$(204)	$(209)	$(214)	$(219)	$(224)
Net Income	$-	$1,032	$1,056	$1,081	$1,106	$1,132	$1,158	$1,185	$1,212	$1,240	$1,268
Add back Deprec.	$-	$162	$162	$162	$162	$162	$162	$162	$162	$162	$162
Free Cash flow	$-	$1,194	$1,218	$1,243	$1,268	$1,294	$1,320	$1,347	$1,374	$1,402	$1,430
NPV	$6423										

Notice the DCF cash flow model begins in 2027. The intent is to model the static cash flows from the end of the option exercise period, based on a range of revenue values, which have been derived from demand and price projections. The NPV is evaluated under each Revenue value from the table above, representing all possible states of nature for demand and price projections.

Because this is an American-style option, each NPV, for every state of nature, is weighed against the strike price, which is the cost of developing the new facility. Table 23 below shows those values based on $MAX(NPV - Strike, 0)$. Where the values are positive, the choice will be to exercise the option and develop the site, where the values are zero the option will expire.

Table 22: Maximum Value of NPV Minus Strike or Zero

(x 1,000,000)		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**

[30] A Net Convenience Yield (ncy) reflects the value leakage (or gains) in holding some asset. In the example at hand, the ncy is negative, which means negative value leakage.

Exercise	$2,380	$2,380	$3,697	$5,271	$7,153	$9,403	$12,093	$15,309	$19,154	$23,750	$29,246
			$1,279	$2,380	$3,697	$5,271	$7,153	$9,403	$12,093	$15,309	$19,154
				$358	$1,279	$2,380	$3,697	$5,271	$7,153	$9,403	$12,093
					$-	$358	$1,279	$2,380	$3,697	$5,271	$7,153
						$-	$-	$358	$1,279	$2,380	$3,697
							$-	$-	$-	$358	$1,279
								$-	$-	$-	$-
									$-	$-	$-
										$-	$-
											$-

However, there is another factor to consider. Since this is an American option, the holder has the right to exercise, or to hold the option open, and wait for a more profitable demand opportunity. The process, therefore, weighs the value of building the facility (which is illustrated in Table 22), or waiting until later. Table 23 below, shows the following calculations for each state of nature:

$$MAX(Value\ of\ Option, Value\ of\ Exercising)$$

Given the positive values from Table 22 at the end of the period, if the holder gets to that point, and sees a demand from the darkly shaded states of nature (Table 22 and Figure 23 above), they will exercise the option, as demand is high enough to support a positive project value. However, in each of the years leading up to the end of the option period, the holder will elect to keep the option open, as they wait to see what might happen. One can compare the values of keeping the option open, with exercising for any state of nature in any year, by comparing Table 22 with Table 23. The lightly colored shading indicates the holder will keep the option open.

Table 23: Values of the Option to Wait

(x 1,000,000)		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Wait option	$3,292	$3,292	$4,453	$5,911	$7,705	$9,880	$12,494	$15,628	$19,380	$23,872	$29,246
			$2,205	$3,101	$4,262	$5,725	$7,522	$9,693	$12,296	$15,416	$19,154
				$1,355	$2,007	$2,897	$4,066	$5,541	$7,340	$9,501	$12,093
					$728	$1,156	$1,789	$2,682	$3,873	$5,362	$7,153
						$309	$541	$927	$1,543	$2,467	$3,697
							$80	$160	$320	$640	$1,279

								$-	$-	$-	$-
									$-	$-	$-
										$-	$-
											$-

The table of demand values, shaded to correspond to the decision rule, is reproduced below, in Table 24. Given this case, the developers of the next phase will choose to wait until the last year offered to invest. The reason is that keeping the option open at each decision point is more valuable than exercising it.

Table 24: Demand Value Triggers

Demand	2500	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Consume mu	0.0223	2500	2734	2989	3268	3573	3907	4272	4671	5108	5585
Consume s.d.	0.0893		2286	2500	2734	2989	3268	3573	3907	4272	4671
U =	1.0934			2091	2286	2500	2734	2989	3268	3573	3907
D =	0.9146				1912	2091	2286	2500	2734	2989	3268
						1749	1912	2091	2286	2500	2734
Wait							1600	1749	1912	2091	2286
Exercise								1463	1600	1749	1912
									1338	1463	1600
										1224	1338
											1119

(Values for the options in this hypothetical case are higher because the value of the underlying is higher than when considering other risk factors simultaneously, especially cost overruns.)

Conclusion

Inga allows for an interesting look at flexible design. Without an ROA analysis, value is left on the table in this phased facility. This value can be leveraged toward incentives of various kinds, possibly increasing investment liquidity around the project. Since flexibility adds value, specific benefits can be expressed in contract clauses such as right of first refusal, or insurance payments. Specifically, the inclusion of real options, used to enhance the full value of the project, add as much as $3.5 billion to the first three phases at Inga. Additionally, the analysis has shown that the full value of the overall project is enhanced by following the *Progressive* pathway, rather than the previously recommended *Accelerated* pathway of development. Furthermore, the framework has also offered a series of right-priced insurance policy options, such that sponsors can protect themselves from a loss on the project of anything greater than $4.9 billion, against an expected cost of $13 billion for phase A only, given the risk cost overruns. (These results come with the caveat that an electricity price of $0.12 has been used in the analysis, which is considerably higher than the existing tariff). The flexible design of a staged development plan also enables the resolution of some uncertainties prior to making decisions; although, I have shown that in this case, since there is no cost to waiting, developers will postpone new development until the expiration of the option. Again, an ROA allows one to track progress, as the future reveals itself, and then respond appropriately.

The Inga Dam could transform much of Africa. However, the risks are complex, and this brief discussion has by no means exhausted them. Other risk factors could be included in the calculus, including currency risk, policy risk, and others. More sophisticated analysis around demand could also be accomplished, built from ground up demand models, especially for a project of such size. A risk factor specifically for environmental policies could also be added.

One of the critiques of real options analyses is that they require a valuation to be performed at regular intervals. Therefore, a future task for this analysis could be to develop the model based on cash flows, rather than valuations. Cash flows are easier to observe, and decisions made on cash flows can be more objective in nature.

Discussions about this mega-project will likely continue; there is no certainty for the project yet. Perhaps an RO framework can enhance the project’s characteristics, making it more attractive to a broad array of interests.

CHAPTER 8

CONCLUSIONS

The case studies and the methodology in this dissertation, have supported the research contributions the thesis seeks to establish. Namely that: 1) The framework presents a method for the valuation of flexible design at hydropower facilities; that is, it makes the intuitive value of flexible design explicit. 2) Without an ROA analysis, other methods have undervalued flexibility, as they counted the costs of the additional resilient capacity against the project, but did not allow for the benefits to accrue. The exception is RDM, which can be combined with ROA to offer an inclusive result. 3) The hidden value, created by optionality, can be leveraged to create incentives for government sponsors and project developers alike. These include preferential rights and insurance clauses designed to attract investors, or insure against losses. An ROA analysis can also be used as a decision-making tool to determine the timing of additional investment through the creation of an American-style option. The contributions are important for decision makers to be able to weigh the full value of flexibly designed projects, and for project sponsors to accurately communicate valuations to grantors, lenders and equity partners.

Several significant results can be identified. The framework offered can give specific valuations of both costs, and benefits of resiliency measures, at the project level. That resiliency is worth $94 million at Batoka Dam, as this is the difference in valuation between the full value of the flexibly designed alternative, and the next-best option. Additionally, the framework showed a potential cost savings of as much as $500 million, a result which could lead sponsors to avoid overbuilding at the site. Were planners to use only a BCA, or an RDM without including option values, they would have automatically chosen a larger design, perhaps overbuilding at the site. Furthermore, if they chose to build a smaller facility (A'), with flexibility, they will have increased the value of that facility by \$870 million over its static counterpart, a 20% increase. Similarly, the full value of the 2400 MW design, with flexibility, exceeds the value of its static counterpart by \$370 million. The reason for the additional value inherent in optionality, is that it represents the possibility of future cash flows, and the right to access those cash flows.

I have also demonstrated that, apart from a real options analysis, BCA and RDM offered incomplete valuations of hydropower at the project design level, given these designs and data. BCA has undervalued flexibility at Batoka by as much as 20% depending on the design in question. RDM, while not attempting to create point values for decision makers, none-the-less points toward a larger design, that is not as valuable as a one that is smaller and more flexible in nature. An exception arises when RDM is combined with a real options analysis. By using the full value of the flexible projects, including their option values, RDM leads planners to choose a small, and flexible design (Configuration A'). This is consistent with a "least regrets" approach, as the cost overrun risk is the most impactful to project values.

Finally, the framework has provided examples of fairly-priced incentives for both public and private parties in a joint agreement. The framework justifies, and makes transparent, preferential rights, insurance clauses, and timing decisions for future investment. For example, there is a significant increase in value at the Inga facility, if the full array of projects is developed, following the *Progressive* pathway. That value could be used to attract, or keep, investors involved in the project. As an example, by optioning the second and third phases of the project, sponsors offer an implicit preferential right worth as much as \$3.5 billion (using my parameters), if the *Progressive* development pathway is followed rather than the *Accelerated*. Also demonstrated were a series of insurance contract values that could offer protection to cost overruns. Results show that the purchase of a policy for the price of \$4.6 billion would protect sponsors from losses, keeping total loss to the value of the option; this is set against expected costs of $13 billion. Other insurance clauses, tied to different risk factors, could also be developed through the creation of put options.

Other findings include that higher IRRs may lead private investors to favor smaller more flexible designs, over large ones; that climate change may not be the biggest risk factor in hydropower project development, at least at Batoka and Inga; and that developers, with an option to wait to develop the next Inga facility, will keep delaying their next investment until the exercise period runs out, unless costs of waiting are high. These results are ancillary to the primary research contributions, but that are nonetheless important findings, highlighted by the framework.

Using an ROA can point to design alternatives undiscovered by traditional analysis. This dissertation has showcased the ability of ROA to highlight valuable designs, that may have been missed by alternative methods. It has also demonstrated its usefulness as a tool for harnessing hidden strategies in development agreements, including financial partnerships, and insurance policies. It has also exposed the need for dialogue around project priorities, as different parties may have different expectations, which will drive them to very different conclusions. For these reasons, this, or any tool, must be informed by broad stakeholder engagement. It is only by bringing together the full cast of characters around the project story, that there can be a semblance of agreement on project priorities and outcomes.

With a multitude of applications, more should be done to promote ROA as a decision-making tool. While there are some computational complexities, models can be used for many purposes, making ROA a truly powerful decision, and valuation tool. Additional research could be pursued to make the tool even more accessible. One example is to build models that offer transparent triggers for both investment and abandonment options. While this study has illustrated these applications, it has focused especially on differences in valuations for decision support. Additionally, with greater agreement on parameters, and open discussion among stakeholders, this type of model could be useful for more accurate valuations, perhaps using specific decision rules such as cash flow availability, or river flow rates, to trigger investment actions.

The Batoka and Inga projects embody many of the risks and rewards of hydropower in Africa. To fully value and evaluate their potential will require a sophisticated look at the various options around their construction and management, much more complete than this analysis. My hope is to point out one direction for future evaluation. To justify investment, planners will need to ensure that investors, whether public or private, are protected from unnecessary risks, including those from climate change, cost overruns and demand uncertainty. For their part, governments are also concerned to capture the full value of projects, including the options that are embedded in flexible designs. As risks are identified, an options analysis is appropriate to design the facility with the risks kept in view.

Hydropower is abundantly available to many nations that are currently underserved by existing power generation infrastructure. As governments and private investors approach these projects, several risks quickly become apparent. No matter the sophistication of projection techniques, no amount of forecasting will generate the pinpoint accuracy required to eliminate risk. Considering complex uncertainties, flexibly designed structures offer sponsors, designers, investors and managers, the right kind of options, to incorporate new information as it arises. As flexible design alternatives are increasingly considered, a framework such as this will be needed to fully appreciate the optionality created in the system. This dissertation has endeavored to offer a how-to, along with a justification, for building such models, especially to value flexible design alternatives. This framework offers planners and investors a broad and accurate tool for understanding, and leveraging, the value of flexible design as a risk mitigating strategy as they approach their projects. It is my hope that its uptake can accelerate the development of infrastructure in places of need.

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APPENDIX 1: MATHEMATICAL JUSTIFICATION FOR REAL OPTIONS

This appendix illustrates the mathematic basis for option valuation using a binomial lattice. It follows the same pathway for problem solving as does the dissertation section 5.E. The process begins with the value of the statically-designed project, and discusses the mathematics behind binomial models of valuation. It then describes the payout of an option, and works backward through the valuation process of that option to the present day (this section draws heavily from Shockley 2007, and Copeland 2003).

Figure 31: Problem Solving Pathway for RO Valuation

$\boxed{1}$ $\longrightarrow$ $\boxed{2}$

Value of the Underlying Asset								
0	1	2	3	4	5			
$ 3,500,000	$ 4,066,420	$ 4,724,506	$ 5,489,093	$ 6,377,416	$ 7,409,500		Strike =	$ 1,000,000
$ -	$ 3,012,478	$ 3,500,000	$ 4,066,420	$ 4,724,506	$ 5,489,093		SD	0.150
$ -	$ -	$ 2,592,864	$ 3,012,478	$ 3,500,000	$ 4,066,420		Δt	1.000
$ -	$ -	$ -	$ 2,231,699	$ 2,592,864	$ 3,012,478		u	1.162
$ -	$ -	$ -	$ -	$ 1,920,841	$ 2,231,699		d	0.861
$ -	$ -	$ -	$ -	$ -	$ 1,653,283		q	0.523
Value of the Option							1-q	0.477
0	1	2	3	4	5		r	0.018
$ 2,586,069	$ 3,135,889	$ 3,777,074	$ 4,524,452	$ 5,395,255	$ 6,409,500			
	$ 2,081,947	$ 2,552,568	$ 3,101,780	$ 3,742,345	$ 4,489,093			
		$ 1,645,432	$ 2,047,838	$ 2,517,839	$ 3,066,420			
			$ 1,267,058	$ 1,610,703	$ 2,012,478			
				$ 938,680	$ 1,231,699			
					$ 653,283			

$\boxed{4}$ $\longleftarrow$ $\boxed{3}$

In the diagram, the first value of the underlying asset is $3,500,000, at time $t = 0$. The value of the asset can then move up or down per the formulation discussed below. The values of the option payouts are given in the lower half of the table, beginning with the end-of-period payout at time t = 5. The valuation to present day then moves backward from step 3 to step 4. On the left side of the table, the inputs are given.

- *Strike*: the investment required to exercise the option

- *SD*: the standard deviation of log returns on the underlying asset (calculations shown below)
- *Δt*: the time steps in the period (*Δt = T/number of time steps, where T is the life of the option*)
- *U and D*: the up and down step multiplier, as calculated below
- *q and (1-q):* the risk-neutral probabilities of the up and down steps
- r_{rf}: the risk-free interest rate

Step 1: Calculate the present value of the statically-designed project.

The present value is calculated by summing the anticipated cash flows, and discounting them to the present day. This is the initial value of the underlying asset. It is important to note that the present value is used, rather than the net present value. The reason is that the initial capital costs are represented in the strike price, and will be subtracted during the calculation of the payout of the option. If one uses the NPV at this first step, the strike price would be double counted.

$$PV = \left(\sum_{t=0}^{\infty} \frac{Cash\ flows}{(1 + Discount\ Rate)^t} \right) \quad \text{(A.1)}$$

Step 2: Model the up and down values to create a binomial tree

To move from step 1 to step two, the initial value (V_0) of the underlying asset is multiplied by and up step and a down step. The process is repeated for each subsequent value to the end of the period. To accomplish this step the expected log returns from the underlying asset, and the up and down multipliers for the asset are required.

Calculating log returns

For a project, with initial value V_0 and a period-ending value of V_1, the log return earned during the period, *r* is:

$$r = ln\left(\frac{V_1}{V_0}\right) \tag{A.2}$$

Since V_1 is a random variable (it is not known), the log return is also random (designated below by the ~). A binomial tree assumes that the asset being modeled has log returns that are distributed normally, with an expected return of *m* and annual standard deviation of σ, as in the following:

$$\tilde{r} \equiv ln\left(\frac{\widetilde{V_1}}{V_0}\right) \sim N(m, \sigma);\ \bar{r} = \overline{ln\left(\frac{V_1}{V_0}\right)} \tag{A.3}$$

Therefore, the expected log return over $\Delta t = m^* \Delta t$, where *m* is the mean geometric log return. We are working in continuous compounding, so *the variance in log returns over* Δt *years* $= \sigma^2 * \Delta t$, and *the standard deviation of log returns over* Δt *years* $= \sqrt{\sigma 2 * \Delta t}, = \sigma\sqrt{\Delta t}$. Importantly, though the expected log return over $\Delta t = m^* \Delta t$, the expected value of the asset itself, after Δt years is not $V_0 * e^{m^*\Delta t}$. While log returns are normally distributed, the *asset values* are *lognormally* distributed, skewed to the right; this is because asset values will not fall below zero (though returns may). So, the *expected* value of the *asset* at Δt is:

$$E\{V_{\Delta t}\} = V_0 * e^{\left(m+\frac{1}{2}\sigma^2\right)*\Delta t} \tag{A.4}$$

The term ½ $*\sigma^2$ enters the equation because of the skewness of the lognormal distribution of the asset values; the term moves the volatility to the right-hand tail of the distribution.

The standard deviation is:

$$stdev\ \{V_{\Delta t}\} = \left[V_0 * e^{\left(m+\frac{1}{2}\sigma^2\right)\Delta t}\right]\left(e^{\sigma^2*\Delta t} - 1\right)^{1/2} \tag{A.5}$$

The expected log return of the asset is not the same as the risk-adjusted rate of return. Rather, the expected log return is the geometric mean return, while the risk-adjusted rate of return on an asset (which is also the required rate used for discounting) is the arithmetic mean return. It is the arithmetic mean return, μ, that relates the current asset value to the expected future value. Using the equation for the expected value at *Δt*, above, and substituting for the arithmetic mean, we have:

$$V_0 e^{\mu * \Delta t} = V_0 * e^{\left(m+\frac{1}{2}\sigma^2\right)*\Delta t} \tag{A.6}$$

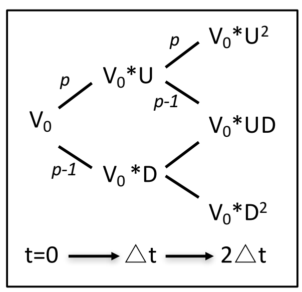
Therefore:

$$\mu = m + .5\sigma^2;\ m = \mu - .5\sigma^2 \tag{A.7}$$

Calculating the up and down multipliers for the underlying asset

Recall from Figure A.1 above, the up and down movements of the asset value over time. Here the figure has been augmented to show the subjective probabilities of the up and down changes in value over time.

Figure 32: Up and Down Movements of Underlying Asset



A binomial model is built around the values of U, D (and p, though p is not necessary to calculate U and D), such that at any *Δt*, the distribution of random values is log-normally distributed with the mean and standard distributions from above. As mentioned, if the distribution of values is log-normally distributed, then the distribution of log returns with be normal with mean = m**Δt* and standard deviation of $\sigma\sqrt{\Delta t}$. Working in continuous compounding the expected log return at the end of the first period is:

$$E\{\log return\} = E\left\{ln\left(\frac{V_{\Delta t}}{V_0}\right)\right\}$$

$$= p\ ln\left(\frac{V_0U}{V_0}\right) + (1-p)ln\left(\frac{V_0D}{V_0}\right)$$

$$= p \ln U + (1-p) \ln D$$

The variance of log returns is:

$$var\ \{\log return\} = var\left\{ln\left(\frac{V_{\Delta t}}{V_0}\right)\right\}$$

$$= p[ln\left(\frac{V_0U}{V_0}\right) + (1-p)ln\left(\frac{V_0D}{V_0}\right)]^2 - [p\ ln\left(\frac{V_0U}{V_0}\right) - (1-p)ln\left(\frac{V_0D}{V_0}\right)]^2$$

$$= p(lnU)^2 + (1-p)(lnD)^2 - [p\ lnU + (1-p)lnD]^2$$

$$= p(1-p)(lnU - lnD)^2$$

This leaves two equations to satisfy, but three unknowns *U, D*, and *p*.

$$p\ lnU + (1-p)lnD = m * \Delta t = (\mu - .5\sigma^2) * \Delta t$$

$$p(1-p)(lnU - lnD)^2 = \sigma^2 * \Delta t$$

So, a restriction is added that *D = 1/U*, leaving the up and down movements symmetrical, and reducing the number of variables for which to solve.

$$(2p-1)lnU = m * \Delta t = (\mu - .5\sigma^2) * \Delta t \tag{A.8}$$

$$4p(1-p)(lnU)^2 = \sigma^2 * \Delta t \tag{A.9}$$

To solve, square the first equation and add it to the second; doing so eliminates *p*:

$$(4p^2 - 4p + 1)(lnU)^2 = (m * \Delta t)^2 = (\mu - .5\sigma^2)^2 * (\Delta t)^2 \tag{A.10}$$

$$(4p - 4p^2)(lnU)^2 = \sigma^2 * \Delta t \tag{A.11}$$

$$(lnU)^2 = (\mu - .5\sigma^2)^2 * (\Delta t)^2 + \sigma^2 \Delta t = (m + \Delta t)^2 + \sigma^2 * \Delta t \tag{A.12}$$

One may then substitute A.5 into A.1 to solve for *p*, and exponentiate to solve for *U*:

$$p = \frac{1}{2} + \frac{\frac{1}{2}}{\sqrt{\frac{\sigma^2 * \Delta t}{(m * \Delta t)^2} + 1}} = \frac{1}{2} + \frac{\frac{1}{2}}{\sqrt{\frac{\sigma^2}{m^2 * \Delta t} + 1}} \tag{A.13}$$

$$U = e^{\sqrt{\sigma^2 * \Delta t + (m * \Delta t)^2}} \tag{A.14}$$

As Δt approaches 0:

$$\lim_{\Delta t \to 0}(p) = \frac{1}{2} + \frac{1}{2} * \frac{m}{\sigma}\sqrt{\Delta t} = \frac{1}{2} + \frac{\mu - .5\sigma^2}{2\sigma}\sqrt{\Delta t} \tag{A.15}$$

$$\lim_{\Delta t \to 0}(U) = e^{\sigma\sqrt{\Delta t}} \tag{A.16}$$

So, the values for *p* (the subjective probability of an up-step), *U* (the up-step multiplier), and *D* (the down-step multiplier) can be found in the equations below. It should be noted that *p* is not required to calculate the values of the underlying asset. However, the *U* and *D* values are the multipliers used in the creation of the binomial tree which models the value of the underlying asset:

$$p = \frac{1}{2} + \frac{(\mu - .5\sigma^2)}{2\sigma}\sqrt{\Delta t} \tag{A.17}$$

$$U = e^{\sigma\sqrt{\Delta t}} \tag{A.18}$$

$$D = 1/U \tag{A.19}$$

Step 3: Calculate end-of-period payouts

The end-of period payout of the option can then be calculated for each state of nature. This is done by subtracting the strike price from the value of the asset.

Option payouts

Option payouts are conditioned on the exercise of the option. For a call option, if the option is "in the money" the strike price of the option will be less than the expected value of future cash flows. In this case the option will be exercised. The decision is based on the expected payout at the time of exercise.

$$Payout = MAX[V_0 - K, 0] \tag{A.20}$$

To understand the end-of-period *expected* payoffs given two states of nature, each with an assigned probability (in this case *q* up and *(1-q)* down) the equation can be expanded:

$$Expected\ end\ of\ period\ payout \tag{A.21}$$
$$= q * MAX[V_U - K, 0] + (1 - q) * MAX[V_D - K, 0]$$

Step 4: Determine current value of the option

To move backward from step 3 to step four requires knowing the value of the risk-neutral probabilities at each step *(q)*. Recall that the current value of the of the underlying asset equals the discounted future value, assuming a risk-neutral probability and discounting at the risk-free rate:

$$dV_{up} = MAX[V_0\text{-}K,0]$$

$$dV_0 = \frac{q*dV_{up}+(1\text{-}q)*dV_{dn}}{e^{(r*\Delta t)}}$$

$$dV_{dn} = MAX[V_0\text{-}K,0]$$

$$dV_0 = \frac{q * dV_{up} + (1 - q) * dV_{dn}}{e^{r*\Delta t}} \tag{A.22}$$

Then, substituting the values from A.11 and A.12:

$$e^{r*\Delta t} = q * e^{\sigma\sqrt{\Delta t}} + (1 - q) * e^{-\sigma\sqrt{\Delta t}} \tag{A.23}$$

yields (recall that q is used to discount *backwards*, to arrive at the current value of the *option*, in the second of the binomial trees created in Chapter VI.

$$q = \frac{e^{r*\Delta t} - D}{U - D} \tag{A.24}$$

The value for q is then substituted back in to equation A.13, but this time to calculate the values of the options (C_0), moving backward. This step is repeated for each cell from time t = 5 back to time t = 0.

$$C_0 = \frac{q * C_{up} + (1 - q) * C_{dn}}{e^{r*\Delta t}} \tag{A.25}$$

The result is the current value of the option: C_0 at time $t = 0$.

APPENDIX 2: MATHEMATICS BEHIND BLACK-SCHOLES FORMULA

If one were to create a binomial tree, solving for the same time-period (*T*) but with ever decreasing *Δt* (dividing the time into smaller and smaller segments), would increase the precision of the binomial model. This is accomplished using the Black-Scholes formula. The Black-Scholes value is the limit of the binomial's approximate solution as the number of steps in the binomial model approaches infinity (Shockley, 2007). The Black-Scholes model:[31]

$$C = S * N(d_1) - Ke^{-rT} * N(d_2) \tag{A.26}$$

$$d_1 = \frac{\ln\left(\frac{S}{K}\right) + (r + .5\sigma^2)T}{\sigma\sqrt{T}} \tag{A.27}$$

$$d_2 = d_1 - \sigma\sqrt{T} \tag{A.28}$$

Where: *C* is the price of the option; *S* is current stock price; *t* is time until option exercise in years; *K* is the option strike price; *r* is the risk-free interest rate; *N* is the cumulative standard normal distribution (mean = 0; σ = 1); *e* is the exponential term; and *s* = standard deviation of returns; *ln* = natural log.

A derivation of the Formula

Consider a European call option: The holder of the call will exercise the option if the cash flows exceed the strike price. Therefore: the potential cash flows, S_t, will occur at time *t*, if $S_t > K$, with a probability of $P(S_t > K)$. The same holds true for put values, though the inequality is reversed. The expected values of the call payouts are expressed as follows:

$$E(payout_{call}) = P(S_t > K)\,[E(S_t \mid S_t > K) - K] \tag{A.29}$$

[31] This derivation is adopted from: "Deriving the Black-Scholes Formula, <https://cran.r-project.org/web/packages/m4fe/vignettes/blackScholesDerivation.pdf>

$$PV_0\left[E(payout_{call})\right] = e^{-rt} * P(S_t > K)\,[E(S_t \mid S_t > K) - K] \quad (A.30)$$

To build the Black-Scholes formula, we need to know the following quantities: *$P(S_t > K)$; and, $E(S_t \mid S_t > K)$*. If *A* is the normally distributed random variable for the stock return, then (see also equation A.4 above for the analogous formula in the binomial tree discussion):

$$S_t = S_0 e^{At}\ where\ A{\sim}N(r, \sigma^2) \quad (A.31)$$

$$\frac{S_t}{S_0} \sim \ln\left(m - \frac{1}{2}e^2\right) t;\ v = \sigma\sqrt{T} \quad (A.32)$$

Recall that *m* is the geometric mean return and *T* is the time for the exercise of the option; *v* is the volatility. For $T = 1$, the volatility of the return equals the volatility of $ln(S_t/S_0)$, otherwise $ln(S_t/S_0)$ must be adjusted for time, so $v = \sigma\sqrt{T}$.

$$P(S_t < K) = P\left(\frac{S_t}{S_0} < \frac{K}{S_0}\right) \quad (A.33)$$

$$= P\left(\ln\left(\frac{S_t}{S_0}\right) < \ln\left(\frac{K}{S_0}\right)\right) \quad (A.34)$$

If *Z* is the standard normal random variable, and $ln(S_t/S_0) \sim Normal\ (m, v^2)$, then $(ln(S_t/S_0) - m)/v = Z \sim N(0,1)$. And:

$$P(S_t < K) = P\left(Z < \frac{ln\left(\frac{K}{S_0}\right) - m}{v}\right) \quad (A.35)$$

$$= P(\mathrm{Z} < -d_2) \quad (A.36)$$

$$= N(-d_2) \quad (A.37)$$

$$P(\mathrm{Z} > -d_2) = N(d_2) \quad (A.38)$$

Again,

$$d_2 = \frac{ln\left(\frac{S_0}{K}\right) + m}{\sigma\sqrt{T}} \quad (A.39)$$

To find the second unknown, $E(S_t \mid S_t < K)$, the following formula is used (*PE* is the partial expectation from $S_t = 0$ *to* $S_t = K$:

$$E(S_t \mid S_t < K) = PE(S_t | S_t < K) \tag{A.39}$$

Note that:

$$PE\left(\frac{S_t}{S_0} | \frac{S_t}{S_0} < \frac{K}{S_0}\right) = E\left(\frac{S_t}{S_0}\right) N\left(\left(ln\left(\frac{K}{S_0}\right) - m - v^2\right)/v\right) \tag{A.40}$$

And:

$$PE\left(S_t | \frac{S_t}{S_0} < \frac{K}{S_0}\right) = S_0\left(PE\left(\frac{S_t}{S_0} | \frac{S_t}{S_0} < \frac{K}{S_0}\right)\right) \tag{A.41}$$

One can simplify in the following manner

$$PE(S_t \mid S_t < K) = PE\left(\frac{S_t}{S_0} | \frac{S_t}{S_0} < \frac{K}{S_0}\right) \tag{A.42}$$

$$= S_0\left(PE\left(\frac{S_t}{S_0} | \frac{S_t}{S_0} < \frac{K}{S_0}\right)\right) \tag{A.43}$$

$$= S_0 E\left(\frac{S_t}{S_0}\right) N\left(\left(ln\left(\frac{K}{S_0}\right) - m - v^2\right)/v\right) \tag{A.44}$$

$$= S_0 e^{m+\frac{1}{2}v^2} N\left(\frac{\left(ln\left(\frac{K}{S_0}\right) - \left(\alpha - \delta - \frac{1}{2}\sigma^2\right)t - \sigma^2 t\right)}{\sigma\sqrt{t}}\right) \tag{A.45}$$

$$= S_0 e^{(\alpha-\delta)t} N\left(\frac{\left(ln\left(\frac{K}{S_0}\right) - \left(\alpha - \delta - \frac{1}{2}\sigma^2\right)t - \sigma^2 t\right)}{\sigma\sqrt{t}}\right) \tag{A.46}$$

$$= S_0 e^{(\alpha-\delta)t} N(-d_1) \tag{A.47}$$

$$d_1 = \left(\frac{\left(ln\left(\frac{K}{S_0}\right) - \left(\alpha - \delta - \frac{1}{2}\sigma^2\right)t - \sigma^2 t\right)}{\sigma\sqrt{t}}\right); \text{ and } d_2 = d_1 - \sigma\sqrt{t} \tag{A.48}$$

Since $E(S_t) = PE(S_t|S_t > K) + PE(S_t|S_t < K)$, then:

$$PE(S_t|S_t > K) = E(S_t) - PE(S_t|S_t < K) \tag{A.49}$$

$$= S_0e^{(\alpha-\delta)t} - S_0e^{(\alpha-\delta)t}N(-d_1) \quad (A.50)$$

$$= S_0e^{(\alpha-\delta)t}(1 - N(-d_1)) \quad (A.51)$$

$$=S_0e^{(\alpha-\delta)t}N(d_1) \quad (A.52)$$

Which leads one to the following formulas:

$$E(S_t|S_t < K) = \left(\frac{S_0e^{(\alpha-\delta)t}N(-d_1)}{N(-d_2)}\right) \quad (A.53)$$

$$E(S_t|S_t > K) = \left(\frac{S_0e^{(\alpha-\delta)t}N(d_1)}{N(d_2)}\right) \quad (A.54)$$

Substituting the formulas above into the formula for a call option (A.29):

$$E(payout_{call}) = P(S_t > K)\,[E(S_t \mid S_t > K) - K] \quad (A.55)$$

$$= N(d_2)\left(\left(\frac{S_0e^{(\alpha-\delta)t}N(d_1)}{N(d_2)}\right) - K\right) \quad (A.56)$$

$$S_0e^{(\alpha-\delta)t}N(d_1) - KN(d_2) \quad (A.57)$$

$$PV_0[E(Payout_{call})] = e^{-rt}\left(S_0e^{(\alpha-\delta)t}N(d_1) - KN(d_2)\right) \quad (A.58)$$

$$= S_0e^{-\delta t}N(d_1) - Ke^{-\alpha t}N(d_2) \quad (A.59)$$

For a European call option:

$$C = S_0e^{-\delta t}N(d_1) - Ke^{-\alpha t}N(d_2) \quad (A.60)$$

Similarly, for a put option:

$$E(payout_{put}) = P(S_t < K)\,[K - E(S_t \mid S_t < K)] \quad (A.61)$$

$$= N(-d_2)\left(K - \left(\frac{S_0e^{(\alpha-\delta)t}N(-d_1)}{N(-d_2)}\right)\right) \quad (A.62)$$

$$KN(-d_2) - S_0e^{(\alpha-\delta)t}N(-d_1) \quad (A.63)$$

$$PV_0\left[E\left(Payout_{put}\right)\right] = e^{-rt}\left(KN(-d_2) - S_0e^{(\alpha-\delta)t}N(-d_1)\right) \quad (A.64)$$

$$= Ke^{-\alpha t}N(-d_2) - S_0e^{-\delta t}N(-d_1) \quad (A.65)$$

For a European put option:

$$P = Ke^{-\alpha t}N(-d_2) - S_0 e^{-\delta t}N(-d_1) \tag{A.66}$$

References:

"Deriving the Black-Scholes Formula, <https://cran.r-project.org/web/packages/m4fe/vignettes/blackScholesDerivation.pdf>

APPENDIX 3: SPECIFICATIONS FOR BATOKA DAM FACILITY

WEAP Modelling Assumptions

The following table represents the parameters in the WEAP model of the BGHD:

1600 MW Design	
Hydropower	
Max turbine flow	1001 CMS
Tail water elevation	590 m
Plant factor	100%
Generating efficiency	90%
Hydropower priority	1
Energy demand	1168 GWH
Physical	
Storage capacity	1754 million m^3
Operation	
Top of conservation	Equal to storage capacity
Top of buffer	Equal to top of inactive
Top of inactive	.9*Top of conservation
Buffer Coefficient	0
Max turbine flow 2400 MW	1502 CMS
Max turbine flow 3000 MW	1877 CMS
All other inputs remained the same	

The Hargreaves inputs include: a reference evapotranspiration, Kc coefficient, precipitation, average temperature, minimum temperature, maximum temperature, solar declination, etc. Data files for these inputs were generously supplied by the World Bank team that authored the ECRAI report.

Table 25: Cost Model/Cost Assumptions

Aspect+B15:L148	Batoka A	Batoka A'	Batoka A'→B	Bat. B (2400MW)	Batoka B'	Batoka B'→C	Bat. C (3000MW)
Cost adjustment for each option =							
SURVEYS AND INVESTIGATIONS							
Surveys	1,720,524	1,720,524		1,720,524	1,720,524		1,720,524
Hydraulic Modeling	860,262	860,262	860,262	860,262	860,262	860,262	860,262
Site investigations	2,580,786	2,580,786		2,580,786	2,580,786		2,580,786
Full study	679,575	679,575		679,575	679,575		679,575
Contingencies	584,114.70	584,115		584,115	584,115		584,115
Total	6,425,262	6,425,262	860,262	6,425,262	6,425,262	860,262	6,425,262
INFRASTRUCTURE							
Site establishement	29,077,815	29,077,815		29,077,815	29,077,815		29,077,815
Access roads and airstrip	84,427,200	84,427,200		84,427,200	84,427,200		84,427,200
Bridge	52,840,800	52,840,800		52,840,800	52,840,800		52,840,800
Housing	41,719,509	41,719,509		41,719,509	41,719,509		41,719,509
Electricity	8,490,690	8,490,690		8,490,690	8,490,690		8,490,690
Mobilization & demobilization	7,995,000	7,995,000	799,500	7,995,000	7,995,000	799,500	7,995,000
Contingencies	22,455,101	22,455,101		22,455,101	22,455,101		22,455,101
Total	247,006,115	247,006,115	799,500	247,006,115	247,006,115	799,500	247,006,115
RESERVOIR							
Clearing vegetation	36,900,000	36,900,000		36,900,000	36,900,000		36,900,000
Contingencies	1,845,000	1,845,000		1,845,000	1,845,000		1,845,000
Total	38,745,000	38,745,000	-	38,745,000	38,745,000	-	38,745,000
CIVIL WORKS							
Diversion works							
soft excavation - diversion tunnels	6,869,550	6,869,550		6,869,550	6,869,550		6,869,550
rock excavation - inlet	8,542,350	8,542,350		8,542,350	8,542,350		8,542,350
rock excavation - tunnel	15,864,540	15,864,540		15,864,540	15,864,540		15,864,540
formwork	6,266,727	6,266,727		6,266,727	6,266,727		6,266,727
Concrete (structural)	15,243,144	15,243,144		15,243,144	15,243,144		15,243,144
reinforcement	8,433,864	8,433,864		8,433,864	8,433,864		8,433,864
unmeasured for tunnels/bottom outlets	11,026,362	11,026,362		11,026,362	11,026,362		11,026,362
sub-total tunnels	72,246,537	72,246,537	-	72,246,537	72,246,537	-	72,246,537
upstream pre- and cofferdam	23,400,000	23,400,000	-	23,400,000	23,400,000		23,400,000
downstream pre- and cofferdam	6,500,000	6,500,000		6,500,000	6,500,000		6,500,000
sub-total cofferdam	29,900,000	29,900,000	-	29,900,000	29,900,000	-	29,900,000
sub-total diversion works	102,146,537	102,146,537	-	102,146,537	102,146,537	-	102,146,537
Dam (RCC)							
Soft excavation	830,000	830,000		830,000	830,000		830,000
Rock excavation	38,560,000	38,560,000		38,560,000	38,560,000		38,560,000
Formwork	10,980,000	10,980,000		10,980,000	10,980,000		10,980,000
Concrete (RCC)	15,300,000	15,300,000		15,300,000	15,300,000		15,300,000
Concrete (mass)	435,744,000	435,744,000		435,744,000	435,744,000		435,744,000
Concrete (structural)	34,272,000	34,272,000		34,272,000	34,272,000		34,272,000
Reinforcement	16,161,600	16,161,600		16,161,600	16,161,600		16,161,600
PVC geomembrane	8,858,460	8,858,460		8,858,460	8,858,460		8,858,460

Outlet in dam	16,236,000	16,236,000		16,236,000	16,236,000		16,236,000
Sluiceway	20,145,801	20,145,801		20,145,801	20,145,801		20,145,801
Plunge pool excavation, formation, concrete	16,743,129	16,743,129		16,743,129	16,743,129		16,743,129
Unmeasured	29,742,999	29,742,999		29,742,999	29,742,999		29,742,999
sub-total dam	643,573,989	643,573,989	-	643,573,989	643,573,989	-	643,573,989
Intake structure							
Soft excavation	750,000	1,125,000		1,125,000	1,406,250		1,406,250
Rock excavation	12,000,000	18,000,000		18,000,000	22,500,000		22,500,000
Formwork	3,495,000	5,242,500		5,242,500	6,553,125		6,553,125
Concrete (structural)	16,730,000	25,095,000		25,095,000	31,368,750		31,368,750
Reinforcement	15,900,000	23,850,000		23,850,000	29,812,500		29,812,500
Unmeasured	3,848,793	5,773,190		5,773,190	7,216,487		7,216,487
Contingencies	3,954,284	5,931,427		5,931,427	7,414,283		7,414,283
sub-total intake	56,678,077	85,017,116	-	85,017,116	106,271,395	-	106,271,395
Penstock (4 steel conduits, 6.5m dia.)							
Rock (tunnel) excavation	14,000,000	21,000,000		21,000,000	26,250,000		26,250,000
Concrete (structural)	3,080,000	4,620,000		4,620,000	5,775,000		5,775,000
Unmeasured	1,000,000	1,500,000		1,500,000	1,875,000		1,875,000
sub-total penstocks	18,080,000	27,120,000	-	27,120,000	33,900,000	-	33,900,000
Spillway							
Soft excavation	207,225	207,225		207,225	207,225		207,225
Rock excavation	6,078,600	6,078,600		6,078,600	6,078,600		6,078,600
Formwork	26,550,000	26,550,000		26,550,000	26,550,000		26,550,000
Concrete (structural)	61,950,000	61,950,000		61,950,000	61,950,000		61,950,000
Reinforcement	75,856,800	75,856,800		75,856,800	75,856,800		75,856,800
Unmeasured	24,000,000	24,000,000		24,000,000	24,000,000		24,000,000
sub-total spillway	194,642,625	194,642,625	-	194,642,625	194,642,625	-	194,642,625
Powerhouse (cavern) & Tailrace							
Soft excavation	5,040,000						
Rock (cavern) excavation	68,880,000						
Formwork	15,489,600						
Concrete (mass)	40,958,400						
Concrete (structural)	8,624,000						
Reinforcement	33,852,000						
Unmeasured	10,000,000						
sub-total Powerhouse, tailrace	182,844,000	274,266,000	-	274,266,000	342,832,500	-	342,832,500
Access tunnel (50m2x830m)							
excavation							
concrete							
formwork		-					
Sub-station civil works							
Extensions							
Sub-stations	40,000,000	60,000,000	6,000,000	60,000,000	80,000,000	8,000,000	80,000,000
sub-total sub station civil works	40,000,000	60,000,000	6,000,000	60,000,000	80,000,000	8,000,000	80,000,000
Contingencies Civil Works	185,694,784	208,014,940		208,014,940	225,505,057	1,200,000	225,505,057
Total	1,423,660,013	1,594,781,000	6,000,000	1,594,781,207	1,728,872,000	9,200,000	1,728,872,000

MECHANICAL AND ELECTRICAL WORKS							
Hydraulic steel structures							
Diversion tunnels and outlets	22,918,352	22,918,352		22,918,352	22,918,352		22,918,352
Dam low level diversion openings	9,045,543	9,045,543		9,045,543	9,045,543		9,045,543
Dam radial gates etc.	68,370,042	68,370,042		68,370,042	68,370,042		68,370,042
Intakes, trash screens, gates	25,217,829	37,826,744		37,826,744	47,283,429		47,283,429
Penstocks steel lining	29,774,843	44,662,265		44,662,265	55,827,831		55,827,831
Powerhouse draft tubes and crane	7,549,812	11,324,718		11,324,718	14,155,897		14,155,897
Subtotal Hydraulic steel	162,876,421	194,147,663	-	194,147,663	217,601,094	-	217,601,094
Mechanical Works							
Turbines & governors	120,000,000	120,000,000	60,000,000	180,000,000	180,000,000	45,000,000	225,000,000
Unit cooling water systems	2,400,000	2,400,000	1,200,000	3,600,000	3,600,000	900,000	4,500,000
Draft tube steel linings	20,000,000	20,000,000	10,000,000	30,000,000	30,000,000	7,500,000	37,500,000
Powerhouse cranes	2,000,000	2,000,000	1,000,000	3,000,000	3,000,000	750,000	3,750,000
Dewatering and drainage systems	4,000,000	4,000,000	2,000,000	6,000,000	6,000,000	1,500,000	7,500,000
Unmeasured	10,000,000	10,000,000	5,000,000	15,000,000	15,000,000	3,750,000	18,750,000
Sub-total Mechanical Works	158,400,000	158,400,000	79,200,000	237,600,000	237,600,000	59,400,000	297,000,000
Electrical Works							
Synchronous generators	104,000,000	104,000,000	52,000,000	156,000,000	156,000,000	39,000,000	195,000,000
Transformers 18/400 kV, single phase	56,000,000	56,000,000	28,000,000	84,000,000	84,000,000	21,000,000	105,000,000
Substation electrical works	263,758,000	263,758,000	131,879,000	395,637,000	395,637,000	98,909,250	494,546,250
Electrical auxilaries	9,000,000	9,000,000	4,500,000	13,500,000	13,500,000	3,375,000	16,875,000
Unmeasured	21,000,000	21,000,000	10,500,000	31,500,000	31,500,000	7,875,000	39,375,000
Sub-total Electrical Works	453,758,000	453,758,000	226,879,000	680,637,000	680,637,000	170,159,250	850,796,250
Contingencies	77,503,442.10	80,630,566.30	30,607,900.00	111,238,466.30	113,583,809.44	22,955,925.00	136,539,734.44
Total Mechanical & Electrical	852,537,863	886,936,229	336,686,900	1,223,623,129	1,249,421,904	252,515,175	1,501,937,079
ENGINEERING, SUPERVISION	256,837,425	277,389,361	34,434,666	311,058,071	327,047,028	26,337,494	352,298,546
ENVIRONMENTAL MANAGEMENT							
Project management	79,704	79,704	39,852	119,556	119,556	59,778	179,334
Resettlement	10,574,187	10,574,187	5,287,094	15,861,281	15,861,281	7,930,640	23,791,921
Construction & Operation	3,332,316	3,332,316	1,666,158	4,998,474	4,998,474	2,499,237	7,497,711
Community relations	2,142,660	2,142,660	1,071,330	3,213,990	3,213,990	1,606,995	4,820,985
Contingencies	4,258,020.89	4,258,020.89	2,129,010	6,387,031	6,387,031	3,193,516	9,580,547
Total enviro management	20,386,888	20,386,888	10,193,444	30,580,332	30,580,332	15,290,166	45,870,498
	Batoka A	Batoka A'	Batoka A'→B	Bat. B (2400MW)	Batoka B'	Batoka B'→C	Bat. C (3000MW)
TOTAL PROJECT COST	2,845,599,000	3,071,670,000	388,975,000	3,452,219,000	3,628,098,000	305,003,000	3,921,154,000

Table 26: Summary Table of Batoka Specifications

Summary Project Data	
Reservoir	
Catchment area	508,000 km2
Full supply level (FSL)	762 m ASL
Minimum operation level	746 m ASL
Maximum flood level	765 m ASL
Gross volume at FSL	1,680,000,000 m3
Live storage	570,000,000 m3
Surface area at FSL	25.6 km2
River Flows	
Annual mean flow	1,082 m3/sec
Maximum recorded daily flow	9,331 m3/sec
Regional maximum flood	20,000 m3/sec
Dam	
Type	Roller compacted concrete (RCC) gravity arch
Height	181 m
Crest level	766 m ASL
Crest length	766.5 m
RCC volume	4,080,000,000 m3
Spillway	
Type	Radial-gated crest
Crest level	752 m ASL
No. of gates	12
Gate width and height	14x13 m
Design capacity	20,000 m3/sec
Power Station	
Type	2 underground, one north and one south bank
Installed capacity	1600 MW
Turbine type	Francis 214 rpm
No. and type	12 x 200 MW
Rated output	205.12 MW
Rated net head	166.55 m
Rated flow	138.82 m3/sec
Access road	
Length Zambia	31 km
Length Zimbabwe	54 km

Source: Environmental Resources Management, "Batoka Gorge HES Scouting Report" (unpublished)

APPENDIX 4: SPECIFICATIONS FOR INGA CASE STUDY

WEAP Modelling Assumptions

The following table represents the parameters in the WEAP model of the BGHD:

1600 MW Design	
Hydropower	
Max turbine flow (A-C)	4400; 8000; 1200
Tail water elevation	0 m
Plant factor	100%
Generating efficiency	90%
Hydropower priority	1
Energy demand	28,000 GWH/mo
Physical	
Storage capacity	10,000 million m^3
Operation	
Top of conservation	Equal to storage capacity
Top of buffer	Equal to top of inactive
Top of inactive	.9*Top of conservation
Buffer Coefficient	0

Again, the Hargreaves inputs include: a reference evapotranspiration, Kc coefficient, precipitation, average temperature, minimum temperature, maximum temperature, solar declination, etc. Data files for these inputs were generously supplied by the World Bank team that authored the ECRAI report.