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The effects of climate risk on hydropower P3 contract value

Preliminary study of the Inga 3 Dam

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Abstract: Large hydropower dams are at the centre of a debate weighing the value and costs of renewable energy against the risks of climate change. The debate is especially relevant on the African continent, which offers vast hydropower potential, but which is exposed to possible climatic changes. This paper presents one possible framework for analysing, valuing, and mitigating the possible impacts of climate change on investment returns. It applies the framework to the proposed series of Inga projects. We find that project concessions can recapture value by phasing dam build-out. Our optionality framework can help structure P3 contracts to improve hydropower project value as well as insure sponsors against climate risk.

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1   Introduction

Large hydropower projects are at the centre of a debate weighing the value and costs of renewable energy against the risks of climate change. 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—it has only developed 2,400 MW (van Der Wat 2013). Many advocate that Africa should first invest in its hydropower resources as it continues to add generation capacity to meet demand. Organizations such as the International Commission on Large Dams urge that hydro offers a low-cost alternative to generation based on carbon fuel sources. However, outside observers point out that hydro-projects are exposed to a number of risks including cost overruns (Ansar et al. 2014), dams' distance to demand centres, and river flow uncertainty. These risks have dampened the enthusiasm of both public and private project sponsors. Are large hydro-projects worth the risk? This question remains important for many African countries with untapped hydro potential and unmet electricity demand.

African governments want to move forward with hydropower, but the size of the purse needed is daunting. In 2012, African Heads of State endorsed the Programme for Infrastructure Development in Africa (PIDA) to close Africa's infrastructure gap, including electricity generation. The programme calls for an expansion of hydroelectric power generation capacity of more than 54,000 MW. The PIDA framework includes a Priority Action Plan listing the highest priority projects. This plan calls for US$21.3 billion worth of hydropower investments for nine hydro-generation facilities (Cervigni et al. 2015). Project prices often exceed what governments can afford. With severely constrained budgets, governments could look to private investors to put up the initial capital requirements. Private consortia may also be better at designing and managing large facilities. Public-private partnerships (P3s) are therefore an attractive alternative to public utilities in developing large hydro-projects. Any interested private consortia however will seek to tailor the returns (private benefits) in a manner commensurate with the projects' risk profiles.

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, as well as other volatility in flows affect generation. When cash flows are tied to firm power delivery, the revenue profile of a project also becomes inherently risky. Further complicating the revenue side of the equation is the long technical and economic life of large hydro-projects; the P3 concessionaire will need to account for climate-induced output and cash-flow risk over the project life cycle.

Another design consideration is the long-term demand trend for the dam's electrical output. 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 to avoid demand shortages and to capture greater returns on investment through economies of scale.

Both public agencies and private investors considering the P3 approach are sensitive to the risk of 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. Project sponsors must account for the risk of overruns in addition to climate-induced revenue risk and demand-risk.

With these issues in mind, we present an approach that could help both public and private entities evaluating a P3 concession approach for large hydropower projects. We explicitly account for the three different types of uncertainty, and study their effect on project value. Since

value is inextricably linked to the actual design of the hydropower facility, we adopt the framework of 'flexibility in design' to understand how different design approaches affect project value in the context of risk. We specifically evaluate the effects of phasing on expected project outcomes. The specific research questions we address in this paper are therefore:

(1) What is the value of phased designs over monolithic approaches in the P3 concession of large hydropower facility, given demand uncertainty and the potential for cost overruns?
(2) What is the climate risk premium that is priced into the P3 contract to account for climate induced revenue risk?

The paper outlines methodological considerations and discusses preliminary findings using the Inga Dam facility example. The Inga project offers a useful case study on the effects of these three types of risk on the project P3 contract value. The site has been well studied, and we can draw on detailed feasibility studies and cost estimates for the purpose of developing our models.

2   Relevant literature

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 (ICOLD 2012) to make a case for the importance of water storage and hydropower infrastructure. The International Commission On Large Dams (ICOLD), the International Commission on Irrigation and Drainage (ICID), the International Hydropower Association (IHA), and the International Water Resources Association (IWRA) all look to an uncertain and resource-constrained future and advocate for the value of well-designed and well-managed dams.

Within the ICOLD agreement, made in Kyoto, the international bodies urge that water infrastructure can help meet society's challenges in the following 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 development 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.

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; the High Aswan Dam, the Narmada Valley Project, and the Three Gorges Dams are well-known exceptions. Most delivered hydropower projects however do not receive the broader attention that is observed in the initial tussles among different stakeholders.

One recent study surveyed the post hoc realized costs of hydropower projects (Ansar et al. 2014), and found the projects plagued by significant cost overruns. 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' for the project under consideration results in optimistic projections of time, costs, and benefits of their decisions.

> Ansar et al. (2014), observes that:
>
> - Three of every four dams suffered a cost overrun,
>
> - Actual costs were 96 per cent higher than estimated costs.
>
> - Actual costs more than doubled for 2 of 10 dams, and tripled for 1 in 10.
>
> - Cost overruns occurred in every region of the world.
>
> - Typical benefit-to-cost ratios have been 1.4, but nearly half the dams studied suffered a cost overrun by 1.4 or greater suggesting that sunk costs would not be recovered.

The findings of the Ansar et al. (2014) study are (unsurprisingly) disputed by the International Commission on Large Dams, which advocates for large projects. The ICOLD states that 'cost recovery has not been a substantial problem for hydropower projects' (Nombre 2014: 3), questioning the data and assumptions of the aforementioned study. 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 depend to a large degree on assumptions and counterfactual benchmarks. This type of disagreement highlights the complexity of decision-making surrounding proposals of large projects under uncertainty.

In an effort to reconcile the different views, the advocates of large dams have typically made a strong general case for the available benefits of large dams, provided they are well planned, efficiently delivered, and operated. 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.

In this paper, we present an approach for assessing the available benefits of a large hydro project while avoiding the typical pitfalls of unduly optimistic forecasts and the limited 'inside view' of a typical project proposal. Our approach makes the impact of uncertainty explicit, via variable stream flows and potential cost overruns. It then evaluates a number of possible designs to 'screen out' those that may erode value, and retain for further evaluation those design concepts that can help safeguard value. Our approach relies substantially on the concepts of real options; a category of techniques intended to maximize the value of investments in real assets under uncertainty. When options are embedded in the P3 concession agreement for a hydro project, they can provide avenues for the public sector agency to engage with and monitor the concessionaire, as well as create incentives for the concessionaire to exercise flexibly decisions to capture the available value and secure the benefits of the project.

3 Foundational concepts: real options in P3s

Black and Scholes (1973), showed that an option is a type of financial insurance—the right, but not the obligation, to take action in the future, to buy or sell an asset. Black and Scholes derived the formula for the valuation of a stock option. 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 value of a future decision can be replicated using existing and available financial products such as stocks and bonds.

Copeland and Antikarov (2003), and Kogut and Kulatilak (2001) offer definitions of real options, extending the discipline of financial call options to managerial decisions, especially in the area of capital budgeting. Real options offer a way to place a value on flexibility in the midst of uncertainty. Specifically, real options are defined as the right, but not obligation, to make an investment decision, at a predetermined cost, within a predetermined period of time. (Copeland and Antikarov 2003).

3.1 Value, flexible design, and real options

The value of any hydropower project is based on the potential cash flows from that project, which will accrue to the owners. These cash flows are discounted and compared with other values for decision-making purposes. 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 the option to expand, contract, or otherwise alter a project (Shockley 2007). This type of optionality in a project is called flexible design.

The value of flexible design lies in the ability of managers to wait before making an expensive decision, the purpose being to gain understanding about an aspect of the market that is unclear. This could include information about the future climate, future demand for electricity, or other conditions that may affect the project. Flexible design anticipates the need to adjust hydro-projects when additional information is gained. The Inga dam facility presents one form of flexible design—that of a phased build-out. With the completion of each new phase, a decision point is reached about whether to move to the next phase. Each decision point presents an option for the future.

Again, an option is the right, but not the obligation to take some action in the future. An option is said to be 'in the money' when exercising the option is worth more than keeping it. For example, when a holder has the option to sell a stock for a specific price, the option will be in the money when the price falls below that predetermined price (called an exercise, or strike price). Until then the option is 'out of the money' because the current price is higher than the strike price; there is nothing to be gained by selling the stock at the lower price. Financial options are financial products that are traded in markets, and represent the right to trade a stock at a specified price. Real options retain the same principles of optionality, but refer to physical projects, rather than financial instruments. Holders of real options may abandon a project, expand it, or alter it in some other way. Just as financial options have monetary value, so do real options. Similar to financial options, real options could be bought and sold, and they are based on the same thing as financial options: the value of future cash flows.

4 Background for the Inga 3 facility

4.1 History of the Inga site and the Congo River

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 1930s, but research was suspended during Second World War. 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 facilities were finally developed in the 1960s and 1970s. *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. Electrical output goes mainly to populated areas in nearby Kinshasa. *Inga 2* was the second hydro 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 and 2* were constructed, and are owned and operated, by the state-owned power utility Société Nationale d'Electricité (SNEL) (Showers 2009; Power-Technology.com 2014).

4.2 Proposed design for Inga 3

In 1974, *Inga 3* was designed as a large concrete arched dam with approximately 150 meters of head. However, the project was never developed. Finally, in late 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 latter. 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.

Alternative 1: *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 11,432 MW, with a construction cost of US$16.2 billion (AECON 2011).

Alternative 2: (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 scenario, *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 5,716 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 15 km up river (Tshombe et al. 2007). An outlet from the reservoir would continue to feed *Ingas 1 and 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).

Phases D–G: 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 1: Head, max generating capacity, and fixed costs for each phase

Summary of Construction Options

Phase	Head (m)	Output (MW)	Initial Costs (US$)
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
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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.

The Inga site holds great promise for Africa. If successfully completed, it could electrify much of the continent, possibly ushering in a new wave of economic growth. However, as in the case of many large projects, its challenges have delayed agreement, and prevented investment. These risks are reflected in the debate around hydro projects generally. If projects such as Inga are to

proceed, investors need a nuanced understanding of risks, and appropriate strategies for mitigation. Private investors will need assurances in P3 contracts that project values will be retained, and governments require strategies to address their own uncertainties. With a new design stimulating new interest in the facility, specific risks should be identified and addressed. What follows is a framework for analysing climate risk that can be extended to other risks as well. It also provides a nuanced assessment of the project's values, especially those values that are embedded in a flexible design approach to development. These risk assessments and valuation techniques can be applied to P3 contracts to make the uncertainties more explicit, and inform decision points for concessionaires and their public partners.

5   Methodology

Step 1: Create WEAP model

To assess the risks of changing river flows under possible climates, a 'screening model' was created using the Water Evaluation and Planning system (WEAP) modelling tool. Data inputs for WEAP include river flow, precipitation, temperature, and competing demands. The specifications for hydropower facilities at the Inga site are also inputs; these include head, turbine capacity, elevation curve, plant factor, and an efficiency coefficient. Various design scenarios were built to model the different configurations of the Inga site. Hydropower generation was then computed in the model using the working head on the turbine, constrained by the maximum turbine flow, and the plant's operation and efficiency, according to Equation 1:

$$HP = 9.806 * Q * H * e \qquad (1)$$

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

To model the climate change scenarios in WEAP, a baseline river flow is developed using historical data. Then, six new possible climates were estimated and added to the baseline. The climates span a range from 'wet' to 'dry' and are differentiated by altering the trends of temperature and precipitation within the model. The data used for these trends is a set of bias-corrected and spatially downscaled climate projections based on global circulation model (GCM) runs from both the CMIP3 and CMIP5 IPCC archives.[1]

From these inputs, hydropower output at the Inga site was modelled for six climate change scenarios, and for different configurations of the site. Results from the configuration that models a full build-out, of the different components, at 5-year intervals, is pictured in Figure 1. The output shows expected energy production from each facility, and the colours are the six climates plus a baseline.

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[1] The climate data used in this study was originally used by the Stockholm Economics Institute for a World Bank study entitled *Enhancing the climate resilience of Africa's infrastructure: the power and water sectors* (Cervigni et al. 2015). The data is a set of Bias-Corrected and Spatially Downscaled climate projections based on GCM runs from both the CMIP3 and CMIP5 IPCC archives. The time step included in this dataset is monthly. The approach involved four steps: (1) select the baseline dataset and GCM-emissions combinations; (2) resolve GCMs and baseline to a common spatial resolution; (3) bias correct the GCM outputs; and (4) spatially downscale those outputs.

Figure 1: WEAP results graphic showing regular build intervals
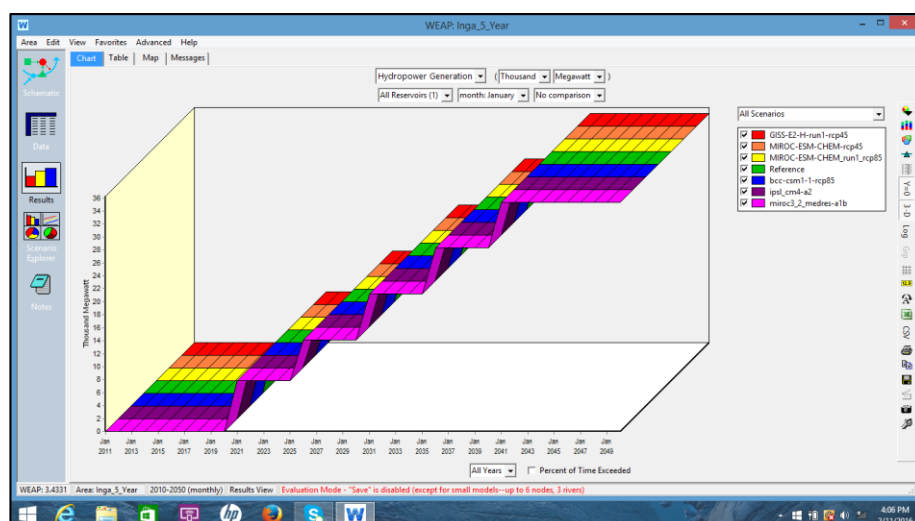
Source: Authors' compilation based on WEAP output.

Step 2: Generate cash flows and project NPV from WEAP's hydro output

The WEAP screening model was run for the phases of the Inga designs. The generated hydropower vectors were then multiplied by projected annually averaged (wholesale) energy prices, in kilowatt-hours, taken from the World Bank study *Enhancing the climate resilience of Africa's infrastructure: the power and water sectors* (Cervigni et al. 2015).[2] This result yielded a series of six annual revenue streams, stretching over 25 years of analysis. Operation and management costs were then subtracted to obtain annual net revenue figures.

Several outputs from this process are required to proceed with the real options calculations. The first among them is the NPV. So, each of the six net revenues was discounted to present day, using a discount rate of 10 per cent.[3] From this number, the initial fixed capital costs[4] were subtracted (discounted over the construction period of 5 years by the risk-free rate of 3 per cent, indicating cost certainty) to give a project net present value. The average of these six NPVs is used as the starting point for the real options analysis, and represents the value of the project without flexibility (NPV results are summarized in Table 5).

Additionally, a rate of return on the project is required. To compute accurately real option values, the continually compounded rate of return is used. This was calculated, for each of the six climate scenarios, using the following formula, and solving for *r*:

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

(2)

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[2] A full discussion of energy price modelling is available in Cervigni et al. (2015). That discussion is outside the scope of this working paper. Additional information about how that team modelled energy prices is also available in that report's appendixes found online at: https://openknowledge.worldbank.org/handle/10986/21875.

[3] The higher the discount rates the lower the initial value of the project. The differences are very large. For example, a discount rate of 20 per cent yields a project valuation of US$2,776,542,832, while a rate of 4 per cent yields a project valuation of US$52,955,711,673.

[4] Capital costs were taken from the AECON feasibility study (AECON 2011).

Where K = initial capital costs; r = rate of return; t = years; and CF = net annual cash flows (revenues—operation and maintenance; no tax or depreciation was included).

Each climate scenario produced a return on investment that differed based on streamflow and climate-impacted energy prices. The final output required from this modelling step is the standard deviation (σ) of the distribution of these returns. These parameters, NPV and standard deviation of returns, are then used to create a binomial tree that estimates the project's value for each time period and state of nature.

The tree is built beginning with the expected NPV. Values are assumed to follow a series of stochastic Brownian steps based on the standard deviation of returns. Using the standard deviation, possible 'up' and 'down' values are calculated from the initial NPV. These two values represent the two 'states of nature' that could occur in year two, given the variability of returns. The *up* value sees the project grow in value, the *down* sees it decline. Then, for each new node, a new up and down value is calculated.

Figure 2: Binomial event tree
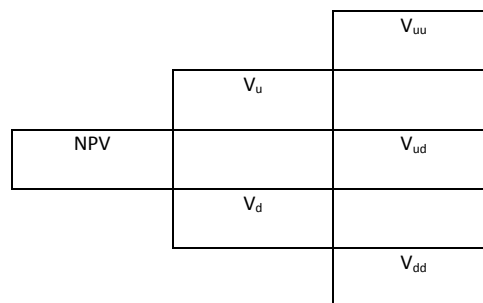
Source: Authors' compilation.

The result is a tree of possible values as graphically shown in Figure 2.[5] The values in the centre of the tree (V_{ud}) are the expected values, and will match the NPV of the project; these are also the values that would be obtained by a DCF. However, the other values also represent distinct possibilities based on the distribution of possible outcomes. The tree offers a better picture of the cumulative value of the project than the DCF because values under many possible states of nature are computed. As the tree expands, the upper and lower bounds represent statistical possibilities, although the probabilities associated with those values become increasingly remote (Copeland and Antikarov 2003).

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[5] The formula for the up percentage is: $u = e^{\sigma\sqrt{h}}$; σ is the standard deviation of rates of return, and h is the interval as a fraction of a year. In this case, since the analysis is based on yearly intervals, $h = 1$. The down percentage is simply $d = 1/u$.

Step 3: Build flexible-design cost models

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 2: Fixed costs per phase

Phase	Initial Costs (US$)
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
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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

Source: Étude de développement du site hydroélectrique et des interconnexions associées: Rapport de préfaisabilité, AECON (2011).

Step 4: Real Options (RO) valuation

The final step is to determine the expected values of the real options. The value of the option represents the value of the right, but not the obligation, to take action in the future. The value of optionality on a project proceeds in two steps. First, the end-of-period payoffs from the option are established. Second, the value of the payoff in present time is calculated. The first step is relatively simple, the second more complex.

First, end-of-period payoffs are simply the maximum of two values. Option payoffs are designed to occur only if certain conditions are met. For example, if the value of a project were to fall below a certain point an option payoff would occur allowing the holder to recapture lost value. Consider the following abandonment option (an abandonment option is the option to sell the project at a predetermined price). If V_0 is the current value of a project in time t, and K is the strike, or predetermined, price of the option, the payout of the option will be the maximum between (V_0-K) and 0. Once the strike price is higher than the value of the project, the option

will be exercised, and the predetermined price will be the payoff. Until that time V_0-K will be positive (meaning the value will exceed the strike price), and the option will go unexercised.

$$Payout = MAX[V_0 - K, 0] \tag{3}$$

The second step in option valuation is more complex, and involves the creation of a replicating portfolio that estimates the value of the option based on the value of the underlying project.[6] This works because we have calculated the value of the underlying project, both today and in the future (the nodes of the decision tree above); and, we know the value of the option in the future (the payout from the first step). As a result, we can calculate the number of shares of the underlying project, plus the number of risk-free bonds, that would be required to create the same value in financial markets. Equation 4 will give us today's value of next year's option:

$$mV_0 + B_{rf} \tag{4}$$

Where m is the number of shares of the underlying asset, V_0 is today's value of the underlying asset, and B_{rf} is the dollar value of risk free bonds.

The value of the option is not the same as the payout; it is the value to the holder, of keeping the future payout. Options are then valued backward from the payoff date to the present period, making the calculation above at every step. The results are a second tree similar to the one described in Figure 2, which shows the value of the option at every state of nature, for each time period.

5.1   Assumptions

The following assumptions were made in the analysis.

- All power was modelled as sold to the Southern African Power Pool (SAPP). The World Bank Report from which energy prices were taken (Cervigni 2015), estimate that the other major power pools may offer different electricity prices, with the Western Africa market being the highest. However, it seems most realistic that the SAPP develop the infrastructure and demand nodes to utilize capacity fully. Unless otherwise indicated, all power is assumed to be sold. Energy demand is an input to the model used by the Bank.
- No transmission costs have been considered.
- Operation and maintenance costs were assumed to be 2 per cent of capital costs, and were held constant.
- The discount rate selected is 10 per cent.[7]
- Unless otherwise indicated, the risk-free rate is 3 per cent.
- Construction costs were discounted at the risk free rate; costs were considered certain.
- For the PV calculations and cost structures, most of our analysis used a 5-year build time (regardless of the scale of the project) and subsequent cash flows of 20 years.

Additional assumptions are given under the description of results for each scenario.

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[6] For a fuller description of the replicating portfolio approach used in this model, please see Swanson (2016, forthcoming). For a complete discussion, see Shockley (2007).

[7] Discount rates differ depending on the perspective of the user. Governments tend to use an economic rate that retains value over a long period of time. Private investors may not be as patient, and require a higher rate that reflects trade-offs from other opportunities.

6 Results

This section includes three hypothetical 'Situations' that were designed to highlight different advantages of the analysis. In Situation 1, we wanted to illustrate the value of the phased design of Inga; so, we calculated the values of the option-to-expand the facility along the lines suggested in AECON's report. Situation 1 illustrates the value of a phased design, and shows that the early phases of the facility contain embedded value that represents real financial worth. In Situation 2, we use the framework to specifically address climate risk, exclusive from other risks. Situation 2 shows how a P3 contract could be structured to protect investors from a decline in value due to climate. In Situation 3, our intent is to showcase that the framework can be expanded to include other risk factors. We therefore introduce the risk of cost overruns, and add the limiting factor of unrealized demand. Situation 3 values the option to build *Inga B'* (after *Inga A'*), along the Progressive schedule, in ten-year's time, but without the ability to sell all of its power. The actual values calculated in this section are less important than the application of the methodology, and the general results that are produced—different situations could be produced using different economic and financial inputs.

<u>Situation 1</u>: Value of the option to expand, modelled as a European call

The first application takes the real options methodology to obtain the hidden value in the Inga project, based on the flexibility of its design. For example, the static NPV calculated for project *A'* (Table 3) is US$3.2 billion. But, the cumulative value of investment opportunity *A'* should include the project itself, and the value of the option to move forward with project *B'* (and beyond), at some point in the future. Table 3 displays the values of the projects as stand-alone facilities, the fixed costs of each, and the value of the various options to expand each phase.

Table 3: Value of expansion options on each phase

	NPV (US$)	PV of CFs (US$)	Fixed Costs (US$)	Years Deferral	Call Value (US$)
For Scenario 1: Black-Scholes Results (European Call Options)					
Inga A'–Prog	2,063,054,294	8,791,635,158	6,728,580,864	NA	NA
Inga B'–Prog	1,714,392,616	4,927,701,921	3,213,309,305	5	2,161,980,971
Inga C'–Prog	1,948,277,597	4,260,720,964	2,312,443,367	10	2,547,620,784
Inga A–Acc	2,495,062,269	8,335,049,250	5,839,986,981	NA	NA
Inga C–Acc	615,424,081	3,296,179,725	2,680,755,644	5	988,831,959
Inga D	3,592,496,840	6,155,954,908	2,563,458,068	15	4,521,421,878
Inga E	1,592,907,969	3,821,462,630	2,228,554,661	20	2,598,405,900
Inga F	608,774,043	2,637,511,554	2,028,737,511	25	1,679,203,810
Inga G	3,619,835	1,643,055,443	1,639,435,608	30	976,510,666

Source: Authors' compilation.

Under our parameters, in US$, the cumulative NPV of Inga *A'–Progressive* is US$2.1 billion plus the option value on *B'* =

$$US\$2.1\ billion + US\$2.2 = US\$4.3\ billion.^8$$

Considering the Accelerated buildout, the cumulative value of *Inga A* would be as follows:

$$US\$2.5\ billion + US\$0.99\ billion = US\$3.49\ billion.$$

The numbers in the final column of Table 5 show the market price of the option—the right, but not the obligation—to invest in the next project. The 'Years Deferral' column shows the number of years until the option may be exercised. For *Inga B'* today's market would charge the price of the call option, US$2.2 billion, for the right to invest US$3.2 billion (the fixed costs of *Inga B*), to receive a series of cash flows worth US$4.9 billion. That investment would take place five years from now.[9]

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[8] The full value of A' should also include the option to build C' given B'. This requires a slightly more complex option valuation based on the conditionality of the intermediate step of B'. This analysis was not completed for this study, but is underway.

[9] Assumptions: The following assumptions were used to calculate these option values:

As these are European-style options, the Black-Scholes Model was used.

The risk free rate was 3 per cent.

The standard deviation was based on climate change (0.16 per cent); higher variance would yield higher option values.

Each project was valued using a full 25-year life cycle that included a 5-year build time.

Energy prices were assumed to be wholesale prices (no retail markup) and were taken from Cervigni et al. (2015).

Construction costs were based on AECON's Prefeasibility Study.

All other inputs reflect the assumptions mentioned above.

<u>Interpreting the results</u>: There are several interesting results. The first is simply that the real options analysis has shown that 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. Additionally, one can see that the standard DCF analysis (from which the NPV is derived) does not show the full value of even the initial project, because it does not allow for the future expansion decision.

The second result is that the subsequent phases (*B'–G*) hold actual financial value—they represent the possibility of future cash flows. This represents embedded value in the early phases of the project, which could be accessed by the owners of the facility, including the P3 concessionaire and the government.

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 the initial costs are lower for the Accelerated design, the values are significantly higher for the Progressive pathway. As a reminder, these options are calculated based on climate risk alone, and more specifically the risk of river flows affecting project value, and overall effects of climate on energy prices. A more complete risk analysis, especially considering demand risk, may be required to value fully the options and therefore the cumulative value of the projects.

<u>P3 connection</u>: How does this analysis inform a P3 agreement? If developers of *Inga A or A'* are offered the option to expand, they will inherit the option values in their current project. This means that the actual value of the project becomes the NPV of the original facility plus the option to expand, as our examples have illustrated. This is real value because the option could be sold to another party. The original investor is rewarded because of the initial risk of the original project. Of course, the P3 could be structured in different ways. For example, the awarder of the contract could also place a price on the option to expand. In this case, concessionaires would be required to pay in advance, for the option to expand the facility. The decision on who holds and benefits from the option would depend on the level of interest in developing the first facility.

Situation 2: Estimate and mitigate climate risk

To analyse climate risk, we focused on the *Inga A* site, which AECON recommends as the first facility. We created a scenario in which a P3 concessionaire wanted to protect the project value against loss from climate change. Specifically, since the NPV of Inga A has been calculated at US$2.495 billion, we set a value floor of 98 per cent of that value, or US$2.445 billion. If the value of the project were to drop below this floor, the concessionaire would be able to exercise an option to exit the project, and to be compensated at the level of the value floor (US$2.445 billion). In other words, the holder of the option would have the right, but not the obligation to sell the asset for US$2.445 billion. We wanted to determine:

(1) Could the project's values fall more than 2 per cent during the 25-year lifespan of the project, due to climate change?
(2) If so, what would be the probabilities associated with the declining value, in which case the holder of the option would exercise this right?
(3) What cash payments might the insurer (likely the government) need to make to the concessionaire, to keep the option 'out of the money' and avoid paying the full exit price?

To do the analysis, the problem was framed as an American put option. This type of option would normally offer the holder the right to sell the asset at a predetermined price, at any time in the future. We would expect the holder to do so, only if the project value fell below the value floor. Since this option is more complex than a simple European call, a binomial method of

evaluation (rather than the Black-Scholes calculations), described in the methodology, was required.

Once again, the RO valuation process begins with the static NPV for the project, and an event tree is built based on the up and down movement around climate change risk. Figure 3 below shows the distribution of possible values of *Inga A* (NPV = μ =$2,454,697,041). The value floor is akin to an exercise price of US$2.445 billion. As long as the project value stays above the exercise price, the holder of the option elects to save the option for the future. If the value remains above the exercise price for the life of the P3 contract, the holder will never exercise the option.

We found the following: 1) Based on climate risk alone, *Inga A* could indeed fall below the value floor of 98 per cent of the static NPV. 2) The probabilities associated with this decline in year 25 are 3 per cent. 3) Finally, for each state of nature, for which values fall below the floor, the insurer could make cash payment to bring the value of the project back up over the floor. This would prevent the concessionaire from exercising the option, saving the expense of the strike price.

Interpreting the results: Once again, the first result is that the value of the project is augmented with the option. While the static NPV is US$2.495 billion, the calculated option value for today is US$54.7 million, making the value of the project with the flexibility of a value floor option equal to US$3.042 billion.

Value of Inga A without flexibility = US$2.495 billion

+ Value of the Value-floor option = US$0.547 billion

Value of Project with flexibility = US$3.042 billion

Figure 3: Histogram of possible values for Inga A
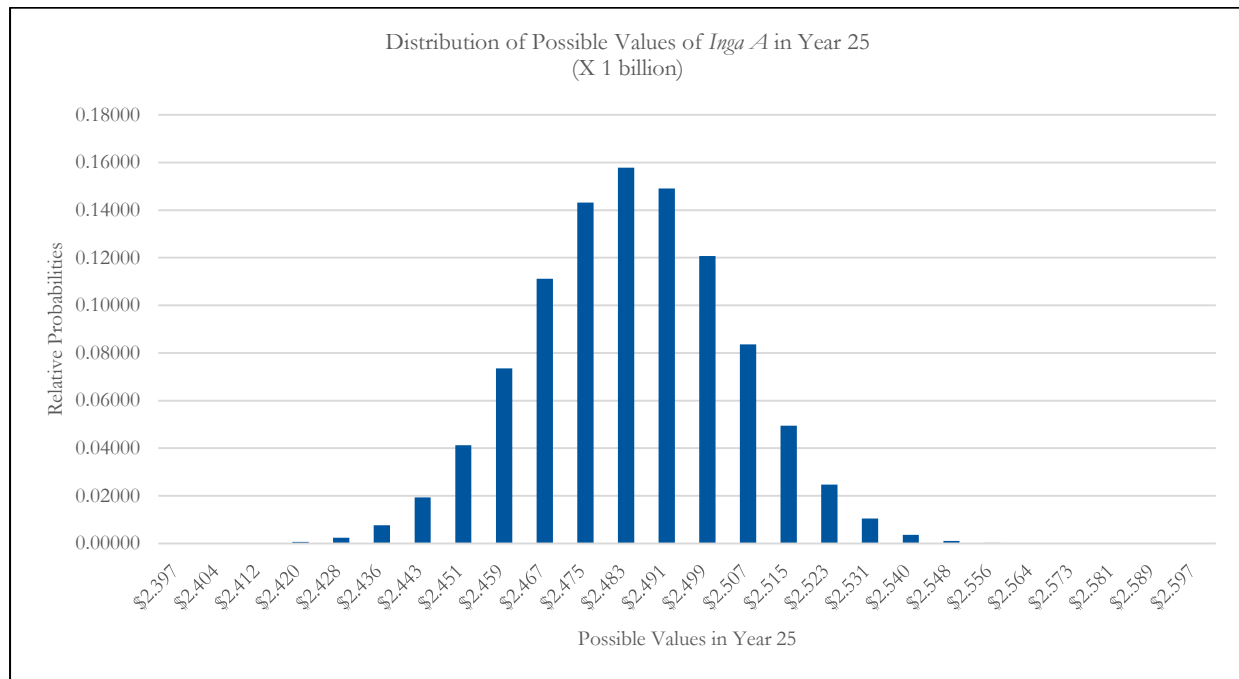
Source: Authors' compilation.

The second result is illustrated in Figure 3. The distribution shows the possible values of *Inga A (Accelerated)*, given the uncertainties of climate change. The expected NPV of the project is US$2.495 billion, but as the distribution shows, the value may drop below that number, though the probability is small. If it drops too far, the holder of the option would exercise their right to sell the project at the exercise price, in this case, our value floor of US$2.445 billion. We found, that given the risk of climate change on financial returns, the probability that the holder of the option would see the value of the project fall below US$2.445 billion, in year 25, is approximately 3 per cent.

The third result is that the insurer can make a relatively small payment to keep the option 'out of the money'. Given our parameters, the lowest payment required in any state of nature is US$1.7 million, and the highest would be US$48.5 million. The highest total payments for the 25-year life of the project would be US$126 million. This means that for a maximum cost of US$126 million, the concessionaire of *Inga A* could be insured against losing more than 2 per cent of the value of the project due to climate change.

Table 4: Possible insurance payments (in US$)

Possible insurance payments by insurer to keep option-to-abandon 'out of the money', by year
cells are different states of nature based on up and down movement of asset value

17	18	19	20	21	22	23	24	25	Total Paid
1,746,982	-	-	-	-	-	-	-	-	1,746,982
9,597,411	5,675,354	1,746,982	-	-	-	-	-	-	17,019,747
17,422,617	13,513,162	9,597,411	5,675,354	1,746,982	-	-	-	-	47,955,526
-	21,325,787	17,422,617	13,513,162	9,597,411	5,675,354	1,746,982	-	-	69,281,313
-	-	25,222,682	21,325,787	17,422,617	13,513,162	9,597,411	5,675,354	1,746,982	94,503,994
-	-	-	29,113,311	25,222,682	21,325,787	17,422,617	13,513,162	9,597,411	116,194,969
-	-	-	-	32,997,685	29,113,311	25,222,682	21,325,787	17,422,617	126,082,082
-	-	-	-	-	36,875,815	32,997,685	29,113,311	25,222,682	124,209,493
-	-	-	-	-	-	40,747,709	36,875,815	32,997,685	110,621,209
-	-	-	-	-	-	-	44,613,378	40,747,709	85,361,087
-	-	-	-	-	-	-	-	48,472,833	48,472,833

Source: Authors' compilation.

P3 connection: Private developers may or may not be concerned with climate risk at the Inga site; flows on the Congo River are very consistent, producing similar returns in all our climate scenarios. However, if a concessionaire were concerned, holding the option to sell the project back to the public at US$2.445 billion would be an appropriate mitigation tactic. The price for such an option would be US$54.7 million according to our calculations. However, the insurer could supply that insurance relatively cheaply by making a cash payment as discussed above, guaranteeing the project's revenues. As long as the project values remain above the value floor, the option will remain unexercised. This would be akin to issuing an option based on the following payoff formula, (where K is the value floor and V_0 is the value of the project):

$$MAX[K - V_0, 0]$$
(5)

Situation 3: Combining uncertainties: climate, cost overruns, and limited demand

The Inga project, as with other infrastructure projects, suffers from uncertainties beyond those of climate change. In this case, two additional project related risks are: 1) possible cost overruns mentioned by Ansar et al. (2014); and 2) whether sufficient infrastructure will be built to carry power to continental demand centres and customers.

The final Situation was designed to answer the question of whether developers would opt to expand the *Inga A'–Progressive* dam to include the *B'* spillway, given the combination of climate and cost overrun risks, especially if the infrastructure to deliver the *Inga B'* power failed to develop fully. To frame the final Situation, we structured a case around the first expansion decision that would be faced by developers: whether to build *Inga B'*. However, in this case, we wanted to determine the decision point, given the additional risk factors. We ran our model including the risk of cost overruns; and we made the additional assumption that *Inga B'* would sell just 75 per cent of its generating capacity (3275 MW * ¾). Under a more limited demand scenario, and higher uncertainty, Situation 3 calculates the value of an option to expand from facility *A'* to B in 10 years' time as a European call option.

To calculate the return risks of cost overrun, we used data from Ansar et al.'s 2014 report, and performed a Monte Carlo simulation based on Ansar et al.'s mean cost overrun of double (2x) the original estimate of the dam, with a standard deviation of 3.6 (Ansar et al. 2014). This gave a series of coefficients for cost overruns, which were used to generate a range of possible costs for one of the facilities. These costs were then used to calculate return on investment for the facility. The standard deviation from this distribution was 2.91 per cent, making the total risk factor 3.03 per cent (risk factor from cost overrun plus risk factor from climate change: 0.16 per cent). To model the truncated demand, we reduced the present value of the *Inga B'* cash flows by 25 per cent.

To calculate the value of the option to expand the project, we again began with the project's static NPV (without flexibility). In this case the static NPV for *Inga A'* = US$2.1 billion. This was the starting value for the event tree to replicate possible values of the project without flexibility. We then introduced a strike price of US$2.8 billion, the discounted cost for building *Inga B'*, in year 10, and added the value of the new Inga B' selling at 75 per cent of its total output.

Table 5 shows that in year 10, there are six states of nature in which the value of the new project is greater than zero (the green shaded cells); but there are five, in which the value of expanding is less than zero (red shaded cells). The values in the non-shaded columns are the values of the

option at each point in time and state of nature. Since this is a European call, no action can be taken until year 10.

Table 5: Values of option to expand (in US$)

Option to expand with limited demand										
Limited demand factor =		75 per cent	All figures X 1,000,000							
0	1	2	3	4	5	6	7	8	9	10
594	614	635	657	679	702	726	751	776	802	829
-	488	505	522	540	559	578	598	619	641	663
-	-	382	396	410	424	440	455	472	488	506
-	-	-	277	287	298	309	321	333	345	358
-	-	-	-	172	179	187	194	202	211	220
-	-	-	-	-	70	73	77	81	85	89
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-

Source: Authors' compilation.

Interpreting the results: Once again, the initial project, Inga A', is more valuable with flexibility. At the outset of the project, the option to expand is worth US$594 million.

Value of Inga A' without flexibility = $2.1 billion

+ Value of the option to expand = $0.594 billion

Value of Project with flexibility = $2.7 billion

An additional result is that the option to expand does not necessarily retain its value for 10 years. After year one, depending on how the two risk factors develop, the option is worth either US$614 million or US$488 million. From years 0 to 5, there is no state of nature in which the value of holding the option to expand is less than positive. However, in year six, it is possible that climate risk and cost overruns, under this demand scenario, have combined to push the value of the underlying asset down, such that it is no longer worth it to expand the facility. Unless project values move back 'up' the tree (toward the green shaded cells), the option to expand will expire worthless,—the expansion will have lost its value. In other words, the present value of *Inga A'* plus the additional value of *Inga B'* minus the strike price (the cost of the new investment to build *B'*) would be less than zero.

$$\text{Payout} = \text{MAX} \left[(\text{Inga A'} + \text{value of Inga B'}_{\text{Limited demand}} - \text{cost of B'}), 0 \right] \qquad (6)$$

P3 connection: As previously illustrated, the option adds value to the project. In this situation, if the P3 partners felt the demand was going to be just 75 per cent of the output, the price of an option to expand to B' in year 10, would be US$594 million.

7 Conclusion

The Inga dam embodies many of the risks and rewards of hydropower in Africa. To value and evaluate its potential fully will require a sophisticated look at the various options around its construction and management, much more complete than this analysis. Our hope has been to point out one direction for future evaluation. To attract investment, planners will need to ensure that investors are protected from unnecessary risks, including those from climate change, and possible cost overruns. 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 understand the risks, and to develop mitigation tactics.

We understand that there are many risks that have not been addressed in this assessment. Further work is being done to model other situations at the Inga site including various time steps for build out, and the option values of waiting to build. More sophisticated analysis around demand could also be accomplished, built from ground up demand models. A risk factor for environmental policies could also be added. Finally, for each of the existing Situations, a Monte Carlo approach could be taken with the various inputs to discover more about the values of expansion, abandonment, or insurance schemes.

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 is 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.

The debate about hydropower will likely continue. Climate change brings the power source once again to the forefront. We believe that concepts such as flexible design and optionality in valuations can enhance the characteristics of these projects, making them robustly adaptable to various possible climate futures, and attract a wide variety of investment.

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