sustainability

Case Report

Value–Risk Calculator for Blended Finance: A Systems Perspective of the Nachtigal Hydropower Project

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Abstract: Hydropower as a renewable source can help many countries achieve their sustainable energy and climate goals, but large projects are challenging to finance because of their costs and risks. To fully realize the climate benefits of such projects, sponsors have recently fashioned complex financing arrangements that structure and allocate risks to reduce financing costs. This paper focuses on the blended financing approach adopted for the Nachtigal Hydropower Plant (NHP) in Cameroon. The purpose of the paper is to present a detailed systems analysis of Nachtigal's financial arrangement to address the question of why the complex financing approach worked in practice. We accomplish this by creating a "financial simulator"—a computational model for evaluating risks and incentives embedded within the financing structure under different contract architectures and risk–event scenarios. Our simulator is a dynamic value–risk calculator that can be easily updated to study other climate-oriented projects that involve complex financial arrangements. We evaluated three aspects of the financing/contractual arrangements that made Nachtigal "bankable:" (i) guarantees that covered nonpayments, (ii) financial options on locally sourced loans; and (iii) an interest rate swap. We found: (i) the guarantees recovered project value threatened by four specific risks often associated with large hydropower investments (cost overruns, schedule delays, offtake risk, and low flow due to climate change); (ii) the mechanism significantly lowered interest rate charges; and (iii) private finance was mobilized—especially due to the options. The financial safeguards employed increased the likelihood of capturing the long-run sustainability benefits from NHP.

Keywords: hydropower; climate finance; risk; public–private partnership; sustainability

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1. Introduction

Large hydropower (HP) projects can deliver energy volumes at scale to support economic growth in many nations. However, inherent risks create barriers to financing, unless they are identified and mitigated, priced, or otherwise allocated. To accomplish this allocation, a project's financial structure can implement a risk allocation process by apportioning risks to those who can best manage them.

Risks may manifest differently for each party involved in the development process, making financial structuring and risk allocation a complex process. From an investor's perspective, risk factors are often out of alignment with returns, resulting in insufficient risk versus return value (when exposed to greater risk, investors demand higher returns). From the developer's perspective, the cost of capital is a significant factor in the cost structure of a large project, leading to a search for a capital structure that makes available the lowest possible rates. Finally, from the perspective of the electricity offtake utility and government, the cost of capital must be kept within a range that allows for reasonably priced electricity.

The Nachtigal Hydropower Plant (NHP) exemplifies the typical risks of HP development. As with any large project constructed in an emerging economy, cost overruns (the risk that the project will cost more than anticipated) were a significant risk. Similarly, project delays (i.e., permitting delays, or technical problems, etc.) postpone revenue collection.

Further, the Cameroon utility and power offtaker has a history of poor financial performance, creating a potential offtake risk. River flow variability from climate change is also a risk, and is being mitigated through the construction of the Lom Pangar project, a smaller hydropower facility located upstream from the Nachtigal site. Lom Pangar provides a stable flow to NHP through its use of a reservoir and regulating dam. [1]. Currency risks were another hurdle, emanating from the fact that loans are typically given in hard currency while revenue, which is the source of repayment, comes in local currency. The result is that currency depreciation, common in emerging economies, makes repayment difficult. Finally, Central African banking rules prevented local banks from offering satisfactory lending terms to large projects. The combination of risks threatened the project.

A financing structure to overcome these hurdles would need to offer protection to potential investors from the financial effects of these risks, while preserving affordability. The goal of the financial structure was therefore to (i) mitigate project risks, (ii) reduce debt servicing expenses, and (iii) attract private sector investors. These results would enable maintenance of market-appropriate tariffs. To achieve these objectives, certain guarantees were provided to investors, options were offered to local lenders, and an interest rate swap was initiated.

Such arrangements are more complex than the norm for typical project-financed infrastructure and raise the question of whether the instruments can be credited for driving the success of project delivery. Addressing the question, however, requires computational tools that are adequate for representing the complexity of the project as a system as well as the implications of the financial structure. We built the computational tool that allowed us to make sense of the project system and its financial arrangements.

To do this, we describe the project as a dynamic system—a set of components and their interactions with the natural environment over time—and characterize each risk event to derive a full distribution of probability-weighted outcomes under specific scenarios. By focusing on the risk events (rather than the coverages only) we were able to trace real-world phenomena, such as river flows, schedule slippage, rising interest rates, etc., to financial outcomes by specifying these in a financial simulator.

The remainder of this paper contains the following. The literature review in Section 2 provides a basic understanding of the importance of hydropower, its risk factors, and available financing strategies. Section 3 covering the methodology and analysis describes the project participants, their financial arrangements and modeling methods. Section 4 sets forth the results of the analysis and contextualizes and describes our findings. The Discussion in Section 5 summarizes and contextualizes our findings. Finally, Section 6 concludes and offers suggestions for additional research.

2. Literature Review

Three primary topics relevant to the development and financing of Nachtigal have received significant attention in the academic literature: (A) the importance of hydropower to achieve sustainable development energy goals, (B) the risk factors endemic to large projects and hydropower specifically, and (C) optimal financing arrangements for hydropower. We build on these topics, hoping to accelerate the discussion of sustainable large-scale finance in the academic press. However, we also seek to bridge a gap by linking the necessary complexity of the financial arrangements with the long-term climate benefits, sometimes referred to as "sustainable outcomes." Without the financial complexity, the project may not have been achieved, and the long-term benefits may never have been realized.

2.1. The Importance of Hydropower to Achieve Sustainable Development Goals

The rationale that Nachtigal will play a key role in promoting power sector sustainability in Cameroon [2] is illustrative of the views of a large body of literature addressing hydropower's viability as a sustainable energy source, [3–5]. Hydropower accounts for over 50% of global renewable electricity and can be a cost-efficient means to boost electricity access rates while contributing relatively low emissions [4,6–8]. Hoes, et al., (in [9] estimate the global theoretical potential for hydropower is 52 PWh/year, equal to 33% of required annual energy (currently built hydropower accounts for 3%). However, to tap the full unrealized potential of hydropower will likely require private investment [10]. It is well recognized that current volumes of financing remain insufficient, and that private finance represents a much larger amount of available capital [6,11–17]).

2.2. Risk Factors Endemic to Large Hydropower Development

Plummer-Braeckman et al. [17,18] identify risk categories that are of particular concern to private financiers, and which need to be overcome to attract investment. Summarized in Table 1, the categories are (i) government risk (lack of responsiveness, corruption, permitting delays, and security); (ii) environmental/social risk (impact on local environmental and social conditions, associated delays, and the reputation damage to the investor that may be at stake); (iii) technical risk (geological, electromechanical, etc.; these were considered easier to mitigate); and (iv) market risks (especially currency exchange and electricity market risk). These risks that often deter investment are also present in the Nachtigal project.

Table 1. Risks, descriptions, and concerns.

Categories	**Descriptions**	**Concerns**
Government Risk	lack of responsiveness; corruption; permitting delays; security	Project delays
Environmental/Social Risk	impact on local environmental and social conditions; associated delays; reputation damage to the investor	Cost overrun; Project delays
Technical Risk	geological; electromechanical etc.; these were considered easier to mitigate	Cost overrun; Low output
Market Risks	currency exchange; electricity market risk; financing misalignment	Currency depreciation; Offtake problems

Source: adapted from [6].

The possibility of bad outcomes from these categories, including combinations of events, deters investors. The specific financial concerns faced by investors in Nachtigal can be easily located within Plummer-Braeckman's risk taxonomy:

Cost overruns and project delays. Cost overruns and project delays may lead to reduced financial value if future revenues do not fully compensate for increased costs. These can be the result of an unresponsive government or delays in permitting (government risk), geological oversights during project planning (technical risk), or an inadequate understanding of environmental and social impacts (environmental/social risk). There is a significant body of literature on the costing of large projects and the bias toward underestimating when forecasting the costs of hydropower. Some say this forecast discrepancy means that dam development should be curtailed. However, studies have found that World Bank-facilitated hydropower investments, though also suffering from cost overruns, have produced positive and substantial net economic benefits. The participation of the World Bank has likely helped to mitigate risk factors by effectively dealing with these problems before projects begin. (See [19] on costing challenges for large projects; [20] on underestimation bias; and [21,22] on the positive impact of World Bank involvement in such projects.)

Low output and offtake problems. Low output risk is the possibility of the plant not producing as much as expected (technical risk), while offtake risk arises if the utility offtaker cannot sell, or collect on, all power produced (market risk). A growing concern is the possibility of reduced river flow from climate change, which would lead to low electricity output. Concerns about offtake arise in many developing countries because insufficient or deteriorated infrastructure may prevent the full evacuation of power, and poor bill collection may lead to a default on payments by the offtaking utility. (See [23,24] on climate impacts to hydropower and [25] on offtake problems.)

Currency mismatches and financing misalignment. Loans typically arrive in hard currency, while the revenues for repayment come from local currency. If the local currency depreciates, loan payments will be more difficult to make (market risk). Furthermore, there is often a mismatch between debt tenor and the useful life of most facilities (market risk). Hydropower plants can often produce for over 50 years, but debt maturities are rarely longer than 15 years and often shorter. This arrangement forces tariffs unnecessarily high during the early years of operation in order to meet debt servicing obligations [26].

2.3. Optimal Financing Arrangements for Hydropower

Developers often conclude that a form of public–private partnership (PPP) financing may help manage these risks. PPPs are one of three main financing modalities [6]. The three modalities are: sovereign (public) finance (or "sovereign"), foreign-aid oriented bilateral finance, and public–private partnerships.

Sovereign (public) financing. Under this arrangement, the host country government uses the strength of its balance sheet to lend funds, or contribute equity, to the power offtaker, who then develops the project. Funds may come from cash reserves or government borrowings that are loaned to the project. Costs of financing depend on the source of the funds and the credit-worthiness of the country; concessional financing may be available from Development Finance Institutions (DFIs) for developing nations. A significant advantage of this structure is that it involves a limited number of parties, reducing the time, effort, and costs of coordination. A disadvantage is the opportunity cost to the government. When capital availability is constrained, funding one project means less money is available for other projects or programs.

Bilateral investment. This is an investment from a foreign government, typically delivered by their national Export-Import bank. These loans are frequently conditional on using a contractor from the investing country, often a state-owned enterprise (SOE). Collateral for the loan may be the project itself or the rights to valuable natural resources within the host country. In either case, a default would mean the transfer of ownership of significant national resources to the lending country. Strengths of this arrangement are that limited, or no cash may be required from the host government, there are few coordination challenges, and there is a shorter time from concept to operation. The weaknesses are that the actual costs to the host country are not known for several years (it is very difficult to estimate the future value of commodity resources), it mortgages the national resources of future generations, and it is difficult to monitor and enforce performance and warranty obligations of the contractor [14,16]. Bilateral finance is relatively new but has quickly become popular for many developing country governments. The development banks of Brazil, Russia, India, Korea, and especially China have been primary lenders [27,28].

Public–private partnership (PPP). Countries that lack central funds, and do not want to leverage sovereign assets can look to PPPs. PPPs are typically delivered through a project finance loan structure that relies on the project's cash flow for repayment. The project's assets, rights, and interests are held as secondary collateral. A project company, called a special purpose vehicle (SPV), is created, whose sole business is the construction, ownership, and operation of the project. Strengths of this arrangement are that no cash is required from the government, project risk is allocated to parties that are willing and able to bear the risks, and thorough due diligence and performance guarantees are required by the SPV. The weaknesses are that coordination is complex (as will be seen through the case study), projects take more time to reach operation, and there are higher up-front costs in time and resources [15,29–34].

We build upon this body of work but also attempt to bridge a gap in the research by linking the complex financial arrangements to the eventual realization of climate benefits. Further, most of the risk literature focuses on economic returns rather than financial. We also find significant survey research that aggregates specific results across a large cross-section of projects but relatively few case studies that present project details. Instead, we analyze the specific risk-mitigating strategies of a PPP project from the perspective of the SPV and its partners—including private partners—from a financial and systems perspective. In so doing, we articulate the connections between financial incentives and sustainable outcomes for Nachtigal.

3. Methodology and Analysis

3.1. Description of Nachtigal Hydropower Arrangements

The Nachtigal Hydropower Plant (NHP) will be a 420 MW facility on the Sanaga river, located in Nachtigal, Cameroon (the primary source of information about the project came from the Project Appraisal Document (PAD) [2]. Construction of the plant began in 2018, and electricity is expected to flow in 2024. Development of the project is being led by the Nachtigal Hydropower Company (NHPC, the project company, SPV) and supported by the Government of Cameroon (GOC). The French energy company EDF is the project's primary sponsor and has collaborated with its subsidiaries, and private sector participants to mitigate the various risks involved. The World Bank and its partners have supported the project through guarantee instruments and development of an upstream project that will help regulate river flows. NHP is expected to reduce the cost of energy in Cameroon, boost power generation capacity, promote sector sustainability, and attract private sector participation. The total cost of the project is estimated at USD 1,383,000,000 not including a contingency.

3.1.1. Participants

The financing arrangements for Nachtigal illustrate a project finance approach, and consist of a series of guarantees, options, and swaps, embedded in contractual arrangements between the parties. A relatively full description of each participant is included, since the project will only be as credit worthy as its owners. A robust credit rating was something neither Cameroon nor the domestic utility could provide on their own, thus the recruitment of EDFI, a subsidiary of EDF. Strategic selection of debt providers is also important. The presence of local banks helps to overcome the currency mismatch of labor and capital costs, the source of considerable depreciation risk. The overall scheme is diagrammed in Figure 1, which offers a picture of all parties (including some that are not discussed in this paper) and the financial arrangements between them.

Equity Holders

Government of Cameroon (GOC). The GOC is one of three primary shareholders, owning 30% of the NHPC. Cameroon is at high risk from external and overall public debt distress, though debt remains sustainable [35]. External debt is estimated to be 29% of overall GDP (2018). Contingent liabilities (those that do not appear on the balance sheet, but that are guaranteed by GOC) add an additional 8.5% of GDP (2018) to the debt picture from SOEs alone, while the full value of PPPs is estimated at just 5.4% of GDP. Reducing debt exposure will require a number of policy actions [35]. Cameroon's credit ratings are B from Fitch, B2 from Moody's, and B- from S&P.

International Finance Corporation (IFC). The IFC is an international financial institution that offers investment and other services to encourage private-sector development in less developed countries; it owns 30% of the NHPC. According to the IFC website, it was to directly invest €60 million in equity and lend up to an additional €110 million. The IFC was also to provide at least one euro interest rate swap to partially hedge the interest rate risk of the Project's euro-denominated floating-rate senior debt. The IFC has been consistently rated triple-A by S&P and Moody's.

EDF International SAS (EDFI). EDFI owns 40% of the NHPC. EDFI is a subsidiary of the holding company EDF, a French utility, and an SOE. EDF is Europe's largest renewable energy producer, with a portfolio representing over 130 GW of generation capacity in, South and North America, and Asia. EDF is an important partner in financing as its presence helps to strengthen the credit rating of the project. EDF is currently rated A-, A3, and A- by S&P, Moody's, and Fitch, respectively [36].

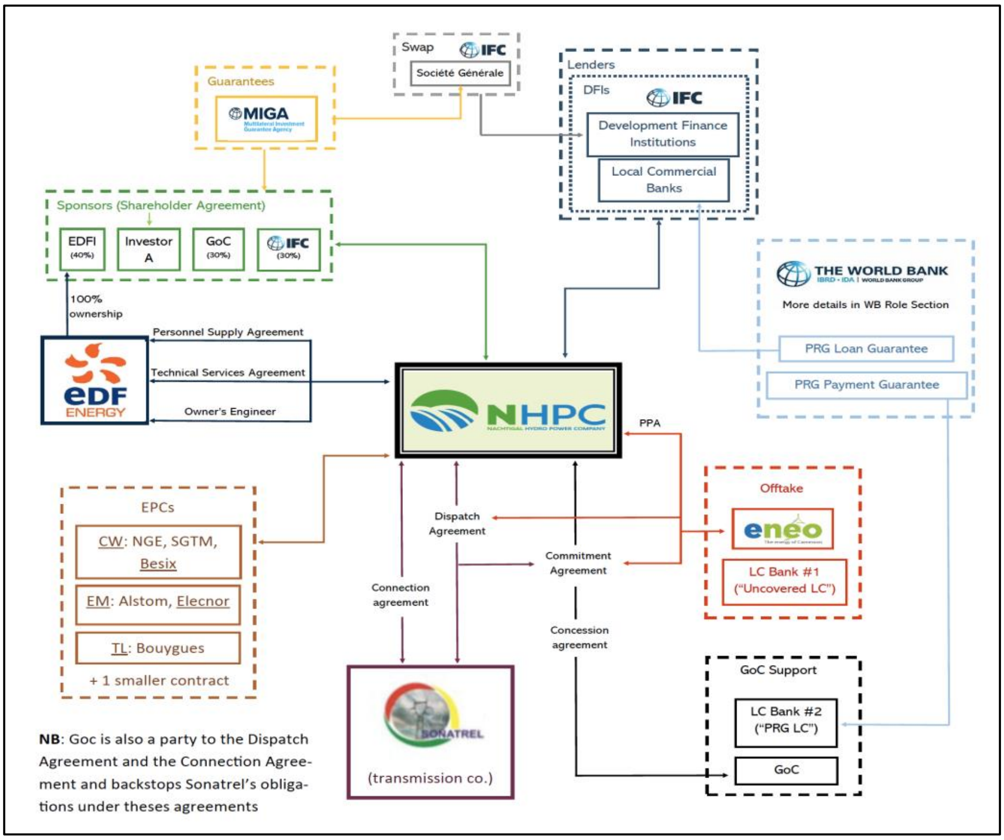

Figure 1. Schematic of Nachtigal's Financing Arrangements. Source: adapted from [2].

Debt Providers

Local banks. A group of four local banks lent about $200 million to the project. These funds are provided in local currency and make up about 19% of the total debt. The banks provided funds on a 21-year term, with repayment following a mortgage-style profile over the entire 21-year tenor. This is an unprecedented action in the local setting, which was made possible by the series of options exercisable at years 7 and 14 of the loan life at the banks' discretion. The put option mechanism allows the banks to extend loan maturities beyond local regulatory restrictions, which are imposed by the Bank of Central African States. Their local currency contribution is vital in paying for locally procured labor for the project.

Development Finance Institutions (DFIs). Eleven DFIs (not specified in the PAD) have joined, providing about $673 million in debt financing (64% of the total debt package). About 20% of this total came in local currency, further mitigating currency risks.

Other Participants

Other lenders. Two other lenders provided the balance of the required debt. In addition to its equity position, the IFC, which also acted as the global coordinator for the entire syndicate, provided about $147 million. A private investor, identified only as Investor A, brought $32 (Investor A also provided a small amount of equity). Finally, the French investment bank Societe Generale is holding escrow funds and facilitating an interest rate swap.

Providers of guarantees. Two organizations provided three important guarantees that brought comfort to the investors. First, the International Bank of Reconstruction and Development (IBRD) provided two guarantees—a payment guarantee and a loan guarantee, totaling $300 million [2,37]. The payment guarantee supports the utility's (ENEO) offtake payments under the power purchase agreement (PPA). The loan guarantee will backstop certain payment obligations of GOC to local lenders. Second, the Multilateral Investment

Guarantee Agency (MIGA), an international financial institution offering political risk insurance, was approached for three breaches of contract guarantees, one for EDFI, another for Investor A, and a third for SG.

The Utility: Energy of Cameroon (ENEO). The national utility, ENEO, will purchase the energy produced by the project, and is, therefore, a key partner. ENEO is owned by shareholders from the private and public sectors. The British investment fund, Actis, controls 51% of the shares, the government of Cameroon owns 44% and employees of the company own the remaining 5%. As a company, ENEO has often been in poor financial health, with negative net profit as recently as 2019 [38]. The PAD mentions high technical and commercial losses (30%) and payment delays on behalf of public institutions, as two important drivers of poor performance. Poor financial health persists despite relatively high electricity tariffs. The costs of electricity service in Cameroon are higher than regional averages, the result of reliance on expensive liquid-fueled thermal generation and poor operational performance. As a result, electricity tariffs have been high for the region. Despite the high tariff, the sector has not been able to achieve full-cost recovery without GOC infusions, which come in the form of a tariff compensation. Between 2012–2018, the GOC paid ENEO an annual tariff compensation averaging EUR 17 million [2].

Unfortunately, even when the compensation is granted, it is often not received in a timely manner, forcing ENEO toward expensive bridge loans, and accumulated account and tax payable balances in the amount of EUR 96 million. Delays in payments to suppliers have resulted in their delayed payments to fuel providers and financiers, creating a series of liquidity problems all along the value chain. With limited available investment capital, the company's distribution performance worsened; for this it was penalized under the rate review, trapping the company in a downward spiral. To help shore up these conditions, a number of legislative actions have been taken to clear ENEO's fiscal debt and avoid the buildup of future arrears. New investment in the distribution network has also been undertaken. In June of 2020, the government paid a substantial portion of its payment arrears helping ENEO clear a significant portion of its debt [39]. Still, these details serve as a reminder of the sectoral risk of the project.

3.1.2. Financing Instruments

Guarantees

There are three separate guarantees that cover different risks within the financial structure. The first is a payment guarantee and is provided by the IBRD. The payment guarantee ensures that ENEO and the GOC honor their commitments to pay for power produced by the NHPC. The payment guarantee was for $100 million, has several layers, and is diagrammed in Figure 1. The second guarantee is a loan guarantee and is also provided by the IBRD. The loan guarantee was for $200 million and ensures that the local banks are able to collect any unpaid principal and interest if they exercise their options to exit their loans. The third type of guarantee protects its holders against Breach of Contract, and was issued by MIGA to EDFI, Investor A, and SG; the total coverage was $188 million for equity and quasi-equity investments. These three guarantees protect their holders in the event the government—who backstops NHPC payments to these parties—does not stay current on its commitments. From a practitioner perspective, these guarantees provided sufficient coverage of the investors' commitments.

Together, the guarantees provided comfort to the lenders, enabling a reduction in interest rates, and a longer repayment schedule than had previously been available for hydropower projects. Repayment schedules that align more closely with a project's useful life help to spread out financing costs and keep tariffs lower. This is critical for large hydropower plants, because with short repayment horizons ratepayers must pay all financing costs during the early years of the project, which may make it unviable

Figure 2 illustrates the payment guarantee. Reading the diagram from right to left, the Power Purchase Agreement obliges ENEO to buy energy from the NHPC. The uppermost Letter of Credit (LoC) is 2.4 months of PPA payments held in escrow at Society General

(SG) bank. If that account is exhausted, the GOC also has an LoC of $100 million, which may be drawn. Finally, if the GOC fails to pay the NHPC, then the IBRD guarantees that payments will be made.

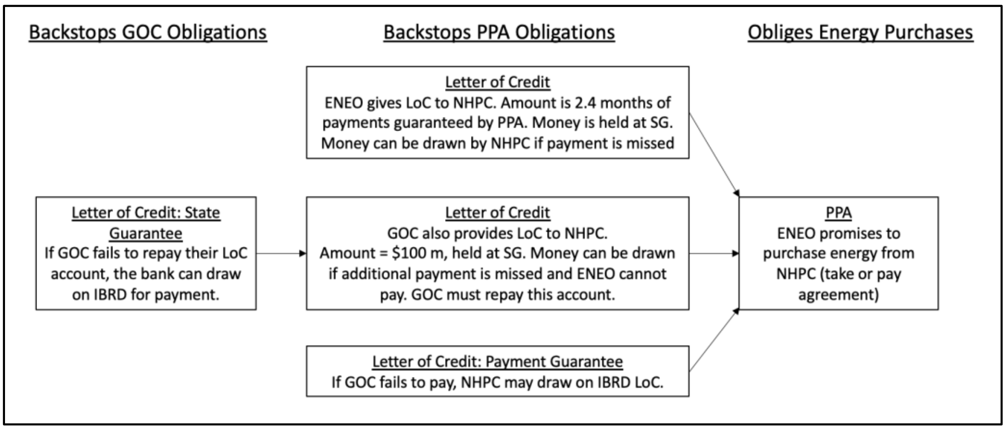

Figure 2. Payment Guarantee Structure. Source: adapted from [2].

Options

The options were perhaps the most important and innovative aspect of the financing. Together with the guarantees, the options helped deliver local financing with a 21-year tenor. A series of two put options were available to the local banks. At the end of years 7 and 14, if a bank decides to exercise its put option, the NHPC has an obligation to find another lender; if it cannot, the GOC is obligated to purchase the loan(s). In addition, the GOC is obligated to pay termination compensation if the PPA is terminated under events that are attributable to the GOC. The obligations ensure the full repayment of principal and interest to the banks. The IBRD's loan guarantee assures the GOC's obligation to purchase the loans at year 7 and 14 if the put option is exercised. It will also make scheduled principal and interest payments if the NHPC does not meet its payment obligations, provided the nonpayment is due to the GOC's failure to pay termination compensation. This series of options, obligations by the government, and the IBRD guarantees were critical in providing relief on behalf of local commercial banks. With these mechanisms in place, the risk of default declined and the NHPC enjoyed a highly competitive bidding process for local lending.

Swap

The financial structure also includes an interest rate swap. The swap exchanges interest rate cash flows between the DFIs and Societé Géneral (SG). The DFIs receive a floating rate payment from the NHPC; they then pass on the floating rate to SG, which pays them a fixed rate in return (see Figure 3). Based on 20 years of year-end 12-month LIBOR from 1998 to 2018, we calculated the fixed rate for the swap to be 1.7% [40]. According to the PAD, the swap(s) represent a loan equivalent exposure (LEQ) to the NHPC of up to US$10 million, meaning this was the expected positive average mark–to–market value of the swap.

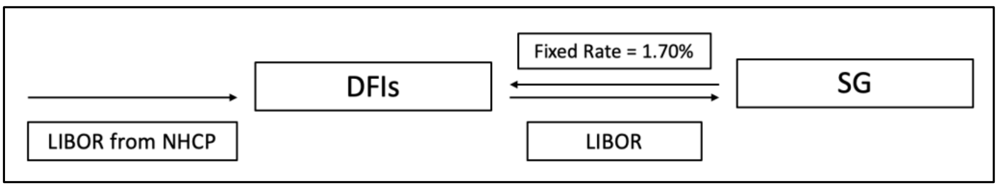

Figure 3. Swap Diagram. Source: Authors.

3.2. Modeling Method

Our method was to build four linked models. Each model was based on practice that is well established in hydropower or financial analysis and is described in detail below. The aim was to recreate the financial models that produced the ex ante evaluation of the project and then to test those models with real-world simulations based on risk events, evaluating the asset's performance. For example, although the guarantees covered investment amounts, our interest was in evaluating the guarantees from a system perspective; how did they stand up against plausible risk of loss from real-world phenomena? We then compared the risk of loss to the guaranteed coverages. Similarly, we modeled the options in a real-world environment of possible interest rates and defaults, absent extracontractual protections.

Most of the necessary information for completing this process was available in the PAD [2]. Some unofficial informational interviews were also granted by World Bank personnel who filled in additional detail. However, certain inputs were not available; in these cases, assumptions were made based on calculated outcomes, or standard industry practice. All models and reporting were conducted using the R programming language. The various models have been fully integrated with an R Markdown output (2022.07.1 Build 554 © 2009–2022 RStudio, PBC). The result is a value–risk calculator that can be adjusted to fit other projects, updated to account for current inputs, and upgraded to provide additional robustness.

The series of linked models functioned to (1) estimate electricity volumes for NHP; (2) derive an annual cost recovery tariff; (3) produce a pro forma financial report for NHCP, forecasting costs and revenues for the concession of 35 years; and (4) evaluate the financing arrangements through a systems lens using (i) a series of Monte Carlo simulations to evaluate the sufficiency of the guarantees, in light of risk events, (ii) binomial models to assess the value of the banks' options, and (iii) a swap model to evaluate the interest rate swap. Figure 4 illustrates modeling the sequence.

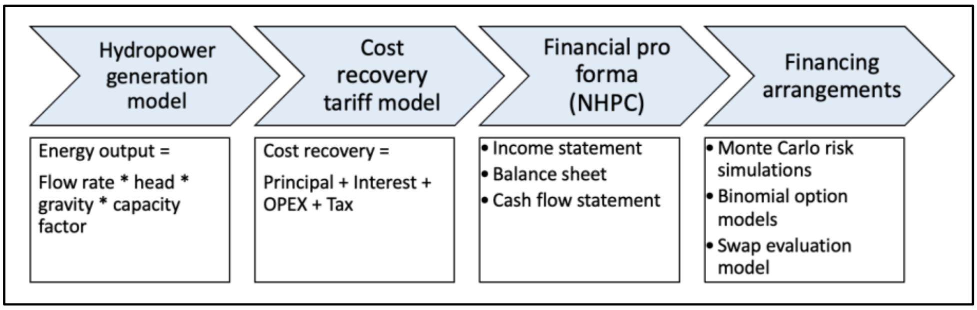

Figure 4. Modeling Sequence. Source: Authors.

3.2.1. Step 1: Hydropower Energy Output

First, we calculated the electricity output that is expected at NHP and compared our figure to the energy volumes estimated in the PAD. Using standard hydropower calculations and based on the specifications for the dam structure and the river flows listed, we were able to successfully approximate the energy volumes from NHP at 2921 GWh per annum, nearly identical to the value given in the PAD.

3.2.2. Step 2: Cost Recovery Tariff

Second, a cost recovery tariff was calculated based on the "all-in" costs to produce the total energy each year. These costs include the total capital costs, operations and management (O&M), financing costs (equity and debt), and additional costs of royalties, taxes, and other fees. The total capital cost was USD 1.38 billion. O&M was considered to be 1.5% of the total capital cost, or $21 million per year. Allowable return on equity (ROE) is often established as a ceiling for many PPAs. In this case, the assumption was made that the ROE allowance was 17%. The cost of debt is the weighted average interest charged by the parties that contributed debt to the project. Not all details of the loans were provided in the PAD, so several assumptions were made regarding the cost of debt. Debt repayment schedules were listed in the PAD, but interest rates for the various loans had to be estimated. This was accomplished through finding interest rates that supported the levelized tariff recorded in the PAD. The weighted average cost of debt was estimated at 8.71%. The tenors of the loans from the various providers were different, with those from private local lenders being longer (21 years), those from international lenders being shortest (15 years), and those from development finance institutions in between (18 years). Table 2 shows the five debt providers and their assumed rates, tenors (in years), and amounts (in USD millions).

Table 2. Debt providers and terms.

	IFC	DFIs	Local Banks	Investor A
Debt rates (%)	6	8	12.5	12.5
Debt tenors (years)	18	18	21	15
Debt amount ($ million)	147.15	672.69	199.71	31.53

Source: [2] and Authors' estimates.

Because the debt servicing payments change during the operational life of the facility, the cost-reflective tariff also changes to reflect annual costs of financing. When averaged over the 35-year concession, the costs listed above led to an average tariff of $0.0611 per kWh; this value is also very close to the value for the levelized tariff of $0.0610 per kWh given in the PAD, signifying the reasonable accuracy of our model. Figure 5 shows the cost-reflective tariff for the full concession period.

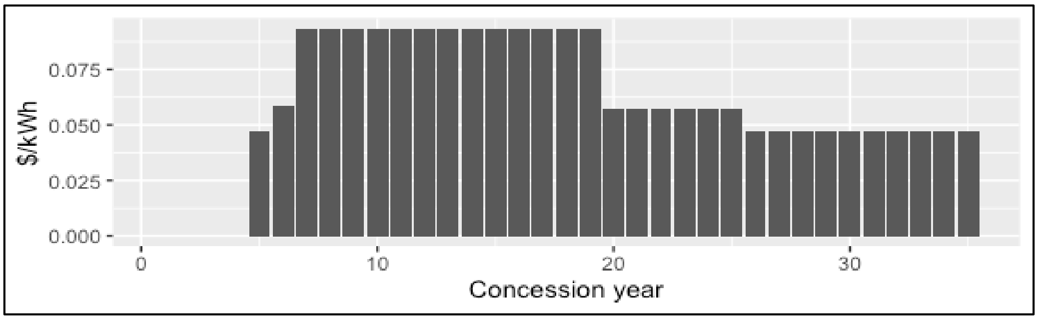

Figure 5. Annual cost of service tariff. Source: Authors.

3.2.3. Step 3: NHPC Pro Forma

Third, a pro forma for NHCP was created. This was a three-statement model (balance sheet, income, and cash flow statements) with revenue and expenses projected over 35 years. A summary of the first several years of each projected statement is available in the Appendix A (Table A1 is the Balance Sheet, Table A2 is the Income Statement, and Table A3 shows the Cash Flow). These assumptions include a four-year construction period, and equal capital disbursements from the providers, across those years (this was a simplifying assumption; the PAD included a capital disbursement schedule that was more nuanced).

3.2.4. Step 4: Evaluate Financing Arrangements in Light of Risk Events

Fourth, aspects of the financial structure were studied by building a series of models to evaluate risk drivers, mapping them to the components of the financing. First, we quantified the risks for comparison against the guarantees; second, we calculated the value of the options under two important scenarios; and third, we evaluated the interest rate swap. This exercise answers three important questions: (1) do the guarantees adequately cover the probability-weighted financial risks? (2) what incentive value can be ascribed to the options? (3) what is the value swap? The answers to these questions reveal why the parties were willing to provide capital at the rates they did.

Step 4a: Quantify Risk Probabilities and Loss Potential; Compare to Guarantees

We evaluated the probabilistic impacts of four sources of risk—cost overruns, scheduling delays, reduced offtake, and low flow due to climate change—on financial outcomes. While there are many risks associated with a project of this size, these four represent the financial manifestation of most of them, as discussed in Section 2.2. We then combined the risk factors to understand the effects of simultaneous impacts. For each risk, and the combinations, a Monte Carlo simulation was performed, with 100,000 runs as described in [24]. Graphical results and discussion are presented in the next section. The goal of the simulations was to discover the full range of possible NPVs, based on the statistical behavior of the risk factors. The Monte Carlo simulations randomized the source of risk within the pro forma model and kept track of the resulting NPV values. The inputs are randomized according to a probability density function, which is defined by an average (mu) and a standard deviation (sigma). Starting values for the inputs are also required. For cost overruns, the capital cost of the project was used as a starting point, and the mu and sigma values were 0.40 and 1.25, respectively [21]. Simulating project delays involved randomizing the number of years for construction from 4 to 10, with 4 being the expected construction timeline and 10 an extreme possibility. The probability of a four-year construction period was assumed to be 50%; probabilities for each subsequent construction time decreased by half. To evaluate reduced offtake, annual energy volumes were simulated downward from a starting value of 684,167,794 GWH, using a mu of −0.0309 and sigma of 0.1129. These values were derived from historical, technical and commercial losses of ENEO. Finally, to model possible flow reduction at the site, the historical flow at Nachtigal was used as a starting point. Grijsen [41] estimates the most significant climate change impacts on the Sanaga River would be a reduction by 22% on the negative side, and an increase by 5% on the positive). Importantly, we held the tariff constant in the model; in actual operations, the tariff would be adjusted upward to cover cost increases. Other assumptions can be seen in the Appendix A. To evaluate the guarantees, we then compared the risk-impacted NPVs with the coverage amounts provided by the guarantees.

Step 4b: Calculate the Value of the Options

The series of two protective put options, available in years 7 and 14, were a key feature of the financing, although they were not evaluated in the PAD. They were included to adapt to local rules regarding long loan terms. But the puts also have the effect of protecting local banks from holding nonperforming assets on their balance sheets. The value of a put option as protection against default yields a clue about the value that the banks placed on the guarantees against default.

Options of this type could also be used to offer additional protection for the banks, especially if interest rates were not adjustable, as they were for NHP [42]. If interest rates were fixed for the entire 21-year term, but the banks found themselves in a rising interest rate environment, it is possible they could decide that the original interest rate is no longer competitive with forward-looking lending rates. Under this case, banks could choose to abandon the loan under the option agreement and lend the money at a higher rate (this problem was addressed for NHCP by including a rate adjustment at year 7 and 14 to market rates [42]. Both of these possibilities—default and changing interest rates—were assessed. The prices of these options were calculated using binomial option models [43–46]. In both cases, two option values were calculated, once for the first option that expires in year seven and again for the second option that expires in year 14. This exercise was undertaken, not to suggest a market value for the options, but rather to demonstrate the theoretical value and incentive to the banks, from this aspect of the financial structure.

Default Options. For the option related to default, the value of the underlying asset at each node in the tree is remaining cash flows expected from the payoff of the loan. At each node of a binomial tree, an up and down value is given, representing an up or down movement in the asset's value. In this case, the "up" values of the tree were the sum of all remaining cash flows that were expected, if the SPV made all payments. These "upward" values reflected the best of all possible worlds, one in which the balance of future cash flows declined only by the scheduled loan payment. The "down" values for each node were calculated by first subtracting the scheduled payment, and then subtracting a probability-weighted default value. The default value was based on the percentage of nonperforming loans in Cameroon (12%). Therefore, at each downward node of the tree, the expected value of the payments was the previous balance multiplied by a default factor (1–0.12) This is not the traditional way to construct a tree for the underlying asset since no sigma is used for upward movement. However, it does represent the best possible world for future cash flows. At the end of the tree, the upward-most value is the remaining cash flows that are anticipated, assuming no changes in the total value of the loan. The downward nodes apply a default factor once for each downward step. Figure 6 illustrates the value of the underlying. The second, backward calculation tree proceeds in typical fashion for binomial evaluation [46]. Under this construction, the option expires "in-the-money" (meaning the holder would exercise) under all scenarios in which a default has occurred during the seven-year period.

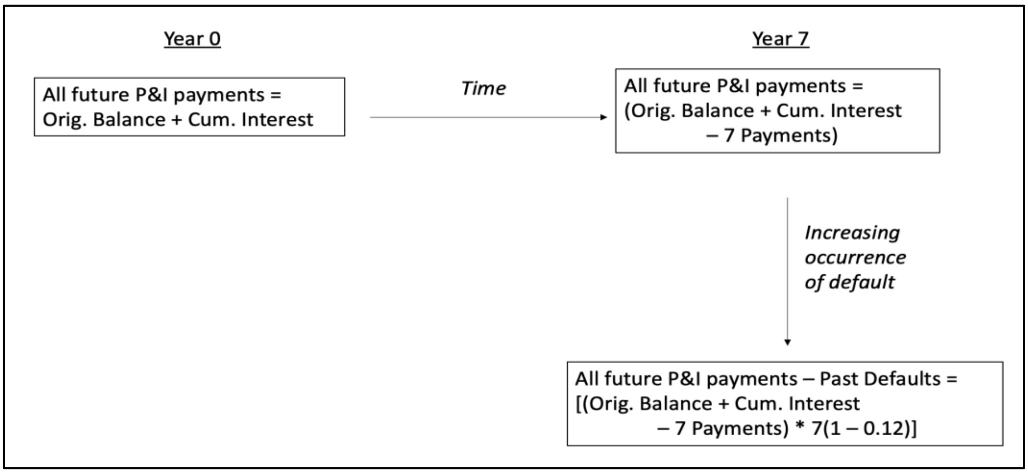

Figure 6. Default option diagram. Source: Authors.

Interest rate options. To model the additional concept of an interest rate option, we took a slightly different approach. In this case, the option may be seen as a call since the holder has the right to "buy" a higher-value loan by forgoing the future cash flows of the original loan. We modeled the option as though the interest rate were fixed over the entire 21-year period (NHP contractual arrangements adjust the rate to the prevailing market in years 7 and 14, when the options expire.) The strike price for the call is the discounted cash flow of the original loan, while the underlying asset is the cash flow from a new loan at a higher rate. In other words, if interest rates were to rise above 12.5% (the assumed amount charged by the banks), a new loan may appear more attractive by comparison, since the banks have the opportunity to abandon the loan and reinvest in other opportunities. The method of evaluation can be found in Shockley's example of an abandonment option [46]. The purpose is not to predict whether banks would exercise this option, nor to offer a specific value as if it would appear on the banks' balance sheet. Rather, it is to show that there may be an incentive to exercise the option if these conditions were met, apart from contractual arrangements.

Step 4c: Evaluate the Interest Rate Swap

Swaps are evaluated on a period basis, with each exchange of cash flows dependent on the prevailing LIBOR rate. To illustrate the swap, we made the simplifying assumption that the payments were to begin immediately. There is no uncertainty about the initial payment. The tenor on the swap is assumed to be 13 years (18 years minus a 5-year grace period) with annual cash flow exchanges occurring on the same day the loan payment is due. Assuming the first payment was due 12 months after close, Table A3 (in the Appendix A) represents the cash flows that would have taken place under illustrative conditions, during the first six years of the schedule (the notional amount of the loan considered for the swap was $819,842,400, which was the amount payable to the DFIs and IFC).

4. Results

The financial architecture of NHCP produced enabling protections and coverages to realize the project. Further, a systems lens evaluation of the impact of risk events on financial outcomes led to three primary findings: (i) risk events were adequately covered, (ii) interest rates were reduced, and (iii) private capital was mobilized. Two additional findings also emerged. First, the option may provide an incentive for banks to exit in situations other than nonperformance of the loan, apart from contractual arrangements that would prevent such action. Second, low interest rates that prevailed at the time of establishing the swap may lock in a low fixed rate during seasons of rising rates, thus favoring the fixed rate payer.

4.1. Risks Were Covered

Absent the introduction of risk factors, the NHPC has an NPV of $827 million, according to our simulator. As risk factors are introduced, the expected NPV begins to fall (holding the levelized tariff fixed), and when all four risks are introduced simultaneously, the expected NPV falls to negative $408 million. However, the guarantees bring this value back above zero. This means the project maintains positive value under a combined risk scenario if and when the guarantees are executed.

Table 3 shows the expected NPV for the simulations absent risk factor (baseline) and then the successive impact of risk events, should they occur. The third column shows the probability that the NPV falls below zero for the particular risk(s). The last two rows combine risks, cost overruns, and project delays in the second to last line (which often occur together), and then all risks in the last line. For example, construction delays by themselves do not make the project NPV negative, but when they interact with other cost overruns, the probability of negative NPVs is increased above that of cost overruns alone. Figure 7, directly below Table 3, shows the probability density functions for the same risk scenarios.

Table 3. Expected NPVs and probability of negative NPV for each risk studied.

Source of Risk	Expected NPVs	Frequency of Negative NPVs
Baseline	$827,246,390	0%
Construction delays	$483,513,178	0%
Offtake risk	$346,232,166	5.9%
Low flow risk	$172,320,630	0%
Cost overrun	$−219,658,398	58%
Cost overrun and delays	$−265,186,205	60%
Combined risk	$−408,405,412	66%

Source: Authors' estimations based on risk factors and information in [2].

Guarantee payout waterfall. As summarized in Table 4 (below), the guarantees would reduce the losses experienced by the project under any risk scenario. It is not necessary that the guarantees be tied directly to a specific risk because they ultimately backstop the GOC in its guarantee to safeguard the project company. For example, if ENEO fails to purchase energy (offtake risk), the payment guarantee ensures that the NHPC receives its agreed payment from the GOC; the reason for ENEO's reduction in purchases does not matter. Similarly, if the banks exit the loan under the option agreement and the GOC fails to cover any missed payments, the loan guarantee covers up to the full principal amount. Finally, the breach of contract guarantee covers EDFI and InvA if the GOC fails in its contract agreements. The GOC is the first line of coverage and is itself backed by the three guarantees. Table 4 shows how the guarantees bring the project back to positive value, beginning with the worst expected impact of simultaneous risk events and adding the coverages.

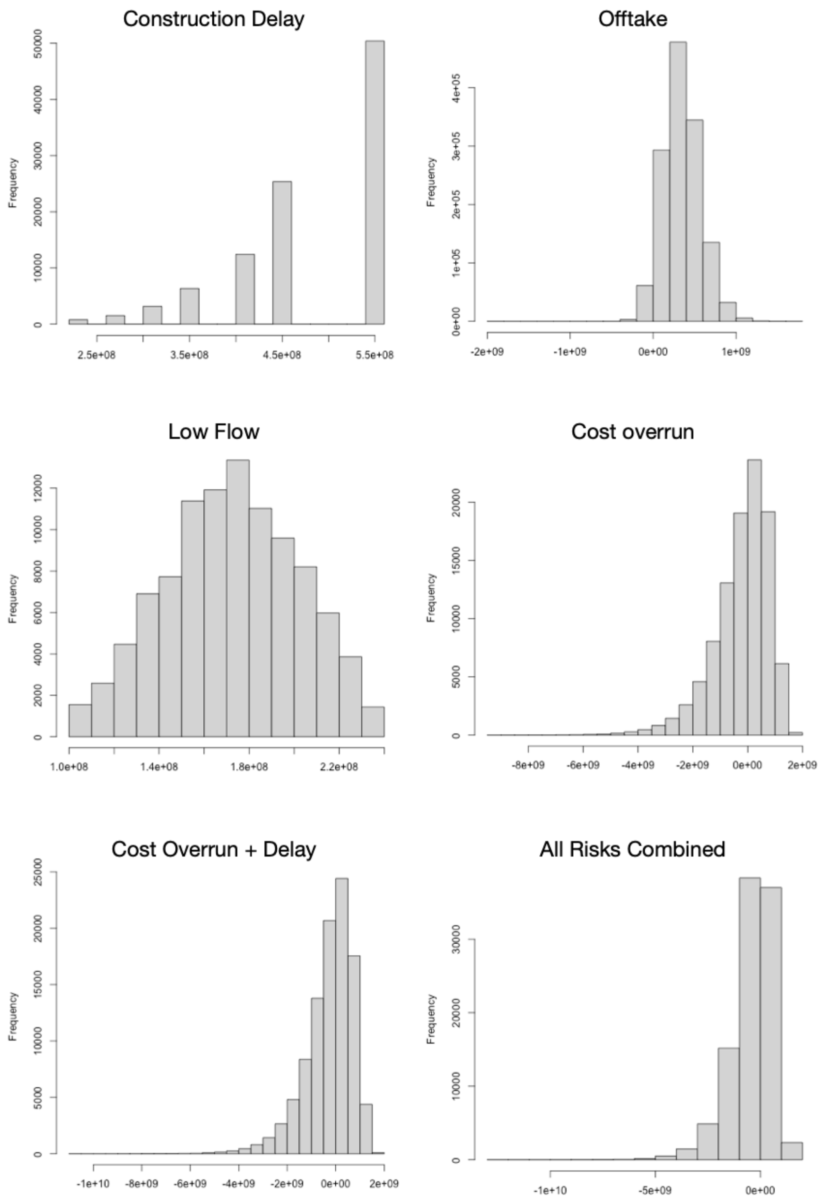

Figure 7. Distribution of NPV Values (in $ million) under specific risks. Source: Authors' analysis.

If project revenues were compromised, the first party to be affected may be the project company by way of reduced offtake. Considered independently, the offtake risk reduced the overall value of the project from $827 million to $346 million. The $100 million payment guarantee does not cover all the loss of project value, but in a combined risk scenario it would improve the negative NPV from $\$-408$ million to $\$-308$ million. Thus, in the waterfall of guarantee payouts, the first goes to the project company and reduces the overall risk exposure by $100 million.

The second party to be affected would likely be the local banks, whose exposure is covered by the loan guarantee. The banks can exit the project and collect any unpaid principal, up to the guarantee amount of $200 million, by exercising their put option. Since the options are at the discretion of the banks, they do not correspond to any particular risk; however, as we have shown, any default event would likely trigger the exercise of the option and default could arise in the wake of impact from any risk factor, making the combined risk scenario a relevant case. If triggered, the loan guarantee would further improve the negative NPV from $−308 million to $−108 million. Thus, in the waterfall of guarantee payouts, the second goes to the local banks and reduces the overall risk exposure by an additional $200 million.

Table 4. Guarantee payout waterfall.

Guarantee	NPV Improves to ($ Million):
Expected NPV under combined risk scenario	−408
Payment guarantee covers offtake risk faced by NHPC. Improves NPV by $100 million.	−308
Loan guarantee covers default risk faced by local lenders if they exercise their options and GOC cannot repay unpaid principal. Further improves NPV by $200 million.	−108
Breach of contract guarantee addresses contingent events resulting in breach for EDFI and InvA. Improves NPV by additional $188 million.	80

Source: Authors' analysis.

The third party to be affected would be the equity holders, EDFI and Investor A. Their positions are partially covered by the MIGA "breach of contract" (by the government) guarantees in the amount of $188 million. Since the government is backing these payments and the GOC's payouts could come in the wake of impacts from any of the risk factors, the combined risk scenario is once again relevant. If triggered, the breach of contract guarantee would further reduce the negative NPV faced under this combined scenario, from $−108 to $80, effectively mitigating the impacts of the worst combination of factors. Thus, in the waterfall of guarantee payouts, the third goes to the equity and senior debt holders, and reduces the overall risk exposure by an additional $200 million. The total value that might be considered "reclaimed" by the guarantees is $488 million, which brings the expected NPV to positive territory, although it does not bring project values back to the original NPV of $827 million.

4.2. Interest Rates Were Reduced

Managing risk is vital in order to reduce the cost of capital from what it would be without the structure. The cost of servicing debt was the largest expense in the NHP pro forma income statement, with significant implications for the resulting tariffs of the project. Risk-adjusted interest rates are in effect payments for a series of risks, which can be explicitly priced as risk premiums [47].

We assessed a counterfactual risk-adjusted rate given interest rate components of (i) a risk-free rate, (ii) an inflation premium, (iii) a risk of default, and (iv) a liquidity and maturity premium. The risk-free rate used was a 7-year US bond rate at the time of financial close, or 2%. To this risk-free rate, an inflation premium of 1.4% was added. Then, a default premium of 16% was added based on default rates in Cameroon. The liquidity premium compensates investors for the risk of loss relative to an investment's fair value if the investment needs to be converted into cash quickly and was estimated to be 2.88%. The maturity premium compensates for the increased sensitivity of the market value of debt to a change in market interest rates as maturity is extended and was valued at 1.157%. These four components add to a composite interest rate of 24% without the project structure, compared to 8.71% with the structure.

4.3. Private Capital Was Mobilized

A total of $372 million in private capital was mobilized for the project. This amount includes $133 million from EDFI, the French SOE. The World Bank considers this a private investment since it comes from outside the country. In order to recruit local providers, NHCP created the series of 7-year options that aligned terms with local banking rules. This feature, combined with the guarantees, created robust participation from local banks. A group of four local banks, including SCB Cameroon (Moroccan Attijariwafa's local branch), Standard Chartered Bank Cameroon, BICEC (French BPCE's local subsidiary), and Societe

Generale Cameroon, lent about $200 million to the project. These funds are provided in local currency and make up about 19% of the total debt. The group was organized by the local unit of Societe Generale (SG), which injected over 50% of the private capital amount and was selected through a competitive bidding process [48]. Private, local participation in this type of project is unprecedented in Africa and would not have occurred apart from the innovative financial structure created by the options.

The options values give an ex ante picture of how important the guarantees were to local banks. The value of a default option would be $56.56 million for the first and $16.38 million for the second. During the first seven years of the payment schedule, the banks receive mostly interest payments, under a mortgage-style amortization schedule (see [2]). The option's underlying asset is the cash flow of remaining interest and principal payments that are due to the bank; the initial total cash flow is $551.57 million. By year seven, under full receipt of all payments, the remaining cash flows are $358.52 million. However, under a default probability of 12%, this value falls each time there is a missed payment. The probability-weighted low value is $57.36 million. Under the option, the banks are entitled to sell the loan, receiving the full value of past payments; so, the strike price is the remaining cash flows assuming no loss for nonpayment, or $358.52 million. Therefore, the option will be in-the-money under any scenario in which even one payment has been missed. For example, it is in-the-money in the low-value scenario of $57.36 million, since $358.52 m. > $57.36 m. The perceived value of protection against default is the value of the option: $56.56 million.

4.4. Additional Findings

Two results from our simulator deserve special attention. The first is the option and the second is the swap. These could have unintended consequences, except for special contractual arrangements.

The option as an interest rate option. An interest rate option is one which would trigger if rates on other projects suddenly produced more attractive lending opportunities than Nachtigal. The options were provided to protect the banks in case of nonperformance on their loans, but options could also be used as an abandonment strategy in an environment of rising interest rates. Viewed in this way, the 7-year abandonment option is valued at $57.3 million, while the 14-year abandonment option is valued at $18.32 million (Table 5). With the exercise of the option, the banks could receive all the remaining principal, allowing them to relend at a higher rate. Recall that the contractual arrangements reassessed the interest rate at years 7 and 14, benchmarking them to prevailing interest rates, thus removing any incentive for the banks to abandon them for a higher rate. However, the evaluation of an abandonment option in the absence of such arrangements is a helpful exercise to understand how a bank might respond in other circumstances.

Table 5. Values of options as exit strategy under default or rising interest rates (in $ millions).

Type of Option	Year 7	Year 14
Default option	56.56	16.38
Interest rate option	57.30	18.32

Source: Authors' analysis.

The swap and rising interest rates. The swap also helped to reduce the overall cost of capital by keeping the DFI's risk exposure in check. Swaps are entered when a party wants to exchange a variable cash flow into a fixed one. By virtue of the swap, the DFIs turn their variable rate asset (interest payments from the NHPC) to a fixed rate of 1.7%, plus any premium charged to NHCP. (In our loan structure, we assumed a constant interest rate for the lenders; but in fact, some repayments will come at a variable rate. For this portion, a premium over LIBOR was likely charged.) Our swap analysis dealt only with the LIBOR rate, which was 1.7% at the time of the loan. If payment had commenced on the date of financial close, SG would have received an initial payment on the notional amount of the loan of 1.7%, or $13,925,559. After that, SG and the DFIs would trade the difference between an interest payment of 1.7% and an interest payment at the prevailing rate. The net cash flow column in the Table 6 shows that difference. The present value of the first six years of net cash flows (CF) to the DFIs is $−4,371,650.

Table 6. Rates and Cash Flows for the DFIs and SG Resulting from Interest Rate Swap (Illustrative).

Dates	12-Month LIBOR	Fixed Rate	DFIs to SG	SG to DFIs	Net CF to DFIs
July 2018	0.0280	0.000	0	0	0
July 2019	0.0219	0.017	17,954,549	13,925,559	−4,028,990
July 2020	0.0047	0.017	3,853,259	13,925,559	10,072,300
July 2021	0.0024	0.017	1,967,622	13,925,559	11,957,937
July 2022	0.0225	0.017	18,446,454	13,925,559	−4,520,895
July 2023	0.0275	0.017	22,545,666	13,925,559	−8,620,107
July 2024	0.0300	0.017	24,595,272	13,925,559	−10,669,713

Source: Authors' analysis.

There is limited information about the swap in the PAD since it is a private transaction, and there are many ways in which it may have been structured. However, the negative cash flows accruing to the DFIs during the first six years are indicative of the difficulty in establishing a fixed rate for a long-term swap. This would be especially true in a situation where interest rates were already close to historical lows, as they were in 2018. The reason is that when rates are low, there is little room for them to fall, but significant room for them to rise, limiting only downward volatility. Furthermore, low rates had prevailed for many years, meaning a volatility figure based on backward-looking rates would be biased toward recent experience. Therefore, as interest rates rise, it may be important to have a resetting clause in the contract that would allow for a new fixed rate to be determined.

5. Discussion

Our simulator enabled a comprehensive risk-based analysis of the NHP's engineered financial arrangements, showing that risk coverage, interest rate reduction, and access to private capital ultimately unlocked financial close. Given the significant complexity of this approach, this section discusses the implications of the use of such instruments.

5.1. Is There Adequate Value Added by the Complexity of the Arrangements?

On its face, the complex structure of the Special Purpose Vehicle and the financing and contractual arrangements raise the legitimate question of whether the additional cost of complexity in the project is warranted in relation to its expected value and risk profile. Our results build on the idea of project safeguards reported elsewhere [49] and suggest that the choice and nature of participation of the entities in the SPV, instruments such as the guarantees, the swap, and the options all introduced complexity [50], but these financial risk management safeguards were necessary in enabling financial close. The value enabled by the complexity of the embedded arrangements and partnerships shows up in the reduced cost of capital, which is ultimately passed on to beneficiaries through a lower tariff structure, and a mitigated risk profile.

The use of the PPP approach allowed the participants to tailor the project structure in a manner that allocated risks and incentives, so as to mitigate principal–agent conflicts [51]. The inclusion of EDFI as the largest shareholder in the syndicate increased the overall credit rating of the project, because of its financial stability and balance sheet. As an expert in international hydropower development and EPC management of large projects, EDFI's presence as an owner provides it with not only strong incentives but also the capability to mitigate cost overruns and project delays. The inclusion of the GOC as an equity owner in the SPV also aligns government interests with the success of the process, for example to streamline permitting and other licenses to operate. Further, in a build–operate–transfer model, the SPV might otherwise have an incentive to reduce costs and improve margins by avoiding important maintenance spending and upkeep. By including the GOC—the entity that would ultimately take ownership of the asset upon "transfer"—in the SPV, the project avoided misalignment between the operator EDFI and the GOC as the ultimate owner.

In addition, the government now has an interest in the financial performance of the utility ENEO. Much of the default risk emanates from ENEO, whose poor performance is based partly on payment arrears by government entities. Under the project arrangements, the GOC would be doubly penalized under default. In the first instance its equity position would be devalued, and in the second it would be directly responsible for ENEO's missed payments. The GOC has indicated an intent to sell its equity portion following construction. This action would mute some of the effects of risk mitigation because it would dissolve the partnership between principal and agent (GOC and EDFI), reducing EDFI's incentive to deliver the highest quality asset. It also removes the GOC's exposure to loss of equity in the event of default by ENEO, although the GOC is still bound by its guarantee.

The group of lenders also reduces currency risk. One unique challenge of large-project development in developing countries is that capital is purchased in hard currency, while labor is purchased in local currency. Problems arise if the local currency devalues during construction. The presence of the local banks enables a portion of required funds to be lent and repaid locally, eliminating this portion of currency risk.

5.2. Is the Project Likely to Accomplish Its Climate and Sustainability Outcomes?

The complex arrangements do not eliminate risk, nor do they fully align all interests of all parties under all circumstances. However, they do partially align parties who otherwise might have divergent interests and provide sufficient incentive to key investors. We conclude that the financial and contractual complexity served not only to close the project, but also to capture the eventual climate and sustainability benefits embodied in a large renewable energy project.

5.3. Can This Approach Be a Recipe for Climate-Oriented Development?

There are three primary ways to finance a project such as NHP: public financing, bilateral investment, and public–private partnership. Public financing was likely off the table for Cameroon. According to IMF assessments, national debt levels are pushing the upper limits of sustainability [35], and the opportunity costs of NHP against other spending are high.

Of the remaining two mechanisms, international bilateral investment was available to the Government of Cameroon. In fact, Cameroon has a history of working with Chinese developers and China's Eximbank. To finance the 210 MW Memve'ele project, a loan of $541 million was signed in May 2011 between the Chinese ambassador and the GOC on bilateral terms. The total cost of the Memve'ele dam was to be $637 million, 85% of which was financed by China's Eximbank, and the other 15% prefinanced by the Cameroonian government. The loan terms are similar to those for Nachtigal: repayment terms of 16 years with a 6-year grace period and an interest rate that tracks the Euribor 6-month rate plus 310 basis points [52]. Why didn't Cameroon pursue the same route for NHP?

The possibility of participation by multilateral organizations in a syndicate may have made the PPP approach more attractive given the climate-oriented objectives on the world stage. The GOC had previous experience with the World Bank through the Lom Pangar HP project transaction, which was finished in 2016. Lom Pangar is a 30 MW project that cost $494 million. A direct comparison between Lom Pangar and Memve'ele shows that interest rates provided by the World Bank were slightly better, but the project preparation time lasted longer [52]. The handling of other aspects of the two projects, such as environmental and social issues, was comparable.

In the end, Cameroon chose the more complex structure. It is possible that the larger Nachtigal project received a better cost of financing under the PPP approach due to the syndicate in place, or that drawbacks to a bilateral arrangement were considerations for the GOC in selecting partners for the NHCP. One of the benefits of the PPP syndicate, including the World Bank, is increased up-front transparency and scrutiny among the various participants. Another dimension is a favorable stance on the desire to integrate local lenders, which may also have played a role in selecting a PPP approach. In the final analysis, the Bank's PPP approach seemed better to the GOC for Nachtigal, although we cannot conclude that sustainability and climate benefits would be precluded through a bilateral financing approach, since those would still be available as long as the project was delivered. The PPP approach seemed to be able to "get the project done" in financial terms, and can thus be the preferred mechanism where transparency, local integration, and risk management are seen as essential co-benefits.

6. Conclusions

The blended and engineered financing of NHP sought to overcome the risks and obstacles of financing a large hydropower project. The use of a financial simulator helped us forensically understand how risk coverage, interest rate reduction, and private participation played a role in project close. The foundation of the right syndicate helped to mitigate the risk of cost overruns and project delays and overcome principal–agent misalignment. Participation of the government ensured its continued interest in the project. The presence of local banks' lending in local currency partially mitigated currency risk; the use of put options allowed those banks to participate while conforming to prevailing banking rules. The use of guarantees to backstop the commitments of the utility and the government mitigated some of the credit risk. The beneficial result of employing these customized financial instruments was to secure a significant portion of loan capital from private sources. Finally, the overall cost of capital kept the expense of servicing debt low, and anticipated tariffs within an acceptable range.

While this significant financial engineering seems to have unlocked the project, several additional questions invite deeper research. First, although a significant portion of funding came from private sources, strictly speaking it was still a minority share. Together, the local banks provided USD 228 million in debt and EDFI an additional USD 133 million in equity; this was 23% of total investments. All other lenders (the IFC and the DFIs) employ concessional lending from public money. Was this an upper limit? Is there an opportunity to expand the base of private investment further? Second, bilateral finance has quickly outpaced PPPs, despite the drawbacks we mention above; why has it been so popular? Do the near-term advantages of bilateral finance (e.g., shorter development times and fewer coordination hurdles) outweigh long-term risks of sacrificing national assets, or are perceived sovereign risks overblown? We see deeper research possibilities into these questions and others as an important piece to accelerating private participation in large-scale sustainable development.

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Appendix A

Table A1. NHPC Balance Sheet Forecast, by year ($ millions).

Year of Operation	**−3**	**−2**	**−1**	**0**	**1**	**2**	**3**	**4**	**5**
Assets	346	692	1037	1383	1439	1492	1506	1516	1522
Liabilities	263	526	788	1051	1051	1048	1004	958	908
Equity	83	166	249	332	389	445	501	558	614

Source: Authors' analysis.

Table A2. NHPC Income Statement Forecast, by year ($ millions).

Year of Operation	**−3**	**−2**	**−1**	**0**	**1**	**2**	**3**	**4**	**5**
Gross Revenue	-	-	-	-	139	171	273	273	273
OM Schedule	-	-	-	-	21	21	21	21	21
EBITDA	-	-	-	-	118	150	252	252	252
Depreciation	-	-	-	-	45	45	45	45	45
Interest Payments	-	-	-	-	0	29	91	88	84
EBT	-	-	-	-	73	77	116	120	124
Tax Expense	-	-	-	-	17	17	17	17	17
Distributable Income	-	-	-	-	56	60	100	103	107
Principal Payments	-	-	-	-	0	4	43	47	50
Profit	-	-	-	-	56	56	56	56	56

Source: Authors' analysis.

Table A3. NHPC Cash Flow Forecast by year ($ millions).

Year of Operation	**−3**	**−2**	**−1**	**0**	**1**	**2**	**3**	**4**	**5**
Cash Operations	-	-	-	-	101	105	144	148	151
Cash Investment	(346)	(346)	(346)	(346)	-	-	-	-	-
Cash Financing	346	346	346	346	-	(4)	(43)	(47)	(50)
Annual Cash	-	-	-	-	101	101	101	101	101
Cumulative Cash	-	-	-	-	101	202	303	404	505

Source: Authors' analysis.

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