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PV- Solar Synergies for Large Hydropower in Angola and Namibia – Epupa-Baynes Revisited

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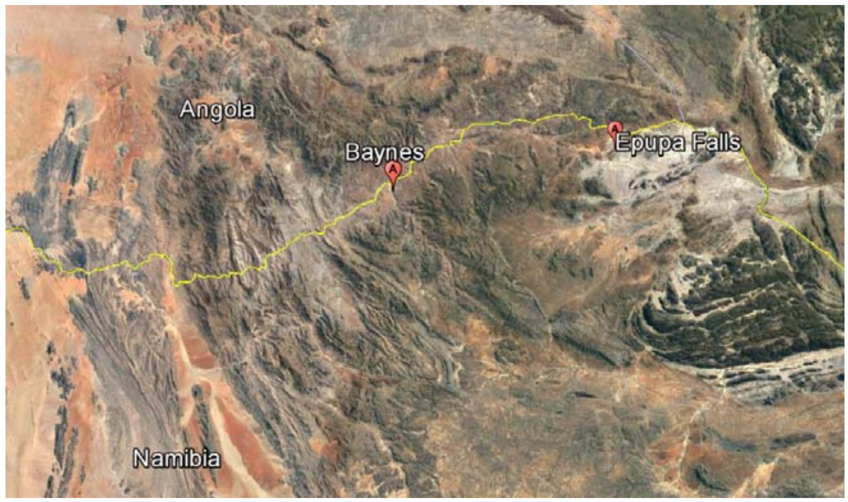
PROJECT REPORT

PV-SOLAR SYNERGIES FOR LARGE HYDROPOWER IN ANGOLA AND NAMIBIA - EPUPA-BAYNES REVISITED



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SUMMARY

This paper examines the financial viability for constructing and operating PV-solar in tandem with hydropower within the context of Sub Saharan Africa using the Baynes Hydropower Project on the border between Angola and Namibia as an example. Specifically, the study re-examines the previous and current optimised installed capacity at 360 MW and 600 MW with the option of a 50 MW floating PV-solar plant on the reservoir created by the 200 meter high dam.

The motivational background is the increasing competition from other renewables, particularly PV-solar in the traditionally hydropower dominated market. Whether and to what extent this transition might influence the future development of hydropower in the region is in addition to a brief review of the power sector (i.e. market conditions) and resulting financial implications among the aspects that are addressed.

In contrast to Angola, where electricity sector is in the process of adapting to increase tariffs and performance standards toward financial sustainability, Nambia´s power sector is more mature, is financially stable with electricity prices that albeit a slight loss in 2016 largely reflect the actual cost of service. Bridging the widely different political risk environments is a main challenge for securing financing at competitive rates.

Using prevailing market prices for electricity in Namibia as a proxy for likely future prices and simplified reservoir model to simulate power production, the results show the impact of increasing installed turbine capacity and addition of PV-solar on tariffs and revenue from power sales. PV-solar increases the financial viability in all cases. However, marginal gains diminish with additional installed turbine capacity as well as with PV-solar installation cost. At the cost of US$1.13/ W (56.5 million) for the proposed 50 MW conjunctive PV-solar plant, the 360 MW with PV-solar emerge as the favoured development alternative for equity holders and host governments.

Noting the prevailing uncertainty on development of market conditions the analyses also estimates the option value of delaying investment in anticipation of higher tariffs in the future. This uncertainty increases the value of the option to develop the

project. Combined with higher variation in available flows due to climate change the analyses illustrates the importance of diversification in the power system.

Given the reliability of financial assumptions (p 31) the risk mitigation capacity remains as the most vulnerable factor. Currency risk has been hedged, and to some extent passed on to governments and consumers. Others risks, like political and macro-economic, remains but has been included in cost of capital calculations. These risks have increased expected cost of capital, but no more than to a level where internal rate requirements still can be met.

The importance of a healthy capital structure is a critical factor for Baynes. Even if a tax-shield benefit would increase NPV at higher debt-ratio than the proposed 70%, it is crucial for Baynes to raise enough equity. If not, we doubt the project´s ability to raise sufficient debt capital. The necessary World Bank backed loan depends on Baynes ability to show economic and financial credibility in a risk volatile environment. Angola-Namibia government cooperation is the main factor in gaining this credibility.

1 INTRODUCTION

1.1 Rationale

This paper embarks on the proposition that investment in power and water infrastructure in emerging economies and sub-Saharan Africa in particular, is experiencing a paradigm shift where other renewables such as photo voltaic (PV) solar and wind is gaining increasing traction compared to hydropower.

Despite the renaissance that appeared imminent when the World Bank in the wake of the World Commission of Dams Report announced its intention to revamp lending for large water infrastructure in 2006/07, a quick search of the Bank's website revealed that this increase was mainly attributed to smaller run of river schemes (World Bank, 2014). Other than the 250 MW Bujagali on the headwaters of the Victoria Nile in Uganda, which after some 10 years of preparations, obtained financial close in 2007 and started producing in 2013, there are few other large hydropower projects in Africa in recent years where the World Bank and other international donor agencies have had a major role.

Whether and to what extent the apparent trend away from large hydro is related to a resurgence of the reputational legacy effects of the previous decade, i.e. that the benefits from large dams disproportionally accrue to big consumers and do not reach the poor (The Guardian, 2013) is however outside the scope of this paper. Instead, the underlying theme of the analyses herein is rather to examine the changing market conditions and how outside forces, such as climate change, influence valuation of hydro and PV solar power in sub-Saharan Africa. (SSA)

Unlike past initiatives in the early part of the millennium-shift where financing for energy and water infrastructure (in sub-Saharan Africa) was largely confined to larger projects (typically hydropower and extension of high voltage transmission networks) with a national utility as main promoter, private capital is now increasingly taking independent steps to invest. This behaviour is particularly evident in the power sector where the falling costs of electricity generation from PV-solar and wind in combination with incentivized payments for power generation has increased private investment (GetFit-Uganda, 2016) as well as spurred governments to increase emphasis on rural electrification toward more off-grid solutions (Rural Electrication Authority, 2017)

A pertinent question is to what extent this changing landscape for how power will be produced and distributed, will influence investments in hydropower, which together with the characteristic of being regarded as a renewable energy source also inherit public sector benefits through providing water security and protection against floods. Does the shift toward off-grid solar and wind pose a threat or an opportunity for initiatives trying to invest in hydropower? How should an energy investor distribute its investment portfolio to increase its overall value? Under what circumstances can it derive synergies with whole scale market transitions toward other renewables?

Not overlooking that the above questions entail underlying policy implications, which may lead to assessments and interpretations that are peripheral to applicable and recognized valuation methods, focus herein is on the latter using the planned Baynes Hydropower Project on the Cunene river between Angola and Namibia as a case in view.

Whereas the project background is outlined in the chapter to follow, because of its strategic location where despite the primary motivation being to increase power capacity, multipurpose benefits from regulation can also be conceived. Combined with the fact that project has been extensively studied, first in the late 90´s and then from 2010-13, has attracted political interest, but to reach financial close, implies in addition to data and information being readily available online, that there are value judgements on benefits and costs that are yet to be reconciled.

In this regard, it is interesting to note that unlike its neighbours in the Southern African Development Community (SADC), the 2025 vision strategy for Angola´s energy sector development plan is almost exclusively focused on large hydro. This despite ample sunshine and potential for wind power, especially along the coast, to supplement hydropower generation in times of drought. Similarly, a main motivation for Namibia is to augment both firm and peak generation capacity to reduce imports from South Africa and comparatively more expensive power from thermal sources, notably the Van Eek and Paratus Power Stations (NAMANG, 1998) and (Nampower, 2015).

This leads to the conjunctive development of a hydro and solar power plant as the central theme of this corporate valuation exercise. To develop this concept further an example of a proposed tentative structure, study topics and valuation methods with next steps is outlined below.

1.2 This Report

From the preceding discussion the aim and objective of the analyses can be summarized as shown in the below listing.

- Aim - to provide a broader perspective on synergies of particularly PV solar on the financial viability of hydropower within the context of sub Saharan Africa.

- Objective – to re-examine the economic and financial viability of the project and the synergies or additional value that can be derived from constructing and conjunctively operating a 50 MW floating PV-Solar plant on the would-be reservoir.

The project analysis is based on a cooperation scenario where Angola and Namibia retail equal ownership, but under alternative management and financing arrangements.

Synergies from PV-solar are treated as real options together with also the option to delay in anticipation of increase in electricity prices. In the process our analyses also seeks to provide a framework for the option value represented in the survey licence including what price the authorities can expect to receive from a competitive bidding to develop and operate the project.

Except for the amount of electricity produced and invoiced in recent years from the Angolan Regulator for Electricity and Water (IRSEA, Instituto Regulador dos Serviços de Electricidade e de Água) all data and information for the study has been obtained from online sources. Acceptance to use Baynes as an example for this valuation exercise was sought from the onset from the Angolan Institute of Water Resources (INRH, Instituto Nacional de Recursos Hidricos). The Director Manuel Quintino welcomed this request and has subsequently contributed comments and clarifications.

The following structure has been adopted:

Chapter 2 – presents the historic background on the hydropower development on the Cunene River, key motivating factors and market outlook for the power sector today and in the years to come. This chapter culminates with a brief description of the project area and the proposed hydro and PV-solar development.

Chapter 3 – presents the approach, underlying assumptions and methods used for estimating the amount of electricity produced and for performing the economic and financial analyses. This chapter also introduces a framework for pricing the project and its components in terms of the respective option values. Specifically, this concerns the right but not the obligation to develop, delay and/ or sell the whole or part of the proposed development before financing has been committed and construction has commenced.

Chapter 4 – outlines relevant financing models, risk allocation and advances application of the adopted approach and methodology to determine appropriate discount rates.

Chapter 5 – presents the results of and discusses the sensitivity of key performance parameters to changes in construction costs and electricity prices with implications on inherent option values.

Chapter 6 - concludes the analyses. In addition to summarizing the main findings this chapter compares these to similar projects to synthesise recommendations for further study.

2 CONTEXT AND PROJECT DESCRIPTION

2.1 Previous Investigations

The historical background presented below is taken from the original feasibility and revised feasibility studies by the NamAng and Cunene Consortiums in 1998 and 2013 as well as from NamPower´s web pages.

Development of hydropower on the Cunene of which parts of the lower portions forms the border between Angola and Namibia started following the agreement between Portugal and South Africa to initiate the first phase of the development of the water resources of the Cunene River in 1969. The agreement resulted in the construction of three schemes during the 1970's. Moving from the headwaters near Humbo in Angola to south and westward these were the Gove Dam, the Ruacana Hydropower Scheme located in Namibia approximately 170km upstream of the proposed Baynes Site and the incomplete Calueque Water Scheme which facilitates water supply to the northern parts of Namibia as well as to irrigation projects inside Angola (NamAng, 1998).

As the demand for electricity grew SWAWEK now Nampower began to consider the construction of a hydropower plant in the vicinity of Epupa Falls. In 1991, the governments of Namibia and Angola agreed to go ahead with the detailed technical and environmental investigations and reinstated the Permanent Joint Technical Commission for the Cunene River (PJTC) to lead the study. Between 1995 and 1998 the NamAng consortium consisting of Norconsult and SwedPower together with two local companies, Soapro of Angola and Burmeister and Partners of Namibia conducted a full Feasibility Study and EIA for the Epupa and Baynes Projects. These studies concluded that while while the Epupa Site was technically preferable due to greater storage capacity, the Baynes site would be less disruptive to the life of the indigenous Himba people, and would have lesser environmental impact. Baynes was at this stage optimized for firm power to Namibia with and installed capacity of 360 MW. It did alas, not go forward due in part to opposition by local and international NGOs and the Himba to the plans of a dam at the Epupa Site as well as alternative options to build a new 400 kV power line and meet the power shortfall through import from South Africa (ERM, 2009).

However, the Firm Power Contract (FPC) with Eskom expired in 2005 and could not be renewed due to a critical power shortage faced in South Africa at the time. Imports became significantly more expensive, especially during peak hours and consequently both the Angolan and Namibian governments agreed to study the Baynes option further. The PJTC appointed the Cunene Consortium (CC) to perform a Techno-economic Feasibility Study (TEFS) on the Baynes Hydropower Project, and

Environmental Resources Management (ERM), to independently conduct the Environmental and Social Impact Assessment (ESIA), in parallel and in close consultation with the techno-economic study.

Studies of the three site alternatives for water levels 580, 560 and 540 metres above medium sea level (mamsl) has culminated with recommendation to maintain the same dam site and regulation as the previous NamAng Study, but to increase the installed capacity to 600 MW to be shared equally by Namibia and Angola. Like Ruacana Power Station, the new dam will function as a mid-merit peaking station, so that NamPower can avoid buying imported power during peak hours. During the wet season the Baynes Power Station will run at near full capacity, while during the dry season the generators will generate at maximum during mid-merit/peak periods only (NamPower, u.d.).

The CC has also deliberated on the Draft Bi-lateral Water Use Agreement on the Cunene River which deals with issues such as the establishment of a Bi-National River Authority, the establishment of the Baynes Hydropower Company, concessionary agreements between Angola and Namibia with the Baynes Hydropower Company for the development, operation and maintenance of the power station.

2.2 Rationale for Angola and Namibia to pursue Baynes

The rationale for both countries to develop Baynes is need for additional generation capacity to meet shortfall in demand. For most of the population this means no or very little access to electricity as alternative supply from diesel powered generators often come at significantly higher cost.

The armed conflict in Angola limited the country's capacity to produce energy through hydropower dams, as the existing ones were affected by the war. During this period it was not possible to initiate new projects. Now, in times of peace, there is a huge demand for energy in Angola due to a number of reasons, namely:

- Increase of domestic demands due to the expansion of access to sources of energy, electrification of urban and peri-urban areas, increase of industrial, mining and housing projects;

- Energy deficit from hydropower sources; and
- Urgent need for the development and use of water resources.

In contrast to Angola Namibia has been able to meet its shortfall by cheap imports from South Africa, which since 2010 has widened from about 1600 GWh to about 3000 GWh in 2016 (e.g. see below). Since 2006, Eskom's supply capacity has come under pressure as the South African domestic demand for electricity has surpassed Eskom's generation capacity, resulting in load shedding throughout the South African Development Community (SADC) region. As a result, Eskom is no longer able to provide electricity to Namibia during all load periods.

Another issue is water security. In this regard, it is important to bear in mind that increasing hydrological variability due to climate change calls for renewed thinking on the balancing role of hydropower. As water becomes scarcer the need to conserve it, use it more efficiently and establish clear values on its use and ownership are likely to be ever more important (The Economist, 2016). In the lower Cunene basin there is potential to expand irrigation at Etunda with off-take at the existing Ruacana power station and at Otjindjangi some 250 kilometres down-stream. The latter could benefit from regulation at Baynes. (Kunene River Awareness Kit, u.d.).

2.3 Market Conditions

Despite recent efforts to separate generation from those of other sector functions the power sector in both Angola and Namibia largely operate as vertically integrated structures, albeit with important differences in terms of overall performance and ability to attract private investment. A brief overview with key issues for each country follow.

2.3.1 Angola

The Ministry of Energy and Water (MINEA) is responsible for development and coordination of energy sector while oversight provided through the national regulator IRSE – Instituto Regulador do Sector Eléctrico. Reflecting the expanded responsibility to also cover the water sector the name was changed to IRSEA Instituto Reguldador dos Servicos Electridade e de Água) in 2016.

Up until 2014 the main power utility company in Angola was the Empresa Nacional de Electricidade (ENE) which managed the transmission network and operated over 80% of power generation facilities and distribution system outside of Luanda. In the capital, power distribution is managed by the Empresa de Distribuição de Electricidade (EDEL). To facilitate design and development of large hydropower projects in the Kwanza river basin (which inherits the bulk of the country's hydroelectric potential), MINEA established a Gabinete de Aproveitamento do Médio Kwanza (GAMEK). In addition to operating the 500 MW Capanda power plant, GAMEK is implementing the 2,000MW Laúca as well as rehabilitation of the Cambamba Hydropower plants.

Similarly, the Cunene River Basin Authority (Gabinete para Administração da Bacia Hidrográfica do Rio Cunene, GABHIC) has had a similar role to GAMEK in developing and rehabilitating hydroelectric schemes in the south of the country.

ENE, EDEL, GAMEK and GABHIC form a vertically integrated market structure, albeit with significant overlaps in their objectives. A main challenge to address the pervasive inefficiencies in terms of perennial supply shortfall, inadequate electricity infrastructure and low revenue collection rates is the lack of contractual obligations between these entities, which prevents effective sector re-capitalisation and motivation for these companies to run efficiently and profitably.

In response to recommendations from the Power Sector Reform Programme (African Development Bank, 2014), the Government of Angola decided to transfer all power generation operations, including those operated by GAMEK and by ENE to a new entity PRODEL (Emprasa Pública de Producão de Electricidade). In addition, the restructuring went further by establishing separate national companies for transmission and distribution (Rede Nacional Transporte de Electridade) and (Empresa Nacional Distribucão de Electridade*)*. Hence it is RNT as opposed to the previous ENE that will be the off-taker that existing and new generation projects will need to obtain a power purchase agreement (PPA) with.

Bearing in mind the short time for the above institutional changes to take effect, the challenges facing the Angolan power sector are expected to prevail. Characteristic features are, (i) inadequate generation capacity, (ii) very low levels of electricity access, averaging 30% nationwide and less than 9% in rural areas, (iii) poor collection rates as over 80% of the consumers are not metered and (iv) high technical and commercial losses. This situation is worsened by high cost of electricity production and distribution (approximately US cent 22/kWh), well above the average consumer tariff that can be calculated from the data reported by IRSE in 2014. This is shown in the below table. Here the average tariff as total kWh invoiced compared to actual kWh paid is calculated as 2.31 and 3.28 US Cents/kWh respectively. While technical losses average 10% compared to available production and distributed capacity, fee collection is only 55% of that invoiced.

Table 1. Electricity Production and Invoicing for 2014

Electricity	Amount (GWh)	Amount (AOA)	US (cents)/kWh*
Produced	5 497 143		
Purchased	3 982 892		
Sub-total (production)	9 480 035		
Distributed	8 513 959		
Invoiced	7 814 609	18 042 371 304	2,31
Collected	3 908 152	12 816 286 122	3,28

*Exchange rate of 2014 100 AOA/USD

(IRSE - Instituto Regulador Sector Électrica, 2014)

To improve sector performance Angola has recently approved the 2018 – 2015 Energy Plan (Ministry of Energy and Water (MINEA), 2017). As the below figure also illustrates Angola purchased 42% of its supply capacity to meet demand in 2014. Even at this rate demand frequent power outages and widespread use of generators indicate that demand is significantly suppressed, especially in the humid months due to cooling.

Focusing on network extension and strengthening to provincial capitals and municipal townships the 2025 plan aims to bring power to 60% of the population. Demand is forecasted to increase from 9.5 GWh in 2014 to 15 GWh in 2017 and further to 39.1 TWh in 2025. To accomplish this it is estimated that generation capacity will need to increase from 2.1 GW today (of which 0.9 MW is hydro) to 9.9 GWh in 2025. The plan gives priority to hydropower (66%) followed by natural gas (19%) and other thermal (8%). New renewables in the form of biomass wind, PV-solar and biomass are estimated at 800 MW comprising 8 %. The bulk of which is biomass 500 MW and remaining 300 MW distributed equally between small hydro, wind and PV-solar. Once the Láuca hydropower plant gets on line in 2017 existing installed capacity will double (MINEA, 2016).

To achieve the vision in the 2018-2025 horizon it will be required to mobilize public and private investments of USD23b. The plan emphasises that strong commitment to losses reduction and a gradual update of electricity tariffs. In comparison estimated generation costs for thermal range from 10 to 15 US cents/kWh, and can be considered a proxy for a representative tariff from other renewable sources.

2.3.2 Namibia

Similar to Angola the Nambian power sector is also organised under the respective ministry (Ministry of Mines and Energy) with a regulator (Electricity Control Board, ECB) to oversee the industry, i.e. generation transmission and distribution). Amongst other aspects, this includes review of pricing to set tariffs in accordance with applicable rules.

Namibia Power Corporation (NamPower) is the country's state-owned power utility. It is registered as a proprietary limited company under the Companies Act with Government as its sole shareholder. Nampower owns country's generation plants, of which there are four (e.g. see figure below) and is the direct supplier of electricity to regional distributors (REDS) and other redistributors such as large mines, a few municipalities and end-users who are located outside the licensed area of local authorities. It also fulfils the role of system operator to balance supply to the prevailing demand and as contractual party, as trader and contracted party for imports of electricity from power utilities in the SADC region.

Details on technical and financial performance of Namprower is provided in the annual reports (Nampower, 2017). A summary of key figures for 2016 follows.

To meet demand Nampower purchases nearly twice as much electricity as it generates itself. Most of the purchased power is from Eskom in South Africa and state power utilities in the neighbouring SADC countries. A lesser amount is purchased from independent producers (IPP), e.g. such as Agrika in Mozambique and the Omhuru PV-Solar Plant. The bulk of power from own generation is supplied from the Ruacana hydropower plant. The below tables show the production from own and external sources that was acquired and sold in 2016 (Nampower, 2016).

Table 2. Generation Plants in Nambia.

Power Station/Type	Commissioned	Location	Capacity (MW)	GWh (2016)
Ruacana – Hydro	1975	Ruacana	275	1359
Van Eck – Coal	1972	N. of Windhoek	120	53
Anixas – Diesel	2011	Walvis Bay	22.4	-
Paratus – Diesel (HFO)	1976	Walvis Bay	24	9
Sum (own production)				1421
Imports (Eskom)				1956
Imports (other SADC)				760
IPP (Agrika 349, Short Term Energy Market 55 and Omhuru PV-solar 12 GWh)				368
Sum (total system)				4505

Table 3. Key Group Statistics for Nampower

Item	Unit	Amount (2016)
Total revenue	NAD	5 005 992 000,00
Gain PSA-Hedge		6 911 000,00
Cost of electricity	NAD	3 615 787 000,00
Cost PPA-Hedge		111 800 000,00
Units Sold	GWh	4 508,00
Selling Price	NAD/kWh	1,11
Selling Price	US Cents/KWh	8,45
Buying Price	US Cents/KWh	6,28

Electricity demand in Namibia is forecasted to increase at a steady pace 2 to 4 percent in the years to come. To meet the strategic policy goal of ensuring that 100% of the peak demand and at least 75% of the electricity energy demand is supplied from internal sources by 2018, implies that development of additional generation capacity is a high priority. Ongoing initiatives such as preparation of the National Integrated Resource Plan Renewable Energy Policy, the Independent Power Producer Policy, and the National Energy Policy will shape the country's energy future as they are driven towards realising energy security in the country.

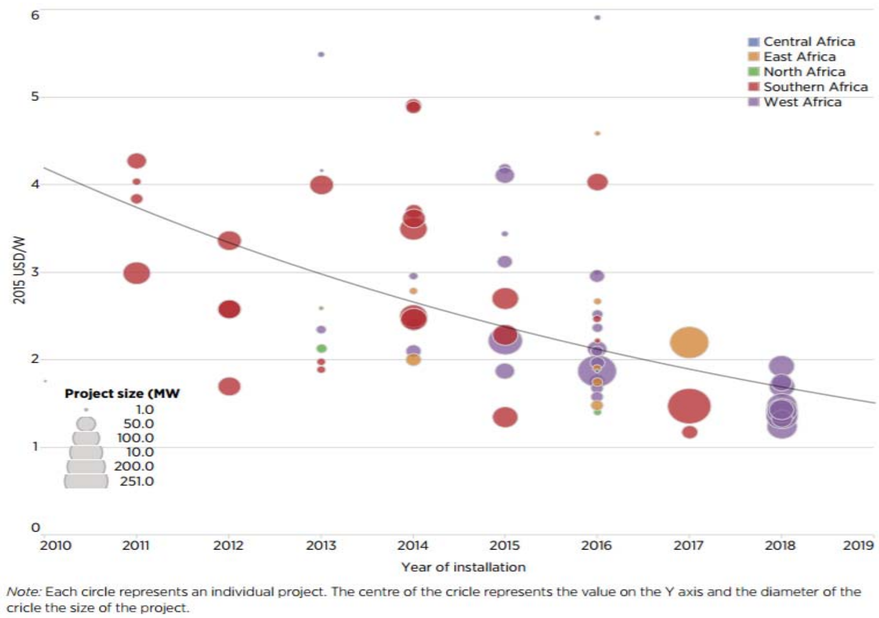
On average the selling and buying price after also accounting for net currency hedge costs was 8,45 and 6,28 US cents/kWh based on an average exchange rate of 13.5 NAD/USD for the same period. Fuel costs for running of Van Eck were 1587 NAD/ton, which for an average consumption of 0.55 kg/kWh gives US cents 12/kWh. Prices for peak and off-peak power quoted in the original feasibility study

(Namang,1998) were 7 and 2 US cent/kWh, which after adjusting for inflation (2% in USD terms) gives 10.2 and 2.9 US cents/kWh in 2017 prices. The press release for the 2017 tariff adjustment posted on the regulator´s website www.ecb.org.na announces that for full cost recovery a bulk tariff of 12.2 US cents/kWh is needed. The tariff schedule for 2017/18 specifies average peak (4.5 hours morning and evening), standard (midday) and off-peak (night time) at 15.9, 10.2 and 7.6 during the high (dry) and 10.2, 8.2 and 5.7 during the wet season respectively (ECB, 2017). The duration of the high and low demand periods could not be found on either Nampower, ECB or the ministry´s web site. In South Africa Eskom defines the period from 1/6 until 31/8 as high demand and the remaining part of the year low demand.

2.3.3 *Solar Energy*

Angola and Namibia have high solar resource potential. Annual average global horizontal radiation between 1.350 and 2.070 kWh/m2/year. Solar energy constitutes the largest and more uniformely distributed renewable resource of these countries.

The most appropriate technology to harness the solar resource is the production of electricity through photovoltaic systems. This technology currently presents the fastest installation time (less than 1 year), has the lowest maintenance costs and is also the technology that has experienced the largest decrease in costs. Since 2009 costs for installation and operation of PV-solar modules have decreases by 80% (e.g., see below figure).



Operating and proposed utility-scale solar PV project installed costs in Africa, 2011-2018 (IRENEA, 2016)

Figure 1. Evolution of PV-solar installation costs.

NamPower has concluded negotiations for a Power Purchase Agreement and Transmission Connection Agreement for both Diaz Power (wind power generation of 44 MW at Lüderitz) and GreeNam (solar PV of 10MW at Hardap and 10MW at Kokerboom sites in the south). It has also issued a tender for a 37 MW solar PV plant at its Hardap transmission station near Mariental as well as for auxiliary supply at Ruacana hydro plant.

2.4 Proposed Development

The Cunene river has a length of 1100 km. It starts in the mountainous forests on the Angolan plateau where conditions are moist with average rainfall at about 1300 mm per year. As it flows southwards through the northern Kalahari (660 km) to Calueque and then flows westward through the Namib desert rainfall decreases to less than 100 mm per year. Despite being a perennial river with mean annual flows of 160 m^3/s the year to year and annual variation is considerable. Long periods of drought has been experienced at the Ruacana Hydroelectric power station, lacking storage for seasonal regulation and thus with a large and unpredictable variation in the electric power generation. With a storage capacity of about half of the annual inflow Baynes will significantly improve seasonal regulation.

The added advantages of conjunctively constructing and operating a PV-solar plant is the economies of scale gained from the common infrastructure, e.g. such as access roads, construction camp and transmission lines, as well as the ability to save water for later release when prices are highest. Main project characteristics for the respective hydro and PV-solar components are described in the sections to follow.

2.4.1 Dam and Power Plant

The dam site is located approximately 40 km downstream of Epupa Falls at river El. 400. The scheme develops the head from reservoir level 580 and down to El. 380. It comprises a 200 meter high roller compacted concrete (RCC) gravity dam, a reservoir, an adjacent underground power station with either 360 or 600 MW installed capacity and high voltage transmission lines to Angola and Namibia. Water will be conveyed from the intake tower in the reservoir through a headrace tunnel and vertical pressure shaft to three or five francic turbines depending on the selected installed capacity (i.e. 360 or 600 MW) and then back into the Cunene River from the tailrace tunnel some 2 km further downstream. To lessen impacts on aquatic ecology in this section of the river, minimum releases at the dam were set at 2 m^2/s in the original Namang (1998) feasibility study and later increased to 5 m^3/s in the revised study of 2010. Similarly, respective minimum operating rates were set at 20 and 50 m^3/s. The salient features are summarized in the below table.

Table 4. Salient features (Namang, 1998) and * (Nampower, 2016)

Item	Namang (1998)	Revised (2010)*	Comment
HWL	580 m		High Water Level
TWL	380 m		Tail Water Level
Gross Head	200 m		At HWL
Max Reservoir Storage	2,547 Mm3		
Min Reservoir Storage	778 Mm3		
Max Surface Area	57.5 km2		
Active Storage	1,769 Mm3		
Reservoir Drawdown	50 m		
Annual Flow	5012.2 Mm3		
Evaporation	1,765 mm per year		
Upstream Abstractions	500 Mm3		Irrigation
Max Discharge	201 m3/s	335 m3/s	
Min Discharge	20 m3/s	50 m3/s	Environmental
Abstraction from dam	2 m3/s	5 m3/s	Environmental
Installed Capacity	3x120 MW	2x71 and 3x156.75 MW	
Production	1440 GWh	1610 GWh	
Total Project Cost	554.38 MUSD	1200 MUSD	

2.4.2 Hydrology

The hydrology for for simulation of power production and civil designs is based on the correlating record at Ruacana from 1961-72 with that of Rundu, Okavango River. Rundu was deemed to display similar rainfall and runoff features as Ruacana and had a reliable record from 1945-92. The correlation was based on the simultaneous records at Rundu and Ruacana for the period 1961-72. The long term record at Rundu was then used to derive a long term synthesised natural flow record at Ruacana, which was applied for the Baynes project after deduction of river channel losses (Table 5).

Table 5. Average monthly natural flows at Ruacana 1945-1994

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
m3/s	164.1	267.0	389.2	445.4	257.9	112.7	72.8	52.0	33.2	18.7	26.3	77.9
MCM	439.5	645.8	1042.3	1154.5	690.8	292.2	195.0	139.2	86.2	50.1	68.1	208.5

2.4.3 PV-Solar

It is proposed that the PV-solar plant for Baynes be in the form of a 50 MW floating facility. Using the freely available PVsyst software at (www.pvsyst.com) to configure a 1 MW scalable plant is calculated to occupy an area of 6488 m^2 with daily varying from 144.3 MWh in February to 167.4 MWh in May yielding a total annual output of 1.98 GWh. Scaling up by multiplying by 50 it is estimated that the 50 MW plant will require an area of approximately 570 by 570 meters and produce 95 GWh per year. A print-out of plant input parameters with configuration details is included in Appendix A. The table below shows mean monthly production.

Table 6. Mean monthly production from a 50 MW PV-Solar Plant at Baynes

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
GWh	7.47	7.22	7.84	7.67	8.37	8.09	8.29	8.11	7.96	7.86	7.95	8.10

Based on projected installation cost by Bloomberg Energy Finance (IEA, 2014) of 1.13 USD/watt, a likely investment cost for a 50 MW PV-solar plant is set at 56.5 million USD.

3 FRAMEWORK AND METHOD OF VALUATION

3.1 Structure and objectives

The framework for valuation consists of a simplified reservoir model to calculate seasonal distribution and amount of power available during peak and off-peak hours and a discounted cash-flow model in excel. The latter includes options to perform both economic and financial analyses and produces output tables with according sensitivities of rates of return and net present value to changes in tariffs, construction costs and interest rates. In the current context emphasis is, however, on the financial viability.

The economic analyses examines the project from a country and government, and seeks to determine (i) whether investing in the Project would represent an efficient use of resources (manpower, capital, materials etc.) as compared to using the resources in alternative investments and (ii) whether the selected project is a least cost option for supplying energy to meet the projected demand. Least cost analyses form the basis for the optimised installed capacities in the original and revised feasibility studies of Namang (1998) and Cunene Consortium (2010). Electricity imports and generation from gas as well as other hydropower projects were among the alternatives considered. Due to the extensive data requirements of such an exercise, the economic analyses in this investigation is limited to the former test. That is the ability of the project to yield higher returns than the opportunity cost of capital, presently taken as 10%.

In contrast, the objective of the financial analyses is to determine if the Project will be able to yield a satisfactory return over the adopted concession period. To this end the financial analysis is done by applying market prices while the economic analysis is in fixed (resource efficient) prices, i.e. meaning that distortions from inflation, taxes, subsidies etc are not included.

The study steps are outlined starting with power production below.

3.2 Power Production

The original 360 MW (Namang, 1998) and revised 600 MW (Cunene Consortium, 2010) were optimized for respective annual production of 1440 GWh and 1610 GWh. Each of these alternatives are assessed with the option of additional 95 GWh of PV-solar power as follows (i.e. other input data are as provided in Tables 4-6 in the preceding chapter):

1. Calculate available inflow as monthly mean flow less minimum release, evaporation loss and upstream abstractions 100 Mm^3/month from January to May

2. Calculate the distribution of discharge and hence power production to reach full supply level from 1 January to 31 May and then subsequently to draw down the reservoir from 1 June until 31 December.

3. Calculate the proportion of monthly production that can be released at design discharge during the 4.5 hour peak period as, $P\ (GWh) = \eta\rho gh\ (Qmax * t)$ where h is turbine efficiency (90%), r is the density of water (1000 kg/m^3), g is gravitational constant (9.8 m^2/s) and Qmax is the maximum discharge and t is time in seconds. The off-peak production is then simply the total minus the peak production.

4. If the design discharge exceeds inflow and the reservoir can store water calculate the avoided discharged from the solar power produced in the same period and release this water at maximum discharge during the 4.5 hour peak period.

5. Add the amount of power produced during peak and off-peak for the low (1/6-31/8) and high (1/9-31/5) demand period.

6. Calculate the weighted power tariff for low (wet) and high (dry) demand period from the above distribution

3.3 Valuation

The project's potential for attracting investors and yielding a satisfactory return is determined primarily by:

- the qualities and characteristics of the project (costs, output, risks)
- the market (domestic or export)
- the financial options and financing terms
- the required return on equity by investors and their risk perception

These factors constitute the framework within which a solution that may lead to project development has to be found. The analysis:

- discusses various financing options, reviews likely terms, and outlines risk aspects
- provides financial projections and calculates various types of return on investment
- provides a basis for financiers to determine the project's ability to service debt with sufficient safety margin
- shows total investment requirements and proposes financing plans, and
- calculates government take through royalty and taxes

Basic Assumptions are common for both types of analyses (financial and economic are listed and/or discussed below. Specific assumptions are found in the sections to follow.

The project will be operated as a mid-merit plant to maximize output during periods of seasonal high and daily peak demand. For financial purposes it is assumed that the power, according to the PPA, will be delivered at the switchyard (also termed busbar) with prices as shown below.

The amount of power produced in each segment is given by the annual production multiplied by the respective weight in the below table. Similarly, the applicable tariff for low and high demand season is obtained by multiplying the approved tariff in the schedule set by the sector regulator ECB in Namibia for 2016/17 by the relative weight of the power produced.

Energy losses of 1.25% are deducted for transformation losses and internal consumption.

Table 7. Namibian tariffs schedules

Calculation of average tariff from production alternatives					
2015/16 (N$c/kWh)			2016/17 (N$c/kWh)		
	Peak	Off-peak		Peak	Off-peak
Low	124,3	86,1	Low	138,7	96,0
High	205,4	108,6	High	229,1	121,0

Table 8. Calculation of average tariff from production alternatives*

360 MW Base (1440 GWh)				360 MW Base + PV (1535 GWh)			
	Peak	Off-Peak			Peak	Off-Peak	
Low	19,5 %	52,2 %	71,7 %	Low	18,5 %	49,6 %	68,1 %
High	7,3 %	21,0 %	28,3 %	High	11,9 %	20,0 %	31,9 %
	26,8 %	73,2 %	100,0 %		30,4 %	69,6 %	100,0 %
			USDc/kWh				USDc/kWh
Low	27,04	50,12	8,18	Low	25,66	47,62	8,18
High	16,80	25,44	11,34	High	27,27	24,21	12,26

600 MW Revised (1610 GWh)				600 MW Revised + PV(1705 GWh)			
	Peak	Off-Peak			Peak	Off-Peak	
Low	33,3 %	37,7 %	71,0 %	Low	31,7 %	35,8 %	67,5 %
High	12,6 %	16,4 %	29,0 %	High	16,9 %	15,6 %	32,5 %
	45,9 %	73,2 %	100,0 %		48,6 %	73,2 %	100,0 %
			USDc/kWh				USDc/kWh
Low	46,23	36,15	8,82	Low	43,93	34,35	8,82
High	28,80	19,90	12,76	High	38,76	18,92	13,47

*Exchange rate - 0,076 NAD/USD, duration of high demand is 1/6-31/8 and low demand is 1/9-31/5

The investment costs expressed in fixed 2017 prices are estimated at MUSD 807 for the base (360 MW), MUSD 1200 for the revised (600 MW) and MUSD 56.5 for the PV-solar option. For the base case current prices are estimated as the present value of the 1998 price at compound rate corresponding to USD inflation of 2%.

The total cost estimate includes the cost of the transmission line to the connecting point on the main grid, as well as environmental mitigation costs. The latter comprise, inter alia, compensation for permanent loss of land and compensation to temporarily affected families.

Foreign components are estimated to comprise hydraulic, electro-mechanical (turbine + generators) and electrical (transformers and switchgear) equipment installations. A breakdown including percentage distribution over the 6-year construction period is shown below.

Table 9. Breakdown of construction costs in (million) MUSD

	% of Base	Base -360 MW 1998-prices	Base - 360 MW 2017-prices	Revised - 600 MW* 2017-prices
Access roads	8,87 %	49,2	71,6	106,4
Operator village	1,14 %	6,3	9,2	13,7
Civil works	39,61 %	219,6	319,9	475,4
Hydraulic and Mechanical	8,81 %	48,8	71,1	105,7
Electrical	6,98 %	38,7	56,4	83,8
Transmission	17,23 %	95,5	139,1	206,7
Environmental mitigation	1,64 %	9,1	13,3	19,7
Management and Engineering	8,26 %	45,8	66,7	99,2
Contingencies	7,46 %	41,4	60,2	89,5
Sum-Total Hydro	100,00 %	554,4	807,6	1 200,0
PV-Solar Plant			56,5	56,5
Sum (Total + PV-Solar)			864,1	1 256,5

*Calculated as the total investment cost MUSD 1200 multiplied by the weight as % of Base, VAT not included.

Table 10. Distribution of construction costs.

Year-1	Year-2	Year-3	Year-4	Year-5	Year-6	Year-7 (total)
7 %	13 %	16 %	27 %	26 %	11 %	100 %

The project evaluation period is 40 years for the economic analysis and 34 years of operation for the financial analysis, which equals the concession period of 40 years minus the construction period of 6 years. Within this period, replacement of equipment will take place that has been accounted for in the annual operation and maintenance cost (O&M) allocation

Annual O&M is accounted for through a 0,8% cost calculated based on total investments, and includes recurrent expenses at 0.5% for staff and equipment maintenance plus 0.3% for environmental mitigation.

The analyses are carried out in USD. An exchange rate of 13.16 NAD per USD has been applied, prevailing as average for the 2016 and first quarter of 2017. A power purchase parity regime is assumed implying that the relative differences in domestic and international inflation rates are counterbalanced by exchange rate adjustments. Price adjustments have been made to revenues (through inflation of the tariff in fixed prices) and costs of 2% per annum.

A discount factor of 10% has been applied in the economic analysis (real terms).

The project is assumed to be developed as a private Special Purpose Company (SPC), with no public ownership, and with financing on commercial terms. The financing may involve loans from multilateral finance institutions and export credit agencies, but at commercial terms.

Reflecting this financing structure, the USD cost of equity has been estimated at 13,9%, and the Weighted Average Cost of Capital (WACC) is estimated at 9,53%

Cost of debt is set at 8,49% + Libor with maturity of 15 years.

The corporate tax rate is presently 32% in Namibia and 30% in Angola (www.tradingeconomics.com, 2016). An average figure of 31% is used for the analyses. No other government fees are included.

The chapter to follow on financing explains the reasoning behind the adopted capital structure, inherent risk factors and implications underlying the assumptions as outlined above. This is considered important to facilitate understanding of the results and conclusions regarding the main impact factors that determine the value of the project.

3.4 Financial Model

A tailor made computerised financial model of Baynes has been developed. The financial model produces pro-forma income statements, flow of funds and balance sheets for the company for a given financial evaluation period defined by the project schedule.

The project schedule is defined by the starting year of calculation (2018), the period required to develop the project to financial closure, the construction period and the concession period – all of which are variables that can be altered.

The income statement calculates revenue from electricity sales to the grid (valued at the station busbar) with split according to seasons and peak/ off-peak hours.

Operation and maintenance cost (O&M) of Baynes as been estimated on the basis of accumulated capital expenditure (CAPEX), including physical contingencies, but excluding financing costs.

The financing requirement is determined by CAPEX, adjusted for price contingencies and interest during construction (IDC), i.e. IDC is capitalised. IDC is calculated on the basis of the relevant financial package

A declining balances depreciation method has been applied. A residual value of the hydropower plant at the end of the concession period has not been used since a free transfer to Government at the end of the concession period is assumed.

The return on equity invested is revenues including interest on bank deposits less operating costs, taxes, and debt service.

Increase/decrease in cash and bank deposits is the residual cash-flow after all payments including repayment of equity and dividends.

Financial Indicators Calculated

Cash-flows

- Net cash-flow of total capital (including revenue less O&M and investments, before taxes)
- Net cash-flow after debt service, equity and taxes

Return on Capital Invested

- EIRR Economic Internal Rate of Return on total capital invested (fixed prices)

- FIRR Financial Internal Rate of Return on total capital invested
- FIRREQ Financial Internal Rate of Return on equity after taxes

Net Present Values (NPVs)

- NPV(WACC) NPV of total capital discounted at WACC (see below)
- NPV (OCC) NPV of total capital discounted at OCC (see below)
- GT NPV of government revenue from royalty and company tax discounted by OCC

Debt Coverage Ratios

- DSCR Annual Debt Service Coverage Ratio defined as gross revenue less O&M and taxes divided by debt service (interest and repayment of loans)

Prices

- EUEC Financial Unit Energy Cost in USc/kWh, at point of supply, defined as discounted total costs (CAPEX and O&M) divided by discounted electricity sales, applying OCC as discount rate

Cost of Capital

- OCC Opportunity Cost of Capital
- WACC Weighted average cost of total capital (debt and equity)
- IRDebt Weighted average interest rate on debt

3.5 Financing Structure

Four main types of hydropower project (HPP) financing can be defined:

- Traditional public financing, i.e. financing with sovereign guarantee primarily in traditional regulated markets organised with a vertically integrated state owned utility as the only or dominant actor. Financing would be host government funds and foreign donor or concessionary financing (multi- and/or bilateral)

- Ordinary recourse financing, i.e. financing with recourse to the balance sheet of the investor, for instance a major energy company, normally privately owned or owned by local and/or central government
- Limited recourse financing, where funding is based on a Power Purchase Agreement (PPA) with one major buyer – often a state owned utility - implying that the PPA is secured by the balance sheet of the state owned entity, possibly backed by a sovereign guarantee. Financing may be a combination of private and public money, including soft finance, i.e. commercial and concessionary finance
- Non-recourse financing, i.e. pure project finance with no recourse to the balance sheet of the investor or to the government (also termed off-balance sheet financing). The sources of funds would be private capital only.

In this study the SPC is set up under a limited recourse model whereby revenues are secured through power purchase agreements (PPAs) denominated in USD with the main off-takers (RNT in Angola and Nampower in Namibia. As such the currency risk is borne by the host governments and the operator is mainly responsible for completion of the project according to specifications, budget and time.

Objectives of Participants in the SPC

The main participants in a hydropower venture are the host government, investors, lenders, contractors and insurance companies.

Typically, the objective of the host government is to exploit the hydropower potential to the maximum benefit of society, i.e. an economic optimisation. In essence, host governments would like to harvest the water value of the hydropower potential at lowest possible cost to society.

The lender will face a considerable downside risk if the project fails or falls short of its potential. His main concern is therefore that the project to service debt with sufficient margin of safety is hence a main concern. Civil contractors, suppliers of electro-mechanical equipment and hydropower engineers, i.e. the contractor group's main objective is to deliver their services (at highest possible price). If they have to contribute towards the financing, they prefer repayment of their investment no later than at the time of commissioning.

3.6 Sources of Finance

The sources of finance available for private hydropower development are equity, loans, guarantees and grants. These sources of finance and their terms are presented below. It should be noted, however, that the financing terms indicated are tentative only. They will depend on a number of factors such as the currency of denomination, the creditworthiness of the participants in the project, and the perceived overall risks of the hydropower investment, including country risk.

3.6.1 Equity

A commitment by the governments of Angola and Namibia would be necessary not only to raise the required capital; it is also a prerequisite for the loan and risk mitigation instruments that The World Bank could provide. Typically, private equity holders investing in infrastructure in emerging markets will seek returns in the range of 15% to 20% (e.g. see below figure). The main risk factor is the market premium, which accounts for approximately half of the required return. Remaining risk are those that relate to the business model (including nature and type of participating entities), currency and political premium.

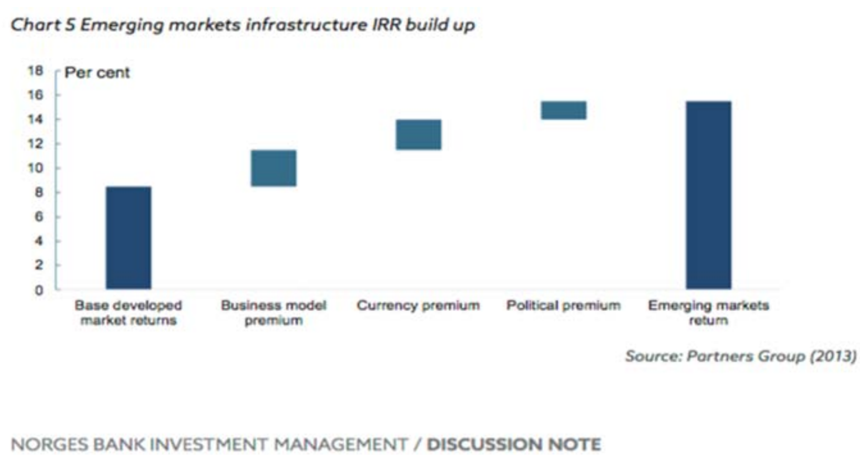


Figure 2. Market IRR build up.

Except for South Africa and to some extent also Namibia, availability of domestic equity is limited. However, the assets of financial intermediaries in Namibia´s economy are the highest in Africa, with 165% of GDP (Irving 2009). For example the pension funds of Namibia could be a possible investor that would be willing to raise equity. Another option: China's involvement in Africa's construction and infrastructure sectors has also proved most effective in building relations with African governments — increasing influence and expanding access to natural resources on the continent. And as an extra win; at the expense of European and South African companies which previously dominated these sectors (Corkin, 2006).

3.6.2 Debt

Private capital flows to the African power sector have been volatile over time. Excluding the Nile basin megaprojects, the typical average annual capital flow to African power sector since 2000 have averaged no more than USD 450 million (Eberhard 2011).

"a lack of liquid, longer-term, domestic investment instruments. (…) Energy, transport, water and information services remain well below international standard on the continent, and this creates serious bottlenecks for African economies trying to achieve the transformational rates of growth that have been witnessed in other emerging markets"(Mezui, 2013)

Five sources of financing (as described in the following chapter) are assumed. These are government financing, domestic markets, World Bank financing, export credit agencies and a minor part of infrastructure bonds. Many projects operating in these markets would obviously prefer to issue corporate bonds, however corporate bond-trading volumes are too low to satisfy the demand of a larger infrastructure project (African Development Bank, 2017).

Government financing, IFS loans and domestic financial markets will be issued in local currency. The International Finance Corporation (World Bank) is issuing debt in local currency - to reduce currency mismatches. Local currency debt is considered to be a security against currency volatility.

Government financing

We make an assumption of Angola and Namibia issuing government bonds to finance the Baynes project. We have tried to calculate what terms the two countries could achieve in the market. In this instance, it would be the government who would carry the currency risk, if bonds are sold on the international market

Standard & Poor's credit rating for Angola stands at B with negative outlook. Considering rating outlooks from fall 2016, both S&P and Moody´s operate with a B rating and negative outlook. From the period 2010-2016 the ratings have been stable between BB- (S&P July 2011) and B+ (S&P Feb 2015). However, by fall 2016 S&P, Moody´s and Fitch all have a “negative” outlook for Angola´s credit rating. According to Moody´s the key drives of the negative outlook are:

- The government´s financial position have deteriorated sharply due to downward shift in oil prices.
- Current account balance relative to GDP moved from a surplus of 6.7% to a deficit of 5.7%.
- GDP decline from 126 billion US$ (2014) to 102 US$ in 2015.
- Annual GDP growth outlook at 0.9-1.2% for period 2017-2019 (World Bank estimate)

December 2nd 2016: Moody´s changed its credit rating outlook for Namibia from stable to negative, and affirmed a rating at Baa3. Fitch also express negative outlook as from 2nd of December 2016, with a rating of BBB-. The underlying reasons are, according to Moody´s, a ”slower than expected fiscal consolidation in the current fiscal year and continued rise in public debt”. The GDP growth forecast for Namibia seems quite robust, with a steady 5-5.5% expected growth in 2017-2019. However, for 2016 Namibia had a GDP growth of only 1.6% and the current account balance is moving towards the largest deficit in over 25 years (World Bank 2017).

Still a relatively stable political landscape and consensus around macroeconomic policies helps securing the Baa3 rating (Moody´s, 2016).

A 10 year Angola government bond is traded at 9,50% coupon rate in 2016. A Namibia 10Y is sold for 5,25%. An average of these rates, 7,38% is used as Baynes government finance lending rate. This loan covers 30% of total debt.

Domestic financial markets

The future of larger energy infrastructure development in Sub-Sahara depends on local finance. This sector has traditionally been raising capital from governments, or international investors. For most countries in this region there is just not enough financial strength in local banking systems to back up larger infrastructure projects. Governments are looking to extend the maturity profile of their security issues in an effort to establish a benchmark against which corporate bonds can be priced. However, corporate bond markets remain small and illiquid (Rosnes 2011). With the exception of South Africa there are no countries with a developed financial market ready to provide necessary financing to larger infrastructure projects. Also, in Angola, where inflation has been high, there are less incentives to save (future money is worth less). This makes it more difficult for financial markets to provide long-term finance - which is exactly what a infrastructure project needs. One consequence of this could be pressure on project management to rush the commercial operation date. However there are signs of change. Private pension providers are emerging, and African institutional investors have begun taking a more diversified portfolio approach in asset allocation (Irving 2009). The cooperation of Angola and Namibia would signal government dedication, and thereby lead to financial opportunities that could raise USD 107 millions. To calculate interest rates, Angolan and Namibian average lending rates from 2006-2017 are used, at 17,25% and 10,23% (data.worldbank.org). An equal loan proportion of 53,5 mill USD from banks from each country, gives the Baynes project a capital access of USD 107 millions. This covers 16% of total debt.

Currency risk will be reduced with funding from domestic financial markets. From a World Bank perspective, this way of financing could be looked at as a sustainable investment option. It will also benefit the local capital markets. Domestic funding has the benefit of better understanding political risk. This is a double-edged sword however; Angola ranked as 164 of 176 countries in Transparency´s Corruption Index - there could be risks involved by funding domestically as well.

World Bank/ IBRD and IFC loans

The International Finance Corporation is a division of the World Bank Group and could play an important role as contributor in this project. Established in 1956, the purpose of the organization has been to support growth in the private sector in the developing world. The IFC´s mission is “to promote sustainable private sector investment in developing countries, helping to reduce poverty and improve people´s lives”.

IFC is the largest global development institution focused exclusively on the private sector in development countries. Particularly in less developed areas, the IFC has, in association with private investors, made investment without guarantee of repayment by the government involved, in cases where sufficient private capital were not available on reasonable terms (ifc.org, 2017).

Traditionally the IFC policy has been to denominate loans to the currencies of major industrial nations. However, the new policy is to structure local-currency products. For the involved countries this would reduce the risk of currency losses. Especially on the Angolan side this could be an important factor, given the huge volatility challenges the Angolan Kwanza has been facing the last few years.

Being members since 1989 (Angola) and 1990 (Namibia), both countries qualify for seeking support from the IFC. To qualify, the project must meet at set of IFSs Performance Standards. As a precondition, we will assume that these demands are met by the Angolan and Namibian involvement in the Baines Hydropower Project.

The IFC loan is covering 16% of Baynes total debt and has a maturity of 20 years. Annual interest rate is 2,8%.

Export Credit Agencies (ECA´s)

Export Credit Agencies, known as ECAs, are public agencies that provide government-backed loans, guarantees, credits and insurance to private corporations from their home country. It is called “the unsung giant of international trade and finance” (Gianturco, 2001) - with reference to the fact that “almost 80% of poor countries´debts to European governments come from export credits, not development loans” (Eurodad, 2011). Large infrastructure project may require large equipment purchases from developed countries. Through ECAs, a project like Baynes can access capital from an exporting country to purchase electro-mechanical equipment for hydropower plants produced in the same country.

In developing countries ECAs often finance large-scale projects, and by doing this also aim to support export industry in their home country. Given “their commercially motivated and demand-driven nature, they cannot be assimilated to development finance. Still they play an important role by mitigating risk” (oecd.org). There have been controversies around this type of financing. The main argument has been that ECA loans provided by rich countries “may soak up aid money, as failing to repay often leads to reduced aid from ECAs home country (Eurodad, 2011). Despite the negative aspects of ECAs, we consider it as a critical financial opportunity, and to meet the Baynes project capital demand, we believe it is a necessity to gain access to this loan. Other sources of financing are more expensive, and we do not consider it realistic to expand the only cheaper loan (IFC) to more than 16% of total debt.

In OECDs “Country Risk Classification of the Participants to the Arrangement on Officially Supported Export Credits” valid as of 27 January 2017, Angola is rated 6 and Namibia 4 on a scale 1-7 (high income OECD countries not included). For renewable energy projects, the Commercial Interest Reference Rates (CIRRs) as of 17 May 2017, on USD loans with maturity of 18 years is 3.60%. We assume this rate is only available for countries rated 1. We have not been able to find a relevant source of interest rate for ECA loan to energy utilities in Angola or Namibia. Therefore we have searched other similar utility projects for comparison. Looking at a hydropower utility project in Nepal, we find an ECA interest rate of (CIRR + 6%) 9,60%. Nepal being rated 6, we find it reasonable to assume that a Country Risk Classification of 5 could mean an interest rate of CIRR + 5% for the Baynes project.

The ECA loan is covering 28% of Baynes total debt and has a maturity of 18 years. Annual interest rate is estimated to 8,60%.

Infrastructure Project Bonds.

Issued by The African Development Bank Group, Infrastructure Project Bonds are meant to raise capital for specific stand-alone projects that are repaid from cash generated by the project. This means projects with participation by government and private entities are considered, as for example an Angolan-Namibia project. The main target for these infrastructure project bonds are to ensure optimal allocation of risk for potential bondholders and efficient financing of important infrastructure. (Mezui, 2013)

Still, bond finance is rare in African infrastructure projects. Infrastructure bonds are mainly of interest to long-term investors, like for example insurance companies or pension funds. However these are institutions who are not very willing, or able to invest in what could be considered as a high-risk investment. A solution could be that infrastructure bonds not are implemented before after the construction phase. In the operational phase for a hydropower utility, which aims to deliver a stable cash flow, we think it might be of interest for example a Nigerian pension fund. Nigeria is one of the few countries in Africa where pension funds are stable enough to be a source of financing for infrastructure projects (Irving, 2009)

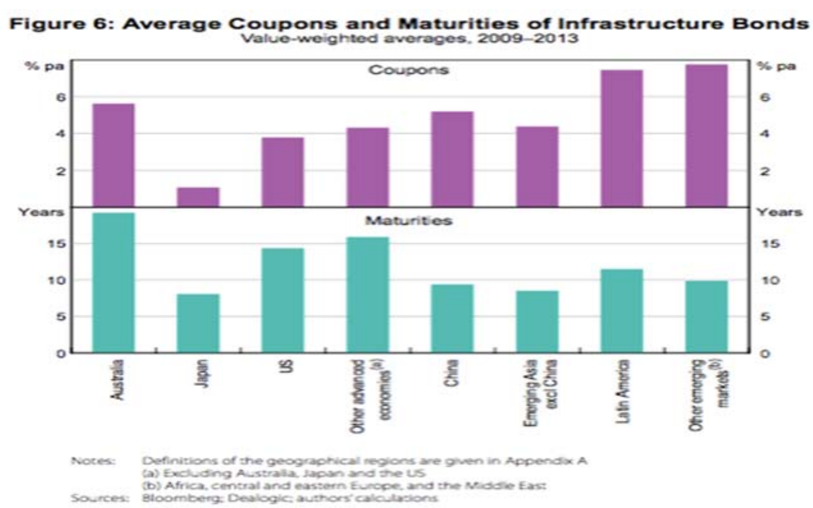


Figure 3. Coupon rates and maturities of infrastructure bonds

As the model shows, the African market for infrastructure bonds is not well developed. Given the fact that government often plays a central role in large projects it means the risk often are connected to political stability. We make the assumption that bond issued with regards to Baynes project will fall under the category “Other emerging markets”. Infrastructure project bonds will finance 10% of total debt, or USD 67 million. With a 10 year maturity date and a coupon rate of 7%, this will be the final source of debt finance.

Financial Structure

Debt issued in Angola Kwanza (AOA)		% of debt	% of local debt
Government debt:	201 mill (USD)	30%	48,4%
Domestic market:	107 mill (USD)	16%	25,8%
World Bank / IFC:	107 mill (USD)	16%	25,8%
Debt issued in US Dollar (USD)			
Export Credit Agencies (ECA):	188 mill (USD)	28%	73,7%
Infrastructure Bonds:	67 mill (USD)	10%	26,3%
Total	671 mill (USD)	100%	

TERMS	Interest rate	Repayment period
Government debt:	7,3%	20
Domestic market:	13,7%	10
World Bank / IFC:	2,8%	20
Export Credit Agencies (ECA):	8,6%	18
Infrastructure Bonds:	7,0%	10

Assumptions for Discounted Cash Flow and WACC

The DCF model has been developed using USD as the operating currency, both for revenues and costs. Reference year for prices/data is 2017. The initial construction date is set to 01.01 2018 with a construction period of 6 years. Ending operational date is set at 31.12 2059, which means a concession period of 42 years.

Discounting cash flow in emerging markets differ somewhat from valuing companies in developed countries. With US Dollar, Angola Kwanza and Namibian Dollar involved the currency issue could be challenging. Both local and USD WACC is calculated.

Libor

The average of USD 10 year (and 30 year) bond yields are used as a proxy for the future USD risk free interest rate. This rate has been set at 2,30%, which is used as a proxy for the future USD Libor rates. This number is lower than historical average USD Libor Rate History numbers, starting 1989. For the period 1989-2017, 3 months Libor average is 3,49% (fedprimerate.com, 2017). A somewhat higher Libor rate, at 2,6% average for the period 2021-2059 is therefore anticipated. For the years 2016-2021 we have assumed a linear increase from 1,1% and a stabilization at 2,6% from 2021.

US and Local Risk Free Rate

USD risk free rate: 10-year US government bonds, traded at 2,30%.

Local risk free rate (1): 10 year Angola Government Bonds is traded at 7,75%, while Namibian is traded at 10,75%. To calculate an average risk free rate with equal shares, an annual rate of 9,25% is expected.

Another approach is to start with 10Y US government bonds yield, and *add projected inflation difference over time* between US and local inflation (Koller, 2015):

USD risk free: 2,30% Projected inflation average Namibia: 6,5%

Projected inflation average Angola: 14,5% (2018) + 9,7% (2059) * 0,5 = 12,1%

Local risk free rate (2) = 9,76%

Average of these two risk free rates calculations; 9,51%

Market risk premium

To find a local market risk premium, we have used the numbers 12,09% for Angola and 8,82% for Namibia. These data are taken from the publication “Country Risk: Determinants, Measures and Implications” by Aswath Damodaran, 2016. Here the equity risk premium is based on rating-based default spread. Market risk premium is the average of Angola and Namibia: 10,46%.

For USD WACC calculation, the same approach has been used, to arrive at a US country risk premium at 5,69%.

Asset and equity beta

A NYU Stern School of Business comparison of 370 power utility companies in emerging markets, are used (Appendix B) to estimate asset beta for local WACC use An average of asset beta at 0,46 was presented (Damodaran, 2017). Not being able to collect relevant material from the African market itself, asset beta from emerging markets has been used. We consider unlevered beta the same as asset beta given the fact that the volatility without leverage is the result of assets only.

$$\boldsymbol{\beta}\ (\boldsymbol{equity}) = \boldsymbol{\beta}(\boldsymbol{asset}) * [\mathbf{1} + (\mathbf{1} - \boldsymbol{Tax})(\frac{\boldsymbol{D}}{\boldsymbol{E}})$$

With tax rate at 30%, and a debt over equity ratio at 70% / 30% a $\boldsymbol{\beta}$ (local equity) of 1,21 is assumed.

Country Risk Premium

Even a very good run company in Angola or Namibia will be hurt badly if the economy collapses due to political reasons or other macro economic instabilities. To calculate the probability of a country crisis is outside this thesis limitations, instead we have used calculations from Stern University (2017) to find a country risk premium. An argument could be that the country risk premium could be diversified away. However, “the significant home bias that remains in investor portfolios exposes investors disproportionately to home country risk, and the increase in correlation across markets has made some of this into non-diversifiable risk” (Damodaran, 2016).

The country risk premium is based on local currency ratings from Moody´s to estimate the default spread over a default free government bond rate. The US CDS spread is subtracted from Angola/Namibia CDS spread, which gives a country spread. Then market premium is added to arrive at the total equity risk premium. In addition, the default spread is multiplied by the relative equity market volatility. The person responsible for this model, Aswath Damodaran (Stern University) then uses an emerging market average of 1,23 (estimated by comparing emerging market equity index to emerging market government/public bond index) to estimate country risk premium. This method gives a country risk premium for Angola at 6,4% and Namibia 3,13%. An average of this, 4,8% is assumed.

Country	Moody´s rating	Rating based default spread	Total equity risk premium	Country risk premium
Angola	B1	2,54%	8,82%	3,13%
Namibia	Baa3	5,20%	12,09%	6,40%

Cost of equity

$$\boldsymbol{Cost\ of\ Equity\ (local) = r_f + \beta * market\ risk\ premium}$$

= 9,51% + (1,2 * 10,46%) $\quad$ $\mathbf{= 22,1\%}$

$$\boldsymbol{Cost\ of\ Equity\ (USD)} =$$

$$\boldsymbol{= r_f + \beta * market\ risk\ premium\ (US) + country\ risk\ premium}$$

= 2,3% + (1,2 * 5,7%) + 4,8% $\quad$ = 13,9%

Cost of debt

Debt Structure	*term*	*annual interest*	*% of total debt*	*% of dom./foreign debt*
Government loan	20	7,3 %	30 %	48 %
Domestic market	10	13,7 %	16 %	26 %
IFC	20	2,8 %	16 %	26 %
ECAs	18	8,6 %	28 %	74 %
Inf str project bonds	10	7,0 %	10 %	26 %
Total			100 %	

Total interest expenses for Baynes, including refinance with a 0,5% debt differential after 14 years, and with a delayed contract entry for some of the loans:

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
i during construction	0,3	0,8	3,0	9,6	19,7	35,6	4,4	0	0	0	0	0	0	0
i initial debt	0	0	0	0	0	0	49	62	62	58	53	49	45	40
i refinance	0	0	0	0	0	0	0	0	0	0	0	0	0	0
total interest	0,3	0,8	3,0	9,6	19,7	35,6	53,4	62,0	62,0	58,0	53,0	49,0	45,0	40,0

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
i during construction	0	0	0	0	0	0	0	0	0	0	0	0	0	0
i initial debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0
i refinance	34	30	26	22	19	16	14	12	10	8	6	3	2	1
total interest	34,0	30,0	26,0	22,0	19,0	16,0	14,0	12,0	10,0	8,0	6,0	3,0	2,0	1,0

This means a total interest expense of USD 694,70. Given the fact that the loans could be refinanced, a total loan period of 34 years is scheduled. If total interest expense is divided by 34 years we arrive at a total cost of debt of only 3,01% per year. This is very low and a too optimistic outcome, with regards to what contract terms Baynes will be able to negotiate. If the loan period is reduced to an average of Baynes five loans term (15,6), the cost of debt is 6,76%.

Another approach spread total debt to each loan over each period :

	term	*annual payment* USD	*total debt contract* USD	*total interest payment* USD
Government loan	20	14,69	201,30	293,90
Domestic market	10	14,71	107,36	147,08
IFC	20	3,01	107,36	60,12
ECAs	18	16,16	187,88	290,84
Inf str project bonds	10	4,70	67,10	46,97
Total		**53,26**	**671,00**	**838,91**

Total interest payment, divided by total debt over loan period gives a cost of debt at 10,61% (libor included). We weigh the three local loans (green) to arrive at an annual cost of local debt at 10,32%. The same approach for US loans (light brown) gives an annual cost of USD debt at 11,09%

Weighted Average Cost of Capital

Two WACC calculations have been made, one for US capital, and one for local capital.

Local WACC		USD WACC	
Local Risk Free Rate	9,51 %	Risk Free Rate USD	2,30 %
Market Risk Premium (Local)	10,46 %	Country Risk Premium	4,80 %
Asset Beta (peers vs. local markets)	0,46	Market Risk Premium (US)	5,69 %
Equity Beta	1,20	Asset Beta (peers compared to S&P)	0,46
		Equity Beta	1,20
Cost of Equity	**22,10 %**	**Cost of Equity**	**13,90 %**
Tax Rate (local)	31,0 %	Tax Rate (local)	31,00 %
Cost of debt (local debt local currency)	10,32 %	Cost of debt (USD)	11,09 %
After Tax Cost of Debt	7,10 %	After Tax Cost of Debt	7,70 %
D/(D+E)	70,0 %	D/(D+E)	70,0 %
Weighted Average Cost of Capital	**11,60 %**	**Weighted Average Cost of Capital**	**9,53 %**

Inflation

The US dollar inflation average is 2,1% for the period 2001-2017, and this number is used for the whole concession period.

The ideal formula approach for trying to forecast inflation would have been:

Expected Inflation = (1+ interest rate 10Y gov bond) / (1 + interest rate inflation protected bond) -1 (Koller, 2015)

Unfortunately we were not able to obtain reliable data on inflation-protected bonds for either Angola or Namibia. We therefore base our assumptions on historical data, combined with expected government and central bank response.

Inflation in Angola and Namibia are volatile, with Angola at 152% in 2001. For inflation forecast, we emphasise that this is a risk factor Baynes.

Angola (2005-2017) average :14,45% Namibia (2005-2017) average : 5,74%

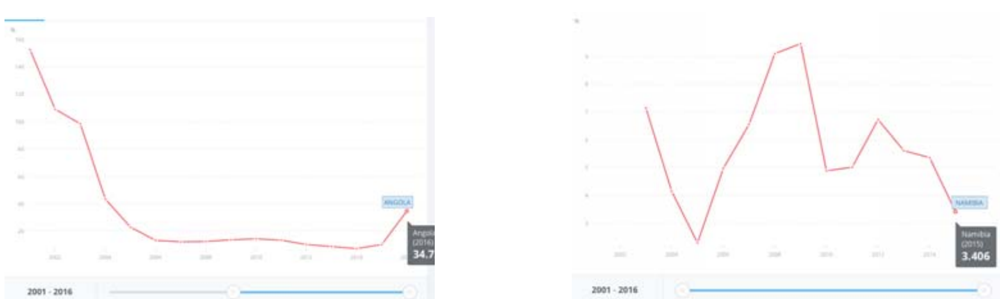


Figure 4. Comparision of inflation rates.

With Angola at 34,37% inflation in 2016, the Angolan central bank is expected to execute monetary policy to lower inflation. This would normally mean higher interest rates in short term, and from 2020 a slightly lower inflation rate is expected towards 2059. Assumption: 14,5% inflation in 2019, which decreases with 1% (1% of 14,5%) a year towards 2059.

Namibia is a more stable economy with historical average inflation rate at 5,74%. In February 2017 Namibian inflation increased to 7,8%, driven by inflation rates for housing, water, electricity, gas, transport and food. On 11th of April 2017 the Monetary Policy Committee of the Bank of Namibia decided to maintain the Repo rate unchanged at 7,00% (Bank of Namibia, 2017). Based on these numbers an annual inflation rate at 6,5% for the period 2019 to 2059 is assumed.

Currency and Exchange Rate

We have used a technical approach to forecast future exchange rates between the currencies involved. This approach analyses the past behaviour of exchange rates for the purpose of finding patterns. The head-and-shoulder pattern (HAS) indicates a downward trending line for Angola inflation, indicating a Kwanza depreciation in the future. As a prerequisite for using inflation numbers as relevant, the international Fischer effect, suggest that an increase or decrease in inflation rate will cause a proportionate increase in the interest rate in the country. Which in turn reflects the expected change in exchange rate (Eun, 2010).

The financial analysis is expressed in USD and includes projections in current prices and in fixed prices of the base year of calculation, which is 2018. Local cost components are converted to USD at an exchange rate of Angolan Kwanza (AOA) 165,9 and Namibian dollar (NAD) 13,5 per USD in the base year. By applying a USD rate of inflation, calculations are made in current prices. *Implicitly, a purchasing power parity regime is assumed where the relative difference in domestic and international inflation rates is counterbalanced by exchange rate adjustments*

Still, it seems reasonable to expect a reduction of Angolan inflation. With a peak of 42% summer 2016, the beginning of 2017 already showed inflation numbers closer to 30%. The Central Bank of Angola has an inflation target of 11% (Reuters, 2016) and an average inflation rate of 12,1% for the concession period 2019-2059 is assumed.

Based on historical exchange data and stable historical inflation, NAD vs USD = 13,5 is estimated for the whole concession period.

Based on inflation estimate for Angola, we assume a minor depreciation of Angola Kwanza against USD in the future. From 2018 we expect USD 1 = 165,9 AOA. With a 1% annual depreciation our estimate for 2048 is USD/AOA = 223,6.

This view is supported by the latest decision by the Angola central bank, to devalue kwanza in the the interbank market. According to FocusEconomics, provider of economic analysis and forecasts for countries over the world "the kwanza has faces substantial pressure (…) next year (2018) the panel sees the currency trading at 192,3 AOA per USD".

Hedge cost

According to United Nations Enviromental Programme (UNEP) there is a lack of commercial markets for currency risk hedging instruments for the Angolan Kwanza and Namibian Dollars (UNEP, 2012). To address this kind of illiquid currency market problem, the Currency Exchange Fund (TCX) was founded. TCX is a provider of over-the-counter derivatives to hedge the currency and interest rate mismatch between international investors and for example infrastructure projects like Baynes. The core risk management philosophy of TCX is the risk-reducing effect of running a globally diversified pool of currency exposures (txcfund.com, 2017).

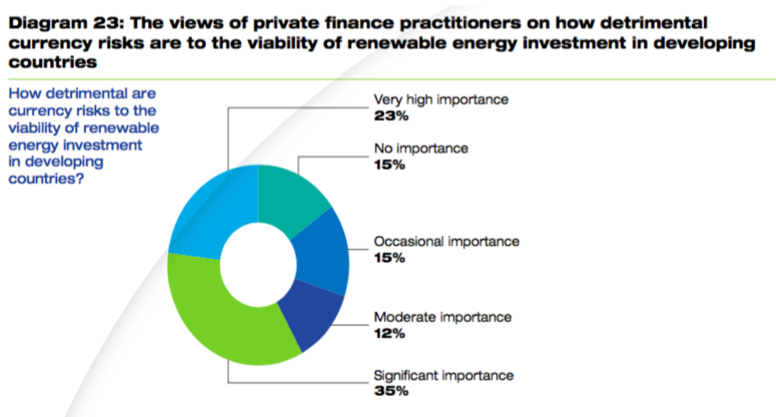
Should Baynes hedge?

Its not given that Baynes cash flow should be hedged. The managing of the exchange risk could be transferred to the government or the consumers.

One also could imagine that an oil driven economy such as Angola, the Kwanza currency to some degree would follow the price of the oil price. If in addition, electricity prices and oil prices are correlated (which could be the case as a part of energy production in Angola is based on fuel) there would be correlation between electricity prices and currency. If this was the case, there would not be the same need for currency hedging, as the local currency would appreciate at times of low electricity prices. This would reduce the negative effects of low electricity prices – as Baynes would be able to repay more USD loan for each Kwanza/Namibian Dollar because of appreciation.

One of the main problems with this approach is the fact that the local electricity price is not set by the market. The government involvement is high and to which degree the prices correlate with the oil price is hard to say. We have not been able to find credible data for historical electricity and oil price correlations either in Angola or Namibia.

As 62% of Baynes loan is made in domestic currency, we believe a large part of currency risk has been hegded. The remaining 38% are USD loans are exposed to currency fluctuations and if these loan payments are not correlated with exchange rate variations – Baynes would benefit from hedging these loans. Since the currencies is general in Sub-Sahara countries are very volatile, the added cost of hedging can be substantial. Fortunately, due to the advancements made in hedge markets and domestic capital markets, local currency can now be considered and accessed for most African power projects (Sway, 2013).



(Source: UNEP, 2012)

Figure 5. Views on currency hedging

Baynes will hedge USD 160 mill of the total USD 255 mill international loan commitments for Baynes (ECA and infrastructure bonds). These would be over-the-counter derivatives, which could be customized to meet Baynes project needs. For Angola (being classified as a category 4 country), the Currency Exchange Fund will only provide floating rate currency swap, based on 6 months T-bills as benchmark, plus or minus a spread, with settlement date every 6 months.

With average lending rates at 7,8% (ECAs and infrastructure bonds) and a AOA lending rates at 9,0% the swap would be based on an exchange rate 1 USD = 165,9 AOA (Kwanza) and look like this:

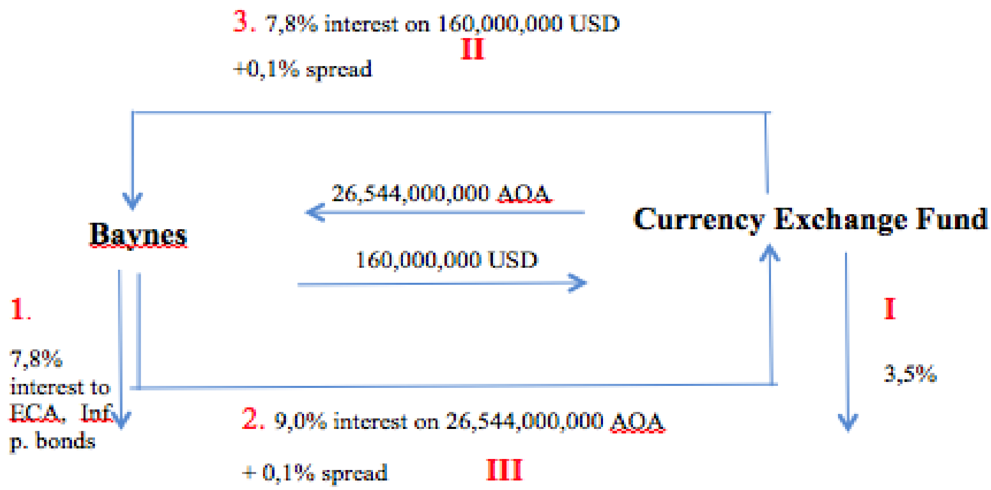


Figure 6. Conceptualization of hedge mechanism

This means every 6 months for the next 8 years (the length of the ECA lending terms) Baynes and the CEF will swap payments. On the other side of CEF, we construct an example where a South African company wanting to invest in Angola, have raised loans in Angola Kwanza AOA.

Wishing to invest in Angola, this South African company is looking to do the same kind of swap through CEF – only opposite direction. If this was the case, it is an example of both Baynes and the South African company using their *competitive advantages* of borrowing in their home market. The South African company would not be able to get a 7,8% loan in Angola, and with CEF as a "middle man" a situation is created where Baynes also gain hedging advantages – as Baynes domestic market interest is 13,7%. With an exchange rate USD/AOA at 165,9 the swap would look like:

Baynes:		=	USD 160.000.000
1.	USD 160M– (USD 160.000 *7,8%* 0,5)	=	USD 153.760.000
2 minus:	(AOA 26.544M *9,0% *0,5 /165,9))	=	USD 146.480.000
3 plus:	(USD 160M *7,9% *0,5)	=	USD 152.800.000

South African counterpart (through CEF) = AOA 26.544.000.000

I AOA 26.544M – (AOA 26.544M *3,6% *0,5) = AOA 25.349.520.000

II minus:	(USD 160M* 7,9% *0,5 *165,9)	=	AOA 24.301.032.000
III plus:	(AOA 26.544M* (3,6% *0,5))	=	AOA 25.508.784.000

Meaning if Baynes swap their USD 160M loan, they would, after 6 months have payed (USD 160M- USD 152,8M) USD 7.200.000 *given that the exchange rate USD/AOA stays at 165,9.* This equals a rate of 9%. In other word, Baynes has taken over their South African counterpart (or CEFs) interest obligations.

However, if the Angola Kwanza should turn out to appreciate to for example 130 AOA pr USD the calculations would be:

Baynes:		=	USD 160.000.000
1.	USD 160M– (USD 160.000 *7,8%* 0,5)	=	USD 153.760.000
2 minus:	(AOA 26.544M *9,0% *0,5 /130))	=	USD 144.469.000
3 plus:	(USD 160M *7,9% *0,5)	=	USD 150.789.600

Baynes would then have paid USD 9.211.400, or 11,51% because of the Kwanza appreciation. Isolated this would be a negative deal, but an appreciation of the Kwanza would at the same time mean lower interest payment on the unhedged USD 140 million loan, which would neutralise the total financial loss.

If, on the contrary, the Angola Kwanza would depreciate to 210 AOA pr USD, the opposite would be the case:

Baynes:		=	USD 160.000.000
1.	USD 160M– (USD 160.000 *7,8%* 0,5)	=	USD 153.760.000
2 minus:	(AOA 26.544M *9,0% *0,5 /190))	=	USD 148.008.800
3 plus:	(USD 160M *7,9% *0,5)	=	USD 154.328.800

Baynes would then pay USD 5.672.200, or 7,09%, which means they have saved 0,71% from the original USD loan. However this benefit would be more or less neutralised through rest of the unhedghed USD loan that now would be more expensive.

In making this swap contracts, Baynes would reduce the currency risk, and we consider that a benefit in an already risky financial environment.

Risk Identification and Allocation

There is growing evidence that risk mitigation instruments provided by public financial institutions can help reduce financial costs and mobilize private capital in financing infrastructure (Frisari, 2015).

Common types of risk in connection with hydropower projects are listed below, together with their financial impact.

Risk type	**Risk examples and financial impacts**
Revenues	
Hydrological risk	Uncertain precipitation in catchment area, short and/or unreliable hydrological records
Technology risk	Output below performance requirements
Market risk	Only one buyer which has been the case in most IPPs so far Impact: Off-take uncertain No influence on electricity tariff, i.e. price fixed by PPA
Capital cost	
Geological risk	Unforeseen complications in tunnelling/cavern and dam site Impact: Cost overrun
Technology risk	Unproven technology, Sedimentation & turbine design Impact: Output below design criteria, Increases in O&M costs
Operating risk	Inadequate maintenance Impact: Increases in O&M costs, Loss of generation
Construction completion risk	Impacts: Cost overruns: Added financial costs (interest), Later production start, Shorter operating period
Environmental risk	Minimum water release requirement, involuntary resettlements. Negative media coverage. Possible delays due to opposition, i.a. by international NGOs.Impacts: Added costs, Delays in construction, Interruption of operation
Payment risk	Inability of off-taker to make payment
Foreign exchange risk	Devaluation of the local currency Unavailability of foreign exchange for debt repayment
Political risk	Change in political regime, expropriation Changes in laws and regulations, Inadequate enforcement, Economic policy and collapse
Force majeure	Flood, earthquake

The different types of risk need to be addressed specifically since they cannot be absorbed by soft budgets or tariff increases as often occurs in the case of public schemes. Hence, the terms of loans, cost of guarantees, and the required return by the investor will be higher for private projects than for comparable publicly owned financed projects.

Access to capital through IFC is another important risk reduction factor. So is the involvement of the Multilateral Investment Guarantee Agency (MIGA), who helps mitigate the risk that the projects financial stability will be reduced by either governments or contractual partners involved.

The size of The World Bank, and its investment experience in the region, allows the IFC to both accept and manage the risk at a lower cost than their private counterparties. The World Bank´s ability to better understand sector needs across the region, and put a single project into context, significantly reduces the probability of payment default or appropriation of assets. This fact both helps mobilizing financing, as well as lower the cost of the private capital (Frisari, 2015)

Political Risk Insurance

Guarantees include those provided by ECAs, commercial banks and the Multilateral Investment Guarantee Agency (MIGA) a member of the World Bank Group. The ECAs being state backed export guarantees against political risk require counter guarantee (sovereign guarantee) from the host government of the borrower. MIGA's guarantees protect investments against-non-commercial risks and can help investors obtain access to funding sources with improved financial terms and conditions (miga.org, 2017)

For the purpose of the financial analysis of Baynes such a guarantee premium for the supply of electro-mechanical equipment is tentatively estimated at around 2% p.a. of the loan balance. Guarantees by commercial banks are more expensive. MIGA provides investment guarantees for private projects against four groups of political risk: inconvertibility, expropriation, war, and breach of contract. MIGA´s guarantee covers the equity holder, if the government as a guarantor not comply with its obligation from the implementation and/or Power purchase agreements (Frisari, 2015).

4 RESULTS AND CONCLUSIONS

4.1 Model Results

We have used the DCF model to calculate the economic viability of the project

The below tables summarize the main economic and financial performance indicators. Based on the assumptions in the preceding chapters the project´s Economic Internal rate of return is XX%, which is well above the opportunity cost of capital at 10%. This results in an economic NPV ranging from XX for the base case to YY for the revised case with option of additional power generation from PV-solar.

Similarly, the corresponding economic unit cost for the project is 7.28 USc/kWh. The table below shows the main results of the modelling, including the economic unit cost at different required returns. The highest returns are obtained for the lower installed capacities. Adding PV-Solar increases returns by MUSD 69 for the revised compared to MUSD 76 for the base case.

Table 11. Main Economic Results

	Base 360 MW		Base + 50 MW PV		Revised 600 MW		Revised + 50 MW PV	
Hurdle rate	NPV	Economic Unit cost	NPV	Economic Unit cost	NPV	Economic Unit cost	NPV	Economic Unit cost
8 %	686	6,11	791	6,14	676	8,13	791	8,04
10 %	391	7,28	460	7,31	334	9,68	410	9,58
12 %	207	8,52	253	8,55	125	11,33	175	11,20
IRR	16,5 %		17,1 %		13,9 %		14,5 %	

Sensitivity analysis on the economic results in Appendix A shows that the economic viability of the project is more robust for the Base case alternatives. With the exception of the revised 600 MW alternative without PV-solar all alternatives can tolerate more than 30% drop in tariffs and still be economically viable, and the construction cost may increase by 40% before the project becomes economically unviable.

The main financial results are shown in the below table, whereas the results of sensitivity analyses are shown in Appendix A.

Table 12. Main Financial Results

Scenario	FIRR	FIRREQ	Equity NPV
Base 360 MW	14,2 %	18,7 %	74
Base + 50 MW PV	14,6 %	19,7 %	95
Revised 600 MW	12,4 %	14,3 %	9
Revised + 50 MW PV	12,8 %	15,3 %	35

Like the economic analyses, the financial viability also increases when PV-solar is added. However, the financial analyses is more sensitive to changes in tariffs, construction and interest costs (e.g. see Appendix A). Sensitivity is highest for the revised alternatives with 600 MW installed capacities. Although adding PV-solar increases the overall financial viability neither alternative can tolerate a 10% increase in construction costs nor decrease in tariff. Resilience to interest rate increases is somewhat higher for the latter, which can tolerate a 1% increase. The financial value decreases when installed capacity in increased from 360 MW to 600 MW because the increases production is not sufficient to offset the increased construction cost.

The alternative that appears to come out best is the Base case + PV-Solar. This alternative gives the highest net present value (MUSD 95) and can tolerate either a 20% increases in construction costs or 20% drop in tariff as well as increases in interest rates.

PV-solar improves the economic and financial viability of the project because of economies of scale with sharing of access roads, construction camp and transmission line. By allowing water to be saved and released during peak demand, it enables the project to obtain a higher price for the produced electricity.

As a corollary to the above case, noting in addition that the adopted installation cost of USD 1.13/W is in the lower end of the range, and may be too optimistic, the effect of increasing the PV-solar installation cost was also examined. The results in Appendix A as well as below show that increasing installation costs decreases net present value and return to equity holder. In the case of a 3-fold increase, the net present value becomes negative for higher installed capacity. This is reasonable since the marginal gain from the ability to generate more peak power decreases with installed capacity, i.e. for plant already designed for delivery of peaking more the ability to deliver more worth is less than for a plant with a smaller designed capacity.

Table 13. Effect of increasing PV-solar installation cost on financial viability

PV-Cost (MUSD)	56,5		113		169,5	
	FIRREQ	NPV	FIRREQ	NPV	FIRREQ	NPV
Scenario						
Base (360MW)	18,7 %	74				
Base + PV (50 MW)	19,7 %	95	18,2 %	75	16,8 %	53
Revised (600 MW)	14,3 %	9				
Revised + PV (50MW)	15,3 %	35	14,4 %	12	13,5 %	-12

Another factor that is likely to exert a significant influence on project viability is hydrological uncertainty. The Cunene river basin is known to display erratic sequences of wetter and drier periods. A prolonged drought extending 2-3 years will be particularly detrimental in the early part of the project life, i.e. as later revenue is discounted and worth less than earlier revenue. Reducing inflow and hence power production by 28% results in negative net present value to equity, (e.g. see the below table). Again, adding PV-solar helps to alleviate the negative effect. This illustrates the importance of diversification in the power system, and the potential for PV-solar and wind in particular to provide base load with balancing load from hydro.

As droughts of the magnitude illustrated below are likely to affect neighbouring river basins in a regional perspective, power prices will probably to some extent increase and counterbalance lost production. Increasing price differences is yet another argument for the beneficical effects of hydropower.

Table 14. Effect of reduced inflow and power production

Scenario	FIRR	FIRREQ	Equity NPV	GWh
Base 360 MW	11,0 %	11,5 %	-39	1235
Base + 50 MW PV	11,7 %	12,8 %	-19	1136
Revised 600 MW	9,3 %	8,5 %	-134	1200
Revised + 50 MW PV	10,0 %	9,7 %	-109	1295

In summary, whereas the results above illustrate the viability of Baynes and the circumstnces under which adding PV-solar is most valuable, the project also inherits other real options. In particular, if one overlooks that electricity prices are politically influenced and consider the price as mainly affected by the market, the expectation of price increase implies that the option to delay is one that also needs to be considered. This is illustrated for the 360 MW Base case for a situation where the probability (p) of a 20% price increase in year T + 1 after commissioning is considered 0.6. The option to delay the decision to invest then becomes:

NPV: MUSD 74, NPV electricity tariff increases: MUSD 148 * (p) + NPV electricity price decrease MUSD -5 * (1-p) = MUSD 84. Discounting by the cost of equity (13.9%) to year T 0 yields MUSD 76.3. The option to delay the investment by one year in anticipation of a higher tariff is worth MUSD 2.3. The larger difference in price expectations the more the option to delay is worth. This leads to discussion of the financing assumptions.

4.2 Implication of Financial Assumptions

The key to successful financial engineering of hydropower projects, is balancing the interests of the host country, the investor and the bankers. In particular, close attention should be devoted to the objective of the government to maximise benefits to society while at the same time allowing financial terms that can be attractive to private investors.

The fiscal regime of the project has to reflect this, should allow for a fast payback of loans and equity, and the investor should be allowed a share of the resource rent as incentive. The latter implies that the justification for a sufficiently high return on equity is acknowledged in order to cover the specific risks of private hydropower compared to other private investment alternatives.

From a financial point of view, a project value of NPV USD 263M at base scenario is satisfying. An IRR at 14,2% and a NPV for equity holders at 74M is also satisfying.

The total financing requirement of Baynes is USD 959 million or AOA 159 098 million.

This includes civil works, steel works and electrical, transmission line costs, environmental mitigation, engineering supervision, contingencies, interest during construction and financing costs.

As long as Baynes is able to raise equity capital of USD 288, which can be invested mainly from year 2021-2025, the capital needed for construction should be met. The accuracy of commercial operation date will of course play an essential role in meeting loan obligations. For equity holders a two year delay, will cause a drop of NPV from USD 74M to -4M. Meaning, at base case, the importance of construction delays is high, but manageable within a period of 48 months. We underline that NPV would be at USD 167 even with a 48 month delay, which gives Baynes room for dividend manoeuvring if equity holders should not be satisfied.

EBITA is expected at USD 138M first year of commercial operation. With USD 148M in equity, debt and interest payment, in addition to change in working capital – a Free Cash to Equity of USD -23M is expected in 2024. EBITA growing to USD 140M following year, and with equity payment reduction, a positive FCF is expected from 2025 (USD 8M).

For capital structure, the assumption of 30% equity was made. If this requirement is not met, Baynes could still be feasible. A 20% equity share would probably imply debt raising problems, but for the financial value of Baynes it would mean a NPV increase of USD 14M. However, for equity holders, it would mean drop from NPV USD 74 to USD 35M. We expect Bayne´s projected NPV benefit from this debt increase to be founded in value of the tax shield of increased debt.

With Baynes in operation, the debt service coverage is 1,89 in year 2024 which is well above initial requirement of 1,4. USD 133M in “cash available for debt service” is acceptable, against debt service requirements of USD 70M. The cash needed for debt service is at a peak in 2026, with USD 101M needed. However a 4,5% cash available increase keeps the DSCR at 1,4x. By 2024 the DSCR has reached 2,11 and keep increasing to 10,13x at end of debt period (2045).

Accordingly, Banyes generate sufficient revenues during the first years of production to comfortably cover interest and repayments.

As long as Baynes avoid a liquidity squeeze during construction period its viability should be satisfactory. According to Cash Flow Statement, equity holder could receive dividend payments of USD 47M from year 2024. For year 2025 however dividends are zero, due to higher repayment obligations. This is a short “dividend intermission" however. In 2026 equity holder should receive USD 40M, an amount projected to increase to USD 76M by 2035.

To estimate Bayne´s vulnerability for macro-economic changes is a demanding exercise. Avoiding currency risk will be of great importance, and the decision to hedge part of the USD loan is advised (see currency and exchange rate chapter).

The government take is estimated to AOA 1,426M (USD 8,1M) in 2024. Dropping to less than half in 2025/26 the tax income contributes to a steady tax increase in 2027 from AOA 2,158M (USD 11,9M) to AOA 18 807M (USD 85,8M) in 2057 – an annual increase of 20,7% tax income for the Angola and Namibia government (nominal numbers). Due to already mentioned significant inflation volatility, these numbers are estimations only, and looking 30 years ahead is challenging given the risk environment.

Free Cash Flow to Firm is negative through the 7 first years. In year 8 (2025) a USD 32M positive free cash flow is expected at a discount factor of 0,48 (WACC 9,5%). FCF is then expected to increase to USD 139M in 2025 and keep between USD 130M-150M for the following 10 years.

4.3 Concluding Remarks

The project report provides an overview of the power sector in Angola and Namibia and rationale for pursuing development of the Baynes Hydropower Plant. Using the latter as an example to illustrate among other aspects the potential synergy for developing in tandem a 50 MW floating PV-Solar plant on top the reservoir, the analyses illustrates that the value of the stored solar power in the form of avoided water discharge requires storage and is highest for lower installed capacity at lower construction cost.

Expectations of higher volatility in electricity prices driven in part by greater hydrological variability illustrates the importance of diversification in the power system.

Results of analysis show that key ratios are above financial desired limits for initiating a profitable project, both for involved governments as well as equity holders. Given the reliability of financial assumptions (p 31) the risk mitigation capacity remains as the most vulnerable factor.

In contrast to Angola, where electricity sector is in the process of adapting to increase tariffs and performance standards toward financial sustainability, Nambia´s power sector is more mature, is financially stable with electricity prices that albeit a slight loss in 2016 largely reflect the actual cost of service. Bridging the widely different political risk environments is a main challenge for securing financing at competitive rates.

In the this study currency risk has been hedged, and to some extent passed on to governments and consumers. Others risks, like political and macro-economic, remains but has been included in cost of capital calculations. These risks have increased expected cost of capital, but no more than to a level where internal rate requirements still can be met.

The importance of a healthy capital structure is a critical factor for Baynes. Even if a tax-shield benefit would increase NPV at higher debt-ratio than the proposed 70%, it is crucial for Baynes to raise enough equity. If not, we doubt the project´s ability to raise sufficient debt capital. The necessary World Bank backed loan depends on Baynes ability to show economic and financial credibility in a risk volatile environment. Angola-Namibia government cooperation is the main factor in gaining this credibility.

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Appendix A: Valuation Results

	360MW	410 MW	600 MW	650 MW
Project cost	**MUSD**	**MUSD**	**MUSD**	**MUSD**
Land	0	0	0	0
Civil works	401	401	595	595
Mechanical, Hydraulic steel works & electrical	128	128	190	190
Transmission line	139	139	207	207
Environmental mitigation	13	13	20	20
Owner's cost, Engineering and construction supervision	67	67	99	99
VAT	0	57	0	57
Contingencies	60	60	90	90
PV 50 MW		57		57
Total Project cost before inflation and financing costs	**808**	**864**	**1 200**	**1 257**
Financing fees, IDC and inflation	151	161	224	234
Total project cost	**959**	**1 026**	**1 424**	**1 491**

Financing	**MUSD**	**MUSD**	**MUSD**	**MUSD**
Debt	671	718	997	1 044
Equity	288	308	427	447
Total	**959**	**1 026**	**1 424**	**1 491**

Base 360 MW

	FIRR	**FIRREQ**	**Equity NPV**
Base Case	14,2 %	18,7 %	74

Base 360 MW + PV 50 MW

Base Case	14,6 %	19,7 %	95

Revised 600 MW

Base Case	12,4 %	14,3 %	9

Revised + PV 50 MW

Base Case	12,8 %	15,3 %	35

PV-Cost (MUSD)		56,5		113		169,5
	FIRREQ	NPV	FIRREQ	NPV	FIRREQ	NPV
Scenario						
Base (360MW)	18,7 %	74				
Base + PV (50 MW)	19,7 %	95	18,2 %	75	16,8 %	53
Revised (600 MW)	14,3 %	9				
Revised + PV (50MW)	15,3 %	35	14,4 %	12	13,5 %	-12

	360 MW			410 MW			600 MW			650 MW		
Economic Sensitivities - Construction Cost	**EIRR**	**Ec. NPV**	**Economic Unit cost**	**EIRR**	**Ec. NPV**	**Econom ic**	**EIRR**	**Ec. NPV**	**Econom ic**	**EIRR**	**Ec. NPV**	**Econom ic**
Construction cost -20 %	20,1 %	504	5,83	20,8 %	580	5,85	17,0 %	501	7,75	17,7 %	584	7,66
Construction cost -10 %	18,2 %	447	6,55	18,8 %	520	6,58	15,3 %	417	8,72	16,0 %	497	8,62
Base Case	16,5 %	391	7,28	17,1 %	460	7,31	13,9 %	334	9,68	14,5 %	410	9,58
Construction cost 10 %	15,2 %	335	8,01	15,7 %	400	8,04	12,7 %	251	10,65	13,3 %	322	10,53
Construction cost 20 %	14,0 %	279	8,74	14,5 %	340	8,77	11,7 %	167	11,62	12,2 %	235	11,49
Construction cost 30 %	13,0 %	223	9,47	13,5 %	280	9,50	10,8 %	84	12,59	11,3 %	148	12,45
Construction cost 40 %	12,1 %	166	10,19	12,6 %	220	10,23	10,0 %	0	13,56	10,5 %	60	13,41

	360 MW		410 MW		600 MW		650 MW	
Economic Sensitivities - Tariff	**EIRR**	**Ec. NPV**	**EIRR**	**Ec. NPV**	**EIRR**	**Ec. NPV**	**EIRR**	**Ec. NPV**
Tariff -30 %	11,9 %	105	12,4 %	142	9,8 %	-17	10,3 %	25
Tariff -20 %	13,5 %	201	14,0 %	248	11,2 %	100	11,8 %	153
Tariff -10 %	15,0 %	296	15,6 %	354	12,6 %	217	13,2 %	281
Base Case	16,5 %	391	17,1 %	460	13,9 %	334	14,5 %	410
Tariff 10 %	18,0 %	487	18,6 %	566	15,2 %	451	15,8 %	538
Tariff 20 %	19,4 %	582	20,1 %	673	16,4 %	568	17,1 %	666
Tariff 30 %	20,8 %	677	21,5 %	779	17,6 %	685	18,4 %	795

	360 MW			410 MW			600 MW			650 MW		
Financial Sensitivities - Construction Cost	**FIRR**	**FIRREQ**	**Equity NPV (MUSD)**	**FIRR**	**FIRREQ**	**Equity NPV (MUSD)**	**FIRR**	**FIRREQ**	**Equity NPV (MUSD)**	**FIRR**	**FIRREQ**	**Equity NPV (MUSD)**
Construction cost -20 %	16,7 %	24,8 %	133	17,2 %	26,1 %	159	14,5 %	19,5 %	101	15,0 %	20,7 %	129
Construction cost -10 %	15,3 %	21,4 %	103	15,8 %	22,5 %	127	13,4 %	16,7 %	57	13,9 %	17,8 %	84
Base Case	14,2 %	18,7 %	74	14,6 %	19,7 %	95	12,4 %	14,3 %	9	12,8 %	15,3 %	35
Construction cost 10 %	13,3 %	16,5 %	43	13,7 %	17,4 %	63	11,4 %	12,3 %	-42	11,9 %	13,3 %	-17
Construction cost 20 %	12,5 %	14,5 %	11	12,8 %	15,4 %	30	10,5 %	10,5 %	-99	11,0 %	11,5 %	-73
Construction cost 30 %	11,7 %	12,8 %	-23	12,1 %	13,6 %	-6	9,6 %	9,0 %	-157	10,1 %	9,9 %	-134
Construction cost 40 %	10,9 %	11,3 %	-60	11,3 %	12,1 %	-43	8,9 %	7,8 %	-213	9,3 %	8,6 %	-194

	360 MW			410 MW			600 MW			650 MW		
Financial Sensitivities - Tariff	**FIRR**	**FIRREQ**	**Equity NPV (MUSD)**	**FIRR**	**FIRREQ**	**Equity NPV (MUSD)**	**FIRR**	**FIRREQ**	**Equity NPV (MUSD)**	**FIRR**	**FIRREQ**	**Equity NPV (MUSD)**
Tariff -30 %	10,6 %	10,9 %	-49	11,1 %	11,7 %	-38	8,7 %	7,5 %	-161	9,2 %	8,3 %	-147
Tariff -20 %	12,0 %	13,6 %	-5	12,4 %	14,5 %	9	10,0 %	9,7 %	-102	10,5 %	10,7 %	-83
Tariff -10 %	13,2 %	16,2 %	36	13,6 %	17,2 %	53	11,3 %	12,1 %	-43	11,8 %	13,0 %	-21
Base Case	14,2 %	18,7 %	74	14,6 %	19,7 %	95	12,4 %	14,3 %	9	12,8 %	15,3 %	35
Tariff 10 %	15,2 %	21,1 %	111	15,7 %	22,3 %	136	13,3 %	16,4 %	58	13,8 %	17,6 %	87
Tariff 20 %	16,2 %	23,6 %	148	16,7 %	24,8 %	178	14,1 %	18,5 %	105	14,6 %	19,6 %	136
Tariff 30 %	17,2 %	26,0 %	186	17,7 %	27,3 %	220	15,0 %	20,5 %	149	15,5 %	21,8 %	187

	360 MW			410 MW			600 MW			650 MW		
Financial Sensitivities - Interest rate	**FIRR**	**FIRREQ**	**Equity NPV (MUSD)**	**FIRR**	**FIRREQ**	**Equity NPV (MUSD)**	**FIRR**	**FIRREQ**	**Equity NPV (MUSD)**	**FIRR**	**FIRREQ**	**Equity NPV (MUSD)**
Interest rate -2 %	13,9 %	20,5 %	96	14,4 %	21,6 %	119	12,1 %	16,0 %	45	12,5 %	17,0 %	70
Interest rate -1 %	14,1 %	19,6 %	84	14,5 %	20,6 %	107	12,2 %	15,1 %	28	12,7 %	16,2 %	54
Base Case	14,2 %	18,7 %	74	14,6 %	19,7 %	95	12,4 %	14,3 %	9	12,8 %	15,3 %	35
Interest rate 1 %	14,4 %	17,9 %	63	14,8 %	18,9 %	83	12,5 %	13,4 %	-11	13,0 %	14,5 %	14
Interest rate 2 %	14,6 %	17,0 %	51	15,0 %	18,0 %	71	12,6 %	12,7 %	-31	13,1 %	13,6 %	-7
Interest rate 3 %	14,8 %	16,1 %	37	15,2 %	17,1 %	57	12,7 %	11,8 %	-55	13,2 %	12,9 %	-28
Interest rate 4 %	14,9 %	15,3 %	24	15,4 %	16,2 %	43	12,7 %	11,0 %	-80	13,3 %	12,0 %	-53
Interest rate 5 %	15,1 %	14,4 %	10	15,5 %	15,4 %	28	12,7 %	10,2 %	-106	13,3 %	11,2 %	-80

Appendix B: Financial Model

	IRR	Spread over HR	NPV		Price Scenario	Base	
Project	14,2 %	5,1 %	298		Price Scenario	Base	
Equity Holder	18,7 %	4,8 %	74		Sale to	Both 50/50	
Economic	16,5 %	6,5 %	391		Methodology	Financial	1
Economic Unit cost		7,28					

2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030

0. Project and Macro Assumptions

a. Project

Name	Analyst	Baynes
Type	Analyst	Greenfield
Location	Analyst	ıgola-Namibia

b. Dates

Intial construction		
Initial construction (date)	Analyst	01/01/2018
Initial Month		1
Initial year		2 018

COD		
Construction period (months)	Analyst	72
COD		01/01/2024
COD Month		1
COD Year		2 024

Ending Date			Financial	Economic
Concesion (years)	Analyst	40	34	40
Ending Operational date		31/12/2057		
Ending month		12		
Ending Year		2 057		

c. Macro Assumptions

CPI		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
CPI USD	Analyst		2,1 %	2,1 %	2,1 %	2,1 %	2,1 %	2,1 %	2,1 %	2,1 %	2,1 %	2,1 %	2,1 %	2,1 %
CPI USD used			2,1 %	2,1 %	2,1 %	2,1 %	2,1 %	2,1 %	2,1 %	2,1 %	2,1 %	2,1 %	2,1 %	2,1 %
Cummulv. (%)		100 %	102 %	104 %	106 %	109 %	111 %	113 %	116 %	118 %	121 %	123 %	126 %	128 %
CPI Angola	Analyst		14,5 %	14,3 %	14,2 %	14,0 %	13,9 %	13,7 %	13,6 %	13,5 %	13,3 %	13,2 %	13,1 %	12,9 %
CPI Angola used			14,5 %	14,3 %	14,2 %	14,0 %	13,9 %	13,7 %	13,6 %	13,5 %	13,3 %	13,2 %	13,1 %	12,9 %
Cummulv. (%)		100 %	114 %	131 %	149 %	170 %	194 %	221 %	251 %	284 %	322 %	365 %	412 %	466 %
CPI Namibia	Analyst		6,5 %	6,5 %	6,5 %	6,5 %	6,5 %	6,5 %	6,5 %	6,5 %	6,5 %	6,5 %	6,5 %	6,5 %
CPI Namibia used			6,5 %	6,5 %	6,5 %	6,5 %	6,5 %	6,5 %	6,5 %	6,5 %	6,5 %	6,5 %	6,5 %	6,5 %
Cummulv. (%)		100 %	107 %	113 %	121 %	129 %	137 %	146 %	155 %	165 %	176 %	188 %	200 %	213 %
Weighted Index	100% USD and 0% L	100 %	102 %	104 %	106 %	109 %	111 %	113 %	116 %	118 %	121 %	123 %	126 %	128 %

Exchange Rate														
AOA vs. USD (year average value)	Analyst	165,9	167,6	169,2	170,9	172,6	174,4	176,1	177,9	179,6	181,4	183,3	185,1	186,9
NAD vs. USD (year average value)	Analyst	13,5	13,5	13,5	13,5	13,5	13,5	13,5	13,5	13,5	13,5	13,5	13,5	13,5
AOA vs. NAD		12,29	12,41	12,54	12,66	12,79	12,92	13,04	13,18	13,31	13,44	13,57	13,71	13,85
NAD vs. AOA		0,08	0,08	0,08	0,08	0,08	0,08	0,08	0,08	0,08	0,07	0,07	0,07	0,07

Interest rates														
Libor	Analyst	1,1 %	1,6 %	1,9 %	2,6 %	2,6 %	2,6 %	2,6 %	2,6 %	2,6 %	2,6 %	2,6 %	2,6 %	2,6 %
Hedge cost		1,0 %	1,0 %	1,0 %	1,0 %	1,0 %	1,0 %	1,0 %	1,0 %	1,0 %	1,0 %	1,0 %	1,0 %	1,0 %
Base rate		2,1 %	2,6 %	2,9 %	3,6 %	3,6 %	3,6 %	3,6 %	3,6 %	3,6 %	3,6 %	3,6 %	3,6 %	3,6 %

1. Revenues Assumptions

a. Production

1) Plant	2) Plants (2*3(	3) Base+PV-sol	4) Revised + PV-solar
Base Case	Revised		
360 MW wo/G	600 MW	360+50 MW	600+50 MW
1440 GWh	2500 GWh		

Capacity (MW)	Analyst	360	360	

Adjust distribution in 1.b Monthly generation to match project (600 or 360 MW wo/PV or 410 c

Gross Production				
Peak (GWh) Dry Season	Analyst	105,6		
Peak (GWh) Wet Season	Analyst	280,9		
Peak (GWh)		387	27 %	
Off Peak (GWh) Dry Season	Analyst	303		
Off Peak (GWh) Wet Season	Analyst	752,0	73 %	
Off Peak (GWh)		1 055		
Total Production (GWh)		1 441		
Dry Season		408		
Wet Season		1 033		
Annual Gross Hours		4 002	GWh produced divided by installed capacity	
Plant load factor		45,7 %		

Net Losses		
Transformation losses	Analyst	1,00 %
Transmission Loses	Analyst	0,00 %
Internal consumption	Analyst	0,25 %
Total Losses		1,25 %

Energy Sold		Gross %	Real %
Free Power	Analyst	0,00 %	0 %
Long term PPAs	Analyst	0,00 %	0 %
Short Term PPAs	Analyst	0,00 %	0 %
Market	Analyst	100,00 %	100 %
		100 %	100 %

b. Prices

		Inflationary adjustment for number of	Last year of adjustment
Price Sensitivity All power	0 %	40	2 064
Price Sensitivity Spot market	0 %		

Dry (peak) season price (USc/kWh)														
Optimistic case	Analyst	12,00	12,3	12,5	12,8	13,0	13,3	13,6	13,9	14,2	14,5	14,8	15,1	15,4
Base case	Analyst	11,34	11,6	11,8	12,1	12,3	12,6	12,8	13,1	13,4	13,7	14,0	14,3	14,6
Pesimistic case	Analyst	6,0	6,1	6,3	6,4	6,5	6,7	6,8	6,9	7,1	7,2	7,4	7,5	7,7
Selected Price		11,3	11,6	11,8	12,1	12,3	12,6	12,8	13,1	13,4	13,7	14,0	14,3	14,6

Wet (off-peak) season price (USc/kWh)														
Optimistic case	Analyst	10,00	10,2	10,4	10,6	10,9	11,1	11,3	11,6	11,8	12,1	12,3	12,6	12,8
Base case	Analyst	8,18	8,4	8,5	8,7	8,9	9,1	9,3	9,5	9,7	9,9	10,1	10,3	10,5
Pesimistic case	Analyst	5,0	5,1	5,2	5,3	5,4	5,5	5,7	5,8	5,9	6,0	6,2	6,3	6,4
Selected Price		8,2	8,4	8,5	8,7	8,9	9,1	9,3	9,5	9,7	9,9	10,1	10,3	10,5
Weighted average tariff Merchant		9,0	9,2	9,4	9,6	9,8	10,0	10,2	10,4	10,7	10,9	11,1	11,4	11,6

2. Costs Assumptions

2.1. P&L Costs

Transmission Costs		
Transmision Cost (USc/kWh)	Analyst	0,00
CPI Escalation (%)	Analyst	0,0 %

O&M		
O&M cost (% of hard cost)	Analyst	0,5 %
CPI Escalation (%)	Analyst	100,0 %

Royalty Fees		Namibia (USD)	Angola (USD)	nibia (MNAD/M	gola (MAOA/M
Capacity fee 0-15 years (USD 1000 per MV	Analyst	2,96	0,12	0,04	0,02
Capacity fee after first 15 years (USD 100(	Analyst	13,33	11,11	0,18	0,15
Annual growth	Analyst	100,0 %	100,0 %		

G&A		
G&A cost (USD per GWh)	Analyst	0,00
CPI Escalation (%)	Analyst	100,0 %

		Namibia (%)	Angola (%)	
Production first 15 years (% of sales)	Analyst	7,5 %	2,0 %	15
Production after first 15 years (% of sales)	Analyst	12,0 %	10,0 %	2 039

Insurance		
Insurance (% Capex)	Analyst	0,5 %

2.2. DCF Costs

Transaction costs
SP Holding Costs

3. Capex + Financing Assumptions

3.1. CAPEX

		USD Portion	100,0 %		
		Local Portion	0,0 %		
CAPEX Disclosure (mn. INR)		Cost overrun	0,0 %		
Land	Analyst	0	0	Total capex incl Fin costs and	959
Civil works	Analyst	401	401		
Mechanical, Hydraulic steel works & elect	Analyst	128	128	Include Transmission? ☑	
Transmission line	Analyst	139	139	TRUE	
Environmental mitigation	Analyst	13	13		
Owner's cost, Engineering and constructic	Analyst	67	67		
VAT	Analyst	0	0		
Contingencies	Analyst	60	60		
Other 1	Analyst	0			
Other 2	Analyst	0			
Other 3	Analyst	0			
Total		**808**			

CAPEX Timeline									
Payment (%)	Analyst	0 %	0 %	7 %	13 %	16 %	27 %	26 %	11 %
Total		100 %							

Development costs (mn. INR)		
Hydroproject	Analyst	0
Transmission	Analyst	0
Total		**0**

Development costs timeline		2 018	2 019	2 020	2 021	2 022	2 023	2 024	2 025
Payment (%)	Analyst	40 %	50 %	10 %	0 %	0 %	0 %	0 %	0 %
Total		100 %							

3.2. Financial Structure

Capital Structure			
Debt	Analyst	70,0 %	Upside 65%-70%
Equity		30 %	
Total		100 %	
Debt to Equity		2,33	

Equity Structure		
Equity	Analyst	100,0 %
Quasi-equity		0 %
Total		100 %

Debt Structure	term	% of total debt	USD	f dom./foreign d
Government loan	20	30,0 %	201	48,4 %
Domestic market	10	16,0 %	107	25,8 %
IFC	20	16,0 %	107	25,8 %
ECAs	18	28,0 %	188	73,7 %
Inf str project bonds	10	10,0 %	67	26,3 %
Total		100 %	671	

Debt Description		Government lc	Domestic market	IFC	:p credit agenci	Inf str bonds
Spread pre COD	Analyst	7,3 %	13,7 %	2,8 %	8,6 %	7,0 %
Spread post COD	Analyst	7,3 %	13,7 %	2,8 %	8,6 %	7,0 %
Repayment Period	Analyst	20	10	20	18	10
Moratorium (post COD)	Analyst	1	0	0	0	0
Interest rate sensitivity	0,0 %					

Quasi Equity Description	
Interest on Quasi-Equity	Analyst
Coversion (QE to Ordinary)	Analyst
Proportion Converted	Analyst

3.3. General Project Finance Assumptions

Gemeral Assumptions		
Upfront Equity requirment	Analyst	No
Initial financing costs (%Capex)	Analyst	1,0 %

Refinance		
Refinance considered	Analyst	No
Considered year	Analyst	14
Interest rate diferential	Analyst	0,5 %

Debt Service Coverage Ratio (DSCR). Debt Service Reserve (DSR)		
Apply min DSCR for Dividend	Analyst	Yes
Minimum DSCR Requirement	Analyst	1,40
Apply DSR	Analyst	No
% of current year debt service	Analyst	40,0 %
Return on DSR and other cash	Analyst	2,0 %

4. Depreciation + Taxes Assumptions

4.1. Depreciation

Accounting depreciation (SLM)		
Number of years	Analyst	40

Fiscal Depreciation (SLM or WDVM)		
Method Choosen	Analyst	WDVM
Number of years (SLM)	Analyst	35
Depreciation rate (WDVM)	Analyst	9,4 %

4.2. Taxes

Tax Rate		
Efective tax rate (%) (including profit shari	Analyst	31,0 %
Dividend distribution tax (%)	Analyst	0,0 %

Tax Holidays		
Tax holiday applicable	Analyst	No
Tax holiday starts (years after	Analyst	0
Tax holiday is applicable for (y	Analyst	0

Carry Forward of Losses		
Carry forward applicable	Analyst	Yes
Years of carry forward	Analyst	7

5. Annual Accounts Assumptions

Working Capital		
Receivables (days of sales)	Analyst	40
Payables (days of COGS)	Analyst	30

Reserves Assumptions		
Total Legal Reserve (% of share capital)	Analyst	0 %
Legal Reserve Annual Allocation (% net in	Analyst	0 %

Minimal cash on Balance Sheet		
Minimal Cash (% of current year COGS)	Analyst	5 %

6. DCF Assumptions

6.1. WACC Assumptions

WACC Selection	Analyst	USD WACC				
Local WACC						
Local Risk Free Rate		9,51 %	"WACC data! 720	9,76 %	If Valuation s2!	5,00 %
Greenfield		0,0 %				
Market Risk Premium (Local)		10,46 %	Same as "equity risk premium" in Stern.			
Asset Beta (peers vs. local markets)		0,46	Same as unlevere Stern: emerging markets			
Equity Beta		1,20				
Cost of Equity		**22,1 %**				
					Calculation in separate word	
Tax Rate (local)		31,0 %			and excel sheet (wo/ libor)	
Cost of debt (local debt local currency)		11,09 %	If gov+dom+ifc:	8,89 %	8,49 %	
After Tax Cost of Debt		7,7 %				
D/(D+E)		70,0 %				
Weighted Average Cost of Capital		**11,98 %**				
USD WACC						
Risk Free Rate USD	Analyst	2,30 %	Valuation s 720. 10Y USD bond........???			
Country Risk Premium	Analyst	4,8 %	Country risk premium in USA or Angola/Namibia? 4,8 is mean A/Nam			
Market Risk Premium (US)	Analyst	5,7 %	equity risk premium. Stern			
Asset Beta (peers compared to S&P)	Analyst	0,46	Stern, emerging markets unlevered beta			
Equity Beta		1,20				
Cost of Equity		**13,9 %**				
					Calculation in separate word	
Tax Rate (local)		31,0 %			and excel sheet (wo/ libor)	
Cost of debt (USD)	Analyst	10,32 %	If LIBOR + ECA + If	9,28 %	7,72 %	
After Tax Cost of Debt		7,1 %				
D/(D+E)	Analyst	70,0 %				
Weighted Average Cost of Capital		**9,15 %**				

6.2. Terminal Value Assumptions

Probability of extending concession	Analyst	0,0 %
Perpetual growth	Analyst	0,0 %

Dry season production													
Gross Peak Generation (GWh)	0	0	0	0	0	0	408	408	408	408	408	408	408
Net Losses (GWh)	0	0	0	0	0	0	-5	-5	-5	-5	-5	-5	-5
Net Peak Generation (GWh)	0	0	0	0	0	0	403	403	403	403	403	403	403
Wet season production													
Gross Off-Peak generation (GWh)	0	0	0	0	0	0	1 033	1 033	1 033	1 033	1 033	1 033	1 033
Net Losses (GWh)	0	0	0	0	0	0	-13	-13	-13	-13	-13	-13	-13
Net Peak Generation (GWh)	0	0	0	0	0	0	1 020	1 020	1 020	1 020	1 020	1 020	1 020
Total Production	0	0	0	0	0	0	1 423	1 423	1 423	1 423	1 423	1 423	1 423
Sales Revenues													
Peak revenues													
Production	0	0	0	0	0	0	403	403	403	403	403	403	403
Price (USc/kWh)	11,3	11,6	11,8	12,1	12,3	12,6	12,8	13,1	13,4	13,7	14,0	14,3	14,6
Sales revenue	0,0	0,0	0,0	0,0	0,0	0,0	51,8	52,9	54,0	55,2	56,3	57,5	58,7
Off-peak revenues													
Production	0	0	0	0	0	0	1 020	1 020	1 020	1 020	1 020	1 020	1 020
Price (USc/kWh)	8,2	8,4	8,5	8,7	8,9	9,1	9,3	9,5	9,7	9,9	10,1	10,3	10,5
Sales revenue	0,0	0,0	0,0	0,0	0,0	0,0	94,5	96,5	98,5	100,6	102,7	104,9	107,1

1. P&L Related Costs (MUSD)

1.1. Transmission costs													
Production weeled	0	0	0	0	0	0	1 427	1 427	1 427	1 427	1 427	1 427	1 427
Transmision cost (USc/kwh)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Transmission cost	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**
1.2. Royalty Fees													
Royalty on capacity	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Capacity	0	0	0	0	0	0	360	360	360	360	360	360	360
Royalty per MW	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000
Royalty on capacity	**0,000**	**0,000**	**0,000**	**0,000**	**0,000**	**0,000**	**0,000**	**0,000**	**0,000**	**0,000**	**0,000**	**0,000**	**0,000**
Royalty on sales													
Sales	0	0	0	0	0	0	146	149	153	156	159	162	166
Royalty percent of sales	0,0 %	0,0 %	0,0 %	0,0 %	0,0 %	0,0 %	0,0 %	0,0 %	0,0 %	0,0 %	0,0 %	0,0 %	0,0 %
Royalty on sales	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**
1.3. O&M													
Operating activity	0 %	0 %	0 %	0 %	0 %	0 %	100 %	100 %	100 %	100 %	100 %	100 %	100 %
O&M cost % of hard cost	0,5 %	0,5 %	0,5 %	0,5 %	0,5 %	0,5 %	0,5 %	0,5 %	0,5 %	0,5 %	0,5 %	0,5 %	0,5 %
Hard cost inflationary adjusted	808	825	842	860	878	896	915	934	954	974	995	1 015	1 037
O&M cost	**0,00**	**0,00**	**0,00**	**0,00**	**0,00**	**0,00**	**-4,58**	**-4,67**	**-4,77**	**-4,87**	**-4,97**	**-5,08**	**-5,18**
1.4. G&A													
GWh	0	0	0	0	0	0	1 427	1 427	1 427	1 427	1 427	1 427	1 427
G&A cost (USD/GWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
G&A Cost	**0,00**	**0,00**	**0,00**	**0,00**	**0,00**	**0,00**	**0,00**	**0,00**	**0,00**	**0,00**	**0,00**	**0,00**	**0,00**
1.5. Insurance													
Insurance (% of Capex)	0,5 %	0,5 %	0,5 %	0,5 %	0,5 %	0,5 %	0,5 %	0,5 %	0,5 %	0,5 %	0,5 %	0,5 %	0,5 %
Capacity activity	0 %	0 %	0 %	0 %	0 %	0 %	100 %	100 %	100 %	100 %	100 %	100 %	100 %
Insurance cost	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**-4,2**	**-4,6**	**-4,5**	**-4,3**	**-4,2**	**-4,1**	**-4,0**

	2018	2019	2020	2021	2022	2023	2024	2025	2026

1. CAPEX (MUSD)

	2018	2019	2020	2021	2022	2023	2024	2025	2026
Capex bugdet	807,9								
Capex schedule (%)	0 %	0 %	7 %	13 %	16 %	27 %	26 %	11 %	0 %
Civil works	0,0	1,7	27,3	52,4	69,0	117,9	114,3	51,8	0,0
Mechanical, Hydraulic steel works & electrical	0,0	0,5	8,7	16,7	22,0	37,6	36,4	16,5	0,0
Transmission line	0,0	0,6	9,5	18,2	24,0	40,9	39,7	18,0	0,0
Environmental mitigation	0,0	0,1	0,9	1,7	2,3	3,9	3,8	1,7	0,0
Owner's cost, Engineering and construction supervision	0,0	0,3	4,6	8,7	11,5	19,6	19,0	8,6	0,0
VAT	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Contingencies	0,0	0,2	4,1	7,9	10,4	17,7	17,2	7,8	0,0
Other 1	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Other 2	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Other 3	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Annual capex (gross)	**0,0**	**3,3**	**55,1**	**105,6**	**139,1**	**237,6**	**230,4**	**104,5**	**0,0**
Interest During Construction	0,3	0,8	3,0	9,6	19,7	35,6	4,4	0,0	0,0
Financing Costs	9,6	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Funding required	**9,9**	**4,1**	**58,1**	**115,1**	**158,8**	**273,2**	**234,8**	**104,5**	**0,0**

2. DEBT

	2018	2019	2020	2021	2022	2023	2024	2025	2026
Financing period	100 %	100 %	100 %	100 %	100 %	100 %	100 %	100 %	100 %

Financing	MUSD
Debt	671
Equity	288

Fund disposal schedule	2018	2019	2020	2021	2022	2023	2024	2025	2026
Equity opening balance	0,0	3,0	4,2	21,6	56,2	103,8	185,8	256,2	287,6
Upfront equity	3,0	1,2	17,4	34,5	47,6	82,0	70,5	31,4	0,0
Debt opening balance	0,0	6,9	9,8	50,5	131,1	242,2	433,5	597,9	671,0
Debt to complete funding requirements	6,9	2,9	40,6	80,6	111,2	191,3	164,4	73,2	0,0

	Opening balance	0	2	3	15	39	73	130	179	192
	Drawdown debt	2	1	12	24	33	57	49	22	0
	Repayment	0	0	0	0	0	0	0	-9	-10
	Refinance repayment	0	0	0	0	0	0	0	0	0
	Closing balance	2	3	15	39	73	130	179	192	183
	Rete pre COD	8,4 %	8,9 %	9,2 %	9,9 %	9,9 %	9,9 %	9,9 %	9,9 %	9,9 %
	Rate after COD	8,4 %	8,9 %	9,2 %	9,9 %	9,9 %	9,9 %	9,9 %	9,9 %	9,9 %
	Rate after refinance	7,9 %	8,4 %	8,7 %	9,4 %	9,4 %	9,4 %	9,4 %	9,4 %	9,4 %
	Interest during construction	0	0	-1	-3	-6	-10	-1	0	0
	Interest initial debt	0	0	0	0	0	0	-14	-18	-19
	Interest refinance	0	0	0	0	0	0	0	0	0
b	Domestic markets									
	Opening balance	0	1	2	8	21	39	69	89	92
	Drawdown debt	1	0	7	13	18	31	26	12	0
	Repayment	0	0	0	0	0	0	-7	-9	-9
	Refinance repayment	0	0	0	0	0	0	0	0	0
	Closing balance	1	2	8	21	39	69	89	92	82
	Rete pre COD	14,8 %	15,3 %	15,6 %	16,3 %	16,3 %	16,3 %	16,3 %	16,3 %	16,3 %
	Rate after COD	14,8 %	15,3 %	15,6 %	16,3 %	16,3 %	16,3 %	16,3 %	16,3 %	16,3 %
	Rate after refinance	14,3 %	14,8 %	15,1 %	15,8 %	15,8 %	15,8 %	15,8 %	15,8 %	15,8 %
	Interest during construction	0	0	-1	-2	-5	-9	-1	0	0
	Interest initial debt	0	0	0	0	0	0	-12	-15	-14
	Interest refinance	0	0	0	0	0	0	0	0	0
c	International Finance Corporation - The World Bank									
	Opening balance	0	1	2	8	21	39	69	92	99
	Drawdown debt	1	0	7	13	18	31	26	12	0
	Repayment	0	0	0	0	0	0	-3	-5	-5
	Refinance repayment	0	0	0	0	0	0	0	0	0
	Closing balance	1	2	8	21	39	69	92	99	94
	Rete pre COD	3,9 %	4,4 %	4,7 %	5,4 %	5,4 %	5,4 %	5,4 %	5,4 %	5,4 %
	Rate after COD	3,9 %	4,4 %	4,7 %	5,4 %	5,4 %	5,4 %	5,4 %	5,4 %	5,4 %
	Rate after refinance	3,4 %	3,9 %	4,2 %	4,9 %	4,9 %	4,9 %	4,9 %	4,9 %	4,9 %
	Interest during construction	0	0	0	-1	-2	-3	0	0	0
	Interest initial debt	0	0	0	0	0	0	-4	-5	-5
	Interest refinance	0	0	0	0	0	0	0	0	0
d	Export credit agencies (ECA)									
	Opening balance	0	2	3	14	37	68	121	161	172
	Drawdown debt	2	1	11	23	31	54	46	20	0
	Repayment	0	0	0	0	0	0	-7	-9	-10
	Refinance repayment	0	0	0	0	0	0	0	0	0
	Closing balance	2	3	14	37	68	121	161	172	163
	Rete pre COD	9,7 %	10,2 %	10,5 %	11,2 %	11,2 %	11,2 %	11,2 %	11,2 %	11,2 %
	Rate after COD	9,7 %	10,2 %	10,5 %	11,2 %	11,2 %	11,2 %	11,2 %	11,2 %	11,2 %
	Rate after refinance	9,2 %	9,7 %	10,0 %	10,7 %	10,7 %	10,7 %	10,7 %	10,7 %	10,7 %
	Interest during construction	0	0	-1	-3	-6	-11	-1	0	0
	Interest initial debt	0	0	0	0	0	0	-14	-19	-19
	Interest refinance	0	0	0	0	0	0	0	0	0
e	Infrastructure project bonds									
	Opening balance	0	1	1	5	13	24	43	55	57
	Drawdown debt	1	0	4	8	11	19	16	7	0
	Repayment	0	0	0	0	0	0	-4	-6	-6
	Refinance repayment	0	0	0	0	0	0	0	0	0
	Closing balance	1	1	5	13	24	43	55	57	52
	Rete pre COD	8,1 %	8,6 %	8,9 %	9,6 %	9,6 %	9,6 %	9,6 %	9,6 %	9,6 %
	Rate after COD	8,1 %	8,6 %	8,9 %	9,6 %	9,6 %	9,6 %	9,6 %	9,6 %	9,6 %
	Rate after refinance	7,6 %	8,1 %	8,4 %	9,1 %	9,1 %	9,1 %	9,1 %	9,1 %	9,1 %
	Interest during construction	0	0	0	-1	-2	-3	0	0	0
	Interest initial debt	0	0	0	0	0	0	-4	-5	-5
	Interest refinance	0	0	0	0	0	0	0	0	0
	TOTAL DEBT									
	Opening balance	0	7	10	50	131	242	433	576	613
	Drawdown debt	7	3	41	81	111	191	164	73	0
	Repayment	0	0	0	0	0	0	-21	-37	-39
	Refinance repayment	0	0	0	0	0	0	0	0	0
	Closing balance	7	10	50	131	242	433	576	613	574

Interest refinance	0	0	0	0	0	0	0	0	0

3 EQUITY

Equity Disclosure	
Equity	288
Quasi-Equity	0

Quasi Equity									
Before Converting									
Opening Balance	0	0	0	0	0	0	0	0	0
Drawdown	0	0	0	0	0	0	0	0	0
Conversion to Ordinary Shares	0	0	0	0	0	0	0	0	0
Closing Balance	0	0	0	0	0	0	0	0	0
Interest for the FY	0	0	0	0	0	0	0	0	0
Interest befor financing	0	0	0	0	0	0	0	0	0
Interest after financing	0	0	0	0	0	0	0	0	0
Converted to Ordinary Shares									
Opening Balance	0	0	0	0	0	0	0	0	0
Conversion Pref to Ordinary	0	0	0	0	0	0	0	0	0
Closing Balance	0	0	0	0	0	0	0	0	0

Ordinary Equity									
Opening Balance	0	3	4	22	56	104	186	256	288
Drawdown	3	1	17	35	48	82	70	31	0
Closing Balance	3	4	22	56	104	186	256	288	288

1. Depreciation

Accounting Depreciation (SLM)

Total Capex	10	4	58	115	159	273	235	105	0	0	0
Balance Sheet: GFA Work in Progress	10	4	58	115	159	273	0	0	0	0	0
Balance Sheet: GFA	0	0	0	0	0	0	854	959	959	959	959
Capex Additions	10	4	58	115	159	273	235	105	0	0	0
GFA	0	0	0	0	0	0	854	959	959	959	959
Opening Balance	0	0	0	0	0	0	0	835	915	891	867
Depreciation	0	0	0	0	0	0	-20	-24	-24	-24	-24
Cummulative Depr.	0	0	0	0	0	0	-20	-44	-68	-91	-115
Closing bablance	0	0	0	0	0	0	835	915	891	867	843

Fiscal Depreciation

Method selected WDVM

a. SLM											
Capex Additions	10	4	58	115	159	273	235	105	0	0	0
GFA	0	0	0	0	0	0	854	959	959	959	959
Opening Balance	0	0	0	0	0	0	0	832	909	881	854
Depreciation	0	0	0	0	0	0	-22	-27	-27	-27	-27
Cummulative Depr.	0	0	0	0	0	0	-22	-50	-77	-105	-132
Closing bablance	0	0	0	0	0	0	832	909	881	854	827
b. WDVM											
Capex Additions	10	4	58	115	159	273	235	105	0	0	0
GFA	0	0	0	0	0	0	854	959	959	959	959
Opening Balance	0	0	0	0	0	0	0	780	812	735	666
Depreciation							-74	-73	-76	-69	-63
Cummulative Depr.	0	0	0	0	0	0	-74	-147	-223	-292	-355
Closing bablance	0	0	0	0	0	0	780	812	735	666	604
c. Selected Method											
GFA	0	0	0	0	0	0	854	959	959	959	959
Opening Balance	0	0	0	0	0	0	0	780	812	735	666
Depreciation	0	0	0	0	0	0	-74	-73	-76	-69	-63
Cummulative Depr.	0	0	0	0	0	0	-74	-147	-223	-292	-355
Closing bablance	0	0	0	0	0	0	780	812	735	666	604

Accounting taxes (P&L and CF)										
Tax Holiday	0	0	0	0	0	0	1	1	1	1
Tax rate	0 %	0 %	0 %	0 %	0 %	0 %	31 %	31 %	31 %	31 %
Adjusted EBT										
EBT	0	0	0	0	0	0	69	54	58	66
Accounting depreciation (add)	0	0	0	0	0	0	-20	-24	-24	-24
Tax depreciation (less)	0	0	0	0	0	0	-74	-73	-76	-69
Adjusted EBT	0	0	0	0	0	0	15	5	6	21
Losses carried forward										
Opening Balance Loss	0	0	0	0	0	0	0	0	0	0
Additional loss carry forward	0	0	0	0	0	0	0	0	0	0
Losses available to deduct	0	0	0	0	0	0	0	0	0	0
Loss utilized	0	0	0	0	0	0	0	0	0	0
Subtotal pre-expiring losses	0	0	0	0	0	0	0	0	0	0
Losses expiring timeline	0	0	0	0	0	0	0	0	0	0
Losses already used	0	0	0	0	0	0	0	0	0	0
Losses lost	0	0	0	0	0	0	0	0	0	0
Closing balance Loss	0	0	0	0	0	0	0	0	0	0
Taxes										
Taxable income	0	0	0	0	0	0	15	5	6	21
Tax Payable	0	0	0	0	0	0	-5	-2	-2	-6
Income tax	0	0	0	0	0	0	-21	-17	-18	-20
Deferred Tax	0	0	0	0	0	0	17	15	16	14

DCF (FCFF)										
EBIT	0	0	0	0	0	0	118	116	119	123
Efective tax rate	0 %	0 %	0 %	0 %	0 %	0 %	-7 %	-3 %	-3 %	-10 %
Tax Expense	0	0	0	0	0	0	-8	-3	-4	-12

1. Profit & Loss

Sales revenues	0,0	0,0	0,0	0,0	0,0	0,0	146,3	149,4	152,5
CDM Revenues	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Total revenues	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**146,3**	**149,4**	**152,5**
Transmission cost	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Royalty on capacity	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Royalty on sales	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
O&M	0,0	0,0	0,0	0,0	0,0	0,0	-4,6	-4,7	-4,8
G&A	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Insurance	0,0	0,0	0,0	0,0	0,0	0,0	-4,2	-4,6	-4,5
Total Operating Costs	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**-8,7**	**-9,2**	**-9,2**
EBITDA	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**137,6**	**140,2**	**143,3**
margin	*0 %*	*0 %*	*0 %*	*0 %*	*0 %*	*0 %*	*94 %*	*94 %*	*94 %*
Amortization	0	0	0	0	0	0	-20	-24	-24
EBIT	**0**	**0**	**0**	**0**	**0**	**0**	**118**	**116**	**119**
margin	*0 %*	*0 %*	*0 %*	*0 %*	*0 %*	*0 %*	*81 %*	*78 %*	*78 %*
Interest expense	0	0	0	0	0	0	-49	-62	-62
Interest Income	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,4	0,8
EBT	**0**	**0**	**0**	**0**	**0**	**0**	**69**	**54**	**58**
margin	*0 %*	*0 %*	*0 %*	*0 %*	*0 %*	*0 %*	*47 %*	*36 %*	*38 %*
Taxes	0	0	0	0	0	0	-21	-17	-18
Net Income	**0**	**0**	**0**	**0**	**0**	**0**	**48**	**37**	**40**
margin	*0 %*	*0 %*	*0 %*	*0 %*	*0 %*	*0 %*	*33 %*	*25 %*	*26 %*

2. Balance Sheet

Assets									
WIP	10	14,03631	72	187	346	619	0	0	0
Gross Fixed Assets	0	0	0	0	0	0	854	959	959
Accum. Depreciation	0	0	0	0	0	0	-20	-44	-68
Net Tangible Assets	10	14	72	187	346	619	835	915	891
Net Intangible Assets	0	0	0	0	0	0	0	0	0
Total Fix Assets	**10**	**14**	**72**	**187**	**346**	**619**	**835**	**915**	**891**
Cash & equivalents		0	0	0	0	0	0	40	41
Accounts receivable	0	0	0	0	0	0	16	16	17
Debt Service Reserve	0	0	0	0	0	0	0	0	0
Total Current Assets	**0**	**0**	**0**	**0**	**0**	**0**	**16**	**56**	**57**
TOTAL ASSETS	**10**	**14**	**72**	**187**	**346**	**619**	**851**	**971**	**949**
Equity + Liabilities									
Accounts Payable	0	0	0	0	0	0	1	1	1
Current Portion Of Long Term Debt		0	0	0	0	21	37	39	39
Short Term liabilities	**0**	**0**	**0**	**0**	**0**	**21**	**38**	**40**	**40**
Debt	6	8	42	110	203	346	452	479	445
Subordinated debt	1	2	8	21	39	66	88	94	89
Deferred tax asset (liability)	0	0	0	0	0	0	17	32	48
Long term Liabilities	**7**	**10**	**50**	**131**	**242**	**412**	**556**	**606**	**583**
Ordinary Equity	3	4	22	56	104	186	256	288	288
Quasi Equity	0	0	0	0	0	0	0	0	0
General Reserves	0	0	0	0	0	0	1	38	38
Legal Reserve	0	0	0	0	0	0	0	0	0
Equity	**3**	**4**	**22**	**56**	**104**	**186**	**257**	**326**	**326**
TOTAL LIABILITIES	**10**	**14**	**72**	**187**	**346**	**619**	**851**	**971**	**949**
Check total	0	0	0	0	0	0	0	0	0
Check annual	0	0	0	0	0	0	0	0	0

EBITDA	0	0	0	0	0	0	138	140	143
Interest expenses	0	0	0	0	0	0	-49	-62	-62
Change in Working Capital	0	0	0	0	0	0	-15	0	0
Income Tax Paid	0	0	0	0	0	0	-5	-2	-2
Cash flow from operation	**0**	**0**	**0**	**0**	**0**	**0**	**69**	**76**	**79**
Capex	-10	-4	-58	-115	-159	-273	-235	-105	0
Interest income	0	0	0	0	0	0	0	0	1
Change in Debt reserve a/c	0	0	0	0	0	0	0	0	0
Cash flow from investment	**-10**	**-4**	**-58**	**-115**	**-159**	**-273**	**-235**	**-104**	**1**
Additional equity	3	1	17	35	48	82	70	31	0
Aditional debt	7	3	41	81	111	191	164	73	0
Principle repayment	0	0	0	0	0	0	-21	-37	-39
Cashflow from financing activities	**10**	**4**	**58**	**115**	**159**	**273**	**213**	**68**	**-39**
Increase/(decrease) in cash	**0**	**0**	**0**	**0**	**0**	**0**	**47**	**40**	**41**
Opening cash balance	0	0	0	0	0	0	0	0	40
Increase /(decrease) in cash	0	0	0	0	0	0	47	40	41
Cash available for distribution	0	0	0	0	0	0	47	40	81
Dividend Initial	0	0	0	0	0	0	-47	0	-40
Adjustment for min. Cash on BS	0	0	0	0	0	0	0	0	0
Dividends Adjusted	0	0	0	0	0	0	-47	0	-40
Cash balance	0	0	0	0	0	0	0	40	41
Interest on cash	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,4	0,8
Check cash	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00

Working Capital									
Accounts receivables	0	0	0	0	0	0	16	16	17
Accounts payable	0	0	0	0	0	0	1	1	1
WC	0	0	0	0	0	0	15	16	16
Change in WC	0	0	0	0	0	0	15	0	0
Legal Reserve									
Legal Reserve	0	0	0	0	0	0	0	0	0
Annual Allocations	0	0	0	0	0	0	0	0	0
Cumulative annual allocations	0	0	0	0	0	0	0	0	0
General Reserve									
Net Income	0	0	0	0	0	0	48	37	40
Legal Reserve	0	0	0	0	0	0	0	0	0
Dividends	0	0	0	0	0	0	-47	0	-40
General Reserve	0	0	0	0	0	0	1	37	0
Debt Service Ratio									
Net Income	0	0	0	0	0	0	48	37	40
Add: Depreciation	0	0	0	0	0	0	20	24	24
Add: Deferred Tax	0	0	0	0	0	0	17	15	16
Add: Interest	0	0	0	0	0	0	49	62	61
Cash available for debt Service	**0**	**0**	**0**	**0**	**0**	**0**	**133**	**139**	**141**
Interest on term loan	0	0	0	0	0	0	-49	-62	-62
Repayment	0	0	0	0	0	0	-21	-37	-39
Debt servicing requirements	0	0	0	0	0	0	-70	-99	-101
DSCR							**1,89x**	**1,40x**	**1,40x**
Debt Credit Reserve									
Target Level	0	0	0	0	0	0	0	0	0
Opening Balance	0	0	0	0	0	0	0	0	0
Additions (Decrease)	0	0	0	0	0	0	0	0	0
Ending Balance	0	0	0	0	0	0	0	0	0
DSR Income	0	0	0	0	0	0	0	0	0
Dividend Calculations									
Dividend Payable	0	0	0	0	0	0	1	0	1
Profits Available for Dividends	0	0	0	0	0	0	48	0	40
Cash Available for Dividends	0	0	0	0	0	0	47	40	81
Gross Dividends (Initial estimate)	0	0	0	0	0	0	47	0	40
Gross Dividends (final estimate)	0	0	0	0	0	0	47	0	40
Tax on divideds	0	0	0	0	0	0	0	0	0
Net dividends	0	0	0	0	0	0	47	0	40
Minimal cash on Balance Sheet									
Min. Cash Target	0	0	0	0	0	0	0	0	0

1. DCF Calculations

1.1. Free Cash Flow to Firm

EBITDA	0	0	0	0	0	0	138	140	143	147
Income tax paid	0	0	0	0	0	0	-8	-3	-4	-12
Capex investment (ex IDC)	-10	-3	-55	-106	-139	-238	-230	-105	0	0
Change in working capital	0	0	0	0	0	0	-15	0	0	0
Terminal Value	0	0	0	0	0	0	0	0	0	0
FCF to firm (local)	**-10**	**-3**	**-55**	**-106**	**-139**	**-238**	**-116**	**32**	**139**	**134**
Discount Period	1	2	3	4	5	6	7	8	9	10
Discount factor	0,92	0,84	0,77	0,70	0,65	0,59	0,54	0,50	0,45	0,42
PV Flows	-9	-3	-42	-74	-90	-140	-63	16	63	56
Financial										
Hurdle rate (WACC)	9,2 %									
NPV	298									
IRR	14,2 %									
Economic										
Financial CF	-10	-3	-55	-106	-139	-238	-116	32	139	134
Plus taxes	0	0	0	0	0	0	8	3	4	12
Plus royalties	0	0	0	0	0	0	0	0	0	0
Economic Cash Flow	**-10**	**-3**	**-55**	**-106**	**-139**	**-238**	**-108**	**35**	**143**	**146**
Capex and operating costs (MUSD)	10	3	55	106	139	238	239	114	9	9
Generation (GWh)	0	0	0	0	0	0	1 423	1 423	1 423	1 423

1.2. Free Cash Flow to Equity

EBITDA	0	0	0	0	0	0	138	140	143	147
Change in working capital	0	0	0	0	0	0	-15	0	0	0
Income tax paid	0	0	0	0	0	0	-5	-2	-2	-6
Change in DSR	0	0	0	0	0	0	0	0	0	0
Equity Payments	-3	-1	-17	-35	-48	-82	-70	-31	0	0
Debt principal repayment	0	0	0	0	0	0	-21	-37	-39	-39
Interest expense	0	0	0	0	0	0	-49	-62	-62	-58
Interest income	0	0	0	0	0	0	0	0	1	1
Terminal value	0	0	0	0	0	0	0	0	0	0
FCF to equity (local)	**-3**	**-1**	**-17**	**-35**	**-48**	**-82**	**-23**	**8**	**41**	**44**
Discount Period	1	2	3	4	5	6	7	8	9	10
Discount factor	0,88	0,77	0,68	0,59	0,52	0,46	0,40	0,35	0,31	0,27
PV Flows	-3	-1	-12	-21	-25	-38	-9	3	13	12
	77									
Hurdle rate (CoE)	13,9 %									
NPV	74									
IRR	18,7 %									
PV tax	-69									
Government Take										
Corporate tax	0,0	0,0	0,0	0,0	0,0	0,0	8,1	3,2	3,7	11,9
Royalty	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
VAT	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Total	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**8,1**	**3,2**	**3,7**	**11,9**
Required return	12,3 %									
NPV (MUSD)	111,4									

Year	Country	data.worldbank.org		fxtop.com			data.worldbank.org		fxtop.com		Construction Cost (MUSD)
	Angola	Angola (% a	Increase (A	AOA/USD	Increase of	Namibia	Namibia (%	Increase 10	NAD/USD	Increase 100 NAD in USD	
1998	*The inflation rate in*			0,38		*Inflation Rate in*			5,45		554
2005	*Angola was recorded*	22,64 %	100	95,58	1,046244	*Namibia is expected to*	2,28 %	100	6,37	15,69859	
2006	*at 36.52 percent in*	13,30 %	113,30	75,57	1,499272	*be 8.70 percent (2nd Q*	4,90 %	104,90	6,77	15,49483	
2007	*March of 2017. It is*	12,20 %	127,12	74,63	1,703371	*2017) . Looking*	6,50 %	111,72	7,05	15,8466	
2008	*the lowest reading*	12,50 %	143,01	74,57	1,917835	*forward, we estimate*	9,00 %	121,77	8,25	14,76038	
2009	*since July. Inflation*	13,70 %	162,61	78,88	2,061431	*Inflation Rate in*	9,40 %	133,22	8,41	15,84065	
2010	*Rate in Angola*	14,50 %	186,18	91,79	2,028364	*Namibia to stand at*	4,90 %	139,75	7,32	19,0912	
2011	*averaged 37.15*	13,50 %	211,32	93,56	2,258639	*9.00 percent in 12*	5,00 %	146,73	7,72	19,00712	
2012	*percent from 2001*	10,30 %	233,08	95,21	2,448105	*months time. In the*	6,70 %	156,57	8,21	19,07019	
2013	*until 2017, reaching*	8,80 %	253,60	96,51	2,62766	*long-term, the*	5,60 %	165,33	9,65	17,13305	
2014	*an all time high of*	7,30 %	272,11	98,32	2,767575	*Namibia Inflation Rate*	5,35 %	174,18	10,85	16,05339	1200
2015	*241.08 percent in*	10,30 %	300,14	119,21	2,5177	*is projected to trend*	3,40 %	180,10	12,68	14,20358	
2016	*January of 2001 and a*	34,37 %	403,29	162,84	2,476612	*around 8.00 percent in*	8,00 %	194,51	13,27	14,65784	
2017	*record low of 6.89*	25,00 %	504,11	165,80	3,040497	*2020.*	8,00 %	210,07	12,47	16,84605	
2022	*percent in June of*	14,02 %					8,00 %				
2027	*2014.*	13,33 %					8,00 %				
2032		12,68 %	Mean - % inflation in	Mean - % USD	Mean - % Inflation in		8,00 %	Mean - % inflation in	Mean - % USD	Mean - % Inflation in	
	Mean annual exchange increase (%		31,4	10,9	17,3	Mean annual exchange increase (%		9,1	8,0	0,6	
Mean 2006-2016		14,45 %					5,92 %				
Mean 2020-2040		19,88 %					8,00 %				

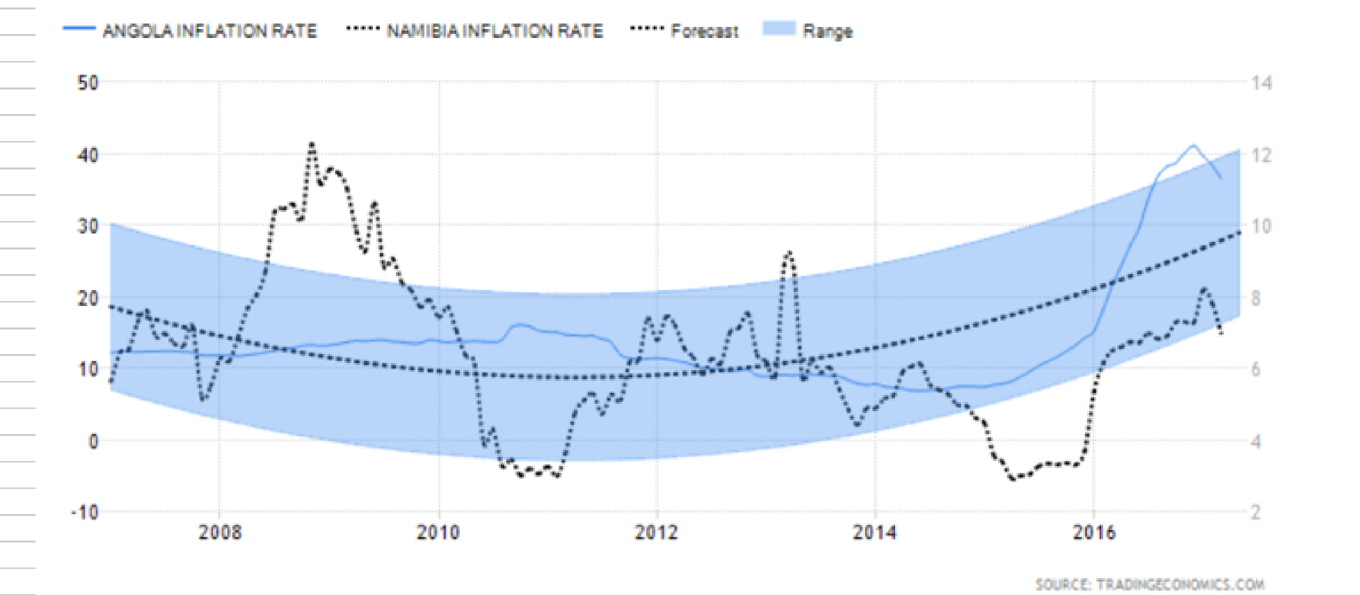
Comments

Angola

High inflation of 23% per year in AOA relative to USD, ensures price increase in USD that are higher than global inflation rates 2 -5% in the same period - inflation supersedes depreciation

Nambia

Inflation in NAD and USD is similar and not sufficient to obtain price increase in USD above global inflation of 2 - 5% in the same period - inflation rate is offset by depreciation



LIBOR HISTORY

LIBOR rate	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
3 mnd USD	9,38 %	8,38 %	7,06 %	4,19 %	3,25 %	3,25 %	6,31 %	5,38 %	5,56 %	6,00 %	5,03 %	6,04 %	5,52 %	1,86 %

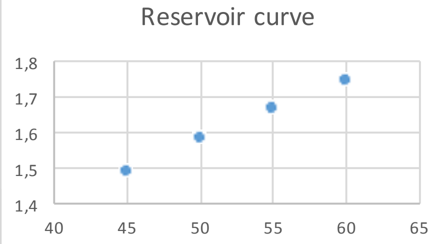
LIBOR rate	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	
3 mnd USD	1,35 %	1,13 %	2,74 %	4,67 %	5,36 %	3,92 %	1,21 %	0,25 %	0,30 %	0,57 %	0,30 %	0,24 %	0,25 %	0,62 %	1,03 %	**3,49 %**

LENDING RATES

	World Development Indicators							
Last Updated Date	23.03.17							
	Lending interest rate (%)	**Inflation, consumer prices (annual %)**	**Real Interest Rate**	**Lending interest rate (%)**	**Inflation**	**Real Interest Rate**		**Inflation**
	Angola	**Angola**	**Angola**	**Namibia**	**Namibia**	**Namibia**		**USA**
2001	95,97	152,56	**-56,59 %**	14,53				2,83
2002	97,34	108,90	**-11,56 %**	13,84				1,59
2003	96,12	98,22	**-2,11 %**	14,70	7,14	**7,56 %**		2,27
2004	82,33	43,54	**38,79 %**	11,39	4,14	**7,25 %**		2,68
2005	67,72	22,96	**44,75 %**	10,61	2,28	**8,33 %**		3,39
2006	19,51	13,30	**6,21 %**	11,18	4,96	**6,22 %**		3,23
2007	17,70	12,25	**5,45 %**	12,88	6,55	**6,34 %**		2,85
2008	12,53	12,47	**0,06 %**	13,74	9,09	**4,64 %**		3,84
2009	15,68	13,73	**1,95 %**	11,12	9,45	**1,67 %**		-0,36
2010	22,54	14,47	**8,07 %**	9,72	4,87	**4,85 %**		1,64
2011	18,76	13,47	**5,29 %**	8,73	5,01	**3,72 %**		3,16
2012	16,66	10,29	**6,36 %**	8,65	6,72	**1,93 %**		2,07
2013	15,81	8,78	**7,03 %**	8,29	5,60	**2,69 %**		1,46
2014	16,38	7,28	**9,10 %**	8,70	5,35	**3,35 %**		1,62
2015	16,88	10,28	**6,60 %**	9,32	3,41	**5,92 %**		0,12
2016		34,37						1,26
		14,47 %			5,74			
Average real interest rate			**4,63 %**			**4,96 %**		**2,10 %**
Average real interest rate combined AGO/NAM periode 2001-2016			**4,79 %**					
Average real interest rate USA periode 2001-2016			**2,10 %**					
Difference between Angola/Namibia and USD inflation			**2,69 %**					
Nominal risk free rate i local currency			**4,95 %**					

Appendix C: Reservoir/ Production Model

Production Simulations								
Parameters								
Storage - active	Km3	1,744	1,744	Reservoir area (km2)	57,5	**Drawdown**	**Active Reservoir**	**PV**
Water level start	m.a.s.l	580	580	Evaporation (mm)/year	1765	**(m below +580)**	**(Mm ^{3})**	**(MUSD)**
Water level end	m.a.s.l	530	530	Loss per year MCM	101,4875	45	1,488	684.1
Peak 2 + 2,5 hours	hours	4,5	4,5	Average Loss per month	8,457291667	50	1,582	683.7
Off-peak	hours	19,5	19,5			55	1,668	683.9
Design discharge	m3/s	200	335			60	1,744	684.3
Variables		Base/ Alt 1	Alt 2					
Hydro	Sum annual	Amount						
Net inflow	Km3	4,349	4,255	site based on correlation of Ruacana series with those of neigbouring catchment				
Inflow - wet	Km3	3,40	3,37	Reducing/ increasing wet season inflow implies lower/higher turbine flow during wet season to fill or prevent the reservoir from spilling				
Inflow - dry	Km3	0,94	0,89					
Installed Capacity	MW	360	600					
Env release	m3/s	20	50					
Min release at dam	m3/s	2	5					
Outputs								
Avg discharge wet	m3/s	134	126					
Avg discharge dry	m3/s	145	145	Must be adjusted to maintain positive storage		GWh= (diff head - m)*(Q - m3/s)*9,8 m2/s*1000 kg/m3) = watts/1e9 watts/gigawatt*hours of operation		
Power produced	GWh	1 847,0	1 814,4	Vol m3 pumping = Production GWh/ hours of operation = effect GW*1e9 watts/GW/ = watts/[(diff head - m)*9,8 m2/s'1000 kg/m3]= Q m3/s * seconds of operation				
Spill		0,0	0					
Check residual water - positive		2 453 791,7	-138 208,3	Vol water saved - m3 = avoided hydro energy = PV-solar energy - GWh* vol - m3/Hydro energy produced - GWh				



Reservoir Model:	Base - 360 MW								
					Vol Stored -	Production (GWh)	Vol consumed in m3 per GWh of hydroproduced	Production (GWh)	
	Reservoir			Net Inflow - Operation	Live Storage	Baynes HPP	m3/GWh	PV-1MW	PV-50MW
Date	Level (masl)	Net Inflow (m3)	Operation (m3)	Vol stored (m3)	Spill (m3)	Total		Total	
Jan	530,00	325 858 708,3	325 858 708,3	0,0	0	119,8	2 721 088,44	0,1493	7,465
Feb	535,30	532 158 708,3	347 328 000,0	184 830 708,3	0	132,2	2 628 240,66	0,1443	7,215
Mar	551,97	928 658 708,3	347 328 000,0	766 161 416,7	0	146,3	2 373 516,43	0,1568	7,84
Apr	571,85	1 040 858 708,3	347 328 000,0	1 459 692 125,0	0	163,3	2 127 523,87	0,1534	7,67
May	578,44	577 158 708,3	347 328 000,0	1 689 522 833,3	0	168,9	2 056 878,96	0,1674	8,37
Jun	575,65	278 558 708,3	375 840 000,0	1 592 241 541,7	0	180,2	2 086 200,29	0,1617	8,085
Jul	570,07	181 358 708,3	375 840 000,0	1 397 760 250,0	0	175,0	2 147 398,12	0,1657	8,285
Aug	562,90	125 558 708,3	375 840 000,0	1 147 478 958,3	0	168,4	2 231 645,37	0,1622	8,11
Sep	554,20	72 558 708,3	375 840 000,0	844 197 666,7	0	160,4	2 343 033,50	0,1592	7,96
Oct	544,47	36 458 708,3	375 840 000,0	504 816 375,0	0	151,4	2 481 643,78	0,1571	7,855
Nov	535,26	54 458 708,3	375 840 000,0	183 435 083,3	0	143,0	2 628 917,99	0,1589	7,945
Dec	530,07	194 858 708,3	375 840 000,0	2 453 791,7	0	138,2	2 719 812,85	0,162	8,1
	Sum annual	4 348 504 500,0							
	sum wet	3 404 693 541,67			Sum (GWh)	1 847,0	Sum	1,9	94,9
	sum dry	943 810 958,33							
					PV wet (GWh)	70,4			
					PV dry GWh)	24,5			
					PV Sum (GWh)	94,9			
					Sum Hydro + PV	1941,9			

Reservoir Model:	Alt 2 - Baynes 600 MW								
						Production (GWh)	Vol consumed in m3 per GWh of hydroproduced	Production (GWh)	
						Baynes HPP	m3/GWh	PV-1MW	PV-50MW
Date	Level (masl)	Inflow (m3)	Operation (m3)	Vol stored (m3)	Spill (m3)	Total		Total	
Jan	530,00	318 082 708,3	318 082 708,3	0,0	0	116,9	2 721 088,44	0,1493	7,465
Feb	535,67	524 382 708,3	326 592 000,0	197 790 708,3	0	124,6	2 621 967,49	0,1443	7,215
Mar	552,71	920 882 708,3	326 592 000,0	792 081 416,7	0	138,2	2 363 303,83	0,1568	7,84
Apr	572,96	1 033 082 708,3	326 592 000,0	1 498 572 125,0	0	154,4	2 115 233,95	0,1534	7,67
May	579,92	569 382 708,3	326 592 000,0	1 741 362 833,3	0	160,0	2 041 588,12	0,1674	8,37
Jun	576,91	270 782 708,3	375 840 000,0	1 636 305 541,7	0	181,3	2 072 816,16	0,1617	8,085
Jul	571,11	173 582 708,3	375 840 000,0	1 434 048 250,0	0	176,0	2 135 708,32	0,1657	8,285
Aug	563,72	117 782 708,3	375 840 000,0	1 175 990 958,3	0	169,2	2 221 715,79	0,1622	8,11
Sep	554,80	64 782 708,3	375 840 000,0	864 933 666,7	0	161,0	2 335 064,72	0,1592	7,96
Oct	544,84	28 682 708,3	375 840 000,0	517 776 375,0	0	151,8	2 476 050,16	0,1571	7,855
Nov	535,41	46 682 708,3	375 840 000,0	188 619 083,3	0	143,1	2 626 403,82	0,1589	7,945
Dec	530,00	187 082 708,3	375 840 000,0	-138 208,3	0	138,1	2 721 160,32	0,162	8,1
	Sum annual	4 255 192 500,0							
		889 378 958,33			Sum (GWh)	1 814,4	Sum	1,9	
					Wet (GWh)	694,0			
					Dry (GWh)	1 120,4			
					PV wet (GWh)	38,6			
					PV dry GWh)	56,3			
					PV Sum (GWh)	94,9			
					Sum Hydro + PV	1909,3			

Vol. Water Saved from 50MW PV Solar Plant (m3)	Peak (GWh)	Off-peak (GWh)	Qpeak (m3/s)	Qoff-peak (m3/s)	available given by inflow (GWh)
PV					
20 312 925,17	35,72	84,03	200,00	108,57	1,00
18 962 756,33	36,98	95,17	200,00	118,77	1,00
18 608 368,84	40,95	105,38	200,00	118,77	1,00
16 318 108,05	45,69	117,57	200,00	118,77	1,00
17 216 076,90	47,26	121,61	200,00	118,77	1,00
16 866 929,36	46,59	133,56	200,00	132,31	1,00
17 791 193,42	45,26	129,76	200,00	132,31	1,00
18 098 643,97	43,56	124,86	200,00	132,31	1,00
18 650 546,67	41,48	118,92	200,00	132,31	1,00
19 493 311,92	39,17	112,28	200,00	132,31	1,00
20 886 753,40	36,97	105,99	200,00	132,31	1,00
22 030 484,10	35,74	102,45	200,00	132,31	1,00
	Peak	**Off-Peak**	**Sum**	**´+PV**	
Total	495,4	1 351,6	1 847,0	1 941,9	
	27 %	73 %	100 %		
	360,0	963,4		1323,4	
Low	19 %	52 %	72 %		
Low + PV	18,5 %	49,6 %		68,1 %	
	135,4	388,2		618,5	
High	7 %	21 %	28 %		
	230,3	388,2			
High+PV	11,86 %	19,99 %		31,85 %	
Vol. Water Saved from 50MW PV Solar Plant (m3)	Peak (GWh)	Off-peak (GWh)	Qpeak (m3/s)	Qoff-peak (m3/s)	available given by inflow (GWh)
PV					
20 312 925,17	59,83268	57,06	335,00	73,73	1,00
18 917 495,41	62,09459	62,47	335,00	77,77	1,00
18 528 302,04	68,89085	69,30	335,00	77,77	1,00
16 223 844,43	76,97021	77,43	335,00	77,77	1,00
17 088 092,54	79,74674	80,22	335,00	77,77	1,00
16 758 718,62	78,54532	102,77	335,00	101,15	1,00
17 694 343,41	76,23232	99,75	335,00	101,15	1,00
18 018 115,06	73,2812	95,89	335,00	101,15	1,00
18 587 115,16	69,72398	91,23	335,00	101,15	1,00
19 449 373,98	65,75392	86,04	335,00	101,15	1,00
20 866 778,39	61,98971	81,11	335,00	101,15	1,00
22 041 398,57	59,83109	78,29	335,00	101,15	1,00
	Peak	**Off-Peak**		**´+PV**	
224 486 502,8	832,9	981,6	1 814,4	1 909,3	
133 415 843,19	46 %	54 %	100 %		
25,24 %	604,8	683,1		1326,5	
Low	33 %	38 %	71 %	69 %	
Low + PV	31,7 %	35,8 %			
	228,1	298,4		582,8	
High	13 %	16 %	29 %	31 %	
High+PV	16,9 %	15,6 %			
High demand					

Appendix D: PV-Solar Simulation Results

Grid-Connected System: Simulation parameters

Project :	**Baynes**			
Geographical Site	**Angola-Scen1-Baynes**		Country	**Angola**
Situation	Latitude	16.91° S	Longitude	13.03° E
Time defined as	Legal Time	Time zone UT+1	Altitude	836 m
	Albedo	0.20		
Meteo data:	**Angola-Scen1-Baynes**	Meteonorm 7.1 (1958-1974), Sat=100% - Synthetic		

Simulation variant :	**Bayne-base**			
	Simulation date	02/03/17 13h36		

Simulation parameters

Collector Plane Orientation	Tilt	20°	Azimuth	0°
50 Sheds	Pitch	6.00 m	Collector width	3.00 m
Inactive band	Top	0.00 m	Bottom	0.00 m
Shading limit angle	Gamma	17.88 °	Occupation Ratio	50.0 %
Models used	Transposition	Perez	Diffuse	Perez, Meteonorm
Horizon	Free Horizon			
Near Shadings	Mutual shadings of sheds			

PV Array Characteristics

PV module Si-poly	Model	**REC 300PE 72**		
Original PVsyst database	Manufacturer	REC		
Number of PV modules	In series	19 modules	In parallel	175 strings
Total number of PV modules	Nb. modules	3325	Unit Nom. Power	300 Wp
Array global power	Nominal (STC)	**998 kWp**	At operating cond.	898 kWp (50°C)
Array operating characteristics (50°C)	U mpp	627 V	I mpp	1433 A
Total area	Module area	**6488 m²**	Cell area	5827 m²
Inverter	Model	**Sunny Central 1000CP XT**		
Original PVsyst database	Manufacturer	SMA		
Characteristics	Operating Voltage	596-850 V	Unit Nom. Power	1000 kWac
			Max. power (=>25°C)	1100 kWac
Inverter pack	Nb. of inverters	1 units	Total Power	1000 kWac

PV Array loss factors

Array Soiling Losses			Loss Fraction	5.0 %
Thermal Loss factor	Uc (const)	29.0 W/m²K	Uv (wind)	0.0 W/m²K / m/s
Wiring Ohmic Loss	Global array res.	7.2 mOhm	Loss Fraction	1.5 % at STC
LID - Light Induced Degradation			Loss Fraction	1.5 %
Module Quality Loss			Loss Fraction	-0.4 %
Module Mismatch Losses			Loss Fraction	1.0 % at MPP
Incidence effect, ASHRAE parametrization	IAM =	1 - bo (1/cos i - 1)	bo Param.	0.05

User's needs : Unlimited load (grid)

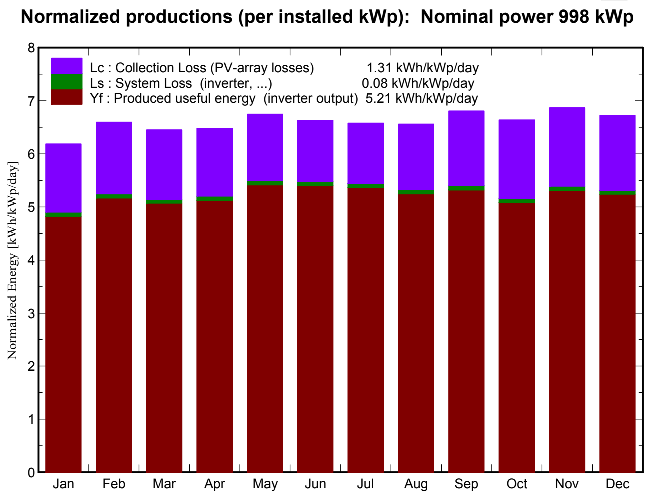
Grid-Connected System: Main results

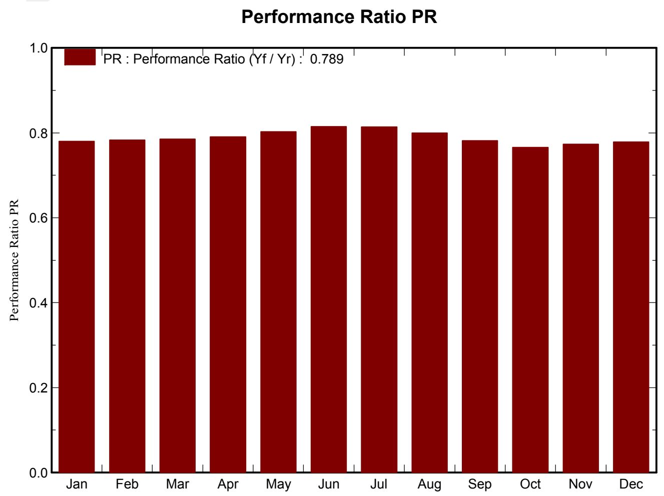
Project : **Baynes**

Simulation variant : **Bayne-base**

Main system parameters System type **Grid-Connected**
PV Field Orientation Sheds disposition, tilt 20° azimuth 0°
PV modules Model REC 300PE 72 Pnom 300 Wp
PV Array Nb. of modules 3325 Pnom total **998 kWp**
Inverter Model Sunny Central 1000CP XT Pnom 1000 kW ac
User's needs Unlimited load (grid)

Main simulation results
System Production **Produced Energy** **1898 MWh/year** Specific prod. 1903 kWh/kWp/year
Performance Ratio PR 78.91 %





Bayne-base
Balances and main results

	GlobHor	DiffHor	T Amb	GlobInc	GlobEff	EArray	E_Grid	PR
	kWh/m²	kWh/m²	°C	kWh/m²	kWh/m²	MWh	MWh	
January	212.0	73.45	26.51	191.8	173.2	151.6	149.3	0.780
February	192.3	68.66	26.20	184.7	167.7	146.6	144.3	0.783
March	194.2	69.48	25.86	200.1	182.2	159.1	156.8	0.785
April	173.5	48.21	24.36	194.5	178.2	155.7	153.4	0.791
May	171.1	34.33	21.90	209.2	192.5	169.9	167.4	0.803
June	155.7	26.52	18.97	199.0	183.3	164.1	161.7	0.815
July	163.1	31.14	18.61	204.0	187.9	168.2	165.7	0.814
August	174.7	47.20	21.84	203.4	186.8	164.7	162.2	0.800
September	190.9	54.65	25.85	204.2	187.1	161.6	159.2	0.781
October	209.9	55.31	29.08	205.7	187.4	159.5	157.1	0.766
November	225.1	61.95	27.67	206.0	186.6	161.3	158.9	0.773
December	235.6	67.97	26.83	208.5	188.3	164.4	162.0	0.779
Year	2298.1	638.88	24.46	2411.2	2201.1	1926.5	1898.0	0.789

Legends:
GlobHor Horizontal global irradiation
DiffHor Horizontal diffuse irradiation
T Amb Ambient Temperature
GlobInc Global incident in coll. plane
GlobEff Effective Global, corr. for IAM and shadings
EArray Effective energy at the output of the array
E_Grid Energy injected into grid
PR Performance Ratio

Grid-Connected System: Loss diagram

Project : **Baynes**

Simulation variant : **Bayne-base**

Main system parameters	System type	**Grid-Connected**		
PV Field Orientation	Sheds disposition, tilt	20°	azimuth	0°
PV modules	Model	REC 300PE 72	Pnom	300 Wp
PV Array	Nb. of modules	3325	Pnom total	**998 kWp**
Inverter	Model	Sunny Central 1000CP XT	Pnom	1000 kW ac
User's needs	Unlimited load (grid)			

Loss diagram over the whole year