Least-cost energy investment study for Namibia

An analysis of the costs, risks and impacts of pursuing an energy future reliant on hydropower versus solar and wind

TMP PUBLIC

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About the Authors

TMP Public

TMP Public is a non-profit consultancy and think-tank that solves complex social and environmental problems through research, analysis and advisory services. TMP has expertise in finance, technology, and social and political sciences and their work spans developed and developing countries on six continents. Since 2009, TMP has helped to measure, analyze and manage social and environmental risks (or opportunities) that arise from our rapidly changing world. Today, TMP is increasingly focused on understanding and preparing for climate change impacts on key systems in the 2020s, which include critical minerals and energy, food systems, and biodiversity and ecosystems.

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Inputs and review: Siziwe Mota, Joshua Klemm and Aqeelah Hassen of International Rivers. Bertchen Kohrs of Earthlife Namibia

Design: Sally Whines

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International Rivers Headquarters
344 20th Street
Oakland 94612
USA
Tel: +1 510 848 1155
www.internationalrivers.org

International Rivers Africa Program
377 Rivonia Boulevard
Rivonia Johannesburg 2128
South Africa
Tel: +27 12 430 2029

Earthlife Namibia
PO box 24892
Windhoek
9000

Cover photo: Panoramic sunset over Damaraland landscape, Namibia | Tomas Drahos, Shutterstock

Namibia is at a critical point in its energy transition, where choices about new energy supply today could determine future energy security and prosperity. To support these decisions, this study provides a least-cost energy investment pathway for Namibia until 2040, alongside a comparative analysis of the proposed Baynes hydropower project and least-cost solar and wind alternatives.

The analysis covers techno-economic factors, and key social, environmental and climate considerations that are often lacking in technology and energy planning. The assessment then identifies the most suitable areas for solar and wind development, drawing on best available datasets alongside one of TMP's unique social risk models.

Photo: Sunset over the Orange river at the South Africa Namibia border | Chris Stenger Unsplash

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Photo: Windfarm at sunrise | Pixabay

1. Executive Summary

1.1 Introduction

Namibia is at a crucial point in the development of its energy system – the country must soon make critical decisions to meet its growing energy demand. In particular, it must decide whether to prioritize the development of large-scale hydropower, namely the Baynes dam, or to develop abundant solar and wind resources.

Namibia has historically relied on hydropower and fossil fuels, but these are increasingly expensive and either vulnerable to climate change or they contribute directly to it. Important decisions about the country's energy future must be made soon and they will have lasting impacts on national energy security and prosperity. This study is designed to help make the right decisions.

This report provides a least-cost energy investment pathway for Namibia through 2040 and finds that there are no material arguments for new hydropower. Large hydropower can be presented as a 'quick fix' to fill gaps in energy supply. But a balanced assessment of its costs and benefits should often deter officials and investors in favor of less complex alternatives, like solar and wind.

We present a balanced assessment by delivering a series of complementary analyses of:

- financial costs under different scenarios
- social and environmental risks and impacts, and
- exposure to climate change.

Our analysis therefore assesses the attractiveness of different energy options from different perspectives, which are then combined to produce optimal development pathways.

Solar and wind are found to be cheaper, with lower negative impact. At the same time, they offer greater socio-economic benefits than both hydropower and fossil fuel options (see "Summary Results" below). We find that solar and wind can be rolled out rapidly because Namibia enjoys large areas that are both high in renewable resource potential (i.e. solar radiation and wind speed) and low in social and environmental risk.[1] Importantly, this lower risk and higher reward profile should also attract substantial private investment.

Governments, developers, energy planners and investors can use this information on costs, risks and impacts under different scenarios to make better decisions about Namibia's energy future. This assessment approach could be replicated in other countries and regions that are at similar cross-roads in their energy transition.

> **Solar and wind are found to be cheaper, with lower negative impact. At the same time, they offer greater socio-economic benefits than both hydropower and fossil fuel options.**

1.2. Background

Namibia has a small energy system that is dominated by its 347MW Ruacana hydropower plant, along with imports from neighbors facing growing supply issues of their own. This system will have to be substantially expanded and improved to satisfy energy demand that is projected to double in the next 20 years. Failure to invest in new energy supply will undermine national development plans and livelihood improvements.

Fortunately, Namibia is endowed with some of the best solar resources in the world, some of the best wind resources in Southern Africa, as well as some hydropower potential and fossil fuel resources. This means that the government has some critical renewable energy planning decisions to make on the best way forward for the country.

One such decision involves plans to jointly develop the proposed 600 MW Baynes hydropower project with Angola,[2] to be located downstream from Ruacana in the lowest section of the Kunene River Basin. This is a project that has been controversial

1. This is important because solar and wind have large land requirements and are not always easy to roll out rapidly.
2. Power from Baynes will be split equally between Namibia and Angola. Similarly, the project costs, responsibilities and benefits with be shared by both countries although the precise details of this split are less clear. This report accounts for this split where relevant.

since it was first assessed alongside the Epupa dam in the 1990s.[3] Since then, the landscape for wind and solar has improved dramatically from both a financial and technological perspective, shifting the calculus for energy planners and investors.

Baynes would cost an estimated $2.4 billion (or more according to our analysis), including grid connection. The project has been on the slate for almost 30 years but has never been able to attract the necessary funding because it offers a weak financial proposition. All in all, Baynes is large and expensive enough to make or break Namibia's energy future.

1.3. Previous studies and our additionality

Existing assessments of Namibia have focused on the state of the electricity sector,[4] its renewable energy auction process,[5] the economic impacts of renewable energy,[6] and challenges associated with off-grid electrification.[7] None, to our knowledge, have attempted a comprehensive assessment of energy options that balances costs, risks and impacts of different scenarios. Namibia's recent draft IRP 2022, for example, does not consider key social, environmental and climate risks and impacts.

Our assessment contributes a new perspective by accounting for and linking techno-economic dimensions, as well as increasingly salient social, climate and environmental considerations. The information we provide can therefore help decision makers to make risk-adjusted decisions that favor least-cost energy pathways as well as options that improve social and environmental impact.

This is a particularly important contribution because the Baynes project has never been subject to a cost-benefit comparison with least-cost alternatives, despite that it equates to roughly a fifth of the county's GDP[8] and is nearly the same size as its entire installed energy capacity. Such a comparison is urgently needed if we expect Namibia to find the best path available to it.

1.4. Structure of the report

We have split this report into three main parts: lowest costs (all things being equal); lowest costs (risk-adjusted); fastest rollout (accounting for likely delay).

The first part of this study presents least-cost energy investment scenarios for Namibia until 2040. This includes a 'Base case' scenario without Baynes, in addition to a comparative scenario in which Baynes is assumed to come online in 2031 following likely delays of around 2.5 years.[9] The scenarios are compared according to the least-cost technologies, carbon emissions, imports and overall capital and operation costs.

The second part of this study then compares least-cost options with the proposed Baynes project directly. This comparison quantifies Baynes' social and environmental risk exposure in financial terms via a Riverscope analysis. We then layer on climate risk in the Kunene River Basin to produce a risk-adjusted financial assessment of Baynes that can be compared with the projected costs of rapid solar and wind expansion.

The third part of the assessment considers the practicality of rapid solar and wind rollout, given the likelihood that Baynes will be slow to deliver energy. It shows that solar and wind can be developed more rapidly than hydropower by picking out large areas of Namibia where solar and wind might be developed with high energy potential but low social and environmental risk.

Finally, the study closes with some brief recommendations for the Namibian government. These recommendations aim to help the country move towards an energy future that is secure and low cost but also one which preserves the country's rich natural heritage and which does as much as it can to address energy poverty as rapidly as possible while respecting human rights.

3. Epupa was later abandoned because of unacceptably high social and environmental impacts: https://www.erm.com/contentassets/decaeb470695428e-a96b9fc4651cd49f/full_version_finalscopingreportoctober09.pdf
4. https://voconsulting.net/wp-content/uploads/2020/03/SNES_2019.pdf
5. https://www.sciencedirect.com/science/article/pii/S0957178722000571
6. https://voconsulting.net/wp-content/uploads/2020/03/Econ-Impacts-Ren-Energy-Namibia.pdf
7. https://link.springer.com/content/pdf/10.1007/s40974-021-00214-5.pdf
8. Based on nominal GDP in 2021 with an average exchange rate in 2022 of NA$: 0.0637US$ https://d3rp5jatom3eyn.cloudfront.net/cms/assets/documents/Annual_National_Accounts_2021.pdf
9. This assumption accounts for likely delays. Reports suggest Baynes would come online in 2028/2029, but a Riverscope assessment suggests that Baynes is likely to be delayed by 2.5 years. This is supported by the fact that an AfDB appraisal to provide expert review of current Baynes technical documents is only expected to be complete by 2025: https://www.afdb.org/en/documents/multinational-independent-panel-experts-baynes-hydro-power-project-project-appraisal-report

1.5. Summary methodology

This assessment draws on a combination of quantitative and qualitative methods which include existing publicly available analytical methods as well as approaches developed by TMP. A fuller description of the methodologies used can be found in the full Methodology in section 2 below.

In brief, our overarching framework draws on three key quantitative approaches. The first is an OSeMOSYS model to identify the least-cost energy investment pathway for Namibia to 2040. This integrated assessment model uses widely accepted inputs to recommend least-cost energy pathways.

The second approach uses geospatial analysis to deliver two linked assessments. One is a climate risk assessment of the Kunene River Basin, which draws on TMP's climate risk model for exposure to extreme drought. The other is a suitability assessment of the best areas for solar and wind development in Namibia. The suitability assessment combines one of TMP's social risk models with an existing resource assessment approach.

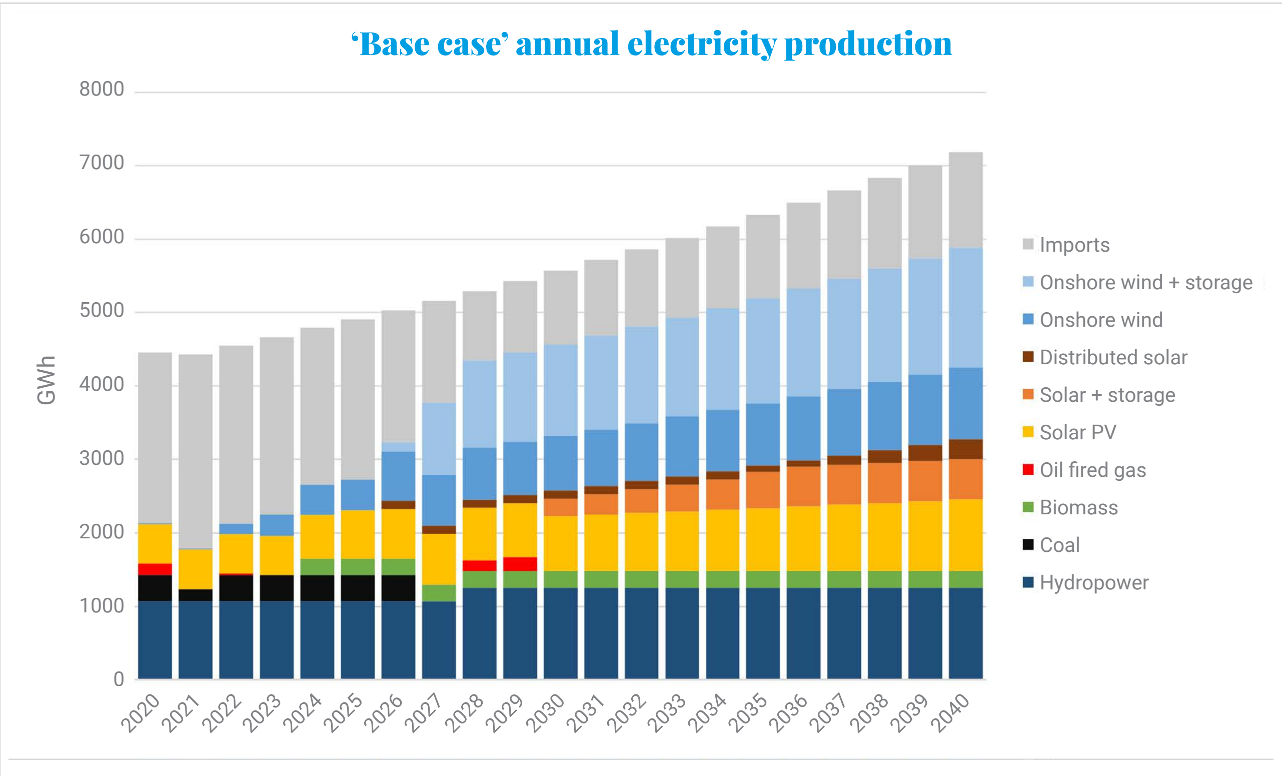
Finally, we use a quantitative Riverscope analysis of the Baynes project to feed into a techno-economic comparison of Baynes and least-cost alternatives.

This analysis factors in the impact of social and environmental risks on the lead-times of energy projects to show the likely real costs of hydropower compared to solar and wind.

All three quantitative approaches are complemented by thorough qualitative research and analysis to provide additional context and insight into the quantitative results. This combination of approaches offers a high-level view of Namibia's least-cost energy pathway, with added granularity into the costs, risks and impacts of available technology options.

1.6. Summary results

Our results indicate that solar and wind with storage make up the largest share of Namibia's energy future under a least-cost energy investment scenario to both 2030 and 2040, cumulatively accounting for 70% and 77% of the country's installed capacity, respectively.[10] Notably, the least-cost model does not include any new hydropower until 2040, unless we artificially remove the cost of grid connection. These results are generally comparable with those in Namibia's draft IRP 2022.



10. See Appendix II for OSeMOSYS installed capacity results

We have found that Namibia has widespread high-quality resources in areas that avoid dense populations, protected areas and sensitive land uses. Nearly 125,000km^2 of the most suitable solar and wind areas also pose relatively low social risk. While strong social engagement and environmental risk assessment is still needed in these locations, they should not create signficant complications that could lead to delay, increased costs and slow project completion.

By contrast, a Riverscope assessment indicates that Baynes is highly susceptible to delays because of high social and environmental risk exposure. Estimates suggest delays of 2.5 years, or in worst-case up to 14 years, in addition to normal lead times. This would bring Baynes online sometime between 2031 and 2042.

There are good reasons to believe Baynes would have problems because of social risks. The Epupa dam, some 40km upstream from the Baynes site, was shelved after both projects faced considerable opposition from local and international groups. This opposition is likely to continue to be a problem for the development of Baynes in a timely manner.

Partly because of these challenges, electricity from Baynes would cost at least 66-166% more than existing domestic wind and solar alternatives by the time it would come online in 2031. So, it will probably be expensive, even compared to other large hydropower projects in Africa. These high costs would be very likely to drive up the price of electricity for Namibia's energy consumers.

Our review demonstrates that solar and wind options could be developed in less than half the time needed for Baynes.[11] If we assume that Namibia can develop 60MW per year it could add a similar capacity to Baynes by 2027.[12] And the country would be more energy secure every year, reducing reliance on imports more rapidly. This is important because extreme drought periods have already created energy shortfalls for Namibia because of its over-reliance on Ruacana.

Drought events are likely to become more frequent and severe by 2030, exacerbated further by competing upstream water demands. They will impact on both Namibia and its neighbors, who use hydropower extensively to generate energy for export. Namibia therefore has good reasons to diversify away from hydropower.

Solar and wind technologies are far more climate resilient and can be dispersed in a way that considerably reduces the chances of a single climate event disrupting the entire energy system. Similarly, their modular nature means they can be sited closer to areas of demand, and according to specific demand requirements, which reduces the need for extensive and disaster-exposed grid infrastructure that is often required for large hydropower.

1.7. Recommendations

Government

- Follow the analysis found in this report and the IRP, which supports investment in wind and solar rather than hydropower and fossil fuels. Reducing hydropower reliance is urgent in the context of climate change.
- Support comprehensive risk assessments and data sharing for energy investments to avoid damaging megaprojects like Baynes or proposed "fracking", while derisking private investment in good projects.

Companies and investors

- Namibia has some of the best solar and wind resources anywhere. Work with experts and local groups to find the best places to exploit it. Your assessment must account for social, environmental and climate risks.
- Work with international financial institutions and governments to develop blended finance solutions that can derisk investments and help crowd in investment partners.

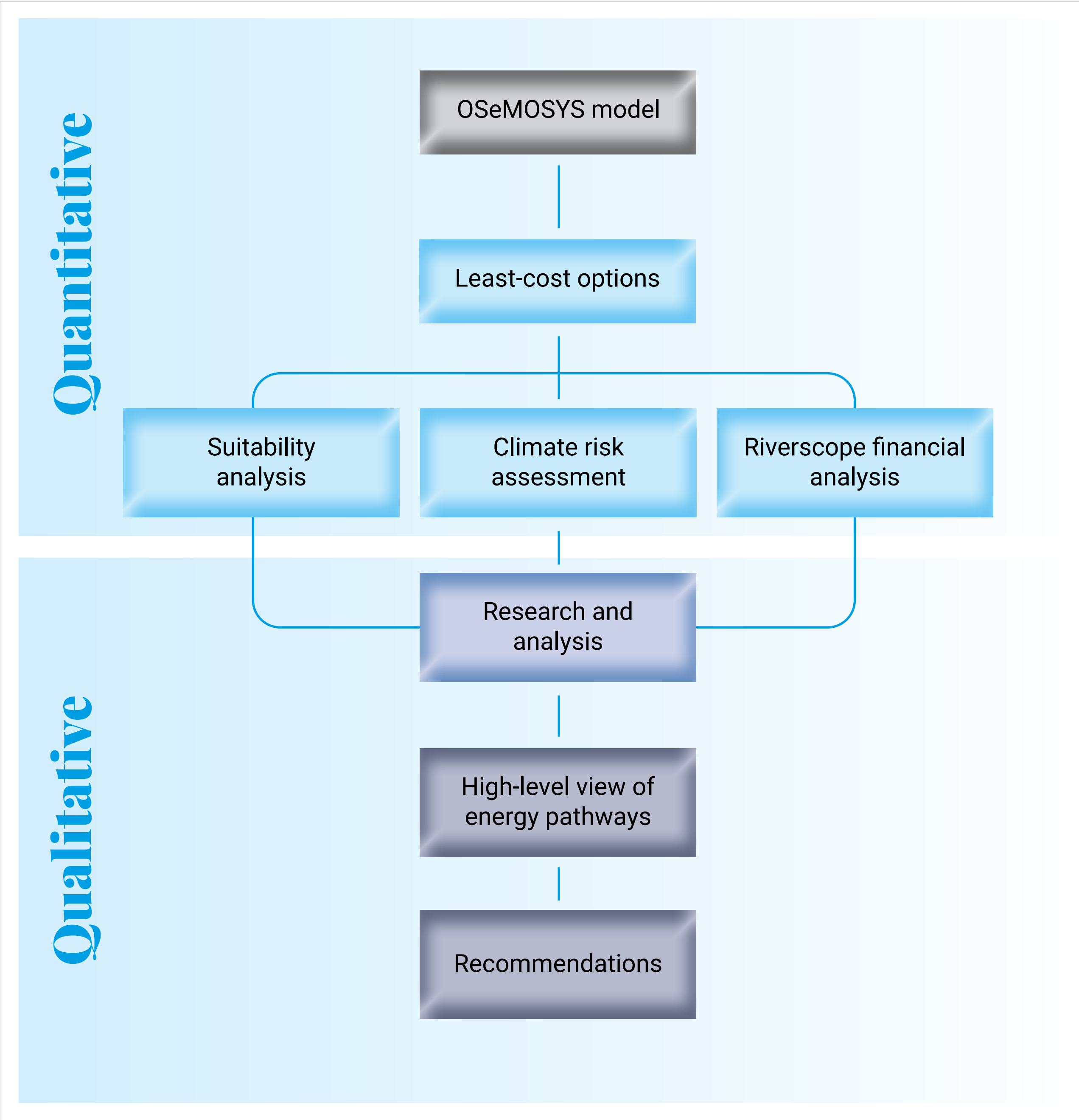
Civil society

- Oppose projects like Baynes using financial arguments and/or arguments based on energy security. Many stakeholders are more sensitive to these problems than rights-based or environmental concerns (however valid).
- Help responsible actors to forge strong social license for good energy projects with extensive local benefit. Consider finding areas and communities that provide free and informed consent for future energy projects so there is a pipeline of possible investment available.

11. For example, The 37MW Hardap PV project was developed within 2 years and provides electricity at less than half the cost expected from Baynes.
12. For comparison, at least 100MW of (mostly) solar and wind was developed between 2016-2018. These were some of the first utility-scale solar and wind projects, so it is safe to assume that development processes today will have improved from this early experience. See: https://www.sciencedirect.com/science/article/pii/S0957178722000571

2. Methodology

This assessment combines quantitative and qualitative methods (see figure below) to determine the least-cost and highest benefit technology pathway for Namibia's future energy mix. These different approaches provide insight into several critical questions for energy planning: What technologies provide reliable and low-cost power? Which technologies have the greatest positive or negative impact on energy security, the social economy and the environment? Where can these technologies be developed to minimize social, environmental and climate risk exposure?



2.1 OSeMOSYS least-cost model

OSeMOSYS[13] was used to develop a least-cost energy investment plan for Namibia until 2040. OSeMOSYS is a full-fledged systems optimization model for long-run energy planning. It has been used within hundreds of different applications, including contributions to official national plans, academic studies, and discussion papers for institutions like the IPCC, the United Nations, and the World Bank.

OSeMOSYS users define multiple sets, parameters and variables that best fit their intended scenario. The OSeMOSYS algorithm then determines which energy supply mix (in terms of installed capacity and energy generation) can meet the stipulated energy demand every year and in every time step, while minimizing total discounted costs.[14]

The OSeMOSYS clicSAND interface was used to develop the least-cost model, with specific focus on Namibia's power sector, building on a base data kit developed for Namibia.[15] Key inputs were updated with the most locally representative data available and parameters were adjusted to reflect Namibia's energy targets (see further assumptions in section 3 and Appendix I).

Most techno-economic updates were drawn from Namibia's latest draft IRP 2022, which is based on existing projects in Namibia. One of the developers of the clicSAND interface was consulted for external support during the development of the model.

2.2 Riverscope analysis

TMP's Riverscope tool was used to provide a risk-adjusted financial analysis of the Baynes dam. Riverscope is a geospatial assessment tool that measures the impact of social and environmental risk for a given hydropower asset in common financial terms. The assessment provides a risk score from 0-100 by drawing on 17 subnational level social and environmental indicators that are statistically correlated with delays for hydropower projects.

These 17 social and environmental indicators were selected following a robust statistical analysis based on two distinct sets of existing hydropower projects: a Test set with projects reported to have experienced problems and delays, and a Control set that did not have reported problems. Over 300 indicators were analyzed to determine which could identify statistically significant differences between the Test and Control sets. This process provided 17 social and environmental indicators at subnational level.

Using these 17 indicators, Riverscope provides an overall risk score for a given hydropower asset's location, which indicates whether the underlying local conditions are more or less similar to the Test or Control set. Through this process, higher scores indicate statistical correlation with problems and delays.

Riverscope's overall risk score is then correlated with TMP's expected delay model to provide a range of potential delays for a given hydropower asset. The delay model was developed from 49 existing hydropower assets with a range of delays from several days to decades. The expected delays are then input into a financial modelling process, using a discounted cashflow model.

The financial modelling process draws on publicly available financial assumptions alongside the potential delays to determine how these delays affect a project's Net Present Value (NPV) and estimated Levelized Cost of Electricity (LCOE). This risk-adjusted LCOE can then be compared with alternative technologies, like solar and wind.[16]

2.3 Geospatial analysis

Geospatial analysis was used for two assessments. The first identified the most suitable sites for solar and wind development. The second provided a climate risk assessment of the Kunene River Basin.

2.3.1 Solar and wind suitability analysis

The solar and wind suitability analysis combined TMP's model for grievance-driven risk with the resource assessment process outlined in IRENA's Multi-criteria Analysis for Planning Renewable Energy (MapRE)[17] to provide a unique macro-level view of the best potential areas for solar and wind development. The assessment adopts social, environmental and technical constraints[18] common

13. http://www.osemosys.org/ ; https://osemosys.readthedocs.io/en/latest/index.html
14. For a more detailed understanding of the OSeMOSYS ethos, structure and development, please see the following three key papers: https://www.sciencedirect.com/science/article/abs/pii/S0301421511004897 ; https://www.sciencedirect.com/science/article/abs/pii/S2211467X18300142 ; https://www.sciencedirect.com/science/article/pii/S2211467X21000365
15. https://www.researchsquare.com/article/rs-481002/v1
16. See the full Riverscope methodology document for a more detailed explanation of Riverscope: https://riverscope.org/wp-content/uploads/2021/12/Riverscope-Rating-System-Methodology_final_15_12_2021.pdf
17. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2015/IRENA-LBNL_Africa-RE-_CEC_2015.pdf
18. See Appendix III for full list of constraints, assumptions and sources

in good solar and wind technical siting assessments but adds a novel social risk component that is generally absent in early renewable energy siting.

TMP's social risk model was developed over several years and draws on 14 social, environmental and governance indicators that are statistically correlated with grievance-driven risks. The model indicates which areas are more likely to be challenging operating environments for development. Early renewable energy siting assessments generally lack this more detailed social risk analysis.

2.3.2 Climate risk assessment

The climate risk assessment of the Kunene River basin drew on one of TMP's climate hazard models for extreme drought risk in the coming decade.[19] The model measures the effect of a global increase in temperature between 1 and 1.5 degrees on extreme drought conditions. The risk factor is determined by the relative likelihood of these extreme events occurring. In other words, areas that are the most likely to experience extreme climate events will score the highest.

Photo: Namibia | Alan Jay Hendry Unsplash

19. The climate model is one of many developed through TMP's Mission Climate Project, which analyzes the social, political and economic impacts of climate change in the 2020s. See more here: https://mission.asktmp.com/

3. Namibia's energy status and least-cost future

3.1 Current energy status

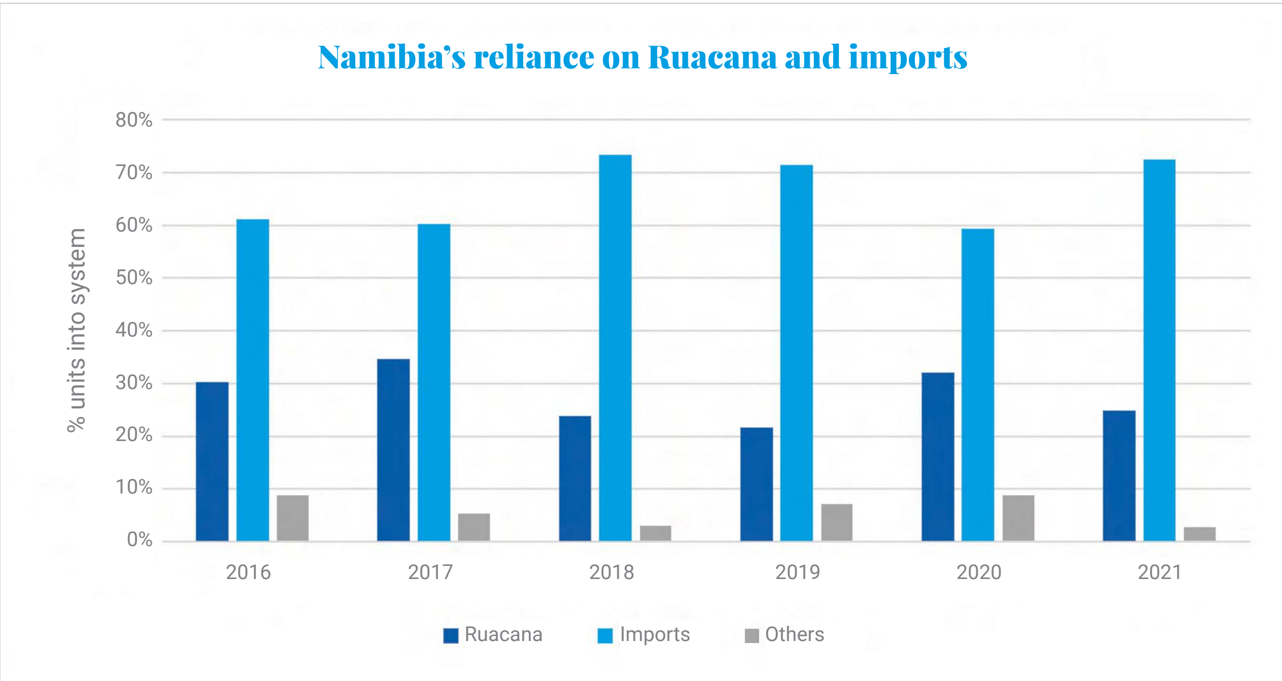
Namibia has a relatively small energy sector, with an estimated installed capacity of ~640MW.[20] This is made up of Nampower's three key powerplants,[21] renewable energy Independent Power Producers (IPPs), as well as some off-grid capacity.

Energy demand projections for Namibia suggest that demand could almost double by 2040 to ~6500GWh, from a base of ~3950GWh in 2021.[22] This will require considerable new investment into technologies that can be developed rapidly, while providing reliable and low-cost electricity.

Namibia is heavily reliant on the 347MW Ruacana hydropower project, which makes up over half the country's installed capacity. But Ruacana can only run at full capacity during the rainy season (which coincides with the low demand season), and operates as a peaking plant for the rest of the year. This seasonal operation partly explains its relatively low average capacity factor of ~41%.[23]

Dependency on Ruacana's performance is coupled with a heavy reliance on more expensive energy imports from neighboring countries, which accounts for 50-70% of annual electricity consumption.[24] For comparison, Ruacana produces electricity at $0,013-0,025/kWh,[25] while imports from South Africa cost anywhere between $0,9-0,12/kWh.[26]

During drier years, Ruacana's performance is hampered, and Namibia is forced to increase its imports from countries like South Africa. Such heavy import reliance is both expensive but also not assured in the long-term given South Africa's own energy security crisis,[27] and the similar reliance of its importers on hydropower.[28] This dual reliance on Ruacana and imports is illustrated in the graphic below.[29]



20. This figure relies primarily on the draft IRP 2022, which was verified through other sources and adjusted slightly where appropriate – e.g. the Hardap solar project has an installed capacity of 45, but its maximum export capacity is really only 37MW
21. These include the 347MW Ruacana hydropower project, the 120MW Van Eck coal plant (with current max output of 41MW) and the 22.5MW Anixas LFO/HFO power station
22. These projections are based on current electricity consumption provided by Nampower, with annual increase projections from the draft IRP 2022
23. Based on the past 5 financial years from Nampower annual reports 2017-2021: https://www.nampower.com.na/Media.aspx?m=Annual+Reports
24. South Africa's utility ESKOM is the largest importer, accounting for roughly 40% of Nampower's total available electricity between financial years 2017-2021: https://www.nampower.com.na/Media.aspx?m=Annual+Reports

By contrast, solar and wind still make up a relatively small portion of the energy consumed by Namibia, at approximately 8%. However, Namibia's recent shift in energy market structure from a Single-Buyer model to Modified Single-Buyer model has helped to promote greater private investment by opening 30% of the electricity market to private competition.

Private investment in wind and solar could help Namibia to move away from dependence on unreliable hydropower and expensive imports. Indeed, our analysis suggests this is the cheapest and best technological pathway for Namibia and should thus be prioritized by energy planners.

3.2 Least-cost models and results

We used OseMOSYS to model two indicative least-cost energy investment scenarios for Namibia till 2040; a 'Base case' scenario, and a 'Baynes' scenario. Both scenarios included the same sets of assumptions, but for the Baynes scenario a constraint was set to force the development of the project in 2031, for comparison.[30] Without this constraint, the model does not select Baynes as a least-cost option.

We used a capital cost assumption for hydropower that excludes grid connection costs.[31] This is extremely conservative given that Namibia's draft IRP 2022 estimates grid connection costs for Baynes at around 46% of overall project costs. Under this assumption, the Base case scenario selects 59MW of new hydropower capacity in 2028 but does not when grid costs are included.

In addition, solar and wind were each constrained to meet 15% of annual demand as a precautionary measure to ensure system flexibility. Both technologies reach this constraint from 2026 onwards, and again, no new hydropower is selected if this constraint is removed.

Additional noteworthy assumptions include the commission of several key Namibian energy projects in later stages of development. These include 7 projects between 2022 and 2024, which account for 50MW of oil-fired gas, 40MW of biomass, 40MW of solar PV and around 135MW of wind. We relied on the draft IRP and publicly available information to verify the expected commission dates for these projects.

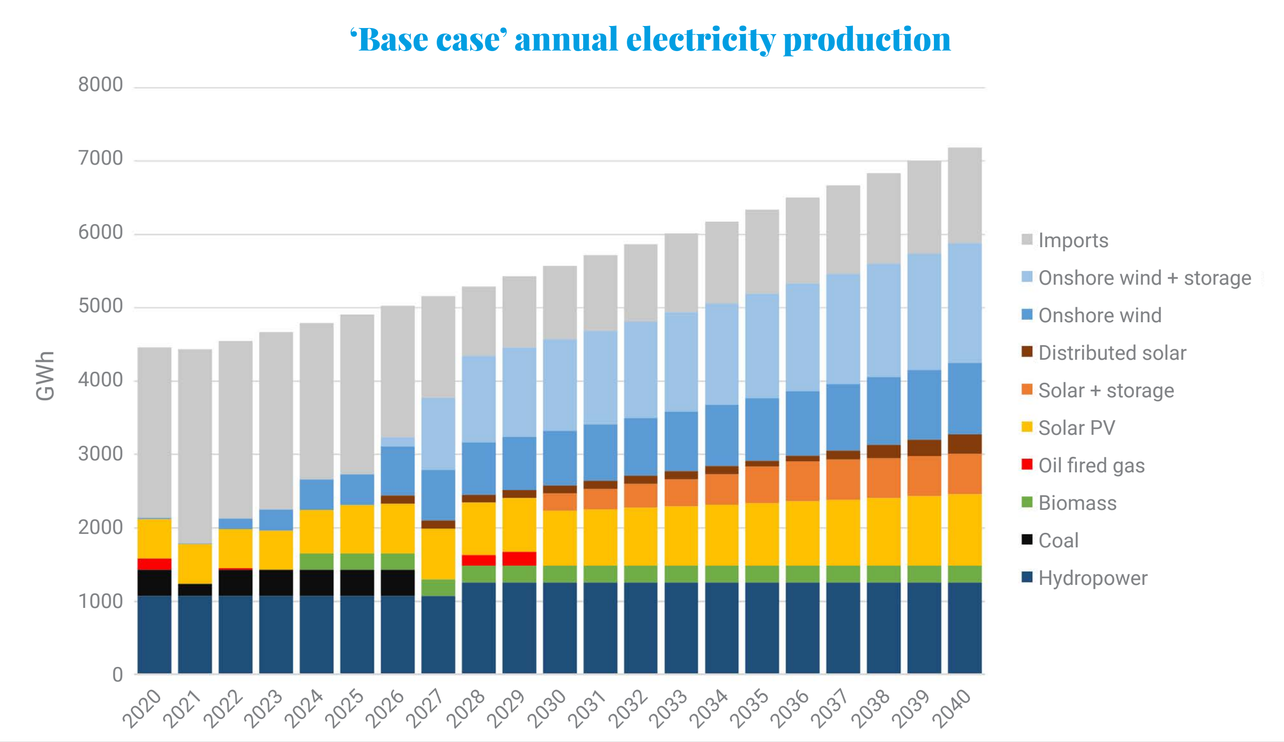
Private investment in wind and solar could help Namibia to move away from dependence on unreliable hydropower and expensive imports. Indeed, our analysis suggests this is the cheapest and best technological pathway for Namibia and should thus be prioritized by energy planners.

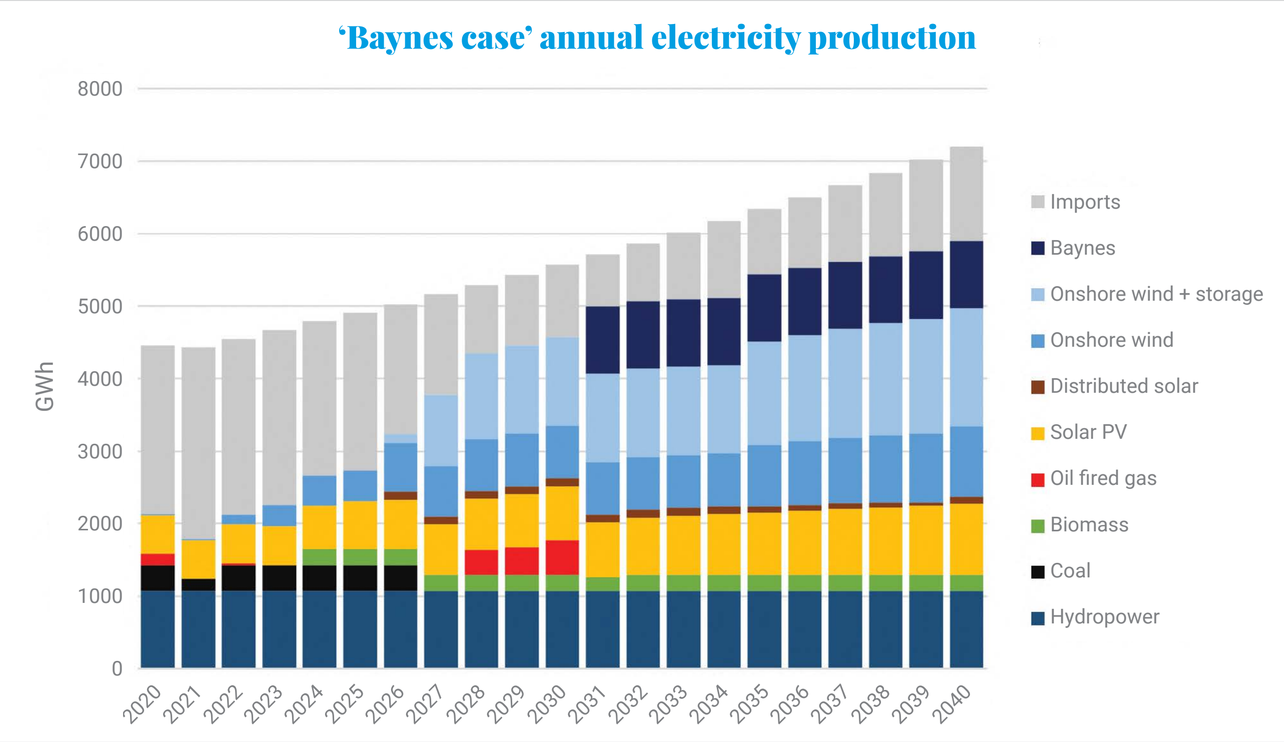
25. This is on the lower end of the cost spectrum for large hydropower, which may be explained by the fact that Ruacana was commissioned in 1978, when hydropower was considerably cheaper. Figure from: https://mcusercontent.com/e29d815e6568beb2d63670a88/files/42bdbb45-c5c4-43cc-8fda-08ba61adeff4/Namibia_Country_Report.pdf
26. https://www.zawya.com/en/projects/utilities/namibia-plans-to-purchase-surplus-power-from-10bln-green-hydrogen-project-b5m0co90
27. https://businesstech.co.za/news/energy/630667/south-africas-horror-year-of-load-shedding-heres-how-it-compares/
28. Zambia and Zimbabwe are the second and third largest source of imports to Namibia, but similarly rely on hydropower for a respective 85% and 65% of their total electricity production https://ourworldindata.org/grapher/share-electricity-hydro?time=latest
29. Nampower annual reports 2017-2021: https://www.nampower.com.na/Media.aspx?m=Annual+Reports
30. We model Baynes at 300MW because half its capacity would be shared with Angola
31. It is uncertain whether the capital costs for solar and wind derived from Namibia's draft IRP 2022 include grid connection costs, although we assume they do. We excluded grid connection costs for hydropower to be conservative. This is amplified by the relatively large grid connection costs for hydro-power compared to solar and wind.

3.2.1 Least-cost options

Despite these assumptions, as well as the forced selection of Baynes, both scenario results are dominated by solar and wind with and without storage by 2040, which strongly indicates that these are the least-cost options for Namibia.[32] This is perhaps unsurprising given their rapidly falling costs to date. Notably, Namibia's recent draft IRP 2022 came to similar findings.

Comparing these two scenario results, we can see that by forcing in the Baynes project in 2031, the project would primarily replace new solar with storage capacity and the additional 59MW of hydropower that we have established is not a least-cost option. In other words, the opportunity cost of investing in Baynes is less investment into least-cost solar and storage.





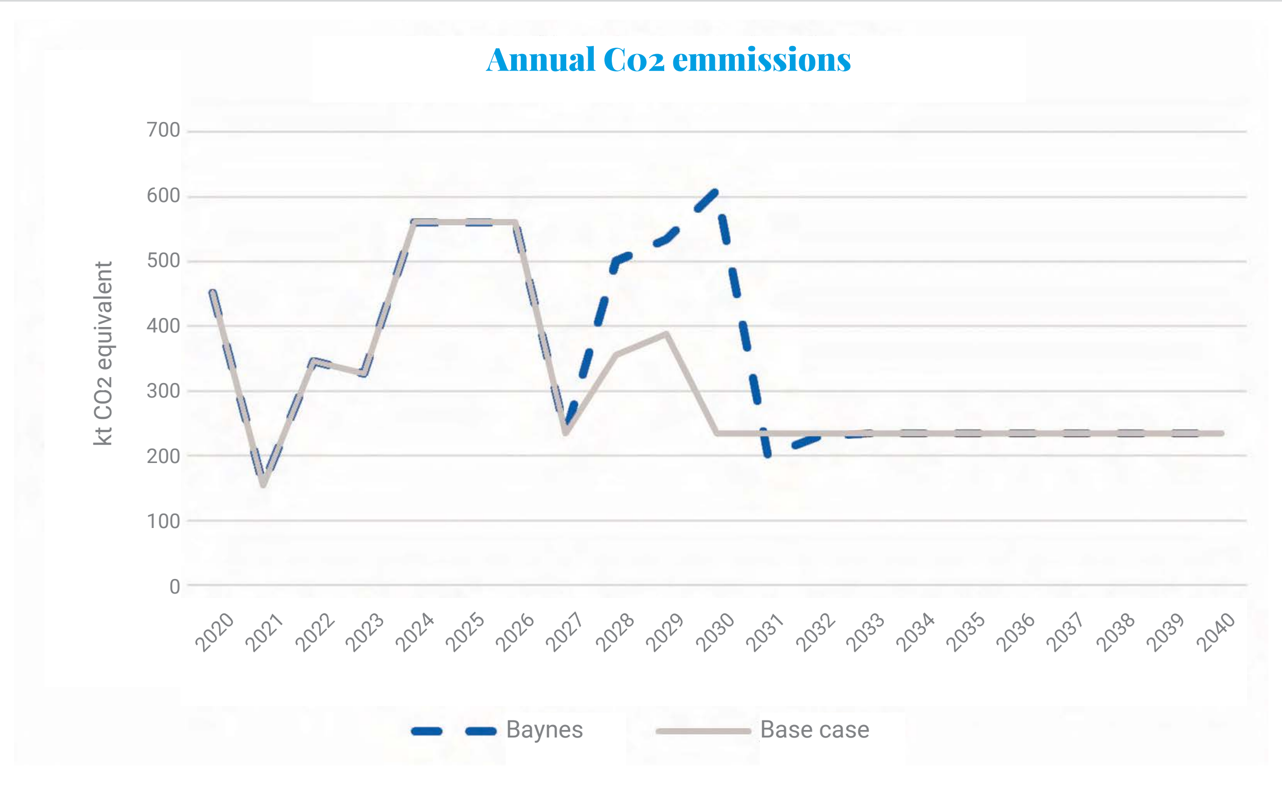
32. See Appendix II for OSeMOSYS installed capacity results

3.2.2 Overall carbon emissions

Interestingly, this replacement of least-cost options with Baynes indirectly increases the overall CO2 emissions for the Baynes scenario. Because no new solar with storage is developed in 2030, the Baynes model relies more heavily on oil-fired gas (the Anixas 1 and 2 projects) in that year. As a result, the Baynes scenario is around 10% more CO2 intensive by 2040 than the Base case, with cumulative contributions of 7,143 and 6,516 kt of CO2 equivalent, respectively.

The above comparison excludes any potential greenhouse gas emissions from Baynes, which are uncertain. However, if we assume potential emissions from Baynes are similar to modelled reservoir emissions in other arid areas,[33] Baynes could contribute 92.7-296.6 kt of CO2 equivalent between 2031-2040. This would make the Baynes scenario 11-14% more CO2 intensive than the Base case.

Overall, however, both scenarios do reflect reduced CO2 emissions between 2020-2040 (see figure below), primarily driven by the assumed decommission of the Van Eck coal plant in 2026,[34] alongside the increasing proportions of solar and wind.



33. Assuming 10–32 kg CO2-eq MWh−1 : https://www.sciencedirect.com/science/article/abs/pii/S1462901121000514

34. The Van Eck coal plant is extremely old and is expected to be decommissioned in the coming years. This especially under increasing global pressure to meet climate targets. Namibia's draft IRP 2022 assume decommission from between 2024-2026.

3.2.3 Import reliance

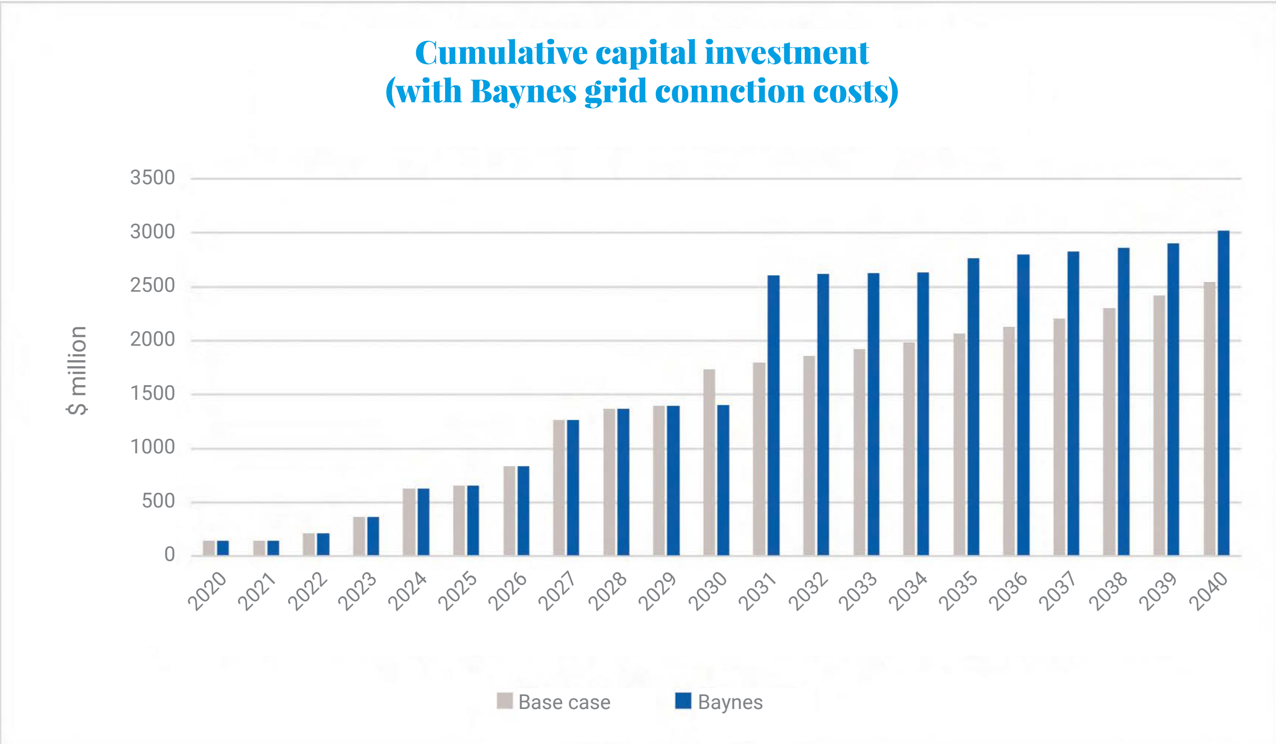
The Baynes scenario results reflect lower electricity imports between 2031 – 2038, with the introduction of Baynes. This suggests that by forcing Baynes into the mix, Namibia could be less reliant on imports over this period. But this lower import reliance may not always materialize given Ruacana's poor performance during drier years, which are likely to become more frequent and severe (see section 4.3 on climate risk).

It is worth noting that we assumed Namibia's import reliance would decline in line with their target to be 80% self-sufficient by 2028,[35] which explains the gradual decline of imports between 2021-2028. From 2028 overall maximum imports are limited to 20% of overall demand. Because overall demand continues to increase, we still see a gradual increase of imports in absolute terms. This suggests that regional imports would continue to play an important role in Namibia's energy mix, albeit less so under a more diverse mix.

3.2.4 Capital investment and operating requirements

Overall, the Baynes scenario costs 3% more than the Base case scenario by 2040,[36] without grid connection costs for Baynes.[37] Solar and wind have lower operating costs than hydropower, which is reflected by the fact that overall capital investment costs for the Baynes scenario, without grid connection costs, are slightly lower than the Base case.

However, the capital cost of grid connection for Baynes is significant. If we compare the capital investment costs of the same two scenarios with added grid connection (as estimated in the draft IRP), the Baynes scenario becomes 19% more capital intensive than the Base case by 2040 (see 2031 in the figure below). Overall, this suggests that these distinctions in cost intensity can primarily be explained by the high upfront capital costs required for large hydropower.



35. https://www.ecb.org.na/images/docs/Spark_Newsletters/2021/Spark_November_2021.pdf
36. This includes capital investment and operational costs.
37. We took a conservative approach by excluding grid connection costs for Baynes because it is uncertain whether grid connection costs were included in the capital costs for solar and wind, derived from Namibia's draft IRP 2022.

Another consideration is that, on average, large hydropower projects experience budget overruns of 33%.[38] This means that the hydropower capital investment costs discussed here could be even higher under a Baynes scenario, should the project run over budget.

These high capital costs for large hydropower may help to explain why Baynes has struggled to receive funding to date.[39] Smaller, less capital-intensive energy projects that offer shorter, lower risk payback periods are generally more attractive for investors. This is reflected in the successful financing achieved for solar, wind and battery storage projects in Namibia, both from private and public finance.[40]

3.3 Integrating least-cost variable renewable energy

Along with greater capacity expansion, Namibia will need to invest resources in building grid flexibility and stability. This is especially true for an energy mix that is increasingly dominated by variable renewable technologies alongside a growing demand profile.

Energy storage systems are one way that Namibia can achieve greater integration of variable energy (as discussed below). Regional interconnections and trading through the Southern African Power Pool (SAPP) are another. This report is more focused on assessing domestically available energy technology options that can support Namibia's ambition to become more energy self-sufficient. But we do recognize that the SAPP is another important means to integrate variable technologies at grid scale, which could also help reduce demand for utility energy storage.

3.3.1 Battery energy storage systems

Energy storage, such as battery energy storage systems (BESS), is a crucial contributor to grid flexibility and stability. BESS can store energy when in low demand (and cheaper) and feed this cheaper energy back to the grid during peak demand periods. This reduces overall costs of electricity and strain on transmission infrastructure. In sparsely populated countries like Namibia, BESS enables off-grid configurations to avoid unnecessary grid extensions.

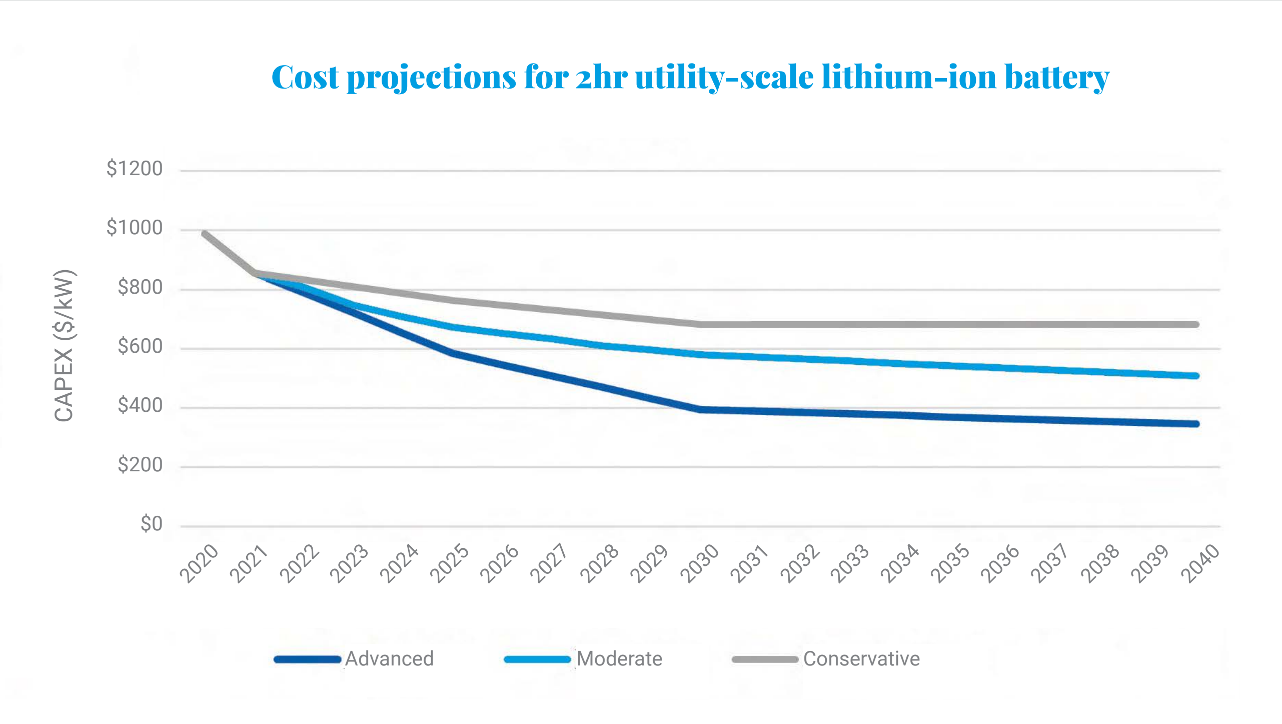
Currently OSeMOSYS does not model storage, nor does it account for system flexibility. However, we did constrain the proportion of annual electricity production from solar and wind to account for these flexibility concerns in a simplified manner.[41]

The storage component was also partly integrated by adding technology options that couple utility-scale solar or wind with storage. In order to mimic the role of storage, we increased the capacity factor for solar and wind during their least productive time of the day and according to the respective hours of storage.[42]

From a cost perspective, we added the CAPEX cost for a standalone storage unit to existing costs for utility-scale solar and wind.[43] These combined costs are likely conservative given that hybrid solar or wind with storage systems are generally cheaper than separate standalone systems.

Energy storage, particularly Lithium-ion batteries, has become increasingly affordable in recent decades. One study found that the real cost of lithium-ion batteries has fallen by 91% since 1991.[44] Meanwhile projections suggest that these costs will continue to fall in coming years (see figure on the next page)[45] as battery companies race to innovate for a growing international energy storage market.

38. https://www.tandfonline.com/doi/full/10.1080/07900627.2019.1568232 ; We do not include this in the least-cost modelling process, but we do in the cost of electricity comparison discussed in the next section.
39. See also section 4 on social, environmental and climate risks
40. See for examples: https://www.sciencedirect.com/science/article/pii/S0957178722000571 ; https://www.namibian.com.na/6216494/archive-read/Germany-gives-grant-for-NamPower-storage-plant ; https://anirep.com/dbns-renewable-energy-funding-tops-n1-2-billion/
41. See Appendix I for further detail on storage and flexibility assumptions
42. For solar with 2 hours of storage, we added two hours of daytime generation to the evening period. For wind with 0.5 hours of storage, but added 0.5 hours of daytime generation to the evening period.
43. These were derived from NREL's Annual Technology Baseline dataset: https://atb.nrel.gov/
44. https://pubs.rsc.org/en/content/articlelanding/2021/EE/d0ee02681f
45. Data from NREL's Annual Technology Baseline 2022 v1 dataset. Based on a representative 2hr utility-scale lithium-ion battery: https://data.openei.org/submissions/5716



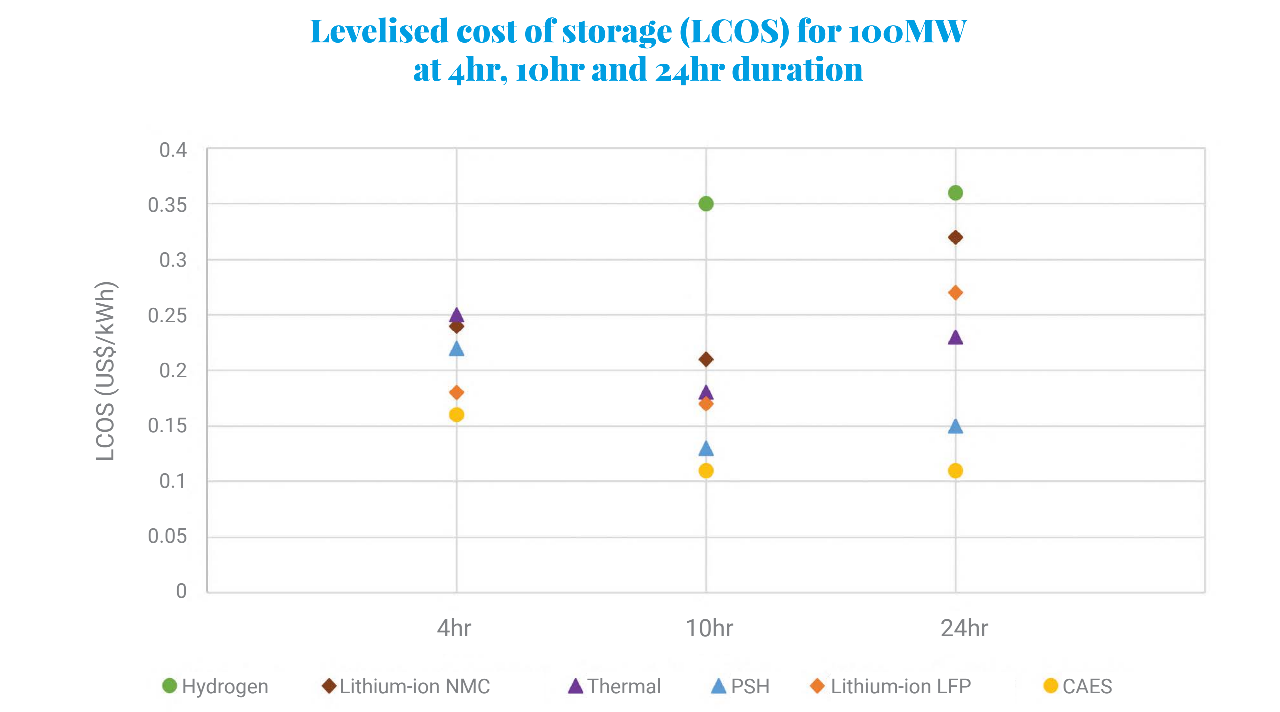
Namibia has begun to recognize the importance of battery storage, as reflected by its first large-scale Omburu BESS project, which is expected to come online in 2023.[46] The project has already received EPC funding from KfW and will be one of the first large-scale battery storage projects in Southern Africa.

The Omburu BESS project will be an important proof-of-concept for large-scale battery storage in Namibia and the region. In this way, it will likely contribute to domestic cost reductions and improved capacity for future projects, which will become increasingly salient under a more variable energy mix.

3.3.2 Long duration storage

Namibia would need to start considering longer duration energy storage options under a majority solar and wind energy mix (e.g. in year 2028). Lithium-ion battery setups can provide storage with 10hr+ durations at quite large capacities (e.g. 100MW), but these systems lose their competitive edge at these longer durations (see figure on the next page).[47] Off-river pumped storage hydropower and compressed air energy storage are two least-cost alternatives worth considering for longer duration storage at large capacities.

46. https://www.nampower.com.na/public/docs/projects/BESS/BESS%20Project%20Fact%20Sheet_12Jul2021_v1.pdf
47. CAES = Compressed Air Energy Storage ; PSH = pumped-storage hydropower : https://www.pnnl.gov/lcos-estimates



Off-river pumped storage hydropower is a lower impact option than conventional pumped storage hydropower systems, but is still heavily constrained by topography, high upfront capital costs and long lead times. Pumped storage at old and abandoned mines may be one way to overcome these challenges, as is currently being investigated in South Africa.[48] This could be a way to repurpose some of the 250+ closed and abandoned mines in Namibia,[49] while reducing associated costs and lead times.

Compressed air energy storage is another worthwhile least-cost long duration energy storage option. Although there are no demonstration projects in Africa yet, there are an increasing number of demonstration and commercial projects being developed in North America and China.[50] Initial assessments show widespread geological resource potential in Northwestern and Southeastern parts of Namibia that could be explored.[51]

Finally, Namibia has shown considerable interest in a large and ambitious green hydrogen project.[52] This project could provide an important source of backup green hydrogen for peaking or emergency generation, which would serve the same function as a long duration storage system.[53] The overall estimated cost of the project is extremely high (estimated at $10 billion).[54] However, from an environmental and social perspective, green hydrogen would be a cleaner use of funds than prospective oil and gas from the Okavango.

48. https://www.esi-africa.com/industry-sectors/asset-maintenance/rehabilitating-gold-mines-to-create-pumped-hydro-storage/
49. https://www.tandfonline.com/doi/abs/10.1080/03736245.2019.1698450?journalCode=rsag20
50. https://www.sciencedirect.com/science/article/pii/S1364032121000022
51. https://www.sciencedirect.com/science/article/abs/pii/S0196890418305351?via%3Dihub
52. https://gh2namibia.com/
53. We recognize that green hydrogen could also play an important role in decarbonizing the transport sector, and that Namibia could become a large exporter of the fuel
54. https://www.engineeringnews.co.za/article/namibian-green-hydrogen-developer-expects-implementation-agreement-on-10bn-project-by-year-end-2022-08-18

4. Comparative analysis of least-cost options and Baynes

This section provides a comparative assessment of the key least-cost options identified by OSeMOSYS (particularly solar and wind), and Namibia's proposed Baynes project. The assessment includes comparison from a techno-economic, social, climate and environmental perspective to provide a more comprehensive view of the energy options available.

4.1 Techno-economic perspective

4.1.1 Lead times and the financial impact of delays

Large hydropower projects generally take years, if not a decade or more, to develop. Indeed, the Baynes project has been on the slate since the 1990s. Under favorable conditions, it can take 5-7 years for construction of a project like Baynes, but because the social and environmental impact of these projects are often quite pronounced, they regularly face resistance from local and international groups that can further protract this process.

A Riverscope assessment of Baynes suggests that it is heavily exposed to social and environmental risks,[55] that are likely to delay the project by 2-3 years. In a worst-case scenario, Baynes could be delayed by as much as 14 years, on top of the 6 years planned for construction. The project has already faced delays in response to strong opposition from local Indigenous communities and international advocacy groups, alongside the now cancelled Epupa dam.[56] These delays not only undermine energy plans, but they have a direct impact on the financial value of projects.

Even if Baynes does not run over budget, a 2- to 3-year delay would lead to losses in NPV of 22-35% or $138–198 million. But on average large hydropower projects see budget overruns of 33%.[57] In this case, Baynes would see NPV losses of 36-50% or $199–253 million.

By contrast, solar and wind projects can be developed in at least half the lead time, and are not exposed to the same level of social and environmental risk. Namibia's 37MW Hardap PV project was the first large PV project in Namibia (larger than 5MW) and was commissioned within just 2 years between 2016-2018. Hardap also became one of the cheapest sources of power on the grid.[58]

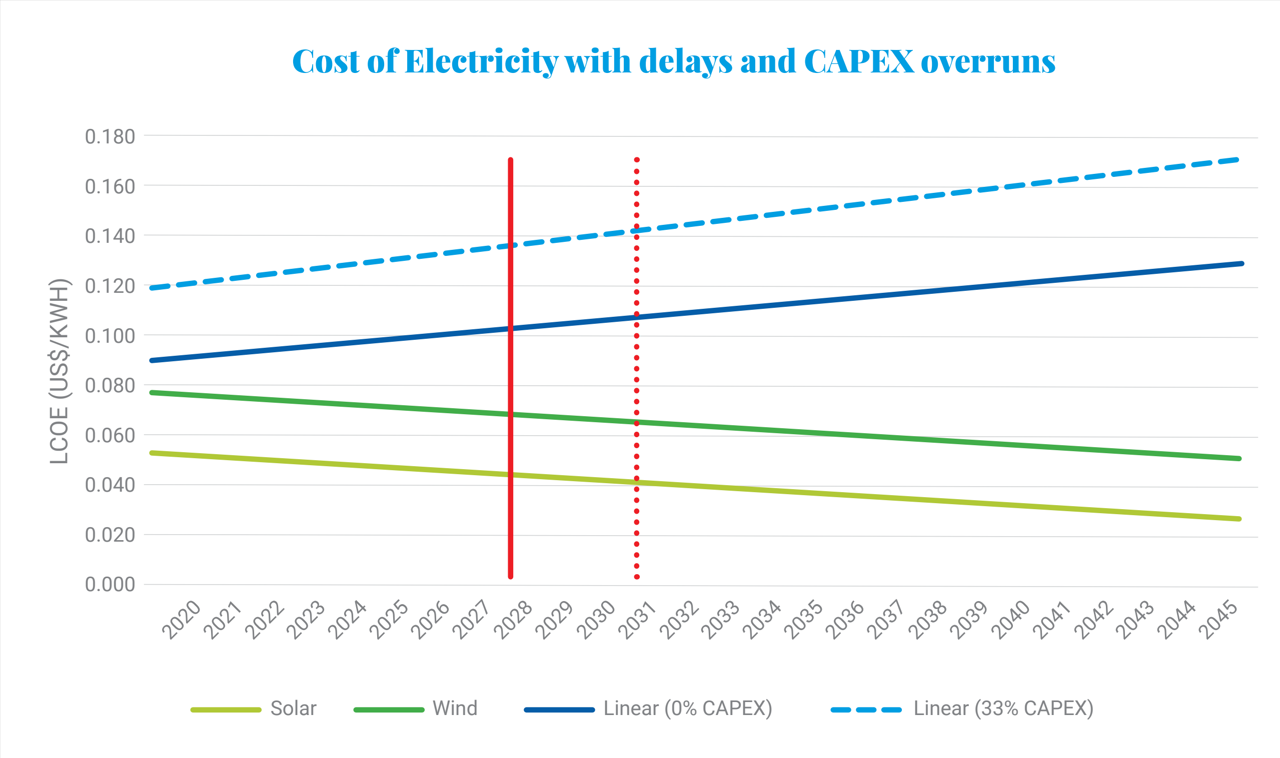
4.1.2 The end costs of electricity

Large hydropower projects have historically been a large source of low-cost electricity. However, they have become increasingly expensive in the past decade, while solar and wind have become more competitive.[59] One common approach for comparing the costs of different energy technologies is to consider their end costs of electricity or LCOE.

Project documents for Baynes indicate that its expected LCOE is $0.11/kWh, while our own financial modeling produces a more conservative estimate of $0.10/kWh at the best-case point of operation in 2028.[60] This suggests that under favorable conditions, Baynes would cost 37-51% more than the average weighted LCOE for large hydropower in Africa, at ~$0.075/kWh.[61]

However, the above costs do not factor in delays, which are extremely common for large hydropower and can drive up the end cost of electricity produced. A 2-3 year delay for Baynes would increase the cost of electricity produced by 3-4%. These higher costs of electricity are most striking when compared to the rapidly falling costs of solar and wind.

55. Baynes got an overall risk score of 86 / 100. Compared to previous Riverscope assessments in Africa, Asia and Latin America, this is on the upper end of the scale of overall risk scores.
56. https://www.berghahnjournals.com/view/journals/regions-and-cohesion/11/1/reco110103.xml
57. https://www.tandfonline.com/doi/full/10.1080/07900627.2019.1568232
58. https://www.sciencedirect.com/science/article/pii/S0957178722000571 ; https://mcusercontent.com/e29d815e6568beb2d63670a88/files/42bdbb45-c5c4-43cc-8fda-08ba61adeff4/Namibia_Country_Report.pdf
59. https://irena.org/-/media/Files/IRENA/Agency/Publication/2022/Jul/IRENA_Power_Generation_Costs_2021.pdf
60. See Appendix IV for a list of financial modelling assumptions used
61. https://irena.org/-/media/Files/IRENA/Agency/Publication/2022/Jul/IRENA_Power_Generation_Costs_2021.pdf
62. The figures assume that Baynes would come online in 2028, with a budget overrun of 33%, and would produce 805 GWh of electricity annually for Namibia (half the expected 1,610 GWh would go to Angola). The LCOE difference and total additional costs increase every year because of the expected falling costs of solar and wind.



The figure above shows the cost of electricity from Baynes with increasing delays (blue lines) against the projected costs of domestic solar and wind (green lines). The graph indicates that Baynes is not competitive and is increasingly less so with additional delays. If Baynes came online in 2028 as previously reported, it would already be 52-137% more expensive than existing domestic alternatives. If delayed till the more likely date of 2031, it would be 66-166% more expensive.

Research suggests that large hydropower projects also run over budget by 33% on average. Considering the same two operation dates of 2028 and 2031, a budget overrun of 33% would make Baynes between 102-216% and 121-254% more expensive than local alternatives under each respective scenario.

The opportunity cost of purchasing more expensive power from Baynes, versus solar or wind, means that Namibia would effectively lose millions of dollars for every year that Baynes operates. The table below shows the LCOE difference and total additional cost that Namibia would incur from Baynes, compared to power from solar or wind.[62]

Year	LCOE difference: Baynes vs wind / solar ($c/kWh)	Total additional cost per year ($ million)
2028	6.86-9.31	55.3-74.9
2029	6.97-9.41	56.1-75.7
2030	7.08-9.50	57.0-76.5
2031	7.19-9.60	57.9-77.2
2032	7.29-9.69	58.7-78.0
2033	7.39-9.78	59.5-78.7
2034	7.50-9.86	60.3-79.4
2035	7.60-9.95	61.1-80.1
2036	7.69-10.03	61.9-80.8
2037	7.79-10.12	62.7-81.4
2038	7.88-10.20	63.5-82.1
2039	7.98-10.27	64.2-82.7
2040	8.07-10.35	65.0-83.3
TOTAL	-	**783-1,031**

62. The figures assume that Baynes would come online in 2028, with a budget overrun of 33%, and would produce 805 GWh of electricity annually for Namibia (half the expected 1,610 GWh would go to Angola). The LCOE difference and total additional costs increase every year because of the expected falling costs of solar and wind.

4.1.3 Grid connection

Our research suggests that hydropower projects are increasingly planned in more remote locations. But these remote sites are both riskier and often require hundreds of kilometers of new transmission infrastructure to reach areas of demand. Extensive transmission requirements can make up a considerable portion of overall project costs, while creating an additional layer of exposure to social and environmental complications.

The Baynes site is located at least 150km away from the nearest town, Opuwo, and will require approximately 450km of new transmission infrastructure to feed into the Namibian and Angolan grids.[63] Namibia's draft IRP 2022 estimates grid connection costs at $1.1 billion, which is almost half of the total project costs. This is an exceptionally large bill for such a high-risk project.

In addition, Namibia is vulnerable to transmission losses because of its expansive land area and low population densities. Around 10% of Namibia's energy supply is already lost to transmission.[64] The further away new projects are sited from the existing grid or energy demand centers, the more power will be lost during transmission.

Such additional grid costs and losses create a strong case for Namibia to pursue least-cost solar and wind options which can be sited closer to areas of demand and within close proximity to existing grid and road infrastructure (see section 5). This would reduce additional costs and risks associated with grid extension. Such siting flexibility is owed to Namibia's widespread solar and wind resources as well as the modular nature of the technologies themselves.

4.2 Social perspective

4.2.1 Local social impact and opposition risk

Opposition from local or international groups to energy development can have a material impact on Namibia's energy transition, either by causing delays or in more extreme cases, cancellations.[65] These social risks can create real problems for the timely development of new energy supply, and by extent energy security for whole countries or regions.

Fossil fuels like coal, oil and gas are the most exposed to these risks, because they pollute water and atmospheric systems, and contribute directly to global warming. Indeed, concerns over oil and gas "fracking"[66] in the Okavango Basin have led to significant local and international opposition because the region drains into the Okavango Delta, a UNESCO World Heritage Site, and is home to indigenous groups who would likely be directly affected.[67]

Of all the renewable energy technologies, hydropower stands out as being the most exposed to such social risks because it also directly affects freshwater resources (e.g. drinking water quality and fisheries) and regularly drives displacement of vulnerable groups (e.g. local and indigenous communities). Namibia's experience with the Baynes and Epupa dams are strong cases in point.

The Baynes and Epupa sites were first assessed in the 1990s but later faced strong opposition from several local indigenous communities.[68] The Epupa site was found to have greater negative impacts, but Baynes would still flood indigenous dwellings, critical grazing land and culturally significant sites.[69] Opposition efforts were supported by an international advocacy group and reported to the United Nations, until Epupa was scrapped altogether. This legacy of opposition is a significant social risk factor for further consideration of Baynes, especially without careful implementation of FPIC processes.

Solar and wind are not necessarily immune to local opposition or conflict, especially in the absence of proper social license processes. However, these

63. https://www.sapp.co.zw/file/1413/download?token=dc-YGRAx
64. https://www.nampower.com.na/Media.aspx?m=Annual+Reports
65. Renewable energy examples include: the Hydel hydropower project in India: https://thediplomat.com/2020/02/controversial-hydel-project-in-indias-northeast-on-way-to-completion/ ; the São Luiz do Tapajós hydropower project in Brazil: https://www.theguardian.com/environment/2016/aug/05/major-amazon-dam-brazil-opposed-by-tribes-fails-get-environmental-license ; and the Kinangop Wind Park in Kenya: https://news.trust.org/item/20160223123846-9mdhy/
66. "Fracking", or hydraulic fracturing, uses high-pressure fluid injections to shatter rock formations and extract oil and gas. Key environmental concerns include large water requirements, which can contaminate local groundwater, air pollution and methane emissions, amongst others.
67. See for example: https://www.bbc.com/news/world-africa-63567513 ; https://www.aljazeera.com/economy/2021/4/22/namibia-indigenous-leaders-want-big-oil-out-of-kavango-basin ; https://savetheokavango.com/ ; https://www.namibian.com.na/208418/archive-read/Wildlife-fund-warns-against-Kavango-drilling
68. https://intercontinentalcry.org/namibia-growing-frustration-in-kaokoland-1000-himba-and-zemba-protest-again-against-dam-and-human-rights-violations/
69. https://www.erm.com/contentassets/decaeb470695428ea96b9fc4651cd49f/non-technical-summary-annotated.pdf

technologies simply do not have the same kind of large-scale environmental and social impacts, which considerably reduces the likelihood of local backlash. Solar and wind can be more easily sited in areas that avoid issues like displacement, especially in Namibia which is well-endowed with suitable areas. Such social risks can be further mitigated with proper application of FPIC.

4.2.2 Employment and access to energy

Namibia is burdened with a combination of high unemployment and low electrification rates. Currently ~22% of the country are without work,[70] while ~44% do not have access to electricity.[71] The scale of energy development needed for Namibia's growing demand provides an opportunity to address these issues simultaneously. However, this will largely depend on Namibia's chosen technology pathway.

Large hydropower projects can provide up to a couple thousand construction jobs over extended construction periods of 5-7 years. We expect that Baynes would create roughly 3,000 construction jobs over the estimated 6 years of construction.[72] But it is well known that once construction comes to an end so do the jobs, for the most part.

Construction of these large projects requires a largely technical labor force. Namibia generally lacks experience with hydropower development[73] and the largest portion of its labor force is relatively low-skilled.[74] This suggests that any jobs created through Baynes would likely be sourced from outside the project area, or indeed the country. The potential benefits of employment from Baynes are therefore unlikely to go to those people most affected by the project.

Of those jobs made locally available, we expect half to go to Angola given that the project benefits are to be shared. While this would be appropriate, it would further reduce potential employment benefits from Baynes for Namibia.

Baynes would unlikely do much for Namibia's electrification needs either. On the one hand, half of the 600MW capacity would go to Angola, on the other, the remaining 300MW would provide bulk supply to the grid primarily on a mid-merit/peaking basis. In other words, Baynes would feed into a grid that reaches just over half the country.

An equivalent investment into 763 – 1,316 MW[75] of new wind and solar could do far more from both an employment and energy access perspective. This added capacity similarly spread over 6 years could provide 1,435 – 3,039 direct jobs in each year.[76]

We also know that all these jobs can be filled by Namibians, based on the recent 20MW Omburu solar PV project.[77] This reflects that solar and wind simply do not require the same niche level of technical expertise needed for large hydropower. Overall, this indicates that the domestic job creation potential of solar and wind is more certain than it is from Baynes.

From an electrification perspective, some of this solar and wind capacity could be sited in areas of growing demand that do not yet have access to electricity. This could be in a mini-grid or off-grid setup depending on the size and nature of the settlement. Increasing access to electricity can also support the growth of local economies and create new employment opportunities in the process.

We found 55,263km^2 and 14,480km^2 of suitable areas for solar and wind, respectively, are at least 50km outside of high voltage transmission lines and primary road access (see next section). This suggests off-grid setups may be more appropriate in these areas. Off-grid options are especially important in sparsely populated countries like Namibia because they can reduce the costs and losses of extensive transmission networks, and are well-suited to meet immediate local energy needs in remote areas.

70. https://data.worldbank.org/indicator/SL.UEM.TOTL.ZS?locations=NA
71. https://data.worldbank.org/indicator/EG.ELC.ACCS.ZS?locations=NA
72. The ESIA summary suggests an influx of 2,000-3,000 construction and work seekers into the project area during construction: https://www.erm.com/contentassets/decaeb470695428ea96b9fc4651cd49f/non-technical-summary-annotated.pdf ; although there is uncertainty around the exact number of jobs expected from Baynes, our expected figure of 3,000 jobs is supported by the similar sized 750MW Kafue Gorge Lower hydropower project in Zambia, which created 3,000-4,000 jobs: https://web.archive.org/web/20190717154646/http://www.xinhuanet.com/english/2019-07/15/c_138229193.htm ; https://twitter.com/EdgarCLungu/status/1418507864684044291
73. Ruacana is Namibia's only hydropower project and was commissioned over 20 years ago in 1978
74. https://d3rp5jatom3eyn.cloudfront.net/cms/assets/documents/NLFS_2018_Report_Final_.pdf
75. This assumes half the total cost of Baynes would be split equally between Namibia and Angola. It uses capital costs of $912/kW for solar and $1574/kW for wind in 2022, derived from Namibia's draft IRP 2022 assumptions and capital cost reduction rates from IRENA's Planning and Prospects For Renewable Power: Eastern and Southern Africa: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/Apr/IRENA_Planning_Prospects_Africa_2021.pdf
76. These estimates are based on a methodology used in South Africa given the lack of publicly available employment data for renewable energy development in Namibia. It is a conservative estimate which excludes indirect, induced and cumulative job-years: https://www.green-cape.co.za/assets/SAREM-Draft-March-2022.pdf
77. "I am proud to say that the workforce involved in the project were all Namibians, including the design consultants, subcontractors and the workers,": https://www.erongo.com.na/energy-ero/nampower-welcomes-omburu-to-its-power-stable2022-06-27

4.3 Climate perspective

Namibia's energy system is already climate exposed because Ruacana accounts for more than half its installed capacity and has proven unreliable during droughts.[78] Nampower have also acknowledged such exposure.[79] It is unclear then why Namibia would consider increasing this climate exposure with additional hydropower capacity, especially on the same river system.

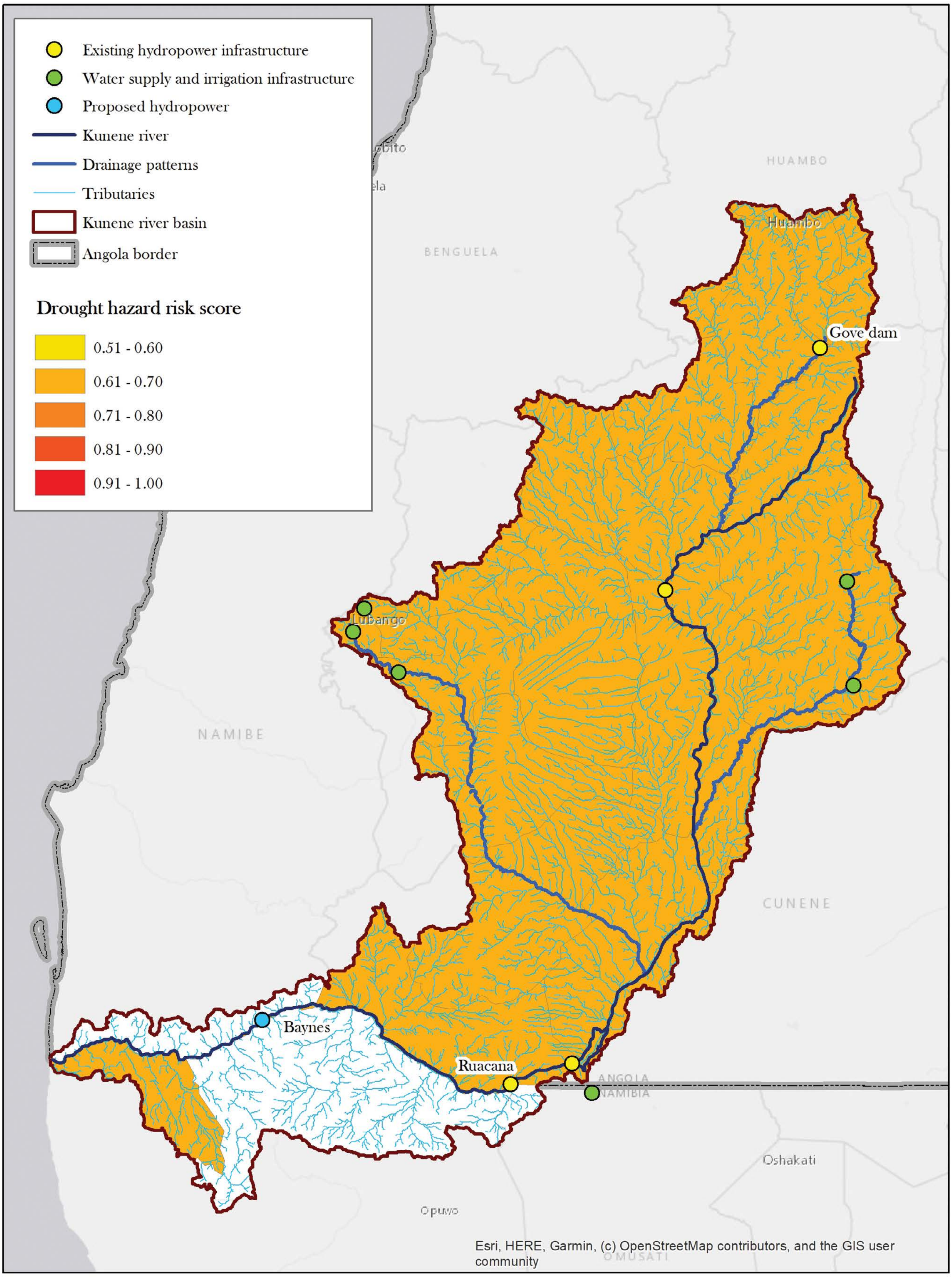
Hydropower production in the lower Kunene River Basin relies on seasonal rainfall, most of which occurs in Angola in the upper parts of the Basin. The region is characterized by high climate variability which is expected to get worse with climate change. The lower Kunene River Basin already struggles with persistent droughts coupled with increasingly unpredictable precipitation.[80]

Such high variability has proven costly for Namibia because of its reliance on imports when Ruacana is unable to perform. South African imports are 5-7 times more expensive than the cost of electricity from Ruacana.[81] This puts upwards pressure on the overall cost of electricity which is passed onto Namibian consumers or taxpayers, should this gap be subsidized.[82]

We carried out a forward-looking drought hazard risk assessment of the Kunene River Basin (see figure on the next page),[83] which indicates extreme droughts are likely to become more frequent by the end of the decade.[84] This is concerning both for the future performance of Ruacana and for local people in the region already struggling to cope with persistent drought conditions.

Photo: Kunene River Basin | International Rivers

78. https://www.reuters.com/article/ozatp-uk-namibia-power-idAFKBN1YM18J-OZATP
79. Nampower identify climate change as an emerging risk to the utility, citing "Climate change is resulting in rising global temperatures, erratic patterns of precipitation and more. This is evident from water-levels at Ruacana, which have dropped significantly.": https://www.nampower.com.na/public/docs/annual-reports/NamPower%20Annual%20Report%202021.pdf
80. https://www.verangola.net/va/en/032022/Environment/30122/Close-to-870000-people-in-Cunene-need-support-due-to-drought.htm ; https://journals.plos.org/plosone/article?id=10.1371/journal.pone.0238982
81. Ruacana figure from: https://mcusercontent.com/e29d815e6568beb2d63670a88/files/42bdbb45-c5c4-43cc-8fda-08ba61adeff4/Namibia_Country_Report.pdf ; Cost of South African imported energy figures from: https://www.zawya.com/en/projects/utilities/namibia-plans-to-purchase-surplus-power-from-10bln-green-hydrogen-project-b5m0co90
82. The most recent Nampower Annual report clearly states: "The cost of electricity increased by 7.1% from N$4.2 billion achieved in the previous financial year to N$4.5 billion … The catchment area for Ruacana did not receive good rainfall during the reporting period … This resulted in NamPower importing 67.4% (2019/20: 59%) of the power from neighbouring countries and SAPP market … The cost of imported electricity was the main contributor to the increased cost of electricity." (pg 82) : https://www.nampower.com.na/public/docs/annual-reports/NamPower%20Annual%20Report%202021.pdf
83. See section 2 for description of the climate risk modelling approach used
84. Any score above 0.51 indicates high exposure to more frequent drought extremes



Existing hydropower infrastructure
Water supply and irrigation infrastructure
Proposed hydropower
Kunene river
Drainage patterns
Tributaries
Kunene river basin
Angola border
Drought hazard risk score
0.51 - 0.60
0.61 - 0.70
0.71 - 0.80
0.81 - 0.90
0.91 - 1.00
HUAMBO
Huambo
BENGUELA
Gove dam
Lubango
NAMIBE
CUNENE
Baynes
Ruacana
ANGOLA
NAMIBIA
Oshakati
Opuwo
OMUSATI
Esri, HERE, Garmin, (c) OpenStreetMap contributors, and the GIS user community

Physical climate assessments regularly discount the effect of climate impacts on existing social conditions. Our research suggests that more frequent climate extremes are likely to exacerbate existing social grievances. We therefore expect more frequent extreme drought conditions to compound the existing grievances in the lower Kunene Basin linked to hydropower development, especially given Baynes would directly affect already scarce freshwater resources.

In addition, the location of Baynes suggests that it would be heavily reliant on competing water uses upstream (see figure above). These upstream water management systems will likely reduce water availability during drought conditions. In this scenario, the Namibian and Angolan governments would either need to leave Baynes dormant, or undermine upstream water demands.

We also reviewed various physical climate risks for solar and wind technologies. Our assessment found that the greatest physical risks to both technologies are extreme weather events (e.g. severe storms or floods) that could damage the infrastructure and force systems temporarily offline. These risks are most acute in the northern parts of the country, which could be avoided by developing solar and wind in other more suitable areas (see next section).

Nevertheless, this exposure suggests an energy system dominated by solar and wind could indeed be temporarily affected by increasingly frequent extreme weather events. But it is highly unlikely that this would be at the scale associated with a single Baynes or Ruacana project. Again, because solar and wind can be developed more widely, it is inherently more resilient to any kind of climate shock. By contrast, Baynes would concentrate an extraordinarily high level of risk into a single project.

4.4 Environmental perspective

4.4.1 Protected areas and untouched ecosystems

Protected areas are a way to preserve some of the world's rarest and most ecologically sensitive plant and animal species from extinction. It therefore makes little sense to consider large infrastructure projects, like Baynes, within or even near to such environmentally sensitive areas when they are regularly drivers of ecosystem damage and biodiversity loss.

The Baynes site borders Angola's Iona National Park, while the Kunene River mouth opens into Namibia's Skeleton Coast National Park. These are remote areas that have seen very little development. Baynes will disrupt such pristine environments during the extended period of construction, which necessarily requires an influx of thousands of people into the area, heavy machinery and new ancillary infrastructure like roads and transmission lines.

Once operational, Baynes would considerably degrade the ecological health of the Kunene River to a state widely considered to "represent the lower limit of degradation allowable under sustainable development".[85] But this relies on the assumption that Baynes would not produce any power during periods of low flow, placing ecological health and energy generation in direct competition.

These findings raise at least two major concerns. First, because water availability in the lower Kunene Basin is likely to face increasing pressure with climate change and upstream demands, Baynes may only remain viable if it considerably degrades downstream ecosystems. And second, local and indigenous communities increasingly rely on fishing as a coping mechanism for drought.[86] Threatening this livelihood strategy will likely provoke dispute.

By contrast, solar and wind simply do not have these same implications for aquatic ecosystems or resources. Our suitability analysis finds that that there are indeed large areas that can be developed outside of protected areas and scarce water resources (see next section). Solar and wind projects still need careful consideration of their environmental impacts, but these are inherently lower and easier to manage.

85. As cited from the ESIA summary: https://www.erm.com/contentassets/decaeb470695428ea96b9fc4651cd49f/non-technical-summary-annotated.pdf
86. https://journals.plos.org/plosone/article?id=10.1371/journal.pone.0238982

4.4.2 Land use requirements

The literature on renewable energy land use requirements is extensive, but overall results vary substantially. We took a simple approach of using existing projects in Namibia to determine the land required per MW for solar, compared to that of Baynes. Data on the actual footprint of domestic wind projects was more difficult to find, so we used an existing wind project in South Africa.

Baynes is expected to inundate 5,900ha of land, which translates to 9.8ha / MW. By contrast, Namibia's 20MW Omburu PV project[87] and its flagship 37MW Hardap PV project[88] required 2.1 – 2.7ha / MW, respectively. The 80MW Kouga wind farm in South Africa is located on a farm of 2,948ha, but the actual footprint of the wind farm translates to just 0.35ha / MW.[89]

This comparison suggests that Baynes would be roughly 4 times more land intensive than existing local solar options and as much as 28 times more land intensive than wind options. This has important implications for the efficient use of available land resources,[90] which may come under increasing pressure with a growing population and energy sector.

Additional land use benefits of solar and wind options are that these technologies can be co-located alongside other land uses, like mines, landfills or agriculture. For example, the remaining 2,920ha of the Kouga wind farm is used for grazing land.

Similarly, solar panels provide favorable environments for shade-tolerant crops, known as "agrivoltaics".[91] Early demonstrations in Africa suggest that agrivoltaics can provide mutual benefits for food, water and energy, with potential to improve economic outcomes for both solar investors and farmers.[92] Given the extreme temperatures and water scarcity in Namibia, this is a concept worth considering.


Photo: Aerial view of solar farm | Abriendomundo, Shutterstock

87. https://www.erongo.com.na/energy-ero/nampower-welcomes-omburu-to-its-power-stable2022-06-27
88. https://www.engineeringnews.co.za/article/namibian-pv-solar-plant-to-start-operating-in-september-2018-03-16/rep_id:4136
89. https://kougawindfarm.co.za/about-kouga-wind-farm/
90. Just 2% of Namibia receives sufficient rainfall to grow crops, while less than 1% is suitable for arable farming: https://www.giz.de/en/downloads/giz2022-en-namibia-agriculture.pdf
91. "Agrivoltaics" refers to the collocation of solar PV with crops to maximise land use efficiency, while creating potential mutual benefits for solar PV performance and crop yields.
92. https://www.mdpi.com/2073-4395/11/10/1906/htm ; https://www.weforum.org/agenda/2022/03/solar-energy-security-farm-africa/

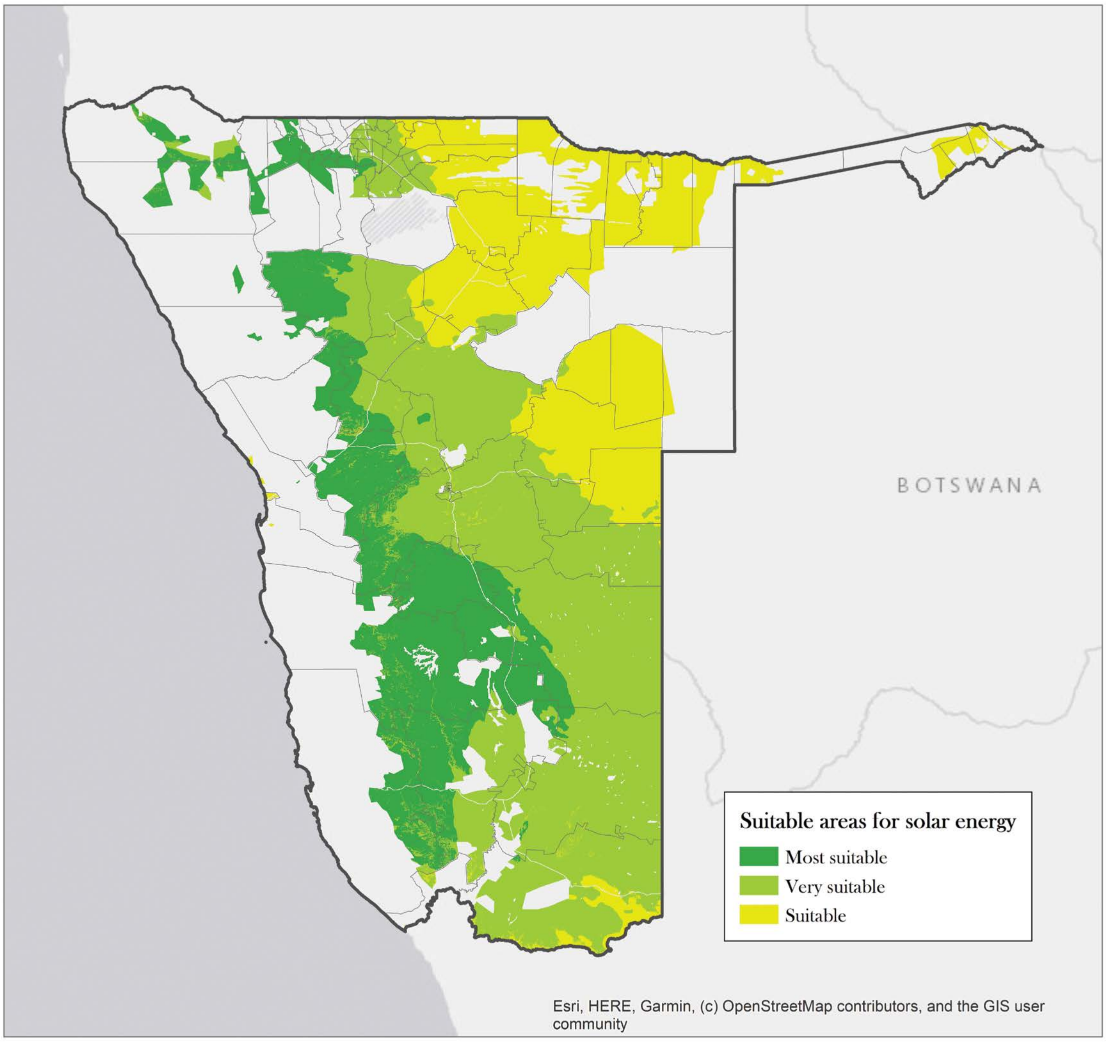
5. Mapping Namibia's solar and wind potential

We carried out a suitability assessment for solar and wind resources in Namibia to identify the best potential locations for investment. The assessment excludes important environmental areas, such as protected areas, water bodies and certain land use types (e.g. high tree cover). In addition to urban areas, it excludes any areas with population densities higher than 100 people / km^2.[93]

Unlike many early technical assessments of renewable energy potential, our assessment also considers a social risk component. This draws from an inhouse social risk model developed through TMP's extensive work on grievance-driven risks in infrastructure development.

Social impacts and risks need to be at the forefront of decision-making to achieve a smooth energy transition. Our experience suggests that some areas are more likely than others to face local grievances and opposition in response to development. These risks can have a material impact on development projects by causing delays or budget overruns, so they need to be considered early in assessment processes.

The two figures below and overleaf show the suitable areas identified for solar and wind in Namibia,[94] respectively, excluding the social risk component. As much as 483,401km^2 and 180,549km^2 of land is suitable for solar and wind



93. See Appendix III for a full list of the constraints used

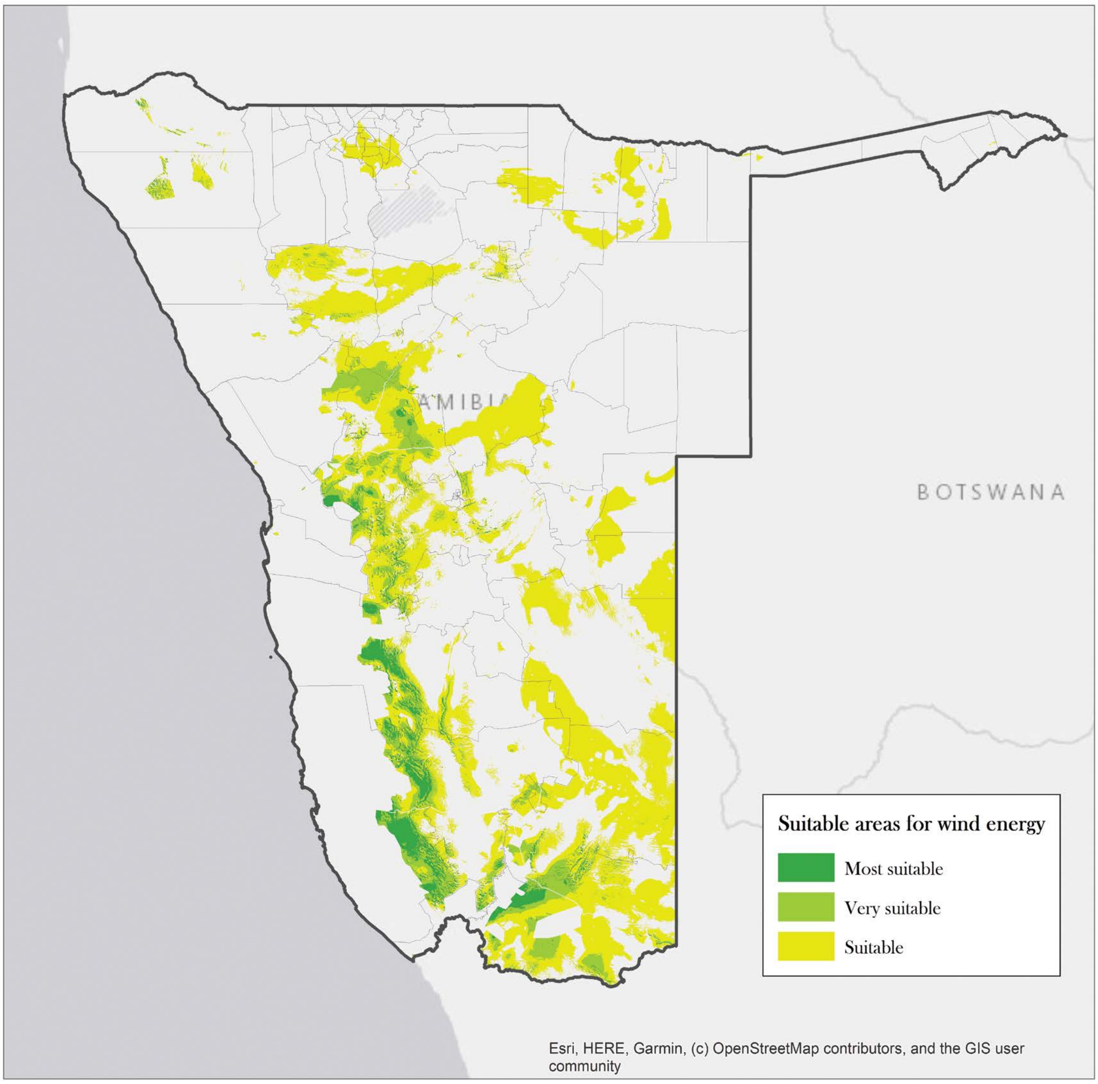
94. The solar suitable area classifications are: Suitable = 4.9-6.3; Very suitable = 6.3-6.5; Most suitable = 6.5-6.7 GHI (kWh/m2/day). The wind area classifications are: Suitable = 200-300; Very suitable = 300-400; Most suitable = >400 Wind power density (W/m2).

development, respectively (of which roughly 0.002% and 0.0006% would be required to replace the 300MW from Baynes, respectively).[95] A respective 39% and 38% of the total solar and wind area is located within 50km from existing high voltage transmission infrastructure[96] and primary road access, while the remaining portions may be better suited for off-grid configurations.

The assessment indicates that there are generally more suitable areas for solar than for wind. In addition, most suitable wind areas are located within suitable areas for solar. This suggests that where these suitable areas overlap, careful consideration should be given to the prioritization of technology choices to ensure that suitable wind areas are maximized. This is important given the high proportion of wind selected in the least-cost model.

To narrow down the best areas for solar and wind development, the figure overleaf only shows areas for solar and wind considered "Most suitable" in areas with relatively low social risk exposure.[97] This indicates that as much as 124,829km^2 of land is highly suitable for solar and/or wind development in areas where grievance-driven risks are likely to be easier to manage.

This assessment suggests that there are plenty suitable areas for Namibia to achieve the ~1,700MW of solar and wind capacity selected by the least-cost model in 2040.[98] A quick calculation shows us that just 0.04% of the most suitable solar and wind areas would be required to meet this target. Similarly, a negligible 0.006% would be required to replace Baynes' capacity of 300MW.[99]



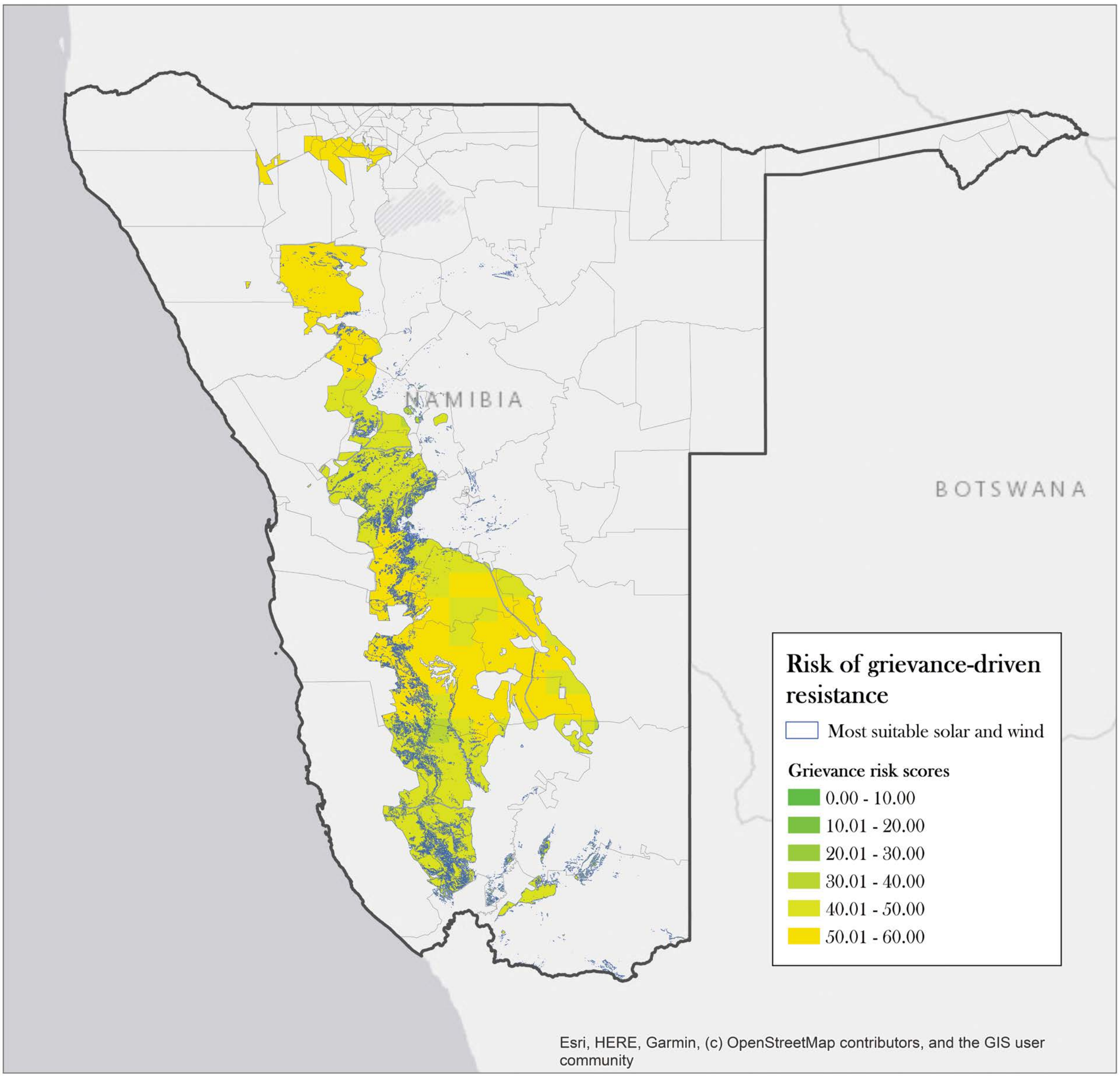
95. This is based on 0.35ha/MW for wind and 2.7ha/MW for solar, derived in section 4
96. Project developers will still need to determine from grid operators / NamPower whether there is available capacity to connect to the nearest transmission line or substation, or whether additional upgrades would be required. This level of detail is not made publicly available.
97. We only included areas with a grievance risk score of <60, out of a total risk score of 100. Areas with a risk score of >60 are considered high risk and are more likely to present challenging operating environments for development.
98. See Appendix II for OSeMOSYS installed capacity results
99. This is based on 2.7ha/MW for solar derived in section 4

Notably, the social risk component does not suggest that higher risk areas are unsuitable for development, but rather that they are likely to be more challenging operating environments from a social perspective. That is to say that anyone interested in these areas (e.g. government, developers or investors) should place greater emphasis on social risk mitigation measures.

In practice this would mean, at minimum, adopting strong community engagement processes and ensuring the risks and benefits associated with development are clearly understood and accepted by local communities. FPIC principles are paramount where solar, wind or other natural resources are used.

We do recognize that solar and wind technologies can have quite large spatial requirements, which will need to be carefully considered. However, there are ways to minimize these requirements by collocating solar and wind alongside other land use sectors, as discussed previously.

Finally, this assessment does not suggest that all identified suitable areas will be available for development. Interested groups will need to engage with local communities and landowners to collectively determine the most beneficial areas for everyone involved. In practice, this could mean avoiding areas where local groups are not interested in development.



6. Recommendations on the way forward

Namibia can make decisions now to ensure energy security, while addressing existing socio-economic challenges around unemployment and energy access. This will only be achieved through careful energy planning and implementation processes. To this end, we provide the following recommendations:

Government

- Follow the analysis found in this report and the IRP, which supports investment in wind and solar rather than hydropower and fossil fuels. Reducing reliance on hydropower is urgent in the context of climate change.
- Support comprehensive risk assessments and data sharing for energy investments to avoid damaging megaprojects like Baynes or proposed fracking while derisking private investment in good projects.
- Raising the limit of the Modified-Single Buyer model (currently at 30% of total energy consumption) would likely boost investor confidence and create a further enabling environment for new solar, wind and storage capacity.
- Insist on high social and environmental standards for energy projects, including FPIC principles in social engagement and robust climate risk assessment.
- Identify partnerships of developers and energy consumers to help invest in much needed energy storage capacity (including long-duration), which can make future investment more attractive while significantly boosting resilience and energy security.

Companies and investors

- Namibia has some of the best solar and wind resources anywhere, so work with experts and local groups to find the best places to exploit it. Your assessment must account for social, environmental and climate risks.
- Work with international financial institutions and governments to develop blended finance solutions that can derisk investments and help crowd in investment partners.
- Develop networks of high-quality local service providers to help with community engagement and environmental risk management. These providers can be cheaper, more knowledgeable, and better trusted. They are often best found among civil society groups.

Civil society

- Oppose projects like Baynes using financial arguments and/or arguments based on energy security. Many stakeholders are more sensitive to these problems than rights-based or environmental concerns (however valid).
- Help responsible actors to forge strong social license for good energy projects with extensive local benefit. Consider finding areas and communities that provide free and informed consent for future energy projects so there is a pipeline of possible investment available.
- Work with government to develop and enforce improved regulation on comprehensive risk assessment and effective local engagement. Develop good performance indicators to assess the impact of energy investments.

Appendices

Photo: Skeleton Coast, Namibia | Pixabay

Appendix I: OSeMOSYS model assumptions

The assumptions used to develop the OSeMOSYS model were based on an initial base data kit for Namibia compiled by 22 academics and energy professionals from 12 reputable research and academic institutions. This original base data, with the names and institutions of those responsible for sourcing it can be found on Research Square.[100]

This Appendix outlines the key assumptions used, which includes our own updates to the original base data mentioned above. The data draws from publicly available sources including Namibia's recent draft IRP 2022, the reports of international organizations, journal articles and existing model databases.

Data assumptions

Existing electricity supply

The total power generation capacity in Namibia is estimated at 642.3 MW in 2020, based primarily on data provided by the draft IRP 2022 on existing power plants.[101] A separate study on Namibia's renewable energy auction process was used to verify installed capacity of utility solar and wind projects.[102] The split of existing power generation capacity is detailed in Table 1 below for 2020.

Table 1: Namibia estimated installed capacity in 2020

Technology	Year	Capacity (MW)
Coal (Van Eck)	2020	41
Oil fired gas (Anixas 1)	2020	22.5
Large hydropower (Ruacana)	2020	347
Solar PV (Utility)	2020	174.8
Onshore wind (Utility)	2020	5
Off-grid Solar PV	2020	52
Total	**2020**	**642.3**

Commission dates and expected operational life data (see Table 2 below) were used to estimate installed capacity of the above technologies in future years. Van Eck was assumed to be decommissioned in 2026 given that it was built in 1972, it is unable to run at full capacity (ie 41MW versus 120MW installed) and there is increasing global pressure to move away from coal-fired power. The draft IRP 2022 assume Van Eck will be decommissioned from 2024 onwards.

Data on Namibia's off-grid solar PV capacity were sourced from yearly capacity statistics produced by IRENA until 2018.[103] The 2020 off-grid solar PV capacity figure was taken from the draft IRP 2022 and we assumed a linear increase between the 2018 and 2020 figures. Because our modelling period covers 2020-2040, these installed capacity figures are most relevant to residual capacity in the model.

Techno-economic data

The techno-economic parameters used for electricity generation technologies are presented in Table 2, including costs, operational life and efficiencies. We used the cost (capital and fixed), operational life and efficiency data from the draft IRP 2022 as much as possible to ensure it was locally representative. Some exceptions include CSP without storage, oil fired gas (SCGT) and distributed solar PV with storage, where we used generic IRENA data that is applicable to Africa.[104] The capital cost data for hydropower was sourced from the draft IRP 2022 and excludes grid connection costs, which considerably increase the overall costs.[105]

100. https://www.researchsquare.com/article/rs-481002/v1
101. Namibia draft IRP 202
102. https://www.sciencedirect.com/science/article/pii/S0957178722000571
103. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2022/Jul/IRENA_Renewable_energy_statistics_2022.pdf
104. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/Apr/IRENA_Planning_Prospects_Africa_2021.pdf ; https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Nov/IRENA_Planning_West_Africa_2018.pdf
105. For example, the capital cost for Baynes without grid costs is $2,167/kW, while with grid connection costs it is estimated at $4,000/kW, according to the draft IRP 2022.

Our capital costs for hydropower can therefore be considered conservative.

Cost data included projected cost reductions for solar PV, solar CSP and onshore wind technologies, based on cost reduction rates extracted from IRENA. It was assumed that costs fall linearly between the data points provided by IRENA.[106] The cost and performance parameters of the remaining technologies are assumed constant over the modelling period because these technologies are considered mature. Only fixed operation and maintenance costs are considered in the analysis, where fuel costs are considered the primary variable cost for relevant technologies.

Country-specific capacity factors for solar PV and solar CSP were sourced from the PLEXOS-World 2015 Model Dataset[107], where the capacity factor for hydropower was extracted from the draft IRP 2022.

Capacity factors for onshore wind were derived by aggregating extracted data from the draft IRP 2022 and data from PLEXOS. This aggregation approach was used for wind because the average capacity factor provided from PLEXOS was far below the average seen in existing projects in Namibia, while the capacity factors provided in the draft IRP 2022 were unusually high. We found the aggregated figures to be more representative of expected capacity factors from onshore wind projects.

Finally, capacity factors for the remaining technologies were sourced from IRENA figures, which are generic figures for Africa.[108]

Table 2: Techno-economic assumptions for power generation technologies in 2020

Technology	Capital cost ($/kW)	Fixed cost ($/kW)	Operational life	Efficiency
CSP with Storage	5,932	59	30	1
Biomass	4,352	131	25	0.35
Solar PV (Distributed with Storage)	4,320	86	24	1
CSP without Storage	4,058	41	30	1
Offshore Wind	3,972	159	25	1
Medium Hydropower (10-100MW)	2,984	90	50	1
Small Hydropower Plant (<10MW)	2,984	90	50	1
Off-grid Hydropower	2,984	90	50	1
Utility PV with 2 hour storage	2,796	18	25	1
Coal	2,500	78	35	0.37
Large Hydropower (>100MW)	2,167	65	50	1
Onshore Wind power plant with storage	1,982	60	25	1
Onshore Wind	1,710	68	25	1
Oil fired gas turbine (SCGT)	1,450	45	25	0.35
Light Fuel Oil Power Plant	1,225	34	20	0,35
Solar PV (Utility)	1030	13	25	1
Gas Power Plant (CCGT)	967	29	35	0.48
Light Fuel Oil Standalone (1kW)	750	23	10	0.16
Gas Power Plant (SCGT)	700	20	25	0.3

106. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/Apr/IRENA_Planning_Prospects_Africa_2021.pdf
107. https://dataverse.harvard.edu/dataset.xhtml?persistentId=doi:10.7910/DVN/CBYXBY
108. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/Apr/IRENA_Planning_Prospects_Africa_2021.pdf ; https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Nov/IRENA_Planning_West_Africa_2018.pdf

Fuel prices

Assumed fuel costs are provided in Table 3 below for years 2020, 2030 and 2040. Namibia does not produce its own fuel commodities, so it was assumed that all are imported, except for biomass which can also be produced domestically.

Table 3: Fuel prices and projections in 2020, 2030 and 2040

	Fuel price ($/GJ)		
Commodity	2020	2030	2040
Crude oil import	12.2	14.3	16.9
Biomass imports	1.8	1.8	1.8
Biomass extraction	1.6	1.6	1.6
Coal imports	2.8	3.1	3.4
Light fuel oil import	14.7	17.3	20.4
Heavy fuel oil import	8.9	10.4	12.3
Natural gas import	10.8	13.0	15.1

The crude oil price is based on an international price forecast produced by the US Energy Information Administration (EIA), which runs to 2050.[109] The price was increased by 10% for imported oil to reflect the cost of importation. The price of imported HFO and LFO were calculated by multiplying the oil price by 0.8 and 1.33 respectively, based on the methods used in TEMBA.[110]

The prices of coal and natural gas were sourced from a regional energy modelling study of Southern Africa.[111] The price for biomass was sourced from IRENA.[112] The cost of domestically-produced biomass was increased by 10% to estimate a cost of imported biomass.

Emission factors

Only carbon dioxide emissions are considered in this analysis. These are counted by assigning carbon dioxide emission factors to each unit of fuel used, rather than each power generation technology. The assumed emission factors are presented in Table 4 below.

Table 4: Commodity CO2 emissions factors

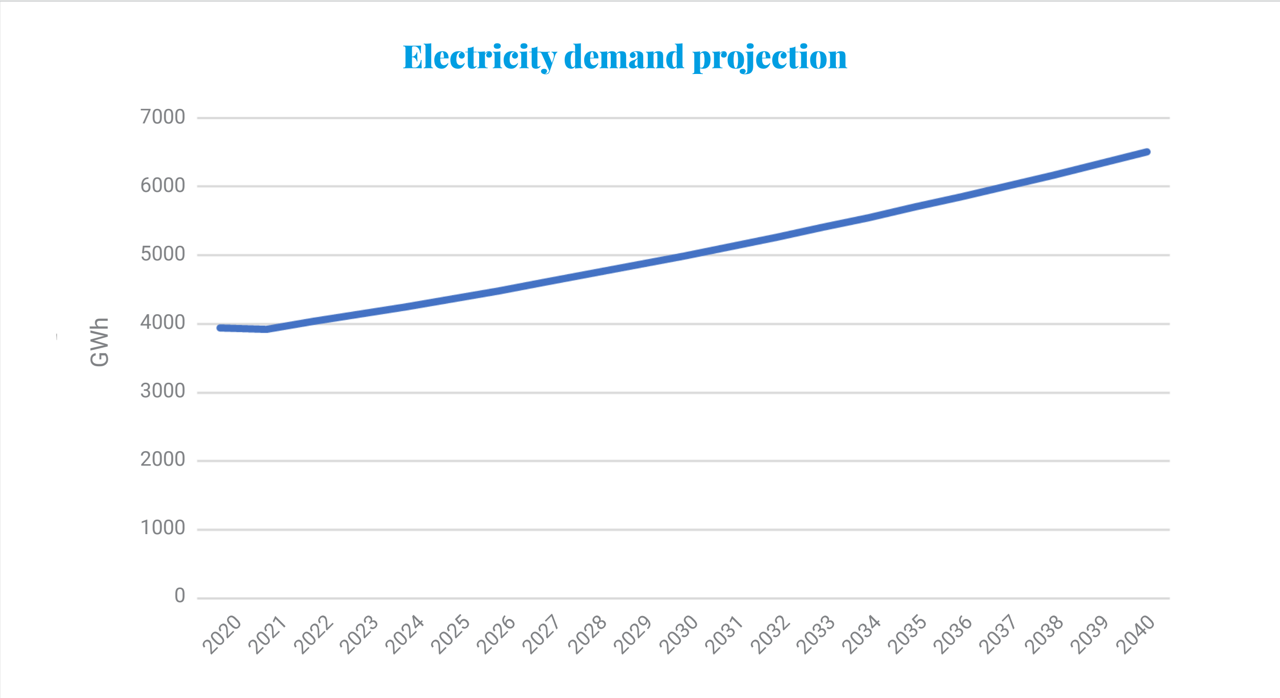
Commodity	CO2 emissions factor (kg CO2/GJ)
Crude oil import	73.3
Biomass imports	100
Biomass extraction	100
Coal imports	94.6
Light fuel oil import	69.3
Heavy fuel oil import	77.4
Natural gas import	56.1

Emissions factors were collected from the IPCC Emission Factor Database[113], which provides carbon emissions factors by fuel.

109. https://www.eia.gov/outlooks/aeo/assumptions/pdf/international.pdf
110. https://publications.jrc.ec.europa.eu/repository/handle/JRC118432
111. https://www.sciencedirect.com/science/article/abs/pii/S254243512200304X
112. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Nov/IRENA_Planning_West_Africa_2018.pdf
113. https://www.ipcc-nggip.iges.or.jp/EFDB/main.php

Electricity demand projection

Final electricity demand in Namibia was assumed to be 3,945 GWh in 2020 and 3,925 GWh in 2021 based on Nampower reported electricity demand.[114] It is then projected to reach 4,989 GWh by 2030 and 6,511 GWh by 2040. This projection is based on a 2.7% annual average increase between 2021 – 2040, as derived from Namibia's draft IRP 2022. The figure below shows the final electricity demand projection.



Modelling assumptions

Supply-side assumptions

The share of total demand that can be met by off-grid solar PV was constrained based on the optimal balance of on- and off-grid provision in a least-cost scenario for 100% electricity access by 2030 from the Global Electrification Platform.[115]

Additional technologies were modelled to represent utility-scale solar PV and onshore wind with storage capacity. Utility-scale PV with two-hour storage and onshore wind with half-hour storage were modelled, with the additional costs of storage estimated based on data from the NREL ATB 2020 Database, which provides cost projections for different durations of storage up to 2050.[116]

The maximum share of total demand that can be met by variable renewables is constrained as follows: utility-scale PV, onshore wind and utility-scale PV with storage are each permitted to meet up to 15% of demand; offshore wind can meet up to 10% of demand and onshore wind with storage can meet up to 25% of demand. Biomass is permitted to meet up to 30% of electricity demand. This analysis is not intended to offer a detailed study of system flexibility. However, the above constraints were included to ensure the system is operational under high renewable shares.

Notably, we assumed that no new coal would be developed in Namibia, which is in line with Namibia's climate change commitments under international treaties like the Paris Agreement.[117] We further assumed no nuclear or geothermal would be developed in line with assumptions from the draft IRP 2022. Namibia lacks the required national regulatory authority, policy and technical expertise to develop nuclear in the next

114. https://www.nampower.com.na/public/docs/annual-reports/NamPower%20Annual%20Report%202021.pdf
115. https://electrifynow.energydata.info/
116. https://atb.nrel.gov/electricity/2020/data.php
117. https://unfccc.int/node/61123

decade or longer. Similarly, there have been no official and thorough technical assessments of geothermal to support the prospect of new development in the next two decades.

Electricity imports and exports were modelled in a simplified manner as single import and export technologies. Upper export and import limits were constrained according to actual reported imports and exports for the years 2020 and 2021.[118] From 2022 onwards, exports were constrained to a maximum of 15% of final demand until 2040. Imports were constrained to slowly decline from a maximum of 60% of final demand in 2022 to 20% of final demand in 2028. This upper import constraint was intended to mimic Namibia's goal of achieving 80% domestic energy production by 2028.[119]

Demand-side assumptions

The total electricity demand shown in the figure above was split by residential, commercial and industrial sector based on the proportions of electricity consumption provided in the Electricity Control Board's most recent publicly available Statistical Bulletin.[120]

In each sector, moderate and high energy efficiency technologies were modelled, with input activity ratios of 1 and output activity ratios of 1.15 and 1.3 respectively. This is a simplified way of allowing the model to invest in energy efficiency in each sector.

The electricity demand profile was sourced from the PLEXOS dataset,[121] which provides estimated hourly demand by country throughout one calendar year. This was used to estimate demand across the 8 time slices (see below) used in the model.

Time representation and discount rate

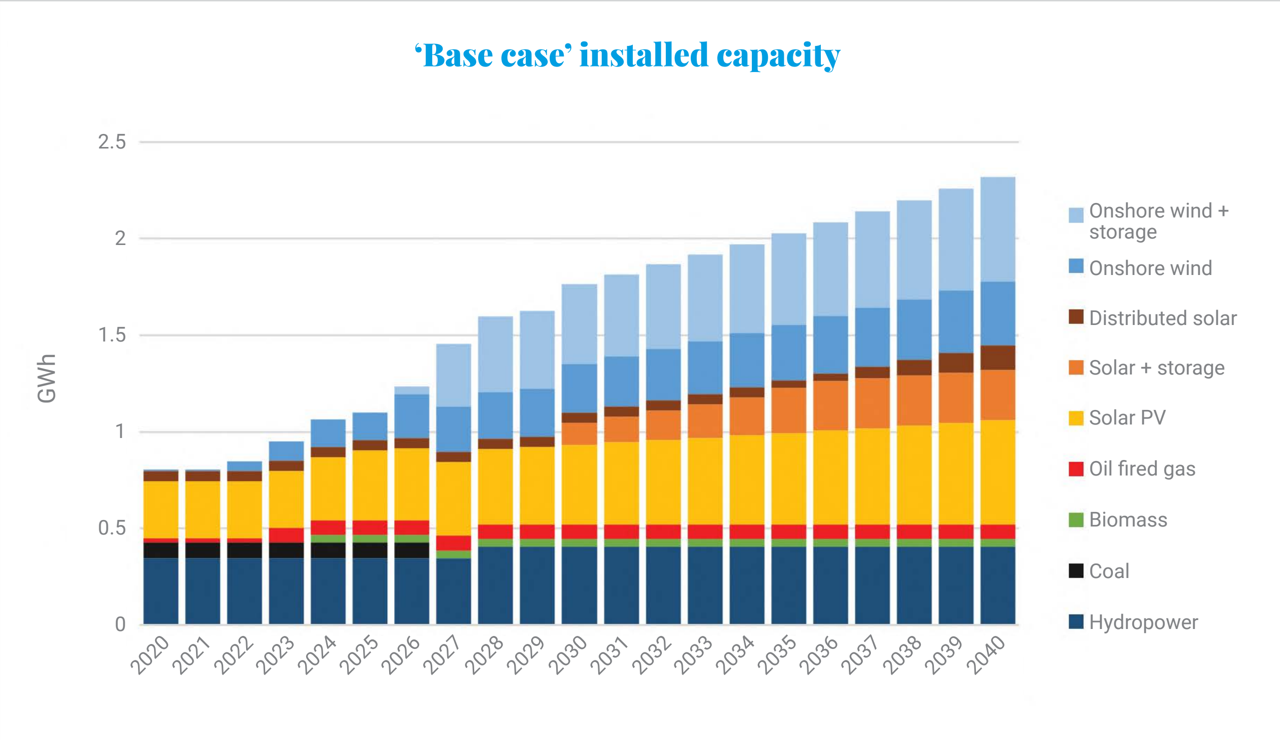
Within each model year, four seasons, each with two 12-hour dayparts, are defined. Daypart 1 starts at 06:00 and finishes at 18:00, while daypart 2 starts at 18:00 and finishes at 06:00. The seasons are defined so that season 1 runs from December to February, season 2 runs from March to May, season 3 from June to August and season 4 from September to November.

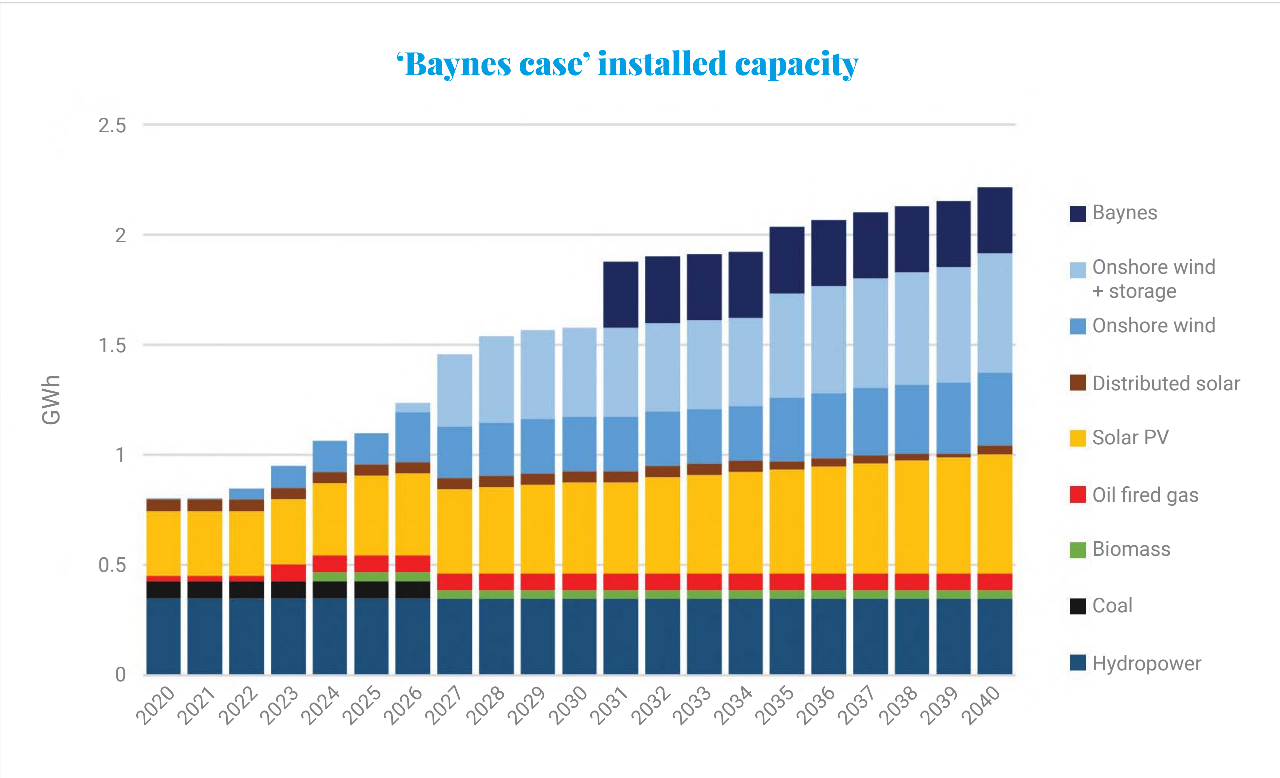
A discount rate of 10% is used.

118. https://www.nampower.com.na/public/docs/annual-reports/NamPower%20Annual%20Report%202021.pdf
119. https://www.ecb.org.na/images/docs/Spark_Newsletters/2021/Spark_November_2021.pdf
120. https://www.ecb.org.na/images/docs/Statistical_Bulletin/Statistical_Bulletin_2019.pdf
121. https://dataverse.harvard.edu/dataset.xhtml?persistentId=doi:10.7910/DVN/CBYXBY ; https://www.sciencedirect.com/science/article/pii/S2211467X-20301450?via%3Dihub

Appendix II: OSeMOSYS installed capacity results

The figures below show the least-cost installed capacity results for both the Base case and Baynes scenarios.





Appendix III: Suitability siting thresholds and datasets

The following table provides the indicator constraints used for the solar and wind suitability maps, as well as the datasets used.

Protected Areas	Wind constraint	Solar constraint	Source
Protected Areas	<1km buffer	<1km buffer	www.protectedplanet.net
ESA-CCI land cover maps	See Landcover table below	See Landcover table below	https://www.esa-landcover-cci.org/
Water bodies	<500m buffer	<500m buffer	https://www.worldwildlife.org/publications/global-lakes-and-wetlands-database-lakes-and-wetlands-grid-level-3
Population	>100 people	>100 people	https://sedac.ciesin.columbia.edu/data/collection/gpw-v4
Solar resource (GHI)		<3.8kwh/m2/day	https://globalsolaratlas.info/download/namibia
Wind power density	<200W/m2		https://globalwindatlas.info/download/gis-files
Slope	Slope (SRTM data) >20%	Slope (SRTM data) >5%	https://cgiarcsi.community/data/srtm-90m-digital-elevation-database-v4-1/
Railway	<500m buffer	<500m buffer	http://riskprofilesundrr.org/layers/geonode:nam_railway_networks_1

Landcover constraints:

Code	Description	Solar	Wind
0	No Data		
10	Cropland, rainfed		In
11	Cropland, rainfed, herbaceous cover		In
12	Cropland, rainfed, tree or shrub cover		In
20	Cropland, irrigated or postflooding		In
30	Mosaic cropland (>50%) / natural vegetation (tree, shrub, herbaceous cover) (<50%)		In
40	Mosaic natural vegetation (tree, shrub, herbaceous cover) (>50%) / cropland (<50%)		
50	Tree cover, broadleaved, evergreen, closed to open (>15%)		
60	Tree cover, broadleaved, deciduous, closed to open (>15%)		
61	Tree cover, broadleaved, deciduous, closed (>40%)		
62	Tree cover, broadleaved, deciduous, open (15-40%)		
70	Tree cover, needleleaved, evergreen, closed to open (>15%)		
71	Tree cover, needleleaved, evergreen, closed (>40%)		
72	Tree cover, needleleaved, evergreen, open (15-40%)		
80	Tree cover, needleleaved, deciduous, closed to open (>15%)		

Code	Description	Solar	Wind
81	Tree cover, needleleaved, deciduous, closed (>40%)		
82	Tree cover, needleleaved, deciduous, open (15-40%)		
90	Tree cover, mixed leaf type (broadleaved and needleleaved)		
100	Mosaic tree and shrub (>50%) / herbaceous cover (<50%)		
110	Mosaic herbaceous cover (>50%) / tree and shrub (<50%)	In	In
120	Shrubland	In	In
121	Evergreen shrubland	In	In
122	Deciduous shrubland	In	In
130	Grassland	In	In
140	Lichens and mosses		
150	Sparse vegetation (tree, shrub, herbaceous cover) (<15%)	In	In
151	Sparse tree (<15%)	In	In
152	Sparse shrub (<15%)	In	In
153	Sparse herbaceous cover (<15%)	In	In
160	Tree cover, flooded, fresh or brakish water		
170	Tree cover, flooded, saline water		
180	Shrub or herbaceous cover, flooded, fresh/saline/brakish water		
190	Urban areas		
200	Bare areas	In	In
201	Consolidated bare areas	In	In
202	Unconsolidated bare areas	In	In
210	Water bodies		
220	Permanent snow and ice		

Appendix IV: Baynes Riverscope financial assessment assumptions

The table of assumptions below were used for the financial assessment of Baynes and its comparison with alternative technologies (i.e. solar and wind).

Assumption description	Value
Total Capital Expenditure	$ 1.3 bn[122]
Capacity factor	31%[123]
Discount Rate	10%
Loan Duration	50 years
PPA cost per kWh	$ 0.07/kWh[124]
Inflation	4%[125]
Solar LCOE 2020	$ 0.052/kWh[126]
Solar LCOE price decrease per year	2.5%[127]
Wind LCOE 2020	$ 0.077/kWh[128]
Wind LCOE price decrease per year	1.6%[129]

122. https://www.kgrtc.org.zm/files/Doc/04.%20Baynes%20HPP%20-%20Christian_PJTC,Angola_Namibia.pdf
123. Based on an average production of 1,610 GWh/year and a total installed capacity of 600MW: https://www.kgrtc.org.zm/files/Doc/04.%20Baynes%20HPP%20-%20Christian_PJTC,Angola_Namibia.pdf
124. This is an assumed rate based on other hydropower projects in Africa because we don't know what the PPA price would be for Baynes.
125. Average inflation over the past 5 years: https://tradingeconomics.com/namibia/inflation-cpi#:~:text=Inflation%20Rate%20in%20Namibia%20is,according%20to%20our%20econometric%20models.
126. Figure derived from the Hardap PV project tariff at NA$80,7/kWh (using an exchange rate of 0.063889): https://mcusercontent.com/e29d815e6568beb2d63670a88/files/42bdbb45-c5c4-43cc-8fda-08ba61adeff4/Namibia_Country_Report.pdf
127. Reduction rate derived from the low projected figure for solar PV in https://irena.org/-/media/Files/IRENA/Agency/Publication/2019/Nov/IRENA_Future_of_Solar_PV_2019.pdf
128. Figure derived from the adjusted Diaz wind project tariff at $0.077/kWh: https://mcusercontent.com/e29d815e6568beb2d63670a88/files/42bdbb45-c5c4-43cc-8fda-08ba61adeff4/Namibia_Country_Report.pdf
129. Reduction rate derived from the low projected figure for wind in https://www.irena.org/-/media/files/irena/agency/publication/2019/oct/irena_future_of_wind_2019.pdf

International Rivers Headquarters
344 20th Street
Oakland 94612
USA
Tel: +1 510 848 1155
www.internationalrivers.org

International Rivers Africa Program
377 Rivonia Boulevard
Rivonia Johannesburg 2128
South Africa
Tel: +27 12 430 2029

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