PRE-FEASIBILITY STUDY FOR THE ESTABLISHMENT OF A PRE-COMMERCIAL CONCENTRATED SOLAR POWER PLANT IN NAMIBIA

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Executive Summary

The Renewable Energy and Energy Efficiency Institute (REEEI) at the Polytechnic of Namibia, on behalf of the Ministry of Mines and Energy (MME) and with support from the Energy and Environmental Program with Southern and East Africa (EEP S&EA), sought technical services on a pre-feasibility study for the establishment of a pre-commercial concentrated solar power plant in Namibia.

The awarded consortium was headed by GESTO Energy Consulting, from Portugal, and included Solar Consulting Services, from the United States of America, Solar - Institut Jülich and CSP Services GmbH (Concentrating Solar Power Services, a spin-off from German Aerospace Agency), both from Germany, and the local company Consulting Services Africa. The consortium team included reputable experts, such as Chris Gueymard, Christian Faber, Eckhard Lüpfert, Norbert Geuder, Antoine Bittar, Agostinho Miguel Garcia and Miguel Barreto. Additionally, the Solar irradiation satellite data was provided by Geomodel, from Slovakia.

Furthermore, in this pre-feasibility study for the establishment of a pre-commercial solar power plant in Namibia several points had to be investigated, as follows:

(i) Namibian electricity sector overview

The economic and development context, namely, the background and future expectations, has been further explored to highlight the full picture of the Namibian Electrical Supply Industry.

(ii) Nation-wide solar resource assessment

Coupled with the available satellite irradiation data, a specific AOD (Aerosols Optical depth) analysis has been performed to generate new data and increase the accuracy as well as to develop the new Solar Atlas of Namibia.

(iii) Site selection and environmental analysis – Top 5 sites

A GIS (Geographical Information System) study based on local data to identify suitable locations for CSP development, 20 site inspections and validation allowed to rank the sites, providing the 5 most suitable sites for developing CSP projects.

(iv) CSP high level technology review, power plant layout and basic engineering for the top 5 sites

CSP technologies overview coupled with selection of technologies for site specific conditions, basic engineering and simple layout of the power plants, and financial analysis for the top 5 sites.

(v) Best practices on solar ground measurements

Best-practices sharing to enable the development, operation and maintenance of a network of ground measurement stations that guarantees solar resource meaningful statistical data.

(vi) CSP development in Namibia and Technology Transfer Program

Definition of the business models for the development of CSP and Renewable Energies to cater Namibia's current and future power needs. Development of a program to develop the CSP industry in Namibia and provide opportunities for skills development and job creation associated with the CSP chain value.

In that sense, the results of this study portrays Concentrated Solar Power as a viable and economic solution for Namibia, as follows:

(i) Namibia has one of the best solar resources in the world

Namibia is endowed with an extraordinary solar resource – almost 3000 kWh/m^2 day in the southern part of the country - ranging at the top worldwide - second only to northern Chile - regarding Direct Normal Irradiation (DNI, which is solar irradiation component required for Concentrated Solar power), that is, the whole country is a hotspot in terms of solar irradiation.

(ii) CSP is a mature technology that can take advantage of Namibia's exceptional solar resource

With more than 1 GW of deployed projects worldwide, CSP can be considered a mature and proven technology. In addition, generally, there are four CSP technologies available for harnessing solar radiation: parabolic troughs power plants, power towers, linear Fresnel collectors and dish Stirling systems. For last, CSP is also possible to be coupled with natural gas, biomass and coal, increasing the interest of deploying this technology in Namibia.

(iii) CSP plants can store solar energy during the day and produce at night peak time

Renewable Energies are claimed to be non-dispatchable and so not able to cater peaks in a reliable fashion. In addition, in order to be dispatchable, they need to encompass storage and the cost of the projects rise as well as the cost of the unit of electricity generated. In this line of thought, the advantage of CSP technology when compared to other renewable energy technologies is the possibility of storing energy. With round-the-clock operation becoming possible, CSP plants have the potential to be used as peaking plant or even as a base load power plant.

(iv) CSP based solar energy can be less expensive than fossil fuel alternatives

Without short-term investment in power generation and only considering the peak and mid-peak periods, Namibia may be confronted with an energy shortage between 2013 and 2016. In addition, the peak demand is expected to be met with rental diesel, given the current generation options of Namibia, and the cost of diesel generated electricity is very high when compared with Renewable Energies. Thus, if Namibia uses part of these potential costs to reduce the initial investment in a CSP plant instead of importing diesel, this would reduce the investment and the required cost for CSP development, becoming cost competitive even with coal.

(v) Namibia has more than 33,000 km^2 of potential sites for CSP development and more than 250,000 MWe of projects

Namibia has suitable land for the development of 250,000 MWe CSP projects, taking into consideration all parameters of site selection: irradiation, slope, soil type, power evacuation facilities, access infra-structure, environmental and social restrictions. More than 40 sites in Namibia were selected with excellent conditions for CSP technologies, 20 of which were ranked and inspected – more than 3000 km were driven - providing a final top 5 selection – Hochland (south near to the border with South Africa), Skorpion Mine (near Rosh Pina), Ausnek (near Aus), Kokerboom (near Ketmanshoop) and Gerus (near Otjiwarongo).

Additionally, mainly based on the available DNI data and the national load, but also considering the restraining conditions on the sites, several options were considered for the generation profile on the selected sites, as follows:

<table>
<tr><th>Location</th><th>Type</th><th>Storage</th></tr>
<tr><td>Hochland</td><td rowspan="4">Pure CSP -
Parabolic troughs or Power towers</td><td>7 ~ 8 hours</td></tr>
<tr><td>Skorpion Mine</td><td>6 ~ 7 hours</td></tr>
<tr><td>Ausnek</td><td rowspan="2">7 ~ 8 hours</td></tr>
<tr><td>Kokerboom</td></tr>
<tr><td>Gerus</td><td>CSP with biomass -
Parabolic troughs, power towers or Linear Fresnel</td><td>No storage</td></tr>
</table>

(vi) A bet on CSP allows the production of cheap and clean energy reducing imports and promoting a national cluster that creates jobs and wealth

Given Namibian energy gap and the most suitable supply options, according to investment, cost, timing and fit with local installed capacity, a two-step approach for capacity development should be pursued: development of up to 100 MW of Wind or Solar PV projects and backup diesel as well as up to 50 MW of CSP power projects (1st step, until 2014) and ~100 MW CSP projects (2nd step, until 2016).

Additionally, the development of CSP in Namibia would have a positive impact on the economy and education sectors, namely, enabling access to development funding for renewable energies in Africa, enhancing Namibia's international visibility and credibility, guaranteeing that up to 40% of the investment in a CSP plant would be sourced from Namibia's economy and promoting local job creation, which would require the creation of new competences in education and, through a CSP technology transfer program, would enhance the renewable competences of Namibian research and education institutions.

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1 Namibian Electricity Sector Overview

1.1 The Economic and Development Context for Energy Policy

This section provides the economic and development context, where the background and future expectations are further explored. Ultimately, the main objective is to highlight the full picture of the Namibian Electrical Supply Industry.

1.1.1 Background

Located in Southern Africa, bordering the South Atlantic Ocean, between Angola and South Africa, Namibia occupies a land area of 823 269 Km^2. Characterized for being mostly high plateau and encompassing the Namib Desert along the coast as well as Kalahari Desert in east, Namibia's climate is hot and dry, where the rainfall is sparse and erratic, and, consequently, the most common natural hazards are brought by prolonged periods of drought.

Moreover, Namibia has slightly more than 2.1 million inhabitants, which, according to international standards, can be considered as a small country. Namibians are of diverse ethnic origins, namely, Ovambo (about 50% of the population), Kavangos (9%), Herero (7%), Damara (7%), Nama (5%), Caprivian (4%), Bushmen (3%), Baster (2%) and Tswana (0.5%), among other.

Geographically, much of southern Namibia is extremely arid and the average Namibian population density is very low – about two people per square km, compared, for example, with about 30 people per square km in South Africa and 25 in the USA. Although Namibia's urban areas are showing signs of rapid growth, 62% of the population live in rural areas, where the dominant economic activity is subsistence farming. Nevertheless, with a high rate of urbanization, more than 3% per annum, there is a clear strain on attempts at economic and social development.

Furthermore, Namibia's economy is heavily dependent, both directly and indirectly, on the primary sectors such as mining, agriculture and fisheries. In 2012, mining alone accounts for 8% of Gross National Product (GNP), to some 50% of foreign exchange earnings and employs about 3% of the population. On the other hand, due to droughts, food shortages are a major problem and, in years of more severe droughts, Namibia may import more than 50% of its cereal requirements.

In 1994, Namibia had a GDP per capita of US $1970 (at constant prices of 1981) which granted the status of lower middle-income country. However, with a GDP per capita of US $7,300 (2011), Namibia has seen its status upgraded to upper middle-income country.

Nevertheless, a high per capita GDP, relative to the region, hides one of the world's most unequal income distributions, as indicated by Namibia's 70.7 GINI index. Moreover, a small percentage of

Namibians are well off, while the majority live in conditions of relative poverty, that is, 55.8% of the population live below the poverty line and, consequently, literacy rates and life expectancy are low.

In this line of thought, while Namibia ranks 99th in the world in terms of GDP per capita, it only ranks 120th in terms of Human Development Index (United Nations Development Programme).

Namibia has only recently begun to grapple with its development problems. Before Independence in 1990, the country was occupied by South Africa and, for many years, Namibia was the site of an internal war of liberation, that is, it was also used as a military base for South Africa's war with Angola. During the South African occupation, Namibia was subject to apartheid-style economic and social development.

As a result of this, Namibia has pockets of affluence, consisting of an excellent network of infrastructure connecting fully serviced, largely white urban areas and commercial farms, side-by-side with large poverty stricken areas. After the war, the transition from South African rule was relatively smooth. Namibia's infrastructure of roads, dams, power lines and pipelines is now well catered for. The government is stable, governance standards appear to be good and fiscal discipline is exercised.

Since Independence, Namibia has experienced a GDP growth averaging 5%. In the past, Namibia has been strongly influenced by its neighbours, and this will probably continue. The value of Namibia's exports and imports are both in the range of approximately 60% of Namibian GDP, which is indicative of an extremely open economy.

South Africa, with a population 25 times the size of Namibia's, and a GDP 40 times the size of Namibia's, is the dominant force. In fact, South Africa supplies about 85% of Namibia's imports. In addition to the sheer relative weight of its economy, South Africa exerts influence through a number of regional bodies such as the Common Monetary Area, the Southern African Customs Union and the Southern African Development Community.

Additionally, Namibian economy is also closely linked to South Africa due to the fact that the Namibian dollar is pegged one-to-one to the South African Rand and, therefore, implies a minimal amount of flexibility in monetary policy.

Furthermore, Angola is also much larger than Namibia and also exerts a strong influence. Unfortunately, the war and instability in Angola has largely exerted a negative influence over the past decades. However, the potential for exerting a strong positive influence on Namibia remains.

Namibia's other main neighbour, Botswana, is a small country in terms of population and GDP, and exerts a far smaller influence.

1.1.2 Namibian Development Goals

Since Independence in 1990, the Namibian government has established development objectives and targets for the country through a 5-year term official document known as the National Development Plan of Namibia (NDP).

Nevertheless, until the development of the First NDP (NDP1), the government of Namibia developed the Transitional National Development Plan (1990-1994) which focused on consolidating democracy and the main achievement obtained was the establishment of the basic organs of government.

Therefore, from 1995/96 to 1999/2000, the first medium-term national development strategy for Namibia was put in place. Build on the achievements of the Transitional National Development Plan, the NDP1 intended to cement the foundation for a truly democratic, transparent and vibrant economy in which all Namibians would be both participants and beneficiaries, that is, its four main goals were:

- Revived and sustained economic growth;
- Employment creation;
- Reduced inequalities; and
- Eradication of poverty.

The Second NDP (NDP2) was prepared soon after completing the execution of NDP1 and the respective launching, during 2001/2002, has provided the much needed continuity and consistence in the application of the country's development strategy.

Growing more conscious of the fact that Namibia's continued economic growth depends very much on its rich natural resources and unique arid environment, the NDP2, initiated the difficult but necessary process of taking into account environmental and sustainability aspects in sectoral, cross-sectoral and regional development planning.

Hence, the NDP2 differs from NDP1 in a number of ways, for example, cross-sectoral policies were prominently outlined and represented, the issue of regional development was addressed for the first time and a number of new and important matters, such as poverty reduction, income distribution, HIV/AIDS, private sector development, among other, were included in NDP2 in order to widen and strengthen the focus and thrust of it.

Moreover, Namibia's Vision 2030 provides the long-term development framework to become a prosperous industrialized nation, developed by its human resources, enjoying peace, harmony and political stability. In that sense, The National Development Plans are seen to be the main vehicles to translate the Vision into action and make progress towards realizing the Vision by 2030.

Thus, for last, in 2007/2008, the most recent step towards the promotion of Namibia as a prosperous industrialized country was given, that is, the Third NDP (NDP3) was launched as the first systematic attempt to translate the Vision 2030 objectives into action.

1.1.3 Namibian Economy

As previously mentioned, Namibia's economy is closely linked to South Africa's economy through trade, investment, and common policies, making economic trends, including inflation, close to those in South Africa.

Prior to the 2009 global financial crisis, Namibia had experienced steady GDP growth, moderate inflation, limited public debt, and steady export earnings. From 1990 to 2008, economic growth averaged 4.3 percent per year (in constant prices), accelerating slightly to an average annual rate of 5.2 percent from 2000 to 2008.

Albeit GDP has, on average, grown, it has done irregularly due to its sensitivity to erratic outputs of the primary agricultural, fisheries and mineral sub-sectors exposed to external factors. Moreover, the contribution of the tertiary sector to GDP grew from 42% in 1980 to 59% in 2011, while the secondary sector's contribution fell from 45% to 34% in the same period. Additionally, currently, agriculture only accounts for less than 10% of GDP, despite the fact that roughly two-thirds of rural dwellers rely on subsistence agriculture.

Furthermore, even though the mining sector's contribution to GDP has declined in the last 15 years, it is still an important sector of the economy. Thus, primarily as a result of declining external demand for diamonds, gold, and agricultural exports, GDP declined by 0.4 percent in 2009.

Nonetheless, through the promotion of countercyclical macroeconomic policies, which reduced these shocks to some extent, the output rebounded quickly in 2010. Consequently, it was registered a GDP growth of 6.6 percent and estimated at 4.4 percent in 2011 as well as projected at 4.4 percent in 2012.

Also, inflation fell after the onset of the crisis, bottoming out at 3.1 percent in February 2011. Since then the inflation rate has been rising, and during the first few months of 2012 it has exceeded the six percent ceiling in the South Africa Reserve Bank's target range.

Still, after experiencing several years of surpluses, the Namibian Government has been registering overall budget deficits of 1.2 percent in FY2009/10 and 4.8 percent in FY2009/11, mainly due to the drop in government receipts from the mining sector and the Southern Africa Customs Union (SACU) revenue pool combined with countercyclical spending.

With a stubbornly high unemployment rate of 51.2%, the Namibian Government budget presented in March 2011 encompasses an ambitious three-year, N$14.7 billion job creation and public works program that is expected to preserve or create 104,000 jobs.

All in all, total spending rose by 35 percent, and the budget tabled in February 2012 calls for an additional increase of 8 percent in the coming year, after which will level off. Also, the stimulus package has pushed deficits to 11 percent of GDP in FY2011/12, which, once again, will decline gradually and approach balance by FY2014/15.

Still, note that the government debt has doubled since 2009 to almost 30 percent of GDP, in part by Namibia's debut offshore bond issue in October 2011 of $500 million in the Eurobond market.

1.1.4 Namibian Energy Sector

As energy is an input to nearly every good and service in the economy, not only the energy sector must be considered a complementary activity of existing economic sectors, but it must also constitute an economic sector in its own right, that is, the energy sector is a vital component of the economy as it not only provides essential inputs for other economic sectors but also for basic needs and social services.

However, the energy sector constitutes a relatively modest share of GDP in many countries, except where the oil and gas income reveal to be large. Albeit the energy sector's impact on the economy is greater than the sum of its parts, this section examines the energy sector contribution to the Namibian economy, namely, the impact on the GDP, Gross Fixed Capital Investment, Government revenues, balance of payments and employment.

1.1.4.1 Contribution to Gross Domestic Product

In order to assess the contribution to Namibian GDP, the sector of water and electricity must be taken into consideration, as indicated by the Namibian national accounts. In this line of thought, the sector's value added in real terms has recorded a growth of 3.6% in 2010 compared to a decline of 0.1% registered in 2009.

Additionally, the contribution from each subsector to the registered growth differs widely, that is, the electricity subsector may be considered the main driver of the registered sector growth of 3.6%, once that it has presented a 4.1% growth against a 1.4% growth in the water subsector.

Nonetheless, the Namibian national accounts show that, in 2010, the water and electricity sector has contributed with N$ 2,089 Million for the National GDP of N$ 81,509 Million, which, in relative terms, corresponds to a contribution of 2,6%.

However, the energy sector's impact on the economy is greater than the sum of its parts, that is, given that electricity is a vital input for the production of other goods and/or services, the electricity subsector, on its own, only makes a negligible contribution to current GDP when compared to its full potential.

For last, as fossil fuels are also vital inputs for the operation of the remaining economic sectors of activity, it must be highlighted the respective contribution for the National GDP. Thus, once the petroleum products as well as coal are imported, the value added by this industry is probably less than 1% of the GDP. Nonetheless, due to proven and prospective national resources potential, this contribution to current GDP may be further enhanced in the near future.

1.1.4.2 Contribution to Gross Fixed Capital Formation

Firstly, it must be noted that the ratio of gross fixed capital formation (investment) to GDP is a pivotal indicator as highlights the future development potential of Namibia. Therefore, the average share of investment to GDP, over the period 2000 to 2010, was of 20.9% and, for the specific year of 2010, it has stood at 22.3%.

Furthermore, for the purpose of this section, it must be noted the energy sector contribution to gross fixed capital formation/investment. In this line of thought, the electricity and water sectors accounted for about 5.2% of the investment.

Moreover, even though Namibia has yet to experience a commercial oil discovery, it is awarded with large energy resources in form of hydro-power and natural gas, namely, Kudu gas field, to be explored. Thus, the contribution of electricity and oil companies to investment, which has been more than 4% since 1993, may significantly increase if new projects of concretization of those energy resources potential are implemented.

1.1.4.3 Contribution to Government Revenues

Once again, the energy sector contribution to government revenues will differ in nature, that is, the revenue collected by the government from the energy sector is derived from direct taxes, income taxes (both company and employees), fuel levies and dividend payments.

Firstly, regarding both income taxes and dividend payments, the best example is brought by Namibia Power Corporation (NamPower), which, in 2010, has paid not only N$ 98 Million in corporate taxes but also a dividend of N$ 10 Million.

Moreover, one of the largest contributions, with a value of N$ 116 Million, in 2010, comes from fuel levies which are imposed on the import of fuel and paid directly into the State revenue Fund.

For last, but not the least, in what concerns direct taxes, the best example and most probably the largest contribution is given by local authority surcharges, that is, in Namibia, local authorities are entitled to tax electricity-service provision through the application of a local-authority surcharge which, in 2010, has contributed to the overall budget requirement of the local-government with a grand total value of N$ 240 Million.

1.1.4.4 Impact on the Balance of Payments

As previously mentioned, liquid fuels, mainly in the form of petrol and diesel, dominate the Namibian energy sector, however, they are imported. Therefore, in 2010, the respective import has represented a total of N$ 3,217 Million.

Furthermore, given that not always the installed capacity for electricity generation is enough to supply energy demand, there is also an electricity import from the neighbor countries. In this line of thought, the electricity accounted for about $N 710 Million, which represented approximately 2% of all imports.

Nevertheless, due to the fact that Ruacana hydro-power stations accounts for about 80% of total installed capacity, it must be noted that the amount of electricity imports will vary considerably depending on local generation, which in turn depends greatly on water flow.

1.1.4.5 Contribution to employment

According to the last version of Namibia Labor Force Survey, in 2008, there were 333,444 persons employed in the Namibian economy. Nonetheless, similar to the previous analysis and accordingly with the referred document, in order to assess the contribution to employment, the sector of electricity, gas and water must be taken into consideration.

As a result of the capital-intensive nature of the respective sector, it is not a major employer. Thus, only 5,384 people are directly employed in the sector, which corresponds to 1.6% of total population employed.

Additionally, accounting for 70% of the people employed in this sector, the employment profile exhibits a predominance of unskilled and/or semi-skilled jobs, namely, clerks, services, shops and market sales workers, craft and trade workers, elementary occupations, among others.

Moreover, the energy sector also contributes significantly to indirect employment through capital projects, sub-contracting, namely, manufacturing, construction, services and transport, among other. One example which portrays perfectly the contribution of this sector to indirect employment is the significantly large contribution of income collected from the transportation of liquid fuels to total income of TransNamib.

For last, albeit that Namibian Development Goals clearly pursues the implementation of job creation policies, the international trends of automation raise a big challenge to the Namibian Government, that is, the Government must balance the demand for technological development, which by its turn increases economic efficiency, with employment creation in a capital-intensive sector.

1.1.5 The Role of Energy in Economic Development

Following the previous analysis, which has identified the vital contribution of the energy sector to Namibian economy, it must be concluded that energy is the lifeblood of the national economy as it is a crucial input to nearly every good and service imaginable.

Therefore, taking into consideration that the energy industry is undoubtedly an engine of growth, namely, powering the economy and promoting social and economic development, stable, reasonably priced energy supplies are central not only to maintain and improve the living standards of Namibian population, but also to promote national economic development.

1.1.6 The Role of Energy in Human Resource Development and Economic Empowerment

Albeit that the energy industry fuels the economy, much depends on the capacity of local suppliers to concretize the potential. Thus, as Namibia clearly lacks of expertise in the energy sector and recurrently relies on foreign assistance, policy formulation as well as planning and implementation processes must be seen not only as a required mean to explore energy related economic benefits but also a way of building expertise in the Namibian energy sector.

Furthermore, in order to build indigenous capacity and reduce Namibia's external dependence, the process of policy formulation must be characterized for being open and inclusive, which will be achieved through, for example, information and education campaigns aimed at empowering communities and individuals to participate in the policy process.

All in all, as previously concluded the promotion of investment in the energy sector may have direct impacts on local capacity building, namely, training and skills dissemination, and, therefore, it must be highlighted the specific role of energy not only in human resource development but also in economic empowerment.

1.2 Namibian Electricity Sector

1.2.1 Introduction

Established in 1964 as the West Africa Water and Electricity Corporation (Pty) Ltd (SWAWEK), Namibia Power Corporation (NamPower) is wholly owned by the Government of Namibia and in charge of generating and supplying power in Namibia.

NamPower not only operates the country´s four power plants and the national power grid but also supplies electricity directly to a number of customers (mostly mines) who are situated beyond the reach of local power providers.

The Ruacana Hydroelectric Station, on the Kunene River, generates electricity in Namibia of which excess is exported to South Africa. The Van Eck coal-fired thermal station (Windhoek), together with small diesel units around the country, also supplies the country with electricity.

In the north, wood is the main source of energy and biomass is the main fuel. Wind power and solar energy can also be harnessed as other energy sources. On the one hand, two wind measurement stations have been installed at Walvis Bay and Luderitz and a solar measurement station at Noordoewer. On the other hand, solar energy is vital in supplying power to distant places.

Nevertheless, due to the increased electrification rate in Namibia (34%), the total installed electrical generation capacity and therefore the maximum that all Namibian power stations could supply if run simultaneously is insufficient to match the demand for electrical energy in Namibia.

Furthermore, Namibia is as member of the Southern Africa Power Pool (SAPP) and enjoys of greater integration in interconnection infrastructure expanding generation capacity in the country. Therefore, NamPower, which is responsible for buying and selling electricity regionally through its energy trading division, imports the majority of its electricity from South Africa and other neighbor African Nations.

Moreover, the Namibian power sector has been undergoing sector reform in the last several years and, therefore, progress has been made in restructuring the Electricity Supply Industry. Historically, Namibia’s different municipalities were responsible for the local supply of electricity to end-users. However, the restructuring of the respective sector grouped municipal power suppliers into five large utility companies, that is, Regional Electricity Distributors (REDs).

In addition, the Namibian Government has stated that it aims to meet 100 percent of the peak demand with local capacity. However, local generation has become increasingly difficult as coal import prices have increased and the flow in the Kunene has been variable, making hydro generation unpredictable.

Hence, NamPower has also undergone in a restructuring process as well as set out to address the challenges of a restructured Namibian electricity supply industry and, consequently, it is actively embarking on ways to raise electricity generation capacity in the country.

Additionally, on the one hand, Namibia’s electricity regulatory authority, the Electricity Control Board (ECB), in conjunction with NamPower, aims to develop renewable energy, particularly wind power, and, on the other hand, the Ministry of Mines and Energy, also along with NamPower, targets the increase of rural electrification, which presently stands at only 30 percent compared with 85 percent of urban households being electrified.

All in all, not only work is ongoing on the energy sector structure and framework but also some recommendations are being considered by the relevant players, that is, ECB, Ministry of Mines and Energy and stakeholders.

1.2.2 Electricity Sector Overview

After the Namibian independence on 21 March 1990, the Ministry of Mines and Energy was established under the leadership of the Hon Minister Dr hc Andimba Toivo ya Toivo and Hon Deputy Minister Helmut Angula, being since then the main player in the electricity supply industry in Namibia.

In order to leverage on the country's natural resources and therefore promote Namibia's socio-economic development, the Ministry of Mines and Energy aims to ensure adequate, affordable and sustainable energy supply. Additionally, the Directorate enforces the compliance of legal requirements of energy legislation and regulations and researches new as well as renewable sources of energy.

In this line of thought, the Ministry conduct functions, such as, petroleum import and export control, pricing and price equalization, the administration of the National Energy Fund, rural electrification and the administration of the Solar Electrification Revolving fund, among others.

Moreover, during the late 1990s, an extensive review was done on the Namibian energy sector, which culminated in the Energy White Paper of 1998. The White Paper, amongst others, recommended the restructuring of the Namibian electricity supply industry (ESI).

Therefore, in order to achieve such regulation, the outdated Electric Power Proclamation of 1922 was revoked and the Electricity Act of 2000 was promulgated to replace the Proclamation. The Electricity Act provided the establishment of an independent statutory regulator, which happened with the creation of the Electricity Control Board (ECB), tasked with regulating the ESI. For the first time, a licensing system for electricity operators and methodical calculation and setting of electricity tariffs was introduced.

The Electricity Control Board (ECB) is a statutory regulatory authority established in 2000 under the Electricity Act 2 of 2000. The later Act has subsequently been repealed by the Electricity Act, 4 of 2007, expanding the ECB mandate and core responsibilities.

The core mandate of the ECB is to exercise control over the electricity supply industry with the main responsibility of regulating electricity generation, transmission, distribution, supply, import and export in Namibia through setting tariffs and issuance of licenses, meaning that under this Act, any person or institution engaged in the generation, transmission, distribution, supply, import or export of electricity must obtain a license from the ECB for such operations.

Additionally, having a non-executive board and being staffed with a chief executive officer supported by various staff members who perform technical and administrative functions, leading to a role of managing licenses and tariffs, the ECB is the regulator in the energy supply industry and, therefore, provides crucial information and feedback to the Ministry of Mines and Energy.

For last, the ECB's independence is nevertheless limited by the single fact that any final decision on licensing and permitting depends on the approval of the Ministry of Mines and Energy, leaving the role of ECB limited to the evaluation of the applications and making recommendation to the Ministry.

Moreover, as previously mentioned, NamPower is a stated-owned utility which is responsible for power generation, transmission, trading and also has distribution functions in selected areas, that is, it is a vertically integrated power utility. It was renamed NamPower in 1996 and, albeit it is wholly owned by the Government, it is also a private limited company which still operated under SWAWEK Act of 1980.

NamPower has enjoyed a complete monopoly position within the electricity industry, although, due to the recent electricity supply industry restructuring efforts, namely, the Electricity Act, which states that transmission and distribution companies must provide access to all existing and potential users of these systems (open access) at a fee, it has ceded some of the respective responsibilities, for example, the distribution of electricity in some areas is currently served by the REDs. Nevertheless, it still remains the single buyer, sole electricity trader, and has the responsibility of being Namibia's electricity system operator.

Furthermore, the creation of REDs, which was in line with the Wither Paper on Energy Policy (1998), earned the adjacent responsibility for the distribution and supply of electricity to consumers within their respective areas.

In June 2009, three REDs were already established and fully operational. NORED was established in 2002, and serves the country's north-central regions. Both CENORED and Erongo RED were established in 2005, and serve the north-central and the Erongo region, respectively. Two additional REDs, namely, one for the central and one for the southern regions, may be established in future.

However, currently, local and regional authorities as well as NamPower remain the licensed distributors in the areas not covered by REDs. There is considerable debate about the establishment of the central and southern REDs. Even in existing REDs the ECB's authority is challenged by some municipalities, local authorities, unions and members of the public, in the sense that a political rather than a regulatory decision remains outstanding to ultimately resolve the matter.

Additionally, also due to the restructuring of the ESI, the deregulation of the respective industry was intended to promote the entry of Independent Power Producers (IPPs). Currently, there are 10 conditional licenses that have been granted to IPPs for generation of electricity from biomass, coal, diesel, gas, hydro, wind and solar. However, only Bush Energy Namibia (biomass) has established an operational power plant, while the other licensees have not developed any power generation infrastructure.

Moreover, albeit that the Namibian energy sector has been clearly dominated over the years by petroleum product imports, local fuel wood supplies and local and imported electricity, Namibia currently still has no indigenous supply of either oil or gas and there is no refinery. In that sense, electricity in Namibia comes mainly from domestic hydropower facilities as well as from coal and oil powered generators plus the imports of electricity mainly made from countries like South Africa, Zimbabwe and Zambia.

The national power grid in Namibia is fed by four domestic power plants and inputs from neighboring countries into the interconnected system. With a rating of 240 MW, the Ruacana (1978) hydroelectric power station is the largest contributor in terms of domestic capacity. Namibia also has three thermal power stations: the coal-fired Van Eck (1973) plant near Windhoek with 120 MW, the 24 MW Paratus (1976) and the 22.5 MW Anixas (2011) diesel fired power plant in Walvis Bay. Note that both Van Eck and Paratus power plants were only installed as an interim solution, because the hydropower plant at Ruacana was not completed until much later than planned.

Originally, it was assumed that Ruacana would be able to provide enough electricity for the entire country, however, since demand for electricity has increased rapidly since then, not only are all four plants still in operation, but more than half of all electricity consumed in Namibia has to be purchased from neighboring countries. Note that, the electricity supplied by South Africa, Zimbabwe and Zambia is less expensive than that generated by the country's own thermal power plants and, therefore, they are mainly[1] used during periods of high peak load.

For last, the utilization of electricity is still scarce, as a large 62 percent of the population still use wood or charcoal as their primary source of energy, be it for cooking or heating. Just fewer than 1.5 million people, or 62% of the Namibian population, live in rural areas and, not only the electrification rate is of 34%, but also roughly 2,400 villages of the 2,855 villages to be found in Namibia still have no link to the national power grid.

1.2.2.1 Namibia's Generation Targets

By examining the capacity and energy balances or deficit registered in Namibia, which will further explored within the upcoming section, it is possible to determine the extent of the surplus or shortages and the required new capacity additions.

According to the Namibian Energy Policy White Paper, "duly considering associated risks, it is the aim of government that 100% of the peak demand and at least 75% of the electric energy demand will be supplied from internal sources by 2010". Nevertheless, as of March 2012, the previous policy was still not implemented and local generation resources could only guarantee up to 421 MW[2], when, in July 2011, the peak demand was already 511 MW, excluding Skorpion Mine.

Moreover, currently, national electricity supply and generation specific targets do not exist in Namibia, which if occurred in a clear articulated and mandatory manner would send an unambiguous signal to investors and, consequently, increase the urgency according to which the projects of national importance should be developed.

Hence, in order to diversify their supply arrangements, and also, as a percentage of their supplies, utilize Namibia's rich endowment of renewable energy sources, stakeholders in the electricity supply industry should be presented with specific targets by the government.

[1] Note that Van Eck must, at least, maintain an utilization rate of 40%;
[2] Note that, this value takes into consideration the installation of Ruacana's fourth unit;

To conclude, it is the mandate of the Ministry of Mines and Energy, in collaboration with the electricity supply industry, to define, implement and promote those national supply targets, which should also provide incentives to the use of indigenous resources as well as carbon neutral technologies.

1.2.2.2 Electricity Tariffs

Through the Energy Policy White Paper (1998), the Government of Namibia expressed its commitment to pursue the following goals:

- Effective governance;
- Security of supply;
- Social upliftment;
- Investment and growth;
- Economic competitiveness and efficiency; and
- Sustainability.

Therefore, given the previous goals must be adopted as the framework for the energy policies development, the respective Cabinet took a decisive stance that established electricity tariffs should be cost-reflective by 2011/2012. Moreover, the ECB believes that the pricing methodology adopted promotes the "recovery of cost of supply plus regulated rate of return while keeping prices affordable to consumers" (ECB Press Statement, 2010).

Nevertheless, consistently with the restructuring of the electricity industry in Namibia (2000), tariffs for generation, transmission and distribution are determined separately. Thus, in order to enhance tariff cost-reflectivity, ECB has been granting tariff increments to NamPower, REDs and Local Authorities.

On the one hand, NamPower has been enjoying tariff increments of, for example, 18% for 2010/2011 (note that, for the same period, the utility has requested an increase of 35.16%). On the other hand, REDs and local authorities must submit revenue requirements to the ECB, according to which are granted varying increases.

Hence, electricity prices for end-users have been increasing and may vary from region to region. Nevertheless, tariffs are a crucial determinant of the viability of any energy business and, therefore, attractive tariffs are pivotal to promote electricity sector investments. In this line of thought, due to relatively low electricity tariffs, Namibia has failed to attract investors in the recent past.

All in all, taking into consideration the Energy Policy White Paper, tariff structures and electricity price determinations by the ECB, in Namibia, should:

- be based on sound economic principles;
- be cost reflective as far as possible;
- reflect long-run marginal costs of supply; and
- give existing and potential electricity industry participants a level playing field.

Generation Tariffs

So far, generation tariffs in Namibia are still determined using an import-parity-pricing methodology, which prices generation at the cost of imported electricity. For that reason, there is no incentive to meet country's electricity needs from internal sources, that is, a significant proportion of the country's electricity needs are met through imports from neighboring countries.

However, during emergency periods such as low river flow at Ruacana, or times when electricity imports are curtailed or limited, and the Van Eck and Paratus power stations run more than intended, the import-parity-pricing regime is suspended, and actual generation costs are taken into account to derive the price.

The Van Eck and Paratus plants have significantly higher running costs, and these are exacerbated when global commodity prices are high. Therefore, when the emergency pricing regime is in force, under-recoveries can occur due to fluctuations in coal or diesel prices, and these could be treated as allowable costs in the ensuing tariff-review period.

Moreover, albeit that Namibia´s Energy Policy White Paper outlines the need for increasing the share of indigenous resources, the Namibian electricity tariffs do not differentiate whether the electrical energy is derived from renewable or fossil fuels, that is, the playing field between conventional and renewable energy technologies is not leveled.

Therefore, in order to address this market failure, it must be pursued one of two options: internalization of external costs of fossil fuel based generation or introduction of special instruments, such as, Renewable Energy Feed-in-Tariffs.

Given that, in Namibia, the majority of fossil fuel power is not generated locally but imported from neighboring countries, it is almost impossible to promote the internalization of external costs. Therefore, the way out is to create tariff structures through the adoption of special instruments which are efficient, effective and maximize consumer surplus. Additionally, these tariff structures must also be created to actively incentivize the investment and use of renewable energy technologies, which by its turn will foster the development of Namibia's rich diversity of indigenous renewable energy endowments.

To conclude, on the one hand, following recommendations of a study that ECB has commissioned, current generation-pricing methodology was under revision and it is likely that a cost-plus-revenue-requirement approach will be adopted in the short term (as previously developed), and, on the other hand, despite a good overall energy policy, Namibia's lack of grid based renewable electricity is due to an absence of a specific renewable energy policy.

Transmissions and Distribution Tariffs

In order to determine both transmission and distribution tariffs, the ECB has adopted the revenue-requirement or cost-plus methodology, which should enable full cost-recovery. However, at the time of writing, it had not been achieved and cost-reflective tariffs were being phased in, which for bulk tariffs, according to the Namibian Government, should have been achieved by 2010 or 2011.

However, in what concerns the transmission tariffs, following the review of the methodology in 2005, the ECB intended to continue with the cost-plus approach but move from the post-stamp method to a load-flow one in its derivation of transmission charges for generators. Note that, the previous method change is likely to coincide with similar changes in the pricing regime used by the Southern African Power Pool.

For last, accordingly with ECB annual report, distribution utilities and local authorities were granted with increases according to the revenue requirements, submitted by each to the ECB, and with the following main regulatory objectives:

- equitably rewarding investors (recovery of cost of supply plus regulated rate of return) while keeping prices affordable to consumer;
- ensuring quality of supply and service (taking cognizance of different quality standards and associated costs); and
- maximizing operational efficiency through restructuring and performance evaluation and monitoring.

Connection Charges

All transmission and distribution utilities in Namibia are required to promulgate connection-charge policies that are approved by the ECB. Therefore, in order to simplify the respective policy establishment, the ECB provides guidance on the features that are expected to be common across all distributors, namely:

- the shallow connection charge approach should be adopted;
- the insurance, operations and maintenance costs of dedicated connection assets should be included the standard tariff; and
- there should be no additional charges in the event of premature replacement of connection assets.

Cost Containment, Asset Valuation and Tariffs

The revenue-requirement methodology provides few incentives for regulated utilities to improve their efficiency. Thus, in order to limit this, on the one hand, the ECB made comparisons with previous years to assess operating expenditure, and, on the other hand, a generally favorable view was given to maintenance expenditure.

In order to incentivize commercial performance within the distribution sector, in 2010, non-technical losses were capped according to the least percentage of revenue, either 1.25 per cent of revenue requirements or the level of the previous year. Additionally, depending on distributor type and location, technical losses were capped at 10 to 15 per cent.

Moreover, asset values are also a crucial component of the revenue-requirement methodology. In that sense, for transmission and distribution, the ECB adopts the current replacement value, which is recalculated every five years.

Note that, this method takes into consideration the likelihood of significant new investments in Namibia's electricity industry and, therefore, limits the impact of electricity tariff increases as new capital is invested.

Additionally, straight-line depreciation is employed in the asset valuations for both transmission and distribution. Electrification assets provided through grants from donors or the government are not permitted to earn a rate of return but are expensed for depreciation.

For last, tariffs are annually renewed and, consequently, the regulatory asset base for transmission and distribution also requires annual updating and revaluing.

The Multiplicity of Retail Tariffs

In order to account for volatile fuel prices and increasing generation prices, the ECB approves the tariffs of 32 distribution companies, which, by differing in tariff structures, places intense pressure on the ECB and is unlikely to be sustainable in the longer term.

In this line of thought, the ECB has proposed the following tariff structure to be adopted by all distribution companies:

- a basic charge;
- an energy charge;
- a capacity charge (small customers); and
- a demand charge (large customers).

Note that, through the adoption of such tariff structure, the extent of cross-subsidization, across and within different customer groupings, would be limited.

1.2.2.3 Local Authority Surcharges

In Namibia, local authorities are entitled to tax electricity-service provision through the application of a local-authority surcharge which, contributes to the overall budget requirements for the local-government service provision.

As this tax is discretionary, it varies widely across the country, from less than 10¢/kWh (Namibia $) up to 50¢/kWh (Namibia $). Therefore, this may cloud the profitability or otherwise of local-authority distributors, making it difficult to regulate them effectively.

Nevertheless, given its significance in local authorities' revenue, it constitutes no surprise that this surcharge was/is hugely political and it is the single most important impediment to the establishment of two of the outstanding REDs.

1.2.2.4 Taxes and Tax Incentives for Continued Electricity Supply Investments Development

Most of nowadays common tax incentives for electricity supply projects do not exist in Namibia, which results in the continuous operation of NamPower as monopolist provider and the only to enjoy access to government subsidies. Thus, it is crucial that steps towards the creation of incentives to new entrants, for example, tax breaks, be created to stimulate the captivation of new investments in the respective industry.

Additionally, the lack of incentives discourages and makes unlikely that major investments will be done in the development of renewable energy technologies in Namibia. Therefore, incentives to the adoption of renewable energy sources, such as, exempting imports of renewable energy technologies from value added tax, introducing tax breaks for renewable energy enterprises, creating tax incentives such as tax-free establishment periods for new energy sector entrepreneurs, introducing carbon taxes, and creating special-purpose supply sector incentives similar to those in free-trade zones, must be taken into consideration to enhance the sector's attractiveness for investors.

1.2.2.5 Rural Electrification

As great parts of the country are rather sparsely populated, the area served by the distribution network covers quite a small portion of the total area, that is, the distribution and supply electricity to end consumers only covers approximately 17,000 end consumers, being the vast majority domestic users.

Nevertheless, Namibia has made substantial progress in the effort of bringing electricity to the every corner of the country. Back in 2009, an effort in rural electrification has been made, yet more than 200,000 households still remain without access to energy services and, thus, the Ministry of Mines and Energy estimates that only some 17% of Namibia's rural population has access to electricity.

Additionally, to the present day, investments in off-grid connections in Namibia have been very small, and only a few real and sustainable successes can be accounted for. The demand for off-grid technologies in rural Namibia remains underdeveloped, despite a number of novel attempts and support mechanisms to introduce affordable financing technologies closer to consumers.

Furthermore, service reliability, the long-term provision of cost-effective maintenance and the collection of fees remain major challenges in rural Namibia. High unemployment does not help either, and limits the abilities of households to secure and service loans.

To conclude, realism in terms of which rural electrification targets are achievable, how rural electrification can be incentivized and a continued commitment by Government to systematically bring affordable energy services to rural Namibia is required, thereby also introducing new and decentralized livelihood, learning and business opportunities.

1.2.2.6 Sustainability

Namibia's continued economic development relies on a vibrant electricity supply sector that provides reliable, affordable and accessible electrical energy. However, as it will be further explored in the upcoming sections, regionally, Namibia finds itself in a situation where the projected supply arrangements will no longer meet the required demand.

Additionally, given that the continued reliance on fossil fuels harms the environment and leads to climate change, and that fossil fuels will eventually become too expensive to be considered the backbone of a developing nation, policies that target the exploration of the national abundant renewable energy potential must be developed.

The increased use of renewable energy technologies is an important step to limit the economic implications of climate change, while at the same time allowing Namibia to become more energy autonomous and benefit from the multitude of added value that the use and beneficiation of local resources holds.

For last, as Namibia urges local electricity supply sector investments that address short term supply constraints and take regional developments and its own sustainability into account, the development of renewable energy technologies is of particular importance.

1.3 Electricity Policies

Over the recent years, the interest in the energy sector of Namibia has grown substantially due to electricity generation shortages in other SAPP member states, an increase in the price of Uranium and favorable wind and solar regimes, which promotes a feasible production of renewable energy.

Namibia is endowed with largely undeveloped energy sources. Firstly, non-renewable energy resources include gas and uranium, however, both have their challenges to develop and, thereby, to provide power to the country. Secondly, the renewable energy resources are in the form of hydro-power, good wind resources, excellent solar radiation, and biomass.

Currently, South Africa provides most of the more than 60% of electricity imports to meet Namibia's energy needs but the recent energy crisis proved that its neighbor could no longer guarantee a steady supply, threatening an energy crisis and undermining Namibia's hopes of economic growth.

Furthermore, in light of the need of promoting further development of the national energy sector as well as cognizant that the country's energy regulatory framework and associated energy laws and regulations are fragmented and outdated, the Ministry of Mines and Energy of the Republic of Namibia has embarked on a review of the energy policies.

Currently, despite a favorable regulatory electricity sector regime, and an established IPP framework, foreign investments in Namibia's energy sector remain very limited. Additionally, the electricity supply industry (ESI) in Namibia faces a number of challenges:

- Major investment requirements in the short to medium term – in generation, transmission and distribution infrastructure and operations;
- Increasing access to electricity among the Namibian population;
- Broadening of local and foreign private sector participation in the ESI;
- Impacts on Namibia of electricity sector reform in Southern Africa (particularly South Africa and the Southern African Power Pool);
- Loss of economies of scale due to a fragmented nature of the ESI;
- Proliferation of a large number of electricity tariffs, often not cost-reflective, resulting in efficiency losses and unequal treatment of customers;
- Insufficient customer focus, leading to sub-optimal quality of supply and service;
- Human resource constraints with negative implications for efficiency and delivery;
- Diverse financial performance of electricity distributors, with adverse consequences for financial viability and sustainability; and
- An inability of many of the current distributors to plan, finance and sustain electrification programs in their areas of supply.

In this line of thought, the following sections explore how Namibia's policy environment supports developments in electricity supply sector.

1.3.1 Vision 2030

Namibia's Vision 2030 envisages "the transformation of Namibia into an industrialized nation with a viable natural resources-based export sector, and increased size of skill-based industrial and service sectors, and market oriented production", that is, through its key policy document, Vision 2030, and its 5-year National Development Plans, the Namibian government seeks to transform Namibia into an industrialized nation by 2030.

In addition, 'Vision 2030', which was formulated in 2004, aims to guide the country's five-year development plans from NDP III through to NDP VII, while providing direction to Namibian Government, the private sector, NGOs and local authorities.

Hence, it also fully embraces the idea of sustainable development which, for the natural resource sector, states:

"The nation shall develop its natural capital for the benefit of its social, economic and ecological well-being by adopting strategies that: promote the sustainable, equitable and efficient use of natural resources; maximize Namibia's comparative advantages; and reduce all inappropriate resource use practices. However, natural resources alone cannot sustain Namibia's long-term development, and the nation must diversify its economy and livelihood strategies".

All in all, Vision 2030 places significant pressure on the Namibian electricity supply industry and challenges its growth and ability to deliver electrical energy on demand. However, substantial challenges, such as unemployment, income dependence from the Southern African Customs Union, income disparities, a fledgling manufacturing sector and high import dependence, need to be addressed.

1.3.2 White Paper on Energy Policy

The White Paper on Energy Policy was developed by the Namibian Energy Policy Committee of the Ministry of Mines and Energy and signaled its first attempt at a more coordinated and formal policy for the electricity sector. It was released in May 1998 and establishes the following broad energy policy goals as framework for the energy policies:

- Effective energy sector governance;
- Security of supply;
- Social upliftment;
- Investment and growth;
- Economic competitiveness and efficiency; and
- Sustainability.

Firstly, as part of the energy policy, Government recognizes the importance of renewable energies in realizing the country's energy-related goals and inspirations. Thus, in order to promote the use of renewable energy, the Government was intended to establish an adequate institutional and planning framework as well as the development of suitable financing systems, human resources and public awareness. Note that, it also sought to meet development challenges through improved access to renewable energy sources, particularly in rural electrification, rural water supply, solar housing and water heating.

Moreover, in order to achieve security of supply, the Government was to pursue an appropriate diversification of economically competitive and reliable sources, with a particular emphasis on national resources. Nevertheless, it would need to be balanced with the intention of ensuring that energy demand by the productive sectors of the economy continues to be met through reliable competitively-priced energy.

Additionally, in what concerns access improvement, namely, in the rural areas, the White Paper gives special attention to the establishment of a rural electrification program based on transparent planning and evaluation criteria for new projects. In this line thought, not only national studies as a basis for future policy development, including the pressing issue of sustainable biomass usage in rural areas and the role of women, were to be developed, but also development initiatives integrated with other ministries ones.

New investment in the sector was to be encouraged through appropriate regulatory, fiscal and environmental frameworks, harmonized with those in SADC countries, that is, electricity tariff structures should be based on sound economic principles, reflecting the long-run marginal cost of electricity supply, dialogue with private investors and financiers should be promoted, among other.

Furthermore, the energy policy goal of sustainability was to be promoted through a requirement for environmental impact assessments and project evaluation methodologies which incorporate environmental externalities. While energy efficiency was to be promoted through policies on better information collection and dissemination, and particularly with respect to energy efficiency and conservation practices in households, buildings, transport and industry.

The White Paper also outlines: “duly considering associated risks, it is the aim of government that 100% of the peak demand and at least 75% of the electric energy demand will be supplied from internal sources by 2010. Risk mitigation measures will be pursued, including the possibility of regional equity participation in, and guarantees for, Namibian generation projects”, which, as previously mentioned, at the time of writing, has not been implemented.

All in all, there are identified sector challenges that still remain relevant today and must be addressed, namely, high dependence on imports, electricity prices that in many instances are not cost-reflectivity, technical, financial and institutional problems in what concerns rural electricity supply and unclear institutional structures and arrangements.

1.3.3 National Development Plan III

The third NDP (NDP3), which encompasses the period from 2009 to 2013, recognizes that the “energy sub-sector plays a pivotal role in the country’s economy and national development”. Nevertheless, it also mentions that “although electricity supply has improved since 2001, the vast majority of Namibian households still have no access to electricity, particularly in the Northern Regions. Fuel wood is still dominant as an energy source putting severe pressure on the natural environment. This situation requires enormous efforts to realize Vision 2030.”

Therefore, interventions regarding the energy sector should be such that would respond to the acute shortage of power supply in the country, contribute to the government’s Action Plan to ensure security of energy supply with a view of enhancing competitiveness and efficiency in economic activities, and support the government’s objective of extending access to energy supply through rural electrification and the extension of links with neighboring countries.

All in all, the sectors’ goal is to ensure “adequate, secure and efficient supply of energy that is environment friendly and leads to a reduction in the country’s reliance on energy imports” and, therefore, specific energy-sector strategies put forward are:

- establish a strong body to regulate and monitor the whole energy sector, that is, an energy regulator;

- establish a commercial trading center for electricity;
- enforce regionally harmonized tariffs for cost recovery that are socially acceptable;
- increase local energy generation with conventional and renewable technologies;
- increase local production of electricity as well as supply of electricity from local plants;
- increase local capacities through, for example, the development of the Kudu gas and Orange River hydro power project, Ruacana fourth turbine installation, among others;
- enhance rural electrification, namely, implement the Rural Electricity Distribution Master Plan and provide remote areas with off-grid renewable energy;
- promote the efficient use of energy by introducing special technologies (such as compact fluorescent lights), programmes (such as demand side management) and public awareness campaigns;
- improve the regional transmission network;

1.3.4 Electricity Act (2007)

The Electricity Act of 2007 was passed by the Parliament and signed by the President in terms of the Namibian Constitution and was published in terms of Article 56 of that constitution. The Act was created to establish the Electricity Control Board and to provide for its powers and functions, requirements and conditions for obtaining licenses for the provision of electricity, powers and obligations of licensees and incidental matters.

In this sense, the respective Act establishes the Electricity Control Board (ECB) as the Namibian Regulator of the electricity sector, making the ECB responsible for controlling and regulating the provision, use and consumption of electricity in the country.

As previously stated, the ECB is a statutory regulatory authority established under the Electricity Act 2 of 2000, which has subsequently been repealed by the Electricity Act, 4 of 2007. Additionally, the ECB executes its statutory functions through the Technical Secretariat headed by the Chief Executive Officer and, amongst others, has developed guidelines to set cost-reflectivity tariffs, and implement an IPP regime in Namibia.

1.3.5 Cabinet Directive (2007)

A Cabinet Directive, dated of 2007, not only approved the implementation of the Off-grid Energy Master Plan, but also directed that the hot water supply to all Government and parastatal buildings were/is to be met by solar water heaters only.

Note that, regarding demand side management, the measure of making solar water heaters mandatory for all public and semi-public buildings must be considered as significant.

1.4 Electricity Demand

According to Namibian IRP, as of 2011, Namibia has registered a peak demand of 511 MW (July 2011) as well as an energy requirement of 3,230 GWh. Additionally, the load factor has also registered a maximum value of 72.1%.

Nevertheless, due to its significant importance for planning, for example, to schedule the generation equipment maintenance, it must be highlighted that both peak demand and energy requirement register a variation depending the various months or seasons of the year.

Firstly, in what concerns the variation of peak demand throughout the year, it is usually at the 87% - 91% of annual peak level from December to the end of March, when it starts to increase until it reaches the maximum value in July (winter peak).

Furthermore, regarding the monthly variation of energy demand throughout the year, the highest demand also takes place in July, registering an energy requirement of 8.69% of the annual energy demand. However, the months from October to December present a similarly relative large demand.

Note that, due to the fact that Ruacana power generation also varies throughout the year, namely, it generates very little during dry season, the latter indicator is of very relevance for planning purposes.

In this line of thought, the following Figure 1.1 presents both the monthly peak and energy demand variation registered in Namibia. Note that, it has been taken into consideration the monthly average for the individual months between 2008 and 2010.

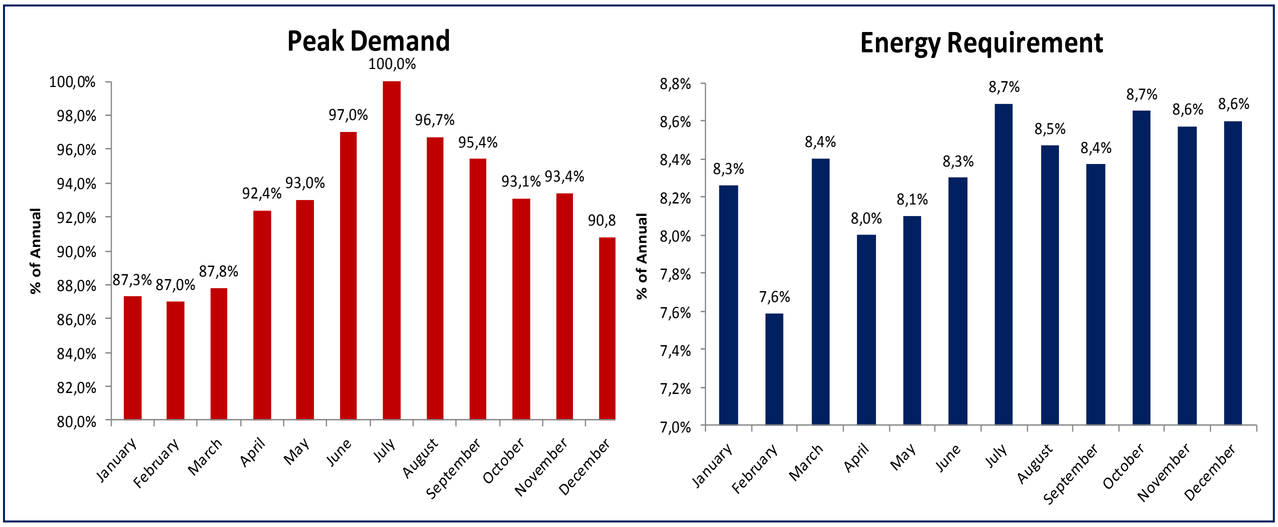


Figure 1.1 - Monthly Peak Demand and Energy Requirement (2008-2010 Average); Source: Namibian IRP

Moreover, between 2008 and 2011, both peak demand (capacity) and energy requirement has increased, on average, at annual growth rate of 5.7% and 5.4%, respectively. Diverse factors have contributed for this increase, namely, large industrial component in the overall demand, increased mining activities (for example, Skorpion zinc mine, which consumes a significant portion of Namibia's overall power demand), increased electrification rate and, consequently, increased commercial and domestic demand, insufficient demand side management programmes, among others.

Nevertheless, as can be seen in Figure 1.2, the registered increase of both peak and energy demand is far away from decreasing in the near future. Note that, of particular interest, between 2014 and 2016, there is estimated a significant increase of demand due to the new mining loads accountability as well as loads of additional projects.

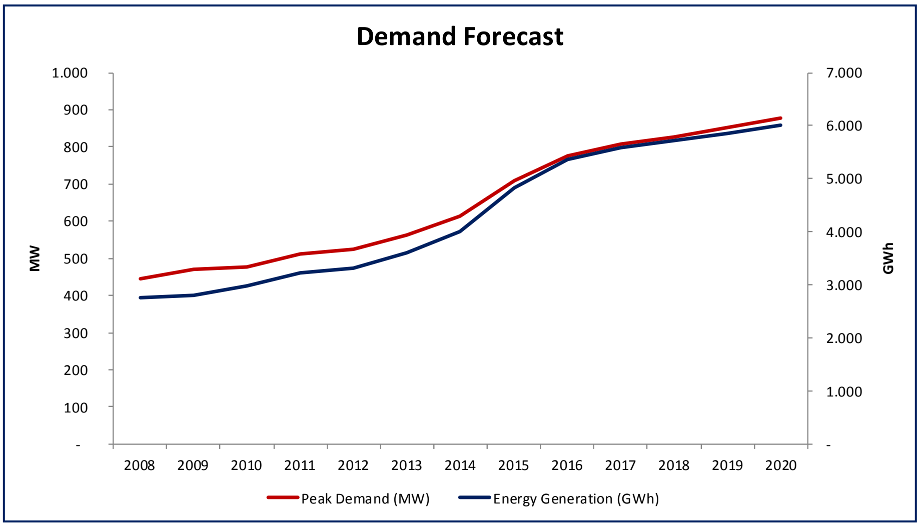


Figure 1.2 - Namibian Demand Forecast: Peak and Energy Generation; Source: Namibian IRP

Additionally, the load factor is also expected to vary in the near future, that is, as the following Figure 1.3 presents, the load factor is expected to reach a maximum value of 79.1% by 2017, contributing to that the addition of significant industrial loads (previously mentioned). Nevertheless, due to the increase of commercial and domestic demand in the load mix, the respective value will start to decrease in 2018.

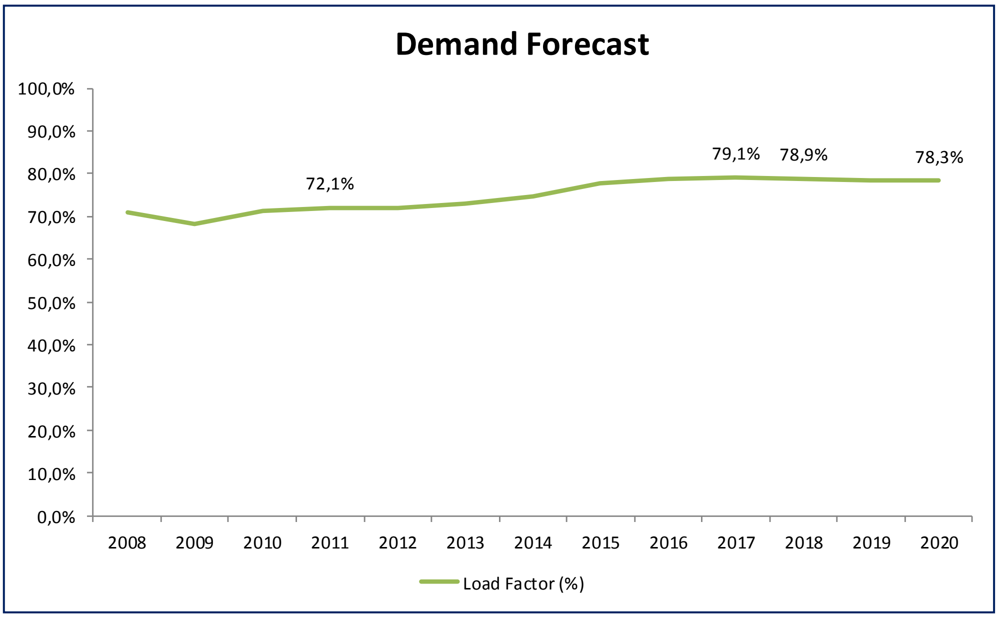


Figure 1.3 - Namibian Demand Forecast: Load Factor; Source: Namibian IRP

All in all, between 2011 and 2020, the overall demand is expected to grow, on average, at an annual rate of 6.2% and 7.3% for peak and energy demand, respectively, that is, on the one hand, the peak demand is estimated to grow up to 877 MW in 2020 and, on the other hand, the energy requirement are expected to reach the value of 6,017 GWh, also in 2020.

1.5 Electricity Supply

Namibia has four major power plants interconnected to the national grid, which are the 240 MW Ruacana hydropower plant, the 120 Van Eck coal fired power plant, the 24 MW Paratus diesel fired power plant and the new 22.5 MW Anixas diesel fired power plant at Walvis Bay. Therefore, as previously mentioned, the national grid is supplied by the local power plants plus the imports of electricity made from SAPP (Southern Africa Power Pool) member countries like Mozambique, South Africa, Zambia and Zimbabwe.

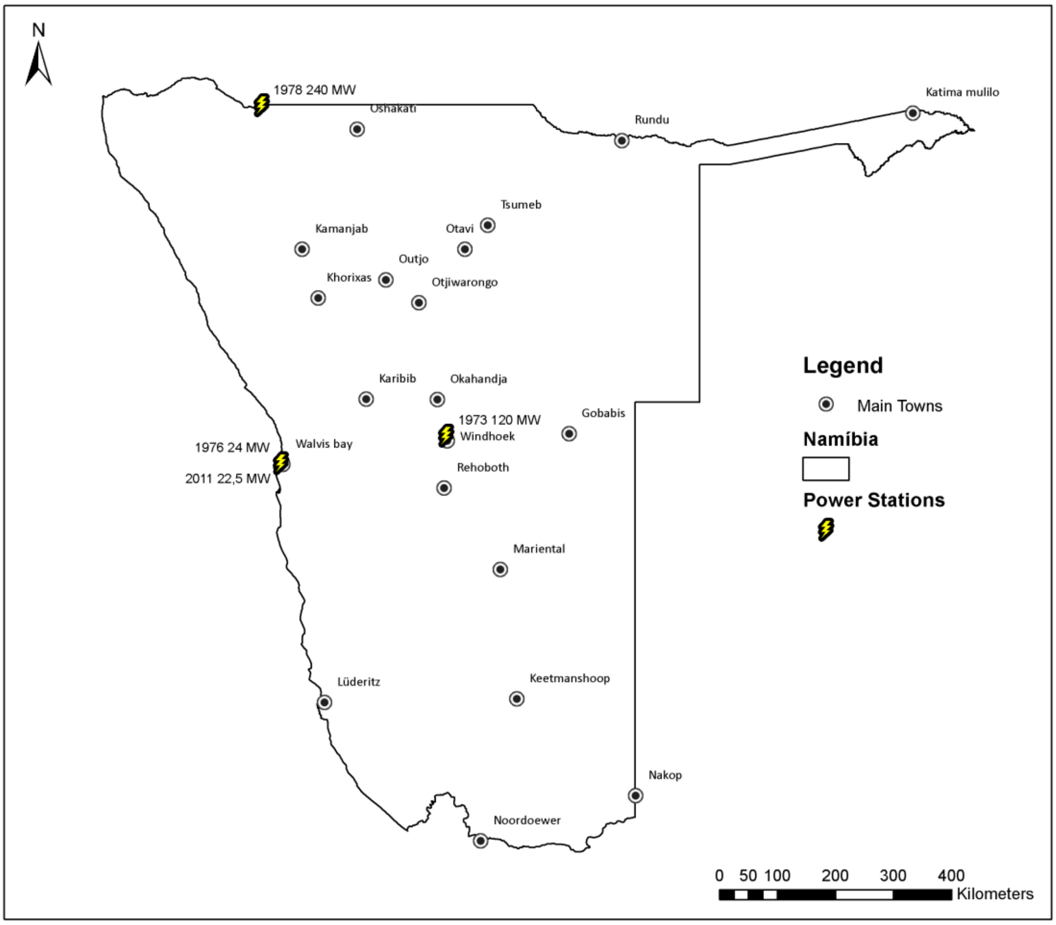


Figure 1.4 - Local Power Plant of Namibia; Source: NamPower

1.5.1 Local Generation Facilities

1.5.1.1 Ruacana Hydropower Station

The Ruacana hydropower station was commissioned in 1978 and it is located on the Kunene River, in the North of Namibia, where the Kunene River becomes the border between Namibia and Angola. Moreover, with a rating of 240 MW, consisting of three 80 MW hydro generators, this power station it is the largest contributor in terms of domestic capacity. Note that, the power plant has black start up diesel generators. Additionally, in order to supply the national grid with the vast majority of the respective output, there is a 330 kV transmission line running from Ruacana to the Omburu substation (570 km).

Furthermore, due to the fact that its upstream storage dams are either not completed or were damaged in the Angolan civil war, the Ruacana station is operated as a run-of-river power plant. Thus, during the rainy season (February to May), it is operated at full output level and as a base load power plant, while for the remainder of the year it is operated predominately as a peaking power station.

Nevertheless, currently, NamPower is installing a 91 MW fourth turbine at Ruacana station, which is expected to be operational in the first half of 2012. Also, NamPower will refurbish the three existing turbines and, therefore, increase the peaking capacity in 4 MW per unit.

For last, even though Ruacana has 240 MW of peaking capacity, which will be upgraded to 343 MW, at last instance, it will only be translated into generating capacity if sufficient water is available.

1.5.1.2 Van Eck Coal Power Plant

The coal-fired Van Eck power plant, just north of Windhoek, has a total rating of 120 MW, using four 30 MW generators, and was commissioned in the 1973. Note that, in order to start-up, the station needs external power and, due to water constraints in Windhoek, the plant was design as a dry cooled station.

Moreover, as previously mentioned the coal used is imported from South Africa and, after, transported by ship to Walvis Bay and then by rail or road to Windhoek, increasing greatly the respective fuel cost. For this reason, the plant is normally operated as a standby and peaking power station. Nevertheless, given the recent regional constraints, it has been running at mid-merit to base load.

The power station has very limited emission control equipment and thus emits high levels of air pollutants. The station is therefore limited to burning 3,500 tons of coal each week, although it may use emergency stockpiles if necessary.

For last, the aging power units are becoming less and less reliable as well as the maximum output that, together, they can reach is only up to 50 MW (according to Namibia’s IRP). Therefore, taking into consideration the various rehabilitation options and the consequent additional output, extension of life and capital costs, it appears that a 5 year life extension and an output of additional 34 MW is likely to be pursued and completed by the beginning of 2015.

1.5.1.3 Paratus Diesel Power Station

Paratus power station in Walvis Bay uses heavy fuel oil and has a total rating of 24 MW, using four 6 MW diesel generators. Additionally, the power station was commissioned in 1976 and, due to the fact that to start-up and shut down uses light fuel oil, switching to heavy fuel oil once a unit is generating more than 2,7 MW, it runs at very high marginal cost.

In addition, note that, the rating of each unit is dependent on the ambient temperature, namely, a rating of approximately 5 MW is registered at low temperatures, while 4 MW are available at high temperatures.

Moreover, similar to Van Eck power station, Paratus is used to match short-term demand peaks, that is, it is mainly used as a standby and peaking power station. Nonetheless, it is also contractually bound as an emergency standby plant for the city of Walvis Bay.

For last, according to NamPower plans, the replacement of the existing machines, with the same 7.5 MW heavy fuel oil units that are installed at Anixas, could be on line as soon as July 2013, increasing the peak capacity of Paratus to a total of 30 MW.

1.5.1.4 Anixas Power Station

Anixas heavy-fuel oil power station is located on lands adjacent to existing Paratus diesel Power Station. This power station commenced commercial operation in July 2011, however, only had its official inauguration in November 2011.

Anixas, which has been in operation ever since July 2011, is constituted by three diesel generators sets, each with a net electrical capacity of 7.5 MW, providing a total of 22.5 MW. All in all, it is a relatively new power station and benefits from proven technology, which ensures higher efficiency and reliability as well as fewer emissions.

1.5.2 Imports

Namibia has been a net importer of electricity for many years and continues to import up to 70% of its electricity consumption from a number of countries in the region. Therefore, the current section aims to describe the agreements established with the neighbor countries and from which these imports are obtained.

1.5.2.1 Non-Firm Supply Agreement with Mozambique

NamPower has a short-term supply contract with EDM (“Electricidade de Moçambique”) for up to 30 MW of supply from hydro generation. Since it is a short-term supply contract, this contract is reviewed on an annual basis. In addition, adjacent to the fact that the established agreement is of non-firm nature, the contract has no capacity charges and defines energy prices for three time periods: Peak, Standard and Off-Peak.

For last, over the last few years, the average trade between NamPower and Mozambique has been 25 MW, with NamPower pursuing further trading opportunities with Mozambique.

1.5.2.2 Non-Firm Supply Agreement with South Africa

There are two contracts in place between NamPower and Eskom, namely, the bilateral and the supplemental contract. Firstly, in what concerns the bilateral contract, power imports between the two utilities are limited by capacity of the 600 MW cross-border transmission line and it can only be put into action during off-peak periods as agreed between the two countries.

Furthermore, supplemental contract signed with ESKOM, which is reviewed annually, encompasses a supply of up to 200 MW of Special Assistance. Due to power supply shortages within South Africa, this supply option can only be requested by NamPower after all local supply options have been exhausted, including active demand management programs in Namibia. Also based on contract clauses, if there is load shedding in South Africa due to generation shortages, NamPower must also shed its load.

Moreover, due to the weight of Eskom's share on the total imports, over the last years, and by the fact that peak load demand is expected to rise to approximately 600 MW by 2014, this agreement is vital to Namibia's security of supply.

However, given the energy crisis felt in South Africa, Eskom has announced that it will no longer be able to supply electricity to neighboring countries in the near future.

1.5.2.3 Firm Supply Agreement with Zambia

The power supply agreement with Zambia Electricity Corporation Limited (ZESCO) entered into force in January 2010. Additionally, this agreement is valid until 2020 and has a firm capacity of 50 MW and a non-firm capacity of 50 MW, being the later confirmed on a daily basis.

Note that, so far, the non-firm agreement has not been executed, which may be partially due to transmission constrains in the ZESCO system.

1.5.2.4 Firm Supply Agreement with Zimbabwe

In October 2008, a 5-year term power supply agreement was signed between NamPower and the Zimbabwe Electricity Supply Authority (ZESA) for the firm supply of 150 MW. This take-or-pay has both capacity and energy charges.

Even though it should be finished in 2013, due to disruptions of supply, the assigned capacity is assumed to be available 80% of the time and, therefore, taking into consideration the banked energy, the supply from ZESA is expected to be in place until October 2014. Nonetheless, ZESA has already expressed that it would not be renewing the contract.

1.5.2.5 Other Power Supply Agreements

Presently, there are no other existing agreements regarding power imports into Namibia. However, there are negotiations between NamPower and the Botswana Power Corporation (BPC) for the supply of 150 to 250 MW of off-peak power. At this time, BPC is searching for potential investors for the creation of a power station that could provide energy generated by the plant at preferential rates. In addition, discussions are ongoing with Société Nationale d'Electricité (SNEL) of the Democratic Republic of Congo, for the supply of 50 MW.

Furthermore, not only, NamPower is a party on a project investigating the development of further transmission interconnection between Zimbabwe, Zambia, Botswana and Namibia (commonly called the ZIZABONA project), that is, regional integration, but also, the Namibia Government is striving to become less dependent on imported electricity by securing enough generating capacity of its own.

1.5.3 Independent Power Producers in Namibia

Despite the liberalization of the sector in 2000 as well as the positive current framework, private-sector participation in the electricity supply industry of Namibia is virtually non-existent. In 2012, there are ten IPPs that have been conditionally licensed by ECB, intending to generate power from biomass, coal, heavy fuel-oil, gas, wind, hydro and solar.

The licensees are at various stages of negotiating power purchase agreements (PPAs) with NamPower, as expected in the single buyer market model, namely, two wind-based projects, Diaz Wind Power (Pty) Ltd and Innowind (Pty) Ltd, and one solar-based project, GreenNam Electricity. However, as yet, only Bush Energy Namibia has established an operational power plant (250 kW fuelled by biomass), which will be connected to the grid as soon as the strengthening of the distribution grid is completed.

Moreover, according to ECB, "little progress was made with regard to the finalization of the investor oriented market report framework and the Modified Single Buyer Model, aimed at enhancing energy supply security and attracting private sector participation in generation".

For last, regarding IPPs further preponderance, the country's flagship Kudu gas-to-power project is facing ongoing delays, and the expectation that IPPs would form an important part of achieving indigenous generation continues to be unfulfilled. Therefore, the ECB has made much progress in its short history, but more work remains if security of electricity supply is to be obtained.

1.6 Power Grid

Namibia has a well-developed transmission network emanating from Windhoek. Due to the fact that Ruacana hydro power station is located on the border with Angola and by the fact that the connection between the Namibian grid and the South African one is located on the southern border, the main transmission line dissects the country from north to south (Figure 1.5 - National Power Grid). Additionally, the Namibian grid is characterized by a greater efficiency, which, for example, between 2001 and 2005, has reduced transmission losses from 9.8% to 5.1%.

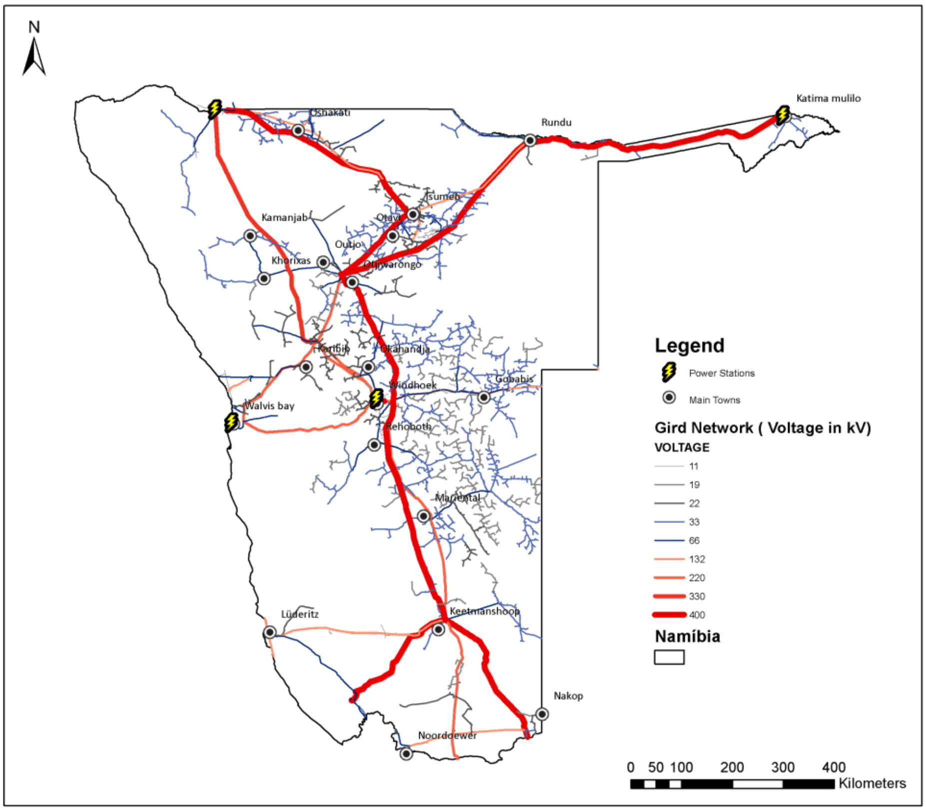


Figure 1.5 - National Power Grid.

Moreover, as shown in Figure 1.5, the Namibian transmission system not only reaches the Caprivi corridor (North), where it borders with the Zambian system, but also extends to the border of Botswana (East). It may also be concluded that the NamPower transmission spine is based on the transmission running at 330 kV, from the Ruacana Power Station to the Omburu substation, and at 220 kV, from the latter substation to the South African border, for a total length of 1,518 km.

Additionally, the transmission system consists of several transmission voltages including 66 kV, 132 kV, 220 kV, 330 kV and 400 kV as well as 350 kV HVDC. In what concerns the distribution lines with the voltage 66 kV and below, they extend radially from the main substations for further dispersion of power to the consumption areas along the coast and inland.

As previously stated, the REDs and local authorities, such as, the City of Windhoek, are responsible for the distribution of electricity to the end customers in their respective areas. In that sense, currently, they serve 17,000 end consumers, however, the vast majority of them are domestic users.

Note that, due to the fact that a great part of the population is highly dispersed within the country, the reach of the distribution network is quite limited and, therefore, only covers a small portion of the total area.

Therefore, rural and off-grid electrification are two of the many programmes that the Ministry of Mines and Energy is developing through the Division of Electricity and Division of Renewable Energy. The Rural Electricity Distribution Master Plan (2000) , which is currently being reviewed, provides a framework for the planning of electrical distribution infrastructure, network planning, area prioritization, financing and implementation of grid electrification. Therefore, it covers all future electricity customers in the country that have not yet gained access to electricity.

Additionally, the Master Plan not only includes provision for grid-connected power but also decentralized electrification with the aid of renewable energy. Various attempts have been made at rural electrification with solar systems, namely, the ones purchased by home owners with funds secured through the Home Power! Programme.

A fee-for-service model was tested in the village of Ovitoto in 2002 and 100 households were equipped with solar systems. Albeit that only the electricity consumed was paid, using a prepayment system, in such a thinly populated area of Namibia, the system maintenance and accounting proved uneconomical. Consequently, the systems were transformed into “normal” solar home systems in 2004, and the users now pay a monthly fixed rate until the respective system is fully paid, after which they assume ownership.

In addition to isolated grids and home solar systems, Namibia also has a number of off-grid areas suitable for electrification with small independent solar networks. Note that, solar energy combined with other sources of energy, for example, wind energy and/or diesel power, can present an alternative to traditional sources of energy. Therefore, in 2004, the Gobabeb Desert Research Station, in the Namib Naukluft Park, commissioned a PV-diesel hybrid facility with a rating of 26 kW/h to serve a network of 25 consumers.

All in all, rural electrification in Namibia faces multiple barriers, namely, limited financial resources to extend the grid and low rural population densities, which by its turn leads to high investment costs and low returns on investment.

1.6.1 Interconnections

The high voltage transmission system that connects the electrical grids in Namibia and neighboring Zambia will be completed with the construction of the Caprivi Link, providing a new route for power imports.

The first stage of the Caprivi Link project, which encompasses a 350 kV HVDC line with a total length of 951 km, was officially commissioned in November 2010 and connects the Zambezi (Katima Mulilo, at the border between Namibia and Zambia) and Gerus (central Namibia) substations (Figure 1.6). Additionally, this interconnection was built with capability of transmitting 300 MW (monopole mode), which could be upgraded to 600 MW (bi-pole mode).

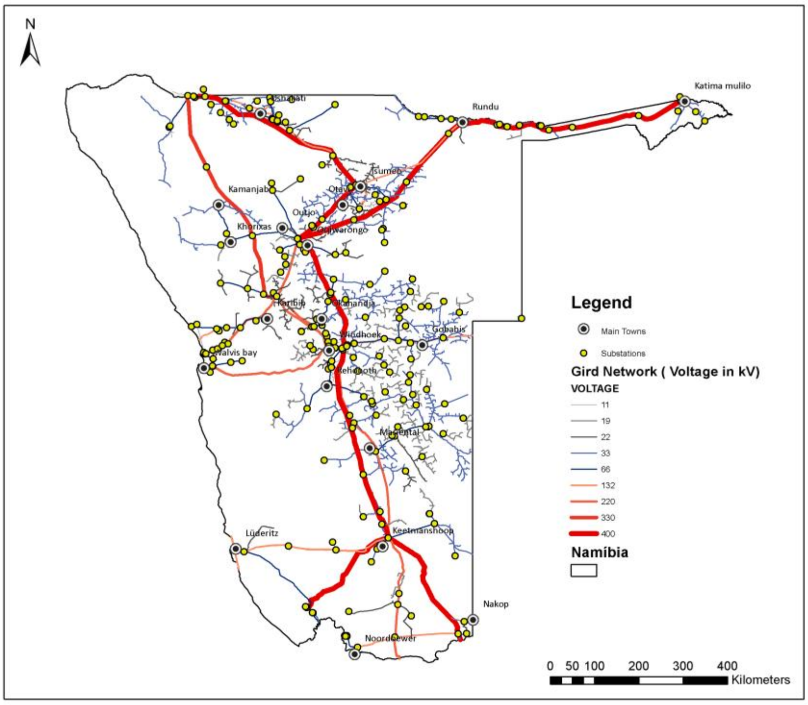


Figure 1.6 - Interconnections of Namibia.

Furthermore, as can be seen from the previous Figure, the other interconnections available (220 kV and 400 kV) are located in the south of Namibia, linking the country to South Africa, namely, Eskom. These interconnections are used to bring in the imports from Eskom and the 150 MW from the power produced in Hwange (Zimbabwe).

1.6.2 Substations

A substation is a part of an electrical generation, transmission, and distribution system. Substations transform high voltage to low, or the reverse, and/or perform any of several other important functions. A substation may also include transformers to change voltage levels between high transmission voltages and lower distribution voltages, or at the interconnection of two different transmission voltages. Note that, between generating plant and consumer, electric power may flow through several substations and its voltage may change in several steps.

Moreover, as central generation stations became larger, smaller generating plants were converted to distribution stations, receiving their energy supply from a larger plant instead of using their own generators. The first substations were connected to only one power station, where the generators were housed, and were subsidiaries of that power station.

Furthermore, on the one hand, a transmission substation connects two or more transmission lines. The simplest case is where all transmission lines have the same voltage. In such cases, the substation contains high-voltage switches that allow lines to be connected or isolated for fault clearance or maintenance.

On the other hand, a distribution substation transfers power from the transmission system to the distribution system of an area. It is uneconomical to directly connect electricity consumers to the main transmission network, unless they use large amounts of power, so the distribution station reduces voltage to a value suitable for local distribution.

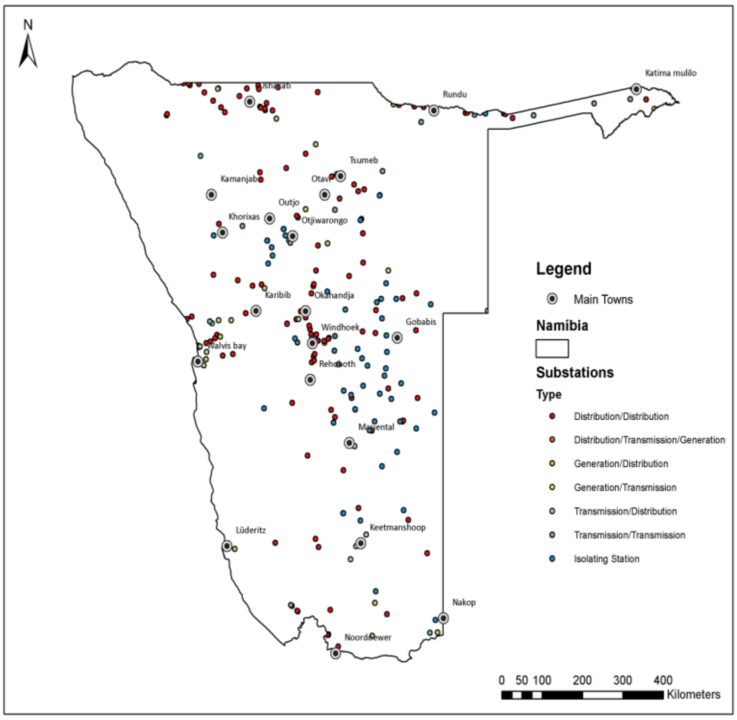


Figure 1.7 - National Substations.

The Figure 1.7 locates all substations in Namibia, dividing them by type. When looking closely to the figure, it can be seen that:

Table 1.1 - National Substations; (Also see Annex 4).

Substations	
Distribution/Distribution	149
Transmission/Distribution	35
Generation/Distribution	1
Distribution/Transmission/Generation	2
Transmission/Transmission	20
Generation/Transmission	3
Isolating Station	55
Total	**265**

As can be concluded, there are a total of 265 substations in Namibia, where the most common are Distribution/Distribution substations with a total of 149 substations. There also are 55 isolating stations, 35 Transmission/Distribution substations along with 20 Transmission/Transmission substations.

For last, there are also 3 Generation/Transmission substations (Walvis Bay S/S, Paratus P/S, and Van Eck P/S), 2 Distribution/Transmission/Generation (Ruacana D/S and Van Eck S/S) and 1 Generation/Distribution substation (Katima Mulilo S/S).

1.7 Namibia's Future Electricity Supply Mix

1.7.1 Supply / Demand Balance

Taking into consideration the, previously described, demand forecast and available supply, a capacity and energy balance, regarding the period of time placed between 2011 and 2020, will be further developed for the Namibian system.

Therefore, in what concerns the available energy capacity of Ruacana, it was assumed that both the fourth unit installation as well as rehabilitation of the respective remaining three would be currently in place, enhancing a total rating of 343 MW. Note that, it was also assumed that Ruacana could supply its full capacity output at any given time.

Additionally, the capacity of Van Eck was assumed to be 50 MW up to the time that the unit would have its 5 year life extension completed (2015) and, consequently, increased the respective capacity to 84 MW.

On the other hand, regarding Paratus and Anixas power stations, the first is considered to have a rating of 17 MW until the committed machine replacement takes place (2013), increasing then the total energy capacity to 30 MW, and the second is assumed to have 22.5 MW for the entire period.

For last, in what concerns the several agreements of energy imports, it is recognized that, due to sufficient banked energy, the 150 MW contract with Zimbabwe (ZESA) will only terminate in 2014, and the 50 MW with Zambia (ZESCO) will be in force until 2020.

Additionally, due to the energy crisis felt in South Africa (Figure 1.8), the bilateral and supplemental contract may not be an option for Namibia. Therefore, pursuing a conservative approach, it will be assumed that both the bilateral and supplement agreement will be only available for execution at off-peak periods.

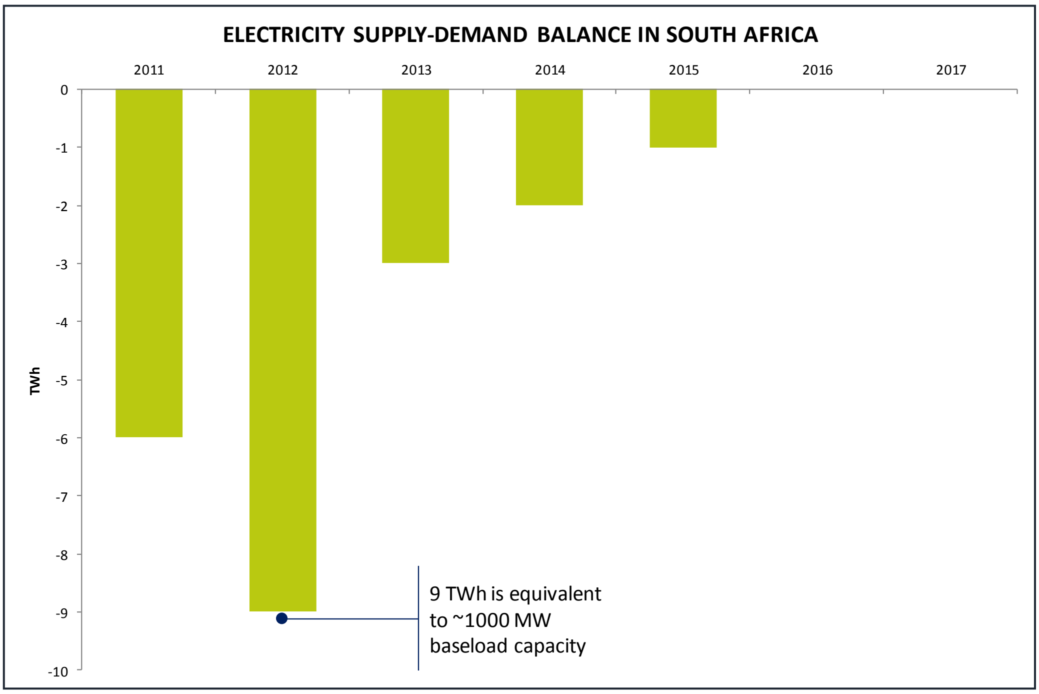


Figure 1.8 - Electricity Supply-Demand in South Africa; Source: SA IRP.

Therefore, taking into consideration the available firm capacity of Namibia as well as the forecasted peak demand for the period 2011-2020, the national supply/demand balance is presented by the Figure 1.9.

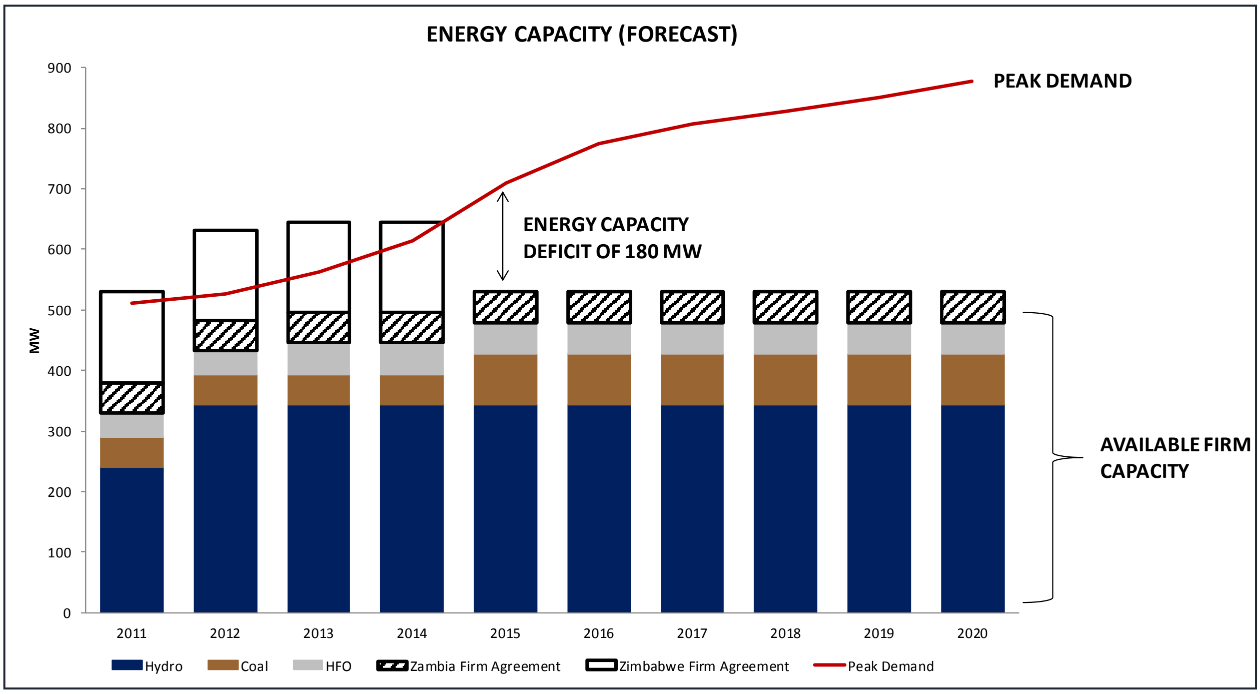


Figure 1.9 - Energy Capacity Forecast of Namibia.

As shown in the previous Figure, the capacity values indicate that there will be a slight increase in generation capacity in 2012, corresponding to the runner replacement at Ruacana, in 2013, due to the increase of capacity at Paratus, and in 2015, corresponding to the rehabilitation of Van Eck boilers. However, by the termination of supply from ZESA, a major drop in capacity availability will happen in 2015, which compounded with peak demand growth, will produce a large capacity deficit of some 180 MW.

To conclude, with the end of the Zimbabwe's supply agreement, Namibia faces a capacity deficit from 2015 onwards, which, given the strong increase in energy consumption in SADC region and, consequently, reduced availability of energy imports at mid-peak and peak periods, may be deepened.

1.7.2 Daily Load Profile by 2015

Due to the fact that Namibia will start to face a capacity deficit in 2015, the daily load profile for the respective year and Namibian supply options must be further considered. This will enable the assessment of the energy gap extent and, thereby, provide a basis for the consideration/development of future energy supply options.

As previously stated, given that Ruacana is mainly operated as a run-of-river power plant, the output of the hydro power station depends on the amount of water available. Therefore, during rainy season, from February to May, the station is operated as base load power plant, while for the remainder of the years it is mostly operated as a peaking power plant.

Additionally, once Ruacana hydropower station will account for approximately 70% of Namibia's energy generation capacity, the variation on its capacity availability will directly and greatly affect the available energy capacity in Namibia.

Therefore, taking into consideration the previously stated assumptions as well as adopting the monthly average energy produced by Ruacana, the daily load profile of Namibia by 2015, for an average day of both rainy and dry season, is represented in Figure 1.10. Note that, the months chosen to represent both seasons are, respectively, the rainiest and the driest month, according to Ruacana's monthly average energy produced.

Therefore, on the one hand, during the rainy season, Ruacana is assumed to run as base load power plant as well as operate at full output level for about 23 hours. Additionally, Van Eck coal fired power station is assumed to register, at least, a 40% utilization rate. Both diesel power stations, Paratus and Anixas, are assumed to operate as mid-peak and peak power stations.

Due to the fact that imports from Zambia are less expensive than diesel-based energy generation, when required to meet peak demand, primacy is given to the respective imports over diesel-based generation. Additionally, note that, as previously mentioned, energy imports, regarding the supplemental contract with South Africa, were only considered during off-peak periods.

For last, albeit that there will be no energy capacity deficit over off-peak periods, during mid-peak and peak periods, Namibia will register an energy capacity deficit up to 121 MW.

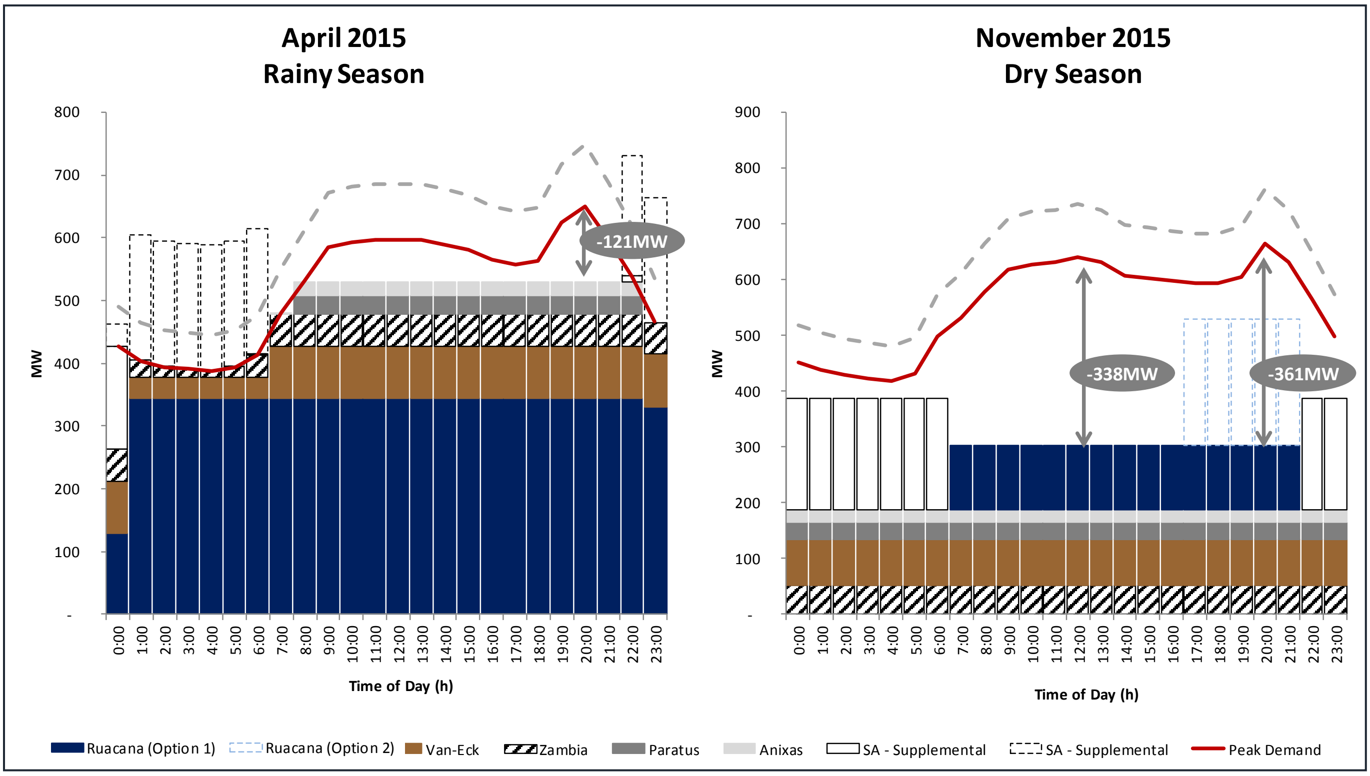


Figure 1.10 - Namibia's Daily Load Profile.

On the other hand, in what concerns the dry season, the first thing to be noticed is that the lack of water availability increases the energy deficit. Therefore, on the dry season, Ruacana will operate as mid-peak and peak power plant and for a maximum of 5 hours or 15 hours, depending if it is running at its full output level or at one third of its full output level, respectively.

Moreover, the Van Eck, Anixas and Paratus power station will run as base load power plants and will operate at the respective full output level. Zambia power agreement will have to be executed for the full 24 hours of the day and, for off-peak periods, the supplemental agreement with South Africa will also be requested at its maximum agreed capacity.

However, even though Namibia runs every available power station at its full output level and executes both energy supply agreements with South Africa and Zambia, during dry season, Namibia may face a continuous (24hours) energy capacity deficit, which may reach a maximum value of 361 MW.

For last, note that, for both seasons' daily load profile, there is a grey line (over the peak demand) which stands for an additional 15% reserve capacity, which, if taken into consideration, could deepen the energy capacity gap registered by Namibia.

1.7.3 The Cost of the Energy Gap

Albeit that a capacity gap is likely to only occur in 2015, the energy deficit could start as early as July 2013 (Figure 1.11), taking into consideration the previously stated assumptions, namely, Ruacana monthly average energy produced.

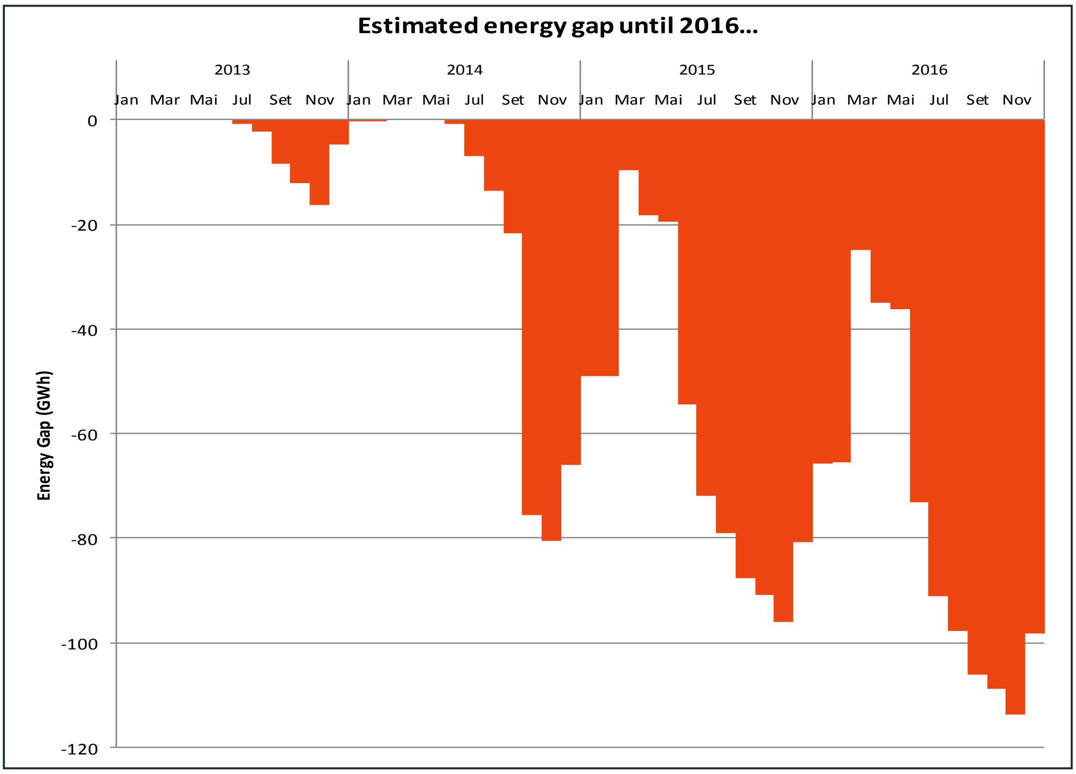


Figure 1.11 - Namibia's Estimated Energy Gap (Until 2016).

Note that, for this estimation a conservative approach has been adopted, namely, only mid-peak and peak periods were subject to the possibility of registering an energy gap, as the off-peak period demand would always be ensured by local supply options plus energy imports from neighboring countries.

Therefore, as can be concluded from the previous figure, between 2013 and 2016, Namibia may face an estimated total gap of 1,932 TWh, which will mainly occur in the dry season. Additionally, note that, even though it may start as soon as July 2013, the energy gap will be significantly deepened in 2014.

Furthermore, without short term investments in power generation, the gap will most probably be met with rental diesel, similar to what happens in Tanzania, which has recently signed large contracts with Aggreko and Symbion, and in Botswana, which had a 70 MW rental diesel unit operating until 2012.

Hence, taking into consideration that the Tanesco (Tanzania) estimated cost with Aggreko and Symbion rented diesel in 2012 amounts to $3,500 Million, it is assumed that Namibia may have to pay approximately N$3,300/MWh of rental diesel.

To conclude, assuming that 75% of the total upcoming Namibian energy gap (until 2016) is met using rental diesel for an average price of N$3,300/MWh of rental diesel, without short term investments, Namibia may be confronted with a total cost of N$6,377 Million.

1.7.4 Short Term Alternatives to Rental Diesel

Keeping in mind that, without short term investments in power generation, the upcoming energy gap of Namibia will most probably be met with rental diesel, which may represent a total cost of N$6,377 Million, time is of the essence and, therefore, Namibia should pursue the development of short term alternatives to rental diesel, namely, Heavy Fuel Oil (HFO), Solar CSP, Solar PV or Wind and backup Diesel.

Hence, the following Figure 1.12 intends to provide the basis for considering the best short term alternative to rental diesel. Note that, for the following analysis, several assumptions were considered, as follows:

- An initial 5 year tax exemption and a 34% tax rate for the remaining period;
- Yearly rent and insurance costs as well as yearly production degradation;
- Inflation of 5%;
- Average project IRR of 15% and 11% in case of commercial and development financing, respectively.

In addition, in what concerns wind parks already with one year wind measurement and environmental impact assessment, it was considered that it would be built in one year. Also, the tariff for wind was calculated considering that 40% of the energy would be sold at off-peak hours at N$350/MWh throughout the period for 2,500 and 3,000 hours of net equivalent generation.

Furthermore, except for Solar CSP and unless when specified, the data used to calculate the different parameters took into consideration the values presented by the Namibian IRP.

Hence, in what concerns, the minimum lead time, rental diesel presents the lowest value and, nevertheless, PV & Diesel as well as existing wind projects (as previously mentioned) appear to be the best alternative with 1 year minimum lead time.

Moreover, as may constitute no surprise, rental diesel will present no investment costs (CAPEX) to be further developed. Although, heavy fuel oil exhibits the least investment cost, presenting a value placed between N$10 Million and N$15 Million per MW.

Additionally, regarding the respective operating cost (cost of fuel plus operations and maintenance), rental diesel will constitute the worst option, costing approximately N$3,300 per MWh. On the other hand, Solar CSP presents an operating cost of about N$250 to N$400 per MWh, which together with Solar PV and Wind, exhibiting also an operating cost of some N$150 to N$200 and N$100 to N$150 per MWh, respectively, will constitute the best options.

	1 HEAVY FUEL OIL	2 SOLAR CSP	3 SOLAR PV / WIND & BACKUP DIESEL	4 RENTAL DIESEL
Minimum Lead Time	1.5 years	2 years	PV & Diesel – 1 year Existing wind – 1 year Other Wind – 2 years*	6 months
Investment (N$/MW)	~$10M to $15M	~$40M	~$16-18M (PV or Wind) ~$2-4M (Diesel) Total: ~$20M	~0
Operating Cost (Fuel + O&M - N$/MWh)	~$1,200	~$250-$400	~$150 – 200 (PV) or ~$100 – 150 (Wind) or ~$2800 (Diesel)	~$3,300 *(based on Tanzania contracts with Aggreko and Symbion)*
Total Cost (N$/MWh)	~$1,750 (@40% utilization & US$120/Brent)	~$1,450 *(Devpt. Banks)* ~$1,770 *(IPP)*	Solar PV & diesel: $1,730 (IPP) Wind & diesel: $1,720 – 2,125 (IPP)	~$3,300

Figure 1.12 - Short Term Alternatives to Rental Diesel

Note that, the total costs' values presented for Solar CSP will differ from the ones presented in the upcoming Financial Analysis chapter as a cost-only perspective was considered, that is, an investor/market perspective for green investments in Namibia was adopted for the analysis undertaken on the current section and, therefore, a 34% tax rate after the initial period of tax exemption, a debt/equity ratio of 60/40 and an average project IRR of 15% and 11% in case of commercial and development bank financing, respectively, was considered.

In addition, as further presented in the upcoming sections, the argument for the value of CSP in terms of dispatchability guaranteed, jobs created, wealth generated, among others, should be factored in during investment decisions.

Nevertheless, in order to choose the best short term energy alternative, Namibia must take into consideration, not only the lead time, but also the total cost per MWh, which by its turn takes into consideration both the investment and operating cost.

Therefore, considering the total cost per MWh of each supply option as well as the minimum lead time, Solar CSP, HFO and Solar PV/Wind & backup diesel seem to be the most adequate energy alternatives. On the one hand, Solar CSP presents a total cost of about N$1,450 and N$1,770 per MWh in case of development and commercial financing, respectively. In addition, the minimum lead time would be relative low, that is, 2 years.

Note that, the value presented for Solar CSP with development bank financing took into consideration the project's development with more favorable financing conditions, namely, a lower interest rate.

Moreover, HFO presents a total cost of N$1,750 per MWh, with 1.5 years lead time, and Solar PV/Wind (Existing) & diesel exhibits a total cost of N$1,730 and N$1,720 – N$2,125 per MWh, respectively, with 1 year lead time.

On the other hand, albeit that the respective lead time is 6 months, with a total cost of about N$3,300 per MWh, rental diesel represents the most inadequate alternative.

All in all, a bet on CSP will always be more cost effective than rental diesel and, if considered the development of CSP projects with available development bank financing, CSP becomes the most economic short to medium term technology alternative. Additionally, integrating Wind and Solar PV projects with backup diesel generators may be an interesting and economic alternative that Namibia may explore together with CSP, as further developed in the upcoming sections.

1.7.5 Other Cost Competitive Alternatives

According to Namibian Integrated Resource Plan (IRP), there are other cost competitive alternatives. However, given that Namibia must target short term alternatives to avoid the likely upcoming energy gap, these alternatives being studied in the National IRP will not come up on time.

Nevertheless, similar to the analysis performed on the previous section, Figure 1.13 intends to present an evaluation of each generation option accordingly to four parameters: minimum lead time, investment (CAPEX), operating cost (fuel plus operations and maintenance) and, for last, the total cost, which takes into account the previous two parameters.

Note that, for the following analysis, no taxes were considered and the CAPEX was annualized using a 15% weighted average cost of capital with equal payments (no inflation). Additionally, the operating cost of a natural gas power plant, namely, the fuel cost, will depend significantly on Kudu gas field exploration agreement. For last, different utilization rates were considered for the various supply options, that is, 50%, 70% and 40% were considered for natural gas, coal and hydro power stations, respectively.

	1 NATURAL GAS	2 COAL	3 HYDRO BAYNES (600MW)	4 HYDRO ORANGE RIVER (100MW)
Minimum Lead Time	5 years (?)	5 years	9 years	6 years
Investment ($N/MW)	~$6M – 12M	~$21M	~$30.5M	~$28.6M
Operating Cost (Fuel + O&M - $N/MWh)	~$635 *(will depend on Kudu exploration agreement)*	~$559	~$50	~$50
Total Cost ($N/MWh)	~$850 – 1,060 (@50% utilization)	~$1,080 (@70% utilization)	~$1,356 (@40% utilization)	~$1,275 (@40% utilization)

Figure 1.13 - Other Alternatives Being Studied in the Namibian IRP.

To conclude, taking into consideration the values presented in Figure 1.13, natural gas is the most adequate alternative in terms of investment, cost and fit with hydro. However, uncertainty on Kudu timeline undermines this option, and, ultimately, coal seems to be the most reliable medium term alternative.

2 CSP Technology Review

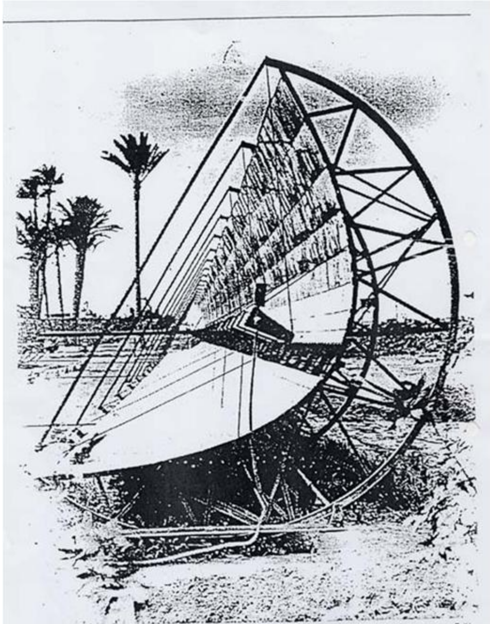
2.1 Introduction and Technology Outline

Solar irradiance at the earth surface is relatively low, reaching around 1000 W/m^2 at solar noon in most places at sea level. This is sufficient for low to mid temperature thermal conversion systems and direct semiconductor electricity conversion systems. For higher temperature conversions and thermochemical processes, this irradiance needs to be concentrated from 50 to over 1000 times, reaching irradiances of 50 suns to over 1000 suns. Concentrating solar power (CSP) achieves this through the use of optical elements that collect the irradiance over a large area and focus it onto a smaller image area. This concentrated power can then be used by various systems to produce electricity via Concentrated Photovoltaics (CPV) or via Solar Thermal systems. The latter are referred to generically as CSP.

In general, CSP technologies aim to use optical systems to concentrate direct beam solar irradiance (or Direct Normal Irradiance), collect its energy as heat in appropriate fluids and use thermodynamical cycles to produce work and so be able to generate electricity. In this respect, some CSP technologies are eminently compatible with traditional steam turbine based power plants and design. Most of the CSP plants are essentially a conventional thermal power plant with a solar field providing the heat input instead of a fossil fuel heat source. CSP is not a new technology; one of its first manifestations dates from the early 20th century in Egypt, where it was used for water pumping for irrigation (Figure 2.1).

But with the introduction of the combustion engine, powered from cheap oil, the technology did not spread. Only after the oil crisis of the late 1970's interest in non-fossil power generation rose again and with public support in the 1980's nine parabolic trough power plants were constructed in the United States – the Solar Electricity Generating Stations (SEGS). Together, they have a capacity of 354 MW and are still operating today, proving the durability of this technology. After the oil crisis, the interest in this technology dwindled again and it took until 2005 for CSP to resurface, when the Saguaro Solar Facility with 1 MW was built in Red Rock, Arizona, followed by the 64 MW parabolic trough power plant Nevada Solar One in the Mojave Desert in 2007. Europe saw the introduction of commercial scale CSP plants in 2008 when the 50 MW parabolic trough plant Andasol 1 was built in the Spanish province of Andalusia. Subsequently and due to different incentive schemes, a number of CSP plants have been built mainly in Spain and the United States until the present day.

Promoter: Sponsors: Developers:
POLYTECHNIC OF NAMIBIA
MINISTRY OF MINES AND ENERGY
EEP ENERGY AND ENVIRONMENT PARTNERSHIP / SOUTHERN AND EAST AFRICA
Gesto ENERGY CONSULTING
Solar Consulting Services
CSP Services CONCENTRATING SOLAR POWER SERVICES
SIJ | SOLAR-INSTITUT JÜLICH FH AACHEN UNIVERSITY OF APPLIED SCIENCES
CONSULTING SERVICES AFRICA



Paracolrinnenkollektor des Solarkraftwerks von Shuman in Meadi bei Kairo. Aufnahme vom Frühjahr 1914 (aus: Technisches Archiv des Deutschen Museums. NL 038/002. Wilhelm Maier. Foto Deutsches Museum München. Bild-Nr. 25056).

Figure 2.1 - Parabolic Trough Collector, Egypt 1914 (Source: German Museum, Munich).

A typical CSP solar plant, shown in Figure 2.2, includes several component blocks, namely:

- A solar field,
- A Heat transfer fluid system and heat exchangers
- Optional back-up parallel boiler or storage system
- A steam cycle feeding into the turbine block
- A power block and ancillary wet/dry condenser, deaerator, feedwater pumps and
- The grid connection.
- Most of the components (ii) to (vi) are similar to those found in conventional thermal power plants and constitute the Balance of plant (BOP). In the past few years, the solar part of CSP has experienced substantial commercialisation as well as technological innovation. At the present time, CSP plants comprise four major technologies (with variants): parabolic troughs, linear Fresnel reflectors concentrators, power towers with heliostat fields and parabolic dish systems coupled mostly to Stirling engines. The main types of optical systems used can be classified as linear focus systems (Parabolic troughs and linear Fresnel reflector systems) or point focus systems (towers and dish systems) as can be seen in Figure 2.3.

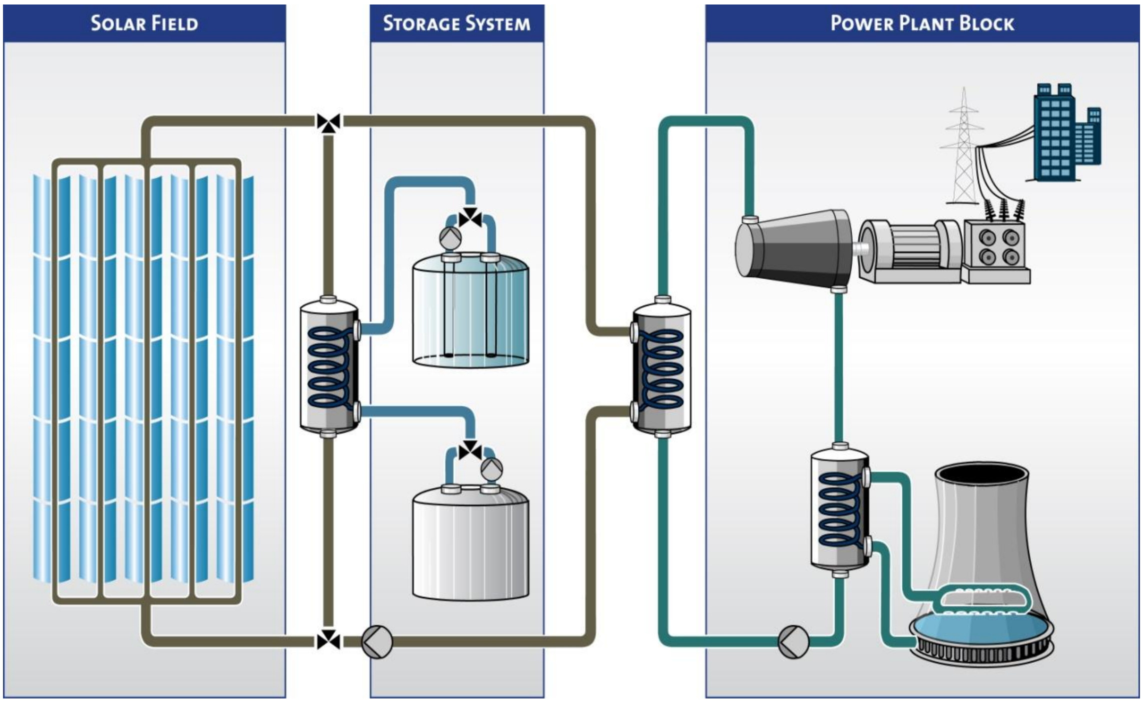


Figure 2.2 - Scheme of a typical CSP plant. Here a parabolic trough solar field is shown (Source: Solar Millennium AG).

Parabolic troughs, so far the leading technology commercially, have gained acceptance with the power industry worldwide; the other technologies, especially power towers, promise more cost effective systems. Given their higher operating temperatures leading to a higher degree of thermodynamic efficiency, towers with steam or molten salt are expected to be able to compete commercially with fossil fuelled power generation technologies.

The power block in CSP plants can in principle be built with any system that converts heat energy to mechanical energy:

- Conventional Rankine-cycle steam turbines (parabolic trough, linear Fresnel reflectors);
- Organic Rankine cycle (parabolic trough, linear Fresnel reflectors);
- Brayton cycle gas turbines (power tower, dish).

Each technology achieves different temperatures, which depends on the concentration factor. Steam conditions in realized projects have spanned all ranges possible for existing turbines – from 270^{o}C saturated steam to 580^{o}C superheated steam and even above. Steam turbine efficiencies up to 37%, using reheat stages, can be used.

Heat transfer fluids in use or contemplated for CSP include: synthetic oils, water, molten salts and air. Heat storage technologies using molten salts (two tanks) have been built for large scale use at temperatures up to 580^{o}C. Development of thermocline storage (single tank molten salt + filler material) and concrete + phase change materials (PCM) systems are in the testing phase.

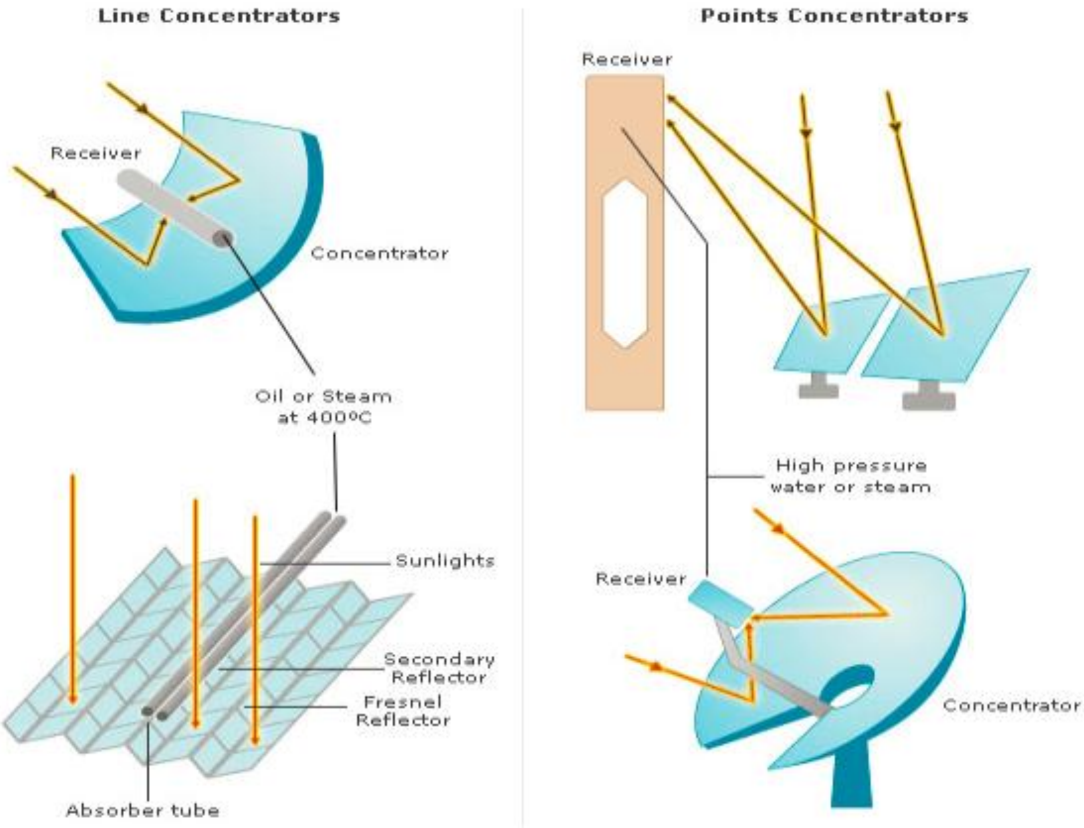


Figure 2.3 - Different types of CSP technologies (Source: Eko-Star EU).

In broad terms, the major inter-CSP differences relate to the way solar heat is collected and concentrated (**optics**), conducted to the steam generation stage (**piping**, **heat transfer fluid - HTF**) to produce steam (**of given steam conditions**) into the turbine generator. Added to these “Solar building blocks” is provision of a standby source to complement the solar source (**heat storage or fossil fuel backup)** and to be able to achieve dispatchability of power. Because of their similarity to conventional thermal power plants, these technologies can also be used to produce steam either for direct industrial use (industrial heat) or as boosters into existing coal or gas fired power plants (steam augmentation/fuel saver or Integrated Solar Combined Cycle – ISCC - plant).

Most combinations of these solar plant “building blocks” have been tried and continue to be developed; however only some have reached commercial large scale maturity so far. These are discussed in the following sections.

CSP has four major advantages compared to other renewable energy sources such as wind or photovoltaic energy:

- Easy and cost effective implementation of thermal storage;
- Easy combination with combustion fuels (hybridization);
- Slow response to short-term fluctuations of solar irradiation due to thermal inertia of the system;

- Usability for other purposes than electricity generation (e.g. solar cooling, process heat, seawater desalination).

Storage and hybridization allow for a dispatchable, theoretically continuous energy generation and help to avoid sudden changes in production. This fosters the stability of the electricity grid which is a main concern when integrating many renewable energy sources that rely on fluctuating resources.

2.2 Parabolic troughs

In the 1980s the SEGS I-IX parabolic trough plants with 354 MW_e capacity were built in California and have remained operational for over 25 years now. These nine plants are used as peaking plants and provide a large experience of operation and maintenance. Until 2000, these were the only commercially deployed utility scale CSP plants. Since then, parabolic trough plants with a capacity over 1 GW_e have been built or proposed, mostly in Spain and the USA, making this the most adopted CSP technology so far.

2.2.1 Characterization

A typical parabolic trough collector is shown in Figure 2.4 and a schematic diagram of a typical plant is shown in Figure 2.5.

Figure 2.4 - EuroTrough Parabolic Trough Collector.

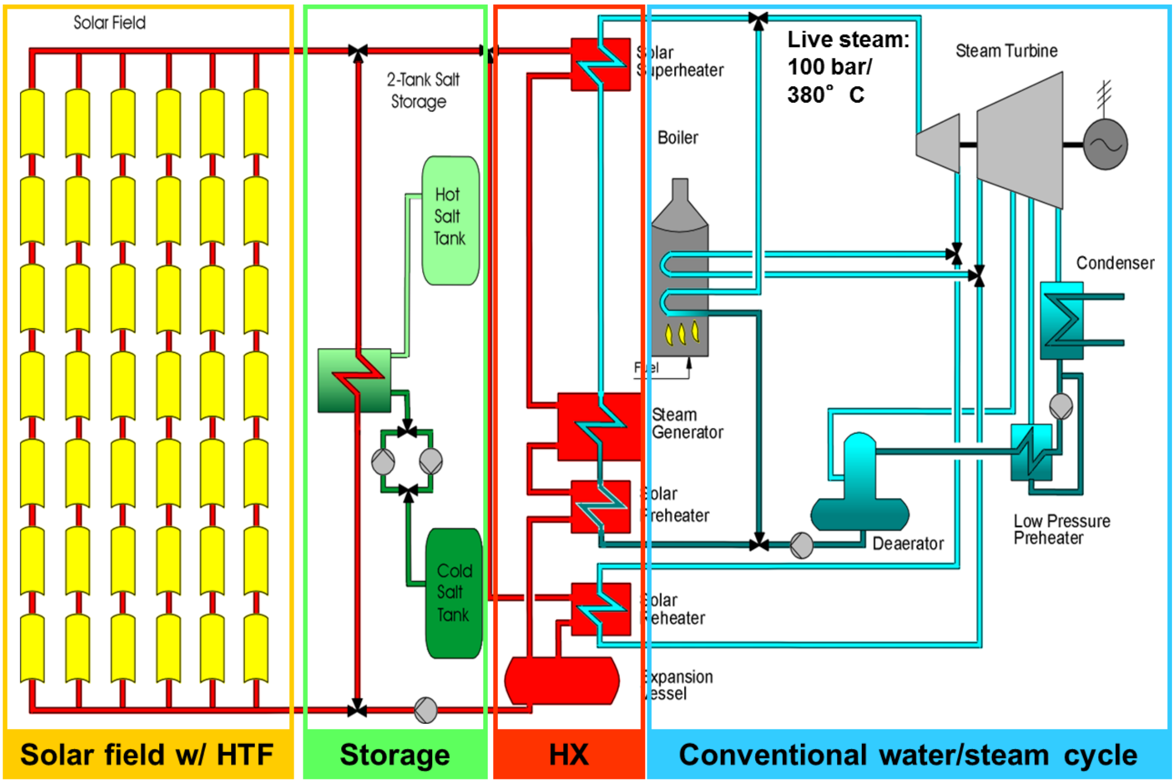


Figure 2.5 - Schematic diagram of a typical parabolic trough solar power plant with optional storage and back-up boiler (Source: Pilkington Solar, 1996).

The operating principle of a parabolic trough power plant with thermal oil as HTF is as follows:

Parabolic mirrors track the sun about one axis, usually north-south, and focus its rays, with typical concentrations of 70-80 suns, onto linear, specially coated, heat collecting elements (**HCE**). These are coated steel pipes with a surrounding evacuated glass tube that minimizes heat losses. A heat transfer fluid (**HTF**) is circulated through the HCEs to carry the heat from the solar field to the power block. Via superheater, boiler and economizer heat exchangers the energy of the HTF is used to produce the superheated steam needed to run the turbine. Beyond this, the plant includes conventional sub-systems – the power block steam turbine and generator, wet cooling towers or air cooled condensers, feedwater pumps and deaerator for the steam cycle. Optional storage and/or auxiliary gas burners can be used to cover transient weather conditions and for production during night time or to protect the HTF against freezing.

Another type of parabolic trough plants are direct steam generating (DSG) plants, where the HTF is replaced by water, which is vaporized and superheated in the solar field. This avoids heat exchangers between HTF and turbine and also allows for higher temperature levels and thus, higher efficiencies.

2.2.1.1 Solar Field

The solar field is subdivided in loops; typically a loop consists of four collectors with 10 to 12 collector modules. Each collector is made up of a supporting steel structure (pylons, framework and cantilever arms), mirror panels and receivers. Furthermore, each collector is equipped with a hydraulic drive system, an angular encoder, a temperature sensor and a local controller board for individual solar tracking. There is one central control system with operator terminals for the solar field (integrated in the central plant control building).

Meteorological stations are installed in the plant to adapt the operation to weather conditions (e.g. collectors have to be put to safety position in case of high wind speed). The stations are equipped with all necessary instruments to measure wind speed and direction, ambient temperature, global horizontal irradiance, direct normal irradiance, rainfall and humidity.

2.2.1.2 Mirror panels

The mirror panels are mostly made from 4 mm thick float glass with low iron content for good transmittance for the solar light and an overall reflectivity of up to almost 95% (1), however different mirror technologies like coated aluminium panels are being developed and under investigation. Mirrors are curved to parabolic shape in a hot sagging process in a specific production line. This type of mirrors has been used in the SEGS plants in the Mojave desert by Luz. In solar fields, average breakage rates of 0.2-0.5% per year due to wind and maintenance were experienced (Flabegsolar, 2011), but mirrors can be replaced easily. The fixation of the mirror panels to the metal support structure is commonly realized with 4 screws into 4 ceramic pads glued on the backside of the mirror.

2.2.1.3 Metal support structure

Various collector types with different metal support structures are available on the market. In this section the design of the metal support structure of the EuroTrough collector is described as an example. The EuroTrough collector has been developed by a European consortium in an R&D project co-funded by the European Commission from 1998 to 2001 and can be regarded as the basis of many collectors developed afterwards. The core of the collector design is a steel tube framework structure. It consists of a central framework beam to which cantilever-arms are attached which give structural support to the mirror panels. A pylon every 12 meters supports the collector on the concrete foundations. Wind tunnel tests have been performed during the design of the EuroTrough collector. The resulting loads have been used for the layout of steel sections and drive system.

2.2.1.4 Drive system

The drive system with hydraulic actuator receives signals from a PV sun sensor tracking device in order to track the sun's position in the sky. The advantage of the hydraulic drives is their long life and low maintenance even though it is performing daily heavy-duty operation. Moreover, the reduction of investment and operational costs were a target during the development. The drive system (1 system per collector) consists of two bidirectional hydraulic cylinders in the central pylon of the collector, an electric pump, 4 stop valves and flow regulators. The pump and valves are operated by a local controller system which includes the signals of a rotation encoder, a differential sun sensor, and the oil temperature at the center of the collector. The system is protected from fatal problems by end-switches on both ends of the angular range of movement, and by a security backflow valve, limiting the pressure in the hydraulic drive to a maximum value in case of overload due to control errors or peak wind.

2.2.1.5 Local control unit

Each collector drive pylon has a local controller board which is used to control the angular movements of the collector according to the commands from the central field control system, and including the signals of the sensors mentioned before. The output channels include pressure at the stop valves, a pump motor, and a feedback controller which sends status information back to the central field control. Local controller boards are installed in small control cabinets and are protected from the weather.

2.2.1.6 Heat collecting element

The receiver, also called heat collecting element (HCE), includes an absorber tube, a glass envelope and bellows on each end of a receiver (Figure 2.6). An HCE has a length of up to 5 m. The steel absorber tube is a core element of the concentrating collector. During operation the absorber tube can reach temperatures of > 400°C. The space between the glass envelope and the tube is evacuated to reduce convective heat losses of the absorber tube. To maintain the vacuum a so-called getter is positioned in between the absorber tube and the glass envelope which has the task to absorb hydrogen that separates from the heat transfer oil and diffuses through the steel tube. The glass envelope is designed with an anti-reflective coating to ensure high solar transmittance. The absorber is coated with a sputtered absorptive coating with black appearance and selective properties, such that absorptivity in the solar spectrum is high, and emissivity in the range of thermal radiation is low (Figure 2.7).

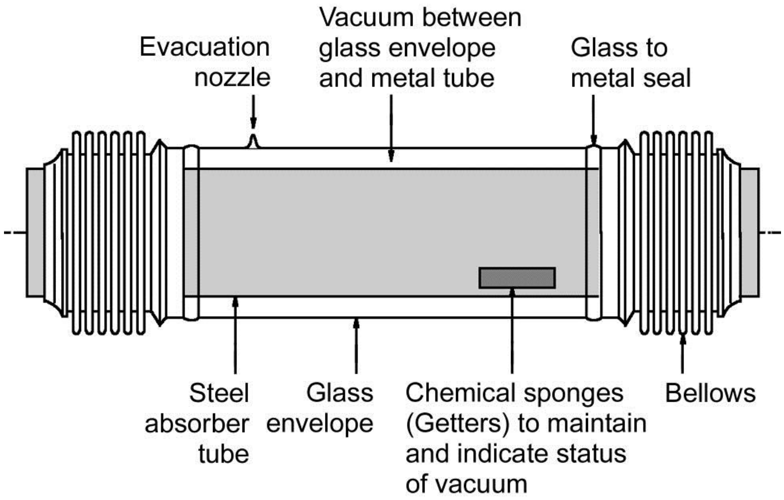


Figure 2.6 - Receiver technology.

Figure 2.7 - Receivers with black, sputter coated inner stainless steel pipe and evacuated glass envelope, reducing thermal losses to a minimum.

More recently, and under the feed-in-tariff mechanism in Spain, the trough supplier field has been growing rapidly. A number of companies, mostly European, have designed and built several trough plants in Spain and the USA. This has fostered a well-populated supply chain both for solar field components and specialized power block components such as steam turbines that are optimized for the requirements of CSP plants. Under Spain's market conditions, all built trough plants have been limited to an electric generation capacity of 50 MW. Some of the plants operate with a two-tank molten salt storage. The parabolic trough technology is now well understood and is commercial since many years, and is accepted by the financial and utility markets. This makes the parabolic trough industry players the leaders on the CSP technology market.

2.2.2 Existing Projects

Dozens of parabolic trough plants have been built and a further large number is under development or construction. An overview of projects can be found under the following sources:

- CSP Today
  http://www.csptoday.com/global-tracker/content.php
- National Renewable Energy Laboratory (NREL), USA
  http://www.nrel.gov/csp/solarpaces/parabolic_trough.cfm
- Wikipedia
  http://en.wikipedia.org/wiki/List_of_solar_thermal_power_stations
- Spanish Association of the solar thermal industry (Protermosolar)
  http://www.protermosolar.com/boletines/23/Mapa.pdf

Some projects that can be considered as milestones in the development and commercial adoption of this technology are:

- SEGS I-IX, California, USA (completed 1981-1990), 354 MW overall electric generation capacity.

  The SEGS (Solar Electricity Generating Station) plants in California were the first commercial CSP plants in the world. The largest plants have a capacity of 80 MW_e each. They are still operational and therefore are the best proof that this technology is both reliable and durable.

- Nevada Solar One, Nevada, USA (completed 2007), 64 MW_e

  This plant was the first parabolic trough plant to be built almost two decades after the SEGS systems. It has a 0.5 hour storage for peak power production.

- Andasol 1, Andalusia, Spain (completed 2008), 50 MW_e

  Andasol 1 was the first commercial CSP plant in Europe and the first one with a large storage which allows full load operation of 8 hours at times of absent direct beam radiation.

- ISCC Morocco, Ain Beni Mathar, Morocco (completed 2011), 470 MW_e total with a 24 MW solar field contribution

  This project can be considered the first large scale hybrid power plant, where waste heat from a gas fired turbine is combined with heat from a solar field to produce steam to drive a steam turbine.

2.2.3 Key Issues for Project Location and Design

Some of the key issues for project location and design are common to all CSP technologies and some are more specific to parabolic trough plants. Besides more general project development issues (e.g. availability of financing, stable social/political/economic/legal environment), these are mainly site specific aspects:

- Solar Resource: The DNI should be sufficient to operate the plant economically. Advantageous are a high solar beam irradiance at the plant's location (a minimum of 2000 kWh/m^2a is often stated in the literature to be necessary for economical operation), dominant clear sky conditions and a smooth distribution of irradiation throughout the year. The temporal distribution is especially important for the plant design.
- Humidity as well as aerosol and particle concentration in the atmosphere should be low. This refers to natural (e.g. sea salt, water vapor, wildfire smoke, dust) and anthropogenic (dust, smoke and soot from industrial or domestic emissions, traffic or agriculture) aerosols and particles (Gueymard, 2011).
- Availability of land for the construction of the plant.
- Electricity grid access
- Accessibility to the site / available infrastructure (transport, qualified workers, supplies, etc.)
- Cooling water availability: If there is no water source available for cooling of the steam cycle, dry cooling has to be used, which increases the plant's own consumption.
- Flatness of terrain: Parabolic trough collectors are mostly built in large dimensions comprising lengths of more than 100 m. To avoid costly earth works, the project site should be flat. The acceptable slope of the terrain strongly depends on the cost of civil works in the project country, a slope of 2-4% in north-south direction should not be exceeded.
- Geographic location: Parabolic trough plants make use of the direct irradiation in the incidence angle of the one-axis tracked collectors. The solar field efficiency decreases with growing distance away from the equator because the incidence angle, which is the same as the zenith angle and is measured from the vertical, increases and leads to increasing optical losses. The result is that a site on latitude of 35° north or south of the equator will harness less energy than a site on 20° latitude north or south of the equator with an identical annual amount of solar energy impinging per square meter.

2.2.4 Technology trends

The parabolic trough technology is – compared to the other CSP technologies – a mature technology. Nevertheless, further improvements towards higher efficiencies are expected. Improvements concerning the field operating temperature are under investigation. For parabolic trough plants using synthetic oil as HTF the temperature is limited to below 400°C, as the oil decomposes above this temperature. Using molten salts or direct steam conversion technology, higher temperatures up to 550-600°C could be reached and would increase steam cycle efficiencies. The replacement of synthetic oil as HTF by either steam or molten salts avoids the oil's flammability issues. Moreover, future molten salt plants would be simplified as HTF/molten salt heat exchangers are no longer required; nevertheless, molten salt trough systems would need electric heaters to prevent freezing of the salt in the tubes. Direct steam generating plants would not require any heat exchangers at all unless a storage system other than a steam accumulator is included, thus reducing investment costs.

New collector developments are in progress, aiming at increased collector dimensions, thus reducing the number of pylons, drives etc., and a higher degree of automation during assembly to decrease cost and increase quality. Cost reductions for the mirrors can be achieved with thin glass mirrors (short term), or reflective polymer mirror materials (long term, once their durability is proven). For storage systems, single-tank thermoclines are expected to reduce cost of storage. Proliferation of the component supply chain for mirrors, HCEs and field components as new suppliers enter the market will maintain a downward pressure on costs. These cost cutting efforts are typical of the development stage of this mature technology.

2.3 Linear Fresnel Reflectors

2.3.1 Characterization

Segmented or zonal lenses and mirrors were developed as far back as the beginning of the 19th century by Augustin Fresnel to replace bulkier, much larger integral lenses (Fresnel, 1822). They replace continuously curved surfaces by zones of nearly flat surfaces, making even large optics relatively easy to construct. They have been extensively used in lighthouses, projectors and even car lights to project parallel light from point sources. CSP application of Fresnel lenses and mirrors dates from work by Giovanni Francia in the 1960s. Francia proposed both linear focus and point focus Fresnel solar fields with appropriate receivers.

The application of linear Fresnel Reflectors (LFR) to commercial CSP was originally pioneered by Australian/USA company AUSRA (formerly Solar Heat and Power and now AREVA Solar) and developed more recently by other companies including Solar Power Group (previously Solarmondo), Industrial Solar (formerly Mirroxx and PSE), Solar Euromed, CNIM (Babcock) and Novatec Solar. These more recent CSP applications are based on well understood technology and can reach solar concentrations of 30 – 100 suns. Importantly, they open the possibility of using simple, non-industry specific, commodity materials as optical and construction elements in CSP plants (see Figure 2.8). The Fresnel reflector fields use flat rather than curved mirrors, low profile construction, leading to rapid on-site assembly. Fresnel receivers, positioned above the rotating reflectors, use evacuated and non-evacuated standard steel tubes and are protected by plain glass sheets. The collector frame structures, unlike parabolic trough receivers, are fixed in place, dispensing with high temperature moving joints. All commercialised linear Fresnel systems have also dispensed with synthetic oil as HTF and implemented direct steam generation (DSG i.e. water as HTF) in the receivers. For these and other reasons mentioned below, the construction of Fresnel solar fields is simpler and cheaper than that of troughs.

Figure 2.8 - Example AREVA Solar "CLFR" field showing the fixed receiver and internal receiver structure.

A typical Fresnel solar power plant operating principle is illustrated in Figure 2.9.

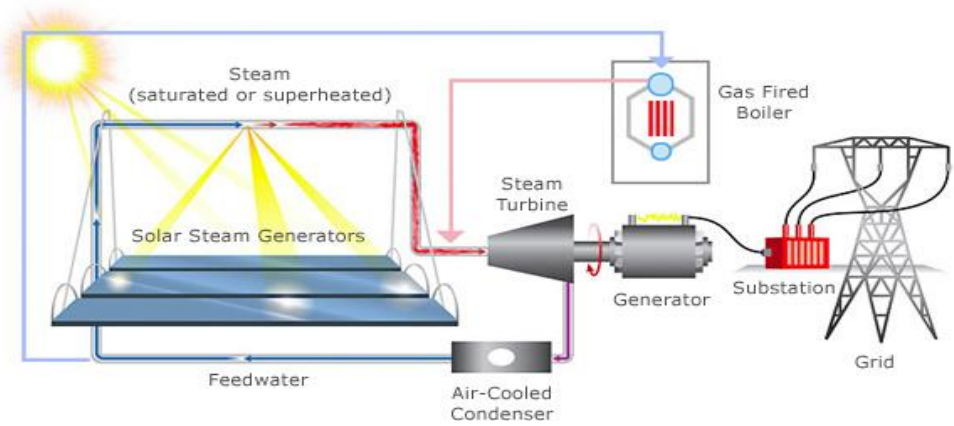


Figure 2.9 - Linear Fresnel operating principle, showing direct steam generation with fossil fuel backup.

The linear Fresnel CSP mirror field uses segmented reflective optics to achieve concentrations of around 40-50 suns. In AREVA Solar's so-called "CLFR" implementation, a series of 13 rows or more of industry standard, essentially flat, mirror reflectors (2.25m wide X up to 940m long or more) are paralleled in a north-south alignment to focus the solar Direct Normal irradiance (DNI) onto a trapezoidal receiver section above the mirrors (Figure 8). Industry standard mirror widths and simple space frame support structures make for relatively cost effective, commodity priced construction. Each mirror row is driven at the appropriate angle to direct the sun's rays onto the receiver at operational times of the day and year. The receiver is a bundle of tubes, coated with a selective surface, forming a linear horizontal target and covered by an upside down windowed housing that minimises conductive, convective and radiative losses due to the high temperatures of operation. Again, construction relies on commodity materials alone, making the "CLFR" a cost effective concentrator. In the receiver structure, and using both flow control and irradiance control, the water HTF is claimed to reach the required superheated steam conditions in a once-through pass. No water recirculation pumps, separator or evacuated collector are required to reach and maintain the superheated steam conditions (~390°C) specified for this system (Conlon, 2011), according to Areva.

Alternative LFR optical arrangements developed by others, among them Novatec Solar, are based on fewer, narrower (~0.7m wide), ganged rows of reflectors and secondary optics in the receiver housing that further concentrate the solar beam onto a single large non-evacuated tube filled with the heat transfer fluid; in this case also water Figure 2.10. This is representative of most other commercial Fresnel systems.

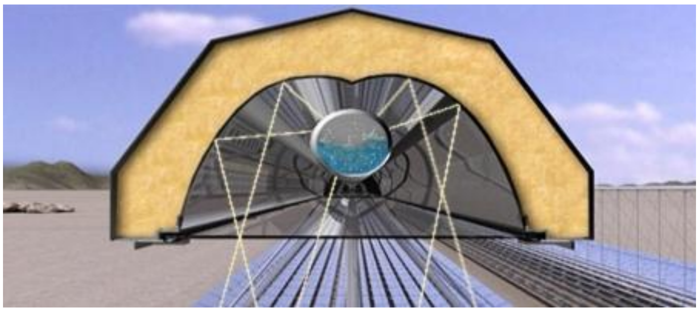


Figure 2.10 - Novatec Solar's NOVA-1 receiver with secondary concentrator mirror and cover glass, fixed above the linear reflector field. The single tube is irradiated from all directions; the water HTF is in the lower part of the tube.

Here, rather than once-through to superheat, these LFR systems have a boiler field where water is heated and brought to boil to produce mixed water/steam flow. A set of high temperature pumps re-circulates the hot water back in the receivers to reach operating temperatures. Saturated steam produced at operating temperature is then collected in the separators of steam drums and fed to an appropriate turbine. The receiver tubes in these are non-evacuated, selective surface coated steel pipes (Figure 2.10) of large diameter. The output from the field is saturated steam with an operating temperature limited to 270°C or below. In more recent developments, some of these LFR saturated steam boilers have been coupled to a separate superheater section which is fed the mixed flow saturated steam from the separators to complete the superheating process, thus reaching superheated steam conditions of 500°C at moderate pressures (Mertins, 2011 and Alliotte, 2011). In this case, the latter receiver sections are different from the boiler sections in that they use more costly evacuated tube heat collecting elements similar to those used by parabolic troughs. With this configuration they can achieve lower losses and reach the higher superheating temperatures required (Figure 2.11).

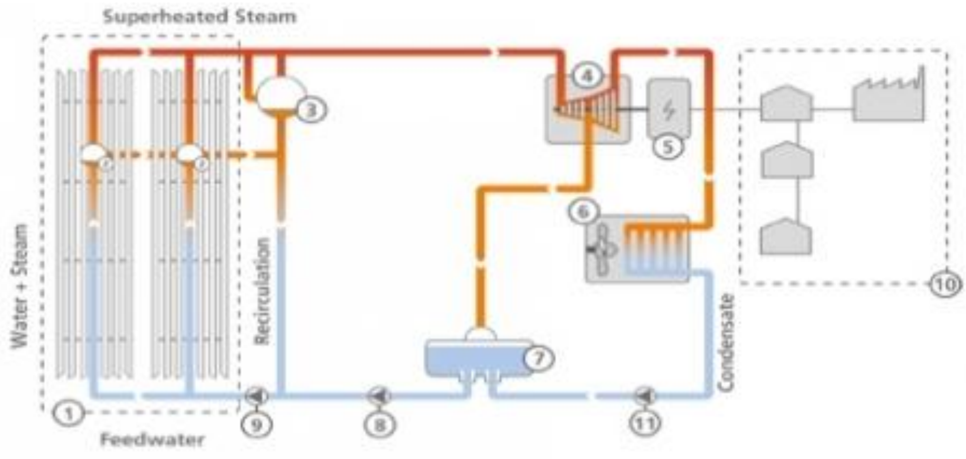


Figure 2.11 - Novatec Solar LFR system with recirculating boiler section and separate superheater section. Also shown are the recirculation circuit and pumps (9), the steam separators and volume balance tank (2,3) required between boiler and superheater.

The development of Fresnel CSP has been driven mostly by the need to reduce costs while still maintaining sufficient overall performance. The main parameters governing the viability of Fresnel systems compared to Parabolic troughs are their optical performance, their thermal losses and the cost reductions due to construction and DSG.

By their very nature, linear Fresnel reflectors have optics that approximate linear parabolic reflectors. Compared to these, the Fresnel mirrors in a solar field incur an extra loss due to their non-ideal angles to the solar position as the sun moves from East to West (for a north-south alignment). Their optical performance is therefore somewhat lower than trough performance and is reflected in a ~5% lower annual optical efficiency.

Also, as they often do not use evacuated tubes in their receivers, their thermal losses are expected to be somewhat higher than for parabolic troughs operating at similar temperatures. Estimates of annual performance comparisons between LFR systems and linear Parabolic systems, both using DSG at operating temperatures around 500°C (not yet achieved by Parabolic troughs) indicate that Fresnel costs need to be between 55% and 70% of trough costs to compensate for their lower yearly performances; a value that would appear to be reached and surpassed with existing technologies (Morin, 2012).

Storage systems based on superheated steam input have been developed which are suitable for interfacing to LFR systems, however none have been implemented commercially so far. In preference, fossil fuelled backup boilers have been proposed to achieve firm dispatchability when solar input is insufficient or missing.

Additionally, the presently commercialised Fresnel technologies have a number of inherent advantages over and above the lower capital cost of plant, especially:

- lower land usage due to compact optics 1,3ha/MW
- Can accommodate land with up to 5° local slope

- Low profile, allowing operation in higher wind speeds before stowage.
- Straightforward field assembly of modular components
- Lower maintenance costs, especially mirror cleaning and replacement
- global availability of standard parts and materials.

2.3.2 Existing Projects

In spite of favourable operational and cost characteristics and several demonstration plants, few LFR commercial projects have been built and operated so far. Demonstration and R&D plants include the initial booster plant built in 2007 which supplied 9MW_t of solar steam to the Liddell coal fired power station in Australia, thus boosting its output by 3MW_e . Further, the Kimberlina plant in California USA and the Puerto Errado PE1 plant in Spain have proven the viability of the LFR technology at various operating conditions. They are connected to their respective grids and have fed electricity to it. Both have since extended operations; the Kimberlina plant with a once–through to superheat and newer SSG4 line that reaches higher temperatures; and PE1 with a separate superheater section using evacuated tube receivers. Both these produce superheated steam at up to 500°C and/or pressures up to 100 bar. Several of the other companies mentioned above have built small prototype lines to highlight their version of the LFR technology and carry out further development work. Again, superheating to 500°C has been trialled with these versions also (6). Finally, and more recently, PE2, a 30MW commercial plant similar in construction to PE1, has been proposed, financed, built and commissioned in Puerto Errado, next to PE1.

The table below lists commercial Fresnel plants in various stages of operation, construction or planning.

Table 2.1 - Comercial Fresnel Plants.

Location	Designation	Capacity [MW_e]	Technology	Status
Qatar	_	0,7	Mirroxx LFR	Operating
Spain	PE2	30	Nova-1	Operating
Australia	Kogan Creek	44	CLFR	Under construction
Australia	Solar Dawn	250	CLFR	Planned
USA	Sundt solar boost	5	CLFR	Planned
India	Reliance Industries	2x 125	CLFR	Planned

Details of the PE2 full scale standalone LFR power plant are one indication of the present status of this technology. With its 302 000 m^2, 1000m long reflector field, It will supply saturated steam at 270°C and 55bar, to a 30MW_e turbine. The yearly output is expected to reach 49 GWh/year.

As an illustration of the technology's booster application, the AREVA solar H. W. Sundt solar boost field in Tucson, Arizona is expected to produce sufficient superheated steam to increase electricity from the coal fired plant by up to 5MW_e during peak demand periods. Successful completion of this project is expected to lead to a further 200MW boost projects by 2015.

In spite of these successes, Linear Fresnel Reflectors systems have yet to gain the same confidence, and therefore bankability, as parabolic troughs.

2.3.3 Key Issues for Project Location and Design

Commercial LFR have a number of recognised advantages including:

- Compact footprint, ~1.3ha / MW at 35° lat., less closer to the equator.
- Slope requirements, they can accommodate up to ~5° slope
- Medium to high operating parameters achievable, temp range 270°C to 500°C and pressures 50 bar to 165 bar suitable for large steam turbines.
- Demonstrated hybridisation with gas
- Low cost, widely available construction materials, potential for high local content
- Simple field assembly
- Modularity, from ~10MW to 250MW
- Applications span industrial steam, fuel saver/Booster and standalone power plant
- Financially Strong companies are backing the technology e.g. Areva, ABB, *JFE*

Main disadvantages of this technology include:

- Lower efficiency, latitude dependence can decrease instantaneous output by 2% to 8% for latitudes 10° to 40°.
- No demonstrated long term storage
- Few implemented projects
- Lack of industry acceptance of the technology and project bankability

2.3.4 Technology Trends

Beyond project execution and acceptability, there are major trends for the Fresnel technology in the years ahead:

- Reaching higher operating temperatures and pressures (potentially 500°C at 160 bar) leading to full integration with higher efficiency power blocks. Small scale demonstrations of these operational parameters have been achieved at Kimberlina and PE1 demo plants.
- Development of viable storage technologies with high round trip efficiencies that effectively circumvent the pinch point issues encountered with phase change heat transfer fluids. This is common to all technologies that use water as HTF.
- Further improvements to the Fresnel optics to reach higher solar concentrations; the theoretical limit of Fresnel optics is closer to 100 suns, substantially higher than achieved by the commercially deployed technologies (Collares-Pereira, 2009).

2.4 Power towers

2.4.1 Characterization

In the power tower technology, the collecting optics, called heliostat field, is made up of a large number of individual 2-axis sun tracking mirrors called heliostats. The heliostats concentrate direct beam sunlight onto an absorber, called receiver, which is fixed atop of a tower. A power tower is usually equipped with a thermal energy storage system and/or a fossil fuel firing system with the ideal aim to allow round-the-clock operation of the plant. There are several different variants of receivers, towers, thermal energy storage systems, heliostats and heliostat field designs. Which variants are chosen depends on various factors, which include the tower/receiver technology a company generally follows, the geographical location of the plant, the field layout/design and the design power output.

Early versions of this technology were developed in the USA as early as the 1970’s to 1980’s, for example the Solar One plant in the Mojave Desert near the city of Barstow. Power towers have known substantial innovation over the last ten years. Several designs and concepts exist for receivers, HTF, thermal energy storage, heliostats and heliostat field layouts. One major advantage of the power tower technology is the realization of very high solar concentration ratios of up to 1000 suns, allowing for very high HTF operating temperatures (starting at about 250°C to more than 1000°C), depending on which technology is used. Power towers therefore have enormous potential for achieving some of the highest Carnot efficiencies among the thermal electric CSP plants.

2.4.2 Existing Projects

Before describing existing power towers some basics regarding the design of heliostat fields are given below. The basic field designs are shown in Figure 2.12. There are 4 field designs which need to be pointed out: north or south, north-south, surround and elliptical. The north-south array is the newest of these. The type of design chosen depends on factors such as the latitude of the location of the plant and the type of receiver used. Even though the field form remains the same there are still numerous methods available for placing heliostats. Several programs have been developed in the past years and decades for finding an optimal layout with regard to field efficiency, land requirement and cost of heliostats. Heliostat fields exist with heliostats erected on concentric arcs or circles, in straight rows and in other patterns.

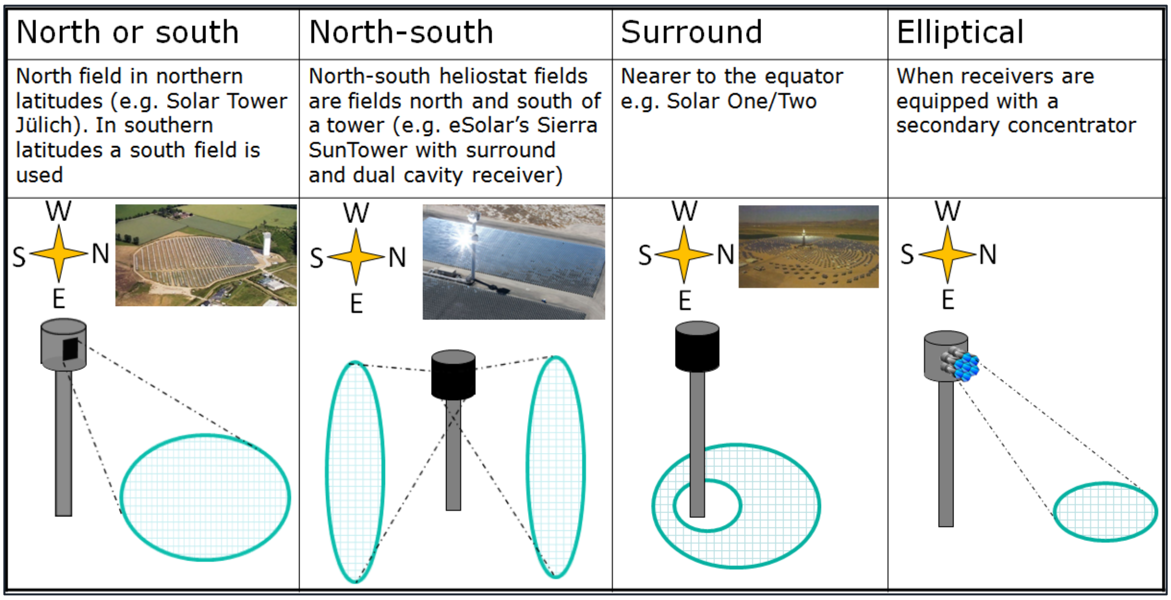


Figure 2.12 - Basic field designs of existing power towers.

When analyzing the market and the existing power tower plants, which have reached commercial status, it becomes evident that two plant concepts are established. These are plants which directly produce steam in a single cycle, and plants using molten salt as HTF and produce steam in a secondary cycle. Another very promising system that reaches high operation temperatures and therefore high efficiencies is the open volumetric solar tower which uses air as a HTF.

2.4.2.1 Direct steam generation towers

Examples of power towers with direct steam generation receiver technology are/were Solar One (USA), Planta Solar PS10, Planta Solar PS20 (Spain) and eSolar's Sierra SunTower (USA).

The technology works thus: Sunlight is concentrated onto an external tubular receiver. Inside the tubes, water flows in upward direction and is evaporated, i.e. turned into steam, by the time the exit of the receiver is reached. This is called direct steam generation. The steam is then passed to the steam turbine. No heat exchangers or intermediate heat transfer fluids are needed with this technology. The hybridisation of such a plant is possible; for example by using a fossil fuel back-up boiler steady steam conditions can be maintained during the times of low or absent direct beam irradiation or for plant start-up . The integration of a storage system for this plant type is, however, limited and has until now only been realized with the use of steam accumulators (e.g. PS10/ PS20). The adoption of a salt based storage system with a steam receiver similar to that used for parabolic trough plants and molten salt power towers would incur a substantial penalty in system round-trip efficiency and heat exchanger costs. Currently, a concrete storage system for direct steam generation plants is under investigation. An example of a plant cycle of a direct steam generation power tower is shown in Figure 2.13.

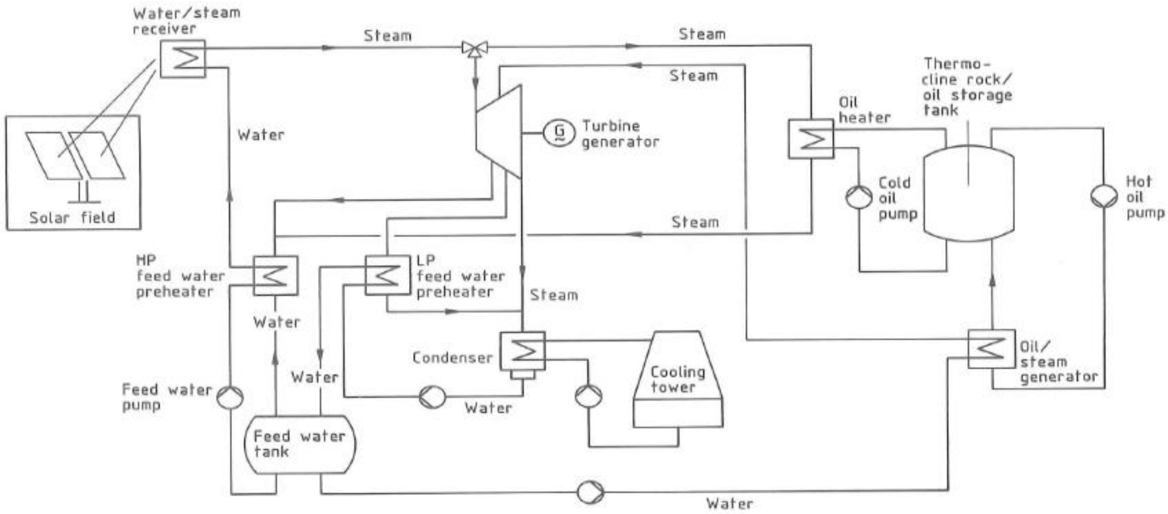


Figure 2.13 - System diagram of the Solar One pilot solar tower power plant (Source: Winter, Sizmann, Vant-Hull, Solar Power Plants – Fundamentals, Technology, Systems, Economics, Springer-Verlag, 1991).

An example of an early power plant is the Solar One plant shown in Figure 2.14, which had a surround heliostat field and cylindrical steam receiver. The Solar One plant was operated for a few years to prove the concepts, operating parameters, storage system technology and overall materials durability of this technology. It was then modified and the name was changed to Solar Two. (More information on the Solar Two tower is given in part b molten salt towers). The operating conditions and heliostat field layout designs for steam receiver solar towers vary widely and show the effects of the different innovations introduced in recent activities. In older direct steam generating plants such as PS10 and PS20, the steam temperature of 250 - 300°C (NREL – National Renewable Energy Laboratory) is quite low, whereas in the latest development of the eSolar towers, the temperature was raised to 440°C at a pressure of 60 bar (eSolar). More information on recently and currently constructed as well as future power tower plants with direct steam generation receiver technology is given in the subsequent section Recent data summary.

Figure 2.14 - Solar One (later converted to Solar Two) (http://zimtstern.wordpress.com/)

2.4.2.2 Molten salt towers

To this day, all molten salt towers have been built with a surround heliostat field and a cylindrical external salt receiver placed atop of a tower, often at more than 140 m height.

Working principle of a molten salt tower (see Figure 2.15): Molten salt is circulated from a cold salt tank at a temperature of 290°C in upward direction through an external tube receiver, in which it is heated to 565°C (NREL – National Renewable Energy Laboratory). From the receiver the hot salt is passed to a hot salt tank. From the hot salt tank the molten salt is passed through a steam generator and from there to the cold salt tank at 290°C (the molten salt is kept at this temperature to prevent solidification at lower temperatures. The solidification is only permitted in some piping where heating systems can melt the salt again. The steam produced by the steam generator drives a steam turbine. A molten salt storage system allows round-the-clock plant operation if the storage capacity is adequately sized.

An example of an early development of a molten salt tower was the Solar Two plant in USA (formerly Solar One). Modifications in the conversion of Solar One were the addition of heliostats, the conversion from a steam to a molten salt receiver as well as a molten salt storage system in the primary cycle. The secondary cycle was the steam Rankine cycle. After some years of operation the Solar Two plant was decommissioned, but the technology has been adopted by existing tower proponents SolarReserve (W.R. Gould, Jr, 2011) and SENER (Burgaleta, et al., 2011). More information on recently and currently constructed as well as future power tower plants using molten salt receiver and storage technology is given in the subsequent section *Recent data summary*.

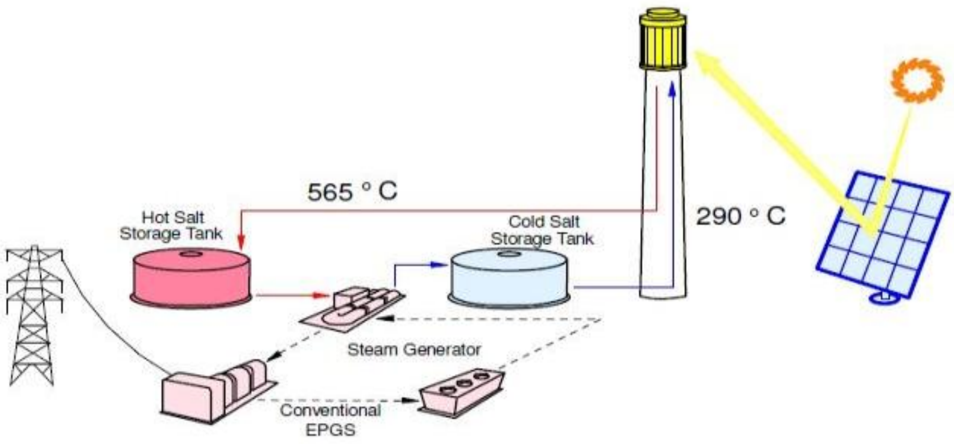


Figure 2.15 - Schematic of a molten salt tower with cylindrical external tube receiver, 2-tank molten salt storage and power block.

2.4.2.3 Air receiver technology

- Regarding the air receiver technology a demonstration plant, which has a commercial character as it produces electricity, is pointed out in detail: the Solar Tower Jülich in Germany.

The Solar Tower Jülich (STJ) uses a receiver technology which is completely different from any other technology currently available on the market: the open volumetric air receiver technology. The STJ is a research and demonstration plant for central receiver systems, feeding 1.5 MW_e of peak power to the grid. The tower commenced solar-only operation in spring 2009. It should be mentioned that the STJ can also be regarded as a commercial plant as it feeds electricity into the grid and because it was owned by the local utility of the town of Jülich. The plant was built by the general contractor Kraftanlagen München (KAM), which is a German piping and plant construction company. The power tower was recently bought by the German Aerospace Center (DLR).

The receiver technology works with a porous ceramic absorber material, which absorbs concentrated radiation inside the volume of the structure. Inside the structure the radiation is transformed into heat. Ambient air is used as HTF, which is sucked through the porous absorbers removing the heat from the receiver. As the air passes through a channeled structure with adequate depth and heat transfer surface area, there is sufficient time for it to heat up. The volumetric depth is essential when using air as heat transfer medium as it has a low heat transfer coefficient.

The solar tower was designed according to the PHOEBUS concept (see Figure 2.16). A power tower of this concept consists of the concentrator system (heliostat field), a hot gas cycle as well as a steam Rankine cycle. The gas in the hot gas cycle, ambient air, is at ambient pressure.

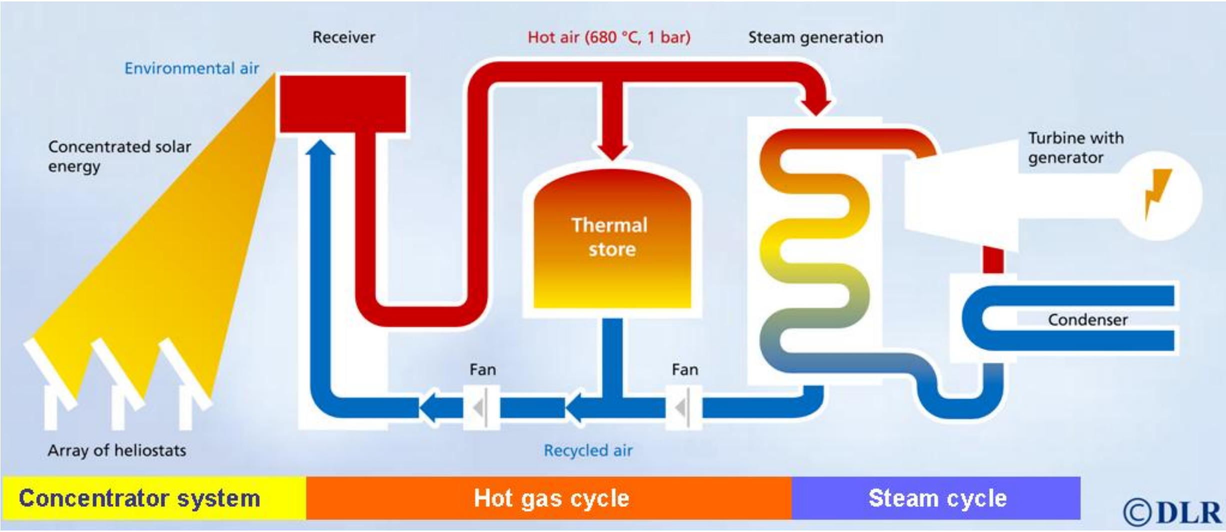


Figure 2.16 - Schematic of the Solar Tower Jülich (PHOEBUS concept) (Source: German Aerospace Center (DLR)).

The Solar Tower Jülich is equipped with a packed-bed thermal energy storage system, which stores energy for operating the Rankine cycle for up to 1.5 hours at times of absent direct solar irradiance.

The north heliostat field consists of 2150 heliostats with a total reflective mirror area of 18,000 m². The average receiver outlet temperature is approximately 680°C. The hot air is passed through a steam generator and/or the thermal energy storage system. The Solar Tower Jülich is equipped with a shell-type heat recovery steam generator (HRSG), in which superheated steam is produced. The steam drives a steam turbine, which is coupled to a generator. After the air has passed the boiler and/or thermal energy storage system it has cooled down to a low, but warm temperature. The warm air is then recirculated and blown back into the environment in front of the receiver, where it mixes with the colder ambient air. The air, which is sucked back into the air system, then has a temperature higher than the ambient temperature; therefore this is a form of heat recovery. The air receiver technology has the advantage that the ambient air is available abundantly, is non-toxic and does not require freeze-protection. Furthermore, with a similar receiver design, the pressurized volumetric receiver, air can be heated to a temperature of about 1200°C with which a gas turbine can be operated. Figure 2.17 shows the STJ in operation.

Figure 2.17 - Solar Tower Jülich with volumetric air receiver technology (Source: SIJ).

2.4.2.4 Demonstration plants

There were and are several demonstration power tower plants in the world. One of the important demonstration facilities is the Plataforma Solar de Almería (PSA) located in Spain. At the PSA several CSP technologies are investigated. Two power tower plants have been built on the site: CESA-1 and CRS. The heliostat field of the CESA-1 facility consists out of 300 heliostats with a mirror area of 39.6 m^2 each and has been used for the TSA (Technology Program Solar Air Receiver) (J. D. Alvares, et al., 2006).

2.4.2.5 Recent data summary

Power tower plant heliostat field costs add up to around 45 to 50% of the total plant construction costs. Naturally, it is desired to reduce the costs of the heliostat field. The current target is to reduce heliostat production costs to US$ 100/m^2 (G. Kolb, et al.), which is thought to be within reach, either with large or small sized mirror designs.

It is expected that the LCOE for power towers will drop due to improved and cheaper manufactured components such as heliostats, improved heliostat field layouts and optical efficiency, upscaling of the systems and maximizing Carnot efficiencies by means of increasing steam parameters.

The heliostat design and size as well as the heliostat field layout have known innovations over the last few years. The general trend for heliostat construction has initially been a move to larger heliostats with up to 150 m^2 of mirror area. More recently, smaller heliostats, with an area as little as ~1 m^2 have been realized in the commercial plant Sierra SunTower built by the company eSolar. Similarly, field designs have also changed; different to the traditional radial concentric fields, straight-row mirror fields used for the eSolar power tower and the Jülich Tower have also been used recently.

Regarding recently built power towers, three plants can be pointed out: SENER/Torresol Energy have recently commissioned the Gemasolar plant, a 19.9 MW_e molten salt receiver solar tower operating at

565ºC. Built with a molten salt thermal energy storage system providing heat for up to 15 hours, the Gemasolar can be operated round-the-clock (Gemasolar, 2011). The other two recently built plants are the already described Solar Tower Jülich and the Sierra SunTower. Figure 2.18 shows the Sierra SunTower, which consists of 2 towers with two different receivers (one tower has a dual cavity receiver and the other a tubular external receiver). The heliostat field consists of north-south, straight-row heliostat fields. Regarding the heliostat design, eSolar follows the concept of using relatively small rack mounted mirrors (~1m^2 mirror area), rather than large, independently mounted heliostats.

Figure 2.18 - eSolar's Sierra SunTower (http://www.esolar.com/)

Figure 2.19 shows some heliostats in the heliostat field mounted on a frame and ballast. This is the biggest innovation and change seen in the heliostat and heliostat field design in the last years. Due to the small sizes the assembly is easier and reduces costs.

Figure 2.19 - Mounted heliostats of the Sierra SunTower heliostat field (http://www.sciencedirect.com/science/article/pii/S0038092X10000216).

Furthermore, because the heliostats are dynamically aligned by a camera system, substantial savings on field calibration costs are achieved. eSolar proposes a modular approach to solar towers whereby a unit consists of 12 towers and several rectangular heliostat fields, providing steam to a single 46 MW_e turbine. By constructing multiple units an overall output of several hundreds of megawatts can be achieved. The Sierra SunTower is a commercial plant with an electric power output of 5 MW_e . Another plant based on eSolar's technology has been built and commissioned at Bikaner, Rajasthan, India and is planned be scaled up to 10 MW (ACME, 2011).

Furthermore, another plant that does not produce electricity but is used solely for the generation of process steam has been built in Coalinga, California, USA (see Figure 2.20). The Coalinga plant, built by BrightSource and consisting of 3822 heliostats, is used to generate 29 MW steam for enhanced oil recovery. The customer is the crude oil extraction company Chevron.

Figure 2.20 - Coalinga, California, USA by BrightSource (Source: http://gigaom.com/cleantech/solar-powered-oil-recovery-plant-starts-up-video-photos/)

With regard to upcoming projects, there are currently several power towers under construction or in planning. From these, it is apparent that the power tower technology has reached a point at which an incredible step in plant upscaling has been undertaken by the companies developing the plants. While the recently completed and commercially operating Gemasolar power tower is still a relatively small plant compared to a conventional power plant, many current or future power tower projects aim at electricity outputs beyond 100 MW_e.

A few projects are presented below (NREL TOWERS).

Table 2.2 – Existing Projects.

Project	Developer	HTF	Capacity	HTF temp	Location	Status
Ivanpah Solar Elecric Generating Station	BrightSource Energy	Water	370 $MW_{e,}$ (gross 392 MW_e)	565°C	San Bernardino, California, USA	under construction (completion in 2013)
BrightSource Coyote Springs 1 (PG&E 3)	BrightSource Energy	Water	200 MW_e (gross).	565°C	Coyote Springs, Nevada, USA	under development, start 2014
Crescent Dunes Solar Energy Project	SolarReserve's Tonopah Solar Energy, LLC	Salt	110.0 MW	565°C	Tonopah, Nevada, USA	under development, start 2013

2.4.3 Key Issues for Project Location and Design

Beyond the usual factors applying to all CSP technologies, main factors to be considered in the choice of location of a power tower include:

Clear atmospheric conditions (e.g. amount of particles in air) and low scattering of radiation by particles, since heliostat to receiver distances can be up to 1.5km.

The site should ideally be flat; a slight slope could be tolerated. Until now, all but one power tower plant, the research tower THEMIS in France (ground is sloped between 6° and 18° (CNRS THEMIS)), were erected on relatively flat ground.

If a form of wet or hybrid cooling technology is to be used then the plant would have to be located near a water source such as a river or a lake which carries or holds sufficient amounts of water throughout the year.

The site must be accessible for large machinery (trucks etc.) for the construction of the plant. In addition the plant should ideally be located in a place where technicians and engineers would be willing to live nearby (e.g. near a town or city).

High earthquake risk zones and environmental habitats should be not considered for location. The location must not lead to an eviction of humans (violation of human rights) or have a significant negative impact on the wildlife habitat and the environment.

Also dazzle and radar interference from the tower may impact houses and airport traffic and should be avoided.

Advantages:

- High concentration ratio, high heat transfer fluid temperatures and high steam parameters achievable, high Carnot efficiencies possible
- Location in hilly regions possible
- Disadvantages:
- Land requirements of up to 6.47 ha/MW

2.4.4 Technology Trends

Several upcoming innovations regarding the development of the power tower technology are described in more detail below:

- *Molten salt technology*: Innovation in the HTF molten salt is expected to raise the operating temperature above the current 565°C. The molten salt used nowadays disintegrates at temperatures above 565°C. Current research efforts aim to raise the working temperature and also improve the power plant processes. Modern supercritical boiler and steam systems handle steam temperatures up to 620°C which offers potential for increasing the Carnot efficiency. This, however, requires higher investments into materials as they become more expensive the more they have to withstand higher operating parameters. Also a slight decrease in the molten salt receiver efficiency is then expected. Therefore, an optimum regarding the optimization of the plant has to be found so that the highest plant efficiency can be achieved (Buck, 2011).
- *Pressurized air receiver technology*: The pressurized air receiver has been developed to work with a Brayton cycle gas turbine process. The air is compressed to 15 bar and the receiver raises the temperature up to 1100°C, which are the parameters necessary for operating the gas turbine. The pressurized air receiver-gas turbine combination plus steam cycle has the potential to achieve a gross thermal to electric efficiency in the high 50% range and overall plant solar-to-electric efficiency of about 20% (Quashning, 2009).
- *Falling particle receiver*: Another technology under investigation is the falling particle receiver. In this technology ceramic particles with a diameter of about 1 mm are both the heat transfer medium and storage medium. The particles are directly exposed to concentrated sunlight and are heated as they fall, by gravitation, from the top to the bottom of a receiver. With such a concept it is possible to reach temperatures of about 1000°C. A lot of investigation will have to take place regarding the abrasive wear resistance as well as the technology which can be used for transporting the particles. The falling particle receiver allows the application in Rankine cycle as well as Brayton cycle processes (Buck, 2011).
- *Heliostat innovations*: As mentioned before the cost of a heliostat field may amount to 45 to 50% of the total plant construction costs. Generally heliostats are high quality optical elements which must track the sun accurately. Combining the quality with reduced production costs will make the power tower technology more cost-effective. Work has taken place regarding hydraulic drive

mechanisms and the designing of autonomous heliostats. Autonomous heliostats can be fed with orientation commands via wireless LAN and the drive mechanism shall be supplied with electricity from individual heliostat-mounted PV panels. This has the advantage that expensive heliostat field cabling becomes redundant. Through intelligent heliostat positioning control, significant improvements in the aiming accuracy by means of using automated calibration measurements is achieved (Buck, 2011).

2.5 Dish Stirling Technology

2.5.1 Characterization

Dish Stirling technology has been developed as relatively small power generation system when compared with other CSP technologies. The reason for this, as mentioned below, relates to the way such concentration systems are designed. The power ratings are between 3 and 25 KW though recently larger systems are being attempted. The system runs as a stand-alone plant tracking the sun in two axes and concentrating the direct solar irradiation onto a receiver. The received is at the focal point of the paraboloid reflector or dish where an engine using a Stirling cycle converts heat into mechanical energy through a piston engine. The mechanical energy is in turn transformed into electricity by an electrical generator directly connected to the engine.

Dish Stirling systems have the highest peak conversion efficiencies of the CSP technologies, above 30 % solar-to-electric and a daily average of up to 25 %. These values are obtained due to the high concentration ratios up to 3000 times, the high working temperatures of above 750°C and good environmental conditions, namely a mild or even cold ambient temperature. The Stirling cycle requires a “cold side” which is directly related to the ambient temperature and in some deserts with clear skies, the perfect conditions are possible to be achieved. In such conditions DNI can be quite high and still due to the bright skies the ambient temperature is not high.

2.5.1.1 Concentrators

Dish Stirling concentrators use a reflective mirror or highly reflective aluminium surface, which is held in the desired shape – usually a full paraboloid - by structural and mechanical metallic frames. Depending on the thickness and iron content, silvered mirrors have solar reflectance values in the range of 90 to 94 %. The size of the solar concentrator for dish/engine systems is determined by the engine size. With current technologies, a 5 kW_e dish/Stirling system would require a 5.5 m diameter concentrator while for 25 kW_e the diameter would have to be increased up to 10 m. The most common concentrator shape is a paraboloid of revolution with a typical concentration ratio of 600 up to 2000 suns.

The development of the frames to conform to the paraboloid shape was done through several joint research programs both in the US and Europe. The following Figure 2.21 shows the EuroDish concentrator.

Figure 2.21 - An Example of the Eurodish.

2.5.1.2 Stirling Engine

The Stirling engine, which was invented by Robert Stirling in 1916, is an external combustion engine which converts heat energy to mechanical energy through a piston movement. Although the thermodynamic efficiency of an external heat engine is theoretically very high, capabilities of engines are in reality limited by the temperature of the materials used in their construction and by efficiency losses due to friction in the mechanical components of the engine. The Stirling engine operates at working gas temperatures between 650°C and 800°C and the working gas is usually hydrogen.

Although any gas, including air and nitrogen, can be used as a working gas in a Stirling engine and yield the same overall thermodynamic efficiencies, the power producing capability of hydrogen or helium is the highest. Hydrogen or helium are preferred not only for high energy densities but also for desirable chemical and physical properties, such as low viscosities, high heat transfer capabilities, chemical and thermal stabilities under typical operating conditions, and thermodynamic efficiencies. Although hydrogen exhibits even better thermodynamic properties and overall better engine efficiencies, it has more material incompatibility issues than helium and introduces an additional safety hazard because of its flammable and explosive properties. More critical for hydrogen is its permeability through common metallic components and gasket materials, especially at the relatively high pressures of 5 to 20 MPa at which dish engines operate in order to maximize their power outputs (Stephens, 1981).

There are two common types of Stirling engines that have been used for power production: the kinematic and the free-piston engine.

2.5.1.3 Kinematic Stirling Engine

Kinematic Stirling engine types are the oldest and most developed designs (see Figure 2.22). The power piston in kinematic engines is mechanically connected to an output shaft through a series of camshafts and linkages. The critical sealing between the high-pressure and low-pressure regions of the engine is created using a simple linear seal on the shaft between the cross-head and the piston. The output shaft then drives an alternator to supply electricity.

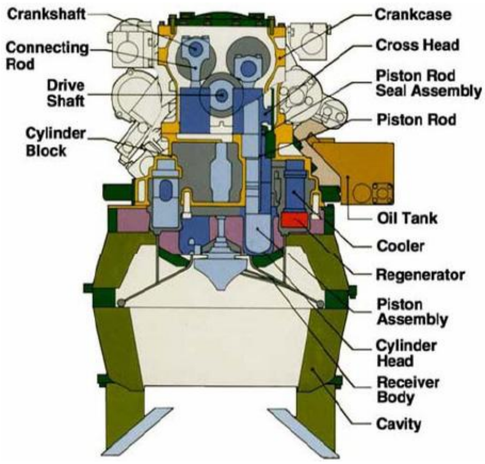


Figure 2.22 - Schematic of a Stirling Engine (Source: SES Stirling Energy Systems).

The following are the merits and demerits of Kinematic Stirling engine:

- *Merits*
    - The oscillations of the moving parts are mechanically coordinated to ensure proper reciprocating motion during start-up, normal operation.

- *Demerits*
    - The cranks and rotating parts, require lubrication;
    - More moving parts imply more frequent maintenance;
    - Moving seals are required between the working gas and the crankcase.

2.5.1.4 Free Piston Stirling Engine

The free-piston Stirling engine is an innovative approach (see Figure 2.23). In this configuration, the power piston is not mechanically connected to an output shaft but moves alternately between the space containing the working gas and a spring which is mechanical or works based on a compressed gas within. In these engines the power generation is achieved with a linear alternator formed by the oscillatory travel of the power piston in a magnetic field. The following are the merits and demerits of Free-piston Stirling engine:

- *Merits*
    - There are no cranks or rotating parts and therefore lubrication is not required;
    - Lower number of moving parts allows longer maintenance intervals;

  - The engine is usually built as a hermetically sealed unit, thus preventing the loss of the working gas.
- *Demerits*
  - The engine is dynamically and thermodynamically complex;
  - Piston position is a critical area of control. If one piston drifts from its neutral position, the oscillation become unbalanced and the power output will be affected.

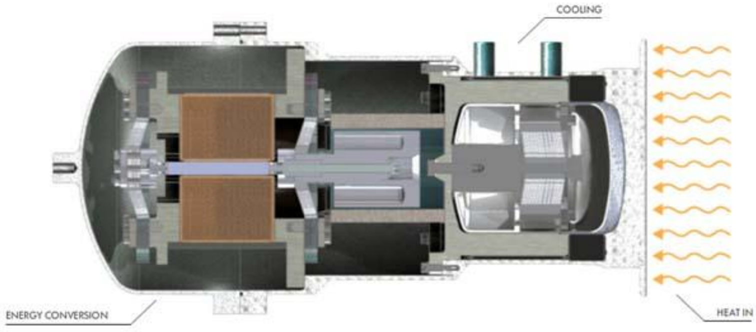


Figure 2.23 - Free Piston Stirling Engine (Source: Infinia).

Commercially, both kinematic and free-piston Stirling engines have been coupled to appropriately sized dishes and mounted on dual axis solar trackers. Complete Dish/engine systems, have been developed by, among others, Schlaich, Bergemann und Partner GrB, in Europe, and by InfiniaCorp and Stirling Energy Systems (SES) in the USA. These two use a free-piston helium gas engine and a kinematic hydrogen gas engine illustrative of the technologies (see Figure 2.24). The former is a small scale 1kW system suitable for distributed and even rooftop installations; the latter has been proposed for large, multi- 100MW, utility scale power plants.

Figure 2.24 – Commercial Dish/Stirling systems.

2.5.2 Existing Projects

The existing projects are presented in Table 2.3.

Table 2.3 – Existing Projects.

Location	Designation	MWe Capacity	Technology	Status
USA	Maricopa Solar Project	1.5	Dish Stirling	Operational
Spain	Aznalcollar	0.08	Dish Stirling	Operational
	Casa de Angel	1	Dish Stirling	Under Construction
	8 MW Puertollano	8	Dish Stirling	Planned
	10 MW Puertollano	10	Dish Stirling	Planned
	10 MW Puertollano	10	Dish Stirling	Planned
	10 MW Puertollano	10	Dish Stirling	Planned
	10 MW Puertollano	10	Dish Stirling	Planned
	10 MW Puertollano	10	Dish Stirling	Planned
	14 MW Puertollano	14	Dish Stirling	Planned
	Envirodish	0.01	Dish Stirling	Operational
Portugal	Quinta Solar Alentec 1	1,5	Dish Stirling	Planned
	Solar Stirling 1	1,5	Dish Stirling	Planned
	Odelouca	1	Dish Stirling	Planned
	Alcanizes	1,5	Dish Stirling	Planned
India	Rajasthan	10	Dish Stirling	Planned
	Mount Abu	Not final	Scheffler Dishes	Planned
Australia	Big Dish SG3	0.32	Big Dish	Operational
	Big dish SG4	0,13 (not final)	Big Dish	Operational
	Whyalla SolarOasis	40	Big Dish	Planned

The above data is based on publicly available databases and projects that benefit from Fit or PPA. Some of the projects in Spain belong to SES which is known to have filed for bankruptcy.

2.5.3 Key issues for Project Location and Design

2.5.3.1 Ratios of land usage

Depending on the system and the site, dish Stirling systems require approximately 3.5 to 4.1 ha of land per MW. The values for land use by capacity (ha/MW), are based on estimates from the actual installations.

Regarding the optics, parabolic mirrors point to the sun and focus the radiation onto the receiver. If the sun's path is considered throughout the day and the year it is easy to see that at noon the shadowing of a neighboring dish system is the smallest compared with the other hours of the day, since the sun is higher at that time of the day. Thus, it means that in the morning as well as in the evening the shadow is larger and that independently of the location (latitude). Simple geometrical considerations show that in that case 5 times the area should be left free to avoid shadowing or blocking. The value given in the references is around 4 which is in line with these considerations.

2.5.3.2 Slope and Other Requirements for Suitable Land

Dish Stirling systems have high flexibility where they can be installed as they are stand-alone systems which are independent of one another. Depending on the system used, dish Stirling systems can be installed on grounds with a slope of up to 4%, since they are mounted on a single pole that stands up several meters above the ground. In this case there is no need for a very flat ground as circular tracking rings to enable azimuth tracking.

The site must have a low salt value in the soil to avoid corrosion and not within a flood zone so that access is always possible and misalignments are avoided.

2.5.3.3 Water usage

Stirling engines do not need water for cooling. The only water requirement for dish engine facilities is for washing mirrors when necessary and for O&M support activities. The amount of water needed for mirror washing depends on the dust conditions and the climate of the region, as well as the time of year, which are all factors that need to be considered in a mirror-washing schedule.

2.5.3.4 Effluents

These systems produce no effluents when operating with solar energy. Leakage of working fluids such as hydrogen or helium from dish Stirling engine is possible but is quite low and the volume of gas released is extremely small and is rapidly dispersed. The risk of ignition is therefore also low, but does exist. Therefore, it is important to put procedures in place to adequately manage this risk.

Dish Stirling systems have the potential of spilling small amounts of engine oil or coolant or gearbox grease.

2.5.3.5 Design constraints

The layout of the solar field of i.e. distances between dishes is critical as it influences the power output of the system and land area requirement. When single units are located close to one another, then land requirements, electrical cabling losses and cost can be reduced, but the dishes can cast shadow on each other and the total solar system performance is reduced. Because of that, sun path and sun position in the sky for the selected site, based on its geographical parameters, have to be calculated to simulate the shadow pattern for any unit, date and time and analyze its impact on adjoining units thereby to optimize the solar plant layout design. In any case, unlike the linear concentrating technologies, 2—axis tracking is more independent of latitude.

Connection to the power grid must be in accordance with power technical rules, which specify acceptable power quality parameters for grid-connected generators. Since most systems use conventional induction generators with well-known characteristics, power quality issues are unlikely to be problematic. As a result of the thermal inertia present in Stirling engine solar generators, some degree of output variation smoothing occurs following the obstruction of direct sunlight in response to cloud passage. Instead of an extremely rapid change in power output, as would occur with PV or CPV, solar dish Stirling generators wind down over several minutes as the engine cools. When direct sunlight resumes, a similar thermal lag occurs, and output increases gradually as the engine returns to its nominal operating temperature. Such gradual changes in output reduce peaks in power flows in the grid, enhancing power quality for consumers and reducing effects such as flicker.

2.5.3.6 The following are the merits and demerits for Dish Stirling Technology

- *Merits*
    - Very high solar to electric conversion efficiency, about 30%;
    - No thermal fluid flow in long pipes, less complicated;
    - No water requirement for cooling the cycle;
    - Easy to manufacture, mass production and assembling at site;
    - Lowest commissioning period compared to other CPS technologies;
    - In the event that one or more dish Stirling system of a dish plant are shut down due to maintenance or other reasons it has no effect on the operation of the remaining dish systems as they are independent of one another;
    - Free piston technology has revolutionized the upcoming market;
    - Flat ground of a site is not a prerequisite;

- *Demerits*
    - Earlier technological problems in gas leakages, piston failures associated with Stirling engines were reported which lead to delays in commercialization;
    - Cannot effectively integrate thermal storage and therefore, lower dispatchability potential for grid integration;
    - The electricity output of a single dish Stirling unit is limited to small ratings of 25 kWe, due to geometrical and structural reasons;
    - Cost of commercial level plant is yet to be established.

2.5.3.7 Cost Analysis

Cost analysis is based on a 10 MW CSP power plant consisting of 400 dish Stirling units based on the design of Stirling Engine Systems (SES - US based company).

The main plant characteristics are presented in Table 2.4.

Table 2.4 - Plant's Main Characteristics.

Collector Properties	
Mirror aperture per dish	89 m^2
Number of dish units	400
Total aperture area	35,600 m^2
Electrical Conversion System	
Installed power per dish	25 kWe
Total power	10,000 kWe

Additionally, in what concerns the cost drivers, the following figure presents the overall investment cost breakdown.

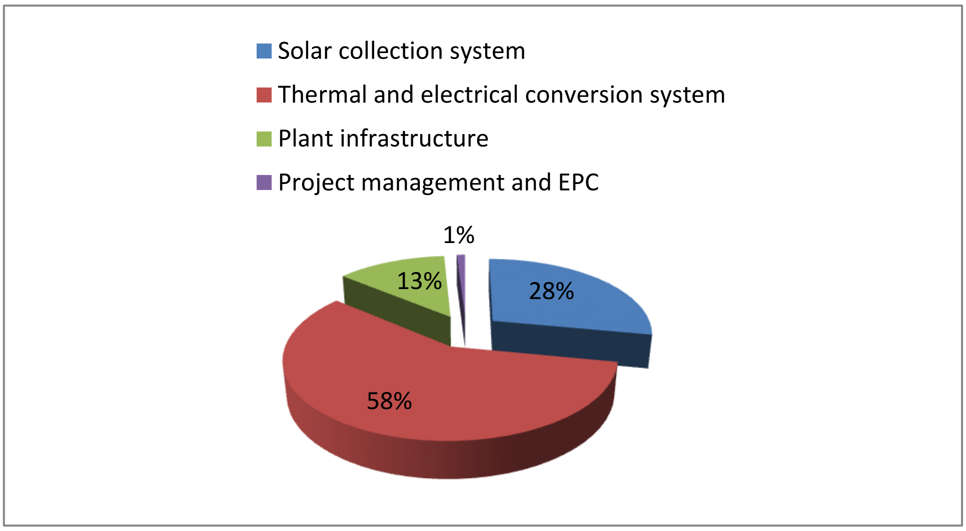


Figure 2.25 - Cost Drivers Overview; (Source: World Bank – 2010).

The CAPEX is estimated to lie between 5 to 6 USD per W (for the system only) while OPEX (Stirling engines) falls within the typical 2% to 2.5% annual cost in terms of the CAPEX cost[3].

[3] Source: http://www.decc.gov.uk/assets/decc/Consultations/fits-review/4307-pb-and-cepa-updates-to-fits-model-documentation-odf

2.5.4 Technology Trends

2.5.4.1 Flexible Reflective Polymer Membranes

New techniques are being tested as for example: the parabolic reflecting surface can be created through the use of flexible reflective polymer membranes which are stretched across a rigid support and forced to assume the desired shape. This is accomplished through the application of pressure or the creation of a vacuum between the reflective membrane and a second membrane stretched across the support frame behind the reflective membrane to form a nearly ideal paraboloid.

This innovative technique has yet to prove its durability for commercial use, and there are problems with decoupling of the metalized reflective coating from the polymer, which have to be solved.

Figure 2.26 – PSA, Spain.

2.5.4.2 Other Stirling engine configurations

The Stirling engine could have a variety of configurations. Basically they are classified into three configurations, such as, Alpha (α), Beta (β) and Gamma (γ). Each one of these configurations has the same thermodynamic cycle, but different mechanical and design characteristics.

Two Piston alpha (α) configurations

Alpha engines have two independent pistons in separate cylinders which are connected in series by a heater, a regenerator and a cooler. One is a “hot piston” and the other one a “cold piston”, both are connected to a crankshaft, usually at a ninety degree angle between each other and the two pistons moving out of phase. In this configuration, the cycle may be thought of as four different phases: expansion, transfer, contraction, and transfer.

Expansion: at this point, most of the gas in the system has just been driven into the hot cylinder. The gas heats and expands driving both pistons inward.

Transfer: at this point, the gas has expanded. Most of the gas is still located in the hot cylinder. Flywheel momentum carries the crankshaft the next 90 degrees, transferring the bulk of the gas to the cool cylinder.

Contraction: now the majority of the expanded gas has been shifted to the cool cylinder. It cools and contracts, drawing both pistons outward.

Transfer: the now contracted gas is still located in the cool cylinder. Flywheel momentum carries the crank another 90 degrees, transferring the gas to back to the hot cylinder to complete the cycle.

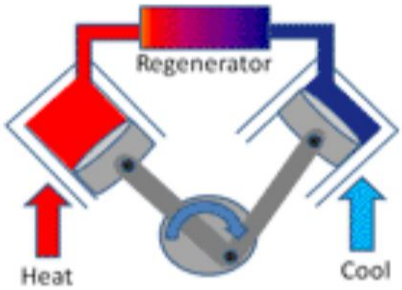


Figure 2.27 - Alpha (α) configuration.

Single piston Beta (β) configuration

This configuration of Stirling engine incorporates a displacer and power piston in the same cylinder. The displacer transfers the working fluid between the expansion and compression space through the heater, regenerator and cooler. The power piston, located at the cold space of the cylinder, compresses the working fluid when the working fluid is in the cold space and expands the working fluid when it is in the hot space.

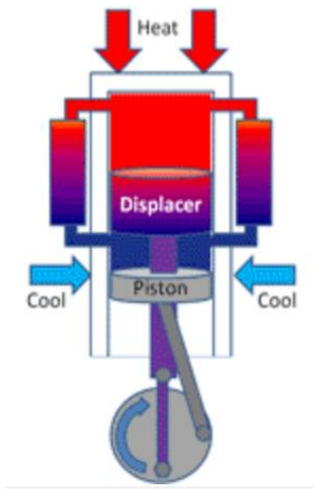


Figure 2.28 - Beta (β) configuration.

Gamma (γ) configuration

The Gamma Stirling engine has common features of alpha and beta configuration. It has two separate cylinders like the in alpha configuration but the power is produced in the same way as in beta configuration.

The power cylinder is connected to the displacer cylinder. The displacer moves the working fluid between the hot and cold spaces of the displacer cylinder through the heater, regenerator and cooler. The power piston both compresses and expands the working fluid.

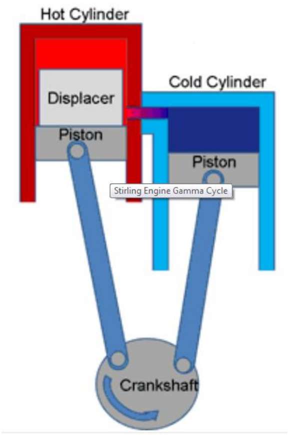


Figure 2.29 - Gamma (γ) configuration.

Hybrid Operation

Stirling engines are powered only by external heat sources. Therefore a hybrid receiver can be used which is also equipped with burner to provide heat by combusting natural gas, landfill gas, diesel or biofuels, including agricultural waste materials. The dispatchability and supply can thus be ensured regardless of cloud conditions or the time of day by switching from solar to the burner.

2.6 Storage in CSP plants

One of the main advantages of CSP over other intermittent solar and renewable energy sources is the possibility of cost effectively storing the thermal energy produced.

Most CSP plants can store heat for short periods due to the bulk of materials used in the construction of their receivers and field piping. This allows them to “ride through” small temporal variations in irradiance, e.g. those due to small cloud passage. Steam accumulators, operating at relatively low temperatures and pressures, can also provide short term (~1hour) storage for steam based systems. However for CSP to realize its full potential as a 24/7 technology, longer term storage systems are required.

Because the solar DNI is intermittent and has daily and seasonal cycles, solar heat collection from a CSP field is necessarily variable and sometimes reaches higher levels than the design maximum of the associated power block. In a plant without storage, this excess heat, often present around midday and in summer periods, cannot be used and is either rejected or clipped before collection (e.g. via mirror defocusing). If storage is present, this excess heat can be stored and then used effectively to supplement the DNI when the latter is either not sufficient to drive the power block alone or is non-existent. As shown in Figure 2.30, heat storage can also effectively stabilize turbine load, extend operating hours of the power plant and contribute, in a cost effective manner, to electricity production during hours of low or no DNI.

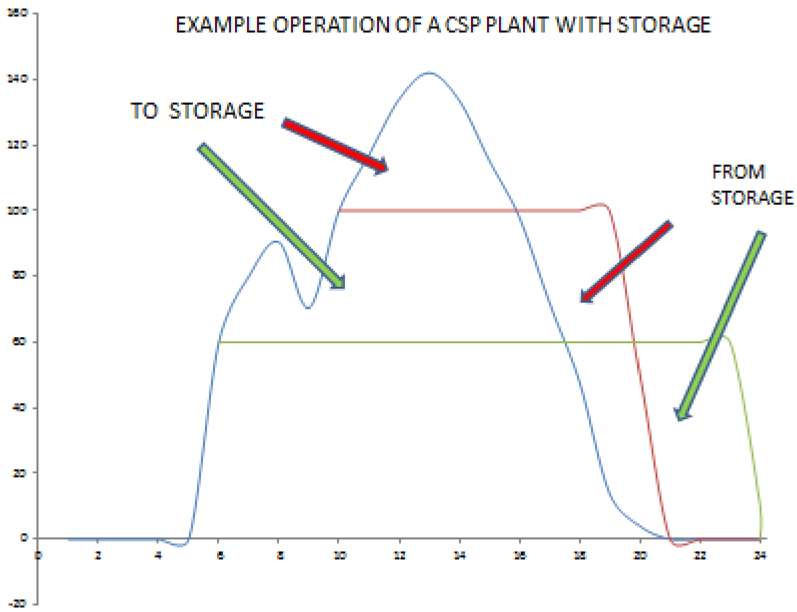


Figure 2.30 - CSP solar field thermal output due to DNI (blue) and two levels of thermal input (red and green) into an associated power block during a typical day.

Further, and as illustrated by the red and green curves and arrows in Figure 2.30, if the solar field size is selected to provide more than the heat needed to drive the power block at maximum rating (i.e. the field has a solar multiple greater than 1), by selecting an operating point for the power block at 100% of its rating, or say 60% of its rating, electricity production can be maintained for a number of hours beyond sunset or through into the evening. Solar multiples for CSP plants with storage are typically greater than 2. This allows extended operation and eventually, 24/7 operation of the power plant. This major, cost effective, and unique advantage of CSP plants gives them flexibility to meet appropriate load profiles. CSP plant may be operated as peaking plant with extended hours or, with sufficient storage, as baseload power plant similar in output profile to conventional fuel plants.

Four major generic thermal storage techniques have been identified: sensible heat storage where an insulated material is heated to higher temperatures; latent heat storage which causes an isothermal phase change in a material (eg from solid to liquid or liquid to gas) through heat input; heat of chemical reaction where chemicals are dissociated by injection of energy (and then stored at ambient temperature for later recombination and heat release); and heat of dilution in which dilution of one chemical in another requires heat input which may be recovered later. Of these, the first three have been used variously with solar energy as heat input in research and developmental applications.

2.6.1 CSP storage system types

Several long term storage systems have been and are being actively developed for commercial CSP applications. They include molten salt storage, ceramic storage with air as the heat transfer fluid, and pipes-in-solid media combined with phase change materials.

2.6.1.1 Molten salts storage systems

Of all CSP storage systems, the most commercially advanced are molten salt two-tank sensible heat storage systems. These have already been successfully implemented in numerous parabolic trough plants as well as in the Gemasolar Power Tower plant (Figure 2.2 and Figure 2.15).

In the storage charging phase of a parabolic trough plant, the synthetic oil heat transfer fluid is circulated through a dedicated heat exchanger to heat molten salts from a “cold” temperature of ~290°C to a hot temperature of ~390°C and stored in a hot tank. In the discharge phase, the hot molten salt is circulated through the heat exchanger in a reverse, hot – to – cold, direction to heat the transfer fluid, which is then able to produce superheated steam for the turbine. This is often called an indirect two tank molten salt storage system. The lower cold temperature is dictated by the lower operating temperature of the molten salt mixture (to avoid salt freezing); the upper temperature is dictated by the upper temperature the synthetic oil withstands without noticeable degradation. Storage capacity is then mostly determined by the product of the mass of salt circulated, its specific heat and its temperature rise of about 100°C. Typical parameters for indirect two tank storage, as illustrated in the Andasol solar plants, are as follows:

- Storage capacity: 7.5 hours
- Tank size: Diameter = 36m; H = 14m
- Salt composition: 60% sodium nitrate, 40% potassium nitrate
- Mass of salt: 28500 tons; equivalent to 1010 MWh of storage.

In contrast, the implementation of storage in salt tower plants exemplified by the Gemasolar plant, and the proposed SolarReserve tower plants (Figure 2.15), is a direct two tank storage system. In this system, the molten salt acts as both heat transfer fluid and storage medium.

In this system, the molten salt acts as both heat transfer fluid and storage medium. At charging phase, the molten salt from the cold tank (at 290°C) is circulated in the tower receiver, heated to 565°C, and stored in the hot tank. At discharge, the stored hot salt is directly pumped through the salt-to-superheater heat exchangers to produce the superheated steam for the turbine. In this case, no dedicated heat exchanger or transfer from heat transfer fluid to storage medium are needed. Both lower and upper operating temperatures are in this case, determined by the properties of the storage salts. The lower by its freezing temperature and the upper by its chemical stability. Over and above their lower capital costs and higher efficiency, direct storage systems have two main, and substantial, advantages over indirect two tank systems.

1. They decouple solar field heat collection from electricity generation processes; salt circulation from cold tank into the tower receiver to the hot tank can proceed in parallel with salt circulation from hot tank, to steam heat exchanger, to cold tank;
2. They can achieve substantially higher heat storage density, due in large part to the higher temperature difference between hot and cold tanks (275°C).

As a consequence, molten salt quantities for these tower plant direct systems can be as small as 25% of those required for parabolic trough indirect storage; and economically feasible plant capacity factors can reach 70% or higher.

In an endeavor to reduce molten salts storage costs further, a single-tank molten salt system is being developed. This uses one tank in which a thermocline, or sharp vertical temperature transition from cold to hot, can be maintained between upper, hot storage medium and lower, cold storage medium. This may be established either through the change in density, and hence buoyancy, of the storage medium itself or through a “floating diaphragm” suitably designed to float on the denser, colder medium. Reducing the amount of molten salts through use of solid “filler” material is also being investigated for these tank based storage systems. These improvements have not been implemented in commercial plants.

2.6.1.2 Ceramic Based Storage Systems

This storage development is suited to higher temperature tower systems reaching operating temperatures of 700°C or above. It combines the use of a gas as the heat transfer fluid and a ceramic material for heat storage at these temperatures. The hot gas, specifically air, is blown through an insulated bed of ceramic materials (silicate sand or aluminosilicate ceramic bricks have been used). An example of this is mentioned in section 2.4.2. Alternately, the sand itself is used as heat transfer and storage fluid. In this case, the sand is directly irradiated by the solar beam as a falling particle curtain inside the receiver, and stored for later use [section 4.4.4]. Steam production can proceed either sequentially or in parallel with solar field heat collection, mirroring indirect or direct tank systems. This storage system is in early development; it is in many respects similar to conventional steel industry regenerators or COWPERS; but has so far not been demonstrated at scale in CSP plants.

2.6.1.3 Pipes in Solid Media plus Phase Change Materials (PCM)

These systems have seen active development over the last few years (Laing, et al., 2008). They usually comprise three sub-systems operating at low, medium and high temperatures respectively. Both low and high temperature ranges are provided by, for example, pipes-in-concrete subsystems relying on sensible heat of the cast concrete. The medium temperature subsystem uses latent heat storage in a PCM which has a phase change temperature close to that of the steam input to the turbine. A pre-commercial scaled demonstration of such a system has been trialed at an existing conventional power plant (D. Laing, C. Bahl, et al., 2009). This type of multiple unit storage is better adapted to the phase changes occurring in the water/steam/superheated steam exchangers required to drive steam turbines (see below section 2.6.1.4).

2.6.1.4 Integration of Thermal Storage in Solar Plants

As previously stated, the vast majority of operating solar fields have been interfaced to steam turbine power blocks. The working fluid, in this case superheated steam, must undergo preheating (sensible heat), boiling (isothermal latent heat) and superheating (sensible heat) stages at various pressures before entering the turbine. The corresponding Temperature-Enthalpy curve, shown in red in Figure 2.31 below, shows two inflection points around which transitions between sensible and latent heating take place in the preheater/boiler/superheater heat exchangers feeding into the turbine. A storage system capable of driving such heat exchange requires operating parameters (shown in green) that are constantly above those of the working fluid, in order to avoid “pinching” at any of the inflection points and to drive heat into the working fluid. Further, for the usual solar field heat transfer fluids used (synthetic oils or solar salts) the solar field operating Temperature-Enthalpy parameters are further above those of the storage system, be it sensible or sensible+latent. Hence storage parameters in a solar power plant are constrained by the solar field and the power block operating parameters. This invariably results in lower operating efficiency than that for non-storage operation, and a non-negligible amount of non-recoverable heat in the storage system

As previously stated, the vast majority of operating solar fields has been interfaced to steam turbine power blocks.

Finally, for plants with direct steam generation in the solar field, such as BrightSource’s tower plants or AREVA’s “CLFR” Fresnel plants, integration of storage, especially those based on sensible systems, incurs further efficiency losses at the field/storage interface, due to further pinch point considerations there.

However this, and the extra costs for larger solar multiples and extra hardware, can of course be substantially offset by the benefits of steady and longer term operation with storage.

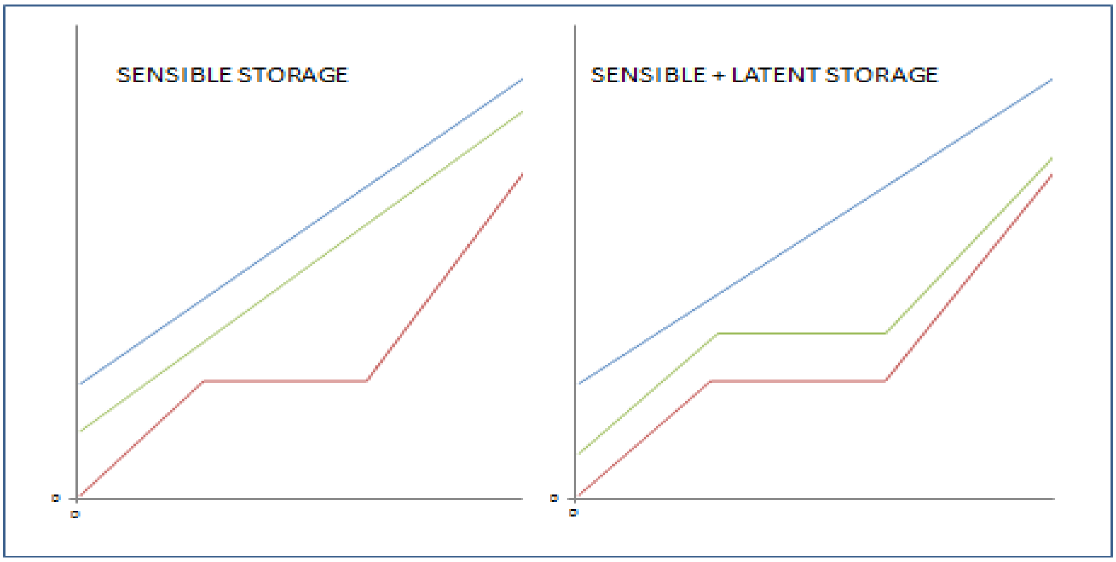


Figure 2.31 - Temperature vs Enthalpy graphs for two storage types: (a) sensible heat storage, (b) sensible+latent heat storage. The curves are for the solar field heat transfer fluid (blue), storage medium (green) and the resultant steam turbine working fluid (red) respectively.

2.7 Hybridization and Augmentation

2.7.1 Hybridization

One of the biggest challenges of concentrating solar power (CSP) is the intermittency associated with clouds during the day and at night which can lead to transients and no steam generation resulting in an undesired shut down of the turbine.

This challenge can be mitigated by using an oversized solar field (solar multiple higher than 1) and then making use of the excess energy to load a thermal or chemical storage system. However, large scale energy storage also has associated technical and cost issues. Another viable alternative that helps to alleviate the challenges associated with intermittency is a hybrid system also called back-up.

All CSP technologies have the option of hybridization, because heat is what generates electricity in: parabolic trough plants, power towers, Linear Fresnel Reflector and dish Stirling systems.

The ease of hybridization for troughs, tower plants and Linear Fresnel Reflector stems from the fact that the boiler is an entirely separate component, while for dish Stirling systems the hybridization needs to be an integral part of the design, and that has proven to be more difficult to design and implement.

Hybridization can come with natural gas, biomass and coal, while in the latter case it is usually called augmentation.

2.7.1.1 Natural Gas Hybridization

The current CSP power plants in Spain have an auxiliary backup natural gas boiler to mitigate the number of shutdowns of the turbine as well as the intermittency associated with the solar radiation and consequent steam generation.

The use of small amounts of gas is called backup and is justified by the investment in the Balance of Plant infrastructure, namely the turbine. Back-up also avoids technical issues related to the number of starts and stops of the turbine. The backup via natural gas boiler has a relatively low investment cost and is mature, low risk technology.

The concept of backup is simply explained in the following diagram (Figure 2.32):

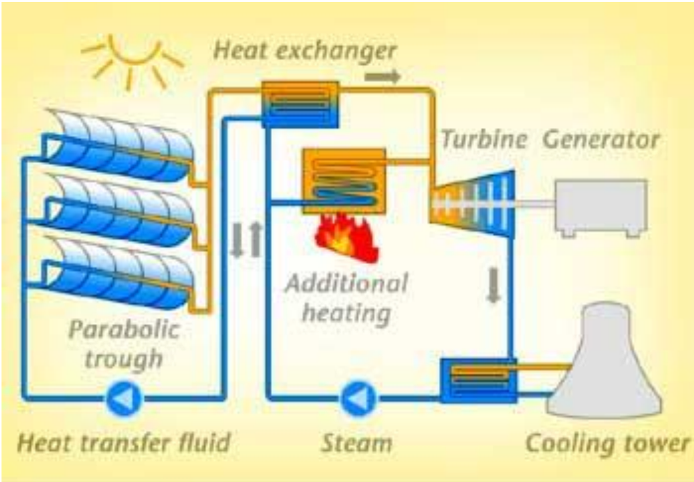


Figure 2.32 - Additional boiler back-up heating for a solar CSP plant.

A further possibility is the integration of CSP technology with a combined cycle power plant. In this case the solar field provides thermal energy to supplement the top-end gas turbine exhaust feeding into the bottom-end steam turbine. This is referred to as integrated solar combined cycle systems (ISCCS) and some examples exist in the world of its application, namely in Morocco and Egypt. The concept is shown in Figure 2.33 below.

The gas boiler generates electricity and at the same time heat which is coupled with the heat from the CSP solar field to generate power through a steam based turbine. The idea is to increase or augment the output of the power plant. This concept has run into some problems and is being questioned as a viable option. In any case the idea is now associated to augmentation and not to hybridization.

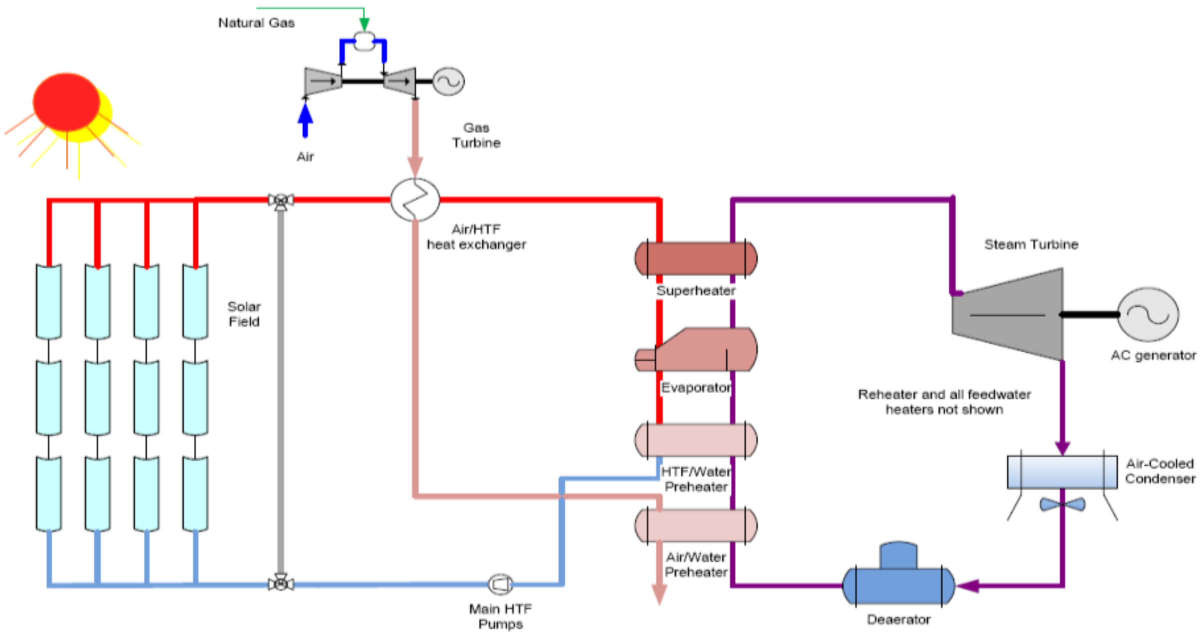


Figure 2.33 - ISCCS System.

A solar tower made of open volumetric receiver which uses air as a HTF can be further upgraded to a hybrid system by combining the plant with a burner or a gas turbine. The burner supplies the heat at day in order to achieve constant operation conditions at nominal load. The receiver acts as fuel saver for the channel burner. Air at nominal mass flow is preheated by the receiver and is heated further to the desired temperature by the channel burner. A further very promising possibility to realize a hybridization is by combining the solar receiver with a gas turbine. The investment costs are higher than using a burner but an additional power production twice the generated steam power is guaranteed (S. Alexopoulos, et al., 2011).

2.7.1.2 Biomass Hybridization

Different types of biomass including wood have become increasingly important for use as fuels to generate electrical power around many parts of the world. It is a low cost, local and completely restorable form of fuel. The advances in technology for effective usage and with less pollution coupled with widespread availability of biomass are making it increasingly a suitable alternative to the existing choice of fossil fuels. One of the advantages of biomass combustion technology is its maturity with a large number of power plants in operation worldwide.

The cost of hybridization with biomass is reasonable because hybridization uses common equipment with CSP power plant, as is the case with all the Balance of Plant. The exception is the boiler for biomass and the burner which is usually all within the same system.

In CSP and biomass power plants (Figure 2.34), heat is generated and carried by steam which will drive the turbine-generator and produce electricity. Since both types work on the same basis a CSP power plant may include a biomass boiler for operation during periods of reduced irradiation, but also during the night. Concepts of biomass-solar power plants or solar-biomass power plants differ on the amount of biomass used and also where the steam generated by solar is actually injected. Here, only solar-biomass plants are covered since the biomass-solar is a special case of augmentation.

The combination of these two technologies benefits from increased overall efficiency of the power plant, reduced number of shutdowns of the turbine and reduced investment per unit of power capacity compared to CSP with molten salts heat storage, for example.

An upgrade of a solar tower with air as a HTF to a hybrid system by combining the solar operation with combustion process for biogas is possible. A gas turbine or a channel burner may be fuelled with biogas. At days of low solar radiation the gas turbine or the burner adds partly or entirely heat to achieve nominal load of the boiler (S. Alexopoulos, et al., 2011).

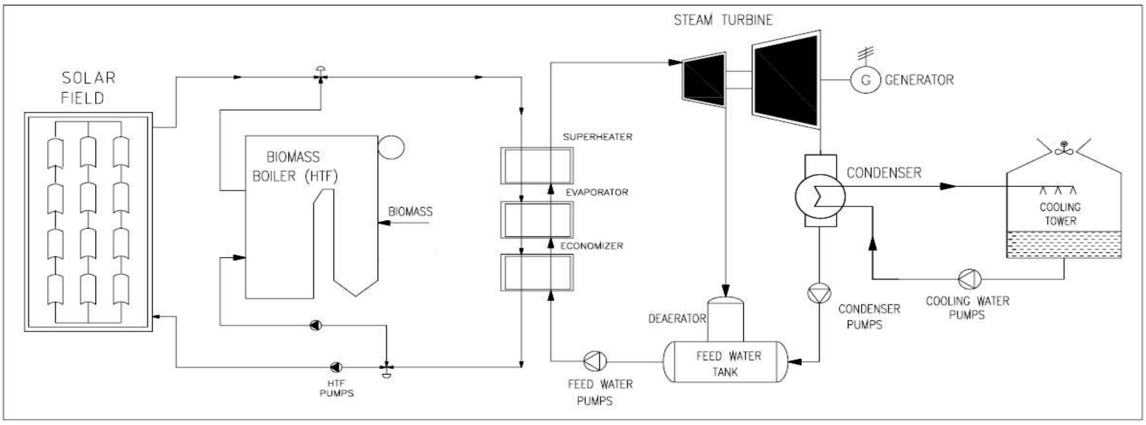


Figure 2.34 - CSP – Biomass hybrid configuration.

CSP generally require a considerable power rating to be economically viable and since it is a technology suitable for utility generation, the biomass boiler requirements are in the MW range. As is common with biomass power plants, the biomass resource cannot be transported from far, so the power plant must be located in the vicinity of a good and sustained feedstock. It is considered that 50 km is the maximum for transport to make commercial sense for biomass and 30 km as the actually average desired distance.

2.7.2 Augmentation of coal fire power plants

CSP systems are highly flexible for integration with conventional power plant design and operation and for blending their thermal output with fossil fuel, biomass and geothermal resources. Basically all technologies that use heat can be coupled or augmented by solar thermal.

Basically two options are available: reduce fossil fuel usage or boost the power output of the steam turbine. To reduce the fuel usage the steam generated by the CSP power plant is injected in a low pressure (LP) point or even high pressure (HP) of the steam cycle or in the economizer. Successful cases have been more successful at the latter and also using LP feed heaters. The heat supplied by the CSP power plant will theoretically avoid the consumption of an equivalent amount of conventional fuel for the same operation. The other way is to boost the turbine electricity yield by avoiding that streams of steam be directed for other purposes as for example heating the deaerator, which usually requires relatively low temperatures around 105°C. By supplying solar heat to the deaerator the turbine may generate more power and so increase the return to the plant owner providing a business case for the use of the CSO solar field.

In terms of costs a CSP solar field is much cheaper than a CSP power plant and in a conventional power plant the whole power plant is available. A CSP solar field generating steam for a conventional power plant will yield interesting paybacks as has been shown by Hu, David Mills, Graham Morrison and Peter Le Lievre in the paper Solar power boosting of fossil fuelled power plants (published in ISES back in 24th May 2003). The Liddel CSP solar field to augment a coal power plant, shown below in Figure 2.35, is one of the first projects of this nature in the world.

Figure 2.35 - Liddell solar field booster for the Liddell coal-fired power plant. (Source: AREVA - Liddell Solar Thermal Station.

2.7.3 Existing Projects

In the Table 2.5 the existing projects are presented.

Table 2.5 – Existing Projects.

Project	Location	Solar Technology	Plant Output, MWe	Solar Contribution, MWe	Status
Kureimat	Egypt	ISCCS-Trough	150	40	Under Construction
Victorville	California (US)	ISCCS-Trough	563	50	Planning
Palmdale	California (US)	ISCCS-Trough	617	50	Planning
Ain Beni Mathar	Morocco	ISCCS-Trough	472	20	Under Construction
Hassi R'Mel	Algeria	ISCCS-Trough	150	25	Under Construction
Yazd	Iran	ISCCS-Trough	430	67	Planning
Agua Prieta	Mexico	ISCCS-Trough	465	12	Planning
Liddel	Australia	Coal CLFR	2004,4	4,4	Constructed

Note that the Spanish company Abantia is constructing the first parabolic trough CSP power plant of 22,5 MW with biomass hybridization – Borges - located in Spain.

2.8 Desalination

This chapter is devoted to desalination processes using thermal heat rather than through electricity and reverse osmosis (RO). Importantly however the technologies mentioned below can be combined with RO resulting in hybrid concepts, which have already been implemented.

2.8.1 Characterization

Renewable energies can be used for desalination based on two ways: heat or electrical power. Usually the electricity route is used with membranes and the heat is used for evaporation. Three technologies stand out as being the most mature: reverse osmosis (RO), Multi-effect distillation (MED) and Multi-stage Flashing (MSF). RO uses electricity to pump water through a membrane while the other technologies use heat to evaporate and condense water. New processes of RO with nanotubes and biomimetics are in development and on the heat side improved concepts are also being researched. Clearly the heat used for the mentioned processes above have traditionally come from fossil fuels and usually such projects are incorporated with thermal power plants to use the waste heat, but some CSP systems have also been developed to provide a way to use solar energy for desalination as well as with biomass. On the RO route the electricity may come from PV modules, wind turbines or any other clean source of electricity, including the CSP for power generation.

The main heat based technologies are the MSF and the MED. The Multi-Stage Flashing, shown in Figure 2.36, consists of a series of stages in which "flash" evaporation takes place from the flow of salt water or brine that occurs on lower part of the evaporator. The vapour released in flashing is filtered to remove brine droplets and condenses to yield water on heat transfer tubes at the top of the evaporator. The seawater or brine flowing through the tubes is heated by the transfer of latent heat from the condensing vapour, giving a temperature rise equal to the temperature drop in "flashing" from the brine in each stage. The heat to operate the process is supplied by steam, which is injected in the brine heater. Below an example of a MSF process:

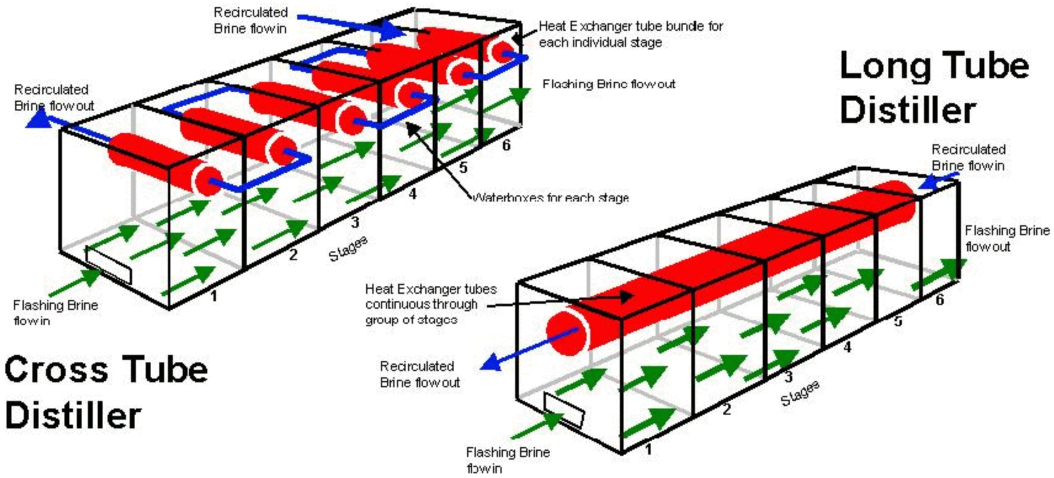


Figure 2.36 – MSF Process.

In a Multi-Effect Distillation system the vapour formed in each chamber flows to the condensing side of the heat transfer surface in the next (lower temperature) effect. The latent heat of condensation is transferred through the tube wall to evaporate part of the saltwater or brine flowing across the surface. The main difference between MSF and MED is in the method of evaporation and heat transfer. In a MED plant, evaporation is from a seawater film in contact with the heat transfer surface, whereas in the MSF plant only convective heating of seawater occurs within the tubes and evaporation is from a flow of saltwater or brine "flashing" in each stage to produce vapour.

Higher heat transfer rates can be achieved in the MED process due to the thin film boiling and condensing conditions. Also the evaporation takes place at a uniform temperature within each effect and it results in the heat transfer area needed for the MED plant being similar to MSF but the plant is operated over a smaller temperature range than MSF. In the MED technologies there are also two ways for obtaining the vapour: thermal vapour compression (TVC) which compresses the available steam and turns into high pressure steam or mechanical vapour compression (MVC) which generates vapour by compressing mechanically the vapour. Figure 2.37, below gives an example of a MED system installed in Plataforma Solar de Almeria (PSA) in Spain which uses a solar field for the heat source.

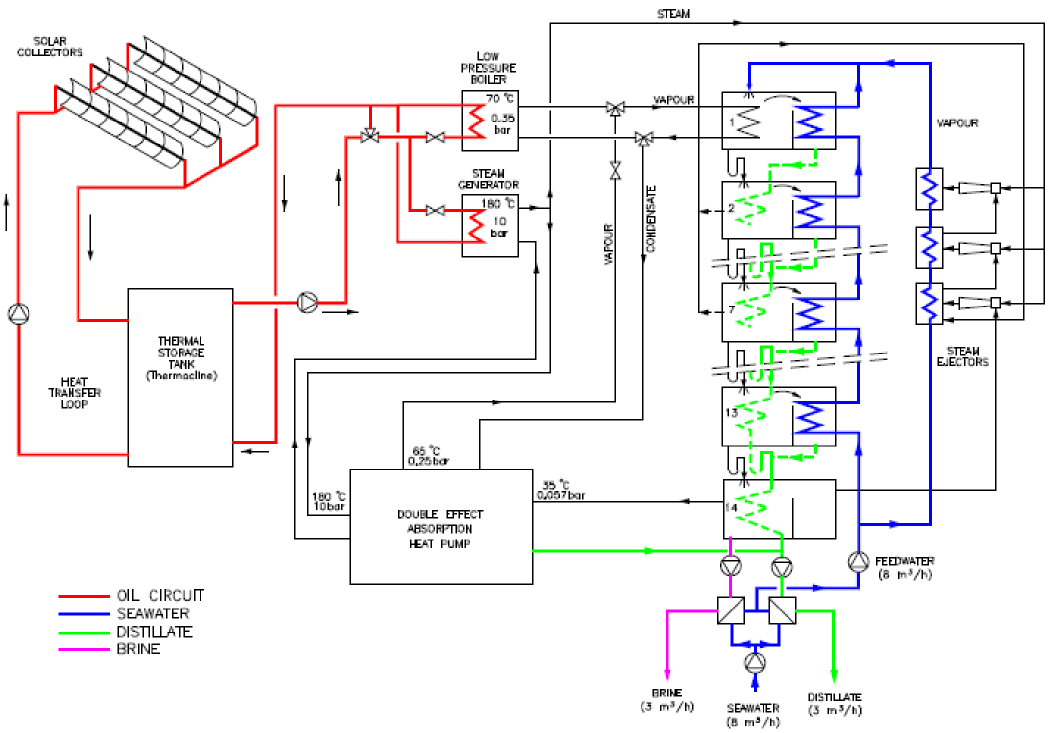


Figure 2.37 - Schematic diagram of the solar MED system installed at PSA 8: Improved version.

It is clear from the above that the heat source is the only difference when we consider the MED/MSF technologies based on CSP or on fossil fuels. The temperature range required for these technologies is low, less than 100ºC, since the main principle is evaporation and that occurs at that temperature for normal atmospheric pressure or higher temperature for higher pressure and lower temperatures for lower pressures. Steam, being the by-product of thermal power plants, has been used, but both parabolic troughs, linear Fresnel collectors and even solar thermal collectors (advanced flat plates and Compound Parabolic Concentrators collectors) can and have been used to provide heat for desalination processes.

2.8.2 Existing Projects

According to the International Desalination Association (IDADESAL), the ten countries with the highest implementation of desalination plants worldwide (2010 data) are:

- Saudi Arabia - 17% of the market with 10.759.693 m3/day;
- UAE - 13% of the market with 8.428.456 m3/d;
- USA - 13% of the market 8.133.415693 m3/d;

- Spain - 8% of the market with 5.249.536 m3/d;
- Kuwait - 5% of the market with 2.876.625 m3/d;
- Argelia - 4% of the market with 2.675.958 m3/d;
- China - 4% of the market with 2.259.741 m3/d;
- Qatar - 3% of the market with 1,712.886 m3/d;
- Japan - 2% of the market with 1.493.158 m3/d;
- Australia - 2% of the market with 1.184.812 m3/d.

These countries are all in climates with hot and dry deserts but with the financial means to invest in desalination plants. According to IDADESAL the main uses for the desalinated water are:

- Cities - 67% - 42.041.086 m3/d;
- Industries - 23% - 14.314.969 m3/d;
- Energy - 6% - 3.707.703 m3/d;
- Agriculture - 2% - 1.100.066 m3/d;
- Tourism - 1% - 890.261 m3/d;
- Military - 1% - 603.758 m3/d.

There are few examples of CSP driven desalination plants (and even less on a commercial level):

- MED plant in PSA, Almeria, Spain (parabolic troughs, CPC collectors)
- MD plant of Acuamed, Carboneras, Spain (high concentration CPC collectors)
- MED plant of Acquasol[4], Point Paterson, Australia (parabolic troughs)
- MSF plant, Kuwait (parabolic troughs)

2.8.3 Technology Trends

Besides MSF and MED some other technologies have been considered and that are interesting to mention on this brief overview.

Multiple Effect Humidification (MEH) desalination units indirectly use heat from highly efficient solar thermal collectors to induce evaporation and condensation inside a thermally isolated, steam-tight container. The solar thermally enhanced humidification of air inside the box separates water and salt, since salt and dissolved solids from the fluid are not carried away by steam. When the steam is recondensed in the condenser, most of the energy used for evaporation is regained. This reduces the energy input for desalination, which requires temperatures of between 70 and 85°C. Over the years,

[4] Source: http://anz.theoildrum.com/node/3926

there has been considerable research carried out into MEH systems and they are now beginning to appear on the market.

Membrane distillation (MD) is a separation technique, which links a thermally-driven distillation process with a membrane separation process. The thermal energy is used for turning water into vapour. The membrane is only permeable to the vapour, and separating the pure distillate from the retained solution. Fraunhofer ISE is developing solar driven compact desalination systems, using MD for capacities between 100 and 500 l/day, and larger systems ranging up to 20 m³/day.

All systems are solar energy-driven, but could also be operated with waste heat. The electricity for auxiliary equipment, such as pumps and valves, could be supplied by photovoltaic modules.

The technologies using solar thermal energy for desalination are more than those covered here, but only those that can be coupled with CSP were covered. CSP thermal driven desalination is still in infant stages and it is advised to use a CSP power plant to generate power and use the waste heat to drive a desalination plant instead of going for a CSP dedicated desalination plant where the solar field will generate the heat/steam. As mentioned above there are no specific collectors designed for desalination or any track record, so MED or MSF concepts should be implemented with the source of heat being from a solar power plant.

2.9 Summary

In summary, Concentrated Solar Power plants capture and concentrate the solar beam irradiance to produce high temperatures suitable for thermodynamic conversion to work and electricity. The conversion from heat to work or electricity uses conventional power blocks commonly found in fossil fired power plants: heat engines, steam turbines, gas turbines or Stirling engines. As such, CSP can be standalone, hybridised with or boosters of, conventionally fuelled plants.

Moreover, since CSP has a thermal basis, it can be a source of industrial process heat and interfaces easily and economically with essential thermal process industries such as desalination, enhanced oil recovery and chemical industries.

Importantly and alone of all renewable sources, CSP benefits from commercially viable and commercially proven thermal storage; enabling 24/7, baseload CSP operations and hence dispatchability of the electricity produced throughout the day and year.

Over the past decades, four main CSP technologies have been developed that differentiate from each other by the method of collection and delivery of heat to the power block: parabolic trough technology with synthetic heat transfer fluid, Linear Fresnel technology with direct steam generation, Power tower technology with either direct steam or salt heat transfer fluids and parabolic Dish technology with either steam engines or Stirling engines. The four technologies have demonstrated and implemented differing capabilities and operational parameters. Parabolic troughs, the most mature technology, can reach

390°C and integrates storage; Linear Fresnel is a lower cost, direct steam technology that has also been applied as hybrid and booster to coal fired plants; Power towers have demonstrated higher temperature operation (>800°C), can use various heat transfer fluids- steam, air, sand, molten salts – and easily accommodate high storage capacities; and dish and dish/Stirling have been developed as standalone and distributed systems with sizes from 1kW to 250kW.

From a commercial point of view, and thanks to their greater maturity and industrial experience, parabolic trough plants have dominated the concentrated solar thermal power industry for the last two decades, winning the confidence of utilities and investors. By the same token, the technology is expected to record incremental changes in performance, typical of later technology development cycles. Therefore, this dominant position in the technology landscape is poised for change. Power towers, with their higher power block efficiencies, less demanding storage requirements, plant design simplicity, and higher yearly output, provide a clear path to electricity cost competitiveness. For Fresnel systems, capital cost reduction, reliance on simple commodity components, possibility of greater local industry participation and ease of hybridisation, also propose a well demonstrated, if not fully commercially accepted, path forward.

Despite their early promises, unquestionably highest electricity conversion efficiency, and possibilities for small scale distributed applications, dish/Stirling systems, lacking commercial storage solutions and/or hybridisation, have lost ground and are not likely to play a prominent role in the utility scale CSP power plant industry worldwide. It is becoming more apparent that a clear focus on storage (up to 24/7) and clear dispatchability of the power generated is driving the CSP market as well as future technological directions and innovations. In this perspective, power towers and Fresnel systems are well placed to go beyond the limitations of parabolic trough technology. The latter will require a step improvement if it is to maintain its market position.

Through its past activities in the Spain and USA markets, the CSP industry has developed a robust, adequately populated value chain – from technology developers, engineering and component providers, to project developers, financiers and vertically integrated companies. Further players are entering the industry as other countries and continents contemplate this promising industry sector, especially in Asia, North and Southern Africa, the Middle East and Australia. CSP Market opportunities are in effect scattered through all continents in areas where the solar resource is sufficient and where energy needs, energy self-sufficiency and/or regulatory requirements are paramount. At present the clear trend of projects worldwide is towards technology providers proving their ability and deployment of known configurations that meet these needs rather than a sustained trend of innovation to bring down the levelized costs of generated power.

This expansion of the CSP industry beyond traditional countries is leading to a truly global industry that is able to provide and plan for a substantial and leading role in utility scale solar energy generation and renewable energy scenarios worldwide for the decades to come.

3 Solar Resource of Namibia

Concentrating solar power (CSP) plants must focus sunbeams on a collector to generate high temperatures. Only direct radiation from the sun can be concentrated this way. This makes CSP plants more sensitive to atmospheric conditions than if they could also use diffuse radiation, as with flat-plate collectors (PV or thermal). This is because diffuse radiation normally varies in the opposite direction of direct radiation. Therefore, direct normal irradiance (DNI) is much more sensitive to clouds or aerosols in the atmosphere than global irradiance (i.e., the sum of the direct and diffuse components of radiation), which is the “fuel” for fixed mounting collectors. This means that an area with a good solar resource in global horizontal irradiance (GHI), which would be satisfactory for fixed mounting collectors, is not necessarily suitable for CSP projects. (The resource for *tracking* flat-plate collectors is larger than GHI and may even be larger than DNI, particularly in the case of 2-axis tracking collectors; therefore, any comparison of the resource available for different solar technologies must be done with care.)

3.1 Solar resource and dynamics

It is common observation that thick clouds completely block the sunbeams, so that DNI drops to zero under such clouds. This is why CSP plants can only be built in regions of low cloudiness. Under cloudless conditions, aerosols are the most important atmospheric constituents that can attenuate DNI. Aerosols are composed of various particles in a large range of sizes. They include sea salt in suspension, sand dust, and many other particles generated by vegetation (e.g., pollen), volcanic activity, anthropogenic emissions (pollution), smoke, etc. Only extremely dense aerosol clouds (such as under sand storms or intense smoke episodes) can nearly completely attenuate DNI. In general, and particularly over areas of high potential for CSP projects, aerosols are barely noticeable. Under such low-aerosol conditions, horizontal visibility is excellent (more than 50 km) and the sky color is dark blue. On days with much higher aerosol loads, the sky becomes hazy (whitish) and visibility decreases significantly. Such conditions greatly affect DNI too. Aerosols move much slower than clouds, so that both very clear and very hazy conditions may last hours, if not many days.

It is obvious from the above discussion that the best solar resource for CSP projects is observed in areas where both cloudiness and aerosols are as low as possible. Furthermore, dry areas tend to have a better DNI resource than humid areas. Similarly, the proper quantification of the solar resource in the absence of local irradiance measurements requires precise information on clouds, aerosols and humidity at any instant. Models do exist to turn this information into estimates of DNI, and such radiative models are widely used in solar resource assessments. What currently limits the accuracy of the DNI estimates offered by data providers is the inherent uncertainty in the underlying data—cloudiness and aerosols most importantly. Improved information on the quality, quantity and variability of aerosols is among the essential goals in current solar resource research, as the literature shows (see, e.g., Cebecauer et al., 2011a, 2011b; Gueymard, 2012b; Stoffel et al., 2010; Xia et al., 2007; Xu et al., 2011). Regular improvements in the way satellite imagery can be used to derive more precise information about clouds and their effect on surface irradiance are also proposed in the literature (e.g., Cebecauer et al., 2010; Dagestad and Olseth, 2007; Girodo et al., 2006; Mueller et al., 2002, 2011; Perez et al., 2010; Polo et al., 2012; Wyser et al., 2002; Zarzalejo et al., 2010), or are directly implemented into proprietary methodologies by commercial data providers.

Among other things, this chapter offers background information on the modeling of solar irradiance and how clouds and aerosols affect it. The aerosol regime over southern Africa, and Namibia in particular, the challenges presented by their precise characterization, and how they can affect the modeled DNI estimates, are topics that are detailed in Annex 2.

3.1.1 Global Horizontal Irradiance and Direct Normal Irradiance

Direct normal irradiance (DNI) is the fraction of the downward flux directly emanating from the sun disk that is incident on a plane normal (i.e., perpendicular) to the sunbeams, and that has not undergone any extinction through the atmosphere. In contrast, global horizontal irradiance (GHI) is the sum of the projected DNI on a horizontal surface and of diffuse horizontal irradiance (usually referred to as DHI), which is the downward flux emanating from the sky vault, excluding the sun. These definitions lead to the basic closure equation:

$$G = B\cos(Z) + D \qquad (1)$$

where *G* is GHI, *B* is DNI, *D* is DHI, and *Z* is the sun's zenith angle. The latter is an astronomical quantity, thus purely deterministic. For identification purposes, Figure 3.1 shows actual traces of the measured *G, B* and *D* during a partly cloudy day at a high-elevation site (Golden, CO), when the morning was cloudless and the afternoon overcast. Note that, around solar noon and under the cloudless conditions then prevailing during this summer day, GHI was larger than DNI, because *D* and *Z* were low, thus cos(*Z*) was large (≈1). During cloudless winter conditions, when cos(*Z*) is much smaller, the reverse is true, since *D* is still small.

On an instantaneous basis, the SI unit of all these irradiances is W/m^2. This unit is also customarily used for hourly average irradiances, a very common format for solar data, e.g., in measured or modeled data series, or Typical Meteorological Years (TMYs). For daily, monthly or annual cumulative energy totals or averages, the term irradiance is replaced by irradiation, and the unit is either MJ/m^2 (SI) or kWh/m^2 (more pragmatic, and thus more frequently used). The conversion between these two units is 1 kWh/m^2 = 3.6 MJ/m^2. In practice, monthly and annual irradiations are either expressed as totals in kWh/m^2 per month or year, or as averages in kWh/m^2 per day. Figure 3.2 shows the long-term monthly-average GHI and DNI irradiations at the same site as in Figure 3.1, demonstrating the seasonal effects caused by natural variations in *Z* and in atmospheric transparency. (Golden's latitude is ≈40°N; at latitudes closer to the equator, like in Namibia, the amplitude of the seasonal variations would be much less, particularly for GHI.)

CSP applications require a high DNI resource. As shown in section 3.3.1, the DNI resource of Namibia is excellent, reaching ≈3000 kWh/m^2 over large areas. This is comparable, if not better, than that of South Africa, and much better than that of Spain, for instance.

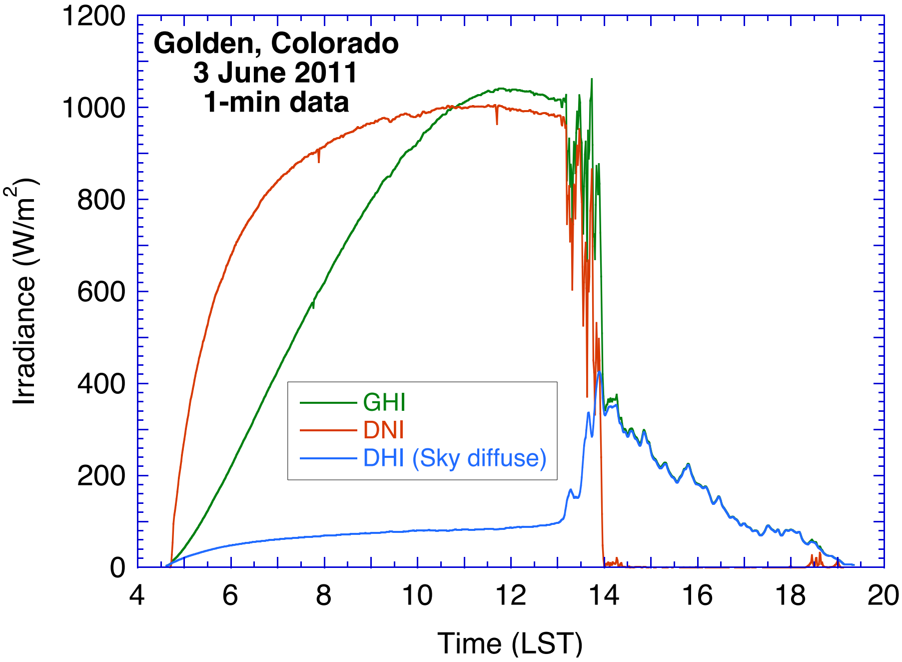


Figure 3.1 - Variations of measured G, B and D during a summer day at a high-elevation site.

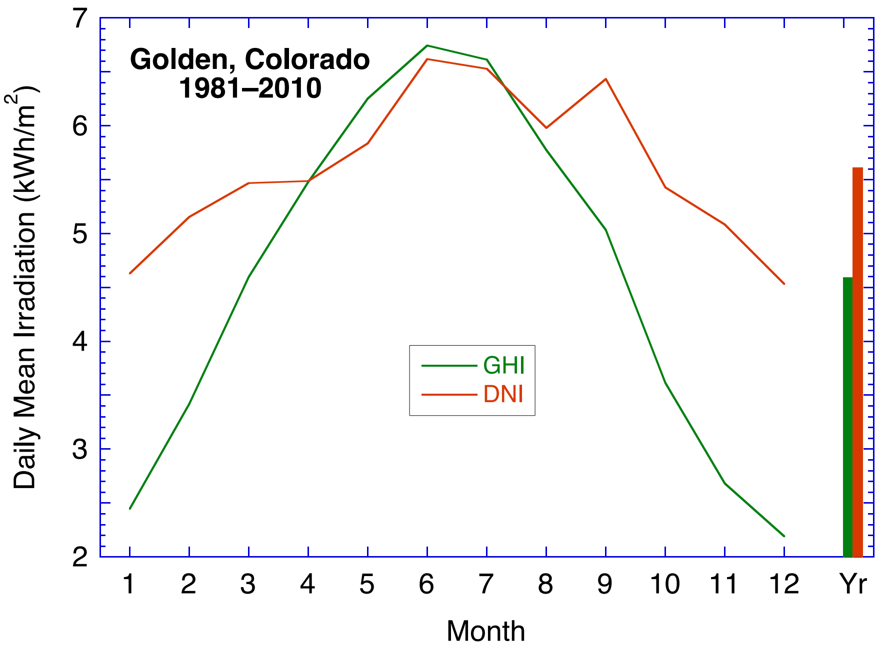


Figure 3.2 - Long-term 30-year monthly-average global and direct measured irradiations at Golden, Colorado. Annual averages are indicated by color bars.

Because of the extinction caused by various atmospheric constituents, DNI is necessarily lower than the extraterrestrial normal irradiance, ETNI. The latter is equal to the solar constant multiplied by the sun-earth distance correction factor, which varies in the range ±3.3% during the year. The solar constant is now estimated at 1362.2 W/m2, based on the latest satellite measurements (Gueymard, 2012a). Similarly as DNI, GHI should also be smaller than the extraterrestrial horizontal irradiance, ETHI, which is equal to the product of ETNI and cos(*Z*). Although this is always true under clear skies, transient GHI values larger than ETHI can occur under partly cloudy conditions and high sun, because of the cloud enhancement (or "cloud lensing") effect. This is illustrated in Figure 3.3. Note that this effect is short lived, and is therefore barely noticeable in hourly-average observations. The effect is caused by a natural concentration of diffuse radiation between the bright sides of vertically extended clouds, such as towering cumulus. Note that DNI is also affected, but to a much smaller extent, due to a slight increase in circumsolar radiation within the (narrow) field of view of the instrument. This effect can seriously affect the design of PV installations (Luoma et al., 2012). Conversely, since the measured effect of cloud enhancement on DNI is small, and also since the field of view of CSP systems is much smaller than that of radiometers measuring DNI, the cloud enhancement effect on CSP is normally negligible.

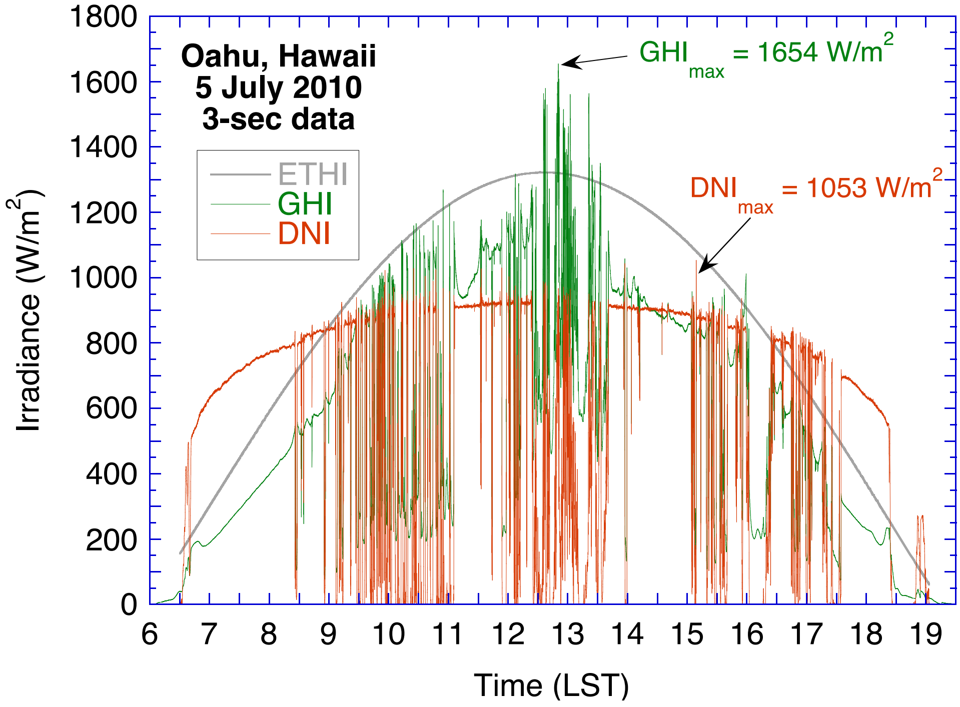


Figure 3.3 - Transient cloud enhancement effects during a partly cloudy summer day.

Besides the strong extinction caused by clouds and the geometrical effect of *Z*, which are both obvious in Figure 3.1 and Figure 3.3, GHI and DNI are affected by the local site pressure (extinction is less at high-elevation sites), by stable atmospheric gases (such as oxygen), and by variable constituents of the atmosphere, most importantly aerosols, water vapor and ozone. Under cloudless conditions, aerosols are the main source of extinction for DNI, about 3–4 times stronger than for GHI. Accurate modeling of DNI thus requires good aerosol data, whose sources are discussed in the following sections. For background information about the aerosol optical characteristics, how they are measured, and a definition of the aerosol optical depth (AOD), see Annex 2 first. Furthermore, note that the results of the aerosol analysis described in Annex 2 have been used to improve the modeling of DNI and GHI, with the method described in section 3.2.

3.1.2 Sources of aerosol data

There are currently three different sources of AOD data, as reviewed below.

3.1.2.1 Ground observations

The AOD at multiple wavelengths can be derived from spectral irradiance measurements obtained with ground-based sunphotometers. Such instruments report the best possible data of this kind, thanks to regular calibration and maintenance. This is why this type of data is widely used as ground truth for the two other sources of AOD data described below. Automated stations have started operations in the mid-1990s, usually under the auspices of international networks such as NASA's AERONET, WMO's GAW, or SKYNET[5]. As discussed below, there are some AERONET sites in southern Africa, but no GAW or SKYNET station. (There are obviously other stations monitoring usual meteorological variables in Namibia.) Obviously, some data points may be erroneous due to instrument problems, incorrect cloud detection, etc., which means that "ground truth" should not be interpreted as "perfect data". Still, most incorrect data points from AERONET are effectively removed using quality control processes that have been devised to produce the "Level 2" (highest quality) data. Only such "Level 2" data are used in what follows.

Because of its diverse scientific goals, AERONET is not just about long-term aerosol monitoring at permanent sites. Although hundreds of AERONET sites in the world have reported data so far, most of them have been short lived, typically recording data during a few weeks for a specific scientific field campaign. In southern Africa, one such field campaign was the Southern African Regional Science Initiative[6] (SAFARI 2000). In Namibia, only three AERONET stations exist or have existed. From north to

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[5] http://aeronet.gsfc.nasa.gov, http://gaw.empa.ch/gawsis/, http://atmos.cr.chiba-u.ac.jp/, http://skyrad.sci.u-toyama.ac.jp/, http://www.euroskyrad.net/.

[6] http://daac.ornl.gov/S2K/historical_UVA_edited/index.html, http://daac.ornl.gov/S2K/safari.shtml.

south, Etosha Pan (near the southwest edge of the large salt desert of the same name) has provided data from 8/2000 to 6/2001; Henties Bay has only recently (11/2011) started operations; and Swakopmund has provided data only during 9/2000. A fourth AERONET station, Sesheke, Zambia, was located across the river and only less than 1 km from Katima Mulilo in northern Namibia. The Sesheke station collected only 4 months of usable data in 1997. There are other stations in bordering countries, but most of them were only set up for the SAFARI 2000 campaign and thus have accumulated only short series of data, typically 1–3 months in 2000.

Figure 3.4 shows the location of all stations of interest for this study, whose data have been used as ground truth. The only stations that have accumulated a significant amount of data are Mongu, Zambia (1995–2010); Skukuza, South Africa (1998–2011); and Wits University, South Africa (2002–2009). Because most other sites were implanted for SAFARI 2000 during the fire season, it must be borne in mind that smoke conditions are heavily over-represented in the ground-truth data. Consequently, no particular station is representative of what could be considered a good site for CSP applications, which is a serious limitation.

This dearth of reliable data in or around Namibia is a hindrance for the development of highly accurate solar resource datasets and maps in the region. In addition to Swakopmund, at least two more permanent stations (one in the north and at least one in the south) would be needed to improve the current AOD estimates in Namibia. Ideally, each of these stations should be collocated with a weather/radiometric station measuring all broadband irradiance components, particularly DNI. Suggesting locations for these aerosol-only or combined aerosol/radiometric stations is beyond the scope of this chapter, but a recent study offers interesting tools to that effect (Shi et al., 2011). Of course, proper resource assessment for CSP applications requires weather/radiometric stations at potential sites, as described in chapter 12. Because of the added costs and difficulties, such stations do not usually include the necessary instrumentation to simultaneously measure AOD, unfortunately. For this reason, the measurement of AOD is normally undertaken by scientific institutions involved in atmospheric physics, remote sensing, and/or climate modeling.

Figure 3.4 - AERONET sites in and around Namibia.

3.1.2.2 Spaceborne observations

There are a few satellites currently carrying spectoradiometers specially developed to observe AOD in a few spectral bands. The best known of these instruments are MODIS and MISR, which fly on the same polar orbiter (Terra). Compared to ground stations, spaceborne observations have the considerable advantage of a large geographical coverage (most of the planet) and virtually no downtime. Moreover, these instruments can evaluate clouds, active fires, ground reflectance, among other important remote sensing tasks. Figure 3.5 illustrates the importance of the information contained in MODIS imagery in relation with the sources of aerosols over Namibia: dust from its deserts (particularly in June each year) and smoke from wildfires during the fire season (mostly August-September).

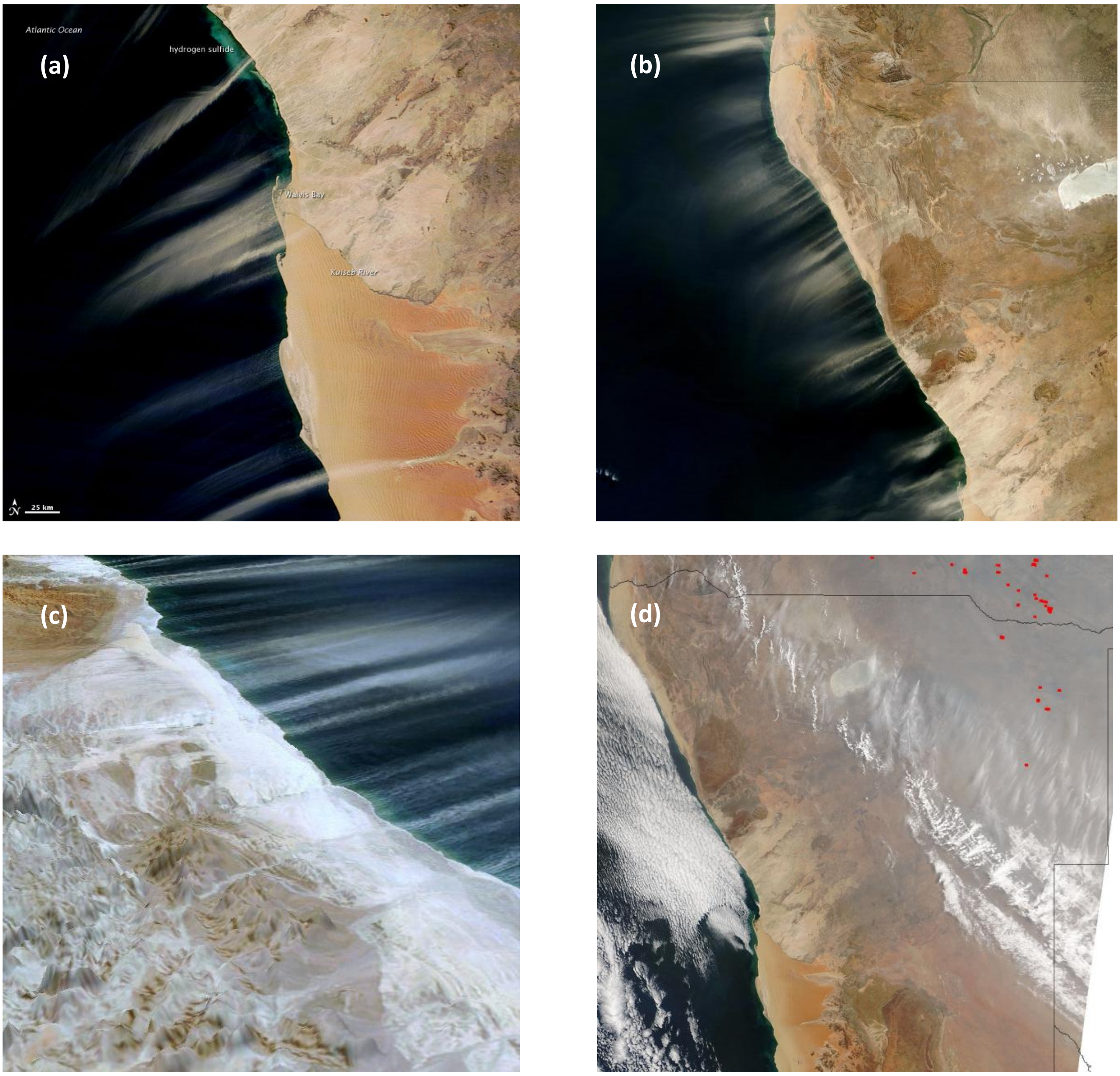

Figure 3.5 - (a) Dust clouds on June 17, 2010; (b) Dust clouds on June 9, 2004 (looking down); (c) White dust clouds on June 9, 2004 (looking south from the Kaokoveld Mountains); (d) Active wildfires (red dots) on Sep. 7, 2005. Source: MODIS/NASA.

The dramatic imagery shown in Figure 3.5 may give the impression that aerosols are easy to detect from space. In reality, this is only true for sufficiently dense plumes of dust, smoke, or volcanic particles. For typical low turbidity conditions over clean areas, the signal reflected by aerosol layers and sensed from space becomes faint, and therefore difficult to assign an accurate AOD value when other signals (such as clouds or highly reflective ground) are much stronger. These difficulties, as well as various sampling issues (Levy et al., 2009), explain why spaceborne AOD data series are not spatially complete, and not accurate (Levy et al., 2010). The retrieval algorithms must assume some optical characteristics of the aerosol type and surface reflectance, which might be in error. Ground-truth data (as reviewed in the previous section) is an important asset to validate spaceborne AOD retrievals, and optimize their algorithms.

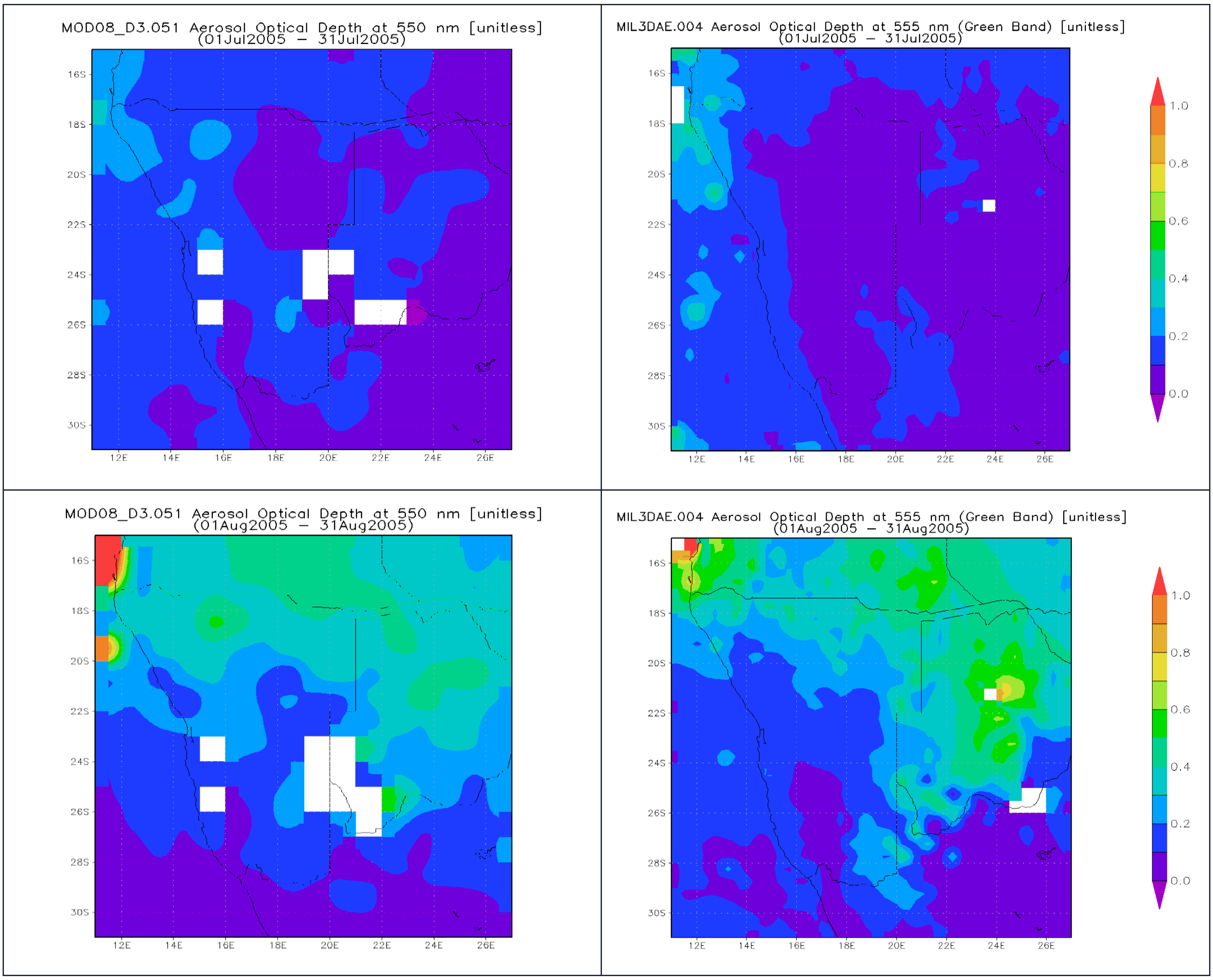

Figure 3.6 - Monthly mean AOD at ≈550 nm as retrieved by MODIS (left plots) and MISR (right plots) during July and August of the 2005 fire season (top to bottom). Source: http://gdata1.sci.gsfc.nasa.gov/.

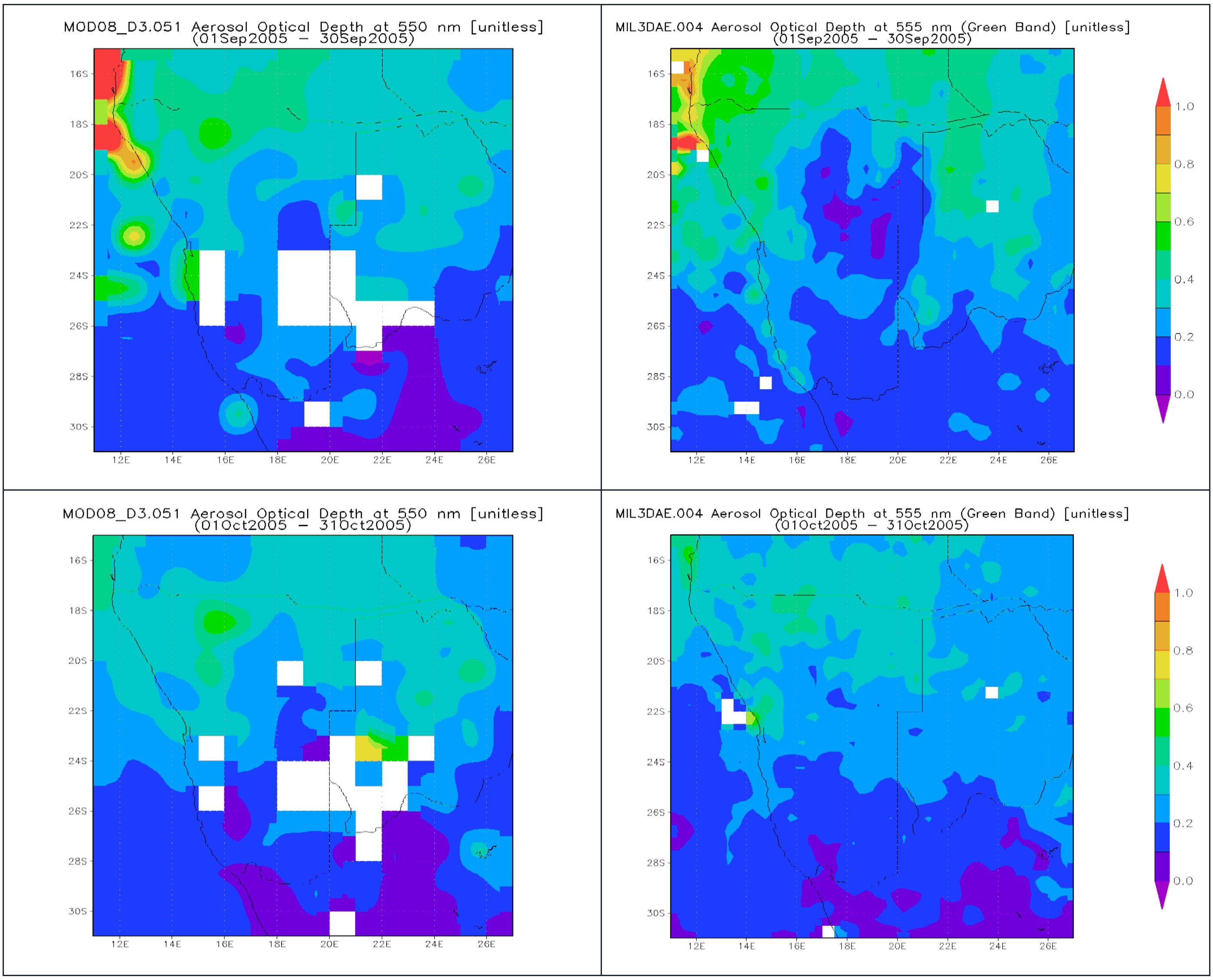

Figure 3.7 - Monthly mean AOD at ≈550 nm as retrieved by MODIS (left plots) and MISR (right plots) during September and October of the 2005 fire season (top to bottom). Source: http://gdata1.sci.gsfc.nasa.gov/.

Figure 3.6 and Figure 3.7 show the mean monthly AOD at ≈550 nm as retrieved by MODIS and MISR during the 2005 fire season. These observations reveal that a strong north-south gradient can be expected from August to October, since most smoke clouds originate from areas north or northeast of Namibia. Figure 3.6 and Figure 3.7 also illustrate the difficulties associated with spaceborne AOD observations:

- There are always missing data (white squares)
- There are large spatial and temporal gradients
- Two different instruments may yield significantly different results, even if observing the same region from the same satellite.

MODIS and MISR provide daily data at high native spatial resolution (typically 1×1 km, depending on instrument and processing level). However, because their platforms are polar orbiters, and because AOD retrievals cannot be made over a cloudy scene, the daily AOD datasets contain a large fraction of missing pixels. For that reason, only the monthly products can be used for solar radiation mapping. The time aggregation (monthly means) and spatial aggregation (1×1° final resolution for MODIS and 0.5×0.5° for MISR) eliminates most of the missing pixels—but not all of them, as confirmed by Figure 3.6 and Figure 3.7. It is emphasized that current spaceborne remote-sensing techniques cannot provide *hourly* AOD data, which would be desirable for CSP applications, and for computerized simulation of solar systems in general. Therefore, the radiative models used by solar resource data providers to obtain long-term irradiance time series at hourly or sub-hourly time intervals cannot be utilized optimally. In most cases, such time series are based on monthly-average AOD data, or even worse, on long-term monthly climatological AOD values. Such extreme simplifications are known to affect the frequency distribution of DNI by artificially lowering the frequency of high-DNI occurrences (Cebecauer et al., 2011b; George et al., 2007), which constitutes a serious hindrance for CSP applications. For the solar resource maps and datasets developed here for Namibia, daily AOD data have been used whenever possible (see section 3.2.1 and Annex 2.)

3.1.2.3 Aerosol/chemical transport models

In this third category, AOD is not observed directly, but is calculated by dynamically combining different models and sources of information: (i) estimated time-dependent emission data for various species of particles and aerosol precursors; (ii) meteorological information (from general circulation models) related to their transport; and (iii) descriptions of the chemical processes involved in the formation, ageing and disposition of the different types of particles. This approach is sophisticated, and has a lot of potential since it can cover the world, with no missing data pixel, over extended periods of time, including before 2000, i.e., before the "modern" spaceborne-AOD era when MODIS and MISR started operation. The uncertainties in the inventories of all aerosol precursors released in the past at any location and moment, as well as the complexity of all transport and chemical mechanisms involved, makes the modeled AOD results generally of lower accuracy than those from satellite observations. Moreover, the spatial resolution is coarser, and the AOD is generally derived at only one wavelength.

A notable exception is the MACC aerosol reanalysis and forecast system developed by the European Centre for Medium-Range Weather Forecasts (ECMWF), because it also uses an assimilation of MODIS data, which constrain the forecast results (of, e.g., AOD) at regular time increments (Morcrette et al., 2009). This dramatically improves the forecasts, as well as the past data (since these are derived from a reanalysis of forecasts at each time increment). Results from this model are available at various wavelengths, and with a spatial resolution of 1.125×1.125°, which is comparable to that of the monthly

MODIS products. The MACC data are available on a 6-hourly basis[7], which is another significant advantage to correctly evaluate the short-term variability in DNI. This is particularly important over areas where AOD is of high magnitude, because it is then also highly variable on a short-term basis (Cebecauer et al., 2011a, 2011b; Gueymard, 2012b). However, this model currently provides AOD data since 2003 only, and has not been extensively validated. Preliminary tests have shown that the MACC aerosol data can be considered “high quality”, and presumably more accurate than more conventional sources of aerosol data still used by most data providers to model DNI time series. Nevertheless, some residual bias is more than likely over many areas of the world. In the context of Namibia, the MACC model’s performance is evaluated in Annex 2.

3.1.3 Impacts of aerosol concentration on direct normal irradiance

As alluded to above, the main sources of aerosols that are anticipated to have a high radiative impact over Namibia are dust from deserts and smoke from wildfires. Such aerosols have both geographical and seasonal characteristics, which ultimately condition the spatial-temporal distribution of AOD. As described by comprehensive world maps (Justice et al., 2002), Namibia has its own share of wildfires, but is also close to (and thus largely affected by) one of the most important regions of biomass burning activity in the world, in central and eastern Africa (Figure 3.8 and Figure 3.9). Figure 3.9 shows the significant impact that wildfires in Zambia or bordering countries have on the AOD in Namibia, particularly over the northeastern part of the country.

[7] http://data-portal.ecmwf.int/data/d/macc_reanalysis/.

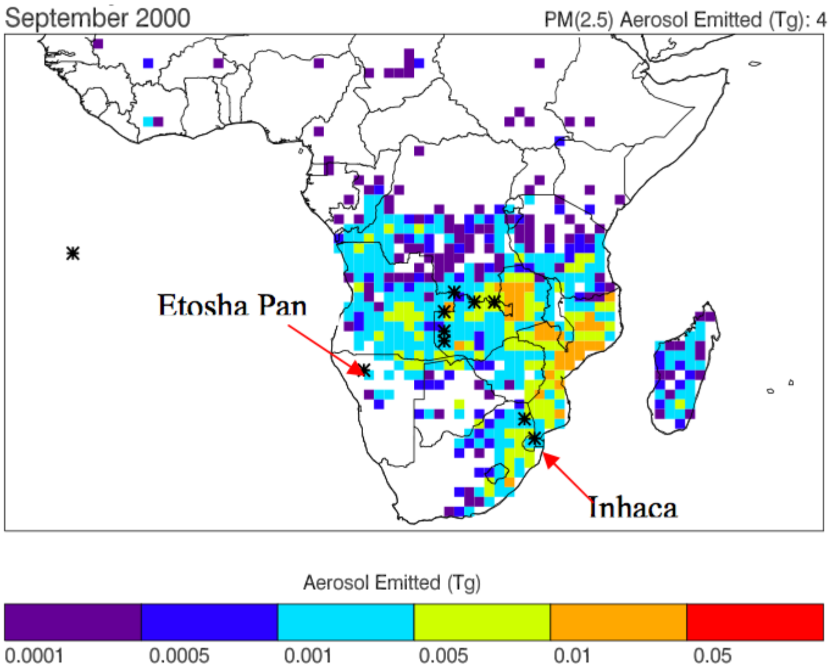

Figure 3.8 - Monthly mean aerosol emissions (in Teragrams) over central and southern Africa during September 2000. Source: Matichuk et al., 2004.

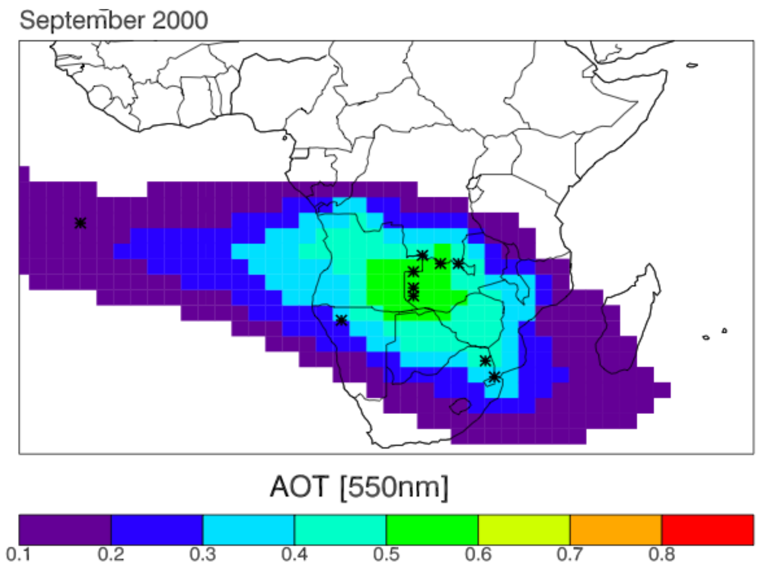

Figure 3.9 - Modeled monthly mean AOD at 550 nm for the month of September 2000. Asterisks identify AERONET sites. Source: Matichuk et al., 2004.

3.2 Geographical distribution of the solar resource in Namibia

3.2.1 Methodology

Solar radiation is most frequently evaluated with numerical models that use parameterizations of various atmospheric extinctions, and a set of inputs characterizing the cloud transmittance, state of the atmosphere and of its constituents, and terrain conditions. The methodology used here is described in several references (Cebecauer and Suri, 2010; Cebecauer et al., 2010; Suri et al., 2010), and is at the root of the SolarGIS datasets offered by GeoModel Solar s.r.o. (hereafter, GeoModel), the solar data provider that has been selected for this study. Requirements for bankability (in terms of uncertainty specifications and probabilistic results) are discussed elsewhere (Cebecauer et al., 2011b; Suri and Cebecauer, 2011).

In the SolarGIS approach, the first step consists in using the simplified SOLIS model (Ineichen, 2008) to evaluate the ideal clear-sky irradiance. This model allows fast calculations of clear-sky irradiances from a set of various input parameters, described below.

- Sun position, a purely deterministic variable, determined by time and astronomical equations.
- Variable (over space and time) concentrations of atmospheric constituents, namely aerosols, water vapor and ozone. The global atmospheric data for these constituents are routinely provided by world atmospheric data repositories (such as NASA) and delivered at a spatial resolution of about 125 km, as described below.
- For aerosols, daily AOD from the MACC model is normally used (see description in Section 5.1.2.3). Its important feature is that it captures the daily variability of aerosols, and allows a more precise simulation of the events associated with extremely low or high aerosol load (Cebecauer et al., 2011a). This reduces the uncertainty in hourly and daily estimates of GHI, and most importantly of DNI, and also guarantees an improved frequency distribution of irradiance values over time. However, the coverage of such daily aerosol data is limited to the period from 2003 onward. For the earlier years (1994 to 2002), monthly long-term averages must normally be used. For Namibia, the AOD obtained from the MACC dataset has been corrected to reflect the lower bias of the monthly AOD specially derived, per the analysis described in Annex 2. For each month, the inherent bias in the daily MACC data has thus been removed as much as possible. This guarantees a lower bias and uncertainty in the derived irradiance data of the final solar resource products.
- Water vapor is also highly variable in space and time, but has a lower impact on solar irradiance than aerosols. The daily GFS and CFSR (from NOAA NCEP) reanalysis data are used in SolarGIS from 1994 to the present.
- Ozone has only a minor effect on broadband solar radiation, so that approximate monthly values can be used.

- Cloudiness, which is the key factor determining the short-term variability of the final product (all-sky irradiance), is an essential input. Cloud extinction is expressed through a parameter called "cloud index", which is calculated from the routine observations of meteorological geostationary satellites. The spatial resolution of the METEOSAT data from the MFG and MSG satellites used in SolarGIS is about 4 x 4 km over Namibia. The time step (granularity) of the satellite data is 15 to 60 minutes, depending on satellite, and thus period. The cloud index is derived by empirically relating the radiance observed by the satellite in four spectral channels and the estimated surface albedo to the cloud optical properties. SolarGIS uses the modified Heliosat-2 calculation scheme to evaluate the cloud index from satellite imagery. A number of improvements have been introduced to better cope with specific situations such as snow, ice, or high albedo areas (arid zones and deserts), and also with complex terrain.
- To obtain the all-sky irradiance at each time step, the clear-sky global horizontal irradiance is coupled with the cloud index, a proxy for cloud transmittance. DNI is finally calculated from GHI using a modified version of the Dirindex model (Perez et al., 1992).

3.3 Map visualization – Annual and monthly values of DNI and GHI

3.3.1 Direct Normal Irradiation (DNI)

The documents needed for a rapid evaluation of the solar resource of Namibia consist of 12 monthly DNI maps and one annual DNI map, which all cover the 18-year period 1994–2011. The original DNI data resolution of ≈4x4 km is disaggregated using a Digital Elevation Model to the final spatial resolution of ≈3 arc-seconds (≈90 m). These 13 maps are provided in GIS layer format, so that further analysis is possible.

The long-term annual average of DNI (Figure 3.10) reveals that the best solar resource for CSP applications is concentrated in the southern half of Namibia. Some extended areas, particularly in the southwest part of the country, have an excellent annual resource, of about 3000 kWh/m^2 or 8.2 kWh/m^2 per day, which is better than that of most of South Africa, for instance.

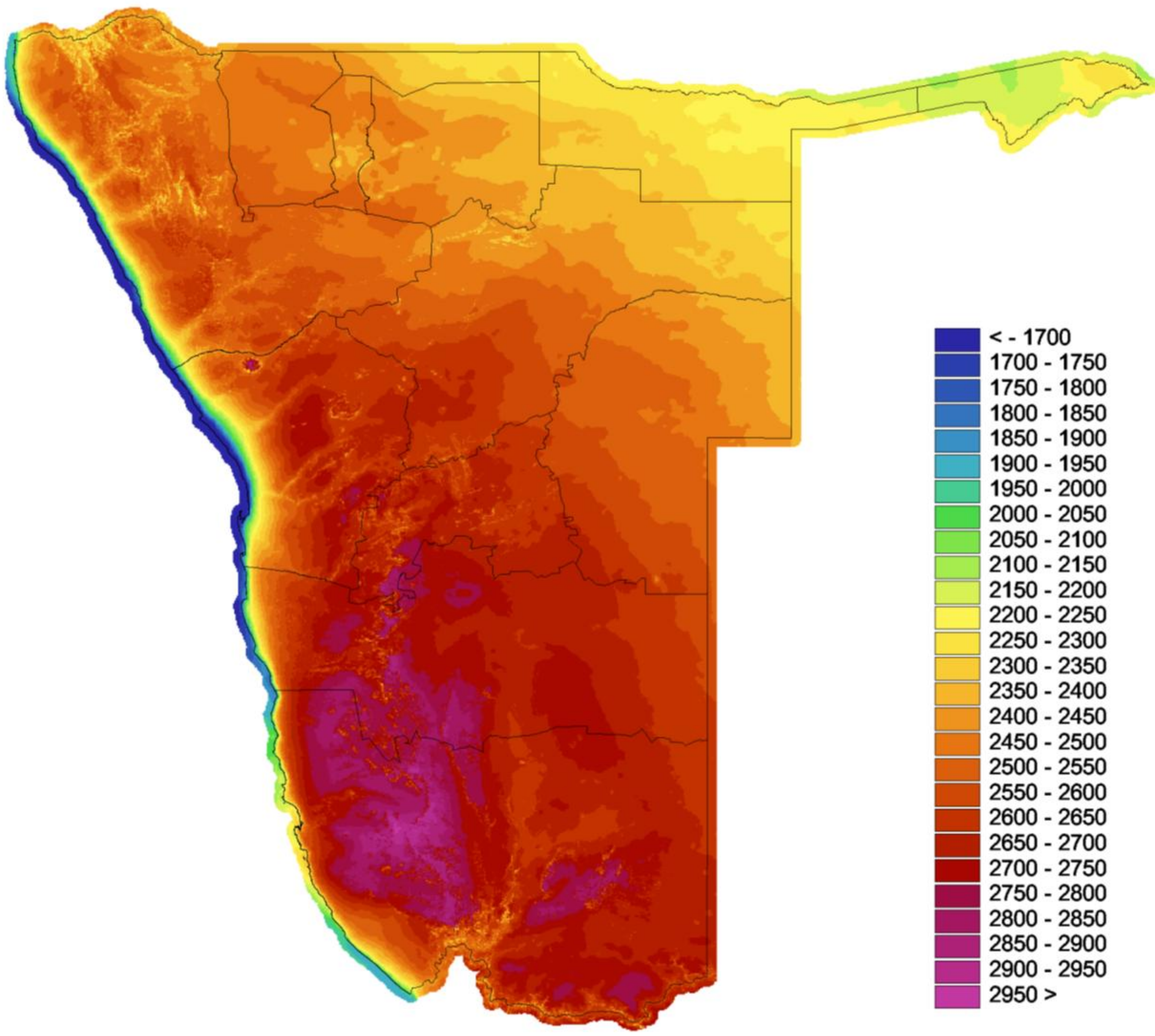

Figure 3.10 - Long-term annual average of DNI [kWh/m^2] over the period 1994-2011, based on SolarGIS v1.8 © 2012 GeoModel Solar.

3.3.2 Global Horizontal Irradiation (GHI)

Similar maps as above are provided for GHI, except that their resolution is ≈900 m. The long-term annual resource map (Figure 3.11) reveals a different pattern than for DNI in Figure 3.10: the best locations for fixed-mounting flat-plate collectors now appear concentrated over the western part of the country. An excellent potential of ≈2350 kWh/m2 is found over a large fraction of the country.

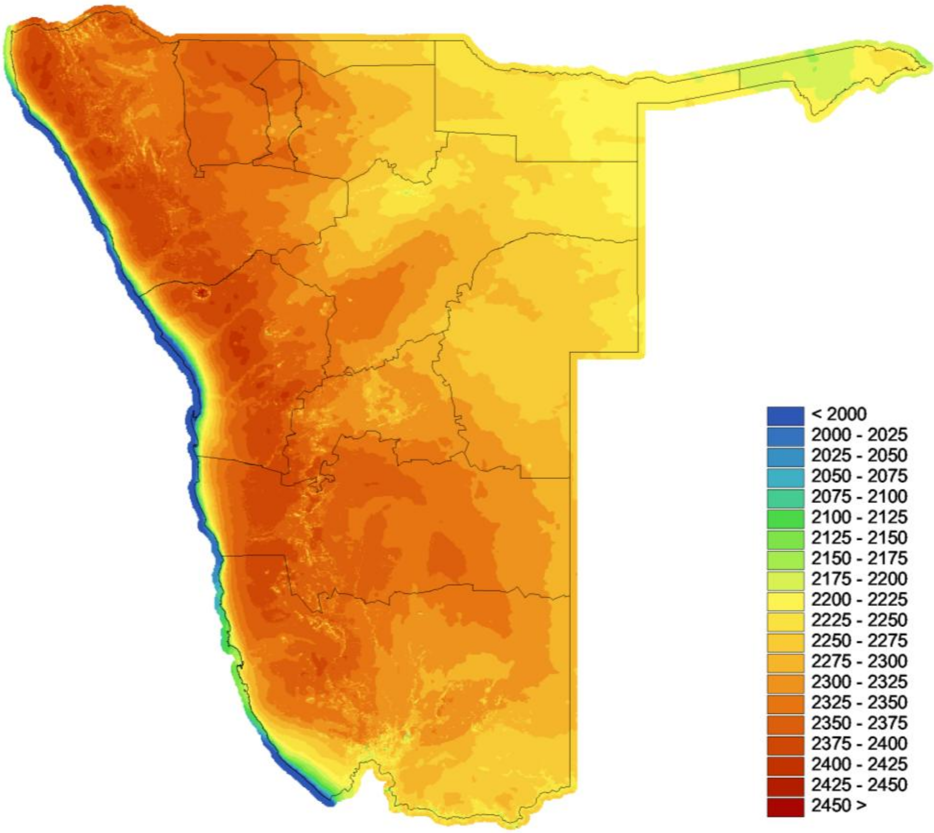

Figure 3.11 - Long-term annual average of GHI [kWh/m^2] over the period 1994-2011, based on SolarGIS v1.8 © 2012 GeoModel Solar.

3.4 Uncertainty and variability of DNI and GHI

3.4.1 Sources of uncertainty in modeled data

The accuracy of satellite-based DNI and GHI depends on that of the applied numerical models and of the data used as inputs to these models. More specifically, the overall accuracy of the modeled DNI and GHI depends on:

- The quality of the clear-sky model and its capability to properly characterize various states of the clear atmosphere;
- The level of detail of the satellite-derived cloud transmittance algorithm, and particularly to what extent it can differentiate clouds or fog from snow or ice. Over arid zones, where the surface is predominantly bare and with a relatively high albedo, a critically needed feature of the radiative model is a correct simulation of the complex multidirectional albedo behavior for various sun-satellite geometries;
- The universality of the diffuse/direct decomposition model;

- The accuracy, temporal and spatial resolution of the model inputs: availability, geometric and radiometric corrections of satellite imagery, resolving occurrences of artifacts in cloud data, appropriate spatial/temporal resolution and quality of aerosol and water vapor data, etc.;
- Spatial resolution and accuracy of the Digital Terrain Model (DTM).

Over semi-arid and desert zones (which are widespread in Namibia), the accuracy of the modeled solar resource data is mainly determined by the parameterization of the atmosphere, especially the proper quantification of aerosol and cloud attenuation. A quantification of the overall uncertainty in the modeled radiation data is described in section 3.4.3.

3.4.2 Interannual variability

Weather changes in cycles, and also has a stochastic nature. Therefore, the annual solar irradiation during a given year (or month) can deviate significantly from its long-term average. The interannual variability in DNI is much larger than that in GHI (Gueymard and Wilcox, 2011). For Namibia, the interannual variability in DNI is based on the analysis of the modeled data for the period 1994–2011. Figure 3.12 shows the spatial variation of this variability, expressed in terms of the normalized annual standard deviation, at a spatial resolution of ≈4 km. These results can be used to estimate the uncertainty in DNI that would result from using only one single year of data (modeled or measured), relatively to the long-term average.

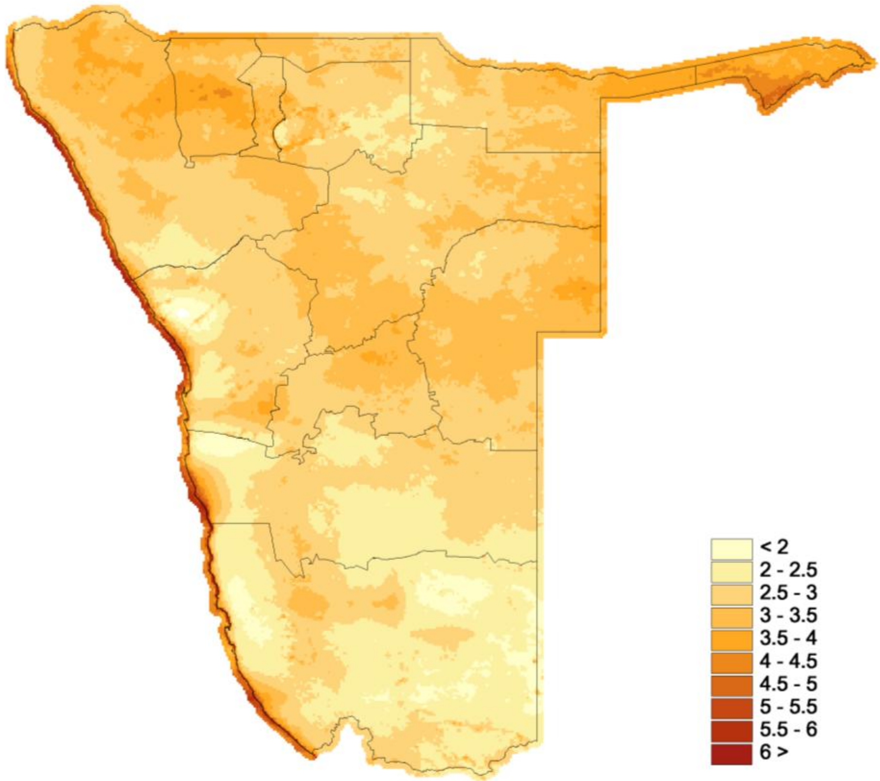

Figure 3.12 - Interannual variability (in %) of DNI during 1994-2011, obtained with SolarGIS v1.8 © 2012 GeoModel Solar.

The effects of possible man-induced climate change effects or natural events such as large volcanic eruptions are not present in the data. A slight decreasing trend of irradiance (usually referred to as “dimming”) has occurred over most of the Southern Hemisphere (including Namibia) since 1950 (Wild, 2009). It is difficult to predict if, or at what pace, this trend will continue during the next decades. An ongoing long-term DNI trend of ≈-1% per decade is a reasonable assumption. (This long-term trend is independent from the interannual variability.) Based on the existing scientific knowledge, the effect on DNI of extreme volcanic eruptions, with emissions of large amounts of stratospheric aerosols, can be estimated from the example of the Pinatubo event in 1991—the second largest volcano eruption of the 20th century. It can be expected (Lohmann et al., 2006; Gueymard, 2012b) that such a large eruption would induce an initial decrease of ≈16% in the annual DNI or more, followed by two other years of progressive recovery.

3.4.3 Solar resource uncertainty over Namibia

The accuracy of the SolarGIS database, version 1.8, has been compared with high-quality ground observations at almost 100 stations worldwide. The details of this validation can be consulted in a separate document[8]. The SolarGIS database demonstrated its high reliability and its superior quality compared to other solar databases on the market in a recent IEA-SHC Task 36 data intercomparison study (Ineichen, 2011).

Quality indicators of GHI and DNI, for some validation sites representing arid regions, are presented in Table 3.1 and Table 3.2. (The bias results appearing in irradiance unit in these tables are calculated for daytime hours only.) The bias for GHI is within ±2.3% and the hourly Root Mean Square Difference (RMSD) is below 16% at these stations. A representative annual average RMSD for arid zones in Namibia is thus estimated at 12–15%. For DNI, the uncertainty is higher than that in GHI, as could be expected. The bias reaches ±8.0% over arid areas, whereas the hourly RMSD is below 24.0% (except for Durban, which is located in a more humid region). The annual average RMSD for arid zones in Namibia is estimated to be in the range 18–22%. For both GHI and DNI, the much higher values of the hourly relative RMSD than the relative bias is a normal feature, which reflects the noise created in part by fundamental differences in the data pairs being compared: ground observations are spot measurements averaged over an hour, whereas modeled data are spatially averaged over the pixel containing the ground station, and are derived from one to four instantaneous satellite pictures taken during that hour.

Table 3.1 - Global Horizontal Irradiance – quality indicators for selected validation sites representing arid climates (source: BSRN, Eskom, and UKZN Howard College Durban).

	Bias		Root Mean Square Deviation, RMSD		
GHI	[W/m²]	[%]	Hourly [%]	Daily [%]	Monthly [%]
De Aar (South Africa)	8.2	1.8	11.5	6.9	2.5
Sede Boqer (Israel)	-5.9	-1.3	9.8	4.3	1.6
Sonbesie (South Africa)	-9.9	-2.3	14.8	9.0	7.1
Tellerie (South Africa)	-7.0	-1.4	14.8	9.0	7.1
Durban (South Africa)	4.5	1.2	15.5	7.5	3.6
Tamanrasset (Algeria)	0.0	0.0	8.5	4.6	1.8

[8] http://solargis.info/doc/_docs/SolarGIS_data_specification.pdf

Table 3.2 - Direct Normal Irradiance – quality indicators for the selected validation sites representing arid climates (source: BSRN, Eskom, and UKZN Howard College Durban).

DNI	Bias		Root Mean Square Deviation, RMSD		
	[W/m^2]	[%]	Hourly [%]	Daily [%]	Monthly [%]
Aggeneis (South Africa)	-24.7	-3.7	18.3	11.5	5.2
De Aar (South Africa)	-6.0	-1.0	16.8	9.9	2.4
Sede Boqer (Israel)	-34.1	-5.5	23.9	16.0	6.4
Paulputs (South Africa)	-53.6	-7.8	18.0	12.4	9.3
Sonbesie (South Africa)	-33.6	-6.4	20.1	12.1	7.8
Upington (South Africa)	-40.6	-6.0	19.7	12.4	7.8
Durban (South Africa)	-22.4	-5.8	32.2	20.3	8.0
Tamanrasset (Algeria)	24.5	3.9	21.6	16.4	5.6

For the sake of simplicity, the uncertainty and interannual variability are considered to behave statistically according to the normal distribution, even though this assumption is not perfect. For both indicators, the estimated range of values applies to ≈80% of the total number of data points (Table 3.3). For the calculation uncertainty, the provided range is estimated from an educated guess based on validation results over similar regions, and from a solid understanding of the model's behavior and of the quality and characteristics of the input data. Thus, the lower value of the uncertainty can be subtracted from the P50 values (represented by the GIS data layers), to calculate the P90 values, which are usually needed for bankability. In contrast, the interannual variability is calculated from the unbiased 18-year standard deviation of GHI and DNI (e.g., Figure 3.12) multiplied by 1.28155, thus again considering a normal distribution for the annual sums.

As discussed further in chapter 12, sophisticated numerical/statistical methods can be successfully used to optimally combine short-term local radiation measurements and long-term modeled data series. This is the only known way to reduce uncertainties in modeled DNI data to below 5% *a posteriori*, and thus produce solid bankable solar resource data and sound predictions of energy production with P90 or P95 probabilities of exceedance.

Table 3.3 - Range of uncertainty of SolarGIS DNI and GHI values for Namibia, based on the period 2003–2011. (N/A: not applicable)

SolarGIS data: Summaries	Direct Normal Irradiation		Global Horizontal Irradiation	
	Calculation uncertainty (%)	Uncertainty due to interannual variability (%)	Calculation uncertainty (%)	Uncertainty due to interannual variability (%)
Annual	6.0 – 8.0	2.8 – 6.5	2.5 – 3.0	1.2 – 2.3
Monthly	8.0 – 10.0	2.7 – 22.7	4.5 – 5.5	1.2 – 10.1
Hourly	18.0 – 22.0	N/A	10.0 – 16.0	N/A

4 Environmental Context

4.1 Stakeholder consultation and key constrains identified

The project team met with a large number of stakeholders to collect data and information for various aspects of the pre-feasibility study. The table below shows the stakeholders who were contacted to provide environmental-related information, as well as data & information required for the GIS-based site analysis. Data was collected for the GIS analysis from available resources as well as a few government ministries.

A meeting was held with the Environmental Commissioner of the Ministry of Environment and Tourism to determine whether a CSP plant could be established within a protected area. The answer was that such a proposal would need to be considered on a case by case basis, i.e. it depends on which protected area, where in the protected area, whether a significant amount of water would be required, etc. Such a proposal would also require consultation with the respective Park Manager.

4.2 Environmental legislation of Namibia

"The State shall actively promote and maintain the welfare of the people by adopting policies aimed at ...The maintenance of ecosystems, essential ecological processes and biological diversity of Namibia and utilization of living natural resources on a sustainable basis for the benefit of all Namibians, both present and future..." [Constitution of the Republic of Namibia - Article 95 (1)].

The above constitutional statement forms the basis of the environmental legislation framework in Namibia, and since then the government and its stakeholders have engaged each other in developing laws and policies to conform to the constitutional obligations.

The key environmental legislation in Namibia is the Environmental Management Act No. 7 of 2007. This law has now become fully operational since the appointment of the Environmental Commissioner in April 2012 and the public gazzetting of the Regulations in February 2012.

Table 4.1 – Stakeholders.

Organisation, Contact Person, and Type of Communication	Date	Project Team Representative	Summary
Ministry of Water, Agriculture and Forestry (MAWF)			
Meeting with Braam Van Wyk and briefly Maria Amakali	23.02.2012	C. Hartz, A. M. Garcia	Introductory meeting, abstraction of water requires assessment, effluent requires analysis, water act, contact with Dr, Koch requested
Email exchange with Braam van Wyk	30.03.2012	C. Hartz	Carter asked if there are general yield values associated with the different aquifer areas shown on the Hydrogeological Map.
Email exchange with Maria Amakali	22.03.2012	C. Hartz	Asked about discharge permit requirements
Calls and Email with G. Hailwa and A.Shishome	28.03.2012	D. Muroua	Introduced project and asked for information on Forest Reserves
Meeting with Mr. Koch	02.04.2012	C. Hartz	Introduced project, asked about permitting, asked for his thoughts on the availability of water for cooling.
NamWater			
Meeting with Hanjorg Drews, Chief Water Planner. Followed up with an email requesting information on 03.04.2012.	02.04.2012	C. Hartz	Introductory meeting, and I asked him if and where water would be available for cooling for 5MWe & 50MWe scenarios
NamPower			
Peter van Langenhoven, Manager of Van Eck power station	04.04.2012	C. Hartz	Learned where coal comes from that is supplied to Van Eck. Also learned about 1) feasibility study being performed for a proposed coal power station near Arandis, and 2) plans to rehabilitate Van Eck.
Ministry of Mines & Energy (MME)			
Meeting with Commissioner of Mines	28.03.2012	D. Muroua, C. Hartz	Introductory meeting and securing mining data and information
Email with Vicky N Do Cabo and Nico Snyders	28.03.2012	D. Muroua	Obtained GIS data relevant to mines
Ministry of Environment and Tourism			
Environmental Commissioner	11.04.2012	D. Muroua	Discussed project and potential issues of developing CSP in a protected park. Conclusion is that each site is to be treated on a case-by-case basis.
Fidelis Nyambe Mwazi	12.04.2012	D. Muroua	Obtained GIS flood information
National Planning Commission			
Timo Hangula - Bureau of Statistics	03.04.2012	D. Muroua	Introductory meeting and securing demographic data and information
Beverly Alexnander	05.03.2012	D. Muroua	provided national heritage register
Polytechnic of Namibia			
Bernard Siepker	29.03.2012	C. Hartz	Asked him for Namibian wind data.
RAISON Consultants			
John Mendelsohn (phone discussion)	15.03.2012	C. Hartz	Confirmed that WGS84 is the most commonly used coordinate system in Namibia
CSA - Internal Discussion			
Francois Smith (Roads Engineer)	28.03.2012	C. Hartz	Francois provided standard widths for road reserves, shoulders and lanes, and type of surface (gravel or bituminous) for different classifications of roads.

Listed below are additional Namibian laws and policies that are relevant to environmental management.

Acts:

1. Agricultural (Commercial) Land Reform Act No. 6 of 1995
2. Atmospheric Pollution Prevention Ordinance No. 11 of 1976
3. Communal Land Reform Act No. 5 of 2002
4. Environmental Management Act No. 7 of 2007
5. Forest Act No. 12 of 2001
6. Hazardous Substances Ordinance No. 14 of 1974
7. Marine Resources Act No. 27 of 2000
8. Mountain Catchment Areas Act No. 63 of 1970
9. National Heritage Act No. 27 of 2004
10. Nature Conservation Ordinance No. 4 of 1975
11. Plant Quarantine Act No. 7 of 2008
12. Soil Conservation Act No. 76 of 1969
13. Water Act No. 54 of 1956
14. Water Management Act No. 24 of 2004

Bills:

1. The Parks and Wildlife Management Bill
2. The Pollution Control and Waste Management Bill

Policies:

1. Desertification and biodiversity Policy
2. Drafts Wetlands Policy
3. Minerals Policy
4. Namibia's Draft Climate Change Policy
5. Namibia's Environmental Assessment Policy
6. National Agricultural Policy
7. National Drought Policy
8. National Forestry Policy

9. National Land-Use Planning Policy
10. National Policy on Human Wildlife Conflict Management
11. National Waste Management Policy
12. National Water Policy
13. Water Supply and Sanitation Policy
14. White Paper Energy Policy

4.3 Environmental Portrait and Framework of Namibia

4.3.1 Environmental Portrait

Namibia has a population of approximately 2.1 million (*Census of Namibia 2011*) and covers an area of 823,680 km^2 (Atlas of Namibia). Population density is generally highest in far northcentral regions. Namibia is the driest country in Sub-Saharan Africa (MAWF National Water Policy White Paper). Rainfall generally occurs during the rainy season of September – March. Rainfall amounts vary significantly from year to year. The largest annual rainfall occurs in the northwest, and the least along the western coast and in the south.

Namibia is a hot, dry country. Average annual temperatures are highest in the far north (more than 22 C) and lowest along the Atlantic coast (less than 16 C) (*Atlas of Namibia*). Relative humidity is high close to the Atlantic coast, but very low in the southeast (*Atlas of Namibia*). The lowest relative humidity occurs east of Keetmanshoop in the dry season, where it is less than 10%.

Five biomes exist in Namibia: Lakes & Salt Pans, Nama Karoo, Namib Desert, Succulent Karoo, and Tree & Shrub Savanna (Figure 4.1).

The Atlas of Namibia lists five important plant species: Welwitschia plant, Quiver Tree, Kiaat tree, Mopane tree, Devil's Claw plant, and Tsamma Melon plant. The figures below indicate where they are found in Namibia. The Welwitschia, Quiver Tree, Kiaat, and Devil's Claw are legally protected species. Large-scale harvesting of the Mopane trees requires a permit from the Namibian Directorate of Forestry.

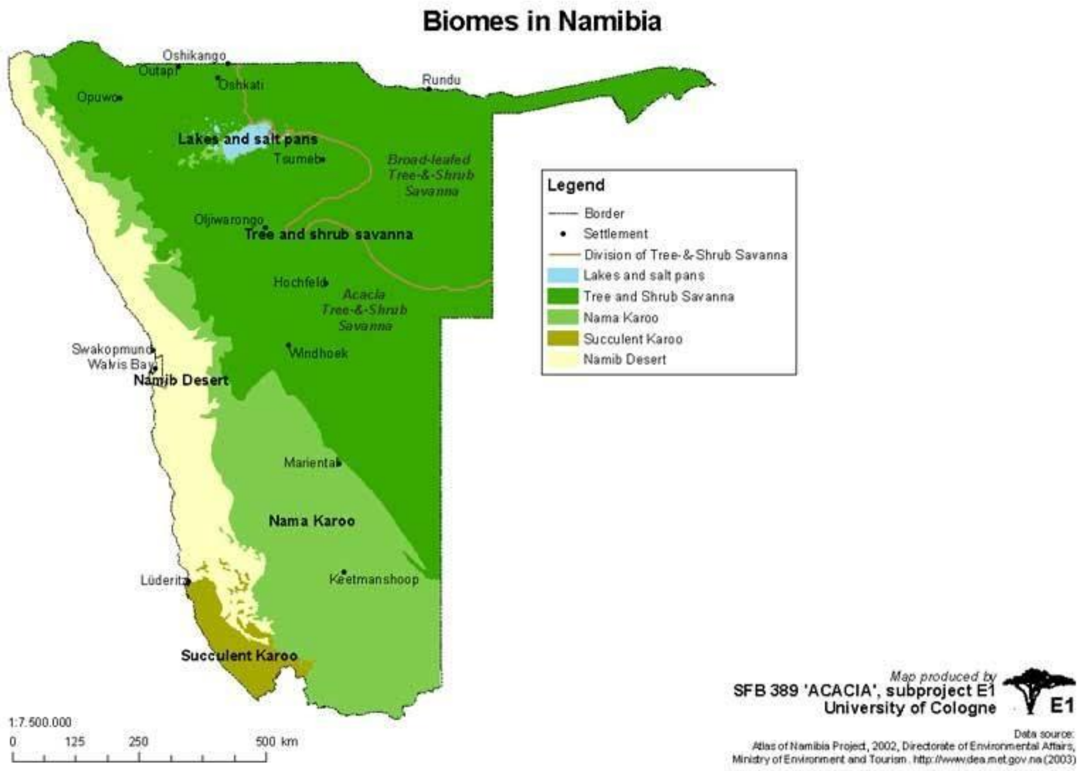

Figure 4.1 – Biomes in Namibia (*Atlas of Namibia*).

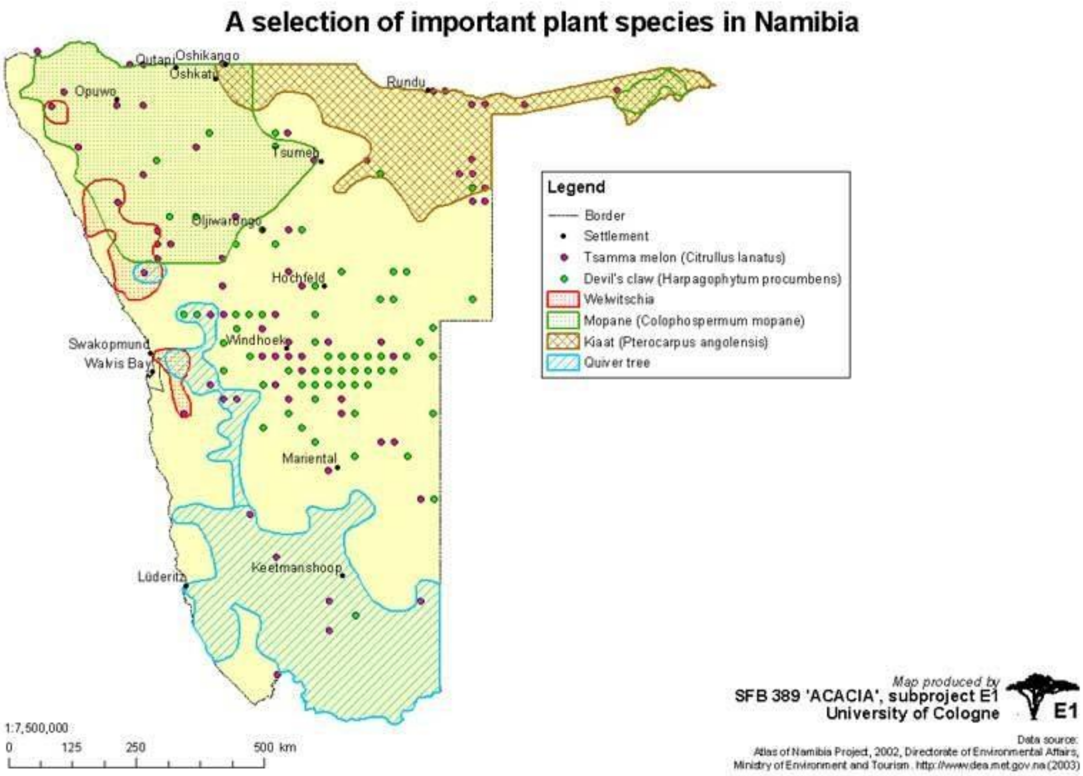

Figure 4.2 – Important plant species in Namibia (*Atlas of Namibia*).

There are approximately 220 species of mammals that live in Namibia, of which 8 species that are endemic to Namibia: Black Faced Impala, several mice, gerbils and bats (*Atlas of Namibia*). There are approximately 260 species of reptiles in Namibia, with the largest concentrations in north-central and the far north-east of the country (*Atlas of Namibia*). There are 30 species of lizards that are endemic to Namibia. (http://www.namibian.org/travel/namibia/wildlife.htm). There are approximately 60 species of scorpions that have identified in Namibia, with the largest concentrations found in the central-east and south-central parts of the country. Approximately 650 birds have been identified in Namibia, of which approximately 70% live and breed in Namibia (*Atlas of Namibia*). 14 bird species are endemic to Namibia. The following figure shows overall terrestrial endemism throughout Namibia.

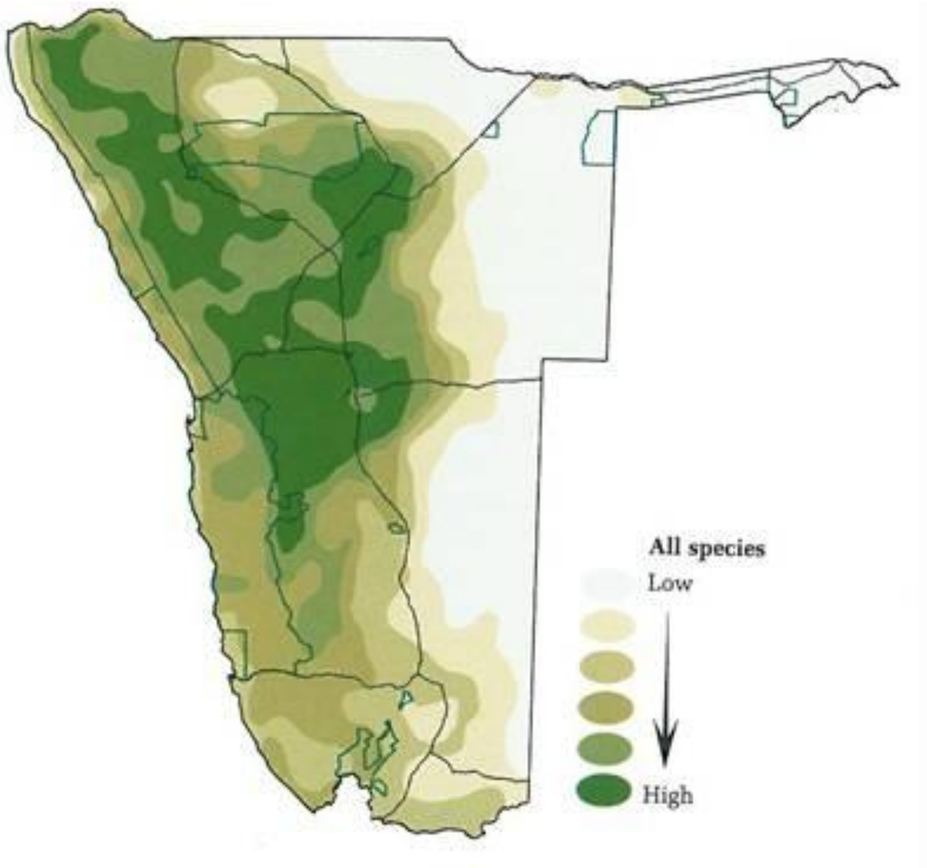

Figure 4.3 - Overall Terrestrial Diversity throughout Namibia (*Atlas of Namibia*).

Namibia has a vast protected area network where plant and animal life are allowed to flourish. The most famous of the Namibia's parks is the Etosha National Park which is located in north-central Namibia. In Etosha alone, there are approximately 120 species of mammals (http://www.namibian.org/travel/namibia/wildlife.htm). The following figure shows Namibia's protected area network, as provided on the website of the Ministry of Environment and Tourism (http://www.met.gov.na/Pages/Maps.aspx).

Significant portions of Namibia's land are owned by the Government. Large areas are also considered communal land and are managed by traditional authorities. The following figure indicates who generally has control over different parts of Namibian land.

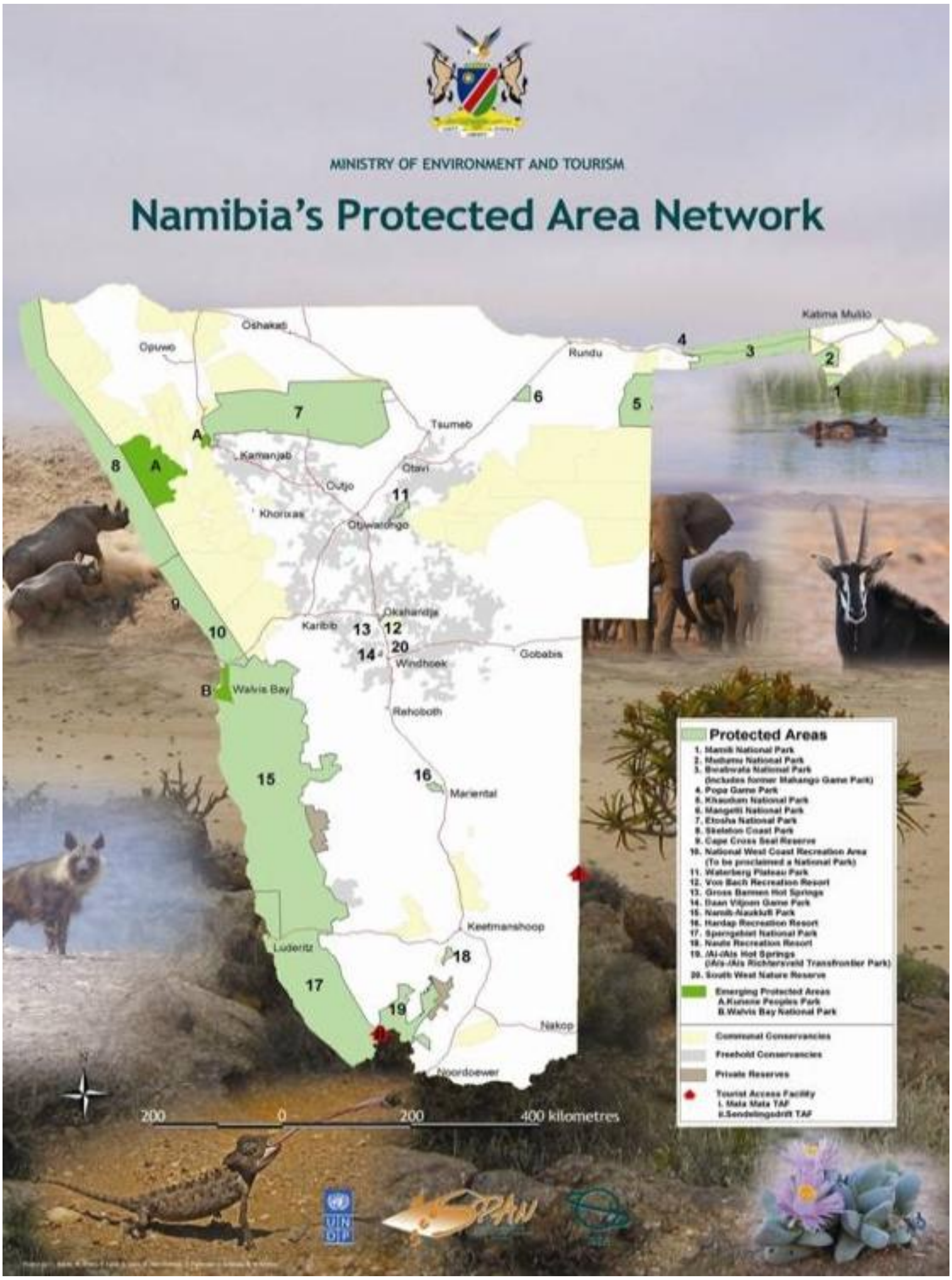

Figure 4.4 – Namibia's protected area network.

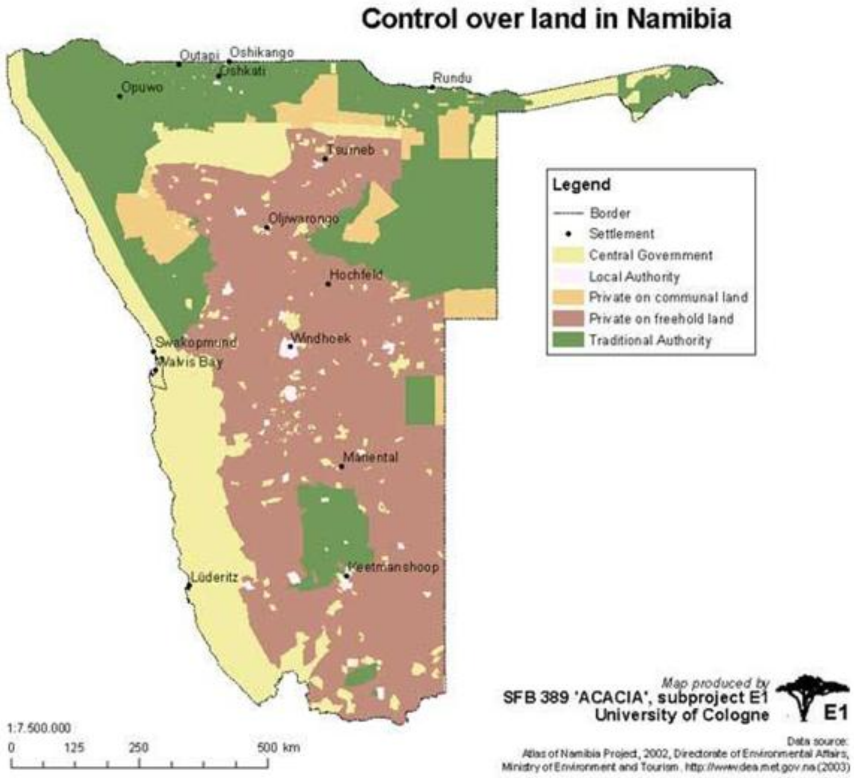

Figure 4.5 – Control over land in Namibia (*Atlas of Namibia*).

Namibia faces several environmental challenges over and above its extensive efforts to preserve its exceptional plant, animal and habitat assets. These challenges include: limited water resources, flooding, bush encroachment, desertification, and bush fires.

As stated above, Namibia is a dry country -- the driest in Sub-Saharan Africa. According to the World Bank, Namibia's annual renewable water resources were approximately 2750 cu m per capita in 2009; whereas the World average was approximately 6250, and the Sub-Saharan average was 4700 (http://data.worldbank.org/indicator/ER.H2O.INTR.PC/countries). Adding to this constraint, Namibia's only has perennial rivers located along its northern and southern boundaries, which are far from much of the population and economic activity. Furthermore, there are many areas where the groundwater is saline and not suitable for human consumption. Areva mine recently constructed a desalination plant at the coast, north of Swakopmund, and NamWater is also investigating the possibility of constructing its own desalination plant in the same area in the future. There is a significant demand for water by the growing mining industry, as well as the growing populations of Walvis Bay and Swakopmund. NamWater and the Ministry of Agriculture, Water and Forestry also face growing challenges to provide adequate water to Namibia's widely separated inland areas.

Approximately 26 million hectares of land -- mostly agricultural rangeland in north-central Namibia -- are subject to the problem of bush encroachment. There are primarily six species of woody shrubs/trees that have overgrown to excess density on valuable rangeland to such an extent that the carrying capacity for livestock and the value of the land have been severely diminished (*Bush Encroachment in Namibia*). To combat the problem, some farmers have entered into the charcoal production business. Others are looking into the possibility of producing biomass fuel for regional and international energy markets. And a number of studies have been performed to investigate the feasibility of establishing a biomass (invader bush) powered electricity generation plant in Namibia. See figure and table below for the areas that have been affected by bush encroachment, as well as very rough estimates of the sustainable yield of biomass that could be harvested:

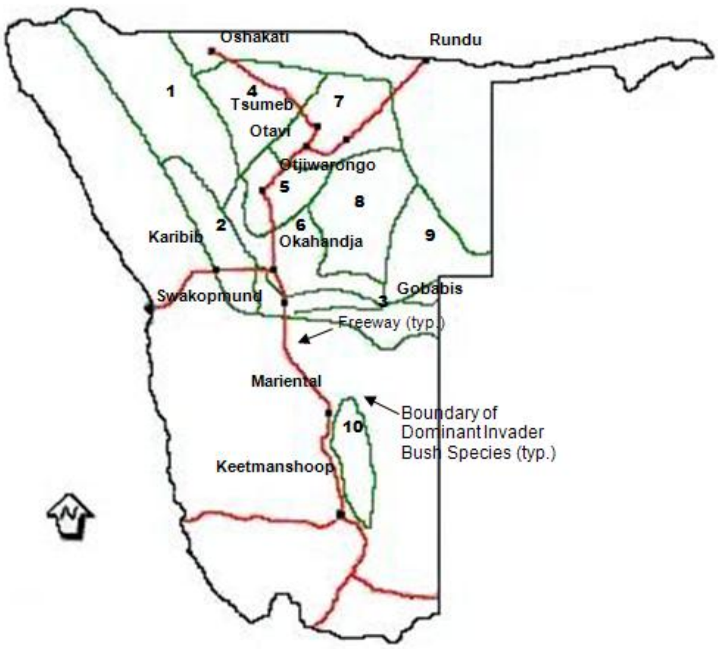

Figure 4.6 – Biomass areas.

Much of Namibia is susceptible to desertification. In Namibia, the driving forces of desertification include: population density, over-dependence on natural resources (wood & land) especially as a result of poverty, poor land management practices (over-fencing, over stocking and grazing, slash & burn land clearing, soil salinisation, and poorly planned farmer resettlement programmes), poorly planned rural water points, and bush encroachment (see paragraph above) (Desertification Policy Review - Extended Summary). Programmes have been implemented in Namibia to research and combat desertification, such as the NAPCOD programme of the 1990's and early 2000's. And in 2005 a comprehensive review of Namibia's various policies for agriculture, water, drought aid, and other sectors was performed to identify recommended policy changes.

Table 4.2 – Biomass areas in Namibia.

Area (1)	Dominant Bush Species	Common Name	Estimated Total Number	Estimated tons / ha of	Estimated Area of	Estimated Area of	Total Land Area (ha)
1	Colophospermum mopane	Mopane	2,500	< 5	1,451,000	2,986,000	4,437,000
2	Acacia reficiens	False umbrella thorn	3,000	5	1,676,000	691,000	2,367,000
3	Acacia mellifera	Black thorn (swart haak)	2,000	< 5	3,360,000	195,000	3,555,000
4	Colophospermum mopane	Mopane	4,000	15 - 20	482,000	1,090,000	1,572,000
5	Acacia mellifera	Black thorn (swart haak)	8,000	20 - 25	2,067,000	13,000	2,080,000
6	Acacia mellifera	Black thorn (swart haak)	4,000	5	2,692,000	210,000	2,902,000
7	Dichrostachys cinerea	Sickle bush	10,000	25 - 30	2,513,000	1,220,000	3,733,000
8	Acacia mellifera	Black thorn (swart haak)	5,000	5 – 15	950,000	2,453,000	3,403,000
9	Terminalia sericea	Silver terminalia	8,000	10 - 15	586,000	1,624,000	2,210,000
10	Rhigozum trichotomun	Three thorn	2,000	< 5	400,000 (2)	1,600,000 (2)	2,000,000
Total					**16,177,000**	**12,082,000**	**28,259,000**

(1) Bessie Bester, 1999 (Information obtained from Bush Encroachment in Namibia, JN de Klerk, 2004)
(2) Rough estimate by Ian Galloway, Jumbo Charcoal and Consulting Services Africa, 2007

Bush Fires are another source of environmental concern in Namibia, particularly in the north-eastern region, which is well documented in the Atlas of Namibia. In the north-eastern region, most bush fires are started deliberately to clear fields or burn away old grass to encourage the growth of new grass for livestock. The problem is that the fires often get out of control and burn many hectares of land that were not intended to be burned, thus damaging trees and important natural habitat. The figure below shows the area of bush fires that occurred during year 2000, which is representative of what occurs annually.

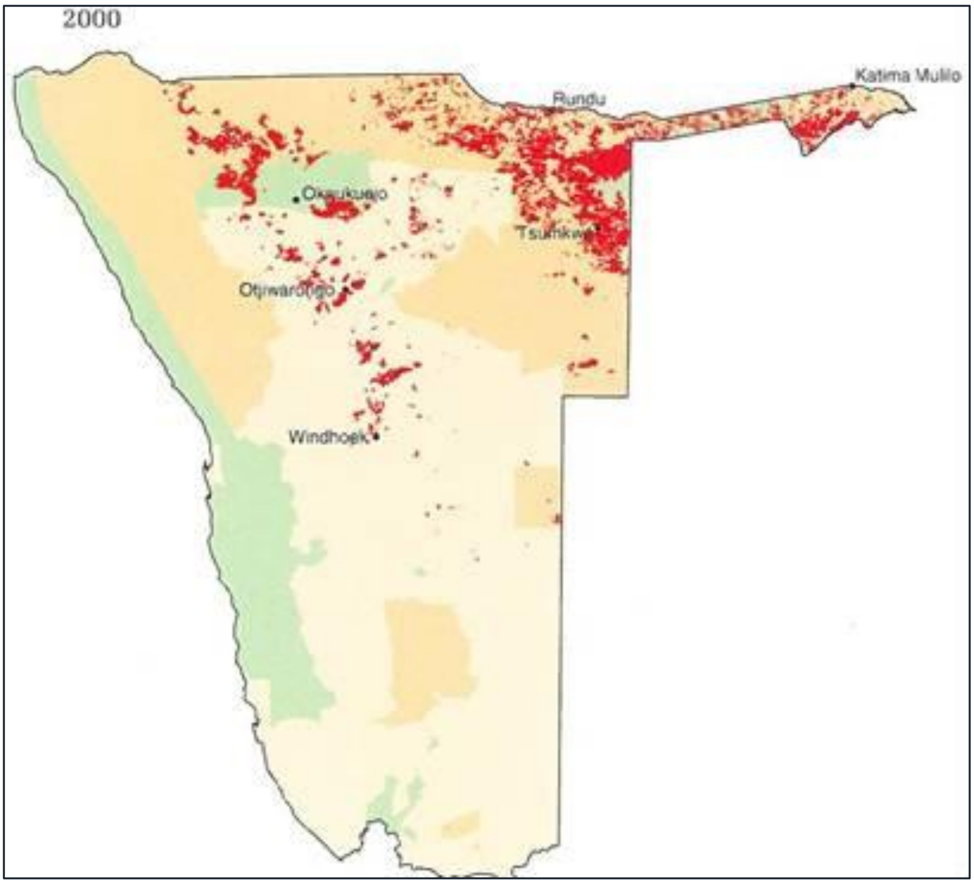

Figure 4.7 - Bush Fires in Namibia during Year 2000 (*Atlas of Namibia).*

4.3.2 General environmental Impacts of CSP technology

The CSP projects generate, regardless of the selected technology, low environmental impacts, being the main factor of concern the significant water consumption of such facilities.

This factor, water consumption, has an increased significance in a geography such as Namibia where the water availability is very low, and for that matter should be given priority to social uses, such as human consumption and farming (irrigation).

With this known potential significant environmental impact one of the, most also significant, mitigation measures applied has considering that regardless of the selected CSP technology, the project must have a dry cooling technology, meaning that the water consumption in this cases can be considered negligible.

A CSP project using dry cooling technology presents a lower efficiency (about 20%) as well as, a higher investment reason why it’s always considered a second option, in an economic point of view.

That said, and considering the CSP projects, the dry cooling technology, the project location and the Namibian environmental framework, the potential impacts that might occur will be related to:

a) Topography and geology

- No relevant impacts expected, however mining concessions may be affected, due to the presence of the project that can constitute an obstacle for a potential expansion of the mining facilities.

b) Ecology

b1) Fauna

- Impacts on threatened animals through habitat destruction
- Interruption of migration corridors
- Avifauna impacts on the power lines and high temperature surfaces (mirrors that can be mistaken for water pools)

b2) Flora

- Establishment and spread of declared weeds and alien invader plants
- Impacts on threatened plant species
- Impacts on protected tree species
- Impacts on indigenous natural vegetation

c) Soils and Erosion Potential

- Impacts on soil through excavation activities and removal of soil for roads, pipelines, and foundations
- Soil degradation through loosening, mixing, wetting, and compacting during earthworks
- Soil pollution by waste products (human and synthetic) and contaminants used in construction (e.g. fuel, oil, chemicals, cement)
- Soil erosion

d) Agricultural Potential

- Loss of agricultural potential and land capability

e) Heritage Resources

- Loss of stone artifact scatters and possible sites during the construction phase
- Impacts on potential colonial sites

f) Landscape and Visual Aesthetics

- Visual impact on users of national and secondary roads within the region
- Visual impact on residents of settlements and homesteads within the region
- Visual impact of ancillary infrastructure within the development footprint on sensitive visual receptors Potential
- Visual impact of lighting at night on sensitive visual receptors
- Potential visual impact of construction activities and accommodation on sensitive visual receptors
- Visual impact of the proposed facility and its ancillary infrastructure on the visual character and sense of place within the region
- Visual impact of the proposed facility and ancillary infrastructure on tourist routes and tourism potential within the region

g) Socio-Economics

- Change in social composition
- Job creation, skill development/inequities
- Local procurement
- Inflow of construction workers and job seekers
- Potential impacts associated with accommodation of the workforce
- Impact on farming activities
- Impact on the Local Municipality
- Impact on traffic
- Impact on tourism
- Impacts on health and safety
- Impacts on noise environment
- Impact on daily living and movement patterns during operation
- Impact on land values

A CSP project, like any other renewable energy project, or for that matter, any energy power plant, needs a power line to evacuate the energy production.

In this case, a servitude of 30 to 50 m in width for the power line will need to be established. Only the center line may need to be cleared for stringing purposes. The remainder of the servitude should not be cleared, except where trees higher than 4 m exist which could interfere with the operation of the power line.

Impacts which may result from the necessary evacuation power line include the potential visual impact, impacts on avifauna as a result of collisions and electrocution (particularly across active cultivated agricultural land).

Potential visual impacts associated with the power line are not possible to mitigate. However, the visual impact is expected to be limited to within 2 km of the location of the power line, and would primarily be associated with views from national roads.

Avifauna may be affected due to potential collisions, and or electrocutions with the power line. Large, slower moving bird species typically collide with the earth wire as they cannot divert their flight path in time. Also, birds of prey, when diving to attack their prey in the ground, are especially vulnerable to these incidents.

This impact on avifauna can be effectively mitigated if the power line should be appropriately marked with Bird Flight Diverters (BFDs) in the most sensitive areas (i.e. through active agricultural land).

To correctly assesse the impacts of any kind of project, cumulative impacts must be discussed and evaluated.

A cumulative impact, in relation to an activity, refers to the impact of an activity that in itself may not be significant, but may become significant when added to the existing and potential impacts eventuating from similar or diverse undertakings in the area.

Ecology – impacts as a result of loss of natural vegetation to agricultural activities and development of natural land. These facilities also result in the loss of vegetation and habitats, so cumulative impacts should be evaluated.

Heritage – Impacts on heritage resources relate to the loss of heritage sites as well as a change in the sense of place of an area. Other land uses can also contribute to this phenomenon, which is the reason why land uses should be considered in the impact analysis.

Visual – The construction of the facility and its associated infrastructure will increase the cumulative visual impact of electricity related infrastructure within the region, which is a potential impact to be evaluated.

Social – The development of the facility will have a cumulative impact on several existing issues within the area, predominately within rural settlements associated with the potential influx of workers and job seekers.

With the increased population density, this may lead to a cumulative impact on housing requirements, services (i.e. water, electricity and sanitation), health issues, safety and security.

New informal townships are unlikely to have the required infrastructure and services. With the existing rural settlements in the area this will have a cumulative impact on the environment and health (i.e. in terms of ablution facilities).

Positive impacts - Cumulative positive impacts are, however, also anticipated should a number of associated / complementary activities be developed in the area, largely due to job creation opportunities, business opportunities for local companies, skills development and training. The development of renewable energy facilities will have a positive impact at a national and international level through the generation of "green energy" which would lessen Namibia dependency on coal generated energy and the impact of such energy sources on the bio-physical environment.

4.3.3 Environmental and legal constrains for CSP projects

The environmental and legal constrains listed in this chapter can be divided in relevant project information and/or "knock out" information.

Relevant information is the information that imposes restrictions to the projects, meaning that changes have to be made in the project in order to comply with the restrictions. These changes can be physical or technological. Physical, for instance, the relocation of a project component within the site, to comply with the mandatory servitude of a power line. For instance, adopting a dry cooling system due to water restriction use is considered a technological change in the project.

Knock-out information, is the information that enables the project to go through, for instance, the project is located in a licensed mining concession that intends to expand to that area.

For a CSP project development in Namibia, is considered relevant to obtain the following information:

- Natural protected areas (both classified or under classification);
- Land Use maps (e.g. Corine Land Cover);
- Animal migration corridors (especially mammals and birds);
- Water quality and availability data (both fresh and underground water);
- Archaeological, paleontological and ethnographic areas or other cultural protected areas;
- Studies related to desertification and/or sand movements in the desert areas;
- High risk flooded zones;
- Water quality and availability data (both fresh and underground water);
- Rivers and dams (mapping)
- Natural protected forest;
- Production protected forest;
- Designated protected forest areas;
- Soil mapping (type of soils and distribution across the country).
- Territorial planning instruments, such as, urban areas, industrial areas, touristic areas, game reserve areas, or other predicted/legislated areas that may create an obstacle to a CSP project;
- Game reserve areas;
- Agriculture areas, both protected or social relevant areas;
- Location of active mines;
- Mining concession areas;

- Protected areas, such as, military facilities, training areas or others;
- Detailed road maps (existent and predicted);
- Location and boundary restrictions for local and international airports
- Detailed railway map (existent and predicted)

4.3.4 Environmental and legal constrains mapping

Figure 4.8 (conservation areas and parks) shown below, represents in the environmental point of view, the main constrains for the development of a CSP project in Namibia.

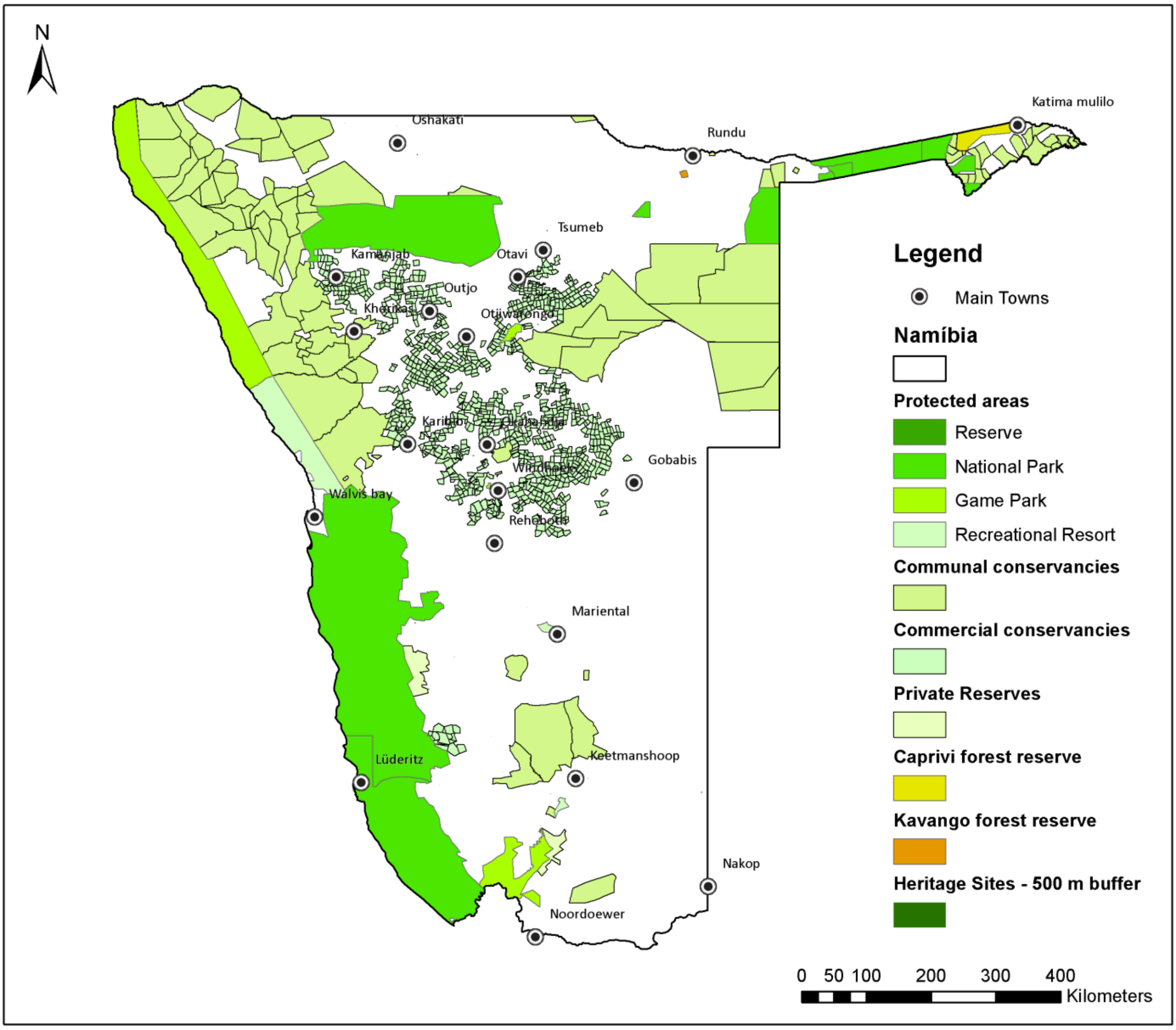

Figure 4.8 - Conservation areas and parks.

4.4 Licensing requirements under Namibian Law

The environmental impacts associated with the proposed CSP project are required to be investigated in compliance with the List of Activities That May Not Be Undertaken Without Environmental Clearance Certificate, as published in the Government Notice No. 29 of 2012 and the Environmental Impact Assessment (EIA) Regulations published in Government Notice No. 30 of 2012, read with Section 27 (2) of the Environmental Management Act, 2007 (Act No. 7 of 2007).

The required environmental studies encompass the undertaking of a Full EIA. This study should be undertaken in two phases: 1) an Environmental Scoping Study (ESS) Phase, and 2) a Specialist Studies Phase including public participation meetings and the compilation of an Environmental Management Plan (EMP). This process will provide a record of all issues identified, evaluation of the significance of identified potential impacts and their mitigation in order to make recommendations regarding the required EMP. The EIA process to be followed should comply with the Environmental Impact Assessment (EIA) Regulations 5 to 8, as published in Government Notice No. 30 of 2012 and with Section 32 to 43 of the Environmental Management Act, 2007 (Act No. 7 of 2007).

The proposed project is a listed activity in terms of Section 27 of Act No. 7 of 2007 and Government Notice No. 29 of 2012. The proponent is therefore required to submit a Full EIA Report and an EMP. The appropriate authority will issue a decision subsequent to their review of the required reports and plans.

4.5 Overview and analysis of international agreements and regulations made by Namibia on environment

Namibia is recognized internationally for its strong commitment to environmental conservation. In addition to protecting much of its land for environmental preservation purposes, Namibia is a signatory to several international environmental agreements.

UN Convention to Combat Desertification (UNCCD) - www.unccd.int

Desertification, along with climate change and the loss of biodiversity, were identified as the greatest challenges to sustainable development during the 1992 Rio Earth Summit. Established in 1994, UNCCD is the sole legally binding international agreement linking environment and development to sustainable land management.

The Convention addresses specifically the arid, semi-arid and dry sub-humid areas, known as the drylands, where some of the most vulnerable ecosystems and peoples can be found. In the ten-year Strategy of the UNCCD (2008-2018) that was adopted in 2007, Parties to the Convention further specified the aim for the future to be ..."to forge a global partnership to reverse and prevent desertification/land degradation and to mitigate the effects of drought in affected areas in order to support poverty reduction and environmental sustainability".

Signatory on 24 October 1994

UN Framework Convention on Climate Change (UNFCCC) - www.unfccc.int

In 1992, countries joined an international treaty, the United Nations Framework Convention on Climate Change, to cooperatively consider what they could do to limit average global temperature increases and the resulting climate change, and to cope with whatever impacts were, by then, inevitable.

By 1995, countries realized that emission reductions provisions in the Convention were inadequate. They launched negotiations to strengthen the global response to climate change, and, two years later, adopted the Kyoto Protocol. The Kyoto Protocol legally binds developed countries to emission reduction targets.

Signatory on 04 September 2003

Convention on Biological Diversity (CBD) - www.cbd.int

The Convention was opened for signature on 5 June 1992 at the United Nations Conference on Environment and Development (the Rio "Earth Summit"). It remained open for signature until 4 June 1993, by which time it had received 168 signatures. The Convention entered into force on 29 December 1993, which was 90 days after the 30th ratification. The first session of the Conference of the Parties was scheduled for 28 November – 9 December 1994 in the Bahamas.

The Convention on Biological Diversity was inspired by the world community's growing commitment to sustainable development. It represents a dramatic step forward in the conservation of biological diversity, the sustainable use of its components, and the fair and equitable sharing of benefits arising from the use of genetic resources.

Signatory on 12 June 1992

The Ramsar Convention on Wetlands - www.ramsar.org

The Convention on Wetlands of International Importance, called the Ramsar Convention, is an intergovernmental treaty that provides the framework for national action and international cooperation for the conservation and wise use of wetlands and their resources.

The Ramsar Convention is the only global environmental treaty that deals with a particular ecosystem. The treaty was adopted in the Iranian city of Ramsar in 1971 and the Convention's member countries cover all geographic regions of the planet.

Namibia has four Ramsar sites - Walvis Bay Wetlands, Sandwich Harbour, the Orange River Mouth and the Etosha Pan.

Signatory on 23 August 1995

Convention on International Trade in Endangered Species (CITES) - www.cites.org

CITES (the Convention on International Trade in Endangered Species of Wild Fauna and Flora) is an international agreement between governments. Its aim is to ensure that international trade in specimens of wild animals and plants does not threaten their survival.

Because the trade in wild animals and plants crosses borders between countries, the effort to regulate it requires international cooperation to safeguard certain species from over-exploitation. CITES was conceived in the spirit of such cooperation. Today, it accords varying degrees of protection to more than 30,000 species of animals and plants, whether they are traded as live specimens, fur coats or dried herbs.

Signatory on 18 December 1990

4.6 CDM and carbon development mechanisms

As a signatory of the UNFCCC and Kyoto Protocol, Namibia supports the principles of Clean Development Mechanism. Namibia is a Non-Annex I signatory, which means that it is not required to reduce its emissions of greenhouse gases, but may participate in the Clean Development Mechanism to obtain carbon credit funding for projects that utilize technologies or processes that create minimal or no greenhouse gas emissions compared to the standard technologies or processes that would typically be utilized.

A Designated National Authority (DNA) was appointed within the Ministry of Environment and Tourism. A committee was also established to assist in the review of Project Idea Notes (PINs) and Project Design Documents (PDD) that are submitted by project developers seeking to obtain carbon credits for their projects.

The first step in applying for CDM assistance is to submit either a PIN or a PDD to the DNA. Submitting a PIN is optional, but a PDD is always a required step in applying for CDM assistance. Sometimes project developers submit a PIN before the PDD because it requires less work and cost, but is a useful step to sort out key issues, present the proposed project to the DNA, and obtain valuable feedback from the DNA prior to investing more time and resources in the full PDD.

To this date, no projects in Namibia have received CDM funding.

5 Site Selection

5.1 Methodology and Criteria Definition

The proposed methodology for the site selection consists on collecting the needed information, to establish a solid GIS Database, enabling an accurate GIS processing, to generate a set of potential sites, carrying out a preliminary environmental analysis, to narrow the set of potential sites, and, finally, undertaking a site survey, to assess the suitability and feasibility of the 5 top selected sites.

In this line of thought, this subsection describes the adopted criteria, mainly according to the information used for building the GIS Database (subsection 5.2), and whose aim was to identify and narrow down potential sites. Then, the methodology scrutinizes the entire country to ultimately select a limited number of potential sites for the establishment of a 5 to 50 MW_e CSP plant and possible solar parks.

The evaluation and selection process retains 5 sites using a detailed methodology, based on solar radiation, temperature, humidity data for the whole country, and various GIS layers to accommodate all the infrastructure and environmental data available for Namibia, as grid and road network.

Moreover, as part of the selection process, the suitability of each site is critically analysed, using the most recent GIS tools and layers, presented in 5.2 GIS database.

In what concerns the screening of the best potential CSP locations, two key aspects were considered: resource and feasibility. Besides these two key aspects, it was also taken into consideration the possibility of promoting different business models, leading to the identification of possibilities in biomass hybridization, gas hybridization, coal augmentation, desalination and mines (5.3.1 Analysis Inputs).

From these inputs, the potential areas were identified and, in those, it was carried a project identification (5.3.2 Potential Areas Identification).

Further, with all the identified projects a GIS analysis was performed, contemplating an economic analysis, feasibility analysis and alternative business models (5.3.3 Best Projects Analysis). The results of the GIS analysis allowed the selection of the TOP 20 sites selection, through prioritization.

Hence, on these TOP20 sites, not only a deeper GIS analysis was performed, but most important, on site visits took place, as well as an environmental classification (5.4 Summary of the Analysis of the Top 20 Sites and Shortlisting).

For last, the prioritization of the Top20 sites allowed choosing Top5 sites, presented in 5.5 Site Survey (top 5 sites) Summary.

5.2 GIS database

5.2.1 DNI Mapping

The Direct Normal Irradiation is an output from Chapter 5 - Solar Resource of Namibia. In Figure 5.1, the map of the daily DNI is presented and, in the Figure 5.2, the monthly sums of DNI are portrayed.

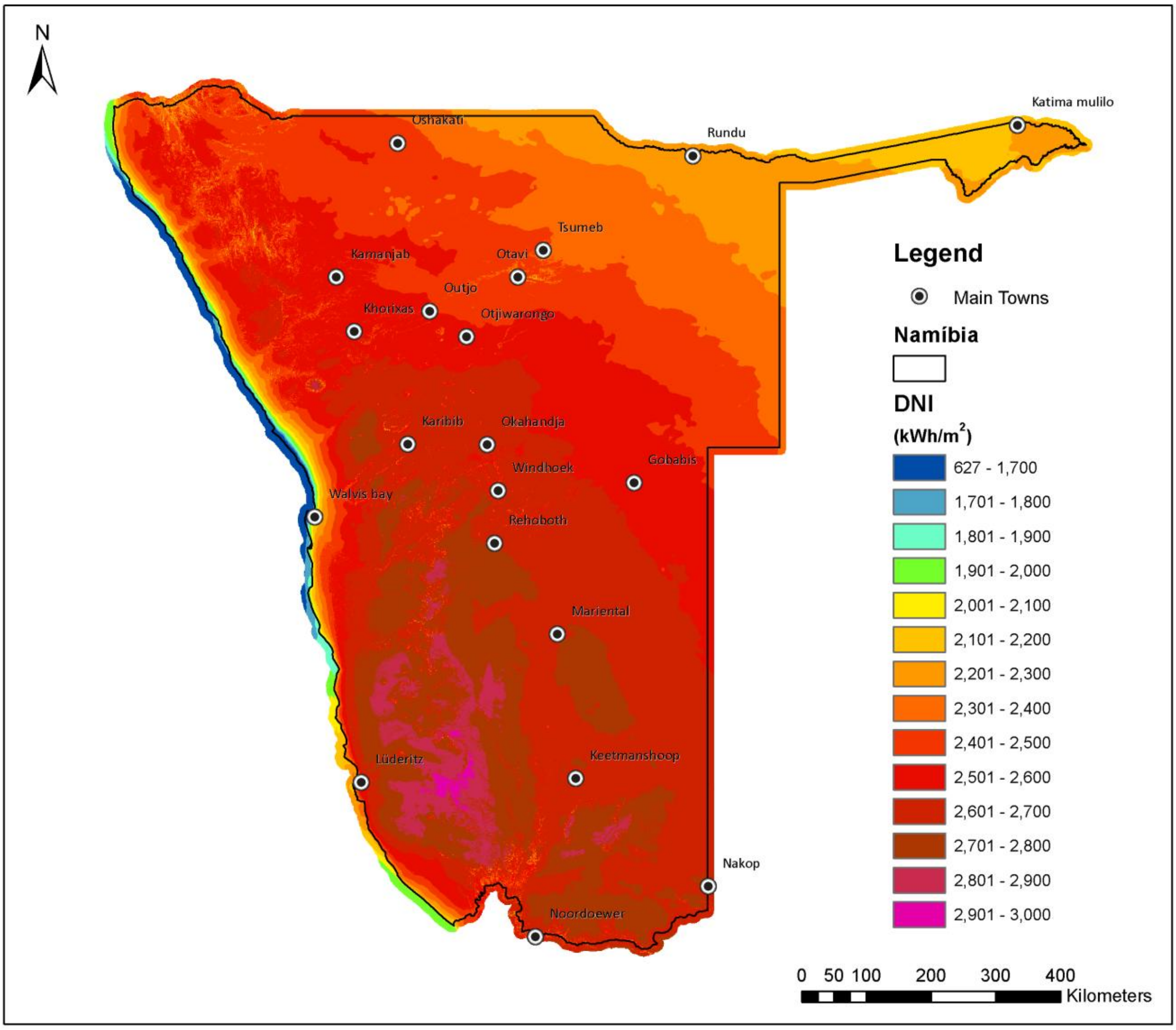

Figure 5.1 – Yearly average of daily direct normal irradiation (kW/m^2/day).

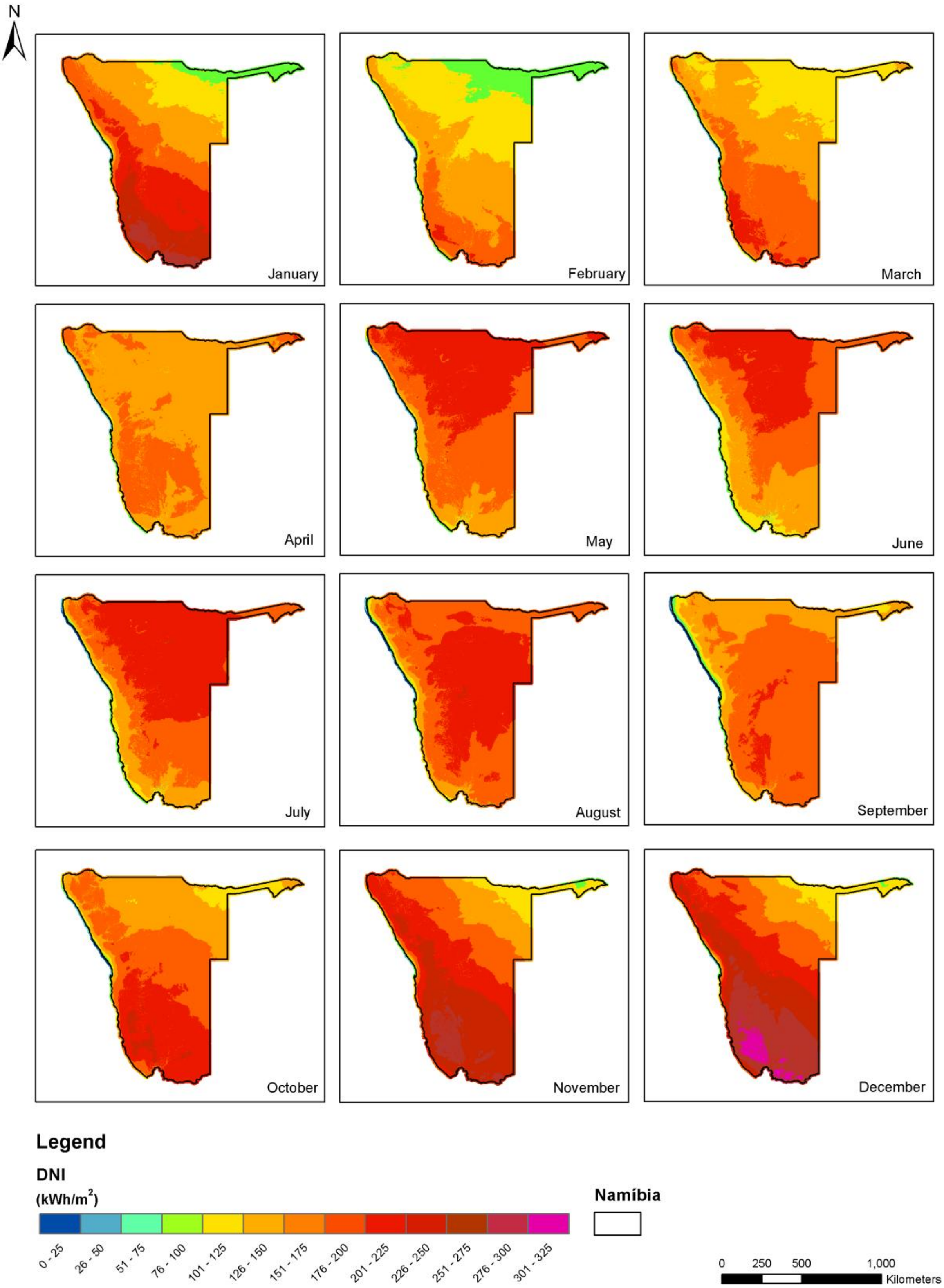

Figure 5.2 – Monthly sums of direct normal irradiation (kWh/m^2/month).

5.2.2 Meteorological Data

5.2.2.1 Air Temperature Mapping

The map of annual and monthly average air temperatures are shown in Figure 5.3 and Figure 5.4, respectively. Note that, this information is part of SolarGIS database.

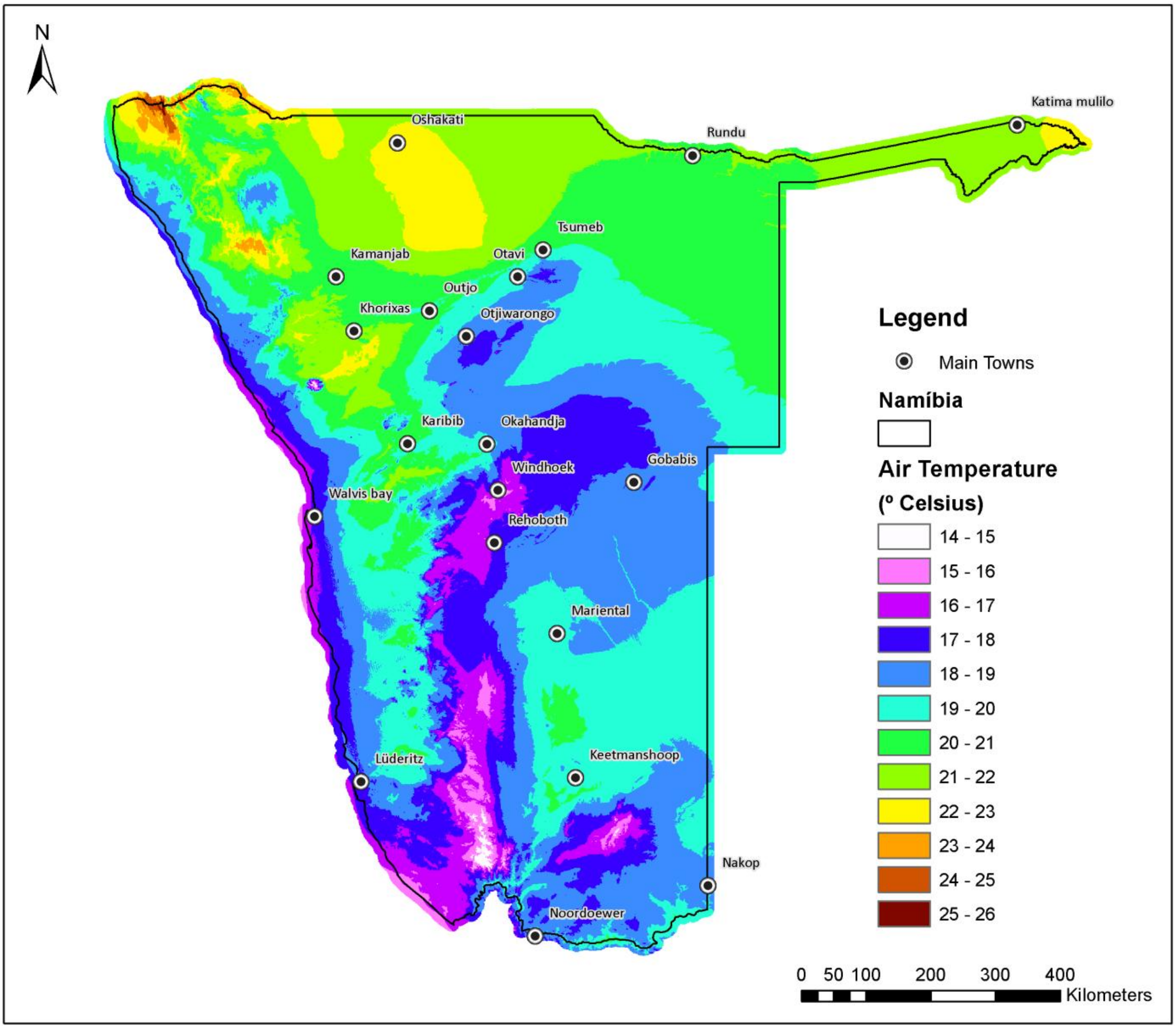

Figure 5.3 – Average annual air temperature.

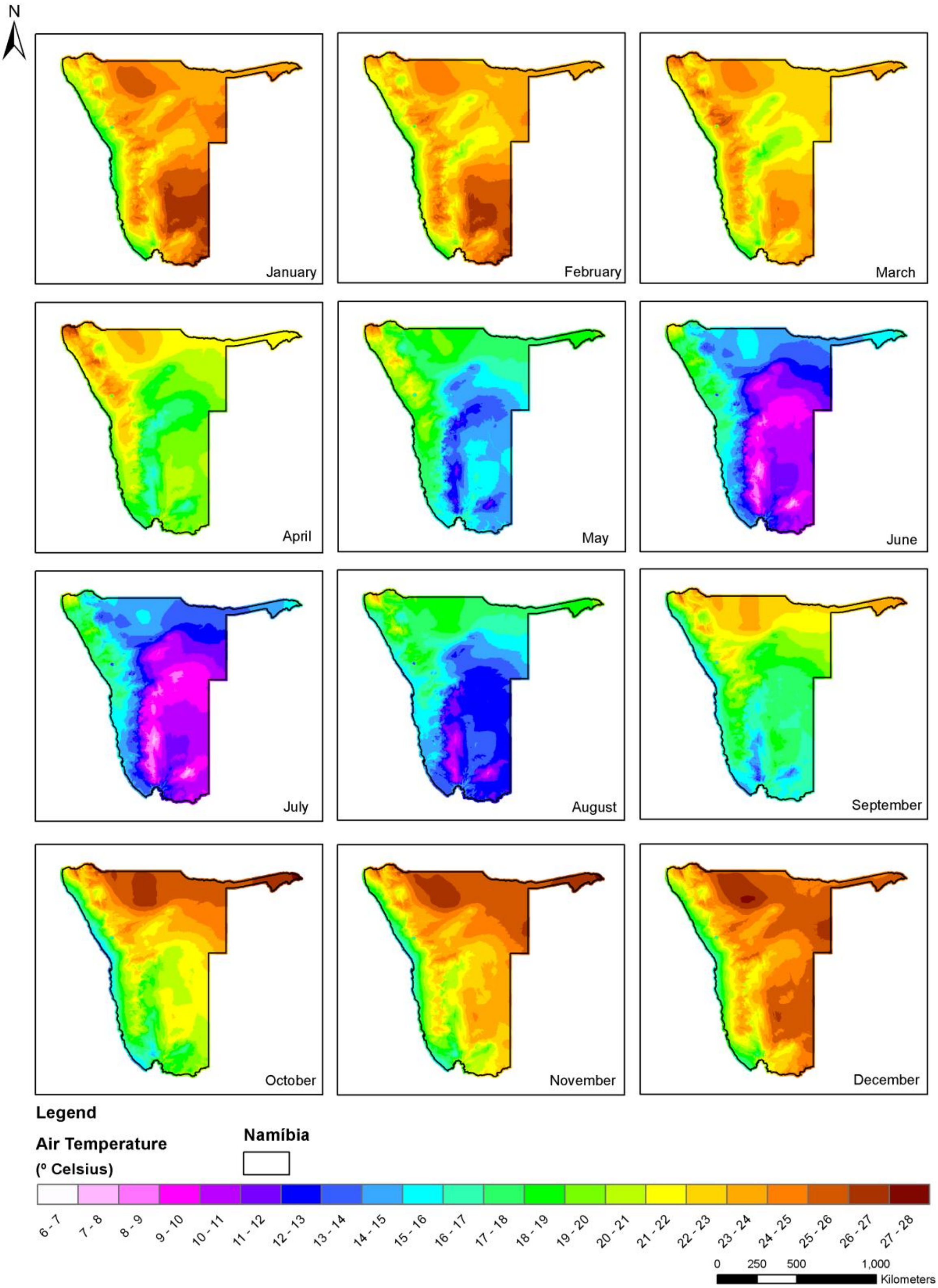

Figure 5.4 – Monthly average air temperature.

Air Temperature is derived from CFSR (© NOAA NCEP) and GFS (© NOAA NCEP) databases. In addition, the original spatial resolution of the primary parameters is 33 km (CFSR) and 50 km (GFS), respectively.

By its turn, the original time resolution is one hour (for CFSR data source) and six hours (for GFS data source).

For last, the original time resolution is harmonized to 1-hour time step, and the spatial resolution is recalculated to 1 km. Note that, regarding data accuracy, for hourly values, the deviation of modelled values to the ground observations can reach several degrees.

5.2.2.2 Wind Speed and Wind Direction Mapping

The wind speed and direction data could only be obtained through the printed publication of the Atlas of Namibia. Thus, the accuracy of this data is unknown and its spatial distribution is very coarse.

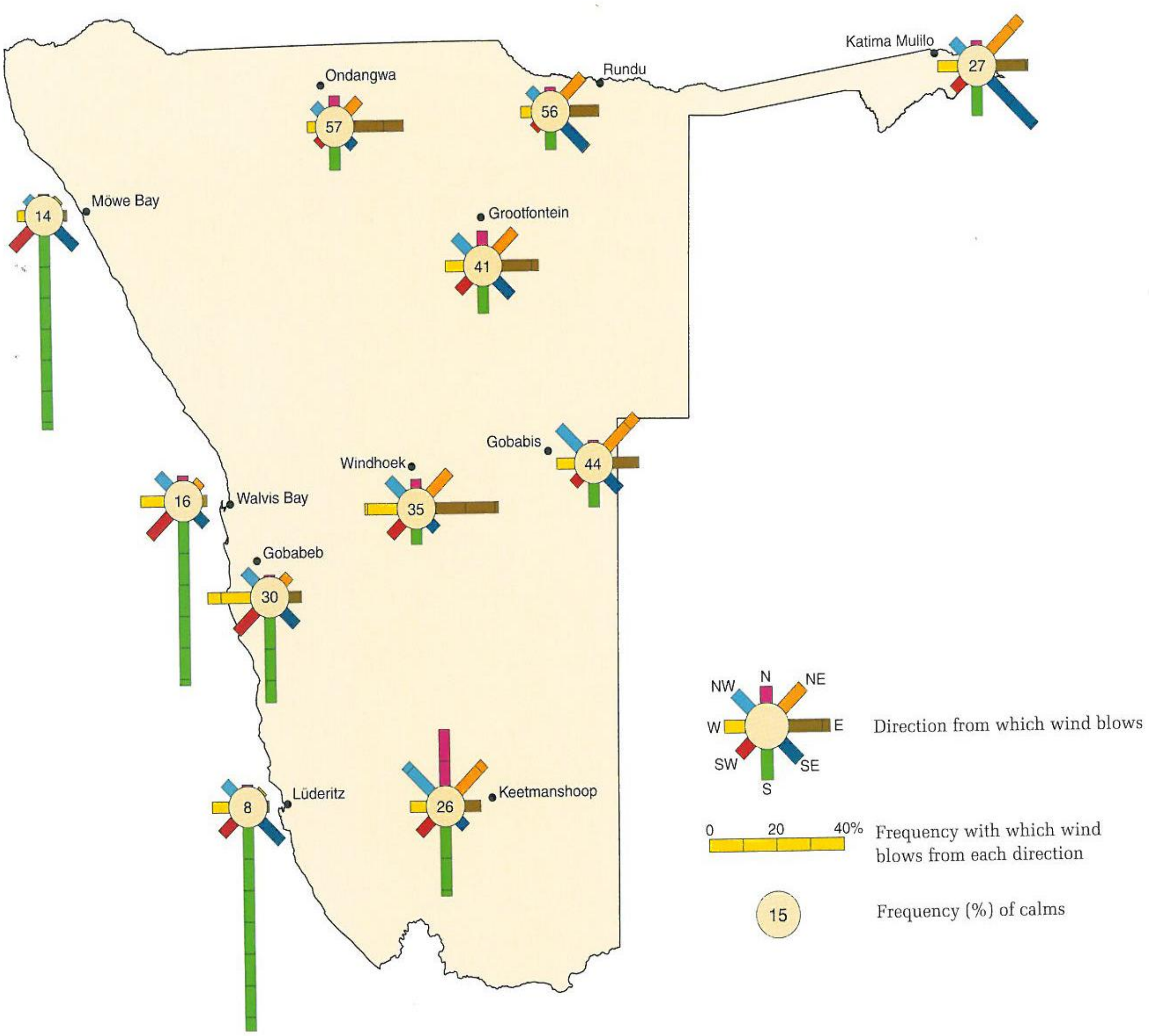

Figure 5.5 – Wind: Direction, frequency, and frequency of calms.

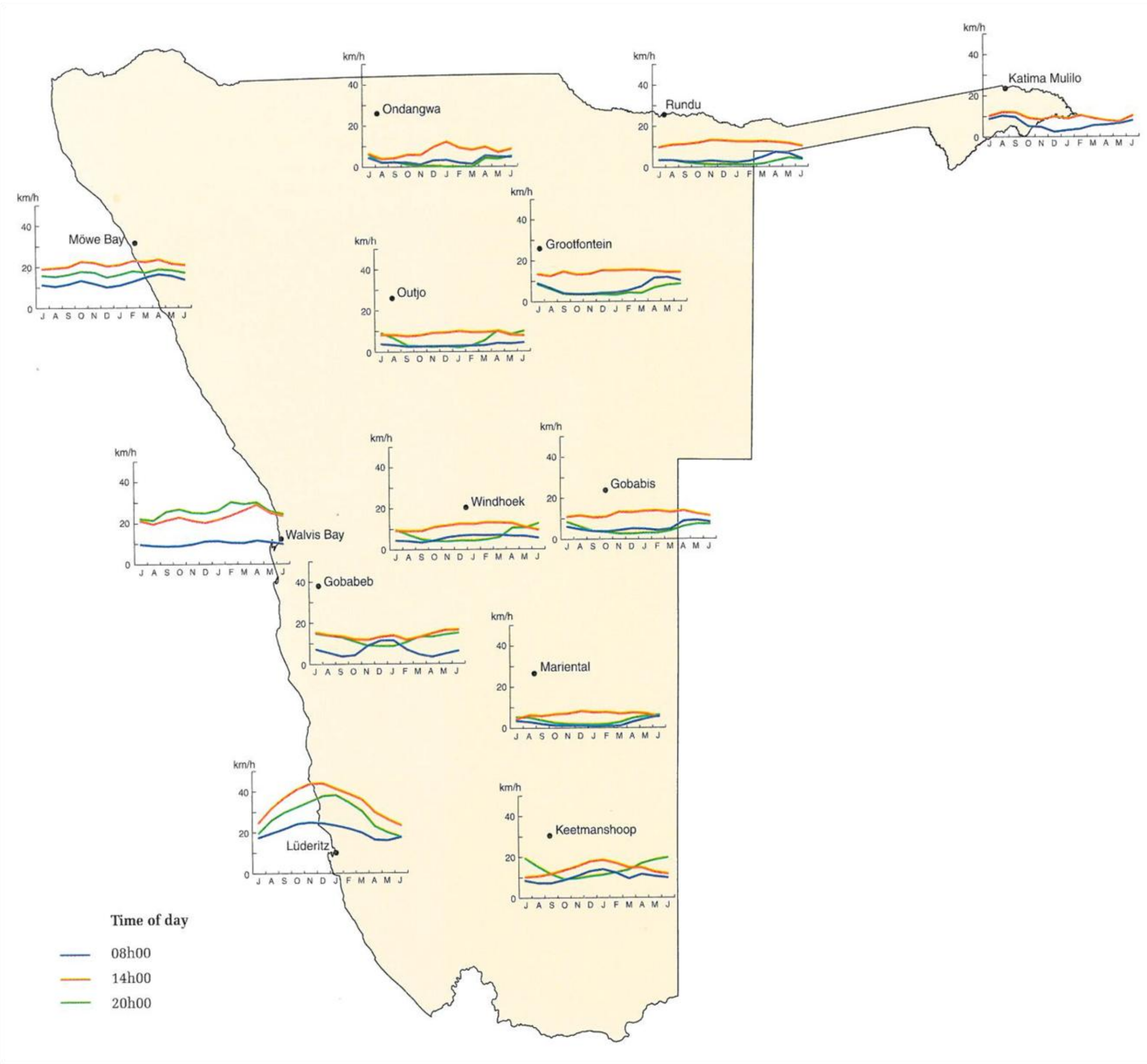

Figure 5.6 – Wind: Average monthly speed at 08h00, 14h00, and 20h00.

5.2.2.3 Rain Fall Mapping

Rainfall mapping was obtained from available shapefiles in the Atlas of Namibia, which, by its turn, was obtained from the original data for almost 300 stations [**1**]. In addition, this information is generally referred to be obtained from interpolation grid of the stations, by classification. Therefore, in the areas with clusters of meteorological stations the results are accurate but, in the areas with low density of rain gauges, the data is coarse and poor.

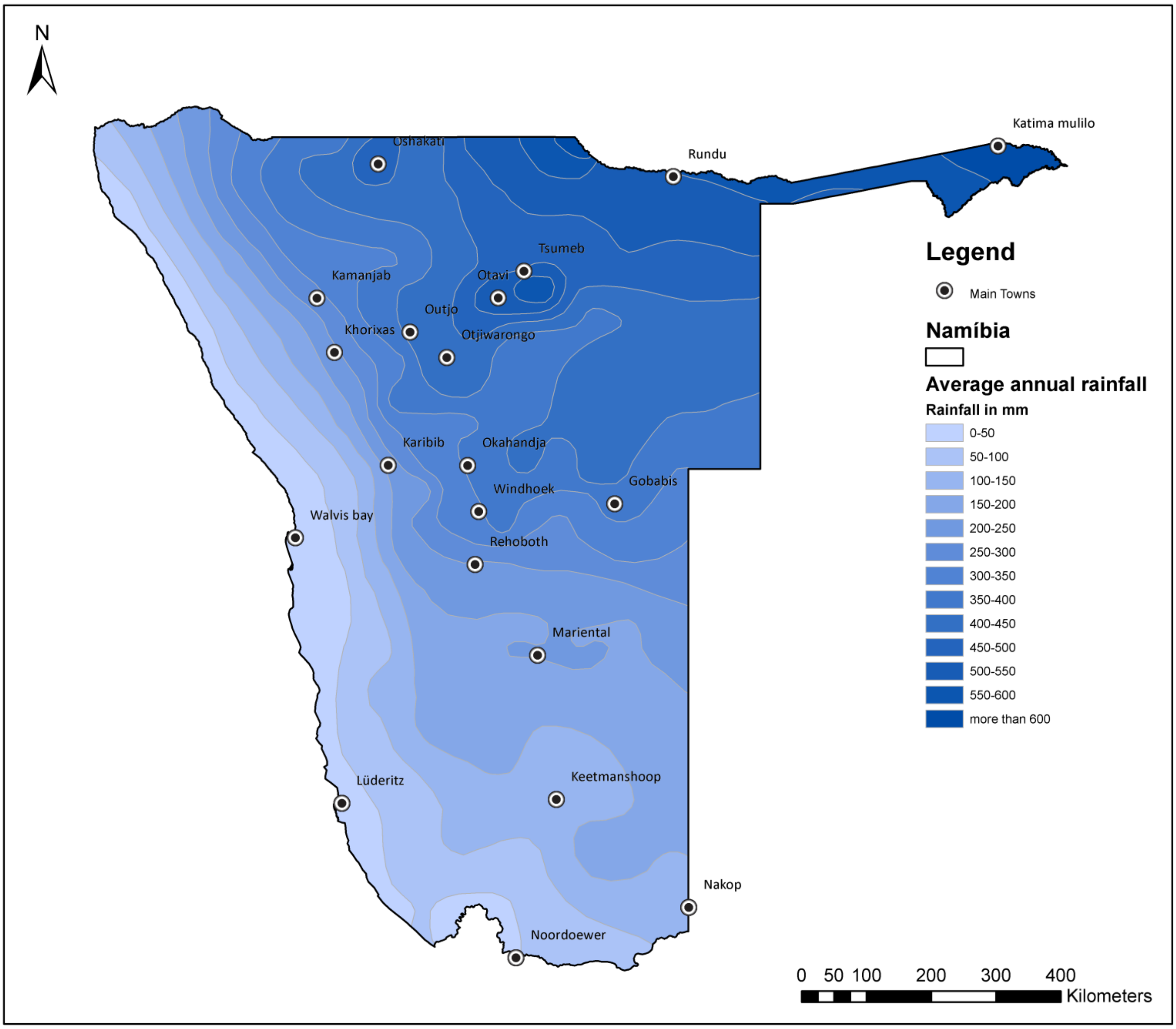

Figure 5.7 – Annual Average Rainfall in Namibia (Atlas of Namibia).

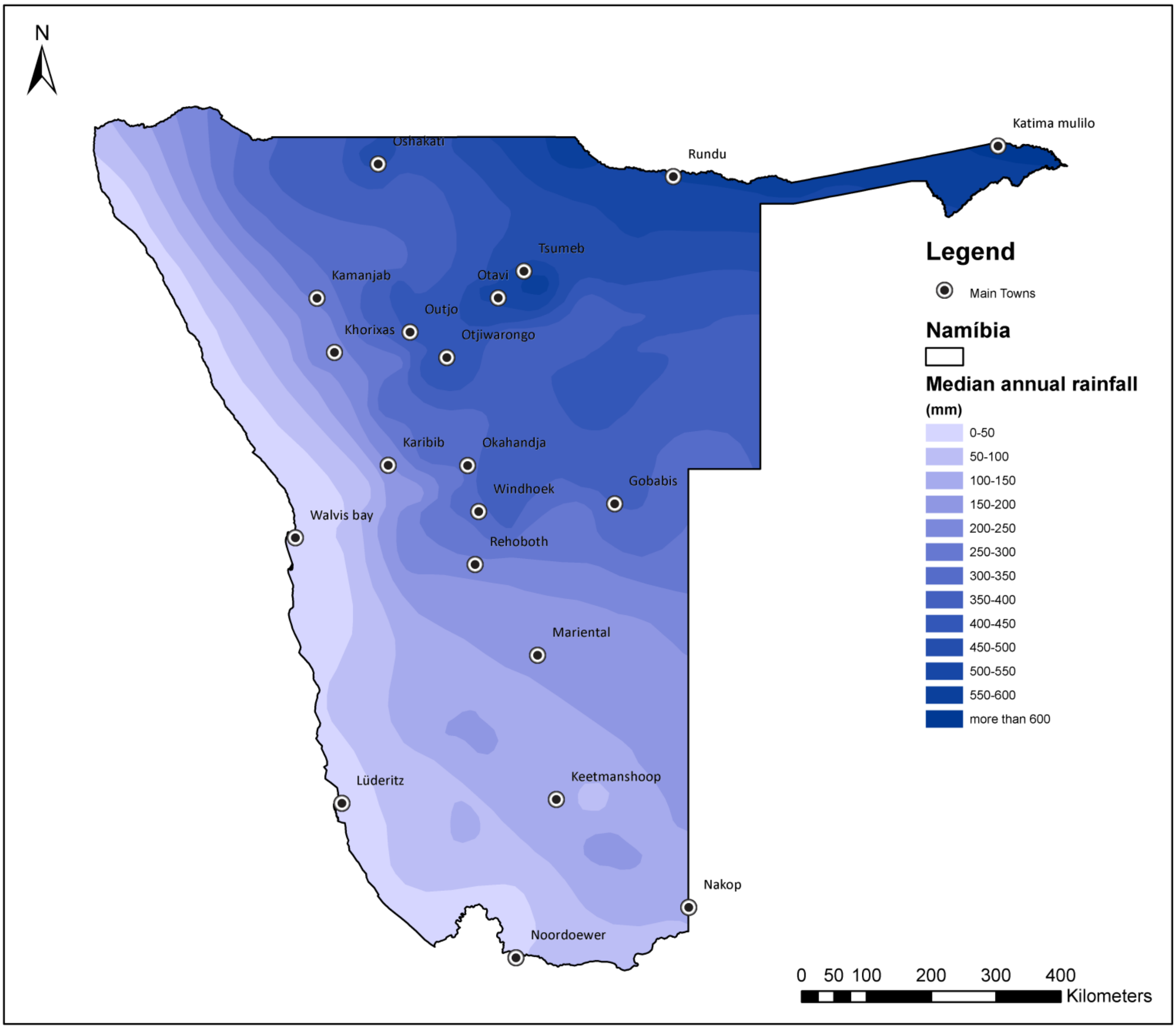

Figure 5.8 – Median annual rainfall (Atlas of Namibia).

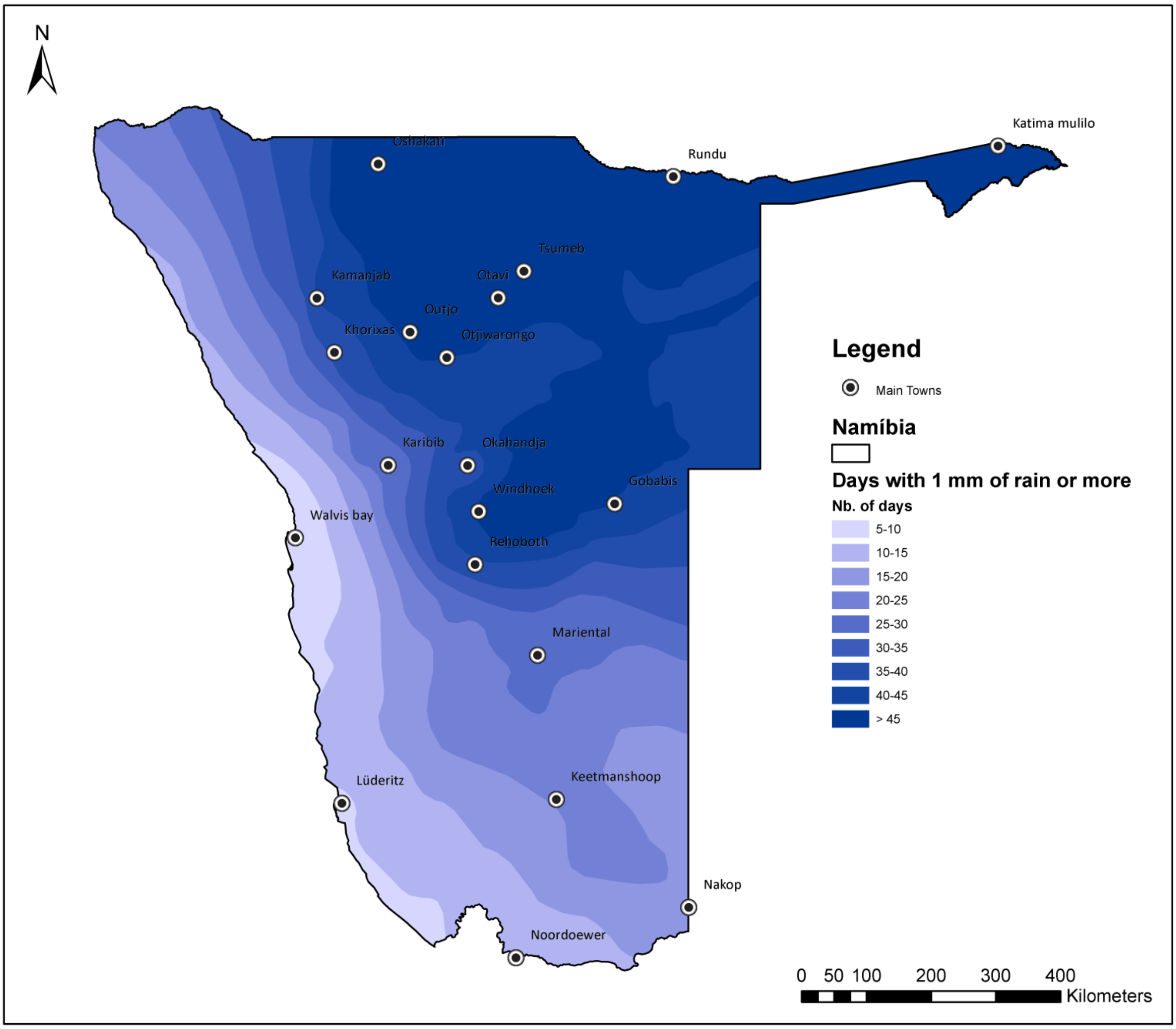

Figure 5.9 – Number of days with 1 mm of rain or more (Atlas of Namibia).

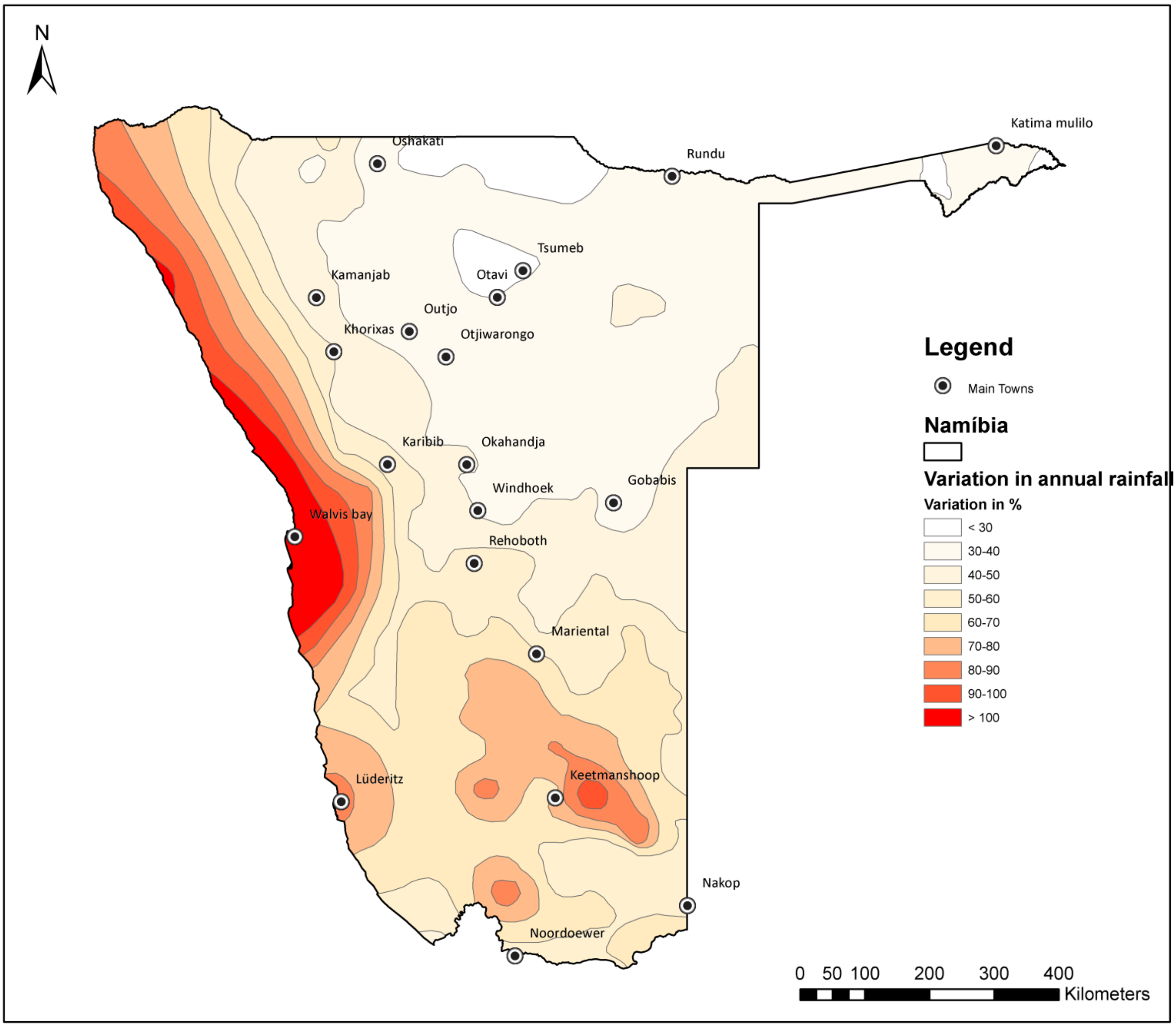

Figure 5.10 – Variation in annual rainfall in Namibia (Atlas of Namibia).

Note that, the shapefiles were not distributed with the base layer of the selected meteorological stations, which did not allow the identification of the zones where data is accurate and the zones where data is not so precise. Consequently, this data should not be used to perform strict evaluations.

5.2.2.4 Humidity Mapping

The relative humidity maps refer to relative humidity values during the least and the most humid months, and were obtained from shapefiles based on data from the Namibia Meteorological Services.

Albeit data are available for 08h00m, 14h00m and 20h00m, maximum daily relative humidity occurs around dawn or shortly afterwards, but certainly before 08h00m. Similarly, minimum relative humidity generally occurs rather later than 14h00m. Thus, the map does not depict the actual maximum relative humidity, which actually occurs (these are rather more extreme - higher maximum), but give an indication of spatial spread and time of the year of the maximum.

Furthermore, the polygons making up the shapefile were created from hand drawn contours on a hard copy map. Note that, this manual interpolation approach was done by Peter Hutchinson using point data from all available stations (42).

To conclude, Figure 5.11 and Figure 5.12 show the map of relative humidity during the most and the least humid months, respectively.

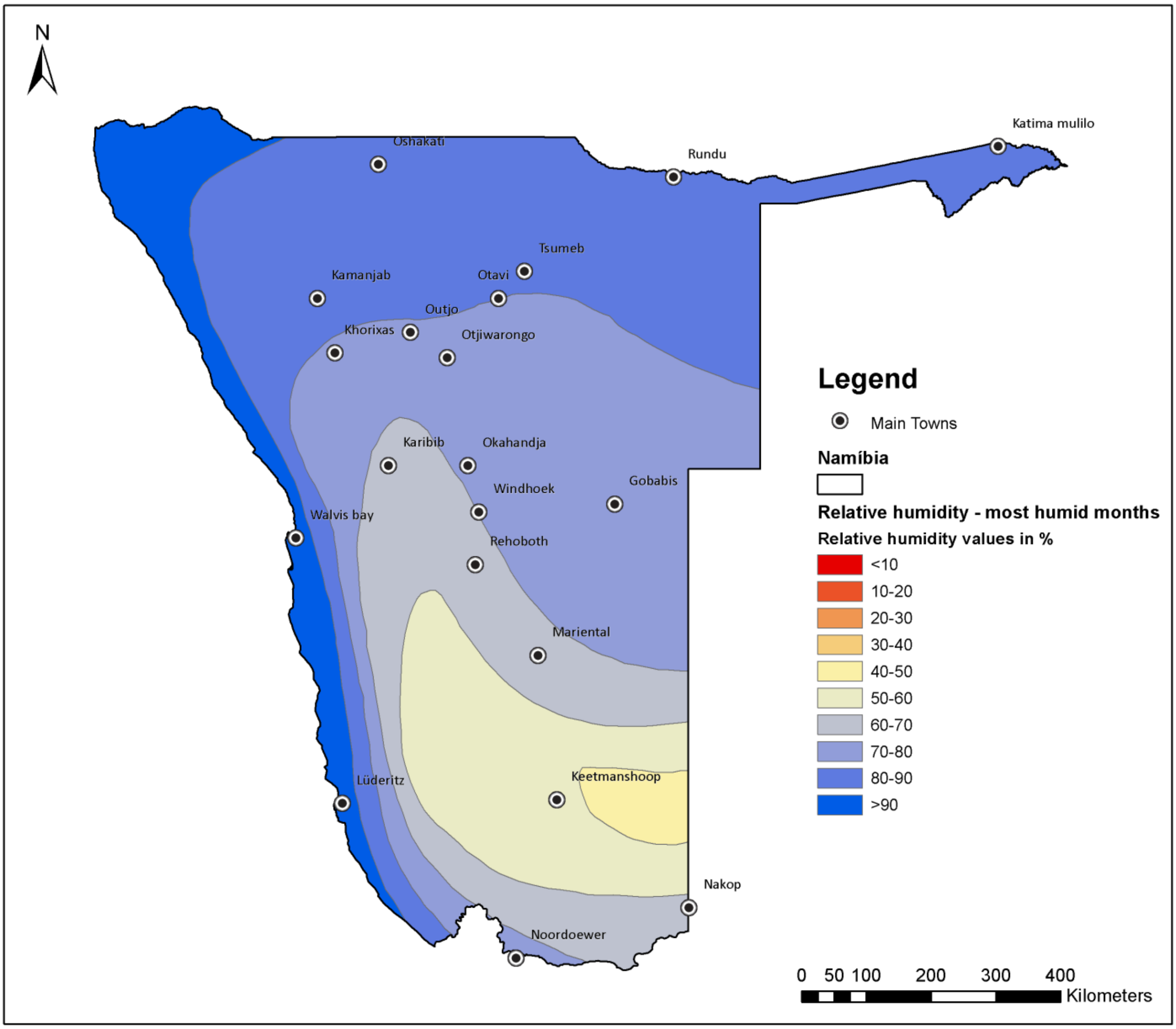

Figure 5.11 – Relative humidity (%) in most humid months.

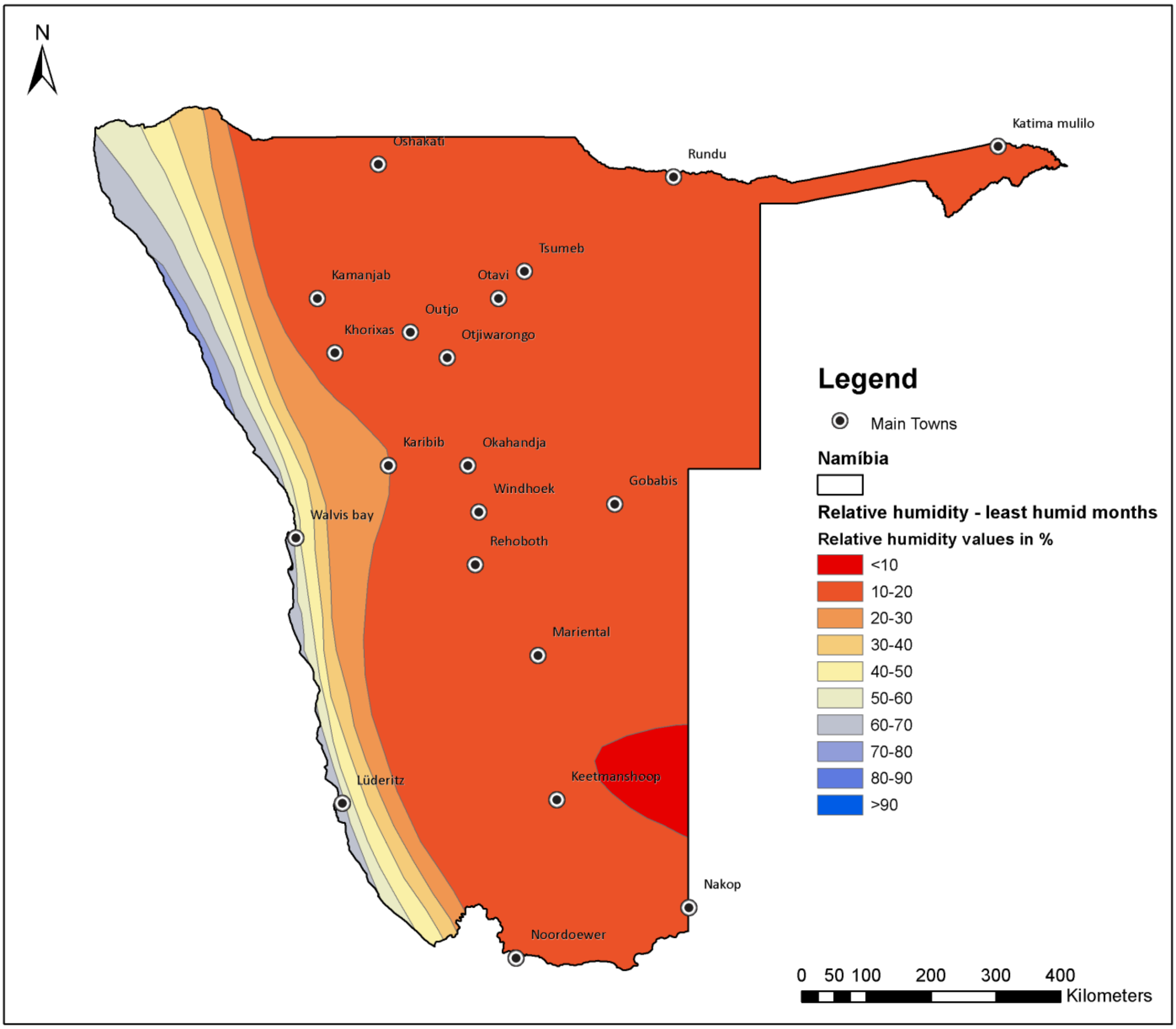

Figure 5.12 - Relative humidity (%) in least humid months.

5.2.2.5 Fog Mapping

The data concerning the approximate number of days of fog per year is based on one year of observations, namely, 1984, using satellite imagery (see source data). Then, fog is recorded when visibility on the ground is reduced to 1,000 m or less.

The polygons making up the shapefile were created from hand drawn contours on a hard copy map. Note that, this manual interpolation approach was done by Peter Hutchinson using the point data from all available stations, because the number of stations was small an automatic interpolation produced nonsense results. Hence, the map of the number of days with fog is presented in Figure 5.13.

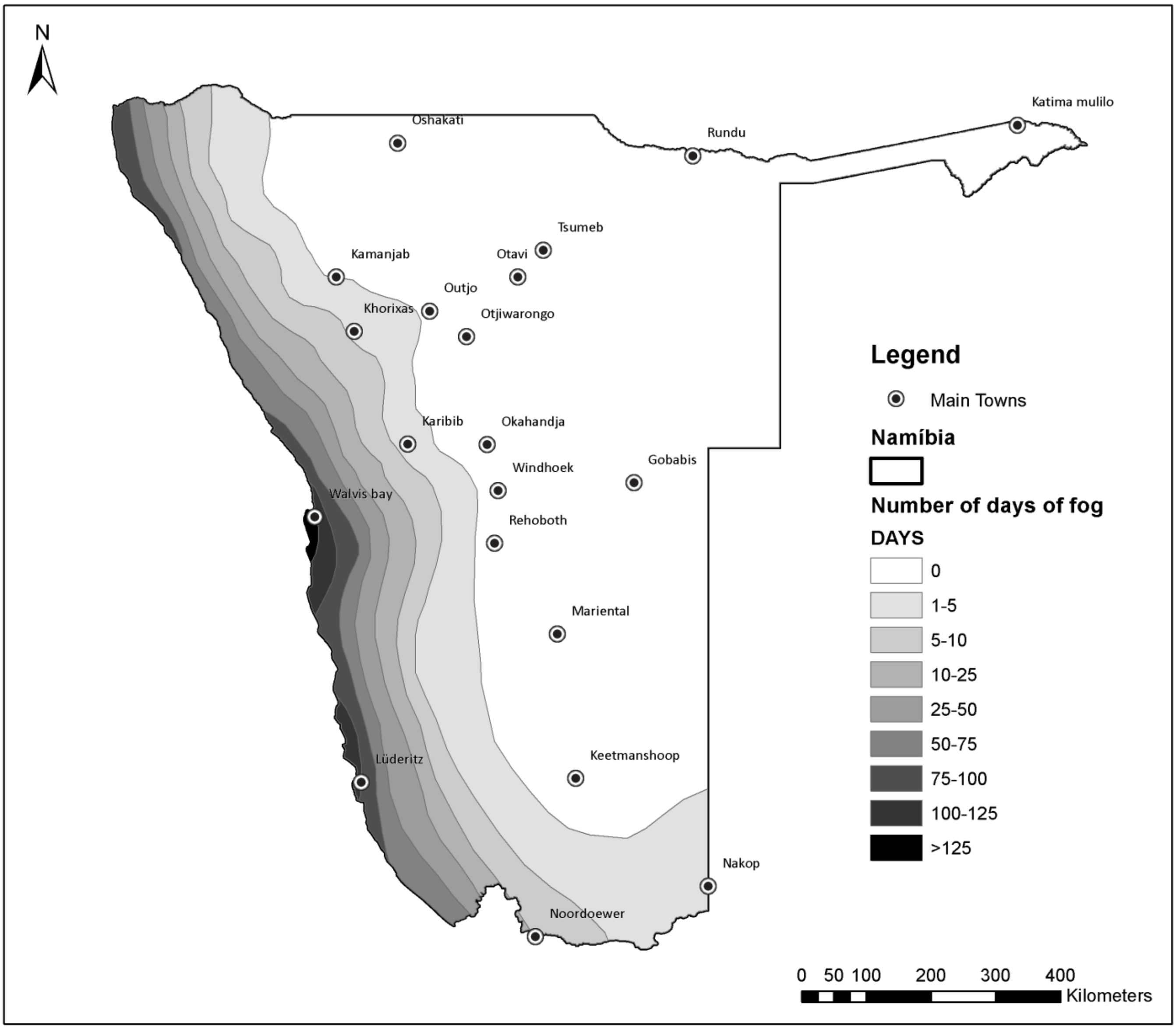

Figure 5.13 – Number of days of fog per year in Namibia.

5.2.3 Soil and Elevation Mapping

5.2.3.1 Geology and Soils

Concerning geology, the provided shapefile contains information about the geology of Namibia, its major rock formations and sequences. Note that, it was obtained from an original simplified digital map that was provided by the Geological Survey of Namibia and was amended to the country borders.

Moreover, Roger Swart (Namcor) and Roy Miller (Geological Survey of Namibia) advised on further simplification and naming of the complexes and groups, correct ages and structuring of the legend. Thus, the map is presented in Figure 5.14.

About the soils of Namibia, the obtained shapefile was compiled and adapted by Sophie Simmonds, from the following base maps:

1. National Soil Survey (phase 1) 1:1 000 000 scale, 1998-2000. Reference: ICC/MAWRD 2000; Project to Support the Agro-Ecological Zoning Program (AEZ) in Namibia. Cooperation Project between the Ministry of Agriculture, Water and Rural Development of Namibia, the Cartographic Institute of Catalonia and the Spanish Agency for International Cooperation, Main Report, 243pp. Annexes, 224 pp. 79 maps.

2. Soil Map of the Etosha National Park (Beugler-Bell, H. and Buch, M.W.; 1997). In Soils and Soil Erosion in the Etosha National Park, Northern Namibia; Madoqua 1997. 3) SWA/Namibia Geological Map 1:1 000 000. Geological Survey of the Republic of South Africa and South West Africa (1980).

As a result of this, the map is shown in Figure 5.15.

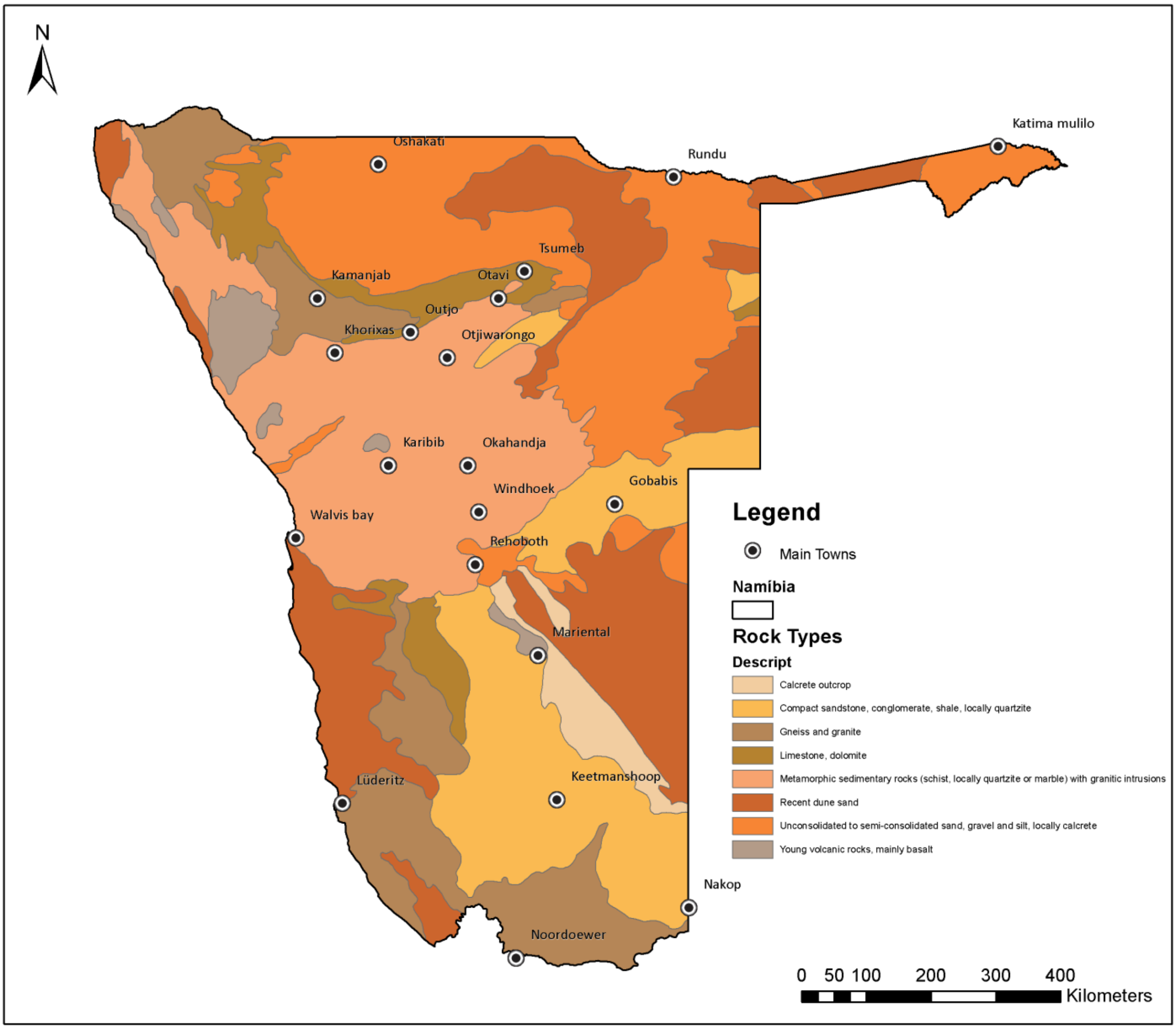

Figure 5.14 – Rock types in Namibia.

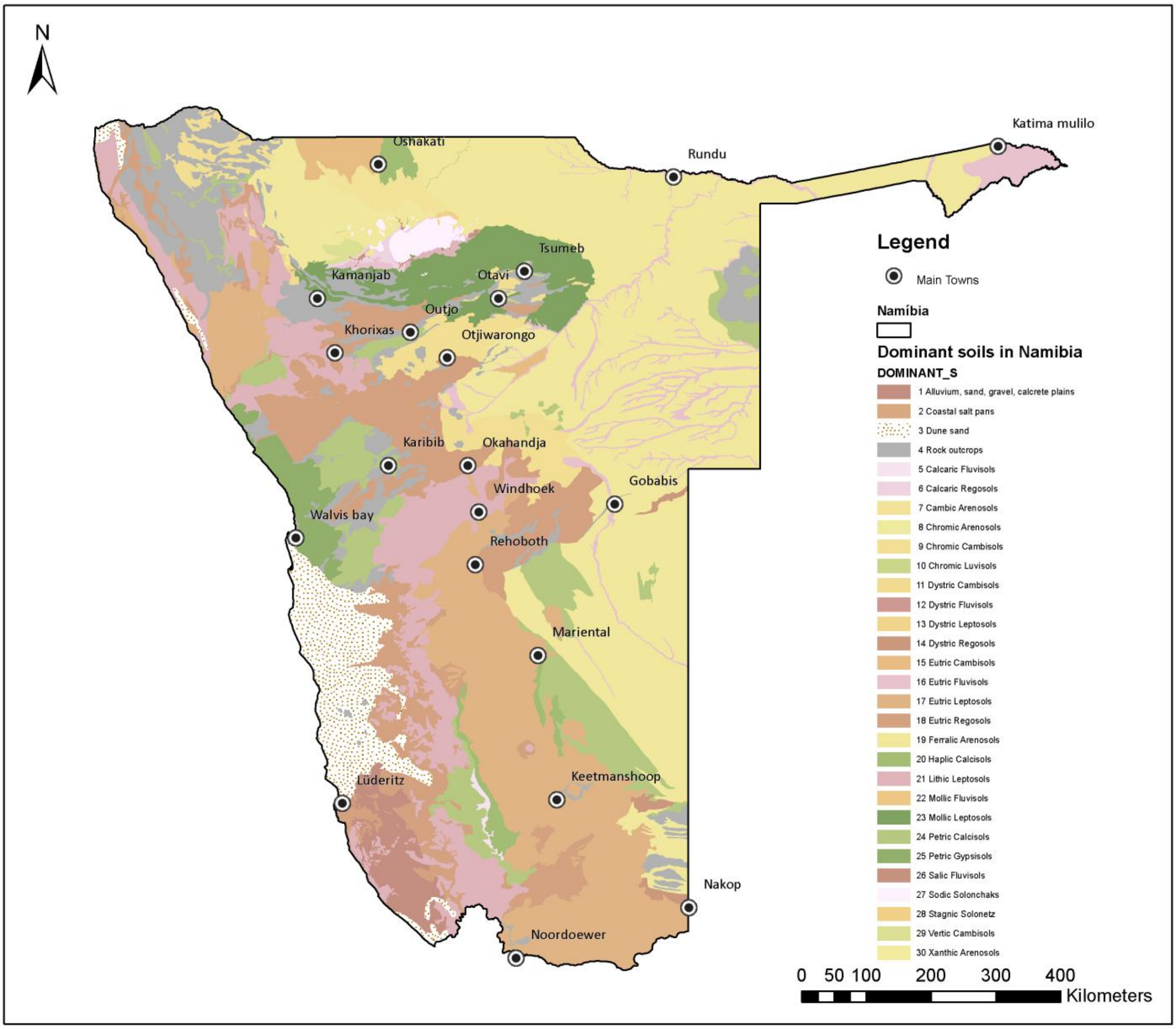

Figure 5.15 – Dominant Soils in Namibia.

5.2.3.2 Elevation Mapping

The elevation data was obtained from the SRTM Global Digital Elevation Model (South Central, one of six data sets), and represents an elevation map (between 60 degrees North and 56 degrees South latitude) of the world from the NASA/NGA Shuttle Radar Topography Mission (SRTM) data sets, from the U.S. Geological Survey's EROS Data Center.

In addition, the resolution is 3 arc seconds (90 meters) and the pixel value represents the elevation in meters.

In Figure 5.16, it is presented the SRTM elevation data set for Namibia's territory.

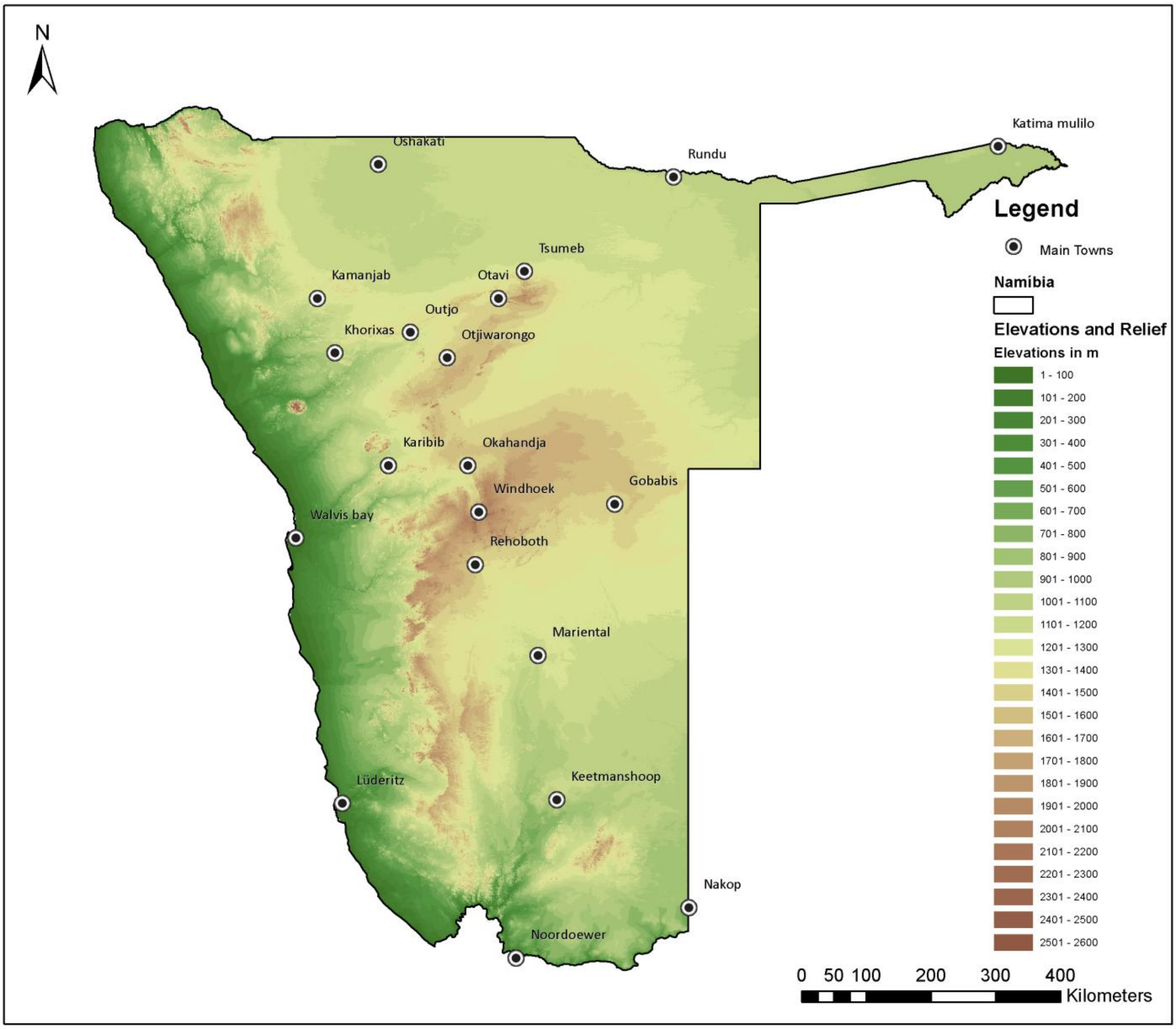

Figure 5.16 – Namibia's SRTM Global Digital Elevation Model.

5.2.4 Administration

5.2.4.1 Land Availability and Ownership

The information about land ownership was obtained through a shapefile of control over land, which was created from the following sources:

1. Private on freehold land was derived from the farms map provided by Marina Coetzee at Ministry of Agriculture, Water and Rural Development (this had ownership details up to date to 1998 from Deeds Office);

2. Central government land was derived from - farms map provided by Marina Coetzee at MAWRD (Note that for several hundred farms, no deed records were available. It was assumed therefore that this was by default government land). - Ministry of Lands, Resettlement and Rehabilitation (info on land purchases and donations) - assumed to be more reliable than MAWRD data - Land values database (compiled from several sources, including ministries and Deeds Office) - assumed to be less reliable than MAWRD data, therefore only used to fill in gaps - protected areas;

3. Local Authority land was derived from a local government map;

4. Traditional Authority land was derived from communal land shapefile; and

5. Private on communal land was derived from the North Central Profile (Mendelsohn, el Obeid & Roberts), the Kavango Profile (Mendelsohn in prep) and various informal communications.

Moreover, according to the following criteria, this information was merged into three categories:

Central government land and Traditional authority land → Central Government

Local Authority land → Local Authority land

Private on freehold land and Private on communal land → Private

Therefore, the resulting land ownership map is shown in Figure 5.17.

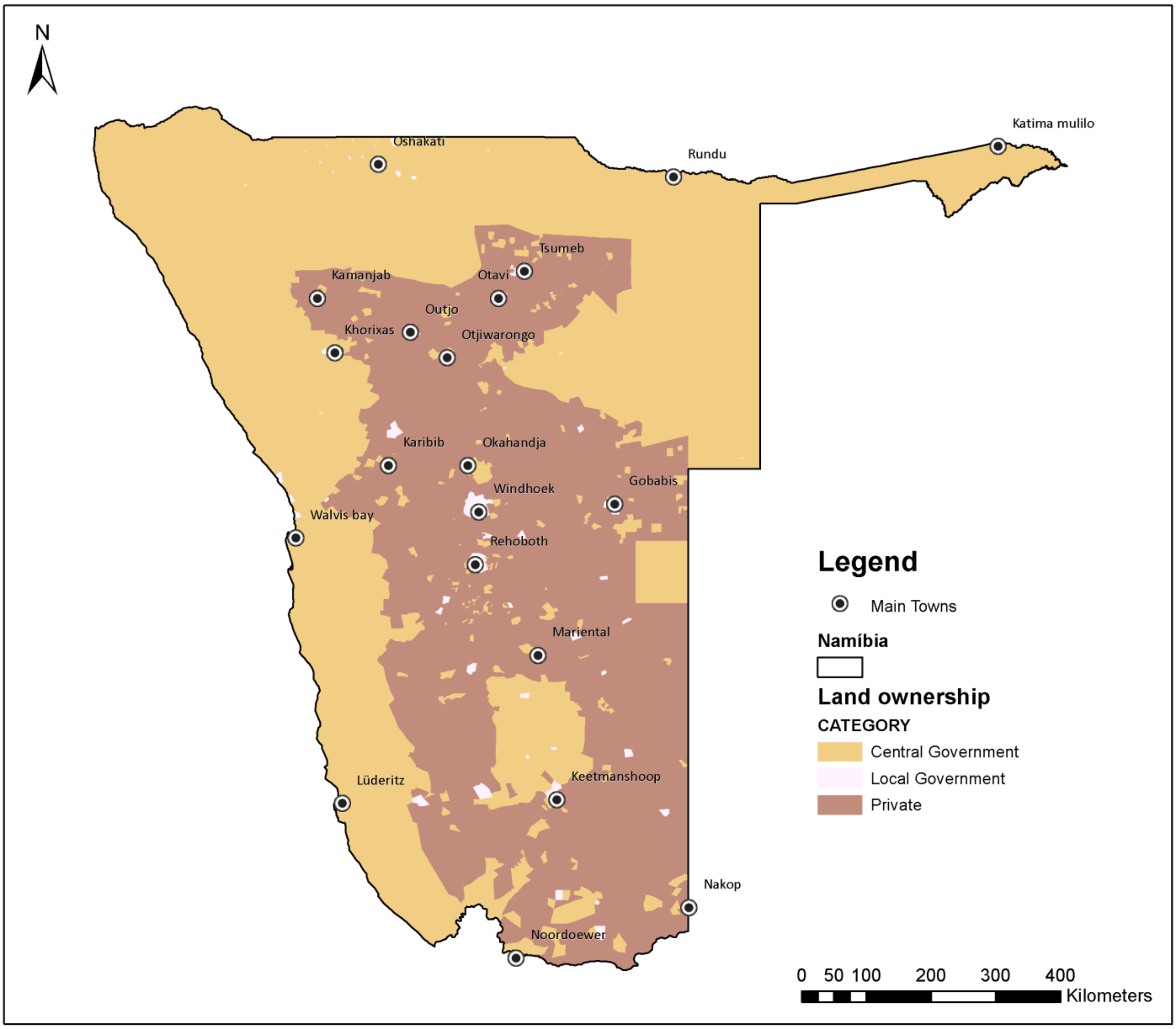

Figure 5.17 – Land Ownership.

5.2.4.2 Land Use

The land use shapefile was created from the following sources:

1. Agriculture and tourism on freehold land was derived from the farms map provided by Marina Coetzee at MAWRD (this had ownership details up to date to 1998 from Deeds Office);
2. Government agriculture, other government/parastatal and resettlement were derived from:

   - farms map provided by Marina Coetzee at MAWRD (Note that for several hundred farms, no deed records were available. It was assumed therefore that this was by default government land);

- Ministry of Lands, Resettlement and Rehabilitation (info on land purchases and donations) - assumed to be more reliable than MAWRD data; and
- Land values database (compiled from several sources, including ministries and Deeds Office) - assumed to be less reliable than MAWRD data, therefore only used to fill in gaps.

3. State protected was derived from: protected areas ;
4. Urban was derived from the townlands shapefile;
5. Large scale agriculture on communal land was derived from the North Central Profile (Mendelsohn, el Obeid & Roberts), the Kavango Profile (Mendelsohn in prep) and various informal communications; and
6. Small scale agriculture on communal land was derived from the communal land shapefile.

The resulting map is presented in Figure 5.18.

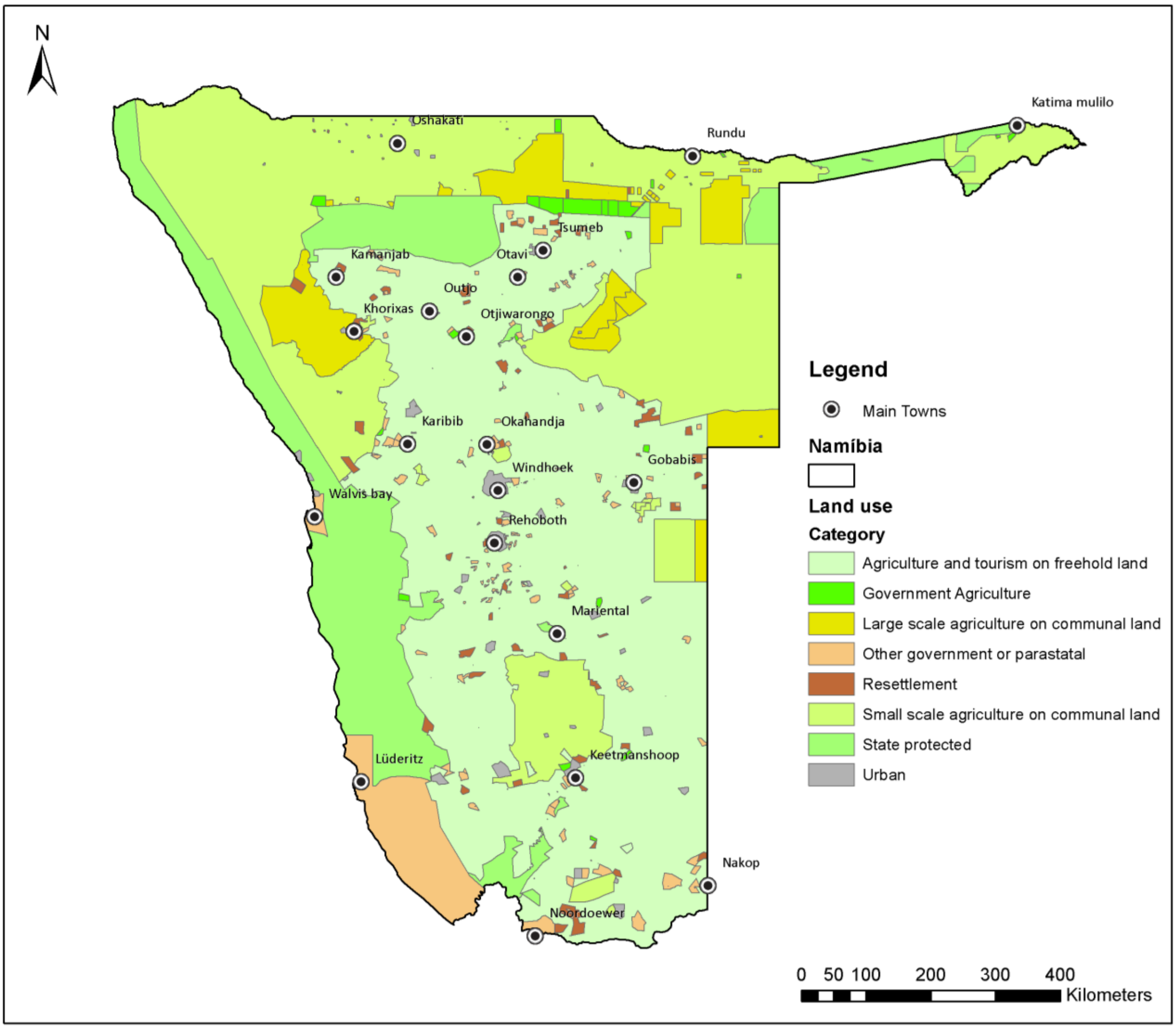

Figure 5.18 - Land use of Namibia.

5.2.4.3 Administrative Boundaries

There are two layers about administrative boundaries: one, representing the country boundaries and, another, regional government areas. The regional government areas shapefile was derived directly from the constituencies' shapefile by merging appropriate polygons. Note that, the government gazette, defining regions, was used as a guide in this process, and the source of this information was the Atlas of Namibia. As a result, the map can be seen in Figure 5.19.

Further, the map of Namibia borders was obtained by merging into a single polygon all of the regional government areas, resulting in the map in Figure 5.20, where it was also added the layer with the Main Towns (missing Metadata).

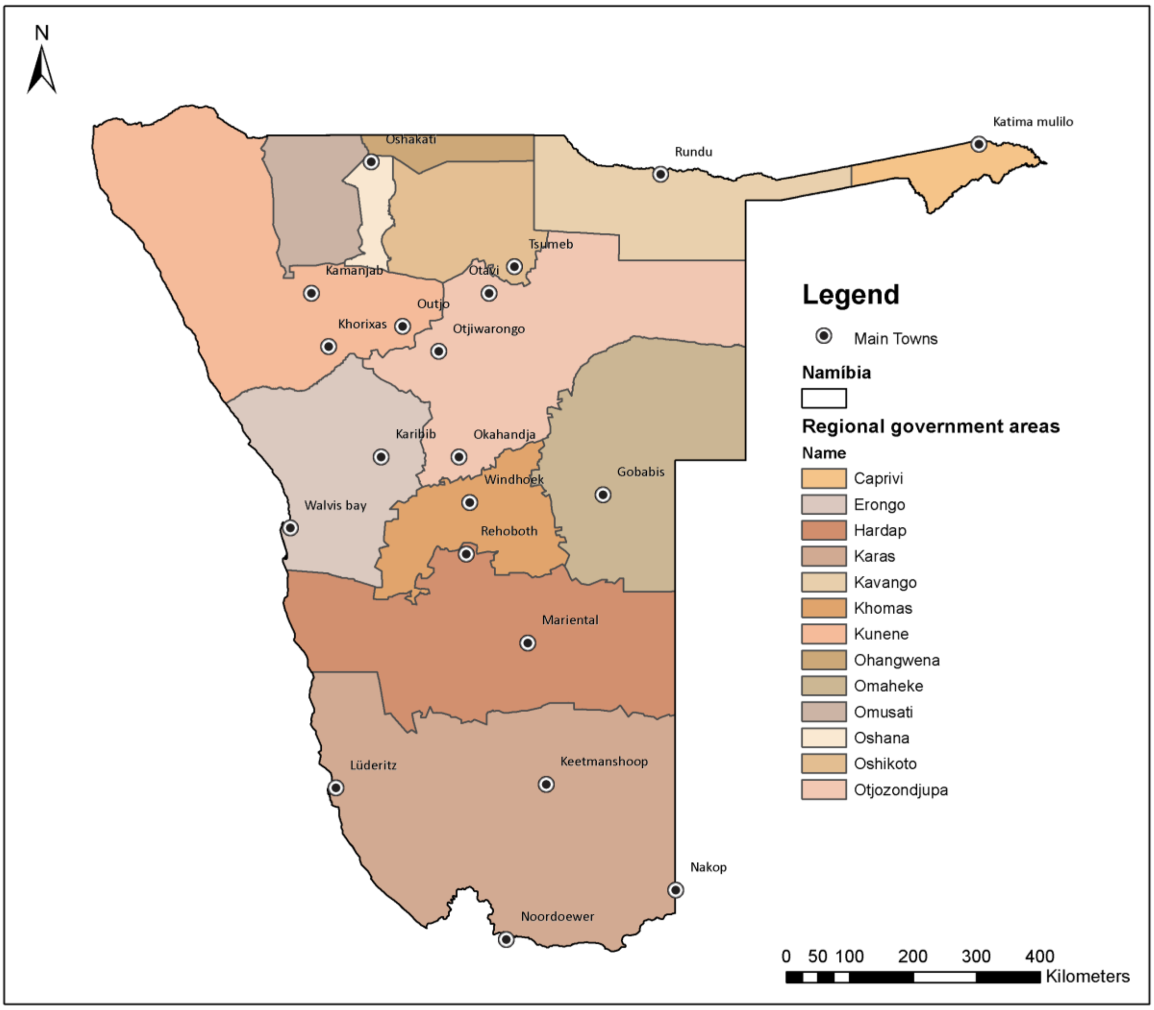

Figure 5.19 – Regional Government areas.

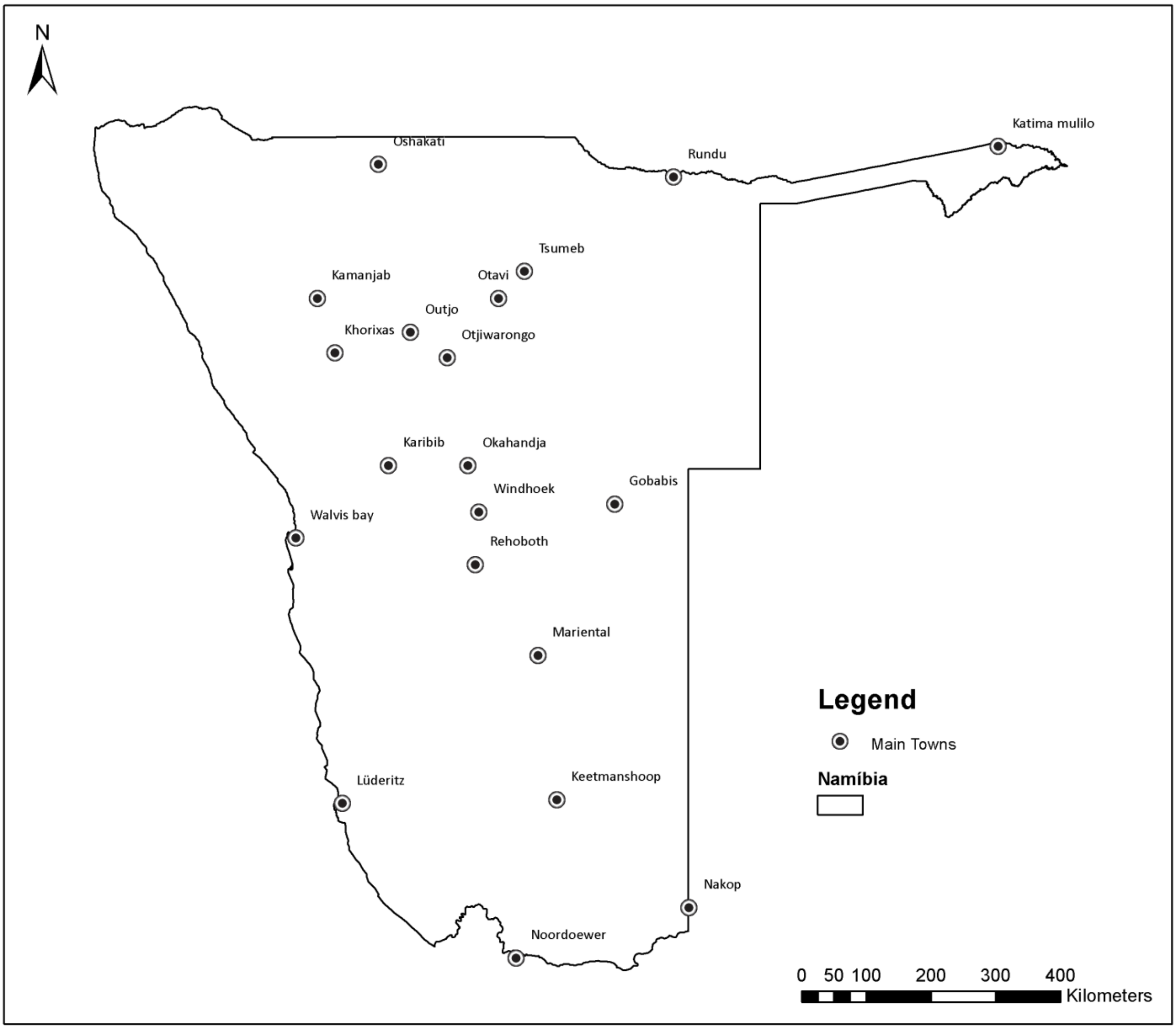

Figure 5.20 – Namibia borders.

5.2.5 Powerlines and Major Sub-stations Mapping

The shapefiles of Namibia grid were developed by NamPower and last updated in 2010. In Figure 5.21, it is shown the map of the grid network and, in Figure 5.22, the map of substations.

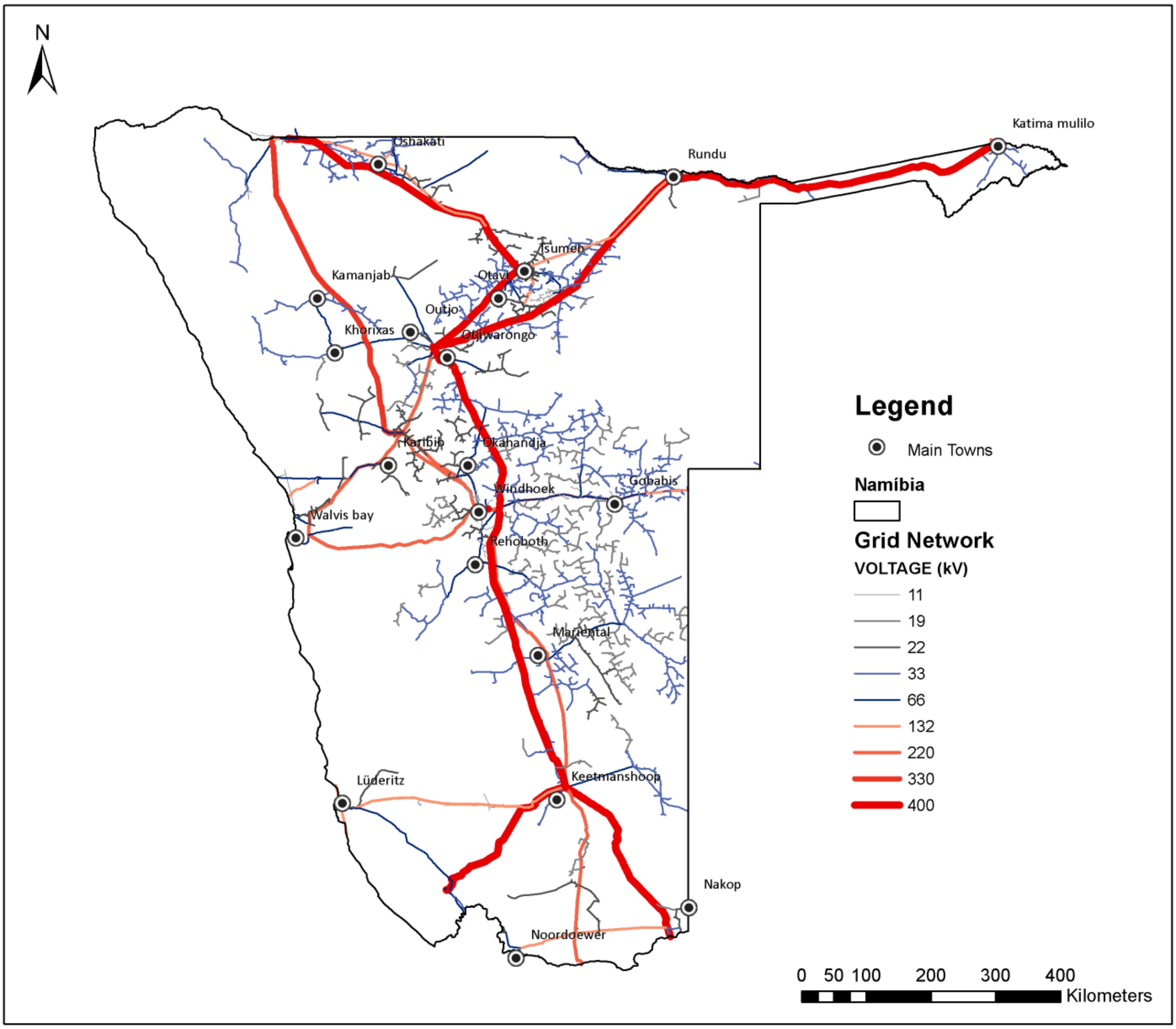

Figure 5.21 – Namibia Power lines.

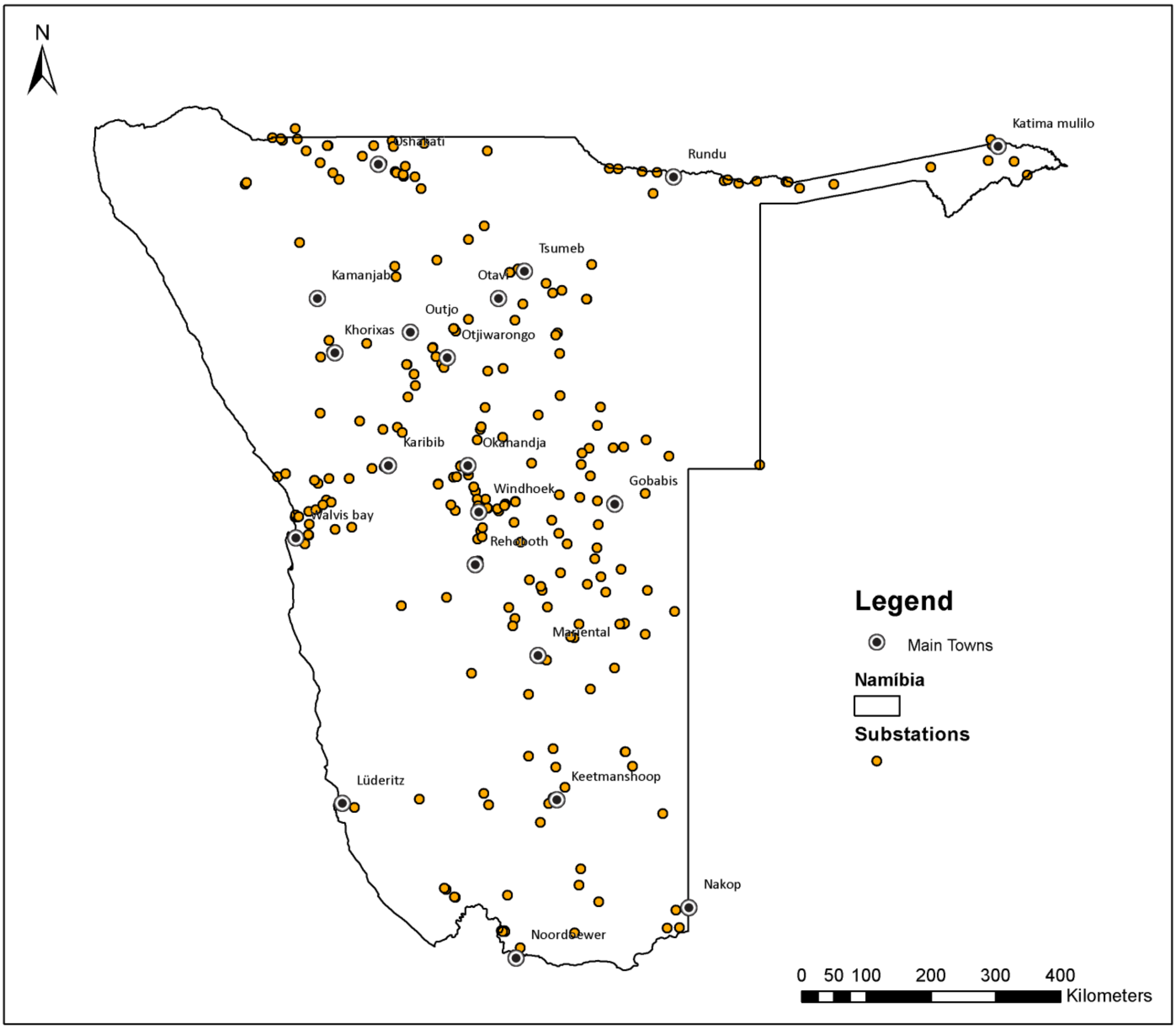

Figure 5.22 – Namibia substations.

5.2.6 Groundwater Resources Mapping

The shapefile of the groundwater basins was obtained from the HYMNAM project and amended to fit the country borders. In Figure 5.23, there is a map with the groundwater basins. Note that, metadata is missing for these layers.

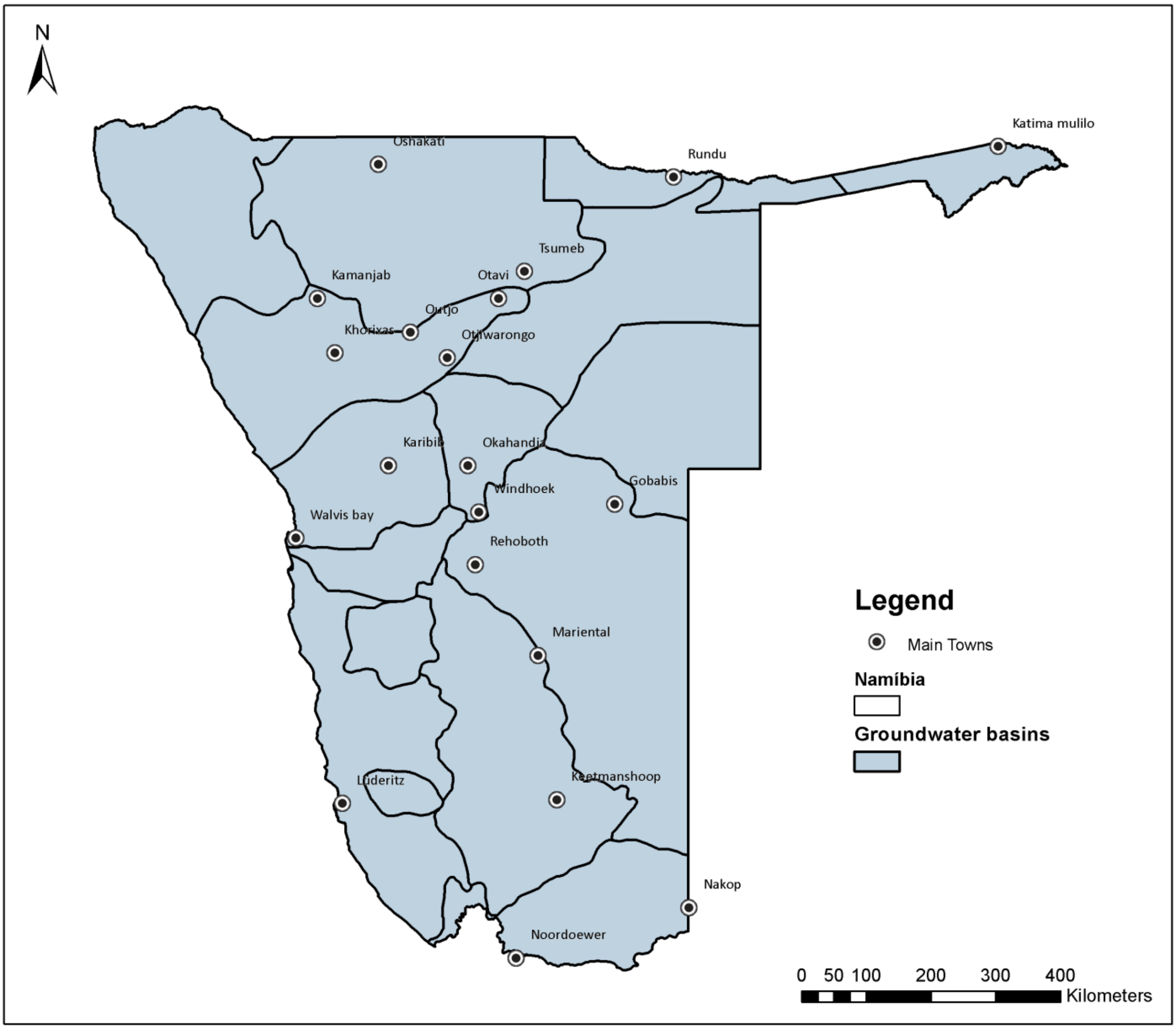

Figure 5.23 – Groundwater basins.

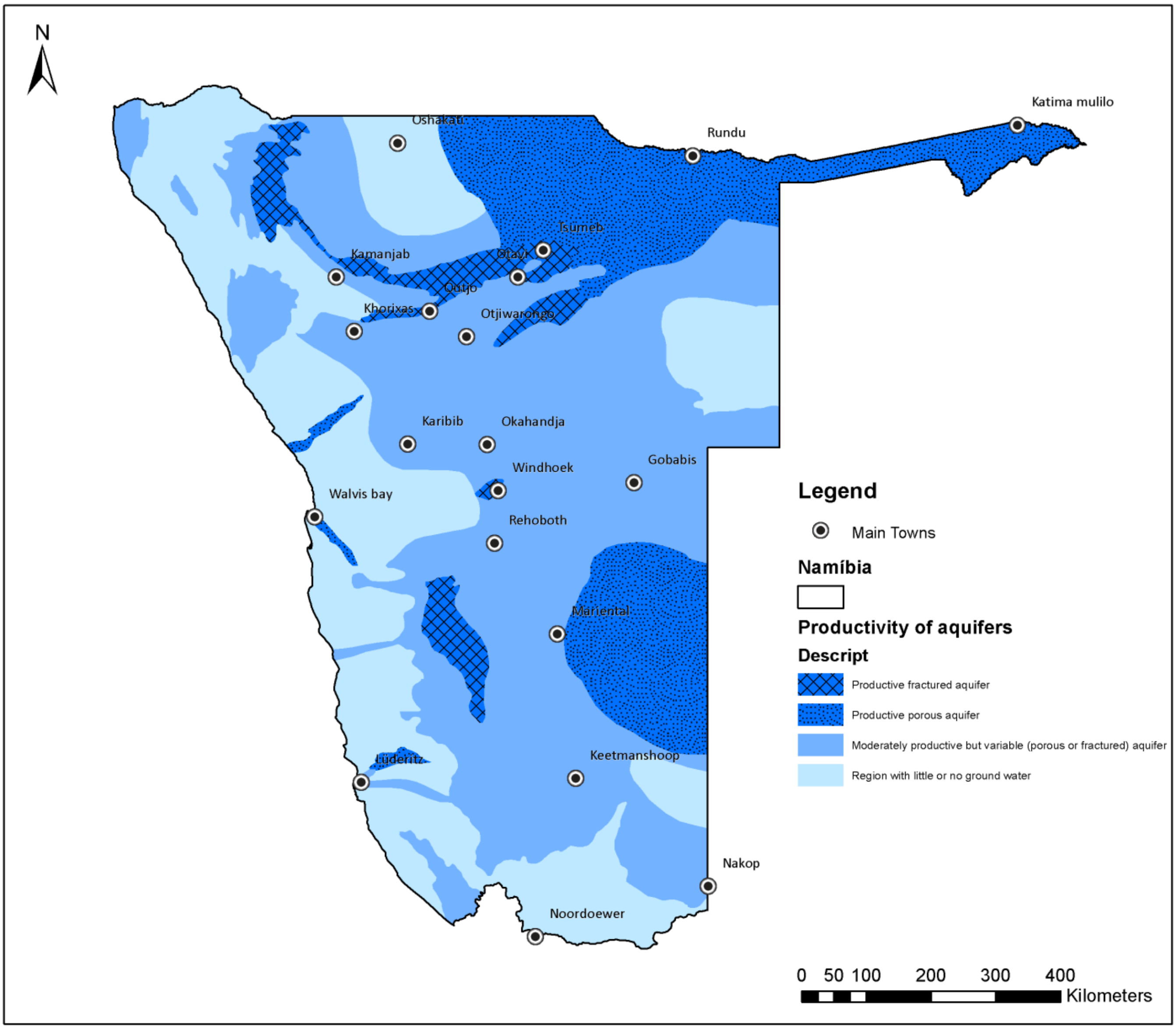

Figure 5.24 - Productivity of aquifers in Namibia.

Furthermore, the aquifers suitable for desalination were mapped and indicated by NamWater (Figure 5.25), taking into consideration the aquifers with brackish water, without other ends, due to the scarcity of water resources in the country.

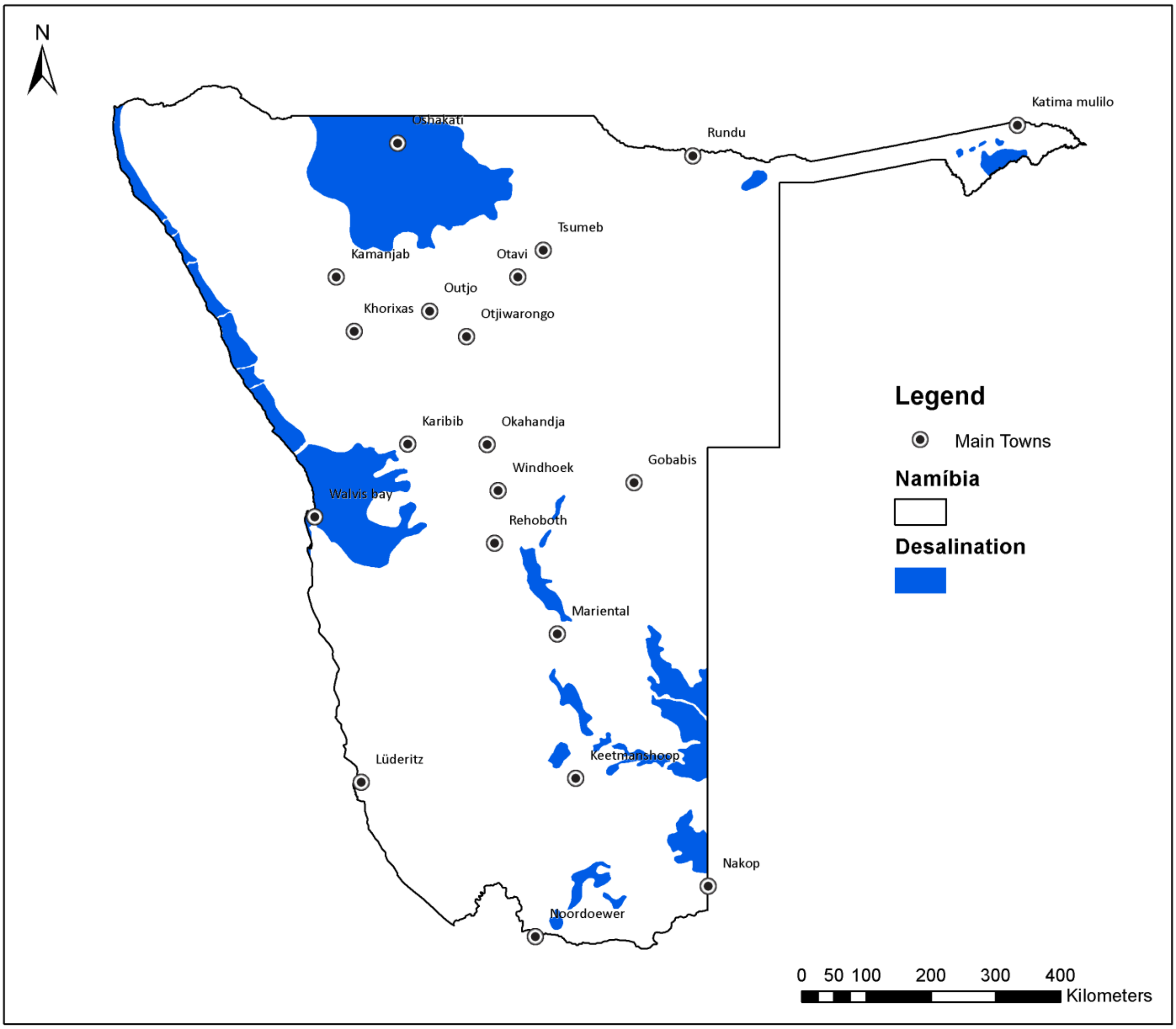

Figure 5.25 – Brackish water aquifers.

5.2.7 Major Dams and Hydrology Mapping

The shapefile of the storage dams in Namibia was obtained from the Atlas of Namibia and contains information about the reservoir capacity in Mm^3. In Figure 5.26, it is presented a map of the storage dams with a graphic scale of reservoir capacity. Note that, metadata was missing for this layer file.

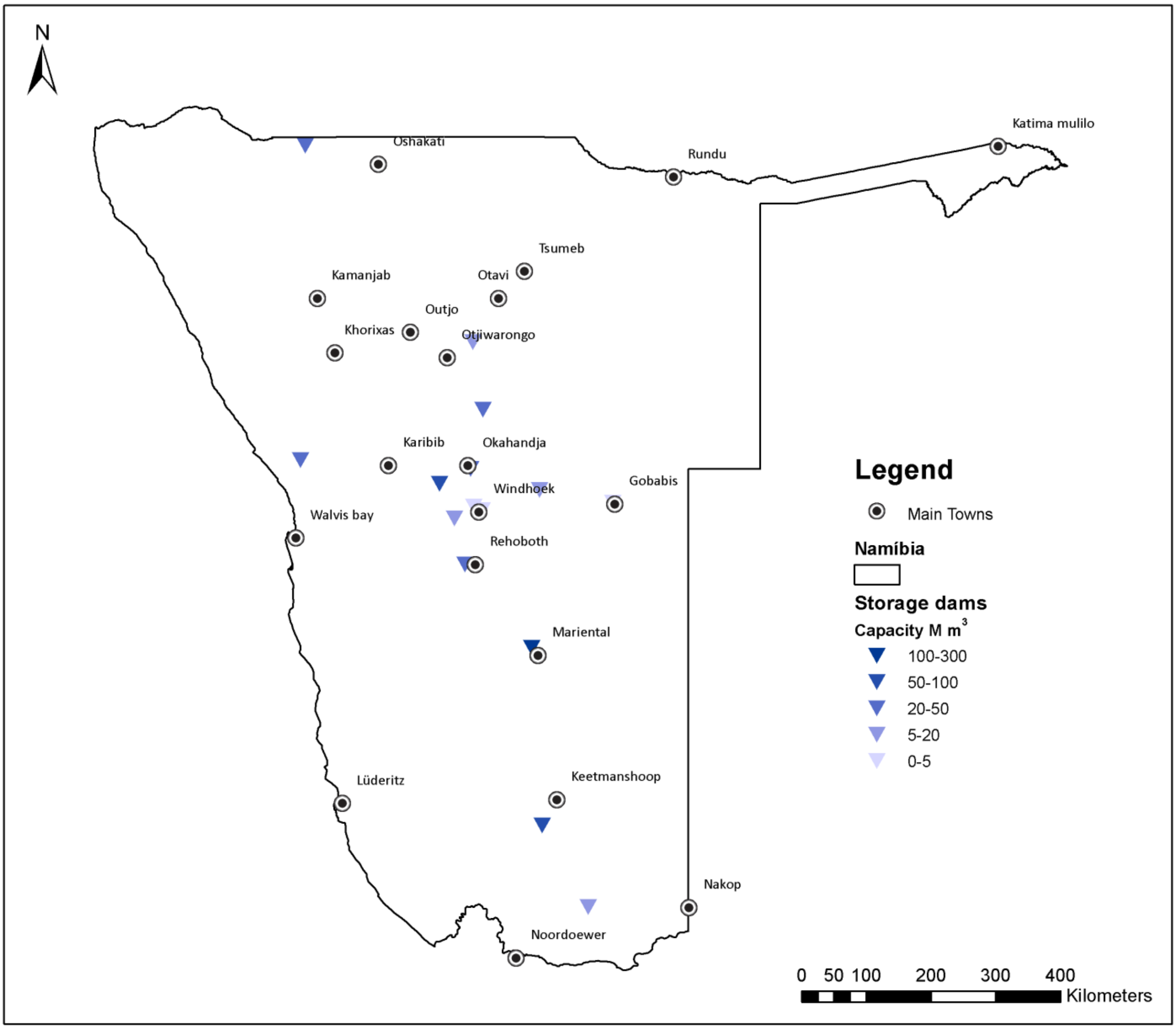

Figure 5.26 – Storage Dams.

5.2.8 Demographic Data

The shapefile of density population of Namibia refers to the population in 2000 and was from a grid smoothed to a 10 km resolution. Consequently, a map of population density is presented in Figure 5.27.

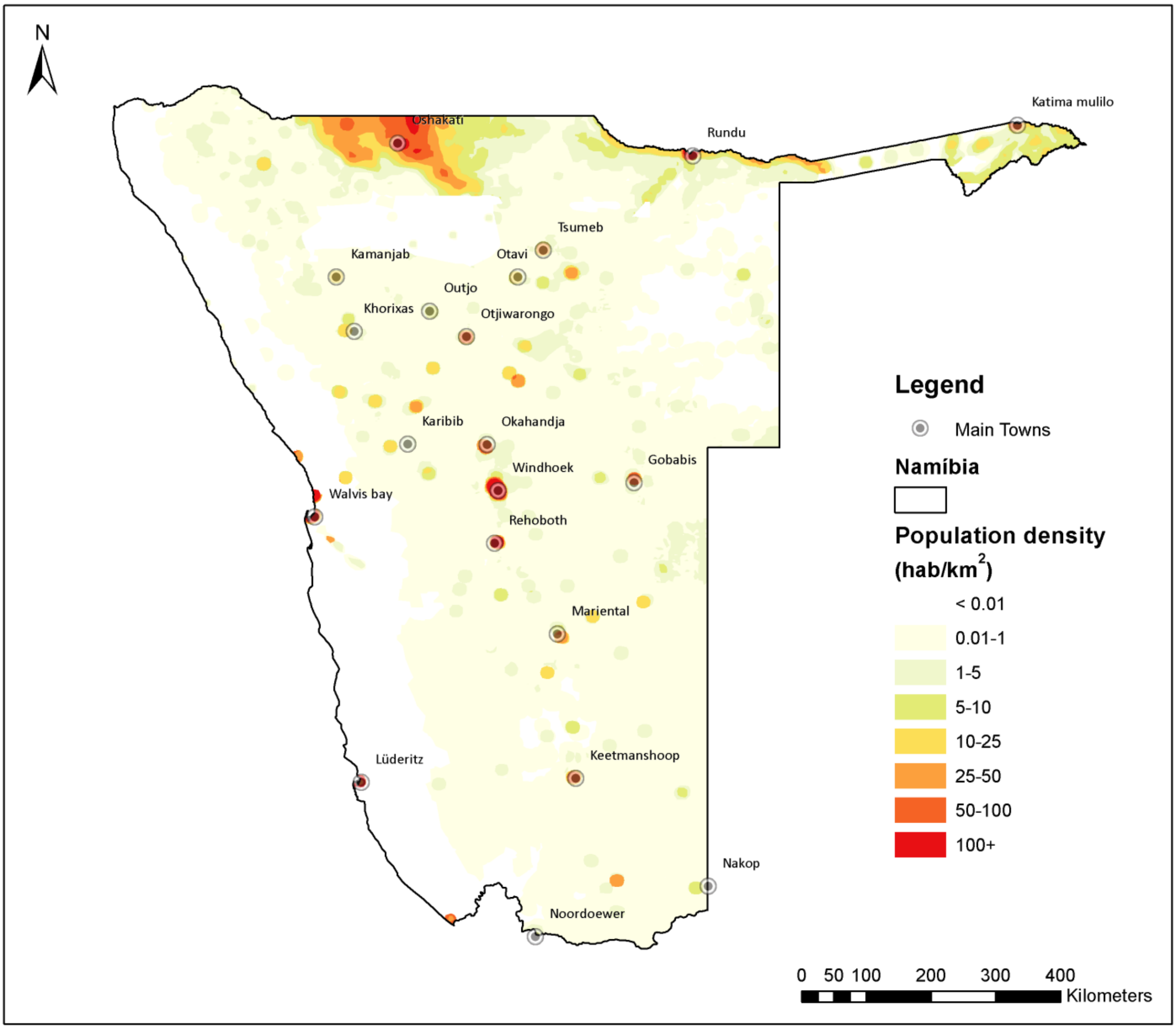

Figure 5.27 – Population density in Namibia.

5.2.9 Road & Rail Infrastructure

The roads shapefile was provided by CSA. Metadata is missing, but when superimposed to the Google Earth, the shapefile was accurate in the sites chosen randomly.

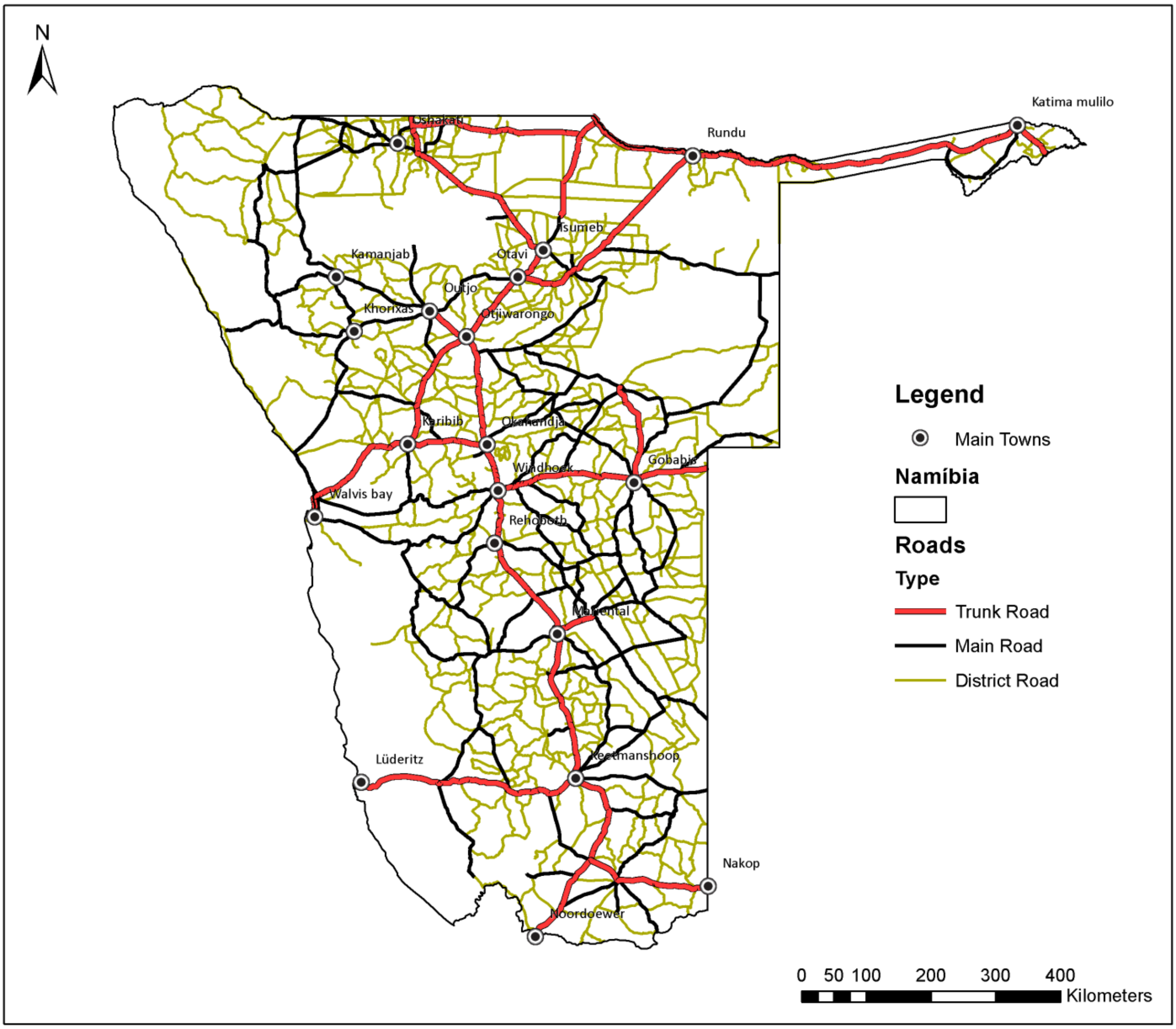

Figure 5.28 – Namibia's Roads

The shapefile of Namibia railways was digitized by John Mendelsohn from a large range of maps of different scales and origins, and obtained from the Atlas of Namibia.

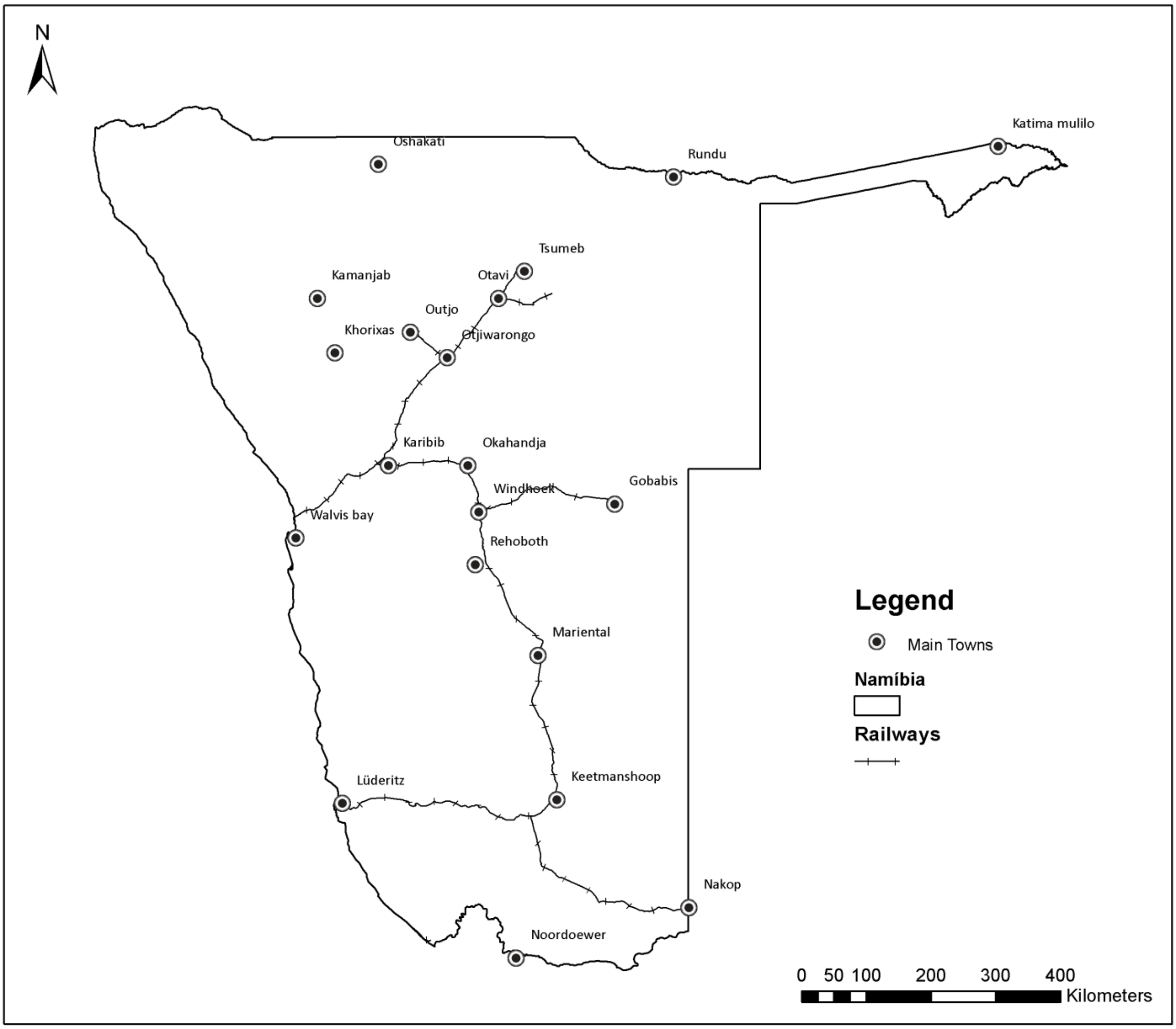

Figure 5.29 – Namibia's Railways.

5.2.10 Conservation Areas and Parks

Namibia's system of protected/conservation priority areas, with numerous types of ownership and management, and the ecological connectivity within this system, is one of the most impressive examples in the world.

With the recent declaration of Dorob National Park in 2010, Namibia became the first and only country in the world to have its entire coastline under protection via a network of four National Parks. Currently, the 1,500km long coastline contributes to an impressive protected area network, totalling about 42% of

Namibia's total land mass, not to mention a newly declared Marine Protected Area (MPA), accounting for an additional 12,000 km^2.

Furthermore, through a determined and conscious effort to address development issues through nature conservation, Namibia is a world leader in conservation, and this human/social aspect is as important as it is the protection of ecosystem services.

Thus, the country has emphasized the need for policies that support and maintain ecosystems, ecosystem processes, and biodiversity within their own constitution, and also recognizes the important connection between conservation and the livelihood of its citizens. In addition, their vision, as stated in the fourth National Report on the Convention on Biological Diversity, is to create a protected area network under different ownership and uses through collaborative and international management.

Although 42% of Namibia's total land mass is under some form of protection, the type of protection is varied. While 17% of the protected area network is under state protection, an additional 18% are registered communal conservancies.

Communal conservancies are areas of land in which the local communities are given the legal rights to manage, use, and benefit from the wildlife within the area. One of the most economically profitable activities conducted in communal conservancies are tourism activities. Because conservancies allow communities to benefit from the wildlife, they not only create an incentive to promote conservation, they also bridge an important gap between conservation and poverty alleviation.

Currently, there are 71 registered communal conservancies with 30 additional areas in development. Out of these 71 conservancies, 42 of them are adjacently connected to other protected areas, creating large protected networks and wildlife corridors. Freehold conservancies and private game reserves make up an additional 6.1% of Namibia's total protected area. Community Forests, along with tourism concessions, make up the remaining 1.3% of the protected area network.

Community forests are a relatively new development but follow the same basic principles of community based natural resource management (CBNRM) that conservancies do. Community forests are meant to benefit the local community by providing them the opportunity to develop a forest management plan in which specific extraction and use quotas are determined. The income generated from the use of resources within the area is meant to benefit the community directly.

While both conservancies and community forests play incredibly important roles in Namibia's conservation goals, monitoring and effective implementation of authority and responsibility are two of the key issues in assuring the goals of the areas are met.

Hence, in a pioneering move, Namibia has protected its entire coastline, including a 12,000 km2 Marine Protected Area (MPA), named The Namibian Islands Marine Protected Area. The MPA is IUCN category VI, meaning the area is managed for long-term protection while meeting community needs through sustainable resource management. In order to create a more effective protected network, the declaration of The Namibian Islands Marine Protected Area was monumental in crossing terrestrial boundaries.

Additionally, Namibia has not only crossed terrestrial boundaries but has made international partnerships to create vast expanses of protected areas. The Namibian coastline meets Richetevsueld National Park in South Africa and Iona National Park in Angola. Namibia and South Africa have also partnered in creating a Transfrontier Park named /Ai-/Ais-Richtersveld.

Therefore, through a vision of internal and internationally collaborative management, Namibia has created a dynamic, successful network of protected areas and corridors. As the most arid country south of the Sahara, Namibia boasts high endemism and biodiversity hotspots, such as, the Succulent Karoo (90% protected) and The Great Western Escarpment (92.5% protected). Namibia is also home to the largest cheetah population, the largest and only free-roaming desert black rhino population, and threatened populations of both black-faced impala and hartmann’s zebra. In addition, it is also the only country in Africa with an expanding, free roaming, population of both lion and giraffe. All of these species have increased populations within the past two decades.

However, there are still obstacles, of course, such as: human population growth, human-wildlife conflict; increases in consumption/production; invasive species; poverty and unemployment; increased uranium and offshore diamond mining; and climate change impacts.

All in all, albeit the existence of a daunting future and current challenges, Namibia continues to place conservation and sustainable development at the top of its priorities.

In the upcoming chapters, a brief description of the main protected areas in Namibia and the potential constrains for CSP projects, due to the different types of land protection and environmental management identified, will be presented.

For last, in Figure 5.30, the conservation areas and parks are presented.

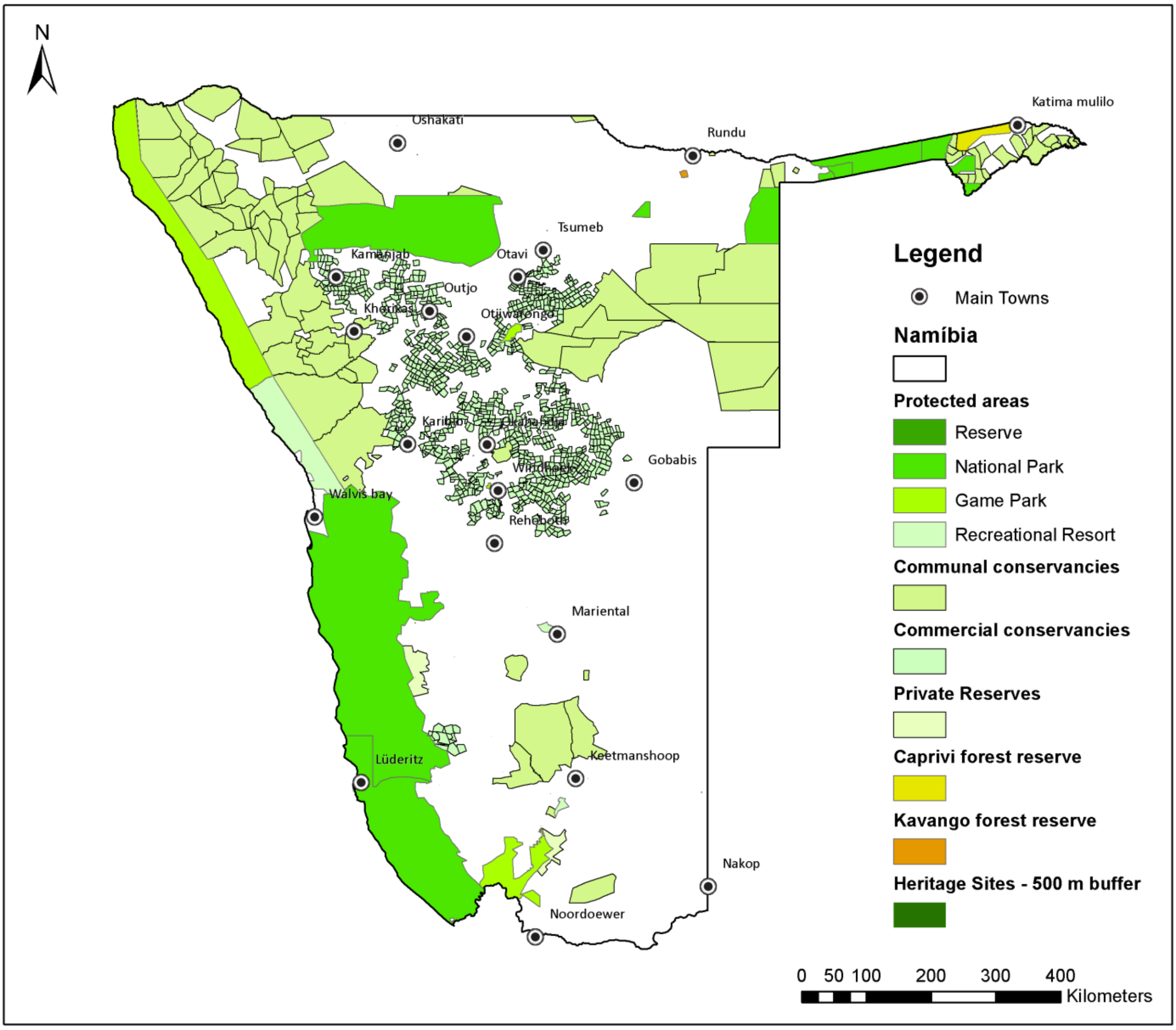

Figure 5.30 – Conservation areas and parks

5.2.11 Mines and Concessions

A set of mines was selected as potential destiny of CSP power output. The main driver in the selection was the power consumption. The selected mines are presented in Figure 5.31.

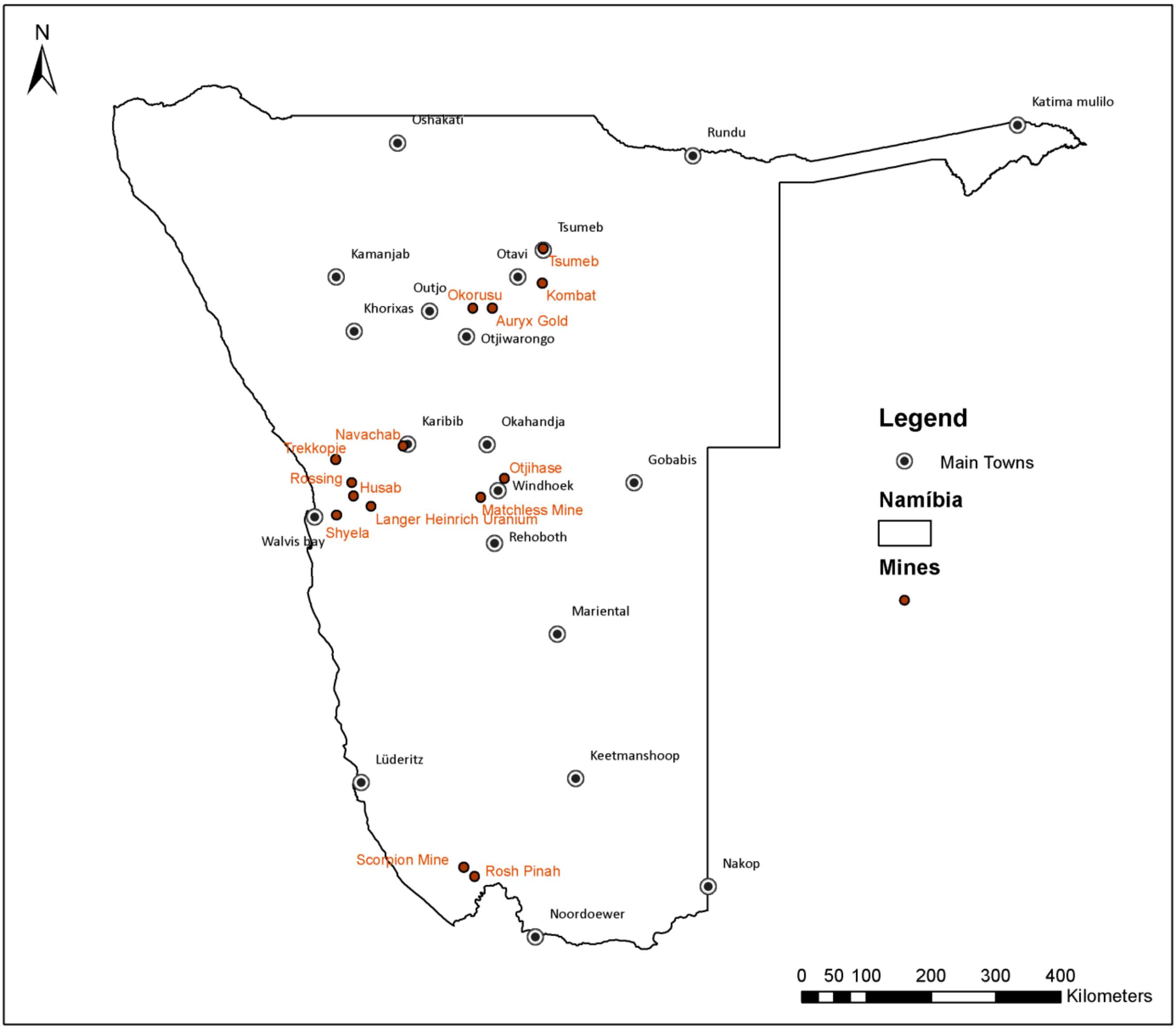

Figure 5.31 – Major mines in Namibia.

5.2.12 Potential Sources of Hybridization and Augmentation

Augmentation is possible in coal fired power plants. Currently, Namibia has one coal power plant in operation (Van Eck) and a project for a new power plant, with 3 project alternatives, according to [**2**].

In Figure 5.32, it can be seen the location and potential location of coal fired power plants.

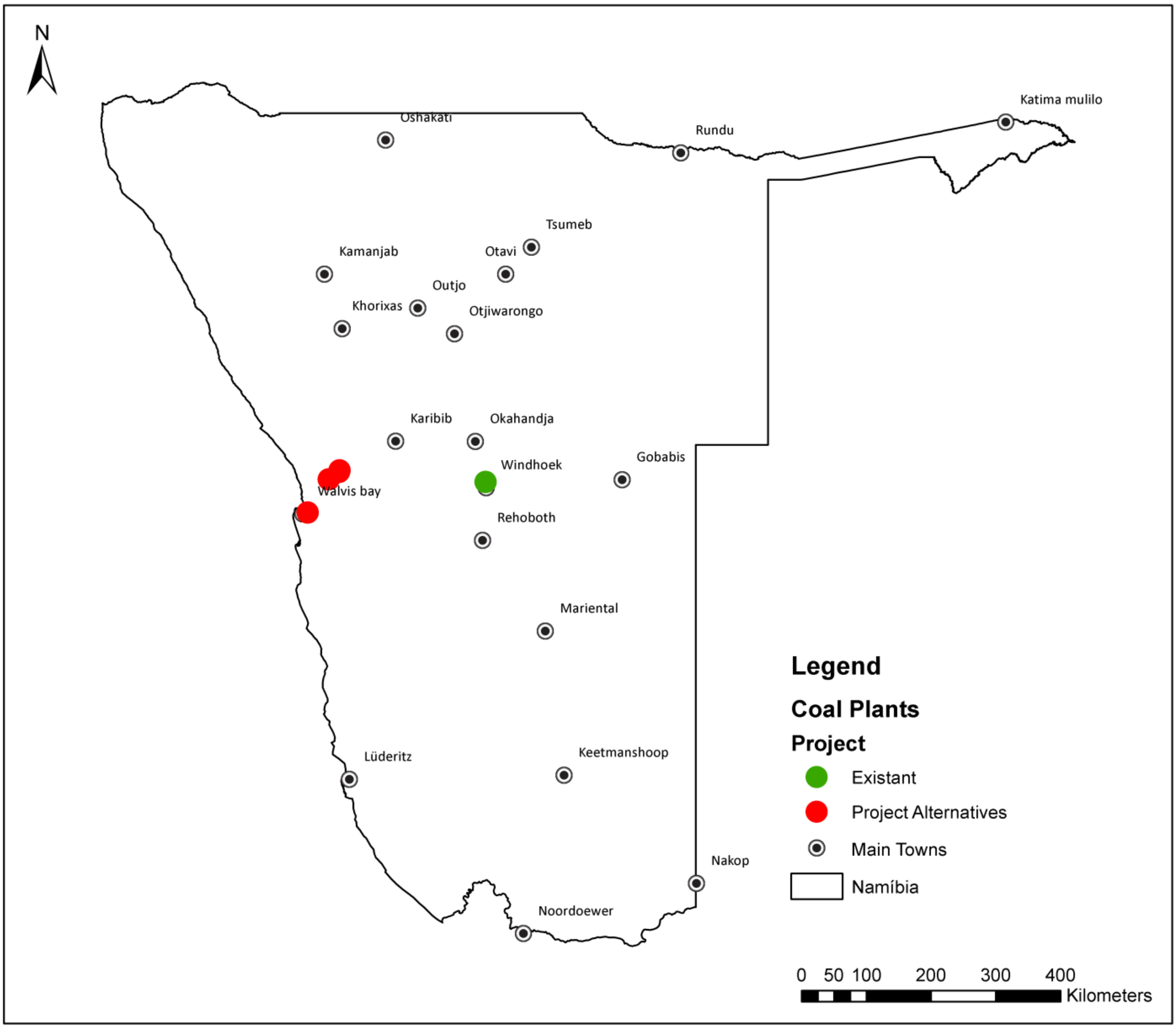

Figure 5.32 – Location of coal power plants (operating and project alternatives).

Moreover, hybridization may be coupled to thermal generation from gas and biomass. However, there is no operational power plant of these kinds in Namibia.

Nevertheless, a gas power plant is planned in Kudu, from the information available in [**3**]. Thus, Figure 5.33 shows the possible locations of the gas fired power plants.

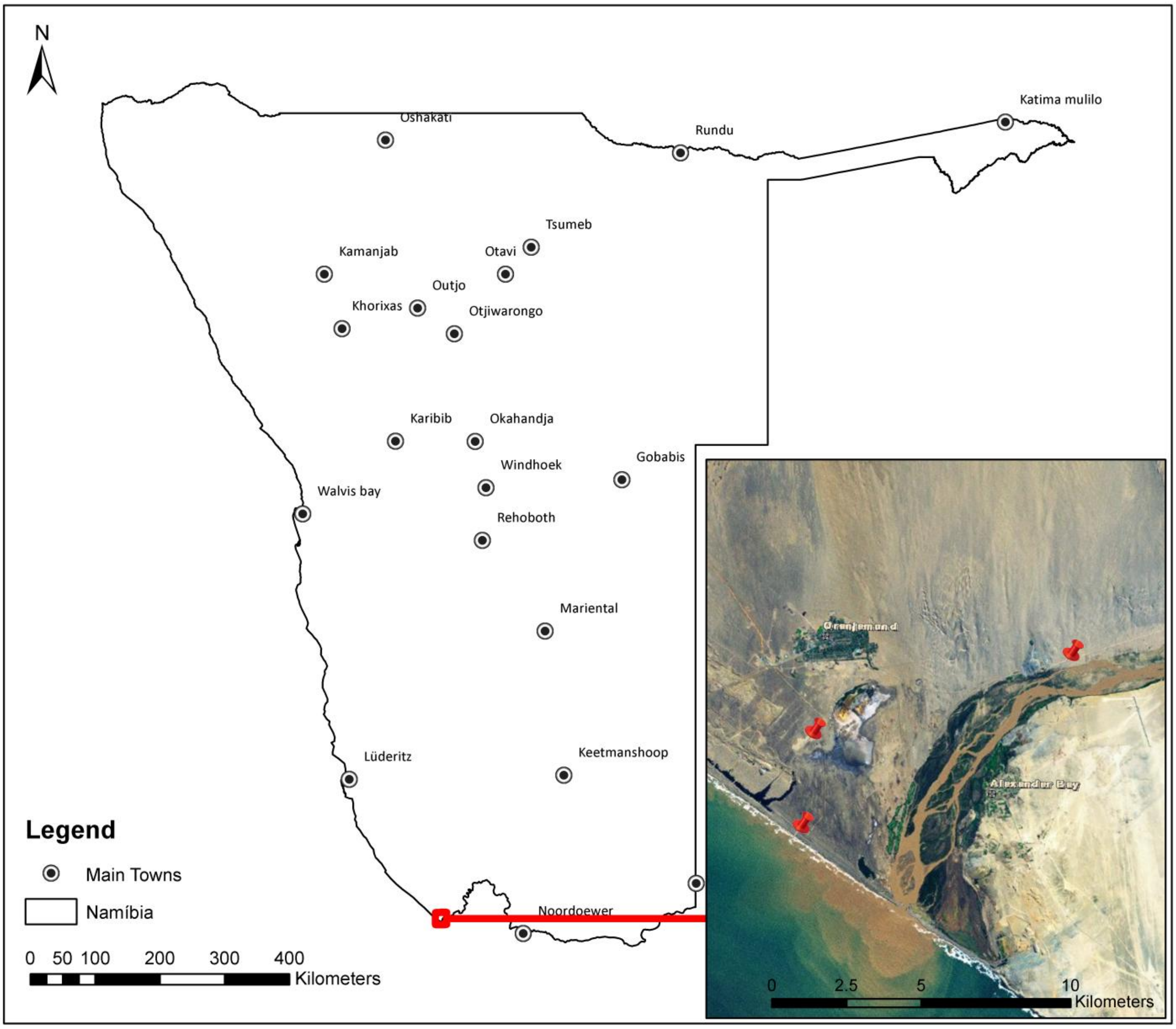

Figure 5.33 – Possible location of gas power plants.

The areas with most biomass potential are presented in Figure 5.34. Note that, this map was reproduced from [**4**]. In the study, it was considered, as areas suitable for a project, the biomass units with more than 20 ton/ha of sustainable bush harvest.

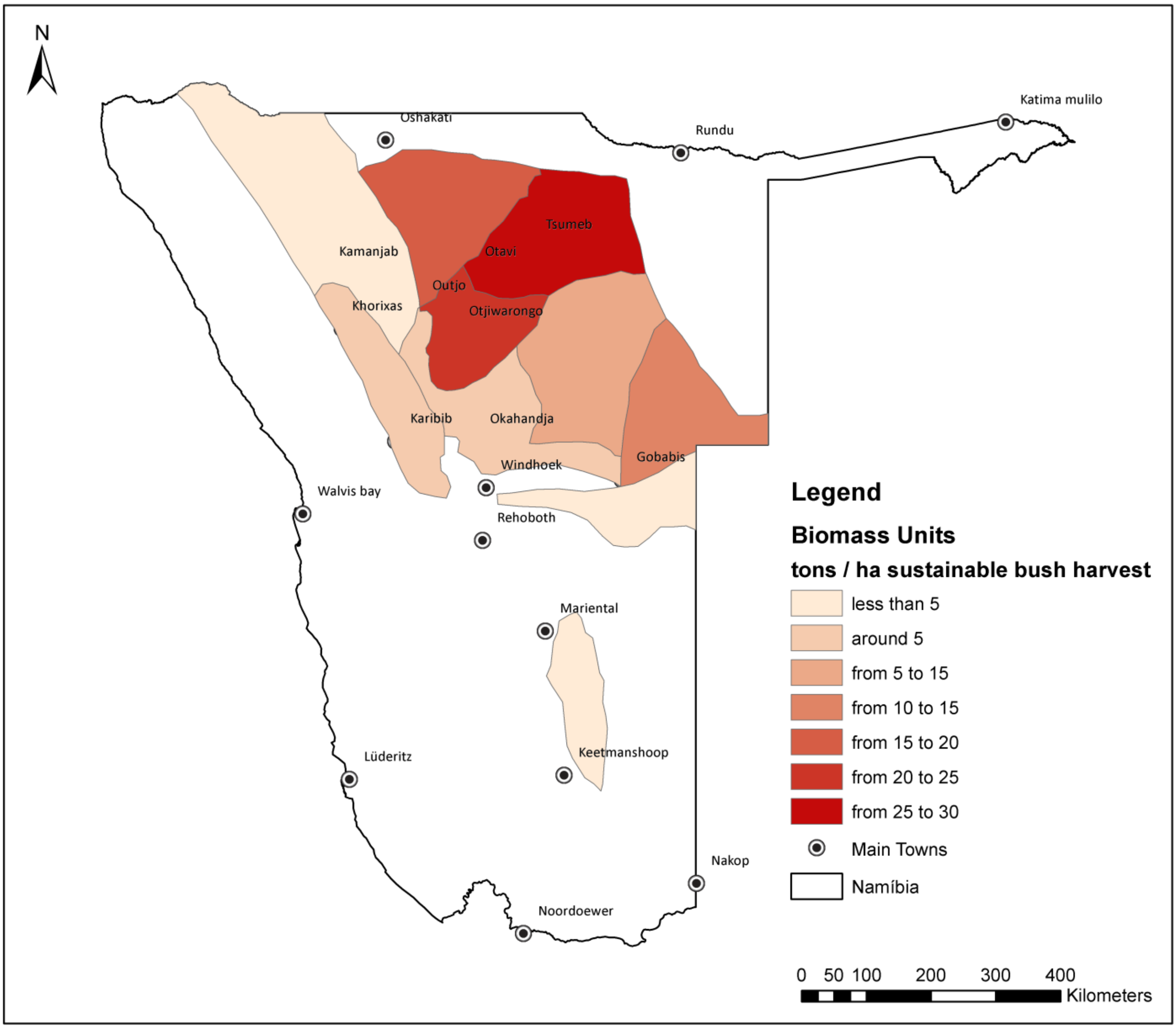

Figure 5.34 – Biomass units with greatest sustainable bush harvest in Namibia.

5.3 Country Wide CSP Potential Scoring and Site Prioritization

5.3.1 Analysis Inputs

5.3.1.1 Resource

Solar resource availability is the key for CSP development, being mandatory DNI greater than 2000 kWh/m^2/year. Thus, considering in this first approach a margin of 20% for uncertainties, a lower cap of 2400 kWh/m²/year was established. In Figure 5.35, the areas not suitable for CSP in terms of DNI were removed from the initial mapping.

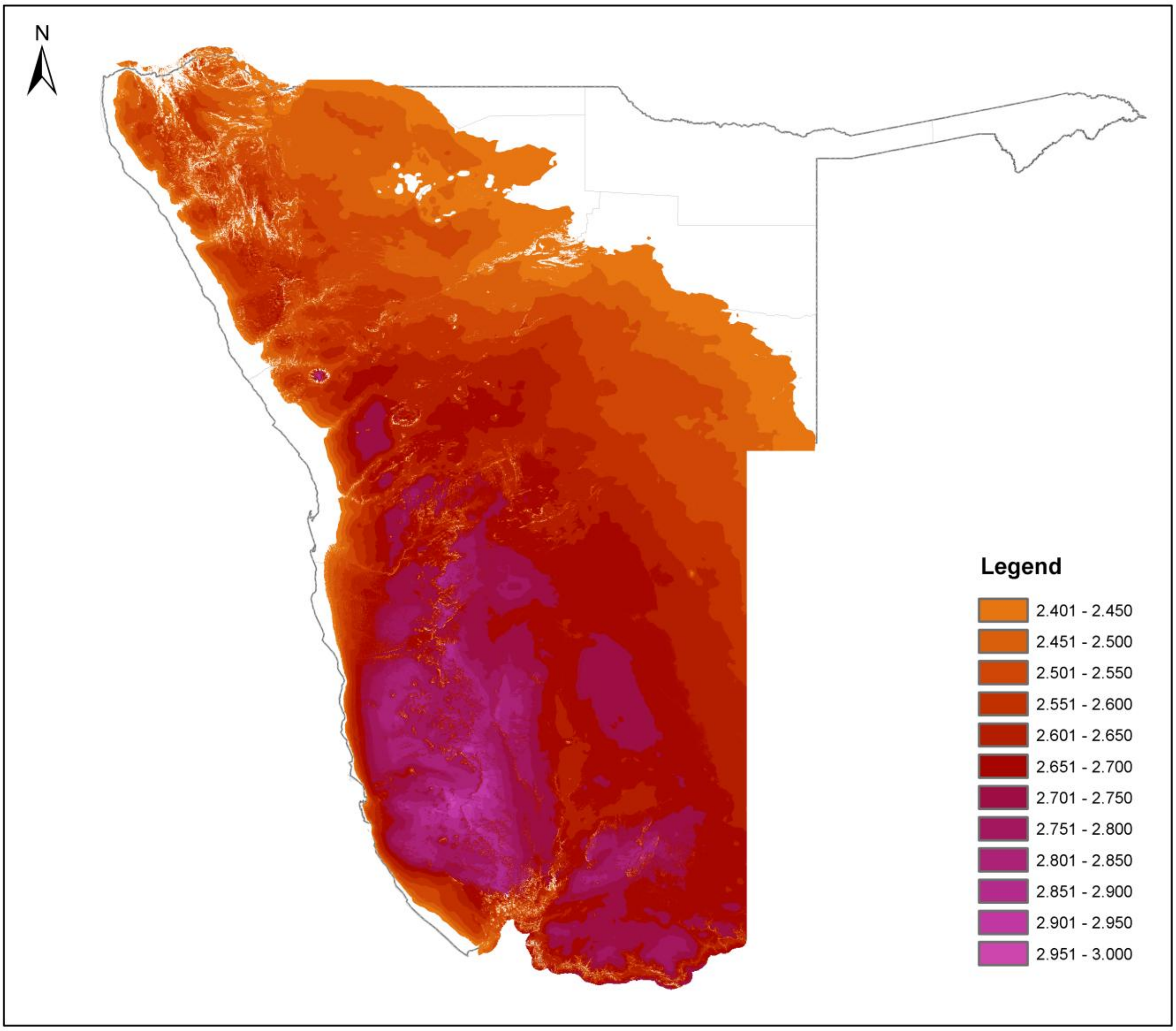

Figure 5.35 – Areas with DNI greater than 2400 kWh/m²/year.

5.3.1.2 Feasibility

- Terrain slope

  As CSP requires large flat areas, only areas with a terrain slope under 3% were suitable for it. Moreover, using a terrain model of Namibia, from the Shuttle Radar Topography Mission (SRTM), the terrain slope was computed, and then classified in terrain slope under 3% and terrain slope over 3% (Figure 5.36).

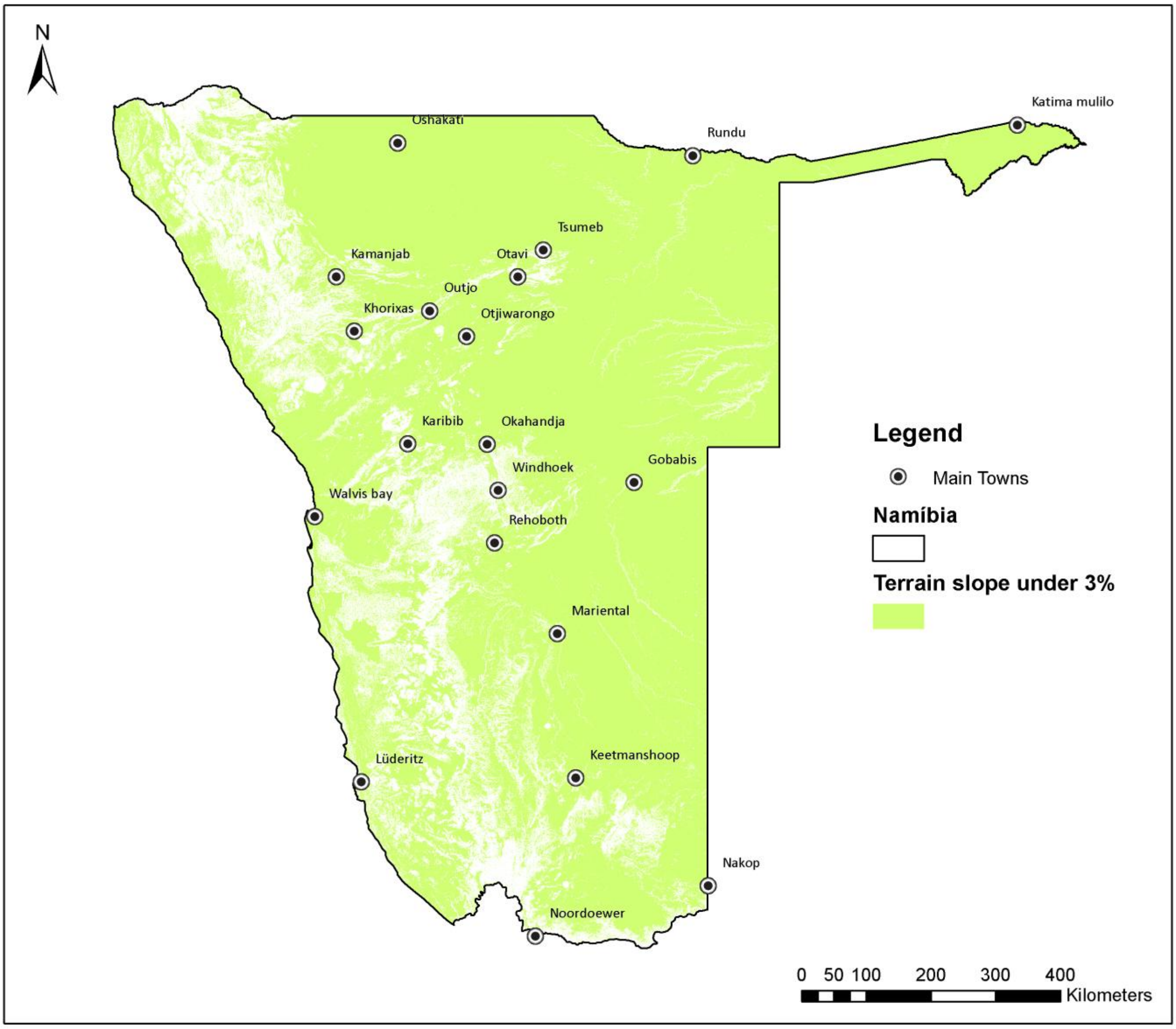

Figure 5.36 – Terrain slope under 3%.

- Soils

Technological or financial criteria make some soils not suitable for the installation of a CSP power plant. Thus, according to the available soil information, the adequate soils were selected, namely: alluviums, sands, gravel, calcrete plains, arenosols, calcisols, fluvisols, leptosols and regosols.

Figure 5.37 shows the selected soil distribution over Namibian land.

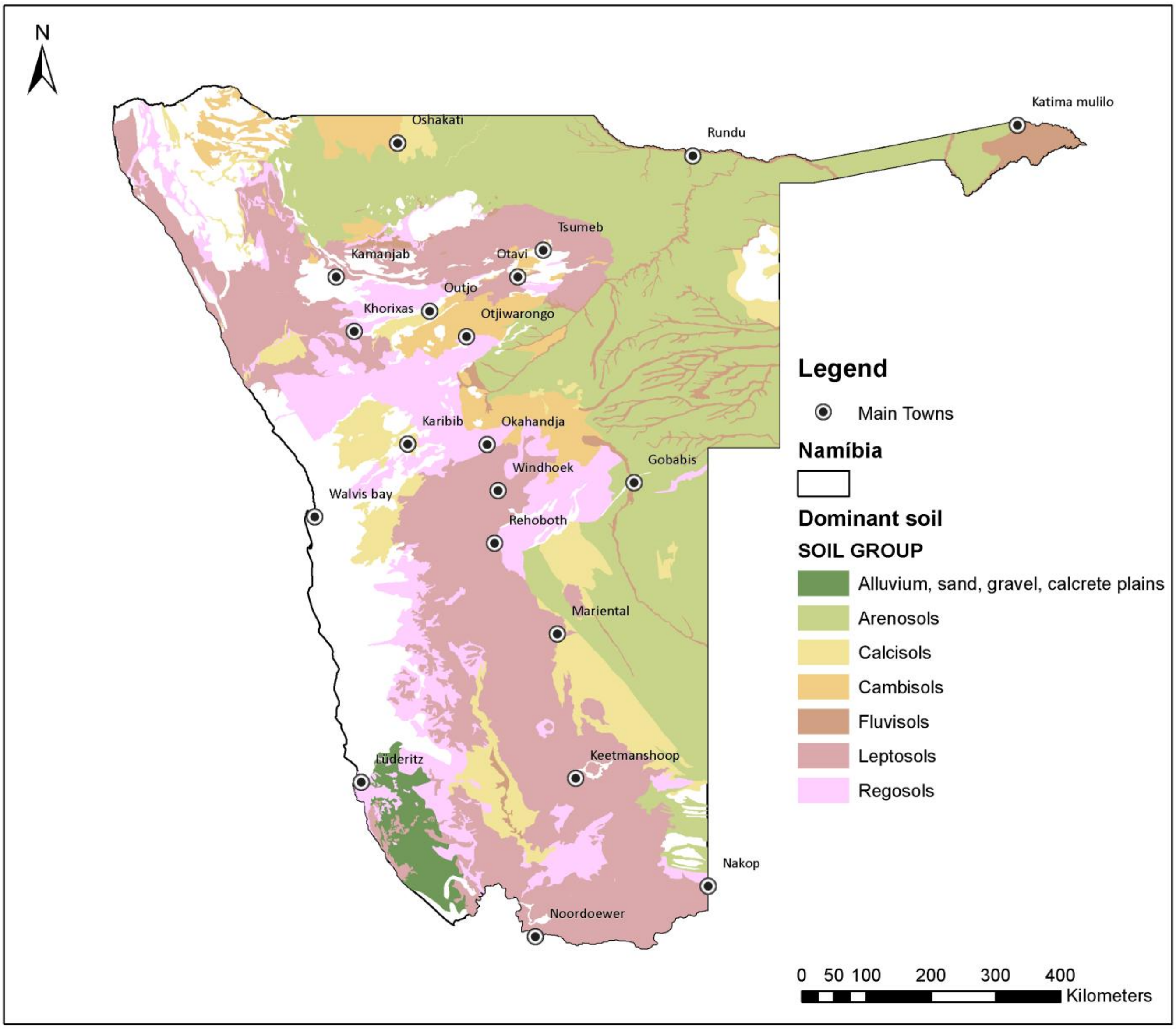

Figure 5.37 – Selected soils for CSP power plant deployment.

Note that, the selection implied the rejection of:

a) Cambisols, usually adequate for agriculture;
b) Gypsisols, which are rare and exclusive of semi-arid regions, namely, the Namib Desert;
c) Coastal salt pans, solonetz and solonchaks, which are referred for high salinity and, thus, may be an indicator of low drainage conditions; and
d) Dune sands areas, which may be prone to abrasion phenomena in the solar field.

Additionally, given that the soils selection was not very restrictive, as the information layer has a very large scale, only few types of soils were removed, maintaining a broad selection to be regarded during the site visits.

For instance, albeit leptosols soil type use for CSP foundations may bring additional costs, since a great portion of the south of Namibia presents leptosols, this type was considered, as it doesn't bring technical restrictions, but only an over cost.

- Reserved areas alongside roads

A 60 m reserve width was adopted as restriction over land nearby roads. To reflect this on the analysis, it was applied a 60 m buffer on all the available roads (trunk, main, district), being the resultant areas considered unavailable for a CSP power plant. Figure 5.38 shows the results of the 60 m buffer.

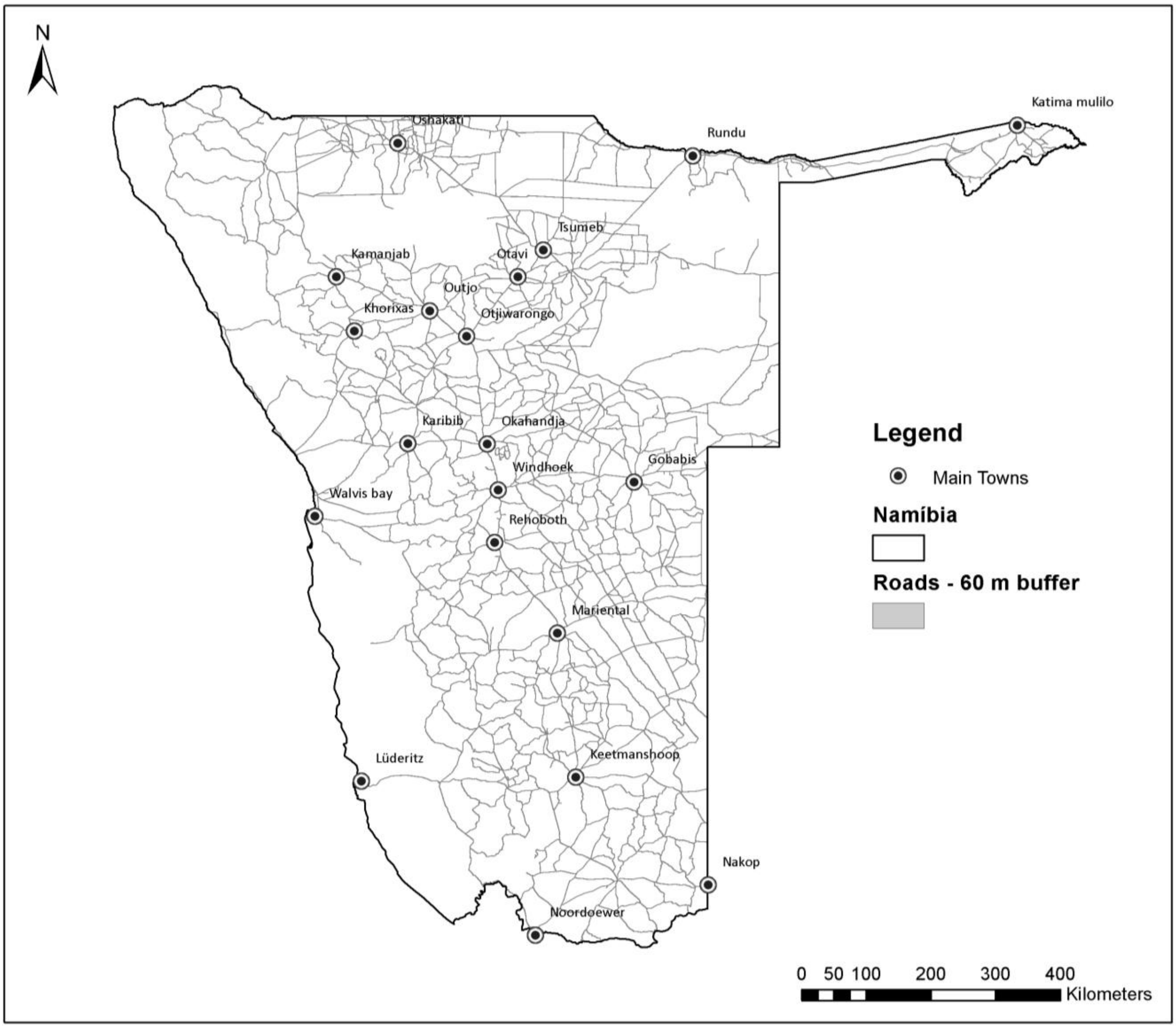

Figure 5.38 – Roads 60 m buffer.

- Grid Connection

Firstly, as CSP technology requires size and is especially suited to utility scale generation, only with a capacity superior to 20 MW a CSP power plant can minimize the costs of major components in the total cost and benefit from economies of scale.

On the other hand, the mid-peak and peak capacity deficit of Namibia's load profile has already surpassed the 50 MW and, therefore, a CSP power plant should be capable of supplying the required capacity, when CSP is competitive with the current generation sources of Namibia.

Additionally, as most of the power plants installed in Spain are of 50 MW, the development of a power plant with the same size would benefit from the existing experience, namely, in what concerns deployment, design, engineering and construction.

Therefore, for the purpose of project identification, a CSP power plant capacity of 50 MW was considered and, consequently, the preferred substations for connecting a CSP 50 MW power plant are clearly substations with voltage levels of 66kV or 132 kV, as it stands for a lower cost in voltage step up.

Thus, in order to cap grid losses, it is considered a maximum distance to the 66 kV substation of 5 km and a requirement of higher step up voltages in the substations (132 kV, 220 kV, 330kV and 400 kV).

In terms of economic feasibility, it is considered a maximum distance of 20 km to the 132 kV substations. Therefore, the most feasible grid connections are considered to be any substation with 132 kV level or 66 kV (and any of the following grid lines: 132 kV, 220 kV, 330kV and 400 kV, in order to cap the grid losses).

Figure 5.39 shows the resulting areas of the feasibility options, considered for a substation grid connection[9].

On a second level of feasibility, in order to reach the higher zones of DNI in the country, the possibility of T connect[10] to an existing grid line with 132 kV or 220 kV was considered. Figure 5.40 presents the resulting areas of the feasibility options considered for a T connection (20 km buffer).

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[9] These areas don't take into consideration the available grid connection. First, all the pretended substations were screened and later in the study the availability issues were addressed to NamPower.

[10] In this sense, means a connection to an existing line where presently there is no substation, by planning a new substation or switching station on place. It should be noted that sectioning high voltage grid line may not be desirable. Therefore, T connections in 400 kV lines were not considered and even the mentioned possibilities should be regarded with caution.

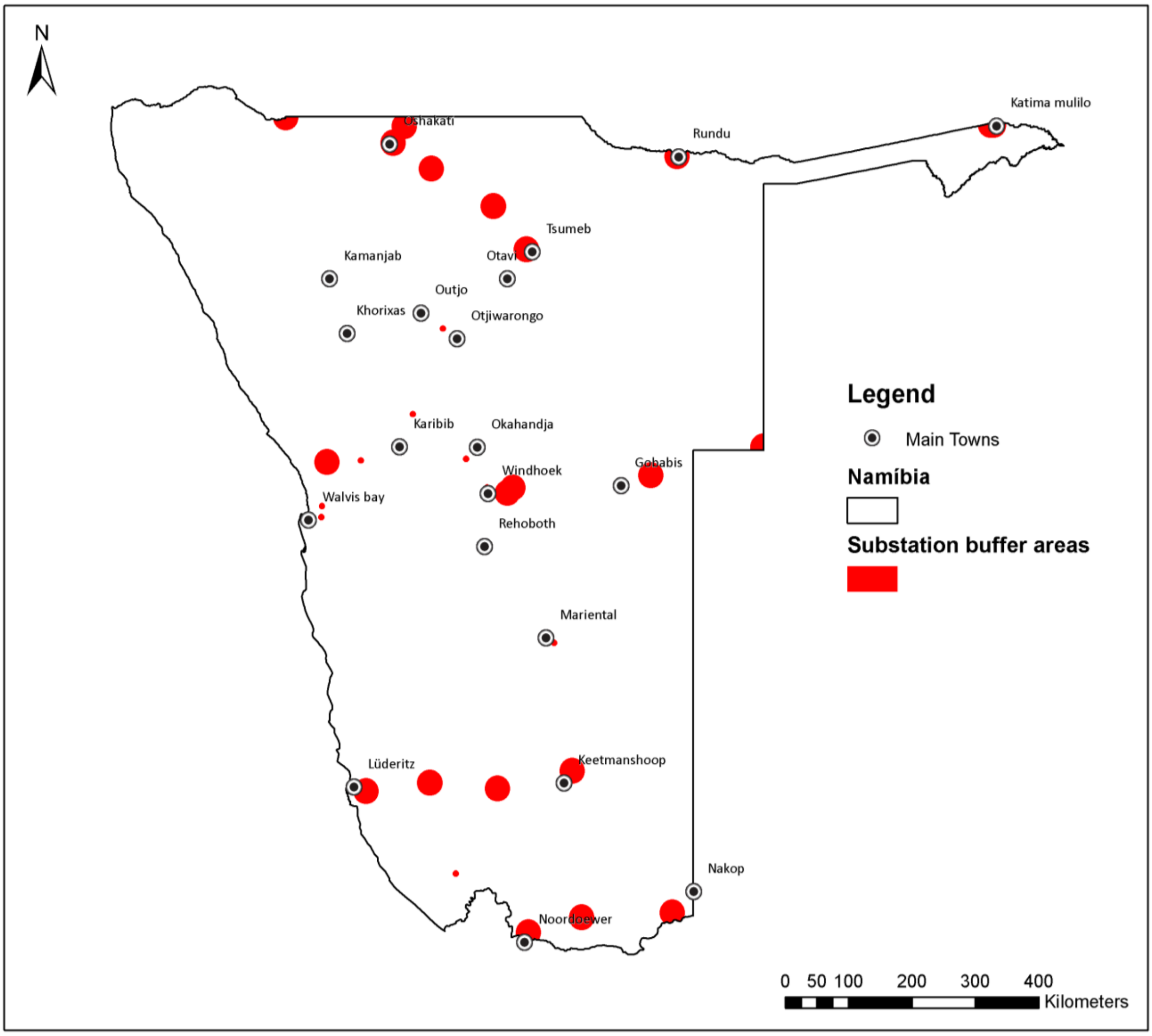


Figure 5.39 – Substation buffer areas for CSP

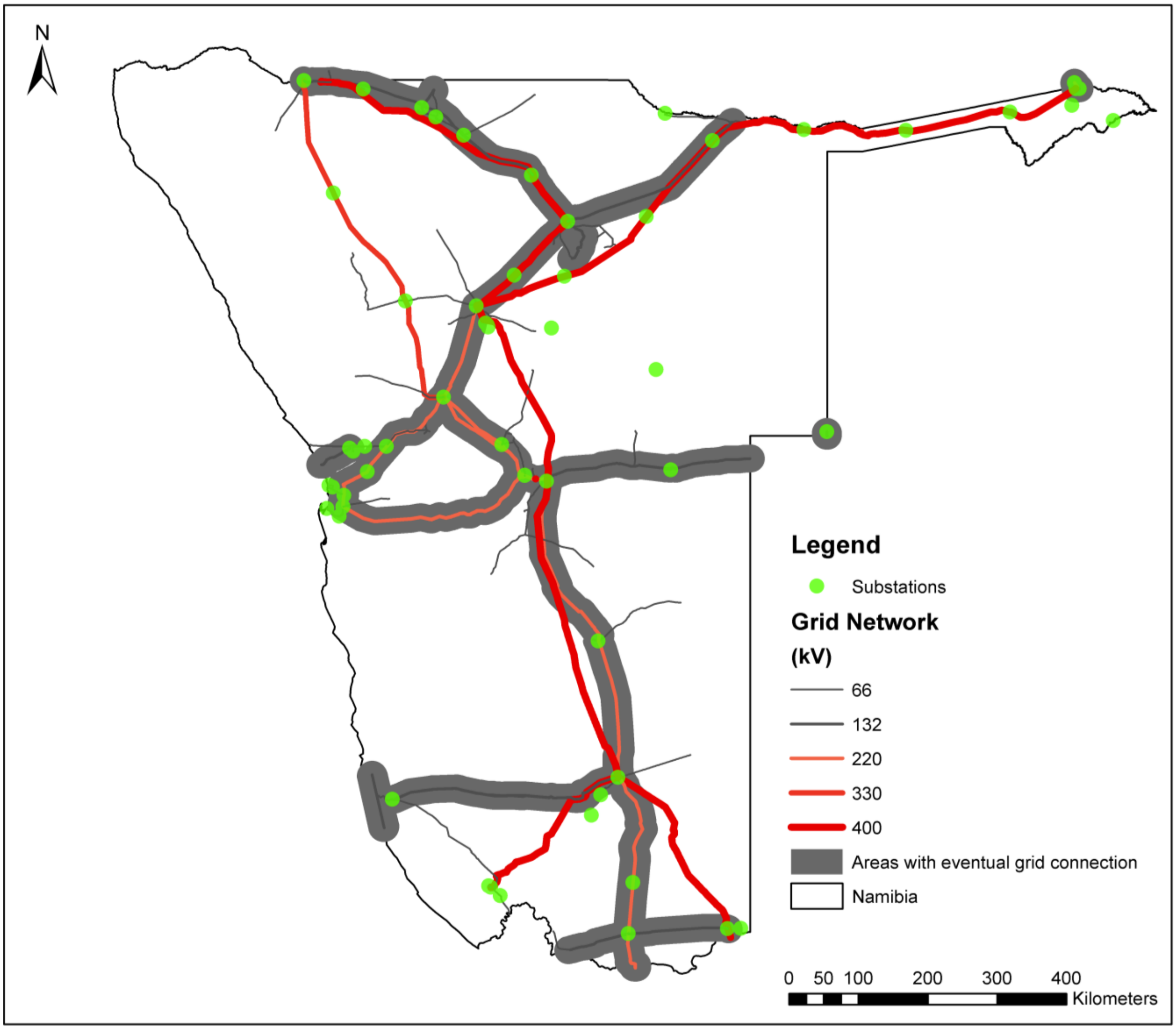


Figure 5.40 – Grid line buffer areas for CSP.

5.3.1.3 Alternative Business Models

- Gas hybridization scenario

The Gas hybridization addresses the use of gas as a back-up to the CSP power plant. Then, the areas considered available for this hybridization were the proposed areas for the construction of a gas power plant.

- Biomass hybridization scenario

The biomass hybridization addresses the use of biomass as a backup to the CSP power plant or as a Biomass plant with CSP booster. Thus, the areas considered reflect the three areas with the highest biomass potential production.

- Coal augmentation scenario

  The coal augmentation business model has the objective of decreasing the use of coal to generate power or augmenting the power generation capacity of the coal power plant by providing steam to the economizer of the coal thermal power plant. Hence, the areas for this scenario result from the areas that are being considered for the construction of a coal power plant.

- Desalination scenario

  It focuses on the use of water without any different ends by considering the desalination of brackish water in aquifers. CSP may provide energy to produce desalinate water as well was have some efficiency gains on wet cooling technology.

- Mines

  Reflects the development possibility of a CSP power plant supplying electric power to the mine plus heat for some industrial process (cogeneration).

All in all, Figure 5.41 shows the location where business model alternatives may be found.

Note that, gas, coal and mines are considered to have a suitable grid connection, which allows relaxing the grid connection criteria, previously referred.

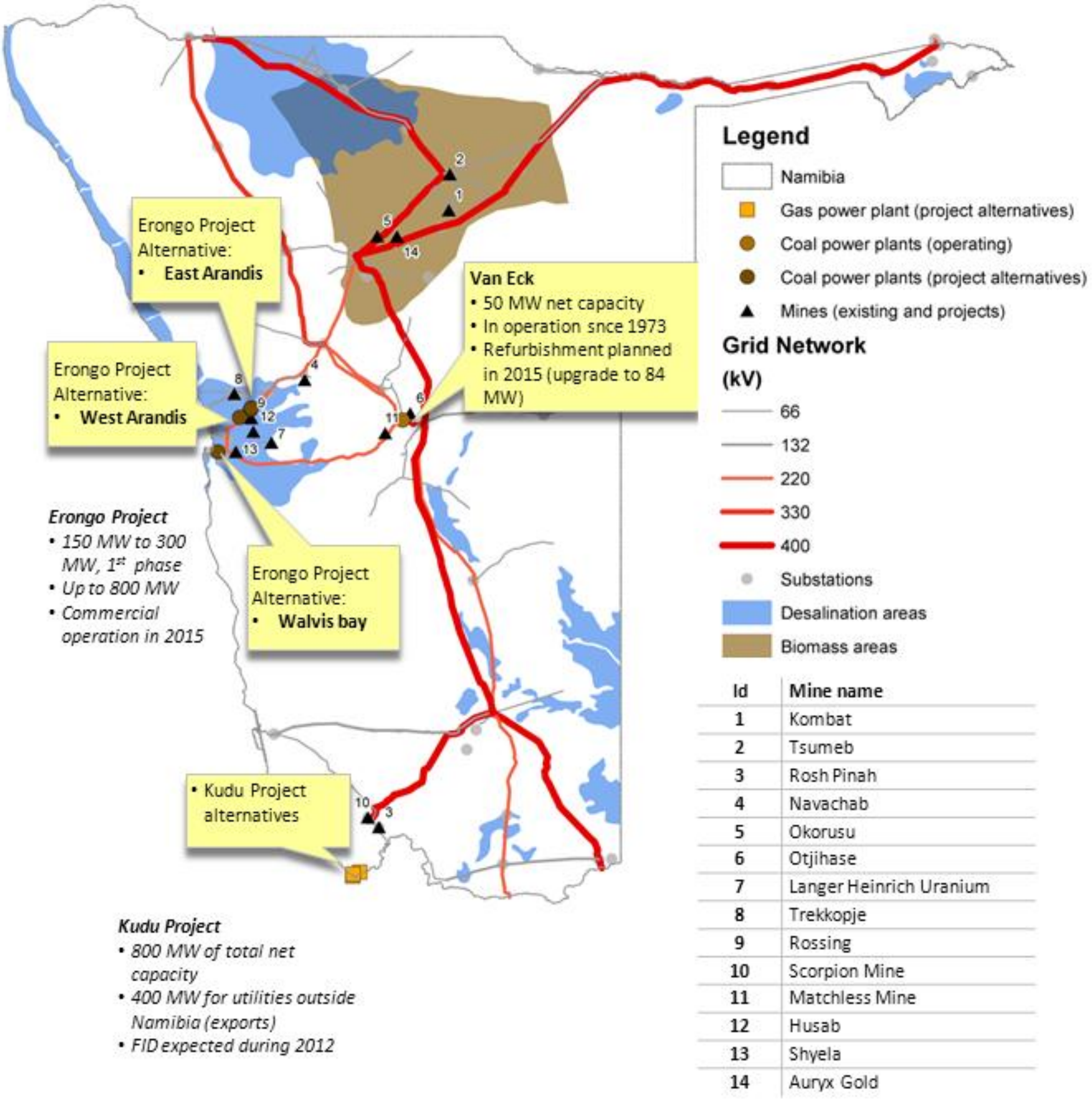


Figure 5.41 – Business models alternatives.

5.3.2 Potential Areas Identification

The potential areas identification result from the intersection of resource, feasibility and alternative business models that may provide new suitable locations for a CSP power plant. Thus, in Table 5.1, it is referred the adopted criteria.

Table 5.1 - Resource and feasibility matrix.

Suitable CSP Areas	**Resource**	
	2400≤DNI <2700 kWh/m^2/year	**DNI≥2700 kWh/m^2/year**
Feasibility	Connection to substation or *Alternative business models* *Gas, coal or mine location*	Connection to substation or T connection or *Alterative business models* *Gas, coal or mine location*
	Slope, soils, reserved areas alongside roads conditions	

Moreover, the intersection of resource and slope, soils and reserved areas conditions results in Figure 5.42.

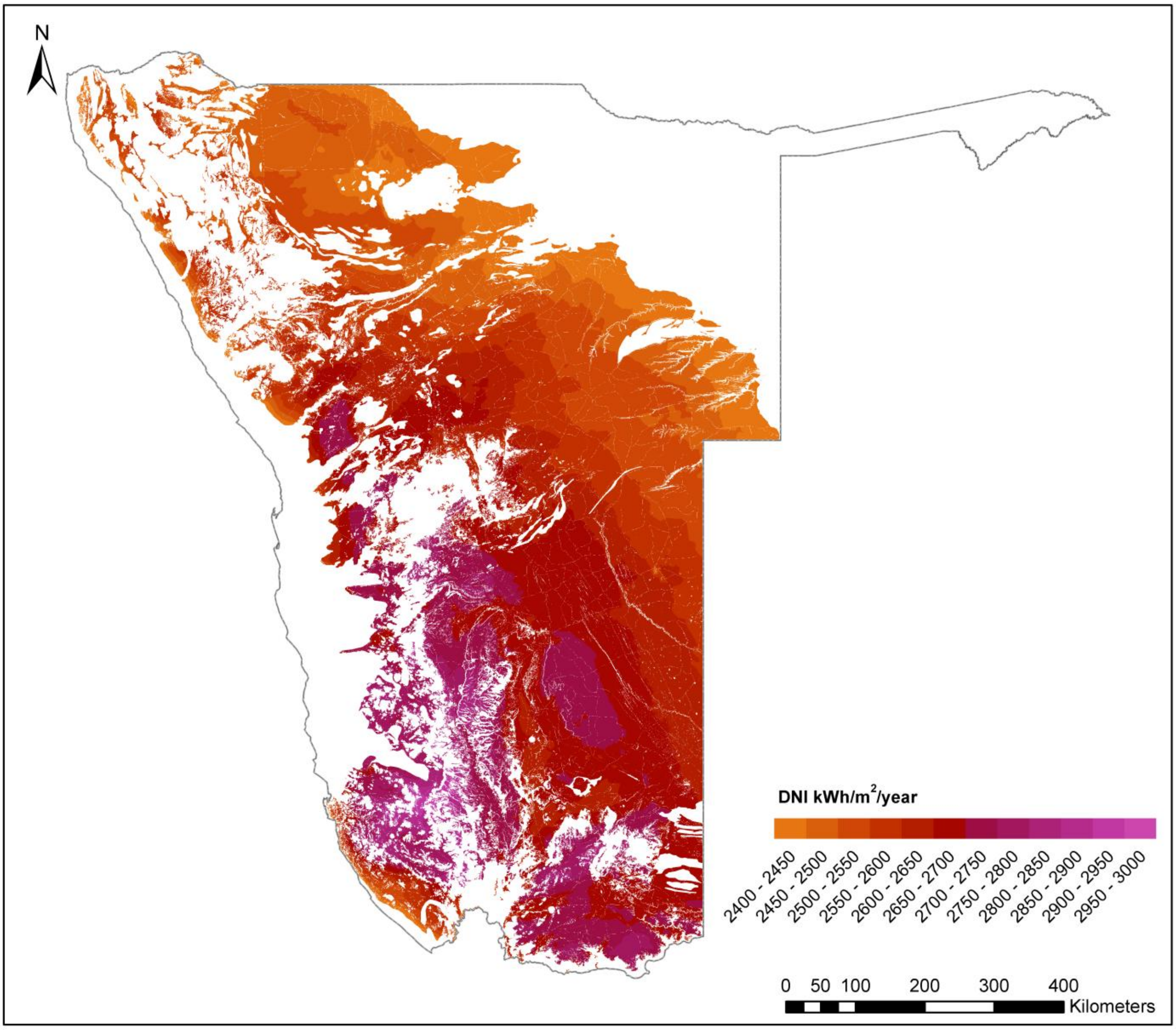


Figure 5.42 – DNI mapping on suitable DNI, slope, soil and respecting reserved areas alongside roads.

Furthermore, by applying the grid connection feasibility level, the available area for the best projects decreases, as it can be seen in Figure 5.43.

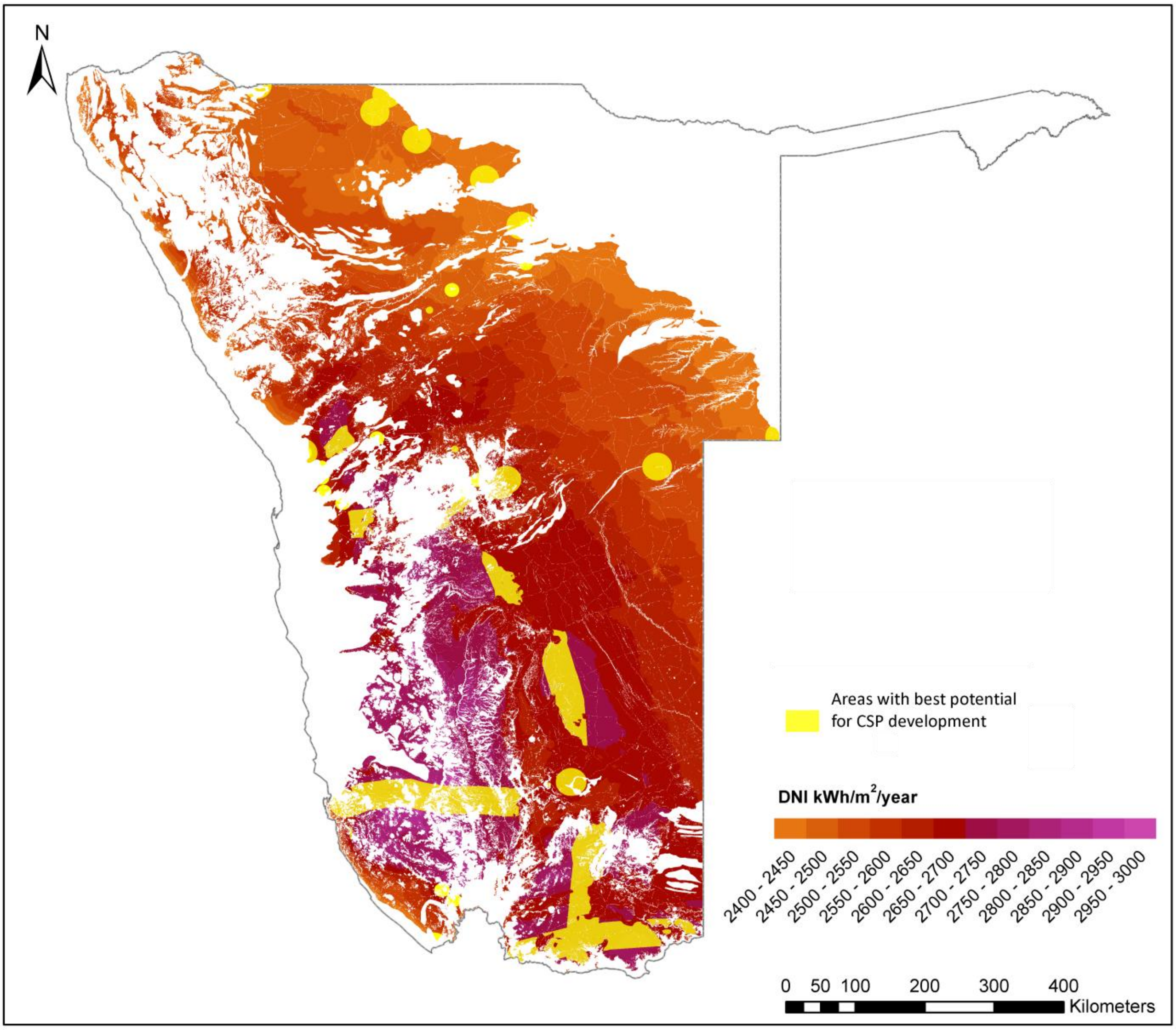


Figure 5.43 – DNI mapping on suitable DNI, slope, soil and respecting reserved areas alongside roads, considering grid connection or the alternative business models locations.

Additionally, for the possible areas, considering the grid line proximity and the alternative business models, projects were identified, recurring to the imagery available in Google Earth. The imagery allows identifying some morphological features, like drainage patterns and soils depositions, that are guide on the terrain selection for a project in Figure 5.44.

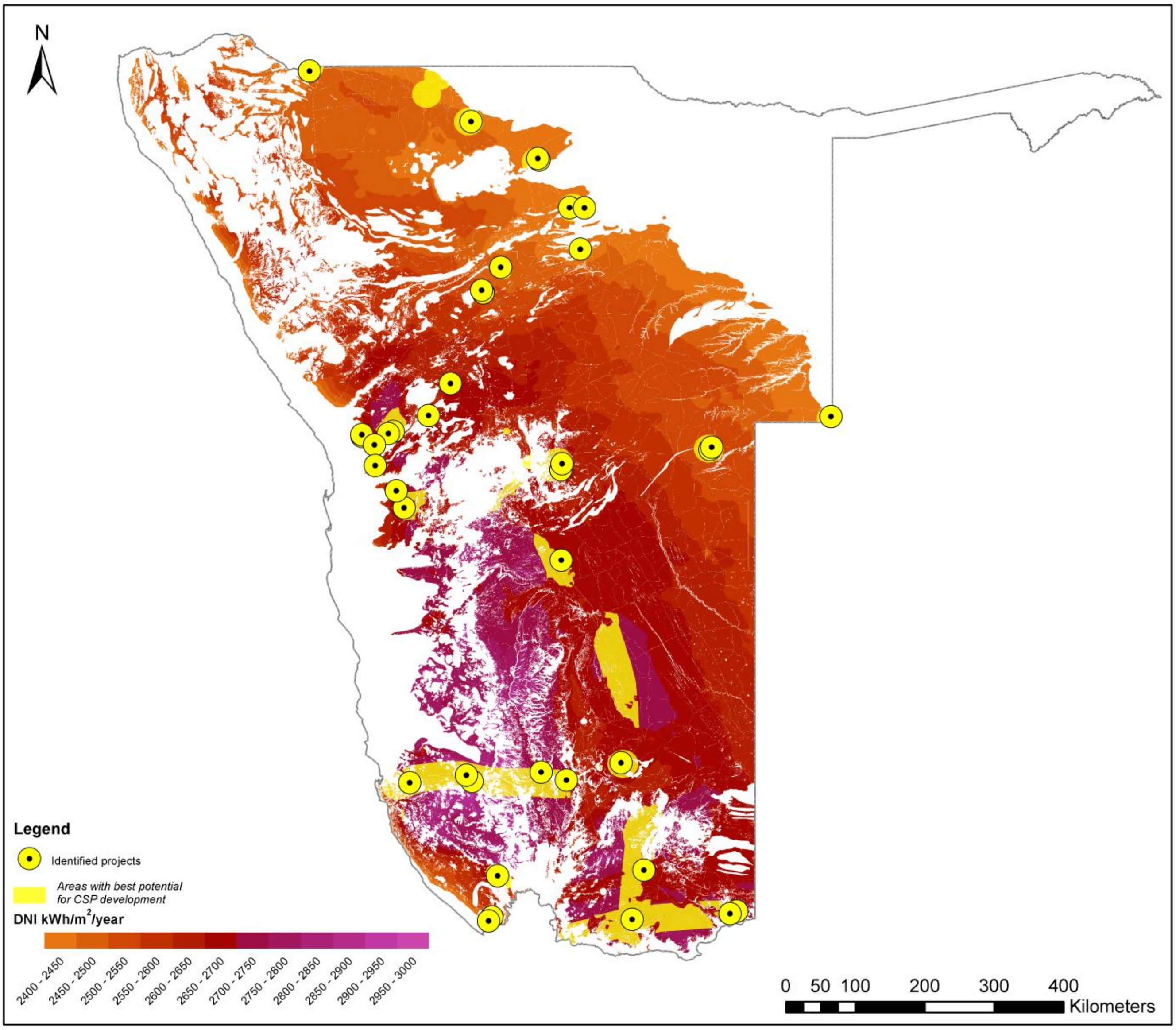


Figure 5.44 – Identified projects

For last, the list of the identified projects and related business models are presented in Annex 3 – Project Identification.

5.3.3 Best Projects Analysis

5.3.3.1 Economic Analysis

In order to rank the identified projects, a preliminary economic analysis was performed. This economic analysis takes into consideration:

- DNI averaged over the considered project area;

- An estimate of temperature losses;
- Estimated cost of grid connection, as % of total investment for 50 MW;
- Estimated cost of access construction, as a % of total investment for 50 MW; and
- Slope.

The estimate of temperature losses was carried through the calculation of lost yield, due to temperature changes. This assumes a simple linear relation between production and DNI. Note that, this simplification is not totally accurate as there are differences in the annual energy productions for projects with similar yearly DNI, but it is considered to be enough for a first screening.

For the final selection of 5 sites, 15 minute interval data will be collected and used in the ranking calculations. For this initial ranking, the temperature dependent yield loss factor used is 0.14%/ºC (Meyer & Chhatbar, 2011).

In addition, for the grid connection evaluation, the linear distance to the nearest substation was calculated. Thus, based on current market values, the cost curves for substation and power line extension have been calculated and are shown in Figure 5.45 and Figure 5.46 respectively.

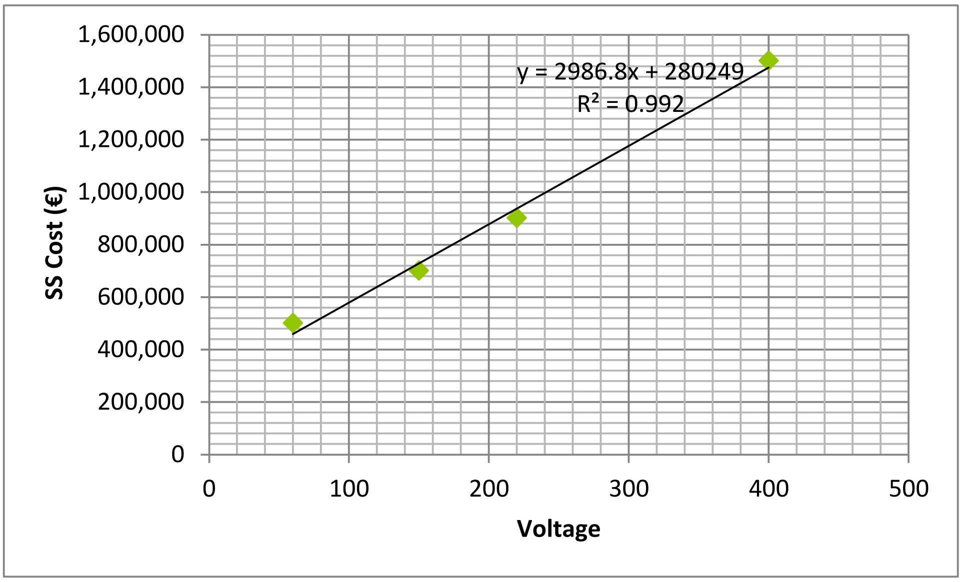


Figure 5.45 - Substation estimated cost regression based on average market values.

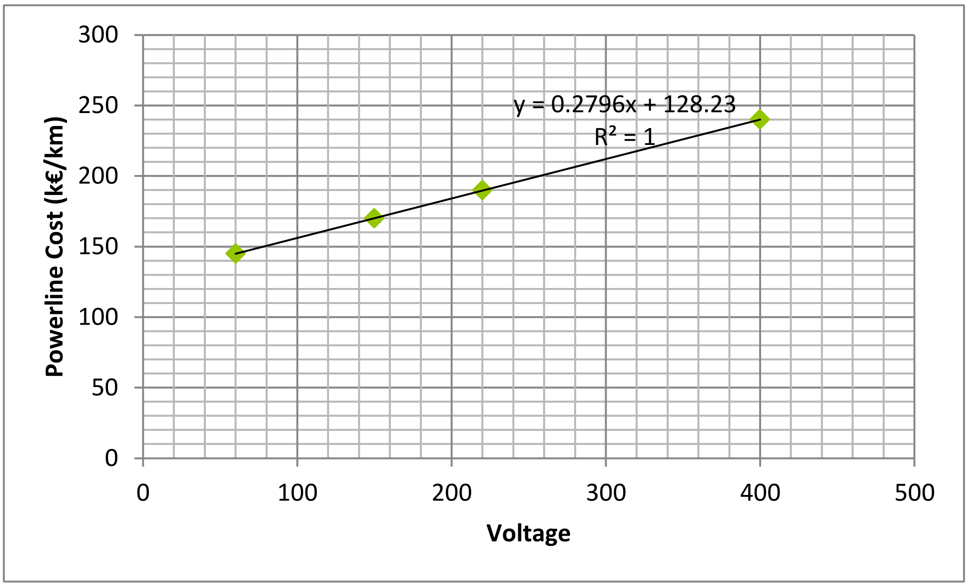


Figure 5.46 – Transmission line estimate cost regression based on average market values.

As the total estimated connection cost to existing substations is therefore calculated according to,

Connection Cost=Transmission Line Cost · Distance + Substation Cost

, in some identified situations, it was possible to T connection to existing lines.

Nevertheless, for all situations, except projects Tsumis e Ganab, T connection was not the preferred option, as nearby substations were more than 70 km away (77 km and 111 km, respectively). For T connections, the substation cost was considered to be double the cost of connection to an existing substation.

Moreover, a selection of connecting substations was submitted to Nampower. After receiving Nampower's feedback, the substations were classified, as presented in Table 5.2.

Estimated cost of the losses, in terms of DNI incurred through grid connection, is calculated as a fraction of the total investment. At this early phase of the study, and since no accurate value for the total investment cost has yet been calculated, indicative investment costs from previous Namibian studies were adopted.

Therefore, the specific investment cost of Nam$60000/kWp presented in ("Development of Procurement Mechanisms for Renewable Energy Resources in Namibia", 2011) has been used in these preliminary calculations, giving a total investment cost for a 50MW plant of Nam$300M. Note that, the assumption of this specific cost value and a € to Nam$ conversion of 10.25, is sufficient to give the relative comparison and ranking required in this study. Hence, considering a conversion between € and Nam$ of 10.25, the estimated equivalent losses were achieved.

Table 5.2 - Nampower feedback on selected substations and classification.

SUBSTATION	NAMPOWER FEEDBACK	CLASS
HARIB T/S	transformer of 40 MVA, connection at 132 KV is possible, 50 MW may be possible, but not likely	2
ROCK S/S	transformer of 10 MVA, 170 km of transmission, maximum 20 MW at 132 KV	0
OBIB S/S	transformer of 160 MVA, local load is 80 MW, possible to connect even at 66 KV	2
AUS S/S	T connection, not ready, costly upgrade, 20 MW at 132 KV is possible, but requires investment	1
KONKIEP S/S	same as Aus	1
KOKERBOOM D/S	transformer of 40 MVA, load of 10 MW at 66 KV, similar to Harib, at 220 KV no problem	2
DETMONT	same as Aus, close by is 50 MW load and there is the request to connect 40 MW of PV	2
KHAN	transformer of 24 MVA, 50 MW possible on 220 KV	2
GERUS D/S	transformer of 24/40 MVA, current load is 8 MW on 66 KV so 50 MW on 66 KV is possible, 50 MW possible on 220 KV, dynamic analysis required	2
NAMIB S/S	311 km of transmission, big restriction	0
KUISEB S/S	less than 30 km of the coast, being upgrade from 66 KV, 50 MW no problem	2
HARDAP D/S	transformer of 40 MVA, 40 MW at 66 KV possible, 50 MW at 220 KV	2
OMBURU D/S	50 MW is possible, but issues related with the power angle and stability issues rule it out	0

0 – excluded
1 – need investment
2 - ok

For the excluded substations, the loss factor was considered to the total DNI, i.e., the site was not viable. For the substations needing investment, the grid connection loss factor was considered to be the double of the resulting loss from the estimated costs.

Further, the estimate costs, related to building accesses to project sites, were considered to be function of the linear distance to the nearest road.

Thus, as orography in Namibia tends to be quite gentle, the average cost of 0.25M€/km was considered. Similarly to the grid connection estimated equivalent loss, an access building equivalent loss was calculated.

The slope was considered to be a direct loss factor, which means 1% more in average terrain slope would mean a 1% increasing costs or equivalent production loss.

All in all, the results of the losses are presented in Figure 5.47.

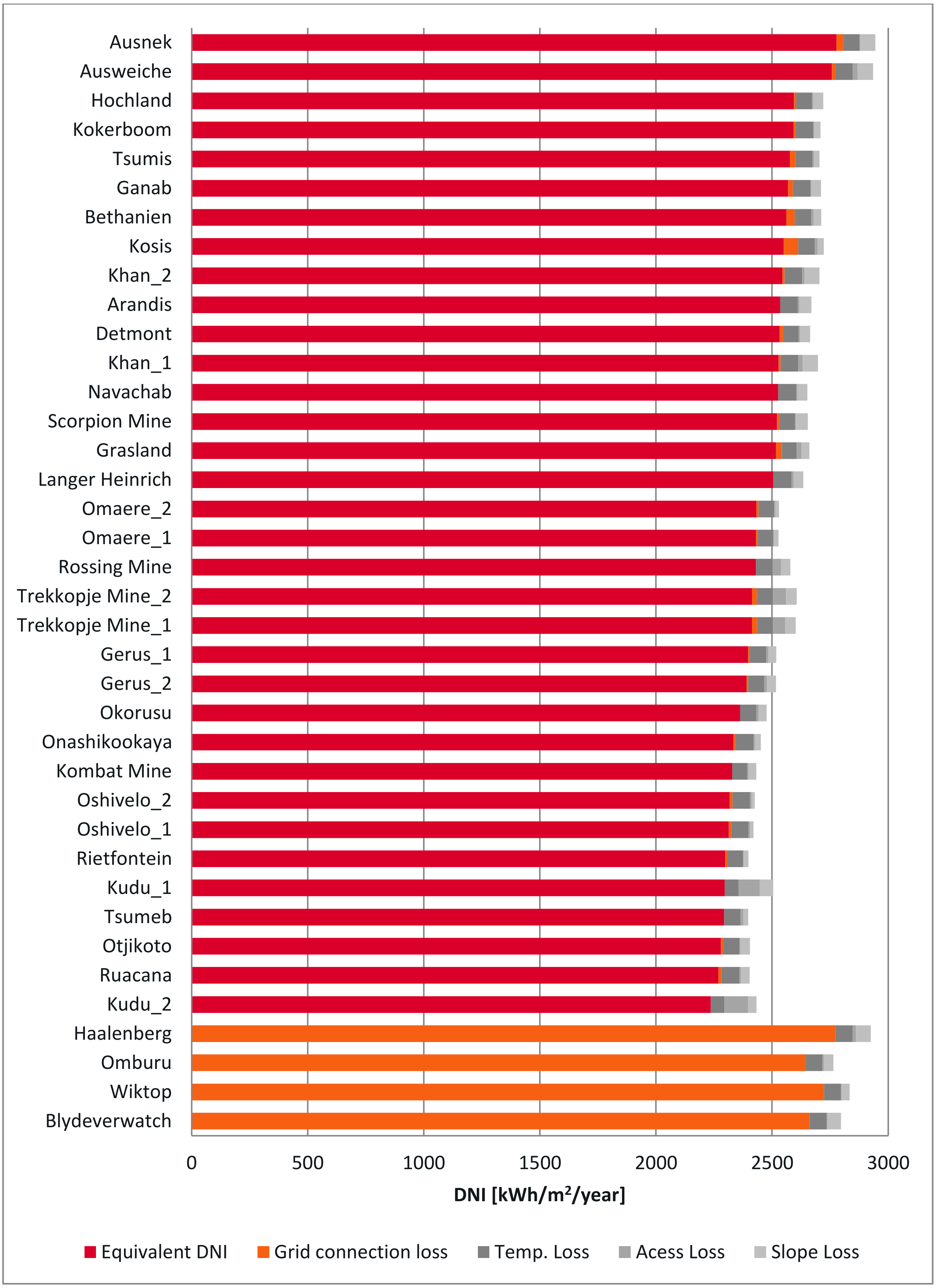


Figure 5.47 – Project site DNI and equivalent losses.

5.3.3.2 Feasibility Analysis and Alternative Business Models

After the prioritization of the projects by equivalent DNI, resulting in a preliminary ranking, it was applied a scoring for the alternative business models, environmental and feasibility analysis, as presented by Table 5.3.

Table 5.3 - Scoring Alternative business models, feasibility and environment on best projects analysis.

Criteria	Application	Scoring
Feasibility	Projects within area of possible grid connection to a substation	1
Feasibility and Environment	Projects outside environmental protected areas and with feasible grid connection to a substation	1
Alternative business models	Hybridization with gas	10
	Hybridization with biomass	10
	Augmentation with coal	10
	Mines	5
	Desalination	

In the scope of this project, it was considered that protected areas implied all the references presented in Figure 5.30. Additionally, this scoring promotes a shift in the projects', as shown in Figure 5.48.

Note that, all the related tables, with the results from the best project analysis, may be found in 5.3.3.

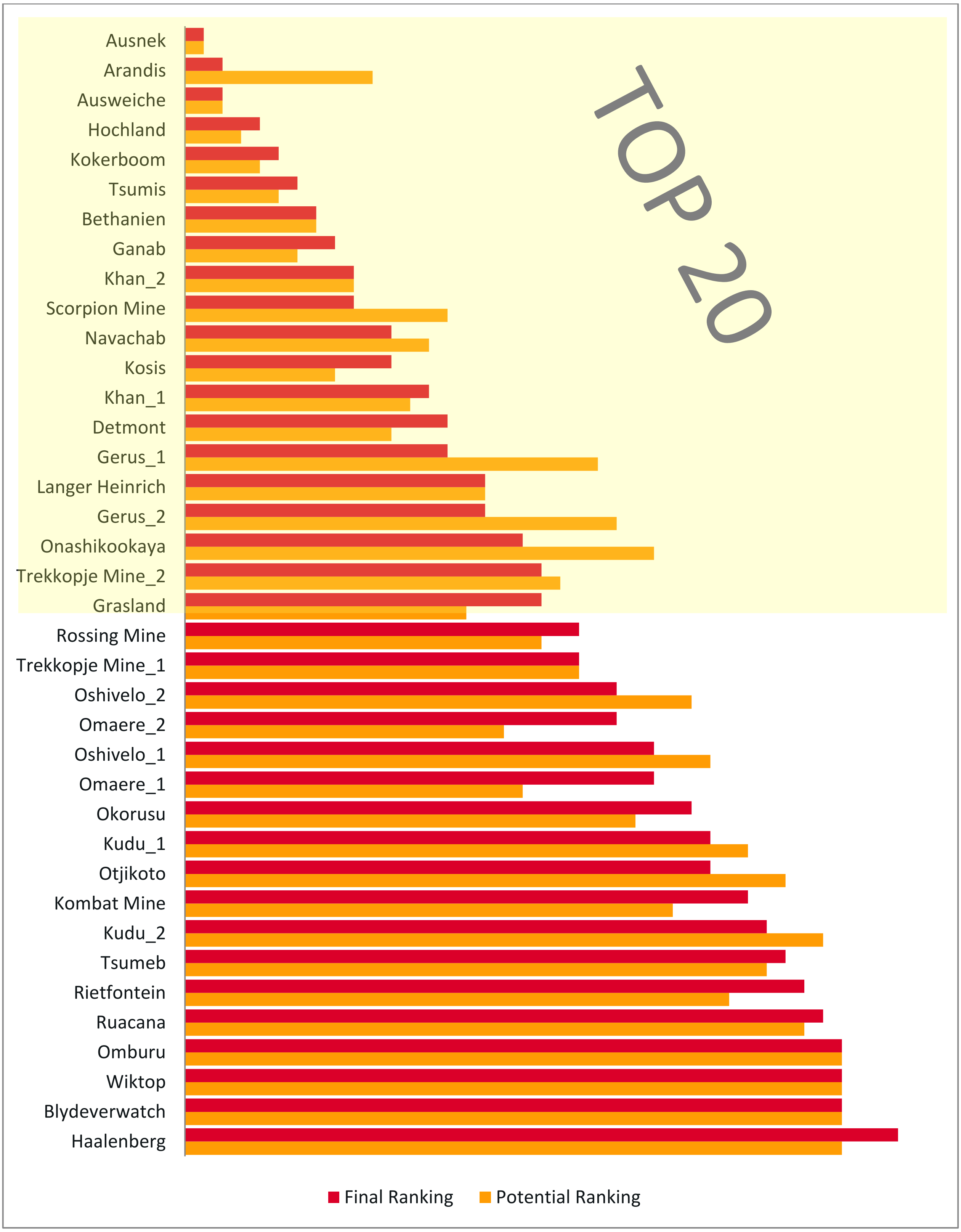


Figure 5.48 – Project Ranking.

5.4 Summary of the Analysis of the Top 20 Sites and Shortlisting

The Top 20 projects, to be analysed and shortlisted, are presented in Figure 5.49.

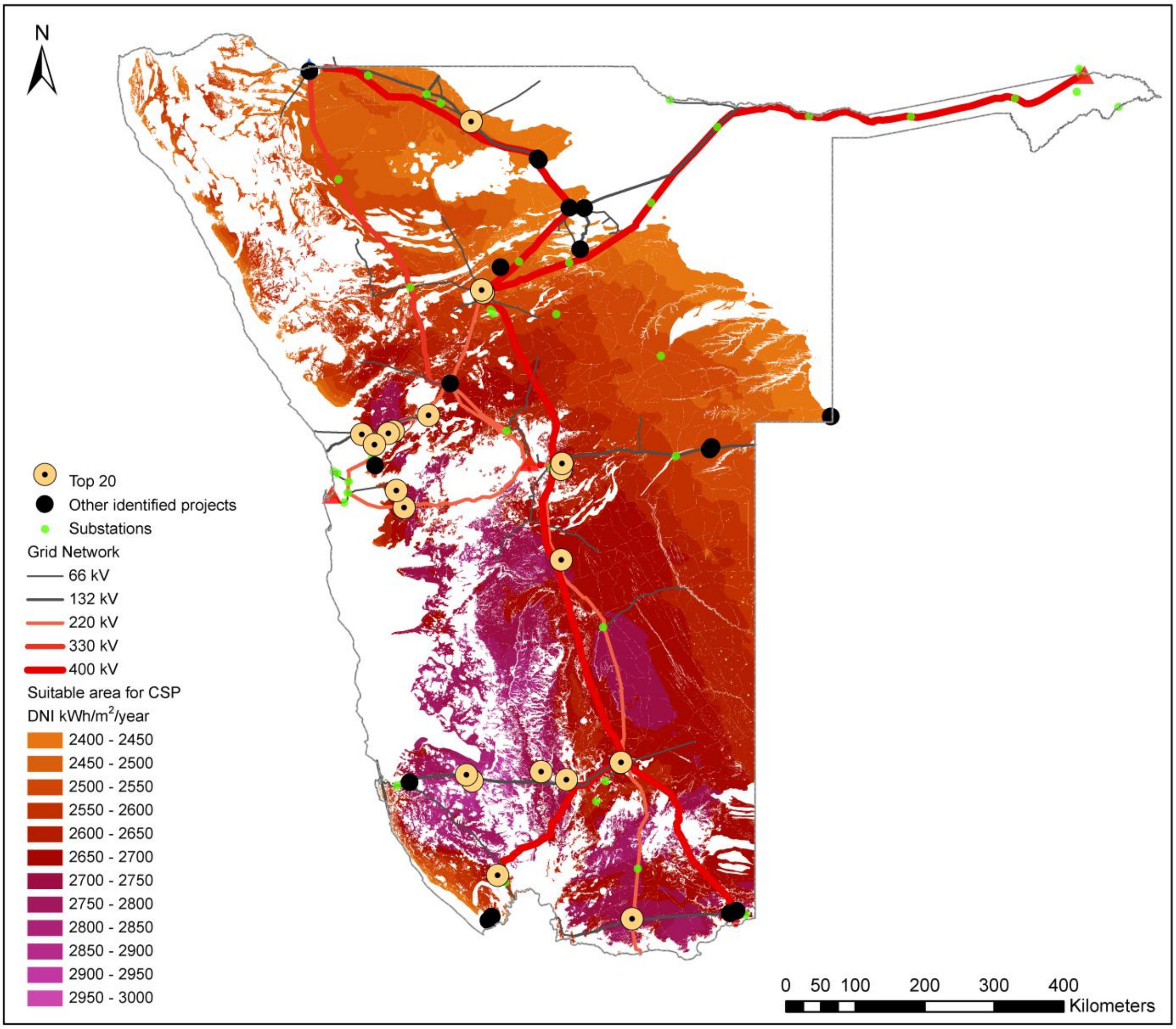


Figure 5.49 – Top 20

Further, the economic analysis includes the estimated equivalent DNI, previously assessed, by weighting it with an additional meteorological scoring.

Thus, the meteorological scoring aims to evaluate and consider favourable and unfavourable meteorological occurrences that may affect the CSP production, even if such phenomena are partially accounted for in the DNI layers. For this intent, additional meteorological information was analysed, as follows:

- Minimum average monthly DNI;
- Maximum average monthly temperature;
- Relative humidity of the average most humid month;
- Number of days with rain; and
- Number of days with fog.

The values for each variable were renormalized to a 0-10 scale, with the null value corresponding to the less desirable condition. Then, for each variable, it was applied a weighting factor, resulting in the Meteo Score, presented in Figure 5.50.

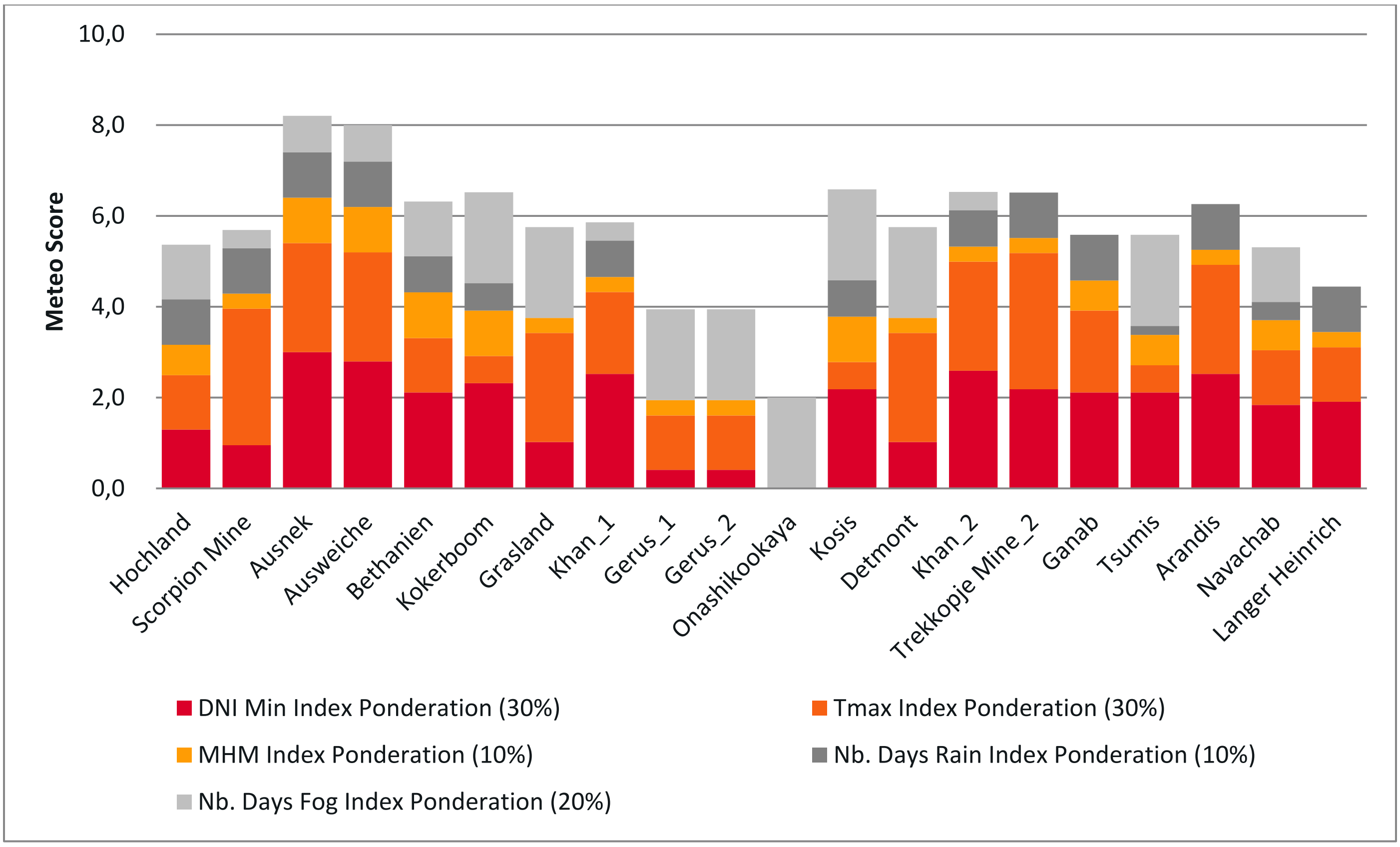


Figure 5.50 – Meteo Score and Variable Index Weighting.

Moreover, one major aspect that was not possible to take into consideration, mostly for the Central Receiver technology, is the average wind speed. However, the available information was not proper to use within this scope, as the presented estimates are punctual and not territory distributed.

Another issue, affecting economic feasibility of CSP projects, is the water availability for wet cooling, which increases the overall efficiency of the power plant, compared to dry cooling technologies. Nevertheless, at the level of the study, it was only possible to attain some indicators of water availability, which become not relevant for the analysis, as it can be perceived from the information included in the Figure 5.51. Thus, in the detailed studies for CSP, a local study on water availability should be performed.

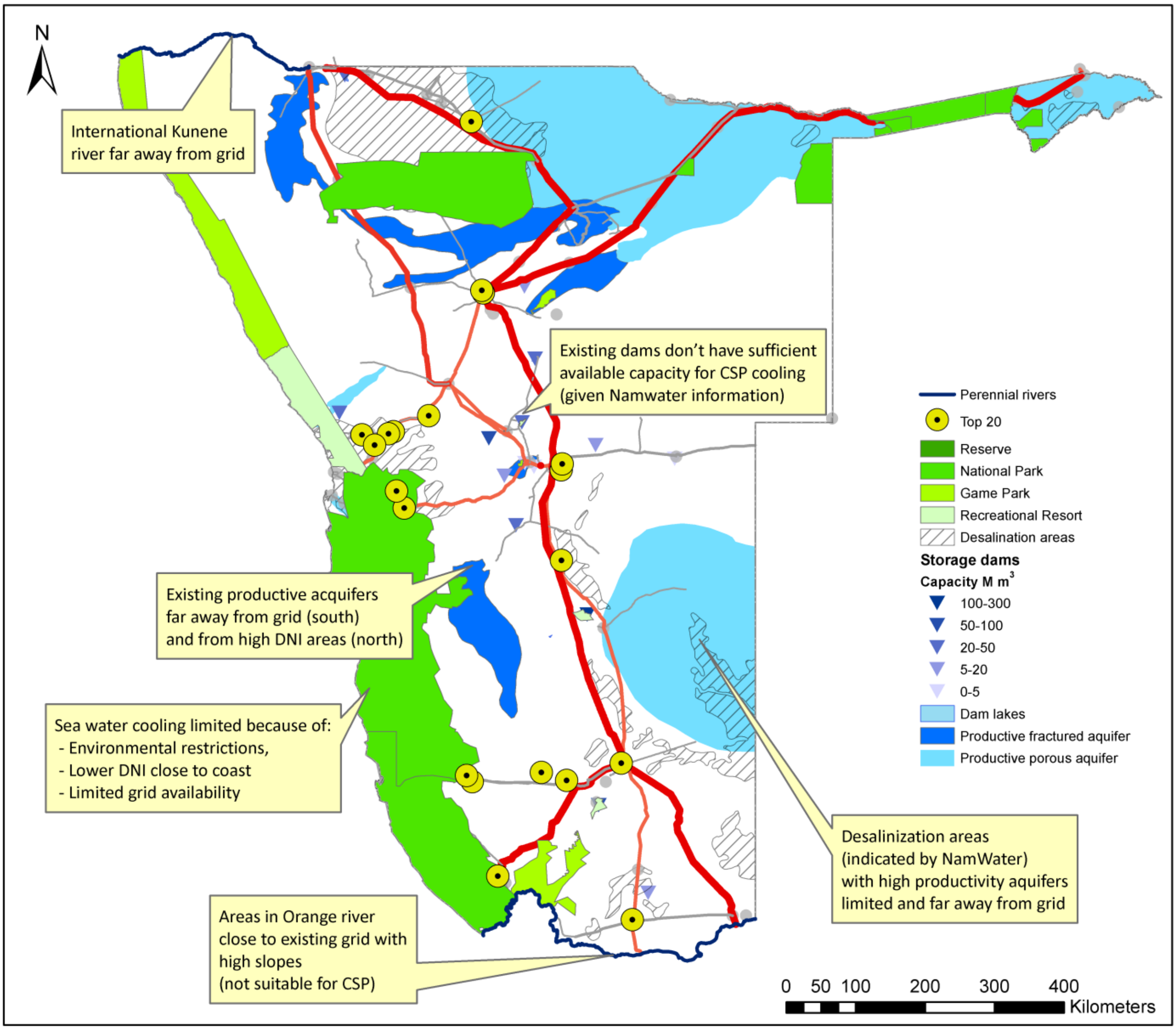


Figure 5.51 – Wet cooling feasibility analysis.

Further, the weighting factors for DNI equivalent score and meteorological score are presented in Table 5.4. In addition, in Figure 5.52, the resultant economic potential is determined for each project.

Table 5.4 – Weighting factors for the economic potential.

Economic Potential	Weighting Factors
DNI Equivalent Potential	75%
Meteorological Scoring	25%

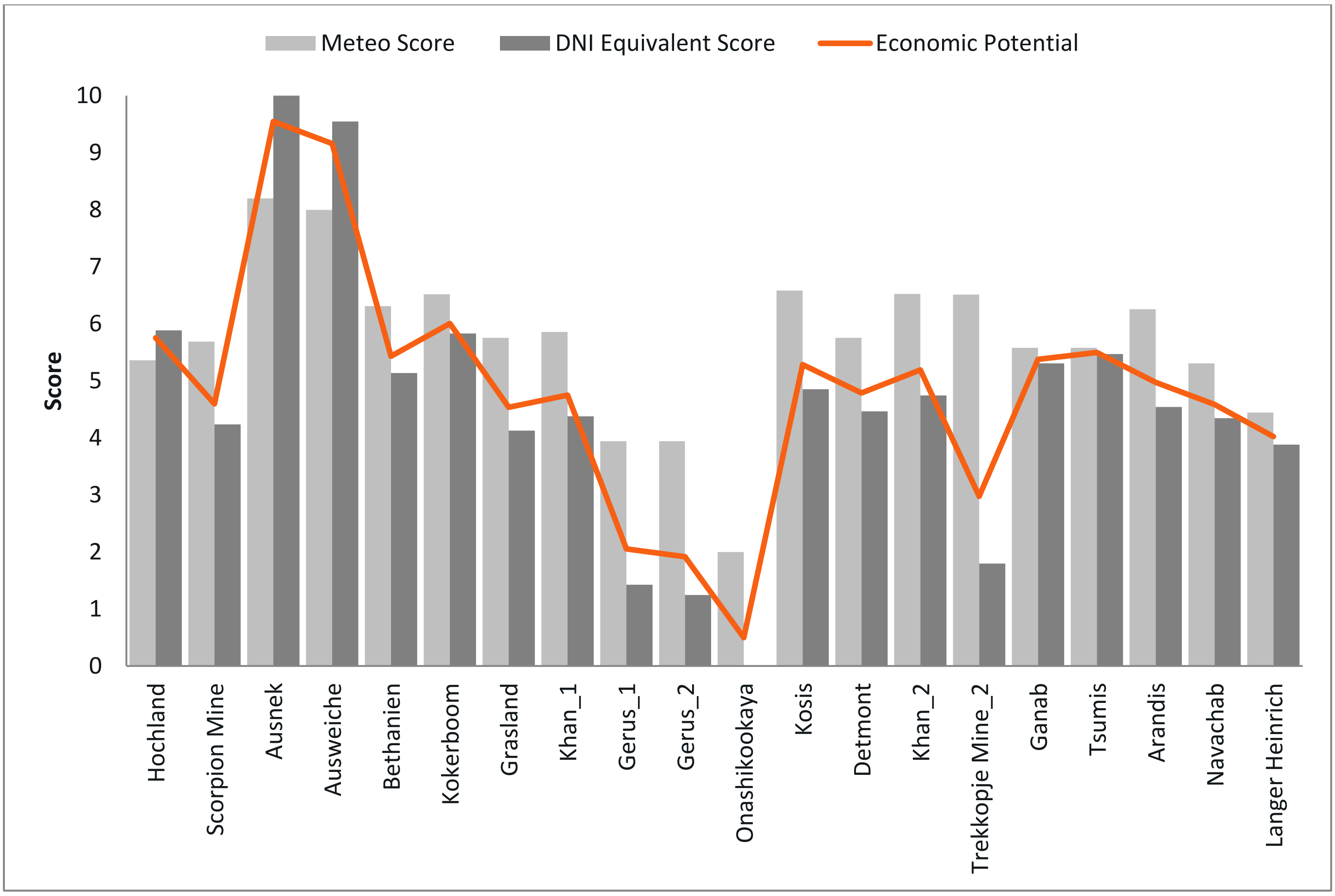


Figure 5.52 – Economic potential (weighting meteo score and DNI equivalent score).

As the technical feasibility scoring is obtained by scoring several variables analysed in the site visits, besides the analysed variables, it is also taken into account the expert opinion about the site, that is, the expert opinion demotes the site location, leading to the technical feasibility classification. Thus, the technical feasibility index is the normalization of the technical feasibility classification to the range [0, 10].

Note that, the tables with all the scoring information may be found in Annex 3 (4. Top 20 Sites Technical Feasibility) and the site visits reports are presented in chapter 6 to chapter 10.

Additionally, the environmental scoring is achieved based on the site visits and previous desk study. Then, the environmental perception of the sites was classified from 0 (worst) to 10 (best). Similar, additional information on classification may be found in Annex 3 (4. Top 20 Sites Environmental Scoring) and Chapter 4 Environmental Context.

For last, the potential for alternative business models is classified with a null value if no alternative business model is related to the project site or with maximum value (10) otherwise.

To conclude, the results are presented in Figure 5.53, along with the weights given for each scoring parameter.

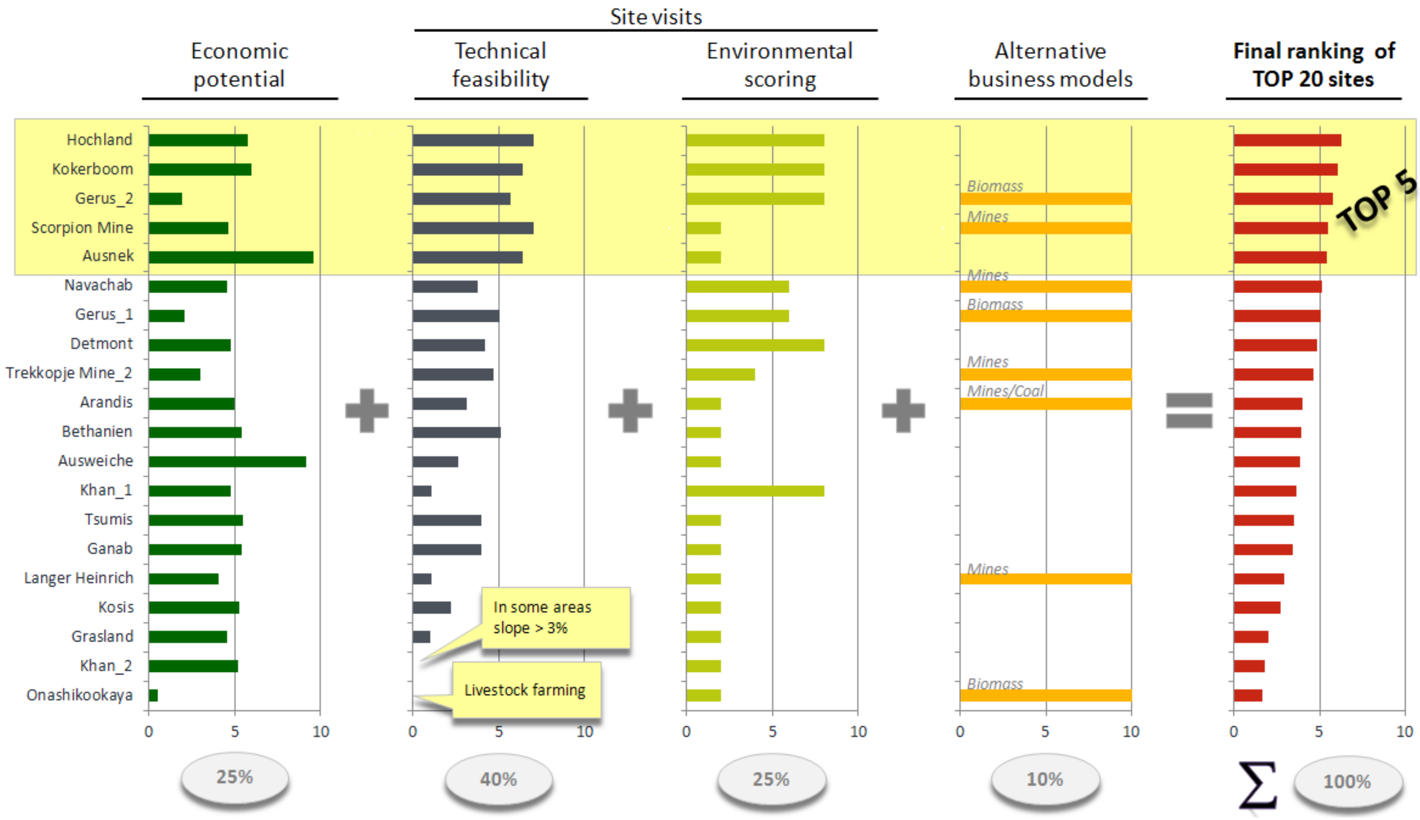


Figure 5.53 – Top 20 scoring

5.5 Site Survey (top 5 sites) Summary

The GIS analysis allowed identifying 38 projects based on feasibility and resource criteria, considering, as well, the identification of different sites regarding specific business models.

From this set of 38 projects, a potential ranking and alternative business models were evaluated in order to achieve the Top 20 projects. Then, the site survey along with a preliminary economic potential, taking into account alternative business models, allowed choosing 5 projects out of the TOP 20, namely:

- Hochland
- Kokerboom

- Gerus_2
- Skorpion mine
- Ausnek

All in all, in the map of the Figure 5.54, it is presented the 5 selected sites.

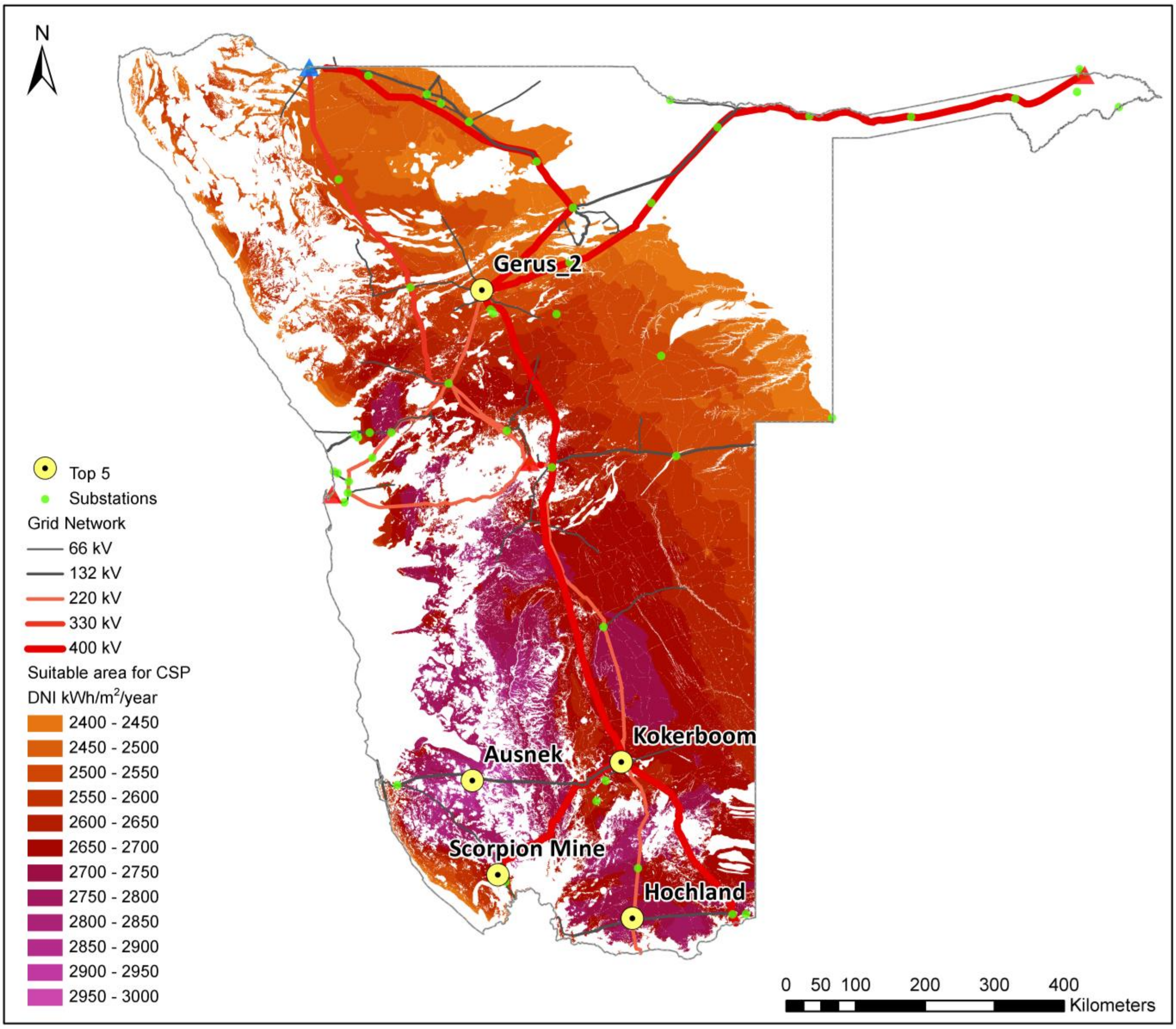


Figure 5.54 – Top 5 sites

6 Project 1 - Ausnek

6.1 Environmental report

6.1.1 Field works – Micro sitting

The Ausnek site is private land located 112 km east of Luderitz and adjacent to national road B4 which runs from Keetmanshoop to Luderitz. The site is 1470 m above sea level. The ground is very flat with an average slope of 2.2%. The soil is very sandy and is not rocky. The site is located in a very dry area that only receives 50-100 mm rain annually. The land appears to be only used minimally for animal grazing.

An endemic and rare succulent species is located on the site: *Euphorbia namibensis*.

Figure 6.1 – Micro-sitting of Ausnek site.

In Table 6.1 is present the results from the sites works performed on the site.

Table 6.1 – Results from the sites work performed on the site.

Project ID	Endemic/protected fauna in the site	Endemic/protected flora in the site	Environmental and social concerns	Landscape	Soil use	Displacement	Wildlife impact	Local population
Ausnek	Verification required	There is one succulent species spotted and verified	Soil erosion, soil pollution, fires, poaching and livestock theft during construction and operations; decrease in aesthetic value of area depending on technology selected.	Site is near the road and it is a scenic place, so there may be a negative impact on tourism and related activities due to the CSP power plant. If no tourism activities are being carried out, no major issues.	Low impact livestock farming observed and springbok seen on site	The site is on private land, hence very low human density. Some buildings were observed near site. The buildings included housing and water infrastructure for maybe herders.	Springbok were seen, termite's mount and aardvark burrows observed. Displacement of wildlife will take place with minimal long-term impacts since the is enough similar habitat in the surrounding area	The site appeared not to have any cultural values during the rapid assessment. Since it is part of a private land, the likelihood of any special utilization for cultural and traditional activities is very low.

6.1.2 Environmental site scoring and selection

The Ausnek site received 2 points because some environmental impact would be expected due to the presence of one endemic flora species. Mitigation efforts would be required to reduce the impact on this flora species.

The site was selected for the DNI resource and its proximity to an adequate substation. Soil erosion was identified on site, and the site is prone to fires. However, precautions could be taken to avoid and mitigate such concerns on site when the CSP plant is developed. One other concern noted was the potential impact on the scenic beauty of the area. This issue should be addressed in the EIA and CSP plant design phases.

Table 6.2 – Ausnek Environmental Scoring,

Information	**5**	**Scoring**
Name of the project	Ausnek	
Endemic/protected fauna in the site	Verification required	
Endemic/protected flora in the site	There is one succulent species spotted and verified	2
Environmental and social concerns	Soil erosion, soil pollution, fires, poaching and livestock theft during construction and operations; decrease in aesthetic value of area depending on technology selected.	6
Landscape	Site is near the road and it is a scenic place, so there may be a negative impact on tourism and related activities due to the CSP power plant. If no tourism activities are being carried out, no major issues.	8
Soil use	Low impact livestock farming observed and springbok seen on site	8
Displacement	The site is on private land, hence very low human density. Some buildings were observed near site. The buildings included housing and water infrastructure for maybe herders.	8
Wildlife impact	Springbok were seen, termite's mount and aardvark burrows observed. Displacement of wildlife will take place with minimal long-term impacts since the is enough similar habitat in the surrounding area	8
Local population	The site appeared not to have any cultural values during the rapid assessment. Since it is part of a private land, the likelihood of any special utilization for cultural and traditional activities is very low.	8

6.1.3 Output for the EIS Terms of Reference

In Annex 6 is presented the Terms of Reference (TORs) for the selected site.

The present TORs, must be considered preliminary document because it was elaborated without relevant Project information, which is still an on-going process.

For that matter, assumptions were made that, with a final version of the project can, and will be, validated.

6.2 Solar resource analysis

6.2.1 Detailed map visualization

In Figure 6.2 is presented the detailed DNI map visualization.

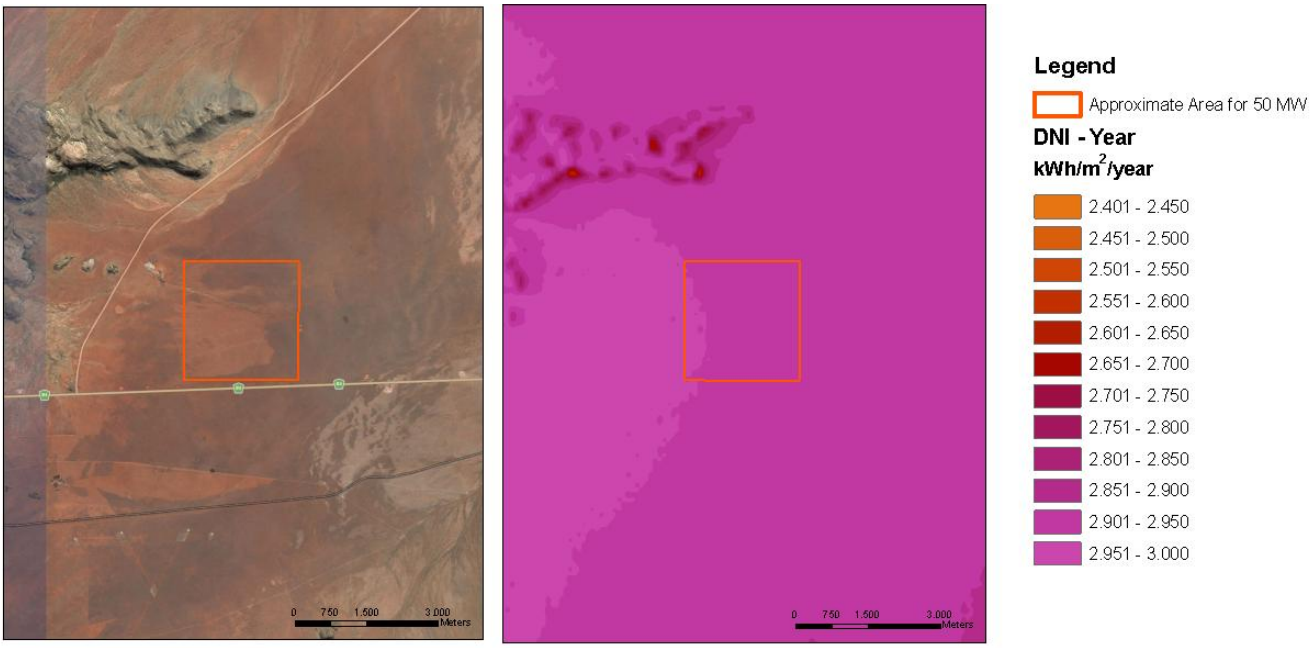


Figure 6.2 – Ausnek detailed DNI map visualization.

6.2.2 Typical meteorological year

TMY (Typical Meteorological Year) data are used to compare the solar resource at alternative sites and to define the probable annual performance of a proposed CSP plant. The TMY is constructed on monthly basis, comparing months of individual years with long-term monthly characteristics: cumulative distribution function and mean (described in Annex 5).

For each site is a screening process is performed selecting the five best months on the basis that the 5 months have the smallest WS values. The results for Ausnek are presented in Table 6.3, with the chosen TMM emphasized in bold numbers.

The remaining best months which meet the persistence criteria are ranked with respect to closeness of the month to the long-term mean. The results for the relative difference of Direct Normal Irradiance are presented in Table 6.4.

Table 6.3 - Weighted Sums (WS) of the FS Statistics for Ausnek.*

	Month											
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
1994	**0,007**	0,016	0,026	**0,008**	0,009	0,014	0,013	0,012	**0,010**	**0,007**	**0,006**	**0,008**
1995	0,020	0,015	0,011	0,017	0,012	**0,008**	0,013	**0,005**	0,011	0,028	**0,006**	0,017
1996	0,023	0,024	**0,010**	**0,009**	0,007	**0,007**	0,021	0,018	0,016	0,014	0,026	0,022
1997	**0,010**	0,014	0,022	0,023	0,008	0,010	**0,004**	0,013	0,026	0,013	0,009	0,024
1998	0,015	0,024	0,016	0,017	**0,006**	0,017	0,008	0,015	**0,008**	0,008	0,008	0,011
1999	0,016	**0,008**	0,041	**0,009**	**0,005**	0,011	0,011	**0,004**	**0,010**	**0,006**	0,017	0,021
2000	**0,011**	**0,006**	**0,007**	0,009	0,011	0,009	**0,006**	0,013	0,012	0,009	0,017	0,012
2001	0,013	0,014	0,011	**0,007**	0,008	**0,007**	0,011	0,012	0,018	**0,004**	0,013	0,017
2002	0,029	**0,009**	0,022	0,012	**0,006**	**0,004**	0,010	0,010	**0,010**	0,009	0,018	**0,008**
2003	0,015	**0,006**	0,012	0,018	0,016	0,013	0,013	0,013	0,015	0,010	0,011	0,011
2004	**0,008**	0,014	0,027	0,011	0,018	0,008	**0,006**	0,016	0,019	0,008	0,026	0,019
2005	0,024	0,013	0,021	0,016	0,010	0,009	0,020	0,014	0,013	0,012	**0,008**	0,014
2006	0,033	0,019	0,013	0,016	0,022	0,010	**0,006**	**0,005**	0,021	0,017	0,014	**0,008**
2007	**0,010**	0,022	**0,008**	0,011	0,007	0,013	0,007	0,015	0,012	**0,007**	**0,007**	0,012
2008	0,013	0,014	0,024	0,012	0,008	0,008	0,009	0,014	0,016	0,012	0,008	0,036
2009	0,018	0,025	**0,006**	0,029	**0,006**	0,016	**0,006**	0,013	**0,005**	**0,007**	0,013	**0,006**
2010	0,022	**0,011**	**0,006**	**0,006**	**0,007**	**0,005**	0,010	**0,008**	0,014	0,010	**0,007**	**0,009**
2011	0,022	0,028	0,033	0,012	0,007	0,012	0,009	**0,006**	0,014	0,009	0,023	0,018

**Bold numbers are for the 5 best years per month (column).*

Table 6.4 – Closeness of the selected month to the long term mean for the remaining best years.

	Month											
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
1994	6,195	-	-	-	-	-	-	-	-	**2,688**	-	11,006
1995	-	-	-	-	-	13,034	-	3,337	-	-	**2,458**	-
1996	-	-	12,190	-	-	6,451	-	-	-	-	-	-
1997	-	-	-	-	-	-	-	-	-	-	-	-
1998	-	-	-	-	11,616	-	-	-	14,610	-	-	-
1999	-	4,695	-	3,177	7,049	-	-	8,653	**0,240**	-	-	-
2000	2,494	7,853	10,667	-	-	-	**0,444**	-	-	-	-	-
2001	-	-	-	6,124	-	**1,159**	-	-	-	3,367	-	-
2002	-	-	-	-	-	-	-	-	13,747	-	-	-
2003	-	**1,503**	-	-	-	-	-	-	-	-	-	-
2004	**0,682**	-	-	-	-	-	6,229	-	-	-	-	-
2005	-	-	-	-	-	-	-	-	-	-	11,023	-
2006	-	-	-	-	-	-	-	-	-	-	-	2,610
2007	-	-	-	-	-	-	-	-	-	15,805	11,925	-
2008	-	-	-	-	-	-	-	-	-	-	-	-
2009	-	-	**5,995**	-	**5,391**	-	2,575	-	-	-	-	9,433
2010	-	-	-	**2,806**	-	-	-	-	-	-	-	**2,241**
2011	-	-	-	-	-	-	-	**0,641**	-	-	-	-

**Bold numbers are for the 5 best years per month (column).*

The TMY procedure and additional results is in Annex 5, including a CD with the data.

6.3 Power generation estimate

In the location Ausnek there are no local consumers or particular load requirements so the generation will be fed to the grid and so Namibia Load is the major consideration to be used. According to the information collected by Hatch on the National Integrated Resources Plan (NIRP) and based on Nampower data the daily load per year and for the previous years displays two peaks: one flat between 9.30 and 13.00 and another at around 20.00.

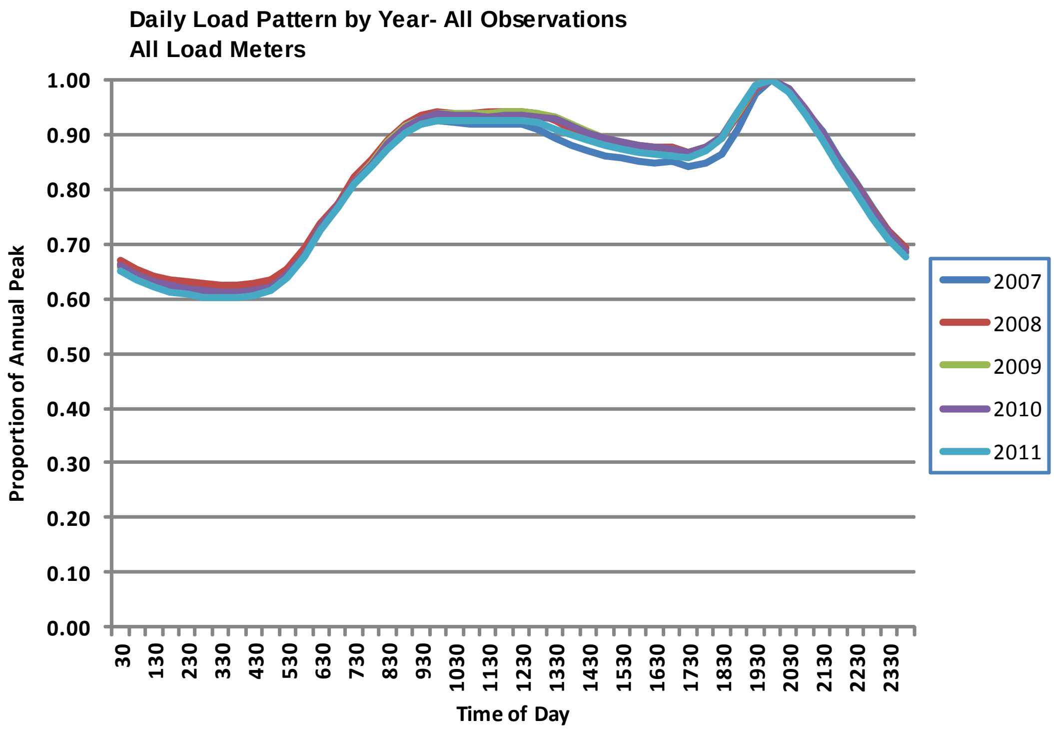


Figure 6.3 – Namibia Daily load pattern per year according to the NIRP study from Hatch.

That is confirmed by the average daily load and also on monthly values. It is visible that there is a slight shift of the peak during the months of the year but within the mentioned values:

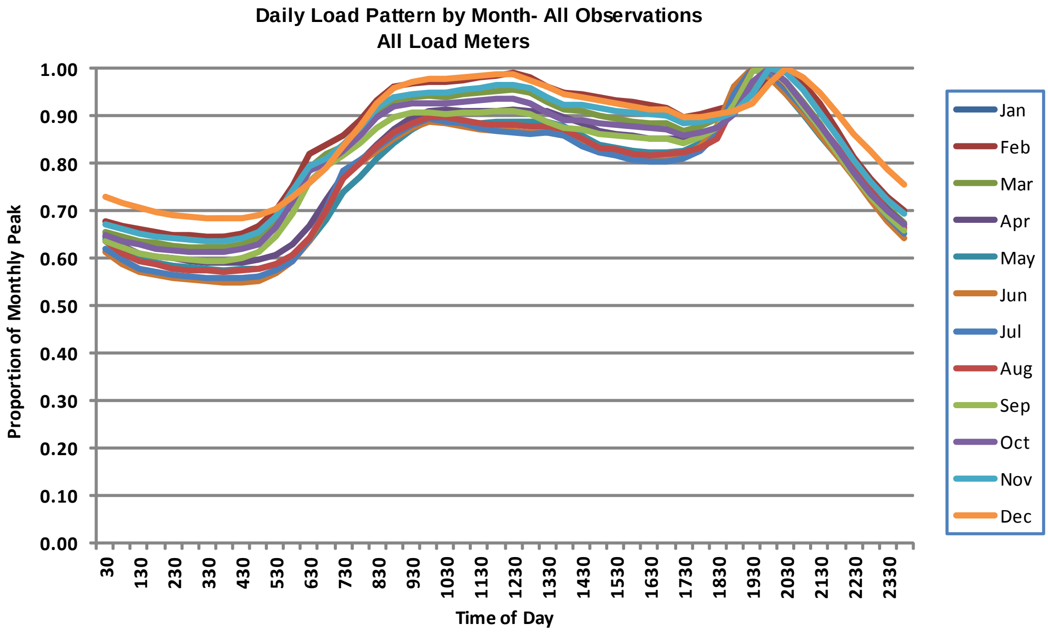


Figure 6.4 – Namibia Daily load pattern per month according to the NIRP study from Hatch

The values of generation (GWh) and peak (MW) were also collected by Hatch on the study mentioned and they are presented below:

	Reference	
	Generation Energy (GWh)	Generation Peak (MW)
2008 a	2,735.7	428.6
2009 a	2,806.9	445.5
2010 a	3,001.6	477.4
2011 e	3,146.7	496.9
2012	3,211.5	507.7
2013	3,402.6	533.2
2014	3,485.1	546.9
2015	4,664.1	683.4
2016	4,740.6	696.0
2017	4,819.4	709.0
2018	4,916.4	725.2

Figure 6.5 – Namibia yearly load for several years according to the NIRP study from Hatch.

The peak is around 50 MW and overshooting that value in the near future.

Based on the load of Nampower it is possible to see that we have 3 periods of “peaks” as shown below:

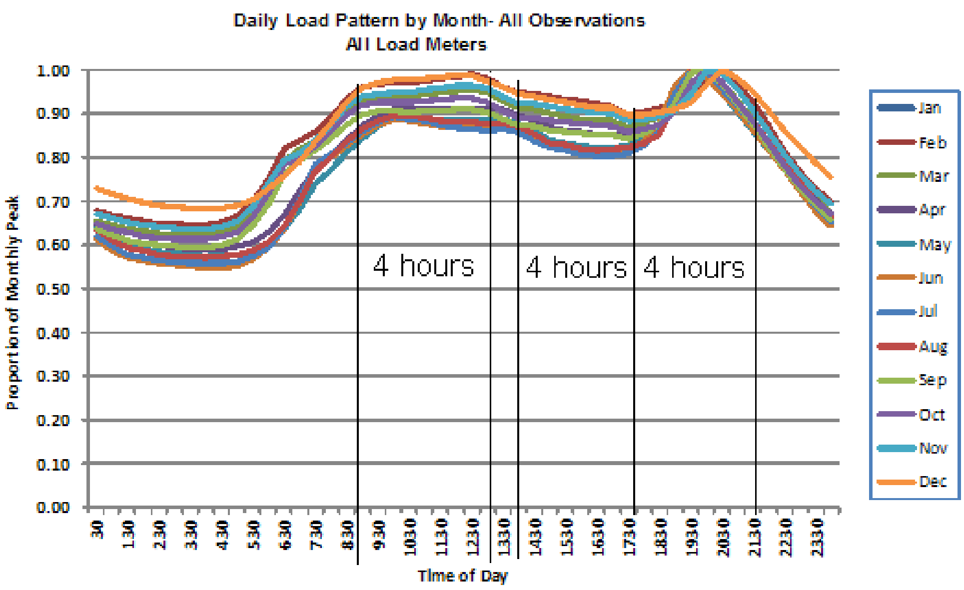


Figure 6.6 – The generation time frames for the Namibian Daily load pattern per month.

In a more detailed analysis and taking into consideration the full generation profile of Nampower and looking at the peak power plants only, it is possible to see that those plants reach stable operation around 7.00 until 21.00 with downward fluctuation in mid-afternoon. In terms of a CSP power plant it results in a mandatory criterion for storage in that period for later generation.

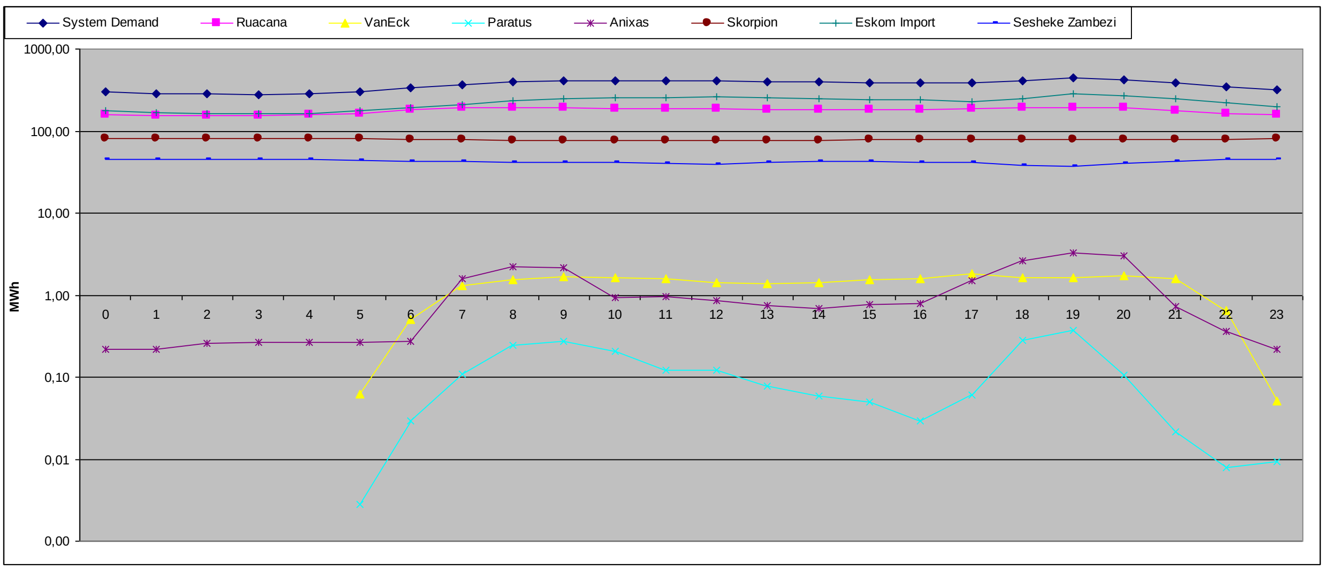


Figure 6.7 – Namibia generation pattern from all available sources showing the operation of peak power plants. It is in logarithmic scale.

Bearing in mind what was outlined before, a 50 MW power plant with a generation pattern of 12 hours on average with adequate storage – 6 to 8 hours – is required. With storage only parabolic troughs and power towers apply. Not enough water is available for wet cooling, so only dry cooling was considered, which translated into an increase in the solar field to overcome the expected loss in efficiency – 15 to 20%.

6.3.1 Parabolic troughs

The DNI provided by Geomodel showed data for 17 years with a 15 min period. Several models for generation were used – DLR proprietary model and SunBD proprietary model (SunBD model has been checked against SAM and also with existing CSP power plants and results are in line). Data with one hour period was also used to check for differences. Models which operate on an energy balance basis do not actually show big differences between the two data sets. Models based on temperature do show more differences and particularly are able to show the transients. For this site no particular difference was seen between the two data sets.

The inputs considered were:

- Average daily output was 12 hours

- Parabolic troughs of Eurotrough type: 5,76 m of aperture and usually assembled in lines of 600 m long (usually 4 sub-segments are considered). Evacuated tubes with diameters of 0,07 m were considered.

- Use of artificial oil for the HTF of the solar field.

- Use of molten salts for the storage medium.

- Solar field with combined efficiency of 76% and Incident Angle Modifier (IAM) of 85%.

- End losses were considered due to the latitude and inclination of the sun (trough only track in one axis).

- Operating temperature of 350ºC and deaerator temperature of 105ºC.

- Water/steam ratio of 2.

- Turbine efficiency was 28% due to dry cooling.

The outputs given are by no means results of a detailed engineering analysis, but on made on basic engineering assumption and to provide figures:

- Solar field – aperture area required – 750000 m^2.

- Plant size = 225 hect.

- Storage hours – 7.

- Generation output (net) – 12,4 hours on average per day.

(a maximum of 17 hours and a minimum of 8 are expected to occur during the year).

- Around 28000 ton of molten slats are required. Two tanks with 38 of diameter by 19 meters high are suitable, but other design criteria can be used for the final sizing.

6.3.2 Power towers

The DNI provided by Geomodel showed data for 17 years with a 15 min period. Several models for generation were used – Julich Institute proprietary model and SunBD proprietary model (SunBD model has been checked against SAM and also with existing CSP power plants and results are in line). Data with one hour period was also used to check for differences. Models which operate on an energy balance basis do not actually show big differences between the two data sets. Models based on temperature do show more differences and particularly are able to show the transients. For this site no particular difference was seen between the two data sets.

The inputs considered were:

- Average daily output was 12 hours.

- Heliostats of 125m^2 were considered.

- Use of molten salts for the HTF of the solar field.

- Use of molten salts for the storage medium.

- Solar field with combined efficiency of 82% and Incident Angle Modifier (IAM) of 85%.

- Concentration factor of 800.

- Operating temperature of 400ºC and deaerator temperature of 105ºC

- Water/steam ratio of 2.

- Turbine efficiency was 30% due to dry cooling.

The outputs given are by no means results of a detailed engineering analysis, but on made on basic engineering assumption and to provide figures:

- Solar field – heliostats area – 690000 m^2.

- Plant size = 276 hect.

- Storage hours – 8.

- Generation output (net) – 12,4 hours on average per day.

(a maximum of 18 hours and a minimum of 8 are expected to occur during the year).

- Around 16000 ton of molten slats are required. Two tanks with 31 of diameter by 16 meters high are suitable, but other design criteria can be used for the final sizing.

6.4 Plant design

The plant design incorporates the following:

- Parabolic troughs were designed with the number of rows as estimated, separations that provide no shadow form each row to the neighbouring one and with a BOP illustrating what was described. The parabolic troughs used were of the Eurotrough type with evacuated tubes and silver mirrors with tempered glasses. The implementation on the ground was selected according to the existing accesses and no electrical connection was idealized, but it does not provide more than an indication.

- Power Towers were designed based on the number of heliostats required and on the distance required between them. The heliostats used were silver mirrors with tempered glasses. No specific study was made for that and so it was attempted to illustrate the different distances according to the distance to the tower and the total plant size considered. A 360º design was chosen to maximize the area usage and also to benefit from the lower latitude. The implementation on the ground was selected according to the existing accesses and no electrical connection was idealized, but it does not provide more than an indication.

6.4.1 Parabolic troughs

The rough plant layout is presented in Figure 1.1.

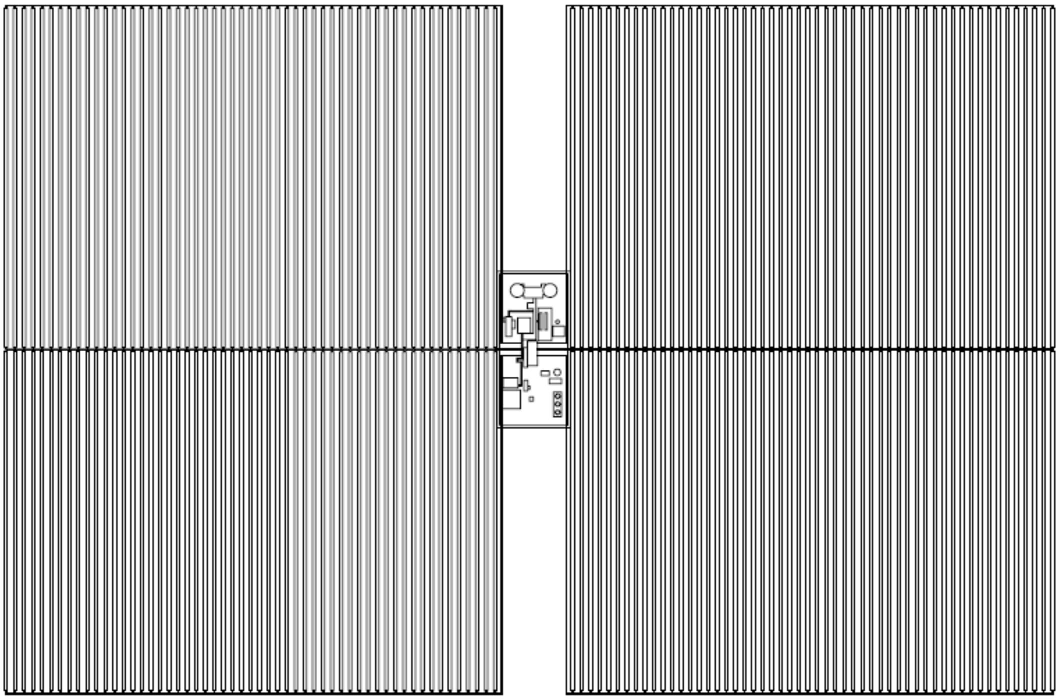


Figure 6.8 - Layout of the parabolic trough power plant.

The implementation in the site is suggested as in Figure 6.9.

Figure 6.9 – Implementation of the parabolic trough power plant in the site.

6.4.2 Power towers

The rough plant layout is presented in Figure 6.10.

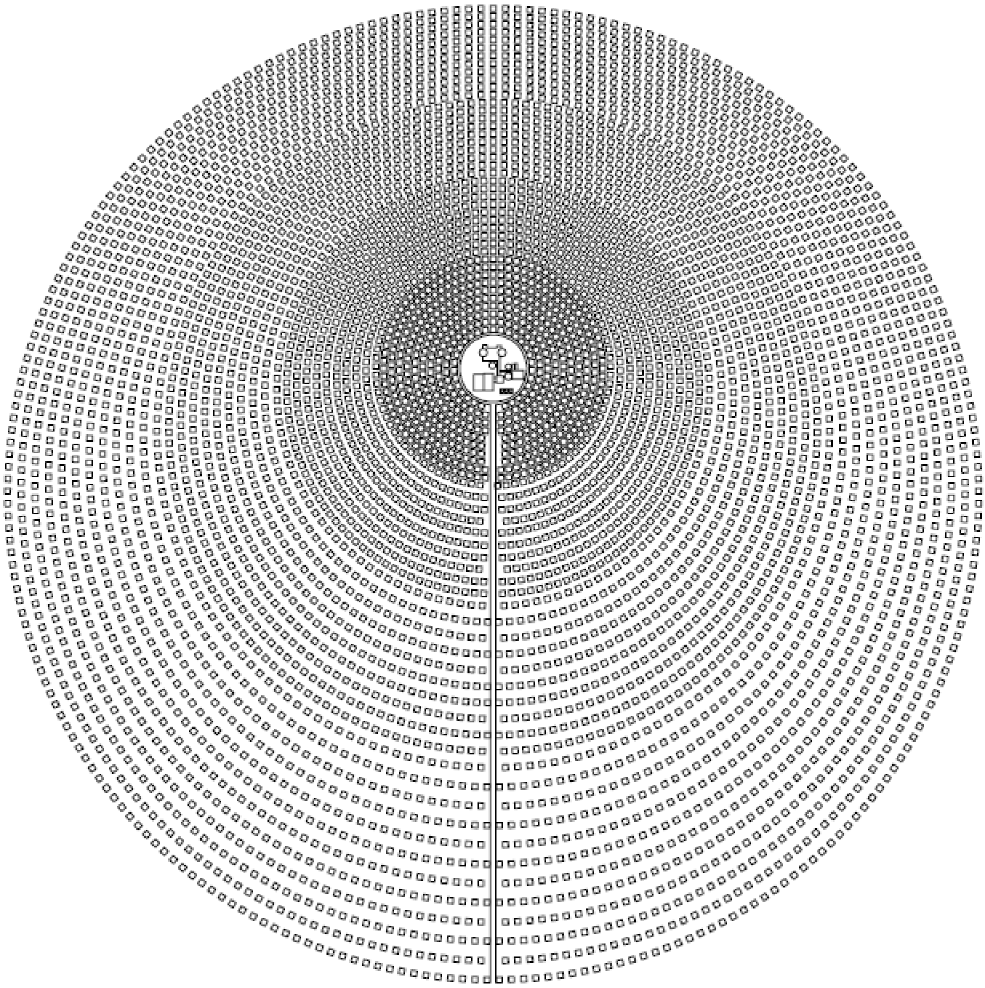


Figure 6.10 – Layout of the power tower power plant.

The implementation in the site is suggested as in Figure 6.11.

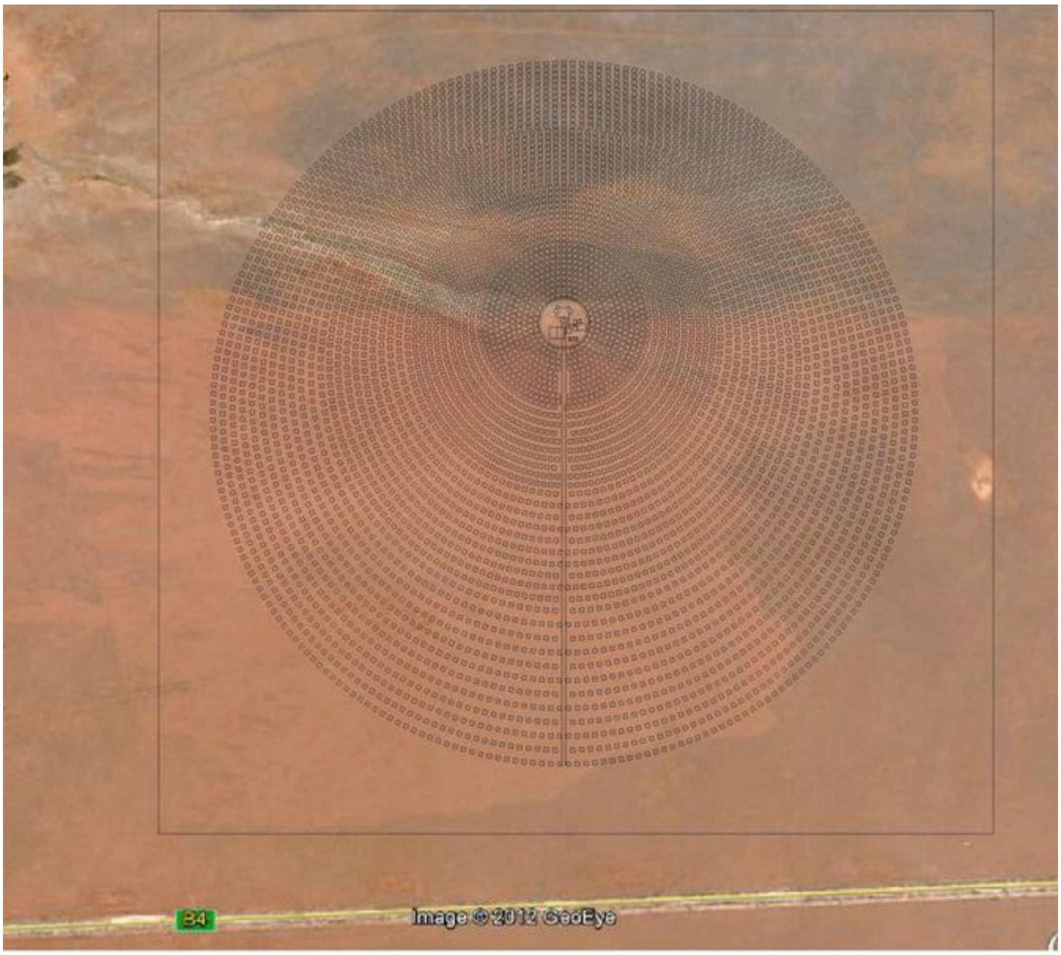


Figure 6.11 – Implementation of the power tower power plant in the site.

6.5 Grid connection point

The grid connection for the site is:

- Ausnek SS (132 KV/220KV) and possibility to connect 20 MW @220KV needing an upgrade.

- 9,5 km distance to the SS.

7 Project 2 - Kokerboom

7.1 Environmental report

7.1.1 Field works – Micro sitting

The Kokerboom site is private land located 22 km northwest of Keetmanshoop and adjacent to a gravel road that runs from the M29 road to the Kokerboom substation. The site is 1168 m above sea level. The ground is very flat with an average slope of 1.0%. Some rocks were found within the topsoil, which indicates that the soil layers underneath will have stony characteristics. The site is located in a dry area that receives 100-150 mm rain annually. The land appears to be used for animal grazing. No protected flora or fauna species were identified on the site.

Figure 7.1 - Micro-sitting of Kokerboom site.

In the following table is present the results from the sites works performed on the site.

Table 7.1 – Results from the sites works performed on the site.

Project ID	Endemic/protected fauna in the site	Endemic/protected flora in the site	Environmental and social concerns	Landscape	Soil use	Displacement	Wildlife impact	Local population
Kokerboom	None spotted	None spotted	Soil erosion, soil pollution, fires, poaching and livestock theft during construction and operations.	No major impact on landscape is expected. It is next to a substation.	Low impact sheep farming observed. Two water points were seen near the site.	The site is on private land, hence very low human density. Except for the water points, no other infrastructures were observed.	No wildlife was observed during the rapid site assessment.	The site appeared not to have any cultural values during the rapid assessment. Since it is part of a private land, the likelihood of any special utilization for cultural and traditional activities is very low.

7.1.2 Environmental site scoring and selection

The Kokerboom site received 8 points because there would be very little environmental impact to develop it for CSP. No endemic flora or fauna were identified on site which could require mitigation efforts.

The site was selected for the DNI resource and proximity to an adequate substation. Soil erosion was identified on site, and the site is prone to bush fires. However, precautions could be taken to avoid and mitigate such concerns on site when the CSP plant is developed.

Table 7.2 – Kokerboom Environmental Scoring,

Information	8	Scoring
Name of the project	Kokerboom	
Endemic/protected fauna in the site	None spotted	8
Endemic/protected flora in the site	None spotted	8
Environmental and social concerns	Soil erosion, soil pollution, fires, poaching and livestock theft during construction and operations.	6
Landscape	No major impact on landscape is expected. It is next to a substation.	8
Soil use	Low impact sheep farming observed. Two water points were seen near the site.	8
Displacement	The site is on private land, hence very low human density. Except for the water points, no other infrastructures were observed.	8
Wildlife impact	No wildlife was observed during the rapid site assessment.	8
Local population	The site appeared not to have any cultural values during the rapid assessment. Since it is part of a private land, the likelihood of any special utilization for cultural and traditional activities is very low.	8

7.1.3 Output for the EIS Terms of Reference

In Annex 6 is presented the Terms of Reference (TORs) for the selected site.

The present TORs, must be considered preliminary document because it was elaborated without relevant Project information, which is still an on-going process.

For that matter, assumptions were made that, with a final version of the project can, and will be, validated.

7.2 Solar resource analysis

7.2.1 Detailed map visualization

In Figure 7.2 is presented the detailed DNI map visualization.

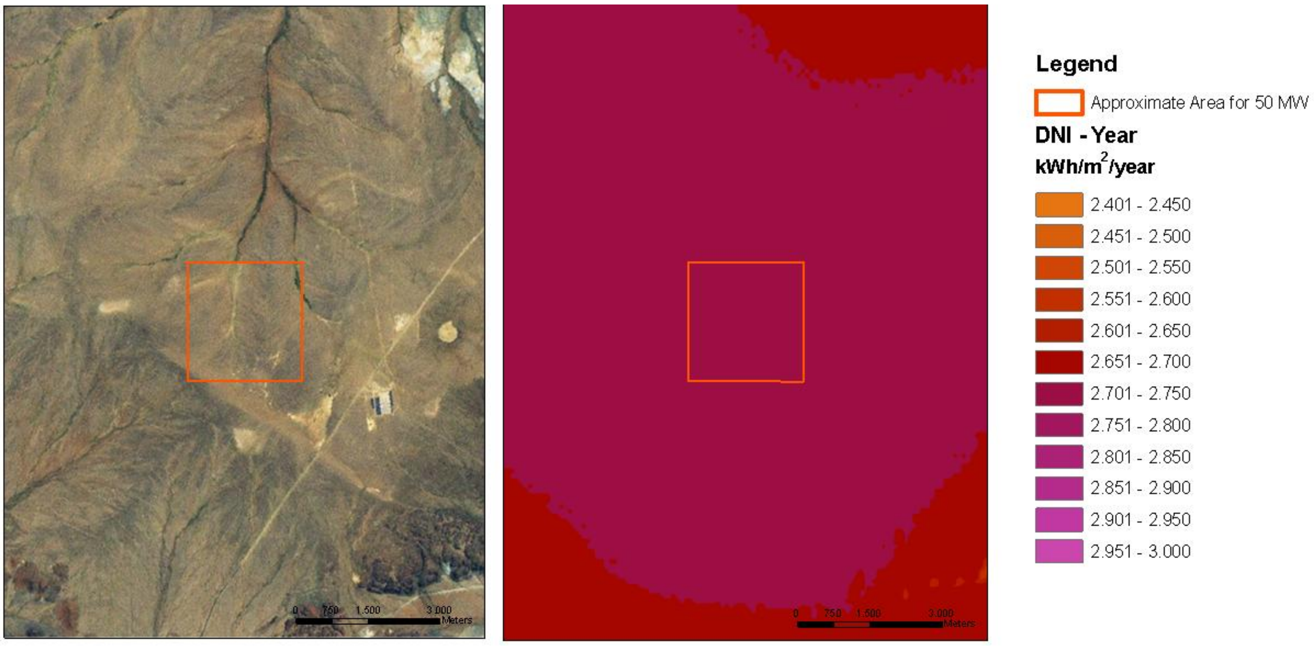


Figure 7.2 – Kokerboom detailed DNI map visualization.

7.2.2 Typical meteorological year

TMY (Typical Meteorological Year) data are used to compare the solar resource at alternative sites and to define the probable annual performance of a proposed CSP plant. The TMY is constructed on monthly basis, comparing months of individual years with long-term monthly characteristics: cumulative distribution function and mean (described in Annex 5).

For each site is a screening process is performed selecting the five best months on the basis that the 5 months have the smallest WS values. The results for Kokerboom are presented in Table 7.3, with the chosen TMM emphasized in bold numbers.

The remaining best months which meet the persistence criteria are ranked with respect to closeness of the month to the long-term mean. The results for the relative difference of Direct Normal Irradiance are presented in Table 7.4.

Table 7.3 – Weighted Sums (WS) of the FS Statistics for Kokerboom.*

	Month											
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
1994	0,014	0,013	0,017	0,012	0,009	0,017	0,012	0,012	**0,011**	0,013	0,012	0,010
1995	0,021	0,015	0,013	0,018	0,010	**0,006**	0,010	**0,006**	0,014	0,022	**0,004**	0,014
1996	0,019	0,016	0,016	**0,006**	**0,007**	**0,006**	0,020	0,018	0,015	0,011	0,025	0,018
1997	0,017	0,013	0,011	0,027	**0,007**	0,010	**0,004**	0,014	0,028	0,016	**0,008**	0,022
1998	0,014	0,013	0,016	0,023	0,010	0,014	0,010	0,012	**0,007**	**0,006**	0,011	**0,008**
1999	**0,013**	**0,009**	0,027	0,010	0,012	0,009	0,009	**0,005**	0,012	**0,006**	0,012	0,031
2000	**0,011**	**0,010**	**0,008**	**0,009**	0,010	0,008	**0,006**	0,016	0,012	0,009	0,014	**0,007**
2001	0,016	0,021	**0,008**	0,014	**0,007**	0,008	0,008	**0,008**	0,015	**0,007**	0,016	0,016
2002	0,029	**0,008**	0,022	0,011	**0,004**	**0,004**	0,010	0,012	**0,010**	0,014	0,015	**0,006**
2003	**0,012**	0,015	0,014	0,019	0,010	0,010	0,012	0,013	0,015	**0,007**	0,012	**0,009**
2004	**0,006**	**0,008**	0,014	0,012	0,019	0,011	0,007	**0,006**	0,018	0,010	0,032	0,014
2005	**0,009**	**0,008**	0,019	0,017	0,009	0,008	0,022	0,011	**0,010**	**0,004**	**0,005**	0,011
2006	0,025	0,013	0,010	**0,009**	0,024	0,008	**0,003**	0,018	0,016	0,008	0,012	0,010
2007	0,020	0,039	**0,009**	**0,010**	0,009	0,013	**0,005**	0,010	0,016	0,009	**0,006**	0,012
2008	0,019	0,013	0,010	0,010	**0,005**	**0,007**	**0,005**	0,013	0,032	0,014	0,013	0,027
2009	0,016	0,027	**0,008**	0,021	0,009	0,014	0,013	0,013	**0,004**	0,013	**0,006**	0,012
2010	0,026	0,014	**0,010**	**0,007**	0,008	**0,006**	0,010	0,010	0,013	0,013	0,014	**0,009**
2011	0,027	0,021	0,024	0,011	0,009	0,010	0,009	**0,005**	0,020	0,015	0,020	0,012

**Bold numbers are for the 5 best years per month (column).*

Table 7.4 – Closeness of the selected month to the long term mean for the remaining best years.

	Month											
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
1994	-	-	-	-	-	-	-	-	18,790	-	-	-
1995	-	-	-	-	-	8,504	-	**0,105**	-	-	5,301	-
1996	-	-	-	-	9,714	**3,809**	-	-	-	-	-	-
1997	-	-	-	-	-	-	1,748	-	-	-	-	-
1998	-	-	-	-	-	-	-	-	11,350	5,282	-	8,907
1999	-	11,440	-	-	-	-	-	5,178	-	-	-	-
2000	-	-	15,312	18,995	-	-	**0,117**	-	-	-	-	5,941
2001	-	-	**0,985**	-	2,791	-	-	-	-	10,282	-	-
2002	-	8,076	-	-	**2,686**	-	-	-	**10,976**	-	-	-
2003	15,904	-	-	-	-	-	-	-	-	-	-	-
2004	**8,356**	16,638	-	-	-	-	-	-	-	-	-	-
2005	15,075	**5,203**	-	-	-	-	-	-	-	**2,118**	**2,011**	-
2006	-	-	-	17,165	-	-	-	-	-	-	-	-
2007	-	-	-	-	-	-	-	-	-	-	-	-
2008	-	-	-	-	-	11,964	4,788	-	-	-	-	-
2009	-	-	10,532	-	-	-	-	-	-	-	8,231	-
2010	-	-	-	**7,193**	-	-	-	-	-	-	-	**2,368**
2011	-	-	-	-	-	-	-	6,163	-	-	-	-

**Bold numbers are for the 5 best years per month (column).*

The TMY procedure and additional results is in Annex 5, including a CD with the data.

Promoter: Sponsors: Developers:

7.3 Power generation estimate

In the location Kokerboom there are no local consumers or particular load requirements so the generation will be fed to the grid and so Namibia Load is the major consideration to be used. According to the information collected by Hatch on the National Integrated Resources Plan (NIRP) and based on Nampower data the daily load per year and for the previous years displays two peaks: one flat between 9.30 and 13.00 and another at around 20.00.

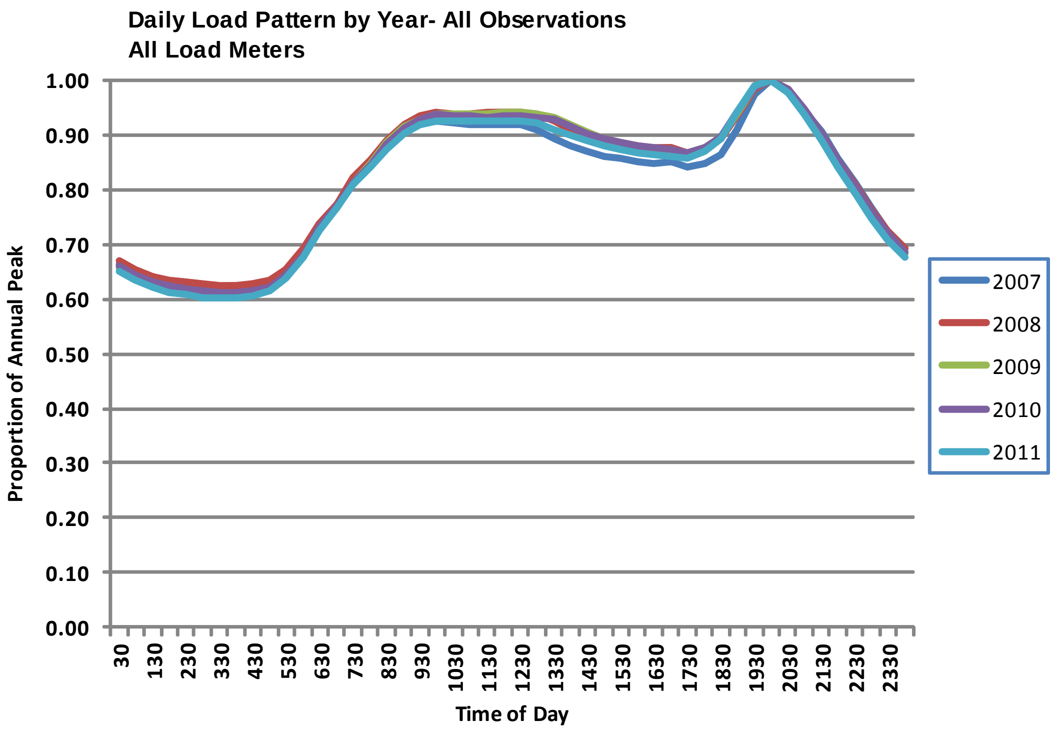


Figure 7.3 – Namibia Daily load pattern per year according to the NIRP study from Hatch.

That is confirmed by the average daily load and also on monthly values. It is visible that there is a slight shift of the peak during the months of the year but within the mentioned values:

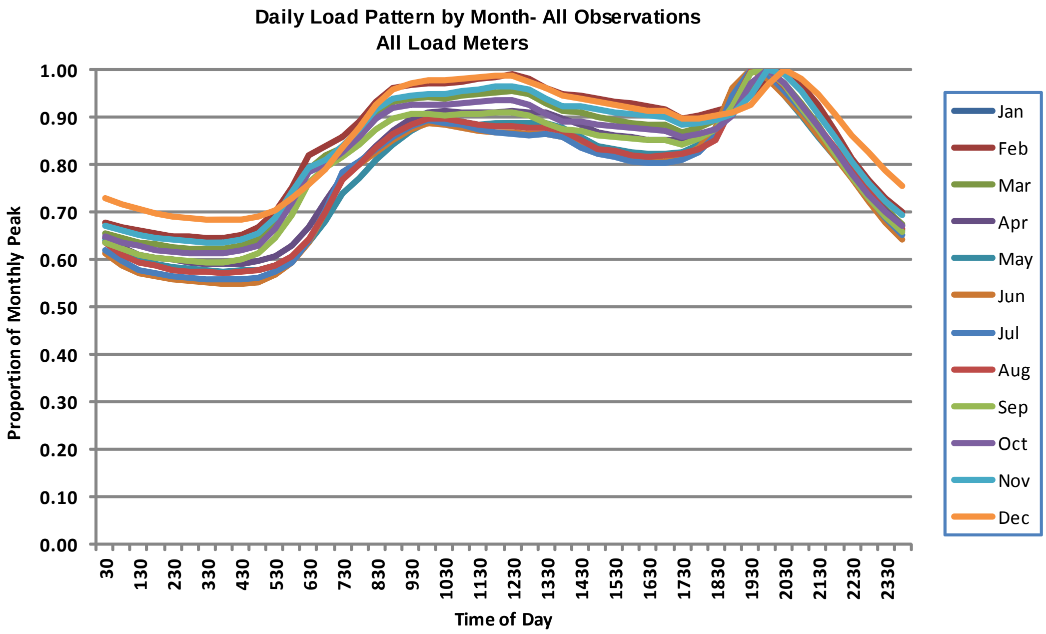


Figure 7.4 – Namibia Daily load pattern per month according to the NIRP study from Hatch.

The values of generation (GWh) and peak (MW) were also collected by Hatch on the study mentioned and they are presented below:

	Reference	
	Generation Energy (GWh)	Generation Peak (MW)
2008 a	2,735.7	428.6
2009 a	2,806.9	445.5
2010 a	3,001.6	477.4
2011 e	3,146.7	496.9
2012	3,211.5	507.7
2013	3,402.6	533.2
2014	3,485.1	546.9
2015	4,664.1	683.4
2016	4,740.6	696.0
2017	4,819.4	709.0
2018	4,916.4	725.2

Figure 7.5 – Namibia yearly load for several years according to the NIRP study from Hatch.

The peak is around 50 MW and overshooting that value in the near future.

Based on the load of Nampower it is possible to see that we have 3 periods of “peaks” as shown below:

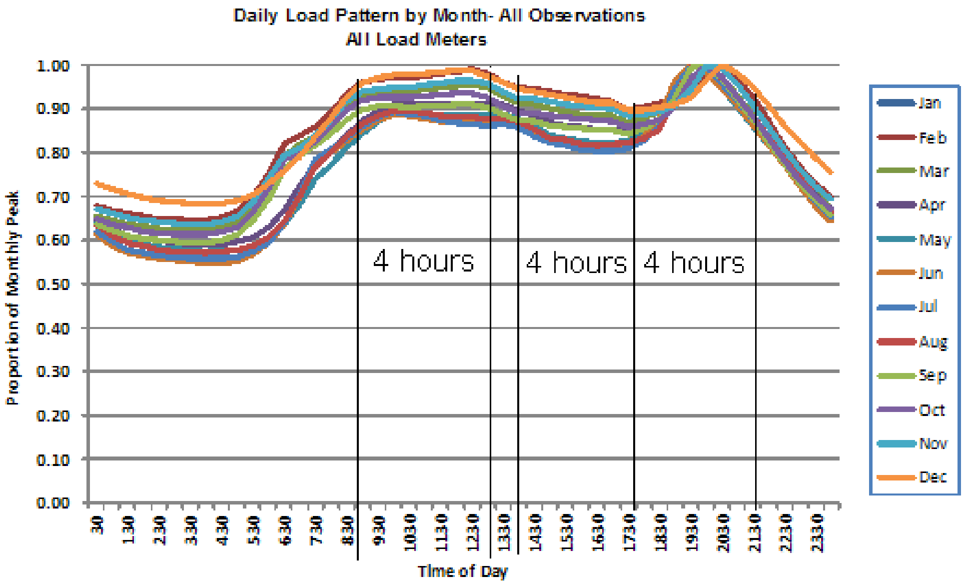


Figure 7.6 – The generation time frames for the Namibian Daily load pattern per month.

In a more detailed analysis and taking into consideration the full generation profile of Nampower and looking at the peak power plants only, it is possible to see that those plants reach stable operation around 7.00 until 21.00 with downward fluctuation in mid-afternoon. In terms of a CSP power plant it results in a mandatory criterion for storage in that period for later generation.

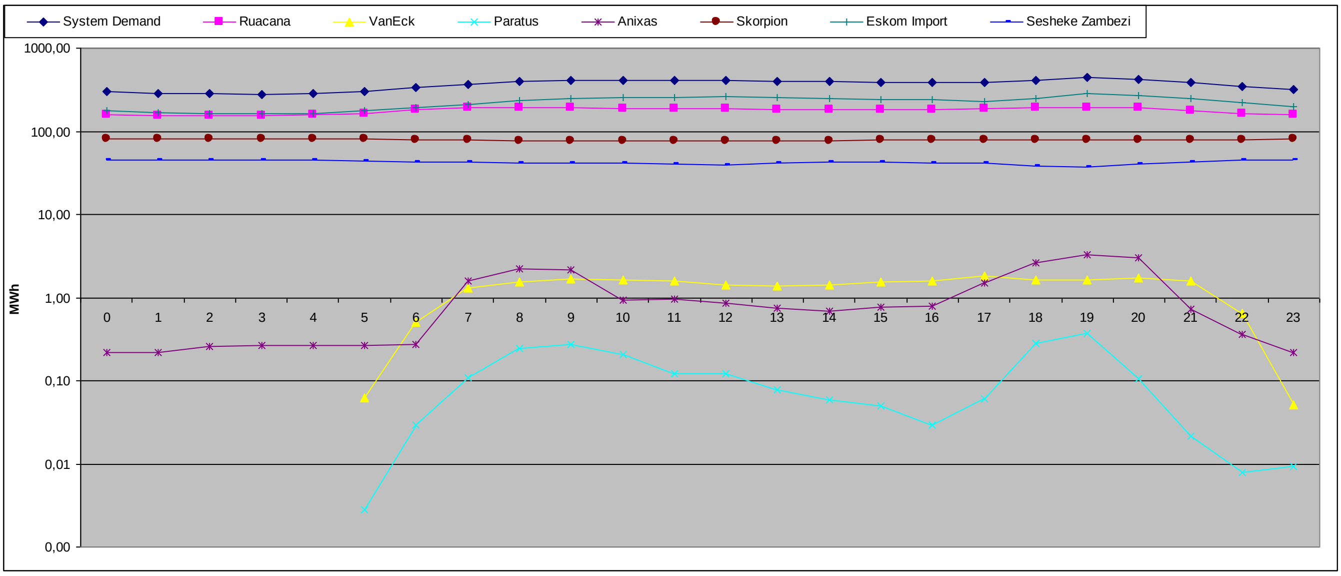


Figure 7.7 – Namibia generation pattern from all available sources showing the operation of peak power plants. It is in logarithmic scale

Bearing in mind what was outlined before, a 50 MW power plant with a generation pattern of 12 hours on average with adequate storage – 6 to 8 hours – is required. With storage only parabolic troughs and power towers apply. Not enough water is available for wet cooling, so only dry cooling was considered, which translated into an increase in the solar field to overcome the expected loss in efficiency – 15 to 20%.

7.3.1 Parabolic troughs

The DNI provided by Geomodel showed data for 17 years with a 15 min period. Several models for generation were used – DLR proprietary model and SunBD proprietary model (SunBD model has been checked against SAM and also with existing CSP power plants and results are in line). Data with one hour period was also used to check for differences. Models which operate on an energy balance basis do not actually show big differences between the two data sets. Models based on temperature do show more differences and particularly are able to show the transients. For this site no particular difference was seen between the two data sets.

The inputs considered were:

- Average daily output was 12 hours.

- Parabolic troughs of Eurotrough type: 5,76 m of aperture and usually assembled in lines of 600 m long (usually 4 sub-segments are considered). Evacuated tubes with diameters of 0,07 m were considered.

- Use of artificial oil for the HTF of the solar field.

- Use of molten salts for the storage medium.

- Solar field with combined efficiency of 76% and Incident Angle Modifier (IAM) of 85%.

- End losses were considered due to the latitude and inclination of the sun (trough only track in one axis).

- Operating temperature of 350ºC and deaerator temperature of 105ºC.

- Water/steam ratio of 2.

- Turbine efficiency was 28% due to dry cooling.

The outputs given are by no means results of a detailed engineering analysis, but on made on basic engineering assumption and to provide figures:

- Solar field – aperture area required – 825000 m^2.

- Plant size = 248 hect.

- Storage hours – 7.

- Generation output (net) – 12,4 hours on average per day.

(a maximum of 17 hours and a minimum of 8 are expected to occur during the year).

- Around 28000 ton of molten slats are required. Two tanks with 38 of diameter by 19 meters high are suitable, but other design criteria can be used for the final sizing.

7.3.2 Power towers

The DNI provided by Geomodel showed data for 17 years with a 15 min period. Several models for generation were used – Julich Institute proprietary model and SunBD proprietary model (SunBD model has been checked against SAM and also with existing CSP power plants and results are in line). Data with one hour period was also used to check for differences. Models which operate on an energy balance basis do not actually show big differences between the two data sets. Models based on temperature do show more differences and particularly are able to show the transients. For this site no particular difference was seen between the two data sets.

The inputs considered were:

- Average daily output was 12 hours.

- Heliostats of 125m^2 were considered.

- Use of molten salts for the HTF of the solar field.

- Use of molten salts for the storage medium.

- Solar field with combined efficiency of 82% and Incident Angle Modifier (IAM) of 85%.

- Concentration factor of 800.

- Operating temperature of 400ºC and deaerator temperature of 105ºC.

- Water/steam ratio of 2.

- Turbine efficiency was 30% due to dry cooling.

The outputs given are by no means results of a detailed engineering analysis, but on made on basic engineering assumption and to provide figures:

- Solar field – heliostats area – 755000 m^2.

- Plant size = 302 hect.

- Storage hours – 8.

- Generation output (net) – 12,4 hours on average per day.

(a maximum of 18 hours and a minimum of 8 are expected to occur during the year).

- Around 16000 ton of molten slats are required. Two tanks with 31 of diameter by 16 meters high are suitable, but other design criteria can be used for the final sizing.

7.4 Plant design

The plant design incorporates the following:

- Parabolic troughs were designed with the number of rows as estimated, separations that provide no shadow form each row to the neighbouring one and with a BOP illustrating what was described. The parabolic troughs used were of the Eurotrough type with evacuated tubes and silver mirrors with tempered glasses. The implementation on the ground was selected according to the existing accesses and no electrical connection was idealized, but it does not provide more than an indication.

- Power Towers were designed based on the number of heliostats required and on the distance required between them. The heliostats used were silver mirrors with tempered glasses. No specific study was made for that and so it was attempted to illustrate the different distances according to the distance to the tower and the total plant size considered. A 360º design was chosen to maximize the area usage and also to benefit from the lower latitude. The implementation on the ground was selected according to the existing accesses and no electrical connection was idealized, but it does not provide more than an indication.

7.4.1 Parabolic troughs

The rough plant layout is presented in Figure 7.8.

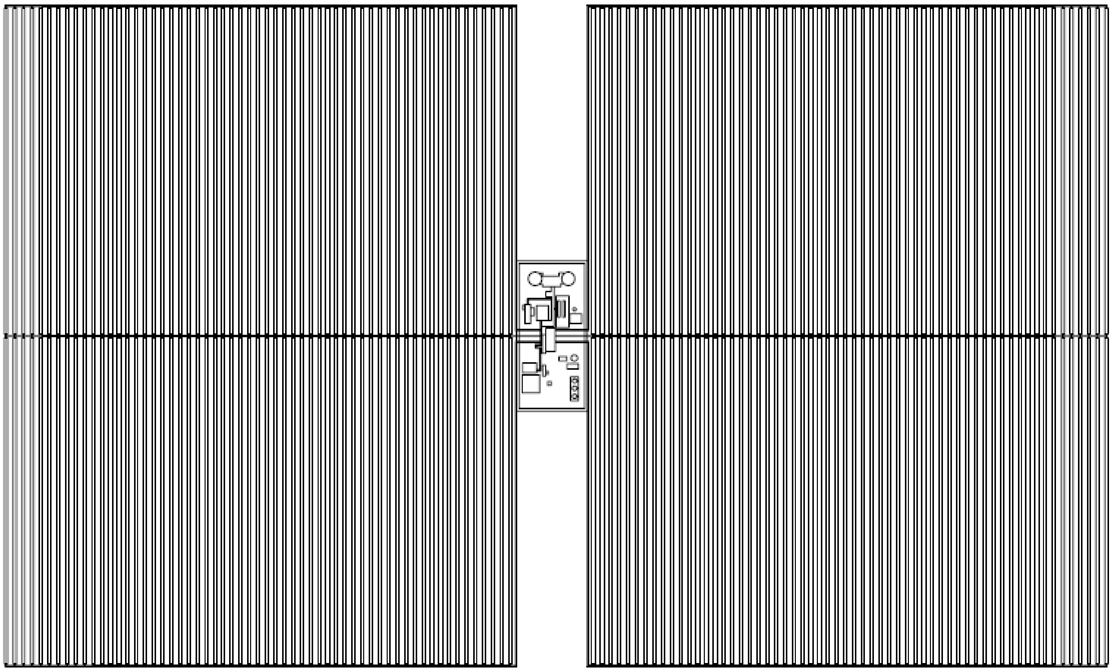


Figure 7.8 – Layout of a parabolic trough power plant.

The implementation in the site is suggested as in Figure 7.9.

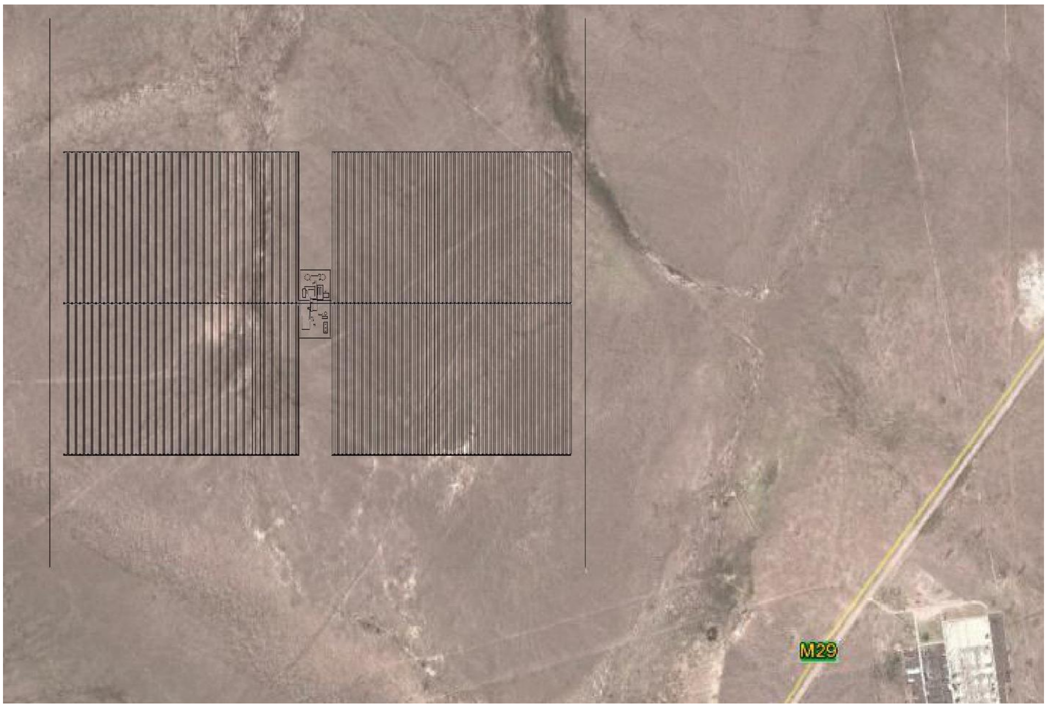


Figure 7.9 – Implementation of a parabolic trough power plant in the site.

7.4.2 Power towers

The rough plant layout is presented in Figure 7.10.

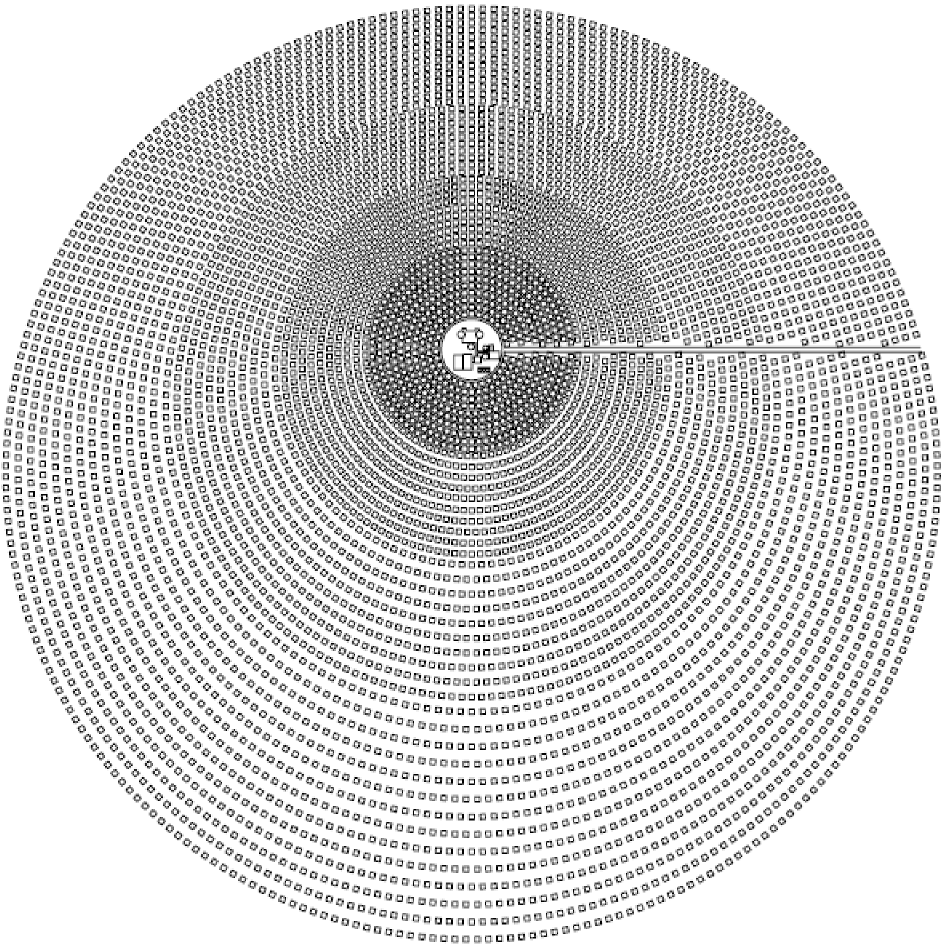


Figure 7.10 – Layout of a power tower power plant.

The implementation in the site is suggested as:

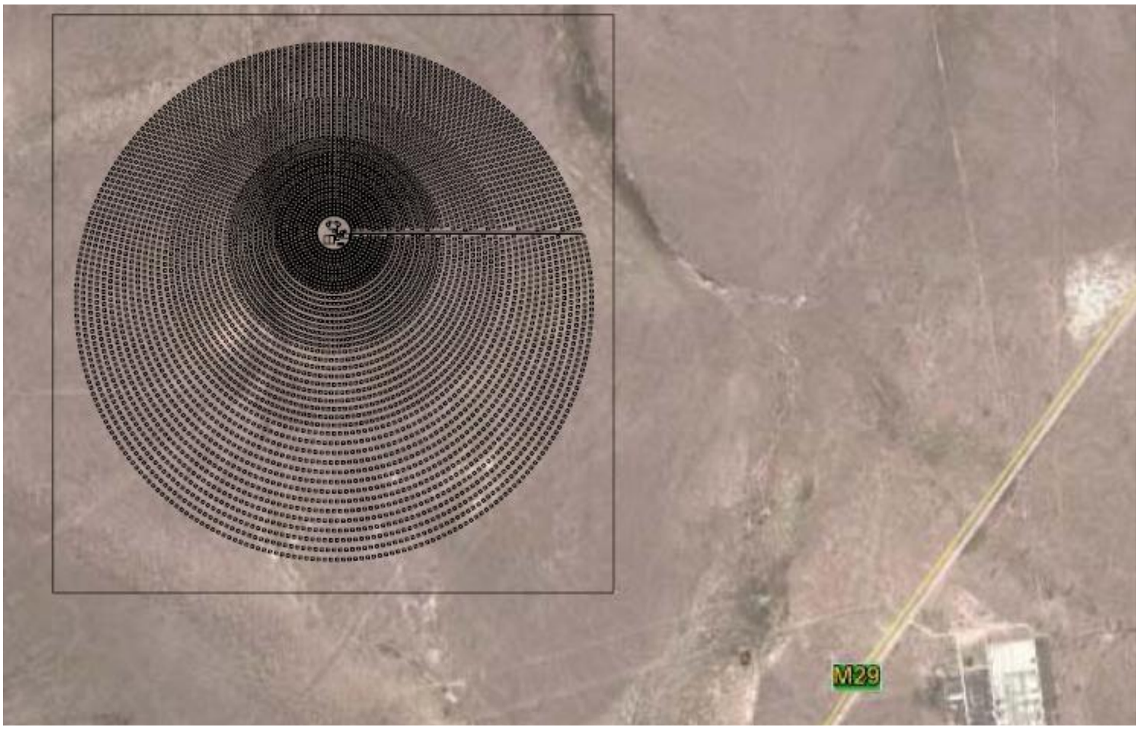


Figure 7.11 – Implementation of a power tower power plant in the site.

7.5 Grid connection point

The grid connection for the site is:

- Kokerboom SS (400 KV/ 220KV/132 KV/66 KV) with 40 MVA and possibility to connect 50 MW @220KV.

- 2,9 km distance to the SS.

8 Project 3 – Gerus 2

8.1 Environmental report

8.1.1 Field works – Micro sitting

The Gerus 2 site is private agricultural land located 27 km north of Otjiwarongo and adjacent to national road B1. The site is 1323 m above sea level. The ground is very flat with an average slope of 1.5%. The top soil of the site did not include rocks and stones. The site is located in an area that receives 400-450 mm rain annually. The land is significantly bush encroached, as this site was selected for its biomass potential.

Figure 8.1 - Micro-sitting of Gerus site.

In the following table is present the results from the sites works performed on the site.

Table 8.1 - Results from the sites works performed on the site.

Project ID	Endemic/protected fauna in the site	Endemic/protected flora in the site	Environmental and social concerns	Landscape	Soil use	Displacement	Wildlife impact	Local population
Gerus_2	None spotted	None spotted	Soil erosion, soil pollution, fires, poaching and livestock theft during construction and operations.	No major impact on landscape is expected. The site is near a sub-station in a bush encroached area.	High impact livestock farming observed.	The site is on private land, hence very low human density. No infrastructures were observed.	There are wildlife spoors/ tracks in the site.	The site appeared not to have any cultural values during the rapid assessment. Since it is part of a private land, the likelihood of any special utilization for cultural and traditional activities is very low.

8.1.2 Environmental site scoring and selection

The Gerus 2 site received 8 points because there would be very little environmental impact to develop it for CSP. No endemic flora or fauna were identified on site which could require mitigation efforts.

The site was selected for the biomass harvesting potential in the surrounding area. Such harvesting activities would need to be investigated within an EIA. Soil erosion was identified on site, and the site is prone to bush fires. However, precautions could be taken to avoid and mitigate such concerns on site when the CSP plant is developed.

Table 8.2 – Gerus 2 Environmental Scoring,

Information	16	Scoring
Name of the project	Gerus_2	
Endemic/protected fauna in the site	None spotted	8
Endemic/protected flora in the site	None spotted	8
Environmental and social concerns	Soil erosion, soil pollution, fires, poaching and livestock theft during construction and operations.	6
Landscape	No major impact on landscape is expected. The site is near a sub-station in a bush encroached area.	8
Soil use	High impact livestock farming observed.	6
Displacement	The site is on private land, hence very low human density. No infrastructures were observed.	8
Wildlife impact	There are wildlife spoors/ tracks in the site.	8
Local population	The site appeared not to have any cultural values during the rapid assessment. Since it is part of a private land, the likelihood of any special utilization for cultural and traditional activities is very low.	8

8.1.3 Output for the EIS Terms of Reference

In Annex 6 is presented the Terms of Reference (TORs) for the selected site.

The present TORs, must be considered preliminary document because it was elaborated without relevant Project information, which is still an on-going process.

For that matter, assumptions were made that, with a final version of the project can, and will be, validated.

8.2 Solar resource analysis

8.2.1 Detailed map visualization

In Figure 8.2 is presented the detailed DNI map visualization.

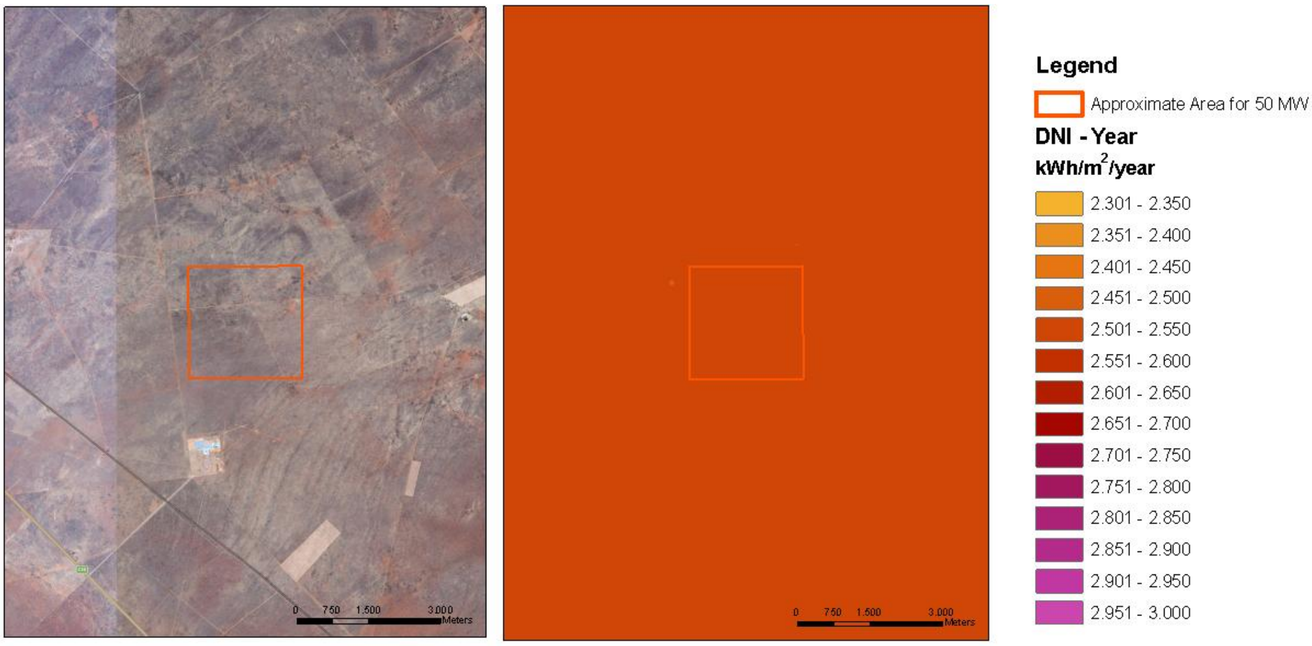


Figure 8.2 – Gerus detailed DNI map visualization.

8.2.2 Typical meteorological year

TMY (Typical Meteorological Year) data are used to compare the solar resource at alternative sites and to define the probable annual performance of a proposed CSP plant. The TMY is constructed on monthly basis, comparing months of individual years with long-term monthly characteristics: cumulative distribution function and mean (described in Annex 5).

For each site is a screening process is performed selecting the five best months on the basis that the 5 months have the smallest WS values. The results for Gerus are presented in Table 8.3, with the chosen TMM emphasized in bold numbers.

The remaining best months which meet the persistence criteria are ranked with respect to closeness of the month to the long-term mean. The results for the relative difference of Direct Normal Irradiance are presented in Table 8.4.

Table 8.3 – Weighted Sums (WS) of the FS Statistics for Gerus.*

	Month											
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	0,013	0,013	0,019	**0,012**	**0,005**	0,018	0,016	0,011	**0,009**	**0,003**	0,029	**0,011**
1995	0,029	0,020	**0,007**	0,023	0,009	**0,006**	**0,005**	0,011	0,016	0,022	**0,009**	0,034
1996	0,014	0,018	0,014	**0,006**	**0,005**	0,008	0,016	0,009	**0,010**	0,019	0,016	0,016
1997	0,027	**0,005**	**0,005**	0,024	0,012	0,015	**0,005**	0,007	0,026	0,009	0,021	0,028
1998	**0,011**	0,020	0,011	0,016	0,027	0,018	0,012	0,014	0,022	0,011	**0,010**	0,023
1999	0,016	0,014	0,012	**0,007**	**0,006**	**0,007**	0,015	0,010	0,019	**0,006**	0,015	0,036
2000	0,021	0,024	**0,004**	**0,006**	**0,005**	**0,006**	**0,005**	**0,006**	**0,008**	**0,008**	0,034	**0,007**
2001	0,021	**0,012**	**0,006**	0,024	0,010	**0,007**	**0,004**	0,012	**0,007**	0,010	**0,009**	0,033
2002	0,037	**0,012**	0,008	0,020	0,016	0,009	0,008	**0,007**	0,011	0,009	0,017	**0,008**
2003	**0,011**	0,013	0,030	0,015	0,009	0,008	0,014	0,029	0,016	**0,008**	0,016	**0,007**
2004	0,014	**0,011**	**0,006**	**0,009**	**0,008**	0,008	0,007	0,015	0,027	0,014	0,027	0,018
2005	**0,011**	0,025	0,013	0,013	0,021	0,031	0,010	0,021	0,013	0,032	0,013	**0,009**
2006	0,026	0,016	0,019	0,022	0,017	0,010	0,007	0,021	0,011	0,021	**0,011**	0,014
2007	0,020	0,030	0,009	0,016	0,009	0,014	0,012	**0,006**	0,011	0,024	0,017	0,025
2008	**0,011**	**0,005**	0,020	0,020	0,011	**0,006**	0,006	**0,004**	**0,010**	0,024	**0,006**	0,015
2009	**0,008**	0,037	0,026	0,013	0,012	0,019	**0,006**	**0,006**	0,024	0,012	0,017	0,016
2010	0,015	0,018	0,021	0,014	0,022	0,010	0,021	0,010	0,012	**0,007**	0,013	0,014
2011	0,043	0,030	0,031	0,031	0,016	0,010	0,014	0,015	0,020	0,020	0,012	0,012

Bold numbers are for the 5 best years per month (column).

Table 8.4 – Closeness of the selected month to the long term mean for the remaining best years.

	Month											
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	-	-	-	20,382	-	-	-	-	19,837	2,307	-	-
1995	-	-	13,527	-	-	-	2,771	-	-	-	18,065	-
1996	-	-	-	**6,007**	**0,633**	-	-	-	**5,251**	-	-	-
1997	-	6,508	-	-	-	-	**0,660**	-	-	-	-	-
1998	20,157	-	-	-	-	-	-	-	-	-	15,426	-
1999	-	-	-	-	6,480	15,808	-	-	-	-	-	-
2000	-	-	-	-	2,397	10,685	5,906	**1,393**	-	**1,929**	-	-
2001	-	30,403	**1,175**	-	-	**0,095**	-	-	9,550	-	-	-
2002	-	-	-	-	-	-	-	10,617	-	-	-	13,669
2003	-	-	-	-	-	-	-	-	-	8,862	-	**0,004**
2004	-	-	1,984	18,547	-	-	-	-	-	-	-	-
2005	**5,586**	-	-	-	-	-	-	-	-	-	-	13,202
2006	-	-	-	-	-	-	-	-	-	-	-	-
2007	-	-	-	-	-	-	-	-	-	-	-	-
2008	-	**1,021**	-	-	-	-	-	2,716	-	-	**3,897**	-
2009	21,444	-	-	-	-	-	-	-	-	-	-	-
2010	-	-	-	-	-	-	-	-	-	6,170	-	-
2011	-	-	-	-	-	-	-	-	-	-	-	-

Bold numbers are for the 5 best years per month (column).

The TMY procedure and additional results is in Annex 5, including a CD with the data.

8.3 Power generation estimate

In the location Gerus there are no local consumers or particular load requirements so the generation will be fed to the grid and so Namibia Load is the major consideration to be used. According to the information collected by Hatch on the National Integrated Resources Plan (NIRP) and based on Nampower data the daily load per year and for the previous years displays two peaks: one flat between 9.30 and 13.00 and another at around 20.00.

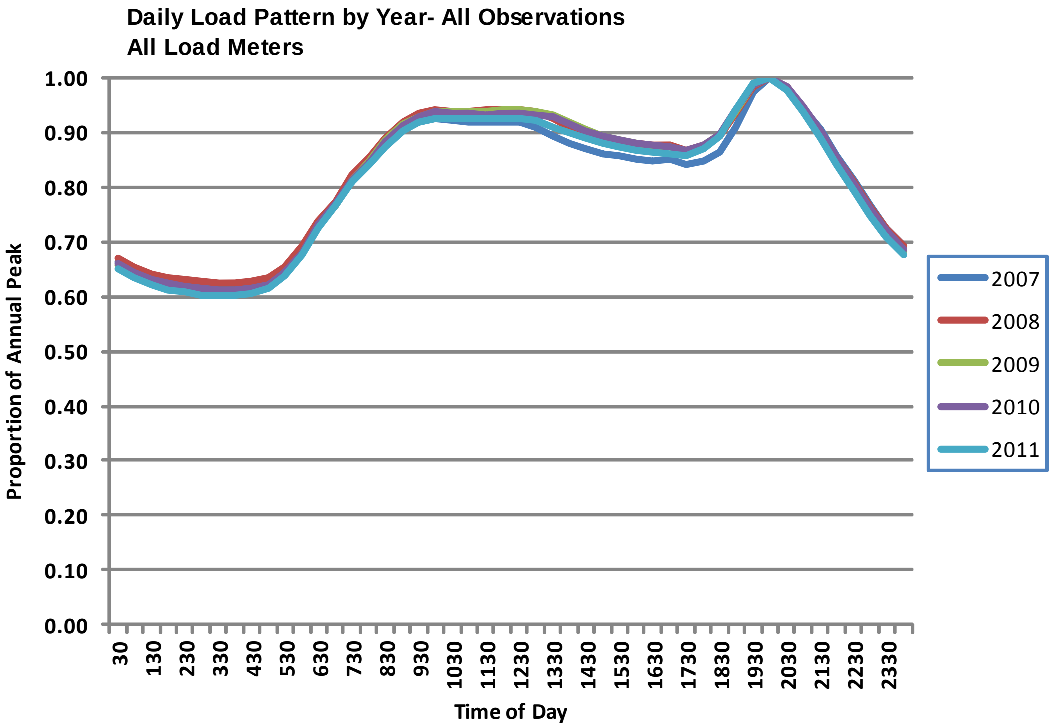


Figure 8.3 – Namibia Daily load pattern per year according to the NIRP study from Hatch.

That is confirmed by the average daily load and also on monthly values. It is visible that there is a slight shift of the peak during the months of the year but within the mentioned values:

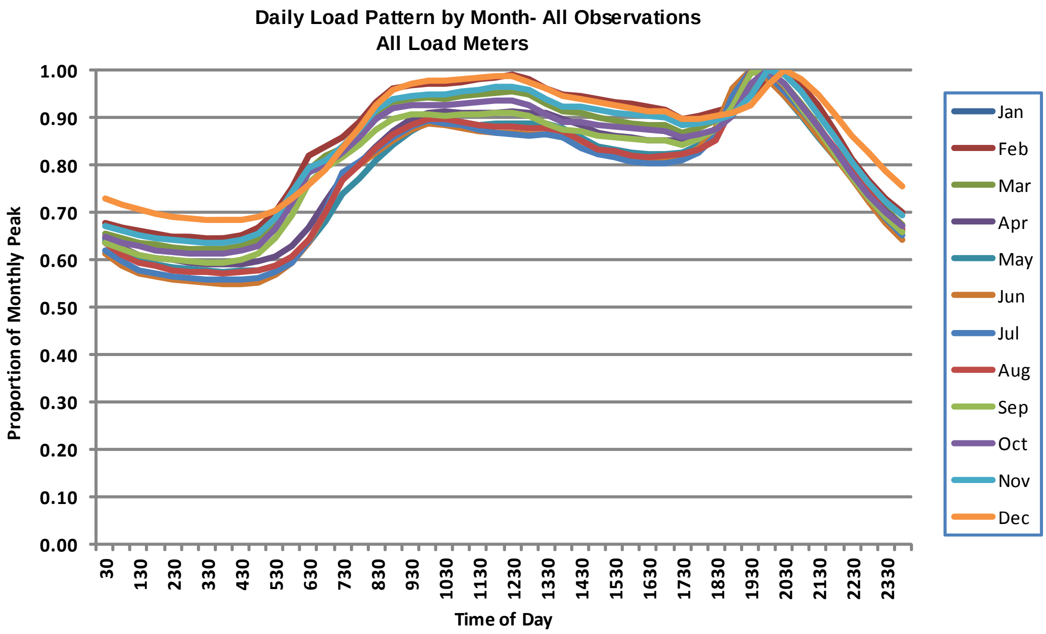


Figure 8.4 – Namibia Daily load pattern per month according to the NIRP study from Hatch.

The values of generation (GWh) and peak (MW) were also collected by Hatch on the study mentioned and they are presented below:

	Reference	
	Generation Energy (GWh)	Generation Peak (MW)
2008 a	2,735.7	428.6
2009 a	2,806.9	445.5
2010 a	3,001.6	477.4
2011 e	3,146.7	496.9
2012	3,211.5	507.7
2013	3,402.6	533.2
2014	3,485.1	546.9
2015	4,664.1	683.4
2016	4,740.6	696.0
2017	4,819.4	709.0
2018	4,916.4	725.2

Figure 8.5 – Namibia yearly load for several years according to the NIRP study from Hatch.

The peak is around 50 MW and overshooting that value in the near future.

Based on the load of Nampower it is possible to see that we have 3 periods of “peaks” as shown below:

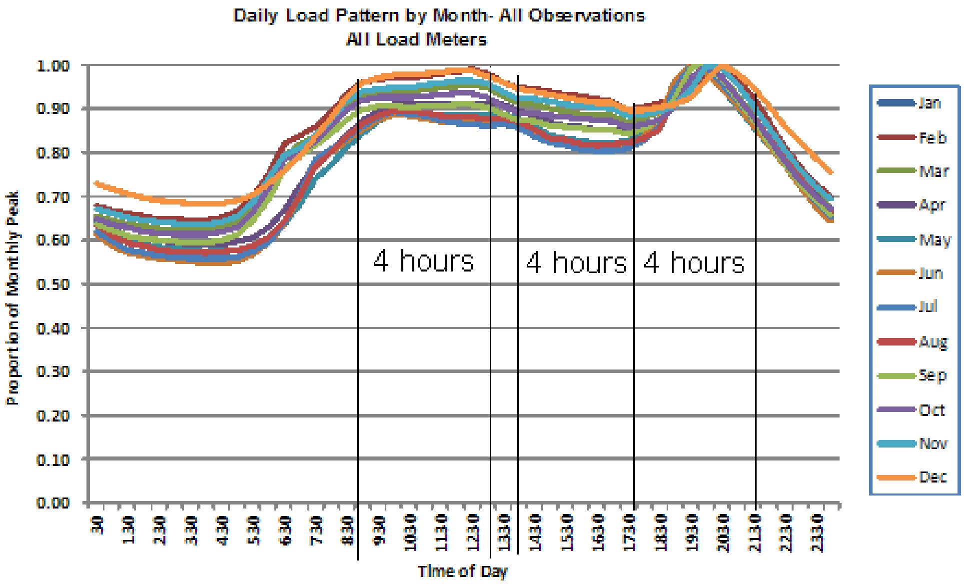


Figure 8.6 – The generation time frames for the Namibian Daily load pattern per month.

In a more detailed analysis and taking into consideration the full generation profile of Nampower and looking at the peak power plants only, it is possible to see that those plants reach stable operation around 7.00 until 21.00 with downward fluctuation in mid-afternoon. In terms of a CSP power plant it results in a mandatory criterion for storage in that period for later generation.

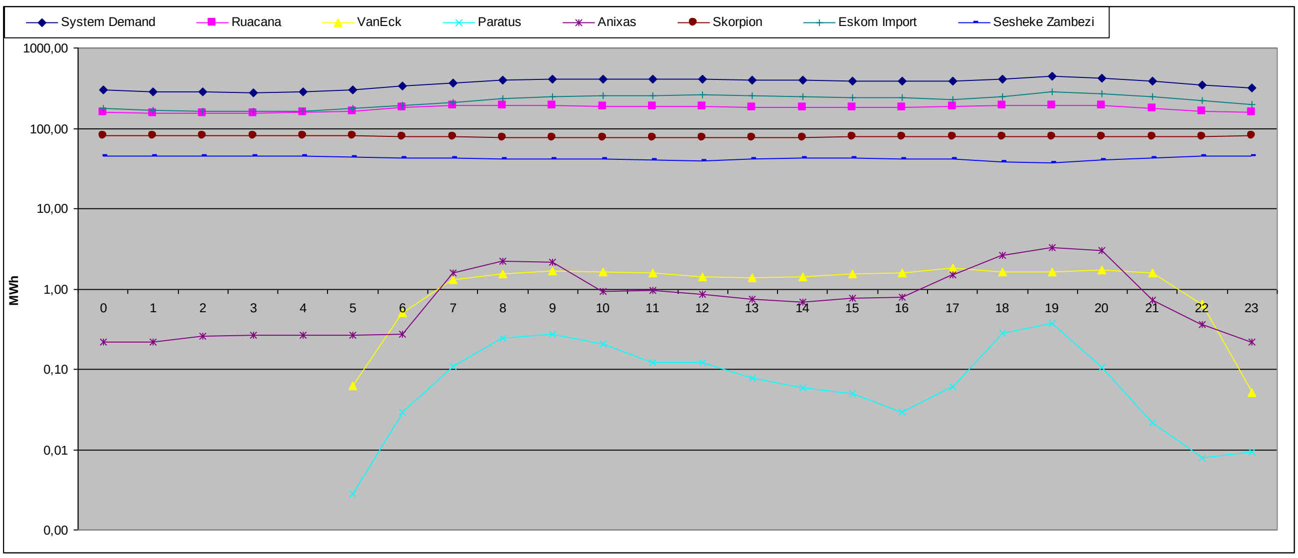


Figure 8.7 – Namibia generation pattern from all available sources showing the operation of peak power plants. It is in logarithmic scale.

Bearing in mind what was outline before, a 50 MW power plant with a generation pattern of 12 hours on average is required. Since Gerus displays a very interesting biomass resource to be used the CSP power plant will be a hybrid. Thus no storage will be mandatory for the solar field and Parabolic Troughs, Power Towers and Linear Fresnel Reflectors apply. The biomass resource will be used as a complement to the CSP power plant to meet the 12 hours on average. Not enough water is available for wet cooling, so only dry cooling was considered, which translated into an increase in the solar field to overcome the expected loss in efficiency – 15 to 20%.

According to the Environmental Impact Assessment (available in the download section of www.agrinamibia.com.na) carried out by Energy For Future (EFF) – Bush to Fuel project (Energy for Future (Pty) Ltd is part of the Schwenk group in Germany and Namibia; EFF is registered in Namibia) for the Ohorongo Cement (Pty) Ltd cement factory on the farm Sargberg No.585, portion 2, which is located 17 km northeast of Otavi and adjacent to the railway line the possibility to use biomass to replace coal for the heating of the kilns. It was estimated that the factory would need 85000 tons of biomass in 2013 when it is in full production. To supply such quantity areas of 200 hectares will be intervened. In Gerus an amount between 40000 and 80000 ton may be required per year, which compares in size to the cement factory. In the selection of the sites the location for Gerus displays a yield of 20 to 25 ton of sustainable biomass per hectare (VTT study) which means each 200 hectares would yield 4000 to 5000 tones, which means that 10 to 20 such plots are required to be intervened to obtain the required amount of biomass.

8.3.1 Parabolic troughs

The DNI provided by Geomodel showed data for 17 years with a 15 min period. Several models for generation were used – DLR proprietary model and SunBD proprietary model (SunBD model has been checked against SAM and also with existing CSP power plants and results are in line). Data with one hour period was also used to check for differences. Models which operate on an energy balance basis do not actually show big differences between the two data sets. Models based on temperature do show more differences and particularly are able to show the transients. For this site no particular difference was seen between the two data sets.

The inputs considered were:

- The output was such that required no storage.

- Parabolic troughs of Eurotrough type: 5,76 m of aperture and usually assembled in lines of 600 m long (usually 4 sub-segments are considered). Evacuated tubes with diameters of 0,07 m were considered.

- Use of artificial oil for the HTF of the solar field.

- No storage.

- Solar field with combined efficiency of 76% and Incident Angle Modifier (IAM) of 85%.

- End losses were considered due to the latitude and inclination of the sun (trough only track in one axis).

- Operating temperature of 350ºC and deaerator temperature of 105ºC.

- Water/steam ratio of 2.

- Turbine efficiency was 28% due to dry cooling.

The outputs given are by no means results of a detailed engineering analysis, but on made on basic engineering assumption and to provide figures:

- Solar field – aperture area required – 435000 m^2.

- Plant size = 225 hect.

- Generation output (net) – 5,2 hours on average per day.

(a maximum of 7 hours and a minimum of 3 hours are expected to occur during the year).

- Biomass required to be used = 105 to 180 ton on average per day – 38000 to 67000 ton per year - (based on 4063 KWh/ton and 2322 KWh/ton, namely mentioned by the VT study and the Hatch NIRP study).

- Biomass boiler with 80% efficiency.

8.3.2 Power towers

The DNI provided by Geomodel showed data for 17 years with a 15 min period. Several models for generation were used – Julich Institute proprietary model and SunBD proprietary model (SunBD model has been checked against SAM and also with existing CSP power plants and results are in line). Data with one hour period was also used to check for differences. Models which operate on an energy balance basis do not actually show big differences between the two data sets. Models based on temperature do show more differences and particularly are able to show the transients. For this site no particular difference was seen between the two data sets.

The inputs considered were:

- The output was such that required no storage.

- Heliostats of 125m^2 were considered.

- Use of molten salts for the HTF of the solar field.

- No storage.

- Solar field with combined efficiency of 82% and Incident Angle Modifier (IAM) of 85%.

- Concentration factor of 800.

- Operating temperature of 400ºC and deaerator temperature of 105ºC.

- Water/steam ratio of 2.

- Turbine efficiency was 30% due to dry cooling.

The outputs given are by no means results of a detailed engineering analysis, but on made on basic engineering assumption and to provide figures:

- Solar field – heliostats area – 375000 m^2.

- Plant size = 150 hect.

- Generation output (net) – 4,2 hours on average per day.

(a maximum of 6 hours and a minimum of 2 hours are expected to occur during the year).

- Biomass required to be used = 120 to 210 ton on average per day – 44000 to 77000 ton per year - (based on 4063 KWh/ton and 2322 KWh/ton, namely mentioned by the VT study and the Hatch NIRP study).

- Biomass boiler with 80% efficiency.

8.3.3 Linear Fresnel Reflectors

The DNI provided by Geomodel showed data for 17 years with a 15 min period. Several models for generation were used – SAM model and SunBD proprietary model. Data with one hour period was also used to check for differences. Models which operate on an energy balance basis do not actually show big differences between the two data sets. Models based on temperature do show more differences and particularly are able to show the transients. For this site some differences were seen between the two data sets since it works with direct steam. Differences were taken into consideration in the final results.

The inputs considered were:

- The output was such that no extra steam was generated.

- Linear Fresnel Reflector rows of 25 m wide (incorporating several lines) and 370 m long. One evacuated tube as the receiver.

- Use of deaerated water as HTF of the solar field.

- No storage.

- Solar field with combined efficiency of 76% and Incident Angle Modifier (IAM) of 65%.

- Concentration ration of 25.

- End losses were considered due to the latitude and inclination of the sun (LFR only tracks in one axis).

- Operating temperature of 300ºC and deaerator temperature of 105ºC.

- Water/steam ratio of 2.

- Turbine efficiency was 22% due to dry cooling.

The outputs given are by no means results of a detailed engineering analysis, but on made on basic engineering assumption and to provide figures:

- Solar field – aperture area required – 650000 m^2.

- Plant size = 130 hect.

- Generation output (net) – 6,4 hours on average per day.

(a maximum of 8 hours and a minimum of 4 hours are expected to occur during the year).

- Biomass required to be used = 86 to 159 ton on average per day – 31000 to 55000 ton per year - (based on 4063 KWh/ton and 2322 KWh/ton, namely mentioned by the VT study and the Hatch NIRP study).

- Biomass boiler with 80% efficiency.

8.4 Plant design

The plant design incorporates the following:

- Parabolic troughs were designed with the number of rows as estimated, separations that provide no shadow form each row to the neighbouring one and with a BOP illustrating what was described. The parabolic troughs used were of the Eurotrough type with evacuated tubes and silver mirrors with tempered glasses. The implementation on the ground was selected according to the existing accesses and no electrical connection was idealized, but it does not provide more than an indication.

- Power Towers were designed based on the number of heliostats required and on the distance required between them. The heliostats used were silver mirrors with tempered glasses. No specific study was made for that and so it was attempted to illustrate the different distances according to the distance to the tower and the total plant size considered. A 360º design was chosen to maximize the area usage and also to benefit from the lower latitude. The implementation on the ground was selected according to the existing accesses and no electrical connection was idealized, but it does not provide more than an indication.

- Linear Fresnel Reflectors were designed with the number of rows as estimated, separations that provide no shadow form each row to the neighbouring one and with a BOP illustrating what was described. No particular design was considered in terms of the number of reflectors per row or height of the receiver, since commercially several concepts are being used. Mirrors were silver based with tempered glass. A biomass boiler was also added as well as storing facility near it to store the biomass and also to dry or keep it dry. The implementation on the ground was selected according to the existing accesses and no electrical connection was idealized, but it does not provide more than an indication.

8.4.1 Parabolic troughs

The rough plant layout is presented in Figure 8.8

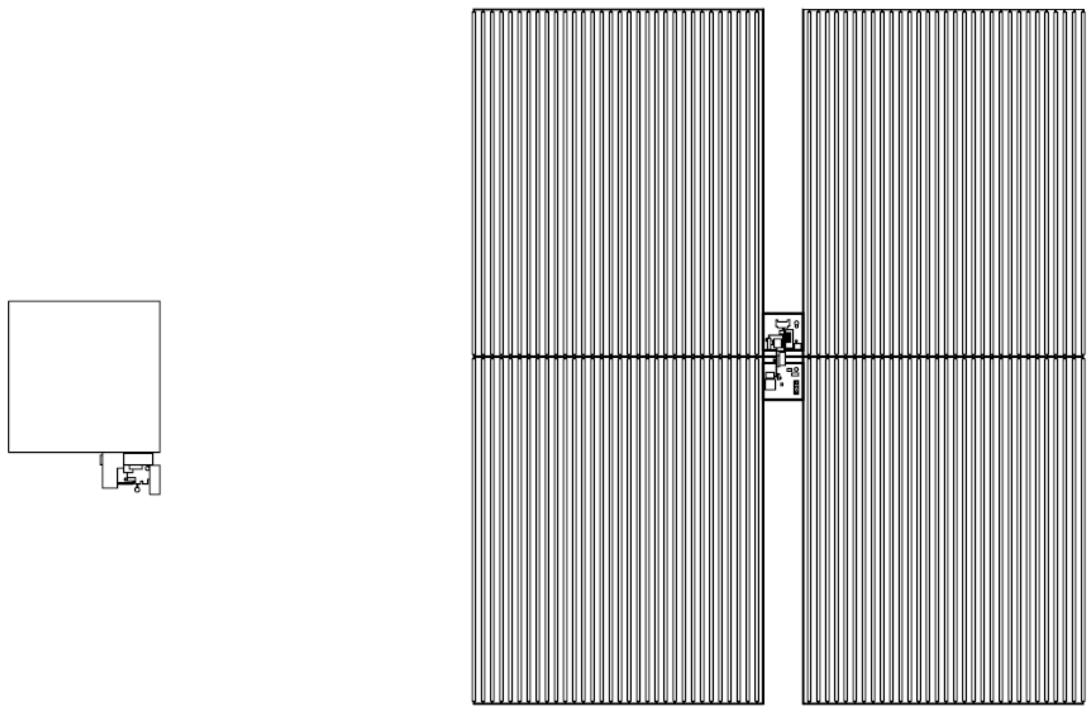


Figure 8.8 – Layout of a parabolic trough power plant with a biomass boiler and storage facility.

The implementation in the site for location 15 and 16 is suggested as in the Figure 8.9 and Figure 8.10

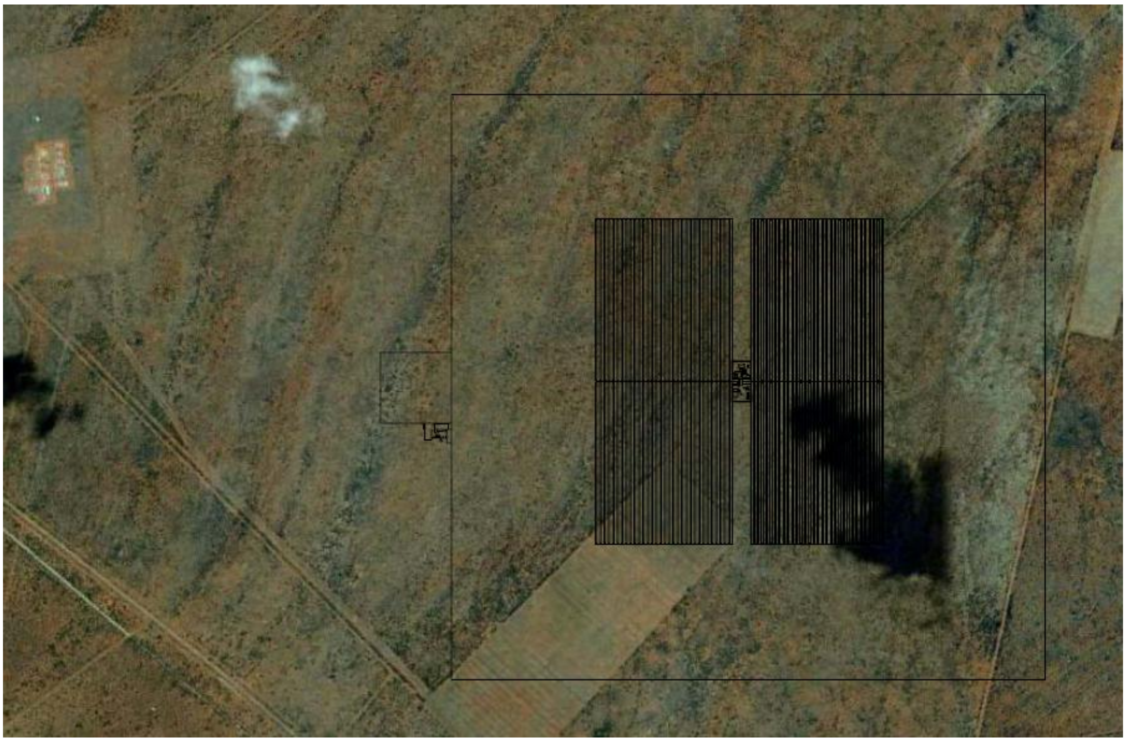


Figure 8.9 – Implementation of a parabolic trough power plant with a biomass boiler and storage facility in location 15.

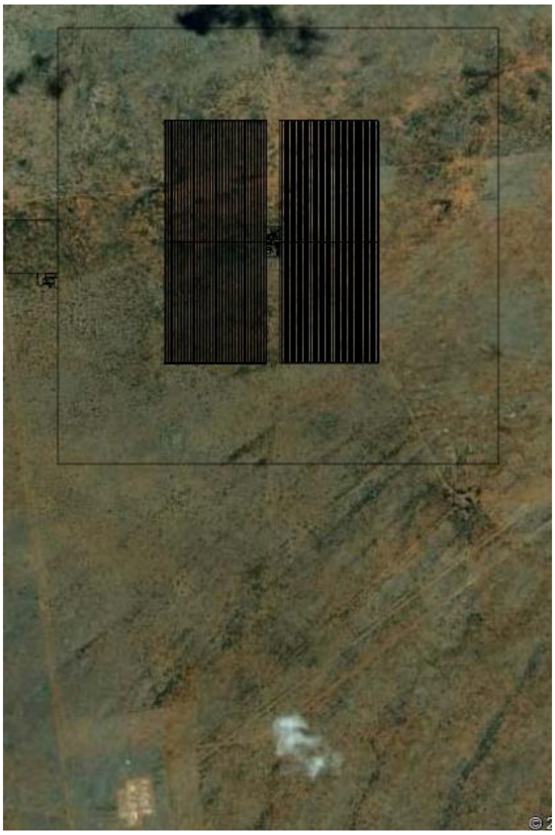


Figure 8.10 – Implementation of a parabolic trough power plant with a biomass boiler and storage facility in location 16.

8.4.2 Power towers

The rough plant layout is presented in Figure 8.11.

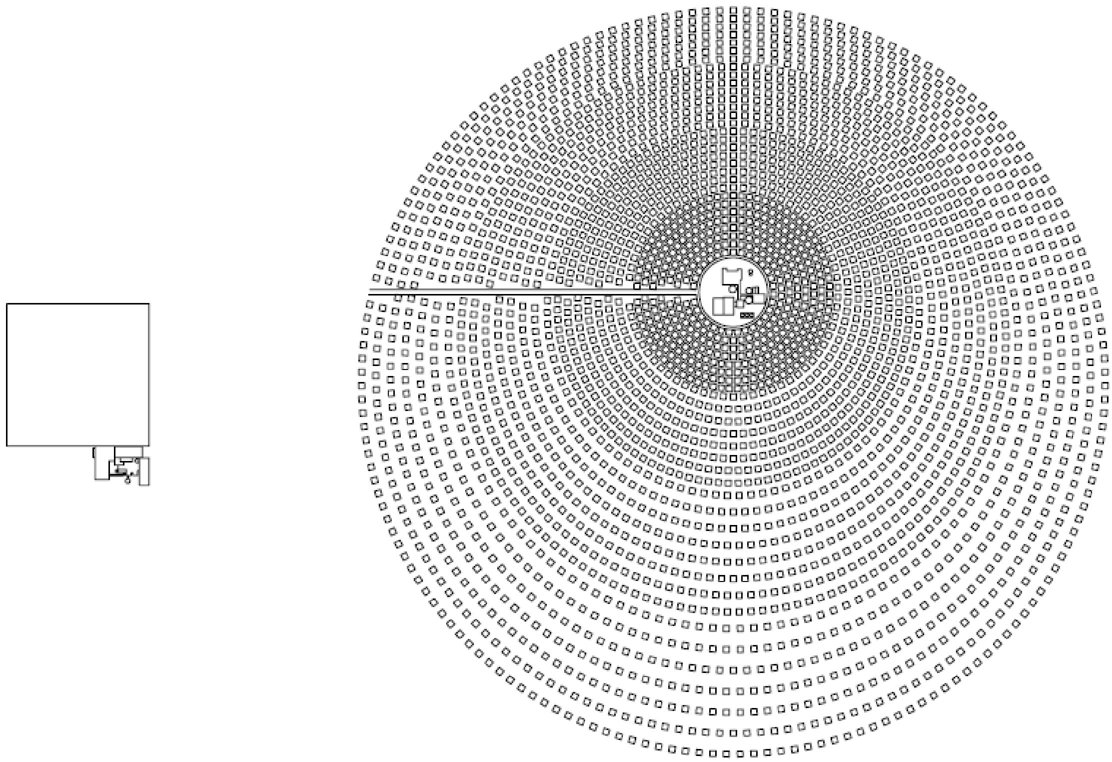


Figure 8.11 – Layout of a power tower power plant with a biomass boiler and storage facility.

The implementation in the site for location 15 and 16 is suggested in Figure 8.12 and Figure 8.13.

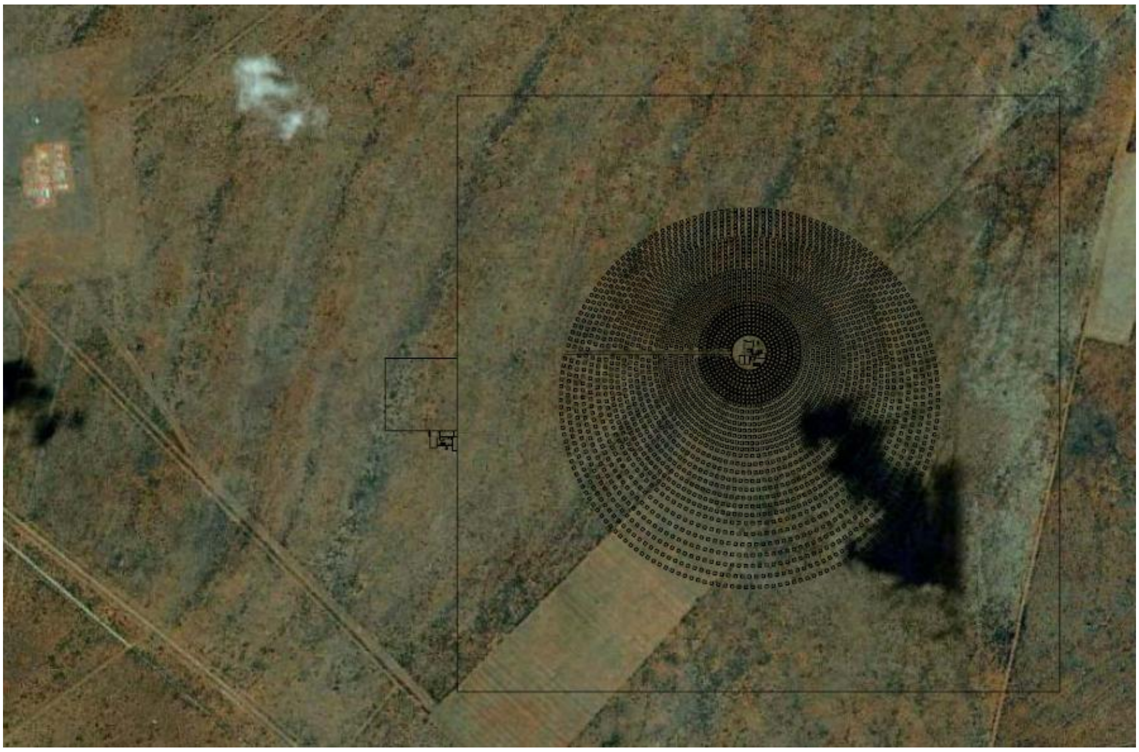


Figure 8.12 – Implementation of a power tower power plant with a biomass boiler and storage facility in location 15.

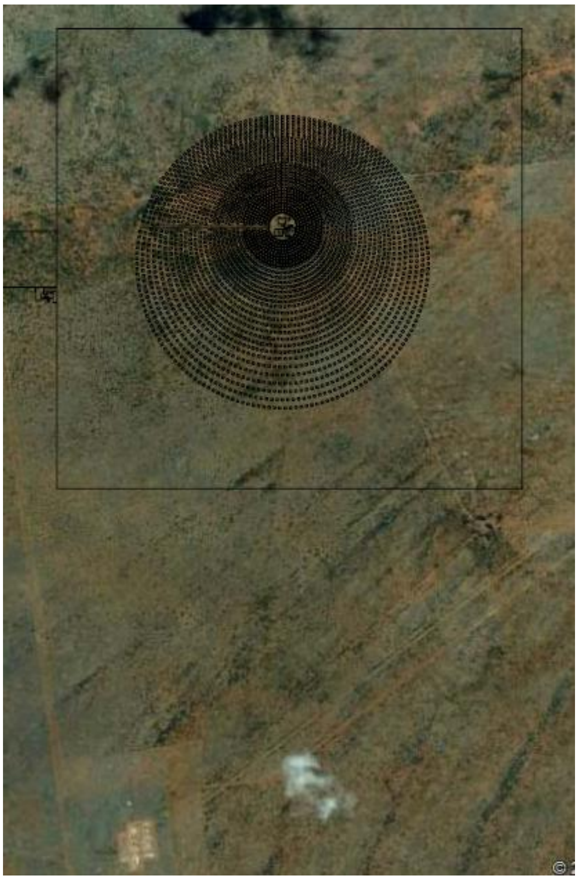


Figure 8.13 – Implementation of power plant with a biomass boiler and storage facility in location 16.

8.4.3 Linear Fresnel Reflectors

The rough plant layout is presented in Figure 8.14.

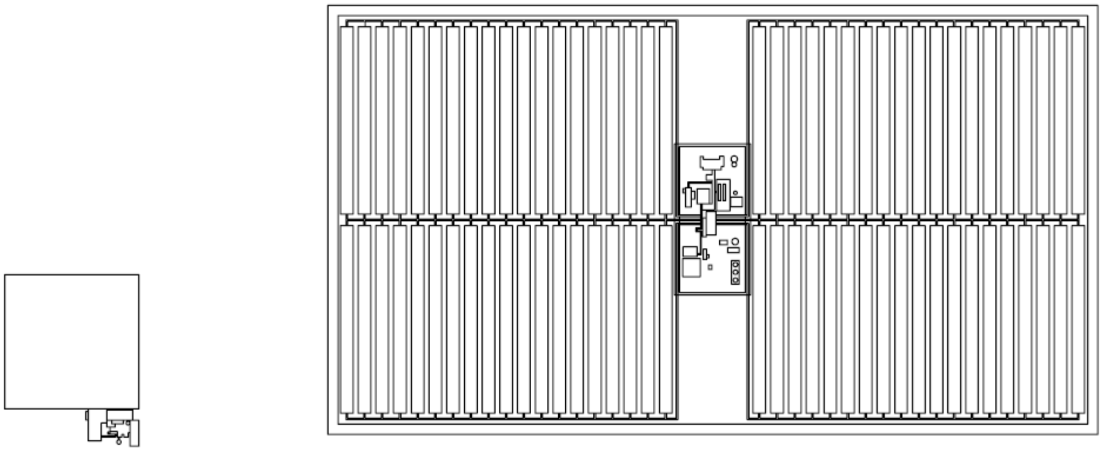


Figure 8.14 – Layout of a Linear Fresnel Reflectors power plant with a biomass boiler and storage facility.

The implementation in the site for location 15 and 16 is suggested as in Figure 8.15.

Figure 8.15 – Implementation of a Linear Fresnel Reflectors power plant with a biomass boiler and storage facility in location 15.

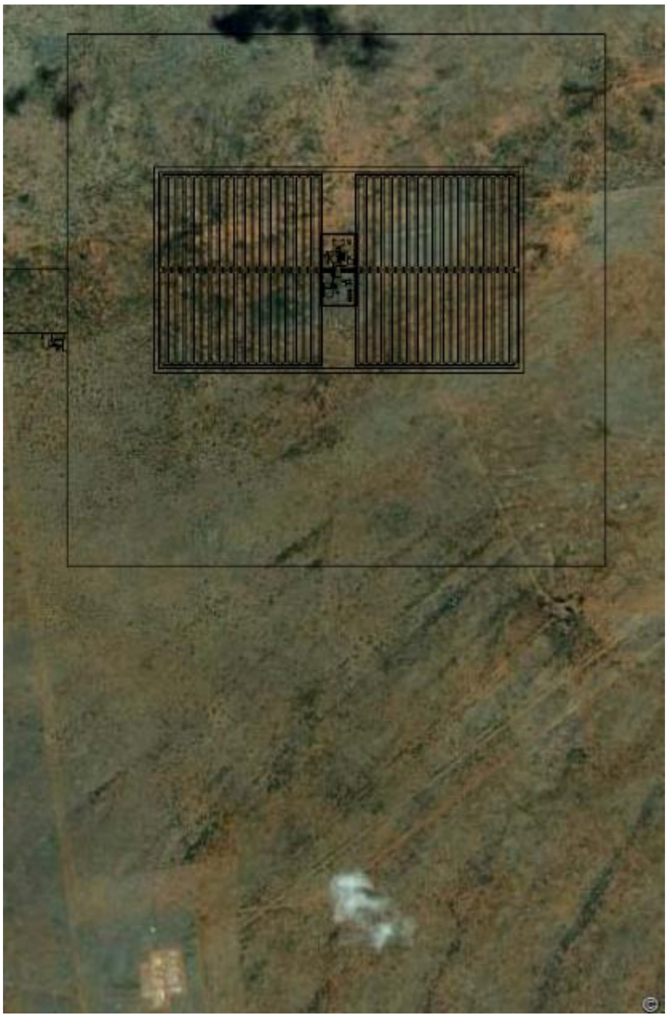


Figure 8.16 – Implementation of a Linear Fresnel Reflectors power plant with a biomass boiler and storage facility in location 6.

8.5 Grid connection point

The grid connection for both sites is:

- Gerus SS - 400 KV/220 KV/ 66 KV with 24/40 MVA and possibility to connect 50 MW @66KV and @220KV (Power angle must be analysed).

- 2,7 to 2,9 km distance to the SS.

9 Project 4 - Hochland

9.1 Environmental report

9.1.1 Field works – Micro sitting

The Hochland site is private agricultural land located 88 km northeast of Noordoewer and located close to national road B1. The site is 954 m above sea level. The ground is very flat with an average slope of 1.6%. The top soil of the site is sandy and rocky in some areas. The site is located in an area that receives 50-100 mm rain annually.

Figure 9.1 - Micro-sitting of Hochland site.

In the following table is present the results from the sites works performed on the site.

Table 9.1 - Results from the sites works performed on the site

Project ID	Endemic/protected fauna in the site	Endemic/protected flora in the site	Environmental and social concerns	Landscape	Soil use	Displacement	Wildlife impact	Local population
Hochland	None spotted	None spotted	Soil erosion, soil pollution, fires, poaching and livestock theft during construction and operations.	The area is very remote; no major impact on landscape is expected. The site is next to a substation.	Low impact sheep farming observed.	The site is on private land, hence very low human density. No infrastructures were observed.	Small mammals such as hare and steenbok were observed during the rapid site assessment. Aardvark burrow and lots of animals spoors also observed.	The site appeared not to have any cultural values during the rapid assessment. Since it is part of a private land, the likelihood of any special utilization for cultural and traditional activities is very low.

9.1.2 Environmental site scoring and selection

The Hochland site received 8 points because there would be very little environmental impact to develop it for CSP. No endemic flora or fauna were identified on site which could require mitigation efforts.

The site was selected for the DNI resource and proximity to an adequate substation. Soil erosion was identified on site, and the site is prone to bush fires. However, precautions could be taken to avoid and mitigate such concerns on site when the CSP plant is developed.

Table 9.2 – Hochland Environmental Scoring.

Information	1	Scoring
Name of the project	Hochland	
Endemic/protected fauna in the site	None spotted	8
Endemic/protected flora in the site	None spotted	8
Environmental and social concerns	Soil erosion, soil pollution, fires, poaching and livestock theft during construction and operations.	8
Landscape	The area is very remote; no major impact on landscape is expected. The site is next to a substation.	8
Soil use	Low impact sheep farming observed.	8
Displacement	The site is on private land, hence very low human density. No infrastructures were observed.	8
Wildlife impact	Small mammals such as hare and steenbok were observed during the rapid site assessment. Aardvark burrow and lots of animals spoors also observed.	8
Local population	The site appeared not to have any cultural values during the rapid assessment. Since it is part of a private land, the likelihood of any special utilization for cultural and traditional activities is very low.	8

9.1.3 Output for the EIS Terms of Reference

In Annex 6 is presented the Terms of Reference (TORs) for the selected site.

The present TORs, must be considered preliminary document because it was elaborated without relevant Project information, which is still an on-going process.

For that matter, assumptions were made that, with a final version of the project can, and will be, validated.

9.2 Solar resource analysis

9.2.1 Detailed map visualization

In Figure 9.2 – Hochland detailed DNI map visualization.Figure 9.2 is presented the detailed DNI map visualization.

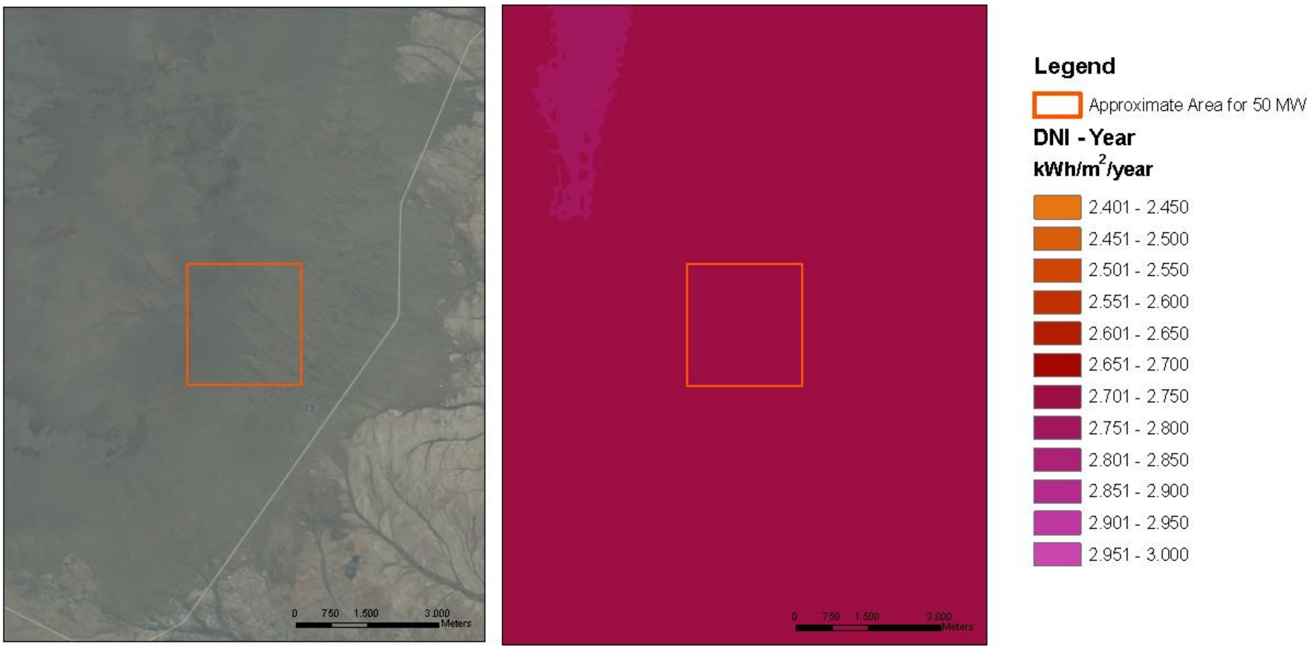


Figure 9.2 – Hochland detailed DNI map visualization.

9.2.2 Typical meteorological year

TMY (Typical Meteorological Year) data are used to compare the solar resource at alternative sites and to define the probable annual performance of a proposed CSP plant. The TMY is constructed on monthly basis, comparing months of individual years with long-term monthly characteristics: cumulative distribution function and mean (described in Annex 5).

For each site is a screening process is performed selecting the five best months on the basis that the 5 months have the smallest WS values. The results for Hochland are presented in Table 9.3, with the chosen TMM emphasized in bold numbers.

The remaining best months which meet the persistence criteria are ranked with respect to closeness of the month to the long-term mean. The results for the relative difference of Direct Normal Irradiance are presented in Table 9.4.

Table 9.3 – Weighted Sums (WS) of the FS Statistics for Hochland.*

	Month											
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
1994	0,011	0,024	0,016	0,017	**0,006**	0,018	0,016	**0,007**	**0,009**	0,010	0,012	**0,004**
1995	**0,009**	0,024	0,013	0,019	0,013	**0,003**	0,015	**0,007**	**0,008**	0,017	0,014	**0,007**
1996	0,017	0,016	0,012	**0,007**	0,011	0,008	0,023	0,019	0,014	0,013	0,034	0,016
1997	**0,007**	0,024	0,013	0,022	0,009	0,013	**0,008**	0,013	0,020	0,017	0,015	0,014
1998	0,013	0,017	**0,008**	0,015	0,009	0,016	0,013	0,014	**0,005**	**0,005**	**0,007**	**0,010**
1999	0,016	**0,007**	0,033	0,010	0,012	0,016	0,011	**0,006**	0,016	0,012	0,017	0,046
2000	0,031	**0,010**	0,012	**0,009**	0,013	0,009	0,011	0,016	0,019	**0,005**	**0,010**	0,012
2001	**0,009**	0,012	0,011	0,017	0,010	0,012	0,009	0,014	0,018	**0,007**	0,020	0,019
2002	0,026	**0,007**	0,016	0,015	**0,008**	0,012	0,010	0,015	**0,009**	0,012	0,016	**0,009**
2003	**0,010**	0,010	**0,009**	0,018	0,014	0,013	0,013	0,015	0,011	0,010	0,015	0,021
2004	**0,006**	**0,010**	0,021	**0,008**	0,021	0,009	0,012	0,014	0,016	**0,007**	0,017	0,018
2005	0,023	0,016	0,014	0,018	0,009	0,009	0,019	0,010	0,009	0,013	**0,007**	0,022
2006	0,025	0,010	0,020	0,011	0,017	**0,007**	0,008	**0,009**	0,015	0,009	0,010	**0,007**
2007	0,010	0,020	0,012	**0,009**	0,012	**0,008**	**0,005**	0,011	**0,007**	0,012	**0,009**	0,018
2008	0,014	**0,009**	**0,010**	0,014	**0,004**	**0,003**	**0,004**	**0,008**	0,026	0,009	0,011	0,014
2009	0,028	0,015	**0,007**	0,022	0,013	0,011	**0,007**	0,011	0,011	**0,005**	**0,010**	0,014
2010	0,013	0,016	**0,010**	0,011	**0,007**	**0,007**	0,015	0,010	0,010	0,011	0,015	0,010
2011	0,011	0,027	0,027	**0,010**	**0,005**	0,011	**0,005**	0,011	0,022	0,014	0,029	0,018

**Bold numbers are for the 5 best years per month (column).*

Table 9.4 – Closeness of the selected month to the long term mean for the remaining best years.

	Month											
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
1994	-	-	-	-	5,852	-	-	-	-	-	-	**2,795**
1995	15,290	-	-	-	-	3,619	-	5,532	15,797	-	-	10,070
1996	-	-	-	9,702	-	-	-	-	-	-	-	-
1997	**7,373**	-	-	-	-	-	-	-	-	-	-	-
1998	-	-	-	-	-	-	-	-	7,564	4,058	10,778	4,538
1999	-	5,318	-	-	-	-	-	**2,100**	-	-	-	-
2000	-	**2,982**	-	**8,652**	-	-	-	-	-	2,199	-	-
2001	-	-	-	-	-	-	-	-	-	-	-	-
2002	-	-	-	-	-	-	-	-	-	-	-	-
2003	18,174	-	-	-	-	-	-	-	-	-	-	-
2004	-	-	-	-	-	-	-	-	-	**0,803**	-	-
2005	-	-	-	-	-	-	-	-	-	-	**4,870**	-
2006	-	-	-	-	-	**0,460**	-	7,377	-	-	-	-
2007	-	-	-	-	-	-	7,241	-	**1,769**	-	6,290	-
2008	-	25,071	6,773	-	3,590	1,633	**0,693**	-	-	-	-	-
2009	-	-	**2,150**	-	-	-	15,014	-	-	-	-	-
2010	-	-	13,746	-	-	-	-	-	-	-	-	-
2011	-	-	-	19,033	**2,025**	-	-	-	-	-	-	-

**Bold numbers are for the 5 best years per month (column).*

The TMY procedure and additional results is in Annex 5, including a CD with the data.

9.3 Power generation estimate

In the location Hochland there are no local consumers or particular load requirements so the generation will be fed to the grid and so Namibia Load is the major consideration to be used. According to the information collected by Hatch on the National Integrated Resources Plan (NIRP) and based on Nampower data the daily load per year and for the previous years displays two peaks: one flat between 9.30 and 13.00 and another at around 20.00.

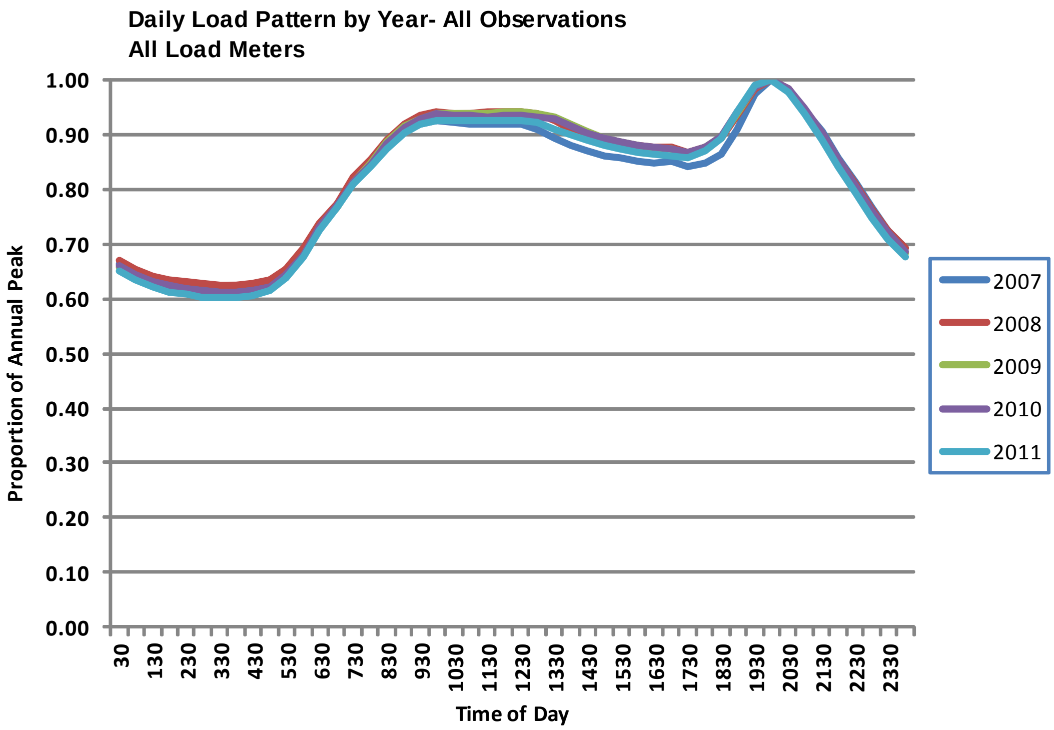


Figure 9.3 - Namibia Daily load pattern per year according to the NIRP study from Hatch.

That is confirmed by the average daily load and also on monthly values. It is visible that there is a slight shift of the peak during the months of the year but within the mentioned values:

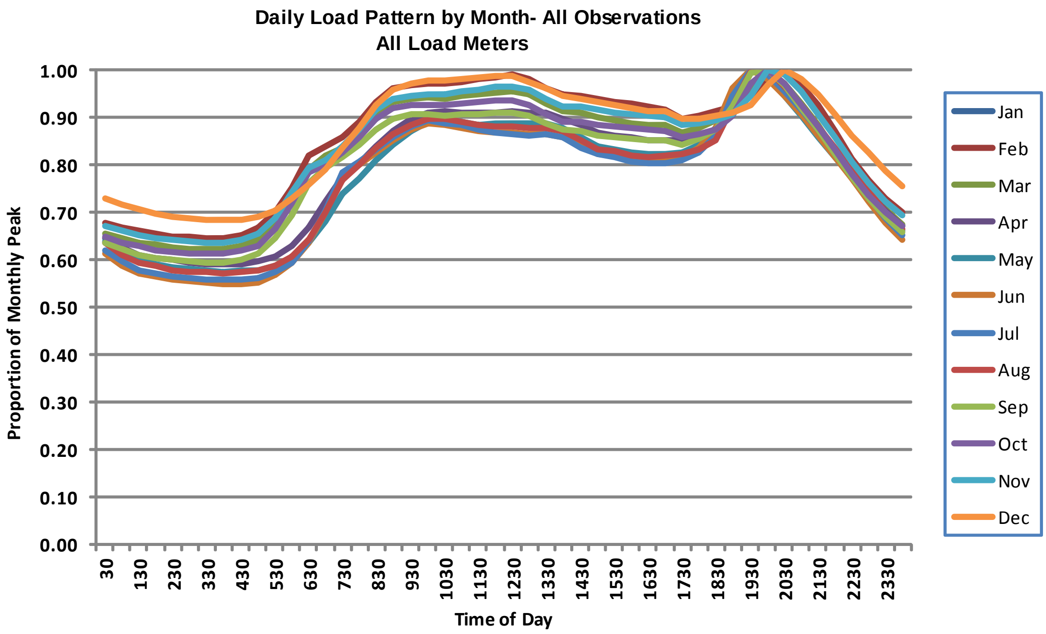


Figure 9.4 - Namibia Daily load pattern per month according to the NIRP study from Hatch.

The values of generation (GWh) and peak (MW) were also collected by Hatch on the study mentioned and they are presented in Figure 9.5.

	Reference	
	Generation Energy (GWh)	Generation Peak (MW)
2008 a	2,735.7	428.6
2009 a	2,806.9	445.5
2010 a	3,001.6	477.4
2011 e	3,146.7	496.9
2012	3,211.5	507.7
2013	3,402.6	533.2
2014	3,485.1	546.9
2015	4,664.1	683.4
2016	4,740.6	696.0
2017	4,819.4	709.0
2018	4,916.4	725.2

Figure 9.5 - Namibia yearly load for several years according to the NIRP study from Hatch.

The peak is around 50 MW and overshooting that value in the near future.

Based on the load of Nampower it is possible to see that we have 3 periods of “peaks” as shown below:

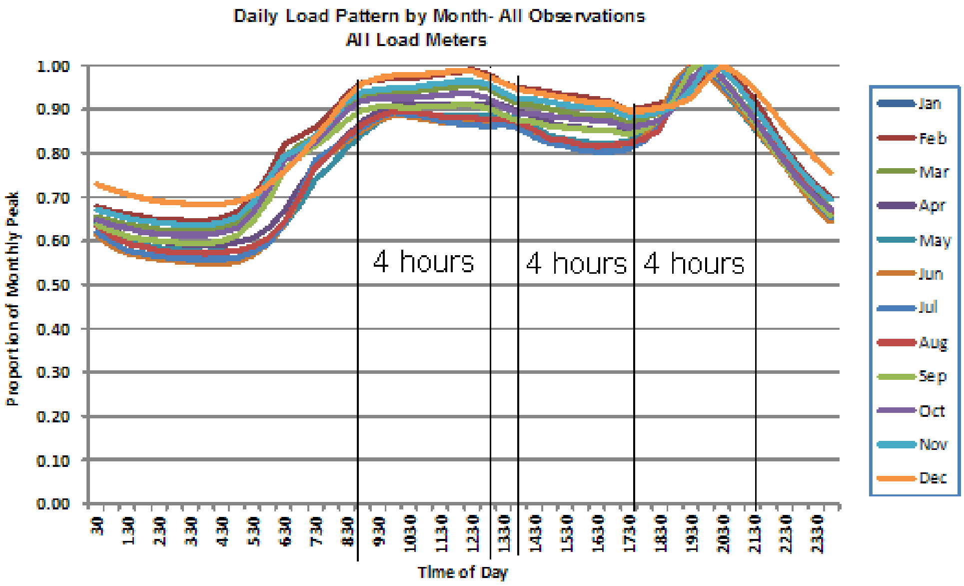


Figure 9.6 - The generation time frames for the Namibian Daily load pattern per month.

In a more detailed analysis and taking into consideration the full generation profile of Nampower and looking at the peak power plants only, it is possible to see that those plants reach stable operation around 7.00 until 21.00 with downward fluctuation in mid-afternoon. In terms of a CSP power plant it results in a mandatory criterion for storage in that period for later generation.

Bearing in mind what was outlined before, a 50 MW power plant with a generation pattern of 12 hours on average with adequate storage – 6 to 8 hours – is required. With storage only parabolic troughs and power towers apply. Not enough water is available for wet cooling, so only dry cooling was considered, which translated into an increase in the solar field to overcome the expected loss in efficiency – 15 to 20%.

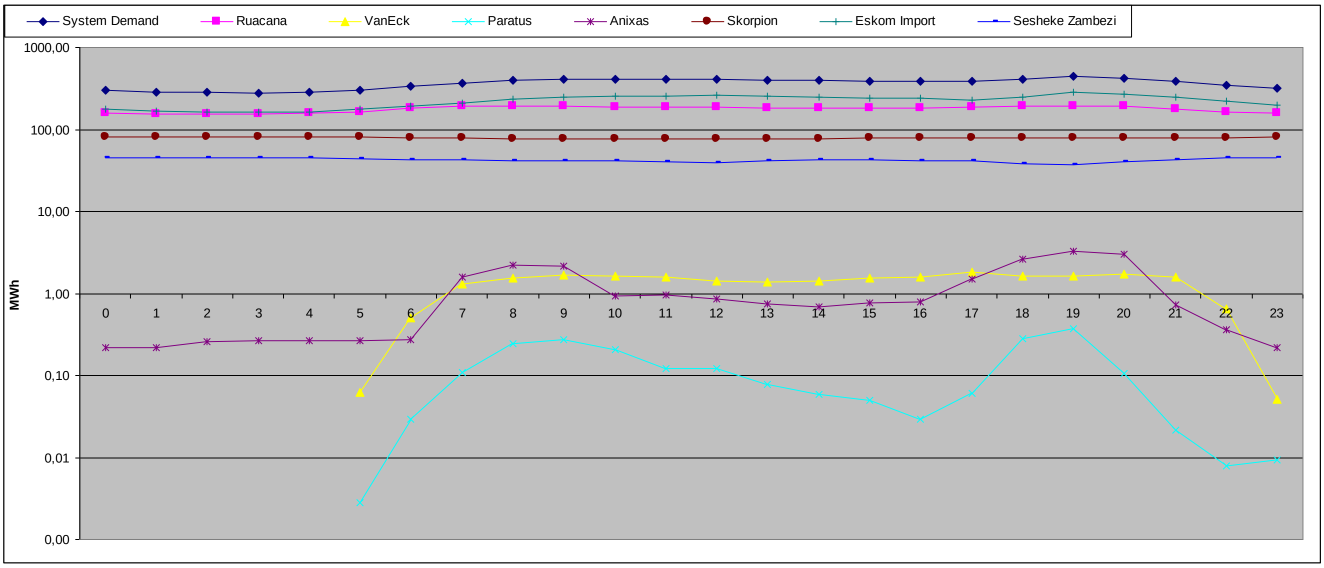


Figure 9.7 - Namibia generation pattern from all available sources showing the operation of peak power plants. It is in logarithmic scale.

9.3.1 Parabolic troughs

The DNI provided by Geomodel showed data for 17 years with a 15 min period. Several models for generation were used – DLR proprietary model and SunBD proprietary model (SunBD model has been checked against SAM and also with existing CSP power plants and results are in line). Data with one hour period was also used to check for differences. Models which operate on an energy balance basis do not actually show big differences between the two data sets. Models based on temperature do show more differences and particularly are able to show the transients. For this site no particular difference was seen between the two data sets.

The inputs considered were:

- Average daily output was 12 hours.

- Parabolic troughs of Eurotrough type: 5,76 m of aperture and usually assembled in lines of 600 m long (usually 4 sub-segments are considered). Evacuated tubes with diameters of 0,07 m were considered.

- Use of artificial oil for the HTF of the solar field.

- Use of molten salts for the storage medium.

- Solar field with combined efficiency of 76% and Incident Angle Modifier (IAM) of 85%.

- End losses were considered due to the latitude and inclination of the sun (trough only track in one axis).

- Operating temperature of 350ºC and deaerator temperature of 105ºC.

- Water/steam ratio of 2.

- Turbine efficiency was 28% due to dry cooling.

The outputs given are by no means results of a detailed engineering analysis, but on made on basic engineering assumption and to provide figures:

- Solar field – aperture area required – 755000 m^2.

- Plant size = 248 hect.

- Storage hours – 7.

- Generation output (net) – 12,4 hours on average per day.

(a maximum of 17 hours and a minimum of 7 hours is expected to occur during the year).

- Around 28000 ton of molten slats are required. Two tanks with 38 of diameter by 19 meters high are suitable, but other design criteria can be used for the final sizing.

9.3.2 Power towers

The DNI provided by Geomodel showed data for 17 years with a 15 min period. Several models for generation were used – Julich Institute proprietary model and SunBD proprietary model (SunBD model has been checked against SAM and also with existing CSP power plants and results are in line). Data with one hour period was also used to check for differences. Models which operate on an energy balance basis do not actually show big differences between the two data sets. Models based on temperature do show more differences and particularly are able to show the transients. For this site no particular difference was seen between the two data sets.

The inputs considered were:

- Average daily output was 12 hours.

- Heliostats of 125m^2 were considered.

- Use of molten salts for the HTF of the solar field.

- Use of molten salts for the storage medium.

- Solar field with combined efficiency of 82% and Incident Angle Modifier (IAM) of 85%.

- Concentration factor of 800.

- Operating temperature of 400ºC and deaerator temperature of 105ºC.

- Water/steam ratio of 2.

- Turbine efficiency was 30% due to dry cooling.

The outputs given are by no means results of a detailed engineering analysis, but on made on basic engineering assumption and to provide figures:

- Solar field – heliostats area – 755000 m^2.

- Plant size = 302 hect.

- Storage hours – 8.

- Generation output (net) – 12,4 hours on average per day.

(a maximum of 18 hours and a minimum of 8 is expected to occur during the year).

- Around 16000 ton of molten slats are required. Two tanks with 31 of diameter by 16 meters high are suitable, but other design criteria can be used for the final sizing.

9.4 Plant design

The plant design incorporates the following:

- Parabolic troughs were designed with the number of rows as estimated, separations that provide no shadow form each row to the neighbouring one and with a BOP illustrating what was described. The parabolic troughs used were of the Eurotrough type with evacuated tubes and silver mirrors with tempered glasses. The implementation on the ground was selected according to the existing accesses and no electrical connection was idealized, but it does not provide more than an indication.

- Power Towers were designed based on the number of heliostats required and on the distance required between them. The heliostats used were silver mirrors with tempered glasses. No specific study was made for that and so it was attempted to illustrate the different distances according to the distance to the tower and the total plant size considered. A 360º design was chosen to maximize the area usage and also to benefit from the lower latitude. The implementation on the ground was selected according to the existing accesses and no electrical connection was idealized, but it does not provide more than an indication.

9.4.1 Parabolic troughs

The rough plant layout is presented in Figure 9.8 and Figure 9.9.

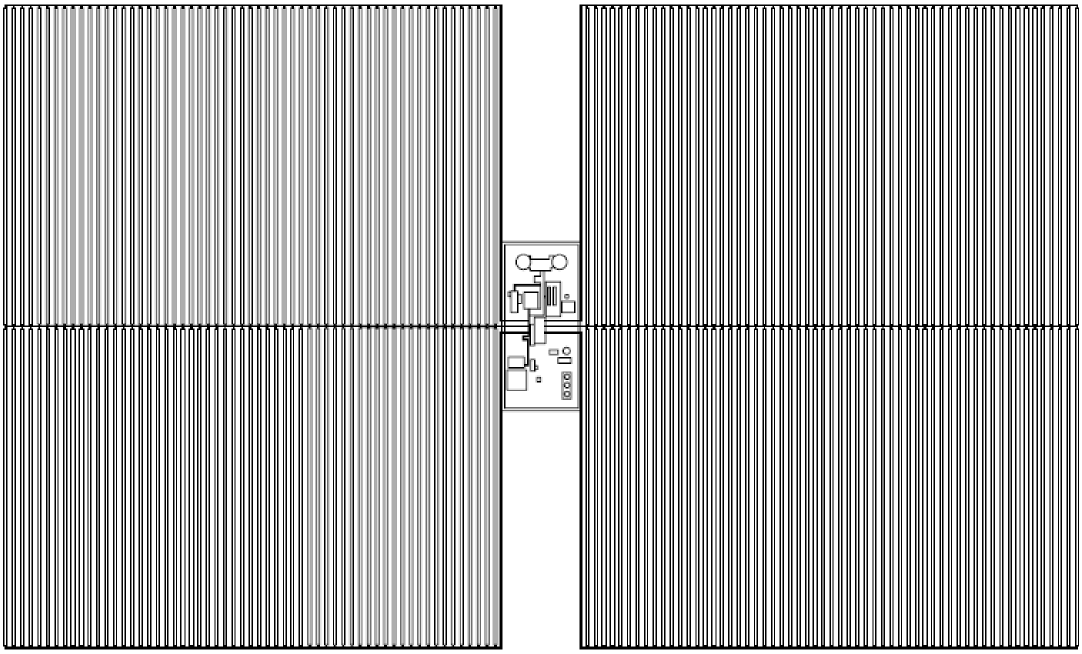


Figure 9.8 - Layout of the parabolic troughs power plant.

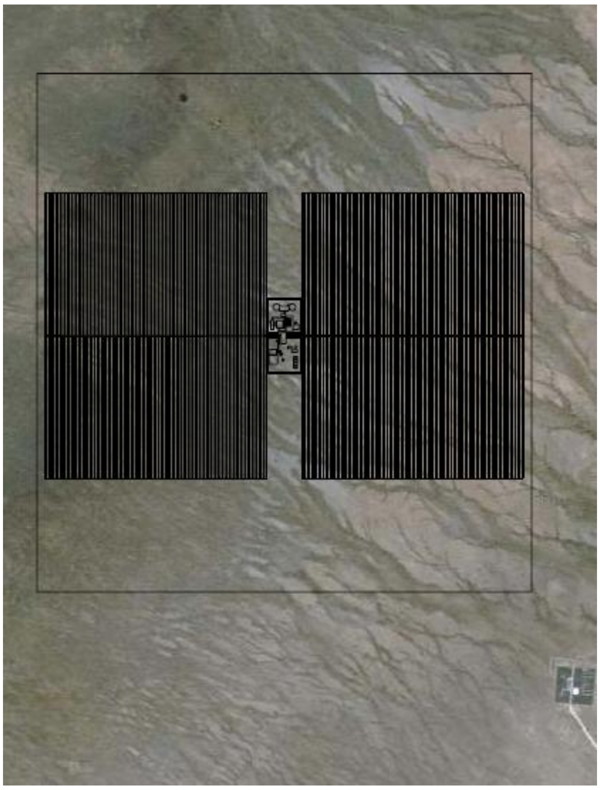


Figure 9.9 - Implementation of the parabolic troughs power plant in the site.

9.4.2 Power towers

The rough plant layout is presented in Figure 9.10.

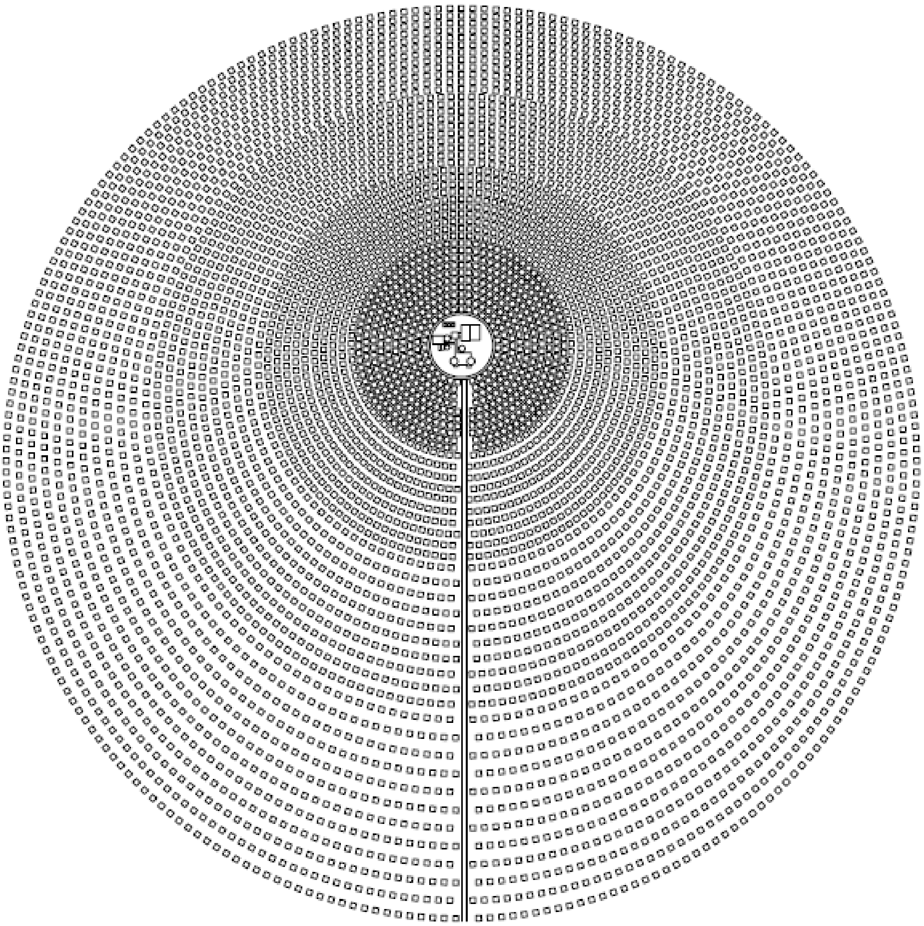


Figure 9.10 - Layout of the power tower power plant.

The implementation in the site is suggested as in Figure 9.11.

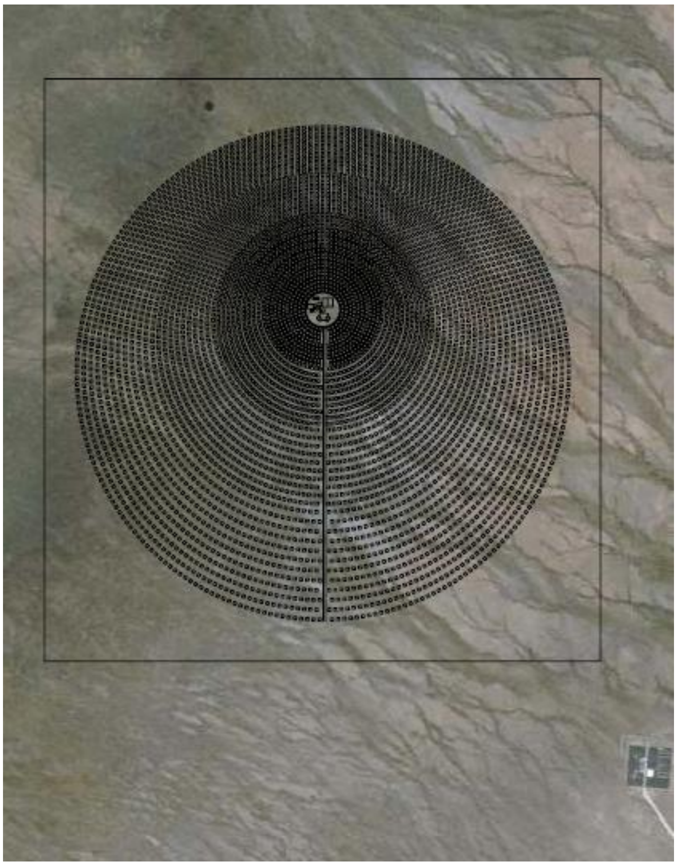


Figure 9.11 - Implementation of the power tower power plant in the site.

9.5 Grid connection point

The grid connection for the site is:

- Harib SS (132 KV/220KV) – 40 MVA - and possibility to connect 50 MW @132KV.

- 1,8 km distance to the SS.

10 Project 5 – Scorpion Mine

10.1 Environmental report

10.1.1 Field works – Micro sitting

The Skorpion Mine site is private land located inside the Skorpion Mine property. The site is approximately 80 km north of Oranjemund. A private gravel road runs through the site. The site is 587 m above sea level. The ground is flat with an average slope of 1.9%. The top soil of the site is sandy. The site is located in an area that receives 50-100 mm rain annually.

There is one rare and endemic succulent species, Euphorbia namibensis. There are also three succulent species which have restricted distribution ranges: Sarcocaulan patersonii, Augea capensis, and Mesembryanthemum.


Figure 10.1 - Micro-sitting of Scorpion site.

In the following table is present the results from the sites works performed on the site.

Table 10.1 - Results from the sites works performed on the site.

Project ID	Endemic/protected fauna in the site	Endemic/protected flora in the site	Environmental and social concerns	Landscape	Soil use	Displacement	Wildlife impact	Local population
Scorpion Mine	Verification required	There are two succulent species spotted. Verification is pending.	Soil erosion and soil pollution, during construction and operations; and decrease in aesthetic value of area depending on technology selected. A mining access road passes through the center of the site.	An access road transporting staff and mining products passes through the middle of the site. It is expected that the holder of the mining license and staff could have an issues with the proposed development.		The site fall within a mining concession. There are no human settlements on site, nor are livelihoods activities are carried out on the proposed site.	No wildlife observed	The site appeared not to have any cultural values during the rapid assessment. Since it is part of a private land, the likelihood of any special utilization for cultural and traditional activities is very low.

10.1.2 Environmental site scoring and selection

The Skorpion Mine site received 2 points because some environmental impact would be expected due to the presence of two endemic flora species. Mitigation efforts would be required to reduce the impact on such flora species.

The site was selected for the DNI resource and its proximity to an existing mine, Skorpion Mine. Development of the site could require some road work, since the access road to the mine passes through the site.

Table 10.2 – Scorpion Mine Environmental Scoring.

Information	4	Scoring
Name of the project	Skorpion Mine	
Endemic/protected fauna in the site	Verification required	
Endemic/protected flora in the site	There are two succulent species spotted. Verification is pending.	2
Environmental and social concerns	Soil erosion and soil pollution, during construction and operations; and decrease in aesthetic value of area depending on technology selected. A mining access road passes through the centre of the site.	6
Landscape	An access road transporting staff and mining products passes through the middle of the site. It is expected that the holder of the mining license and staff could have an issues with the proposed development.	6
Soil use		8
Displacement	The site fall within a mining concession. There are no human settlements on site, nor are livelihoods activities are carried out on the proposed site.	8
Wildlife impact	No wildlife observed	8
Local population	The site appeared not to have any cultural values during the rapid assessment. Since it is part of a private land, the likelihood of any special utilization for cultural and traditional activities is very low.	8

10.1.3 Output for the EIS Terms of Reference

In Annex 6 is presented the Terms of Reference (TORs) for the selected site.

The present TORs must be considered preliminary document because it was elaborated without relevant Project information, which is still an on-going process.

For that matter, assumptions were made that, with a final version of the project can, and will be, validated.

10.2 Solar resource analysis

10.2.1 Detailed map visualization

In Figure 10.2 is presented the detailed DNI map visualization.

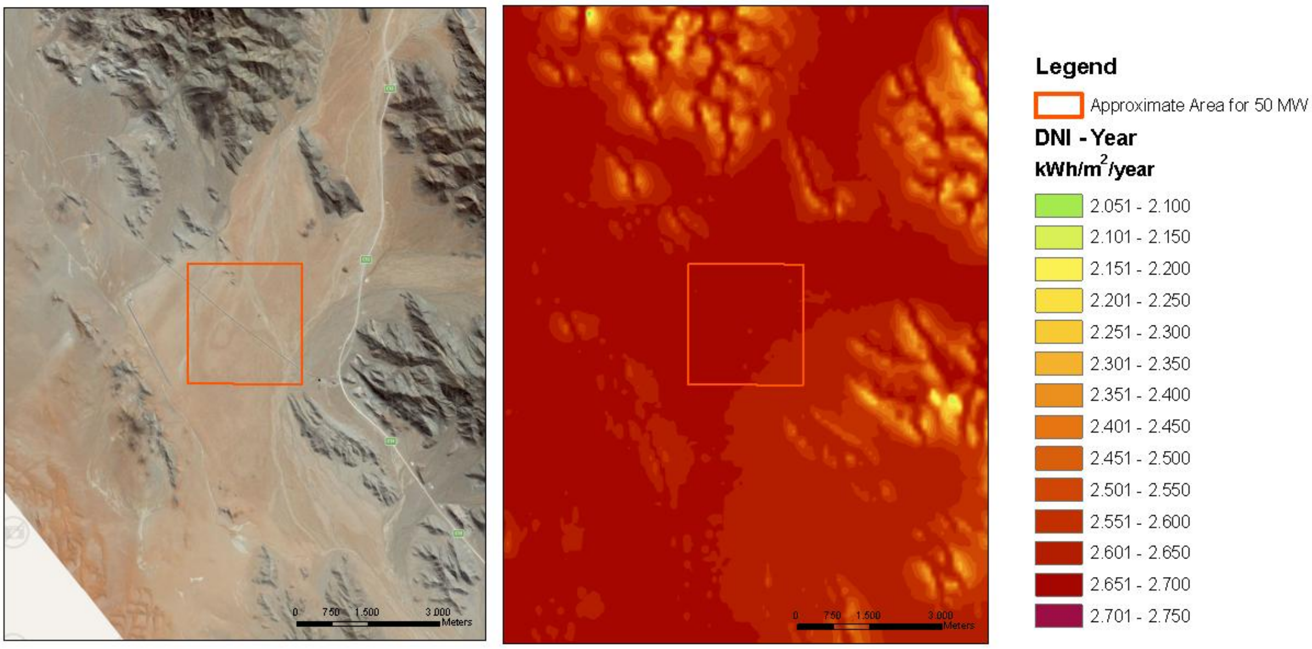


Figure 10.2 – Scorpion Mine detailed DNI map visualization.

10.2.2 Typical meteorological year

TMY (Typical Meteorological Year) data are used to compare the solar resource at alternative sites and to define the probable annual performance of a proposed CSP plant. The TMY is constructed on monthly basis, comparing months of individual years with long-term monthly characteristics: cumulative distribution function and mean (described in Annex 5).

For each site is a screening process is performed selecting the five best months on the basis that the 5 months have the smallest WS values. The results for Scorpion are presented in Table 10.3, with the chosen TMM emphasized in bold numbers.

The remaining best months which meet the persistence criteria are ranked with respect to closeness of the month to the long-term mean. The results for the relative difference of Direct Normal Irradiance are presented in Table 10.4.

Table 10.3 – Weighted Sums (WS) of the FS Statistics for Scorpion.*

	Month											
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
1994	**0,007**	0,017	0,015	0,014	0,011	0,015	0,015	**0,008**	**0,009**	0,012	0,012	**0,008**
1995	0,007	0,015	**0,006**	0,017	0,011	**0,005**	0,018	**0,008**	**0,007**	0,016	**0,004**	**0,007**
1996	0,026	0,018	**0,006**	**0,008**	**0,004**	0,009	0,018	0,011	0,013	0,015	0,031	0,014
1997	**0,007**	0,022	0,020	0,016	**0,007**	0,011	**0,007**	0,011	0,019	0,011	0,010	0,014
1998	**0,005**	0,014	0,007	0,011	**0,007**	0,018	0,010	**0,008**	**0,006**	0,010	0,009	**0,005**
1999	**0,006**	**0,005**	0,028	**0,006**	**0,007**	0,013	**0,006**	**0,007**	**0,006**	0,007	0,009	0,018
2000	0,007	**0,009**	**0,005**	0,016	0,018	0,010	0,008	0,011	0,013	**0,004**	0,009	0,013
2001	0,011	0,012	**0,006**	0,008	0,012	**0,006**	**0,006**	0,012	0,015	**0,003**	0,012	0,013
2002	0,019	0,016	0,015	**0,008**	**0,007**	**0,007**	0,008	0,009	0,016	**0,006**	0,019	**0,006**
2003	0,016	**0,006**	0,012	0,013	0,015	0,021	0,015	0,015	0,013	0,011	0,009	0,015
2004	**0,006**	0,016	0,033	**0,007**	0,015	0,008	0,011	0,015	0,022	0,011	0,013	0,010
2005	0,023	0,012	0,012	0,010	0,011	0,008	0,022	0,012	0,009	0,013	**0,005**	0,015
2006	0,025	0,012	0,014	0,010	0,010	0,014	0,013	**0,007**	0,017	0,015	0,009	**0,010**
2007	0,009	0,018	**0,007**	0,013	0,007	0,008	0,008	0,013	0,012	0,008	**0,008**	0,017
2008	0,010	**0,010**	0,026	**0,007**	0,012	**0,007**	**0,006**	0,009	0,017	**0,006**	**0,003**	0,018
2009	0,017	0,024	0,012	0,024	0,007	0,019	0,008	0,009	**0,008**	**0,004**	0,011	0,010
2010	0,014	**0,010**	0,009	0,008	0,012	**0,006**	0,016	0,010	0,016	0,012	**0,006**	0,011
2011	0,017	0,025	0,027	0,011	0,014	0,011	**0,007**	0,010	0,022	0,010	0,029	0,014

**Bold numbers are for the 5 best years per month (column).*

Table 10.4 – Closeness of the selected month to the long term mean for the remaining best years.

	Month											
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
1994	6,111	-	-	-	-	-	-	9,260	-	-	-	-
1995	-	-	8,658	-	-	12,056	-	-	13,472	-	**2,004**	14,090
1996	-	-	-	14,703	**3,386**	-	-	-	-	-	-	-
1997	6,916	-	-	-	-	-	8,891	-	-	-	-	-
1998	-	-	-	-	13,472	-	-	13,649	-	-	-	**0,968**
1999	**1,833**	2,574	-	**0,961**	8,277	-	**1,224**	-	**10,804**	-	-	-
2000	-	-	**4,658**	-	-	-	-	-	-	**4,135**	-	-
2001	-	-	-	-	-	-	-	-	-	-	-	-
2002	-	-	-	-	-	-	-	-	-	8,212	-	3,007
2003	-	**1,694**	-	-	-	-	-	-	-	-	-	-
2004	-	-	-	-	-	-	-	-	-	-	-	-
2005	-	-	-	-	-	-	-	-	-	-	2,661	-
2006	-	-	-	-	-	-	-	**6,247**	-	-	-	3,390
2007	-	-	13,903	-	-	-	-	-	-	-	5,914	-
2008	-	20,127	-	14,001	-	**6,907**	4,169	-	-	4,694	-	-
2009	-	-	-	-	-	-	-	-	13,777	-	-	-
2010	-	-	-	-	-	9,638	-	-	-	-	-	-
2011	-	-	-	-	-	-	-	-	-	-	-	-

**Bold numbers are for the 5 best years per month (column).*

The TMY procedure and additional results is in Annex 5, including a CD with the data.

10.3 Power generation estimate

In the location Skorpion Mine there is a very strong local consumer – the Skorpion Mine and so particular load requirements follow. It is clear after discussion with the mines in Namibia that all of them operate on Time of Use (TOU) tariffs and the peak tariffs are associated with the time frames 8h-13h; 18h-21h and 7h-12h; 17h-20h (seasonal differences between summer and winter). We are thus talking about 8 hours of load to which a CSP power plant could cater based on the expensive price of that energy. The generation of Skorpion is known and can be seen below.

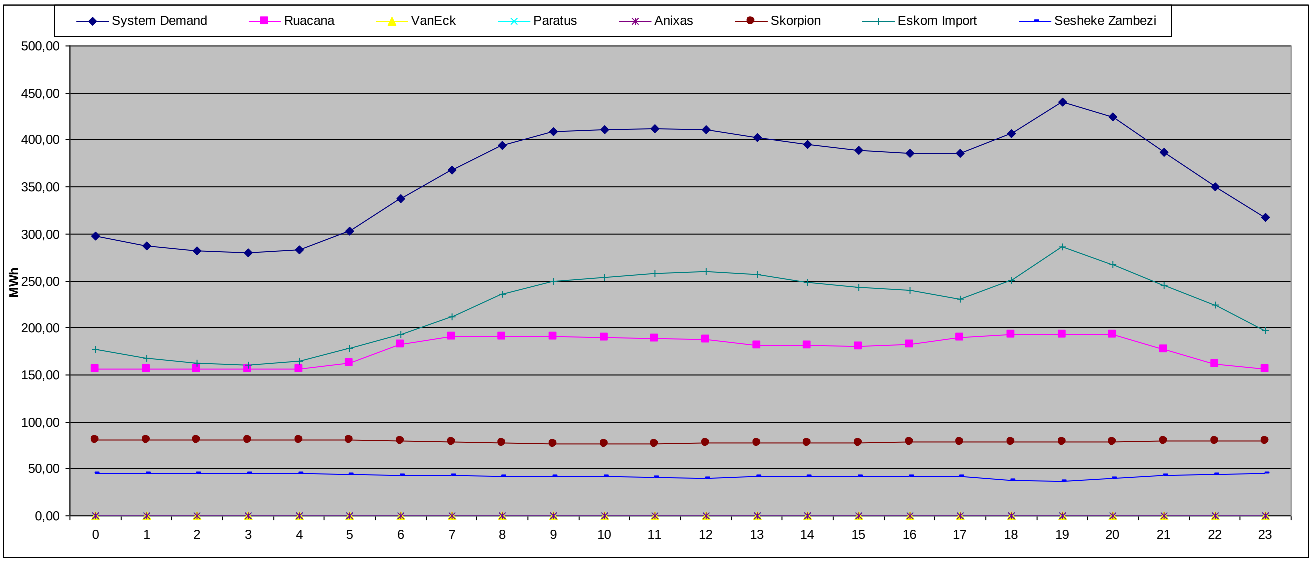


Figure 10.3 – Namibia generation pattern from all available sources showing the operation of Skorpion Mine.

Bearing in mind what was outline before as well as the contracted power of Skorpion mine – above 70 MW - a 50 MW power plant with a generation pattern of 8 hours on average with adequate storage – 4 to 6 hours was considered. With storage only parabolic troughs and power towers apply. Not enough water is available for wet cooling, so only dry cooling was considered, which translated into an increase in the solar field to overcome the expected loss in efficiency – 15 to 20%.

10.3.1 Parabolic troughs

The DNI provided by Geomodel showed data for 17 years with a 15 min period. Several models for generation were used – DLR proprietary model and SunBD proprietary model (SunBD model has been checked against SAM and also with existing CSP power plants and results are in line). Data with one hour period was also used to check for differences. Models which operate on an energy balance basis do not actually show big differences between the two data sets. Models based on temperature do show more differences and particularly are able to show the transients. For this site no particular difference was seen between the two data sets.

The inputs considered were:

- Average daily output was 8 hours with all energy produced in the afternoon shifted to the TOU afternoon period mentioned above, which meant 4 hours additional to the storage already required to provide 8 hours on average.

- Parabolic troughs of Eurotrough type: 5,76 m of aperture and usually assembled in lines of 600 m long (usually 4 sub-segments are considered). Evacuated tubes with diameters of 0,07 m were considered.

- Use of artificial oil for the HTF of the solar field.

- Use of molten salts for the storage medium

- Solar field with combined efficiency of 76% and Incident Angle Modifier (IAM) of 85%.

- End losses were considered due to the latitude and inclination of the sun (trough only track in one axis).

- Operating temperature of 350ºC and deaerator temperature of 105ºC.

- Water/steam ratio of 2.

- Turbine efficiency was 28% due to dry cooling

The outputs given are by no means results of a detailed engineering analysis, but made on basic engineering assumptions and to provide adequate figures:

- Solar field – aperture area required – 580000 m^2.

- Plant size = 174 hect.

- Storage hours – 7.

- Generation output (net) – 8,3 hours on average per day.

(a maximum of 12 hours and a minimum of 4 are expected to occur during the year).

- Around 10500 ton of molten slats are required. Two tanks with 27 of diameter by 14 meters high are suitable, but other design criteria can be used for the final sizing.

10.3.2 Power towers

The DNI provided by Geomodel showed data for 17 years with a 15 min period. Several models for generation were used – Julich Institute proprietary model and SunBD proprietary model (SunBD model has been checked against SAM and also with existing CSP power plants and results are in line). Data with one hour period was also used to check for differences. Models which operate on an energy balance basis do not actually show big differences between the two data sets. Models based on temperature do show more differences and particularly are able to show the transients. For this site no particular difference was seen between the two data sets.

The inputs considered were:

- Average daily output was 8 hours.

- Heliostats of 125m^2 were considered.

- Use of molten salts for the HTF of the solar field.

- Use of molten salts for the storage medium.

- Solar field with combined efficiency of 82% and Incident Angle Modifier (IAM) of 85%.

- Concentration factor of 800.

- Operating temperature of 400ºC and deaerator temperature of 105ºC.

- Water/steam ratio of 2.

- Turbine efficiency was 30% due to dry cooling.

The outputs given are by no means results of a detailed engineering analysis, but on made on basic engineering assumption and to provide figures:

- Solar field – heliostats area – 550000 m^2.

- Plant size = 220 hect.

- Storage hours – 7.

- Generation output (net) – 8,2 hours on average per day.

(a maximum of 12 hours and a minimum of 4 hours are expected to occur during the year).

- Around 10000 ton of molten salts are required. Two tanks with 27 of diameter by 13 meters high are suitable, but other design criteria can be used for the final sizing.

10.4 Plant design

The plant design incorporates the following:

- Parabolic troughs were designed with the number of rows as estimated, separations that provide no shadow form each row to the neighbouring one and with a BOP illustrating what was described. The parabolic troughs used were of the Eurotrough type with evacuated tubes and silver mirrors with tempered glasses. The implementation on the ground was selected according to the existing accesses and no electrical connection was idealized, but it does not provide more than an indication.

- Power Towers were designed based on the number of heliostats required and on the distance required between them. The heliostats used were silver mirrors with tempered glasses. No specific study was made for that and so it was attempted to illustrate the different distances according to the distance to the tower and the total plant size considered. A 360º design was chosen to maximize the area usage and also to benefit from the lower latitude. The implementation on the ground was selected according to the existing accesses and no electrical connection was idealized, but it does not provide more than an indication.

10.4.1 Parabolic troughs

The rough plant layout is presented in Figure 10.4

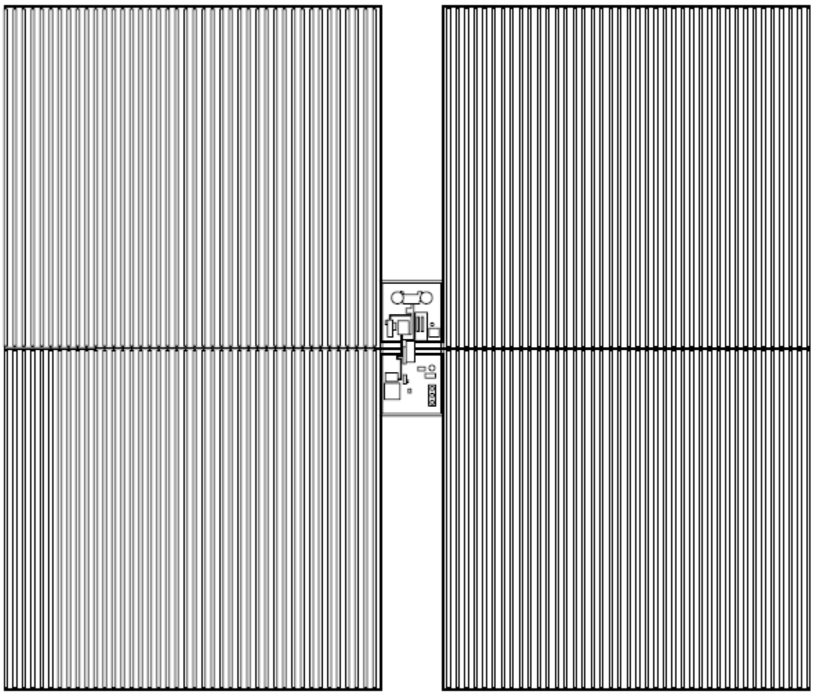


Figure 10.4 – Layout of the parabolic trough power plant

The implementation in the site is suggested as in Figure

Figure 10.5 – Implementation of the parabolic trough power plant in the site

10.4.2 Power towers

The rough plant layout is presented Figure 10.6

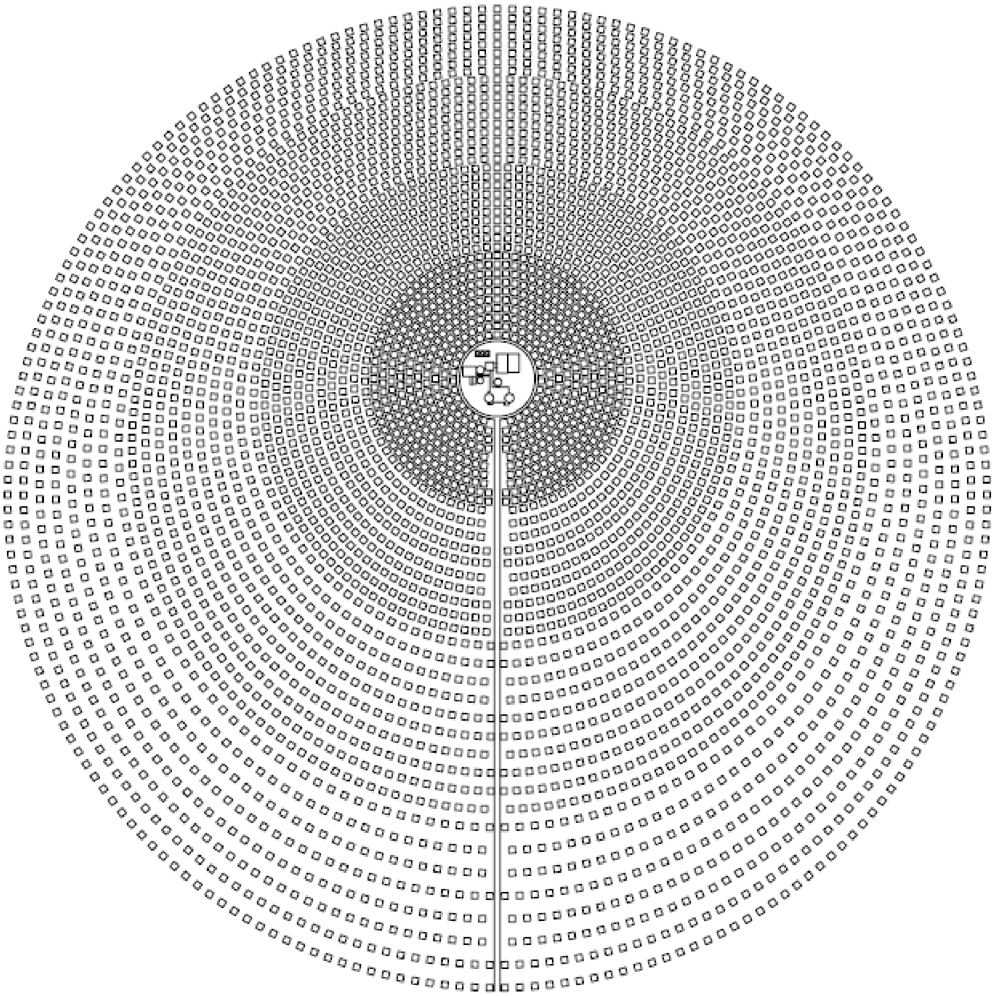


Figure 10.6 – Layout of the power tower power plant

The implementation in the site is suggested as in Figure 10.7

Figure 10.7 – Implementation of the power tower power plant in the site

10.5 Grid connection point

The grid connection for the site is:

- Obib SS (400 KV/66KV) – 160 MVA - and possibility to connect 50 MW @66KV.

- 4,1 km distance to the SS.

11 Financial Analysis

11.1 Financial Analysis Methodology

The financial analysis methodology (Figure 11.1) is composed by four main steps: (A) Identifying the required information sources; (B) Defining the resulting modelling inputs; (C) Running the financial model; and (D) Interpreting the model outputs.

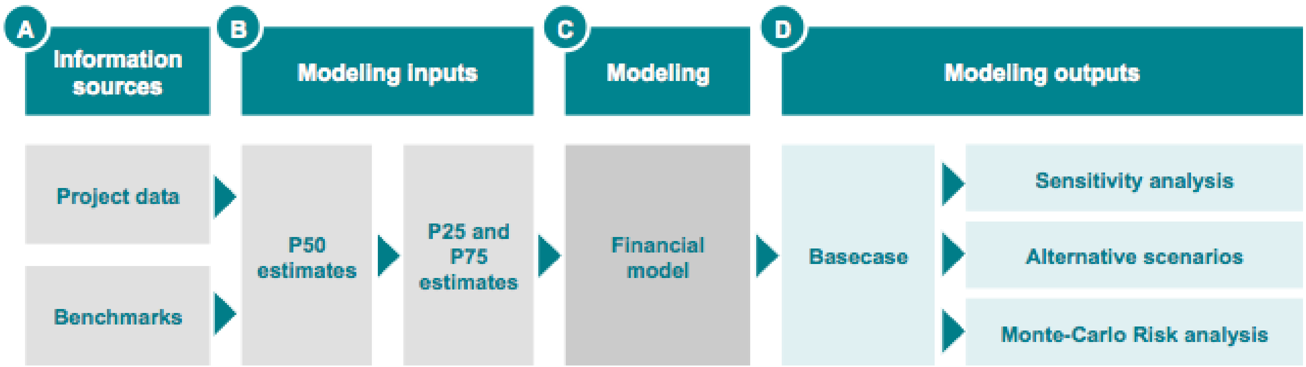


Figure 11.1 - Financial analysis methodology.

11.1.1 Information Sources

The present study was the primary source of information for the financial analysis: expert inputs, country data, field measurements and technical simulations have provided a comprehensive and country-specific dataset for each one of the considered 5 projects. Nevertheless, the data collected during the study was crosschecked against industry benchmarks, to ensure that the modelling results are comparable with those of other studies.

11.1.2 Model Inputs

The main model inputs are described in Table 11.1. Three data points were produced for each input: P50 (an average estimate, for which there is an equal probability that the actual value is above or below the estimate); P90 (a conservative estimate, with a 90% probability of underestimation); and P10 (an aggressive estimate, with a 10% probability of underestimation). This provides a tangible and quantified understanding of the uncertainties associated with each estimate, and is the basis for the Monte-Carlo risk analysis.

Table 11.1 - Main modelling inputs.

Type	Parameter	Unit	Description
Technology	Plant size	MW	Rated electrical power output of the plant
	Plant lifetime	year	Operational lifetime of the plant
	Construction period	years	Time required to erect the plant, from the initial ground works to the start of operations
	Net energy yield	MWh/MW.year	Energy production of the plant, net of losses and auto consumption
	Productivity losses	%/year	Average annual decrease in energy yield, due do the aging of key plant components
CapEx (without financial costs)	EPC	€/MW	Total capital costs for the plant EPC contract
OpEx (without financial costs)	OpEx	€/MWh	Total operational and maintenance costs, including rents, licenses, insurance, natural gas and water
Macro-economic	Inflation	%/year	Average inflation for Namibia during the project lifetime
	Free risk rate	%	Current return of risk free investments in Namibia
	Market risk premium	%	Premium over free risk returns expected by the project investors
	Depreciation	year	Accounting depreciation period applicable to the major plant capital costs
Financing	Loan duration	year	Expected loan duration to be offered by commercial banks for these projects
	Swap interest rate	%	Average swap interest rate expected for the duration of the loan
	Spread	%	Expected spread to be offered by commercial banks for these projects
	Minimum DSCR	#	Expected minimum Debt Service Coverage Ratio to be demanded by commercial banks for these projects
	EPC payment schedule	%/year	Expected payment schedule to be agreed with the contractor during the construction period
	Debt arrangement fee	% of total debt	Expected fee to be demanded by commercial banks to set up the loan
	DSCA	months	Expected amount (measured in months of debt) necessary to meet debt service obligations
	WACC	na	The rate that a company is expected to pay on average to all its security holders to finance its assets.

Not all values were obtained, but global figures were possible to be obtained and thus enable the financial analysis.

11.1.3 Modelling

Each one of the 5 projects was modelled individually, using a DCF (Discounted Cash Flows) methodology.

11.1.3.1 Model Outputs

The financial model's main outputs are:

- **LCoE** (Levelized Cost of Energy, in USD/MWh and NAD/MWh)
  It is the average cost at which the plant will produce energy during its lifetime, once all capital and operational costs are factored in. The LCoE is calculated by driving the NPV (Net Present Value) to zero, and thus represents the price at which the generated electricity needs to be sold in order for the plant to reach 'break-even';
- **Starting Tariff** (ST, in USD/MWh and NAD/MWh)
  It is the tariff at which the generated electricity needs to be sold in order to reach an NPV of zero. The ST is given at the project's Year 1, and is updated every year according to inflation.

Without inflation, the LCoE and the ST will be the same. As inflation increases, the LCoE will increase (because a higher average energy cost is required to compensate for the increasing operational costs) and the ST will decrease (because, in absolute terms, the plant's revenues will increase more than the costs). Taking into consideration both the LCoE and ST is thus particularly relevant for a country such as Namibia, which historically has had high levels of inflation:

- The LCoE can be used as a basis to negotiate a PPA (Power Purchase Agreement). PPAs, such as the ones in the US, are typically constant throughout the entire contract, irrespective of the fact that the costs of running the plant will typically raise with the inflation rate;
- The ST can also be used as a basis to define a feed-in tariff regime for CSP in Namibia. Feed-in tariffs, such as the ones in Spain, are typically updated every year according to inflation, or also fixed throughout the entire time as in India.

Irrespective of the chosen tariff model, it is advisable to perform yearly reassessments. These reassessments should compare the estimated and actual values of external factors such as inflation and, if necessary, update the tariff in order to maintain the contracted investor return. Figure 11.2 illustrates this adjustment for an example where the actual inflation rate ranged from 7 to 2%, instead of the forecasted 5%.

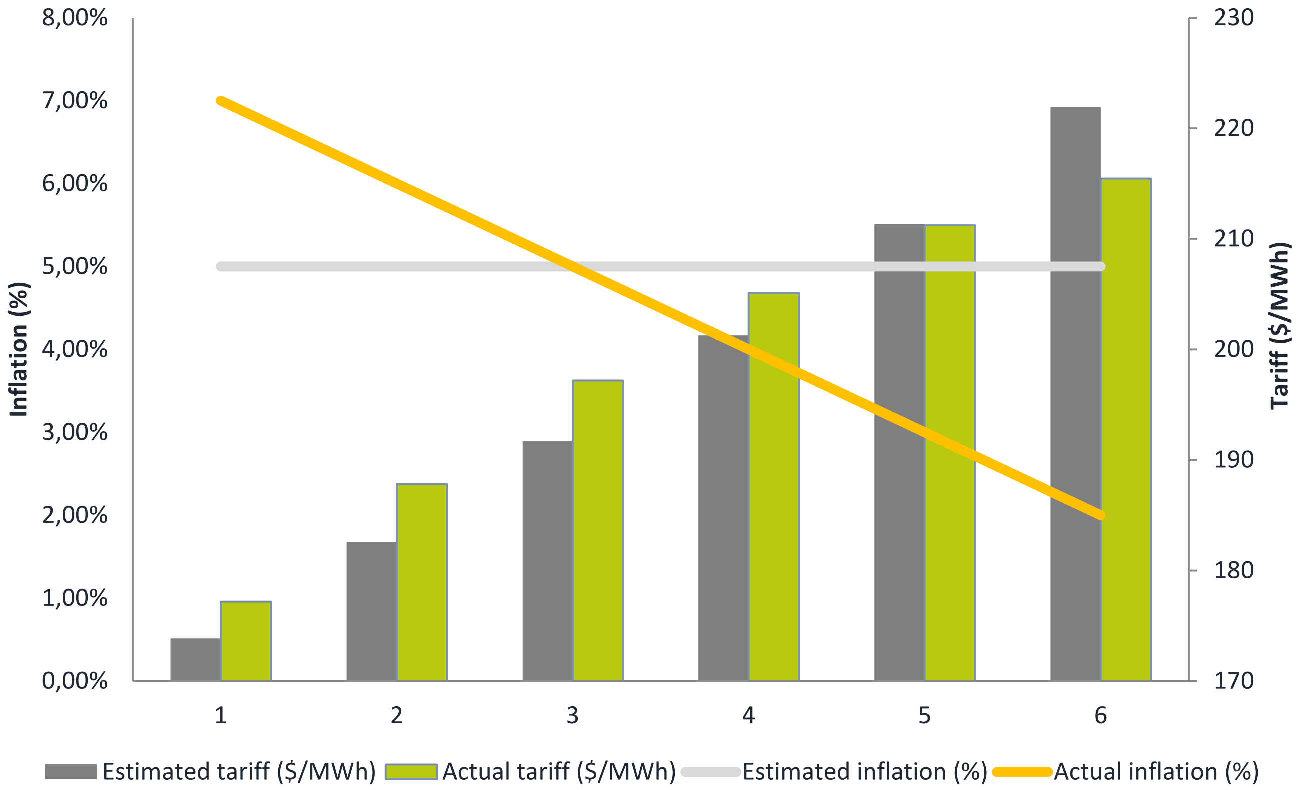


Figure 11.2 - Illustrative tariff reassessment process during a 6-year period, for a case where the actual inflation ranged from 7 to 2%, instead of the estimated constant 5%. The yearly updates adjusted the tariff in order to maintain the same LCOE and investor returns that were contracted, irrespective of the varying inflation values.

Furthermore, the LCoE and ST are calculated individually for each project under a Base Case scenario, which reflects the most probable technical and financial configurations, and assumes the P50 data points for all modelling inputs. The Base Case scenario thus provides an estimate that has an equal probability of being under or overestimated.

The sensitivity analysis calculates the tariff (in USD/MWh and NAD/MWh) required for a given project's equity investor WACC (Weighted Average Cost of Capital). This is also done under the Base Case scenario.

Additionally, the alternative scenarios test the impact of different technical (e.g. parabolic trough instead of power towers technology) and financing configurations (e.g. hard currency loan instead of domestic currency loan). All alternative scenarios are also calculated for P50 data points.

For last, the risk analysis uses a Monte-Carlo simulation (Figure 11.3) to predict how the Base Case scenario will be affected by variations in the modelling inputs. This provides a quantified assessment of the potential impact that factors, such as, estimate errors, technological risks and economical uncertainties, will have on the financial analysis.

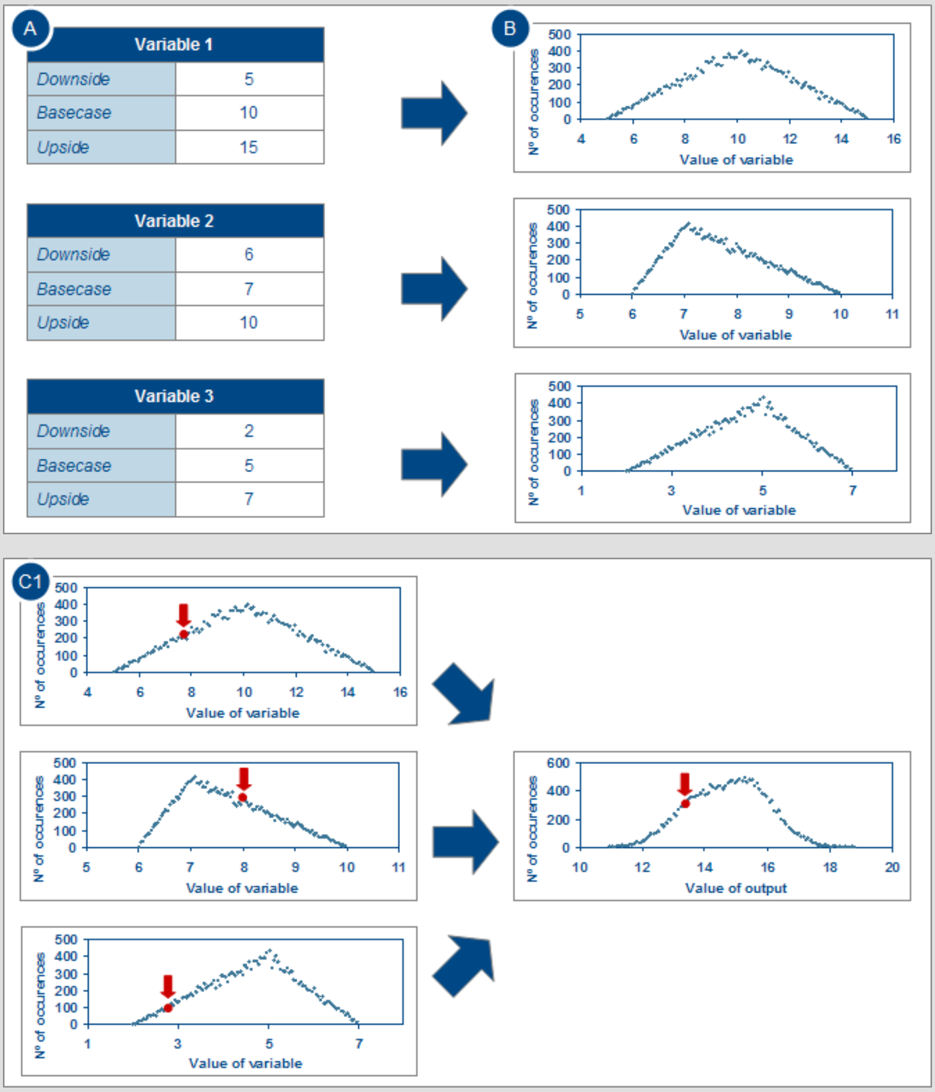
The Monte-Carlo simulation methods are very often used in a broad range of applications, including finance, e.g. to evaluate investments in a project or to assess risk. These methods are particularly useful for studying models with many variables. The basic working principle is common to all Monte-Carlo methods and proceeds as follows:

A) A range of possible values for each of the variables is defined, i.e., a Base case, a Downside and an Upside;

B) The model randomly generates a given number of values within the defined ranges, for each of the variables. In this particular simulation, the random values were produced following a normal probability distribution, as it is one of the most widely used distributions in simulation analysis, and easy to implement and interpret;

C) The randomly produced values are then used as inputs for the model, i.e., in each iteration of the model a value is randomly picked from the probability distribution of each variable and the output is returned. The outputs are then aggregated into a final result.

Each iteration of the model corresponds to a set of values (i.e., one random value for each variable), and the model undergoes as many iterations as there are sets of values. In order to produce statistically representative results, several thousand sets of values are created, with which the Monte Carlo simulation will in turn produce a statistically valid probability distribution for the model's outputs.



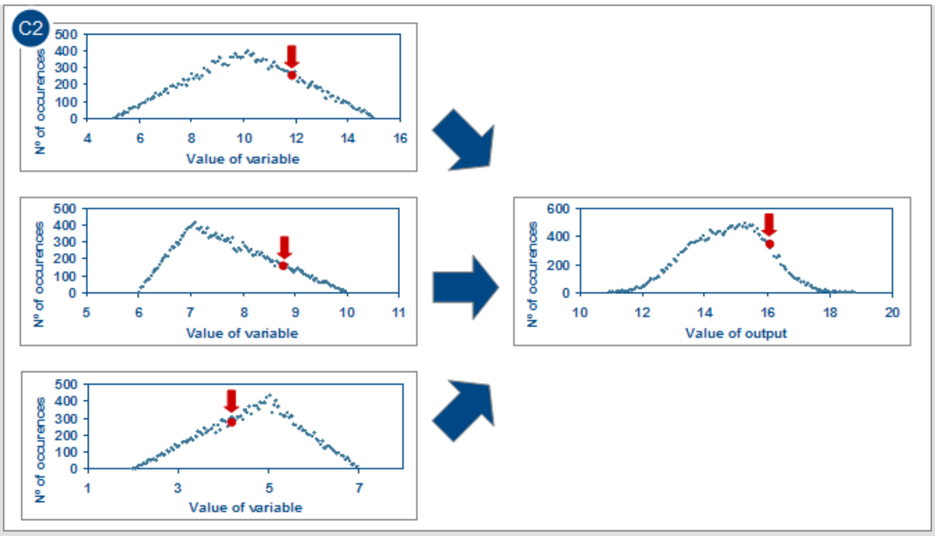


Illustration of the sensitivity analysis using a Monte Carlo simulation: a range of possible values (Downside, Base case and Upside) is defined for each of the variables (A), and this range is used to randomly generate values for each of the variables, following a given probability distribution - in this case we used the normal distribution (B); in each iteration of the Monte Carlo simulation, random values are chosen for the variables and the output is returned (C1 and C2), resulting in a statistically relevant distribution of the model's outputs

Figure 11.3 - The Monte-Carlo sensitivity analysis.

11.2 Overall Results

The next sections detail the overall results and the results discriminated by project. Table 11.2 has a summary of the modelling data used for the Base Case in each project. The Base Case was defined as the scenario that leads to the lowest LCoE in the expected financing circumstances, with a commercial technology. For all the locations, this proved to be true for Power Towers, with financing in Namibia. In the upcoming sections, we will simulate the results for different technologies and financing conditions and compare the results.

If we compare the results obtained in terms of ST for each location of the total five with the benchmark (Table 11.3 and Figure 11.5), easily comes that the values obtained for Namibia fall short. This happens because the feed-in tariffs in Spain, South Africa and even the US (although at a different level) were established to allow a return for the investor of some 20% (in Spain) and 30% in South Africa, while the values presented here for Namibia consider a return equal to the WACC (around 13% in the Base Case), allowing the calculation of the LCoE in that case. In the US the returns of these investments are lower when compared with other countries due to the existence of PPAs negotiated between the parties (thus more dependent on negotiation and on market necessities), instead of feed-in tariffs attributed directly by the government, which for some locations will yield significant returns.

As explained in the above methodology section, the difference between LCoE and ST lies essentially in the inflation. In the absence of inflation, both values would be the same.

Table 11.2 – Base Case results

	Ausnek	Kokerboom	Hochland	Skorpion Mine	Gerus
Technology	Power Towers				
Plant size (MW)	50				
Plant lifetime (years)	25				
Construction period (y)	2				
Net energy yield (MWh/MWy)	4.270			2.800	4.290
Productivity losses (%/year)	1				
CapEx (M USD/MW)	5,01	5,28		4,42	4,95
CapEx (M NAD/MW)	41,08	43,30		36,24	40,59
CapEx split (1st year) (%)	40%				
OpEx (USD/MWh)	29,33	30,91	30,91	39,46	43,85
OpEx (NAD/MWh)	240,51	253,46	253,46	323,57	359,57
Inflation	5%				
Cost of Capital	15%				
Loan duration (years)	13				
Interest rate	11%				
Debt/equity	50%				
Debt arrangement fee	1,5%				
DSCA (months)	6				
WACC	13%			12,8%	13%

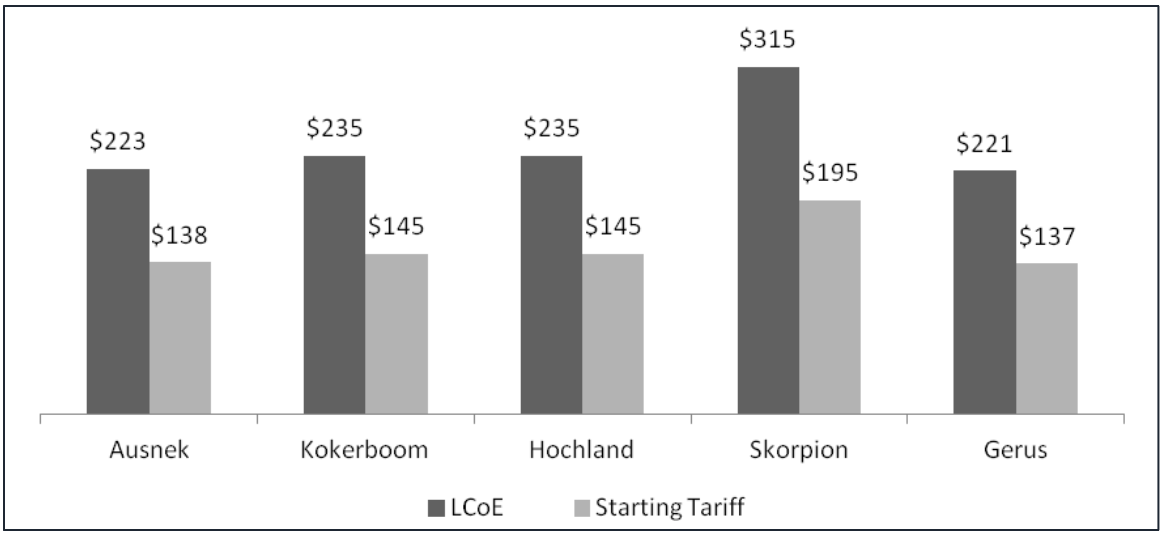
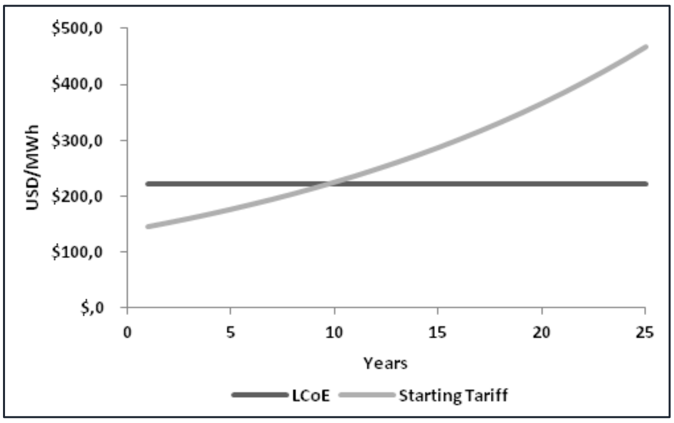


Figure 11.4 - Overall LCoE and ST results for the five locations under study in USD/MWh.

Table 11.3 - Overall LCoE and Starting Tariff data for the five locations under study in USD and NAD (note: conversion from USD to NAD at 1:8,2 as of 11/07/2012, from http://www.xe.com/ucc/).

		Ausnek	Kokerboom	Hochland	Skorpion Mine	Gerus
USD/MWh	LCoE	*223*	*235*	*235*	*315*	*221*
	Starting Tariff	*138*	*145*	*145*	*195*	*137*
NAD/MWh	LCoE	*1.826*	*1.925*	*1.925*	*2.584*	*1.813*
	Starting Tariff	*1.131*	*1.192*	*1.192*	*1.596*	*1.123*



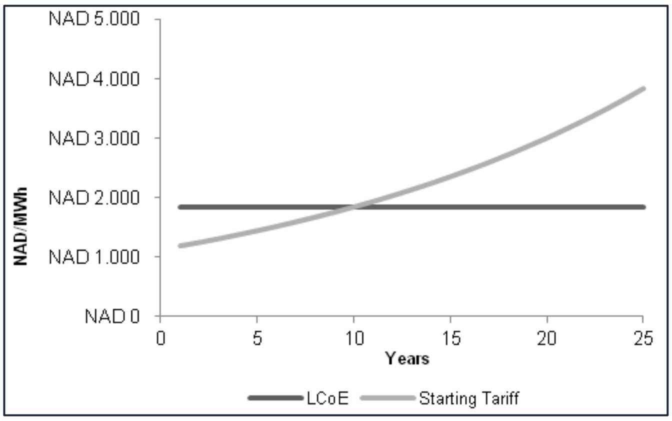


Figure 11.5 - Illustrates the correlation between the LCoE and the ST in the Base Case for an illustrative project (Ausnek).

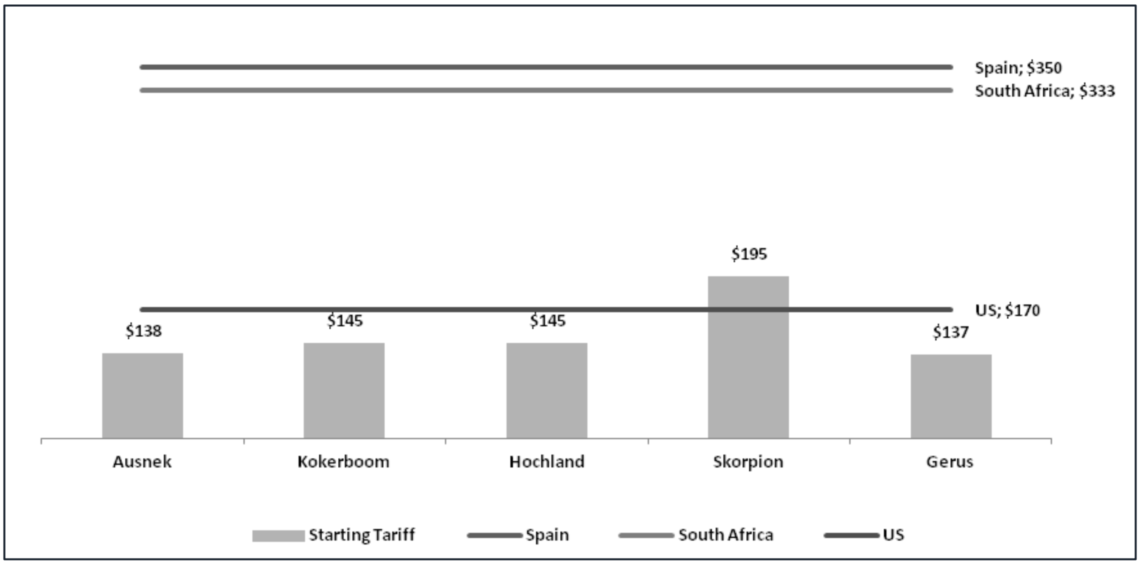


Figure 11.6 – Starting Tariffs benchmark and comparison with the five locations under study.

Promoter: Sponsors: Developers:

Figure 11.17 and Figure 11.8 illustrates the variation of the LCoE and the ST with the WACC. Investors typically look for costs of capital around 30% for investments with this profile, corresponding fairly to a WACC of some 20%. At a 20% WACC, the LCoE increases approximately to 275 USD/MWh (2.255 NAD/MWh) and the ST to 185 USD/MWh (1.517 NAD/MWh) (with slight variations, depending on the location).

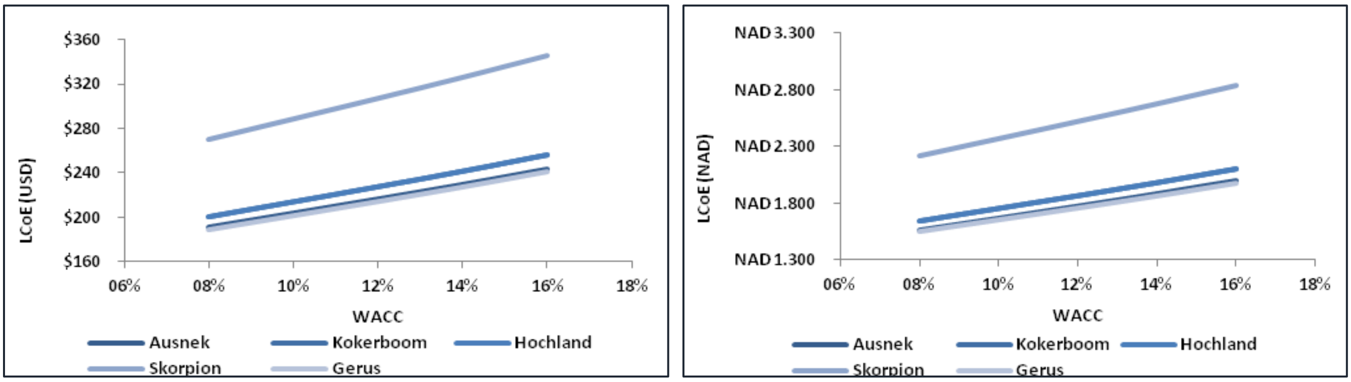


Figure 11.7 – Variation in LCoE with the WACC for the five locations under study in USD and NAD (note: conversion from USD to NAD at 1:8,2 as of 11/07/2012).

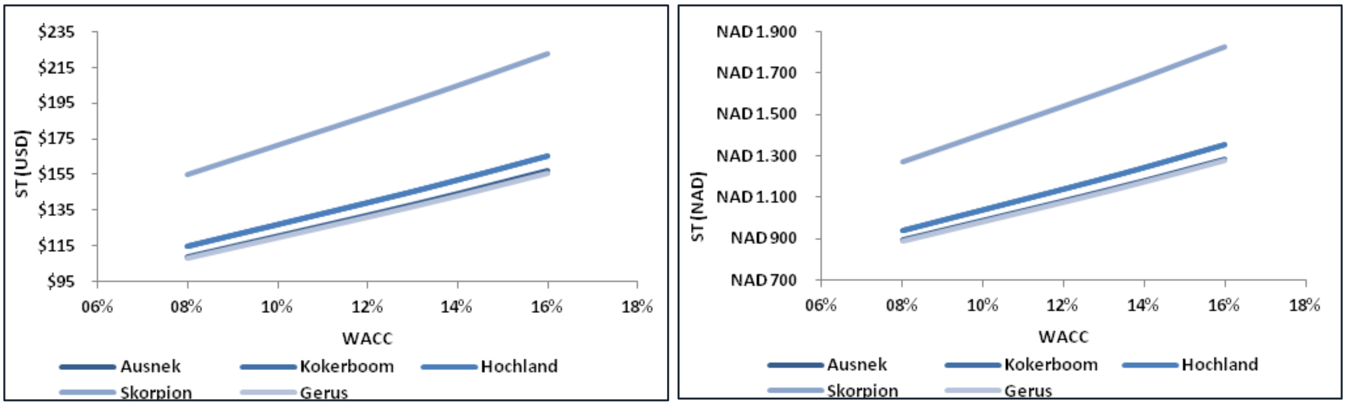


Figure 11.8 – Variation in the Starting Tariff with the WACC for the five locations under study in USD and NAD (note: conversion from USD to NAD at 1:8,2 as of 11/07/2012).

11.3 Top 5 Sites Detail Analysis

11.3.1 Hochland

For each location, in addition to the Base Case, two other scenarios were considered: a change in technology and a change in the financing conditions. For the technology scenario (AS I), parabolic troughs instead of Power Towers were considered. For the AS II we considered the financing conditions typically obtained in A rated markets, with some adjustments to the Namibian reality (currency hedging, country risk). This was performed for all the locations, with exception for Gerus, were besides Parabolic Trough, Linear Fresnel Reflectors were also considered. Table 11.4 describes the three scenarios under study (Base Case and two Alternative Scenarios) for Hochland and Table 11.5 present the results obtained.

Table 11.4 - Alternative scenarios (AS) characteristics (only the changes regarding the data in Table 11.2 are presented).

	Base Case	AS I – Technology	AS II - Financing
Technology	Power Towers	Parabolic Trough	Power Towers
Net energy yield (MWh/Mwy)	4.270	4.270	4.270
CapEx (M USD/MW)	5,28	5,56	5,28
CapEx (M NAD/MW)	43,30	45,59	43,30
OpEx (USD/MWh)	30,91	32,55	30,91
OpEx (NAD/MWh)	253,46	266,91	253,46
Interest rate	11%	11%	6%

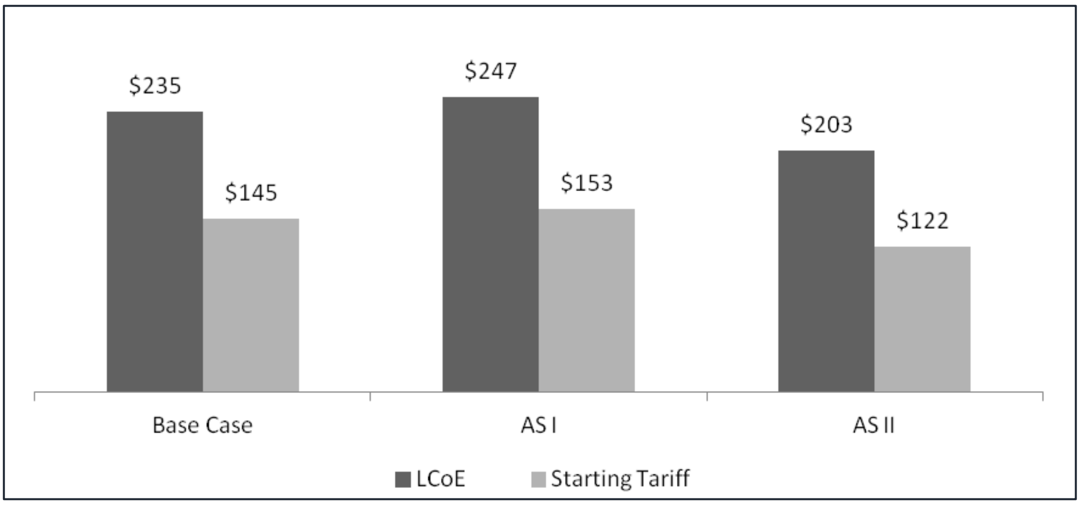


Figure 11.9 – LCoE and Starting Tariff for the Base Case and alternate scenarios, for Hochland.

Table 11.5 - LCoE and Starting Tariff data for the Base Case and alternate scenarios, for Hochland in USD and NAD.

		Base Case	AS I – Technology	AS II - Financing
USD/MWh	LCoE	*235*	*247*	*203*
	Starting Tariff	*145*	*153*	*122*
NAD/MWh	LCoE	*1.925*	*2.027*	*1.660*
	Starting Tariff	*1.192*	*1.255*	*997*

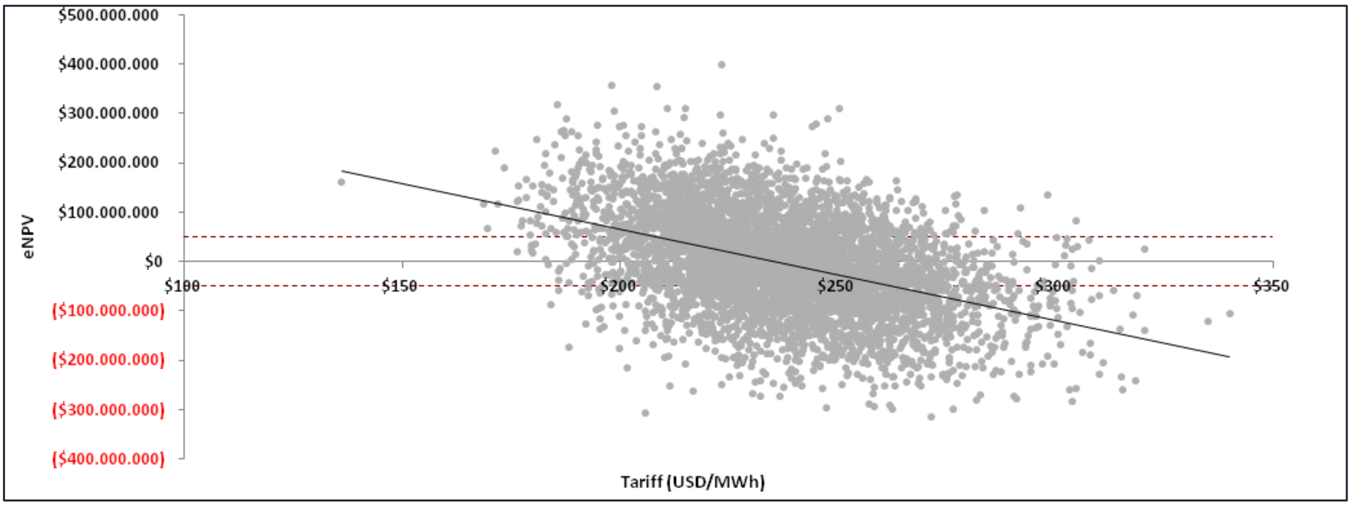
Table 11.6 presents the P90, P50 and P10 inputs for CapEx and Energy Yield for the Monte Carlo Analysis:

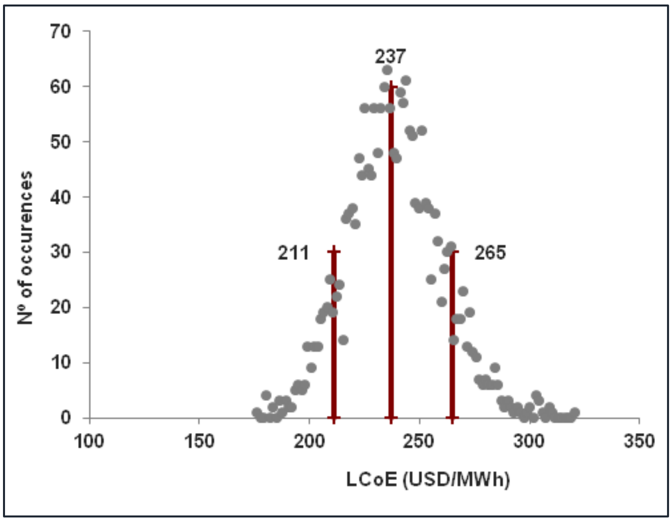
Table 11.6 - CapEx and Energy Yield inputs for the Monte Carlo analysis for Hochland, in USD and NAD.

	P90	P50	P10
Energy Yield (MWh/MWp)	*4.000*	*4.270*	*4.540*
CapEx (M USD/MW)	*6,32*	*5,28*	*4,24*
CapEx (M NAD/MW)	*51,82*	*43,30*	*34,77*

In Figure 11.10 and Table 11.7 we have the Monte Carlo LCoE results for this simulation. These results are obtained by selecting the tariff values for which the NPV is 0[11].

[11] In order to have statistical significance, we broadened the interval, and instead of considering only the values with NPV=0, we considered the interval of -50 M$<NPV<50M$. The results obtained indicate that this approximation is valid. This approach was repeated for all the locations.





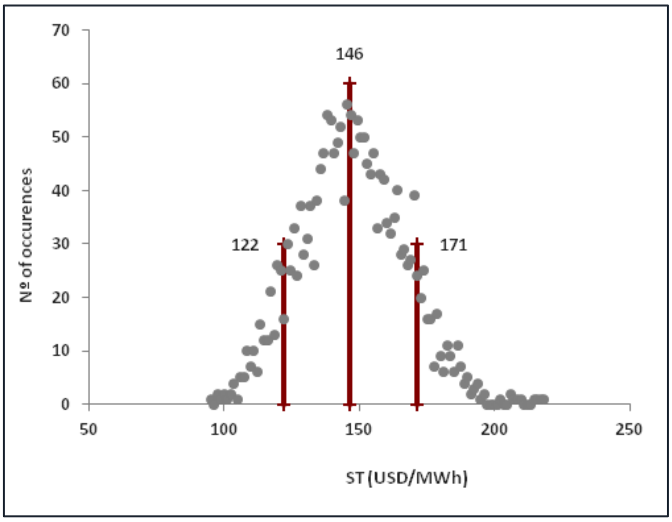


Figure 11.10 – Results for the Monte Carlo analysis for Hochland "Base Case", with the P10, P50 and P90 signaled. A total of 5.000 iterations were used.

Table 11.7 - Monte Carlo analysis results for Hochland, in USD and NAD.

	P90	P50	P10
LCoE (USD/MWh)	*265*	*237*	*211*
LCoE (NAD/MWh)	2.173	1.943	1.730
ST (USD/MWh)	171	146	122
ST (NAD/MWh)	1.402	1.197	1.000

11.3.2 Skorpion Mine

Table 11.8 describes the three scenarios under study (Base Case and two Alternative Scenarios) for Skorpion Mine and Figure 11.11 and Table 11.9 presents the results obtained.

Table 11.8 - Alternative scenarios (AS) characteristics (only the changes regarding the data in Table 11.3 are presented).

	Base Case	AS I – Technology	AS II – Financing
Technology	Power Towers	Parabolic Trough	Power Towers
Net energy yield (MWh/MWy)	2.800	2.810	2.800
CapEx (M USD/MW)	4,42	4,56	4,42
CapEx (M NAD/MW)	36,24	37,39	36,24
OpEx (USD/MWh)	39,46	40,57	39,46
OpEx (NAD/MWh)	323,57	332,67	323,57
Interest rate	11%	11%	6%

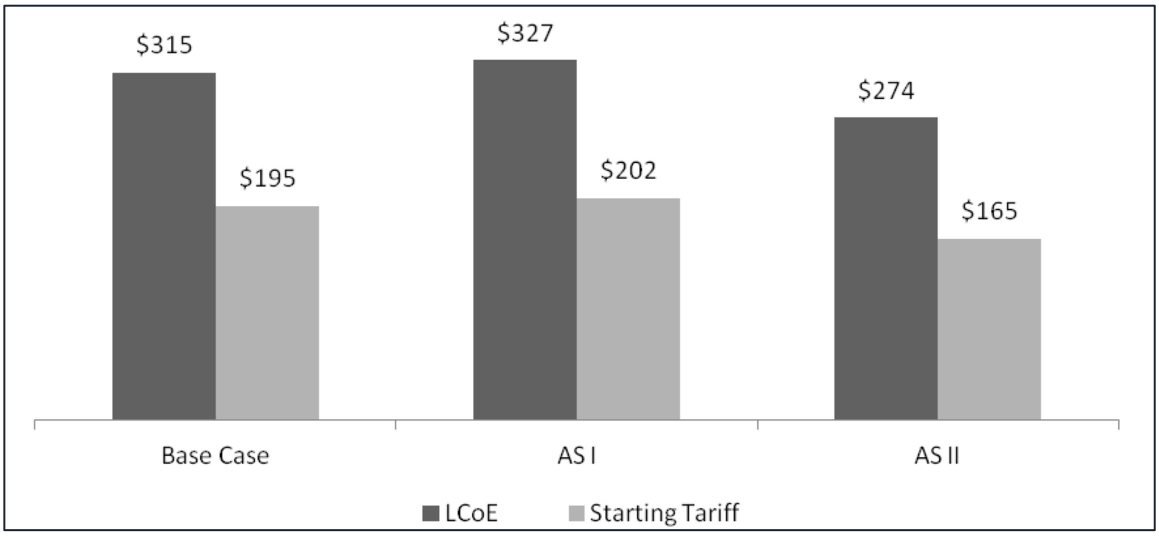


Figure 11.11 – LCoE and Starting Tariff for the Base Case and alternate scenarios, for Skorpion Mine.

Table 11.9 - LCoE and Starting Tariff data for the Base Case and alternate scenarios, for Skorpion Mine in USD and NAD.

		Base Case	AS I – Technology	AS II - Financing
USD/MWh	LCoE	*315*	*327*	*274*
	Starting Tariff	*195*	*202*	*165*
NAD/MWh	LCoE	*2.584*	*2.679*	*2.250*
	Starting Tariff	*1.596*	*1.655*	*1.352*

Table 11.10 presents the P90, P50 and P10 inputs for CapEx and Energy Yield for the Monte Carlo Analysis.

Table 11.10 - CapEx and Energy Yield inputs for the Monte Carlo analysis for Skorpion Mine, in USD and NAD.

	P90	P50	P10
Energy Yield (MWh/MWp)	*2.600*	*2.800*	*3.000*
CapEx (M USD/MW)	*5,18*	*4,42*	*3,66*
CapEx (M NAD/MW)	*42,48*	*36,24*	*30,01*

In Figure 11.12 and Table 11.11 we have the Monte Carlo LCoE results for this simulation. These results are obtained by selecting the tariff values for which the NPV is 0.

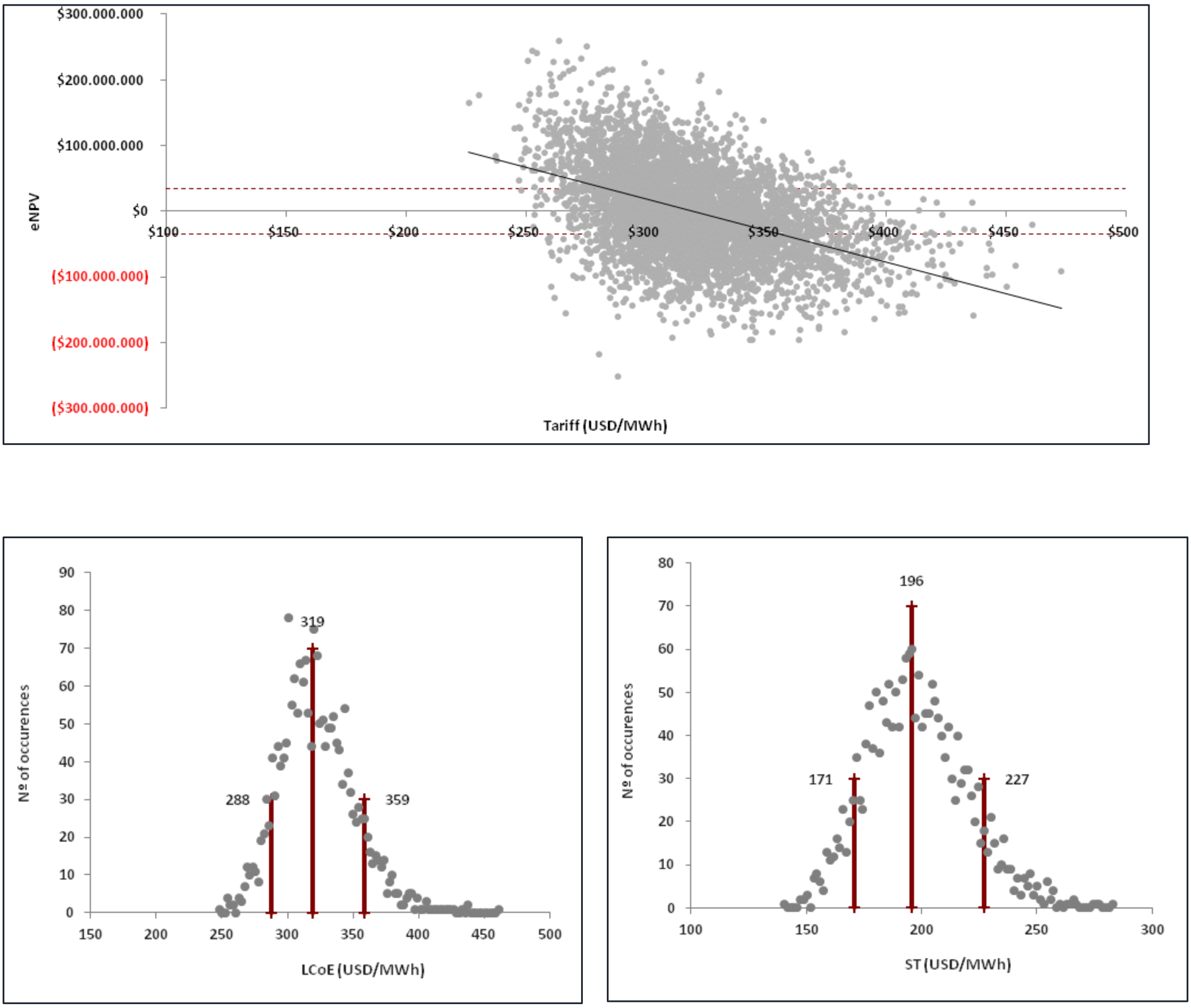


Figure 11.12 – Results for the Monte Carlo analysis for Skorpion Mine "Base Case", with the P10, P50 and P90 signaled. A total of 5.000 iterations were used.

Table 11.11 - Monte Carlo analysis results for Skorpion Mine, in USD and NAD.

	P90	P50	P10
LCoE (USD/MWh)	359	319	288

LCoE (NAD/MWh)	2.944	2.616	2.362
ST (USD/MWh)	227	196	171
ST (NAD/MWh)	1.861	1.607	1.402

11.3.3 Ausnek

Table 11.12 describes the three scenarios under study for Ausnek and Figure 11.13 and Table 11.13 present the results obtained.

Table 11.12 - Alternative scenarios (AS) characteristics (only the changes regarding the data in Table 11.3 are presented).

	Base Case	**AS I – Technology**	**AS II – Financing**
Technology	Power Towers	Parabolic Trough	Power Towers
Net energy yield (MWh/MWy)	4.270	4.270	4.270
CapEx (M USD/MW)	5,01	5,26	5,01
CapEx (M NAD/MW)	41,08	43,13	41,08
OpEx (USD/MWh)	29,33	30,8	29,33
OpEx (NAD/MWh)	240,51	252,56	240,51
Interest rate	11%	11%	6%

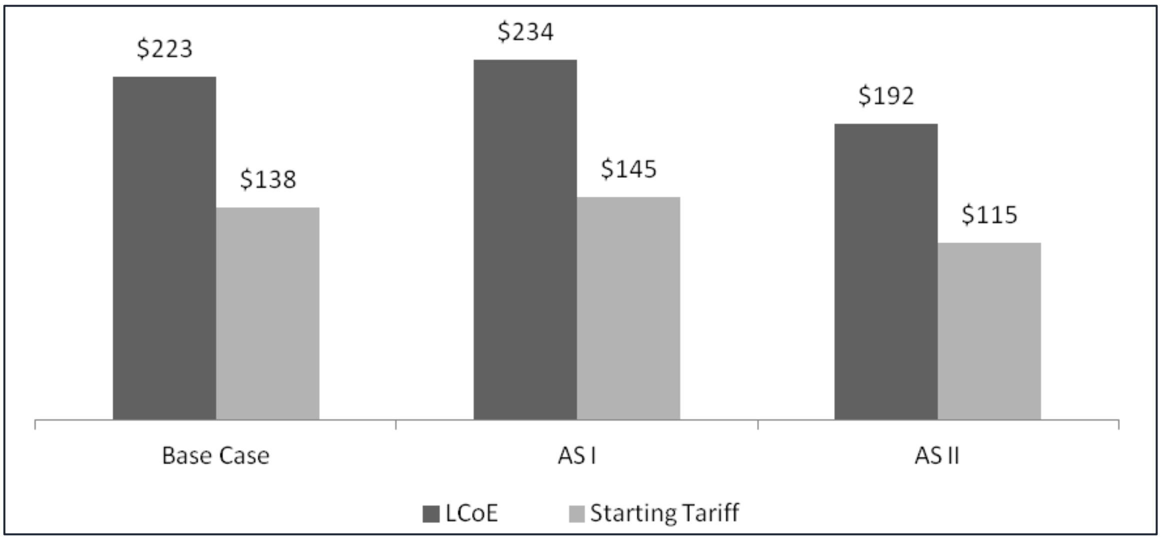


Figure 11.13 – LCoE and Starting Tariff for the Base Case AS I and AS II, for Ausnek.

Table 11.13 - LCoE and Starting Tariff data for the Base Case and alternate scenarios, for Ausnek in USD and NAD (note: conversion from USD to NAD at 1:8,2 as of 11/07/2012).

		Base Case	AS I – Technology	AS II – Financing
USD/MWh	LCoE	*223*	*234*	*192*
	Starting Tariff	*138*	*145*	*115*
NAD/MWh	LCoE	*1.826*	*1.918*	*1.576*
	Starting Tariff	*1.131*	*1.188*	*946*

The increase in CapEx (and OpEx) is the main driver for the increase in LCoE and ST for the AS I. On the other hand, the lower interests contribute for a lower LCoE and ST values in AS II.

A Monte Carlo sensitivity analysis was performed in the Base Case to the Energy Yield and CapEx.

Table 11.14 presents the P90, P50 and P10 inputs for CapEx and Energy Yield.

Table 11.14 - CapEx and Energy Yield inputs for the Monte Carlo analysis for Ausnek, in USD and NAD.

	P90	P50	P10

Energy Yield (MWh/MWp)	*4.000*	*4.270*	*4.540*
CapEx (M USD/MW)	*5,96*	*5,01*	*4,06*
CapEx (M NAD/MW)	*48,87*	*41,08*	*33,29*

Figure 11.14 and Table 11.15 present the Monte Carlo LCoE results for this simulation. These results are obtained by selecting the tariff values for which the NPV is zero.

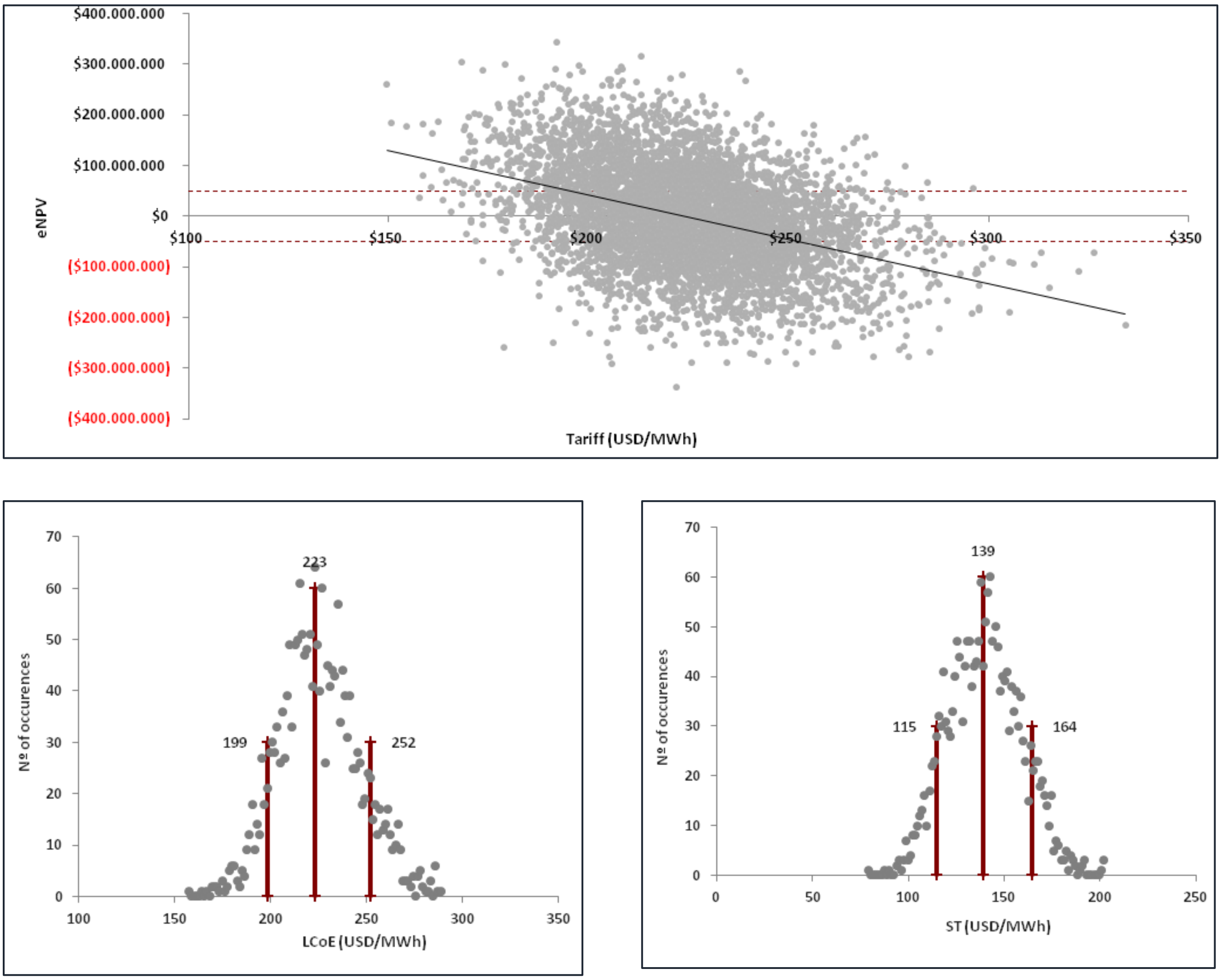


Figure 11.14 – Results for the Monte Carlo analysis for Ausnek "Base Case", with the P10, P50 and P90 signaled. A total of 5.000 iterations were used.

Table 11.15 - Monte Carlo analysis results for Ausnek, in USD and NAD.

	P90	P50	P10
LCoE (USD/MWh)	*252*	*223*	*199*
LCoE (NAD/MWh)	*2.066*	*1.829*	*1.632*
ST (USD/MWh)	164	139	115
ST (NAD/MWh)	1.345	1.140	943

11.3.4 Kokerboom

Table 11.16 describes the three scenarios under study (Base Case and two Alternative Scenarios) for Kokerboom and Figure 11.15 and Table 11.16 present the results obtained.

Table 11.16 - Alternative scenarios (AS) characteristics (only the changes regarding the data in Table 11.3 are presented).

	Base Case	AS I – Technology	AS II – Financing
Technology	Power Towers	Parabolic Trough	Power Towers
Net energy yield (MWh/MWy)	4.270	4.280	4.270
CapEx (M USD/MW	5,28	5,55	5,28
CapEx (M NAD/MW)	43,30	45,51	43,30
OpEx (USD/MWh)	30,91	32,42	30,91
OpEx (NAD/MWh)	253,465	265,84	253,46
Interest rate	11%	11%	6%

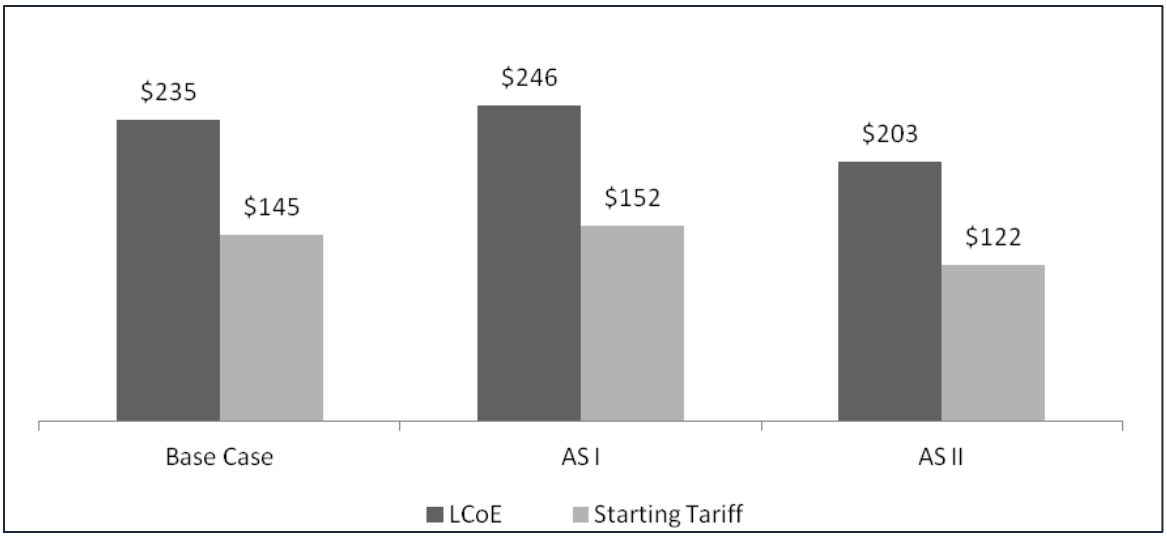


Figure 11.15 – LCoE and Starting Tariff for the Base Case and alternate scenarios, for Kokerboom.

Table 11.17 - LCoE and Starting Tariff data for the Base Case and alternate scenarios, for Kokerboom in USD and NAD.

		Base Case	AS I – Technology	AS II – Financing
USD/MWh	LCoE	*235*	*246*	*203*
	Starting Tariff	*145*	*152*	*122*
NAD/MWh	LCoE	*1.925*	*2.019*	*1.660*
	Starting Tariff	*1.192*	*1.250*	*997*

Table 11.18 presents the P90, P50 and P10 inputs for CapEx and Energy Yield for the Monte Carlo Analysis:

Table 11.18 - CapEx and Energy Yield inputs for the Monte Carlo analysis for Kokerboom, in USD and NAD.

	P90	P50	P1’
Energy Yield (MWh/MWp)	*4.000*	*4.270*	*4.540*
CapEx (M USD/MW)	*6,32*	*5,28*	*4,24*
CapEx (M NAD/MW)	*51,82*	*43,29*	*34,77*

In Figure 11.16 and Table 11.19 we have the Monte Carlo LCoE results for this simulation. These results are obtained by selecting the tariff values for which the NPV is 0.

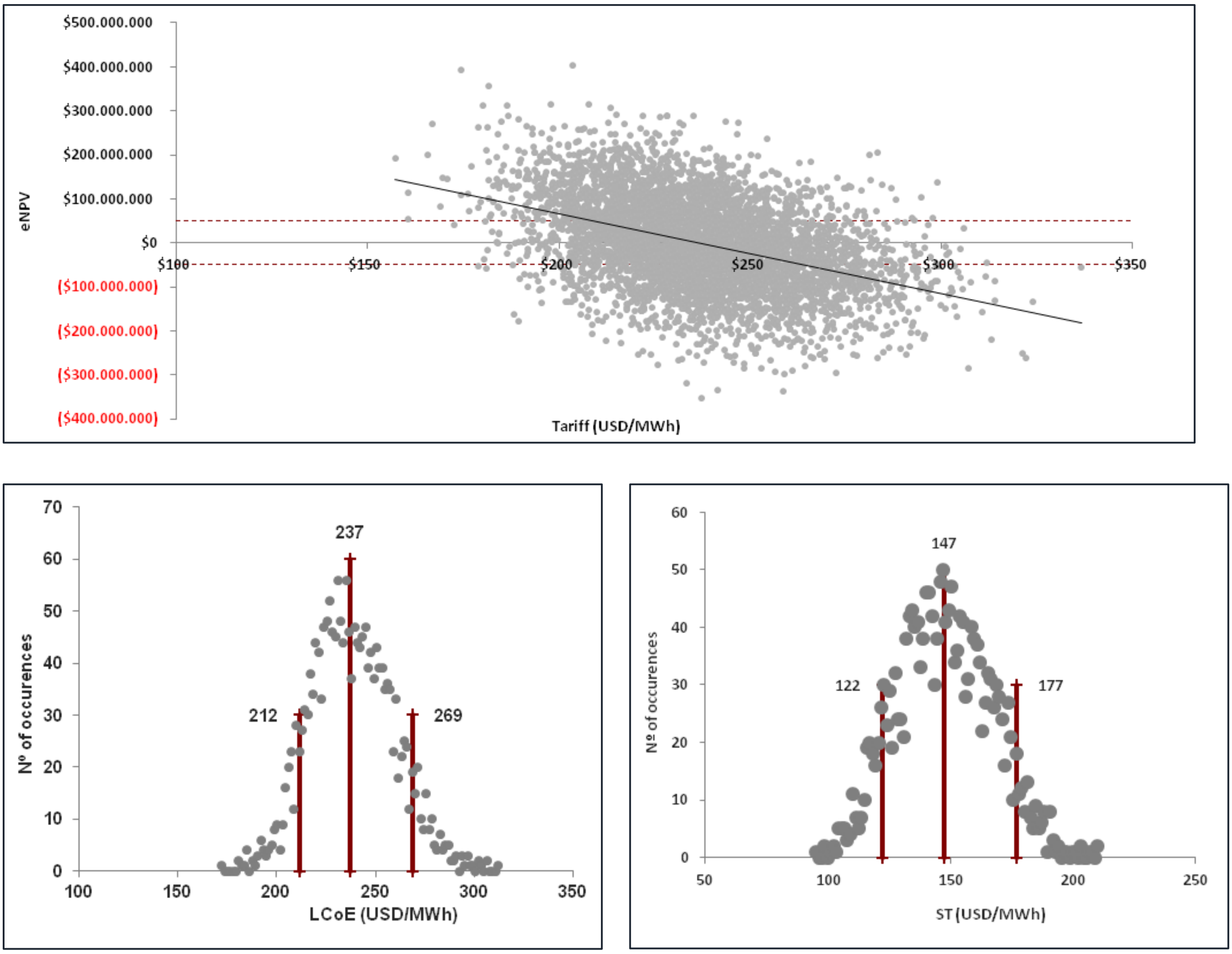


Figure 11.16 – Results for the Monte Carlo analysis for Kokerboom "Base Case", with the P10, P50 and P90 signaled. A total of 5.000 iterations were used.

Table 11.19 - Monte Carlo analysis results for Kokerboom, in USD and NAD.

	P90	P50	P10
LCoE (USD/MWh)	269	237	212
LCoE (NAD/MWh)	2.206	1.943	1.738
ST (USD/MWh)	177	147	122
ST (NAD/MWh)	1.451	1.205	1.000

11.3.5 Gerus

Table 11.20 describes the three scenarios under study (Base Case and three Alternative Scenarios) for Gerus. As mentioned before, Gerus has the specificity of having a biomass boiler coupled to the solar power plant, thus changing the structure of the OpEx values in this scenario. Biomass prices were considered to be around 73 USD/ton (598,6 NAD/ton). Figure 11.17 and Table 11.21 present the results obtained. In this location, besides the two scenarios considered for the remaining locations, a third scenario was equated: AS Ib), corresponding to Linear Fresnel Reflectors.

Table 11.20 – Alternative scenarios (AS) characteristics (only the changes regarding the data in Table 11.3 are presented).

	Base Case	AS Ia) – Technology	AS Ib) - Technology	AS II – Financing
Technology	Power Towers	Parabolic Trough	Fresnel	Power Towers
Net energy yield (MWh/MWy)	4.290	4.280	4.210	4.290
CapEx (M USD/MW)	4,95	5,16	5,94	4,95
CapEx (M NAD/MW)	40,59	42,31	48,71	40,59
OpEx (USD/MWh)	43,85	43,18	46,18	43,85
OpEx (NAD/MWh)	359,57	354,08	378,68	359,57
Interest rate	11%	11%	11%	6%

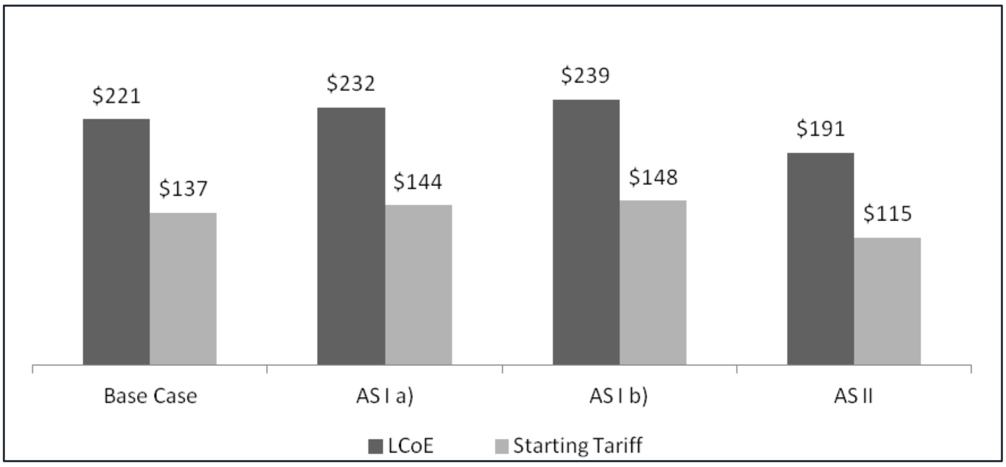


Figure 11.17 – LCoE and Starting Tariff for the Base Case and alternate scenarios, for Gerus.

Table 11.21 - LCoE and Starting Tariff data for the Base Case and alternate scenarios, for Gerus in USD and NAD.

		Base Case	AS I a) – Technology	AS I b) – Technology	AS II – Financing
USD/MWh	LCoE	*221*	*232*	*239*	*191*
	Starting Tariff	*137*	*144*	*148*	*115*
NAD/MWh	LCoE	*1.813*	*1.903*	*1.956*	*1.565*
	Starting Tariff	*1.123*	*1.178*	*1.211*	*940*

Table 11.22 presents the P90, P50 and P10 inputs for CapEx and Energy Yield for the Monte Carlo Analysis:

Table 11.22 - CapEx and Energy Yield inputs for the Monte Carlo analysis for Gerus, in USD and NAD.

	P90	P50	P10
Energy Yield (MWh/MWp)	*4.200*	*4.290*	*4.380*
CapEx (M USD/MW)	*5,40*	*4,95*	*4,50*
CapEx (M NAD/MW)	*44,28*	*40,59*	*36,90*

In Figure 11.18 and Table 11.23 we have the Monte Carlo LCoE results for this simulation. These results are obtained by selecting the tariff values for which the NPV is 0.

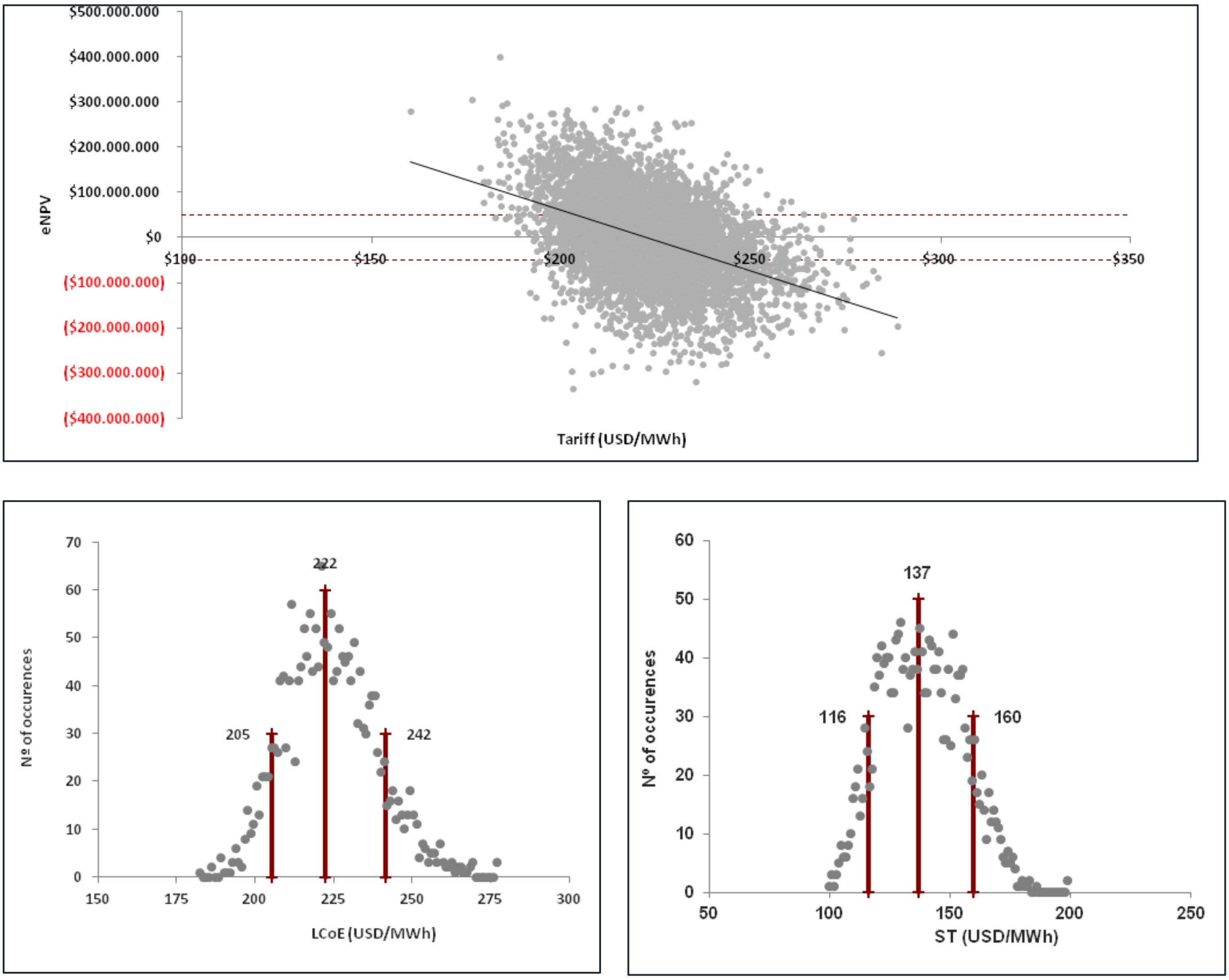


Figure 11.18 – Results for the Monte Carlo analysis for Gerus "Base Case", with the P10, P50 and P90 signaled. A total of 5.000 iterations were used.

Table 11.23 - Monte Carlo analysis results for Gerus, in USD and NAD.

	P90	P50	P10
LCoE (USD/MWh)	242	222	205
LCoE (NAD/MWh)	1.984	1.820	1.681
ST (USD/MWh)	160	137	116
ST (NAD/MWh)	1.312	1.123	951

11.4 Conclusions

The LCoE results obtained for the five locations range from 221 USD/MWh (1.813 NAD/MWh) to 235 USD/MWh (1.925 NAD/MWh), with exception for Skorpion Mine, with 315 USD/MWh (2.584 NAD/MWh). In terms of ST, the values go from 137 USD/MWh (1.123 NAD/MWh) to 145 USD/MWh (1.192 NAD/MWh), with Skorpion Mine presenting a higher value of 195 USD/MWh (1.596 NAD/MWh).

The high LCoE value registered in Skorpion Mine is due to the design criteria which targeted a TOU peak period, meaning that the power plant would not need much storage but since almost the whole afternoon generation is shifted for the TOU peak period later in the afternoon storage is required increasing the cost of generation. On the other hand, the CSP project in Skorpion Mine allows the project owner lower electricity costs (compared with the current TOU peak tariff) and the guarantee of electricity supply for the next 25 years, which is extremely valuable, given the high probability of power shortages in the region in the near future.

These LCoE values were calculated for a 13% WACC. If we increase the WACC up to 20% (allowing costs of capital of some 30% to reflect the typical investors' expectations in this region) we obtain LCoE values around 275 USD/MWh (2.255 NAD/MWh) and ST of roughly 185 USD/MWh (1.517 NAD/MWh). These are aligned (although on the lower side) with the benchmarks provided (Spain, South Africa).

The technology selection has some influence in the LCoE values, however this is not very significant. In Ausnek, for example, the LCoE for power tower is 223 USD/MWh (1.829 NAD/MWh), while for Parabolic Trough is 234 USD/MWh (1.919 NAD/MWh). This difference might be dimmed if the developer has access to better financing conditions with parabolic troughs when compared with power towers, or if their competences and negotiation capacity in the EPC in parabolic troughs surpasses those in power towers. That said, despite the impact that the technology has in the LCoE values, the final decision will always be dependent on the investor/developer profile and technical capabilities.

The financing conditions for A rated countries/companies are more favorable than those in Namibia, even after considering currency and country hedging. However the probability of this scenario is lower, and it is much more common to finance these projects directly with local currency. Yet, once again, the profile of the investor/developer has a crucial importance here. Depending on their ability to raise finance and on the financing conditions obtained, these LCoE results can improve or worsen a lot.

The Monte Carlo analysis showed that the LCoE results range from 199 USD/MWh (1.632 NAD/MWh) (P10 in Ausnek) to 269 USD/MWh (2.206 NAD/MWh)) (P90 in Kokerboom). The exception goes to Skorpion Mine, that given the above-mentioned constraints, ranges from 288 USD/MWh (2.362 NAD/MWh) (P10) to 359 USD/MWh (2.944 NAD/MWh) (P90).

For the Starting Tariff the Monte Carlo analysis showed that the results range from 115 USD/MWh (943 NAD/MWh) (P10 in Ausnek) to 177 USD/MWh (1.451 NAD/MWh)) (P90 in Kokerboom). The exception goes to Skorpion Mine, that given the above-mentioned constraints, ranges from 171 USD/MWh (1.402 NAD/MWh) (P10) to 227 USD/MWh (1.861 NAD/MWh) (P90).

A last note for the way the cost values were obtained. Based on the simulations and models used for the emulation of the power plants power yield and costs, the costs were given on a conservative side, so P10 values may not be actually that underestimated. A second detail is that the exchange rate considered was 8,2 NAD per USD while the more commonly used and accepted figure is 7.5, so the NAD values may be almost 10% above expected exchange rate conversion.

The equity/debt ratio considered was low compared to the expected 30/70 and the reason is the Debt Coverage Ratio, which was not allowed to be less than 1,3, considered extremely favorable. The fact that a LCoE approach was used required low NPV values and so to balance the DCR requirement a lower debt portion was the solution. If a higher ratio was to be used the LCoE would not be able to be calculated and a tariff for the specific inputs would be the result.

12 Best Practices on Ground Measurements

This best-practice manual for ground measurements contains an overview of the different sensors currently used for solar radiation and meteorological measurements. Furthermore, recommendations are given for the selection of the most appropriate equipment to be deployed at any specific site, for site selection and preparation, as well as for operation and maintenance of the equipment. The necessary steps to evaluate the measurement uncertainty and to perform a meaningful data analysis are also described.

12.1 General overview of the instrumentation

On-site measurements are indispensable when planning a large-scale solar power plant. To obtain reliable data sets with a high level of accuracy and temporal coverage, including a good estimate of the data uncertainty, it is necessary to select the suitable instrumentation carefully, prepare the measurement campaign in detail, and set up an appropriate maintenance schedule.

12.1.1 Types of sensors or instruments and their accuracy

The two types of sensor most commonly used for measuring solar radiation are thermopiles (pyrheliometers and pyranometers) and photodiode detectors. At any given site, the most appropriate type should be chosen according to the purpose, budget, and additional requirements regarding the measurements.

Thermopiles use a thermoelectric sensor unit with a black coating that allows measurement of the nearly complete solar spectrum, because the spectral response of this black coating is close to that of a blackbody emitting radiation, such as the sun. Moreover, the protective window of pyrheliometers is made of quartz, which is transparent to ≈99 % of the spectrum[12], between about 200 and 4000 nm. Pyrheliometers measure only direct radiation (within an aperture of approximately 2.5° around its optical axis) and therefore have to be pointed towards the sun, requiring a two-axis tracking system. Pyranometers have a hemispherical opening angle and thus sense both direct and diffuse radiation. Their dome window has a slightly reduced spectral transmission compared to pyrheliometers, but still covers most of the solar spectrum (Figure 12.1). Pyranometers can also be used to measure diffuse radiation only if a shading device (continuously blocking the sun) is added.

[12] Proper calibration, against a windowless reference instrument, compensates for the spectral limitation created by the window.

Photodiode (silicon) sensors convert sunlight to an electric signal via the photoelectric effect. The signal is approximately proportional to the incident irradiance, so that, in essence, these sensors behave like "calibrated photovoltaic cells". Their response time is only a few milliseconds, which is great to track rapid changes in irradiance due to cloud passages; however, their spectral sensitivity is not flat and only covers a small part of the solar spectrum (Myers. 2011). Compared to pyrheliometers, this yields systematic deviations of their response, which needs to be appropriately corrected in order to obtain usable measurements. For this correction, some variables, such as sensor temperature or air mass, and various functions have to be determined. There are different correction formulas available at present, which differ slightly in their method and accuracy (e.g., Geuder et al., 2008; Vignola, 2006).

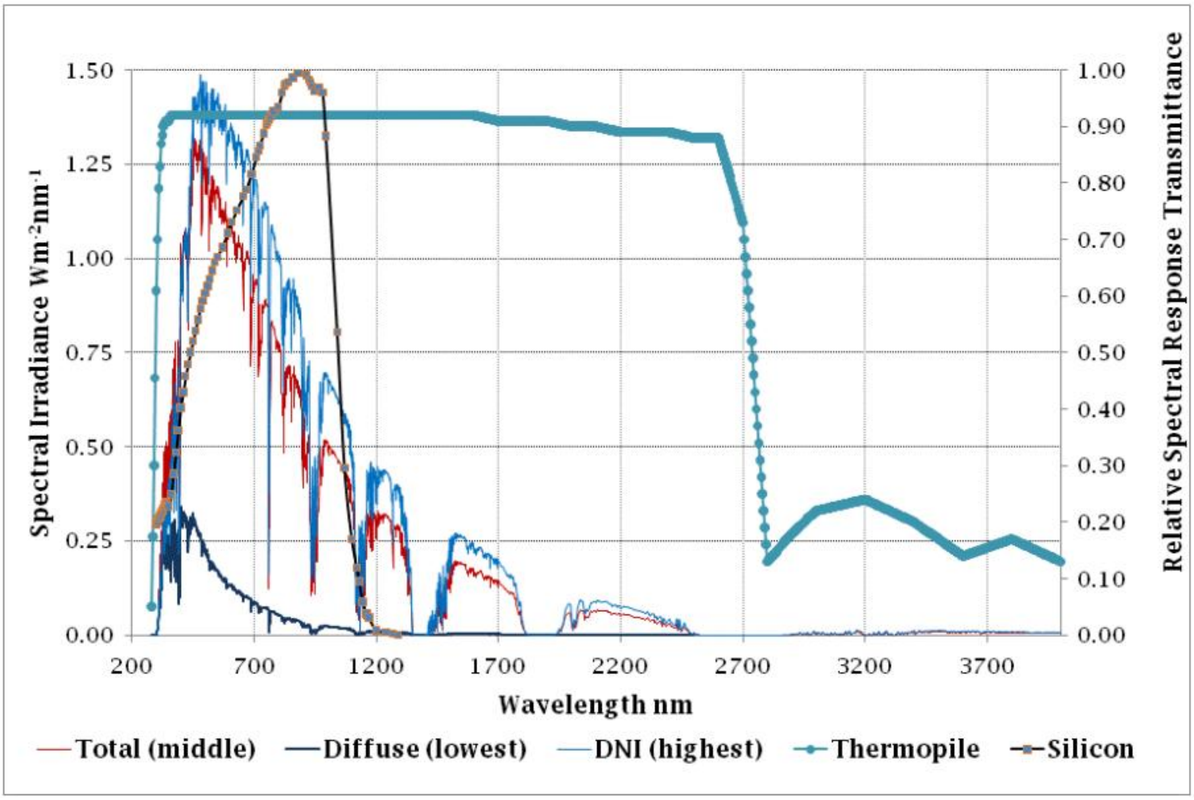


Figure 12.1 - Sun spectrum and spectral response of thermopile pyranometers and silicon sensors (Myers, 2010a).

Figure 12.1 shows the solar spectrum at the Earth's surface as well as the nominal spectral response of a thermopile pyranometer and a silicon sensor. It is clearly visible that thermopiles cover nearly the entire solar spectrum (in the range 280–2800 nm for pyranometers and 2004100 nm for pyrheliometers), whereas silicon sensors respond to the spectrum between 300 and 1100 nm only, and therefore are insensitive to large parts of the near-infrared spectrum. Because of their essentially flat spectral response, thermopiles have a higher accuracy than photodiode sensors. However, they are far more expensive, and additionally need substantial electric power for the tracker (pyrheliometer) or ventilator (pyranometer). Additionally, pyrheliometers are notably affected by soiling, thus require daily maintenance at sites exposed to frequent dust. Photodiode sensors are usually less sensitive to soiling and can easily be designed as part of a self-sufficient remote system with an independent power supply (PV panel and battery).

Figure 12.2 shows the different soiling characteristics from a one-month comparison period at Almería, Spain. At the end of that specific month, the DNI signal reduction was 25 % with the thermopile and only 2 % for the photodiode. The exact curves and soiling factors obviously depend on many factors (occurrence of dust, in combination with wind, dew, precipitation, etc.), and thus are highly site-specific. The daily effect cannot necessarily be approximated by a linear relation. Figure 2 shows that the pyrheliometer's signal lost up to 3 % during 24-hour periods at that site and during that month. The results in this figure should not be considered typical because higher losses were recorded in other occasions and also because sites with commonly less soiling exist (especially in moderate climates with plenty of vegetation).

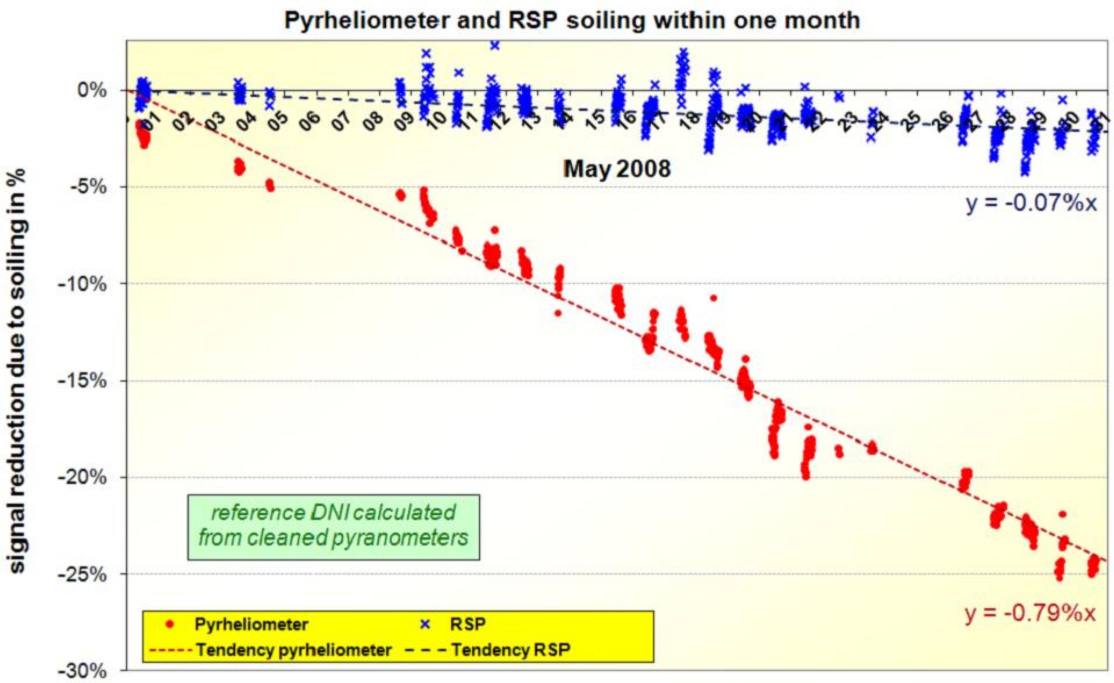


Figure 12.2 - Soiling comparison between silicon (RSP; blue crosses) and thermopile (Pyrheliometer; red dots) sensors during a month (Geuder, 2010).

For the determination of the different solar radiation components (direct, diffuse and global) with only one sensor, a Rotating Shadowband Irradiometer (RSI) [previously referred to in the literature as either rotating shadowband pyranometer, like in Figure 12.2, or rotating shadowband radiometer] is used, where a small shadowband rapidly rotates around the photodiode sensor at regular intervals, thus intermittently blocking the direct radiation component from the sensor. The global and diffuse irradiances are determined from the unshaded and shaded sensor response, respectively, and the direct irradiance is ultimately calculated at each instant by difference.

Various studies have been published to evaluate the comparative performance of various types of radiometers (Gueymard and Myers, 2009; Michalsky et al., 2005, 2011; Myers, 2010a; Myers and Wilcox, 2009). Such studies can help make sound decisions about the most appropriate type and brand of sensor to buy, depending on the specificities of each project, including budget.

Based on these two different physical principles behind radiometric sensors, two different types of measurement stations are commonly used:

A two-axis tracker equipped with Pyrheliometers and Pyranometers, hereafter referred to as “High-Precision Station” or “HP Station”). These stations need a grid power supply or a large photovoltaic installation due to significant power consumption. (For instance, a tracker has an electrical consumption of ≈25 W, and ventilation of the pyranometers additionally requires up to 30 W.) Such instruments also require frequent and regular maintenance, as well as regular cleaning (see Figure 12.2). When all this can be provided, they offer an excellent, research-class measurement quality. For this type of station (equipped to measure all components of solar radiation, temperature, pressure, air humidity, wind speed and direction), the hardware cost is usually in the range 35,000–55,000 USD, depending on equipment.

Figure 12.3 - Examples of HP Stations; left: Eppley (Source: NREL), right: Kipp&Zonen (Source: Gengenbach Messtechnik).

- A station equipped with an RSI sensor, hereafter referred to as “Autonomous Station”. Because of their low power requirement, such stations can use a small PV generator to be self-sufficient. Their raw solar irradiance signal needs to be post-processed to include temperature and spectral corrections. Although their nominal accuracy is lower than HP Stations, they have proven to be very reliable at remote sites, even in difficult environments. Moreover, their accuracy is considered good enough to finance utility-scale solar power projects based on their measurement. Hardware costs for this type of station (equipped to measure all components of solar radiation, temperature, barometric pressure, relative humidity, wind speed and direction) are roughly in the range 13,000–25,000 USD, depending on equipment.


Figure 12.4 - Examples of RSI stations. Left: Irradiance, Inc. right: CSP Services GmbH.

In contrast to RSI instruments, the Delta-T Devices SPN1 pyranometer uses various thermopiles that are partially shaded by a fixed computer-designed shading grid. The design of the shading grid is such that there are always some simultaneously shaded and unshaded thermopiles, thus allowing the determination of all irradiance components. The instrument produced DNI estimates with errors of about 15 to 20 % for DNI levels below 400 W/m² and about 10 % for higher DNI (Myers, 2010a). However, so far the present authors have not made any experiments with the SPN1 for field measurement at remote locations. Therefore, it is currently not considered a possible alternative to the radiometers described above.

Another type of sensor that must be mentioned for completeness is the absolute cavity radiometer (ACR). This sophisticated instrument is used to obtain the best possible measurement of DNI, to maintain the World Radiometric Reference (WRR) in Davos (Gueymard and Myers, 2008), for the transfer of calibration between the WRR and regional laboratories, and for calibration of primary sensors at such laboratories—but normally not for field measurements. An ACR uses the electric compensation principle, and mainly consists of two cavity receivers, one of which having a precision opening through which radiation passes and induces a change in temperature. The second receiver, which is not receiving any radiation, is heated to the same temperature, and the electrical energy needed to keep both receivers in thermal balance is by definition equal to the incident solar irradiance. For different reasons (including the lack of a protective window), ACRs are not designed for continuous field operation, particularly under adverse weather conditions.

12.1.2 Recommended equipment for Solar Resource Assessment at unattended and remote sites

In conditions such as in Namibia, where high dust loads during the dry season can be expected in some areas, an RSI-type sensor is recommended for measurements with the purpose of Solar Resource Assessment at unattended, remote sites. At such sites, daily maintenance of the irradiance sensors is usually not possible. Typical reasons include: long travel for the maintenance personnel to the site and usually long distances between this type of site and the nearest grid power supply. An RSI sensor can be powered with a self-sufficient power supply (PV panel and battery) and requires cleaning only every 1 to 4 weeks. The optimal frequency of cleaning needs to be evaluated on site during the first weeks of the measurement campaign. For this purpose, response changes must be evaluated by directly comparing the signal before and after cleaning. The cleaning intervals should be selected in a way that no large signal alteration occurs because of cleaning. Therefore, short cleaning intervals should be considered first. They can then be increased gradually until an optimum relation between maintenance expenses and necessary instrument cleanliness is achieved but must be continuously monitored and potentially adapted due to possible seasonal variations. Soiling-induced measurement signal reduction possibly should not exceed 1 %.

Alternatively, the use of high-precision instruments (HP stations) may be preferable, budget permitting, but is only recommended when regular daily cleaning can be secured. Such stations are also desirable if used for quality assurance during a parallel measurement campaign. In this context, quality assurance means that a temporary or permanent HP station is set up next to a remote Autonomous station at a site where high-quality maintenance (and possibly grid power supply) is guaranteed. This way, the *a posteriori* corrections described above to overcome the systematic deviations of the RSI photodiode sensor can be validated and the overall measurement accuracy determined.

Another important use of HP equipment is as the main weather station once the solar power plant becomes operational, and is therefore manned on a daily basis.

In any case, the weather station site should be prepared with foundations for the instruments to make sure that they stand on firm ground that will not move during the measurement campaign, and with a fence to prevent humans or animals to enter the site and damage or alter the installations.

A site visit is recommended at the very end of the site preparation to ensure that is has been done correctly. The qualified personnel who will install the weather station shortly after will normally have only a short stay on site, and will not be able to correct infrastructure problems.

12.1.3 Ancillary meteorological and other measurements

Additional meteorological variables that should be measured are

- Temperature and Humidity
- Important information for the design of cooling systems in CSP plants as well as module efficiency in PV plants.
- Barometric Pressure
- Important information for the design of cooling systems in CSP plants.
- Wind Speed and Direction

- Give important information for the design of sufficiently strong and rigid collector or heliostat supports, and about the expectable occurrence frequency of high winds, which may result in plant shutdowns.
- Precipitation
- Allows estimations of water availability for cooling and mirror cleaning, or for the design of eventual drainage systems and can deliver important information on soiling on radiation sensors or solar collectors.
- Atmospheric Visibility
- May give a hint to the near-ground aerosol loads, which is considered to be an important information for solar tower systems to assess the expected atmospheric attenuation of sun beams reflected from the heliostats to the receiver. The effectiveness of these measurements is actually contested, because visibility meters are made to detect bad visibility conditions only, which normally correspond to high aerosol loads, and thus low DNI and inappropriate solar resource conditions for CSP (Gueymard, 2012).

Optional measurements that might be considered are

- Exposure to site-specific outdoor conditions of those materials (steel, coatings, mirrors…)
- Intended to be used by the power plant. This way, corrosive environments or other effects can be detected in advance.
- Dust depositing and mirror soiling tests help to estimate the collector or heliostat
- Cleaning requirements at the site under scrutiny.

12.2 Data acquisition guidelines

12.2.1 Measurement site selection and preparation recommendations

Selecting an appropriate site for an automatic meteorological measurement station is critical in order to obtain accurate and representative meteorological data. In general, the site should be representative of the whole area of interest, and should not be affected by obstructions like mountains, buildings or trees. Guidelines for site selection are contained in the WMO Guide to Instruments and Measurements (WMO, 2008) and are summarized in the following paragraphs.

12.2.1.1 General requirements

- Dimensions should be at least 10×10 m², with a recommended free area of 25×25 m².
- The base surface should be a firm and horizontally leveled ground.
- Accessibility should be granted by car or truck, but should not offer public access. Preferably, a fence should be constructed around the site.

- Remote data transmission is essential and can be secured by a landline connection or by a mobile phone network. The signal strength and integrity should be checked before installing the equipment on site, e.g. using a regular mobile phone. Where none of these options exist, satellite data transfer might be considered.
- No power lines should cross the site, either underground or above ground. If any part of the Weather Station touches a power line, serious injury or death may result. Local utilities should be contacted for the location of buried utility lines before digging or driving ground rods. Also, electric fields of alternating current power lines might disturb the measurements by inducing noise signals in the cabling of the station.
- Bushes, trees and other high-growing plants should be avoided or, where necessary and responsibly feasible, trimmed or cut down. The site may also be filled up with gravel to facilitate keeping it clear and less susceptible to regrowth.

12.2.1.2 Additional requirements for measurement of solar radiation

- The location must be free of any obstruction above the sensor plane (2.0 m off ground), because any obstruction above the horizon affects the measurements and leads to errors. At sites where it is not possible to avoid obstructions, complete details of the horizon and any obstructions should be included in the description of the station to facilitate a subsequent assessment of their impact.
- No direct shade on sensor should occur at all times of the day or year.
- No parasitic reflections on the sensor should occur at all times of the day and year.
- No artificial light source should exist in the field of view of the sensors.
- Construction features that may attract roosting birds should be avoided, unless spike strips are used.

12.2.1.3 Additional requirements for measurement of wind

- Wind sensors should be installed on a tower at a standard height of 10 m.
- The station should be located at least 10 times its height away from any obstacle in the environment.
- The topography of the site should be carefully considered. Avoid narrows, mountain flanks and other sites that could be associated with untypical wind characteristics.
- Wind towers should be set up in the direction of the solar sensors where the sun never appears during the entire year (i.e., to the south in the southern hemisphere).

12.2.1.4 Requirements for measurement of temperature and humidity

- An open, horizontal area with 9 m in diameter around the station is required.

- The ground should be covered with short grass. Where grass does not grow, a natural earth surface is required.
- The instruments must be at least 30 m away from large paved areas.

12.2.1.5 Locations that should be avoided

- Low places where water accumulates after rainfall
- Erosion-prone areas
- Large industrial areas
- Proximity to any emitting source of dust, aerosols, soot or other particles
- Steep slopes
- Sheltered hollows
- Existing high vegetation, or risks of fast growing seasonal vegetation
- Shaded areas
- Swamps
- Areas with snow drifts
- Dry and dusty areas with a frequented road close by (particularly if it is a dirt road)
- Irrigated agricultural land.

12.2.1.6 Security and surveillance

To avoid theft or damage of equipment, as well as animal interference, the station should be protected as described below:

- A fence is highly recommended. It must be at a distance of at least twice the difference between instrument height and fence height.
- Recommended locations for the weather station are either a private property or the property of a public institution.
- For security and surveillance reasons it is recommended to have local staff near the station to watch the station at regular intervals and report possible vandalism, lightning damage, malfunction, etc.
- For added monitoring, surveillance and information gathering, a weatherproof webcam can be installed on the wind tower with an overlooking view over the whole site. This obviously assumes that the communication bandwidth is sufficient to handle a constant upload.

12.2.2 Measurement equipment operation and maintenance recommendations

A thorough operation of the meteorological station with regular maintenance of the equipment and frequent (daily) data check assures its proper functioning, reduces possible shortcomings thanks to early detection, and avoids or reduces the number and duration of data gaps.

12.2.2.1 General

A logbook should be provided to the technician(s) attending the station, who will be trained to fill it properly during each visit. Sometimes, when in doubt about the validity of data at a later time, the detailed information recorded in the logbook can be of the highest value. Normal or unusual events should be described. The possible presence of insects, nesting birds or animals at short distance needs to be known. Occurrences of localized dust clouds (such as caused by traffic on a dusty road), haze or fog should be mentioned. Any abnormal event, the condition of the instruments, infrastructure and environment should be documented on any occasion when such observations are made. The level of the instruments should be checked occasionally, particularly if their pedestal or the ground around it shows signs of alteration or erosion.

Any instrument maintenance should be done by qualified, trained personnel. The frequency and extent of maintenance visits also depends on the instrumentation and requires careful consideration during the planning stage of the measurement campaign. The cost of maintenance during a long-term measurement campaign can easily exceed the initial cost of the instrumentation. This has to be considered in the budgetary framework. Conversely, a lack of regular maintenance and cleaning could ruin the whole measurement campaign, with dire consequences.

12.2.2.2 Prevention from consequences of power outages

The equipment should be protected from failure following any power outage, by securing and checking proper operation of the uninterruptible power supply (UPS). It should be ensured that an alarm is sent when the UPS starts providing backup power, so that the situation can be remedied if the outage lasts long enough that the UPS stops working. Since the efficiency of UPS batteries tends to degrade over time and under severe environmental conditions, they must be tested at regular intervals (e.g., every 6 months) and replaced if necessary.

12.2.2.3 Instrument cleanliness

It is imperative that all radiometric sensors, but also other sensors, be cleaned at frequent, regular intervals, according to the sensor type and local conditions. Pyrheliometers, in particular, require daily cleaning when used at sites with high exposure to contaminants. Each cleaning and the state of the sensors should be documented and the measurement values should be checked to evaluate the effect of cleaning on the recorded values (as described in Section 14.1.2). Photographic records of anomalies (using, e.g., a smart phone) can be worth a thousand words.

12.2.2.4 Instrument alignment

Accurate alignment of sensors has to be checked regularly. Pyrheliometers (and their tracker) have to be properly aligned, with a stringent error tolerance of only 0.1° in pointing accuracy. Pyranometers and photodiodes measuring global and diffuse radiation must also be leveled perfectly. Any misalignment needs to be rapidly corrected and documented.

12.2.2.5 Sensor calibration recommendations

The proper calibration of any radiometer is a key factor that determines its accuracy from the first day. Calibration procedures have evolved over time, and are now more sophisticated than ever, thus keeping uncertainties as low as possible (Gueymard and Myers, 2008). This essential step should be performed by qualified personnel only.

Sensor calibration certificates should be traceable to a certified international reference calibration device (if done “internally”), or should be delivered by an internationally recognized institution (like WRC, NREL, DLR, CIEMAT, etc.) to demonstrate certified quality, if calibration is done at their facility. A detailed description of the calibration method and the calibration period should be available. The overall uncertainty of the instrument, under laboratory conditions, should be mentioned in all data files for further reference and better judgment of data accuracy.

Each radiometer should be calibrated just before or during installation of the weather station, and then on a regular basis, per the manufacturer’s recommendations. This allows monitoring and compensating a possible drift of sensor readings, and maintains a high level of data quality and reliability.

The calibration of RSI-type sensors should be done either on site or under climatic conditions comparable to those that can be anticipated at the prospected site. Most particularly, the aerosol and temperature conditions at the calibration site should be similar to those of the prospected site, since they both have a notable incidence on the RSI’s spectral effects to be corrected. This remote transfer of calibration between such distant sites should be known to be valid from earlier experience. Due to remaining inaccuracies in the sensor response under variable weather and aerosol conditions, the calibration period of RSI sensors should last at least approximately 4 weeks. If an on-site calibration is not possible, the local instrument(s) to be calibrated should be sent to an appropriate facility, and replaced by a temporary (and freshly calibrated) identical instrument to maintain continuity of the data stream. Additionally, a thermopile pyranometer for global irradiance can be operated in parallel to the RSI for continuous monitoring during the RSI calibration period, thus providing important information about the differing affinities for soiling of these instruments.

12.2.2.6 Data collection and measurement-parallel analysis

A program, algorithm or procedure should be available to enable automatic data collection, screen the collected data regularly for measurement failures, evaluate data quality in near real time, and perform data analyses. Rapid detection of measurement problems is an asset. This can be achieved with visual quality assessment tools (Wilcox, 1996). Incorrect or missing data can either be interpolated if the gap is smaller than 5 hours which is the standard used in the NSRDB (National Solar Radiation Dabatase) (Marion and Urban, 1995). Frequent and regular visual checks of the measurement data are useful to detect sensor malfunctions and other problems, see also section 12.3.2.

If developing such capabilities is beyond the reach of the analyst in charge of using the data, specialized data acquisition and quality management software should be obtained from commercial sources or an expert consultant should be hired to ensure continuous data quality checks. To secure utmost data accuracy, scientific corrections of systematic measurement deviations shall be devised. Furthermore, a procedure for analysis and correction of soiling effects should be included in the analysis software. If onsite cleaning cannot be made at the necessary frequency (particularly during periods of maximum soiling), an appropriate and automated (or remote controlled) cleaning device should be installed on the instruments.

12.2.2.7 Maintenance frequency

Weather stations with high-precision equipment should be maintained and the sensors cleaned on a daily basis to maintain the sensor accuracy. Maintenance time should be preferably during the morning hours and optimally before sunrise to avoid influencing the measurement data. Sensor leveling and tracker alignment should be checked, and any shortcoming documented and corrected. Desiccant cartridges of sensors and other equipment should be checked regularly, e.g. on a monthly basis.

Remote stations with RSI sensors should be inspected and the radiation sensor cleaned on a weekly to monthly basis, depending on the soiling risk of the site. Presence of soiling should be detected during the inspection visit. The inspection frequency should be increased if soiling is notable (>2 % change in measured values before and after cleaning) and is observed as a recurrent situation.

All cleaning and maintenance actions should be properly documented with exact date and time, also mentioning the person, type of action and any notable events. This facilitates tracking any data error, and significantly increases the trustworthiness of the data for research, validation and project financing purposes.

12.3 Accuracy and data analysis

Besides the continuous data quality screening during the measurement period that is intended to detect and remove errors and correct incorrect data, the data should be subject to an accuracy and uncertainty analysis at the end of the measurement campaign. All possible sources of uncertainty or inaccuracy need to be evaluated, and the overall accuracy of the measured data determined.

Especially the uncertainty analysis is often demanded by financing institutions or investors because it can be included in their financing models and gives valuable information on the project risk.

12.3.1 Uncertainty analysis

The determination of uncertainties is described in the Guide to the Expression of Uncertainty in Measurements, commonly referred to as GUM (BIPM, 2008). Measurement uncertainty is a term that refers to the fact that every measurement is only an approximation of the real measurand's value. GUM defines uncertainty as a "parameter associated with the result of a measurement that characterizes the dispersion of the values that could reasonably attributed to the measurand". The uncertainty U consists of two components: *Type A uncertainty*, U_A, is evaluated by statistical measures (e.g., the standard deviation of repeated measurements under the same conditions), whereas *Type B uncertainty*, U_B, is evaluated by other means (e.g., experts educated guess, manufacturer's specifications).

Each contributing factor is assigned a specific uncertainty. All individual uncertainties are combined into a total Type-A or Type-B uncertainty, according to the law of propagation of error (the formula below corresponds to type A, but it would be equivalent for Type B):

$$U_A = \sqrt{\sum U_{A,i}^2} \tag{2}$$

The combined uncertainty U_C is a result of the combination of Type A and B uncertainties:

$$U_C = \sqrt{U_A^2 + U_B^2} \tag{3}$$

The *expanded uncertainty*, which is the one that is the final measure given with the measured data, is the combined uncertainty multiplied by a coverage factor k:

$$U_E = k * U_C \tag{4}$$

For the most usual confidence level of 95 %, which means that 95 % of all values are within this deviation from the true value, the factor k is equal to ≈2.

In the case of solar radiation measurements, the Type-A uncertainty would mostly cover all sources of uncertainty that are **specific to the measurement instrument and procedures used** (calibration, installation, hardware characteristics, etc.). This uncertainty would be the same wherever and whenever the measurement is taken, and thus could be statistically assessed by measuring a constant irradiance from a calibrated light source, for example. In contrast, a Type-B uncertainty would result from factors that are **specific to each respective situation**.

The concept above can be described with an example of instrument alignment. A Type-A uncertainty would result from the uncertainty of the alignment control device, e.g. the leveling instrument, which would be the same in any place and time and not depending on the person who uses it. A Type-B uncertainty in the instrument alignment would result from irreproducible factors, such as the viewing angle with which the installing person operates the leveling instrument, or his personal use of this instrument. The resulting measurement errors cannot be determined, but are in a certain range that can be estimated and stated. Taking into account all known or already determined uncertainties of participating equipment, the remaining uncertainties can be deduced and estimated by means of a thorough analysis of parallel measurements, which should preferably be done with another, more accurate type of sensor.

For RSIs, such analyses have been performed and described by several institutions like the National Renewable Energy Laboratory (NREL), Sandia National Laboratories, the University of Oregon, the University of Almería, or the German Aerospace Center (DLR). Since the raw spectral response of the photodiode sensor is known to differ systematically from the true irradiance, different corrections have been developed and applied to the raw signal of the analyzed RSIs to improve the accuracy of measurement data. The most important corrections are described in (Alados-Arboledas et al., 1995; Geuder et al., 2008, 2011; King et al., 1997, 1998; Pape et al., 2009; Vignola, 2006). Moreover, a proper calibration of the RSI sensor head must be part of the analysis because the manufacturer’s calibration of the SI photodiode is not accurate enough (Geuder et al., 2008, 2009; King et al., 1997, 1998; Wilbert et al., 2010). Using RSIs without applying corrections and a proper calibration is categorically not recommended. Further investigations have been performed concerning transferability of calibration between different sites experiencing differing ambient conditions. Moreover, different correction functions and calibration procedures have been examined and compared (Geuder et al., 2010, 2011; Pape et al., 2009).

To the knowledge of the authors, four correction methods are currently in regular use for RSI measurements with corresponding calibration methods. They are listed and succinctly described here for the sake of subsequent accuracy analyses (details can be retrieved from the referenced literature):

- **US-1:** corrections based on (King et al., 1997, 1998; Vignola, 2006); one overall Calibration Factor is used for GHI, DHI and DNI, derived from merely GHI measurements;
- **US-3:** corrections based on (King et al., 1997, 1998; Vignola, 2006); contrarily to US-1, three Calibration Factors are derived separately, one each for GHI, DHI and DNI;
- **DLR 2008:** corrections according to (Geuder et al., 2008, 2010);
- **CSPS 2011:** corrections based on (Geuder et al., 2011).

The quality of the measurements, including correction algorithm and calibration, is judged on their capability to reproduce the reference observations from high-precision sensors. Since the quality of the calibration subsequently determines the remaining sensor uncertainty for each radiation component, different calibration methods and their time requirements have been examined by experts (in combination with the corresponding corrections).

Figure 12.5 shows the results of a separate calibration (minimizing the RMS deviation) of the global and diffuse radiation components, expressed as a relative deviation of the Calibration Factor (CF) from its mean or from the pre-calibration reported by the manufacturer of the SI photodiode, respectively. In this survey, 23 RSIs have been examined. It is obvious that the Calibration Factors for the global and diffuse irradiance components are not identical, and may differ by approximately ±2 %. The reason for this difference is probably a specimen-specific varying spectral sensitivity of the photodiode. These results demonstrate why the use of only one single Calibration Constant for all three radiation components is not advisable.

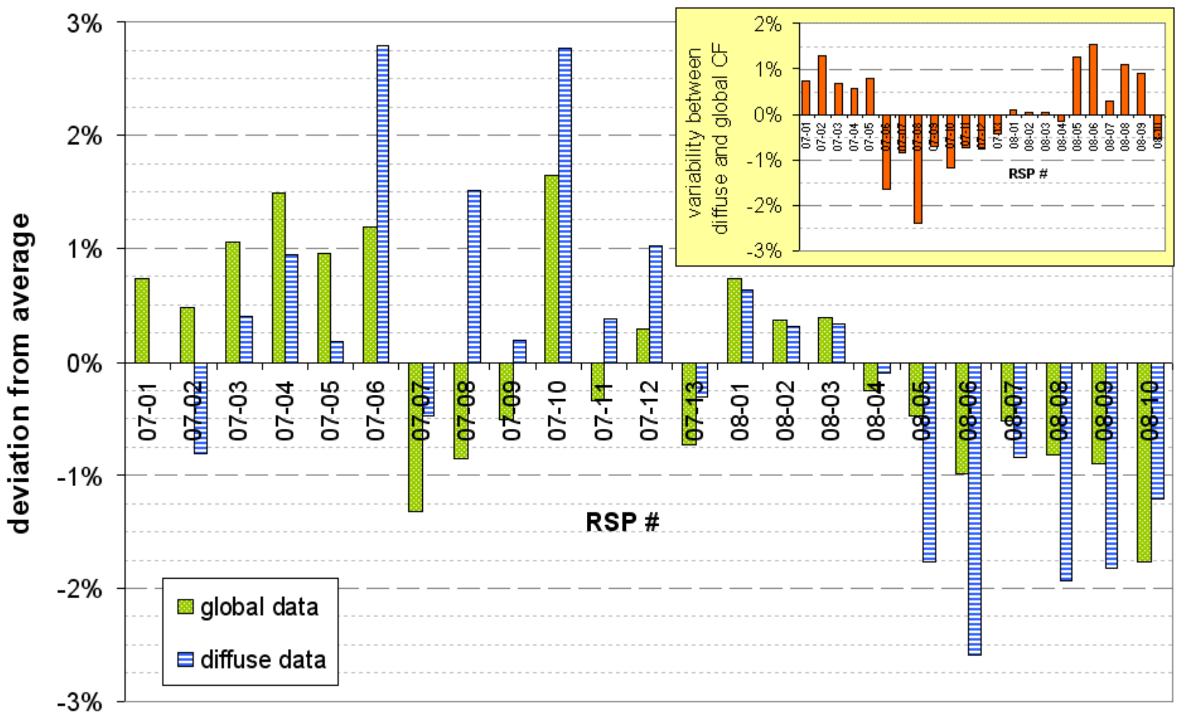


Figure 12.5 - Variability of the Calibration Factors (CF) for Global and Diffuse radiation relative to the pre-calibration from the manufacturer of the SI photodiode (LI-COR Inc.) as derived from 23 RSI specimens. The CFs of each particular RSI are clearly not identical for the two radiation components (Geuder et al. 2008).

Due to the restricted spectral sensitivity of the SI photodiode, RSIs are usually calibrated under natural sunlight to avoid additional uncertainties and errors originating from differing spectra of artificial radiation sources. When using natural rather than artificial conditions, the calibration process necessarily requires a much longer period to capture and include all relevant spectra for each radiation component. The calibration must result in certain instrument-specific CFs that would be ideally independent from prevailing atmospheric conditions, season and site where the calibration takes place. However, when conditions significantly differ between the intended calibration location and the actual deployment site (e.g., a high mountain site with clear skies vs. a sea-level site with frequent haze), problems arise due to spectral mismatch and other factors (Myers, 2011). In such cases, a local calibration against a traveling reference instrument should be organized.

The normal calibration routine consists of long-term comparisons (several months to more than one year) between the RSIs and one or more reference instruments (e.g., a high-performance thermopile pyrheliometer). Calibration Factors can thus be determined for different intervals within the long-term period: Figure 12.6 presents the relative deviation of CF when derived at daily, weekly or monthly scale, compared to the average value over the whole period. In this case, the comparison was performed between the DNI component measured with an RSI and that from the German Aerospace High-Precision meteorological station at the Plataforma Solar de Almería (PSA). Daily CF values can be erroneous: errors of ≈7 % may result when the calibration is performed by chance during an extremely unsuitable day. With a one-week period, erroneous values of nearly 5 % may still be reached, unluckily. The error decreases under ≈1 % (which is also the calibration uncertainty for usual field thermopiles) for calibration periods of more than 4 weeks. Therefore, calibration periods of no less than 4 weeks are recommended.

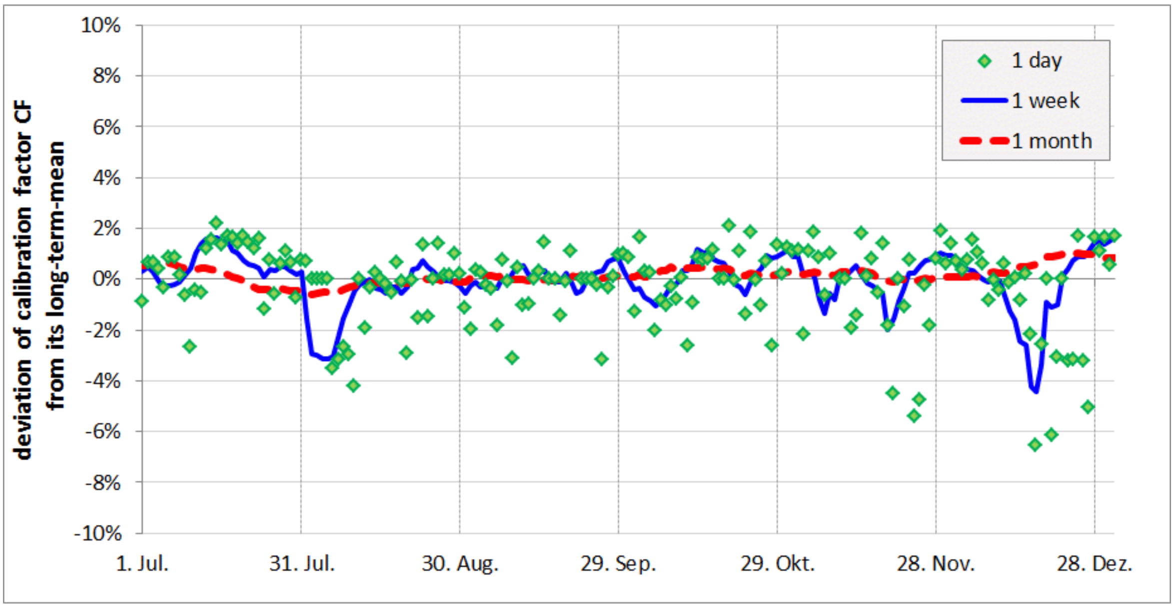


Figure 12.6 - Relative deviation of the resulting RSI Calibration Factor from its long-term value for different durations of calibration process within a period of 6 months (summer to winter).

For an evaluation of the drift of the LI-COR Inc. photodiode sensitivity over time, the change in CF of nine RSIs has been monitored between their first and second calibration instances (both by DLR at PSA); the latter occurred 24 to 45 months later than the former. Figure 12.7 indicates a drift of less than ≈1 % for each examined sensor (each bar represents a single instrument), which is the same order of uncertainty in the calibration of usual field pyrheliometers. The manufacturer (LI-COR Inc.) of the SI photodiode specifies a sensor drift of less than 2 % per year. In this case, the experimental results confirm the manufacturer's specifications (which may actually be on the conservative side).

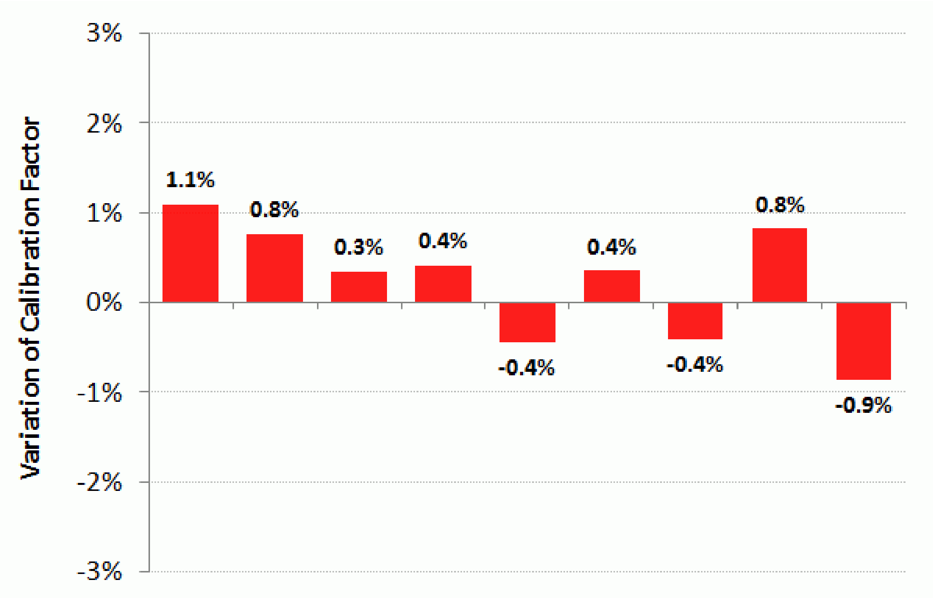


Figure 12.7 - Long-term variation of the DNI Calibration Factor of nine RSI specimens, expressed as the relative change in their original CF after 2 to 3.75 years (Geuder et al. 2010).

With the calibration uncertainty of an RSI reduced, thanks to a thorough calibration process, and duly quantified, the remaining uncertainty in the measured data can be analyzed. To that end, the deviation of the instantaneous values of all three radiation components must be evaluated. Cumulative statistics, such as mean bias (MB) or root mean square deviation (RMSD) can then be calculated over the total comparison period. The total annual irradiation (sometimes also expressed as annual mean daily value over 365 days or mean hourly value over 8760 hours of a non-leap year) is one of the most interesting parameters for solar power plants, since it determines the annual power production, and subsequently the Levelized Cost of Energy (LCOE).

Figure 12.8 shows the deviation between instantaneous RSI values and reference DNI values for a 10-minute time resolution, plotted against the intensity of the reference irradiance. To appreciate the improvement resulting from the correction process, the original response (raw DNI) is shown in addition to the corrected DNI (using the DLR 2008 method). The displayed data set is built from the observations of 23 RSI instruments. The distribution of the corrected RSI direct beam irradiance data is spread mainly within a range of ±25 W/m² around the reference value. Several outliers deviate by up to 100 W/m² or more, most probably because of a non-negligible spatial distance between the sensors, in combination with rapidly changing sky conditions. Depending on the correction and calibration methods, an absolute RMSD of 14 W/m² is reachable after correction. In contrast, the raw (uncorrected) DNI values show a clear overestimation of up to 150 W/m², mainly when DNI is ≈550 W/m². This is reflected in a much larger absolute RMSD value of 54 W/m², i.e. 4 times larger than after optimal correction.

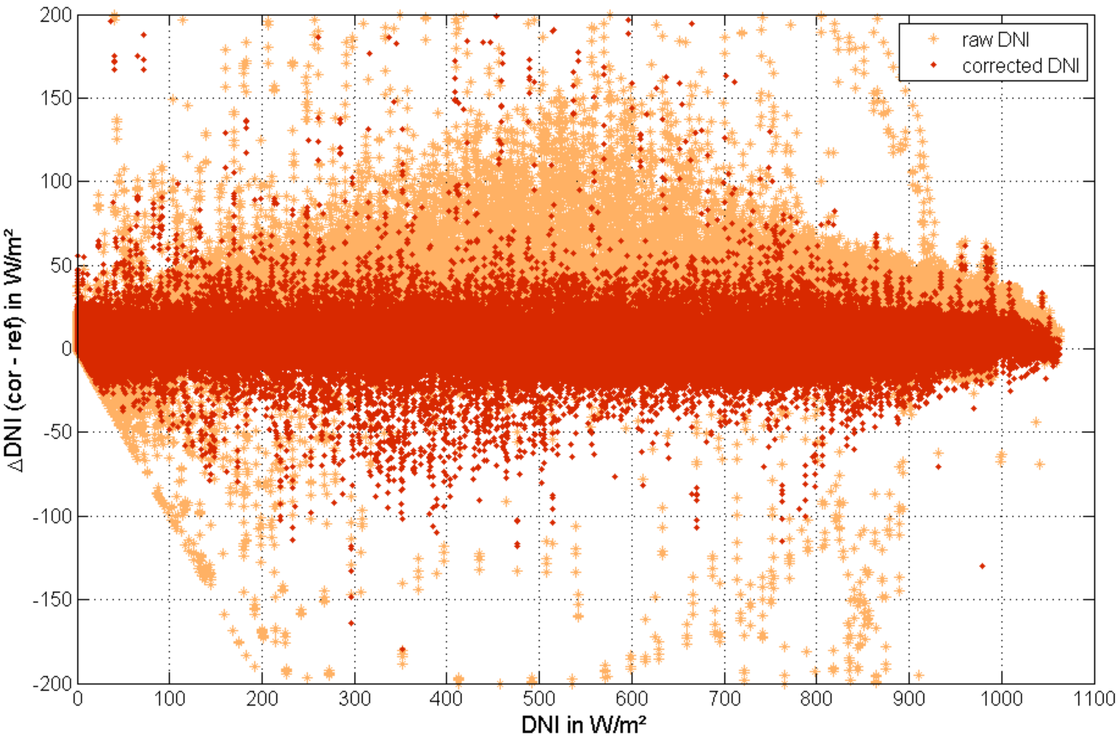


Figure 12.8 - Deviation of instantaneous corrected or raw RSI beam irradiance values from the reference value (10-min time resolution), using measurements from 23 RSIs.

Similar plots as in Figure 12.8, but for global and diffuse irradiance, are presented in Figure 12.9. For global irradiance *(*still using the DLR 2008 method), the distribution of the corrected data is reduced to within a range from -20 to 30 W/m² over its entire range with an RMSD of 10 W/m². The original (raw) global response of the LI-COR sensor results in a clear underestimate of the true irradiance, with typical deviations of up to -40 W/m² over 800 W/m² and with an overall RMSD of 17 W/m².

For diffuse irradiance, the CSPS 2011 corrections achieve a reduction of the original RMSD from 21 W/m² to a significantly lower value of 4 W/m², mainly due to the effective spectral correction. Therewith, deviations of raw values up to -40 W/m² are reduced to less than ±20 W/m².

The deviations of the instantaneous values plotted in Figure 12.8 and Figure 12.9 refer to a combined data set from 23 different sensors and represent the mean spread of accuracy before and after applying a single set of correction functions (DLR 2008); other corrections methods should yield similar results. The accuracy of one particular RSI specimen usually shows a somewhat narrower spread.

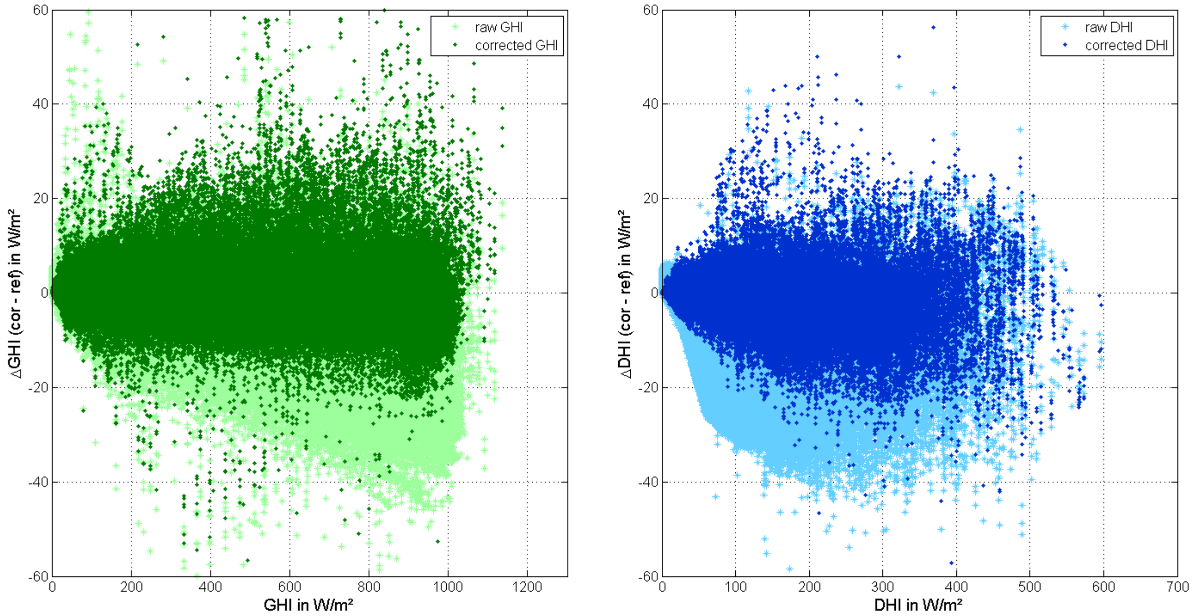


Figure 12.9 - Deviations of the corrected global (left graph) and diffuse RSI values (right graph) to their corresponding reference irradiance values, based on measurements from 23 RSIs.

To compare the performance of the four correction methods (including their implied calibration) mentioned above, and evaluate the improvement they provide over the raw, uncorrected data, the RMS deviations of 39 RSIs have been analyzed for each irradiance component. Figure 12.10 illustrates the mean, maximum and minimum values of the RMS deviations thus obtained. On average, the raw, uncorrected DNI values can be expected to deviate 32 W/m² (RMS) from reference measurements. However, individual instruments can show a wide spread around this value, with mean deviations between 15 and 57 W/m², mainly depending on the quality of the manufacturer's pre-calibration. For raw GHI, the expectable RMS deviation value is 17 W/m², averaged over the observed range of 6 to 28 W/m² for the different specimens. For raw DHI, the average RMS deviation is 21 W/m², with a more limited individual variation (17 to 25 W/m²).

Figure 10 also shows that the US-1 correction method with only one calibration constant derived for GHI effectively reduces the RMS deviations for GHI and DHI, and to a minor extent also that for DNI, but this approach provides the least improvement in RSI data. It even results in worsened DNI under adverse circumstances, as evidenced by its range of individual RMS errors that is larger than that of the raw data. The US-3 method yields RMS deviations in the range 14–35 W/m² for DNI, with a mean of 22 W/m². For GHI and DHI, the average RMS deviations are respectively 5 and 13 W/m².

The DLR 2008 set of corrections further lowers the RMS deviations of DNI down to between 8 and 32 W/m² (average 15 W/m²) the RMS deviations for GHI down to 5–16 W/m² (average 11 W/m²), and those for DHI to an average of 6 W/m². The best performance is obtained with the CSPS 2011 corrections and component-specific calibrations. The RMS deviations are 8–31 W/m² (average 14 W/m²) for DNI, 5–16 W/m² (average 10 W/m²) for GHI, and 4 W/m² average for DHI.

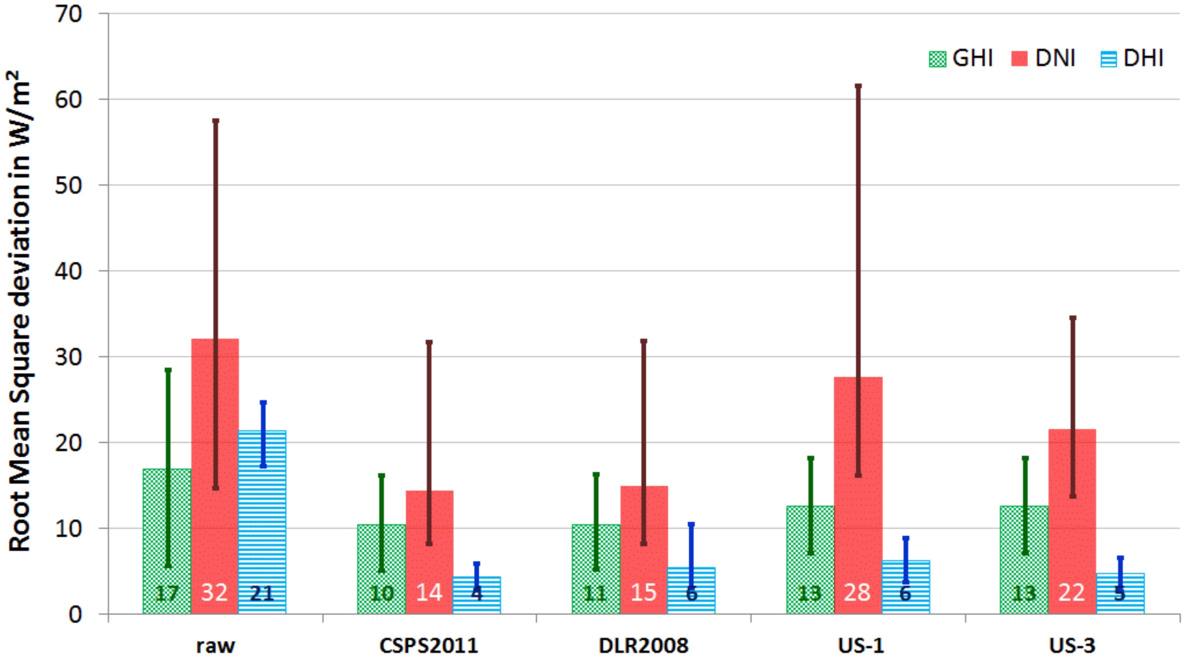


Figure 12.10 - RMS irradiance deviations for a time resolution of 10 min relative to reference thermopile sensors, derived from 39 RSI sensors. The deviations of the uncorrected raw values as well as those resulting from four different correction methods are analyzed and their mean values shown as thick bars. The individual range of values (minimum to maximum) are also shown as thin error bars.

The evaluation of the relative annual irradiations (Figure 12.11) yields similar results: The measured annual DNI with an uncorrected RSI is 0–7 % overestimated, depending on specimen, with an average of 3.3 %. On the contrary, GHI can be underestimated by 0–6 % (2 % on average). The annual DHI is underestimated by 11 to 20 %, mainly due to the low sensitivity of the LI-COR sensor at short wavelengths. The US-1 correction method improves the DHI results, but tends to deteriorate the DNI results, with annual deviations of up to 10 % for some specimens. Using the three calibration constants of the US-3 method considerably improves the latter results.

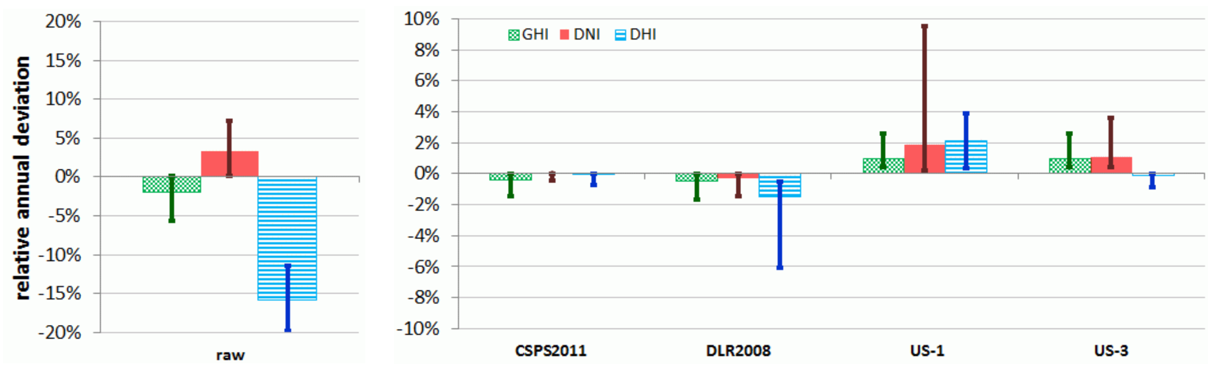


Figure 12.11 - Relative deviations of annual irradiation as acquired by RSIs compared to reference measurements with (right graph) or without (left graph) data correction (at differing scales).

In comparison with the US-3 method, DLR 2008 brings an improvement in the DNI and GHI results but a concomitant degradation in the DHI results. Finally, the CSPS 2011 method yields the lowest annual deviations: less than 0.5 % for all radiation components on average.

Analyses of long-term data (more than two years, except in the case of only a single specimen) result in similar values and identical conclusions. Variations of the calibration period (with implied seasonal changes) do not result in significant changes to the above results, inasmuch as the duration of the calibration is of at least one month. Additionally, the current (limited) experimental dataset does not show crucial changes when the correction methods are applied to RSIs after relocation to different sites or elevations. For six sample RSIs, Table 12.1 provides the relative change in annual DNI after on-site re-calibration at a location different from the primary calibration site. In this case, the re-calibration took place in the Middle East (hot and arid climate with frequent hazy skies), whereas the primary calibration site was at the Plataforma Solar de Almería (PSA), Spain — a more moderate climate with significantly less aerosol load and haze. The tested RSIs remained within ±1 % of their original calibration when adjusting the measurements with a proper calibration and specific site-adapted set of corrections. The only exception was unit #1, with a slightly larger variation of -1.4 %. The results from such a small number of instruments and sites that were examined in this limited investigation are of course not to be construed as definitive or of universal validity, especially considering that 1 to 2 years elapsed between the calibration at PSA and the on-site recalibration. A potential sensitivity drift and spectral effects from differing site conditions might be at play, but in this case at least, such potential effects would have canceled out almost completely. Although these results are particularly encouraging, further investigations would be necessary to confirm them.

Table 12.1 - Relative change in annual DNI for six RSIs after on-site calibration in a hot and arid climate in the Middle East, compared to a first calibration at the Plataforma Solar de Almería.

RSI unit #	1	2	3	4	5	6
Variation in annual DNI (%)	-1.4	+0.5	-0.2	-0.6	-1.0	-0.9

Other details and practical information, which might be needed to obtain good estimates of measurement uncertainty in practice, can be found in (Reda, 2011). It is important to point out that the uncertainty of a freshly calibrated instrument under laboratory conditions is only representative of ideal conditions of utilization. Under field conditions, which are contemplated here, additional sources of uncertainty arise, and may easily double or triple the laboratory uncertainties (Gueymard and Myers, 2008; Myers, 2005). Seasonal variations in field uncertainty are also to be expected (Myers, 2010b).

Table 12.2 - DNI Measurement uncertainties for thermopiles (TP) and silicon sensors (Si) (Stoffel et al., 2010).

Type A Error Source	U_{std}(%) TP#	U_{std}(%) Si^	Type B Error Source	U_{std}(%)	U_{std}(%) Si^
"Fossilized" calibration error	0.615	0.615	"Fossilized" calibration error	0.665	0.665
Data logger precision (± 50 μV/10 mV)*	0.5	0.5	Data logger bias (1.7 μV/10 mV)*	0.02	0.02
Si detector cosine response	0	0.5	Si detector cosine response	0	1.5
Pyrheliometer detector temperature response (D20℃)	0.25	0.05	Detector temperature response	0.25	0.05
Pyrheliometer detector linearity	0.100	0.10	Day-to-day temperature bias (10ºC)	0.125	0.10
Solar alignment variations (tracker or shade band) and pyranometer level for Si)	0.2	0.10	Solar alignment variations (tracker or shade band) and pyranometer level for Si)	0.200	0.20
Pyrheliometer window spectral transmittance	0.1	1.0	Pyrheliometer window spectral transmittance	0.5	1.0
Optical cleanliness (blockage)	0.2	0.1	Optical cleanliness (blockage)	0.25	0.1
Electromagnetic interference and electromagnetic field	0.005	0.005	Electromagnetic interference and electromagnetic field	0.005	0.005
TOTAL Type A**	0.889	1.382	**TOTAL Type B****	0.934	1.938

In what follows, uncertainty will always refer to the definition of expanded uncertainty at a 95% confidence level. For properly calibrated, installed and maintained field instruments, the NREL *CSP Best Practices Handbook* (Stoffel et al., 2010) estimates the uncertainty of sub-hourly measurement data for DNI at 2.58 % with a pyrheliometer and 4.76 % with a RSI. Other authors are more optimistic, however. For instance, (Suri and Cebecauer, 2011) quote values of 0.7–1.5 % for hourly and 0.5–1 % for DNI measurements with a pyrheliometer, or 2–3 % for hourly and 1.5 % for annual values with an RSI, respectively, whereas (Meyer et al., 2008) state a "long-term" uncertainty of 3 % for RSI-derived DNI values. These RSI related values include the application of one of the correction methods reviewed above.

Uncertainties in global and diffuse irradiance measurements are somewhat higher, due to additional sources of error, which are caused by imperfect cosine response or thermal balance, for instance. Therefore, the indirect determination of DNI from the difference between the global and diffuse irradiances measured by two separate pyranometers has a much larger uncertainty than that for a direct measurement with a pyrheliometer. This indirect procedure is therefore not recommended. In parallel, it is stressed that the best determination of global irradiance is not obtained by using an unshaded pyranometer, as would seem logical, but by combining DNI measured with a pyrheliometer and diffuse irradiance measured with a shaded pyranometer with low thermal imbalance (Gueymard and Myers, 2009; Michalsky et al., 1999). The latter procedure is more costly, and therefore is typically only implemented at research-class stations.

To keep uncertainties as low as possible, the responsible in charge of the measurement campaign should make sure that the instruments are properly calibrated and installed, cleaned and maintained and that all malfunctions or irregularities that could not be avoided are properly documented. Typical factors that can increase the field uncertainty are:

- Bad sensor alignment (sun tracking and horizontal leveling)
- Insufficient sensor cleaning
- Unstable electric power supply
- Instrument deterioration (leaks, corrosion, brittle seals, unstable electronics...)
- Long-term effects of high temperatures and/or high humidity
- Bad cables or connections
- Parasitic electromagnetic fields (e.g. from power lines crossing the site)
- Local effects (e.g., shading).

The measurement uncertainty is an input to the overall uncertainty analysis of the solar resource data (long-term time series or TMY files) and derived exceedance statistics (P50, P90) that will ultimately be used for system design, energy production simulations, and financing. Because of the stringent bankability requirements that have become the norm in solar projects, the evaluation of uncertainties must be seriously substantiated. From the very beginning of a measurement campaign, this process can be started by:

- Documenting the selection of instruments
- Choosing a renowned company or institution to conduct or assist the measurement campaign
- Documenting sensor calibration with proper calibration certificates
- Meticulously documenting the instrument installation and alignment
- Performing and documenting regular sensor cleaning, maintenance and verification of alignment
- Cautiously and continuously checking data for errors and outliers
- Flagging suspect data, and applying corrections if possible, during and after the measurement campaign
- Stating and justifying the uncertainty estimate in a detailed report after the measurement campaign.

When these requirements are fulfilled, financing institutions and investors usually accept the uncertainty estimations. Depending on project size, the reported uncertainty may be reviewed by an independent expert for a second opinion.

12.3.2 Measurement data analysis

Generally speaking, measurement data analysis should follow the mechanism of a quality assurance cycle (Stoffel et al., 2010). The acquired dataset should constantly be assessed for its quality. This initial assessment triggers a feedback loop for operations, which should provide the necessary interactions, improvements or changes in operational procedures. These interactions directly affect the acquisition and quality of data, again being reviewed, and so on (Figure 12.12).

Figure 12.12 - Quality assurance cycle.

In the practice of solar resource monitoring, the measured data should be continuously screened during (and again after) the measurement campaign. This consists of automatic and manual test components:

- Check for instrument errors. This can partly be done automatically by integrating self-check routines in the hardware (e.g. low power supply, non-functional moving parts or other), partly by regular inspection on site, and partly by interpretation of measurement data by experienced operators
- Check for (random) erroneous data. This can partly be done automatically by checking the data for physical boundaries (e.g. solar irradiance above some physical limit, spurious changes over short time intervals, etc.), and partly by manual interpretation of measurement data by experienced operators
- Check for missing data (automatically or manually).

Whenever errors are detected, their cause needs to be identified and removed; the result of any action to remove errors needs to be closely observed again.

Measurements are recorded in comma-separated text files by most common data loggers. These consist of a file header, which usually contains information about the station and the recorded quantities, and time-stamped data in sequential order. An example of how such a data file may look like is given in Figure 12.13.

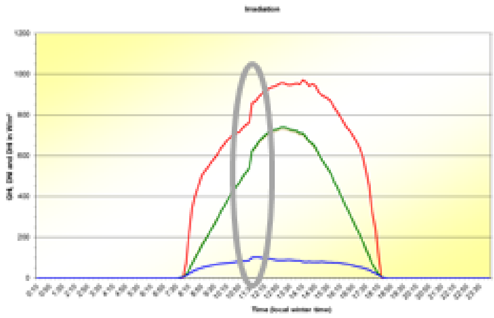
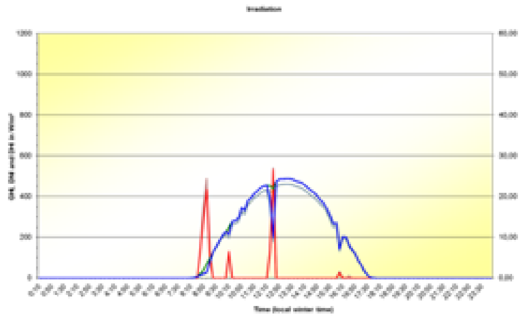
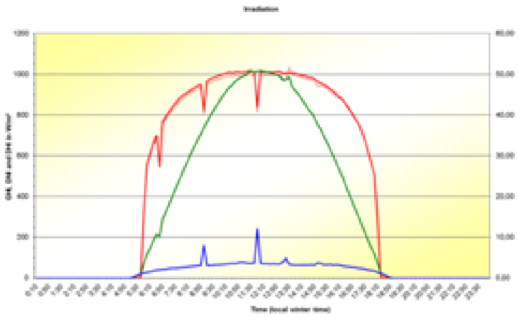
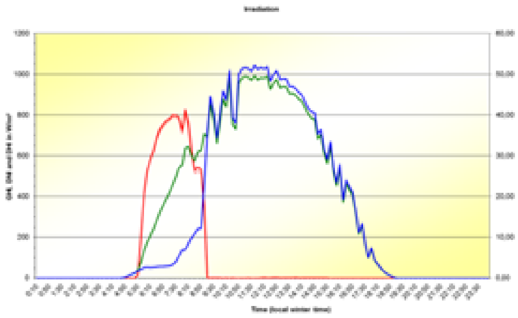
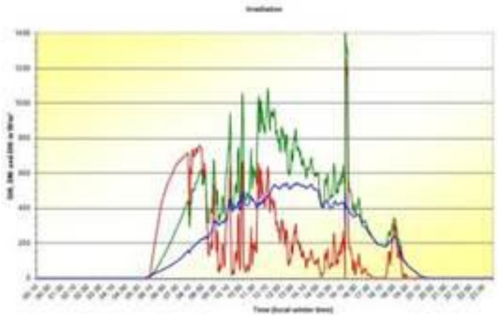
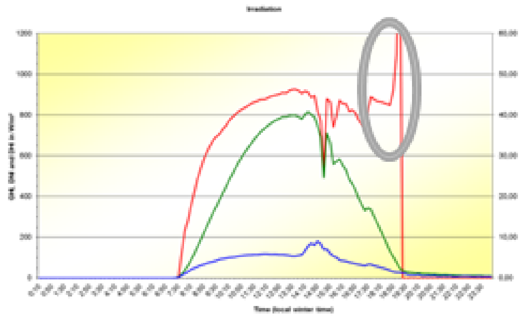
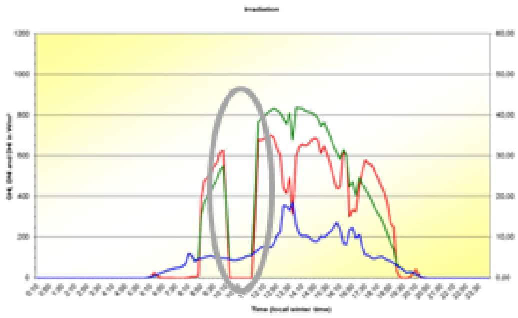
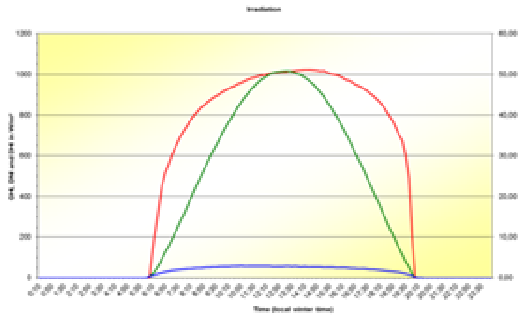
```
"TOA5","ProjectX
meteostation","CR1000","E1293","CR1000.Std.20","CPU:ProjectX_
2011-02-25_str.CR1","63995","Min10Avg"
"TIMESTAMP","RECORD","GHI_corr_Avg","DNI_corr_Avg","DHI_corr_A
vg","Sensor_Temp_Avg","Tair_Avg","RH_Avg","WS_WVc(1)","WS_WVc
(2)","WSgust_Max","LoggerVoltage_Min","LoggerTemp_C_Max","Suns
hineduration_Tot","Pressure_Avg","Rain_Tot","Error"
"TS","RN","W/m2","W/m2","W/m2","","C","%","m/s","m/s","","",""
,"","mbar","mm",""
"","","Avg","Avg","Avg","Avg","Avg","Avg","WVc","WVc","Max","M
in","Max","Tot","Avg","Tot","Smp"
"2012-04-17
07:00:00",54253,435.963,567.0132,226.8058,22.27,19.33,63.67,2.
595,10.74,4.125,12.76,18.23,10,512.4,0,0
"2012-04-17
07:10:00",54254,347.3723,536.334,137.2834,22.24,19.31,65.4,2.5
35,60.2,3.871,12.79,18.82,9,513.9,0,0
"2012-04-17
07:20:00",54255,396.3266,650.2709,112.1288,21.95,19.17,65.18,2
```

Figure 12.13 - Sample comma-separated ASCII data file.

These data files can be easily stored into a database or converted into spreadsheets. After a first step of quality control, consisting of automatic checks for violation of physical limits and boundary conditions, it is possible to visualize the data graphically, allowing for visual screening for outliners and measurement errors. Screening should be done by experienced operators who can identify irregularities in measurement from a rapid look at data curves. Some examples of frequently occurring errors are given in Table 12.3 below.

As mentioned earlier (section 12.2.2), more sophisticated visualization tools or analysis software exist for quality control. One of them is SERI-QC, which has been developed at NREL (http://rredc.nrel.gov/solar/pubs/seri_qc/), and has been used on a day-to-day basis by some research-class stations, such as those of the scientific ARM program (http://www.arm.gov/publications/tech_reports/handbooks/sirs_handbook.pdf?id=71). As an example, a sample output of SERI-QC is shown in Figure 12.14. SERI-QC can be used in tandem with DQMS, a commercial analysis tool and user-friendly software (http://www.dqms.com/).

Table 12.3 - Examples of irradiance measurement errors

 Extreme soiling at sensor cleaning detected: Large jump in the curves after sensor cleaning	 Tracking error / RSI rotation error during an almost entire day (blockage): GHI and DHI are identical on a clear-sky day, except for a few successful tracking or rotation attempts
 Tracking errors / RSI rotation errors: Small unrealistic peaks in DHI/DNI, but no corresponding marks in GHI	 Sudden tracking error / RSI rotation error: DNI becomes zero while DHI/GHI are identically high (at least under partially clear skies)
 Values above physical limits: Both GHI and DNI significantly exceed the extraterrestrial irradiance	 Wrong datalogger time/coordinates, resulting in incorrect DNI calculation from GHI and DHI
 Shadow on sensor by some obstruction: DNI and GHI are blocked, leaving only some DHI	 Sensor badly leveled: The curves are skewed toward morning or afternoon (here: to the afternoon)

red: DNI, blue: DHI, green: GHI; with brief interpretation of each error.

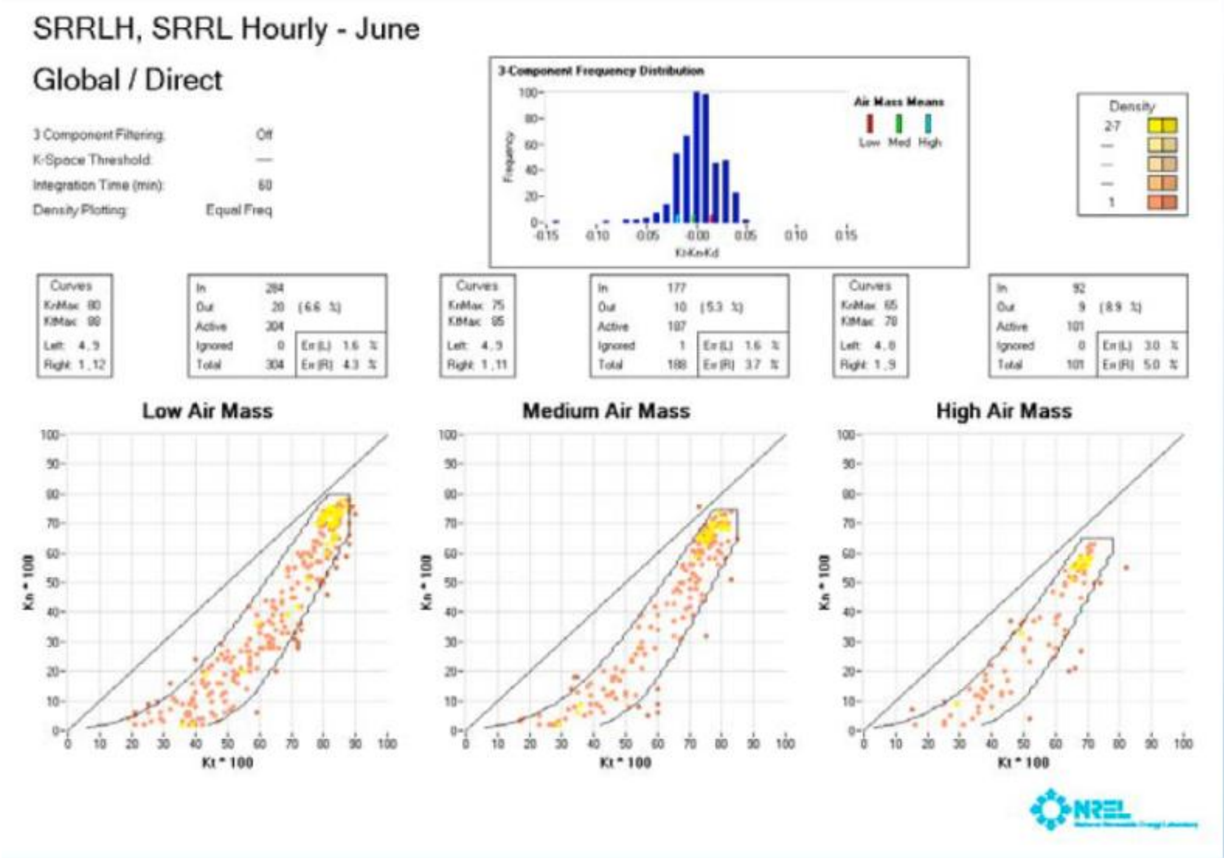


Figure 12.14 - NREL's SERI-QC software tool for radiation data quality control.

12.3.3 Combination of ground measurement and satellite data, creation of Typical Meteorological Year datasets

As already mentioned in Chapter 5 above, an important application of short-term ground observations is to enhance the value of long-term satellite derived time series, so as to obtain a high-quality and bias-free assessment of the long-term solar resource for the specific site under scrutiny. This way, satellite data can be "adjusted" to the site and enhanced in accuracy (Schnitzer et al., 2012). This process is often necessary to meet the stringent bankability requirements of financial institutions, particularly in the case of CSP projects. Various methods exist to conduct these corrections. Some of them have a physical approach, derived from sophisticated numerical weather prediction techniques, such as Model Output Statistics (Gueymard et al., 2012) or Measure Correlate Predict (Thuman et al., 2012). These methods have been used by the wind industry for a long time, to serve similar purposes, and are therefore well accepted by banks. Other techniques use simpler, purely statistical approaches, (e.g., Meyer et al., 2008; Schumann et al., 2011). There is currently no comprehensive comparison of the improvement potential offered by each of these methods, unfortunately.

After correction with one of the methods just described, the long-term modeled datasets, which usually consist of hourly or sub-hourly data over periods of 12–20 years, provide the basis for refined statistical analyses, leading to bankable solar assessment reports. The information that banks are primarily interested in is a series of statistical indices describing the worst-case scenarios in terms of exceedance probabilities, such as P90 or P95, i.e. the minimum annual (or seasonal) energy production of the solar power plant that will be exceeded at least 90 % or 95 % of the time in future years. Such results are dependent on the uncertainty in the radiation data (Schnitzer et al., 2012). By "adjusting" the long-term satellite-derived data series and removing their bias, the exceedance probabilities have a much higher confidence level (Gueymard et al., 2012), and thus can improve bankability.

Typical Meteorological Year (TMY) datasets can be derived from either "raw" or "adjusted" satellite-derived data series of at least ≈15 years. TMY data are constructed using proven statistical techniques (e.g., Marion and Urban, 1995), and are designed to represent the long-term average, or "P50" conditions. Since the worst periods are excluded by design, such data series do not have bankable value. However, they are heavily used by solar engineers to refine the design of their systems, simulate and optimize energy flows, and predict long-term average electricity production. TMY datasets are affected by the same uncertainties as in their original data. Therefore, using corrected or adjusted satellite data time series can lead to better TMYs than when using their original, uncorrected counterpart.

12.4 Implementation on the ground

When implementing a ground measurement campaign after the project location has been carefully selected, the following steps have to be taken:

- Find a good spot for the meteorological station at the project location or closely nearby (see section 12.2.1 for details)
- Clarify the ground property conditions and make sure that it is legal to set up a meteorological station there
- Find out if there are power lines, underground structures or other obstacles at that location
- Check/define the budget for instrumentation, maintenance and measurement related services (data quality checks, reporting, data evaluation, etc.)
- Select the appropriate measurement equipment based on budget considerations, local conditions on site, and maintenance possibilities (see section 12.1.1 and 12.1.2 for details)
- Find local maintenance personnel to clean the sensors, maintain the equipment and record all occurring events
- Find/select a measurement system supplier and service provider
- Prepare the measurement site according to the supplier's specifications (foundations, fencing, etc.)
- Install the measurement equipment
- Conduct the measurement campaign (see section 12.2.2)

In the chapters below the top 5 sites selected in previous chapters are analyzed in more detail.

12.4.1 Project 1

Project location name: Ausnek.

Figure 12.15 - Overview of Ausnek site (Project 1) from Google Earth.

Since the site is in a remote, off-grid area, it is recommended to rely on an autonomous RSI station for radiation/weather measurement.

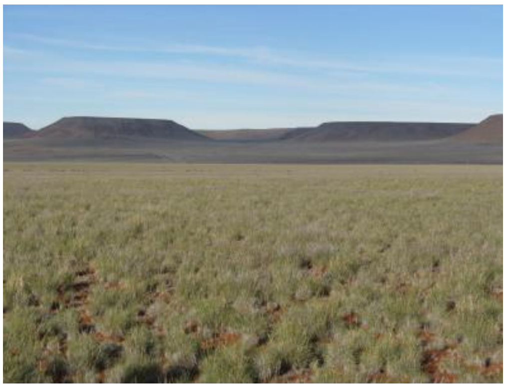


Figure 12.16 - Overview of Ausnek site (project 1) from Google Earth (left) and on-site photo (right).

The aerial picture of the site shows a ravine or temporary river, which is probably filled with water after rainfalls. This ravine is not a good site for a weather station. Otherwise, all of the remainder of the site seems to be flat, grass-covered terrain. The ground is reported as a Leptosols type, which should not constitute any problem. Taking into account the above mentioned recommendations regarding site selection and implementation of a measurement campaign, the site seems fit for installing a weather station. It should be located away from the temporary river and at a reasonable distance (200-500 m) from the road to avoid road dust deposition on the solar sensor, but within a distance that allows an easy access by car or truck from the road.

12.4.2 Project 2

Project location name: Kokerboom

Figure 12.17 - Overview of the Kokerboom site (project 2) from Google Earth.

Since this Project 2, like project 1, shows the characteristics of a remote site, it is again recommended to rely on an autonomous RSI station for radiation/weather measurement.

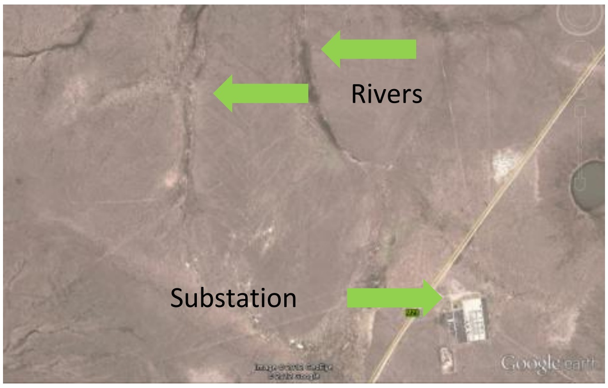


Figure 12.18 - Overview of the Kokerboom site (project 2) from Google Earth (left) and on-site photo (right).

The aerial view of the site reveals the presence of an electric substation on the other side of the road, as well as some temporary water streams. The ground for this site is reported to be of the Regosols type, thus imposing no special difficulties.

When selecting the final site for the measurement station, the proximity to the substation, power lines and rivers should be avoided (>100 m distance). Similarly, a minimum distance from the road (200-500 m) should be kept to avoid dust deposition due to traffic.

12.4.3 Project 3

Project location name: Hochland

Figure 12.19 - Overview of the Hochland site (project 3) from Google Earth.

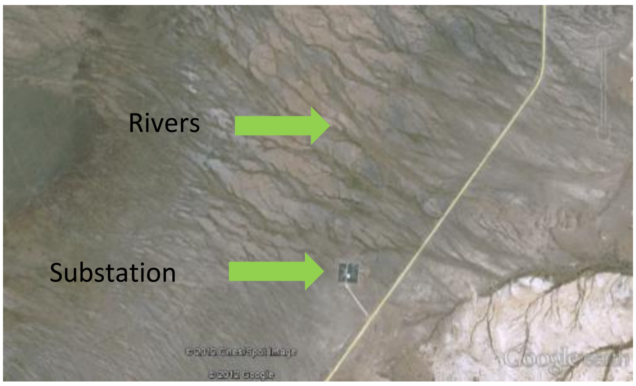


Figure 12.20 - Overview of the Hochland site (project 3) from Google Earth (left) and on-site photo (right).

The ground at this site is alluvium soil mixed with sand, gravel and calcrete plains. Therefore, the weather station should be erected where proper foundations can be constructed. The aerial view also shows a substation and some dry river beds in the area. The latter can potentially form temporarily rivers after strong rainfalls. The weather station should be erected far enough from these dry river beds and from the substation and power lines. Furthermore, a distance of 200-500 m from the road should be considered to avoid dust deposition caused by traffic.

12.4.4 Project 4

Project location name: Skorpion mine

Figure 12.21 - Overview of the site (project 4) from Google Earth.

As with the previous sites, an autonomous RSI station is recommended for this remote location.

Figure 12.22 - Overview of the site (project 4) from Google Earth (left) and on-site photo (right).

The aerial picture shows a mining area west of the selected area, and also an airport runway close in short distance. Furthermore, dry riverbeds are again observable, and a road crosses the selected site area.

The weather station should be located on the eastern side of the project site in an elevated area, far from low areas or dry river beds, sufficiently far from the mine, the airport runway, and from the road. The ground on the site (Leptosols type) does not create special issues.

12.4.5 Project 5

Project location name: Gerus

Figure 12.23 - Overview of two sites (project 5) from Google Earth.

Like for the other sites, an RSI station is recommended due to the site’s remoteness.

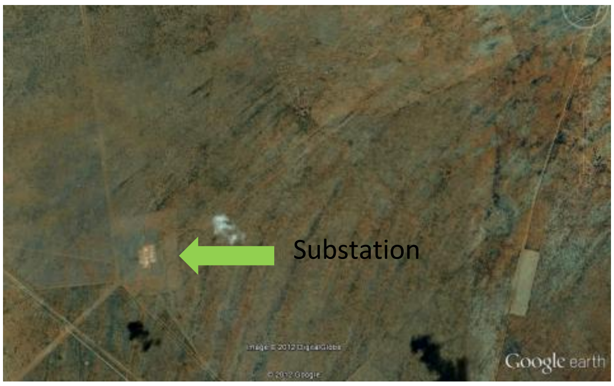


Figure 12.24 - Overview of the sites (project 5) from Google Earth (left) and on-site photo (right).

The aerial view again shows a substation close to the site area. As with the other sites, the weather station should not be located close to the substation, power lines, or the road. The on-site picture reveals some trees, bushes, scrubland, tall herbs and grass. The selected site for the weather station's surroundings must be free from trees and high bushes, particularly to avoid shadows on the radiation sensor at any time during the year, even in the future. The weather station's PV panel should not be shaded either.

The types of soil there (Calciosols and Regosols) are of no special concern.

13 Renewable Energy Procurement Instruments/Mechanisms & Financing Models

Despite a good overall energy policy, Namibia's lack of grid based renewable electricity is due to an absence of a specific renewable energy policy. Therefore, the present section provides a comprehensive comparative analysis of not only the different incentive systems for renewables but also the main alternative business models and their applicability for the case of Namibia.

13.1 Incentive Systems for Renewables

The different incentive systems for renewables can be divided into four main categories: fixed tariff, variable tariff, financing incentives and investment or tax incentives. Additionally, the first category may be split in sub-categories, namely, negotiated fixed tariff, fixed tariff and auction based fixed tariff. Similarly, the variable tariff may be split into market plus premium and green certificates and/or obligations.

13.1.1 Fixed Tariff

Firstly, the negotiated fixed tariff, which is defined for each project separately, encompasses a power purchase agreement directly negotiated with promoters for the pre-established duration. Note that, this is the current system in Namibia, under the Independent Power Producer regime, and Botswana.

If, on the one hand, this system will be fast to deploy, given the existing IPP system, stable for investors and guarantees an easy control of the capacity awarded, on the other hand, it will have the risk of attracting "opportunistic" developers interested in selling rights instead of building, requiring careful negotiation, and the risk to be largely dependent on incumbent.

To conclude, the negotiated fixed tariff will be the fastest model to deploy and can be efficient, considering South Africa bid results.

Secondly, the fixed tariff, which is the most applied incentive model in Europe, for example, in France and Portugal (initial regime in 2001), is typically applied through the establishment of an a priori defined tariff.

As main advantages, this system is stable for investors, easy to establish and less dependent on incumbent. However, it may be proven to be difficult to control capacity award, the promotion of "first come first served" policy is too risky relative to capacity implementation and there is a risk of setting the tariff too high and overpaying.

To conclude, the fixed tariff is very popular in many European countries but not recommendable given high risk of overpaying.

For last, through the application of the auction based fixed tariff, a quantitative target for renewables is realized by auction, where investors are invited to apply a bid for a renewable contract. Thereby, successful bidders will receive a fixed price in accordance with their bid.

Moreover, proven examples of the application of this incentive system are the South African Refit System, the new Italy regime (2012) and the Portuguese "win bid" regime.

In what concerns the respective main advantages, this system can be an efficient model if there are sufficient players or bidders. It will also be stable for investors, easy to control capacity awarded and less dependent on incumbent. Although, it takes time to design and launch, and there is an adjacent risk of raiders who want to sell licenses and that lower too much the price, making the projects not financeable.

In conclusion, this incentive system is an efficient mechanism, however requires relevant investment and time.

13.1.2 Variable Tariff

Firstly, the market price plus premium system is such that a renewable power generator receives two types of revenues: the market price of energy (variable) and a premium, which may be fixed, negotiated or auctioned. As an example of this system, the Spanish regime must be considered.

Moreover, if, on the one hand, this system is compatible with the multi-buyer approach intended by ECB, has the possibility to make bilateral agreements with mines (using hard currency) and enables the variability of price (peak vs. off-peak & rainy vs. dry), on the other hand, it presents higher risk for investors, requires involvement of mines and has an implicit risk of overpaying in case market prices grow significantly.

To conclude, the market price plus premium system is not recommendable in the short term given higher risk. However, when targeting the mines, it may constitute a good option (medium term).

Secondly, under green certificates and/or obligations regime, a minimum share of power coming from renewables is required for utilities. Therefore, eligible technologies are defined, targets are set, green certificates for each MWh of renewable energy are awarded to producers and if a utility is lacking certificates must pay a penalty. The best examples are given by the U.K. and Italian (old) regimes.

As main advantage, this system gives incentives only to the most cost competitive type of renewables. However, as disadvantages, it increases the risk for investors (as future value is unknown) and the risk of high incumbent power (depending on buying obligations), and it is a complex system to implement and monitor.

In conclusion, the green certificates and /or obligation system is not recommendable given the high risk and, therefore, it is being abandoned in many countries (for example, Italy).

13.1.3 Financing Incentives

Financing incentives encompasses various types of debt arrangements, with lower cost, accessible for middle income countries, such as, State guarantee, World Bank IDA or IBRD partial risk guarantee (PRG), DFI financing, AFDB financing, among others.

A good example of the application of this type of incentive system is that Cape Verde financed a 7.5 MW solar plant with a concessionary loan and a 25 MW wind project was also financed with World Bank support.

These types of incentives reduce the cost of debt for investors and are characterized by the respective complementarity with other types of incentives. However, the access to them may be limited given Namibia's middle income status and it requires public leadership and involvement.

In conclusion, financing incentives are very relevant as Namibia can have access to development banks or concessionary loans with low cost debt.

13.1.4 Investment or Tax Incentives

These types of incentives are applied in several countries as a complementary incentive and may assume different formats, such as, tax exemptions, subsidies, among others. One example of this is given by the tax credit mechanism established in United States of America.

The main advantages of these incentives are the adjacent limited cost for the Government, in the sense that without investment there would be no tax, and the complementarity with other types of incentives. Although, as disadvantage, it reduces short term Government budget revenue.

To conclude, investment or tax incentives are recommendable additional measures as reduces tariff costs.

13.2 Dimensions for Tariff Design

When considering the tariff design, four important dimensions must be considered, namely, currency, duration, time structure and counterpart. Therefore, once again, a description for each dimension will be presented as well as recommendations for Namibia's reality.

Firstly, tariffs may be paid in local currency or a "hard" currency, such as US Dollars or Euros, which may reduce the exchange rate risk in case of external financing. The alternatives regarding this dimension encompass: Namibian dollars, US dollars and Euros.

Hence, given that Namibia economy exports mainly in US Dollars and high investments in energy, it is recommended the tariffs to be set in US Dollars or to create a compensation mechanism for exchange fluctuations.

Secondly, tariff incentives typically have durations between 10 and 25 years, except in case of hydro projects, where the period is normally higher (up to 50 years). Thus, the available alternatives in what concerns the duration of the tariff are: 10, 20 (as in South Africa) or 25 (economic life) years.

For the specific case of Namibia, it is recommended the tariffs to have duration of 20 years as value of money after 20 years becomes too high and 10 years are only sufficient to recover investment and may imply higher short term tariffs.

Thirdly, the dimension of time structure may be divided into inter annual and intra annual (daily, weekly or seasonal). On the one hand, regarding inter annual time structure, tariffs may be stable, downward or upward and/or grow with inflation. However, downward systems facilitate market convergence and reduce the total interest cost. Thus, given that Namibia short term energy gap would be met with rental diesel and a coal power plant will be commissioned in 2017, it is recommended a two-step downward system to reflect the cost of rental diesel and coal in the short and medium term, respectively. Note that, this time structure will be further developed in the upcoming sections.

On the other hand, in what concerns intra annual time structure, energy tariffs vary according to time, between off-peak, mid-peak and peak time or, even, between months or seasons. Therefore, the alternatives to be considered are a fixed tariff, a peak/off-peak tariff and a seasonal tariff.

Nevertheless, given high dependence on hydro and available low cost off-peak energy in the region, it is recommended the tariffs to change between peak and off-peak and to be reduced during the rainy season (to be in line with marginal value).

Lastly, the payment risk will depend on the reliability of the counterpart. Normally, the local utility is defined as counterpart, however in some cases a public institution may guarantee the payments. In this line of thought, the alternatives to be considered include: a PPA with NamPower, a payment by ECB, a PPA with NamPower and State guarantee, and a Multibuyer (e.g. the mines).

To conclude, given Namibia's current single buyer model, in the short term, it is recommended the counterpart to be NamPower with State guarantee.

13.3 The Preferred Option for Namibia

Taking into consideration the, previously described, different incentive systems and the four dimensions to be taken into account in tariff design, four main alternative business models for Namibia were studied.

The first alternative targets a business model based on the participation of a development bank. The project would be developed by NamPower or a Strategic private partner with Government institutions (for example, REEEI), which would facilitate the access to low cost debt from development institutions. Additionally, the incentives systems included would be the negotiated fixed tariff, debt incentives and tax exemptions.

For last, regarding the tariff design dimensions, it would be preferred the adoption of US Dollars as currency and a duration of 20 years. In addition, a downward tariff would also be preferred, however as alternative it could be considered a tariff growing with inflation.

Secondly, a business model based on a downward negotiated tariff, which encompassed a negotiated IPP and PPA contract with private investors, was also considered. Thus, the incentives systems would be the negotiated fixed tariff and tax exemptions. Additionally, the tariff would most likely adopt Namibian dollars, even though the preferred solution is US dollars. It would also have duration of 20 years, a downward tariff (a two-step approach with the second step growing at a fixed rate) and NamPower as buyer with State guarantee.

The third alternative contemplates a Renewable Feed-in-Tariff (Refit) with auction. Similar to South African Refit program, this alternative pre-establishes a maximum Refit, which is determined through an auction, that is, the tariff is defined through an auction and from a maximum tariff towards a smaller one (downward). Thus, as incentive systems, it includes an auction based fixed tariff and tax exemption.

Lastly, the tariff would be in Namibian dollars, have duration of 20 years, grow with inflation or at a fixed rate and have NamPower as buyer with State guarantee.

The last alternative business model includes a market price plus a fixed premium. It is recommended only in the medium term given higher risk for investment, nevertheless, this alternative would contemplate a multi-buyer bilateral agreement plus a fixed premium, being the bilateral agreements with mines based on the market price.

Hence, this business model would have as incentive systems the market price plus premium tariff as well as tax exemptions. Additionally, the premium would be in Namibian dollars, the duration would be of 20 years, and a downward premium tariff and a Multi-buyer counterpart with ECB paying the premium were to be established.

All in all, due to the previously described respective characteristics as well as the electricity sector status, the first two alternative business models are recommended for Namibia in the short term.

For that reason, taking into consideration those two business models as well as the short term energy supply options and respective costs, further developed on the previous sections, the following Figure presents the required Feed-in-Tariff for each technology, relative to the rental diesel cost.

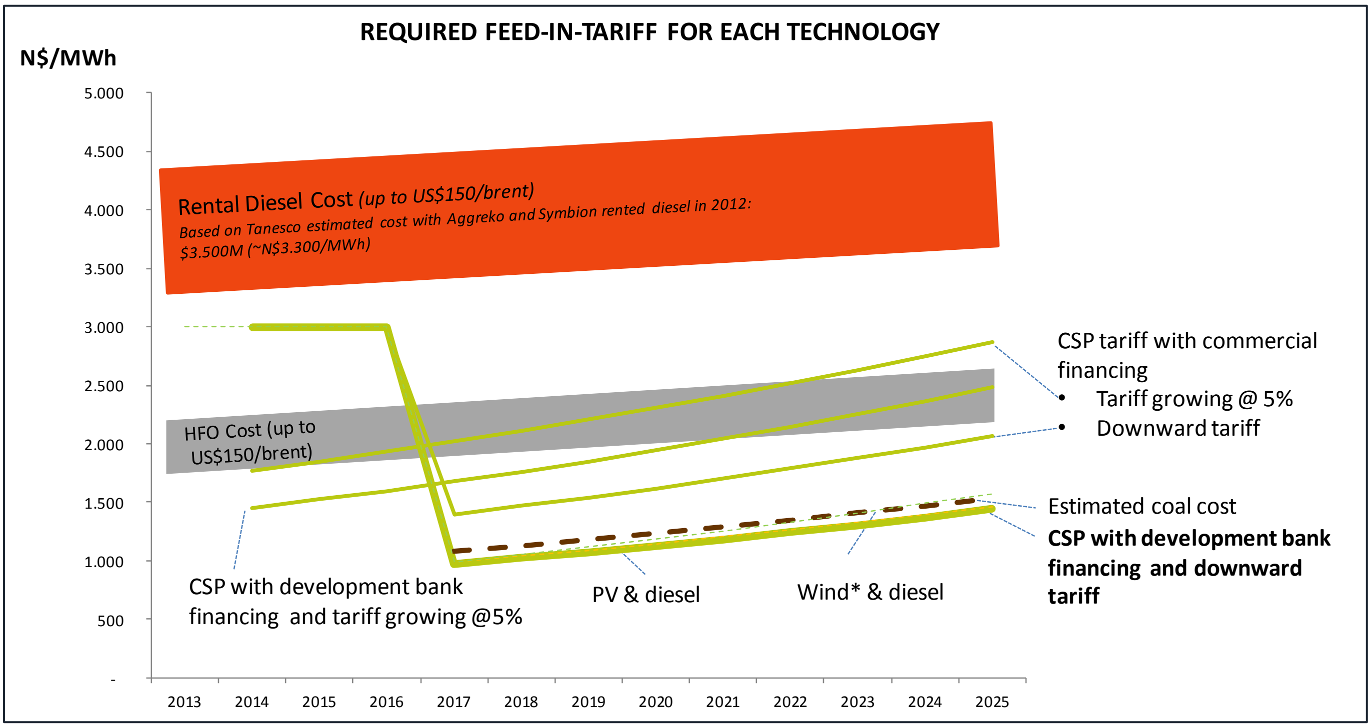


Figure 13.1 - Required Feed-in-Tariffs for Each Technology

Firstly, throughout the period under review, the Rental Diesel cost can vary, that is, it will start at a value ranging between N$3,300/MWh and N$4,318/MWh, depending on the variation of the brent price (assumed to be up to US$150/brent), and, then, it is assumed to grow accordingly with operating costs' increase.

In what concerns the Heavy Fuel Oil (HFO), considering brent prices forecast for 2013, it was assumed to have an initial cost of N$1,750/MWh to N$2,186 per MWh (considering a cost of US$150/brent). Nevertheless, throughout the years, both values are assumed to grow accordingly with operating costs' increase.

For the supply option constituted by Coal, due to the previously stated lead time, it was assumed that it would only be available in 2017 and would present an initial estimated cost of N$1,080/MWh, which would also grow according to operating costs' increase, either fuel or O&M.

Moreover, for both Solar PV or Wind and Diesel, the downward tariff was adopted and, therefore, until the end of 2016 (four years), the tariff would be set up for both supply options at N$3,000/MWh (a 10% discount to rental diesel). However, after this initial period, the tariff for Solar PV or Wind and Diesel would decrease to N$990/MWh and N$992/MWh[13], respectively, and would also start to grow with inflation (5%).

For last, regarding the supply option constituted by Solar CSP, it has been evaluated four types of tariff schemes. Thus, firstly, it was considered both commercial and development bank financing options, with an interest rate of 11% and 6%, respectively, which resulted on an initial tariff difference of N$320/MWh, that is, with commercial financing the required tariff would be of N$1770/MWh, opposing to N$1450/MWh with development bank financing. Note that, throughout the years, the tariff would grow at 5% inflation.

Additionally, it was also considered the possibility of developing CSP through the combination of a commercial financing and a downward tariff. In this case, from 2014 to 2016 (three years), the CSP project would enjoy a fixed tariff of N$3,000/MWh (10% discount to rental diesel), and, after, it would decrease to be cost competitive with the previous alternatives, that is, it and would be of N$1400/MWh. Note that, from that point on until the end of the tariff, it would grow at 5% (inflation rate).

For last, the required feed-in tariff for the development of the CSP project, with development bank financing and a downward tariff, was calculated. In this case, from 2014 to 2016 (three years), the CSP project would require a fixed tariff of N$3,000/MWh (10% discount to rental diesel), and, after, it would decrease to be cost competitive with all the previous energy alternatives, that is, it would be of N$975/MWh, which is actually less than the estimated coal cost. Note that, from that point on until the end of the tariff, it would grow at 5% (inflation rate).

To conclude, the CSP supply option with development bank financing is the preferred option, as it may become cost competitive even with coal, and a two-step downward tariff would allow renewables, such as, CSP, to be exported to SADC region with profit, after coal is installed.

13.4 Advantages of CSP for Namibia

A bet on CSP allows the production of cheap and clean energy, reducing imports and promoting a national cluster that creates jobs and wealth, that is, Solar CSP projects have significant advantages for Namibia which should be factored in during investment decisions.

On the one hand, taking into consideration the previous sections, CSP has direct advantages for Namibia, as follows:

[13] Tariff for wind calculated considering 40% of the energy will be sold a t off-peak hours at $N350/MWh throughout the period for 2,500 and 3,000 hours net equivalent generation;

- Namibia's world class solar resource and short term energy deficit outlook make CSP the most competitive short term energy alternative for Namibia

  Namibia has the second and best DNI solar radiation in the world, just after Chile, which along with short deployment time (compared to coal, hydro or natural gas plants) allows CSP investment to be quickly repaid, if used instead of short term diesel alternatives.
  Additionally, low operating costs allows CSP to become cost competitive even with coal in the medium term.

- CSP development in Namibia can have access to development funding for renewable energies in Africa and a CSP program could enhance Namibia's international visibility and credibility

  It would significantly decrease the cost of debt, increase the required tenors, which would result in lower tariffs, and increase the access to available financing (particularly important due to high investment requirements until 2017).

- CSP is a proven technology with more than 1 GW of plant capacity already installed

  Not only, Spain and the USA have more than 750 MW and 440 MW installed electric power, respectively, but also, energy storage has been already tested and deployed in many projects around the world.

- CSP can guarantee dispatchable peak power even for the night peak time and does not need to produce electric power at off-peak periods when the value of energy in the region is very low

  Note that, dispatchability can be guaranteed through storage or hybridization with biomass.

Nevertheless, on the other hand, the creation of a CSP cluster (Figure 13.2) could maximize CSP's advantages for Namibia, with a positive impact on the economy and education sectors.

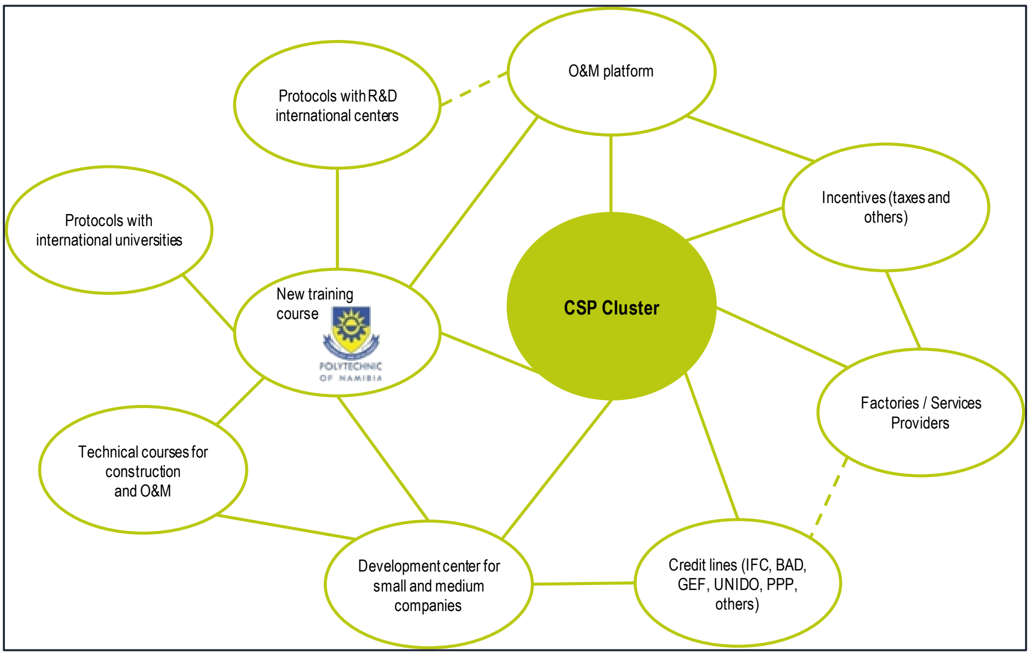


Figure 13.2 - Namibian CSP Cluster

Firstly, up to 40% of the investment in a CSP plant could be sourced from Namibia's economy, increasing demand and business volume for existing companies in Namibia, namely, construction, metallic structures, glass, among others, that is, for example, in case of a 150 MW CSP power plant, 40% of the total investment could be sourced from Namibia's economy with an estimated value of ND $3,000 million, as can be seen in Figure 13.3.

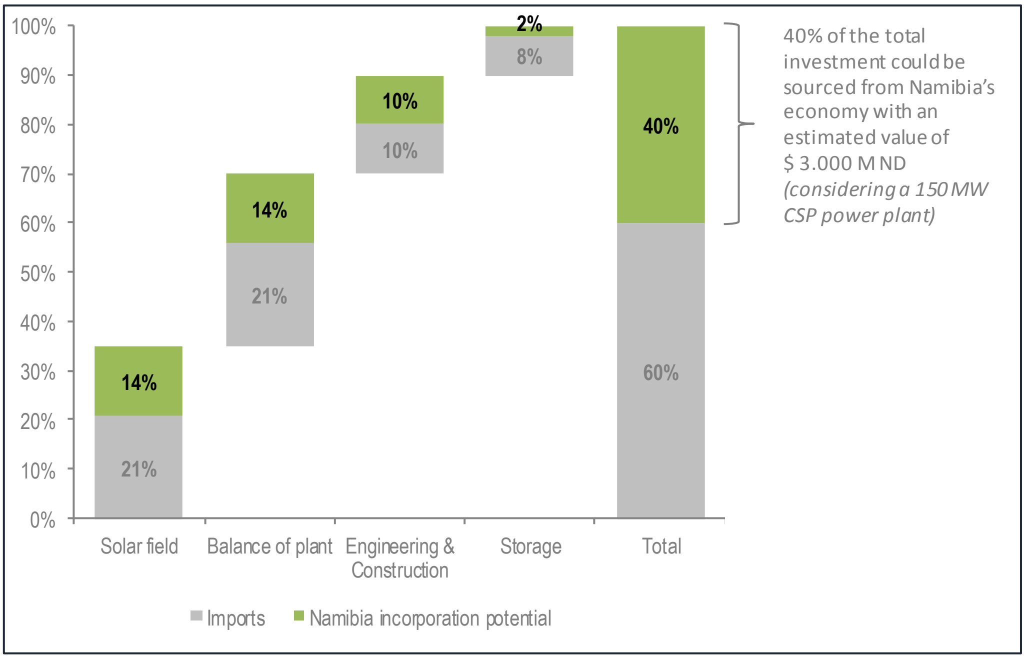


Figure 13.3 - Namibia Incorporation Potential; Source: Solar-Institut Jülich and SunBD;

Moreover, CSP has a strong potential for local job creation, which may be significantly increased if biomass hybridization is used. Once again, in case of a 150 MW CSP power plant, it could lead to more than 100 O&M permanent jobs and 1,700 jobs during the construction phase.

For last, the development of a CSP strategy in Namibia would create new need within the labor market, which by its turn would require the creation of new competences in education, from technological courses, for construction and O$M, to power plant engineering, that is, a CSP technology transfer program could enhance the renewable competences of Namibian research and education institutions.

13.5 Tackling Namibian Energy Gap

Given the previous analysis of the Namibian energy gap and the most suitable supply options, according to investment, cost, timing and fit with local installed capacity, the Figure 13.4 presents a two-step approach for capacity development.

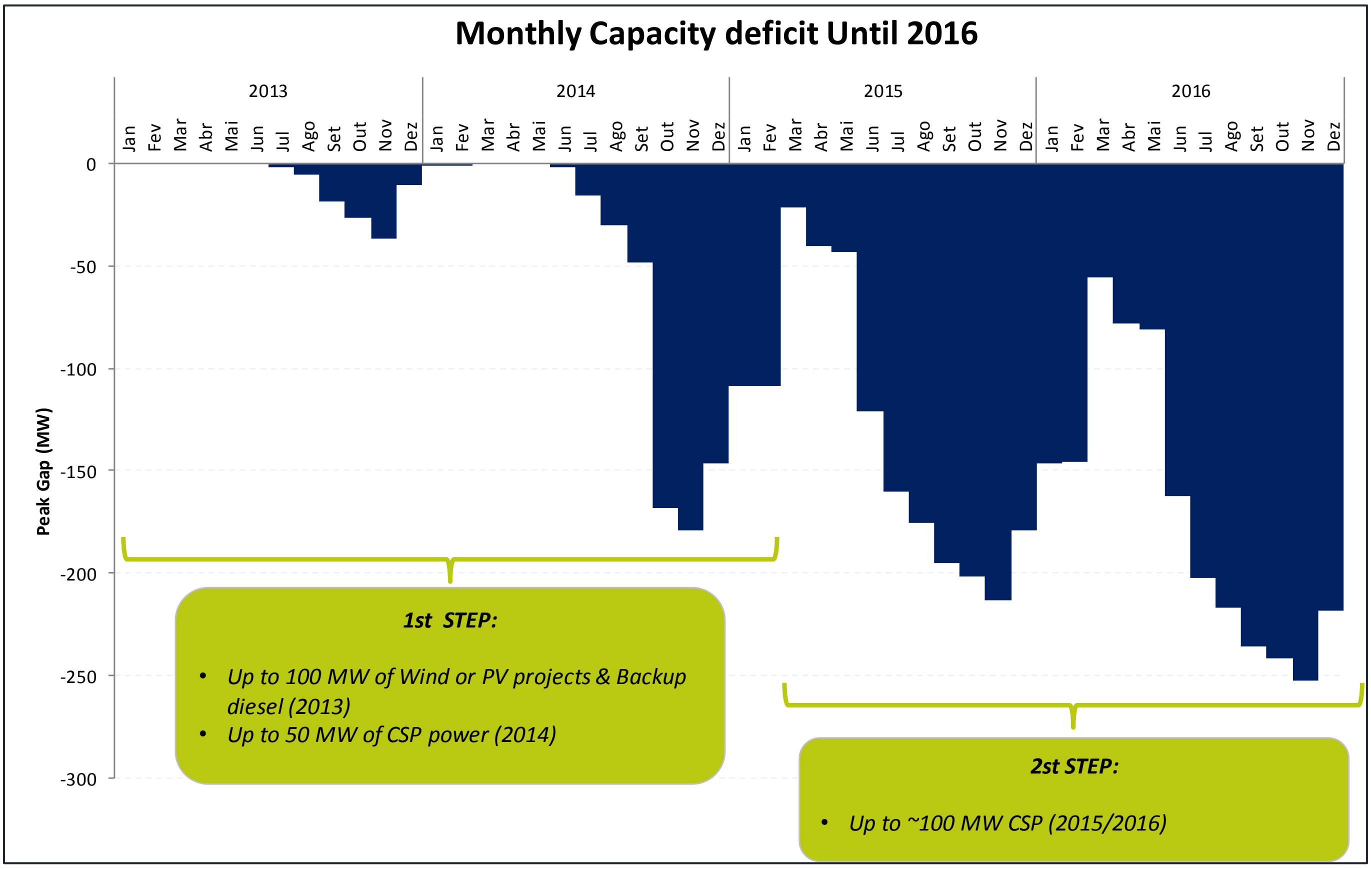


Figure 13.4 – A Two-Step Approach to Tackle Namibian Energy Gap

Note that, based on Namibia's Energy Policy, 75% coverage of peak demand with internal resources was considered. Additionally, the capacity of Ruacana was equally distributed between mid-peak and peak hours according to average water availability.

Hence, the two-step approach would consist on the development of up to 100 MW of Wind or Solar PV projects and backup diesel as well as up to 50 MW of CSP power projects (1st step) and ~100 MW CSP projects (2nd step). Note that, in what concerns CSP projects' development, it would be pursued with development bank financing, in both steps.

In addition, this approach would not only guarantee the fastest development of local capacity as well as the least cost enhancement but would also promote the development of renewable technologies in Namibia.

For last, given that, concerning the total cost of energy supply, the previous sections provide the required framework and analysis to confirm that this approach will ensure the least cost option, the following Figure is intended to provide the project timeline, confirming that Namibia's energy short term shortfall would be solved.

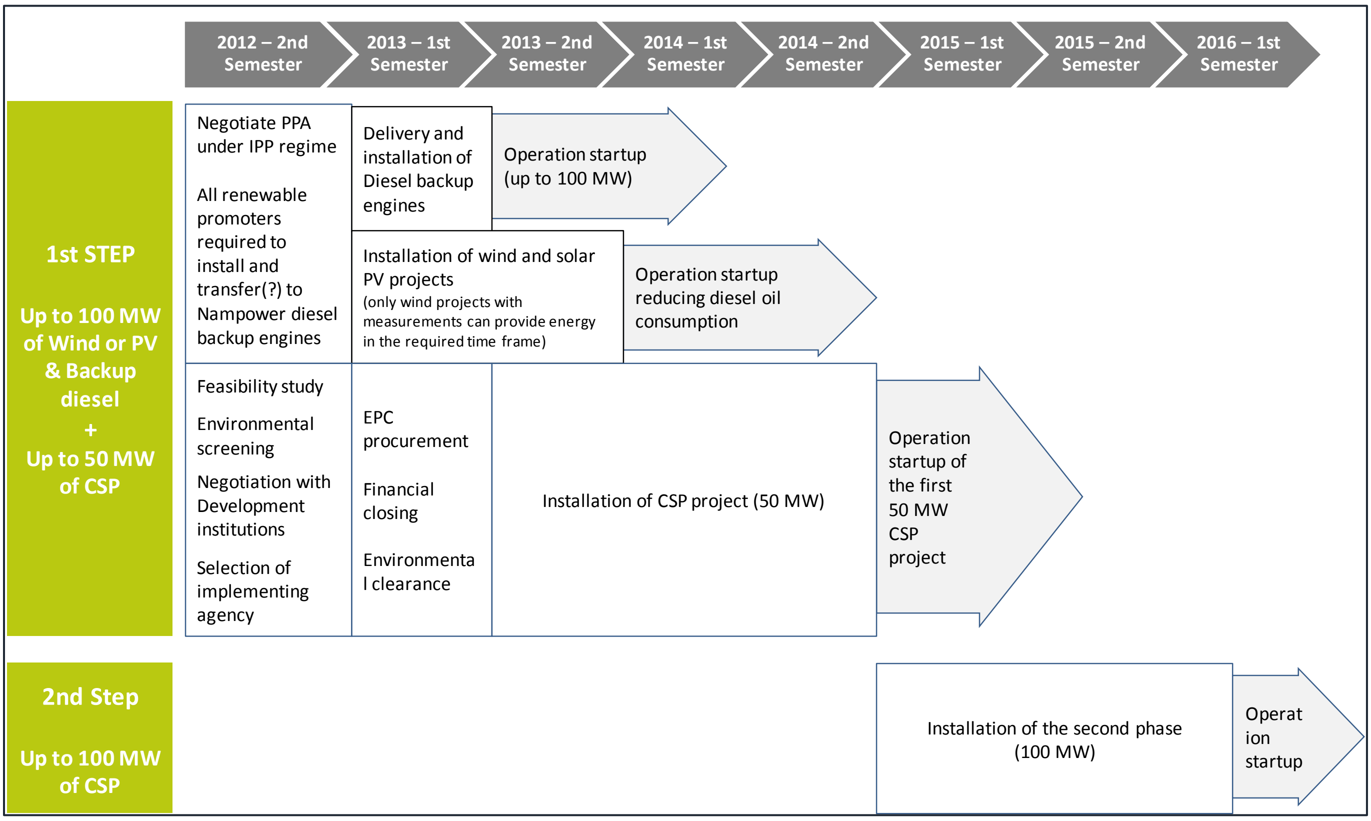


Figure 13.5 - Two-Step Approach Timeline

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