Electric Power from Kudu Gas: An Alternative to Epupa
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Earthlife Africa is a progressive environmental action group with members who share a commitment to contribute their skills, resources and experience to create a new society where protection of the environment is a priority. It is a voluntary, non-profit organization which works on a multitude of environmental issues, ranging from toxic waste, mining, water conservation and nuclear related issues to environmental education and legislation. The Namibia Branch was founded in 1990 and is an affiliate to Earthlife Africa, which has offices throughout Southern Africa.

Urgewald

Urgewald is a German non-profit organization which focuses on environment and development issues. Founded in 1992, Urgewald works closely with environmental and human rights grass-roots movements in the South to monitor and reform international development lending. Much of Urgewald’s work is devoted to advocacy on individual projects that have serious repercussions for the environment and local populations. In cooperation with local and international non-governmental organizations, Urgewald has played an important role in campaigning against destructive development schemes throughout the world and in redirecting aid to sustainable alternatives that pay due respect to the concerns of local people and the environment.

Urgewald’s basic theme is a new orientation of international development policies. This covers issues such as freedom of information, accountability, making project quality instead of quantity the priority and establishing mechanisms allowing for a participatory approach to development. Urgewald’s director, Ildiko Schücking, was awarded the Goldman Environmental Prize in 1994.
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SUMMARY

Kudu Gas as Alternative to Epupa Hydropower: A Summary

The Purpose of this Study
Since becoming independent in 1990, Namibia has been striving to upgrade and develop its infrastructure. A major component of this aspiration is the expansion of the country's power generating capacity. This the government proposes to achieve by having a second hydroelectric scheme constructed at the Epupa Falls on the lower Cunene River. A prefescasibility study has been completed and the feasibility study is now underway.

Remarkably, all attention has been focused on the Epupa scheme while other alternatives have been neglected. The Epupa feasibility study, which was supposed to provide an appraisal of other options, effectively ignored all of them, dismissing important alternatives in a few pages.

One possible alternative power-generating scheme is the development of the Kudu gas field, located offshore some 180 kilometres from Oranjemund. Appraisal wells drilled in the 1980's and first results from seismic surveys indicated that the field is a major find, both in size and gas quality, and thus represents an important natural resource for Namibia. Latest drilling results confirm these earlier optimistic appraisals, and plans for development of the gas field are going ahead, along with negotiations to open up the South African market. A 1993 joint report by the United Nations Development Programme and the World Bank on energy issues in Namibia already rated the potential of the Kudu gas field higher than that of Epupa, both economically and environmentally. The fact that this report was ignored entirely by the Epupa feasibility study and the cursory treatment of alternatives causes one to fear that these might not be considered properly in the feasibility study either.

Numerous studies have in recent years pointed out the enormous social, environmental and economic costs of large dams. Nevertheless, aid agencies and national governments have seldom explored concrete alternatives to these projects. This study is an attempt to do both: we document some of the effects, costs and hidden disadvantages of Epupa while also spelling out a specific alternative in the Kudu gas field. This is not to say that there are no other alternatives worth exploring: we envisage this study as a constructive contribution to discussion within Namibia and internationally, and are hopeful that it will inspire the Namibian authorities and public to debate a whole range of options.

Electricity from Gas
Given the Kudu field, electric power obtained from gas-fired power stations becomes a distinct possibility. Because gas-fired power plants have short construction times and low investment costs, they have become the method of choice in many developing and developed countries alike.

Using two possible scenarios for the actual size of the Kudu gas field, we have made an economic analysis of costs and benefits of building two kinds of gas-fired power plant: the inexpensive simple cycle and the more sophisticated combined cycle power plant. Based on this analysis, we recommend that the more expensive but far more efficient Combined-Cycle Gas Turbine type of plant be built. We estimate initial costs for a 300 MW plant at US$ 150 million plus gas field development, translating into a unit price of 2.2 US cents per kilowatt-hour under the conditions specified in the study. Additional turbines or plants can be constructed if and when needed. In a sensitivity analysis, we have checked the effect of changes in interest rates, capacity factor and gas fuel price on the final cost of electricity.

We conclude that Kudu gas can provide electric power at a cost of between 1.9 and
2.8 US cents per kWh. An identical analysis shows that electricity from Epupa would cost two to three times as much: 4.7–6.9 US cents per kWh. Based on a purely economic point of view, Kudu gas therefore seems highly competitive or superior to Epupa.

One may argue that Namibia could reap maximum benefit by developing both Epupa and Kudu in parallel. This is not true: The Kudu field is probably so large that gas use by a power plant would not diminish other potential sales and uses of gas, but would on the contrary make its development cheaper overall. Spending money on Epupa while not using the available Kudu gas for power would then amount to paying double for the same benefit (reduced offtake of gas plus full cost for Epupa).

Kudu versus Epupa: beyond Economics

Apart from immediate economic considerations, other important factors also tip the balance away from Epupa:

Reliability: Kudu gas would flow at a constant rate independent of season or rainfall. Gas plants are also very reliable technically, resulting in few stoppages and therefore a better return on investment. Epupa, by contrast, would be highly dependent on rainfall and in constant danger of running out of water. This problem was recognised in the prefeasibility study, resulting in two recommendations: to make the reservoir as large as possible (in order to alleviate seasonal fluctuations and periods of drought) and to build an oil-fired plant for emergencies. Both “remedies” make the problem even worse: the huge size of the lake increases costs, water wastage and environmental and social damage, while the oil-based backup plant voids any claim that Epupa would be independent of fossil fuel. If fossil fuel is needed anyhow, why rely on hydropower and imported oil when Namibia itself has a huge reserve of gas?

Environment: Gas-fired power such as provided by Kudu produces only a fraction of the pollutants emitted by other fossil fuel plants. Also, burning gas produces less carbon dioxide than any other fossil fuel and would, by substituting for coal, reduce overall CO₂ emissions in Southern Africa. Environmental damage due to underwater drilling appears to be small and is certainly much smaller than disruption caused by current offshore diamond mining operations.

In the case of large dams such as Epupa, on the other hand, environmental damage is massive: the Epupa prefeasibility study itself lists a whole catalogue of damaging consequences. For example: The Cunene River and its shores will be submerged for 75 km upstream of the dam. There is great danger of erosion around the reservoir, and fluctuating water levels would prevent any vegetation from re-establishing itself on the shores. The river downstream of the dam and the estuary are expected to suffer irreparable damage in flow patterns, loss of habitat, animals and plants; a number of these would become extinct and others endangered. Plant pests will probably infest the reservoir and decaying vegetation can lead to fish deaths and surging growth of plankton and macrophytes.

Social impact: As it would probably be located in the desert, a gas power station would have minimal impact on social life. Building the Epupa dam would entail the removal, possibly by force, of several thousand Himbas living in the area. The Cunene River and its shores are crucial to their semi-nomadic lifestyle, so that their culture and economic self-sufficiency would be ended by resettlement. Most Himbas are said to be vehemently opposed to the scheme even after being offered compensation and other benefits. What economic value is to be put on human rights and freedom of choice?

Besides the destruction of the Himbas, large lakes have long been known to be health hazards, leading to increased prevalence of malaria, hepatitis and tuberculosis. The Epupa prefeasibility
study warns that, besides these, bilharzia will likely be introduced to the area.

In this context, the question of who is actually in need of and benefitting from additional power should be addressed. At the moment rural consumption of electricity amounts to less than 10 percent of the total, while mines consume almost 50 percent. While no one contests the continued importance of mining to the Namibian economy, the question remains whether the planned large increases in electricity production really are to the benefit of the people.

Wasting water: Namibia is an arid country and water is precious. A Kudu gas power plant would need only negligible amounts of water. Epupa, on the other hand, would effectively sacrifice the Cunene’s water for power, because all available water would be needed for driving the turbines. As concluded in the prefeasibility study, neither irrigation nor future alternative use of Cunene water would be feasible. Moreover, the proposed 300-square-kilometre reservoir in such an extremely dry and hot region would result in a massive increase in evaporation to amounts far exceeding current urban consumption. In this context, it seems questionable that plans are being drawn up to divert water from the Okavango River to urban areas even while far larger amounts of Cunene water would be wasted through increased evaporation.

Secondary Benefits of Kudu

As recognised by both the developers and the government, Kudu gas would have a huge impact reaching far beyond power generation. Besides providing power more cheaply than Epupa could, development and use of Kudu gas would entail substantial benefits such as:

Secondary industries and job creation: Industries using gas as raw material or cheap fuel would become feasible, providing a much-needed basis for a manufacturing economy in Namibia. In building either Epupa or a gas power station, only a few thousand jobs would be created, and only for a limited time. Secondary industries, by contrast, would provide long-term job opportunities; the more industries get started, the more jobs there will be.

Exporting gas and power: Gas exported to the Western Cape could replace expensive coal both in power generation and in many existing industries. Studies indicate that substitution of gas for coal in the Western Cape would be viable and that gas could be delivered at a competitive price. Export of electricity may at some point become feasible as ESKOM of South Africa has voiced the possibility of importing power early in the next century. Power from either Epupa or Kudu could be exported; however, transmission to South Africa from Oranjemund would be shorter by some 1000 km than from the northern Cunene Region. Not only is the construction of transmission lines expensive, but much energy (and therefore money) is lost during transmission.

Construction time: Experience from other offshore gas fields is that, since field development and power plant construction can proceed in parallel, electric power from Kudu gas could be provided 4 to 6 years after construction starts. This timescale is similar to, or shorter than, the estimated construction time for Epupa.

Flexibility: Since it is very difficult to predict growth in demand, flexibility in implementation can avoid costly overcapacity or shortages. In the case of gas, power generating capacity can easily be increased when necessary by adding more turbines in the plant. For Epupa, no such flexibility exists: once construction starts, a fixed amount of power will become available after 6–7 years, independently of whether this is too much or too little at that point. Further expansion in capacity would require an entirely new project.
SUMMARY

Inflation: For a gas-fired plant, capital would be raised privately; for Epupa, loans and bonds would have to be raised by the government and SWAWEK. Financing of the entire project from SWAWEK coffers alone is highly unlikely, while international donors are becoming increasingly sceptical. Loans are strongly susceptible to inflation and currency depreciation and many “cheap” loans have cost the borrowers dear. Moreover, claims that Epupa is better because water is inflation-free are invalid: Kudu gas is as free of inflation and international price fluctuations as Cunene water.

Infrastructure: Much of the infrastructure needed to construct a power plant, house workers and personnel etc. is already in place at Walvis Bay and Oranjemund. For Epupa, infrastructure has to be developed from scratch hundreds of kilometres from the main centres.

Cost and time overruns: A study published recently by the World Bank on 70 large hydroelectric dam projects shows that, on average, the cost overrun was 30 percent of the quoted price. The size of the cost overrun increased with dam size. Time overruns are also very common. Regarding Epupa specifically, the UNDP/World Bank expresses doubt whether the cost estimates published for Epupa are realistic.

Solar and Wind Power

Kudu gas is of course not the only possible power source. Of the available other options, energy savings measures, wind energy and continued importing of power from South Africa seem most attractive. For the remote rural areas, solar energy is already competitive because it needs no expensive distribution system. Other possibilities such as large-scale solar energy exist and, while still too expensive, are rapidly improving in technology and coming down in price. A quantitative comparison of all these should be at least attempted instead of simply pronouncing them unviable.

A long-term and comprehensive energy plan for Namibia is urgently needed instead of considering options such as Epupa in isolation. Renewable and sustainable energy will of necessity increase in importance. Starting with small projects in rural areas and expanding these systematically rather than piecemeal could place Namibia at the forefront of international developments.

In short: A gas-fired power plant at Oranjemund supplied by the Kudu field seems superior to the proposed hydroelectric scheme at Epupa from every point of view.

The present facts and figures, while clearly preliminary in nature, provide a strong motivation for an in-depth study of Kudu gas as an alternative source for electric power. A complete study on this and other alternatives is needed urgently and should be completed before any decision is made about future power generation in Namibia.

The strongest argument in favour of Kudu is that, if the gas field is developed anyhow, erecting a gas-fired power station becomes far cheaper for Namibia than building a large dam from scratch. So much gas will probably be available that there is no good reason to develop both Kudu and Epupa in parallel.

We call on the governments of Namibia and Angola, SWAWEK and NAMCOR, international donors, the contractors for the Epupa feasibility study as well as the business sector to fully investigate not only the Epupa scheme but all other alternatives. In particular, the possibility of simply adding a power station onto the developed Kudu gas field should be regarded as a serious candidate to replace the Epupa project.
1 Introduction

Economic and population growth in Namibia result in rising demand for electric power. Depending on the availability of the main power plant at Ruacana, this demand already exceeds supply and is partially met by imports from South Africa. The gap between supply and demand is expected to widen further as urban and rural electrification projects progress. Namibian independence has also brought about a greater desire to be independent of imported South African power.

While there is currently an overcapacity of power in South Africa, demand there is estimated to overtake available capacity by the years 2000–2010, depending on future growth rates ([1], p. 4.12). This opens up the possibility of exports at that time but also highlights the dangers of relying on uncertain projections.

How are Namibian needs best met in this situation? Which alternatives exist? How do they compare in terms of cost, flexibility, environmental and social impact? Such questions must necessarily be asked and answered with great care before one of the possible candidate solutions is selected.

So far, only a single solution has received any serious attention: the construction of a hydroelectric power generating scheme near the Epupa falls on the Cunene River. The prefeasibility study for this project [1], which was released in November 1993, concentrates almost exclusively on Epupa: power from gas is not even mentioned in the study, while other alternatives receive short shrift.

This is not surprising, given that the terms of reference for the Epupa prefeasibility study were defined rather narrowly. For this very reason, though, the prefeasibility study does not provide reasonable proof that Epupa is in fact the best solution to the problem posed by Namibia’s expanding power requirements: it has not given serious consideration to the alternatives.

The most impressive of the neglected alternatives is the development of the Kudu gas field situated offshore of Oranjemund. For various reasons expounded below, it could well be a better option than the Epupa scheme. This view was first propounded in a report by the Energy Sector Management Assistance Programme (ESMAP) of the Joint United Nations Development Programme (UNDP)/World Bank [2], where it is claimed that the development of the Kudu gas field would be technically and economically feasible and possibly superior to Epupa.

The present study attempts to correct existing misconceptions that the building of Epupa is unavoidable and that it represents the best solution by default. It also tries to restore the Kudu gas field to its deserved position among the alternatives, namely as a viable option that should be considered seriously before any decision on building Epupa or any other type of plant is taken.

The lack of publicly available data on the characteristics of the Kudu gas fields and the current status of exploration and negotiations between the various parties make this a difficult task. Clearly, the facts and conclusions presented here can be preliminary only. In this sense, the present study in no way lessens the need for a comprehensive overall study, nor can it pre-empt the conclusions of such a study. Nevertheless, there is enough evidence and sufficiently firm ground for believing that, at the very least, the development of Kudu gas for power generation as an alternative to Epupa deserves serious attention. Judging by the present facts, the gas alternative is superior to Epupa economically and environmentally.
2. THE EPUPA HYDROELECTRIC SCHEME

In order to make this study accessible to the layman, concepts pertaining to the economics of power generation are explained in somewhat more detail than is customary in technical studies. Sections 2 and 3 give some relevant information and facts for Epupa and the Kudu gas field respectively. Two different gas power plant types are discussed briefly in Section 4, followed by principles of cost calculation in Section 5 and a detailed cost comparison of a Kudu gas-fired power plant with Epupa hydropower in Section 6. Other economic considerations relating to Kudu and Epupa follow in Section 7, while Section 8 sketches social and environmental issues involved. Section 9 briefly explains why development of Epupa in parallel with Kudu is not a good idea. We end with a short outlook for sustainable energy sources and the conclusions.

With the exception of Table 2, which should be studied, the technical discussions of plant types and cost estimates in Sections 4 and 5 can be omitted without loss of continuity. All costs are given in US Dollars.

2 The Epupa Hydroelectric Scheme

The Cunene river, forming part of the border between Angola and Namibia, descends steeply over the last part of its journey to the sea, from an elevation of some 1100 metres above sea level at Calque. The largest drop at Ruacana has already been exploited for hydropower. Not surprisingly, the next-most-suitable site is in the vicinity of the Epupa falls, some 60 km downstream from Ruacana, where a drop of about 200 m could be harnessed. This possibility was mooted repeatedly over the years and now forms the focus of governmental efforts to provide for future power requirements.

Following earlier hydrological studies, the Namibian power utility SWAKEK has since 1990 increasingly pushed this option, culminating in the commissioning of a prefeasibility study. Completed in September 1993 and made public two months later, this study [1] was accepted by Namibian and Angolan authorities, and the final feasibility study is now being undertaken by a consortium consisting of Norconsult, SwedPower, Burmeister van Eekhout and the Angolan firm Soapro. The stated aim is to complete the feasibility study by the year 1997 and construction is to start soon after.  

Both Norway and Sweden are playing a significant role in the Epupa project: funding for the prefeasibility study was provided by the Norwegian aid agency NORAD, while the feasibility study is funded in part by NORAD and the Swedish aid agency BITS (now merged with SIDA). The Norwegian firm Norconsult is taking a leading role in the consortium undertaking the feasibility study. Norwegian and Swedish firms would have a good chance of landing large contracts if the Epupa dam were to be constructed.

At the same time, the international community is growing increasingly sceptical about Epupa. Apart from environmental and other NGO’s, the World Bank has already expressed doubts [2], while the European Union has decided not to fund the project. Even within NORAD and SIDA, there are increasing signs of unease about the scope of Epupa and the way its development is being handled [3].
Various plant sizes between 250 and 450 MW are under discussion. A larger plant size in the order of 400 MW seems to be the favoured choice as it provides a better unit cost of electricity [1], [2]. ESMAP finds that a 450 MW plant size with an annual energy output of 1800 GWh would result in lowest unit cost of electricity while the feasibility study proposes a plant size of 415 MW with an estimated annual energy production of 1650 GWh.

The 150 metre high dam would create a reservoir with a storage volume at full supply level of 9000 million cubic metres ([1], p. 8.17), which is about twice the mean annual run-off of the Cunene river. In the PFS it is recommended that the largest possible reservoir be built, as this would permit better regulation of the annual river flow fluctuations and provide a more reliable supply during dry years. The inundated area would be 295 square kilometres at full supply level (705 metres above sea level) and 89 square kilometres at the maximum drawdown level (665 m.a.s.l.). Normal seasonal fluctuation in water level, caused by filling up over the rainy period and emptying the reservoir during the dry months (the “drawdown”), would lie in the range of 7 to 8 metres. The maximum drawdown, which may take place over two consecutive years, would expose a barren area of 206 square kilometres.

Costs calculations and other economic factors pertaining to Epupa are contained in Section 6.2 below.

3 The Kudu Gas Field

3.1 Background

The Kudu gas field was discovered in 1973 by the oil company Chevron on license block 2814A [2], [4]. It is located approximately 180 kilometres offshore from Oranjemund under 170 metres of water. Chevron found high pressure gas in Barremian age sandstones, but did not test the well due to the high pressure and poor hole condition. Due to the political situation in the country and international boycotts, Chevron did not follow up on the initial-discovery.

In 1987–88 South African companies completed further seismic surveys of Kudu and drilled two appraisal wells, Kudu 9A–2 and 9A–3. These drillings found good quality aeonian sandstones within volcanic sequence and delivered high quality dry gas at rates up to 38 MMcfd. While upper reservoirs are poorer, the lower reservoir is of extremely good quality. The properties of the 9A–2 well are [2]:

- Reservoir pressure is about 7800 psi.
- The gas column is about 268 m.
- Gas composition is nearly pure methane, with little ethane, traces of propane and butane but no sulfur and heavier hydrocarbons, i.e. a very high quality fuel.
- Oil and Gas Journal [4] quotes a field size of 2 trillion cubic feet (Tcf); other estimates have ranged from anywhere between 5 and 55 Tcf in size\(^{(a)}\).

\(^{(a)}\)Troll, the largest offshore gas field discovered to date in Europe, has estimated reserves of 42 Tcf [5]
The seismic surveys indicate that the reservoir is a very large geological trap rather than the more common structural trapping. This fact makes it more difficult to estimate the exact size of the field, but there is little doubt that the reservoir is a world-scale gas field and few exploitation difficulties are expected [2].

A useful indication of international high regard for Kudu’s potential is that Shell acquired 75% of the license block 2814A (with Engen/South Africa holding the remaining 25%) and has undertaken a 200 square kilometre three-dimensional seismic survey and a 1500 line kilometre two-dimensional seismic survey of the field. Shell must fulfil a contractual obligation of drilling two wells before May 1997. Drilling operations are currently under way to determine the size and location of the field more accurately.

Field development is viable only if a large market is found for the gas. According to a recent press release [6], current results look sufficiently good that serious negotiations are underway with ESKOM, the South African power supply parastatal, to supply gas to South Africa. A pipeline to the Western Cape and a possible power station at Saldanha are under discussion.

Apart from Shell and Engen, other companies such as Sasol, Chevron, Ranger and Norsk Hydro AS are involved in exploration and wildcat drilling. Norsk Hydro is searching blocks along the north-western coast while Ranger is active close to the deep-sea harbour of Walvis Bay [4]. While the search is primarily for oil, finding gas in this area would, of course, be of significance because of the available infrastructure close by at Walvis Bay.

3.2 The Price of Kudu Gas

Generally, the exploration of an offshore gas field includes the magnetic and/or seismic geological surveys, the exploration drilling and the final appraisal drillings needed to establish the limits of the field. Typical offshore exploration costs lie in the range $15–30 million, somewhat higher than onshore costs of $10–15 million [7].

The development, production and piping costs for Kudu are hard to quantify at present, since well depth, gas treatment, transmission length etc. vary from site to site. However, in 1991 a cost estimate was undertaken in the “Kudu Gas Utilization Study” authored by Pencol Engineering Consultants. While not directly available, many details of this study are quoted in the ESMAP report [2]. The Pencol study considers two scenarios, namely reservoir sizes of 2 Tcf and 10 Tcf; the findings, summarized in Table 1, will be used as reference values.

<table>
<thead>
<tr>
<th>Reservoir Size</th>
<th>2 Tcf</th>
<th>10 Tcf</th>
</tr>
</thead>
<tbody>
<tr>
<td>Plateau production</td>
<td>275 MMcfd</td>
<td>1000 MMcfd</td>
</tr>
<tr>
<td>Field exploration and development costs</td>
<td>$353 million</td>
<td>$1168 million</td>
</tr>
<tr>
<td>Gas costs after taxation</td>
<td>1.34 $/Mcf</td>
<td>1.14 $/Mcf</td>
</tr>
</tbody>
</table>

Table 1: Gas costs for a 2 Tcf and 10 Tcf reservoir scenario.

Note:
- The quoted exploration and development cost estimates include later expansion costs for
3.3 Other African Gas Fields

The years 2002–2005 of $38 million for the 2 tcf case and $357 million for the 10 tcf case respectively, which might not be incurred if demand does not meet projections at that time.

- New technology now becoming available may lower these costs even further [2].
- These costs should be spread over not only the cost/benefit of Namibia’s direct power needs, but also other industries and/or export of gas and power. See Section 7.1.
- The quoted net price of gas is the price after taxation for which gas could be delivered onshore at Oranjemund and includes the entire exploration and development costs (i.e. including said later expansion costs). We conduct our analysis for the prospects and economics of using gas for power based on this case.
- The gas costs quoted above are low compared to international rates, which may lie up to 50 percent higher. The effect of higher costs of gas are considered in a sensitivity analysis in Section 6.1.

3.3 Other African Gas Fields

These costs are comparable to those of similar gas field projects in Africa. Because of the many advantages, gas is fast becoming the most popular method of power generation in Africa:

In Mozambique, the Pande onland gas field is currently being developed by Mozambican and South African companies at an estimated cost of $700 million. Eleven wells drilled so far indicate recoverable gas reserves of about 1.7 Tcf. The field will supply gas to markets in the Johannesburg area via a 900 km pipeline. Estimated capital costs of the pipeline, including compressors, are $400–500 million. Design, procurement, construction and commissioning of the system is expected to take about 5 years [8].

In Tanzania, TransCanada Pipelines Ltd and Ocelot Energy Inc are constructing a 220-kilometre pipeline to connect an offshore gas field to a 100 MW gas-fired power plant at Dar Es Salaam. Estimated pipeline costs are $200 million [9]. Gas-fired power stations are also under construction and/or active consideration in other African countries, notably Morocco and Benin.

4 Gas–Fired Power Plants

We now turn to a technical description of the relevant power plants. In this section, the two types of gas–fired power plants that are in common use are described, namely the Simple–Cycle Gas Turbine Power Plant (SCGT) and the Combined–Cycle Gas Turbine Power Plant (CCGT). New large-scale CCGT's are being built at an increasing rate world-wide, while many existing power plants are "repowered" to gas power plants to increase efficiency and reduce harmful emissions. Gas power plants now contribute 16% of the total world–wide generated power [5].

4.1 Simple–Cycle Gas Turbine Power Plant (SCGT)

In the SCGT, air is compressed in the compressor to high pressure, at which point the gas is injected and ignited. The expanding air escapes through the gas–turbine which drives the generator [10].
Little equipment is required to realize such a simple process, so that the SCGT is the cheapest thermal plant. On the other hand, only low thermal efficiencies in the order of 30–35 percent are obtained.\(^6\)

Available gas turbine unit sizes vary from about 1 MW to 200 MW [5]. It is customary to have more than one unit in a plant, as this prevents total plant shut-down when one unit requires maintenance.

Some of the advantages of the SCGT are:

1. Since no coolant is required in the generation process, it is suited to arid and hot environments such as encountered in Namibia. Coal- and oil-fired plants, nuclear plants and of course hydropower plants all need water to some degree.

2. Power generation is independent of external factors and can be generated when needed. This is not the case for hydroplants which have to be shut down during very dry periods and are vulnerable to upstream water use.

3. Short start-up times of as little as 14 to 20 minutes make this plant ideal for peak-load power, i.e. supplementing other plants during times of heavy demand.

4. Although ideal as peak-load plant, the SCGT can also be used for base-load power generation if inexpensive fuel is available in abundance.

5. The plant construction time is extremly short, about six to twelve months for turbine units yielding 70–100 MW (see also Figure 3).

6. The simple process requires little operating staff, thereby reducing operating costs.

The disadvantages are that

1. A great deal of heat escapes into the atmosphere and is therefore wasted, resulting in relatively low efficiency.

2. The turbine has a short lifetime of about 100 000 hours, after which it has to be replaced.

If the required plant is to be used as base-load plant, i.e. if the operating time exceeds 6000 hours per year, the *combined-cycle* power plant becomes a better alternative, due to its higher efficiency.

### 4.2 Combined-Cycle Gas Turbine Power Plant (CCGT)

Of all the fossil-fuel based power plants, the CCGT is the most efficient. As the name already implies, the CCGT combines a gas turbine with a steam turbine. In Figure 1, a schematic layout of a CCGT is shown. As in the SCGT, air is compressed in a compressor, gas is added and ignited. The expanding air escapes through the gas turbine which drives the first generator. However, the exhaust gases are not lost to the atmosphere as in the SCGT but are channeled into conventional steam turbines. In this way, the heat of the exhaust gases is utilized effectively for additional power generation [11].

In a CCGT, the large temperature drop between the gas entering the gas turbine and the exhaust gas in the condensor of the steam turbine is exploited effectively. This difference in temperature is

\(^6\) Thermal efficiency is the ratio of generated energy to the energy available in the fuel.
4.2 Combined-Cycle Gas Turbine Power Plant (CCGT)

some 60 to 100 percent higher than in a conventional steam turbine. Therefore, a CCGT is up to 10 percent more efficient than a conventional steam turbine power plant.

In the past, only small-sized gas turbines were available, limiting the utilization of CCGT’s in larger projects. However, recent technological progress has made it possible to construct larger gas turbines yielding up to 200 MW output. Also, new technology now enables gas turbines to function at even higher temperatures, resulting in an overall thermal efficiency of 55% or more. The highest efficiency that can be gained from conventional steam turbines lies between 38% and 41%, depending on the fuel used.

A CCGT has significant advantages. As in the case of SCGT’s, the CCGT can be constructed in stages, and has short start-up times. In addition,

1. Waste heat and pollutant emissions are lower than for all other thermal plants.
2. The CCGT is an ideal medium-load to base-load plant.
3. High reliability ensures that power is available when required. CCGT’s that have been installed recently operate at availability factors of up to 0.9 (i.e. 90% of the time).
4. The environmental impact is negligible compared to the irreversible land usage of hydroelectric schemes.
5. Overall expenses are reduced due to short construction times of about two or three years.

These points will be addressed in more detail later.

Figure 1: Simplified diagram for a Combined-Cycle Gas Turbine (CCGT).
5. Power Plant Costs

The costs of a project play a major — in developing countries often the deciding — role in evaluating its merits. Therefore, a careful assessment should be made of all the costs involved in the construction and maintenance of a power plant, i.e. of the short-term and long-term costs. Other factors being equal, the type of power plant with the lowest overall cost and the highest expected return on investment should be selected.

5.1 Factors Determining Cost

The simplest way of assessing the costs of a plant is to calculate the unit price of the generated electricity (e.g. in dollars per kilowatt hour, $/kWh) and compare it to the corresponding unit price of other plants under consideration. This method has been adopted widely ([10], [13]) and is used in the present study. Other methods involve the net present value of the plant. Underlying all methods is the essential assumption of the time value of money [14].

The most important factors which determine the overall cost of generated electricity of a plant are:

1. **Investment Costs** ($C_{inv}$): are the costs of capital investments (building the power plant, offices, workshops, pipelines etc.) and are fixed. In order to facilitate comparison between plants of different types and sizes, it is common practice to specify the capital investment costs independently of the plant size. The investment costs are then referred to as the **specific investment costs**, $C_{spec}$, denoted in ($$/kW) or dollars per installed kilowatt of capacity.

2. **Operation and Maintenance** (O&M) expenses are mainly costs for operating labour, materials and tools for routine and emergency plant maintenance. These expenses are not a direct function of either plant capital cost or generating capacity. They vary each year and generally rise as the plant becomes older. They also vary according to the size of the plant, the type of fuel used, the load schedule and the operating characteristics, i.e. whether the plant is used for peak-load or base-load operation. O&M expenses are generally estimated in dollars per year and can be expressed as a percentage value of the investment costs $C_{inv}$ [13].

3. **Fuel Costs** ($C_{fuel}$): The largest single cost factor in the operation of thermal power plants is the raw energy. The cost of raw fuel depends on the plant's efficiency, the unit fuel costs at the particular site and the amount of electricity produced.

4. **Thermal Efficiency** ($\eta$) is defined as the ratio of generated energy to the energy contained in the fuel, i.e. the amount of energy that can be utilized effectively. It is expressed as a percentage value or a fraction of one.

5. **Economic Lifetime** ($t$) or **amortization period** is the time for which a plant will operate economically at rated conditions. The initial investment costs are spread over this lifetime. Accordingly, the longer a plant produces power, the cheaper the unit costs of its produced power becomes. Typical average lifetimes for different types of power plants are listed in Table 2.

6. **Capacity Factor** ($CapF$), sometimes referred to as the **average plant factor**, is the average time (expressed as a percentage value) during which the plant is producing electric power. Stated more formally, it is defined as the ratio of actual plant output to the maximum plant output, where the maximum output is the product of the plant’s power rating and the 8760
5.2 Calculating Total and Specific Costs

hours contained in a year. For instance, a capacity factor of 0.8 would indicate that the plant runs at its rated output 80 percent of the time.

The higher the capacity factor, the cheaper the electricity becomes because the invested capital is used more effectively. Also, whenever a unit is shut down, its usual electricity output must be either generated in another power station or purchased from another electric utility. In both cases, the replacement energy is more expensive than the energy generated by the plant itself, since capital costs are incurred whether the plant is running or not.

7. The Availability Factor, in contrast to the capacity factor, is the fraction of the year that the unit is ready for power generation. Although the plant is available, it may remain on stand-by as a result of a low energy demand by consumers. For this reason the capacity factor usually takes on a lower value than the availability factor.

8. The Cost of Capital (i), sometimes also referred to as the rate of return or the discounted rate is the minimum return on the invested capital acceptable to the investor (strictly speaking, this is not the interest rate). It is therefore used as a hurdle rate in evaluating capital projects. The choice of a specific number for the cost of capital is a crucial and complex matter which depends on the relative values of equity and debt financing and on inflation rates. When two projects are compared to each other, a typical “test discount rate” is used that is applied to both projects.

9. The Capital Recovery Factor (CRF) relates an initial payment to a uniform series of payments over a specified lifetime. In other words, we want to know what amount A we have to pay each year to pay off over t years an initial amount C_{inv} while taking into account the cost of capital. This amount is given by

\[ A = CRF \times C_{inv} \]

where the capital recovery factor is calculated as

\[ CRF = \frac{i}{1 - (1 + i)^{-t}} \]  \hspace{1cm} (1)

and

- \( i \) = cost of capital [\text{\%}]
- \( t \) = lifetime [years]
- \( A \) = equivalent annual costs [\$]
- \( C_{inv} \) = initial investment costs [\$]

10. Construction Time: The costs of a power plant increase with the construction time because interest and tax payments have to be made continually and the investment capital is devaluated by inflation while not earning income during this time.

11. Income Tax, Property Tax and Depreciation are sometimes added to the cost of capital to give the “fixed charge rate”. The cost of capital is usually preferred to the fixed charge rate in a preliminary economic estimate.

5.2 Calculating Total and Specific Costs

The factors mentioned above can be combined to give the cost of electricity generated by a plant. In a simplified version, the total generating costs of a power plant are calculated from only the investment cost, fuel cost and plant O&M costs,

\[ (\text{Total Generating Costs}) = (CRF \times \text{Capital investment}) + (\text{Fuel Costs}) + (\text{O&M costs}), \]  \hspace{1cm} (2)
from which the cost per generated kilowatt-hour is

\[ C_{\text{gen}}[\$/\text{kWh}] = \frac{C_{\text{inv}}}{W \times H} + \frac{C_{\text{fuel}}}{\eta} + \frac{O&M}{W \times H} \]  

(3)

where

- \( C_{\text{inv}} \) – capital investment costs, [$]
- \( W \) – rated plant size, [kW]
- \( H \) – plant utilisation time (\( \text{Cap}F \times 8760 \) hours), [hours/annum]
- \( C_{\text{fuel}} \) – fuel costs, [$/\text{kWh}]
- \( \eta \) – thermal efficiency, [-]
- \( O&M \) – operation and maintenance costs, [$].

This expression can now be used to estimate the cost of the electricity generated by the power plant. In the following sections, the most important of these factors are considered in more detail.

<table>
<thead>
<tr>
<th>Power Plant (plant size)</th>
<th>Economic lifetime (years)</th>
<th>Specific investment costs ( C_{\text{spec}} ) ($/kW)</th>
<th>O &amp; M (% of ( C_{\text{spec}} ))</th>
<th>O &amp; M ($/kW)</th>
<th>Fuel costs ( C_{\text{fuel}} ) ($/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydro, Low Cost 50 - 1000 MW</td>
<td>30</td>
<td>800</td>
<td>0.5</td>
<td>4</td>
<td></td>
</tr>
<tr>
<td>Hydro, Med Cost 50 - 1000 MW</td>
<td>30</td>
<td>1700</td>
<td>0.5</td>
<td>9</td>
<td></td>
</tr>
<tr>
<td>Hydro, High Cost 50 - 1000 MW</td>
<td>30</td>
<td>2500</td>
<td>0.5</td>
<td>13</td>
<td></td>
</tr>
<tr>
<td>SCGT 5 - 80 MW</td>
<td>10</td>
<td>200 - 500</td>
<td>2</td>
<td>4 - 10</td>
<td>0.017 - 0.070</td>
</tr>
<tr>
<td>CCGT 50 - 500 MW</td>
<td>15</td>
<td>400 - 700</td>
<td>2</td>
<td>8 - 14</td>
<td>0.017 - 0.070</td>
</tr>
<tr>
<td>Diesel 200 - 1000 kW</td>
<td>15</td>
<td>1000 - 1200</td>
<td>1</td>
<td>10 - 12</td>
<td>0.027 - 0.090</td>
</tr>
<tr>
<td>1 - 10 MW</td>
<td>15</td>
<td>800 - 1100</td>
<td>2</td>
<td>16 - 22</td>
<td></td>
</tr>
<tr>
<td>Oil and Gas Steam 10 - 900 MW</td>
<td>20</td>
<td>750 - 1500</td>
<td>2</td>
<td>15 - 30</td>
<td>0.022 - 0.075 Oil: 0.017 - 0.070</td>
</tr>
<tr>
<td>Hard Coal Steam 50 - 1200 MW</td>
<td>20</td>
<td>1000 - 1400</td>
<td>2</td>
<td>20 - 28</td>
<td>0.015 - 0.045</td>
</tr>
<tr>
<td>Nuclear 1300 MW</td>
<td></td>
<td></td>
<td>2</td>
<td>34 - 60</td>
<td>0.005 - 0.012</td>
</tr>
<tr>
<td>Solar Photovoltaic 20 MW</td>
<td>20</td>
<td>6200 - 8200</td>
<td>1.5</td>
<td>93 - 123</td>
<td></td>
</tr>
<tr>
<td>Thermal 10 - 30 MW</td>
<td>20</td>
<td>2200 - 2500</td>
<td>1.5</td>
<td>33 - 38</td>
<td></td>
</tr>
<tr>
<td>Wind 10 - 30 MW</td>
<td>20</td>
<td>800 - 1400</td>
<td>3</td>
<td>24 - 42</td>
<td></td>
</tr>
</tbody>
</table>

Table 2: Typical lifetime and costs of power plants [10], [11], [13], [15], [16], [17].
5.3 Cost Comparison of Different Plant Types

Using the concepts and formulae of the previous sections, the different types of power plants can now be compared. Table 2 provides a concise summary of lifetimes, specific investment costs, O&M and fuel costs obtained from the literature. Figures 2, 3 and 4 show in addition literature values for investment costs, construction time and thermal efficiencies for the different types of plants. Based on Table 2 and the three figures, we observe the following:

- **Lifetime**: A hydroelectric power plant has the longest lifetime but it is also the most expensive power plant apart from the nuclear power plant.

- **Specific investment costs**: As can be seen in this table, the specific investment costs vary widely. By far the cheapest power plant available is the SCGT. The CCGT is almost as cheap as the SCGT.

Kehlhofer [11] presents the specific investment costs for various thermal plants for different rated plant output as shown in Figure 2. These costs are valid for an installation including a transformer but excluding workshops, office staff facilities and the like. They are based on 1988 price levels and do not include interest payment during construction.

![Figure 2: Investment costs required for various plant types (price basis: 1988)](image)

---

CC – combined cycle plant
ST-RC – reheat steam turbine plant, coal-fired
ST-NR – non-reheat steam turbine plant, oil or gas-fired
ST – steam turbine plant, oil or gas-fired
ST-R – reheat steam turbine plant, oil or gas-fired
GT – gas turbine power plant

5. **POWER PLANT COSTS**

Figure 2 indicates the trends but should be interpreted with some caution. Many factors affect the price of a power plant such as commercial risk, impediment to construction, legal regulations, etc. However, it very clearly indicates the low investment costs required for the gas turbine plants. This has contributed significantly to the widespread acceptance of gas-fired power plants.

- **Operation and Maintenance costs:** As can be seen in Table 2, gas turbines have the lowest O&M costs. The O&M costs of hydropower plants are of the same order as those of gas plants.

- **Availability factor:** Experience has shown [11] that all the thermal plants under consideration have similar availability factors when used under the same operating conditions. Some typical values are given in Table 3. These figures are valid for base-load plants and would be lower for medium-load or peak-load plants because frequent start-ups and shutdowns reduce their life expectancy.

<table>
<thead>
<tr>
<th>Plant Type</th>
<th>Availability Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas turbine</td>
<td>88 – 95 %</td>
</tr>
<tr>
<td>Steam turbine</td>
<td>85 – 90 %</td>
</tr>
<tr>
<td>Combined-cycle</td>
<td>85 – 90 %</td>
</tr>
</tbody>
</table>

Table 3: Typical values for the time availability factor of well-maintained thermal power plants.

Gas-fired plants attain high availability factors because they are very reliable. This in turn allows a higher plant utilization which is reflected in a high capacity factor, representing a significant cost advantage over low capacity factor plants. Hydroelectric power plants, by contrast, are forced to run at low capacity factors if annual river flow fluctuations occur, irrespective of high availability factors.

- **Construction times:** As shown in Figure 3, the SCGT plant can be built within a very short time because its design is simple and standardized. More time is needed to built a CCGT power plant as both gas and steam turbines have to be housed. The power plant can already produce electricity as a SCGT after the gas turbines have been installed, i.e. 60–70% of the expected total power output is available after the same short construction time of a SCGT of about one to two years [11].

Hydropower plants have a much longer construction time of five to seven years. Clearly, the gas turbines are superior to hydropower plants in this respect.

- **Efficiency:** Figure 4 shows how the thermal efficiency for various fossil-fired plants depends on the power output. Due to their high efficiency, CCGT's make ideal base-load plants. The cheap SCGT's are used for peaking hours, when much power is suddenly needed for a short time. When cheap fuel is available, it can also be used as base-load power plant. The high efficiency of the CCGT, besides saving money, is also an environmental asset: from any given amount of fuel energy, a higher amount of electricity is produced than for a less efficient power plant. This reduces the amount of heat and waste products emitted. See also Section 8.1.
5.3 Cost Comparison of Different Plant Types

Figure 3: Construction time for various power plants (d) [11].

Figure 4: Comparison of efficiency for various plant types (d) [11].

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>CC</td>
<td>combined cycle plant</td>
</tr>
<tr>
<td>ST-RC</td>
<td>reheat steam turbine plant, coal-fired</td>
</tr>
<tr>
<td>ST-NR</td>
<td>non-reheat steam turbine plant, oil or gas-fired</td>
</tr>
<tr>
<td>ST</td>
<td>steam turbine plant, oil or gas-fired</td>
</tr>
<tr>
<td>ST-R</td>
<td>reheat steam turbine plant, oil or gas-fired</td>
</tr>
<tr>
<td>GT</td>
<td>gas turbine power plant</td>
</tr>
</tbody>
</table>
6 Economic Comparison of Kudu and Epupa

6.1 Cost Calculation for Kudu Gas Plants

A few scenarios that could arise from a development of the Kudu gas field are discussed in this section and the corresponding estimated costs of electricity generated by a SCGT and a CCGT are given. It is assumed that a 2 Tcf natural gas reservoir is developed. Larger reservoir sizes would very probably reduce overall costs, so that the figures given below amount to a maximum.

Four different power plant configurations are analysed:

1. All the available gas from a 2 Tcf reservoir is used for firing
   (a) a base-load SCGT and
   (b) a base-load CCGT.

2. Of the available gas from a 2 Tcf reservoir only as much gas is used for the power plants as to produce a fixed power rating of 300 MW. The rest of the gas is assumed to be exported to South Africa (Western Cape). Again, the two types of gas–fired power plants are selected, namely
   (a) a base-load SCGT and
   (b) a base-load CCGT.

<table>
<thead>
<tr>
<th></th>
<th>Case 1(a) (SCGT)</th>
<th>Case 1(b) (CCGT)</th>
<th>Case 2(a) (SCGT)</th>
<th>Case 2(b) (CCGT)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel power consumed</td>
<td>3358</td>
<td>3358</td>
<td>636</td>
<td>420</td>
</tr>
<tr>
<td>for power generation [MW]</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fraction of gas used for power generation [%]</td>
<td>100</td>
<td>100</td>
<td>19</td>
<td>13</td>
</tr>
<tr>
<td>Gas power available for other purposes [MW]</td>
<td>0</td>
<td>0</td>
<td>2722</td>
<td>2938</td>
</tr>
<tr>
<td>Thermal plant efficiency η [-]</td>
<td>0.33</td>
<td>0.50</td>
<td>0.33</td>
<td>0.50</td>
</tr>
<tr>
<td>Rated plant output power ( \bar{W} ) [MW]</td>
<td>1100</td>
<td>1700</td>
<td>300</td>
<td>300</td>
</tr>
<tr>
<td>Capacity factor ( \text{CapF} ) [-]</td>
<td>0.70</td>
<td>0.70</td>
<td>0.70</td>
<td>0.70</td>
</tr>
<tr>
<td>Specific investment costs ( C_{\text{spec}} ) [$/kW]</td>
<td>250</td>
<td>500</td>
<td>250</td>
<td>500</td>
</tr>
<tr>
<td>Economic lifetime ( t ) [years]</td>
<td>10</td>
<td>15</td>
<td>10</td>
<td>15</td>
</tr>
<tr>
<td>O&amp;M costs (% of ( C_{\text{spec}} ) [$]</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Cost of capital ( i ) [-]</td>
<td>0.10</td>
<td>0.10</td>
<td>0.10</td>
<td>0.10</td>
</tr>
<tr>
<td>Construction time [years]</td>
<td>2+</td>
<td>3</td>
<td>2-</td>
<td>3-</td>
</tr>
<tr>
<td>Fuel costs (after taxation) ( C_{\text{fuel}} ) [$/kWh]</td>
<td>0.0046</td>
<td>0.0046</td>
<td>0.0046</td>
<td>0.0046</td>
</tr>
<tr>
<td>Plant salvage value [$]</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Capital recovery factor ( CRF ) [-]</td>
<td>0.1627</td>
<td>0.1315</td>
<td>0.1627</td>
<td>0.1315</td>
</tr>
<tr>
<td>Generated energy/annum [GWh/year]</td>
<td>6745</td>
<td>10424</td>
<td>1840</td>
<td>1840</td>
</tr>
<tr>
<td>Total plant costs ( C_{\text{inv}} ) [$ million]</td>
<td>275</td>
<td>815</td>
<td>75</td>
<td>150</td>
</tr>
<tr>
<td>Cost of electricity ( C_{\text{gen}} ) [$/kWh]</td>
<td>0.021</td>
<td>0.022</td>
<td>0.021</td>
<td>0.022</td>
</tr>
</tbody>
</table>

Table 4: Economic comparison of four gas–fired power plant scenarios.
Example: Case 1(a)

The 2 Tcf reservoir would deliver gas at a flow rate of 275 MMcf/d, i.e. at 3183 ft³ per second. This is equivalent to 3358 MW of “fuel power” (the power delivered if a gas plant had 100% efficiency).

The following specifications apply to the base-load SCGT:

- Thermal plant efficiency $\eta = 0.33$
- Representative capacity factor (base-load plant) = 0.70 (6132 hours/annum)
- Specific investment costs $C_{spec} = 250 \$/kW$
- Economic lifetime $t = 10$ years ($\approx 100000$ hours)
- Construction time = 2 years
- Operation and Maintenance Costs O&M = 2% of investment costs
- Cost of capital $i = 0.10$
- Fuel cost (after taxation) $C_{fuel} = 1.34 \$/Mcf (0.0046 \$/kWh)
- Plant salvage value = $0$

A cost of capital of 10% was chosen because it is the cost of capital used by the World Bank if the cost value specific to the country is not available. It has remained near 10% in most countries for some time.

The plant rating is defined by the plant thermal efficiency:

$$\text{Rated Plant Output Power } \bar{W} \approx \text{Efficiency } \times \text{Fuel Power}$$
$$= 0.33 \times 3358 \text{ MW}$$
$$\approx 1100 \text{ MW}$$

In other words, a 1100 MW plant would consume the assumed 275 MMcf/d of gas.

The capital recovery factor is obtained from equation (1), Section 5.1:

$$CRF = \frac{0.10}{1 - (1 + 0.10)^{-10}}$$
$$= 0.1627$$

Now the cost of electricity is calculated by equation (2):

$$C_{gen} = \frac{0.1627 \times 250 \times 1.1 \times 10^6}{1.1 \times 10^6 \times 6132} + \frac{0.0046 \times 0.33}{1.1 \times 10^6 \times 6132} + \frac{0.02 \times 250 \times 1.1 \times 10^6}{1.1 \times 10^6 \times 6132}$$
$$= 0.021 \$/kWh$$

The total plant costs are obtained by multiplying the specific investment costs with the plant size and are about $275 million.

The net generated energy per annum amounts to

$$1100 \text{ MW} \times 8760 \text{ hours} \times 0.70$$
$$= 6745 \text{ GWh}.$$
The results for all four scenarios are presented in Table 4. As an example, the detailed calculations for Case 1(a) are shown below; the other scenarios were treated in the same fashion.

The calculation assumes that the gas flow from the gas field will be halted at times when the plant is out of operation. Interest during construction is not included, neither for Kudu nor Epupa.

It should be noted that only the fuel costs include taxes. As stressed before, the costs are estimates only and can differ somewhat depending on legal regulations and the circumstances in Namibia.

While the final cost of electricity for Cases 1 and 2 is the same, they differ substantially in that, as Table 4 shows, plants in Case 1 generate much more electricity, using all the gas from the 2 Tcf reservoir to produce electricity. Therefore, if the power cannot be exported at an attractive rate to neighbouring South Africa, Case 1 would not be viable.

The situation in Case 2 with the fixed plant size of 300 MW is different. The cost of electricity at 0.022 $/kWh is slightly higher for the CCGT than for the SCGT, and only 13% of the available gas is burnt in the plant; the rest would be available either to local industry or for export to South Africa via pipeline. The generated energy amounts to 1840 GWh/annum. Epupa is expected to have a similar annual energy yield.

How much do these costs change when important parameters are varied? To answer this question, a sensitivity analysis is presented in Table 5 to test whether the plant will remain competitive if it is used in a medium-load scenario (with a capacity factor of 0.50) rather than a base-load scenario (with a capacity factor of 0.70). The table also shows how a deviation of the cost of capital and of the capacity factor would influence the cost of electricity. It further shows what happens if it is used at a very high capacity factor of 0.85. Such a high capacity factor can, of course, only be attained when the power demand does not fluctuate significantly.

The cost of electricity increases either when the cost of capital increases or when the capacity factor decreases. As the capacity factor decreases, less fuel is consumed, as can be seen from Table 5. This is obvious as the plant operating time decreases.

The price of gas is another important influence on the total cost of electricity. The landed cost of gas quoted in Table 1 from figures provided by Pencol are low by international standards (see Fuel Costs in Table 2). Table 5(c) shows the effect of fuel price on the cost of electricity using the two figures from Table 1 plus a value of 2.01 $/Mcf, fifty percent above the baseline value of 1.34 $/Mcf. Parameters not shown are as in Table 4.

Tables 4 and 5 show that the price of electricity ranges between 0.019 $/kWh and 0.028 $/kWh under the given conditions for both the SCGT and CCGT. ESMA [2] claims that on the basis of international experience, a 1300 MW CCGT burning gas priced in the range indicated in the Gas Utilization Study would generate power at a cost of about 0.030 – 0.035 $/kWh. Unfortunately, details such as the capacity factor used are not provided. However, the price difference is considered to be within the range that estimates provide.
### 6.1 Cost Calculation for Kudu Gas Plants

<table>
<thead>
<tr>
<th>Cost of capital [-]</th>
<th>0.10</th>
<th>0.10</th>
<th>0.10</th>
<th>0.10</th>
<th>0.12</th>
<th>0.12</th>
<th>0.12</th>
<th>0.12</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacity factor [-]</td>
<td>0.50</td>
<td>0.60</td>
<td>0.70</td>
<td>0.85</td>
<td>0.50</td>
<td>0.60</td>
<td>0.70</td>
<td>0.85</td>
</tr>
<tr>
<td>Capital recovery factor [-]</td>
<td>0.1627</td>
<td>0.1627</td>
<td>0.1627</td>
<td>0.1627</td>
<td>0.1770</td>
<td>0.1770</td>
<td>0.1770</td>
<td>0.1770</td>
</tr>
<tr>
<td>Fuel power consumed for power generation [MW]</td>
<td>455</td>
<td>545</td>
<td>636</td>
<td>773</td>
<td>455</td>
<td>545</td>
<td>636</td>
<td>773</td>
</tr>
<tr>
<td>Fraction of gas used for power generation [%]</td>
<td>14</td>
<td>16</td>
<td>19</td>
<td>23</td>
<td>14</td>
<td>16</td>
<td>19</td>
<td>23</td>
</tr>
<tr>
<td>Gas power available for other purposes [MW]</td>
<td>2903</td>
<td>2813</td>
<td>2722</td>
<td>2585</td>
<td>2903</td>
<td>2813</td>
<td>2722</td>
<td>2585</td>
</tr>
<tr>
<td>Generated energy per annum [GWh/year]</td>
<td>1314</td>
<td>1577</td>
<td>1840</td>
<td>2234</td>
<td>1314</td>
<td>1577</td>
<td>1840</td>
<td>2234</td>
</tr>
<tr>
<td>Cost of electricity $C_{gen}$ [$/kWh$]</td>
<td>0.024</td>
<td>0.023</td>
<td>0.021</td>
<td>0.020</td>
<td>0.025</td>
<td>0.023</td>
<td>0.022</td>
<td>0.021</td>
</tr>
</tbody>
</table>

Table 5(a): Sensitivity to a change in cost of capital and capacity factor for Case 2(a): 300 MW SCGT.

<table>
<thead>
<tr>
<th>Cost of capital [-]</th>
<th>0.10</th>
<th>0.10</th>
<th>0.10</th>
<th>0.10</th>
<th>0.12</th>
<th>0.12</th>
<th>0.12</th>
<th>0.12</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacity factor [-]</td>
<td>0.50</td>
<td>0.60</td>
<td>0.70</td>
<td>0.85</td>
<td>0.50</td>
<td>0.60</td>
<td>0.70</td>
<td>0.85</td>
</tr>
<tr>
<td>Capital recovery factor [-]</td>
<td>0.1315</td>
<td>0.1315</td>
<td>0.1315</td>
<td>0.1315</td>
<td>0.1468</td>
<td>0.1468</td>
<td>0.1468</td>
<td>0.1468</td>
</tr>
<tr>
<td>Fuel power consumed for power generation [MW]</td>
<td>300</td>
<td>300</td>
<td>420</td>
<td>510</td>
<td>300</td>
<td>300</td>
<td>420</td>
<td>510</td>
</tr>
<tr>
<td>Fraction of gas used for power generation [%]</td>
<td>9</td>
<td>11</td>
<td>13</td>
<td>15</td>
<td>9</td>
<td>11</td>
<td>13</td>
<td>15</td>
</tr>
<tr>
<td>Gas power available for other purposes [MW]</td>
<td>3058</td>
<td>2998</td>
<td>2938</td>
<td>2848</td>
<td>3058</td>
<td>2998</td>
<td>2938</td>
<td>2848</td>
</tr>
<tr>
<td>Generated energy per annum [GWh/year]</td>
<td>1314</td>
<td>1577</td>
<td>1840</td>
<td>2234</td>
<td>1314</td>
<td>1577</td>
<td>1840</td>
<td>2234</td>
</tr>
<tr>
<td>Cost of electricity $C_{gen}$ [$/kWh$]</td>
<td>0.027</td>
<td>0.024</td>
<td>0.022</td>
<td>0.019</td>
<td>0.028</td>
<td>0.025</td>
<td>0.023</td>
<td>0.020</td>
</tr>
</tbody>
</table>

Table 5(b): Sensitivity to a change in cost of capital and capacity factor for Case 2(b): 300 MW CCGT.

<table>
<thead>
<tr>
<th>Gas costs [$/Mcf]</th>
<th>1.14</th>
<th>1.34</th>
<th>2.01</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas costs [$/kWh]</td>
<td>0.0039</td>
<td>0.0046</td>
<td>0.0069</td>
</tr>
<tr>
<td>Cost of electricity $C_{gen}$ [$/kWh$]</td>
<td>0.020</td>
<td>0.022</td>
<td>0.026</td>
</tr>
</tbody>
</table>

Table 5(c): Sensitivity to a change in gas fuel price for Case 2(b): 300 MW CCGT.

*(a)* Parameters that are not specified explicitly remain the same as those given in Table 4.
6. ECONOMIC COMPARISON OF KUDU AND EPUPA

6.2 Comparison to Epupa Generating Costs

In a similar calculation, we now estimate the cost of electricity generated by a hydropower plant at Epupa. Cost estimates for three power plant alternatives at Epupa are included in the World Bank report [2]. They lie in the range of 0.040–0.068 $/kWh for a cost of capital \( i = 10\% \), and 0.050–0.083 $/kWh for a cost of capital \( i = 12\% \).

Based on international experience, Epupa is rated as a medium to high cost hydropower plant [2]. The corresponding specific investment costs, O&M and economic lifetime are taken from Table 2. A 450 MW plant size, referred to as alternative III in [2], is selected for comparison. The data for Epupa can be summarized as follows:

- **Installed capacity** \( W \) = 450 MW = 0.450 GW
- **Specific investment costs** \( C_{\text{spec}} \) = 1700 – 2500 $/kWh
- **Economic lifetime** \( t \) = 30 years
- **Construction time** = 5 to 7 years
- **Operation and Maintenance Costs, O&M** = 0.5% of investment costs
- **Cost of capital** \( i \) = 0.10
- **Annual energy output** = 1800 GWh

The corresponding plant capacity factor is calculated as

\[
\text{CapF} = \frac{1800 \text{ GWh}}{0.450 \text{ GW} \times 24 \text{ h} \times 365} = 0.45
\]

A similar capacity factor is obtained from the PFS [1] with 415 MW installed capacity and 1650 GWh annual energy yield. This low capacity factor reflects high plant investment costs versus low output of generated power. The main reason for this low value is the annual fluctuation in river water flow which the reservoir cannot entirely compensate for (see also Section 7.7 below).

Under the above conditions, the unit price of electricity obtained by using the same approach as in the previous section is

\[
C_{\text{gen}} = 0.047 \text{ to } 0.069 \frac{\text{\$}}{\text{kWh}}
\]

(for \( C_{\text{spec}} = 1700 \text{ to } 2500 \frac{\text{\$}}{\text{kWh}} \))

The resulting unit price is about the same as the price given in the World Bank report [2]. This means that, under similar conditions, the unit price of power generated at Epupa is about **three times higher** than for power generated by a CCGT (Case 2b):

<table>
<thead>
<tr>
<th>Plant Characteristics</th>
<th>Kudu CCGT</th>
<th>Epupa hydro</th>
</tr>
</thead>
<tbody>
<tr>
<td>Installed capacity [MW]</td>
<td>300</td>
<td>450</td>
</tr>
<tr>
<td>Annual energy yield [GWh]</td>
<td>1840</td>
<td>1600</td>
</tr>
<tr>
<td>Specific investment costs [$/kW]</td>
<td>500</td>
<td>1700 – 2500</td>
</tr>
<tr>
<td>Capacity factor [-]</td>
<td>0.7</td>
<td>0.45</td>
</tr>
<tr>
<td>Cost of capital [-]</td>
<td>0.10</td>
<td>0.10</td>
</tr>
<tr>
<td>Cost of electricity [$/kWh]</td>
<td>0.019 to 0.028</td>
<td>0.047 to 0.069</td>
</tr>
</tbody>
</table>

Table 6: Comparison of economic parameters for Kudu and Epupa.
6.2 Comparison to Epupa Generating Costs

Even though the actual costs may deviate somewhat from those given here, such a large cost difference between a gas-fired plant and Epupa cannot be overcome by changing the values of some parameters.

It must be emphasized that the costs to build and maintain a fully-functional additional power plant to substitute for Epupa when the river flow ceases during the drought periods are not included. Also not taken into consideration are the indirect costs resulting from the environmental impact of the hydroelectric scheme, resettling of people etc. Although these costs are not immediately evident, they are very high in the long run and will contribute to the final bill.

How would Kudu compare with Epupa in total investment costs? Comparison must be based on the total electricity output per year: As shown above and in Table 4, a 300 MW gas power plant would generate 1840 GWh per year, while 450 MW must be installed for Epupa to achieve a similar 1800 GWh per year.

For Epupa, there are two existing cost estimates, one by SWAWEK, the other by the World Bank study. SWAWEK, as cited in [2], estimated capital costs at $450 million, using very low specific investment costs of 1000 $/kW. Later, in the prefeasibility study, total costs of R 1469 million (before interest) and R 1741 million (after interest) are quoted for a 415 MW plant, translating roughly into US $440–530 million for a 450 MW plant.

The World Bank report considers these estimates very optimistic; they “fall outside the lower end of a wide range of costs that appears realistic on the basis of international and Bank supported experience in projects of this type.” ([2], pp. 35 and 54–55). Instead, the World Bank estimates costs at $525–800 million, using specific investment costs of 1160–1777 $/kWh. The lower estimate of $525 million would correspond to “an efficiently managed project in better than average site conditions”. The site conditions at the Epupa falls, being in a very remote and undeveloped corner of the country, are more likely worse-than-average.

From Table 2, Medium Cost and High Cost hydropower projects are cited in the literature as costing 1700–2500 $/kWh, i.e. higher still than the World Bank figures. These two figures would translate into capital investment costs of $765–1125 million for a 450 MW plant.

These figures must be compared to those for a 300 MW Combined-Cycle gas power plant, which costs some $150 million. Added to this must be a part of the field and exploration costs. If the whole cost of $353 million needed for the small 2 Tcf field size (see Table 1) must be borne by a single power plant, the total costs would hence amount to some $503 million, comparable to Epupa costs. That, however, is not a realistic comparison: Field and exploration costs will be divided by all applications making use of gas, including export of gas and power and secondary industries. This analysis emphasizes the importance of finding secondary uses for Kudu gas besides Namibia’s immediate power needs. See Section 7.1 below.

The wide range in the above total cost estimates underscores that these are not good measures of the potential viability of a project since they neglect a number of economic factors. We emphasize that a proper analysis, as presented in Sections 5.1–6 and culminating in Table 6, is more complete and hence carries more credibility than the above simple total cost estimates.

In a nutshell: Kudu gas costs would initially seem to be similar to, or lower than,
Epupa capital investment costs. However, Kudu gas would provide fuel not only to a single power plant but to a range of applications. Epupa hydropower costs provide for a single purpose only. If a market for gas is found, as now seems increasingly likely, then electricity from Kudu gas would be 2–3 times cheaper than from Epupa hydropower.

7 Other Economic Factors

The above comparative cost estimates highlight only the direct financial benefits of choosing a gas-fired plant over the Epupa option. Other factors which play an important role are discussed in this section.

7.1 Gas Utilization

The large amount of gas from the Kudu gas field cannot be absorbed by the relatively small power station serving the domestic market alone; additional markets for gas must be found. While this is an important prerequisite for developing the Kudu field, the export of power and/or raw gas and the creation of secondary industry would form a potential source of revenue:

Export of power: At present, South Africa's power company ESKOM has an over-supply of power; however, an energy shortage is expected in the next decade. ESKOM intends to import power at that stage, so that the power generated in Namibia would then certainly find a market. ESKOM currently generates power at a price of 0.020 to 0.031 $/kWh. There would only be interest in imported power if it is offered at a comparable rate [2]. As discussed at length above, gas-fired power, being much cheaper than Epupa and closer to the export market, is much more likely to meet this cost requirement.

Gas exports: Gas itself can be exported to the Western Cape via a pipeline, serving as fuel for power generation in Cape plants and as a replacement for coal in the industry. Indeed, negotiations are currently underway regarding just such a pipeline and a power plant at Saldanha. Again, gas would be competitive if the delivered price of gas does not exceed 2 $/Mcf. The Kudu gas field could reach this goal and deliver gas at 1.80–2.00 $/Mcf in the Western Cape [2]. The prospects of converting existing power stations in urban areas of Cape Town to low-emission CCGT's are promising, given the increased pressure to reduce high urban pollution levels. Studies have shown that the Western Cape could absorb the full amount of gas flowing from a gas field with a size of 2 Tcf in the early years of the next century. An up-to-date survey of market conditions, especially in the Western Cape, must urgently determine to what extent the positive conclusions reached by these studies have changed since they were undertaken.

Secondary industry: Within Namibia, the power sector represents the major potential user of gas, capable of developing an initial and primary market for the natural gas resources. Once this "seed" exists, a series of secondary industries could become possible, both by directly utilizing the available gas and by using the power generated by the gas plants. The development of Kudu gas thus could play a crucial role in moving Namibia from a resource-based toward a manufacturing economy. If, on the other hand, the "seed" of gas-fired power plants does not exist, then it is unlikely that these secondary industries and the gas field itself will be developed at all.
Job creation: Neither the Kudu nor the Epupa power plant would be a major creator of jobs: a few thousand workers would find employment during construction, but after that, permanent staff would be minimal. By contrast, gas-powered secondary industry would provide a long-term employment market and permanent enhancement of skills.

7.2 Construction Times

From experience, the construction time for a hydroelectric scheme is five to seven years, about three to five years longer than for a gas-fired plant (see Section 4). While the prefeasibility study estimates two-and-a-half years to fill the reservoir, starting concurrently with the last phases of construction, this depends, again, on prevailing rainfall conditions. Even under the optimistic time schedules provided by the PFS, the Epupa scheme would be completed by 2002 at the earliest.

As Shell will complete its two-well exploratory drillings on the Kudu gas field by 1997 [4], and if it is assumed that the development of the gas field will follow, gas could be delivered to shore after another three to five years. The construction of the gas power plant could proceed simultaneously with the development of the Kudu gas field, and the plant could therefore be commissioned together with the Kudu gas field by the year 2000-2002.

This implies that if construction of Epupa starts (optimistically) by the end of 1997, it will be completed at the same time as a gas-fired plant of the same size started in 2000. Therefore, the development timescales of the Kudu gas field compare well with those of Epupa.

7.3 Flexibility

At a time of rapid change in Southern Africa, predicting future trends has become even more difficult than usual. The demand for power is no exception: on the one hand, the successful transition to democracy in South Africa has created expectations of an economic boom; on the other hand, there is much potential for disaster. Predicting whether and when the present ESKOM power surplus will turn into a shortfall is nearly impossible. Namibia's economy suffers from the same uncertainties, aggravated by the ups and downs in commodity prices on which its well-being depends.

In such a situation, great flexibility in meeting changing trends is a vital asset. Gas-fired power has some flexibility, while Epupa hydropower would have none.

If, for example, economic growth in Southern Africa during the next decade lags behind predictions, exports and local demand would not justify expansion in the local power generation capacity, while ESKOM would no doubt be pleased to sell its unwanted surplus cheaply. Under such worst-case conditions, it would be best if neither hydropower nor gas were developed at all. For this very reason, it would be best to delay a decision for as long as possible until a clear trend emerges. Gas, having shorter development times than Epupa, can be delayed for a longer time before a decision is made.

Under a medium growth scenario, a single small gas-fired station would become possible while further expansion and costs are deferred. Should growth proceed rapidly, both ESKOM and SWAWEK will need extra power. It would then be a simple matter to build additional gas-fired plants, ensuring that Namibia gets its share of the growth.
If Epupa plant construction were to start, say, by the end of 1997, then after that all flexibility is gone: no matter how demand changes, there will be 450 MW of power available seven years later. At that stage, this amount could be either far too small or too large. See also Table 1 and the discussion following it and Section 7.7.

Thus, while Kudu gas field development is also a major undertaking with all the inherent risks, it would allow for more flexibility in meeting changing needs. Unlike the single-purpose and single-size hydropower plant, there are many different uses for gas and sizes of power plants.

7.4 Taxes, Risks, Inflation and Currency Depreciation

Private oil companies would pay the costs of bringing the gas field to production and bear the risk of development. This would provide additional taxation revenues for the government and greater freedom from risks. A recent press release [6] speaks tentatively of some 12.5% in royalties and a profit tax of 42% flowing into government coffers.

Epupa, on the other hand, would generate no tax revenues, and the full development costs would have to be borne by SWAWEK and the Namibian state. Any cost overruns, errors in power demand projections and resultant loss in sales, losses due to currency depreciation etc. would inevitably be paid for by higher consumer prices and personal income taxes.

Kudu uses domestic gas while Epupa uses domestic water from the Cunene River. Hence both gas and water are independent of international fuel prices and in this sense “inflation-free”. However, bonds and international loans needed to pay for power plants are not inflation-free at all. Apart from their nominal interest rates in Namibian Dollars, loans may carry a hidden inflationary cost due to the fact that they have to be repaid in hard currency: Any devaluation of the Namibian Dollar would directly raise not only the interest rates, but also the repayable principal sum of such loans. For every percent the Namibian Dollar falls, the effective cost of the loan rises by one percent. It is well known that a large number of developing countries have fallen into this “debt trap” and are paying dearly for “cheap” loans. This effect should be taken into account in any cost analysis.

7.5 Cost Overruns

It is common practice to underestimate costs of large projects in order to land the contract. Large dams are no exception. Recent figures from a World Bank analysis show that the 70 dam projects in which it was involved cost, on average, 30% more than initially estimated. In Section 6.2, we already touched on the fact that cost estimates provided by the Epupa feasibility study are considered low compared to similar projects elsewhere. In general, the larger the dam, the larger also the cost overrun.

While they occur for gas plants also, the World Bank found that such overruns are on average only some 11 percent and are spread over the whole lifetime of the plant. For large dams, overruns are far more costly because nearly the total investment must be made before the first light bulb can be switched on.
7.6 Electricity Transmission

The costs of electricity transmission have been omitted in the calculations of the previous sections, since the cost of electricity at the plant site already gives a first indication whether the plant is economically viable or not.

If electric power is to be transmitted over long distances, and the transmission losses are to be kept at an acceptably low level (usually 10%), the transmission line voltage has to be increased. This, in turn, increases line costs. Therefore, long transmission lines are not only more expensive because of their length, but also because of the higher line voltage.

Transmission losses and line construction costs will increase the costs of power from Epupa significantly if the intention is realized to export power to South Africa. These costs would be much lower when power is exported from a power station at Oranjemund as it is much closer to the export market.

One could argue that Epupa would be better for exporting power to Angola and other neighbours to the north. However, this is very unlikely. The prefeasibility study recognises that present demand in southern Angola is minimal: "The Southern and Central systems in Angola are not likely to be supplied with power from Namibia within the period considered in this study" ([1], 4.10). Furthermore, Namibia's own power needs are projected to exceed Epupa's capacity sometime between 2000 and 2010, leaving no excess capacity for possible Angolan needs. It is an open question, in fact, why Angola would want to participate in the destruction of the Cunene when it has nothing to gain from the project.

7.7 Epupa May Need Fossil Fuel

One of the eminent qualities of a gas-fired power plant is its availability when power is needed. This would not be the case for Epupa as prolonged years of drought will reduce the plant output significantly, and could even bring it to a standstill. This, of course, will depend on how the reservoir was regulated in the years preceding the drought. This deficiency is acknowledged in the PFS ([1], p. 3.11). Over and above its sensitivity to drought, the Epupa scheme would be vulnerable to upstream water use for other purposes.

As one of the main justifications being put forward for the Epupa project is to become independent of South African power supply, an alternative domestic supply must be provided during hydrological dry years. Incredibly, it is proposed in the PFS that an additional oil-fired gas turbine plant be built to meet this requirement: A 60 MW plant is suggested for a medium load scenario and a 160 MW plant for a high load scenario ([1], section 12.9). The construction of the power station at Epupa cannot be justified if an additional fossil-fired power plant has to be constructed anyway. As shown in detail above, a gas power plant can generate the required base-load power on its own, without need for Epupa, and at a much higher capacity factor throughout the year and during drought periods.

7.8 Water Resources

Once Epupa has been built, upstream water abstraction for human and live-stock consumption as well as implementation of large-scale irrigation schemes will not be possible. In other words, one of the most precious resources of an arid country with a growing population will no longer be available.
If actual economic growth would differ from current projections, there would be no flexibility for adjusting today’s decisions in the future – a risky approach.

Evaporational losses from the reservoir surface area would waste huge amounts of water. Assuming that the dam will be regulated between its full supply level and normal annual draw down, estimates of evaporational losses range from 500 to 900 million cubic metre (MCM) of water per year, a sizeable percentage of the Cunene mean annual run-off of 5500 MCM and many times more than the total urban human consumption. Not being available for future uses, the unnecessary loss of this resource would have long-term financial implications in that alternative sources of water will have to be found and paid for.

7.9 Infrastructure and Tourism

The infrastructure is well established in the coastal region of Oranjemund and Walvis Bay. Oranjemund’s closer proximity to the gas field and the Western Cape favours this site to set up a power and gas operation industry there.

Epupa is located in one of the remotest areas of Namibia, and existing infrastructure is minimal. Ecotourism, the only cash industry, has little need for infrastructure and would indeed be driven out by the Epupa scheme. Use of the Epupa lake for conventional tourism, on the other hand, is most unlikely because of its remoteness. A great deal of additional infrastructure would therefore be built solely for the purpose of building the dam and power plant. For example, the road linking the Epupa falls to Opuwo would have a length of 192 km, of which 77 km would have to be constructed from scratch [1]. This, too, increases the effective cost of the Epupa scheme.

8 Environmental and Social Costs

8.1 Environmental Considerations

Gas and the environment: Gas–fired power plants pose fewer environmental problems than other fossil-based fuel plants and hydropower. As can be seen in Table 7, coal–fired power plants have much higher values for the various solid and liquid waste products.

<table>
<thead>
<tr>
<th></th>
<th>Coal Power Plant</th>
<th>CCGT</th>
<th>(CCGT/Coal Plant) ×100%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel consumed [tonnes]</td>
<td>16500</td>
<td>6500</td>
<td></td>
</tr>
<tr>
<td>Waste heat [GW\text{h}]</td>
<td>76</td>
<td>52</td>
<td></td>
</tr>
<tr>
<td>$SO_2$ produced [tonnes]</td>
<td>350</td>
<td>negligible</td>
<td></td>
</tr>
<tr>
<td>$NO_x$ produced [tonnes]</td>
<td>50 - 150</td>
<td>10 - 50</td>
<td>20 - 30 %</td>
</tr>
<tr>
<td>$CO_2$ produced [tonnes]</td>
<td>39 000</td>
<td>18 000</td>
<td>46%</td>
</tr>
<tr>
<td>Net efficiency [%]</td>
<td>38</td>
<td>48</td>
<td>126%</td>
</tr>
</tbody>
</table>

Table 7: Typical activity values for a 2000 MW coal and CCGT power plant [5].

Recent concern about climate change has focused attention on the amount of “carbon emission” as a long-term threat to the earth. As reflected in Table 7, natural gas contains a greater proportion of hydrogen to carbon, and hence produces less carbon dioxide on combustion, than any other fossil fuel. Therefore, substitution of gas for coal in South African power stations and Western
8.1 Environmental Considerations

Cape industry (see Section 7.1) would reduce overall carbon emission and atmospheric pollution on the subcontinent.

Thus a gas-fired plant is among the most environmentally friendly of all available power plants, since it is based on a clean and complete combustion process, the plant is small in size and can be built on a site where it does not interfere with sensitive ecosystems or cause irreversible environmental damage, and no dangerous waste products are produced.

Epupa is an environmental disaster: At the same time, it is not permissible to tout the Epupa scheme as "environmentally friendly" solely because of its CO₂-free power generation process: As shown by a string of studies, the list of potential environmental damage wrought by the dam is long. Here is a short selection taken from the Epupa prefeasibility study itself (page numbers in brackets refer to the PFS [1]):

1. Erosion: "After flooding, the steep hill slopes will abut directly on the high water line in some areas. This may result in greater erosion as livestock concentrate around the water's edge for drinking and for moving from place to place. Greater erosion, in turn, will reduce even further the already limited potential for germination of woody and other plant species in the area" (10.51).

2. Vegetation: "From immediately below the greater construction area associated with the dam wall to the upstream limits of the flooded basin (approximately 75 km) the Cunene flood plain and its associated vegetation will be eliminated. As the fluctuating water level and other factors will prevent re-establishment of a flood plain, this vegetation has no chance of becoming re-established along the edge of the flooded basin." (10.52). "Large variations in water level are too rapid for the establishment of most terrestrial or aquatic vegetation along the lake margin" (10.52). Up to 200 square kilometres of land would be affected (see Section 2).

3. "There is a specialised flora associated with the rocks of the Epupa Falls that is dependent on continually moist to wet conditions; a number of species not noted in this report may grow only in this limited area" (10.23). "Should dam Sites B be used, the podostemaceous flora of the falls will be totally eliminated from this region and probably from Namibia." (10.52)

4. Impacts on water quality: "...fish deaths and a spring surge of phytoplankton and macrophytic growth ...". "Such an unstable stage in a new lake may last for many years and possibly delay the potential for fisheries development" (10.42). "There is also good potential for infestation of the dam basin with alien aquatic vegetation" (10.43).

5. Downstream effect: "Alteration of the flow regime is perhaps the most important effect of the impoundment on downstream processes." (10.53) "Rapid water level fluctuations can adversely affect species such as crocodiles, otters and waterfowl that breed close to the waters edge" (10.54).

6. Fauna: "The fauna of the Cunene River, from the eastern edge of the inundated basin to the sea will be seriously affected by the Epupa hydro-power scheme." (10.55). "Species diversity downstream will be influenced in unpredictable ways" (10.55).

   - Birds: "Of the species recorded in the project area, 21 are listed as red data species and six have a Namibian distribution that is confined to the Cunene River." (10.10, Table 10.4)
"The discovery of two new, undescribed species or subspecies of snake and two species of gecko during the previous year may indicate that the reptile fauna is particular specious in this area. The reptile species could be vulnerable to extinction through a loss of habitat" (10.10).

Fish: some 91 species are found in the lower Cunene, 71 of which are found in non-estuarine section. At least 7 are endemic to the Cunene, 2 are listed as rare in the red data book and at least 6 have specialised habitat requirements, being vulnerable to environmental changes" (10.24). "Reduction of annual floods can eliminate spawning triggers for many fish species, thus reducing diversity as well" (10.53-4).

7. River mouth: The Cunene River mouth is sensitive to changes such as reduction of flow. The "reduction in river discharge may, at least during periods, close the outlet to the ocean because of the beach drift." "The reduction of peak floods may however distort this balance [of aeolian input of sediments and coastal sediment transport] and the entire ecology of the river mouth area." (10.50)

8. Human health: Large man-made lakes have long been known as health hazards. In the case of the Epupa reservoir, the prefaseability study expects, for example, increased prevalence of malaria, hepatitis and tuberculosis. The Epupa study also warns that bilharzia will likely be introduced to the area.

Fish, birds, vegetation, water, topsoil, health: these are hard or impossible to measure in terms of dollars, yet there is no doubt that they are valuable and, in some cases, irreplaceable. Economic analyses — and decisions taken — pertaining to large projects which budge their value are misleading and, in the long term, very expensive.

8.2 Social Impact

Major resettlement costs usually occur when moving affected indigenous people and compensation costs have to be paid on a large scale. In general, displaced people take many years before they become a cohesive and productive unit again.

For the Himbas living in the Cunene area affected by the dam, the effects of resettlement would likely be far worse: resettlement would result not simply in a change of lifestyle but in their destruction. As the prefaseability study notes, they are at present economically independent and their social structures, while under stress, are largely intact. Their nomadic lifestyle optimizes land use under given arid conditions. Merely moving them to another area would destroy these nomadic patterns because there is simply no suitable land available. Leaving them on the shores of the new lake would have the same effect, because their present strong reliance on Cunene floodplains and continual crossing into Angola would become impossible.

Resettlement of the Himba, probably by force, would make them dependent on government handout for many years. Western "upgrading" of their lifestyles in any way should respect their own preferences rather than be imposed on them. True development, wherever it occurs in the world, allows the people affected to speak and decide for themselves.

It is well known that the Himbas themselves are vehemently opposed to the Epupa dam project, predicting the death of their people if it were to be built. What economic value is to be put on human rights and freedom of choice?
This study has shown that there are other options besides Epupa which are both cheaper and would not affect the Himba. Epupa is not a necessity.

9 Parallel Development of Kudu and Epupa?

Given that development of the Kudu gas field appears attractive and indeed imminent, it might seem that Namibia could gain maximum benefit by building Epupa anyway, in parallel with Kudu.

However, this argument does not hold true. As shown in this study, it is and remains cheaper to produce power from gas than from Epupa, both for domestic needs and for export. Neither domestic needs nor export can make Epupa more attractive, because expensive power from Epupa could not be easily sold on the competitive South African market. And the Kudu field is large enough easily to serve all needs in Namibia and South Africa.

Developing both Kudu and Epupa therefore does not benefit Namibia. On the contrary, the development of Kudu simply makes the Epupa dam superfluous: the gas would be there, ready for use, and it would be strange not to generate cheap power from it inside Namibia while at the same time raw gas exported to South Africa is converted into power there.

While there are no benefits to building Epupa in parallel, there is a substantial penalty: the huge amount of money that would flow from the Namibian economy into the dam project would be lost to other investments. If, as claimed, SWAWEK has substantial cash reserves with which to finance Epupa in part, then cancelling the Epupa project would presumably free a large amount of money for investment into more worthwhile projects such as further rural electrification, low-tech solar and wind energy devices and savings measures. Such projects, going hand in hand with large-scale power generation from gas, would lay the foundations for a comprehensive and far-sighted energy strategy for the country.

10 Beyond gas: present and future

While development of Kudu gas appears to be best for meeting immediate large-scale needs, this does not preclude the use and investigation of other options suited to Namibian conditions.

Measures available immediately: It is obvious that immediately available options such as energy savings should be implemented anyhow, independently of the larger debate over Epupa and Kudu. Namibia should join the world, now, in efforts to move toward sustainable energy production, and the first and easiest step is to save energy. Changes in tariff structures and continued import of power from South Africa are but two other measures that can be implemented immediately.

Wind and solar energy: Namibia is a large country with a small population. Large distances and few electricity users except for the urban centres and concentrations in the north mean that it is uneconomical to provide grid power to the countryside as a whole. Decentralised modes of power generation therefore acquire special significance here. Despite being more expensive, small solar
units can be operated in the most remote regions and already compete effectively with grid power there. Rapidly-improving technology and falling prices will make photovoltaic units increasingly attractive especially in sun-drenched countries like Namibia.

Even large-scale solar energy is approaching the point where serious consideration should be given to building solar thermal power stations. Wind energy as a supplement to base-load power is becoming commercially competitive and is enjoying a world-wide boom. Certainly the cost of solar and wind energy will decline sufficiently over the next two decades to make them prime candidates for power plants succeeding the presently-planned generation.

**Rural electrification:** In this context, it is far from clear from the Epupa prefeasibility study that one large centralized power generation system is really what Namibia needs: 50 percent of 1990/1 power was drawn by the mines (the three largest, Rössing, Tsumeb and ODM alone drawing 32 percent of Namibia’s total power), followed by 43 percent for the local authorities. A paltry 7 percent was used in rural areas and small towns. Projections based on total energy usage therefore have very little relation to the real needs and possible growth rates of rural electrification: even if power consumption were, say, to triple in rural areas over the next fifteen years, the overall increase would amount to only 14 percent. Claims that power from Epupa is necessary in order to upgrade the quality of life in rural areas are therefore false: the power will go not into rural homesteads but into more mines and city houses. For rural needs, solar and wind options represent a better solution.

A coherent long-term energy policy assessing not only immediate needs and following not only conventional wisdom would be a great asset to Namibia. Gas, hydropower, solar, wind and other sources need to be investigated as a whole and with the above future trends in mind.

### 11 Conclusions

1. To meet Namibia’s expanding power requirements, only one alternative, the Epupa hydropower scheme, has so far been given serious consideration, despite the fact that an existing World Bank report on energy in Namibia recommends that the alternative of Kudu gas field development be studied in detail. The present study attempts to expand on the preliminary World Bank figures and bring gas back into serious contention.

2. Data and information on the Kudu gas field are sketchy because existing data is not freely available. Estimates on size and economic viability of developing the field made in this study can therefore provide preliminary indications only and cannot replace or pre-empt a full feasibility study.

3. **Based on this limited and preliminary set of facts and information, the present study shows that a gas-fired power plant would be superior to the Epupa hydropower scheme:** it would be cheaper, less vulnerable to outside factors, and environmentally and socially more acceptable.

4. The true size of this Namibian offshore gas resource will remain unclear until drilling has been completed. Unless current estimates are grossly optimistic, however, the size of the Kudu gas reservoir as inferred from available data probably exceeds 2 Tcf [2]. **Even this**
minimum reservoir size would suffice to maintain a fuel price that is low enough for generating cheap electric power. This price is also low enough to make gas a competitive replacement fuel for the power sector and industry in the Western Cape. Larger reservoirs would provide correspondingly greater room for manoeuvre.

5. A combined-cycle power plant fueled with natural gas from Kudu can generate power at an estimated price of 0.019 to 0.028 $/kWh, depending on capacity factor. This price is up to three times lower than for power generated by Epupa (0.047 to 0.069 $/kWh).

These estimates do not include

(a) costs for transmission lines and transmission losses, which would increase the price of power generated by Epupa more than it would increase the price of Kudu-generated power,
(b) costs of infrastructure which has to be developed from scratch for Epupa,
(c) risks inherent in raising capital for Epupa on the international loan and bond circuit,
(d) large potential costs due to overcapacity or undercapacity once Epupa comes online,
(e) economic development through gas-powered secondary industry.

6. Natural gas can be supplied on demand throughout the year, thereby allowing high plant utilization and reducing costs. This cannot be said for the hydropower plant: prolonged years of drought or unforeseen upstream water use would reduce the output from Epupa significantly, and could even bring it to a standstill. To provide sufficient power during such times, either an additional stand–by plant will have to be provided or power has to be imported. Thus, developing the Kudu gas–field would provide for Namibia’s entire energy needs. No additional stand–by plant would be needed as in the case of Epupa.

7. Gas-fired plants are less harmful to the environment than other types of power plants. It is widely acknowledged that the social and environmental costs of hydropower schemes are large and irreversible. When such indirect costs are taken into account besides standard economic considerations, gas-fired power becomes even more attractive.

8. From an economic point of view, it would not make sense to build the Epupa dam while the Kudu gas field is being developed.

9. Since either Epupa or Kudu would represent a major investment, great efforts should be made fully to ascertain whether Kudu gas would in fact be the better solution. A full power–from–gas feasibility study should therefore now be a top priority for Namibia. Urgent action is also needed to confirm existing assessments on the Western Cape gas market and move from negotiations on gas export toward concrete action.
References

[1] Epupa Hydropower Scheme, Prefeasibility Study, 1993


[4] Namibia Wildcat Drilling, Licensing Round Planned, Oil and Gas Journal, September 6, 1993


[9] Oil and Gas Journal, April 25, 1994


Nomenclature

Symbol — Name of Unit

<table>
<thead>
<tr>
<th>Symbol</th>
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<tbody>
<tr>
<td>Btu</td>
<td>British thermal unit</td>
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<td>foot</td>
</tr>
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<td>gigawatt hour</td>
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<tr>
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<td>trillion cubic feet (American, 1 $\times$ 10^{12} ft^3)</td>
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<td>$</td>
<td>US Dollars</td>
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Conversion Factors

1 kWh $= 3412.14$ Btu
1 ft^3 $= 0.028317$ m^3
1 ft^3 natural gas $= 0.293103$ kWh \(^{(f)}\)

\(^{(f)}\)Natural gas equivalents assume 1000 Btu/ft^3 gross, i.e. 0.293103 kWh/ft^3