# Project Deliverable

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# Abstract

This document is built upon the information already presented in deliverables D3.1 “Report on System Cost Analysis” and D3.2 “Report on Potential Markets for Small-Scale Solar-Dish microturbines”. Upon these grounds, a final report is now delivered wherein a thorough assessment of the financial performance of OMSoP is provided.

In short, deliverable D3.1 provided a detailed breakdown of the system cost. Abundant information was presented concerning the manufacturing cost of each component as well as the cost of transportation, import and construction/erection. An extensive literature review was performed, the result of which was then compared against the actual data provided by the consortium partners.

Deliverable D3.2 focused on screening the potential markets where OMSoP could find the boundary conditions (both environmental, technical and socio-economic) needed to become a cost-competitive solution for the small scale power generation network (distributed generation) based on renewable energies.

The present deliverable puts both sources of information together to estimate, for the given detailed costs and boundary conditions, the expected cost of electricity produced by OMSoP. This assessment is done for two different applications. First, systems producing electric power only are considered, both with solar-only or hybrid operation. Then, a system where heat and electric power are produced simultaneously is evaluated. The same approach is applied to a very favourable market (South Africa), a favourable market (Morocco) and an unfavourable market (China) for which a comparison against other small-scale solar technologies (dish-Stirling and photovoltaic panels) is performed.

The main outcomes of this analysis are as follows. The standard OMSoP technology is more cost-effective than an equivalent dish-Stirling system, regardless of the boundary conditions. Nevertheless, this better economic performance does not suffice to beat PV technology which still yields lower Levelised Cost of Electricity (LCoE). Nevertheless, for certain markets with favourable financial conditions and large solar resources, the upgraded versions of OMSoP (based on more complex layouts incorporating intercooling and reheat) become cost effective against PV. This is not to say that they always yield lower LCoE; they are actually rather similar and which one is eventually lower is case-specific. Rather, it must be taken as an indication that the dish and microturbine technology is not inherently costlier than photovoltaics. Therefore, in these circumstances, other features of solar thermal generators like the potential for hybridisation might favour this option versus the standard PV approach.

The analysis of a combined heat and power system based on OMSoP shows that this does not seem an interesting option cost-wise, as opposed to standard solutions employing independent power and heat generators.

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# Introduction

## *Role of project appraisal in project engineering*

The role of a decision maker in an engineering project is to select the best development options within those available on a rational basis (or at least on a common basis for the project team given that the decision-making process could, in practice, be also performed on an irrational basis). The process that is in charge of exploring, reviewing and evaluating the development options defined in the project planning process is usually known as project appraisal.

The decision-maker drives his selection by rational approaches to the project's objectives. These objectives are mostly economic but they can also include technical, environmental and even social concerns that must be numerically implemented in the objective function to be minimised/maximised. At the same type, economic, technical, environmental and social boundary conditions can be put in place.

Project appraisal is therefore the process that helps the decision maker in selecting a nearly optimal system design, where optimality is a trade-off between economic, environmental, social and technical aspects. The project appraisal engineer combines all these critical aspects in some indicators of optimality measures which are then interpreted by the decision-maker that has to motivate and discuss the decision made. Interpretation is the task in which the project appraisal engineer shows the model results (technical, economic, environmental and social) in their numerical values and discusses the results to assess how they answer the question posed in the project. Therefore, not only does the author calculate some numerical results, but he also has to contextualise them to inform the decision maker which the better choices are.

From a practical standpoint, project appraisal is the link between system costing, system analysis and system optimisation. These tasks are all affected by the effect of time, in particular the economic calculations, and thus the definition of an economic and financial model is a very important step. This is presented and discussed in this document: in particular when applied to the design process of renewable energy systems (RES). Indeed, the reasons why the appraisal of a renewable energy project like OMSoP needs special attention are discussed by M. Rogers and A. Duffy in (M. Rogers, 2012). These reasons are summarised below:

- Investment structures for RES differ from conventional power projects, as they typically require high up-front capital expenditures and in general lower operational costs.
- The environmental impact that are inherent to conventional power plants are reduced (global warming owing to carbon dioxide emissions and other harmful effects due to the emission of other pollutants).
- Technical and political risks are higher, what brings about a higher financial cost. This adds to the aforesaid higher capital cost.
- The profitability of the project is largely affected by market characteristic, thus requiring a greater effort in risk assessment.
- System boundaries should include measures to tackle the intermittence of renewable energy sources. This can take the form of backup or storage systems or, alternatively, complementary power generation systems that can balance the grid.

- Renewable energy projects are very heterogeneous in nature so particular attention should be made to compare systems with the same quality of supply, whether renewable or conventional (like-to-like basis).

The most important aspects that should be taken into account to ensure the success of the OMSoP project are presented in (M. Rogers, 2012). The first important aspect is to describe the investor that is considering the project since different investor types are likely to assess and prioritise the same economic figures differently, even if they use the same economic and financial assumptions. For instance, there is a large difference between the governmental and industrial perspectives, as the former would consider system life cycle environmental and social issues that would not be accounted for by a private investor until these aspects are not economically valuable (even if through the corporate social responsibility). On the other hand, subsidy-free feasibility of a project is capital for a private investor in renewable energy projects because they must ensure profitability even under legislative changes made by the authority.

Project appraisal should evaluate all the life cycle including planning, procurement, design, construction, operation, maintenance, major refurbishment and decommissioning. In this process, and for the case of the OMSoP project, the estimation of capital costs is of great importance as they incorporate virtually all of the costs of the project (especially if they are renewable only; i.e., no fuel back-up). The estimation of non fuel-related operation costs is also very important as, along with capital costs, they are the second contributor to cash-flow balance and, therefore, profitability. In other words, capital (and the associated) financial costs are the fundamental item determining profitability with operation and maintenance having a lower order of magnitude influence; this is in contrast to power plants based on fossil fuel technologies where capital and O&M costs have a similar influence on the final cost of electricity.

The last factors that the project appraisal has to consider is the depreciation of assets with time and the time value of money. The first aspect is measured through the residual value of the asset (end-of-life value) whilst the second is quantified through the discount rate. The discount rate applies to both positive and negative cash-flow streams and stands for the interest that one could earn on a given amount of money invested today. In other words, it represents the fact that a Euro today is worth more than a Euro in the future given that it could be invested and generate interests after a period of time; this potential annual interest is the discount rate which reduces the current (present) value of future cash-flows in comparison to cash-flows that are closer in time. As said, the values given to the discount rate depend on the investor and this information is not usually disclosed in the public domain. In the electricity sector, another parameter that is widely used is the (WACC) “weighted average cost of capital”. It is defined as the minimum rate that a utility must earn to fund its capital components, including debt and preferred and common shares.

Wrapping up the foregoing discussion, it becomes clear that project appraisal is the process followed to answer the following questions, as claimed by (E. L. Grant, 1964):

- Why do this at all?
- Why do it now?
- Why do it this way?

Looking at the engineering design process (already discussed in the previous deliverable report covering cost analysis), it is important to understand the problem under analysis as this helps the project appraiser to fix the objective functions and the structure of the optimisation problem. The characteristics of the problem are most of all ill-defined though: the problems are not well formulated, data required are not immediately at hand, decision variables are interrelated, and even if the economic considerations are of overriding importance, there are also considerations of a different nature to be accounted for. Bejan et al. (Bejan A., 1996) consider that these ill-defined conditions can be solved by asking "what?" instead of "how?" before the design process starts. In other words, the objectives should be fixed before the concept development stage in terms of which "qualities" the system should hold rather than how it can be engineered to comply with the specifications (requirements). The question "how?" is then solved internally during the conceptual development stage.

It comes natural from the description of project appraisal that it can be implemented in various ways. As a matter of fact, the characteristics (both the concept and the implementation) depend on the product, investor, industry, size of company, target market, production volume, and a myriad of other parameters. Therefore, an overview of the general methodologies and structures possible for an engineering project appraisal is presented now along with a discussion of the general structure applied to the appraisal of OMSoP.

The decision-making action is only needed when there is a choice between different options. The techniques to address the motivations for each of these options can then be non-analytic or analytic. Amongst them, the second type is particularly useful when complex decisions involve irreversible allocations of large resources. In contrast, non-analytical decisions are made without conscious considerations but based on an intuition or perception that they are "right". This kind of decisions are inherently intuitive and very risky and they have to be minimized during the design process. Non-analytical decisions can also be of the judgemental type; these are applied to recurrent situations and are based on statistic, past experience and general knowledge. This non-analytical decision making is widely applied to planned decision-making problems.

On the other hand, non-planned decisions are instead useful for new, unstructured and ill-defined situations of a non-recurring nature, requiring substantial analysis by the decision-maker. These decisions involve large number of factors and need correcting actions to achieve the desired results. The *reasoned choice method* provides technical foundation for non-programmed, non-recurring decisions and involves the following steps:

- Recognition of the problem; i.e., the decision to make.
- Identification of goals (required outcome).
- Generation and characterisation of a set of alternative options.
- Analysis and evaluation of the information about all the options considered.
- Selection of the preferred option.
- Implementation of the preferred option.
- Re-evaluation.

The basic rational procedure, which is the practical adaption of the reasoned choice method into an analytical methodology, is outlined by Rogers in (M. Rogers, 2012). It can be summarised in five fundamentals steps, shown in the following Table 1.

| # | Step | Purpose |
|---|---|---|
| 1 | Definition of goals and objectives | To define and agree the overall purpose of proposed project |
| 2 | Formulation of criteria/measures of effectiveness | To establish standards by which the options can be assessed in relative and absolute terms |
| 3 | Generation of alternatives | Generate as wide a range of alternatives as possible |
| 4 | Evaluation of alternatives | Evaluate the relative merit of each option |
| 5 | Selection of preferred alternative | Make a final decision regarding the most favourable option |

***Table 1. Basic rational procedure for decision making.***

## *OMSoP project appraisal: research project overview*

In this paragraph, the general OMSoP project engineering process is presented, highlighting the tasks related to project appraisal and the interrelations with other tasks in terms of inputs/outputs, objectives, requirements and concurrent design approaches.

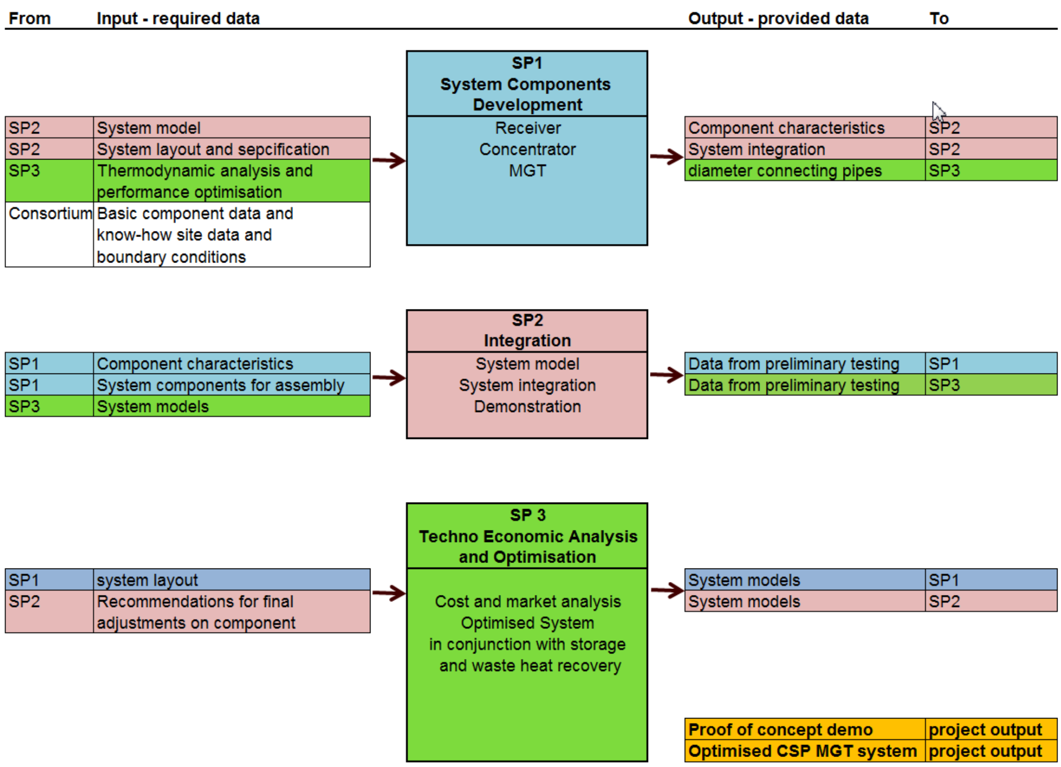


***Figure 1. General project engineering process of OMSoP.***

The overall engineering process comprises three work packages:

- System components development.
- System integration.

- Techno-economic analysis and optimisation.

The lack of conceptual design stage in this list (where all the items are related to the detailed design process) is actually due to the project team (consortium) having already generated and screened the basic concept of the system during the preparation of the proposal. This means that the base case flow sheet is already available and thus the detailed design effort is the next natural stage to carry on the new system development within the timeframe of the project. In addition, a pilot plant is currently under construction and will enable developing models that will provide more accurate technical and economic data. These data will be useful to iterate the design process with higher accuracy.

In effect, the design effort requires iterations and thus some results, deliverables/reports and technical models exchange information forth and back between work packages 2 and 3. This activity is necessary to improve the quality of the design, reduce risks and ensure commercial success as much as possible. In particular, the role of project appraisal (in conjunction with cost analysis) in OMSoP is to demonstrate and explore the pathway to commercialisation and assess the expected profitability of the product. In addition to these global objectives, indications should be provided for decision making at all the project engineering levels (components design, system integration) as these indications are also driven by economic considerations.

# Methodology

## *Project appraisal. Literature review*

Project appraisal includes a number of tasks including cost analysis, economic analysis, financial analysis and evaluation of the figure(s) of merit obtained through critical thinking. The specific methodology adopted for the cost analysis has been already presented in the previous deliverable report and will not be repeated here. It is to note though that the *Cost Analysis Report* (D3.1) did not take into account the estimation of indirect costs nor the operation and maintenance costs. Therefore, an additional section connected with the estimation of these costs is presented in this document prior to the economic and financial analysis.

A complete conceptual review of the engineering project appraisal methods is provided by Rogers in (M. Rogers, 2012). As already said, some of them are based on non-analytical decision-making and even if they rely on intuitive and judgemental decisions, they can be applied for recurring decision problems. When non-programmed project decisions are needed, the risks are highly reduced if analytical decision-making methods based on reasoned or rational approaches are adopted. The analytical structures for the decision-making process provide tools for more coherent non-programmed decisions. The technical foundation provided by the *reasoned-choice* models is useful for these non-programmed, non-recurring decisions. The framework of such models comprises the following steps, already presented in the previous section with slight variations:

- Recognition of the problem.

- Identification of the goals.
- Generation and identification of options.
- Search and assessment of information about all options.
- Selection of preferred options.
- Implementation of decision.
- Evaluation of results (feedback).

The actual evaluation of the individual projects options is the main task which is performed applying a properly structured evaluation framework. The models fall in two categories: optimisation methods and compromise methods, differing in the set of rules (evaluation method) used to compare the options. The challenge in producing these sets of rules is that they must be appropriate for the both the primitive decision problem and the available information. If optimisation methods are used, it is considered that the rational method permits to calculate the *single best* of all the options proposed. This is expressed in terms of a single parameter which allows for the loss in one specific objective to be directly compensated for by the gain in another. If, as in most cases, the information is limited regarding the decision situation, optimising methods are not the best. In such cases, the *compromise* principles should be considered; these methods apply also to multi criteria analyses.

Optimising methods apply to projects where the economic analysis is predominant, as it is the case of most engineering projects (for instance OMSoP). In these cases, engineering economics provide techniques to calculate numerical figures of merit termed measures of economic worth. The most common figures are the net present value, the internal rate of return, payback, levelised cost of electricity and benefit/cost ratio; all these indices are described in the following along with the process to implement the time value of money in the cash-flow balance. The formulae used to calculate the already cited measures of economic worth have been taken from (R. A. Brealey, 1996), (M. Rogers, 2012) and (Boehm R.F., 1987). This information has been complemented with that made available by the National Renewable Energy Laboratory in (NREL, 1995), where a detailed discussion regarding economic and financial cash flow models for different investor profiles is provided.

# OMSoP project appraisal: model description

The project appraisal model is presented in three stages. First, the business cases are described; this part is useful to define the features of the system. Second, the additional costs of the system that were not covered in the previous deliverable report are presented. The final stage describes the user requirements and the financial structure of the cash-flow models considered to assess the profitability of the various business projects.

## *Business cases*

### Business case #0. Power-only system

This is the simplest business case. The system makes use of the *base-case* technology to produce electric power only (there are no secondary outputs like heat or water). The electricity is exported to the grid (end-user) producing revenues in return.

Figure 2 shows a schematic of the mass and energy flows in the solar-only (left) and hybrid (right) systems. Ambient air and solar power, the main inputs to the system, do not bring with them an associated cash inflow as they are renewable resources available in the environment. On the contrary, fuel in the hybrid system case represents an additional operational cost for this business case (actually, the only operating cost). Other complementary costs that are common to both configurations are maintenance costs, project contingencies direct costs, project indirect soft costs, land costs and engineering procurement and construction costs.

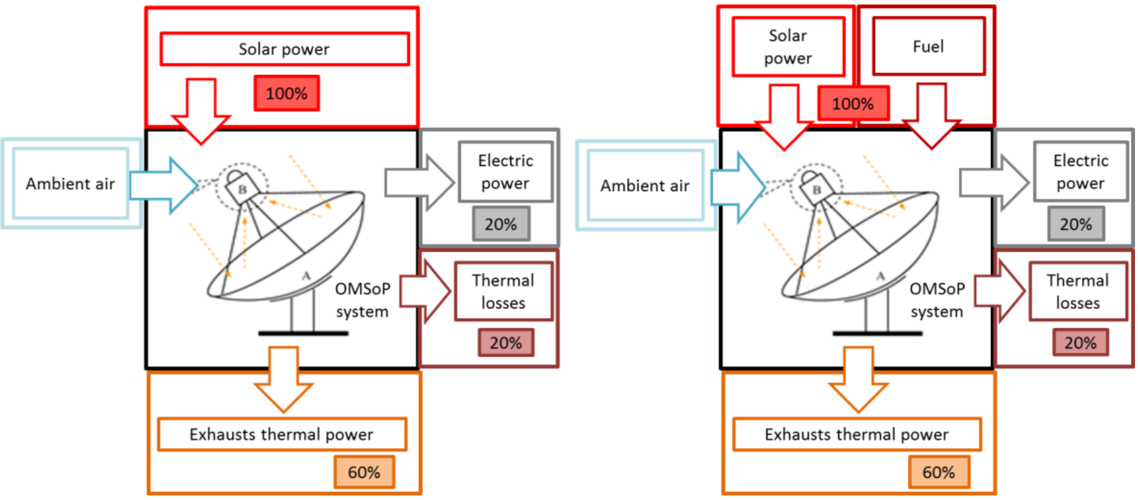


***Figure 2. Mass and energy balance of the solar-only (left) and hybrid (right) OMSoP. Business case #0: power-only system.***

As shown in Figure 2, the thermal energy available in the exhaust gases is ~60% of the total solar energy input to the system. This energy is released to the environment (thus representing a loss) and no further utilisation of it is considered in this business case where the only output generating revenues is electricity. The advantages of using such a system are the simplicity of the system and the lowest fixed investment cost amongst all possible configurations. The latter can be a critical advantage considering that the fixed costs of OMSoP are actually very high, in particular when compared to operation and maintenance costs. Financial-wise, the lower the fixed investment cost, the more likely the profitability.

Having just one source of revenue is the most evident disadvantage of the system, which is aggravated by the very high upfront costs and low global efficiency (higher capital investment for the same output). As seen in Figure 2, the amount of energy released to the environment is roughly three times the amount of electricity produced. This poses the need to achieve a trade-off between increased production/revenues and increased capital/operation costs.

Business case #1. Combined heat and power system

This second business case is also very simple. It is based on the previous case but features combined heat and power production. The production of heat is in the form of hot water at 90ºC whilst electricity is produced by the generator of the micro gas turbine as usual.

Hot water is produced in a waste heat recuperator (WHR) installed in the exhaust stream of the micro gas turbine, Figure 3, where a large amount of heat is available. The economic implications of this additional feature involve a higher initial capital (fixed) cost and higher maintenance costs, whose calculations are presented in the following sections.

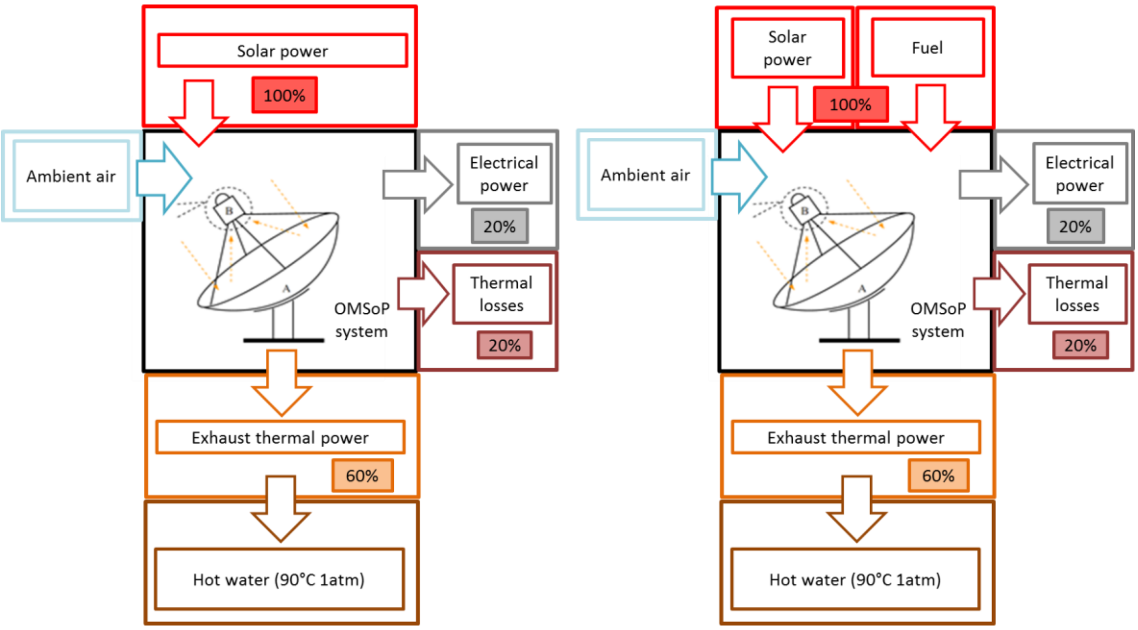


***Figure 3. Mass and energy balance of the solar-only (left) and hybrid (right) OMSoP. Business case #1: combined heat and power.***

This business case has the advantage of using most of the energy collected from the sun. Thermal losses to the environment are kept to a minimum and they are only found in the receiver (small fraction) and the exhaust gas stream, which is now at a much lower temperature. The thermal power produced is at a temperature level useful for buildings (residential applications) and industrial processes. On the negative side, the main disadvantage is the low-grade heat that is produced from the high temperature exhaust gases (i.e., the large destruction of exergy in the heat recovery process). This means a lower economic value of the energy that is now recovered.

Figure 4 depicts a detailed layout of the OMSoP system for combined heat and power applications, showing that the water loop is made up of a water pump and a waste heat recuperator. The water loop is pressurised to 2 bar in order to ensure that steaming does not take place, which is critical in terms of maintenance costs. It is to note that the addition of a

WHR loop brings about a higher backpressure on the turbine, thus having a detrimental effect on micro gas turbine performance.

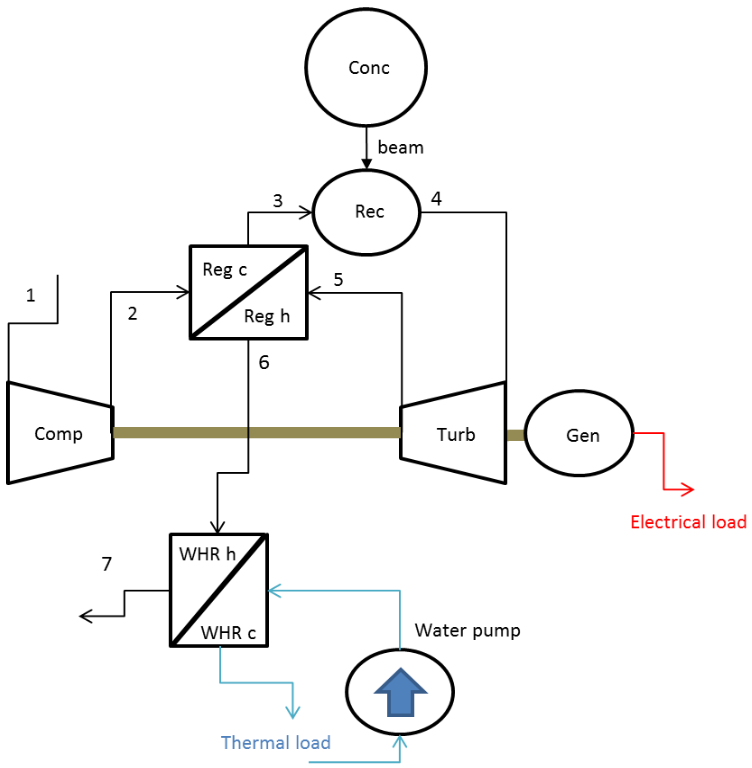


***Figure 4. Layout of the OMSoP system for combined heat and power.***

## *Cash-flow models*

### Business case #0. Power-only system

The cash flow model applied to the economic and financial analysis of the power-only production is the *commercial* model used by the System Advisory Model software by (NREL, 2016). The reference investor of the commercial project considered in the analysis is a single user that buys and sells power at retail rates. It is assumed in these cases that a single entity develops, owns and operates the project, and that this is financed through either a loan (no equity) or cash payment (discount rate). The *Levelised Cost of Electricity* (LCoE) can be conceptually regarded as the present cost of each kilowatt-hour produced over the plant lifetime accounting for all the lifetime costs of the project (installation, operation, maintenance and also financial costs, insurance, taxes and dismantlement costs). Financially, this is the cost of electricity that yields NPV=0. Depreciation schedules are also applied for tax reductions.

For the commercial project model, the loan considered is standard (no tax deductible) and is characterised by the following parameters:

- Debt fraction or debt/equity ratio ($R_{D/E} = \frac{Debt}{Equity}$): percentage of the net capital cost to be borrowed from the bank.

- *Loan term* ($N_{loan}$): number of years required to pay off the loan.
- *Loan rate* ($r_{loan}$): annual nominal interest rate for the loan.
- *Principal* ($P_{loan}$): amount borrowed. It is deduced from the total capital cost and debt fraction.

Other secondary, more general financial parameters are:

- *Project lifetime* ($N_{tot}$): timeframe of the analysis.
- *Inflation rate* ($i$): annual rate of change of costs, typically based on an escalation price index.
- *Real discount rate* ($r$): annual interest that the investor would obtain on the same amount of money if invested in a different project. Also interpreted as the interest rate on the capital that the investor would like to obtain.
- *Nominal discount rate* ($n$): discount rate considering inflation. Calculated from the inflation rate and the real discount rate as follows:

$$n = (1 + r) \cdot (1 + i) - 1$$

Regarding taxes and insurance, the following parameters must be provided to calculate the weighted average cost of capital:

- *Income tax rate* ($Tax_{income}$): where applicable, this rate applies to taxable incomes and is used to calculate the tax benefits and liabilities of the project.
- *Sales tax*: a one-time tax to be included in the project's total installed cost.
- *Annual insurance rate*: annual rate to be applied to the total installed cost. This cost is then increased with inflation.
- *Property tax*: annual operating expense, tax deductible. The parameters to be provided are the assessed percent, the assessed value (assessed percent multiplied by the total installed cost), the assessed value decline and the property tax.
- *Weighted average cost of capital* (WACC): minimum return that the project must earn to cover its financial costs. It is calculated as follows:

$$WACC = \left(1 - R_{D/E}\right) \cdot n + R_{D/E} \cdot r_{loan} \cdot (1 - Tax_{income})$$

The last set of financial parameters is related to the residual value of the system at the end of the project lifetime, termed salvage value in the American tax scheme. This is implemented as an income in the final year of the project (cash-inflow) and it is calculated as a percentage of the total (initial) installed cost. This is then treated as a pre-tax revenue that increases the taxable income.

Cash-flow analysis relies on technical parameters also, which are needed to calculate the amount of energy produced in a year. This annual production of electricity, usually termed *yield*, is employed to calculate the specific cost of electricity (*Levelised Cost of Electricity*), revenues, variable operating costs, etc. It is obvious that the production of electricity changes from year to year mostly due to changes in meteorological conditions, unscheduled maintenance (forced outages) and degradation of the components; such variability can be included in the calculation of the annual yield or, most commonly, a standard typical meteorological year can be considered. Amongst these items, only the last one is taken into account in the following form:

$$E_{year(N)} = E_{year(N-1)} \cdot (1 - \delta_{Deg})$$

Where $\delta_{Deg}$ is the annual degradation rate and $E_{year(N)}$ is the annual yield in year $N$ calculated with the performance model running hourly simulations for the new and clean conditions (start-up year).

The revenues from selling electricity to the grid are calculated as follows:

$$Revenues_{(N)} = E_{year(N)} \cdot e_{price(0)} \cdot (1 + i)^{N-1}$$

Where:

- $e_{price(0)}$: Electricity sale price in year 0 [€/kWh].

Once the annual yield and revenues are known, the next step is to calculate the operating expenditures. These include operation and maintenance (O&M), insurance and property tax payments. In this category, the residual value is considered a negative operating cost and O&M costs are made up of different contributions:

- *Fixed annual costs*: these depend on the system regardless of its capacity (output) and the number of operating hours.
- *Fixed annual costs by capacity*: these costs depend on the size of the system but are independent from the number of operating hours.
- *Variable annual costs*: these depend on the annual production of electricity. When the system is not operated, then they are null.

The next equations show how each of these costs is defined:

$$C_{O\&M,fixed(N)} = C_{O\&M,fixed}\big|_0 \cdot \left(1 + i + e_f\right)^{N-1}$$

$$C_{O\&M-kW(N)} = c_{O\&M-kW}|_0 \cdot \mathbb{P}_{el} * (1 + i + e_{kW})^{N-1}$$

$$C_{O\&M-kWh(N)} = c_{O\&M-kWh}|_0 \cdot E_{year(N)} * (1 + i + e_{kWh})^{N-1}$$

Where:

- $C_{O\&M,fixed}\big|_0$: fixed O&M costs in year 0 (project start-up) [€].
- $c_{O\&M-kW}|_0$: specific O&M costs per unit rated output in year 0 [€/kW].
- $c_{O\&M-kWh}|_0$: specific O&M costs per kWh produced in year 0 [€/kW]. This is then multiplied by the annual yield in year $N$ [€/kWh].
- $\mathbb{P}_{el}$: rated output of the plant [kW].
- $i$: Inflation [-].
- $e$: O&M cost escalators [-].

These costs must be complemented by fuel costs if hybrid operation is considered:

$$C_{fuel(N)} = F_{LHV(N)} \cdot f \cdot c_{fuel}\big|_0 * \left(1 + i + e_{fuel}\right)^{N-1}$$

Where:

- $F_{LHV(N)}$: annual fuel energy consumption in year $N$ [$kWh_{LHV}$].
- $c_{fuel}\big|_0$: specific cost of fuel in year 0 [€/$kWh_{LHV}$].
- $f$: conversion factor (0.003413 [MMBTU/ $kWh_{LHV}$]).

The next step is to calculate the insurance cost, property taxes, residual value and, finally, the operating costs. The calculation of these costs is summarised below:

$$C_{Insr,(N)} = C_{Inst,tot} \cdot r_{Insr} * (1 + i)^{N-1}$$

Where:

- $C_{Insr}$: insurance cost [€].
- $C_{Inst,tot}$: total installation cost of the system [€].
- $r_{Insr}$: insurance rate [-].

Regarding the value of the assets and their depreciation over time, these are calculated as follows:

$$PV_{assd(N)} = PV_{assd(0)} \left(1 - r_{dep}(N - 1)\right) \geq 0$$

$$Tax_{property(N)} = PV_{assd(N)} \cdot t_{property}$$

Where:

- $PV_{assd(N)}$: value of the property assessed in year $N$ [€].
- $r_{dep}$: depreciation rate [-].
- $Tax_{property(N)}$: property taxes in year $N$ [€].
- $t_{property}$: property tax rate [-].

The summation of all these secondary operating costs and the primary O&M costs yields the total operation and maintenance costs in year $N$:

$$C_{O\&M,tot}\big|_{(N)} = C_{O\&M,fixed(N)} + C_{O\&M-kW(N)} + C_{O\&M-kWh(N)} + C_{fuel(N)} + C_{Insr,(N)} + Tax_{property(N)} - V_{Res}$$

In the tax scenario of most countries, these total operating costs in a year can be deduced from the income taxes. Where applicable, the following equation holds:

$$C_{Ded,(N)} = -C_{O\&M,tot}\big|_{(N)}$$

The cash flow balance must also incorporate financial costs brought about by the repayment of loans. In a general case, there are two sources of funding for an investment project. A fraction of the total investment is borrowed from a bank (loan) at a given interest rate whilst the investors (owners) provide the rest. The difference between the value of the assets (total installed cost) and the liabilities on them (loan) is termed equity. A financial term typically used to define how the total investment is structured is the debt/equity ratio ($R_{D/E}$), defined before, which can also be substituted by simply the debt fraction ($f_D$).

$$D_{(0)} = f_D \cdot C_{Inst,tot}$$

$$D_{(N)} = D_{(N-1)} - RP_{(N-1)}$$

Where:

- $D_{(N)}$: remaining debt (principal) in year $N$ [€].
- $RP_{(N)}$: repayment of principal (i.e., debt repayment excluding interests) in year $N$ [€].

Then annual interest paid on the debt is calculated as follows:

$$C_{D(N)} = r_D \cdot D_{(N)}$$

Where $r_D$ is the loan interest rate and $D_{(N)}$ is the remaining debt excluding interests (principal). As known, this structure brings about larger annual financial costs at the beginning of the project and negligible costs at the end of the pay-off time. It is thus usual to distribute the loan repayment evenly throughout the project. This is the approach adopted in this analysis so it is implemented as such in the cash-flow balance sheet.

In order to evaluate the effect of taxation on equity, some complementary assumptions must be made:

- The income tax paid on the value of energy (sale of electricity and, eventually heat) is accounted for in the after-tax cash flow (i.e., tax-deductible scenario).
- Project operating costs are tax deductible.
- Debt interest payments are deductible.

The annual depreciation of the assets represents the equivalent value of an asset that is used in a year. This is consistent with the different value of the system at the beginning (total installed cost) and end (residual/salvage value) of a project lifetime. Depreciation is usually non-linear, with faster decay of value at the beginning and slower at the end. The annual depreciation is the product of depreciation percentage and depreciable base (equal to the total installed cost $C_{Inst,tot}$ as the incentives were not taken in consideration):

$$DP_{(N)} = r_{Dep}\big|_{(N)} \cdot C_{Inst,tot}$$

Where:

- $DP_{(N)}$: annual depreciation in year $N$ [€].
- $r_{Dep}\big|_{(N)}$: annual depreciation rate in in year $N$ [-].

Once all the possible tax deductions (liabilities) have been calculated, the annual income tax can be calculated. This annual income tax is calculated as follows:

$$Tax_{tot,(0)} = Tax_{income} \cdot \left(C_{Ded,(1)} - C_{D(1)} - DP_{(1)}\right)$$

$$Tax_{tot,(N)} = Tax_{income} \cdot \left(C_{Ded,(N)} - C_{D(N)} - DP_{(N)}\right)$$

Where $Tax_{income}$ is the income tax rate. A negative value of $Tax_{tot,(N)}$ indicates a net tax liability (tax owed), and a positive value a net tax benefit (tax refund). Based on this, it is possible to calculate the tax savings by merely multiplying the expressions above by (-1).

$$Tax_{save,(N)} = -\,Tax_{tot,(N)}$$

The after-tax net equity cost represents the summation of net annual costs including any potential saving. This final figure for cost is very important inasmuch as the levelised cost of energy is calculated using the after-tax cost flow.

$$Cost_{(0)}^{after} = -(1 - f_D) \cdot C_{Inst,tot}$$

$$Cost_{(N)}^{after} = Tax_{save,(N)} - C_{O\&M,tot}\big|_{(N)} - C_{D(N)} - RP_{(N-1)}$$

$$Cash_{(N)}^{after} = Cost_{(N)}^{after} + Revenues_{(N)} \cdot (1 - Tax_{income})$$

Where:

- $Cost_{(N)}^{after}$: after-tax cost flow in year $N$ [€].
- $Cash_{(N)}^{after}$: after-tax cash flow in year $N$ [-].

These are the last financial figures needed to present the main figures of merit of the financial model of the system. These figures are presented below and will be used throughout the rest of the document.

- *Net present value (NPV)*: present worth of the project applied to either the real ($r$) or nominal discount rate ($n$).

$$NPV_{Nominal} = -\sum_{N=0}^{N_{tot}} \frac{Cash_{(N)}^{after}}{(1+n)^N}$$

$$NPV_{Real} = -\sum_{N=0}^{N_{tot}} \frac{Cash_{(N)}^{after}}{(1+r)^N}$$

- *Levelised cost of electricity (LCoE)*: specific cost of electricity applied to either the real ($r$) or nominal discount rate ($n$).

$$LCoE_{Nominal} = \frac{-Cost_{(0)} - \sum_{N=0}^{N_{tot}} \frac{Cost_{(N)}^{after}}{(1+n)^N}}{\sum_{N=0}^{N_{tot}} \frac{E_{(N)}}{(1+n)^N}}$$

$$LCoE_{Real} = \frac{-Cost_{(0)} - \sum_{N=0}^{N_{tot}} \frac{Cost_{(N)}^{after}}{(1+n)^N}}{-\sum_{N=0}^{N_{tot}} \frac{E_{(N)}}{(1+r)^N}}$$

- *Internal rate of return (IRR)*: the discount rate for which the net present value of the project is null. It is thus a breakeven discount rate for the project's profitability. It is considered, that positive cash flows are reinvested at the same rate of return as that of the project that generated them. The analysis of IRR has to take into account the cash flows signs since, if positive and negative cash flows alternate, more than one IRR can be calculated generating misleading results.

$$0 = -\sum_{N=0}^{N_{tot}} \frac{Cash_{(N)}^{after}}{(1+IRR)^N}$$

### Business case #1. Combined heat and power system

The economic model of the BC#1 requires a different cash flow statement and a different approach to provide meaningful economic figures of merit. In order to assess the feasibility of combined heat and power production, a residential comparative cash flow model is built based on the methodology used for the BC#0 from (NREL, 2016). This cash flow evaluates the economic savings from producing electricity and heat with a single OMSoP system in comparison with the alternative to a use heat provided by conventional gas heater and electricity by the national grid.

To compare alternatives that are mutually exclusive, the incremental cash flow analysis is required as explained in (M. Rogers, 2012) and (Brealey R., 2011). With this peculiar cash flow analysis, projects that are mutually exclusive can be ranked and compared in order to give consistency to the financial metrics results and enable a consistent selection of the best investment option. To this end, a standard system wherein the end user imports electricity from the grid and makes use of a natural gas boiler/heater to produce hot water is taken as reference (case A); case B is based on OMSoP used as a combined heat and power generator. As stated in (M. Rogers, 2012), the project with the lower investment has to be taken as reference for the incremental cash flow analysis.

The cash flow model for the two investment options are calculated with the same structure as for the BC#0. Nonetheless, the main difference between the approaches is that there are no revenues in this case as the two cash flow statements are used to calculate the money savings in one investment as compared to the other. Taxation and depreciation are excluded.

The figures of merit calculated for the economic feasibility analysis of BC#1 are:

- Incremental NPV of the two investment options: in these cases the NPV of the single option is always negative as no revenues are considered.
- IRR of the incremental cash flow.

All these figures, together with the basic cash flow model were already presented so their discussion will not repeated here

## *Cost estimation*

### Additional purchased equipment cost (PEC) estimation

The cost of purchased equipment for the reference case (power-only) has already been presented in the previous deliverable report and in earlier sections of this document. Nevertheless, when other applications are considered, for instance combined heat and power, additional equipment is needed. These additional equipment are costed in this section but with a noteworthy difference with respect to the main equipment: these secondary components are off-the-shelf equipment bought in the market and thus the quoted cost is actually the corresponding market price. This means that there is no sensitivity to production volume.

#### *Business case #0. Power-only system*

Business case #0 does not require any additional equipment cost estimation as the whole assembly was already costed in the previous deliverable. For such reference case, Table 2 shows the selected specifications while Table 3 and Table 4 summarise the Purchased Equipment Cost and the installation costs of the simple recuperated (SR), intercooled recuperated (ICR) and intercooled, recuperated and reheated (ICRR) OMSoP systems for the production of electric power only and without non-solar energy supply (i.e., solar-only operation).

| BC #0 | | Air flow [g/s] | Net rated output [$kW_e$] | System efficiency [%] | Net mGT efficiency [%] | Dish aperture area [$m^2$] | Net receiver output [$kW_t$] |
|---|---|---|---|---|---|---|---|
| 800ºC-85% | SR | 200 | 15.4 | 15.7 | 24.9 | 122.7 | 61.9 |
| | ICR | 200 | 21.7 | 16.1 | 25.6 | 168.2 | 84.8 |
| | ICRR | 100 | 12.4 | 16.9 | 26.8 | 91.8 | 46.3 |
| 900ºC-90% | SR | 200 | 19.3 | 19.12 | 30.4 | 126.0 | 63.5 |
| | ICR | 200 | 27.9 | 19.5 | 30.9 | 179.2 | 90.3 |
| | ICRR | 100 | 15.5 | 20.1 | 31.9 | 96.4 | 48.6 |

***Table 2. BC #0 systems specifications.***

| BC #0-Solar | | mGT [€] | Receiver [€] | Dish [€] | BOP [€] | Total PEC [€] | Specific PEC [€/$kW_e$] |
|---|---|---|---|---|---|---|---|
| 800ºC-85% | SR | 7934 | 1561 | 36522 | 398 | 46415 | 3014 |
| | ICR | 9776 | 1891 | 54059 | 417 | 66143 | 3048 |
| | ICRR | 5992 | 2025 | 26984 | 386 | 35387 | 2854 |
| 900ºC-90% | SR | 9274 | 1936 | 37613 | 399 | 49222 | 2550 |
| | ICR | 9274 | 1936 | 37613 | 399 | 49222 | 2550 |
| | ICRR | 6374 | 2548 | 28329 | 388 | 37639 | 2428 |

***Table 3. BC #0. Purchased Equipment Cost of the solar-only system.***

<table>
<tr><th colspan="2" rowspan="2">BC #0-Solar</th><th colspan="3">Specific Installed cost [€/kW$_e$]</th></tr>
<tr><th>South Africa</th><th>Morocco</th><th>China</th></tr>
<tr><td rowspan="3">800ºC-85%</td><td>SR</td><td>4566</td><td>4693</td><td>4880</td></tr>
<tr><td>ICR</td><td>4547</td><td>4707</td><td>4887</td></tr>
<tr><td>ICRR</td><td>4353</td><td>4441</td><td>4628</td></tr>
<tr><td rowspan="3">900ºC-90%</td><td>SR</td><td>3837</td><td>3950</td><td>4107</td></tr>
<tr><td>ICR</td><td>3855</td><td>3998</td><td>4150</td></tr>
<tr><td>ICRR</td><td>3687</td><td>3769</td><td>3926</td></tr>
</table>

***Table 4. BC #0. Installed costs of the solar-only system.***

Business case #0 also includes a hybrid version of OMSoP where dual heat input, solar energy and fossil fuel, can be supplied simultaneously. The specific installed costs are slightly different when a combustor is incorporated into the system and the corresponding values are summarised in Table 5.

<table>
<tr><th colspan="2" rowspan="2">BC #0-Hybrid</th><th colspan="3">Specific Installed cost [€/kW$_e$]</th></tr>
<tr><th>South Africa</th><th>Morocco</th><th>China</th></tr>
<tr><td rowspan="3">800ºC-85%</td><td>SR</td><td>4607</td><td>4736</td><td>4925</td></tr>
<tr><td>ICR</td><td>4575</td><td>4738</td><td>4919</td></tr>
<tr><td>ICRR</td><td>4387</td><td>4475</td><td>4662</td></tr>
<tr><td rowspan="3">900ºC-90%</td><td>SR</td><td>3869</td><td>3984</td><td>4142</td></tr>
<tr><td>ICR</td><td>3877</td><td>4022</td><td>4174</td></tr>
<tr><td>ICRR</td><td>3716</td><td>3798</td><td>3955</td></tr>
</table>

***Table 5. BC #0. Installed costs of the hybrid system.***

### *Business case #1. Combined heat and power system*

Business case #1 results from the addition of a waste heat recovery to the base-case system (business case #0). In order to provide a cost estimate and technical guidelines for system integration, the combined heat and power catalogue applications released by the Environmental Protection Agency (EPA, 2015) is used. In this document, information is provided for a CHP system built around a 30-kWe Captone turbine. These data are summarised in Table 6 where the cost of the additional WHR sub-system is shown in absolute and specific terms (dividing the heat recovery equipment cost by the net output of the microturbine). Given that the cost model should be adapted to different engine layouts with different efficiencies, it is considered better to use the specific cost as a function of the net heat produced in order to estimate the cost of the subsystem.

| Catalogue of CHP technologies – Microturbines 2015 | |
|---|---|
| **Equipment costs** | |
| Gross electric output [$kW_e$] | 30 |
| Net electric output [$kW_e$] | 28 |
| Net thermal output [$kW_t$] | 61 |
| Generator set package [€] | 47886 |
| Heat recovery unit [€] | 12174 |
| Fuel compressor [€] | 7846 |
| **Power Specific Cost [€/kWe]** | **434.8** |
| **Heat Specific Cost [€/kWt]** | **199.6** |
| **Installation costs** | |
| Labour/Materials [€] | 20381 |
| Project and construction management [€] | 8116 |
| Engineering and fees [€] | 8116 |
| Contingency [€] | 3427 |
| Finance [€] | 631 |
| Specific equipment cost [€/kWe] | 2425 |
| **Specific installed cost [€/$kW_e$]** | **3878** |

***Table 6. Cost data for CHP units based on micro gas turbines* (EPA, 2015).**

Similar cost data have been found in (NREL, 2003) where specifications of the Capstone 330-30 kW are reported. The information is presented in Table 7 containing similar information as Table 6. The only difference is that installed cost are considered in the latter while, in the former, the WHR cost is shown in specific purchased equipment cost terms.

| Gas-fired Distributed Energy Resources Technology Characterizations 2003 | |
|---|---|
| **Microturbine design** | |
| Gross electric output [$kW_e$] | 30 |
| Net electric output [$kW_e$] | 28 |
| Net thermal output [$kW_t$] | 54 |
| **Microturbine cost** | |
| Installed cost for power only [€] | 79700 |
| Installed cost for CHP [€] | 92837 |
| Installed cost of waste heat recovery unit [€] | 13137 |
| **Specific microturbine cost** | |
| Installed cost for power only[€/$kW_e$] | 2846 |
| Installed cost for CHP only [€/$kW_e$] | 3316 |
| **Specific cost for CHP units [€/$kW_e$]** | **469** |
| **Specific cost for CHP units [€/$kW_t$]** | **243** |

***Table 7. Cost data for CHP units based on micro gas turbines* (NREL, 2003).**

The information in Table 7 confirms that the cost of the heat recovery unit needed to produce hot water is in the order of 200-245 €/kWt. Within this range, the upper limit is selected as a representative installed WHR cost for this business case.

Table 8 and Table 9 summarise the design technical specifications and the rated performances of the SR, ICR and ICRR OMSoP systems in CHP configuration (business case #1).

| Business-case #1. Design specifications | | | |
|---|---|---|---|
| WHR water inlet temperature [ºC] | 20 | mGT exhaust gas inlet pressure [Pa] | 103390 |
| WHR water outlet temperature [ºC] | 90 | mGT exhaust gas outlet pressure [Pa] | 101325 |
| WHR water inlet pressure [Pa] | 202650 | mGT mass flow rate [g/s] | 200 |
| WHR water outlet pressure [Pa] | 196570 | WHR minimum ΔT [ºC] | 20 |

*Table 8. Design specifications of business case #1.*

| Business-case #1. Technical and cost specifications | | | | | | |
|---|---|---|---|---|---|---|
| Technology level | Stack temperature [ºC] | WHR effectiveness [%] | Water mass flow rate [g/s] | Water mass flow rate [l/min] | Net heat output [$kW_t$] | WHR subsystem cost [€] |
| SR OMSoP systems | | | | | | |
| 800ºC-85% | 228.4 | 90.5 | 130.7 | 7.8 | 38.3 | 9382 |
| 900ºC-90% | 215.2 | 89.8 | 121.4 | 7.3 | 35.6 | 8716 |
| ICR OMSoP systems | | | | | | |
| 800ºC-85% | 215.5 | 89.9 | 121.6 | 7.3 | 35.6 | 8732 |
| 900ºC-90% | 207.6 | 89.4 | 116.1 | 6.7 | 34.0 | 8334 |
| ICRR OMSoP systems | | | | | | |
| 800ºC-85% | 238.9 | 91.0 | 69.0 | 4.1 | 20.2 | 4955 |
| 900ºC-90% | 224.7 | 90.3 | 64.0 | 3.8 | 18.8 | 4597 |

*Table 9. Specifications of business case #1 using simple recuperated (SR) technology.*

Finally, Table 10 shows the specific installed costs (per electric kilowatt) for the OMSoP systems in combined heat and power configuration.

| BC #1 | | Specific Installed cost [€/$kW_e$] | | |
|---|---|---|---|---|
| | | South Africa | Morocco | China |
| 800ºC-85% | SR | 5851 | 6020 | 6252 |
| | ICR | 5525 | 5703 | 5903 |
| | ICRR | 5306 | 5404 | 5189 |
| 900ºC-90% | SR | 4845 | 4994 | 5153 |
| | ICR | 4634 | 4793 | 4961 |
| | ICRR | 4445 | 4536 | 4710 |

*Table 10. Specific installed costs of business case #1 in the selected locations.*

As previously discussed in the introduction to business case #1, an alternative technology to benchmark OMSoP-CHP has been selected. This alternative electric and thermal power generator is based on electricity imported from the grid plus hot water at 90ºC produced by a natural gas heater. The costs required for the comparative cash flow analysis are the installed cost of the heater and the specific price of fuel. The first item is taken from (Compass International Inc., 2015) whilst the reference fuel price is taken from (Financial Times, 2016).

| Comparative CHP system cost | |
|---|---|
| Boiler cost [€/$kW_t$] | 65.00 |
| Methane fuel price [€/MWh] | 8.27 |

*Table 11. Reference technology to benchmark business case #1.*

## Project direct capital costs

When estimating the direct costs of a project there is always room for uncertainty, not only due to the uncertain value of the known list of equipment but also due to the unexpected needs; i.e., additional equipment or labour that might be needed. These are also referred to as the known-unknowns because the cost analyst is well aware of their existence. As a standard approach, and due to the impossibility of providing detailed costs for it, this uncertain cost is lumped in a single figure under the name of contingency cost.

Contingencies are usually estimated at 5-10% of the project direct cost in dish and similar applications. Based on this, a default value of 7% of the total installed cost is adopted in this analysis, yielding the following total direct cost:

$$C_{D,Tot} = C_{Ins,Tot} * (1 + 7\%)$$

## Project indirect costs

In addition to the direct cost associated to individual equipment and installation/erection, there are other costs in a project that cannot be directly attributed to an object/item. These are usually called indirect costs and might (or not) include overheads (which are the costs incurred by merely running the project). Amongst the different costs that could fall in this category, only the most relevant to OMSoP are considered in this analysis. These are the land cost and the owner and "EPC" cost. It has to be acknowledged that accounting for EPC costs in such a small project (where, most of the times, a single unit is installed) does not seem to make much sense. Yet, these are included to account for the cost of integrating OMSoP, the waste heat recovery unit and the end-user facilities. Since these three subsystems must be integrated thermally and operationally, there is an additional effort/cost needed to engineer, procure and finally assemble the whole plant.

Land costs are based on a specific cost [€/m$^2$] multiplied by the footprint of the system. This footprint was estimated as a square with side length equal to 1.5 the dish diameter (see Cost Analysis Deliverable Report). Nevertheless, for business case #1, this estimate is increased to a square with side length equal to 2.5 times the diameter of the dish in order to allow a larger area to install the waste heat recovery unit. The specific cost of the land is obviously largely variable and thus virtually any value could be considered. The default specific cost for the reference OMSoP system is 2.23 €/m$^2$ as in (NREL, 2016)

Regarding "EPC" costs, these are set to 11% based on the reference value also provided by the Solar Advisory Model SAM developed by NREL (NREL, 2016). Table 12 summarises the indirect costs in specific terms.

| Project indirect costs | |
|---|---|
| **Land cost [€/m$^2$]** | 2.23 |
| **EPC cost [%]** | 11% |

***Table 12. Indirect costs of Business Case #1.***

$$C_{I,Tot} = C_{I,Land}$$

$$C_{I,Land} = 2.23 * (2.5 * d_{dish})^2 * N_{dish}$$

$$C_{I,EPC} = 1.11 * C_{D,Tot}$$

### Project operation and maintenance costs

The costs needed to operate OMSoP are attributable to the fuel, which apply to the hybrid configuration only. Therefore, no operating costs are considered for the solar-only system.

The fuel considered for the operation of a standard hybrid OMSoP is diesel, whose main properties (for heating value and energy density) are presented in Table 13 along with reference prices for the selected countries in Table 14, excerpted from the Global Petrol Prices website (www.globalpetrolprices.com). It must be noted that estimating fuel price is not an easy task due to the volatility of fuel prices in recent years and the large influence of regional influences (i.e., plant site).

| Reference properties of diesel fuel | |
|---|---|
| Low Heating Value [MJ/kg] | 42.612 |
| Density [kg/m³] | 850 |

***Table 13. Reference fuel properties.***

| Country | Diesel price [€/m³] |
|---|---|
| South Africa | 689.01 |
| Morocco | 733.75 |
| China | 1163.27 |

***Table 14. Reference national fuel prices (www.globalpetrolprices.com).***

The estimation of maintenance costs is based on information provided by Consortium partners and also information found in literature. These costs are grouped as follows (see previous section for further details):

- Fixed annual costs [€/year].
- Capacity based fixed annual costs [€/kW$_e$ year].
- Generation based variable costs [€/kWh$_e$].

Maintenance costs for the micro gas turbine are taken from the range provided by (Soares, 2007): 0.96-1.92 [c€_2007/kWhe]. The cost is expressed as Eurocents per kWh, as a variable cost depending on the total energy produced, which is actually a function of (primarily) the number of operating hours of the micro gas turbine.

The information about maintenance costs of parabolic dishes and solar receivers in the public domain is very scarce. Moreover, when available, it refers to systems based on Stirling engines so a direct extrapolation to gas turbine based systems is not possible. This is particularly acute for the receiver owing to the different design and reportedly lower reliability. With this caution in mind, Table 15 presents a summary of the maintenance costs of the Envirodish (dish Stirling) system installed at the University of Seville. These values are taken as an upper limit for the same items in OMSoP due to the reasons mentioned above and taking into account that the system is not optimised and thus several unexpected added costs arose during operation. Another value that can be used as a reference is provided by SAM, where the estimate of maintenance costs for this technology is 18 €/kW$_e$·year.

| Eurodish Sevilla | | | |
|---|---|---|---|
| **Component** | **Annual cost [€/year]** | **Annual cost by capacity [€/year·m²]** | **Total annual cost by capacity (only dish) [€/year·m²]** |
| **Dish** | 100.98 | 1.7 | **5.9** |
| **Servomotors** | 233.52 | 3.9 | |
| **Auxiliaries** | 16.41 | 0.3 | |
| **Receiver** | 50.49 | 1.9 | |

***Table 15. Maintenance costs of the Envirodish system in Seville, Spain.***

With all this information, the final maintenance costs assumed for OMSoP are provided in Table 16. Values are given for the reference business case #0 (power-only) and for combined heat and power applications, business case #1.

| Business case | Maintenance cost based on capacity [€/(kW$_e$·year)] | Maintenance cost based on generation [€/MWh] |
|---|---|---|
| **OMSoP BC#0 – Solar** | 15 | 15 |
| **OMSoP BC#0 – Hybrid** | 15 | 20 |
| **OMSoP BC#1 - CHP** | 20 | 30 |
| **Benchmark CHP** | 15 | 10 |

***Table 16. Maintenance costs of the OMSoP system for business cases #0 and #1.***

## *Off design performance and energy production*

### Business case #0-S. Solar-only, power-only system

This section provides information about the performance model employed to evaluate the off-design behaviour of the system, used to calculate the annual yield. It is organised in two parts. First, the reference simple-recuperated model is introduced and, then, the system incorporating intercooling and reheat is presented.

The strategy considered to operate the solar-only system is to run the microturbine at variable speed, letting the mass flow rate and electric power output free to change proportionally to the heat input received by the receiver. The variable speed operation of the micro gas turbine is based on changing the rotational speed and the mass flow rate to maintain the turbine inlet temperature constant at its design point value. This can be numerically implemented by complex models incorporating mathematical descriptions of the physical phenomena involved or, instead, through the utilisation of a performance matrix. This second option is preferred in this work for the sake of simplicity. Other deliverable reports of OMSoP provide abundant information about the performance models behind the matrix.

The performance matrix is provided by ENEA and considers the ideal behaviour of the cycle; i.e. no limitations to the maximum operating temperature of the regenerator nor to the maximum rotational speed are taken into account. The matrix input data set includes DNI and ambient temperature and, in return, it provides the electric output. The information was plotted to illustrate the impact of these parameters on power generation; this is shown in Figure 5 and Figure 6 for efficiency and power output. Values are given in relative terms with respect to the rated values, corresponding to 800 W/m$^2$ and 25ºC: 7.5 kW$_e$ and 15.3% solar to electric efficiency.

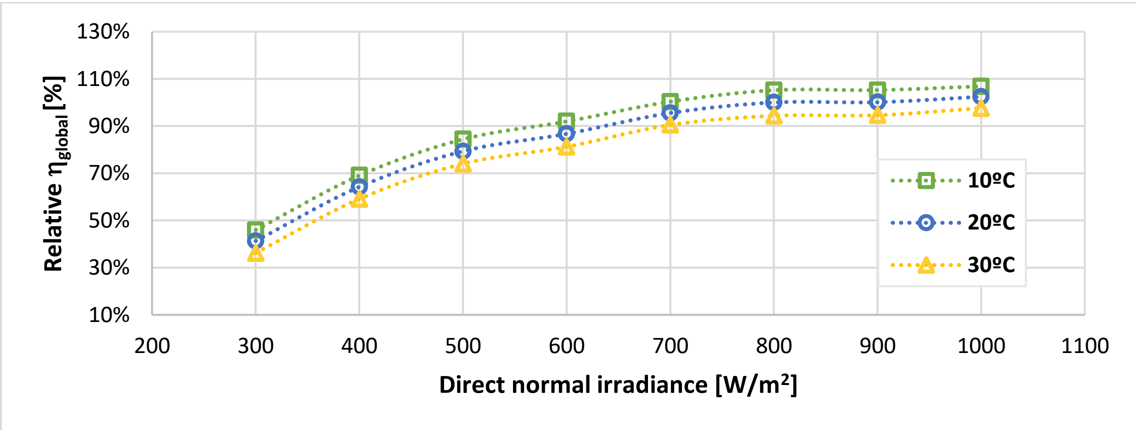


***Figure 5. Relative total efficiency (solar to electric) of the reference base-case OMSoP system.***

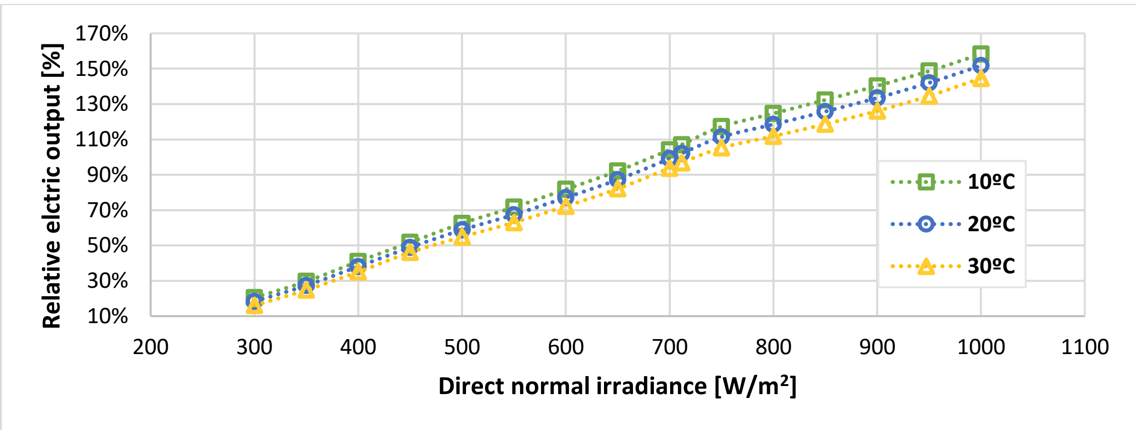


***Figure 6. Relative electric output of the reference base-case OMSoP system.***

The matrix is then transformed into a fitting curve to enable the continuous evaluation of $(DNI, T_{Dry\ Bulb})$ pairs without a time-consuming physics-based model. The fitting is a polynomial which is 2nd order on dry bulb temperature and 4th order on radiation, as shown in the following equations:

$$\eta_{rel} = \frac{\eta}{\eta_{DP}}$$

$$T_{amb,rel} = \frac{T_{amb}\ [K]}{T_{amb,DP}\ [K]}$$

$$DNI_{rel} = \frac{DNI}{DNI_{DP}}$$

$$\begin{aligned}\eta_{rel} = a_0 + a_1 \cdot T_{amb,rel} + a_2 \cdot DNI_{rel} + a_3 \cdot T_{amb,rel}^2 + a_4 \cdot T_{amb,rel} \cdot DNI_{rel} + a_5 \cdot DNI_{rel}^2 \\ + a_6 \cdot T_{amb,rel}^2 * DNI_{rel} + a_7 \cdot T_{amb,rel} \cdot DNI_{rel}^2 + a_8 \cdot DNI_{rel}^3 + a_9 \cdot T_{amb,rel}^2 \\ * DNI_{rel}^2 + a_{10} \cdot T_{amb,rel} \cdot DNI_{rel}^3 + a_{11} \cdot DNI_{rel}^4\end{aligned}$$

$$\mathbb{P}_{el} = \eta_{DP} \cdot \eta_{rel} \cdot DNI_{DP} \cdot A_{dish}$$

$$E_{el} = \sum_{h=1}^{8760} \mathbb{P}_{el}(h)$$

The comparison between the performance matrix provided by ENEA and the interpolating functions is shown in Figure 7 and Figure 8. The agreement is, as expected, satisfactory.

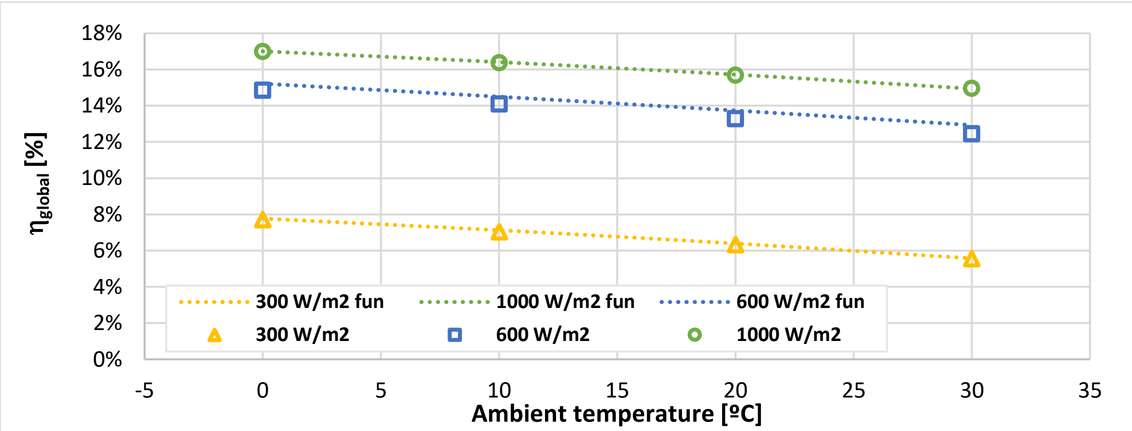


***Figure 7. Comparison between raw data provided by ENEA (markers) and interpolating functions (dotted lines). Dependence of global (solar to electric) efficiency on ambient temperature.***

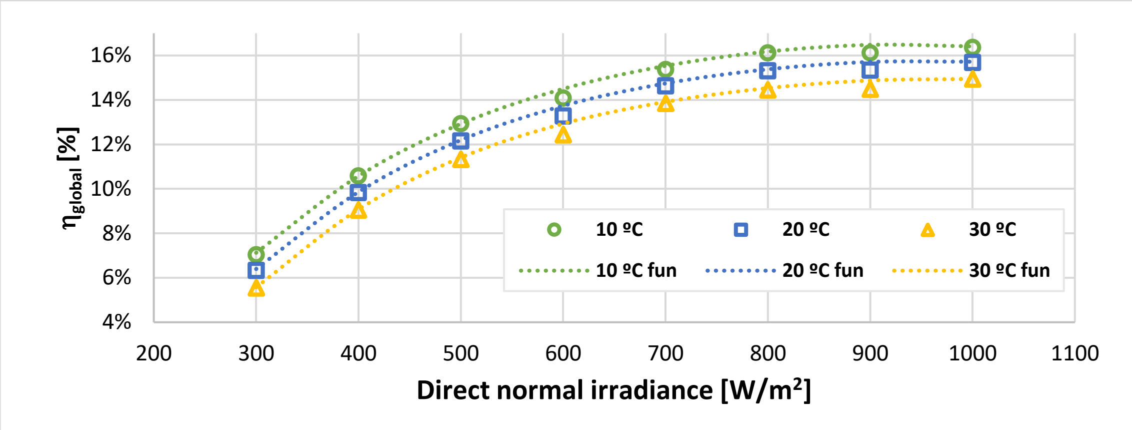


***Figure 8. Comparison between raw data provided by ENEA (markers) and interpolating functions (dotted lines). Dependence of global (solar to electric) efficiency on direct normal irradiance.***

Based on the methodology described, annual simulations are performed for the OMSoP base-case design point characterised by the following variables: ambient temperature (25ºC), DNI (800 W/m$^2$) and solar-to-electric efficiency of each of the systems studied. The following figures show the mean annual yield (Figure 9), average conversion efficiency (Figure 10) and system capacity factor (Figure 11) for the three countries of interest. In all cases, the system modelled is based on a 200 g/s simple recuperated microturbine for which two different specifications are considered: base (800ºC turbine inlet temperature and 85% recuperator effectiveness) and upgraded (900ºC turbine inlet temperature and 90% recuperator effectiveness).

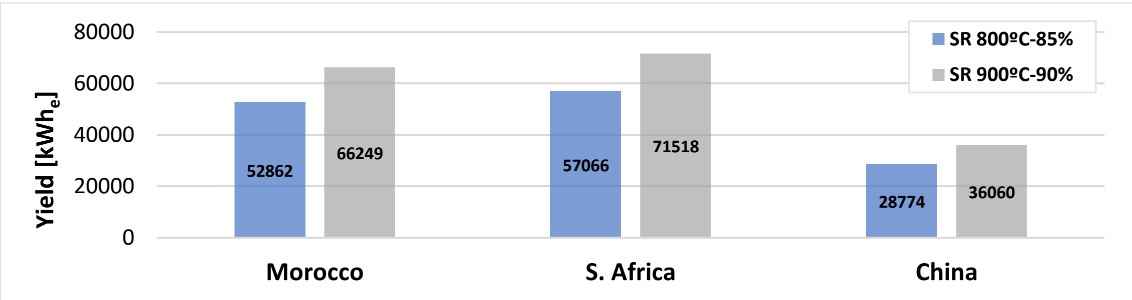


***Figure 9. Annual yield for three selected locations. Values are given for both the base and upgraded engine (simple recuperative layouts in both cases).***

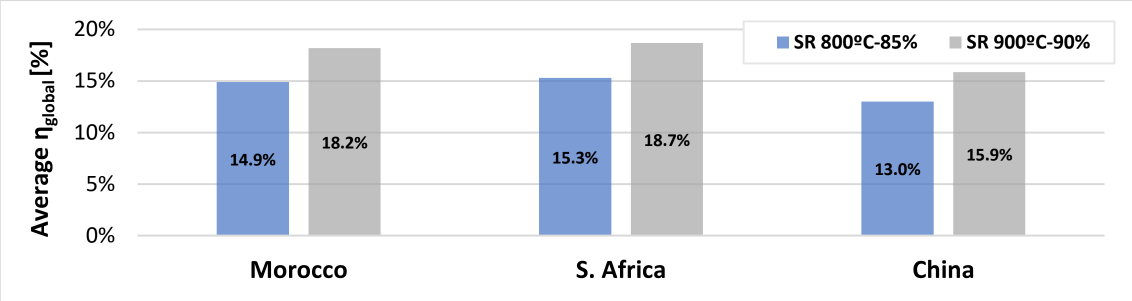


***Figure 10. Average global (solar-to-electric) efficiency for three selected locations. Values are given for both the base and upgraded engine (simple recuperative layouts in both cases).***

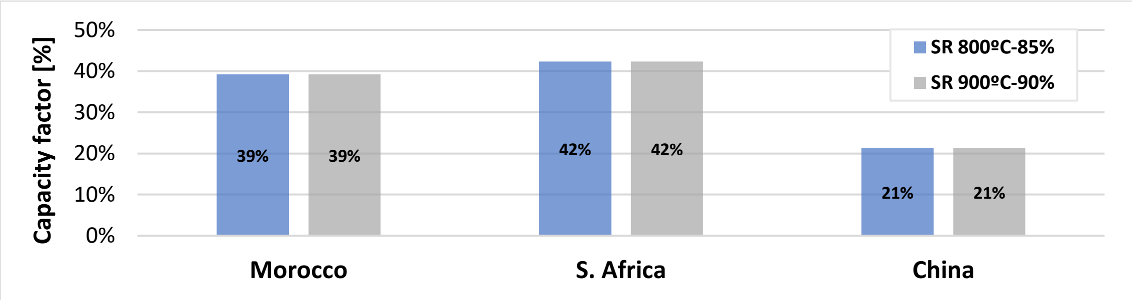


***Figure 11. Annual capacity factor for three selected locations. Values are given for both the base and upgraded engine (simple recuperative layouts in both cases).***

There are some interesting observations in these results:

- In all cases, the utilisation of the upgraded technology has the potential to boost the production of electricity by 25%.
- The location of the plant turns out critical as deduced from the fact that Morocco and South Africa exhibit much higher yield than China thanks to the also higher design DNI. Actually, the yield in South Africa almost doubles that of China for the same system size (air mass flow through the turbine).
- The previous bullet point is confirmed by the different capacity factor.
- The system based on the standard (base) technology provides an average efficiency of more than 15% for a good location whereas this drops to 13% in a location that is not so good.
- Further to the previous bullet point, capacity factors in good sites are in the order of 40%.

The average performance of the system proves to be satisfactory, thanks to the good part-load performance exhibited by recuperated gas turbines. From the results, the benefit of incorporating the upgraded system components is also evident. Based on this, and in order to explore the remaining gains in evolving the technology, OMSoP systems incorporating more complex engine layouts (already studied in the previous deliverable report on cost analysis) are now studied.

The systems considered in these new simulations are those corresponding to the lowest installation costs as follows (note that the specifications of the reference simple recuperative engine layout are also given for completeness):

- Simple recuperative (SR) layout: micro gas turbine with 200 g/s air mass flow rate delivering 15.4 kWe for 800ºC turbine inlet temperature and 85% recuperator effectiveness.
- Intercooled recuperative (ICR) layout: micro gas turbine with 200 g/s air mass flow rate delivering 21.7 kWe for 800ºC turbine inlet temperature and 85% recuperator effectiveness.
- Intercooled and reheated, recuperative (ICRR) layout: micro gas turbine with 100 g/s air mass flow rate delivering 12.4 kWe for 800ºC turbine inlet temperature and 85% recuperator effectiveness.

It is noted that these the two first systems have the same mass flow whereas the third one (ICRR) is smaller in size. This reflects in Figure 12 and Figure 13 showing the annual yield and average global (solar-to-electric) efficiency of the intercooled, recuperative system. The same information is shown in Figure 14 and Figure 15 for the intercooled and reheated, recuperative system. A summary of the annual yield in each case is presented in Table 17.

| BC #0 | | | Total yield [$kWh_e$] | Annual conversion efficiency [%] |
|---|---|---|---|---|
| South Africa | 800ºC-85% | SR | 57066 | 15.3% |
| | | ICR | 80411 | 15.7% |
| | | ICRR | 45949 | 16.5% |
| | 900ºC-90% | SR | 71518 | 18.7% |
| | | ICR | 103386 | 19.0% |
| | | ICRR | 57437 | 19.6% |
| Morocco | 800ºC-85% | SR | 52862 | 14.9% |
| | | ICR | 74487 | 15.3% |
| | | ICRR | 42564 | 16.0% |
| | 900ºC-90% | SR | 66249 | 18.2% |
| | | ICR | 95770 | 18.5% |
| | | ICRR | 53205 | 19.1% |
| China | 800ºC-85% | SR | 28774 | 13.0% |
| | | ICR | 40545 | 13.4% |
| | | ICRR | 23168 | 14.0% |
| | 900ºC-90% | SR | 36060 | 15.9% |
| | | ICR | 52129 | 16.1% |
| | | ICRR | 28960 | 16.7% |

*Table 17. Annual performance results (simulated) of the OMSoP BC #0-Solar systems.*

The first set of figures confirms a drastic increase in the production of electricity when intercooling is incorporated, thanks to the very large reduction of compression work. Indeed, the annual yield increases from 65 – 70 MWh to 75-95 MWh, which means some 20% rise for the same engine throughput. The same performance enhancement can be seen if efficiency is considered since the larger output comes about because of a higher conversion efficiency for the same system size.

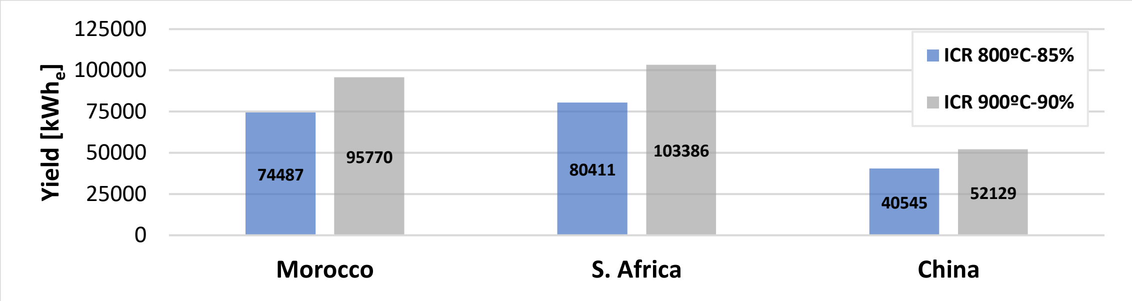


*Figure 12. Annual yield for three selected locations. Values are given for both the base and upgraded engine (intercooled recuperative layouts in both cases).*

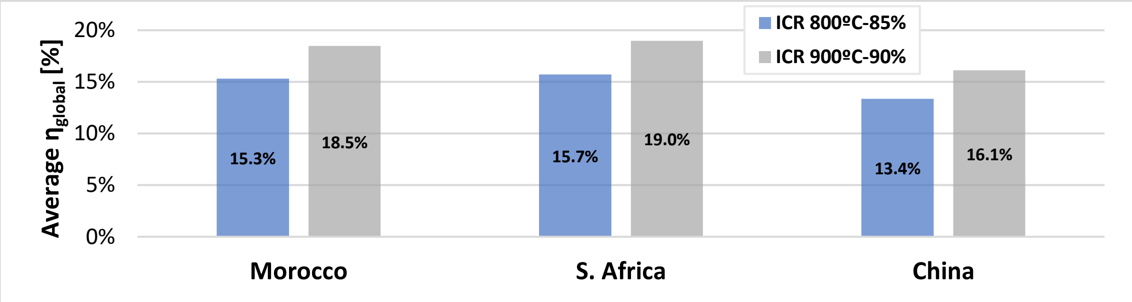


*Figure 13. Average global (solar-to-electric) efficiency for three selected locations. Values are given for both the base and upgraded engine (intercooled recuperative layouts in both cases).*

The adoption of reheat involves a more complex receiver but is compensated for by a larger production of electricity. A direct comparison of Figure 9 and Figure 14 actually confirms that the intercooled and reheated, recuperative system produces 20% less electricity but with half the air flow rate. Even if it must be acknowledged that each kg/s of air is heated twice in the ICRR engine, there is a true performance enhancement as deduced from the higher solar-to-electric efficiency (Figure 15).

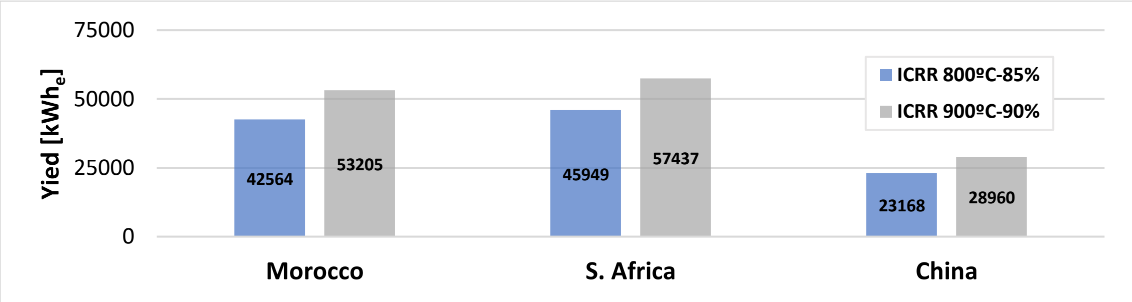


*Figure 14. Annual yield for three selected locations. Values are given for both the base and upgraded engine (intercooled and reheated, recuperative layouts in both cases).*

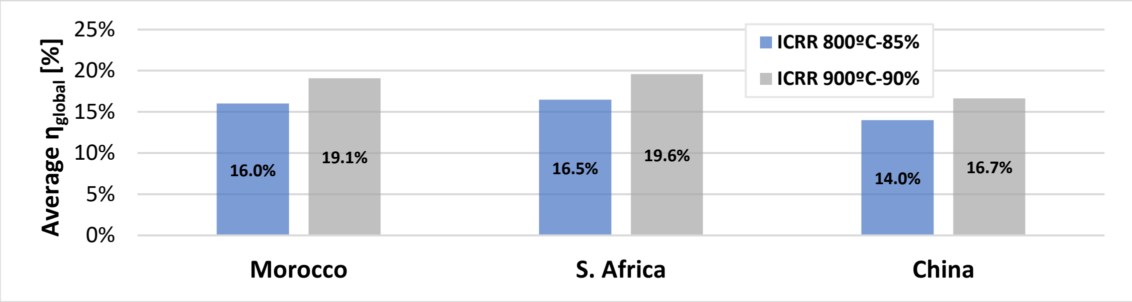


***Figure 15. Average global (solar-to-electric) efficiency for three selected locations. Values are given for both the base and upgraded engine (intercooled and reheated, recuperative layouts in both cases).***

Based on the results shown, it is concluded that the reference OMSoP system selected in the previous cost analysis is capable of producing some 60 MWh in a year if the location has good solar conditions. For sites with less solar resource, a drastic drop of roughly 50% must be expected. At the same time, it also becomes evident that there is a very large potential for performance enhancement if better (upgraded) components and even more complex system layouts are incorporated. In the best case (ICRR), average efficiencies in the order of almost 30% are possible.

## Business case #0-H. Hybrid, power-only system

A variant of business case #0 is the operation in hybrid mode to produce electric power only, whose differences with respect to solar-only operation are discussed in this section. The calculation of the annual yield is based on the assumption that the system is required to produced full power (rated capacity) as long as the DNI is higher than the lower operational limit (set to 240 W/m$^2$). Therefore, fuel is burned when the solar heat input does not suffice to achieve the rated conditions, either to further increase the temperature of pressurised air at turbine inlet or to enable higher mass flow rates. The required fuel heat input (and consequently the fuel flow rate) is calculated by subtracting the solar heat input from the design point total heat input and then manipulating the result with the Lower Heating Value of the fuel and the efficiency of the combustion process. It is noted that the rated capacity is delivered regardless of ambient temperature, should this be possible; therefore, for very high ambient temperatures, the operational limits of the engine will prevent it from achieving the rated output. Accordingly, the power output of the hybrid system ranges between the design point value and the maximum power provided by solar energy only.

$$\mathbb{P}_{el}[kW_e] = \begin{cases} \begin{cases} \mathbb{P}_{el,sol} & if\ \mathbb{P}_{el,sol} > \mathbb{P}_{el,DP} \\ \mathbb{P}_{el,DP} & if\ \mathbb{P}_{el,sol} \leq \mathbb{P}_{el,DP} \end{cases} & if\ DNI \geq 240\ \left[\frac{W}{m^2}\right] \\ 0 & if\ DNI < 240\ \left[\frac{W}{m^2}\right] \end{cases}$$

$$\dot{Q}_{fuel}[kW_t] = \begin{cases} \begin{cases} 0 & if\ \mathbb{P}_{el,sol} > \mathbb{P}_{el,DP} \\ \dot{Q}_{sol,DP} - \dot{Q}_{sol} & if\ \mathbb{P}_{el,sol} \leq \mathbb{P}_{el,DP} \end{cases} & if\ DNI \geq 240 \left[\frac{W}{m^2}\right] \\ 0 & if\ DNI < 240 \left[\frac{W}{m^2}\right] \end{cases}$$

$$\dot{m}_{fuel}\left[\frac{kg}{s}\right] = \frac{\dot{Q}_{fuel}}{LHV \cdot \eta_{comb}}$$

$$m_{fuel}[kg] = \sum_{h=1}^{8760} \dot{m}_{fuel}(h)$$

Table 18 presents a summary of the results obtained from the annual simulation; these are discussed in the following paragraphs. Figure 16 to Figure 18 show the annual yield of the hybrid OMSoP system using the three possible engine layouts: simple recuperative, intercooled recuperative and intercooled and reheat recuperative layout. A comparison with the corresponding figures in the solar-only version confirm that there is a parallel increase in the production of electricity for all of them when hybrid operation is enabled. Thus, regardless of the layout, the incorporation of fossil fuel backup brings about an increase in production estimated at 17% for South Africa, 22% for Morocco and 60% for China. As expected, the upsurge in annual yield is highest in those locations with worst solar conditions.

| BC #0-H | | | Total yield [$kWh_e$] | Annual efficiency [%] | Capacity factor [%] | Annual fuel burn [$m^3$] | Solar share [%] |
|---|---|---|---|---|---|---|---|
| South Africa | 800ºC-85% | SR | 67027 | 15.3% | 49.7% | 3.13 | 85.1% |
| | | ICR | 94446 | 15.7% | 49.7% | 4.30 | 85.1% |
| | | ICRR | 53969 | 16.5% | 49.7% | 2.34 | 85.1% |
| | 900ºC-90% | SR | 84001 | 18.7% | 49.7% | 3.22 | 85.1% |
| | | ICR | 121431 | 19.0% | 49.7% | 4.58 | 85.1% |
| | | ICRR | 67462 | 19.6% | 49.7% | 2.46 | 85.1% |
| Morocco | 800ºC-85% | SR | 64994 | 14.9% | 48.2% | 3.74 | 81.3% |
| | | ICR | 91583 | 15.3% | 48.2% | 5.12 | 81.3% |
| | | ICRR | 52333 | 16.0% | 48.2% | 2.80 | 81.3% |
| | 900ºC-90% | SR | 81454 | 18.2% | 48.2% | 3.84 | 81.3% |
| | | ICR | 117749 | 18.5% | 48.2% | 5.46 | 81.3% |
| | | ICRR | 65416 | 19.1% | 48.2% | 2.94 | 81.3% |
| China | 800ºC-85% | SR | 46390 | 13.0% | 34.4% | 2.86 | 62.0% |
| | | ICR | 65368 | 13.4% | 34.4% | 3.92 | 62.0% |
| | | ICRR | 37353 | 14.0% | 34.4% | 2.14 | 62.0% |
| | 900ºC-90% | SR | 58138 | 15.9% | 34.4% | 2.94 | 62.0% |
| | | ICR | 84044 | 16.1% | 34.4% | 4.18 | 62.0% |
| | | ICRR | 46691 | 16.7% | 34.4% | 2.25 | 62.0% |

***Table 18. Annual performance of OMSoP BC #0-Hybrid systems.***

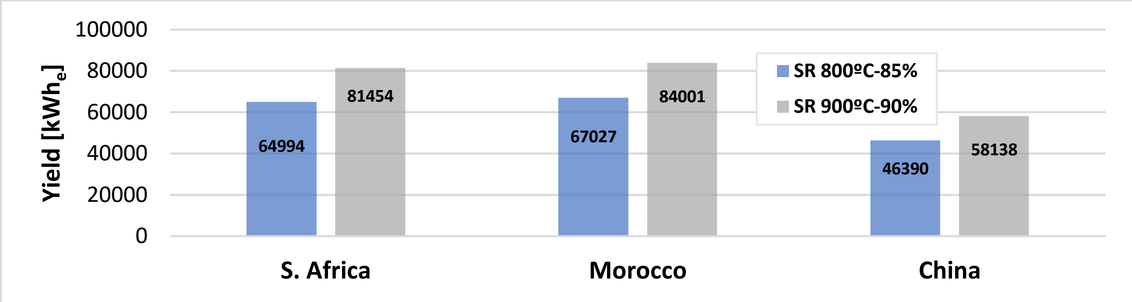


***Figure 16. Annual yield for three selected locations. Values are given for both the base and upgraded hybrid engine (simple recuperative layouts in both cases).***

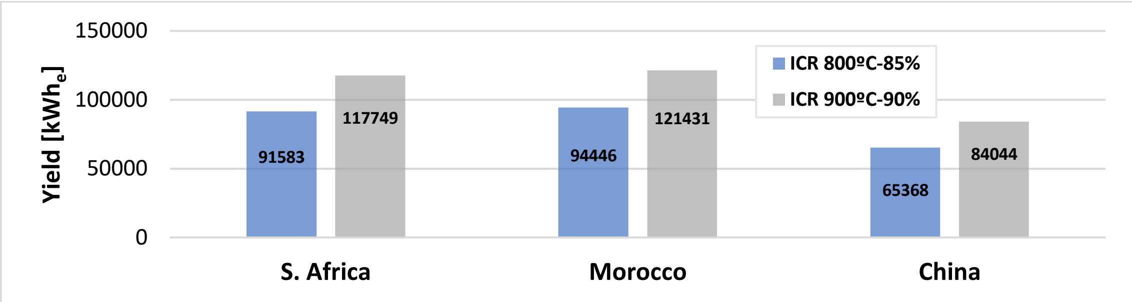


***Figure 17. Annual yield for three selected locations. Values are given for both the base and upgraded hybrid engine (intercooled recuperative layouts in both cases).***

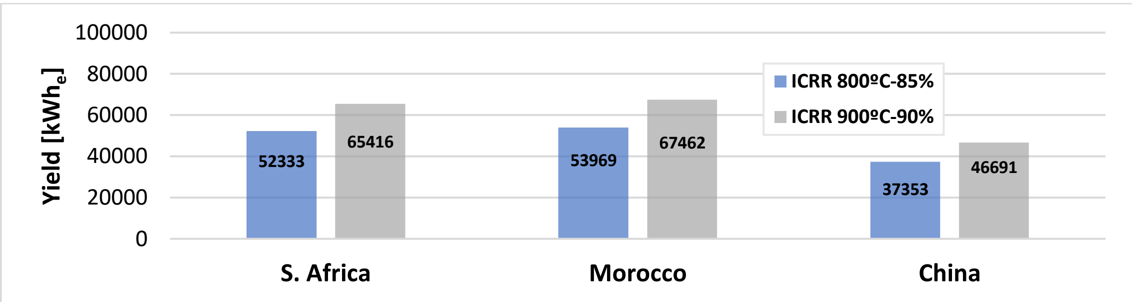


***Figure 18. Annual yield for three selected locations. Values are given for both the base and upgraded hybrid engine (intercooled and reheated, recuperative layouts in both cases).***

A similar set of figures presents the total fuel burn in a year, Figure 19 to Figure 21. It is interesting to see that in spite of the very heavy firing strategy, the amount of fuel needed is modest, not exceeding 5000 litres in most cases. In this regard, the much larger fuel consumption of the intercooled reheat engine (ICR) is worth noting. This higher fuel demand of the ICR engine is actually in approximate proportion to the higher output of the engine with respect to the standard simple recuperated solar-only unit (21.7 kWe / 15.4 kWe), with a minor deviation from this ratio due to slight changes in efficiency. In other words, the change in fuel consumption is due to a change in capacity which is, to a much lesser extent (two orders of magnitude), compensated for by the higher efficiency of the ICR engine. In any case, the capacity of the fuel tank needed is well within the usual industrial practice and hence this element is not expected to bring with it any added complexity to OMSoP.

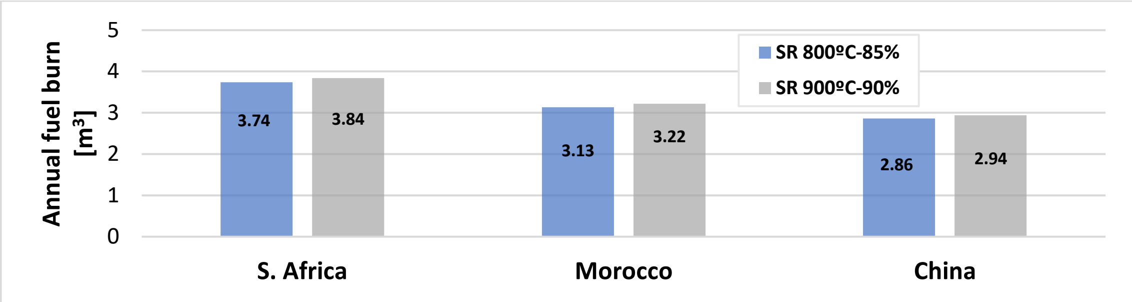


*Figure 19. Annual fuel burn for three selected locations. Values are given for both the base and upgraded hybrid engine (simple recuperative layouts in both cases).*

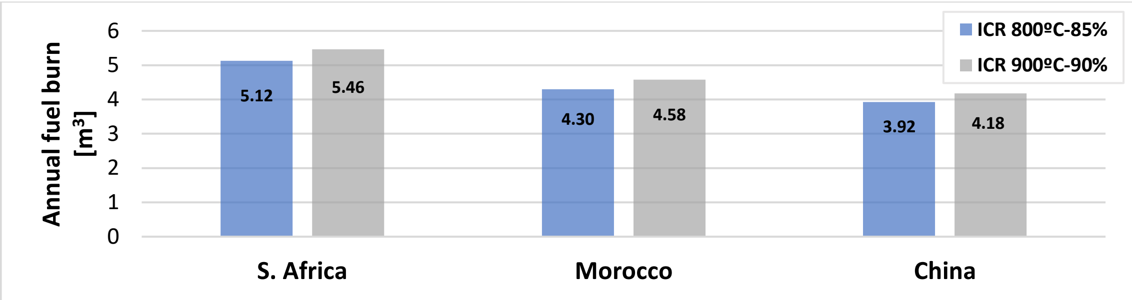


*Figure 20. Annual fuel burn for three selected locations. Values are given for both the base and upgraded hybrid engine (intercooled recuperative layouts in both cases).*

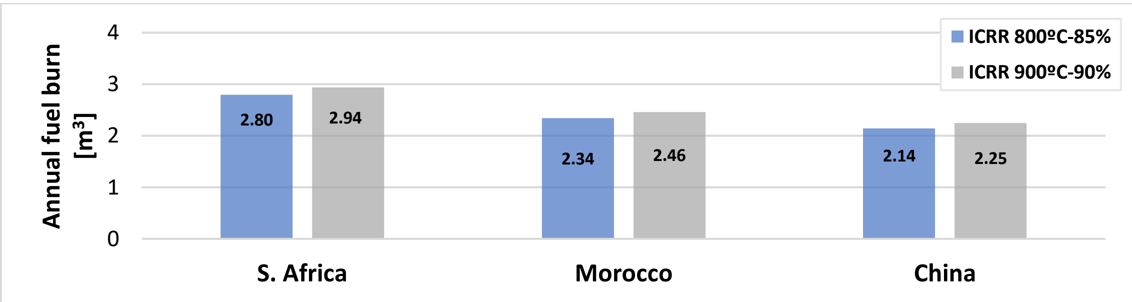


*Figure 21. Annual fuel burn for three selected locations. Values are given for both the base and upgraded hybrid engine (intercooled, reheat recuperative layouts in both cases).*

The last set of figures (Figure 22 and Figure 23) shows the annual capacity factor and solar share. Given that the three engine layouts (SR, ICR and ICRR) show similar results, only one set of plots is shown, corresponding to the results for the simple recuperative engine. The solar share is defined as the fraction of total heat input that comes from solar energy:

$$Q_{sol}[kWh] = \sum_{h=1}^{8760} A_{dish} \cdot DNI(h)$$

$$Q_{fuel}[kWh] = \sum_{h=1}^{8760} \dot{Q}_{fuel}(h)$$

$$SS[\%] = \frac{Q_{sol}}{Q_{fuel} + Q_{sol}}$$

The increase in capacity factor with respect to the solar-only recuperative case coincides, naturally, with that already observed for the annual yield in the paragraphs above (Figure 16). Nevertheless, it is shown here again in a different format to evidence that the incorporation of hybrid capabilities boosts the capacity factor to values that are close to 50%. Moreover, the combined analysis of Figure 22 and Figure 23 shows that this higher capacity factor (which is very helpful in bringing down the cost of electricity of the system) is achieved at the expenses of a fuel supply that is not as high as expected from the initial assumptions. Indeed, the fact that the system operates at full capacity regardless of the available solar energy turns out to not bring about as a heavy firing as one could have thought. On the contrary, the system still receives more than 80% of the total heat input from the sun and only a fifth (or less) from diesel fuel (except for the most unfavourable location).

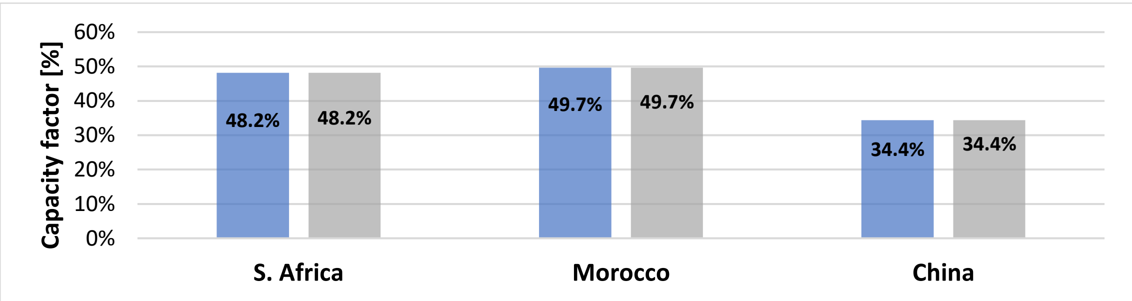


***Figure 22. Annual capacity factor for three selected locations. Values are given for both the base and upgraded hybrid engine.***

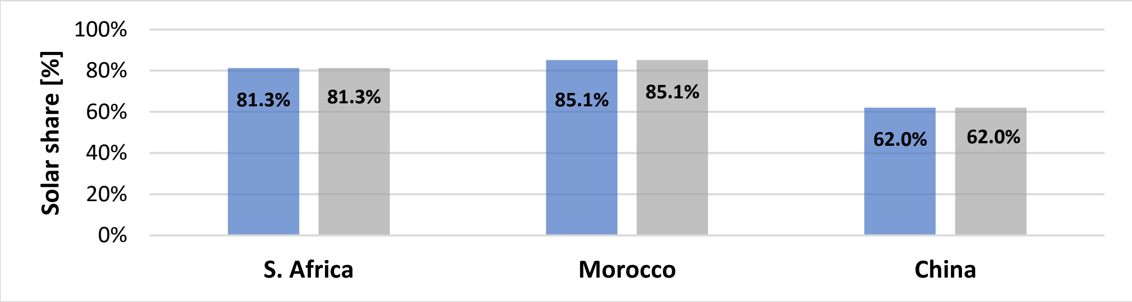


***Figure 23. Annual solar share for three selected locations. Values are given for both the base and upgraded hybrid engine.***

The overall conclusions drawn from this analysis is that the incorporation of hybrid operation largely increases the reliability and flexibility of the system without, in practice, changing the generation paradigm to a system closer to standard diesel gensets.

### Business case #1. Solar-only, combined heat and power system

This second business case considers the production of power and thermal energy in the form of water at 90ºC (mainly for domestic and residential applications). The simulation of power generation is replicated from the previous business cases and thus no further comments are needed. Then, a complementary model to estimate the production of thermal energy is added.

The thermal energy produced by the waste heat recovery unit installed in the exhaust gas stream depends upon the available energy borne by such gases and on the inlet/outlet water temperatures. It is assumed that the control variable of the subsystem is water flow, meaning that this is varied for the particular operating conditions in order to keep the outlet temperature of water at the rated value.

The model used to calculate the available energy downstream of the gas turbine is of the lumped volume type, given the simplicity of the bottoming system and in order to reduce the computational burden. In this context, the base performance model is used as an input, yielding the following simple formula that provides the energy available downstream of the recuperator:

$$\dot{Q}_{exh} = (1 - \eta_{mGT}) \cdot \frac{\mathbb{P}_{el}}{\eta_{mGT}}$$

where $\mathbb{P}_{el}$ and $\eta_{mGT}$ are the electric output and micro gas turbine efficiency (heat-to-power) respectively. The specific enthalpy of the exhaust gases and, therefore, their temperature is then calculated as follows (shown for specific enthalpy), making use of the mass flow rate provided by the main performance model:

$$h_{mGT,out} = h_{ref} + \frac{\dot{Q}_{exh}}{\dot{m}_{mGT}}$$

Once the inlet gas temperature to the waste heat recovery unit is known, the energy balance and the production of water are calculated by assuming that the pinch point of the heat exchanger remains constant. This option is preferred to computing the actual heat exchange coefficient since this would imply drafting a preliminary geometry or, instead, making other simplifications. At the same time, this assumption is conservative as it is known that the pinch point of a waste heat recovery unit decreases when operated at part load (Ganapathy, 2003); this means that the results so obtained cannot be considered optimistic or overestimated in any way. Regarding the water flow control, this is implemented through a Matlab model incorporating a reference performance map of pumps with similar characteristics.

The resulting model is used to produce a set of matrices similar to those in the main performance model (power generation). This new set of matrices provides the net heat recovered (or the production of hot water) under different operating conditions, with inputs being DNI and ambient temperature. Each matrix is then replicated by a set of fitting curves, normalised to the rated values for standardisation. The polynomial has the following aspect:

$$\dot{Q}_{rel} = \frac{\dot{Q}_{net}[kW_t]}{\dot{Q}_{net,DP}[kW_t]}; \; T_{amb,rel} = \frac{T_{amb}\ [K]}{T_{amb,DP}\ [K]}; \; DNI_{rel} = \frac{DNI[W/m^2]}{DNI_{DP}[W/m^2]}$$

$$\dot{Q}_{rel} = b_0 + b_1 \cdot T_{amb,rel} + b_2 \cdot DNI_{rel} + b_3 \cdot T_{amb,rel}^2 + b_4 \cdot T_{amb,rel} \cdot DNI_{rel} + b_5 \cdot DNI_{rel}^2$$

Figure 24 shows the amount of heat recovered for variable heat input (DNI), with data shown relative to the rated value. As expected, a reduction of DNI brings about a linear reduction of the amount of heat recovered, a pattern that is very similar for the three ambient temperatures considered. Indeed, lower heat input means lower mass flow rate and pressure ratio. This involves a reduction in both the mass flow rate and temperature of stack gases coming from the microturbine and therefore a reduction in the amount of heat recovered.

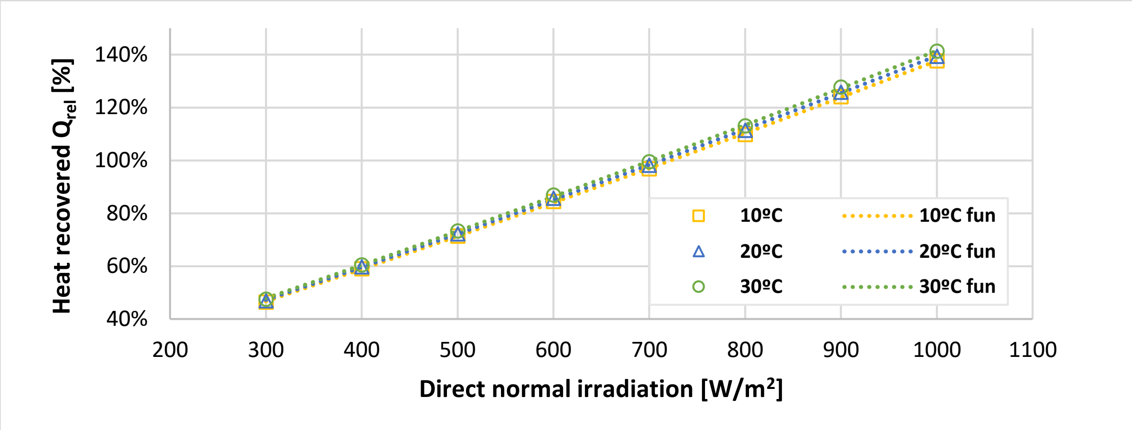


***Figure 24. Heat recovered (relative to design point) for variable direct normal irradiation and constant ambient temperature. Values provided by model and fitting curve.***

Figure 25 shows similar information but applied to variable ambient temperature at constant DNI. This plot might seem shocking at first sight given that the fraction of heat recovered seems to be almost constant for different temperatures. The key to interpreting this pattern is noting that the values given are relative to the rated heat recovery. When ambient temperature is reduced at constant DNI, the efficiency of the engine increases, which means that the fraction of heat input rejected to the environment (i.e., sensible heat in the exhaust gases) decreases. Nevertheless, at the same time, the output of the engine increases in the same direction (descending ambient temperature) and thus both effects virtually cancel each other out. This is why only a slight descent in the amount of heat recovered is observed in the plot.

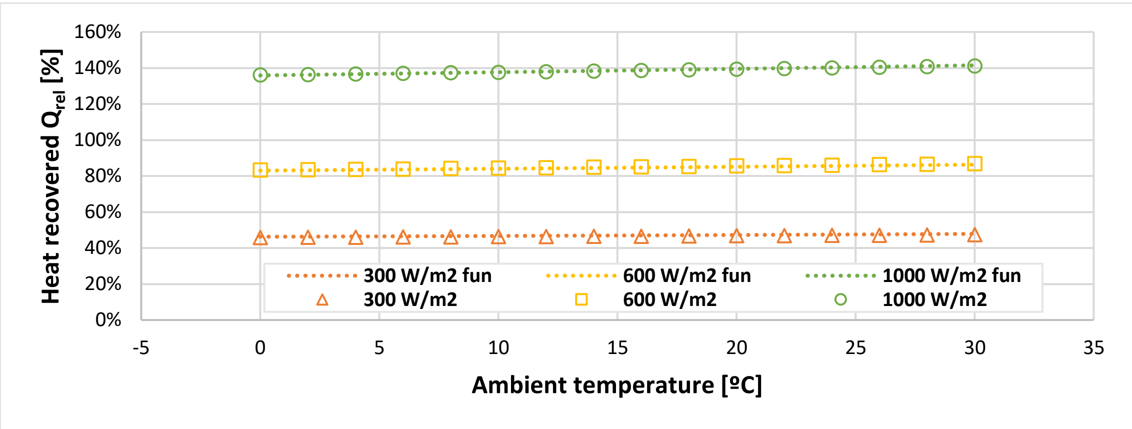


***Figure 25. Heat recovered (relative to design point) for variable ambient temperature and constant direct normal irradiation. Values provided by model and fitting curve.***

The application of the complete business case #1 model to the three selected locations yields the results presented in Figure 26 to Figure 28. These plots show, for a Combined Heat and Power OMSoP system based on the simple recuperative engine, the production of heat (thermal yield), the thermal to electric yield ratio and the average CHP efficiency. This latter parameter is defined as:

$$Q_{net} = \sum_{h=1}^{8760} Q_{rel}(h) \cdot \dot{Q}_{net,DP}$$

$$\eta_{CHP} = \frac{E_{el} + Q_{net}}{DNI \cdot A_{dish}}$$

| BC #1 | | | Total electricity yield [kWh$_e$] | Electricity conversion efficiency [%] | Electricity capacity factor [%] | Total heat yield [kWh$_e$] | Total conversion efficiency [%] | Heat capacity factor [%] | Heat / Electricity ratio [%] |
|---|---|---|---|---|---|---|---|---|---|
| **South Africa** | **800ºC-85%** | **SR** | 57066 | 15.3% | 42% | 145774 | 57.1% | 43% | 255% |
| | | **ICR** | 80411 | 15.7% | 42% | 135670 | 44.4% | 43% | 169% |
| | | **ICRR** | 45949 | 16.5% | 42% | 76989 | 46.3% | 43% | 168% |
| | **900ºC-90%** | **SR** | 71518 | 18.7% | 42% | 135421 | 56.8% | 43% | 189% |
| | | **ICR** | 103386 | 19.0% | 42% | 129479 | 44.9% | 43% | 125% |
| | | **ICRR** | 57437 | 19.6% | 42% | 71424 | 46.2% | 43% | 124% |
| **Morocco** | **800ºC-85%** | **SR** | 52862 | 14.9% | 39% | 139047 | 54.0% | 41% | 263% |
| | | **ICR** | 74487 | 15.3% | 39% | 129409 | 41.9% | 41% | 174% |
| | | **ICRR** | 42564 | 16.0% | 39% | 73437 | 43.7% | 41% | 173% |
| | **900ºC-90%** | **SR** | 66249 | 18.2% | 39% | 129172 | 53.6% | 41% | 195% |
| | | **ICR** | 95770 | 18.5% | 39% | 123504 | 42.3% | 41% | 129% |
| | | **ICRR** | 53205 | 19.1% | 39% | 68128 | 43.5% | 41% | 128% |
| **China** | **800ºC-85%** | **SR** | 28774 | 13.0% | 21% | 80035 | 30.6% | 24% | 278% |
| | | **ICR** | 40545 | 13.4% | 21% | 74488 | 23.6% | 24% | 184% |
| | | **ICRR** | 23168 | 14.0% | 21% | 42270 | 24.6% | 24% | 182% |
| | **900ºC-90%** | **SR** | 36060 | 15.9% | 21% | 74351 | 30.3% | 24% | 206% |
| | | **ICR** | 52129 | 16.1% | 21% | 71089 | 23.8% | 24% | 136% |
| | | **ICRR** | 28960 | 16.7% | 21% | 39214 | 24.4% | 24% | 135% |

***Table 19. Annual simulation performance results of OMSoP BC #1 systems.***

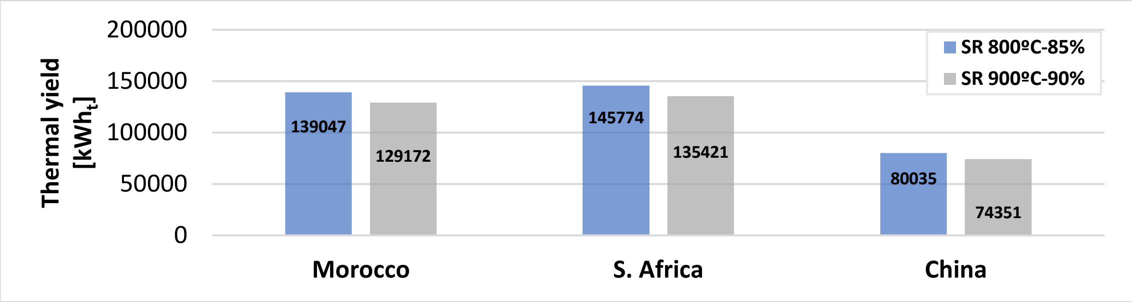


***Figure 26. Annual production of heat (thermal yield) for three selected locations. Values are given for both the base and upgraded solar-only engines (simple recuperative layouts in both cases).***

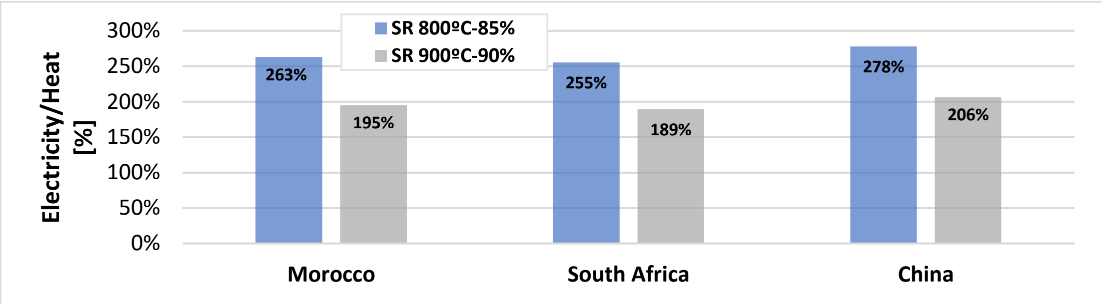


***Figure 27. Thermal to electric yield ratio for three selected locations. Values are given for both the base and upgraded solar-only engines (simple recuperative layouts in both cases).***

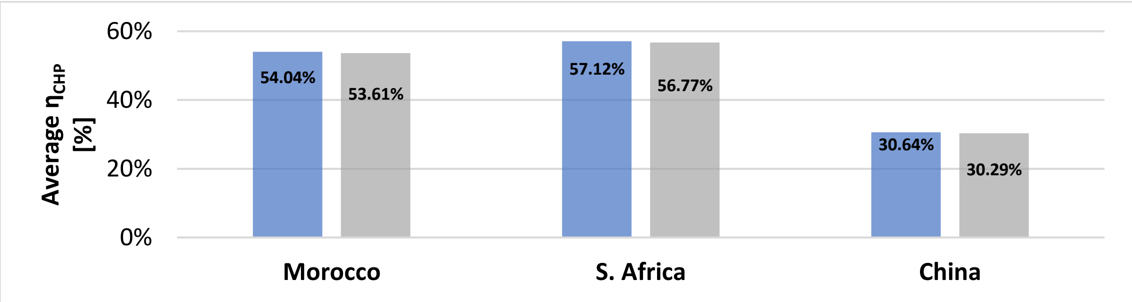


***Figure 28. Average combined heat and power efficiency for three selected locations. Values are given for both the base and upgraded solar-only engines (simple recuperative layouts in both cases).***

As expected, the trend for thermal yield with regards to location in Figure 26 is similar to that found for the electric yield in business case #0, Figure 9: larger production of heat in better locations and lower production in areas with lower DNI. On the contrary, the trend followed by the thermal yield for a given location is found to mirror that in Figure 9, which makes sense given that the heat available downstream of the gas turbine is inversely proportional to its efficiency (Figure 10).

The thermal to electric yield ratio (thermal energy produced in a year over annual production of electricity) is similar to that of other technologies used for cogeneration like, for instance, piston engines. There exist differences between locations but these are not as large as it could have been expected, with the average value being 2.5-3 kWh$_t$ per kWh$_e$.

In terms of overall efficiency, it is remarkable that more than 50% of the incident solar energy can be converted into useful energy, either electricity or heat. This makes OMSoP a very attractive system, in particular when compared with photovoltaic panels whose production of electricity must be complemented by heat coming from a different system/technology.

It is also interesting to highlight that the added benefit of cogeneration can be obtained without interfering with the original system. Indeed, the prime mover in OMSoP is only affected by a small backpressure, with no perturbation or constraint posed on the overall control system of the power-only unit.

Figure 29 to Figure 34 show the same information for the systems incorporating intercooling (ICR) and reheat (ICRR), and the trends found follow the comments in the previous paragraphs. These advanced systems achieve higher solar to electric efficiency and thus the amount of heat available for cogeneration decreases. Also, in the intercooled and reheated engine (ICRR) the drastic drop in thermal yield is due both to the higher solar to electric efficiency of the system and the lower mass flow rate (100 g/s vs. 200 g/s for the SR and ICR systems).

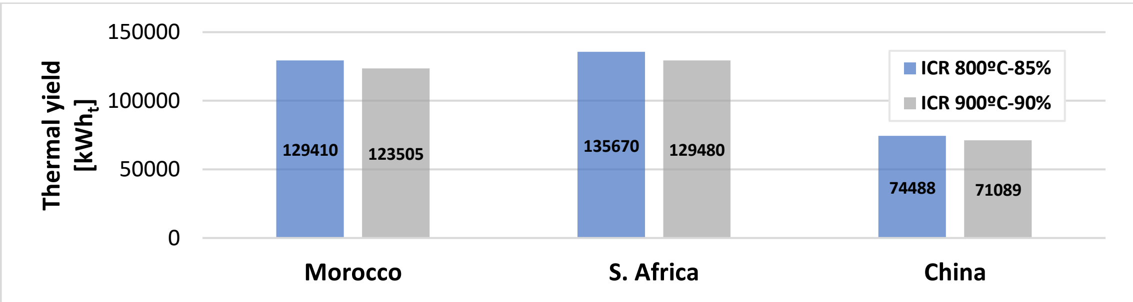


***Figure 29. Annual production of heat (thermal yield) for three selected locations. Values are given for both the base and upgraded solar-only engines (intercooled recuperative layouts in both cases).***

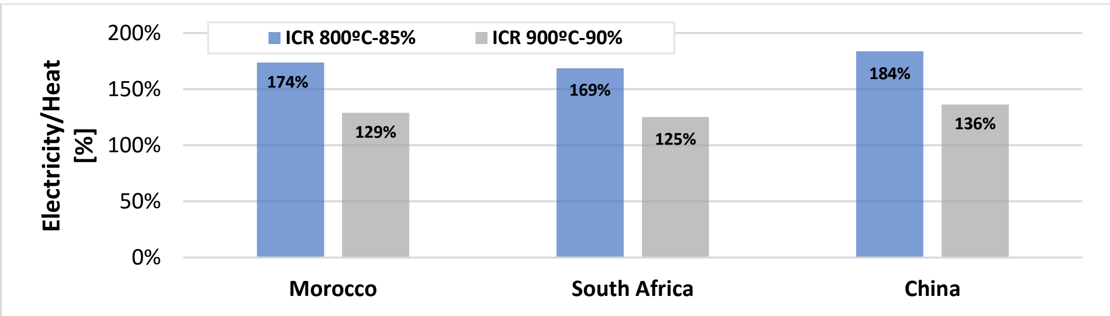


***Figure 30. Thermal to electric yield ratio for three selected locations. Values are given for both the base and upgraded solar-only engines (intercooled recuperative layouts in both cases).***

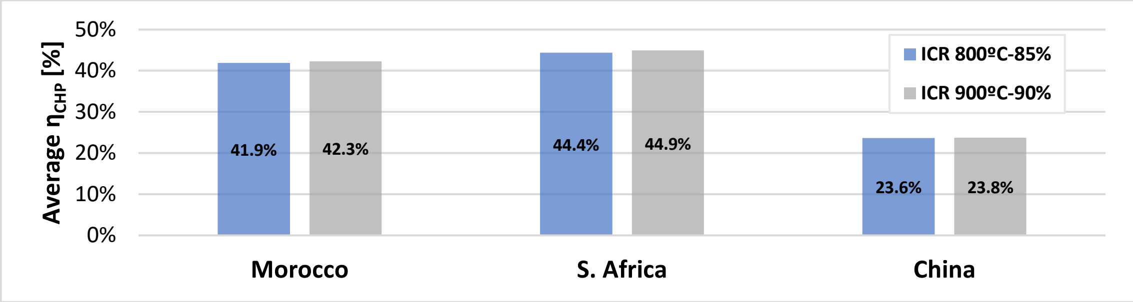


*Figure 31. Average combined heat and power efficiency yield for three selected locations. Values are given for both the base and upgraded solar-only engines (intercooled recuperative layouts in both cases).*

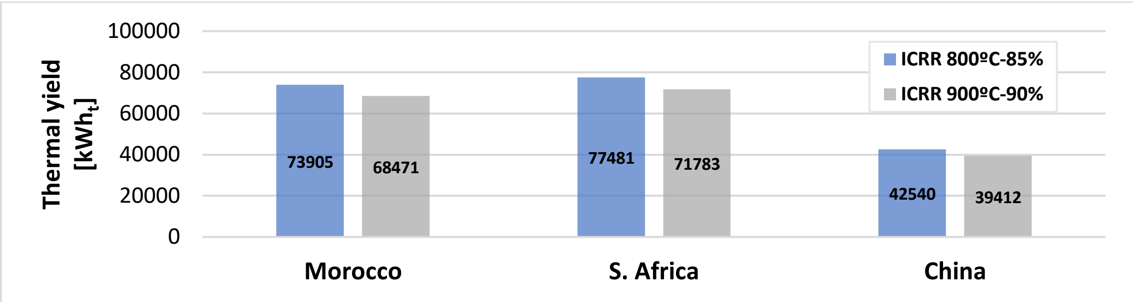


*Figure 32. Annual production of heat (thermal yield) for three selected locations. Values are given for both the base and upgraded solar-only engines (intercooled, reheat recuperative layouts in both cases).*

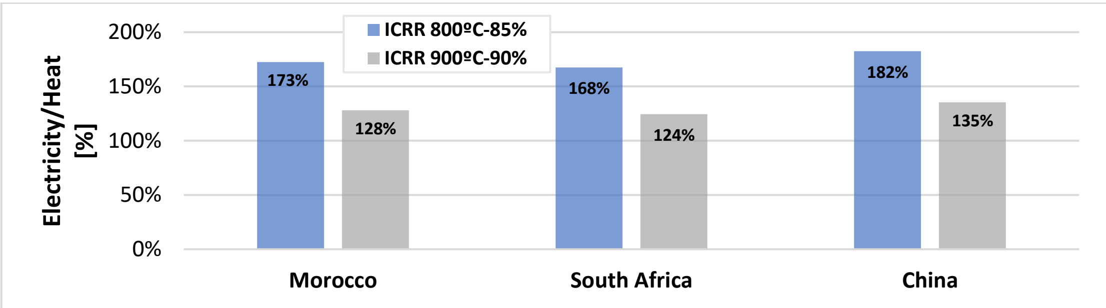


*Figure 33. Thermal to electric yield ratio for three selected locations. Values are given for both the base and upgraded solar-only engines (intercooled, reheat recuperative layouts in both cases).*

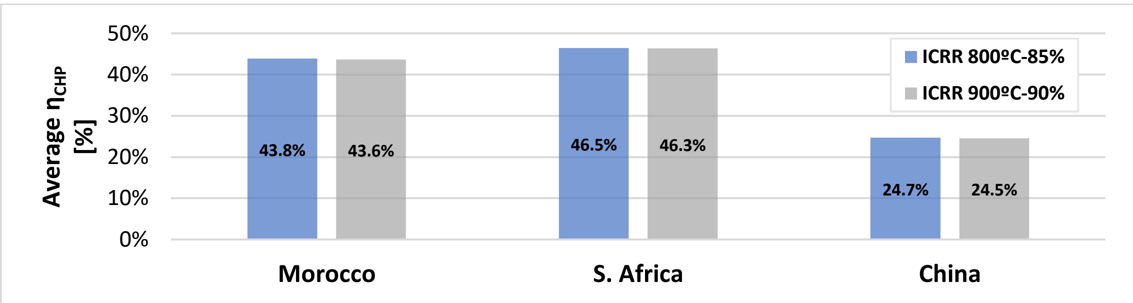


*Figure 34. Average combined heat and power efficiency for three selected locations. Values are given for both the base and upgraded solar-only engines (intercooled, reheat recuperative layouts in both cases).*

## *Assessment of energy use in distributed applications*

This section provides a general discussion about the results shown in business cases #0 and #1. The standard approach to OMSoP is to utilise the system in remote, probably off-grid applications providing electric power and also heat to independent users. In these cases, the engine produces power, which might not be consumed entirely, and the same happens to the thermal energy produced. Sometimes, it would be possible to export the surplus electricity to the grid whereas the most usual approach to managing surplus thermal energy is storage.

Complementarily to supplying electricity to households, a screening of alternative solutions is explored along with an assessment of the capacity of the standard OMSoP unit to cover different demands:

- Residential electricity and heat supply: reference benchmark values for these applications are taken from the World Energy Council for the three countries considered.
- Charging stations for electric vehicles: these are substations distributed geographically and far from the grid lines. The reference benchmark values considered in this case are the capacity of the battery in kWh, divided in three different levels (low, medium, and high), representing three different technologies available nowadays.
- Motorhome campsites: the reference values, again divided in three different levels, are considered in terms of daily electricity consumption.
- Seawater desalination: the electricity required to operate a reverse osmosis process is expressed in terms of kWh/m$^3$ of processed water.

Table 20 and Table 21 show the reference benchmark data of electricity consumption.

| | South Africa | Morocco | China |
|---|---|---|---|
| **Households [kWh$_e$/hh·year]** | 3216 | 1622 | 1430 |

***Table 20. Annual consumption of electricity for standard household (World Energy Council).***

| | Low | Medium | High |
|---|---|---|---|
| **Electric car recharge [kWh$_e$/recharge]** | 20 | 40 | 60 |
| **Motorhomes [kWh$_e$/mh·year]** | 3600 | 5400 | 7200 |
| **Seawater desalination [kWh$_e$/m$^3$]** | 2.5 | 3 | 3.5 |

***Table 21. Consumption of electricity for various applications.***

Table 22 shows the resulting productivity of OMSoP in various applications. A very interesting result is that the solar-only system is able to supply electricity to between 15-30 households, depending on the solar resource and the electricity consumption per household (both of which parameters depend on the location). This means that OMSoP could supply electricity to small communities.

Regarding the charging stations for electric vehicles, an average of five cars could be charged daily. This means that a fleet of ten solar-only OMSoPs could provide the electricity required to charge (fully) some fifty cars, which is a reasonable number in an off-grid location. Also, it must be considered that these cars do not charge from a dead battery but, rather, the battery is half charged what would increase the size of the fleet that would depend on the OMSoP array.

| | South Africa | Morocco | China |
|---|---|---|---|
| **Electric yield [$kWh_e$/year]** | 52862 | 57066 | 28773 |
| **Households [hh]** | 16.4 | 35.2 | 20.1 |
| **Electric car charge [charges/day]** | 2.3 - 6.9 | 2.5 - 7.4 | 1.2 - 3.7 |
| **Motorhomes [mh]** | 7.3 - 14.7 | 7.9 - 15.9 | 4 - 8 |
| **Seawater desalination [$m^3$/day]** | 39 - 55 | 42 - 59 | 21 - 30 |

***Table 22. Productivity of OMSoP in various applications.***

The application to van campsites is an interesting market niche and the results are also interesting. An OMSoP unit could provide electricity to ten, maybe fifteen of these motorhomes thus stepping forth as environmentally friendly power supply systems to rise the green profile of a campsite. Finally, also the application to seawater desalination through reverse osmosis show interesting results with an OMSoP unit producing some fifty cubic metre a day of fresh water.

Based on these results, it is confirmed that the OMSoP system is very flexible and therefore fits with a wide variety of distributed generation applications. The next section explores the financial performance of the system in order to confirm that this good technical performance also makes economic sense.

### *Financial parameters*

The financial parameters presented in Table 23 are adopted in the appraisal of OMSoP. As observed, the investment is fully financed through a loan (i.e., no equity) at a reference interest rate (6%), the loan being paid off in half the lifetime of the project. Reference insurance rate and property tax are set to 1% and a MACRS depreciation scheme (Modified Accelerated Cost Recovery System) is considered (system currently applied in the US). The project lifetime set to 20 years.

| Main financial parameters | |
|---|---|
| Lifetime of project [years] | 20 |
| Loan | |
| Debt/Equity ratio [%] | 100% / 0% |
| Term (payoff time) [years] | 10 |
| Interest rate [%] | 6% |
| Taxes and insurances | |
| Insurance rate [%] | 1% |
| Property tax [%] | 1% |
| Depreciation | |
| Type | MACRS (Mid Quarter) |

***Table 23. Boundary conditions of the financial analysis.***

The parameters used to estimate the profitability of the OMSoP commercial stand-alone system are discussed in the following. First of all, the inflation was derived by calculating the mean inflation rate registered during the last ten years for the countries considered. The raw data, shown in Figure 35, were taken from (IECONOMICS, 2016) and the final average values drawn from them are summarised in and Table 24.

| | South Africa | Morocco | China |
|---|---|---|---|
| Mean inflation rate 10Y [%] | 6.072% | 1.533% | 2.973% |

***Table 24. 10Y mean inflation rate for the countries of interest.***

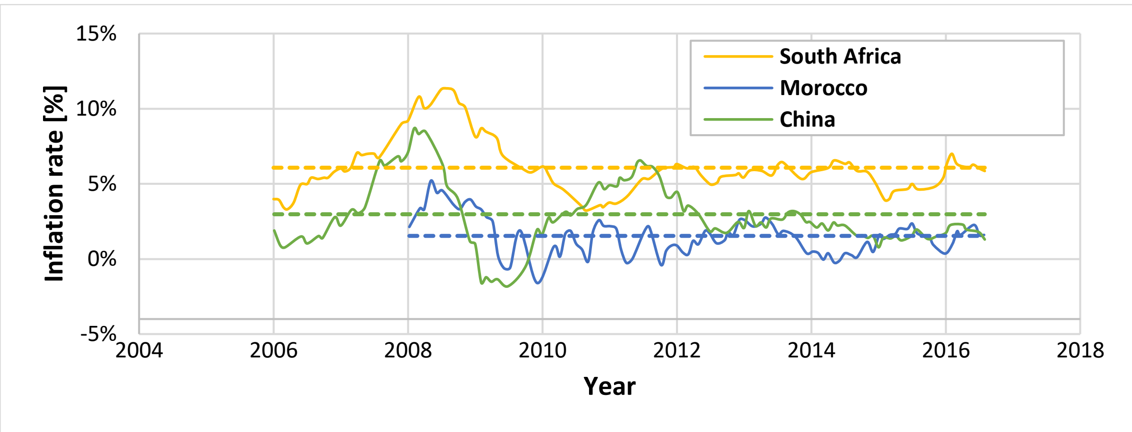


***Figure 35. Inflation rate and mean inflation rate of last 10 years.***

For what concern the real discount rate to apply to the financial cash flows, this parameter has been calculated starting from a reference value (taken as the reference real discount rate in

Spain) by scaling with the financial risk factor calculated for stand-alone systems in the Potential Market Analysis OMSoP Report. The real discount rate assigned to the reference country Spain is equal to 10%. The other values relative to the three countries selected are derived with the following formula.

$$r_{country} = r_{Spain} \cdot \left( \frac{F_{F,Spain}}{F_{F,country}} \right)$$

The real discount rates calculated and applied to the financial cash flow models are shown in the next Table 25.

.

| | Financial risk factor [%] | Real discount rate [%] |
|---|---|---|
| **China** | 48.44% | 15.96% |
| **Morocco** | 51.53% | 15.00% |
| **South Africa** | 68.89% | 11.22% |
| **Spain (reference)** | 77.32% | 10.00% |

***Table 25. Financial risk factors (from Market analysis report) and calculated real discount rates from the countries of interest.***

The selling price of the produced electricity to the grid and the purchase price of electricity from the grid are both estimated from various sources (as indicated in the table); the values adopted are shown in the next Table 26.

| | Electricity selling price [€/kWh$_e$] | Electricity purchase price [€/kWh$_e$] |
|---|---|---|
| **South Africa** | 0.320 (feed-in-tariff) (Energypedia, South Africa, 2016) | 0.116 (Eskom, 2016) |
| **Morocco** | 0.118 | 0.137 (Energypedia, Morocco, 2016) |
| **China** | 0.137 (feed-in-tariff) (SolarPACES, 2016) | 0.691 (NationalEnergyAdministration, 2016) |

***Table 26. Electricity rates: selling price to the grid and purchase price from the grid for the selected countries.***

With this set of financial variables, the financial cash flows can be completed and the profitability of the systems of interest can be evaluated.

# Financial analysis

The cash flow analysis of the business-cases considered integrates the capital (Capex) and operational/maintenance (Opex) system costs with the revenues obtained from the electricity sales. The system costs and revenues are integrated in a cash flow model that permits calculating the most important financial metrics, therefore indicating:

- whether or not the project is economically and financially feasible;
- the profitability during the lifetime;
- and the levelised cost of the electricity produced.

## *Business case #0. Solar-only, power-only system*

The LCoE's of the solar-only, power-only (BC#0) OMSoP systems are summarised in Table 27. The nominal LCoE values ranges from a minimum of 10.68 to a maximum of 25.07 c€/kWh, which translates into 7.40-21.25 c€/kWh when the real LCoE is considered. As expected, the most promising locations are Morocco and South Africa, due to the high solar energy available along the year. The financial metrics for the same set of cases are summarised in in Table 28. There are some observations to note:

- According to the Net Present Value, there is just one location for which the system turns out profitable, South Africa, owing to the high subsidies and solar resource. Neither Morocco, with a less intense incentive scheme, nor China, where the Direct Normal Irradiance is lower, make interesting economic cases.
- For the case of South Africa, the payback period is just below 4 years for the standard, base-case technology (800ºC and 85%) whilst this figure goes down to 3¾ if the upgraded technology is used.
- In terms of the benefit to cost ratio, the rightmost column confirms that the potential benefit is very large, regardless of the technology level considered. This also appreciated when assessing the net present value of the projects.
- The internal rates of return are not shown because they have no mathematical meaning given that all cash flows are positive.

| BC #0 | | | LCoE Nominal [c€/kWh] | LCoE Real [c€/kWh] |
|---|---|---|---|---|
| South Africa | 800ºC-85% | SR | 12.94 | 8.96 |
| | | ICR | 12.77 | 8.84 |
| | | ICRR | 12.32 | 8.53 |
| | 900ºC-90% | SR | 11.23 | 7.77 |
| | | ICR | 11.16 | 7.73 |
| | | ICRR | 10.78 | 7.46 |
| Morocco | 800ºC-85% | SR | 13.63 | 12.45 |
| | | ICR | 13.47 | 12.30 |
| | | ICRR | 12.81 | 11.70 |
| | 900ºC-90% | SR | 11.42 | 10.43 |
| | | ICR | 11.36 | 10.37 |
| | | ICRR | 10.94 | 9.99 |
| China | 800ºC-85% | SR | 25.31 | 21.44 |
| | | ICR | 24.87 | 21.08 |
| | | ICRR | 23.68 | 20.06 |
| | 900ºC-90% | SR | 21.50 | 18.22 |
| | | ICR | 21.46 | 18.18 |
| | | ICRR | 20.43 | 17.31 |

*Table 27. Levelised Cost of Electricity for the OMSoP BC #0-Solar projects.*

| BC #0-Solar | | | PB [years] | NPV Nominal [€] | NPV Real [€] | Before tax | | After tax | | B/C RATIO [%] |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | IRR [%] | MIRR [%] | IRR [%] | MIRR [%] | |
| South Africa | 800ºC 85% | SR | 3 3/4 | 63953 | 107854 | - | - | - | - | 169% |
| | | ICR | 3 3/4 | 90811 | 152918 | - | - | - | - | 173% |
| | | ICRR | 3 3/4 | 52949 | 88813 | - | - | - | - | 183% |
| | 900ºC 90% | SR | 3 1/4 | 86409 | 143650 | - | - | - | - | 211% |
| | | ICR | 3 1/4 | 125243 | 208107 | - | - | - | - | 212% |
| | | ICRR | 3 1/4 | 70717 | 117156 | - | - | - | - | 224% |
| Morocco | 800ºC 85% | SR | 12 3/4 | -9892 | -10216 | 1.68% | 7.46% | 1.35% | 5.97% | -25% |
| | | ICR | 12 2/4 | -13287 | -13690 | 2.12% | 7.70% | 1.69% | 6.16% | -24% |
| | | ICRR | 12 | -6069 | -6177 | 4.08% | 8.75% | 3.27% | 7.00% | -21% |
| | 900ºC 90% | SR | 11 | -4461 | -4230 | 9.89% | 11.39% | 7.91% | 9.11% | -11% |
| | | ICR | 10 3/4 | -6101 | -5739 | 10.26% | 11.54% | 8.21% | 9.23% | -10% |
| | | ICRR | 10 1/4 | -2192 | -1895 | 12.94% | 12.52% | 10.35% | 10.01% | -7% |
| China | 800ºC 85% | SR | 18 2/4 | -17573 | -19707 | -6.88% | 3.20% | -5.50% | 2.56% | -50% |
| | | ICR | 18 1/4 | -23919 | -26795 | -6.52% | 3.39% | -5.21% | 2.71% | -50% |
| | | ICRR | 17 2/4 | -12341 | -13777 | -5.46% | 3.94% | -4.37% | 3.15% | -47% |
| | 900ºC 90% | SR | 16 | -15461 | -17110 | -3.22% | 5.07% | -2.58% | 4.06% | -42% |
| | | ICR | 15 3/4 | -22231 | -24596 | -3.17% | 5.10% | -2.53% | 4.08% | -42% |
| | | ICRR | 15 | -10925 | -12017 | -1.92% | 5.73% | -1.53% | 4.58% | -39% |

*Table 28. Financial metrics for the OMSoP BC #0-Solar projects.*

Some of the foregoing tabular results are now presented graphically in order to provide a more comprehensive comparison of the estimated financial performance of OMSoP in different locations. Figure 36 shows the nominal LCoE where it is confirmed that South Africa and Morocco make a good case for the technology, at least LCoE-wise. Moreover, when South Africa is considered, comparing the green and blue lines evidences that there is a large potential for LCoE reduction (~15%) if a more advanced technology is used.

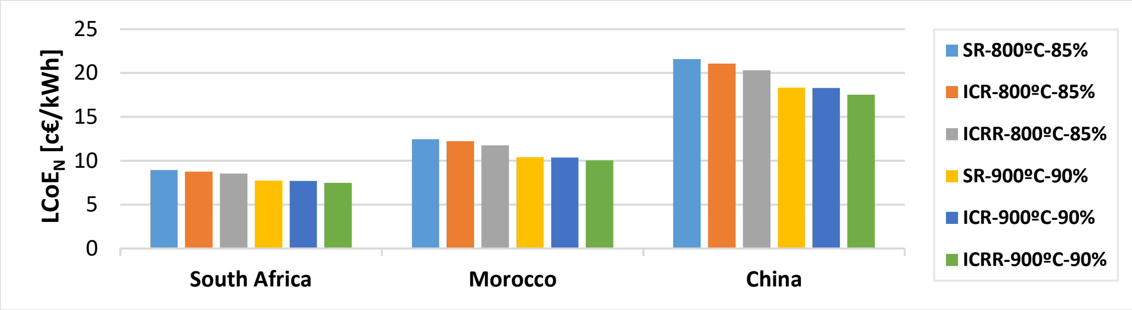


***Figure 36. Business case BC #0-Solar. Nominal LCoE.***

The differences between locations are amplified when the time to pay off the initial investment is calculated. Indeed, Figure 37 shows the very large gap between the payback for South Africa and China, with Morocco being closer to the latter due to less attractive economic boundary conditions. Nevertheless, it is worth noting that the calculated payback times for the latter countries are still shorter than the project lifetime, which confirms the need to complement this figure of merit with other information that provides an assessment of whether or not the investment is actually interesting.

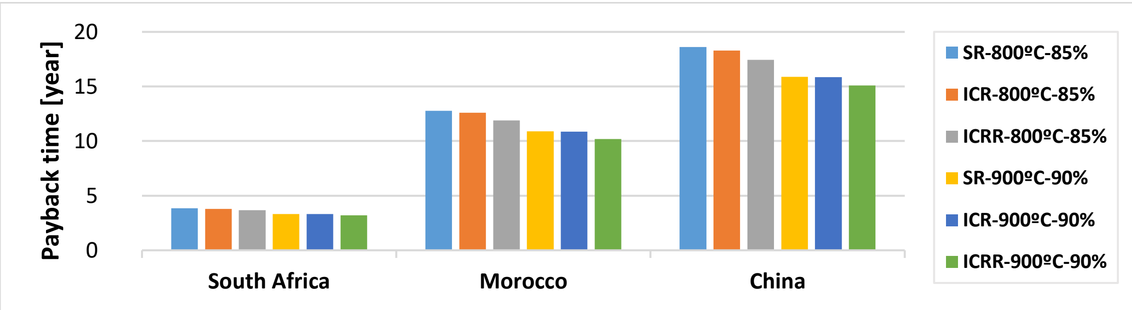


***Figure 37. Business case BC #0-Solar. Payback time.***

The nominal net present value can probably serve this purpose, as shown in Figure 38 to Figure 40 for the simple recuperated, intercooled recuperated and intercooled recuperated reheated layouts respectively. In all of them, the present value of the project in South Africa is much higher than in the other locations for which this figure of merit is actually negative. This negative value is generally considered as a recommendation to not proceed with the investment, though this cannot be taken as an absolute statement.

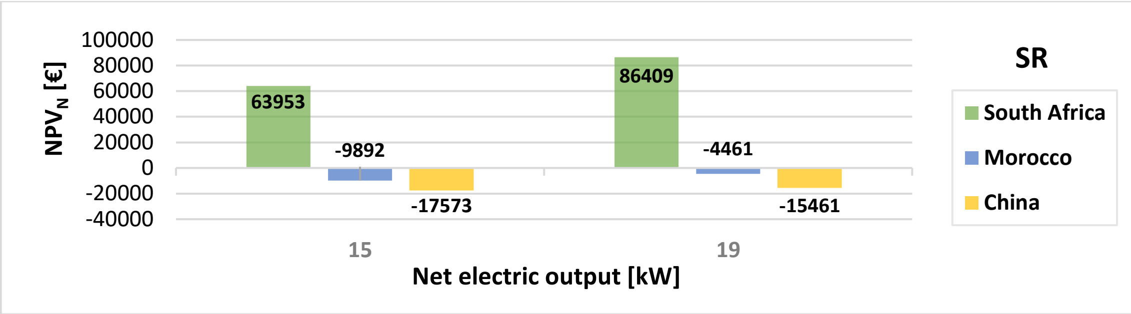


*Figure 38. Business case BC #0-Solar. Nominal NPV for the simple recuperated layout.*

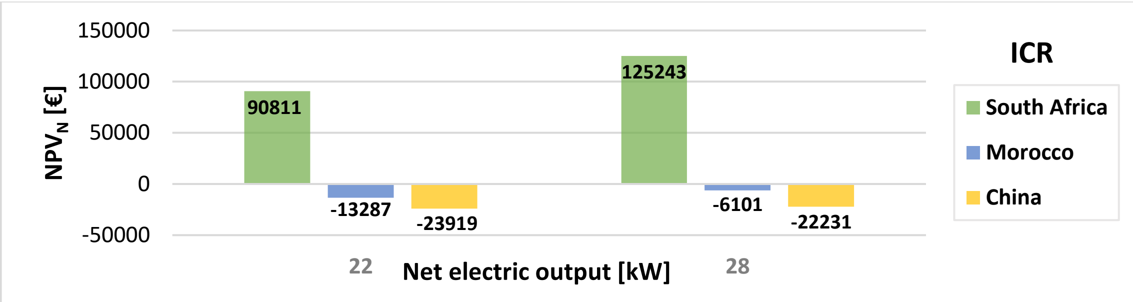


*Figure 39. Business case BC #0-Solar. Nominal NPV for the intercooled recuperated layout.*

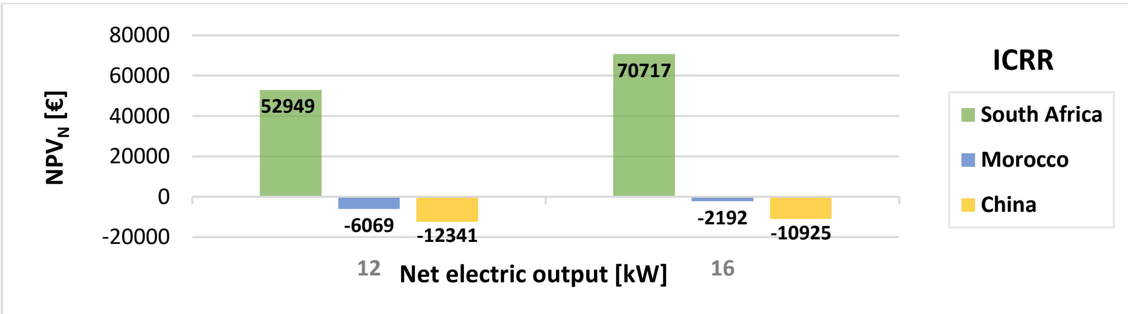


*Figure 40. Business case BC #0-Solar. Nominal NPV for the intercooled, recuperated, reheated layout.*

Regarding the charts for Net Present Value, an interesting aspect to note is the different rated output of each system, which is optimised for each layout independently. Thus, whilst the SR and ICR cycles are based on an engine with the same mass flow rate, the more efficient ICRR layout employs smaller turbomachinery (half the mass flow rate of the former). Interestingly, the ratio of NPV and power output is not in direct correspondence with the ratio of mass flow rate.

These considerations can be lumped in the benefit to cost ratio shown in Figure 41. The chart is eloquent with regards to the influence of the location and market conditions in the economic performance of the OMSoP system. Three conclusions are drawn from the plot, each of them corresponding to a particular location:

- South Africa: the OMSoP technology makes a very strong economic case in this location as the return on the investment is very large. The favourable incentive scheme and solar conditions unite to yield a very interesting investment overall: short payback period, high benefit to cost ratio, high net present value and benefit to cost ratio much higher than 100%.

- Morocco: this is an interesting case. For the boundary conditions assumed, Morocco does not make an interesting case yet as the system is not profitable. Nevertheless, given the not outrageously high payback period and moderately negative NPV, it is suggested that with adequate changes in the economic boundary conditions the situation could be reversed. Such changes could come from a more favourable legislation (incentive scheme) or a modified set of financial assumptions (discount rate, loan rate…). This is of course not a suggestion to reverse-engineer the boundary conditions in order to get positive financial results. On the contrary, it is a comment to highlight that, given the proximity to a favourable investment, care must be taken with respect to setting as accurate as possible boundary conditions for the analysis.
- China: the results for China are clearer than from Morocco and suggest that it is presently difficult to make a favourable business case for this region. Nevertheless, an appropriate incentive scheme would very likely reverse this situation, yielding new market opportunities for small scale solar thermal power generators. This process could also be accelerated by incorporating other interesting by-products like heat or even desalinated water.

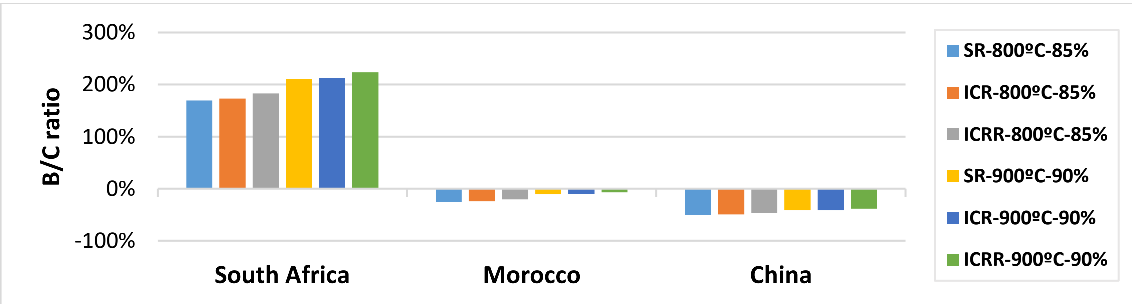


***Figure 41. Business case BC #0-Solar. Benefit to cost ratio.***

Figure 42 and Figure 43 aim to shed light on the two last bullet points of the previous list. These charts present the breakeven purchased equipment cost of the entire system [€/kWe] and dish [€/m$^2$] respectively. These are the values that would yield null NPV and hence, can be regarded as the maximum specific costs below which the investment would make economic sense. Accordingly, given the aforecited favourable conditions found in South Africa, this location enables higher specific costs of both system and dish whilst still yielding positive NPVs. On the contrary, any system PEC above 2245 €/kWe in China yields NPV<0 and thus is not economically feasible. Morocco is in between these two, even if closer to the first one.

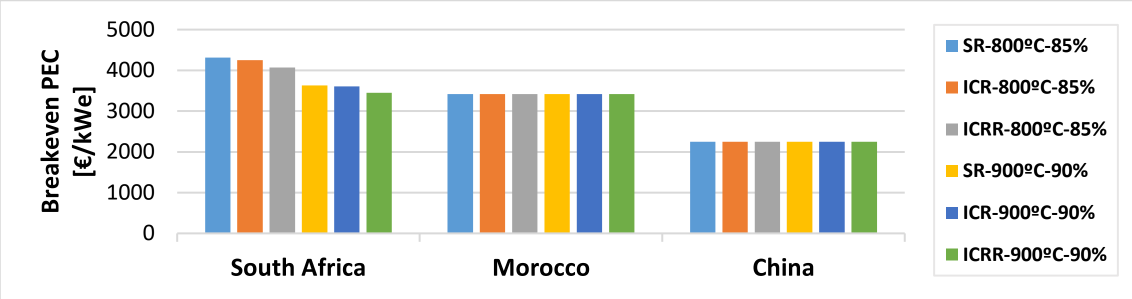


***Figure 42. Business case BC #0-Solar. Breakeven system PEC.***

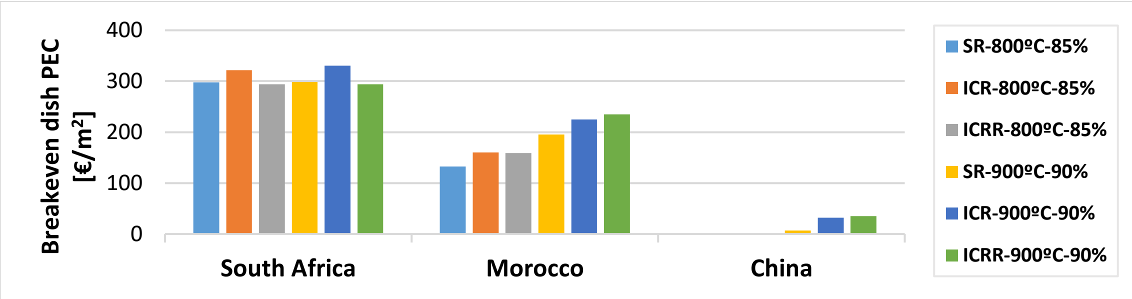


***Figure 43. Business case BC #0-Solar. Breakeven dish PEC.***

Figure 43 is even more interesting than Figure 42 for it evidences that neither the SR nor the ICR layouts are economically feasible in the location considered. It is only the ICRR engine which would achieve positive NPVs under very specific circumstances, associated to a very low cost dish. Actually, this breakeven cost for the ICRR in China (~50 €/m$^2$) is less than half the cost of a heliostat in a solar tower (150-200 €/m$^2$).

The main conclusion drawn from the analysis presented in the previous paragraphs is that the available solar resource is, as expected, of vital importance. This is actually critical in a vast country like China where the solar conditions are so dissimilar and where consumption and production nodes of the electricity market might become so distant. These considerations turn more important when the power system becomes smaller, like OMSoP, for it does not need a large extension with good solar radiation or with heavily populated urban centres nearby. With this in mind, an analysis is now presented where the breakeven DNI that would make the technology economically feasible in China is calculated. This information is aimed at providing guidelines so as to which so-called hot spots would be feasible for OMSoP; i.e., which small regions with high solar irradiance would favour OMSoP against other competing technologies.

Figure 44 presents the annual DNI that would yield NPV=0 in China (the aforecited breakeven DNI), the rest of the technical and financial variables being equal for the location under consideration. As observed, the values range from 3000 to slightly less than 4000 kWh/m$^2$ which are very high DNIs for the most part of the country, Figure 45. Nevertheless, favourable regions near the West border achieve DNI values in this range thanks to a very high altitude, indicating that there is still a market niche where the OMSoP technology could be commercialised.

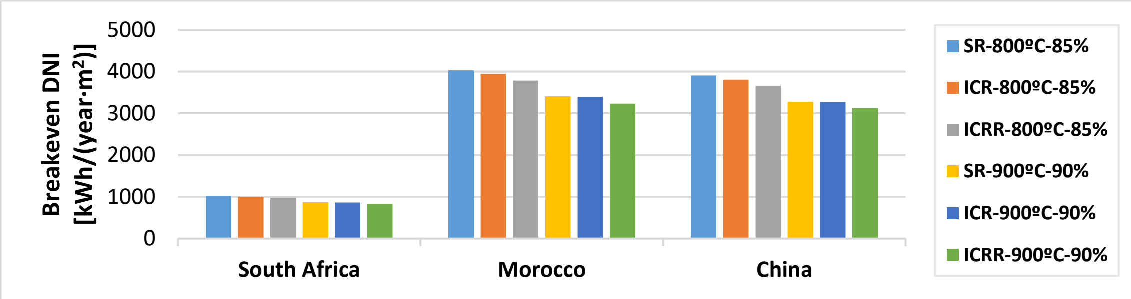


***Figure 44. Business case BC #0-Solar. Breakeven DNI.***

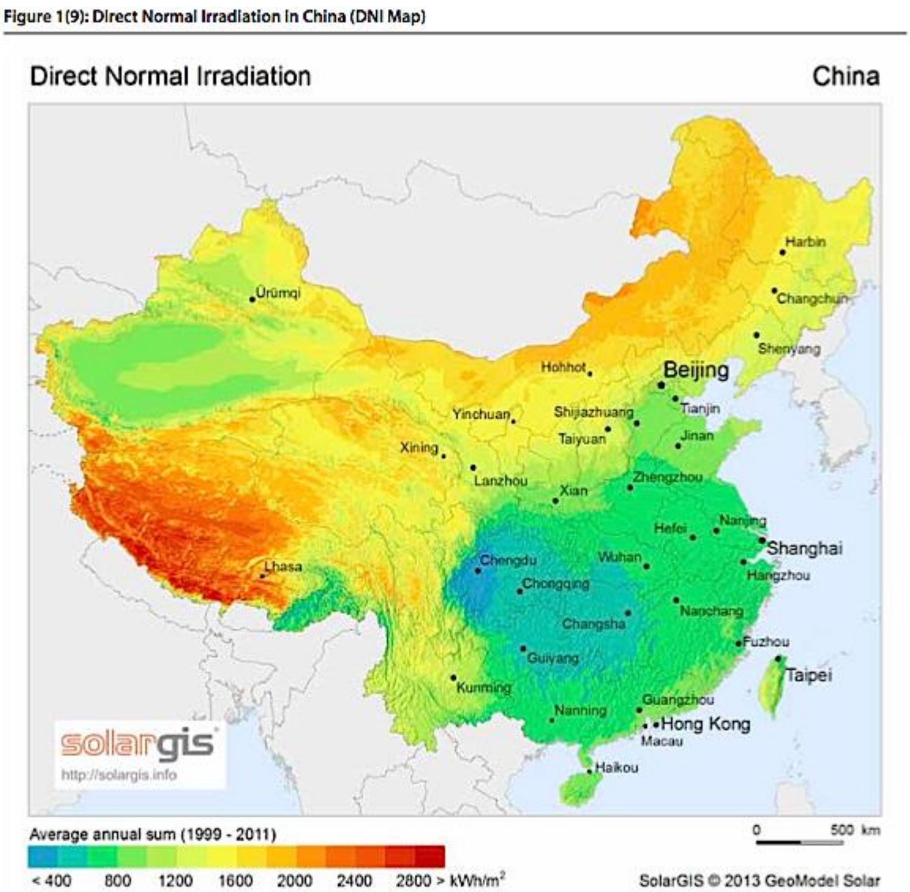


***Figure 45. Average annual cumulative DNI in China (Source: solargis).***

A similar analysis could have been presented for Morocco, where a lower breakeven DNI should be expected. In both cases, the two main overall conclusions drawn from these results are:

- The preliminary results obtained from the market analysis methodology, presented in deliverable D3.2 and published in (Sánchez, y otros, 2016), are confirmed by the very detailed project appraisal carried out in this section. Hence, the *index of market potential* obtained originally was higher for South Africa, lower for China and intermediate for Morocco, same as the results shown above.

- The current scenario considered for the OMSoP technology yields negative financial performance when the average solar resource of certain countries is considered. Nevertheless, this value is not meaningful for very large countries where large disparities in local DNI are found across the country. In these cases, a local analysis must be performed in order to identify potential market niches.

### *Business case #1. Combined heat (low temperature 90ºC) and power systems*

The cash flow sheet of the second business case (namely BC#1) integrates the Capex and Opex of those OMSoP systems that produce electricity (as in BC#0) and heat by recuperating the exhaust heat from the engine (sensible heat) in a waste heat recovery subsystem. Economic wise, the cash flow analysis does not consider any revenues from the heat produced but, rather, it compares the economics of OMSoP with those of producing the same amount of electricity and heat by means of dedicated systems: a natural gas boiler to produce heat and electricity imported from the grid, in amounts equal to the annual yield of electricity and thermal energy of OMSoP-CHP.

The financial metrics employed in the calculation result from the comparative cash flow (difference between the cash flow of the investment options with highest and lowest capital costs). The comparative cash flow metrics are the incremental cash flow NPV, the incremental cash flow IRR and the savings to cost ratio. These parameters are considered sufficient to compare the two mutually exclusive projects.

A first set of results is presented in Table 29 below, complemented by the graphical information in Figure 46 (levelised cost of electricity) and Figure 47 (levelised cost of electric plus thermal energy). As expected, the cost of electricity in Figure 46 is higher than in the previous business case, Figure 36 due to the added cost of the bottoming subsystem for the same annual yield of electricity. The ratio is in the order of two ($LCoE_{BC\#1}$/ $LCoE_{BC\#0}$) as deduced from the vertical scales in both charts.

| BC #1 | | | LCoE electricity Nominal [c€/kWh$_e$] | LCoE electricity Real [c€/kWh$_e$] | LCoE total Nominal [c€/kWh$_{e+t}$] | LCoE total Real [c€/kWh$_{e+t}$] |
|---|---|---|---|---|---|---|
| South Africa | 800ºC-85% | SR | 24.49 | 16.95 | 6.89 | 4.77 |
| | | ICR | 22.39 | 15.50 | 8.33 | 5.77 |
| | | ICRR | 21.67 | 15.00 | 8.10 | 5.61 |
| | 900ºC-90% | SR | 21.16 | 14.65 | 7.31 | 5.06 |
| | | ICR | 19.44 | 13.46 | 8.63 | 5.98 |
| | | ICRR | 18.82 | 13.03 | 8.39 | 5.81 |
| Morocco | 800ºC-85% | SR | 25.24 | 18.53 | 6.95 | 5.10 |
| | | ICR | 23.36 | 17.15 | 8.53 | 6.26 |
| | | ICRR | 22.31 | 16.38 | 8.19 | 6.01 |
| | 900ºC-90% | SR | 21.85 | 16.04 | 7.41 | 5.44 |
| | | ICR | 20.15 | 14.79 | 8.80 | 6.46 |
| | | ICRR | 19.26 | 14.14 | 8.45 | 6.20 |
| China | 800ºC-85% | SR | 46.54 | 30.16 | 12.31 | 7.97 |
| | | ICR | 43.72 | 28.33 | 15.41 | 9.98 |
| | | ICRR | 41.79 | 27.08 | 14.79 | 9.59 |
| | 900ºC-90% | SR | 39.23 | 25.42 | 12.81 | 8.30 |
| | | ICR | 37.44 | 24.26 | 15.84 | 10.26 |
| | | ICRR | 35.79 | 23.19 | 15.20 | 9.85 |

*Table 29. Levelised Costs of Electricity and Energy for the OMSoP-CHP (BC#1) projects.*

Figure 47 is interesting when compared with Figure 46 as it exemplifies the large amount of heat that can potentially be recuperated from the hot exhaust gases of OMSoP. Indeed, the substantial drop in LCoE when total energy is considered (c€/kWh$_{e+t}$) comes from a higher energy yield at constant discounted costs. Also, it is interesting to see how in both cases, Figure 47 and Figure 46, the costs of electricity/energy in South Africa and Morocco become more similar than in the previous business case.

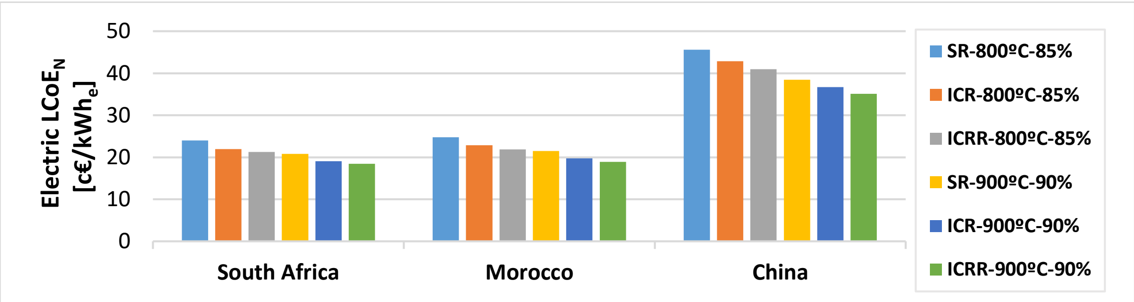


*Figure 46. BC #1 Nominal Levelised Cost of Electricity.*

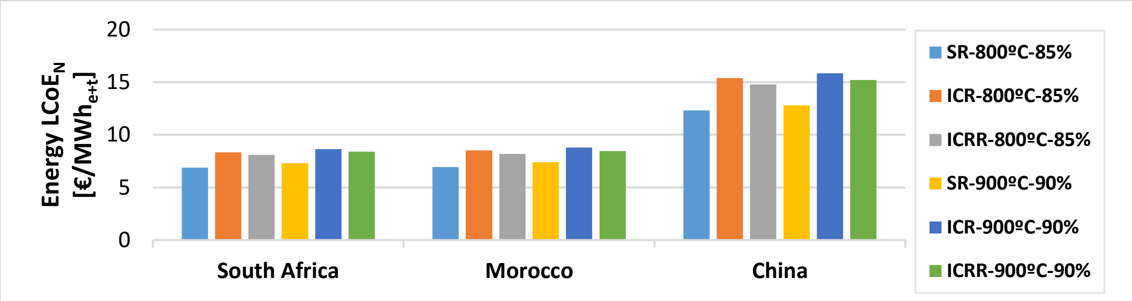


***Figure 47. BC #1 Nominal Levelised Cost of Energy.***

Table 30 shows the financial metrics of business case BC#1 where, given that no taxation was applied, only one set of real incremental IRR is presented. The information in the table confirms that the CHP business case is not financially feasible, as deduced from the following observations:

- The incremental IRRs are lower than the real discount rate, which is here considered as the minimum acceptable rate of return for the projects.
- The NPV is negative for all cases except one, the most refined ICRR system (900ºC and 90%) located in South Africa. Nevertheless, even for this case, the net present value is just too small to make it an interesting investment project.
- The savings to costs ratio, with respect to the alternative natural gas water heater and grid supply, is lower than 100% except for the cited case in South Africa (102%). This means that the alternative, conventional technologies for the production of heat and electricity are more interesting than the OMSoP-CHP system.

These conclusions can also be drawn from the graphical information shown in Figure 48 to Figure 50 where the incremental cash flow NPVs for the various microturbine layouts are shown. As already shown in Table 30, the proposed OMSoP-CHP technology is far from being profitable and, even if more complex engine layouts help reduce the total loss of money, this does not suffice to achieve positive earnings from the initial investment (not even for the most favourable locations).

| BC #1 | | | Incremental IRR [%] | Incremental NPV [€] | S/C RATIO [%] |
|---|---|---|---|---|---|
| South Africa | 800ºC-85% | SR | 11.03% | -9516 | 87% |
| | | ICR | 12.35% | -10141 | 89% |
| | | ICRR | 13.68% | -4133 | 92% |
| | 900ºC-90% | SR | 15.39% | -3374 | 96% |
| | | ICR | 17.47% | -882 | 99% |
| | | ICRR | 19.43% | 1291 | 102% |
| Morocco | 800ºC-85% | SR | 4.32% | -16071 | 78% |
| | | ICR | 5.32% | -19505 | 79% |
| | | ICRR | 6.89% | -8763 | 83% |
| | 900ºC-90% | SR | 7.57% | -10990 | 86% |
| | | ICR | 9.86% | -11328 | 89% |
| | | ICRR | 12.12% | -3752 | 93% |
| China | 800ºC-85% | SR | -13.93% | -44641 | 30% |
| | | ICR | -14.17% | -60182 | 29% |
| | | ICRR | -13.66% | -32270 | 30% |
| | 900ºC-90% | SR | -13.10% | -45199 | 33% |
| | | ICR | -13.19% | -63498 | 32% |
| | | ICRR | -12.65% | -33009 | 33% |

*Table 30. Financial metrics for the OMSoP BC#1 projects.*

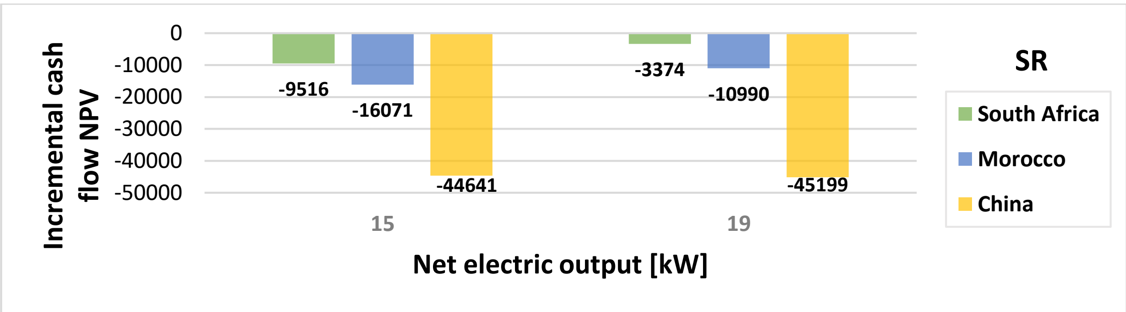


*Figure 48. BC#1 Nominal incremental NPV for the simple recuperated (SR) layout.*

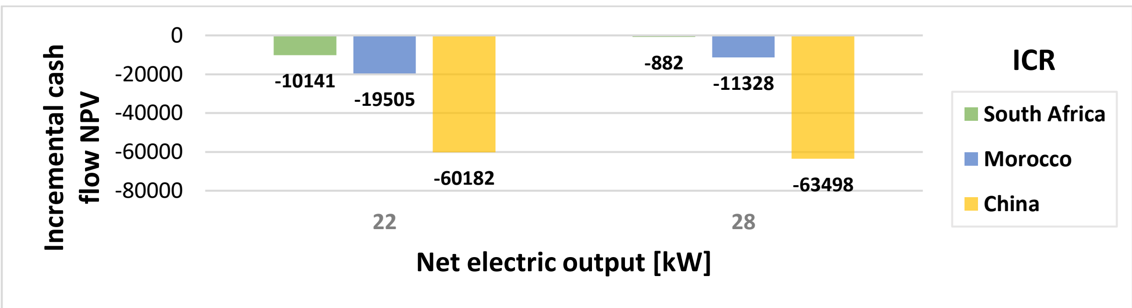


*Figure 49. BC#1 Nominal incremental NPV for the intercooled recuperated (ICR) layout.*

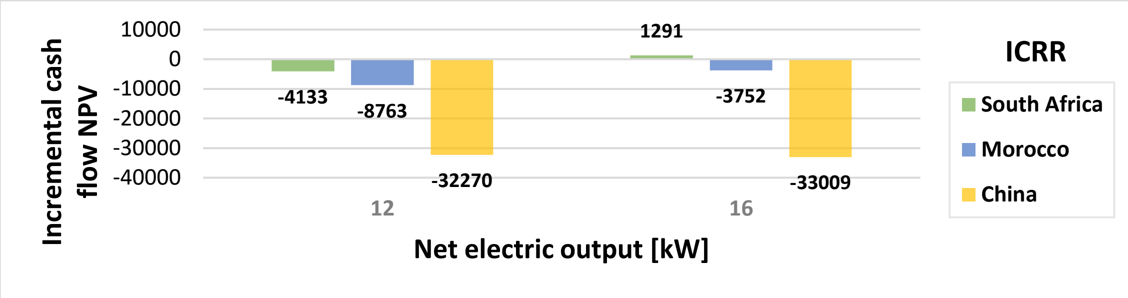


***Figure 50. BC#1 Nominal incremental NPV for the intercooled, recuperated, reheated (ICRR) layout.***

The incremental internal rate of return is plotted in Figure 51, confirming the results that were already anticipated by the previous charts. When considering competing investment options, it is generally assumed that the option with higher IRR should be given preference, in particular when this IRR is higher than the discount rate assumed in the analysis (the nominal discount rates in China, Morocco and South Africa are 19.41%, 16.77% and 17.97% respectively). Nevertheless, this does not have scale differences into consideration, as it is the case in the comparison presented here. In these cases, the IRR approach is preferred for it provides more consistent (comparable) results.

Indeed, the results shown in Figure 51 suggest that the cheapest option making use of a natural gas heater and connection to the grid should be adopted except for the ICR and ICRR cases at 900ºC and 90% located in South Africa. For all the other cases, the incremental IRR is lower than the discount rate and thus the OMSoP-CHP solution is not economically advantageous.

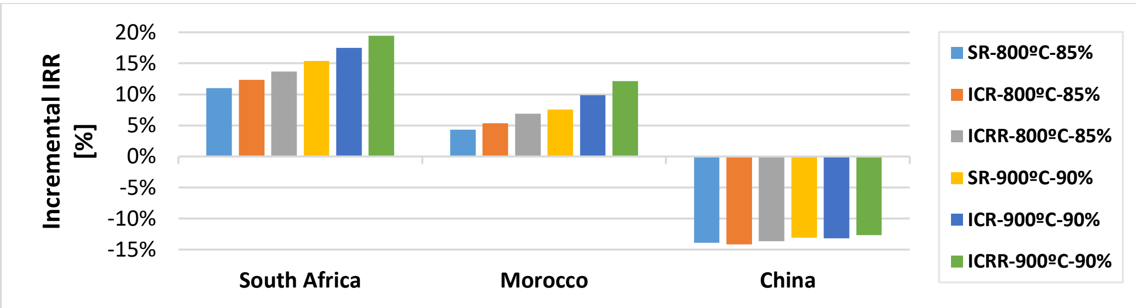


***Figure 51. BC#1 incremental Internal Rate of Return.***

Finally, the saving to cost ratio is presented in Figure 52. This index provides a non-dimensional value of the potential savings of OMSoP-CHP with respect to the standard combined technology (natural gas heater and grid), relative to the net present cost (cumulative discounted cost) of OMSoP. With this definition, the criterion to decide whether or not OMSoP-CHP is the preferred option is the S/C ratio being higher than 100%. If it is higher, then OMSoP is preferred. As observed, this only happens for the most advanced technology located in South Africa; the base technology (simple recuperated or even intercooled recuperated) and the other less-than-optimum locations do not reunite the boundary conditions or techno-economic performance needed to make a favourable business case for OMSoP.

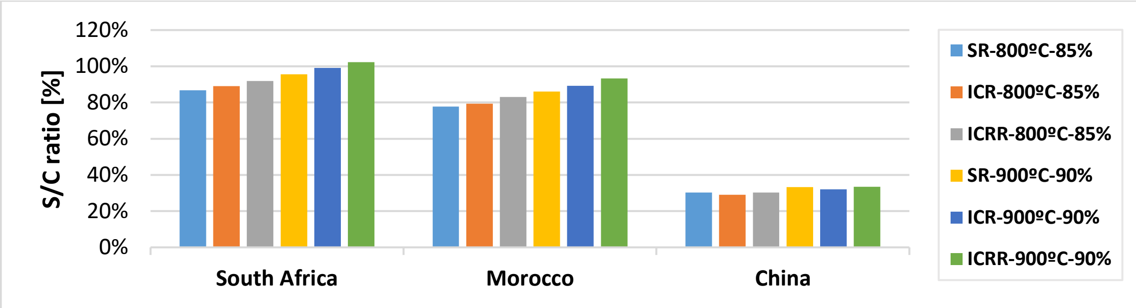


***Figure 52. BC #1 Savings to cost ratio.***

## *Business case #0. Hybrid, power-only systems*

Based on the results shown previously, it is concluded that the utilisation of OMSoP for the production of power makes economic sense under certain boundary conditions, both technical (for instance DNI) or economic (favourable market conditions). On the contrary, it is difficult to devise a case where OMSoP could be used for combined heat and power given the added cost of the downstream equipment. With this in mind, and in order to exploit the initial capital investment in a power-only OMSoP, fossil fuel hybridisation is now considered. The main aim of this modified layout is to achieve a much higher load factor (annual operating hours), which is expected to help reduce the levelised cost of electricity drastically.

Therefore, the cash flow has the same structure of the solar-only project with the main differences that a(i) more energy is produced thanks to combustion of fuel, and (ii) the operational costs account for the cost of the fuel burnt. In this regard, the assumption made to evaluate the cost-competitiveness of a hybrid OMSoP is to operate the system at full capacity (rated output) as long as the DNI is higher than the cut-in DNI (minimum DNI for which the system would achieve stable operation). As already justified in the document, the cut-in DNI of OMSoP is estimated at 240 W/m$^2$ (30% of the design DNI, 800W/m$^2$).

The LCoE for this modified configuration of BC#0 are summarised in Table 31 where ΔLCoE stands for the LCoE difference between the hybrid layout and the solar-only reference ($\Delta LCoE = LCoE_{Hybrid} - LCoE_{Solar}$). A negative ΔLCoE indicates that the hybrid solution yields lower cost of electricity whilst the contrary holds true if this index is positive. It is interesting to see that incorporating fuel back up for extended operation is not cost-effective in locations where the available solar resource is large (South Africa and, to a lesser extent, Morocco). On the contrary, the additional operating hours manage to drive costs down where the irradiance is low, for instance China. This is somewhat contradictory with the results initially foreseen (lower LCoE for the hybrid case) and stem from the higher operating cost and weak influence on capacity factor. In this latter regard, the capacity factor when fuel back-up is used rises from 21% to almost 35% in China whereas the increase is from 42% to only 49% in South Africa. For Morocco, this factor changes from 39% to 47% when fuel is burnt. It is actually the extent of this change in capacity factor which drives the impact on LCoE, resulting on a beneficial effect of fuel back-up in China as opposed to a detrimental impact in South Africa.

| BC #0-Hybrid | | | LCoE Nominal [c€/kWh] | ΔLCoE Nominal [c€/kWh] | LCoE Real [c€/kWh] | ΔLCoE Real [c€/kWh] |
|---|---|---|---|---|---|---|
| South Africa | 800ºC-85% | SR | 15.21 | 2.27 | 10.53 | 1.57 |
| | | ICR | 15.03 | 2.26 | 10.41 | 1.57 |
| | | ICRR | 14.55 | 2.23 | 10.07 | 1.54 |
| | 900ºC-90% | SR | 13.03 | 1.8 | 9.02 | 1.25 |
| | | ICR | 12.99 | 1.83 | 9.00 | 1.27 |
| | | ICRR | 12.62 | 1.84 | 8.74 | 1.28 |
| Morocco | 800ºC-85% | SR | 15.32 | 1.69 | 13.99 | 1.54 |
| | | ICR | 15.21 | 1.74 | 13.89 | 1.59 |
| | | ICRR | 14.57 | 1.76 | 13.30 | 1.6 |
| | 900ºC-90% | SR | 12.75 | 1.33 | 11.65 | 1.22 |
| | | ICR | 12.80 | 1.44 | 11.69 | 1.32 |
| | | ICRR | 11.68 | 0.74 | 10.66 | 0.67 |
| China | 800ºC-85% | SR | 23.37 | -1.94 | 19.81 | -1.63 |
| | | ICR | 23.15 | -1.72 | 19.62 | -1.46 |
| | | ICRR | 22.19 | -1.49 | 18.81 | -1.25 |
| | 900ºC-90% | SR | 19.81 | -1.69 | 16.78 | -1.44 |
| | | ICR | 19.80 | -1.66 | 16.78 | -1.4 |
| | | ICRR | 19.06 | -1.37 | 16.15 | -1.16 |

*Table 31. Levelised Cost of Electricity for the OMSoP BC #0-Hybrid projects.*

The complete set of financial metrics of the hybrid BC#0 are presented in Table 32. A detailed analysis of the different figures of merit for each location and technology would be redundant at this stage and hence only an overall evaluation of the interest of hybridisation for the different reference markets is provided here.

| BC #0-Hybrid | | | PB [years] | NPV Nominal [€] | NPV Real [€] | Before tax | | After tax | | B/C RATIO [%] |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | IRR [%] | MIRR [%] | IRR [%] | MIRR [%] | |
| South Africa | 800ºC 85% | SR | 3 3/4 | 67342 | 112430 | - | - | - | - | 129% |
| | | ICR | 3 3/4 | 95723 | 159697 | - | - | - | - | 132% |
| | | ICRR | 3 2/4 | 56043 | 93209 | - | - | - | - | 140% |
| | 900ºC 90% | SR | 3 1/4 | 93730 | 154409 | - | - | - | - | 167% |
| | | ICR | 3 1/4 | 135734 | 223626 | - | - | - | - | 168% |
| | | ICRR | 3 | 76688 | 126068 | - | - | - | - | 176% |
| Morocco | 800ºC 85% | SR | 20 | -18112 | -19387 | -11.67% | 1.14% | -9.33% | 0.91% | -34% |
| | | ICR | 20 | -24976 | -26714 | -11.01% | 1.45% | -8.80% | 1.16% | -33% |
| | | ICRR | 18 3/4 | -12446 | -13278 | -8.96% | 2.46% | -7.17% | 1.97% | -30% |
| | 900ºC 90% | SR | 14 1/4 | -11356 | -11941 | 840.79% | 6.03% | 672.63% | 4.83% | -20% |
| | | ICR | 14 2/4 | -16713 | -17588 | -2.27% | 5.88% | -1.82% | 4.71% | -20% |
| | | ICRR | 11 3/4 | -5308 | -5390 | 4.84% | 9.46% | 3.87% | 7.57% | -13% |
| China | 800ºC 85% | SR | 20 | -24040 | -27779 | - | -5.76% | - | -4.61% | -46% |
| | | ICR | 20 | -33183 | -38304 | - | -4.93% | - | -3.94% | -46% |
| | | ICRR | 20 | -17245 | -19868 | - | -3.41% | - | -2.73% | -43% |
| | 900ºC 90% | SR | 20 | -20202 | -23107 | -14.29% | 0.09% | -11.43% | 0.07% | -37% |
| | | ICR | 20 | -29174 | -33344 | -13.83% | 0.29% | -11.07% | 0.23% | -37% |
| | | ICRR | 20 | -14562 | -16596 | -11.93% | 1.22% | -9.54% | 0.98% | -34% |

***Table 32. Financial metrics for the OMSoP BC #0-Hybrid projects.***

The first conclusion from Table 32 refers to the interest of hybridisation in favourable markets. As already said in the previous paragraph, it is not beneficial to incorporate hybridisation in markets with high DNI. This is confirmed by the lower benefit to cost ratio for the systems located in South Africa, resulting from a comparison between Table 28 and Table 32. In particular, this B/C ratio drops from about 175% to 150% on average, with extreme cases falling from 225% to 175%. This is due to the added operating cost which cannot be compensated for by a larger net present value. In other words, the added NPV comes about because of higher costs which impact on the B/C ratio negatively.

For markets with moderate or low DNI, burning fuel to extend the operating hours does not manage to turn the investment project into a profitable option. The net present value is even more negative due to the fuel costs and the benefit to cost ratio remains negative. Thus, despite small changes in the economic metrics, OMSoP does not step forward as an interesting option for the production of renewable electricity.

Finally, a common impact on both good and not so good locations is the longer payback time. For very favourable locations, this impact is minor whereas it changes substantially if the locations exhibits low DNI.

In summary, incorporating hybridisation does not seem an interesting option from an economic standpoint as it yields worse economic performance in markets where OMSoP is profitable and does not manage to revert the situation in markets where the system was already not profitable. This being said, it is acknowledged that hybrid capabilities might turn essential for operational reasons as these yield a much more flexible power generation system able to respond quickly to changing boundary conditions. Given that this is actually a technical issue, it will be left out from the analysis (i.e., the monetary value of this capability/flexibility) is difficult to estimate.

### *Competing technologies*

This section introduces a techno-economic comparison of OMSoP and the competing technologies that are currently commercialised or under development for low scale solar power generation. There are, essentially, two competing technologies: dish-Stirling and photovoltaic panels. The former shares the fact that it is based on solar-thermal energy conversion whereas the latter is the current technology of choice worldwide. Other than these, there are no real alternatives for solar power generation at the small scale.

Therefore, the alternative systems considered are a photovoltaic array producing 20 kWe (DC power) and a dish-Stirling system rated at 20 kWe (AC power). The specific purchase equipment cost (PEC) of such systems was presented in the previous Cost analysis Report, from which the figures shown in Table 33 have been excerpted. It is reminded that the reference PEC for the photovoltaic system was taken from (NREL, 2015) while the dish-Stirling PEC was provided by (Guidetti, 2013) from data produced by Innova. The latter information is presented in Table 34.

| | **Commercial PV - PEC** |
|---|---|
| **Net electric output [$kW_e$]** | 20 |
| **Module [€]** | 12800 |
| **Inverter [€]** | 2600 |
| **BOS [€]** | 7200 |
| **Total [€]** | 22600 |
| **Specific [€/$kW_e$]** | 1130 |

***Table 33. Commercial PV system. Reference Purchased Equipment Cost.***

| | **Dish-Stirling - PEC** |
|---|---|
| **Net electric output [$kW_e$]** | 20 |
| **Engine [€]** | 14417 |
| **Receiver [€]** | 4404 |
| **Dish [€]** | 27435 |
| **BOP [€]** | 9251 |
| **Total [€]** | 55507 |
| **Specific [€/$kW_e$]** | 2775 |

***Table 34. Commercial dish-Stirling system. Reference Purchased Equipment Cost.***

The final installation costs are presented in Table 35 and Table 36 for the photovoltaic and Stirling systems respectively, based on the system PECs presented in the paragraph above. For photovoltaic systems, the general recommendations in (NREL, 2015) are followed whilst for dish-Stirling the same methodology applied to OMSoP is employed.

| | Commercial PV Installed cost [€/kW$_e$] |
|---|---|
| PEC [€] | 22600 |
| Installation [€] | 5000 |
| Transportation [€] | 11700 |
| Total [€] | 39300 |
| Specific [€/kW$_e$] | 1965 |

***Table 35. Commercial PV system. Reference installed system cost in Ouarzazate (Morocco).***

| | Dish-Stirling Installed cost |
|---|---|
| PEC [€] | 59392 |
| Installation [€] | 7835 |
| Transportation [€] | 11700 |
| Total [€] | 78947 |
| Specific [€/kW$_e$] | 3947 |

***Table 36. Commercial dish-Stirling system. Reference installed system cost in Ouarzazate (Morocco).***

The comparison is performed with the System Advisory Model developed by NREL, using the same set of financial assumptions (boundary conditions) already used for the appraisal of the OMSoP project. To this end, the maintenance costs shown in Table 37 are used for photovoltaic and dish-Stirling systems.

| Competing technology | Maintenance cost based on capacity [€/(kW$_e$·year)] | Maintenance cost based on generation [€/MWh] |
|---|---|---|
| Commercial PV | 15 | 10 |
| Commercial Dish Stirling | 20 | 15 |

***Table 37. Competitive systems maintenance reference cost.***

The results of the comparison in terms of Levelised Cost of Electricity are presented in Table 38 and Figure 53 for a system located in Ouarzazate, Morocco.

| Commerical BC #0 | | | LCoE Nominal [c€/kWh] | LCoE Real [c€/kWh] | Capacity factor [%] |
|---|---|---|---|---|---|
| Ouarzazate (Morocco) | OMSoP 800ºC-85% | SR | 13.6 | 12.5 | 39.2 |
| | | ICR | 13.5 | 12.3 | |
| | | ICRR | 12.8 | 11.7 | |
| | OMSoP 900ºC-90% | SR | 11.4 | 10.4 | |
| | | ICR | 11.4 | 10.4 | |
| | | ICRR | 10.9 | 10.0 | |
| | Photovoltaic | | 11.9 | 10.9 | 22.0 |
| | Dish-Stirling | | 17.0 | 15.5 | 27.2 |

***Table 38. LCoE comparison for OMSoP systems vs competitive PV and dish-Stirling systems (Ouarzazate, Morocco).***

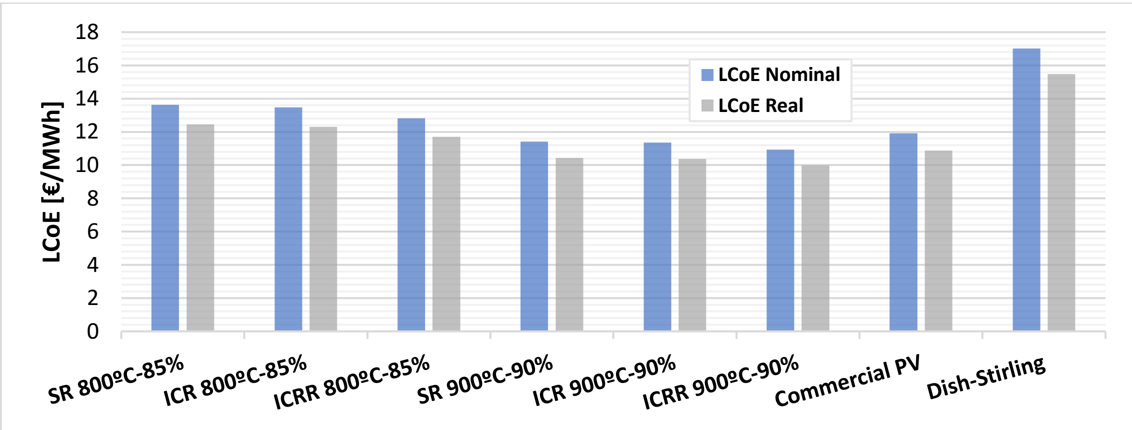


***Figure 53. LCoE comparison for the solar-only BC#0 (power generation). Location: Ouarzazate, Morocco***

Table 38 and Figure 53 show very interesting information, which is better presented in a bulleted list:

- The OMSoP technology yields a much higher capacity factor than both dish-Stirling and photovoltaic technology.
- LCoE-wise, the OMSoP system is much more cost competitive than an equivalent system (same output) using dish-Stirling technology. The difference is in the order of 3-4 c€/kWh.
- Nevertheless, as of today, the state-of-the-art OMSoP system kWh (simple recuperated OMSoP sysem operating at 800ºC and 85% recuperator effectiveness) is still more expensive (LCoE-wise) than a system based on photovoltaic technology. The difference is larger than 1.5 c€/kWh.
- Even if more complex cycle layouts were used (intercooled or intercooled and reheated cycles), photovoltaics would still be more cost-effective than OMSoP. This can be ascertained by comparing the figures for PV and any of the OMSoP cases with 800ºC and 85%.

- However, if the technology used in OMSoP enabled higher turbine inlet temperature and recuperator effectiveness (900ºC and 90% respectively), this technology would become as competitive as photovoltaic.
- Moreover, for more sophisticated OMSoP systems (based on intercooled cycles or even intercooled and reheated cycles) operating at 900ºC and 90%, the technology has the potential to reduce the LCoE of photovoltaic systems by 0.5-1 c€/kWh.

These results are very promising as they credit that the OMSoP technology has the potential to reduce the LCoE achieved by small PV systems with outputs in the range of 20-25 kWe. This is not to say that OMSoP is more cost-effective than PV under any circumstances or for every project. Indeed, large photovoltaic power plants with outputs larger than a megawatt still yield lower LCoE than OMSoP but these very low costs of electricity (~5-8 c€/kWh) are only attainable in very large power plants (strong economies of scale) located in very favourable sites (very high solar resource) ( Mayer, Philipps, Hussein, Schleg, & Senkpiel, 2015). On the other hand, the results in Table 38 and Figure 53 do confirm that OMSoP is more competitive than dish-Stirling systems as a general statement that can be applied to any project (note that the generalisation of this statement is based on the very similar features of both systems, as opposed to PV).

Further to this discussion, it must be acknowledged that OMSoP is still behind PV when the market conditions are not as favourable as they are in the location considered in Table 38 and Figure 53. This is shown in Table 39 and Figure 54 where the same set of results is given for a 20 kWe system located in China.

| Commerical BC #0 | | | LCoE Nominal [c€/kWh] | LCoE Real [c€/kWh] | Capacity factor [%] |
|---|---|---|---|---|---|
| Ouarzazate (Morocco) | OMSoP 800ºC-85% | SR | 25.5 | 21.6 | 21.2 |
| | | ICR | 24.9 | 21.1 | |
| | | ICRR | 24.0 | 20.3 | |
| | OMSoP 900ºC-90% | SR | 21.6 | 18.3 | |
| | | ICR | 21.6 | 18.3 | |
| | | ICRR | 20.7 | 17.5 | |
| | Photovoltaic | | 15.8 | 13.4 | 18.3 |
| | Dish-Stirling | | 32.1 | 27.0 | 14.9 |

***Table 39. LCoE comparison for OMSoP systems vs competitive PV and dish-Stirling systems (Bailing-Miao, China).***

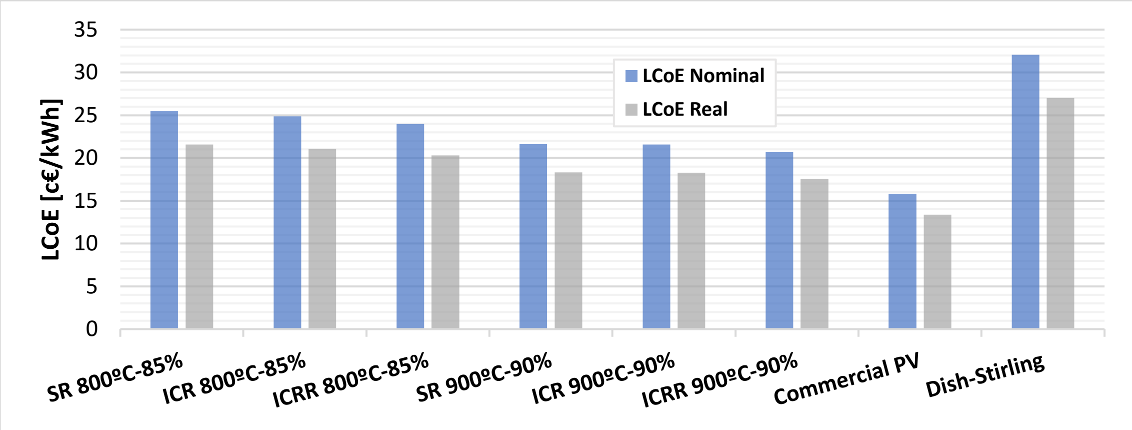


***Figure 54. LCoE comparison for the solar-only BC#0 (power generation). Location: Bailing-Miao, China.***

This new set of results is very interesting as it confirms that photovoltaic technology is still more cost-effective than OMSoP in the Chinese market where the available solar resource is not as high as in other locations considered. Even if OMSoP demonstrates the superior economic performance when compared against dish-Stirling technology, photovoltaic panels are still the preferred option by a margin of some 8-10 c€/kWh for the current state of the art.

Moreover, it looks difficult that OMSoP can eventually achieve the low costs of photovoltaic panels with the given boundary conditions of this market as this would mean a drastic drop in cost accompanied by a significant rise in performance. This conclusion confirms that the methodology employed is able to discriminate among countries with dissimilar characteristics.

# Conclusions

This document summarises the work developed at the University of Seville in order to assess whether or not a small-scale solar power generator based on a solar dish collector and micro gas turbine engine can become cost competitive against photovoltaic systems in different countries in the world.

This analysis relies on the work already developed in previous tasks of the OMSoP project (Work Package 3) regarding market screening and cost analysis. Further to this previous work, a methodology for project appraisal has been set up and tuned to the particular operating and boundary conditions that apply to the technology. All the analytical and numerical information is provided so that any interesting reader can recreate the calculations.

Regarding the technical content of the analysis, the following conclusions must be highlighted:

- OMSoP is more competitive than dish-Stirling systems. This observation has been confirmed for several markets, confirming that the margin for LCoE reduction with respect to the latter technology is in the order of 20-25% consistently.
- For the present state of the art of the technology (i.e., the OMSoP technology demonstrated in the project), OMSoP is not cost-competitive against photovoltaic

systems. The difference in LCoE is in the order of 3-10 c€/kWh depending on boundary conditions (location, size, etc.).

- Nevertheless, further development of the technology (which means better component performance, higher operating temperatures and more complex cycle layouts) can potentially make OMSoP competitive against PV. This could be the case for favourable markets with high Direct Normal Irradiance and low import taxes.

These conclusions apply to a reference (base) case where OMSoP is used for power generation only. A business case where OMSoP is used for combined heat and power has been explored, resulting in disappointin economic performance. The added cost of the heat recovery unit brings in an additional economic burden that is not paid off by a more efficient utilisation of primary energy. Therefore, unless very specific boundary conditions are met, the combined heat and power version of OMSoP does not seem to provide a clear advantage over independent heat and power generators.

The interest of hybridisation has also been explored. The results of this assessment confirm that it does not seem to be worth from an economic standpoint. For those markets where OMSoP is already profitable, it does not increase the benefit/cost ratio but, rather, this figure is decreased. On the other hand, even if it improves the economic performance of the technology in markets where this is not cost-competitive (profitable), this improvement is not large enough to revert the situation; i.e., it does not turn non-profitability into profitability. It must be acknowledged though that the possible operational benefits coming from hybridisation have not been evaluated.

With all these results in mind, this final deliverable report confirms that OMSoP has the potential to become a cost-competitive solar thermal generator for distributed generation. Nevertheless, before this happens, further research is needed in order to both reduce the cost of the technology (according to the forecast provided by the industrial partners) and improve its thermal performance.

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