Solar Power and Chemical Energy Systems
IEA Technology Collaboration Programme

SolarPACES Guideline for Bankable STE Yield Assessment

Version 2017

Edited by Tobias Hirsch

Intentionally left blank

Further information on the IEA-SolarPACES Program can be obtained from the Secretary, from the Operating Agents or from the SolarPACES web site on the Internet http://www.SolarPACES.org.

Editors

Tobias Hirsch	German Aerospace Center (DLR)	tobias.hirsch@dlr.de
Jürgen Dersch	German Aerospace Center (DLR)	juergen.dersch@dlr.de
Thomas Fluri	Fraunhofer ISE	thomas.fluri@ise.fraunhofer.de
Javier García-Barberena	Cener	jgbarberena@cener.com
Stefano Giuliano	German Aerospace Center (DLR)	stefano.giuliano@dlr.de
Fred Hustig-Diethelm	Suntrace GmbH	fred.hustig-diethelm@suntrace.de
Richard Meyer	Suntrace GmbH	richard.meyer@suntrace.de
Norbert Schmidt	DNV-GL	norbert.schmidt@dnvgl.com
Markus Seitz	German Aerospace Center (DLR)	markus.seitz@dlr.de
Enver Yildiz	Fichtner GmbH & Co. KG	enver.yildiz@fichtner.com

Experts involved in the preparation of the guideline document

Camille Bachelier, Frenell

Juan Ignacio Burgaleta, Sener

Markus Eck, University of Applied Science Osnabrück

Mary Jane Hale, Skyfuel

Olaf Goebel, Hamm-Lippstadt University of Applied Science

Lourdes González, CIEMAT-PSA

Carsten Hoyer-Klick, German Aerospace Center (DLR)

Nicole Janotte, German Aerospace Center (DLR)

Dave Kearney, KA Solar LLC

Hank Price, Solar Dynamics

Michael Puppe, German Aerospace Center (DLR)

Christoph Rau, IATech

Heiko Schenk, German Aerospace Center (DLR)

Manuel Silva, University of Seville

Boris Westphal, Suntrace

Publisher: IEA Technology Collaboration Programme SolarPACES
E-mail: secretariat@solarpaces.org
Apartado 39, 04200 Tabernas, Spain

Published: January 2017

Acknowledgements

The guideline project has been funded by the German Federal Ministry Economic Affairs and Energy under contract No. 0325293.

Gefördert durch:
Bundesministerium für Wirtschaft und Energie
aufgrund eines Beschlusses des Deutschen Bundestages

The guiSmo project has been financially supported by SolarPACES.

Contents

Preface

Concentrating solar thermal energy plants (STE) are expected to play an important role in the world's future electricity supply. Thermal storage as essential part of a concentrating solar thermal power plant allows decoupling of solar energy harvest and electricity production from this energy. By this means, demand oriented power production can be realized. By hybridisation with fossil fuel burners (or gas turbines/reciprocating engines) time periods of low solar ressource are bridged.
Besides improvements in technical issues of the plants it is of vital importance for a broad market introduction to predict the electricity outcome and thus the financial revenues with a high quality. Both, the physical outcome of the plant and the cost/revenue balance are the keys to get projects financed. So far, there is no standard available that gives guidance to the persons involved in yield predictions of STE systems.
In 2009, a group of SolarPACES experts started a mission under the headline "guiSmo-a guideline for standardized yields analysis of solar thermal power plants". Several steps have been carried out in various workshops and meetings resulting in a compilation of relevant physical effects, a general modeling framework, a first compilation of important terminology, and handbook chapter structure. Due to limited funding, the activities slowed down. In 2014, national funding was obtained from the German government in order to relaunch the activities with the mission to work out a handbook proposal for discussion in the international expert group of SolarPACES. The present document is the first version of this handbook derived from this national project focussing on general modeling aspects, the parabolic trough oil technology, and molten salt towers. It is foreseen to complement the present guideline document by a number of appendices that provide distinct modeling approaches and default parameters for the technologies.
Version 1 of the document comes along with the terminology appendix T. Further appendices are under preparation. Draft versions of these documents are being published in early 2017 at the website http://www.dlr.de/sf/en/desktopdefault.aspx/tabid-11126/19467_read-48251 .

The guideline main document and the appendix T have passed several rounds of review within the German project team and a review by a number of selected international experts. Essential structural elements and philosophies have been discussed in various guiSmo workshops from 2010 to 2016. Finally, a review within the SolarPACES task I group has been completed which led to the approval of the SolarPACES Executive Committee.

1. Introduction

1.1. Why do we need standardized methodologies?

The prediction of electricity production for installations using fluctuating renewable energy sources like solar or wind is crucial for the financial evaluation of such power plant projects. For solar PV and wind, a number of standards exist providing guideance for project developers, contractors, and financing partners. For STE plants, no such standards exist although the complexity of yield prediction is even higher due to the option to shift production in time by thermal storage and the hybridisation options opening the field of optimum fossil fuel usage. On the resource side, reliable time series of direct normal irradiance are required. Such time series are usually composed of data from different sources like ground measurements, satellite images, and atmospheric models. Standards on generation and usage of representative meteorological data are needed to ensure high quality input data.

A large number of mainly project reports on yield assessment for individual technologies or configurations is available from literature. However, a comprehensive, generally applicable, and verified compilation of best practices for yield analysis is not yet available. It is the intention of this guideline to fill this gap and contribute to the standardization of the yield assessments for STE plants.

1.1.1. Large-scale STE implementation: reliability as key driver

Financing large infrastructure assets like solar thermal power plants requires a detailed risk analysis. Such risk analyses should consider all effects which might have a significant impact on the yield of the plant, but also on the costs. Goal in project finance usually is to eliminate cost-related risks by closing supply contracts, which guarantee certain prices for the EPC (engineering, procurement, construction) and also for the plant operations and maintenance (O&M). If EPC and O&M contracts are properly closed with reliable suppliers, and malperformance is compensated by adequate penalities, the main risks remaining are

- financial risks, like volatility of currencies,
- political risks, like modification of regulations e.g. on tariff models or taxes and
- uncertainty of energy yields.

The first two points are well known to the financial industry and not specific for STE plants. Thus, this guideline focuses on the uncertainty of energy yields from STE plants, which still seems to be considered as a major source of risk due to lack of knowledge and missing best practices. The overall goal of this guideline is to avoid principle errors in yield calculation and trying to minimize the uncertainty of the power output. To achieve this goal the guideline identifies and defines the relevant terms, it recommends principles to follow when designing performance simulation tools, and procedures how to create reliable input data.

Investment costs at the beginning of the STE plant life time are the dominating part of the economic calculation. Thus, an investor wants to be sure to make enough money from electricity sales in order to cover the debt service and his profit margins. Mainly three aspects need to be considered:

1. The expected net energy production of the plant: mainly depending on solar resource, co-firing options, and plant design.
2. The financial yields from electricity sales depending on the production convoluted with the achievable prices minus the operation and maintenance costs.
3. Debt service conditions significantly depending on the expected risks of the project.

High quality performance calculations are the key to get a realistic view of the electricity production of the plant. This requires combining the knowledge of resource, plant processes, and operation strategy. Annual energy production and financial revenues are usually expressed in terms of expectancy values with certain probability levels e.g. P50 or P90, which refer to 50 % or 90 % probability of exceedance.

Based on the reliability of these values and the evaluation of additional risks, the lender will add smaller or larger risk surcharges. E.g. assuming a relatively high risk level as still observed today for STE projects the debt service coverage ratio (DSCR) could be as high as a factor of 1.3 related to the P90 yield level. Compared to wind energy, which often realizes a DSCR of 1.05 or 1.1, this is an unfavorable financial situation. Since the uncertainty and variability of the direct normal irradiance is not higher than the one of wind, STE projects should offer significant potential in lowering the DSCR.

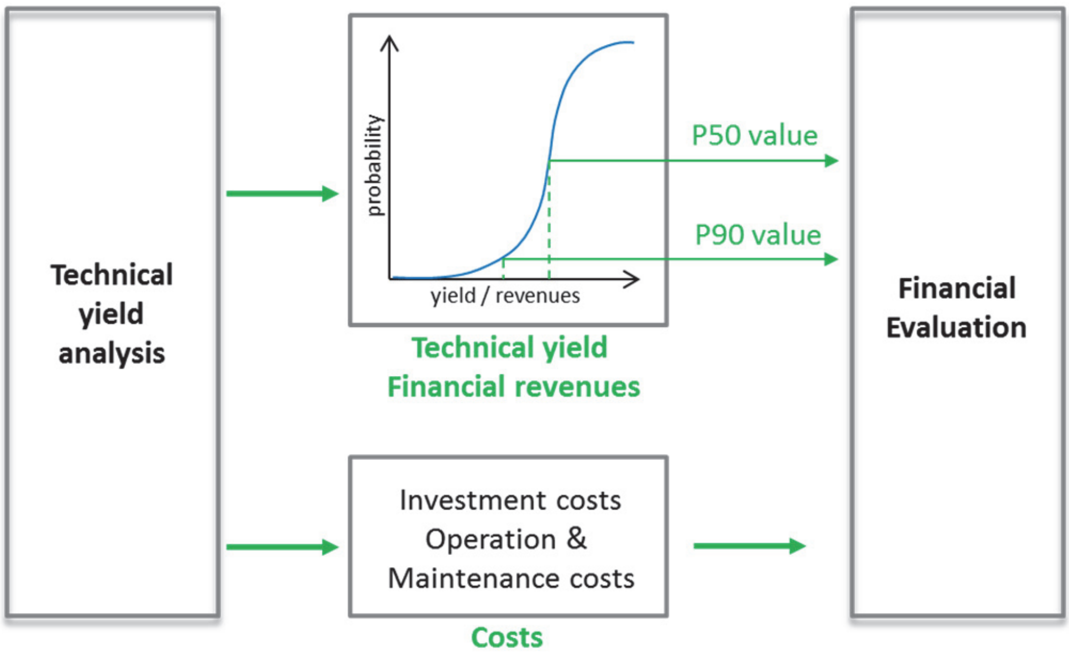


Figure 1-1: Yield analysis as the interface between technical and economic world of a project

By increasing the reliability of the expectancy values, risk surcharges can be lowered and effective costs of electricity from STE plants are reduced apart from any technical improvement in the plant. A standard for high reliability yield analysis for STE plants is thus a vital part to further improve of the bankability of these renewable energy projects. Being accepted by both, the technical players and the financial players, a standard clearly defines the interfaces which are usually electricity production, associated revenues, and costs. Especially in terms of risk analysis, a standard helps to avoid redundancies in risk buffers on the technical and financial side by introducing clear documentation rules and interfaces.

1.1.2. Evaluation of new STE technologies

With the STE technology having just started the path on the learning curve, significant improvements of components and processes are expected in the near future. The actors in research and development compare their innovations with the state-of-the-art technology to prove advantages of their products. A standardized approach for yield calculation assures that such comparison is carried out on an approved basis. Furthermore, studies of different authors can be compared more easiliy if they are based on the same approach and, in an ideal case, even on the same set of parameter values. As an example, different studies on the impact of dispatch optimization in various market regimes could be better compared to each other if similar or even equal performance parameters are used for the underlying technology. In this sense, also meteorological data sets for selected sites are provided for comparative studies.

1.1.3. Guiding developers of yield simulation tools and supporting model validation

For tool developers, it is vital to base their models on approved procedures. Especially the definition of top-level terms and generic modeling approaches should be aligned in order to allow future extension of the models.

1.2. What do we consider as yield analysis?

This guideline for STE yield analysis covers both, the technical and economic part, and can be separated into the following fields:

- local conditions, mainly representative solar radiation values,
- technical performance of the plant resulting in output of electric energy,
- capital and operation & maintenance costs,
- financial model used to evaluate the economics of the plant.

As a general concept, we distinguish between <u>mathematical models</u> used to describe the performance, the <u>parameters of these models</u> which are constant for one set-up, and the <u>boundary conditions</u> varying with time, also compare Table 1-1. We thus limit yield analysis to a fixed configuration of the plant represented by a set of modeling equations, a set of parameters, and a set of boundary conditions both for the technical and economic part. Repeated yield analysis runs accordingly to this definition can be realized during the design phase of a plant by calculating yields and economic figures with varying input parameters or even configurations. However, each of these runs is considered as a single yield analysis run. During a plant optimization phase, e.g. heliostat field layout optimization, a yield analysis approach with reduced accuracy requirements can be appropriate in order to reduce the computational effort. For a final evaluation with high reliablility demands the calculation approach provided by this handbook can be used. Evaluation of uncertainties associated with certain technical or economic results plays a key role in the yield analysis task and is therefore described in the next section.

1.3. What about accuracy of yield analysis?

Yield analysis for a solar power plant project is usually performed long before the physical installation of the plant. This is important when talking about accuracies since accuracy is usually defined as a difference of the calculated value to the real or measured value. Since the real value is a priori not known a specific approach to express the uncertainty of yield analysis is required.

For STE plants, the main sources of uncertainty in energetic yield calculations are modeling approach, technical parameters, and boundary conditions. The set of mathematical equations used to describe relevant effects is also called "modeling approach". Technical parameters are specific input into these equations. During a simulation run, these parameters usually are held constant as they represent the technical specifications and characteristics of the system. The modeling approach and the technical parameters together form a representation of the real physical system. The third major source of uncertainty comprises the boundary conditions of the simulation, anything influencing the performance without being part of the physical system. The dominating source of uncertainty here is the accuracy of the direct normal irradiance (DNI) assumed for the simulation run. Accuracy of DNI is defined as the deviation of the predicted from the measured DNI usually measured over a long time period of 10 to 20 years. Interannual variation of DNI is a natural effect which has to be considered for the cash-flow calculation in the financial model by carrying out annual simulation for different kinds of years. Another temporarily variable boundary condition which can have strong financial impact is the electricity demand expressed as a load curve or time dependend electricity price curves. Table 1-1 summarizes the three main sources of uncertainty in STE yield assessments and provides examples for each of them.

Table 1-1: Categories of uncertainty sources in yield calculation

Source of uncertainty	Description	Examples
Modeling approach	The way physical effects are translated into a mathematical formulation and discretized in time. Simplifications are necessary since some effects are not fully understood or detailed modeling would be computationally to expensive. Inaccuracies are also caused by averaging within one time step.	Simplified representation of a start-up procedure in the model, not considering that high wind speeds cause additional optical losses
Technical parameters	The performance values and physical properties of the technical configuration considered. Uncertainties arise from deviations between planning and realization as well as uncertainties in the measurement of physical properties.	Underestimation of actual mirror reflectivity, overestimation of absorber heat losses, underestimation of turbine efficiencies in part load, overestimation of cooling tower efficiency at high humidity
Boundary conditions	All time-dependent inputs into the simulation tool are a forecast of the expected situation when the plant is build. Uncertainties arise from this prediction.	Overestimating the annual solar resource, underestimating wind speed

Estimating the uncertainty of a yield analysis is crucial since it directly impacts the economic assessment of the project. In general, we can formulate the rule, that the financing costs increase with uncertainty. It is common practice for lenders to assign risk surcharges to a project which directly depend on the uncertainty of the projected yields and associated costs of the project. Besides efforts to increase technical performance and to reduce investment and operation costs of STE technology, there is still significant economic potential in the reduction of risk surcharges. A profound uncertainty analysis for a yield calculation helps to express the amount of uncertainty associated with the calculated yield values. In order to avoid redundant risk surcharges, both, in the technical part and the financial part, a transparent methodology to calculate and express uncertainty is crucial to reduce financing costs. Chapter 12 of this guideline introduces such a methodology.

During the course of project development beginning with first feasibility studies, followed by yield calculations required for proposal engineering, and ending with assessment of predicted to installed performance, the understanding of yield analysis uncertainty changes slightly. Recalling the introductory paragraphs about the uncertainty as a measure for the difference between projected and measured value in the plant as built, it becomes clear that uncertainty in early stages of project development is systematically higher than in a final state. During the sucessive phases of project development as depicted in Figure 1-2, the design of the technical system and the operating boundary conditions get more and more concrete and elaborate. As the realization of the project becomes more likely, a higher effort will be spent on reducing the remaining uncertainties in model parameters and input data. While the design at the level of feasibility studies for example is typically based on preliminary assumptions, later stages require detailed information ideally based on supplier offers. In terms of meteorological data, DNI data derived from satellite time series will be calibrated by ground measurements at the site under investigation as the project proceeds. Finally, the parameters and inputs used during the yield calculation ideally approach those present in the real plant.

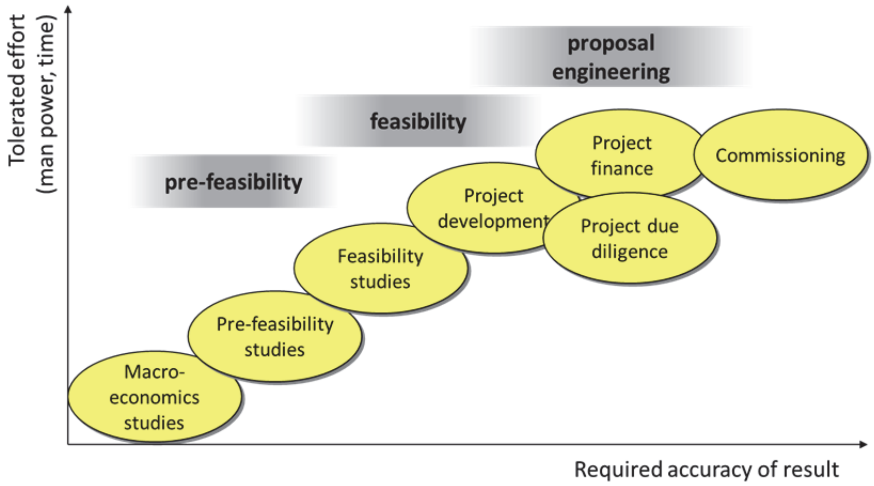


Figure 1-2: Different phases in STE project development and implementation together with the three quality levels introduced in this guideline.

Despite the increasing degree of details in the course of project development, even at the project finance state, there will always remain uncertainty from the three sources modeling approach, parameters, and boundary conditions. This is the final uncertainty that has to be reflected within the project financing. Reasonable technical measures will not be able to further reduce these values.

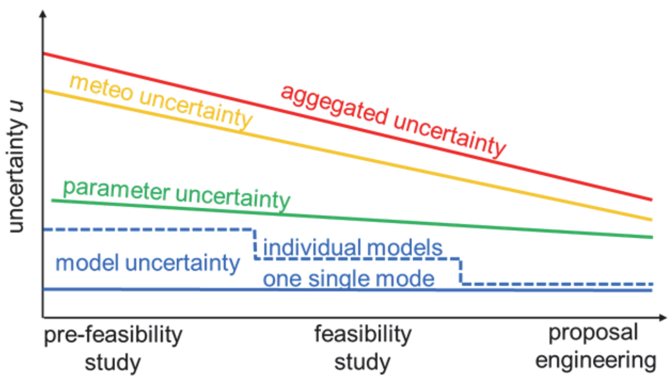


Figure 1-3: Decreasing uncertainty levels during the course of project development

Clearly, with each step in project development the input data will become more and more representative for the expected real situation at the end. First models start by being rough and then, asymptotically, the complexity is increased aiming to become identical with that original situation. For STE performance modeling in the pre-feasibility step, relatively complex models are already applied today. If starting with such a detailed model in the pre-feasibility stage, the same model can be applied even in a later project development phase. However, due to lack of knowledge, e.g. which turbine model finally will be used, and the limited budgets and time available for a pre-feasibility study, the early stage modeling makes some simplifications in the determination of the technical and input values of the models compared to the high effort spent on finding accurate model parameters and inputs for models used when aiming to achieve financial close. Although there exists a systematically higher degree of deviation of calculated values to final realized values especially in the early stages it is recommended to estimate uncertainty also for these early phases in order to raise the awareness that every yield calculation includes uncertainties and to allow for a sound interpretation of the results.

Although elements for uncertainty analysis are presented in literature, no concise procedure for calculating the overall uncertainty of energy yields from STE plants is available today. Simple yield assessments only consider the uncertainty of DNI as in many cases this is causing the highest uncertainty. However, this approach is too crude and not sufficient for financing purposes, because the other sources of uncertainty can also reach significant values. A suitable methodology for uncertainty analysis is described in chapter 13.

1.4. The three project development phases covered by this guideline

Different stages in the project development process have already been sketched in the previous chapter. Table 1-2 provides a compact definition of the three phases pre-feasibility study, feasibility study, and proposal engineering that are covered by this guideline. Figure 1-4 provides a broader view of a project life-time by not only covering the time before the plant is built but including also the commissioning and acceptance test phases. Although the yield of the plant plays an important role also during these stages, the requirements and respective approaches differ from the ones in the projecting phase. Therefore, this guideline does not explicitely cover the so-called contractual phase with topics like guarantee models, acceptance tests, and performance monitoring although some elements of this guideline might be applied for those tasks.

Table 1-2: Definition of three project development phases covered by this guideline

Name	Characterization
Pre-feasibility	Concept indicating the site, capacities of main sub-systems available. Low quality meteo data. May lead to decision on preferred collector technology.
Feasibility	Capacities and performance of the main components are available from supplier quotations and conceptual design. Different configurations are analysed in parallel in order to economically optimize the configuration. Different operating strategies with the same plant might be analysed in parallel in order to show benefits of electricity contracts May lead to decision on storage capacity, fossil fuel use and cooling technology.
Proposal engineering	Detailed engineering for the whole plant is available. Only one configuration is left. Engineering of main components is supported by supplier offers. Sub-ordinate components might be designed on common practice in engineering. High quality meteo data based on long-term satellite and at least 6 months ground measurement available.

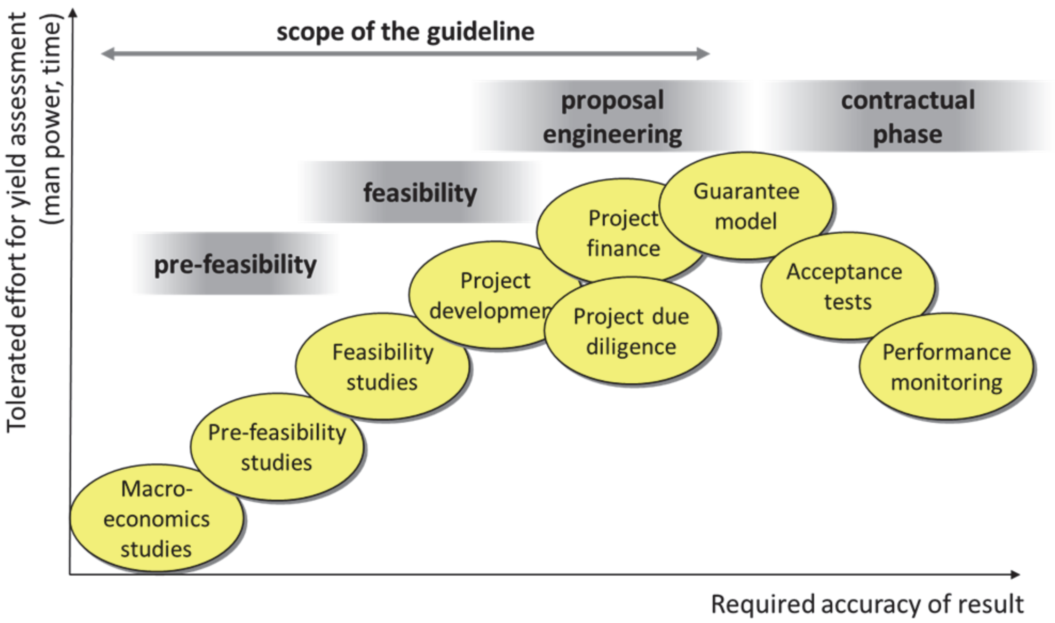


Figure 1-4: Phases of project development and scope of the guideline

1.5. Relation between guideline main document and appendices

The guideline document is intended to formulate the requirements and useful methodologies in a generic, technology-independent way. It provides a broad overview on all topics of yield assessment ranging from technical yield calculation over uncertainty estimation to financial engineering. It this contributes to a better understanding especially at the interface between technical and financial engineers. The guideline in its current version is shipped with the Appendix T that provides a comprehensive list of terms required for yield assessment.

In a next stage, the guideline will be extended by further appendices that provide working material on a more detailed level. As an example, Appendix C will provide specific modeling approaches with respective default parameters that enable a modeler to program a yield calculation simulation tool. Draft versions of some appendices originating from a German national project with several partners are already available online although they are not yet reviewed by an international expert group. Future activities intend to bring these important documents to a status comparable to the guideline main document.

As contribution to a standardization, this guideline makes use of existing or currently developed standards in the field of solar technology. It is the philosophy of the guideline to make use of established definitions wherever possible. The definition of terms provided as Appendix T to this document is largely based on the standards:

- ISO 80000-x Quantities and units
- ISO 9488 Solar energy – Vocabulary
- UNE 206009 Solar thermal electric plants – Terminology
  (currently used as a basis for a new international IEC standard)

Some of the standards are currently developed or revised. If new versions are available, the terminology of this guideline document might be adapted.

2. Financial evaluation of projects based on yield analysis

Since both, technical performance and financing conditions, have large impact on the economics of a solar power plant, the technical yield analysis and financial modeling need to be aligned. This chapter introduces principles of financial evaluation, especially project financing schemes. Electric or economic yields are input to this financial model. A second strong link is on the cost side since deviations in technical performance are often correlated to deviations in costs. Section 2.1.7 describes a methodology how to group cost items in a general and finance model compatible form.

2.1. Financial evaluation of projects

2.1.1. Principles of solar project financing

Project finance is a specific form of the more general term *structured finance*. In the renewable and in particular in the solar industry, project financing structures have not only been able to mobilise high percentages of inexpensive, long term debt, but also brought up new types of equity investors in addition to the "usual players" like utilities, independent power producers (IPP) or engineering procurement, and construction companies (EPC). A new landscape of financial investors like asset managers, infrastructure and pension funds as well as private individuals of all types have invested into solar as one of the main renewable assets classes. They all appreciate long term cash flows with stable dividends over long terms. As a consequence, both, debt and equity of project financings, have reduced the capital cost for solar PV to a good extent. This is one of the main factors for the increasing competitiveness of solar power in many countries.
Project financings are loans provided to a special purpose vehicle (SPV) on the basis of the assessment of its future cash flows. A solar SPV uses these funds together with a portion of equity to finance the construction of a solar power plant. After construction, the power plant generates cash flows by selling power (and/or heat or certified emission rights). These cash flows are being used to pay O&M cost and cover the debt service for the loans, i.e., interest and principal. Cash flows exceeding the above mentioned cost items can be used for being disbursed as dividends to equity providers or shareholders, who in the project finance business are called *Sponsors*. The project company (SPV) acts as an economically independent entity. For lenders, key to so-called bankability of the SPV is a secure assessment of future cash flows and their likelihood of realization. The project cash flows are the main source for lender's debt service payments, therefore, their secure assessment is the key to a bankable transaction. As collateral for the loans, lenders usually rely on the project's assets and shares. Unlike in corporate financing (balance sheet finance), lenders have no or very limited entitlement (non-recourse or limited recourse) to other assets or cash flow of sponsors. Hence, project financings often are also regarded as *off-balance sheet finance*. By contrast, corporate finance usually provides funds from the balance sheet of the investing firm. With capital intense, long-term fixed assets, the impact to even strong balance sheets is noticeable and enduring and can have significant impacts on key balance sheet ratios, limiting further borrowing power.

2.1.2. Structure of a project finance transaction

Each project finance transaction is a complex network of different contracts that are arranged around a project company. Contracts negotiated between the SPV and its counterparties all refer to either the pre-completion phase or the post-completion phase of the project. It is essential that the contract design encourages all parties to act in a way that is beneficial for the project objectives. On the other side, all counterparties' interests need to be equally considered. Figure 2-1 illustrates a typical structure of a project finance transaction.

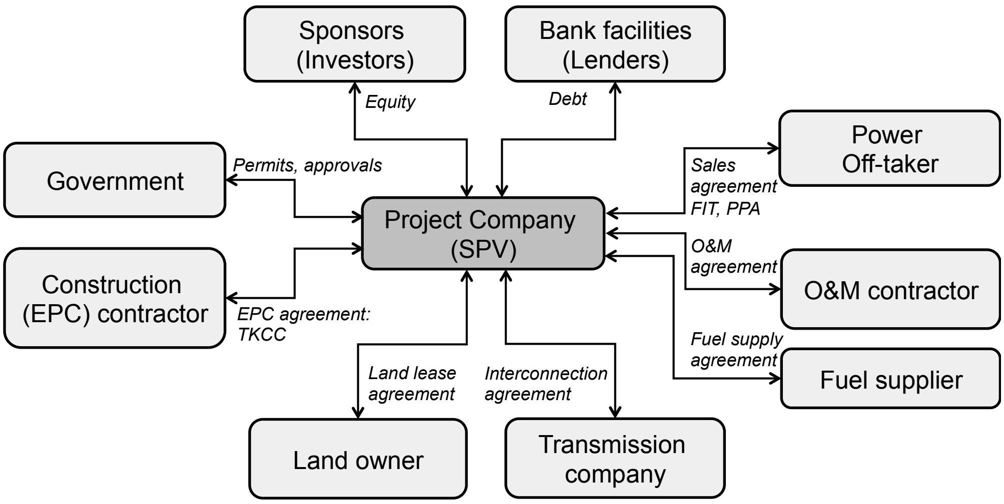


Figure 2-1 Typical structure of project finance

In order to understand the idea of project finance as "cash flow based lending", the image of the cash flow waterfall is essential to understand the fundamental structure of each project financing. The cash flow waterfall rules the hierarchy of the "cash flow food chain". From the operative revenues of a solar power project, there is a clear rule telling which cost elements are being covered in which order. First, operative cost and maintenance cost are being paid, together with taxes and insurance, since without these, the plant would stop operating and generating cash flow. The remaining amount is being called cash flow available for debt service (CFADS). CFADS is being used to cover first senior debt, and possibly junior debt such as subordinated debt in order. Any remaining amount of cash flow then would be - after all reserve accounts are filled to the satisfaction of lenders - available for the distribution to sponsors as dividends.

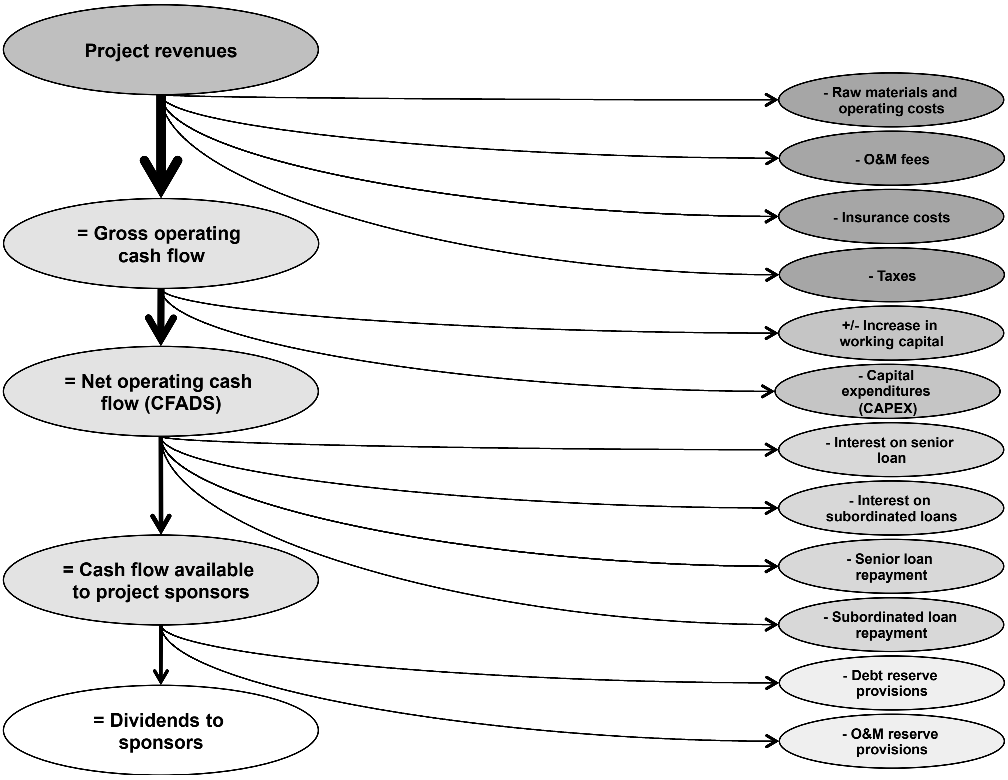


Figure 2-2 Summarizing waterfall structure from sale revenues to sponsor dividends

2.1.3. Lenders' and sponsors' perspective

Both, investors as well as banks, fundamentally rely on projected cash flows of the project. Both have different key indicators for their interest. Lenders are most concerned about the project's capability to cover the debt service, i.e., payments of interest and principal. For the debt sizing or the assessment of the debt capacity of a project, the main ratio that banks use is the so-called debt service coverage ratio (DSCR). The DSCR expresses the project's capability in every time interval investigated (typically semi-annually) to generate enough free cash flow for covering debt repayments (principal) and interest. On top, banks require a buffer, so that a typical DSCR ranges from 1.2 to 1.4, depending on the Lender's risk perception of a project cash flow (valid under long term power sales agreements with stable offtakers). Now, any uncertainty of projected cash flows – in our case, resulting from energy yield predictions or missing agreements on applied standards for measurement – causes lenders to make discounts to the projected cash flows and, as a consequence, reduces the amount of debt conceded to the project. More expensive equity needs to come up for the balance. In addition, lenders may require higher interest on their loans and/or reduce debt tenors, all of which increase the capital cost of the project.

Any standardization of energy yield predictions and increase of precision of the same would result in higher comfort to lenders and hence to higher concessions in the terms of debt financing. A standardization would significantly allow to reduce long lasting, expensive, and controversial discussions between sponsors' and lenders' technical advisors. Usually, much time and effort is spent to find an agreement between sponsors' and lenders' technical advisors as well as with the EPC on the

subject which procedures and results can be considered as trustworthy. These discussions can last months and mostly lead to even higher uncertainty (=risk premiums) for lending parties, not to speak of the cost involved if technical and legal advisors as well as lenders and sponsors need to attend.
Main investors (or sponsors) are usually the ones who initiate and care for implementation of a project, their individual interest is of essential importance. For sponsors, the key figure usually is the return on their investment (mainly equity). To measure economics, a range of figures can be used. For solar projects, however, the two most important ones are the project internal rate of return (Project IRR) and the equity internal rate of return (Equity IRR). The project IRR indicates the interest the project generates on the overall capital. This figure disregards any financing scheme or the sources of such capital and hence is a measure for the economic strength of the overall project. Now if – as usual - the cost of debt (interest rate) is lower than the project IRR, and the lenders would be willing to provide a portion of debt to the overall sourcing of the project, there are two principle effects for equity investors: first, equity investors or sponsors only have to provide the balance of the total funding, for example a 30% of total funds. Second, since debt cost are lower than project IRR, the remaining portion of project IRR cash flow that is not needed to cover principal and interest of lenders can be used to pay dividends. As a consequence, the equity IRR is higher than the project IRR. This is called the leverage effect. It is one of the main reasons for the application of project (and other structured-) financing and helps to optimize the capital structure.
Under a given electricity sales scheme such as a feed-in tariff, an equity investor would therefore strive to maximize leverage (debt share) in order to minimize his equity investment and maximize equity IRR. On the other side, in a process where competitiveness of the power price is key, a high leverage and low capital cost can contribute to the competitiveness of the project by lowering the capital cost.

2.1.4. Influence of uncertainties on financing

Figure 2-3 illustrates the influence of uncertainty in energy yield on the net present value (NPV, compare also Table 2-1) by means of an example which covers three different scenarios:

- Conervative case (conservative financial conditions, e.g. commercial banks, low leverage, short tenor, high interest rate)
- Base case (typical financial conditions with experienced STE lenders)
- Optimistic case (financing from DFIs, multilateral institutes, Worldbank, etc. with high leverage, long tenors, low interest rates)

The NPV in this example is based on a 100 MW STE parabolic trough plant. Within each case, the financing conditions remain the same while only the uncertainty associated to the energy yield is varied. One can see that the NPV decreases as the uncertainty rises. From a certain point on financing becomes impossible since the debt service coverage ratio falls below a minimum value or the internal rate of return is too low for an investment. In this case, only better financing condition help to realize the project. From the red to the blue line these are obtained by including lenders with experience in STE financing which leads to reduced requirements e.g. in terms of debt service coverage ratio. At even higher uncertainty levels conventional financing products are not sufficient. Any kind of supplemented financing is neceassary to cover the high risk level. From a practical experience, uncertainty levels of 10% are assumed during financing. From the diagram it becomes clear that this level does not allow for financing based on the conservative assumptions. The three lines, although just plotted for an example clearly indicate the need for better calculating and, in the end,reducing the uncertainty level associated to STE yield calculations.

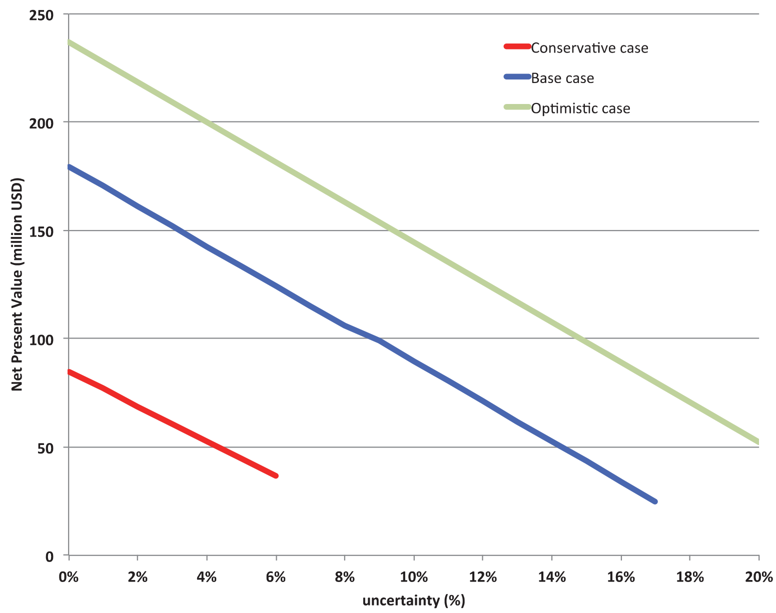


Figure 2-3 Impact of energy yield uncertainty and financing conditions on the net present value (lines terminate when DSCR falls below the threshold or the setup would not allow a project finance any more)

2.1.5. Required input data for financial modeling

For evaluating the economic performance of a project, financial model are used. The following parameters are required as elementary input for such financial model:

- **Schedule**: Start of construction, start of commercial operation, PPA term
- **Operation data**: PPA tariff or Feed-in tariff, net annual electricity generation, efficiency/availability of electricity output, reduced output in first year after COD
- **CAPEX**: capital expenditures – EPC costs, owners costs
- **OPEX**: operational expenditures – fixed and variable O&M costs
- **Escalation factors**: escalation per operation period for OPEX and indexation of PPA tariff
- **Depreciation, tax, dividends and discount rate**
- **Working capital** assumptions
- **Financing**: cost of equity (IRR_{eq}), leverage, bank interest rate (interest rate and margin), repayment profile, tenor, up-front fees, commitment fee, DSRA account and interest on DSRA account

2.1.6. Recommendations for project evaluation depending on purpose of study

Different financial figures are used to express the economics of a STE project. Depending on the purpose of the study, selected figures are most meaningful. Table 2-1 lists some of the most common financial indicators and their preferred usage for project evaluation.

Table 2-1: Financial figures for different tasks of an economic study

Name	Main benefit	Typically used for
LCOE (levelized cost of electricity)	• Easy to calculate approach requiring only a few technical and economical figures. • Reduced number of parameters leads to transparency and reproducibility • Comparability of Life Cycle Cost for Renewables among each other	• R&D • Feasibility studies • Assessment of competitiveness[1] (Attention! Often wrongly used to compare RE with regular tariffs of conventional power, where the last one has a fuel cost – pass through clause!)
IRR (internal rate of return)	• Project IRR indicates the interest the project generates on the overall capital. • Equity IRR indicates the return on the transaction for the equity investors (of which the major ones are also named "Sponsors").	• Project IRR reflects the fundamental economic viability and return of a project, disregarding financing mechanism and conditions • Equity IRR to assess the return of the investors on their equity, usually after debt financing
NPV (net present value)	• is used to analyze the profiability of a future investment or project. • Can be used to judge whether an additional cost investment is justified (i.e., if a meteostation installed on a site results in a higher NPV than without installing) • Reflects whether the project yields a better return on investment than the cost of capital (WACC or discount rate)	• To decide about investments: a positive NPV tells us whether the project return is higher than investor's applicable capital cost for the investment • If project IRR = WACC (discount rate) => NPV = 0 • Since absolute terms, dimension of investment in present value becomes illustrative
DSCR (Debt service coverage ratio)	• Defined as *Cash available for debt service divided by debt service of a defined period*. The DSCR illustrates whether a project is capable at all times to service a calculated amount of debt service.	• For debt sizing of the project • Assessing the robustness of the financing structure

[1] Unfortuntately, LCOE's are being calculated and the result is being compared to initial tariffs of convenitional power plants such as fossil fuels , disregarding the fact that for fossil fuels, life cycle cost can hardly be assessed as electricity tariffs have a large element of fuels cost (coal fired power ca. 40%, combined-cycle gas power ca. 60%), which can hardly be fixed over the life cycle. As a consequence, comparing LCOE's with initial tariffs of convenitonal plants results in disfavour of the former and represents a metholdogically incorrect mechanism.

2.1.7. Revenues of a dispatchable power plant

The financial analysis of a STE project is based on the revenues the plant generates in the respective reporting period (e.g. 3 months, one year). Total revenues originate from

- Operational revenues calculated from the amount of electricity produced multiplied with a tariff. Tariffs might vary throughout the day so step wise evaluation is required.
- Capacity revenues are revenues paid to the plant operator for providing certain capacities in stand by or for guaranteeing certain load change ramps

The various financial contracts determine the respective tariffs and payments for capacity services. In high quality yield assessments these specific revenue situation has to be taken into account. Under such incentive schemes the operation of the plant and thus the amount of power produced during certain periods depends on the tariff structure. Even short-term fixing of the tariff prices might take place if the plant participates actively in the electricity market. The topic is closely related to the operation strategy that is discussed in chapter 10. The operational revenues have to be calculated on the specific scheme foreseen for the project. Capacity revenues have to be added if applicable.

2.2. Cost structures of STE plants

Depending on the project phase when project costs are estimated, the project structure and the type of STE technology, respective level of detail for cost structures and the accuracy of estimates will differ. Although the cost structures will differ in the level of detail, the overall structuring can be applied to all phases. The cost structure described below are usually applied during the planning phase (feasibility study) of a STE project. During later stages needed for financial close the level of detail is extend so that more cost items are added on second and third level.
In general, project expenses are divided into capital expenditures (CAPEX) and operational expenditures (OPEX). The following sections provide a general introduction into the cost groups.

2.2.1. Capital expenditures (CAPEX)

Capital expenditures represent the costs for planning, erecting and commissioning of the power plant as well as the financing costs for this investment. The commercial operation date (COD) is usually used to distinguish between expenditures allocated to capital costs and expenditures allocated to operation and maintenance costs (see next section).
Capital expenditures can be divided into the following three main categories:

- EPC costs
- Owner’s costs and
- Financing costs

The sum of the EPC costs and the owner’s costs is often referred to as “overnight cost”. Financing costs mainly refer to interest during construction and financing fees. Table 2-2 provides an overview of the overnight cost breakdown for a STE plant, together with the respective cost references for each of the cost items. Referencing the cost items to respective plant parameters and using corresponding scaling factors, will allow for techno/economic optimizations, necessary during the planning phase of each project. It should be noted that this kind of cost approximation based on reference numbers and scaling factors does not include all impact parameters and can thus only be used in early stage cost estimation (pre-feasibility and feasibility stage of a project). Depending on the type of STE technology and the actual plant configuration, the cost structure will differ in some parts.

Table 2-2: Cost structure - capital expenditures (overnight costs)

Item	Reference value	Unit
EPC Costs		
Site preparation	total land area	$\$/m^2_{land}$
Solar field / heliostat field	solar field reference aperture area	$\$/m^2$
Heat transfer fluid system (incl. central receiver, if applicable)	solar field reference aperture area or thermal capacity	$\$/m^2$or $\$/kWh_t$
Thermal energy storage (TES)	thermal capacity of storage system	$\$/kWh_t$
Solar tower (if applicable)	tower height	$/m
Power block and Balance of Plant (BoP)	nominal capacity of power block	$\$/kW_e$
Auxiliary heater (if applicable)*	thermal capacity of auxiliary heater	$\$/kW_t$
Engineering, management and other EPC services	EPC direct costs	%
Profit margin and contingencies	EPC direct costs	%
Owner's costs		
Project development	total EPC cost	%
Land cost (if applicable / not considered in OPEX)	total land area	$\$/m^2_{land}$
Utility connections**	project specific	$
Additional Owner's costs	total EPC cost	%
Total Overnight cost		

* HTF heater or supplementary firing for steam generation

** to be determined on a project specific basis, depending on project constraints

2.2.2. Operation and maintenance expenditures (OPEX)

The operation and maintenance (O&M) expenditures are divided into fixed and variable O&M cost. Fixed O&M are the costs of operating and maintaining the STE plant regardless of how much electricity is generated, i.e. regardless of the number of operating hours. In comparison, variable O&M costs are a function of the operation of the plant, i.e. the more operating hours the higher the variable O&M costs. While fuel costs in case of conventional power plants are generally provided in a separate line item, i.e. provided separately from the variable O&M costs, they are considered as part of the variable O&M costs for a STE plant, given there is only small fuel consumption. Table 2-3 provides an overview of OPEX cost items, together with the respective references and proposed calculation for each of the cost items.

Table 2-3: Cost structure - O&M costs

Item	Reference / calculation
Fixed O&M costs	
Solar field & HTF system (material and maintenance)	Fixed percentage of solar field & HTF system direct costs
TES system (material and maintenance)	Fixed percentage of TES system direct costs
Power block, BoP and aux. heater (material and maintenance)	Fixed percentage of PB, BoP and aux. heater direct costs
Personnel	Number of staff times average manpower costs
Administration & management	Fixed percentage of direct cost
Land lease	Land area times land lease costs; location-specific
Insurance	Percentage of total direct costs
Variable O&M costs	
Fuel	Fuel price times fuel consumption
Raw water	Raw water price times raw water consumption
Electricity	Electricity price times downtime electricity consumption
Others (e.g. HTF, nitrogen, other consumables etc.)	Fixed value [$/MWh$_e$] times annual power generation
Total OPEX	

2.2.3. Cost estimation

Cost estimation represents an interface of engineering and economics. It combines both, technical knowledge of the object under investigation and economic skills in order to analyze cost data and perform reliable cost estimates. In the field of cost estimation or cost engineering, several international and national associations and organizations are promoting the application of scientific principles and techniques in the discipline of cost engineering. These institutions like the AACE International (formerly the Association for the Advancement of Cost Engineering) or the International Cost Engineering Council (ICEC) are providing respective guidelines for cost estimation.

AACE International has defined five estimate class levels. The classification level depends primarily on the level of project definition with end use, methodology, accuracy, and estimating effort secondary characteristics. The table below provides an overview of the cost estimate classes, based on AACE International's Recommended Practice No. 18R-97[2]. This practice is further used as basis in the ASTM Standard E2516-11 (Standard Classification for Cost Estimate Classification System)[3]. The 18R-97 is the recommended practice for cost estimation classification for the process industries and is a reference document that provides extensions and additional details for applying the principles of estimate classification specifically to project estimates for engineering, procurement, and construction (EPC) work.

Table 2-4: Cost estimating classification matrix (following AACE International)

	Primary characteristic	***Secondary characteristic***		
Estimate class	**Maturity level of project definition deliverables** Expressed as % of complete definition	**End usage** Typical purpose of estimate	**Methodology** Typical estimating method	**Expected accuracy range** Typical variation in low and high ranges*
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%
* The state of process technology, availability of applicable reference cost data, and many other risks affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.				

The different cost estimation methods can be grouped into two fundamental cost estimate approaches: the "top-down" approach and the "bottom-up" approach. The top-down approach (classes 4 and 5) uses historical data from similar projects to estimate the costs of a new project, taking into account different cost influencing-factors in order to be able to normalize costs. Important factors are: the date a project has been built (inflation or deflation, prevailing regulatory framework, technological improvements / learning curve, etc.), the location (currency, import duties, site development cost, transport cost, special building codes, labor cost, etc.), and the size of the plant and

[2] AACE International Recommended Practice No. 18R-97: Cost Estimate Classification System - As Applied in Engineering, Procurement and Construction for the Process Industries, Rev. November 29, 2011

[3] ASTM E2516-11, Standard Classification for Cost Estimate Classification System, ASTM International, West Conshohocken, PA, 2011

subsystems (economy of scale). The top-down approach is best used during the early development stages of a project, when alternatives are still being developed and refined. The bottom-up approach is a more detailed method of cost estimating (classes 1 to 3) and, thus, requires more detailed project specific information such as bill of materials, unit rates, budget quotations etc. The term "bottom-up" is used because the approach requires estimates of cost elements at the lower levels of the cost structure, which are then aggregated to obtain the total cost of the project.

2.3. Cost impacts arising from site and meteorological conditions

Local site conditions either geological, meteorological, or infrastructural can strongly influence the investment and operation/maintenance costs of a STE plant. The following sub-chapters give a brief overview of the most important site-related factors to be considered during cost estimation. The topic of solar radiation and auxiliary meteorological parameters, which are highly relevant for yield of STE plants is described in chapter 12.

2.3.1. Natural hazards

Natural hazards may cause serious damage to a solar plant as it is covering large areas of land with relatively fragile components. The most relevant natural hazards for STE plants are summarized in Table 2-5. If certain natural hazards at a plant site are regarded as a serious risk, plant design must be done in way that the plant can withstand these. At least design should be strong enough to mitigate hazards the more frequent events of small to medium intensity.

Table 2-5: Selected natural hazards' relevant to STE plants.

Risk types	Phenomena and causes	Possible effects	Preventive measures	Recommended assessment
Precipitation / Flooding	-Seldom, but intensive rainfall events -Rising river levels (Wadis*) -Slope of the embankments -Rising sea water due to storm surge at high tides with tendency to increase by due to sea level rise	-Flooding -Erosion -Undermining foundations -Flushing ducts	-Installation of drainage system -Construction of dikes and embankments -Surface protection by gravel layers, sealings, limit angle of repose - Regular visual inspection	-Precipitation analysis focusing on statistical analysis of re-occurance periods of extreme events - Topographical and hydrogeological analysis of catchment area upstream the plant and potential runoff peaks
Wind load	-Storms and gusts, thunderstorms -Extreme low pressure systems (tornados, hurricans/cyclones)	-Physical damage to plant and staff during construction and operation - Breakage and wear of plant components - Erosion of surfaces - Plant outage	-Robust collectors & foundations -Smart controls of the tracking system -Wind breakers, fences -Surface protection by gravel layers	-Prior on-site wind measurements combined with historical data sets from reanalysis runs
Hail	-Thunderstorms -Mirror strength	-Mirror breakage -Optical damage of	-Installation of site-appropriate mirrors	-Evaluation of historical weather data

		non glass mirrors	acc. to standards and technical specification	
Snow	-Snow events	-High system loads due to snowpacks -Performance losses	-Appropriate system design -Snow drop control mode	-Assessment of historical weather data - Snow height measurements
Lightning	-Thunderstorms	- Damage to electric components -Structural damage** -Damage to service*** -Injury of living beings	-Installation of appropriate lightning protection system	-Lightning risk assessment according to int. standards and local regulations
Earthquake / Soil Liquefaction	-Regional seismic activity -Soil conditions	-Damage to power block -Damages of piping and solar collectors	-Building the plant according to international codes and local regulations	-Earthquake zone information - Building Code -Geotechnical reports
Wild fire	- Higher danger of fires in arid regions -Amount of biomass nearby the plant	-Fire on the plant -Significant reduction of direct solar radiation over several days or weeks also from more distant fires	- Taking into account provisions for fire prevention	-Local historical documents that cover at least one century -Biomass index
Sand storms	- Dust storms in desert areas such as MENA region - High probability of occurrence in summer periods	- Significant reduction of direct solar radiation over several days - Equipment damage and wear, risks to health and safety, loss of profit, increased maintenance costs (mirror cleaning, sand removal etc.)	- Installation of wind and sand breakers - Consideration of alternative materials and coatings for components that may be directly exposed to sand storms - Constructive measures preventing sand to enter (e.g. cabinets and covers)	-Verification of measures from time to time, e.g. in order to improve wind fences -On site wind measurements at representative height of 10 m and dust measurements
Volcanic eruption	-Volcanic activity	-Significant reduction of DNI over many months -Volcanic tephra hitting the solar field from nearby volcanoes	-Apply more co-firing during times with significnantly reduced DNI - Propose cleaning procedurs	-Analyze probability of volcanoe eruptions, check Volcanic Explosivity Index (VEI)****

* Wadis: suddenly rising water level in normally dry water beds due to heavy rainfalls
** Plant structure includes plant components and incoming lines
*** Plant service includes telecommunications, power, water, gas and fuel distribution network
**** VEI classifies strength and type of eruptions, VEIs>5 (worldwide effect) are very rare

In common for all of the presented environmental hazards, careful assessments, insurance costs and appropriate plant design usually results in higher capital and operating costs. On the other side, the mitigation measures reduce potential damages leading to downtime or perhaps long or permanent failure. Thus, the proposed assessments and preventive measures should be worth the additional expenditure during planning with respect to averting future expenses, yield, and revenue losses.

2.3.2. Environmental site conditions

Further environmental site conditions compromise meteorological, geological, and other characteristics of a site that can and should be determined carefully in advance in order to consider their typically large influence on the required plant design and costs from the beginning of a STE project. Of particular concern is the availability of water, which is used in the water/steam cycle, for cooling and other purposes, such as cleaning and service water. Table 2-6 lists important further environmental site conditions, with its origin, impacts, and mitigation masures.

Table 2-6: Environmental site conditions

Types	Possible origin and influence factors	Possible impacts	Assessment and mitigation
Soiling	• Frequency of rainfall • Aerosols in atmosphere	• Deposition of particles on collector and absorber tubes • Plant yield • OPEX costs depending on required cleaning methods and frequency	• Soiling/dust measurements in parallel to meteorlogical campaign • Consideration of soiling in performance simulations • Cleaning strategy
Topography	Most suitable slope around 0.5% to 2%, preferably facing towards equator	• Site preparation: excavation, leveling /cut-and fill • Layout of drainage system	• Topographic survey producing map and digital elevation model (DEM)
Geotechnical conditions	• Ground bearing capacity, caverns, caves and obstacles • Water levels, soil layers • Contamination	• Cost increase and time delay of civil works • Assessment increases comparability of bids, risk assignment to the contractor and avoidance of later claims	• Geotechnical survey
Archeological situation	• Archaeologically relevant findings, ordnance	• Lot of the plant needs to be relocated to avoid distruction of important archeological reamains • Cost increase and time delay of civil works	• Archeological survey
Corrosion	• Exposure to sea water, sea water spray • Other nearb sources of highly corrosive conditions • Increased by a hot and humid environment	• Reduction of plant components' lifetime	• Corrosion test over one year in conjunction with met station • Selection of special materials and foundation types • Exclusion of an unsuitability project site
Environmental and social impact	• Environmental and social effects of the project • Objective is to ensure an efficient project implementation with regard to both financial and economical aspects	• If not done: additional future costs, • project delays or cancellation	• Environmental and social impact study (ESIA) • Guidelines and rules: e.g. from international institutions such as World Bank, KfW, EIB, local addtional requirements • Preparation time of several months

2.3.3. Infrastructure

Non-environmental conditions such as transportation and road connection, fuel supply and other relevant aspects for constructing and operating a STE plant, such as security issues and housing compounds have significant influence on the CAPEX and OPEX of STE plants. Constructing power lines is also a major cost factor.

Regarding the use of existing infrastructure for transportation purposes, especially for heavy and sensitive equipment, distance, load bearing capacity, dimensions (width and height), and possible further restrictions of near unloading facilities and road connections to the plant site should be considered. In case of insufficient conditions, high additional investment costs and project schedule delay may arise from necessary rehabilitation or construction of bridges, buildings, and roads.

Fuel supply usually is provided in form of liquid, gaseous, and (rarely) solid fuels, mainly of fossil origin. They are required for example for freeze protection of the HTF and for additional power generation, such as during emergency cases and plant outages or for partly supporting electricity generation. Fuel supply system components that should be considered with respect to system design, capital, and O&M costs are: supply structure and conditions, unloading and take-over of the fuel at the plant boundary, storage and distribution within the plant and proper disposal of residues. Local and international codes and standards on safety, fire fighting and environmental impacts should be strictly observed. In addition to fuels, numerous other chemicals, lubricants, and technical gases are used in a STE plant for various purposes, e.g. chemical fuel, flue gas, water and condensate treatment, lubrication, and laboratory analyses. Usage of all chemicals and materials should be in accordance with national and international codes and standards which may cause country specific additional costs.

The need for security measures depends on local requirements. In MENA regions, specific codes and standards have to be applied on facilities whose destruction or damage could temporarily or permanently affect the economy or well being of population. Capital and O&M costs for boundary corridors and fences and reduction of available area for the installation of the actual plant have to be taken into consideration.

STE plants located in remote areas may require additional expenditures for staff transportation or set-up of new housing compounds, which should be considered in the course of a project. During construction depending on plant size and design several hundred workers are needed on site. During operations a totöl staff of 20 to 50 is typically required at the plant. Regarding housing compounds for permanent staff, additional room for relatives and support people should be included in the planning.

2.4. Standardized yield analysis report

Discussions on yield analysis results between different players in a project are one of the main targets of this guideline. A common understanding of terms representing main inputs and results of the calculation process as defined in the guideline and terminology avoid misunderstandings efficiently. It is therefore reasonable to define a number of key figures that should be mentioned in each yield report. This figures refer to the definitions in the underlying terminology which exactly defines their meaning. Since such project performance overviews might have an individual graphical layout depending on the partners involved the guideline recommends the terms to be listed in such a report. They are considered as a minimum requirement to represent the project as a whole. Details on performance parameters applied have to be listed in an additional technology specific databook. Information in the project performance overview can be grouped into 7 categories. The following tables provide the advised terms to be listed in each of the categories together with some examples for filling.

Section 1: Customer, author, and type of study	
Project name/identifier	*Big Solar Installation 1*
Purpose of yield analysis	select from: Pre-Feasibility, Feasibility, Proposal Engineering *Feasibility study*
Prepared by company	*Best solar consultant ever*
Author	*Mr. Mechanical Engineer*
Reviewer(s)	*Dr. Genau Obachecka*
Approved by	*Ms. Mary Boss*
Client	*World Solar Energy Int.*
Date	*2016-07-20*
Simulation code used	*inhouse code “super sim”, Solar field analysis code “super solar sim” and thermal system analysis code “super thermal sim”*

Section 2: Technical project description	
Project site	*Las Vegas, NV, USA*
Site coordinates	36.3° North, 114.9° West of Greenwich
Start of constr./Comm. operation	*July/2017 / April 2019*
Overall plant concept	e.g. direct molten salt tower, oil based parabolic trough with two-tank molten salt storage, direct steam generation linear Fresnel without storage
Collector technology	parabolic trough (solar tower, linear Fresnel)
Collector type / supplier	*Powertrough 166 / Best collector system Inc.*
Receiver / supplier	*EVAC Tube 5.5 / Best receiver company*
Heat transfer medium	*73,5 % Diphenyloxid/26,5 % Diphenyl (Water/Steam, $NaNO_3$/KNO_3, Air)*
Solar field parameters (nominal load)	Inlet/outlet temperature: 290 °C/393 °C Mass flow: 2110 kg/s Thermal power: xxx MW Nominal aperture area: 600.000 m^2 Solar field efficiency @design: 65 %
Type of power block	*Rankine Cycle* (*Brayton Cycle*, *Organic Rankine Cycle)*
Condenser technology	Wet cooling tower (Air cooled condenser)
Power cycle parameters (nominal load)	Inlet/outlet temperatures: 393 °C/290 °C Live steam temperature/pressure: 388 °C / 110 bar Mass flow: 1055 kg/s Thermal power: xxx MW Gross electric power: MW Gross electric efficiency: xy,z %
Type of thermal energy storage	*Two tank molten salt*
Thermal energy storage parameters (nominal load)	Inlet/outlet temperatures: 393 °C/290 °C Charge/ Discharge mass flow: xxx / xxx kg/s Charge/discharge thermal power: xxx / xxx MW Thermal energy capacity: MWh
Type of auxiliary heater	none
Type of auxiliary fuel	*Natural gas* (*biogas, none*)

Section 3: Electricity price and operation strategy	
Operation strategy	*pure solar driven*
Overhaul period	*first 14 days in January*
PPA tariff or feed-in tariff / indexation	*150 US$/MWh / 2% increase per year*
tariff termination	20 years

Section 4: Meteorological boundary conditions		
Term	**Value**	**unit**
Annual DNI average (P50)	…	$kWh/m^2/a$
Annual DNI average (P90_single)	…	$kWh/m^2/a$
Inter-annual volatility (DNI rel. standard deviation)	…	%
Average ambient temperature	…	°C
Number of satellite data years considered	…	a
Number of years considered in simulation (1 means one TMY, >1 means set of annual data)	…	
Time resolution of met data file	…	min
Time resolution of simulation	…	min
Data files considered: 1. CCSSS_TMY_CASE_yyyymmdd.txt 2. CCSSS_MY90m_ CASE_yyyymmdd.txt 3. CCSSS_MY90s_ CASE_yyyymmdd.txt	…	 $kWh/m^2/a$ $kWh/m^2/a$ $kWh/m^2/a$

Where

- CCSSS is site identifier with CC for ISO 2-letter country code and SSS for site name
- CASE may be acronym for various cases of calculating DNI, generating TMYs, etc. based on various satellite data, processing of measurements etc.
- yyyymmdd is date of approval of input data set or unique identifier

Section 5: Energetic results				
Term	**Symbol**	**P50 value**	**P 90[4] value**	**Unit**
Annual gross electricity production	E_{gross}	…	…	GWh
Annual net electricity production to grid	E_{grid}	…	…	GWh
Reduced annual net electricity production to grid in first year after start of commercial operation	$E_{grid,year1}$	…	…	GWh
Electric auxiliary consumption	E_{aux}	…	…	GWh
Electricity consumption from grid	$E_{fromgrid}$	…	…	GWh
Annual fuel consumption	Q_{fuel}	…	-	GWh
Annual anti-freeze consumption, thermal	$Q_{aux,AF}$	…	-	GWh
Annual anti-freeze consumption, electrical	$P_{aux,AF}$	…	-	GWh
Annual plant capacity factor	F_C	…	-	-
Effective plant availability (including scheduled overhaul period of *xx* days)	F_{avail}	…	…	%
Fraction of electric energy production by solar	F_S	…	…	%
Solar multiple	F_{SM}	…	…	-
Number of power block starts (cold/warm/hot)	-	…	…	-

[4] Project specific probabilities of exceedance can be used alternatively, e.g. P75, ….

It is recommended to show an uncertainty chart for the net electricity production to the grid in addition to the tabulated numbers above.

Section 6: Financial parameters		
Term	**value**	**unit**
Capital expenditures (CAPEX) EPC costs / owners cost	…/…	US $
Operational expenditures (OPEX) fixed / variable	…/…	US $ / a
Escalation rate for OPEX	…	% / a
Earnings from electricity sales[5]	…	US $ / a
Total Investment Costs (TIC)	…	US $
Required minimum DSCR	…	-
Average Debt Service Coverage ratio ($DSCR_{average}$)	…	%
Leverage	…	%
Tenor	…	a
Interest rate (all-in)	…	%/a
Project Internal Rate of Return (after tax) ($IRR_{project}$)	…	%
Equity Internal Rate of Return (IRR_{eq}) with debt-equity ratio	…	%

Section 7: Details of uncertainty analysis				
Meteorological uncertainty				
Input data for uncertainty analysis	P50, P90 TMY or Multi year time series (30 years, 45 uncertainty data sets)			
Parameter uncertainty – List of parameters selected	**Distribution type**	**P50 value**	**1 σ value**	**Impact on yield in terms of 1 σ**
e.g. Optical efficiency at normal incident	normal	0.765	0.014	5 GWh/a
…				
Model uncertainty				
Bulk model uncertainty (if used)	3%			
Model uncertainty parameters	Distribution type	P50 value	1 σ value	Impact on yield in terms of 1 σ
e.g. Start-up energy	normal	122 MWh	25 MWh	3 GWh/a
…				
…				

[5] Additional figures might be required here.

3. Definitions and generic modeling principles

The intention of this chapter is to introduce key ekements for STE modeling independent of a specific technology. The application of this general set-up to specific technologies is illustrated in the successive chapters.

3.1. Top-level principles of yield analyses

A number of elementary principles for yield analysis are defined. Although these aspects are worked out in detail in other chapters, the intention of this compilation is to give a brief overview on the most important pre-requisites and concepts:

- We assume that the technical configuration is fixed for the yield analysis. Thus, this guideline does not cover approaches for optimizing plant layout although the methods for yield analysis presented can be used during the optimization process.
- The focus is on annual yield calculations as a prediction of expected yield. The concepts developed can only partly be used for yield calculation during performance testing and O&M[6].
- The calculation is based on at least annual data of direct normal irradiance. As a minimum requirement, we consider usage of a typical meteorological year which was derived for the site considered from data (ground and/or satellite) covering a time period of 10 to 20 years. Requirements for generating representative meteorological years are provided with this guideline. For risk assessment in project finance, a multi-year calculation can be required in addition.
- For high quality yield analysis as needed for proposal engineering, a temporal resolution of 10 min is recommended for the meterological input data. For pre-feasibility studies, a temporal resolution of 60 min is considered as sufficient. In general, estimation of annual yield based only on a number of reference hours is not meaningful. Further details on the selection of a time step are given in section 3.5.
- For modeling purpose, the whole solar thermal power plant can be split into sub-systems which are connected on system level, see section 3.2.
- Plant models used for yield analysis represent physical effects that can be well described by steady-state assumptions and effects that require taking transient processes into consideration. Most modeling approaches today are based on steady-state modeling with additional correction terms to reflect transient behavior. More details are given in section 3.4.2.
- Thermodynamic modeling as required for detailed yield analysis needs to take temperatue effects into account. Although many models are historically based on a heat flow modeling approach, it is required to consider at least some temperature effects. A consistent way of

[6] They can be used to evaluate the plant yield over long periods like several month. Special calculation approaches are needed to compare yield simulations with operational data during acceptance tests.

implementing this is to base the model on mass flows and temperatures (enthalpies) instead of heat flows. If a heat flow approach is being used, correction terms for distinct temperature effects are required. Simplified approaches using just energy flows are considered as not sufficiently accurate. Further explanations can be found in section 3.4.2.

- Sub-systems can be represented by detailed models or resulting characteristic lines. Both modeling approaches are acceptable as long as all required effects are included appropriately, see also section 3.4.1.
- Due to strong interactions between the plant sub-systems, iterative solution procedures are usually required for calculation of operation points.
- The annual yield depends on the chosen operating strategy. Basic strategies are introduced (e.g. solar driven) in this handbook. Recommendations are provided how to document individual operation strategies, see chapter 10.
- If not otherwise stated, annual simulations are initialized with a empty storage and shut-down system (usually warm-start level) in order to have unique initial conditions. The same holds for the re-start after an overhaul period although remaining energies might be left in the storage tanks. In case operation strategy (e.g. power production all the night through) or environmental conditions (1st of January on southern hemisphere is in summer season) suggest other initial states they can be used, too. A remaining amount of energy in the storage or any other system at the end of the simulation period is not explicitely considered for determining the annual yield.
- Fluid property data are assumed to be constant over the life time of the project. In case a degradation of the fluid has severe effects for certain technologies it can be considered in the same way component degradation is handled, see section 11.1.

3.2. Breakdown into sub-systems

For analyzing complex technical processes, it is helpful to split the whole plant into smaller units that can be covered separately from each other. Solar thermal power plants with a number of typical functional units like solar field, power block, or thermal energy storage are well suited for such structuring. For yield analysis purpose, this offers a number of advantages:

- Complexity of a sub-system is reduced compared to the whole system.
- Sub-system modelling can be realized by respective experts.
- Inputs and outputs from one sub-system can be arranged in a sub-system specific way.
- Meaningful figures of merit can be defined.
- Flexible arrangements of multiple/different sub-systems guarantee that also new plant designs can be treated with the same methodology.
- A clear interface definition helps to illustrate the boundary conditions for the sub-systems.
- The simulation software can be split into functional units that can be developed and built independently from each other (Software engineering aspects).

The structuring defined in this document is based on functional units suited for the STE yield analysis and comprises the 5 sub-systems[7] illustrated in Figure 3-1. These sub-systems are used as a structure for

- Providing modeling approaches,
- Reporting results (energetic yield and electric demand of sub-systems),
- Allocating costs (investment and O&M costs).

In order to reach the consistence between these areas, each component is clearly assigned to a specific sub-system. Combination of the individual sub-systems is realized on the system level. The system level is responsible for

- Balancing mass and energy flows between all sub-systems.
- Implementing the operation strategy of the plant.
- Providing an iteration procedure for solving the final set of equations.
- Calculating variables that cannot be calculated on sub-system level (e.g. pumping power of main pumps).
- Providing meaningful figures of merit by combining results from the sub-systems.
- Considering system-level effects or modeling approaches like availability and degradation.

3.2.1. Underlying principles for sub-system break-down

The following rules are derived for defining the interfaces between the sub-systems:

1. Heat exchangers are a natural interface between two sub-systems. The heat exchanger is always assigned to the sub-system that makes primary use of the heat transferred. That means that the heat exchanger between HTF and power cycle is assigned to the power block. The heat exchanger of an indirect storage system is assigned to the storage since the storage makes primary use of the heat and the heat exchanger would not be necessary without thermal storage. However, the heat exchanger of a auxilliary heater is assigned to the heater sub-system since this sub-systems consists mainly of this heat exchanger.
2. The solar field comprises all components for conversion of solar energy into thermal energy and transportation of this energy to the power block/storage connecting point. This means that apart from the solar receiver itself, all pipings like headers and runners belong to the solar field.
3. Pumps required to circulate the heat transfer fluid through the solar field, the storage, and the power block heat exchanger are assigned to one of the sub-systems in terms of costs although calculation of pumping power can only be realized on system level since pressure differences of at least two separate sub-systems are needed. Pumping power in secondary heat transfer fluid cycles like molten salt cycle in indirect storage systems or feed water pump in power block are considered in the respective sub-systems (here: thermal energy storage, power block). The total

[7] Remark for deviations from former guiSmo project definitions: The “Operation Management System” defined in the guiSmo project is not considered as an individual sub-system since it does not reflect physical components. For the same reason “Ambient conditions” are not considered as a sub-system itself. The “Heat transfer System” discussed in earlier guiSmo stages is not considered as separate sub-system. The whole heat transfer fluid cycle is assigned to the solar field for simplicity and clarity reasons.

pumping power required by steam cylce based solar plants is thus composed of the pumping power in the HTF cycle and the feed water pumping power in the water-steam cycle. Please note some special cases:

   a. In case of direct power cycles (e.g. direct steam generation, solar gas turbine) the feed pump or compressor, respectively, is assigned to the power block sub-system for practical modelling reasons: First, the pressure drop fraction is higher in the heat engine compared to any of the other sub-systems. Second, the compressor is integral part of a gas turbine (in terms of performance, modelling, and costs) and cannot virtually be separated from the power block. For consistence reasons, the direct steam generation cycle should be treated in the same way as the solar gas turbine cycle.
      For comparison of results with indirect cycles, the electric consumption of the feed pump/compressor can be split into to fractions in a yield report. The fractions assigned to the system level fluid transport and to the power block are calculated based on the pressure drop relation between system level pressure drops and power cycle pressure drop (with the same steam mass flow through both of them).
   b. In direct molten salt power plants, the molten salt pumping power in the storage-power block loop is part of the system level although the pump for constructional reasons is closely connected to the storage. The same holds for the molten salt pump for the solar cycle.
   c. Heat tracing pumps of indirect molten salt storage systems used to keep the storage and the storage heat exchanger warm are assigned to the storage sub-system since no other sub-systems are involved in the operation. For direct molten salt plants the assignment of anti-freeze pumps for keeping the solar field and heat exchanger warm are assigned to the system level (like also the main pumps).

4. Secondary equipment used by a heat transfer fluid cycle like expansion tanks are considered as part of the solar field sub-system.

3.2.2. Catalogue of sub-systems

Based on the rules explained in the last section the interface definitions for a parabolic trough power plant with two-tank molten salt storage are shown in Figure 3-1.
The sub-system **solar field (SF)** comprises the concentrators, receivers, and the piping from the receiver to a connecting point to power block and/or storage. Usually, the solar field has one inflow and one outflow. Distribution on sub-fields (if any) is realized within the sub-system solar-field. In terms of costs, the solar field comprises the solar field costs as well as the HTF piping and HTF component costs (HTF storage, HTF expansion tank, HTF preparation system if required) and the HTF itself since a separate HTF sub-system is not foreseen.

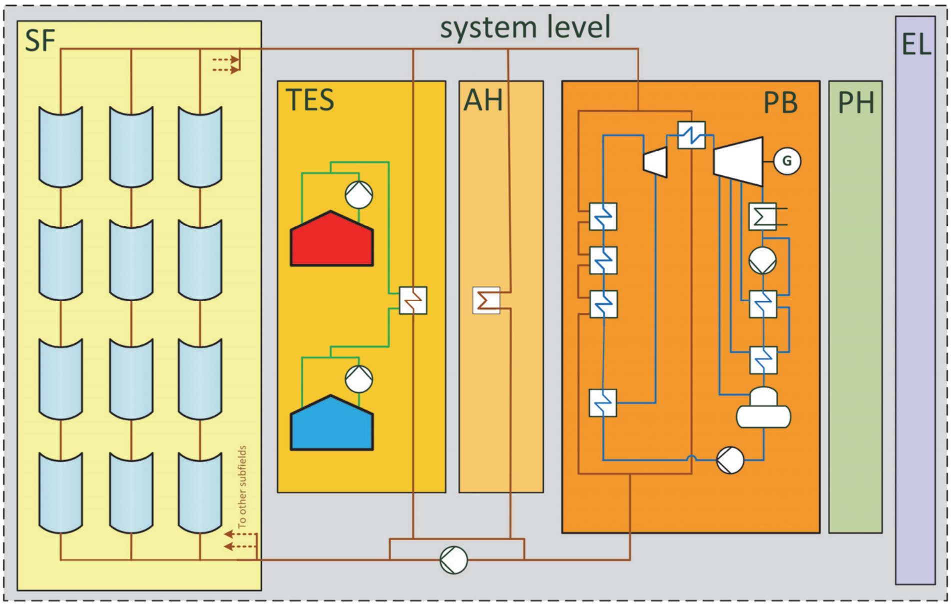


Figure 3-1: Break-down into sub-systems for the example of a parabolic trough oil system

The **power block (PB)** comprises the heat exchangers that transfer heat from HTF to the power cycle fluid and the power cycle itself. A separate heat exchanger sub-system is not introduced since steam generator, steam turbine, and pre-heater are closely linked and usually described together. The generator is part of the power block whereas the consecutive electrical losses belong to the electrical sub-system.

The **thermal storage sub-system (TES)** includes the storage system itself, the heat exchangers for indirect storage systems, as well as the piping to the connecting point and pumps associated to the TES system.

Auxialliary heat input is realized by the **auxiliary heater (AH)** sub-system. It includes the fossil burner and the connecting pipes.

Special treatment is required for the HTF main pumps since they often cannot functionally be assigned to a single sub-system. In these cases, the calculation of the pumping power is realized in one designated sub-system (e.g. power block for DSG or gas turbine systems) or on system level. In the latter case, the costs are assigned to one of the sub-systems and not to the system level. The **system level** itself does not hold any components except the main pumps (if not assigned to a sub-system). Thus, heat and pressure losses do not occur on system level but have to be represented by the respective sub-system.

The **electrical system (EL)** finally acts as a summing unit for all generated and consumed electric flows. Also minor electric losses inside the plant, the electric losses of the main transformer and electric losses outside of the plant in the transmission line to the grid connecting point are calculated there.

Application of the sub-system concept for other technologies is introduced together with the respective technology in chapter 4.

Although not covered in this version of the guideline, a sub-system **process heat (PH)** is already introduced in the schematics.

3.2.3. Classification of variables

The sub-system definition provides a transparent way of breaking down the whole plant into smaller modeling units. A unique set of sub-system interface variables is introduced to assure that sub-system models can be replaced without modifying the whole set-up. Apart from the interface variables that are needed to transmit information between the sub-systems and the system level, additional variables can be defined for the sub-systems. It is useful to distinguish between the four categories shown in Table 3-1.

Table 3-1: Variable categories at the sub-system interfaces

Type	Meaning
interface variable	Needed at the interfaces between sub-systems in order to exchange information between sub-systems and the system level during the calculation of a time step.
reporting value	Output variable calculated at the end of a calculation based on the simulation results.
characteristic figure	Integrated value over a certain period of time, as e.g. one year. Can be calculated based on interface or monitoring variables.
Parameter	Fixed input/design value for the model which is not changed during iteration.

Interface variables denominate variables that can or must be exchanged with other sub-systems during each iteration or part of the calculation steps. They are needed to specify the current state, the needed input, and especially the output of the corresponding sub-system. For “Solar Field”, e.g. this could be temperature and mass flow at the inflow and outflow of the solar field. Information is exchanged to other sub-systems only via the interface variables. The meteorological boundary conditions like irradiance or temperature are a special interface variables since the information flow goes only into the sub-systems.

Reporting values and characteristic figures are not directly needed for the calculation process itself but for evaluating and comparing the results (usually during post-processing step). Definition of these variables is useful since specific information from each sub-system is required to evaluate the overall system performance. Reusability of evaluation algorithms requires a unique definition of the required inputs. While reporting values depict the current state of a sub-system at a specific output time step, characteristic figures are integrated or averaged over a certain time span (one day, one month, one year).

For the sub-system “Solar Field”, e.g. the reporting value could be the heat flow or the solar field efficiency, while the characteristic figure could be the overall thermal heat output or the average annual solar field efficiency.

Parameters represent another category of variables that represent fixed input of the model like a design value, which is not changed during the simulation.

3.3. Definition of operation points

STE plants undergo a large number of different operating conditions. Distinct load conditions are often used for design purpose or comparison with alternative technologies. In order to avoid misunderstanding in terminology we define the following terms:

- Operation mode
  An operation mode describes a controller set-up either for the whole plant or on sub-system level. Usually, each sub-system has several operation modes (down, regular, start-up, stand-by, …) that describe in which way the unit is controlled. On plant level, the combination of sub-system operation modes yields a larger number of system level operation modes (e.g. solar field operation with storage assisted power block operation)
- Operation point
  In contrast to the operation mode, an operation point indicates one unique set of operating conditions, i.e. specific instantaneous values of mass flow, temperature, load.
- Design point (or Nominal point)
  Operation point used to design the components of the plant. Important fluid dynamic properties like mass flow, temperatures, and pressures needed for dimensioning the plant components are derived from the design point. The design point can, but need not, be the point of maximum authorized load. There is one individual design point for each sub-system (e.g. storage charge design point, storage discharge design point). For yield analysis purpose, the design point is often used to express a design or nominal efficiency. Efficiencies in other operation points are then described in relation to the design point (e.g. power block efficiency). Please note, that within a sub-system, the main components may have an individual design point in terms of engineering, often called rated conditions. It is a matter of the modeling approach if individual design points are explicitely maintained in a sub-system model or if the overall performance is mapped to a single design point of the sub-system.
- Load point
  Any tolerated load condition either at sub-system or system level. We prefer the term load point instead of part load point since at least in some cases, a load point can reflect also design conditions when looking at single sub-systems. We distinguish between regular load (no restrictions) and overload (restrictions regarding the number of acceptable operating time in this mode).
- Maximum load point
  The load point at which the sub-system reaches its maximum continuous load.
- Minimum load point
  The load point at which the sub-system reaches its minimum regular load.
- Overload point
  Load condition at which the sub-system exceeds the maximum regular load. Such overload conditions are usually tolerated only over a certain time interval and a maximum number of hours per year. Otherwise, life time of the components is reduced.

- Reference point

  Load condition defined by a set of ambient conditions (temperatures, DNI,..) and pre-requesites on the operation mode used to compare different STE systems under a common framework. Reference conditions are used mainly for performance evaluation purposes. In real plant operation, the reference point is only theoretical and corrections must be applied for the real conditions.

3.4. Different modeling philospophies

The minimum requirements formulated in this guideline can be met by means of different modeling approaches. The chosen approach often depends on the availability of input data or the usage of the yield analysis tool also for other purposes like plant design or performance guarantee modeling. The following sections provide on overview on typical differences in modeling approaches as seen today.

3.4.1. Granulated versus integral modeling approaches

The performance of all technical sub-systems can be described in different ways. In principle, we can differentiate between a granulated, physical oriented approach, and an integral - more empirical - approach.

Granulated physical modeling:

- Effects are represented by equations that are derived based on the underlying physics. Since several physical effects are present in most system this modeling approach typically ends up in a large number of equations.
- The equations describing a physical relation include parameters that specify the actual configuration. The granulated modeling approaches breaks down into a high degree of detail, so many parameters are needed on a very detailed level. Examples could be material properties, reflection characteristics, or heat loss coefficients.
- Due to their generic structure, the models can be used for a variety of configurations by modifying their parameters.
- Effects can be tracked down to a very detailed level which enables are profound comparison of alternative configurations.
- The approach requires detailed knowledge of the individual effects, their interaction, and the dominating parameters.

Integral, more empirical modeling:

- Empirical models usually describe a number of interacting effects numerically e.g. by using multi-dimensional data tables. Allthough the driving input variables on the top level are the same as for granulated approaches, they do not describe the overall performance by combining many sub-ordinate effects.
- In order to gain the knowledge of the overall performance, the user has to rely on either simulations with more detailed models or on measured data that reflect the performance for

all required variations in input variables. Allthough the information for yield analysis can originate from a more detailed simulation model (could be similar to a model using the above described granulated approach), the difference to the granulated modeling approach is that this model is not directly included in the yield analysis tool.

- Empirical relations are limited in re-use since they can only be used for systems very similar to the one they were derived for.
- If high quality measurement data is available, the integral approach can result in higher accuracy since uncertainty can directly be estimated from the overall performance measurements and needs not to be integrated from many uncertainty contributions in the case of granulated modeling approaches.

The user has to select the approach appropriate for his application. Combinations of both approaches are typically found for modeling of various sub-systems. Here are some examples:

- Although the thermodynamic performance of the power block can well be modeled by linking the various turbine stages to corresponding feed-water pre-heaters, the performance of the whole system expressed in terms of thermal efficiency, outlet temperature, and auxiliary electric consumption can be described by a very limited number of variables (load, inlet temperature, cold end conditions). Multi-dimensional look-up tables or empiricial fits to these data are sufficient to represent the power block for yield analysis.
- Whereas some solar field models break down a collector loop into collectors and interconnecting piping, further split up the collector into optical and thermal performance metrics, users with access to high quality measured data for a whole loop might rely on this measured data for the whole loop seeing no need to go to more granular models.
- Another example is heat loss modeling of parabolic trough vacuum receivers where two principle approaches exist:
    - Physical modeling based on convection, conduction and radiation heat transfer between fluid, receiver, glass tube, and ambient.
    - Measured data usually providing thermal loss in W/m as a function of the operating temperature.

3.4.2. Mass flow versus heat flow based modeling

Although the process chain from solar input to electrical output can be illustrated by means of energetic flows and losses a simulation program simply relying on energy flows is not sufficient to cover all relevant effects required for proposal engineering. In many cases, the energy flow has a certain “quality” (in thermodynamics called exergy) that defines the extent a certain amount of energy can be transferred into another form of energy (e.g. from thermal to mechanical in the turbine). The exergyof thermal energy flow between different sub-system can well be described by using the mass flow in combination with temperature or specific enthalpy. The mass flow holds the information on quantity while the temperature/enthalpy transports the quality information. The following examples illustrate situations where temperature information is required in addition to the energy flow:

1. Inlet temperature to the solar field has an impact on SF efficiency.
2. Outlet temperature of the solar field depends on load conditions. Differences in outlet temperature can affect the storage tank temperature and thus the storage tank capacity.
3. Inlet temperature to the power block has an impact on PB efficiency.
4. Discharge temperature of indirect storage systems differs from solar field outlet temperature. Thus, the power block is supplied by different temperature levels in SF and TES operation which causes different efficiencies and possibly different maximum power block output.

A simulation tool based on mass flow as primary variable automatically considers these effects. Tools based on heat flow as primary variable can be extended to the same functionality by adding respective temperature equations and mixing processes if several fluid streams are involved. The guideline recommends to use mass flow based tools.

3.4.3. Approaches to model transient processes

Modeling of technical processes becomes more complex if transient behavior has to be considered.

Table 3-2 gives an overview on approaches commonly used for simulation. For STE annual yield calculation, appropriate approaches have to be selected. Whereas some effects can well be represented by a quasi-static approach, some others require dynamic approaches. In general, it is considered as sufficiently accurate to use quasi-dynamic approaches that represent the impact of underlying transient behavior on the energy yield. Fully dynamic modeling tools are considered as alternative approach, that gives more insight into the process. Such tools can be used to identify parameters required in quasi-dynamic approaches. A typical example of an quasi-dynamic approach would be the start-up of the solar field, where a certain amount of energy is required to heat up the system. In addition, a minimum start-up duration might be needed to consider any limitations in ramp rates.

Table 3-2: Definition of static[8], quasi-static, quasi-dynamic, and fully dynamic modeling approaches

Type of model	Application to model processes
Static	The process to be modeled is static, that means always in equilibrium.
Quasi static	The process to be modeled includes some transient behavior caused by e.g. mass or thermal intertia, but the impact of the transient behavior is negligible compared to the static behavior. The simulation assumes a sequence of static steps in time.
Quasi dynamic	The process includes significant transient effects that have to be considered in their impact on performance. In contrast to the fully dynamic approach it is sufficient to represent the impact of the transient effects by means of simplified correction terms to the quasi-static performance. This approach reduces model complexity and calculational effort while considering the transients in a sufficient mannor. Parameters for this kind of model have to be derived from experimental data, detailed fully dynamic simulations studies, or data bases (not really available today).
Fully dynamic	The process includes significant transient effects that need to be considered since they have a large impact on the results. The transient effects are included in the modeling equations which results in differential equations in time. Incorporating fully dynamic behavior in the modeling of physical components usually requires to also model the corresponding control system in a reasonable level of detail. The approach reveals a deep insight into the process and can be used to optimize the configuration.

3.4.4. Representative meteorological years versus multi-annual time series

There are two basic philosophies for considering the effect of solar resource on yield:

1. Simulate only one year with a representative Typical Meteorological Year (TMY) which is constructed in a way that it represents the long-term average over many years.
2. Simulate multiple years by means of a multi-year meteorological data set that represents natural variations around the long-term average.

Table 3-3 gives an overview on the benefits and drawbacks of the two approaches. More details on the requirements for generating multi-year meteorological data sets are given in Röttinger et al. (2014) and Fernández-Peruchena et al. (2015). Polo et al. (2016) report that applying multi-year time-series from satellite is now a feasible yield simulation approach when using very fast STE-simulation tools to represent the effect of inter-annual variability. However, Polo et al. do not provide a suitable recipe for considering uncertainty in the multi-annual data. The ususal multi-year data sets only represent the effect of variability, but not the effect of uncertainty introduced e.g. by imperfect DNI measurements. Up to date, no consens is reached for handling uncertainty when using multi-year time

[8] The term steady-state is often used as alternative to static

series. It seems that several hundred annual data sets may be required as in Röttinger et al. to derive realistic probability density functions, from which P90 yield values can be concluded.
Instead of applying multi-year data sets, the effect of the interannual variability of annual averages of DNI may also be expressed by calculating the standard deviation *s* over all annual DNI values from a site. This simpler approach may be done as annual DNI values are roughly following a normal distribution. If the effect of less sunny years on the cash-flow should be evaluated in a finanacial model, expectations on lower yields can be estimated applying the normal distribution.
Thus, this guideline considers it as sufficient to work with typical meteorological year TMY data sets representing the long-term average DNI_{P50} which is the P50 value, that should be exceeded with a probability of 50%. Further explanantions on this topic are given in chapter 12.

Table 3-3: Comparison between usage of TMY and the multi-year simulation approach

Discipline	Typical Meteorological Year (TMY)	Multi-year time series
Met. data preparation	Multi-year time series is basis for compiling a TMY. Composition of TMY by combing fractions of underlying time series in order to be consistent on different statistical mean values. Exceptional years e.g. by volcanic eruptions can be neglected in the calculation of the relevant statistical figures.	Multi-year time series as derived from combination of satellite and ground data can directly be used. Need for gap filling strategies since an uninterrupted sequence is required. Exceptional years can be removed if not to be considered.
Computation time for the base case	1 year simulation sufficient for the base case. Risk analysis to assess influence of DNI uncertainty on yield can be done with a minimum of 1 additional annual data set.	At least 10, better more than 20 years, have to be simulated for deriving the long-term average as base case. For risk analysis several 100 of years need to be simulated to derive the probability density function.
Accurateness	Different weather situations need to be considered by fulfilling various criteria during the comnpilation process (daily, weekly, monthly, annual means and additional statistical measures).	Simulation of more weather situations with the simulation tool reveals potential non-linearities in the relation between annual mean solar resource and plant yields.
Impact of inter-annual fluctuation	Expressed by a statistical figure like standard deviation from long-term mean. Identification of expected inter-annual variation from this figure is acceptable as long as the impact can be considered as approximately linear.	Directly considered in the simulation. Results from n years can be used in financial analysis. Additional perturbation of such real (non-synthetic) years possible to reflect sequencing effects.
Uncertainty analysis	Estimation of uncertainty in the long term mean value can easily be realized by constructing at least one more representative year that should be exceeded with a certain probability e.g. 90% probability of exceedance (P90). Only 1 additional annual simulation then is sufficient to consider uncertainty.	A large number of multi-year data sets can be constructed by artificially manipulating the basis time series in order to represent uncertainty of long-term mean. No established methods available today for this process.
Accurateness	Different weather situations need to be considered by fulfilling various criteria during the compilation process (daily, weekly, monthly, annual means and additional statistical measures).	Simulation of more weather situations with the simulation tool reveals potential non-linearities in the relation between solar resource and plant yields. Multi-year data sets are essential, when yields from STE plants should be matched with historic demand and price-curves to demonstrate how well STE electricity meets demand or output can be optimized to price-patterns.

3.4.5. Combining several modeling tasks in one single model

This guideline works on the assumption that the design of the underlying plant has already been fixed by a previous design process. This is consistent to the viewpoint of a technical consultant in a late stage of project development. For STE plants, repeated yield analyses are an essential part of the design process since each modification in design is evaluated in terms of performance and cost implications. Technology developers and EPCs use more detailed models for their design tasks. Often, the same detailed model is directly used as annual yield simulation tool. Developers and EPCs might even user their combined design and yield analysis tool to derive performance guarantee models as a black-box compilation.

This illustrates that a guideline on yield analysis cannot pre-scribe or select one distinct modeling approach because the circumstances for the different groups of players are diverse. Instead, the guideline focuses on defining the minimum requirements to be met by each yield analysis tool and also recommends approaches that are considered as sufficiently accurate, generic, and easy to implement.

3.5. Appropriate time steps for yield analysis

3.5.1. Definition of different time step meanings

Time steps are used at several point in the simulation process. An overview on the definitions used by this guideline is given in Table 1-1. The ideal case in terms of consistence is given if the meteorological data time steps equals the input time step and the output time step. Interpolation on different time grids is avoided and there is a 1:1 translation between meteorological data and result data. The simulation time step used by a model can be smaller than the input/ouput time steps. However, it is adviceable to at least have input/output time steps as a multiple of the simulation time steps in order to avoid interpolation during the reading and storing of data. Many tools today that make use of quasi-dynamic modeling approaches use a common time step for all of the four classes.

3.5.2. Recommendation for harmonized time steps

Historically, the time step for annual simulations was set to one hour since available meteo data files could only provide this kind of resolution. The meteorological time step thus defined the time step used by most models. With advances in meteorology, improved products are on the market and further refinements can be expected in the future. Opinions about the best choice for the time step are broad ranging from one hour down to one minute. However, these extrem cases do not well serve as a general recommendation.

The guideline strongly recommends to use **a harmonized time step of 10 min** for the

- meteorological data time step
- simulation tool input time step
- output time step

The time stepping of the numerical simulation tool cannot be fixed in general since it depends on the underlying modeling philosophy (quasi-dynamic or fully dynamic). In case of quasi-dynamic tools, it is recommended to use the 10 min time step also as calculation time step.

Table 3-4: Definition of different time steps for yield simulation

Name	Description
Time step of meteorological data file	Meteorological data fiels used as input for the yield simulation are shipped in a certain time discretization of e.g. 10 min, 15 min, 60 min.
Input time step of simulation tool	Time steps by which a simulation tool reads/accepts input data like meteorological data. If the input time step of the tool does not fit to the meteorological data time step interpolation with potential loss of precission is needed. Some tools allow flexible input time steps.
Calculation time step (tool internal)	Time step of the numerical discretization of the simulation model. The time steping chosen strongly depends on the modeling approach. Fully dynamic modeling usually requires smaller steps than quasi-dynamic models. Constant time step length as well as adaptive time steping can be used for the different approaches. Quasi-dynamic modeling usually works with constant time steping.
Output time step	Time step at which simulation results are stored for post-processing.

The following bullet points illustrate the main considerations leading to this recommendation:

- Although it might be reasonable to choose a time step individually for each project there are good reasons to head towards a harmonized time step:
    - Comparison of results is significantly simplified if all result files are based on the same time step
    - Tool developers can optimize their codes and visualization functions for this time step.
    - Providers of meteo data have a clear orientation what is expected by the user and can design their products accordingly.
- An annual or multi-annual yield calculation model does not need to fully resolve transient processes like start-up or shut-down. In quasi-dynamic models, sufficient accuracy is reached if the whole process is represented by a small number of time steps (e.g. 1 to 5 time steps of length 10 min for a process that takes about one hour). The duration of the process can be estimated by the time constants directly related to the main flows of energy in the plant. STE systems are usually characterized by a significant amount of thermal inertia inducing power gradients in the range of 10 (small inertia) to 2 (large inertia) percent per minute. The duration of the whole process is thus 10 min to 50 min.

- The computational effort severly depends on the number of time steps. Although the impact on a single year calculation is not critical, features like multiple year calculations as well as comprehensive uncertainty analyses multiply the required computation time.
- While meteorological ground measurements can be recorded in minute intervals (higher resolution difficult due to the characteristics of the measurement devices) typical time steps of satellite based products are still one hour. New generations of satellites enhance repetition rate from 2 to 4 per hour leading to one instantaneous observation every 15 min. When entering the below 5 minutes time step level we are talking about modeling single cloud systems. These can be represented by ground measurements but not by satellite products. Pixel sizes of geostationary operational weather satellites are typically in the range of several kilometers, while the DNI-relevant cumulus clouds are in the 100 m scale. If these small time steps are desired, artificial cloud systems need to be generated from satellite time series taking into account local cloud system characteristics obtained from ground measurements. Along with shorter time increments must go smaller spatial resolution. Stepping into such fine spatio-temporal resolution would require also solving the issues of 3D clouds. To solve the parallax problem would also require to have at least cloud top and bottom heights available in high resolution and ideally information about various multi-cloud layers. Such kind of DNI products are topic of ongoing research and beyond. It is unlikely that satellite-derived longterm-data sets in minute-time resolution become available within the next decade.
- On the modeling side, resolving individual clouds would mean a dramatic increase in model complexity. While annual yield calculations are based on an average irradiance value over the whole field, modeling clouds would require spatially resolved models. Moreover, the reaction to these fast disturbances depends on the control strategy. A significantely higher level of control algorithms would be needed in the code. The gain of accurancy associated to such highly resolved modeling is considered very small or even negative compared to the effort.
- In systems with thermal energy storage the storage reaches its upper and lower limit within a time step interval. The modelling can either react by virtually splitting the time step in two parts in order to exactly match the instant the storage reaches the critical level. Or, it is tolerated that the storage is slightly charged above or discharged below its limits within one time step assuming that the effects cancel out over a certain period of time. The handbook proposes the second approach. With a typical charge time of 8 hours and a time step of 10 min the over/underload equals approx. 2%.

4. Modeling the system level of STE plants

4.1. Generic approach and variable definitions

4.1.1. Effects typically modeled on the system level

The generic approach to break down the whole STE plant into smaller units, called sub-systems is introduced in section 3.2. Following this concept, the large majority of the modelling takes place inside the respective sub-systems. Chapters 5 to 9 provide the principles for modeling these sub-systems. However, some effects remain to be handled on the top, the so-called, system level since they comprise at least two of the sub-systems. Table 4-1 lists these effects and links to the respective chapters where modeling is described. Please remember that all heat losses and pressure losses in piping are not assigned on the system level but in one of the sub-systems.

Table 4-1: Effects modeled on system level

Effect	Description	Link
Mass and energy balance	Mass and energy flows on system level need to sum up to zero since neither heat nor mass losses are foreseen on system level.	Section 4.1.3
Main HTF circuit pumping power (pressure balance)	Pumping power calculation needs to consider pressure drop within all sub-systems operated by a pump station. Since information on pressure drops in other sub-systems are by default not available in a sub-system this calculation has to be done on system level. In addition to the pumping power the heat input due to non-ideal pump might have to be considered.	Section 4.1.2
Operation control	Operation control includes all “hard-coded” rules of plant operation. The plant operator cannot influence them. Especially start-up and shut-down procedures that require two or more sub-systems need synchronization on system level.	
Operation strategy	Operation strategy describes the way the plant is used to produce electricity. Based on the electricity market model the operator takes decisions when to activite and deactivate sub-systems like storage or auxiliary heater.	Chapter 10
Effects considered on an annual basis.	Some effects like degradation and availability can be considered as a post-processing step based on the annual results.	Chapter 11

4.1.2. Main HTF circuit pumping power

Depending on the technology one or more pumping stations are used to circulate the heat transfer fluid from solar field to power block, through the storage system, and the auxiliary heater. The pressure head to be overcome by the pump is given by the individual pressure heads of the *j* sub-systems operated by this pump,

$$\Delta \mathrm{p}_{\mathrm{pump}} = \sum_{j=1}^{n} \Delta p_{\text{sub-system}}^{\mathrm{j}} \quad . \tag{4.1}$$

In case of parallel flow channels, the maximum pressure drop of the parallel channels is relevant for the overall pressure drop. Combinations of sub-systems in parallel and series can occur. In this case, the parallel branches have to be replaced by the branch with the highest pressure loss. The technical realization will foresee a throttling or control valve in the path with lower pressure drop in order to establish the desired flow distribution on the parallel channels. The effect of this valve needs to be considered on system level since its opening depends on the load situation of all adjacent sub-systems. The pressure drop of each sub-system is calculated in each sub-system and made available to the system level via the sub-system interface variables

$$\Delta p_{\text{sub-system}}^{\mathrm{j}} = p_{\mathrm{in}}^{\mathrm{j}} - p_{\mathrm{out}}^{\mathrm{j}} \quad . \tag{4.2}$$

Since fluid properties in a sub-system especially for direct steam generation may depend on the pressure, either inlet or outlet pressure should be given as input to the respective sub-system. This interaction typically results in an iterative calculation procedure where several updates of the sub-system calculations are required for one time step. The hydraulic power at the pump is obtained from pressure head and volumetric flow rate,

$$P_{\text{pump,hyd}} = \Delta \mathrm{p}_{\mathrm{pump}} \, \dot{\mathrm{V}}_{\mathrm{pump}} \quad . \tag{4.3}$$

The electric power required is usally defined by a nominal value of the overall efficiency and a part load correction factor,

$$P_{\text{pump,el}} = \frac{P_{\text{pump,hyd}}}{\eta_{\text{pump}}} = \frac{P_{\text{pump,hyd}}}{\eta_{\text{eff,0}} \; f_{\eta}\left(P_{\text{pump,hyd}}\right)} \quad . \tag{4.4}$$

The overall efficiency, $\eta_{\text{eff,0}}$, takes into account the efficiency of pump, motor, and converter. In case high pumping power is required, the heat input into the HTF while passing the pump might reach significant values. A pre-check should clarify if an additional heat source

$$\dot{Q}_{\text{pump}} = \frac{P_{\text{pump,hyd}} \left(1 - \eta_{\text{pump}}\right)}{\eta_{\text{pump}}} \tag{4.5}$$

has to be foreseen at the location of the pump. It is assumed that efficiency loss is mainly caused by the hydraulic losses in the pump and that losses of other components not directly in touch with the fluid are of minor importance. If several circuits with individual pump stations are present, these powers are summarized to a total pumping power consumption.

4.1.3. Mass and energy balance

The system level represents the interface to all sub-systems, thus all fluid flows from and to the sub-systems are handled on system level. Unless the fluid streams have the same temperature independent of load conditions, both, the mass flow and the corresponding temperatures need to be considered. In a steady-state situation, the mass

$$0 \quad = \sum_{j=1}^{n} \dot{m}^{\mathrm{j}}_{\text{sub-system}} \tag{4.6}$$

and energy balance

$$0 \quad = \sum_{j=1}^{n} \dot{m}^{\mathrm{j}}_{\text{sub-system}}\, h^{j}_{\mathrm{in/out}} \; + \; \dot{Q}_{\mathrm{pump}} \tag{4.7}$$

have to be fulfilled. Depending on the way transient behavior is implemented, the mass and energy equation might require additional terms to cover the impact of thermal inertia.

4.1.4. Reporting values and characteristic figures determined on system level

The interaction of the various sub-systems leads to the final performance of the plant. On System level a number of reporting variables and characteristic figures are defined (see section 3.2.3 for difference between these two categories). The definition on system level is useful to have a common, technology-independent, basis for technology comparisons. Some of the values require input from more than one sub-system. All inputs to the reporting values and characteristic figures should be obtained from the interface variables defined in the sub-system interfaces. This ensures full replaceability of sub-systems. Table 4-2 list the most important values and figures and indicates from which sub-system information is needed for the respective figure. More detailed definitions of the terms are given in the terminology document.

Table 4-2: Reporting values and charcteristic figures defined on system level

Characteristic figure	**Instant. (reporting value)**	**Annual (Char. Figure)**	**Symbol**	**Input from sub-systems**
Solar field efficiency	x	x	η_{SF}	SF
Power block thermal efficiency	x	x	η_{PB}	PB, EL
Gross plant solar efficiency	x		$\eta_{\mathrm{gross,solar}}$	SF, PB
Gross plant efficiency	x		η_{gross}	SF, AH, PB
Net plant solar efficiency	x		$\eta_{\mathrm{net,solar}}$	SF, PB, EL
Net plant efficiency	x		η_{net}	SF, AH, PB, EL
Solar multiple	x		F_{SM}	SF, PB
Annual electricity production to grid		x	E_{grid}	EL
Solar fraction		x	F_{S}	SF, AH, PB, EL
Effective plant availability		x	F_{avail}	system level
Annual plant capacity factor		x	F_{C}	PB, EL
Equivalent operating hours		x	f_{EOH}	PB, EL

4.2. Parabolic trough with oil and two-tank molten salt storage

Parabolic trough systems with oil as heat transfer fluid and molten salt storage tank have been implemented many times and represent a state-of-the-art technology. The sub-system diagram is given in Figure 4-1. In terms of annual yield modeling, this configuration shows the following characteristics:

1. All sub-systems are operated by a single pump. The flow paths especially for storage charge and discharge operation are established by valves.
2. The indirect storage system makes use of an heat exchanger to transfer heat from the HTF to the molten salt and back. Since the typical configuration is based on a single heat exchanger (several parallel trains possible) the storage can either be charged or discharged within one time step. This needs to be considered when modeling switch over from storage charge to storage discharge mode in the evening.
3. Another implication of the indirect storage system is the temperature drop during charge and discharge operation. Compared to the temperature spread of the solar field (~100 K) the sum of charge and discharge temperature drop leads to a reduction of the hot oil temperature entering the steam generator of about 10-15 K compared to the direct utilization of the HTF from the solar field.
4. The power block consists of a reheat rankine cycle. Steam is generated by a HTF driven steam generator.
5. The viscosity of the HTF increases with low temperatures. Anti-freeze protection is required to maintain a minimum temperature (typically at about 60 °C).
6. The auxiliary heater, if present is operated in parallel to the solar heater and usually does not have the same power as the steam generator (typically 10 to 30%).
7. Mass and energy balances on system level can be established on the cold and hot side.

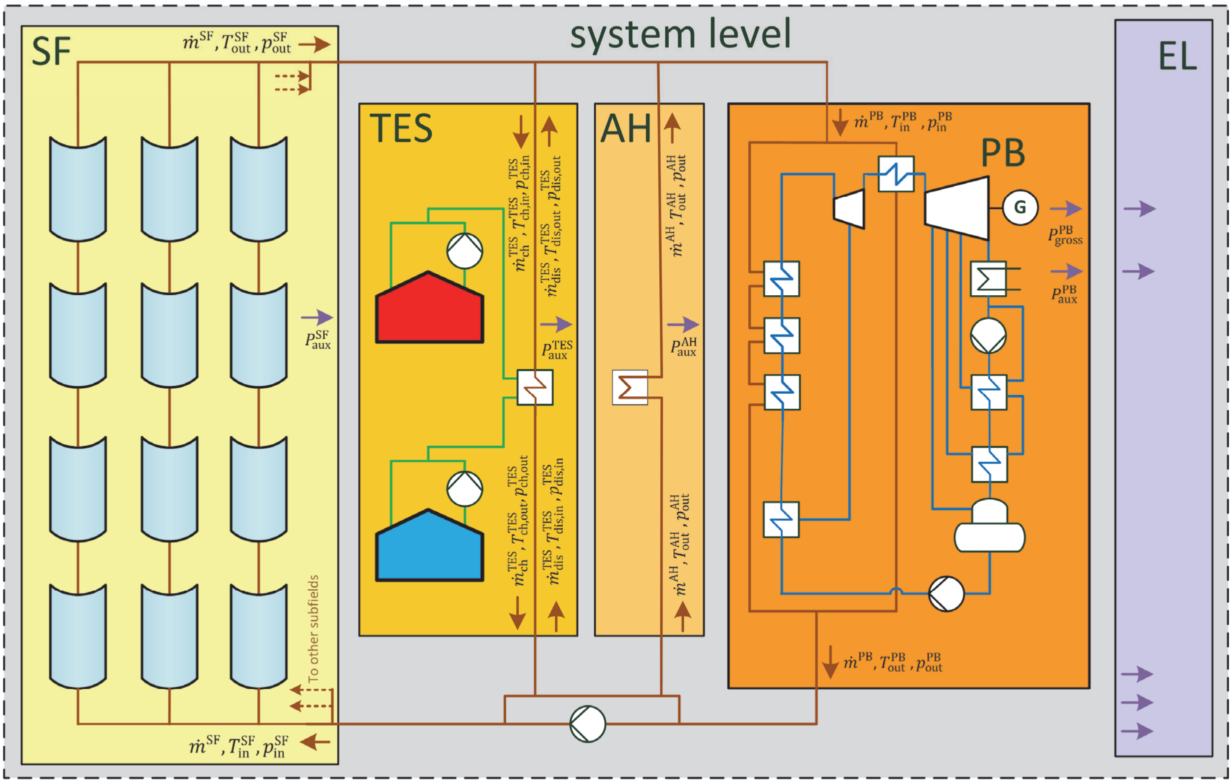


Figure 4-1: Sub-system schematic with main interface variables for a parabolic trough plant with two-tank storage and auxiliary heater

4.3. Solar tower with molten salt storage

First molten salt tower plants were coming online in 2011. Due to their high process temperature of about 560 °C and the straight forward direct storage option this configuration is becoming more and more attractive. The sub-system diagram is shown in Figure 4-2. In terms of annual yield modeling, this configuration shows the following characteristics:

1. There are two independently operated fluid cycles, one for the solar field (including the heliostat field and the receiver system) and one for the power block. On system level, two pumping powers need to be calculated.
2. The configuration makes use of a direct molten salt storage system which can be charged and discharged at the same time. In fact, there is no direct solar field-power block operation mode but all operation takes place via the storage system.
3. Depending on the salt mixtures used the salt shows a freezing temperature well above the ambient (e.g. ~240 °C for “solar salt”). The whole system needs to be prevented from freezing. The solar receiver is usually drained during stand-still periods which affects the start-up procedure.

4. The power block consists of a rankine cycle often equipped with a reheat. Unless drained at stand-still the steam generator needs to be kept above freezing temperature. In effect, a certain thermal or electrical power is required if the power block is not operational.
5. A mass and energy balance on system level must be established for the cold and hot side for the solar cycle and the power block cycle.
6. Pumping power in the solar cycle is significant due to large tower height. Special care must be spent on the modeling taking into account the foreseen concepts for pressure head recovery. New developments use energy recovery systems to minimize the pumping power.
7. As for all tower systems the heliostat and receiver designs are closely linked. A new configuration, e.g. in terms of capacity, usually requires to update performance characteritics of both parts.

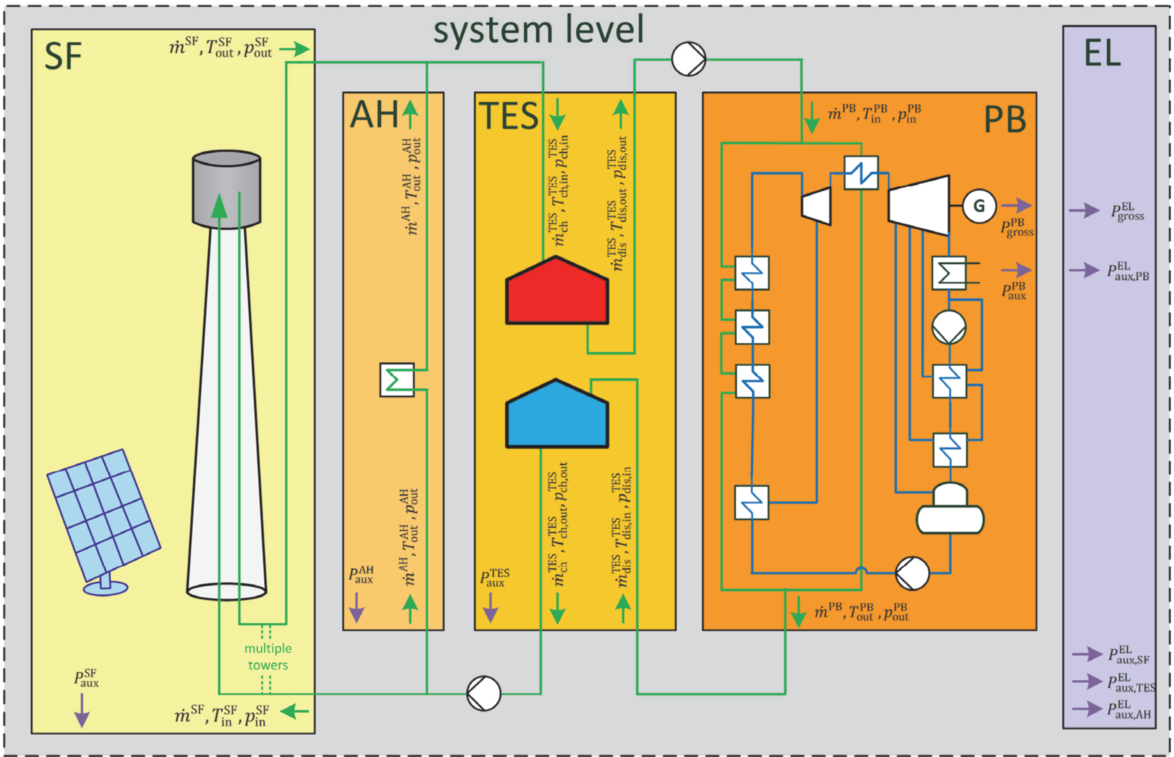


Figure 4-2: Sub-system schematic with main interface variables for a molten salt tower plant

5. Modeling of the sub-system Solar Field (SF)

Although we find a broad range of concentrator and receiver technologies today, the modeling as required for yield analysis can be based on the same framework. Some generic definitions are given in 5.1 whereas sections 5.2 and 0 provide requirements for modeling various line focusing and point focusing technologies. It is important to mention that the term **"Solar Field" in the context of this guideline describes the whole solar heat generator including concentrator, receiver, and any piping required to transport the HTF** to the other plant sub-systems. For solar tower systems it thus includes the heliostat field as well as the receiver and tower.

The general energy balance equation for the solar field of STE systems may be written as

$$\frac{dE^{\mathrm{SF}}}{dt} = \dot{Q}_{\mathrm{avail}} - \sum \dot{Q}_{\mathrm{loss}} + \sum \dot{Q}_{\mathrm{gain}} - \dot{Q}^{\mathrm{SF}} \tag{5.1}$$

The change of energy content of the solar field, dE^{SF}/dt, is the difference between the available radiant power, $\dot{Q}_{\mathrm{avail}}$, all heat gains, $\dot{Q}_{\mathrm{gain}}$, and heat losses, $\dot{Q}_{\mathrm{loss}}$, in the field and the solar field power, $\dot{Q}^{\mathrm{SF}}$, delivered by the solar field sub-system to the rest of the plant. The primary source of energy is the available radiant solar power

$$\dot{Q}_{\mathrm{avail}} = G_{\mathrm{bn}}\, A_{\mathrm{nom}} \tag{5.2}$$

which is the product of the direct normal irradiance and the nominal aperture area. Losses include optical losses during the concentration process and as well as thermal losses of the receiver and all piping required to transport the HTF from the receiver to the other sub-systems. Heat gains originate from different effects like electrical heating, dissipation of pressure head, or other thermal heating. The thermal power provided by the solar field sub-system at its interface is obtained from the enthalpy difference

$$\dot{Q}^{\mathrm{SF}} = \dot{m}^{\mathrm{SF}}\left(h_{\mathrm{out}}^{\mathrm{SF}} - h_{\mathrm{in}}^{\mathrm{SF}}\right) = \dot{m}^{\mathrm{SF}} \int_{T_{\mathrm{in}}^{\mathrm{SF}}}^{T_{\mathrm{out}}^{\mathrm{SF}}} c_{\mathrm{HTF}}(T)\,dT\ . \tag{5.3}$$

Annual yield models often use a quasi dynamic approach. In this case, the term on the left hand side of equation (5.1) is approximated by a correction term $\dot{Q}_{\mathrm{trans}}$ that considers the impact of the relevant transient effects on the energetic yield. The thermal power delivered by the solar field in each time step is then given by the rearranged equation

$$\dot{Q}^{\mathrm{SF}} = \dot{Q}_{\mathrm{avail}} - \sum \dot{Q}_{\mathrm{loss}} + \sum \dot{Q}_{\mathrm{gain}} - \dot{Q}_{\mathrm{trans}}\ . \tag{5.4}$$

Due to the thermal inertia of most STE concepts neglecting the transient correction term will result in a solar field output following the DNI immediately and thus assuming an ideal controllability of the system. The energetic output not considering these operational effects, e.g. by the transient correct term, would lead to higher energy yields than found in reality.

The equations in this chapter are typically written in terms of the nominal aperture area of the solar field. This reference value has been chosen instead of the net or gross aperture area because a definition of these figures common to all STE technologies is still not available. As long as there is no common understanding about the definition, each supplier defines the aperture area of his reflectors as he wants. Therefore, in this guideline the nominal aperture area is used, which is the one defined by the supplier. It is very important to use all other parameters (e.g. peak optical efficiency and specific cost figures) in a way consistent with the nominal aperture area. For more details also compare the definitions for aperture areas in the Appendix “Terminology”.

5.1. Generic sub-system interface and variable definition

The sub-system systematics as explained in section 3.2 describes the way the solar field sub-system interacts with the rest of the plant model. Since the principle functionality of the solar field is similar for all types of STE technologies, at least when it comes to the interfaces, a generic set of interface and reporting variables can be defined as given in Table 5-1. The first block holds the elementary interface variables as introduced in section 3.2. Technology specific extensions to this list are provided in the respective chapters dealing with these technologies.

Apart from the interface variables required for the system simulation a number of generic reporting variables is defined that allow systematic comparison between different technological approaches and evaluation of annual performance figures on system level. Important variables for the sub-system solar field are illustrated in Figure 5-1 and explained in the following. It is unique for all STE systems that direct normal irradiance falling onto an aperture plane is reflected to the receiver systems. As a common basis for definition of solar field efficiency figures we introduce the available radiant solar power which is the product of direct normal irradiance and the nominal aperture area, $\dot{Q}_{\mathrm{avail}} = G_{\mathrm{bn}}\, A_{\mathrm{nom}}$. It reflects the solar power that is available to any technical system that has a certain nominal aperture area which is fully oriented towards the sun.

The large reflector systems considered in this guideline track the sun in a manner that the sun rays are often not perpendicular to the aperture normal but in a certain incidence angle. The resulting projection of available radiant power, $\dot{Q}_{\mathrm{proj}} = \dot{Q}_{\mathrm{avail}}\ \cos\theta_{\mathrm{i}}$, into a non-perpendicular area causes a reduction in effective power. The corresponding losses are called cosine losses. Although shading by other reflectors might reduce $\dot{Q}_{\mathrm{avail}}$ this effect is considered seperately and is excluded by definition from $\dot{Q}_{\mathrm{avail}}$.

The reflector systems are nonideal and several loss mechanisms like partial absorption, shading, deviations from the ideal shape, etc. are summarized as optical losses of the concentrator. The reflected sunlight enters the intercept area of the receiver. This intercept area is usually defined to separate the model of the concentrator from the one for the receiver. Overall optical losses $\dot{Q}_{\mathrm{loss,opt}}$ of the solar system can thus be devided into optical losses of the concentrator, $\dot{Q}_{\mathrm{loss,opt,conc}}$ and optical losses of the receiver $\dot{Q}_{\mathrm{loss,opt,rec}}$.

For qualification of concentrator systems, the radiant power in the intercept plane, $\dot{Q}_{\text{inter}}$, is measured and compared to the available radiant solar power resulting in the concentrator optical efficiency $\eta_{\text{opt,conc}}$. Optical losses of the receiver reduce the intercept power to the absorbed power, $\dot{Q}_{\text{abs}}$, with the respective ratio $\eta_{\text{opt,rec}}$. The absorbed power represents the power available at the surface of the receiver. Heat losses at the receiver surface, $\dot{Q}_{\text{loss,rec}}$, reduce the power to the effective available power from the receiver, $\dot{Q}_{\text{rec}}$. The ratio of receiver thermal power and absorbed power is the receiver thermal efficiency $\eta_{\text{rec,th}}$. After subtracting heat losses from interconnecting piping between receiver units, $\dot{Q}_{\text{loss,pipe}}$, header piping, $\dot{Q}_{\text{loss,head}}$, and additional equipment of the HTF cycle, $\dot{Q}_{\text{loss,equ}}$, the thermal power available from the solar field sub-system, $\dot{Q}^{\text{SF}}$, is obtained.

For quasi-steady state modeling approaches it is useful to separate the solar field thermal power into a fraction that is obtained under steady-state conditions and correction terms that reflect the impact of transient processes like start-up, $\dot{Q}_{\text{SF,startup}}$, temperature or mass variations during operation, $\dot{Q}_{\text{SF,loadchange}}$, or cloud passages, $\dot{Q}_{\text{loss,cloud}}$, on the yield compared to a steady-state situation.

Important performance measures for the solar field are the collector efficiency $\eta_{\text{coll}} = \dot{Q}_{\text{rec}} / \dot{Q}_{\text{avail}}$ and the solar field efficiency $\eta_{\text{SF}} = \dot{Q}^{\text{SF}} / \dot{Q}_{\text{avail}}$. It should be mentioned here that $\dot{Q}_{\text{loss,cloud}}$ refers not to the reduction of direct irradiance because this is already covered by G_{b} but rather to additional losses which are caused by partial shading of the solar field.

Different reasons may require a partial defocusing of the solar field (e.g. temperature limits of the receiver). The percentage of the solar field operational measured in terms of aperture area, $f_{\text{foc,A}}$, is a useful way to express the fraction of energy effectively wasted due to such operational constraints. The defocussed energy which cannot be used due to maximum load contraints is defined as $\dot{Q}_{\text{defoc,max}}$. Annother virtual power refers to the minimum load defocussing $\dot{Q}_{\text{defoc,min}}$. In contrast to all other power figures these defocussing powers cannot be measured in a real plant since they represent a quantity of energy that could, but was finally not, produced. Apart from the heat input to solar energy, other heat sources of thermal power $\dot{Q}_{\text{gain}}$ may exist, either driven by electrical heating or by dissipation of pressure head in the field.

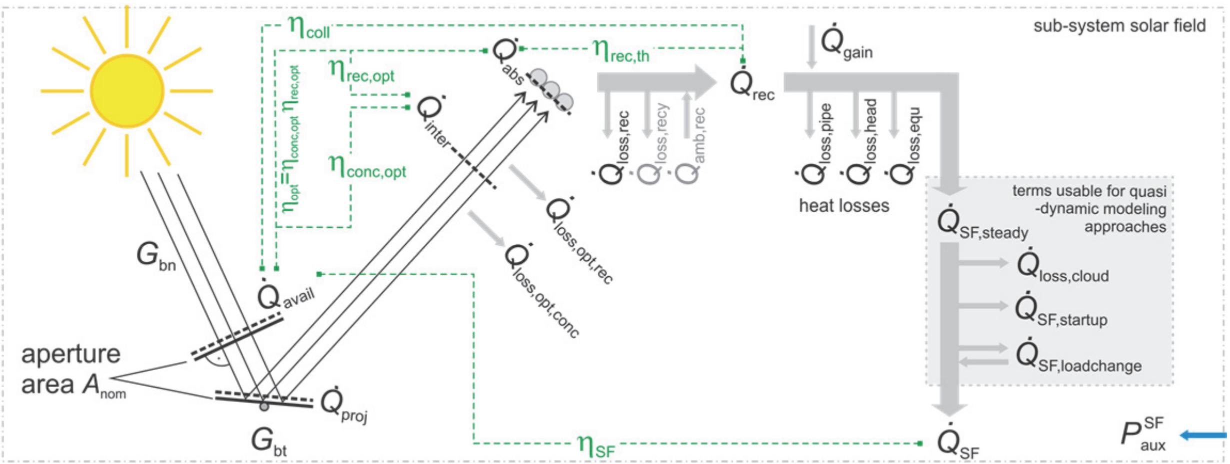


Figure 5-1: Illustration of generic variables for the sub-system solar field (please note that not all technologies require all of these variables)

Table 5-1: Generic interface (I), meteorological (M) and reporting (R) variables valid for solar field technologies (*indicates variables that might not be available for all types modeling approaches)

Type	Name	Symbol	Comment
I	Inlet temperature [2]	$T_{\mathrm{in}}^{\mathrm{SF}}$	
I	Outlet temperature [2]	$T_{\mathrm{out}}^{\mathrm{SF}}$	
I	Inlet pressure	$p_{\mathrm{in}}^{\mathrm{SF}}$	
I	Outlet pressure	$p_{\mathrm{out}}^{\mathrm{SF}}$	
I	Mass flow	$\dot{m}^{\mathrm{SF}}$	
M	Ambient temperature	T_{amb}	
M	Direct normal irradiance	G_{bn}	
M	Average wind speed	v_{wind}	
M	Wind direction	γ_{wind}	
M	Relative humidity	φ	Useable for soiling models
M	time	t	Needed to calculate the sun position
I	Auxiliary electrical demand	$P_{\mathrm{aux}}^{\mathrm{SF}}$	Electrical demand of all electrical installations in the field except the main HTF pumps.
I[1]	Acceptable minimum/maximum mass flow	$\dot{m}_{\mathrm{min/max}}^{\mathrm{SF}}$	Limitations on the actual tolerated mass flow.
I[1]	Set point outlet temperature	$T_{\mathrm{out,set}}^{\mathrm{SF}}$	Set point for the HTF outlet temperature. Could vary depending on season or desired load conditions.
I[1]	Set point mass flow	$\dot{m}_{\mathrm{set}}^{\mathrm{SF}}$	Mass flow expected to be delivered to the system level.
R	Solar field thermal power	$\dot{Q}^{\mathrm{SF}}$	
R	Available radiant solar power	$\dot{Q}_{\mathrm{avail}}$	
R	Absorbed power	$\dot{Q}_{\mathrm{abs}}$	
R	Percentage of field operational*	$f_{\mathrm{foc,A}}$	
R	Maximum load defocussed power*	$\dot{Q}_{\mathrm{defoc,max}}$	
R	Minimum load defocussed power*	$\dot{Q}_{\mathrm{defoc,min}}$	
R	Receiver heat loss power*	$\dot{Q}_{\mathrm{loss,rec}}$	
R	Solar field[3] piping thermal loss power*	$\dot{Q}_{\mathrm{loss,pipe}}$	
R	Header piping thermal loss power*	$\dot{Q}_{\mathrm{loss,head}}$	
R	HTF equipment thermal loss power*	$\dot{Q}_{\mathrm{loss,equ}}$	
R	Auxiliary power for anti freeze	$P_{\mathrm{AF}}^{\mathrm{SF}}$	

[1] Usage as interface variable depends on the implementation and the operation strategy. Set-up shown here reflects methodology proposed by this guideline.
[2] Specific enthalpy can be used instead of temperature. In this case the inlet and iutlet temperatures should be provided as reporting variables.
[3] In this context “solar field” means the subsystem. In case of solar tower systems the piping connecting receiver with storage abd power block.

5.2. Line focusing systems

The nature of line focusing technologies allows to treat all technologies based on a similar scheme. Section 5.2.1 compiles minimum requirements for modeling these systems. Individual technologies might require additional effects to be considered in yield analysis. These might arise either from the concentrator type (parabolic trough, linear Fresnel) or the heat transfer medium used (oil, molten salt, water, …). Each technology is treated in a separate section, 5.2.2. ff. However, these technology-specific description largly refers to the generic list of effects to be considered.

5.2.1. Relevant effects for all line focusing systems

Line focusing systems are arranged in loops, several loops are connected by headers. The whole solar field may be divided into subfields supplied by individual headers. For annual yield calculations it is usually sufficient to model the whole field by means of one or a small number of representative loops with the total power obtained by multiplying the output of the representative loops by the total number of loops. Header losses and thermal losses caused by other HTF equipment must additionally be considered at field level.

5.2.1.1. Incidence angle definitions

For single axis tracking systems the incindence angle θ_i is used to express the impact of sun position on projected solar power available for the solar field. For tracked parabolic trough collectors, it is the angle between the normal of the solar collector aperture plane and the line along the incident solar beam towards the center of the solar disk, see Figure 5-2. The tracking position of the collector is described by the collector track angle ϱ_track which is the angle between the vertical and the aperture normal[9]. A precise definition extended by sign conventions is provided in the terminology.
For linear Fresnel collectors, the aperture plane exposed to the sun is fixed in space and usually horizontal. It is defined by the axes of the individual reflector lines. The incidence angle on the aperture plane θ_i (angle ∢BAD for LFC in Figure 5-2) is only dependent on the solar position, and for horizontally aligned Fresnel collectors it is equal to the solar zenith angle θ_Z. To fully describe the change of optical efficiency for non-perpendicular solar irradiance at least three more angles have to be introduced:

- The axial angle[10] $\theta_\mathrm{i,axial}$ is the projection of the incidence angle into the plane spanned by the collector axis and the incident solar beam (angle ∢CAD for LFC in Figure 5-2). It can also be described as the angle between the transversal plane - the plane perpendicular to the collector axis - and the incident solar beam.

[9] The symbol ϱ is used for the track angle to differentiate between the incident angle which only depends on sun position but not on the actual track state of the collector.
[10] The axial angle $\theta_\mathrm{i,axial}$ described here is often incorrectly called incidence angle θ_i in literature, so before using existing optical models for linear Fresnel collectors the basic definitions should be checked.

- The transversal angle $\theta_{\mathrm{i,trans}}$ is defined as the projection of the incidence angle into the transversal plane (angle ∢BAC for LFC in Figure 5-2). It can also be described as the angle between the collector aperture normal and the incident solar beam projected on the transversal plane).
- The longitudinal angle $\theta_{\mathrm{i,long}}$ is defined as the projection of the incidence angle into the longitudinal plane - the plane spanned by the collector axis and the collector aperture normal (angle ∢BAE in Figure 5-2). It can also be described as the angle between the collector aperture normal and the projection of the solar beam into the longitudinal plane.

A collector-specific tracking angle is not defined for linear Fresnel collectors, as the reflector lines are tracked individually. For the level of detail of the following optical model perfect tracking is assumed and information on the tracking angles of the individual reflector lines is not needed. Figure 5-2 illustrates the angle definition both for parabolic trough collectors and linear Fresnel collectors.

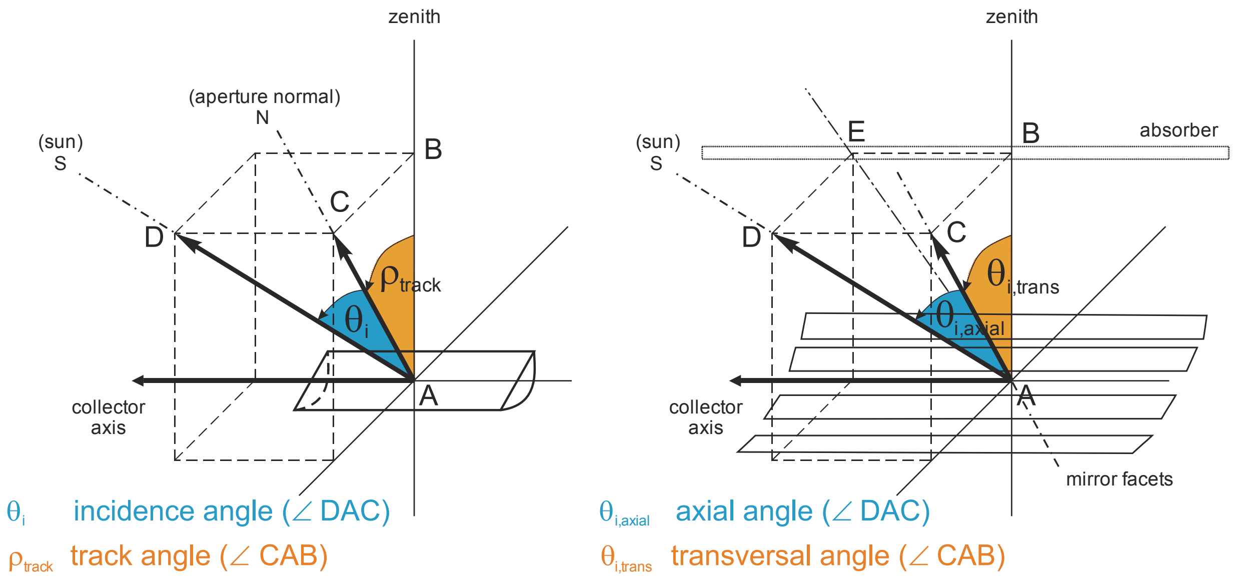


Figure 5-2: Angle definitions for parabolic troughs (left) and linear Fresnel collectors (right)

5.2.1.2. Optical losses – compilation of relevant effects

In this chapter, individual losses are listed and characterized in a generic form. Afterwards, a structured modeling approach applicable to line focusing systems is formulated.

Losses caused by non-perpendicular sun beams to the aperture area

Cosine losses

When the collector aperture is not perpendicular to the sun rays, the projected aperture area is reduced. Parabolic trough collectors are tracked in a manner that sun beams are within the plane defined by the collector aperture normal and the collector axis. Since parabolic trough collectors are single axis tracking collectors there is a certain angle between sun vector and aperture normal vector for most sun positions (the incidence angle). Thus, the apparent aperture area as seen from the sun is reduced. The reduced aperture area depends on the cosine of the incidence angle which is the reason for calling these losses cosine losses, often formulated as cosine efficiency,

$$\eta_{\mathrm{cos}} = cos(\theta_{\mathrm{i}}) = \frac{G_{\mathrm{bt}}}{G_{\mathrm{bn}}} \tag{5.5}$$

For linear Fresnel systems, the term cosine efficiency is not used since the Fresnel collector does not show a designated aperture area that is tracked towards the sun. Instead, a correction term depending on the incident angle in two planes is considered.

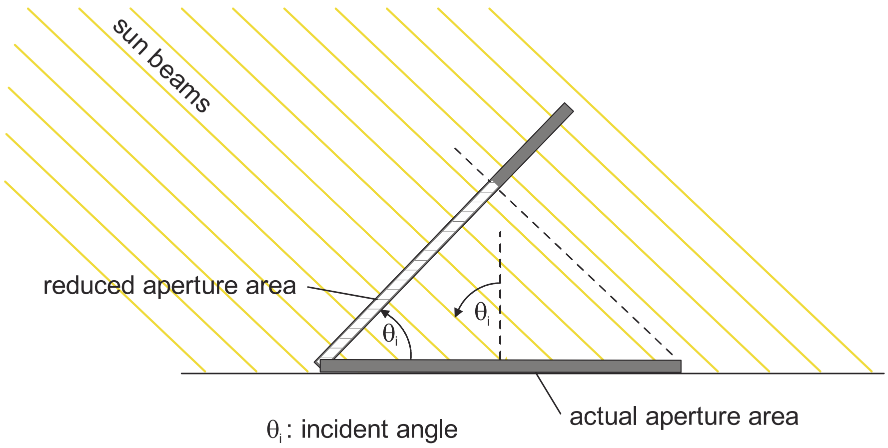


Figure 5-3: Effective aperture reduction caused by non-perpendicular sun rays onto the aperture (cosine losses)

Shading losses

Shading losses may be broken down into three parts:

1. Row-to-row shading causes losses for low sun angles and must be considered on solar field level. It might be calculated from basic geometrical information and is typically the same factor for all collector rows except for the first row in sun direction. For linear Fresnel, shading by receivers of the neighbouring loop happens at low sun elevations.
2. Some parts of the total aperture area may be shaded by structural elements, receiver supports, receiver covers, etc. This kind of shading often depends on the incidence angle and is often considered by an indidence angle modifier.
3. Shading by buildings, wind fences, plume of cooling towers, geographical elements (mountains), etc.

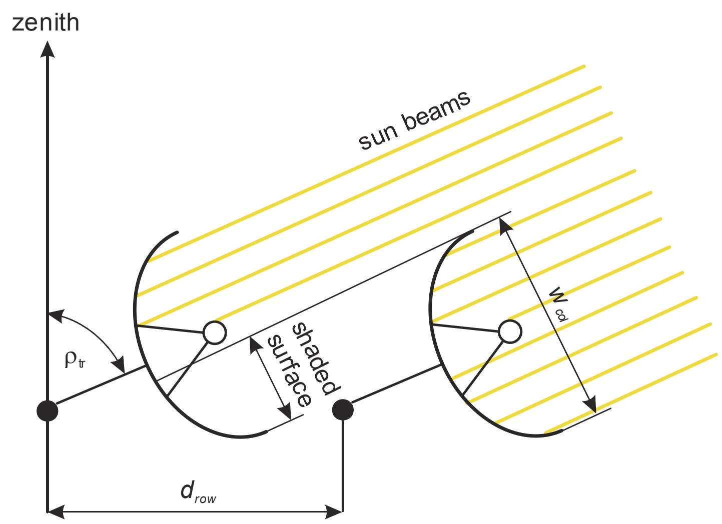


Figure 5-4: Row-to-row shading in a parabolic trough solar field

End losses

Line focusing systems like parabolic troughs and linear Fresnel systems may have end losses. End losses occur when reflections of a collector do not hit the receiver of this collector. Their magnitude also depends on the incident angle and the calculation is based on geometrical considerations.

All these losses depend on the sun position, the incidence angle, and the arrangement of collectors in the solar field.

Reflector efficiency

Reflectivity

Technical reflectors are not perfect but a certain fraction is lost due to absorption and scattering.

Nonideal geometry

Technical reflectors mounted on a structure show deviations from the perfect shape either caused by the production process of the reflectors or by the mounting or non-ideal tracking.

Soiling

Since the solar field of STE plants are large outdoor installations, they cannot be considered as perfectly clean. Thus, the mirrors and receivers show reduced reflectivity and transmission compared to laboratory measurements. To minimize soiling losses, parabolic trough plants are cleaned periodically. The soiling rate and the frequency of cleaning is site-specific and is a part of the O&M concept. Generally, cleanliness varies with time and location of the site and within the solar field.
A common approach to consider soiling in annual performance models for STE plants is the utilization of a mean effective cleanliness factor without any variation in time and space. This **effective mean cleanliness factor** just describes the reduction of the solar field efficiency caused by soiling with a single value valid for the whole field and over the whole time period simulated.
The cleanliness factor is defined by the ratio of optical efficiency in certain dirty conditions and the optical efficiency with the same optical element in unsoiled, clean condition.

Blocking

Some reflected sun beams may be blocked by other reflectors, structural elements, etc. Thus, the intercept power will be reduced by this effect.

Attenuation

Depending on the distance between reflector and absorber, aerosols and water vapor in the boundary layer may absorb and/or scatter a relevant fraction of the reflected light. For line focusing systems this effect is usually small and implicitely included in the nominal optical performance of the collector.

Reflection and absorption at the cover

If the receiver has any kind of transparent cover, a fraction of the energy is lost through reflection and absorption at this cover..

Efficiency of secondary reflectors

Some systems are using secondary reflectors. These may have similar imperfections as primary reflectors.

Intercept efficiency

A fraction of the reflected sun beams will miss the receiver and thus cannot be used. This loss is caused by circum-solar ratio, sun shape, beam quality influenced by the shape of mirrors, slope error, or tracking errors and the size of the receiver.

Direct normal irradiance today is measured by instruments with a certain acceptance angle which is about 10 times larger than the solar disk angle[11]. Therefore, G_{bn} measurements contain a certain fraction of scattered radiation, which is called circumsolar radiation. This circumsolar radiation can only partially be used by concentrating collectors. Furthermore, it varies for different sites and is time dependent. The normalized radiance profile as function of the angular distance from the center of the sun is denoted as “sun shape” and Wilbert[11] has shown that the impact of the sun shape on annual yield of a trough plant might be an overestimation up to 0.5 to 1.1 % depending on the site. Since todays irradiance measurements do not contain any information about sun shape, it is not possible to consider it in annual yield calculation. Anyhow, for sites with high scattering atmosphere this additional loss should at least be estimated.

Reflection at receiver surface

Solar absorbers are not perfect black bodies. A certain fraction of the incoming irradiation is reflected, e.g. at the glas envelopes and the absorber itself has imperfections especially in some wavelentghs.

Optical losses caused by wind

Increased wind velocity can reduce the geometrical accuracy of collectors and heliostats. Certain sections of parabolic troughs located far from the drives can be twisted significantly from the ideal pointing direction. Thus, the optical efficiency is reduced even when the wind velocity is below the operation limit.

Solar field availability

A certain fraction of the solar field is usually not available because of different reasons. Missing or broken mirrors, broken absorbers, or collectors with damaged drives, reduce the actual aperture which can be used to collect heat. The solar field availability does not cover losses caused by system outages. It is only a reduction of usable solar field aperture.

[11] S. Wilbert: Determination of Circumsolar Radiation and its Effect on Concentrating Solar Power, Dissertation RWTH Aachen, Germany, 2014

5.2.1.3. Optical losses – common modeling approach

A common approach to express the effects compiled in the last section is to define efficiencies for all relevant effects reducing the available power to the absorbed power. Equation (5.6) shows this approach and the individual effects which must be considered in the calculation of the absorbed power.

$$\dot{Q}_{\mathrm{abs}} = \eta_{\mathrm{phi}}\ \eta_{\mathrm{shad}}\ \eta_{\mathrm{refl,0}}\ \eta_{\mathrm{clean}}\ \eta_{\mathrm{block}}\ \eta_{\mathrm{atten}}\ \eta_{\mathrm{inter}}\ \eta_{\mathrm{wind}}\ \eta_{\mathrm{trans}}\ \eta_{\mathrm{abs}}\ \eta_{\mathrm{avail}}^{\mathrm{SF}}\ f_{\mathrm{foc,A}}\ A_{\mathrm{nom}}\ G_{\mathrm{bn}} \tag{5.6}$$

with:

$\dot{Q}_{\mathrm{abs}}$	Absorbed thermal power in kW
η_{phi}	Incidence angle efficiency including all losses caused by non-perpendicular sun rays into the aperture plane, dimensionless
η_{shad}	Shading efficiency, dimensionless
$\eta_{\mathrm{refl,0}}$	Clean reflector efficiency, dimensionless
η_{clean}	Cleanliness factor, dimensionless
η_{block}	Blocking efficiency, dimensionless
η_{atten}	Atmospheric attenuation efficiency, dimensionless
η_{inter}	Intercept factor, dimensionless
η_{wind}	Factor considering optical losses caused by wind, dimensionless
η_{trans}	Transmission through receiver glass cover (if any), dimensionless
η_{abs}	Receiver absorptance dimensionless
$\eta_{\mathrm{avail}}^{\mathrm{SF}}$	Continous solar field availability, dimensionless
$f_{\mathrm{foc,A}}$	Percentage of the available aperture area in focus (the available aperture area is the nominal aperture area corrected by the continuous non-availability of collectors, $\eta_{\mathrm{avail}}^{\mathrm{SF}}$)
A_{nom}	Nominal aperture area without receiver area in m²
G_{bn}	Direct normal solar irradiance in W/m²

For line focusing systems several of the optical effects listed above are typically considered by two parameters: the optical efficiency at normal incidence, $\eta_{\mathrm{opt,0}}$, and the incidence angle modifier , $K(\theta_{\mathrm{i}})$. Using these parameters, equation (5.6) can be written as

$$\dot{Q}_{\mathrm{abs}} = \eta_{\mathrm{opt,0}}\ \cos(\theta_{\mathrm{i}})\, K(\theta_{\mathrm{i}})\ \eta_{\mathrm{shad}}\ \eta_{\mathrm{clean}}\ \eta_{\mathrm{wind}}\ \eta_{\mathrm{avail}}^{\mathrm{SF}}\ f_{\mathrm{foc,A}}\ A_{\mathrm{nom}}\ G_{\mathrm{bn}} \tag{5.7}$$

Optical efficiency at normal incidence

The optical efficiency at normal incidence (or peak optical efficiency, as commonly used for parabolic trough systems) is the ratio of power absorbed by the receiver and available solar power at normal incidence of the irradiance.

$$\eta_{\mathrm{opt,0}} = \frac{\dot{Q}_{\mathrm{abs,0}}}{G_{\mathrm{bn}}\ A_{\mathrm{nom}}} \tag{5.8}$$

It considers the reflectivity and nonideal geometry of the mirrors, shading and blocking by structural elements of the collector, reflection and absorption at the receiver glass cover, intercept efficiency, and imperfect absorption of the receiver. The optical efficiency at normal incidence is typically measured using a complete collector under the following boundary conditions:

- Incidence angle is perpendicular to the collector aperture
- The collector is perfectly clean
- No external shadows on the aperture area

Normally, the optical efficiency at normal incidence is provided by collector suppliers. Since the available solar power depends on the definition of the collecting area, the optical efficiency shows this dependency, too. Thus, it is very important to know the corresponding collecting area when using a certain value of the peak optical efficiency.

The utilization of nominal aperture area (see Appendix T “Terminology”) and the corresponding nominal peak optical efficiency is recommended in order to have a common base for comparison. It is typically given for a single collector unit but can also be used for a whole loop or even the whole solar field, provided that identical collectors are used. This is because effects like row-to-row shading, end losses, etc., are calculated separately.

It should be mentioned that with this definition, for line focusing collectors, the optical efficiency at normal incidence includes also the optical effects of the receiver. Therefore, the value of the optical efficiency at normal incidence will change when another type or size of receiver is installed.

Incidence angle modifier

Some optical losses mentioned above are varying with the incidence angle. For line focusing systems the so called incidence angle modifier (IAM) is often used in combination with the peak optical efficiency to account for the dependency on the incidence angle of the sun rays onto the aperture. It is defined as:

$$K(\theta_{\mathrm{i}}) = \frac{\eta_{\mathrm{opt}}(\theta_{\mathrm{i}})}{\eta_{\mathrm{opt,0}}} \tag{5.9}$$

The IAM is typically measured at a single collector or determined by detailed ray tracing simulations and provided by suppliers as polynomial or lookup table as a function of the incidence angle. Often, the proposed IAM functions have the structure

$$K(\theta_{\mathrm{i}}) = 1 + \sum_{k=1}^{n} \frac{a_k \theta_{\mathrm{i}}^k}{\cos(\theta_{\mathrm{i}})} \tag{5.10}$$

With a_k representing the polynomial coefficients and *n* representing the order.

For linear Fresnel collectors, a 2-dimensional incident angle modifier is commonly used, extending equation (5.7) by another factor.

$$\dot{Q}_{\mathrm{abs}} = \eta_{\mathrm{opt,0}}\, K\left(\theta_{\mathrm{i,axial}}, \theta_{\mathrm{i,trans}}\right)\; \eta_{\mathrm{shad}}\, \eta_{\mathrm{clean}}\, \eta_{\mathrm{wind}}\, \eta_{\mathrm{avail}}^{\mathrm{SF}}\, f_{\mathrm{foc,A}}\, A_{\mathrm{nom}}\; G_{\mathrm{bn}} \tag{5.11}$$

The shading efficiency refers to shading between two parallel collector rows. Shading between mirror facets within one row is already contained in *K*. The description by axial and transversal incidence angle is advantageous since it allows an approximation of the two-dimensional relation K by a product of two factors, each only depending on one angle,

$$K\left(\theta_{\mathrm{i,axial}}, \theta_{\mathrm{i,trans}}\right) \cong K_{\mathrm{l}}\left(\theta_{\mathrm{i,axial}}\right)\; K_{\mathrm{t}}\left(\theta_{\mathrm{i,trans}}\right) . \tag{5.12}$$

Solar field availability

The general approach to handle availability issues is provided in section 11.2. The continuous unavailability of parts of the solar field is described by an availability factor

$$\eta_{\mathrm{avail}}^{\mathrm{SF}} = \frac{A_{\mathrm{nom,reduced}}}{A_{\mathrm{nom}}} \tag{5.13}$$

for the solar field is defined with values between 0 and 1. For typical commercial STE plants with suitable maintenance of the solar field, the solar field availability should be close to 1, typical values range between 0.97 and 1.00, i.e. almost 97 to 100 % of the aperture is available.

5.2.1.4. Thermal losses and gains

Receivers for the concentrated sunlight have thermal losses caused by radiation, convection and conduction. These losses depend on the temperature of the receiver and the temperature of the ambient (actually the system for heat interchanging with the receiver). They depend further on SF load, wind, receiver geometry, material, and surface. The same holds for piping used to connect individual collectors to rows or loops and to power block and to thermal storage (known as headers and runners) as well as for vessels, tanks, and other equipment used in the solar field.

$$\dot{Q}_{\mathrm{loss}} = \dot{Q}_{\mathrm{loss,rec}} + \dot{Q}_{\mathrm{loss,pipe}} + \dot{Q}_{\mathrm{loss,head}} + \dot{Q}_{\mathrm{loss,equ}} \quad (5.14)$$

With:

$\dot{Q}_{\mathrm{loss,rec}}$	receiver heat losses in W
$\dot{Q}_{\mathrm{loss,pipe}}$	heat losses of the loop piping in W
$\dot{Q}_{\mathrm{loss,head}}$	header and runner heat losses in W
$\dot{Q}_{\mathrm{loss,equ}}$	heat losses of other SF equipment (like tanks,vessels, etc.) in W

The single contributions are described in the following paragraphs.

Thermal losses of receivers

These losses are typically the main source of thermal losses in line focusing fields and need to be considered in the correct manner. The general dependency of receiver heat losses on operating and ambient conditions is:

$$\dot{Q}_{\mathrm{loss,rec}} = \mathrm{f}(T_{\mathrm{amb}}, T_{\mathrm{abs}}, v_{\mathrm{wind}}) \quad (5.15)$$

Direct normal irradiance, incidence angle modifier and incidence angle are often used to represent the absorber surface temperature:

$$\dot{Q}_{\mathrm{loss,rec}} = \mathrm{f}(T_{\mathrm{HTF}}, T_{\mathrm{amb}}, G_{\mathrm{bn}}, K(\theta_i),\ \cos(\theta_i), v_{\mathrm{wind}}) \quad (5.16)$$

Since line focusing systems often use absorber tubes with a glass envelope and evacuated annulus, heat losses caused by radiation are much higher than losses caused by conduction and convection. Thus, the impact of ambient conditions is small and the HTF temperature is the dominating parameter These kind of receivers are typically tested in laboratories and heat losses for different HTF temperatures are reported as lookup table or given as polynomials. Since most of these laboratory tests are heating the absorber tubes from inside, the absorber surface temperature will be higher under real operating conditions.

For typical parabolic trough systems with HTF inlet temperatures at about 290 °C and outlet temperatures at about 390 °C the utilization of bulk fluid temperature instead of absorber surface temperature will cause an underestimation of 1 to 3 % of the heat losses. For other technologies, e.g.

direct molten salt, the inlet/outlet temperature difference may be larger and a discretisation of the SF is necessary rather than assuming a bulk temperature over the entire loop.
Another effect not considered in lab tests is the radiation energy absorbed by the glas envelope which yields a higher glas temperature compared to the lab tests. Due to the increase temperature of the glas envelope the heat loss of the receiver is slightly reduced. Usually, this effect is neglected.
Wind impact is also not measured during these experiments. Therefore, the polynomial or look-up tables do not consider any wind effects. Using the data and model parameters of Burkholder[12], heat losses of Schott PTR 70 absorbers are increased about 5% when the wind velocity increases from 0 to 14 m/s.
Sometimes heat loss or thermal efficiency measurements are available for a whole collector or a whole loop. In contrast to the laboratory measurements for single absorbers they are done under real operating conditions and the bulk fluid temperature is measured and reported. In these cases, no correction factors would be necessary and the functions can be used directly to model heat losses. In any case, the description for an individual performance model shall contain information about the heat loss function together with reference to the origin, the range of validity, and modifications made in order to use it for annual performance simulation.

Thermal losses of piping, headers, and runners

Interconnecting piping that links receiver elements or collectors to each other and header and runner piping represents further significant heat losses and have to be considered.

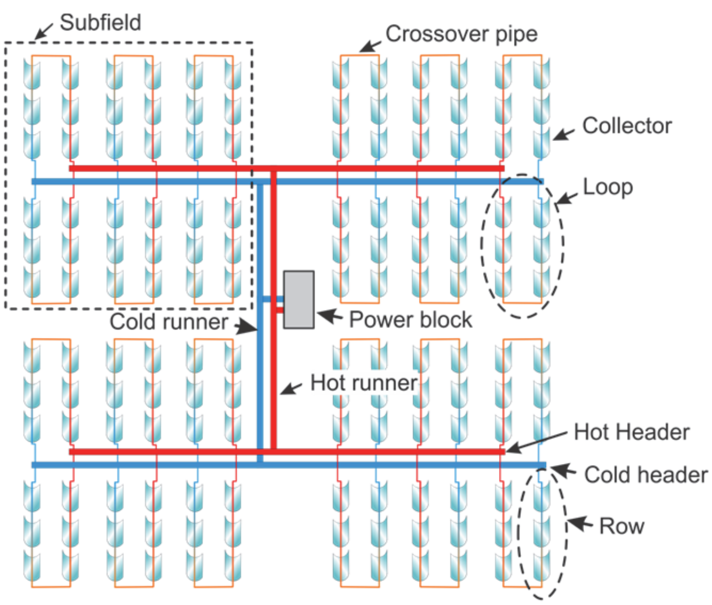


Figure 5-5: Typical layout of a parabolic trough STE plant and definition of the sections

[12] F. Burkholder and C. Kutscher: Heat Loss Testing of Schott's 2008 PTR70 Parabolic Trough Receiver, Technical Report NREL/TP-550-45633, May 2009

The general equation for heat transfer calculation caused by convection and conduction for a pipe is:

$$\dot{Q}_{\mathrm{loss,pipe}} = U_{\mathrm{pipe}}\, A_{\mathrm{pipe}}(T_{\mathrm{HTF}} - T_{\mathrm{amb}}) \tag{5.17}$$

With

U_{pipe}	Overall heat transfer coefficient for the pipe in W/(m²K)
A_{pipe}	Surface area of the pipe in m²
T_{HTF}	Bulk HTF temperature in K
T_{amb}	Ambient temperature in K

Equation(5.17) neglects radiation heat losses of the pipe, but they are typically small since the temperature difference between the outer pipe surface and ambient is small. The overall heat transfer coefficient for the pipe is a function of flow velocities and fluid properties of both fluids inside and outside the pipe, pipe diameter and wall thickness, thickness and properties of insulation material. Since most of these parameters are not constant but vary troughout the field, equation (5.17) must be applied for each section of pipe, header and runner and the respective heat losses must be summed up.

The difficulty of this detailed approach is that all these informations are not always available for those parties who are performing annual yield calculations. Therefore, specific heat losses are often used for the piping in W/m² of aperture area or W/m of piping length. The idea behind this approach is that a project developer or owner of a STE plant might require such specific heat losses for design point operation during the proposal phase of the plant and the EPC contractor has to design and build the piping in an appropriate manner to fulfill these requirements. Using the reasonable assumption that these heat losses are linear with temperature differences, the calculation of heat losses for other than nominal temperatures may be done according to:

$$\dot{Q}_{\mathrm{loss,pipe}} = l_{\mathrm{pipe}}\, \dot{q}_{\mathrm{loss,pipe}} = l_{\mathrm{pipe}}\, \dot{q}_{\mathrm{loss,pipe,nom}}\, \frac{(T_{\mathrm{HTF}} - T_{\mathrm{amb}})}{(T_{\mathrm{HTF,nom}} - T_{\mathrm{amb,nom}})} \tag{5.18}$$

Analogous equations like (5.18) can be used to calculate header heat losses.

Header and runner heat losses may cause a significant temperature drop at the interface between SF and power block for low load conditions. Each HTF has a certain upper temperature limit. This limit often defines the highest temperature allowed in the solar field which occurs at the hot outlet of each row. In plants with long runners between hot row outlet and solar steam generator (or thermal storage) the SF outlet temperature at the relevant interface might be significantly lower than the row outlet temperature. This is of particular importance for part load operation of the SF when the row outlet temperature is typically kept close to the design temperature and the mass flow rate is reduced. In this case heat losses are almost as high as for design conditions and temperature at interface between SF and power block might be significant lower than for design conditions.

Once the header heat losses are known, HTF temperature at the interface between SF and PB may be calculated with the specific heat capacity c of the fluid from

$$T_{\text{out}}^{\text{SF}} = T_{\text{loop,out}} - \frac{\dot{Q}_{\text{loss,hot head}}}{\dot{m}_{\text{HTF}}\ c_{\text{HTF}}} \quad . \tag{5.19}$$

Thermal losses of other equipment used in the solar field

Individual STE plants may have further equipment in the solar field which is passed through by the HTF and which may cause additional heat losses. If this applies, these losses must be described and considered in the annual yield model.

Thermal gains

Thermal gains of a STE plant stem mainly from two sources:

$$\dot{Q}_{\text{gain}} = \dot{Q}_{\Delta p} + \dot{Q}_{\text{TH}} \tag{5.20}$$

with:

$\dot{Q}_{\Delta p}$ heat gain due to dissipation from pressure loss in W

$\dot{Q}_{TH}$ heat gain from trace heating in W

The main HTF pumps are used to induce the pressure head to compensate the solar field pressure drop and their electrical power consumption is considerable. This pressure head is dissipated while the HTF travels through the solar field. The total heat caused by this dissipation should be considered as a heat gain in the solar field.

Some plants may use trace heating elements in the solar field for several purposes. In case that this heat is not negligible, it must be considered as heat gain. In contrast to the dissipation of the pumping power, a certain fraction of this heating will not reach the HTF but will be lost to the ambient. The STE model shall estimate and report the fraction of trace heating power which actually reached the HTF.

In some cases, thermal energy either from storage tanks or from fossil fuel fired auxiliary heaters is used for freeze protection of the solar field. In case that the individual HTF is prone to freezing, a minimum temperature has to be maintained in the solar field during stand-still which is typically above the actual freezing temperature of the HTF in order to have a safety margin. This heat input (and eventually also electrical demand) is not shown in equation (5.20) because it is outside the limits of the solar field as defined by the methodology. Instead, this anti freeze energy is considered by higher inlet temperature of the HTF entering the solar field.

5.2.1.5. Energy losses caused by operational limits

In a real STE plant most of the installed technical equipment has well defined limits for operation and sometimes the limit of one single part restricts the output of the whole plant. These limits are mainly:

Minimum operation limit: Many parts of the solar field (receivers, pumps, etc.) have a minimum fluid flow in order to maintain stable working conditions, thus not every sun beam can be used for plant operation.
Maximum operation limit: The same is valid for maximum flows and temperature limits. Once the maximum flow for an individual plant is reached a part of the solar field needs to be defocused. A reduction in effective aperture area, e.g. by means of a defocusing factor, should be included to ensure that the solar field is not overheated.

The thermal storage has a limited capacity and during sunny summer days it might be totally charged prior to sunset. For the remaining time steps, partial defocusing will be necessary.

Maximum wind velocity (or gusts): Collectors have a certain upper wind speed for operation (the relevant value is provided by suppliers). Above that wind speed, they must be turned into stow position in order to avoid damages. Time periods with high irradiation and high wind velocity can not be used for production.

In annual performance models, it is important to define and report these limits in order to obtain comparable results. The solar field power cannot exceed the limits and the solar field model must provide interface variables as output specifying the minimum and maximum possible HTF mass flow rate. These values might be constant or variable from time step to step, depending on the actual plant design.
The fraction of the theoretical solar field heat output which cannot be used due to operational limits is called **defocussed energy**. The defocussed energy of each timestep should be reported since it can be used to evaluate the design of a STE plant.

5.2.1.6. Transient effects

Solar radiation is a highly fluctuating source of energy and thus solar thermal power plants are particularly exposed to transient effects. On the other hand, they contain large amounts of HTF and steel masses providing large thermal inertia. This is the justification for using quasi dynamic models for annual yield calculation. Nevertheless, solar field temperature and usable power do not follow the fluctuating irradiance immediately. A yield calculation model should at least consider the following effects:

- Energy required to heat up the field during the start-up which cannot be used for sending useable thermal energy to the storage or power block.

- Ramp rate restrictions of the solar field that require to defocus parts of the field in order to reduce the amount of heat collected. Such ramp rates are often expressed by minimum time span for a certain process.
- Energy required or set free from the thermal inertia of the field during a load change process. It has to be evaluated if positive and negative values cancel out and can therefore be neglected.
- Effective loss of heat collected due to defocusing events caused by the control system during cloud passage.

In case of applying a quasi dynamic modeling approach like the one sketched in equation (5.4), these effects can be described by the following approach:

<u>**Heat up and cool down of the solar field**</u>

Heating up of the HTF and the piping is necessary after sunrise and cooling down takes place after sunset but these effects are also occuring in case of longer periods without direct irradiance during daylight hours. The minimum heat required for heat up or provided by the HTF and steel mass during cool down for a single time step may be calculated from:

$$\mathrm{Q}^{\mathrm{SF}}_{\mathrm{inertia,ideal}} = \sum_i \left(m_{\mathrm{HTF,i}} \cdot c_{\mathrm{HTF,i}} + m_{\mathrm{pipe,i}} \cdot c_{\mathrm{pipe,i}}\right)\left(T_{\mathrm{HTF,i}} - T_{\mathrm{HTF,\,t\text{-}\Delta t,\,i}}\right) \tag{5.21}$$

This equation accounts for the heat capacity of HTF inventory and the heat capacity of the piping (receiver pipes included) in contact with the fluid. It is called ideal since it does not consider the impact of adjacent parts (like supports or insulation) or any process prescribed waste of energy.

The equation is shown in a manner appropriate for an approach dividing the piping into several sections which may have individual temperatures and material properties. If only one representative solar field temperature is considered in the model, it may be simplified accordingly.

A correction factor Ψ can be used to increase the ideal energy to a realistic amount of energy observed under real conditions. Following the quasi dynamic approach, the resulting heat up energy can be converted into a power just by dividing it by the time step length.

$$\dot{Q}^{\mathrm{SF}}_{\mathrm{loss,startup}} = Q^{\mathrm{SF}}_{\mathrm{inertia,ideal}} / \Delta t \cdot \Psi_{\mathrm{SU}} \tag{5.22}$$

In this quasi-dynamic approach it is required to calculate the cool-down of the field in order to have the correct starting condition for the next start-up. <u>A similar approach can be realized for load changes of the field,</u>

$$\dot{Q}^{\mathrm{SF}}_{\mathrm{loss,loadchange}} = Q^{\mathrm{SF}}_{\mathrm{inertia,ideal}} / \Delta t \cdot \Psi_{\mathrm{LC}} \tag{5.23}$$

The solar field typically contains components which may have restricted ramp rates for heat up, particularly the receiver tubes. Thus, even when the radiation increases fastly, the SF might not be able to make use of all available heat due to ramp rate restrictions. The energy which cannot be used is considered as loss and is included in the respective loss terms for load change and start-up.
In a quasi-daynamic model using time steps of 10 minutes or even larger these rate restrictions may not be limiting for the solar field, depending on the individual system under consideration. A practical approach could be to neglect them and check the validity of this assumption by comparison of the results with the allowed ramp rates.

Losses caused by passing clouds

Clouds may shade parts of the solar field or even the whole solar field for a short time period, causing fluctuations in heat output, either temperature or mass flow fluctuations or both. In extreme situations, this might be so pronounced that the power block cannot be operated allthough the mean DNI over a the time period would be sufficient.
Transient models are able to consider these effects as long as they are set up in a manner that the 2-dimensional arrangement of the solar field is considered and the direct normal irradiance is available in the required spatial and temporal resolution. This information is often not available for annual yield calculation. A simple approach for quasi dynamic models is to define a reduction factor to account for the overall impact of theses losses,

$$\dot{Q}^{\mathrm{SF}}_{\mathrm{loss,cloud}} = \dot{Q}^{\mathrm{SF}}_{\mathrm{steadyl}} \cdot \Psi_{\mathrm{cloud}} \qquad (5.24)$$

The difficulty is to estimate this reduction factor since it depends on the solar field design as well as on the conditions at site during the individual time step. The impact is subject to current research and as long as no details are known the factor might be set to unity. It is just mentioned here to bear in mind that there might be an effect.

5.2.1.7. Pressure loss across the solar field

The flow of HTF through receivers, headers, pipe fittings, and valves etc. leads to losses of flow energy due to irreversible processes which can be denoted as pressure losses. The solar field model must be capable to calculate these losses since main HTF pumps have to provide this pressure difference (plus the pressure difference caused by the solar steam generators and the storage heat exchangers).
During detailed engineering of a STE plant, dimensioning of piping and headers follows a techno-economic optimization since there is always a trade-off between minimal pressure loss and minimal HTF and steel masses.

The common approach for calculating pressure loss in a pipe system with fitting, valves, etc. is:

$$p_{\mathrm{in}}^{\mathrm{SF}} - p_{\mathrm{out}}^{\mathrm{SF}} = \frac{\rho_{\mathrm{HTF}}}{2}\, v_{\mathrm{HTF}}^{2} \left(\lambda \frac{l_{\mathrm{pipe}}}{d_{\mathrm{pipe}}} + \sum \zeta_i \right) \tag{5.25}$$

With

ρ_{HTF}: Density of HTF in kg/m³
v_{HTF}: Velocity of the HTF in m/s
λ: Friction factor dimensionless
l_{pipe}: Length of pipe in m
d_{pipe}: Inner diameter of pipe in m
ζ_i: Pressure loss coefficents dimensionless

Since fluid velocity and friction factor may vary for different sections of the solar field, it might be necessary to calculate separate pressure losses for individual parts and sum it up for the total pressure loss. Changes in kinetic pressure energy between inlet and outlet can often be neglected. For direct steam generation systems the difference can get relevant and should be considered. Equation (5.25) can be applied for every time step. As an alternative, the off-design pressure drop may be calculated by using the quadratic scaling law and a nominal pressure drop Δp_{nom} ,

$$p_{\mathrm{in}}^{\mathrm{SF}} - p_{\mathrm{out}}^{\mathrm{SF}} = \Delta p_{\mathrm{nom}} \left(\frac{v_{HTF}}{v_{HTF,nom}} \right)^2 = \Delta p_{\mathrm{nom}} \left(\frac{\dot{m}_{\mathrm{HTF}} \cdot \rho_{\mathrm{HTF,nom}}}{\rho_{\mathrm{HTF}} \cdot \dot{m}_{\mathrm{HTF,nom}}} \right)^2 \tag{5.26}$$

5.2.1.8. Auxiliary electric consumption

The solar field needs electrical power, mainly for the following electrical consumers:

- drives used to turn the reflectors and for tracking the sun
- instrumentation and control devices
- trace heating of pipes and vessels which need freeze protection

Please note, that the electric consumption of the main HTF pumps are associated with the plant system level and do not appear as consumer in the solar field sub-system.

The electrical consumers of a solar field may be divided into several groups:

- Equipment with load dependent consumption
- Equipment with almost constant consumption when the solar field is in operation (e.g. tracking drives, auxiliary consumers of the HTF system)
- Equipment with almost constant consumption when the solar field is out of operation (e.g. those parts of I&C which are used for continuous monitoring)
- Equipment which is only used under special conditions (e.g. trace heating, freeze protection pumps or solar field recirculation pumps)

Therefore, the electric power consumption of the solar field depends on the status of the solar field itself. Even at night and during periods without useful irradiance solar fields will have a certain electrical power consumption which must be considered in the models.

5.2.1.9. Additional reporting variables for line focus systems

The list of generic reporting variables as given in Table 5-1 is extended for line focus systems by including the additional variables provided in Table 5-3. The direct normal irradiance multiplied by the cosine of the incident angle is a typical measure for the solar energy impinging on the parabolic trough collectors. All collectors of the same nominal aperture area and same orientation have this solar power available. It can thus be used to define a solar efficiency specific for parabolic trough systems. The incidence angle modifier represents several effects reducing the optical performance and shall therefore be reported.

Table 5-2: Additional reporting variables valid for line focus technology

Type	Name	Symbol	Comment
R	Incidence angle modifier	K	
R	Projected radiant solar power	$\dot{Q}_{\mathrm{proj}}$	only used for parabolic trough

5.2.2. Parabolic trough field with oil as heat transfer medium

For parabolic trough solar fields operated with thermal oil as heat transfer fluid the same requirements regarding modeling can be applied as described in section 5.2.1. Specific characteristics of operation with thermal oil need to be considered in addition:

- Thermal oil is limited in the upper operating temperature. Todays fluids are limited to about 395 °C but new fluids with increased upper temperature might be available in the future.
- The temperature rise in the solar field is typically 100 K or less. This limited temperature rise, in combination with the thermal properties of the fluid, justify the utilization of a single arithmetic mean temperature to calculate the thermal behavior of the solar field.
- Viscosity of typical HTFs increases strongly when approaching the freezing point. Fluids like VP-1 have a freezing point at approximately 12 °C. Freeze protection starts above this temperature (typically at 60 °C) in oder to have a safety margin and avoid the high viscosity region of this HTF. Respective thermal and/or electric consumption needs to be considered.
- If the plant under consideration is equipped with a regeneration and reclamation system for the HTF, this will consume thermal and electrical energy when operated.

5.3. Solar Tower Systems

The nature of solar tower technologies allows to treat all technologies based on a similar scheme. Most of all this is true for the heliostat field and up to a certain detail the receiver system. The following chapters compile minimum requirements for modeling these systems. Individual technologies might require additional effects to be considered in yield analysis. These might arise either from the concentrator (Heliostat) type or the heat transfer medium used (molten salt, water,…) that defines the receiver technology. Each technology is therefore treated in a separate section that serves as an entry point for the reader interested in a specific technology. However, these technology-specific description largly refers to the generic list of effects described in the sections before.

For solar tower technologies it is convenient to separate the solar field model in two sub-components, the heliostat field and the receiver system (which includes the tower), as they are separate, both in their physical nature as in their spatial relation (see following figure and compare it also to Figure 5-1). The receiver system includes the receiver (i.e. mainly the absorber panels) and some peripheral equipment on top of the tower that is needed to operate the receiver (e.g. piping, vessels, etc.). Following this definition also the riser, downcomer and horizontal piping on the ground is part of the peripheral system.

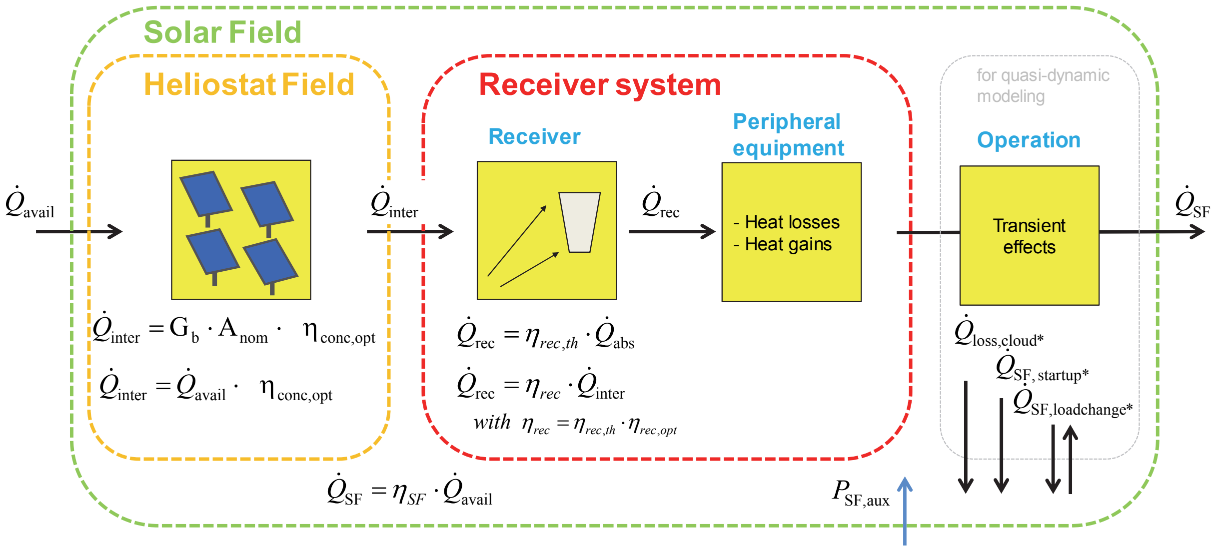


Figure 5-6: Illustration of sub-system solar field for solar towers and its parts

5.3.1. Heliostat field - relevant effects for all solar tower systems

Compared to parabolic trough and linear Fresnel STE systems, modeling of solar tower systems is more complex by additional degrees of freedom in the arrangement of concentrator (i.e. heliostats) and receiver. Solar tower systems are usually designed for a specific location and the heliostat positioning and the solar field optical performance vary with size.

5.3.1.1. Optical losses of heliost field – compilation of relevant effects

There are several effects that cause optical losses in the heliostat field. The relevant losses of the heliostat field to be considered for yield analysis purposes are described in this chapter.

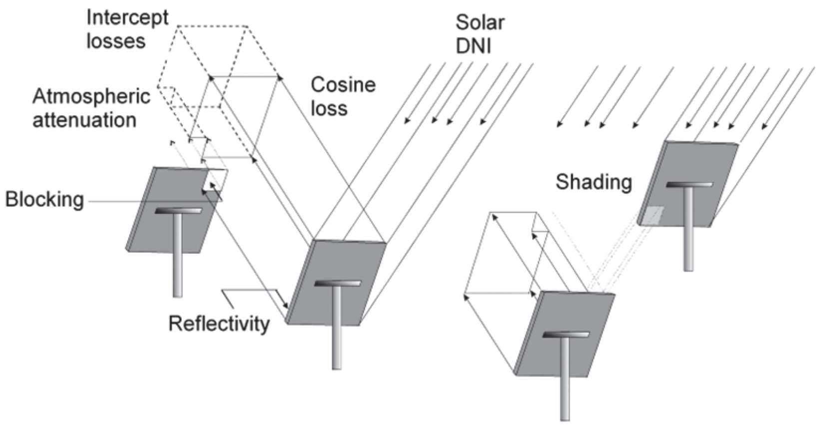


Figure 5-7: Illustration of optical losses in the heliostat field

Optical losses of Heliost Field:

- Losses caused by non-perpendicular sun rays onto the aperture of each heliostat are considered by **cosine losses**.
- Part of the solar irradiation is not reflected by the mirrors due to **mirror reflectivity** and **mirror cleanliness**.
- Part of the solar radiation is lost due to **shading** before (from heliostats or tower/ other structures) or **blocking** after the heliostat surface. Here, also the topography of the terrain needs to be considered.
- Between the heliostat and the receiver surface (intercept area) the losses due to **atmospheric attenuation** need to be considered.
- There are many effects that cause the reflected sunrays from the heliostat to (partially) miss its aim, the receiver surface (intercept area). Those effects are labeled as intercept losses. Relevant contributions are caused by
    - a time and location dependent deviation from the ideal **sunshape**
    - possibly a heliostat **aiming strategy** to limit the receiver surface temperature[13]
    - different sizes of the reflected image and the size of the receiver surface (intercept area).
    - effects related to the accuracy of the heliostat such as
        - **tracking errors**
        - **slope errors**
        - **astigmatism**

[13] The aiming strategy modulates the temperatures on the surface of the receiver and it hast o accomplish several limits. The optimized aiming strategy is the one which maximizes the energy on the receiver while accomplishing all temperature limits. In ordert o reduce temperature peaks selected heliostats aim more to the edge oft he receiver and thus cause spillage losses.

- **facet cant** and **curvature**
- **gravity**
- **wind-induced deflection** (of heliostats and tower/ receiver)

- A number of heliostats in the field are temporarily not available since they need to be reconfigured, cleaned, or repaired. This results in a **continuous non-availability** of a fraction of the functional units, namely the heliostats.

5.3.1.2. Optical losses of heliostat field – common modeling approach

A common approach is to define efficiencies for all relevant effects reducing the available power to the intercepted power of the intercept area (receiver aperture area). Equation (5.6) shows this approach and the individual effects which must be considered in the calculation.
The intercept area for an external receiver is the curved surface area of the receiver that is exposed to the heliostat field. For cavity receivers the intercept area is the aperture area of the cavity that is exposed to the heliostat field.

$$\dot{Q}_{\text{inter}} = \eta_{\text{cos}}\ \eta_{\text{shad}}\ \eta_{\text{refl,0}}\ \eta_{\text{clean}}\ \eta_{\text{block}}\ \eta_{\text{atten}}\ \eta_{\text{inter}}\ \eta_{\text{wind}}\ \eta_{\text{avail}}^{\text{SF}}\ f_{\text{foc,A}}\ A_{\text{nom}}\ G_{\text{bn}} \qquad (5.27)$$

$$\dot{Q}_{\text{inter}} = \eta_{\text{conc,opt}}\ A_{\text{nom}}\ G_{\text{bn}} \qquad (5.28)$$

With:

$\dot{Q}_{\text{inter}}$	Intercepted power to intercept area(receiver aperture) area in W
η_{cos}	Incidence angle efficiency including all losses caused by non-perpendicular sun rays into the aperture plane, dimensionless. Also called cosine efficiency.
η_{shad}	Shading efficiency, dimensionless
$\eta_{\text{refl,0}}$	Clean rReflector efficiency, dimensionless
η_{clean}	Cleanliness factor, dimensionless
η_{block}	Blocking efficiency, dimensionless
η_{atten}	Atmospheric attenuation efficiency, dimensionless
η_{inter}	Intercept factor, dimensionless
η_{wind}	Factor considering optical losses caused by wind, dimensionless
$\eta_{\text{avail}}^{\text{SF}}$	Continuous solar field availability, dimensionless
f_{focA}	Percentage of the available aperture area in focus (the available aperture area is the nominal aperture area corrected by the continuous non-availability of collectors, $\eta_{\text{avail}}^{\text{SF}}$) efficiency over the nominal intercept efficiency
A_{nom}	Nominal aperture area of heliostat field in m²
G_{bn}	Direct normal solar irradiance in W/m²

For the heliostat field of a solar tower, the optical effects listed above need to consider the performance of each heliostat. Equation 5.26 can be applied for each heliostat of the heliostat field using the single heliostat aperture and negelecting the focusing factor and the availability. The heliostat field of solar tower systems is usually designed for a specific location and the heliostat positioning and the optical performance vary with size of the heliostat field. The power of each single heliostat depends on the current sun position and its position relative to the tower. The power of a single heliostat is also affected by the surrounding heliostats due to blocking and shading and all other effects listed above. Thus, the layout and optimization of the heliostat field of solar tower systems is a complex problem that is preferably performed with computer-based simulation.

A variety of programs (e.g. Raytracing codes etc.) are used to obtain an optimized plant layout for a given plant location and project boundaries and to calculate the performance of a heliostat field. This guideline does not give a recommendation which specific tool should be used. Instead, it provides an overview of the relevant losses of the heliostat field, which should be considered for yield analysis.

A common result of such programs is an efficiency matrix of the heliostat field that can be used for annual yield calculations. An alternative approach is to use individual flux maps depending on the solar position.

For the efficiency matrix approach the solar field efficiency is depending on the solar altitude angle α_s and the solar azimuth angle γ_s. All optical losses can be considered. As the atmospheric attenuation efficiency is depending on meteorological conditions (comparable to the DNI) it should be considered separetly. Same for optical losses caused by wind, as the wind velocity and direction can not be related to the sun angles and heliostat field positioning. Important to mention is that the intercepted power is depending on the heliostat aiming strategy (for different sun positions and operation requirements). The optical losses coming from that are already considered in $\eta_{\mathrm{conc,opt*}}$ for the specific aiming. Therefore, depending on the receiver technology, it can be necessary to have individual efficiency maps that reflect the flux distribution resulting from different aiming strategies. The resulting intercept power is

$$\dot{Q}_{\mathrm{inter}} = \eta_{\mathrm{conc,opt*}}(\alpha_s, \gamma_s)\, \eta_{\mathrm{clean}}\, \eta_{\mathrm{atten}}\, \eta_{\mathrm{wind}}\, \eta_{\mathrm{avail}}^{\mathrm{SF}}\, f_{\mathrm{foc,A}}\, A_{\mathrm{nom}}\, G_{\mathrm{bn}} \tag{5.29}$$

with

$$\eta_{\mathrm{conc,opt*}}(\alpha_s, \gamma_s) = \eta_{\mathrm{cos}}\, \eta_{\mathrm{shad}}\, \eta_{\mathrm{refl,0}}\, \eta_{\mathrm{block}}\, \eta_{\mathrm{inter}} \quad . \tag{5.30}$$

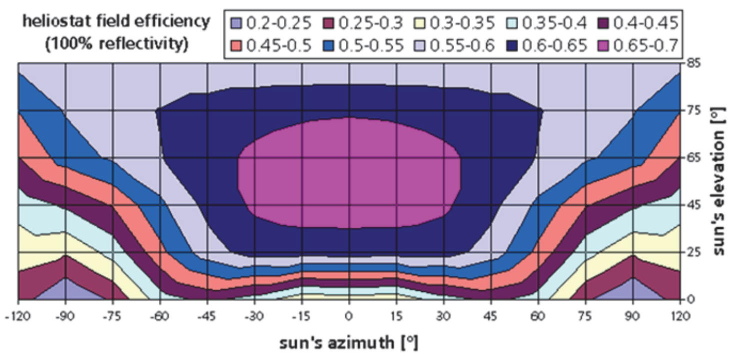


Figure 5-8: Illustration of optical losses in the heliostat field in terms of $\eta_{\mathrm{conc,opt*}}(\alpha_s, \gamma_s)$

5.3.2. Receiver system - relevant effects for all solar tower systems

There are several optical and thermal loss effects in the receiver system. Remember that the receiver system starts with the intercept plane. The most relevant losses are described in this chapter. Common receiver system are external receiver and cavity receiver. Depending on the system setup (compare Fig. 5-6) beside of the receiver (i.e. mainly the receiver absorber panels) the receiver system can include different additional components (e.g. vessels, piping, downcomer, riser and horizontal piping on the ground).

5.3.2.1. Optical and thermal losses of the receiver system– compilation of relevant effects

As depicted in Figur 5-1 the receiver losses can be divided into optical and thermal losses.

The following loss effects need to be considered:

- A part of the intercepted power is not absorbed by the receiver surface due to reflection → **optical losses**.
- **Thermal losses** caused by heat **radiation** of the receiver surface.
- **Thermal losses** caused by **convection**. The **velocity of wind** has a significant effect on convective heat losses and should be considered.
- **Thermal losses** of heat transport from the receiver into the tower structure should be included, depending on the quality of insulation (**conduction**).
- **Thermal losses** of the **peripheral equipment on the tower**, the **riser**, the **downcomer**, and the **horizontal piping on the ground.**
- The heliostat aiming strategy has a relevant effect on the flux distribution on the receiver aperture area.
- The **receiver availability** has to be considered (e.g. due to maintenance outages).

5.3.2.2. Optical and thermal losses of receiver [14]– common modeling approach

The receiver converts the intercepted power to a useful receiver power

$$\dot{Q}_{\mathrm{rec}} = \eta_{\mathrm{rec}}\, \dot{Q}_{\mathrm{inter}} \tag{5.31}$$

where

$$\eta_{\mathrm{rec}} = \eta_{\mathrm{rec,opt}}\, \eta_{\mathrm{rec,th}} \tag{5.32}$$

with

$\dot{Q}_{\mathrm{rec}}$	Thermal power from receiver in W
η_{rec}	Effficiency of receiver, dimensionless
$\eta_{\mathrm{rec,opt}}$	Optical efficiency of receiver, dimensionless
$\eta_{\mathrm{rec,th}}$	Thermal effficiency of receiver, dimensionless .

[14] Only Receiver, not receiver system (compare Figure 5-1).

Optical losses of receiver

A common approach is to define efficiencies for all relevant effects reducing the intercepted power to the absorbed power. Equation (5.6) shows this approach and the individual effects which must be considered in the calculation.

$$\dot{Q}_{\mathrm{abs}} = \eta_{\mathrm{rec,opt}}\, \dot{Q}_{\mathrm{inter}} = \eta_{\mathrm{sec}}\ \eta_{\mathrm{trans}}\ \eta_{\mathrm{abs}}\, \dot{Q}_{\mathrm{inter}} \tag{5.33}$$

with

$\eta_{\mathrm{rec,opt}}$	Optical efficiency of receiver, dimensionless
η_{sec}	Efficiency of secondary concentrator (if any), dimensionless
η_{trans}	Transmission through receiver glass cover (if any), dimensionless
η_{abs}	Receiver absorptance dimensionless

Thermal losses of Receiver

Receivers for the concentrated sunlight have thermal losses caused by radiation, convection and conduction. These losses depend on the temperature of the receiver and the temperature of the ambient (actually the system for heat interchanging with the receiver). They depend further on SF load, wind, receiver geometry, material and surface,

$$\dot{Q}_{\mathrm{rec}} = \dot{Q}_{\mathrm{abs}} - \dot{Q}_{\mathrm{loss,rec}} = \eta_{\mathrm{rec,th}}\ \dot{Q}_{\mathrm{abs}} \tag{5.34}$$

with:

$\eta_{\mathrm{rec,th}}$	thermal effficiency of receiver, dimensionless
$\dot{Q}_{\mathrm{loss,rec}}$	receiver heat losses in W

The thermal losses of the receiver are:

$$\dot{Q}_{\mathrm{loss,rec}} = \dot{Q}_{\mathrm{loss,rad}} + \dot{Q}_{\mathrm{loss,conv}} + \dot{Q}_{\mathrm{loss,cond}} \tag{5.35}$$

with:

$\dot{Q}_{\mathrm{loss,rad}}$	radiation heat losses in W
$\dot{Q}_{\mathrm{loss,conv}}$	convection heat losses in W
$\dot{Q}_{\mathrm{loss,cond}}$	conduction heat losses in W

Thermal losses of receivers are typically the main source of thermal losses and need to be considered in the correct manner. The general dependency of receiver heat losses on operating and ambient conditions is:

$$\dot{Q}_{\mathrm{loss,rec}} = \mathrm{f}(T_{\mathrm{abs}}, T_{\mathrm{amb}}, v_{\mathrm{wind}}) \tag{5.36}$$

5.3.2.3. Thermal losses and gains of receiver system – common modeling approach

In the receiver system of solar towers several additional thermal losses and gains need to be considered for piping used to connect the receiver to the power block and to the thermal energy storage (known as risers and downcomers) as well as for vessels, tanks, and other equipment used to transport the thermal energy from the receiver to the consumers. The thermal power finally available from the solar field is

$$\dot{Q}_{\mathrm{SF}} = \dot{Q}_{\mathrm{rec}} - \sum \dot{Q}_{\mathrm{loss}} + \sum \dot{Q}_{\mathrm{gain}} \;. \tag{5.37}$$

<u>Thermal losses of receiver system</u>

$$\dot{Q}_{\mathrm{loss}} = \dot{Q}_{\mathrm{loss,pipe}} + \dot{Q}_{\mathrm{loss,equ}} \tag{5.38}$$

with:

$\dot{Q}_{\mathrm{loss,pipe}}$	heat losses of the riser, downcomer, and piping in W
$\dot{Q}_{\mathrm{loss,equ}}$	heat losses of other receiver system equipment (like tanks,vessels, etc.) in W

The single contributions are described in the following paragraphs.

Thermal losses of riser, downcomer, piping - $\dot{Q}_{\mathrm{loss,pipe}}$

Interconnecting piping that links receiver elements to each other and header and runner piping represents further significant heat losses and have to be considered.

The general equation for heat transfer calculation caused by convection and conduction for a pipe is:

$$\dot{Q}_{\mathrm{loss,pipe}} = U_{\mathrm{pipe}}\, A_{\mathrm{pipe}} (T_{\mathrm{HTF}} - T_{\mathrm{amb}}) \tag{5.39}$$

With

U_{pipe}	Overall heat transfer coefficient for the pipe in W/(m²K)
A_{pipe}	Surface area of the pipe in m²
T_{HTF}	Bulk HTF temperature in K
T_{amb}	Ambient temperature in K

Equation (5.17) neglects radiation heat losses of the pipe, but they are typically small since the temperature difference between the outer pipe surface and ambient is small for insulated pipes. The overall heat transfer coefficient for the pipe is a function of flow velocities and fluid properties of both fluids inside and outside the pipe, pipe diameter and wall thickness, the thickness and properties of insulation material. Since most of these parameters are not constant but vary troughout the piping system, equation (5.17) must be applied for each section of pipe, downcomer, and riser and the respective heat losses must be summed up.

The difficulty of this detailed approach is that all these informations are not always available for those parties who are performing annual yield calculations. Therefore, specific heat losses are often used for the piping in W/m² of aperture area or W/m of piping length. The idea behind this approach is that a project deveoper or owner of a STE plant might require such specific heat losses for design point operation during the proposal phase of the plant and the EPC contractor has to design and build the piping in an appropriate manner to fulfill these requirements. Using the reasonable assumption that these heat losses are linear with temperature differences, the calculation of heat losses for other than nominal temperatures may be done according to

$$\dot{Q}_{\text{loss,pipe}} = l_{\text{pipe}}\ \dot{q}_{\text{loss,pipe}} = l_{\text{pipe}}\ \dot{q}_{\text{loss,pipe,nom}}\ \frac{(T_{\text{HTF}} - T_{\text{amb}})}{(T_{\text{HTF,nom}} - T_{\text{amb,nom}})}. \tag{5.40}$$

Thermal losses of other equipment used in the receiver system - $\dot{Q}_{loss,equ}$

Individual STE plants may have further equipment in the solar field which is passed trough by the HTF and which may cause additional heat losses. If this applies, these losses must be described and considered in the annual yield model. For tower systems this can be equipment required on the tower that is not directly part of the receiver.

Thermal gains of receiver system

Thermal gains of a STE plant stem mainly from three sources:

$$\dot{Q}_{\text{gain}} = \dot{Q}_{\Delta p} + \dot{Q}_{\text{TH}} + \dot{Q}_{\text{AF}} \tag{5.41}$$

With:

$\dot{Q}_{\Delta p}$ heat gain from pressure loss in W

$\dot{Q}_{TH}$ heat gain from trace heating in W

$\dot{Q}_{AF}$ heat gain from anti freeze measures in W

The main HTF pumps are used to induce the pressure head to compensate the solar field pressure drop and their electrical power consumption is considerable. This pressure head is dissipated while the HTF travels through the solar field. The total heat caused by this dissipation should be considered as a heat gain in the receiver system.

Some plants may use trace heating elements in the solar field for several purposes. In case that this heat is not negligible, it must be considered as heat gain. In contrast to the dissipation of the pumping power, a certain fraction of this heating will not reach the HTF but will be lost to the ambient. The STE model shall estimate and report the fraction of trace heating power which actually reached the HTF.

Freeze protection for the solar field needs electrical energy and often also thermal energy either from storage tanks or from fossil fuel fired auxiliary heaters. In case that the individual HTF is prone to freezing, a minimum temperature has to be maintained in the solar field during stand-still which is typically above the actual freezing temperature of the HTF in order to have safety margin. Respective thermal and/or electric heat input needs to be considered.

5.3.2.4. Pressure loss across the receiver system

The flow of HTF through receivers, headers, pipe fittings, and valves etc. leads to losses of kinetic energy due to irreversible processes which can be denoted as pressure losses. The solar field model must be capable to calculate these losses since main HTF pumps have to provide this pressure difference (plus the pressure difference caused by the solar steam generators and the storage heat exchangers). During detailed engineering of a STE plant, dimensioning of piping and headers follows a techno-economic optimization since there is always a trade-off between minimum pressure loss and minimum HTF and steel masses.
In solar tower plants, the main HTF pumps also have to surmount the hydrostatic pressure to transport the fluid from ground level up to the receiver. It can be treated as another source of pressure loss in annual yield calculations, however the hydrostatic pressure loss remains constant independently of the reduced mass flow in part-load conditions.

The total pressure loss of the receiver system is the sum of the flow pressure loss caused by pipes and receiver and the hydrostatic pressure loss.

$$\Delta \mathrm{p} = p_{\mathrm{in}}^{\mathrm{SF}} - p_{\mathrm{out}}^{\mathrm{SF}} = \Delta \mathrm{p}_{\mathrm{flow}} + \Delta \mathrm{p}_{\mathrm{hydro}} \tag{5.42}$$

The hydrostatic pressure drop is defined by the altitude difference Δz from ground level to the receiver, the gravity, and the nominal HTF density,

$$\Delta \mathrm{p}_{\mathrm{hydro}} = \rho_{\mathrm{HTF,nom}}\, g\, \Delta z\,. \tag{5.43}$$

Depending on the hydraulic configuration parts of the pressure head needed to pump the fluid to the top of the tower might be re-gained in the downcomer.

The common approach for calculating pressure loss in a pipe system with fitting, valves, etc. is

$$\Delta p_{\mathrm{flow}} = \frac{\rho_{\mathrm{HTF}}}{2}\, v_{\mathrm{HTF}}^{2} \left(\lambda \frac{l_{\mathrm{pipe}}}{d_{\mathrm{pipe}}} + \sum \zeta_i \right) \tag{5.44}$$

with

ρ_{HTF}:	Density of HTF in kg/m³
v_{HTF}:	Velocity of the HTF in m/s
λ:	Friction factor dimensionless
l_{pipe}:	Length of pipe in m
d_{pipe}:	Inner diameter of pipe in m
ζ_i:	Pressure loss coefficents dimensionless

Since fluid velocity and friction factor may vary for different sections of the solar field, it might be necessary to calculate separate pressure losses for individual parts and sum it up for the total pressure loss. The previous equation can be applied for every time step. As an alternative, the off-design pressure drop may be calculated by using the quadratic scaling law and a nominal pressure drop Δp_{nom} ,

$$\Delta p_{\mathrm{flow}} = p_{\mathrm{in}}^{\mathrm{SF}} - p_{\mathrm{out}}^{\mathrm{SF}} = \Delta p_{\mathrm{nom}} \left(\frac{v_{HTF}}{v_{HTF,nom}} \right)^2 = \Delta p_{\mathrm{nom}} \left(\frac{\dot{m}_{\mathrm{HTF}} \cdot \rho_{\mathrm{HTF,nom}}}{\rho_{\mathrm{HTF}} \cdot \dot{m}_{\mathrm{HTF,nom}}} \right)^2 . \quad (5.45)$$

5.3.3. Operation and transient effects - relevant effects for all solar tower systems

5.3.3.1. Energy losses caused by operational limits

In a real STE plant, most of the installed technical equipment has well defined limits for operation and sometimes, the limit of one single part restricts the output of the whole plant. These limits are mainly:

- Minimum operation limit: Many parts of the receiver system (receivers, pumps, etc.) have a minimum fluid flow in order to maintain stable working conditions, thus not every sun beam can be used for plant operation.
- Maximum operation limit: The same is valid for maximum flows and temperature limits. Once the maximum flow for an individual plant is reached, a part of the heliostat field needs to be defocused. A reduction in effective aperture area, e.g. by means of a defocusing factor, should be included to ensure that the receiver system is not overheated.
- The thermal storage has a limited capacity and during sunny summer days it might be totally charged prior to sunset. For the remaining time partial defocusing will be necessary.
- Maximum wind velocity (or gusts): Heliostats have a certain upper wind speed for operation (the relevant value is provided by suppliers). Above that wind speed they must be turned into stow position in order to avoid damages. Time periods with high irradiation and high wind velocity can thus not used for production.
- Temperature gradients: Some parts of the plant (particularly heat exchangers and steam turbine) have restrictions for heating-up or cooling down and these restrictions may cause that the receiver system heat production can actually not be used during certain time steps although it could deliver heat.
- Outages: STE plants, like other technical installations, will show outages accidentally. Compare section 11.2 for a general methodology to handle these effects.

In annual performance models, it is important to define and report these limits in order to obtain comparable results. The solar field power cannot exceed the limits and the solar field model must provide interface variables as output specifying the minimum and maximum possible HTF mass flow rate. These values might be constant or variable from time step to step, depending on the actual plant design.

The fraction of the theoretical solar field heat output which cannot be used due to operational limits is called **defocussed energy**. The defocussed energy of each timestep should be reported since it can be used to evaluate the design of a STE plant.

5.3.3.2. Auxiliary electric consumption

The solar field (heliostat field and receiver system) needs electrical power, mainly for the following electrical consumers:

- drives used to turn the heliostats and for tracking the sun
- instrumentation and control devices
- trace heating of pipes and vessels which need freeze protection

Please note, that the electric consumption of the main HTF pumps are associated with the plant system level and do not appear as consumer in the solar field sub-system.

The electrical consumers of a solar field may be divided into several groups:

- Equipment with load dependent consumption
- Equipment with almost constant consumption when the solar field is in operation (e.g. tracking drives, auxiliary consumers of the HTF system)
- Equipment with almost constant consumption when the solar field is out of operation (e.g. those parts of I&C which are used for continuous monitoring)
- Equipment which is only used under special conditions (e.g. trace heating, freeze protection pumps or solar field recirculation pumps)

Therefore, the electric power consumption of the solar field depends on the status of the solar field itself. Even at night and during periods without useful irradiance solar fields will have a certain electrical power consumption which must be considered in the models.

5.3.3.3. Transient effects

Solar radiation is a highly fluctuating source of energy and thus, solar thermal power plants are particularly exposed to transient effects. On the other hand, they contain large amounts of HTF and steel masses providing large thermal inertia. This is the justification for using quasi-dynamic models for annual yield calculation instead of very detailed fully dynamic models. Nevertheless, solar field temperature and usable power do not follow the fluctuating irradiance immediately.
The transient effects are depending on the solar tower technology e.g. if a molten salt tower or a tower with open volumetric receiver system is used. However, for all solar tower systems, generic transient effects can be defined.
In case of applying a quasi-dynamic model approach like equation (5.4), at least the following tansient effect have to be considered.

<u>Heat up and cool down of the solar field</u>
Heating up of the HTF and the receiver system (incl. piping etc.) is necessary after sunrise and cooling down takes place after sunset.These effect are also occuring in case of longer periods without direct irradiance during daylight hours.
The minimum heat required for heat up or cool down for a single time step may be calculated from:

$$Q^{SF}_{inertia,ideal} = \sum_i (m_{HTF,i} \cdot c_{HTF,i} + m_{rec} \cdot c_{rec} + m_{equ,i} \cdot c_{equ,i})(T_{HTF,i} - T_{HTF,\, t\text{-}\Delta t,\, i}) \quad (5.46)$$

This equation accounts for the heat capacity of HTF inventory, heat capacity of receiver, and the heat capacity of the other equipment (piping, etc.) in contact with the fluid. It is called ideal since it does not consider the impact of adjacent parts (like supports or insulation) on the thermal inertia nor any process prescribed water of energy. A correction factor can be used to increase the ideal energy to a realistic amount of energy observed under real conditions. Following the quasi dynamic approach, this heat up energy can be converted into a power just by dividing it by the time step length.

The equation is shown in a manner appropriate for an approach dividing the piping into several sections which may have individual temperatures and material properties. If only one representative receiver system temperature is considered in the model, it may be simplified accordingly.

Losses caused by passing clouds

Clouds may shade parts of the heliostat field or even the whole heliostat field for a short time period, causing fluctuations in heat output, either temperature or mass flow fluctuations or both. In extreme situations, this might be so pronounced that the power block cannot be operated though the mean DNI over a the time period would be sufficient.

Transient models are able to consider these effects as long as they are set up in a manner that the 2-dimensional arrangement of the solar field is considered and the direct normal irradiance is available in the required spatial and temporal resolution. This information is often not available for annual yield calculation. A simple approach for quasi dynamic models is to define a reduction factor to account for the overall impact of theses losses,

$$\dot{Q}^{SF} = \dot{Q}^{SF}_{ideal} \cdot \xi_{cloud} \,. \quad (5.47)$$

The difficulty is to estimate this reduction factor since it depends on the solar field design as well as on the conditions at site during the individual time step.

Maximum ramp rates

The solar field typically contains components which may have restricted ramp rates for heat up, particularly the receiver tubes. Thus, even when the radiation increases fast, the SF might not be able to make use of all available heat due to ramp rate restrictions. The energy which cannot be used is considered as loss and shall be reported as defocussed energy.

5.3.4. Additional reporting variables for solar tower plants

The list of generic reporting variables as given in Table 5-1 is extended for solar tower systems by including the additional variables provided in Table 5-3.

Table 5-3: Additional reporting variables valid for solar tower technology (*indicates variables that might not be available for all types modeling approaches)

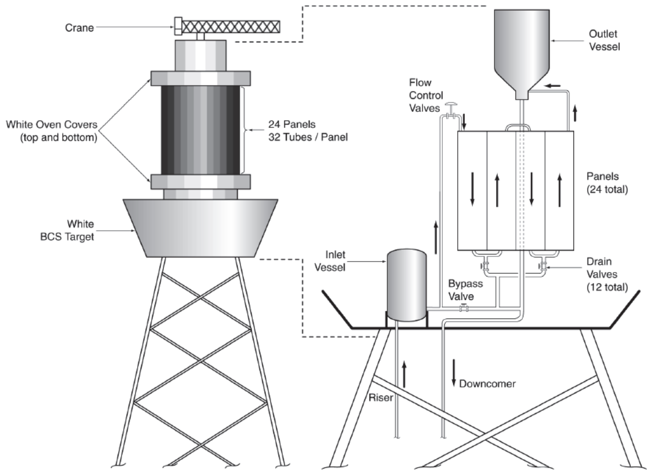
Type	Name	Symbol	Comment
R	Intercept power	$\dot{Q}_{\mathrm{inter}}$	
R	Receiver power	$\dot{Q}_{\mathrm{rec}}$	

5.3.5. Solar tower with molten salt as heat transfer medium

The solar field of a solar tower with molten salt as heat teat transfer medium is described in this chapter (also called molten salt tower). The same requirements regarding modeling can be applied as described in section 5.3.1, 5.3.2 and 5.3.3. Specific characteristics of operation with molten salt need to be considered in addition:

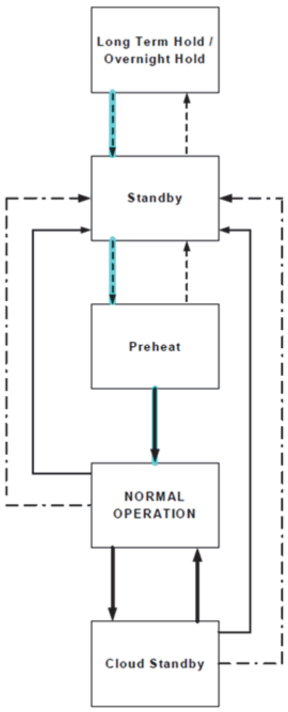
- The receiver is a tubular receiver with single phase heat transfer medium. Known receivers for molten salt towers were build mainly as external receivers, but also as so called cavity receivers. Both use tubes where the molten salt is used to cool down the absorber tubes and thus to collect the heat from the heliostat field.
- Molten salt is limited in the operating temperature. Today, most common is solar salt which is used in the temperature range between 290 and 565 °C. The freezing points starts below ~240 °C. Freeze protection starts above this temperature (typically at ~265 °C) in order to have a safety margin. The upper temperature is limited to about 565 °C (degradation of molten salt, corrosion). New fluids with increased upper temperature or measures to operate the fluids at higher temperatures might be available in the future.
- The heliostat aiming strategy needs to work appropriate to protect the receiver tubes from overheating but also from freezing of molten salt.
- The main components of a receiver system of a typical molten salt tower are shown in Figure 5-9. The thermal losses and gains as described in section 5.3.2 needs to be considered.
- Due to the high density of the molten salt the hydrostatic pressure to overcome is significant. Depending on the hydraulic configuration a fraction of the pressure head can be re-gained in the downcomer section.
- For the operation of a molten salt tower several operating states are defined (Figure 5-10)[15] and need to be treated appropriately.
- The transitions between those states is important for the transient effects that need to be considered (Figure 5-11)[16]. Since molten salt receivers together with the riser and downcomer are typically drained during night or longer cloud periods the pre-heating and filling process has significant impact on the annual performance. Sequential procedures and ramp rates have to be maintained for each start-up. In case the receiver system is drained due to cloud passage the filling and start-up will reduce the solar field power after clouds have passed.

[15] The given numbers are only examples.
[16] The given numbers are only examples.



Component	Function
Receiver pump	• supply cold salt to the receiver inlet vessel
Inlet Vessel (pressurized)	• Balance mass flow gradients • Absorber cooling in case of pump or power loss
Receiver Absorber Panels	• Heat molten salt
Flow control valves	• Receiver Mass flow control
Outlet vessel	• Balance mass flow gradients
Drain system	• Draining an filling of receiver
Heat Tracing System	• Prevent salt freezing • Reduce thermal stresses

Figure 5-9: Components of a receiver system of a molten salt tower [17]



state	explanation
Long Term Hold/ Overnight Hold	• The heliostats are in the stow position • the receiver is drained • the electric heat trace circuits are inactive
Standby	• The heliostats are focused on the standby aim point • the receiver pump is operation • Salt is flowing in the riser, the receiver bypass line, and the downcomer.
Preheat	• The receiver electric heat trace circuits are active • the preheat heliostats are focused on the receiver • the receiver pump is in operation • Salt is flowing in the riser, the receiver bypass line, and the downcomer.
Normal Operation	• All of the available heliostats are focused on the receiver • the receiver flow rate is controlled to achieve an outlet temperature of 565°C (1,050°F) • the electric heat trace circuits are de-energized at normal operation temperature set points.
Cloud Standby	• All of the available heliostats are focused on the receiver, the receiver flow rate is controlled to achieve an outlet temperature of 510°C (950°F) under theoretical clear sky conditions • the electric heat trace circuits are de-energized at the normal operation temperature set points.

Figure 5-10: Operation states of a receiver system of a molten salt tower [18]

[17] Reilly, H. E. and Kolb, G. J., "An Evaluation of Molten-Salt Power Towers Including Results of the Solar Two Project", SAND2001-3674, 2001.

[18] Zavoico A., “Solar Power Tower - Design Basis Document; Sandia National Laboratories”, SAND2001-2100, 2001.

transition	explanation
1. Long Term Hold → Standby	• The operator moves the heliostats from the stow positions to tracking the standby aim points • The temperatures of the riser, the receiver bypass line, and the downcomer are raised to 260°C (500°F) • The receiver pump is started, and a flow is established in the riser, the bypass line, and the downcomer.
2. Standby → Preheat	• The temperatures of the receiver ovens and interpanel piping are raised to 315°C (600°F). • The preheat heliostats, selected by the DAPS, are moved from the standby aim points to the preheat aim points.
3. Preheat → Standby	• The preheat heliostats are moved from the preheat aim points to the standby aim points.
4. Preheat → Normal Operation	1. the receiver is filled by flooding 2. serpentine flow is established 3. a flow rate corresponding to clear sky conditions is established, 4. the heliostats are moved from the standby (or preheat) aim points to the normal aim points 5. the flow rate is controlled to achieve a nominal outlet temperature of 565°C (1,050°F)
5. Normal Operation → Cloud Standby	• Automatic temperature control is suspended • The flow rate is controlled to achieve an outlet temperature of 510°C (950°F) under theoretical clear sky conditions.
6. Cloud Standby → Normal Operation	• Automatic temperature control is resumed • the flow rate is controlled to achieve a nominal outlet temperature of 565°C (1,050°F).
7. Normal Operation → Standby	• The heliostats are moved from the normal aim points to the standby aim points • the inlet vessel is vented to the atmosphere • the receiver is drained
8. Cloud Standby → Standby	• The heliostats are moved from the normal aim points to the standby aim points • the inlet vessel is vented to the atmosphere • the receiver is drained.
9. Standby → Long Term Hold	• The heliostats are moved from tracking the standby aim points to the stow position • the receiver pump is stopped • the electric heat trace circuits are inactive.

Figure 5-11: Transition between operating states of a receiver system from a molten salt tower[18]

6. Modeling the sub-system Power Block (PB)

The power block transforms the thermal energy provided by the solar field, the thermal energy storage, and the auxiliary heater into electricity, the final product of a STE plant. For solar heat in the temperature range between 300 °C and 600 °C Rankine power cycles are used. Solar applications enabling higher temperature levels can make use of Brayton cycles. Prior to describing modeling requirements for Rankine and Brayton[19] cycles some general definitions for the interface and reporting variables need to be defined.

6.1. Generic sub-system interface and variable definition

The power block sub-system in the sense of this guideline comprises the turbine, the generator, all heat cycle components and systems, as well as the heat exchanger between the heat transfer fluid used in the solar part and the working fluid of the heat engine (water/steam or a gas like air or CO_2). As illustrated in Figure 6-1, the power block sub-system shows very clear interfaces to the rest of the plant which are:

- Hot HTF entering and cold HTF leaving the steam generator in case of the indirect Rankine cycles,
- Steam entering and water leaving the power block cycle for direct steam generation rankine cycles, and
- Hot gas entering and cold gas leaving the power cycle in case of Brayton systems.

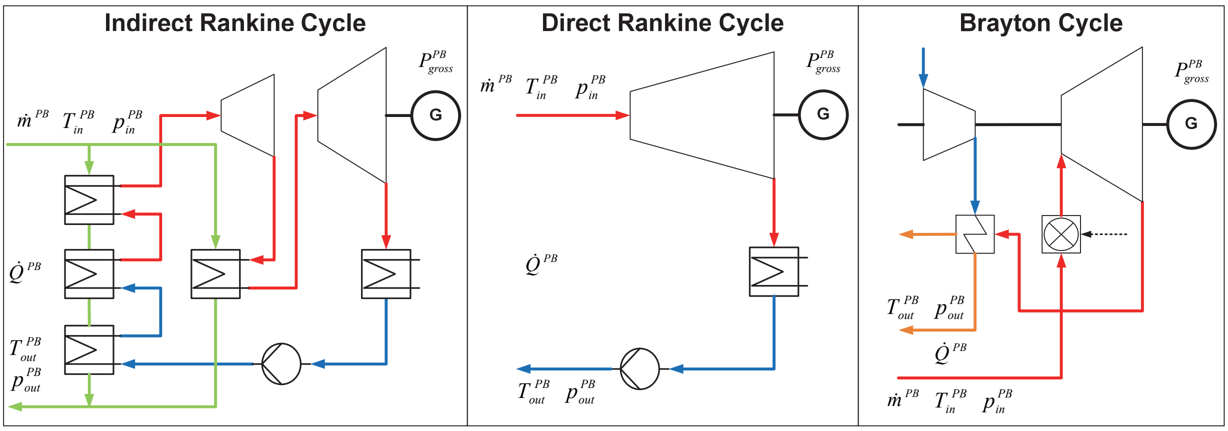


Figure 6-1: Sub-system boundaries for three types of power block configurations

In case of the depicted Brayton cycle configuration, a pressurized air receiver was considered as the solar heat delivering technology. Thereby, the compressed air is preheated through a recuperator using exhaust gases and afterwards heated up by means of the receiver. This allows for increasing the

[19] Brayton cycles are not covered in version 1 of the guideline

efficiency of the combustion and at the same time of the gas turbine cycle. Other configurations are also possible such as an Integrated Solar Combined Cycle (ISCC).
The fluid streams entering and leaving the power block sub-system are characterized by mass flow, temperature, and pressure as listed in Table 6-1. Ambient conditions like temperature, relative humidity, wind speed and atmospheric pressure determine the cold end conditions of the cycle. The output of the power block is the gross electric power measured at the generator terminals, $P_{\mathrm{gross}}^{\mathrm{PB}}$. The power block requires auxiliary electrical energy, $P_{\mathrm{aux}}^{\mathrm{PB}}$. Heat is rejected either at the cold side, $P_{\mathrm{ex}}^{\mathrm{PB}}$, or can be extracted for process heat applications, $P_{\mathrm{ext}}^{\mathrm{PB}}$. The power block sub-system also induces a pressure loss either by the pressure loss in the HTF path of the steam generator/heat exchanger or by the turbine itself in case of direct systems. Since pumping power for the main HTF cycle is allocated on the system level, the power block model needs to calculate the pressure loss as a function of actual load.

Table 6-1: Generic interface (I), meteorological (M) and reporting (R) variables valid for the power block sub-system (*indicates variables that might not be available for all types of modeling approaches)

Type	Name	Symbol	Comment
I	Inlet temperature [2]	$T_{\mathrm{in}}^{\mathrm{PB}}$	
I	Outlet temperature [2]	$T_{\mathrm{out}}^{\mathrm{PB}}$	
I	Inlet pressure	$p_{\mathrm{in}}^{\mathrm{PB}}$	
I	Outlet pressure	$p_{\mathrm{out}}^{\mathrm{PB}}$	
I	Mass flow	$\dot{m}^{\mathrm{PB}}$	
I	Gross electricity production	$P_{\mathrm{gross}}^{\mathrm{PB}}$	
I	Auxiliary electrical demand	$P_{\mathrm{aux}}^{\mathrm{PB}}$	
M	Ambient temperature	T_{amb}	
M	Average wind speed	v_{wind}	
M	Wind direction	γ_{wind}	
M	Relative humidity	φ	For wet cooling systems
M	Cooling water temperature	T_{cool}	For once through cooling
I[1]	Acceptable minimum/maximum mass flow	$\dot{m}_{\mathrm{min/max}}^{\mathrm{PB}}$	
I[1]	Tolerated maximum inlet temperature gradient	$T_{\mathrm{in,grad,max}}^{\mathrm{PB}}$	
I[1]	Tolerated maximum mass flow gradient	$\dot{m}_{\mathrm{grad,max}}^{\mathrm{PB}}$	
I[1]	Set point gross electric production	$P_{\mathrm{gross,set}}^{\mathrm{PB}}$	
R	Power block thermal power	$\dot{Q}^{\mathrm{PB}}$	
R	Exhaust thermal power*	$\dot{Q}_{\mathrm{ex}}$	
R	Extraction thermal power*	$\dot{Q}_{\mathrm{ext}}$	Only for systems with process heat extraction.

[1] Usage as interface variable depends on the implementation and the operation strategy. Set-up shown here reflects methodology proposed by this guideline.
[2] Specific enthalpy can be used instead of temperature. In this case the inlet and outlet temperatures should be provided as reporting variables.

6.2. Rankine cycle power blocks

6.2.1. Relevant effects for indirect Rankine cycle power block

Rankine cycle power blocks as illustrated in Figure 6-2 are a complex combination of steam generator components, turbine stages, feed-water preheaters, vessels, pumps, and the cooling system. Heat cycle simulation tools are required for the design of such a system and to calculate its part-load behavior. This section deals with indirect Rankine cycles where the steam is produced in a steam generator which is operated by the primary working fluid used in the solar/thermal energy storage cycle. The gross electric production of a Rankine cycle is determined by the inlet mass flow of the HTF, the inlet temperature of the HTF, and the cooling conditions. Depending on the temperature of the HTF available for the power block, the cycles might be equipped with a re-heater to reduce moisture content in the low pressure turbine stages and/or to increase cycle efficiency. The type of condenser (wet, dry) together with the relevant ambient conditions define the condenser pressure.

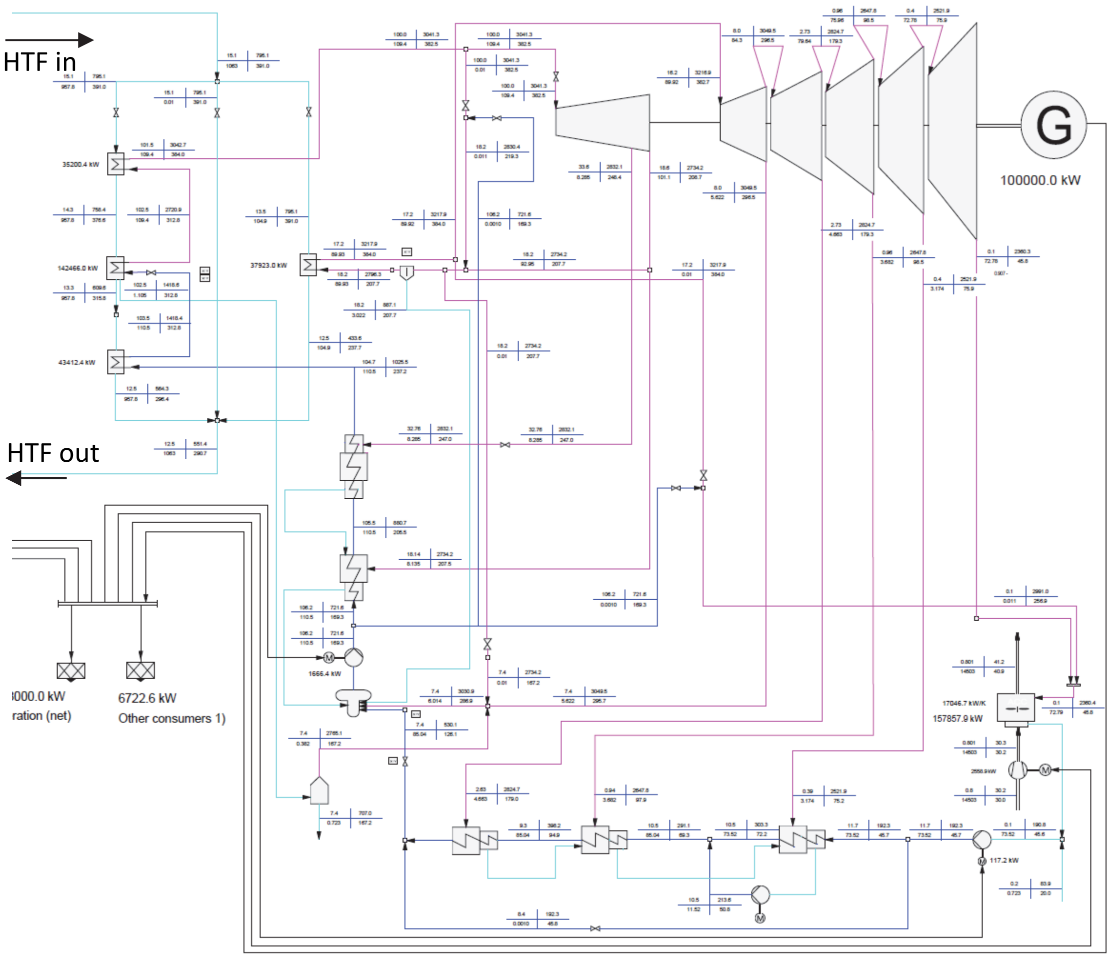


Figure 6-2: Heat flow diagram for a Rankine cycle with re-heater operated with thermal oil

For STE yield analysis, one heat cycle calculation could be executed for each time step which yields a very precise thermodynamic representation of the power block. However, this procedure is usually time consuming and often causes numerical problems. Therefore, black box models are an alternative to reduce computational effort in annual simulations. The power block of an indirect Rankine cycle can be expressed by a very limited number of relations that characterize the complex process as a whole. Based on the input variables inlet mass flow of HTF, inlet temperature of the HTF, and the cooling conditions, the output variables HTF outlet temperature, gross electrical efficiency, auxiliary electrical consumption, and the HTF outlet pressure can be determined based on the results of a parameter variation of this variables obtained from detailed heat cycle calculations. The part-load performance strongly depends on the chosen power block control strategy like sliding pressure approach, partial admission, or throttling. The results of these calculations can be shown either in form of matrices or described as functions of the input variables. Although mass flow is defined as primary interface variable of the power block sub-system,thermal power
written as

$$\dot{Q}^{\mathrm{PB}} = \dot{m}^{\mathrm{PB}} \left(h\left(T_{\mathrm{in}}^{\mathrm{PB}}\right) - h\left(T_{\mathrm{out}}^{\mathrm{PB}}\right)\right) \tag{6.1}$$

is the more significant quantity to determine the gross efficiency. For determining the auxiliary electrical consumption in the framework of performance simulations, the gross output of the power block is used because the auxiliary electrical consumption is often expressed as a percentage of the gross output. The power block gross output can be calculated based on the gross electric efficiency by

$$P_{\mathrm{gross}}^{\mathrm{PB}} = \eta_{\mathrm{gross}}^{\mathrm{PB}} \; \dot{m}^{\mathrm{PB}} \left(h\left(T_{\mathrm{in}}^{\mathrm{PB}}\right) - h\left(T_{\mathrm{out}}^{\mathrm{PB}}\right)\right) \tag{6.2}$$

The above stated efficiency is related to the power block sub-system which includes the steam generator efficiency. Since heat losses of the steam generator unit are usually small compared to its thermal power, the contribution to the efficiency related to the steam generator is approximately 1.

Although not necessarily required, it is beneficial to formulate the relations with a nominal value, indicated by “0”, and a corresponding part-load correction function, *f*. Especially for early feasibility studies, this concept allows to use typical part load curves and only modify the nominal value. High quality yield analysis, however, requires that the part load curves are obtained from detailed power block simulations since design of the components has an impact on the actual part load performance. A very generic formulation is obtained when also the input variables are normalized by their design value. Although mathematically interesting, this approach reduces the transparency in the data and hence is not recommended.
The gross efficiency thus can be expressed as a product of its nominal value and a part-load correction function that depends on the thermal load, the inlet temperature, and the cooling conditions

$$\eta_{\mathrm{gross}}^{\mathrm{PB}} = \eta_{\mathrm{gross},0}^{\mathrm{PB}} \cdot f_1\left(\dot{Q}^{\mathrm{PB}}, T_{\mathrm{in}}^{\mathrm{PB}}, T^*\right) \tag{6.3}$$

Although different cooling technologies require information on different ambient parameters, the impact of ambient parameters can be mapped to a single characteristic temperature *T**. This characteristic temperature acts as variable for the relations mentioned above. The maximum dimension of the input variables into the matrices is thus 3. Table 6-2 gives an overview which input variable information is needed to determine the characteristic temperature *T**. For wet cooling towers, the characteristic temperature is equal to the wet-bulb temperature that is obtained from the ambient air parameters.

Table 6-2: Dependency of characterictic Temperature *T** on applied cooling technology

Interface variable	Wet cooling tower	Air cooled condenser	Once through cooling
Ambient air temperature	X	X	
Atmospheric pressure	X		
Rel. humidity	X		
Water temperature			X

The gross electric efficiency $\eta_{\text{gross}}^{\text{PB}}$, or its part-load correction f_1, depends on three variables and can be expressed in various ways. Some of them are given here:

1. Three-dimensional matrix $f_1\left(\dot{Q}^{\text{PB}}, T_{\text{in}}^{\text{PB}}, T_{\text{cond}}\right)$ with appropriate interpolation between the nodes. The number of nodes in each dimension has to be chosen to well reflect the underlying curves. The main impact arises from load and cold end conditions and 10 to 20 nodes are usually appropriate to reflect the physics. The nodes have to cover the whole range of operating conditions. The impact of inlet temperature is usually smaller and can be resolved by 3 to 5 nodes. In any case, the user has to identify an appropriate number of nodes for the specific performance curves of his application. Different interpolation schemes as linear, quadratic or spline can be used to obtain values between the nodes. If higher order interpolation is applied, special care has to be spent to match the values at the boundaries of the domain.
2. Two-dimensional matrix $f_{1,\text{a}}\left(\dot{Q}^{\text{PB}}, T^*\right)$ with an additional correction factor $f_{1,\text{b}}\left(T_{\text{in}}^{\text{PB}}\right)$ for the third dimension. The correction factor should hold the variable with the lowest impact, typically the inlet temperature, compare Figure 6-4. This approach is an approximation to the precise data and validity should be checked over the whole range of parameters. Figure 6-3 shows a typical behavior of the load and wet bulb temperature for a wet cooling tower installation.
3. Multi-dimensional approximation functions can be used to fit the underlying three dimensional matrix. Due to the non-linear behavior especially in load, the type of the fitting function and the corresponding parameters have to be carefully chosen. For power block performance tests, correction curves are state of the art. In most cases, polynomial functions based on each input variable are choosen and the resulting correction factors for each variable are multiplied to obtain the resulting correction factor. This approach can be used for the yield calculation, too.

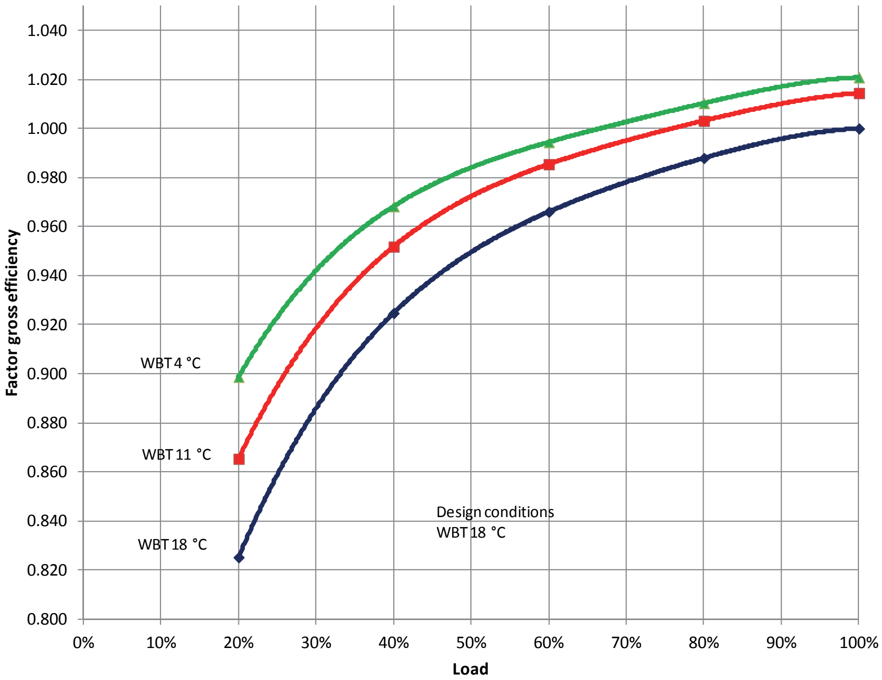


Figure 6-3: Impact of load, $\dot{Q}^{\mathrm{PB}}/\dot{Q}_0^{\mathrm{PB}}$, and wet bulb temperature on gross efficiency correction function f_1 for a thermal oil driven Rankine cycle with wet cooling tower.

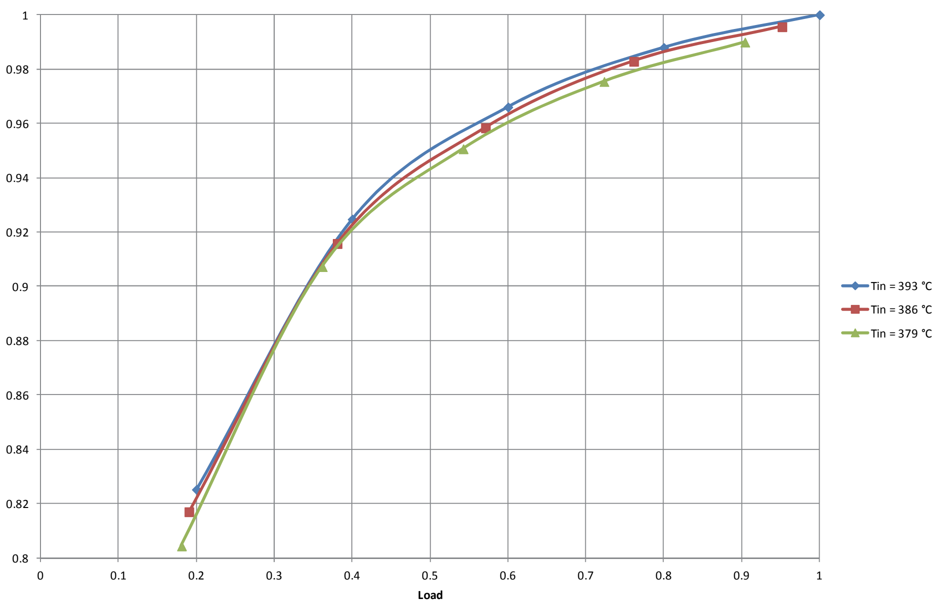


Figure 6-4:Impact of load, $\dot{Q}^{\mathrm{PB}}/\dot{Q}_0^{\mathrm{PB}}$, and inlet temperature, $T_{\mathrm{in}}^{\mathrm{PB}}$, on the gross efficiency correction function f_1 for a thermal oil driven Rankine cycle with wet cooling tower.

Figure 6-5 shows the gross effciciency plotted as a function of thermal power and mass flow. Although it is possible to express all relations in terms of HTF mass flow, the formulation with thermal power as independent variable has several advantages:

- The formulation is valid independent of the actual inlet and outlet temperature (within the usual operating conditions). While the outlet temperature is a function of load in the upper load range, many configurations stabilize the outlet temperature in the lower temperature range. This leads to a thermal load which is not proportional to the mass flow for high mass flow and a thermal load which is directly proportional to the mass flow in case of fixed outlet temperature. Therefore two approximation formulas are necessary for these conditions.
- Especially for indirect storage systems the HTF inlet temperature into the power block during discharge is significantly lower than during normal operation from the solar field while the mass flow can be higher than in normal conditions. A normalized formulation would result in values higher than 1.
- Power block correction curves are usually expressed in terms of thermal or electrical power. For consistence reasons it is beneficial to use this approach also for yield calculation.

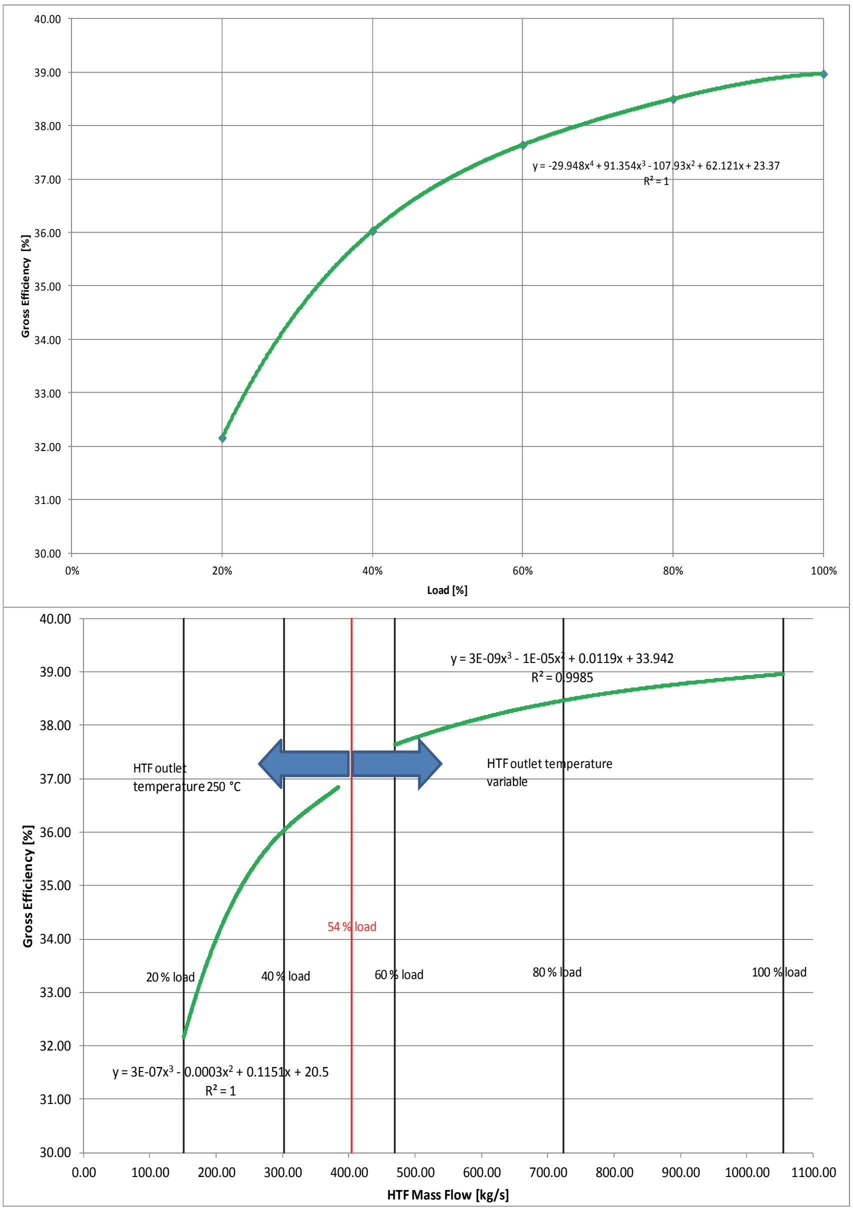


Figure 6-5: Impact of load and HTF inlet temperature on gross efficiency, $\eta_{\text{gross}}^{\text{PB}}$, for a thermal oil driven Rankine cycle. The upper figure shows the data plotted as a function of normalized thermal power, $\dot{Q}^{\text{PB}}/\dot{Q}_0^{\text{PB}}$, the lower figure as function of HTF mass flow, $\dot{m}^{\text{PB}}$.

HTF outlet temperature

A similar modeling approach can be used for the HTF outlet temperature. As a simplification, this temperature does not depend on the cooling conditions, thus a two-dimensional relation remains,

$$T_{\text{out}}^{\text{PB}} = T_{\text{out,0}}^{\text{PB}} \cdot f_2\left(\dot{m}^{\text{PB}}, T_{\text{in}}^{\text{PB}}\right) \tag{6.4}$$

Auxiliary electrical consumption

Auxiliary electrical consumption of an indirect Rankine cycle is determined by the load-dependent pumping power in the water/steam cycle and a load-independent electric consumption. Pumping power on the HTF side is considered on the system level and not in the power block sub-system. The electrical consumption can be described by a nominal value and a load-dependent correction and an additional constant consumption for load independent consumers[20],

$$P_{\text{aux}}^{\text{PB}} = P_{\text{aux,const}}^{\text{PB}} + P_{\text{gross,0}}^{\text{PB}} * f_{\text{aux}}\left(P_{\text{gross}}^{\text{PB}}, \; T^{*}\right). \tag{6.5}$$

Figure 6-6 provides exemplary part-load auxiliary consumption for different 50 MW power block configurations. It can be seen, that the load-independent fraction plays a significant role and that this part often follows a quadratic law. The actual design significantly influences the magnitude and the part-load behavior of the auxiliary consumption. An adaption to the design under investigation is always required. Especially for air cooled condensers, the electric consumption strongly depends on the ambient temperature, since the temperature determines the required volume flow of cooling air.

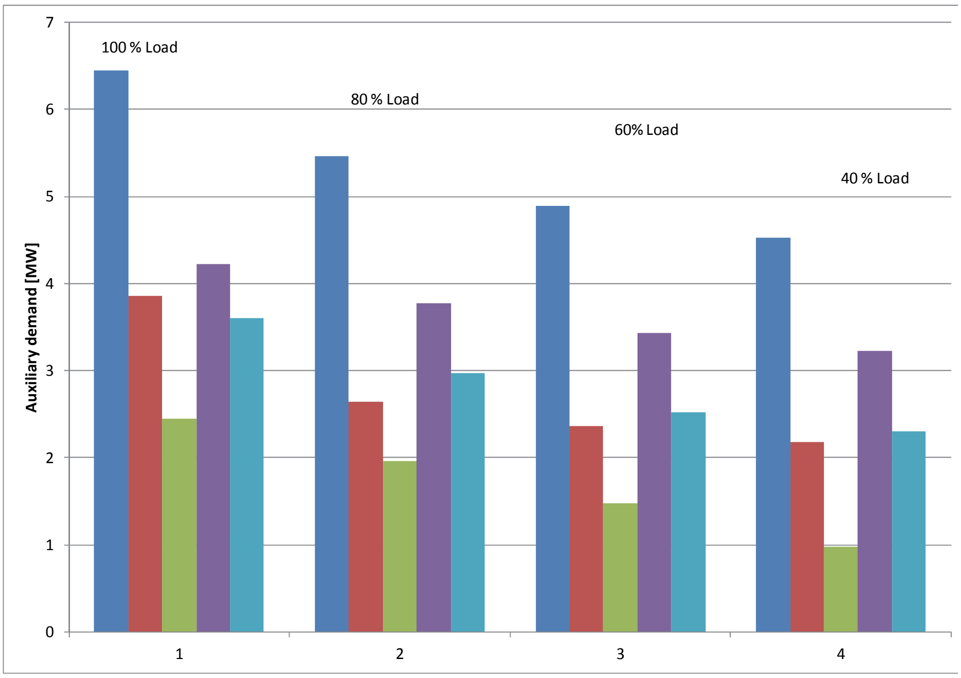


Figure 6-6:Auxiliary electrical consumption for different electrical load cases of a 50 MW power block equipped with ACC. The five bars refer to different designs of the same configuration.

[20] Load indepenent consumers are e.g. illumination, control system equipment, pumps needed for circulating fluids apart from the main fluid paths.

Pressure losses in the HTF path of the power block

For the calculation of overall HTF pumping power, the sub-system power block has to specify the pressure losses in the HTF path of the steam generator as a function of actual operating conditions

$$p_{\mathrm{in}}^{\mathrm{PB}} - p_{\mathrm{out}}^{\mathrm{PB}} = \Delta p_0^{\mathrm{PB}} * (\dot{m}^{\mathrm{PB}} / \dot{m}_0^{\mathrm{PB}})^2 . \tag{6.6}$$

The dominating impact is the HTF mass flow while the temperature level is usually neglected since it has only minor impact on the fluid properties like density and viscosity.

Transients

High operating pressure of the water/steam cycle requires thick wall materials of piping, vessels and turbine components. This creates significant thermal inertia and limitations in tolerated ramp rates. The start-up process of a Rankine cycle steam generator and water/steam cycle is a complex procedure that cannot be handled in detail in a yield analysis tool. However, the impact of inertia and limitations on yield has to be taken into account by appropriate simplifications. The following approaches are suitable to model these impacts:

- Ramp rate restrictions result in a minimum time the power block needs to be heated up. This time constraint has to be considered since the power block cannot be used to produce electricity during the start-up process. Based on the time passed since last operation it is common to differentiate into cold start-up (between 8 and 12 h), warm start-up (2 to 8 h) and hot start-up. Minimum start-up times should be defined for each of the categories. Depending on the operation strategy extreme cases like cold-start or very hot start might not occur and can be neglected. The indicated downtimes are approximate values and have to be adapted to the design of the plant.
- The amount of thermal energy required to heat up the power block has to be estimated since it is lost energy and not available for electricity production. It is useful to model the required amount of energy in relation to the state of the power block by applying a cool-down curve.
- Load changes during power block operation are usually not required to model since they take place quite fast and energy amounts during change of operation load are small compared to overall power. Positive and negative contributions typically cancel out over the day.

6.2.2. Rankine cycles with oil as heat transfer fluid

Rankine cycle power blocks operated with thermal oil as heat transfer medium are a typical representative of Rankine cycle systems. All modeling aspects described in the above chapter are applicable to this technology. Due to the limited temperature of thermal oil the power block needs to be equipped with a reheater in order to avoid critical moisture in the low pressure turbine and to increase the Rankine cycle efficiency. To avoid very low HTF outlet temperatures a by-pass is necessary to control the HTF outlet temperature.

6.2.3. Rankine cycles with molten salt as heat transfer fluid

Rankine cycle power blocks operated with molten salt as heat transfer medium allow higher live steam temperatures leading to higher thermal efficiency. To avoid freezing of the molten salt in part load operation an additional feedwater preheater operated with high pressure steam is necessary.

7. Modeling the sub-system Thermal Energy Storage (TES)

The thermal energy storage system is the sub-system that makes STE plants attractive compared to solar photovoltaic plants. Depending on the heat transfer fluid used in the solar field in its process parameters a variety of storage technologies can be applied for STE systems. The following criteria can be used to categorize the storage concepts:

- Direct and indirect storage systems
  - Direct storage use the primary heat transfer fluid as storage medium.
  - Indirect storage systems use a distinct storage medium. Thus a heat transfer from the primary HTF to the storage medium and vice versa is required. This category can be sub-divided into
    - Direct contact heat exchange, i.e. primary HTF and storage medium are in direct contact (e.g. air-rocks)
    - Indirect contact heat exchange, i.e. the heat transfer take space via an heat exchanger (e.g. thermal oil-molten salt)
- Sensible or latent heat storage
  - Sensible heat storage systems heat up the storage medium, thus make use of sensible heat (e.g. molten salt, solid particles)
  - Latent heat storage media make use of a phase change of the storage material (usually from solid to liquid) and thus store by means of latent heat.
- Phase of the storage material
  - Liquid storage systems use a liquid as storage medium, e.g. molten salt
  - Solid storage systems make use of solid storage materials.

This classification helps to define structured modeling approaches for the thermal storage system. The following chapters first introduce a generic sub-system interface and the most important reporting variables before explaining modeling principles for two-tank molten salt storage systems, both direct and indirect.

7.1. Generic sub-system interface and variable definition

In contrast to the other sub-systems the thermal energy storage shows two distinct operation modes which are

- Charge operation indicated by index “ch”
- Discharge operation indicated by index “disch”

Depending on the storage technology, charging and discharging can be realized by means of the same flow path, i.e. same piping, or by individual flow paths for charge and discharge fluid flow. A generic interface definition is obtained if the two flow paths are considered separately. Thus, the storage system interface incorporates four distinct fluid interfaces (compared to two for the other sub-systems):

- Charge operation inlet
- Charge operation outlet
- Discharge operation inlet
- Discharge operation outlet

Thus, temperature and pressure variables are foreseen at each of the interfaces as illustrated in Figure 7-1 and listed in Table 7-1. It can usually be assumed that mass flow entering and leaving is equal so only one mass flow is defined at the interface for charge, $\dot{m}_{\mathrm{ch}}^{\mathrm{TES}}$, and discharge, $\dot{m}_{\mathrm{disch}}^{\mathrm{TES}}$, operation. As a result of mass flow, temperatures, and pressures the thermal charge and discharge power is obtained, as

$$\dot{Q}_{\mathrm{ch}}^{\mathrm{TES}} = \dot{m}_{\mathrm{ch}}^{\mathrm{TES}} \left(h_{\mathrm{ch,in}}^{\mathrm{TES}}\left(T_{\mathrm{ch,in}}^{\mathrm{TES}}, p_{\mathrm{ch,in}}^{\mathrm{TES}}\right) - h_{\mathrm{ch,out}}^{\mathrm{TES}}\left(T_{\mathrm{ch,out}}^{\mathrm{TES}}, p_{\mathrm{ch,out}}^{\mathrm{TES}}\right) \right) \tag{7.1}$$

$$\dot{Q}_{\mathrm{disch}}^{\mathrm{TES}} = \dot{m}_{\mathrm{disch}}^{\mathrm{TES}} \left(h_{\mathrm{disch,out}}^{\mathrm{TES}}\left(T_{\mathrm{disch,out}}^{\mathrm{TES}}, p_{\mathrm{disch,out}}^{\mathrm{TES}}\right) - h_{\mathrm{disch,in}}^{\mathrm{TES}}\left(T_{\mathrm{disch,in}}^{\mathrm{TES}}, p_{\mathrm{disch,in}}^{\mathrm{TES}}\right) \right) . \tag{7.2}$$

Please note that both, charge and discharge power, have a positive sign. The mass flow as interface variable is crucial for the thermal storage system since the state of charge depends on both, mass flow and associated temperature (sometimes also pressure). The storage system loses energy to its surroundings. The corresponding thermal power is indicated by $\dot{Q}_{\mathrm{HL}}^{\mathrm{TES}}$.

Table 7-1: Generic interface (I), meteorological (M) and reporting (R) variables valid for thermal storage systems (*indicates variables that might not be available for all types modeling approaches)

Type	Name	Symbol	Comment
I	Charge operation inlet temperature [1]	$T_{\mathrm{ch,in}}^{\mathrm{TES}}$	
I	Discharge operation inlet temperature [1]	$T_{\mathrm{disch,in}}^{\mathrm{TES}}$	
I	Charge operation inlet pressure	$p_{\mathrm{ch,in}}^{\mathrm{TES}}$	
I	Discharge operation inlet pressure	$p_{\mathrm{disch,\ in}}^{\mathrm{TES}}$	
I	Charge operation mass flow	$\dot{m}_{\mathrm{ch}}^{\mathrm{TES}}$	
I	Discharge operation mass flow	$\dot{m}_{\mathrm{disch}}^{\mathrm{TES}}$	
I	Auxiliary electrical demand	$P_{\mathrm{aux}}^{\mathrm{TES}}$	
I	Minimum/maximum tolerated charge operation mass flow [2]	$\dot{m}_{\mathrm{ch,\ min/max}}^{\mathrm{TES}}$	
I	Minimum/maximum tolerated discharge operation mass flow [2]	$\dot{m}_{\mathrm{disch,\ min/max}}^{\mathrm{TES}}$	
M	Ambient temperature	T_{amb}	
R	Charge thermal power	$\dot{Q}_{\mathrm{ch}}^{\mathrm{TES}}$	greater/equal 0
R	Discharge thermal power	$\dot{Q}_{\mathrm{disch}}^{\mathrm{TES}}$	greater/equal 0
R	Charge operation outlet temperature [2]	$T_{\mathrm{ch,out}}^{\mathrm{TES}}$	
R	Discharge operation outlet temperature [2]	$T_{\mathrm{disch,out}}^{\mathrm{TES}}$	
R	Charge operation outlet pressure	$p_{\mathrm{ch,out}}^{\mathrm{TES}}$	
R	Discharge operation outlet pressure	$p_{\mathrm{disch,\ out}}^{\mathrm{TES}}$	

R	Actual energy content	$C^{\mathrm{TES,t}}$	
R	Thermal heat loss power	$\dot{Q}_{\mathrm{HL}}^{\mathrm{TES}}$	
R	Limitation mass flow charging operation [3]	$\dot{m}_{\mathrm{lim,ch}}^{\mathrm{TES}}$	
R	Limitation mass flow discharging operation [3]	$\dot{m}_{\mathrm{lim,disch}}^{\mathrm{TES}}$	

[1] Specific enthalpy can be used instead of temperature. In this case the inlet and outlet temperatures should be provided as reporting variables.
[2] Usage as interface variable depends on the implementation and the operation strategy. Set-up shown here reflects methodology proposed by this guideline.
[3] The limitation mass flow is used for the control logic of the yield calculation for the next time step. This might can be done in another suitable way.

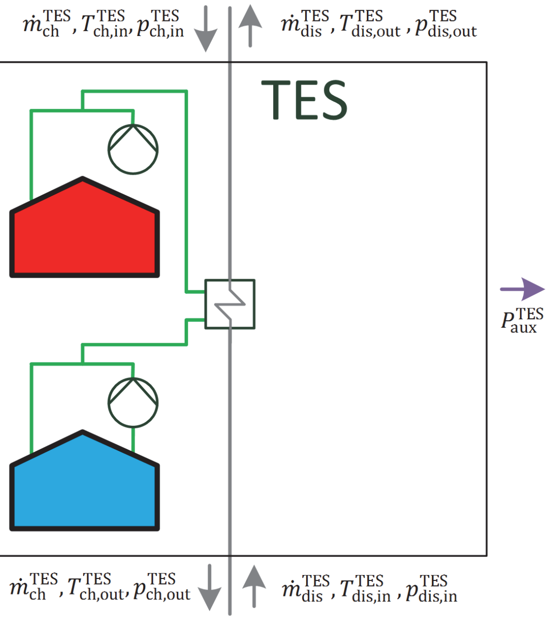


Figure 7-1 Illustration of generic variables for the sub-system solar field for direct and indirect thermal storage systems

The state of charge $f_{\mathrm{SOC}}^{\mathrm{TES}}$ of a thermal energy system describes the energy level of the TES system and is calculated by the actual energy content $\mathrm{C}^{\mathrm{TES,t}}$ divided by the rated thermal capacity $\mathrm{C}_0^{\mathrm{TES}}$ of the storage system,

$$f_{\mathrm{SOC}}^{\mathrm{TES}} = \frac{C^{\mathrm{TES}}}{C_0^{\mathrm{TES}}} \quad . \tag{7.3}$$

The state of charge is used for a normalized evaluation of the TES. The energy content depends on the temperature or temperature profile in the storage and may also depend on the mass of storage material if a direct storage system is used.

7.2. Two-tank molten salt storage systems

Two-tank molten salt storage systems are used as direct storage in molten salt solar towers or molten salt line focusing systems. They can also be applied as indirect storage for solar cycles operated with another heat transfer medium like thermal oil. Section 7.2.1 describes the relevant effects for direct storage configurations. Section 7.2.2 extends the approach to indirect storage configurations with additional heat exchanger.

7.2.1. Direct two-tank molten salt storage systems

The two-tank direct molten salt storage system consists of two tanks, one for storage of cold molten salt and one for storage of the hot molten salt. High capacity storages encounter multiple cold and hot tanks since size of a single tank is limited. During charge operation, fluid from the cold tank is heated in the solar field and stored in the hot tank. For discharge, hot fluid is extracted from the hot tank, used for electricity production, and stored as cold fluid in the cold tank. The following effects need to be considered when modelling a direct two-tank molten salt storage system.

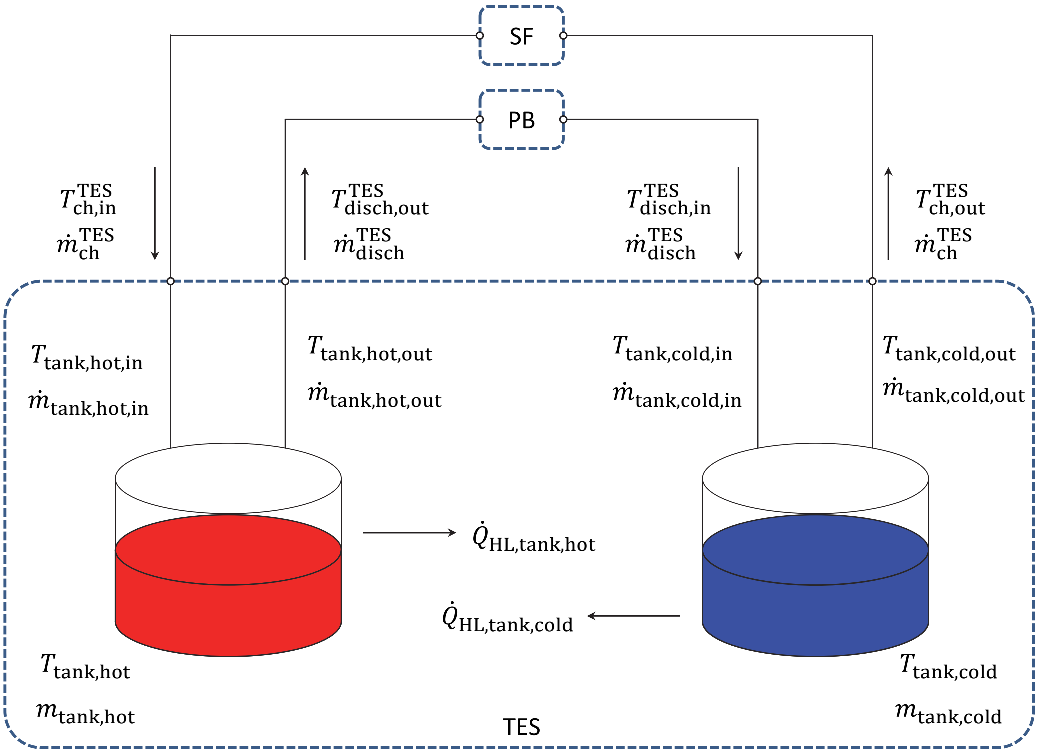


Figure 7-2 Scheme of a two-tank direct molten salt storage system

For direct storage systems, the mass flows and temperatures at the tank boundaries are directly related to the thermal energy storage interface variables as

$$\dot{\boldsymbol{m}}_{\mathrm{ch}}^{\mathrm{TES}} = \dot{\boldsymbol{m}}_{\mathbf{tank,hot,in}} \qquad \boldsymbol{T}_{\mathrm{ch,in}}^{\mathrm{TES}} = \boldsymbol{T}_{\mathrm{tank,hot,in}} \qquad \boldsymbol{h}_{\mathrm{ch,in}}^{\mathrm{TES}} = \mathbf{h}_{\mathrm{tank,hot,in}}$$

$$\dot{m}_{\mathrm{ch}}^{\mathrm{TES}} = \dot{m}_{\mathrm{tank,cold,out}} \qquad T_{\mathrm{ch,out}}^{\mathrm{TES}} = T_{\mathrm{tank,cold,out}} \qquad h_{\mathrm{ch,out}}^{\mathrm{TES}} = h_{\mathrm{tank,cold,out}}$$

$$\dot{m}_{\mathrm{disch}}^{\mathrm{TES}} = \dot{m}_{\mathrm{tank,cold,in}} \qquad T_{\mathrm{disch,in}}^{\mathrm{TES}} = T_{\mathrm{tank,cold,in}} \qquad h_{\mathrm{disch,in}}^{\mathrm{TES}} = h_{\mathrm{tank,cold,in}}$$

$$\dot{m}_{\mathrm{disch}}^{\mathrm{TES}} = \dot{m}_{\mathrm{tank,hot,out}} \qquad T_{\mathrm{disch,out}}^{\mathrm{TES}} = T_{\mathrm{tank,hot,out}} \qquad h_{\mathrm{disch,out}}^{\mathrm{TES}} = h_{\mathrm{tank,hot,out}}$$

The energy content $C^{\mathrm{TES,t}}$ and thus the state of charge $f_{\mathrm{SOC}}^{\mathrm{TES}}$ for a direct molten salt storage system is determined by the usable mass of storage material in the hot tank and the difference between the hot tank enthalpy and the nominal enthalpy of the cold storage tank,

$$C^{\mathrm{TES}} = \left(m_{\mathrm{tank,hot}} - m_{\mathrm{tank,min,hot}}\right) \cdot \left(h_{\mathrm{tank,hot}} - h_{\mathrm{tank,cold,0}}\right) . \tag{7.4}$$

Deviations from the nominal tank temperature originate from heat losses over the tank surface and deviations of the hot fluid temperature during charge operation. Although the intention is to charge the storage at its nominal temperature (use full storage capacity and enable efficient conversion of thermal into electric energy) circumstances in the individual configuration might lead to a loading with lower temperature.

For yield analysis purpose, it is sufficient to model the storage material with a homogeneous temperature. In case strong layering effects are present due to special tank configurations (e.g. thermocline storage tanks) a more detailed approach with a local discretization of the storage material might be required.

Modeling the charge and discharge process

During charge, discharge, and stand-still the energy content of the storage system changes. In direct systems more than one process can happen at the same time. Depending on the technical configuration the following assumptions are typically appropriate:

1. The mass flow entering the hot tank is the same as the mass flow leaving the cold tank and vice versa. This assumption holds as long as the mass storage effect in the connected sub-systems SF and PB is negligible.
2. The mass flow leaving either one of the storage tanks has the same temperature as the storage tank itself. This assumption holds as long as we can assume a homogeneous temperature across the tank inventory.

With these assumptions the change of specific enthalpy in the hot and cold tank during one time step Δt can be calculated from

$$h_{\mathrm{tank,hot}}^{\mathrm{t}} = \frac{m_{\mathrm{tank,hot}}^{\mathrm{t-\Delta t}} \cdot h_{\mathrm{tank,hot}}^{\mathrm{t-\Delta t}} + \left(\dot{m}_{\mathrm{tank,hot,in}} \cdot h_{\mathrm{tank,hot,in}} - \dot{Q}_{\mathrm{HL,tank}}\right) \cdot \Delta t}{m_{\mathrm{tank,hot}}^{\mathrm{t}}} \tag{7.5}$$

The changes are modeled on a time step basis using the specific enthalpies of the two tanks at the end of the last time step $t - \Delta t$, the fluid streams entering the tanks, and the heat losses of the tanks. A mean tank temperature can be calculated for the actual time step from the arithmetic mean of temperature at the beginning and ending of the time step. A precise formulation is obtained when using the specific enthalpies which already take into account variations of specific heat capacity with temperature

$$h_{\mathrm{tank,hot,mean}}^{\mathrm{t}} = \frac{h_{\mathrm{tank,hot}}^{\mathrm{t}} + h_{\mathrm{tank,hot}}^{\mathrm{t-\Delta t}}}{2} \; . \tag{7.6}$$

This mean temperature over the time step can be used to calculate the heat losses and the temperature of fluid streams leaving the tanks. The new state of charge after the charge or discharge process is then given by

$$C^{\mathrm{TES,t}} = C^{\mathrm{TES,t-\Delta t}} + \left(\dot{Q}^{\mathrm{TES}} + P_{\mathrm{AF}} - \dot{Q}_{\mathrm{HL,tank}}\right) \cdot \Delta\mathrm{t} \; . \tag{7.7}$$

The term P_{AF} refers to any amount of electric energy that is used to heat up the tanl content, e.g. for anti-freeze purposes.

Thermal losses of storage tank

The thermal losses of the storage containment shall consider the following effects:

- Thermal losses to the ambient air by conduction and convection
- Thermal losses to the ground through the foundation (including potential active cooling of the foundation)

The effect of the thermal losses is expressed by the according temperature reduction of the storage medium in the according containments. If not modeled in larger detail, the thermal losses in design conditions can be treated as a system parameter and are usually expressed in a normalized form. In most cases the design thermal losses can directly be applied regardless of the state of charge or dependence on the tank status.

Auxiliary electrical consumption

The direct two tank molten salt system is a passive device. Fluid flow is initiated by the molten salt pumps on system level. Other auxiliary consumers are usually negligible. As the main auxiliary electrical consumption the electric freeze protection heaters of the storage tanks need to be considered for the yield assessment. Other auxiliary consumers are usually negligible.

Pressure losses in the storage system

The connecting piping for the storage system is short and the resulting frictional pressure losses small compared to the rest of the system. They are usually neglected. While pumping molten salt from one tank to the other, a geodetic pressure difference occurs. If the tank level in the source tank is lower than the one in the target tank the pump has to provide this additional power. With the other way round, the tank produces a geodetic pressure head which helps the pump to move the fluid. Although on a time step basis, an alternating positive and negative impact on the pumping power exists, the contribution approximately cancel out on an annual basis. Thus, they can usually be neglected.

Transients

The two-tank storage system itself does not show and limitations in transients. Ramp-up times of molten salt pumps are rather faster and need not be considered explicitely. The only transient effect to be considered is the charge/discharge process itself as already described above.

7.2.2. Indirect two-tank molten salt storage systems

The storage tanks for an indirect system are very similar to the ones for a direct system in section 7.2.1. However, the additional heat exchanger between the primary heat transfer fluid in the solar cycle and the fluid of the storage system makes a difference in terms of temperatures and mass flows. Additional modeling equations are required to represent:

- Temperature difference between primary and secondary fluid cycle due to the heat exchange
- Heat losses of the heat exchanger installation to the surroundings
- Mass flows at the interfaces are not the same as at the tanks inlet and outlets
- Pumping power for the molten salt cycle
- Pressure loss in the HTF path of the heat exchanger

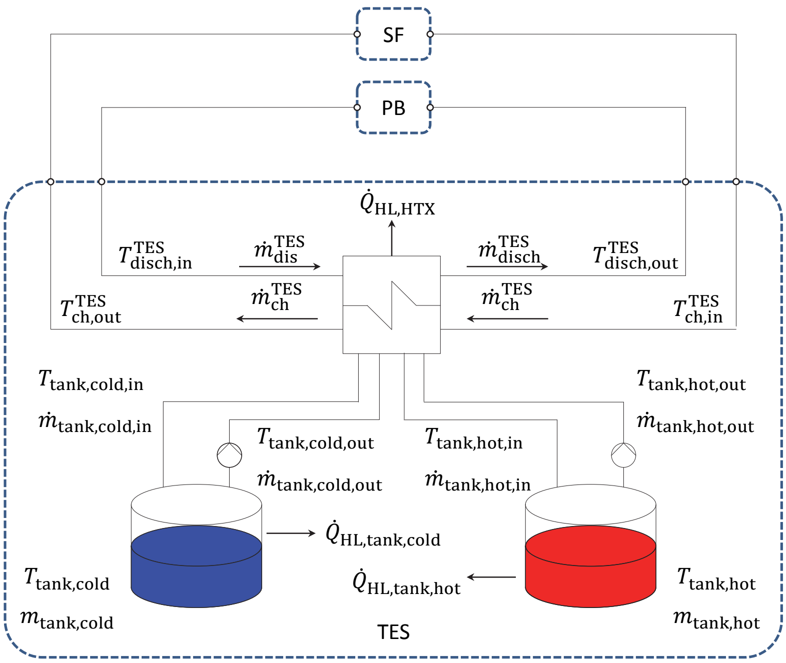


Figure 7-3 Scheme of a two-tank indirect molten salt storage system

Thermal losses of the heat exchanger

The thermal losses of the heat exchanger (HTX) consider the thermal losses to ambient by conduction and convection only. If the HTX is not modeled in detail with 2D or 3D physical heat loss models,the thermal losses can be specified at design conditions. Normalizing them to the design power of the HTX enables to define generally applicable values. Since these losses only depend on the temperature of the HTX, part load conditions have to be considered only if the HTX cools down. Due to high efficiencies of current HTX, the losses are kept very low and it might be checked if they could even be neglected for yield analysis.

Temperature losses in heat exchanger

Heat transfer in the HTX is driven by a temperature difference between the hot and the cold fluid. Thus, the temperature of the fluid on the cold side is accordingly lower than the fluid temperature on the hot side. During charge operation with a primary fluid of temperature $T_{\mathrm{ch,in}}^{\mathrm{TES}}$ the hot tank is charged with a temperature $T_{\mathrm{tank,hot,in}} < T_{\mathrm{ch,in}}^{\mathrm{TES}}$. When discharged, the primary fluid will reach a temperature of $T_{\mathrm{disch,out}}^{\mathrm{TES}} < T_{\mathrm{tank,hot,out}}$. This double temperature difference leads to a change of exergy between the charging and discharging stream. Usually, these temperature difference effects cannot be neglected since they have impact on efficiency and maximum load of the steam generator and turbine.

Partial load behavior of the heat exchanger

For yield analysis purpose it is sufficient to fix a nominal temperature difference for design conditions, which can be the same or different for the hot and cold sides of the HTX. Since the temperature differences are reduced in off-design conditions, when the mass flows are reduced, the provided temperature differences may be modified depending on the mass flows or load during the simulation. Adding the heat exchanger increases the modeling complexity.

The modeling approach via the mean logarithmic temperature difference (LMTD) for indirect storage systems with an additional heat exchanger is complex and results in a comprehensive set of equations with several iteration loops. Due to this, it is possible to use other modeling approaches like the ε-NTU method[21]. This method is often used for the description of part load behavior of heat exchangers of STE systems with indirect storage. For this method, an equation for the part load behavior of heat exchangers with counter-current flow arrangement is needed[22]. A clear disadvantage of this method is the fixed behavior of the heat exchanger equation, which cannot be adapted to given manufacturer partial load characteristic. For that reason, the guideline proposes the modeling approach via the logarithmic temperature difference and the required iteration process.

[21] Wagner, M. J.; Gilman, P.: *Technical Manual for the SAM Physical Trough Model.* Technical Report, NREL/TP-5500-51825, June 2011.

[22] Nellis, G.; Klein, S.: *Heat Transfer.* Cambridge University Pres, New York, USA, 2009.

Auxiliary electrical consumption

The main auxiliary electrical consumption results from the molten salt pumps. This pumps needs to compensate the pressure loss at the molten salt side of the heat exchanger of the indirect two-tank molten salt storage. Other relevant auxiliary consumers are the anti-freeze heater, already discussed within the direct two-tank molten salt storage. Other auxiliary consumption is negligible.

Pressure losses in the storage system

The heat exchanger required for indirect storage systems causes a pressure loss on its primary and secondary side. For the sub-system interface, the pressure drop at the HTF side is the relevant one since it needs to be overcome by the main HTF pumps associated with the system level. The calculated or estimated pressure loss at design conditions is adapted by the following equations to part load conditions of the indirect tow-tank molten salt storage

$$p_{\mathrm{ch,in}}^{\mathrm{TES}} - p_{\mathrm{ch,out}}^{\mathrm{TES}} = \Delta p_{\mathrm{ch,0}} \left(\frac{\dot{m}_{\mathrm{ch}}^{\mathrm{TES}}}{\dot{m}_{\mathrm{ch,0}}^{\mathrm{TES}}} \right)^2 \tag{7.8}$$

$$p_{\mathrm{disch,in}}^{\mathrm{TES}} - p_{\mathrm{disch,out}}^{\mathrm{TES}} = \Delta p_{\mathrm{disch,0}} \left(\frac{\dot{m}_{\mathrm{disch}}^{\mathrm{TES}}}{\dot{m}_{\mathrm{disch,0}}^{\mathrm{TES}}} \right)^2 \quad . \tag{7.9}$$

Transients

In comparison to the two-tank molten salt storage, an additional heat exchanger is needed for the operation of the indirect two-tank molten salt storage. This heat exchanger has a specific heat-up rate, which is defined by the manufacturer. For the minimization of heat losses, the heat exchanger is coated with a thermal isolation against the surrounding. With a daily charging and discharging cycle, the heat exchanger is assumed to keep its operational temperature. The transient effects of the storage tanks are already considered by the described calculation procedure above. Due to this assumption, it is usually reasonable to neglect the transient behavior of the two-tank molten salt storage within a yield calculation.

8. Modeling the sub-system Auxilliary Heater (AH)

Since the primary heat source in a solar thermal power plant is fluctuating and not always available, auxiliary heat sources can be necessary to provide heat to support plant processes, e.g. to maintain power block operation or to keep critical plant processes running. Auxiliary heat can base on electricity, fossil, or bio fuels. In this chapter fuel based auxiliary heaters are addressed which either directly or indirectly heat the plant's working fluid.

8.1. Auxiliary Heater Application

Depending on plant design and operation philosophy there are different application scenarios of auxiliary heaters:

Freeze protection

Such systems are used to heat the working fluids (thermal oil and molten salt) to maintain their viscosity and to prevent crystallization under any circumstances. Regarding the installed thermal capacity those systems are rather small.

Start up support

This kind of systems help to speed up plant start up to feed electricity into the grid earlier as it would be possible by using just the available solar energy. This means that the installed capacity needs to be sufficient to provide energy to heat up the steam generating system and to produce a sufficient amount of steam in the correct quality (pressure, temperature) to be sent to the steam turbine. To reduce thermal stress situations "controlled" or planned ahead warm up of subsystems is especially important during situations when the sky clears up rapidly after a longer phase of complete cloud cover. Systems which are able to support start up cover also the functionality of freeze protection.

Production support

The auxiliary heater can also be sized in a way so that it can maintain the power block operation during the total absence of thermal energy from the solar field. This requires a thermal power installed which corresponds at least to the minimum load of the power block.

8.2. Auxiliary Heater Types

In the different kinds of STE different types of auxiliary heaters are applied. In parabolic trough plants gas fired heaters (HTF heaters) are utilized which heat the thermal oil being used as HTF. In tower plants with molten salt as HTF such heaters are not necessary because freeze protection is realized by immersion heaters placed in the storage tanks and production support is covered by thermal energy stored in large storage systems. Tower plants with volumetric receivers using air as heat transfer fluid use duct burners to facilitate fossil energy . In tower plants which use a gas turbine for electricity production with air as working fluid auxiliary heat would be introduced by injecting fossil fuel directly into the gas turbine's combustion chamber.

HTF Heaters

Fired heaters usually are made up of two cylindrical sets of coiled tubing arranged concentrically to each other built into a common flue gas casing. In the 1st pass, the radiant burner chamber, the flame burns and transfers heat to the coiled tubing, through which the heat transfer medium flows, primarily via radiation. The flue gas is then diverted at the bottom of the boiler into the 2nd pass before finally being diverted into the 3rd pass. In the latter two passes the heat is transferred via convection. Since the flue gas after leaving the casing still is on a relativlely high temperature level (above the cold HTF temperature) further use can be made of it by the help of an air preheater in which the combustion air is heated up before it enters the burner chamber. This measure enhances the heater system's efficiency significantly but extra investment costs have to be considered. Whether this additional investment pays back strongly depends on the application and thus on the operation hours of the heater.

Duct Burners

Duct burners are placed in the exhaust duct of volumetric receivers to further heat up the air before it enters the steam generating system. Duct burners consist of an array of fuel manifolds to deliver the fuel into the receivers exhaust stream.

Gas turbine burners

Efficiency reasons and operational needs make a continues co-firing in solar gas turbine applications necessary. Fuel insertion is realized directly into the air flow which comes from the receiver. The fuel is inserted in a conventional combustion chamber.

8.3. Generic sub-system interface and variable definition

All types of auxiliary heaters can be described by a unique, generic sub-system interface definition. It consists of an inflowing and outflowing stream. For HTF heaters this fluid stream equals the HTF to be heated. For duct burners or gas turbine internal heat supplies it is the air stream to be heated. The primary variable is the the mass flow $\dot{m}^{\mathrm{AH}}$ through the device. Imbalances between inlet and outlet mass flow caused during heat-up or cool-down processes can be neglected. The mass flow is typically prescribed by the system level. A set-point for the outlet temperature can be used if different operating conditions require different outlet temperatures. The overall plant control on system level will define the set-points for the auxiliary heater sub-system. Calculation of the pumping power needed to push the working fluid through the heater is determined on system level. The sub-system model has to provide a load dependent pressure difference between inlet and outlet. Main result values of the sub-system are the fuel consumption, the CO_2 emisions, and the effective thermal power transferred to the working fluid. For indirect heaters information on the ambient air conditions at the intake of the burner might be needed. As for all sub-systems, an auxiliary electric consumption results from the operation of the heater.

Table 8-1: Generic interface (I), meteorological (M) and reporting (R) variables valid for auxiliary heaters

Type	Name	Symbol	Comment
I	Inlet temperature [1]	$T_{\mathrm{in}}^{\mathrm{AH}}$	
I	Outlet temperature [1]	$T_{\mathrm{out}}^{\mathrm{AH}}$	
I	Inlet pressure	$p_{\mathrm{in}}^{\mathrm{AH}}$	
I	Outlet pressure	$p_{\mathrm{out}}^{\mathrm{AH}}$	
I	Mass flow	$\dot{m}^{\mathrm{AH}}$	
I	Auxiliary electrical demand	$P_{\mathrm{aux}}^{\mathrm{AH}}$	
I	Set point for outlet temperature	$T_{\mathrm{out,set}}^{\mathrm{AH}}$	
I	Acceptable minimum/maximum mass flow	$\dot{m}_{\mathrm{min/max}}^{\mathrm{AH}}$	
R	Auxiliary heater thermal power	$\dot{Q}^{\mathrm{AH}}$	
R	Fuel mass flow	$\dot{m}_{\mathrm{fuel}}$	
(R)	Net calorific value of fuel	q_{NCV}	Needed as interface variable if varying fuel qualities are handled
R	Carbone dioxid mass flow	$\dot{m}_{\mathrm{CO2}}$	

[1] Specific enthalpy can be used instead of temperature. In this case the inlet and outlet temperatures should be provided as reporting variables.

8.4. Relevant effects for HTF gas heaters

Gas operated HTF heaters handle two fluid streams,

- the working fluid to be heated
- the air/fuel mixture that provides the heat .

The fluid flow interface variables as described in the last section refer to the working fluid since only this fluid stream is linked to the other sub-systems. The relevant effects to be considered for annual yield analysis are compiled in the following:

<u>Heat balance</u>

Heaters for heat transfer fluid used in the solar cycle are usually operated by natural gas or any other kind of gaseous fuel, e.g. biogas. The fuel is burnt together with ambient air. The flue gas still contains thermal energy relative to the ambient when leaving the chimney. Therefore, the thermal efficiency is limited to values below 100 %. The thermal power delivered by the heater to the HTF can be expressed in terms of the net calorific value, q_{NCV}, the fuel mass flow, $\dot{m}_{\mathrm{fuel}}$, and the thermal efficiency, η_{AH}, as

$$\dot{Q}_{\mathrm{AH}} = \eta_{\mathrm{AH}}\, \dot{m}_{\mathrm{fuel}}\, q_{\mathrm{NCV}} \,. \tag{8.1}$$

Special care should be spent on the selection of the correct net calorific value, since large differences exist even within one class of fuels (e.g. typical values for natural gas range between 36 to 50 MJ/kg). The equation above is formulated using the net calorific value q_{NCV} since the water content after the combustion process is in gaseous form. However, in certain countries it is usual to use q_{GCV} (gross calorific value). The difference between the physical meaning of both values needs to be borne in mind. Thermal power and mass flow are linked by the relation

$$\dot{Q}_{\mathrm{AH}} = \dot{m}^{\mathrm{AH}}\,\bar{c}_{\mathrm{p,HTF}}\left(T_{\mathrm{out}}^{\mathrm{AH}} - T_{\mathrm{in}}^{\mathrm{AH}}\right). \qquad (8.2)$$

<u>Heater efficiency</u>

The thermal efficiency of the process depends on the thermal load and the inlet temperature of the HTF. Usage of a nominal efficiency and a part-load correction is recommended for modeling,

$$\eta_{\mathrm{AH}} = \eta_{\mathrm{AH,0}}\; f_{\eta}\left(\dot{Q}^{\mathrm{AH}}\right). \qquad (8.3)$$

Relative humidity does not have to be taken into account due to its practical irrelevance with respect to the heater efficiency. Ambient temperature is recorded and processed during acceptance measurements but has a neglegtable influence on heater efficiency.

The dominating energy losses are the thermal losses across the heater surface and the thermal energy content of the flue gas, which is lost after exhausting to the ambience. In case the heater system is equipped with an air-preheater and the excess air rate is kept constant, the flue gas exhaust temperature can be kept nearly constant for all heater loads. However, since HTF outlet temperature shall be kept constant - independent of heater load - the absolut heat losses across the heater surface remain the same. Due to the lower HTF massflow at lower loads, the relative heat losses increase which leads to an efficiency decrease. On the other hand, heat transfer improves because of the relative increase of heat transfer area. Roughly 1 % of the heater's nominal thermal power is lost via the heater's outer surface. Given that HTF heaters have efficiencies higher than 90 %, those losses account for about 10 % of the total losses. This means that about 90 % of the losses are related to the flue gas. As the flue gas temperature can be kept nearly constant by the air-preheater the percentaged flue gas loss is constant across the the heater load. Thus, the heater efficiency can be considered as constant down to low thermal loads without impacting the calculated annual amount of fuel consumption significantly. However, in case that detailed vendor information regarding the exact efficiency behavior is available, this information might be used in the simulation model. Normally, power plants are equipped with several units of the same size or different sizes because of redundancy reasons. That's why heater load can be reduced down to relatively small values with respect to the total installed capacity, which means that the influence of load level on heater efficiency is further reduced.

Emissions

The dominant emmissions in gas fueled combustion processes are nitrogen oxides and carbon oxides, which are harmful substances and carbon dioxide. All auxiliary heater systems must be designed in a way that local emission limits are met. Carbon dioxide emissions which might be of interest regarding regulatory issues can be calculated by using the emission factor (t CO_2/GJ). The emission factor is related to the utilized fuel Net calorific value. For natural gas, values of about 0,056 t CO2/GJ are common. In any case, the correct emission factor needs to be applied.

Auxiliary electric consumption

Pumping power on the HTF side is considered on the system level and not in the auxiliary heater sub-system. The main source for auxiliary electric consumption is the power of the fans needed to push the air through the burning chamber. This electric consumption can be described by a nominal value and a load-dependend correction in case that the fan drive is equipped with a frequency converter and an additional constant consumption for load independent consumers,

$$P_{\mathrm{aux}}^{\mathrm{AH}} = P_{\mathrm{aux,0}}^{\mathrm{AH}} \quad f_{\mathrm{aux}}\left(\dot{Q}^{\mathrm{AH}}\right) \frac{\eta_{aux,0}^{AH}}{\eta_{aux}^{AH}(\dot{Q}^{\mathrm{AH}})} + P_{\mathrm{aux,BL}}^{\mathrm{AH}} \,. \tag{8.4}$$

$P_{\mathrm{aux,BL}}^{\mathrm{AH}}$ stands for auxiliary base load which covers control cabinet, valve drives, measurement devices etc. With respect to annual yield analysis this consumption is negligible.

The nominal fan power is normally stated in the data sheets for heater systems. In case the heater does not possess a fan with variable speed, the nominal power stays the same independent of the load level. The power reducing effect of a variable speed drive can be modeled using

$$f_{\mathrm{aux}} = f\left(\frac{\dot{Q}^{\mathrm{AH}}}{\dot{Q}_0^{\mathrm{AH}}}\right)^3, \tag{8.5}$$

wherein index 0 stands for nominal load. Fan power can be written as the product of pressure increase and volume flow. Pressure difference is proportional to the second power of fluid speed and volume flow is propotional to fluid speed. That is why fan power is proportional to the third power of the air volume flow the fan produces which is equivalent to the heater load.

$\eta_{\mathrm{aux}}^{\mathrm{AH}}$ stands for the efficiency of the auxiliary heater's fan depending on its operating point. In case that the fan is equipped with a frequency converter, rotational speed is adjusted to the heater's load. The fan's design aims for a maximum of fan efficiency when it is operated at the nominal volume flow. In case the fan's volume flow is decreased to deliver air for heater part load its efficiency decreases as well. If detailed information based on vendor data is available such decrease should be considered according to the equation 8.5.

Pressure loss of the HTF path

For calculation of overall HTF pumping power requirements the sub-system auxiliary burner has to specify the pressure drop in the HTF path as a function of actual operating conditions.

$$p_{\mathrm{in}}^{\mathrm{AH}} - p_{\mathrm{out}}^{\mathrm{AH}} = \Delta p_0 \; f_{\mathrm{p}}\left(\dot{Q}^{\mathrm{AH}}\right). \tag{8.6}$$

The nominal pressure loss inside the coiled tubing can be taken from the heater data sheet or calculated indepentently in case total length, inner diameter and surface conditions are known. Due to the large coil diameter the coil can be considered and calculated as a straight pipe. The dominating impact on the pressure loss is the HTF mass flow while the temperature level has some impact on the fluid properties like density and viscosity. The load dependent pressure loss reduction can be modeled using

$$f_{\mathrm{p}} = f\left(\frac{\dot{Q}^{\mathrm{AH}}}{\dot{Q}_0^{\mathrm{AH}}}\right)^2, \tag{8.7}$$

wherein index 0 stands for nominal load.

Transient effects

Due to thermal inertia (steel mass and HTF inventory) and ramp rate restrictions, HTF heaters require a start-up process. For STE yield analysis a detailed dynamic modeling of the start-up and cool-down behavior is usually not required. The reasoning behind this simplification is

- If the heater is used as a start-up or anti-freeze heating device the equipment can be heated prior to its usage. The expected time when heat is required can well be foreseen at least from time step to time step.
- If the heater is used in a stand-by mode to fastly compensate for any reductions in heat input from the solar field the heater needs to be kept warm and it can more or less instantaneously be ramped up to full load.
- Technical heaters usually apply an internal bypass for pre-heating so the start-up process can be realized independent from the rest of the plant. Strong interactions do not exist and do not need to be modeled.

Although a detailed modeling of start-ups is usually not required the impact of start-up fuel consumption has to be considered. The recommended option is to add a certain amount of fuel within the time step the heater is first used to provide heat to the process. Since only integral values of fuel consumption are of relevance an precise time resolution of the fuel usage is not required. Depending on the cool-down behavior and typical scheduling of heater operation the additional amount of fuel can be assumed as constant or can be described as dependent from the cool-down state (only for devices that are not constantly held in stand-by mode).

9. Modeling the sub-system Electrical (EL)

Electric consumption of all components in the plant has significant impact since it reduces the gross electricity production to a net and finally a grid value which is available for feeding into the grid. In the following, the general approach how to consider electric consumption in the various sub-systems is introduced. The specific sub-system “Electrical System” is introduced as a kind of balancing system for all electric productions and consumptions.

9.1. Generic sub-system interface and variable definition

The interface of the Electrical System to the rest of the plant is defined by the auxiliary consumption of the other sub-systems. These results of the sub-systems are input into the electrical system since the electrical system does not have in feedback on the thermodynamic sub-systems. The main results obtained from the electrical sub-system are the power delivered to the grid (infeed) and the power purchased from the grid (backfeed).

Table 9-1: Generic interface (I) and reporting (R) variables valid for the electrical system

Type	Name	Symbol	Comment
I	Auxiliary electrical demand of solar field	$P_{\mathrm{aux,SF}}^{\mathrm{EL}}$	
I	Auxiliary electrical demand of power block	$P_{\mathrm{aux,PB}}^{\mathrm{EL}}$	
I	Auxiliary electrical demand of thermal storage	$P_{\mathrm{aux,TES}}^{\mathrm{EL}}$	
I	Auxiliary electrical demand of auxiliary heater	$P_{\mathrm{aux,AH}}^{\mathrm{EL}}$	
I	Gross electric power of generator	$P_{\mathrm{aux,AH}}^{\mathrm{EL}}$	
R	Electric power delivered to grid	$P_{\mathrm{grid,infeed}}^{\mathrm{EL}}$	
R	Electric power consumed by the grid	$P_{\mathrm{grid,backfeed}}^{\mathrm{EL}}$	

9.2. Generic modeling approach for sub system “Electrical System”

Consisting mainly of the electrical transmission, distribution, and transformation system, the electrical system is responsible for the transmission of the generated electricity into the public grid and for supplying electricity to the plant’s electrical consumers upon transformation.
Following the sub-system break-down as introduced in section 3.2, the electric demand within each sub-system is systematically described within these sub-systems. The main reason for assigning the electric demand calculation to the sub-systems is the fact that calculation especially of variable components requires the information on the actual load situation in the respective sub-system. A systematic exception is the demand of main HTF pumps which cannot in every case be assigned to one

distinct sub-system. For parabolic trough system with oil as HTF, the main HTF pumps serve all sub-systems in various configuration at a time (solar field, power block, thermal storage, auxiliary heater). Thus, calculation of the required power depends on the actual operation mode and the load in all affected sub-systems. The guideline suggests to evaluate the electric consumption of the main HTF pumps on the system level since there, all mass flows and pressure differences over the sub-systems are available.

In general, we distinguish between base load consumption and variable consumption. Base load consumption is independent of load. If the system is in operation, the base load consumption is added to the variable consumption. The base load consumption may have different contributions that can depend on the operating mode. The base load consumption of a sub-system might be reduced if certain parts of the consumers are shut-down during off-times of the sub-system (tracking for solar field, auxiliary consumers of the HTF system). Variable consumption directly depends on the load and is thus zero when the system is not in operation. Recirculation consumption and anti-freeze consumption are variable consumptions since they depend on the actual ambient conditions and the state of the system.

The total electric consumption can thus be calculated from the contributions of the sub-systems and one term for auxiliary consumption from the system level

$$P_{\mathrm{aux}} = P_{\mathrm{aux,SF}}^{\mathrm{EL}} + P_{\mathrm{aux,TES}}^{\mathrm{EL}} + P_{\mathrm{aux,PB}}^{\mathrm{EL}} + P_{\mathrm{aux,AH}}^{\mathrm{EL}} + P_{\mathrm{aux}}^{\mathrm{System}} \quad . \qquad (9.1)$$

Note, that a differentiation between base load and variable consumption is not given in the above equation due to the complexity in determining those values for individual sub-systems. Similarly, the auxiliary electrical consumption of HTF freeze protection pumps or SF recirculation pumps is difficult to be specified for modeling purposes. For example, it might get complex to model the auxiliary consumption in case of HTF freeze protection operation in the SF and a parallel discharge operation of the TES system.

All losses resulting from the transport of electric power from the generator to the grid are described within the sub-system “Electrical System”. All base-load consumption that cannot directly be assigned to one of the other sub-systems are modelled in the Electrical System, too.

Focusing on the net output of the STE plant at the metering point, all consumption and losses within the electrical system need to be taken into account. The electric power injected into the electrical system by the generator is reduced on its way to the grid connection (and metering) point by the auxiliary electrical consumption of the plant as well as the losses caused by transformer and transmission losses as shown in Figure 9-1.

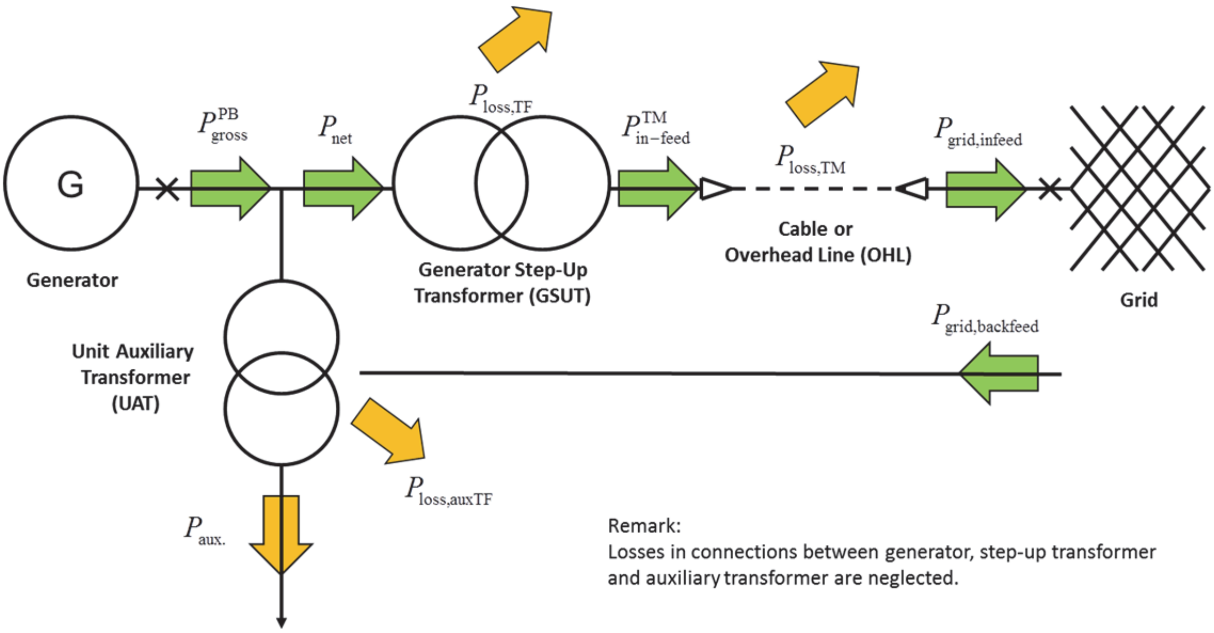


Figure 9-1: Simplified single line diagram and losses of electrical system for normal operation

The electric energy injected into the grid is obtained by

$$P_{grid,infeed} = P_{gross}^{PB} - P_{aux} - P_{loss,auxTF} - P_{loss,TF} - P_{loss,TM} \tag{9.2}$$

P_{gross}^{PB}	Gross capacity of power block @ generator terminals
P_{aux}	Auxiliary electrical consumption of the plant
$P_{loss,auxTF}$	Electrical losses of auxiliary transformer
$P_{loss,TF}$	Electrical losses of main/step-up transformer
$P_{loss,TM}$	Electrical losses in transmission line from main transformer up to grid interconnection point .

10. Implementing the operation strategy

Representing the operation strategy is one of the most challenging tasks in STE yield calculation since the operation strategy directly influences the energy yield. The same plant configuration may have different annual electricity production and financial earnings if different operation strategies are applied. For an example, Figure 10-1 gives results for three different strategies applied to the same plant in a varying electricity price market. Although this is just an example, similar considerations can be applicable to different electricity market characteristics and different operation strategies.

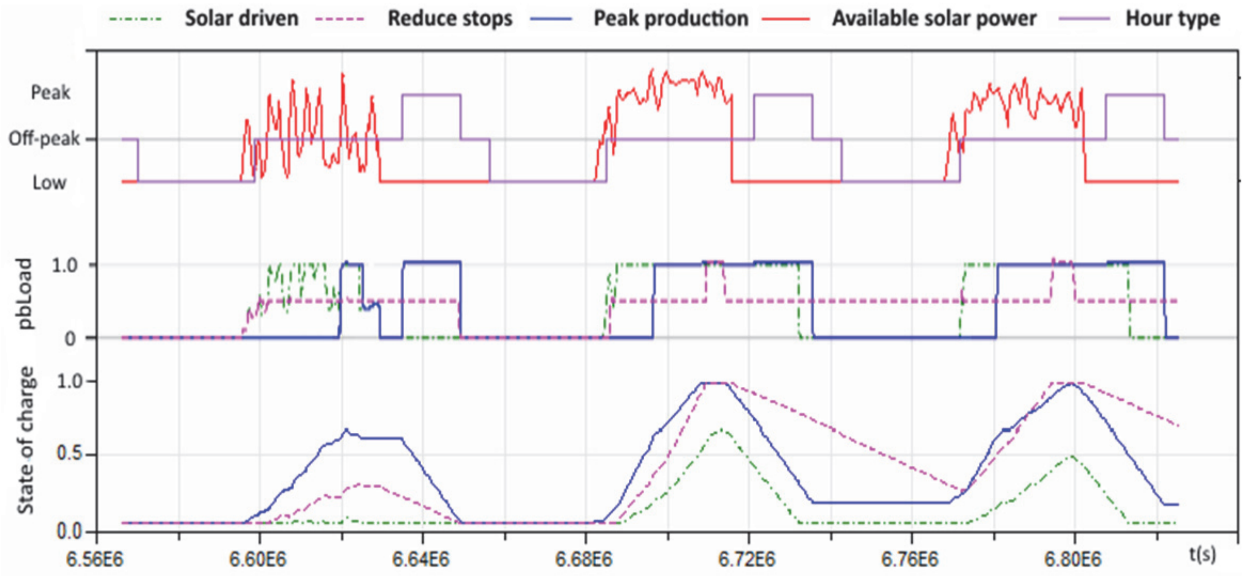


Figure 10-1: STE power plant operation with three different operation strategies. In this exemplary calculation the peak production strategy increases the energy revenues by 1.3 % while the reduced stops strategy reduces it by 14.5 % (taken from: Javier García-Barberena, Ioseba Erdocia: "Simulation and Comparison of Different Operational Strategies for Storage Utilization in Concentrated Solar Power Plants", SolarPACES2015 conference, Cape Town, South Africa, 13.-15. October 2015).

For this reason, establishing an appropriate framework to simulate the operation strategies is a crucial issue in energy yield assessments and bankability studies. However, due to the immense flexibility of the operation strategies in STE plants, this can become a cumbersome task when different players and simulation models are involved in the process.

Especially when "complex" operation strategies are foreseen for a project, the question arises if such specific strategies can be reproduced by all players involved in the project. For instance, when it comes to meteorological and electricity price forecast based strategies, or when fuel contingents are to be optimized, the modeler can either implement a quite complex calculation algorithm or needs to simplify certain aspects, which causes a deviation from the original strategy foreseen. While the developer, owner, or operator of the plant will tend to use really sophisticated models, technical consultants may not be able to simulate in the same level of detail.

The purpose of this guideline is to provide a set of rules for the definition and simulation of the operating strategies in STE plants that can be adopted by all players, facilitating the understanding and comparison of the outcomes from different models throughout the complete project process.
Some of the most important challenges of defining such rules for the operation strategy include:

- Operation modes strongly depend on the individual design of the plant (e.g. turbine minimum load depends on the individual configuration and can vary between 10 and 50%).
- The optimum operation strategy severely depends on local market conditions, like tariff structure, feed-in restrictions, electricity prices.
- Details of the operation strategy are often treated as confidential by the operator/developer.
- Many operation strategies require a forecast of irradiance and/or selling price within the next hours or days. As soon as forecasting is required, yield analysis has to include optimization processes in order to find the appropriate operation trajectory.
- When co-firing is foreseen in the plant, the fuel usage strategy may also require a specific optimization task, possibly covering a whole year if yearly fuel usage limitations apply.

A general methodology can only be developed if the boundary conditions between plant control and operation strategy are clearly defined. The guideline is based on the assumption that there is a plant control which is closely linked to the technical installation. The plant control covers all foreseen procedures the plant can follow. Examples are start-up procedures, load change procedures, or reactions of the control system to cloud passage. We assume that these plant control actions are integral part of the technical installations and cannot be manipulated by the operator in the control room. In semi-automated control systems the operator will carry out some of these control tasks but they can clearly be distinguished from the operation strategy.

Figure 10-2 shows the plant control block in grey color. There are a number of pre-defined channels by which the operation strategy communicates with the plant control level. On the one hand, the operation strategy needs to know the actual states of the plant in order to take reasonable decisions (e.g. storage tank level). Decisions made by the operation strategy are communicated in the form of set-points to the plant model. The plant control will try to follow the demands of the operation strategy taking into account any limitations on plant model level (e.g. restrictions in ramp rates, start-up times, etc.). This concept of strict separation between plant control and operation strategy allows systematically defining rules for the operation strategy in a reasonably clear and concise way that would be otherwise impossible.

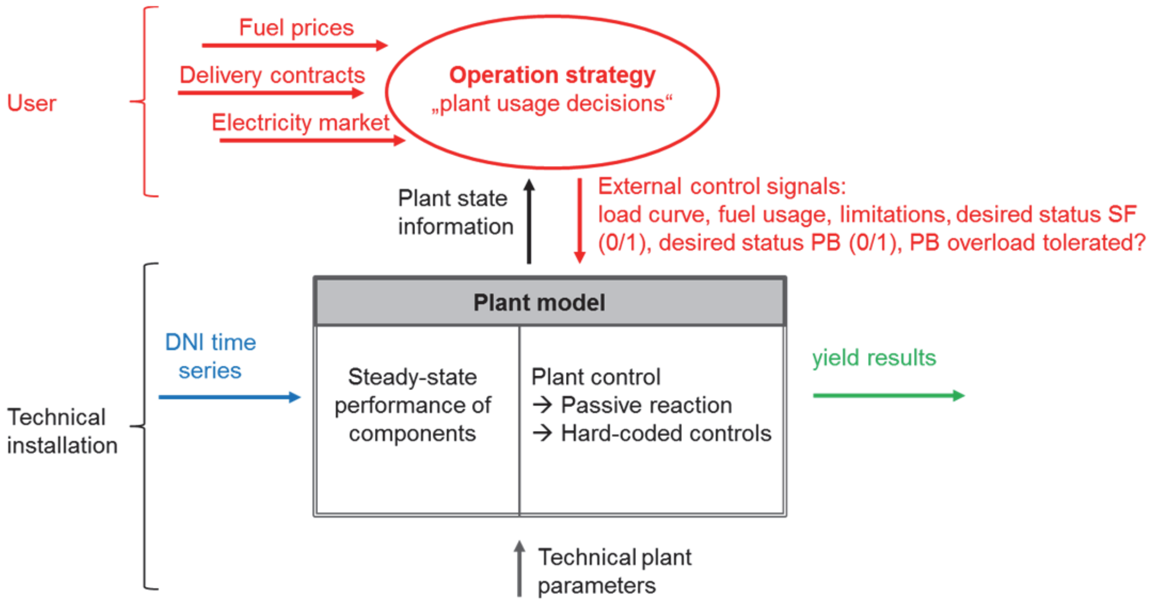


Figure 10-2: Interface between plant control and operation strategy

The definition of all tolerated operating modes of a plant helps to define the rules for the operation strategy. To address the establishing of these rules in a rather systematical way, it is suggested to differentiate between three categories of operation strategies as illustrated in Figure 10-3.

The first level comprises operation strategies which are commonly used, simple, and easy to implement in any yield calculation tool. These strategies can be defined by none or a small number of parameters and the operation is straightforward, with no dependencies on the plant systems status. These strategies can be considered as pre-defined strategies that can be widely used as reference operation strategies either during the initial phases of a project or for most research and comparison purposes. These reference strategies are detailed in chapter 10.1.

The second level goes beyond these simple strategies and might require some additional coding-work before the simulation can be carried out. Level 2 strategies are those strategies that use more complex decision making logics, requiring a detailed knowledge of the plant status and probably of the current (time depending) demand or price values, but can still be pre-defined by the user in terms of a (larger) number of parameters. This means that level 2 strategies are relatively complex strategies but still can be completely defined before simulation and are not based on forecasting. It is foreseen that the effort for the coding work is manageable, and all players should be able to simulate level 2 strategies within the project. The guideline provides examples that help to systematically document the rules of the specific operation strategy in chapter 10.2. Also a flexible approach to simulate a wide range of these level 2 strategies is provided.

Finally, <u>level 3</u> strategies, are “complex” strategies that can’t be, in principle, pre-defined in terms of a limited set of parameters. Additional degrees of freedom making a strategy “complex” most times include the dependency on weather and electricity price forecasts or fossil fuel contingents usage over the year which require optimization processes within a simulation. These strategies are typically defined by an objective function to be maximized or minimized, e.g. “maximum revenues strategy”.

Level 3 strategies also include any other possible strategy not included in levels 1 and 2. When it comes to these third level strategies, the degree of complexity of the operation strategy is quite high and the effort for its implementation is beyond the scope of usual due diligence activities. Some examples of these level 3 strategies are provided in chapter 10.3. A recommendation on how the simulation of these strategies can be carried out by all players is outlined in the same chapter.

	Type of operation strategy		**Recommendation**
Level 1	<u>Reference Operation Strategies:</u> Chosen operation strategy is similar to one of the reference operation strategies	→	All players should be able to simulate the reference operation strategy. Used for initial project phases as well as research and comparison purposes.
Level 2	<u>Pre-defined Operation Strategies:</u> Chosen operation strategy is project specific. The strategy is pre-defined by a set of parameters and the implementation is possible for all players.	→	All players should be able to simulate the operation strategy. Some coding work might be needed for some players.
Level 3	<u>Complex Operation Strategies:</u> Chosen operation strategy requires complex calculations (e.g. forecast based optimization) which cannot be implemented with reasonable effort by all players.	→	Calculation/optimization of the strategy is performed by the relevant player (typically the developer, owner, or operator). Mechanisms should be found to share the optimized strategy definition so it can be simulated by all partners.

Figure 10-3: Recommendations for different types of operation strategies

It is worth noting that the strategies from levels 1 and 2 could require, in some cases, the optimization of their defining parameters to achieve good project results. Even in these cases, the strategies essentially differ from level 3 strategies, since once the parameters are set, the strategies are fully pre-defined and easily transferred to other players' simulation tools.

10.1. Level 1: Reference operation strategies

Four simple reference operation strategies are depicted in this section. The reference operation strategies selected enable a simple implementation, based on none or a small number of parameters. These operation strategies are completely pre-defined and all players should be able to simulate them. Table 10-1 gives the principle rules defined for the four reference operation strategies.

Table 10-1: Reference operation strategies

	Solar driven	**Base load**	**Solar driven with fuel fill factor**[23]	**Simple Load Curve**[24]
Priority of solar field (SF)	1. operate PB 2. charge TES	1. operate PB 2. charge TES	1. operate PB 2. charge TES	1. operate PB to an hourly specified load 2. charge TES
Power block operation (PB)	Produce at nominal load until TES is empty, then shut-down.	Produce at nominal load until TES is empty, then shut-down.	Produce at nominal load from SF or TES and up to an hourly specified load from AH.	Produce according to load curve until TES is empty, then shut down.
Storage operation (TES)	Discharge at maximum load until storage is empty.	Discharge at maximum load until storage is empty.	Discharge at maximum load until storage is empty.	Use storage to support PB load curve operation.
Auxiliary heater operation (AH)	only for anti-freeze	Use aux heater to run the PB at nominal load if no SF or TES is available.	Use aux heater to run the PB at an hourly specified load if no SF or TES is available.	only for anti-freeze

[23] The solar driven with fuel fill factor strategy requires the definition of the fill factor for each hour of the simulation period (typically a year), which can be done in different ways: daily, week-day/weekend, with or w/o seasonal or monthly differences, etc. Note that this strategy is the same as the base load strategy if the fill factor is always 1 (full load).

[24] The simple load curve strategy requires the definition of the desired load curve for each hour of the simulation period (typically a year), which can be done in different ways: daily, week-day/weekend, with or w/o seasonal or monthly differences, etc.

In this guideline, these four reference strategies are considered simple and convenient enough for model comparison and simple operation strategy approaches that may be valid for some applications. However, other simple strategies may be defined in similar terms in a future, covering a wider range of possible applications.
To show how a reference strategy can be described and to outline the coding requirements for its simulation, the “Solar driven with fuel fill factor” strategy is explained in more detail. The basic idea behind this strategy is to produce the electricity at full load whenever enough solar energy is available and to use the auxiliary heater to increase the electricity production up to a pre-defined hourly PB load value (i.e. the fill factor) whenever the available solar energy is not enough to reach the desired production. According to this reference strategy, the operation of the plant depends on the time. Allthough more complex approaches are straightforward to implement, for the purposes of this guideline it is assumed that the fill factor has a value of 80% from sunrise till midnight and 0% else.

According to this strategy, the heat from the solar field is first used to run the PB at nominal load. If there is an excess of heat from the SF, the storage system is charged. If not enough power is available from the SF to run the PB at nominal load, the energy in the TES is used to support the PB operation at full load until it is depleted. In clear days, the plant will typically be running at full load during daytime and for some hours after sunset. The TES will be depleted in the evening and the auxiliary heater will then be used to extent the operation of the PB at 80% of its rated capacity until midnight. If the auxiliary heater has a limited capacity and it is not able to provide enough power to the PB to run at 80% load, the AH will be used at its maximum power and the PB will run below the desired 80%. Once midnight is reached, the fill factor becomes 0% and the plant is shut down.

During overcast days or during cloud passage periods, the solar field may not be able to run the PB at full load and the TES will not be charged (or quickly depleted). In such days, the auxiliary heater will be used to support the SF in order to keep the PB running at 80% load. This is, when the SF provides enough power to run the PB at least at 80% of its capacity, the auxiliary heater will not be used. However, when the SF is not providing enough power to run the PB at 80%, the auxiliary heater is used to reach this power output (or at its maximum capacity if the 80% load is not reached). Again, this situation will be kept until midnight, when the fill factor changes and the plant is shut down.

From the explanation above it is obvious that this strategy needs only one parameter, the fill factor, which varies with time and thus requires a different value for each hour of the simulation. This can be realized in different ways by pre-scribing either daily, week-day/weekend, with or w/o seasonal or monthly differences, etc schedules. The most flexible way is to implement an array of 8760 values for each hour in the year. Higher resolution of time are required if the specific market situation relies on sub-hourly differences.

By setting this single parameter, the “Solar driven with fuel fill factor” strategy is completely defined and all players in a project can run the same simulation. The coding requirements for this strategy comprises checking the fill factor at each simulation step. When the power block can be run over the desired fill factor, the operation of the plant is similar to the reference “Solar Driven” strategy, else the auxiliary heater is used to provide the additional heat required to reach the desired power output. Therefore, only an if statement and appropriate selection of the operation mode is needed to implement this reference strategy.

10.2. Level 2: Pre-defined operation strategies

As stated above, level two strategies are more complex strategies that represent project specific strategies in a pre-defined way. This means that the strategies in this level can be as detailed as needed for a specific application, but still do not depend on online optimization processes and therefore can be completely set prior to a simulation through a number of parameters and conditions. This ensures that all project players can receive a specific strategy description and code it in their models with no need for substantial changes to the simulation process. Since these strategies are project specific, no reference strategies can be provided. However, to serve as a guide for the modeler, some examples of rather simple level 2 strategies are depicted. These exemplary strategies are briefly described in Table 10-2.

To show how a level two strategy can be described and to outline the coding requirements for its simulation, the “Simple Peak hours production” strategy is explained in more detail. The basic idea behind this strategy is to produce the maximum possible energy during certain specific hours, commonly related to higher energy selling prices or demand peaks. According to this exemplary strategy, the operation of the plant depends on the time. Althoug more complex schedules are straightforward to implement, for the purposes of this guideline it is assumed that there are peak hours and non-peak (valley) hours defined uniquely for each day.

During a peak hour, the goal is to produce the maximum energy; therefore the heat from the solar field is first used to run the PB at nominal load. If there is an excess of heat from the SF, the storage system is charged. If not enough power is available from the SF to run the PB at nominal load, the energy in the TES is used to support the PB operation until it is depleted. Optionally, the auxiliary heater can also be used during peak hours to increase PB load up to nominal.

During non-peak hours, the strategy tries to always keep enough energy in the storage to run the PB at nominal load during peak hours. For this, when in a non-peak hour, the heat from the solar field is firstly used to charge the storage to a specified state of charge. Then, the PB is operated up to nominal load and the excess heat is used to charge the storage up to its maximum capacity. If the heat delivered by the SF is not enough to run the PB at nominal load, the storage is discharged until the specified SOC is reached. This way, there is always a certain amount of energy in the TES to run the PB at nominal load during peak hours. In non-peak hours, the auxiliary heater is used only for anti-freeze protection.

Table 10-2: Exemplary pre-defined operation strategies

	Solar driven with reduced number of shut-downs	**Simple Peak-Hours production**	**Load curve**
Priority of solar field	1. charge TES to a certain state of charge 2. operate PB	Peak hours: 1. operate PB 2. charge TES Non-Peak hours: 1. charge TES to a certain state of charge 2. operate PB	1. operate PB 2. charge TES
Electricity production	Produce at nominal load if storage is over a specified state of charge, and at a reduced load until storage is empty	Produce at nominal load until storage is empty (peak hours) or it reaches certain state of charge (non-peak hours), then shut-down.	Operate PB according to load curve.
Storage operation	Discharge at maximum load until storage reached certain state of charge, then at a reduced load	Discharge at maximum load until storage is empty (peak) or keep a minimum amount in order to operate PB during peak hours (non-peak).	Use storage to support PB load curve operation.
Auxiliary heater	only for anti-freeze	Optionally support PB operation during peak hours, and only for anti-freeze else.	Use aux heater to fill gaps when the heat from SF and TES is not sufficient

A list of defining parameters for this strategy can be inferred from the explanation above:

- Peak and non-peak hours definition. This can be done in different ways: daily, week-day/weekend, with or w/o seasonal or monthly differences, etc. The most flexible way is to implement an array of 8760 values for each hour in the year.
- Use of the auxiliary heater. A Boolean variable to enable or disable the use of the AH to support PB operation during peak hours.
- Storage state of charge set point for non-peak hours. This parameter sets the state of charge to be reached and maintained before running the PB in non-peak hours. It is intended to ensure that enough energy is stored to run the PB during peak hours.

By setting these three parameters, the “Simple Peak hours production” strategy is completely defined and all players in a project can run the same simulation. The coding requirements for this strategy comprises checking the hour type and the storage state of charge at each simulation step. When in a peak hour or when the storage state of charge is over the set point, the operation of the plant is similar to the reference “Solar Driven” strategy, else all the heat produced by the solar field should be stored. Therefore, only an “if-statement” and appropriate selection of the operation mode is needed to implement this exemplary strategy. If the auxiliary heater is to be used in peak hours, little additional coding will be needed.

Of course, the above defined strategy is a simple example, more detailed strategies, requiring increased coding effort but yet completely pre-defined before simulation are likely to be used in real projects. In the following, a non-exhaustive list of additional options and improvements to this strategy is outlined:

- Establishing more hour types, with different strategies. For instance, a hour type representing the hours followed by peak hours will be useful to start-up the PB before the peak hours.
- Sub-hour hours classification (e.g. 10-15 min) could permit better following a specific demand or price curve.
- A different PB load set point could be used for non-peak hours, so the storage won’t be used to reach full load in these hours but to keep it, for instance, at a minimum load.
- Different storage state of charge set points could be included for charging and discharging.
- Different fuel fill factors for peak and non-peak hours could be used to enable a more complex usage of the auxiliary heater. For instance, the AH could be also used in non-peak hours to keep the PB online at minimum load until the next peak hours arrive.

To ensure that this strategy achieves efficient results in the plant energy yield and provides increased revenues, the optimization of the defining parameters is likely to be needed. For instance, depending on the number of peak and non-peak hours in each day and the time of the day they occur, the best storage state of charge set point to be used can be different. Evidently, if some of the previous modifications are included, the optimization would be even more convenient. Note, that these are optimization processes carried out to define a good strategy, but the strategy itself does not require any optimization process during the simulation. Typically, one of the players will define and optimize the strategy, while the rest will only simulate it.

10.3. Level 3: “Complex” operation strategies

Complex strategies refer to those strategies that can’t be completely defined through a set of parameters before the simulation. As stated before, usually these complex strategies critically depend on the specific weather or the electricity market characteristics, and usually require costly optimization processes within the simulation itself. Other conditions that make a strategy complex include limited fuel usage over the simulation period, what also require optimization processes.

The most obvious complex strategy for STE plants may be an operation strategy aiming to maximize the revenues of the plant over a certain period (a year) in a competitive (varying price) electricity market. In this case, the decision on when to run the PB and at which load and, consequently, when to charge/discharge the TES is usually the result of a daily optimization depending on the wheather and price forcasts. A typical prodecure to define this strategy will use the wheather and price forecasts for the present and next day(s) to perform a numerical optimization of the hourly plant production for the two (or more) days. By considering more than one day, keeping some energy in the storage for the next day is enabled, what may be convenient if the energy can be sold at a higher price during the next day. Once the optimum strategy is obtained for the present and next day based on forecasts, it is only used for the present day, repeating the optimization every day. Sometimes, ideal forecasts are used for this process. In this optimization, the appropriate constraints in terms of available solar heat in each time have to be applied. In many cases, dynamic programming (DP) with mixed-integer linear programming (MILP) or similar approaches relaying on simplified models and constraints are used.

It is expected that this optimization will be carried out exclusively by some of the relevant players, probably the developer, owner, or the operator. However, once the meteorological conditions for the yield calculation and the electricity market details for the financial analysis are defined in a specific project, the optimized trajectories for storage charging and discharging, power block load and fossil fuel usage can be some times treated as pre-defined strategies. This means that, regardless on how the strategy has been calculated, other players can simulate the strategy as a relatively simple level 2 strategy. For instance, the optimized complex strategy may be reduced to an hourly PB load curve for the complete simulation period (typically one year), similar to the above “Load Curve” strategy, and therefore simulated by all players in a similar way.

It is therefore recommended, if possible, to use this approach when dealing with complex operation strategies. Although representing some of these strategies by a level 2 strategy won’t be easy, in many cases it will be possible with a small amount of extra work. Obviously, even if the strategy can be represented by a level 2 strategy, it won’t be the optimum strategy according to the different models, but results are expected to be close if the models are accurate and thus similar enough.

10.4. Modeling a “flexible operation strategy”

If the previous level 1 and level 2 operation strategy examples are examined, most of the operation rules can be treated in a similar way and it shows up that the same model can be used for all them. In this way, different operation strategies can be easily simulated if a flexible enough operation strategy simulation framework is implemented in the models. This flexible model is here referred as a “flexible” operation strategy model.

The modeling concept presented in the following is an example that allows the implementation of a wide range of specific strategies regarding the use of the storage and auxiliary heater depending on the date, time, and status of the plant. The modeler may include simpler or more complex models for the operation strategy, however, it is recommended to keep a relatively similar approach in terms of the definition of rules, what will ensure a good communication and proper understanding with other players when needed.

Basically, by the definition of a reduced set of parameters, it is possible to control the state of charge of the TES and the electric production of the power block. These parameters can be modified in order to obtain different strategies oriented to reach different goals. The way this flexible strategy works is schematically shown in Figure 10-4 and explained in the following paragraphs through the description of its defining parameters.

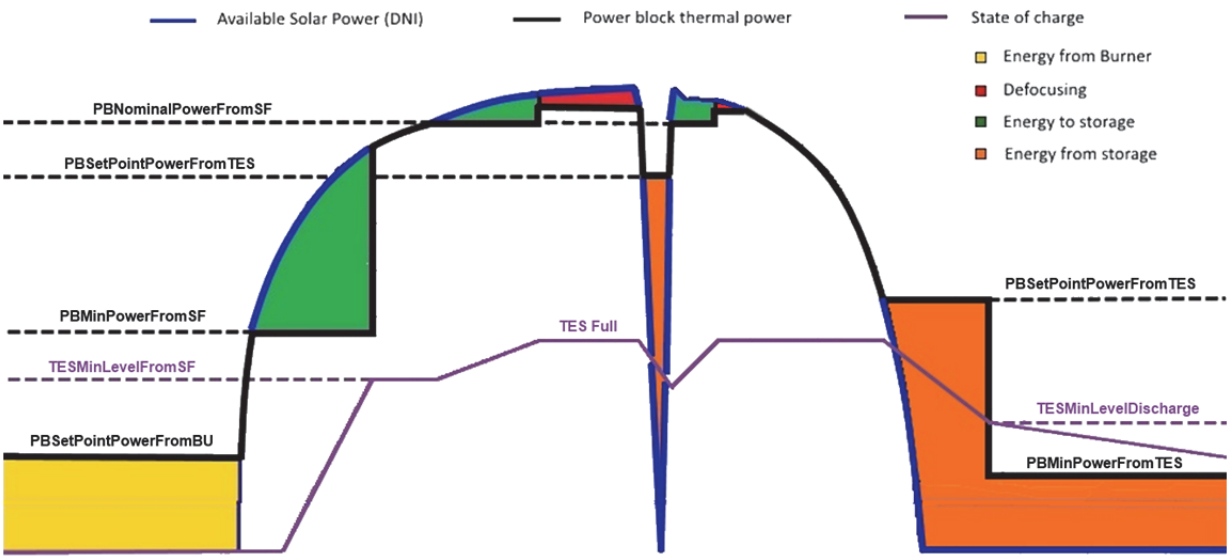


Figure 10-4: Conceptual behavior of the power block power (black, solid), storage state of charge (purple, solid) and available solar power (blue, solid) for a reference day according to the flexible operational strategy.

According to this proposal, there are three parameters for defining the TES charging and the operation of the power block:

- Power block minimum load from solar field supply (pbMinPowerFromSF in Figure 10-4).
  The minimum load at which the PB should be operated when the SF is delivering enough heat. This is the first priority for the SF heat utilization.
- Storage minimum state of charge from solar field (tesMinLevelFromSF in Figure 10-4).
  The desired state of charge to be reached in the TES before running the PB at nominal load. This is the second priority for the SF heat utilization.
- Power block nominal power from solar field (pbNominalPowerFromSF in Figure 10-4).
  The nominal or desired PB load, once the TES has reached its minimum desired level.

If the solar field provides more heat than needed for running the PB at its nominal load, the excess is used to charge the storage system up to its maximum capacity. PB overload could be allowed before defocusing occurs.
When the heat provided by the solar field is not enough to operate the PB at certain desired load, the storage will be discharged to reach such desired load. A second set of parameters is used to control the discharging of the TES:

- Power block nominal power from storage supply (pbSetPointPowerFromTES in Figure 10-4): The PB load to be reached when discharging the TES while the state of charge is over a specified one ("tesMinLeveldischarge").
- Power block minimum power from storage supply (pbMinimumPowerFromTES in Figure 10-4). The PB load to be reached when discharging the TES if the state of charge is lower than a specified one ("tesMinLeveldischarge").
- Storage minimum level to discharge (tesMinLevelDischarge in Figure 10-4). The TES state of charge threshold to operate the PB at nominal or minimum power from the storage system (two previous parameters).

Finally, it is possible to use the auxiliary heater to provide additional power for the PB. The following parameter is used to control the AH use:

- Power block set point power from burner supply (pbSetPointPowerFromBU in Figure 10-4). Desired PB load when part of the heat is provided by the AH. The AH is used to complete the heat from the SF and/or TES, to operate the PB at this load.

All these parameters should permit different values for each hour of the year (or higher frecquency if neede), providing enough flexibility to operate the plant in a different way depending on the time and date and, therefore, allowing the consideration of demand or price curves. This can be seen in Figure 10-4 by means of the parameter pbSetPointPowerFromTES, which has different values at midday and in the afternoon. For simplicity and clearness, a unique value is shown in the figure for the rest of the parameters.
Table 10-3 shows how this flexible strategy can be used to represent the reference strategies (level 1) in a simple way by setting appropriate values to each of the parameters. The level 2 "Simple Peak-Hours production" as described in this guideline is also included in the table as an example of a more complex strategy.

Table 10-3: Definition of the flexible strategy parameters used to represent the reference strategies. Values from 0 to 1 refer to the nominal load of the respective system.

Parameter \ Operation strategy	Solar driven	Base load	Solar driven with fuel fill factor	Simple Load Curve	Simple Peak-Hours production
pbMinPowerFromSF	1	1	1	Load Curve	Peak: 1 Non-Peak: 0
tesMinLevelFromSF	0	0	0	0	Peak: 1 Non-Peak: 0.6 (e.g.)
pbNominalPowerFromSF	1	1	1	Load Curve	Peak: 1 Non-Peak: 1
pbSetPointPowerFromTES	1	1	1	Load Curve	Peak: 1 Non-Peak: 1
pbMinimumPowerFromTES	1	1	1	Load Curve	Peak: 1 Non-Peak: 0
tesMinLevelDischarge	0	0	0	0	Peak: 1 Non-Peak: 0.6 (e.g.)
pbSetPointPowerFromBU	0	1	Fill Factor Curve	0	0

Although only some simple examples have been provided here, this flexible approach can be used to represent reasonably complex operation strategies.

11. Effects typically modelled on an annual basis

Apart from the effects modeled on a time step basis, see former chapters, some effects are sufficiently covered as a correction of the annual yield. The motivation for this approach is to simplify the modeling without loss of accuracy or a lack of better knowledge. The following effects can be treated on this basis:

1. Variation of plant performance over the life-time (degradation as well as improvement)
2. Availability of the plant due to unscheduled down times
3. Cummulation of physical effects characterized by low level of maturity in modeling but not generally negligible impact on yield.

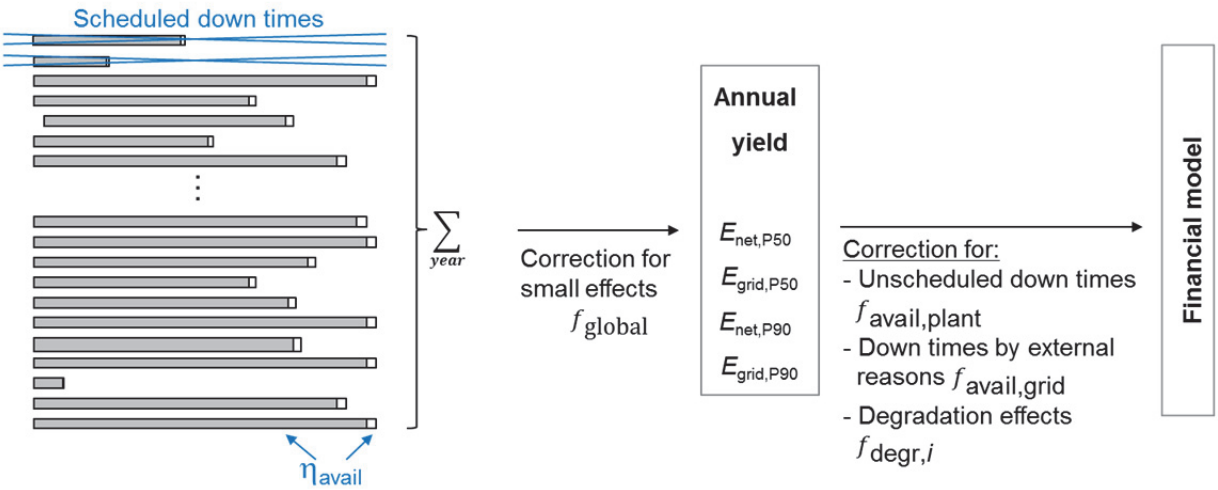


Figure 11-1: Effects modelled on an annular basis

11.1. Variation of plant performance over the life-time

During their life-time, STE plants may undergo changes in their technical performance due to

- Degradation of components that lead to reduced efficiency
- Increased overall efficiency due to learning effects of the operation team
- Replacement of components by new ones with higher efficiency (upgrade)

For a detailed financial project evaluation, these time dependent effects have to be considered. Due to the close link between technical performance and maintenance effort all three issues are covered in the financial analysis rather than in the technical performance modeling. Based on the annual yields obtained for the reference year, a correction term f_{degr} on the yield can be applied that represents the impact of performance changes. As a consequence, degradation effects are not considered during the performance calculation for one year. Appropriate description on the underlying technical and financial assumptions need to be given.

The impact of performance improvements by replacement with new components with higher performance is quite hard to predict. Since such components usually not exist when the yield analysis is carried out, the relation of performance gain and associated cost is not profound. In case a scheduled replacement of components (e.g. tower receiver replacement interval of x years) annual calculations can be performed with varying component performance in order to identify the correction term f_{degr} that is then used for the correction on annual yield basis. Additional reasons for considering degradation on an annual basis are:

- Financial engineers are used to degradation factors on an annual basis
- Simulation of degradation within each time step would require a simulation run for many years which increases computation time.

11.2. Availability

Availability describes the ratio of hours a plant (or a sub-system of the plant) is able to operate to the planned number of hours the plant should be able to operate. Although in reality, some of the sub-systems can be available whereas others are not available at the same time we consider the whole plant for STE yield analysis. Thus, we do not distinguish between solar field availability and power block availability but consider an effective value over all sub-systems. Due to different modelling approaches we distinguish between four categories:

1. A continuous non-availability of a fraction of functional units within a sub-system that does not lead to a down-time of the whole sub-system but to a reduced performance, since only a certain fraction of the units is available. For STE systems, this is typically the case for solar fields. As example, we can list a regular maintenance at collectors/heliostats in the field or non-availabilities due to regular calibration measures especially for heliostats. The value of $\eta_{\text{avail}}^{\text{SF}}$ represents the fraction of aperture area available to the total installed aperture area. Since it refers to the installed capacity rather than a nominal load the factor $\eta_{\text{avail}}^{\text{SF}}$ is always smaller/equal 1.
2. For scheduled down-time of the whole plant a down-time Δt_{over} of several days is foreseen directly in the annual yield calculation. That means, that during the overhaul period no electricity is produced by the plant (but probably consumed). Typically, an overhaul period of 2 weeks is foreseen in the winter season. In the yield report the applied overhaul period has to be specified.
3. Unscheduled down-times are considered in the financial analysis by reducing the annual yield by a certain factor. Please note that the plant availability factor $f_{\text{avail,plant}}$ refers to the time interval 8760 h - Δt_{over}. For a scheduled overhaul period of Δt_{over}=14 days and additional 10 days of unscheduled down-time the value of $f_{\text{avail,plant}}$ is (365-14-10)/(365-14)= 97,15 %.
4. Plant down-times caused by external reasons like non-availability of the electric grid are considered in the financial analysis by a factor $f_{\text{avail,grid}}$ on the annual yield that remains when all other availabilities have been considered. The grid availability factor is defined as the average over 8760 h.

For reporting purpose a effective plant availability can be defined based on the above mentioned figures. It is composed of the scheduled down-times, the unscheduled down-times, and the down-times due to external reasons. The continuous non-availability is not taken into account since this reflects an intrinsic part of the component performance and not a failure rate. The formula for the effective availability is

$$F_{\mathrm{avail}} = \frac{8760 - \left(\Delta t_{\mathrm{over}} + (1 - f_{\mathrm{avail,plant}}) \cdot (8760 - \Delta t_{\mathrm{over}})\right)}{8760} \cdot f_{\mathrm{avail,grid}} \tag{11.1}$$

11.3. Effects with non negligible impact but low level of maturity in modeling

Although the modeling approaches presented in this guideline are already of high quality there is still a lack of knowledge on certain effects. Often, it is known that an impact exists, but there are no established methods to quantify it. For these kind of effects the guideline recommends to consider them as global corrections to the annual yield calculated on a time step basis. We recommend to prepare a table that compiles all effects and the estimation used for the calculation. An example is given in Table 11 for a parabolic trough system. Depending on the project configuration, neglecting the effects will lead to significant errors in the yield calculation. Ideas following the concept that positive and negative effects cancel out each other somehow can be valid for certain configurations but do not represent a general methodology. By naming and estimating the effects, the guideline wants to enhance transparency and trust in the methodology. As soon as reliable calculation approaches are available for the effects they might be considered in the time step calculation.

Table 11: Effects without modeling approach to be considered on an annual basis.

Effect	Typical range for correction	Example value
Dew on mirrors	-0.5% … 0%	-0.25 %
Snow on mirrors	-0.5% … 0%	0 %
Aggregated		-0.25 %

12. Meteorological times series as input for yield analysis

Available solar radiation at the site and its characteristics are essential input values for simulating the performance of a solar thermal power plant. Other meteorological parameters like wind have some influence on efficiency of the plant and - if too strong - can lead to shut down of the solar field. Air temperature and humidity are relevant for the cooling conditions which influence the efficiency of the power cycle. As demonstrated by Ho[25] and Chhatbar[26] the direct normal irradiance is by far the most dominating meteorological parameter for yield of STE plants. Thus, focus is on DNI when defining STE-relevant meteorological data sets.

12.1. Description of relevant meteorological parameters

This section provides an overview on the relevant meteorological parameters.

12.1.1. Direct normal solar irradiance as primary input for yield analysis

According to ISO 9488[27], the direct solar irradiance is symbolized by G_b. This not necessarily specifies the orientation of the receiving surface, e.g. horizontal or normal to the sun. Following Blanc[28] and IEC TC117[29] (draft Technical Specification 2016), Direct Normal Irradiance (DNI) in this handbook is defined as follows: "Direct normal irradiance is the radiation flux originating from a small solid angle centered in the sun's disk incident on a plane pointing perpendicular to the sun". Following ISES[30] for expressing the normal direction the subscript n is used, so DNI can be symbolized by G_{bn} .

The sun's disk appears on Earth's surface at a field-of-view angle of about 0.5°. The part of the scattered radiation around the sun's 'disk is called the *circumsolar radiation* (see definition in section 12.1.3) is included. Depending on the actual atmospheric conditions, relevant parts of the measured beam radiation are not truly direct radiation from the sun originate from scattering in the atmosphere. The wider the acceptance angle of the measurement device the higher than fraction of scattered irradiance. Typically, direct normal solar irradiance is measured by instruments with field-of-view angles of 5°. Historical pyrheliometer acceptance angles range from 5° to 10°. The World

[25] Ho, C; Kolb, G. J., 2010, Incorporating Uncertainty into Probabilistic Performance Models of Concentrating Solar Power Plants, J. Sol. Energy Eng., **132**(3) http://doi.org/10.1115/1.4001468

[26] Chhatbar; Meyer, R., 2011, The influence of meteorological parameters on the energy yield of solar thermal power plants, SolarPACES Symposium, Granada, Spain http://doi.org/10.1594/PANGAEA.763963

[27] 1999, Solar energy –- Vocabulary. Standard of the International Organization for Standardization (ISO) Retrieved from http://www.iso.org/iso/home/store/catalogue_tc/catalogue_detail.htm?csnumber=17217

[28] Espinar, B., 2014, Direct normal irradiance related definitions and applications: The circumsolar issue, Sol. Energy, **110** http://doi.org/10.1016/j.solener.2014.10.001

[29] 015, IEC/TS 62862-1-1 Ed. 1.0 Solar thermal electric plants - Part 1-1: Terminology Retrieved from http://www.iec.ch/dyn/www/f?p=103:23:0::::FSP_ORG_ID,FSP_LANG_ID:7851,25

[30] Units and symbols in Solar Energy, Solar Energy, 73(1), III–V.

Meteorological Organization[31] recommends that the opening half-angle is 2.5° (6 · 10^3 sr) and the slope angle 1° for all new designs of direct solar radiation instruments.

The spectral responsivity of field pyrheliometers is usually limited to the range of approximately 0.3 µm to 3 µm. Some instruments with quartz windows are sensitive even up to 4 µm. Usually, more than 99% of the direct solar radiation received at ground level is contained within the wavelength range from 0.3 µm to 3 µm. This wavelength range, where the sun emits most of its radiation is called *solar spectral range*. As most mirrors and solar thermal absorbers are sensitive in the same spectral range no spectral analysis is required for STE applications. Usually, DNI measurements and model-derived DNI refer to the 'full' solar range. If other spectral ranges are measured or should be used in applications additional indication of the spectral range must be given. This guideline always refers to the full solar range. If measurements are done by instruments with limited spectral sensitivity spectral corrections must be applied to refer the measurement signal into the full solar spectrum.

Direct solar irradiance is best measured at normal incidence using a pyrheliometer mounted on a sun tracker. Alternatively, DNI can be gathered by the differential measurement of global and diffuse radiation. This can be done either by thermopile pyranometers using a shadow-ball slowly tracking with the sun to shade one of the pyranometers. Alternatively, DNI also can be measured using Rotating Shadowband Irradiometers[32].

Following ISO 9488, the measurement unit for DNI as for other irradiance components is W/m². When averages of DNI are taken, it is also popular to indicate DNI in units of kWh/(m²·a) referring to the annual average or kWh/(m²·d) referring to daily averages. Monthly averages should be avoided as values of months with different number of days cannot be directly compared. To avoid dependency on the daylength it is strongly recommended to give DNI averages in W/m² referring to 24 hour daylength.

Apart from average irradiance values, also the term irradiation H is used. According to ISO 9488 irradiation is the temporal integral of irradiance, which typically is expressed in units of J/m^2. The annual sum of DNI for a regular year may be expressed as

$$H_{\mathrm{bn,y}} = \int_{t=0}^{8760\,\mathrm{h}} G_{\mathrm{bn}}(t)\, dt \qquad (12.1)$$

[31] 2011, *Guide to climatological practices*, Geneva, Switzerland: Secretariat of the World Meteorological Organization (WMO) Retrieved from http://www.wmo.int/pages/prog/wcp/ccl/guide/guide_climat_practices.php
[32] Wilbert, S., N. Geuder, M. Schwandt, B. Kraas, W. Jessen, R. Meyer, and B. Nouri (2015), Best Practices for Solar Irradiance Measurements with Rotating Shadowband Irradiometers. IEA Solar Heating & Cooling Programme (SHC) Task 46 Solar Resource Assessment and Forecasting, 68 p.

With adequate integration periods, similar $H_{bn,M}$ for the monthly sums of DNI or $H_{bn,d}$ for the daily sums of DNI can be defined. However, the usage of $H_{bn,y}$ or $H_{bn,M}$ is error-prone since effects like leap years or different number of days in a month result in slightly different integrals. Annual averages as

$$\bar{G}_{\mathrm{bn,y}} = \frac{1}{8760} \int_{t=0}^{8760\,\mathrm{h}} G_{\mathrm{bn}}\,(t)\,dt \tag{12.2}$$

or monthly averages like

$$\bar{G}_{\mathrm{bn,M}} = \frac{1}{24\,\mathrm{h} \cdot (\mathrm{nr\ of\ days})} \int_{t=0}^{24\,\mathrm{h} \cdot (\mathrm{nr\ of\ days})} G_{\mathrm{bn}}\,(t)\,dt \tag{12.3}$$

are more suitable for comparing data sets or doing statistics.

12.1.2. Auxiliary meteorological parameters

In STE industry, non-radiation meteorological parameters are typically called auxiliary meteorological parameters. The minimum set relevant for STE analysis consists of:

- Dry air temperature related to WMO recommended height of 2 m
- Relative humidity related to WMO recommended height of 2 m (or alternatively due point temperature or wet bulb temperature referring to same height above ground)
- Wind speed at 10 m height following WMO recommendations

In addition, several other meteorological parameters are recommended to better characterize the local condition at the site:

- Wind direction at 10 m height following WMO recommendations
- Rain gauge and
- Snow height in regions, where snow might occur.

Concerning the wind measurements, it is stronlgy recommended to measure at the standard height of 10 m, because measurements at lower heights such as 3 m are not representative due to wind shear and vortices close to the ground. It leads to more correct data to measure at 10 m and scale to e.g. average collector height using adequate roughness lengths. Although wind gusts are responsible form damaging solar collectors, the wind gust value is not used to trigger overload wind situations. The thresholds given by the manufacturers are usually based on average wind speed and already include a safety margin for wind gusts.

12.1.3. Sunshape

STE systems do not only collect the solar radiation directly orignating from the sun's disk, but also some of the Circum Solar Radiation (CSR). According to IEC TC117[33] CSR is the radiation scattered by the atmosphere so that it appears to originate from an area of the sky immediately adjacent to the sun. The quotient of the radiant flux of the circumsolar radiation on a given plane receiver surface to the area of that surface is called circumsolar irradiance. The concentration factor of a specific STE system defines the acceptance angle within which solar beams are still reflected onto the receiver. Depending on the atmospheric conditions at the site, the CSR can increase significantly and reduce the direct part of the beam radiation. This is especially the case when thin cirrus clouds lead to much scattering or high levels of scattering on aerosol particles increase the sun's corona.
In case the STE system is very sensitive to CSR or the site shows a high degree of CSR, the meteorological data files have to include an estimate for CSR. Since CSR measurement is not yet standardized and mostly not available within default ground measurement stations, highly resolved values of CSR as needed in a meteorological data file are often not available. In this case, an estimate of the CSR impact has to be carried out in the simulation model assuming the expected CSR for the specific site.

[33] 2015, IEC/TS 62862-1-1 Ed. 1.0 Solar thermal electric plants - Part 1-1: Terminology Retrieved from http://www.iec.ch/dyn/www/f?p=103:23:0::::FSP_ORG_ID,FSP_LANG_ID:7851,25

12.1.4. Near ground atmospheric visibility

An additional auxiliary meteorological parameter is either visibility in km along the surface or the extinction coeffient. Both can be used to estimate the attenuation of the beam along the path between heliostats and the receiver e.g. according to Hanrieder et al.[34]. Extincition coefficient and/or visibility can be derived e.g. from so-called 'present weather sensors'. To achieve usable results visibility range should exceed 70 km.

12.2. Inter-annual variation and uncertainty of long-term mean

12.2.1. Definitions

As all meteorological parameters, also the direct normal irradiance undergoes i**nter-annual variations**. Averaging DNI values over 10 or more years gives a good estimate of the **long-term mean** value. When working with multiple year time series the annual averages of direct normal irradiance as defined in section 12.1.1 are used to characterize differences in solar resource $\bar{G}_{\mathrm{bn,y},i}$ over the years *i*. The longterm mean of annual DNI averages is obtained by arithmetic averaging over the *n* yearly sums,

$$\bar{G}_{\mathrm{bn}} = \frac{1}{n}\sum_{i=1}^{n}\bar{G}_{\mathrm{bn,y},i} \quad . \tag{12.4}$$

Since every measurement, either from ground stations or satellite data, suffers from measurement uncertainty the long-term mean value $\bar{G}_{\mathrm{bn}}$ obtained from such a time series also shows uncertainty. The uncertainty of the long-term average DNI is indicated by u_{DNI}. The following aspects need to be considered for determining the uncertainty of the longterm mean:

a) the uncertainty of the underlaying DNI ground station measurements,
b) the uncertainty of the DNI satellite retrieval, including the uncertainty introduced by adapting the satellite/model-derived DNI to ground-based measurements
c) the number of years taken to calculate the longterm average, and
d) if the measurements and satellite data do not directly refer to the project site the uncertainty from the difference in location.

Figure 12-1 illustrates annual averages of direct normal irradiance together with their uncertainty expressed in $\pm 1\sigma$ bands. The uncertainty $u_{\bar{G}}$ of the long-term mean $\bar{G}_{\mathrm{bn}}$ can be expressed in form of the standard deviation σ assuming a normal distribution, compare section 13.1. Mathematically spoken, the long-term mean is the mean value of the distribution, $\bar{G}_{\mathrm{bn}} = \mu$. From the long-term mean and its standard deviation of uncertainty, individual levels of exceedance of the long term mean can be calculated. **It is important to systematically differentiate between the uncertainty of the longterm mean, $u_{\bar{G}}$, and the inter-annual variability, *s*.** In particular, the uncertainty of the long-term

[34] Hanrieder, N., M. Sengupta, Y. Xie, S. Wilbert, and R. Pitz-Paal (2016), Modeling beam attenuation in solar tower plants using common DNI measurements, Solar Energy, 129, 244–255, doi:10.1016/j.solener.2016.01.051.

mean **cannot** be obtained by analyzing the variation of DNI sums within the time series. The interannual variability, s, refers to the standard deviation from the distribution of the yearly averages of the time series.

The uncertainty of the long-term mean depends on the number of years considered for averaging although the number of years used to calculate the average has only a small influence on the total uncertainty of the long-term average $u_{\bar{G}}$. Under the assumption that the DNI-averages $\bar{G}_{\mathrm{bn,y},i}$ of individual years are independent from each other and DNI does not show systematic trends at the site, the influence of the number of years *n* on the uncertainty strongly reduces for long observation periods. The uncertainty u_{obs} contribution on the long-term mean $u_{\bar{G}}$ due to the limited observation period is approximately given by

$$u_{\mathrm{obs}} = \frac{s}{\sqrt{n}} \,. \qquad (12.5)$$

Thus, for regions with low inter-annual variability, s, and many years of observation, *n*, the influence of the variability is getting quite low.

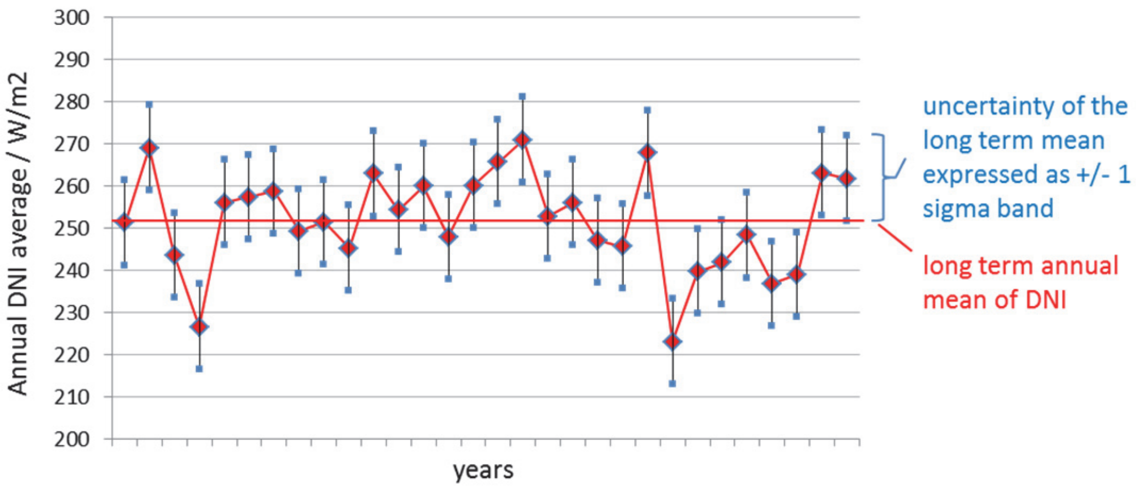


Figure 12-1: Illustration of DNI long-term mean (251,2 W/m^2), its uncertainty of the long-term mean (10 W/m^2=4%), and inter-annual variability (s=12 W/m^2)

Whereas the mean $\bar{G}_{\mathrm{bn}}$ of DNI represents the longterm best estimate of the annual average of DNI, financial evaluation often requests for an annual sum of DNI that will be exceeded with a higher probability like 75% or 90%. These values are indicated as $\bar{G}_{\mathrm{P75}}$, $\bar{G}_{\mathrm{P90}}$, or generally $\bar{G}_{\mathrm{Pxy}}$ where “xy” indicates a certain percentage, which statistically should be exceeded with the likelihood of “xy” %. The basic case for risk assessment of STE plants in most cases is the P90 value. When applied to the annual average of irradiance it reflects the annual DNI average that can expected with a 90% likelihood. There is only 10% likelihood that this annual average will not be met in a long term.

This sort of a irradiance sum P90-value is ignoring the effect of inter-annual variability since it always refers to the uncertainty of the longterm mean. It is called the *multi-year P90-value*, or $\bar{G}_{\mathrm{P90,multi}}$. It is calculated from the long term mean and the knowledge of measurement uncertainty associated to the longterm mean. It is important to understand that a single year is likely to underperform the so-define $\bar{G}_{\mathrm{P90,multi}}$ value if the natural inter-annual variation is large compared to the uncertainty of the longterm mean. With the uncertainty of the long-term mean expressed in terms of $u_{\bar{G}}$, the multi-year $\bar{G}_{\mathrm{P90,multi}}$ value is calculated as

$$\bar{G}_{\mathrm{P90,multi}} = \bar{G}_{\mathrm{bn}} \cdot (1 - 1{,}282\, u_{\bar{G}}) \ . \tag{12.6}$$

Other levels of exceedance are obtained in the same way as

$$\bar{G}_{\mathrm{P70,multi}} = \bar{G}_{\mathrm{bn}} \cdot (1 - 0{,}53\, u_{\bar{G}}) \tag{12.7}$$

$$\bar{G}_{\mathrm{P75,multi}} = \bar{G}_{\mathrm{bn}} \cdot \left(1 - 0{,}674\, u_{\bar{G}}\right) \tag{12.8}$$

$$\bar{G}_{\mathrm{P99,multi}} = \bar{G}_{\mathrm{bn}} \cdot (1 - 2{,}326\, u_{\bar{G}}) \ . \tag{12.9}$$

The above mentioned annual sums always refer to the longterm mean value. A $\bar{G}_{\mathrm{P90,multi}}$ value does reflects the average of annual values that can be expected with a 90% likelihood within a period of multiple years, typically the depreciation period or life time of a STE plant.

Apart from the longterm mean, financial analysis focuses on distinct values since revenues in each year of operation should be high enough to cover all costs. Even a $\bar{G}_{\mathrm{P90,multi}}$ value does not mean that individual years may significantly underperform this value since natural inter-annual variation can lead to significant over- or underperformance compared to the longterm mean. If a 90% probability of exceedance is requested for each single year, the extend of inter-annual variation has to be taken into account. The corresponding annual sum of DNI is called *single-year P-level*. A $\bar{G}_{\mathrm{P90,single}}$ value means that the annual sum of each individual year exceeds the given value with a likelihood of 90%.
Whereas the uncertainty of the longterm mean can well be assumed as normally distributed, the distribution of annual averages of a time series not necessarily follows a normal distribution as can be seen from Figure 12-2.

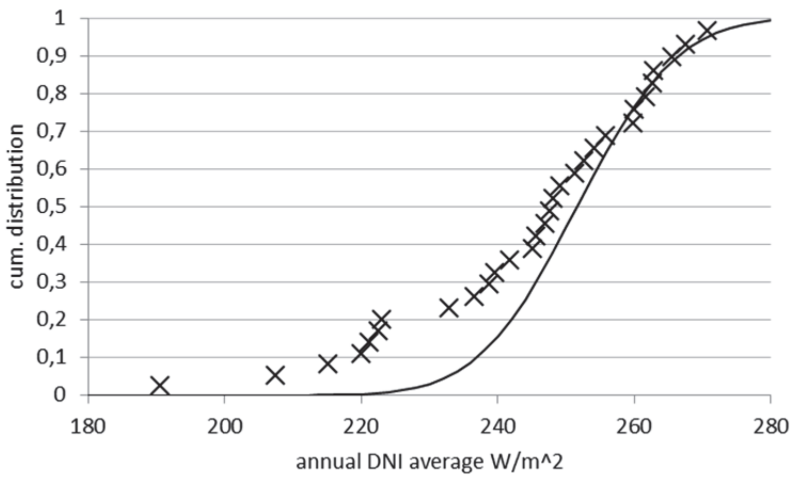


Figure 12-2: Cumulative distribution function of the time series given in Figure 12-1 (crosses) and the corresponding normal distribution based on the mean (251,2 W/m^2) and standard deviation (s=12 W/m^2) of the time series

If normal distribution for the inter-annual variability can be assumed, the single year P-values can be calculated from the multi-year P-values and the standard deviation of the inter-annual variation s as

$$\bar{G}_{\mathrm{P90,single}} = \bar{G}_{\mathrm{bn}} \cdot \left(1 - 1{,}28\sqrt{u_{\bar{G}}^2 + s^2}\right). \tag{12.10}$$

Quadratic summation is allowed since the two uncertainties of longterm mean and inter-annual variation are statistically independent and both have the same mean value $\overline{H}$. The above described approach to calculate Pxy-levels for DNI is assuming a normal distribution of uncertainty and natural variability of DNI. However, due to the fact that there are no negative DNI values and a natural upper limit of DNI the distribution of DNI values rather follows a log-normal distribution. However, it is assumed that the deviations of the simplified statistical approach leads only to minor deviations and therefore still can be regarded as a proper way for bankable yield assessments.

12.2.2. Recommendations for yield analysis

For risk assessments today it is current practice to prepare additional meteorological year (MY) data sets, which show DNI-averages $\bar{G}_{\mathrm{bn}}$, which closely match the respective P-level. E.g. a MY90-data set is representing the $\bar{G}_{\mathrm{P90,multi}}$ level, when averaged over the whole year. More details on generation of such data sets are given in section 12.5.

For risk analysis, it is recommended to use at least one additional meteorological year data set, which represents the multi-year-P90-value $\bar{G}_{\mathrm{P90,multi}}$. This multi-year-P90-DNI value only considers the effect of uncertainty, but not the additional effect of variability.

Yield simulations applying annual data sets representing the lower $\bar{G}_{\mathrm{P95,multi}}$ lead to less power output and thus more conservative yield prognosis then using the data representing the higher $\bar{G}_{\mathrm{P75,multi}}$ value.

However, it is assumed that in the financial risk assessment the yield results are properly associated to the respective level of exceedance. In most cases, also the financial risk assessment assumes a normal Gaussian distribution to derive, e.g. the recommended Debt Service Coverage Ratio (DSCR) for a project. If this is followed properly and as the yield is roughly linear related to the DNI, there will be only a minor influence on financing, which P-level is actually applied. Thus, additional meteorological years representing e.g. $\bar{G}_{\mathrm{P75,multi}}$ or $\bar{G}_{\mathrm{P90,multi}}$ can be taken to cross-check results.

12.3. Climate change and singularities

The main fuel and impact factor of STE yields is beam radiation. DNI is mainly sensitive to cloud occurance and properties and to aerosol. Optical properties and frequency of occurance of these atmospheric constitutents may vary from year to year and could systematically change to to climate change. Thus, it is important to check the potential effect of such changes. Lohmann et al. [35] analyzed the changes of DNI over an observation period of 21 years from 1984 to 2004. During this time at few regions on Earth some significant increases or decreases of DNI were observed.

At least the datasets show some increase in DNI after filters for coal power plants and reduction measures of car emission were introduced. This is subject of current research and trends are different for different areas with high uncertainties. As in most regions trends are not significant it is recommended better not to consider. If substantial changes in the recent past are likely and there are good reasons to assume the conditions observed on the most recent years, rather will prevail, it is recommended better to use the most recent 10 years or few more years instead of the past 30 years, which due to regional climate change are not regarded as respresntative any more.

12.4. Quality requirements for meteorological source data

Compilation of meteorological data files suitable for STE yield analysis requires not only one but several sources of data:

- Long-term time series of direct normal irradiance based on satellite derived data
- Ground measurements of irradiance and other meteorological parameters usually available for a small number of years
- Reanalayis data from numerical weather models providing meteorological parameters to complement ground measurement data to time series of 10 to 30 years.

The following sections compile quality requirements for these kinds of data sources.

12.4.1. Requirements for ground measurement data

At most potential sites for STE plants historic ground measurement data of high quality is not available. In order to correct long-term time series obtained from satellite data ground measurement

[35] Lohmann, S., C. Schillings, B. Mayer, and R. Meyer (2006), Long-term variability of solar direct and global radiation derived from ISCCP data and comparison with reanalysis data, Solar Energy, 80(11), 1390–1401, doi:10.1016/j.solener.2006.03.004.

stations are installed already in early project development phases in order to get a sufficiently long record of on-site data. Good quality of data can only be obtained if the installed station fulfills the following **minimum requirements**.

- DNI has to be measured at least in "good" quality:

Ideally measured by 1st class pyrheliometers, only applicable if cleaning frequency higher than than once every three days , but preferabl daily following McArthur[36].

    - Rotating Shadowband Irradiometer (RSI) , only applicable if cleaning frequency is at least once a month, preferably weekly or better, and sensor is properly calibrated and corrected following best practices as given e.g. in IEA 2015[37].
    - As difference of global and diffuse using at least 2 high quality thermopile pyranometers fulfilling ISO 9060,1900 secondary standard requirements. At least one of these pyranometers must be unobstructed to measure global horizontal irradiance in high quality. At least one pyranometer shall be shaded using a shadowball on a 2-axis solar tracker. Cleaning frequency of both pyranometers must be at least once a week, but preferabl daily following McArthur[36]. Not acceptable are diffuse pyranometer measurements obtained by means of stationary shadowrings.
- Recalibration frequency at least once every 2 years
- Horizon at least fulfilling WMO class 3 for Direct Radiation according to the WMO-CIMO-guide, 2012. This means no shade of surrounding obstacles is projected onto the sensor, when the sun is at angular height of over 7°. Recommendation is to reach better WMO Direct Radiation Class 2, where the limit is lowered to over 5°. Ideally WMO Direct Radiation Class 1 is reached with unobstructed measurements down to 3° sun height.
- Proper documentation of site, station & instruments is maintained
- Auxiliary meteorological data to be measured at same site:
    - Ambient temperature & relative humidity with radiation shield sufficiently ventilated
    - Wind direction & speed at 10 m height
    - Barometric pressure
- Temporal resolution of all devices higher than 10 min
- Thorough quality checks (QC) of the measured data are essential. Recommendation is to do daily automatized checks like described in Schwandt[38] and in addition visual checks at least on a quarterly, preferably monthly base.

Apart from these minimum requirements this guideline recommends to apply the following more demanding criteria in order to assure high quality data

- Temporal resolution of at least 1 min

---

[36] McArthur, L. J. B. (2005), Baseline Surface Radiation Network. Operation Manual, Operation Manual, WMO/BSRN, 188 p.

[37] Wilbert, S., N. Geuder, M. Schwandt, B. Kraas, W. Jessen, R. Meyer, and B. Nouri (2015), Best Practices for Solar Irradiance Measurements with Rotating Shadowband Irradiometers. IEA Solar Heating & Cooling Programme (SHC) Task 46 Solar Resource Assessment and Forecasting, 68 p.

[38] Schwandt, M., K. Chhatbar, R. Meyer, I. Mitra, R. Vashistha, G. Giridhar, S. Gomathinayagam, and A. Kumar (2014), Quality Check Procedures and Statistics for the Indian SRRA Solar Radiation Measurement Network, Energy Procedia, 57, 1227–1236, doi:10.1016/j.egypro.2014.10.112.

- Cleaning frequencies: Pyrheliometer ≤ 1/d
  Pyranometer ≤ 1/d
  RSI ≤ 1/week
- Soiling correction should be applied to avoid systematic underestimation
- Check/recalibration to be carried out yearly
- Additional auxiliary parameters for site qualification:
  - Precipitation by rain gauge (snow depth sensor where relevant amount of snow may occur)
  - Soiling measurements
  - Corrosion test with an exposure of one year according to [ISO 9226:2012] and analysis of corrosion rates according to [ISO 8407:2009].
  - Visibility sensor or transmittometer, if solar tower technology is considered an option. Recommendation is that visibility range is at least 50 km better more than 70 km.
  - More than 1 station for very large sites > 10 km^2 – especially if hilly terrain

12.4.2. Requirements for satellite derived data resources

Satellite data is hardly anywhere available for at least 15 years into the past. Satellite data therefore represent the most important source for predicting the long term mean of irradiation at a specific site. Due to strong inter-annual variation of direct normal irradiance at least 15 years of data should be used to average out fluctuations. Satellite derived data sets should always be calibrated by appropriate ground measurements since the bias associated with satellite-only products is usually too high. The following list provides minimum requirements for input data from satellite sources

- Temporal coverage ≥ 15 a
- Temporal resolution ≤ 60 min
- Spatial resolution ≤ 10 km or 0.1°
- Absolute accuracy: mean bias MB < 20%
- Representing DNI fluctuations: standard deviation of diff. SDD_{60min} < 40%
- Realistic frequency distribution

12.4.3. Requirements for reanalysis from numerical weather models

Since wind, temperature, humidity, and other near to surface parameters can not be derived from satellite data reanalysis by means of numerical weather models helps to create consistent ground parameter data to an existing satellite derived irradiance data set. For this purpose the numerical weather models are operated in retrospective. The following minimum criteria should be fulfilled for this kind of data source:

- Spatial resolution of the numerical weather model less than 1° / approx. 100 km
- Temporal resolution of the numerical weather model less than 6 h

However, more demanding recommendations are provided for reanalysis data:

- Temporal disaggregation to the same resolution as radiation data, i.e. 10 to 60 min
- Spatial disaggregation by regional models down to approx. 10 km

- Adaption to local measurements

12.4.4. Requirements for correcting satellite retrievals by ground measurements

Polo et al.[39] review various methods of adapting satellite/model-derived to measurements. Some like e.g. Mieslinger et al.[40] do a post-processing to adjust the model-derived data, while others adjust the input of the model - typically the turbidity data so that the derived DNI better matches the measurements. Whatever statistical procedure is applied, the first objective shall be to minimize bias so that the amount of incoming solar energy is not showing systematic over- or under-estimation. Second objective is to adapt the frequency distribution of the model-derived data as close as possible to the observations from ground.

Requirements for algorithms to adapt satellite DNI to ground measurements

- Overlap ≥ 1 year
- Shall minimize bias MB of sat-DNI on average
- Should improve frequency distribution of sat-DNI to better match measured

Recommendations

- Overlap ≥ 3 years
- Adaption should result in realistic annual pattern
- 60 min sat DNI should be temporally disaggregated to 10 min

12.5. Requirements for generating representative meteorological years

Generating typical meteorological year data sets (TMY) is a way to condense long-term time series of meteorological data into one single characteristic year. Various methods how to create such TMY data sets have been presented e.g. by Wilcox[41] , Hoyer-Klick[42], or Cebecauer[43]. Currently, under the IEC TC117 STE experts just agree on an International Technical Specification for creating STE-specific TMY data sets[44]. This standard under preparation is recommended to be used for STE yield simulations. In the following sub-chapters the recommended methodology for generating STE-sprecific TMY-data sets is briefly described.

Apart from meeting the average DNI value of the long-term time series various other criteria have to be fulfilled in order to represent well the meteorological characteristics of a specific site. When it comes to uncertainty assessment, the TMY method can be used to create a representative year with a

---

[39] Polo, J. et al. (2016), Preliminary survey on site-adaptation techniques for satellite-derived and reanalysis solar radiation datasets, Solar Energy, 132, 25–37, doi:10.1016/j.solener.2016.03.001.

[40] Mieslinger, T., F. Ament, K. Chhatbar, and R. Meyer (2014), A new method for fusion of measured and model-derived solar radiation time-series, Energy Procedia, 48, 1617 – 1626, doi:http://dx.doi.org/10.1016/j.egypro.2014.02.182.

[41] Wilcox, S., and W. Marion (2008), Users Manual for TMY3 Data Sets, Innovation for Our Energy Future, Technical Report, National Renewable Energy Laboratory - NREL, Golden, Colorado, USA.

[42] MESoR Existing Ground Data Sets.

[43] Cebecauer, T., and M. Suri (2015), Typical Meteorological Year Data: SolarGIS Approach, Energy Procedia, 69, 1958–1969, doi:10.1016/j.egypro.2015.03.195.

[44] IEC TC117 (2016), IEC/TS 62862-1-2 Ed. 1.0 Solar thermal electric plants - Part 1-2: Procedure for generating a representative solar year.

mean DNI that is exceeded by a certain probability. The guideline in the following sections provides minimum requirements for the construction of representative meteorological years.

12.5.1. Length of the source data to be considered

The primary goal of STE-specific solar resource assessments is to derive the longterm average of DNI as precicesly as possible. Climatological variability of annual averages of DNI at most sites is in the order of 10 %. Therefore, as many years as possible should be averaged for a stable representative DNI longterm average. Minimum requirement is to average at least 10 years of suitable DNI data. Recommended is to use up to 30 years of data to create normal[45].

Multi-year ground measurements carried out at the site under investigation provide a very good basis for yield calculations. However, ten years time series are usually not available. Thus, a combination of DNI values obtained from historic satellite images with calibration based on multiple-month ground measurements is considered as the state of the art method to reduce uncertainties in DNI prediction. The more information is used to construct the time series used in the yield calculation the more representative the result will be.

However, up to 30 years should be used only, if the site is not showing strong climate change in the recent past and data quality is high also for early years. According to WMO[45] the optimal length of record for predictive use of normals varies with element, geography and secular trend. The most recent 10-year observation period can have as much or better predictive value as a 30-year record. In some regions in the last 30 years, emissions decreased or increased strongly. In such a case, averaging only the most recent 10 years is to be preferred. However, associated uncertainty levels need to be set to higher values due to shorter duration of observations.

Occasionally due to poor availability of satellite data uncertainty of certain years can be much higher than in other years with better coverage or quality. Then it is permitted to exclude these years with exceptional high uncertainty in order to reach a lower overall uncertainty. But minimum requirement remains that at least a total of at least 10 years. The overall goal is to reach the lowest possible total uncertainty of the longterm DNI, but besides the uncertainty of the DNI depending on the derivation method also the number of years taken for the averaging needs to be considered in the uncertainty calculation.

[45] 2011, *Guide to climatological practices*, Geneva, Switzerland: Secretariat of the World Meteorological Organization (WMO) Retrieved from http://www.wmo.int/pages/prog/wcp/ccl/guide/guide_climat_practices.php

12.5.2. Matching the DNI distribution function

Adaption processes such as described by Polo[46] primarily aim to minimze bias between satellite/model-derived time-series and measurements considered as „ground truth“. Procedures such as Mieslinger[47] in addition also adapt higher orders of the statistic distribution. Such is strongly recommended, because the distribution function of DNI due to non –linear effects of STE plants, may have strong impact on the potential STE yield.

12.5.3. Matching the temporal distribution

In addition to the long-term mean of DNI its temporal distribution at the plant site must be considered when creating representative meteorological data sets. Temporal distribution shall at least cover the following aspects:

a) Inter-annual variability from year to year
b) Seasonal cycle
c) Daily cycles
d) Intra-day fluctuations

The inter-annual variation should be indicated as the standard deviation (1-sigma, σ_{IAV}) over all annual averages of DNI. It is used to estimate how strong actual DNI yearly values may exceed or undermine the longterm average DNI. The extend of natural variations from one year to the other is of high relevance for the financial engineering of the project since annual cash-flows depend on the output of the plant.

The distribution of DNI over the year – the seasonal cycle – shall be well represented in STE-specific meteorlogical data sets. Reason is that the distribution of potential energy yields of a solar thermal plant should be representative for the region. To reach a good characterization according to Hoyer-Klick[48] the monthly averages of DNI in TMY data sets should be within +-5% of the longterm average of each calendar month. In multi-year data sets no such filtering should be done as on average the monthly averages are already well representing the longterm monthly averages. The mult-year data set has the additional advantage over the TMY that the variation of the seasonal cycle from year to year is represented.

The daily cycles should well represent variation during the days and also high frequency fluctuations down to the the minute time scale. Other then for the monthly averages there is no requirement for TMY generation. The goal is to get DNI fluctuations showing characteristics, which are very similar to those observable at the STE site. Ideally a TMY data set is derived from actually measurerd data at the

---

[46] Polo, J. et al. (2016), Preliminary survey on site-adaptation techniques for satellite-derived and reanalysis solar radiation datasets, Solar Energy, 132, 25–37, doi:10.1016/j.solener.2016.03.001.

[47] Mieslinger, T., F. Ament, K. Chhatbar, and R. Meyer (2014), A new method for fusion of measured and model-derived solar radiation time-series, Energy Procedia, 48, 1617 – 1626, doi:http://dx.doi.org/10.1016/j.egypro.2014.02.182.

[48] Hoyer-Klick, C; Hustig, F., 2009, Characteristic Meteorological Years from Ground and Satellite Data, Proceedings of SolarPACES 2009, Berlin, Germany Retrieved from http://solarpaces2009.org

site. To achieve this it is recommended to follow the concatenating method developed by Hoyer-Klick[48]. If multi-year data sets are applied in yield assessments, those years when there are no ground-based measurements but use only satellite/model-derived data also should show similar temporal characteristics as the ground-based data.

12.5.4. Expressing the uncertainty of the long-term mean

The true value of the longterm average actually may be little higher or lower than the value given in an assessment. When an assessment is issued the longterm average of DNI should be the best estimate – the value most likely representing the longterm average of DNI. It should not under- or overestimate meaning it should be free of bias. But this best estimate always shows uncertainty as introduced in section 12.2. It is obligatory for a bankable solar resource assessment that the uncertainty of the longterm average of DNI is indicated. This may be given in absolute values such as in units of W/m² referring to averaging over 24 h. Alternatively, uncertainty can be reported in relative values such as % in relation to the longterm average. Since most times it can be assumed that the uncertainty follows a normal distribution it is recommended to indicate the uncertainty level of DNI related to a single standard deviation (1 sigma, $\sigma_{\overline{H}}$). If other conventions are used (e.g. the 95 % uncertainty range) it must be clearly indicated and consistently used in the full assessment.

12.5.5. Time step of meteorological data files

Time resolution of the STE-specific meteorological data set shall be at least 60 min. However, for bankable yield assessments the overestimation of yields caused by application of houly smoothed time-series must be corrected by the performance simulation tool. To avoid this error preferably data sets with 10 min time resolution min or better should be used (see also section 3.5).

12.6. Recommendation for considering weather forecasting

For prognosis of potential yields of a STE plant the quality of the to be applied weather forecasts may have significant influence on results – especially if advanced models are applied, which realisticly simulate the operation rules to be applied. Today already specialized STE-weather forecasts are available, which cover the nowcasting scale from few minutes ahead to about +3 h, over short-term forecasting up to +3 days to mid-term forecasting, which may reach up to +30 days and could be useful for smart plant maintance scheduling.

In principle such met data providers could supply pseudo-forecasts. Such “hindcasts” (historic forecasts) could represent a population of potential forecasts using their specific forecast system for the site based on historic input data from “reanalysis”. Such ensemble data sets of hindcasts would need to cover vast amount of cases to represent various realizations of meteorolgical forecasts to be used. For each potential forecast supplier to be considered another such hindcast data sets would need to be provided. However providing such hindcast data sets for evaluation today is not a common practice and it is highly questionable whether any simulation expert actually would makes the brute force computing effort to evaluate such a third order effect on STE yield by such a probabilistic approach.

To approach the effect in a much simpler way the following 2-way approach is recommended.

1. The simplest forecast is assuming persistence of weather conditions. As weather tends to remain stable from day to day, already relatively good forescast quality is achieved if simply the weather from the day before is copied. This would represent the simplest forecast, which every serious STE-specific forecast should be able to exceed.
2. To see the effect of the 'ideal forecast' the actual time-series could be taken, which would represent utmost forecasting skills, which never will be reached.

Both forecasts can be taken simply from the actual weather file. Reality depending on forecast skill then will be somewhere in between both extreme cases. Today no systematic quantification is yet given how to weight both cases depending on forecasting skill factors. Expert guess is to weight the result of the persistence forecast 75% and 25% to the ideal forecast.

12.7. Data formats

Several different formats for providing meteorological input data to solar simulation tools exist. Most of them use „text"-files, which pass the values by using ASCII-characters. In most cases, the data type is floating point values, using a reasonable number of digits displayed by numerical numbers using „." as digital separator. Although such text-files are not very efficient in handling large amounts of data and may cause problems to be read automatically, they have the advantage that they can be easily displayed and manipulated using text-editors. Most programming languages and spreadsheet calculation software allow to read them easily at least, if time-resolution is not very high and not very many years are represented by the data file.

Wilcox[49] have defined the TMY3-data format, which can be easily input to the popular simulation software tools like SAM or Greenius. However, the TMY3 data format is restricted to hourly time-resolution and the description of the meta-data is limited. To overcome these shortcomings, Hoyer-Klick[50] have defined the MESoR version 1 data format. This is also a text-file-format, which allows a free number of columns – called ‚channels' - which may be extensly defined and described in the header. This allows e.g. to add non-standard parameters like visibility or near-surface extinction coefficient. Recently, the experts Meeting of the collaborative IEA Task SHC-Task 46 / SolarPACES Task V approved a slightly advanced version of this format as described in Hoyer-Klick[51]. The format is available online at www.mesor.org . It is planned to publish this format also as a Technical Specification document TS 62862-1-3 of IEC TC 117 Solar thermal electric plants.

[49] Wilcox, S., and W. Marion (2008), Users Manual for TMY3 Data Sets, Innovation for Our Energy Future, Technical Report, National Renewable Energy Laboratory - NREL, Golden, Colorado, USA.
[50] Hoyer-klick et al.: MESoR Existing Ground Data Sets. 2008
[51] Hoyer-Klick, C., R. Meyer, and S. Wilbert (2016), Data format for meteorological data sets. Draft Report of IEA-SHC-Task 46 / SolarPACES Task V, International Energy Agency (IEC) Solar Heating & Cooling (SHC) Task 46 / SolarPACES Task V.

13. Representing uncertainties

The prediction of the energetic yield of a STE plant is always associated with a certain degree of uncertainty since:

- The performance values of the components actually installed in the plant differ to a certain extend from the ones assumed for the yield analysis
  → parameter uncertainty
- The solar resource can be estimated from past time series but as every measurement this involves uncertainty. In addition, there is the possibility that the resource in the future differs from past measurements.
  → uncertainty of meteorological input data
- Modeling always implies simplifications since the real behavior is too complex to model for yield analysis purposes and there is always some lack of knowledge concerning details of the process. Differences between the operation strategy assumed during yield analysis and the one applied during operation constitute a further source of uncertainty.
  → model uncertainty

The engineering task is to model the process as correctly as possible and as detailed as necessary. The remaining uncertainty needs to be estimated for consideration in the financial engineering of the project. The intention of this chapter is to provide a concept and framework for such an uncertainty analysis as a first step towards a transparent and harmonized approach.

13.1. Mathematical description of uncertainty

Some elementary statistical terms need to be explained for handling uncertainties.

Definition of uncertainty

The uncertainty of a measurement is defined as a parameter that characterizes the dispersion of the measured values around the true value or the interval about a measured value that is likely to encompass the actual value with a certain probability. The uncertainty of a simulation result should represent the vagueness of the predicted quantity for a certain coverage probability. As no measurement process nor equipment, nor set of input parameters, nor simulation approach is perfect, every measurement and simulation result must be fraught with uncertainty.

Formerly, uncertainty was often considered as “error”. The concept of error implies that there is a true value relative to which the magnitude of errors can be quantified. In practice however, such true values are never known. Uncertainty in contrast, refers to the measured or predicted value itself. In terms of the mathematics involved, the two concepts of “error” and “uncertainty” are very similar and commonly described in literature, but the concept of uncertainty is preferred today. The term error rather tends to be associated with actual errors that can occur due to deficient measurement set-ups or inadequate modelling. Such errors are to be reduced to a minimum with reasonable care and identified remaining risks are to be translated into uncertainty contributions. In terms of STE yield analysis, a typical “error” would be a mistake in the implementation of the simulation tool resulting in a calculation result other than intended. Obligatory quality checks of tools are expected to reduce this type of error to a minimum. Thus, the guideline focuses on the “uncertainty” that remains after all “errors” are eliminated. The general rules for expressing and evaluating measurement uncertainty are set in the “Guide to the Expression of Uncertainty in Measurement” – the so called GUM. GUM is a standard by the International Standards Organization and the basis for the following uncertainty evaluation in general. It can also be applied for propagation of uncertainty into predicted/simulated quantities.

Expressing uncertainty and probability of exceedance

Given a data set with multiple results, e.g. annual yields simulated by varying the input parameters within the expected uncertainty intervals, statistical methods can be applied to describe the underlying distribution. Figure 13-1 (left) shows an uncertainty density distribution of the annual electrical yield *E*. The curve is obtained by splitting the yield axis in discrete intervals and counting the number of results falling into this interval. By means of arithmetic averaging of the values of the data set time series the mean value which is also called the P50 value is obtained. If the underlying time series is used to forecast the expected yields, the P50 value indicates the energy yield that can be expected with a 50% probability. This means that 50% of the values will fall below or equal the P50 value while 50% will fall above or equal the P50 value.

For illustration purposes, a density distribution is transformed into a cumulative density function by integrating the probability density function up to a certain value and plotting the resulting cumulated probability as a function of this upper integration limit. Thus, the cumulative density function shows the probability of staying below a certain value. In the case of a finite number of available data sets (as typical in yield analysis) a similar information is obtained by sorting the yields in ascending order, summing up their frequencies up to a certain limit, deviding the result by total number of data sets and plotting plotting the results as a function of that limit which yields an empirical density distribution.

Although the cumulative density function is widely used, it is more instructive to consider its inverse when dealing with annual yields. The inverse is obtained by inverting the y-axis value as illustrated in Figure 13-1 (right). The probability value then reflects a probability of exceedance which is usually the figure of interest in yield analysis. For financial assessment, a probability of exceedance of 90% is often considered since it reflects a value that is to be exceeded with a 90 % probability. When dealing with an amount of energy or yield we write E_{P90} for this value. In the example shown, the difference $\Delta E_{50/90}$ between the 50 % probability value of 150 GWh and the 90 % probability value of 124 GWh amounts to 26 GWh.

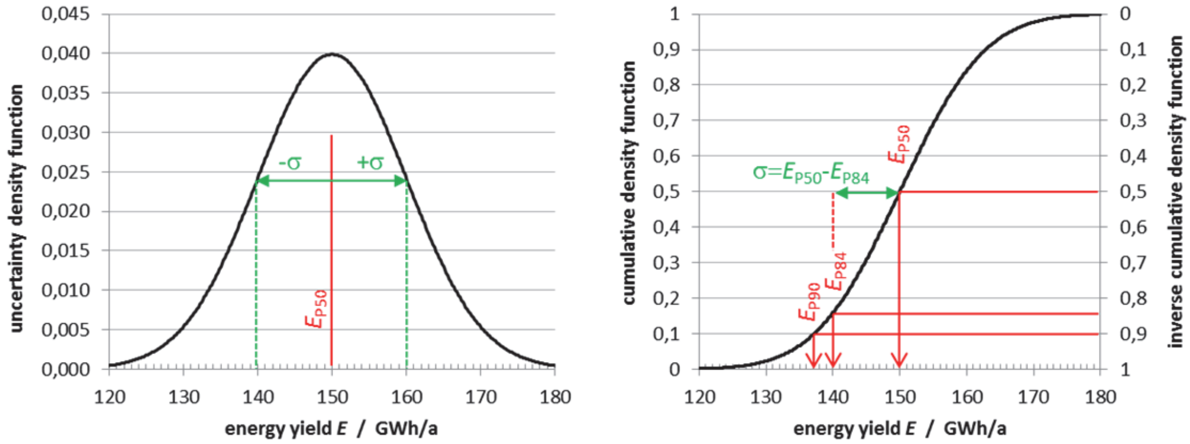


Figure 13-1: Uncertainty density distribution (left) and cumulative density function (right) of the energy yield

Uncertainties of measured values and evaluation results based on a large number or independent inputs often follow a normal distribution, also called Gaussian distribution. A normal distribution is fully defined by its mean value μ and the standard deviation σ. For a normal distribution 68,3% of the realizations are found in an interval of $\mu \pm \sigma$, 95,4% in the interval $\mu \pm 2\sigma$, and 99,7% in the interval $\mu \pm 3\sigma$. When looking at the cumulative density distribution the $\pm\sigma$ values correspond to a 84,15% probability of exceedance (68,3% are within the $\pm\sigma$ interval and (100%-68.3%)/2 additional are below the $\mu + \sigma$ value). Given a cumulative density distribution, the standard deviation is directly obtained as

$$\sigma = E_{\mathrm{P50}} - E_{\mathrm{P84}}\,. \tag{13.1}$$

Although the σ notation is default in statistics it is valueable to transform the uncertainties into figures used in practice, at least when dealing with annual yields. Individual values of exceedance, E_{Pxy},

$$E_{\mathrm{Pxy}} = \mu \cdot \left(1 - f_{\mathrm{xy}} \cdot \sigma\right) = E_{\mathrm{P50}} \cdot \Big(1 - f_{\mathrm{xy}} \cdot (E_{\mathrm{P50}} - E_{\mathrm{P84}})\Big) \tag{13.2}$$

can be calculated based on the μ and σ value with the factors provided in Table 13-1.

Table 13-1: Factors to calculate the probability of exceedance Pxy of a normal distribution depending on the 1-sigma uncertainy.

Pxy	P99	P95	P90	P84	P75	P70
f_{xy}	2.326	~1.645	~1.282	1	0.674	0.524

Methods to aggregate different uncertainty contributions

In case the overall uncertainty u_c of a process $f(x_i)$ depends on several uncertainty contributions u_i, established mathematical methods are available to aggregate contributions to an overall value. If the uncertainty distributions of all parameters can be assumed as normal, the uncertainties of the contributions are independent of one another, the combined uncertainty uc can be calculated as

$$u_{\mathrm{c}} = \sqrt{\sum_{i=1}^{n} \left(\frac{\partial f}{\partial x_i} u_i\right)^2} \; . \tag{13.3}$$

For normal distribution, the uncertainty of the individual parameter distributions and thus the resulting combined uncertainty is expressed as the 1 σ value.
For cases not meeting the above mentioned criteria more complex calculation procedures have to be applied involving the correlation of uncertainty effects in case of dependent inputs [GUM 2008].
An alternative to these structured approaches is to generate a large number of samples covering the whole range of parameter variations and carry out a simulation for each of them. When plotted as a empirical cumulative density function the characteristic values mean and standard deviation can easily be derived. Monte-Carlo or Latin Hypercube sampling are methods to reduce the number of samples needed for the analysis.

13.2. Sources of uncertainty for STE plant yield analysis

The particular approach recommended for calculating uncertainty contributions depends on the origin of the individual source of uncertainty. Three classes of uncertainty are introduced for classification.

Table 1-1 illustrates the three main sources to be considered in STE yield assessments and providesexamples for each. Since the characteristics of each class are very individual, specific approaches for handling the classes are recommended.

Table 13-2: Categories of uncertainty sources in STE plant yield analysis

Source of uncertainty	Description	Examples
Modeling approach	Uncertainties in modeling the physical plant The way physical effects are translated into a mathematical formulation and discretized in time. Simplifications are necessary since some effects are not fully understood or detailed modeling would be computationally to expensive. Inaccuracies arise by averaging within one time step. Uncertainties in modeling the operation strategy A major contribution is the uncertainty originating in the implementation of the operation strategy.	Unrealistic representation of a start-up procedure in the model, not considering that high wind speeds cause additional optical losses. Assumption of an "ideal" weather forecast within the time step. Impact of the human operator.
Technical parameters	The performance values and physical properties of the technical configuration considered. Uncertainties arise from deviations between planning and realization as well as uncertainties in the measurement of physical properties.	Underestimation of actual mirror reflectivity, overestimation of absorber heat losses, underestimation of turbine efficiencies in part load, overestimation of cooling tower efficiency at high humidity
Boundary conditions	All time-dependent inputs into the simulation tool are a forecast of the expected situation when the plant is built. Uncertainties arise from this prediction.	Overestimation of the annual solar resource, only rough information on sunshape and atmospheric visibility (especially relevant for solar towers)

Difference between uncertainty and design changes

Having a look at uncertainties during the different project development phases helps to better understand the above mentioned categories. Clearly, with each step in project development the input data will become more and more representative for the expected real situation at the end, see also chapter 14. First models start off rough and then, the complexity is increased asymptotically aiming to bring the simulated value close to the actual value. It is important to understand that the uncertainty always refers to the plant configuration that is currently studied. While a lot of design changes will take place in the course of project development the uncertainty in each stage describes the expected differences of yield between the simulated and measured value based on the actual configuration. Although the design of the plant might strongly change from pre-feasibility and proposal engineering stage (e.g. solar field size doubled) the uncertainty of yield prediction does not include this design change. In fact, the predicted value of an early stage yield analysis is never compared to the value measured in the actual plant.

Figure 13-2 illustrates the development of yield calculation in the course of project development. The uncertainty of meteorological input data clearly decreases since more effort is spent on preparing and assessing the data. Additional sources are used and more ground measurement data from the site are available for validation. Whereas a typical value of the standard deviation of the long-term mean is in the range of 8% in a pre-feasibility study, high quality resource assessment can bring this value down to 4-5% (depending on the site).

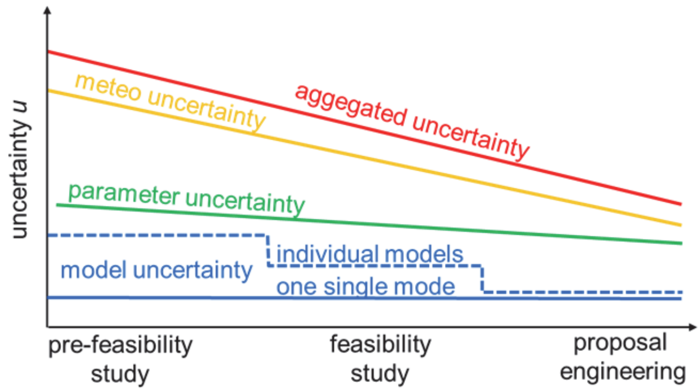


Figure 13-2: Reduction of uncertainty levels in the course of project development

The uncertainty associated with the parameters does not decrease to the same extend as meteorological data in the course of project development. Since design changes are not part of the parameter uncertainty, the parameter uncertainty represents the difference in performance of certain parts of the system compared to the performance assumed during the simulation. As an example, a turbine designed to have a 80 to 90% isentropic efficiency might show some deviation from this design value when finally installed. The difference arises from:

- Production-related minor variations (within the normal tolerance range) in the performance of each technical system
- Slightly modified performance values during the purchasing process (due to cost or other reasons)
- Irregularities during maintenance work

An improvement (=reduction) of parameter uncertainty is obtained if more precise data become available that allow to reduce the uncertainty estimate for certain parameters. This could be due to specific manufacturer information indicating higher precision of its product. The smaller uncertainty should only be applied if this information is trust-worthy and ideally supported by other data.

Model uncertainty

Model uncertainty evolution in the course of project development can take several forms. In many cases, models developed for the proposal engineering phase are also used in earlier stages simply to avoid phase-specific tools. While the parameters for early stages are rough estimates and the uncertainty is quite high, the simplifications by the model itself (equations describing the effects) remain more or less constant. A decrease in uncertainty might be obtained if the model is specifically validated for the configuration used in the project. In case different tools are used for different phases, early-stage tools typically include more simplifications which may lead to higher uncertainty. When switching to higher accuracy models in one of the next stages an important step in accuracy can be reached.

13.3. Approach to determine the overall uncertainty

Similar to the modeling approach itself the method to determine uncertainty can be based on individual analysis of the three components parameter, model, and meteorological input uncertainty. The idea behind this is the assumption that all contributions to the combined uncertainty can be grouped into three sources “parameter”, “model”, and “meteo” with the uncertainty of one of the groups always being independent of the uncertainty of the other two. Assuming further that the resulting uncertainty distributions from each of the groups are normal the three components can be combined by

$$u_{\mathrm{c}} = \sqrt{\left(\frac{\partial f}{\partial x_{\mathrm{param}}} u_{\mathrm{param}}\right)^2 + \left(\frac{\partial f}{\partial x_{\mathrm{model}}} u_{\mathrm{model}}\right)^2 + \left(\frac{\partial f}{\partial x_{\mathrm{meteo}}} u_{\mathrm{meteo}}\right)^2} . \tag{13.4}$$

The impact of parameter uncertainties $u_{\mathrm{param},i}$ on the overall result is obtained in a separate calculation process (e.g. by Monte-Carlo simulation). The resulting normal distribution is described by its standard deviation $\sigma_{\mathrm{param}}=\frac{\partial f}{\partial x_{\mathrm{param}}} u_{\mathrm{param}}$. In a similar way, the uncertainties on the energetic yield due to model uncertainty and uncertainty of meteorological input parameters are obtained. Representing all three uncertainty distribution by their respective standard deviation the combined uncertainty in terms of standard deviation is obtained by

$$\sigma = \sqrt{\sigma_{\mathrm{param}}^2 + \sigma_{\mathrm{model}}^2 + \sigma_{\mathrm{meteo}}^2} . \tag{13.5}$$

The assumption of a normal distribution is suitable for expressing the uncertainties of the three components[52]. In case analyses of the three components reveal alternative distribution functions, one might either use more complex analytical formula to combine the terms or use Monte-Carlo simulations to numerically determine the overall uncertainty.

[52] Please keep in mind that the uncertainty of the long-term mean of direct irradiation can well be described by a normal distribution whereas the distribution of inter-annual variation might follow other distribution functions.

The separate assessment of the three proposed sources contributing to the final uncertainty of the simulated yields a well-structured approach which can be implemented rather easily for yield simulation with the added benefit that information about their relative uncertainty contributions is readily available. This might be used in deriving steps to reduce overall uncertainty. The approach is sketched and explained in the next paragraphs for the three individual categories.

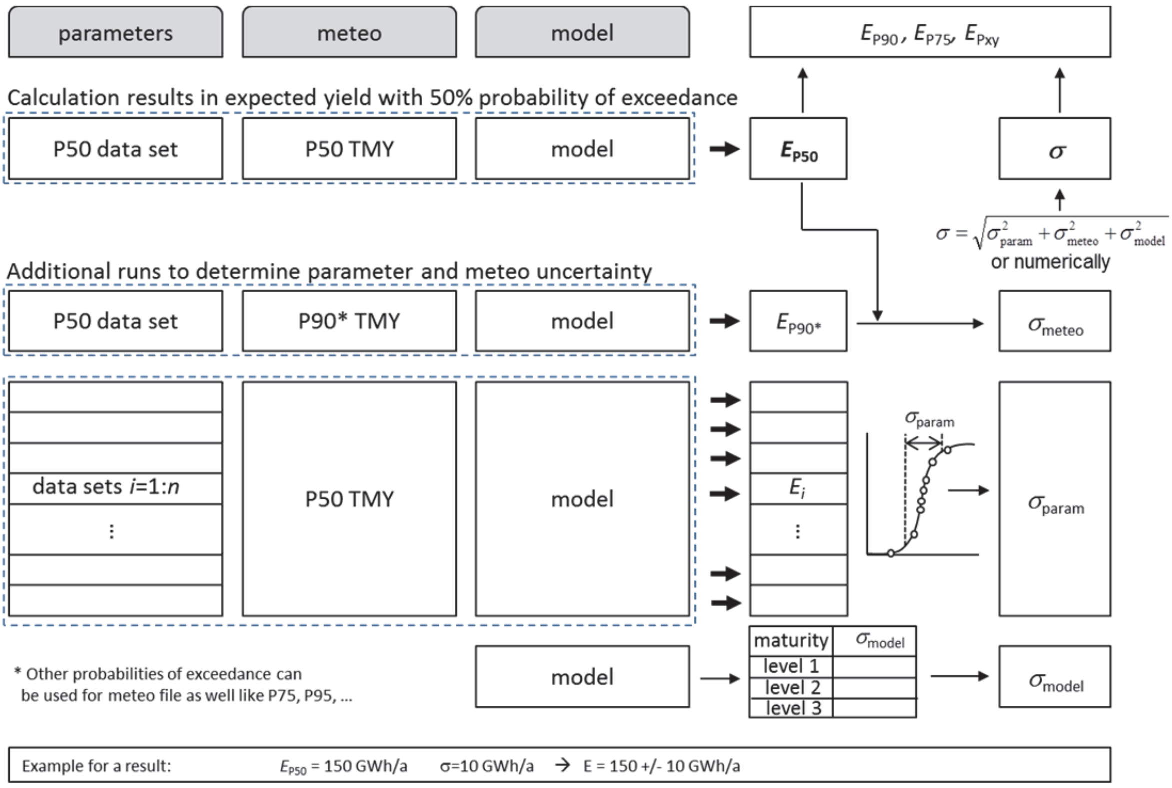


Figure 13-3: Structured approach to determining overall uncertainty based on the three categories parameter uncertainty, model uncertainty, and uncertainty of the meteorological input data.

Calculating parameter uncertainty

The uncertainty of the annual yield due to the uncertainty of the model parameters is best determined by means of probabilistic modelling. This approach is based on the generation of a sufficiently large number of random sets of model parameters representing their respective uncertainty distributions and honoring their potential correlations. The performance model is then evaluated for every parameter set (called sample). On the basis of the results obtained, the probability densitiy and cumulative density functions of the target quantity, usually the annual energetic yield, are generated allowing the assessment of the target quantity in terms of expected value and different probabilities of exceedence. These consecutive steps of a probabilistic uncertainty assessment are illustrated in Figure 13-5.

The calculation starts with the identification of the model parameters that have to be treated with uncertainty. Both, the impact of a parameter and its estimated uncertainty need to be taken into

account in order to identify those parameters with high impact. A pre-study is usually required for that. It is not possible to set up a generic list of parameters that need to be considered since the set of model parameters strongly depends on the chosen modeling approach. In order to reduce the number of parameters for the probabilistic analyses it is advisable to aggregate the impact of low level model parameters to a higher level, e.g. describing the aggregated uncertainty of the optical and thermal efficiency of a collector instead of processing a large number of individual model parameters.
As a minimum requirement the uncertainty analysis has to cover the impact of the dominating physical effects, Figure 13-4. During feasibility study it can be assumed that the uncertainty determined for the design conditions can also be applied in off-design operating conditions. A closer look is required for proposal engineering. The number of off-design effects is usually large. In order to reduce the number of probabilistic runs it is recommended to aggregate uncertainty in off-design operation into one or two meaningful parameters. Additional effects like start-up energy or wind impact shall be considered for proposal engineering since they have certain impact on the result and parameters are often associated with high uncertainty.
The yield report has to include an information which parameters are considered for probabilistic analysis and which distribution has been assumed for them. It is recommended to report the following entries:

- Name of the parameter making clear its physical relevance
- Type of uncertainty distribution assumed
- Mean value, 1 sigma, other required characteristic values for the chosen distribution
- Guarantee value (estimate of aggregated parameter)
- Impact in terms of uncertainty contribution on the energetic annual yield

Pre-feasibility studies	
Whole plant	Bulk uncertainty

Feasibility studies	
Solar Field	Design optical efficiency
	Design overall heat loss
Power block	Design gross efficiency
Thermal storage	Design heat loss
Auxiliary heater	Design efficiency
Electrical	Design aux. consumption (without main pumps)
System level	Design aux. consumption main pumps

Proposal engineering	
Solar Field	Design and off-design optical efficiency
	Design and off-design receiver heat loss
	Design and off-design piping heat loss
	Sun shape impact (for towers)
	Wind impact
	Start-up energy
	Effective mirror reflectivity
Power block	Design and off-design gross efficiency
	Start-up energy
Therm.storage	Nominal heat loss
	Nominal storage capacity
Aux. heater	Nominal efficiency
Electrical	Nominal aux. consumption (w/o main pumps)
System level	Aux. consumption main pumps
	System level availability

Figure 13-4: Minimum requirements for probabilistic modeling in the three phases.

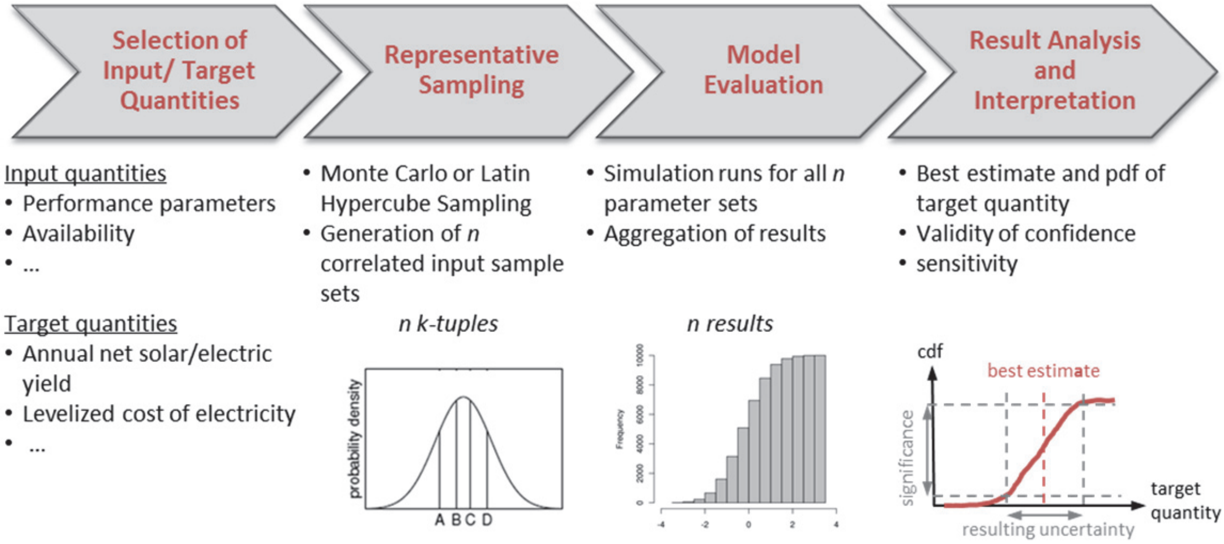


Figure 13-5: Estimating parameter uncertainty by probabilistic assessment

For the chosen parameters, samples are generated by means of Monte-Carlo or Latin Hypercube sampling. Both methods aim at reducing the number of theoretical variations to a minimum that is sufficient to represent the underlying uncertainty distributions. Annual yield calculations are carried out for each sample. With the results plotted in a distribution function, the interesting values like mean and standard deviation can be read from the diagram. From the distribution the 1-sigma value σ_{param} is obtained as

$$\sigma_{\text{param}} = E_{\text{P50}} - E_{\text{P84}} \quad . \tag{13.6}$$

Requiring only the performance model itself and the statistical means for the generation of parameter samples and evaluation of the resulting distribution of the target quantity, the probababilistic uncertainty assessment is considered as the most efficient, versatile, and meaningful means of evaluating the impact of parameters onto simulation results.

<u>Determining model uncertainty</u>

A simulation model is always an incomplete approximation of a real physical system. An accurate model is reached once the error induced by the simplifications is small relative to the results. When it comes to STE yield modeling, the majority of modeling approaches has reached a high level of maturity, meaning that only slight deviations are induced by the simplifications. Nonetheless, some of the modeling approaches used today have not yet been sufficiently validated against real plant data. Thus, the magnitude of the error induced by the simplifications is not well known. Although the uncertainty for these approaches is higher, it is common practice to apply them due to a lack of alternatives. It is expected that knowledge will increase in the near future and modeling approaches may then be updated.

In order to describe the maturity level of a model categories are defined which refer to existing standards. Following ISO 9004 (2009) and the Capability Maturity Model (CMM) of the Software Engineering Institute (SEI, Paulk, 1994) five levels of maturity from the initial Level 1 to the most mature Level 5 are proposed. Levels 4 and 5 may only be achieved by very detailed models, which require the full knowledge of the detailed final design of the plant. Level 4 could only be achieved by detailed models, which are adjusted to the specific plant layout. The highest Level 5 may only be achieved by models with a very high level of detail, which are tuned with at least 1 year of high resolution operational data from the actual plant. The operational data need to cover a period that is representative for the lifetime of the project. Thus, it should be clear that for STE plant proposal engineering purposes the model maturity level 3 usually be achieved. With detailed validation and on the basis of final design data level 4 can be reached.
For classification of the overall maturity of STE models the following process should be followed: Each major sub-process should be assessed and classified according to the five levels of maturity. The maturity level of the full model should then be set according to the majority of the classifications of sub-processes[53].
If the overall model uncertainty is not quantified by any other means the following assumptions for 1-sigma model uncertainty shall be made depending on the maturity level:

- $\sigma_{\text{model}} = 15$ % for Level 1 models
- $\sigma_{\text{model}} = 10$ % for Level 2 models
- $\sigma_{\text{model}} = 5$ % for Level 3 models
- $\sigma_{\text{model}} = 3$ % for Level 4 models
- ($\sigma_{\text{model}} = 2$ % for Level 5 models)

These default values can be lowered, if actual deviations are proven to be smaller by independent validation.

An alternative to this rather empirical approach is to resolve the model uncertainty in terms of uncertainties of the respective model parameters. As an example, the uncertainty arising from a simplification in plant-start-up modeling could be assigned to a characteristic parameter used in the simplified start-up model (e.g. the value of the start-up energy). The resulting set of parameters can then be handled in the same way as the model parameters. Although this approach helps to generate more transparency than just applying a “default” estimate for the model uncertainty, special care has to be taken to identify appropriate uncertainty measures for the parameters.

<u>Determining meteorological input data uncertainty</u>

The uncertainty of the long-term mean associated with a meteorological data set has to be evaluated during the preparation of this data set, compare section 12.5.4. A common approach in working with representative meteorological years is to generate a data set that represents the long-term mean and

[53] This approach reflects a general way how to do that. More practical approaches still need to be defined in order to make this applicable.

an additional one that represents a lower annual DNI sum corresponding to a higher probability of exceedance. Typical levels of exceedance for the data sets are 90%, 75% or 70% resulting in a MY90, MY75, and MY70 data set. The yield simulation tool is used to carry out two simulations, one for the MY50 and one for the MY90 (or other values). The correlations given in section 13.1 can be used to determine the corresponding 1-sigma meteo uncertainty, u_{meteo}, from these two values.

This approach is very efficient since it only requires one additional simulation run to express the uncertainty induced by the uncertainty of of the meteorological input data. It is applicable, when the whole yield analysis is based on representative meteorological years. If multi-year time series are directly used without condensing their information into just one single year, expressing uncertainty becomes far more complicated. The fundamental difference between inter-annual variability and uncertainty of the long-term mean as explained in section 12.2 must be remembered . Thus, the distribution function of annual yields obtained from a multi-year time series does not reflect the uncertainty of the long-term mean but the inter-annual variation. Incorporating the uncertainty of long-term mean into the multi-year data set is generally possible but no established methods are available today. Due to this lack of proven methods the recommendation of this guideline is to apply the approach of representative meteorological years.

13.4. “Guarantee” versus “most likely” performance values

When assigning values to the model parameters the general question arises whether to use performance guarantee values likely to be achieved. While guarantee values result in a conservative, i.e. lower, annual yield, most likely performance value represent a yield that can be expected but is not supported by contractual guarantees. In practice, developers will carry out simulation runs for both alternatives in order to reflect the lenders’ (guarantee) and the sponsors’ (most likely) perspective. The uncertainty analysis approach provides a good method to address this kind of question in a systematic way. In case the expected performance of a component is higher than the guarantee value the probability density distribution of this parameter should be chosen such that the guarantee value is not the mean value, as illustrated in Figure 13-6.

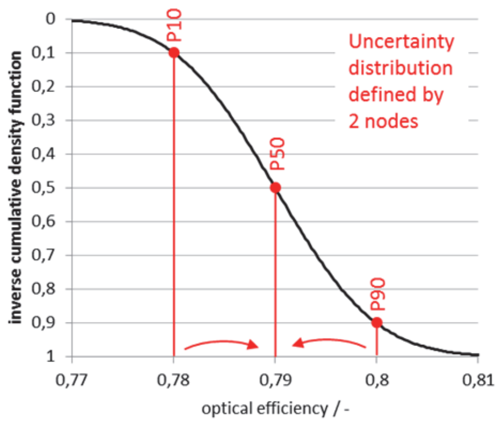


Figure 13-6: Distribution function reflecting the impact of guarantee values for the example of the optical efficiency

Although a guarantee value is usually available the selection of the expected mean value is not straight forward unless specific data on the variation of the parameter are available. In case no additional information is available a pragmatic approach is the following:

1. Define the guarantee value as the value that is expected with 90% probability (P90)
2. Estimate a value that is expected with only small probability of 10% (P10)
3. Determine the parameters mean (P50) and standard deviation for the distribution function assuming normal distribution based on these two fixed values.

For the estimate of the P10 value several information can be used:

- Data from experimental campaigns for this specific component or a similar component.
- Scatter of literature data for similar components
- Best case estimates from physical models

In case extended test data is available the measured data can directly be mapped into a respective distribution function.

The selection of the distribution functions, and thus the P10 value, has to be done with care due to the direct impact of the chosen distribution on the yield results. When carrying out the probabilistic analysis as suggested in section 13.3, the set of samples should include at least the case when all parameters are set to guarantee values and the second case when all parameters are set to the P50 values. A result plot from the probabilistic analysis can be used to mark the two distinct data sets as shown in Figure 13-7.

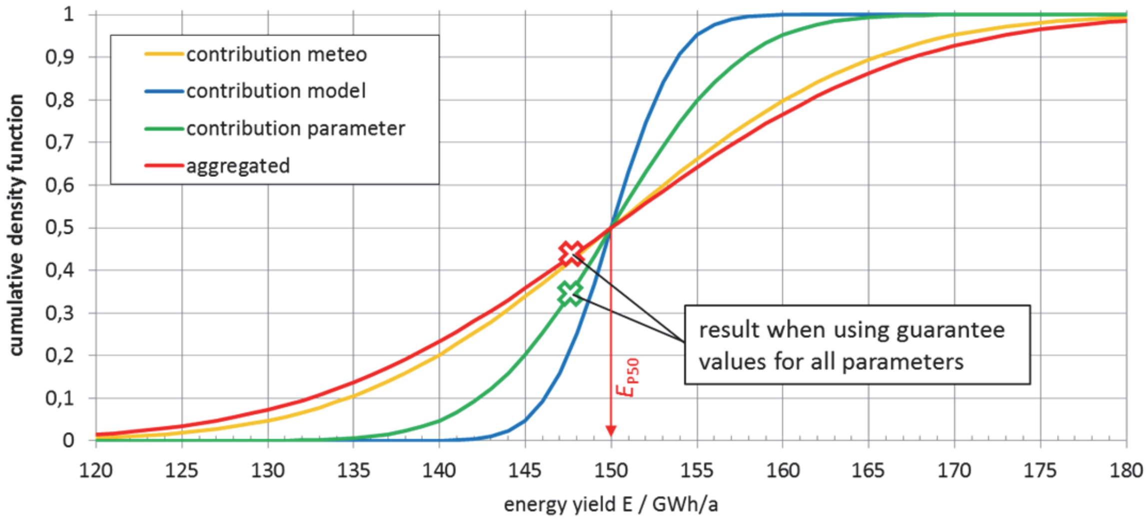


Figure 13-7: Result of the probabilistic analysis for model parameters with marked values for mean and guarantee value.

14. Usage of the guideline during different phases

The intention of the guideline is to provide modeling approaches suited for high quality yield analyses like it is required for proposal engineering of STE plants. Since most players in the field will be active also in earlier stages of a project (e.g. pre-feasibility, feasibility studies) it is straight-forward to use the same bundle of modeling approaches with a less accurate set of parameters. This enables the user to have a single yield calculation tool for all phases. The parameter values used in the models ideally converge to the values finally realized during construction. Default values and first estimates as delivered with the guideline can be used in early stages whereas the final stage requires that all parameters influencing the performance are derived from detailed engineering supported by supplier information. Table 14-1 gives an overview in which way the modeling approaches provided by this guideline can be applied to the phases defined in the last section. The table gives an idea of the concept to be applied and some practical recommendations. More details on possible simplifications during the three stages are given in the respective modeling chapters in the appendices[54].

Table 14-1: Usage of the guideline for different stages of a project

	Pre-Feasibility	**Feasibility**	**Proposal engineering**
General concept	All parameters based on default values. Key parameters like solar field or power block efficiency chosen based on preliminary information available for the project (usually taken from similar projects or publications without detailed cross-checking)	Key parameters like solar field or power block efficiency adapted to design values defined for the project. Second level parameters adapted to first information on the project. All other parameters based on default values.	All parameters chosen based on supplier information.
Applied to solar field	Best estimates for: Peak optical efficiency Nominal thermal losses Auxilliary consumption	Design values for: Peak optical efficiency Nominal thermal losses Auxilliary consumption Best estimates for: Incident angle correction Piping losses Part load behavior	Parameters chosen according to supplier information and detailed engineering calculations.
Applied to power block	Best estimate for nominal efficiency taking into account HTF temperature and first estimate for cooling conditions. Part-load	Load dependent efficiency curve based on preliminary design of turbine and cooling conditions. Approximation equations sufficient to	Parameters derived from heat cycle calculations using supplier information. High quality matrix representation to cover al operating

[54] Will be available in the next version of the guideline since still under construction. It will be discussed if sub-system models with different quality levels can be used together in the simulation if, e.g. a supplier wants to analyse in detail a certain component and needs to consider the rest of the system only roughly.

	behavior based on default values from the guideline or similar projects.	represent main dependencies.	conditions with high quality.
Applied to storage	Best estimates for heat losses and heat exchanger performance.	Performance parameters derived from preliminary engineering.	Performance parameters based on detailed engineering.
Applied to meteo data	Usage of rough meteo products.	Meteo data applied to the site including a certain set of ground measurements or specific adaptions to the site conditions.	Meteo data based on long year satellite data corrected by ground measurements of at least one year. Detailed analysis of uncertainty.
Applied to transient modeling	Time step of one hour (to be checked of this is possible with the start-up modeling approach proposed)	10 min time step	10 min time step
Applied to uncertainty analysis	Default values for model uncertainty Default values for parameter uncertainty Rough estimates for meteo uncertainty	Default values for model uncertainty. Uncertainty analysis for key performance parameters with uncertainty distributions taken from default values of this guideline. Pre-liminary meteo uncertainty analysis specific for the data of this site.	Default values for model uncertainty. Uncertainty analysis for the main influencing parameters. Detailed uncertainty evaluation for meteo data.
Applied to operation strategy	Usage of one of the default operation strategies.	Calculations with 2 default strategies for result intercomparison and individual adaptations to specific boundary conditions of the project.	Calculations with 2 default strategies for result intercomparison and individual adaptations to specific boundary conditions of the project.
Applied to cost estimates	Based on default values of the guideline, other publications, or values applied for similar projects in the past.	Refined cost estimate for main components based on budgetary quotations and cost data bases.	Detailed cost break-down based on offers.