Scenario modelling for short to long term rollout of concentrating solar power in South Africa

by
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DECLARATION

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ABSTRACT

South Africa is currently in the process of greatly expanding its electricity generating infrastructure. A significant portion of the new capacity will be made up out of renewable energy systems. The aim of this study was to investigate potential benefits and pitfalls of introducing concentrating solar power (CSP) into the South African electricity generating system, by making use of spatio-temporal modelling. Government policy for the expansion of the generating fleet is defined in the Integrated Resource Plan for electricity (IRP). A draft update of the IRP that describes a number of possible scenarios for the composition of the generating fleet was released in 2013. Three of these were selected and modelled for the 2030 and 2050 fleet composition and projected demand for the purpose of this study. The effect of implementing a two tier tariff designed to incentivise electricity production during evening peak by CSP plants was also investigated.

All modelling was done on an hourly basis. Spatio-temporal modelling was used to model wind, photovoltaic and CSP electricity production. The balance of the generating system was modelled using a behavioural model. The system performance was compared across scenarios by using the following system adequacy measures: electricity shortfall, open cycle gas turbine capacity factor and coal plant capacity factor.

Comparing CSP plants that were optimised to be remunerated under a two tier tariff with plants that were optimised to minimise levelized cost of electricity showed that imposing the tariff had a significant impact on plant configuration and electricity production. Using CSP plants that were under a rigid two tier tariff was also found to have a negative impact on system adequacy measures in a system with a high renewable energy uptake. The results were reasonable for a system with a moderate uptake in renewable energy and good for a system with a low uptake. For example: acceptable levels of electricity shortfall in a projected system would be equal to 20 GWh per year. With the two tier tariff in place the low uptake scenario averaged 32.9 GWh, the moderate uptake scenario 99.6 GWh and the high uptake scenario 5059.7 GWh for 2050.

Results for the two higher uptake scenarios were improved significantly by redeploying a large portion of the CSP plants as base load units that were responsive to system needs. The results for a system with a high uptake of renewable generating capacity was still not at acceptable levels (e.g. 844.52 GWh shortfall), but the moderate uptake system performed well. This may indicate that the higher the uptake is of renewable energy, the more flexible the electricity output of the CSP will have to be for optimal overall system performance. While this flexibility is technically feasible, according to this study a rigid remuneration structure will not incentivise the CSP plants to act on this capability.

UITTREKSEL

Suid Afrika is in die begin fase van ŉ grootskaalse uitbreiding in kragopwekking infrastruktuur. Hernubare energie, insluitend sonpanele, windkrag en gekonsentreerde sonkrag, gaan ŉ beduidende porsie van die uitbreiding wees. Die doelwit van hierdie studie was om die potensiële voordele en nadele van die byvoeging van gekonsentreerde sonkrag tot die kragopwekkings stelsel te bestudeer met behulp van tydruimtelike modellering. Die regering se beleid vir die uitbreiding van kragopwekking infrastruktuur is saamgevat in die Geïntegreerde Hulpbronne Plan vir elektrisiteit. ŉ Voorgestelde opdatering van die dokument, wat ŉ aantal moontlike scenarios vir die tegnologie samestelling van die beoogde kragopwekking infrastruktuur bevat, is in 2013 uitgereik. Drie van die scenarios en die geprojekteerde kragaanvraag vir 2030 en 2050 was in hierdie studie gemodelleer. Die effek van ŉ twee vlak tarief, wat ontwerp is om gekonsentreerde sonkragstasies aan te moedig om krag gedurende die aand piek aanvraag periode op te wek, is ook ondersoek.

Alle modellering was op ŉ uurlike basis uitgevoer. Tydruimtelike modellering was gebruik om sonpanele, windkrag en gekonsentreerde sonkrag se modelleer. Die res van die kragopwekking was met ŉ gedrag gebaseerde model gemodelleer. Die scenario was aan die hand van drie kriteria geëvalueer: totale elektrisiteit tekort, oop siklus gas turbine kapasiteitfaktor en steenkool kapasiteitfaktor.

Daar was gevind dat ŉ twee vlak tarief ŉ beduidende inpak op die konfigurasie en elektrisiteit lewering van ŉ gekonsentreerde sonkragstasie het. Verder was gevind dat die gebruik van gekonsentreerde sonkragstasies wat onder so ŉ tarief ontwerp was ŉ negatiewe impak op die stelsel uitkomste gehad het, veral vir die scenario met ŉ hoë opname van hernubare energie. Die resultate was goed vir die scenario met ŉ lae opname en redelik vir die scenario met ŉ matige opname van hernubare energie. Ter illustrasie: 20 GWh per jaar word as ŉ aanvaarbare vlak van elektrisiteit tekort gereken in ŉ gegewe scenario. Met ŉ twee vlak tarief vir gekonsentreerde sonkrag lewer die scenario met ŉ lae opname in hernubare energie ŉ tekort van 32.9 GWh, die scenario met ŉ matige opname lewer 99.6 GWh en die scenario met ŉ hoë opname lewer 5059.7 GWh in 2050.

Resultate vir die twee scenarios met hoër opnames in hernubare energie kan aansienlik verbeter word deur ŉ groot porsie van die gekonsentreerde sonkragstasies te loop as stasies wat vrag aanpas na gelang die stelsel aanvraag. Die resultate vir die scenario met ŉ hoë opname in hernubare energie bereik nog steeds nie aanvaarbare vlakke nie (bv. 844.52 GWh elektrisiteit tekort), maar die matige opname scenario bereik dit wel. Hierdie resultate toon moontlik dat hoe hoër die opname in hernubare energie is, hoe meer aanpasbaar gekonsentreerde sonkrag se beheer deur die stelsel sal moet wees om optimale uitkomste moontlik te maak. Volgens hierdie studie is die aanpasbaarheid tegnies moontlik maar dit sal nie deur gekonsentreerde sonkragstasies ten toongestel word onder ŉ onbuigbare tariefstruktuur nie.

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1. INTRODUCTION

In this chapter the background to the study is given in section 1.1 and the motivation for doing the study is discussed in section 1.2. The objective of the study is stated in section 1.3. The methodology is outlined in section 1.4 and an overview of the chapters of the report is given in section 1.5.

1.1 Background

The idea behind concentrating solar power (CSP), using mirrors that concentrate solar radiation to generate thermal energy for a heat engine, is a concept that has been around for a long time. Over the last hundred years it has generally been explored at times when it became economically attractive in relation to other energy sources. At these instances, the development of CSP had subsequently been curtailed by either the discovery of other cheaper energy sources or by regaining access to such sources.

From a global perspective, CSP has again recently become an attractive option. A significant difference, in relation to previous occasions, lies in the fact that its current attractiveness has not been based purely on economic considerations but also for environmental reasons. In a world where curbing carbon emissions has been becoming more and more of a priority, renewable energy technologies are of increasing interest.

In 2010 the South African government developed the Integrated Resource Plan (DoE, 2011), which lays out the intended capacity expansion in all types of electricity generation technologies in South Africa between 2010 and 2030. The final policy adjusted plan was put together based on the following priorities:

- Affordable electricity
- Carbon mitigation
- Reduced water consumption
- Localization
- Regional development

The IRP was developed as a living document, and subsequently, in 2013, a revised plan was suggested. The plan makes adjustments based on updated cost information, adjusted demand projections and an expanded perspective on the impact of carbon mitigation.

1.2 Motivation

The renewable energy technology options that are available to South Africa are not cost competitive with large coal-fired power stations, the current main source of local electricity (DoE, 2011). Renewable energy technologies were included in the IRP due to policy directives not directly related to cost. For the most part, carbon mitigation was the most important of these policy directives; but when evaluating different renewable energy technologies against each other, both electricity cost and localization played an important role.

CSP is not cost competitive when compared to the other primary renewable energy technologies that were considered in the IRP. Both wind and photovoltaic systems (PV) are significantly less expensive when considering the cost per unit of electricity produced (DoE, 2011). However, both these technologies are intermittent in nature. Wind power is only available when the wind is blowing, and PV is only available when the sun is shining. PV availability is of particular note as the hours of peak electricity demand in South Africa occur after sunset. PV capacity was added to the system purely as a low cost means of saving fuel and, given that the main fuel source in South Africa is coal, as a low cost means of reducing carbon emissions.

While CSP is, as has been noted, more expensive than these well-developed renewable technologies, it has the advantage of being dispatchable. Thermal energy can be stored in a CSP plant. Thus the hours of operation can be extended past sunset, and CSP plants can contribute to the capacity the system requires to meet peak demand. The CSP plant output can also be varied in order to adapt to system needs without a significant loss in terms of possible overall electricity output (IEA, 2014).

In the IRP update (DoE, 2013), the adequacy of a given system configuration scenario is evaluated not only based on cost, but also on the following criteria:

- Minimization of demand shortfall (indicative of ability to meet electricity demand at all times)
- Minimization of open cycle gas turbine (OCGT) gross capacity factor (indicative of ability to meet electricity demand at all times)
- Base load plant capacity factor (indicative of overall base load plant supply)

The interaction between the possible contribution that can be made by CSP plants and the above factors means that the cheapest renewable energy option might not be optimal from a system perspective. Furthermore, designing a CSP plant to optimize its impact on the overall system might result in a plant configuration that does not align with a cost optimal plant. For this reason, studying the impact that

CSP plant configuration has on the overall system function as well as system cost becomes of interest.

1.3 Objective

The objective of this study is to use a spatio-temporal approach to model the potential contribution of renewable energy technologies to the South African power system, if rollout follows the 2013 IRP update, and to outline the potential costs and benefits of the contribution of the respective technologies.

The focus of the study will be on the effect that the power contributed by renewables has on the rest of the installed capacity as well as on the overall cost of supplying power in South Africa, with particular interest on the impact and contribution of CSP.

Furthermore, the impact of optimizing CSP plants for configuration and operation will be studied – not for plant electricity unit production cost, but for the overall potential benefit to the system. In this regard, both the impact on system adequacy measures and electricity cost will be investigated.

1.4 Methodology

The first step was to do a literature review to determine the context within which the study took place. A model of the generating system was then constructed. The following technologies were all modelled on an hourly basis:

- Renewables:
    - Wind
    - PV (various types of tracking were remodelled and the results smeared)
    - CSP (both parabolic trough and tower type plants were modelled)
- Conventional system:
    - Base load (imported hydro, nuclear, coal, combined cycle gas turbines (CCGT))
    - Peaking (domestic hydro, pumped storage, OCGT)

The separate parts of the system and the way they combine were then validated. The model was used to simulate scenarios from the IRP update (DoE, 2013). The results were processed and analysed and from this observations and recommendations arose.

Only effects that are observable on an hourly scale were taken into account and only the generating system was considered.

1.5 Overview

Brief overviews of the chapters that make up this report are given below:

Chapter 2: Contains the literature review that includes South African policy, international electricity system modelling, CSP studies and case studies and relevant South African studies.

Chapter 3: Contains an overview of how the various generation technologies are modelled and how the system as a whole has been put together. It also gives information on the overall modelling approach.

Chapter 4: Shows how the four main renewable energy technologies that were considered for the study were modelled and how the models were validated.

Chapter 5: Shows how the balance of the generating system was modelled and validated.

Chapter 6: Here the impact of imposing a tariff system on CSP plants is studied. Both the impact on plant configuration and plant behaviour is considered.

Chapter 7: The results of modelling three scenarios from the 2013 IRP update are shown. The scenarios are modelled for 2030 and 2050. CSP output curves generated via tariff imposed operation are used in the models.

Chapter 8: The impacts of using system responsive CSP plants are shown in order to showcase the advantages that CSP dispatchability offers to the system.

Chapter 9: Concludes the study and reviews the findings.

2. LITRATURE REVIEW

This literature review covers applicable South African government policy in section 2.1, global renewable modelling in section 2.2, international CSP modelling in section 2.3, the System Advisor Model and some of its uses in section 2.4 and local CSP modelling in section 2.5. These topics are covered in this literature review because both international and local studies serve to inform policy, and it is this that finally determines what is actually built. The review is concluded in section 2.6.

2.1 Policy in South Africa

The rollout of renewable energy technology, as with all power plants, in South Africa is governed by government policy. The IRP was gazetted by the South African government in May 2011 (DoE, 2011).

The IRP states the planned capacities of each type of power plant that will be constructed in South Africa between 2010 and 2030. The IRP also gives some detail pertaining to the scenarios that were analysed in order to draw up the actual plan. According to the IRP, 20% of South Africa's installed generating capacity will be made up of renewable energy by 2030 (this total excludes nuclear power and hydropower) with 10.3% wind capacity, 9.4% PV and 1.3% CSP.

A proposed IRP update (DoE, 2013) was issued in 2013 by the Department of Energy, but this document has not yet been accepted by Parliament. The update considers a range of possible scenarios for the composition of the future South African electricity generation system. An approach of branching decision-making is taken where the point at which it would make sense to move from one possible scenario to another is emphasized. The updated IRP is extended through to 2050, and in most scenarios there is a significant increase in CSP capacity allocation — both in the 2010 to 2030 window and in the 2030 to 2050 window.

The low initial allocation of CSP capacity in the 2010 IRP contrasts quite strongly with global expectations of CSP generating capacity in South Africa, as laid out by the International Energy Agency (IEA) (IEA, 2010). Here South Africa is listed amongst countries that should be getting 12% of their power from CSP by 2030 and have up to 40% of their power provided by CSP by 2050.

Technology roadmaps are often used to address changes in energy policy because the roadmapping process lends itself to involving all stakeholders and building consensus amongst them (Amer & Diam 2010).

Amer and Diam (2010), however, show that on the national level there are significant differences in emphasis in CSP roadmaps depending on what type of organization develops the roadmap. Roadmaps developed by nongovernmental organizations focus on environmental issues like climate change and curbing the emission of greenhouse gases. CSP roadmaps developed by governmental agencies tend to place more emphasis on keeping down the cost of electricity, ensuring energy security, decreasing the amount of energy imported and increasing the competitiveness of the country.

It is interesting to note that while the IRP is not a roadmap, its motivations when it comes to renewable energy allocation share more with NGO developed roadmaps than would be expected from the government document. The inclusion of renewable energy is mostly seen in the IRP as a method for curbing carbon emissions and meeting environmental policy expectations. There is no expectation in the IRP that including CSP, wind or PV will lead to a reduction in overall energy cost except in relation to reducing carbon mitigation costs.

The IEA CSP technology roadmap, on the other hand, expects CSP to become cost competitive with peaking power plants between 2010 and 2030. The ability of CSP to provide power during evening peak is not recognized in the initial 2010 IRP. In some measure this has been remedied in the 2013 IRP update. The increase in allocated CSP capacity in the short-term shows that the benefits of CSP plants are now better understood. However, the document makes no distinction between CSP plants that have been configured to produce power during evening peak — i.e., the plants that will be competitive between 2010 and 2030 — and CSP that has been configured to run as base load and mid merit plants, which will become competitive post 2030.

2.2 Worldwide renewable power modelling

Strides have been made internationally towards modelling the impacts of adding renewable energy to existing power systems. While the focus has mostly been on the impact of intermittent renewable energy sources like wind, some large scale studies have included CSP.

The impact of the intermittency of wind has been studied a great deal because for a long time wind was seen as one of the cheapest forms of renewable energy. A summary of case studies compiled by Holttinen *et al.* (2008) on the cost of adding wind to a power system focuses on the following areas:

- Balancing: adding wind increases the need to allocate and use short-term reserves.
- Adequacy of power: there is significant variation on a regional basis, which makes it hard to establish how to properly assess the aggregate capacity credits of wind power in the relevant peak load situations.
- Grid: the impact of wind power on transmission depends on the location of wind power products related to the load.

Another compilation study by Albadi and El-Saadany (2010) goes into more detail on balancing cost. They also concur with Holttinen *et al.* (2008) on two key points: the incremental cost of balancing the system increases as levels of wind penetration increase and geographical dispersal minimizes integration costs.

The above-mentioned issues are relevant to any study that looks at the impact that CSP has on the system that is likely to include wind power. The impact of intermittent renewables like wind and PV will influence how a CSP plant will have to be run to optimize the overall cost of electricity.

The Western Wind and Solar Integration Study (WWSIS) is a large scale study in the western part of the United States that uses simulated weather data to give time series based results for the modelled renewable plants. This study investigates the operational impact and feasibility of adding up to 35% energy penetration of wind, PV and CSP onto the power system operated by the West-Connect group of utilities in the states of Arizona, Colorado, Nevada, New Mexico and Wyoming (Lew *et al.* 2009)

The study made use of a mesoscale numerical weather prediction model to essentially re-create the weather in a three-dimensional physical representation of the atmosphere in the western states mentioned above over the course of three years. This was then used as an input to model the power output of renewable plants.

The study includes scenarios with up to 30% wind power and up to 5% solar power of which a significant proportion is made up of CSP. While the effect of a completely different distribution system and a conventional generating system that contains a great deal more gas power plants should not be disregarded, the findings of the study are of interest. The scale of the study is such that it has been divided up into phases. The first phase of WWSIS investigates the viability of adding 35% power input to the system from a system stability point of view (Lew *et al.* 2009). The second phase investigates how adding the 35% of renewables will impact on the plants in the existing system (Lew, 2013).

Amongst many of the findings, the study emphasizes both the importance of having a large balancing area and of adjusting load scheduling on a sub-hourly basis. The importance of having highly accurate wind and solar forecast data that is integrated into the unit commitment process is also emphasized (Lew *et al.* 2009).

Another interesting finding is that there is no need to commit additional reserves to cover the increased variability that comes from adding intermittent renewables. When the system is run with high renewables scenarios, thermal units are routinely backed down but not shut down because it is more economically viable to run them at low capacity factors than to shut them down and start them up again. Thus, adding intermittent renewables actually increases the amount of spinning reserves in the system. This finding speaks to the way in which adding renewables to the system might impact negatively on coal-fired power plants. Increased cycling from high to low capacity factors leads to additional wear and tear and an increase in maintenance costs (Lew, 2013).

The findings show that, even with this cycling, the emissions of greenhouse gases are still reduced significantly by adding renewables to the system. It is also concluded that the additional maintenance cost tied to cycling the plant and additional unit start-ups caused by adding renewalables to the system is negligible when considered against the fuel saving that results from adding renewables(Lew 2013). It should be noted that the study is done from the perspective of a system operator. While the impacts on coal plants are viewed as acceptable by the study, the entities that own the plants might not share that perspective.

Pfenninger *et al.* (2014a) see energy systems models, such as the ones used to produce WWSIS, as important sources of insight. They hold that the models that were developed during the latter half of the twentieth century are still relevant, but face certain challenges in maintaining that relevance when renewable energy is added to the mix. They identify the four groups of models shown in table 2.1.

Table 2.1: The four model groups (Pfenninger *et al.* 2014a)

Model family	Examples	Primary focus
Energy system optimization models	MARKAL, TIMES, MESSAGE,OSeMOSYS	Normative scenarios
Energy system simulation models	LEAP, NEMS, PRIMES	Forcasts, predictions
Power system and electricity market models	WASP, PLEXOS, ELMOD, EMCAS	Operational decisions, business planning
Qualitive and mixed methods scenarios	DECC 2050 pathways, Stabilization wedges	Narrative scenarios

They go on to identify the challenges these systems face as:

- Resolving the details of time and space
- Uncertainty and transparency
- Complexity and optimization across scales
- Capturing the human dimension

The first of these is of particular interest to this study as they identify the importance of special detail and temporal resolution when incorporating significant amounts of renewable energy into a system model (Pfenninger *et al.* 2014a).

2.3 Worldwide CSP studies

It is important to consider local conditions when working with renewable energy, but much can still be learnt from studies carried out in the rest of the world. While these studies were carried out in systems and conditions that are different from South Africa, these differences could highlight important points, and there will also be similarities which can prove useful.

Spain is the country with the most recent experience in CSP technologies that make use of storage. Storage is an integral part of ensuring the dispatchability of the technology and makes it possible for the plants to be optimised to provide power during peak demand periods or even run as base load plants if said storage is sufficiently large. It is understood that the way in which utilities are remunerated for producing renewable energy determines whether the technology becomes financially viable or not. Recent research on policies Spain has implemented show that the way remuneration is structured affects the storage capacity and solar multiple of the CSP plants that are being built (Kost *et al.* 2013).

Kost *et al*. (2013) clearly indicate that if there is an economic incentive to deliver power at times when the sun might not be shining, it becomes attractive to build larger storage facilities and the requisite collector field to fill them. This is a very significant finding in the South African context because South African peak power demand takes place after sunset (Eskom, 2010).

As noted above, when making use of studies on CSP that concern different areas of the world, some drivers for development of the technology as that were identified by Viebahn *et al.* (2011) will not necessarily be of interest in the South African context. For instance, since South Africa is an exporter of coal, security of supply (at least in as far as the import of fuels go) is of lesser concern than it is in Europe.

On the other hand, many factors that are applicable are also mentioned. For instance, the fact that CSP offers the opportunity for a lot of local content in the building stage is of interest as this can lead to the development of local industry and job creation. The fact that CSP is a non-intermittent renewable is also mentioned. This latter point is especially significant because it addresses one of the reasons why CSP can be useful, beyond simply helping to reduce carbon emissions, by contributing towards meeting the reserve margin requirements discussed in the IRP (Viebahn *et al*. 2011).

Viebahn *et al.* (2011) go on to identify some critical instruments for insuring the economic viability of CSP. The likelihood of carbon tax decreasing the competitiveness of fossil fuel plants is emphasized and increased research and development is also mentioned as an imported measure. Although these points definitely play into the South African situation, some of the other measures mentioned are less applicable.

Even CSP studies that initially do not appear to have any relevance in the South African context, due for example to a dissimilar climate or the socio-political situation, still have something to teach us.

Trieb, Müller-Steinhagen and Kern (2011) show in their study on oil-rich countries that one of the largest benefits that CSP can provide lies in acting as a fuel saver. These countries generate most of their power by burning fuel oil. If CSP plants can be run to reduce the amount of oil that has to be consumed internally to meet electricity demands, the additional surplus can be exported to gain revenue. In the short-term in South Africa, it is not an increase in revenue but a decrease in fuel imports that is significant. South Africa currently burns diesel in OCGT in order to meet peak demand. It would be significantly cheaper to meet peak demand rather with CSP that is acting as a fuel saver. The gas turbines would then still ensure security of supply but rarely ever run (Silinga & Gauché, 2013).

A study was done by Pfenninger *et al.*(2014b) where they simulated the operation of CSP plant networks in four world regions, but because one of the regions was South Africa this study is discussed further in section 2.5 with the focus on the South African results.

2.4 The System Advisor Model

The System Advisor Model (SAM) is a computer program used to calculate the performance and financial metrics of renewable energy plants. SAM uses computer models developed by the National Renewable Energy Laboratory (NREL), Sandia National Laboratories, the University of Wisconsin and other organizations (Blair *et al.* 2014).

Technologies simulated by SAM include PV, CSP, solar water heating, wind, geothermal and biomass. A specific technology model in SAM would require system design parameters and appropriate climate data for a given location to predict plant performance for a given location and plant configuration (Blair *et al.* 2014).

The results of modelling CSP plants in SAM can be used to assess the potential of the technology in a region (Le Fol & Ndhlukula, 2013; Purohit *et al*. 2013). Some studies go further and use SAM outputs to examine the value of CSP within a generating system (Brand *et al.* 2012; (Malagueta *et al.* 2014).

2.5 Modelling done in South Africa

There have been a number of studies that focus only on the modelling of CSP and on the impact that CSP might have in South Africa. Gauché *et al.* (2012b) argue that CSP is currently underrepresented in the 2010 IRP, yet it holds great future value for South Africa, both in terms of localization opportunities and in terms of providing dispatchable power in the future.

Gauché *et al.* (2012a) also demonstrate, using a fast solving CSP plant model, that when CSP plants are distributed widely across South Africa and the plants are provided with sufficient storage, CSP can provide dispatchable power throughout the year regardless of weather conditions. This study does not optimize the position of the plants but simply distributes them on a grid over the entire country. In order to provide base load power it is also shown that the storage would need to be significantly oversized. At this point this approach would not be cost competitive as a base load technology. However, the paper does illustrate that CSP can provide reliable base load power in South Africa should it be required.

This is expanded on by Pfenninger *et al.* (2014b) when they systematically tested the ability of CSP to provide either base load or dispatchable power. They simulated the operation of CSP plant networks in four world regions. They find that if the plants are designed and operated in a coordinated fashion up to half of peak capacity can be guaranteed before costs rise substantially. The CSP plant outputs for the South African plants in the study are shown in Figure 2.1. In the figure the plants for which results are shown in part B have twice the solar field size when compared to the plants that produce part A.

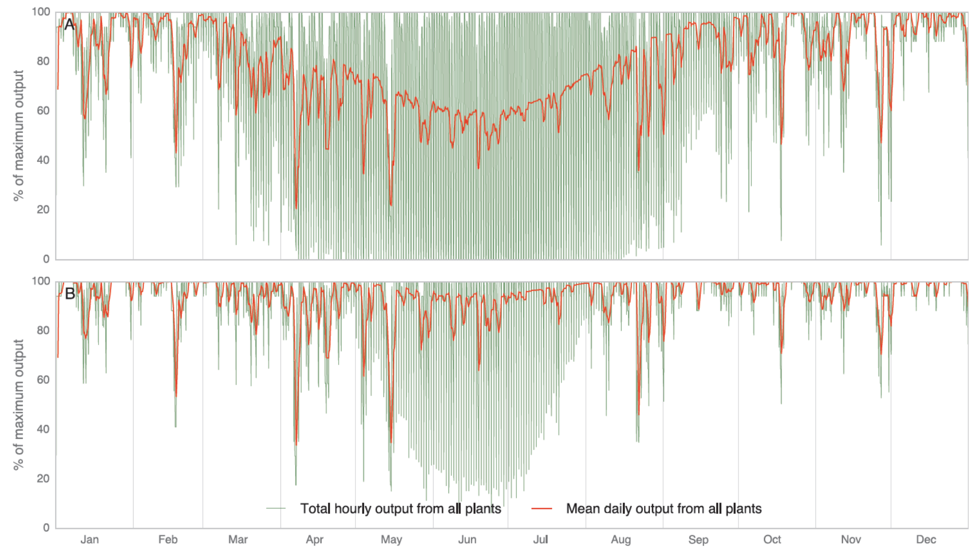

Figure 2.1: Total 2005 output from 100 CSP plants spread across South Africa. (Pfenninger *et al.* 2014)

In the South African context, some CSP and renewable modelling that considers the system as a whole and makes use of real weather information has also been done. Such modelling has either been very short-term (Giglmayr, 2013), however, or focused more on exploring methodology than specific scenarios (Ummel, 2013).

Ummel (2013) advocates for using spatio-temporal modelling when it comes to planning a large-scale rollout of wind and solar power plants. The main contention is that the correct positioning of wind and solar renewable power plants will have a very large effect on their output, and correct locations should be identified from a system point of view. While the study looks at modelling various scenarios for 2040, this is mostly done to advocate for developing more detailed modelling efforts that can be incorporated into probabilistic system models.

Giglmayr (2013) models all renewable projects approved by mid-2013 that appears in the 2010 IRP. Weather information from 2010 is used to simulate the output of the various renewable power plants. The study gives outputs on an hourly basis and indicates the variance that can be expected from the renewables that would be added to the system. The focus is on projects that will be implemented in round 1 and 2 of the REIPPPP (Giglmayr 2013), and the actual locations of these projects are used in the study. The study serves to show the contribution by renewables that would be made during peak consumption times.

Moreover, it illustrates the ways in which this contribution varies from winter to summer.

The above study (Giglmayr, 2013) uses an approach that is very similar to the one intended for this thesis, although slightly different techniques will be used to model some of the power plants. The main difference is that the intended study will focus more on the medium- to long-term rollout of CSP and the effect that this rollout has on the rest of the system. The concentration will be on optimal ways in which CSP technology can be utilized, as opposed to the way South Africa currently plans to utilize CSP.

2.6 Conclusions

In terms of South African electricity planning there is sufficient literature to indicate policy factors that will impact on the roll out of CSP in South Africa. The factors that impact on CSP viability have been investigated in international studies, and the findings of these studies are to a large extent locally applicable.

On a local level, there are sufficient studies to attest to the viability of CSP in South Africa. Notably there is no spatio-temporal model of scenarios from the IRP that models the entire electricity system, which is a gap this study aims to address. The next chapter gives an overview of the model that will be used to do this.

3. INTEGRATED SYSTEM MODEL

This chapter gives an overview of the different technologies that make up the South African generating fleet and the general approach to modelling their outputs and interaction. The approach to calculating the average levelized cost of electricity (LCOE) and a short overview of Chapters 4 and 5 are also given.

3.1 Introduction

The intention of this study is to model the complete South African power system in order to project the possible future benefits derived from using CSP and the ways in which to maximise these benefits. There are two main components to the system model: the current and planned conventional system and the renewable energy system model. In all cases, the amount of power generated by the renewable power stations will be subtracted from the projected load curve first. The conventional system then will attempt to provide the balance of the required generation. This is by no means an ideal situation. But it reflects a philosophy where renewable energy plants are given production priority, and all possible energy that they can deliver is accepted into the grid. This is apparently the way the renewable energy independent power producer procurement program (REIPPPP) that sources the renewable energy capacity specified in the IRP is set up. For the model this practise will be assumed.

When independent power producers (IPPs) are being contracted, a remuneration rate for the power they produce is agreed upon. In the case of wind and PV, this remuneration rate is simply a flat rate at the moment. The IPPs then build their plants to minimize cost and maximize power output in order to maximize profit. In the case of CSP, a modified remuneration rate is currently proposed where production during peak demand times is highly remunerated, production during moderate demand times is moderately remunerated and production during low demand times is not remunerated at all. This setup incentivizes the CSP plants to deliver energy during evening peak (Silinga *et al.* 2014)

The process is not necessarily a bad approach for the non-dispatchable types of renewable energy such as PV and wind. It reflects a philosophy where maximizing the hours of renewable energy output is a priority. The weakness with this approach lies in the fact that it disregards the potential that CSP plants have in terms of dispatchability (IEA, 2014) to fill in the gaps in the hourly power profile created by the intermittency of the other types of renewable energy.

It should be noted that hydropower stations and pumped storage power stations under Eskom control are included in the conventional system model. This inclusion ties in with the fact that the other renewable energy types mentioned will be produced by IPPs who will be trying to maximize their profit and will not necessarily be responsive to group needs. Domestic hydro and pumped storage power stations on the other hand will be under Eskom control and will thus be responsive to system needs (DoE, 2011).

3.2 Hourly modelling

All modelling for this study was done on an hourly basis, which is a typical approach for systems analysis. A demand curve was generated using the energy consumed during every hour of a year as measured in megawatt hours (Eskom, 2010). Because the total energy is measured for an hour, the value for that hour is equivalent to the average power in megawatt that was consumed. This results in a demand curve as seen in figure 3.1 that is further amplified uniformly to meet specific scenario requirements.

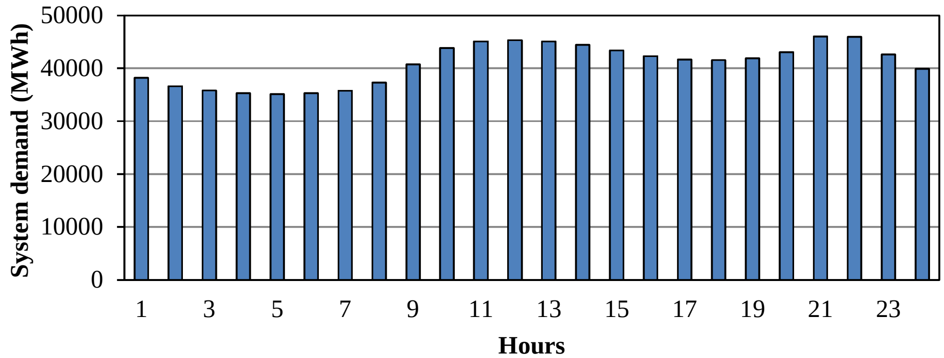

Figure 3.1: 10 January 2010 demand curve

In much the same way, the amount of input energy available during any given hour to renewable energy plants is based on hourly average weather information at the plant in question. Calculations are done based on the assumption that conditions do not vary significantly over the course of an hour and that results reasonably represent cumulative hourly production.

This hourly scale of the model precludes the study of sub-hourly phenomena like issues of grid stability. To address the resulting hourly step changes in demand, a minimum ramp rate is supposed as follows:

$$\text{Ramp Rate(MW/h)} = \frac{D_t(\text{MWhr}) - D_{t-1}(\text{MWhr})}{(1\ \text{hour})^2} \qquad (3.1)$$

Where D is the demand. If the cumulative ramp rate of all the units available at any given hour is greater than the above ramp rate, it is assumed that there are no load losses due to swing in demand.

The hourly approach can clearly not be used to determine how the system will react to demand or supply shocks of short duration. Nevertheless, it is still a useful tool when it comes to projecting the overall adequacy of a given system to meet a set demand. Moreover, it can provide useful cost information.

3.3 Merit order

Merit order refers to the order in which the load generated by the various units in the system will be increased or decreased. In a system with no other constraints, merit order is based on marginal costs. The units with the lowest cost per unit of electricity will pick up production first and drop production last (Sheble, 1989).

Plants that have the lowest marginal cost and run continuously are referred to as base load plants. Plants that provide power for a significant part of the day but do not necessarily run continuously are referred to as mid merit plants. The plants that run only a few hours per day are referred to as peaking plants. Figure 3.2 shows the ideal base load plant contribution in blue, mid merit plant contribution in red and peaking plant contribution in green for the same day as was shown in figure 3.1.

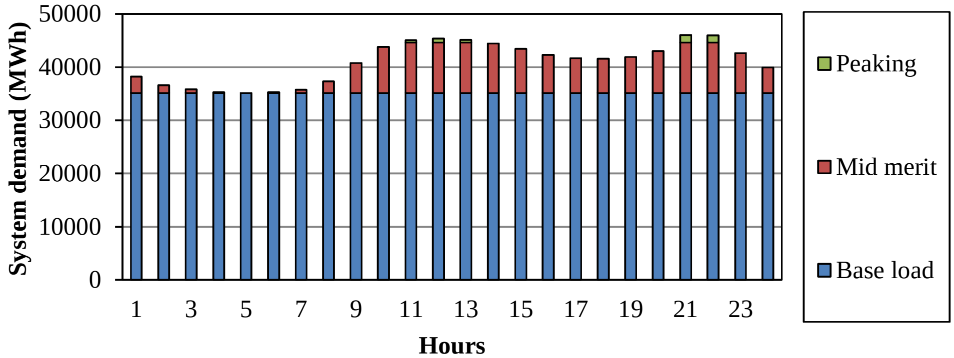

Figure 3.2: Merit based output for 10 January 2010

It should be noted that the Eskom generating fleet is divided into only base load and peaking plants. Instead of constructing mid merit plants, base load plants are designed to run at optimal efficiency when at about 80% of output capacity. These plants experience a slight deterioration in efficiency when run at 100%. (Eskom, 2012) The distinction between base load and mid merit plants is thus internalised to the capacity at which each of the base load plants are running.

In a typical system, the merit list would not simply distinguish between the types of plants (e.g., coal as a base load plant and OCGT as a peak load plant), but also between different plants of the same type based on cost. Furthermore, some other aspects, such as having some margin on certain base load plants set aside as spinning reserve would also be taken into account. The merit order used in this study does not take the above mentioned details into account. All plants of the same type are instead treated as if they are of equal merit.

The merit order assumed in this study is as follows:

1. PV, Wind and CSP
2. Imported Hydro
3. Base load plants: Coal, Nuclear and CCGT

4. Domestic Hydro

5. Pumped Storage

6. OCGT

Because of policy directives related to the uptake of renewable energy, the merit order is not based exclusively on marginal cost. Wind, PV and CSP plants are instead given production priority over less expensive base load plants. The balance of the plants in the system will have be operated to meet whatever demand remains after the electricity produced by PV, CSP and Wind have been absorbed. This situation is depicted in figure 3.3.

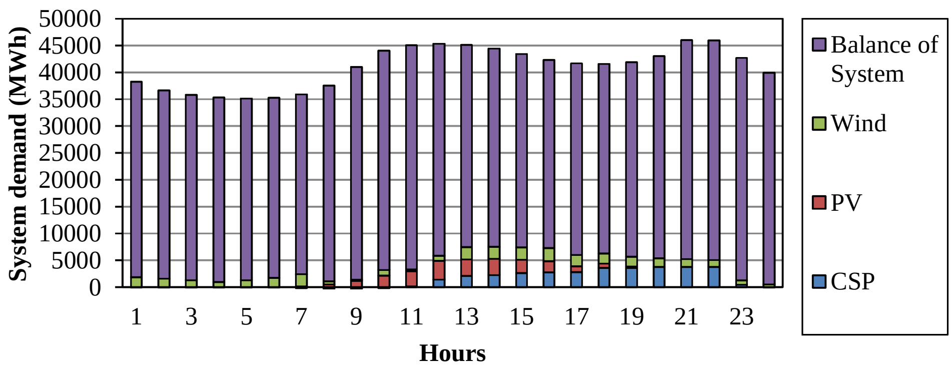

Figure 3.3: Illustration of potential Wind, PV and CSP contribution and effect on subsequent demand for 10 January 2010

3.4 Outages

Outages occur when a generating unit is shut down for maintenance. Some maintenance is expected and scheduled well in advance. This type of outage is called a planned outage. In cases where the unit is forced to shut down unexpectedly, the outage is called an unplanned outage.

Unplanned outages cannot be controlled, so the system needs to have some generating capacity held in reserve to handle their occurrence. Planned outages can sometimes be temporarily deferred if generating capacity is unexpectedly low.

When determining the planned outage schedule, forecasted demand will be considered in conjunction with system need on the conventional system units. In the case of CSP each separate plant will plan its outage based on the period it is forecasted to generate the least revenue. It should be noted that in this model CSP plants make their outage scheduling decision based on perfect knowledge. In reality, such a decision would be based on imperfect forecasts in the short term and historical data in the long term.

In the conventional system model the planned outage scheduled is a model input and these outages are then executed depending on the systems ability to meet demand. The CSP model allows each separate plant to schedule its own outage based on lowest loss of revenue.

Unplanned outages are treated similarly for CSP plants and the plants that make up the conventional system. A set number of outage days are allocated per generating unit. These days are then distributed randomly over the course of the year for each unit.

In the IRP (DoE, 2011) it was expected that a typical generating unit would be on outage for 10% of the year even though the Eskom fleet had not been able to achieve that mark in proceeding years and even with extensive deferring of planned outages (Eskom, 2011). In the updated document this assumption is amended. It is projected that plants from the existing fleet will be on outage for 20% of the year.

3.5 System Adequacy

Modelling the generating system produces a lot of data that has to be evaluated. System adequacy measures were employed to process the data in ways that facilitate meaningful comparisons across scenarios. The three system adequacy measures that were considered in this study are: shortfall, OCGT capacity factor and coal capacity factor.

Shortfall refers to the number of megawatt hours of demand that is not met by the modelled generating system over the course of the year. After generating units have been ramped up or down to meet demand, the model checks whether the electricity produced by the system is sufficient. When this is not the case, the amount by which demand was not met is added to the total shortfall for the year.

The OCGT capacity factor is calculated by adding up the megawatt hours of electricity produced by OCGT plants and dividing that total by the amount of electricity that could have been produced by the OCGT plants if all units ran at full load for the entire year. As OCGT plants are loaded last, this number indicates how often the system is placed under stress due to a lack of generating capacity.

The coal capacity factor is calculated in exactly the same way as the OCGT capacity factor. In this case, the capacity factor is indicative of the supply of base load power stations. If it is too high it indicates that there is an insufficient number of base load plants in the system, and if it is too low it indicates that the base load plants are running inefficiently.

Ideally, the shortfall and OCGT capacity should be as low as possible and the coal capacity should be between 60% and 70%. The system adequacy measures are discussed in more depth in section 7.3.3.

3.6 Meteorological Data

In order to simulate renewable energy plant performance weather information for the plant location is required. For this study, the information was supplied from their GIS database by GeoModel Solar. The resolution of the data is given in table 3.1.

Table 3.1 Resolution of data supplied by GeoModel Solar (GeoModel, 2014)

Data Point	Spatial Resolution	Temporal Resolution
Air temperature	1 km	1 h
Wind speed, Wind derection	30 km	1h
Global horizontal irradiance (GHI), Direct Normal Irradiance (DNI)	3 arc seconds	15 min

GeoModel makes use of ground measurements to validate and update their models (GeoModel, 2014), and their accuracy has been verified by third party research (Ineichen, 2013).

Data corresponding to the 2010 calendar year was used in this study. While the resolution of the solar data is entirely adequate, some manipulation of the wind data was required. This is addressed in section 4.5.

Figure 3.4 indicates the points at which data was sampled. Each circle indicates a single sampling point. These points are the locations where full degrees of longitude and latitude intersect.

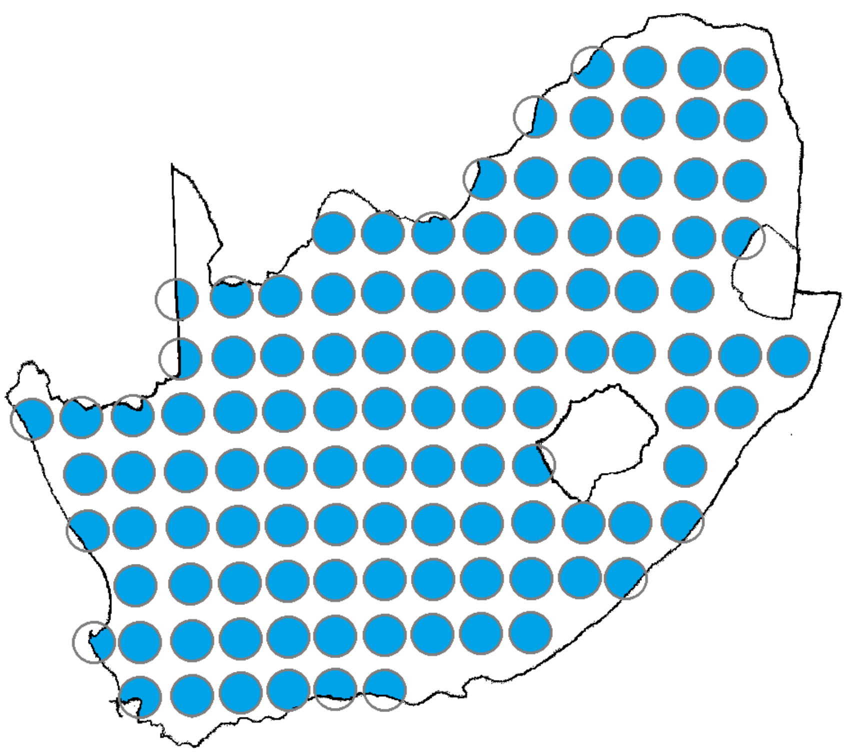

Figure 3.4: Meteorological data sampling points distributed at one degree intervals of longitude and latitude

3.7 Conclusion

This chapter detailed the ways in which the different types of power stations that make up the South African power supply pool will interact with each other, or not interact with each other, in order to meet electricity demand. It further gives background information on the data used by the renewable energy models as input. The next two chapters go into detail on how the electricity output of the various types of power plants is modelled. Chapter 4 covers wind, CSP and PV, and Chapter 5 covers the conventional generating system.

4. RENEWABLE ENERGY MODELS

The models used to generate hourly electricity output curves for tower type CSP, parabolic trough type CSP, large scale wind and PV power stations are discussed in this chapter. The two CSP models are discussed in more detail as they were configured for this study, while the PV and wind models are replicas of models used in a previous study.

4.1. Introduction

CSP technologies concentrate solar radiation converted to thermal energy used to generate electricity. There are various types of CSP plants, but for the purpose of this study only two technologies were modelled: parabolic trough and tower.

Both of these technologies concentrate solar radiation to heat a working fluid. Of the two, more parabolic trough plants have been commercially deployed. The technology for parabolic trough plants is generally better understood, so securing financing for them is easier. Tower plants, on the other hand, are capable of higher thermal efficiency and thus are thought to hold more promise for the future. Currently more parabolic trough capacity is being built because cheaper financing makes the technology more attractive. However, it is generally understood that tower plants will be the technology most favoured once it matures leading to lower financing and total cost (EIA, 2014).

Because of these balancing advantages both types of technology are likely to be built in South Africa on a relatively large scale. For this reason, both technologies were modelled for this project.

Tower plant technology and the tower plant model that was developed are discussed in section 4.2., while parabolic trough plant technology and the corresponding model are discussed in section 4.3.

The methods used to model PV are discussed in section 4.4. It should be noted that only large scale commercial installations are addressed in this section. Rooftop PV is not specifically addressed, but various solar tracking methods are amalgamated, some of which would be compatible with rooftop PV in terms of the shape of the power output curve.

All solar plants are modelled as units with a sendout of 100 MW.

The model used for onshore wind is discussed in section 4.5, and the chapter is concluded in section 4.6.

4.2. Tower model

The tower plant layout that was modelled during the study can be seen in figure 4.1.

Tracking mirrors, called heliostats, are used to concentrate solar radiation on a receiver that is mounted on a tower. The heliostats make up the heliostat field. In the receiver, the concentrated solar radiation energy is transferred to a molten salt working fluid. The salt is pumped from a cold storage tank (typically at 290 ºC), through the receiver where it is heated and transferred into a hot storage tank (at 565 ºC). The size of these tanks determines how much energy can be stored for later use. Thermal energy from the hot salt is transferred in a heat exchanger to turn water into steam. The cooler salt is then transferred back to the cold storage tank. Once steam has been generated, the rest of the plant functions in the same manner as a conventional power station: superheated steam drives a turbine and generator that delivers alternating current electricity. The exhaust steam is then condensed and the condensate once again cycles through the heat exchanger to generate steam. Condensation is achieved assuming dry cooling, as most of the CSP plants will be built in water scarce areas.

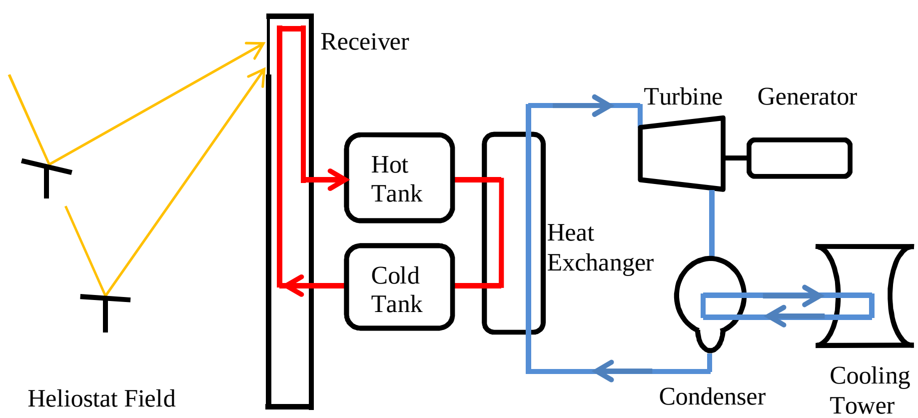

Figure 4.1: Tower plant layout for molten salt receiver and two tank storage configuration

The model looks at each separate part of the cycle and models the efficiency of each of the components that has been discussed. Furthermore, the model assesses the way in which the components interact with each other when the plant is generating electricity.

An overview of the inputs the model uses is given in section 4.2.2. The method for determining the amount of energy that reaches the heliostat field and the modelling of the heliostat field efficiency is discussed in section 4.2.3. The receiver heat balance is then discussed in section 4.2.4.

The plant does not generate electrical output based solely on the amount of output that it is possible to create. There are considerations that determine the optimal output in order to maximize profit. These considerations are discussed in section

4.1.5. The model can also handle outages in various ways, which is covered in section 4.1.6. Financial aspects are discussed in section 4.2.7 and the final validation of the entire model is covered in section 4.2.8.

The first thing, however, that has to be addressed is the way in which the sizing of various plant components interact with each other and influence how the plant works, the amount of power the plant will produce as well as the daily power output profile. This is addressed in section 4.2.1.

4.2.1 Plant configuration

There are two primary factors when considering a CSP plant configuration: the number of hours of storage and the size of the heliostat field relative to the size of the turbine and generator assembly, referred to as solar multiple.

The concept of hours of storage is a fairly simple one. The storage capacity required to store enough energy for the plant to run at full load for one hour is considered to be an hour of storage. Thus, a plant that can store enough energy to run continuously for eighteen hours, at full load, without collecting additional energy is said to have eighteen hours of storage.

The relationship between the heliostat field size and the sizing of the rest of the plant is slightly more complicated. When the heliostat field and receiver is large enough to collect more power than is required for the turbine to run at full output, this can result in a surplus of energy. This surplus energy can then be stored and used at a later stage if the plant has storage capacity. Given that solar radiation is only available to be collected for a certain number of hours every day, it makes sense that it might be desirable to store energy for use at a later time. In the South African context, this is particularly desirable given the fact that peak electricity consumption occurs after sunset when there is no solar energy available.

The factor by which the heliostat field size is related to the turbine size is referred to as the solar multiple. If, during the hour of the year that has the best solar resource, exactly enough energy can be collected to run the turbine at full output, the plant is said to have a solar multiple of 1 (Duffie & Beckman, 2006).

Even without significant storage capacity, building a plant with a solar multiple of 1 would make no sense, as this would result in the turbine and generator assembly only being fully utilized for one hour of the year. CSP plants without storage typically have solar multiples in the 1.1 to 1.5 range (IRENA, 2012)

Depending on the remuneration structure and location of the plant, the optimal solar multiple and number of hours of storage can vary significantly.

4.2.2 Input data

The model requires a number of site specific inputs:

- The coordinates of the site location are used in a number of calculations, amongst others, solar position.

- The hourly average direct normal irradiation (DNI) is used to calculate the available power at the specific site for each hour of the year. DNI represents the component of solar radiation that has not been scattered and that can be redirected onto a target using mirrors.
- The hourly average wind speed is used to calculate forced convection heat loss.
- The hourly average ambient temperature is used to calculate receiver losses and the thermal efficiency of the plant. As it is assumed that only dry cooling systems will be built, hourly humidity is not required to calculate thermal efficiency.

In order to make the model flexible and use it to determine the most economical plant configurations for a specific location, the hours of storage available and the solar multiple are also taken as inputs.

4.2.3 Collected energy

To determine the amount of energy that can be reflected by the heliostats to the central receiver at any given hour of the year, this model requires two items of site-specific information for every hour of the year: DNI and the zenith angle. The zenith angle is the angle between vertical and a line to the sun.

All equations used to determine the zenith angle are from Duffie and Beckman (2006). The first step towards determining the zenith angle is to relate clock time to solar time. To achieve this, the equation of time is used to calculate the number of minutes by which solar time deviates from clock time at the relevant time zone meridian.

$$\begin{aligned}\mathrm{E} = 229.2 * (0.000075 + 0.001868 \cos \mathrm{B} - 0.032077 \sin \mathrm{B} \\ - 0.014615 \cos 2\mathrm{B} - 0.04089 \sin 2\mathrm{B})\end{aligned} \tag{4.1}$$

where B is given by

$$\mathrm{B} = (n-1) * \frac{360}{365} * \frac{\pi}{180} \tag{4.2}$$

The solar time at the longitudinal coordinates of the site in question is then determined by equation 4.3 (where degrees east are taken as positive):

$$\text{Solar time} = \text{Clock time} + \frac{\left(\mathrm{E} + 4(\mathrm{L_{loc}} - \mathrm{L_{st}})\right)}{60} \tag{4.3}$$

Solar time is used to determine the hour angle, which is the angular displacement of the sun east or west of the local meridian and with displacement east being negative and west positive:

$$\omega = 15(\text{Solar time} - 12) * \frac{\pi}{180} \tag{4.4}$$

The other angle required to determine the zenith angle is the declination angle, which is the angle between the position of the sun and the plane of the equator at solar noon. This can be calculated by equation 4.5 shown below:

$$\begin{aligned}\delta = \ & 0.006918 - 0.399912\cos B + 0.070257\sin B \\ & - 0.006758\cos 2B + 0.000907\sin 2B \\ & - 0.002697\cos 3B + 0.00148\sin 3B\end{aligned} \tag{4.5}$$

where B is calculated from equation 4.2, as was done for the equation of time.

The zenith angle is then calculated using the declination angle, the hour angle and the latitudinal position of the site using equation 4.6:

$$\theta_z = \cos^{-1}(\cos\emptyset\cos\delta\cos\omega + \sin\emptyset\sin\delta) \tag{4.6}$$

where $\emptyset$ is the latitude of the location, with degrees south taken as negative.

Gauché *et al.* (2012) have developed equation 4.7. It relates the optical performance of the heliostat field to the zenith angle. They rely on the fact that the zenith angle has the dominant impact on the optical performance of CSP plants with a circular heliostat field layout.

$$\begin{aligned}\eta_{opt} = \ & 0.42540{\theta_z}^6 - 1.1480{\theta_z}^5 + 0.35070{\theta_z}^4 + 0{,}7550{\theta_z}^3 \\ & - 0.59180{\theta_z}^2 + 0.08160\theta_z + 0.832\end{aligned} \tag{4.7}$$

Using this efficiency and hourly DNI data, the amount of power that is delivered to the receiver per square meter of aperture can be determined.

The aperture area has to be sized for each location to be in line with the input solar multiple. Aperture area indicates the size of the heliostat field. This is a set plant feature that has to be determined before the hourly calculations are executed. To facilitate the calculation of the aperture area prior to more detailed analysis, the following assumptions are made in the model:

- Tower thermal efficiency of 90%
- Boiler (heat transfer) efficiency 99%

It should be noted that the above mentioned thermal efficiency refers only to the efficiency of the receiver and the efficiency of the heliostat field is not included. A design point power block thermal efficiency is calculated using the Chambadal-Novikov equation:

$$\eta = 1 - \sqrt{\frac{T_{cold}}{T_{hot}}} \tag{4.8}$$

where the hot well temperature is set as 565 °C and the cold well temperature is the average hourly ambient temperature of the site in question over the course of the year.

These assumed efficiencies are used in conjunction with the maximum amount of power delivered to the receiver per square meter of aperture, over the course of the year as calculated for the site, to determine the aperture size required to satisfy the solar multiple.

After the aperture size is set, it is multiplied with the hourly optical efficiency and DNI for every hour of the year to calculate the amount of power delivered to the receiver on an hourly basis.

4.2.4 Calculating receiver losses

Three types of losses are taken into account at the receiver: convection loss, radiation loss, and reflection loss.

Both forced and natural convection is taken into account and calculated as prescribed by Çengel (2002) when determining convection losses. For both types of convection, the properties of air at 300 °C and the actual hourly wind speeds are used to calculate approximate Reynolds numbers.

The following equation is used to calculate the forced convection Nusselt number:

$$\mathrm{Nu_{forced}} = 0.3 + \frac{0.62\mathrm{Re}^{1/2}\mathrm{Pr}^{1/3}}{[1 + (0.4/\mathrm{Pr})^{2/3}]^{1/4}}\left[1 + \left(\frac{\mathrm{Re}}{282000}\right)^{5/8}\right]^{4/5} \tag{4.9}$$

The following equation is used to calculate the natural convection Nusselt number:

$$\mathrm{Nu_{nat}} = \left(\frac{0.825 + 0.387\mathrm{Ra}^{1/6}}{\left(1 + \left(\frac{0.492}{\mathrm{Pr}}\right)^{9/16}\right)^{8/27}}\right)^2 \tag{4.10}$$

The Raleigh number used in equation 4.10 is calculated as follows:

$$\mathrm{Ra} = \frac{9.81\mathrm{Pr}(\mathrm{T_s} - \mathrm{T_{atm}})\mathrm{L}^3\mathrm{T_{film}^{-1}}}{v^2} \tag{4.11}$$

where v is the kinematic viscosity, T_s is the surface temperature of the receiver, T_{atm} is the ambient temperature, L is the height of the receiver and T_{film} is the thin film temperature taken as the average of the other two temperatures. The receiver is assumed to have a cylindrical surface area that is at a uniform temperature of 565 °C.

The two Nussult numbers are combined, and the convection heat loss coefficient is calculated as follows:

$$\mathrm{Nu_{comb}} = \left(\mathrm{Nu_{nat}^3} + \mathrm{Nu_{force}^3}\right)^{1/3} \tag{4.12}$$

$$h_{\text{conv}} = \frac{k\text{Nu}_{\text{comb}}}{0.5(\text{L}+\text{D})} \tag{4.13}$$

where k is the thermal conductivity of air and D is the receiver diameter.

Using the above results and the receiver surface area, A, the convection heat loss is calculated as follows:

$$\text{Q}_{\text{Conv}} = h_{\text{conv}}\text{A}(\text{T}_{\text{s}} - \text{T}_{\text{atm}}) \tag{4.14}$$

The radiation heat loss is also calculated using an equation from Çengel (2002: 46):

$$\text{Q}_{\text{Conv}} = \varepsilon\sigma\text{A}(\text{T}_{\text{s}}^4 - \text{T}_{\text{atm}}^4) \tag{4.15}$$

An emissivity of 0.85 is assumed (Ho *et al.* 2014).

The reflection losses are calculated using an assumed absorptivity of 0.96 (Ho *et al.* 2014); i.e., 4% of the energy aimed at the receiver is lost.

When determining the size of the convection and radiation losses at the receiver, the size of the actual receiver is a very important factor. The receiver size will vary depending on the solar multiple, as the receiver can only handle a certain amount of heat flux per area.

The receiver size was scaled using a receiver output heat flux of 0.567 MW/m2, which delivered results that matched the receiver sizes utilized in the SAM model well, as can be seen in figure 4.2. Notice that the SAM model does not scale the receiver size completely linearly, as it is much more complex and takes actual available pipe sizes etc. into account.

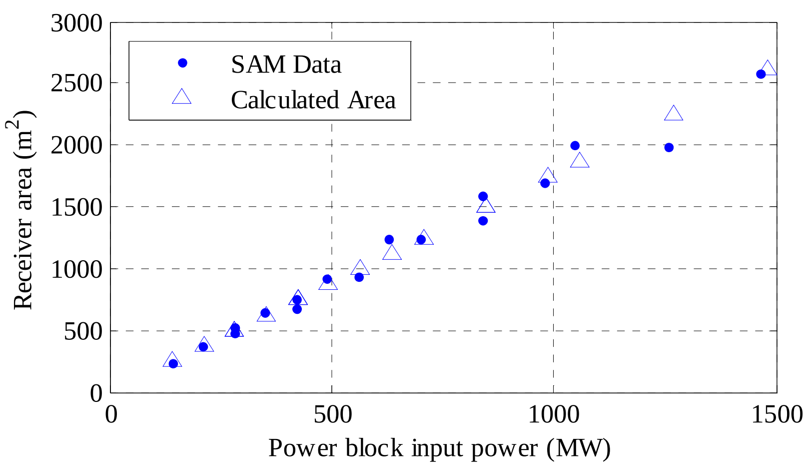

Figure 4.2: Receiver size validation of model vs SAM

4.2.5 Calculating electrical output

The Chambadal-Novikov efficiency is used to model the thermal efficiency of the power block. Storage is assumed to have an hourly efficiency of 99.8%, which corresponds to an hourly temperature drop of one degree Celsius and a daily efficiency of 95% which is slightly conservative (IEA, 2014).

The current favoured remuneration structure for CSP plants pays a premium for electricity during evening peak hours, a lower tariff during the rest of the day and nothing between midnight and five o'clock in the morning. The intention behind the tariffs is clearly to incentivize IPPs to construct and run CSP plants that will provide power during peak and mid-merit demand periods. Incentivizing CSP plans to shut off during the night time hours would support improved capacity factors and efficiency on the conventional system base load plants.

In order to respond to this tariff structure, the model is set up to bias electricity production towards evening peak. In effect, the model will fill the thermal storage to a certain percentage before allowing electricity production during daylight hours. The percentage to which the storage is filled is an adjustable input to the model. The reason why the percentage needs to be adjustable is that for plants with high solar multiples it would result in excessive spillage of energy during the day if a large portion of storage must first be filled before power can be produced by the rest of the plant.

For a specific plant setup, the plant can be run with anything from a very strong storage bias to a very weak storage bias. The outputs from these running methods can then be compared in order to identify the most favourable option.

Starting up a plant is an energy intensive process, and multiple light-up cycles during a day can increase the wear and tear on the plant. The model consumes the equivalent of half an hour's worth of thermal energy during light-ups, and the plant is constrained to running at half load for the hour during which the light-up occurs.

To prevent an excessive number of light-ups, the plant is prevented from lighting up in cases where there is not enough energy available for the plant to run for at least two hours after light-up at full load. Furthermore, there is a slight bias during the daylight hours towards running at a slightly lower load in cases where there is not enough energy currently available to run the plant at full load until the evening peak. This is done to prevent the plant from being shut down during daylight hours and having to restart in the evening.

At all times when the station is producing power, a 5 MW parasitic loss is subtracted from the power produced.

4.2.6 Outages

The tower model can handle outages in one of two ways depending on the requirements of the scenario being investigated.

First, in situations where there is a need to not attach too much importance to when an outage occurs at any given plant, the overall plant output can be adjusted downwards to represent the impact outages have on overall power production.

The second way the model handles outages is in situations where outage behaviour is of particular interest (e.g., where the impact that the remuneration structure has on when outages are being scheduled is under investigation). Here the model can be set up to schedule outages over the fourteen days of the year when the least profit is being generated. In this case, an additional seven days is blanked of on a random basis when the outputs are used in the system model. The seven days in question represent unplanned outages.

4.2.7 LCOE, LPOE and Return

While the pre-set remuneration structure described in section 4.2.4 is used to schedule power production, the relative merits of various locations for CSP plants still have to be weighed against each other. In order to do this on an equitable basis, the LCOE at each location would normally be determined using equation 4.16.

$$\mathrm{LCOE} = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}} \tag{4.16}$$

In this equation, L_t is the investment expenditures in the year t, M_t is the operations and maintenance expenditures in the year t, F_t is the fuel expenditures in the year t which in this case is 0, Et is electricity generated in the year t, r is the discount rate and n is the life of the plant. For the purpose of calculating LCOE, the plant is assumed to have a life of 20 years and a discount rate of 12%.

While LCOE gives a good indication of what each unit of electricity would cost to produce, it would only indicate the most favourable configurations and locations for plants in cases where there is a flat tariff; i.e., when there is no distinction in terms of profit between units of electricity that are generated at different times of the day.

In order to take into account tariffs that incentivize production during specific hours of the day, a slightly different measure, levelized profit of electricity (LPOE), was developed by Silinga *et al.* (2014):

$$\mathrm{LPOE} = \frac{\sum_{t=1}^{n} \frac{P_t - (I_t + M_t + F_t)}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}} \tag{4.17}$$

where P_t is the amount of profit generated by electricity sales over the course of a year. LPOE resembles the definition of CSP net value developed by Namovicz (2013), but it does not include payments for participating in reliable reserve.

Equation 4.18 is used to determine the best plant configuration in terms of return on investment. The equation can also be calculated as LCOE divided by LPOE.

$$\text{Return} = \frac{\sum_{t=1}^{n} \frac{P_t - (I_t + M_t + F_t)}{(1+r)^t}}{\sum_{t=1}^{n} \frac{(I_t + M_t + F_t)}{(1+r)^t}} \tag{4.18}$$

This return related metric was the actual method used to determine the plant configuration at various plant locations for the study. IPPs will not design CSP plants in configurations that optimize LCOE; they will design to optimize return on investment.

In order to calculate investment expenditure for a multitude of plant configurations, cost information from a World Bank report on South African CSP technology options that was compiled by Fichtner (2010) was used. The data shown in the table below was scaled according to aperture, electricity send-out and hours of storage as indicated.

Table 4.1: World Bank report data on tower plant cost (Fichtner, 2010)

Item	Unit	Central Receiver CSP		
		50 MWe & 15 h Storage	100 MWe & 9 h Storage	100 MWe & 15 h Storage
Aperture Area	1000 m2	636.3	866.1	1340.0
Scale with Aperture:				
Site Preparation	mil US$	19.9	27.0	42.4
Heliostat Field	mil US$	165.4	218.3	323.3
Receiver System	mil US$	85.8	106.4	144.3
Balance of Plant	mil US$	30.0	40.7	55.0
EPC Contractors Engineering	mil US$	34.0	46.1	62.8
Scale with Electrical Output:				
Tower	mil US$	8.8	15.0	15.0
Power Block	mil US$	65.4	110.0	110.0
Scale with Thermal Storage:				
Thermal Energy Storage	mil US$	49.3	58.7	95.3
Percentage of total:				
Contingencies	mil US$	42.5	57.6	78.5
Owners Costs	mil US$	27.6	37.4	51.0

The operating cost is set at 1.85% of initial investment expenditure.

To identify optimal storage bias and plant configurations, the following processes were followed: At each major grid point DNI, ambient temperature and wind information was used to simulate the CSP plant output for a range of solar multiples and hours of storage. Each configuration was run with a range of storage biases. The plant configuration and running method that gave the highest return was considered optimal for that location for a given remuneration structure. The electric output curve for that given optimal configuration and running method was then set as the output curve for the location for a given remuneration structure.

4.2.8 Validation

Validating the model required comparing the outputs for a specific location with the outputs generated by SAM for the same location.

Three different aspects were covered for validation of the model. The first of these was comparing the net amount of thermal energy collected by the receiver in the model versus SAM. In figure 4.3, the energy collected during a week with good DNI is shown along with a week with bad DNI:

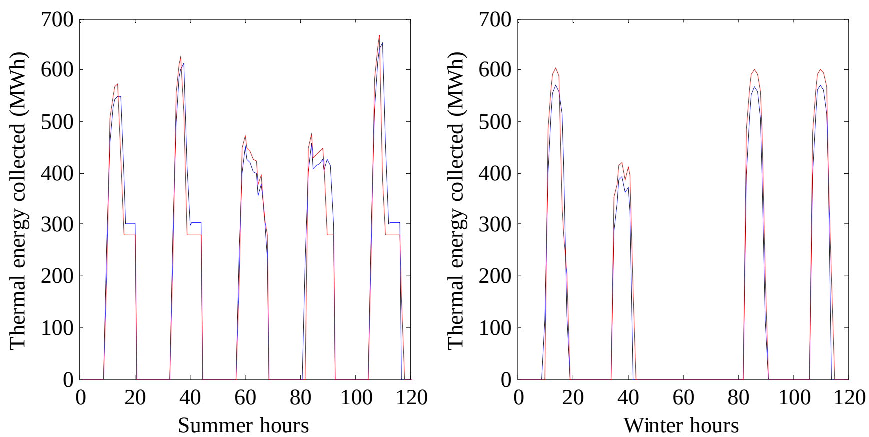

Figure 4.3: Comparison of net thermal energy collected showing SAM results in red and model results in blue

As figure 4.3 illustrates, the model compares reasonably well to SAM. It appears that the SAM receiver tends, during peak times, to collect slightly more energy than the modelled receiver. This is possibly due to a slightly higher receiver thermal efficiency in the SAM model. The other disparity that can be seen during a good DNI week is that when storage is full and the models start to spill (i.e., when heliostats are aimed away from the tower because no further energy can be absorbed), SAM will spill slightly more energy than the model, indicating that other processes within SAM are happening at higher efficiencies. Overall, however, a reasonably good correlation is shown and this part of the model is considered valid for system analysis.

In order to show that reasonable results are achieved over a range of configurations, table 4.2 shows the percentage deviation between SAM and the model at maximum total electrical output for a range of configurations in terms of storage and solar multiples.

While the largest deviation at both ends of the spectrum is about 18%, the model matches SAM reasonably well for solar multiples of 2 to 3 with about six to twelve hours of storage. This happens to be the range in which most of the optimal plants, for a two tier tariff that incentivizes evening peak production, can be found.

Table 4.2: Model deviation from SAM

Storage	Solar Multiple		
	1.5	2.25	3
6	17.97%	11.44%	2.75%
12	17.75%	2.33%	-13.44%
18	17.51%	6.99%	-16.73%

The increased deviation between the model and SAM when optimised for the two tier tariff is attributed to the attempt to handle the optimal tariff structure and is not assumed to be attributable to the technical validity of the CSP model. Part of the goal in this project was to develop a CSP model that is fundamentally programmable in full and this deviation highlights the difficulties of using simulation tools that do not allow in-depth model parameter settings.

The last aspect of validation looks at the hourly electricity output of the model versus the hourly output of SAM. Figure 4.4 shows the two outputs for five days that have good DNI and five that have bad DNI for cases where SAM and the model were run with strong and weak peaking bias. The graphs marked A and B have a weak peaking bias and the graphs marked C and D have a strong peaking bias.

Even in cases where the model was run with a weak peaking bias (A & B) it still tended to produce less electricity than SAM. This trend is definitely amplified in the cases where the model was run with a strong peaking bias (C & D). Moreover, during the five days with bad DNI in the case where both SAM and the model were run with a strong peaking bias (D), there was a day where the model produced evening peak electricity and SAM produced nothing.

This section of the validation process serves to show that while both SAM and the model gather the same amount of energy, it is in certain cases being applied in a different manner. The model can be set to have a stronger peaking bias than SAM; this is not necessarily a good or bad thing, it is a function of the way the model has been programmed to behave. In cases where both were run with a weak peaking bias, the model was still reasonably close to SAM's outputs in terms of energy production. These results demonstrate that the model can allow for a stronger bias towards the plant being run to provide power during evening peak. Whether this is how the plant will run, however, depends on financial performance.

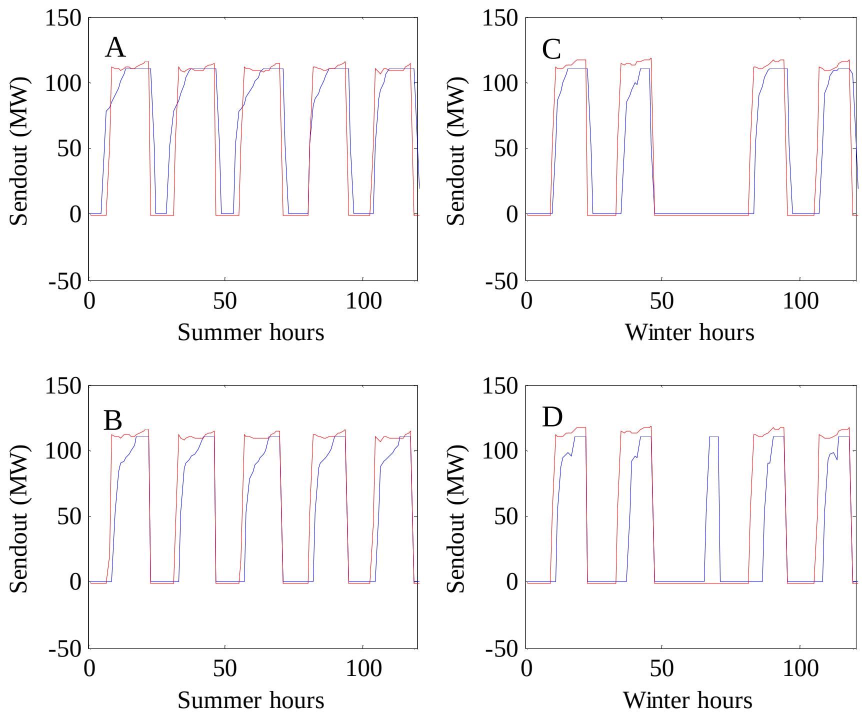

Figure 4.4: Hourly electricity output showing SAM results in red and model results in blue

4.3. Parabolic trough

A diagram of the parabolic trough plant layout can be seen in figure 4.5. There are four separate heat transfer fluid loops:

- Solar heated oil loop to storage – oil is pumped through collector tubes that have trough shaped heliostats focused on them and the thermal energy is transferred via a heat exchanger to salt storage.
- Solar heated oil loop to power block – oil is pumped through collector tubes that have trough shaped heliostats focused on them and the thermal energy is transferred via a heat exchanger to the conventional power block.
- Storage heated oil loop to power block – oil is heated by the thermal energy stored in the molten salt and. The thermal energy is then transferred to the steam cycle via a heat exchanger.
- Steam cycle in power block – steam conveys the energy from the heat exchanger to the turbine.

The model looks at each separate part of the cycle and models the efficiency of each of the components that has been discussed. The way in which the components interact with each other in order to generate electricity is also observed.

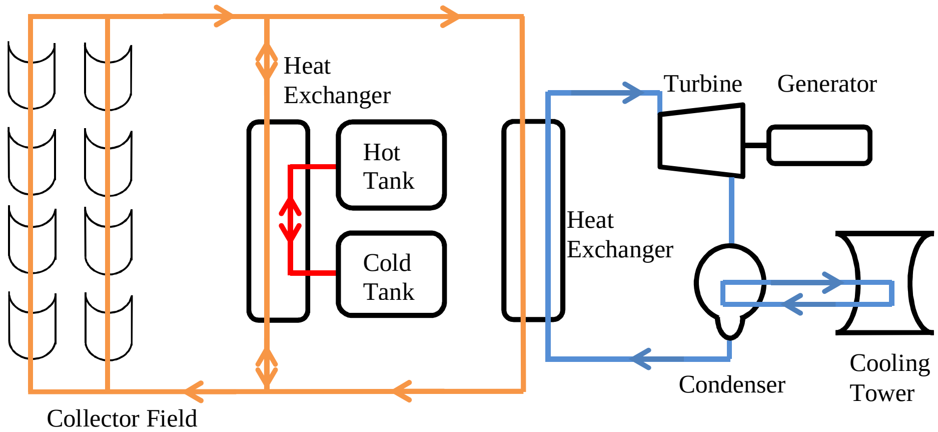

Figure 4.5: Parabolic trough plant layout

Many parts of the model function follow the tower model. A comparison of the modelling of the two technologies is made in section 4.3.1. The method for determining the amount of energy that reaches the collector field and the modelling of the collector field efficiency will be discussed in section 4.3.2. The receiver heat balance is discussed in section 4.3.3.

The electrical output and outages are covered in section 4.3.4 and 4.3.5 respectively. Financial aspects are discussed in section 4.3.6 and the final validation of the entire model is in section 4.3.7.

4.3.1 Comparisons to tower plant

While the storage and power block here resemble the ones for the tower plant type in section 4.1, there are significant differences. These differences, listed below, are caused by the lower maximum temperature at which the collector section of the parabolic trough plant can function (about 390 ºC) due to the use of oil as the transfer medium:

- Lower thermal efficiency
- Larger cooling load – bigger fans used for forced draft cooling causes a proportionately larger cooling load that leads to higher internal plant power consumption

- Increasing component size – an increase in steam volume required to produce the same power output necessitates increasing the component size throughout the power block
- Larger storage size – because of the smaller heating range, larger storage must be built to accommodate the same amount of thermal energy

Furthermore, there are large pumping requirements brought about by the need to circulate the oil through the very large collector field.

Notwithstanding these differences, the model still uses the same input data types, and the concepts of the solar multiple and hours of storage is consistent.

4.3.2 Calculating available power

To calculate the amount of redirect-able solar radiation, the incidence angle (θ) is required. It can be calculated from the following:

$$\cos\theta = \sqrt{(1 - \cos^2\delta \sin^2\omega)} \tag{4.19}$$

where δ is the declination angle and ω is the hour angle. Both were calculated as described in section 4.1.3. The above calculation works on the assumption of a plane rotating around an east-west axis where continuous adjustments are made to minimize the angle (Duffie & Beckman 2006:21).

In cases where the collectors are set up to rotate around a north-south axis, equation 4.20 is used instead:

$$\cos\theta = \sqrt{(\sin^2\theta_z - \cos^2\delta \sin^2\omega)} \tag{4.20}$$

where θ_Z is the zenith angle. For the purpose of this study, only parabolic trough configurations with a north-south axis layout were considered. The relative merits of the two configurations are discussed in Appendix A.

The cosine of the incidence angle was then used in equation 4.21 to calculate the irradiation available per m^2 of aperture for each hour of the year.

$$P = DNI * IAM * \eta_{opt} * \cos\theta \tag{4.21}$$

where η_{opt} is the optical efficiency, which is set at 75%, and IAM is the incidence angle modifier as defined by F. Burkholder and C. Kutscher (2009):

$$IAM = \min\left(1, \frac{\cos\theta + 0.000884\theta - 0.00005537\theta^2}{\cos\theta}\right) \tag{4.22}$$

In order to calculate the plant aperture from the solar multiple and the maximum available irradiation calculated, the following design assumptions were made:

- Collector thermal efficiency of 90%

- Heat exchanger efficiency 99%

The abovementioned collector efficiency does not include the optical efficiency, but refers only to the thermal efficiency of the collector. The design point power block thermal efficiency was again calculated using the Chambadal-Novikov equation. The hot well temperature was set as 390 °C, and the cold well temperature was again the yearly average ambient temperature of the site in question.

The calculated aperture was then multiplied with the available power to calculate the power redirected to the receiver.

4.3.3 Calculating receiver losses

The heat loss per meter of receiver tube was calculated using an equation developed by F. Burkholder and C. Kutscher (2009).

$$HL_{avg,W/m} = \frac{HLTerm1 + HLTerm2 + HLTerm3 + HLTerm4}{(T_o - T_i)} \tag{4.23}$$

$$HLTerm1 = \left(A0 + A5\sqrt{V_w}\right)(T_o - T_i) \tag{4.24}$$

$$HLTerm2 = \left(A1 + A6\sqrt{V_w}\right)\left(\frac{T_o^2 - T_i^2}{2} - T_{amb}(T_o - T_i)\right) \tag{4.25}$$

$$HLTerm3 = \frac{(A2 + A4 I_b IAM \cos\theta)}{3}\left(T_o^3 - T_i^3\right) \tag{4.26}$$

$$HLTerm4 = \frac{A3}{4}\left(T_o^4 - T_i^4\right) \tag{4.27}$$

where V_w is the wind velocity, T_{amb} is the ambient temperature, T_o is the temperature at which heat transfer fluid leaves the collector field and T_i is the temperature at which heat transfer fluid enters the collector field. The values for A0 through to A6 can vary depending on the state of repair of the receiver tube. All coefficients are given in Appendix B.

The losses were calculated for each tube condition. Then the final losses were combined using the assumption that 98% of the tubes were under vacuum conditions, 0.5% of tubes had broken glass (the glass envelope is completely missing), 1% of tubes had lost vacuum (the glass envelope is present but is cracked) and in 0.5% of the tubes sufficient hydrogen was present between the absorber and the glass envelope to conduct a significant amount of thermal energy.

4.3.4 Calculating electrical output

Calculating the electrical output was done exactly as described in section 4.2.5 with the exception of the method for calculating auxiliary power. In addition to the 5 MW loss that is taken whenever the unit is producing power, there is an additional pumping loss that is included whenever thermal energy is being collected, regardless of whether the unit is running. The amount of power required to move thermal oils through the collection field is significant and is scaled with field size.

4.3.5 Outages

As with the tower type of plant, outages can be handled in one of two ways. The plant can be shut down for a set number of days that coincides with the lowest profit generating period. Or, the overall power output can be lowered by a set percentage.

4.3.6 LCOE, LPOE and Return

The same method as described in section 4.2.7 was used to determine the plant configuration and running method that generates the highest rate of return. The data used to calculate investment expenditure is shown in table 4.3 (Fichtner, 2010).

The yearly operating cost is set at 1.97% of initial investment expenditure.

Table 4.3: World Bank report data on parabolic trough plant cost (Fichtner, 2010)

Item	Unit	Trough CSP		
		100 MWe & 9 h Storage	100 MWe & 4.5 h Storage	100 MWe & 13.4 h Storage
Aperture Area	1000 m2	1086.0	1216.0	1282.0
Scale with Aperture:				
Solar Field	mil US$	284.4	323.6	334.2
HTF System	mil US$	59.9	68.1	70.3
Balance of Plant	mil US$	46.0	45.0	55.7
Engineering	mil US$	37.3	36.4	45.1
Scale with Electrical Output:				
Power Block	mil US$	107.7	107.7	107.7
Scale with Thermal Storage:				
Thermal Energy Storage	mil US$	123.6	62.7	184.4
Percentage of total:				
Contingencies	mil US$	62.2	60.7	75.2
Owners Costs	mil US$	34.2	33.4	41.4

4.3.7 Validation

In validating the parabolic trough model, outputs for specific location were compared with the outputs generated by SAM for the same location and plant configuration.

As with validation of the tower plant, three separate aspects were covered for validation of the model. Firstly, the amount of thermal energy collected by the model and SAM were compared. The graph below shows the amount of energy collected during five days with good DNI and during five days with bad DNI:

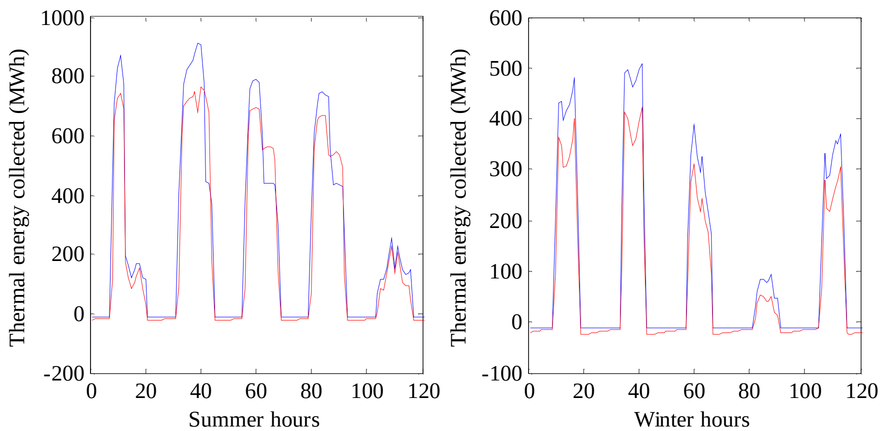

Figure 4.6: Thermal energy collected showing SAM results in red and model results in blue

It can be seen that during peak collection periods, the model collects significantly more energy than SAM. This happens because the model has a much larger collector field. The larger collector field is due to the model's power block having a lower design thermal efficiency than the power block modelled in SAM. A further discrepancy is caused by the fact that SAM does not start to spill thermal energy only when the thermal storage is full, but in fact spills pre-emptively. This contributes to the lower peak collected energy and to SAM collecting more energy once storage is "full".

Figure 4.7 shows the summation of both the collected and estimated spilled energy of the model and SAM. Notice that, aside from the impact of the different aperture sizes, the model and SAM correspond reasonably well in terms of thermal energy collection.

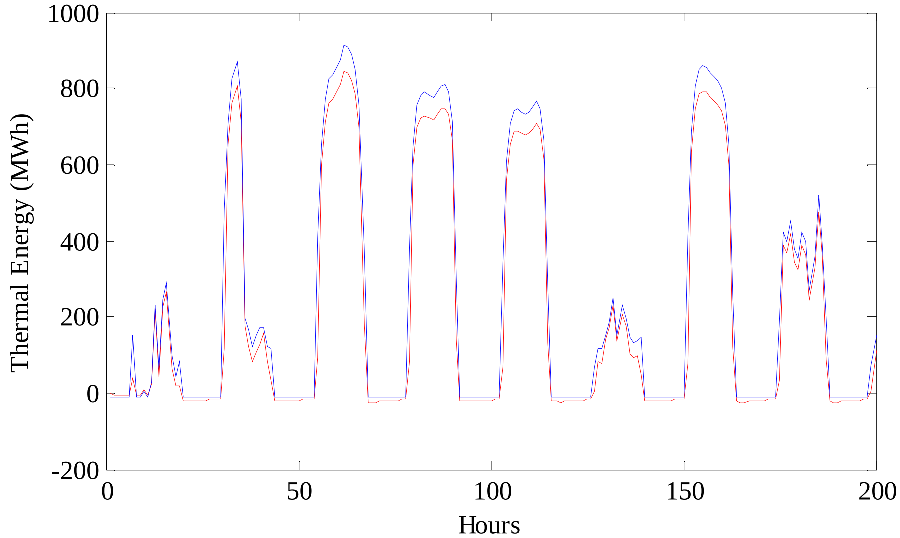

Figure 4.7: Collected and estimated spilled thermal energy showing SAM results in red and model results in blue

Secondly, the deviation between the total amount of electricity produced by the model and SAM, when both are running for maximum output (table 4.4), show that the model performs reasonably well for a range of configurations:

Table 4.4: Model deviation from SAM

Storage	Solar Multiple		
	1.5	2.25	3
6	-3.51%	-2.69%	-4.23%
12	-2.23%	-3.08%	-5.41%
18	-1.56%	-1.36%	-3.47%

Lastly, the hourly energy output of the model is plotted versus the hourly output of SAM. Figure 4.8 shows the two outputs for five days with good DNI and five days with bad DNI for cases where SAM and the model were run with strong and weak peaking biases. The graphs marked A and B have a weak peaking bias and the graphs marked C and D have a strong peaking bias.

As with the tower model, the parabolic trough model tends to produce slightly less electricity than SAM even when both are run with a weak peaking bias (A & B). The model is much more likely to shift energy production towards evening peak hours than SAM. One consequence of this is that the model actually tends to use more energy than SAM, as it is sometimes running the collector field while it is not producing energy. Due to high pumping costs associated with moving the heat transfer fluid through the large collector field, the electricity consumed when this happens is significant. It should be noted that the plant configuration used for validation is not necessarily the optimum plant configuration for the site in question.

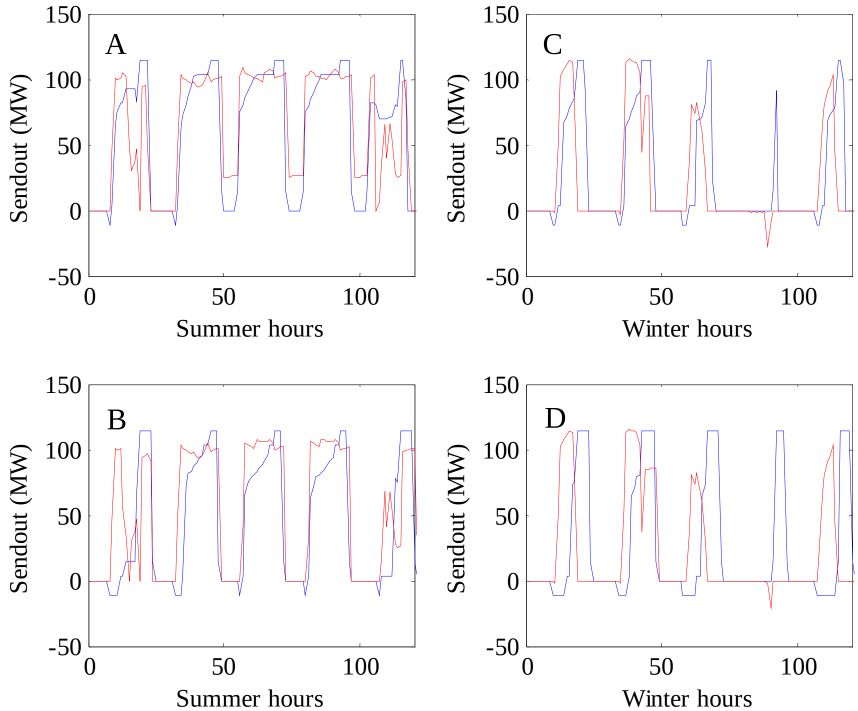

Figure 4.8: Parabolic trough hourly electricity output showing SAM results in red and model results in blue

4.4. PV

An already existing model created by Gauché and validated by Giglmayr (2013) was used to model the PV plants specified in the IRP. The PV plant model uses hourly DNI, DHI and ambient temperature information as inputs. The GeoModel data set does not include DHI information so DHI is calculated from GHI and DNI using equation 4.28:

$$\mathrm{DHI} = \mathrm{GHI} - \mathrm{DNI}\cos\theta_z \tag{4.28}$$

where θ_z is the zenith angle. In cases where, during the early hours of the day, small measurement inaccuracies cause the above equation to get negative results, the DHI is set to 0.

The model further makes use of the following assumptions:

- Cell efficiency: 15%
- Irradiance efficiency: 0.000125 W/m^2 below 1000 W/m^2
- Temperature efficiency: -0.005/°C above 25°C
- Ground reflectivity: 0.1

PV panels work by converting solar irradiation to electrical output via a physical process. PV panels convert not only the direct component of solar irradiation, but also diffuse irradiation as well as direct irradiation that have been reflected from other surfaces onto the panel. These different types of solar irradiation can be seen in figure 4.9. Because the PV panel does not have to redirect the radiation, it can make use of energy that would have gone to waste in a CSP plant.

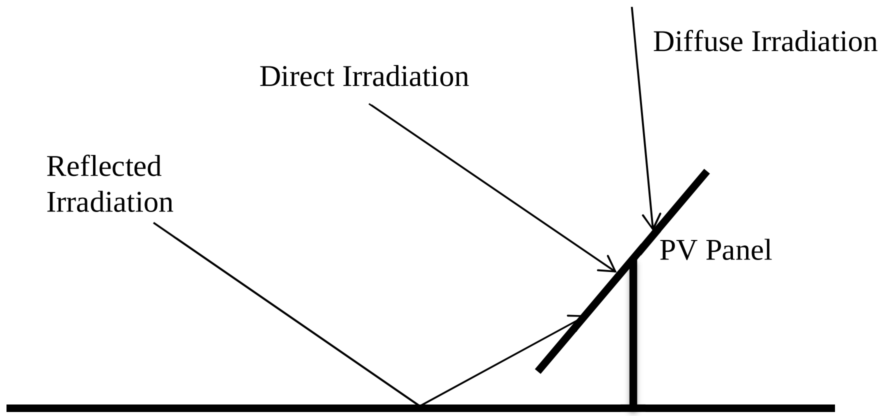

Figure 4.9: Irradiation onto PV panel

The effective irradiance intercepted by a PV panel is known as the total aperture irradiance and is calculated using the equation below:

$$I_t = I_d \cos\theta + \left[I_{dif}\left(\frac{1+\cos\beta}{2}\right) + \rho I_g\left(\frac{1-\cos\beta}{2}\right)\right] \tag{4.29}$$

where I_d is the DNI, θ is the angle of incidence, I_{dif} is the diffuse irradiance, I_g is the total irradiance falling on a horizontal surface, β is the angle between the collector panel and horizontal and ρ is the reflectance of the surrounding area. (Stine & Geyer, 2001).

As the above makes clear, the direction in which the panel faces is important. A PV panel that tracks the sun and maximizes the amount of direct irradiation it receives will collect more energy than a stationary PV panel. On the other hand, tracking technology incurs more cost, both during construction and operation. There is no one single trend when it comes to large PV installations, and thus the various types of tracking strategies are included in the model:

1. Fixed latitude tilt – the panel is fixed in position with an angle that matches the latitude of the installation between the panel and the ground. The panel faces towards the equator.
2. Fixed tilt – as above, but the angle between the panel and the ground does not match the latitude of the installation.

3. Declination tilt – the panel is installed with an angle between it and the ground and facing the equator, but the angle is adjusted according to the time of year in order to maximize yield.
4. Azimuth tracking – the panel tracks the sun only along one axis. The panel still faces the equator at all times, but the angle between the panel and the ground shifts in order to minimize the angle to the sun.
5. Hour angle tracking – the panel shifts along both axes to keep it facing the sun, but the panel only shifts position on an hourly basis.
6. Full tracking – the panel shifts position to keep directly facing the sun at all times during the day.

Because it is not known which type of tracking plant will be built in the future, the approach will be to simulate all six types of plants and average the resulting power output for each location. The irradiation experienced by each type of tracker over the course of a single summer day is shown in figure 4.10.

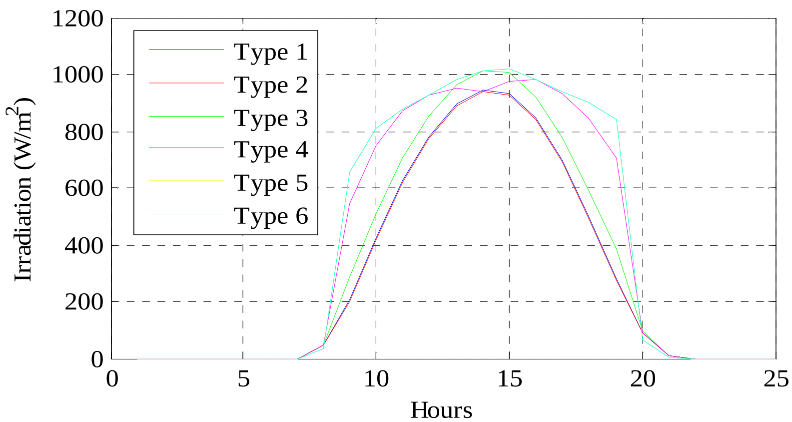

Figure 4.10: Irradiation per tracker type

The annual duration curve for the smeared PV output at a single site is shown in figure 4.11.

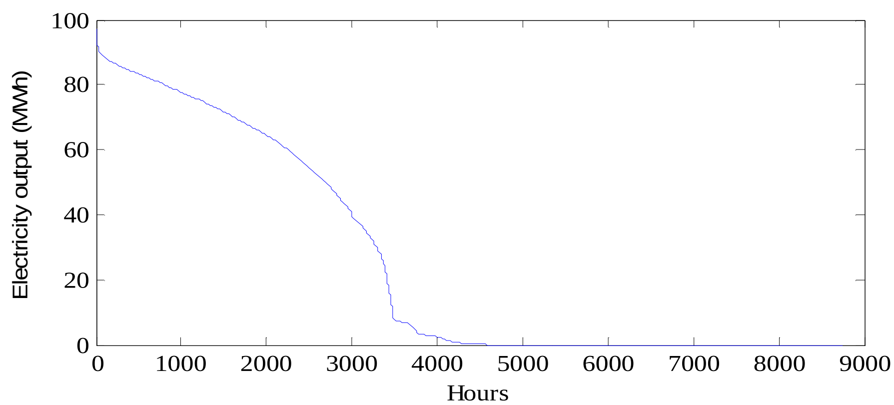

Figure 4.11: PV annual duration curve for a single site

4.5. Wind

Converting wind speed to wind turbine power output is a fairly simple process if the wind speed at the correct altitude and the type of wind turbine are both known. The wind speed can simply be matched to a fitted curve with the electricity production data provided by the wind turbine manufacturer. The outputs can then be multiplied by the size and number of units installed. This modelling method assumes the absence of field effects.

Unfortunately, the available wind velocity information that has sufficient granularity (provided by GeoModel) was measured at 10 m above the ground, while wind turbines typically operate at heights of about 100 m. A method to convert the data measured at 10 m to reasonable electricity outputs was developed and validated by Giglmayr (2013). This method was used to develop wind power output curves and is described below:

- Extrapolate wind speed at 100 m. The Hellman exponential law is used to extrapolate the wind speed at 100 m from the wind speed at 10 m.

$$\frac{v}{v_0} = \left(\frac{H}{H_0}\right)^{\alpha} \tag{4.30}$$

  In the above, v represents the wind speed in m/s, H is the heights at which the speeds occur and α is a friction coefficient. The basic premise is that wind speed is lower at ground level due to friction caused by surface obstructions. The friction coefficient was set to 0.126. This value was developed to represent ground conditions in areas where wind farms were likely to be constructed (Giglmayr, 2013).

- Calculate the electrical output. The wind speeds calculated in the step above are converted to electrical outlet using the fitted curve that matches the data provided by the manufacturer of the Enercon E-101, which is a 3050 kW wind turbine. For the purpose of this study, only one type of wind turbine was considered in order to simplify the modelling approach. Both fitted curve and manufacturer data points are presented in the figure 4.12.

- Calculate the capacity factor. Capacity factor for wind turbines is calculated by using equation 4.31.

$$CF = \frac{E}{P * 8760} \tag{4.31}$$

  where E is the total output of the wind turbine for the year and P is the rated size of the turbine, i.e. 3050 kW. The capacity factors generated using the wind velocity data extrapolated in the step above will generally fall over a much wider range than would be expected for sites that are being considered for commercial wind farm operations.

The generally expected capacity factor bandwidth would be between 27% and 42%

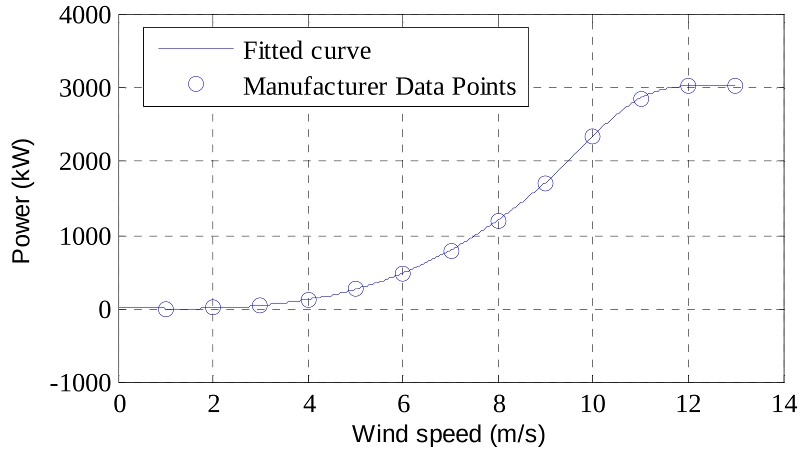

Figure 4.12: Enercon E-101 power output vs. wind speed

- Calculate the velocity adjustment factor. For each site, a factor must then be calculated that would move the calculated capacity factor into the required capacity factor range while maintaining its proportionate position amongst the sites being considered. The equations below show how the velocity adjustment factor was calculated.

$$\mathrm{CF_{req}} = \mathrm{CF_{min,req}} + \frac{\mathrm{CFRange_{req}}\left(\mathrm{CF_{actual}} - \mathrm{CF_{min,actual}}\right)}{\mathrm{CFRange_{actual}}} \tag{4.32}$$

$$\mathrm{Adjustment} = \sqrt[3]{\frac{\mathrm{CF_{req}}}{\mathrm{CF_{actual}}}} \tag{4.33}$$

- Iterate the above two steps. It is not possible to adjust the capacity factors in one step. Adjusting the wind turbine speeds might either move the lower wind speeds from a range where the turbine is not moving into a range where the turbine is moving or move the higher velocities into a range where the turbine no longer functions. There is also a significant part of the speed range where output power does not very. Thus, the above two steps must be iterated until the difference between the achieved and desired capacity factors fall within a reasonable error margin.

Figure 4.13 shows the annual duration curve and figure 4.14 shows total hourly electricity output for a week for a scenario where there is a total installed capacity of 4250 MW based on wind data from twenty-five sites.

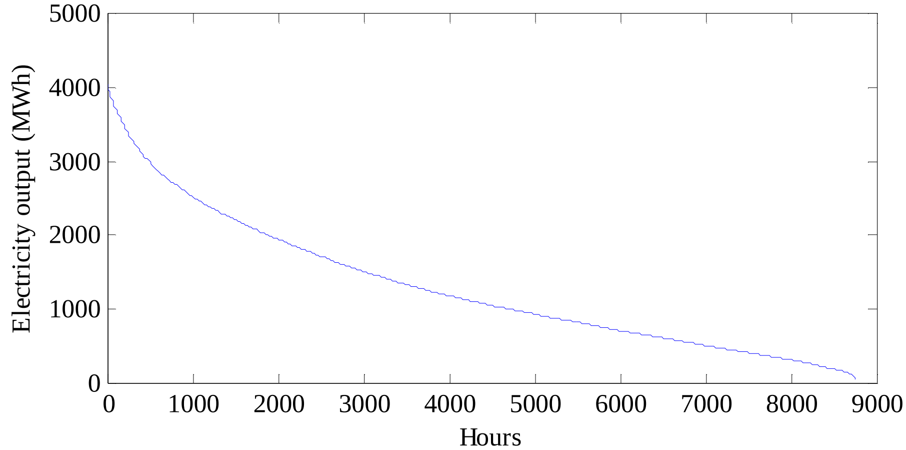

Figure 4.13: Wind annual duration curve

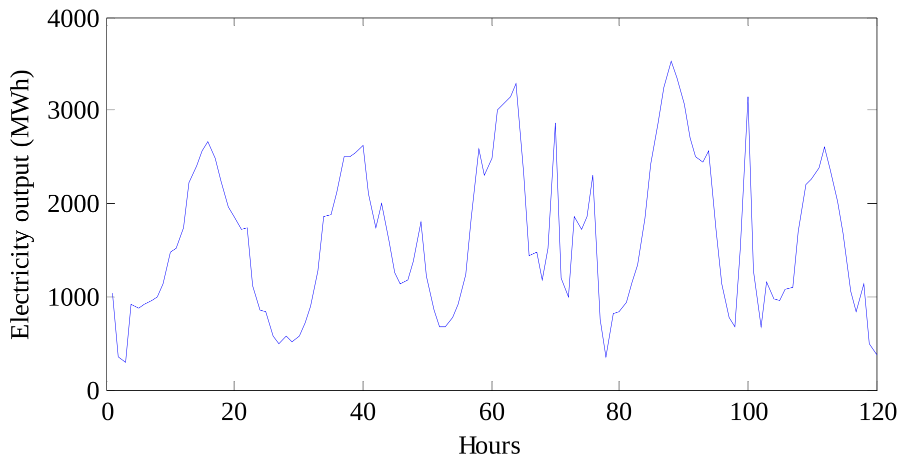

Figure 4.14: Hourly electricity output

4.6. Conclusion

In this chapter hourly models for four renewable technologies were developed and validated to the point that they are considered appropriate for further use in the system model. In the next chapter the conventional energy system model will be discussed.

5. CONVENTIONAL SYSTEM MODEL

This chapter covers the conventional system model that consists of all the generating units in the grid not covered in Chapter 4. The technologies covered in this section are much more dispatchable, and the nature of the modelling differs in that output is governed by demand. This chapter expands on work published in the proceedings of SASEC 2014 (Auret & Gauché, 2014).

5.1 Introduction

The conventional system model operates from the assumption that the plant output is governed by system needs. This is in contrast with the IPP controlled plants where each plant would be operated with an eye on maximum profit. The model runs on two nested loops. The outer loop contains all daily activities, and the inner loop contains all hourly activities. These two loops can be seen in figure 5.1, which shows the conventional system model flowchart. The technology types are divided into base load and peaking categories. Distinctions between these two categories and how different technologies are handled are discussed in section 5.2. Almost every step in the model involves either updating or processing data from the unit list table discussed in detail in section 5.3. As with other technologies, the generating units in the conventional system model are also subjected to both planned and unplanned outages. How these outages are assigned and timed is discussed in section 5.4. Cost and validation are covered in sections 5.5 and 5.6 respectively.

5.2 Types of plants

The conventional generating units are divided into base load units and peaking units. These types of units are handled in different manners. Coal-fired, CCGT and nuclear plants are seen as base load units. They are deployed first in order to meet demand. Coal plants are operated at loads ranging between 40% and 100% of their full capacity, and CCGT plants can vary their load from 50% to 100%. Nuclear units are never run below 80% capacity (Black & Veatch, 2012).

Peaking units are only deployed in cases where the base load units are incapable of meeting demand. Such cases occur either when the base load units are already running at their full capacity and more power is required, or when the base load units cannot ramp up power production fast enough due to limitations on the rate at which they can pick up load.

The model deals with three different types of peaking units: hydro power stations, pumped storage stations and OCGT stations.

In the case of hydro power stations and pumped storage stations, the number of hours that each of these unit types can operate during any given day is limited. Other countries may run their hydro power stations as base load stations, but

South Africa is a water scarce country. Hydro stations are generally used to balance load distribution over the country (Eskom, 2013). In the model, hydro power stations are simply considered as peaking power stations that are limited to eight hours of full load operation per day.

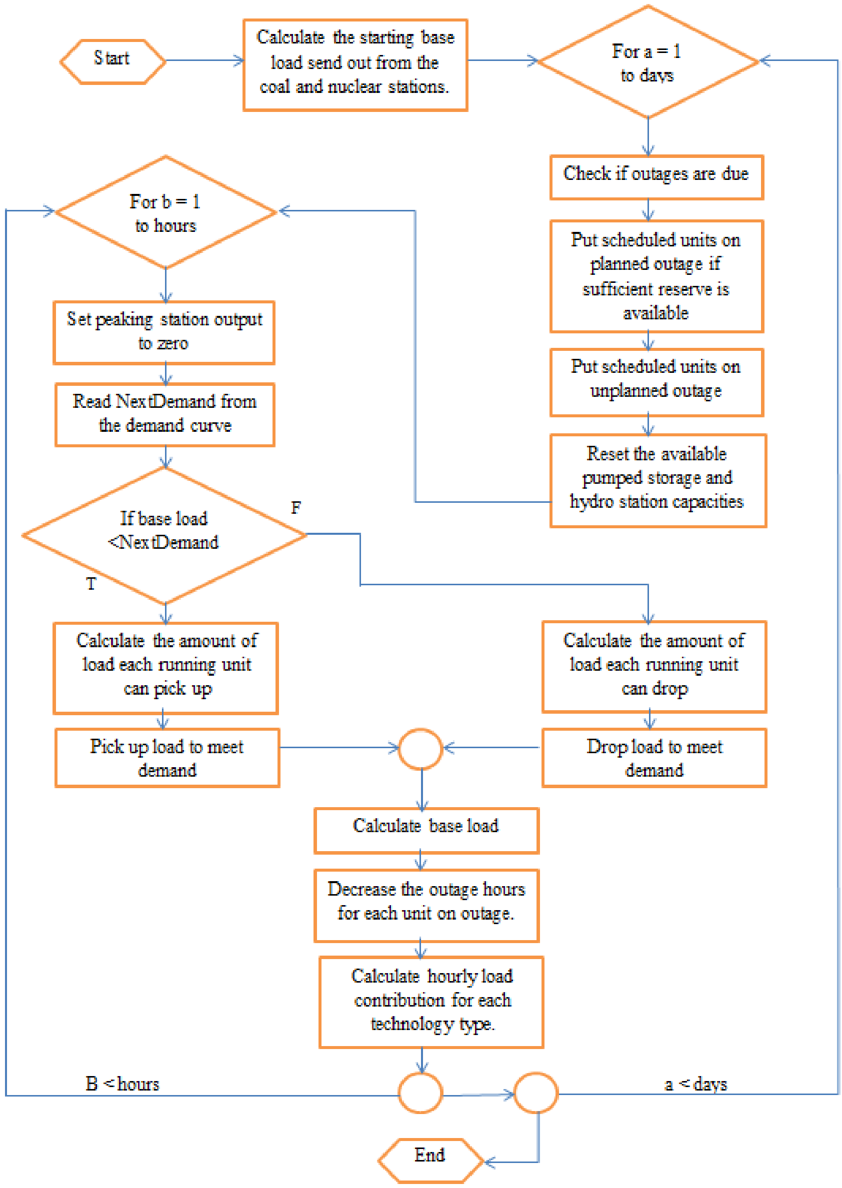

Figure 5.1: Conventional system flow chart

Pumped storage stations are limited in the number of operating hours during which they can run full load because they must be loaded (by having water pumped back up to the upper reserved dam). In the model, pumped storage stations are limited to eight hours of full load operation in every 24-hour cycle. Of the eight hours four are reserved for evening peak operation.

OCGT units do not have the same limitations as hydro power stations and pumped storage stations, but they are the most expensive form of power in the conventional system. To minimize cost, pumped storage and hydro units are always loaded first when available. Only in cases where there is still a shortfall after the pumped storage units are at full load does the model run the OCGT units.

5.3 Unit information table

The unit information table is a table that contains information on each generating unit in the system. Some of the information contained in the table is static and is setup as an input to the model. Other fields will change with every iteration. An example of a unit information table showing single units of various types is shown in table 5.1. Notice that in cases where specific information is known about unit output, i.e. for existing plants, exact data is used (Eskom, 2013). Where this is not available, generic units are added (Black & Veatch, 2012).

Table 5.1: Unit information table example

	Max Load (MW)	Min Load (MW)	Ramp Rate (MW/h)	Outage Status	Load (MW)	Up Available	Down Available	Type	Pump Hours
Old Coal	615	246	190	0	246			0	
Nuclear	900	720	900	0	720			1	
Pumped Storage	200	0	200	0	0			2	
Domestic Hydro	90	0	90	0	0			3	
OCGT	147	0	147	0	0			4	
New Coal	600	240	600	0	240			5	
Imported Hydro	750	750	750	0	750			6	
CCGT	600	300	600	0	300			7	

The descriptors shown in the first column of the example table are not actually included in the table used in the model but are included here for clarity. The Max Load column indicates the maximum power output that a generating unit can deliver to the system.

The Min Load column indicates the lowest load at which a generating unit is allowed to function in cases where it is not on outage. In cases where the value is 0, this indicates that that generating unit will be started up and stopped on a regular basis. This is usually the case for peaking plants.

The Ramp Rate column indicates the number of megawatts that the unit can pick up during an hour. In cases where the ramp rate is equal to the max load, the unit in question can ramp up to full load in an hour or less. This is the case for all peaking plants, but more and more it is also becoming the norm for new base load plants.

The first three columns in table 5.1 are static. The next four columns can change with each iteration of the inner loop, i.e. on an hourly basis. The Outage Status column indicates whether a plant is available to generate electricity or not. It also indicates how long the plant will be unavailable if it is unavailable. If the column contains a 0, the plant is available to generate load. Any number larger than 0 indicates the number of hours for which the plant will be unavailable.

The Load column simply indicates the load that a given unit is currently generating.

The Up Available and Down Available columns indicate how much load a given generating unit can either pick up or drop during a given hour. Each is only updated when necessary. When the previous base load output exceeds the current generating requirement, the amounts by which each base load unit can drop load before it reaches its minimum load is calculated and put into the Down Available column. In cases where the previous base load output is lower than the current generating requirement, the amount that each base load unit can pick up before reaching its maximum load is calculated and stored in the Up Available column. Since the model sets the peaking plant generation to zero after every hour, only the Up Available column is ever used by the peaking plant. This measure is calculated only if the base load plants are not capable of meeting full demand.

The Type column indicates the plant type. This is used when determining what actions should and should not be taken with a given plant. The numbers indicated in the example correspond to the types shown in the description column.

The Pumped Capacity column is used to show how many megawatt hours in a given 24-hour cycle pumped storage and hydro plants have left to produce. For each unit, this is a capped amount that is reset each day.

In some versions of the model, an additional column was used to indicate when a given unit was constructed. This was used for costing purposes in cases where technologies had learning rates.

5.4 Outages

Two types of outage are taken into account: planned and unplanned. Both run on predetermined lists. Both lists include start dates, durations and, of course, the unit numbers. All outages are assumed to start at hour 1 and last for multiples of 24-hours.

At the start of every 24-hour cycle, the model checks the planned outage list for outages that are due. All due outages are then moved to the outage execution list. Planned outages on any given unit only occur if there is sufficient generating capacity over the duration of the outage for the remaining units to be able to supply the highest demand that occurs during the entire period plus a predetermined margin. The model checks the outage execution list to see if there is sufficient generating capacity available for any of the due outages to occur. If there is sufficient capacity, the number of outage hours is added to the Outage

Status column in the unit information table, and the outage is removed from the outage execution list. Planned outages do not necessarily happen on the day for which they are planned, but can be deferred until there is sufficient generating capacity available.

The margin that is referred to in the case of outage planning is a pre-set percentage. This percentage is multiplied with whatever the maximum demand in a given period is to determine the amount of surplus generating capacity that must be kept in reserve to cope with unplanned outages. The percentage margin is a model input and can in fact even be negative. When determining the amount of generating capacity that is available to meet demand plus the margin, not all generating capacity is treated equally. All of the generating units that make up the conventional system are allowed to contribute 100% if they are not on outage. However, only 6% of available wind capacity is counted towards reserve margin as it is intermittent in nature. No contribution from PV is taken into account because PV does not contribute during the traditional peak hours. CSP that is set up to prioritise electricity production during evening peak contributes 80%, but only during peak hours.

Only after planned outages have been set up and committed to are the unplanned outages implemented. The unplanned outage list also has dates and durations, but unlike planned outages, they cannot be deferred depending on system demand. The start date and duration of unplanned outages are randomly drawn up, and the limitations are that each unit will only half a certain percentage of outage hours per year.

5.5 LCOE

The LCOEs, calculated by EPRI (EPRI, 2012), that are used to calculate system costs in the 2013 IRP amendment document will also be used to give an indication of system costs in this model. These costs will be used for technologies included in the conventional model as well as for wind and PV. For each technology, the IRP LCOE will be multiplied by the number of kilowatt hours contributed by that technology to the grid. All these costs are added together and divided by the total power produced over the course of the year. The relative cost per kilowatt hour produced in the above method can then be used to compare outcomes within scenarios.

Note that the LCOE produced in the EPRI study for the OCGT is based on the assumption that the OCGT plant will run on LP gas and not on diesel (EPRI, 2012). This does not reflect the current situation but instead is based on the long-term plan. The impact of this is that the LCOE of the OCGT is about R4/kWhr lower in the projections than in reality (EPRI, 2012, Silinga & Gauché, 2013). While all renewable energy plants are cost competitive with OCGT plants that burn diesel, only some of them can compete when LP gas is used as fuel (DoE, 2013).

The uncertainty with regard to the source and cost of fuel is reconciled by considering the amount of OCGT power as a separate system adequacy measure. This is further discussed in section 7.2.

5.6 Validation

The initial validation of the model consists of checking that the model behaves as it is expected to behave. This is accomplished by plotting the stacked electricity generation for each technology against demand over a given period. An example of this can be seen in figure 5.2

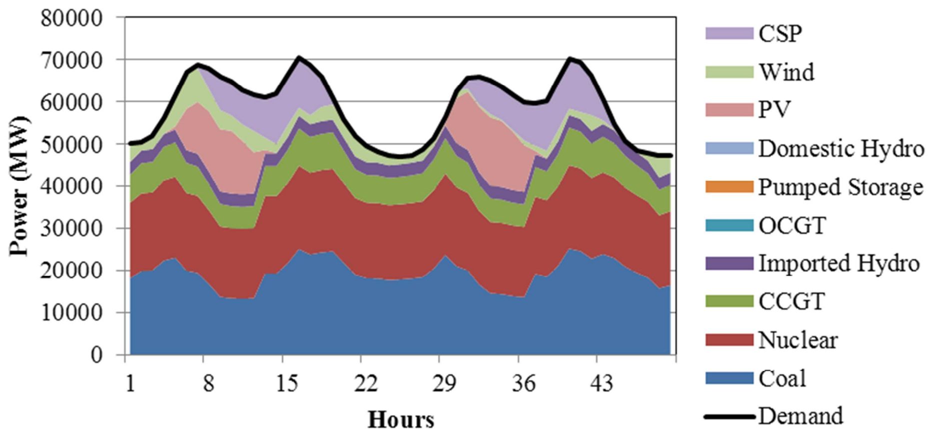

Figure 5.2: Conventional system base load validation

The intent here is to test if the integrated model behaves logically. This initial validation also provides a first check of demand/supply balance. Note that the wind, PV and CSP curves in the graph are produced and subtracted from the demand curve before the rest of the system responds. In figure 5.2 the renewable contribution and the available base load stations are sufficient to fulfil demand. Consequentially, none of the peaking plants contributes. The conventional base load ramps up and down to fill up all the gaps left after PV, wind and CSP has been taken into account.

Figure 5.3 shows the model output for a case where the base load plants could not generate enough electricity to fill all the gaps left over after PV, wind and CSP production had been taken into account. Both the peaking plant merit order and the fact that hydro power station output is restricted in terms of the number of megawatt hours that can be utilised in a 24-hour cycle can be clearly observed. On the first day, the hydro power runs out. It can also be seen that pumped storage does not start unless the demand gap cannot be filled by the hydro plant. This is evident from the fact that at hour seventeen, hydro power stations are the only type of peaking plant that is generating electricity. OCGT is last on the merit order, and this is clearly supported by figure 5.3 because the OCGT plant only contributes in cases where all other units are producing at full capacity or are simply not available.

The model further has a measure of built-in validation. For every hour of the year, a check is run to ensure that every technology option is generating equal to or less load than the available capacity for the technology. In other words, available capacity is never exceeded.

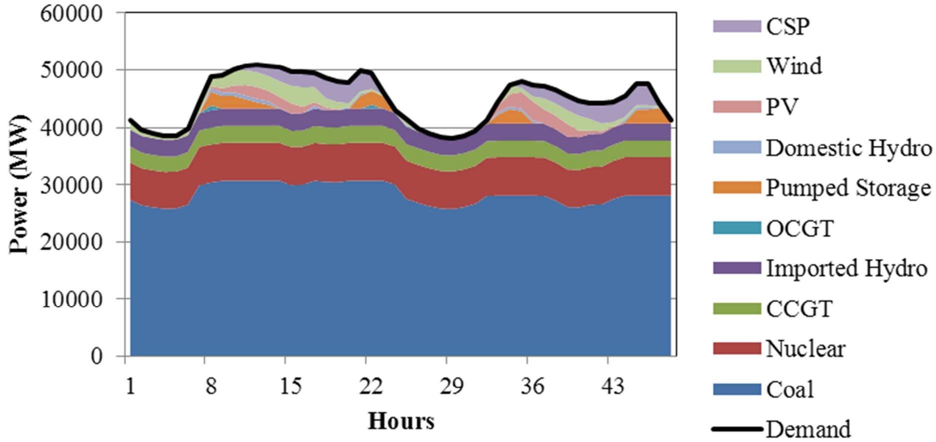

Figure 5.3: Conventional system peak load validation

5.7 Conclusion

The conventional model is almost entirely behavioural in nature, but it was validated to perform within acceptable bounds. The model appears to operate well when combined with the more fundamentally derived renewable energy models. It, in conjunction with the Chapter 4 models, can be used to model the potential electricity generating systems described in the 2013 IRP update. The outcomes from doing this are described in Chapter 7.

6. OPTIMIZING CSP PLANT CONFIGURATIONS

This section describes the relation between the impact of tariff structure on both the outage planning and CSP plant configuration observed during the CSP modelling process. The aim is to highlight the extent to which these aspects factor into the amount of energy that the plants produce as well as the times when energy is produced. These impacts are significant enough that their effects should be taken into account when analysing the energy system as a whole.

6.1 Introduction

The tariff structure proposed in the current bidding round of the REIPPPP resembles the following structure (Silinga *et al.* 2014):

- 05:00 to 17:00 and 22:00 to 23:00 ➔ R1.65/kWhr
- 17:00 to 22:00 ➔ R3.95/kWhr
- All other times ➔ no remuneration

This structure has two apparent aims. It incentivizes the construction of sufficient storage to provide for electricity production during the hours of evening peak, and it incentivizes a lack of production during very low electricity consumption times. This fits neatly with the requirements of the rest of the system. There is a need for peak production to minimize the use of OCGTs, but at the same time it is necessary to ensure that there is sufficient electricity demand left over during low demand times to keep base load plants running at reasonable capacity factors. This simple remuneration structure thus looks very sensible. It emphasizes the time of day value of electricity production. Unfortunately, the time of year value is disregarded.

Figure 6.1 shows the weekly output of the twenty-five most economically viable CSP plant locations that were optimized based on the above mentioned remuneration structure. It should be noted that the CSP plants were allowed to schedule planned outages based on perfect weather forecasting, which resulted in the sharp drop in output at week 27. In reality plants will schedule outages based on imperfect forecasts and historical data and the effect of planned outages can be expected to be more distributed. The effect of unplanned outages was not included in the data represented here.

Figure 6.1 shows that CSP power production is at its height during the summer and dips down during the winter. As the South African evening peak demand is higher in the winter it appears that seasonal CSP behaviour is opposite to the country's energy requirements. As mentioned in the literature review, Kost *et al.* (2013) shows that the type of remuneration structure put in place impacts on the type of plant that is built in terms of both the solar multiple and hours of thermal storage. A remuneration structure that incentivizes higher winter power production might very well result in a change in plant configuration.

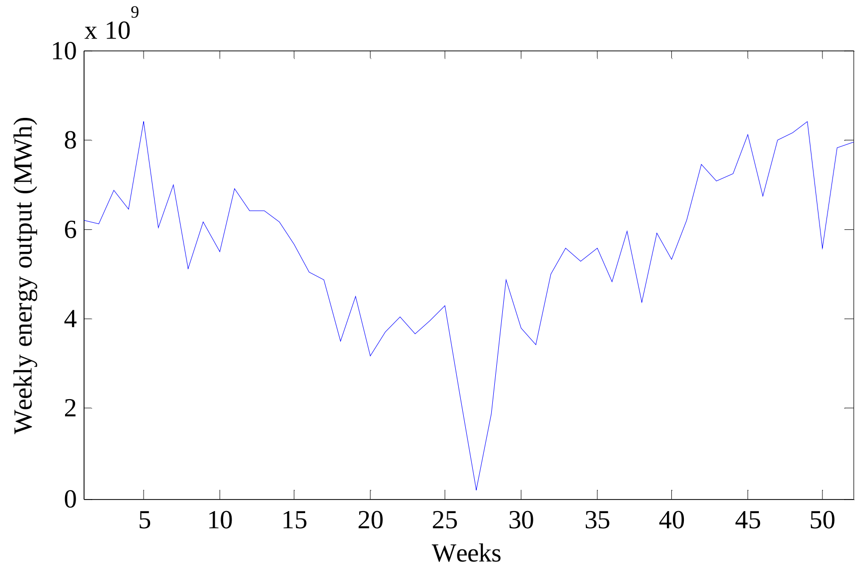

Figure 6.1: Weekly energy output for 25 CSP plants on a two tier tariff

In order to investigate the impact of a seasonal tariff, two fairly simple seasonal tariffs were constructed: in the first case, for the months of June, July and August the tariff was raised by 60% across the board; the tariff was lowered by 20% for all other months. In the second case, for the months of June, July and August the tariff was raised by 100% and the 20% drop for the other months was maintained.

The seasonal tariffs were then compared to the two tier tariff by determining the optimal plant configuration at 111 different locations across the country for each tariff. At each location, outputs were calculated for solar multiples ranging between 1.3 and 3.3 and for hours of storage ranging between one and eighteen. The optimum configuration and running method for each location was then determined based on profits generated. In all cases, outages were handled by allowing the plant to shut down for the fourteen consecutive days, during which the least profit was generated.

The impact that a tariff system like the one described above will have on the plant configuration is discussed in section 6.2, and the impact on outage planning is discussed in section 6.3. The reasons why these impacts are significant when modelling the generating system are discussed in section 6.4, and the conclusions are given in section 6.5.

6.2 Impact on configuration

The CSP tower and parabolic trough models were run for a range of inputs in terms of both hours of storage and solar multiple. The configurations that led to the maximum return on investment were captured for each location in the country. The optimum return on investment for each location was then compared against each other to determine the fifty most profitable combinations of type, configuration and location. This was done for each of the tariff structures mentioned in section 2.1 as well as for a plant that was configured to run on a flat tariff. It should be noted that the maximum return on investment configuration does not coincide with the minimum LCOE configuration, except in the case of the flat tariff. The resulting configuration information and LCOEs can be seen in table 6.1. For each tariff the minimum LCOE that could have been achieved at the selected sites if the plants were optimised for minimum LCOE is shown in the last row of the table.

Table 6.1: CSP configuration under different tariff schemes

	Two Tier Tariff	Seasonal Tariff 1	Seasonal Tariff 2	Flat Tariff
Hours of Storage	7.060	6.780	6.740	14.100
Solar Multiple	1.564	1.572	1.568	3.288
LCOE (R/kWh)	2.260	2.327	2.345	1.666
Optimal LCOE (R/kWh)	1.964	2.009	2.019	1.666

Table 6.1 shows that the first three tariff options lead to reasonably similar results that are nevertheless not identical. As the financial emphasis shifts towards providing peak power, and specifically winter peak power, the hours of storage and the solar multiple can be seen to decrease gradually. The corresponding decrease in energy output causes an increase in LCOE. While the first three tariffs differ slightly from each, all three of the others are essentially set up to encourage CSP energy production during evening peak hours. The configuration that corresponds to the flat tariff is significantly different. The flat tariff lends itself to a plant configuration that maximizes electricity output. Thus, a high solar multiple and large storage can be observed. The flat tariff plant configuration represents a base load, or mid merit type plant, while the other configurations are optimised to provide power during evening peak.

6.3 Impact on planned outages

The impact of a seasonal tariff on outage planning and electricity send-out can be seen in figure 6.2.

The graph in figure 6.2 makes clear that when winter production is not incentivized, plants tend to be shut down during the winter. This happens because the winter is the lowest revenue-generating period. If IRP electricity production is only controlled via a simple non-seasonal tariff, the plants will tend to shut down during the winter for planned maintenance. If winter production is incentivized, the shutdown phases tend to be more distributed.

It is additionally interesting to note that when winter production is incentivized, plant locations further north tend to become slightly more economical. The reason for this is that during the winter months, irradiation density tends to shift northward.

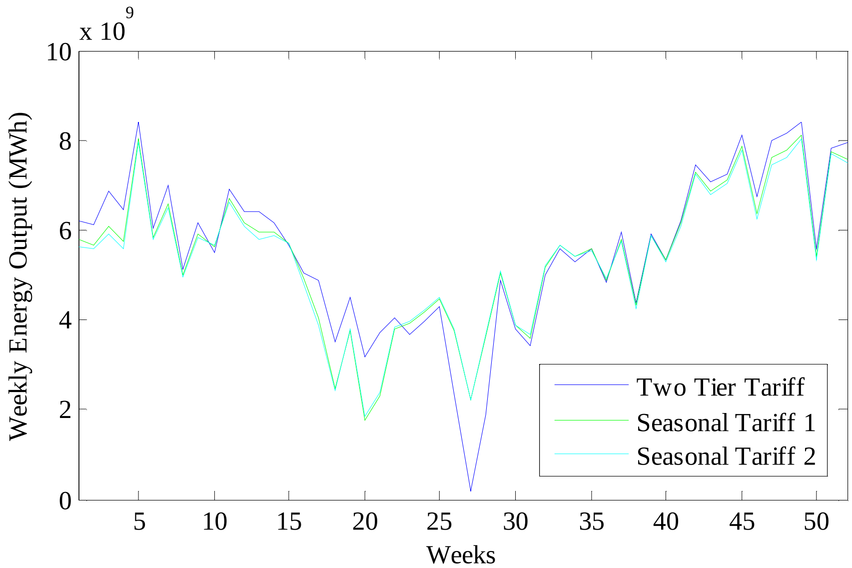

Figure 6.2: Average weekly outputs for two tier and seasonal tariffs

6.4 LCOE vs returns

In sections 4.2.7 and 4.3.6 it is stressed that the optimum plant configuration and running bias is selected based on a rate of return, i.e. the most profit per unit of money invested in the plant. The importance of using such a rate instead of LCOE to determine the optimum plant configuration once remuneration has shifted away from a flat rate is illustrated in the graph in figure 6.3.

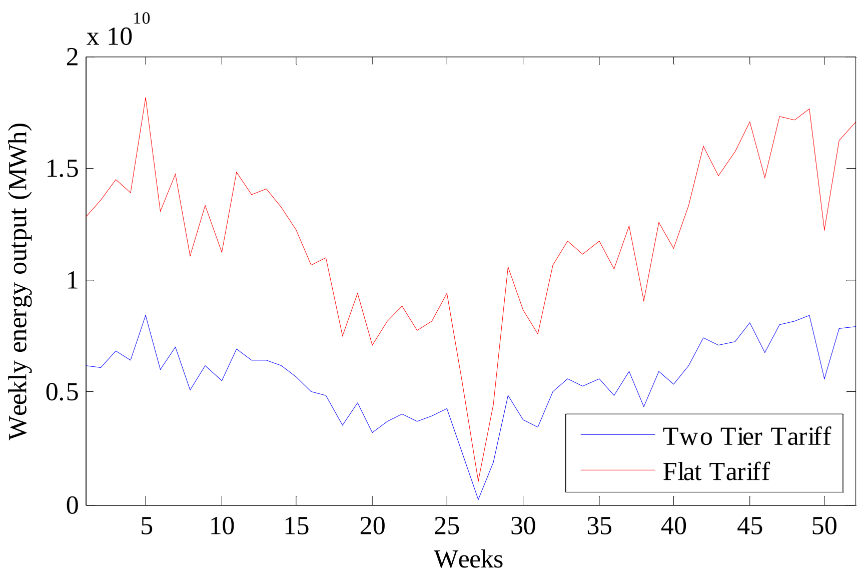

Figure 6.3: Impact of configuration criteria on weekly energy output

This graph shows the average weekly total energy output for the best twenty-five plants under the two respective tariffs. It seems clear that if a structured tariff is offered, then the effects that the tariff will have on the total output must be taken into consideration when CSP plant output is being modelled. As figure 6.3 illustrates, it is clearly inappropriate to make use of a power profile that is based on plant configuration and that has been optimized for a flat tariff/minimum LCOE.

If the expected CSP contribution to a proposed system is projected based on the assumption that plants will be configured to minimize LCOE, but there is a rigid tariff system such as the one described in section 6.1, the realised megawatt hour contribution made by CSP plants to the system will be less than projected.

The inappropriate nature of using an output profile generated by a plant optimized for minimum LCOE if there is a structured tariff in the system can also be seen in the graph in figure 6.4.

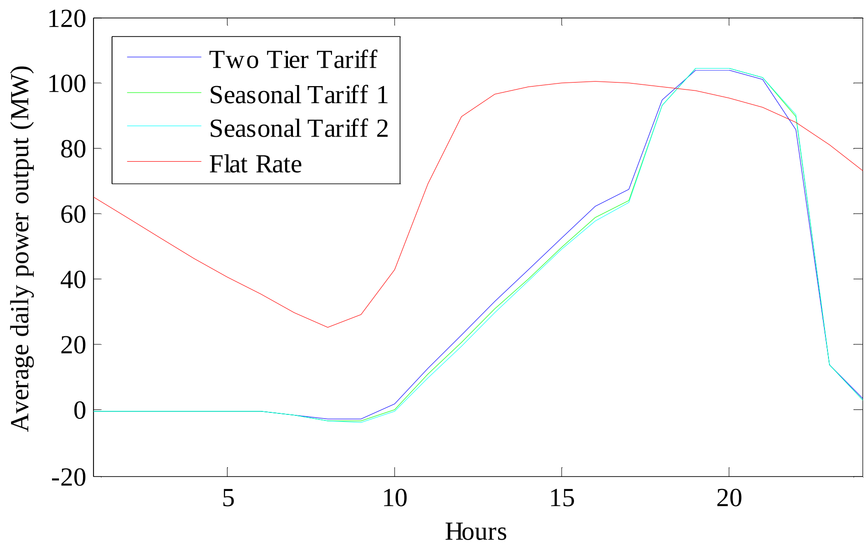

Figure 6.4: Characteristic output curve for all tariff structures considered

Figure 6.4 shows the difference in the average daily electricity output of plants constructed and run to satisfy the two different tariff types. The red curve shows the output for the best performing CSP units that were configured to minimize LCOE. The blue line shows the output of plants that were configured to maximise return. As can be seen, the two outputs are rather dissimilar. This reiterates the point made while discussing figure 6.3. If a tariff is in place, the behaviour of a plant that is run to minimize LCOE cannot be used to model CSP plant sendout.

6.5 Conclusions

A rigid tariff system that is set in place to incentivize CSP power production during certain times of the day without reference to actual system needs can be seen to have the following impacts:

- Lower solar multiple relative to a plant designed to optimize LCOE

- Less storage relative to a plant designed to optimize LCOE
- Lower monthly power output
- Planned outages scheduled for winter months
- Altered daily power output profile

None of the above mentioned points are necessarily negative. In fact, all but the fourth point can be argued to be an intended outcome of the described tariff system. The impacts must simply be taken into account when modelling various proposed systems and interpreting the outcomes.

7. SIMULATION OF THE IRP

The results of modelling certain scenarios from the 2013 IRP update, using the models developed in Chapters 4 and 5 and the tariff systems discussed in Chapter 6, are shown and analysed in this chapter.

7.1 Introduction

Three separate scenarios for the possible make-up of the generating system in 2030 and 2050 were modelled. These scenarios are discussed in section 7.2. The results are considered in terms of cost, average output curves and system adequacy measures. All of these results are given in section 7.3, and then the chapter is concluded in section 7.4.

7.2 Scenarios

In order to investigate the impact that CSP plants can have on the system as a whole, three scenarios from the 2013 IRP update (DoE, 2013) were modelled for 2030 and for 2050. The scenarios were selected because they showcase a large range in the possible uptake of CSP, ranging from a very high long term uptake in the “high nuclear cost” scenario to a very low uptake in the “big gas” scenario. The “moderate decline” scenario covers the middle ground. This latter scenario is also in general representative of the magnitude of CSP capacity uptake in the IRP scenarios not covered by this study. The unit information tables for the various scenarios can be seen in Appendix C.

7.2.1 The moderate decline scenario

Details for the amount of installed capacity for this scenario are given in table 7.1.

Table 7.1: Moderate decline installed capacity allocation (DoE, 2013)

Technology Option	Mod Decline 2030 (MW)	Mod Decline 2050 MW
Existing Coal	36230	16120
New Coal	2450	12700
CCGT	3550	9230
OCGT / Gas Engines	7800	11400
Hydro Imports	3000	3000
Hydro Domestic	690	690
PS (incl Imports)	2900	2900
Nuclear	6660	20800
PV	9630	25000
CSP	3300	10900
Wind	4250	10680
Other	640	
TOTAL	81100	123420

The moderate decline scenario was developed to meet the South African Department of Environmental Affairs requirements for reducing carbon emissions. In this scenario, carbon emissions start to decline steadily by 2037.

7.2.2 The high nuclear cost scenario

This scenario was developed to consider the possibility of nuclear power stations becoming prohibitively expensive. The decreased nuclear capacity is mostly made up by adding wind, PV and CSP capacity in order to still meet carbon emission reduction goals. Details for the amount of installed capacity for this scenario are given in table 7.2.

Table 7.2: High nuclear cost installed capacity allocation (DoE, 2013)

Technology Option	High Nuclear Cost 2030 (MW)	High Nuclear Cost 2050 (MW)
Existing Coal	36230	16120
New Coal	2950	11950
CCGT	2840	20590
OCGT / Gas Engines	5760	2640
Hydro Imports	3000	3000
Hydro Domestic	690	690
PS (incl Imports)	2900	2900
Nuclear	1860	0
PV	10270	25000
CSP	13400	38100
Wind	7450	25280
Other	640	
TOTAL	87990	146270

7.2.3 The big gas scenario

The Big gas scenario was developed to address the possibility of a large supply of LNG gas becoming available at reasonable prices. Details for the amount of installed capacity for this scenario are given in the table 7.3.

Table 7.3: Big gas installed capacity allocation (DoE, 2013)

Technology Option	Big Gas 2030 (MW)	Big Gas 2050 MW
Existing Coal	35090	11690
New Coal	1200	1200
CCGT	16330	62480
OCGT / Gas Engines	4560	6720
Hydro Imports	3000	3000
Hydro Domestic	690	690
PS (incl Imports)	2900	2900
Nuclear	1860	0
PV	4710	15900
CSP	300	0
Wind	1300	1170
Other	640	
TOTAL	72580	105750

7.3 Results

7.3.1 Cost

In the 2013 IRP update, the composition of the generating fleet is optimised for specific scenarios. In most of the cases, these scenarios investigate the effects of variations in technology cost. For this reason there are different input cost assumptions for each scenario in the IRP. This means that comparing electricity cost across scenarios for one set of input cost assumptions does not have a great deal of relevance. Weighing up the CSP LCOE against a set of other technology LCOEs, on the other hand, is of interest.

Table 7.4 shows the LCOE assumptions for specific technologies taken from the 2013 IRP update with appropriate learning rates implemented where relevant. The corresponding CSP LCOEs are shown in table 7.5.

Table 7.4: IRP LCOEs (DoE, 2013)

Type of plant	2010 LCOE	2020 LCOE	2030 LCOE
Old Eskom	R 0.2274	R 0.2274	R 0.2274
Coal with CCS	R 0.9957	R 0.9957	R 0.9957
Nuclear	R 0.6928	R 0.6864	R 0.6737
OCGT	R 1.6290	R 1.6290	R 1.6290
CCGT with CCS	R 1.1730	R 1.0865	R 1.0353
Wind	R 0.6939	R 0.6311	R 0.6059
PV	R 1.6210	R 0.9056	R 0.6617
Imported Hydro	R 0.2887	R 0.2887	R 0.2887

Tabel 7.5: CSP LCOE for moderate decline

	LCOE
2010 CSP ‘Peakers’	R 2.26
2020 CSP ‘Peakers’	R 1.25
2030 CSP ‘Peakers'	R 1.12
2030 CSP Base Load	R 0.85

Comparing the calculate CSP LCOEs (adjusted with learning rates from the IRP) with the LCOEs in table 7.4 shows that CSP plants that are optimised to provide power during evening peak are expected to be cost competitive with OCGT by 2020. Moreover, a CSP base load plant is expected to be cost competitive with new coal plants that employ carbon capture by 2030.

7.3.2 Daily average curves

Each of the scenarios described in section 7.1 were analysed under three sets of circumstances:

- Installed capacity and demand for 2030 with CSP incentivised to produce power during evening peak.

- Installed capacity and demand for 2050 with CSP incentivised to produce power during evening peak.
- Installed capacity and demand for 2050 with CSP capacity built up to 2030 incentivised to produce power during evening peak and CSP capacity constructed after 2030 set up to run base load. (Adjusted case)

In all cases the CSP plants are assumed to produce power based on a tariff system.

Two types of output curves are shown in the following subsections: 1) stacked curves that show the contribution that each technology has produced during a single hour of the day as averaged over a year, and 2) curves that show the system demand before and after PV, CSP and wind power has been taken into account.

7.3.2.1 Moderate decline scenario

The stacked, averaged moderate decline curves are shown in figures 7.1, 7.2 and 7.3. Figure 7.1 shows that CSP and PV appear to complement each other quite well when the CSP plant is incentivised to run during the evening peak hours. It can be seen that the net effect of CSP and PV is to flatten out the daily demand profile as the two technologies impact only during high demand periods and complement each other well.

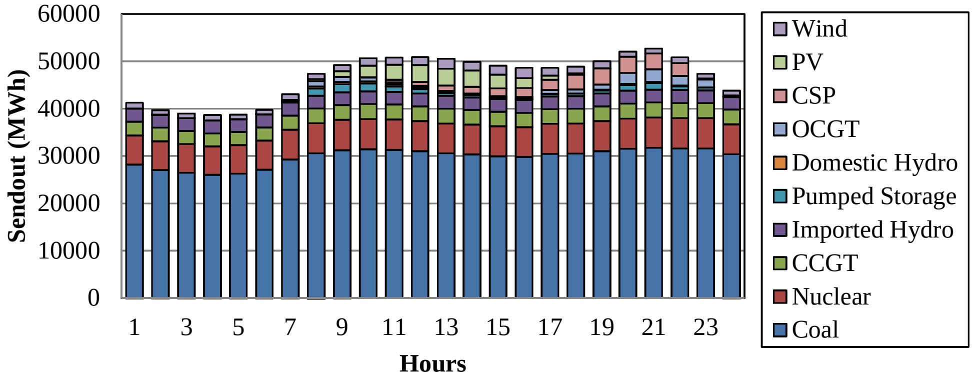

Figure 7.1: 2030 Annual averaged moderate decline by hour of the day

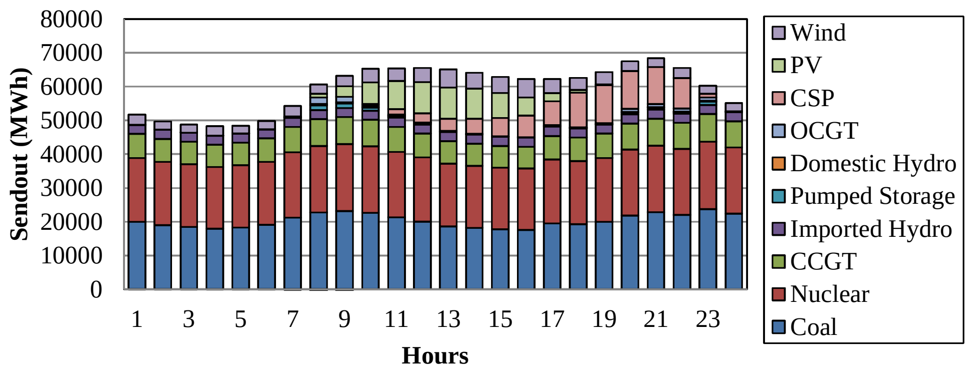

Figure 7.2: 2050 Annual averaged moderate decline by hour of the day

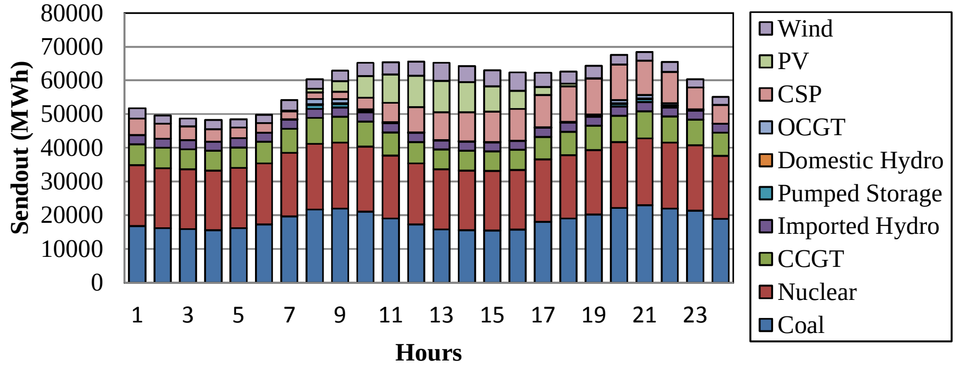

Figure 7.3: 2050 Adjusted annual averaged moderate decline by hour of the day

In figures 7.2 and 7.3, the effect mentioned in regard to figure 7.1 is still present. However figure 7.3 shows that when some CSP plants are run on a flat tariff, the total CSP electricity contribution is larger. That happens because the flat rate optimized plant has higher solar multiples and more hours of storage than the peaking optimized plant. This results in an overall higher output of electricity.

The figures 7.4, 7.5 and 7.6 show the system demand curves before and after CSP, PV and wind have been taken into account.

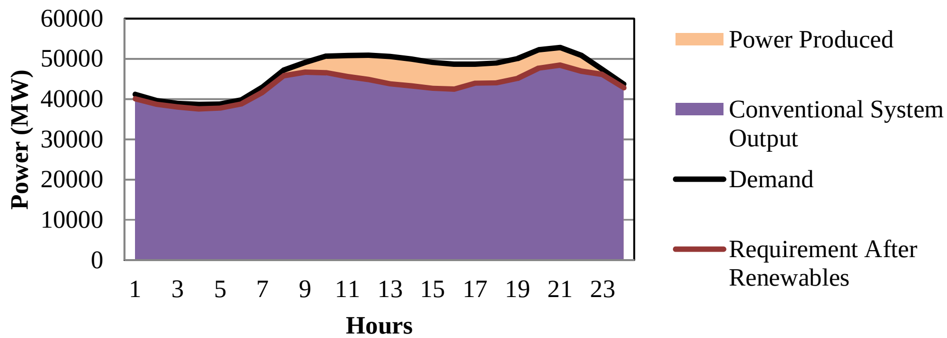

Figure 7.4: 2030 Annual averaged moderate decline demand curves by hour of the day

From figures 7.4, 7.5 and 7.6 it can be seen that in both cases where CSP has been implemented to provide power mainly during evening peak, the demand was not largely affected by the addition of renewable energy plants during the night. It is interesting to note that in the 2030 curve, the shape of the demand curve during peak and mid merit times is roughly the same before and after the addition of renewables, only lower.

In the 2050 curves, the shape of the demand curve is more noticeably affected. In both cases the two peak demand periods are much more distinct, have developed in the post renewable energy profiles and peak demand has shifted to nine o'clock in in the morning. Evening peak has, in these scenarios, effectively been displaced. This highlights a key weakness in relying on tariffs that demand CSP production during specific time slots. Incentivizing production at a specific hour of the day assumes that that period has the highest demand and thus power produced during that period is of the greatest value. However, there comes a point when production has been over allocated to meeting that demand, and the actual period of maximum demand for the rest of the system will move to a different peak demand period.

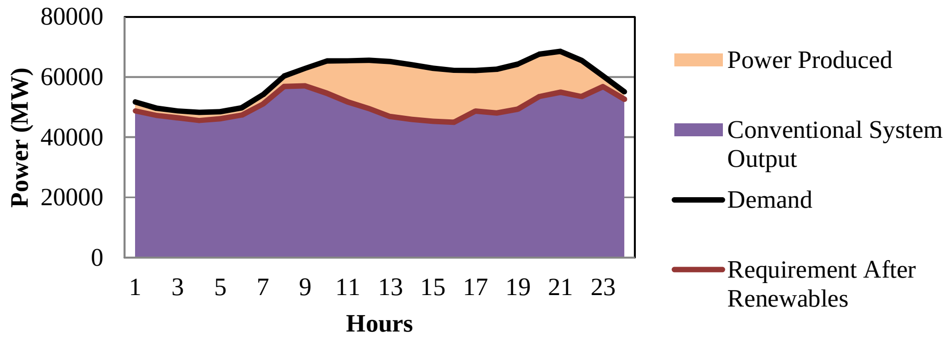

Figure 7.5: 2050 Annual averaged moderate decline demand curves by hour of the day

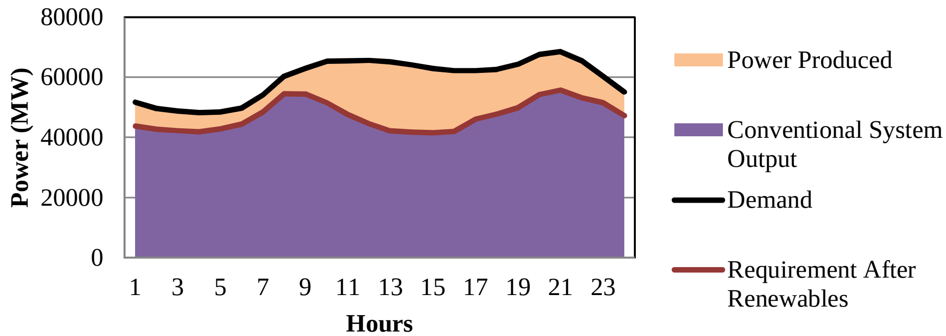

Figure 7.6: 2050 Annual averaged adjusted moderate decline demand curves by hour of the day

The CSP power that is produced when it is no longer peak period will still be remunerated based on the assumption that it is producing valuable electricity, but it will have lost some of its value to the system.

7.3.2.2 High nuclear cost scenario

The stacked average high nuclear cost scenario curves are shown in figures 7.7, 7.8 and 7.9. Most of the effects observed in the moderate decline scenario can also be seen in these figures. However, the effects are exaggerated by the increased wind, PV and CSP capacity represented in this scenario. The larger impact can already partially be seen in figure 7.7.

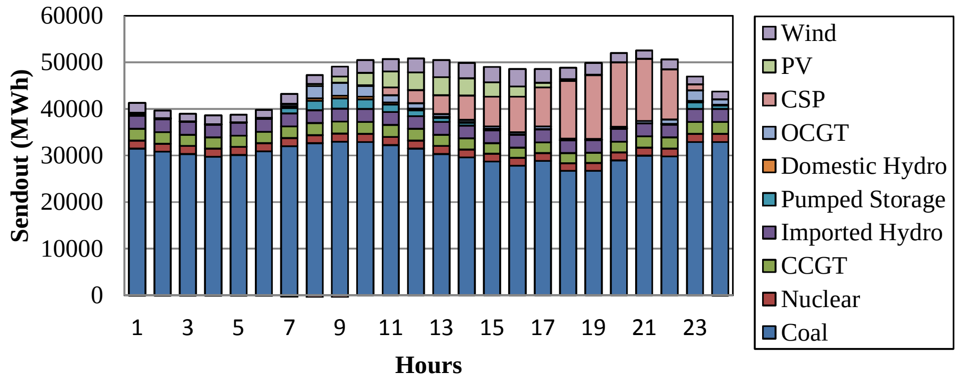

Figure 7.7: 2030 Annual averaged high nuclear cost by hour of the day

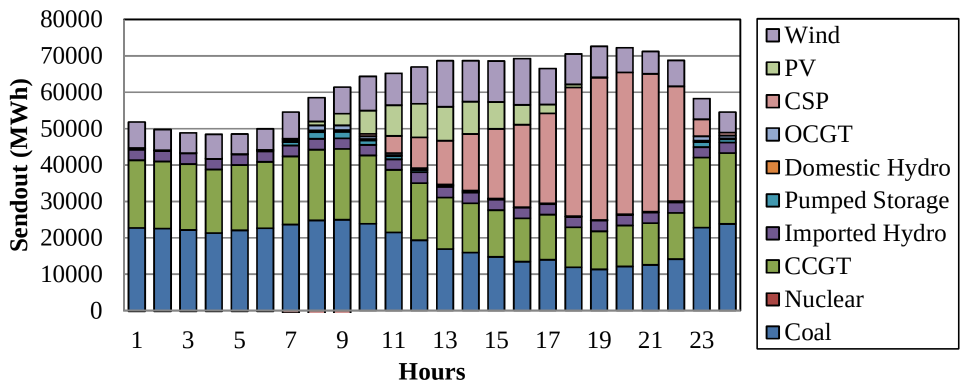

Figure 7.8: 2050 Annual averaged high nuclear cost by hour of the day

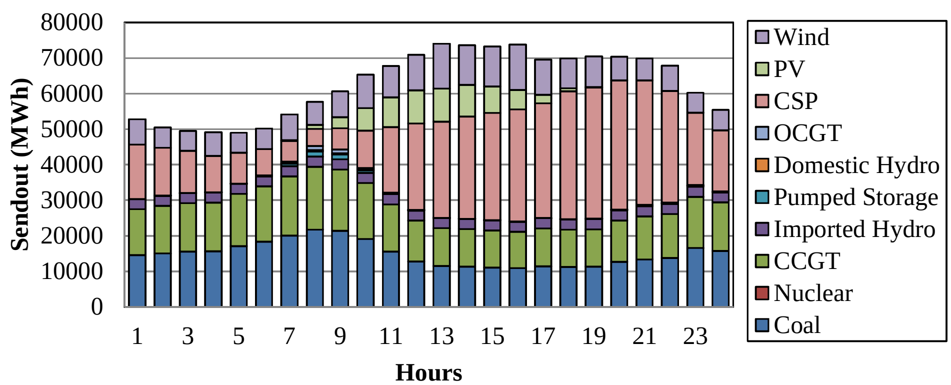

Figure 7.9: 2050 Annual averaged adjusted high nuclear cost by hour of the day

Of particular note is the behaviour of the conventional system peaking plant. Due to the philosophy of absorbing wind, PV and CSP into the system on a priority basis, the conventional system peaking plant shows where the conventional system plants are experiencing peak demand. Here, the conventional system peak demand shifts away from the periods during which PV and CSP power production occurs.

This effect becomes even more apparent when viewing the system demand curves before and after CSP, PV and wind has been taken into account. This is shown in figures 7.10, 7.11 and 7.12.

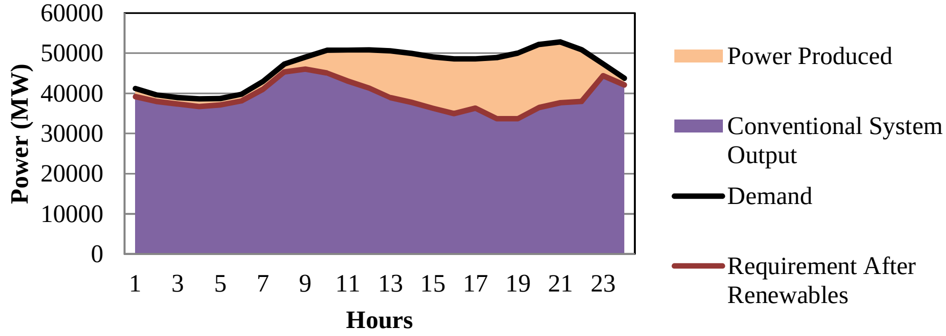

Figure 7.10: 2030 Annual averaged high nuclear cost demand curves by hour of the day

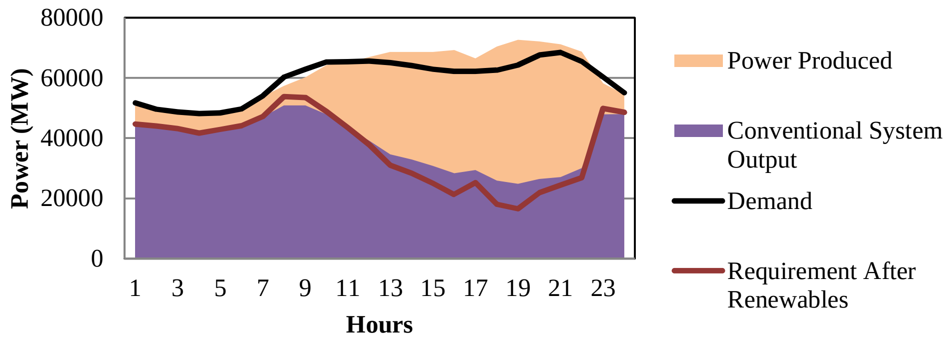

Figure 7.11: 2050 Annual averaged high nuclear cost demand curves by hour of the day

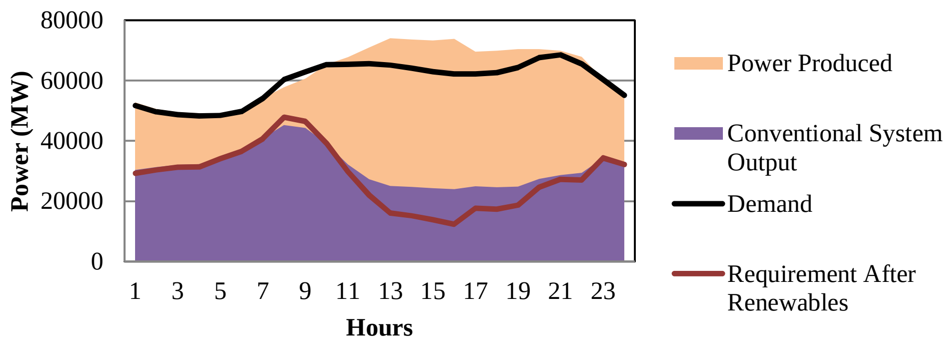

Figure 7.12: 2050 Annual averaged adjusted high nuclear cost demand curves by hour of the day

Two problematic phenomena can be observed in the above curves:

- Insufficient generating capacity: There is insufficient conventional system generating capacity to meet the new post renewable peak demand that occurs during the morning.
- Suppressed base load output: During the periods of maximum renewable production in the conventional system, base load plant energy production is being pushed down to the point where, even when the base load plants are running at minimum generation, too much power is being produced. Effectively this means that some of said units would have to be switched off during the day in order not to oversupply the system. The combination of two shifting base load units has a detrimental impact on the aging of equipment and plant reliability. Light-ups on coal plants are also expensive due to fuel oil consumption.

Looking at all the above graphs it becomes very obvious that displacing CSP power production would reduce a large deal of the pressure on the system. However, comparing figure 7.11 and 7.12, it can also be seen that simply introducing plants that run on a flat rate does not sufficiently distribute CSP production. In fact it appears that what is mostly needed are CSP plants that are responsive to the demand the system experiences after PV and wind outputs have been absorbed.

7.3.2.1 Big gas scenario

This scenario has mostly been included because it does not include a great deal of intermittent renewable energy and includes almost no CSP. As such, it serves to highlight what a system that has access to mostly dispatchable energy looks like.

Because there is no CSP in the 2050 scenarios, the adjusted curves are not shown, since they are exactly the same as the unadjusted curves.

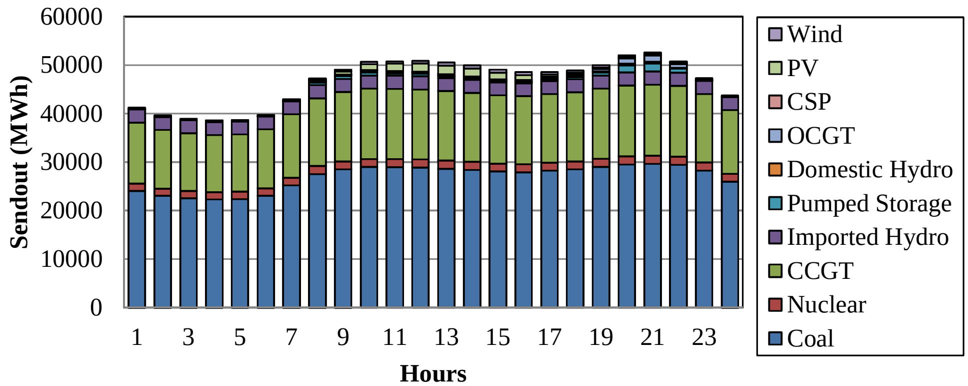

Figure 7.13: 2030 Annual averaged Big gas by hour of the day

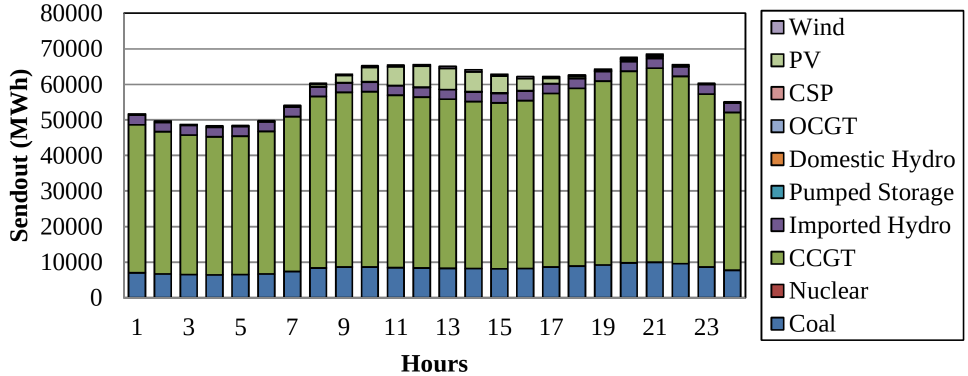

Figure 7.14: 2050 Annual averaged big gas by hour of the day

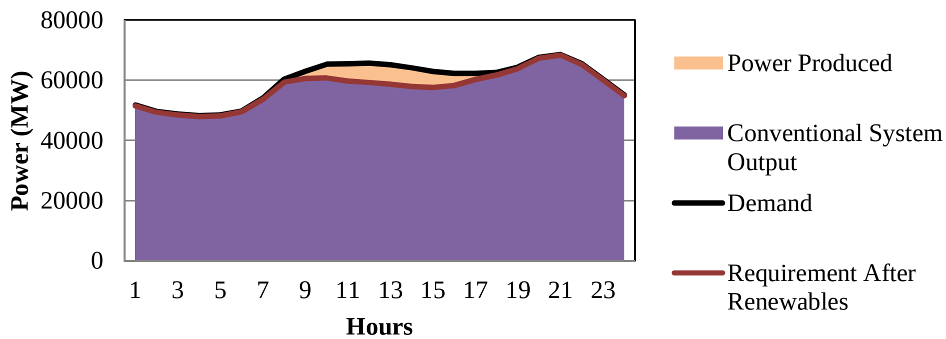

Figure 7.15: 2030 Annual averaged big gas demand curves by hour of the day

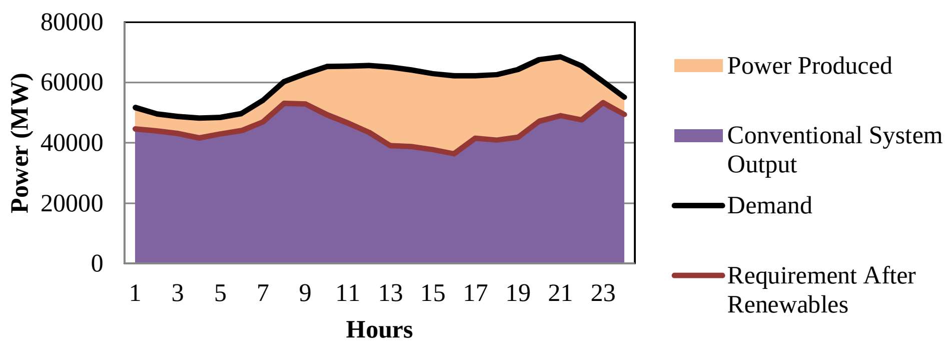

Figure 7.16: 2050 Annual averaged big Gas demand curves by hour of the day

It is clear that evening peak is not displaced in the figures above, and the impact of PV is merely to lower demand during the day.

7.3.3 Adequacy

System adequacy relates to how reliable the system is. The adequacy of the configured systems is measured for each scenario using the following criteria:

- Minimization of demand shortfall

- Minimization of OCGT gross capacity factor
- Base load plant capacity factor

The first two factors are indicative of the ability of the system to meet electricity demand at all times. The third is indicative of overall base load plant supply.

The first adequacy measure investigated is shortfall, which is shown in table 7.6. An adequate system would have this measure at or below 20 GW hours. While none of the scenarios actually achieve this, it can be seen that the big gas scenario comes the closest. The moderate decline scenario does reasonably well in comparison to the high nuclear cost scenario, which performs poorly.

It can be seen that replacing the CSP plants, optimised to provide power during evening peak, that were built between 2030 and 2050 with a base load CSP plant operated on a flat tariff significantly reduces shortfall for both the moderate decline and the high nuclear cost scenarios. This is partly due to the fact that the flat rate plants have higher electricity output, but also because with flat rate plants, the energy production is spread out much more over the 24-hour period.

Table 7.6: Shortfall

	Moderate Decline	High Nuclear Cost	Big Gas
2030 (GWh)	128.8	1924.4	263.5
2050 (GWh)	99.6	5059.7	32.9
2050 Adjusted (GWh)	69.8	3779.8	32.9

As previously implied in figure 7.12, even in the case where flat rate CSP stations are being used, there is significant oversupply during times of high solar renewable availability coupled with shortfall during morning peak in the high nuclear cost scenario. Figure 7.17 illustrates that, for this scenario, even during the winter months there are cases where there is an oversupply in solar renewables.

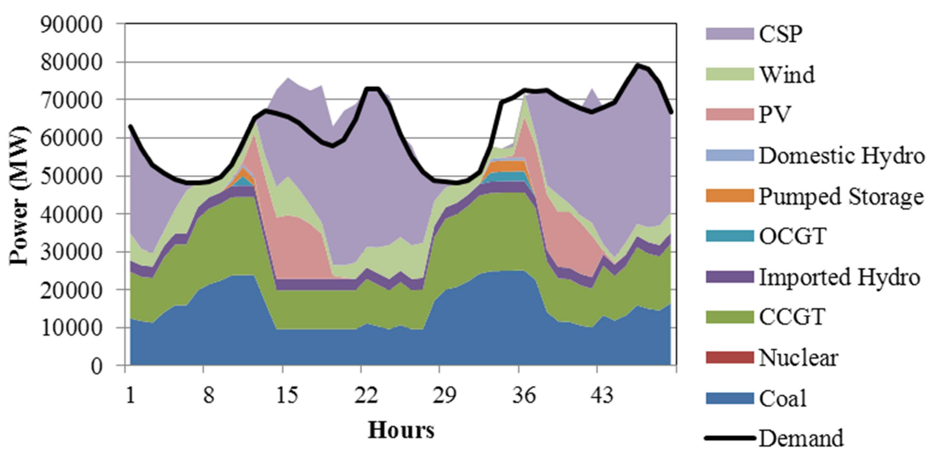

Figure 7.17: CSP oversupply and shortfall

If this oversupplied power could be stored for later use, subsequent shortfall could be avoided. The pattern of shortfall and oversupply is likely to become more acute in subsequent decades.

In a system where renewable energy uptake is prioritized, coal or other base load plants would have to shut down during periods of oversupply. From the CSP plant perspective, storing thermal energy and deferring power production is less efficient than immediately producing the maximum output. Thus, the behaviour most beneficial to individual CSP plant profits is detrimental to the adequacy of the system as a whole.

The second adequacy measure is closely related to the first, as both of them shed light on the ability of the system to provide power at all times. This measure is the overall capacity factor at which OCGT plants in the system run, which is shown in table 7.7. Where the overall capacity factor is the ratio between the total number of megawatt hours produced by a technology and the number of megawatt hours that could have been produced by that technology had it been running at full load for every hour of the year.

The relationship between this adequacy measure and the previous one can easily be seen by the result that the high OCGT capacity factor corresponds quite well to high shortfall. A capacity factor below 5% is considered reasonable. Because OCGT plants are the most expensive to run, they are always loaded as a last resort. The more often they are loaded the less adequate the system appears to be. Furthermore, a high OCGT capacity factor has a negative impact on overall electricity costs. This is noteworthy in cases where these plants are run on diesel, as is currently the case in South Africa.

Table 7.7: OCGT capacity factor

	Moderate Decline	High Nuclear Cost	Big Gas
2030	8.87%	19.35%	4.96%
2050	3.38%	13.98%	0.57%
2050 Adjusted	2.42%	8.37%	0.57%

Reserve margin, within the confines of this study, is defined as the measure by which the available capacity must exceed the projected demand in order for a planned outage to be scheduled. Reserve margin is an input to the conventional system model which is systematically lowered until all planned and unplanned outages are executed within the model run. While the reserve margin at which all outages are completed is not an adequacy measure, it does serve to illuminate the first and second adequacy measures to some extent.

As can be seen in table 7.8, the high nuclear cost scenarios all run on negative reserve margins. Within the confines of the conventional system model, this means that, in order to complete all planned outages, the planned outages have to be scheduled in cases where system capacity is lower than projected demand. This means that shortfalls are almost guaranteed in the model when reserve margins are negative. Even in cases with low reserve margin, shortfalls are likely to happen because there is very little capacity to absorb unplanned outages. It should be noted that wind, PV and CSP that was incentivised to produce power during evening peak only contribute to the reserve margin in a very limited fashion. The reserve margin thus serves to indicate a low availability of dispatchable power.

Table 7.8: Reserve margin

	Moderate Decline	High Nuclear Cost	Big Gas
2030	10.00%	-3.00%	9.00%
2050	8.00%	-11.00%	15.00%
2050 Adjusted	14.00%	-5.00%	15.00%

The third and last adequacy measure is the coal plant capacity factor, which is displayed in table 7.9. This measure serves to indicate whether there is an over- or undersupply of base load units in the system. Bearing in mind that an old coal plant has an availability factor of 80% when planned and unplanned outages are taken into account, and a new coal plant has an availability of 90% after outages, a coal plant capacity factor close to 80% would indicate that the coal plants are running close to their full capacity almost all the time. An example of this is shown in figure 7.18. Here the base load capacity that is available to the system can clearly be seen to be insufficient. This low base load availability can be seen to go hand in hand with high OCGT based electricity production.

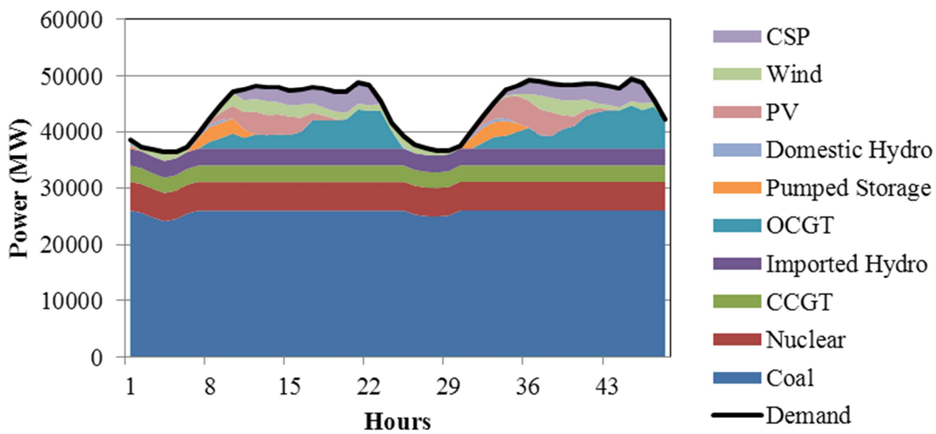

Figure 7.18: Constrained base load capacity

On the other hand, the minimum load at which coal plants can safely generate is about 40% of their full load. In cases where this number is approached it would indicate that base load send-out is being suppressed, as is the case in figure 7.17. This is not only indicative of the fact that there might be an oversupply of base load plants at certain times of day. It is also a negative indicator because coal plants tend to become very inefficient when run at loads below 60% of their full load (Eskom, 2012). Lower thermal efficiency on a coal plant leads to an increase in cost and carbon emissions since more coal must be burned per kW of electricity produced. The alternative is that some base load units might be shut down for portions of the day and only started up during periods of high demand. Repeating such a cycle ages the plant and leads to increased maintenance costs. In general, a coal plant capacity factor between 60% and 70% can be considered reasonable.

Table 7.9: Coal capacity factor

	Moderate Decline	High Nuclear Cost	Big Gas
2030	77.01%	76.70%	74.29%
2050	70.47%	67.33%	63.05%
2050 Adjusted	64.39%	52.21%	63.05%

As can be expected, adding the flat rate CSP plants to the system lowers the contribution from coal plants. In the high nuclear cost scenario an oversupply of base load plant is indicated. The fact that this oversupply still coincides with large electricity supply shortfalls shows that the CSP plants and the high renewable energy uptake relied upon in that scenario is not serving the system particularly well.

7.4 Conclusions

CSP and PV complement each other well when CSP is set up to provide power during evening peak. But the larger the installed PV and CSP capacity becomes, the less effective the system becomes.

The moderate decline scenario performs well in terms of the adequacy criteria while absorbing a reasonable amount of intermittent renewable energy and CSP. The big gas scenario has the most stable performance, which is only to be expected as it includes very little intermittent renewable energy. Although it outperforms the moderate decline scenario, they are at least comparable in most regards. On all measures, the high nuclear cost scenario performs very poorly.

Introducing flat rate CSP plants after 2030 can be seen to have a positive impact on two out of three of the adequacy measures, shortfall and OCGT capacity factor. While electricity shortfall is reduced significantly in both the high nuclear cost and moderate decline scenarios, introducing flat rate plants is not on its own sufficient to address the problems that exist in the high nuclear costs scenario. Simply put, the CSP plants are not sufficiently responsive to the system needs. This is further addressed in Chapter 8.

8. ANALYSIS AND DISCUSSION

The results shown in Chapter 7 are further analysed here. The benefits of introducing CSP plants that produce electricity in response to demand are investigated. Additionally, some consideration is given to how the plants may be induced to act in such a beneficial manner.

8.1 Introduction

Introducing CSP plants that produce based on rigid tariffs shifts the time at which the peak demand to which the rest of the system must respond, occurs. Effectively, this means that CSP production based around a single tariff, or even one or two tariffs, becomes less valuable as the number of producing units increases. In turn, this increase causes the system need to shift away from the period during which the plants are incentivized to produce power.

Dispatchability is a large part of the CSP value proposition. Fixed tariff-based production effectively curbs CSP dispatchability. As the number of CSP units in the system increases, it will likely become more and more necessary for CSP electricity production to react to system demand.

Section 8.2 discusses the results of modelling the CSP plants added between 2030 and 2050 as a system responsive base load. Other options for addressing an electricity shortfall are discussed in section 8.3. The analysis is concluded in section 8.4.

8.2 System responsive CSP base load

To showcase the benefits of having CSP plants react to system demand, the 2050 case for the three scenarios discussed in the previous chapter was modelled with system responsive CSP. This was accomplished by modelling all CSP capacity added after 2030 as base load plants that are ramped up and down in response to system demand. The modelling was conducted in the same manner in which coal plants and CCGT plants are operated. The CSP plants, however, are still governed by the amount of energy that they have collected and stored, as well as the other parameters that constrain the generating units in the conventional model.

The effects on the adequacy measures can be seen in table 8.1. It should be noted that the 2050 big gas scenario has no CSP and is included for comparison sake.

Adding CSP into the system as base load plants lowers the overall coal capacity factor. This is only to be expected since all base load units are loaded up and down proportionately. Additionally, the increase in base load plant capacity caused by adding the CSP plants would lead to all base load plants being run at lower capacity factors.

In the moderate decline scenario, the coal capacity factor is still within the desired range. In the high nuclear cost scenario, it appears that adding so much CSP base load capacity leads to an excess of base load plants. In both cases, it can be seen to have a significantly positive effect on both the OCGT capacity factor and electricity shortfall. It should be noted that this still does not bring the shortfall experienced in the high nuclear cost scenario within an acceptable range. The excess base load capacity available in the high nuclear cost scenario, combined with the still high shortfall, indicates that the remainder of the problem is probably due to a lack of dispatchable peaking capacity.

Table 8.1: System responsive CSP adequacy measures

	Moderate Decline	High Nuclear Cost	Big Gas
Coal Capacity Factor	66.82%	56.74%	63.05%
OCGT Capacity Factor	1.47%	2.19%	0.55%
Shortfall (GWh)	23.44	844.52	32
Reserve Margin	15.00%	11.00%	15.00%

Running the CSP plants in the manner described has a significant impact on the CSP LCOE. By running the plants in response to system needs, the overall electricity output that is generated is significantly reduced. This in turn results in the higher LCOEs displayed in table 8.2.

Table 8.2: System responsive CSP LCOE

	Moderate Decline	High Nuclear Cost	Flat Rate
LCOE (R/kWhr)	R 0.9937	R 1.1989	R 0.850

The flat-rate LCOE, shown for comparison, corresponds to the cost that would be achieved if the CSP plants were run for the minimum LCOE. The difference between the high nuclear cost LCOE and the moderate decline LCOE is due to the higher capacity factor at which the base load plant is run in the moderate decline scenario. This higher capacity factor results in higher overall electricity production. When more electricity is produced and costs remain the same, LCOE naturally declines.

The effect of this adjusted LCOE is that the case where the model is run with the system responsive CSP is generally not cost competitive with the flat rate base load CSP case on a per unit cost basis. The gains in terms of system reliability must perforce be evaluated against the increased costs of achieving that reliability. Table 8.3 shows how the high per unit cost of a CSP plant output translates into a higher system LCOE.

Table 8.3: System LCOE

	LCOE (R/kWhr)		
	Moderate Decline	High Nuclear Cost	Big Gas
2050	R 0.7076	R 0.8076	R 0.9032
2050 Adjusted	R 0.7042	R 0.7848	R 0.9033
2050 CSP Base load	R 0.7115	R 0.8627	R 0.9033

Looking at the average daily contributions of the various technologies for the moderate decline and high nuclear cost scenarios, it can clearly be seen that CSP plants that were allocated as base load, behaved similarly to the other base load plants.

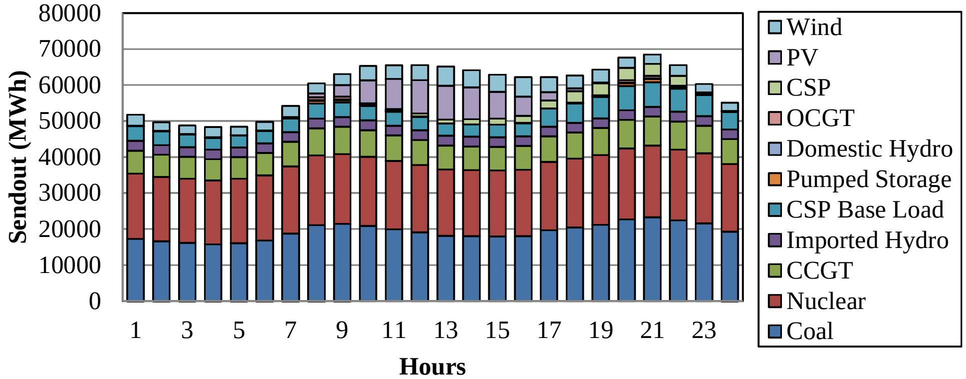

Figure 8.1: 2050 Moderate decline system responsive CSP technology contributions

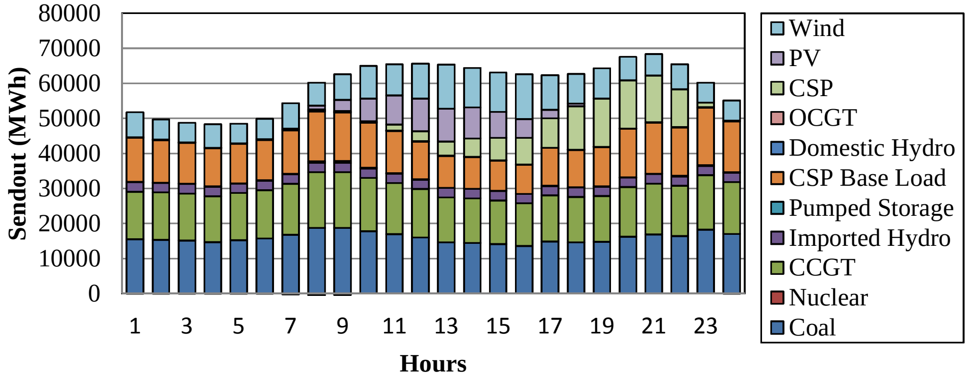

Figure 8.2: 2050 High nuclear cost system responsive CSP technology contributions

When considering the system demand curves before and after PV, wind and CSP that has been optimised to provide power during evening peak has been absorbed by the system, for the high nuclear cost scenario (shown in figure 8.3), the demand curve that the balance of the system has to fulfil is not met at 9 am.

It is no coincidence that at this hour the CSP plant storage would be at its lowest level, just before energy collection becomes feasible, particularly in the winter.

It is, however, an over simplification to suggest that electricity shortfalls occur when CSP energy stores run out at nine in the morning. As shown in figure 8.4, it is more accurate to say that a shortfall occurs whenever the CSP energy stores run out. It is also clear that if the other base load plants had been running at a higher capacity during the first 24-hours, there would have been sufficient energy stored in the CSP energy stores to prevent shortages during the subsequent 24-hour period.

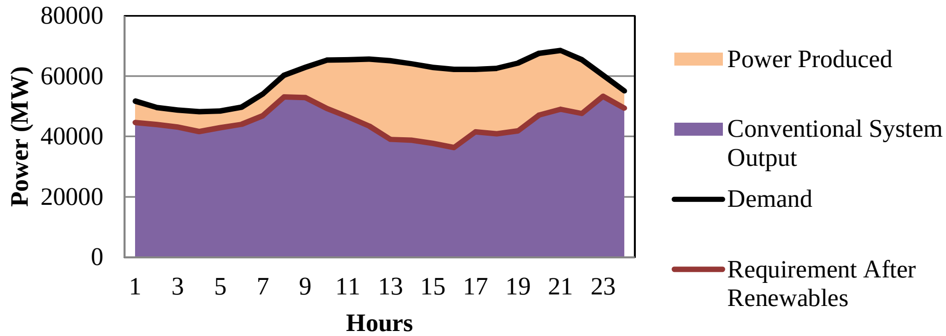

Figure 8.3: 2050 High nuclear cost demand curves

Figure 8.4 indicates that the dispatchability of CSP is not as consistent as that of other base load technologies. The CSP plants used in this analysis were configured for minimum LCOE, i.e. flat rate production. These plants had on average fourteen hours of storage. Increasing storage across the board by 25% reduces shortfall by 15%. This change has a negative impact on CSP LCOE.

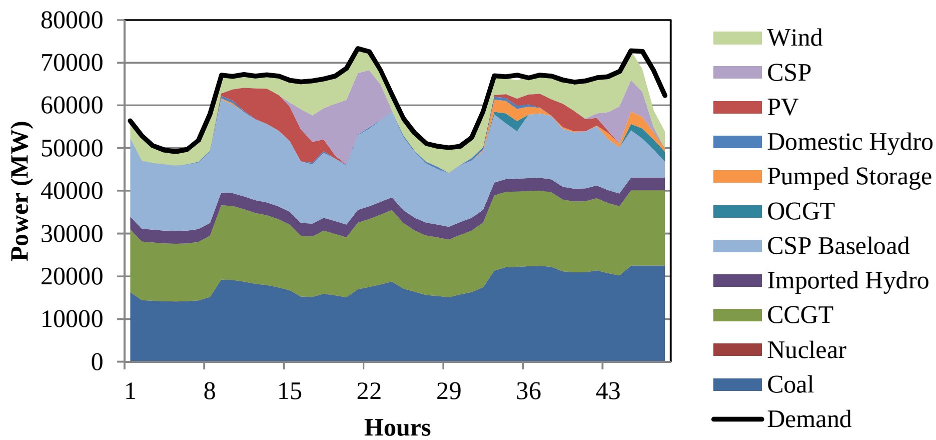

Figure 8.4: 2050 High nuclear cost stacked generation

In cases such as the high nuclear scenario where a great deal of intermittent renewable energy and CSP has been absorbed into the system, treating a portion of the CSP plants as base load plants with dispachability equal to other base load plants does not deliver an adequate supply of electricity.

8.3 Discussion of CSP options

The preceding section makes clear that adding system responsive CSP plants that act as base load delivered very satisfactory results in the moderate decline scenario. It did not suffice, however, in the high nuclear cost scenario. From this and the results shown in Chapter 7 it can be seen that the need for CSP plants to respond to system demand in order to achieve optimum system adequacy increases as the amount of CSP and intermittent renewables present in the system increases.

One of the ways in which the shortfall that is still present in the high nuclear cost scenario could be addressed would be to add additional OCGT capacity. Instead of further manipulating the CSP send-out, additional OCGT plants may be constructed to diminish shortfall. This is not viewed as a particularly elegant solution. It furthermore ignores the fact that the generating capacity in the system might be capable of meeting demand if the CSP plants are optimally utilized from a system perspective.

Another option for making more efficient use of the CSP plants would be to use them as mid merit plants and energy banks. In order to keep the CSP energy stores as full as possible at all times, the CSP plants would be deployed before the peaking plant but after the base load plants on the merit order. This would ensure that a reasonable reserve of stored CSP energy would be available to the system at all times. The problem with such an approach is that it would reduce the total electricity output of the CSP plants even further than would running the plants as a system responsive base load. Consequently, the CSP LCOE and system LCOE would rise.

It should be noted that the scenarios that were explored here for maximising the positive impact of CSP were by no means exhaustive. The potential value of CSP as a low carbon source of dispachable power must not be underestimated.

For CSP plants to behave in a way that optimises system adequacy outcomes, the plants would have to run in a fashion that would be against their own interest if a simple flat tariff is employed. This is the case when running the plants as a system responsive base load, and it would be even truer of a situation where CSP is used as a mid-merit plant.

For CSP plants to contribute effectively to a system with a high uptake in renewable energy, a remuneration system that aligns system and plant interest would be required.

8.4 Conclusion

The potential CSP plants’ contribution to system reliability increases both with CSP capacity increases and as the CSP plants become more responsive to the demand the system needs to meet after intermittent renewables have been absorbed. By limiting CSP plant output, thermal energy stores are built up that allow the plants to respond during times of increased demand. This increased usefulness is reflected in rising LCOE, as the limiting plant’s send-out increases the cost per unit of electricity.

For any given scenario in the 2013 IRP update (DoE, 2013), the balance that would need to be struck between the reliability the CSP plants add to the system and the cost of the electricity produced by the CSP plants might well rest at different levels of demand responsiveness. The amount of CSP and other renewable capacity present in the scenario would, however, have a large impact on what that level is.

9. CONCLUSIONS

The objective of modelling the 2013 IRP update in order to study the potential impact of CSP on the system as a first study using this method, has been met, based on the specific assumptions of technology definition placement and plant vs. system behaviour. Interesting results have been reached and discussed in the preceding chapters. The final conclusions are discussed in this chapter.

9.1 Summary of findings

While constructing a complete system model for the IRP based on a spatio-temporal approach might be ambitious, the scope, assumptions and availability of resource data have none the less enabled this firs study to be completed with results that appear sensible.

The investigation into the effect of tariff systems reveals that tariffs that aim to incentivise electricity production during certain times of the day and inhibit it during others impact how the plant is run as well as the constructed plant configuration in terms of solar multiple and hours of storage. This in turn significantly impacts the total megawatt hours of electricity output that the plant will be able to produce.

Depending on the tariff structure, the daily power output profile and amplitude might vary significantly from what might be expected if a plant was constructed based on minimum LCOE. These aspects need to be taken into account, not only when designing the tariff structure, but also when modelling the electricity system as a whole.

Additionally, CSP power production is seasonal. In the most profitable CSP areas, more power is produced during the summer months than the winter months. Effectively, it is more profitable to schedule planned outages during the winter months as less income is lost. While this would not necessarily have a large detrimental effect on the system as a whole, the impact still has to be managed.

Modelling various scenarios from the 2013 IRP update brings to light the fact that if CSP power plants are built and run under a peaking incentive tariff, over time the peak demand window that the rest of the system experiences will shift away from the incentivized period. The contribution made by the CSP plants will then become less valuable to the system as a whole.

When a large amount of renewable energy is absorbed into the system on a priority basis, base load send-out might be suppressed during parts of the day. This might lead to base load plant running at low capacity factors. Should this happen, some base load plants might need to be two shifted in order to prevent an oversupply of electricity. Both these situations lead to increased costs that the base load stations, and thus the system as a whole, would have to absorb.

Investigating the impacts of making CSP plants respond directly to system demand brought to light that the greater the contribution CSP plants are required to make to ensuring system reliability, the higher the cost of CSP produced electricity rises. For any given system, the balance will have to be struck. While it is clear that simple tariff systems will probably suffice until 2030, the larger the uptake is in CSP, the sooner such a system will lead to problems.

9.2 Conclusions

Due to its temporal resolution an hourly spatio-temporal model will not give insight into sub hourly impacts on the distribution system, however the model could, if a higher spatial resolution is employed, be useful when considering where CSP plants are likely to be constructed under set remuneration conditions, which might serve as a useful input into the long-term grid planning process. The main use of the model lies in the insight it can give into the potential impact that CSP power stations can have on the generating system as a whole.

Furthermore, it can be seen that the insights gained from this model could be used to inform decision makers of potential impacts that renewable energy plants in general and CSP plants specifically might make on the generating system. Elements of a policy brief resulting from the findings of this study is shown in Appendix D to illustrate this point.

According to this study CSP is a versatile technology that can deliver dispatchable electricity for the system when it needs it. The technology can be used to improve the reliability of the generating system or can simply serve as a source of peaking power. Optimal utilization of the technology will largely depend on having clear goals in mind and setting up suitable remuneration structures to incentivise IPPs to build CSP plants that will contribute to those goals.

9.3 Contributions

A paper arising from this study was presented at SASEC 2014: Replacing intermittent renewable capacity in the 2010 IRP with CSP: effect on coal fired power station capacity factors in 2030.

Furthermore, this study is the first known spatio-temporal model of scenarios from the 2013 draft IRP update and for the South African electricity plan as a whole.

9.4 Further Research

Many additional research topics could continue from this project. A few research possibilities that could follow directly and that could have high impact are provided here.

More sophisticated tariff structures and other renewable energy remuneration schemes may be the richest area of further investigation arising from this study, both in terms of their effect on CSP plant configuration and behaviour and in terms of the collective knock on effect on the system as a whole. Finding a balance where CSP plants will act in the interest of the system without compromising the price of the electricity produced would be an interesting challenge.

The other scenarios in the 2013 IRP update could be investigated in the future should events unfold in a way that makes them of interest.

Additionally, the composition of the generating system may be varied in order to investigate the trade-off between system adequacy and electricity cost, or a measure that quantifies carbon emission reduction as an adequacy measure may be introduced.

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APPENDIX A: PARABOLIC TROUGH PLANT TRACKING AXIS

When collecting irradiation the amount of energy that can be collected is maximised when the zenith angle of the collector is zero. Parabolic trough collectors rotate around a fixed axis. A much smaller zenith angle is achievable at solar noon if the axis is laid out east to west than that which is achievable when the axis is laid out north to south. However the north south layout is preferable as it achieves a good zenith angle for a larger portion of the day than the east west layout. This is reflected in figure A.1 where the north-south axis is indicated in blue and the east-west axis in red.

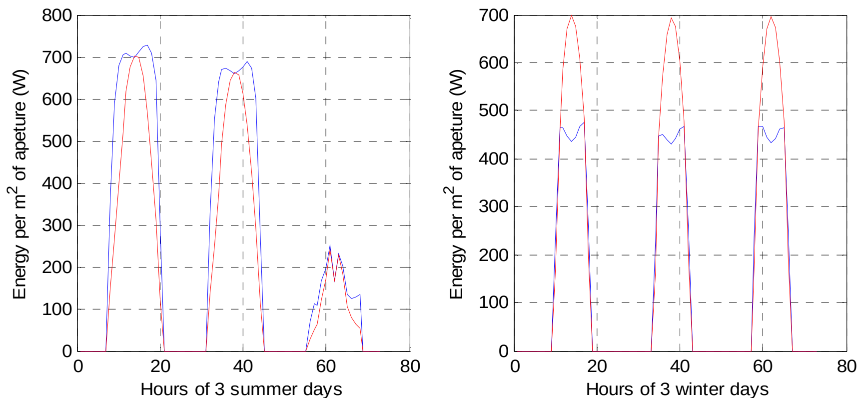

Figure A.1: North south-axis vs east-west axis in terms of incident irradiation per m^2

It is notable that while the north-south axis has better results during most of the year, the east-west axis performs better in the winter. In order to verify if the north-south layout would still be preferrable under a tariff system that favors winter production, both layouts were tested for a range of configurations at locations distributed over South Africa. The second seasonal tariff described in chapter 6 was used during the test. The results, plotted in figure A.2 show that even with a tariff that heavily favours winter production the north-south layout still outperforms the east- west layout.

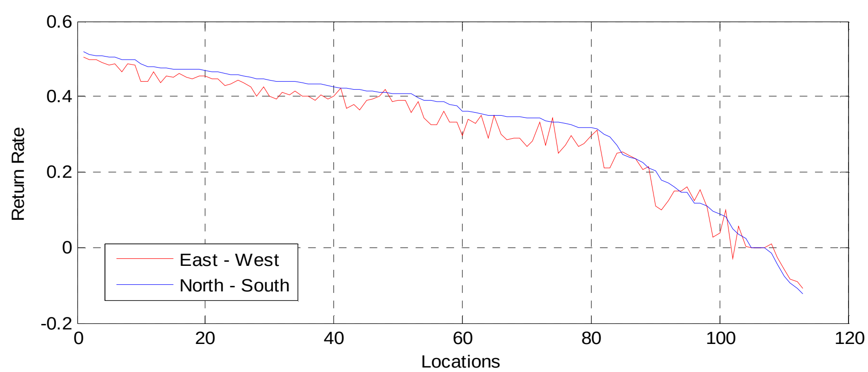

Figure A.2 Comparison of north-south layout with east-west layout in terms of return

Furthermore, displaying the locations where the east-west axis gives better results, as done in figure A.3, reveals that this layout is only favored in areas where building CSP plants would not normally be concidered.

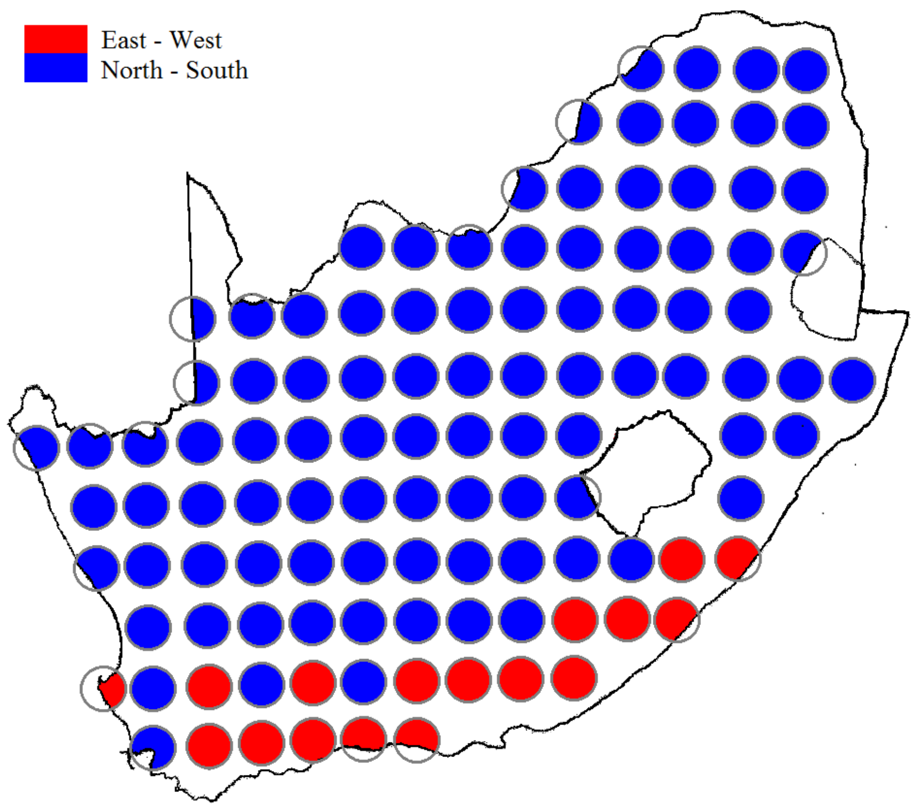

Figure A.3: Parabolic trough plant collector axis layout preferences at selected South African sites

In conclusion, east-west collector axis plants were not of interest for this study as they do not compare favourably with north-south collector axis plants under the conditions investigated.

APPENDIX B: PARABOLIC TROUGH RECEIVER HEAT LOSS COEFFICIANTS

The appropriate coefficients for various tube conditions are shown in table B.1.

Table B.1: Heat loss coefficients

Case	Heat loss coefficient	2008 PTR70
Vacuum	A0	4.05
	A1	0.247
	A2	-0.00146
	A3	5.65E-06
	A4	7.62E-08
	A5	-1.7
	A6	0.0125
Hydrogen	A0	11.8
	A1	1.35
	A2	7.50E-04
	A3	4.07E-06
	A4	5.85E-08
	A5	-4.48
	A6	0.285
Lost vacuum	A0	50.8
	A1	0.904
	A2	5.79E-04
	A3	1.13E-05
	A4	1.73E-07
	A5	-43.2
	A6	0.524
Broken	A0	-9.95
	A1	0.465
	A2	-8.54E-04
	A3	1.85E-05
	A4	6.89E-07
	A5	24.7
	A6	3.37

APPENDIX C: UNIT INFORMATION TABLES

Table C1: Unit information table for 2030 moderate decline scenario

Max Load (MW)	Min Load (MW)	Ramp Rate (MW/h)	Outage Status	Load (MW)	Up Available	Down Available	Type	Pump Hours
480	192	272.7	0	240	0	0	0	0
480	192	272.7	0	240	0	0	0	0
480	192	272.7	0	240	0	0	0	0
480	192	272.7	0	240	0	0	0	0
480	192	272.7	0	240	0	0	0	0
480	192	272.7	0	240	0	0	0	0
580	232	240	0	290	0	0	0	0
580	232	240	0	290	0	0	0	0
580	232	240	0	290	0	0	0	0
580	232	240	0	290	0	0	0	0
580	232	240	0	290	0	0	0	0
580	232	240	0	290	0	0	0	0
590	236	205.979	0	295	0	0	0	0
590	236	205.979	0	295	0	0	0	0
590	236	205.979	0	295	0	0	0	0
590	236	205.979	0	295	0	0	0	0
590	236	205.979	0	295	0	0	0	0
590	236	202.98	0	295	0	0	0	0
580	232	202.98	0	290	0	0	0	0
580	232	202.98	0	290	0	0	0	0
580	232	202.98	0	290	0	0	0	0
580	232	202.98	0	290	0	0	0	0
580	232	202.98	0	290	0	0	0	0
580	232	202.98	0	290	0	0	0	0
610	244	189.991	0	305	0	0	0	0
610	244	189.991	0	305	0	0	0	0
610	244	189.991	0	305	0	0	0	0
610	244	189.991	0	305	0	0	0	0
610	244	189.991	0	305	0	0	0	0
610	244	189.991	0	305	0	0	0	0
580	232	150	0	290	0	0	0	0
580	232	150	0	290	0	0	0	0
580	232	150	0	290	0	0	0	0
580	232	150	0	290	0	0	0	0
580	232	150	0	290	0	0	0	0

580	232	150	0	290	0	0	0	0
630	252	114.356	0	315	0	0	0	0
630	252	114.356	0	315	0	0	0	0
630	252	114.356	0	315	0	0	0	0
630	252	114.356	0	315	0	0	0	0
630	252	114.356	0	315	0	0	0	0
630	252	114.356	0	315	0	0	0	0
610	244	110.856	0	305	0	0	0	0
610	244	110.856	0	305	0	0	0	0
610	244	110.856	0	305	0	0	0	0
670	268	110.856	0	335	0	0	0	0
670	268	110.856	0	335	0	0	0	0
670	268	110.856	0	335	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
740	296	740	0	370	0	0	0	0
750	300	750	0	375	0	0	0	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
650	260	550	0	325	0	0	5	0
640	256	300	0	320	0	0	0	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
550	275	550	0	275	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
930	744	930	0	720	0	0	1	0
930	744	930	0	720	0	0	1	0
900	720	900	0	720	0	0	1	0
900	720	900	0	720	0	0	1	0

900	720	900	0	720	0	0	1	0
600	480	600	0	480	0	0	1	0
600	480	600	0	528	0	0	1	0
900	720	900	0	720	0	0	1	0
250	0	250	0	0	0	0	2	0
250	0	250	0	0	0	0	2	0
250	0	250	0	0	0	0	2	0
250	0	250	0	0	0	0	2	0
90	0	90	0	0	0	0	3	0
90	0	90	0	0	0	0	3	0
90	0	90	0	0	0	0	3	0
90	0	90	0	0	0	0	3	0
90	0	90	0	0	0	0	3	0
200	0	200	0	0	0	0	2	0
200	0	200	0	0	0	0	2	0
500	0	500	0	0	0	0	2	0
500	0	500	0	0	0	0	2	0
500	0	500	0	0	0	0	2	0
120	0	120	0	0	0	0	3	0
120	0	120	0	0	0	0	3	0
57	0	57	0	0	0	0	4	0
57	0	57	0	0	0	0	4	0
57	0	57	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
57	0	57	0	0	0	0	4	0
57	0	57	0	0	0	0	4	0
57	0	57	0	0	0	0	4	0
147	0	150	0	0	0	0	4	0
147	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0

150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
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150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0

Table C2: Unit information table for 2030 high nuclear cost scenario

Max Load (MW)	Min Load (MW)	Ramp Rate (MW/h)	Outage Status	Load (MW)	Up Available	Down Available	Type	Pump Hours
480	192	272.7	0	240	0	0	0	0
480	192	272.7	0	240	0	0	0	0
480	192	272.7	0	240	0	0	0	0
480	192	272.7	0	240	0	0	0	0
480	192	272.7	0	240	0	0	0	0
480	192	272.7	0	240	0	0	0	0
580	232	240	0	290	0	0	0	0
580	232	240	0	290	0	0	0	0
580	232	240	0	290	0	0	0	0
580	232	240	0	290	0	0	0	0
580	232	240	0	290	0	0	0	0
580	232	240	0	290	0	0	0	0
590	236	205.979	0	295	0	0	0	0
590	236	205.979	0	295	0	0	0	0
590	236	205.979	0	295	0	0	0	0
590	236	205.979	0	295	0	0	0	0
590	236	205.979	0	295	0	0	0	0
590	236	202.98	0	295	0	0	0	0
580	232	202.98	0	290	0	0	0	0
580	232	202.98	0	290	0	0	0	0
580	232	202.98	0	290	0	0	0	0
580	232	202.98	0	290	0	0	0	0
580	232	202.98	0	290	0	0	0	0
580	232	202.98	0	290	0	0	0	0
610	244	189.991	0	305	0	0	0	0
610	244	189.991	0	305	0	0	0	0
610	244	189.991	0	305	0	0	0	0
610	244	189.991	0	305	0	0	0	0
610	244	189.991	0	305	0	0	0	0
610	244	189.991	0	305	0	0	0	0
580	232	150	0	290	0	0	0	0
580	232	150	0	290	0	0	0	0
580	232	150	0	290	0	0	0	0
580	232	150	0	290	0	0	0	0
580	232	150	0	290	0	0	0	0
580	232	150	0	290	0	0	0	0
630	252	114.356	0	315	0	0	0	0
630	252	114.356	0	315	0	0	0	0

630	252	114.356	0	315	0	0	0	0
630	252	114.356	0	315	0	0	0	0
630	252	114.356	0	315	0	0	0	0
630	252	114.356	0	315	0	0	0	0
610	244	110.856	0	305	0	0	0	0
610	244	110.856	0	305	0	0	0	0
610	244	110.856	0	305	0	0	0	0
670	268	110.856	0	335	0	0	0	0
670	268	110.856	0	335	0	0	0	0
670	268	110.856	0	335	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
740	296	740	0	370	0	0	0	0
750	300	750	0	375	0	0	0	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
650	260	550	0	325	0	0	5	0
500	250	500	0	250	0	0	5	0
640	256	300	0	320	0	0	0	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
520	260	550	0	260	0	0	7	0
520	260	600	0	260	0	0	7	0
930	744	900	0	720	0	0	1	0
930	744	900	0	720	0	0	1	0
250	0	250	0	0	0	0	2	0
250	0	250	0	0	0	0	2	0
250	0	250	0	0	0	0	2	0
250	0	250	0	0	0	0	2	0
90	0	90	0	0	0	0	3	0

90	0	90	0	0	0	0	3	0
90	0	90	0	0	0	0	3	0
90	0	90	0	0	0	0	3	0
90	0	90	0	0	0	0	3	0
200	0	200	0	0	0	0	2	0
200	0	200	0	0	0	0	2	0
500	0	500	0	0	0	0	2	0
500	0	500	0	0	0	0	2	0
500	0	500	0	0	0	0	2	0
120	0	120	0	0	0	0	3	0
120	0	120	0	0	0	0	3	0
57	0	57	0	0	0	0	4	0
57	0	57	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0

150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0

Table C3: Unit information table for 2030 big gas scenario

Max Load (MW)	Min Load (MW)	Ramp Rate (MW/h)	Outage Status	Load (MW)	Up Available	Down Available	Type	Pump Hours
480	192	272.7	0	240	0	0	0	0
480	192	272.7	0	240	0	0	0	0
480	192	272.7	0	240	0	0	0	0
480	192	272.7	0	240	0	0	0	0
480	192	272.7	0	240	0	0	0	0
480	192	272.7	0	240	0	0	0	0
580	232	240	0	290	0	0	0	0
580	232	240	0	290	0	0	0	0
580	232	240	0	290	0	0	0	0
580	232	240	0	290	0	0	0	0
580	232	240	0	290	0	0	0	0
580	232	240	0	290	0	0	0	0
590	236	205.979	0	295	0	0	0	0
590	236	205.979	0	295	0	0	0	0
590	236	205.979	0	295	0	0	0	0
590	236	205.979	0	295	0	0	0	0
590	236	205.979	0	295	0	0	0	0
590	236	202.98	0	295	0	0	0	0
580	232	202.98	0	290	0	0	0	0
580	232	202.98	0	290	0	0	0	0

580	232	202.98	0	290	0	0	0	0
580	232	202.98	0	290	0	0	0	0
580	232	202.98	0	290	0	0	0	0
580	232	202.98	0	290	0	0	0	0
610	244	189.991	0	305	0	0	0	0
610	244	189.991	0	305	0	0	0	0
610	244	189.991	0	305	0	0	0	0
610	244	189.991	0	305	0	0	0	0
610	244	189.991	0	305	0	0	0	0
610	244	189.991	0	305	0	0	0	0
580	232	150	0	290	0	0	0	0
580	232	150	0	290	0	0	0	0
580	232	150	0	290	0	0	0	0
580	232	150	0	290	0	0	0	0
580	232	150	0	290	0	0	0	0
580	232	150	0	290	0	0	0	0
630	252	114.356	0	315	0	0	0	0
630	252	114.356	0	315	0	0	0	0
630	252	114.356	0	315	0	0	0	0
630	252	114.356	0	315	0	0	0	0
630	252	114.356	0	315	0	0	0	0
630	252	114.356	0	315	0	0	0	0
610	244	110.856	0	305	0	0	0	0
610	244	110.856	0	305	0	0	0	0
610	244	110.856	0	305	0	0	0	0
670	268	110.856	0	335	0	0	0	0
670	268	110.856	0	335	0	0	0	0
670	268	110.856	0	335	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
350	140	350	0	375	0	0	0	0
600	240	600	0	300	0	0	5	0

600	240	600	0	300	0	0	5	0
640	256	300	0	320	0	0	0	0
650	325	650	0	325	0	0	7	0
640	320	640	0	320	0	0	7	0
640	320	640	0	320	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
930	744	930	0	720	0	0	1	0
930	744	930	0	720	0	0	1	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
250	0	250	0	0	0	0	2	0
250	0	250	0	0	0	0	2	0
250	0	250	0	0	0	0	2	0
250	0	250	0	0	0	0	2	0
90	0	90	0	0	0	0	3	0
90	0	90	0	0	0	0	3	0
90	0	90	0	0	0	0	3	0
90	0	90	0	0	0	0	3	0
90	0	90	0	0	0	0	3	0
200	0	200	0	0	0	0	2	0

200	0	200	0	0	0	0	2	0
500	0	500	0	0	0	0	2	0
500	0	500	0	0	0	0	2	0
500	0	500	0	0	0	0	2	0
120	0	120	0	0	0	0	3	0
120	0	120	0	0	0	0	3	0
90	0	90	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0

500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0

Table C4: Unit information table for 2050 moderate decline scenario

Max Load (MW)	Min Load (MW)	Ramp Rate (MW/h)	Outage Status	Load (MW)	Up Available	Down Available	Type	Pump Hours
610	244	189.991	0	305	0	0	0	0
630	252	114.356	0	315	0	0	0	0
630	252	114.356	0	315	0	0	0	0
630	252	114.356	0	315	0	0	0	0
630	252	114.356	0	315	0	0	0	0
630	252	114.356	0	315	0	0	0	0
610	244	110.856	0	305	0	0	0	0
610	244	110.856	0	305	0	0	0	0
610	244	110.856	0	305	0	0	0	0
670	268	110.856	0	335	0	0	0	0
670	268	110.856	0	335	0	0	0	0
670	268	110.856	0	335	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
720	288	720	0	360	0	0	0	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0

600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
650	260	550	0	325	0	0	5	0
600	240	600	0	300	0	0	5	0
650	260	550	0	325	0	0	5	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
550	275	550	0	275	0	0	7	0
550	275	550	0	275	0	0	7	0
550	275	550	0	275	0	0	7	0
550	275	550	0	275	0	0	7	0
550	275	550	0	275	0	0	7	0
550	275	550	0	275	0	0	7	0
550	275	550	0	275	0	0	7	0
580	290	580	0	290	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
900	720	900	0	720	0	0	1	0
900	720	900	0	720	0	0	1	0
900	720	900	0	720	0	0	1	0
900	720	900	0	720	0	0	1	0
900	720	900	0	720	0	0	1	0
600	480	600	0	480	0	0	1	0
600	480	600	0	480	0	0	1	0
600	480	600	0	480	0	0	1	0
880	704	880	0	480	0	0	1	0
900	720	900	0	720	0	0	1	0
600	480	600	0	480	0	0	1	0
900	720	900	0	720	0	0	1	0

600	480	600	0	480	0	0	1	0
900	720	900	0	720	0	0	1	0
600	480	600	0	480	0	0	1	0
660	528	600	0	528	0	0	1	0
900	720	900	0	720	0	0	1	0
900	720	900	0	720	0	0	1	0
600	480	600	0	480	0	0	1	0
900	720	900	0	720	0	0	1	0
600	480	600	0	480	0	0	1	0
900	720	900	0	720	0	0	1	0
600	480	600	0	480	0	0	1	0
900	720	900	0	720	0	0	1	0
600	480	600	0	480	0	0	1	0
660	528	600	0	528	0	0	1	0
900	720	900	0	720	0	0	1	0
250	0	250	0	0	0	0	2	0
250	0	250	0	0	0	0	2	0
250	0	250	0	0	0	0	2	0
250	0	250	0	0	0	0	2	0
90	0	90	0	0	0	0	3	0
90	0	90	0	0	0	0	3	0
90	0	90	0	0	0	0	3	0
90	0	90	0	0	0	0	3	0
90	0	90	0	0	0	0	3	0
200	0	200	0	0	0	0	2	0
200	0	200	0	0	0	0	2	0
500	0	500	0	0	0	0	2	0
500	0	500	0	0	0	0	2	0
500	0	500	0	0	0	0	2	0
120	0	120	0	0	0	0	3	0
120	0	120	0	0	0	0	3	0
57	0	57	0	0	0	0	4	0
57	0	57	0	0	0	0	4	0
57	0	57	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0

147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
57	0	57	0	0	0	0	4	0
57	0	57	0	0	0	0	4	0
57	0	57	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
147	0	150	0	0	0	0	4	0
147	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0

150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0

Table C5: Unit information table for 2050 high nuclear cost scenario

Max Load (MW)	Min Load (MW)	Ramp Rate (MW/h)	Outage Status	Load (MW)	Up Available	Down Available	Type	Pump Hours
610	244	189.991	0	305	0	0	0	0

630	252	114.356	0	315	0	0	0	0
630	252	114.356	0	315	0	0	0	0
630	252	114.356	0	315	0	0	0	0
630	252	114.356	0	315	0	0	0	0
630	252	114.356	0	315	0	0	0	0
610	244	110.856	0	305	0	0	0	0
610	244	110.856	0	305	0	0	0	0
610	244	110.856	0	305	0	0	0	0
670	268	110.856	0	335	0	0	0	0
670	268	110.856	0	335	0	0	0	0
670	268	110.856	0	335	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
720	288	720	0	360	0	0	0	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0

600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
550	220	550	0	275	0	0	5	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
520	260	520	0	260	0	0	7	0
520	260	520	0	260	0	0	7	0
580	290	580	0	290	0	0	7	0
580	290	580	0	290	0	0	7	0
550	275	550	0	275	0	0	7	0
550	275	550	0	275	0	0	7	0
550	275	550	0	275	0	0	7	0
580	290	580	0	290	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
560	280	560	0	280	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
250	0	250	0	0	0	0	2	0
250	0	250	0	0	0	0	2	0

250	0	250	0	0	0	0	2	0
250	0	250	0	0	0	0	2	0
90	0	90	0	0	0	0	3	0
90	0	90	0	0	0	0	3	0
90	0	90	0	0	0	0	3	0
90	0	90	0	0	0	0	3	0
90	0	90	0	0	0	0	3	0
200	0	200	0	0	0	0	2	0
200	0	200	0	0	0	0	2	0
500	0	500	0	0	0	0	2	0
500	0	500	0	0	0	0	2	0
500	0	500	0	0	0	0	2	0
120	0	120	0	0	0	0	3	0
120	0	120	0	0	0	0	3	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
117	0	147	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0

Table C6: Unit information table for 2050 big gas scenario

Max Load (MW)	Min Load (MW)	Ramp Rate (MW/h)	Outage Status	Load (MW)	Up Available	Down Available	Type	Pump Hours
610	244	189.991	0	305	0	0	0	0
630	252	114.356	0	315	0	0	0	0
630	252	114.356	0	315	0	0	0	0
630	252	114.356	0	315	0	0	0	0
630	252	114.356	0	315	0	0	0	0
630	252	114.356	0	315	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
600	240	600	0	300	0	0	0	0
730	288	730	0	360	0	0	0	0
600	240	600	0	300	0	0	5	0
600	240	600	0	300	0	0	5	0
640	320	640	0	320	0	0	7	0
640	320	640	0	320	0	0	7	0
650	325	650	0	325	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0

600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
550	275	600	0	275	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0

600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0

600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
600	300	600	0	300	0	0	7	0
250	0	250	0	0	0	0	2	0
250	0	250	0	0	0	0	2	0
250	0	250	0	0	0	0	2	0
250	0	250	0	0	0	0	2	0
90	0	90	0	0	0	0	3	0
90	0	90	0	0	0	0	3	0
90	0	90	0	0	0	0	3	0
90	0	90	0	0	0	0	3	0
90	0	90	0	0	0	0	3	0
200	0	200	0	0	0	0	2	0
200	0	200	0	0	0	0	2	0
500	0	500	0	0	0	0	2	0
500	0	500	0	0	0	0	2	0
500	0	500	0	0	0	0	2	0
120	0	120	0	0	0	0	3	0
120	0	120	0	0	0	0	3	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
147	0	147	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0

150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
150	0	150	0	0	0	0	4	0
500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0
500	500	500	0	0	0	0	6	0

APPENDIX D: POLICY BRIEF

Long term view on CSP remuneration

Currently IPPs interested in developing CSP plants in South Africa are being offered a two tier tariff. They are offered one rate for electricity produced during most of the day, a premium for power produced during evening peak and nothing for power produced during the other hours of the night. The idea is to incentivise power production when demand is high.

Spatio-temporal modelling shows that in the short to medium term (up to 2030) this simple system appears to work reasonably well. However, in the long term and in scenarios with a high uptake in renewable energy, problems arise. An oversupply of 'peak' power and afternoon power results in a premium being paid for power that is not representative of maximum demand and new shortfall patterns develop. The rigid tariff system disincentives the CSP plants, that could respond and fill these new gaps, from doing so. The plants respond to the tariff instead of actual demand.

In a generating system with a high uptake in renewable energy the current tariff system would waste the potential CSP has for responding to system needs. A more sophisticated remuneration system would have to be put in place to prevent this from happening.

From the observations and findings in this study, consideration could be given to the following in future:

- Enable tariff structures that recognise the value of CSP to the system rather than to the IPP. A primary consideration is to view a system of CSP plants to be remunerated for serving availability to mid-merit or peaking needs rather than remunerating based only on the delivery of power. Ultimately a tariff linked to time of day pricing would be ideal, however it is understood to be a challenge with respect to project bankability. Accordingly, a tariff guaranteed on availability and delivery plus an incentive structure to provide power during the times of highest need could satisfy the needs of all stakeholders.

- Part of an optimal system of CSP plants is recognition of spatial distribution to more closely match demand for a range in temporal response. CSP plants need a high probability of availability within hourly needs but the system of plants needs seasonal balancing. A combination of a system planner together with the aforementioned incentive structure to provide power when it is most needed could aid in more optimal plant sizing and locating.