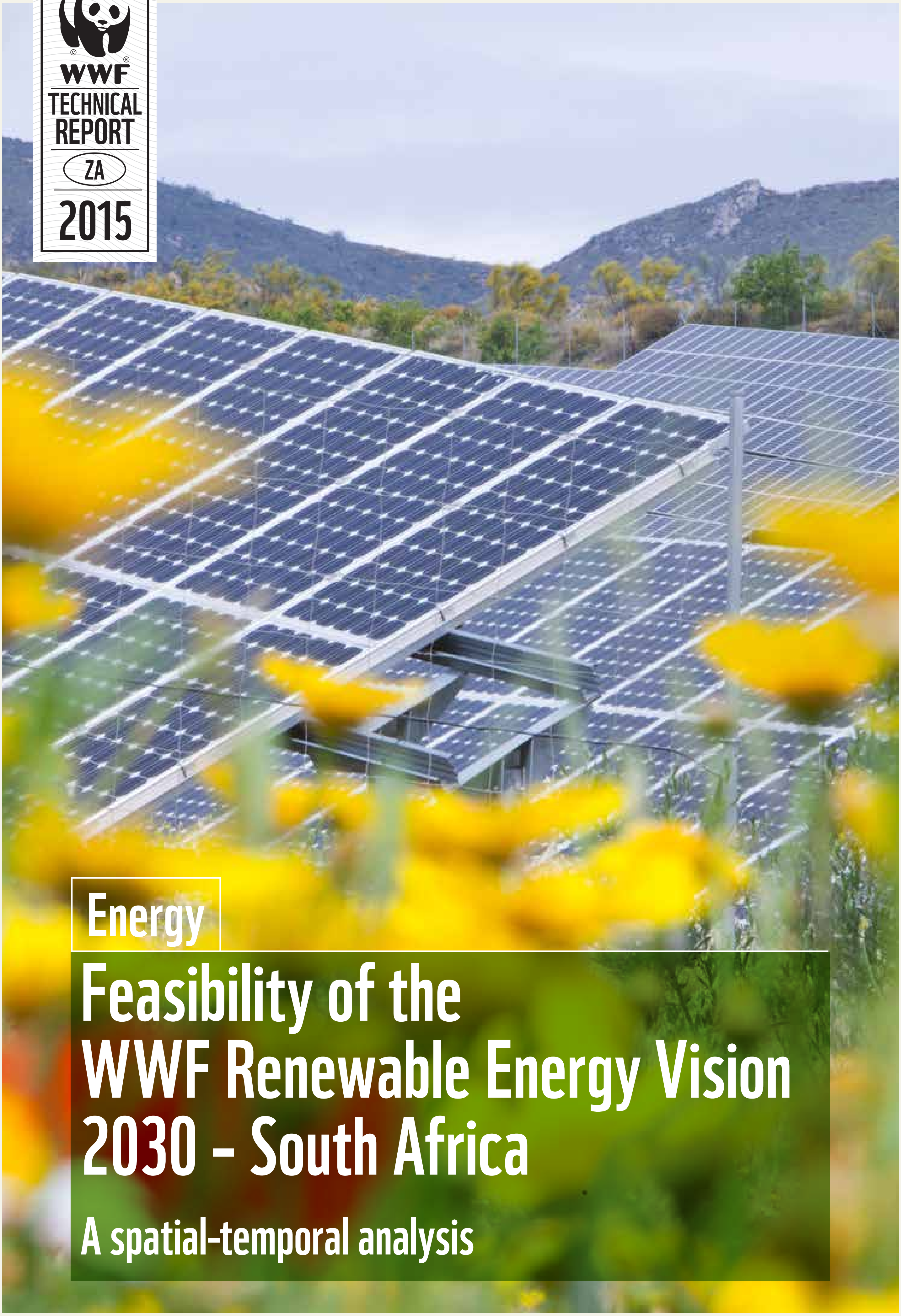


WWF TECHNICAL REPORT ZA 2015

Energy

Feasibility of the WWF Renewable Energy Vision 2030 – South Africa

A spatial-temporal analysis

CONTENTS

EXECUTIVE SUMMARY

Attempts to introduce renewable energy (RE) to South Africa date back to the White Paper on Renewable Energy of 2003. These attempts have come a long way to their current position in the updated draft version of the 2010 Integrated Resource Plan (IRP Update).

Regardless, it is necessary to step up RE targets in the coming years in order to lessen the carbon intensity of South Africa's economy and move towards an electricity supply system that allows greater room for flexibility without economically degrading power cuts or electricity buy-backs from intensive energy users.

WWF-SA identified the continued reliance on coal to generate more than two-thirds of the country's electricity as a threat to natural resources such as land and water, which are critical to the agricultural sector and will consequently present increased challenges in terms of the food-energy-water nexus. As a result of this concern, WWF-SA proposes an increase in the percentage of RE generation capacity into the South African system to achieve 11-19% of generation capacity from renewable sources as opposed to the 6-9% share proposed in the IRP2010 Update for 2030.

This report uses WWF-SA's Renewable Energy Vision Report for 2030 (2014) as a starting point to test the technical and cost (techno-economic) feasibility and merits of the scenarios that the vision report proposes. The two scenarios in the Vision Report are referred to as the WWF High and WWF Low scenario.

The feasibility and merits of targeting 20% annual electricity generation by 2030 are tested by performing a spatial-temporal analysis on the complete electricity system of South Africa. While the WWF scenarios define and delineate the work in general, the analysis is confined neither to the proposed system makeup nor to prescribed technology performance characteristics. An intended outcome of this work is to validate the general idea and refine a conceptual electricity system for 2030. Scenarios are compared using a single metric – cost of electricity in Rand per kilowatt-hour (R/kWh) in order to reach this objective – and this cost is tested against various demand forecasts.

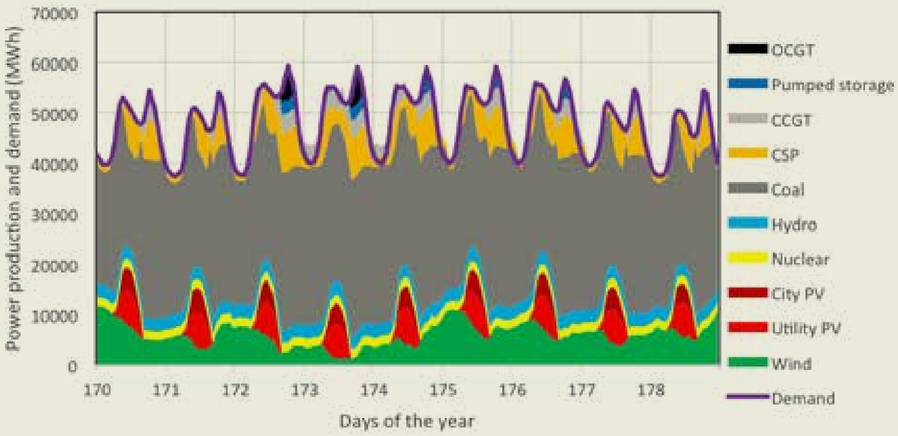
In order to create a reasonable representation of the electricity system, the recent past and current status of the electricity system required review. The status and plans of the Renewable Energy Independent Power Producer Procurement Programme (REIPPPP) was also reviewed in order to validate some assumptions about the ability to add renewable capacity in future.

The spatial-temporal model requires a definition of the system. This is primarily grouped into categories of demand, technology, energy resource and system rules. Electricity demand in 2030 is taken from the respective scenarios and applied over the span of a year in the same form as the reported Eskom 2010 hourly demand by simple scaling. In this way, evening peaks and other characteristics are preserved.

Technology (plants) are represented in enough detail to offer sufficient hourly accuracy. This requires that plant behaviour accounts for ramp rate, turndown limit, availability (relating to maintenance) and other technology-specific characteristics. The cost of each technology is represented as a range of cost for capital expenditures (CAPEX), operational expenditures (OPEX) and fuel for the 15 year period leading to 2030.

Environmental, weather and transmission system constraints were set for renewable plants and a distributed network of wind and solar power nodes were selected.

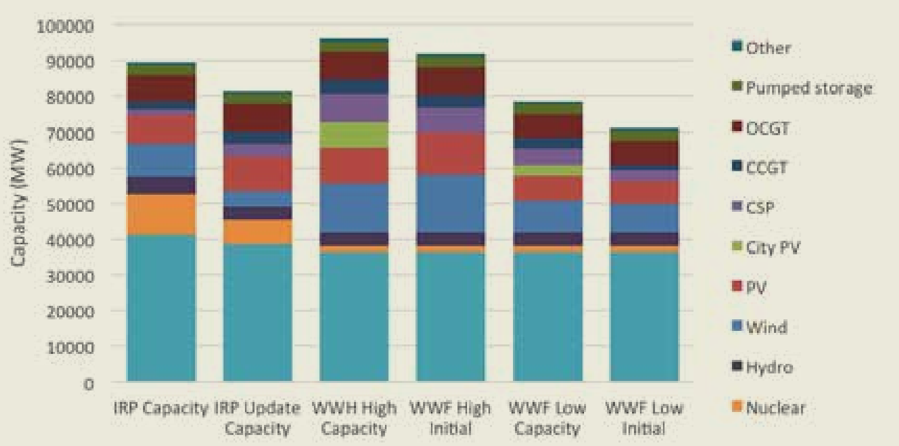
Figure 1: **Deep winter characteristics of the WWF High scenario.**



The spatial-temporal model performs hourly analysis for the whole electricity network and synchronously handles hourly demand as a single node, conventional (eg. Coal) power as a virtual node and renewable plants in spatially distributed nodes near the current transmission network. The model has multiple rules and constraints to emulate the network. The result is that electricity generation aims to meet demand at each hour, but will track shortfalls and times where over generation occurs. The model is deterministic for system performance based on the technique, but cost analysis is probabilistic in order to represent a range of future outcomes. Figure 1 is an example of how the WWF High scenario meets the demand in a deep winter period.

The resulting WWF scenario capacities are shown in Figure 2. The final WWF RE capacities were increased above the capacities suggested in the WWF vision and in general, the WWF vision proposal was maintained.

Figure 2: **Capacities for each scenario.**



The WWF scenario definition was optimised for lowest cost where cost is a function of the total cost of running all plants and the cost of unserved electricity in the system. Cost analysis is represented by a cumulative distribution curve and histogram from 300 cost simulations per scenario. The result offers a sense of typical cost and cost uncertainty, both valuable outputs for decision making.

The results of the optimized WWF scenarios were somewhat unexpected. The increased RE capacity resulted in an increase in annual electricity production by RE to 25%. At this point, the lowest system cost was achieved and no other tested combinations of technology could reach this lowest cost. The resulting WWF High scenario achieved an average system generation cost of about R 0.62/kWh with very little variance.

The four scenarios were also subjected to the range of 2030 demand levels assumed in the report. While the WWF High scenario was optimised for the medium demand growth, it outperformed the IRP scenario in a high demand case. A variant of the WWF scenario achieves lowest cost regardless of demand in 2030.

Figure 3: **Cost probabilities of the scenarios using simple LCOE and 50th percentile cost values.**

While this is a first test of the WWF vision, the report does indicate that a balanced RE configured system can perform very well and can do so at lowest cost to the system. Considering that RE projects are expected to generate within two years of construction, with evidence shown in the first REIPPP project rounds, a focus on renewable power generation would appear to be the logical economic choice.

As an initial validation of the WWF vision, many improvements to the analysis are possible and encouraged. In particular, the transmission system was not modelled in sufficient detail. Any future scenario is likely to require significant transmission investment and planning and a spatial-temporal system evaluation will only be valuable to decision makers when this is comprehended.

ACKNOWLEDGEMENTS

The authors are grateful to WWF-SA for the financial support provided to undertake this research as well as for inputs provided on the contents of the report.

GeoModel Solar provided solar and wind data at a substantially reduced rate in support of this project. The data reference: SolarGIS data © 2012 GeoModel Solar s.r.o. WASA data is free to download for purposes aligned with this project. The data is very useful for wind turbine/plant modelling as it complements the high quality solar data.

The authors would like to acknowledge the following persons for their contributions during the project: Christina Auret from ESKOM for her assistance on power plant modelling, Sebastian Giglmayr for his contributions towards photovoltaic and wind power within the system, Alex Lupion for his assistance on wind power modelling, and Megan Sager for her inputs regarding economics and the context of the proposed WWF scenarios.

The authors appreciate all opinions, inputs and suggestions provided by others. All conclusions, outcomes and errors are the responsibility of the authors.

LIST OF FIGURES AND TABLES

Executive Summary

List of Figures

List of Tables

LIST OF ABBREVIATIONS

CAPEX	Capital expenditure
CCGT	Combined cycle gas turbine
Cf	Capacity factor
COUE	Cost of Unserved Energy
CSIR	Council for Scientific and Industrial Research
CSP	Concentrating solar power
DoE	Department of Energy
DNI	Direct normal irradiance
EHV	Extra high voltage
EPRI	Electric Power Research Institute
FGD	Flue-gas desulfurization
GCCA	(Eskom) Generation Connection Capacity Assessment
GDP	Gross domestic product
GHI	Global horizontal irradiance
GIS	Geographic information system(s)
GJ	Gigajoule
HV	High voltage
IPP	Independent power producer
IRP	Integrated resource plan
kV	kilovolts
kWh	Kilowatt hour
LCOE	Levelized cost of electricity
LNG	Liquefied natural gas
MTS	Main Transmission System
MW	Megawatt
MWh	Megawatt hour
OCGT	Open cycle gas turbine
O&M	Operation and maintenance
OPEX	Operational expenditure
PF	Pulverized fuel
PPA	Power purchase agreement
PV	Photovoltaic
RE	Renewable energy
REIPPP(P)	Renewable Energy Independent Power Producers Procurement (Programme)
TDP	Transmission development plan
TES	Thermal energy storage
TMY	Typical meteorological year
TNSP	Transmission Network Service Provider
TWh	Terawatt hour
SGP	Strategic grid plan
WTS	Weathering the storm
WWF	World Wide Fund for Nature
WWF-SA	World Wide Fund for Nature South Africa
ZAR	South African Rand

DEFINITIONS

Availability: The ratio or fraction that a **plant** or **technology** is available to produce power during a year. In the assumptions of this report, **availability** is reduced by planned and unplanned maintenance only and not due to the availability of its energy (re)source.

Capacity factor (Cf): The ratio or fraction of actual electricity production in a year to the plant or technology rated power output multiplied by the number of hours in a year, i.e. the actual output divided by output as if it could run flat-out continuously. In this analysis, **Cf** is an output that includes the impact of **availability**.

Capital cost: See CAPEX, Investment cost and Overnight cost.

Electricity (generation) system: All power plants and generators, typically in a transmission-connected system and controlled by a utility company. In this case, this is mostly the South African electricity grid. In this report, a single **power plant** is not referred to as a **system**.

Electricity (generation) technology: The foundational type of technology upon which a power plant is based. This is often linked to the fuel source. E.g. Coal power plants based on steam generators and turbines connected to an electric generator.

Fixed operating cost (Fixed OPEX): The cost to maintain a power plant regardless of output. This annual cost is a function of technology and size of plant.

Generator: Same as **power plant** in most of this report. Technically speaking, a **generator** converts energy in one form (such as a mechanically rotating shaft) to AC power and is therefore a component of a **power plant**.

Grid: Same as **transmission system**.

Investment cost: Also known as 'real' cost. This is the cost of capital including the impact of the time of construction, mostly due to financing costs prior to operation.

IRP (case): The original IRP 2010 in this technical model.

IRP (draft) Update (case): The 2013 IRP draft updated base scenario in this technical model.

Load shedding: Intentional cutting of power to customers in a scheduled manner when the **electricity system** cannot meet demand in order to avoid total system failure (or system blackout).

Operating cost: See OPEX, Variable operating cost and Fixed operating cost.

Overnight cost: The cost of capital without consideration for length of construction (and hence cost of finance during construction).

Planned maintenance: Scheduled routine maintenance required for achieving reliable performance over the expected life. Scheduling is planned in context of the **electricity system**. This has an impact on **availability** and **capacity factor**.

Power plant: A single instance of a power generation **technology**.

Ramp rate: The rate at which a **power plant** or **technology** can increase or decrease its output to match demand. **Ramp rate** is an important consideration in a system with conventional large thermal power plants where demand fluctuates and/or intermittent generation elsewhere in the system causes fluctuation in the balance of demand.

Spatial: A geographical relation, in this case typically the specific locations of plants in GPS coordinates giving reference to resource information.

Spatial-temporal (model or method): Also known as the **spatio-temporal** method referring to a fully synchronous analysis method accounting for specific geographical locations.

Substation: A node in a transmission system that connects **transmission lines** of different voltages and capacities. **Substations** are important when new power plants or generators are added to the system, particularly in areas that have typically not supplied or consumed electricity before.

Synchronous time: The same hour in the same year for all **spatial** locations and resource availabilities. This study relies on synchronous information, making **Typical Meteorological Year (TMY)** time and data invalid.

Temporal: In this report, **temporal** relates to demand, weather and energy resource **synchronous time** in hourly increments starting from hour 1 to hour 8760 in a calendar year, also referred to as 'year hours' in the report.

Turndown fraction: The fraction of current **plant** output to its rated power.

Turndown limit: The lowest **turndown fraction** that a **plant** can stably operate at before it needs to be stopped or set to a standby mode.

Transmission line: A conductive line transmitting (carrying) electricity from one point (a **substation**) to another.

Transmission system: The sum of all **transmission lines**, **sub-stations** and control within a "grid connected" region usually controlled by a regional utility; informally referred to as "the **grid**".

Typical Meteorological Year (TMY): Meteorological data collected over many years for a single location and stitched "by committee" on a month-by-month basis to provide an average (typical) year. **TMY** and its variants are traditionally used in early site identification, **plant** scoping and profit analysis. **TMY** data is, by definition, not relevant to **spatial-temporal** analysis.

Unplanned maintenance: Maintenance that occurs out of schedule due to unplanned and unexpected events, such as failure or breakage, and that impacts **availability** and **capacity factor**.

Variable operating cost (Variable OPEX): The cost to maintain a power plant based on output. This cost is proportional to the amount of power produced and is a function of technology and size of plant.

WWF High (case): The report's interpretation of the WWF high demand scenario in this technical model.

WWF Low (case): The report's interpretation of the WWF low demand scenario in this technical model.

INTRODUCTION

"The reason solarpower generation will increasingly dominate: it's a technology, not a fuel. As such, efficiency increases and prices fall as time goes on."

Tom Randall, Bloomberg, 29 October 2014

Background

South Africa is blessed with a wide array of natural resources including some of the most envied sustainable energy resources, particularly sunlight and wind. Despite this, the country is continuously reliant on fossil energy, predominantly coal, for electricity generation and is likely to remain so in the near future given the long planning horizons associated with energy system planning (Scholvin 2014). Attempts to introduce renewable energy (RE) date back to the White Paper on Renewable Energy of 2003 and have come a long way to their current position in the updated draft version of the 2010 Integrated Resource Plan (IRP Update) (DoE 2003; DoE 2013a). Regardless, it is necessary to step up RE targets in the coming years in order to lessen the carbon intensity of South Africa's economy and move towards an electricity supply system that allows greater room for flexibility without economically degrading power cuts or electricity buy-backs from intensive energy users.

WWF-SA identified the continued reliance on coal to generate more than two-thirds of the country's electricity as a threat to natural resources such as land and water, which are critical to the agricultural sector and will consequently present increased challenges in terms of the food-energy-water nexus. As a result of this concern, WWF-SA proposes an increase in the percentage of RE generation capacity into the South African system to achieve 11-19% of generation capacity from renewable sources as opposed to the 6-9% share as proposed in the IRP2010 Update for 2030 (WWF-SA 2014).

This report uses WWF-SA's Renewable Energy Vision Report for 2030 (2014) as a starting point to test the technical and cost (techno-economic) feasibility and merits of the scenarios that the vision report proposes. The intention is to assess the viability, cost, risk and reliability of the national generating system that aims to provide 20% of annual electricity by renewable resources, excluding hydropower. This study uses a bottoms-up analysis methodology that accounts for every hour of the year. Scenarios are conceptually designed and compared to the IRP 2010 and its draft update of 2013. Key concerns are energy and economic security, which are gauged by scrutinising the ability to meet electricity demand for every hour of the year coupled with the likely costs of each scenario representing South Africa's 2030-electricity system. The study assumes that only a direct economic argument will drive change and excludes analysis on the cost and impact of climate change and other externalities.

Figure 1: **From left to right: A wind turbine at Sere wind farm (STERG 2014a), construction at Khi Solar One (Abengoa 2014a), Florida Power, and Light Company's DeSoto Next Generation Solar Energy Center (NREL 2010).**

Given that electricity systems exhibit a high degree of inertia when it comes to the provision of capacity, a summary of South Africa's recent electricity history is worth reviewing.

South Africa's post-apartheid electricity generation system is characterised by dwindling reserve margins, periodic load-shedding when demand exceeds supply, price increases beyond inflation and a fleet of large thermal (e.g. coal, nuclear) power plants showing signs of age and maintenance backlogs.

Reasons for the current state of the system are a continuous debate, and while engaging on that topic is not the purpose of this report, some understanding of the complexity of the situation is necessary before sensible technology solutions can be proposed. The following narrative can be found in many publications over the last decade and is captured succinctly by Heun *et al.* (2010).

On the political front, the country has experienced disruptive change in government and administration. The young democracy is battling the twin struggles of learning to perform while delivering on a democratic promise to provide fair access to services such as electricity. The result is that Eskom, South Africa's single state-owned utility, has been unable to fund or deliver new capacity to the grid that matches the growing demand to be connected.

Other coincidental or related factors have compounded the situation. Global pressure on greenhouse gas emissions and the more recent emphasis on the status of finite fossil resources and resource extraction rates suggest that to continue on this path is risky. As a high emitter, South Africa has committed to reducing its carbon footprint significantly. On the nuclear front, South Africa has, for some time, identified this category of power generation technology to be an opportunity to reduce emissions and to develop next generation plants to benefit accordingly. A first attempt to encourage RE independent power producers (IPPs) fell flat with the argument that nobody could compete on price with Eskom. At the same time, there has been failure to deliver on the local nuclear promise. Both realities have added pressure to the system.

New challenges present at this junction. The electricity options available tend to have an "oil and water" mixing problem. Baseload plants, particularly nuclear, tend to be inflexible in that they do not fluctuate easily with demand or react to the intermittent nature of renewables. These large plants also take many years to commission, during which time the system would need to rely on existing capacity. The IRP also acknowledges that there is uncertainty about future construction and fuel costs as well as fuel availability for coal and nuclear technologies. Backup generators, a necessity for any generation system that might not be able to guarantee supply due to insufficient baseload, intermittent renewable generation or both, need to ramp quickly and tend to be very expensive to run. A future electricity generating system that is not based on big coal implies that there is a complex and difficult set of decisions to be made. Any future plan will need to be continuously reviewed and refined in order to balance supply and demand while keeping cost and risk under control. The IRP provides an excellent framework for such a plan, and part of the motive for this report is to promote higher fidelity analytical methods to support the IRP.

The IRP of 2010 (DoE 2011) makes progress towards planning for electricity generation over a 20-year horizon. Acknowledging existing shortcomings, the IRP and related planning activities – such as the Draft Integrated Energy Plan (IEP) of 2012 (DoE 2013b) and the associated implementing plans such as the Renewable Energy Power Producer Procurement Programme (REIPPPP) (DoE 2012) – seem to be heading in the right direction.

The first REIPPP projects began to come online in the 2014 timeframe, typically within 2 years of project commencement. By the end of 2014, these projects had added about 1,600 MW of wind and solar power to the grid. A recent study by the CSIR (2015) illustrates the net benefit to the South African economy during just 2014 to be close to R1 billion due, in part, to reducing the amount of unserved electricity in the economy.

Spatial-temporal modelling

Spatial-temporal modelling is emerging as a best-in-class simulation method for energy systems modelling in the instance where a significant fraction of the system contains renewable technologies or other causes of intermittent sources or processes. A period of time (a year for instance) is simulated in time increments (hourly for instance), and the result is a model that can more accurately approximate the system based on the resolution of the time increments and definition of the model. A good spatial-temporal method thus eliminates ambiguity regarding the contribution of intermittent resources such as wind or sunlight and instead quantifies their benefits and drawbacks to a system.

Perhaps best introduced by the following figures (Figure 2 and Figure 3), spatial-temporal modelling does not use average or typical conditions but discrete points in time and space based on what is really measured giving results that should correlate more precisely to reality.

Figure 2: **Spatial visualization of results from the spatial-temporal model (in this case, work presented at SASEC 2012 – Gauché et. al. 2012[1]).**

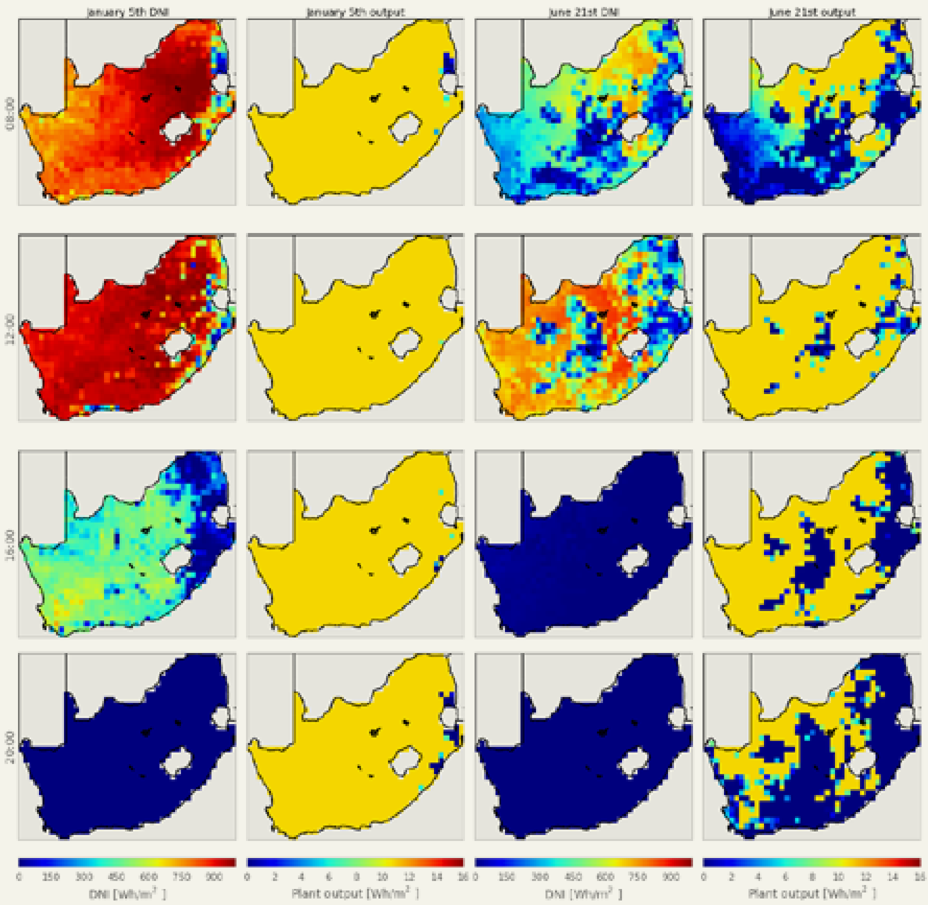


Figure 2 is an output from a study that looks at the value of concentrating solar power (CSP) in a distributed system in South Africa. It compares a good sunny summer day with a very stormy winter day. The impact of sunrise, local storms (see Kruger Park cloud cover on the January morning) and the movement of storms during the day (as morning progresses to noon on the winter day) soon become apparent. The second and fourth columns show the potential of a CSP plant at any location for those four points in time.

1 Gauché, P., Pfenninger, S., Meyer, A.J., Von Backström, T.W and Brent, A.C., Modeling Dispatchability Potential of CSP in South Africa. SASEC 2012, 21-23 May, Stellenbosch, South Africa.

Figure 3: **Temporal visualization of results from the spatial-temporal model (in this case, WWF High for the month of January).**

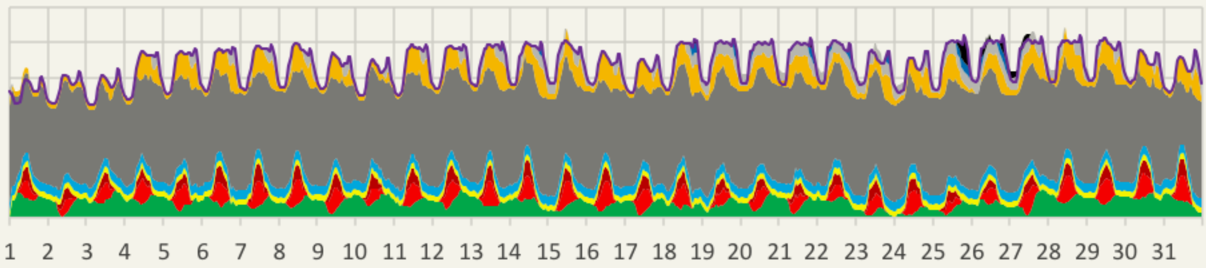


Figure 3 demonstrates results of a system where the power output of all power plants is aggregated for each point in time. In this case, the output for the month of January in the model is illustrated. It is important to note that there is simply too much information in the method to be able to show results spatially and temporally at the same time.

While system spatial-temporal modelling is commonly conducted using hourly increments as demonstrated, the system method does not capture short-duration effects such as wind gusts or intermittent cloud cover which can result in short-duration transmission stability problems between a power plant and its initial connection point in the system. This matter will require additional time resolution at a plant level to resolve. Beyond this, hourly spatial-temporal modelling is showing increasing value in both understanding and scoping of energy generation and transmission systems.

Objective & WWF scenario

The WWF Renewable Energy Vision 2030 – South Africa (WWF-SA 2014) proposes amending the draft IRP Update (DoE 2013a) Base Case scenario to scenarios prioritising RE technologies. Hereafter, this is referred to as “the WWF scenario(s)”.

Both WWF Scenarios propose that besides environmental benefits, a combination of RE capacity, storage and flexible gas-turbine generation offers South Africa a far more flexible energy system at a time of uncertainty regarding future electricity demand.

Table 1: **The planned capacities for 2030 according to the Base-Case scenarios of the IRP 2010 and IRP Update, as well as the WWF High and Low Demand scenarios (DoE 2011; DoE 2013a; WWF-SA 2014).**

Energy technology	IRP 2010 Base Case	IRP Update Base Case	WWF High Demand	WWF Low Demand
	Capacity (MW)			
Solar	9 600	13 070	18 884	9 334
Wind	9 200	4 360	16 134	8 184
Hydro	4 809	3 690	3 690	3 690
Existing coal	34 746	36 230	36 230	36 230
New coal	6 250	2 450	-	-
Nuclear	11 400	6 660	1 860	1 860
Open cycle gas	7 330	7 680	7 680	6 720
Combined cycle gas	2 370	3 550	3 550	1 420
Pumped storage	2 912	2 900	2 900	2 900
Other	915	760	760	640
Total	**89 532**	**81 350**	**91 688**	**70 978**
Expected 2030 demand (TWh)	454.4	409.1	407	358.1
% Expected 2030 Renewable Energy generation contribution	9%	9%	19%	11%
% Renewable Energy capacity in system	21%	21%	38%	25%

The objective of this project is to use the WWF scenario as a starting point to test the technical and cost (techno-economic) feasibility and merits of the proposed scenarios. More specifically, the feasibility and merits of targeting 20% annual electricity generation by 2030 are tested by performing a spatial-temporal analysis on the complete electricity system of South Africa[2]. While the WWF scenarios define and delineate the work in general, the analysis is confined neither to the proposed system makeup nor to prescribed technology performance characteristics. An intended outcome of this work is to validate the general idea and refine a conceptual electricity system for 2030. Scenarios are compared using a single metric – cost of electricity in Rand per kilowatt-hour (R/kWh) in order to reach this objective – and this cost is tested against various demand forecasts.

The WWF Scenarios make provision for a high demand[3] and low demand scenario, based on demand forecasts in the IRP Update. The proposal includes increases in wind, photovoltaic (PV) and CSP generation capacities by 2030 for the high demand

2 This is a method that, to the authors' knowledge, has not been used to this extent in South Africa to date.

3 The authors do not intend to question the demand assumptions, definitions of what constitutes an environmentally safe technology or in the economic assumptions or proposals made. These are definitions in this study.

scenario, but a decrease in solar power generation capacity for the low demand scenario compared to what is included in the IRP Update. The IRP 2010, IRP Update and WWF Scenarios are presented in Table 1. Excluded from the WWF increased RE capacity scenarios are new nuclear and coal builds. The low demand scenario also includes less open-cycle gas turbine and combined-cycle gas turbine capacity by 2030.

WWF's proposal acknowledges that there are certain limits and constraints associated with the country's transmission network and that grid expansions will be necessary in order to realise a large rollout of renewable capacity in this timeframe. A starting constraint in this work is an assumption that economic realities in South African and in Eskom will result in limited grid expansion expenditure. As an independent study, the ability to accurately quantify and define grid constraints and costs is not possible. The study does attempt to minimise the cost burden of the transmission system to be somewhat comparable to other scenarios that can fulfil the same future demand.

The spatial-temporal method used in this report has been validated and published in several journals as well as presented at international conferences. The study, however, makes many simplifying assumptions relating to information that the authors were unable to obtain independently. Accordingly, this work aims to spark debate for its independent view and merits with a view to further refinement in cooperation with other stakeholders in the electricity sector.

Report outline

Chapter 2 summarises the methodology of the project. This includes the decisions on the future electricity system based on big assumptions and constraints and the introduction of the spatial-temporal method, which is described in more detail in Chapter 6.

Chapter 3 describes the current electricity system in enough detail to provide context to the proposed scenarios.

Chapter 4 frames policy and practice relating to a big entry to utility renewable power and describes key renewable technologies and their value.

Chapter 5 provides more information on the characteristics of the different components within the generation system and continues from the previous chapter in contextualising the potential of wind and solar in South Africa in relation to land and infrastructure limitations.

Chapter 6 fully introduces the spatial-temporal modelling of the system and embedded technologies.

Chapter 7 demonstrates the implementation of the model and presents the resulting scenarios.

Chapters 8 and 9 move through a discussion of the results, the dissemination of the findings and suggestions on how the proposal can be fast-tracked.

METHODOLOGY

The methodology developed for this study is summarised here to provide a 'bird's eye view' to the method presented in the report. This section also clarifies key limitations, assumptions and overall scope.

Measuring the objective: The objective of the study is a set of key measures to evaluate the proposed WWF scenario against the IRP and IRP Update scenarios using a spatial-temporal modelling approach. The final measure for comparison is the cost of electricity taking into account the following:

- Cost of constructing all power plants in the system, including the cost of debt;
- Operating and maintenance (O&M) costs, both fixed and variable;
- Fuel costs;
- Cost of electricity not served (the cost to the economy);
- The amount of electricity delivered by the whole system.

Literature and data review: In order to account for the cost and generation parameters, a detailed survey of the existing, planned and forecasted power plants was required. For each plant, as much information as possible was gathered about life span, age, reliability, resource use, cost and other information that could impact the analysis.

Neutrality: As much information as possible was gathered in the public domain about the electricity system, the national transmission network and plans for expansion.

For the sake of expedience and neutrality, only publically available literature was used, and while advice and feedback was welcomed in order to best represent the outcomes, the report represents only the views and findings of the authors.

Assumptions and limitations: A key consideration in this study deals with handling transmission stability and capacities. The placement of renewable power plants – assuming that the country will be economically constrained over the next decade – warranted careful consideration. Placement of plants also required the consideration of local resources and spatial distributions necessary for good system performance. Two important assumptions are listed specifically:

- All 2030 scenarios will experience transmission infrastructure cost increases that are significant and commensurate with both an increase in capacity and a shift away from the traditional power generation regions. All likely scenarios experience such changes, and through consultation, the authors assume that the cost burden is equal to all scenarios.
- An argument is made that transmission infrastructure costs can be no worse, if not somewhat lower, provided RE capacity is installed within proximity of the existing transmission system. While this proposal is actually implemented in the WWF scenario model in the report, the inability to assess the cost benefit implies that the equal cost burden assumption is merely more likely.

Technical model: The level of detail in the spatial-temporal model required careful consideration. The model needed to simulate the national electricity generation and transmission system in a fair and comparable manner. Many simplifications and assumptions were required in order to make this tangible. Once determined, all necessary performance and cost for each type of power generation technology was tabulated as inputs to the model.

In-house spatial-temporal technology models have been developed, refined and validated over years. These technology models are combined into an overall system model containing system rules and constraints. The spatial-temporal model also has an hourly demand profile for a full year, which is scaled on the demand scenario.

Handling future scenarios: As scenarios are modelled for 2030, there is, by definition, a great deal of uncertainty. This uncertainty relates to the cost, demand, type and performance of technology. A way to represent a variety of outcomes was determined by accounting for a range in future costs and a range in the demand forecast for 2030.

Fair and comparable treatment of the various scenarios in pursuit of studying the merits of a renewable focussed future is a desired outcome of this report. It is not the objective to perform a direct comparison of the scenarios and, for this reason, each scenario typically maintains its own demand level. Analysis and interpretation of the IRP and IRP Update in this study result in some significant departures with respect to their original definition. Multiple reasons for this exist and these are explained in the report (with two mentioned explicitly here).

- A major departure in definition of the IRP scenario is the assumption on lower coal power availability in this report, which is detrimental to the performance of the IRP scenario.
- The WWF scenarios benefited from model-based optimization while the IRP and IRP Update scenarios maintained a static definition.

A single direct comparison between scenarios is performed by subjecting each scenario to each demand level. This comparison leads to an interesting result, but the details thereof are not included to avoid providing a false impression of the rigor of the comparison.

Making sense, recommendations and conclusions: Once the optimal scenarios are defined, the report synthesises the results with recommendations and conclusions.

CURRENT ELECTRICITY GENERATION SYSTEM

The first step in this review relates to the current electricity system. This section provides a summary of the recent history and status of the system and includes the contribution already noted by the first REIPPP projects coming online. The following chapter explores the REIPPP in more detail.

Summary

The most prominent characteristic of the current Eskom-owned electricity supply is that the generation system is dominated by coal power, generating around 93% of electricity and supply baseload alongside the country's only nuclear power station, Koeberg. Of the 13 coal power stations in operation, three are return-to-service stations, which are stations that have been re-commissioned to supply to the growing demand for electricity after being mothballed in 1990[4]. The two new supercritical coal-fired power stations, Medupi and Kusile, are the only new coal generation capacities currently under construction. The generation capacity that is now in operation and owned by Eskom is summarized in Table 2.

Figure 4: **Matimba 3990 MW direct dry-cooling coal power plant. Eskom, South Africa (Eskom 2013).**

4 From Eskom Generation Map. Available at http://www.eskom.co.za/Whatweredoing/ElectricityGeneration/PowerStations/Documents/EskomGenerationDivMapREV8.pdf

In addition to this capacity, there are non-Eskom generation plants that are considered part of the existing fleet. Renewable energy capacity owned by IPPs is also expected to have an increased share as the generation system develops. These projects, some of which have already connected to the grid, are not included in the table. According to industry experts, construction of the 100MW Eskom CSP plant is not expected to start any time before 2016, making the 100MW Sere wind farm Eskom's first major RE plant when it comes into operation.

Table 2: **The existing generation capacity in South Africa. Values are as given in the IRP Update and might differ slightly to those given by Eskom (Sources: DoE 2013a; Eskom 2011).**

Generation type	Generation technology	Capacity (MW)	New Capacity (MW)
Eskom owned			
Baseload	Coal	35 980	9 564
	Nuclear	1 860	
Peak demand	Hydroelectric	600	
	Small hydroelectric	61	
	Pumped storage	1 400	1 332
	Gas turbines	2 460	
Renewable energy – new build	Concentrating solar power		100
	Wind	Not operational	100
	Total Eskom owned	**42 361**	**11 096**
Non-Eskom generation			
	Various	3 330	12 581
	Total generation capacity	**45 691**	**12 354**

Note: Eskom Grid Capacity Presentation. 2 December 2014. Cape Town.

System assessment

The impacts and implications of the current electricity supply system are many and embedded in a historically complex context. Although matters such as delayed policy implementation and limited funding affect the electricity supply system, the authors agree with Giglmayr (2013) that the issues related to the current system can be grouped into three categories. These are limited reliability, unsustainable practices and power losses due to transmission distances.

Reliability: A system that sufficiently provides for the needs of the country should have a reserve margin that can meet electricity demand through both planned and unplanned outages at power stations. The reserve margin of the South African system was at 25% in 2002. When the first rolling blackouts started in 2008, this figure had declined to 10%, and in 2014, the reserve margin had been reported to be at or around 1% (Paton 2014). Furthermore, the unreliability of the current generation system imposes a cost to the customer according to the timing and probability of occurrence expressed as the Cost of Unserved Energy (COUE).

Unsustainability: Apart from coal being a finite fossil resource, a system that is almost entirely coal-dependent is bound to have high corresponding CO_2 equivalent emissions. South Africa is one of the highest carbon emitters globally, and emission levels have increased by a factor of 7 since 1950 (Winkler 2007). In terms of carbon emissions for power utility companies worldwide, Eskom ranked second highest in 2012 with 1.015tCO_2eq/MWh.

Figure 5: **Gariep 360MW hydroelectric power plant. Eskom, South Africa. (Eskom n.d.a).**

This is 45% higher than the mean CO_2eq/MWh level in Europe (Letete et al 2009). Further social and environmental issues include risks of respiratory disease, water use and contamination and various impacts on land (Jenner & Lamadrid 2013).

Transmission losses: The majority of electricity generation capacity is geographically concentrated in the northeast of the country because power plants are built in close vicinity to the coalmines. Transmitting this electricity to the areas with demand occurs over distances of more than 1000km in some instances, resulting in a significant level of losses. These losses were at 9.5% in 2010 (World Bank 2013); however, an expert has suggested that this figure is now closer to 15% (Uken 2013).

Inevitably, an increase in RE in the electricity generation system has the potential to contribute positively in all three of these problem areas by diversifying the electricity mix, reducing reliance on carbon intensive resources and generating electricity closer to demand areas.

Figure 6: **Koeberg 1800MW nuclear power station. Eskom, South Africa (Eskom n.d.b).**

Figure 7: **Ankerlig 1338MW open cycle gas turbine power plant. Eskom, South Africa (Eskom n.d.c).**

Arguably, the aging fleet of coal-fired power stations are associated with further risks and implications relating to reliability. Since the electricity supply shortage in 2008, demand has apparently been met by not complying with standard maintenance schedules on the coal fleet. As a result, the fleet has been subject to deterioration, and where the expected annual performance was thought to be 86% in 2010, the actual performance was reportedly below 80% (DoE 2013a). Due to the small-to-non-existent reserve margin, any unexpected event at a coal power plant results in load shedding; this was the case in November 2014 when a coal silo collapsed at the 4110MW Majuba plant, the youngest of Eskom's coal-fired stations[5]. There are, however, an array of incidents that can occur as a result of dwindling maintenance practices, affecting not only the individual consumer, but also business owners and industries with an ultimate effect on the economy (SABC 2014). The impact of practices as mentioned above in order to "keep the lights on" is bound to become more severe given Eskom's admission to such practices in January 2015 and their further admission that it will be impossible to continue in the same manner due to the current condition of the generation system (van Rensburg 2015).

Figure 8: **Palmiet 400MW pumped storage scheme. Eskom, South Africa (Eskom n.d.d).**

In order to keep meeting the increasing demand for electricity while the major power generators within the system face these continuous challenges, RE will thus not only be a cleaner alternative, but a key component to increase the cost-effectiveness of a system that is required to be highly adaptive and dynamic in most aspects. The benefits of having approximately 1.6GW of combined wind and PV generation capacity by the end of 2014 is illustrated by the report released by the CSIR in early 2015 (CSIR 2015). Significant fuel costs were avoided due to the contribution from PV and wind power, and the economy was spared the cost of 117 unserved hours. These results provide early evidence that renewables have a key role to play in South Africa and should no longer be regarded as a 'nice-to-have' option.

5 Eskom Media Briefing on 3 November 2014. Available at http://www.eskom.co.za/news/Documents/141102_MajubaFINAL.pdf

UTILITY SCALE RE IN SOUTH AFRICA

This chapter explores the currently applicable RE legislated policy process and the associated renewable power capacity allocations. The WWF scenarios are summarised with context to current policy and balance of system concerns. The chapter concludes with a review of the process and status of the implementation programme for renewable technologies.

IRP

The efforts that led to the first IRP for electricity generation in South Africa can be described as an intensive and challenging learning experience that attempts to balance provision for the needs of different economic sectors, avoid socio-economic and environmental injustice, support the sustainable use of resources available and explore innovative technologies through research and project development.

As mentioned, the first goals for RE in South Africa were set out in the White Paper on Renewable Energy in 2003. This White Paper not only recognised the potential of RE in the country, it provided an outline of the vision, policy principles, goals and objectives of the government for including and promoting RE at a national level.

The White Paper was followed by the National Energy Act of 2008, which set the objective for a long-term Integrated Energy Plan (IEP) (DME 2008). Although the IRP was published as a subset of the IEP with the intent to be governed by the IEP, the IRP was promulgated in 2011 (DoE 2011), a year before the release of the draft IEP. A final IEP has still not been released at the time of this report. While legislation, policies and planning serve as basis for developments in the energy system, delays such as these and on this level are a fair representation of the level of complexity of the system.

Generally, integrated planning is considered an especially valuable tool for developing countries to address inequality issues, safeguard sagacious use of resources and ensure effective supply to meet the demand side (D'Sa 2005). Furthermore, integrated planning holds great potential for balancing objectives and minimizing direct and indirect costs (Dixit et al. 2014) compared to traditional electricity planning that involves a narrower range of considerations (D'Sa 2005). The IRP takes into account long-term demand forecasts based on various scenarios for economic growth, policy implementation and resource acquisition.

The Department of Energy (DoE) stipulated that the technical and financial data used in the IRP must be developed by an independent source, and the Electric Power Research Institute (EPRI) was approached to provide the necessary data for the 2010 IRP. For processes of updating the IRP, the EPRI updated the data for South African conditions. Furthermore, the EPRI incorporated technology enhancements and configurations, market factors and improvements with regards to cost estimates. All the data per technology is summarized in a report[6] written specifically for the purpose of the IRP.

The different scenarios in the IRP are developed using technical and financial data together with several assumptions – e.g., demand forecasts, economic growth rates and fuel costs, decision trees and recommendations. In order to develop the different scenarios, which take into account an array of complexities, the modelling of the electricity system is done with the powerful power market and system simulator tool, PLEXOS[7].

Resource availability and uncertainties associated with demand growth are considered in several scenarios using a stochastic programming approach. The anticipative method is included as one of the scenarios, where decisions can be made by the user before uncertainty is observed. The objective of all models is to minimize costs, but other constraints with regards to investment, load and generation are all inputs under which simulations are conducted (Fouché 2014).

IRP Update

Regardless of delays in the IEP, the IRP was updated in 2013, although a formal iteration of the second IRP is still pending. The Update was necessary in terms of the following aspects: renewed technology and fuel options, changes related to electricity demand and the relationship thereof with economic growth, possibilities for carbon mitigation and the price of electricity along with the associated impact on demand and supply after 2030 (DoE 2013a).

In the IRP Update, the CSIR Green Shoots demand forecast is considered for the Base Case scenario, causing the demand projection for 2030 to decrease from 454TWh to closer to 345-416TWh. The Green Shoots forecast plans for a 2.7% annual electricity demand growth up to 2030, and an aspirational average economic growth rate of 5.4% is considered as suggested in the National Development Plan. This growth rate is in line with poverty alleviation and a shift towards a less energy intensive economy, and the risks associated with overbuilding generation capacity should this growth rate not be realised are recognised.

The modelling parameters that were changed in the IRP Update are summarized in the IRP report[8] and pertain to instantaneous reserves, fuel price merit order, maximum load factors, unit commitments, minimum stable generation levels, capacity profiles and modelling updates for the demand, PV and wind profiles.

6 EPRI. 2012. Power Generation Technology Data for Integrated Resource Plan of South Africa. Final Technical Update

7 The PLEXOS Integrated Energy Model, developed by Energy Exemplar, is one of the most recognized of its kind.

8 IRP Update Report. Page 109.

In addition to the Base Case, several other demand forecasts, sensitivities regarding learning rates, fuel availability and costs, new build options and combinations of these parameters have resulted in 14 other scenarios in the IRP Update[9].

The IRP of 2010 is still recognised as the official plan of the government, but the IRP Update proposes seemingly valuable changes with the aim of improving the next formal iteration of the IRP.

WWF scenario

WWF proposes an increase from the 17 430MW allocated to CSP, PV and wind power collectively in the IRP Update to 35 018MW for a high demand and 17 518MW for a low demand scenario, which would represent 19% and 11%, respectively, of annual generation in 2030. These allocations are shown in Table 1 alongside the capacities for the IRP 2010 and the IRP Update.

Figure 9: **Sere 100MW wind power plant. Eskom, South Africa (STERG 2014b).**

The IRP Update makes provision for annual capacity build limits for solar (1000MW per year for PV) and wind (1600MW per year). The two proposed WWF scenarios remain within these limits.

The WWF scenarios do not include new coal builds beyond Medupi and Kusile. As discussed earlier, there are reliability concerns related to the current electricity system, one of these being the age of some of the coal power plants currently in operation. The aging fleet is recognised in the IRP, and apart from including an assumed decommissioning plan, it also indicates which coal power plants are likely to undergo life extension given the 'Weathering the Storm', 'Moderate Decline' or 'Big Gas scenarios'.

9 These scenarios are Systems Operator (SO) Moderate, SO Low, Weathering the Storm, Constant Emissions, Moderate Decline, Advanced Decline, Carbon Tax, Regional Hydro, Rooftop PV, Solar Park, Big Gas, Fuel Price Sensitivity, Learning Rates Sensitivity and Nuclear Cost Sensitivity.

In order to determine which coal power plants will still be operational in 2030, and for the objective of this study, life extension was added to the respective plants in line with the assumed decommissioning plan. Table 3 summarizes the coal power stations currently in operation and highlights the likely range of capacity of the known fleet in 2030.

Table 3: **The assumed decommissioning plan as given in the IRP Update. Note: Capacity stated by Eskom slightly differs from the IRP Update (Sources: Eskom 2011; DoE 2013a).**

ESKOM generation	Capacity (ESKOM)	2013 Capacity (IRP Update)	Capacity by 2030*	Capacity by 2030 with LifEx**
Arnot	2 352	2 220	0	0
Camden	1 510	1 520	0	0
Duvha	3 600	3 480	2 320	3 480
Grootvlei	1 200	1 080	0	0
Hendrina	1 965	1 900	0	0
Kendal	4 116	3 840	3 780	3 840
Komati	940	940	0	0
Kusile	0	0	4 800	4 800
Kriel	3 000	2 880	0	2 880
Lethabo	3 708	3 540	3 540	3 540
Majuba	4 110	3 840	3 840	3 840
Matimba	3 990	3 720	3 720	3 720
Matla	3 600	3 480	1 740	3 480
Medupi	0	0	4 764	4 764
Tutuka	3 654	3 540	3 480	3 540
TOTAL	37 745	35 980	31 984	37 884

** Assuming decommission schedule as presented in the IRP Update.*
*** Adding life extension to all plants except RTS and those older than 50 years in 2030*

The WWF scenarios also do not include new nuclear capacity. Koeberg's planned life span is 40 years; with a 20-year extension, it is scheduled for decommissioning in 2043/2044.

Furthermore, the capacities allocated to OCGTs and CCGTs remain the same for the WWF High Demand Scenario compared to that of the IRP Update Base Case. For the WWF Low Demand scenario, the capacities for both technologies are lower.

Figure 10: **Dreunberg 75MW photovoltaic power plant. Scatec Solar, South Africa (Scatec Solar 2014).**

For the purpose of this report, the majority of assumptions will be based on the Base Case scenario (according to the Green Shoots demand forecast) and will be viewed in comparison with the WWF High Demand and WWF Low Demand scenarios, of which the latter will also be compared to the Weathering the Storm (WTS) scenario. The WTS scenario is based on the CSIR WTS forecast with a GDP growth of 2.9% and an annual electricity demand growth of 1.8% up to 2030.

Figure 11: **Touwsrivier 44MW concentrated PV facility under construction. Soitec, South Africa (CRSES n.d.).**

The model used to analyse this proposal is a spatial-temporal model, and the description of the characteristics of this modelling method will follow in Chapter 6.

REIPPPP

To date, RE capacity is predominantly the result of the Renewable Energy Independent Power Producer Procurement Programme (REIPPPP). The programme, launched in 2011, is an initiative of the DoE that awards bids to applicants according to allocations set per technology. Initially, the total allocation to renewable generation was 3725MW, but by the end of 2012, an additional 3200MW was allocated and is expected to be online by 2020. At the time of writing, three rounds of allocations have been concluded. Financial closure for the Round 3 projects has not yet been reached due to complications beyond the control of the IPPs such as issues relating to grid connectivity. Round 3.5 was added to allocate extra CSP capacity and preferred bidders were announced in late 2014. Round 4 preferred bidders were announced in early 2015.

Figure 12: **Khi Solar One: 50MW central receiver. Abengoa, South Africa (Abengoa 2014b).**

Table 4 shows the capacity allocated to projects for different RE technologies throughout the bidding rounds already finalized.

The tariffs allocated to REIPPPP projects have become increasingly competitive with each bidding round and are, in instances, better than the expected generation costs for Medupi and Kusile. In the third bidding window, wind power projects had the lowest tariffs at R0.66/kWh, PV followed at R0.82/kWh, and CSP at R1.46/kWh. These tariffs were lowered even further with approximately R0.10/kWh for both wind and PV in the fourth bidding window[10]. The exception to the tariff structure for CSP lies in the benefit of receiving 270% of the standard tariff when a plant generates electricity during the evening peak demand hours. Despite this adjusted tariff for what is currently the most expensive RE technology, this tariff is already cheaper than the cost of OCGTs currently used as last resort to serve peak demand hours as per the IRP Update and also according to analyses by Silinga & Gauché (2014). This ability of CSP to supply both baseload and during peak hours makes it unique compared to other RE technologies and, consequently, a very promising RE technology for the South African environment.

10 Presentation by Department of Energy, REIPPPP: Bid Window 4, Preferred Bidders' Announcement. 16 April 2015.

Table 4: **Allocated capacities through the rounds of the REIPPPP. These projects are at different statuses in terms of grid connection and commercial operation (Energy blog 2014).**

Technology	Bidding window					Total	Allocation remaining
	1	2	3	3.5	4[2]		
Wind	634	563	787		676	2 660	660
PV	632	417	435		415	1 938	626
CSP	150	50	200	200		600	0
Small Hydro	0	14	0		5	19	116
Biomass	0	0	16		25	16	19
Biogas	0	0	0			0	60
Landfill	0	0	18			18	7
					Total	**5 037**	**1 488**

Figure 13: **Solana 280MW parabolic trough power plant in Arizona. Abengoa, USA (NREL 2012).**

Apart from successfully completing a very extensive application process and acquiring the necessary finance, the development and successful operation of REIPPPP projects also depend on available grid capacity. REIPPPP applicants are advised to access the Generation Capacity Connection Assessment in order to determine whether the intended location of a project is feasible with regard to capacity at substation and supply area level (Eskom 2014a). More about grid capacity and the transmission network is discussed in Chapter 5.5.

SYSTEM CHARACTERISTICS

This chapter defines the system characteristics used in this analysis and precedes an introduction to a description of the system and plant model in the next chapter. Definitions are supplied for time, space, demand, technology groupings, technology characteristics, resources and constraints such as water and transmission lines for the model. The chapter clarifies key system assumptions and simplifications.

Load profile

One of the significant outcomes of the IRP Update, compared to the IRP 2010, is that the projected growth in demand is lower than the IRP 2010 projections. Arguably, this could be due to practices such as electricity buy-back from intensive users, supressed demand due to supply side constraints, increases in electricity tariffs and enhanced energy efficiency; but the underlying growth curve indicates a lower-than-expected demand nonetheless (DoE 2013a). Although capacity is planned according to the expected annual demand peak, demand fluctuates during day, week and season cycles as illustrated in this section and is accounted for in the system.

System demand is referred to simply as 'demand', but demand and generation are both geographically dispersed and not synchronous. The result is that loads will vary on transmission lines resulting in dynamic stability and capacity limitations.

The model implemented in this report looks at overall demand with some recognition for these limitations. More specifically, the spatial-temporal model accounts for the expected system demand for every hour of 2030, and it also accounts, to a limited degree, for transmission line constraints for a greater renewable generating system to meet this demand.

The model accounts for four demand scenarios in 2030. Hourly demand in 2030 is assumed to take much the same form as is experienced now, with morning and evening peaks, weekend and public holiday dips and higher winter daily peaks. A complete hourly set of 2010 Eskom demand was used, and every hour was simply scaled with the ratio of annual 2030 scenario demand to total 2010 demand. No efforts were made to account for changes in behaviour or technology advances that aim to improve time-of-day demand balancing that might exist in the system in 2030. Accordingly, the 2010 shape of annual demand was assumed to be representative enough, likely more challenging to meet than a future demand-side managed system, and a level playing field for all scenarios.

For simplicity and to reiterate that this report does not aim to replicate or validate the analysis of the IRP, annual demand for each scenario is taken "as-is" and no discounting is performed for efficiency measures that might occur in future. Demand in this report needs to be satisfied by power generation only. The ratio multiples are given in Table 5, and in particular it should be noted that WWF High and the IRP Update Base Case scenarios are practically the same.

Table 5: **The multiples used to calculate hourly demand for 2030.**

Annual demand (TWh)	Scenario	Multiples
250	2010	n/a
358	WWF Low	1.430
407	WWF High	1.625
409	IRP Update	1.634
454	IRP 2010	1.816

The following figures give a sense of the typical daily and seasonal profiles from the 2010 national demand data. The figures were adjusted for the 2030 IRP Update Base Case.

Figure 14 shows the annual hourly maximum, minimum and average demand with the intention of illustrating the daily trends of current demand in South Africa. Figure 15 shows the system demand duration curve for a year. System duration curves guide planning for the amount of time needed for different types of generators. Figure 16 shows the daily peak, average and minimum for a year. This figure illustrates seasonal behaviour in the system as well as the impact of weekends and holiday periods such as Easter and Christmas.

Figure 14: **Minimum, average and maximum hourly demand based on the IRP Update Base Case scenario for 2030.**

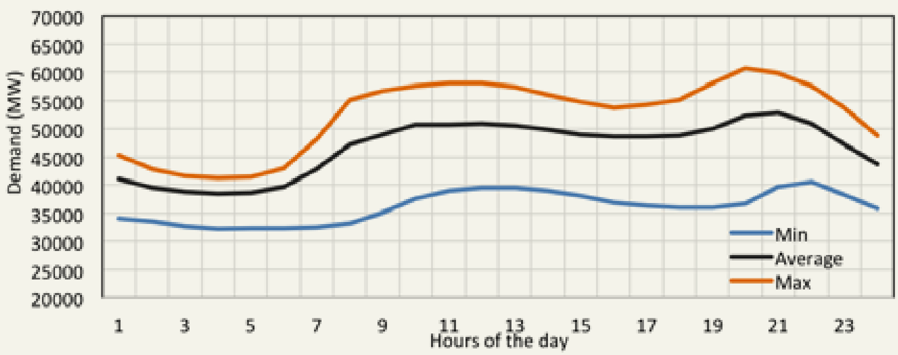


Figure 15: **System demand duration curve. Based on the IRP Update Base Case Scenario for 2030.**

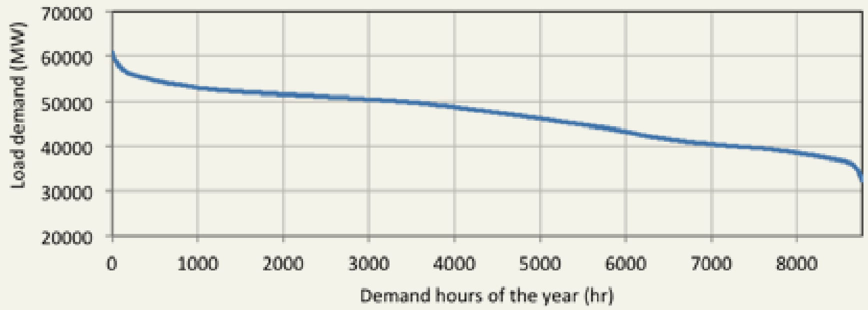
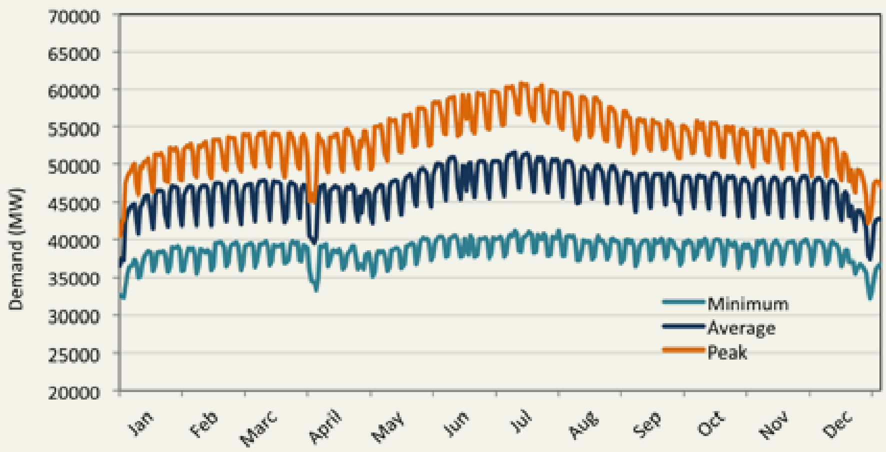


Figure 16: **Daily minimum, average and peak demand for a year illustrating seasonal, weekend and holiday behaviour. Based on the IRP Update Base Case scenario for 2030.**



The hourly characteristics were preserved for all scenarios in this analysis with the intention to test a future electricity network against the demand of winter, evening peaks and dips where power generation is not needed.

Technology characteristics

The performance characteristics and behaviour of each technology and, where possible, each known plant needs sufficient and fair definition in the model. These characteristics are a function of many variables including technology, local conditions, trends and forecasts. Additional complexity results from data sources that have differing definitions, contradicting characteristics or missing information. Power generation characteristics in the model result from a distillation of many sources requiring many assumptions.

Table 6 summarizes the technologies included in the proposed WWF scenario, and the following paragraphs outline key motivations for the choices made.

Ranges given for the costs of the various technologies aim to allow for variations from predicted costs in terms of learning rates, exchange rates and resource availability. The values given as upper and lower bounds are drawn from various sources, predominantly the IRP Update and Black & Veatch (2012). As pointed out in the methodology chapter, cost was modelled using a probabilistic (statistical) method, and the cost ranges result in the exploration of the full range between the high and low values. Specifically, a constant probability distribution was assumed in all cost ranges for lack of better foresight.

Capital costs given are estimates for the year 2022 in 2014 ZAR, the midpoint year for the years leading up to 2030. Technology costs in 2022 were assumed to represent an average for the duration in real terms.

'Investment' (or 'real') capital costs were used rather than 'overnight' capital costs. This accounts for cost of capital during the construction phase. In the case of coal power, only technologies that do not include carbon capture and sequestration (CCS) were taken into account on the assumption that cost and maturity risks are too high for South Africa in the next 15 years. The range for nuclear power was based on the IRP Update on the low end (R60,000/kW) and on other sources for the high end (under R90,000)[11]. No decommissioning or other externality costs were factored into the analysis.

The CAPEX range for CSP is represented for fixed plant configurations as typically found in the relevant literature, but the model uses a more detailed breakdown in order to correctly account for scaling the size of storage, turbine rating and collector field.

Operational costs are as given by the sources for the respective year; the reference year is 2012 for most of the technologies. Gas costs are according to the predictions made about gas acquisition in the IRP Update. A high degree of uncertainty notably exists around the availability of gas for the large additional capacity of OCGTs and CCGTs, and the following assumptions were made:

The significant new planned CCGT capacity will play a mid-merit to peaking role due to their characteristics. In instances where a scenario is underserved, the CCGT fleet will be permitted to operate as baseload. Accordingly, higher capacity factors were expected than for the OCGT fleet. Economically, it will be important that these plants run on gas, and therefore it was assumed that all CCGT plants will run on gas. The fuel cost range was based mostly on costs given in the IRP Update.

The even higher reliance on an OCGT fleet is a different matter. Assuming that the OCGTs could span the range from only relying on gas to only relying on diesel due to uncertainty around sourcing gas for all gas turbines, suggests that a range of costs warrants consideration. What must be kept in mind is that a fleet of CCGTs running only on gas will already significantly increase gas infrastructure needs. The upper value assumes super-inflationary diesel costs between now and 2030, and the lower value is given with the anticipation of higher gas availability in South Africa within the next ten years; this is similar to what is described as the 'Big Gas Scenario' in the IRP Update (DoE 2013a). This means that in this model the average outcome is that half the OCGT plants use diesel and half use gas.

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11 Initially, there were uncertainties about the correct range and it was decided to keep it wider in this study. Most recent data (IEA 2005; Black & Veatch 2012; UK Hinkley power plant) seems to be suggesting that when factoring in the construction time, the correct range centres around $9,000/kW, implying that the nuclear cost has been underestimated here. This is an item to revisit.

Table 6: **A summary of costs and technology characteristics for the options included in the proposed WWF scenarios. Sources: Black & Veatch 2012; DoE 2013a; IEA 2013; IRENA 2012a-d), WWF-SA 2014; Own analysis.**

Technology	Range	CAPEX R/kW	Fixed OPEX R/kW/a	Variable OPEX R/MWh	Fuel Costs R/GJ	Avail-ability	Turn-down limit	Ramp rate (%/min)*	Maximum Life Span (years)**
PV Fixed tilt	Upper	13 115	484	0	0	90%	NA		25
	Lower	11 210	208	0	0				
CSP – 6h TES	Upper	37 610	573	29	0	90%	0	6%	30
	Lower	36 726	573	0	0				
CSP – 9h TES	Upper	43 259	573	29	0	90%	0	6%	30
	Lower	42 242	573	0	0				
Wind	Upper	19 463	400	0	0	90%	NA		20
	Lower	14 502	310	0	0				
OCGT	Upper	5 738	78	0.2	500	90%	0	22.2%	30
	Lower	5 615	78	0.2	92				
CCGT	Upper	8 708	163	0.7	92	90%	0	5%	30
	Lower	8 524	163	0.7	70				
Nuclear	Upper	87 754	1017	29.5	10	90%	0.80	5%	60
	Lower	60 000	532	29.5	6.8				
Coal (PF with FGD)	Upper	34 938	552	79.8	22-35	80%–85%	0.40	2%	60
	Lower	34 894	368	51.2	17.5				
Pumped storage	Upper	56 846	333	0	0	90%	0	50%	60
	Lower	23 973	247	0	0				
Imported Hydro	Upper	28 341	344	13.9	0	66.7%	0	2%	60
	Lower	12 044	80.2	0	0				
Domestic hydro	Upper	28 341	344	13.9	0	96.6%	0	2%	60
	Lower	12 044	80.2	0	0				

** Represents spin ramp rate for baseload and intermediate load technologies and quick start rate for peaking technologies as per Black & Veatch (2012).*
***The maximum life span includes life extension plans for the coal-fired power plants.*

In addition to capital, operational and fuel costs associated with the various technology options, there is a cost to bear when electricity cannot be supplied due to limited generation capacity. This is known as the COUE[12], which encourages the system planner to balance the incremental costs of supplying the energy that was not served with the total COUE. The COUE is not a parameter that can be measured directly and varies greatly between customer sectors according to load segments and timing of unplanned electricity outages. The current COUE estimation ranges from R10/kWh (based directly on the relationship between GDP and total demand)

12 Department of Energy. Cost of Unserved Energy – IRP 2010 Input Parameter information sheet (supply input).

to R150/kWh (based on many other factors linked to the disruption in the provision of power). The IRP Update assumes R75/kWh, but given that cost is handled probabilistically, the extent of the IRP Update data range is simply used. On average, this study's result is similar to the assumptions in the IRP Update.

It is categorically stated, before analysis, that the entire broad range of COUE is higher in cost than the highest cost of generation of any of the technologies in this model. This simply and firstly implies that the cost of unserved energy is a completely avoidable item in the national interest.

The initial reason for accommodating the COUE is that this model simulates a complete year of generation and reflects all over- and under-generation. In scenarios with insufficient capacity, varying levels of unserved electricity were observed. In order to compare or improve scenarios using a single cost metric, COUE was added in all cases.

The technology characteristics in Table 6 are used as part of the performance definition in the model. More detail of how this works is given in the following chapters, but each is briefly explained here in context of the choices made.

Availability: Plant or technology availability requires explicit definition in this model as this is primarily driven by choices and realities regarding the reliability and maintenance of plants. Most values are typical, perhaps with the exception of coal power. 80% was chosen for coal plants prior to Medupi and 85% for all new builds based on assumptions made in the IRP Update as well as what was understood to be the harsh reality of the ageing coal power fleet. While 80% is low for such units, there was no basis to justify higher numbers. This has serious implications for the results.

Capacity factor: This was not provided as input. The model calculates these values and provides them as outputs.

Turndown limit: Turndown limits are relevant mostly to coal and nuclear, but other technologies have built-in rules governing lower limits to performance that are not useful at a plant level. It was assumed that nuclear plants can operate down to 80% of rated performance based on the way that Eskom manages the Koeberg plant. While modern nuclear plants as described in the references can apparently turn down to 50%, it was assumed that on a usage basis, predictable and maximum operation would be preferred. Regardless, none of the scenarios required much nuclear turn down, and assuming a lower value would not have changed the results much.

Ramp rate: It was necessary to govern how quickly a power plant can adjust its output at the request of the system. In the event that the system of plants cannot respond fast enough to changes in demand or changes elsewhere in the system (such as a very sudden system-wide drop in wind power), the model would simply be forced to under- or over-produce. The ramp rate values used are typical, and no noteworthy events were found in any scenarios.

Impact on water resources

WWF-SA recognises the demand on South Africa's water resources in a previous study[13] that identified the country's greatest water source areas along with the associated threats to these sources.

An additional benefit to a greater percentage of renewable electricity generation is avoiding the impacts of coal mining and wet-cooled coal power stations on water resources. Although new regulation prohibits new power plants from being wet-cooled, significantly reducing water consumption, existing coal power plants use an estimated 1.5% of the country's annual water consumption (Eskom 2010). Of the RE technologies proposed in the WWF scenario, CSP is the highest water user, but with dry-cooling, this is still much lower than that of wet-cooled coal power plants. Dry-cooled CSP plants use an estimated 0.25-0.3m^3/MWh compared to 1.9-2.1 m^3/MWh for wet-cooled coal power plants (IRENA 2012; Hughes et al. 2012).

The second National Water Resource Strategy (DWA 2013) confirms that surface water accounts for the primary water source of South Africa with a volume of 9 500 million m^3/annum being abstracted from dams and rivers. Groundwater is the only source in the greatest areas of the country and thus also a significant source. The groundwater yield was estimated at 2 000 million m^3/annum at time of writing, while the sustainable potential yield is 7 500 million m^3/annum at high assurance. The quantitative availability of water should, however, be put in context with other water quality and use related issues such as poorly treated wastewater, pollution, endangered water ecosystems and inefficient use of water.

Together with areas with high solar resources and proximity to the existing high voltage lines, the availability of water is also a determining factor for the placement of CSP plants in the arid Northern Cape. A Groundwater Resource Assessment for South Africa (DWAF 2006) indicates that although the availability of groundwater is lower than most other parts of the country, the exploitability factor of the groundwater resources in certain areas of the region is higher than the average for the country. The exploitability factor is a function of the probability of successfully establishing a borehole and the probability that it yields more than 2 l/s. The utilisable and potable potential of sources of the area proves to be lower than the eastern and southern regions of the country but is still available. These potentials take into account the availability of the resource after basic human need and ecological requirements are accounted for.

This study has assumed that the areas identified for renewable power projects, particularly CSP plants, have sufficient sustainable water extraction resources. This assumption was based on a migration towards solar tower technologies that achieve continued improvements in efficiency. However, it is recognised that water will remain a challenge requiring far greater scrutiny in the provision of electricity.

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13 WWF-SA report: An introduction to South Africa's water source areas, 2013. Available at http://awsassets.wwf.org.za/downloads/wwf_sa_watersource_area10_lo.pdf

Solar and wind resources

South Africa's past and current electricity generation system has been based on the availability of fossil resources, specifically coal (e.g. Scholvin 2014). In light of commitments to the UNFCCC and diversifying the electricity generation mix, it should be acknowledged that South Africa is well endowed with RE resources. However, an important difference between RE sources and conventional sources such as coal and/or gas is that RE sources are location-dependent, meaning electricity generation cannot occur in an area other than where the resource is located.

Compared to countries where greater levels of solar energy deployment have taken place, e.g. Spain and the U.S., South Africa has an exceptional solar resource. The potential for viable PV and CSP capacity calls for the investigation of two different measurements of solar irradiance. Global horizontal irradiance (GHI) is the basic measurement for PV projects, whereas direct normal irradiance (DNI) is the relevant measurement for CSP projects.

The largest part of South Africa has annual DNI levels greater than 2000 kWh/m^2, but in the north-western part of the country these values go up to around 3000 kWh/m^2. The country with the highest capacity of CSP and associated knowledge, Spain, has some areas with DNI values of 2200 kWh/m^2, but the majority of the CSP plants are in areas with 2000-2100 kWh/m^2 (GeoModel Solar 2013). Studies show that a difference in annual DNI from 2100 kWh/m^2 to 2600 kWh/m^2 indicates a decrease in LCOE of R0.28/kWh by 2020[14].

PV power plants in Germany currently generate power at R2.08/kWh at GHI levels of 1000 kWh/m^2. At 1200 kWh/m^2 the cost goes down to R1.11, and these values are expected to decrease even further by 2025. Again, South Africa's resources promise even more when compared to the 1800-2000 kWh/m^2 values in Spain where costs are as low as R0.83/kWh (Fraunhofer 2013), which compares almost perfectly with that of PV projects in bidding window 3 of the REIPPPP. However, South Africa's annual GHI values exceed that of Spain in the north-western part of the country where values higher than 2300 kWh/m^2 are mapped (GeoModel Solar 2014a&b). Taking into account these values along with positive learning rates and South Africa's emerging RE market, the prospect looks very promising.

Figure 17 and Figure 18 show the most recent GHI and DNI values across South Africa.

14 L. Crespo. The Spanish Experience and the South Africa's Opportunities in Solar Thermal Electricity. Presentation at CSP Leadership Dialogue, October 2014.

Figure 17: **DNI map of South Africa (GeoModel Solar 2014a).**

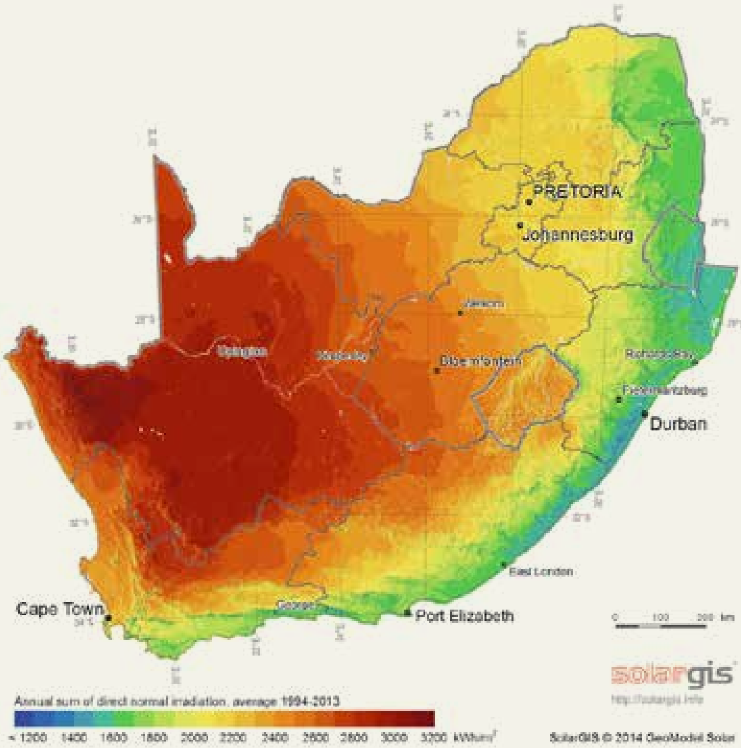
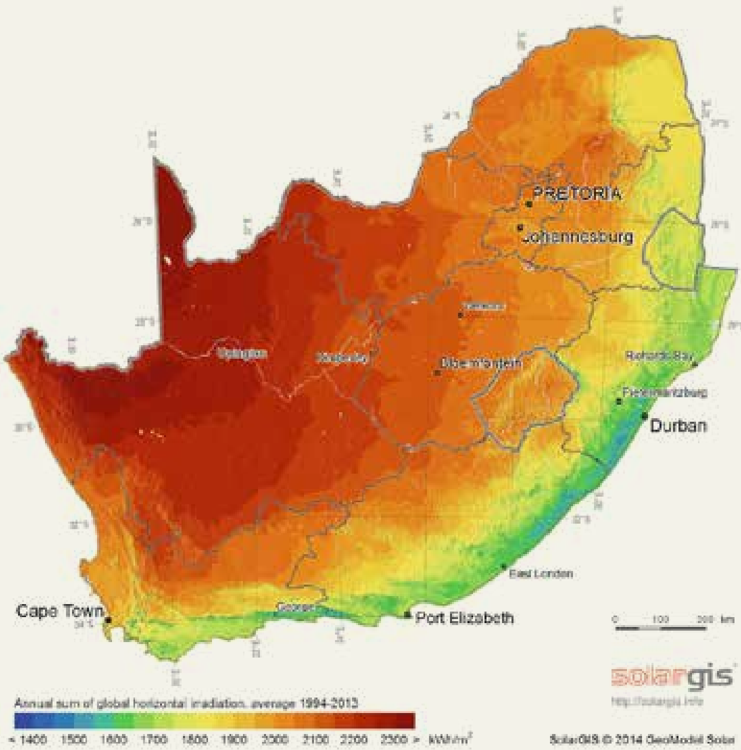


Figure 18: **GHI map for South Africa (GeoModel Solar 2014b).**

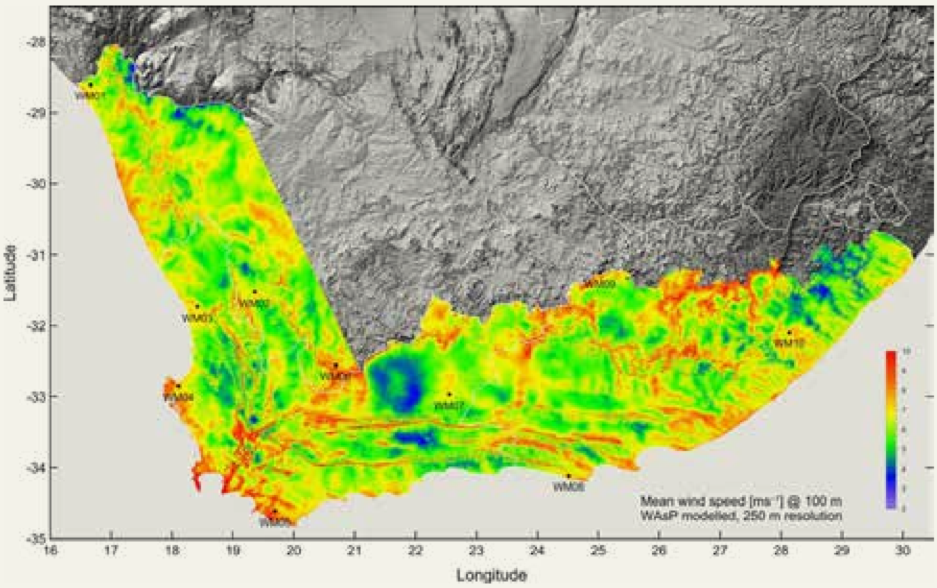


These annual solar resource maps show multi-year annual averages based on data obtained and derived from satellites in increments of 15 minutes. GeoModel Solar licensed solar and weather data is used in this project. The data is averaged hourly and has a spatial resolution of about 500m. Real 2010 data is used to coincide with the Eskom 2010 demand data. In non-technical terms, it is known when and where it is fully or partially sunny or fully cloudy at the points of interest. This information enabled the accurate prediction of CSP and PV performance in a spatial-temporal manner.

Variations in wind speed occur between summer and winter and on a diurnal vs nocturnal scale. Short timeframe variations such as inter-minute to inter-hour differences are insignificant compared to the more stable daily and seasonal patterns. More information on what this variability means for grid integration is presented in Chapter 5.6.

South Africa has wind resources competitive with those of countries with the biggest markets for wind power15. Figure 19 is the wind resource map for the Eastern Cape, Western Cape and Northern Cape as developed for the Wind Atlas of South Africa (WASA) project and the DoE. This map was specifically designed for GIS-based Strategic Environmental Assessments (SEA) for wind power projects in this region (CSIR 2014). The WASA data is regarded as the most accurate and reliable wind data available and hourly wind data for 2010 was retrieved for all sites of interest.

Figure 19: **Wind resource map for the Western, Eastern and Northern Capes based on Strategic Environmental Assessment (SEA) (CSIR 2014).**



15 Presenation by K. Hagemann. Available at http://www.sanea.org.za/CalendarOfEvents/2013/SANEALecturesCT/Feb13/KilianHagemann-G7RenewableEnergiesAndSAWEA.pdf

Transmission network

Generation reliability, grid stability and transmission capabilities usually need to be considered simultaneously in energy systems analysis. While generation is modelled in some detail, this study does not account for transmission stability or capacity limitations in detail. The existing transmission system and publically known transmission plans have been used to guide the definition of the WWF scenario, which tests the viability of RE generation in proximity of the current transmission system.

Apart from Eskom's role as the primary electricity supplier, it is also the sole transmitter, or Transmission Network Service Provider (TNSP), in South Africa. Based on the generation scenarios of the IRP, the main plan relating to the transmission grid is the Strategic Grid Plan (SGP) that covers a planning horizon of 20 years. The SGP also provides input for the Transmission Development Plan (TDP) that covers a shorter planning horizon and is revised on an annual basis.

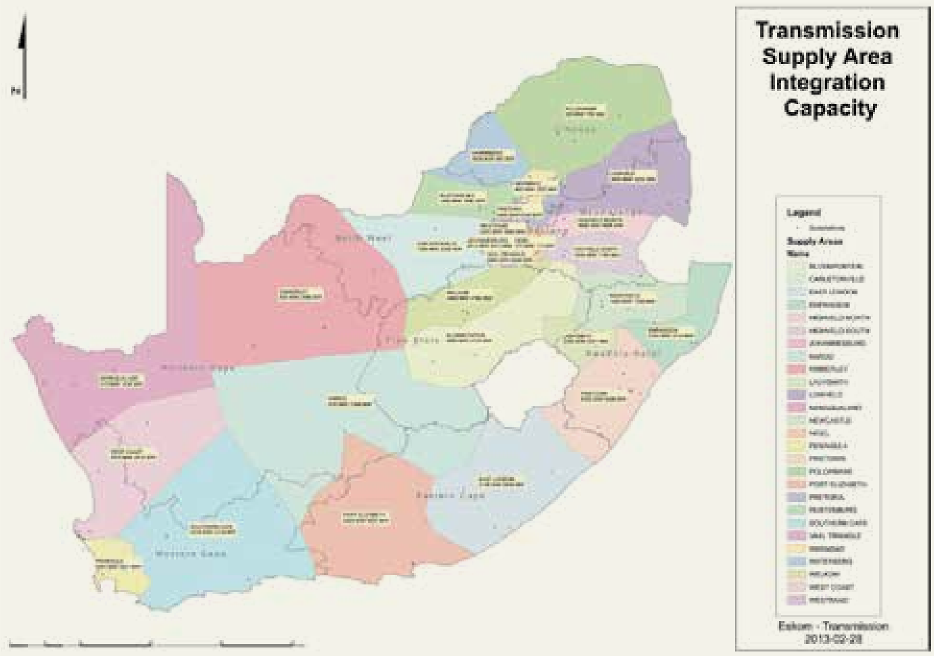
Figure 20: **The current transmission network of South Africa (Googlemaps 2013).**

Connecting RE power plants located in areas of high resource availability and low electricity demand is a problem that is likely to continue for some time due to limited existing transmission infrastructure, assumed funding constraints for expansion and time needed for approvals and construction. A relatively concise view on the current transmission system is provided as an indication of what will be needed for developers to connect new projects to the Main Transmission System.

Eskom's Generation Connection Capacity Assessment for the 2016 Transmission Network (GCCA 2016) (Eskom 2014a) was released in 2013 and revised in June 2014. Figure 20 shows the current main transmission grid across South Africa.

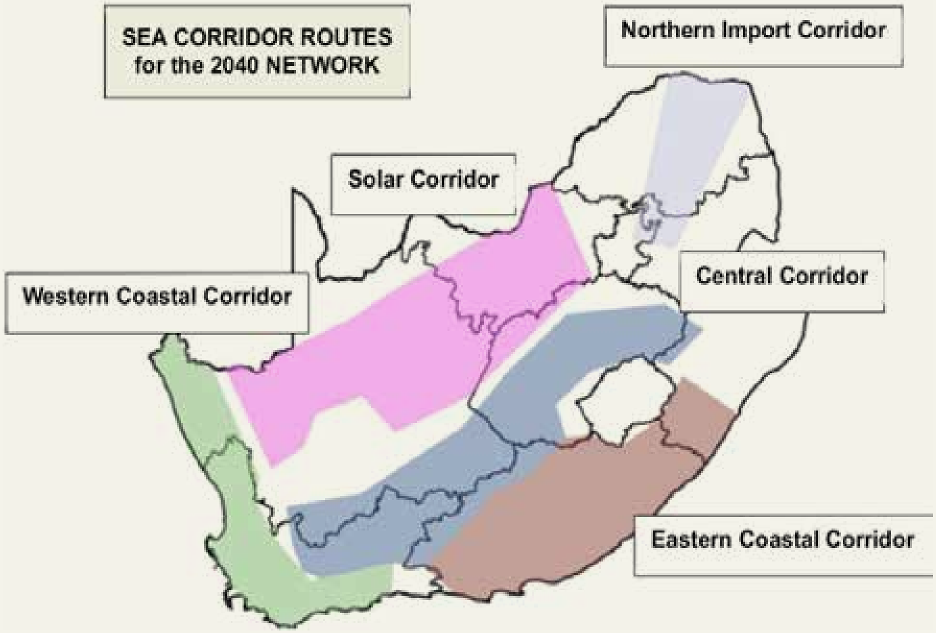
The GCCA 2016 states that even though connections from RE projects are at distribution level, new connections might be delayed due to capacity constraints at transmission level. Figure 21 shows the supply areas of the main transmission system (MTS) into which the transmission system is divided. This report makes use of generation capacity available to RE projects as a guideline for regional and local capacity limits.

Figure 21: **Supply areas of the Main Transmission System as given in the GCCA for 2016 (Eskom 2014a).**



The IRP Update's transmission impact indicated that to enable key generation scenarios, five Transmission Power Corridors will probably be required, see Figure 22. This impact assessment was conducted by locating future generation capacity in a spatially reasonable manner according to knowledge and information available at the time. The IRP Update explicitly identifies opportunities to improve future location strategies for generation capacities, a key value of the spatial-temporal method used in this study.

Figure 22: **Transmission corridors as per the IRP Update (DoE 2013a).**



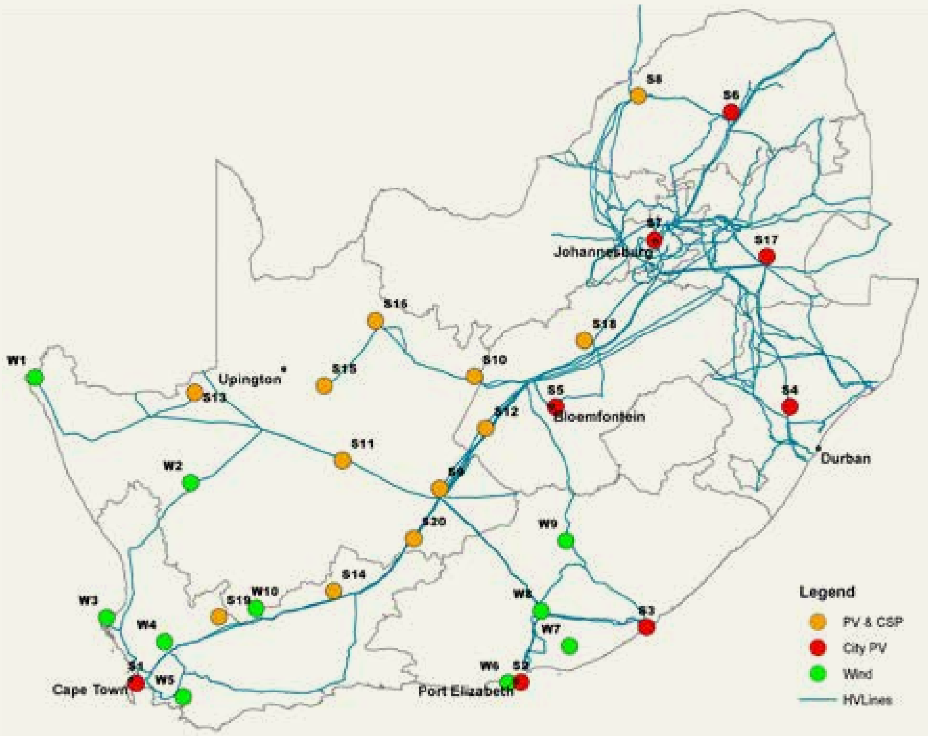
Node selection

Defining the location and limitations of RE capacity for the WWF scenario is the final step in defining the system. No single analytical method was used to synthesise all assumptions and definitions. Rather, a selection of nodes were chosen in order to attempt a practical and fair balance given all constraints. Key factors in this selection include:

- Locating very close to the existing transmission system in order to comply with the assumption that this will reduce the cost burden of transmission, particularly in the near term.
- Experience gained in prior work confirming that distributed RE generation can be cost-effective and meet demand.
- Selecting locations that have good to excellent renewable resources whilst also offering resource independence.

The generation areas (nodes) for PV, CSP and wind selected for this study are shown in Figure 23. These points are consistent with the five corridors mentioned before with the exception of three points in the eastern and north-eastern region of the country that were selected at points of consumption. Each node is located at or close to an existing Eskom substation in order to satisfy the assumption on cost. Although recognised that the substations themselves are generally not sufficient now to attach new capacity, the model relies on an assumption that the regional transmission line capabilities are not a major constraint within the definition of the MTS. Additionally, the nodes must be able to accommodate additional renewable power within a 20km radius of the substation in order to contain the additional cost of low voltage lines between the plant and substation.

Figure 23: **CSP, PV and Wind nodes selected for the model in this report.**



Node capacities are constrained based on the MTS connection limits of the GCCA 2016 and shown in Table 7.

The limits set out in the GCCA for 2016 are respected at the regional extraction levels in the model. Beyond this, the model contains no futher definition of the transmission or connection system.

The additional assumption that a high RE scenario is likely no greater a cost burden than other future scenarios is illustrated conceptually in Figure 24 a and b.

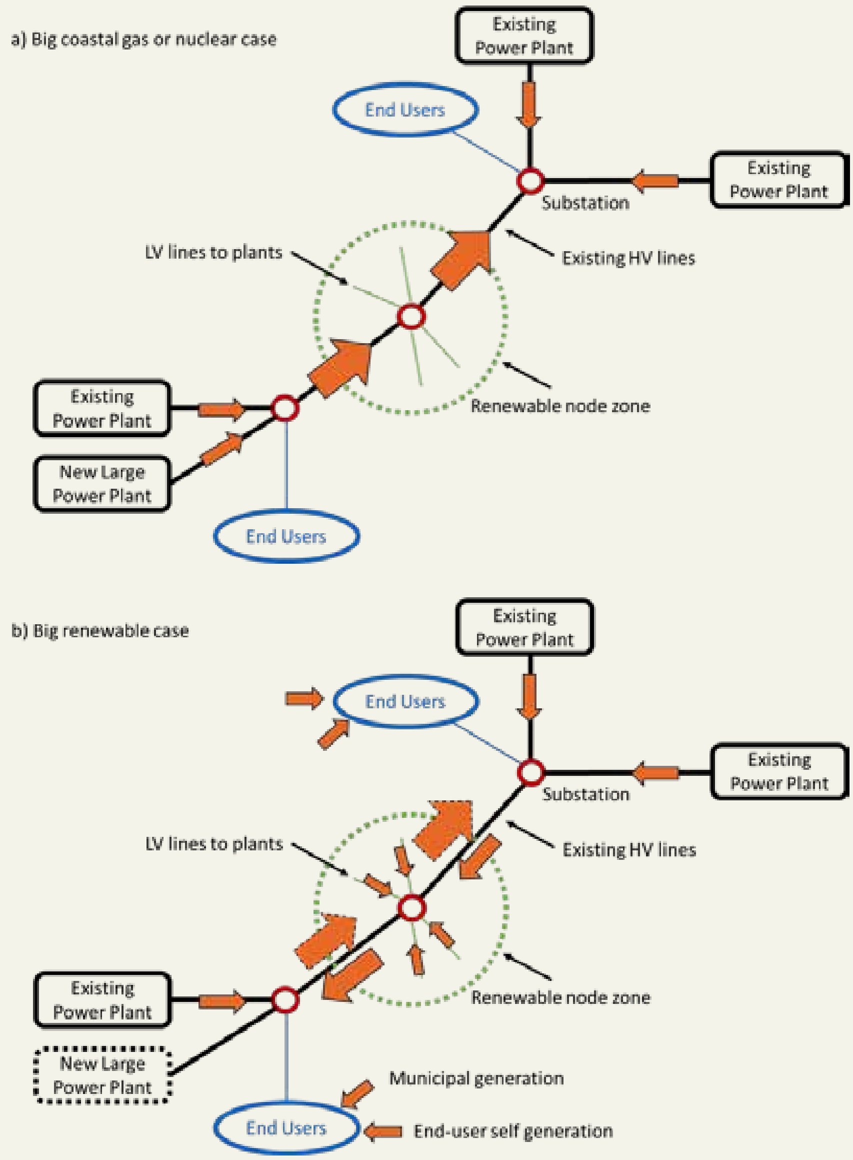
Table 7: **Grid connection limits per node according to supply areas within the MTS (Eskom 2014a).**

Renewable Energy nodes				Limits in MW		
Supply Area	Techno-logy	Name	Point ID	Lowest	Lower	Upper
Bloemfontein	PV	Bloemfontein	S5	2 370	2 865	4 745
East London	PV	East London	S3	1 210	3 145	3 898
	Wind	Dorper wind farm	W9	1 210	3 145	3 898
Highveld North	PV	Witbank	S17	2 808	4 685	4 685
JHB	PV	Johannesburg	S7	2 734	2 815	4 315

		Renewable Energy nodes				Limits in MW
Supply Area	Techno-logy	Name	Point ID	Lowest	Lower	Upper
Karoo	PV + CSP	De Aar	S9	167	670	2 398
	PV + CSP	Prieska	S11			
	PV + CSP	De Aar North	S12			
	PV + CSP	De Aar South	S20			
Kimberley	PV + CSP	Kimberly	S10	293	830	2 580
	PV + CSP	Groblershoop	S15			
	PV + CSP	Kuruman	S16			
Namaqualand	PV + CSP	Pofadder	S13	174	470	1 235
	Wind	Alexander Bay WASA station	W1			
Peninsula	PV	Cape Town	S1	2 484	3 251	3 251
	Wind	Gouda wind facility	W4	2 484	3 251	3 251
	Wind	Dassiesklip wind energy facility	W5			
Pinetown	PV	Pietermaritz-burg	S4	47 65	6 800	5 466
Polokwane	PV	Polokwane	S6	390	520	735
	PV + CSP	Lephalale	S8	390	520	735
Port Elizabeth	PV	Port Elizabeth	S2	1 431	3 325	3 523
	Wind	Metrowind	W6	1 431	3 325	3 523
	Wind	Waainek wind power	W7			
	Wind	Nojoli wind farm	W8			
Southern Cape	PV + CSP	Fort Beufort	S14	558	3 318	3 318
	PV + CSP	Laingsburg	S19			
	Wind	Mulilo wind	W10			
Welkom	PV + CSP	Welkom	S18	1 500	4 865	4 765
West Coast	Wind	Khobab wind farm	W2	1 145	2 616	2 616
	Wind	Aurora wind power	W3			

Meaning of Lowest, Lower and Upper limits	
Lowest	2016 Generation limit; i.e. steady state for area according to capacities, committed generation, busbar and transformer limits at substation level.
Lower	Steady state; i.e. MTS supply area level according to Grid Code.
Upper	Stability; i.e. technically feasible integration into Transmission system.

Figure 24: **Conceptual transmission burdens based on two scenarios a) Big coastal gas or nuclear case and b) Big renewable case.**



The current transmission system incurs losses around 10% due to long transmission distances. Most electricity consumption centres around the Gauteng region with most power generation in the north-eastern part of the country. In most 2030 scenarios, this report assumes that while total demand rises, power generation in the traditional north-eastern region drops and new generation occurs at even greater distances from the economic hub around Gauteng.

Figure 24a conceptually illustrates scenarios dominated by gas and or nuclear power. Very large loads are transmitted from the new generators to the end user. Figure 24b conceptually illustrates the WWF scenario alternative where RE capacity also occurs away from the north-eastern region. Due to the distributed nature of the generation, the burden is lower in portions of the transmission system. In all scenarios, significant transmission expansion is assumed.

While this is conceptual and requires detailed analysis, the definitions and assumptions in the model lead to an assumption that all scenarios carry an equal (and significant) cost burden for transmission upgrades over time. Because this is not quantifiable, the objective of this report is limited to the cost of generation only.

Managing variability and intermittency

This study does not directly consider sub-hourly fluctuations that could impact the stability of transmission, particularly from wind and PV generators. The implication is that items such as wind gusts that cause surges or cloud movements that cause relatively sudden changes in outputs to individual PV installations are not quantified. These matters are generally treated in the design of the plant and the local transmission infrastructure. Several countries have already achieved RE capacity fractions significantly beyond the scoping in this report for 2030. While transmission burdens and mismatches between demand and generation are well known in countries that have pioneered these efforts, local grid stability is not seen as a primary concern. South African grid codes and standards certainly require assessments to be done regarding intermittence at short time scales. Nye (2014) researched the effects of intermittence in PV plants for Eskom grid code compliance and found that for a larger PV plant, the rate at which clouds change outputs is generally of little concern. Nye also makes various technical proposals that permit high penetration levels of PV.

Similarly for wind, large wind farms have tens of turbines or more resulting in plant-level, self-regulation of power output to the grid due to wind gusts not impacting all turbines at once.

CSP is fundamentally different in that the technology is based on conversion of solar energy; first to thermal energy and then to electricity. Without thermal storage, a CSP plant has sufficient thermal inertia in the timeframe of several minutes. Future CSP plants in South Africa are likely to all have significant thermal storage capabilities, raising their availability status to dispatch-capable rather than intermittent.

Variability and intermittence is otherwise an intrinsic matter to this project in that the fluctuations of all power outputs were captured at each node at each hour. By keeping within the GCCA capacity limits, grid stability concerns are assumed to be minimal and over- and under-generation is directly quantified at each hour.

Figure 25: **One of the 46 Siemens 2,3VS-108 turbines at Sere wind farm, rated at 2.3MW each. Eskom, South Africa (STERG 2014c).**

SPATIAL-TEMPORAL MODEL

With technologies and system constraints described, the report now addresses the spatial-temporal model. This section covers some basics of the approach, both at the system level and at the individual plant level. The actual scenarios follow in the next chapter.

Role of spatial-temporal modelling

Energy systems modelling originated out of a long era of electricity systems comprised mostly of conventional energy technologies. These modelling platforms have been refined to handle system optimization on a stochastic or probabilistic basis due to the large size of multi-year optimization models and the scarcity of good resource data. Another way to put it is that they lack geographical definition and are dependent on appropriate descriptions of technologies, their input resources and availability assumptions in order to produce good results. This has two key implications:

- Results are as good as the assumptions in the model, not just in the validity of the model, but also in the boundary conditions of each power plant or technology.
- These methods can quantify total capacity of a technology needed at a particular time (dependent on model validity) but cannot provide accurate guidance on where the technology should be placed. Placement is based on the consideration of resources and constraints outside of the model.

The latter implies that configuration of systems with a high renewable fraction is a potentially serious problem.

Spatial-temporal modelling methods fit into the “emerging approaches” category for energy system modelling. Although not yet commonplace, the ability to discretely recognise resources spatially and in time is increasingly acknowledged as vital in the optimal configuration of future energy systems (Pfenninger et al. 2014).

Spatial-temporal modelling has the potential to overcome the limitations of conventional models particularly because the definition of a power plant’s environment is implicit. All other things being equal, this means that

- Technologies do not need to be defined behaviourally by default. As an example, the capacity factor of a PV plant is not an input to the model, but rather a result of the model.
- System-wide performance is known deterministically at each time step making the system resources at that time dependant rather than independent, as is the case in a stochastic model. This results in the ability to optimally place capacity and technology type for the benefit of the system.

These more discrete approaches have their own challenges. Besides the higher computational demand, as well as the reliance on accurate resource information in time and space, these methods require long sequential periods of historical data in order to produce statistically reliable energy systems.

Key limitations of the model

The first major limitation in this study relates to the data set. The 2010 year is the only complete year for which hourly data for demand and renewable resources is available. This 2010 data set was used and scaled for the needs of the 2030 scenarios.

RE resources can vary significantly over time and the spatial-temporal method requires multiple years of data to produce reliable results.

The 2010 data set is fully synchronous, meaning that actual demand, resource and environmental conditions are somehow linked. As an example, it is clear in the data that winter evening peaks are higher when ambient temperatures are lower. Similarly, summer days that are hot and generally windless disrupt the so-called "Table Mountain" summer profile. The implication is that while a longer timeframe is required for reliability, the single year model accounts for factors linking climate to electricity consumption.

Multi-year analysis, however, is certainly required in the event that the method is adopted for national planning.

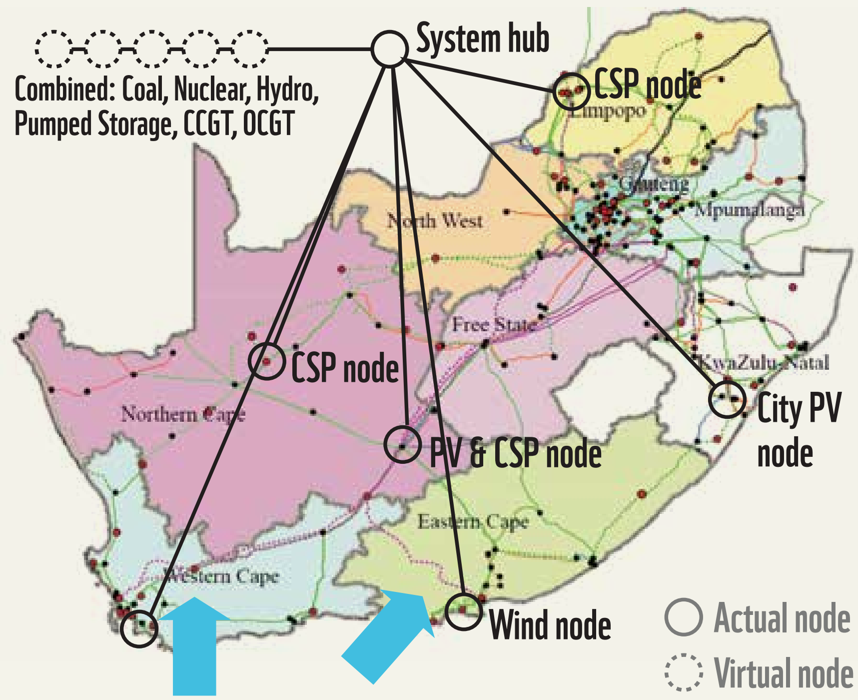
Many other assumptions were made in the model relating to the handling of availability, performance, merit loading of plants and other details that are simply neither feasible nor valuable for the objective. Perhaps the most notable assumption is in the implementation of availability. In all plants, availability is accounted for as a technology or plant efficiency. Due to variations in scenario definition, the large number of plants in the system and for the sake of simplicity and comparison, discrete scheduled and unscheduled maintenance in the model was not applied. One variance is the assumption that the majority of scheduled maintenance for coal power plants occurs during summer. This balances the seasonal impact, particularly of solar power.

A secondary goal of this report is to demonstrate the benefit of a spatial-temporal approach and define it sufficiently to illustrate the merits of a high renewable scenario.

System

The electricity system comprises multiple nodes, some of which are virtual while others are spatial. Virtual nodes represent conventional power plants where performance is not significantly linked to location. Figure 26 illustrates the concept of nodes in conjunction with the transmission system and current weather at a point in time.

Figure 26: **A map of major Transmission Development Plan projects for 2015-2024 broadly indicating the node concept, the reasoning behind selecting the RE nodes in this project. Background image from the Transmission Grid Planning Team (Eskom 2014b).**

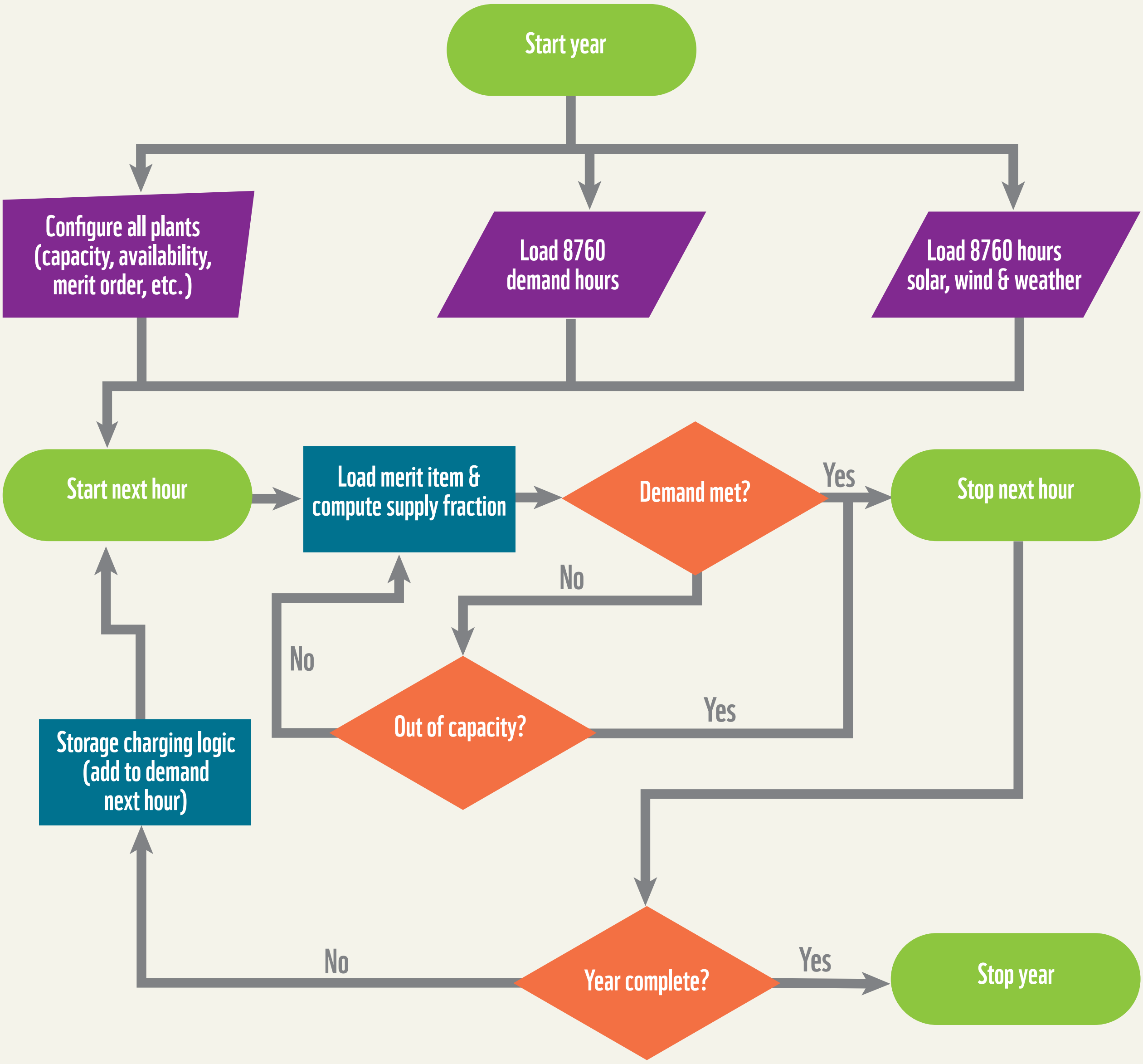


The system is controlled by the system hub, which is responsible for balancing system demand with total system generation. The overall flow process of the system model is illustrated in Figure 27. The model requires configuration of the system, which consists of the following key items:

- A cascaded system of technologies and nodes
  - System rules
    - Merit order (the priority order governing which power plants or technologies supply power to meet demand)
    - System notification event rules such as pumped storage level indicators that trigger capacity allocation
    - Regional capacity constraint monitoring
  - Virtual nodes (e.g. Coal)
    - Power plant description by technology or to the level of individual plants where possible
    - Availability factor for the virtual node (seasonally adjusted for reserve margin)
    - Cost ranges
  - Renewable technology nodes (e.g. Wind)
    - Each node representing a 20km radius area near a substation with potentially multiple power plants of varying capacity and configuration
    - Each node configurable for total capacity and plant scaling (for CSP)
    - Substation capacity limits
    - Area capacity limits
    - Technology availability factors
- Demand for 8760 hours of the year

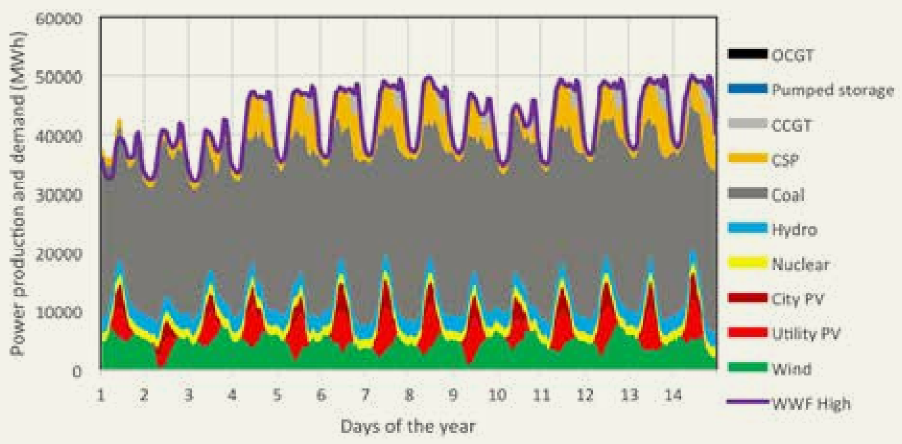
- Resource information averaged for the same hours and for every geographic node
    - Wind speed
    - Ambient temperature
    - Direct sunlight (Direct Normal Irradiation – DNI)
    - Total sunlight (Global Horizontal Irradiation – GHI)

Figure 27: **High-level system logic flow diagram.**



With the configuration set and data loaded, the simulation steps through each hour of the year. This process results in a time series of power produced broken down by technology (and plant where possible) compared with demand. Figure 28 provides a graphical example of the output for the first 17 days of the year for the final WWF High scenario.

Figure 28: **Example of the time series result of the spatial-temporal model where the horizontal axis shows the day of the year (WWF High scenario). In all of the time series plots, the purple line represents demand for that scenario.**



The time-axis plot in Figure 28 illustrates some important attributes of the modelling method.

- Capacity factor is calculated: In the example, coal power has a generating ceiling around 30GW, illustrating total coal availability at that time. Coal power plants that are not generating due to maintenance are excluded, but the model permits the coal power plants to reduce performance in the system to accommodate other generators. This adjustment results in a calculated capacity factor that will generally be lower than the availability factor.
- System demand is matched to generation most of the time. In the example, there are events showing generation that exceeds demand. This is shown intentionally. Mismatches can occur in the following cases:
  - When pumped storage systems are not full and spare capacity is available to charge them, given rules in the system, the energy required to charge the pumped storage is not recognised as demand. In these events, total generation exceeds demand by the amount of energy used to increase storage levels. The events on day 1 in Figure 28 represent such a case.
  - When the system cannot react fast enough to changes in demand or changes elsewhere in the system, over- or under-supply would occur. This was not observed in any scenarios, even with the highest levels of renewable generation reported.
  - If over-production of RE resulted in a last resort violation of the turndown limits of coal and nuclear, the over-production was simply permitted. Rare instances were observed in some scenarios.
  - Unserved energy due to capacity shortfall at any time was experienced frequently and is discussed in further detail in the next chapter.
- The timing and scale of power produced by renewables is central to the objective of this report. As power generation is a result of the model and not prescribed at any level, results immediately offer insight regarding the merits and drawbacks of the system. A few details from Figure 28 are worth pointing out:
  - Around New Year's weekend (1 January, occurring on a Friday), three days of low demand resulted in significant fuel savings in the system. Coal power generation reduced significantly, CSP was indeed suppressed or used for pumped storage charging and no emergency generators were needed.

- On day 14 (a Thursday – it becomes easy to identify the day of the week because most weekends have lower demand), notice that the combined solar, wind and CCGT capacity were not sufficient to satisfy the evening peak. In this case, the pumped storage systems were able to fulfil demand. Excess solar power the following day was used to re-charge the pumped storage at some expense to reducing coal consumption.

Outputs and cost model

With a simulation complete, hourly results are processed into various types of output as summarized in Table 8. With the outputs of the system model complete, probabilistic cost modelling follows.

Two simple methods of determining a LCOE were used and both were found to provide good relative costs for each scenario. A fuller definition of LCOE which accounts for the time value of money, was not used due to the static definition of the model and the complexity of the system.

Simple LCOE based on life of plants in the system

Per plant:

$$\text{LCOE\_life} = \frac{(\text{lifetime cost of capital} + \text{lifetime fixed OpEx} + \text{lifetime variable OpEx} + \text{lifetime fuel cost})}{\text{lifetime generation of power}}$$

Because of the variations of completion date and life expectancy of plants, the cost in a single year is unknown, but the long-term effective cost is known. In order to estimate the cost in a given year, the other approach was used, which is equivalent to the simple LCOE used by NREL and the WWF scenario (WWF 2014).

Simple LCOE based on a given year

Per plant:

$$\text{LCOE\_year} = \frac{(\text{annual cost of capital} + \text{fixed OpEx} + \text{annual variable OpEx} + \text{annual fuel cost})}{\text{annual generation of power}}$$

System LCOE

The system LCOE is the sum of the plant LCOEs plus the system COUE, weighted by individual plant and system annual power produced.

$$\text{System LCOE} = \frac{(\Sigma\,(\text{LCOE x annual power})\text{plant} + \text{COUE x annual unserved electricity})}{\text{annual system demand}}$$

Table 8: **Summary of outputs of system model.**

Level	Output	Note
System	Annual power generated (TWh)	
	Fraction of annual demand to annual power generation	Usually < 1.0 due to pumped storage charging
	Annual power generation for renewables (TWh)	For wind and solar only
	Fraction of power generation for renewables to annual demand	A key measure in the study
	Annual system shortfall (TWh)	The amount of energy not served (load shed)
	Number of equivalent load shed hours per year assuming 10% of system is load shed	Simple and convenient measure of load shedding
	Annual system surplus (TWh)	When there is too much supply from renewables and the whole electricity system could not drop capacity elsewhere
	Number of equivalent surplus hours per year assuming 10% of system curtailment	Simple and convenient measure of curtailment (energy dumping)
	Cost per year (R/year)	Bounded by cost ranges
	Cost per energy unit (R/kWh)	Based on 2 approaches: Simple lifetime LCOE and simple LCOE for that year
Technologies	Annual output per technology (TWh)	All nodes for that technology
	Capacity factor (Cf)	On a technology and node basis if required
	Fraction of system generation per technology	
	Cost per year per technology (R/year)	Bounded by cost ranges
	Cost per technology per energy unit (R/kWh)	Based on 2 approaches: Simple lifetime LCOE and simple LCOE for that year

For system LCOE, the model generates a probability distribution of cost, cumulative distribution of cost, mean cost and standard deviation (where sensible). This was achieved by running 300 Monte Carlo-type cost simulations for each scenario to determine the system cost probability data.

Figure 29: **Example of cost probability: Case of the WWF High scenario.**

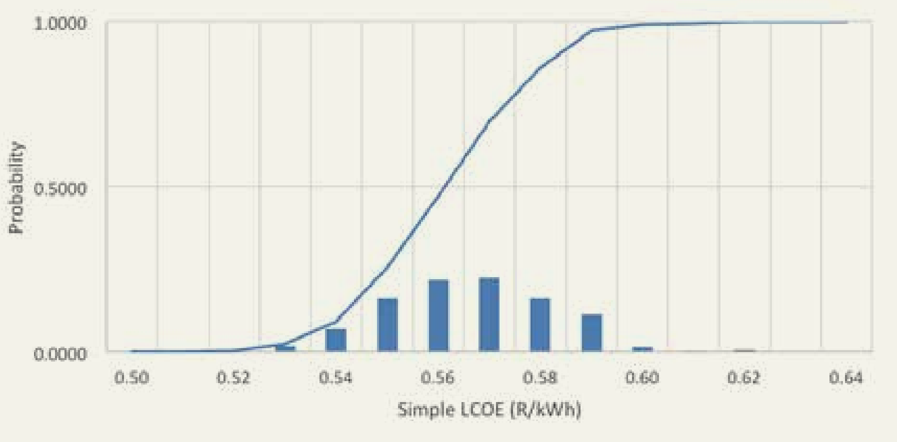


Figure 29 illustrates one scenario, namely the cost probabilities of the WWF High scenario. The solid line is the cumulative distribution curve of simple LCOE. This is a cumulative summation of the cost histogram (probability distribution), which is represented in histogram format above (and later, simply as a dotted line).

In this example, the result indicates that it is not possible for the system to produce power at less than R0.50/kWh (on average). There is a 50% probability that the average cost will be less than or equal to (just under) R0.56/kWh, and in all cost futures, this system will generate at an average cost of less than R0.63/kWh. The confidence of this range is dependent on the reliability of cost limits given in Table 6.

For the same data, a normal distribution produces a mean of R0.56/kWh and a standard deviation of R0.0165/kWh. The standard deviation provides a single metric of the degree of cost uncertainty in the scenarios. A single standard deviation represents 68% of probabilities in a normal distribution, to which the results generally adhere.

A cost probability approach was used in this project to avoid speculating on unknowns. The IRP methodology considers various contingent scenarios, and it optimises the system according to these futures. The IRP Update considers scenarios relating to higher cost nuclear, big gas, rooftop PV, reduced learning rates and carbon tax (climate change mitigation). In each case, the optimal system ends up very different and perhaps unnecessarily complicated. By assigning cost ranges to all contingent futures, the goal was an electricity system that is lowest cost with high certainty in terms of both mean and variance.

Each system was tested against all demand projections to quantify cost robustness due to demand uncertainty.

Electricity generation technologies

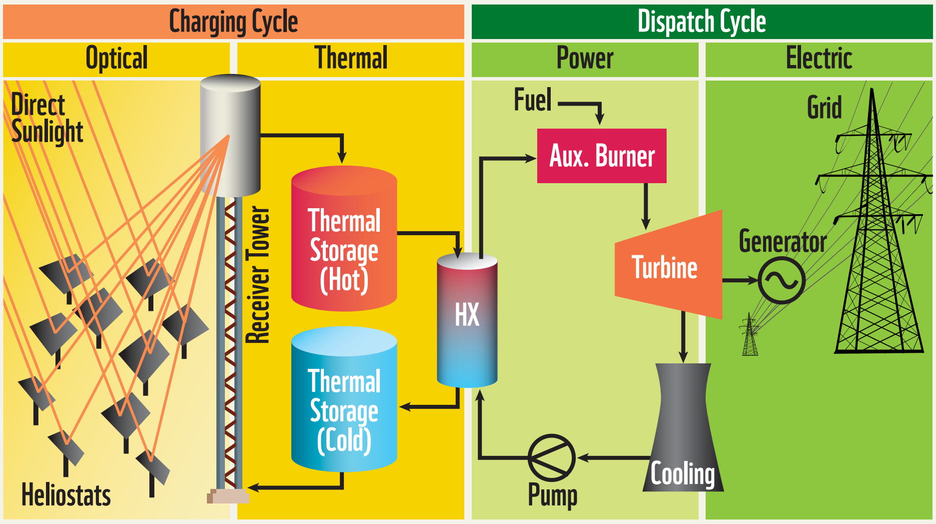
CSP

Besides hydropower, CSP is the one RE technology applicable to South Africa that can viably store and deliver electricity based on need, albeit restricted to the availability of its own storage system.

The CSP model used and adapted for this study is a systematic model of a CSP tower system by Gauché et al. (2012) and is conceptually illustrated in Figure 30. The system has two distinct and mostly independent cycles (Figure 30).

The basic logic of how the technology collects and dispatches electricity is illustrated in Figure 31.

Figure 30: **Illustration of the basic model layout of a molten salt storage central receiver CSP plant.**



Charge cycle: The solar collector system that focuses concentrated sunlight to a receiver that converts to high temperature thermal energy. This thermal energy charges a thermal storage system, provided the storage is not full.

Discharge cycle: The power plant aims to deliver power to demand by depleting the storage system as needed, provided the storage is not empty.

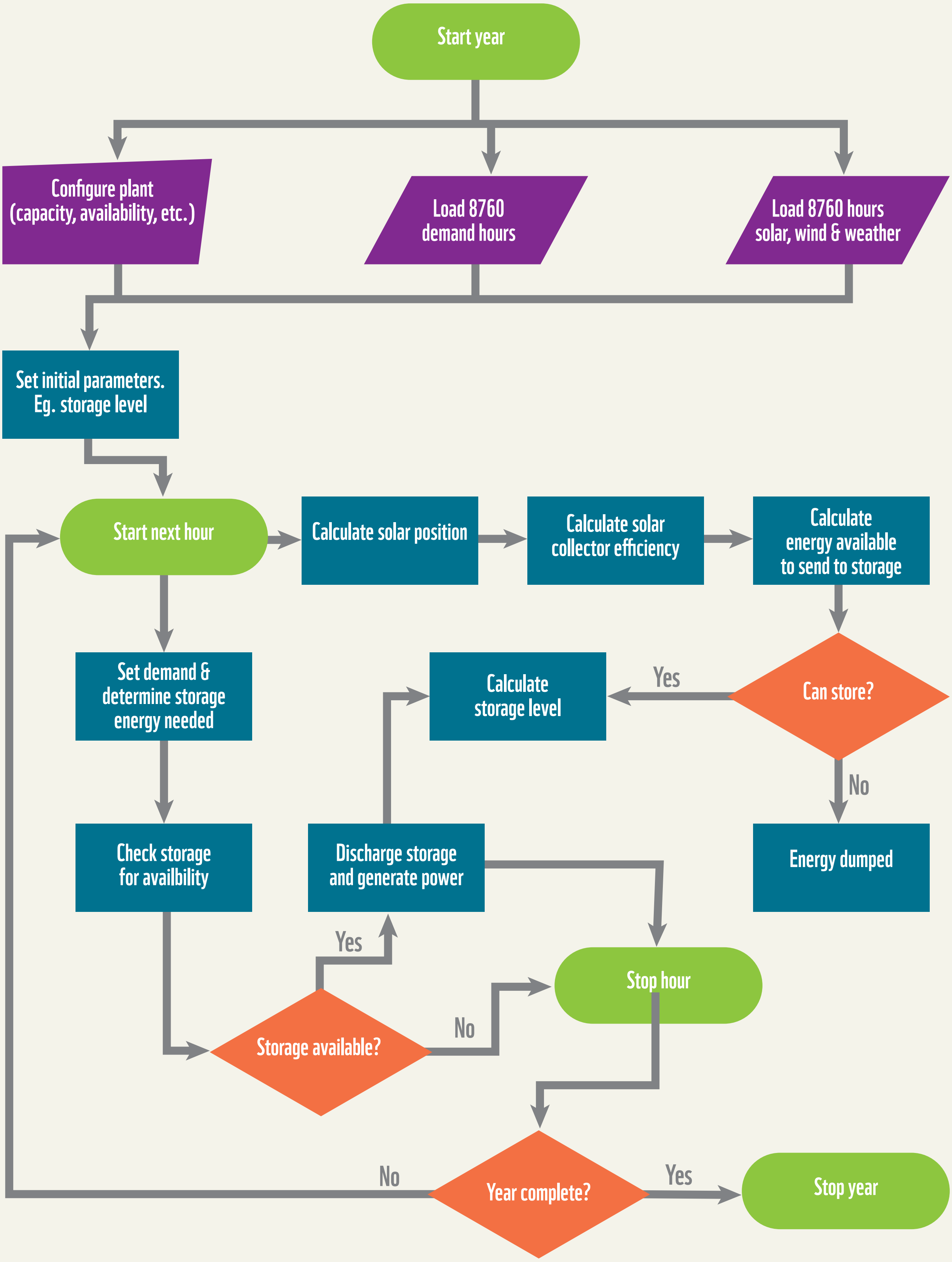
These cycles are independent, but not mutually exclusive. This means that storage charging and discharging can occur simultaneously or separately. To draw an analogy, it is like a laptop computer; when you use it and when you charge it are not necessarily the same and you are restricted only by the charge level.

The economic viability of CSP with storage is a somewhat unintuitive matter. The LCOE of a CSP plant tends to drop when storage is added. The lowest LCOE is a function of the cost of the various components and the ability to supply as much of the collected energy to the grid as possible. The primary reason for storage having a negative marginal effect on LCOE is that storage is included in the collector system prior to the turbine and generator. A larger storage size translates to a smaller turbine and generator. This also implies that transmission infrastructure costs can be lower for the same accumulated power delivered compared with other renewables.

CSP plants can be configured for various roles in a system ranging from baseload to peaking assistance. The default role of the CSP fleet in this system is to prioritise availability to the system before maximum output from the CSP fleet. Accordingly, the CSP fleet aims to avoid the use of last-resort generators and unserved electricity. To avoid excessive curtailment that could result in this role, several steps are taken to ensure profitability for the system and for the CSP plants:

- When beneficial and allowable, CSP plants are permitted to generate power during the day, even if the system does not request this generation. This only occurs in the event that the CSP storage systems are full, preventing further energy collection. Permitting the CSP plants to generate and deliver power makes better use of the CSP plants without violating their role in serving availability. This mostly occurs when CSP overrides CCGT capacity serving a similar role.
- Spatial and dimension optimization of CSP plants present opportunities. Within grid and other resource constraints, the CSP fleet was spread out to achieve higher levels of availability. At the same time, the node capacity allocation and size of the collector, turbine and storage sub-systems were also fine-tuned.
- A floor for minimum demand was set in the model. In the event that a scenario results in underutilization of the CSP fleet, the plants were allowed to deplete the storage system, even at times when the system does not call for the use of the power. This setting essentially forces a fraction of the CSP fleet to act in a baseload manner. No scenario in this project really warranted this because of the generally low penetration of renewables.

Figure 31: **High-level CSP logic flow diagram.**



The performance and role of CSP is also visible in the first 17 days of January in Figure 28. CSP is shown to assist demand-matching on most days in as much as capacity and storage levels permit. Notably, CSP plants aid in supporting the evening peak needs at a time that PV cannot and wind does not do reliably.

A final model decision that requires clarification relates to system forecasting. Due to perfect knowledge of the simulated demand as well as perfect knowledge of the various energy resources, it is possible that forecasting could be implemented for a day ahead. In such a case, CSP would stand out as the beneficiary in the model for the following primary reasons:

- Optimal dispatch of CSP availability to serve times of "avoided cost" generation or unserved energy periods.
- Maximum utilization of the CSP fleet to avoid curtailment when serving in standby availability mode.

While forecasting in this way would be beneficial, it was assumed that the central system decision makers would have enough on their hands in balancing demand with current monitoring and forecasting infrastructure. Accordingly, the more conservative route was taken, which dispatches all power based on forecasting for the next hour only.

Figure 32: **Winter week illustrating CSP in non-forecasting role: WWF High scenario.**

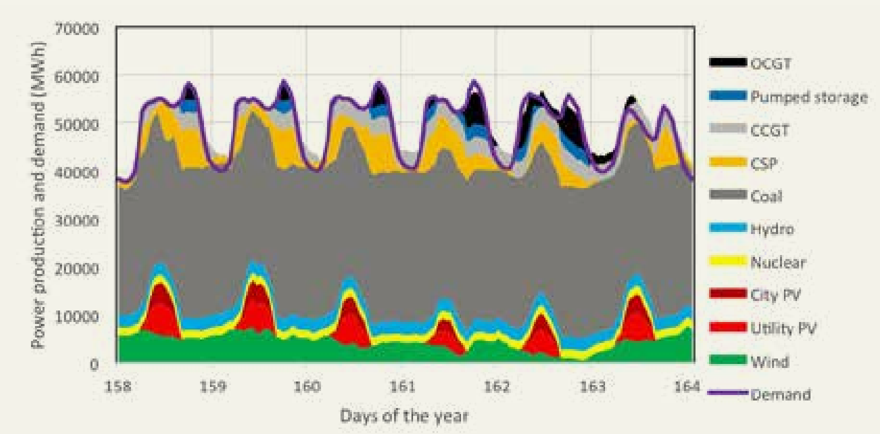


Figure 32 represents a winter week from a Monday to a Saturday. The ability for the system to fulfil demand dwindles as the week goes on. On Thursday, both wind and solar struggle to supply energy with the situation worse on the Friday as system-wide wind virtually stops. Only a small fraction of power was unserved (represented by the white space between the demand line and the full capacity utilization of the OCGTs). If day-ahead forecasting had been used, the OCGTs would have been prioritised to run more often that week to spare the emergency times for CSP.

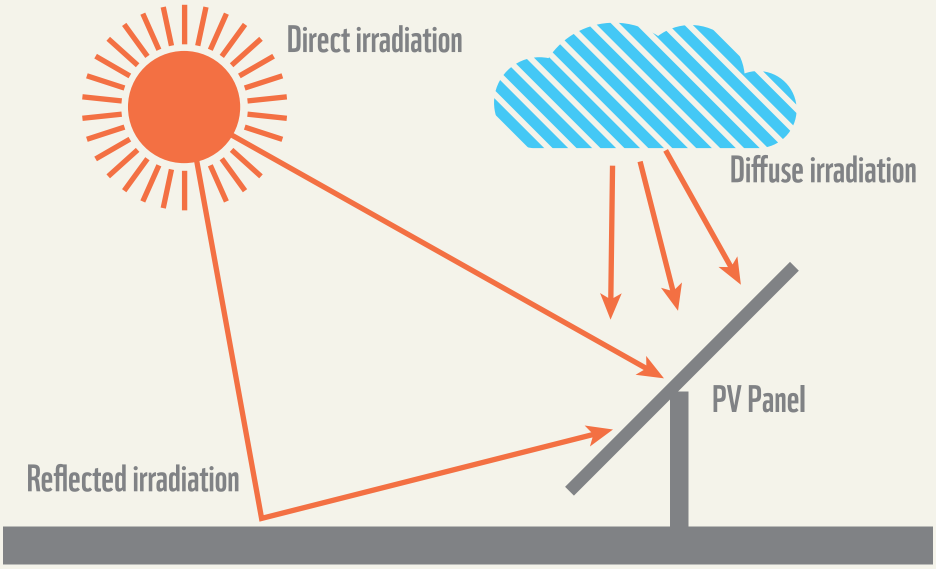
PV

An in-house PV model that has been used and validated in previous studies was used almost as-is.

The PV model assumes no storage and, accordingly, dispatches to the grid immediately. PV, as with wind, is ranked first in the merit order of all plants due to the workings of their remuneration structure and generation behaviour. The following steps provide background to the model:

- Calculate incident solar flux (combination of direct sunlight (DNI) based on sun position, diffuse irradiation (DHI) and reflected irradiation). See Figure 33.
- Iteratively refine the cell temperature and output efficiency using ambient temperature, wind and cell efficiency.
- Check any cell shading and adjust performance.
- Calculate PV plant gross and net outputs.

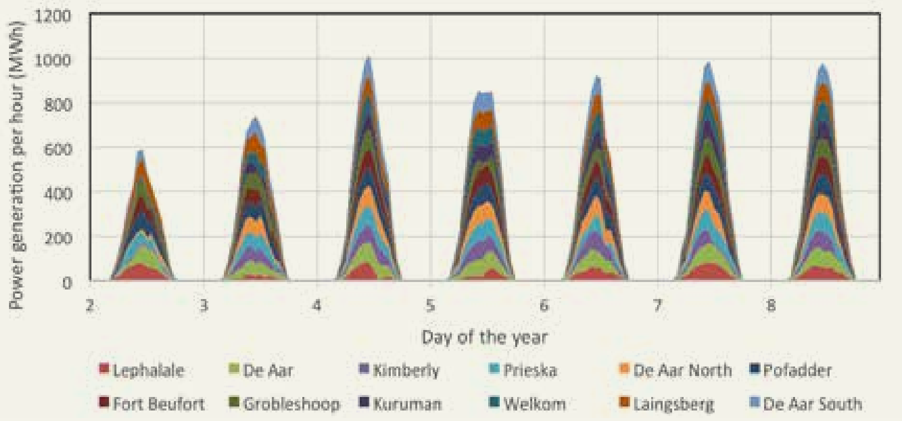
Figure 33: **Illustration of sunlight onto a PV panel.**



The model is capable of handling all known PV installation types, including stationary and tracking types. In order to simplify cost assumptions, however, scenarios only assumed stationary PV.

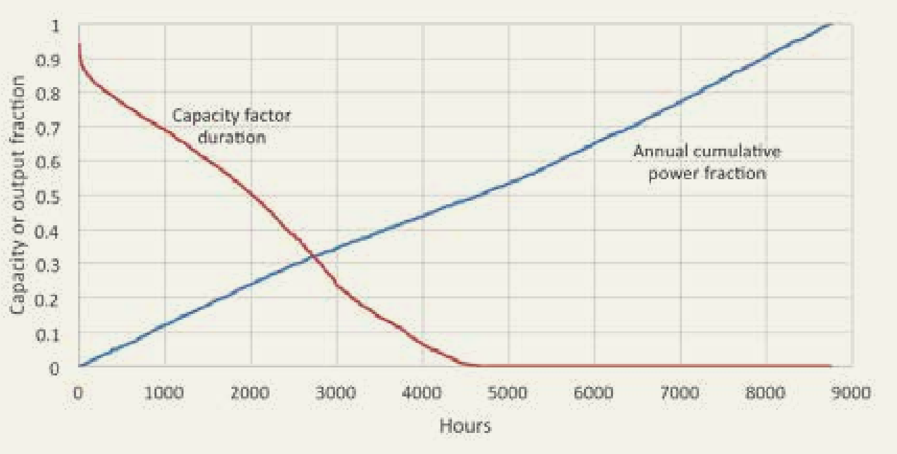
It is worth pointing out that while PV output at a single node is not highly predictable, the authors reached similar conclusions to the work done by Suri et al. (2014), who show that distributed PV systems increase output predictability and decrease output fluctuation. A test for the 12 utility PV nodes with equal capacity at each shows integrated behaviour for 7 days of January in Figure 34.

Figure 34: **Behaviour of PV plant output for the 12 model nodes containing 100MW each – 7 days of January.**



Predictability is high for most of the year, and Figure 35 illustrates this using a cumulative power production curve. Besides predictability at any point of the year, the lower production rate in winter is noticeable. While this could have been lower still, the clearer sunny skies of winter in the eastern regions assist with balancing the system.

Figure 35: **Combined system PV power performance indicators. Capacity factor duration curve (as a fraction by ranked hour) and annual cumulative power output (as a fraction by year hour).**



The PV model results in a system-wide capacity factor of 19% for utility power plants; this closely correlates with the assumption in the IRP Update.

In support of a key message by CSIR that solar and wind effectively have a negative marginal cost to the current South African power generation system (CSIR 2015), it is believed that this will hold true for a long time to come due to the anticipation of capacity shortfalls. In order to bring more benefit to the system and by circumventing the constraints of the national transmission system, the authors advocate PV power generation within urban areas. This is referred to simply as

“City PV” in this model. City PV acts as a fuel saver in the system and otherwise has no negative implications to transmission at times when it is not used. The model is identical, but as urban regions in sub-optimal sunny places were chosen, the net capacity factor of this is lower at 17.6%.

While this capacity was not restricted based on transmission limits, a quick assessment on available rooftop area[16] was conducted to ensure basic viability of this capacity.

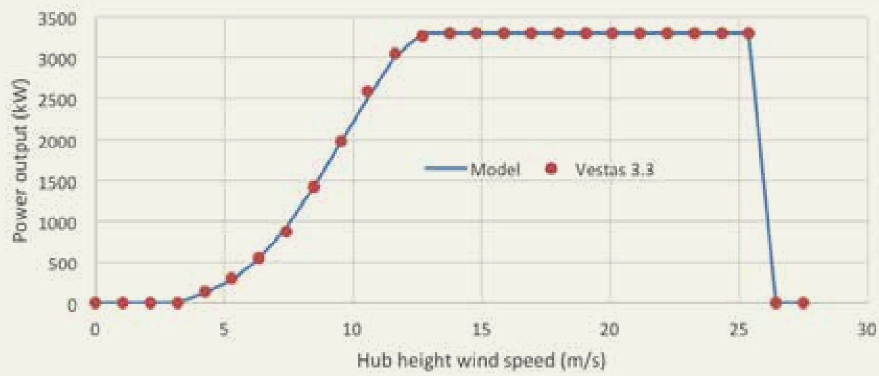
Wind

ThIs research benefited significantly from the recently updated wind atlas project (WASA 2014). As part of the WASA project, a multi-year downloadable set of hourly wind data is available based on a grid of the WASA region. Complete hourly 2010 data sets were obtained for all wind nodes.

The wind model was refined for the study to handle more generalised cases incorporating hub height, wind speed adjustment and performance based on blade swept area. The model was validated against published performance data and other published stochastic models. Figure 36 demonstrates validation to a selected Vestas 3.3MW unit which is assumed applicable for all wind turbines in this study.

At the wind farm level, it is important to recognise that not all turbines enjoy the best available wind, and wake effects require slight downgrading of the overall capacity factors. All nodes were forced to operate between a capacity factor range of 0.3 to 0.4, which is the range expected for commercially viable wind. This required scaling down the wind speeds used from the WASA set as in some instances, results showing capacity factors slightly above 0.5[17] were observed.

Figure 36: **Characteristic and model validation of a wind turbine output based on hub height wind speed.**

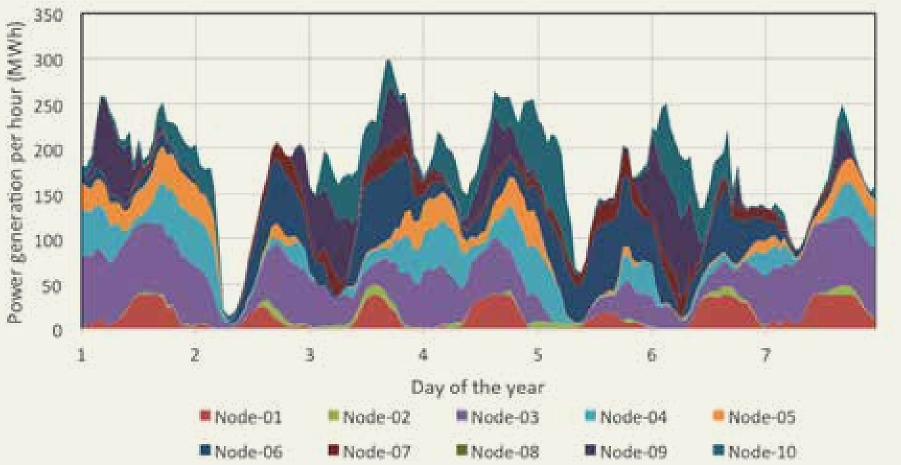


16 Based on 2011 Census data.

17 While no public reference is available, a large wind farm project in the southeastern part of the country is reportedly measuring close to the numbers observed in the model before suppressing the model into the typical range. Until evidence of the value of wind in this region has been published, the authors will maintain their capacity factor forcing.

The 10 wind nodes are generally very well distributed, and at certain times, the aggregated power output demonstrates the independence of some regions. There are, however, events throughout the year that show wind output at all nodes dropping to near zero output as can be seen in Figure 37.

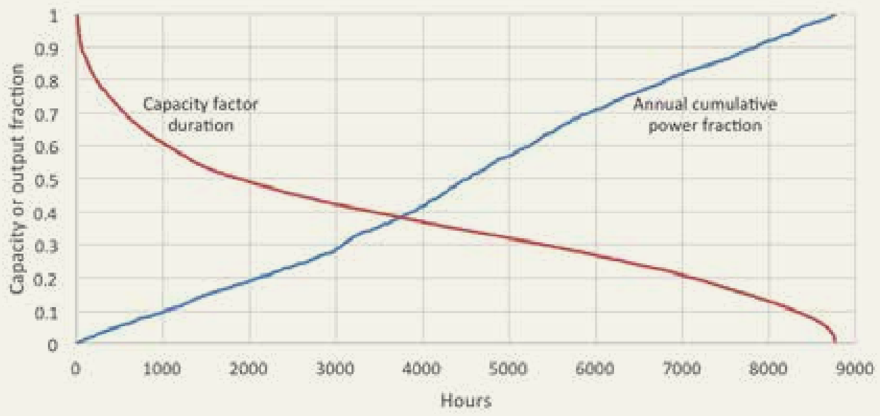
Figure 37: **First week of January at all wind nodes in the system and 500MW of capacity in this example.**



The combined system output for wind exhibited the ability for some fine-tuning. Except in cases where node capacity limits were reached, capacity allocation optimization resulted in a slight improvement in output predictability and a bias towards winter and evening peak.

Figure 38 indicates the overall performance of all wind nodes combined in a configuration tuned to favour winter production, evening peak and lowest intermittence. The ability for the wind system to achieve higher outputs in winter in a near "mirror image" manner is encouraging as this suggests good complementarity between wind and solar power.

Figure 38: **Combined system wind power performance indicators. Capacity factor duration curve (as a fraction by ranked hour) and annual cumulative power output (as a fraction by year hour).**



Hydro

The hydroelectric power in this study refers to the impoundment hydroelectric facilities. IRP assumptions are used for availability of hydro and the following hydro projects are in all models:

- 360MW from Gariep @ 96.6% availability
- 240MW from Vanderkloof @ 97.4% availability
- 1500MW from Cahora Bassa @ 66.7% availability

Coal

The coal model is a straightforward behavioural model with a few principle parameters.

Each coal power plant is characterised by

- Capacity
- Availability factor (for seasonal planned and unplanned maintenance)
- Ramp rate (ramp up and down assumed the same)
- Turndown limit (the lowest stable operating point of a plant)
- Fuel efficiency

Coal power remains dominant in all scenarios and is a primary baseload supplier. Coal is preferred in the system after wind, PV and nuclear power.

Nuclear, OCGT, CCGT

The nuclear, OCGT and CCGT models are principally the same as the coal power model besides variances in technology description.

Major differences in ramp rate (dispatchability) and cost exist between these types. As a result, a few key merit order-based rules require explanation.

- CCGT plants are good at ramping and providing dispatch capability, but tend to prefer to run more continuously than OCGT plants. While there is uncertainty, the literature assumes that gas will be available to power these units at a much lower cost than the current diesel powered OCGT plants. Accordingly, gas is assumed for all CCGT capacity with a range of gas posts based on expected supply.
- For this reason, CCGT plants have a similar merit order to CSP plants. While they have major rule differences in the system model, they often exchange roles based on other events occurring in the model.
- Generally, the scenarios have a large OCGT capacity component. It is acknowledged that there is risk in assuming that these plants will all run off gas, and accordingly, a wide range in costs is recognised based on future costs of diesel and gas. For this reason, OCGT plants are the plants of last resort, and their use was minimised. Some criteria exist where the model is capable of dispatching even OCGT plants before pumped storage is dispatched in order to maintain or build reserves of the pumped storage systems. This was implemented once the cost of unserved electricity was seen in the results. By avoiding unserved electricity hours, the system costs drop significantly.

Pumped Storage

Pumped storage plants are used as peaking plants similar to the OCGT systems. The pumped storage model is, however, very different to all other models. The performance during charging and discharging is as simple as the models for conventional power. Round trip efficiency is accounted for during charging, and the pumped storage plants perform up to their rating otherwise. Apparently, these plants have very rapid ramp rates enabling them to switch roles within any single hour. Other key notable aspects of the pumped storage model are:

- Storage level is always checked and is restricted in a similar manner to the CSP storage model. In other words, pumped storage plants cannot be over-filled or over-used, and tehy cannot charge or discharge at rates exceeding their capabilities.
- Charging of pumped storage is based on a list of system indicators that include
    - Current charge level: In the event that storage levels are low, charging gets a higher priority and more generator types are used to increase storage levels. The ideal situation is that RE in an unconstrained system is used to charge the pumped storage systems.
    - Available spare generator capacity in the system is in accordance with rules dictated by the current charge level. Excess renewable power is ideal, and thereafter, the model will use available coal capacity and, if required, available capacity from all other generators in extreme cases. Given the cost of unserved energy, it was worth keeping as much pumped storage availability as possible.
- Charging places an additional burden on the system demand. In all of the time series plots, the most likely reason for generation exceeding demand is due to an event causing pumped storage charging.
- Discharge is similarly complicated and is a function of the constraints in the system.

THE SCENARIOS

This chapter covers the conceptual configuration, results and some specific explanation of the four scenarios before the final chapter closes with a proposed plan of action and conclusions.

As outlined in the methodology, the scenarios are not intended to be used for direct comparison, but rather to gauge the merits of a high renewable scenario. All scenarios are defined to serve this purpose. In particular, the IRP scenario in this study is subject to numerous differences compared with the original IRP model, making comparison invalid.

The chapter commences with high level outcomes first and where details are warranted, explores the WWF scenario deeper into the chapter. The chapter ends with a test of demand versatility between scenarios, providing perhaps the closest performance comparison between scenarios.

Scenario capacities

The resulting WWF scenarios are summarised in Figure 39 and Table 9. The final generating capacities for the WWF scenario are shown relative to the two IRP variants and the two WWF vision study starting points. The first observation is that the proposed WWF scenario RE capacities are higher, but otherwise, the system is similar to the starting proposal.

Figure 39: **Capacities for each scenario.**

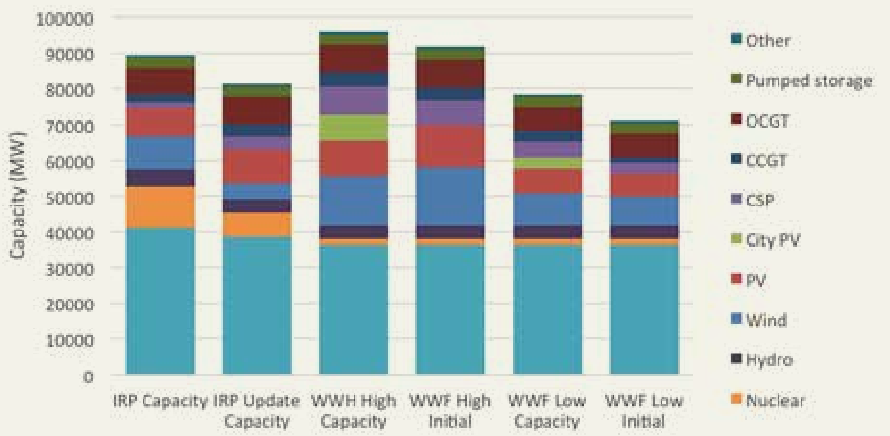


Table 9: **Capacities for each scenario.**

	IRP Capacity	IRP Update Capacity	WWF High Capacity	WWF High Initial	WWF Low Capacity	WWF Low Initial
Wind	9 200	4 360	14 000	16 134	9000	8184
PV	8 400	9 770	10 000	11 884	7000	6334
City PV	0	0	7 000	0	3000	0
CSP	1 200	3 300	8 000	7 000	4500	3000
Coal	40 995	38 680	36 230	36 230	36230	36230
Nuclear	11 400	6 660	1 800	1 860	1800	1860
CCGT	2 370	3 550	4 000	3 550	3000	1420
OCGT	7 330	7 680	7 680	7 680	6720	6720
Pumped storage	2 900	2 900	2 900	2 900	2900	2900
Hydro	4 809	3 690	3 690	3 690	3690	3690
Other	915	760	760	760	640	640
Total	89 519	81 350	96 060	91 688	78480	70978

The system definitions of the IRP and the IRP Update were kept intact, and there is little deviation between their definition and performance at a plant level. In both cases, the amount of power delivered per unit (and hence capacity factors) by RE was well validated. In order to match well to the CSP capacity factor in this model, storage needed to be set around 6 hours full-load on average. This appears to be consistent with the authors' understanding of the original and draft update documents.

Other notable points regarding the system capacities are summarised:

- The starting WWF capacities did not differentiate solar PV from CSP; this was left to the authors to configure.
- City PV is essentially a demand-side matter and could have been applied in some measure to the IRP and IRP update, but was not due to stated assumptions.
- The IRP update base case is somewhat comparable to the WWF scenarios and did form the basis on the WWF vision study assumptions.
- CSP capacity on its own is misleading. The IRP and IRP update models assume 6 hours of storage, while the optimal storage levels in the proposed WWF scenarios tended to exceed 12 hours.
- The WWF High and WWF Low capacities for solar increased and wind remained similar, pushing the overall system capacity up in both cases.
- Results showed that a marginally higher capacity was required for combined cycle gas turbines (CCGTs) in the WWF scenarios. Because it is generously assumed that gas will be available under all cost probability assumptions, this might seem like a violation in the parity rule. Parity for the CCGT and OCGT fleet does need monitoring, but this is measured by actual use rather than capacity. As will be demonstrated, the WWF scenarios use significantly less gas than the scenarios representing the IRP and IRP Updates.

- A more generalised point regarding capacity is that all initial scenarios fall short in expectation when tested against what might be considered a gruelling demand curve. In combination with the assumed availability of coal power, other changes and assumptions and the use of a system-wide spatial-temporal approach, it is perhaps not unexpected that this occurred.

Primary performance and cost metrics

Table 10 summarises the performance and system cost metrics. Only the most obvious findings will be covered here with more elaboration in Chapter 7.3.

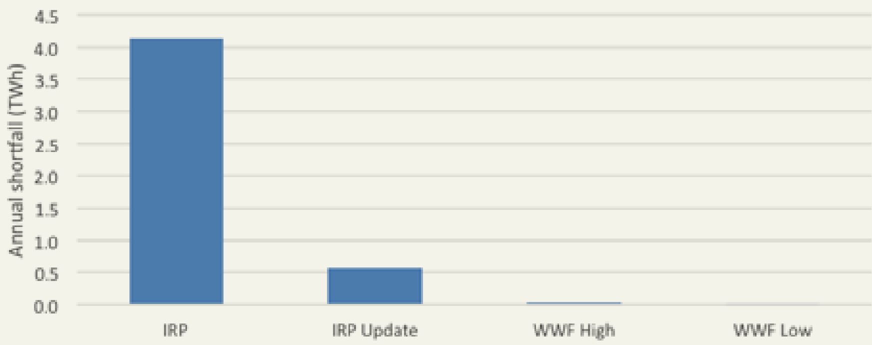
Table 10: **Summary of primary performance and cost.**

	IRP		IRP Update		WWF High		WWF Low	
	Annual power (TWh)	Annual fraction	Annual power (TWh)	Annual fraction	Annual power (TWh)	Annual fraction	Annual power (TWh)	Annual fraction
Annual demand	454.7	0.99	409.1	0.98	407.0	0.99	358.0	0.99
Wind	26.2	0.06	12.4	0.03	39.9	0.10	25.6	0.07
Utility PV	14.3	0.03	16.6	0.04	17.0	0.04	11.9	0.03
City PV	0.0	0.00	0.0	0.00	10.8	0.03	4.6	0.01
CSP	4.5	0.01	11.9	0.03	36.1	0.09	17.9	0.05
RE supply	45.0	0.10	40.9	0.10	103.8	0.25	60.1	0.17
Hydro	29.2	0.06	22.8	0.05	22.8	0.06	22.8	0.06
Coal	245.2	0.53	254.6	0.61	245.7	0.60	246.2	0.68
Nuclear	93.0	0.20	54.3	0.13	14.7	0.04	14.7	0.04
CCGT	15.1	0.03	21.5	0.05	19.0	0.05	13.7	0.04
OCGT	25.3	0.06	16.4	0.04	2.1	0.01	1.5	0.00
Pumped storage	6.6	0.01	5.6	0.01	3.1	0.01	2.9	0.01
Annual actual	459.4		416.0		411.1		361.9	
Shortfall	4.1		0.6		0.0		0.0	
Surplus	0.0		0.0		0.0		0.0	
System cost high (R/kWh)	R2.32		R1.04		R0.67		R0.61	
System cost low (R/kWh)	R0.59		R0.49		R0.48		R0.44	

The resulting WWF scenarios have been optimised to reduce cost which automatically tends to mean that the level of unserved energy would be very low. Besides understanding a breakdown of energy delivered in a year, Table 10 gives a first sense of the link between cost and the level of unserved electricity. The capacity stressed scenarios also indicate a high reliance of available OCGT capacity, causing further stress to system cost.

A comparison of annual unserved electricity is given in Figure 40. A common perception of a high RE future is that it cannot viably meet demand needs. The WWF scenario in this case illustrates that it is possible to achieve a reliable system that is renewable-centric.

Figure 40: **Unserved annual electricity for each scenario.**

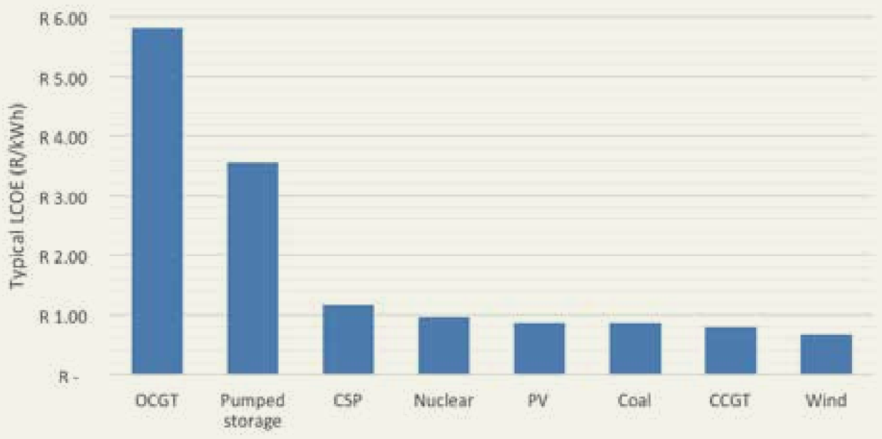


With all initial scenarios falling short in performance, this study found that the WWF High scenario needed increased RE capacity before cost stopped dropping. The cost floor occurred when annual power produced by RE approached 25%.

Once the optimized WWF scenarios were established, alternative scenarios were attempted to test for lowest cost, but favouring other technologies such as nuclear and coal power. This needed to be applied with care so as not to violate limits of fuel availability and cost. While not exhaustively tested, no other system configuration could be found that could match the cost of the WWF scenario. A renewable favoured system in 2030 seems to be explained by studying typical LCOE values of each technology that could be added to the system. Figure 41 is a plot of typical LCOE values for the technologies. These values were extracted[18] from the WWF High scenario (and in the case of nuclear, from the IRP Update).

18 LCOE is a factor of fixed, time dependant and productivity dependant costs as well as capacity factor. These are, in turn, factors of complexities in the model. Accordingly, in this case, LCOE for a technology, node or plant are always associated with a specific scenario.

Figure 41: **Typical system based LCOE values for new capacity in the WWF High scenario (and IRP Update in the case of nuclear).**



The complexities of the system make it difficult to fully understand the trade-offs, let alone explain them. Nonetheless, some high-level explanations are argued here.

- In a capacity constrained system, any new capacity helps directly, so the lowest cost options would benefit the system.
- Additional CCGT capacity does help, but care is needed to maintain parity. If gas resources do not support additional capacity, the marginal cost will increase. The CCGT capacity in the WWF High scenario was indeed increased, and because more would be needed if renewable capacity was removed, this is not something that the authors would advocate. While this model does not adjust for this marginal cost, it is still not expected that the cost will drop with significant additional CCGT capacity in exchange for renewables.
- A reason for this might be the care that was taken to balance wind, PV and CSP, noting that CSP, in this case, plays a sacrificial availability role. When renewable capacity is reduced, the system relies more heavily on OCGT capacity to meet demand. Had CSP been used as a baseload option, LCOE for CSP would be about 20% lower and thus competitive with nuclear.
- The aforementioned balancing of wind, PV and CSP is a particular virtue of the spatial-temporal method.
- Nuclear simply cannot lower LCOE under any condition when added at the expense of renewables. CSP automatically takes on the role of baseload capability in a marginal sense when compared to nuclear and coal power. Neither can compete with CSP, and this characteristic of CSP value and cost is intrinsic to the model. This occurs despite the likely underestimation of the real costs of new nuclear power plants in this work.

After several attempts of different configurations, it was found that by trying to reduce cost further, something else would "pop" – i.e. the marginal cost elsewhere in the model would rise. What stood out was the impact of the availability of existing coal power capacity. Assuming that better maintenance management of the existing coal fleet is cost-neutral (the higher cost of proper maintenance offset by the cost of wear-and-tear from poorly maintained plants), increasing availability to normal levels leads to a lower system cost. More importantly, the system shows improved availability, and this is reflected in the high probability end of the cost values. While the objective and scope of this study do not deal with management of the Eskom coal power fleet and while the authors do not advocate for more coal power emissions, it would be remiss not to point out this significant finding. Two corollary implications are also worth mentioning. Firstly, it may be marginally more cost effective to reduce the size of the coal fleet to ensure improved maintenance of the best plants resulting in the same available capacity level. Secondly, capacity loss due to the decommissioning of existing coal plants will result in a rise in system cost regardless of the configuration of new capacity.

Scenario characteristics

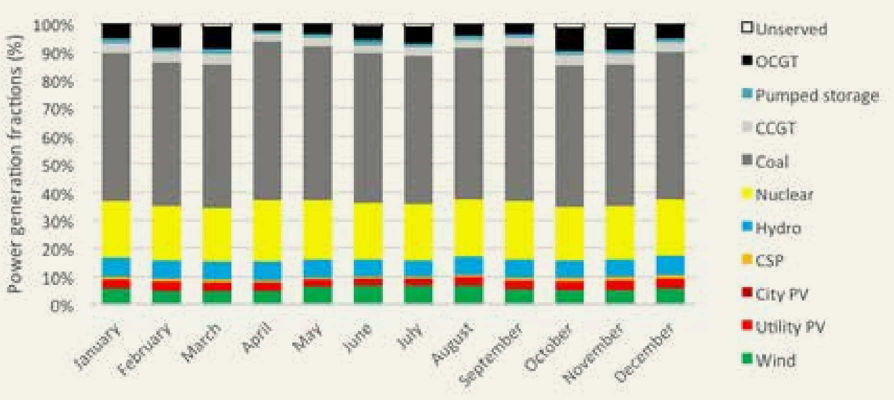
Before discussing the final cost analysis, this section explores the scenarios in more detail to understand what makes them work or fall short. Due to the large amount of data, it was difficult to convey the results in detail. Consequently, results are either given and discussed in data reduced format or by considering very specific events to understand the behaviour in certain scenarios.

Performance by month

Slightly extending the high-level outcomes in the previous sub-section, the power production is summarised by month and by technology type for each scenario. It is worth looking at this to comprehend the effects of seasonality in each scenario.

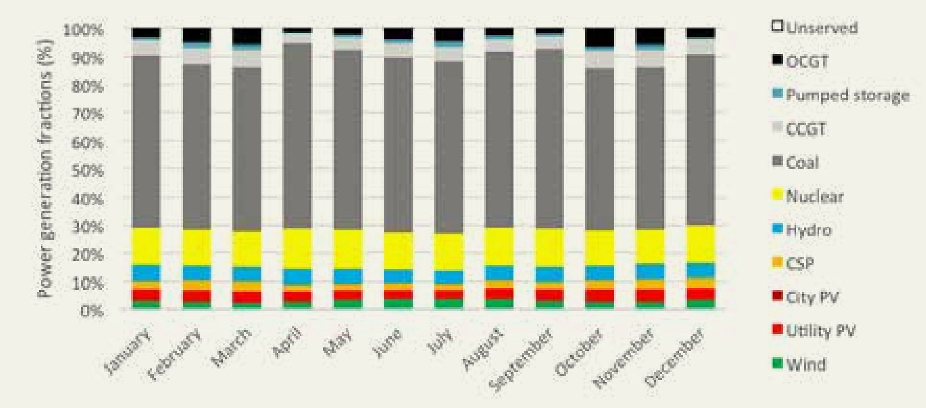
Renewable capacities are grouped first in order to judge monthly values comparatively. Traditional baseload, mid-merit and peaking options are then added. Where a month experiences any unserved power, this unserved power is allocated to the stack as if it were a power generation technology.

Figure 42: **IRP scenario monthly power generation fractions by technology (and unserved power).**



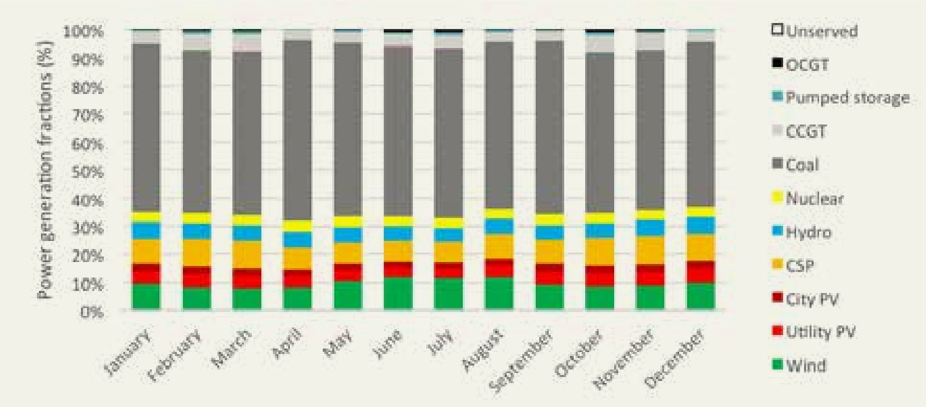
The IRP case (Figure 42) is characterised primarily by several months of unserved electricity and overused OCGTs for reasons explained earlier. The relatively small renewable contribution is not particularly noteworthy, other than the steady year-round performance due largely to the contribution of wind power in winter.

Figure 43: **IRP Update scenario monthly power generation fractions by technology (and unserved power).**



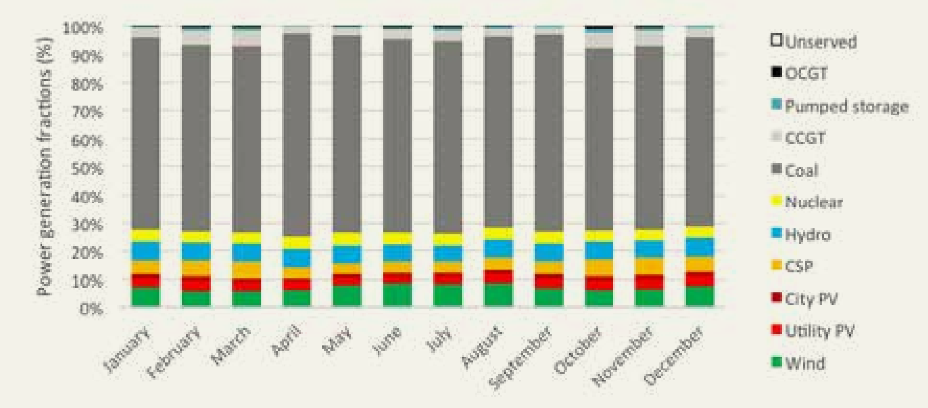
The IRP Update scenario (Figure 43) shows the impact of a lower allocation for wind power, again noting the assumptions and definition of the model. Even with the coal power fleet enjoying higher availability in winter, the system struggles to keep up in July just as it does on the fringes of summer when coal power availability is lower.

Figure 44: **WWF High scenario monthly power generation fractions by technology (and unserved power).**



The WWF scenario is discussed for both variants together (Figure 44 and Figure 45). The higher availability of coal during winter is clear as in the other scenarios. At around the time that the model switches to higher coal availability in April, and then in the last month of higher availability in September, the combined wind and solar output declines. In part, this is due to a choice in the model where the CSP capacity is set to a mode to reduce system cost by sacrificially providing availability in order to reduce the cost of the most expensive generators. With exception also of a particularly good August for renewables, the system demonstrates balanced contributions year-round.

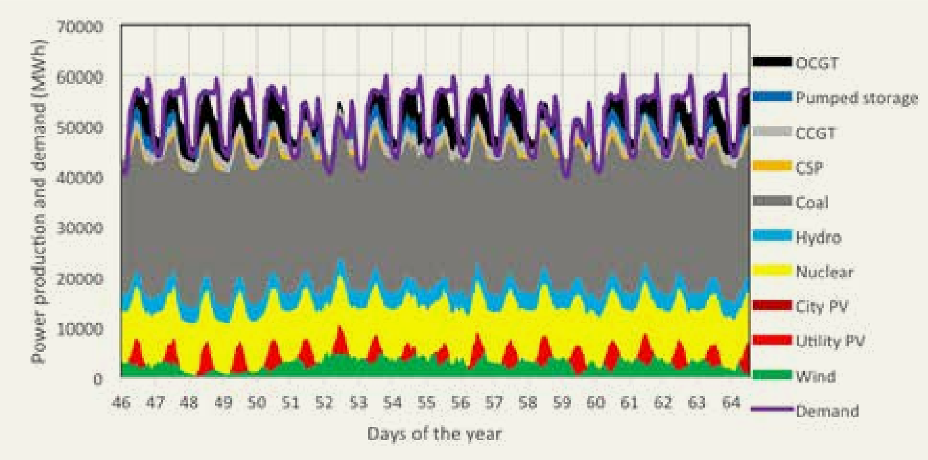
Figure 45: **WWF Low scenario monthly power generation fractions by technology (and unserved power).**



IRP: Lack of capacity

It is increasingly clear that nothing is more damaging to the full cost of the system than a shortfall in available capacity. The IRP scenario experiences close to 800 hours of load shedding in which a load shed hour is defined as an equivalent hour where 10% of average system demand is unmet. Figure 46 illustrates such an example over a period of roughly three weeks in summer.

Figure 46: **IRP case illustrating many hours of unserved electricity (white spaces).**

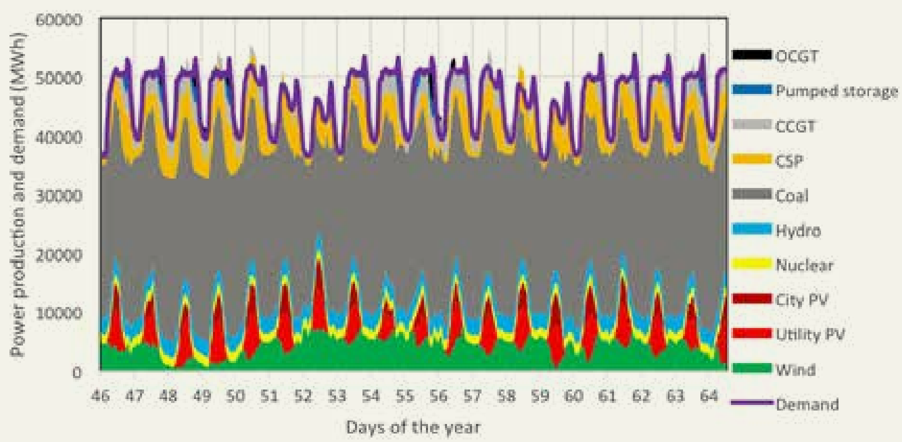


The contribution to cost in the system due to unserved energy in addition to the very high utilization of high cost OCGT plants are the key contributors to the very high cost of the system.

Secondary considerations in the IRP scenario relate to the choice in technologies. As already stated from the overall findings, the choice to add the majority of new capacity (weighted by capacity factor) to nuclear and coal makes no sense according to the cost ranges that were used in this study. Wind and PV (combined in a system) is lower in cost than coal and nuclear, while CSP and nuclear have very similar mean costs in that timeframe contingent on how CSP is used. The IRP scenario is not just short of capacity, it also lacks sufficient dispatch capacity for peak periods. CSP, OCGT, pumped storage and to some degree, CCGT capacities combined are insufficient for the given baseload.

The same timeframe in the WWF High scenario is shown in Figure 47. Despite no new nuclear or coal capacity and noting the difference in demand, this period of time never reflects any shortfall.

Figure 47: **WWF High case illustrating how a renewable case with significant reduction in coal and nuclear can serve electricity.**



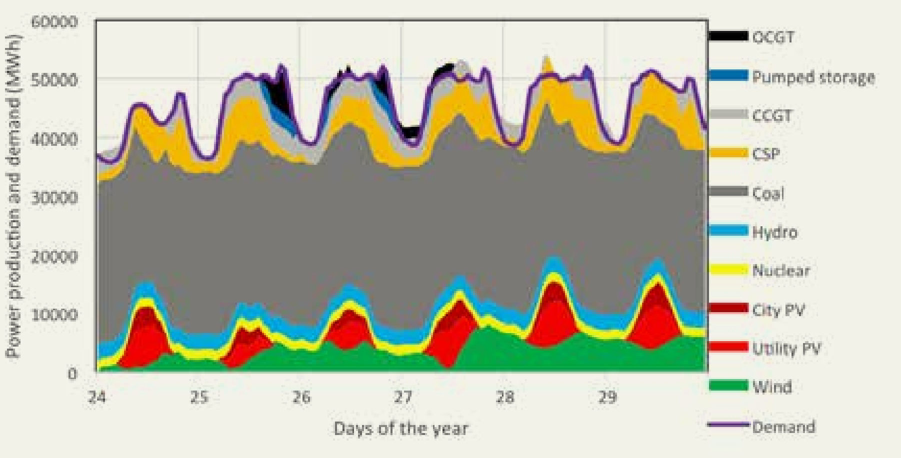
What is noteworthy about the WWF High case is that the reduced baseload capacity, together with the combination of PV, wind, CSP, pumped storage and flexible gas, offers a system of greater flexibility and at lower cost. These virtues were successfully tested by exposing the scenario to all annual demand scenarios. This test is discussed in section 7.4.

WWF scenario: Balancing maintenance, solar and wind

A somewhat surprising outcome of the study was the degree to which the entire WWF scenario, with all its associated constraints, could be configured for a high degree of complementarity between technologies. This relied on the assumption that the coal power fleet availability was 10% lower in summer than in winter while maintaining an overall fleet availability as per the assumptions in Table 6.

Figure 28 illustrates the near-daily predictability of wind complementing solar during summer periods. Additional examples are shown for interesting characteristics of the WWF High case.

Figure 48: **Summer event with poor sun.**



Large weather systems occur periodically during summer where usually sunny skies in the arid region are affected by significant cloud cover. Figure 48 illustrates two days in the series where reduced PV output and depleted CSP storage results in significant use of pumped storage and OCGTs. During this period, the pumped storage capacity is depleted to the point that the system chooses to use all spare generators to re-charge overnight on the second day of decreased sunlight. This pumped storage charging continues into the next day when possible and is eventually replaced with solar energy on the fourth day of the start of the event.

Figure 49: **Sunny summer days where wind drops.**

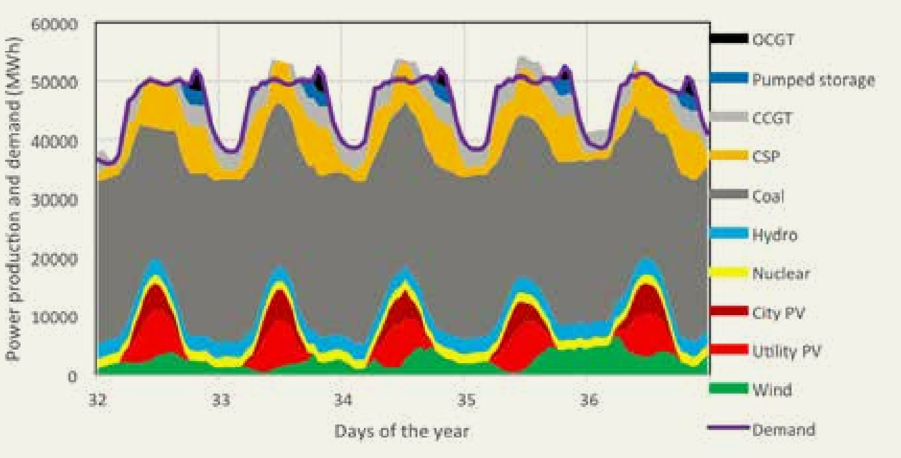


Figure 49 illustrates an event of lower than average wind across the country during a summer period. Wind is not supportive on the fringe of the day requiring a significant CCGT capacity, but during the day, solar power is produced in excess since it is utilized to recharge pumped storage. Given that there is very little suppression of coal output, this apparent excess of solar power is not considered excess as it only recharges the pumped storage. CSP remains supportive during evening peak, but OCGT, pumped storage and OCGT capacity is required during all evenings during peak.

Figure 50: **Transition to winter with higher baseload availability.**

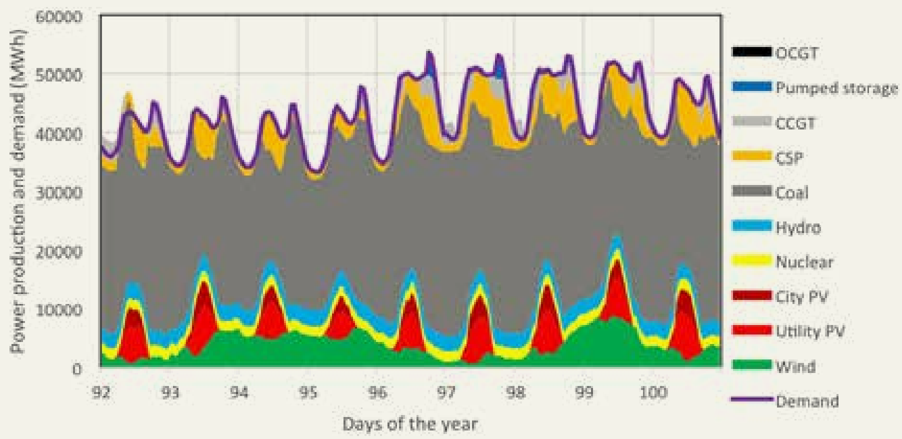


Figure 50 illustrates the time around Easter where, coincidentally, coal power availability just increased in the model. This very early winter stretch demonstrates excess renewable power that causes coal power to frequently ramp down and back up. During this period, the system experiences no excess renewable power (as with all scenarios at all times). The model was set to use CCGT capacity as mid-merit and this allowed these plants to immediately recharge pumped storage used during the previous very high peaks. The frequent ramping of the coal fleet does not exceed the ramping that the current Eskom fleet needs to manage based on the majority of power presently generated by coal and nuclear.

Figure 51: **Deep winter characteristics.**

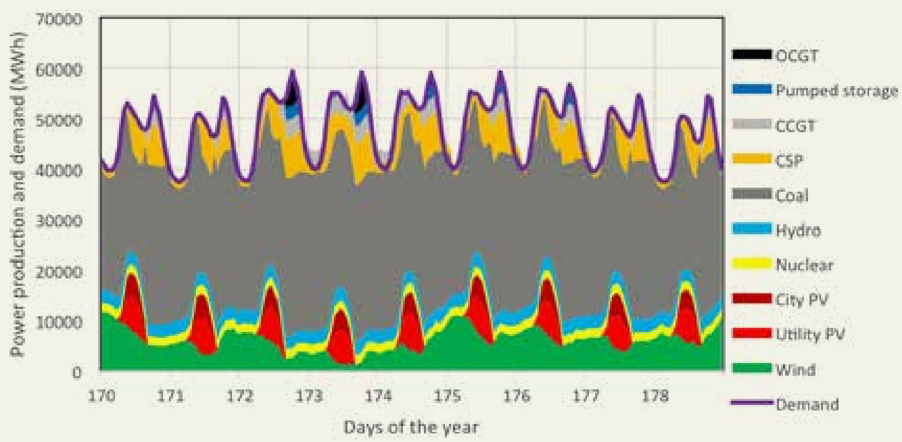


Figure 51 illustrates perhaps the most challenging period of the year with the shortest days and the highest evening peaks. This period shows an example of lower frequency wind cycles with higher amplitudes, including daily frequency peaks and dips. In this example, the majority of the week is very windy until it ebbs off over the weekend. Wind generally continues to complement sun during these times year round. Daily peaks are higher, but during most of winter, peaking events seem to be of shorter duration. Perhaps due to the higher coal power availability, pumped storage reservoirs deplete less before recharging. With the exception of two winter episodes, pumped storage reservoirs do not generally dip below 80%.

Figure 52 is a plot of the system pumped storage charge level for the WWF High scenario. Besides the variation between seasons, a key attribute that stands out is the degree to which the pumped storage system is available throughout the year. The pumped storage charge level appears to be a good indicator in the model for total system capacity sufficiency. When pumped storage tends to start showing good availability, the system cost is low.

Figure 52: **System pumped storage charge level for the year (WWF High) illustrating the shorter duration but frequent pumped storage usage in winter with exception of two significant winter events.**

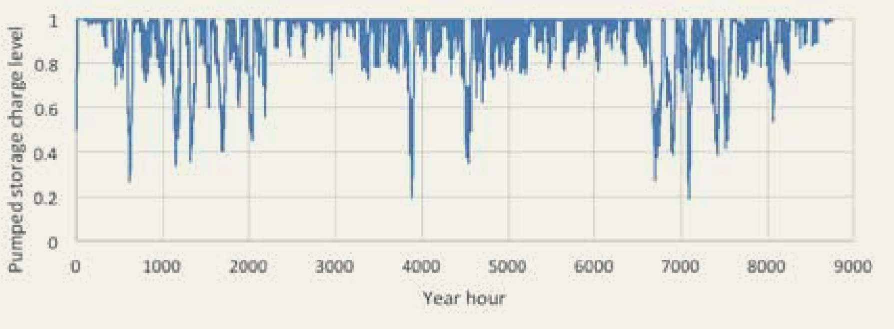


Figure 53: **System pumped storage charge level for the year (IRP) illustrating insufficiency in the system.**

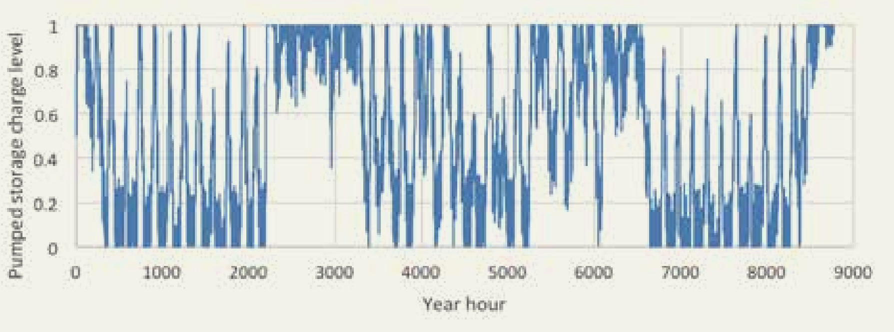


Figure 53 is the IRP scenario version of the system pumped storage level illustrating system insufficiency. An interesting observation is that the South African pumped storage system does not appear to be insufficient for a well-planned, high renewable scenario in future. Increased pumped storage capacity would certainly be advantageous, but it only supports a system as a capacitor. In a high renewable case, the model outcome suggests that once the Ingula project is complete, the total reservoir capacity is very good and perhaps only limited by turbine rating.

Reaching the right balance

Having looked at the performance in a balanced scenario, all scenarios are addressed with particular emphasis on only those components that work in the mid-merit to peaking range.

In sub-section 7.3.2, the IRP scenario is shown to be short in capacity. While this is especially true under the modified availability for coal power, the spatial-temporal model also shows an imbalance in the technology capacity allocation. While capacity is better suited to demand in the IRP Update, this capacity balancing problem remains. Up to this point, the report should make the role of spatial-temporal modelling clear; however, it is perhaps the need for better balancing that emphasises the critical value of the method.

Figure 54: **Comparison between WWF High (left) and IRP Update (right) for an early summer event demonstrating the importance of technology capacity balancing.**

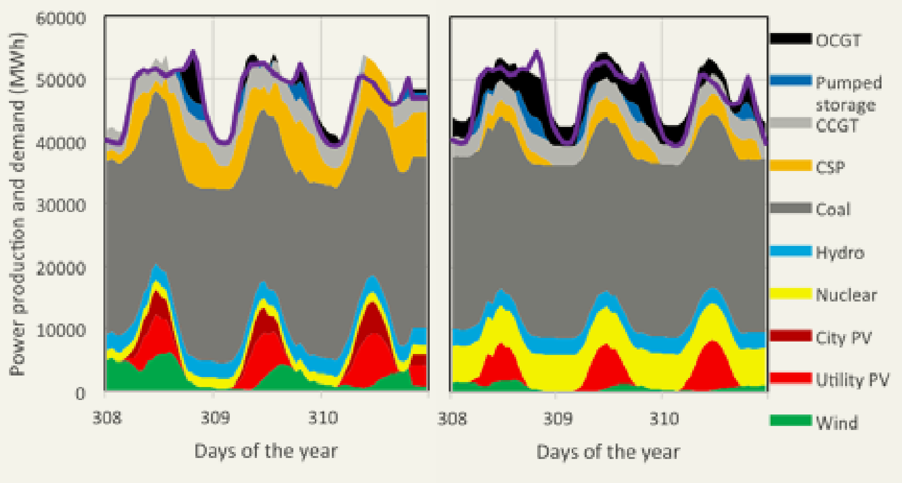


Figure 54 is a side-by-side comparison of the IRP Update scenario and its direct derivative, the WWF High scenario, for three days (Thursday to Saturday) in early summer. In the IRP Update, CSP output largely overlaps PV output (as it does most of the year in both the IRP and the IRP Update). There is not enough capacity or storage to assist the system into the evening. Besides overall insufficient capacity, the system runs out of all options as wind output drops. Pumped storage reservoirs completely deplete or urgently charge using last-resort generators.

In the WWF High scenario, after serving the earlier part of the day with good to excellent resources, the system switches into a role serving demand using all available mid-merit storage and, where needed, emergency generators. Specifically, CSP storage reserves are designed for this event despite the decision not to forecast. CSP is underutilized during the sunniest time of day and serves the mornings and evenings in support of PV (and wind when it drops).

These results suggest that the only way to determine mid-merit and peaking solutions in a renewable mix is by using a deterministic temporal simulation of the system as has been demonstrated here. Figure 55 and Figure 56 are plots of the capacity and output balances respectively between the renewable, mid-merit and peaking options in the four scenarios.

Figure 55: **Capacity balance for renewable, mid-merit and peaking for all 2030 scenarios.**

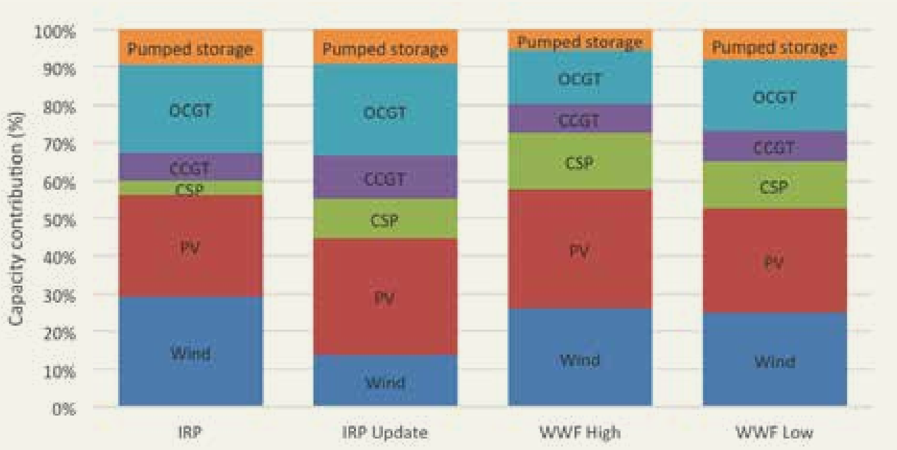
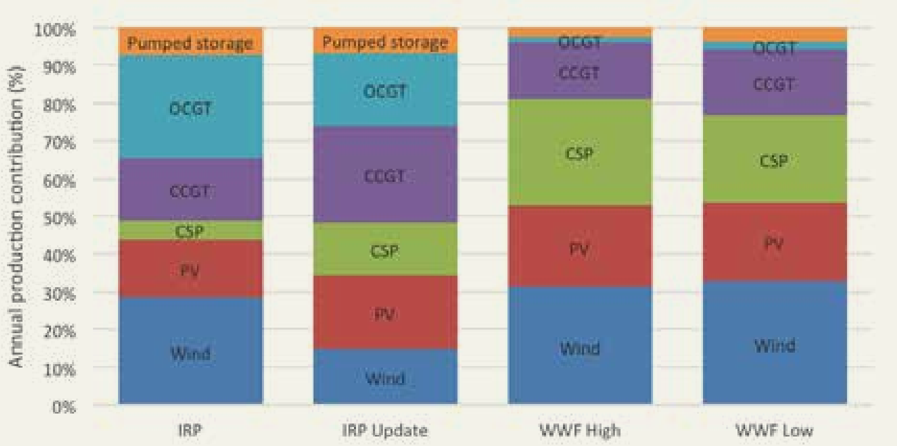


Figure 56: **Annual electricity production balance for renewable, mid-merit and peaking for all 2030 scenarios.**



By capacity and by output, the three renewables (wind, PV and CSP) are more uniformly allocated than the wind and PV bias in the IRP and the solar bias in the IRP Update. Lower CSP capacity hides the dispatch role of the technology, but the impact is revealed in the second plot where CSP and wind produce similar annual power. The WWF Low scenario has not been discussed much in this section, mostly as it is the easiest case to solve and it is, in reality, a derivative of the WWF High scenario. It is proposed that the more balanced system is not just optimal for the demand it is optimised for, but that a balanced and optimised WWF Scenario would likely offer considerable spare reserves in the event of a sudden increase in demand. This chapter closes with a look at the cost of each scenario, and this proposition is also tested using cost as the ultimate objective metric.

Cost probabilities of the scenarios

Once each scenario model has been defined, there is a switch to the cost probability model. As mentioned before, rather than assume a set of static cost scenarios, a cost continuum for a proposed system makes it easier to find a good robust system for the future. For example, if there is a possibility that nuclear CAPEX will be lower cost in the future, the cost range is simply set to include this possibility. The Monte Carlo-based cost method produces a probability distribution for each scenario, possibly giving all the guidance needed to make decisions. This is perhaps best illustrated by looking at the combined cost result.

Figure 57: **Cost probabilities of the scenarios using simple LCOE. The solid lines are cumulative distributions made up of probability distribution data represented by the dotted lines. Cost values use the simple LCOE technique.**

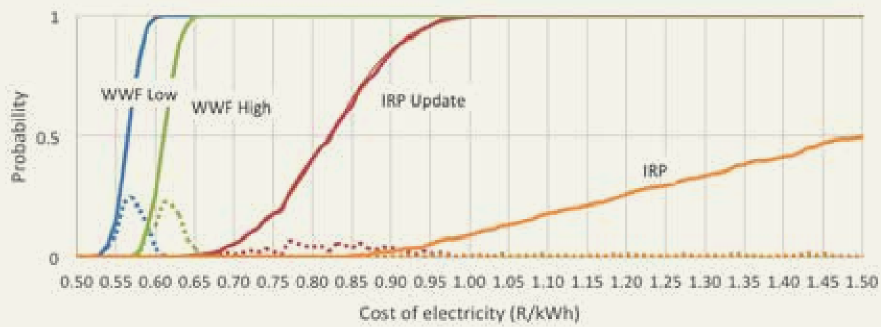


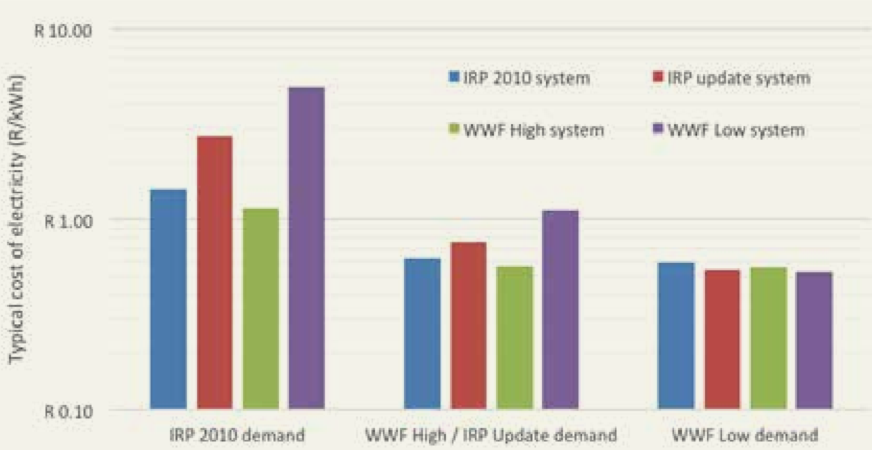
Figure 57 is a cumulative distribution function (CDF) plot of the four scenarios using simple LCOE, but based on an assumption that all power plants operating prior to the end of 2014 have been paid for, all plants brought into operation from 2015 onwards requires full capital budgeting and no cost is associated with transmission system upgrades as explained in the report methodology. In other words, the values are somewhat relevant but, strictly speaking, only for comparative purposes. Figure 58 presents the same data in simplified standard deviation format. While the IRP case does not resemble a normal distribution, the other three scenarios do. Thus, for the WWF scenarios and the IRP Update, the standard distribution represents roughly a 68% probability given the cost assumptions.

Figure 58: **Simple LCOE of the same scenarios expressed as a standard deviation.**

The bias towards low cost for the WWF scenarios speaks for itself. The IRP Update scenario is both higher cost and higher uncertainty. The IRP scenario suffers from excessive use of all expensive fuels, very high fuel cost uncertainty, and most of all a very high cost of unserved electricity.

The final test of the WWF scenario is the test of cost robustness. Each scenario was subjected to each demand level in the four scenarios. As the IRP Update and WWF High demand expectations are essentially the same, comparisons were made against the IRP, IRP Update and WWF Low demands as the high, medium and low demand cases respectively. The result is plotted in Figure 59.

Figure 59: **Cost probabilities of the scenarios using simple LCOE and 50th percentile cost values.**



It was anticipated that the WWF High scenario would benefit from the balanced system described earlier, but not to the extent to which it offered robustness in the results. Unexpectedly, the result shows that the WWF High system outperforms the IRP system for the high (IRP) demand case. The IRP Update struggles with the high demand case, as was expected, while the WWF Low is the worst performer.

On the low demand side, the scenarios largely collapse, but with WWF Low and the IRP Update looking similar. Interestingly, the cost of the WWF High scenario is not much higher than the lowest cost options. This scenario benefits from fuel savings, hence the slight decrease in cost compared with the medium demand.

A renewable-centric system is one that can add capacity at short notice, even at utility scale. Given this definition, which is conceptualised for low dependence on system needs from a demand response point of view, the WWF High and WWF Low are essentially variants of the same overall WWF scenario. Accordingly, the WWF scenario outperforms in every case by a considerable margin making it highly resilient to changes in demand, fuel cost uncertainty and technology cost uncertainty.

CONCLUSIONS

The report concludes with a summary of findings and conclusions before recommendations are made regarding follow up work and the authors' recommendations on how to commence with some immediate actions towards a faster rollout of renewable energy.

Summary of findings

While conducting research for this project, references confirmed – as has been heard and experienced by the authors – that the coal power fleet reliability is decreasing. The IRP Update does not anticipate coal power availability to improve significantly. Adding to this problem is the long and delayed commissioning of the new coal power plants as well as uncertainty regarding the cost and timing of new nuclear capacity. To counter this, solar and wind projects are successfully connecting to the grid in typically 18 to 24 months of closing. In a way, this highlights a key point in this work: that the scalability, flexibility and ability to incrementally add power to the system quickly must be taken seriously.

A 2030 electricity system that prioritises RE over nuclear or coal power appears initially to not only be feasible, but advantageous. Within constraints of the Eskom grid plans, excellent renewable resources within proximity of the current grid and assuming that all scenarios expect a high cost burden on transmission in the future, the WWF scenario offers best performance and cost.

The proposed distribution of solar and wind power, in combination with sufficient mid-merit storage and peaking plants, provides for a system that is lowest cost and surprisingly resilient to changes in demand. Additionally, because of the lower dependence on resources from abroad or volatility in fuel prices in general, the low cost renewable case also has a more predictable cost. Using the study's cost assumptions, the generation system produces power from about R0.60/kWh (in today's terms) on average without much variance for the next 15 years.

This system likely requires significant investment in gas supply to avoid the cost of diesel. At the same time, the system benefits from fuel savings in coal, gas and diesel due to the balance between solar, wind and pumped storage capacities.

For this first system-wide electricity model, the decision was made not to include too many dispatch rules, including forecasting. Instead, the scenarios are presented on a simpler, more conservative, but equal footing as a basis for initial discussion. High renewable scenarios will likely benefit more from detailed optimization, including forecasting, system operator behaviour and specific maintenance scheduling amongst many other possible improvements. In turn, these can lead to a more robust system, possibly reducing the burden on avoided cost generators using diesel and gas.

Finally, various ways of configuring the system were attempted, but given the assumptions in cost, technology and modelling method, a system that is anything but renewable-centric could not be justified. It is necessary, nevertheless, to take care of South Africa's existing fleet of power plants to avoid increased cost of power in this timeframe.

Conclusions

As proposed in the WWF scenario, a renewable-centric system is a more sensible system for the future. Although well understood but not explicitly covered in this report, renewables offer a higher share of localization, industrialization and employment. In a system that can expand at a rate needed for demand at any time and with local energy resources, energy security is bound to be higher.

This study suggests that the WWF scenario is not only viable, it is economically advantageous to accelerate the fraction of power generation beyond the proposed 20% threshold by 2030. The benefit of the lower cost WWF scenario is directly demonstrated in this analysis, but other benefits of a higher fraction renewable system were also encountered. While a balanced system needs significant backup generation capacity, the inexpensive CCGT and OCGT capacity is very sparingly used, which reduces the availability and cost uncertainty of gas and diesel. An uncomfortable degree of uncertainty relating to the cost of nuclear power was observed. Some recent data suggests that the nuclear capital cost range used in the study is significantly underestimated. Uncertainty regarding construction duration, permitting and risk are out of the scope of this work but will need to be accounted for. Even with the lower nuclear cost assumptions made, replacement of renewable capacity for nuclear capacity did not make sense in this model.

The double-benefit of the WWF scenario in providing resilience to changing demand and in being responsive to additional capacity implies that the provision of electricity should not hold up the economy. Based on the success of the REIPPPP to date, it will also add to the economy in the participation of adding and maintaining renewable power.

If this adventurous step is taken, a benefit could be seen from an accelerated learning rate that will ensure that South Africa will be ready with even lower cost solutions when a large fraction of the older coal power fleet eventually starts to be decommissioned.

Next steps

While several investigations have been undertaken using spatial-temporal techniques by the authors, this report documents a first step seeking to conceptually scope an improved electricity system with a significant uptake of renewables. The authors plan to improve, expand and promote the methods in order to offer more tools to the South African electricity community. Some suggestions for further work include

- Studies considering longer time series of demand and resource information that will inspire higher confidence.
- Improved technical and cost assumptions based on broader stakeholder input.

- Integration of a transmission system model and detailed demand modelling by location and by forecasting of end-user behaviour in future. This work will need to be undertaken in partnership with Eskom and DoE, particularly for information relating to the real electricity system and plans.

Beyond these next step items, many other improvements and refinements that relate to forecasting, transmission stability and the overall optimal design and operation of a renewable-centric system are possible and likely necessary. In general, a migration towards full integration of bottom-up technology behaviour in a spatial-temporal simulation integrated into energy systems optimization tools would not only be desirable, but viewed as essential.

Fast-track ideas

An electricity system that has a much higher fraction of renewables can be implemented in a relatively short span of time. At this time in particular, any additional capacity will help the system as outlined in the recent CSIR report (2015).

The following list is based on experiences in the authors' workspace and the literature studied to develop and refine the scenarios for this project.

Facilitate adoption of solar PV at every level now. If a programme existed now to add a single 250W solar panel on 5 million residential rooftops, the system would add 1,250MW to demand side management. The same is applicable to every commercial, industrial and municipal rooftop. Keep in mind that this renewable-centric system does not mind ebbs and flows in daily demand fluctuations, so there is likely no imminent limit in a safe and sensible allocation to this proposal.

Construct renewable power capacity at pumped storage systems and other power plants. Given existing infrastructure, it would make sense to immediately plan for solar and wind power at existing nodes that are capable of taking on power. Renewable power at pumped storage plants means that the generator is located at an existing storage system. While not considered in the scope of this work, in hindsight it appears to be an optimal opportunity. As the current electricity crisis is a result of insufficient capacity, the pumped storage systems do not receive sufficient charging time, exacerbating the situation. Adding renewable power there would provide charging options, effectively boosting total system availability. During times of excess power where pumped storage is not needed, the same renewable system can feed into the grid. Similar benefits would exist at existing coal power plants.

Provide stability through secure (multi-year) and critical mass REIPPPP allocations. If IPPs were able to secure enough new capacity each year, industrialization could accelerate with higher local content and employment. Provided power plants are sensibly located and sized, IPPs do not pose an investment risk to the public.

Increase modelling awareness and resources. The authors believe that much work is still needed to improve energy systems forecasting in South Africa. The various national stakeholders need to commit to working collaboratively in the national interest. It is vital that a well performing and economically viable system be well considered from the start.

Set incentives in the interest of the system. Renewable projects are currently incentivised primarily for maximum self-interest resulting in the geographic placement and design optimised for plant profit. Even a set time of day tariff structure does not accommodate a renewable system in the national interest. Coordinated planning is required in a renewable-centric system to ensure a diversity of sites are optimally used and that power generation is rewarded based on when it is most needed in the system.

Closing

This study is a first step in what will hopefully lead to a greater emphasis in conceiving the future South African electricity system based on more detailed techno-economic analysis. Many improvements and refinements are possible and indeed required that would be at a tenfold or hundredfold level in comparison with this early spatial-temporal simulation.

It is hoped that the report and the debates and arguments that follow will be vigorous. This work is only as good as the many assumptions that have been made, and in order to take the work further, the input of all role players is required.

Finally, the authors appreciate the foresight of WWF-SA and Sustainable Solutions in creating the WWF renewable vision for South Africa and enabling the authors to demonstrate their methods. If these findings are generally valid, placing all stakeholder efforts in a well-designed electricity system based on renewable technologies could result in an enviable path towards energy independence that can earn dividends immediately.

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STERG SOLAR THERMAL ENERGY RESEARCH GROUP

CENTRE FOR RENEWABLE & SUSTAINABLE ENERGY STUDIES

CRSES & STERG

The Centre for Renewable and Sustainable Energy Studies (CRSES) acts as a central point of entry into Stellenbosch University for the general field of renewable energy. Some contract research projects are completed within CRSES while others end up in the other academic departments or research entities of the University. Stellenbosch University has a Division for Research Development that, in cooperation with the Finance and Legal Departments, manages all larger research contracts within the University, including those of CRSES.

The Solar Thermal Energy Research Group (STERG) is housed in the Department of Mechanical and Mechatronic Engineering and is affiliated with the Centre for Renewable and Sustainable Energy Studies. STERG's vision is to be a world leading university solar thermal and CSP research group, delivering graduates that will enable South Africa to achieve its solar energy potential from within and be competitive abroad.

http://concentrating.sun.ac.za/

GeoModel SOLAR

GeoModel Solar

GeoModel Solar is the technical consultant, developer and operator of the SolarGIS database and online system. The company aims to increase efficiency and reduce uncertainty in solar energy projects by delivering bankable solar resource data and innovative software services for the planning, financing, monitoring and forecasting of solar power.

The company builds on 25 years of expertise in geoinformatics and environmental modelling, and 14 years in solar energy and photovoltaics. GeoModel Solar strives for the development and operation of high-resolution, quality-assessed global databases with a focus on solar resource and energy-related weather parameters. The company is also a member of the European Photovoltaic Industry Association, International Solar Energy Society and Slovak Association of Photovoltaic Industry.

Based on scientific knowledge, dedication and professional attitude, GeoModel Solar aims to contribute to the change of the global economic strategies towards sustainable energy production and consumption and support of solar energy.

http://geomodelsolar.eu/

WASA

The Wind Atlas for South Africa project is coordinated by The South African National Energy Development Institute and is the result of a twinning arrangement between the Danish Research Institute and world leader in wind energy (DTU) and South African partners. The main aim of the programme is to develop and employ numerical wind atlas methods and to develop capacity to enable the planning of large-scale exploitation of wind power in South Africa, including a dedicated wind resource assessment and siting tools for planning purposes; i.e. a Numerical Wind Atlas and database for South Africa. WASA data also represents a valuable contribution to this project.

http://www.wasaproject.info/

WWF

WWF is one of the world's largest and most experienced independent conservation organisations, with over 5 million supporters and a global network active in more than 100 countries. WWF's mission is stop the degradation of the planet's natural environment and to build a future in which humans live in harmony with nature, by conserving the world's biological diversity, ensuring that the use of renewable natural resources is sustainable, and promoting the reduction of pollution and wasteful consumption.

The Global Climate & Energy Initiative (GCEI) is WWF's global programme addressing climate change and a move to 100% renewable energy through engagement with business, promoting renewable and sustainable energy, scaling green finance and working nationally and internationally on low carbon frameworks. The team is based over three hubs – Mexico, South Africa and Belgium.

www.panda.org/climateandenergy

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Feasibility of the WWF Renewable Energy Vision 2030 – South Africa

Why we are here
To stop the degradation of the planet's natural environment and to build a future in which humans live in harmony with nature.

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