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20170331-CSIR-EC-ESPO-REP-DOE-1.1A Rev 1.1

Formal comments on the Integrated Resource Plan (IRP) Update Assumptions, Base Case and Observations 2016

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April 3, 2017

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EXECUTIVE SUMMARY

As defined in the Electricity Regulation Act, 2006; the Department of Energy (DoE), the system operator and the National Energy Regulator of South Africa (Nersa) are responsible for the development of the **Integrated Resource Plan (IRP) as a plan for the electricity sector at the national level in South Africa**. The IRP broadly includes input planning assumptions (on the supply and demand side), a modelling process and scenario planning following which a base plan is derived from the least-cost generation investment requirements within the electricity sector. The primary result from the IRP is the identification of the **generation capacity required (per technology) and the requisite timing in the long-term** based on a set of input assumptions and predefined constraints.

The most recent approved and gazetted version of the IRP is the IRP 2010-2030. The **current revision of the IRP (the Draft IRP 2016) was published by the DoE for public comment in October 2016** and includes updated input assumptions including demand forecasts, existing plant performance, supply technology costs, decommissioning schedules and newly commissioned/under construction as well as preferred bidder power generators (as part of the Renewable Energy Independent Power Producer Programme (REIPPPP) and base-load coal Independent Power Producer (IPP) program). The time horizon for the draft IRP 2016 is up to the year 2050. The plan defined some preliminary results in the form of a proposed Base Case and two other selected scenarios.

As part of the IRP update process, the DoE engages in a multi-stage stakeholder engagement process (including public engagements) to ensure all affected stakeholders are consulted including national and local government, business, organised labour and civil society. **This document contains the CSIR's formal comments on the draft IRP 2016**.

The CSIR determined the **least cost, unconstrained electricity mix by 2050 as input into the IRP 2016 public consultation process**. A **conservative approach** is always taken where pessimistic assumptions for new technologies and optimistic assumptions for established technologies are always made. More specifically; conventional technologies (coal, nuclear, gas CAPEX) were as per IRP 2016, stationary storage technologies (batteries) were as per IRP 2016, natural gas fuel costs were assumed slightly more expensive than IRP 2016, solar PV was aligned with original IRP 2010 cost assumptions while wind is kept constant into the future at the latest South African REIPPPP result (by 2030/2040/2050). Job numbers were also conservative (from McKinsey study commissioned by the DoE in the context of the Integrated Energy Plan (IEP)) but adjusting upwards for coal power generation and coal mining.

The result of this is that it is **least cost for any new investment in the power sector to be solar PV, wind or flexible power**. Solar PV, wind and flexible power generators (e.g. gas, CSP, hydro, biogas) are the cheapest new-build mix. There is no technical limitation to solar PV and wind penetration over the planning horizon until 2050. A >70% renewable energy share by 2050 is cost optimal, replacing all plants that decommission over time and meeting new demand with the new optimal mix.

South Africa has the unique opportunity to decarbonise its electricity sector without pain. By this, the authors mean that **clean and cheap are no longer trade-offs anymore**. The Least Cost scenario run is the mix that is the cheapest, emits less CO_2 , consumes less water and creates more jobs in the electricity sector than both Draft IRP 2016 Base Case and Carbon Budget scenarios.

In this submission, deviations from Least Cost have been quantified to inform policy adjustments. Compared to the Least Cost:

- The **IRP 2016 Base Case** is **R70-billion/yr more costly**, emits twice as much CO_2, two and a half times more water is consumed and provides 10% less jobs by 2050.
- The **IRP 2016 Carbon Budget** is **R60-billion/yr more costly**, emits 15% more CO_2, consumes 20% more water and provides 20% less jobs by 2050.
- The **Decarbonised** scenario is **R50-billion/yr more costly**, 95% decarbonised, uses 30% less water and provides 5% more jobs by 2050.

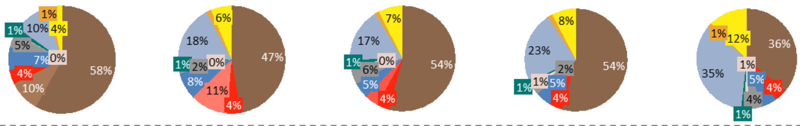
The Least Cost scenario is also adaptable and resilient to a range of input assumption changes relative to other scenarios and therefore more robust against unforeseen changes in demand and cost.

In addition to the detailed study performed to determine the Least Cost energy mix for South Africa, this submission includes technical aspects of power system operations and planning including transmission network infrastructure requirements and system services.

The **cost of ensuring system frequency stability (sufficient system inertia)** has been quantified in this submission. Connecting conventional technologies (nuclear/coal/gas) via HVDC and/or solar PV/wind to the grid reduces system inertia. This reduces the inherent stabilising effect of synchronous inertia during contingency events. Many technical solutions to operate low-inertia systems are available but the CSIR assumed a worst case using state-of-the-art technology (very high costs, no further technology and/or cost advancements) nor further increase in engineering solutions to deal with low-inertia systems. In all scenarios, the **worst-case cost are well below 1% of total cost of power generation by 2050** (some scenarios are much lower than 1%).

Transmission network infrastructure was costed at a high level for selected scenarios (Base Case, Carbon Budget and Least-Cost). The high-level cost estimates for shallow and deep grid connection costs for all scenarios showed that the **Least Cost scenario scenario is also R20-30 billion/yr cheaper** compared to the Draft IRP 2016 Base Case and Carbon Budget case on transmission network infrastructure requirements.

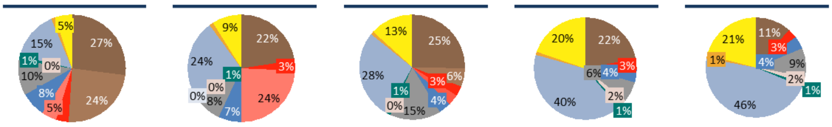
Scenario summaries for 2030, 2040 and 2050 (conservative costs applied)

2030		As per Draft IRP 2016: IRP 2016 Base Case	As per Draft IRP 2016: IRP 2016 Carbon Budget	As per DoE: Unconstrained Base Case	Least Cost	Decarbonised
Energy Mix in 2030	Demand: 343 TWh					
Cost in 2030	Total system cost[1] (R-billion/yr)	384	403	374	367	370
	Average tariff (R/kWh)	1.12	1.17	1.09	1.07	1.08
Environ-ment in 2030	CO_2 emissions (Mt/yr)	251	176	214	204	141
	Water usage (billion-litres/yr)	216	167	204	196	142
Jobs[2] in 2030	Direct & supplier ('000)	93-153	100-142	96-146	101-149	112-144

Because of lack of data, zero jobs for biomass/-gas assumed (affects Decarbonised)

Coal | Nuclear | Hydro+PS | Peaking | Other storage | CSP
Coal (new) | Nuclear (new) | Gas | Biomass/-gas | Wind | Solar PV

[1] Only power generation (Gx) is optimised while cost of transmission (Tx), distribution (Dx) and customer services is assumed as ≈0.30 R/kWh (today's average cost for these items)
[2] Lower value based on McKinsey study (appendix of IEP), higher value based on CSIR assumption with more jobs in the coal industry; Sources: Eskom on Tx, Dx cost; CSIR analysis; flaticon.com

2040		As per Draft IRP 2016: IRP 2016 Base Case	As per Draft IRP 2016: IRP 2016 Carbon Budget	As per DoE: Unconstrained Base Case	Least Cost	Decarbonised
Energy Mix in 2040	Demand: 428 TWh					
Cost in 2040	Total system cost[1] (R-billion/yr)	535	530	511	495	498
	Average tariff (R/kWh)	1.25	1.24	1.19	1.15	1.16
Environ-ment in 2040	CO_2 emissions (Mt/yr)	251	176	214	113	141
	Water usage (billion-litres/yr)	216	167	204	66	142
Jobs[2] in 2040	Direct & supplier ('000)	185-241	191-216	199-234	234-258	242-254

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Coal | Nuclear | Hydro+PS | Peaking | Other storage | CSP
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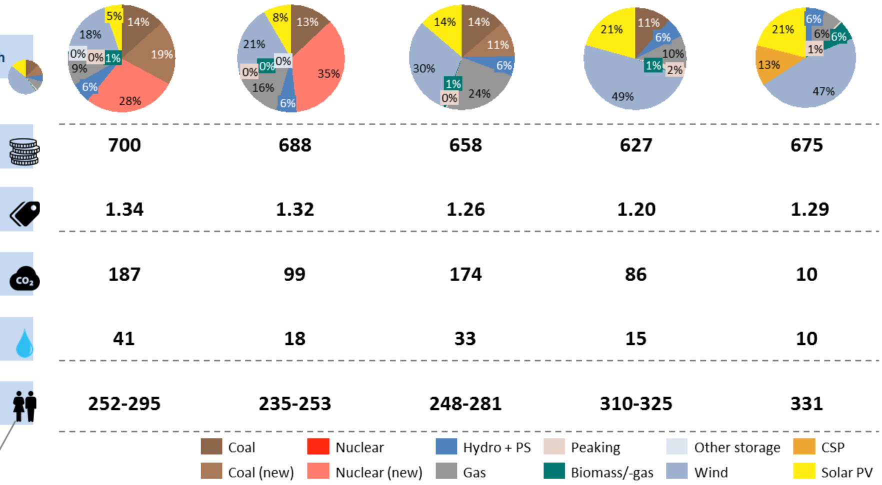
2050		As per Draft IRP 2016: IRP 2016 Base Case	As per Draft IRP 2016: IRP 2016 Carbon Budget	As per DoE: Unconstrained Base Case	Least Cost	Decarbonised
Energy Mix in 2050	**Demand: 522 TWh**					
Cost in 2050	**Total system cost**[1] (R-billion/yr)	700	688	658	627	675
	Average tariff (R/kWh)	1.34	1.32	1.26	1.20	1.29
Environ-ment in 2050	**CO_2 emissions** (Mt/yr)	187	99	174	86	10
	Water usage (billion-litres/yr)	41	18	33	15	10
Jobs[2] in 2050	**Direct & supplier** ('000)	252-295	235-253	248-281	310-325	331



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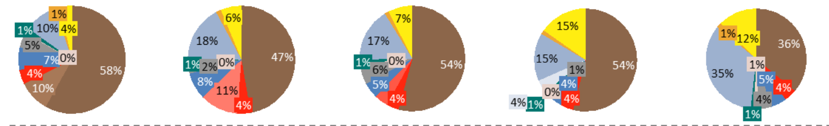
[2] Lower value based on McKinsey study (appendix of IEP), higher value based on CSIR assumption with more jobs in the coal industry; Sources: Eskom on Tx, Dx cost; CSIR analysis; flaticon.com

Scenario summaries for 2030, 2040 and 2050 (expected costs applied)

2030		As per Draft IRP 2016: IRP 2016 Base Case ("Expected" costs)	As per Draft IRP 2016: IRP 2016 Carbon Budget ("Expected" costs)	As per DoE: Unconstrained Base Case ("Expected" costs)	Least Cost ("Expected" costs)	Decarbonised ("Expected" costs)
Energy Mix in 2030	Demand: 343 TWh					
Cost in 2030	Total system cost[1] (R-billion/yr)	382	399	369	353	355
	Average tariff (R/kWh)	1.11	1.16	1.08	1.03	1.03
Environ-ment in 2030	CO_2 emissions (Mt/yr)	251	176	214	206	141
	Water usage (billion-litres/yr)	216	167	204	193	142
Jobs[2] in 2030	Direct & supplier ('000)	93-153	100-142	96-146	106-156	112-144



Because of lack of data, zero jobs for biomass/-gas assumed (affects Decarbonised)

Coal, Coal (new), Nuclear, Nuclear (new), Hydro+PS, Gas, Peaking, Biomass/-gas, Other storage, Wind, CSP, Solar PV

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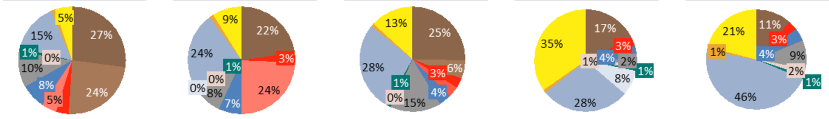
[2] Lower value based on McKinsey study (appendix of IEP), higher value based on CSIR assumption with more jobs in the coal industry; Sources: Eskom on Tx, Dx cost; CSIR analysis; flaticon.com

2040		As per Draft IRP 2016: IRP 2016 Base Case ("Expected" costs)	As per Draft IRP 2016: IRP 2016 Carbon Budget ("Expected" costs)	As per DoE: Unconstrained Base Case ("Expected" costs)	Least Cost ("Expected" costs)	Decarbonised ("Expected" costs)
Energy Mix in 2040	Demand: 428 TWh					
Cost in 2040	Total system cost[1] (R-billion/yr)	548	526	489	444	465
	Average tariff (R/kWh)	1.28	1.23	1.14	1.04	1.09
Environ-ment in 2040	CO_2 emissions (Mt/yr)	251	176	214	91	141
	Water usage (billion-litres/yr)	216	167	204	53	142
Jobs[2] in 2040	Direct & supplier ('000)	185-241	191-216	199-234	273-294	242-254



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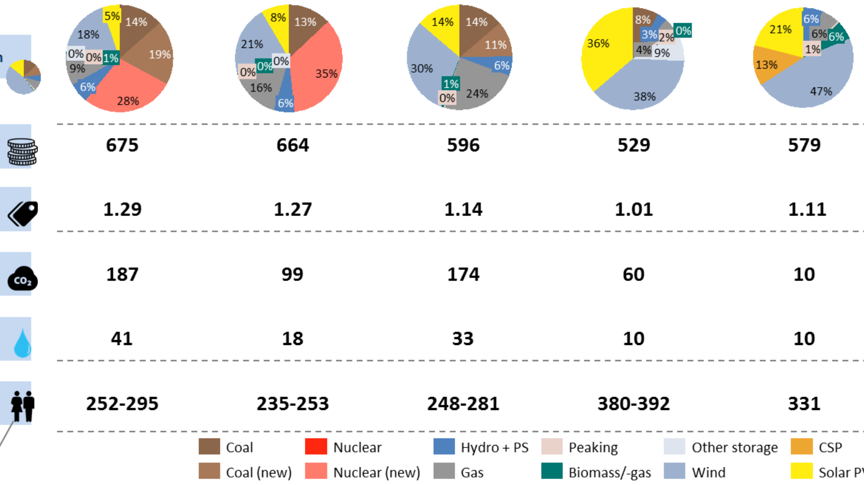
[2] Lower value based on McKinsey study (appendix of IEP), higher value based on CSIR assumption with more jobs in the coal industry; Sources: Eskom on Tx, Dx cost; CSIR analysis; flaticon.com

2050		As per Draft IRP 2016 IRP 2016 Base Case (“Expected” costs)	As per Draft IRP 2016 IRP 2016 Carbon Budget (“Expected” costs)	As per DoE Unconstrained Base Case (“Expected” costs)	Least Cost (“Expected” costs)	Decarbonised (“Expected” costs)
Energy Mix in 2050	Demand: 522 TWh	(see charts below)				
Cost in 2050	Total system cost[1] (R-billion/yr)	675	664	596	529	579
	Average tariff (R/kWh)	1.29	1.27	1.14	1.01	1.11
Environment in 2050	CO_2 emissions (Mt/yr)	187	99	174	60	10
	Water usage (billion-litres/yr)	41	18	33	10	10
Jobs[2] in 2050	Direct & supplier ('000)	252-295	235-253	248-281	380-392	331



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ABBREVIATIONS

AMPS	All Media and Products Survey
BW	Bid Window
CAES	Compressed Air Energy Storage
CCT	Critical Clearing Time
COMELEC	Comité Maghrébin de l'Electricité
COUE	Cost of Unserved Energy
CPI	Consumer Price Inflation
CSIR	Council for Scientific and Industrial Research
CSP	Concentrated Solar Power
DEA	Department of Environmental Affairs
DoE	Department of Energy
EAPP	Eastern African Power Pool
EIUG	Energy Intensive User Group of Southern Africa
EMS	Energy Management System
ENTSO-E	European Network of Transmission System Operators for Electricity
ERCOT	Electricity Reliability Council of Texas
EAF	Energy Availability Factor
EWH	Electric water heating
FCEH	Final Consumption Expenditure of Households
FOM	Fixed Operations and Maintenance
GCCA	Grid Connection Capacity Assessment
GHG	Greenhouse Gas
GDP	Gross Domestic Product
HVDC	High Voltage Direct Current
IEP	Integrated Energy Plan
INDC	Intended Nationally Determined Contribution
IPP	Independent Power Producer

IRP	Integrated Resource Plan
LCOE	Levelised Cost of Electricity
LDC	Load Duration Curve
LNG	Liquified Natural Gas
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
MACE	Ministerial Advisory Council on Energy
MapRE	Multi-criteria Analysis for Planning Renewable Energy
MILP	Mixed Integer Linear Programming
NDC	Nationally Determined Contribution
Nersa	National Energy Regulator of South Africa
openmod	Open Energy Modelling Initiative
OPSD	Open Power System Data
OnSSET	OpeN Source Spatial Electrification Toolkit
OSeMOSYS	Open Source Energy Modelling System
PM	Particulate matter
PPD	Peak Plateau Decline
PSAT	Powerflow and Short-Circuit Analysis Tool
PyPSA	Python for Power Systems
RE	Renewable Energy
REIPPPP	Renewable Energy Independent Power Producer Programme
RoCoF	Rate of Change of Frequency
SAARF	South African Audience Research Foundation
SAPP	Southern African Power Pool
SciGRID	Scientific GRID
SCO	Synchronous Condensor
SGP	Strategic Grid Plan
SSAT	Small-Signal ATool

STATCOM	Static Synchronous Compensator
SVC	Static VAr Compensator
TDP	Transmission Development Plan
TSAT	Transient Security Assessment Tool
TSO	Transmission System Operator
UNFCCC	United Nations Framework Convention on Climate Change
VoLL	Value of Lost Load
VSAT	Voltage Security Assessment Tool
WSAT	Wind Security Assessment Tool
VOM	Variable Operations and Maintenance
WAPP	Western African Power Pool
WECC	Western Electricity Coordinating Council

1 Background

1.1 The IRP process and new generation capacity in South Africa

The IRP is the the plan that informs the electricity sector specifically. As described in the Electricity Regulation Act No. 4 of 2006 [1] and regulations in the Electricity Regulations for New Generation Capacity published in 2009 [2]; the DoE, the system operator and Nersa are responsible for the development of the IRP as a plan for the electricity sector at the national level. The IRP broadly includes input planning assumptions (on the supply and demand side), a modelling process and scenario planning following which a base plan is derived from the least-cost generation investment requirements with the inclusion of all primary costs within the electricity sector.

The IRP is a living plan that is updated periodically in order to ensure future generation capacity investments are made on an informed basis considering the latest trends and developments both locally and internationally in supply technology costs, demand forecasts for electricity and existing generation fleet performance. The primary result from the IRP is the identification of the generation capacity required (per technology) and the requisite timing in the long term based on a set of input assumptions and predefined constraints. Risk adjustment is included in this process based on the most probable scenarios and government policy objectives including renewable and alternative energies, demand side management and energy efficiency [2]. The primary responsibility for energy policy objectives and priorities are provided by the DoE but guided by policy priorities from other national departments. Following this process, the plan is approved by the Minister of Energy and gazetted in the Government Gazette. The Minister then makes Determinations informed by the gazetted IRP on generation capacity to be procured. This process is shown graphically in Figure 1 with the scenario based approach taken in this process shown graphically in Figure 2.

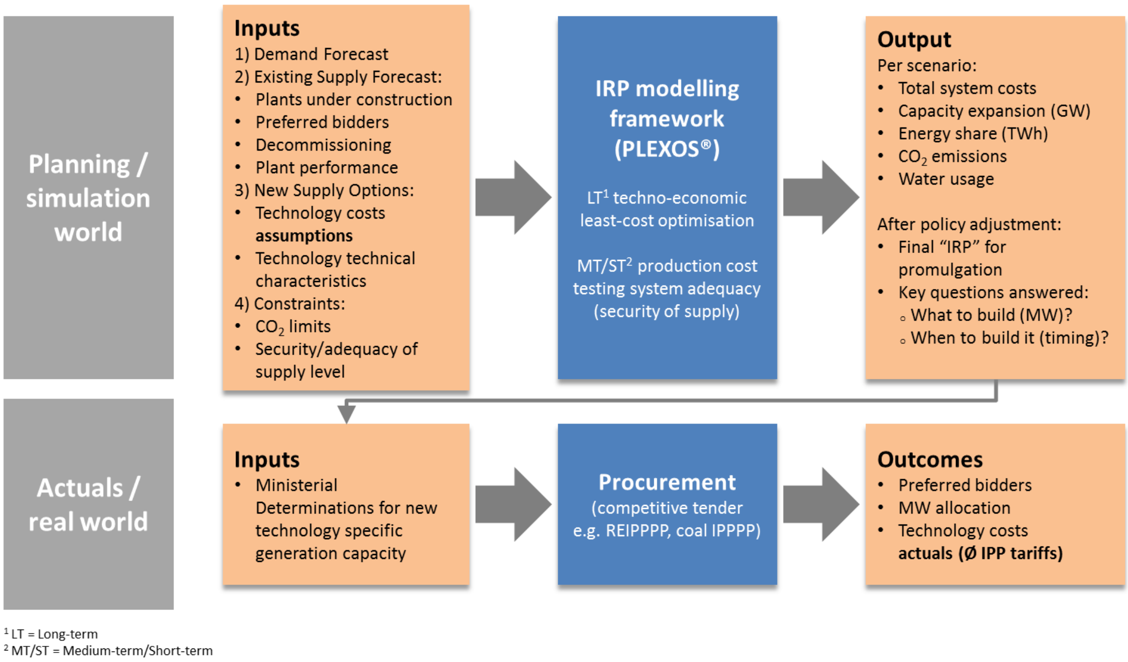


Figure 1: High level process of the IRP in South Africa and implementation highlighting how simulation/modelling is translated into real world/implementation of new generation capacity in South Africa.

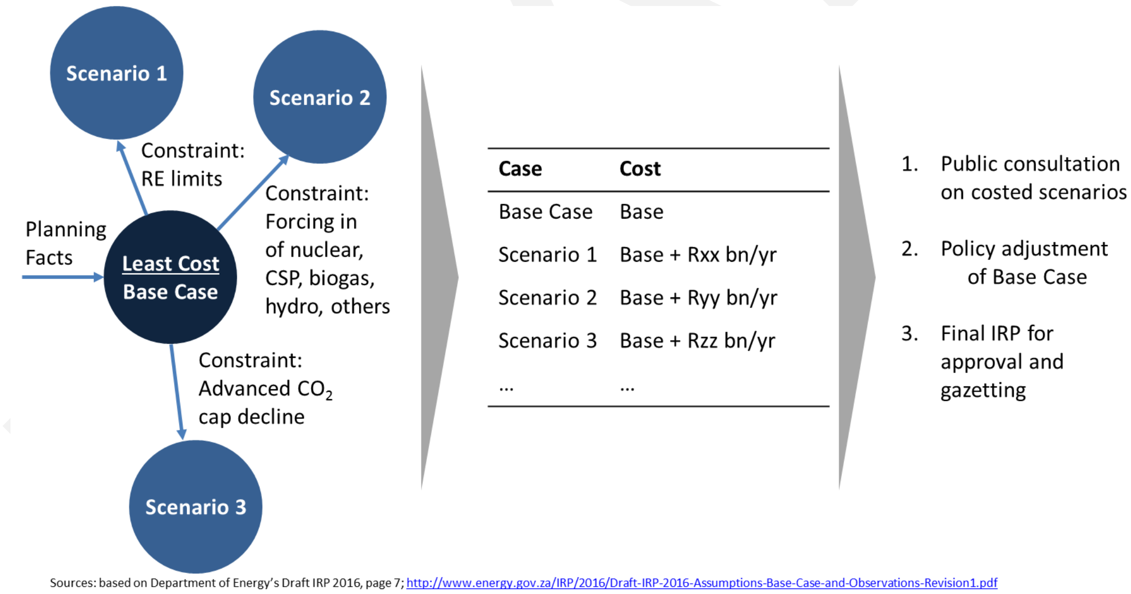
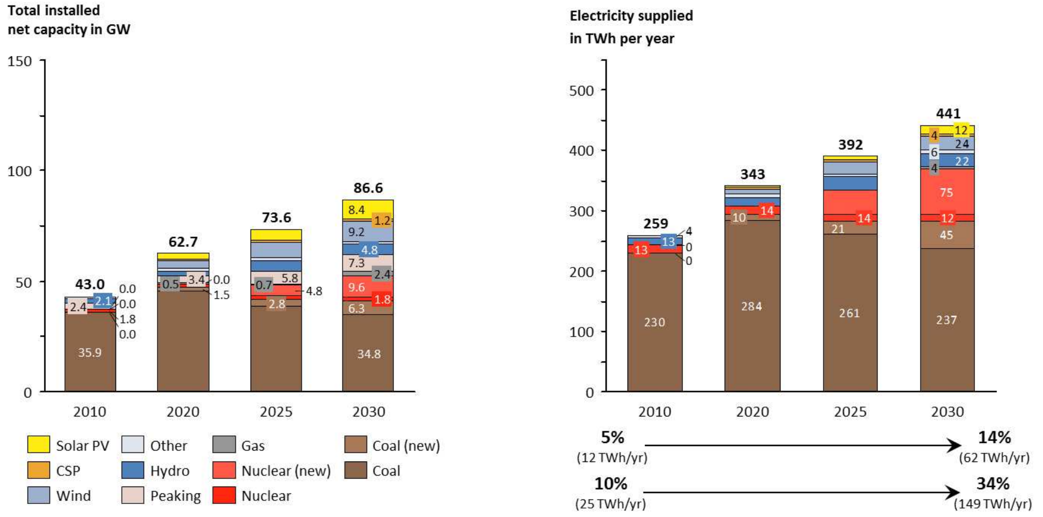


Figure 2: Scenario based planning as adopted in the IRP planning process in South Africa [3].

The most recent version of the IRP that has been approved and gazetted is the IRP 2010-2030 [4]. The Policy Adjusted Scenario from the IRP 2010-2030 is currently being implemented and is summarised in Figure 3. There was an update to the IRP 2010-2030 published in 2013 but this was never approved or gazetted [5].

The current revision of the IRP (the "IRP 2016") was published by the DoE for public comment in October 2016 and includes updated input assumptions including demand forecasts, existing plant performance, supply technology costs, decommissioning schedules and newly commissioned/under construction as well as preferred bidder power plants (as part of the REIPPPP and base-load coal IPPs. The time horizon for the published draft of the IRP 2016 is 2060 (but only up to 2050 is reported on). Some preliminary results are also shared in the form of a proposed Base Case (as shown ini Figure 4) and two other selected scenarios [3, 6]. As part of the IRP update process, the DoE engages in a multi-stage stakeholder engagement process (including public engagements) to ensure all affected stakeholders are consulted including national and local government, business, organised labour and civil society. The DoE is currently engaging publicly on the IRP 2016 with the comment period open until 31 March 2017.



Note: Installed capacity and electricity supplied excludes pumped storage; Renewables include solar PV, CSP, wind, biomass, biogas, landfill and hydro (includes imports).
Sources: DoE IRP 2010-2030; CSIR Energy Centre analysis

Figure 3: Installed capacity (GW) and energy mix (TWh) to 2030 from the IRP 2010 (Policy adjusted) showing goal of 23.6 GW of RE based electricity which then contributes 14% to the overall energy mix

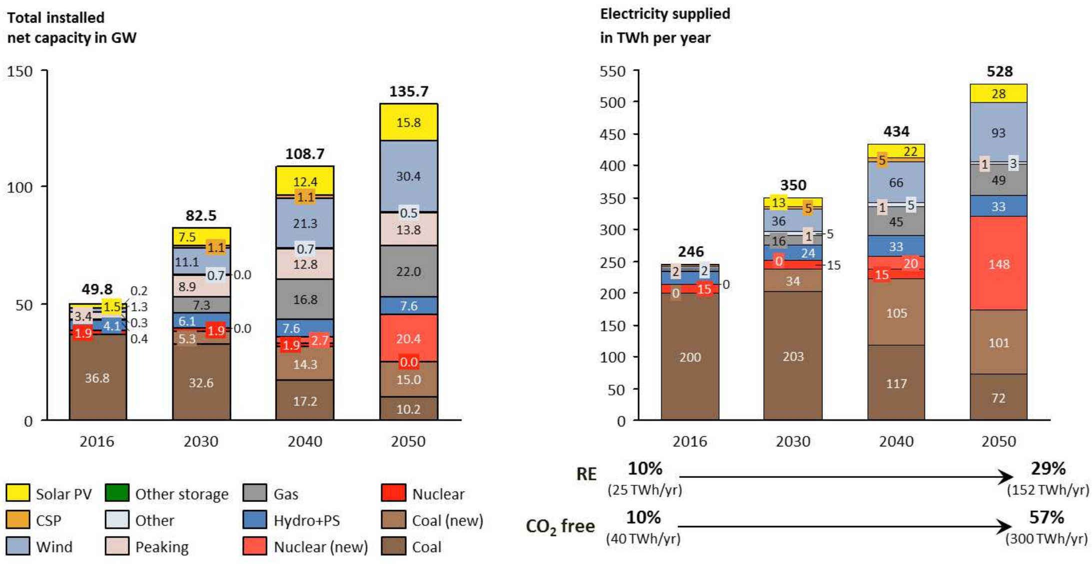


Figure 4: Installed capacity (GW) and energy mix (TWh) to 2050 from the Draft IRP 2016 showing goal of ≈24 GW and ≈51 GW of RE based electricity by 2030 and 2050 respectively (contributing ≈21% and ≈28% to the energy mix in 2030 and 2050 respectively)

1.2 CSIR mandate and this submission/contribution

The global energy industry is in a restructuring phase, driven by the need for more efficient use of energy, the proliferation of Renewable Energy (RE) and new technologies (electric vehicles, hydrogen, batteries). The CSIR's energy research responds to global mega-trends while addressing national research priorities. The objective is to make CSIR the leading research institution on the African continent in energy and to be globally recognised. The formal comments provided as part of this submission is part of the energy research under one of the research groups at the CSIR Energy Centre (as shown in Figure 5)- *"Energy Systems"*.

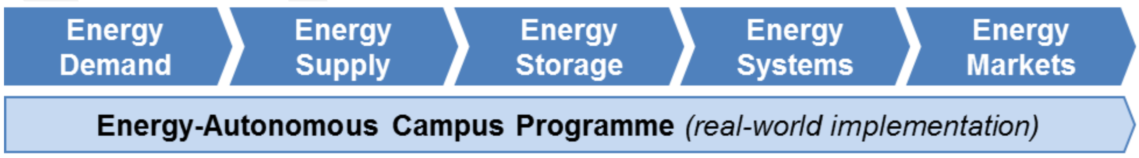


Figure 5: High level representation of CSIR Energy Centre research group focus areas.

As part of the IRP 2016 update process, the DoE has requested for inputs from the public as part of provincial roadshows undertaken towards the end of 2016 and beginning of 2017. The Council for Scientific and Industrial Research (CSIR) has already provided oral inputs (in early December 2016) as part of these roadshows [7].

The CSIR was established in 1945 and is mandated by the Scientific Research Council Act of 1988 (updated in 1990) [8] section (3) as follows:

> *The objects of the CSIR are, through directed and particularly multi-disciplinary research and technological innovation, to foster, in the national interest and in fields which in its opinion should receive preference, industrial and scientific development, either by itself or In co-operation with principals from the private or public sectors, and thereby to contribute to the improvement of the quality of life of the people of the Republic, and to perform any other functions that may be assigned to the CSIR by or under this Act.*
> *- THE SCIENTIFIC RESEARCH COUNCIL ACT No 46 of 1988*

This submission made by the CSIR is made in the spirit of openness and transparency to allow for appropriate discussion, peer-review and scrutiny of energy data and models. This is inspired by open collaboration initially driven by open source and collaborative software initiatives (which have been in existence for decades). This philosophy is starting to proliferate into the energy planning and operations environment with the key concepts presented briefly by Pfenninger in [9] with some examples of open modelling initiatives recently cited like Open Power System Data (OPSD) [10], Open Energy Modelling Initiative (openmod) [11] and open energy data via European Network of Transmission System Operators for Electricity (ENTSO-E) [12]. Examples of modelling tools like Open Source Energy Modelling System (OSeMOSYS) [13], Balmorel [14], Calliope [15], Python for Power Systems (PyPSA) [16], the OpeN Source Spatial Electrification Toolkit (OnSSET) [17], Scientific GRID (SciGRID) [18] and Dispa-SET [19] further reveal the trend towards open, transparent and collaborative energy data and models. Of particular interest considering the modelling framework used for the IRP 2016[1] is the open publishing of PLEXOS® models in continental Europe [21], Ireland [22], Australia [23] and the USA [24]. PLEXOS® datasets for various regions including inter alia Southern African Power Pool (SAPP), Eastern African Power Pool (EAPP), Western African Power Pool (WAPP), Electricity Reliability Council of Texas (ERCOT), Western Electricity Coordinating Council (WECC), the Caribbean, Phillipines and Chile are also provided by Energy Exemplar but are commercial at this stage [20].

This submission by the CSIR forms part of formal written inputs as requested by the DoE. The written inputs provided are informed by independent electricity sector modelling and analysis performed by CSIR in order to provide additional scientific knowledge and a fact base for the IRP public consultation process. The submission includes:

- Report (this document): *Formal comments on the Integrated Resource Plan (IRP) Update Assumptions, Base Case and Observations*.
- Model input assumption sheets (see section 4 and Appendix A for details).
- PLEXOS® model of the South African power system for long-term expansion planning and short-term to medium-term production cost modelling. To be available soon.

1.3 Document structure

This Report is structured as follows:

[1] PLEXOS® Integrated Energy Model by Energy Exemplar [20]

- Chapter 1 is this chapter and provides context as well as background to this document as part of the South African IRP 2016 public consultation process.
- Chapter 2 provides brief domestic and global context of key technology and primary fuel supply markets that are dominant in the IRP 2016.
- Chapter 3 outlines the methodology and approach followed in the work performed as part of the work undertaken.
- Chapter 4 presents a summary of key input assumptions that are used in the modelling undertaken.
- Chapter 5 presents the results from the key scenarios and sensitivities run by the CSIR as part of this submission.
- Chapter 6 takes a more detailed look at the medium-term horizon (2016-2030) to consider scenarios that are pertinent as well as to link the long-term capacity expansion planning performed to the 2050 horizon to a more current view of immediate and medium-term needs.
- Chapter 7 provides qualitative (and selectively quantitative) discussions on key technical considerations not necessarily included as part of the modelling framework used as well as not explicitly included in the IRP 2016 either e.g. power system stability, network infrastructure requirements.
- A number of Appendices complete the document and provide supplementary information ass part of this submission.

1.4 Acknowledgements

The authors would like to thank the CSIR Executive and Management for their continued support in preparing this submission.

This work is wholly funded by Parliamentary Grant funding.

2 A global and domestic review of supply technologies

Please refer to the attached slide deck that accompanies this submission [25] for a global view on the various supply technologies available to South Africa.

3 Methodology and approach

3.1 Electricity sector expansion planning and the modelling framework

Integrated resource planning for electricity is a long-term capacity expansion planning process typically applying least-cost planning principles to find the optimal mix of existing supply resources and new build supply options to meet expected future demand reliably in a city, province/state, country and/or region. A geospatial context can be considered in this optimisation where transmission and/or distribution network expansion is also considered and co-optimised with generation capacity expansion but this is currently not the case for South Africa in the IRP (but could be in future). In South Africa, an Integrated Resource Plan (IRP) for electricity is performed periodically at a national level with the DoE being the custodian of this process (see chapter 1 for more details on the IRP process).

Although significant reference works exist which detail the generation capacity expansion planning problem (amongst other aspects of power system economics and markets) [26, 27, 28, 29, 30], the least-cost objective can be graphically summarised as shown Figure 6. The total system cost $T(x)$ as a function of the level of investment in new generation capacity x is minimised. The level of investment at which this happens is x_{opt}. Total system cost is the sum of production costs $P(x)$ and investment costs $I(x)$. The costs that define investment costs $I(x)$ are the costs that characterise new capital investments i.e. capital costs (and the associated parameters that define this). Production costs $P(x)$ are the costs associated with operating existing as well as new candidate generation capacity investments i.e. Fixed Operations and Maintenance (FOM), Variable Operations and Maintenance (VOM) and fuel costs. Production costs also include the value placed on system adequacy via the Value of Lost Load (VoLL) metric (often referred to as the Cost of Unserved Energy (COUE)).

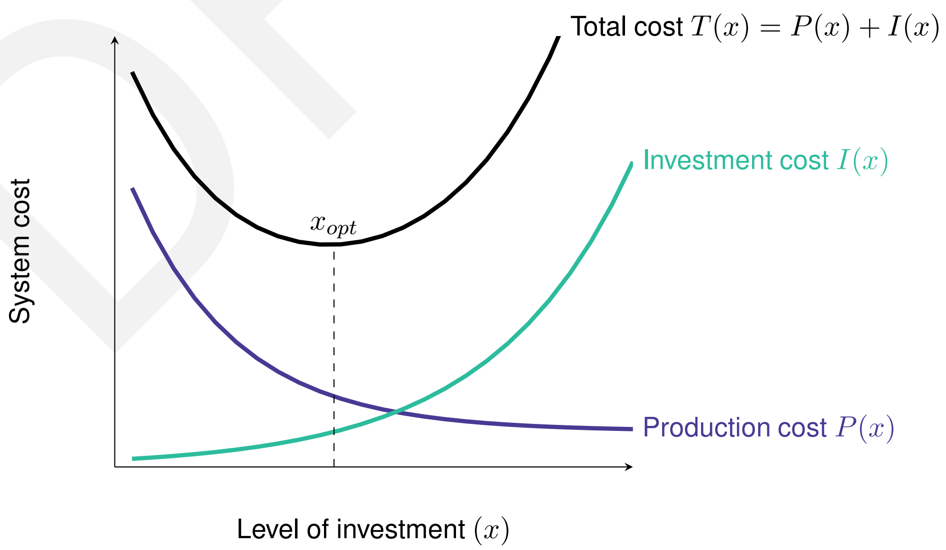


Figure 6: Conceptual illustration of optimisation performed in solving the capacity expansion planning problem

More specifically for South Africa, the capacity expansion planning problem can be summarised briefly by the graphical illustration given in Figure 7. In the South African context, the capacity expansion planning problem objective function is least-cost (more specifically, least total electricity system cost). Thus, it is solved by the co-optimisation between existing resource utilisation (generators which decommission over time) and new technology investments while ensuring the energy balance is maintained in every period in the least-cost manner (subject to adequacy requirements i.e. reserves and COUE). This optimisation is also subject to a range of other user-defined constraints e.g. supply technology technical characteristics (ramp rates, start/stop costs, minimum up/down times etc), supply technology reliability, CO_2 emission trajectories, operational limitations (pumped storage weekly cycling) etc.

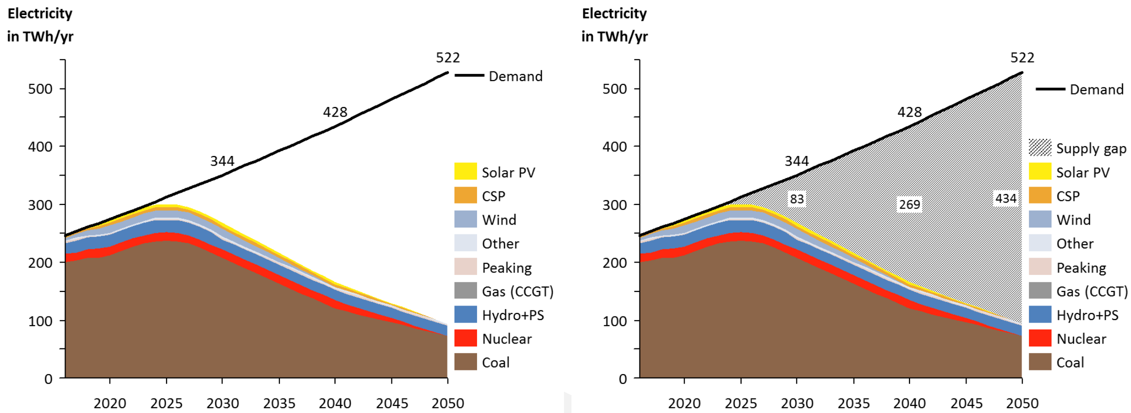


Figure 7: Illustration of the capacity expansion planning problem (the opening supply gap should be met in the least-cost manner by a range of available existing and new resources with particular cost characteristics).

As mentioned briefly before, an important aspect that needs to be considered in a capacity expansion plan is that of system adequacy. The least cost capacity expansion plan must adhere to an acceptable level of system adequacy (typically an input defined by the user). System adequacy can be measured using a number of metrics, including the use of deterministic planning reserve margins or probabilistic metrics such as the Loss of Load Probability (LOLP)/Loss of Load Expectation (LOLE). Although the long-term capacity expansion obtained provides significant insight into the least-cost optimal long-term capacity and energy mix, the level of detail required to determine whether the expansion plan truly meets adequacy requirements is generally not sufficiently captured in the long-term capacity expansion formulation. Thus, the approach taken in this submission was a two-stage process.

In the first stage, the long-term capacity expansion plan is obtained whereby the least-cost new build options are obtained. Following this, the second stage is then run whereby the chosen expansion plan is run with a significantly higher level of detail in a unit-commitment and economic dispatch production cost model. In this model, additional operational constraints are considered in the model including explicit reserve classes (see section 4.6 for more details), minimum up/down times for generators and hourly chronology. The adequacy of the new build expansion plan can then be checked and this informs the expansion plan in an iterative process. The production cost model also inherently ensures that system flexibility requirements are met. System flexibility refers to the ability of the power system to respond adequately to various levels of uncertainty and variation [31, 32]. In recent years, the focus on system flexibility has shifted towards the impact of variable RE on the residual demand (demand after the subtraction of variable RE like solar PV and wind). Figure 8 illustrates the concept of changing flexibility requirements as variable RE changes the shape of the system demand, resulting in a new residual demand which must be met by the remaining generation fleet. At certain times, the magnitude and slope of the residual demand compared to the original system demand (without variable RE) results in different ramping requirements as well as the number of peak load (or high-load) hours.

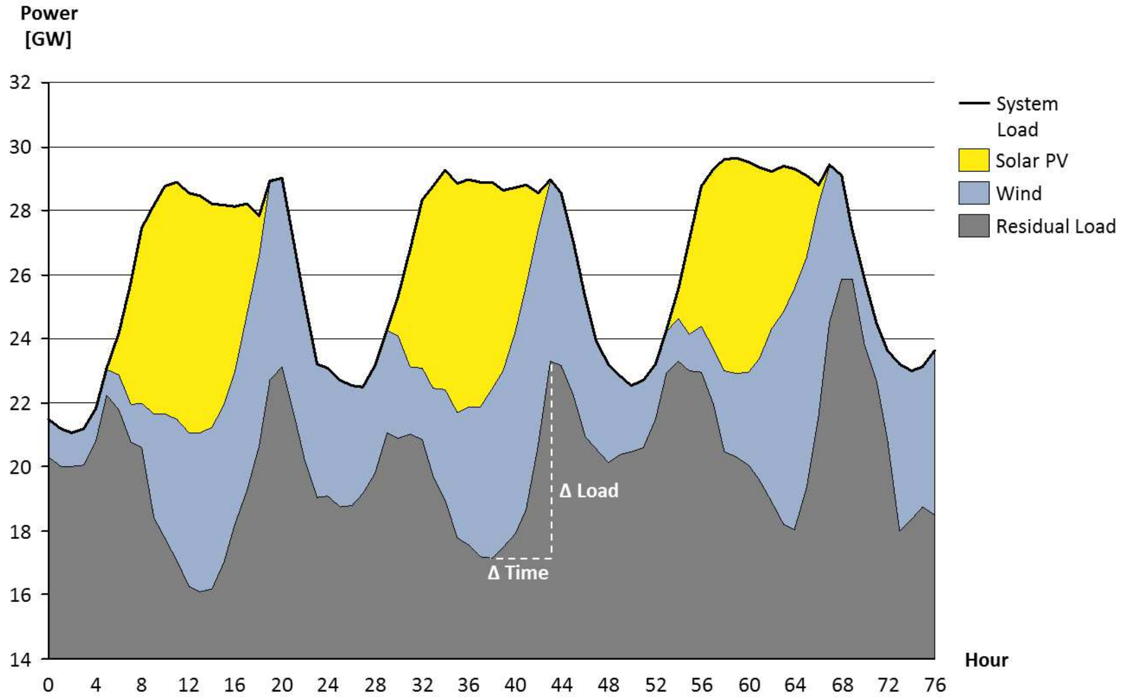


Figure 8: Illustration of flexibility requirements and increasing need to represent demand chronology in long-term expansion planning for a system with relatively high solar PV and wind penetration (correlation between demand and variable RE results in increased ramping requirements as well as more peak (or high-load hours) in the residual demand profile).

Historically, the primary reason for running the second-stage outlined above was that in long-term capacity expansion planning exercises the chronology of system demand was removed and an equivalent Load Duration Curve (LDC) model for system demand was used. This was mostly to reduce system complexity and simplify the problem size. However, with the advent of significant computing speed combined with the effects that variable RE have on the residual demand profile (demand profile less variable RE), planners have needed to incorporate demand chronology explicitly in long-term expansion planning. Although RE penetration is currently relatively low in South Africa, the cost competitiveness of RE as realised during recent REIPPPP bid windows motivated CSIR to opt for a chronological representation of demand in the long-term expansion planning performed. More specifically, fitted chronology is used where the chronology of the demand profile is maintained but intervals are combinied together to simplify the problem size based on chosen settings. This approach taken (along with other similar approaches) is becoming increasngly common amongst energy planners around the world especially in high penetration RE scenarios [33, 34, 35, 36, 37, 38].

Due to the complexity of solving the capacity expansion planning problem, specialized software packages are commonly used. The CSIR applies an energy system modelling software package called PLEXOS® [20]. PLEXOS® is a commercially available power systems modelling tool used for electricity, gas and water market modelling. It is currently used by the DoE for IRP modelling. PLEXOS® applies Mixed Integer Linear Programming (MILP) to simultaneously solve the capacity expansion planning problem as well as unit commitment and economic dispatch problem when performing production cost modelling.

Power generation cost characteristics can be grouped into two broad categories, namely capacity-driven costs (fixed costs) and energy-driven costs (variable costs) as shown in Figure 9. These costs are modelled explicitly within the PLEXOS modelling framework used by the CSIR in this submission (as is done in the IRP 2016). The modelling framework considers all of these costs together along with system demand to determine the least-cost expansion plan. It is important to note that the utilisation of a generator (if it is chosen as part of the least-cost energy mix) is an output of the PLEXOS modelling framework and is not provided to the model as an input. As is well-known, the fixed and variable costs of any generator form part of the calculation of the well-known Levelised Cost of Electricity (LCOE) and is used as a valuable metric (typically to compare the relative costs of different power generation technologies). Capacity-driven costs consist of the capital investment cost ("capex") associated with building a power generator and Fixed Operations and Maintenance (FOM) costs for operating a power generator. The energy driven costs consist of Variable Operations and Maintenance (VOM) and fuel costs and are a function of utilisation of the generator. Start costs could also be explicitly included in the LCOE calculation if not already included in the FOM and/or VOM/fuel costs.

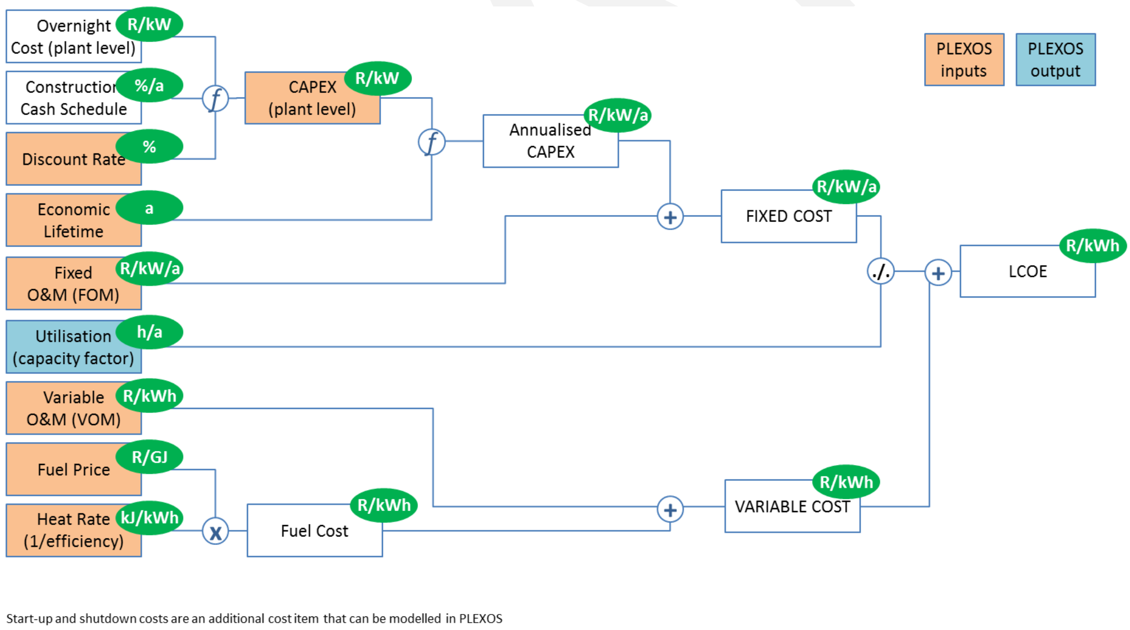


Figure 9: Conceptual breakdown of generator cost drivers.

3.2 Total system costs and average tariff trajectory

The Draft IRP 2016 [3] does not quantify total cost of power generation, total system costs or average tariff trajectory into the future. These are fundamental outcomes of the long-term capacity expansion planning being performed and should likely be included in future drafts of the IRP when published. This submission includes the total cost of power generation, total system costs and average tariff trajectories.

As shown graphically in Figure 10, total system cost is made up of a number of components. The cost of power generation for each scenario is inclusive of all fixed costs (power generator capital investment and O&M), variable (fuel and O&M) and start/stop costs for all existing and new build power generators. Figure 9 outlines these cost drivers and how they relate to the total cost of a particular power generator. The sum of all of the existing and new generator costs outlined above makes up the total cost of power generation. The transmission (Tx), distribution (Dx), system services (often referred to as ancillary services) and other costs are not explicitly included in the PLEXOS modelling framework. As a result, a high level assumption of 0.30 R/kWh for all of these cost components is made consistently across all scenarios.

The actual tariff trajectory is the total system cost described above divided by the customer demand in each year for all scenarios. Some detailed network infrastructure investment analysis for key scenarios has been performed and is included in section 7.1 but the above assumption is used for consistency across all scenarios at this stage. An ex-post calculation is also performed to consider the "cost" of CO_2 emissions at *120 R/tonne*.

It is appreciated that the absolute costs that result from scenarios run by the CSIR in this submission may differ slightly to that of those run by the DoE. However, it is important to note that the comparisons made between scenarios are all relative comparison to each other and thus the absolute total system costs are not as important. Instead, it is the relative difference in costs between the scenarios that is more important. Particularly, the relative costs of each scenario when compared to the Base Case.

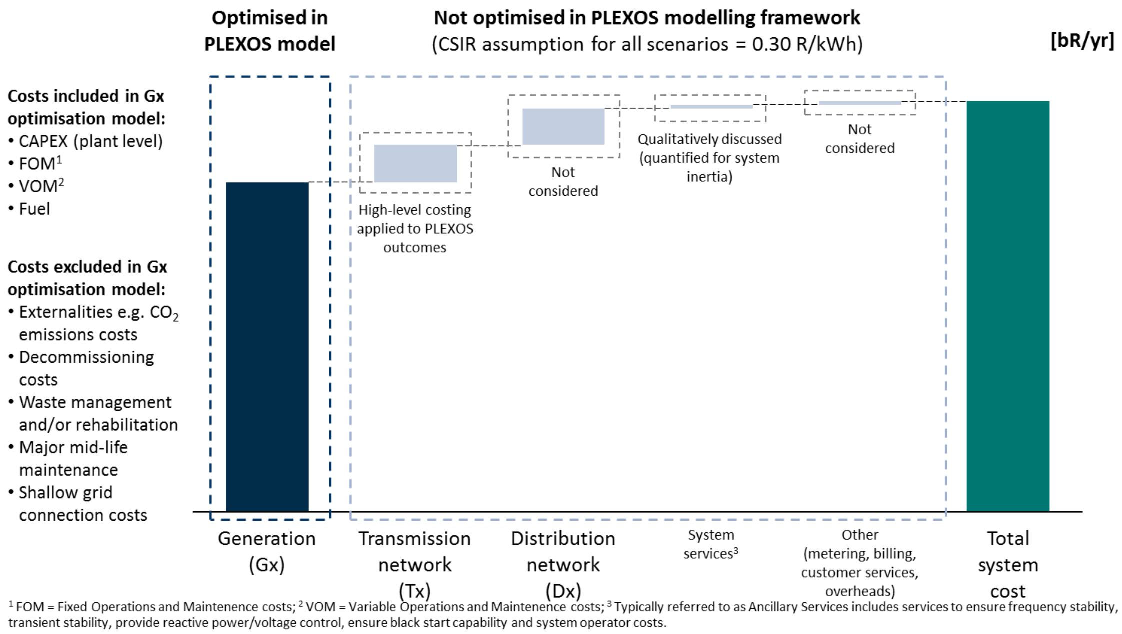


Figure 10: Modelling framework inclusions/exclusions and total system cost reporting approach.

3.3 Model exclusions

As described previously, the modelling framework considers all primary cost-drivers directly relevant within the electricity sector. It is important to note the exclusions from the modelling framework which are not necessarily included in the optimisation:

- Network infrastructure requirements for each scenario (see section 7.1 for ex-post assessment). The modelling framework is capable of this inclusion but this has not yet been included in this submission nor in the IRP 2016 or previous versions thereof.
- System services (stability, reactive power and voltage control, black-start requirements). See section 7.2 for ex-post assessment of these (particularly system stability).
- Mid-life generator major maintenance and overhauls for any technology.
- End of life decommissioning costs for any technology.
- Socio-economic development opportunities of each scenario.
- Localisation potential of each scenario. Although, a brief inclusion of the number of jobs expected to be directly created per scenario is included (ex-post).
- Regional development opportunities of each scenario.

3.4 Scenarios

As discussed in section 1, the Base Case is the scenario which results from an unconstrained model outcome with the most recent input assumptions. From this, various scenarios could be defined and changes made to input assumptions to then obtain the change in total system costs (total cost of power generation previously described).

A summary of the scenarios included in the long-term expansion plan to 2050 are summarised in Figure 1. The scenarios included in the medium-term outlook are slightly different as the focus changes from the long-term vision of South Africa's possible future energy mix to a more practical medium-term outlook to 2030 and these are summarised in Figure 2.

Table 1: Scenarios for long-term expansion planning to 2050.

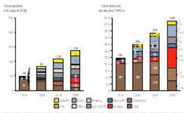
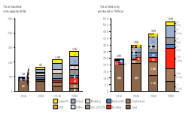
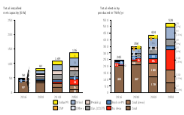
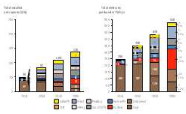
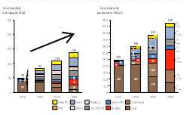
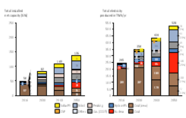
Scenario		Source	Difference to Draft IRP 2016 Base Case
Draft IRP 2016 Base Case		**Department of Energy** Draft IRP 2016 as of November 2016	N/A
Draft IRP 2016 Carbon Budget		**Department of Energy** Draft IRP 2016 as of November 2016	Tighter carbon reduction targets
Draft IRP 2016 "Unconstrained Base Case"		**Department of Energy** Scenario run by DoE/Eskom as per request of the Ministerial Advisory Council on Energy (MACE)	No constraints on any new build technologies
Least Cost		**CSIR**	No constraints on any new build technologies RE costing aligned with latest REIPPPP Demand shaping from residential EWHs
Decarbonised		**CSIR**	No constraints on new build technologies Significantly less electricity sector CO_2 emissions (95% reduction by 2050) Early coal fleet decommissioning Medupi and coal IPPs decommissioned from 2045 Kusile is not commissioned
Least-cost ("Expected" costs		**CSIR**	No constraints on new build technologies Expected further cost reductions for solar PV, wind and CSP, storage Electric vehicle uptake (demand flexibility)

Table 2: Scenarios for medium-term outlook to 2030.

Scenario		Source	Difference to Draft IRP 2016 Base Case
Draft IRP 2016 Base Case		**Department of Energy** Draft IRP 2016 as of November 2016	N/A
Draft IRP 2016 Carbon Budget		**Department of Energy** Draft IRP 2016 as of November 2016	Tighter carbon reduction targets
Least Cost		**CSIR**	No constraints on any new build technologies RE costing aligned with latest REIPPPP Demand shaping from residential EWHs
Least Cost Linear Build		**CSIR**	Spread wind and solar PV new build from 2030 Least Cost result linearly from 2021 Re-optimise other supply options around linear build
Decarbonise		**CSIR**	Significantly less electricity sector CO_2 emissions (95% reduction by 2050)

3.5 Sensitivities

Since the planning horizon is relatively long (2016-2050), various degrees of uncertainty in input assumptions do present themselves. As a result, a range of sensitivities have been run to provide a broader appreciation for the sensitivity of scenario outcomes to input assumption changes. A summary of the sensitivities run for the long-term expansion plan to 2050 are summarised in Figure 3. The range of sensitivities run for the medium-term outlook to 2030 are summarised in Figure 4.

Table 3: Sensitvities for long-term expansion planning to 2050.

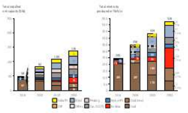
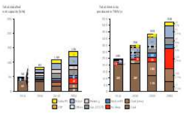
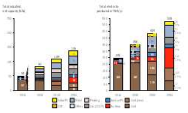
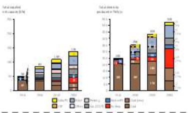
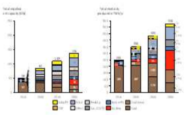
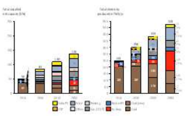
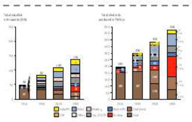
Sensitivity	Source	Difference to Draft IRP 2016 Base Case
Base Case (Low demand) 	**CSIR**	**Low demand (EIUG)**
"Unconstrained Base Case" (Low demand) 	**CSIR**	**Low demand (EIUG)** **No constraints on any new build technologies**
Least Cost (Low demand) 	**CSIR**	**Low demand (EIUG)** **No constraints on any new build technologies** **RE costing aligned with latest REIPPPP** **Demand shaping from residential EWHs**
Supply technology tipping points 	**CSIR**	**Least cost scenario input assumptions** **Lower costs for supply technologies not in least cost scenario e.g. nuclear, CSP etc**

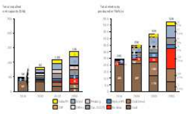
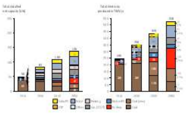
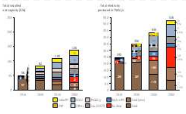
Table 4: Sensitvities for medium-term outlook to 2030.

Sensitivity	Source	Difference to Draft IRP 2016 Base Case
Least Cost (Low demand) 	**CSIR**	**Low demand (EIUG)** **No constraints on any new build technologies** **RE costing aligned with latest REIPPPP** **Demand shaping from residential EWHs**
Least Cost Linear Build (Low demand) 	**CSIR**	**Spread wind and solar PV new build from 2030 Least Cost result linearly from 2021** **Re-optimise other supply options around linear build**
Low Supply 	**CSIR**	**Least cost scenario input assumptions** **Delay Medupi and Kusile by 1 year per unit** **Follow Eskom's low plant performance path**

3.6 What-if analyses

A separate set of analyses is proposed to answer a range of "What-if?" queries. A summary of the what-if analyses performed for the medium-term to 2030 is shown in Figure 5.

Table 5: What-if analyses for medium-term outlook to 2030.

What If	Source	Difference to Draft IRP 2016 Base Case
Draft IRP 2016 Base Case (over-investment) 	**CSIR**	**Least cost scenario input assumptions** **Low demand (EIUG)** **Hard-coded installed capacity from this scenario but with lower demand forecast**
Draft IRP 2016 Carbon Budget (over-investment) 	**CSIR**	**Least cost scenario input assumptions** **Low demand (EIUG)** **Hard-coded installed capacity from this scenario but with lower demand forecast**
Least Cost (over-investment) 	**CSIR**	**Least cost scenario input assumptions** **Low demand (EIUG)** **Hard-coded installed capacity from this scenario but with lower demand forecast**

4 Input assumptions

4.1 General economic parameters

Relevant general economic input parameters are aligned with that of the IRP 2016 [3] unless otherwise stated. These can be summarised as discount rate (8.2%) and COUE (77.30 R/kWh).

4.2 Supply technologies: Cost structures

The cost structures of all technologies are included as an Appendix to this submission in Appendix A but summarised briefly in Table 6-reftab:CSIRExpected-Inputs-Costs-Storage. All supply technology input cost assumptions are aligned with the IRP 2016 [3] updated to April-2016 rands using Consumer Price Inflation (CPI) [39] unless otherwise specified. Key input assumptions include overnight capital cost, construction time, capital phasing schedule, Fixed Operations and Maintenance (FOM), Variable Operations and Maintenance (VOM), fuel costs and efficiency (heat rate).

Figure 11 expresses these explicit input cost assumptions as an LCOE (without learning) assuming a typical capacity factor. As mentioned in section 3.1, the modelling framework (PLEXOS®) does not consider the LCOE as an input parameter but considers all cost components explicitly as listed in Table 6-14.

Key differences between input assumptions for solar PV, wind and CSP in the IRP 2016 and this submission are highlighted in Figure 12- 14. As can be seen, the IRP 2016 seems to assume the starting point for solar PV and wind to be similar to levels achieved in the REIPPPP Bid Window (BW) 3 while CSP is at the latest REIPPPP BW equivalent tariff achieved. These are followed by a moderate level of further learning by 2030 (≈20% for solar PV, ≈10% for wind and ≈20% for CSP) following which costs remain constant.

The CSIR cost assumptions for scenarios in this submission (except the Unconstrained Base Case and already defined Base Case and Carbon Budget) are summarised in (as summarised in Table 9-11). The assumptions are that solar PV, wind and CSP start at the most recently achieved REIPPPP BW 4 (Expedited) levels in 2016. From this, solar PV has a moderate level of learning of ≈20% by 2050 (reaching the mid-point of the IRP 2010-2030 cost assumptions by 2050). Wind is assumed to have no further learning and costs remain at those achieved in the REIPPPP BW 4 (Expedited). CSP is assumed to follow a similar learning curve shape to that of the IRP 2010-2030 until 2030 following which costs remain constant.

In the Least-cost ("Expected" costs) scenario (as summarised in Table 12-14), further levels of learning are assumed for solar PV, wind and CSP. The resulting costs are also summarised graphically in Figure 15-17.

Table 6: Technology cost input assumptions (conventionals) - IRP 2016.

Property			Conventionals										
			Coal (PF)	Coal (FBC)	Coal (PF with CCS)	Coal (IGCC)	Nuclear (DoE)	OCGT	CCGT	ICE (2 MW)	ICE (10 MW)	Demand response	Inga
Rated capacity (net)		*[MW]*	4 500	250	4 500	644	1 400	132	732	2	9	500	2 500
Overnight cost per capacity	*2016*	*[ZAR/kW]*	35 463	42 806	68 598	55 051	60 447	8 173	8 975	12 751	13 667	0	45 372
	2030-2050	*[ZAR/kW]*	35 463	42 806	53 771	66 436	58 816	8 173	8 975	12 751	13 667	0	45 372
Construction time		*[a]*	9	4	9	4	8	2	3	1	1	1	8
Capital cost (calculated)[1]	*2016*	*[ZAR/kW]*	39 328	47 354	76 074	60 900	78 023	8 777	9 956	12 751	13 667	0	67 249
	2030-2050	*[ZAR/kW]*	39 328	47 354	59 631	73 495	75 917	8 777	9 956	12 751	13 667	0	67 249
Fuel cost		*[ZAR/GJ]*	27	14	27	27	8	126	126	126	126	0	0
Heat rate		*[GJ/MWh]*	9 812	10 788	14 106	9 758	10 657	11 519	7 395	9 477	8 780	4	0
Fixed O&M		*[ZAR/kW/a]*	924	621	1 576	1 423	968	161	165	422	475	9	907
Variable O&M		*[ZAR/MWh]*	80	173	148	75	37	2	22	70	120	1 441	0
Load factor (typical)		*[./.]*	82%	82%	82%	82%	90%	6%	36%	36%	36%	2%	70%
Economic lifetime		*[a]*	30	30	30	30	60	30	30	30	30	1	60
			2%		2%								
			6%		6%		5%						20%
			13%		13%		5%						25%
			17%		17%		15%						25%
Capital phasing		[%/a]	17%		17%		15%						10%
			16%	10%	16%	10%	20%						5%
			15%	25%	15%	25%	20%		40%				5%
			11%	45%	11%	45%	10%	90%	50%				5%
			3%	20%	3%	20%	10%	10%	10%	100%	100%	100%	5%

[1] *From capital phasing, discount rate and economic lifetime.*
All costs in Apr-2016 Rands

Table 7: Technology cost input assumptions (renewables) - IRP 2016.

Property		Renewables															
		Wind	Solar PV (tracking)	Solar PV (fixed)	CPV	CSP (trough, 3h)	CSP (trough, 6h)	CSP (trough, 9h)	CSP (tower, 3h)	CSP (tower, 6h)	CSP (tower, 9h)	Biomass (forestry)	Biomass (MSW)	Landfill Gas	Biogas	Bagasse (Felixton)	Bagasse (gen)
Rated capacity (net)	*[MW]*	100	10	10	10	125	125	125	125	125	125	25	25	5	5	49	53
Overnight cost per capacity	*2016 [ZAR/kW]*	21 011	19 536	18 443	50 375	86 499	106 787	131 003	77 184	94 910	107 523	74 450	143 004	31 048	77 287	17 821	34 165
	2030-2050 [ZAR/kW]	18 358	15 430	14 685	50 375	86 499	106 787	91 018	53 277	65 702	74 705	74 450	143 004	31 048	77 287	17 821	34 165
Construction time	*[a]*	4	2	1	1	4	4	4	4	4	4	4	4	1	1	2	3
Capital cost (calculated)[1]	*2016 [ZAR/kW/a]*	21 643	19 697	18 443	50 375	95 690	118 134	144 923	85 385	104 995	118 948	82 361	158 199	31 048	77 287	18 303	35 589
	2030-2050[ZAR/kW/a]	18 910	15 556	14 685	50 375	95 690	118 134	100 689	58 938	72 683	82 642	82 361	158 199	31 048	77 287	18 303	35 589
Fuel cost	*[ZAR/GJ]*	0	0	0	0	0	0	0	0	0	0	32	0	0	0	81	81
Heat rate	*[GJ/MWh]*	0	0	0	0	0	0	0	0	0	0	14 243	18 991	12 302	11 999	26 874	19 327
Fixed O&M	*[ZAR/kW/a]*	606	280	327	314	1 023	1 050	1 077	941	981	1 009	1 655	6 470	2 373	1 941	172	390
Variable O&M	*[ZAR/MWh]*	0	0	0	0	1	1	1	1	1	1	66	114	62	52	9	27
Load factor (typical)	*[./.]*	36%	28%	24%	30%	32%	38%	46%	38%	50%	60%	85%	85%	85%	85%	55%	50%
Economic lifetime	*[a]*	20	25	25	25	30	30	30	30	30	30	30	30	30	30	30	30
Capital phasing	*[%/a]*																
		5%				10%	10%	10%	10%	10%	10%	10%	10%				
		5%				25%	25%	25%	25%	25%	25%	25%	25%				10%
		10%	10%			45%	45%	45%	45%	45%	45%	45%	45%			33%	30%
		80%	90%	100%	100%	20%	20%	20%	20%	20%	20%	20%	20%	100%	100%	67%	60%

[1] From capital phasing, discount rate and economic lifetime
All costs in Apr-2016 Rands

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Table 8: Technology cost input assumptions (storage) - IRP 2016.

Property			Storage technologies			
			Pumped Storage	**Battery (Li-Ion, 1h)**	**Battery (Li-Ion, 3h)**	**CAES (8h)**
Rated capacity (net)		*[MW]*	333	3	3	180
Overnight cost per capacity	*2016*	*[ZAR/kW]*	22 326	9 891	24 301	24 492
	2030-2050	*[ZAR/kW]*	22 326	9 891	24 301	24 492
Construction teme		*[a]*	8	1	1	4
Capital cost (calculated)[1]	*2016*	*[ZAR/kW/a]*	27 841	9 891	24 301	27 672
	2030-2050	*[ZAR/kW/a]*	27 841	9 891	24 301	27 672
Fuel cost		*[ZAR/GJ]*	0	0	0	164
Heat rate		*[GJ/MWh]*	0	4 045	4 045	4 444
Round-trip efficiency		*[%]*	78%	89%	89%	81%
Fixed O&M		*[ZAR/kW/a]*	201	618	618	212
Variable O&M		*[ZAR/MWh]*	0	3	3	2
Load factor (typical)		*[./.]*	33%	4%	12%	22%
Economic lifeteme		*[a]*	50	20	20	40
			1%			
			1%			
			2%			
			9%			
Capital phasing		*[%/a]*	16%			
			22%			25%
			24%			25%
			20%			25%
			5%	100%	100%	25%

All costs in Apr-2016 Rands

[1] From capital phasing, discount rate and economic lifetime.

Table 9: Technology cost input assumptions (conventionals) - CSIR.

Property			Conventionals										
			Coal (PF)	Coal (FBC)	Coal (PF with CCS)	Coal (IGCC)	Nuclear (DoE)	OCGT	CCGT	ICE (2 MW)	ICE (10 MW)	Demand response	Inga
Rated capacity (net)		*[MW]*	750	250	-	644	1 400	132	732	-	-	-	2 500
Overnight cost per capacity	*2016*	*[ZAR/kW]*	35 463	42 806	-	55 051	60 447	8 173	8 975	-	-	-	45 372
	2030-2050	*[ZAR/kW]*	35 463	42 806	-	66 436	58 816	8 173	8 975	-	-	-	45 372
Construction time		*[a]*	9	4	-	4	8	2	3	-	-	-	8
Capital cost (calculated)[1]	*2016*	*[ZAR/kW]*	39 328	47 354	-	60 900	78 023	8 777	9 956	-	-	-	67 249
	2030-2050	*[ZAR/kW]*	39 328	47 354	-	73 495	75 917	8 777	9 956	-	-	-	67 249
Fuel cost		*[ZAR/GJ]*	27	14	-	27	8	150	150	-	-	-	0
Heat rate		*[GJ/MWh]*	9 812	10 788	-	9 758	10 657	11 519	7 395	-	- -		0
Fixed O&M		*[ZAR/kW/a]*	924	621	-	1 423	968	161	165	-	- -		907
Variable O&M		*[ZAR/MWh]*	80	173	-	75	37	2	22	-	- -		0
Load factor (typical)		*[./.]*	82%	82%	-	82%	90%	6%	36%	-	- -		70%
Economic lifetime		*[a]*	30	30	-	30	60	30	30	-	- -		60
			2%		-					-	- -		
			6%		-		5%			-	- -		20%
			13%		-		5%			-	- -		25%
			17%		-		15%			-	- -		25%
Capital phasing		[%/a]	17%		-		15%			-	- -		10%
			16%	10%	-	10%	20%			-	- -		5%
			15%	25%	-	25%	20%		40%	-	- -		5%
			11%	45%	-	45%	10%	90%	50%	-	- -		5%
			3%	20%	-	20%	10%	10%	10%	-	- -		5%

[1] From capital phasing, discount rate and economic lifetime.
All costs in Apr-2016 Rands

Table 10: Technology cost input assumptions (renewables) - CSIR.

Property		Renewables															
		Wind	Solar PV (tracking]	Solar PV (fixed)	CPV	CSP (trough, 3h)	CSP (trough, 6h)	CSP (trough, 9h)	CSP (tower, 3h)	CSP (tower, 6h)	CSP (tower, 9h)	Biomass (forestry)	Biomass (MSW)	Landfill Gas	Biogas	Bagasse (Felixton)	Bagasse (gen)
Rated capacity (net)	*[MW]*	100	-	10	-	-	-	-	-	-	125	25	25	5	5	49	53
Overnight cost per capacity	*2016 [ZAR/kW]*	13 250	-	9 243	-	-	-	-	-	-	93 260	43 893	143 004	31 048	12 751	17 821	34 165
	2030-2050 [ZAR/kW]	13 250	-	8 274	-	-	-	-	-	-	55 402	43 893	143 004	31 048	12 751	17 821	34 165
Construction ttme	*[a]*	4	-	1	-	-	-	-	-	-	4	4	4	1	1	2	3
Capital cost (calculated)[1]	*2016 [ZAR/kW/a]*	13 648	-	9 243	-	-	-	-	-	-	103 169	48 557	158 199	31 048	12 751	18 303	35 589
	2030-2050[ZAR/kW/a]	13 648	-	8 274	-	-	-	-	-	-	61 288	48 557	158 199	31 048	12 751	18 303	35 589
Fuel cost	*[ZAR/GJ]*	0	-	0	-	-	-	-	-	-	0	32	0	0	114	81	81
Heat rate	*[GJ/MWh]*	0	-	0	-	-	-	-	-	-	0	12 386	18 991	12 302	11 999	26 874	19 327
Fixed O&M	*[ZAR/kW/a]*	500	-	200	-	-	-	-	-	-	1 009	1 655	6 470	2 373	422	172	390
Variable O&M	*[ZAR/MWh]*	0	-	0	-	-	-	-	-	-	0	66	114	62	52	9	27
Load factor (typical)	*[./.]*	36%	-	20%	-	-	-	-	-	-	60%	85%	85%	85%	20%	55%	50%
Economic lifettme	*[a]*	20	-	25	-	-	-	-	-	-	30	30	30	30	30	30	30
			-		-	-	-	-	-	-							
			-		-	-	-	-	-	-							
			-		-	-	-	-	-	-							
			-		-	-	-	-	-	-							
Capital phasing	*[%/a]*		-		-	-	-	-	-	-							
		5%	-		-	-	-	-	-	-	10%	10%	10%				
		5%	-		-	-	-	-	-	-	25%	25%	25%				10%
		10%	-		-	-	-	-	-	-	45%	45%	45%			33%	30%
		80%	-	100%	-	-	-	-	-	-	20%	20%	20%	100%	100%	67%	60%

[1] From capital phasing, discount rate and economic lifetime
All costs in Apr-2016 Rands

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Table 11: Technology cost input assumptions (storage) - CSIR.

Property		Storage technologies			
		Pumped Storage	Battery (Li-Ion, 1h)	Battery (Li-Ion, 3h)	CAES (8h)
Rated capacity (net)	*[MW]*	333	3	3	180
Overnight cost per capacity	*2016 [ZAR/kW]*	22 326	9 891	24 301	24 492
	2030-2050 [ZAR/kW]	22 326	9 891	24 301	24 492
Construction time	*[a]*	8	1	1	4
Capital cost (calculated)[1]	*2016 [ZAR/kW/a]*	27 841	9 891	24 301	27 672
	2030-2050[ZAR/kW/a]	27 841	9 891	24 301	27 672
Fuel cost	*[ZAR/GJ]*	0	0	0	164
Heat rate	*[GJ/MWh]*	0	4 045	4 045	4 444
Round-trip efficiency	*[%]*	78%	89%	89%	81%
Fixed O&M	*[ZAR/kW/a]*	201	618	618	212
Variable O&M	*[ZAR/MWh]*	0	3	3	2
Load factor (typical)	*[./.]*	33%	4%	12%	22%
Economic lifetime	*[a]*	50	20	20	40
		1%			
		1%			
		2%			
		9%			
Capital phasing	*[%/a]*	16%			
		22%			25%
		24%			25%
		20%			25%
		5%	100%	100%	25%

All costs in Apr-2016 Rands

[1] *From capital phasing, discount rate and economic lifetime.*

Table 12: Technology cost input assumptions (conventionals) - "Expected" costs.

Property			Conventionals										
			Coal (PF)	Coal (FBC)	Coal (PF with CCS)	Coal (IGCC)	Nuclear (DoE)	OCGT	CCGT	ICE (2 MW)	ICE (10 MW)	Demand response	Inga
Rated capacity (net)		*[MW]*	750	250	-	644	1 400	132	732	-	-	-	2 500
Overnight cost per capacity	*2016*	*[ZAR/kW]*	35 463	42 806	-	55 051	60 447	8 173	8 975	-	-	-	45 372
	2030-2050	*[ZAR/kW]*	35 463	42 806	-	66 436	58 816	8 173	8 975	-	-	-	45 372
Construction time		*[a]*	9	4	-	4	8	2	3	-	-	-	8
Capital cost (calculated)[1]	*2016*	*[ZAR/kW]*	39 328	47 354	-	60 900	78 023	8 777	9 956	-	-	-	67 249
	2030-2050	*[ZAR/kW]*	39 328	47 354	-	73 495	75 917	8 777	9 956	-	-	-	67 249
Fuel cost		*[ZAR/GJ]*	27	14	-	27	8	150	150	-	-	-	0
Heat rate		*[GJ/MWh]*	9 812	10 788	-	9 758	10 657	11 519	7 395	-	- -		0
Fixed O&M		*[ZAR/kW/a]*	924	621	-	1 423	968	161	165	-	- -		907
Variable O&M		*[ZAR/MWh]*	80	173	-	75	37	2	22	-	- -		0
Load factor (typical)		*[./.]*	82%	82%	-	82%	90%	6%	36%	-	- -		70%
Economic lifetime		*[a]*	30	30	-	30	60	30	30	-	- -		60
			2%		-					-	- -		
			6%		-		5%			-	- -		20%
			13%		-		5%			-	- -		25%
			17%		-		15%			-	- -		25%
Capital phasing		[%/a]	17%		-		15%			-	- -		10%
			16%	10%	-	10%	20%			-	- -		5%
			15%	25%	-	25%	20%		40%	-	- -		5%
			11%	45%	-	45%	10%	90%	50%	-	- -		5%
			3%	20%	-	20%	10%	10%	10%	-	- -		5%

[1] From capital phasing, discount rate and economic lifetime.
All costs in Apr-2016 Rands

Table 13: Technology cost input assumptions (renewables) - "Expected" costs.

Property		Renewables															
		Wind	Solar PV (tracking]	Solar PV (fixed)	CPV	CSP (trough, 3h)	CSP (trough, 6h)	CSP (trough, 9h)	CSP (tower, 3h)	CSP (tower, 6h)	CSP (tower, 9h)	Biomass (forestry)	Biomass (MSW)	Landfill Gas	Biogas	Bagasse (Felixton)	Bagasse (gen)
Rated capacity (net)	*[MW]*	100	-	10	-	-	-	-	-	-	125	25	25	5	5	49	53
Overnight cost per capacity	*2016 [ZAR/kW]*	13 250	-	9 243	-	-	-	-	-	-	93 260	43 893	143 004	31 048	12 751	17 821	34 165
	2030-2050 [ZAR/kW]		-		-	-	-	-	-	-	36 935	48 557	158 199	31 048	12 751	18 303	35 589
Constructton ttme	*[a]*	4	-	1	-	-	-	-	-	-	4	4	4	1	1	2	3
Capital cost (calculated)[1]	*2016 [ZAR/kW/a]*		-		-	-	-	-	-	-	103 169	48 557	158 199	31 048	12 751	18 303	35 589
	2030-2050[ZAR/kW/a]		-		-	-	-	-	-	-	40 859	48 557	158 199	31 048	12 751	18 303	35 589
Fuel cost	*[ZAR/GJ]*	0	-	0	-	-	-	-	-	-	0	32	0	0	114	81	81
Heat rate	*[GJ/MWh]*	0	-	0	-	-	-	-	-	-	0	12 386	18 991	12 302	11 999	26 874	19 327
Fixed O&M	*[ZAR/kW/a]*	500	-	200	-	-	-	-	-	-	1 009	1 655	6 470	2 373	422	172	390
Variable O&M	*[ZAR/MWh]*	0	-	0	-	-	-	-	-	-	0	66	114	62	52	9	27
Load factor (typical)	*[./.]*	36%	-	20%	-	-	-	-	-	-	60%	85%	85%	85%	20%	55%	50%
Economic lifettme	*[a]*	20	-	25	-	-	-	-	-	-	30	30	30	30	30	30	30
			-		-	-	-	-	-	-							
			-		-	-	-	-	-	-							
			-		-	-	-	-	-	-							
			-		-	-	-	-	-	-							
Capital phasing	*[%/a]*		-		-	-	-	-	-	-							
		5%	-		-	-	-	-	-	-	10%	10%	10%				
		5%	-		-	-	-	-	-	-	25%	25%	25%				10%
		10%	-		-	-	-	-	-	-	45%	45%	45%			33%	30%
		80%	-	100%	-	-	-	-	-	-	20%	20%	20%	100%	100%	67%	60%

[1] From capital phasing, discount rate and economic lifetime
All costs in Apr-2016 Rands

Table 14: Technology cost input assumptions (storage) - "Expected" costs.

Property			Storage technologies			
			Pumped Storage	Battery (Li-Ion, 1h)	Battery (Li-Ion, 3h)	CAES (8h)
Rated capacity (net)		*[MW]*	333	3	3	180
Overnight cost per capacity	*2016*	*[ZAR/kW]*	22 326	9 891	24 301	24 492
	2030	*[ZAR/kW]*	22 326	2 000	6 000	
	2040	*[ZAR/kW]*	22 326	1 000	3 000	
	2050	*[ZAR/kW]*	22 326	800	2 400	
Construction time		*[a]*	8	1	1	4
Capital cost (calculated)[1]	*2016*	*[ZAR/kW]*	27 841	9 891	24 301	27 672
	2030	*[ZAR/kW]*	27 841	2 000	6 000	27 672
	2040	*[ZAR/kW]*	27 841	1 000	3 000	27 672
	2050	*[ZAR/kW]*	27 841	800	2 400	27 672
Fuel cost		*[ZAR/GJ]*	0	0	0	150
Heat rate		*[GJ/MWh]*	0	4 045	4 045	4 444
Round-trip efficiency		*[%]*	78%	89%	89%	81%
Fixed O&M		*[ZAR/kW/a]*	201	618	618	212
Variable O&M		*[ZAR/MWh]*	0	3	3	2
Load factor (typical)		*[./.]*	33%	4%	12%	22%
Economic lifetime		*[a]*	50	20	20	40
			1%			
			1%			
			2%			
			9%			
Capital phasing		*[%/a]*	16%			
			22%			25%
			24%			25%
			20%			25%
			5%	100%	100%	25%

All costs in Apr-2016 Rands

[1] From capital phasing, discount rate and economic lifetime.

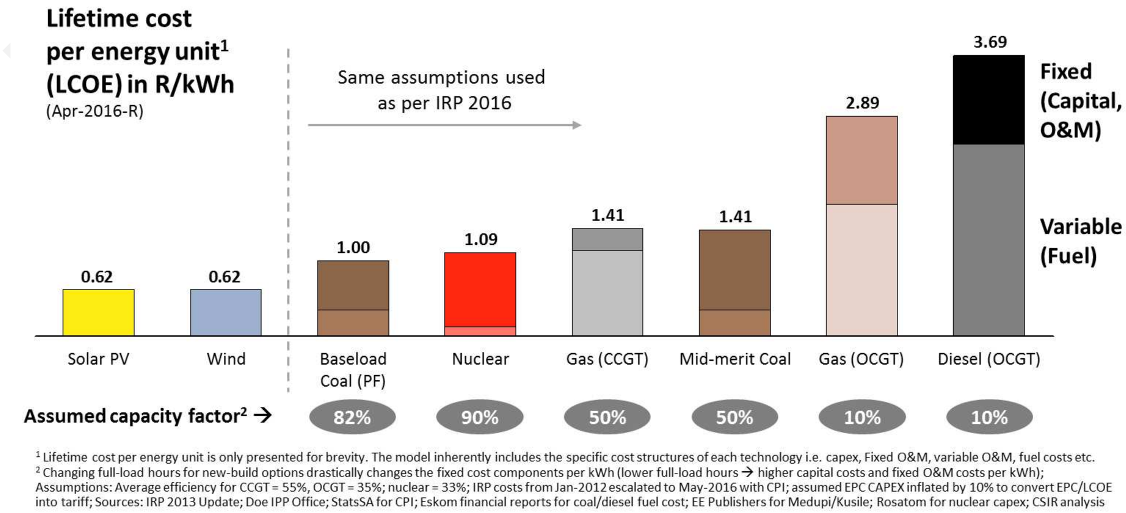


Figure 11: Resulting LCOE from input cost assumptions for key new supply technologies as assumed by CSIR based on IRP 2016 (using a typical capacity factor)

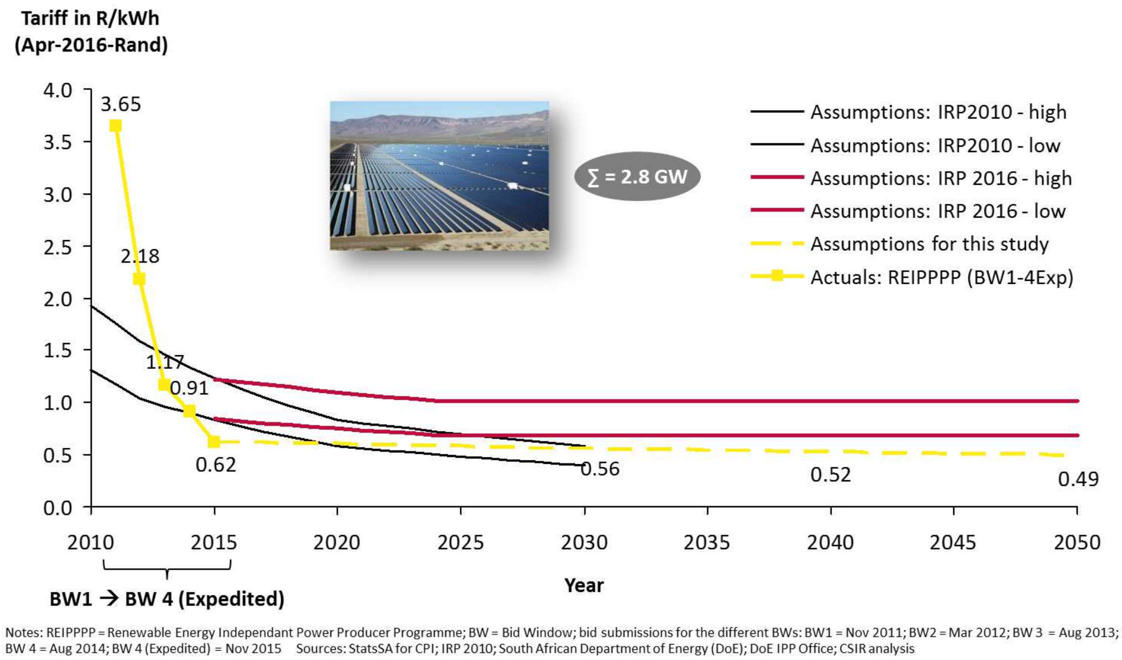


Figure 12: Equivalent cost assumption for solar PV based on fundamental cost structure of the technology (IRP 2016 and CSIR cost assumption).

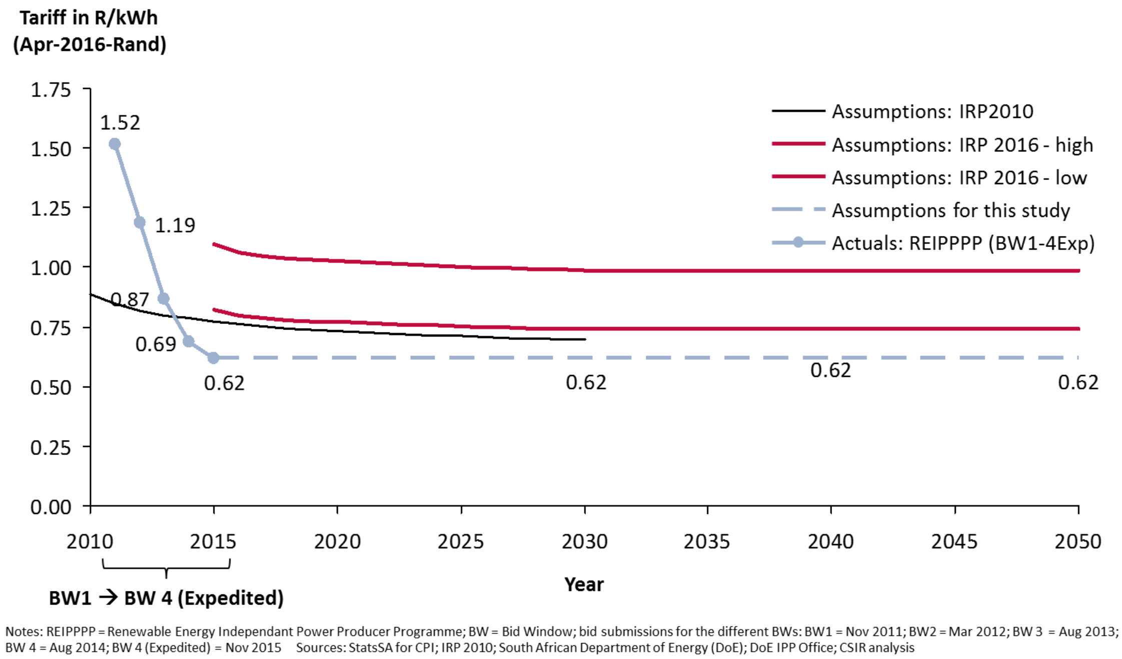


Figure 13: Equivalent cost assumption for wind based on fundamental cost structure of the technology (IRP 2016 and CSIR cost assumption).

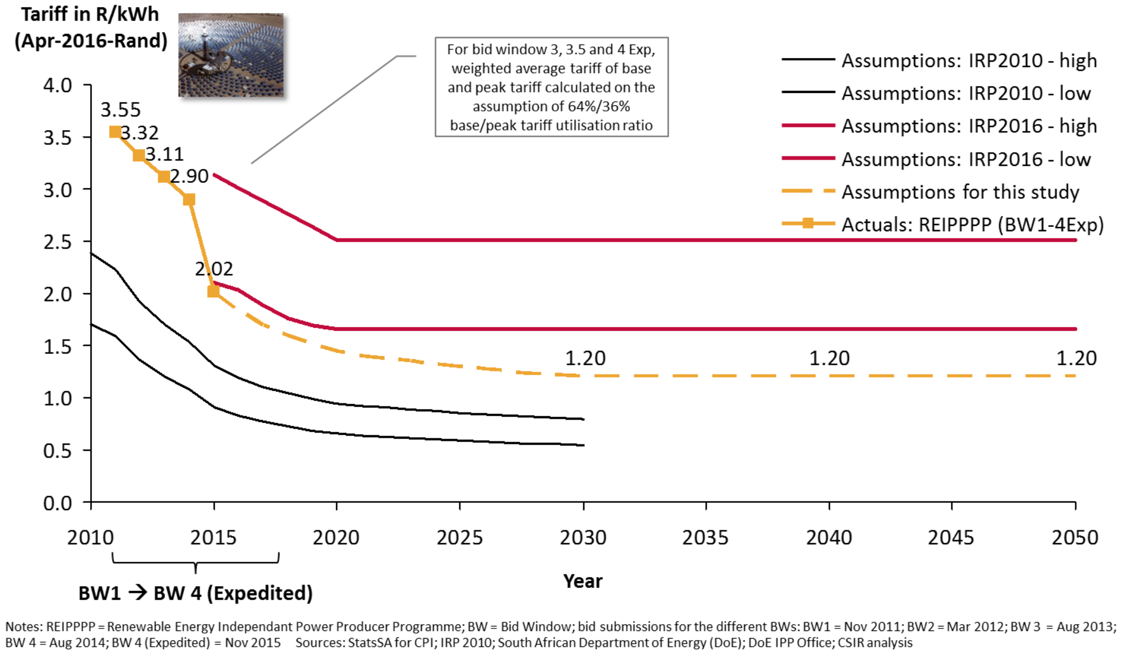


Figure 14: Equivalent cost assumption for CSP based on fundamental cost structure of the technology (IRP 2016 and CSIR cost assumption).

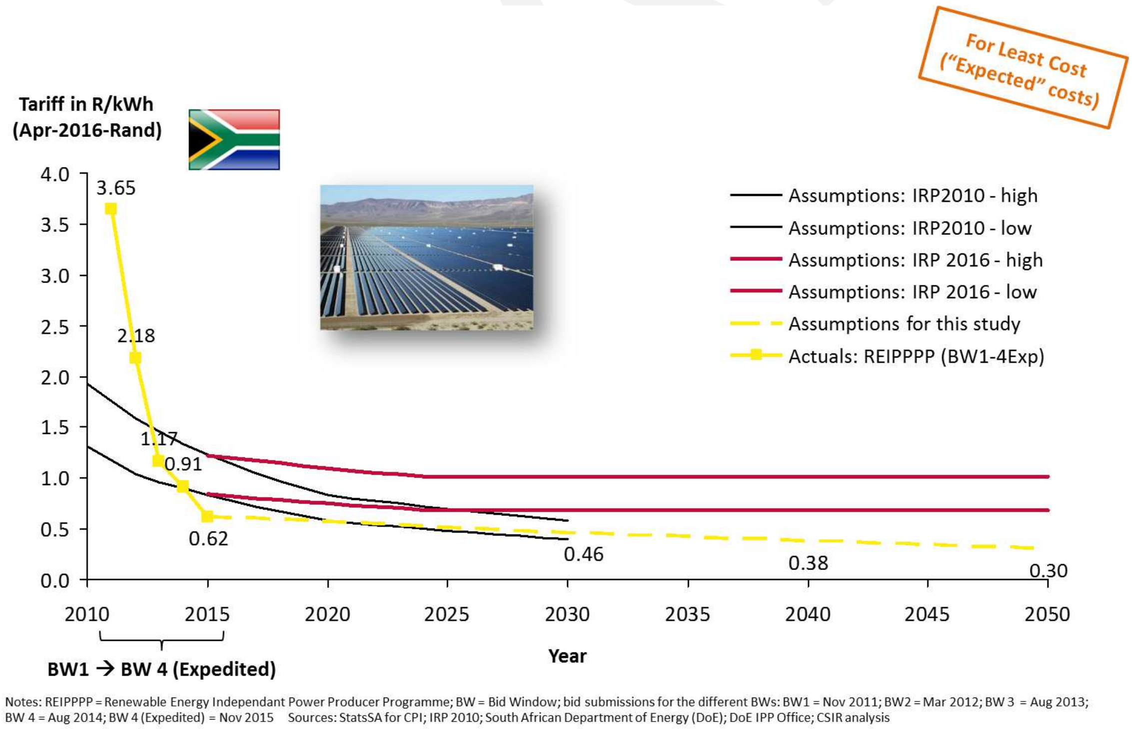


Figure 15: Equivalent cost assumption for solar PV based on fundamental cost structure of the technology ("Expected" costs scenario).

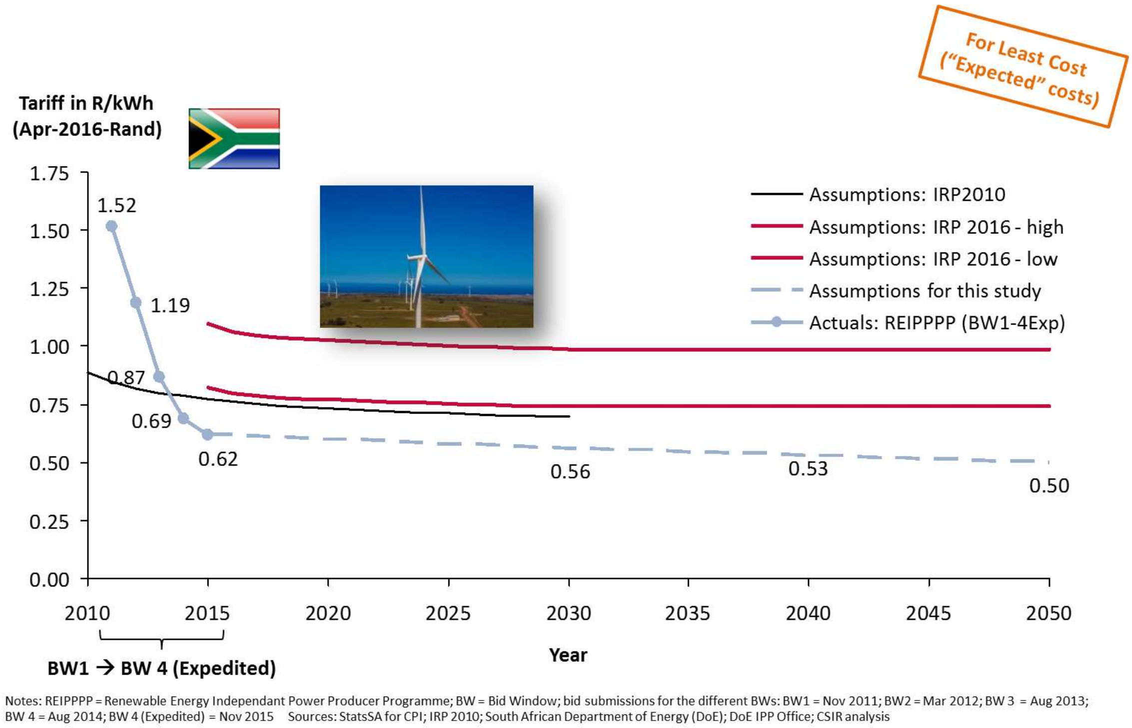


Figure 16: Equivalent cost assumption for wind based on fundamental cost structure of the technology ("Expected" costs scenario).

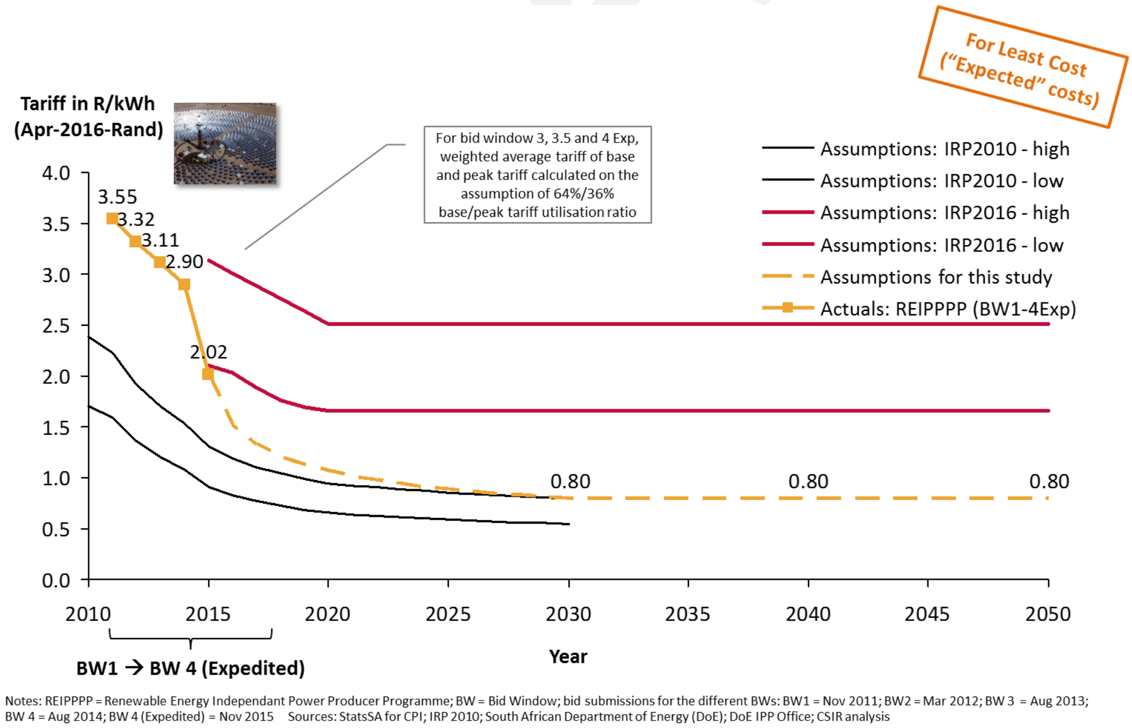


Figure 17: Equivalent cost assumption for CSP based on fundamental cost structure of the technology ("Expected" costs scenario).

4.3 Supply technologies: Technical characteristics

A number of technical characteristics for each supply technology have been specified in the capacity expansion and production cost model. Figure 18 shows the technical characteristics of a conventional dispatchable generator which were specified in the model. These technical characteristics are included as constraints in the model placed on the operational capability of the generator (at unit level).

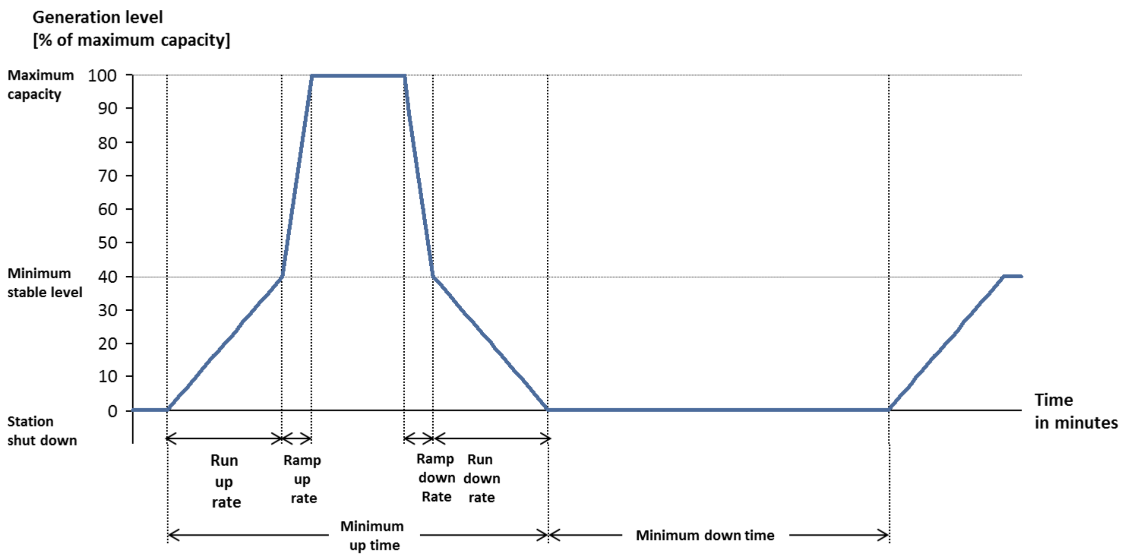


Figure 18: Representation of key technical characteristics of dispatchable generators included in the modelling framework.

Wind and solar PV power generators are assumed to be driven by defined profiles. These profiles are based on datasets that were obtained from the work done in [40] by the CSIR and uses the 27 supply areas (defined by Eskom) as shown in Figure 19. The wind and solar PV profiles for these 27 supply areas are aggregated into one solar PV and wind profile and then used to define any new solar PV and/or wind power generator being built. The IRP 2016 uses the same dataset from [40] (albeit aggregated slightly differently). As examples, wind and solar PV profiles for January and July are shown in Figure 21 and 22 respectively. The duration curves that define solar PV and wind are also shown in Figure 20.

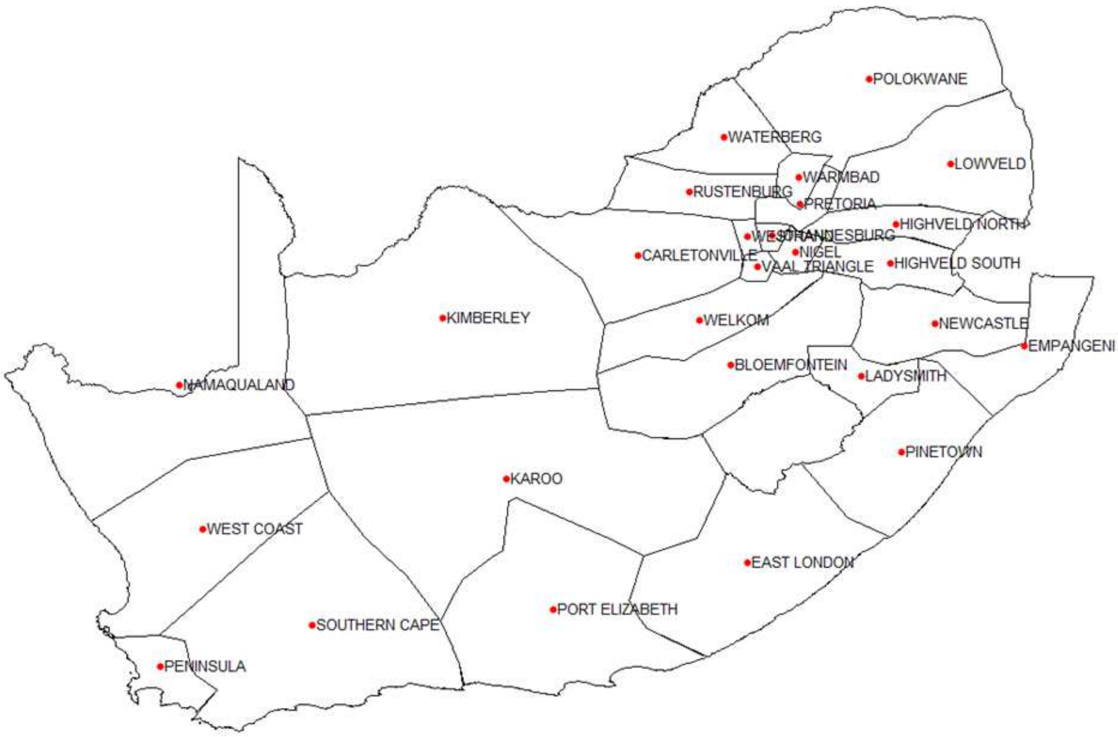


Figure 19: Geographical view of the 27 supply areas in South Africa.

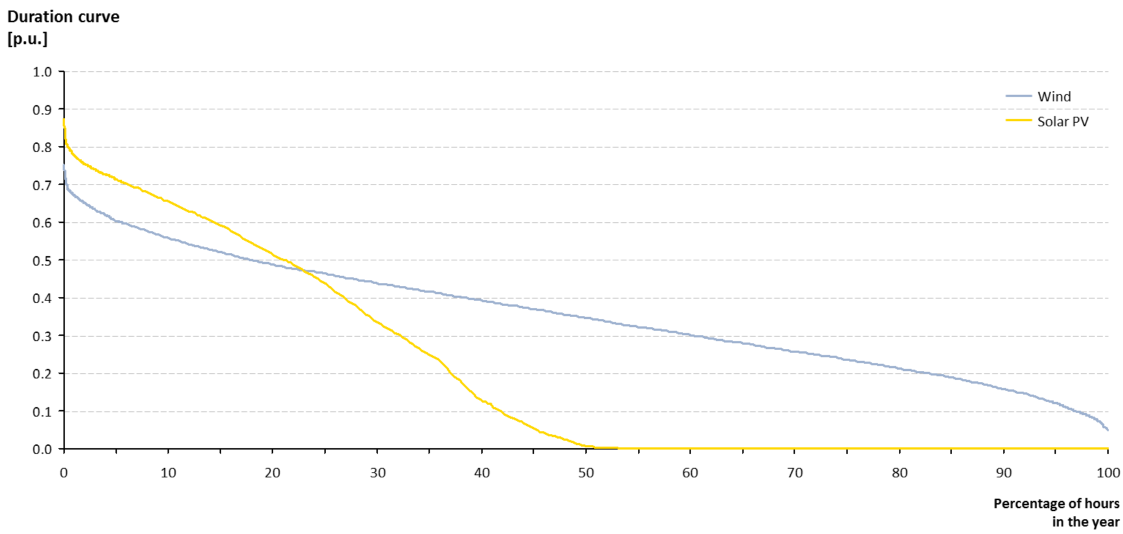


Figure 20: Duration curves for aggregated solar PV and wind profiles.

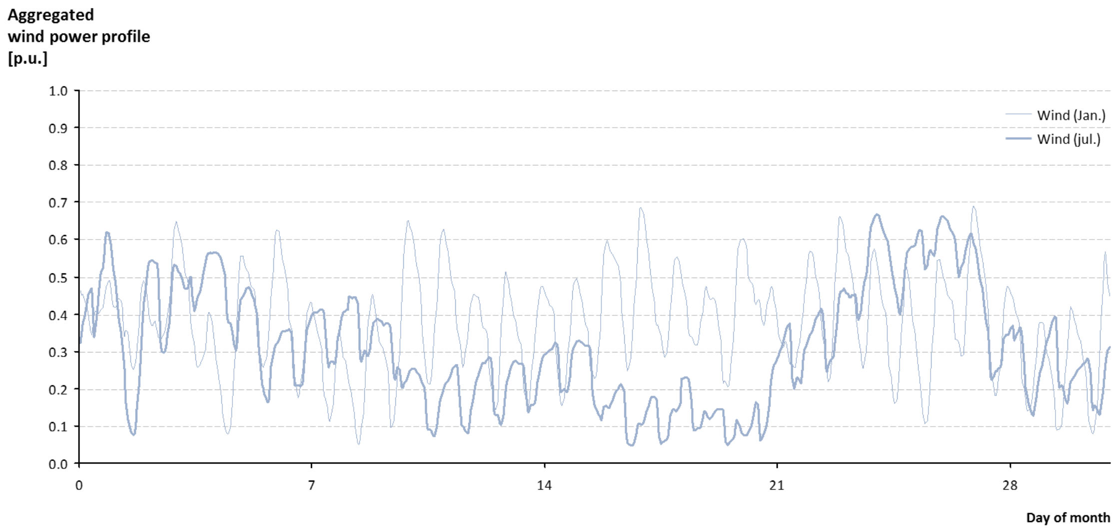


Figure 21: Aggregated wind profiles (normalised to 1, shown for January and July).

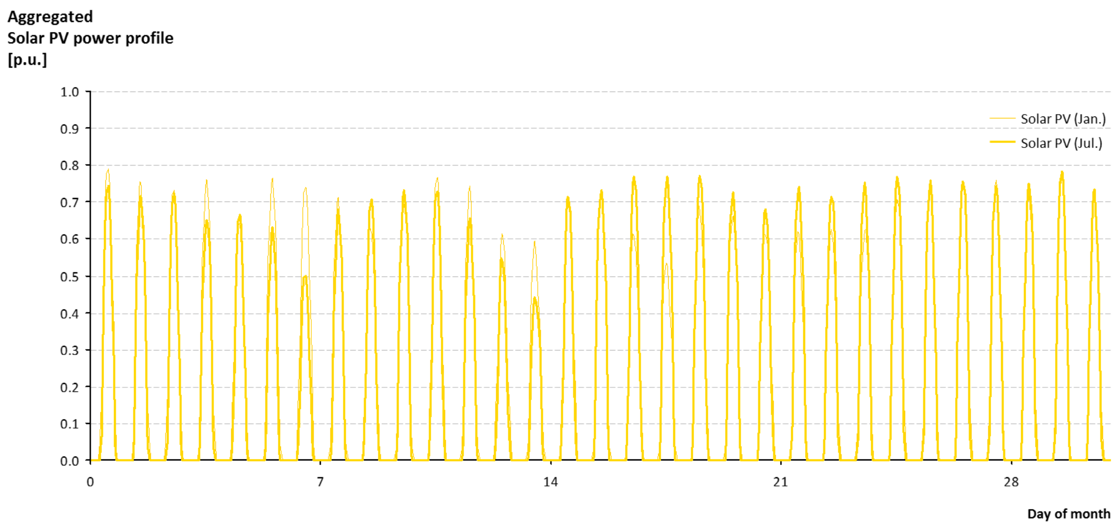


Figure 22: Aggregated solar PV profiles (normalised to 1, shown for January and July).

4.4 Supply technologies: New-build limitations

In the draft IRP 2016, annual new-build constraints are placed on selected technologies in the Base Case and Carbon Budget scenarios presented. The imposed annual new-build constraints are placed specifically on solar PV and wind technologies only (1000 MW and 1800 MW respectively). These are summarised in Table 15 along with the relative new-build constraints as the power system grows into the future (assuming the *High (Low Intensity)* demand forecast). The effect of these new-build constraints is that the capacity expansion planning model is not allowed in any given year to add more solar PV and/or wind capacity than these [2]. No annual new-build limits are applied for any other technology included

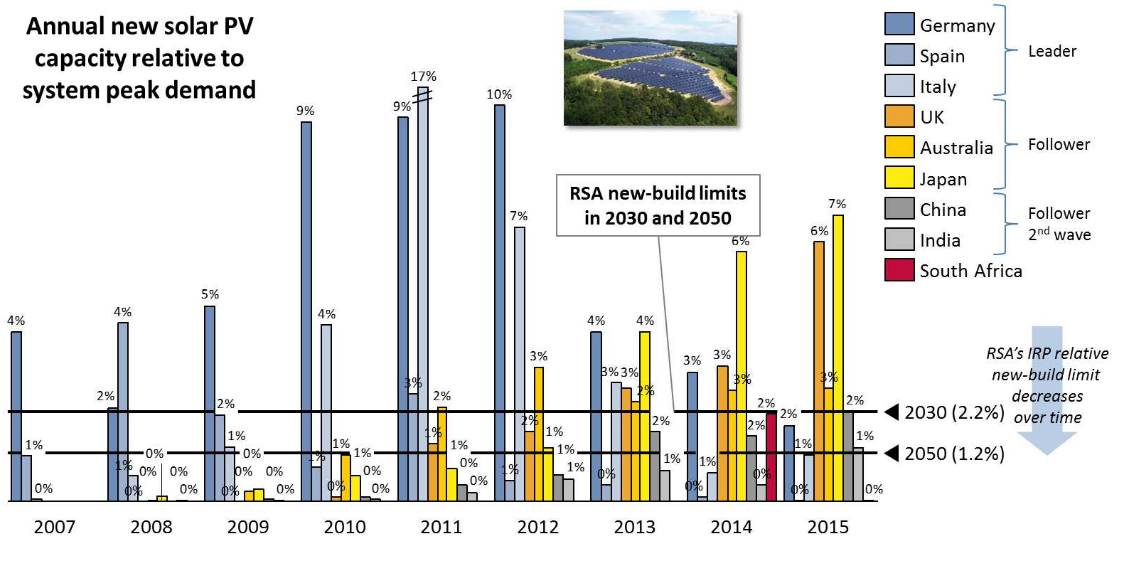
[2]Whether the implementation of annual new-build limits was applied with/without spatial context or with/without cost ladders, the same system effect remains. That is, annual new-build constraints are applied without any techno-economic justification.

in the modelling framework. As mentioned, the relative new-build limits for solar PV and wind actually decrease into the future as the power system grows. There is also no techno-economic justification provided for these limits remaining constant until 2050 while the power system grows to almost double it's current size.

Table 15: Annual new-build constraints placed on solar PV and wind (from Draft IRP 2016).

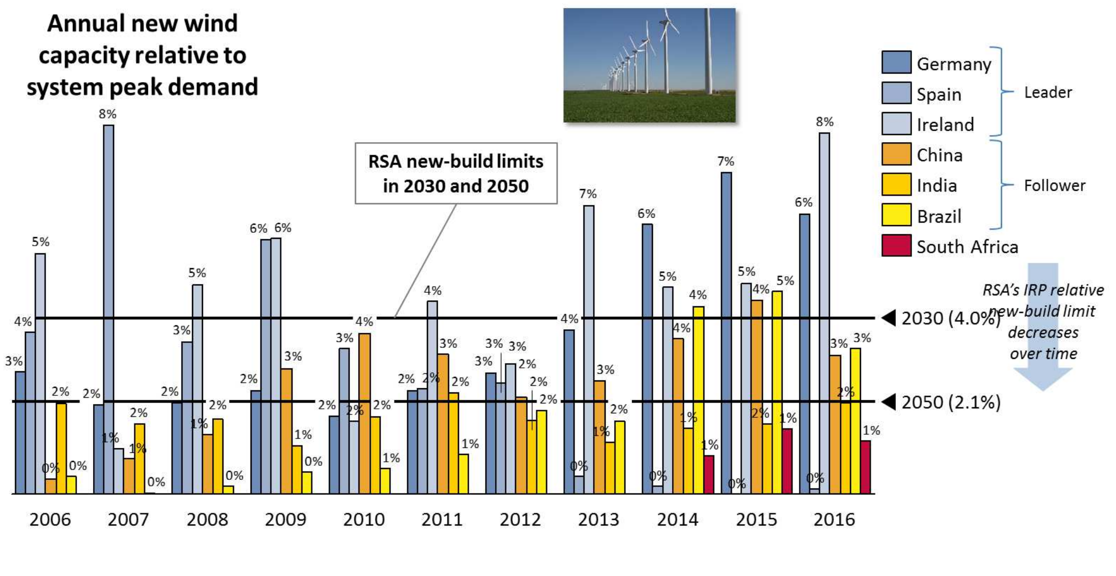
Year	System Peak Load *(High (Low Intensity)* [MW]	New-build limit Solar PV [MW/yr]	Relative new-build limit Solar PV [%/yr]	New-build limit Wind in MW/yr [MW/yr]	Relative new-build limit Wind [%/yr]
2020	44 916	1 000	2.2%	1 800	4.0%
2025	51 015	1 000	2.0%	1 800	3.5%
2030	57 274	1 000	1.7%	1 800	3.1%
2035	64 169	1 000	1.6%	1 800	2.8%
2040	70 777	1 000	1.4%	1 800	2.5%
2045	78 263	1 000	1.3%	1 800	2.3%
2050	85 804	1 000	1.2%	1 800	2.1%

For some international context on current deployment of solar PV and wind in a range of countries around the world, Figure 23 and 24 show annual new solar PV and wind capacity as well as relative new-build capacity respectively (relative to system peak demand) along with the recent installation of new capacity from the REIPPPP . Cumulative installed capacity relative to system peak demand for solar PV and wind is given in Figure 25 and 26 respectively along with the planned deployment of solar PV and wind (from the draft IRP 2016 Base Case). It is clear that developed as well as developing countries around the world are already deploying significant solar PV and wind but the annual new-build constraints placed on solar PV it seems like the



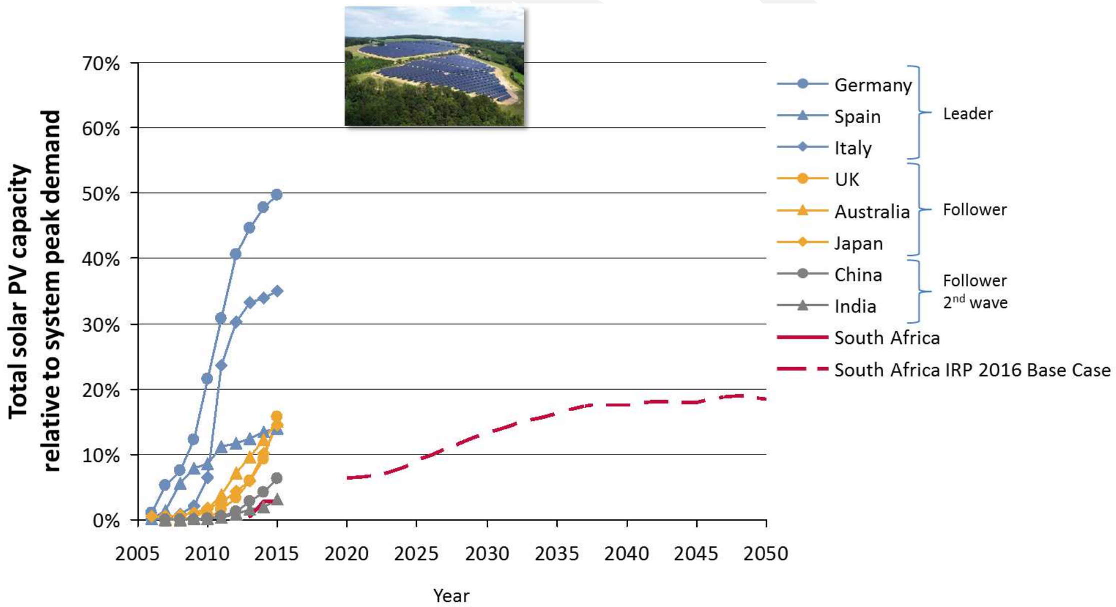
Sources: SolarPowerEurope; CIGRE; websites of System Operators; IRP 2016 Draft; CSIR analysis

Figure 23: Annual new solar PV capacity relative to system peak demand for a range of countries (including leaders, followers and 2^{nd} wave followers) along with the Draft IRP 2016 Base Case annual new-build capacity.



Sources: GWEC; CIGRE; websites of System Operators; IRP 2016 Draft; CSIR analysis

Figure 24: Annual new wind capacity relative to system peak demand for a range of countries (including leaders and followers) along with the Draft IRP 2016 Base Case annual new-build capacity.



Sources: SolarPowerEurope; CIGRE; websites of System Operators; IRP 2016 Draft; CSIR analysis

Figure 25: Cumulative solar PV capacity relative to system peak demand (including leaders, followers and 2^{nd} wave followers) along with the Draft IRP 2016 Base Case cumulative capacity.

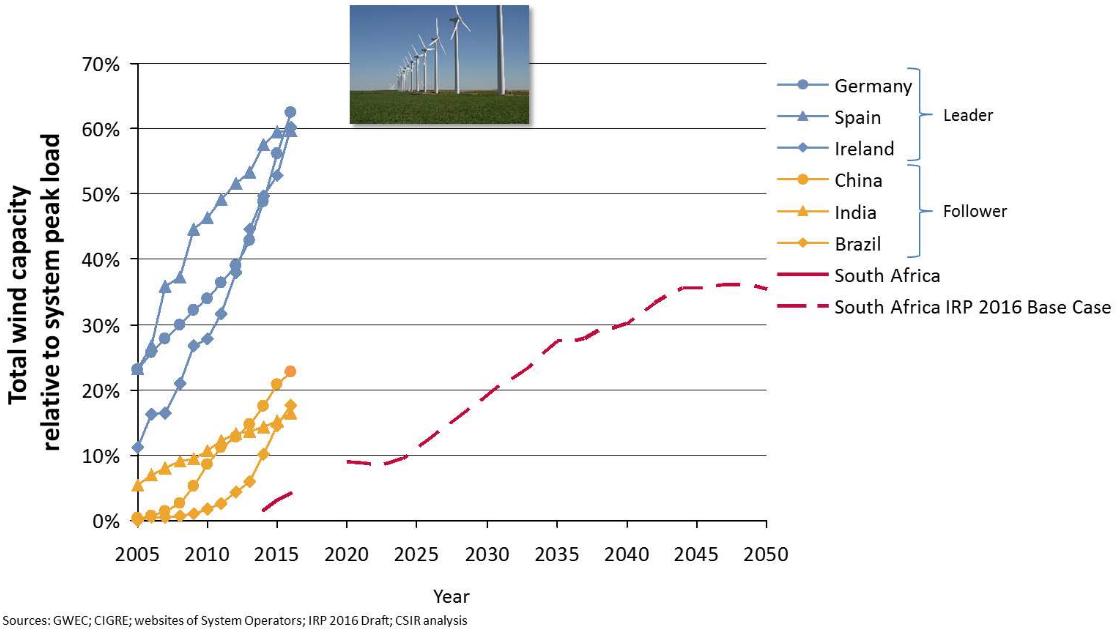


Figure 26: Cumulative wind capacity relative to system peak demand (including leaders and followers) along with the Draft IRP 2016 Base Case cumulative capacity.

4.5 Existing fleet

4.5.1 Decommissioning schedule

Existing generation capacity in South Africa will decommission over time and this combined with the demand forecast will inform the electrical energy supply gap that will need to be met. Based on the data included in the IRP 2016 in [3], a graphical summary of the generation capacity decommissioning schedule to 2050 is given in Figure 27. As can be seen, South Africa currently has just under 50 GW of installed generation capacity. The commissioning of Eskom new build capacity (Medupi, Kusile and Ingula) as well as commissioning of REIPPPP capacity and coal IPP capacity to 2020 results in an installed capacity of just under 62.5 GW by 2021. The Eskom coal fleet starts to decommission from the mid-2020s onwards with 9.6 GW decommissioning between 2020-2030, 14.8 GW between 2030-2040 and 7 GW between 2040-2050. By 2050, only Medupi, Kusile, coal IPPs and one unit at Majuba is still in operation. Most existing peaking capacity decommissions just before 2040 while the only existing nuclear capacity (Koeberg) decommissions in the mid-2040s. The capacity that came online as part of the REIPPPP starts to decommission in the mid-2030s until the late 2040s while the 2.2 GW hydro and 2.9 GW pumped storage capacity is still in operation by 2050.

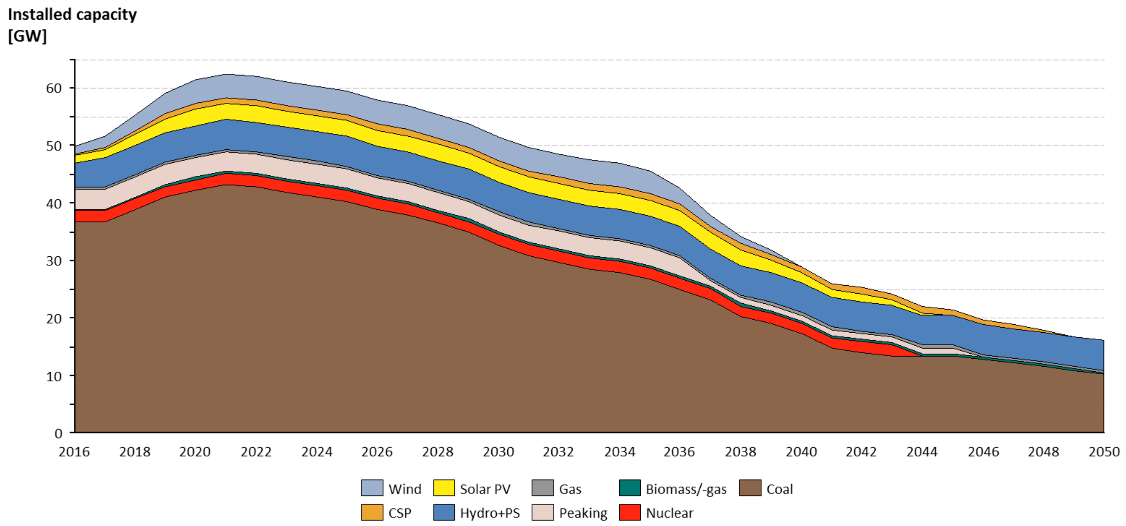


Figure 27: Decommissioning schedule of existing South African generation capacity (2016-2050) [3]

In the Decarbonised scenario run for this submission, no "smart decommissioning" is assumed where an optimisation of the decommissioning of the coal fleet is performed. Instead, due to time constraints (for this submission), an earlier decommissioning schedule is assumed for the existing coal fleet where all Eskom coal generation capacity from 2030 onwards is assumed to decommission 5 years earlier. In addition, Kusile is not commissioned and Medupi as well as the coal IPPs are decommissioned from 2045. This updated decommissioning schedule is shown in Figure 28.

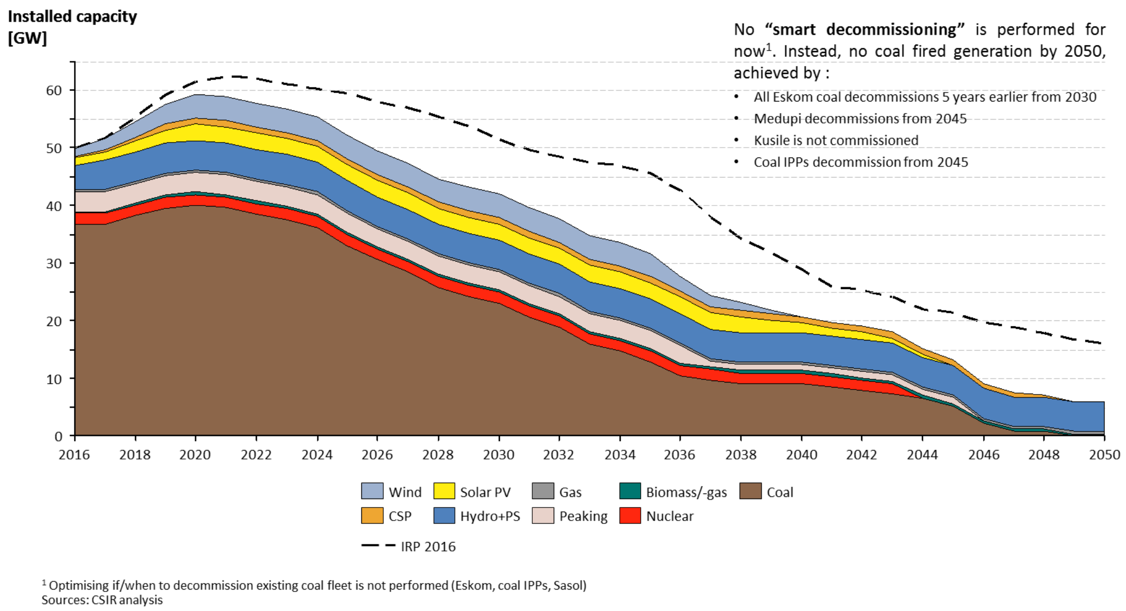


Figure 28: Assumed "Decarbonise" decommissioning schedule of existing South African generation capacity (2016-2050)

4.5.2 Performance

The existing fleet of power generators in South Africa is predominantly made up of the Eskom coal fleet. As defined in the IRP 2016, the performance of this fleet is as summarised in Figure 29 via the Energy Availability Factor (EAF). Of the three fleet performance profiles shown, the IRP Base Case uses the Moderate fleet performance profile. In this profile, the fleet performance improves from the current $\approx 72\%$ to 80% by 2020 and remains there until just after 2040 where slightly higher performance is assumed towards 82% (dominated by Medupi and Kusile).

In addition to the Eskom fleet, the reliability of each technology has been modelled explicitly in terms of planned and unplanned outage rates in line with IRP 2016 input assumptions. More details are provided in Appendix A.

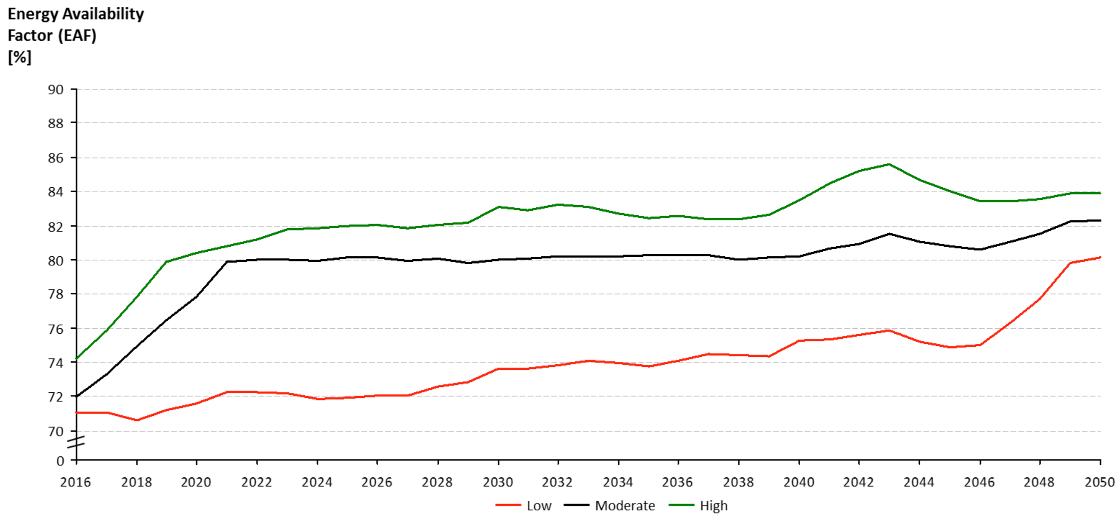


Figure 29: Existing Eskom fleet performance based on Energy Availability Factor (EAF) (2016-2050) [3]

4.6 Reserve requirements

The IRP 2016 does not explicitly mention reserve requirements other than those shown implicitly in the results tables given [3]. It seems like the firm capacity reserve requirement is around 20%. it is likely that this is strongly linked to the Eskom Ancillary Services Technical Requirements (at least until 2021/22) [41]. Without delving into too many of the details, the existing approaches taken for the three reserve classes that make up operating reserves (Instantaneous, Regulating and 10-Minute) are informed by dynamic simulation studies (for Instantaneous reserves), a load/renewables variation study (for Regulating reserves) and the largest multiple contingency event (to determine ten-minute reserve requirements).

The assumptions on reserve requirements made for this submission are summarised in Table 16. Without any additional information (or detailed reserve requirement investigations at this stage), the assumptions made on reserve requirements are based on the information presented in the Eskom Ancillary Services Technical Requirements for 2017/18 - 2021/22 [41]. From 2022 onwards, the assumptions made are based on the rules applied in [41] for Instantaneous, Regulating and 10-Minute reserve categories as far as possible. Each of these reserve categories are modelled explicitly for production cost model runs while the sum of Instantaneous, Regulating, 10-Minute, Supplemental and Emergency reserves are used for the long-term capacity expansion planning reserve requirement.

The largest multiple contingency event is initially ≈2000 MW (3x669 MW) but then becomes ≈2200 MW once three Medupi units are online i.e. 3x722 MW from 2018. Looking further into the future, the "worst case" assumption for a multiple contingency event is that of two large coal units (at Medupi) and one new nuclear unit i.e. ≈3400 MW. The regulating reserve requirement is assumed to scale linearly with demand into the future and the 10-Minute reserve requirement is still calculated to be the difference between the multiple contingency event, Instantaneous and Regulating reserve requirements (as defined in [41]). It is appreciated that there will need to be further investigations into system reserve requirements as higher penetration of variable RE sources (like solar PV and wind) are realised but this is not the focus of this submission and will likely only be necessary at a much later stage.

Table 16: Assumed reserve requirements to 2050

			2016-2019	2020-2022	2023-2024	2025-2029	2030-2034	2035-2039	2040-2044	2045-2049	2050-2054
Instantaneous	Summer	Peak	500	500	500	500	500	500	500	500	500
		Off-peak	500	500	500	500	500	500	500	500	500
	Winter	Peak	500	500	500	500	500	500	500	500	500
		Off-peak	800	800	800	800	800	800	800	800	800
Regulating	Summer	Peak	550	550	570	640	720	800	890	990	1 010
		Off-peak	550	550	570	640	720	800	890	990	1 010
	Winter	Peak	600	600	630	720	820	920	1 020	1 120	1 140
		Off-peak	600	600	630	720	820	920	1 020	1 120	1 140
Ten-minute	Summer	Peak	1 150	1 150	1 130	2 260	2 180	2 100	2 010	1 910	1 890
		Off-peak	850	850	830	1 960	1 880	1 800	1 710	1 610	1 590
	Winter	Peak	1 100	1 100	1 070	2 180	2 080	1 980	1 880	1 780	1 760
		Off-peak	800	800	770	1 880	1 780	1 680	1 580	1 480	1 460
Operating	Summer	Peak	2 200	2 200	2 200	3 400	3 400	3 400	3 400	3 400	3 400
		Off-peak	2 200	2 200	2 200	3 400	3 400	3 400	3 400	3 400	3 400
	Winter	Peak	2 200	2 200	2 200	3 400	3 400	3 400	3 400	3 400	3 400
		Off-peak	2 200	2 200	2 200	3 400	3 400	3 400	3 400	3 400	3 400
Supplemental	Summer/	Peak/	1 300	1 300	1 300	1 300	1 300	1 300	1 300	1 300	1 300
Emergency	Winter	Off-peak	300	900	900	900	900	900	900	900	900
Total	Summer/ Winter	Peak/ Off-peak	3 800	4 400	4 400	5 600	5 600	5 600	5 600	5 600	5 600

4.7 Electrical energy demand forecast

The electrical energy demand forecasts for the IRP 2016 were developed by the CSIR (details of which can be found in Appendix A) [42]. In [42], forecasts for national demand for electricity were undertaken at a macro-level using a sectoral regression model. The approach is based on macro-level economic and demographic drivers of electricity consumption in end-use sectors (agriculture, transport, domestic, commerce/manufacturing and mining). These drivers include Gross Domestic Product (GDP), population, expected Final Consumption Expenditure of Households (FCEH) and relevant manufacturing and mining indices. Multiple regression was used within the individual electricity end-use sectors by relating these drivers to demand in each of the end-use sectors. For some drivers, namely population, only one set of forecasts was used throughout all scenarios. A correction factor for changes in electricity intensity was included in the manufacturing and commercial sector to reflect the change in electrical energy intensity in these sectors that have been noted in recent years. The sectoral forecasts were aggregated and then adjusted for losses in order to obtain a forecast for national consumption. The demand forecast is inclusive of all domestic demand and exports (including electrical losses and pumped storage pumping load).

Four growth scenarios were specified for the forecasts performed in [42], namely:

- High (Same sectors);
- High (Low Intensity) - IRP 2016 Base Case;
- Moderate; and
- Low

Figure 30 shows the historical electrical energy demand for South Africa [43] along with key demand trajectories (*High (Low Intensity)* and *Low* from [42] as well as a demand forecast obtained from the *EIUG*). The historical electrical energy demand from 1985 to 2016 shows how South Africa's demand has almost doubled in 30 years [**?**]. The IRP 2010-2030 demand forecast is also shown in Figure 30 for reference. The IRP 2016 uses the *High (Low Intensity)* forecast in the Base Case. Electrical energy demand has almost doubled since 1985 (1.9x in 30 years) but has noticeably slowed down in recent years as can be noted when compared to the expected demand forecast from the IRP 2010-2030. The IRP 2010-2030 expected an annual average electrical demand growth rate of 2.8% (for the 20 year horizon). The IRP 2016 assumes annual average growth rates of 2.3% and 1.4% in the *High (Low Intensity)* forecast and *Low* forecast respectively (for the 34 year horizon 2016-2050). The EIUG forecast has the same annual average growth rate as the *Low* forecast but follows an S-curve as energy demand still increases until 2050 but annual growth rates of energy demand slow down over time from over 2.0% in 2020 to 0.6% by 2050.

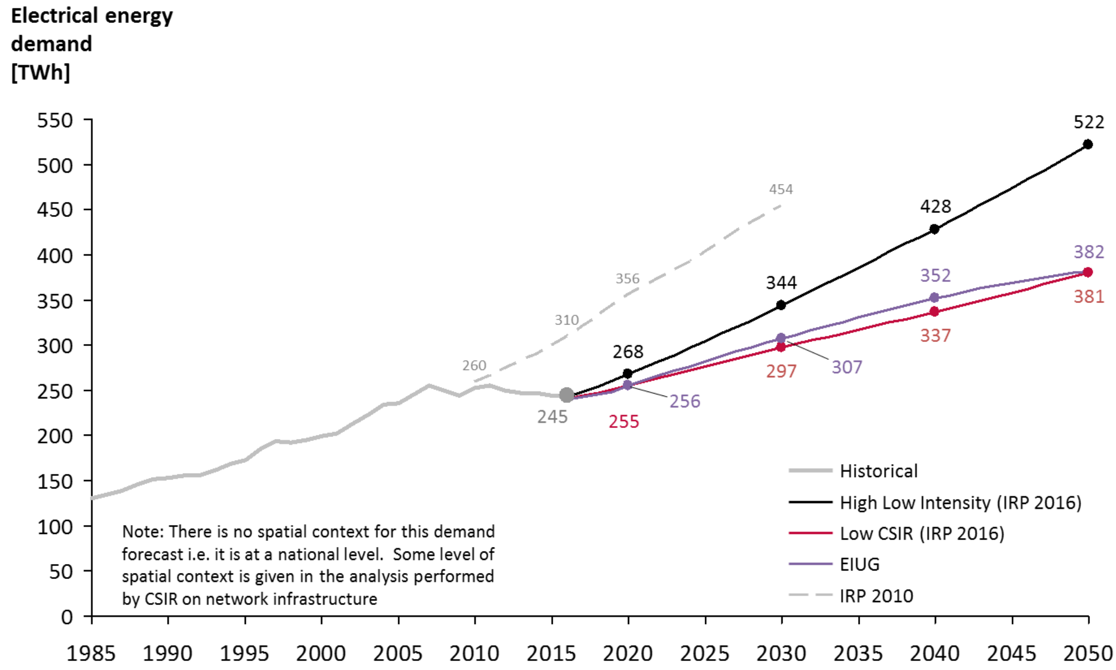


Figure 30: Electrical energy demand forecasts for South Africa (historical from StatsSA and projected from the the draft IRP 2016 and EIUG)

4.8 Electricity sector emissions

Emissions rates for CO_2, SOx, NOx, Hg and particulates for all technologies are aligned with those included in the IRP 2016 and are detailed further in Appendix A.

A specific focus on electricity sector CO_2 emissions trajectories is included here as it is a key constraint included in the IRP 2016 over the study horizon (2016-2050). These trajectories were driven initially in 2011 by South Africa's National Climate Change Response White Paper [44] which defines a Peak Plateau Decline (PPD) trajectory for Greenhouse Gas (GHG) emissions as part of the mitigation strategy for South Africa. This has been recently formalised into South Africa's Intended Nationally Determined Contributions (INDCs) and then Nationally Determined Contributions (NDCs) following the commitments as part of the United Nations Framework Convention on Climate Change (UNFCCC) Paris Agreement [45, 46].

The PPD Upper and Lower trajectories for CO_2 emissions are shown in Figure 31 along with the assumption made in the IRP 2010 (Update) and IRP 2016 (electricity sector contributing ≈45% to total emissions) [5, 3]. In the IRP Update (2013) as well as the IRP 2016, CO_2 emissions were either assumed to decline moderately from 2037 onwards (from 275 Mt/a to 210 Mt/a in 2050) or assumed to to decline further in an advanced decline scenario (from 275 Mt/a in 2030 aready and end at 140 Mt/a by 2050) [5, 3].

In the scenario run in this submission "Decarbonise the electricity sector", a different emissions trajectory is assumed for electricity sector CO_2 emissions. This trajectory is shown in Figure 33 and is an ≈35% reduction of 2016 emissions by 2030, ≈65% reduction by 2040 and 95% reduction of 2016 CO_2 emissions by 2050.

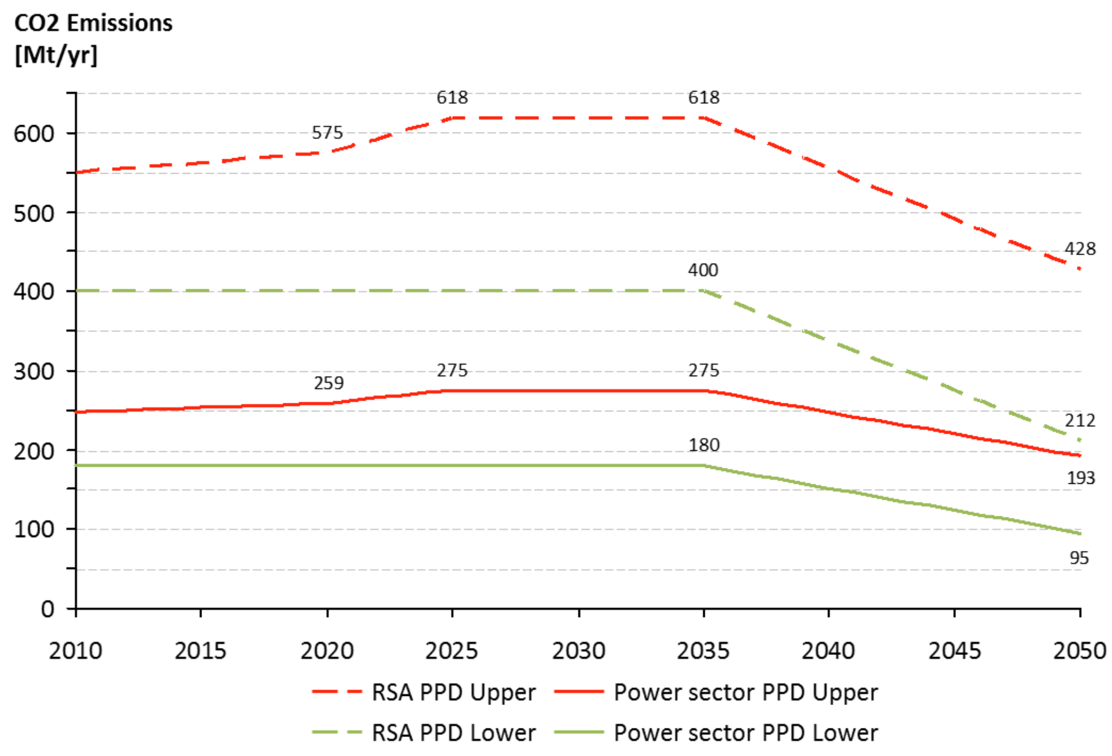


Figure 31: Total CO_2 emissions trajectory for South Africa with power sector specific carbon emissions trajectories (assuming 45% share).

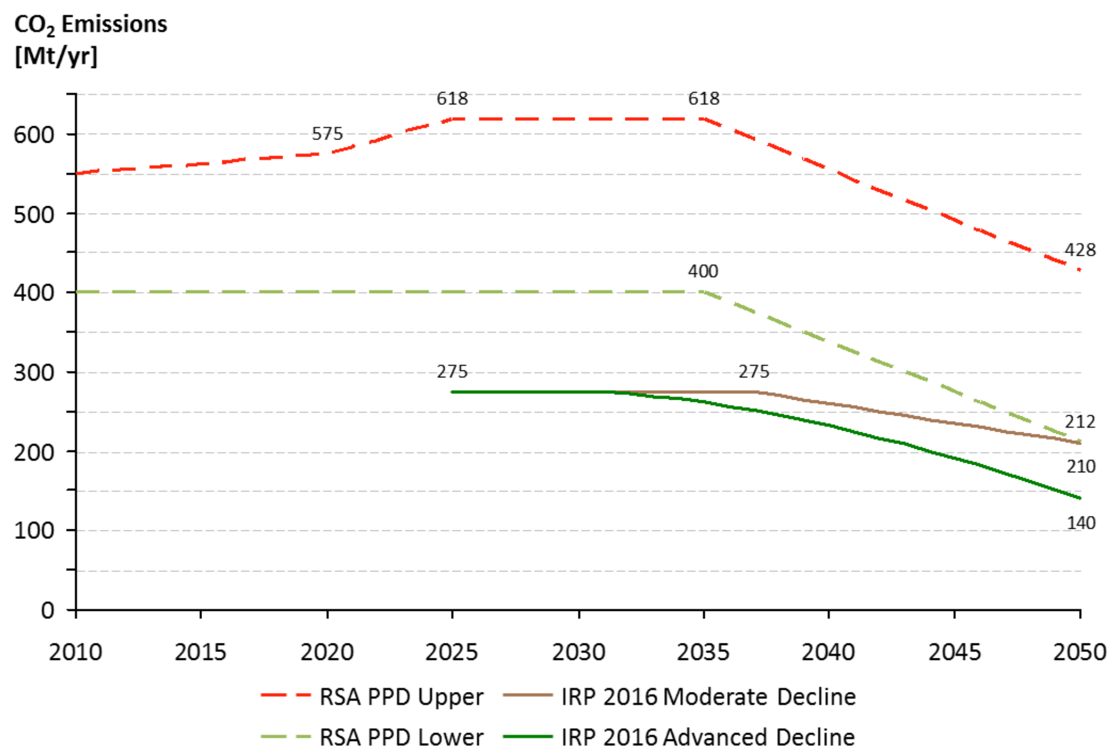


Figure 32: Total CO_2 emissions trajectories for South Africa along with the assumed Moderate and Advanced CO_2 emissions trajectories from the IRP (Update) 2013 (the same assumptions are made for the IRP 2016 with the Moderate decline applied for the Base Case).

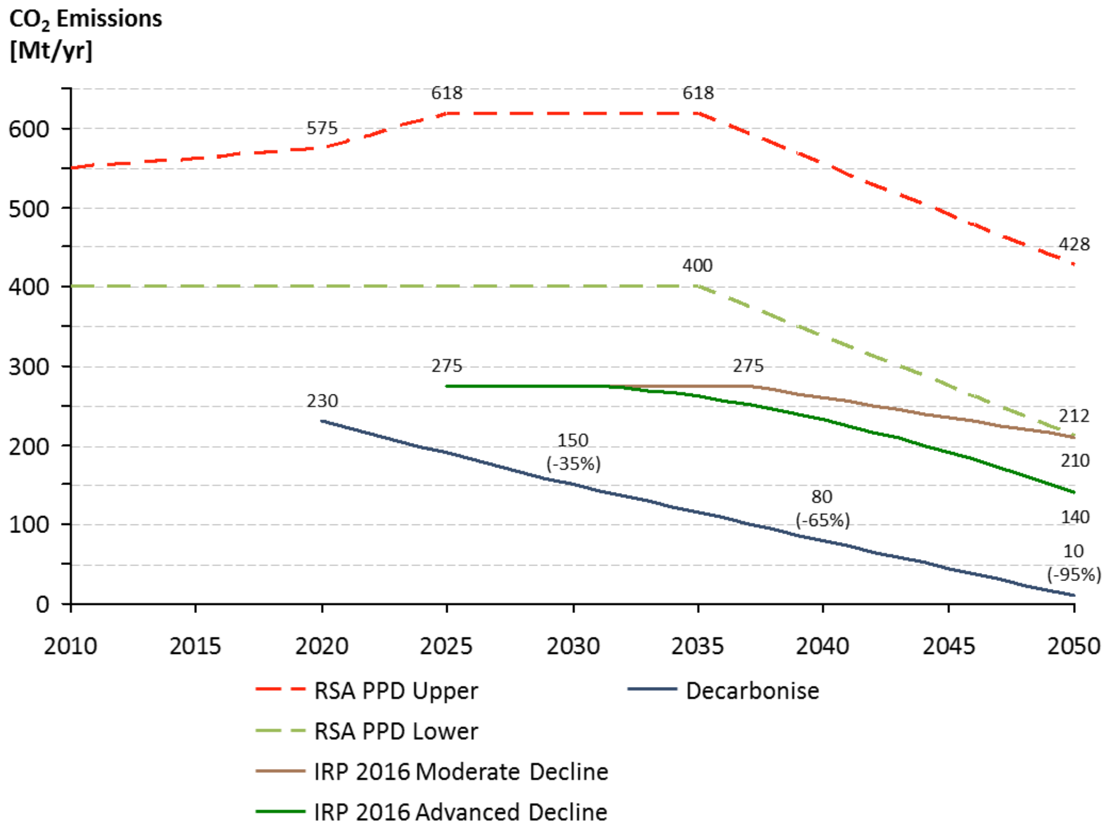


Figure 33: Electricity sector CO_2 emissions trajectory for the "Decarbonise" scenario (shown along with overall PPD trajectories and assumed Moderate and Advanced CO_2 emissions trajectories from the IRP 2016).

4.9 Localised jobs

Using the information provided in [47] from the study commissioned by the DoE and undertaken by McKinsey & Company on potential for job creation and localisation of the main generating technologies, a high level analysis of localised job creation potential for all scenarios has been performed as part of this submission. The input data used is summarised in Figure 34. Only direct and supplier related jobs are included (up to *"potentially localisable with significant investment"* as categorised in [47]). Indirect as well as induced jobs are not included as part of the analysis.

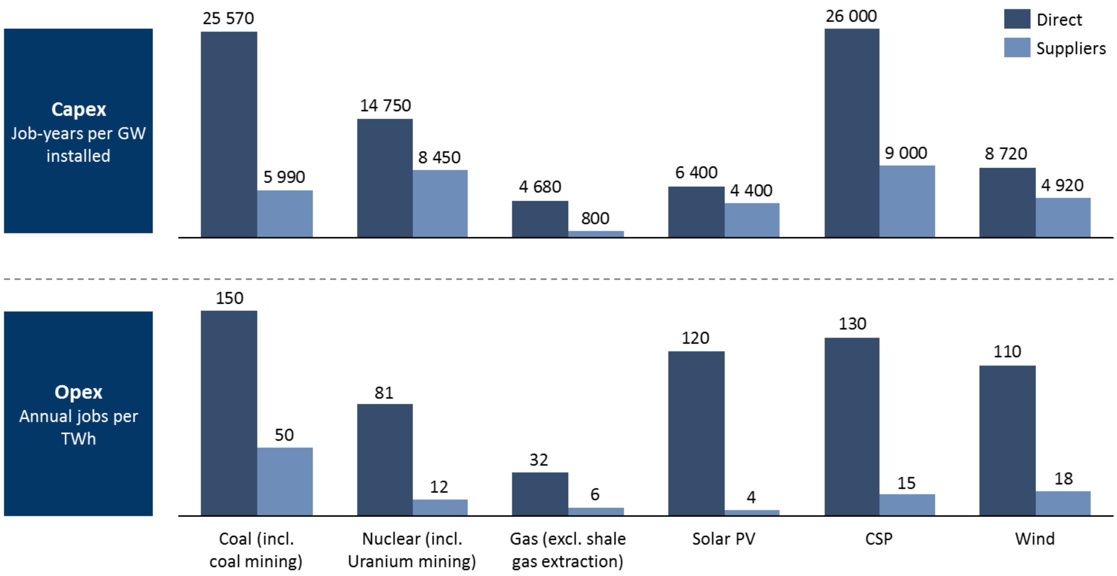


Figure 34: Localised job creation per technology is a function of capital (build-out) as well as operations (utilisation) for each technology (see [47] for further details)

4.10 Demand shaping - Electric water heating (EWH)

A notable addition that has been included in some of the scenarios assessed is that of demand shaping. Although there are many opportunities for demand shaping in a number of end-use sectors (domestic, industrial, commercial), the intention of including one particular demand shaping opportunity is to demonstrate the impact that this can have on the power system. Specifically, demand shaping in the residential sector with a particular focus on the intra-day control of residential Electric water heating (EWH) demand i.e. control of EWHs. This has been investigated and reviewed for a range of end-use appliances in [48, 49] but specifically for EWH in [50, 51, 52] (amongst others). In the South African context for example; a simple, low-cost and easy to implement distributed control method paradigm for EWH using system frequency as an input signal has been proposed by Cooper and Cronje in [53].

For the work undertaken, the modelling of residential EWH as a demand shaping resource is kept as simple as possible while basing the fundamentals on empirical existing data and likely future adoption. A summary of key parameters which define the EWH resource for demand shaping are given in Table 17 while a brief description of the approach follows.

For calibration purposes, the share of residential end-use in total electrical energy demand is determined along with the typical EWH component of this based on information from the South African Audience Research Foundation (SAARF) All Media and Products Survey (AMPS) Survey, Eskom and CSIR [54, 42, 55]. The population growth from [42], number of households fromStatsSA [56], estimates for the number of people per household and the expected number of households with EWHs are then used to obtain the future expected number of households as well as households with EWHs in South Africa. From this (and the previous calibration performed), a range of parameters including an assumed adoption rate of demand shaping from EWHs, capacity of electric water heating elements over time determine the EWHs resource available to shape demand on an intra-day basis. It is assumed that there is no substitution effect (energy demand needs to be met on a daily basis but can be shifted depending on system requirements). Although demand shaping could strictly be included as a capacity resource that contributes to system adequacy [57, 58]; the authors assume no capacity value for EWHs demand shaping i.e. a conservative approach is taken.

Table 17: Input parameters and calculations for demand shaping over the time horizon 2016-2050

Property	Unit	2016-2019	2020	2030	2040	2050
Population	[mln]	55.7 - 57.5	58.0	61.7	64.9	68.2
Number of HHs	[mln]	16.9 - 18.1	18.5	22.4	26.0	27.3
Residents per HH	[ppl/HH]	3.29 - 3.17	3.13	2.75	2.50	2.50
HHs with EWH	[%]	28 - 33	34	50	75	100
HHs with EWH	[mln]	4.7 - 5.9	6.3	11.2	19.5	27.3
Demand shaping adoption	[%]	-	2	25	100	100
Demand shaping	[TWh/a]	-	0.4	5.4	28.3	26.4
Demand shaping	[GWh/d]	-	1.1	14.9	77.4	72.3
Demand shaping (demand increase)	[MW]	-	371	4 991	25 970	24 265
Demand shaping (demand decrease)	[MW]	-	46	620	3 226	3 015

4.11 Demand flexibility - Electric vehicles (e-vehicles)

Similar to the modelling of a demand shaping resource for EWHs, electric vehicles (e-vehicles) are included as a flexible demand side option in the Least-cost ("Expected" costs) scenario. This will also demonstrate the impact on the power system as more e-vehicles make up the South African vehicle fleet. The e-vehicle fleet is modelled similarly to the EWH demand shaping resource. It also has intra-day controllability (can be dispatched as needed on any given day) based on power system needs but needs to have a net-zero energy balance on a daily basis (no substitution effect).

Using key input parameters and assumptions on the likely e-vehicle fleet by 2050, the potential demand flexibility via e-vehicles is calculated. Key input parameters include current population, expected population growth to 2050, current number of motor vehicles, expected motor vehicles per capita by 2050, adoption rate of e-vehicles by 2050, e-vehicle capacity (MW), e-vehicle energy requirement (GWh/d) and proportion of the e-vehicle fleet connected simultaneously. The calculations performed to estimate the likely e-vehicle fleet and key properties used in modelling the fleet for demand side flexibility is summarised in Table 18.

Table 18: Input parameters and calculations for demand side flexibility from e-vehicles over the time horizon 2016-2050

Property	Unit	2016-2019	2020	2030	2040	2050
Population	[mln]	0 - 0	58.0	61.7	64.9	68.2
Number of motor vehicles	[mln]	7 - 7.3	7.3	8.0	8.4	8.9
EVs adoption rate	[%]	0 - 0	0.9	10.0	25.0	55.5
Number of EVs	[mln]	0 - 0	0.1	0.8	2.1	5.0
EVs energy requirement	[TWh/a]	-	0.2	2.4	6.3	15.0
EVs energy requirement	[GWh/d]	-	0.5	6.6	17.3	41.1
EVs (demand increase)	[MW]	-	600	7 700	20 400	48 300
EVs (demand decrease)	[MW]	-	-	300	700	1 700

4.12 Stationary storage technologies

Stationary storage technologies have been included in the IRP 2016 in the form of Lithium-ion batteries (1 hour and 3 hour storage capacity) as well as Compressed Air Energy Storage (CAES). The input cost assumptions for these technologies are applied for all scenarios (no learning rate is assumed) with the exception of the Least-cost ("Expected" costs) scenario. In this scenario, learning rates summarised in Table 19 are assumed while in all other scenarios the costs for storage are assumed to remain at IRP 2016 assumed costs in 2016.

Table 19: Input parameters and learning rates assumed for stationary storage technologies over the time horizon 2016-2050 (learning rates are only assumed for the Least-cost ("Expected" costs) scenario).

Technology		2016		2030		2040		2050	
(Apr-2016 ZAR)	Capacity	Capex[1]	FOM[2]	Capex[1]	FOM[2]	Capex[1]	FOM[2]	Capex[1]	FOM[2]
	[MW]	[R/kWh]	[R/kW/yr]	[R/kWh]	[R/kW/yr]	[R/kWh]	[R/kW/yr]	[R/kWh]	[R/kW/yr]
Lithium-ion (1 hrs)	3	9 891	618	2 000	309	1 000	309	800	309
Lithium-ion (3 hrs)	3	9 891	618	2 000	309	1 000	309	800	309
CAES (8 hrs)	180	3 459	212	3 459	212	3 459	212	3 459	212

5 Long-term expansion planning to 2050

Results from all scenarios are compared in a number of dimensions. These are:

- Net generation capacity (per technology) - [MW]
- Generation energy share (per technology) - [TWh]
- Total system cost - [ZAR-billion]
- Average tariff - [R/kWh]
- CO_2 emissions - [Mt/yr]
- Water usage - [bl/yr]
- Localised job potential - [number of jobs]

Please see section 4 and Appendix A for details on the definition of various input assumptions.

5.1 Scenarios

5.1.1 Draft IRP 2016: Base Case

The Draft IRP Base Case scenario is defined by the following input assumptions:

- Demand: *High (Low Intensity)*
- Supply technologies costs: *IRP 2016*
- Supply technologies new-build limits: *IRP 2016*
- CO_2 emission trajectory: *IRP 2016 (Moderate Decline)*
- Existing fleet performance: *IRP 2016 (Moderate)*
- Existing fleet decommissioning: *IRP 2016*
- Reserves requirements: *Eskom (to 2022), assumed thereafter*

The results summary for the Draft IRP 2016 Base Case are shown in Figure 35. A typical plot of weekly generation profile to meet demand is shown in Figure‘**??**.

The Draft IRP Base Case results in new coal investment supplementing the existing coal fleet by 2030 along with new gas, solar PV and wind investments. The initial phase of import hydro (via Inga as a proxy) is also included (1000 MW). By 2050, ≈33% of the energy mix is coal (existing and new) complemented by just less ≈28% nuclear and the remaining energy coming from gas (≈9%), solar PV (≈5%), wind (≈18%) and hydro energy (≈5%).

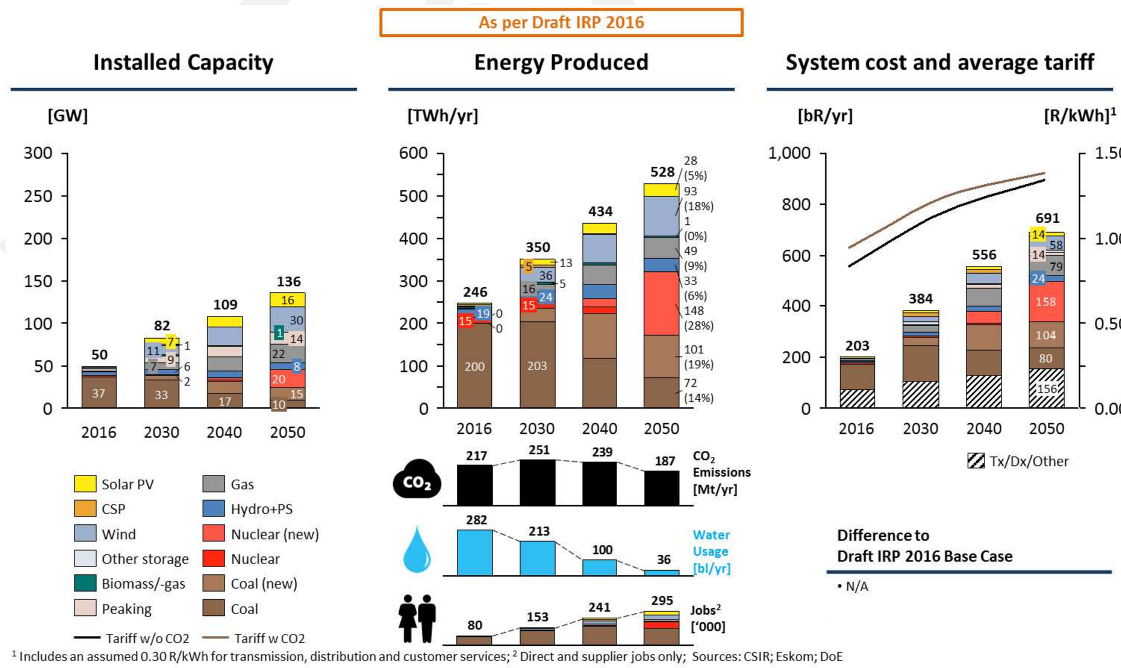


Figure 35: Scenario: Draft IRP 2016 Base Case

5.1.2 Draft IRP 2016: Carbon Budget

The Draft IRP Carbon Budget scenario is defined by the following input assumptions:

- Demand: *High (Low Intensity)*
- Supply technologies costs: *IRP 2016*
- Supply technologies new-build limits: *IRP 2016*
- CO_2 emission trajectory: *Stricter CO_2 emissions limits*[3]
- Existing fleet performance: *IRP 2016 (Moderate)*
- Existing fleet decommissioning: *IRP 2016*
- Reserves requirements: *Eskom (to 2022), assumed thereafter*

The results summary for the Draft IRP 2016 Carbon Budget are shown in Figure 36.

The Draft IRP Carbon Budget scenario results show no investment in new coal capacity (as a result of the tighter CO_2 emissions constraints). The scenario also invests earlier in nuclear relative to the Base Case (first unit by 2026). The primary reason for this is the annual new-build constraints placed on solar PV and wind (see section 4.4 for details). The tighter CO_2 emissions limits mean that once the model has chosen the maximum annual new-build solar PV and wind it chooses the next available CO_2 free technology i.e. nuclear. This is perpetual and continues into the future with a ≈26 GW nuclear fleet by 2050. Slightly more than 30% of the energy mix is nuclear by 2050 with a similar share for solar PV, wind, biomass/-gas and hydro combined. Gas fired generation at ≈16% provides flexibility while the remaining coal capacity provides ≈13% of the energy mix.

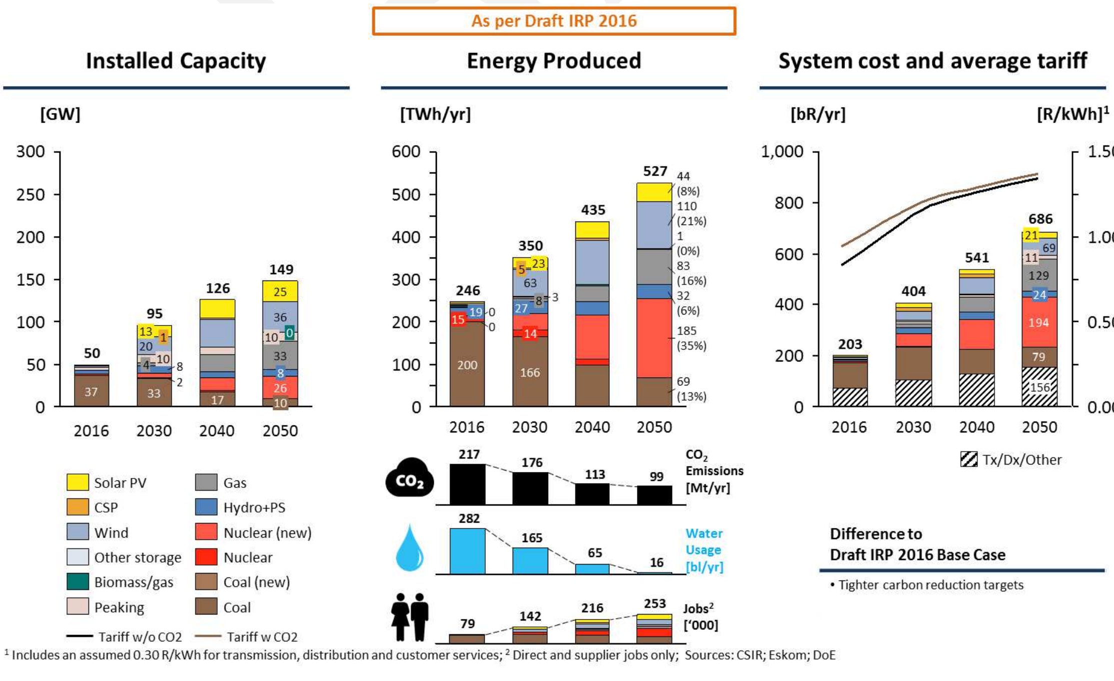


Figure 36: Scenario: Draft IRP 2016 Carbon Budget

5.1.3 Unconstrained Base Case

The Unconstrained Base Case is based on the inputs into the IRP 2016 public consultation process by the Ministerial Advisory Council on Energy (MACE) [59]. It is defined by the following input assumptions:

- Demand: *High (Low Intensity)*
- Supply technologies costs: *Draft IRP 2016*
- Supply technologies new-build limits: *None*
- CO_2 emission trajectory: *IRP 2016 (Moderate Decline)*
- Existing fleet performance: *IRP 2016 (Moderate)*
- Existing fleet decommissioning: *IRP 2016*
- Reserves requirements: *Eskom (to 2022), assumed thereafter*

The results summary for the Unconstrained Base Case scenario are shown in Figure 37.

This scenario is run to demonstrate the effect of removing the annual new build limits placed specifically on solar PV and wind technologies while assuming the same costs for all technologies (including solar PV and wind) as in the draft IRP 2016 (see section 4.4 for further details). As can be clearly seen, the effect of removing these annual new-build constraints is significant. The scenario results in some new coal investment but only post 2030 (3.75 GW by 2040 and 7.5 GW by 2050), no new nuclear capacity but significant deployment of solar PV and wind. The energy mix by 2050 is made up of ≈65% RE by 2050 (dominated by solar PV and wind along with hydro and biomass/-gas) complemented by ≈23% coal (existing and new) and ≈10% of gas fired generation capacity.

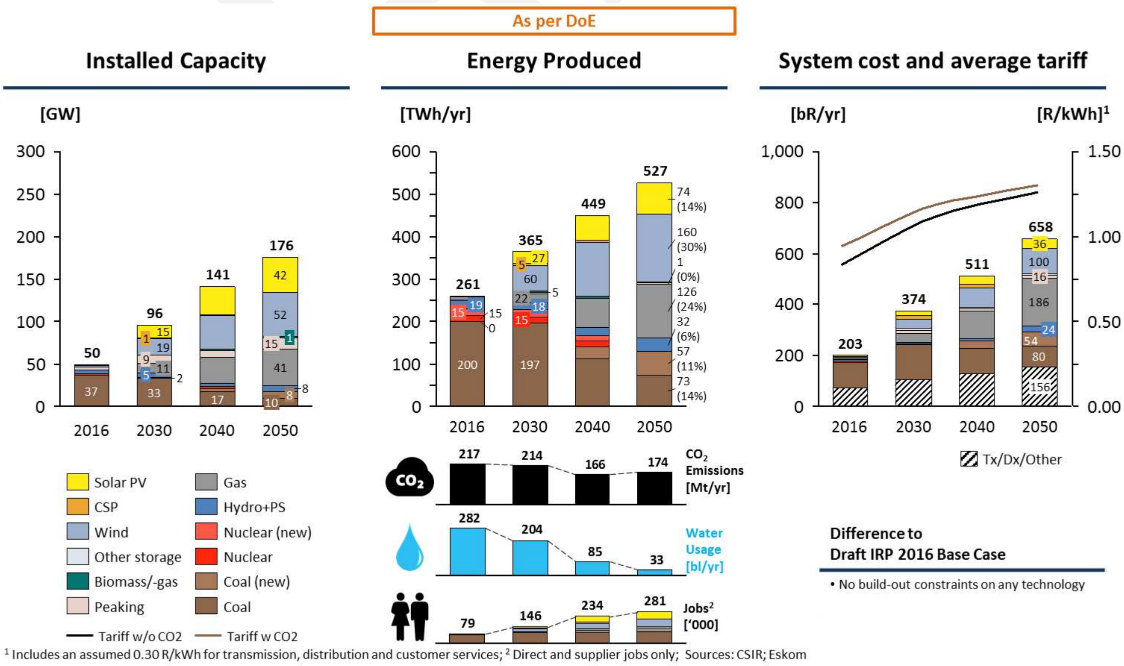


Figure 37: Scenario: Unconstrained Base Case

5.1.4 Least-cost

The Least Cost scenario is defined by the following input assumptions:

- Demand: *High (Low Intensity)*
- Supply technologies costs: *Draft IRP 2016 except for solar PV, wind, biomass/-gas and EWH*[4]
- Supply technologies new-build limits: *None*
- CO_2 emission trajectory: *IRP 2016 (Moderate Decline)*
- Existing fleet performance: *IRP 2016 (Moderate)*
- Existing fleet decommissioning: *IRP 2016*
- Reserves requirements: *Eskom (to 2022), assumed thereafter*

The results summary for the Least-cost scenario are shown in Figure 38.

The Least-cost scenario is run to demonstrate the true basis/starting point from which adjustments to various input assumptions could then be made for comparative purposes and policy adjustment (as outlined in Figure 2 in section 1). The Least-cost scenario invests significantly in solar PV and wind as expected with gas fired generation capacity providing system flexibility and adequacy along with hydro and some biomass/-gas. By 2050, the energy mix is ≈21% solar PV, ≈49% wind, ≈12% gas, ≈6% hydro with the remaining coal capacity at Medupi/Kusile (and one unit at Majuba) providing ≈11%.

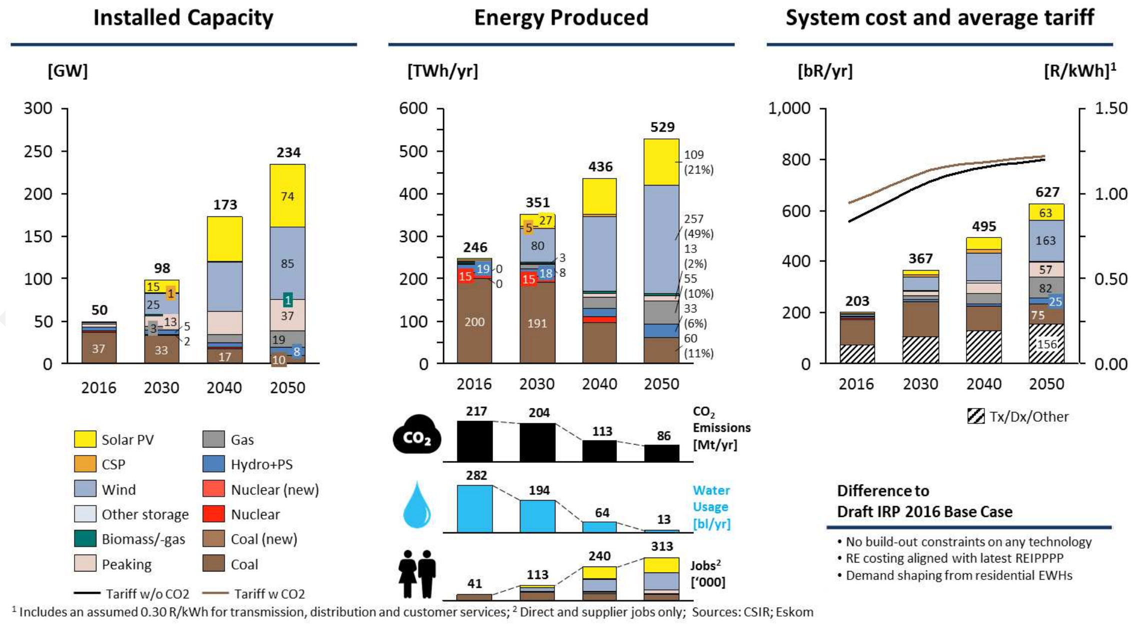


Figure 38: Scenario: Least-cost

5.1.5 Decarbonised

The Decarbonised scenario is defined by the following input assumptions:

- Demand: *High (Low Intensity)*
- Supply technologies costs: *Draft IRP 2016 except for solar PV, wind, biomass/-gas and EWH*[5]
- Supply technologies new-build limits: *None*
- CO_2 emission trajectory: *Decarbonised*
- Existing fleet performance: *IRP 2016 (Moderate)*
- Existing fleet decommissioning: *Decarbonised*
- Reserves requirements: *Eskom (to 2022), assumed thereafter*

The results summary for the Decarbonised scenario are shown in Figure 39.

This scenario is run to demonstrate what the cost impacct would be if a decarbonisation trajectory in the electricity sector is pursued (95% CO_2 reduction by 2050). It is purposefully chosen to be as extreme on CO_2 emissions as possible. Initial investments to 2030 are similar to the Least-cost (solar PV, wind and gas). One notable difference is the investment in more of these technologies and specifically in gas fired generation capacity as a result of the earlier coal fleet decommissioning assumptions made as well as Kusile not being commissioned. From 2040 onwards, the CO_2 emissions constraint becomes significant. Continued investment in solar PV and wind but investment in Concentrated Solar Power (CSP), biomass/-gas, hydro as well as additional pumped storage is notable. The energy mix by 2050 is made up of ≈93% RE and is dominated by solar PV (≈22%) and wind (≈48%) complemented by CSP (≈13%), biomass/-gas (≈6%), hydro (≈6%) and gas fired generation (≈5%).

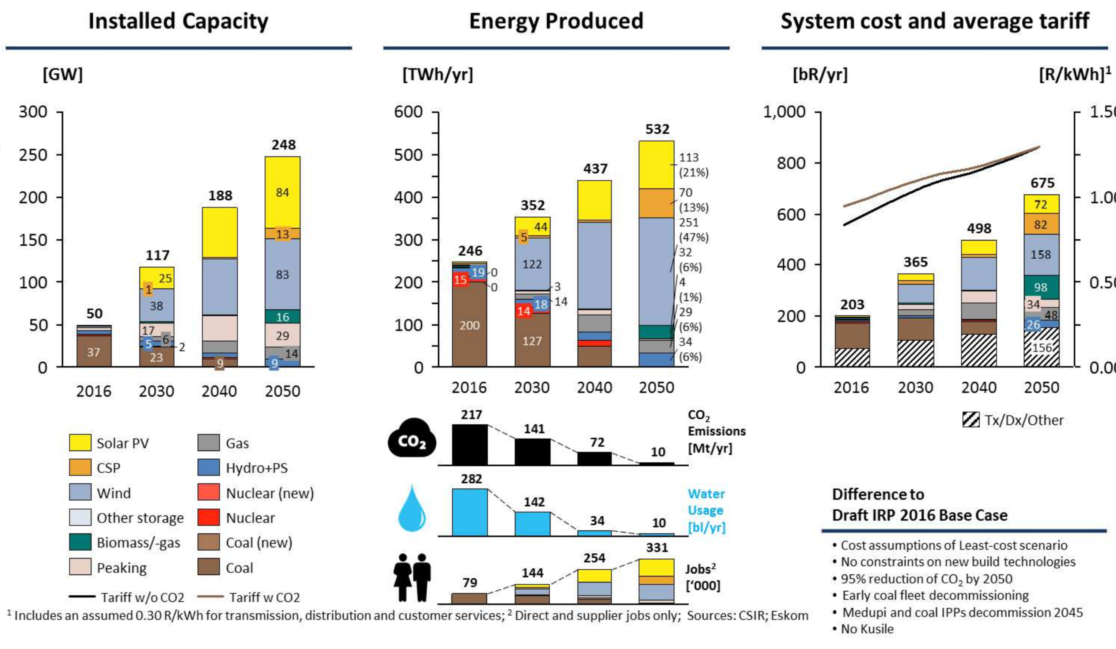


Figure 39: Scenario: Decarbonised

5.1.6 Least cost (Expected costs)

The Least-cost ("Expected" costs) scenario is defined by the following input assumptions:

- Demand: *High (Low Intensity)*
- Supply technologies costs: *IRP 2016 except for solar PV, wind, biomass/-gas, EWH & e-vehicles*[6]
- Supply technologies new-build limits: *None*
- CO_2 emission trajectory: *IRP 2016 (Moderate Decline)*
- Existing fleet performance: *IRP 2016 (Moderate)*
- Existing fleet decommissioning: *IRP 2016*
- Reserves requirements: *Eskom (to 2022), assumed thereafter*

The results summary for the Least-cost ("Expected" costs) scenario are shown in Figure 40.

This scenario is similar to the Least-cost already presented but with an additional demand side resource (e-vehicles), higher learning rates for solar PV and wind as well as learning rates for stationary storage (Lithium-ion battery storage is used as a proxy in this regard). As can be seen, significant deployment of stationary storage (as a result of learning rates assumed) is complemented by cheap solar PV and wind which also have notable cost reductions into the future. Solar PV is deployed in significantly higher quantities relative to other scenarios as a result of it's relatively significant reduction in costs. The deployment of cheap stationary storage shifts the large amounts of excess solar PV during the day (and wind at times) into periods when it is needed. Gas capacity and peaking capacity is still invested in but at a later stage to assist in system adequacy (mostly peaking capacity is required). Storage also assists in system adequacy along with the remaining coal capacity to 2050.

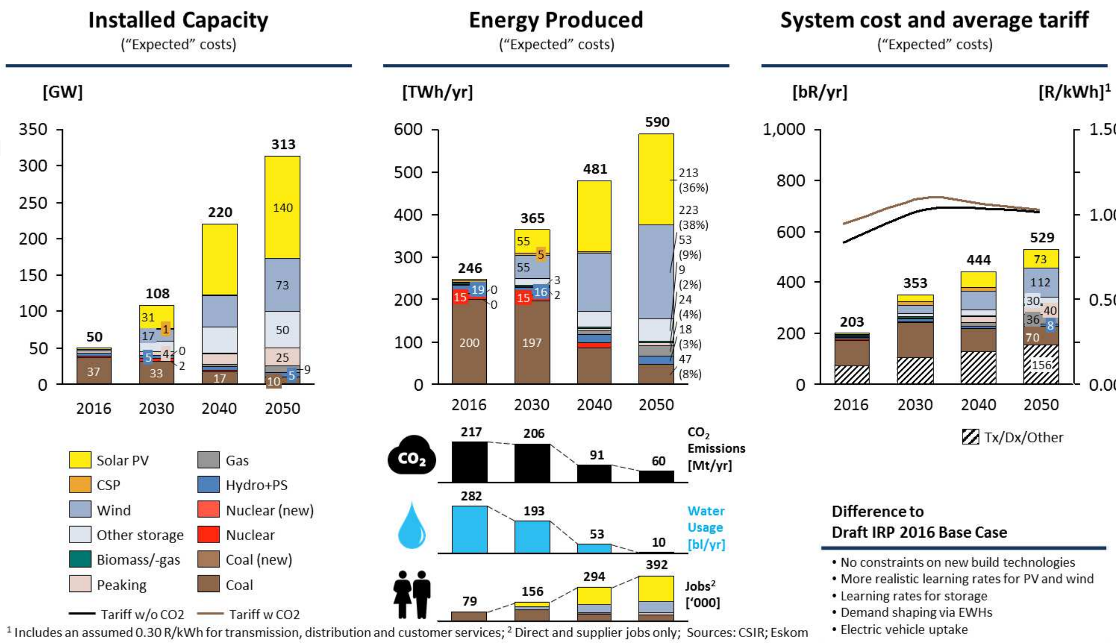


Figure 40: Scenario: Least-cost ("Expected costs")

5.1.7 Scenario comparison and summary

Summaries of the total system costs (with and without the cost of CO_2) and estimated average tariff (with and without the cost of CO_2) are given in Figure 41 and 42 respectively. The CO_2 emissions and water consumption for these scenarios are summarised in Figure 43.

A comparison of the scenarios on installed capacity, energy mix and total system cost in the year 2050 is given in Figure 44.

Summaries of the scenarios for the year 2030, 2040 and 2050 are shown in Figure 45-47.

If one were to utilise the cost assumptions made in the Least-cost ("Expected" costs) scenario for other scenarios presented, it is clear that total system costs for all scenarios would change but by how much and relative to each other how would these change is an interesting outcome. Summaries of total system costs (with and without the cost of CO_2) and estimated average tariff (with and without the cost of CO_2) are given in Figure 48 and 49 respectively. A summary of this is provided for the year 2030, 2040 and 2050 in Figure 50-52.

As can be seen across most scenarios (with the exception of the Carbon Budget and Decarbonise scenarios), coal continues to play a dominant role in the South African energy mix until at least 2030. Beyond 2030, the bulk of the existing coal fleet decommissions over time resulting in the energy mix being less coal intensive and replaced by other resources dominated by solar PV, wind and flexibility (in the form of natural gas fired gas and peaking capacity). Only in the Base Case and Unconstrained Base Case is some new coal capacity built.

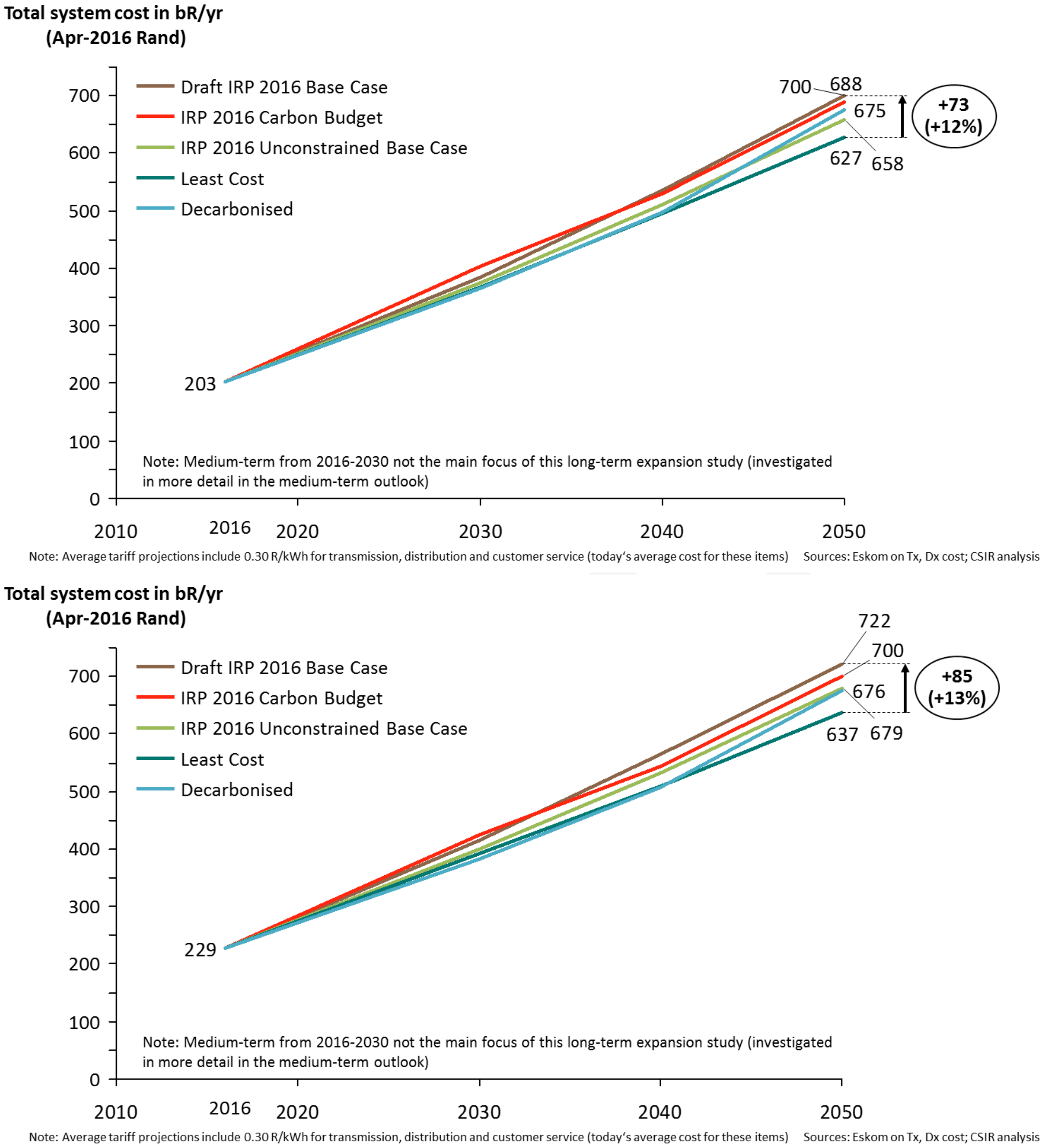
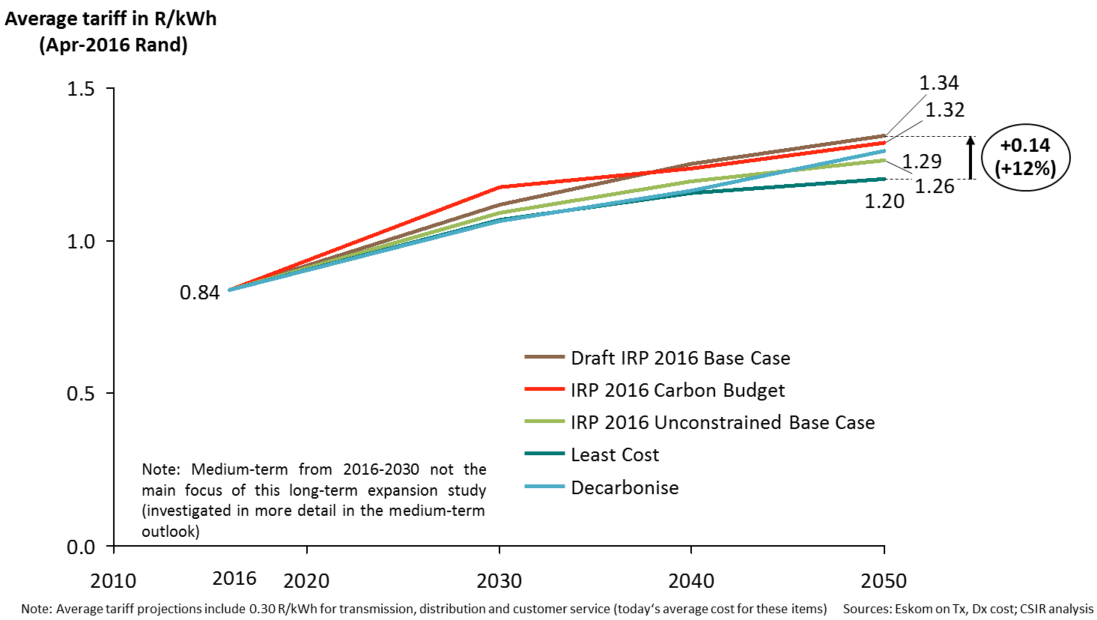


Figure 41: Total system costs for scenarios (with and without the cost of CO_2)



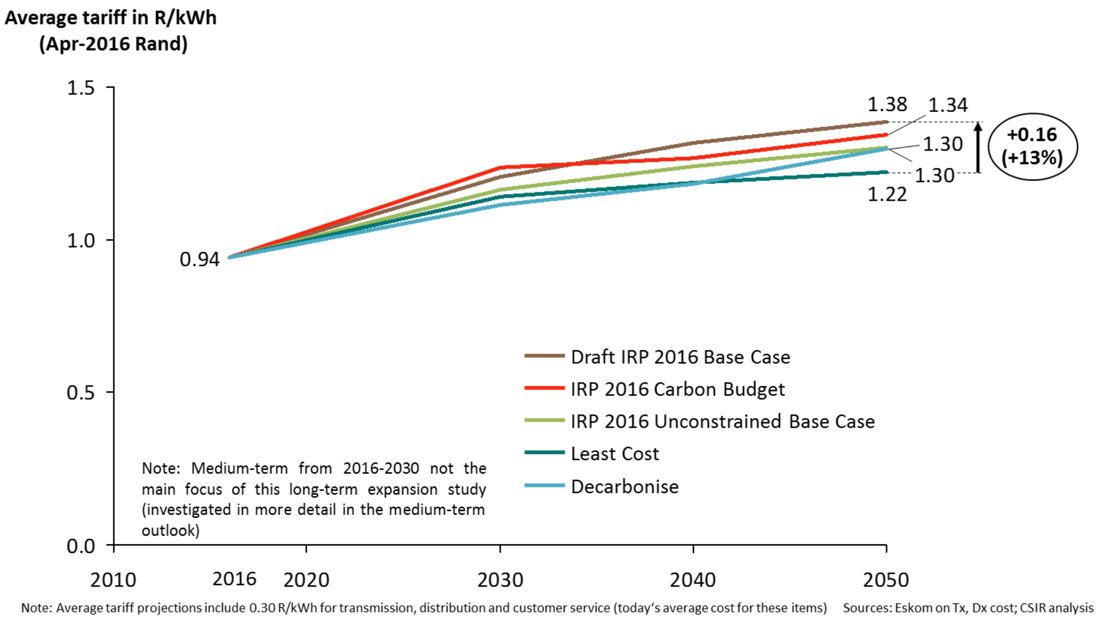


Figure 42: Average tariff for scenarios (with and without the cost of CO_2)

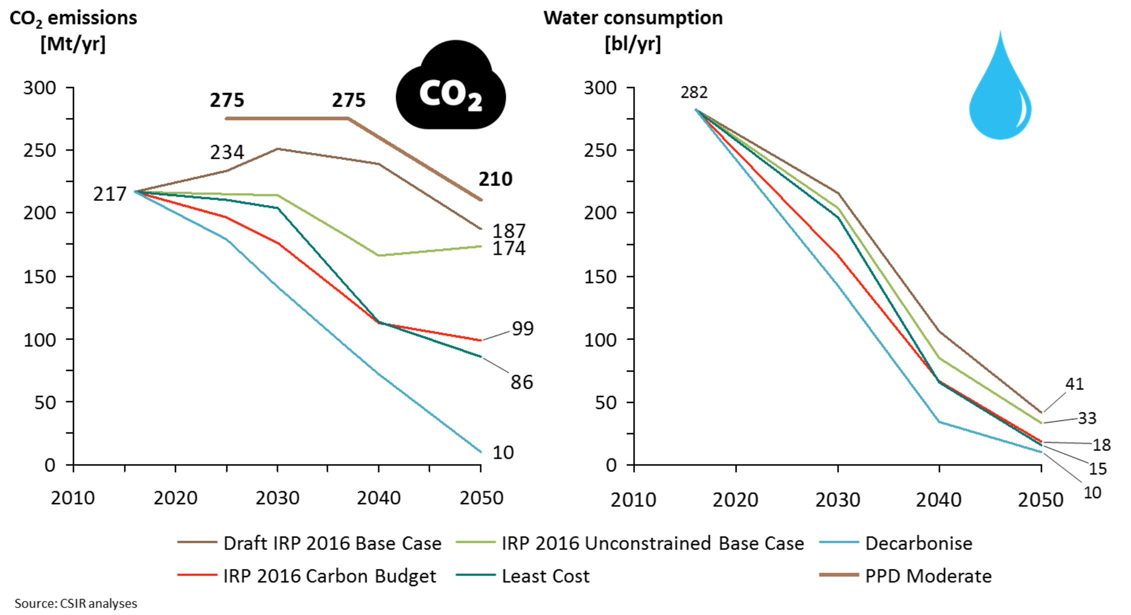


Figure 43: CO_2 emissions and water consumption for scenarios presented (2016-2050).

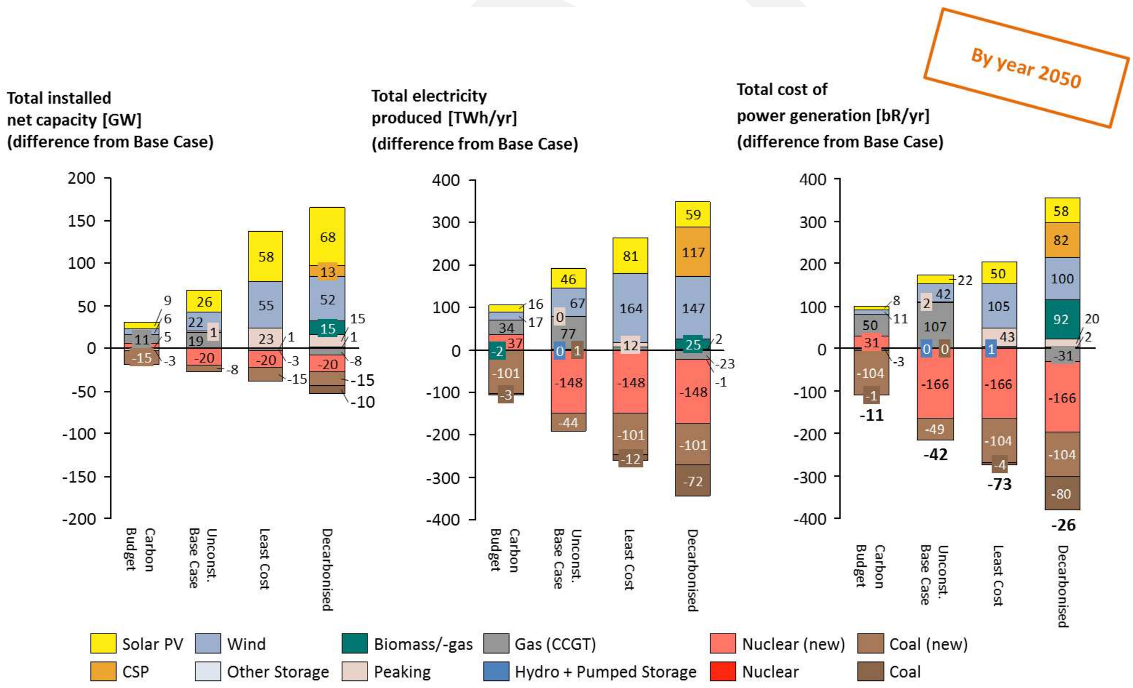


Figure 44: Comparison of scenario differences relative to Base Case for the year 2050

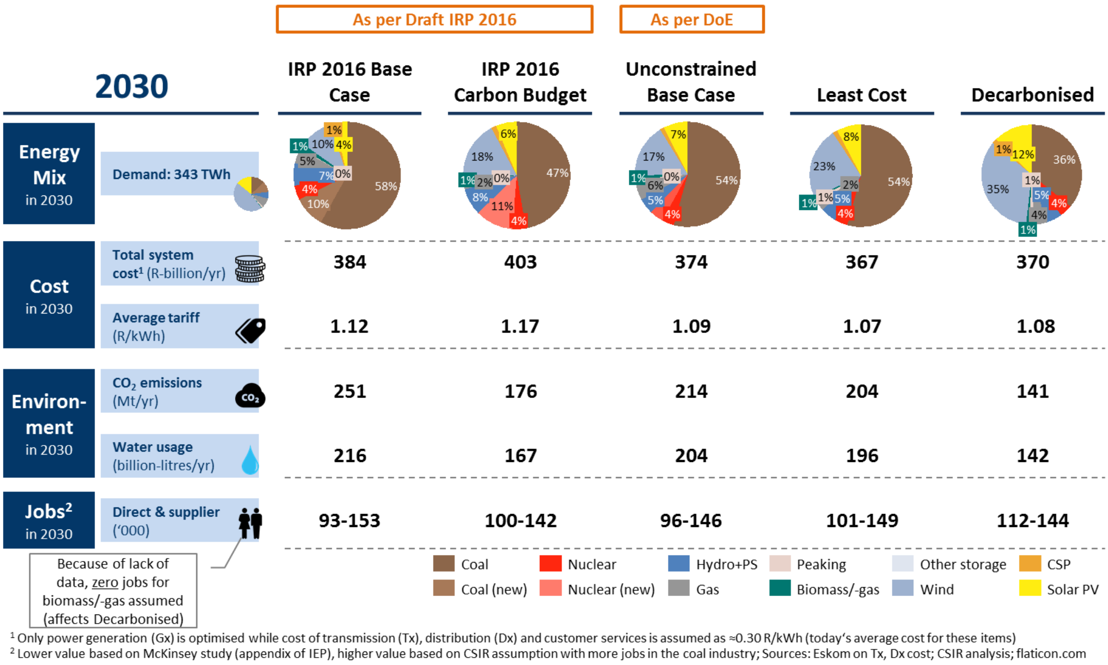


Figure 45: Scenario summary for the year 2030

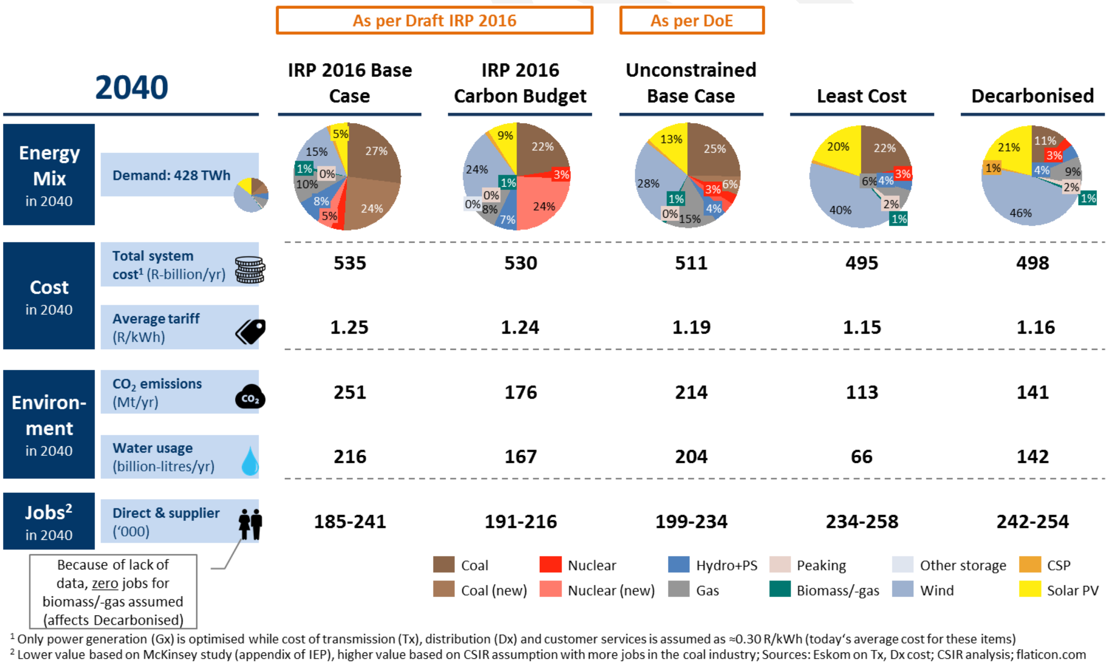


Figure 46: Scenario summary for the year 2040

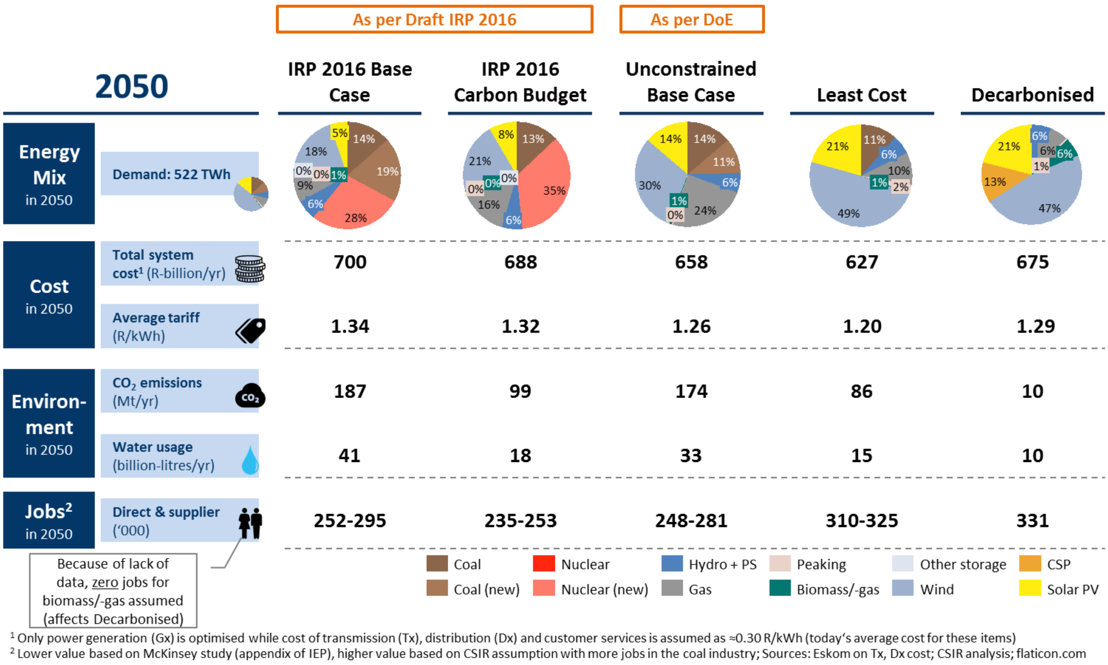
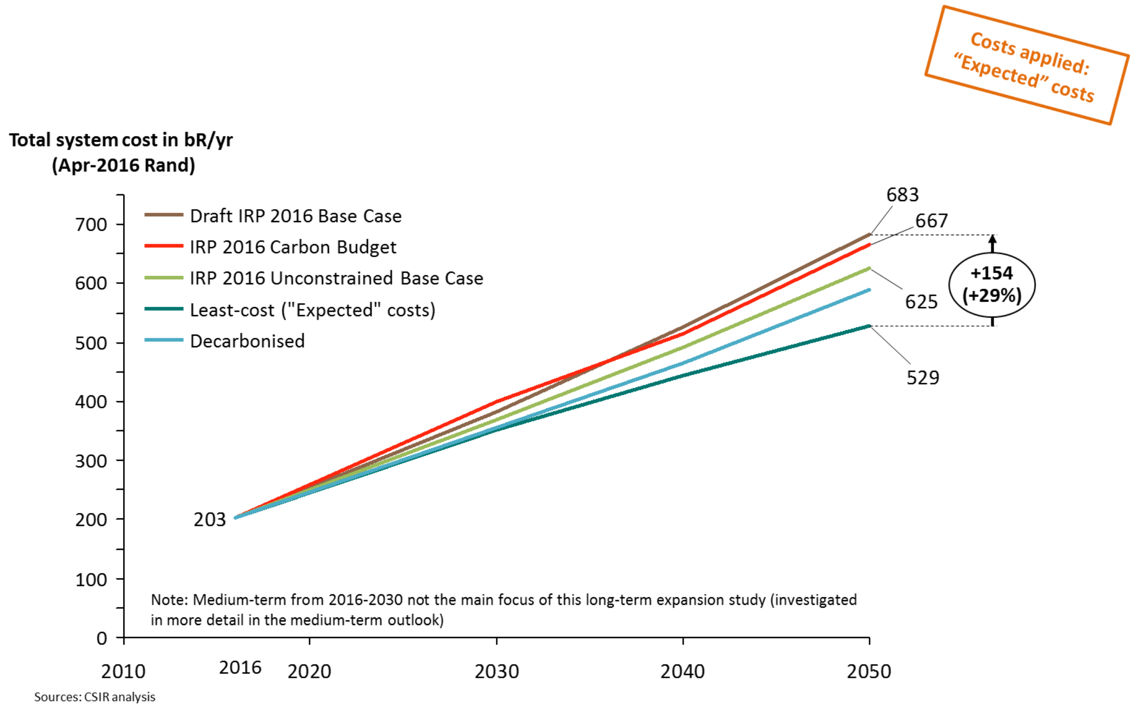


Figure 47: Scenario summary for the year 2050



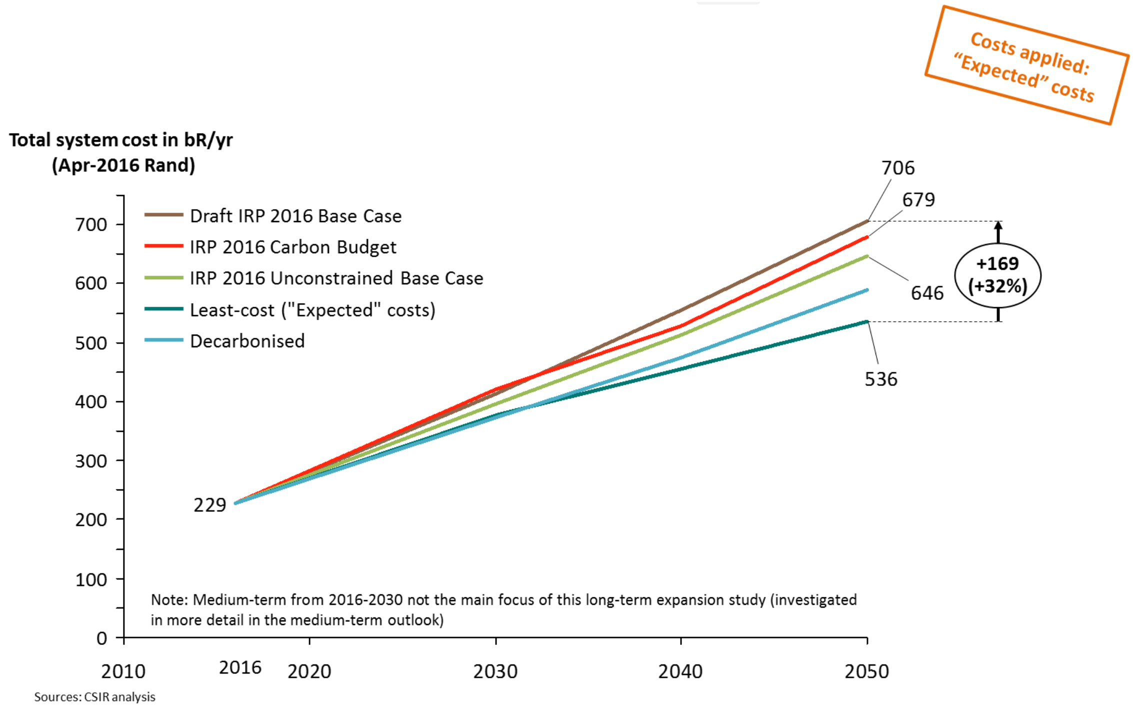
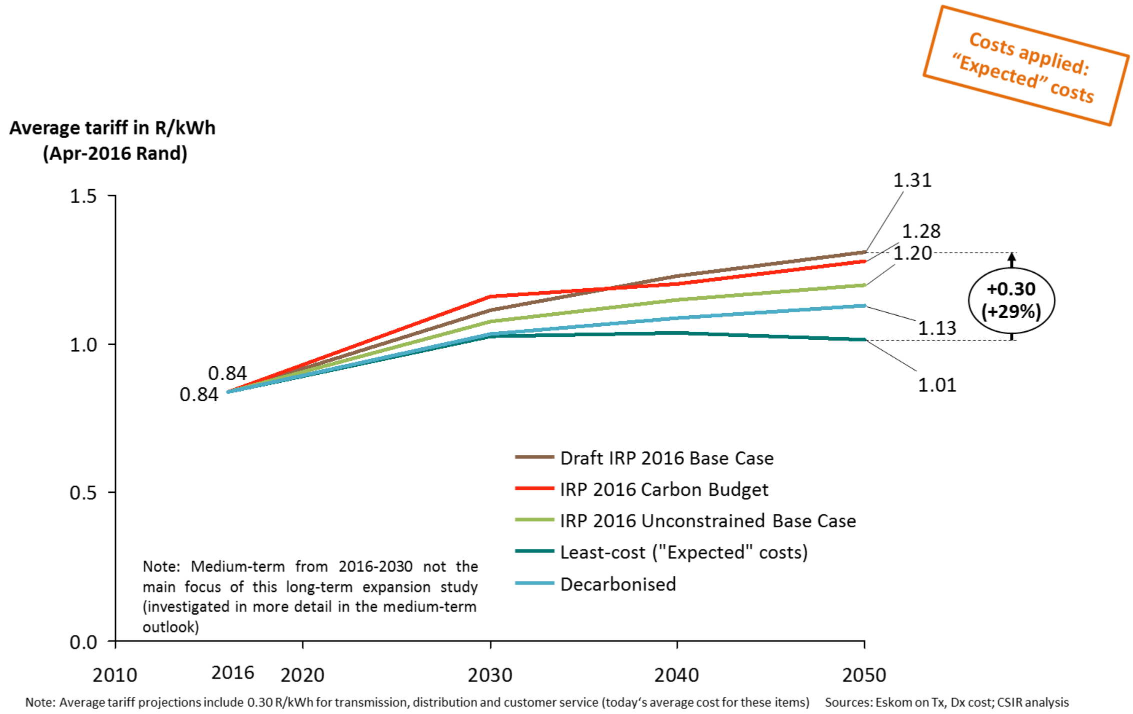


Figure 48: Total system costs for scenarios (with and without the cost of CO_2) assuming costs from Least-cost ("Expected" costs) scenario



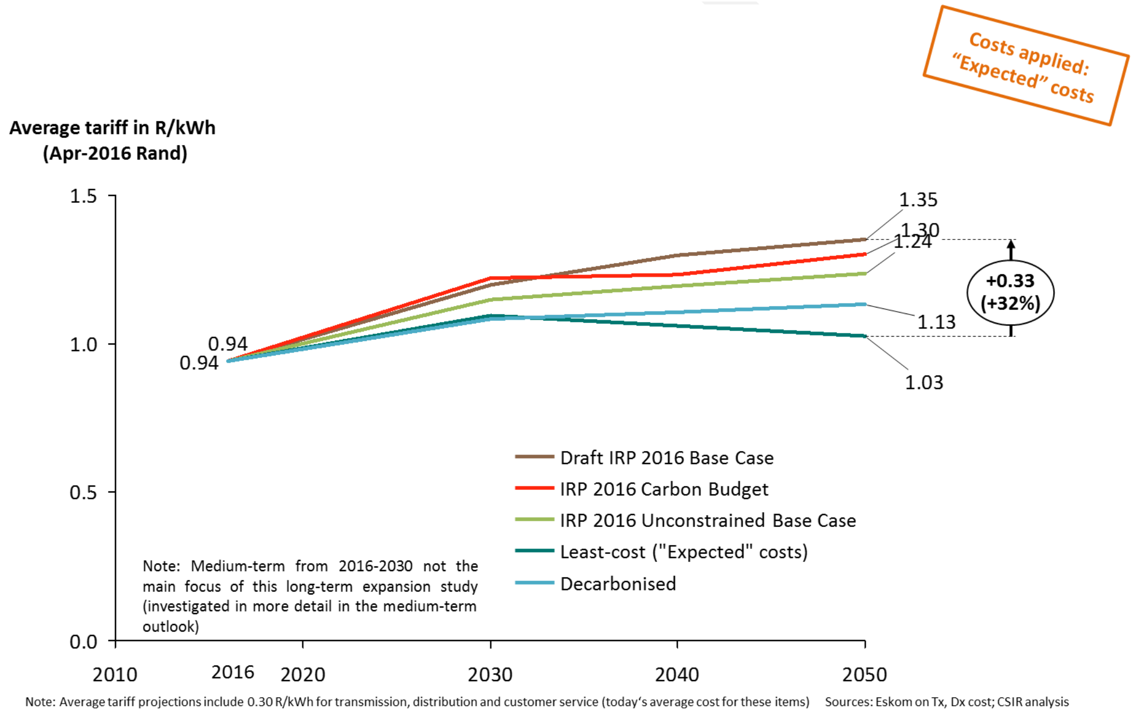


Figure 49: Average tariff for scenarios (with and without the cost of CO_2) assuming costs from Least-cost ("Expected" costs) scenario

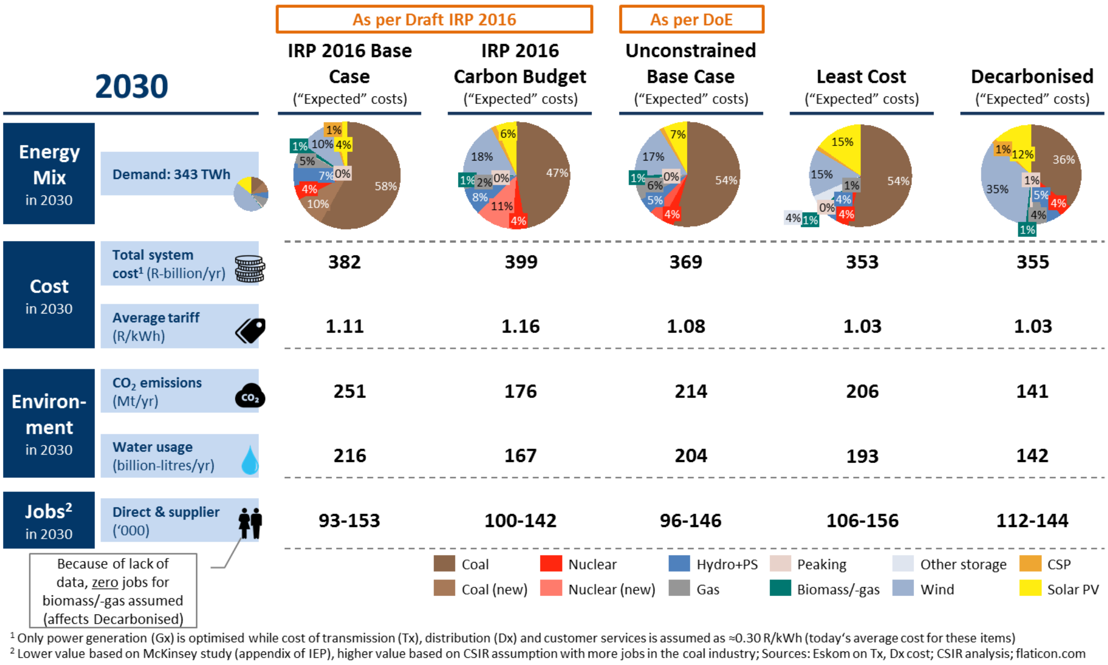


Figure 50: Scenario summary for the year 2030 (applying cost assumptions from Least-cost ("Expected" costs) scenario)

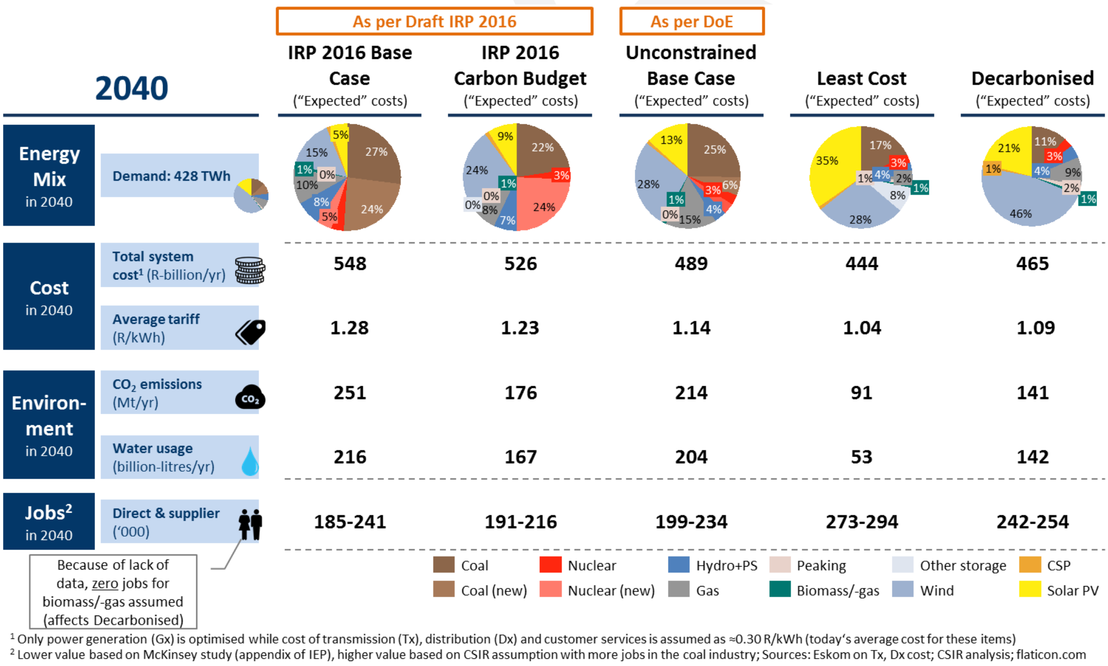


Figure 51: Scenario summary for the year 2040 (applying cost assumptions from Least-cost ("Expected" costs) scenario)

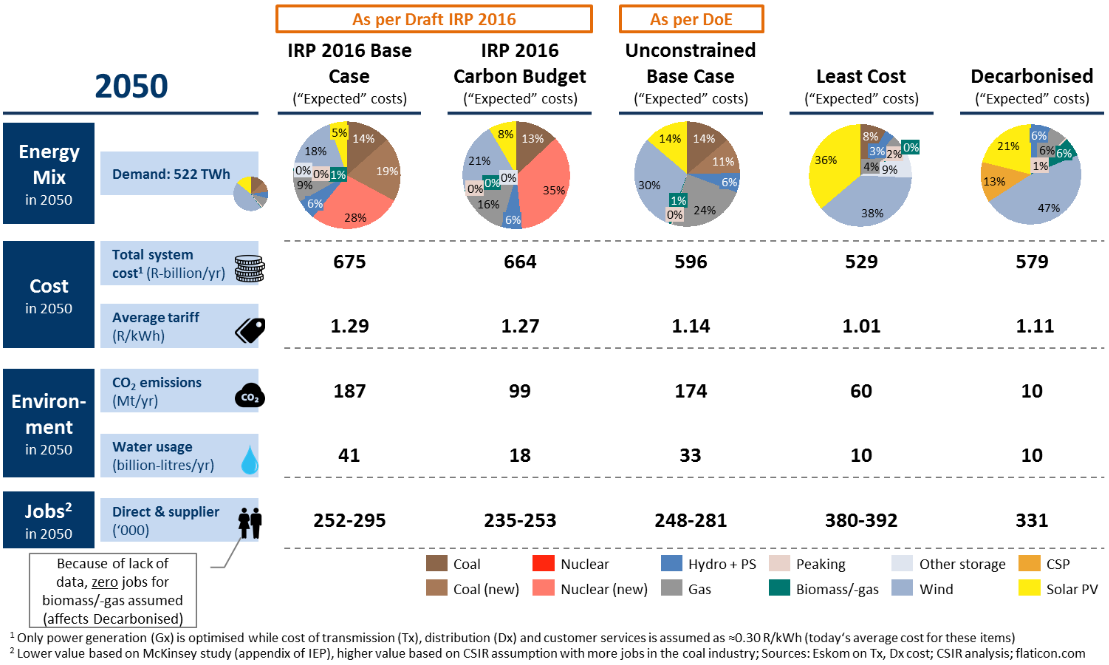


Figure 52: Scenario summary for the year 2050 (applying cost assumptions from Least-cost ("Expected" costs) scenario)

5.2 Sensitivities

5.2.1 Low demand forecast

The input assumptions applied for the Base Case, Unconstrained Base Case and Least-cost scenarios are applied for this set of sensitivities with the only change being the demand forecast. Instead of applying the CSIR High (Low Intensity) demand forecast, a low demand forecast is applied. This low demand forecast is the EIUG Low demand forecast. It is very similar to the CSIR (Low) demand forecast with almost identical demand by 2050 (≈380 TWh).

Results summaries for the Base Case, Unconstrained Base Case and Least-cost are shown in Figure 53-55 with the low demand forecast applied.

Summaries of the total system costs (with and without the cost of CO_2) and estimated average tariff (with and without the cost of CO_2) are given in Figure 56 and 57 respectively.

The CO_2 emissions and water consumption for this set of sensitivities are summarised in Figure 58. A comparison of the scenarios relative to the Base Case in the year 2050 is given in Figure 59. A summary of the sensitivities for the year 2030, 2040 and 2050 is shown in Figure 60- 62 for reference.

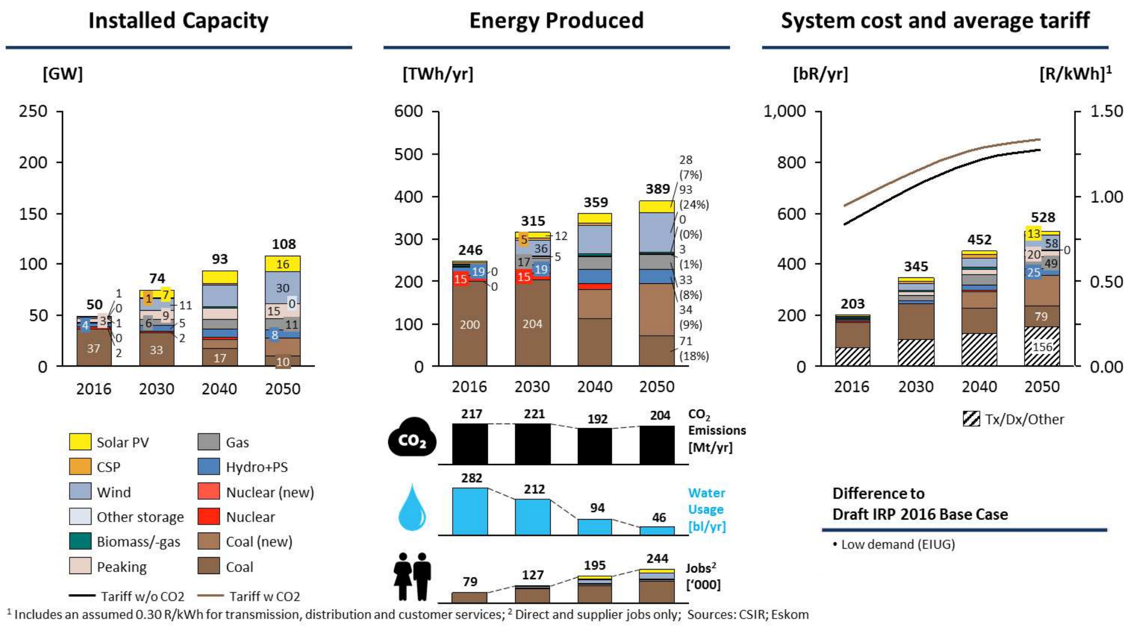


Figure 53: Sensitivity: Draft IRP 2016 Base Case (low demand)

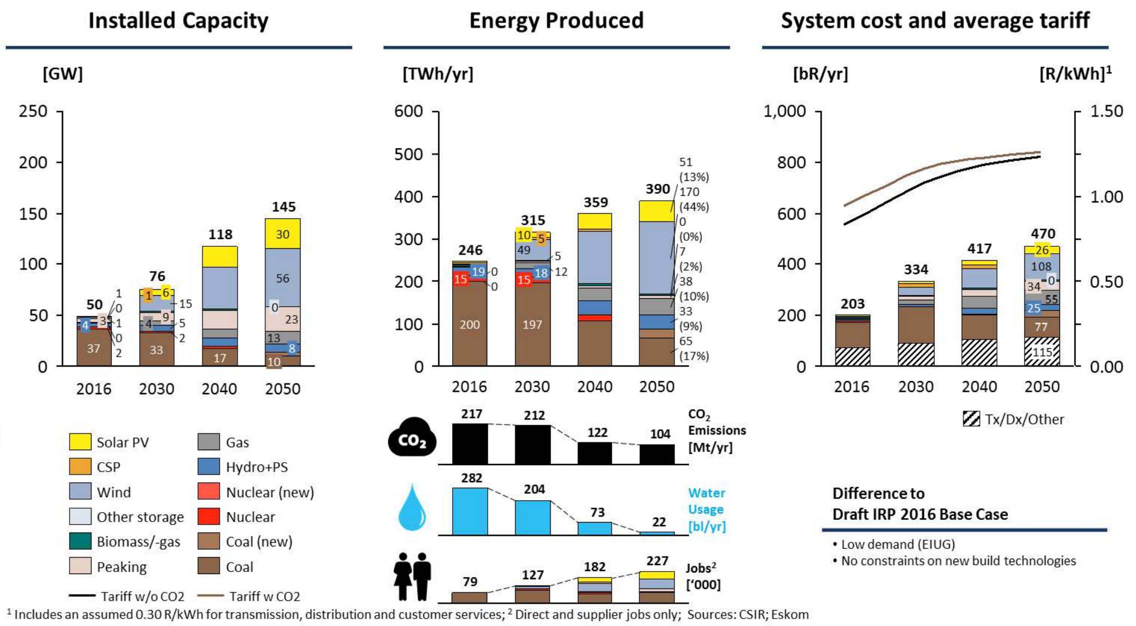


Figure 54: Sensitivity: Draft IRP 2016 Unconstrained Base Case (low demand)

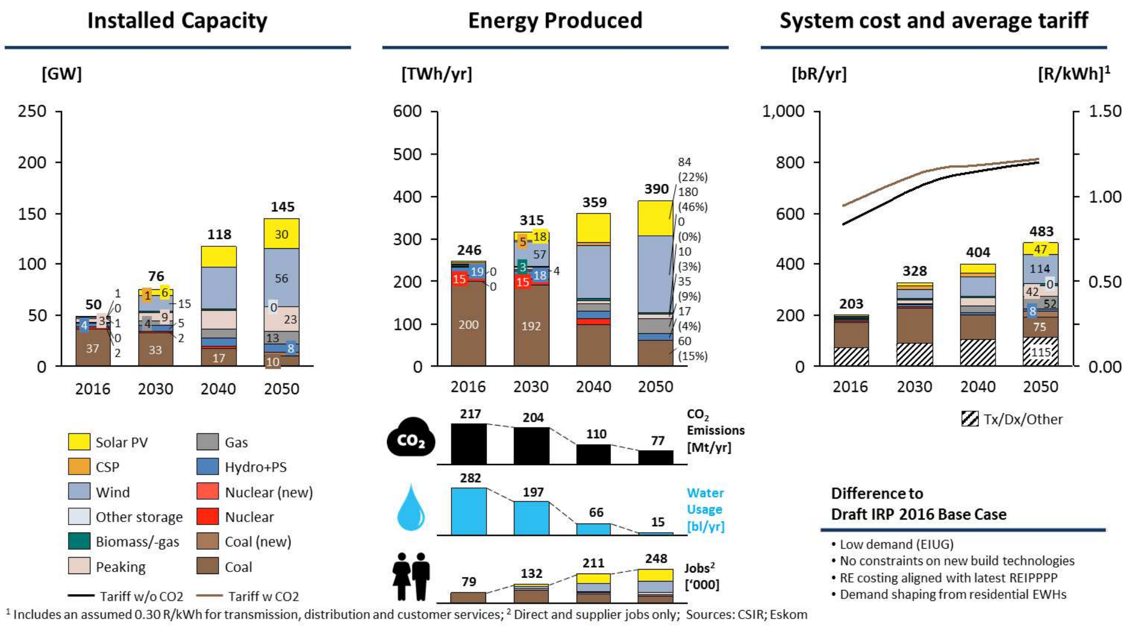
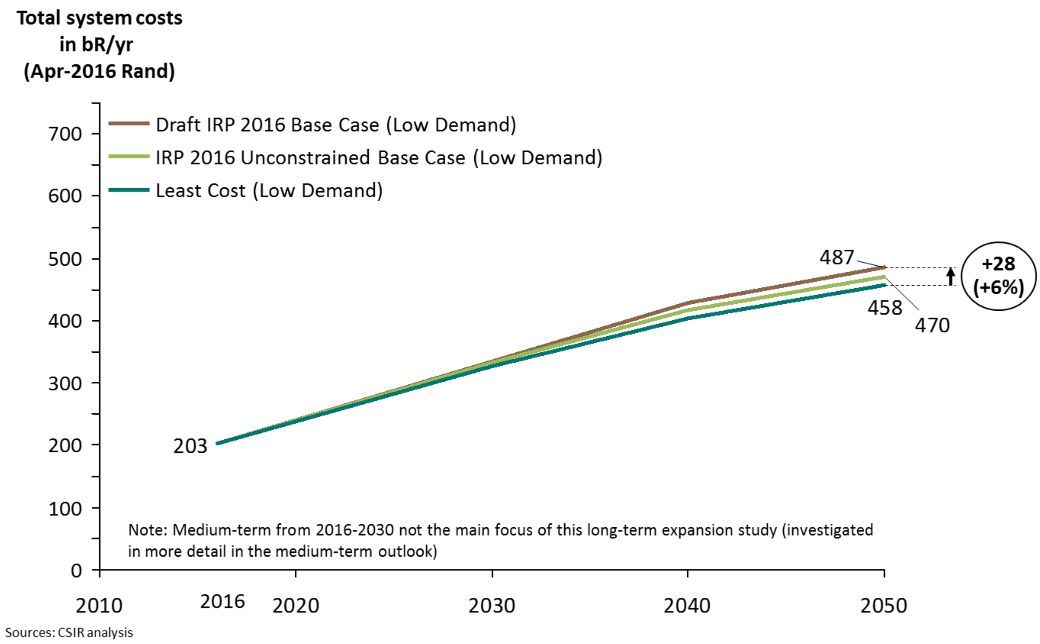


Figure 55: Sensitivity: Draft IRP 2016 Least Cost (low demand)



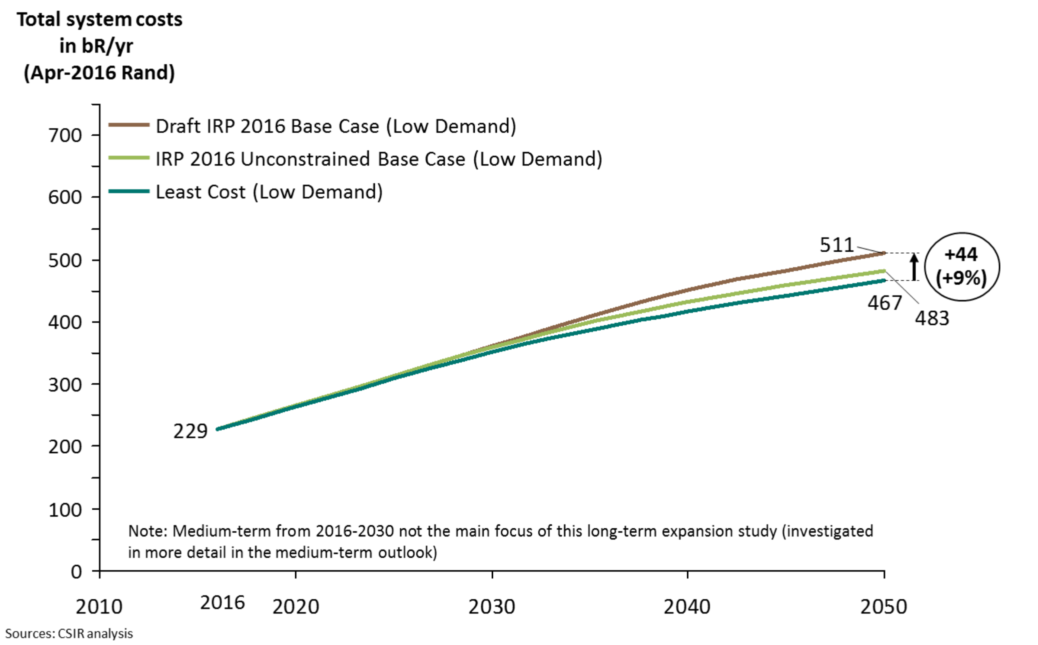
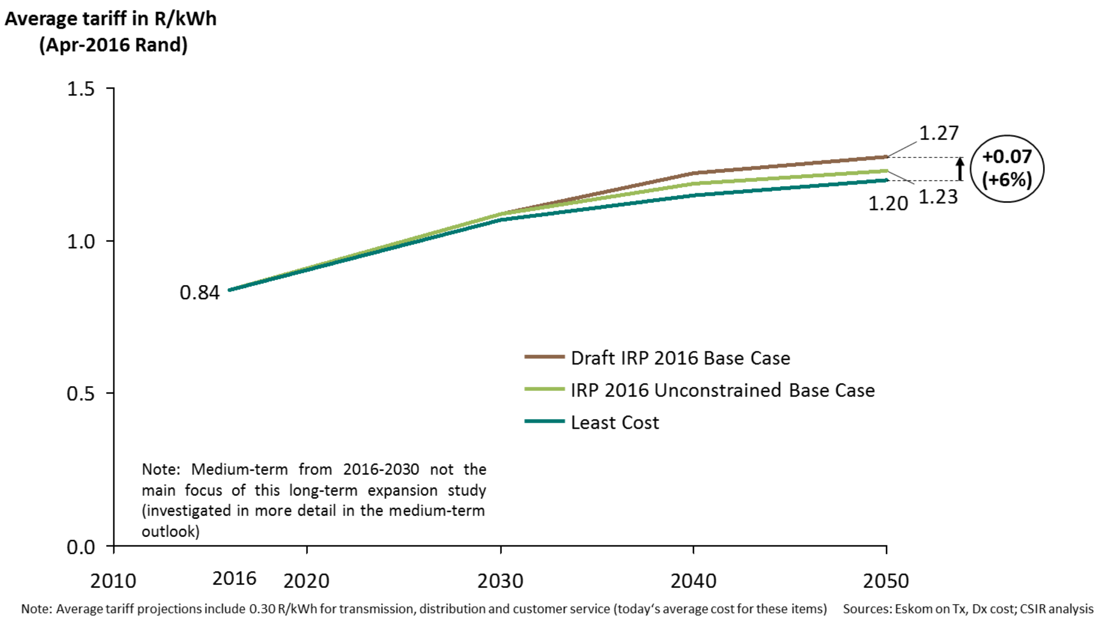


Figure 56: Total system costs for low demand sensitivities (with and without the cost of CO_2)



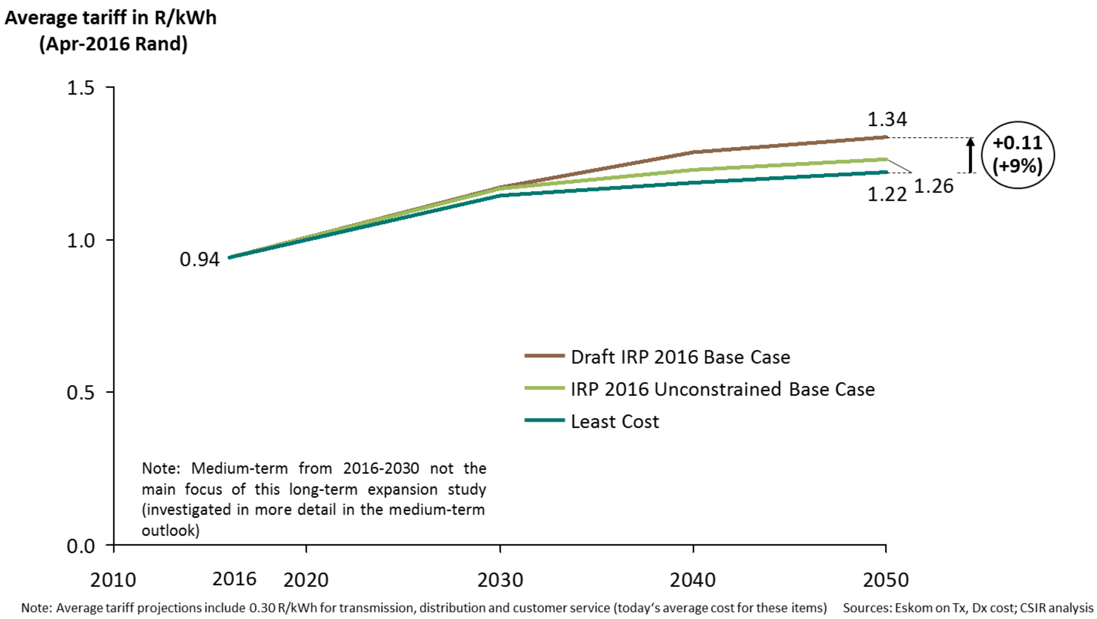


Figure 57: Average tariff for low demand sensitivities (with and without the cost of CO_2)

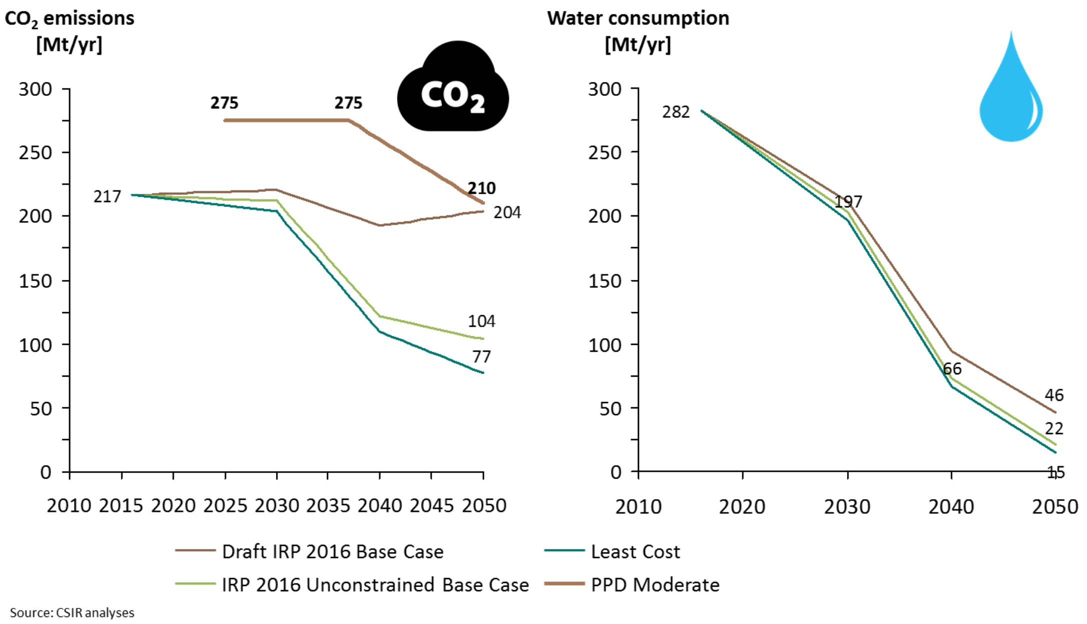


Figure 58: CO_2 emissions and water consumption for low demand sensitivities (2016-2050).

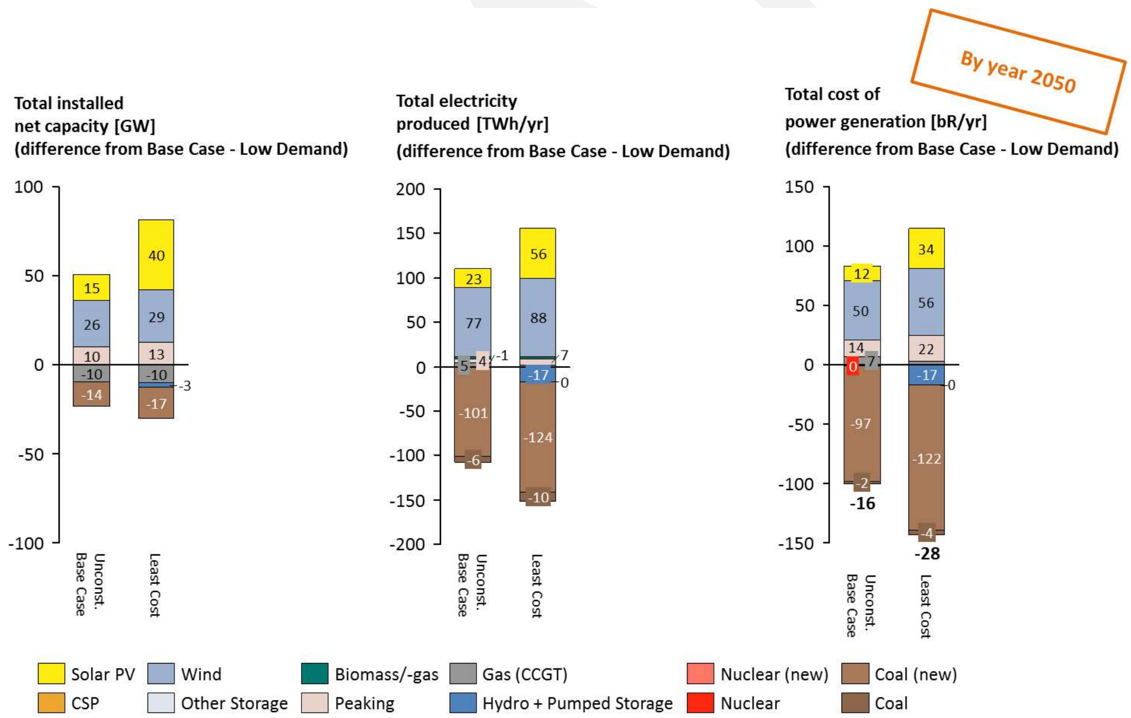


Figure 59: Comparison of low demand sensitivities' differences relative to Base Case for the year 2050.

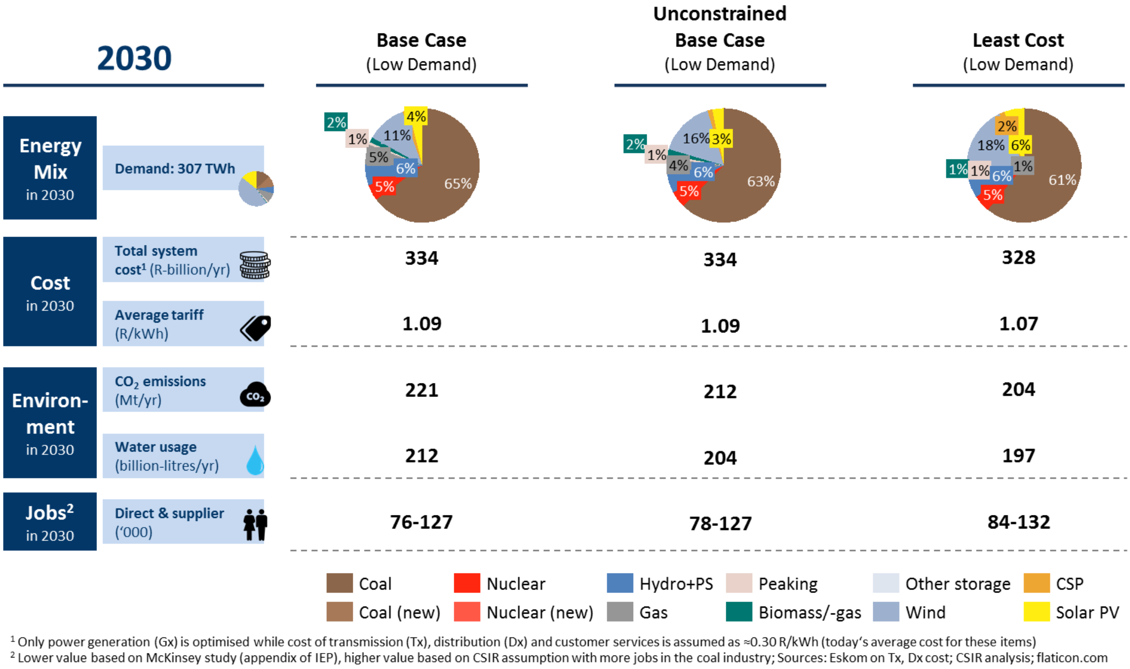


Figure 60: Sensitivities' summary for the year 2030.

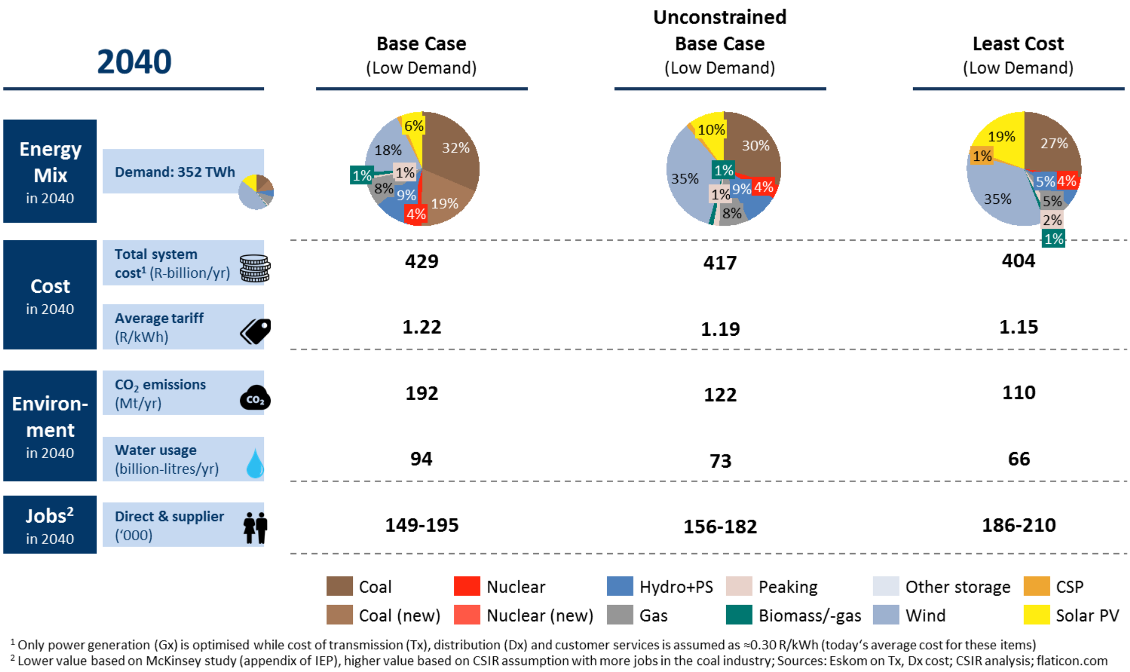


Figure 61: Sensitivities' summary for the year 2040.

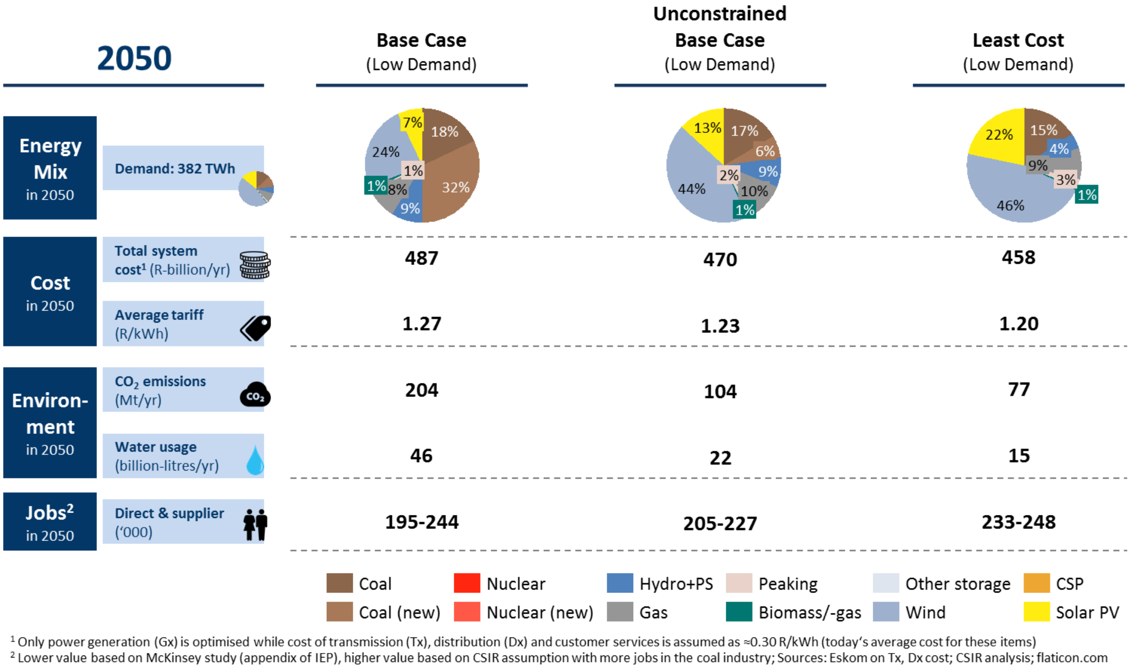


Figure 62: Sensitivities' summary for the year 2050.

5.2.2 Tipping points for supply technologies

The CSIR propose that tipping point analyses be performed on technologies not included in the Least-cost scenario. This is performed for one technology here (CSP) but can be applied to any of the other technologies not included in the Least-cost scenario e.g. nuclear, biogas, biomass, storage etc.

To demonstrate this, a long-term capacity expansion is performed that parametrises the cost of CSP as a function of capacity factor (assuming the input cost assumptions from the Least-cost scenario for all other supply technologies). Results from this are shown in Figure 63. As can be seen, the reason for the long-term capacity expansion planning model not choosing CSP is that it did not reach the cost level at which the model would start to pick it (assuminig a 60% capacity factor CSP power generator, this would be ≈0.80 ZAR/kWh). If the CSP power generator were to operate as a base-supply plant (at ≈90% capacity factor, it would need to cost ≈0.75 ZARc/kWh or less for the model to choose it. Similarly, if the CSP plant were to operate as a mid-merit plant to peaking plant with a capacity factor of 20-30% - it would need to cost ≈1.15-1.30 ZARc/kWh or less in order for the model to pick it over the alternatives.

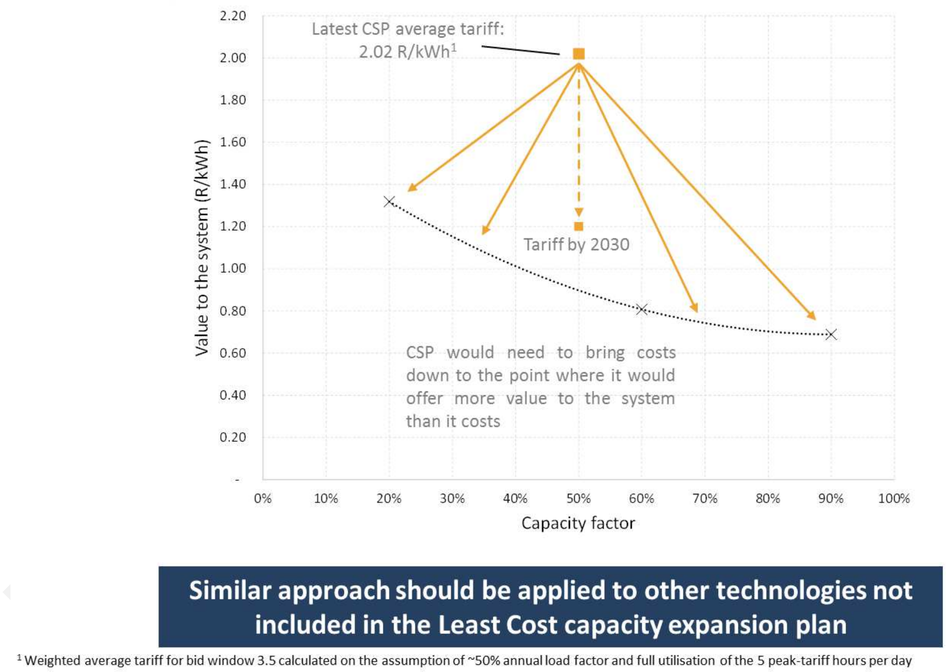


Figure 63: Tiping point analysis as a function of capacity factor performed for one of the technologies not included in the Least-cost scenario (CSP).

6 Medium-term outlook to 2030

This section considers the annual expansion plan in the short to medium term horizon (years 2016 to 2030) in order to gain insight into the more immediate planning decisions that should be made for South Africa. The medium-term outlook to 2030 is based on the outputs of the long-term expansion plans previously presented (section 5). This Medium-Term Outlook to 2030 allows for a deeper analysis of the short-term to medium-term capacity planning and implementation requirements. All modelling assumptions in this planning horizon remain the same as the long-term capacity expansion planning previously performed. This analysis is performed for the full time horizon from 2016 to 2030 for each year in the time horizon. From this, the least-cost expansion plan is obtained.

Similar to the long-term capacity expansion performed to 2050, results from all scenarios are compared in a number of dimensions. These are:

- Net generation capacity (per technology) - [MW]
- Generation energy share (per technology) - [TWh]
- Total system cost - [ZAR-billion]
- Average tariff - [R/kWh]
- CO_2 emissions - [Mt/yr]
- Water usage - [bl/yr]

Please see section 4 and Appendix A for details on the definition of various input assumptions.

6.1 Scenarios

6.1.1 Draft IRP 2016: Base Case

The results summary for the medium-term outlook for the IRP 2016 is shown in Figure 64.

The earliest new build capacity is solar PV in 2021, followed by new wind capacity in 2023, peaking capacity in 2024, gas capacity in 2025 and coal capacity in 2028. There is no investment in new nuclear capacity by 2030 while there is investment in new coal capacity as a result of the annual new-build limits placed on solar PV and wind as well as the fact that the CO_2 emissions trajectory is not binding yet. By 2030, ≈68% of the energy contribution is coal-fired, ≈14% is from solar PV and wind, ≈7% from hydro and pumped storage generation, ≈4% from nuclear power (Koeberg) and ≈5% from gas-fired generation. Total system cost increases from 203 bR/yr in 2016 to 384 bR/yr in 2030.

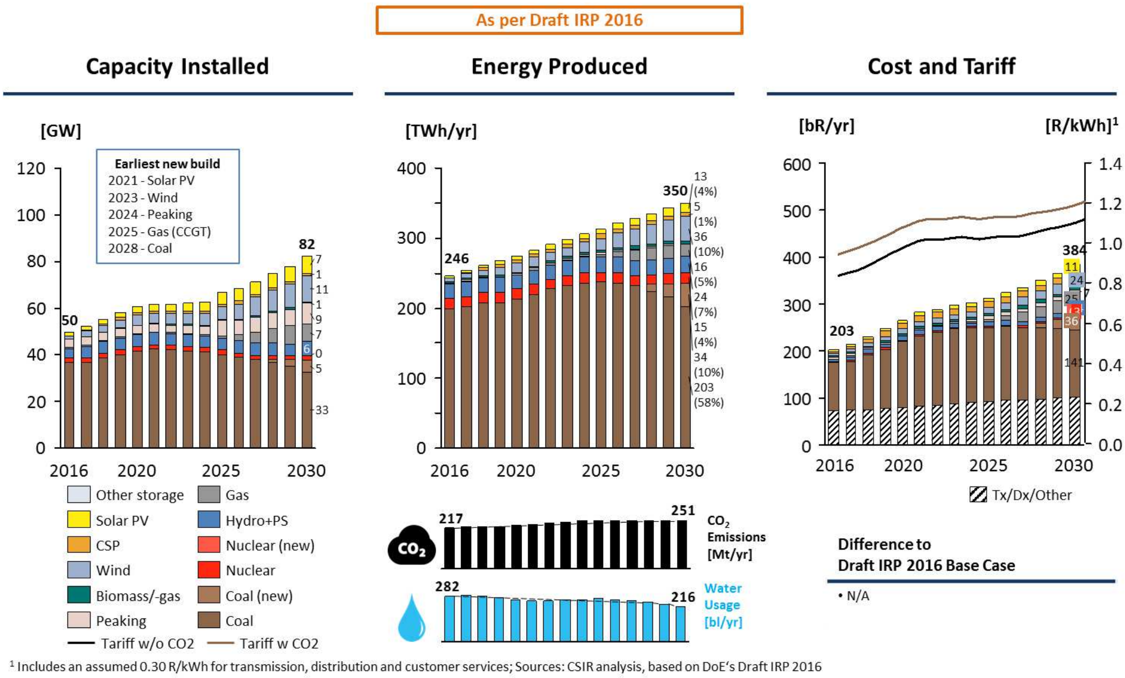


Figure 64: Scenario: Draft IRP 2016 Base Case (MT outlook to 2030)

6.1.2 Draft IRP 2016: Carbon Budget

The results summary for the medium-term outlook for the IRP 2016 Carbon Budget scenario is shown in Figure 65.

The key differences in outcomes to the Draft IRP 2016 Base Case for this scenario is that there is no investment in new coal capacity by 2030 (as a result of the tighter CO_2 emissions constraints). The annual new-build limit on solar PV and wind along with the high demand and tighter CO_2 emissions constraints results in an earlier nuclear capacity investment (first unit by 2026 as opposed to 2037). By 2030, $\approx$47% of the energy contribution is from coal-fired generation, $\approx$24% is from solar PV and wind, $\approx$15% from nuclear, $\approx$8% from hydro and pumped storage generation and $\approx$2% from gas-fired generation. Total system cost increases from 203 bR/yr in 2016 to 403 bR/yr in 2030. This is $\approx$20 bR/yr more expensive than the Draft IRP 2016 Base Case.

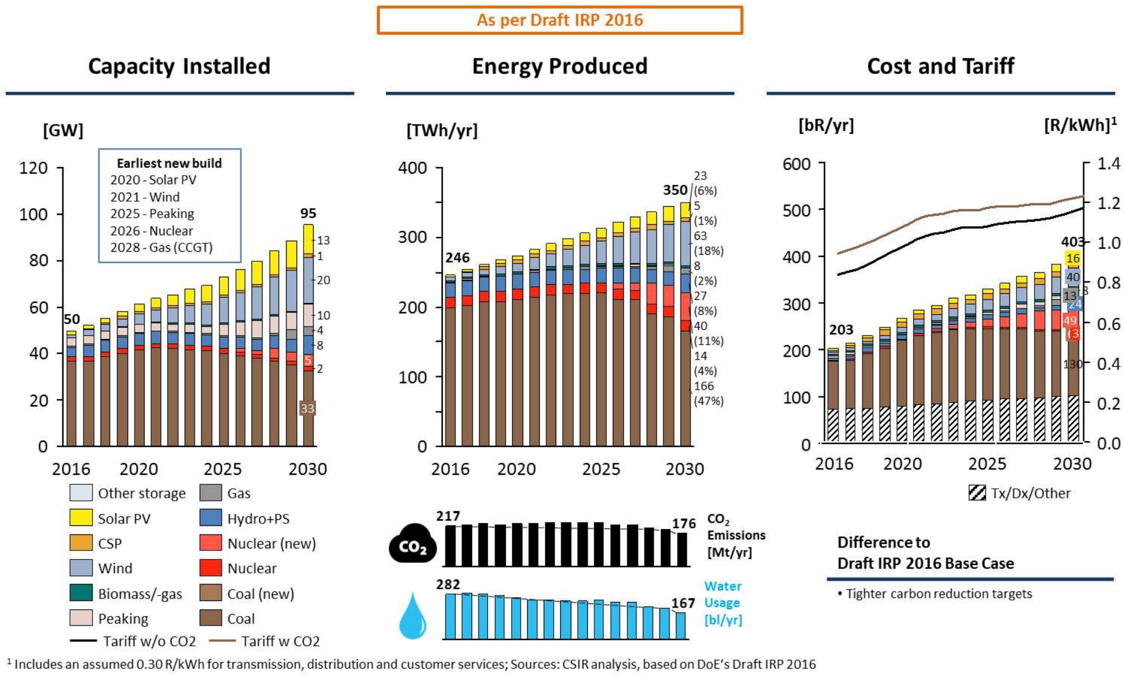


Figure 65: Scenario: Draft IRP 2016 Carbon Budget (MT outlook to 2030)

6.1.3 Least-cost

The results summary for the medium-term outlook for the Least-cost scenario is shown in Figure 66.

The earliest new build capacity is peaking capacity in 2023, followed by new solar PV capacity in 2024, wind capacity in 2025 and gas (CCGT) capacity in 2028.

The key differences when compared to the Draft IRP 2016 Base Case is that there is no investment in new coal capacity by 2030 (as a result of removing the annual new build limits for wind and solar PV and using updated cost assumptions). By 2030, ≈54% of the energy contribution is from coal-fired generation, ≈31% is from solar PV and wind, ≈5% from hydro and pumped storage generation, ≈4% from nuclear (Koeberg) and ≈2% from gas-fired generation. Total system cost increases from 203 bR/yr in 2016 to 367 bR/yr in 2030. This is ≈17 bR/yr less than the Draft IRP 2016 Base Case.

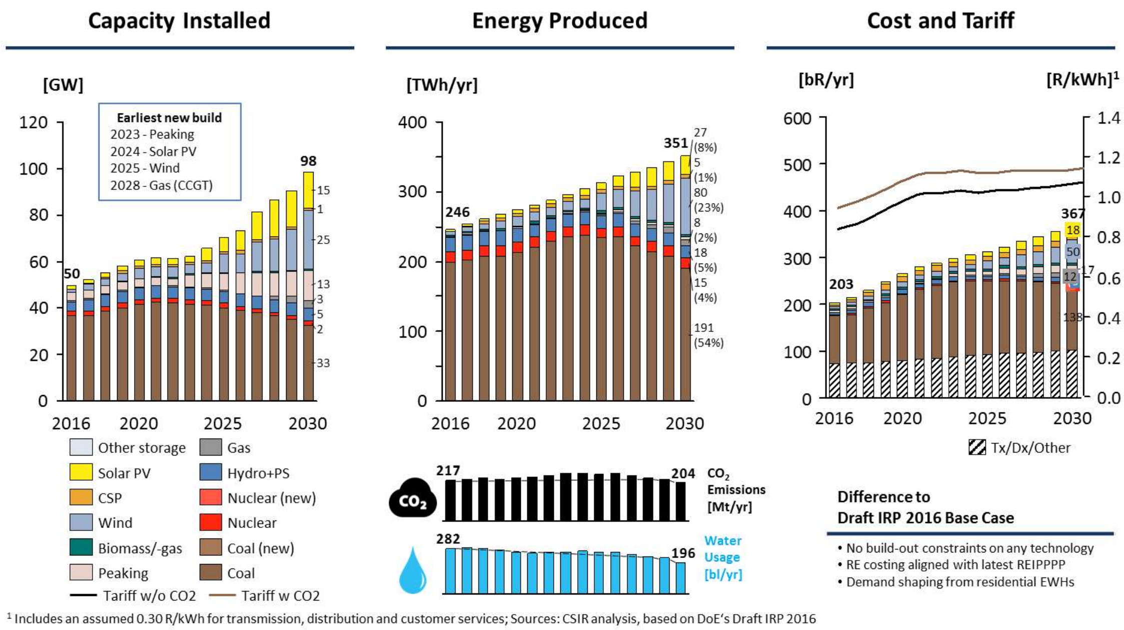


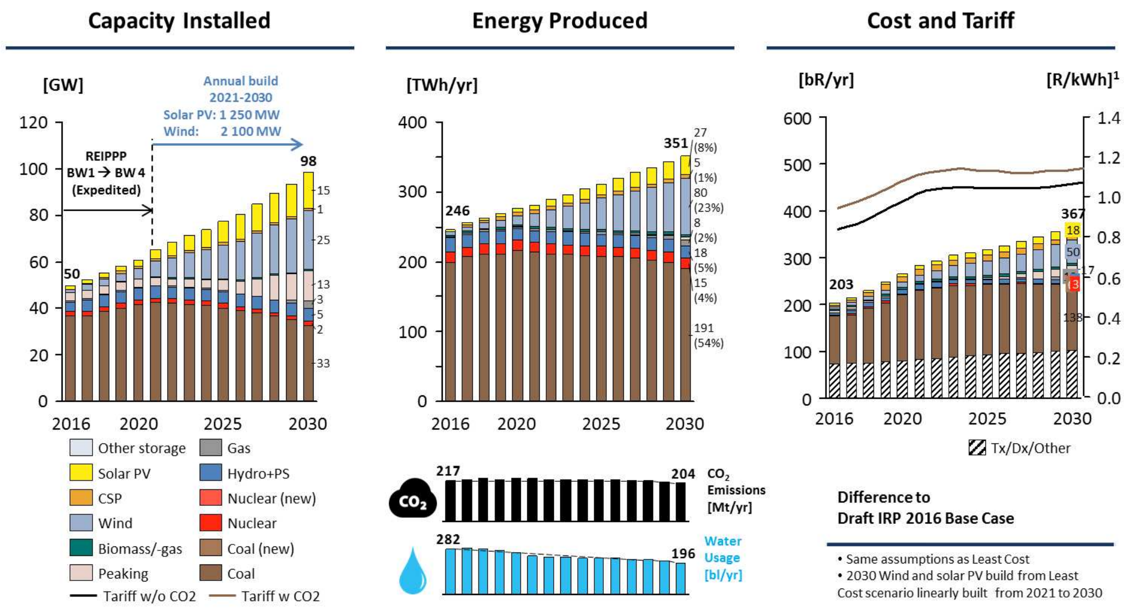
Figure 66: Scenario: Least-cost (MT outlook to 2030)

6.1.4 Linear build-out to 2030

The Linear build-out scenario uses the 2030 wind and solar PV new build capacity from the Least-cost scenario and analyses the increase in total system cost if wind and solar PV are installed linearly from the year 2021 to 2030 (after the current REIPPPP BWs are installed by 2020). The purpose of the Linear build-out scenario is to quantify the cost impact of continuing with the construction of new wind and solar PV (which is built anyway in the Least-cost scenario) once the last of the committed REIPPPP BWs capacity is built.

The results summary for the medium-term outlook for the Least-cost linear build out scenario is shown in Figure 67.

The earliest new build capacity is the linearly phased in wind and solar PV capacity in 2021, followed by new peaking capacity in 2024 and gas (CCGT) capacity in 2029. No new coal or nuclear capacity is built by 2030.



¹ Includes an assumed 0.30 R/kWh for transmission, distribution and customer services; Sources: CSIR analysis, based on DoE's Draft IRP 2016

Figure 67: Scenario: Least-cost with linear build-out of solar PV and wind (MT outlook to 2030)

6.1.5 Scenario comparison and summary

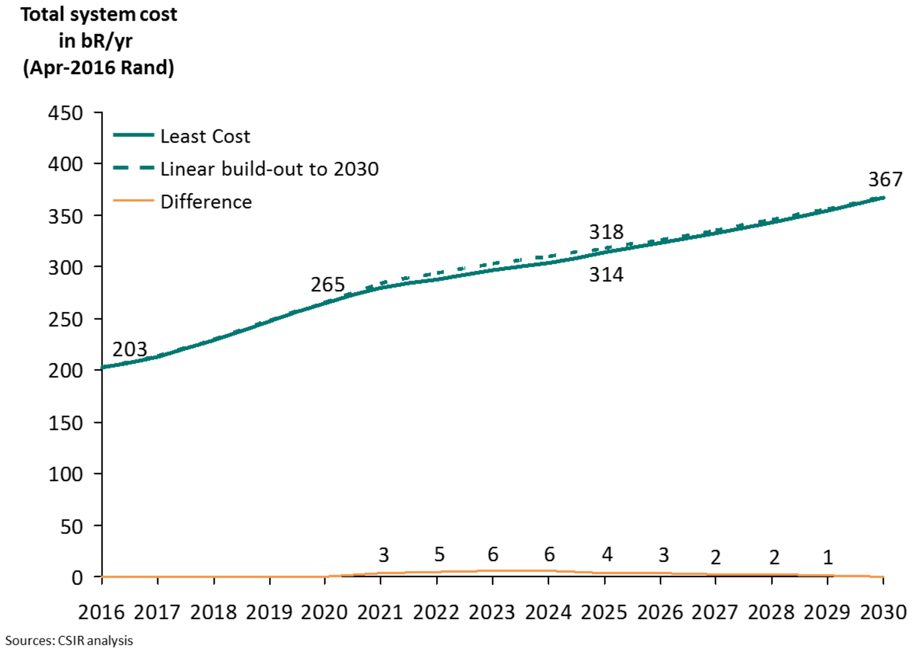
The difference in total system cost between the Least-cost scenario and least-cost with linear build-out is shown in Figure 68 (with and without the cost of CO_2). The difference in average tariff between the Least-cost scenario and least-cost but with linear build-out is shown in Figure 69 (with and without the cost of CO_2). It can be seen that Deviating from the Least-cost scenario and building as per the Linear build-out scenario results in marginally higher system costs of 1-7 bR/yr between 2021 and 2029. The average tariff (without cost of CO_2) is approximately 1-2 R/kWh higher between 2021 and 2029 in the Linear build-out scenario with a lower difference in the average tariff when the cost of CO_2 is included.

A comparison of the cumulative new installed capacity as well as decommissioning to 2030 is shown in Figure 70. The difference from the Base Case in total installed net capacity is summarised in Figure 71.

Summaries of the total system costs for all scenarios in the medium-term (with and without the cost of CO_2) and estimated average tariff (with and without the cost of CO_2) are given in Figure 72 and 73 respectively. The total system cost for the IRP 2016 Carbon Budget scenario is distinctly higher than the IRP 2016 Base Case and Least Cost scenario from 2022 onwards, ending at a system cost of $\approx$20 bR/yr more than the IRP 2016 Base Case by 2030. The primary reason for the higher system costs early on is due to the phased in capital expenditure incurred on the nuclear fleet (first unit commissioned by 2026).

The CO_2 emissions and water consumption for these scenarios are summarised in Figure 74. The CO_2 emissions and water consumption are the highest for the Draft IRP 2016 Base Case due to the higher energy share from coal-fired generation. The IRP 2016 Carbon Budget has the lowest annual CO_2 emissions by 2030 due to the nuclear fleet being integrated into the energy mix earlier and displacing energy that would have been generated from coal-fired generation (due to tighter CO_2 emission limits in this scenario and the new-build limits on solar PV and wind).

The IRP 2016 Base Case, Carbon Budget and Least Cost scenarios indicate that the first new build capacity required between 2020 and 2025 is wind, solar PV and gas fired peaking capacity. From 2025 to 2030 the technology choices between the three cases vary (new coal, nuclear) but all three require solar PV, wind and gas capacity during this time.



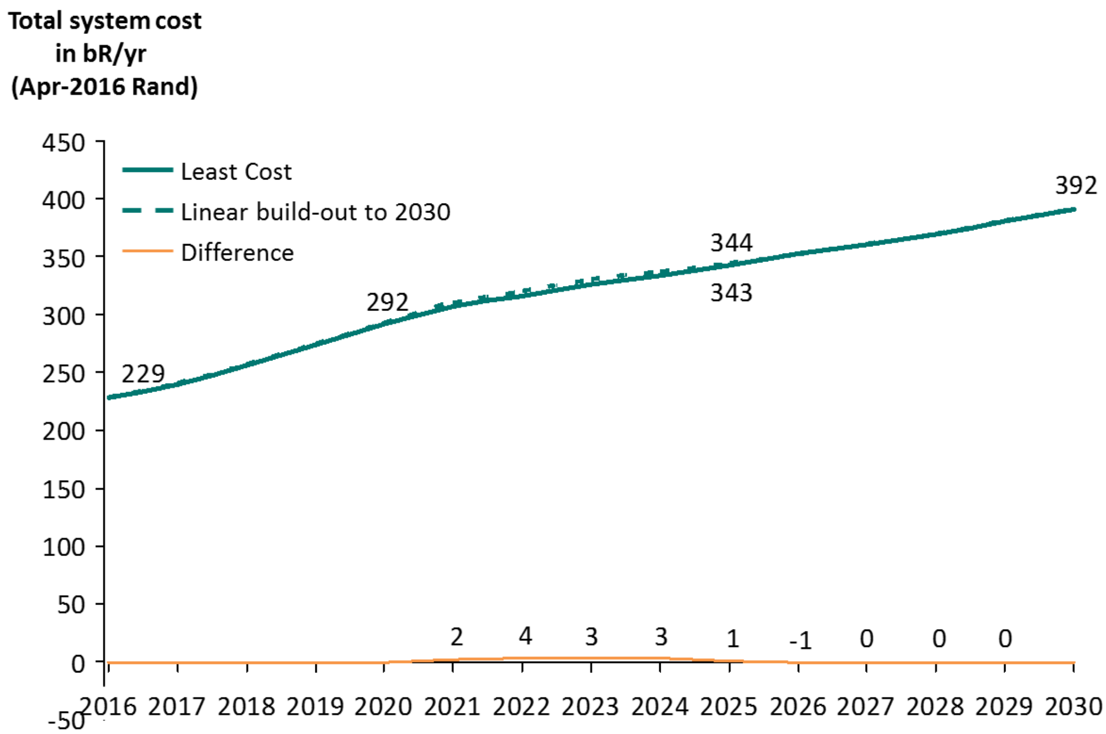
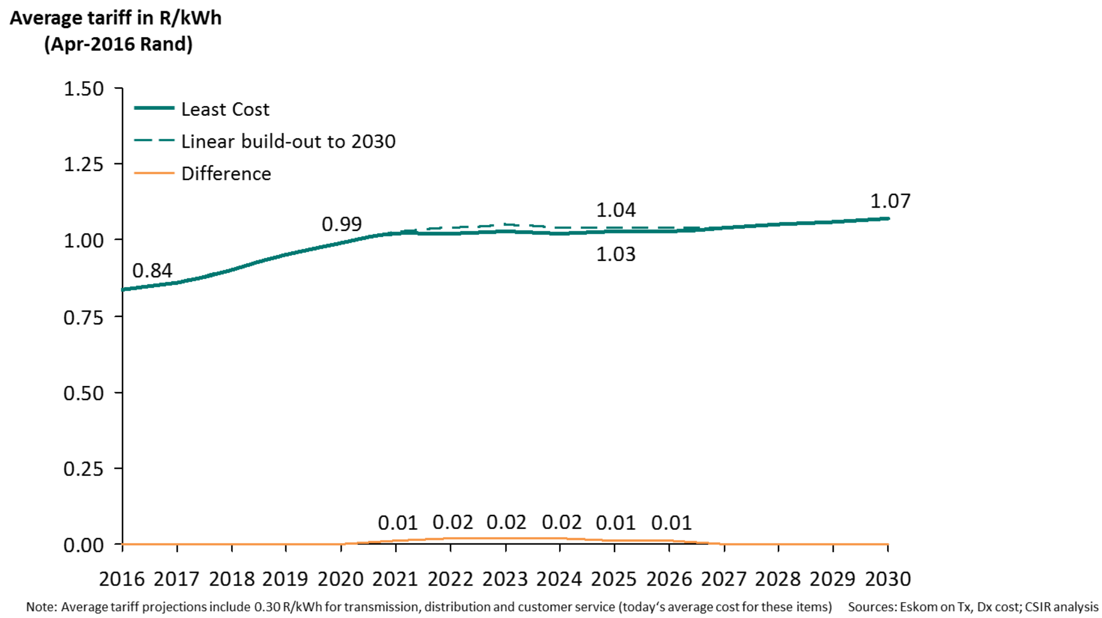


Figure 68: Difference in total annual system cost with and without cost of CO_2 for the Least-cost scenario and the linear build out (ending at the least-cost scenario by 2030)



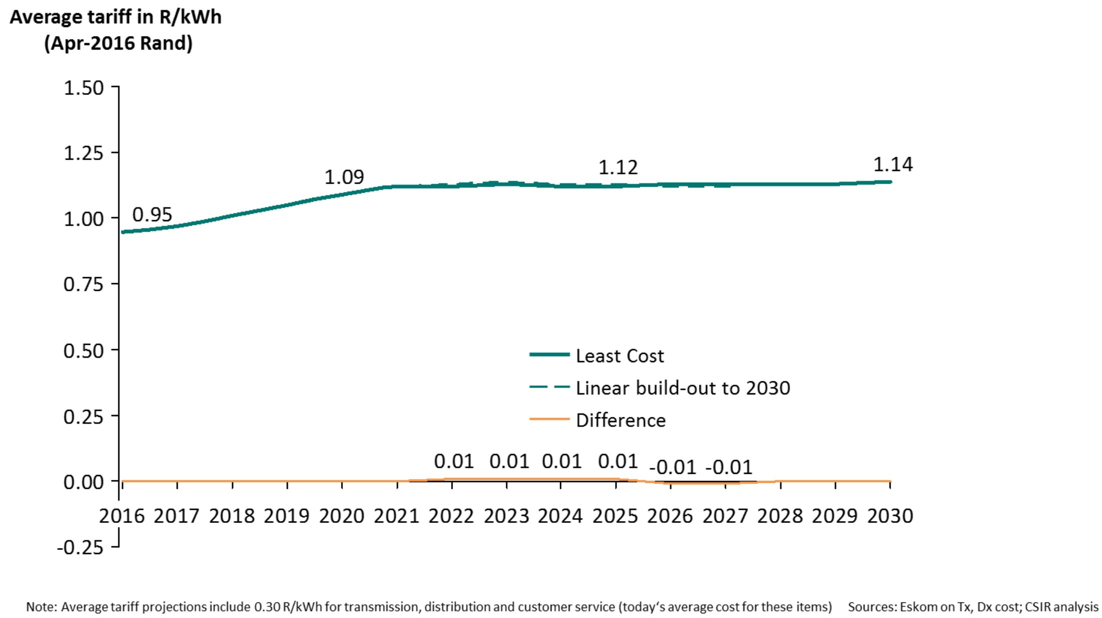


Figure 69: Difference in average tariff with and without cost of CO_2 for the Least-cost scenario and the linear build out (ending at the least-cost scenario by 2030)

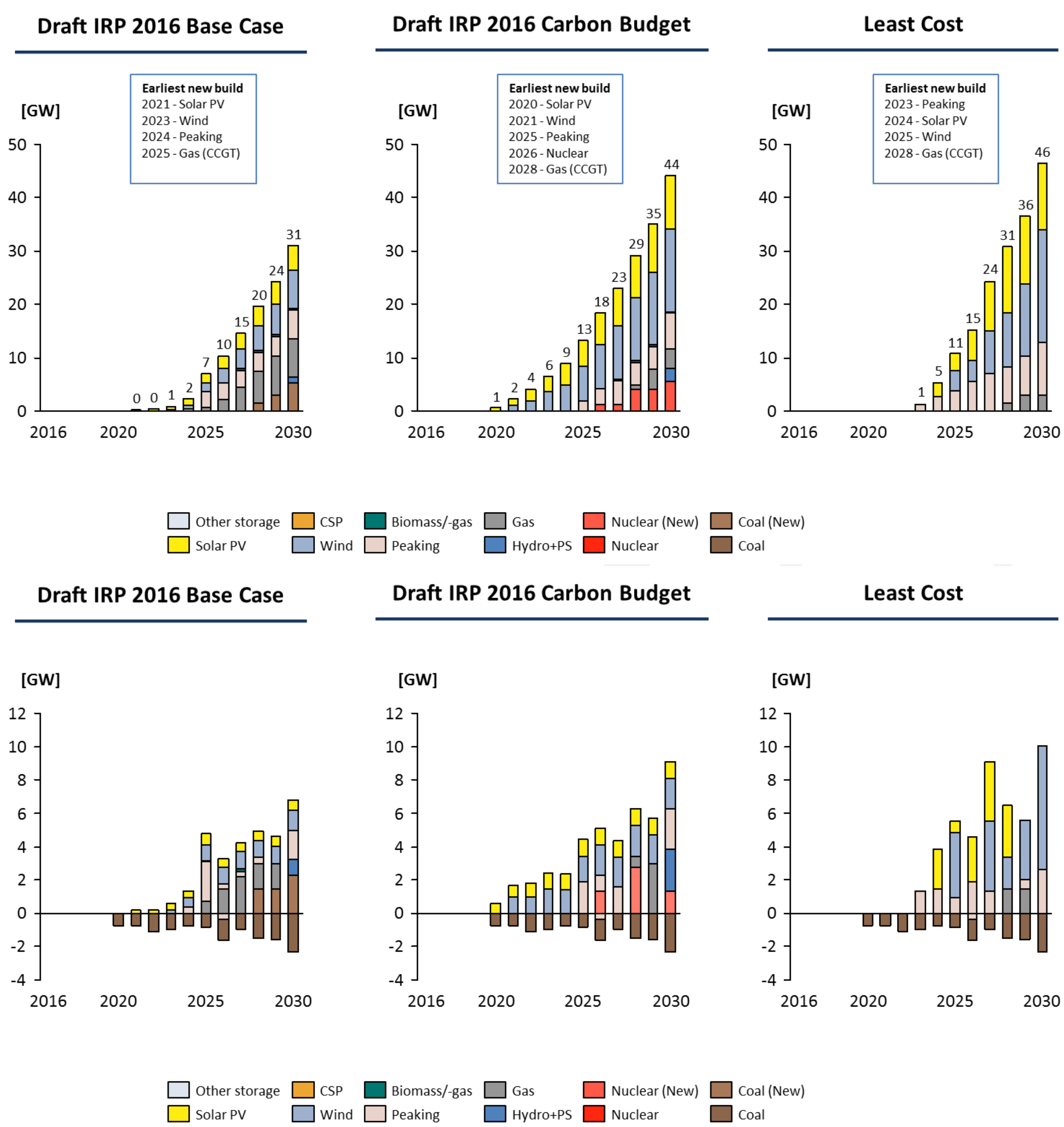


Figure 70: Comparison of cumulative installed new capacity as well as annual new capacity with decommissioning for scenarios (medium term to 2030)

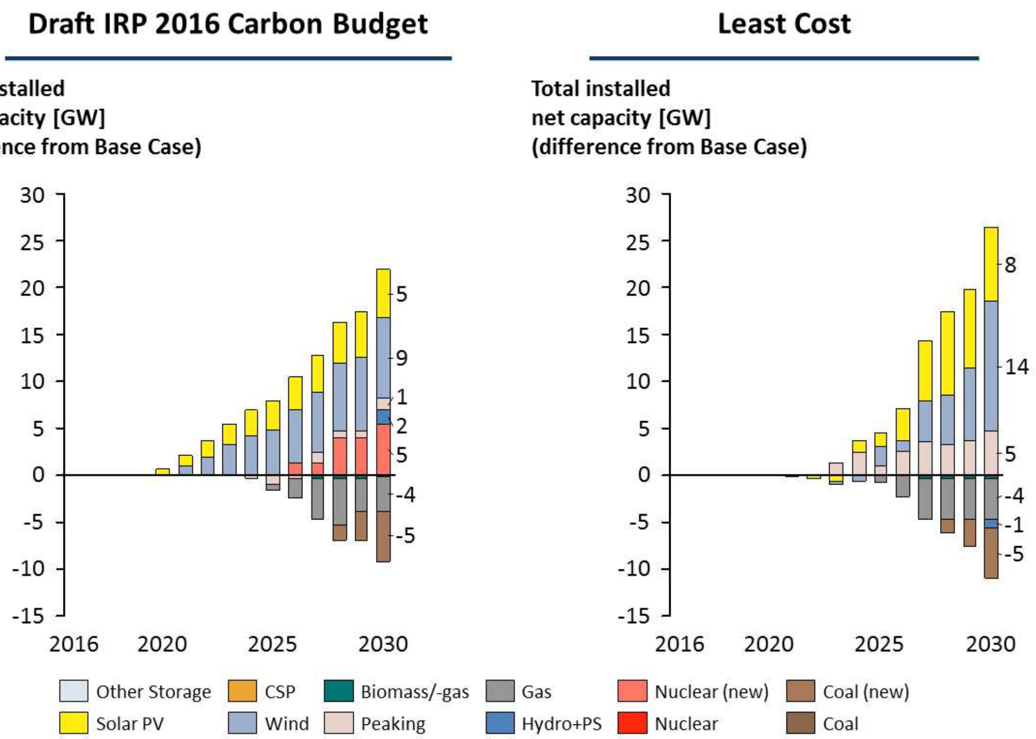
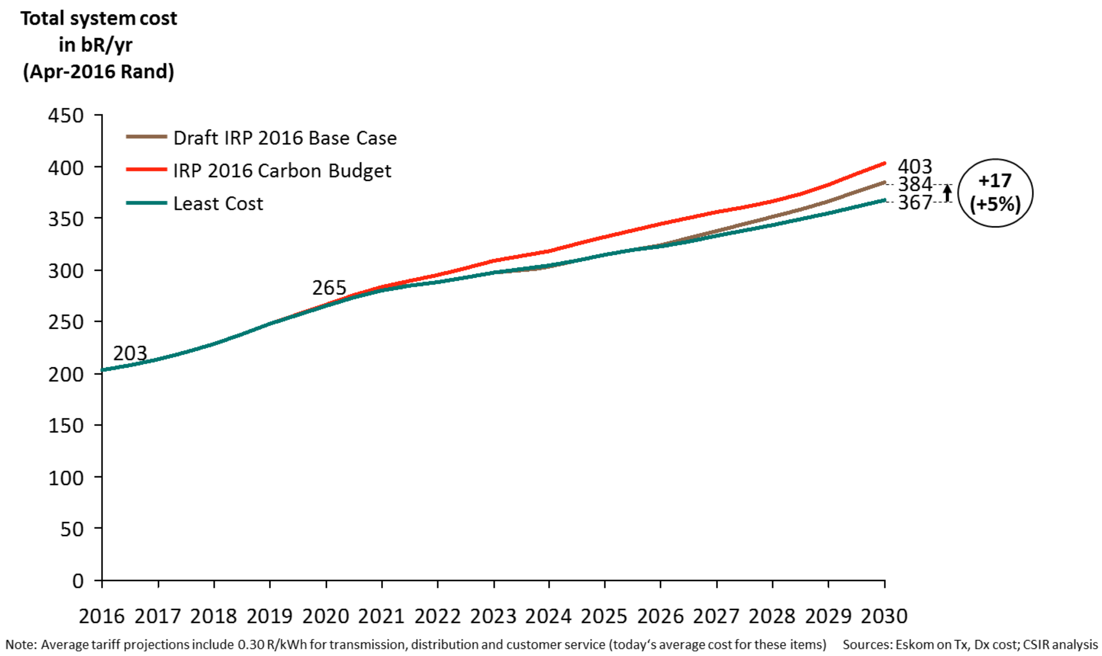


Figure 71: Comparison of total net installed capacity to the Base Case (medium term to 2030)



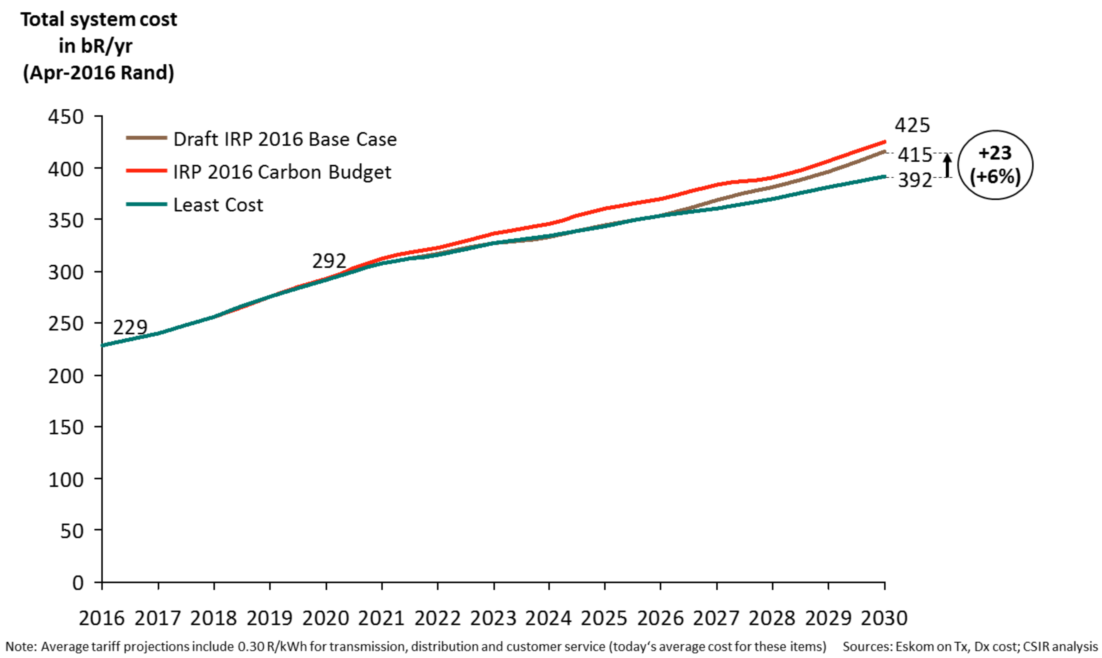
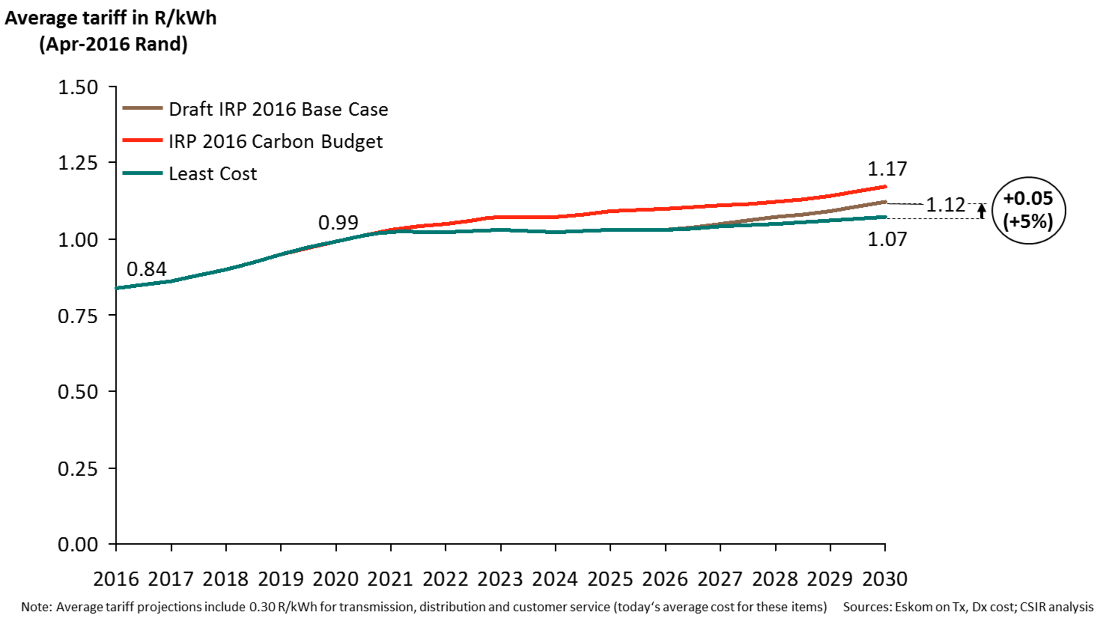


Figure 72: Total system costs for scenarios considered with and without the cost of CO_2 (medium-term outlook to 2030)



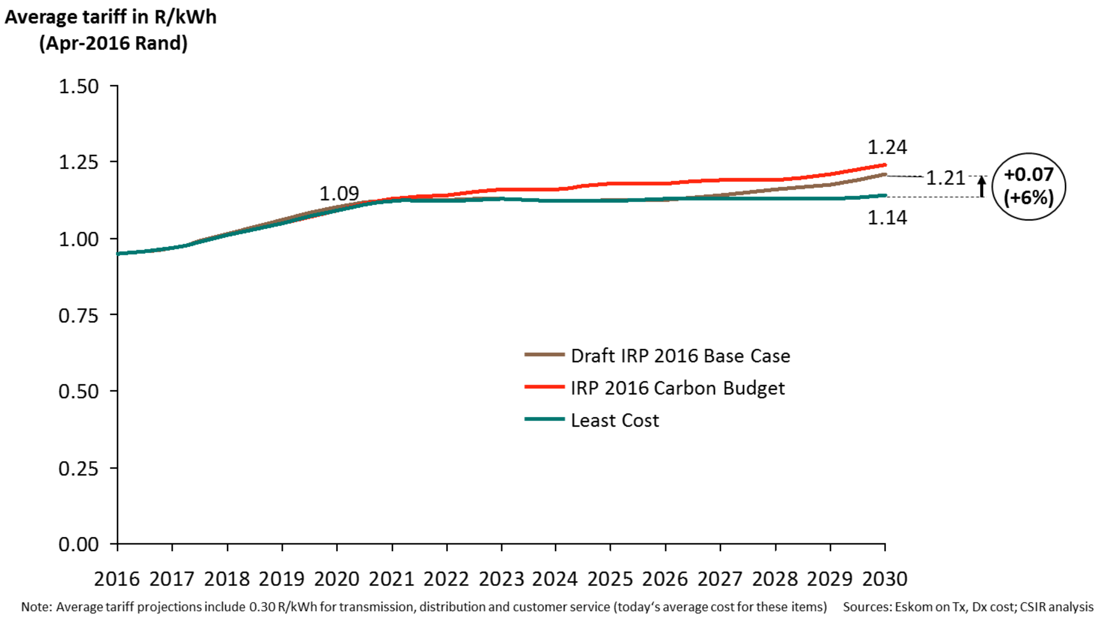


Figure 73: Average tariff for scenarios considered with and without the cost of CO_2 (medium-term outlook to 2030)

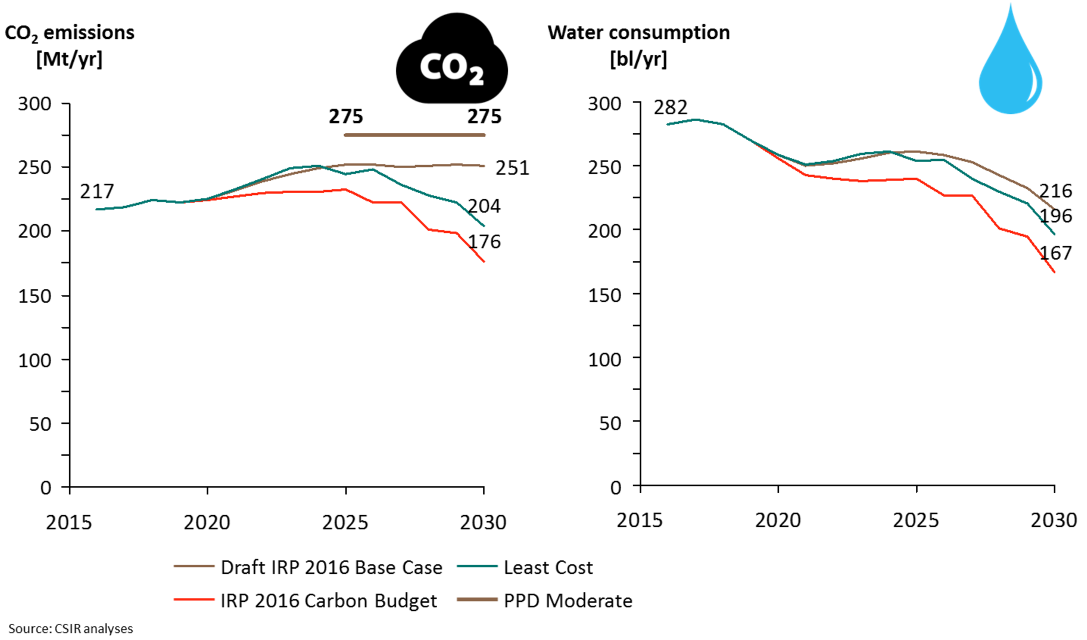


Figure 74: CO_2 emissions and water usage in the electricity sector for the scenarios considered (medium-term outlook to 2030)

6.2 Sensitivities

Four sensitivities were analysed in the medium-term horizon. These were the Least Cost (low-demand), Linear build-out (low-demand), Low Supply and the Low Supply (low demand) sensitivities. The input assumptions applied for the Least Cost scenario shown previously are applied for the Least Cost (low demand) and Linear build-out (low demand) sensitivities with the only change being the demand forecast. The low demand forecast applied is the same as that applied in the long-term capacity expansion planning (EIUG demand forecast, which is very similar to the CSIR (Low) demand forecast in the draft IRP 2016). For the Linear build-out scenario, the wind and solar PV capacity build-out to 2030 from the Least Cost (low demand) optimization were used as a basis for defining the linear build-out capacity from 2021 to 2030. The primary reason for choosing to perform a Linear build-out sensitivity is based on the information obtained in the Least-cost long-term capacity expansion planning where significant solar PV and wind is deployed and thus a linear deployment in the medium-term would prepare and build on the relevant industries to enable the significant deployment seen in the Least-cost scenario in the long-term to 2050.

6.2.1 Low demand forecast

6.2.1.1 Low demand forecast - Least-cost

The input assumptions applied for the Least-cost scenario are applied for this sensitivity with the only change being the demand forecast. Instead of applying the CSIR High (Low Intensity) demand forecast, a low demand forecast is applied. This low demand forecast is the EIUG Low demand forecast. It is very similar to the CSIR (Low) demand forecast with almost identical demand by 2050 (≈380 TWh).

A result summary for the Least-cost scenario is shown in Figure 75 with the low demand forecast applied.

The earliest new build capacity is solar PV and peaking capacity in 2025, followed by new wind capacity in 2027 and gas capacity in 2029. As in the Least Cost scenario, there is no investment in new coal or nuclear capacity by 2030 (predominantly as a result of removing the annual new build limits for wind and solar PV but complemented by updated cost assumptions for these technologies).

By 2030, ≈61% of the energy contribution is from coal-fired generation, ≈24% is from solar PV and wind, ≈6% from hydro and pumped storage generation, ≈5% from nuclear (Koeberg) and 1% from gas-fired generation. Total system cost increases from 203 bR/yr in 2016 to 327 bR/yr in 2030.

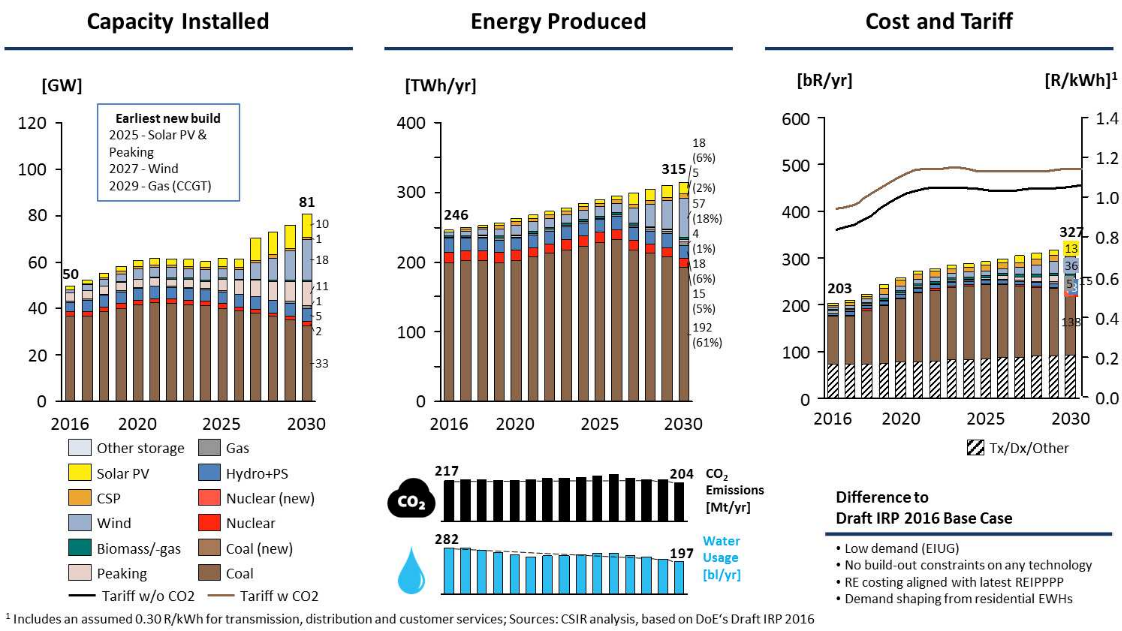


Figure 75: Sensitivity: Least-cost to 2030 (low demand)

6.2.1.2 Low demand forecast - linear build-out to 2030

A result summary for the Least-cost scenario with linear build-out to 2030 is shown in Figure 76 with the low demand forecast applied.

The earliest new build capacity is the linear build-out is the linear phased in wind and solar PV capacity in 2021, followed by new peaking capacity in 2026 and gas capacity in 2030. No new coal or nuclear capacity is built by 2030. Total system cost increases from 203 bR/yr in 2016 to 327 bR/yr in 2030.

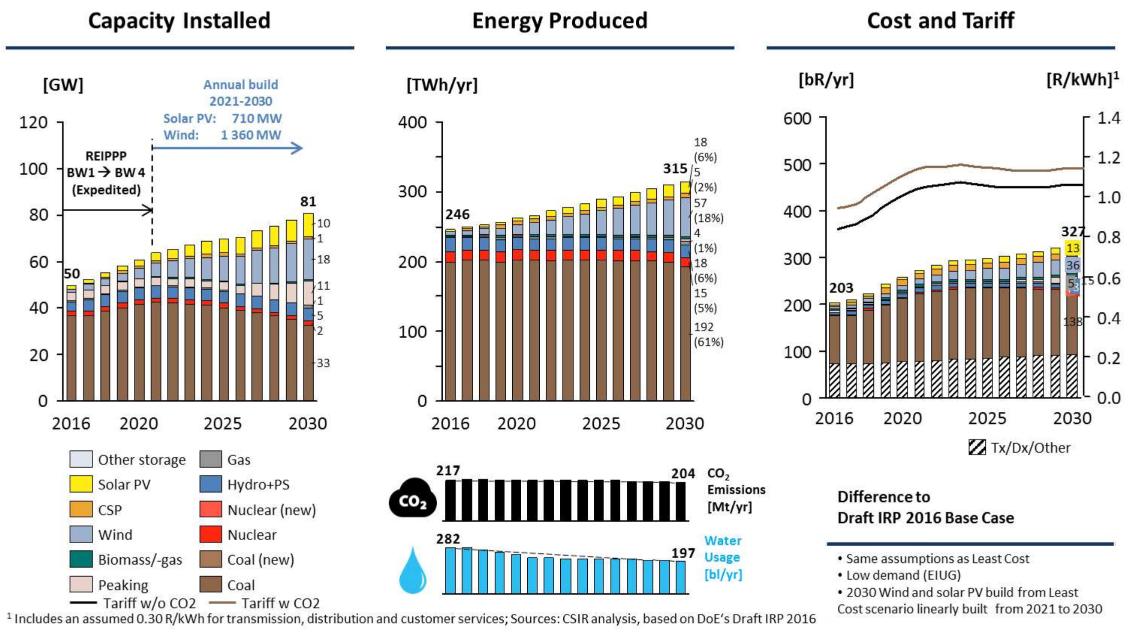


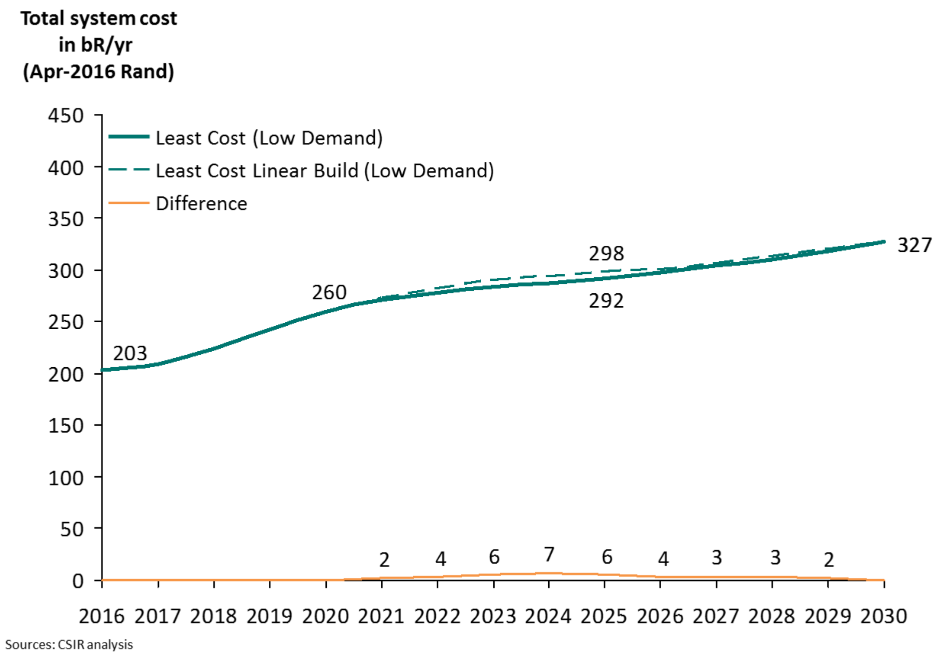
Figure 76: Sensitivity: Least-cost with linear build-out to 2030 (low demand)

6.2.2 Sensitivity comparison and summary - demand forecast & linear-build

A comparison of total system costs between the Least-cost optimal build-out and Linear build-out is given in Figure 77 (with and without the cost of CO_2). A comparison of the average tariff for this is also given in Figure 78.

The new build technology mix for the Least Cost (low demand) scenario is identical to that of the CSIR High (Low Intensity) demand forecast (just scaled to match the lower demand forecast). That is; wind, solar PV, peaking and gas capacity. This indicates that the least cost technology choices are insensitive to the demand forecast assumption. The demand forecast will merely determine the scale at which the new-build technology mix is built over time.

Figure 79 summarizes the total new build capacity from the Least Cost and Linear build-out scenarios for both the CSIR High (Low Intensity) demand forecast and the low demand forecast. It can be seen that the annual new build solar PV capacity in the linear build-out cases ranges from 720 MW/yr for the low demand and 1 250 MW/yr for the CSIR High (Low Intensity) demand. The annual new build wind capacity ranges from 1 360 MW/yr for the low demand to 2 100 MW/yr for the CSIR High (Low Intensity) demand. Figure 79 also shows that the peaking and gas capacity build-out is shifted later by one year in the Linear build-out.



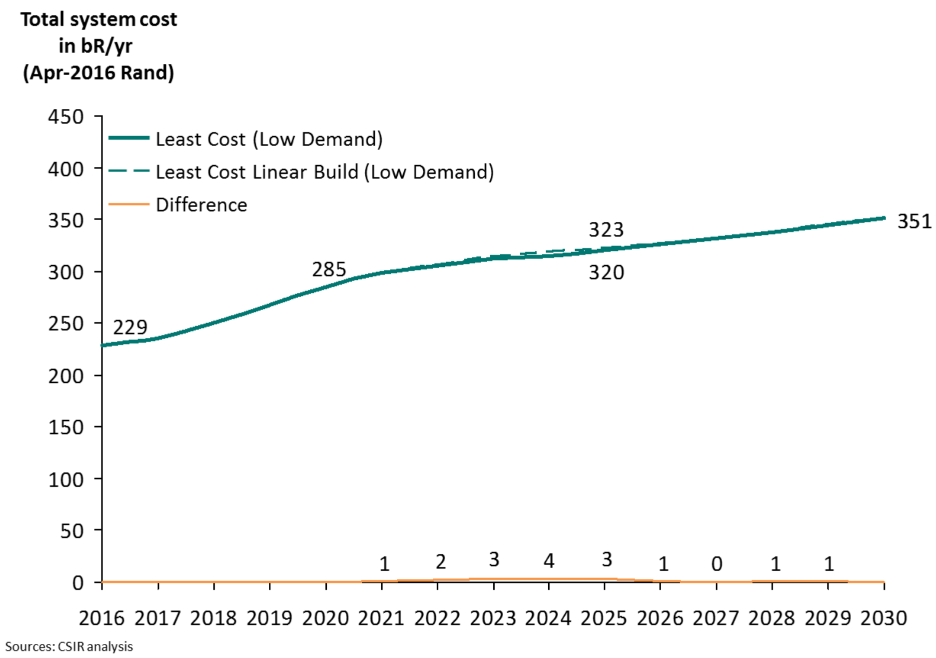
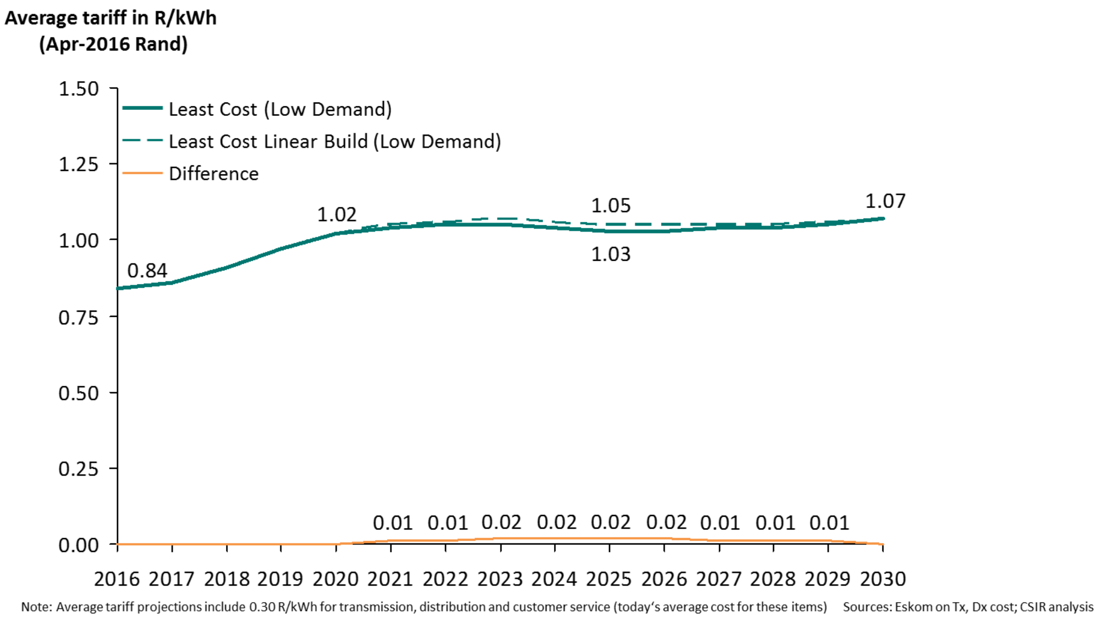


Figure 77: Difference in total system cost between least-cost optimal build-out to linear build out to 2030 with and without the cost of CO_2 (low demand)



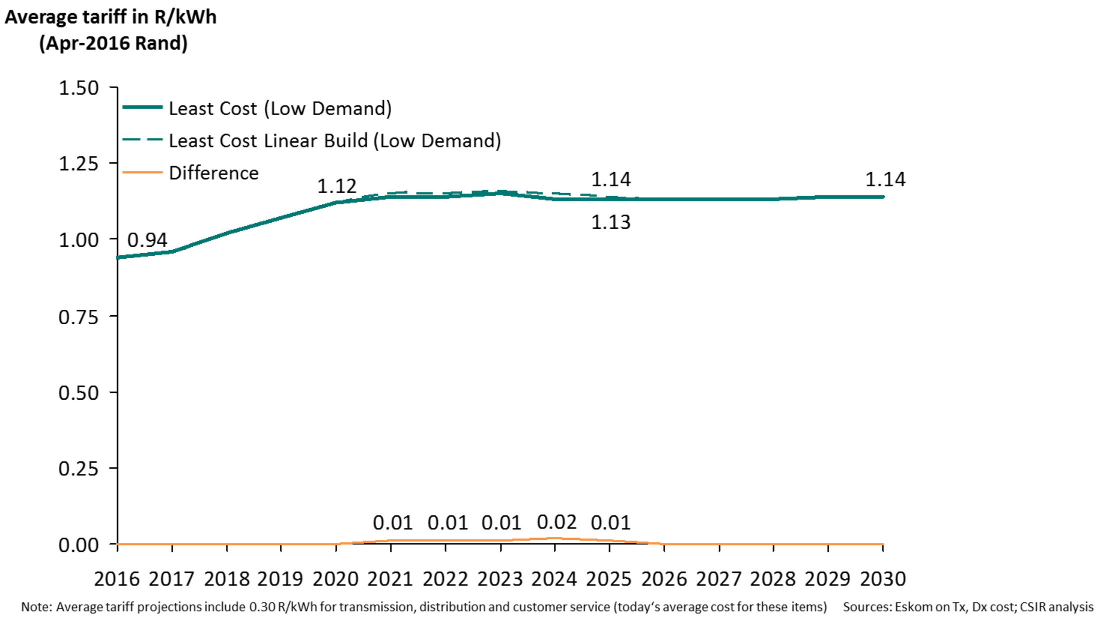


Figure 78: Difference in average tariff with and without cost of CO_2 for the Least-cost sensitivity and the linear build out (low demand)

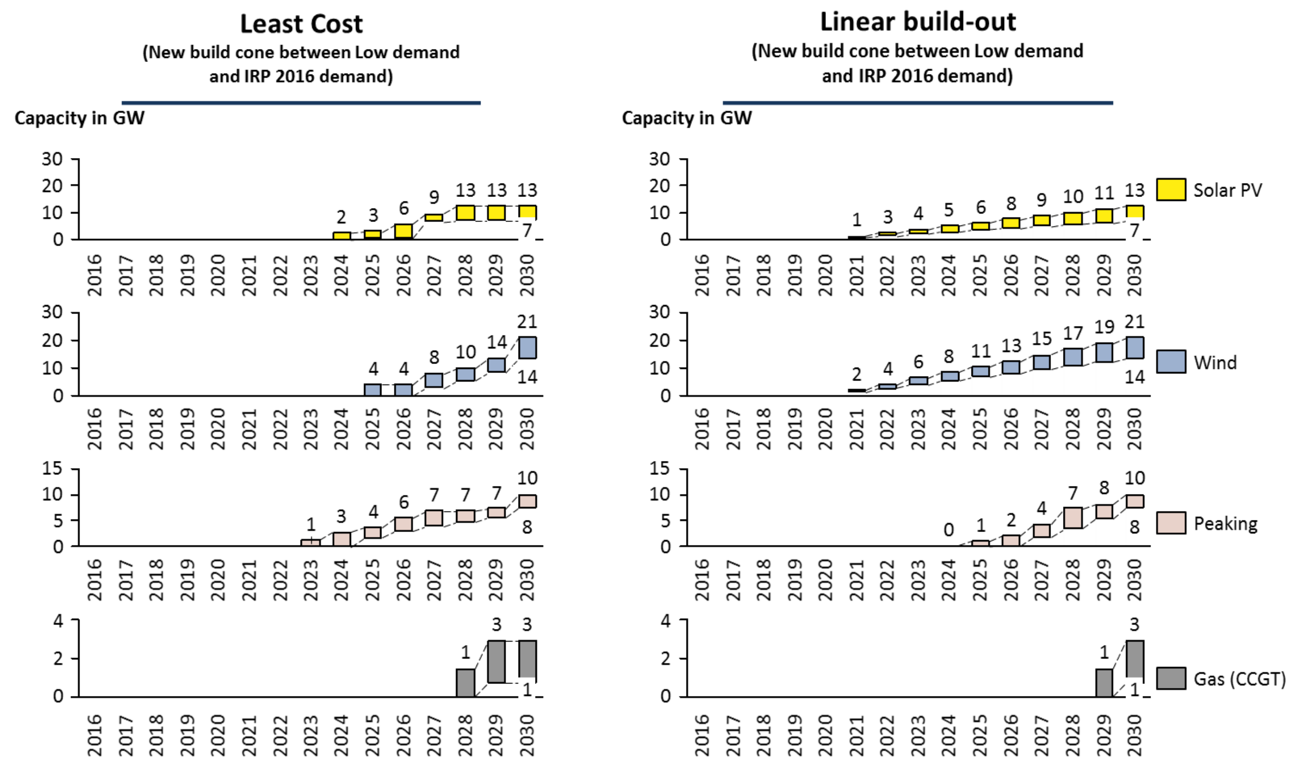


Figure 79: Cone for Least-cost optimal build-out and Least-cost with a linear build out for both the CSIR High (Low Intensity) forecast and low demand forecast.

6.2.3 Low supply (low plant performance and delayed new builds)

The Low Supply sensitivity has two differences to the assumptions from the Least-cost scenario. These are; the low plant performance of the Eskom fleet is assumed (see section 4.5 for details) and the commercial operation dates of Medupi and Kusile units not yet in commercial operation are assumed to be delayed by one year.

This sensitivity implicitly required lead-time constraints on new-build capacity as an immediate supply shortage occurs (due to relative decrease in plant availability assumed and delays in committed new build capacity). In addition, it would not be realistic to build new capacity immediately. As a result, lead times were assumed for each technology from today (2017) and as a result the first solar PV and wind were assumed possible from 2020, peaking and gas capacity from 2021, coal from 2022 and nuclear from 2025.

6.2.3.1 CSIR High (Low Intensity) demand forecast

A result summary for the Low-supply scenario is shown in Figure 80. The earliest new build capacity is solar PV and wind in 2020, followed by peaking capacity in 2021 and gas capacity in 2025. No new coal or nuclear capacity is built by 2030. Since no new capacity can be built before 2020 there is an initial supply shortage prior to these years for this sensitivity. By 2030, ≈47% of the energy contribution is from coal-fired generation (lowered by the poor plant performance), ≈37% is from solar PV and wind, ≈7% from hydro and pumped storage generation, ≈4% from nuclear (Koeberg) and ≈3% from gas-fired generation. Total system cost increases from 203 bR/yr in 2016 to 383 bR/yr in 2030.

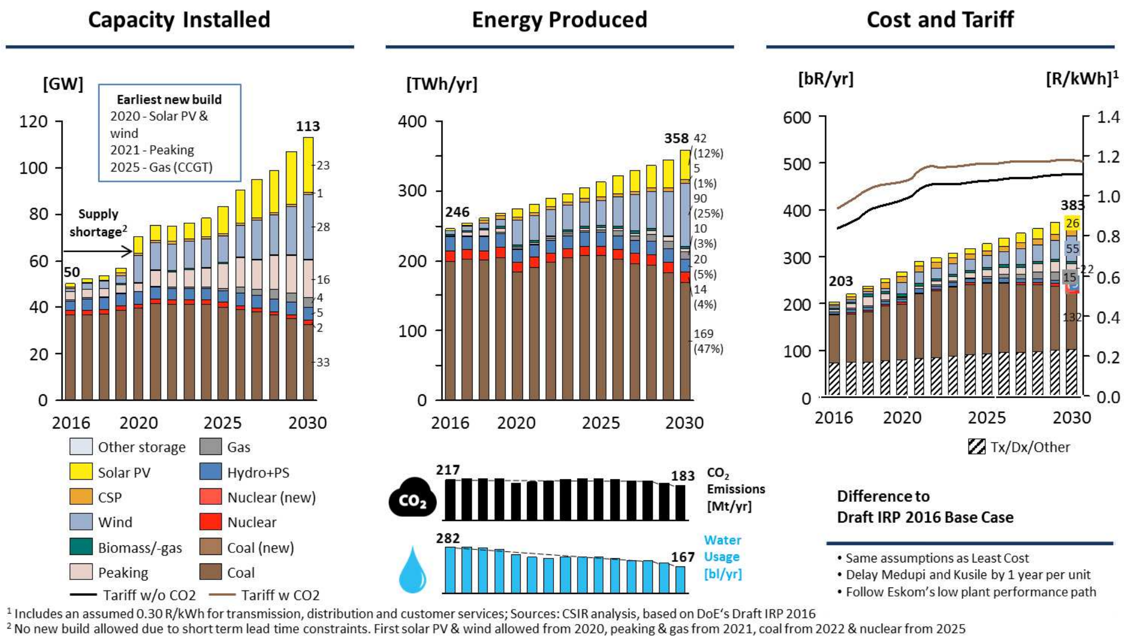
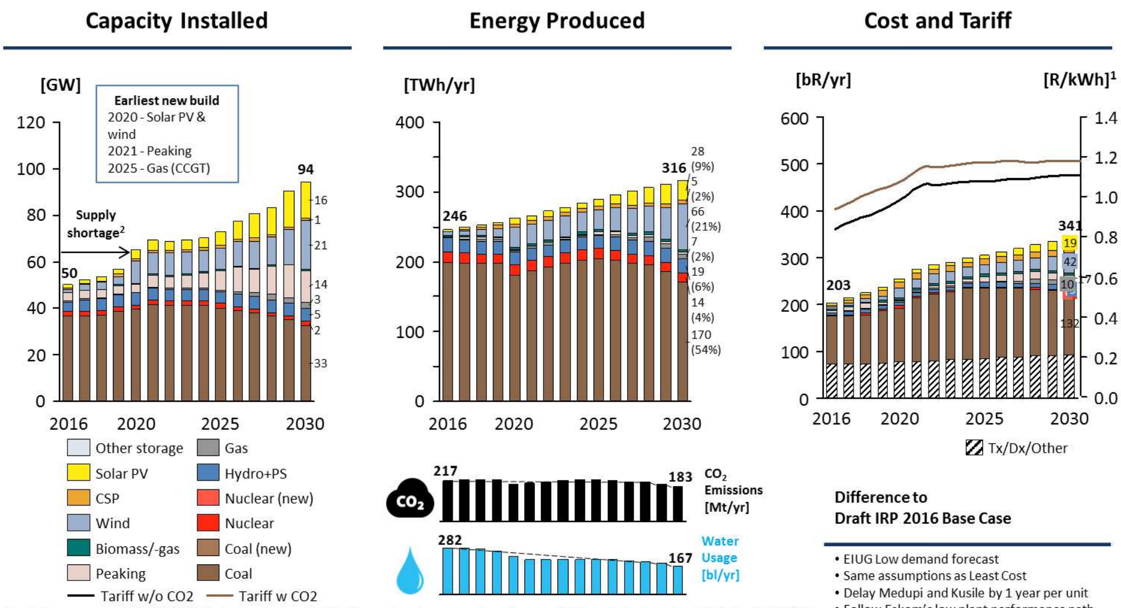


Figure 80: Sensitivity: Low-supply to 2030.

6.2.3.2 Low demand forecast

A result summary for the Low-supply scenario is shown in Figure 81 with the low demand forecast applied. The earliest new build capacity is solar PV and wind in 2020, followed by peaking capacity in 2021 and gas capacity in 2026. No new coal or nuclear capacity is built by 2030. Despite the lower demand forecast assumed in this sensitivity there was also an immediate supply shortage (due to the relative decrease in plant availability and delays in committed new build capacity). The same lead time constraints for new build capacity were applied as in the Low Supply sensitivity. Since no new capacity can be built before 2020 there is a supply shortage prior to this year for this sensitivity. By 2030, ≈54% of the energy contribution is from coal-fired generation (lowered by the poor plant performance), ≈30% is from solar PV and wind, ≈6% from hydro and pumped storage generation, ≈4% from nuclear (Koeberg) and ≈2% from gas-fired generation. Total system cost increases from 203 bR/yr in 2016 to 341 bR/yr in 2030.



¹ Includes an assumed 0.30 R/kWh for transmission, distribution and customer services; Sources: CSIR analysis, based on DoE's Draft IRP 2016
² No new build allowed due to short term lead time constraints. First solar PV & wind allowed from 2020, peaking & gas from 2021, coal from 2022 & nuclear from 2025

Figure 81: Sensitivity: Low-supply to 2030 (low demand).

6.3 What-if analysis

6.3.1 Over-investment

What-if analyses were performed to test the risk of over-investment for the IRP 2016 Base Case, IRP 2016 Carbon Budget and the Least-Cost scenarios already presented. The over-investment cases considered the impact of deploying the capacity expansion plans for each scenario but instead of the planned demand forecast (the CSIR (High) Low-Intensity), the low demand forecast materialises.

Results summaries for the Base Case, Carbon Budget and Least-cost scenarios with over-investment are shown in Figure 82-84.

In the Base Case (with over-investment); by 2030, ≈65% of the energy contribution is from coal-fired generation, ≈15% is from solar PV and wind, ≈7% from hydro and pumped storage generation, ≈5% from nuclear (Koeberg) and ≈5% from gas-fired generation. Total system cost increases from 203 bR/yr in 2016 to 362 bR/yr in 2030.

In the Carbon Budget (with over-investment); by 2030, ≈42% of the energy contribution is from coal-fired generation, ≈27% is from solar PV and wind, ≈18% from nuclear, ≈8% from hydro and pumped storage generation and ≈3% from gas-fired generation. Total system cost increases from 203 bR/yr in 2016 to 382 bR/yr in 2030. This is ≈20 bR/yr more than the IRP 2016 Base Case (over-investment).

In the Least-cost (over-investment); by 2030, ≈58% of the energy contribution is from coal-fired generation, ≈27% is from solar PV and wind, ≈6% from hydro and pumped storage generation, ≈5% from nuclear (Koeberg) and ≈2% from gas-fired generation. Total system cost increases from 203 bR/yr in 2016 to 347 bR/yr in 2030. This is ≈15 bR/yr less than the IRP 2016 Base Case (over-investment).

A comparison of total system cost between the scenarios in the over-investment analyses performed is given in Figure 85 (with and without the cost of CO_2). A comparison of the average tariff for this is also given in Figure 86.

The CO_2 emissions and water consumption for the scenarios assessed for over-investment are summarised in Figure 87.

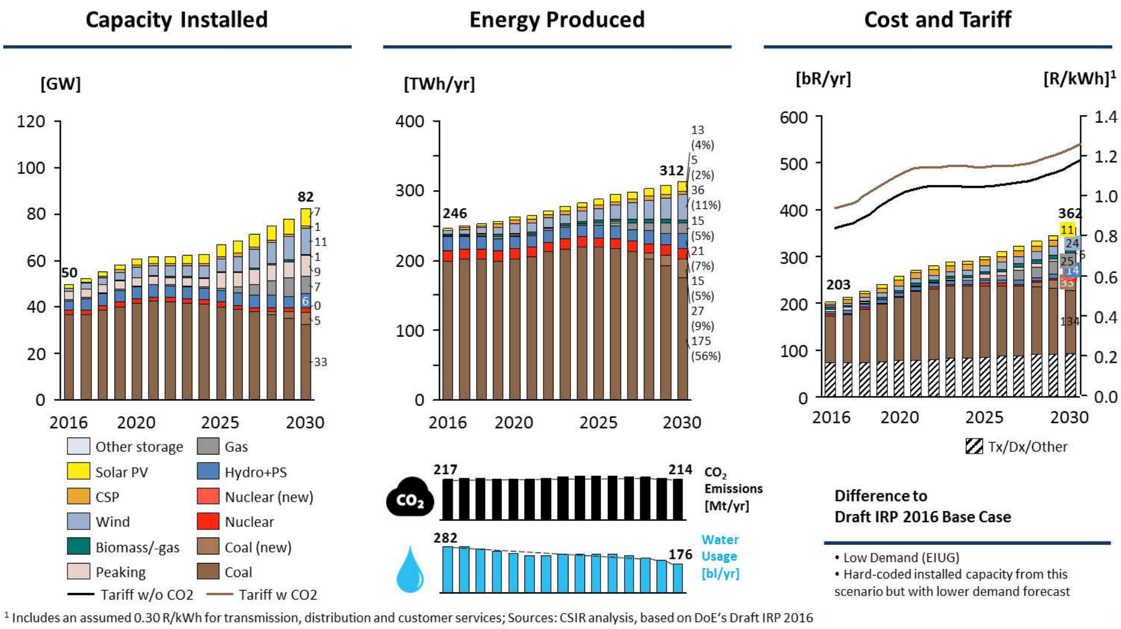


Figure 82: What-if analysis: Draft IRP 2016 Base Case, over-investment

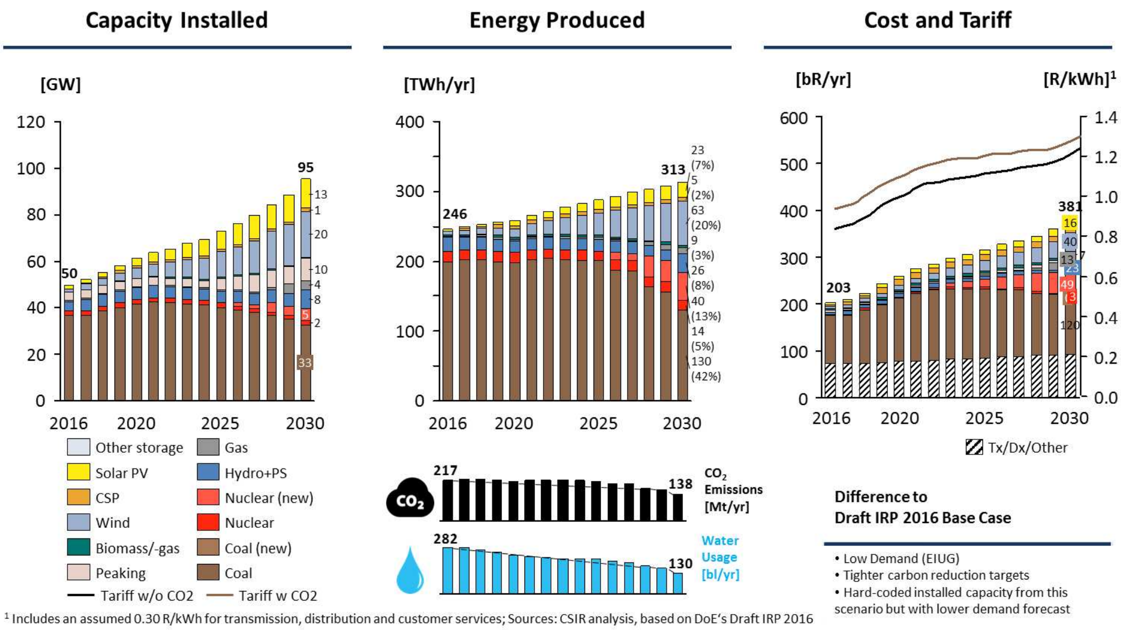
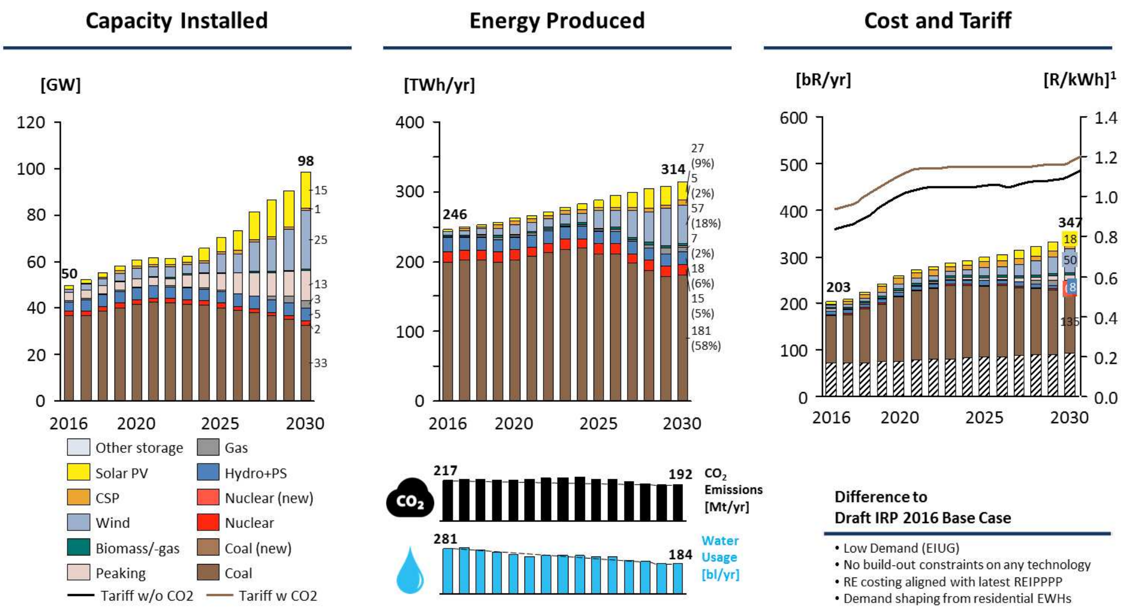
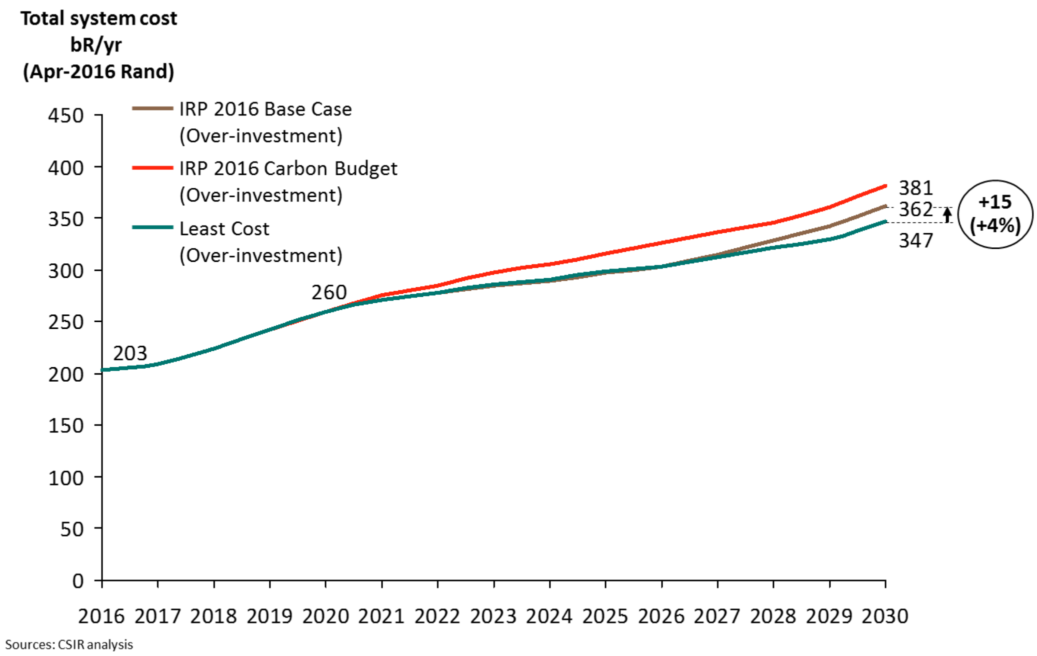


Figure 83: What-if analysis: Draft IRP 2016 Carbon Budget, over-investment



1 Includes an assumed 0.30 R/kWh for transmission, distribution and customer services; Sources: CSIR analysis, based on DoE's Draft IRP 2016

Figure 84: What-if analysis: Least-cost, over-investment



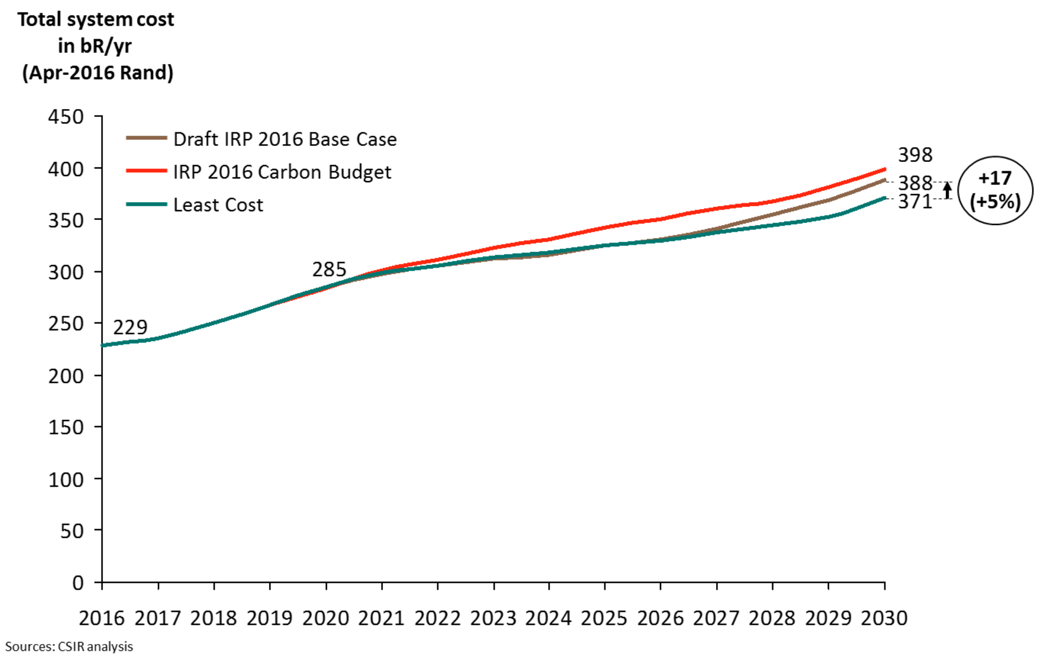
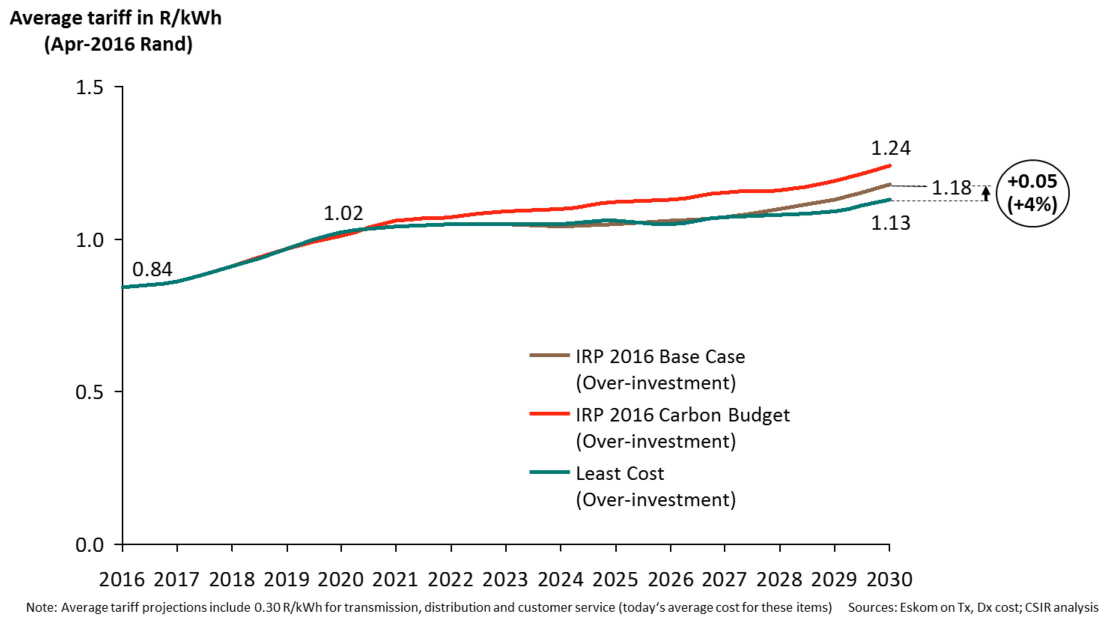


Figure 85: Difference in total system cost between scenarios for the over-investment to 2030 what-if analysis (with and without the cost of CO_2)



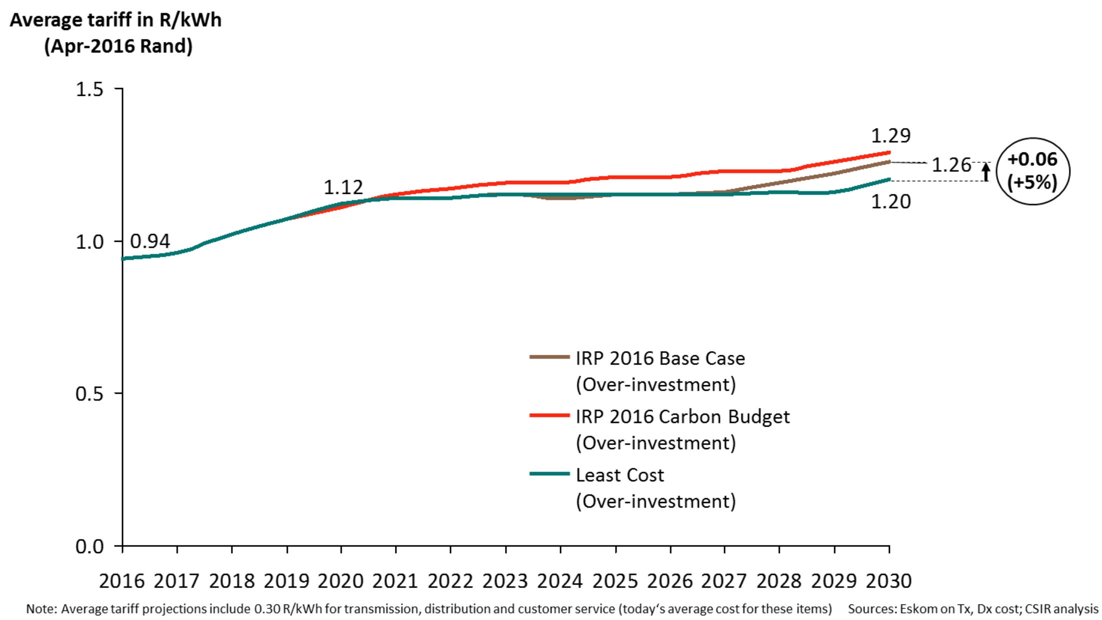


Figure 86: Difference in average tariff between scenarios for the over-investment to 2030 what-if analysis (with and without the cost of CO_2)

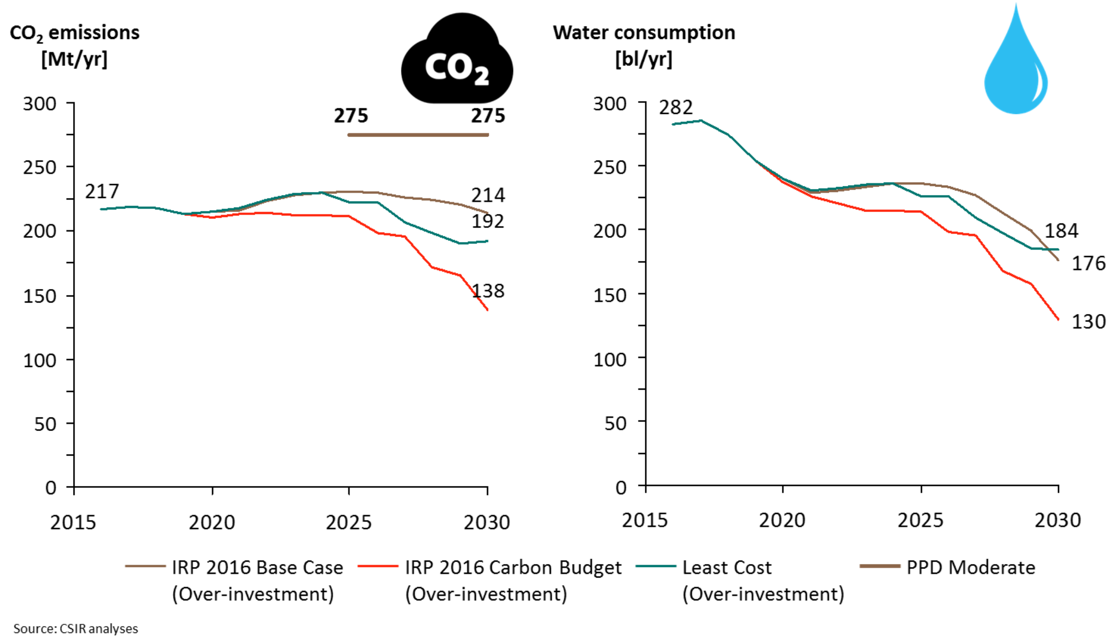


Figure 87: CO_2 emissions and water usage in the electricity sector for the scenarios considered when over-investment i.e. low demand (medium-term outlook to 2030)

7 Modelling approach exclusions (technical)

7.1 Network infrastructure

Please refer to the attached slide deck that accompanies this submission [25] for a global view on the various supply technologies available to South Africa.

7.2 System services

With the integration of higher levels of significantly cheaper RE (specifically solar PV and wind) into a number of power systems around the world in recent years, the challenge has become a matter of integration and not that of economics anymore in a number of countries [60, 61]. The key driver behind system services into the future will be the appropriate valuation of the necessary system services to incentivise market players to provide these system services as required by Transmission System Operators (TSOs). At the core of these system services is flexibility (both technical and financial). In the following sections, some key system services and how variable RE sources like solar PV and wind will affect them will be discussed briefly.

7.2.1 Power system stability - focus on new technologies in South Africa

7.2.1.1 Transient stability

Transient stability is the ability of the power system to maintain synchronism when a large transient disturbance occurs (typically an electrical fault) [62]. More specifically, it is the ability of synchronous generators to maintain synchronism with eachother by ensuring that rotor angle deviations are not too large to then lose synchronism (as governed by the well known power-angle relationship). The amount of time that a fault can remain on the network before synchronism is lost is known as the Critical Clearing Time (CCT) and is the maximum time a fault can remain on the power system before which generators lose synchronism. The CCT is used as a determining factor when performing any power system planning with particular reference to requirements in the Grid Code within which the analysis is being performed [63]. If with the addition of a new power generator, CCTs increase, the impact of the new power generator is positive and vice versa.

With specific reference to wind and solar PV generators, these generators are likely to be interfaced via power electronics and thus their impact on transient stability will be indirect (positive or negative). In this regard, an example of a positive impact is the improvement of power transfers (in the case where they are installed in exporting areas). An example of a negative impact would be the reduced synchronising torque between remaining synchronous generators in different areas. the impact will depend on the specific situation and thus the standard grid planning approach should be followed when conducting the relevant integration studies (as is already the case within Eskom).

At an operations level, tools and facilities can be deployed by the System Operator (as is being done by many TSOs around the world, including Eskom) to assess transient stability in real-time. An example of this is the deployment of synchronised wide area monitoring (synchrophasors) for real-time system awareness as well as improved integration with tools like the DSATools suite developed by Powertech [64] and specifically Transient Security Assessment Tool (TSAT) in this case [64]. Tools like these (as well as others) are being integrated into the Energy Management System (EMS) of system operators around the world in order to assist in ensuring system security and stability. More specifically with higher penetrations of wind and solar PV, the specific tool developed for and being applied by EirGrid/SONI, Wind Security Assessment Tool (WSAT), could be an example of what is available (or could be developed in South Africa) to manage high wind and solar PV penetration in the South African context.

7.2.1.2 Voltage stability and reactive power control

Reactive power and voltage control can be provided by modern solar PV and wind power generators. In South Africa, static as well as dynamic reactive power and voltage control is a pre-requisite for grid connection for particular size renewable energy generators as defined in the Grid Code [65]. Modern wind turbines and solar PV inverters as well as the associated plant level controllers are designed for and capable of static and dynamic reactive power control similar to what conventional synchronous power generators are capable of.

As is well known, reactive power is locational and thus needs to be procured in specific supply areas to ensure acceptable voltage levels as well as voltage control capability. The distributed nature of solar PV and wind could act in their favour in this regard as well designed procurement can geographically spread wind and solar PV plants around the country thereby ensuring acceptable voltage levels and reactive power control is available in areas where it is needed. However, it is appreciated that many wind and solar PV generators may be integrated at distribution voltage levels while typical voltage control is performed at the transmission level. If it is not optimal or feasible to place wind and/or solar PV plants in the requisite locations for this, other devices may need to be deployed to ensure the system service is obtained e.g. existing and future synchronous generators, strategically placed capacitor banks, Static VAr Compensators (SVCs), Static Synchronous Compensator (STATCOM), Synchronous Condensors (SCOs) etc.

The required reactive power compensation is informed by the typical grid planning as is already performed by Eskom Grid Planning and will continue to into the future. Examples of this include the Transmission Development Plan (TDP) [66], Strategic Grid Plan (SGP) [67] and Grid Connection Capacity Assessment (GCCA) [68]. Similar to tools being applied at system operations level for transient stability, similar tools and facilities can be deployed by the System Operator for voltage stability and security. An example of this for voltage stability and security is Voltage Security Assessment Tool (VSAT) in this case complemented by tools like WSAT.

7.2.1.3 Frequency stability (inertia focus)

A particular focus is placed on frequency stability (and more specifically, system inertia) as this seems to be the most significant concern from TSOs around the world when integrating high levels of variable

RE [7]. The initial system RoCoF following a large disturbance (loss of generation/load and/or transmission import/export) is predominantly dependant on the amount of system inertia on the network at the time of the disturbance. A stylised representation of the RoCoF is shown in Figure 88 [69] for the loss of a large generator and/or transmission infeed (imports). The term "inertia" when used in this context actually refers to the total amount of kinetic energy that is stored in the rotating masses of all synchronously connected generators (and loads). Using the well known swing equation [62], linearised over the small disturbance range and removing primary frequency control (to be as conservative as possible), one can derive the minimum amount of system inertia required at any time to ensure that the RoCoF remains below a pre-defined threshold:

$$E_{kin.(min)} = P_{cont.} \frac{f_n}{2(\text{RoCoF})} + E_{kin(cont.)} \tag{1}$$

where

$E_{kin.(min)}$	=	Minimum system inertia i.e. minimum synchronous system energy required;
f_n	=	System frequency (50 Hz);
$P_{cont.}$	=	Size of largest contingency (MW);
RoCoF	=	Pre-defined acceptable RoCoF (Hz/s);
$E_{kin(cont.)}$	=	Amount of energy lost in contingency (MW.s).

Using equation 1 and assuming an acceptable RoCoF as well as reasonable contingency size, one can define the amount of synchronous system energy ("system inertia") that needs to be in the system at any point in time to ensure the pre-defined RoCoF is not exceeded. Assuming the following:

- $P_{cont.}$ = 2 400 MW (loss of three large coal units simultaneously);
- RoCoF = 1 Hz/s;

The choice of a RoCoF = 1 Hz/s is based on the requirement in Ireland where the TSO has recommended 1 Hz/s [70, 71]. The South African Grid Code (for renewables) only requires a RoCoF = 1.5 Hz/s at this stage [65].

From these input assumptions, the minimum amount of system inertia required will be $\approx$ 65 000 MW.s. This defines the minimum amount of system inertia that needs to be in the power system for all hours of the year.

The authors have taken the hourly unit commitment and economic dispatch solutions for the Base Case, Carbon Budget and Least-cost scenarios in 2030 and 2050 and calculated the amount of system inertia online for all hours of the year. This is calculated based on assumptions for typical inertia constants for all generator technologies (for details see Appendix A). This system inertia is then ordered in a similar manner to a LDC to obtain an inertia duration curve. The previously calculated minimum system inertia is then overlaid onto this and compared to get an indication of the amount of system inertia each scenario lacks (if any) and the number of hours for which the system has insufficient system

[7] The authors appreciate that there are various other areas that need sufficient planning, investment and operational experience but the system inertia concern is ubiquitous and is thus a particular focus

inertia. It is important to note that any technology coupled through a power electronics interface (solar PV, wind, generators coupled via HVDC interconnection) do not contribute to system inertia. Thus, if a coal/gas/nuclear fleet were to be interconnected purely via HVDC, these generators would not contribute to system inertia.

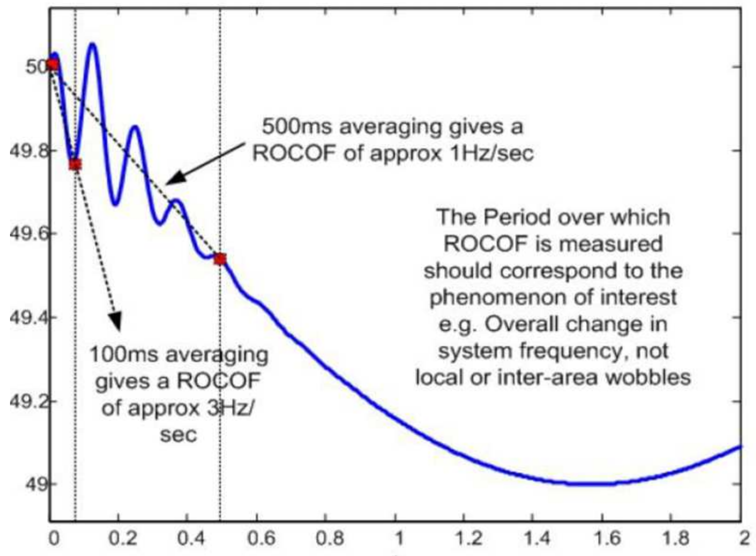


Figure 88: Illustration of RoCoF following a large contingency event (measured over different averaging windows) [69]. Typically, averaging window is 500 ms as this is the phenomenon one is interested in (not localised and/or inter-area modes/oscillations).

Results from the analyses assuming either none, half or all new nuclear generation is HVDC integrated for 2030 and 2050 are summarised in Figure 89-94. A summary of this is provided in Table 20. The Least-cost scenario requires ≈22 500 MW.s of additional system inertia by 2030 for ≈440 hours of the year. It is interesting to note that in the Carbon Budget case, whether half or all new nuclear capacity is HVDC integrated will also require additional system inertia by 2030 - ≈30 900-47 700 MW.s for between 660-2 100 hours of the year. By 2050, the Base Case would also require additional system inertia if half or fully HVDC integrated (up to ≈2 700 MW.s for ≈200 hours of the year). The Least-cost scenario requires ≈58 000 MW.s of additional system inertia for almost half of the year (≈4 320 hours). The Carbon Budget scenario also requires significant additional system inertia if fully HVDC integrated (≈54 100 MW.s for ≈3 240 hours of the year) but significantly less if half HVDC integrated (≈9 400 MW.s for ≈205 hours of the year).

In principle, there are two ways to deal with lower system inertia:

a) Conservative: Introduce additional intrinsic inertia (synchronous inertia) to reduce RoCoF.

b) Progressive: Introduce reactive measures and control algorithms to deal with an increased RoCoF i.e. synthetic inertia.

Although a range of solutions in the progressive approach are available and a number of investigations and operational experiences have been outlined for a range of jurisdictions [72, 73, 74, 75, 76, 77, 78, 79, 80, 81, 82, 83, 84, 85], the approach taken by the authors is to only outline the technical solutions in the conservative approach to increase system inertia and reduce RoCoF. These technical solutions are [69]:

- Synchronous compensators that are new purpose built devices and retro-fitting of decommissioned generators, with/without flywheels;
- Rotating stabiliser devices typically a multi-pole device incorporating a flywheel, which can be based on a Doubly-Fed Induction Generator or synchronous machine;
- Wind turbines: Only when directly coupled (typically with doubly-fed induction generators);
- Pumped hydro generators assuming synchronous machines are deployed;
- "Parking" of conventional generators i.e. operating generation plant at low output levels but with reduced/no capability to provide system services (like operating reserves) at the lower output levels;
- Reduction in the minimum stable level thresholds of conventional generation while still leaving the plant with the capability to fully provide system services;
- New flexible thermal power plants with high inertia constants.

To cost system inertia in the most conservative manner possible, the installation of a fleet of rotating stabiliser devices (directly coupled flywheels) is assumed. The authors appreciate that this is not the optimal solution but it is the most conservative approach in that it costs system inertia in the most "expensive" manner possible. The rotating stabilisers are assumed to be connected to the power system for all hours of the year (even though they may only be required for a selected number of hours). The costs for additional system inertia via the deployment of a fleet of flywheels (as required per scenario) is summarised in Table 21 (assuming the typical technical characteristics, investment and operations costs for rotating stabilisers as shown). As can be seen in Table 21, additional costs for rotating stabilisers are never more than 1% of total system costs.

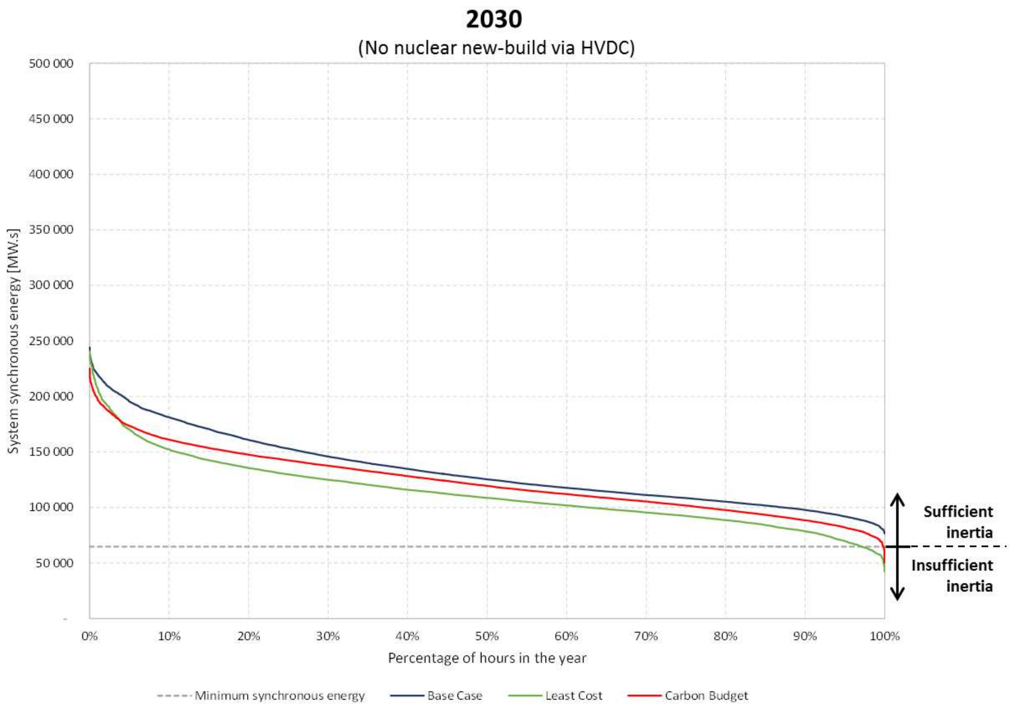


Figure 89: System inertia and minimum system inertia requirement for 2030 (no new nuclear generation integrated via HVDC)

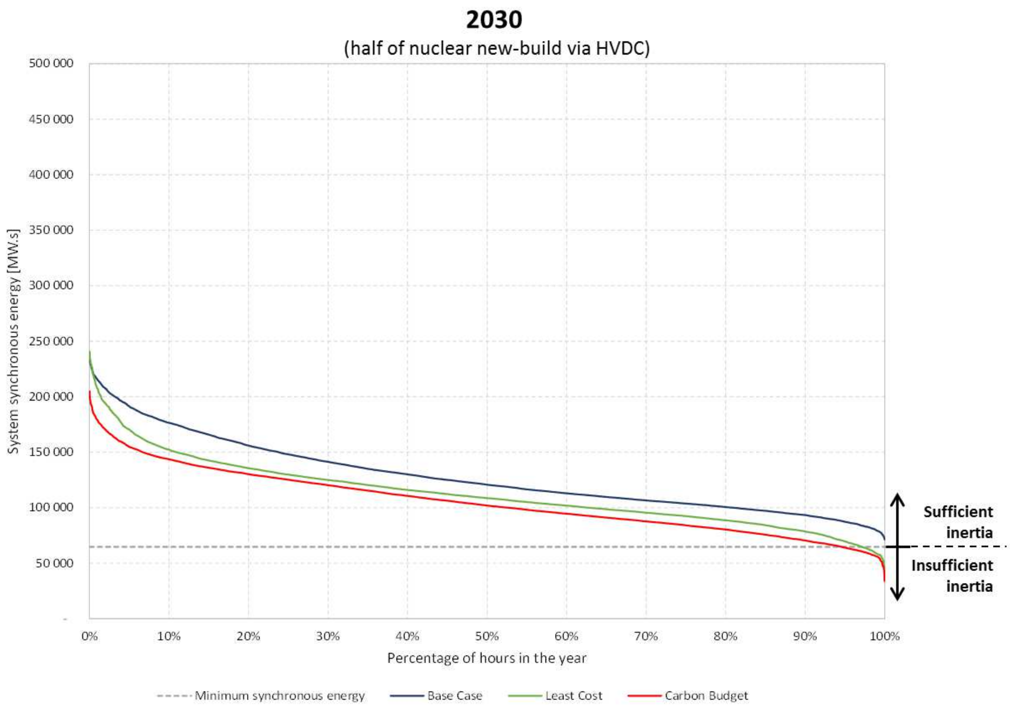


Figure 90: System inertia and minimum system inertia requirement for 2030 (half all new nuclear generation integrated via HVDC)

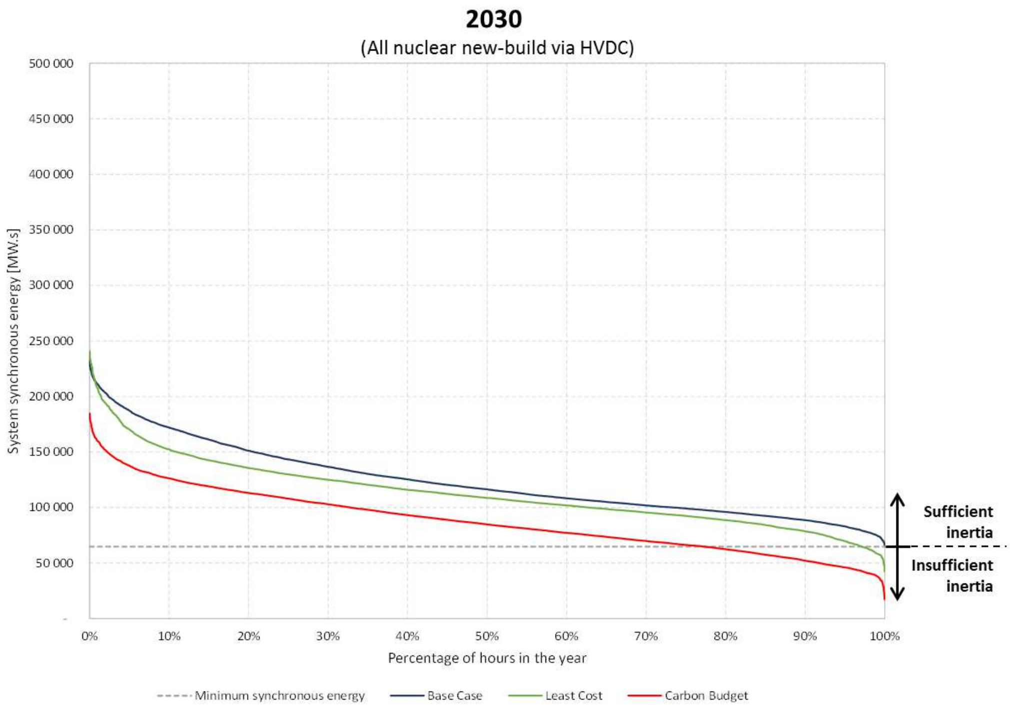


Figure 91: System inertia and minimum system inertia requirement for 2030 (all new nuclear generation integrated via HVDC)

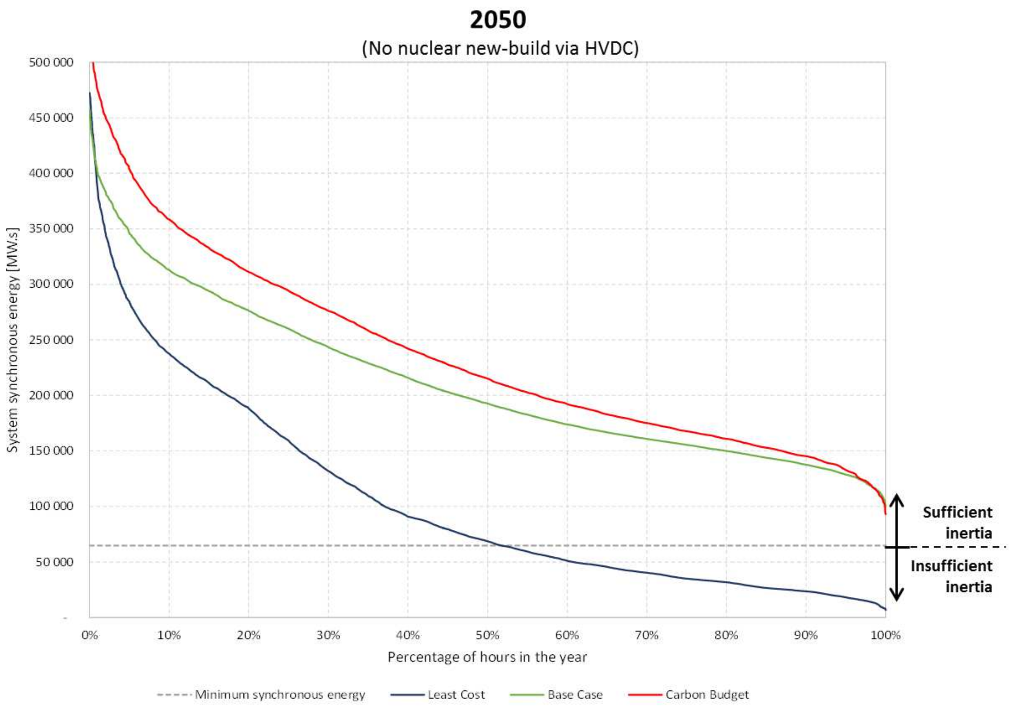


Figure 92: System inertia and minimum system inertia requirement for 2050 (no new nuclear generation integrated via HVDC)

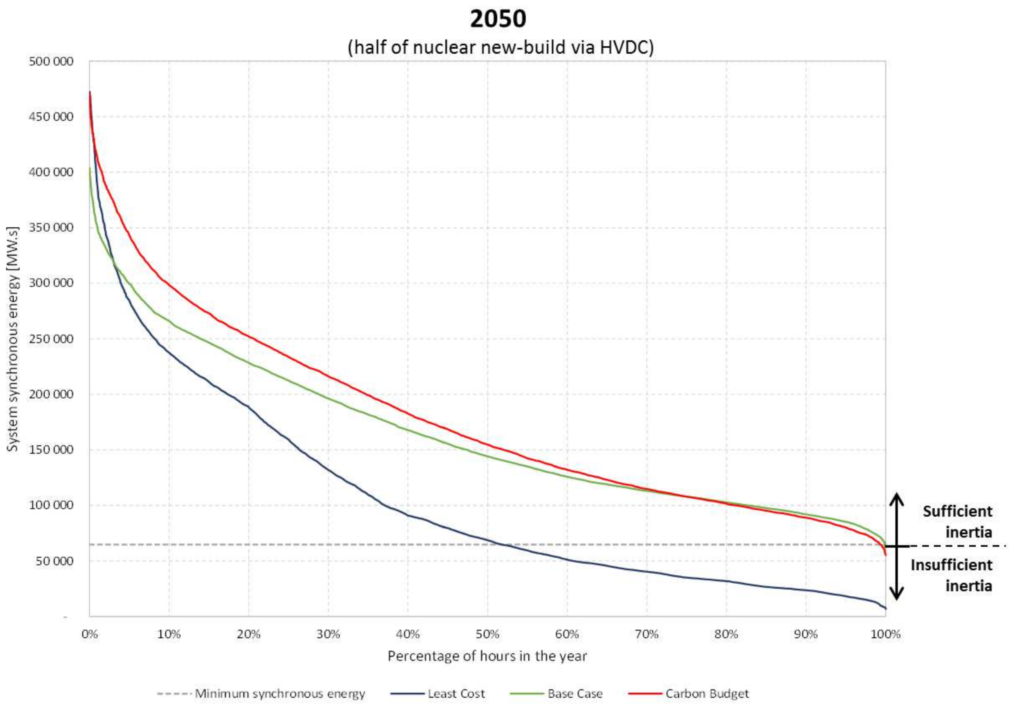


Figure 93: System inertia and minimum system inertia requirement for 2050 (half all new nuclear generation integrated via HVDC)

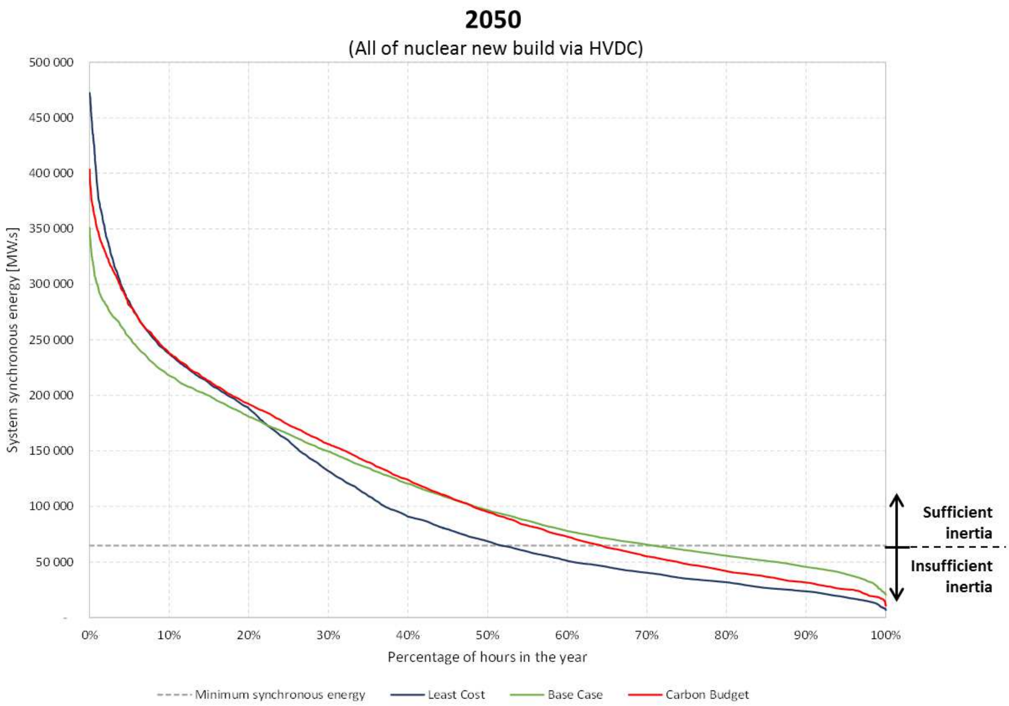


Figure 94: System inertia and minimum system inertia requirement for 2050 (all new nuclear generation integrated via HVDC)

Table 20: Summary of system inertia requirements for selected scenarios in 2030 and 2050 assuming none, half or all of new nuclear generation is integrated via HVDC.

No nuclear fleet via HVDC

		2030			2050		
		Base Case	Carbon Budget	Least cost	Base Case	Carbon Budget	Least cost
Minimum inertia needed	[MW.s]	64 800	64 800	64 800	64 800	64 800	64 800
Minimum inertia (actual)	[MW.s]	76 500	50 300	42 300	100 200	93 100	6 800
Additional inertia needed	[MW.s]	-	14 500	22 500	-	-	58 000
Number of hours	[hrs]	-	210	440	-	-	4 320

Half nuclear fleet via HVDC

		2030			2050		
		Base Case	Carbon Budget	Least cost	Base Case	Carbon Budget	Least cost
Minimum inertia needed	[MW.s]	64 800	64 800	64 800	64 800	64 800	64 800
Minimum inertia (actual)	[MW.s]	71 300	33 900	42 300	62 100	55 400	6 800
Additional inertia needed	[MW.s]	-	30 900	22 500	2 700	9 400	58 000
Number of hours	[hrs]	-	660	440	200	250	4 320

Full nuclear fleet via HVDC

		2030			2050		
		Base Case	Carbon Budget	Least cost	Base Case	Carbon Budget	Least cost
Minimum inertia needed	[MW.s]	64 800	64 800	64 800	64 800	64 800	64 800
Minimum inertia (actual)	[MW.s]	66 200	17 100	42 300	20 600	10 700	6 800
Additional inertia needed	[MW.s]	-	47 700	22 500	44 200	54 100	58 000
Number of hours	[hrs]	-	2 140	440	2 680	3 240	4 320

Table 21: Summary of resulting additional costs for selected scenarios in 2030 and 2050 assuming none, half or all of new nuclear generation is integrated via HVDC.

		2030			2050		
		Base Case	Carbon Budget	Least cost	Base Case	Carbon Budget	Least cost
Additional inertia needed	[MW.s]	-	14 500	22 500	-	-	58 000
Number of hours	[hrs]	-	210	440	-	-	4 320
Rotating stabilisers needed	[MW]	-	360	560	-	-	1 450
Annual cost for rotating stabilisers	[bR/yr]	-	1.1	1.7	-	-	4.5
(% of system costs)	[%]	0.0%	0.3%	0.5%	0.0%	0.0%	0.7%

Half nuclear fleet via HVDC

		2030			2050		
		Base Case	Carbon Budget	Least cost	Base Case	Carbon Budget	Least cost
Additional inertia needed	[MW.s]	-	30 900	22 500	2 700	9 400	58 000
Number of hours	[hrs]	-	660	440	200	250	4 320
Rotating stabilisers needed	[MW]	-	770	560	70	240	1 450
Annual cost for rotating stabilisers	[bR/yr]	-	2.4	1.7	0.2	0.7	4.5
(% of system costs)	[%]	0.0%	0.6%	0.5%	0.0%	0.1%	0.7%

Full nuclear fleet via HVDC

		2030			2050		
		Base Case	Carbon Budget	Least cost	Base Case	Carbon Budget	Least cost
Additional inertia needed	[MW.s]	-	47 700	22 500	44 200	54 100	58 000
Number of hours	[hrs]	-	2 140	440	2 680	3 240	4 320
Rotating stabilisers needed	[MW]	-	1 190	560	1 110	1 350	1 450
Annual cost for rotating stabilisers	[bR/yr]	-	3.7	1.7	3.4	4.1	4.5
(% of system costs)	[%]	0.0%	0.9%	0.5%	0.5%	0.6%	0.7%

Rotating stabiliser properties: CAPEX = 20 000 R/kW; FOM = 3% of CAPEX; all year operation; cost of electricity = 1 R/kWh; H = 40 MW.s/MVA

7.3 Variable resource forecasting

As mentioned in previous sections, when variable RE penetration reaches relatively high levels, the system operator will need to be equipped with the relevant tools and skills to operate and manage the power system accordingly. As can be seen in all scenarios analysed, RE penetration will only start to become relevant and a priority post-2030. By these definitions, the IEA has recently defined this into four phases [61] where only once variable RE penetration levels of 20-30% or more (by annual energy) does it start to become relevant and a priority .

In this specific dimension of variable RE forecasting, the system operator will need to have sufficient tools and skills to forecast the variable resource (wind and solar irradiation) with sufficient level of accuracy in a number of timeframes (15 minute ahead, hour-ahead, 12 hour-ahead, day-ahead and further). Tools and best practices are already being applied around the world in this regard and South Africa could leverage off of this to ensure a level of preparedness at the the requisite time to ensure the variable resource can be forecasted and associated risk managed accordingly. Examples of global variable resource forecasting being applied in system operators around the world include Germany [86, 87], Texas (USA) [88], Ireland [89] and Denmark [90] to name a few.

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Appendix A Input Assumptions

Selected input assumption sheets developed by CSIR and used in this work accompany this submission. Other ancillary input data is intended to be published soon after this submission. Key input assumptions can either be found in the form Excel spreadsheets or within the PLEXOS® dataset and models that will also be published.

Appendix B Results

Selected results sheets from scenarios, sensitivities and what-if analyses performed as part of this submission accompany this submission in the form of Excel spreadhseets at this stage. A full package of detailed results is expected to be published soon after this submission.