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INTEGRATED RESOURCE PLAN UPDATE

ASSUMPTIONS, BASE CASE RESULTS AND OBSERVATIONS

REVISION 1

November 2016

This IRP update documentation has been released for consultation purposes only.
Final IRP update will be published once the consultation process and policy adjustment has been concluded.

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Purpose of the Report

The Integrated Resource Plan (IRP) 2010-30 was promulgated in March 2011. It was indicated at the time that the IRP should be a "living plan" which would continue to be revised by the Department of Energy (DoE).

This report highlights the process, progress and observations from the IRP Update Base Case (the starting point) as well list the scenarios to be analysed before the IRP is finalised. The sections of the report therefore cover:

- The IRP Update Process
- Assumptions
- Results and observations from the base case
- List of scenarios that are being considered

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List of Abbreviations

CCGT	Combined-Cycle Gas turbine
CoD	Commissioning Dates
CoGen	Cogeneration
CSP	Concentrated Solar Power
DMP	Demand Market Participants
DEA	Department of Environmental Affairs
DoE	Department of Energy
DSM	Demand Side Management
EAF	Energy Availability Factor
EUF	Energy Utilisation Factor
EPRI	Electric Power Research Institute
FOR	Forced Outage Rate
GDP	Gross Domestic Product
GJ	Giga Joule
ICE	Internal Combustion Engine
IPP	Independent Power Producer
IRP	Integrated Resource Plan
LNG	Liquefied Natural Gas
MTSAO	Medium Term System Adequacy Outlook
NERSA	National Energy Regulator of South Africa
OCGT	Open Cycle Gas Turbine
POR	Planned Outage Rate
PPA	Power Purchase Agreement
PPI	Producer Price Index
REBID	DOE Renewable Energy Bid Window Programme
RFP	Request For Proposal
kW	Kilo Watts
MW	Mega Watts
GW	Giga Watts
kWh	Kilo Watt hour
TWh	Tera Watt hour

Glossary

Discount Rate: The discount rate is a critical factor influencing any analysis of economic effects over time. Discount rates effectively express a time preference for money – money right now is preferred to money in the future.

Exchange Rate: Quantifies the amount of Rands required to get one dollar.

Cost of Unserved Energy: The COUE is the value (in Rands per kWh) that is placed on a unit of energy not supplied due to an unplanned outage of short duration.

Overnight Capital Cost: Describe the cost of building a power plant overnight and is expressed in R/kW

Lead Time: Describe the number of years required to bring the plant to full commercial operation.

Fixed O&M Cost: Describes the amount of fixed operation and maintenance per year that the power will incur regardless of the station's output in R/KW per year.

Variable O&M Cost: Describes the amount of variable operation and maintenance that the

Planned Outage Rate: This parameter describes the amount of time during which the plant is down on planned maintenance and is expressed as a percentage

Unplanned Outage Rate: This parameter describes the amount of time during which the plant is down on unplanned maintenance and is expressed as a percentage

Heat Rate: This parameter describes the amount of fuel energy required to produce one MW and is expressed in GJ/MWh

Fuel Price: Describe the price of fuel in R/GJ.

Energy Content: Describes the amount of energy content per tonne of fuel supplied and is expressed in GJ/tonne

Price Elasticity of Demand: This parameter describes how energy demand changes per unit increase in electricity price and is expressed as a ratio.

Reserve Margins: This parameter measures how much the installed capacity is exceeding/falls short of meeting peak demand

P50 and P80: Refers to 50% and 80% probability of materialising respectively

1. IRP Update Process

The IRP 2010-30 identified the preferred generation technology required to meet expected demand growth up to 2030. The policy adjusted IRP incorporated a number of government objectives, including affordable electricity, carbon mitigation, reduced water consumption, localisation and regional development, producing a balanced strategy toward diversified electricity generation sources and gradual decarbonisation of the electricity sector in South Africa.

There has been some progress over the past three years, since the promulgation of the IRP 2010-30, in executing the programmes identified in the plan. A number of Ministerial Determinations have been issued and these include, renewable energy, nuclear, coal and gas.

While the IRP 2010-30 remains the official government plan for new generation capacity until it is replaced by an updated plan, there are a number of assumptions that have changed and they include:

- The changed electricity landscape over the past three years, in particular in electricity demand and the underlying relationship with economic growth;
- New developments in technology and fuel options (locally and globally);
- Scenarios for carbon mitigation strategies and the impact on electricity supply up to 2050; and
- The affordability of electricity and its impact on demand and supply.

The IRP update process is as depicted in Source: DOE

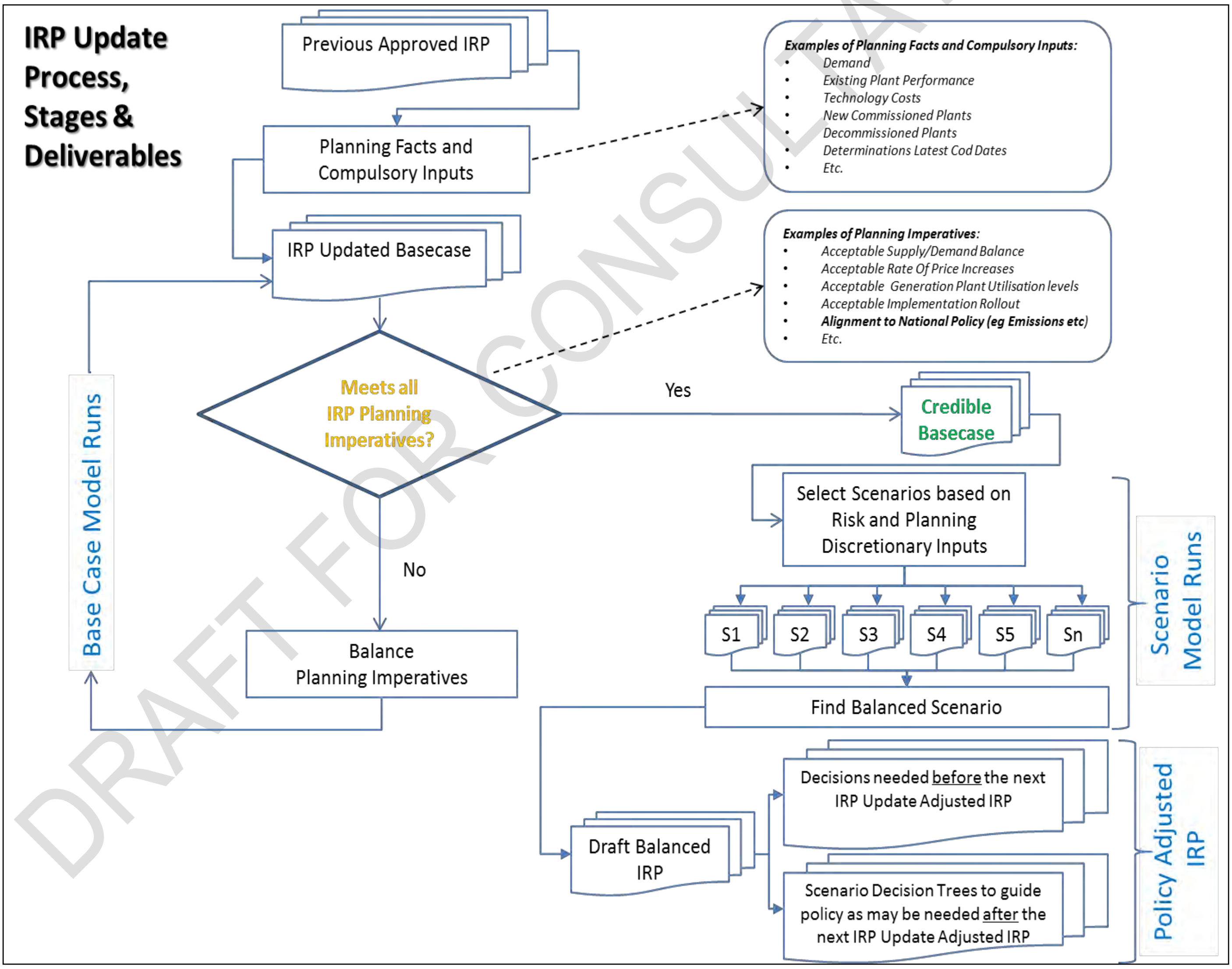
Figure 1 below takes the following approach:

1. Collating the latest Assumptions from the various sources;

2. Developing a credible Base Case from the IRP 2010 by updating the underlying assumptions based on new information;

3. Considering different scenarios or test cases based on alternative government policies or strategies and differences in future economic and resource terrains. Information from these scenarios will be used to inform the policy adjustment phase of the IRP; and

4. The development of a proposed path of least regret, incorporating the benefits of flexibility by developing decision trees to indicate decisions needed before the next update.



Source: DOE

Figure 1: IRP Update Process

The current IRP update process progress is as follows:

Table 1: IRP Update Progress

Activity	Status	Comments
Assumptions	Done	This is subject to comments from various stakeholders.
Base Case	Done	This is subject to change based on to be comments received on the assumptions.
Scenarios	In Progress	The results of the scenarios will also be impacted by changes to the assumptions. Number of scenarios may also change based on feedback from public consultations.
Policy Adjusted IRP	To follow after scenarios	This will follow once the scenarios and public consultation is completed

Source: DoE

2. Planning Assumptions and Input Parameters

Key assumptions that have changed, from the promulgated IRP 2010-30, include amongst others, technology costs, electricity demand projection, fuel costs and Eskom existing fleet performance. The costs for generic technologies used in the IRP 2010-30 were based on the July 2010 report by the Electric Power Research Institute (EPRI). EPRI is a US based independent and non-profit organisation that conducts research and development relating to the generation, delivery and use of electricity.

In the IRP 2010-30 development, the generic technology data from EPRI was used for all options, except for solar photovoltaic generation which was provided by the Boston Consulting Group in their report ("Outlook on Solar PV"); sugar bagasse generation (provided by the sugar industry as part of the public hearings); pumped storage costs (provided by Eskom) and the regional hydro, gas and coal options (which were based on data compiled in previous Southern African Power Pool plans).

At the request of the DoE, EPRI has developed an updated report on the generic technology with the latest version of report released in September 2016. For photovoltaic and wind, the figures from the DoE IPP Office Renewable Energy bid window 4 were used. For sugar bagasse and regional options the 2010 costs are used but inflated with South African consumer inflations rates, while Eskom has provided an updated view of the water pumped storage costs. A hybrid cost is used for Nuclear based on the study commissioned by the DoE Nuclear Branch. The DoE report looks at costs in Asia which are generally less than those from the West which are in the EPRI report.

2.1 Expected Demand

The energy demand forecast as developed by the CSIR is shown in Figure below. Report detailing the approach followed in compiling the forecast can be found on the DoE website.

The IRP update uses the High (less energy intense) forecast.

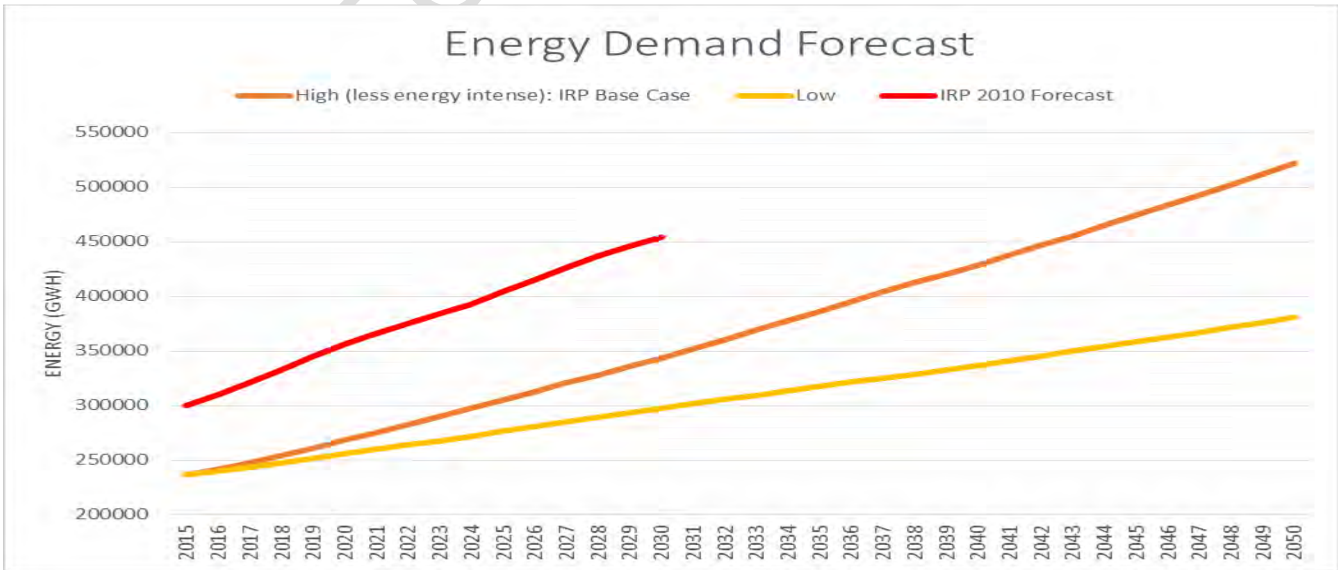


Figure 2: Energy Demand Forecast

2.2 Economic parameters

Table 2 below indicates economic parameters used for the IRP. Economic parameters such as the exchange rate (currently fixed at January 2015 rate) will be adjusted for the final plan as this number changes daily. This does not impact on the results as this is a comparative analysis and all options are impacted equally.

Table 2: Economic Parameters

Parameter	Value used in model		Comment
Discount Rate	8.2%[1]		Net discount rate before tax
Exchange Rate	R/$ 11.55		Based on January 2015 exchange rate
Cost of Unserved Energy	Total (direct and indirect) economic cost of R77.30/kWh[2]		NERSA to provide a report detailing the base year for cost
Study horizon	2016-2050		The period 2016-2060 will be studied with only up to 2050 used for reporting purposes.
GDP/Energy forecast	-		Refer to CSIR forecast report
Fuel cost in R/GJ[3]	Coal Pulverized with FGD	25 (~R/t 450)[4]	Price for Coal FBC assumed half the price of Coal Pulverized due to lower grade of coal used
	Coal FBC with FGD	12.5 (~R/t 225)	
	Coal Pulverized with CCS	25 (~R/t 450)	
	Coal IGCC	25 (~R/t 450)	
	Liquefied Natural Gas	115.5[5]	Price of LNG for use as a feed stock in OCGT/CCGT plants
	Nuclear	7.35 (R76/MWh)	As per EPRI report.

[1] Calculated by RSA National Treasury for the IEP process
[2] Based on NERSA study
[3] All fuel costs are provided by the EPRI 2015 report
4 Coal (CV 22) cited as R/ton 541 at Richards Bay Coal Terminal for FY 201/15
[5] Based on IRP 2010 Update escalated to 2015 rand values

2.3 Eskom Plant Performance

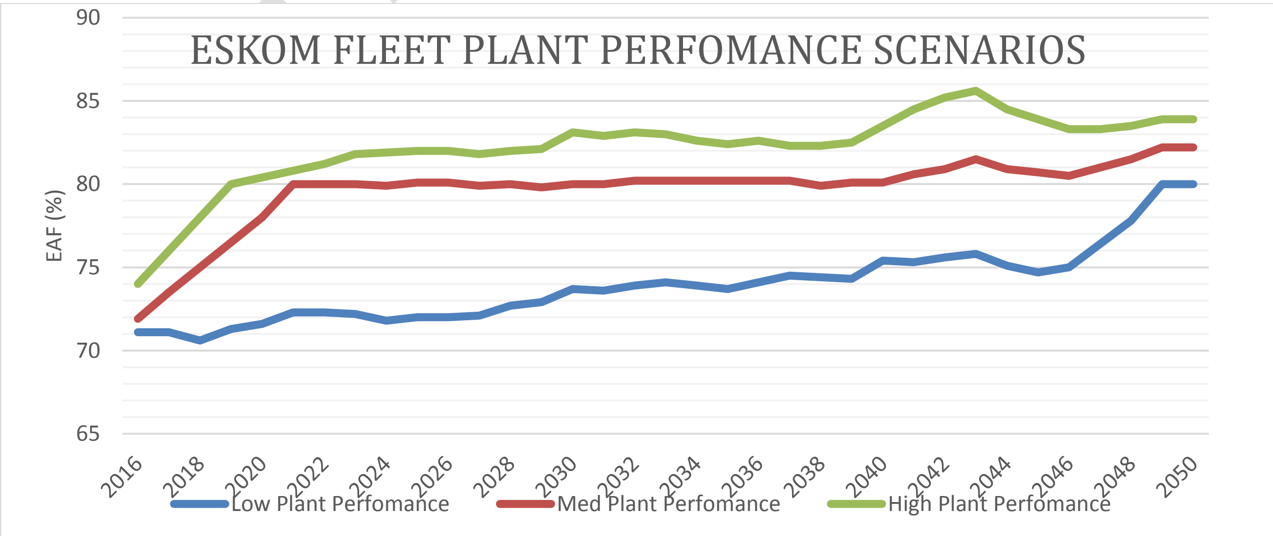
The IRP 201-30 assumed and average existing Eskom fleet plant performance of 86%, however actual performance has in the recent past declined to less than 70%. Eskom has since adopted a new operation and maintenance strategy which has seen this performance improve significantly and is reflective of the Eskom submission for the IRP update assumptions dated January 2016.

Source: **Eskom**

Figure 3 below lists three (3) plant performance scenarios provided by Eskom. The plant performances are based on the following:

- the high plant performance is aligned to Eskom Design to Cost (DTC) target and restores EAF to acceptable levels
- the medium plant performance or the Business as Usual case restores EAF to acceptable but at a slower rate that the high plant performance case and is based on Eskom's Shareholder Compact 2017 and Corporate Plan target, and
- the low plant performance is the progressive EAF from current levels and is based on Eskom in-house statistical model

The moderate and low plant performance will be used in the IRP update base case scenario analysis respectively.



Source: Eskom

Figure 3: Eskom Fleet Plant Performance

2.4 Committed Eskom New Build Dates

Table 3 below shows committed build options based on P80 commissioning dates for Medupi, Kusile and Ingula.

Table 3: Committed New Build Dates

	Medupi[6] (P80)	Kusile[7] (P80)	Ingula[8] (P50)
1st Unit	Commissioned	July 2018	Jan 2017
2nd Unit	Mar 2018	July 2019	Mar 2017
3rd Unit	July 2018	Aug 2020	May 2017
4th Unit	June 2019	Mar 2021	Jul 2017
5th Unit	Dec 2019	Nov 2021	-
6th Unit	May 2020	Sep 2022	-

Source: Eskom

2.5 Non-Eskom plant

Table 4 shows other existing, non-Eskom plant considered in the base case.

Table 4: Non-Eskom Capacity

	Installed Capacity (MW)	Decommissioning Date	Planned Outages (%)	Unplanned Outages (%)
Kelvin	160	01-Jan-2018	4.8	20
Sasol InfraChem	125	Post 2050	4.8	15
Sasol SSF Coal	600	01-Jan-2031	4.8	15
Other Non-Eskom Coal	18	01-Jan-2026	4.8	15
Other NonEskom Gas	16	01-Jan-2021	6.9	11
Sasol Infra Gas	175	Post 2050	6.9	11
Sasol Synfuel Gas	250	Post 2050	6.9	11
DOE IPP	1005	Post 2051	7	5
Colley Wobbles	65	Post 2050	6.9	11
Other Hydro	12	Post 2050	6.9	11
Cahorra Bassa	1500	Post 2050	4	4
REBID Hydro	19	Post 2050	4	4

6 The second unit of Medupi was synchronized on 08 September 2016

7 First fires for the first unit of Kusile were achieved on 16 October 2016

8 Three units of Ingula reached COD by end August 2016 and the fourth unit was synchronized to the grid by end October 2016

Steenbras	180	Post 2050	4	10

Source: NERSA and Eskom

2.6 Ministerial Determinations

The new generation capacities announced in the Ministerial Determinations that are not yet committed to (and are not in the procurement stage) are not considered in the IRP update base case. This implies all projects that are in Bid Window 4.5, expedited, smalls and the 900 MW of base load coal are considered committed and will be included in the IRP update base case as indicated in table below. These are reflected in Table 5 below.

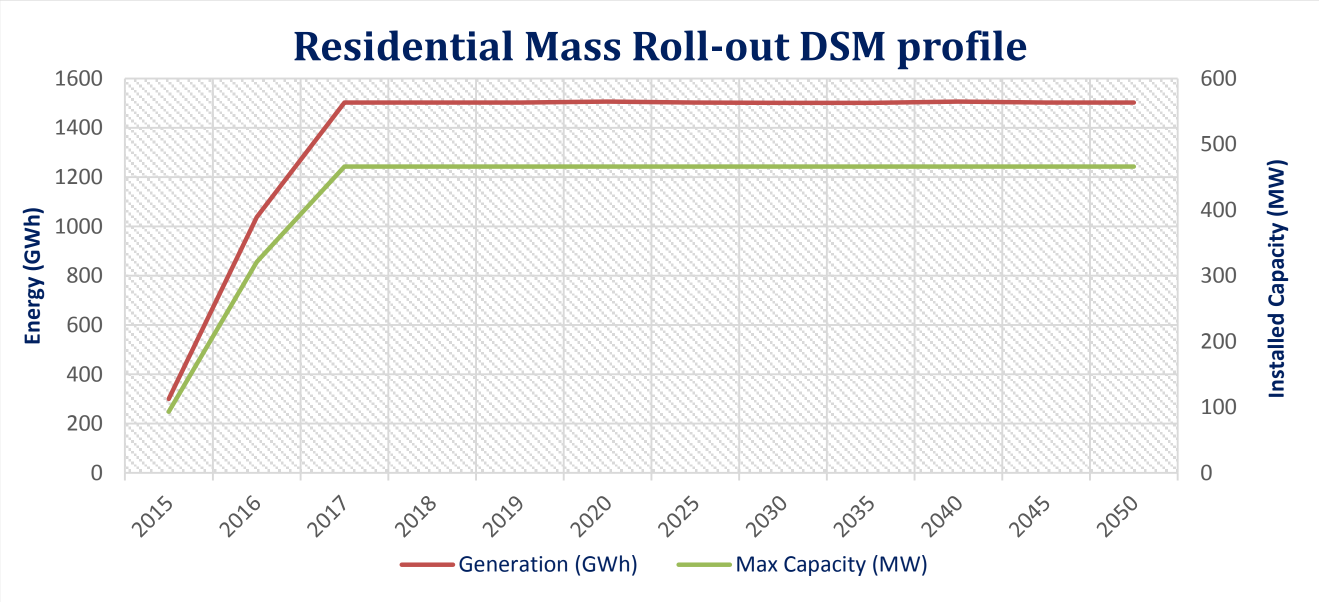
Table 5: MW cumulative capacity from Ministerial Determinations – IRP update base case

	Renewables							Coal	Gas	Import Hydro	Nuclear	Co-Gen
	PV	Wind	CSP	Landfill	Hydro	Biomass	Biogas					
2016	1328	1373	200	-	14	-	-	-	-	-	-	-
2017	1478	1994	300	13	14	-	-	-	-	-	-	11
2018	1842	2378	600	13	14	17	-	-	-	-	-	-
2019	2412	3188	1050	28	59	142	25	-	-	-	-	-
2020	2811	4006	1050	-	-	-	-	-	-	-	-	-
2021	-	-	-	-	-	-	-	900	-	-	-	-

Source: DoE IPP Office

2.7 Anticipated Integrated Demand Management

The Integrated Demand Management is pursuing additional Residential Mass Rollout lighting LED program that commenced for FY2015/2016. The program is expected to continue until FY2017/2018, reaching cumulative savings of 466 MW and is shown in Figure 4. These savings are sustainable over the period and are over and above the 11.8 TWh of existing DSM programs.



Source: Eskom

Figure 4: Profile of Residential Mass Rollout DSM

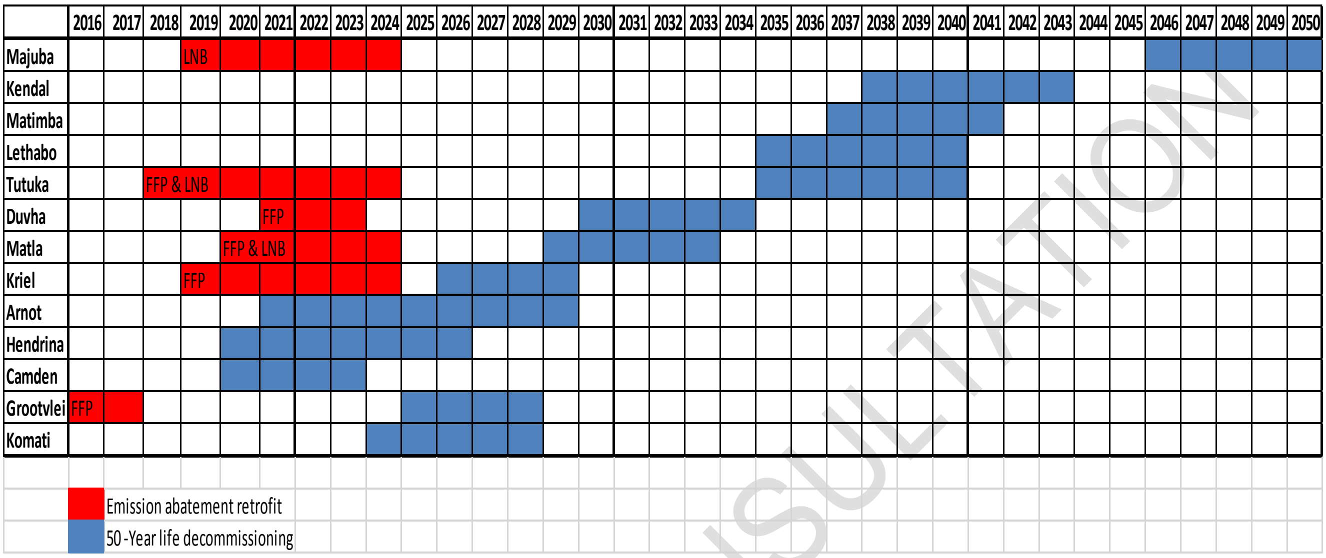
2.8 Eskom Plant Life and Air Quality Retrofit

Extensive emission abatement retrofits are required at Eskom's power stations to ensure compliance with the Minimum Emission Standards which were published in terms of section 21 of the National Environmental Management Act (NEMA): Air Quality Act (Act no 39 of 2004) on April 2010. This meant existing plant standards need to be complied with by 1 April 2015 and the more stringent 'new plant' standards need to be complied with by new power stations immediately and existing power stations by 1 April 2020. These limits are concentration limits that are applicable per unit (or per stack in case of combined stacks) and the primary objective is to reduce emissions associated with:

a. Particulate matter (pm)
b. Sulphur dioxide (SO_2)
c. Oxides of nitrogen (NO_x)

Compliance with these standards will require extensive retrofits of fabric filter plants (FFP), NO_x abatement technologies and flue gas desulphurisation (FGD). This will have an impact on funding, unit outage and water requirements. Eskom has thus prioritised upgrades at the newer and high emitting power stations and had applied for 5 year postponements of the Minimum Standards compliance timeframes at power stations that will not comply on time. Eskom is expected to execute the emission abatement retrofit programme that was committed to as shown in Table 6.

Table 6: Air Quality Retrofits



Source: Eskom and DEA

3. New Generation Technology Cost and Performance Characteristics

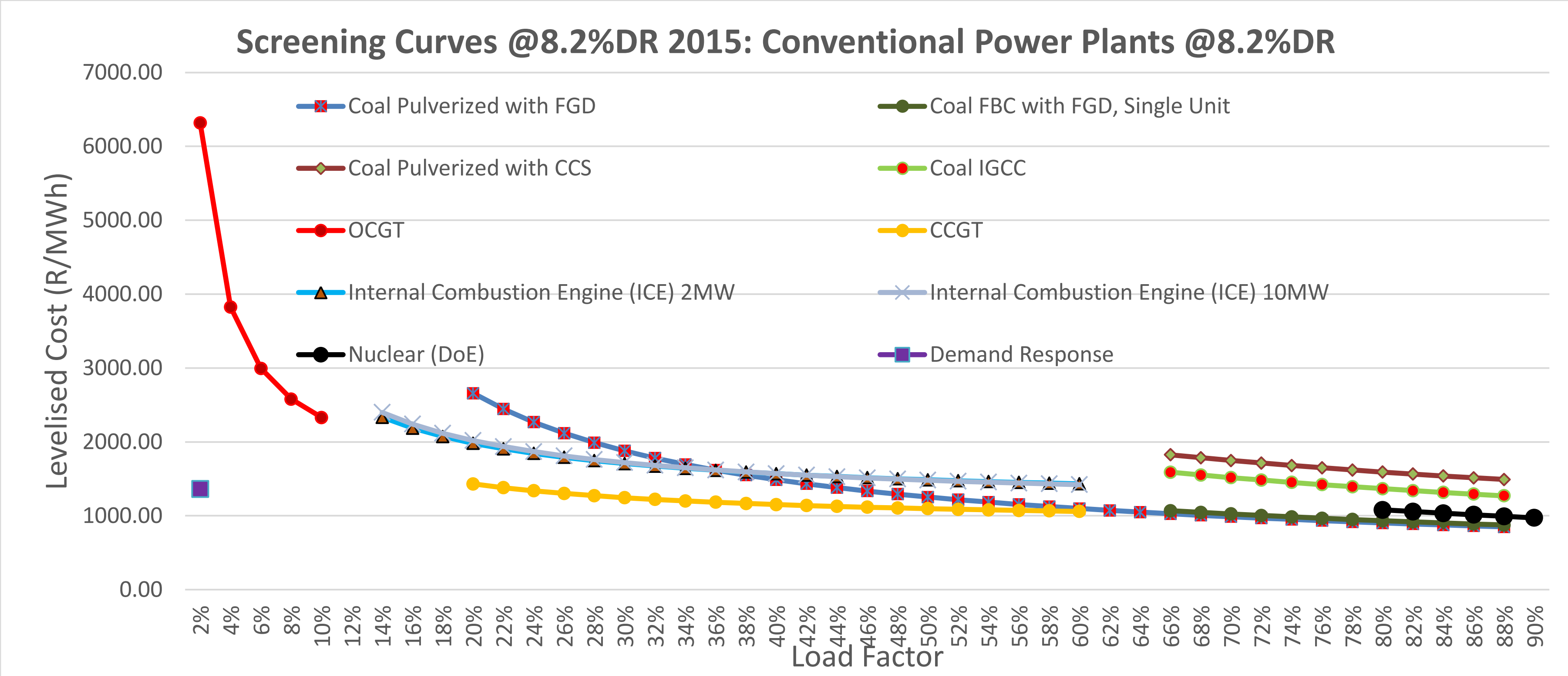
3.1 Conventional Power Plants

Table 7 below shows a list of all conventional generating technologies as provided by the EPRI with the exception of nuclear technology overnight cost.

Table 7: Option Cost Conventional Power Plants

	Coal Pulverized with FGD	Coal FBC with FGD, Single Unit	Coal Pulverized with CCS	Coal IGCC	Nuclear (DoE)	OCGT	CCGT	Internal Combustion Engine (ICE) 2MW	Internal Combustion Engine (ICE) 10MW	Demand Response
Rated Capacity, MW Net	4500	250	4500	644	1400	132	732	1.90	9.40	500.00
Total Overnight Cost, ZAR/kW (Jan 2015 Rands)	32420.0	39133.0	62712.0	50327.0	55260	7472.0	8205.0	11657.0	12494.0	0.0
Lead-times and Project Schedule, years	9.0	4.0	9.0	4.0	8	2.0	3.0	1.0	1.0	1.0
Phasing in capital spent (% per year) (* indicates commissioning year of 1st unit)	2%, 6%, 13%, 17%*, 17%, 16%, 15%, 11%, 3%	10%, 25%, 45%, 20%	2%, 6%, 13%, 17%*, 17%, 16%, 15%, 11%, 3%	10%, 25%, 45%, 20%	5%,5%,15%, 15%, 20%, 20%, 10%, 10%	90%, 10%	40%, 50%, 10%	100.00%	100.00%	100.00%
Fuel Energy Content, HHV, kJ/kg	17850.0	17850.0	17850.0	17850.0	1299000000	39.3	39.3	39.3	39.3	#N/A
Fuel Cost (R/GJ)	25.0	12.5	25.0	25.0	7.35	115.5	115.5	115.5	115.5	0.0
Heat Rate (kJ/kWh)	9812.0	10788.0	14106.0	9758.0	10657	11519.0	7395.0	9477.0	8780.0	3.6
Fixed O&M Cost (R/KW/Year)	845.0	568.0	1441.0	1301.0	885	147.0	151.0	386.0	434.0	8.0
Variable O&M Cost (R/MWh)	73.1	158.2	134.9	69.0	34	2.2	20.0	64.0	110.1	1317.0
Equivalent Availability (%)	91.5	91.5	91.5	85.2	92	88.5	88.5	88.5	88.8	N/A
Planned Outage Rate (%)	4.8	4.8	4.8	4.7	3	6.9	6.9	6.9	6.9	N/A
Unplanned Outage Rate (%)	3.7	3.7	3.7	10.1	6	4.6	4.6	4.6	4.6	N/A
Typical Load Factor (%)	85.0	85.0	85.0	85.0	90	8.0	48.0	48.0	50.0	1.5
Economic Life	30.0	30.0	30.0	30.0	60	30.0	30.0	30.0	30.0	1.0
Water Usage (l/MWh)	231.0	33.3	320.0	256.7	0	0.0	19.8	0.0	0.0	N/A
Sorbent Usage (kg/MWh)	15.8	41.0	22.8	0.0	0	0.0	0.0	0.0	0.0	N/A
CO_2 Emissions (kg/MWh)	947.3	1003.0	136.2	930.0	0	574.0	367.0	491.0	455.0	N/A
SOx Emissions (kg/MWh)	0.5	0.5	0.7	0.2	0	0.0	0.0	0.0	0.0	N/A
NOx Emissions (kg/MWh)	1.9	0.3	0.4	0.2	0	0.3	0.2	1.3	0.1	N/A
Hg (kg/MWh)	0.1	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	N/A
Particulates (kg/MWh)	0.1	0.1	0.2	0.4	0	0.1	0.0	0.0	0.0	N/A

Figure 5 below shows how the technology options compare against each other on a levelised cost production basis. Fossil fuel fired technologies as shown here do not include the cost of externalities.



Source: IRP Analysis

Figure 5: Conventional Power Plants screening curves

3.2 Renewables Power Plants

Table 8 below shows all the RE technology options as contained in the EPRI report with the exception of PV and Wind. The cost for wind and PV are provided by the DoE IPP Office and are based on weighted average REIPP Bid Window 4 PPA prices.

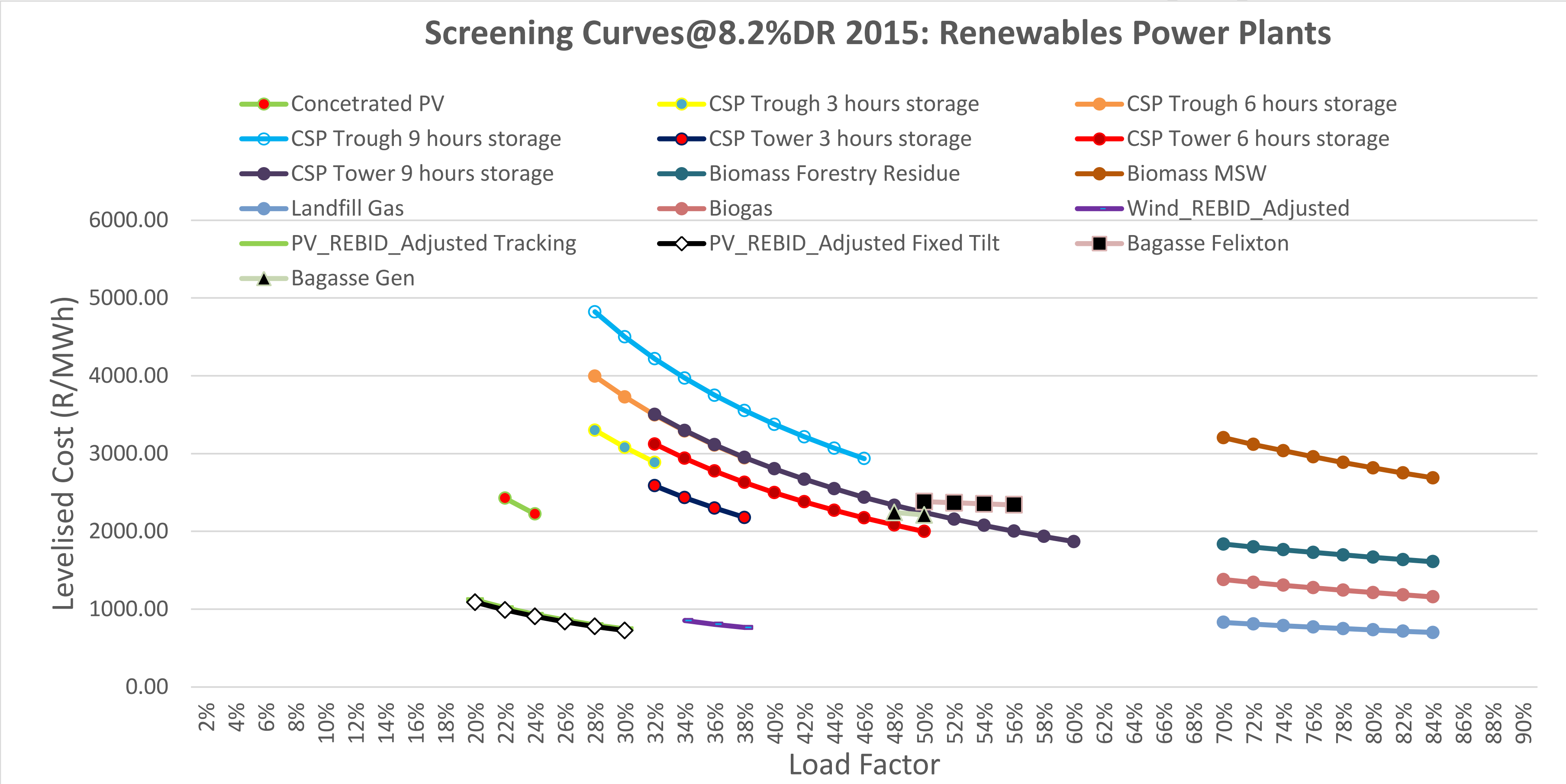
Table 8 : Option Cost Renewables Power Plants

	Wind REBID Adjusted	PV REBID Adjusted Tracking	PV REBID Adjusted Fixed Tilt	Concentrated PV	CSP Trough 3 hours storage	CSP Trough 6 hours storage	CSP Trough 9 hours storage	CSP Tower 3 hours storage	CSP Tower 6 hours storage	CSP Tower 9 hours storage	Biomass Forestry Residue	Biomass MSW	Landfill Gas	Biogas	Bagasse Felixton	Bagasse Gen
Rated Capacity, MW Net	100	10	10	10	125	125	125	125	125	125	25	25	5	5	49	52.5
Total Overnight Cost, ZAR/kW (Jan 2015 Rands)	19208[9]	17860[10]	16860[11]	46052	79077	97624	119762	70561	86766	98297	68062	130733	28384	70655	16291.4	31233.6
Lead-times and Project Schedule, years	4.0	2.0	1.0	1.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	1.0	1.0	2	3
Phasing in capital spent (% per year) (* indicates commissioning year of 1st unit)	5%, 5%, 10%, 80%	10%,90%	10%,90%	100%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	100%	100%	33%,67 %	10%, 30%,60 %
Fuel Energy Content, HHV, kJ/kg	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	11763.0	11388.0	18.6	18.6	-	-
Fuel Cost (R/GJ)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	29.3	0.0	0.0	0.0	74.1	74.1
Heat Rate (kJ/kWh)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	14243	18991	12302	11999	26874	19327
Fixed O&M Cost (R/KW/Year)	554	256	299	287	935	960	985	860	897	922	1513	5915	2169	1774	156.9	356.3
Variable O&M Cost (R/MWh)	0.0	0.0	0.0	0.0	0.8	0.7	0.7	0.8	0.8	0.8	60.5	104.4	56.5	47.4	8.1	24.6
Equivalent Availability (%)	94.0	95.0	95.0	95.0	95.0	95.0	95.0	92.0	92.0	92.0	90.0	90.0	85.0	85.0	90	90
Planned Outage Rate (%)	6.0	5.0	5.0	5.0	5.0	5.0	5.0	8.0	8.0	8.0	6.0	6.0	5.0	5.0	4	4
Unplanned Outage Rate (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.0	4.0	10.0	10.0	6	6
Typical Load Factor (%)	34	26	26	22	32	38	46	38	50	60	85	85	85	85	55	50
Economic Life	20	25	25	25	30	30	30	30	30	30	30	30	30	30	30	30
Water Usage (l/MWh)	0.0	0.0	0.0	16.2	80.8	78.6	78.1	81.9	87.1	86.3	227.0	227.0	0.0	0.0	217	217.0
Sorbent Usage (kg/MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO_2 Emissions (kg/MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1243	1633	806	787	2807.0	2129
SOx Emissions (kg/MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.6	0.0	0.0	0.0	0.0
NOx Emissions (kg/MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	2.2	0.6	0.6	0.0	0.0
Hg (kg/MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Particulates (kg/MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.4	5.6	2.6	2.3	0.8	0.5

Source: EPRI 2015 Report unless otherwise stated

9 REBID Window 4 weighted average price capitalised: REBID 4 PPA were capitalised using well known lead times and performance characteristic and were further adjusted for South African inflation to the year 2015.
10 REBID Window 4 weighted average price capitalised: REBID 4 PPA were capitalised using well known lead times and performance characteristic and were further adjusted for South African inflation to the year 2015.
11 REBID Window 4 weighted average price capitalised: REBID 4 PPA were capitalised using well known lead times and performance characteristic and were further adjusted for South African inflation to the year 2015.

Figure 6 below shows screening curves for RE technologies.



Source: IRP 2015 Analysis

Figure 6: Renewable Energy Technologies Screening curves

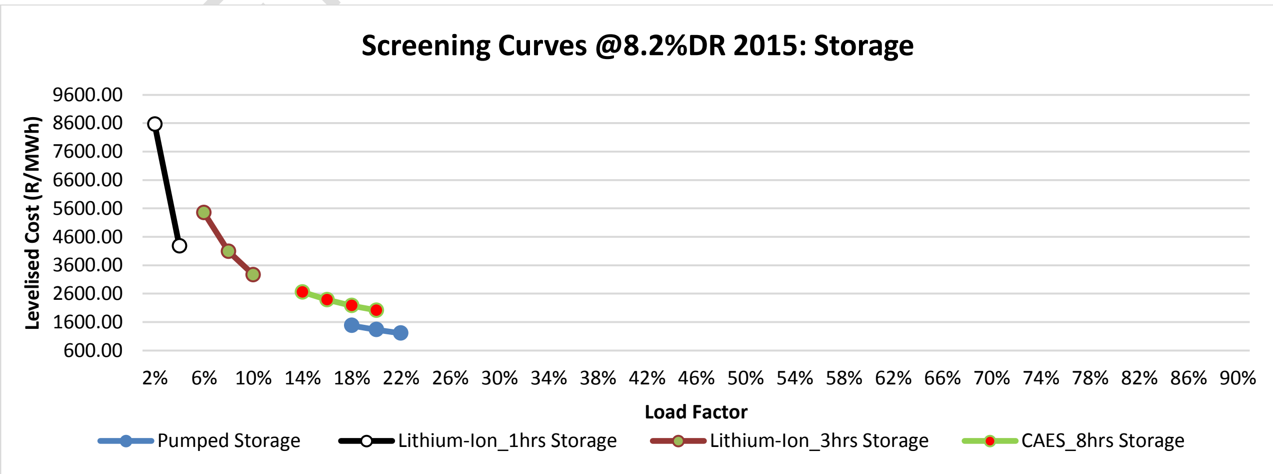
3.3 Energy Storages

Table 9 below reflects energy storage options provided by the EPRI 2015 report with the exception of the water pumped storage. It is important to note the difference between the overnight costs for Lithium-ion 1 and 3 hour storage. All storage options are depended on the energy generated by the system for charging/pumping.

Table 9: Energy Storage

	[12]Pumped Storage	Lithium-Ion_1hrs Storage	Lithium-Ion_3hrs Storage	CAES_8hrs Storage
Rated Capacity, MW Net	333	3	3	180
Total Overnight Cost, ZAR/kW (Jan 2015 Rands)	20410.0	9042.0	22216.0	22390.0
Lead-times and Project Schedule, years	8.0	1.0	1.0	4.0
Phasing in capital spent (% per year) (* indicates commissioning year of 1st unit)	1%, 2%, 9%, 16%, 22%, 24%, 20%, 5%	100%	100%	25%, 25%, 25%, 25%,
Fuel Energy Content, HHV, kJ/kg	N/A	N/A	N/A	39.3
Fuel Cost (R/GJ)	0.0	0.0	0.0	51.8
Fixed O&M Cost (R/KW/Year)	184.0	565.0	565.0	194.0
Variable O&M Cost (R/MWh)	0.0	2.9	2.9	2.2
Cycles/Year	No Limit	300.0	300.0	No Limit
Minimum Load	0.0	0.0	0.0	0.0
Round Trip AC/AC Efficiency/Pump Efficiency, %	78%	89%	89%	81%
Equivalent Availability (%)	94.7	94.1	94.1	97.2
Planned Outage Rate (%)	3.0	1.9	1.9	2.3
Unplanned Outage Rate (%)	2.4	4.0	4.0	0.5
Typical Load Factor (%)	33.0	N/A	N/A	22.0
Min Load Factor (%)	0.18	0.1	0.1	0.14
Max Load Factor (%)	0.26	0.3	0.3	0.20
Economic Life	50.0	20.0	20.0	40.0
CO_2 Emissions (kg/MWh)	0.0	0.0	0.0	574.0
NOx Emissions (kg/MWh)	0.0	0.0	0.0	0.3
Particulates (kg/MWh)	0.0	0.0	0.0	0.1

Source: EPRI 2015 Report



[12] Pumped Storage data was submitted by Eskom for the IRP 2010 Update and was adjusted for South African inflation since the bulk of the costs is local.

Figure 7: Storage options screening curves

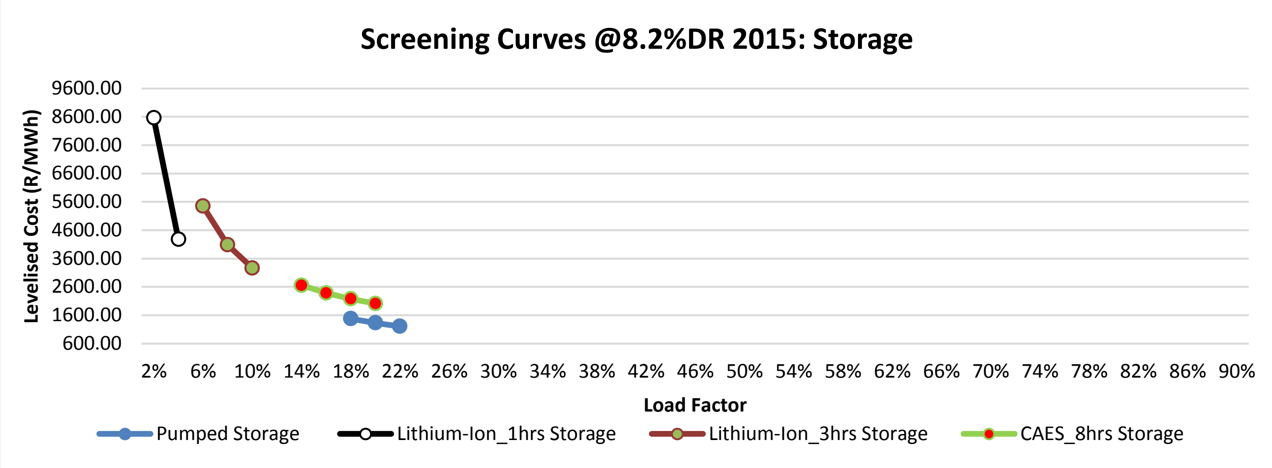


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Figure 8: Energy Storage options

3.4 Learning Rates

Learning rates used in the IRP 2010-30 are maintained in the IRP update base case with PV and wind technology learning rates adjusted to reflect the steep decline in prices experienced in RSA and are reflected in Table 10.

Table 10: Technology learning Rates

Technology	2015 (R/kW)	2050 (R/KW)
PV (fixed tilt)	16860.6	13425.03408
PV (tracking)	17860.6	14221.26959
Wind	19208.1	17287.405
Nuclear	55260	53768.80047

Source: IRP Analysis

4. Emission constraints and costs

4.1 CO_2 Emission Constraints

In line with Government policy to reduce GHG emission, the IRP update applies the moderate decline annual constraints as an instrument to reduce these emissions. This is subject to change following recent correspondence received from the DEA proposing that carbon budget be used instead as the preferred instrument to achieve the objective of reducing GHG emissions.

Figure 9 below shows the CO_2 emission constraint considered in the base case and is the same as in the IRP 2010 Update.

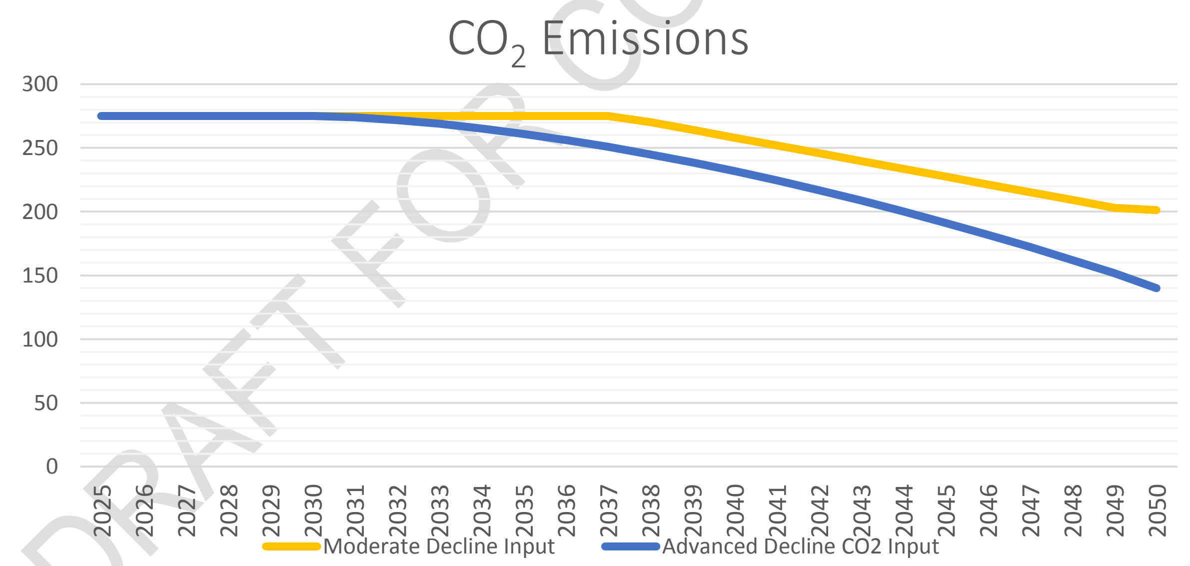


Figure 9: Emission Constraints

4.2 Externalities Costs

Table 11 below shows the cost of externalities considered in the IRP update base case.

Table 11: Cost of externalities

	CO_2 (R/t)	NOx (R/kg)	SOx (R/kg)	Hg (Rm/kt)	PM (r/kg)
2015-2050		4.455	7.6	0.041	11.318

Source: DoE

5. Results and Observations from the IRP update Base Case

The IRP update base case is produced by updating the optimisation model (using IRP 2010-30 as a base) with the above (latest) assumptions and input parameters. A number of Government policy positions imposed in the IRP 2010-30 are maintained, inter alia, the annual build constraints for new capacity for Wind (1600 MW) and PV (1000 MW) and emissions constraints. This means at any given year the optimisation model is not able to build more the stipulated quantum of wind and PV.

It is important to note that due to different technology dynamics associated with cost and operating characteristics, each technology will be considered differently by the model in order to balance supply and demand in the course of the study horizon. This means the technology contribution to the energy mix will be determined by both the system requirement taking into account the technology dynamic (Baseload, mid-merit or peaking etc.) as mentioned above. Figure 10 above shows the percentage share of installed capacity per technology for the periods 2016, 2020, 2030, 2040 and 2050.

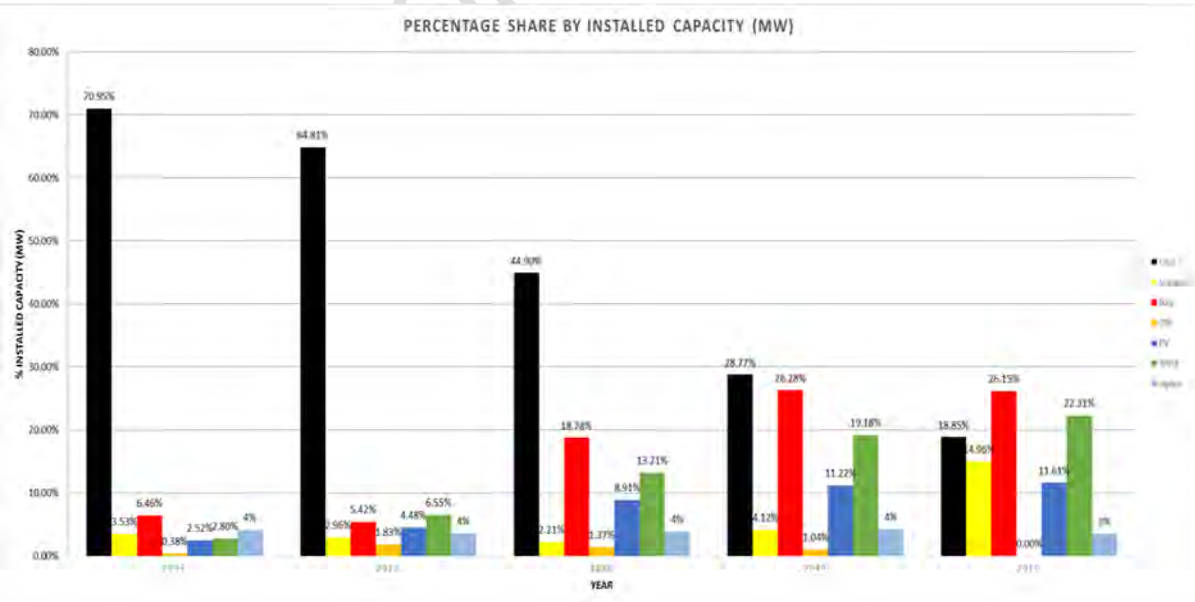
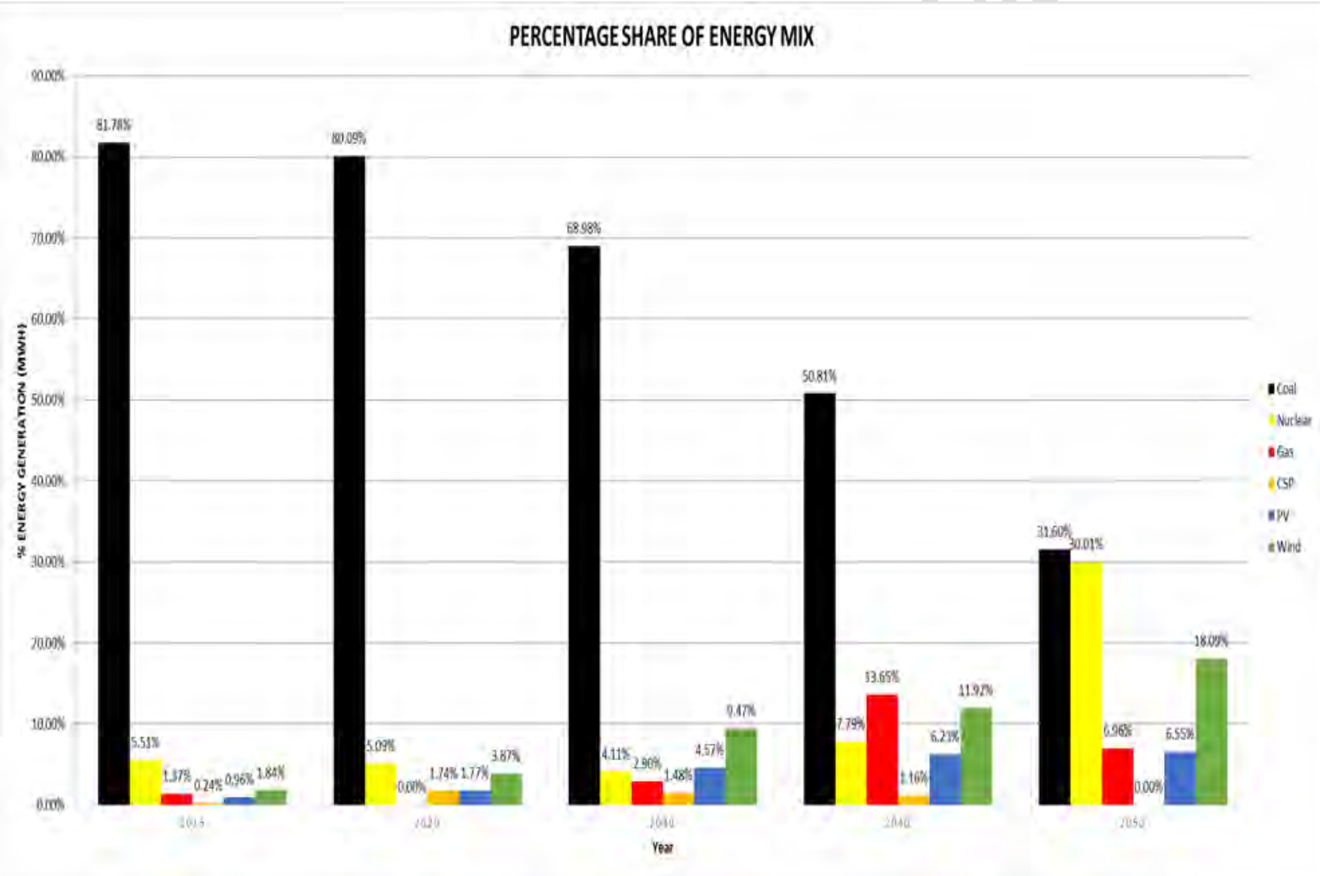


Figure 10: Technology Percentage share by Installed Capacity (MW)

Figure 11 below shows the percentage share of the technology energy contribution for the years 2016, 2020, 2030, 2040 and 2050. Higher share of installed capacity per technology does not necessarily result in higher share of energy contribution for that technology. For instance high installed capacity share of gas and renewable technologies does not result in a high share of energy contribution from these technologies. Coal and nuclear technologies contribute the most to the energy share and can be referred to as base load options, with load factors above 85% in general while gas CCGT is considered mid merit or OCGT peaking with load factors ranging from 30% to 5% respectively. .



Source: IRP analysis

Figure 11: Technology Energy Production Percentage share (TWh)

Table 12 below reflects the timing and capacity mix for the IRP Base Case.

Table 12: IRP update base case results

	Base Case8.2% Dicount rate											
	New Build Options											
	PV	Wind	LandfillGas	DR	Nuclear	OCGT	CCGT	Coal PF w FGD	Inga	CO2 Emissions	Peak Demand (MW)	Firm Reserve Margins (%)
2016												
2017												
2018												
2019												
2020										253	44916	24
2021	160									264	46130	28
2022	160									268	47336	23
2023	370	200								272	48547	20
2024	440	500		1000		396				279	49656	18
2025	650	1000	15	1000		2376	732			278	51015	19
2026	580	1000	5	1000		264	1464			278	52307	19
2027	580	1000	230	1000		264	2196			276	53561	19
2028	580	1000		500		396	1464	1500		277	54567	20
2029	580	1100		1000			1464	1500		273	56009	18
2030	580	1200		1000		1716		2250	1000	274	57274	20
2031	580	1200		1000		1584		750		274	58630	20
2032	580	1000		500			732	1500	1000	278	59878	22
2033	580	1200					1464	750	500	276	61388	23
2034	580	1600		1000		1452				278	62799	22
2035	580	1600		500			1464	1500		278	64169	23
2036	580	1600		1000				1500		278	65419	21
2037	580	1400		500	1359		732	2250		277	66993	22
2038	580	1600				1848	1464	750		273	68375	22
2039	650	1500			1359		2928			267	69584	22
2040	650	1600		1000		1056	732			261	70777	20
2041	650	1600		1000	4077	792		750		236	72343	21
2042	650	1600		500			2196			233	73800	21
2043	650	1600		500						232	75245	21
2044	650	1800		500	1359					228	76565	21
2045	770	1600			2718		2196			230	78263	23
2046	790	1600		500	1359	924				225	79716	20
2047	720	1800		1000	1359		732			219	81177	19
2048	720	1600		500	2718	264				211	82509	20
2049	660	1500		500	1359					206	84213	20
2050	720	1400		500	2718					196	85804	20
Total (MW	17600	37400	250	500	20385	13332	21960	15000	2500			

DR is Demand Response and it is not cumulative

The table above shows the least cost plan with moderate GHG emission constraints trajectory. The plan has not been optimised or adjusted to take into account some of the qualitative factors.

The following observations can be made:

- 18 GW of PV, 37 GW of wind, 20 GW of nuclear, 34 GW of gas, 2.5 GW of import hydro, 15 GW of coal is required by the end of the study period (2050)
- The timing of when the various technologies start producing power is highly sensitive to changes in assumptions such as various primary fuel costs and emission assumptions. As an example, preliminary results from the carbon budget scenario indicate a significant change in the energy mix and timing with increased renewables, no new capacity from coal, and nuclear coming online around 2026.
- Following the point above, it is evident that the pace and scale of Ministerial Determinations issued to date will to some extent be impacted and will be looked at in more detail during policy adjustment phase.

Scenarios will impact on the IRP update in various ways. Given various technologies lead times (10 years for nuclear) and security of supply issues, the final IRP will be quite from that illustrated in the Base Case.

Scenario analysis is therefore crucial before drawing any conclusions from the Base Case.

6. IRP Update Scenarios

A number of scenarios is currently under consideration and will be used to inform the policy adjustment of the IRP update. These scenarios include but are not limited to the following:

- Carbon budget as an instrument to reduce GHG emission
- Primary fuel price tipping point (coal, gas and nuclear)
- Low demand trajectory
- Embedded generation (rooftop PV)
- Enhanced energy efficiency

- Low Eskom plant performance
- Regional options (Hydro, Gas)
- Indigenous Gas
- Un-constrained Renewable Energy
- New Technology (Storage)
- Electricity Network Implications
- Additional Sensitivity Analysis